TECHNICAL CRITERIA FOR AN
AREA-OF-REVIEW
VARIANCE METHODOLOGY

APPENDIX B

Technical Criteria for an Area-of-Review Variance Methodology

DE-FG22-94-MT94003

MASTER

TECHNICAL CRITERIA FOR AN AREA-OF-REVIEW VARIANCE METHODOLOGY

developed by the
Underground Injection Practices Research Foundation Variance Plan Committee

DOE/MT/94003--T4

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UNDERGROUND INJECTION PRACTICES
UIPRF
RESEARCH FOUNDATION

~~DRAFT~~

January, 1994

MASTER

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EXECUTIVE SUMMARY

This guidance was developed by the Underground Injection Practices Research Foundation to assist UIC Directors in implementing proposed changes to EPA's Class II Injection Well Regulations that will apply the Area-Of-Review (AOR) requirement to previously exempt wells. EPA plans to propose amendments this year consistent with the recommendations in the March 23, 1992, Final Document developed by the Class II Injection Well Advisory Committee, that will require AORs to be performed on all Class II injection wells except those covered by previously conducted AORs and those located in areas that have been granted a variance. Variances may be granted if the Director determines that there is a sufficiently low risk of upward fluid movement from the injection zone that could endanger underground sources of drinking water.

This guidance contains suggested technical criteria for identifying areas eligible for an AOR variance. The suggested criteria were developed in consultation with interested States and representatives from EPA, industry and the academic community. Directors will have six months from the promulgation of the new regulations to provide EPA with either a schedule for performing AOR's within five years on all wells not covered by previously conducted AORs, or notice of their intent to establish a variance program. It is believed this document will provide valuable assistance to Directors who are considering whether to establish a variance program or have begun early preparations to develop such a program.

TECHNICAL CRITERIA FOR AN AREA-OF-REVIEW VARIANCE METHODOLOGY

BACKGROUND

The Underground Injection Control Regulations (1) promulgated in 1980, under the Safe Drinking Water Act of 1974, require Area-of-Review (AOR) studies be conducted as part of the permitting process for newly drilled or converted Class II injection wells (2). Existing Class II injection wells operating at the time regulations became effective were excluded from the AOR requirement.

In January 1988, the EPA initiated a Mid-Course Evaluation (MCE) of the adequacy of its regulations for Class II injection wells and, in August 1989, published a report of its findings. As a result of the MCE, EPA's Office of Drinking Water identified areas of concern to be further studied. Among the areas of concern was the need to further evaluate AOR requirements.

In April 1991, the agency proposed and did form a Federal Advisory Committee (FAC) whose charge was to make recommendations to EPA regarding the Class II injection well program. The Committee examined data and information gathered by the EPA during the Mid-Course Evaluation of the Class II program and in subsequent studies, identified regulatory gaps, and made recommendations for program changes where they were appropriate.

The FAC held its first formal meeting on June 11-12, 1991 during which the Committee approved its charter and identified issues to be addressed, including AOR requirements. The FAC met for a seventh and final time in January 1992. A March 23, 1992, draft Final Document was prepared summarizing the recommendations of the FAC. Those recommendations received formal endorsement by the organizations and individuals

represented on the Committee in August, 1992.

EPA plans to propose amendments in 1994 to its Underground Injection Control (UIC) program regulations (40 CFR Parts 144, 145 and 146) as they pertain to Class II injection wells. The Final Document developed by the FAC provides the framework for EPA to revise its UIC regulations (see Appendix C). The proposed rule will amend current provisions relating to construction standards and mechanical integrity testing and will apply the AOR/corrective action requirement to previously exempt wells.

With respect to the AOR requirement, the FAC Final Document recommends an AOR be performed within five years of promulgation of the new regulations on all Class II injection wells except those covered by previously conducted AORs. The FAC also reached consensus that an exception to this AOR requirement should be allowed for those wells located in areas that have been granted a variance by the Program Director based upon criteria presented in a variance plan approved by EPA prior to issuing variances. Variances may be granted where there is sufficiently low risk of upward fluid migration from the injection zone into underground sources of drinking water. Known high risk areas are not eligible for a variance, and AORs must be performed on all wells in these areas within two years of promulgation of the regulations.

The FAC recommendations contain provisions that are important to the oil and gas producing states and the oil industry for they recognize the variability of geologic and engineering conditions that exist among injection operations. The final document ties that recognition to variable requirements ranging from the need for early performance of AORs to a variance from the performance of AORs.

