UNDERGROUND INJECTION CONTROL

INSPECTION MANUAL

Respectfully Submitted To
US Environmental Protection Agency

by

Engineering Enterprises, Inc.
Norman, Oklahoma

February, 1988

ENGINEERING ENTERPRISES, INC.

Revision of the Underground Injection Control Inspection Manual was done for the United States Environmental Protection Agency (USEPA) under contract No. 68-03-3416, Work Assignment No. 0-0-7-1. The USEPA Work Assignment Manager was Mr. Donald M. Olson, Chief, Compliance and Enforcement Section, UICB, Washington, D.C.

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PREFACE

Much of the information and material in this edition of the _Underground Injection Control Inspection Manual_ was originally assembled by Ken E. Davis Associates of Houston, Texas (July 1984), under the title _UIC Inspection Guide_. The guide was prepared in support of the U.S. Environmental Protection Agency's Underground Injection Control (UIC) Program, required to satisfy the mandate of the 1974 Safe Drinking Water Act.

The original guide was developed to meet two goals: (1) train prospective field inspectors and their UIC program supervisors in the many intricacies of injection well inspection and reporting; and (2) provide a useful reference for actual field inspections of underground injection facilities.

A revised edition of the Guide was prepared by the engineering staff of Engineering Enterprises, Inc. (EEI) in February 1985. This resulted in reorganization of the material, some rewriting, correction of errors, and reduction in volume. The work was accomplished under terms of a general contract between EEI and EPA. It was recognized by both EEI and EPA that, as experience was gained by the UIC programs across the country, the need for further revisions would likely develop.

In order to bring the scope and material of the Guide more in line with current needs as revealed by experience and improved technology, the EPA Underground Injection Control Branch (UICB) in May of 1986 initiated Work Assignment 0-7 Task 1 under EPA Contract No. 68-01-7011 with Engineering Enterprises. This _Underground Injection Control Inspection Manual_ is the result of that action.

This manual has been notably strengthened by the inclusion of new material on quality assurance and control, classification of injection wells, definitions for exempted aquifers, improved guidance on legal matters related to inspections, possible appropriate responses to violations, and chain of custody for samples, among others. Readers will appreciate the inclusion of an index of more than 300 entries.

Engineering Enterprises, Inc. is grateful for the opportunity to participate in the preparation of this essential document. We especially appreciate the support and understanding of Mr. A. Roger Anzzolin, EPA Project Manager; and the professional dedication and attitude demonstrated by Ms. Nancy Zeller and by Mr. Donald M. Olson, Chief of the Compliance and Enforcement Section of UICB, in our mutual efforts to make this undertaking a success.

1 Introduction

THE SAFE DRINKING WATER ACT

The 1974 Safe Drinking Water Act (SDWA), with amendments, established a joint Federal-State system for protecting the nation's underground sources of drinking water (USDW). It specifically instructed the United States Environmental Protection Agency (USEPA) to establish a program that would protect the nation's potentially usable fresh water aquifers from contamination by underground injection well operations. At the present time such an aquifer or its part is defined by EPA as that "which supplies any public water system or which contains a sufficient quantity to supply a public water system; and which currently supplies drinking water for human consumption, or contains fewer than 10,000 mg/l total dissolved solids (TDS), and which is not an exempted aquifer" (40 CFR § 146.3). These are referred to as USDW's.

UNDERGROUND INJECTION CONTROL

EPA has required all States to have an Underground Injection Control (UIC) program. Each State has the option of implementing its own program. If a State does not assume primary enforcement responsibility, EPA must administer an UIC program in that State. Currently, EPA administers full or partial programs in 24 States and territories and on Indian Lands.

An essential part of the UIC program is the field inspection of underground injection operations to monitor compliance with provisions of the SDWA, the UIC regulations, and with conditions set forth in UIC permits.

1:1 Purpose of the Inspection Guide

This UIC Inspection Guide was developed specifically for inspection personnel.

Every effort was made to include information useful to the inspector in carrying out his duties in the field. A conscious effort was also made to exclude material that does not enhance his ability to perform as required.

This Guide is intended to help the inspector complete inspections efficiently and prepare comprehensive, well organized reports. New personnel may wish to reinforce their knowledge by reading certain other publications. The inexperienced inspector should read and keep at hand the following references:

40 CFR Parts 124, 144, 146 and 147

An Introduction to the Technology of Subsurface Wastewater Injection. (EPA-600/2-770240), December 1977

Injection Well Construction Practices and Technology. Prepared for the USEPA Office of Drinking Water under Contract No. 68-01-5971, October 1982

Major Policy Statements and Guidance Documents from the Office of Water and the UIC Branch

Other references are cited at the end of each chapter

INJECTION WELL CLASSIFICATION SCHEME

The inspector should be familiar with the UIC well classification scheme and the basis for categorizing each well into its appropriate class. He should understand the basic structural and functional differences between injection well types. Figure 1.1 illustrates the five major well classes, with one or two possible configurations for each class.

Regulations developed under the Safe Drinking Water Act classify injection wells into the following five major groups:

Class I:	Industrial and municipal wells that inject below USDW's (includes hazardous waste wells)
Class II:	Oil and gas wells
Class III:	Solution mining wells
Class IV:	Wells that are used to inject hazardous or radioactive wastes into or above USDW's (these wells are banned)
Class V:	Wells not included in any of the above classifications

1:2 Sub-classifications [(1)]

1:3 Class I

1. Wells used by generators of hazardous waste or owners/operators of hazardous waste management facilities to inject hazardous waste beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water

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(1) From 40 CFR § 146.5 - Classification of injection wells

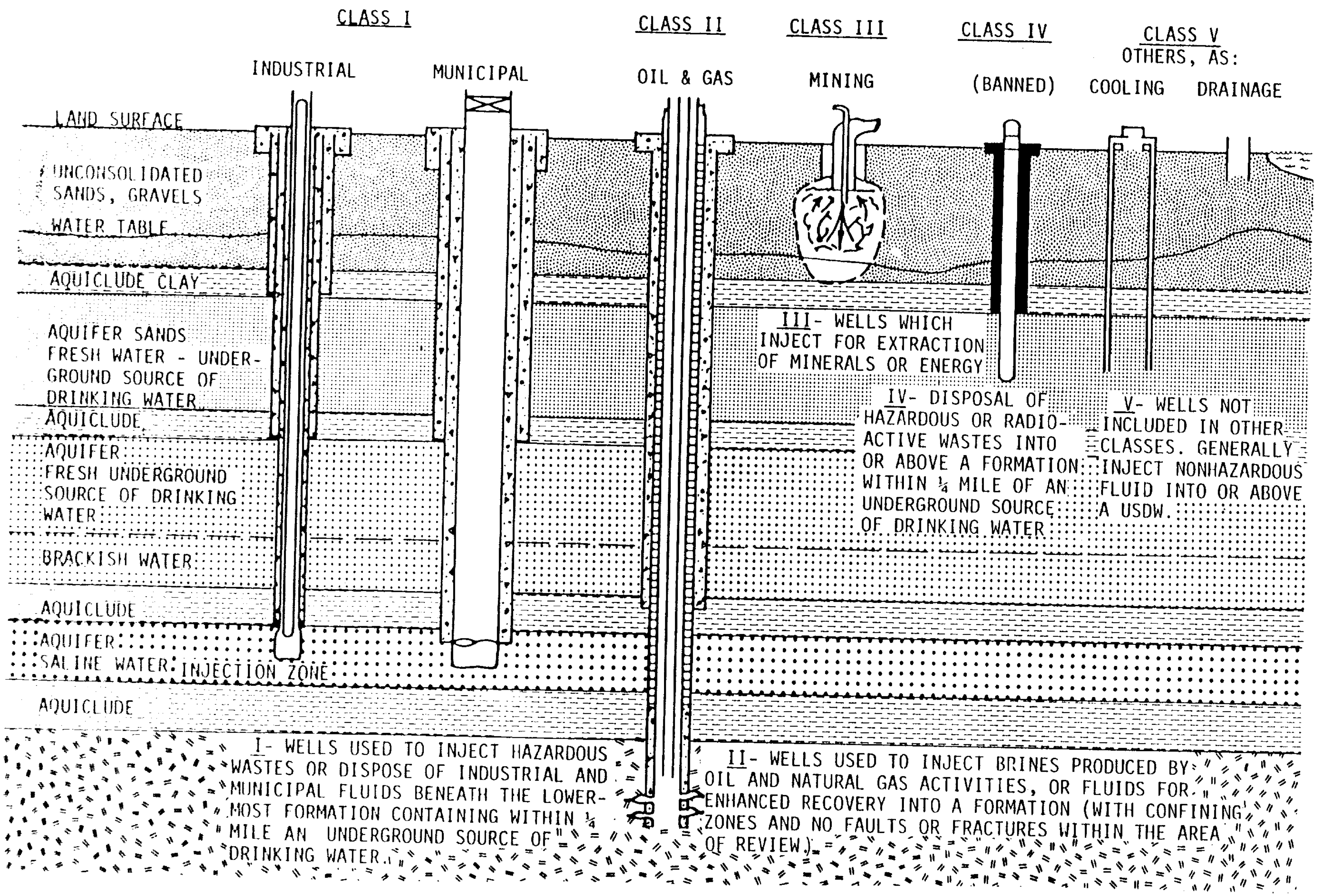

Figure 1.1 Underground Injection Control Program Classification of Wells

2. Other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water

1:4 Class II

Wells which inject fluids:

1. Which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection

2. For enhanced recovery of oil or natural gas

3. For storage of hydrocarbons which are liquid at standard temperature and pressure

1:5 Class III

Wells which inject for extraction of minerals, including:

1. Mining of sulfur by the Frasch process

2. In-situ production of uranium or other metals

This category includes only in-situ production from ore bodies which have not been conventionally mined. Solution mining of conventional mines such as stopes leaching is included in Class V.

3. Solution mining of salts or potash

1:6 Class IV

1. Wells used by generators of hazardous or of radioactive waste, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous or radioactive waste into a formation which within one quarter mile of the well contains an underground source of drinking water

2. Wells used by generators of hazardous or of radioactive waste, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous or radioactive waste above a formation which within one quarter mile of the well contains an underground source of drinking water

3. Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities, to dispose of hazardous wastes which cannot be classified under Section 146.05(a)(1) or Section 146.05(d)(1) and (2), e.g., wells used to dispose of hazardous wastes into or above a formation which contains an aquifer which has been exempted pursuant to UIC Regulations (Section 146.04)

1:7 Class V

Injection wells not included in Class I, II, III, or IV. Class V wells include:

1. Air conditioning return flow wells used to return to the supply aquifer the water used for heating or cooling in a heat pump

2. Cesspools, including multiple dwelling, community or regional cesspools, or other devices that receive wastes, which have an open bottom and sometimes have perforated sides (the UIC requirements do not apply to single family residential cesspools which receive solely sanitary wastes and have the capacity to serve fewer than 20 persons a day)

3. Cooling water return flow wells used to inject water previously used for cooling

4. Drainage wells used to drain surface fluid, primarily storm runoff, into a subsurface formation

5. Dry wells used for the injection of wastes into a subsurface formation

6. Recharge wells used to replenish the water in an aquifer

7. Salt water intrusion barrier wells used to inject water into a fresh water aquifer to prevent the intrusion of salt water into the fresh water

8. Sand backfill and other backfill wells used to inject a mixture of water and sand, mill tailings or other solids into mined out portions of subsurface mines whether what is injected is a radioactive waste or not

9. Septic system wells used to inject the waste or effluent from a multiple dwelling, business establishment, community or regional business establishment septic tank (the UIC requirements do not apply to single family residential septic system wells, nor to non-residential septic system wells which are used solely for the disposal of sanitary waste and have the capacity to serve fewer than 20 persons a day)

10. Subsidence control wells (not used for the purpose of oil or natural gas production) used to inject fluids into a non-oil or gas producing zone to reduce or eliminate subsidence associated with the overdraft of fresh water

11. Radioactive waste disposal wells other than Class IV

12. Injection wells associated with the recovery of geothermal energy for heating, aquaculture and production of electric power

13. Wells used for solution mining of conventional mines such as stopes leaching

14. Wells used to inject spent brine into the same formation from which it was withdrawn after extraction of halogens or their salts

15. Injection wells used in experimental technologies

16. Injection wells used for in situ recovery of lignite, coal, tar sands, and oil shale

2 Review of Inspection Requirements

OVERVIEW OF SDWA AND AMENDMENTS

Section 1445 (B) (1) of the Safe Drinking Water Act gives the Administrator or his designated representative the authority to enter upon and to inspect any facility subject to Underground Injection Control (UIC) Program requirements. Additionally, 40 CFR § 144.51 (I) states that the permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as required by law, to:

1. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of the permit

2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit

3. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit

4. Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location

These provisions apply to operators of wells authorized by either permit or rule.

2:1 The Safe Drinking Water Act, Its Regulations and Authority for Inspections

2:2 Enforcement Program

The Safe Drinking Water Act requires that injection well owner/operators who violate the provisions of the UIC regulations be subject to either civil or criminal penalties in the case of willful violation of the UIC regulations. The Agency also has the authority to require the facility to take any actions necessary to achieve compliance. This section presents a brief review of the enforcement programs established to deal with violations and the penalties that may be assessed under various circumstances.

2:3 Enforcement Procedures

EPA has the authority to issue an Administrative Order for compliance or penalties or both or initiate a civil or criminal action for owners/operators of injection wells failing to meet statutory or regulatory requirements. Enforcement actions may be taken in several types of situations:

1. Failure to apply for permit (where required)

2. Failure to comply with permit or rule-authorized requirements (UIC Regulations)

3. Failure to take all reasonable steps to protect underground sources of drinking water from any adverse impact resulting from noncompliance

See the UIC regulations for more detailed information on criteria and standards applicable to Class I, II and III wells (40 CFR Part 146, Subparts B, C, and D).

EPA has a variety of mechanisms for identifying noncompliance. First, to identify wells requiring permits, EPA can utilize well inventories and related well records. Second, inspections of sites by EPA officials during construction and after operation begins can provide information on such noncompliance. Third, material provided to EPA in permit applications, monitoring reports, and operating records can reveal cases of noncompliance. Finally, EPA may rely on information provided by interested citizens or by a non-compliance report itself.

2:4 Penalties for Noncompliance

2:5 Civil Penalties for Noncompliance (Safe Drinking Water Act § 1423(b))

"Any person who violates any requirement of an applicable underground injection control program (UIC regulation) or an order requiring compliance under subsection (c) shall be subject to a civil penalty of not more than $25,000 for each day of such violation, and if such violation is willful, such person may, in addition to or in lieu of the civil penalty (authorized above), be imprisoned for not more than 3 years or fined in accordance with Title 18 of the United States Code, or both."

2:6 Administrative Penalties for Noncompliance (Safe Drinking Water Act § 1423(c))

"In any case in which the Administrator is authorized to bring a civil action under this section with respect to any regulation or other requirement of this part other than those relating to the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production, or any underground injection for the secondary or tertiary recovery of oil or natural gas, the Administrator may also issue an order under this subsection either assessing a civil penalty of not more than $10,000 for each day of violation for any past or current violation, up to a maximum administrative penalty of $125,000, or requiring compliance with such regulation or other requirement, or both."

For cases involving underground injection of brine or other fluids brought to the surface in connection with oil or gas production, or injection for secondary or tertiary recovery of oil or natural gas, the civil penalty shall be "not more than $5,000 for each day of violation for any past or current violation, up to a maximum administrative penalty of $125,000, or requiring compliance with such regulation or other requirement, or both."

2:7 Underground Sources of Drinking Water

Federal underground injection control regulations promulgated under the authority of the Safe Drinking Water Act are directed toward protecting underground sources of drinking water (USDW). Underground source of drinking water (USDW) means an aquifer or its portion:

1. Which supplies any public water system

2. Which contains a quantity of groundwater sufficient to supply a public water system

a. currently supplies drinking water for human consumption

b. contains fewer than 10,000 mg/l total dissolved solids

c. which is not an exempted aquifer

Under the UIC program, it is not necessary to identify specific aquifers as USDW's. The Agency has ruled that any aquifer or portion thereof that fits the definition is, in fact, a USDW (40 CFR Part 144).

2:8 Exempted Aquifer

An aquifer or portion of an aquifer which meets the criteria for an USDW in § 146.3 may be designated an exempted aquifer if it meets the following criteria:

1. It does not currently serve as a source of drinking water for human consumption

2. It cannot now and will not in the future serve as a source of drinking water because:

a. It is mineral, hydrocarbon or geothermal energy bearing with production capability, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible

b. It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical

c. It is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption, or

d. It is located above a Class III well mining area subject to subsidence or catastrophic collapse

The total dissolved solids content of the groundwater is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system (40 CFR §146.4).

2:9 Area of Review

Fluids injected under pressure into a geologic formation could, under certain conditions, force formation fluids and possibly contaminants to move upward into underground sources of drinking water via features such as improperly abandoned wells and undetected fault/fracture systems that penetrate the injection zone.

The area of review is the area surrounding an injection well or a group of injection wells to be studied by permit applicants for the possible presence of pathways through confining strata and along which formation or injected fluids, under pressure from the injection operation, might be forced into a USDW (40 CFR § 146.6). An area of review for injection wells should be determined on a case-by-case basis, using appropriate formulas and available geological information. The area of review should have a radius of no less than 1/4 mile unless the use of a mathematical model for the facility in question results in a radius of less than 1/4 mile. Many states have more stringent requirements. That is, the minimum allowable radius is greater than 1/4 mile. See figures 2.1, 2.2, 2.3, 2.4 and 2.5.

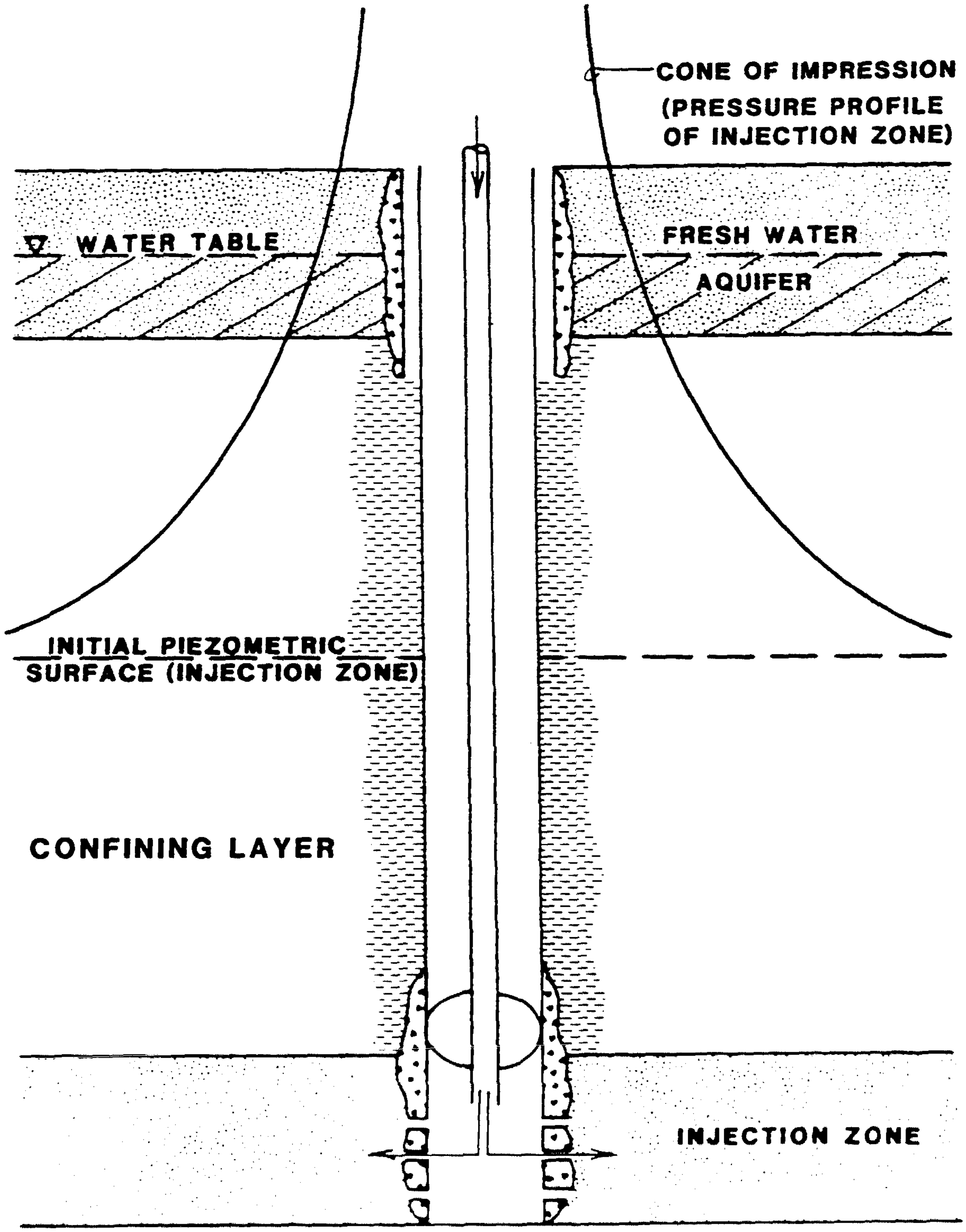

Figure 2.1 Idealized Example of Cone of Impression

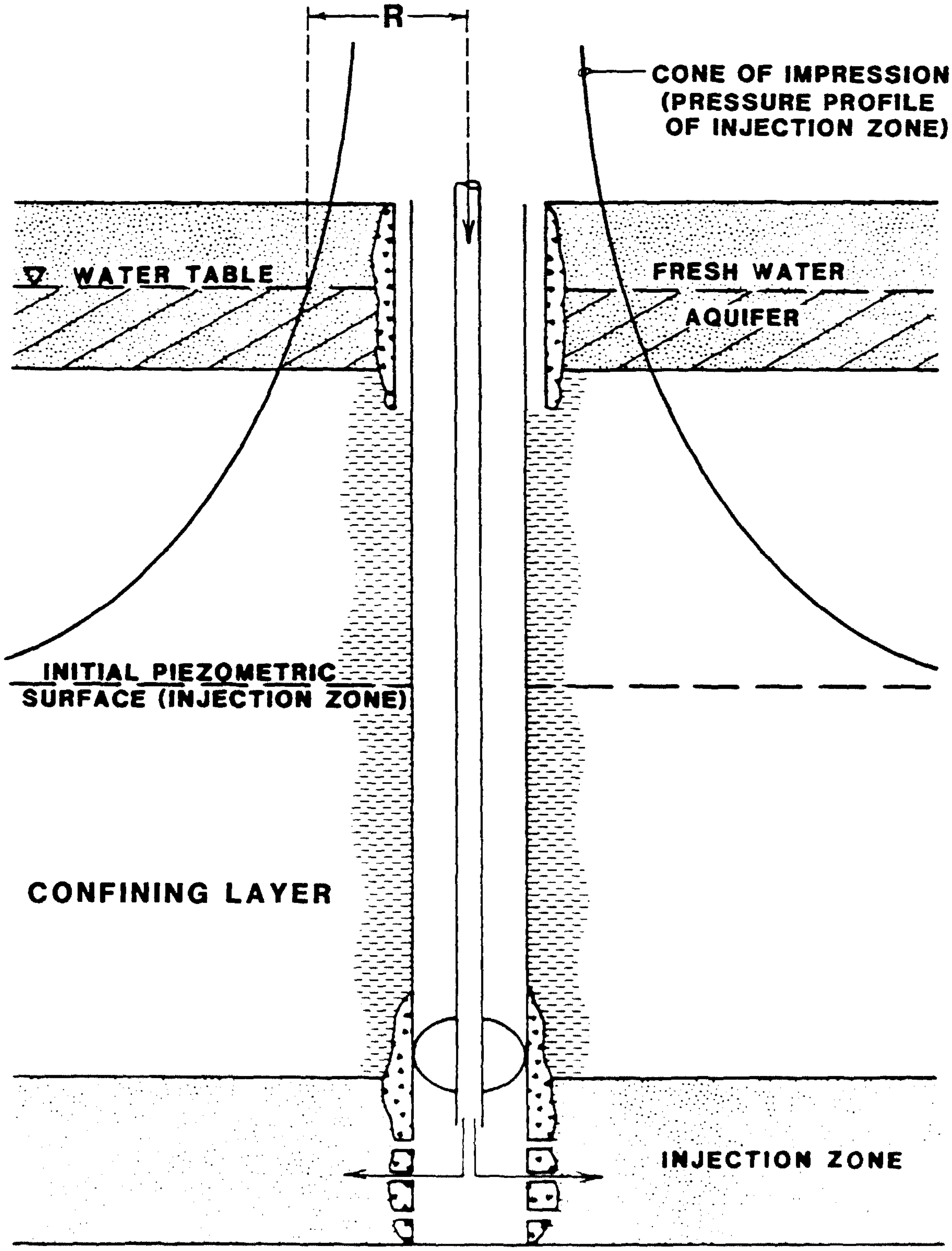

Figure 2.2 How the Position of the Cone of Impression defines the radius, R, of the Area of Review

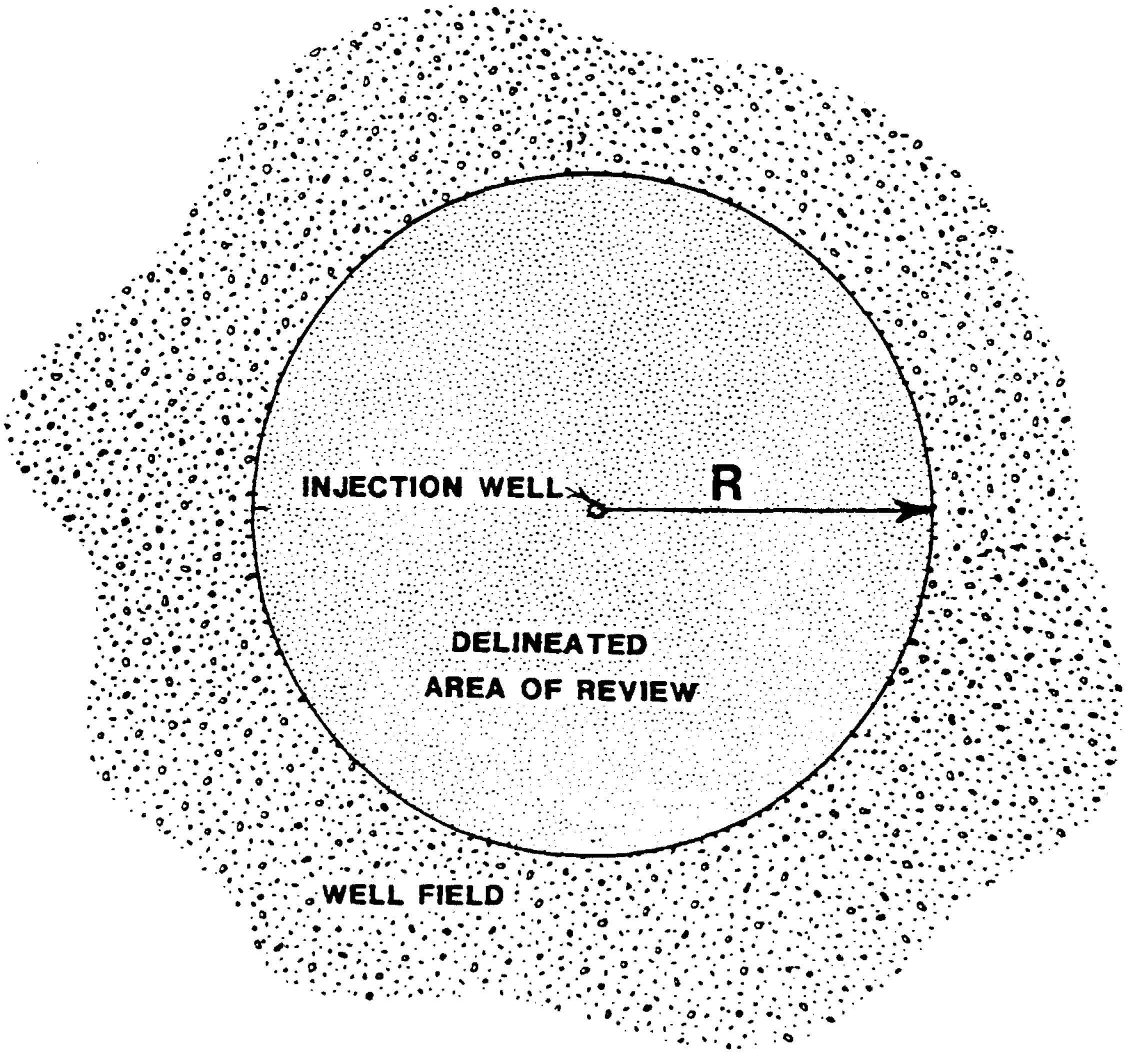

Figure 2.3 Plan view of Area of Review

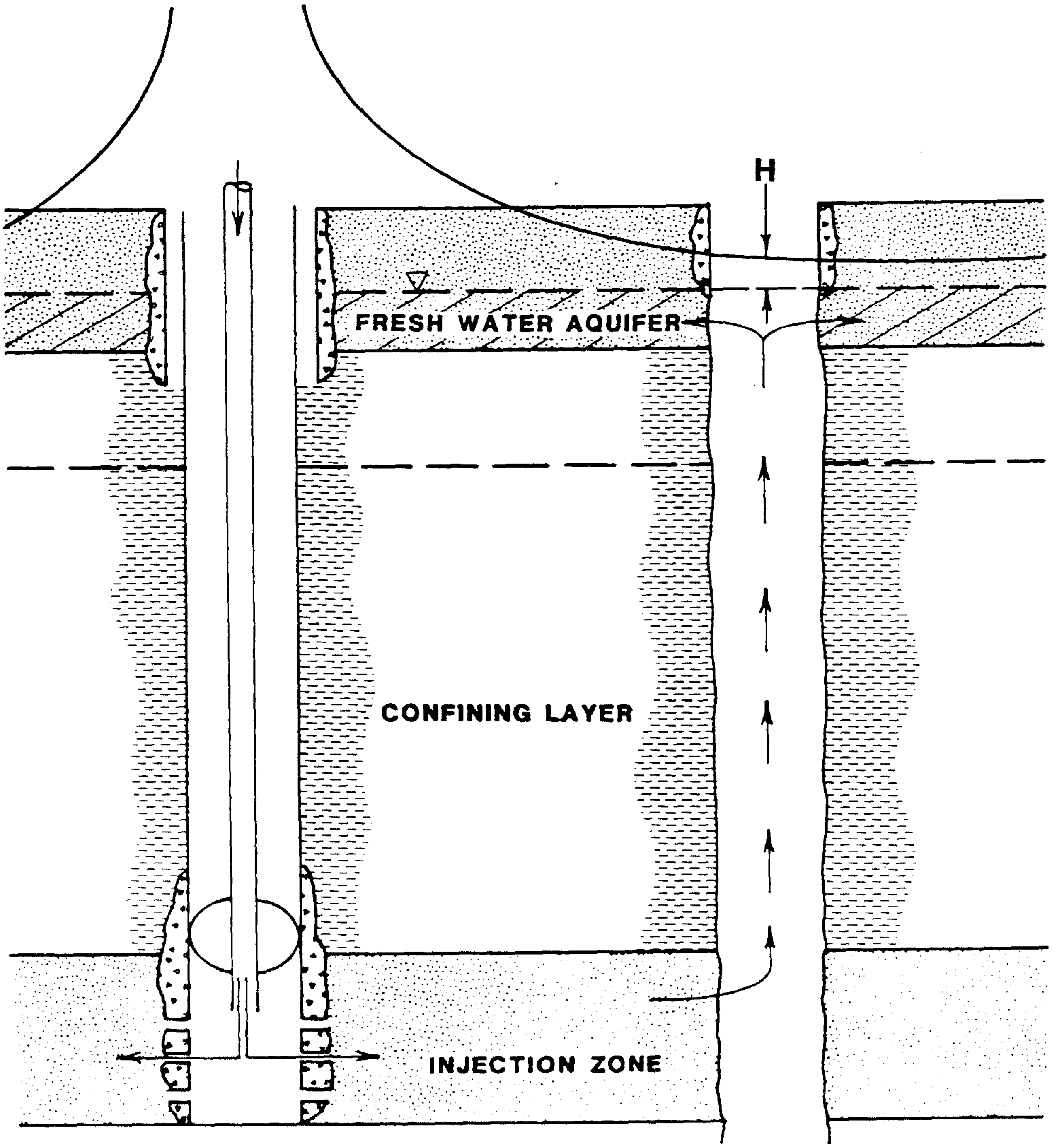

Figure 2.4 Example of fluid migrating from the injection zone into a fresh water aquifer through an unplugged well. Migration is made possible because of the pressure differential, shown as H.

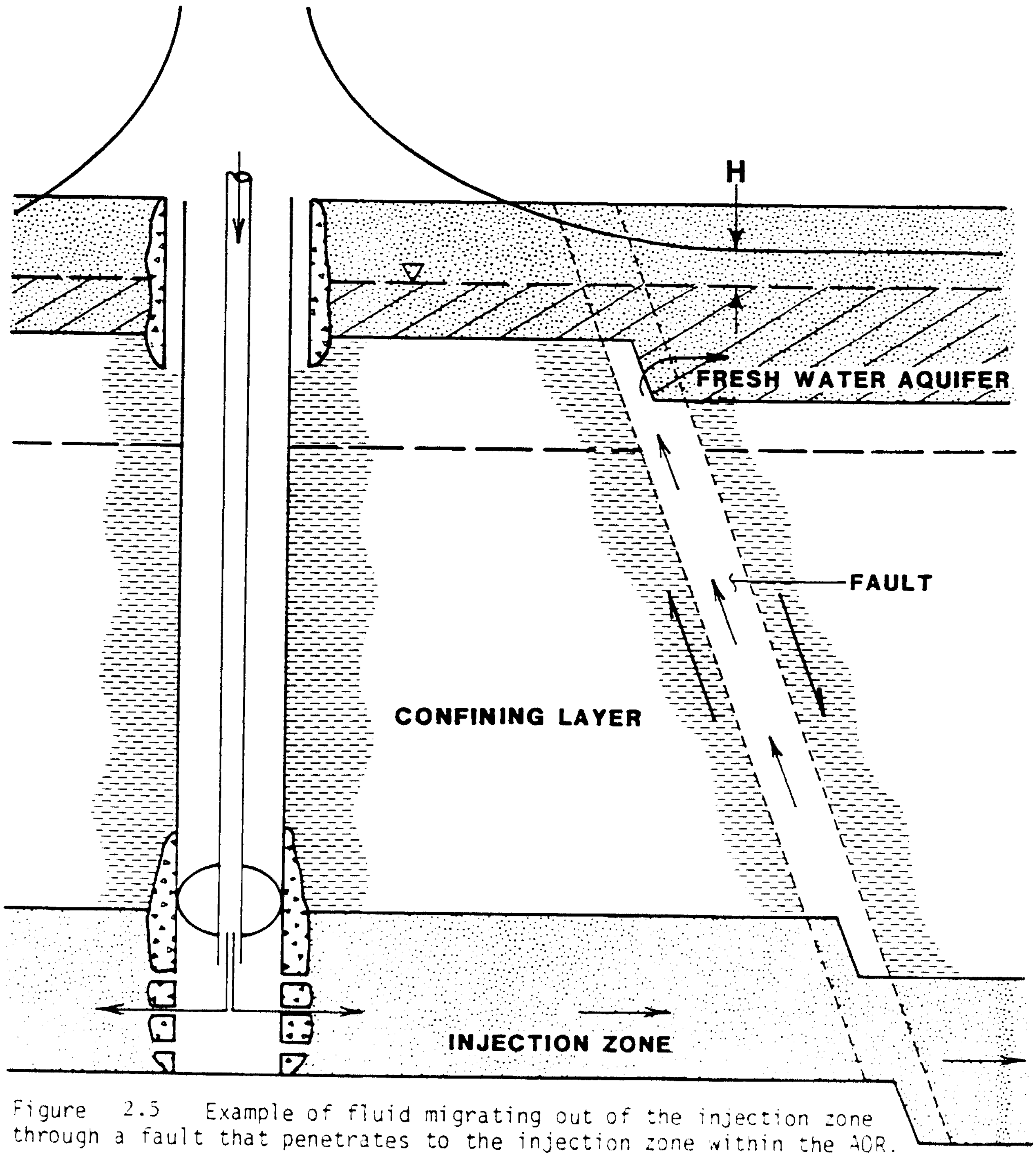

Figure 2.5 Example of fluid migrating out of the injection zone through a fault that penetrates to the injection zone within the AOR.

2.10 Corrective Action

EPA may require that corrective action be taken as necessary to prevent movement of fluid into an USDW when any well, that penetrates the injection zone, within the area of review of an injection operation is inadequately constructed, plugged, or abandoned. The EPA may require under the authority granted in 40 CFR §144.12, that an improperly completed well in the area of review be plugged or repaired even if the associated injection well is authorized by rule. In general, the regulatory staff will review data submitted by the applicant, evaluate the proposed corrective action plan, and if the plan is approvable, incorporate it as a permit provision.

Requirements under 40 CFR §146.7 state that the Director consider the following technical information in the permit application to determine the adequacy of the corrective action plan and to determine what additional steps are needed to prevent fluid movement into a USDW.

1. Nature and volume of injected fluid

2. Nature of native fluids or byproducts of injection

3. Potentially affected population

4. Geology

5. Hydrology

6. History of the injection operation

7. Completion and plugging records. Abandonment procedures in effect at the time the well was abandoned

9. Hydraulic connections with underground sources of drinking water

The applicant submits a corrective action plan for any wells within the area of review which may potentially endanger an USDW because of the proposed injection.

Corrective action plans may require:

1. Physical alteration and correction of any inadequate well system within the area of review prior to beginning injection operations, or

2. The operation of the injection facility at reduced pressure levels until such time as EPA determines that physical alteration and correction of an inadequate well system is accomplished, or

3. Reduced pressure operation of the facility for the life of the project

2:11 Quality Assurance

The General Grants Regulations require under 40 CFR §130.503(e) that all data used in any programs receiving assistance from EPA to have adequate quality assurance (QA). Internal EPA directives require the same of all EPA-implemented programs.

Data gathered during inspections and received in the form of self-monitoring report therefore need to meet QA requirements. These QA requirements have been put in place to guarantee that data are adequate for the purpose intended and of known quality. The Office of Drinking Water will issue guidances on how to apply QA principles to all "environmental measurements" used in the UIC program. These guidances will be issued in phases: (1) Chemical tests; (2) Physical tests; and (3) Geophysical tests. The chemical test guidance on Quality Assurance has been issued and the remaining guidances are forthcoming.

2:12 Barlow's Guidance, an Overview of Other Federal Regulations

The Supreme Court decision in Marshal vs. Barlow's Inc., U.S., 98 S. Ct. 1816 (1978) was an important case affecting the conduct of EPA inspections. The decision bears upon the need under certain circumstances to obtain warrants or other processes for inspections pursuant to EPA-administered Acts.

In Barlow's, the Supreme Court held that an OSHA inspector was not entitled to enter the non-public portions of a work site without either (1) the owner's consent, or (2) a warrant.

In summary, Barlow's has two (2) major effects on EPA enforcement inspections:

1. Where an inspector is refused entry, EPA will seek an inspection warrant through the local U.S. Attorney's Office

2. Sanctions will not be imposed upon the owners of establishments who insist on a warrant before allowing inspections of the non-public portions of an establishment

Barlow's decision is discussed in Chapter 3.0. For additional information obtain a copy of the EPA procedural guidelines concerning this decision from the USEPA Office of Enforcement and Compliance Monitoring.

2:13 Kinds of Inspections

As part of the EPA's compliance monitoring program, the UIC staff may be called upon to verify that certain injection well facility construction, completion, operation, maintenance, and closure procedures are performed according to approved plans and schedules and meet all permit or rule requirements. On-site inspections will be a major part of this verification effort.

2:14 Purposes of Inspections

Inspections may serve one or more of the following purposes:

1. Emergency Inspections
2. Preoperational Inspections (verification of compliance with construction requirements)
3. Mechanical Integrity Tests
4. Compliance Verification
5. Plugging and Abandonment Verification
6. Class IV Closure Verification
7. General Maintenance Inspection
8. Citizen Complaint Investigation

2.15 Emergency, Compliance, and Citizen Complaint Inspections

One of the above inspection types may be conducted, when appropriate to:

1. Investigate complaints from the public
2. Determine whether there is a violation
3. Provide basis for enforcement action
4. Define nature and extent of violation
5. Provide data to assist in determining cause of violation

Complaints alleging improper construction, completion, operation or maintenance at an injection well facility received by UIC staff will be thoroughly investigated. Response to complaints may consist of:

1. Establishing the nature of the complaint

2. Reviewing appropriate EPA files

3. Establishing contact with the operator to verify the complaint and discuss corrective action

4. Coordinating with other EPA, State or local regulatory authorities

5. Performing a site inspection to determine if a problem exists

6. Referring the complaint to Regional Counsel for appropriate enforcement action

2:16 Preoperational Inspections

Site inspections to verify or witness drilling and completion procedures will be conducted by UIC staff according to need and to availability of resources. Owner/Operators are required to notify EPA of the initiation of construction operations. Construction operations and testing that may be witnessed or supervised by the staff include:

1. Well logging

2. Setting and cementing surface casing

3. Setting and cementing protection casing

4. Setting of tubing and packer

5. Formation pressure and injectivity testing

6. Formation fluid testing

7. Mechanical integrity testing

2:17 Mechanical Integrity Test Inspections

Inspections to verify or witness mechanical integrity tests may be conducted on a scheduled basis during Routine Maintenance Inspections, prior to authorizing injection into a new well as part of a Preoperational Inspection, or at the conclusion of a well workover. The scope of the inspection is dependent on well construction. Inspection activities could include:

1. Reviewing historical pressure monitoring data

2. Witnessing pressure test of annulus to evaluate internal mechanical integrity

3. Witnessing logging or reviewing cementing records to evaluate external mechanical integrity

Satisfactory mechanical integrity tests are required to be performed and witnessed once every five years for Class I, II and some Class III wells. All new Class I, II and III wells must have a demonstration of mechanical integrity prior to authorization to inject.

2:18 Plugging and Abandonment Inspections

Abandonment of all classes of injection wells is witnessed by UIC inspectors to insure that closure is performed according to approved plans and schedules. (Plugging and abandonment and notification requirements are found in 40 CFR §144.28 (c), (j), and (k).) Inspections will generally follow an operator's notification of intent to plug and abandon a well but could result from an enforcement action taken by the Agency. Plugging and abandonment field activities will generally include both well preparation and plugging.

2:19 Closure of Class IV Wells

Injection into Class IV wells has been banned (Resource Conservation and Recovery Act of 1976 as amended by the Hazardous and Solid Waste Amendments of 1984, Sec. 7010). Proper closure of Class IV wells could be more complex than for other classes of wells, because of the nature of these operations and their potential for threatening public health. Inspections are performed in order to:

1. Evaluate previously plugged Class IV facilities

2. Determine if reentry into a previously plugged well is required

3. Evaluate degree of hazard to public health

4. Install monitoring facilities if required

5. Witness plugging procedures

In addition to witnessing the closure of a Class IV well, Class IV inspections involving sampling and reviewing company records may be conducted to determine if, in fact, a well is a Class IV well.

2:20 General Maintenance Inspections

The UIC staff may conduct regularly scheduled inspections of permitted injection facilities in order to:

1. Verify that operations being carried out conform to conditions set forth in the corresponding permit

2. Detect developing conditions that might lead to future violations of permit conditions or of regulations

3. Update EPA records on the facilities and their operations

4. Verify that operations are being conducted using adequate quality assurance/quality control procedures

3 Techniques for Efficient Inspections

INSPECTION GOAL

A primary goal of the inspector is to assemble information that can be used for determining compliance with permit conditions, applicable regulations and other requirements of the EPA UIC program. This information may ultimately result in enforcement case development and support. In performing these duties, inspectors should observe standard procedures for conducting legal and effective investigations and in meeting accepted safety practices and quality assurance requirements.

3:1 Legal Responsibilities for EPA UIC Program

The Environmental Protection Agency is given authority under the Safe Drinking Water Act to establish a program to regulate underground injection, to define control technologies, to obtain information through compliance inspections and specific requests for information, and to take administrative, civil and/or criminal enforcement actions when violations of the Act or implemented regulations are discovered. Inspectors should be familiar with the terms and conditions set forth by the SDWA and should conduct all investigations with its legal framework in mind. This includes the following:

1. Presentation of proper credentials (SDWA §1445 [b][1])

2. Presentation of required notices and receipts (Notice of Inspection Form, figure 3.1)

3. Proper handling of necessary warrants when facility entry is denied

4. Handling of confidential information

5. Proper handling of samples (Chain-of-Custody) and photographs

3:2 Investigative Techniques and Procedures

This section describes the step by step procedures that should be followed in making a thorough and efficient inspection. Inspectors should be familiar with these general investigative procedures to ensure accurate, concise and legally defensible inspections. An outline of procedural responsibilities in the inspection process is shown in table 3.1.

3:3 Pre-Inspection Planning

Pre-inspection preparation is essential to the effective planning and overall success of an inspection. Pre-planning an inspection will ensure that it is properly focused and efficiently conducted.

TABLE 3.1

INSPECTOR RESPONSIBILITIES

1. <u>Pre-Inspection Preparation:</u>

   - Establish purpose and scope of inspection
   - Review background information and Agency records
   - Develop plan for inspection
   - Prepare documents and equipment
   - Coordinate schedule with laboratory if samples are to be collected

2. <u>Entry:</u>

   - Present official credentials. (As per SDWA §1445 [b][1])
   - Manage denial of entry if necessary

3. <u>Opening Conference:</u>

   - Discuss inspection objectives and scope
   - Establish working relationship with facility officials

4. <u>Facility Inspection:</u>

   - Review facility records
   - Inspect monitoring equipment and operations
   - Collect samples
   - Prepare documentation of inspection activities

5. <u>Closing Conference:</u>

   - Collect missing or additional information
   - Clarify questions with facility officials
   - Prepare necessary receipts

6. <u>Follow-up:</u>

   - Prepare a follow-up letter to confirm inspection and summarize results

The first step is to establish the purpose and scope of the inspection. This should give an indication of the extent and degree of preparation required for the inspection.

Next, inspectors should become familiar with all facility operations to be inspected and collect and review all background information necessary to conduct an efficient and thorough inspection. The types of information available to the inspector for gaining insight into facility operations are:

General Facility Information

1. Maps showing facility location, well locations, and geographic features
2. Well names, numbers, and current operating status
3. Names, titles, and phone numbers of responsible facility officials
4. Nature of pretreatment and injection
5. Production levels - past, present and future
6. Hydrological data
7. Geology/hydrogeology of the area
8. Changes in facility conditions since previous inspection/permit application

Requirements, Regulations, and Limitations

1. Copies of existing permits, regulations, and requirements--Federal, State, and local--and restrictions placed on discharges, compliance schedules, monitoring and reporting requirements, monitoring location(s), available monitoring equipment and analytical methods used by facility
2. Any exemptions and waivers
3. Previous facility applications for water, air, and solid waste permits (these files may contain useful data not shown elsewhere)

Injection Well and Pre-Treatment Systems

1. Description and design data for injection well system and process operation
2. Sources and characteristics of injected fluids

3. Type and quantity of fluids injected

4. Spill prevention control and containment (SPCC) plan

5. Available by-passes or diversions and spill containment facilities

6. Pollution control, treatment methods, and monitoring systems

7. Well completion information

8. Inspection history of flow and pressure meters

Facility Compliance and Enforcement History

1. EPA and State compliance files

2. Correspondence among facility, local, State and Federal agencies

3. Complaints and reports, follow-up studies, findings, and remedial action

4. Previous inspection reports, records, correspondence on past incidents of violations, status of requested regulatory corrective action, if any, and compliance by facility

5. Status of current and pending administrative and/or judicial action against facility

6. Self-monitoring data and report

7. Previous EPA, State, and consultant studies and reports

8. Previous deficiency notices issued to facility

The above information can be obtained from compliance files of Federal, State and local agencies.

Other sources of information are:

1. Laws and Regulations - The Safe Drinking Water Act and amendments, the Resource Conservation and Recovery Act (RCRA) and amendments, and the Underground Injection Control Regulations establish procedures, controls, and other requirements applicable to a facility. In addition, State laws and regulations, and sometimes even local ordinances, are applicable to the same facility.

2. Permits and Permit Applications - Permits provide site specific information on the limitations, requirements, and restrictions applicable to underground injection/compliance schedules as well as monitoring, analytical, and reporting requirements. Permit

applications provide technical information on facility size, layout, and location of waste sources; treatment and control practices; contingency plans and emergency procedures; waste characteristics, types, and volumes; and locations of wells.