The Final Document lists conditions that could be considered by a Director in determining whether to grant a variance. A variance could be granted based on information indicating any of the following conditions:

* the absence of USDWs,

* the reservoir is underpressured relative to the USDW,
* local geological conditions preclude upward fluid movement that could endanger USDWs, and/or
* other compelling evidence.

INTRODUCTION

In an effort to assist Class II UIC Directors who elect to establish a variance program, the UIPRF created a committee of State, EPA and industry representatives to develop a model variance plan. The committee members are noted in Appendix A. The goal established by the committee is as follows: to *Develop a Model Area-of-Review Variance Process Including Administrative Guidance and Technical Criteria That Will Be Acceptable to EPA and Utilized by UIC Class II Direct Implementation and State Directors.* That effort began on June 2, 1993. This document, which contains the committee's recommendations regarding the technical basis for AOR variance decisions, was submitted to the UIPRF Board of Directors on February 6, 1994 for approval. Guidance for the implementation and administration of the AOR variance process will be completed by this committee after such time as the EPA publishes proposed amendments to its Class II UIC program regulations, sometime in 1994.

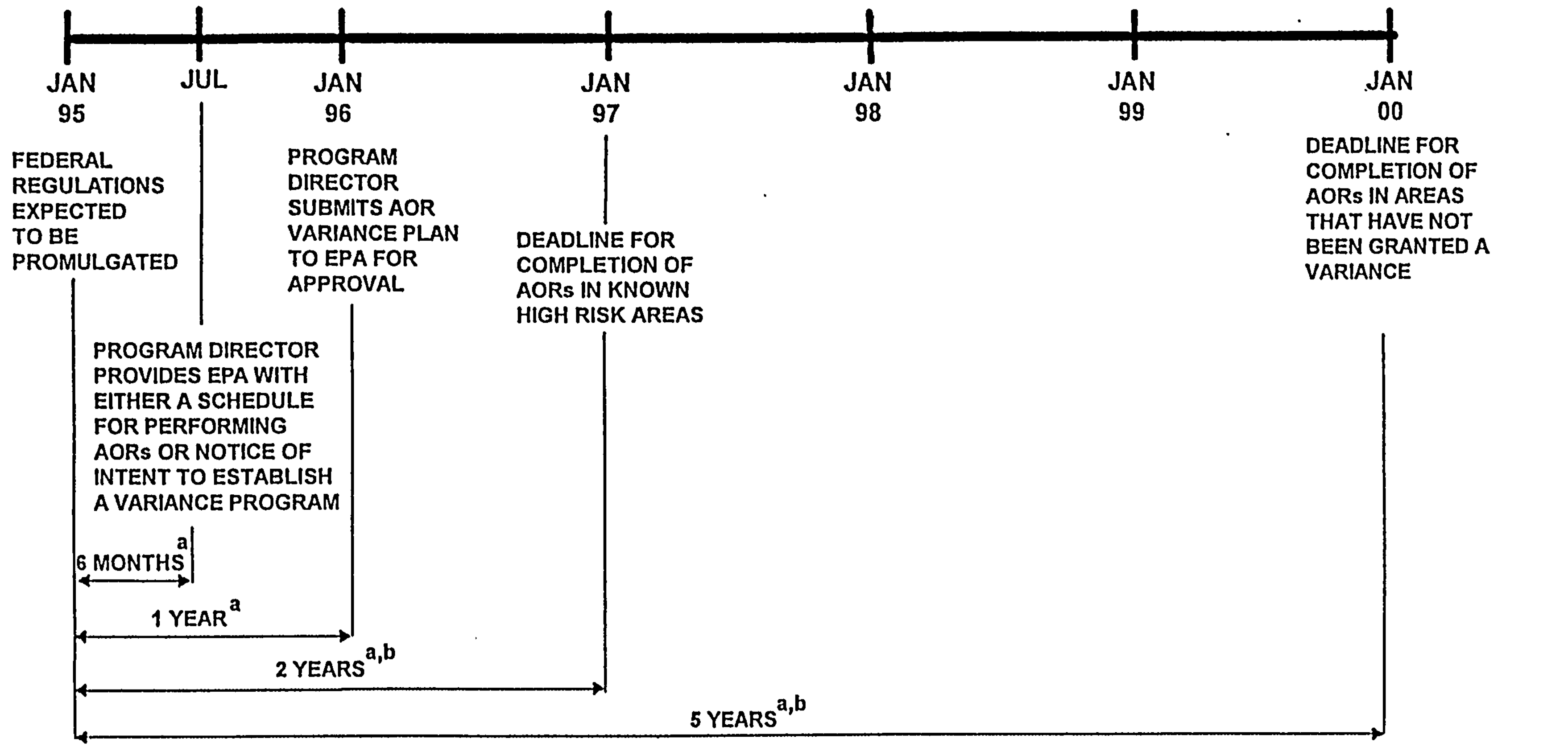
EPA estimates its amendments to the existing regulations will be effective no sooner than January, 1995. The new regulations will go into effect immediately in states where EPA directly implements the Class II UIC program. Figure 1 on the next page is the estimated timeline for implementation of the new AOR requirements in Direct Implementation (DI) States. Primacy States, however, will have approximately one year (from the effective date of the new regulations) to demonstrate their programs are effective to prevent endangerment of USDWs, in light of the new federal rule. EPA will likely issue additional guidance sometime in the future containing information on; 1. how States that obtained primary enforcement responsibility under Section 1425 of the Safe Drinking Water Act may apply for approval of program revisions; and 2. the criteria EPA will use in approving or disapproving applications.