3. Regional and State Files and Contracts - Files and contracts often can provide facility self-monitoring data, inspection reports, and permits and permit applications related to individual facilities. They can provide compliance, enforcement, and litigation history; exemptions and waivers applied for and granted or denied; citizen complaints and actions taken; process and operational problems/solutions; pollution problems/solutions; laboratory capabilities or inadequacies; and other proposed or historical remedial actions. Consultant reports can provide design, construction and operation data and recommendations for remedial measures and safe operating parameters.

4. Technical Reports, Documents, and References - These sources provide information on enhanced recovery operations, as well as data on available pretreatment techniques

5. Other Statutory Requirements - Facility files maintained pursuant to other statutory/regulatory requirements

3:4 Inspection Plan Development

Once the purpose of the inspection has been established and all necessary background information has been reviewed, a plan for inspection should be developed. This should include a comprehensive list of tasks to be performed and the resources needed to complete them. Procedural steps and scheduling should also be detailed in the inspection plan. The following items generally should be included in an inspection plan:

Objectives:

1. What is the purpose of the inspection?

2. What is to be accomplished?

Tasks:

1. What tasks are to be completed?

2. What information must be collected?

Procedures:

1. What procedures are to be used?

2. Will the inspection require special procedures?

Resources:

1. What personnel will be required?

2. What equipment or instruments will be required?

3. What safety precautions should be taken? What safety precautions are required by the facility owner/operator? (This is especially important when the facility is injecting hazardous wastes.)

3:5 Inspection Schedule

1. What will be the time requirements for inspection activities?

2. What will be the key tasks to be accomplished during the inspection?

3. Has there been schedule coordination with the lab where samples are taken?

3:6 Notification of Interested Parties

The final step in pre-inspection preparation concerns notification of personnel and agencies to be involved in the inspection process. Notifications may be made by telephone, particularly in an emergency situation, and followed promptly by a letter. This procedure is used in several states. A notice of inspection usually requests information regarding specific facility safety regulations and may include the date of inspection and a schedule of procedures for coordinating inspection activities with the facility.

3:7 Unannounced Inspections

Situations involving suspected illegal discharges or emissions may warrant an unannounced inspection if there is concern some crucial evidence may be altered or destroyed. See also 3:14, "Emergency" Situations.

3:8 Facility Entrance

Consensual entry will be the norm for most inspections and the following procedures should be applied when entering a facility. The inspector should arrive during normal working hours and immediately locate the facility owner or appropriate agent. The inspector should clearly identify himself as an EPA UIC inspector, present the proper credentials and a notice of inspection (figure 3.1). Credentials must be presented before performing any inspection duties.

Inspectors should not sign any "waiver" or "release" that relieves the facility of responsibility for injury or restricts the use of information obtained during the course of the inspection. This approach does not,

U.S. ENVIRONMENTAL PROTECTION AGENCY

Notice of Inspection

Address (EPA Regional Office)

Date

Hour

Firm Name

Firm Address

Inspector Name & Title

Inspector Signature

Notice of Inspection is hereby given according to Section 1445 (b) of the Safe Drinking Water Act (42 U.S.C. §300 f *et seq*.).

Reason for Inspection

For the purpose of inspecting records, files, papers, processes, controls and facilities, and obtaining samples to determine whether the person subject to an applicable underground injection control program has acted or is acting in compliance with the Safe Drinking Water Act and any applicable permit or rule.

Section 1445 (b) (c) of the SDWA (42 U.S.C. §300 j-4 (b) (c) is quoted on the reverse of this form.

EPA FORM

Receipt of this Notice of Inspection is hereby acknowledged.

Name: ______________________

Title: ______________________

Date: ______________________

Figure 3.1 Notice of Inspection

Section 1445.

* * * * *

(b)(1) Except as provided in paragraph (2), the Administrator, or representatives of the Administrator duly designated by him, upon presenting appropriate credentials and a written notice to any supplier of water or other person subject to (A) a national primary drinking water regulation prescribed under section 1412, (B) any applicable underground injection control program, or (C) any requirement to monitor an unregulated contaminant pursuant to subsection (a), or person in charge of any of the property of such supplier or other person in charge of any of the property of such supplier or other person referred to in clause (A), (B), or (C), is authorized to enter any establishment, facility, or other property of such supplier or other person in order to determine whether such supplier or other person has acted or is acting in compliance with this title, including for this purpose, inspection at reasonable times, of records, files, papers, processes, controls, and facilities, or in order to test any feature of a public water system, including its raw water source. The Administrator or the Comptroller General (or any representative designated by either) shall have access for the purpose of audit and examination to any records, reports, or information of a grantee which are required to be maintained under subsection (a) or which are pertinent to any financial assistance under this title.

(2) No entry may be made under the first sentence of paragraph (1) in an establishment, facility, or other property of a supplier of water or other person subject to a national primary drinking water regulation if the establishment, facility, or other property is located in a State which has primary enforcement responsibility for public water systems unless, before written notice of such entry is made, the Administrator (or his representative) notifies the State agency charged with responsibility for safe drinking water of the reasons for such entry. The Administrator shall, upon a showing by the State agency that such an entry will be detrimental to the administration of the State's program of primary enforcement responsibility, take such showing into consideration in determining whether to make such entry. No State agency which receives notice under this paragraph of an entry proposed to be made under paragraph (1) may use the information contained in the notice to inform the person whose property is proposed to be entered of the proposed entry; and if a State agency so uses such information, notice to the agency under this paragraph is not required until such time as the Administrator determines the agency has provided him satisfactory assurances that it will no longer so use information contained in a notice under this paragraph.

(c) Whoever fails or refuses to comply with any requirement of subsection (1) or to allow the Administrator, the Comptroller General, or representatives of either, to enter and conduct any audit or inspection authorized by subsection (b) shall be subject to a civil penalty of not to exceed $25,000.

however, apply to contractors. Denial of entry will be discussed in Section 3:16.

3:9 Opening Conference

The initial meeting with the permittee should detail the scope of the inspection and the schedule to be followed during the inspection. The authority under which this investigation is being conducted should be specified and the names of all personnel (EPA and Contractor) involved with this inspection should be provided to the permittee. This opening conference should promote cooperation and a professional working atmosphere which will ultimately contribute to the success of the inspection.

Inspection Objectives:

An outline of the inspection objectives informs facility officials of the purpose and scope of the inspection and may held avoid misunderstandings.

Inspection Schedule:

A discussion of the order in which operations will be inspected helps eliminate wasted time by allowing officials time to make records available and start up intermittent operations.

Split Samples:

Facility officials should be informed during the opening conference of their right to receive a split of any sample collected for laboratory analysis.

Meetings:

A schedule of meetings with key personnel allows them to allocate clear times to spend with the inspector.

Records:

A list of records to be inspected allows officials to gather and make them available to the inspector.

Accompaniment:

It is important that a facility official accompany the inspector during the inspection not only to describe the site and its principal operating characteristics, but also for safety and liability considerations.

Permit Verification:

The inspector should verify the following information with facility officials:

1. Name and address of facility
2. Composition and source of injection fluids
3. Injection rates and pressures
4. Number and location of injection wells
5. Operating status of injection wells
6. Adequate quality assurance/quality control
7. Calibration and maintenance of monitoring devices

Safety Requirements:

The inspector should determine which EPA, OSHA and facility safety regulations are applicable to the inspection, and should be prepared to meet these requirements (See chapter 5.0).

New Requirements:

The inspector should discuss any new rules and regulations that apply to the facility and answer any questions pertaining to them.

Photographs:

Photographs are used to clarify and supplement written information in the inspection report, and to provide evidence for enforcement proceedings. The facility, however, may object to the taking of photographs. If a mutually acceptable solution cannot be reached and photographs are considered essential to the inspection, Agency supervisory and legal staff should be contacted for advice.

Facility personnel may also request that any photographs taken during the inspection be considered confidential. The Agency is obliged to comply with this request pending further legal determination. Self-developing film, although lower quality, is useful in certain situations. The facility's official representative may refuse permission to take photographs unless they can see the finished print. Duplicate photographs (one for the inspector and the other for the Company) should satisfy this need.

3:10 Facility Inspection and Documentation

The inspector is responsible for providing documentation of any suspected permit violations or other discrepancies uncovered during an inspection. A detailed record of inspection procedures, field observations and physical evidence collected should be maintained for later use in any enforcement proceedings, as a basis for written reports, or for examination by compliance personnel. Inspectors should use a hardbound field notebook with numbered pages. All documentation should be done in ink (mistakes and corrections initialed). The following types of information should be recorded during an inspection:

<u>Observations:</u>

All conditions, practices, and other observations that will be useful in preparing the inspection report or that will contribute to valid evidence should be recorded.

<u>Procedures:</u>

Inspectors should describe all procedures followed involving entry, sampling, records examination and document preparation.

<u>Documents:</u>

All documents taken or prepared by the inspector should be noted and related to specific inspection activities.

<u>Samples:</u>

"Chain-of-custody" procedures must be followed to control the fate and condition of samples from collection to final analytical results reported. The system must ensure that no alterations or loss of samples occurred from the time they were taken to the time they were analyzed. All quality assurance/quality control procedures should be strictly adhered to.

<u>Statements:</u>

Formal statements obtained from facility personnel can be useful in documenting an alleged violation. The person making the statement should have personal, firsthand knowledge of the information. The following procedures and considerations should be used when documenting a formal statement:

1. Determine the need for a statement. Will it provide useful information? Is the person making the statement qualified to do so by personal knowledge?

2. Ascertain all the facts and record those which are relevant and which the person can verify in court, making sure all information is factual and firsthand, and avoiding taking statements that cannot be personally verified.

Statement Preparation:

1. Use a simple narrative style, avoiding stilted language
2. Narrate the facts in the words of the person making the statement
3. Use the first-person singular ("I am manager of...")
4. Present the facts in chronological order (if possible)
5. Positively identify the person (name, address, position)
6. Show why the person is qualified to make the statement
7. Present the pertinent facts
8. Have the person read the statement and make any necessary corrections before signing. If necessary, read the statement to the person in the presence of a witness
9. All mistakes that are corrected must be initialed by the person making the statement
10. Ask the person making the statement to write a brief concluding paragraph indicating that he or she read and understood the statement (this safeguard will counter a later claim that the person did not know what he or she was signing)
11. Have the person making the statement sign it
12. If he or she refuses to sign the statement, elicit an acknowledgment that it is true and correct. Ask for a statement in his or her own hand ("I have read this statement and it is true but I am not signing it because..."). Failing that, declare at the bottom of the statement that the facts were recorded as revealed and that the person read the statement and avowed it to be true. Attempt to have any witness to the statement sign the statement including witness' name and address
13. Provide the person with a copy of the statement

Photographs:

Photographs provide an objective view of facility conditions during the inspection. The permittee's approval should be obtained before photographing any facility operations; however, photographs may always be taken from public areas. The following details should be recorded when taking photographs during an inspection:

1. Name and title of the photographer and witness (if any)

2. Type of film used (i.e., brand, size, expiration date, ASA number, etc.)

3. Focal length of the lens being used

4. F-stop and shutter speed at which the camera is set

5. Lighting conditions encountered

6. Time of day, weather conditions

7. Date

8. Location, and direction camera is facing

9. A brief description (scale) of the subject being photographed

Record a brief description of the photograph (location, subject, date, etc...) on the back of the photograph to simplify later identification.

Drawings and Maps:

Maps, drawings and charts are valuable tools in producing an accurate schematic representation of the facility under inspection. Oilfield maps can be used to locate production and injection wells.

Records and File Copies:

This information can provide important insight into a facility's condition and operations. Records and files can be in several forms -- written or printed materials, computer or electronic records, or photographic records. Follow these suggestions when examining and copying records.

1. Group related records together

2. Handle confidential business records according to EPA procedures. Not all records may be claimed as business confidential (see 40 CFR Part 2). If in doubt, treat the records as confidential until a decision on the claim can be obtained from the appropriate EPA official

3. Note physical location of the original record (i.e., address of the facility, building number, room number)

4. Obtain and record information about a facility's recordkeeping procedures which may be useful in later inspections

5. Return originals, after copying, to the proper personnel or to their correct location

Unusual Conditions and Problems:

Describe unusual conditions and problems in detail.

General Information:

List in the inspection report the names and titles of facility personnel and the activities they perform, along with any pertinent statements they made.

3:11 Closing Conference

Following the inspection the results may be discussed with the facilities management team or operating personnel in a closing conference. This discussion may cover all specific findings of the investigation and where appropriate, the findings should be compared with the facility's UIC permit requirements.

The inspector must refrain from discussing any legal or enforcement consequences with the permittee. He should not recommend any service company or consultant for correcting existing or potential well problems.

3:12 Sample Collection and Handling

Size and Approximate Number of Samples to be Taken

The number of samples depends on the inspection objective, type of site inspected and information desired. The sample, representative of the main body of waste, must be adequate in size for all needs including laboratory analyses or splitting with other organizations. Appendix D presents data on recommended containers, preservatives and holding times for various analyses. All sample containers, including those used in sampling hazardous waste, should be filled to overflowing before capping to reduce the loss of any volatile components and to reduce possible oxidation. All sampling should follow the approved Quality Assurance Project Plan for the State.

Sample Containers

Sample containers must be chemically clean and of the design and size specified by the analytical laboratory for the particular type of waste, the required preservation, and the required analytical procedure. The EPA Handbook for Analytical Quality Control in Water and Wastewater Laboratories (EPA 600/4-79/019) gives special instructions for the cleaning of bottles to be used for organic analysis. For some samples it is possible to use a new plastic container and dispose of it after completing the analysis.

Types of Samples -- Grab or Composite

A grab sample is one taken from only one point at one particular time. Most Class II well facilities will require grab samples. If sampling points are provided, the wellhead is an ideal place to take a grab sample of the injected fluids. It should be noted that all samples of the waste stream should be taken at a point which is down line from all treatment units, such as a filter. Widemouth sampling containers are preferred to facilitate rapid collection; the sample volume is set by the analytical laboratory. Individual grab samples are required if analyses for dissolved gases, residual chlorine, sulfides, or pH are to be made. These require immediate preservation and sealing (see appendix D).

A composite sample is a mixture of individual samples collected "over time." A composite is more representative of the average waste composition than a grab sample. Care must be taken not to mix incompatible wastes.

A Class I injection stream should be sampled proportional to the flow rate. A typical ratio is one milliliter sample for each gallon per minute of flow. Automatic liquid samplers composite samples on the basis of flow or time.

3:13 Chain of Custody

Follow Chain-of-Custody Procedures. The Agency must be in a position to demonstrate the reliability of analytical test results by proving the chain of possession from the time of collection through transportation to the laboratory, storage, handling and analysis. Procedures have been established by the EPA to create an accurate written record that can be used to trace the possession of the sample from the moment of its collection through its introduction into evidence. Details of sample control are included in the NEIC Policies and Procedures Manual (EPA-330/9-78-001) and in the Regional or State UIC Quality Assurance Project Plan. Instructions for completing the Chain-of-Custody record are included in appendix A. Further sources of information on sampling and sample handling are included in the reference section at the end of this chapter.

3:14 The Right of Warrantless Entry

"Emergency" Situations

In an emergency, where there is not time to get a warrant, a warrantless inspection is permissible. The Regions will always have to exercise considerable judgment concerning whether to secure a warrant when dealing with an emergency situation. However, if entry is refused during an emergency, the Agency would need the assistance of the U.S. Marshal to gain entry, and a warrant could probably be obtained during the time necessary to secure the Marshal's assistance.

An emergency situation would include potential imminent hazard situations, as well as situations where there is potential for destruction of evidence or where evidence of a suspected violation may disappear during the time that a warrant is being obtained.

"Open Fields" and "In Plain View" Situations

Observation by inspectors of things that are in plain view, that is, things that a member of the public could be in a position to observe, does not require a warrant. Thus, an inspector's observations from the public area of a plant or even from certain private property not closed to the public are admissible. Observations made even before presentation of credentials while on private property which is not normally closed to the public are admissible.

3:15 Withdrawal of Consent to Inspection

The owner may withdraw his consent to the inspection at any time. The inspection is valid to the extent to which it has progressed before consent was withdrawn. Thus, observations by the inspector, including samples and photographs obtained before consent was withdrawn, would be admissible in any subsequent enforcement action. Withdrawal of consent is tantamount to a refusal to allow entry and should be treated as discussed above, unless the inspection had progressed far enough to accomplish its purposes.

3:16 Denial of Entry

Denial of entry into a facility requires certain procedural steps that should be undertaken by the inspector to ensure that proper legal guidelines are followed. The steps outlined below are in accordance with the Safe Drinking Water Act and the 1978 U.S. Supreme Court decision in Marshal vs. Barlow's, Inc., U.S., 98 S. Ct. 1816, and should be followed in the event entry to a facility is denied for inspection purposes. A professional attitude should prevail at all times.

Inspector Identification

Upon arrival at the facility the inspector should clearly identify himself as an EPA UIC inspector and present the proper credentials and notice(s) of inspection to the facility owner or agent in charge.

The establishment owner may complain about allowing an inspector to enter or otherwise express his displeasure with EPA or the Federal government. However, as along as he allows the inspector to enter, the entry is voluntary and consensual. On the other hand, if the inspector gains entry in a coercive manner (either in a verbal or physical sense), the entry would be not be consensual.

Barlow's clearly establishes that the owner does have the right to ask for a warrant under normal circumstances. Therefore, refusal to allow entry for inspectional purposes will not lead to civil or criminal penalties if the refusal is based on the inspector's lack of a warrant and the situation is such that the right of warrantless entry doesn't exist (to be discussed later). If the owner were to allow the inspector to enter his establishment only in response to a threat of enforcement liability, it is quite possible that any evidence obtained in such an inspection would be inadmissible. An inspector may, however, inform the owner who refuses entry that he intends to seek a warrant to compel the inspection.

Reason for Denial

If entry is not granted, ask why. Tactfully probe the reason for the denial to see if obstacles (such as misunderstandings) can be resolved. If resolution is beyond the authority of the inspector, he or she may suggest that the facility officials seek advice from their attorneys on clarification of the scope of EPA's inspection authority under the Safe Drinking Water Act.

Denial Confirmed

If entry is still denied, the inspector should leave the premises immediately and telephone the designated Regional Enforcement Attorney as soon as possible for further instructions. The Regional Enforcement Attorney should contact the U.S. Attorney's Office for the district in which the establishment desired to be inspected is located and explain to the appropriate Assistant United States Attorney the need for a warrant to conduct the particular inspection. The Regional Attorney should arrange for the United States Attorney to meet with the inspector as soon as possible. The inspector should bring a copy of the appropriate draft warrant and affidavits.

Record Details of Denial

All observations pertaining to the denial are to be carefully noted in the field notebook. Include facility name and exact address, name and title of person(s) approached, authority of person(s) who refused entry, time of denial, reason for denial, facility appearance, any reasonable suspicions that refusal was based on a desire to cover up regulatory violations, etc. All such information will be important should a warrant be sought.

3:17 The Warrant

In the event that a warrant becomes necessary the inspector should be aware of what information is required to obtain a warrant. There are several general rules for securing warrants. Three documents have to be drafted:

1. An application for a warrant

2. An accompanying affidavit

3. The warrant

Each document should be captioned with the District Court of jurisdiction, the title of the action, and the title of the particular document.

The application for a warrant should generally identify the statutes and regulations under which the Agency is seeking the warrant, and should clearly identify the site or establishment desired to be inspected (including, if possible, the owner and/or operator of the site). The application can be a one or two page document if all of the factual background for seeking the warrant is stated in the affidavit, and the application so states. The application should be signed by the U.S. Attorney or by his Assistant U.S. Attorney.

The affidavits in support of the warrant application are crucial documents. Each affidavit should consist of consecutively numbered paragraphs, which describe all of the facts that support warrant issuance. If the warrant is sought in the absence of probable cause, it should recite or incorporate the neutral administrative scheme which is the basis for inspecting the particular establishment. Each affidavit should be signed by someone with personal knowledge of all the facts stated. In cases where entry has been denied, this person would most likely be the inspector who was denied entry. Note that an affidavit is a <u>sworn</u> statement that must either be notarized or personally sworn to before the magistrate or judge. See appendix F for examples of the documents described above.

3:18 Inspection with Warrant

Once the warrant has been issued by the magistrate or judge, the inspector may proceed to the establishment to commence or continue the inspection. Where there is a high probability that entry will be refused even with a warrant or where there are threats of violence, the inspector should be accompanied by a U.S. Marshal when he goes to serve the warrant on the recalcitrant owner. The inspector should never himself attempt to make any forceful entry of the establishment. If the owner refuses entry to an inspector holding a warrant but not accompanied by a U.S. Marshal, the inspector should leave the establishment and inform the Assistant

U.S. Attorney and the designated Regional Attorney. They will take appropriate action such as seeking a citation for contempt. Where the inspector is accompanied by a U.S. Marshal, the Marshal is principally charged with executing the warrant. Thus, if a refusal or threat to refuse occurs, the inspector should abide by the U.S. Marshal's decision whether it is to leave, to seek forcible entry, or otherwise.

The inspector should conduct the inspection strictly in accordance with the warrant. If sampling is authorized, the inspector must be sure to carefully follow all procedures, including the presentation of receipts for all samples taken. If records or other property are authorized to be taken, the inspector must provide a receipt for the property taken and maintain an inventory of anything taken from the premises. This inventory will be examined by the magistrate to assure that the warrant's authority has not been exceeded.

3:19 Returning the Warrant

After the inspection has been completed, the warrant must be returned to the magistrate or judge. Whoever executes the warrant, i.e., whoever performs the inspection, must sign the return of service form indicating to whom the warrant was served and the date of service. He should then return the executed warrant to the U.S. Attorney who will formally return it to the issuing magistrate or judge. If anything has been physically taken from the premises, such as records or samples, an inventory of such items must be submitted to the court, and the inspector must be present to certify that the inventory is accurate and complete.

3:20 Seeking a Warrant before Inspection

The Barlow's decision recognized that, on occasion, the Agency may wish to obtain a warrant to conduct an inspection even before there has been any refusal to allow entry. Such a warrant may be necessary when surprise is particularly crucial to the inspection, or when a company's prior bad conduct and prior refusals make it likely that warrantless entry will be refused. Pre-inspection warrants may also be obtained where the distance to a U.S. Attorney or a magistrate is considerable so that excessive travel time would be consumed if entry were denied. At present, the seeking of such a warrant prior to an initial inspection should be an exceptional circumstance, and should be coordinated through Headquarters. If refusals to allow entry without a warrant increase, such warrants may be sought more frequently (see appendix F).

3:21 Professional Business Ethics

Inspectors should conduct their inspections with a high degree of professionalism and workmanship. Since the inspector is usually the initial or only contact between the operator and the regulatory agency it is imperative that he be dignified, tactful, courteous and diplomatic. To promote good working relations and establish a cooperative atmosphere the inspector should be firm but responsive. The following rules should be applied when inspecting a facility:

1. The inspection should be developed and reported with complete objectivity

2. Information acquired during an inspection is for official use only

3. No favors or benefits should be accepted under circumstances that might be construed as influencing the inspector's performance of duties

3:22 Inspection Report

Inspection reports are essential and valuable tools in preparing evidence reports and in providing clear, concise methods for correcting problems and deficiencies noted during the inspection. A well organized inspection report should follow the general guidelines discussed in this section.

<u>Organization and Arrangement</u>

The organization and arrangement of a report should be:

1. Accurate: All information must be factual and based on sound inspection practices. Observations should be the verifiable result of firsthand knowledge. Compliance personnel must be able to depend on the accuracy of all information.

2. Relevant: Information in an inspection report should be pertinent to the subject. Irrelevant facts and data will clutter a report, reducing its clarity and usefulness.

3. Comprehensive: Suspected violation(s) should be substantiated by as much factual, relevant information as feasible to gather. The more comprehensive the evidence is, the better and easier the enforcement task will be.

4. Coordinated: All pertinent information should be organized into a complete package. Documentary support (for example, photographs, statements, samples and documentation) should be clearly referenced.

5. Objective: Information should be objective and factual; the report should not speculate on the ultimate result of any factual findings.

6. Clear: The information in the report should be presented in a clear, well organized manner.

7. Neat and Legible: Allow time to prepare a neat, legible report, type written if possible.

Preparing and Writing the Inspection Report

Basic steps in preparing and writing the inspection report are:

1. Reviewing the Information: The first step in preparing the narrative is to collect all information gathered during the inspection. The inspector's field notebook should be reviewed in detail. All evidence should be reviewed for relevance and completeness. Gaps may need to be filled by a phone call or, in unusual circumstances, by a follow-up visit.

2. Organizing the Material: The information may be organized in many forms, depending on the individual need, but should be presented in a logical manner. An example of an inspection report form has been included in appendix N.

3. Referencing Accompanying Material: Documentary support for a narrative report should be clearly referenced so that the documents can be readily located. Documents should be checked for clarity.

4. Writing the Narrative Report: The purpose of the narrative is to record factually the procedures used in, and findings resulting from, the evidence-gathering process. The inspector should refer to routine procedures and practices used during the inspection, but should describe facts relating to potential violations and discrepancies in detail. The field notebook is a guide for preparing the narrative report.

Main Body of the Report

The main body of the report should contain all pertinent facts and information acquired during the inspection. It generally will contain three basic items listed below:

1. Permittee Compliance History

2. Documentary Support

3. Supplementary Narrative Information

Useful Guidelines in Writing

Useful guidelines in writing a narrative report include:

1. General Information

   - State location of facility and name, title and phone number of person in charge

   - Give general description of facility

- o State the purpose of the inspection and how the facility came to be inspected (for example, operator notification, complaint response, etc...)

2. Findings and Conclusions

- o State what the findings of the inspection were. Include any problem areas that currently do, or potentially may, affect compliance
- o Compare compliance with permit requirements, including effluent limitations where appropriate
- o Describe any problems, such as denied or withdrawn consent of entry to the facility; reluctance; or if a warrant was needed

3. Facility Information

- o Give the size of the facility based on observations and previous data for both production and injection flows; give number of wells
- o Describe the injection system and the operations
- o Compare permit or permit application with actual facility conditions (include sampling points and monitoring locations)

4. Documentation

- o List the records reviewed, noting the reasons for their review, and referencing documents that were borrowed or copied
- o Describe any inadequacies in recordkeeping procedures, or if any required information was unavailable, incomplete or inaccurate; special consideration should be given to pressure and flow measurement records, and construction schedules (if relevant)
- o Note and reference any statements taken during the inspection
- o Reference any photographs taken during the inspection that relate to possible violations
- o Reference any drawings, maps, charts, or other documents made or taken during the inspection

5. Monitoring Information

   - Describe sampling points and techniques used
   - Note if split samples were taken
   - Describe methods of annulus and injection pressure monitoring
   - Describe chain-of-custody procedures used in handling samples

6. Attachments

   - Prepare a list of all supporting documents (a general index will help compliance personnel to locate specific documents)

REFERENCES

United States Environmental Protection Agency. NPDES Compliance Inspection Manual. Draft Report, EPA Office of Water Enforcement and Permits, Washington, D.C., March, 1984.

United States Environmental Protection Agency. Sampling Document for U.S. EPA Direct Implementation Program. Engineering Enterprises, Inc., Norman, OK, March, 1986.

United States Environmental Protection Agency. Handbook for Sampling and Sample Preservation of Water and Waste Water, EPA-600/4-82-029, Washington, D.C.

United States Environmental Protection Agency. Revised Draft Protocol for Ground Water Inspections at Hazardous Waste Treatment and Disposal Facilities, prepared for EPA by Versar, Inc., October, 1985.

4 Inspections

INTRODUCTION

The general techniques for inspections were discussed in detail in Chapter Three. The purpose of Chapter Four is to examine the different types of inspections that an inspector may be asked to perform. These include preoperational inspections, mechanical integrity test inspections, plugging and abandonment, Class IV closure verification, emergency inspections, compliance verification, and citizen complaint investigations. Each of the following sections provides pertinent background information and describes the procedures required to perform each type of inspection.

4:1 General Inspection Procedures

General inspections by UIC Staff to verify or witness facility operations may be conducted routinely according to a general plan, or in response to a complaint or other indications that a violation may exist. The procedures outlined below are to be followed during all types of inspections. They are general guidelines for the inspector, and any observations made with regard to any of the items in the following lists should be duly recorded.

4:2 General Inspections

General inspection of the injection facilities and monitoring wells should be routinely conducted by the inspector while he is on site and should include at least the following items:

1. Check for changes to the injection system, including supply lines, treatment, storage, and monitoring devices

2. Verify that there has been no change in facility process which could affect the waste stream

3. Check for signs of surface spills related to injection facility

4. Check for signs of well workover since last inspection

5. Check for signs of corrosion, rust, wear and damage to surface facilities

6. Check instruments (gages, manometers, recorders, meters, etc.) for sensitivity and accuracy

7. Verify that number and identity of injection and monitoring wells agree with those listed in the permitting documents

Review records to verify compliance with permit and/or regulatory conditions: The inspector should verify that all required information has been accurately recorded and is up-to-date. Facility operations should be compared with permit conditions to verify compliance. The records review should include an examination of operator records on QA/QC for all monitoring devices and for the sampling analyses of injected fluid. (Include review of sampling method.)

If any activities differ from those stated in the permit the inspector should note whether EPA was notified. An examination of records showing injection rates and pressures and physical and chemical properties of the injected fluids can reveal the operating history of the facility. Figures 4.1, 4.2, and 4.3 are EPA forms used by injection well owners/operators to report required information.

Review the self-monitoring system and reporting procedures: The EPA UIC Program requires that permittees maintain records and report periodically the amount and nature of waste injected. Routine inspections should be conducted at all permitted facilities to verify compliance with permit and/or regulatory requirements. A review of facility records should encompass the following:

1. Is the monitoring performed according to permit or rule requirements?

2. Is all required information available?

3. Is the information correct?

4. Is the information being maintained for the required period of time?

5. Are the monitoring gauges properly maintained and frequently calibrated?

Evaluate the operation and maintenance of the facility. After careful observation of a facility and review of its performance records, the inspector should determine if anything requires further investigation. He should decide whether the owner/operator has complied with applicable requirements or if he needs assistance.

4:3 Check List for General Site Inspection

Examination of Injection Facility. Verify:

1. Information contained in the permit

2. Adequacy of equipment calibration and maintenance

3. Adequacy of backup facilities (if any)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

CLASS __

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

NAME AND ADDRESS OF EXISTING PERMITTEE	NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N

W E

S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY

- ☐ Brine Disposal
- ☐ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT

- ☐ Individual
- ☐ Area

Number of Wells ____

Lease Name

Well Number

Monitoring Location:
(if manifold monitoring) ____________________

Nature of Inje ion Fluid ____________________

		INJECTION PRESSURE		TOTAL VOLUME INJECTED		FLOW RATE (BBL/Day)	
MONTH	YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	MCF	AVERAGE	MAXIMUM

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE (Please type or print)	SIGNATURE	DATE SIGNED

EPA Form 7520-11 (2-84)

Figure 4.1 Annual Injection Monitoring Report

EPA UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

INJECTION WELL MONITORING REPORT

Form Approved
OMB No. 2000-0042
Approval expires 9-30-86

YEAR	MONTH	MONTH	MONTH
Injection Pressure (PSI)			
1. Minimum			
2. Average			
3. Maximum			
Injection Rate (Gal/Min)			
1. Minimum			
2. Average			
3. Maximum			
Annular Pressure (PSI)			
1. Minimum			
2. Average			
3. Maximum			
Injection Volume (Gal)			
1. Monthly Total			
2. Yearly Cumulative			
Temperature (F°)			
1. Minimum			
2. Average			
3. Maximum			
pH			
1. Minimum			
2. Average			
3. Maximum			
Other			

Name and Address of Permittee		Permit Number
Name and Official Title *(Please type or print)*	Signature	Date Signed

EPA Form 7520-8 (2-84)

Figure 4.2 Monthly Monitoring Report

For Sample Use Only - Comparable Format Acceptable

U.S. ENVIRONMENTAL PROTECTION AGENCY MONTHLY MONITORING REPORT
FOR CLASS ___ INJECTION WELLS

Insert Operator Name & Address

Sheet ___ of ___

Please complete and submit this report at the end of each month. This report must be postmarked no later than the 10th day of the following month.

PERMIT NUMBER ________ MO. ___ YEAR ___

check one —> ECR ___ SWD ___

DATE	INJECTION PRES. (psig)	ANNULUS PRES. (psig)	FLOW RATE (BPD)	CUM. VOL. (BPD)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
AVERAGE				
HIGHEST VALUE				
LOWEST VALUE				

Specific Gravity of Injected Fluids: ________

Figure 4.3 Daily Monitoring Report

4. Performance of pre-injection facilities

5. Suitability and operation of monitoring equipment

6. Efficiency of manifold monitoring

7. Evidence of surface contamination

8. Evidence of noncompliance with regulatory requirements

<u>Permit Verification and Compliance Review.</u> Verify:

1. Name and mailing address of permittee

2. Facility description in permit

3. Proper notification of any operational changes to EPA/State

4. Maintenance of accurate records of injection volumes and pressures

5. Number and location of wells as described in the permit

6. Description and source of injection fluids

7. Permits for all wells in use

<u>Self-Monitoring and Reporting Review.</u> Verify:

1. All data, measurements, and analyses required by permit

2. Monitoring well locations

3. Calibration of monitoring equipment

4. Sampling and analysis data adequacy

o Dates, times, location of sampling

o Name(s) of individual(s) performing sampling

o Sample volumes, kinds of containers, preservation, and storage

o Analytical methods and techniques

o Results of analyses

o Names of laboratories and personnel performing analyses

o Instantaneous flow at grab sample stations

Operation and Maintenance Evaluation. Verify:

1. All required information available and current

2. Information maintained for required period

3. Plant records adequacy

- O & M Manual

- "As-built" engineering drawings

Injection Fluid Samples.

1. Obtain either grab (using procedures from Chapter 3) or composite samples, as required

2. Measure pH, temperature and conductivity of injection fluid, where possible

3. Observe quality assurance/quality control procedures

4. Follow chain-of-custody procedures

5. Obtain split samples, if owner/operator so requests

6. Document samples in field notebook

The remaining sections in this chapter will address the correct protocol to be followed, in addition to those outlined in 4:2 and 4:3, when performing each type of inspection. The inspection types to be discussed are:

Preoperational

Compliance verification

Mechanical integrity test

Plugging and abandonment

Class IV closure

Emergency

Citizen complaint investigation

4:4 Preoperational Inspections

After a new UIC permit is granted and prior to start-up, the inspector may perform several preoperational inspections. The purpose of these inspections is to (1) assure that the well is constructed so as to protect the USDW; (2) assure that any deviations from the construction design were approved by the EPA; (3) determine if the geology and hydrogeology encountered during drilling are as described in the permit application; and (4) assure that the well has mechanical integrity and injection potential prior to being approved for use.

There are certain critical construction activities the inspector should witness. Some of the more important are:

<u>Open hole and cased hole logging</u>

<u>Primary cementing</u>

<u>Formation pressure and injectivity testing</u>

<u>Mechanical integrity testing</u>

It is strongly recommended that the owner/operator be required to notify the EPA when drilling begins, and not less than 72 hours before any other critical construction activity (as defined by EPA) is scheduled to take place. This permits the inspector to plan in advance his visit to the site.

4:5 Logging

Several comprehensive references on well log analysis are listed at the end of this chapter. A brief description of commonly used logs is presented below. A general checklist for witnessing well logging in the field is also included.

Logging provides subsurface information on:

<u>Geologic strata</u> -- kinds and thicknesses -- penetrated by the well

<u>Condition (regularity) of the drilled (open) bore hole</u>

<u>Kinds of fluids present in the strata</u>

<u>Integrity of cemented intervals</u>

<u>Integrity of steel casing in the well</u>

<u>Presence and significance of leaks through the annulus</u> outside the casing and through the formations close to the well.

Some logging tools yield useful information only in open (uncased) holes; others only in cased holes; a few in both open and cased holes. Electric logs, borehole caliper logs, and density logs are limited to open-hole conditions, because any casing present in the hole would shield the tools from required contact with, or effect of, the rocks. Cement bond, casing, and radioactive tracer logs are used only in cased holes.

Radioactive (gamma and neutron) and temperature logs can be used in either open or cased holes.

Many logging techniques require circulation of drilling or workover fluids prior to logging; some can be run in dry holes.

Some logging tools are not suitable for use in conductive fluids (drilling mud, brine, etc.), while others are adversely affected by nonconductive fluids. With the proper selection and use of logging equipment temperature, pressure, resistivity, flow, depth, hole size, and lithology can all be measured or described. Some parameters must be calculated or inferred from logs. For example, no logging method can now directly measure permeability, extent of rock fracturing, or mechanical properties of formation rocks.

Well logging can be divided into five general categories: lithologic, electrical, radioactive, acoustical, and specialized. The methods, with their applications, are shown in table 4.1. Well servicing companies have different trade names for equivalent types of geophysical logs (see table 4.2).

4:6 Lithologic Logging

Many formations can be identified by examination of samples retrieved during drilling.

Rotary drilling provides continuous formation samples obtained as cuttings. A sample or mud log is a continuous description of the geologic character of each stratum and the depth at which each change occurs. It may also include drilling times and gas content of the mud. Ideally, representative samples should be collected at measured depths and at such intervals as will show the lithologic character of the formations penetrated.

4:7 Electric Logging

Electric logging is a process by which electrical measurements provide data on the formations penetrated by the borehole. The principal downhole measurements made are voltage and resistance. These electrical properties are measured by lowering a tool into the borehole and recording spontaneous potential (voltage), resistivity, and the inverse of resistivity: conductivity.

TABLE 4.1 - WELL LOGGING METHODS AND USES

Method Type	Formation Identification	Physical Formation* Characteristics	Fluid Flow	Well Construction Influence	Well Construction Evaluate
Lithologic					
Coring	▬▬▬	▬▬▬		▬▬▬	
Mud Log	▬ ▬ ▬	▬ ▬ ▬		▬▬▬	
Cuttings Samples	▬▬▬	▬ ▬ ▬		▬▬▬	
Electrical					
Resistivity	▬ ▬ ▬	▬▬▬		▬▬▬	
Spontaneous Potential	▬▬▬	▬ ▬ ▬		▬▬▬	
Radioactivity					
Natural Gamma Ray	▬▬▬			▬▬▬	▬ ▬ ▬
Gamma-Gamma (Density)	▬ ▬ ▬	▬▬▬		▬▬▬	
Neutron	▬▬▬	▬ ▬ ▬		▬▬▬	
Radioactive Tracer			▬▬▬		▬▬▬
Acoustic					
Cement Bond					▬▬▬
Sonic Logs	▬ ▬ ▬	▬▬▬		▬ ▬ ▬	▬ ▬ ▬
Visual					
Downhole Televiewer	▬▬▬	▬ ▬ ▬		▬ ▬ ▬	▬▬▬
Specialized					
Temperature			▬ ▬ ▬		▬ ▬ ▬
Directional Survey				▬ ▬ ▬	▬ ▬ ▬
Caliper				▬ ▬ ▬	▬▬▬
Flow Meter		▬ ▬ ▬	▬ ▬ ▬		▬ ▬ ▬
Casing-Collar Locator					▬ ▬ ▬
Casing-Inspection Log					▬▬▬

▬▬▬ Primary Application

▬ ▬ ▬ Secondary Application

* Porosity, Permeability, Fluids, Etc.

TABLE 4.2 SOME GEOPHYSICAL WELL LOGGING SERVICES AVAILABLE FROM THREE COMPANIES PROVIDING WELL LOGGING SERVICES. EQUIVALENT TYPE LOGS ARE LISTED ON THE SAME LINE ACROSS THE TABLE.

COMPANY		
WELEX	SCHLUMBERGER	DRESSER - ATLAS
Electric Log	Electrical Log	Electrolog
Induction Electric Log	Induction Electrical Log	Induction Electrolog
Dual Induction Guard Log	Dual Induction Laterolog	Dual Induction Focused Log
Guard Log	Laterolog-3, Laterolog-7	Laterolog
Contact Log	Microlog	Minilog
FoRxo Log	Microlaterolog	Micro-Laterolog
	Proximity Log	Proximity Log
Acoustic Velocity Log	Sonic Log	Acoustilog
Compensated Acoustic Velocity Log	BHC Sonic Log	BHC Acoustilog
Fracture Finder Log	Amplitude Log	Fraclog
Micro-Seismogram Log	Variable Density Log	Variable Amplitude Density Log
Density Log	Formation Density Log	Densilog
Compensated Density Log	Compensated Formation Density Log	Compensated Densilog
Simultaneous Gamma Ray-Neutron Log	Gamma Ray-Neutron Log	Gamma Ray-Neutron Log
Side Wall Neutron Log	SNP Neutron Log	Epithermal Sidewall Neutron Log

The resulting resistivity helps to identify rock types (clay, sand, limestone, etc.) and detect the presence of water and hydrocarbons.

Self-potential (SP) can reveal large changes in Total Dissolved Solids (TDS), for example, from fresh water to salt water or brine. It can, under certain conditions, help to confirm conclusions drawn from the resistivity curve. Both curves are useful in locating the depths at which changes in formations occur, and can be used to verify depth measurements and other information reported by the driller.

A more detailed description of electric logging is found in appendix C.

4:8 Radioactivity Logging

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

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

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

4:9 Acoustic Logs

An acoustic-velocity log is a record of the transit time of an acoustic pulse through a fixed length of rock or casing parallel to the borehole between transmitters and receivers in a logging sonde. The chief uses are for determining porosity, identifying fractures, and evaluating the cement bond between the casing and the formations. See Cement Bond Log, appendix C. Some of the more common acoustic logging tools which have received wide use and acceptance in downhole acquisition of data are (1) cement bond, (2) borehole compensated sonic velocity, and (3) the sonic televiewer.

4:10 Temperature Log

Gives a continuous record of temperature immediately surrounding a sensor in the borehole. This log can also be used to detect movement of fluids behind casing and to detect the top of a recently placed cement column.

4:11 Directional Survey

Provides information on borehole slope and direction and establishes bottom-hole location in relation to the surface entry point.

4:12 Caliper Log

Provides a continuous measurement of borehole or casing diameters.

4:13 Fluid-movement Logging

Measures naturally or artificially induced flow within the borehole.

4:14 Casing Collar Locator

Accurately locates well casing collars and perforations in a well.

4:15 Casing Inspection Log

Used to detect pipe corrosion.

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

4:16 Witnessing Wire-line Logging — Procedural Checklist

Obtain construction details of the well. These will include the following:

1. Well name and number

2. Well location

3. Elevation of drill floor, or reference point

4. Hole diameters and depths

5. Casing information

6. Mud characteristics, including type, lost circulation, viscosity, fluid weight, fluid loss, filter cake, and pH

7. Hole conditions, including oversized hole, doglegs, tight spots, and deviation records

Verify that the details on the log headings are correct and that any log faults that would affect log interpretation and that are not rectified at the well site are included in the "Remarks" section.

Check the depth and register of logs. The casing shoe may be used as a reference point. Any disagreement between driller's depth and maximum logging depth should be reconciled immediately.

Verify that the correct speed and time constant are being used. A gap appears in the line at the margin of track one, or once per minute, so logging speed can be checked for consistency and correctness.

Verify that the time constant is recorded in the log heading.

Obtain details of the horizontal and vertical scales to be used. Most logs are run on 1:200 and 1:500 scales.

Tell the operator how many field prints are required.

Check the general character of the logs:

1. Logs should be run on one scale, or a backup should appear

2. Cyclic variations, zero values, and constant readings should arouse suspicion

3. Be suspicious of logs that constantly peak or level out at less than full-scale deflection

4. Look especially for events that demonstrate the range of response of the tool, e.g. high-and low-porosity beds, shales, salts, anhydrite, and washouts

Request details from the logging company on the quality assurance/quality control checks run on the tool prior to beginning the log run.

4:17 Cementing

Primary cementing of injection wells involves pumping a cement slurry down through well casing. Pump pressure forces cement out from the bottom of the casing, and then upward into the annular space outside the casing wall. This is the preferred method of primary cementing. (The practice of dumping cement down this annulus on top of a packer is unacceptable.)

The number of cementing operations and the total length of each cement column varies somewhat by well class (see figure 1.1 for typical examples).

After cement is displaced through the casing, pumps are shut down and cement outside the casing string is allowed to set. Primary cementing restricts fluid movement between downhole formations, and protects and supports the casing. Secondary cementing refers either to remedial attempts to complete an inadequate primary job, or to seal off a particular injection zone without abandoning the entire well. "Squeeze cementing" is a common term for secondary cement jobs that isolate particular zones.

Despite precautions, loss of circulation may end any cement job prematurely. This is usually caused by weak formations ("thief zones") into which a large portion of the cement flows. When cement fails to return to the surface, a temperature log and cement bond log should be run to locate the top of the cement. If the bond log indicates that the injection zone was not safely isolated by the primary cement job, then it will be necessary to perforate the casing and squeeze cement through the perforations to complete the job. Another way is to cement directly into the unfilled annulus through a small work string (sometimes referred to as a tremie pipe); however, this method may be effective to depths of only a few hundred feet.

For more information on the technical aspects of cementing, refer to appendix D.

4:18 Witnessing Primary Cementing - Procedural Checklist

1. Check cement volumes against integrated caliper log if caliper log has been run. Otherwise, be sure the volume to be used is based on gauged hole size, plus a safety factor for hole enlargement. Request several samples of cement for later analysis

2. Check preflush and spacer volumes

3. Check actual number and placement of centralizers against requirements

4. Note if casing is rotated or reciprocated during cementing

5. Observe mud returns during cement displacement to detect return of preflush and cement at the surface (very important). Items to watch for are color change, odor, pH change, increased funnel viscosity, and density (using a pressurized mud balance). Record time and cement volume pumped when cement returns are observed

6. Witness bumping of top plug (moment top plug lands on bottom plug, shutting off flow). Record time, displacement volume and pressure

7. Note if casing is open or closed during "waiting-on-cement" (WOC) time. Holding pressure on the inside of the casing during the WOC period can produce a microannulus at the casing-cement interface.

8. At end of job, run material balance on water and cement used to confirm that cement was mixed as designed

9. Get copy of cement service company's field report from owner/operator at end of job

4:19 Injectivity and Aquifer Testing

Permeability, thickness, and porosity are important aquifer properties upon which groundwater reservoir calculations are based. These hydraulic properties may be determined by means of injectivity and pumping tests. The effects on a reservoir from pumping or injecting at a known rate is measured in the subject well or in other (observation) wells penetrating the reservoir. Graphs of pressure buildup (or drawdown) versus time during pumping or injection operations are used to determine hydraulic properties of a reservoir.

Bottom hole pressure tests are conducted immediately after well completion to establish the initial reservoir pressure before injection operations commence. This may be done with one of various types of downhole pressure instruments which are run on an electric line or wireline. A less accurate method is to measure the depth to the top of the fluid in the well and calculate the hydrostatic pressure at the bottom. If a bottom hole pressure determination is made by the latter method, the wellbore fluid must be of known, uniform density.

Injection or production tests conducted prior to putting a well into operation can provide a fair estimate of formation properties. Because of the transient state of a reservoir during the early part of an injection test, interpretation of test results from short tests may be misleading. Injectivity tests conducted later in the injection operation when steady-state conditions have been achieved are more reliable. Average reservoir pressure, permeability and reservoir volume can be determined from pressure decay or falloff data measured in the shut-in well following steady-state injection.

Injectivity tests should continue for sufficient time to insure that steady-state conditions are approached in the reservoir. The well is then "closed in" for a pressure decay test. Bottom-hole and surface pressure are recorded during the flow and shut-in periods.

4:20 Witnessing Injectivity Tests - Procedural Checklist

Verify that injection (pumping) rate is kept as nearly constant as possible throughout the test. Character of the injected fluid should not change.

Note variations in pressure and flow rates.

Note if there are other pumping or injection operations tapping the same injection zone and close enough to affect test results.

Note time injection starts and when it ends; also note time when test ends.

4:21 Other Preoperational Inspections

Insist on baseline well data in new injection areas. Various reporting forms have been developed and used by EPA for well inventory and database development.

Obtain formation water samples and analyze for common anions, cations, and TDS. For a field of wells completed to similar depths only representative samples should be required.

Obtain a copy of the analysis report if cores are taken from the injection and/or confining zones. For a field of wells completed to similar depths, only representative coring should be required.

Request corrosion data from a representative wastewater sample for Class I well projects.

4:22 Compliance Verification

A set of unique permit conditions is established during the permit application process for each injection well to maintain the integrity of that well and to protect underground sources of drinking water. The owner/operator is required to operate the facility in strict accordance with these permit specifications. Failure to do so constitutes a permit violation and the facility is considered to be in a state of noncompliance. For example, the operator is required to limit the injection pressures strictly to that specified in the permit. Injection of any fluid at a pressure in excess of that authorized by the Agency constitutes a permit violation and the facility is no longer in compliance.