Similarly, in 1981, EPA issued guidance for applying for primary enforcement responsibility under the then, new Section 1425 of the Safe Drinking Water Act. Section

FIGURE I

IMPLEMENTATION OF THE CLASS II INJECTION WELL ADVISORY COMMITTEE'S RECOMMENDATIONS FOR UIC RULE REVISIONS

TIMELINE FOR DIRECT IMPLEMENTATION STATES



a. RECOMMENDED BY ADVISORY COMMITTEE
b. SCHEDULES SET FORTH BY THE STATE FOR PERFORMING AORs MAY BE ADJUSTED BY THE ADMINISTRATOR FOR GOOD CAUSE

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1425, added to the Act when it was amended in 1980, establishes an alternative method for a State to obtain primacy, in lieu of the showing required under Section 1422(b)(1)(A) of the Act. State program submissions under Section 1425 are required to meet a different legal standard from State program submissions under Section 1422(b)(1)(A). Under Section 1422(b)(1)(A), the State is required to show that its UIC program meets the requirements of regulations issued by the Administrator under Section 1421. Under Section 1425, the State is required to demonstrate that its program meets the statutory goals of Section 1421(b)(1)(A) through (D) and represents an effective program to prevent underground injection which endangers drinking water sources. EPA's initial guidance for implementation of the alternative demonstration provided for in Section 1425 can be found in 46 FR 27333, May 19, 1981. Requirements issued by the Administrator for revisions of State programs approved under Section 1422(b)(1)(A) are contained in 40 CFR 145.32.

As recommended in the FAC Final Document, the technical criteria the Program Director intends to consider in determining whether to grant variances must be presented in a variance plan approved by EPA. Directors can begin immediately to develop such criteria and identify areas eligible for a variance; since EPA's proposed rulemaking, which is expected to be published sometime in 1994, will provide little, if any, additional information on technical criteria. Release of this committee's recommendations on the technical basis for AOR variance decisions, prior to the release of EPA's proposed rule, may provide valuable assistance to Directors who are still considering whether to establish a variance program or have begun early preparations to develop such a program.

While EPA's proposed rule will likely contain information significantly affecting implementation of the variance process and other AOR aspects of the FAC recommendations; there are, nevertheless, numerous things that Program Directors can begin now thinking about and working on that will result in smoother implementation of the new AOR requirements. These things are identified herein as "Early State Actions".

EARLY STATE ACTIONS

The following measures can be taken now by Program Directors to help ensure effective and efficient implementation of the AOR aspect of the new regulations:

1. **Review and become familiar with this document.** The FAC has recommended that Program Directors have six months from the promulgation of the new regulations to provide EPA with either a schedule for performing AORs within five years on all wells not covered by previously conducted AORs, or notice of their intent to establish a variance program. In considering whether to establish a variance program, Program Directors should begin as soon as possible a review of the technical criteria suggested in this document for identifying areas eligible for an AOR variance. The suggested criteria were developed in consultation with representatives of the States, the EPA, the petroleum industry and the academic community. This document will undergo further EPA review with the goal of obtaining EPA endorsement, such that a State application which meets the suggested criteria should be approvable.