The permit outlines certain monitoring and reporting requirements. Among these is a description of the required monitoring program -- what is to be monitored; how; how often; and with what precision. It may be necessary to detail the installation and maintenance of monitoring equipment. The permit must clearly state the reporting requirements. Reporting and monitoring requirements may vary with well classification. When monitoring forms or reports show permit violations, the regulator should examine facility monitoring records for trends, and should study future reports for further violations and trends. Obvious violations or unfavorable trends call for an investigation by the inspector. The investigation, if it confirms a violation, may require enforcement action.

Compliance inspections resulting from reported violations or the discovery of unfavorable trends will include visual inspection of the facility and review of well records. Sampling of the injected fluid may be included to determine compliance with the permit or well classification.

In the conduct of inspections to verify compliance with UIC permit and/or regulatory requirements, the inspector must ensure that the information is collected in such a manner that it is admissible as evidence in any judicial enforcement action. To ensure this admissibility the inspector must:

Select the inspection target using a neutral administrative scheme. Neutral selection of inspection targets is only required for facilities where the Agency does not have reason to believe that a violation has occurred or is occurring.

Gain admittance to the facility legally. That is, inspect the facility at a reasonable time (generally during normal operating hours) and present the required written inspection notice Section 1445(b)(1) SDWA and appropriate credentials to the person authorized to consent to the inspection.

Examine surface installations for apparent violations of permit conditions. In general, he should look for signs that:

1. The present installation design differs from that shown in the application for permit

2. The facility is not being operated as permitted, for example, injection pressure exceeds that authorized, or rate of injection is greater than that authorized

3. Records of wastes injected show unauthorized fluids are being, or have been, injected

4. There have been leaks or discharges to the surface (to ground surface, pits, ponds, water courses, drainage ditches, etc.)

5. There is rust or corrosion, or lack of general maintenance (lubrication, cleaning, painting)

6. The facilities are not adequately protected from vandalism, fire, accidents, or sabotage

Ensure that samples are representative. All samples must be collected using EPA-approved sampling procedures and containers and preserved according to laboratory recommendations. Quality assurance procedures should be followed in all cases.

Ensure that samples are transported to the laboratory using chain-of-custody procedures (see appendix A). The Agency must be able to document that the samples reached the laboratory within recommended holding times, and without tampering.

Ensure that visual observations, photographs and notes are properly documented. All observations should be recorded in a bound notebook in a clear and concise manner. If information is obtained from employees of the facility, the name and title of the employee should be recorded.

Ensure that all violations are clearly and specifically documented.

If asked to leave, do so. Then telephone the appropriate Regional enforcement attorney for instruction, in accordance with procedures outlined in chapter 3.

The inspector should be aware that field inspection is generally not appropriate as a sole or final Agency response to a violation. Other actions which may be appropriate are included in table 4.3. A number of these responses must be initiated at either the State, Regional or Federal offices and require approval of the appropriate official(s). Examples of situations and their proper responses have been included in appendix E.

4:23 MECHANICAL INTEGRITY (MI) TEST INSPECTIONS

Mechanical integrity (MI) inspections are expected to be a major activity of inspection teams. Several test methods are approved under the UIC regulations to determine injection well integrity. The particular method employed is related to well construction and the detection sensitivity required. Special techniques have been proposed for determining the integrity of certain Class II wells that do not have protection casing. The MI tests described in this chapter are either specified by the EPA (section 146.08) or are available for use as alternative methods upon approval by the Director.

Mechanical integrity test inspections of Class II wells are to be run on a 5-year cycle with priority levels assigned to wells according to Regional guidelines.

4:24 MI Testing Procedures

By current legal definition there are two aspects to mechanical integrity as explained in 40 CFR 146.8. First, an injection well has mechanical integrity if there is no significant leak in the casing, tubing or packer(s) and there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the well bore (§146.8(a)(1) and (2)). The first requirement is referred to as "internal" MI and the second is referred to as "external" MI.

TABLE 4.3

POSSIBLE APPROPRIATE RESPONSES TO VIOLATIONS

A. Telephone call (must have appropriate documentation).

B. Warning letter tailored to individual operator notifying him/her of the nature of the violation and required responses (must include possible criminal/civil liabilities).

C. Field inspection (generally not appropriate as a final response to a violation).

D. Opportunity for consultation ("show cause" meeting) which provides the violator a chance to ask questions of the agency and get information.

E. Formal request for information (may include new information, mechanical integrity test, monitoring, etc. - see §144.27). Note: Owner/operator's failure to respond to this request results in automatic termination of authorization by rule, (§144.27[c]).

F. Request for permit application (§144.27; 144.12[c] or [d]). Note: When §144.27 information request authority is not appropriate, the §144.25 authority can be used to terminate authorization by rule if the permit application is not submitted in a timely fashion, or if the permit is denied.

G. Initiate permit modification, alteration or termination or impose or modify a compliance schedule.

H. Issue Administrative Order to owner or operator of a Class V well requiring such actions as may be necessary to prevent primary drinking water standard violations or to prevent contamination which may otherwise adversely affect the health of persons. (§144.12[c][2]).

I. Commence bond forfeiture or utilize other financial mechanisms to plug the well.

J. §1431 SDWA Administrative Order or, where well is injecting solid or hazardous waste, RCRA, §3008 or §7003 Administrative Order (or where appropriate, a CERCLA §106 Administrative Order).

K. Issue Administrative Order.

L. Referral to State AG/Department of Justice (DOJ) (Civil or Criminal).

4:25 Internal Mechanical Integrity

Internal MI is to be demonstrated, in most wells, by either monitoring pressure in the space between the casing and tubing (the annulus) or by conducting a pressure test with liquid or gas in the annulus and monitoring for pressure losses or gains. This is possible only in wells whose annuli are sealed at the top and at the bottom. Some wells operate with fluid seals instead of a packer. These wells cannot be pressure tested, thus requiring careful monitoring of the annulus pressure at all times. In some areas of the country, alternative procedures for demonstrating internal MI in certain Class II wells may be necessary because of well construction features. Some of these wells have "open hole" completions, that is, are uncased below the surface casing depths. There is, therefore, no closed annular space between the protection casing and the injection tubing which may be pressurized. Methods for testing these Class II wells are discussed in section 4:32. The procedures that follow apply to cased wells with packers and wellhead seals.

4:26 Internal MI (Static Pressure Test)

<u>Determine the weight, in pounds per gallon, of the annulus fluid</u>.

<u>Determine the weight, in pounds per gallon, of the injection fluid</u> (in the tubing).

<u>Ensure that the hydrostatic pressure in the annulus (test procedures) is (1) greater than the formation pressure at all depths and (2) greater than the hydrostatic pressure in the tubing</u>. That is:

$$P_{A/S} + 0.052\ (W_{AF})(D) \quad > \quad 0.433\ (S.G.)\ (D)$$

$$P_{A/S} + 0.052\ (W_{AF})(D) \quad > \quad (0.052)\ (W_{IF})\ (D) + P_{TSI/S}$$

where:

$P_{A/S}$ - annulus pressure at the surface, psi

$P_{TSI/S}$ - tubing pressure, shut-in, at the surface, psi

W_{AF} - weight of annulus fluid, pounds per gallon

W_{IF} - weight of injection fluid, pounds per gallon

D - depth to packer, feet

S.G.* - specific gravity of formation fluid (unitless)

The constant, 0.052, converts pounds per gallon to psi, and 0.433 is the approximate pressure gradient for fresh water that converts feet of fresh water to psi.

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*Specific gravity can be approximated using the total dissolved solids (TDS) content of the fluid. For example, a formation fluid having a 100,000 TDS content has 100,000 mg/l TDS.

This reduces to:

$$100{,}000 \text{ mg}/1{,}000\text{g} = 100\text{g}/1{,}000\text{g}$$

The total weight of the fluid, including the weight of solids, would be:

$$100 \text{ g} + 1000 \text{ g} = 1100 \text{ g}$$

Specific gravity is the weight of a volume of fluid divided by the weight of an equal volume of water:

$$S.G. = 1{,}100\text{g}/1{,}000\text{g} = 1.1$$

For example, if the well has a packer at 3000 feet with a 10 ppg annulus fluid and 8.5 ppg tubing fluid with no surface shut-in pressure and the formation fluid has 100,000 TDS, then the necessary casing pressure must satisfy:

$$P_{A/S} + 0.052(W_{AF})(D) > 0.433(S.G.)(D)$$

$$P_{A/S} + 0.052(10 \text{ ppg})(3000 \text{ ft}) > 0.433 \text{ psi/ft } (1.1)(3000 \text{ ft})$$

$$P_{A/S} + 1560 \text{ psi} > 0.476 \text{ psi/ft } (3000 \text{ ft})$$

$$P_{A/S} + 1560 \text{ psi} > 1428 \text{ psi}$$

and

$$P_{A/S} + 0.052(W_{AF})(D) > 0.052(W_{IF})(D) + P_{TSI/S}$$

$$P_{A/S} + 0.052(10 \text{ ppg})(3000 \text{ ft}) > 0.052(8.5 \text{ ppg})(3000 \text{ ft}) + 0$$

$$P_{A/S} + 1560 \text{ psi} > 1326 \text{ psi}$$

In this example, both conditions are satisfied, as long as $P_{A/S} > 0$, and the test may proceed.

Determine Type of Packer

If the packer in the well is a compression set packer (that is, tubing weight is placed on the packer to effect a seal), then additional annulus pressure will tend to effect a better seal. However, a tension-set packer (tubing tension needed to effect a seal) will tend to unseat itself with increased annulus pressure.

The original tubing tension at the time the well was completed will determine the possibility of unseating. The owner/operator may decide the proposed test pressure is unsafe. If he so decides, then an alternate test procedure is given in the next Section.

Check to be sure the annulus is absolutely full of liquid. Air bubbles will sometimes dissolve in the annulus during testing, causing a change in the shut-in pressure.

Apply the pressure test for 30 minutes. The well can be said to have internal MI if the total change in pressure falls within the acceptable range for that facility as established by the State or Region. Slight pressure decreases may be the result of an air bubble; or perhaps temperatures in the well bore have not stabilized. If the pressure change exceeds the acceptable level, repressure the annulus and monitor again. If, during this second test, the pressure again decreases by an unacceptable amount, a leak is probable.

Initial pressure increases are also possible, but they should not continue. For instance, the heating of the pressure gauge itself by sunlight might cause small errors in readings.

4:27 Internal MI (Dynamic Test) -- Procedural Checklist

Conduct a dynamic test (one conducted while injecting) if the injection well can not be tested statically following the above procedures. The most dependable method for a dynamic test calls for the use of continuous monitoring charts taken over a period of time (usually seven days), and will include a continuous record of tubing injection pressure and casing annulus pressure.

Be aware that continuous monitoring charts will, unfortunately, reflect annulus pressure changes caused by injection pressure changes and injection temperature changes in addition to leaks. These anomalies must be identified and adjusted for to avoid missing possible leaks.

Maintain the annulus pressure so that the hydrostatic pressure in the annulus at any depth is greater than both formation pressure and tubing hydrostatic pressure. (The case where annulus hydrostatic pressure is not greater than tubing hydrostatic pressure will be addressed under Item D, below. The formation pressure at any depth is given by:

$$P_{Fm} = 0.433(S.G.)(D)$$

where: P_{Fm} = formation pressure, psi

S.G. = specific gravity of formation fluid

D = depth, feet

The tubing hydrostatic pressure at depth is given by:

$$P_{TD} = 0.052(W_{IF})(D) - P_{Fr}\frac{(D)}{100} + P_{I/S}$$

where: W_{IF} = weight of injection fluid, ppg

D = depth to packer, feet

P_{Fr} = frictional pressure loss per 100 feet (see figure 4.3), psi

$P_{I/S}$ = surface injection pressure, psi

The annulus hydrostatic pressure at depth is given by:

$$P_{AD} = 0.052(W_{AF})(D) + P_{A/S}$$

where: W_{AF} = weight of annulus fluid
$P_{A/S}$ = surface annulus pressure, psi

For example, if a well has a tubing injection pressure of 1100 psi, a 2 bbls per minute flow rate in a 2-7/8" tubing, a packer at 4000 feet, 10 ppg water annulus fluid and a minimum surface pressure of 600 psi (as recorded on a continuous recording device), then the following conditions exist:

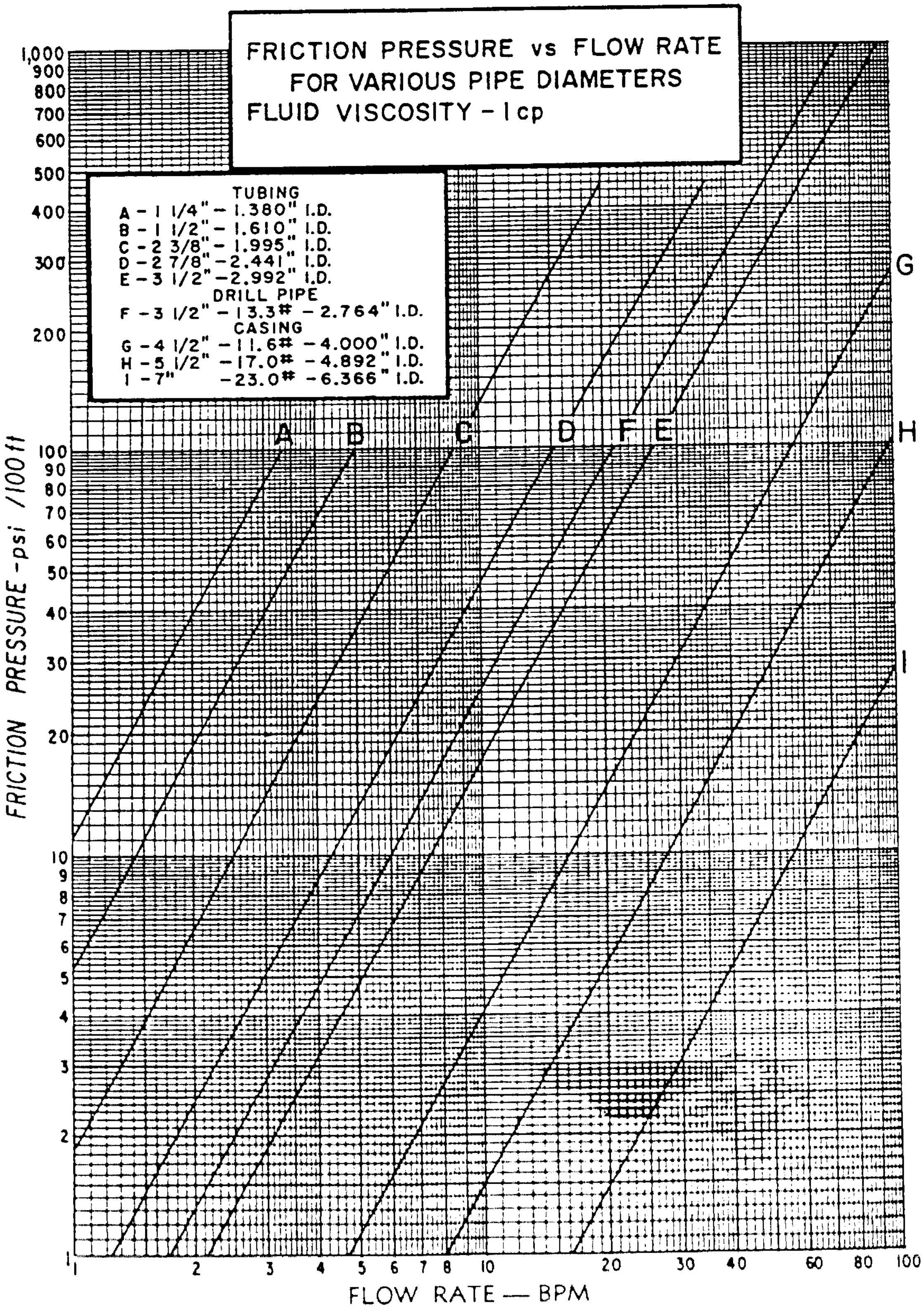


Figure 4.4 Head Loss Chart

Formation Pressure (for a formation fluid with a 100,000 TDS content):

$$P_{FM} = (0.433)(S.G.)(D)$$

$$= (0.433\ psi/ft)(1.1)(4000\ ft)$$

$$= 1905\ psi$$

Frictional pressure drop, P_{FR} (from figure 4.4), is 2.5 psi/100 ft. for 2 bbls/min. so the total over 4000 feet of depth is:

$$P_{FR}\frac{(D)}{100} = (2.5\ psi)\frac{(4000\ ft)}{(100\ \ ft)} = 100\ psi$$

Tubing hydrostatic pressure:

$$P_{TD} = 0.052\ (W_{IF})\ (D) - P_{FR}\frac{(D)}{100} + P_{I/S}$$

$$= 0.052(9\ ppg)(4000\ ft) - 100\ psi + 1100\ psi$$

$$= 2872\ psi$$

Annulus Pressure:

$$P_{AD} = 0.052(W_{AF})(D) + P_{A/S}$$

$$= 0.052(10\ ppg)(4000\ ft) + 600\ psi$$

$$= 2080\ psi + 600\ psi$$

$$= 2680\ psi$$

The above example concludes that the surface annulus pressure is too low to prove MI since the relationship

$$P_{AD} > P_{TD}$$

must be maintained. Approximately 200 psi additional annulus pressure would result in hydrostatic pressures being equal at the packer. Consequently, an additional 200+ psi annulus pressure would be recommended. That is, annulus pressure in excess of 800 psi should be used in the above example to prove MI from continuous monitoring records. If this annulus pressure is unacceptable for any reason, the following alternative test procedures should be considered.

<u>Where annulus hydrostatic pressure does not exceed tubing hydrostatic pressure</u>, the annulus hydrostatic pressure must at least be greater than the formation pressure to be sure there are no casing leaks. That is,

$$P_{A/S} + 0.052(W_{AF})(D) > (0.433)(S.G.)(D)$$

where: $P_{A/S}$ = surface annulus pressure, psi

W_{AF} = annulus fluid weight, ppg

D = depth to packer, feet

$S.G.$ = specific gravity of formation fluid

Once this criterion is met, the tubing can be tested for leaks.

If the tubing hydrostatic pressure is greater than the annulus hydrostatic pressure both at the surface and at the packer, then it is normally greater at every depth.

This would prove the integrity of the tubing since, if a leak did exist, annulus pressure during injection would rise. Therefore:

$$P_{I/S} > P_{A/S}$$

and

$$P_{I/S} + 0.052(W_{IF})(D) - P_{FR}(D)/100 > P_{A/S} + 0.052\,(W_{AF})(D)$$

where: $P_{I/S}$ = surface injection pressure, psi

$P_{A/S}$ = surface annulus pressure, psi

W_{IF} = injection fluid weight, ppg

W_{AF} = annulus fluid weight, ppg

D = depth to packer, feet

P_{FR} = frictional pressure loss per 100 feet (see figure 4.4)

4:27

In the previous example of the well injecting 2 bbls per minute, we see that

$$P_{A/S} + 0.052\ (W_{AF})\ (D) \quad > \quad 0.433\ (S.G.)\ (D)$$

$$P_{A/S} + 0.052\ (10\ ppg)(4000\ ft) > 0.433\ psi/ft\ (1.1)\ (4000\ ft)$$

or

$$600\ psi + 2080\ psi > 1905\ psi$$

That is, the annulus hydrostatic pressure exceeds formation pressure at any depth. Also, looking at the tubing hydrostatic pressure, we have

$$P_{I/S} \quad > \quad P_{A/S}$$

$$1100\ psi > 600\ psi$$

and

$$P_{I/S} + 0.052\ (W_{IF})D - P_{FR}(D)/1000 > P_{A/S} + 0.052\ (W_{AF})D$$

$$1100\ psi + 0.052\ (9\ ppg)\ (4000\ ft) - 2.5\ psi/ft\ (40\ ft)$$

$$> 600\ psi + 0.052\ (10ppg)(4000\ ft)$$

$$1100\ psi + 1872\ psi - 100\ psi > 600\ psi + 2080\ psi$$

$$2872\ psi > 2680\ psi$$

This shows that tubing hydrostatic pressure exceeds casing hydrostatic pressure by approximately 192 psi. A pressure differential of this magnitude is a good indication that no tubing leaks exist.

In case none of the above techniques proves mechanical integrity, another test can be run. Either raising or lowering injection or annulus pressure will set up a new set of conditions. If changing either does not affect the other, MI has been proven.

It should be apparent from the above that MI testing procedures may have to be adjusted to fit particular situations.

4:28 External Mechanical Integrity

4:29 Geophysical Logs

Two geophysical logs have been designated as acceptable under 40 CFR 146.08 to determine the absence of fluid movement behind the casing (external MI). These are the Noise Log and the Temperature Log. Their interpretations, applications and limitations are discussed below. An additional method for proving external MI that may be used in conjunction with the above methods but is not required under 40 CFR 146.08 is the radioactive tracer survey. This method is discussed further in section D.

The Noise Log

The Noise Log is used to determine mechanical integrity of injection wells by measuring and analyzing noise generated downhole by flowing liquids (or gases).

This tool records sound amplitude and frequency levels versus depth to produce a log capable of tracing a channel flow pattern. In addition, the tool is normally capable of discriminating between single phase (all liquids or all gases) and two-phase (liquid and gas) flow. In injection wells the flow will almost always be single phase (liquid).

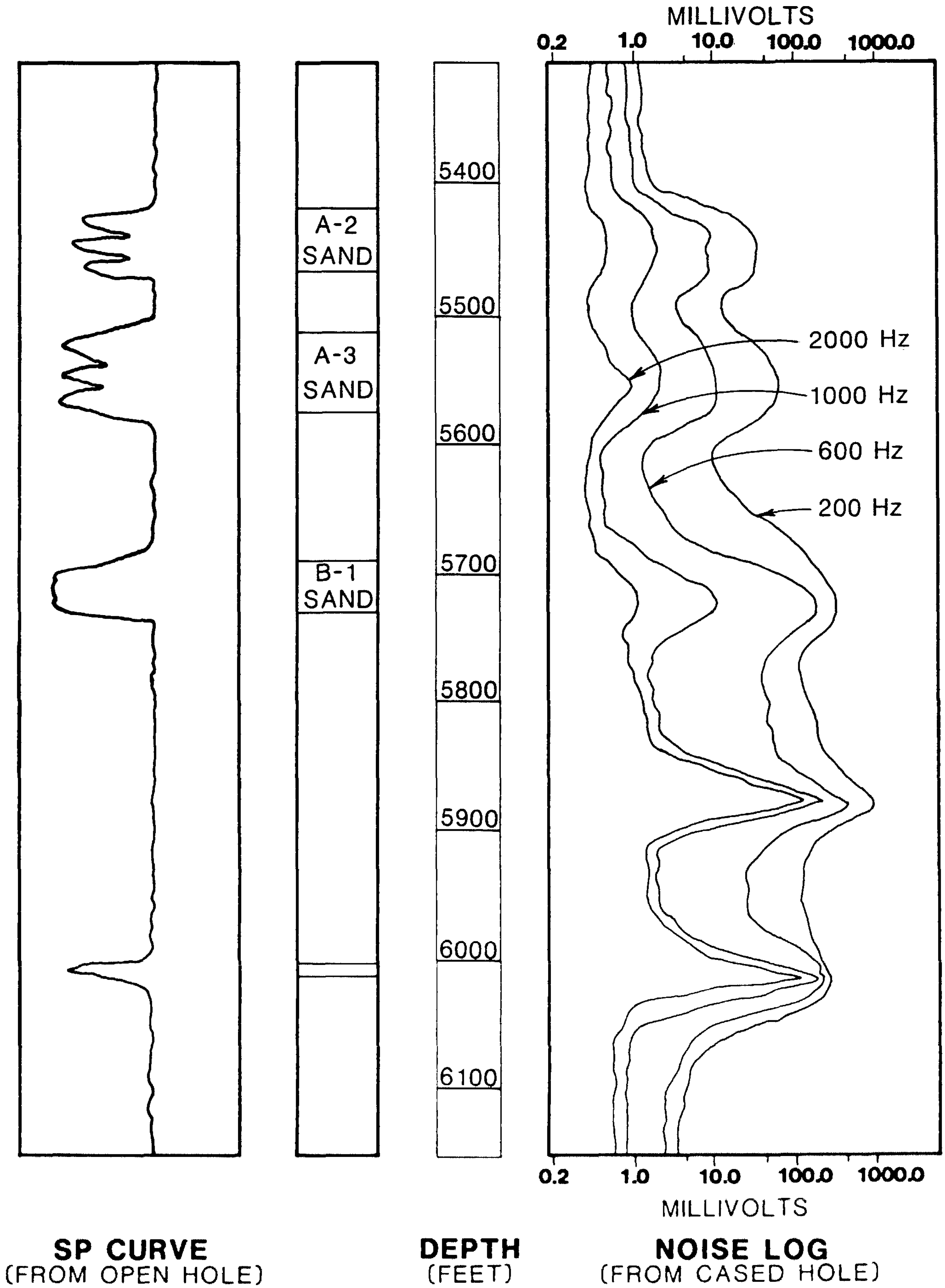
The amplitude profile is a measure of the amount of noise generated by a flow which in turn is proportional to the volume of the flow and the pressure differential acting on the flow. The greatest pressure differential occurs at the point of escape of the flow (i.e., the difference in pressure between the channel and the formation accepting the flow). The Noise Log shows these differences in pressure as peaks.

The frequency range of the Noise Log is about 200 to 6000 Hertz (Hz). It is registered on the log as amplitude at various frequency levels. The frequency levels reflect the pressure differentials described above. The greater the pressure difference, the higher the frequency level.

Figure 4.5 illustrates high-rate channeling in an injection well. High injection pressures are forcing fluid through a cement channel into receptive upper sands (B-1, A-3, A-2). Note also that the 200 Hz amplitude curve varies from a minimum of 4 mv below 6100 feet (the no-leak level) to a maximum of 1000 mv at 5870 feet where there is an apparent obstruction in the channel behind the pipe.

The four traces represent sound intensities (in millivolts) for the four frequencies used - 200 Hz, 600 Hz, 1000 Hz, and 2000 Hz. The 200 Hz curve represents all frequencies 200 Hz and higher, the 600 Hz all frequencies 600 Hz and higher, and so on.

Where the lines come close together (as at 5870 feet and 6800 feet), there is a single phase flow (all gas or all liquid); where the


MILLIVOLTS
0.2
1.0
10.0
100.0
1000.0
5400
5500
5600
5700
5800
5900
6000
6100
A-2
SAND
A-3
SAND
B-1
SAND
2000 Hz
1000 Hz
600 Hz
200 Hz
0.2
1.0
10.0
100.0
1000.0
MILLIVOLTS
SP CURVE
(FROM OPEN HOLE)
DEPTH
(FEET)
NOISE LOG
(FROM CASED HOLE)

4.5 Noise Log

separation is substantial (as at 5800 feet), there would be two-phase (gas and liquid) flow. In most injection wells the single phase flow would, of course, be liquid.

The Temperature Log

Temperature log surveys are used to locate cement tops, tubing or casing leaks, and channeling behind casing. This log measures well temperature variations that are dependent on volumes of materials, rate of fluid movement, temperature differences between the media, and length of time that heat transfer has taken place.

In locating cement column tops, temperature surveys are run approximately 6 to 12 hours after a string of casing has been cemented. During the setting process the cement gives off heat. The temperature log records this heat wherever there is cement column outside the casing (see figure 4.6).

Tubing or casing leaks can be confirmed and pinpointed by temperature logging. Fluid entering or exiting a point in the well should result in a detectable temperature change. The resulting temperature profile is then compared with an assumed or normal temperature gradient for the well. Examples of these types of situations are illustrated in figure 4.7.

To detect channeling behind the casing, static conditions in the well are needed. A flowing well cannot be studied with a temperature log because the log would record only the temperature of the flowing fluid.

Limitations of Noise and Temperature Logs

The Noise and Temperature Logs are potentially useful in all classes of injection wells. However, certain construction details may affect their usefulness:

1. The well must have casing

2. The amplitude of the Noise Log may be affected by different construction materials

3. In many cases, before running either log, the injection tubing must be removed from the well

4. The larger the diameter of the well the less reliable the Temperature Log

5. Temperature Logs may not be very reliable at shallow depths (less than 1000 ft)

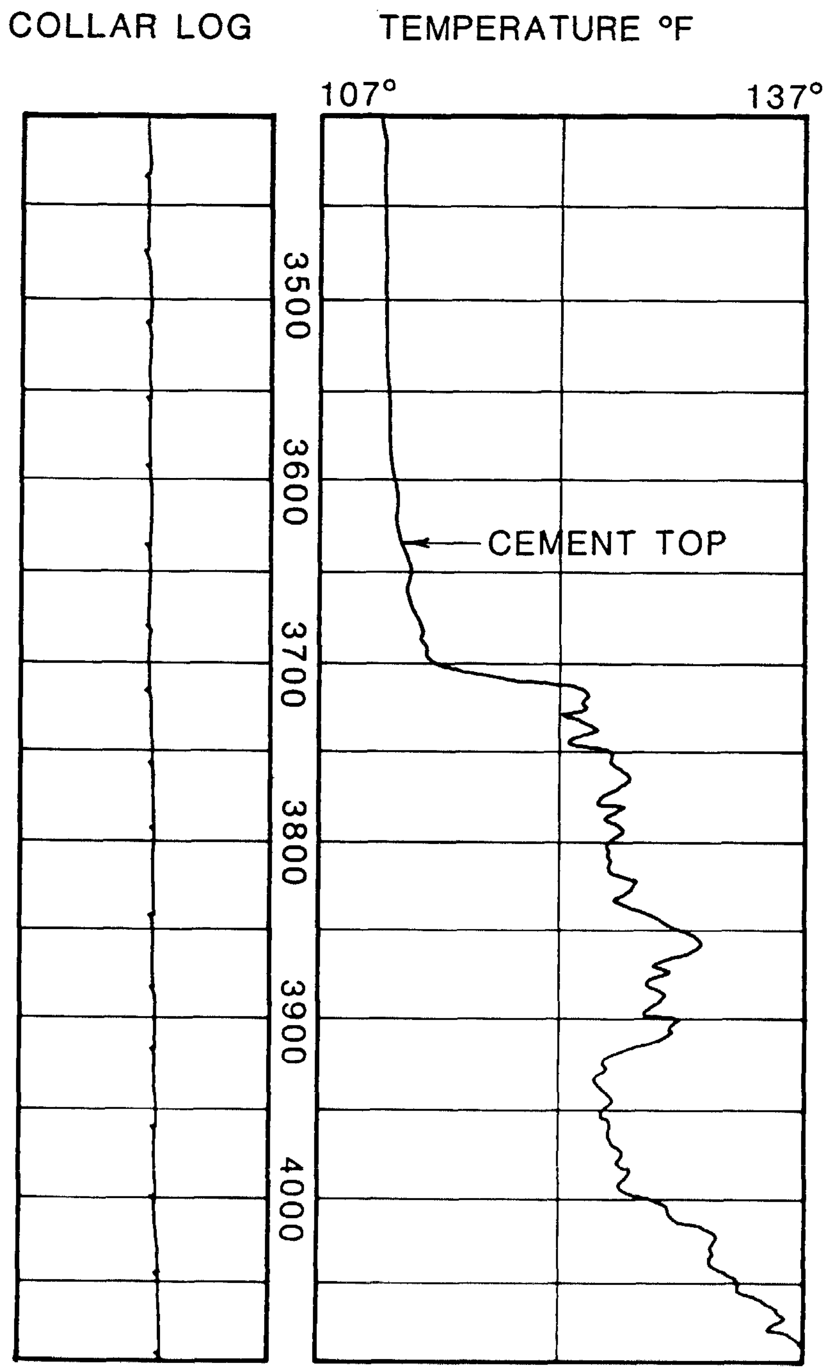
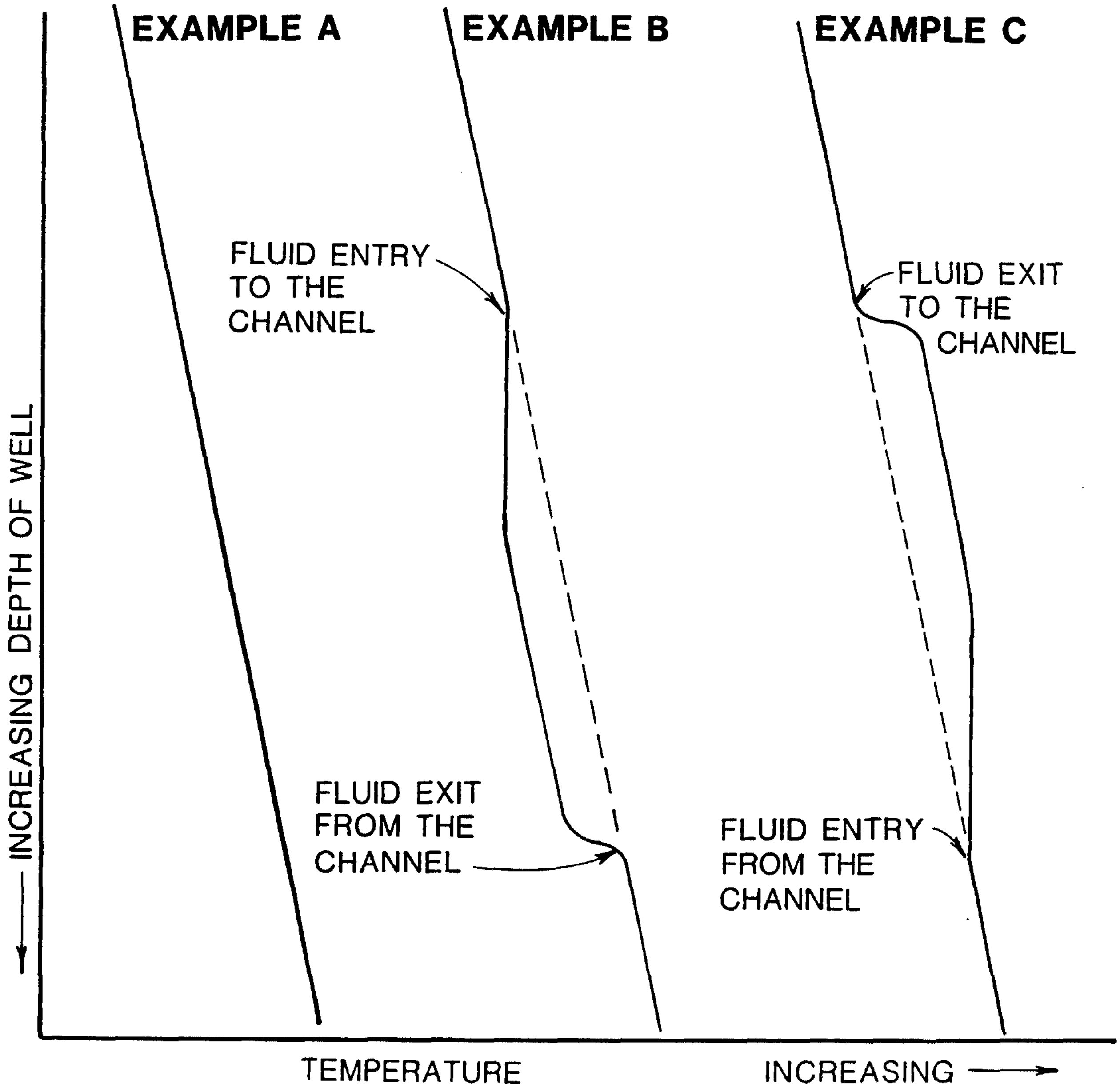


Figure 4.6 Temperature Log Showing Cement Top



EXAMPLE A - NATURAL GEOTHERMAL GRADIENT AS MEASURED IN A STABLE WELL

EXAMPLE B - TEMPERATURE ANOMALY SUPERIMPOSED ON GEOTHERMAL GRADIENT INDICATIVE OF DOWNWARD FLOW THROUGH A CHANNEL BEHIND THE WELL CASING

EXAMPLE C - TEMPERATURE ANOMALY SUPERIMPOSED ON GEOTHERMAL GRADIENT INDICATIVE OF UPWARD FLOW THROUGH A CHANNEL BEHIND THE WELL CASING

Figure 4.7 Temperature Log Showing Fluid Loss

4:30 Application and Interpretation of the Radioactive Tracer Survey (RATS)

In cased injection wells with tubing and packer installed, it is possible to conduct a Radioactive Tracer Survey (RATS) in addition to running a Temperature or Noise Log. The RATS has been approved as an alternative MI test; however, there are limitations on its use described in the Federal Register approval notice (see FR 52, 237, pp 46837-38, December 10, 1987).

The RATS is run using an iodine isotope solution. Radioactive iodine has an 8-day half-life and decays "totally" within 30 days. The survey is carried out as follows: (1) The Gamma Ray tool is run through the tubing, from total depth up past the zone of interest, to get a "background" log; (2) The radioactive solution is introduced into the injection fluid either at the surface or directly from the logging tool, as injection proceeds; (3) the Gamma Ray tool moves through the zone of interest several times in order to "track" the radioactive solution (a) in the tubing; (b) in the wellbore below the packer; (c) into the injection interval; and (d) (if external MI has failed) in the channel outside the casing.

While conducting the Radioactive Tracer Survey, fluid is pumped into the well at a rate slightly above that for normal operating conditions. One repeat run of the Gamma Ray log is obtained over the injection interval and immediately above this section. If no change in Gamma Ray count above the top of the disposal interval is detected, then no external migration of injected fluid is occurring. Specific guidance for running RATS is included in appendix C.

The Radioactive Tracer Log in figure 4.8 indicates a leak in the casing and fluid movement in a channel behind the casing. Note that the log run after injecting radioactive material is superimposed on the base log.

To avoid misinterpretation and possible oversight of conditions indicating a lack of mechanical integrity, all noise, temperature, and radioactive tracer surveys should be analyzed by a qualified individual who has had training and experience in well log interpretation.

4:31 Well Record Evidence of Mechanical Integrity

The external MI of Class II and certain Class III injection wells (see 40 CFR 146.08) may be demonstrated by well records showing the presence of adequate cement to prevent fluid migration. (Note: This method may not be used to prove mechanical integrity in Class I wells. New Class II wells must have either a cement bond log, a temperature log, or an unfocused density log which defines the condition of cement behind the pipe. This is in addition to the information provided by cementing records.)

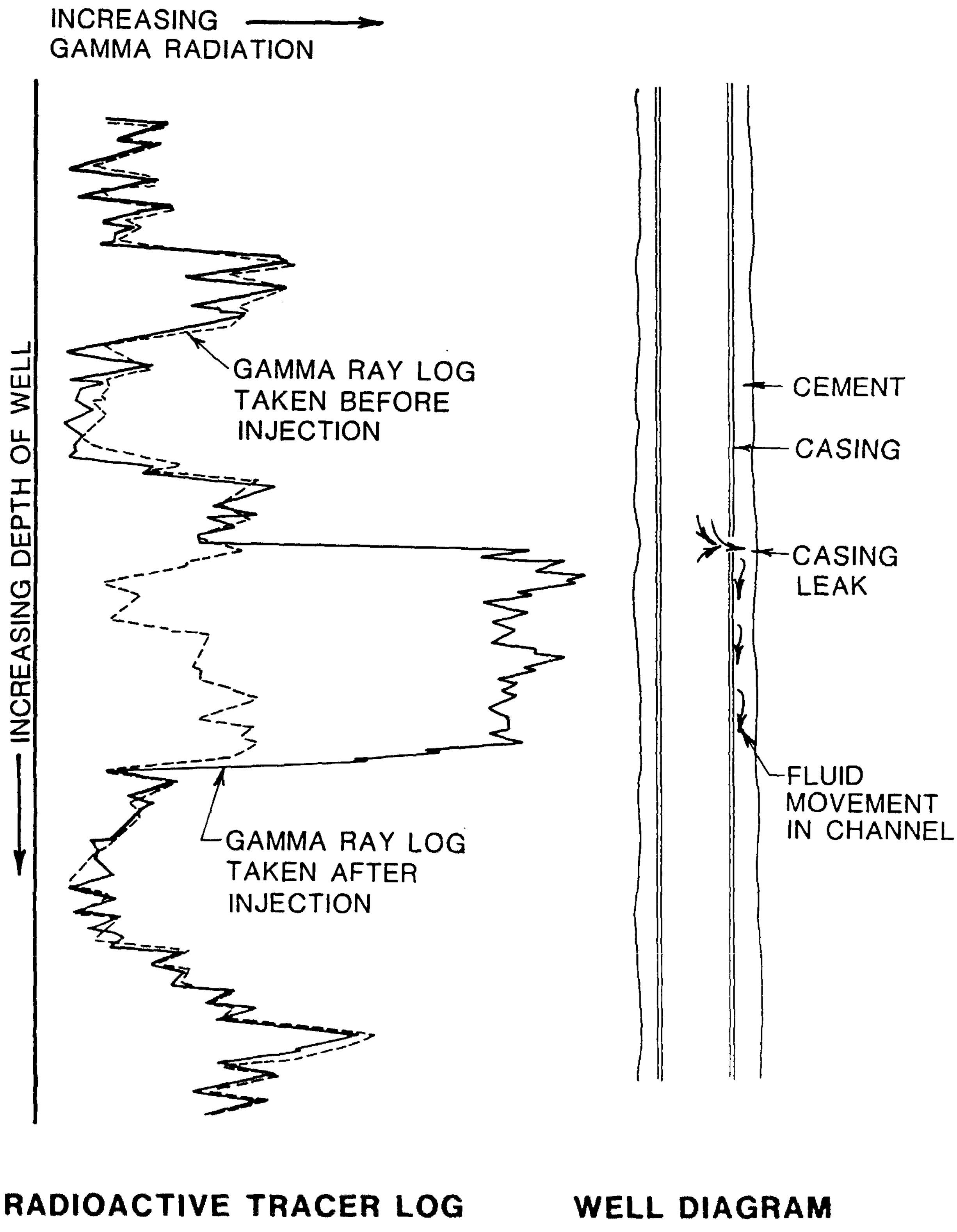


Figure 4.8 Radioactive Tracer Log Showing Fluid Movement

Procedure

1. Determine whether adequate cement exists in the well by comparing the emplaced cement volume with the volume of the space (annulus) between the outer casing and well bore. The annulus volume is calculated from the outside casing diameter and a caliper log reading of the well bore. An adequate cement seal is likely to exist when the injected cement volume exceeds the calculated annular volume by at least 20%.

2. Evaluate cement bond logs and temperature logs as an indication of adequate cement in the well. Owners/operators should keep records of these logs for evidence of mechanical integrity.

3. The cement top in a relatively new shallow well can be located by dropping a weighted line down the annulus space until it contacts a solid barrier.

The internal MI of certain Class II enhanced recovery wells can be demonstrated by the examination of monitoring records. Records of injection well monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate can be used to demonstrate internal mechanical integrity for those Class II wells that are completed without either a packer or long string casing between the surface casing and the injection zone casing.

4:32 Water-in-annulus Test

Limitations on the use of Water-in-annulus Mechanical Integrity Test

Use of the water-in-annulus test is limited to existing Class II enhanced recovery injection wells (existing wells are those wells in operation prior to June 25, 1984):

1. Located in Allegany, Cattaraugus, and Steuben Counties, N.Y. and Elk, Forest, McKean, Potter, Venango, Warren, and Washington Counties, PA

2. Injecting through a tubing string the size of which severely restricts the placement of temporary plugs for pressure testing or logging

3. Constructed without long string casing due to the competent nature of the rock in the uncased interval

4. Constructed with surface casing set through the lowermost underground source of drinking water

5. Constructed and tested with no obstruction in the surface casing to interfere with the test

6. Constructed with tubing and packer cemented into the hole immediately above the injection zone

Procedures for Conducting the Water-in-annulus Mechanical Integrity Test

The water-in-annulus test as approved under the one year interim extension consists of the following procedures:

1. Determine with a verifiable procedure that there are no obstructions in the annulus to at least the depth of the surface casing seat which could interfere with the test

2. Shut the well in at least 24 hours before running the test and bleed off pressure on the injection tubing

3. Measure the injection tubing pressure and the existing water level in the annulus and record the values

4. Fill the annulus between the injection tubing and surface casing to the top of the casing and measure and record the water levels for one-half hour

5. Record the final water level

6. Begin injection into the well and wait for the pressure to stabilize before beginning the second half of the test. Record the stabilized pressure

7. Repeat steps 4 and 5

8. Compare the rate of water level change between shut-in and operating conditions

Test Interpretation

1. The well has mechanical integrity if there is no change in the water level in either shut-in or operating conditions or the rate of change is less than 2 1/2 feet per one-half hour

2. The well does not have mechanical integrity if the water level rises with the well operating, but does not change with the well shut-in

3. The well does not have mechanical integrity if the rate of change is less than 2 1/2 feet per one-half hour and if that rate of change is not equal between shut-in and operating conditions (e.g., if the water level declines 2 1/2 feet during shut-in conditions and 1 1/2 feet during operating conditions, the well fails mechanical integrity). The well must be shut-in until a successful mechanical integrity test demonstration is made

4. The well does not have mechanical integrity if the water level drops at a rate greater than 25 feet in one-half hour or if the annulus could not be filled to the top with water to perform the test. Each of these cases requires that the well be shut-in until a successful mechanical integrity test demonstration is made

5. The test is inconclusive regarding integrity of the surface casing if the water level drops at the same rate under both conditions and the rate of change is between 2 1/2 feet and 25 feet per one-half hour. This result requires one of the following options to be exercised.

Option 1 - Repeat the water-in-annulus test on a quarterly basis to show integrity of the tubing and packer

Option 2 - Show that the water loss is not due to a leak in the surface casing by either plotting the water level rate of fall as it drops through and below the surface casing, thereby indicating the location of the leak, or by pumping the water level down to the base of the surface casing and comparing the rate of fall with the rate of fall with the annulus filled

Option 3 - Repair the well by inserting a liner pipe inside the injection tubing on a packer or by filling the annulus full with cement

Option 4 - Demonstrate mechanical integrity by one of the other methods outlined in Part 146.8

Figures 4.9 and 4.10 are forms that may be used to record results of the water-in-annulus test.

4:33 Manifold Monitoring for Mechanical Integrity Testing

The agency currently contends that injection wells are to be tested for mechanical integrity individually. Available evidence indicates a manifold system is not suited to MI testing, but may be used for routine monitoring in some Class II and III wells.

This method of MI testing involves continuous monitoring of the injectivity of a cluster of wells. Permanent flow rate and pressure recording instruments are set up at a designated number of manifold sites where each manifold supplies a cluster of wells in its area.

Manifold monitoring would at best indicate that one of the methods of mechanical integrity testing described in the preceding sections have to be performed on each well to locate a leak.

Mechanical Integrity Test Results
Water-in-Annulus Test

Company Name ____

Lease Name ____

Well Number/Name ____

Well Shut-In

Date	Casing Sizing	Tubing Size	Shut-in Pressure	Water Level*		Time		Comments
				Start	End	Start	End	

* Measured at ten minute intervals

Figure 4.9

Mechanical Integrity Test Results
Water-in-Annulus Test

Company Name ______________________________

Lease Name ______________________________

Well Number/Name ______________________ Date ____________

Injection Pressure	Water Level		Time		Test Results (P/F)	Comments/ Reasons for Failure
	Start	End	Start	End		

Test Witnessed By

____

Figure 4.10

4:34 PLUGGING AND ABANDONMENT (P&A)

Proper plugging and abandonment of injection wells is essential to the protection of underground sources of drinking water. An inadequately plugged well could serve as a conduit for contaminants. Inspections are conducted both during and after a plugging operation to assure a thorough and careful completion of the task. The inspector should be familiar with the regulations that govern the plugging and abandonment of a well and the technologies that are involved in well plugging. The remainder of this section will discuss the legal and technical aspects of plugging and abandonment.

The Underground Injection Control program includes regulations (40 CFR 146.10) that are implemented to ensure that abandoned injection wells do not allow the movement of fluid either into or between underground sources of drinking water. Specific requirements for the P&A plan, notice of abandonment, and the P&A report are found in 40 CFR 144.28(c), (j) and (k). The owner/operator is required to notify the Regional Administrator of impending plugging and abandonment at least 45 days prior to such activities in EPA-administered programs.

4:35 The P&A Program and Well Classification

The operational status of an injection well should be characterized as one of the following:

1. under construction
2. active
3. temporarily inactive (shut-in)
4. plugged and abandoned
5. abandoned and not properly plugged

The Abandonment Schedule

Current regulations specify that the time between cessation of operations and the actual date of abandonment for Class I, II, and III wells not exceed two years (Sec. 144.28). It may be necessary to abandon an injection well within a determined length of time (less than two years) to avoid the risk of environmental damage. Under certain circumstances EPA will decide whether to abandon a well immediately upon cessation of operations.

4:36 The Objective of P & A

The objective of all plugging and abandonment is to restore, insofar as feasible, the controlling hydrogeological conditions that existed before the well was drilled. USDW's will be protected when internal and external MI have been assured.

4:37 Major Phases in P&A

An abandonment procedure involves two phases: (1) well preparation; and (2) well plugging. In many cases, the well can be entered and inspected to ascertain its condition. Tubing, packer, salvageable casing, and other materials should be removed. Remedial activities such as well cleanout, fishing, milling, or squeeze cementing may be necessary to ensure well integrity and the effective placement of the cement plug(s).

Plugging involves placing cement in a well either over its entire depth or at a series of discrete locations. If a series of plugs is set, a plugging fluid (generally drilling fluid) is left in the well between the plugs. In addition to cement plugs, Class III wells can be plugged with other plugs at the discretion of the Director. Bridge plugs alone are not allowed. A variety of placement techniques is available; they generally involve pumping the cement through drill pipe or tubing. P&A designs are developed by the operator/owner and submitted to the Director for approval.

4:38 Well Abandonment and Plugging

The Influence of Well Construction

Procedures used for proper abandonment of an injection well depend on well construction -- especially the casing and cementing program and the completion method. However, some deficiencies can be overcome in the final preparation for abandonment. In some cases well preparation involves installing a plug inside the tubing near the packer and then cutting the tubing above the cement plug. The four most common well constructions are:

1. Open hole with surface pipe not cemented and no protective casing

2. Open hole with surface pipe partially cemented and no protective casing

3. Open hole with surface pipe cemented to surface and no protective casing

4. Both surface pipe and protective casing cemented

Agricultural and Mineral Reserve Areas

Procedures for agricultural areas may require cutting the conductor casing below plow depth (about 3 feet). Plugs may also be required across potentially commercial mineral reserves (including oil or gas).

4:39 Location of Cement Plugs

In most cases it is not necessary to install continuous plugs. A series of plugs set across or above underground sources of drinking water, across or above potential oil and gas producing zones, at the base of the surface casing, at the surface, and above the packer will be sufficient--provided the plugs are separated by an adequate plugging fluid (see figures 4.11 and 4.12).

Well Preparation

Review the well construction (figures 4.13, 4.14 and 4.15) and determine what changes are required before actually placing plugs. For example, consider a well with insufficient surface casing, i.e., the casing does not extend below the base of the USDW fresh water. A suitable plugging design is that shown in figure 4.14. Study the well diagrams included in appendix G, illustrating some plugging strategies used in Texas. Prior to plugging, decide where sections of casing should be perforated so that the open annulus can be squeezed.

4:40 Corrosion and Mechanical Integrity

Injection well casing and cements are subject to corrosion and degradation by injection fluids and formation fluids. Corrosion of the well casing or degradation of primary cement can make successful P&A difficult. Plugs inside the well casing will serve little purpose if injection fluids or formation fluids are able to migrate through a poorly cemented annular space between the casing and the formation.

4:41 Stress-Induced Damage and Mechanical Integrity

Injection wells are also subject to mechanical stresses -- during installation and operation -- that may result in casing damage and leakage. Deformation of the casing may also occur, interfering with the normal function of tools required in plugging operations.

4:42 P & A for Class III Wells

Unlike Class I and Class II wells, Class III mineral extraction wells may be shallow, and completed in unconsolidated sand and gravel formations; however, if the well is a deep one, the plugging procedure would be the same as that for Class II wells.

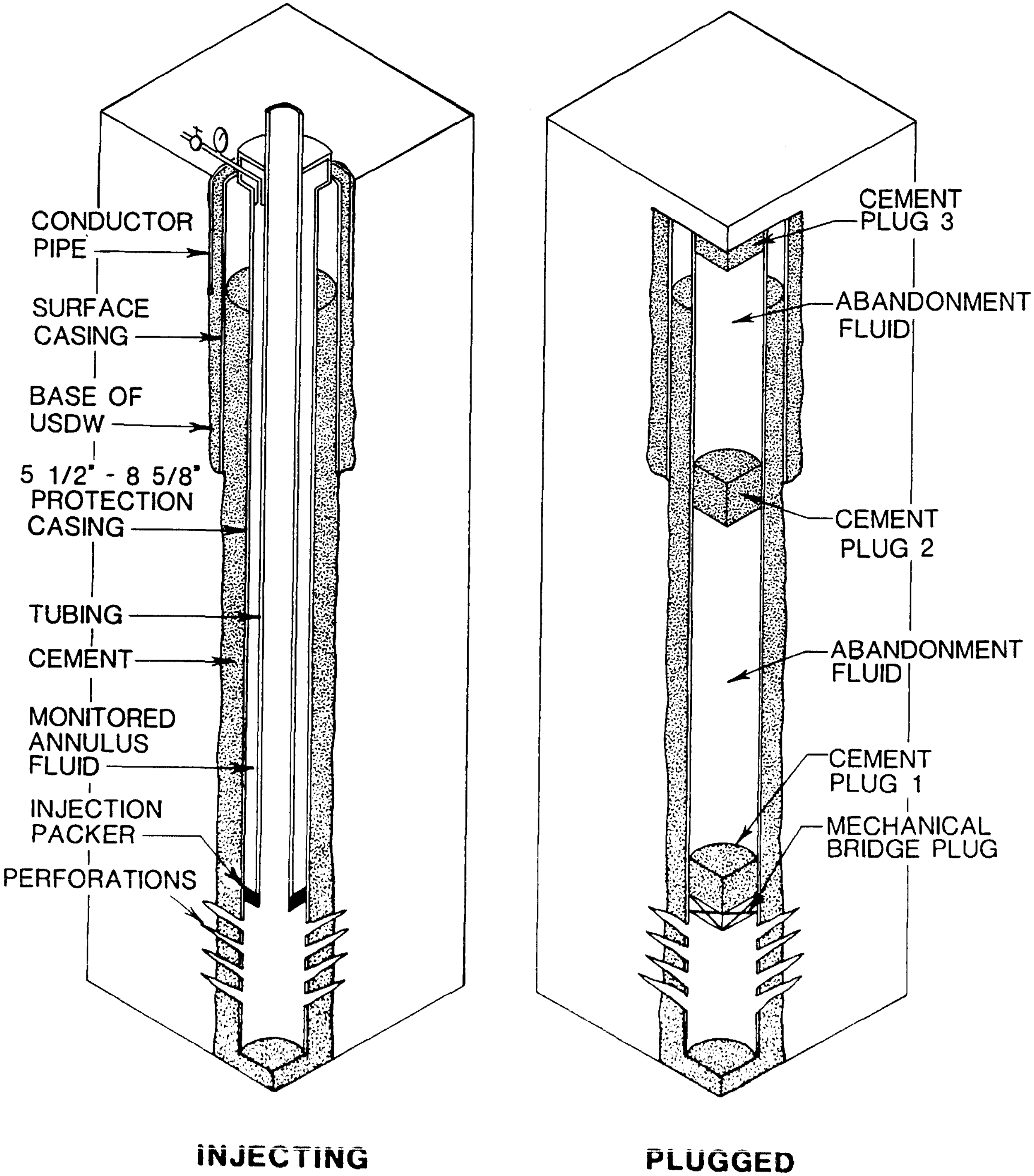


Figure 4.11 Well Plugging - Cased and Cemented Well with Removable Packer

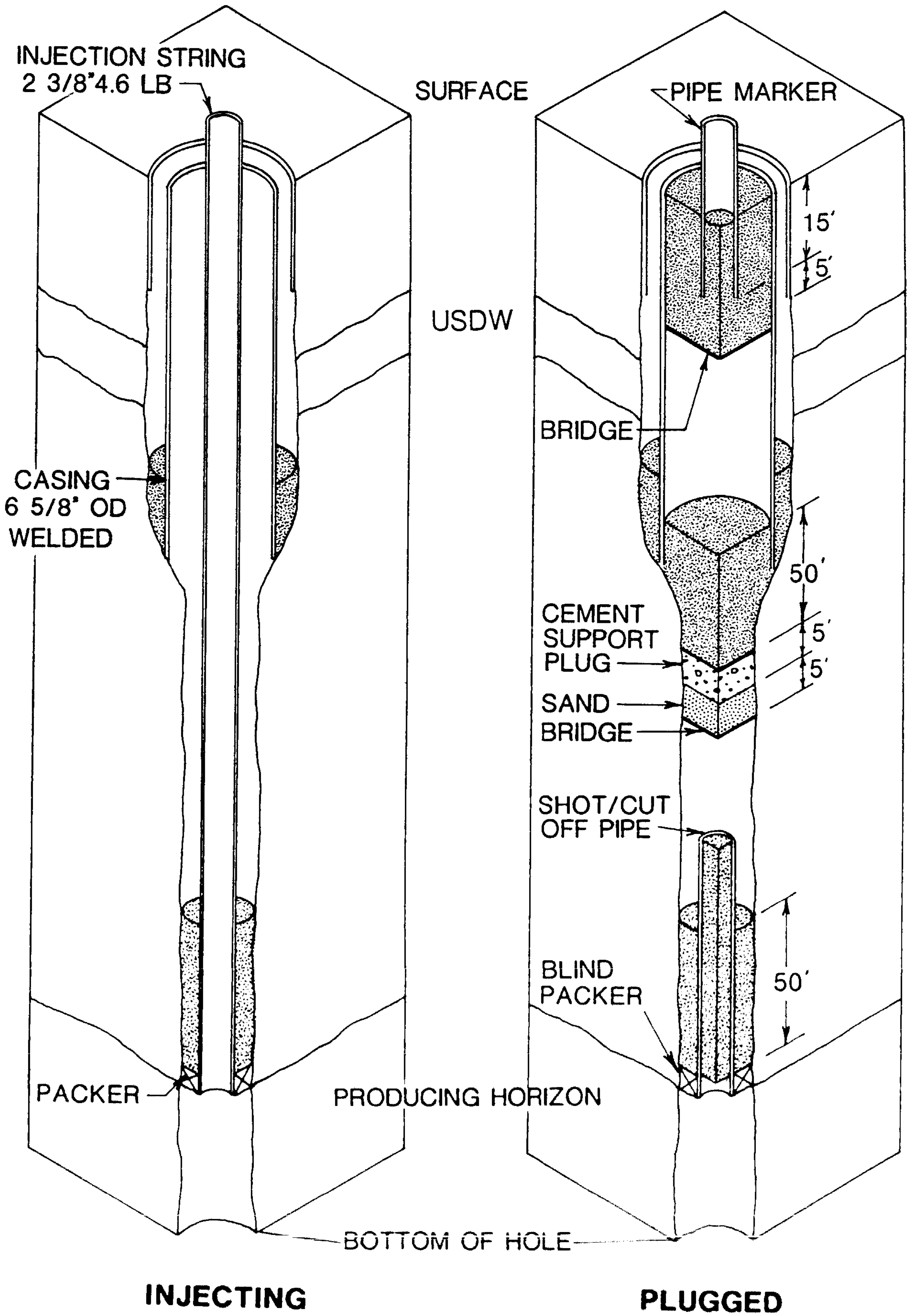


Figure 4.12 Well Plugging - Partially Cased, Partially Cemented Well with Non removable Packer

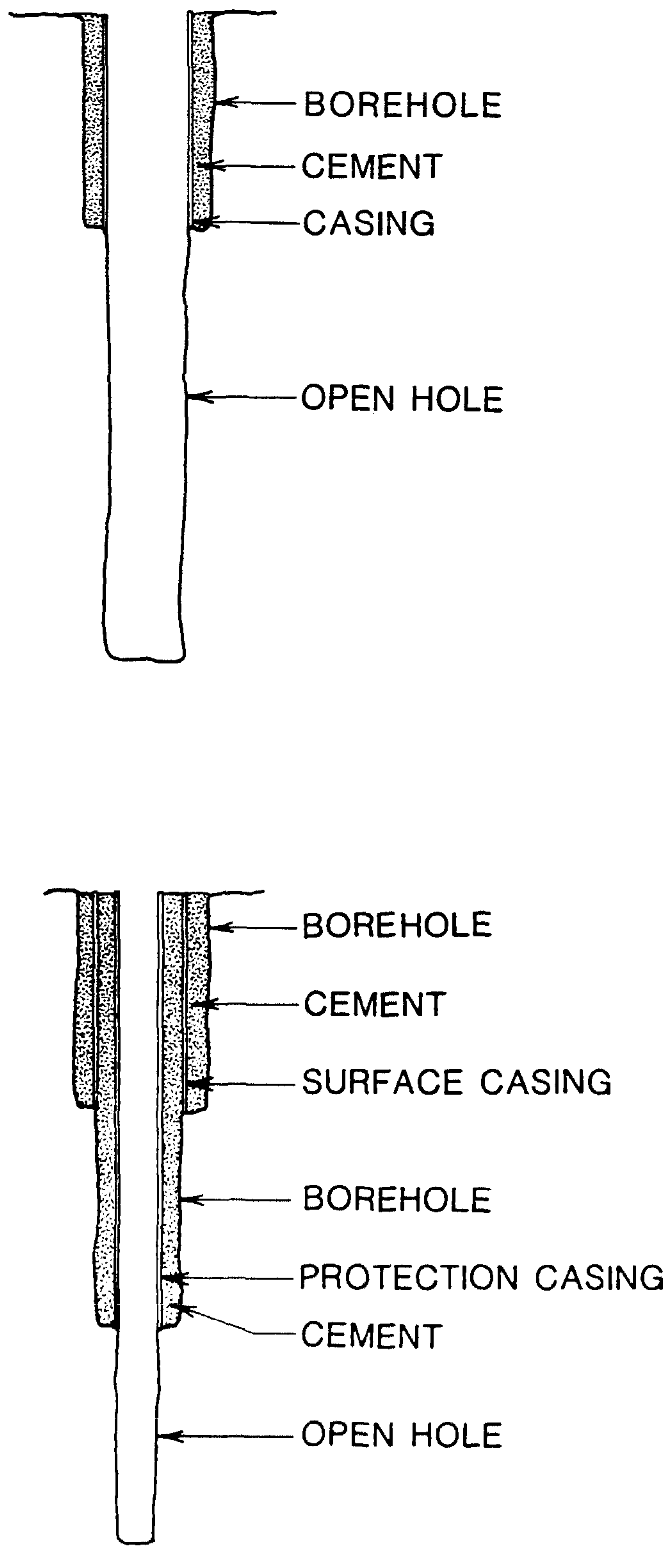


Figure 4.13 Kinds of Open-hole Construction

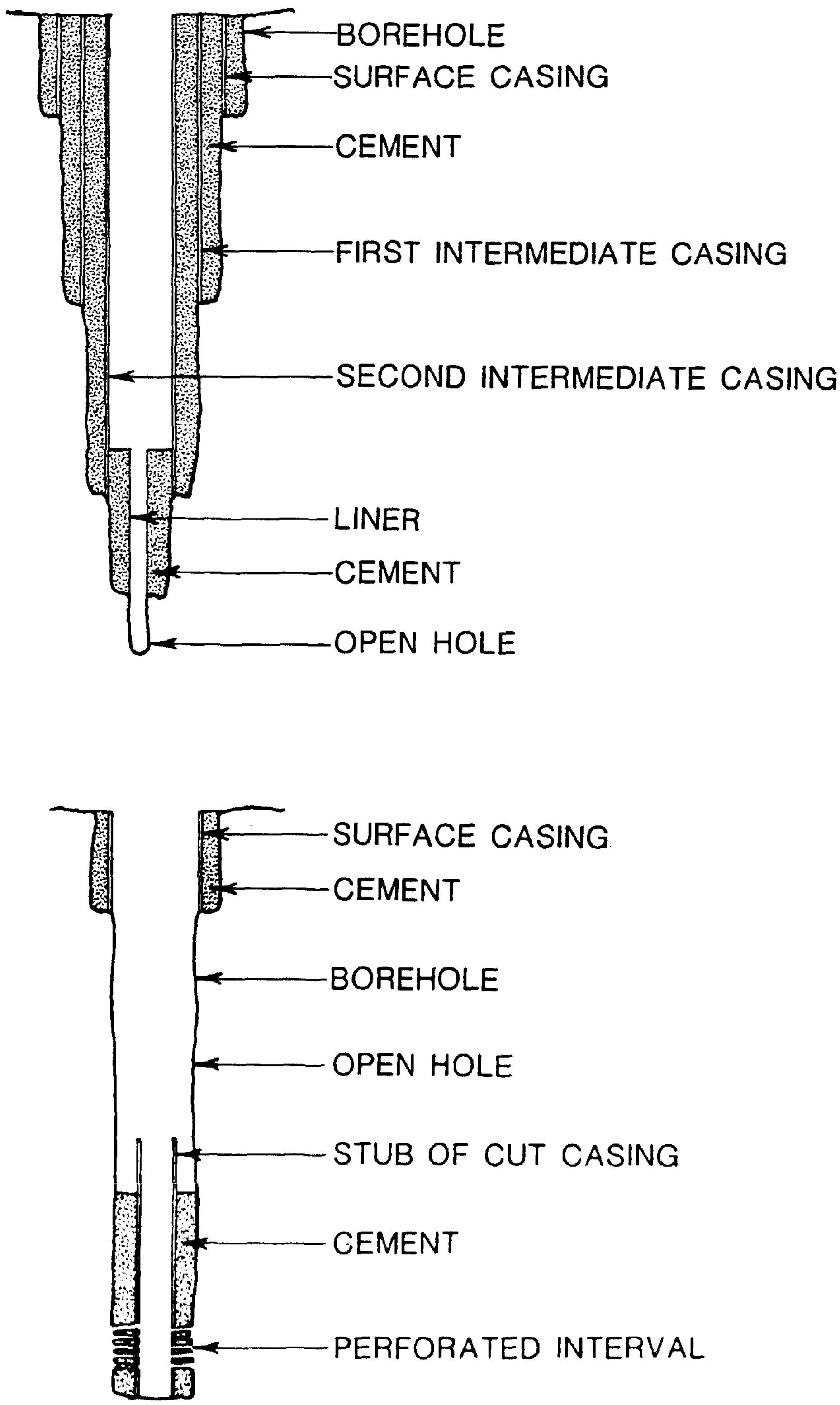


Figure 4.14 Kinds of open-hole construction

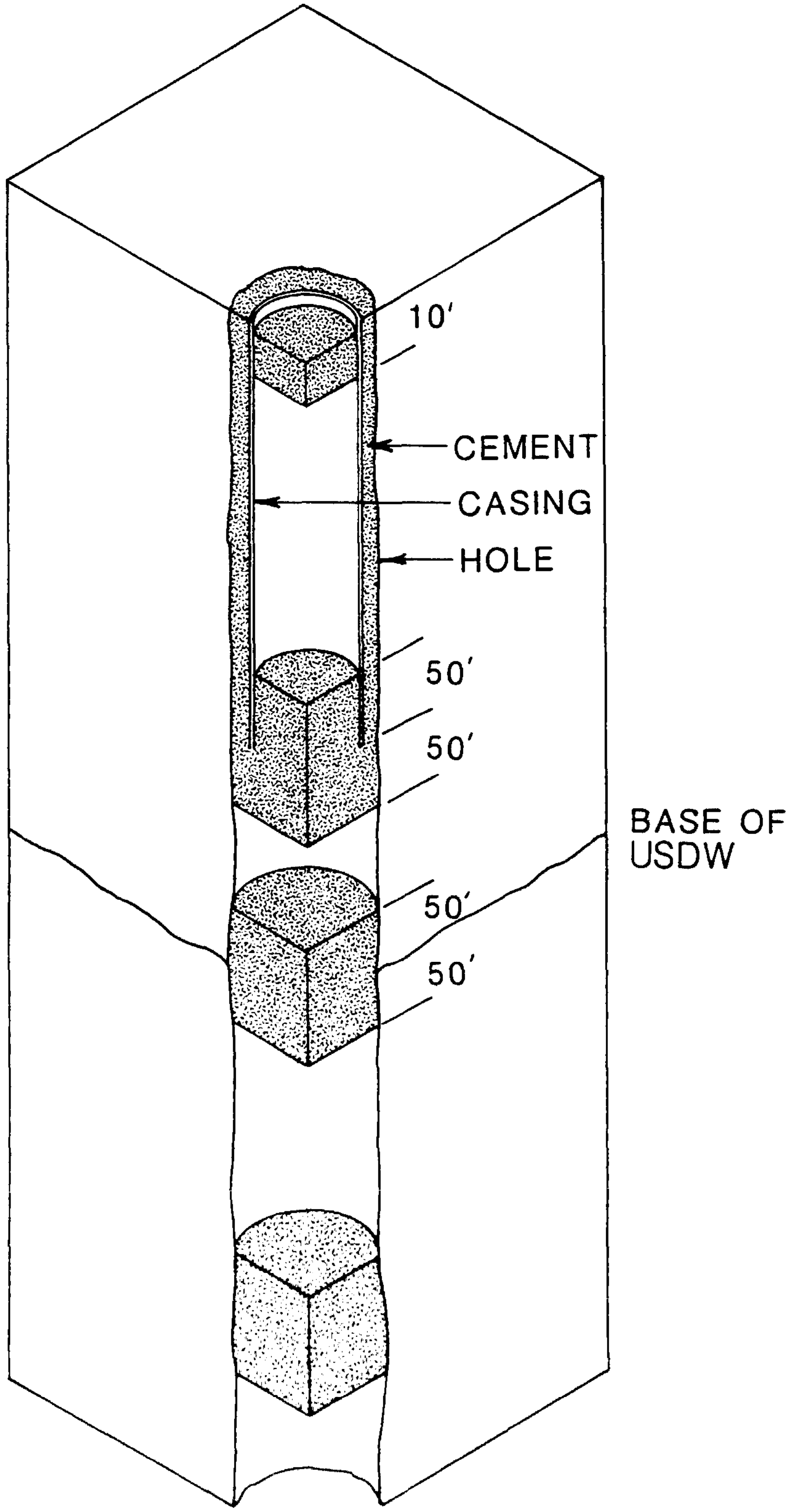


Figure 4.15 Plugging - Well with Insufficient Casing

The relative shallowness and small diameter of Class III wells have resulted in abandonment practices which typically differ in several respects from those of Class I and II wells. Generally, Class III wells are easier and less expensive to cement from bottom to top using no mechanical plug or an inexpensive rubber plug.

4:43 Cement Selection for P & A

Selection of the best cement for a plug will depend on well depth, temperature, character of ambient fluids, and mud properties. Recommended thickening time is "job running time" plus one (1) hour -- at the temperature and pressure conditions for the plug depth. The cement used should develop a high compressive strength and tolerate mud contamination likely to occur during placement.

For example, Class A cement is often used for Class II wells. This cement is intended for use from the surface to a depth of 6000 feet. The recommended water-cement ratio, according to the American Petroleum Institute (API), is 0.46 by weight (5.2 gallons/sack). A wide variety of additives is available to alter the properties (weight, strength, permeability) of the cement and to accelerate or retard its setting time.

4:44 Well Preparation and Plug Installation Procedures

The following is an example of the general procedure used in performing a P&A program:

Move in workover rig and remove tubing

Move in a workover rig of a size and power suited to the well depth and diameter. Next, remove any injection tubing in the well. Where there are tubing and packer, it may be possible to remove both. If not, set a plug inside the tubing, at packer depth; then cut off the tubing just above the packer and remove the tubing from the well.

Clean the hole, if necessary

Subsequent steps depend upon the condition of the casing. If the well casing above the cut-off tubing and packer is in good condition, it is possible to complete abandonment by placing cement plugs at the required locations.

In some cases, it may be necessary to clean out the hole. This operation may be quick and easy, or it may be long and arduous. Proper hole preparation is important to effective sealing.

Achieve static equilibrium

After cleaning the hole, design a mud system and, by circulating it, achieve static equilibrium. Indicators of static equilibrium are the absence of mud movement and the exclusion of fluids that might cause movement. Achieving static equilibrium is important to prevent any contamination, breakup or dilution of the cement that would produce a weak plug. In wells under pressure, the mud can be weighted with additives such as salt, barite, iron oxide or galena; or a blowout preventer can be used to overcome the pressure. With a blowout preventer in place, mud can be circulated to static equilibrium.

Clean the casing or open hole surfaces with rotating scratchers:

The final step in well preparation is to prepare the casing wall or wall of the open hole for cementing. The lower portion of the tubing or drill pipe that is lowered in the hole to set the plug and cement should be equipped with centralizers and rotating wall scratchers. The rotation of the scratchers cleans the bore to improve bonding, allows bypassed mud to mix uniformly with the cement, minimizes the formation of channels in the cement, and reduces mud contamination. This tool may be used with a scouring chemical wash which will flush the sides of the well.

Install Plugs

The circumstances under which static equilibrium of the mud system was achieved will control how the plug is placed. If the mud has been brought to static equilibrium without the use of a blowout preventer, a mechanical bridge plug is lowered very carefully to the desired depth. A small cement plug is then spotted on top of the bridge plug. Additional cement plugs may then be placed at selected intervals, using either the balanced or two plug method.

With a blowout preventer in place, cement plugs can be set through the preventer. After the bottom plug has set up, the pressure in the well can be bled off. If the pressure falls to zero and remains there, the bottom plug is good. The preventer can then be removed and additional plugs set as required.

Common Methods of Plug Installation

Several methods of plug installation are acceptable under the UIC program. Of these, the Balance Method is the most common. The Cement Retainer and Two-plug methods can also be used.

4:45 The Balance Method of Plug Installation

This technique involves setting a cement plug in the bottom of the casing or at some other predetermined point that may be above the bottom of the casing or in the open hole below the casing. The cement slurry is pumped down the drill pipe or tubing and back up to a calculated height that will balance the cement inside and outside the pipe. The pipe is then pulled slowly out of the cement. When the pipe is a considerable distance above the top of the cement, it is cleaned by reverse circulation.

A small-diameter pipe or tubing string is used in order to leave as large an annulus area as possible outside of the cementing pipe. This will allow the cementing pipe to be pulled from the well without causing an excessive drop in the cement or a surge of the cement plug, thereby decreasing the chance of mud contamination.

The mud system must be in static equilibrium, as any fluid movement can cause a poor plug. For a balanced plug job, calculations must be made to determine cement volumes and heights of fluid. An example of the calculations involved is presented in appendix F.

4:46 The Cement Retainer Method

This technique involves the installation of a cement retainer (packer) plug within a cased hole. The cement can be displaced through the cement retainer so that the formations below the retainer can be squeezed with cement. After the cementing of those formations, the cement retainer can be closed at the bottom and the cement pipe disconnected from the top of the retainer. Cement then can be placed on top of the retainer by slowly withdrawing the cement pipe above it.

1. Cement is placed <u>below</u> the retainer, assuring an effective plug upon closing the retainer valve

2. Cement is forced into the formation without subjecting the old casings to high pressure

3. Good control of the cement is maintained

4. Gas percolations from the formations up past the retainer are prevented, allowing the cement to set above the retainer without any gas diffusion

5. The pressure test can be carried out immediately after the retainer is set

This method is one that is highly regarded for placing cement under pressure into a producing formation or injection zone -- through an open borehole, through casing perforations, or through screens.

4:47 The Two-plug Method

This method is used principally in open holes, employing a plug catcher (figure 4.16) mounted on the bottom of a cementing string or drill pipe. A bridge plug is usually first set in the hole at the desired depth

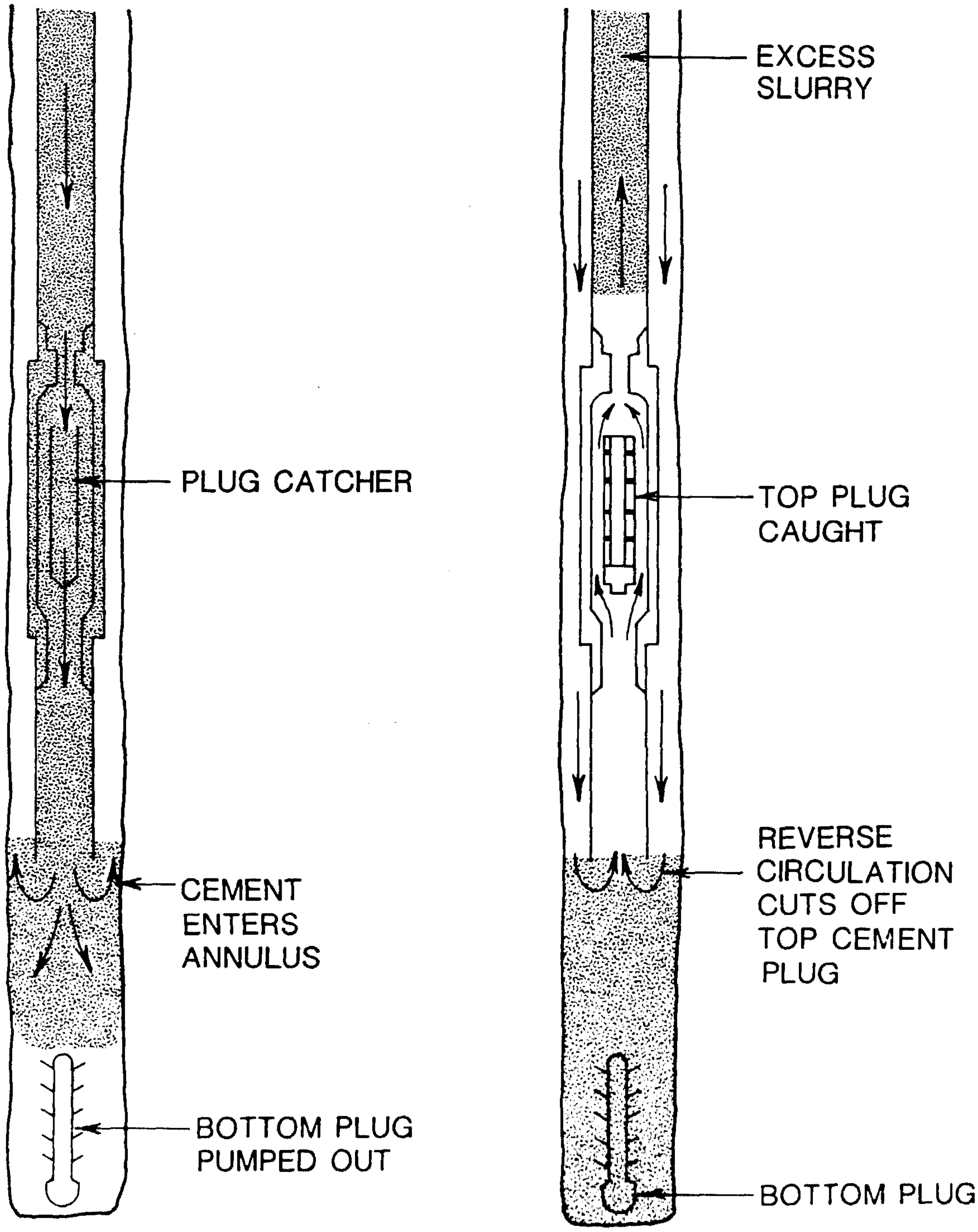


Figure 4.16 Plug-catcher Method of Well Cementing

(bottom of the cement plug). The plug catcher is designed to permit the first of two travelling plugs to pass through, and to catch the second plug -- the one following the cement slurry. When the second plug lands, a sudden rise in cement pressure announces its arrival. A latching device locks the second plug in place and helps to prevent cement from moving back into the string, but still permits reverse circulation of cement and fluids out through the cementing string.

After the cement has been placed, the cementing string is raised so that the top of the plug can be removed ("dressed off") at the desired height by reverse circulation.

Centralizers and scratchers can be installed at the bottom of the cementing string to minimize contamination of the cement and to improve bonding.

Advantages of the Two-Plug Method

1. It minimizes the likelihood of overdisplacing the cement

2. It forms a tight, hard cement

3. It establishes a definite top for the plug

The two-plug method of plugging is preferred to the balance method.

4:48 Dump Bailer Method

This method (figure 4.17) is available for setting plugs in shallow wells. A wireline truck lowers a bailer into the well. Generally, a bridge plug or cement basket is first placed in the hole at the specified depth. The bailer opens upon contact with the bridge plug and releases the cement slurry at this location, as it is raised.

Advantages of the Dump Bailer Method

1. The depth of the cement plug is easily measured

2. The cost is low compared with others that require pumping equipment

Disadvantages of the Dump Bailer Method

1. It is less suited to setting deep plugs

2. Mud can contaminate the cement unless the hole is circulated before dumping (this is also true of the balance method)

3. There is a limit to the quantity of slurry that can be placed per run, and an initial set may be required before the next run can be made

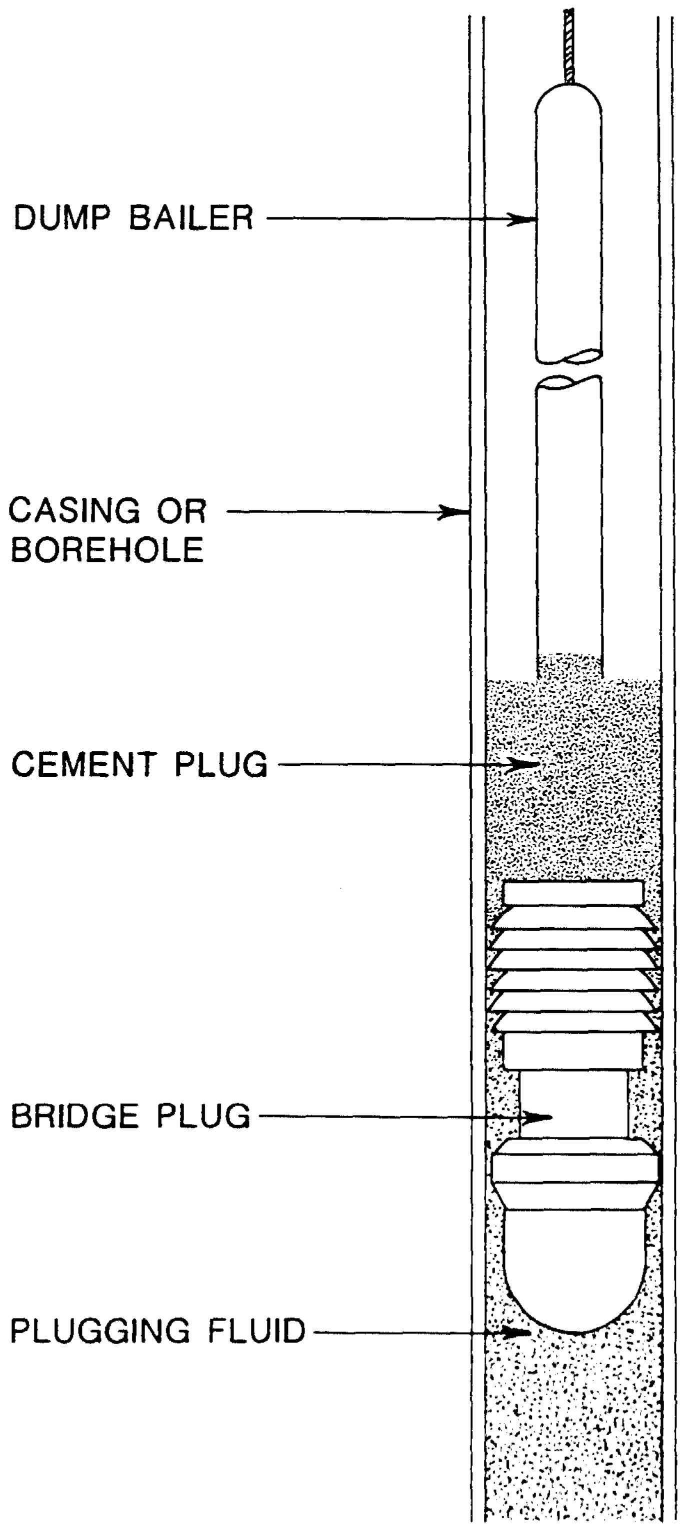


Figure 4.17 Dump Bailer Method of Well Cementing

4:49 Check List for Witnessing P & A

Table 4.4 presents a checklist that should be helpful in witnessing a P&A. If an inspector is available to witness the field procedures, he may visit the site when events 7 through 11 are being completed.

4:50 CLASS IV CLOSURE

Construction or operation of an injection well to dispose of hazardous or radioactive water into or above an underground formation which contains drinking water is prohibited under the Safe Drinking Water Act and under the Hazardous and Solid Waste Amendments (1984) to the Resource Conservation and Recovery Act (1976, Section 7010(a)). The proper closure of Class IV wells is of high priority.

Most Class IV wells differ dramatically in construction from Class I or Class II wells. Some are better described as cesspools or sumps. Some are uncased excavations varying in surface dimensions and ranging in depth from 4 to 20 feet. Others are cased, or partially cased, with large diameter pipe (up to 16") to depths of hundreds of feet.

4:51 Plugging Considerations for Class IV Wells

Because of the varied construction found in Class IV wells, closure procedures must be determined on a case by case basis. Plugging and abandonment of these wells should be witnessed by an EPA inspector.

<u>The Objective</u>

The plugging operation should eliminate vertical movement of water within any annular space that exists, and within the well bore. If artesian conditions prevail, the plugging must confine the water to the aquifer in such a way as to prevent loss of artesian pressure and prevent circulation between two or more aquifers.

When abandoning a Class IV well every effort should be made to restore the geologic and hydrologic conditions that existed before the well was drilled and constructed.

<u>Well Preparation</u>

All materials which may interfere with the sealing operation must be removed. If possible, the casing should be removed. If the casing cannot be removed, it should be torn or perforated to allow the grout to completely fill any annular space, as well as the interior of the casing or bore holes.

TABLE 4.4
CHECK LIST FOR PLUGGING AND ABANDONMENT

EVENT	ACTIVITY
1	Review drilling records and well construction records
2	Review operations history
3	Review regional hydrogeologic data
4	Determine plugging intervals
5	Determine plug height and volume requirements for each plug (refer to Appendix F)
6	Develop preliminary plugging and abandonment plan
7	Provide notice to EPA of intent to plug and abandon
8	Remove tubing, packers, and salvageable casing, as applicable
9	Inspect well casings and primary cement for corrosion breaks and voids
10	Repair and clean out well as necessary
11	Finalize abandonment plan, that is, make any necessary modifications based on results of Events 8 and 9
12	Establish static equilibrium of plugging fluid, if necessary
13	Install bottom plug
14	Allow cement adequate time to set, if necessary
15	Pressure test plug for basic integrity
16	Install intermediate plugs, as needed
17	Repeat events 13 and 14 for each intermediate plug
18	Install top plug, cut off casing 3' below grade, install monument if desired

Plugging Materials

Acceptable plugging materials include cement and, in certain cases, non-permeable clays. If a non-permeable clay is used, it is important that the predominant grain size be very small (diameter less than 1/256 mm), with a very small percentage of particles in the silt- and sand- size ranges. A quick and practical way to test a clayey material for significant amounts of silt or sand, is to rub the material vigorously in the palm of the hand. A gritty feeling indicates the presence of larger particles.

Cement is an excellent plugging material for Class IV wells. The cement should be used alone, without any sand or gravel. The use of concrete mix for well plugging is discouraged because, when the mix is placed in water, the coarser sand and gravel materials separate from the mix and settle to the bottom, forming a permeable zone in the plug.

Plug Placement

Regardless of the type of material that is used to plug a well, care must be taken to completely fill the well bore. The easiest way to accomplish this is to mix the material with water to the consistency of a heavy slurry. The material should be introduced into the well at the bottom, or at the bottom of the interval to be sealed (or filled), and placed progressively upward.

In preparing a plugging slurry the mixture should be brought to a weight of about 15 pounds per gallon. Table 4.5 can be used as a guide in determining the amount of material required to fill most round boreholes of nominal size. Let us suppose that a well 6 inches in diameter and 250 feet deep is to be plugged. On the 6 inch diameter line of table 4.5 we find that the volume of each linear foot is 0.196 cubic foot and that each linear foot has a capacity of 1.47 gallons. Thus, for the 250 foot well, the volume is 49.0 cubic feet (0.196 x 250), or a total capacity of 367.5 gallons (1.47 x 250). If this well were to be filled with cement, we find that each liner foot would require 0.18 sack of cement, or a total of 45 sacks (0.18 x 250) of cement to completely fill the well.

All sealing materials should be placed by grout pipe, tremie pipe, cement bucket or dump bailer in such a way as to avoid segregation or dilution of the sealing materials.

If the well is very shallow and surface dimensions are large, backfilling with clay using earth moving equipment may be acceptable. This type of plugging and abandonment would be similar to closure of an unlined pond.

TABLE 4.5
CAPACITY OF HOLE

Diameter of Hole (inches)	Volume per Lin. Ft. (cu.ft.)	Capacity per Lin.Ft. (gals.)	Sacks Cement per Lin. Ft.*	Lin. Ft. Per Sacks Cement
2	0.022	0.16	0.02	50.25
2.5	0.034	0.25	0.03	32.15
3	0.049	0.37	0.04	22.52
3.5	0.067	0.50	0.06	16.47
4	0.087	0.65	0.08	12.64
4.5	0.117	0.88	0.11	9.94
5	0.136	1.02	0.12	8.06
5.5	0.165	1.23	0.15	6.67
6	0.196	1.47	0.18	5.60
6.5	0.230	1.72	0.21	4.77
7	0.267	2.00	0.24	4.12
7.5	0.307	2.30	0.28	3.59
8	0.349	2.61	0.32	3.15
8.5	0.394	2.95	0.36	2.79
9	0.442	3.31	0.40	2.49
9.5	0.492	3.68	0.45	2.23
10	0.545	4.08	0.50	2.02
10.5	0.601	4.50	0.55	1.83
11	0.650	4.94	0.60	1.67
11.5	0.721	5.39	0.66	1.53
12	0.785	5.87	0.71	1.40
12.5	0.852	6.37	0.77	1.29
13	0.922	6.90	0.84	1.19
13.5	0.994	7.44	0.90	1.11
14	1.069	8.00	0.97	1.03
15	1.227	9.18	1.12	0.90
16	1.396	10.44	1.27	0.79
17	1.576	11.80	1.43	0.70
18	1.766	13.21	1.61	0.62
19	1.969	14.73	1.79	0.56
20	2.182	15.95	1.98	0.50
22	2.640	19.75	2.40	0.42
24	3.142	23.50	2.86	0.35
26	3.687	27.58	3.36	0.30
28	4.276	31.99	3.89	0.26
30	4.909	36.72	4.46	0.22
36	7.069	52.88	6.43	0.16

*Cement calculations based on the volume of an average cement mixture being 1.1 cubic feet per sack of cement.

If a clay slurry is used for plugging, at least the upper few feet of the well should be filled with cement. This will help to prevent thinning of the mud slurry by surface water and provide a solid upper surface.

Upper Well Terminus

Cut the casing off below grade if the well is located in an area where cultivation or construction is probable. This could be done before plugging begins. With the recommended cement plug in place, fill material can then be placed over the well.

4:52 EMERGENCY INSPECTIONS

An inspector must be prepared to conduct a facility inspection when an emergency situation arises. An emergency situation includes any situation that poses an imminent and substantial threat to the health of persons or danger to the environment. The operator may wish to perform a workover, convert the well(s), revise permit conditions, drill a new well or conduct an environmental cleanup. These actions require the issuance of a temporary emergency permit. Inspectors have no authority to issue permits -- written or verbal. Permits can only be issued, modified, suspended or canceled by the Director of the UIC Program or his delegate.

Before a temporary permit is issued, it is important for the inspector to ascertain whether an emergency condition actually exists and that the situation is not the result of improper planning and/or noncompliance. In addition, the proposed action(s) must be carefully examined to assure that they will not result in movement of fluid into underground sources of drinking water. It should be emphasized that any permit issued to correct an emergency situation is temporary in nature and that the term of the permit shall not exceed the time necessary to prevent or correct the hazard.

After a temporary permit has been issued, the owner/operator must adhere to the permit conditions while the proposed action is being performed. When evaluating the facility to verify the validity of the emergency or when conducting an inspection while the proposed action is being carried out, the inspector should keep a detailed inspection record and should follow all applicable protocols as they are outlined elsewhere in this guidance.

4:53 CITIZEN COMPLAINT INVESTIGATION

A complaint of either noncompliance or groundwater contamination which has been registered by a citizen, or citizens group, against an injection well facility requires a response from the Agency. One possible response is a site investigation of the facility. In some cases, the inspector may have to inspect other wells in the area. Sampling of injected fluid(s), water wells, and/or surface seeps may be required.

4:53

The inspector should follow the procedures outlined for compliance and general inspections (chapter 2 and sections 2:15 and 2:20) with appropriate modifications included to allow verification of the citizen's specific complaint(s).

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5 Field Safety

The UIC inspector is required to visit many different types of injection sites operating under constantly changing conditions. Heavy machinery and tools are used to perform most injection well construction and servicing, and many times adverse weather and hostile environmental conditions exist. Fortunately direct exposure to hazardous situations is minimal for an inspector. Safety in the highly competitive well drilling field is, however, often sacrificed for speed; it then becomes the individual's responsibility to protect himself. One cannot always rely on the well operator or his contractors to specify what equipment and precautions are required.

5:1 Personal Protective Equipment

In general, certain personal protective equipment is always required in the field. This includes head, eye, and foot protection. Where special circumstances warrant, hand and hearing protection may also be needed. Breathing equipment will be needed by the UIC field inspector when respiratory hazards are present. Respiratory hazards are characterized by either contaminated atmospheres or oxygen-deficient atmospheres.

Head Protection

1. An approved helmet (safety hard hat) is required to be worn by all inspectors while within a control area, with the exception of self-contained areas such as truck cabs and field offices

2. A helmet to protect the head from limited electric shock and burn should comply with requirements and specifications set forth in American National Standards Safety Requirements for Industrial Head Protection, Z89.1 - 1969. (Class A helmets are recommended)

3. Employees should inspect and maintain liners in helmets to comply with standards and they should be worn properly

4. Helmets should not be modified in any manner

Eye and Face Protection

Safety glasses must be worn at all times during field inspections, and must meet the ANSI Eye Protection Standard Z87.1 - 1979.

Foot Protection

1. Safety shoes or safety boots are required for all field inspections

2. Safety-toe footwear must meet the requirements and specifications in American National Standard for Safety-Toewear, Z41.1 - 1967, and must be properly maintained

General Protective Equipment

1. Unreasonably loose, poorly fitted or torn clothing should not be worn

2. Hazardous jewelry, such as finger rings, chain bracelets, etc., should not be worn. This is not intended to include wrist watches equipped with bands which will easily break

3. When conditions warrant, typically during drilling and workovers, gloves and hearing protectors should be worn

4. Long hair that may become entangled in moving or rotating machinery should be contained in a suitable manner. Beards and sideburns should be kept in such condition and of such length so as not to interfere with the proper and efficient use of gas masks, air masks, or other safety apparel or equipment. Any facial hair lying between the sealing surface of a respirator facepiece and the wearer's skin that will prevent a good seal shall not be allowed

5:2 Suggested Personal Protective Equipment Specifications

The following provides information on features needed in all types of personal protective equipment used in drilling and well servicing operations (API, 1981). This equipment is not needed or necessary in all circumstances, but, if in your own judgment such equipment is necessary, the following description may prove helpful.

Head Protection

1. Field personnel should use high density polyethylene hats. The shell should have three major features:

o A rain trough to prevent water from running down the back of the neck

o Structured ribs molded into the crown to assure maximum strength and rigidity

o A flat facade to accomodate hot stamping of EPA identification. The Hard Hat should weigh 13 ounces and have adjustable headband and four-point suspension

2. Winter liners, which are universally sized and designed to fit under most brands of safety caps or hats, should cover the back of the neck and be flame retardant

   The liner should fold up, out of the way, on the outside of the cap or hat when not in use

Eye Protection Equipment

1. Eye protection must meet the requirements of American National Standard Z87.1-1979, each lens having been subjected to a rigorous drop-ball test before leaving the factory

   Lenses that should be accepted are as follows:

- o True Color--neutral grey lenses primarily used as anti-glare lenses outdoors
- o Clear--to be used indoors and outdoors
- o Calobar--green lenses designed to be worn as a safeguard against glare, ultraviolet and infrared radiators

2. All eye protection should use side shields made of 24 or 40 wire mesh with plastic binding and reinforcing brace bar, to provide maximum lateral protection

3. Cover goggles should have four slotted air vents (or air directing baffles) to control air flow and prevent inner fogging, meeting the requirements of ANSI X871-1979 for eye protection devices and having lenses of a molded polycarbonate material, ophthalmically correct and free of distortion and aberrations

Hearing Protection

1. Muff-type hearing protectors should be lightweight, rotational units that can be worn over the head, behind the head, or under the chin and should have been tested in accordance with ANSI Z24.22-1957

2. Self-adjusting hearing protectors should be lightweight, easy-to-wear, properly fitted, disposable and individually wrapped, with attenuation tested in accordance with ANSI Z24.22-1957

3. Self-fitting in-the-ear hearing protectors, attached to a vinyl-covered stainless steel headband that is designed to be worn over the head, under the chin or behind the head, should be non-toxic, non-allergenic high tear strength silicone rubber, with attenuation tested in accordance with ANSI S-3.19, 1975

Hand Protection

1. General Purpose:

- o Determine the physical conditions to which the glove will be subjected (cutting, puncturing, abrasion, etc.)