2. **Begin to develop examples of other compelling evidence for a variance.** Directors should begin to identify the special situations in their states that provide good reason for granting a variance. While this committee has attempted to identify most such special cases, there may be other valid technical criteria that the committee has overlooked or is unaware of. Area operators should be encouraged to assist in identifying other compelling evidence.

3. **Begin preliminary work to identify areas eligible for a variance.** It is important to begin gathering the information and data necessary to identify all areas eligible for a variance. Area maps, ground water studies, and reservoir studies are examples of information that can be used to justify a variance.

4. **Be aware of the requirements for notification of intent to establish a variance program.** If the Program Director intends to establish a variance program, he/she must provide EPA with notice. A letter to the EPA Regional Administrator must be received within six months from promulgation of EPA's new regulation. Moreover, in some states, it may be necessary to provide public notice of the State's intent to develop a variance process and a preliminary timeframe for the expected work products, hearings, etc.

5. **Begin planning the variance process.** Existing committees at the state level, including industry associations and environmental interest groups, or a newly-formed committee could begin working together to develop the variance process and the components of the variance plan. The FAC has recommended that the variance plan set forth the specific types and sources of information that will be considered in making variance determinations, and that Directors provide notice and opportunity for public comment in the development of the variance plan and in the granting of variances. It is important during the beginning planning stages to take advantage of all available sources of information and expertise to assist in the variance program development.

6. **Begin operator interaction.** It is important to hold early meetings with operators to advise them of the variance process including the areas that the State intends to identify for variance and to receive information and input from the operators regarding variance criteria. Interaction would also include what may be required of operators to seek additional variances.

7. **Begin to compile a list of known high risk areas.** The FAC has recommended that, within six months of promulgation of the new regulations, Program Directors must provide EPA with schedule for completing AORs in known high risk areas within two years of promulgation of the new regulations. **<u>Known</u> high risk areas are the areas where USDWs have already been determined to be susceptible to**

possible contamination. Early delineation of such areas enables the Director to appropriately prioritize, schedule, and complete the necessary reviews on time. Operators should be advised of any known high risk areas as soon as possible.

8. **Begin to develop an AOR completion schedule.** A schedule will help ensure that all AORs are completed within the time frames recommended in the FAC Final Document. Workshops for operators, regulators and other interested parties can play an important role in the effort to involve these parties early in the specifics of the AOR schedule and the variance program, so that AOR completion schedules can be developed and maintained and variance applications can be submitted in a timely fashion. Operators must be kept well informed of agency requirements.

The Director's commitment to effect performance of the necessary reviews within the specified time frames could be set forth in amendments to the State/EPA Agreement (SEA). The Director's commitment could be in the form of a numerical allocation of AORs to be performed on an annual or quarterly basis. The FAC Final Document provides that schedules set forth by the State for performing AORs may be adjusted by the Administrator for good cause. If the Director is provided additional information after implementation of the schedule has begun that suggests the timeline for performing an AOR on a particular well or group of wells should be changed, such changes could be carried out through the annual SEA negotiation process.

TECHNICAL CRITERIA USED FOR JUSTIFICATION OF VARIANCE AREAS

This section will look at the technical criteria that can be used in justification of areas which would be eligible for variances from AOR requirements. Pursuant to the AOR requirement, the area surrounding an injection well or wells is reviewed to identify all pathways by which injected fluids can migrate out of the injection zone and into a USDW. All of those pathways must be repaired or the operation of the permitted injection well modified (e.g., injection pressure and volumes reduced) to ensure that the USDW is not endangered. This is known as corrective action. The FAC has recommended that AORs be performed on all Class II injection wells except those covered by previously conducted AORs. It is estimated that 80,000 - 100,000[1] Class II injection wells will become subject for the first time to AOR requirements as a result of the FAC recommendations.

The FAC has also recommended that an exception to this AOR requirement should be allowed for those wells located in areas where there is sufficiently low risk of upward fluid migration from the injection zone into USDWs. Factors that decrease the potential for contamination are numerous, causing injection wells to vary greatly in the risk they pose to USDWs. Many injection wells may pose little or no risk.