- Consider the glove features required to perform the work (dexterity, protection, grip, etc.)

- Choose the style which provides the best combination of features and resistance to physical conditions

2. Specific Use Requirements:

- Choose glove types with highest ratings for the chemical and physical conditions involved, using two sets of gloves with the outer set appropriate to the types of fluids involved

- Select unsupported gloves for extra dexterity and sense of touch, picking a fabric-lined style if cut, snag, puncture or abrasion resistance are important

- Select an appropriate palm finish to provide the grip needed for the job-- smooth, sprayed, dipped or embossed (sprayed and dipped finishes grip best when wet)

- Choose glove length according to depth to which arm will be immersed, and to protect against chemical splash

- Select thin-gauge gloves for jobs demanding sensitivity and high flexibility, choosing a heavy duty style, particularly in dealing with organic solvents, if greater protection or durability is wanted

- Choose the glove size or sizes that will assure optimum wear, dexterity, working ease, comfort and employee satisfaction

3. Comprehensive Protection:

Determine the degree of glove toughness, sheerness, fit, sensitivity and disposability required and then select the glove which provides those benefits in order of their importance

5:3 Other General Considerations for Personal Safety

Protective Clothing and Injury

Wearing special protective clothing can reduce an individual's hearing, vision and agility and greatly increase the chance of injury by drilling tools, equipment and vehicles.

Eating, Drinking, Smoking

Personnel must not eat, drink, chew gum or tobacco, smoke, take medicines or perform any other practice that might increase hand to mouth transfer of toxic materials from gloves, unwashed hands or equipment.

Mustaches, Beards

If respirators are required, personnel should not have excessive facial hair (heavy mustaches, beards) which can prevent the proper fit of respirators.

Inspector's Vehicle

The inspector's vehicle should be parked well clear of the control area with keys left inside so that it may be moved in the event of an emergency situation.

5:4 Hazards Related to Injection Well Operations

The UIC inspector will encounter different types of hazards depending on the type of inspection being conducted. These fall into three main categories:

1. Hazards during Well Treating Operations

2. Hazards during Drilling and Well Workover

3. Hazards during Routine Inspections

5:5 Safety during Well Treating Operations

Well treating usually consists of hydraulic fracturing, acidizing, or both. The principal hazards are high pressures and corrosive materials. Treating pressures of up to 5,000 psi are not uncommon. When lines give way under this type of pressure flying objects can become deadly projectiles. For this reason all pressurized hoses should be hydrostatically tested, secured by chains and sometimes covered with hose covers to deflect fluid leaks. Normally as an added precaution well treating is scheduled during daylight hours. A face shield is required whenever acids are to be handled.

The principal acids used in well stimulation work include hydrochloric, acetic, formic and hydrofluoric acids. Some special acids such as sulfamic, citric, lactic and others are used on occasion for special applications. A short discussion of chemical hazards is presented in section 5:11.

During well treatment the inspector should stay clear of the controlled area, which should be plainly designated. The most advantageous location to witness treatment is on the treatment truck where injection pressures can be monitored. The industry requires that treatment trucks and tanks be located at least 100 feet from the well and out of fall line of the derrick.

5:6 Drilling and Well Workover Safety

The inspector's greatest exposure to accidents is probably during well drilling and workover operations. To protect himself from a serious accident he must be able to recognize unsafe conditions and unsafe practices.

General Safety Rules

The following general safety rules should apply anytime the inspector is involved in monitoring construction, workovers, plugging and abandonment, or other activities requiring a drilling or workover rig.

1. Park outside of guylines
2. Wear hard hat, safety shoes and safety glasses at all times within the guylines
3. Note location of fire extinguishers. They could be stored at different locations on each job but are normally at an obvious and easily accessible place
4. Never smoke near flammable materials
5. Insure that pipe stored on pipe rack is adequately chocked with a chock pin
6. Stay clear of shear relief valves and lines when under pressure

Safety in the Working Area

Normally an inspector's duties will not require him to go on the rig floor; however, should this become necessary, he must be accompanied by the operator or his representative. While in the immediate working area the following safety rules should be followed:

1. Wear gloves for greasy and slippery handrails and to protect against potential hand injuries
2. Keep hands off of and feet clear of all lines that are moving
3. Watch for greasy or slippery floor
4. Stand clear of rig crew members when they are breaking apart tools or tubular goods
5. Watch for wickers on wire rope
6. Note that guard rails on ladders and platforms must be in place

7. Stay alert. Consider the hazards related to the work being performed

5:7 Safety during Routine Inspections

Protective Equipment

Hard hat, safety glasses, outer protective coveralls and safety shoes are minimal safety equipment required for entering any operating area.

Services Provided by Operator's Personnel

Insist that any gauge calibration or sampling be performed by the operator's personnel. This is especially important when performing an inspection at a Class I hazardous waste facility. High pressures and faulty equipment can also be dangerous. The well operator should know the best way to take a sample, what safety measures his personnel should take, and what isolation points are necessary to "swap out" (replace) gauges, if this is required.

5:8 Class I Injection Well Hazards

Class I injection operations are especially hazardous since corrosive or toxic chemicals may be involved. The inspector may come into contact with high concentrations of hazardous materials. Sampling equipment will, in many cases, become unavoidably contaminated. These items must be thoroughly cleaned before the next use or discarded. The decontamination procedure will vary greatly depending on the type and strength of the hazardous material and the nature of site activities. In general, the more hazardous the contaminant, the more thorough the decontamination should be. Contaminated equipment must not be placed where it may expose others to hazardous substances. If splashed during testing operations, personnel should shower themselves immediately.

5:9 Disposable Clothing and Equipment

Use disposable clothing and sampling devices to minimize the amount of equipment to be cleaned and volumes of decontaminants and rinse solutions to be disposed of.

5:10 Decontamination

Steam cleaning or high pressure spraying, utilizing water with a general purpose low sudsing soap or detergent, is the decontamination method of choice (Maslansky, 1983). Physical scrubbing by disposable or easily decontaminated brushes may be necessary to loosen caked-on materials. In most instances hot water (120-180°F) is more effective than cold. Flushing should be done under high pressure, taking care not to damage such items as dials, gauges and loosely hanging wires or hoses.

5:11 Safe Handling of Hazardous Chemicals

Information on potentially hazardous materials and chemicals is available from manufacturers' catalogs and specific handling guides, such as Baskin (1975). The documents tell how to safely handle chemical materials encountered at injection well sites. In addition, fire hazard, chemical reactivity and first aid measures are presented so that steps necessary for accident prevention may be taken.

When a Class I hazardous waste facility is to be inspected the inspector should determine which hazardous substances may be present at that site. This information should be included in the permit. The inspector should, at a minimum, determine the hazardous properties of these substances and take all necessary precautions to ensure his or her safety. A little advance preparation will make performing the inspection that much safer.

REFERENCES CHAPTER 5

American Petroleum Institute. Recommended Practices for Occupational Safety and Health for Oil and Gas Well Drilling and Service Operations. API RP54, Dallas, Texas, 1981.

Association of Oilwell Servicing Contractors, Recommended Safe Procedures and Guidelines for Oil and Gas Well Servicing. AOSC, Dallas, Texas 1980.

Baskin, David A. Handling Guide for Potentially Hazardous Materials. Materials Management and Safety, Incorporated, Niles, Illinois, 1975.

Maslansky, S.P. Well Drilling and Hazardous Material Sites. Waste Water Journal, April 1983, pp 46-50.

Environmental Protection Agency Order 1440.3, Respiratory Protection, July 24, 1981.

INDEX OF SUBJECTS

APPENDIX A

CHAIN OF CUSTODY

APPENDIX A

CHAIN-OF-CUSTODY

A:1 Chain-of-Custody Procedures

In any activity that may be used to support litigation, the sampler must be able to provide the chain-of-possession and custody of any samples which either are offered as evidence or for which test results are introduced as evidence. Written procedures must be available and followed whenever evidence samples are collected, transferred, stored, analyzed or destroyed. The primary objective of these procedures is to create an accurate written record which can be used to trace the possession and handling of a sample from the moment of its collection through analysis and its introduction as evidence.

A sample is defined as being in someone's "custody" if:

- o It is in one's actual possession; or
- o It is in one's view, after being in one's physical possession; or
- o It is in one's physical possession and then locked up so that no one can tamper with it; or
- o It is kept in a secured area, restricted to authorized personnel only.

The number of persons involved in collecting and handling samples should be kept to a minimum. Field records should be completed at the time the sample is collected and should be signed or initialed, including the date and time, by the sample collector(s). Field records should contain the following information:

- o Unique sampling or log number
- o Date and time
- o Source of sample (including name, location and sample type)
- o Preservative used
- o Analyses required
- o Name of collector(s)
- o Pertinent field data (pH, DO, chlorine residual, specific conductance, temperature, redox potential, etc.)
- o Serial number on seals and transportation cases.

Each sample must be labeled using waterproof ink and sealed immediately after it is collected. Labels should be filled out before collection to minimize handling of sample container.

The sample container should then be placed in a transportation case along with the chain-of-custody record form, pertinent field record, and analysis request form as needed. The transportation case should be sealed or locked. A locked or sealed chest eliminates the need for close control of individual samples. However, on those occasions when the use of a chest is inconvenient, the collector should seal the cap of the individual sample container with tape in a way that any tampering would be easy to detect.

When transferring the samples, the transferee must sign and record the date and time on the chain-of-custody record, which should have been prepared according to enforcement requirements. Custody transfers made to a sample custodian in the field should account for each sample, although samples may be transferred as a group. Every person who takes custody must fill in the appropriate section of the chain-of-custody record. To minimize custody records, the number of custodians in the chain-of-possession should be minimized. Figure A.1 is an example of a chain-of-custody record.

A:2 Instructions For Filling Out Chain-of-Custody Record (Tag)

Note: All signatures must be legible

1. Sample No: Record in field log as well as on tag

2. Source of Sample: Be specific

3. Preservative: Be specific

4. Sample collector/witness: Signatures only (new procedures)

5. Remarks: Specify lab to receive samples and analyses to be performed; specify whether sample is grab or composite; for composite samples specify the type of composite, for example, 24 hour composite, 1/2 depth-bottom composite, etc.; specify unusual characteristics that may require special laboratory handling, for example, nauseous odor, flammability, etc.

<u>Situation A</u>: Sampler or witness personally delivers sample to lab.

Receipt of Sample: To be filled out by lab personnel receiving sample.

1. Received from: Name must be sampler or witness as shown on reverse side of tag.

2. Disposition of Sample: Record lab log number in this space.

CHAIN OF CUSTODY RECORD

ENVIRONMENTAL PROTECTION AGENCY
Environmental Services Division
Edison, New Jersey 08837

Name of Unit and Address		
Sample Number	Number of Containers	Description of Samples

Person Assuming Responsibility for Samples	Time	Date

Sample Number	Relinquished by	Received by	Time	Date	Reason for Change of Custody
Sample Number	Relinquished by	Received by	Time	Date	Reason for Change of Custody
Sample Number	Relinquished by	Received by	Time	Date	Reason for Change of Custody
Sample Number	Relinquished by	Received by	Time	Date	Reason for Change of Custody

Figure A.1

Situation B: Sampler of witness sends sample to lab by certified mail or common carrier.

Dispatch of Sample: To be filled out by sampler or witness.

1. Date/time Obtained: Same as reverse side of tag.

2. Source: Enter company or water body name and sample number.

3. Date/time Dispatched: Enter date and time custody of sample was transferred to postal or carrier agent.

4. Method of Shipment:

(a) Common Carrier: Prepare GBL, listing and identifying all samples being sent. Sign GBL. Enter name of carrier and GBL number on tag.

(b) Postal Service: Enter Certified Mail in this space. Prepare a list of sample numbers sent, include name of lab receiving samples and record certified mail number on this list. Sign and date this list. Affix certified mail receipt to listing of sample numbers.

5. Sent to: Specify name of lab and person receiving samples.

Situation C: Sampler or witness sends sample to lab by courier. Courier completes dispatch of sample:

1. Date/time obtained: Specify when custody of sample transferred from sampler or witness to courier.

2. Source: Must be sampler or witness by name.

3. Method of Shipment: Specify type of vehicle used.

4. Date/time dispatched and sent to: Same as B.3 and B.5 above.

If two couriers are required: First courier fills out Receipt of Sample Section as follows:

5. Received from: Must be sampler or witness

6. Disposition of sample: Record name of second courier. Second courier fills out Dispatch of Sample as in C.1 to C.4 above.

Situation D: Sampler or witness transfers samples to courier who sends samples by certified mail or common carrier to lab.

Carrier fills out Dispatch of Sample as follows:

1. Date/time obtained and source:
Same as C.1 and C.2 above.

2. Date/time Dispatched, Method of Shipment, Sent To Sections: Same as B.3, B.4, and B.5.

Situation E: Sampler or witness personally performs analyses (no change of custody). Fill out Remarks Section on front tag as follows. "I personally performed the required analyses." Give date, time, and laboratory name and sign. If any unusual situations arise, contact Regional Enforcement personnel for advice.

APPENDIX B

SAMPLING CONTAINERS, PRESERVATIVES AND ANALYTICAL PARAMETERS

Table B.1 Required Containers, Preservation Techniques, and Holding Times

Measurement Table/Parameter	Container	Preservative	Maximum Holding Time
IA Bacterial Tests			
Coliform, fecal and total	P,	Cool, $4^{o}C$ 0.008% $Na_2S_2O_2$[5]	6 hours
Fecal streptococci	P, G	Cool $4^{o}C$ 0.008% $Na_2S_2O_2$[5]	6 hours
IB Inorganic Tests			
Acidity	P, G	Cool, $4^{o}C$	14 days
Alkalinity	P, G	Cool, $4^{o}C$	14 days
Ammonia	P, G	Cool, $4^{o}C$ H_2SO_4 to pH<2	28 days
Biochemical oxygen demand	P, G	Cool, $4^{o}C$	48 hours
Biochemical oxygen demand carbonaceous	P, G	Cool, $4^{o}C$	48 hours
Bromide	P, G	None required	28 days
Chemical oxygen demand	P, G	Cool, $4^{o}C$ H_2SO_4 to pH<2	28 days
Chloride	P, G	None required	28 days
Chloride Residual	P, G	None required	Analyze immediately
Color	P, G	Cool $4^{o}C$	48 hours
Cyanide, total and amenable to chlorination	P, G	Cool $4^{o}C$ NaOH to pH> 12 0.6g ascorbic acid	14 days[6]

Table B.1 Required Containers, Preservation Techniques, and Holding Times

Measurement Table/Parameter	Container	Preservative	Maximum Holding Time
IB Inorganic Tests (cont.)			
Fluoride	P	None required	28 days
Hardness	P, G	HNO_3 to pH<2	6 months
Hydrogen ion (ph)	P, G	None required	Analyze immediately
Kjeldahl and organic Nitrogen	P, G	Cool, 4°C H_2SO_4 to pH<2	28 days
Chromium VI	P, G	Cool, 4°C	24 hours
Mercury	P, G	HNO_3 to pH<2	28 days
Metals, except above	P, G	HNO_3 to pH<2	6 months
Nitrate	P, G	Cool 4°C	48 hours
Nitrate-nitrite	P, G	Cool 4°C H_2SO_4 to pH<2	28 days
Nitrite	P, G	Cool, 4°C	48 hours
Oil and grease	P, G	Cool 4°C H_2SO_4 to pH<2	28 days
Organic carbon	P, G	Cool, 4°C HCl or H_2SO_4 to pH<2	28 days
Orthophosphate	P, G	Filter immediately Cool, 4°C	48 hours
Oxygen, Dissolved Probe	G Bottle and Top	None required	Analyze immediately
Winkler	G Bottle and Top	Fix on site and store in dark	8 hours
Phenols	G only	Cool, 4°C H_2SO_4 to pH<2	28 days

Table B.1 Required Containers, Preservation Techniques, and Holding Times

	Measurement Table/Parameter	Container	Preservative	Maximum Holding Time
IB	(Cont.)			
	Phosphorus (elemental)	G	Cool, 4°C	48 hours
	Phosphorus, total	P, G	Cool, 4°C H_2SO_4 to pH<2	20 days
	Residue, total	P, G	Cool, 4°C	7 days
	Residue, Filterable	P, G	Cool, 4°C	7 days
	Residue, Non-filterable (TSS)	P, G	Cool, 4°C	7 days
	Residue, settleable	P, G	Cool, 4°C	48 hours
	Residue, volatile	P, G	Cool, 4°C	7 days
	Silica	P	Cool, 4°C	28 days
	Specific conductance	P, G	Cool, 4°C	28 days
	Sulfate	P, G	Cool, 4°C	28 days
	Sulfide	P, G	Cool, 4°C add zinc acetate plus sodium hydroxide to pH>9	7 days
	Sulfite	P, G	None required	Analyze immediately
	Surfactants	P, G	Cool, 4°C	48 hours
	Temperature	P, G	None required	Analyze immediately
	Turbidity	P, G	Cool, 4°C	48 hours

Sample Preservation and Maximum Holding Times Specific to Class II Well Samples

The sampling preservation and maximum holding times are defined to maintain the integrity of the samples so that accurate and reliable data will be generated by the laboratories analyzing such samples. It is incumbent on the sampling teams to understand these requirements and plan the sampling projects so that the requirements are met. It is also necessary that the laboratory personnel understand the requirements and notify the proper authorities when there are problems so that corrective action can be taken.

Sampling containers should be made from polyethylene with polyethylene-lined lids. Glass is required only when dissolved oxygen samples are stabilized in the field and titrated later. Glass sample bottles may be used for all other sample types but polyethylene-lined lids are necessary.

When filtration is required, it should be performed on-site. If conditions preclude field filtration, the samples must be delivered to facilities and filtered within four (4) hours. Samples should be chilled to 4^{o}C during transit.

Table B.2 summarizes preservation and holding times for some tests.

TABLE B.2

Parameter	Preservation Technique	Maximum Holding Time
Major Cations (Na^+, K^+, Ca^{+2}, Mg^{+2})	HNO_3 to pH <2.0	6 months
Major Anions (Cl^-, SO_4, F^-, Br^-)	Cool to 4°C	1 month
Trace Metals (Fe, Mn, Zn, Pb, Hg)	HNO_3 to pH < 2.0	6 months
Alkalinity	Cool to 4°C	14 days
Sulfide	Cool to 4°C Add Zn Acetate Reagent plus NaOH to pH >9.0	7 days
pH	None	1 hour maximum
Dissolved Oxygen	Meter method--none	determine on-site
	Winkler method--add $MnSO_4$ and Azide-NaOH reagents	8 hours
Specific Conductance	Cool to 4°C	28 days
Total Dissolved Solids	Cool to 4°C	7 days
Compatability	Cool to 4°C	48 hours

Note: Holding time and preservation requirements for other parameters may be obtained from the RQAOs.

APPENDIX C

ELECTRICAL LOGGING
RADIOACTIVITY LOGGING

APPENDIX C

ELECTRICAL LOGGING

Electrical logging is a process by which electrical measurements provide data on formations penetrated by the borehole.

C:1 Self Potential (SP) Logging

The principal downhole measurements made are voltage and resistance. The voltage measured is the spontaneous potential (SP) of the drilling mud column in the borehole with respect to the ground potential near the drilling rig.

The SP is generated through the operation of several mechanisms involving borehole fluids and the boundaries between subsurface strata. Measurement of this voltage is accomplished by lowering a sonde that carries one electrode down the hole, and by recording the difference in voltage between the sonde-borne electrode and an electrode driven into the ground at the surface. The SP log is useful in detecting large changes in the chemical character of formation fluids. Total Dissolved Solids (TDS) content of the formation water can be calculated from a properly calibrated SP log.

C:2 Electrical Resistance

Resistance of subsurface strata is measured in two general ways. One method involves impressing a voltage across 2 electrodes suspended -- one above the other -- on a cable lowered into the liquid-filled bore hole. The flow of current from one electrode to the other induces a voltage difference between two other electrodes located between the first two. The voltage induced across the second pair of electrodes is recorded continuously on a graph at the surface. A variation of this method is to monitor the amount of current that is actually forced into the formation from the electrodes. The first method requires that the drilling mud be conductive. The second method involves induction, and so nonconducting muds can be used.

An induction log uses a transmitter in one end of a sonde to generate a magnetic field that induces eddy currents into the formation surrounding the borehole. These eddy currents in turn generate their own magnetic fields which are sensed by a receiver in the other end of the sonde. The magnitude of the induced eddy currents and their associated magnetic fields is a function of formation resistivity; the sonde receiver records the apparent formation resistivity.

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

RADIOACTIVITY LOGGING

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

C:3 Natural Radiation Log

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

C:4 Gamma Density (Gamma-Gamma) Log

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

C:5 Neutron Log

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

APPENDIX C

LOUISIANA DEPARTMENT OF NATURAL RESOURCES
OFFICE OF CONVERSATION
RADIOACTIVE TRACER SURVEY GUIDELINES AND PROCEDURE
for Injection Wells Completed with Tubing and Packer
that have Tubing, Packer, and Casing Integrity

Guidelines:

A. The gamma-ray log may be run up to 60 ft/min at a time constant of 1 second (suggested) or up to 30 ft/min at TC 2 or up to 15 ft/min at TC 4. Indicate logging speed and time constant on the log heading.

B. Include a collar locator for depth control.

C. Vertical scale may be 1", 2", or 5" per 100 ft, 2" being preferred.

D. Indicate in API units the horizontal scale. It is suggested that two gamma-ray curves be recorded on each log pass at different sensitivities (such as one at 20 API units per division and one at 100 API units per division). If only one gamma-ray curve is recorded, make sure the sensitivity used is such that the tracer material will be obvious when detected and will not be confused with normal "hot spots" in the formations; i.e., choose a low sensitivity. It should be sensitive enough to show lithology.

E. Indicate beginning and ending clock times on each log pass.

F. Indicate injection rate (if any) during each log pass.

G. Indicate volume of water injected between log passes.

H. Indicate volume and concentration of each slug of tracer material.

If preferred, most of the above may be shown in tabular form rather than on the log, as long as all information is provided (the Injection and Mining Division will provide forms on request).

Procedure:

1. Run a base log from the injection zone (starting 100 ft below, if possible) to at least 100 ft above packer depth.

2. Release tracer material from the tool into the tubing about 100 ft above packer depth (or, if tool will not release tracer, tracer may be injected at the surface, although it will probably string out going down). Trace the slug to at least the top of the previously

recorded slug depth (to show whether any tracer was left behind). Although it is difficult to determine the number of passes needed, the complete pathway followed by all of the tracer needs to be demonstrated. Ideally, the following passes should be made:

1. upon release of the tracer about 100 ft above packer depth;

2. below packer depth (whether in tubing or casing) but before leaving the casing;

3. while or just after leaving the casing;

4. to ?) continuing to follow the tracer with several passes until it virtually disappears; the last pass should essentially duplicate the base log.

It is suggested that pumping not occur during logging; that is, pump only to move tracer downhole between log passes. Be cautious of the volume of water pumped during or between log passes to prevent premature loss of the tracer! If the tracer has been prematurely lost, it will be necessary to release another slug and follow it from the point of the last good log pass.

3. A few passes may be shown on one log segment if desired as long as each gamma-ray curve along with its collar locator is distinguishable. Otherwise, make each pass on a separate log segment.

4. An interpretation of the log must be supplied by the logging company on the log itself.

5. Include a schematic diagram of the well on the log itself. The diagram should show the casing diameters and depths, tubing diameter and depth, packer depth, perforated intervals and total or plugged back depth. Indicate the pathway the tracer material appears to have taken using arrows.

6. Write Serial Number of well on log heading, if available.

NOTE: The above "Guidelines" and "Procedure" will apply in most instances. In certain situations, it will be necessary to deviate from these directions. Necessary modifications may be made as long as the pathway the tracer follows from packer depth on down can be demonstrated.

April/84

LOUISIANA DEPARTMENT OF NATURAL RESOURCES
OFFICE OF CONSERVATION
RADIOACTIVE TRACER SURVEY GUIDELINES AND PROCEDURE
for Annular Disposal Wells

The purpose of running a radioactive tracer survey in an annular disposal well is twofold:

1. to show whether injected fluids will leak through a hole or holes in the casing above the casing shoe; and

2. to show whether injected fluids will migrate vertically outside the casing after reaching the casing shoe.

Guidelines:

A. The gamma-ray log may be run up to 60 ft/min at a time constant of 1 second (suggested) or up to 30 ft/min at TC 2 or up to 15 ft/min at TC 4. Indicate logging speed and time constant on the log heading.

B. Include a collar locator for depth control.

C. Vertical scale may be 1", 2", or 5" per 100 ft, 2" being preferred.

D. Indicate in API units the horizontal scale. It is suggested that two gamma-ray curves be recorded on each log pass at different sensitivities (such as one at 20 API units per division and one at 100 API units per division). If only one gamma-ray curve is recorded, make sure the sensitivity used is such that the tracer material will be obvious when detected and will not be confused with normal "hot spots" in the formations; i.e., choose a low sensitivity. It need not be sensitive enough to show lithology.

E. Indicate beginning and ending clock times on each log pass.

F. Indicate injection rate (if any) during each log pass.

G. Indicate volume of water injected between log passes.

H. Indicate volume and concentration of each slug of tracer material.

If preferred, most of the above may be shown in tabular form rather than on the log, as long as all information is provided (the Injection and Mining Division will provide forms on request).

Procedure:

1. Run a base log from at least 200 ft below the casing shoe to the surface.

2. Pump tracer material, Iodine ^{131}, into the annular space and trace the slug with the gamma-ray tool. Run short (approximately 500 ft) overlapping log passes following the tracer downhole. Each pass should extend from about 100 ft below the slug depth to at least 25 ft above the top of the previously recorded slug depth (to show whether any tracer was left behind). An ideal sequence would be something like:

   a. place gamma-ray tool at 475 ft;

   b. pump tracer down until detected by tool;

   c. log from 600 ft to the surface slug discovered at 475-500 ft);

   d. place tool at 975 ft;

   e. pump tracer down until detected by tool;

   f. log from 1100 ft to 450 ft (25 ft above previous slug)

   g. place tool at 1475 ft;

   h. pump tracer down until detected by tool;

   i. log from 1600 ft to 940 ft (25 ft above previous slug).

   and so on at approximately 500-ft increments (assuming no tracer was previously left behind). It is suggested that pumping not occur during logging; that is, pump only to move tracer downhole between log passes to prevent premature loss of the tracer! If the tracer has been prematurely lost, it will be necessary to inject another slug and follow it from the last point of the last good log pass.

3. As soon as the tracer reaches the casing shoe, stop pumping (or slow as much as possible) and run a log to the surface.

4. As tracer is pumped out of the casing into the well bore, run a few short log passes from at least 50 ft below the slug depth to at least 50 ft above the slug depth showing the pathway the tracer follows. Continue running passes until the tracer virtually disappears. The last pass should essentially duplicate the base log.

5. Another log may be run to the surface after Step 4. This should be done particularly if the log run in Step 3 still shows "hot spots" due to leaks or to pipe scaling entrapping some of the tracer material.

6. A few passes may be shown on one log segment if desired as long as each gamma-ray curve along with its collar locator is distinguishable. Otherwise, make each pass on a separate log segment.

7. An interpretation of the log must be supplied by the logging company on the log itself.

8. Include a schematic diagram of the well on the log itself. The diagram should show the casing diameters and depths, tubing diameter and depth (if any), perforated intervals, and total or plugged back depth. Indicate the pathway the tracer material appears to have taken using arrows.

9. Write Serial Number of well on log heading, if available.

NOTE: The above "Guidelines" and "Procedure" will apply in most instances. In certain situations, it will be necessary to deviate from these directions. Deep wells will probably need a concentrated slug in order to show integrity along the entire length of casing. Necessary modifications may be made, as long as the two purposes stated at the top can be demonstrated as evidence of well integrity.

April/84

LOUISIANA DEPARTMENT OF NATURAL RESOURCES
OFFICE OF CONSERVATION
RADIOACTIVE TRACER SURVEY GUIDELINES AND PROCEDURES
for Casing Disposal Wells (completed without Tubing or Packer)

The purpose of running a radioactive tracer survey in an injection well is twofold:

1. to show whether injected fluids will leak through a hole or holes in the casing above and, in some cases, below the intended disposal interval; and

2. to show whether injected fluids will migrate vertically outside the casing after reaching the intended disposal zone.

Guidelines:

A. The gamma-ray log may be run up to 60 ft/min at a time constant of 1 second (suggested) or up to 30 ft/min at TC 2 or up to 15 ft/min at TC 4. Indicate logging speed and time constant on the log heading.

B. Include a collar locator for depth control.

C. Vertical scale may be 1", 2", or 5" per 100 ft, 2" being preferred.

D. Indicate in API units the horizontal scale. It is suggested that two gamma-ray curves be recorded on each log pass at different sensitivities (such as one at 20 API units per division and one at 100 API units per division). If only one gamma-ray curve is recorded, make sure the sensitivity used is such that the tracer material will be obvious when detected and will not be confused with normal "hot spots" in the formations; i.e., choose a low sensitivity. It need not be sensitive enough to show lithology.

E. Indicate beginning and ending clock times on each log pass.

F. Indicate injection rate (if any) during each log pass.

G. Indicate volume of water injected between log passes.

H. Indicate volume and concentration of each slug of tracer material.

If preferred, most of the above may be shown in tabular form rather than on the log, as long as all information is provided (the Injection and Mining Division will provide forms on request).

Procedure:

BEFORE LOGGING: REMOVE TUBING, IF PRESENT, FROM WELL (REQUIRES WORK PERMIT FROM THE INJECTION AND MINING DIVISION). IF THE LOGGING TOOL CANNOT GET DOWN TO AT LEAST THE UPPERMOST PERFS, THE WELLS WILL NEED TO BE CLEANED OUT BEFORE RUNNING THE SURVEY.

1. Run a base log from the injection zone (starting 200 ft below, if possible) <u>to the surface</u>.

2A. <u>If the well takes fluid on a vacuum</u> or the static fluid level is below the top of the casing:

   a. indicate fluid level on the log;

   b. release tracer material from the logging tool in the top 20 ft of fluid;

   c. log from at least 50 ft below to at least 50 ft above the slug <u>before pumping</u> the tracer downward.

2B. <u>If the well does not take fluid on a vacuum</u>:

   a. place logging tool at 50 ft;

   b. pump tracer material into the well <u>from the surface</u> until it is first detected by the logging tool; stop pumping;

   c. log from at least 50 ft below the slug <u>to the surface</u> before resuming pumping.

3. Pump tracer down and run short (approximately 500-ft) <u>overlapping</u> log passes following the tracer downhole. Each pass should extend from about 100 ft below the slug to at least 25 ft above the top of the <u>previously recorded slug depth</u> (to show whether any tracer was left behind). An ideal sequence would be something like:

   a. place gamma-ray tool at 450 ft;

   b. pump tracer down until detected by tool;

   c. log from 600 ft <u>to the surface</u> slug discovered at 425-500 ft);

   d. place tool at 950 ft;

   e. pump tracer down until detected by tool;

   f. log from 1100 ft to 400 ft (<u>25 ft above previous slug!</u>).

   g. place tool at 1450 ft;

   h. pump tracer down until detected by tool;

   i. log from 1600 ft to 885 ft (<u>25 ft above previous slug!</u>).

and so on at approximately 500-ft increments (assuming no tracer was previously left behind). It is suggested that pumping not occur during logging; that is, pump only to move tracer downhole between log passes to prevent premature loss of the tracer! If the tracer has been prematurely lost, it will be necessary to inject another slug and follow it from the last point of the last good log pass.

4. As soon as the tracer reaches the injection level, stop pumping and run a log to the surface.

5. Return to the injection interval and run several short log passes from at least 50 ft below the slug depth to at least 50 ft above the slug depth showing the pathway the tracer follows. Continue running passes until the tracer virtually disappears. The last pass should end up being similar to base log.

6. Another log may be run to the surface after Step 5. This should be done particularly if the log run in Step 4 still shows "hot spots" due to leaks or to pipe scaling entrapping some of the tracer material.

7. A few passes may be shown on one log segment if desired as long as each gamma-ray curve along with its collar locator is distinguishable. Otherwise, make each pass on a separate log segment.

8. An interpretation of the log must be supplied by the logging company on the log itself.

9. Include a schematic diagram of the well on the log itself. The diagram should show the casing diameters and depths, tubing diameter and depth (if any), perforated intervals, and total or plugged back depth. Indicate the pathway the tracer material appears to have taken using arrows.

10. Write Serial Number of well on log heading.

NOTE: The above "Guidelines" and "Procedure" will apply in most instances. In certain situations, it will be necessary to deviate from these directions. Deep wells will probably need a concentrated slug or multiple slugs injected downhole in order to show integrity along the entire length of casing. Necessary modifications may be made, as long as the two purposes stated at the top can be demonstrated as evidence of well integrity.

April/84

APPENDIX C
CEMENT BOND LOG
The Bond Index Method

The bond index method relates the amplitude attenuation in a zone of interest to the attenuation in a zone that is ideally 100% cemented. The advantage of this technique is that is depends on a ratio of attenuations and not absolute values, thus minimizing possible errors resulting from unknown parameters or conditions. Zone isolation predictions are dependent upon the bond index and the length of bonded interval, which varies with casing size.

Gearhart Industries, Inc. has developed an interpretation table (following page) for cement bond log evaluation. One simply has to find the appropriate casing size and weight, read to the right to obtain the millivolt value for 100% cement (assuming a cement of 3000 psi compressive strength) and the good bond cutoff value (bond index of 0.6). The 100% cement value is listed for those cases where the lowest value on the log may not be 100% cement.

A vertical line is drawn on the log at the appropriate millivolt value for good bond cutoff. Any reading to the left of this line (lower millivolt values) is considered a good bond; any reading to the right (higher millivolt values) is considered a poor bond. The column on the far right of the table is the required vertical length of good bonding necessary for isolation.

Cement Bond Log Interpretation Guide

Gearhart Industries, Inc.

Casing Size	Wt.	Travel Time u-sec	Free Pipe Signal	Class H Cement 3000 psi 100% Cement	Class H Cement 60% Bond Cutoff	Interval For Isolation
4 1/2"	9.5			0.2 mv	2.3 mv	
	11.6	254	81 mv	0.6 mv	4.6 mv	5 feet
	13.5			1.0 mv	7.0 mv	
5"	15.0			0.9 mv	5.5 mv	
	18.0	258	76 mv	2.2 mv	10.0 mv	5 feet
	21.0			3.6 mv	15.0 mv	
5 1/2"	15.5			0.7 mv	4.8 mv	
	17.0	269	72 mv	1.0 mv	6.0 mv	6 feet
	20.0			2.1 mv	9.0 mv	
	23.0			3.5 mv	13.0 mv	
7"	23.0			1.0 mv	5.5 mv	
	26.0			1.7 mv	7.5 mv	
	29.0			2.4 mv	9.3 mv	
	32.0	289	62 mv	3.3 mv	13.0 mv	11 feet
	35.0			4.0 mv	14.0 mv	
	38.0			5.0 mv	15.0 mv	
	40.0			6.0 mv	17.0 mv	
7 5/8"	26.4			1.1 mv	5.5 mv	
	29.7	302	59 mv	1.8 mv	7.5 mv	12 feet
	33.7			2.6 mv	10.0 mv	
	39.0			3.5 mv	13.0 mv	
9 5/8"	40.0			1.8 mv	6.8 mv	
	43.5	332	51 mv	2.2 mv	8.5 mv	15 feet
	47.0			2.7 mv	9.0 mv	
	53.5			4.0 mv	12.0 mv	
10 3/4"	40.5			1.2 mv	5.1 mv	
	45.5			1.8 mv	6.5 mv	
	48.0	352	48 mv	2.1 mv	7.6 mv	18 feet
	51.0			2.5 mv	8.0 mv	
	54.0			2.7 mv	8.4 mv	
	55.5			2.8 mv	8.8 mv	

APPENDIX D

CEMENTING OF WELLS

APPENDIX D

CEMENTING OF WELLS

D:1 Cements

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

D:2 Cement Additives

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

D:3 Cement Volume Requirements

The volume of cement needed for a casing job includes the calculated volume of annular space outside the wall, plus an excess volume of annular space outside the wall, plus an excess volume of cement for lost circulation or hole washouts and high porosity zones. Volume of the annular space outside the casing wall is considered to be equal to the hole volume determined from a good caliper log, minus the volume of the casing string to be cemented. An additional volume of cement, equal to from 20 to 30 percent of the calculated annular cement volume, should also be on location and ready for pumping in case it is needed. If a good caliper log cannot be obtained for the borehole, the required cement volume can be calculated from an estimate of hole diameter based on drill bit size. However, the percent of excess cement should then be increased to allow for the relative inaccuracy of this method.

D:4 Cementing Devices

To obtain a good primary cement job, a number of devices can be installed in a casing string during assembly. A guide shoe installed on the bottom of each casing string helps guide the casing downhole to the setting depth. The shoe is constructed with a beveled edge on the bottom. A float collar is installed on top of the first, or lowest, joint of a casing string. This tubular device contains a valve which allows mud and cement to be pumped down through the pipe, but prevents backflow of fluid up inside the casing. The float collar holds the cement slurry in place outside the casing.

Multiple stage tools, or DV (differential valve) tools, may be installed in a casing string to allow the casing to be cemented in separate operations, or stages. Use of such tools may be advisable in certain areas to prevent downhole formations from being subjected to high cement slurry hydrostatic pressures that may fracture formations. The stage tool also is used to emplace different types of cement in the same hole, for example, to separate epoxy from Portland cements. Typically, a stage tool is placed at an intermediate depth, or about one-half the total cementing depth.

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

D:5 Centralizers

Centralizers, to hold the casing in the center of the hole, contribute to a successful cement job. Also, scratchers may be installed on the casing in wells that have been drilled with mud, where the casing is free to be rotated or reciprocated in the hole; this enhances the cement bond by removing mud cake from the borehole. Viscous preflush, or mud flush used ahead of the cement slurry, and casing wiper plugs ahead of and behind the slurry help keep it free of mud contamination. Turbulent flow conditions in the annulus also increase the chances for good cement bond.

APPENDIX E

RESPONSE TO NONCOMPLIANCE

TABLE E.1
RESPONSES TO NONCOMPLIANCE
(non-SNC)

CATEGORY I	Appropriate Response (See Table E.2)											
	A	B	C	D	E	F	G	H	I	J	K	L
24 Hour Reporting and/or Written Follow-up §§144.28(b), 144.51(1)(6)		X	X	X	X	X	X	X			X	X
Well Construction, 1/ Part 146, §144.28(e)		X	X	X	X	X	X	X		X	X	X
Operating Requirements §§144.28(f), 144.52(e) Part 146, §§144.51(e)		X	X	X	X	X	X	X		X	X	X
Failure to Plug and Abandon Properly if nonendangering		X	X	X	X	X	X	X	X	X	X	X
Contamination of USDW, §§144.12, 1431, SDWA		X	4/	4/		X				X	X	X
Compliance Schedule 1/, §§144.39(a)(4), 144.57(1)(5), 144.53		X	X	X		X				X	X	X
Record Retention, §§144.28(l), 144.51(j)(2)		X	X	X	X		X	X			X	X

1/ Suspected/known endangerment; willful violations
2/ Strongly recommended in conjunction with referral, as applicable
3/ Suspected/known endangerment
4/ Where an aquifer exemption is pending, these responses may, in some cases, be appropriate while the exemption is being processed
SNC Significant Non-Compliance

CATEGORY II	Appropriate Response (See Table E.2)											
	A	B	C	D	E	F	G	H	I	J	K	L
Financial Responsbility (Inadequate and/or failure to submit) §§144.28(d), 144.60-70, 144.52(a)(7)	X	X		X	X	X	X				X	5/
Failure to Make Required Notification (P&A, MIT, transfer of ownership, etc.) §§144.28(g), (j) (1) 144.23(b)(3), 144.51(1)(n), 144.13		X	X	X	X	X	X				X	X
Failure to Monitor, §§144.28(g), Part 146		X	X	X	X	X	X				X	X
Well Construction (below ground construction, no suspected endangerment) §144.28 (e)		X	X	X	X	X	X				X	X
Operating requirements (no suspected endangerment but violation substantial), 144.28(f), Part 146, §§144.51(a), (e)		X	X	X	X	X	X				X	X
Failure to P&A properly (no suspected endangerment), §§144.52(a)(6), 144.28(c) 146.10, 144.51(o), 144.23b		X	X	X	X	X	X		X		X	X
Failure to run M.I.T., §§144.28(g) 144.51(p)		X	X	X	X	X	X		X		X	X
Compliance Schedule (non-endangering) §§144.25 (Result in unauthorized injection)	X	X	X	X			X				X	X
Failure to comply with permit condition, §144.51(a) (not included elsewhere)	X	X	X	X			X		X	X	X	X
Failure to apply for a permit, §§144.25 (Results in unauthorized injection)	X	X	X	X	X	X				X	X	X
Mechanical Integrity Failure which is not endangering and is not included under SNC milestones		X	X	X	X	X				X	X	X

5/ Repeated or unusual (willful or bad faith)

CATEGORY III	A	B	C	D	E	F	G	H	I	J	K	L
	Appropriate Response (See Table E.2)											
Report - Incomplete - No Report - Late - Incorrect §§144.28(h), (k), 144.51(o), Part 146,	X	X	X	X	X		X				X	5/
Well Construction (above ground, nonsubstantial), §§144.28(e) 1/	X		X	X	X	X	X				X	5/
Operating requirements (non endangering, repetitive or substantial), §144.52(a), Part 146	X	X	X	6/	X	6/	X				X	5/
No P&A Plan 8/, §§144.23(b)(2), 148.28(c)	X	X	X		X							
Unauthorized P&A (non-endangering) §§144.23, 144.28(c)		X	6/	X	X	6/	7/		X		X	5/
Inventory Requirements 7/ (1 Year Inventory Requirements) §144.26	X	X	X	X	X	X						

5/ Repeated or unusual (willful or bad faith)

6/ Area Permits Only

7/ Failure to submit Inventory results in automatic termination of authorization by rule - see unauthorized injection in Categories I and II

8/ Request operator to submit P&A plan under §§144.27. Failure to submit plan after request results in termination of authorization by rule - see unauthorized injection in Categories I and II

TABLE E.2
POSSIBLE APPROPRIATE RESPONSES TO VIOLATIONS

A. Telephone call (must have appropriate documentation).

B. Warning letter tailored to individual operator notifying him/her of the nature of the violation and required responses (must include possible criminal/civil liabilities).

C. Field inspection (generally not appropriate as a final response to a violation).

D. Opportunity for consultation ("show cause" meeting) which provides the violator a chance to ask questions of the agency and get information.

E. Formal request for information (may include new information, mechanical integrity test, monitoring, etc. - see §144.27). Note: Owner/operator's failure to respond to this request results in automatic termination of authorization by rule, (§144.27[c]).

F. Request for permit application (§144.27; 144.12[c] or [d]). Note: When §144.27 information request authority is not appropriate, the §144.25 authority can be used to terminate authorization by rule if the permit application is not submitted in a timely fashion, or if the permit is denied.

G. Initiate permit modification, alteration or termination or impose or modify a compliance schedule.

H. Issue Administrative Order to owner or operator of a Class V well requiring such actions as may be necessary to prevent primary drinking water standard violations or to prevent contamination which may otherwise adversely affect the health of persons. (§144.12[c][2]).

I. Commence bond forfeiture or utilize other financial mechanisms to plug the well.

J. §1431 SDWA Administrative Order or, where well is injecting solid or hazardous waste, RCRA, §3008 or §7003 Administrative Order (or where appropriate, a CERCLA §106 Administrative Order).

K. Issue Administrative Order.

L. Referral to State AG/Department of Justice (DOJ) (Civil or Criminal).

APPENDIX F

WARRANT DOCUMENTS

Michael R. Spaan
United States Attorney
District of Alaska
Federal Building, Room 252
701 C Street
Anchorage, Alaska 99513

U.S. DISTRICT COURT
DISTRICT OF ALASKA

IN THE MATTER OF: UNOCAL CORPORATION Kenai Gas Field Anchorage, Alaska	Civil No. ____________ APPLICATION FOR WARRANT FOR ENTRY AND INVESTIGATION PURSUANT TO SECTION 1445 OF THE SAFE DRINKING WATER ACT, 42 U.S.C. §300j-4 et seq.

The United States of America, at the request of the Administrator of the United States Environmental Protection Agency (EPA), applies to this Court for a warrant authorizing EPA officials and their assistants to enter upon land hereinafter referred to as the Unocal Facilities, and then and there conduct such initial monitoring, testing or analysis, or any combination thereof, together with such attendant sampling, surveying, information gathering, and photographing as may be reasonable and necessary to ascertain whether Unocal Corporation has acted or is acting in compliance with its EPA emergency permit and Part C of the Safe Drinking Water Act (SDWA), 42 U.S.C. §300h, at the Unocal Facilities in Alaska.

The EPA submits this application pursuant to the SDWA, 42 U.S.C. §300f, and alleges for this application as follows:

A. The EPA may enter the Unocal Facilities to perform investigations, sampling, and other actions pursuant to the authority vested in the Administrator by Section 1445 of the SDWA, 42 U.S.C. §300j-4.

B. Section 1445(a)(1) SDWA, 42 U.S.C. 300j-4(a)(1), authorizes the EPA to take any response measure to determine whether a person subject to an applicable underground injection control (UIC) program or subject to the permit requirement of 42 U.S.C. §300h-3 either has been or is in compliance.

C. Whenever the conditions set forth in Section 1445(a)(1) of the SDWA are present, Section 1445(b)(1) of the SDWA, 42 U.S.C. §300j-4(b)(1), authorizes the EPA to take the following range of investigative activities:

> [The EPA] is authorized to enter any establishment, facility, or other property of [a person subject to the underground injection control program] in order to determine whether such . . . person has acted or is acting in compliance with this subchapter, including for this purpose inspection, at reasonable times, of records files, papers, processes, controls and facilities . . . .

Therefore, under Section 1445 of the SDWA, EPA has the statutory authority to (1) enter and investigate and (2) obtain samples from the Unocal Facilities.

D. The investigations, sampling, and other response actions for which this warrant is sought include the following:

(1) A detailed walking inspection of the entire inspection site and gravel pit;

(2) The taking of samples, collected at sample ports and/or drums and tanks via sample containers and/or thiefs, from injection waste streams and reservoirs/containers that may contain waste intended for injection into well KU WD-1;

(3) The examination of records, files papers, processes and controls required by permit to be found either on-site or at Unocal's offices;

(4) The taking of photographs; and

(5) Any additional activities, including interviews and conferences, as necessary to ascertain compliance or noncompliance with permit conditions.

E. Although EPA was, and is, entitled to a warrantless entry upon the Unocal Facilities under the SDWA (and EPA does not waive this legal position by this application), in order to assure peaceful acquiescence by the owners and operators of the Unocal Facility to the EPA action, EPA applies for this warrant.

F. The United States Supreme Court decisions in Camara v. Municipal Court, 387 U.S. 523 18 L.Ed. 2d 930, 87 S.Ct. 1727 (1967) and Marshall v. Barlow's Inc., 436 U.S. 307 56 L.Ed. 2d 305, 98 S.Ct. 1816 (1978), provide ample authority for this Court to issue a warrant where a statute, such as the SDWA confers a right of entry. See also Bunker Hill v. EPA, 658 F.2d 1280 (9th Cir. 1981) and Accord Public Service Co. of Indiana v. United States Environmental Protection Agency, 509 F. Supp. 720 (S.D. Ind. 1981). The standard for probable cause justifying the issuance of an administrative search warrant, less rigorous than for a search and seizure warrant in a criminal investigation, requires only a showing of either "specific evidence of an existing violation" or "reasonable legislative or administrative standards" for conducting a particular inspection, Marshall v. Barlow's Inc., 436 U.S. 307, 320 56 L.Ed. 2d 305, 98 S.Ct. 1816 (1978):

> For purposes of an administrative search such as this, probable cause justifying the issuance of a warrant may be based not only on specific evidence of an existing violation but also on a showing that reasonable legislative or administrative standards for

conducting an inspection are satisfied with respect to a particular establishment." Camara v. Municipal Court, 387 U.S. 523, 538 18 L.Ed. 2d 930, 87 S.Ct. 1727 (1967).

G. The EPA has reviewed available information and has determined that Unocal has not acted and is not acting in compliance with its permit or Part C of the SDWA, 42 U.S.C. 300h et seq. Steinborn Affidavit at paragraphs 10 and 11. In addition, past practice of providing prior notice of an inspection may have resulted in the concealment of violations. Steinborn Affidavit at paragraph 16. Further, if EPA was denied warrantless access, the geographic remoteness of the Unocal Facility would preclude subsequent inspection by EPA this year. Steinborn Affidavit at paragraph 10. Finally, EPA seeks a warrant to assure peaceful acquiessence to EPA actions by the owners and operators of the Unocal Facilities.

H. EPA has established requisite probable cause, and has shown reasonable legislative and administrative standards, satisfying the requirements set forth in the Barlow and Camara decisions, supra, to allow for a warrant to issue.

I. In this case, EPA has demonstrated that (1) EPA has reason to believe that a violation has occurred or is occurring (Steinborn Affidavit at paragraphs 10 and 11); (2) investigations, sampling, and other response actions are necessary and/or appropriate to ascertain the nature and extent to the violations which have occurred at the Unocal Facilities (Steinborn Affidavit at paragraph 13); and (3) consent for EPA and its officers, employees, representatives to enter upon the Unocal Facilities to carry out any response activities described herein has not been requested because of the need for surprise to assure noncompliance is not concealed, and given the remote geographic area subsequent inspections by EPA this year would not be economically possible if access is denied (Steinborn Affidavit at paragraph 16).

J. It is estimated that the activities for which this warrant is sought will take two (2) working days to complete beginning on Thursday, August 6, 1987. Should two (2) days prove to be an insufficient period of time for the EPA to conduct such activities due to circumstances unforeseen at this time, the United States will apply to this Court for an extension of any warrant granted by this Court.

A form of warrant is attached to this application.

DATED this ________ day of August, 1987.

Respectfully submitted,

MICHAEL SPAAN
United States Attorney

By: ______________________
MARK ROSENBAUM
Assistant United States Attorney

By: Monica Kirk
MONICA KIRK
Assistant Regional Counsel
U.S. Environmental Protection Agency

Michael R. Spann
United States Attorney
District of Alaska
Federal Building, Room 252
701 C Street
Anchorage, Alaska 99513

U.S. DISTRICT COURT
DISTRICT OF ALASKA

IN THE MATTER OF: UNOCAL CORPORATION Kenai Gas Field Anchorage, Alaska	Civil No. A87-82m WARRANT FOR ENTRY AND INVESTIGATION PURSUANT TO SECTION 1445 OF THE SAFE DRINKING WATER ACT, 42 U.S.C. §300j-4

TO: THE UNITED STATES MARSHAL FOR THE DISTRICT OF ALASKA AND ANY OFFICER, EMPLOYEE, OR DESIGNATED REPRESENTATIVE OF THE UNITES STATES ENVIRONMENTAL PROTECTION AGENCY.

An affidavit by Daniel Steinborn of the United States Environmental Protection Agency (EPA), having established that the need to determine whether Unocal Corporation acted or is acting in compliance with its EPA emergency permit and Part C of the Safe Drinking water Act, 42 U.S.C. §300h, in its operation of the Alaska Unocal Facilities, namely, (a) KU WD-1 located at T.5N, R.11W, Section 31, 1/4 Section 5E, 606 feet from the south line and 2297 feet from the east line in the Alaska Kenai Gas Field and (b) Poppy Lane Gravel Pit located at W 1/2, SW 1/4 Section 27 T5N, R.11W Seward Meridian, Alaska, and Unocal's Alaska offices on behalf of the

EPA, having established that the issuance of this warrant is constitutional, and that the right of the EPA to enter and investigate the Unocal Facilities is authorized by the Safe Drinking Water Act, (SDWA), 42 U.S.C. §300f; and this Court having found that reasonable grounds exist for issuance of a warrant for entry and investigation of the Unocal Facilities:

IT IS HEREBY ORDERED that upon service of this Warrant upon a duly designated representative of the Unocal Corporation, officers, employees and designated representatives of the EPA, including employees of the State of Alaska Department of Environmental Conservation (ADEC) and the Alaska Oil and Gas Conservation Commission (AOGCC), and the United States Marshal, shall be permitted to enter upon the property described as:

a. KU WD-1 located at T.5N, R.11W, Section 31, 1/4 Section SE, 606 feet from the south line and 2297 feet from the east line in the Alaska Kenai Gas Field.

b. Poppy Lane Gravel Pit located at W 1/2, SW 1/4 Section 27 T5N, R.11W Seward Meridian, Alaska.

c. The Unocal Corporate offices located in Anchorage, Alaska.

IT IS FURTHER ORDERED that officers, employees and designated representatives of the EPA, including any employees of the State of Alaska Department of Environmental Conservation (ADEC) and the Alaska Oil and Gas Conservation Commission (AOGCC), and the United States Marshal, shall be authorized and permitted to enter and, as necessary, to re-enter the above-described premises during the hours of 8:00 a.m. to 6:00 p.m., on August 6 and 7, 1987 to conduct thereon the following activities:

1. A detailed walking inspection of the entire inspection site and gravel pit;

2. The taking of samples, collected at sample ports and/or drums and tanks via sample containers and/or thiefs, from injection waste streams and reservoirs/containers that may contain waste intended for injection into well KU WD-1;

3. The examination of records files, papers, processes and controls required by permit to be found at the Unocal Facilities;

4. The taking of photographs; and

5. Any additional activities, including interviews and conferences, as necessary to ascertain compliance or noncompliance with permit conditions.

IT IS FURTHER ORDERED that a copy of this Warrant shall be left at the premises at the time of investigation.

IT IS FURTHER ORDERED that a brief inventory identifying any materials removed form the premises shall be furnished by EPA the the owner, operator, or representative of the Unocal Corporation.

IT IS FURTHER ORDERED that the duration of the entry, investigation, and activity authorized by this Warrant shall be of such reasonable length to enable the EPA to satisfactorily complete the above-described activities, but in no instance shall entry be permitted for longer than ten (10) working days from the date hereof.

IT IS FURTHER ORDERED that the United States Marshal is hereby authorized and directed to assist officers, employees, and representatives of the EPA in such manner as may be reasonable and necessary to properly execute this Warrant and all the provisions contained herein.

IT IS FURTHER ORDERED that a prompt return of this Warrant shall be made to this Court within twenty (20) days from the date hereof, showing that this Warrant has been executed, and that the entry and activities authorized herein has been completed within the time specified above.

Dated this 7th day of August 1987.

United States Magistrate

INVENTORY OF PROPERTY RECEIVED
PURSUANT TO WARRANT

While conducting the entry and inspection of the Unocal Facilities on the 6th and 7th days of August, 1987, I, Glen Bruck seized certain property.

The following is an inventory of the property seized:

I hereby swear and affirm that a receipt for the property was signed by me and left with Bob C. Smith, Kenai [?] Gas Field Foreman [?].

____

____

RETURN OF SERVICE

I hereby certify that a copy of the within Warrant was served by presenting a copy of the same to Bob C. Smith, an agent of Unocal Corporation on August 6, 1987, at the Unocal facilities in Alaska.

Glenn Bruck
Glenn Bruck

Hydrogeologist
Official Title

RETURN

Inspection of the establishment described in this Warrant completed on August 7, 1987.

Glenn Bruck
Glenn Bruck

Michael R. Spaan
United States Attorney
District of Alaska
Federal Building, Room 252
701 C Street
Anchorage, Alaska 99513

U.S. DISTRICT COURT
DISTRICT OF ALASKA

IN THE MATTER OF: UNOCAL CORPORATION Kenai Gas Field Anchorage, Alaska	Civil No. ____________ AFFIDAVIT IN SUPPORT OF APPLICATION FOR WARRANT FOR ENTRY AND INVESTIGATION PURSUANT TO SECTION 1445 OF THE SAFE DRINKING WATER ACT, 42 U.S.C. §300j-4

I, Daniel I. Steinborn, being duly sworn, state as follows:

1. I make this affidavit in support of the attached warrant which is sought pursuant to the authority of the Safe Drinking Water Act, 42 U.S.C. §300f et seq. I base this Affidavit on personal knowledge, discussions with representatives of Unocal Corporation and my review of government and other records.

2. I am a Supervisory Environmental Protection Specialist in the Water Division of the United States Environmental Protection Agency (EPA), Region 10, Seattle, Washington. I have been employed in the Water Division of the U.S. EPA, Region 10, since 1976.

3. Since February 1987, I have been the Chief of the Underground Injection Control (UIC) and Program Support Section, Drinking Water Branch

Form OBD-183
12-8-76 DOJ

Water Division, Region 10 of the EPA. I am responsible for supervising EPA's implementation of the UIC program in Region 10.

4. I received a Bachelor of Arts degree in Political Science at Western Washington State College, Bellingham, Washington in June 1969. I received a Master of Public Policy degree at the University of Michigan, Ann Arbor, Michigan in 1980.

5. In my capacity as Chief of the UIC Section, I am responsible for directing and coordinating the regulation and investigation of injection well KU WD-1 which is located in the Kenai Gas Field, Alaska and the Poppy Lane Gravel Pit site which is located near Meridian, Alaska. Both sites are owned and operated by Unocal Corporation (Union Oil Company of California) and are subject to the underground injection control (UIC) program of Part C of the Safe Drinking Water Act, 42 U.S.C. §300h et seq.

6. KU WD-1 is located at T.5N, R.11W, Section 31, 1/4 Section SE, 606 feet from the south line and 2297 feet from the east line in the Alaska Kenai Gas Field. The Poppy Lane Gravel Pit site is located in the W 1/2, SW 1/4 of Section 27 T5N, R11W Seward Meridian, Alaska.

7. KU WD-1 is operated subject to permits issued by EPA, pursuant to 42 U.S.C. 300h-3, and Alaska Oil and Gas Conservation Commission (AOGCC) which has received delegated authority from EPA to regulate Class II injection wells in Alaska.

The EPA emergency permit is issued for operating a Class II produced water well. The AOGCC permit authorizes the disposal of non-hazardous oil field wastes by injection. Both permits prohibit the injection of hazardous wastes.

8. In addition to injecting wastes generated by producing wells in the Kenai Gas Field, KU WD-1 is allowed to inject wastes obtained from the Poppy Lane Gravel Pit. Portions of the gravel pit were used for uncontrolled refuse disposal prior to and after Unocal's purchase in 1965. The site has also been used for disposal of construction and demolition debris, plus peat and soils not suitable for construction. Some of this waste may have been contaminated with gas well condensate.

9. Contamination investigations of the Poppy Lane Gravel Pit site have been conducted by the Alaska Department of Environmental Conservation (ADEC) since 1985. An extraction well located in the north west corner of the gravel pit has been used for removal of contaminated ground water. These waste fluids were transported and injected into KU WD-1. This action is allowable under the EPA emergency permit so long as Unocal demonstrates that the injected fluids are equivalent in composition to produced waters.

10. On or about November 14, 1986, EPA requested that Unocal demonstrate that the injected fluids are equivalent in composition to produced waters from the Kenai Gas Field. The analyses were incomplete and a chemical analysis of the actual injectate was not provided. EPA notified Unocal on May 27, 1987, that the demonstration was insufficient. Unocal has failed to provide further information and has, thereby, not demonstrated produced water equivalence.

11. Unocal's EPA permit establishes a maximum injection pressure of 1100 psi. Unocal's exceedence of the maximum injection pressure in October 1985, November 1985, February 1986, March 1986, April 1986 and August 1986 was confirmed.

12. On April 10, 1987, EPA informed Unocal by letter that it was in violation of the permit and that corrective actions were necessary.

13. In order to evaluate compliance with all permit conditions and to determine the operating status of the facility, EPA must enter and investigate the Unocal KU WD-1 injection well site, the Poppy Lane Gravel Pit and the Unocal office in Anchorage, Alaska (Unocal Facilities).

14. The following investigative activities must be performed at the Unocal Facilities:

(1) A detailed walking inspection of the entire inspection site and gravel pit;

(2) The taking of samples, collected at sample ports and/or drums and tanks via sample containers and/or thiefs, from injection waste streams and reservoirs/containers that may contain waste intended for injection into well KU WD-1;

(3) The examination of records, files papers, processes and controls required by permit to be found either on-site or at Unocal's offices;

(4) The taking of photographs; and

(5) Any additional activities, including interviews and conferences, as necessary to ascertain compliance or noncompliance with permit conditions.

15. The above described activities should take approximately two days and can be completed on August 6 and 7, 1987.

16. Because (1) injection activities are subject to easy and immediate alteration thereby concealing violations, (2) prior notice of the inspection in previous years has resulted in the appearance of concealment,

and (3) the remoteness of the site from Seattle precludes, for economic resource reasons, further EPA inspections in the event access is denied without prior notice, a warrant is necessary to ensure surprise and guarantee entry.

Daniel I. Steinborn
Daniel I. Steinborn

Subscribed and sworn to before me this 30th day of July, 1987.

Marie L. Atkinson
NOTARY PUBLIC

APPENDIX G

BASIC BALANCE PLUG JOB

APPENDIX G

BASIC BALANCE PLUG JOB

A cement plug may be set anywhere in a hole that is static. To set a balanced plug, the height of each fluid inside and outside the work string must be equal. In order to do a balanced plug job, certain volumes and heights of fluids must be calculated. These include volume of cement in cubic feet and sacks, mixing water for the cement, displacement fluid required to spot the cement, and (if water is run ahead of the cement) the volume of water required behind the cement to balance the water ahead.

A plug job could be as follows: set a 200 ft plug of Class A cement, 15.6 lb/gal, in an 8 3/4 in. open hole with 15 bbl of water run ahead of the cement. The plug is to be spotted through a work string of 4 1/2 in. EU 16.6 lb/ft drill pipe. The drill pipe is run to a depth of 6,000 ft (which will be the bottom of the cement plug). There is mud in the hole.

The first calculation would be the cubic feet of cement required for the job. Since a 200 ft plug is to be left in the open hole, go to the Cementing Tables, Section 210*, for capacity of the open hole in cu ft/lin ft and find

$$0.4176 \text{ cu ft/lin ft} \times 200 \text{ ft} = 84^{**} \text{ cu ft}$$

Class A cement mixed at 15.6 lb/gal is to be used for the job. Slurry properties for Class A cement are in Section 230 of the Cementing Tables. For 15.6 lb/gal, the water requirement is 5.2 gal/sk and the yield is 1.18 cu ft/sk. With this information, the sacks of cement can be determined by dividing the cubic feet required by the yield of a sack of cement.

$$\frac{84 \text{ cu ft}}{1.18 \text{ cu ft/sk}} = 71 \text{ sk}$$

Once the number of sacks has been determined, the volume of mixing water can be calculated from the slurry properties obtained for the Class A cement in Section 230. Each sack of cement requires 5.2 gal/sk; therefore,

$$71 \text{ sk} \times 5.2 \text{ gal/sk} = 369 \text{ gal of water}$$

$$\frac{369 \text{ gal of water}}{42 \text{ gal/bbl}} = 8.8 \text{ bbl of water}$$

Since 15 bbl of water are to be pumped ahead of the cement, we need to determine the height of this water in the annulus. The height of 15 bbl of

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*Section numbers are those found in Halliburton Cementing Tables, Halliburton Services, Duncan, Oklahoma 1981 or later.

**Results rounded to practical significant figures water in the annulus must be balanced by the same height of water inside the drill pipe. The 15 bbl of water ahead of the cement will end up in the annulus between the drill pipe and the hole; therefore, go to Section 122 (volume and height between drill pipe and hole) in the column headed lin ft/bbl and find 18.2804 lin ft/bbl. Calculate

15 bbl x 18.2804 lin ft/bbl = 274 ft of water in the annulus

There must be 274 ft of water inside the drill pipe to have equal balance. The volume required in the drill pipe is determined by going to Section 210 in the column bbl/lin ft to find .0142 bbl/lin ft for 4 1/2 in. EU 16.0 lb/ft drill pipe. Since each foot of this drill pipe will hold .0142 bbls, then

.0142 bbl/lin ft x 274 ft = 3.9 bbl of water

will be required in the drill pipe behind the cement or above the cement.

The displacement necessary to spot the cement plug must now be calculated. In order to calculate the displacement to spot the plug, the height of the cement must be determined. Cement height must be the same in the annulus and in the drill pipe when the plug is set. Therefore, for each foot of cement height in the annulus, there should be one foot of cement height in the drill pipe. The volume required to fill one linear foot of annulus can be found in Section 122. For the 4 1/2 in. to 8 3/4 in. annulus, under the column headed cu ft/lin ft, this value is 0.3071 cu ft/lin ft. To balance the one foot in the annulus, one foot in the drill pipe will require .0798 cu ft/lin ft. This is found in Section 210 in the column headed cu ft/lin ft for 4 1/2 in. EU 16.6 lb/ft drill pipe. Therefore, one linear foot of hole with the drill pipe in the hole has a volume of

.3071 cu ft/lin ft	(annular volume)
+ .0798 cu ft/lin ft	(drill pipe capacity)
.3869 cu ft/lin ft of hole with drill pipe in the hole.	

Since the volume of cement for the job was calculated as 84 cu ft, the height of cement can be calculated by dividing:

$$\frac{84 \text{ cu ft}}{.3869 \text{ cu ft/ft}} = 217 \text{ ft}$$

With the bottom of the drill pipe at 6,000 ft, then

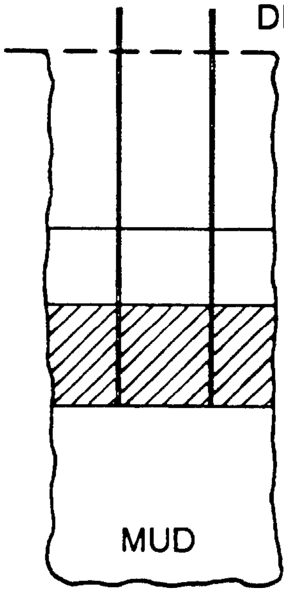
6,000 ft - 217 ft (cement height) - 274 ft (water height) =

5509 ft (mud displacement depth)

The volume of mud required for displacement is calculated by going to Section 210 for capacity of 4 1/2 in. EU 16.6 lb/ft drill pipe. In the column marked bbl/lin ft. find .0142 bbl/lin ft. With this figure, the calculation is

.0142 bbl/lin ft x 5509 ft = 72.2 bbl
of mud displacement to spot the plug

BASIC BALANCE PLUG JOB is calculated as follows:



PLUG JOB

Set 200 ft plug in 8 3/4 in. hole.

4 1/2 in. EU 16.6 lb/ft drill pipe to 6,000 ft

Class A cement mixed at 15.6 lb/gal

15 bbl of water ahead

CALCULATE:

1. Volume of cement in cu ft

   84 cu ft

2. Number of cement sacks

   71 sk

3. Mixing water in bbl

   8.8 bbl

4. Water behind cement in bbl

   3.9 bbl

5. Mud displacement in bbl

   78.2 bbl

1. Capacity of 8 3/4 in hole

   .4176 cu ft/ft x 200 ft = 84 cu ft

2. Sacks of cement

$$\frac{84 \text{ cu ft}}{1.18 \text{ cu ft/sk}} = 71 \text{ sk}$$

3. Mixing water

$$71 \text{ sk} \times 5.2 \text{ gal/sk} = 369 \text{ gal}$$

then

$$\frac{369 \text{ gal}}{42 \text{ gal/bbl}} = 8.8 \text{ bbl}$$

4. Water behind

V and H 18.2804 ft/bbl x 15 bbl = 274 ft

Capacity 4 1/2 in. drill pipe .0142 bbl/ft x 274 ft = 3.9 bbl

5. Mud displacement

Height of cement - V and H 4 1/2 in. x 8 3/4 in.	.3071 cu ft/lin ft
Capacity 4 1/2 in., 16.6 lb/ft	+ .0798 cu ft/lin ft
drill pipe	.3869 cu ft/lin ft

$$\frac{84 \text{ cu ft}}{.3869 \text{ cu ft/lin ft}} = 217 \text{ ft of cement}$$

6,000 ft - 217 ft of cement - 274 ft of water = 5509 ft of drill pipe to be displaced with mud

Capacity 4 1/2 in. EU 16.6 lb/ft drill pipe

.0142 bbl/ft x 5509 ft = 78.2 bbl

USEFUL BALANCE PLUG FORMULA

1. <u>BARRELS OF FRESH WATER AHEAD WHEN BARRELS OF FRESH WATER BEHIND IS GIVEN</u>

   The total volume of fresh water ahead of the cement plug is the product of the annulus capacity times the volume of fresh water behind the plug divided by the volume of the drill pipe. To calculate this volume in barrels use the following formula:

$$VFWA = \frac{(VA)\ (VFWB)}{(VDP)}$$

where:

- VFWA = Volume of fresh water ahead of the cement plug in barrels
- VDP = Volume (capacity) of the drill pipe in barrel/foot
- VA = Volume of annular space between the drill pipe and open hole or casing in barrels per foot
- VFWB = Volume of fresh water behind the cement plug in barrels

or:

Barrels of fresh water ahead of cement = (feet/barrel of drill pipe) x (barrel/feet of annulus) x (barrels of fresh water behind).

2. <u>BARRELS OF FRESH WATER BEHIND WHEN BARRELS OF FRESH WATER AHEAD IS GIVEN</u>

   The total volume of fresh water behind the cement plug is the volume of the fresh water ahead divided by the product of the drill pipe capacity times the annulus capacity. To calculate this volume in barrels use the following formula:

$$VFWB = \frac{(VDP)(VFWA)}{VA}$$

the symbols and units are the same as in 1. above.

or:

(feet/barrel in annulus) x (barrels of fresh water ahead) = Height of fresh water in annulus (HFWA) in feet; and (HFWA) x (barrel/foot in drill pipe) = Barrels of fresh water behind the cement.

3. HEIGHT OF CEMENT WITH DRILL PIPE IN

The vertical distance covered by a cement plug before the drill pipe is withdrawn from it is the total cement slurry volume divided by the sum of the capacities of the drill pipe plus the annular space between the open hole or casing. To calculate this distance in feet use the following formula:

$$HDC = \frac{TSV}{(VDP) + (VA)}$$

where:

HOC = Height of cement column in feet
TSD = Total cement slurry volume in barrels
VDP = Volume (capacity) of drill pipe in barrels/foot
VA = Volume of annular space between the drill pipe and casing or open hole in barrels/foot

or:

(barrel/foot of drill pipe) + (barrel/foot of annulus) = total barrels per foot (TBPF), and the (total slurry of volume in barrels) - (TBPF) = height of cement (HOC).

4. MUD TO BALANCE

The volume of mud required to displace and balance the cement plug is the sum of the total depth of the drill pipe minus the height of cement minus the height of water times the volume (capacity) of the drill pipe. To calculate the volume of mud required to balance the system in barrels use the following formula:

$$MTB = (TDP - HOC - HOW) \times (VDP)$$

where:

MTB = Volume of mud to balance in barrels
TDP = Total depth of drill pipe in feet
HOC = Height of cement plug in feet
HOW = Height of water in feet

or:

(total footage of drill pipe) - (height of cement column in feet) - (height of water column in feet) = height of mud column (HOM), and (HOM) x (barrel/feet of drill pipe) = mud to balance.

APPENDIX H

SCHEMATIC WELL DIAGRAMS SHOWING PLUG LOCATIONS

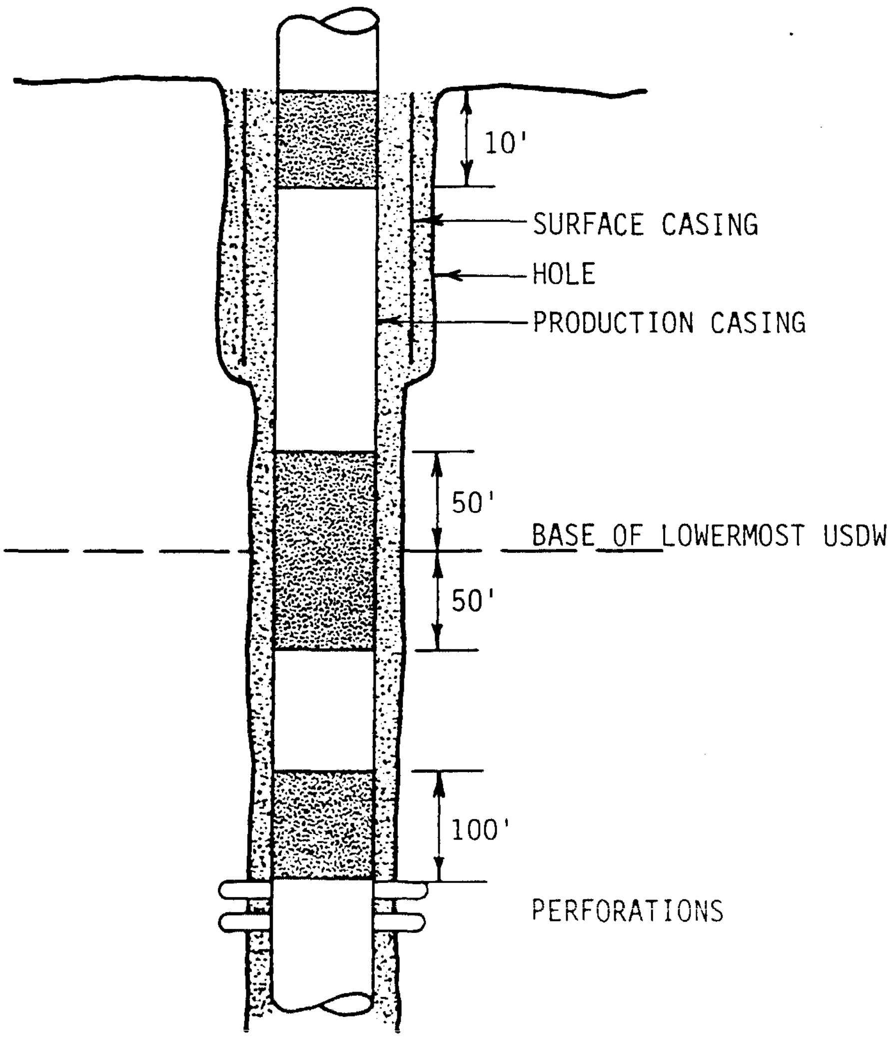


Fig. H.1 Wells with production casing and cemented through all USDW's and production horizons.

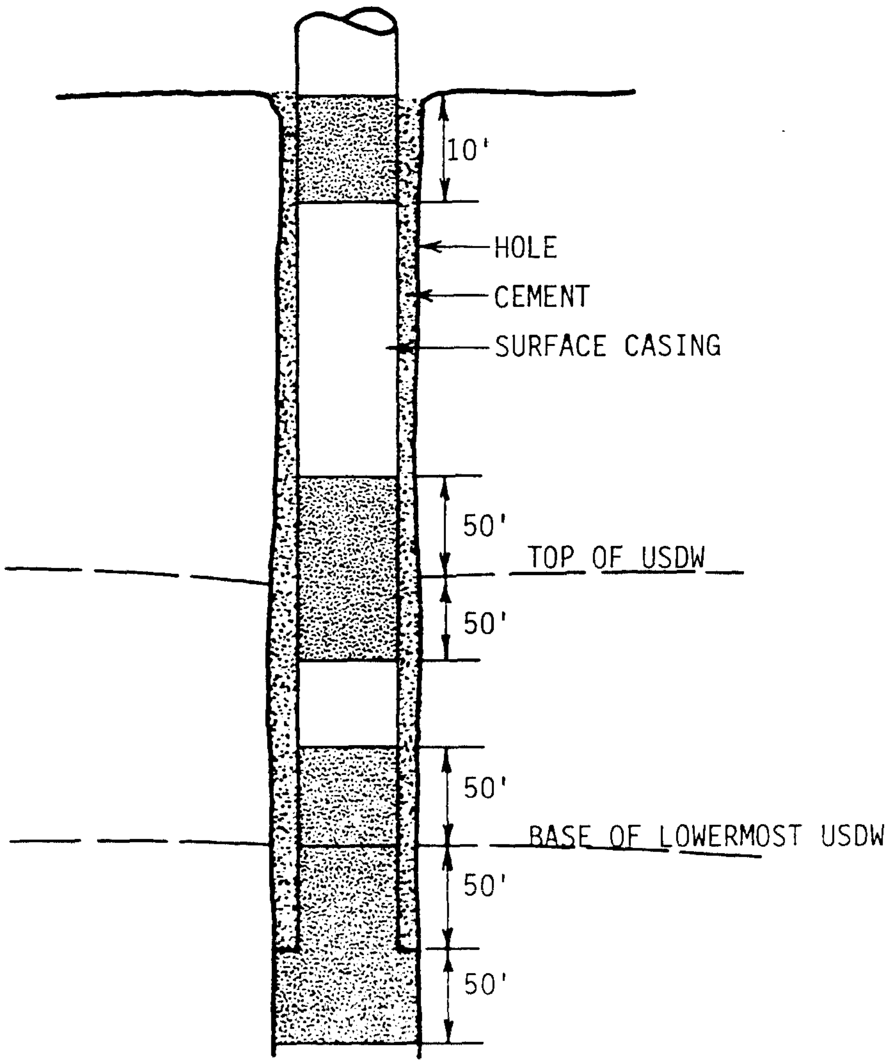


Fig. H.2 Well with sufficient casing set to protect all USDW's.

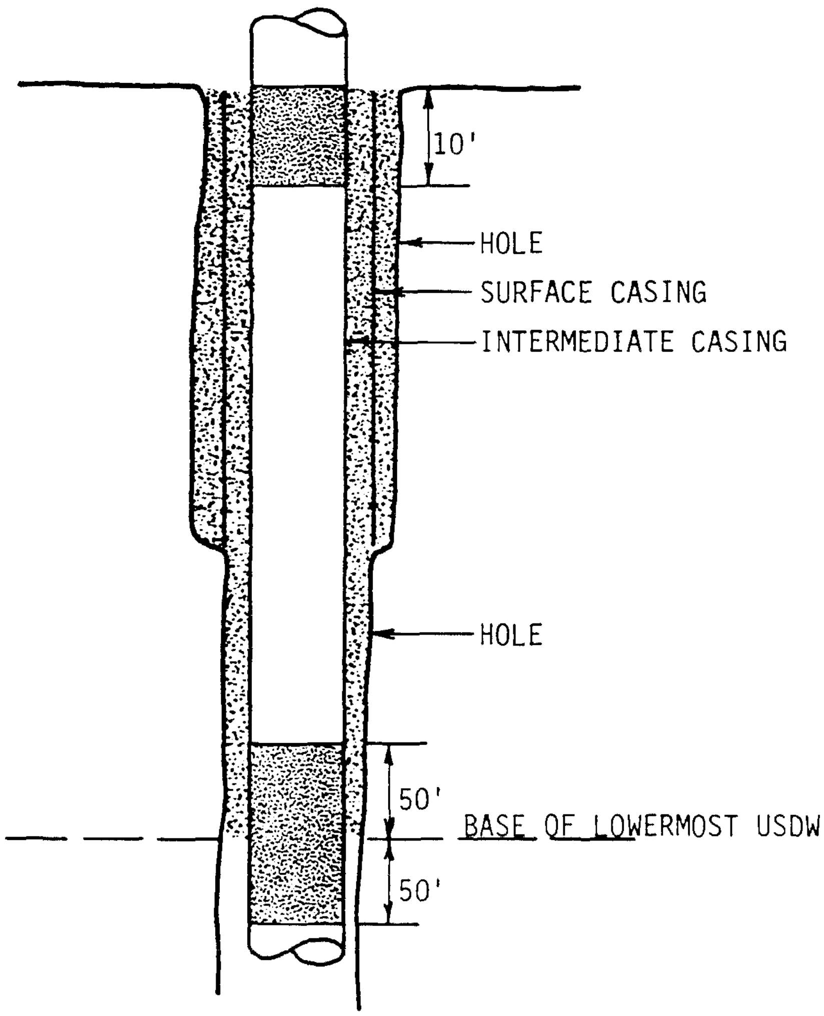


Fig. H.3 Well with intermediate casing and cemented through all USDW's and production horizons.

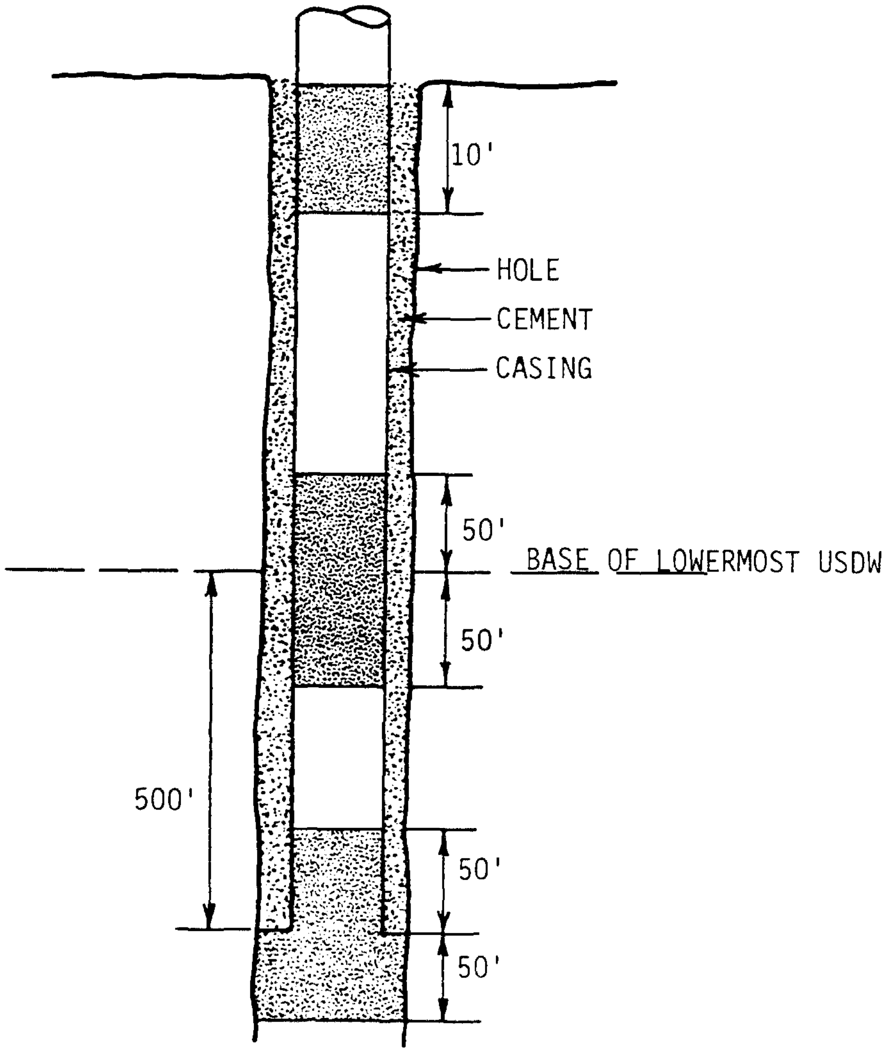


Fig. H.4 Well with surface casing set deeper than 200 feet below base of the USDW.

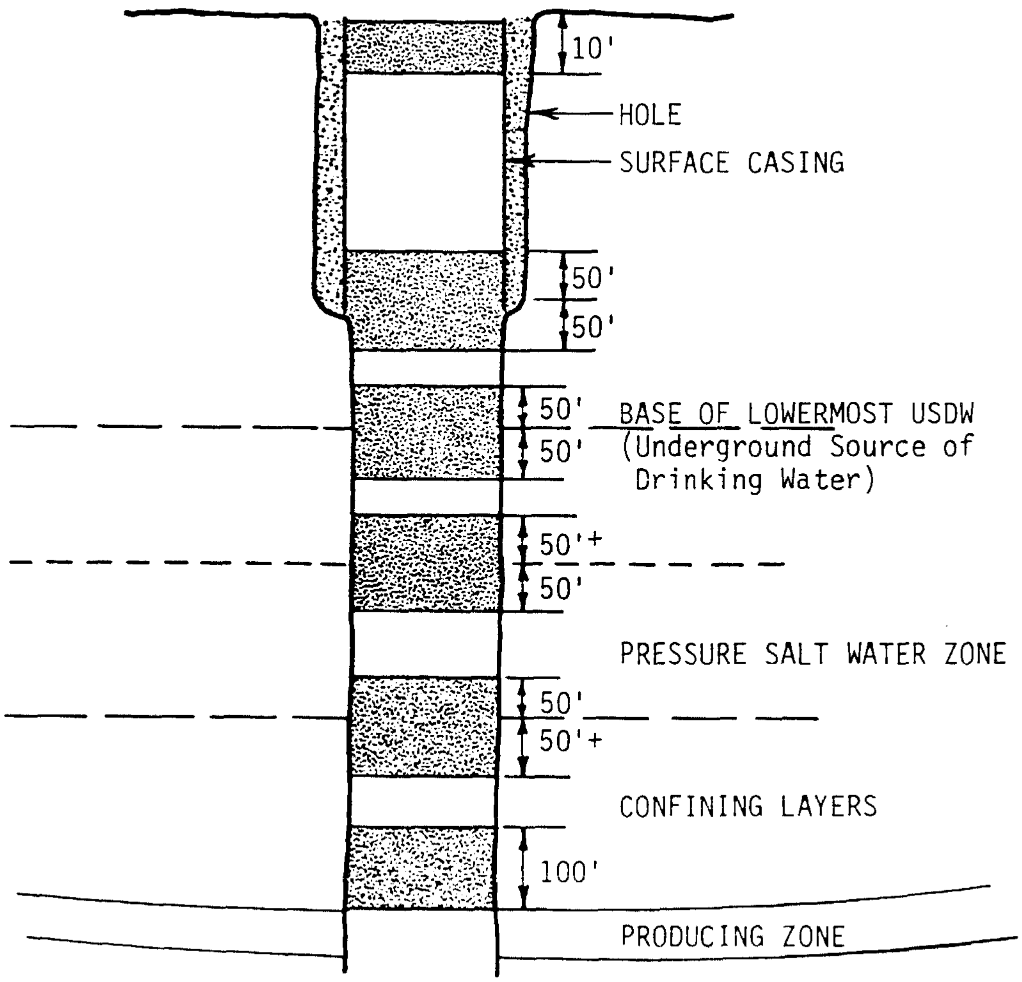


Fig. H.5 Well without production casing.

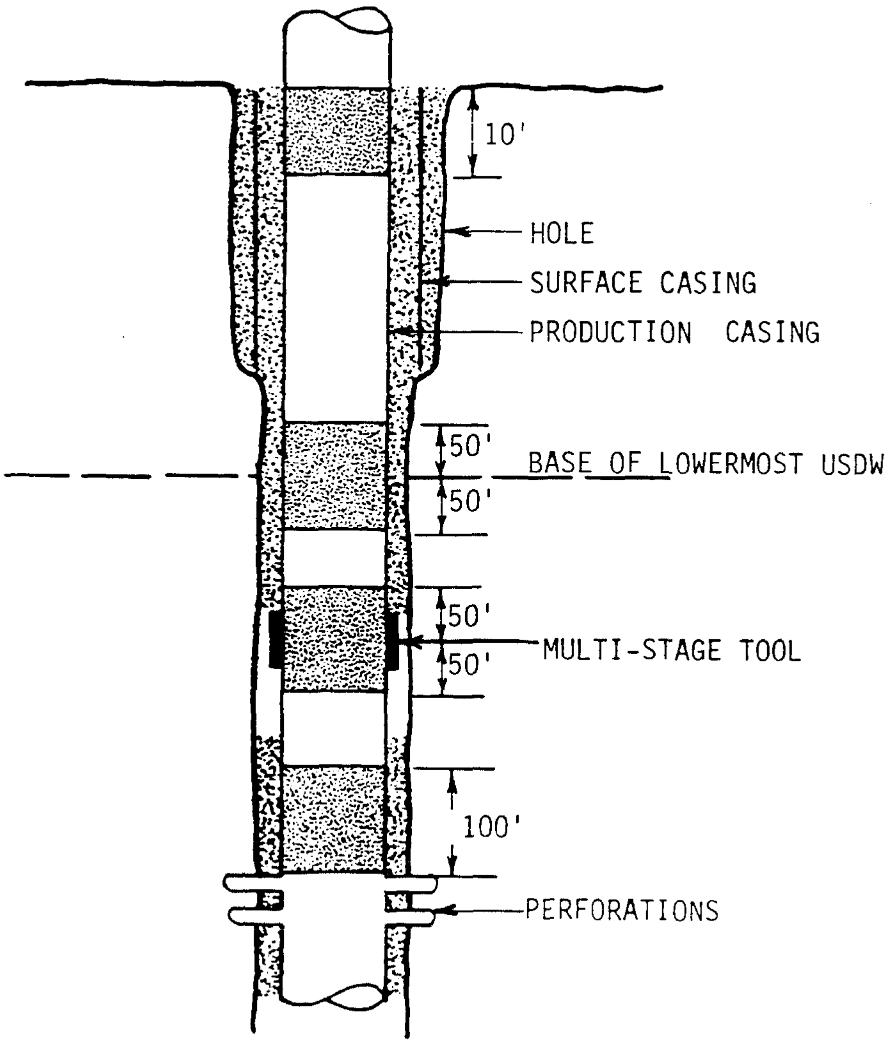


Fig. H.6 Multi-cased, cemented well with production casing.

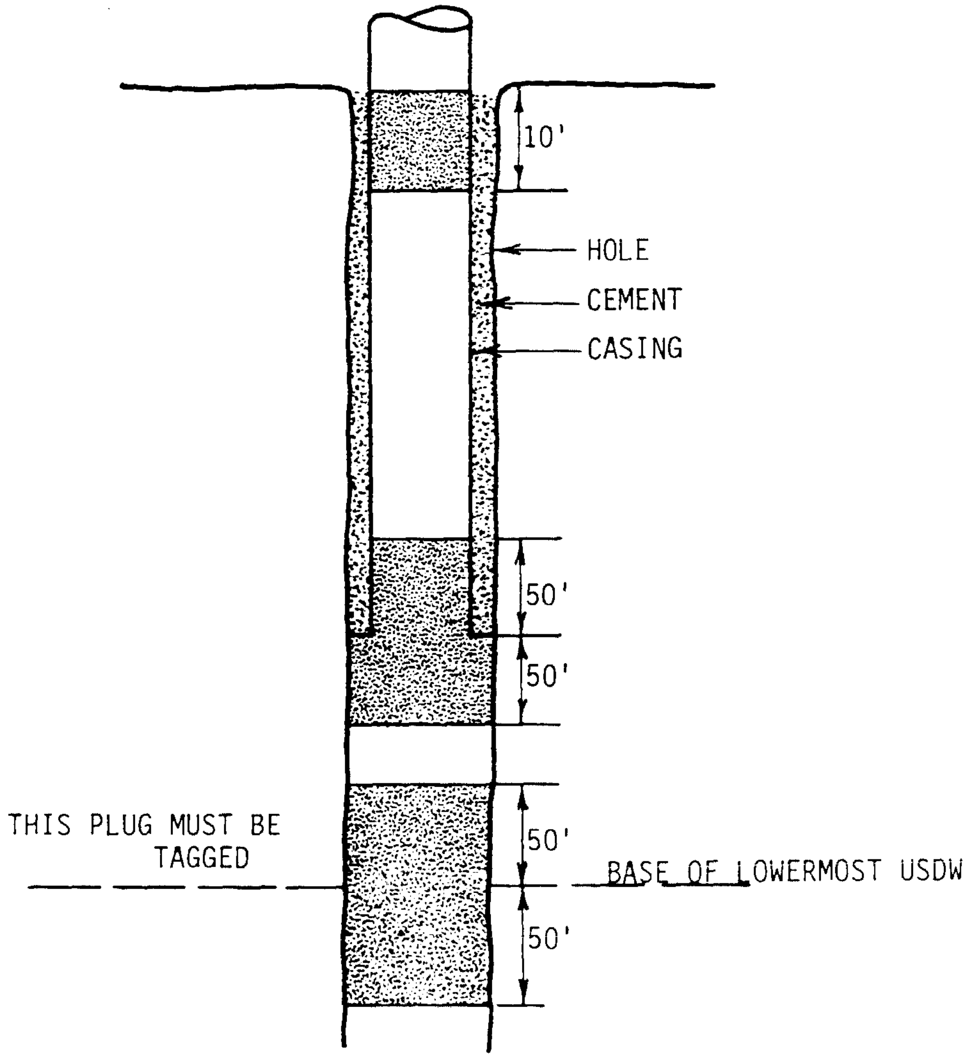


Fig. H.7 Well with insufficient casing set to protect all of the USDW.

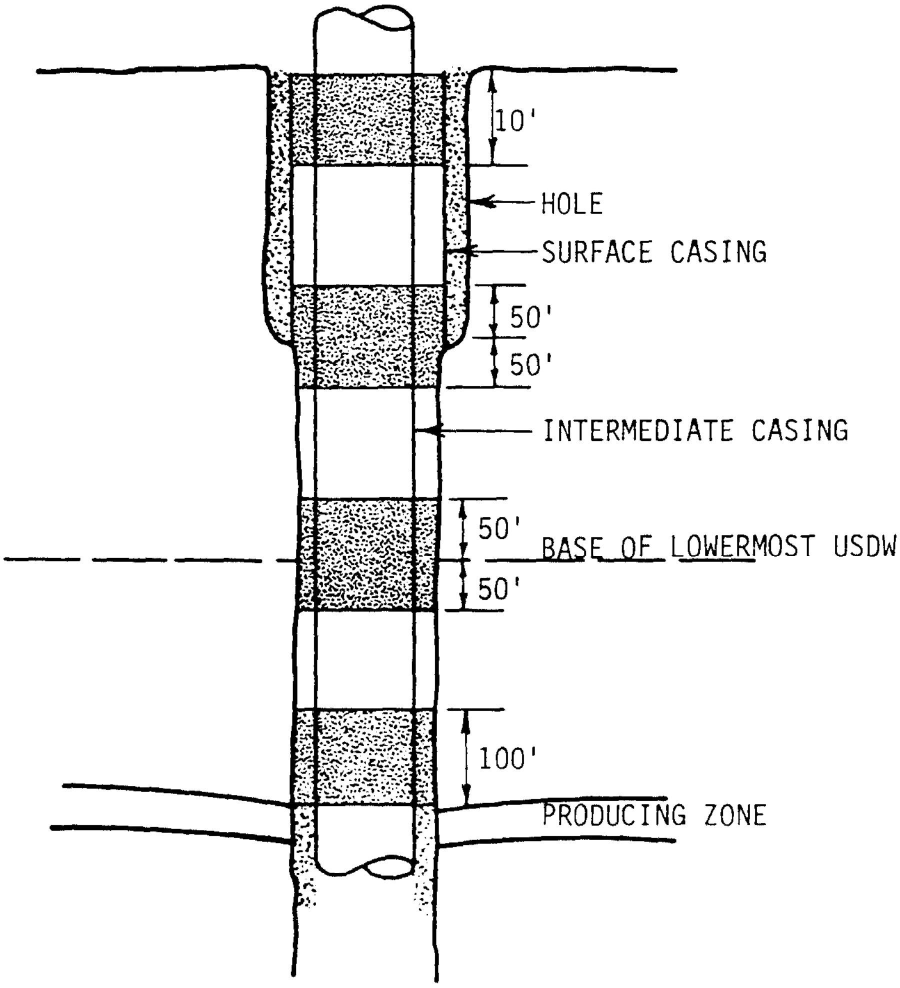


Fig. H.8 Well with intermediate casing not cemented through all USDW and production horizons.

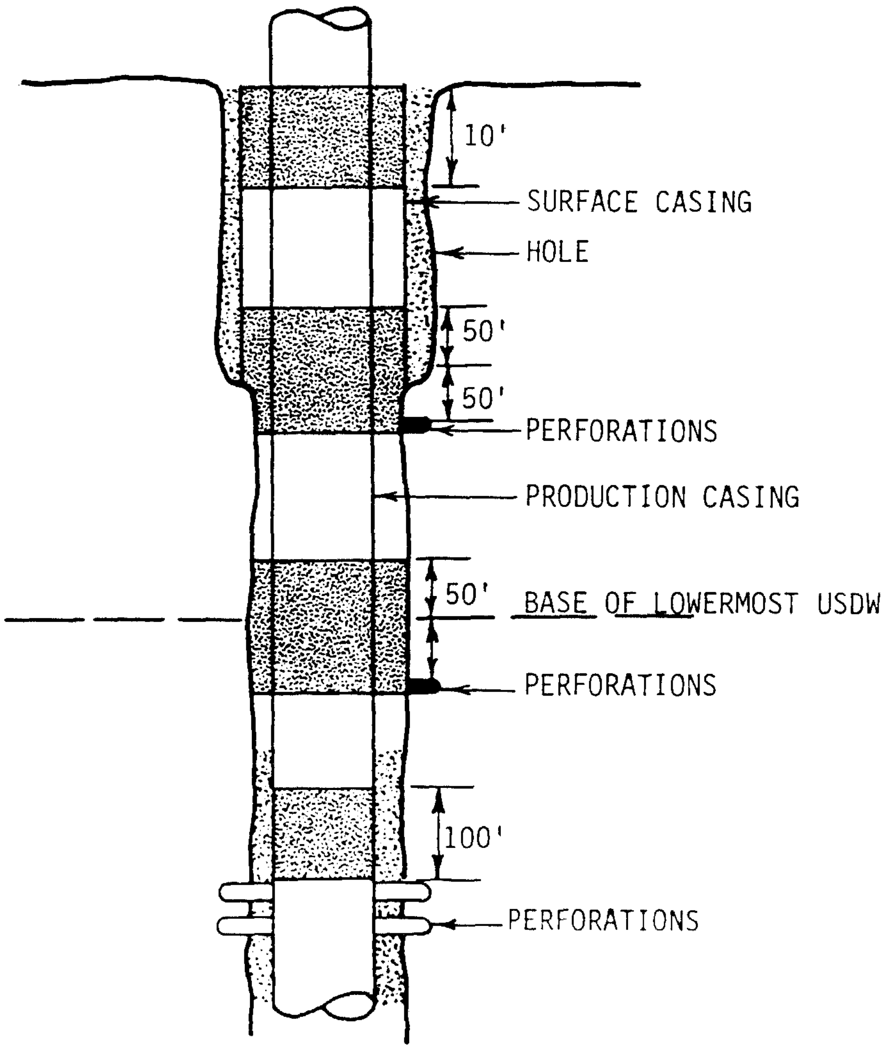


Fig. H.9 Well with production casing not cemented through all USDW's and production horizons.

APPENDIX I

WELLHEAD CONFIGURATION AND MONITORING

APPENDIX I

WELLHEAD CONFIGURATION AND MONITORING

I:1 Equipment and Instrumentation

Surveillance of an injection operation is primarily one of monitoring certain critical operating parameters at the wellhead. The greatest risk of escape of injected fluids is normally through or around the outside of the injection well itself, rather than through semi-impermeable confining beds, fractures, or unplugged wells. This section describes wellhead equipment and instrumentation used to monitor the integrity of an operating well.

Pressure- and flow- measuring instrumentation are of primary importance in monitoring an injection well. Miscellaneous parameters such as pH, temperature, wastewater chemistry, etc. may also be measured.

I:2 Process Flow Diagram

Ask the operator for a process flow diagram; with this you will be able to locate and identify instrumentation of special interest to you. Figure I.1 is a piping and instrumentation diagram (P & ID) around a Class I wellhead. Class II wellhead equipment is usually simpler (see Figure I.2).

I:3 Instrument Specifications

Ask for specification sheets for the monitoring instruments. A manufacturer's catalog will furnish detailed information on instrument calibration procedures, sensitivity, materials of construction and parts identification.

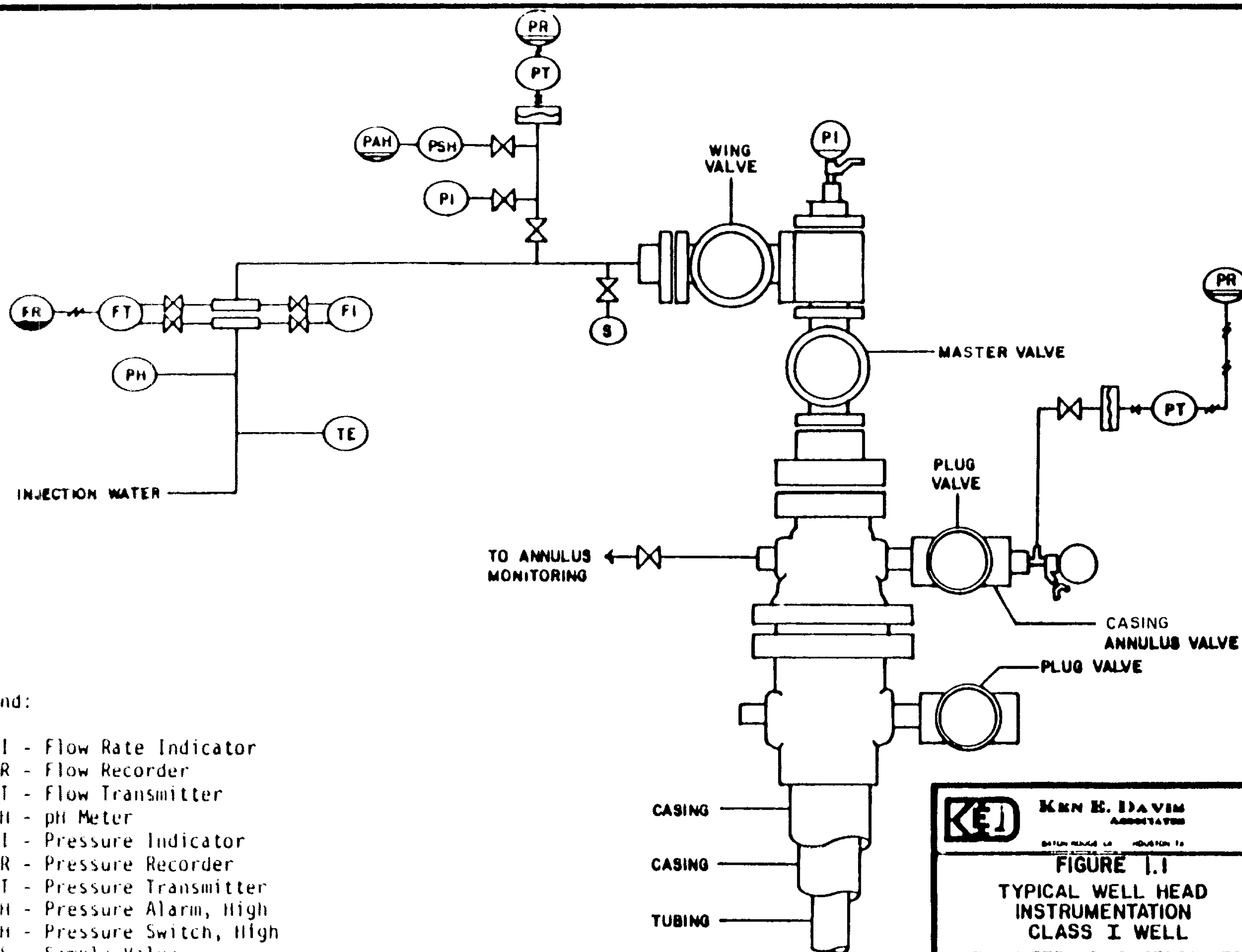
I:4 Meters and Gauges

As you inspect a well facility you will see pressure gauges located on the wellhead and/or wellhead piping. A flow meter will generally be located on the injection pipeline, whereas all recorders and totalizers are normally found in a control room or operations shelter.

Wellhead Configuration

I:5 Functions of Wellhead Equipment

The wellhead is used to maintain surface control of the well. It is usually made of cast or forged steel, machined to a close fit to form a seal and prevent well fluids from blowing out or leaking at the surface. Heavy fittings with parts designed to hold pressures up to 20,000 lbs per sq in (psi) may be found on some. Other wellheads may be just simple assemblies to support the weight of the tubing in the well, not made to hold pressure (Figure I.2).

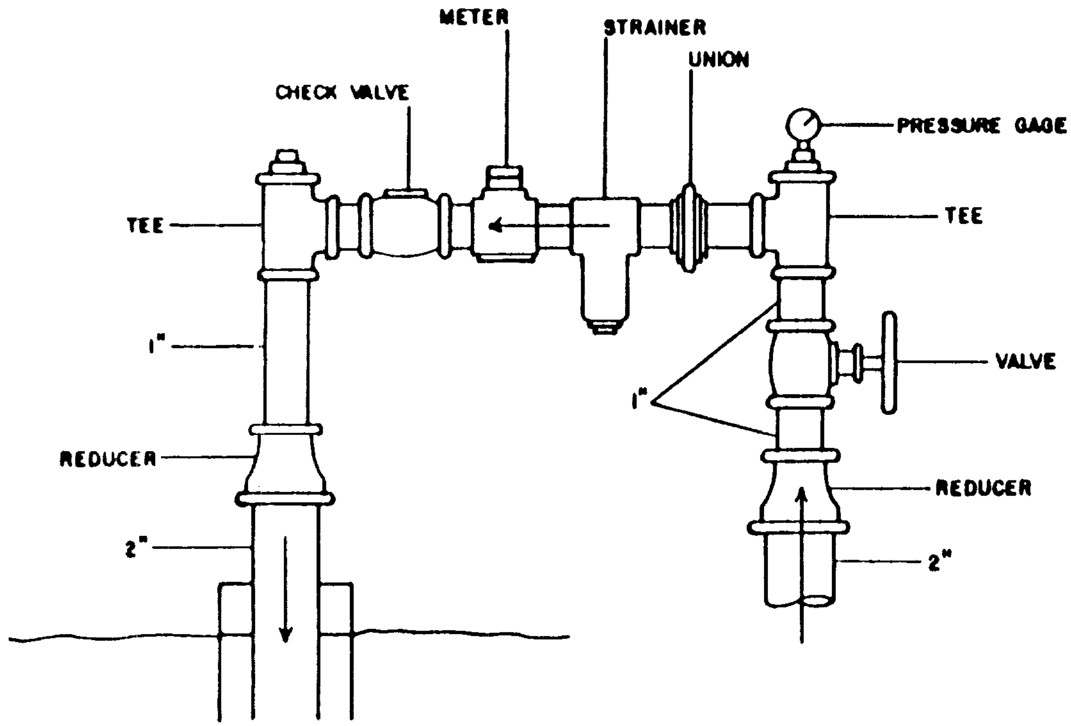


Legend:

FI - Flow Rate Indicator
FR - Flow Recorder
FT - Flow Transmitter
PH - pH Meter
PI - Pressure Indicator
PR - Pressure Recorder
PT - Pressure Transmitter
PAH - Pressure Alarm, High
PSH - Pressure Switch, High
S - Sample Valve

FIGURE 1.1
TYPICAL WELL HEAD
INSTRUMENTATION
CLASS I WELL
ENGINEERING ENTERPRISES

KEN E. DAVIS ASSOCIATES



KEN E. DAVIS
ASSOCIATES
BATON ROUGE LA   HOUSTON TX

FIGURE 1.2

TYPICAL WELLHEAD
CLASS II WELL

ENGINEERING ENTERPRISES, INC.

DATE 8-17-84	CHECKED BY MDJ	JOB NO 84-383
DRAWN BY PJR	APPROVED BY MDJ	DWG. NO 383-2

I:6 Well Components

The wellhead consists of casing head, tubing head, valves and pressure gauges.

1. Casing Head

During the drilling of the well, as each string of casing is run into the hole, it is necessary to install heavy fittings at the surface to which the casing is attached. Each string of casing is supported by a casing head already installed at the top of the next larger string of casing when it was run.

Each part of the casing head usually provides for the use of "slips" (gripping devices) to hold the weight of the casing. The casing head is used during drilling and workover operations as an anchor base for pressure-control equipment.

2. Tubing Head

The tubing head is similar in design; it sits on top of the uppermost casing head. Its most important functions are to:

- Support the tubing string
- Seal off pressures between the casing and outside of tubing at the surface
- Provide connections at the surface with which the flowing liquid can be controlled

In some wells that have only one string of casing, the casing head may not be used and the tubing head is supported on the top of the casing at or near ground level. Tubing heads vary in construction depending on the need to withstand pressure.

The tubing head must be easily taken apart and put together to facilitate well-servicing operations. Many different types have been developed for use under high pressures, with different designs and pressure ratings to fit expected well conditions.

3. Valving and Piping above the Wellhead

Injection wells that are expected to handle corrosive fluid (or high pressure) are usually equipped with special, heavy valves above the casing head (or tubing head). This group of valves (called a Christmas tree because of its shape and the large number of fittings), controls the flow of fluid into the well.

Pressure gauges are used to measure the annular and tubing pressures. The pressures are monitored for injection control and to comply with UIC regulations.

I:7 Injection Pressure Measurement

Injection pressure is monitored to provide a record of reservoir performance and to document compliance with regulations. Injection pressures are limited, to prevent hydraulic fracturing of the injection reservoir and confining beds and to prevent damage to well equipment. As with flow data, injection pressure should be continuously recorded.

A continuous recording will tell whether injection operations have been without incident. Increases in wellhead pressures can indicate formation plugging, tubing or packer restriction, or increase in reservoir pressure. Decreases in pressure can mean fracture of reservoir rocks, fracture of confining layer(s), or loss of external mechanical integrity.

I:8 Equipment Maintenance

Pressure indicators and recorders require periodic service. Lack of maintenance can yield poor data. A test gauge can be used to check the accuracy of the operator's gauge.

I:9 Pressure Gauges

The Bourdon Tube pressure gauge is the type generally used for measuring wellhead pressures. Gauges are available to cover pressure ranges of 0 to 5000 psi or higher. They are offered in a variety of materials to resist corrosive fluids.

I:10 Pressure Recorders

Circular chart recorders are frequently used to record pressures. They are driven by clocks available in a variety of time cycles: one to several hours, half-day, full day, week, etc. (Figures I.3 and I.4).

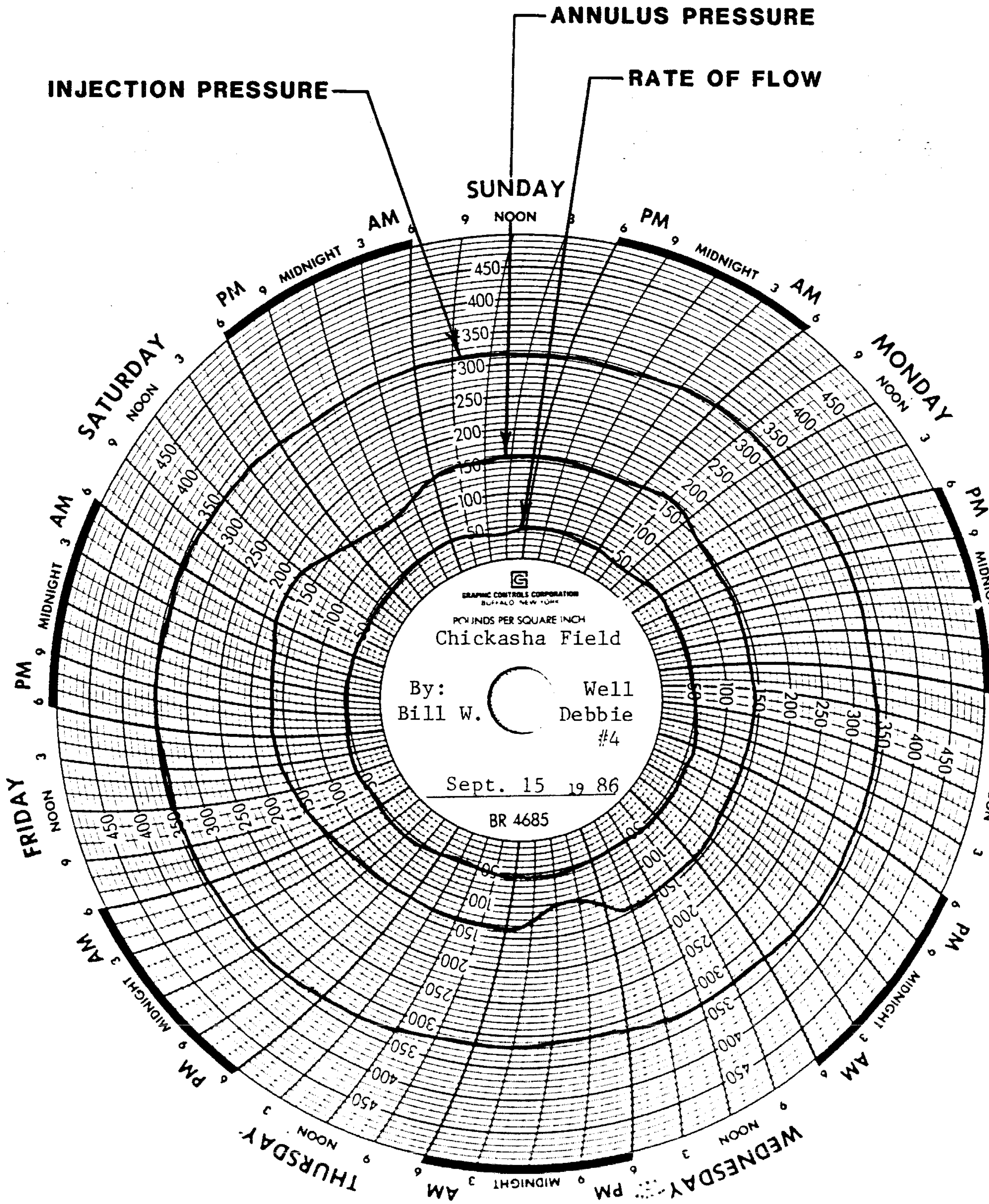
Strip chart recorders are generally used in a control room. Most commercially available strip chart recorders transform a voltage or current signal into displacement of a pen. They provide easily read graphic displays while compiling permanent historical records.

I:11 Injection Flow Volume and Rate Measurements

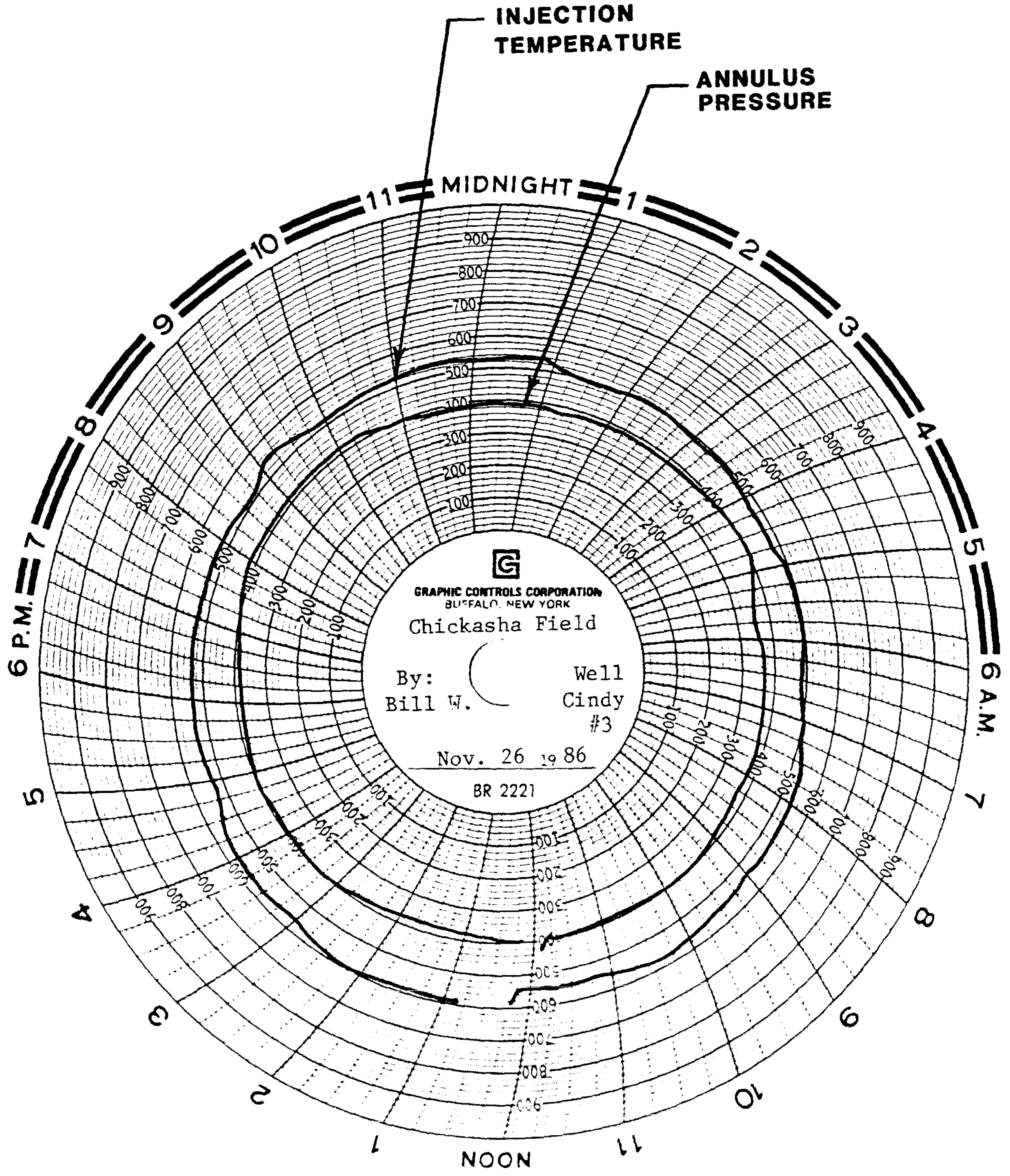
Purpose of volume measurement:

The purpose of monitoring the injected volume is to permit estimating the radial distance of injection fluid dispersion, to allow for interpretation of pressure data, and to provide a permanent record. This record provides evidence of compliance, aids in interpretation of well behavior, and may signal the need for well maintenance.

Flow meters also require regular maintenance. Current flow rate readings are necessary for the proper interpretation of pressure changes. The accuracy of a flow meter can be checked by: (a) comparing its performance with another known to be accurate; (b) comparing its readings



CONTINUOUS MONITORING
INJECTION PRESSURE/RATE OF FLOW/ANNULUS PRESSURE
SEVEN DAY RECORD
FIGURE I.3



CONTINUOUS MONITORING
INJECTION TEMPERATURE/ANNULUS PRESSURE
TWENTY-FOUR HOUR RECORD
FIGURE I.4

with rates calculated by observed changes in volume in a tank over a measured time period; or (c) comparing its readings with rates calculated while filling a container of known volume over a measured period of time.

If positive displacement pumps are used, flow measurements can be checked against the volumetric discharge of the pump. Pump strokes are counted for a specified period of time, say one minute, and the number of strokes multiplied by the discharge volume of the pump in gallons per stroke. Tables containing volumetric discharge data for various models of duplex and triplex pumps using different liner sizes are found in Appendix I.

I:12 Flow Regulation

Where positive displacement pumps are not used, flow may be controlled by special valves or by flow-control chokes. The automatic valve is used at the wellhead to adjust automatically to pressure changes. It consists of a valve body, an actuator (closing mechanism), and a pilot (sensing assembly). Its function is to protect both the well and the reservoir. When a pressure change occurs (indicating a leak) the automatic valve can stop the flow. Some valves are designed to close gradually to avoid destructive surge phenomena.

I:13 Common Types of Flow Meters and Recorders

Propeller (or turbine) meters and magnetic flow meters are commonly used to measure flow through pipe lines. Other types are venturi tube meters, ultrasonic meters and rotameters. The flow recorders will be identical to those used for pressure recording. Often flow and pressure will be traced on a single chart; in this case, a different color ink is used for each record.

I:14 Miscellaneous Measurement

Check the permit to determine if measurements other than flow rate and pressure are required;

- If the injected fluid is corrosive, pH may be (continuously) measured. Corrosion measurements may also be made.
- If fluid temperature is important, it may be measured.
- In some wastewater streams suspended solids measurement is important as a measure of the tendency to plug the receiving formation.
- Chemical analysis of injection water may be periodically conducted on grab samples to check compatibility or to identify constituents.

Annulus and Manifold Monitoring Systems

I:15 Annulus Pressure Monitoring

An annulus pressure monitoring system can reveal the loss of mechanical integrity before environmental damage is done. This is very important in Class I injection wells.

Pressure in the casing-tubing annulus of Class I wells should be monitored to detect changes that might indicate leakage through the injection tubing or the tubing-casing packer. Any unexplained change in annulus pressure should call for investigation of the cause.

I:16 Annulus Fluid Level Monitoring

The fluid level in the annulus of a well having casing and injection tube (but no packer) can be monitored by an electrode suspended in the annulus.

In the same kind of construction, i.e., no packer, a corrosive liquid can be pumped down the injection tubing while a non-corrosive liquid is pumped simultaneously down the annulus at a slightly greater pressure.

In another variation, a non-corrosive hydrocarbon -- such as kerosene -- floats in the annulus on top of the water. The interface between the hydrocarbon and the water -- or injection fluid -- is maintained constantly at a predetermined level.

I:17 Manifold Monitoring for a Cluster of Wells

Monitoring requirements are less stringent for Class II wells. Annulus monitoring is not specifically required. Where well density is high, manifold monitoring may be practiced. Flow and pressure measuring instruments are installed at locations where each manifold feeds a number of wells. Injectivity of each cluster of wells is monitored continuously.

REFERENCES - APPENDIX I

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Donaldson, E.C. Subsurface Disposal of Oilfield Brines and Petro- Chemical Wastes, Volume I. U.S. DOE, Environmental Control Symposium, 1978.

APPENDIX J

PUMP DISCHARGE PRESSURE AND VOLUME DATA

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Security DRESSER

Manufacturer: BETHLEHEM – Duplex																		
Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in) 4-3/4	5	5-1/4	5-1/2	5-3/4	6	6-1/4	6-1/2	6-3/4	7	7-1/4	7-1/2	7-3/4	8
225	225	60	14	2	–	1249	1121	1016	924	845	775	714	659	610	568	528	495	463
					–	4.4	4.9	5.4	5.9	6.5	7.1	7.7	8.3	8.9	9.6	10.3	11.0	11.8
325	325	60	16	2-1/4	–	1610	1450	1310	1190	1085	995	910	845	780	725	675	650	590
					–	4.9	5.5	6.0	6.6	7.2	7.9	8.6	9.3	10.0	10.8	11.6	12.4	13.2
450	450	60	16	2-1/2	–	2300	2055	1855	1680	1530	1400	1287	1186	1098	1018	945	884	826
					–	4.8	5.3	5.9	6.5	7.1	7.8	8.5	9.2	10.0	10.8	11.6	12.3	13.1
600	600	55	18	2-1/2	–	2965	2650	2395	2293	1972	1808	1660	1530	1415	1312	1220	1141	1068
					–	5.3	6.0	6.6	7.3	8.0	8.8	9.5	10.4	11.2	12.1	13.0	13.9	14.8
B-1640	1999	90	16	3-1/2	–	–	–	–	–	4570	–	3900	–	3360	–	2920	–	2570
					–	–	–	–	–	6.5	–	7.9	–	9.3	–	10.9	–	12.6
G-35	468	100	14	2-1/8	–	1485	–	1227	–	1031	–	878	–	757	–	660	–	580
					–	4.3	–	5.3	–	6.4	–	7.6	–	8.9	–	10.3	–	11.8
G-46	606	100	16	2-1/2	–	1691	–	1397	–	1174	–	1001	–	863	–	751	–	660
					–	4.8	–	5.9	–	7.1	–	8.5	–	10.0	–	11.6	–	13.1
G-65	874	100	16	2-1/2	–	2460	–	2033	–	1708	–	1456	–	1255	–	1093	–	961
					–	4.8	–	5.9	–	7.1	–	8.5	–	10.0	–	11.6	–	13.1
G-86	1212	100	18	2-3/4	–	3066	–	2534	–	2129	–	1814	–	1564	–	1363	–	1198
					–	5.2	–	6.5	–	7.9	–	9.4	–	11.1	–	12.8	–	14.7
H-25	336	100	12	2	1383	–	1132	–	944	–	799	–	685	–	593	–	–	–
					3.4	–	4.2	–	5.1	–	6.1	–	7.1	–	8.2	–	–	–
H-150	177	65	12	2	1180	–	948	855	779	711	653	600	555	515	478	–	–	–
					3.4	–	4.2	4.6	5.1	5.5	6.1	6.6	7.1	7.7	8.2	–	–	–

Manufacturer: CONTINENTAL-EMSCO – Duplex																	
Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in) 4-1/2	4-3/4	5	5-1/4	5-1/2	5-3/4	6	6-1/4	6-1/2	6-3/4	7	7-1/4	7-1/2
D-125	125	85	10	1-3/4	840	748	670	604	548	499	456	419	386	357	326	308	–
					2.5	2.9	3.2	3.5	3.9	4.3	4.7	5.1	5.5	6.0	6.4	6.9	–
D-175	175	75	12	1-7/8	1130	1000	898	807	731	666	608	558	514	475	–	–	–
					3.0	3.4	3.8	4.2	4.6	5.1	5.6	6.1	6.6	7.1	–	–	–
D-225	225	70	12	1-7/8	1551	1379	1234	1111	1007	916	838	769	708	654	607	565	–
					3.0	3.4	3.8	4.2	4.6	5.1	5.6	6.1	6.6	7.1	7.7	8.3	–
D-300	300	70	14	2	–	1600	1430	1280	1162	1060	965	886	815	754	698	650	602
					–	3.9	4.4	4.9	5.4	5.9	6.5	7.1	7.7	8.3	8.9	9.6	10.3
D-375	375	70	14	2	–	1991	1777	1600	1451	1318	1156	1104	1018	939	871	810	744
					–	3.9	4.4	4.9	5.4	5.9	6.5	7.1	7.7	8.3	8.9	9.6	10.3
DA-500	500	65	16	2-1/2	–	2720	2350	2100	1902	1710	1566	1435	1317	1225	1122	1035	970
					–	4.2	4.8	5.3	5.9	6.5	7.1	7.8	8.5	9.2	10.0	10.8	11.6
DB-550	550	65	16	2-1/2	–	2915	2580	2317	2090	1894	1727	1577	1449	1336	1235	1146	1067
D 560					–	4.2	4.8	5.3	5.9	6.5	7.1	7.8	8.5	9.2	10.0	10.8	11.6
DB-700	700	65	16	2-3/4	–	–	–	–	2727	2463	2236	2044	1875	1726	1593	1478	1374
DA-700					–	–	–	–	5.8	6.4	7.0	7.7	8.4	9.1	9.8	10.6	11.4
DB-850	850	60	18	3	–	–	–	–	–	2954	2680	2440	2240	2055	1895	1758	1629
DA-850					–	–	–	–	–	7.0	7.7	8.4	9.2	10.0	10.9	11.7	12.7
DC-1000	1000	60	18	3	–	–	–	–	–	3480	3153	2871	2635	2418	2229	2068	1917
D-1000					–	–	–	–	–	7.0	7.7	8.4	9.2	10.0	10.9	11.7	12.7
DC-1350	1350	60	18	3-1/2	–	–	–	–	–	–	4474	4058	3706	3392	3123	2880	2669
D 1350					–	–	–	–	–	–	7.3	8.1	8.8	9.6	10.5	11.4	12.3
DC 1650	1650	60	18	3-1/2	–	–	–	–	–	–	5489	4980	4530	4146	3817	3520	3262
D 1650					–	–	–	–	–	–	7.3	8.1	8.8	9.6	10.5	11.4	12.3

NOTE: Top Value: Discharge Pressure / Bottom Value: Discharge Volume

Security

DRESSER

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Manufacturer CONTINENTAL-EMSCO — Triplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 3½	3¾	4	4¼	4½	4¾	5	5¼	5½	5¾	6	6¼	6½	6¾	7	7¼	7½
F-350	350	175	7	3525 0.9	3080 1.0	2705 1.1	2390 1.3	2135 1.4	— —	1730 1.8	1570 2.0	1428 2.2	1309 2.4	1200 2.6	1106 2.8	1020 3.0	949 3.2	— —	— —	— —
F-500	500	165	7½	4851 1.0	— —	3818 1.2	3282 1.4	3025 1.5	2632 1.7	2440 1.9	2154 2.1	2024 2.3	1794 2.5	1699 2.7	1565 3.0	1447 3.2	1341 3.5	— —	— —	— —
F-650	650	160	8	— —	— —	— —	4237 1.5	3788 1.6	3401 1.8	3070 2.0	2770 2.3	2525 2.5	2336 2.7	2128 3.0	— —	1816 3.5	1685 3.7	— —	— —	— —
F-800	800	150	9	— —	— —	5585 1.5	— —	4415 1.9	3970 2.1	3590 2.3	3260 2.5	2965 2.8	2715 3.0	2490 3.3	2295 3.6	2120 3.9	1968 4.2	— —	— —	— —
F-1000	1000	140	10	— —	— —	— —	— —	5340 2.1	4790 2.3	4330 2.5	3920 2.8	3575 3.1	3270 3.4	3010 3.7	2770 4.0	2558 4.3	2370 4.6	— —	— —	— —
F-1300	1300	120	12	— —	— —	— —	— —	— —	— —	— —	— —	4516 3.7	4126 4.0	3791 4.4	3494 4.8	3260 5.2	2997 5.6	2789 6.0	— —	— —
F-1600	1600	120	12	— —	— —	— —	— —	— —	— —	— —	— —	5558 3.7	5078 4.0	4665 4.4	4299 4.8	4012 5.2	3688 5.6	3423 6.0	— —	— —
FA-1300	1300	120	12	— —	— —	— —	— —	— —	— —	5464 3.0	— —	4516 3.7	4126 4.0	3892 4.4	3494 4.8	3234 5.2	2997 5.6	2789 6.0	2598 6.3	2428 6.9
FA-1600	1600	120	12	— —	— —	— —	— —	— —	— —	5500 3.0	— —	5500 3.7	5078 4.0	4665 4.4	4299 4.8	3981 5.2	3688 5.6	3423 6.0	3197 6.3	2988 6.9

Manufacturer: ELLIS WILLIAMS CO. - Duplex

Model	Max. I.H.P.	Max. S.P.M.	Stroke Length	Rod Size	Liner Size (in) 5	5½	6	6½	7
14W-400	400	75	14	2-1/4	1774 4.4	1444 5.4	1200 6.5	1013 7.7	868 8.5
15W-600	600	70	15	2-5/8	2801 4.5	2258 5.5	1863 6.7	1566 8.0	1334 9.4
16W-800	800	65	16	2-3/4	3883 4.6	3113 5.8	2562 7.0	2142 8.4	1822 9.8

Manufacturer: ELLIS WILLIAMS CO. — Triplex

Model	Max. I.H.P.	Max. S.P.M.	Stroke Length	Liner Size (in) 2	2½	3	3½	3¾	4	4¼	4½	5	5½	6	6½	7
W-330	300	450	7	3601 3	2305 4	1600 6	1176 9	1024 1.0	900 1.1	—	—	—	—	—	—	—
W-440	440	420	6	—	—	—	2155 8	1878 9	1650 1.0	1462 1.1	1304 1.2	—	—	—	—	—
WH-440	525	300	7	—	—	—	—	—	2368 1.1	—	1868 1.4	1512 1.8	1389 2.2	1050 2.6	880 3.0	—
W-600	600	135	8-1/2	—	—	—	—	—	—	—	—	3159 2.2	2615 2.6	2198 3.1	1870 3.7	1612 4.3
WH-600	600	150	10	—	—	—	—	—	—	—	2988 2.1	2419 2.6	2000 3.1	1680 3.7	1432 4.3	1234 5.0
W-850	850	115	9-1/2	—	—	—	—	—	—	—	—	4716 2.4	3890 2.9	3269 3.5	2788 4.1	2401 4.8
W-1000	1000	135	9-1/2	—	—	—	—	—	—	—	—	4716 2.4	3898 2.9	3275 3.5	2791 4.1	2408 4.8
W-1400	1400	110	14	—	—	—	—	—	—	—	—	5000 3.6	4548 4.3	3819 5.1	3254 6.0	2806 7.0
W-1700	1700	110	15	—	—	—	—	—	—	—	—	5000 3.8	5000 4.6	4335 5.5	3687 6.5	3180 7.5
W-2000	2000	110	15	—	—	—	—	—	—	—	—	5000 3.8	5000 4.5	5000 5.5	4338 6.5	3741 7.5

NOTE: Top value: Discharge Pressure
Bottom value: Discharge Volume

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Security
DRESSER

Manufacturer GARDNER-DENVER — Duplex

Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in) 5	5-1/4	5-1/2	5-3/4	6	6-1/4	6-1/2	6-3/4	7	7-1/4	7-1/2	7-3/4	8
FH-FXL	625	55	20	2-1/2	2559 5.9	2280 6.7	2115 7.4	1929 8.2	1777 8.9	1631 9.8	1514 10.6	1404 11.5	1306 12.5	1217 13.5	1132 14.4	1065 15.5	1000 16.5
FK-FXK	255	70	14	2	1163 4.4	— —	961 5.4	— —	807 6.5	— —	688 7.7	638 8.3	593 8.9	543 9.6	— —	— —	— —
FO-FXO	149	70	10	1-3/4	772 3.2	— —	638 3.9	— —	536 4.7	— —	457 5.5	423 6.0	393 6.4	367 6.9	— —	— —	— —
FO-FXQ	320	65	16	2	1319 5.0	1259 5.6	1132 6.1	1031 6.8	951 7.4	876 8.1	810 8.8	751 9.5	699 10.2	651 11.0	605 11.8	570 12.6	— —
*FXN	400	75	14	2	1692 4.4	— —	1398 5.4	— —	1175 6.5	— —	1001 7.7	— —	863 9.0	805 9.6	752 10.3	— —	— —
FZ-FXZ	220	70	12	2	988 3.7	— —	817 4.6	— —	686 5.5	— —	585 6.6	542 7.1	504 7.7	470 8.2	— —	— —	— —
GR-GXP	625	70	16	2-1/2	2725 4.8	— —	2205 5.9	— —	1825 7.1	— —	1530 8.5	1410 9.2	1305 10.0	1205 10.8	— —	1055 12.3	— —
GR-GXPA	550	65	16	2-1/2	2400 4.8	2140 5.3	1990 5.9	1820 6.5	1670 7.1	1550 7.8	1425 8.5	1320 9.2	1225 10.0	1145 10.8	1070 11.6	— —	— —
GR-GXR	825	60	18	2-3/4	— —	— —	2636 6.5	2510 7.2	2215 7.9	2025 8.6	1887 9.4	1750 10.2	1627 11.1	1517 11.9	1418 12.8	— —	— —
GXH	1250	60	18	3-1/4	— —	— —	— —	— —	3942 7.7	— —	3281 9.2	3035 10.1	2793 10.9	2580 11.8	2400 12.7	2232 13.6	— —
GXN	500	70	14	2-1/4	2435 4.3	— —	1974 5.3	— —	1633 6.4	— —	1377 7.6	1271 8.2	1177 8.8	1094 9.5	— —	— —	— —
GXP	700	70	16	2-1/2	3060 4.8	— —	2470 5.9	— —	2040 7.1	— —	1712 8.5	1578 9.2	1460 10.0	1357 10.8	1171 11.6	— —	— —
GXO	350	70	16	2-1/4	1470 4.9	— —	1195 6.0	— —	1000 7.3	— —	843 8.6	778 9.3	720 10.1	668 10.9	— —	— —	— —
GXR	1000	60	18	2-3/4	— —	— —	— —	— —	3113 7.8	2815 8.6	2578 9.4	2373 10.2	2194 11.1	2035 11.9	1903 12.8	1172 13.7	— —
KXF	700	70	16	2-1/2	— —	— —	2470 5.9	— —	2040 7.1	— —	1712 8.5	1578 9.2	1460 10.0	1357 10.8	1171 11.6	— —	— —
KXG	1000	60	18	2-3/4	— —	— —	— —	— —	3113 7.8	2815 8.6	2578 9.4	2373 10.2	2194 11.1	2035 11.9	1903 12.8	1172 13.7	— —
KXJ	1500	60	18	3-1/4	— —	— —	— —	— —	4845 7.5	— —	4025 9.0	3640 10.0	3350 10.9	3095 11.8	— —	— —	— —

Manufacturer GARDNER-DENVER — Triplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 3	3-1/4	3-1/2	4	4-1/2	5	5-1/2	6	6-1/4	6-1/2	7
PJ-8	275	175	8	3118 .7	2657 .9	2290 1.0	1753 1.3	1386 1.6	1122 2.0	— —	— —	— —	— —	— —
PY-7	500	160	7	— —	— —	— —	— —	3150 1.4	2550 1.8	2110 2.2	1770 2.6	— —	1510 3.0	1300 3.5
PZ-7	550	165	7	— —	— —	— —	— —	3556 1.4	2880 1.8	2380 2.2	2000 2.6	— —	1705 3.0	1470 3.5
PZ-8	750	165	8	— —	— —	— —	5381 1.3	4238 1.6	3433 2.0	2843 2.5	2385 2.9	2200 3.2	— —	— —
PZ-9	1000	150	9	— —	— —	— —	— —	5530 1.9	4485 2.3	3710 2.8	3110 3.3	2875 3.6	2650 3.9	2285 4.5
PZ-10	1350	130	10	— —	— —	— —	— —	— —	— —	5200 3.1	4400 3.7	— —	3700 4.3	3200 5.0
PZ-11	1600	130	11	— —	— —	— —	— —	— —	— —	5595 3.4	4702 4.0	— —	4006 [illegible]	3454 [illegible]

* Liner also available in 4" and 4-1/2" sizes

NOTE: Top Value Discharge Pressure / Bottom Value Discharge Volume

Security

DRESSER

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Manufacturer HALLIBURTON — Triplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 5	5½	6
HT-400D	275	75	8	4500	3000	3000
				2.0	2.5	2.9

Manufacturer IDECO — Duplex

Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in) 3-3/4	4	4-1/2	4-3/4	5	5-1/4	5-1/2	5-3/4	6	6-1/4	6-1/2	6-3/4	7	7-1/4	7-1/2	7-3/4	8
MM-200	200	80	10	1-7/8	2000	1825	1460	—	1163	—	970	864	790	—	667	617	—	—	—	—	—
					1.7	2.0	2.5	—	3.1	—	3.8	4.2	4.6	—	5.5	5.9	—	—	—	—	—
MM-300 MM-300GB	300	80	12	2	2500	2380	1830	—	1458	—	1185	—	985	—	832	—	712	662	—	—	—
					2.0	2.3	3.0	—	3.7	—	4.6	—	5.5	—	6.6	—	7.7	8.2	—	—	—
MM-450	450	80	12	2-1/4	—	—	2830	2510	2225	—	1810	—	1500	—	1265	1165	1082	1000	—	—	—
					—	—	2.8	3.2	3.7	—	4.5	—	5.5	—	6.5	7.0	7.6	8.2	—	—	—
MM-550 MM-550F	550	65	15	2-1/2	—	—	—	3120	2775	2480	2235	2020	1845	1690	1550	1425	1320	1220	—	—	—
					—	—	—	4.0	4.5	5.0	5.5	6.1	6.7	7.3	8.0	8.7	9.4	10.1	—	—	—
MM-600	600	65	16	2-1/2	—	—	—	—	2830	2540	2280	2060	1880	—	1582	1348	1250	1165	—	—	—
					—	—	—	—	4.8	5.3	5.9	6.5	7.1	—	8.5	9.2	10.0	10.8	—	—	—
MM-700 MM-700F	700	65	16	2-3/4	—	—	—	—	—	3038	2730	2470	2246	—	1878	—	1595	1487	1375	1285	—
					—	—	—	—	—	5.2	5.8	6.3	7.0	—	8.4	—	9.9	10.6	11.4	12.2	—
MM-900	900	65	16	3	—	—	—	—	—	—	3810	3250	2950	—	2459	—	2085	1933	1795	1670	1562
					—	—	—	—	—	—	5.2	6.0	6.8	—	8.2	—	9.7	10.4	[illegible]	12.1	12.9
MM-1000 MM-1000GB	1000	65	16	3	—	—	—	—	—	—	4020	—	3280	—	2735	2510	2325	2155	[illegible]	1860	1740
					—	—	—	—	—	—	5.2	—	6.8	—	8.2	8.9	9.7	10.4	11.2	12.1	12.9
MM-1250	1250	65	18	3-1/8	—	—	—	—	—	—	—	—	3680	3350	3065	2820	2600	2400	2230	2079	1940
					—	—	—	—	—	—	—	—	7.6	8.4	9.2	10.0	10.8	11.7	12.6	13.5	14.5
MM-1450F	1450	65	18	3-1/8	—	—	—	—	—	—	—	—	4270	3880	3560	3270	3010	2790	2590	—	—
					—	—	—	—	—	—	—	—	7.6	8.4	9.1	10.0	10.8	11.7	12.5	—	—
MM-1625	1625	65	18	3-3/8	—	—	—	—	—	—	—	—	4920	—	4060	3790	3430	3170	2940	—	—
					—	—	—	—	—	—	—	—	7.4	—	8.9	9.7	10.6	11.5	12.4	—	—
MM-1750F	1750	65	18	3-3/8	—	—	—	—	—	—	—	—	5000	4800	4380	4020	3700	3410	3175	—	—
					—	—	—	—	—	—	—	—	7.4	8.2	9.0	9.8	10.6	11.5	12.3	—	—

Manufacturer IDECO — Triplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 4	4½	5	5½	6	6½	7	7½
T-500	500	165	8	3588	2826	2289	1895	1591	1356	1169	—
				1.3	1.6	2.0	2.5	2.9	3.4	4	—
T-800	800	150	9	—	4424	3588	2960	2488	2121	1828	—
				—	1.9	2.3	2.8	3.3	3.9	4.5	—
T-1000 HP	1000	140	10	—	5339	4322	3580	3002	2559	2204	—
				—	2.1	2.5	3.1	3.8	4.3	5	—
T-1300 HP	1300	120	12	—	—	5462	4514	3793	3232	[illegible]	2428
				—	—	3.0	3.7	4.4	5.2	6.0	6.9
T-1600 HP	1600	120	12	—	—	5558	5556	4669	3978	3430	2988
				—	—	3.1	3.7	4.4	5.2	6.0	6.9

NOTE: Top value: Discharge Pressure / Bottom value: Discharge Volume

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Security
DRESSER

Manufacturer: NATIONAL SUPPLY – Duplex																					
Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in) 4	4-1/4	4-1/2	4-3/4	5	5-1/4	5-1/2	5-3/4	6	6-1/4	6-1/2	6-3/4	7	7-1/4	7-1/2	7-3/4	8
C-150-B	185	70	12	1-7/8	–	–	–	–	1205	1085	985	895	820	750	690	640	595	550	–	–	–
					–	–	–	–	3.8	4.2	4.6	5.1	5.6	6.1	6.6	7.1	7.7	8.3	–	–	–
C-250	320	65	15	2-1/4	–	–	–	–	1810	1625	1465	1330	1215	1115	1025	945	875	810	–	–	–
					–	–	–	–	4.6	5.1	5.6	6.2	6.8	7.4	8.1	8.8	9.5	10.2	–	–	–
C-350	495	60	18	2-3/8	–	–	–	–	2685	2405	2170	1965	1790	1640	1510	1390	1290	1195	1115	1040	–
					–	–	–	–	5.4	6.0	6.7	7.4	8.1	8.9	9.7	10.5	11.3	12.2	13.1	14.0	–
E-600	590	70	14	2-5/8	–	–	–	–	3000	2670	2400	2170	1970	1805	1660	1530	1415	1310	1215	1135	1060
					–	–	–	–	4.1	4.6	5.3	5.6	6.2	6.8	7.4	8.0	8.7	9.4	10.1	10.8	11.5
E-700	825	65	16	3-1/8	–	–	–	–	–	–	–	3000	2480	2085	1780	1535	1260	–	–	–	–
					–	–	–	–	–	–	–	6.1	6.8	7.4	8.1	8.8	9.6	–	–	–	–
G-700	700	70	14	2-5/8	–	–	–	–	3535	3175	2855	2585	2350	2150	1970	1815	1680	1560	1450	1350	1265
					–	–	–	–	4.1	4.6	5.3	5.6	6.2	6.8	7.4	8.0	8.7	9.4	10.1	10.8	11.5
G-1000-C	1000	65	16	3-1/8	–	–	–	–	–	–	–	–	3310	3010	2755	2530	2335	2160	2010	1865	–
					–	–	–	–	–	–	–	–	6.8	7.4	8.1	8.8	9.6	10.4	11.2	12.1	–
H-850-A	850	70	15	2-7/8	–	–	–	–	–	–	3320	2995	2720	2480	2275	2095	1935	1790	1665	1550	1450
					–	–	–	–	–	–	5.3	5.9	6.5	7.1	7.8	8.4	9.1	9.8	10.6	11.4	12.2
H-1250	1250	65	16	3-1/8	–	–	–	–	–	–	–	–	4135	3765	3445	3165	2915	2700	2505	2335	–
					–	–	–	–	–	–	–	–	6.8	7.4	8.1	8.8	9.6	10.4	11.2	12.0	–
K-180	180	80	10	2	–	–	–	1170	1050	945	855	775	710	650	600	555	515	475	–	–	–
					–	–	–	2.8	3.1	3.5	3.8	4.2	4.6	5.0	5.5	5.9	6.4	6.9	–	–	–
K-280	280	75	12	2	–	–	–	1620	1450	1305	1180	1075	980	900	830	770	710	660	–	–	–
					–	–	–	3.3	3.7	4.2	4.6	5.1	5.5	6.0	6.6	7.1	7.7	8.2	–	–	–
K-380	380	70	14	2-3/8	–	–	–	2100	1875	1675	1520	1370	1255	1145	1055	970	900	835	–	–	–
					–	–	–	3.8	4.2	4.7	5.2	5.8	6.3	6.9	7.5	8.1	8.8	9.5	–	–	–
K-500	513	70	15	2-5/8	–	–	–	2735	2425	2170	1950	1765	1605	1470	1350	1245	1150	1065	990	–	–
K-500-A					–	–	–	3.9	4.4	4.9	5.5	6.0	6.6	7.3	7.9	8.6	9.3	10.0	10.8	–	–
K-700	700	65	16	2-7/8	–	–	–	–	–	–	2760	2490	2265	2065	1890	1740	1605	1490	1385	1290	1205
K-700-A					–	–	–	–	–	–	5.7	6.3	6.9	7.6	8.3	9.0	9.8	10.5	11.4	12.2	13.0
KSH-180	180	80	10	2	1725	1510	1320	1170	1050	945	855	775	710	–	–	–	–	–	–	–	–
					1.9	2.2	2.5	2.8	3.1	3.5	3.8	4.2	4.6	–	–	–	–	–	–	–	–
KSH-280	280	75	12	2	2400	2070	1820	1620	1450	1305	1180	1075	980	–	–	–	–	–	–	–	–
					2.3	2.6	3.0	3.3	3.7	4.2	4.6	5.1	5.5	–	–	–	–	–	–	–	–
N-1000	1000	65	16	2-7/8	–	–	–	–	–	–	3945	3560	3235	2950	2705	2485	2295	2130	–	–	–
					–	–	–	–	–	–	5.7	6.3	6.9	7.6	8.3	9.0	9.8	10.5	–	–	–
N-1300	1300	65	16	3-1/8	–	–	–	–	–	–	–	4750	4300	3915	3580	3290	3030	2810	–	–	–
					–	–	–	–	–	–	–	6.1	6.8	7.4	8.1	8.8	9.6	10.4	–	–	–
N-1600	1600	65	16	3-3/8	–	–	–	–	–	–	–	–	5440	4940	4505	4135	3810	3515	–	–	–
					–	–	–	–	–	–	–	–	6.6	7.3	7.9	8.7	9.4	10.2	–	–	–

NOTE: Top Value: Discharge Pressure / Bottom Value: Discharge Volume

Security

DRESSER

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Manufacturer: NATIONAL SUPPLY – Triplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 3¾	4	4¼	4½	4¾	5	5¼	5½	5¾	6	6¼	6½	6¾	7	7¼
7-P-50	500	165	7½	4830	3695	–	2920	–	2365	–	1955	–	1645	1515	–	–	–	–
				1.0	1.3	–	1.6	–	2.0	–	2.4	–	2.8	3.1	–	–	–	–
8-P-80	800	160	8½	–	–	4925	4395	3945	3560	3230	2940	2690	2470	2280	–	–	–	–
				–	–	1.6	1.8	2.0	2.2	2.4	2.6	2.9	3.1	3.4	–	–	–	–
9-P-100	1000	150	9¼	–	–	–	5385	4830	4360	3955	3605	3300	3030	2790	2580	2395	–	–
				–	–	–	1.9	2.1	2.4	2.6	2.9	3.1	3.4	3.7	4.0	4.3	–	–
10-P-130	1300	140	10	–	–	–	–	–	–	5095	4645	4250	3900	3595	3325	3085	–	–
				–	–	–	–	–	–	2.8	3.1	3.4	3.7	4.0	4.3	4.6	–	–
12-P-160	1600	120	12	–	–	–	–	–	–	–	5555	5085	4670	4305	3980	3690	3430	3200
				–	–	–	–	–	–	–	3.7	4.0	4.4	4.8	5.2	5.6	6.0	6.4

Manufacturer: OIL WELL – Duplex

Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in.) 5	5-1/2	6	6-1/2	6-3/4	7	7-1/4	7-3/4	8
212-P	220	70	12	1-7/8	1200	–	820	690	640	600	550	–	–
					3.8	–	5.6	6.6	7.1	7.7	8.3	–	–
214-P	350	70	14	2-1/4	–	1375	1140	960	890	820	765	–	–
					–	5.3	6.4	7.6	8.2	8.8	9.5	–	–
218-P	500	65	18	2-1/4	2040	–	1370	1155	1065	985	915	–	–
					5.5	–	8.2	9.7	10.5	11.3	12.2	–	–
220-P	600	60	20	2-1/2	2650	–	1785	1485	1370	1270	1175	1020	955
					5.9	–	8.9	10.6	11.5	12.5	13.4	15.4	16.6
816-P	700	65	16	2-3/4	–	2725	2235	1875	1725	1598	1478	1280	1197
					–	5.8	7.0	8.4	9.1	9.8	10.6	12.2	13.1
818-P	925	65	18	3-1/4	–	–	2990	2480	2275	2100	1940	1675	1560
					–	–	7.5	9.0	9.9	10.7	11.6	13.4	14.4
1400-P	1400	65	18	3-1/2	–	–	4310	3560	–	3000	–	–	–
					–	–	7.3	8.8	–	10.5	–	–	–
1700-P	1700	65	18	3-1/2	–	–	5000	4320	–	3640	–	–	–
					–	–	7.3	8.8	–	10.5	–	–	–
7000-P	–	65	18	3-1/4	–	3660	2990	2480	2275	2100	1940	1675	–
					–	6.1	7.5	9.0	9.9	10.7	11.6	13.4	–
A-700-P	700	65	16	2-3/4	–	2725	2235	1875	1725	1593	1478	1280	–
					–	5.8	7.0	8.4	9.1	9.8	10.6	12.2	–
A-850-P	850	65	16	3-1/4	–	3500	2850	2370	2175	2005	1870	1600	–
					–	5.4	6.7	8.0	8.8	9.5	10.2	11.9	–
A-1000-P	1000	65	18	3-1/4	–	3660	2990	2480	2275	2100	1940	1675	–
					–	6.1	7.5	9.0	9.9	10.7	11.6	13.4	–

NOTE: $\frac{\text{Top Value: Discharge Pressure}}{\text{Bottom Value: Discharge Volume}}$

Security

DRESSER

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Manufacturer: OIL WELL — Triplex

Model	Max I.H.P.	Max S.P.M.	Stroke Length	Liner Size (in) 4	4-1/2	5	5-1/2	5-3/4	6	6-1/2	6-3/4	7	7-1/4	7-1/2	7-3/4
350-PT	350	175	8	2400	1900	1500	1250	1144	1050	900	–	770	–	–	–
				1.3	1.6	2.0	2.5	2.7	2.9	3.4	–	4.0	–	–	–
850-PT	850	160	9	5000	4400	3560	2940	–	2470	2110	–	–	–	–	–
				1.5	1.9	2.3	2.8	–	3.3	3.9	–	–	–	–	–
1100-PT	1100	150	10	–	5000	4500	3700	–	3110	2650	–	–	–	–	–
				–	2.1	2.6	3.1	–	3.7	4.3	–	–	–	–	–
A560-PT	560	175	8	3780	2990	2420	2000	1830	1680	1430	–	1240	–	–	–
				1.3	1.6	2.0	2.5	2.7	2.9	3.4	–	4.0	–	–	–
A1400-PT	1400	150	10	–	–	5000	4723	4321	3968	3381	3135	2915	2718	2540	2378
				–	–	2.5	3.1	3.4	3.7	4.3	4.6	5.0	5.4	5.7	6.1
A1700-PT	1700	150	12	–	–	5000	4723	4321	3968	3381	3135	2915	2718	2540	2378
				–	–	3.1	3.7	4.0	4.4	5.2	5.6	6.0	6.4	6.9	7.3

Manufacturer: OMEGA GEOSOURCE — Triplex

Model	Max. I.H.P.	Max. S.P.M.	Stroke Length	Liner Size (in) 4½	5	5½	6	6½	7
D-750	750	120	8	3000	3000	3000	3000	2562	2209
				1.6	2.0	2.5	2.9	3.4	4.0

Manufacturer: OPI INC. (GIST) — Triplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 1½	2	2½	3	3½	4	4½	5	5½	6	6½	7	7½
OPI 160D	160	230	6	–	–	–	–	–	1098	866	–	–	–	–	–	–
				–	–	–	–	–	1.0	1.2	–	–	–	–	–	–
OPI 200	200	400	6	5650	3183	2031	1415	1039	796	–	–	–	–	–	–	–
				0.1	0.2	0.4	0.5	0.7	1.0	–	–	–	–	–	–	–
OPI 350D	350	120	8	–	–	–	–	–	–	2610	2114	1747	1469	–	–	–
				–	–	–	–	–	–	1.6	2.0	2.5	3.0	–	–	–
OPI 700D OPI 700HDL OPI 700DL	700	150	8	–	–	–	–	–	–	4089	3312	2737	2300	1960	1690	–
				–	–	–	–	–	–	1.6	2.0	2.5	3.0	3.4	4.0	–
OPI 1000DL	1000	132	10	–	–	–	–	–	–	–	4585	3790	3184	2713	2340	2038
				–	–	–	–	–	–	–	2.6	3.0	3.7	4.3	5.0	5.7

NOTE: Top Value: Discharge Pressure / Bottom Value: Discharge Volume

Security

DRESSER

Pump Discharge Pressure (psi)
Pump Discharge Volume (gal./stroke)

Manufacturer: SKYTOP-BREWSTER – Duplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 4¾	5	5¼	5½	5¾	6	6¼	6½	6¾	7
B550F	550	70	14	2997	2678	2404	2171	1969	1796	1648	1515	1393	1293
				3.8	4.3	4.7	5.3	5.8	6.4	6.9	7.6	8.2	8.8
B750F	750	65	16	–	3642	3255	2920	2645	2400	2185	2010	1850	1710
				–	4.6	5.2	5.8	6.4	7.00	7.7	8.4	9.1	9.9
B1000F	1000	60	18	–	–	–	3885	3510	3167	2884	2648	2428	2241
				–	–	–	6.2	6.9	7.7	8.4	9.2	10.0	10.8

Manufacturer: SKYTOP-BREWSTER – Triplex

Model	Rated I.H.P.	Rated S.P.M.	Stroke Length	Liner Size (in) 4	4½	5	5½	6	6½	7
B1000T	1000	130	10	5000	5000	4660	3846	3233	2754	2372
				1.6	2.1	2.6	3.1	3.7	4.3	5.0
B1300T	1300	120	12	5000	5000	5000	4558	3790	3234	2785
				2.0	2.5	3.1	3.7	4.4	5.2	6.0
B1600T	1600	120	12	5000	5000	5000	5000	4664	3980	3427
				2.0	2.5	3.1	3.7	4.4	5.2	6.0

Manufacturer: WHELAND – Duplex

Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in) 5	5-1/2	5-3/4	6	6-1/4	6-1/2	6-3/4	7	7-1/4	7-1/2	7-3/4
HP 8000	343	70	12	2	1220	995	–	826	–	698	644	597	555	–	–
					3.7	4.6	–	5.5	–	6.6	7.1	7.7	8.2	–	–
HP-14000	574	65	14	2-1/4	–	1558	–	1290	–	1035	1000	927	862	802	–
					–	5.3	–	6.4	–	7.6	8.2	8.8	9.5	10.2	–
HP-16000	600	65	16	2-1/2	–	2337	–	1921	1751	1608	1480	1367	1268	1178	1098
					–	5.9	–	7.1	7.8	8.5	9.2	10.0	10.8	11.6	12.4
HP-18000	750	60	18	2-3/4	–	2700	–	2314	2113	1937	1782	1648	1526	1419	1322
					–	6.5	–	7.9	8.6	9.4	10.2	11.1	11.9	12.8	13.8
HP 8000A	200	60	12	2	–	995	–	826	–	698	644	597	555	–	–
					–	4.6	–	5.5	–	6.6	7.1	7.7	8.2	–	–
HP-14000A	353	60	14	2 1/4	–	1627	1476	1346	1233	1135	1047	970	900	838	–
					–	5.3	5.8	6.4	7.0	7.6	8.2	8.8	9.5	10.2	–

Manufacturer: WILSON – Duplex

Model	Max I.H.P.	Max S.P.M.	Stroke Length	Rod Size	Liner Size (in) 4	4-1/2	5	5-1/2	6	6-1/2	7	7-1/2	8
600	600	95	14	2 1/4	3000	2500	2050	1700	1400	1200	–	–	–
600H					2.6	3.4	4.3	5.3	6.4	7.8	–	–	–
900	900	80	16	2 3/4	–	–	3300	2730	2300	1960	–	–	–
					–	–	4.6	5.8	7.0	8.4	–	–	–
1250	1300	78	18	2 3/4	–	–	4250	3500	2490	2500	2160	–	–
					–	–	5.2	6.5	7.9	9.4	11.1	–	–
Giant	595	95	14	2 1/4	3000	2500	2050	1700	1400	1200	1050	900	–
					2.6	3.4	4.3	5.3	6.4	7.6	8.8	10.2	–
Titan	1237	75	18	2 3/4	–	–	4000	3500	2940	2500	2160	1880	1660
					–	–	5.2	6.5	7.9	9.4	11.1	12.8	14.7

NOTE: Top Value: Discharge Pressure / Bottom Value: Discharge Volume

APPENDIX K

TROUBLESHOOTING

APPENDIX K

TROUBLESHOOTING WELLS

Loss of mechanical integrity in a well may be evident from changes in the annulus pressure or injection pressure and flow. Locating the cause may be more difficult. Diagnostic tests -- static or dynamic -- performed on the well may point to the general assembly at fault: the injection tubing, the casing, or the packer. But identifying the single pipe, piece of tubing, or joint that has the leak requires opening the well and (where possible) removing the tubing and packer.

Lengths of injection tubing can be individually inspected and tested at the surface, as can the packer. If monitoring data indicate a possible leak in the casing, there are casing evaluation tools and procedures that pinpoint probable locations and give an idea of their seriousness. These tools and procedures were described in Chapter 4.

Some common problems are described below. Following that, case histories of some problem wells are presented.

K:1 Types of Problems

K:2 Untreatable Problems

If the well is untreatable, it will eventually be abandoned. Some examples of untreatable problems are:

- Local formation unsuitable for injection, that is, transmissivity (kh) too low
- Because of several injectors in the given area or other natural reasons reservoir pressure too high
- "Confining" strata protecting underground water not really confining
- Well repairs no longer cost effective

Considerable time, effort and costs may be required to conclude that the well problem is untreatable.

K:3 Treatable Problems

If the well problem is treatable, the operator will develop a program to correct the problem, submit it to the Director for approval, and then contract with qualified service companies to get the work done. The Inspector may have to be present during the workover -- or during critical phases of it -- to verify that the work is performed as specified.

K:4 Formation and Borehole Problems

Formation and borehole problems develop gradually from a variety of causes. Among the more common are:

- o Plugging of the borehole face, formation and/or filter by suspended solids in the injected fluid
- o Plugging of borehole face and/or filter by the growth of organisms
- o Swelling of clays by "imcompatible" injection fluid
- o Plugging from oils, emulsions, etc.
- o Damage from workover and stimulation activities
- o Poor filter design or installation

K:5 Common Examples of Troubleshooting

Example 1: Tubing Leak

An operator injecting wastewater in a Class I well in Deer Park, Texas reported communication between the tubing and annulus. An engineering company performed a mechanical integrity test which indicated a leak in the injection tubing. The problem was solved as described below:

The tubing leak followed a similar failure of this well two months before. The previous leak was tracd to the injection tubing at a depth of 3025 feet, which was subsequently repaired (Workover No. 3) with a wireline-set tubing patch. The current workover, unlike Workover No. 3, involved pulling the injection string. A service rig was moved on location and set up on September 13, 1983. The following day the injection tubing was removed from the well.

Selected joints of tubing were placed on the pipe rack and visually inspected. The remainder was stood back in the derrick to expedite reinstallation. All of the visually inspected tubing appeared to be in good condition.

The two joints containing the Pengo tubing patch from Workover No. 3 were set aside. A small 1/8" hole was noted in the body of one of the joints. This hole was not detected in the caliper log conducted during Workover No. 3 on July 12, 1983 (the hole was thought to be at a threaded connection).

The presence of a hole in the body of a joint indicated that a downhole corrosion problem existed. An Otis Caliper survey was run to a depth of 3600 feet. In-line corrosion coupon testing had previously indicated a "moderate" corrosion rate of 10 mils per year (mpy).

After pulling all of the tubing out of the well and redressing the seal assembly, the tubing was run back into the well while hydrotesting each 60 foot stand internally to 4000 psi.

A total of six joints were replaced with new 3 1/2", 9.3#, J-55 tubing. Counting from the top of the well the following joints were replaced:

Joint No.	Description of Failure/Defect
95	1/8" hole in body - patched during previous workover
96	patched during previous workover
124	1/8" hole in body
129	corroded threads
130	hydrostatic test failure at 3000 psi
183	hydrostatic test failure at 2500 psi

Mechanical integrity was restored to the well after the four-day workover. The annulus was pressured to 1010 psi on September 16, 1983. There was no measurable loss in 30 minutes on the 2000 psi field gauge.

The well was then turned over to operations. A recommendation was made to inject water compatible with carbon steel tubing or replace the existing tubing with corrosion-resistant fiberglass tubing.

Example 2: Casing Leak

This example describes the detection and repair of a casing leak of a Class I injection well in South Louisiana. Continuous monitoring of the annulus and injection pressures had previously indicated a leak of the packer, tubing or casing.

A series of nine pressure tests were run on the 7" protection casing to determine the location of leaks in the casing. This was accomplished by setting a test packer at different depths and pressuring up on the casing. The leak was determined to be in the interval between 4071' and 4081'.

The following day 12 barrels of cement were spotted and squeezed. The cement was allowed to set, under pressure, overnight, and was then drilled out and the hole was circulated clean. After pressure testing the casing, another 4 1/2 barrels of cement were spotted and squeezed, and allowed to set up.

Four days later the cement was drilled out and the hole was circulated clean; however, subsequent pressure tests still indicated a small leak in the casing. It was decided that the best approach to that problem would be to set the packer about 20 feet above the leak. Verbal concurrence was received from the Louisiana UIC office, with the understanding that a letter confirming the conversation would be sent to the UIC office as soon as practicable.

Thereafter, the cast iron bridge plug at 4196 feet was fished out and the well was washed and circulated clean.

The Otis RB-1 packer was then redressed, run back in the hole on 100 joints of 4 1/2" tubing, set at 4035 feet (bottom of packer) and pressure tested satisfactorily at 515 psi for 4 1/2 hours.

The 4 1/2" x 7" annulus was filled with brine containing Tretolite corrosion inhibitor and sodium sulfite (oxygen scavenger).

After pressure testing the tubing, the test plug and collar stop were retrieved, the wellhead installed, the annulus pressurized, and the workover rig released.

Example 3: Packer seal leak, acidization

This workover was performed to repair an annular leak, restore injectivity and demonstrate mechanical integrity of a well in South Texas.

After pulling the 5 1/2" injection tubing it appeared that the Otis Seal Assembly (which was inserted into the packer) had been leaking. Bad threads were also found on 6 joints of the tubing by surface visual inspection.

The injection packer was subsequently retrieved and an open-ended mule shoe was run to reverse circulate shale and sand from 4347' to 4540'. After cleaning the wellbore, previous difficulty in seating a test packer was corrected by scraping the 7" protection casing.

A radioactive tracer survey established the point of exit from the casing to be 4460' - 4464'. This survey was conducted to fulfill part of the mechanical integrity test requirements set forth by the Texas Department of Water Resources. The log showed all of the fluid was moving into the disposal interval and there were no indications of vertical migration.

The well was acidized next by washing the perforations with 1260 gallons of 28% HCl and 840 gallons of 15% HCl. This was followed by 1000 gallons of 15% HCl, 7500 gallons of 22% HCl plus 6% HF acid, and 1000 gallons of 15% HCl. The acid was displaced with 32,000 gallons of 9 ppg low-calcium brine. The initial flush rate of 840 gpm @ 1200 psi was reduced to 420 gpm @ 690 psi after 10,000 gallons had been pumped.

The well was reassembled using a new Brown Oil Tool Type "D" Liner Hanger Packer. External hydrostatic testing of the tubing connections was performed while running it into the well. Prior to setting the new packer, the annulus was filled with 9 ppg brine inhibited with NL Baroid Coat B-1400. Wellhead modifications were required to achieve annular pressure integrity.

Example 4: Well Cleanout and Reperforation

This example describes the methods used to restore injectivity to a Class I disposal well in Louisiana.

After rigging up the service rig, the well was killed with 100 BBL of brine water. The tree was removed, followed by installation of the blowout preventer.

The 4 1/2" injection tubing was cleaned and washed from 2375' to the surface with a 3 7/8" bit, scraper, and hydrojet. The injection tubing and 4 1/2" x 7" Texas Iron Works (TIW) "LH" packer were pulled out of the well. The 7" protection casing was cleaned down to 3525' (PBTD) using a stripper and power swivel. The perforations at 2760'-2766' were selectively washed, and surged to recover solids from the formation. This was repeated until the formation appeared to be clean.

To restore the injectivity of the receiving zone, the well was acidized with a mixture of 15% HCl, and 12% HCl/3% HF, followed by an injection test. When the injection test proved unsatisfactory, the well was surged and washed again. This sequence of surging, washing, acidizing and injection testing was repeated several times without success. Therefore, it was recommended the well be perforated at the 2400-foot sand above the existing injection interval. This procedure was approved by the Louisiana Department of Natural Resources.

A block squeeze was made between 2469'-2470' with 100 sacks of Class "H" cement to prevent upward migration of fluid. The squeeze was tested to 1800 psi. A cement bond log was run from 2620' to the bottom of the surface casing. A casing caliper log was also run from 2620' to the surface. The casing was perforated between 2605' and 2635' with four (4) shots per foot. The well was washed and cleaned and an injection test was conducted satisfactorily.

The 7" x 4 1/2" TIW "LH" packer was set at 2664' after 4 1/2" injection tubing was run in the hole while hydrostatically testing each joint to 3000 psi for three (3) minutes. The annulus was filled with brine and tested for two (2) hours at 1010 psi. A Radioactive Tracer Log was run to determine the direction of flow. The bottom hole pressure was also determined. The equipment was rigged down.

The well was returned to service.

APPENDIX L

BLOWOUT PREVENTION AND CONTROL

APPENDIX L

BLOWOUT PREVENTION AND CONTROL

A blowout is by definition the uncontrolled flow of formation fluids to the surface or another underground zone. They can occur during drilling or workover if excessive formation pressures are encountered.

The UIC inspector may never see a blowout. However, since a single blowout or spill, depending on its magnitude, time or place, can do irreparable environmental harm, a basic discussion on blowout prevention needs to be addressed. This section of the Inspection Guide is obviously not intended as a course to train the inspector in how to prevent or control a blowout. Blowout control can be quite complex, requires detailed planning, practice and precise execution. It is a primary responsibility of the drilling or workover crew working under potentially high pressure conditions.

Every phase of well control follows logical concepts. These concepts can be placed into one of three levels of well-control:

- o Primary Control
- o Secondary Control
- o Tertiary Control

L:1 Primary Control

Primary Control is the prevention of kicks. A kick is the entry of formation fluids into the wellbore in large enough quantity to require shutting in the well under pressure. This level of control is the most critical - if kicks are prevented, blowouts cannot occur.

Formation fluids cannot enter the hole at a given point as long as the hydrostatic pressure of the mud in the annulus is greater than the formation pressure. Hydrostatic pressure depends on only two variables - density and height of the fluid column. The density is expressed in lbs per gal or psi/ft. The height is simply the depth to the pressure zone. In directional wells, the fluid column height is the true vertical depth.

L:2 Causes of Kicks

Any event or chain of events that results in insufficient hydrostatic pressure can cause a kick. The most common causes are:

- o Failure to keep the hole full on trips
- o Excessive swab pressures
- o Insufficient mud density

- o Loss of circulation
- o Abnormally-pressured formations

Several drilling studies have shown that the most frequent cause of kicks is insufficient mud weight.

Another frequent cause of blowouts is kicks encountered while drilling shallow gas accumulations. Reaction time is short; minimum blowout prevention equipment is present; total containment of formation pressure is difficult, if not impossible; and the hole unloads in a very short time.

In some Class I disposal wells kicks and even blowouts have occurred during workovers. This has been due to gas accumulations resulting from interactions between the wastewater and formation, for example, acidic wastewater reacting with carbonate rocks to form carbon dioxide.

Kicks can be minimized if the rig crews:

- o Understand the causes of kicks
- o Use proper equipment and techniques to detect an unexpected reduction in hydrostatic pressure

L:3 Secondary Control

Loss of Primary Control does not mean that the well is "out of control". As long as the kick is properly handled, control can be maintained until the invading fluids are circulated out and Primary Control restored. This is called Secondary Control. A kick that is not contained can rapidly deteriorate into a blowout.

Closing-in the well - that is, shutting in the well quickly is the first and most important step in Secondary Control. This requires continual practice by drilling and workover crews. Blowout preventer (BOP) drills should be conducted routinely for crews working in high pressure areas.

Not all wells should be shut-in. If casing is set shallow or fracture gradients are especially low, shutting-in the well may cause immediate blowing ("broaching") to the surface or to an underground formation. Diverting flow away from the rig may be the best alternative. The well eventually may be killed by pumping heavy mud at a fast rate, setting a cement or barite plug, or natural bridging of the formation.

L:4 BOP Equipment

Control cannot be maintained without equipment. The blowout preventers, closing unit, manifolding, choke and auxiliary equipment are all important. To insure that each segment will operate in an emergency, the equipment must periodically be maintained and tested. All preventers and related equipment should be tested with water to full rated pressure, with the exception of the annular preventer. Testing of the annular preventer to more than 70% of the working pressure could damage the sealing element.

In addition to pressure testing, ram-type preventers should be actuated on the drill pipe once each trip, but not less than once each day. The annular preventer should be actuated on the drill pipe once each week. An inside BOP and work/drill string safety valves should be kept in an accessible location on the rig floor at all times.

L:5 Stripping or Snubbing

It is difficult to kill a well if the drill string is not on bottom. If the kick was detected while tripping, the drill string may have to be stripped or snubbed into the hole. Excessive pressures should be bled off to prevent breaking down the formation or exceeding surface equipment pressure ratings.

L:6 Circulating Out the Kick

Full Primary Control is not restored until the kick is circulated out and mud balances the pressure in the kicking formation. The two important concerns while accomplishing these two tasks are:

- Keep the bottomhole pressure imposed on the formation higher than the formation pressure. If it is not, more formation fluids can enter the hole.

- Do not let surface pressures get too high while trying to overbalance the formation pressure. Excessive surface pressure can fracture the formation, or rupture casing and blowout prevention equipment.

L:7 Well-Control Methods

The only proper way to circulate out a kick is to maintain a constant bottomhole pressure. Conventional industry methods are special cases of a more general Constant Bottomhole Pressure Method. They differ, in a practical sense, by the mud weight selected for the first circulation:

- DRILLER's METHOD
  New Mud Weight = Original Mud Weight

- WAIT AND WEIGHT (ENGINEER'S) METHOD
  New Mud Weight = Kill Mud Weight

- CONCURRENT (COMPOSITE) METHOD
  New Mud Weight increasing from Original Mud Weight to Kill Mud Weight

Each version has advantages and disadvantages. The proper value to use for the new mud weight depends on well conditions, crew capability, barite supplies, mixing facilities and company policy.

L:8 Standpipe Pressure Control

Changes in the bottomhole pressure imposed on the formation are monitored by the standpipe or drill pipe pressure gauge. In order to maintain the proper bottomhole pressure, the required standpipe pressure must be determined at the beginning of circulation. The final standpipe pressure should be maintained from the time the new mud reaches the bit until it is detected at the surface.

The initial standpipe pressure is the reduced pump pressure plus the shut-in drill pipe pressure. This is valid regardless of the "method" chosen. The final standpipe pressure depends on the new mud weight. If the mud is not weighted up (Driller's Method), the initial and final pressures are the same. If the mud is weighted to kill mud weight (Wait and Weight Method), the final standpipe pressure is equal to the new reduced pump pressure (old value modified by a mud weight ratio).

The reduced pump pressure values should be taken and recorded hourly to insure they are available in an emergency. For wells using subsea stacks, it is also important to measure the choke-line pressure losses at the kill pump rate. The kill pump rate is reduced from the normal rate, usually to about a half or a third. The selected kill pump rate should be maintained constant throughout the kick-circulation process.

A schedule can be prepared to show the required standpipe pressures as new mud is circulated. (The Driller's Method does not require a schedule.) Essentially, we need to know how much new mud is in the drill string, when the new mud reaches the bit, and the associated standpipe pressures. One method of developing the standpipe pressure schedule is to use graph paper. Another way is to calculate a pressure reduction per 100 strokes.

L:9 Potential Difficulties

Even with the best planning and training, difficulties can be encountered while killing the well. The crew should look for problem signs and take appropriate action. Among these difficulties are:

- Starting up the pump
- Barite contamination
- Loss of circulation
- Hole in the pipe
- Plugged pipe or bit nozzle

- o Pump failure
- o Choke plug or washout
- o Stuck pipe
- o Sour gas (H_2S), and
- o Drill string off bottom

L:10 Effect of Influx

Formation fluids entering the wellbore can be gas, oil, saltwater, or a combination of all three. The type of influx can affect the well behavior.

The constant bottomhole pressure method is not affected by the type of influx. Essentially each kick is treated as gas, the worst case. The differences that do exist include pit volume changes, required casing pressures and disposal at the surface.

Gas is compressible; oil and saltwater are not. Gas must be allowed to expand as it is circulated out of the hole. Otherwise, pressures in the hole increase and endanger fracturing the formation. Most of the gas expansion occurs in the top 1000-2000 ft. The gas expansion reduces the hydrostatic pressure in the annulus. Thus, casing pressures on a gas kick will be higher throughout the kill operation.

If the invading fluid cannot be incorporated into the mud easily (such as small amounts of saltwater or oil), the kick fluid physically must be removed from the mud system. Gas is processed through a mud-gas separator and degasser, and flared. Large volumes of oil and water can be routed away from the active circulating system and disposed of carefully.

L:11 Tertiary Control

Tertiary Control is the proper use of equipment and techniques to regain control after a blowout has occurred. The blowout can be a surface or underground blowout. In either case, control of the well has been lost.

If the casing and at least part of the wellhead equipment are still intact, a blowout at the surface is generally capped. Otherwise, a relief well must be drilled. A relief well is directionally drilled in an attempt to establish communications with the blowout. This can be quite difficult if multishot surveys are not available. Once the relief well is close to the flowing wellbore, thousands of barrels of water usually are pumped to establish communications and "load" the hole. The water is followed by heavy mud and later by cement, if necessary.

L:11

Underground blowouts are also usually controlled by relief wells. In some situations, however, the well can be killed by pumping heavy mud down the drill pipe at a relatively high rate. Once well control has been attained, a liner can be set and cemented across the loss zone.

REFERENCES APPENDIX L

IADC, "Blowout Prevention," Lessons in Rotary Drilling, Unit III, Lesson 3. Petroleum Extension Service, University of Texas, Austin.

Zamora, Mario and Kimball, Mike, "New CBHP Method Solves Kick-Control Problems," Oil and Gas Journal, March 6, 1978.

Hamby, T.W. and Smith, J.R. "Contingency Planning for Drilling and Producing High Pressure, Sour Gas Wells," SPE 2512, 1971.

Nelson, R.F., "The Bay Marchand Fire." Journal of Petroleum Technology, March, 1972.

APPENDIX M

INSPECTIONS CHECK LIST

INSPECTIONS CHECK LIST

____/____/____ Date of inspection

____/____/____ Date of last inspection

DESCRIPTION OF CORROSION PREVENTION/MONITORING SYSTEM:

☐ Corrosion loop

☐ Weight Loss Coupons

☐ Electrical Resistance Probes

☐ Polarization Resistance Probes

☐ Logs-Type ____________________

☐ Cathodic Protection

☐ Soil Potential Survey

☐ Other (please describe)

____

____

DATE OF LAST CORROSION EVALUATION BY OPERATOR:

Type

☐ Visual

☐ Other
(describe briefly)

____

____

RESULTS

☐ OK

Corrosion of:

☐ Casing; depth _____.

☐ Tubing; depth _____.

☐ Packer

INSPECTIONS CHECK LIST (continued)

☐ Other (indicate component) ____________________

____

Injection fluid released YES ☐ NO ☐

Contaminated USDW YES ☐ NO ☐

CASING MATERIAL

☐ Steel

☐ Stainless Steel

☐ Monel

☐ Titanium

☐ Other; specify ____________________.

TUBING MATERIAL

☐ Steel

☐ Stainless Steel

☐ Fibercast

☐ Fiberglass

☐ Other ____________________

PACKER TYPE AND MATERIAL

☐ Tension

☐ Compression

☐ Material: Steel ☐; Other ☐, specify ____________________

☐ Special protection (please indicate). Note that some packers, especially tension packers, have rubber pads or special coatings to prevent contact with injection fluids .

WASTE CHARACTERISTICS

pH = _______________

☐ Dissolved oxygen (concentration) _____ mg/l

☐ Hydrogen Sulfide, H_2S (concentration) _____ mg/l

☐ Carbon Dioxide, CO_2 (concentration) ______ mg/l

☐ Amenable to biological degradation

☐ Acidic

☐ Basic

☐ Most recent sample analysis (attached) indicates no significant changes

EVALUATION OF THE CASING/TUBING/PACKER MATERIALS TO RESIST CORROSION

(By consulting the tables in page _____ of the manual a preliminary evaluation can be made. The inspector may also use different criteria for evaluation; however, he/she should indicate the reason for the decision.)

☐ Adequate

☐ Inadequate

Criteria used: ____

____

____

____

PRESSURE GAUGE INSPECTION CHECKLIST

<u>Pressure Gauges</u>

	Yes	No	N/A
1. Is Bourdon tube gauge protected from corrosion and freezing?			
2. Is pressure reading relatively constant? (absence of rapid pointer movement due to pulsating pressure or pipeline vibration)			
3. Are gauge materials suitable for the media monitored?			
4. Is a pressure transducer properly installed?			

5. Date gauge last calibrated: ________________

6. Method of calibration: ____________________

____

<u>Pressure Recorders</u>

1. Are pressure recorders properly installed? (e.g., chart protected from weather, etc.)

2. Are pressure recorders operational? (e.g., ink, charts moving, etc.)

3. Is back-up gauge provided?

4. Do back-up pressure and recorded pressure agree?

FLOW MEASUREMENT INSPECTION CHECKLIST

A. <u>Flow Measurement Inspection Checklist</u> - General

Yes No N/A (a) Primary flow measuring device is properly installed and maintained.

Yes No N/A (b) Is there a straight length of pipe before and after the flowmeter of at least 5 to 20 diameters? This depends on the type of flowmeter and the ratio of pipe diameter to throat diameter. Also, the introduction of straightening vanes may reduce this requirement.

Yes No N/A (c) If a magnetic flowmeter is used, check for electric noise in its proximity and that the unit is properly grounded.

Yes No N/A (d) Is the full pipe requirement met.

Yes No N/A 2. Flow records are properly kept.

(a) Records of flow measurement are recorded in a bound numbered log book.

Yes No N/A (b) All charts are maintained in a file.

Yes No N/A (c) All calibration data is entered in the log book.

Yes No N/A 3. Sharp drops or increases in flow values are accounted for.

Yes No N/A 4. Actual flow is measured.

Yes No N/A 5. Secondary instruments (totalizers, records, etc.) are properly operated and maintained.

Yes No N/A 6. Appropriate spare parts are stocked.

Electrical noise can sometimes be detected by erratic operation of the flowmeter's output. Another indication is the flowmeter location in the proximity of large motors, power lines, welding machines, and other high electrical field generating devices.

B. Flow Measurement Inspection Checklist.

1. Type of flowmeter used: ______________________________

2. Note on diagram flowmeter placement in the system. Observe the direction of flow, the vertical height relationship of the source, outfall, and measuring meter. Give all dimensions in pipe diameters.

3. Is meter installed correctly?

(a) If magnetic flowmeter, it should be installed in an ascending column, to reduce air bubbles and assure full pipe flow.

(b) If differential pressure meter such as venturi, it should be installed in a horizontal plane so that high pressure tap is on the inlet of flow and taps are horizontal sloping slightly downward with facilities for cleaning taps.

4. Flow range to be measured:________________________

Yes No N/A 5. Flow measurement equipment adequate to handle expected ranges of flow values.

6. What are the most common problems that the operator has had with the flowmeter?

7. Flowmeter flow rate: ________mgd; Totalizer flow rate: _______mgd; Error ______%

8. Permit project flow: ______________________________

Yes No N/A 9. Flow totalizer is properly calibrated.

10. Frequency of routine inspection by trained Operator _______/month.

11. Frequency of maintenance inspections by facility personnel: _______/year.

12. Frequency of flowmeter calibration:_______________

13. Indicator of correct operation:
redundant flowmeters_____ auxiliary flowmeters_____
pressure readings_______ other __________________
power usage of pumps______

14. Indicators of proper Quality Assurance:
redundant flowmeters____ frequent calibrations____
other__________________

APPENDIX N

INSPECTION REPORT FORMS

APPENDIX N

INSPECTION REPORT FORMS

Engineering Enterprises, Inc. recommends the form on the following page for recording mechanical integrity test (MIT) data when running the standard annulus pressure test. As alternative MIT are approved by the Director of the Office of Drinking Water, forms will need to be developed to ensure documentation appropriate for the particular MIT.

Two additional forms follow: a Class I inspection form that has been well received; and a form for field verification of well files. EEI does not recommend conducting file reviews for the UIC Federal Reporting System commitments in the field; however, field review of files can be a valuable addition to site inspections by providing confirmation of information contained in the EPA Regional files.

UIC MECHANICAL INTEGRITY TEST

WELL IDENTIFICATION

Owner/Operator: ____________________ Well/Unit: ______________ No. __________
Address: ____________________ Field: ____________________
City: __________ State: ____ Zip: ______ Type: ______ EOR. ______ SWD. ______ Other.

Primary Contact: ____________________ State Permit No.: ____________________
Phone: (_____) ____________________ Federal Permit No.: ____________________

Facility No.: ____________________ Inspection/Test Date: ______________

WELL LOCATION

State: ______________ T _____ ;R _____ ;Sec _____. ______ 'from ______ line.

County: ______________ Qtr Sec: ____ ____ ____. & ______ 'from ______ line.

WELL/TEST DATA

Type of Test: ___ Shut-in. Injected Fluid: ____________ SG: ______
___ Injecting. Annulus Fluid: ____________ SG: ______

Injection Formations: ____________ Injection Rate(BPD): ____________
____________ Injection Pressure(PSI): __________

Perforated Intervals: ____________ Packer Type: ______________
____________ Set at: ______________

Tubing: ____________ @ ____________ Casing: ____________ @ ____________

RESULTS:

TIME	PRESSURE (PSIG) ANNULUS	TUBING

TEST PRESSURE: ____________ PSI

Max. Allowable Pressure Change:

Test Pressure x .03 ____________ PSI
Half Hour Pressure Change ________ PSI

TEST PASSED ___ TEST FAILED ___ (CHECK ONE)

IF FAILED, NO INJECTION MAY OCCUR UNTIL CORRECTIONS HAVE BEEN MADE AND WELL PASSES.

SIGNATURE OF COMPANY REPRESENTATIVE ____________________ DATE ____________

SIGNATURE OF EPA REPRESENTATIVE ____________________ DATE ____________

4-18-85

Sheet ____ of ____

UIC FILE REVIEW

Review Date ____

FILE IDENTIFICATION

OPERATOR ____

☐ SINGLE WELL ID # BELOW ☐ AREA REVIEW LIST ATTACHED ____ WELLS

ADDRESS ____

FACILITY NO. KYS

STATE PERMIT NO. ____

LEASE NAME - WELL NUMBER ____ - ____

POOL ____

WELL LOCATION

CARTER COORDINATES

____ FNL / FSL : ____ FEL / FWL : ____ - ____ - ____

STATE NAME/CODE KY./21 TN./47 (circle one)

COUNTY NAME ____ COUNTY CODE ____

WELL COMPLETION

WELL TYPE (code) 2- TOTAL DEPTH ____ (ft) SURFACE ELEVATION ____ (ft MSL)

DEPTH TO TOP OF CEMENT	CASING STRING	CASING DIAMETER (inches)	CEMENT SHOE DEPTH	CEMENT VOLUME (sacks/type)	PERFORATED INTERVALS
	Surface				
	Intermediate				
	Production				
	Tubing				

PACKER TYPE ____

PACKER DEPTH ____ (ft)

LOWERMOST USDW
- FORMATION NAME ____
- BASE ELEVATION ____ (MSL)

CONFINING FORMATION
- NAME ____
- TOP ELEVATION ____ (MSL)
- THICKNESS ____ (ft)
- PERMEABILITY ____ (darcy)

INJECTION FORMATION
- FORMATION NAME ____
- TOP ELEVATION ____ (MSL)

OPERATING CONDITIONS
- MAX. INJECTING PRES. ____ (psi)
- EST. FRACTURE PRES. ____ (psi)

FILE EVALUATION

1 EACH WELL IS COMPLETED INTO A CONFINED, NON-USDW FORMATION ? [Y] [N] ____ WELLS NOT IN COMPLIANCE (list of wells and explanation attached)

2 EACH WELL IS DESIGNED FOR EXPECTED USE ? [Y] [N] ____ WELLS NOT IN COMPLIANCE (list of wells and explanation attached)

3 EACH WELL IS CASED AND CEMENTED TO PREVENT MOVEMENT OF FLUID INTO OR BETWEEN USDWs ? [Y] [N] ____ WELLS NOT IN COMPLIANCE (list of wells and explanation attached)

4 EACH WELL IS OPERATED AT AN APPROPRIATE PRESSURE AND WITH ADEQUATE CONTROLS TO PREVENT FRACTURING OF THE CONFINING ZONE ? [Y] [N] ____ WELLS NOT IN COMPLIANCE (list of wells and explanation attached)

5
- A PLUGGING AND ABANDONMENT PLAN HAS BEEN SUBMITTED FOR EACH WELL ? [Y] [N] ____ WELLS NOT IN COMPLIANCE (list of wells and explanation attached)
- OPERATOR MAINTAINS APPROPRIATE FINANCIAL ASSURANCE ? [Y] [N] ____ WELLS NOT IN COMPLIANCE (list of wells and explanation attached)

6 EACH WELL IS MONITORED AND REPORTED AS REQUIRED ? [Y] [N] ____ WELLS NOT IN COMPLIANCE (list of wells and explanation attached)

6-6-85

Sheet ____ of ____

UIC - FILE REVIEW/MIT

WELL IDENTIFICATION

OPERATOR ______________________ FACILITY NO. ______________________

LEASE NAME-NO. ______________________ POOL ______________________

EXTERNAL MIT - CEMENT CALCULATIONS

FOR SURFACE CASING

CASING DIA. ________ (in.) HOLE DIA. ________ (in.)

CALCULATED ANNULAR VOLUME ____________ (cu.ft./ft.)

CEMENT YIELD PER SACK ________________ (cu.ft.)

SACKS USED ______ CEMENT VOLUME ______ (cu.ft.)

DEPTH-TOP OF CEMENT(w/20% loss) ____________ (ft)

FOR INTERMEDIATE AND PRODUCTION CASING

CASING DIA. ________ (in.) HOLE DIA. ________ (in.)

CALCULATED ANNULAR VOLUME ____________ (cu.ft./ft.)

CEMENT YIELD PER SACK ________________ (cu.ft.)

SACKS USED ______ CEMENT VOLUME ______ (cu.ft.)

DEPTH-TOP OF CEMENT(w/20% loss) ____________ (ft)

COMMENTS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION V

CLASS I INSPECTION REPORT

STREET:______________________ STATE PERMIT No:______________________

COUNTY:______________________ WELL NAME & No:______________________

CITY/ST/ZIP:______________________ TYPE OF WELL: HAZARDOUS / NONHAZARDOUS

INSPECTION DATE:______________ TIME OF INSPECTION:______________________

TYPE OF INSPECTION: ROUTINE / MIT / COMPLAINT / COMPLIANCE / PERMIT

NAME(S) OF PERSON(S) UIC INSPECTOR MET WITH DURING INSPECTION:

NAME	TITLE	PHONE No.

A. INJECTION WELL INFORMATION

INJECTION PRESSURE:__________(psig) ANNULUS PRESSURE:__________(psig) RATE:______________

AVERAGE DAILY VOLUME:______________ INJECTION FLUID TEMPERATURE:______________(°F)

1. IS THERE DOCUMENTATION OF GAUGE CALIBRATION: *|_| YES |_| NO

*DATE OF CALIBRATION:______________

2. IS INJECTION RATE AND VOLUME: (MEASURED OR ESTIMATED) ?

3. DOES THE TYPE OF INJECTION FLUID FLUCTUATE: |_| YES |_| NO

4. WHAT TYPE & SPECIFIC GRAVITY FLUID IS IN THE ANNULUS:______________________

5. WHAT IS THE SPECIFIC GRAVITY OF THE INJECTION FLUID:______________________

WELL INFORMATION CONTINUED

6. LOCATION OF PERFORATIONS AND/OR OPEN HOLE:________________________________

7. TYPE AND MODEL OF PACKER:(TENSION/COMPRESSION/NEUTRAL/OTHER [PLEASE SPECIFY BELOW]):

   PACKER TYPE:____________________________ MODEL:__________________________

8. WHAT IS THE SETTING DEPTH OF THE PACKER:________(ft) , ________(ft)

9. HOW IS INJECTION PRESSURE RECORDED: MANUAL / AUTOMATIC / COMPUTER

10. HOW IS ANNULUS PRESSURE RECORDED: MANUAL / AUTOMATIC / COMPUTER

11. IS FLUID TEMPERATURE RECORDED: ☐ YES ☐ NO

12. IS ANNULUS FLUID VOLUME RECORDED: ☐ YES ☐ NO

WELL INFORMATION COMMENT SECTION

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B. ANNULUS PRESSURE MAINTENANCE SYSTEM

1. IS ANN. PRES. CONTINUOUSLY MAINTAINED IN ACCORDANCE WITH PERMIT: ☐ YES ☐ NO
2. IS ANNULUS PRESSURE REQUIRED TO BE GREATER THAN INJECTION PRESS.: ☐ YES ☐ NO
3. IS ANNULUS PRESSURE CONTINUOUSLY GREATER THAN INJECTION PRESSURE: ☐ YES ☐ NO
4. HOW IS ANNULUS PRESSURIZED: POSITIVE DISPLACEMENT PUMP / NITROGEN / OTHER
5. IS ANNULUS FLUID VOLUME CONTINUOUSLY MONITORED/RECORDED BY OPERATOR: ☐ YES ☐ NO
6. HAS OPERATOR RECEIVED TRAINING ON WELL OPERATION ☐ YES ☐ NO

MAINTENANCE SYSTEM COMMENT SECTION

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C. ALARM SYSTEM

1. IS INJECTION WELL ALARM SYSTEM OPERABLE: |_| YES |_| NO
2. WHAT TYPE OF ALARM SYSTEM IS UTILIZED: MANUAL SYSTEM / AUTOMATIC SYSTEM
3. HAS ALARM SYSTEM BEEN TESTED BY A UIC INSPECTOR |_| YES |_| NO
4. ON WHAT FREQUENCY IS ALARM SYSTEM TESTED: ____________________
5. IS ALARM TRIGGERED BY HIGH PRESSURE |_| YES |_| NO , LOW PRESSURE |_| YES |_| NO

   LOW PRESSURE DIFFERENTIAL |_| YES |_| NO , OTHER |_| YES |_| NO
6. IS THERE A TIME DELAY BEFORE ALARM SOUNDS TO ACCOUNT FOR START - UPS |_| YES |_| NO
7. IS OPERATOR ON SITE 24 HOURS PER DAY TO RESPOND TO FAILURES: |_| YES |_| NO

ALARM SYSTEM COMMENT SECTION

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D. TESTING

1. WAS A MECHANICAL INTEGRITY TEST CONDUCTED AT THIS INSPECTION: |_| YES |_| NO
2. WAS A START-UP TEST CONDUCTED AT THIS INSPECTION: |_| YES |_| NO

TESTING COMMENT SECTION

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* IF TESTING IS CONDUCTED AT THIS INSPECTION PLEASE ATTACH A COPY OF THE TEST REPORT.

E. OVERALL INSPECTION COMMENTS

INSPECTORS NAME INSPECTORS SIGNATURE DATE

* INSPECTOR IS: (CONTRACTOR / EPA EMPLOYEE).