For example, the adjacent wells may not penetrate the injection formation and, therefore, cannot serve as pathways for flow from the injection zone into the USDW. In wells that do penetrate the injection zone, the presence of flow impediments (e.g., casing, cement, bridge plugs, etc.) is dependent upon the well construction and abandonment procedures

[1] The number of Class II injection wells that will become subject to AOR requirements was estimated by the Cadmus Group, 1992, and API, 1993. All estimates are based on what was at the time the latest information available from the states. This information remains approximative, though, since it is not easily accessible due to the nature of many of the states' record keeping systems.

utilized. Such procedures probably have been driven by regulations and, therefore, are a function of well age and location. These procedures also may be influenced by operator practices; sometimes operators may exceed regulatory requirements due to wellbore conditions.

In addition, many injection wells may be located in areas where the pressure imbalance induced by injection is insufficient to cause contamination. The geologic and hydrologic setting is also a major factor in decreasing contamination potential. For contamination to occur, a USDW must be present. Furthermore, the collapsing or sloughing of formations into a wellbore can prevent flow. In addition, fluids moving up a wellbore may be bled off into salt water-bearing formations and never reach a USDW.

Variance programs that permit consideration of these important factors, should be established by UIC Directors. This would allow Directors to avoid the unnecessary dedication of resources to areas posing sufficiently low risk. And, while there is a workload factor in determining which wells qualify for variance, it is expected to be significantly less than the workload required to review all wells.

Present Requirement for AOR Studies

Definition of the AOR. The Area of Review (AOR) is the area surrounding an injection well or wells defined by either the radial distance within which pressure in the injection zone may cause migration of the injection and/or formation fluid into an underground source of drinking water (USDW) or defined by a fixed radius of not less than one-fourth mile.(3) In the method where injection pressure is used to define the AOR radial distance, the AOR is also known as the "zone of endangering influence".

Information Required for an AOR. Underground Injection Control (UIC) Program requirements are enforced by the states, where the state has applied for and received primacy from the EPA under Section 1425 of the Safe Drinking Water Act. In the

absence of an approved state program, the requirements are directly implemented by EPA (Direct Implementation or DI states).

State requirements may differ from those established by EPA as long as USDWs are protected. For an AOR study, in conjunction with an EPA UIC Class II injection well permit application, the information that must be submitted is included in the EPA Permit Application and list of required attachments thereto (Appendix B).

It is clear, from the information in Appendix B, that a major effort is required to prepare an application for an EPA UIC Class II injection well permit. Permit requirements can be equally burdensome in primacy states.

Variance Concept and Variance Criteria. As discussed in the Introduction, a FAC has considered and made recommendations concerning implementation of AOR requirements for existing Class II injection wells that were excluded from that process in 1980.

The FAC recommends that AORs be performed for existing injection wells but also introduces the concept of variance from the AOR process. If the FAC recommendations are adopted as amendments to the regulations, then EPA regions will have to implement the revised regulations by granting variances or requiring AORs in DI states. A primacy state would have to show that its UIC program meets the statutory requirements in view of the amended regulations. Primacy states could comply with federal regulations without requiring AORs on all existing injection wells if the state's rules provide for an approved variance program. The FAC recommendations provide for the granting of a variance because of the conditions previously listed in the Introduction and as contained in Appendix C.

The details of the basis for each of the variance conditions are presented in the following pages and the technical procedures that have been developed for qualifying an area for variance are also given.

AOR Variance Methodology

The following discussion, which is modified from Warner, et al. 1993 (4), describes a methodology developed for identifying a producing basin, trend, region or field or a portion of such areas which would be eligible for variance from AOR requirements. Variance would be sought for the largest scale area that could be encompassed by the methodology. The methodology comprises a series of logical decisions based on FAC variance criteria and other compelling evidence. The AOR evaluation methodology is shown in Figure 2. Five general methods are proposed for obtaining variance from well-by-well AOR's as shown in Figure 2. These methods can be used in any order, singly or in combination, to provide variance for some or all wells. Wells not excluded by variance would be subject to conventional AORs.

It is believed that all five of the methods can be applied over large geographic areas but the four methods based upon geologic and hydrologic criteria are most easily visualized as "global" methods. This is because they can be conceived to be broadly effective in protecting USDWs regardless of the presence of individual wells that might not be adequately constructed or abandoned. These methods are discussed in detail in this document.

The fifth method requires evaluation of the manner by which the wells in the area under consideration were completed and abandoned. The present AOR procedure normally requires that this be done on a well-by-well basis for all wells immediately around each injection well. Alternative procedures will be described in section titled "Variance Based on Well Construction And Abandonment Methods" that would provide for variance from that requirement on the basis of broader perspectives of active and abandoned well characteristics.

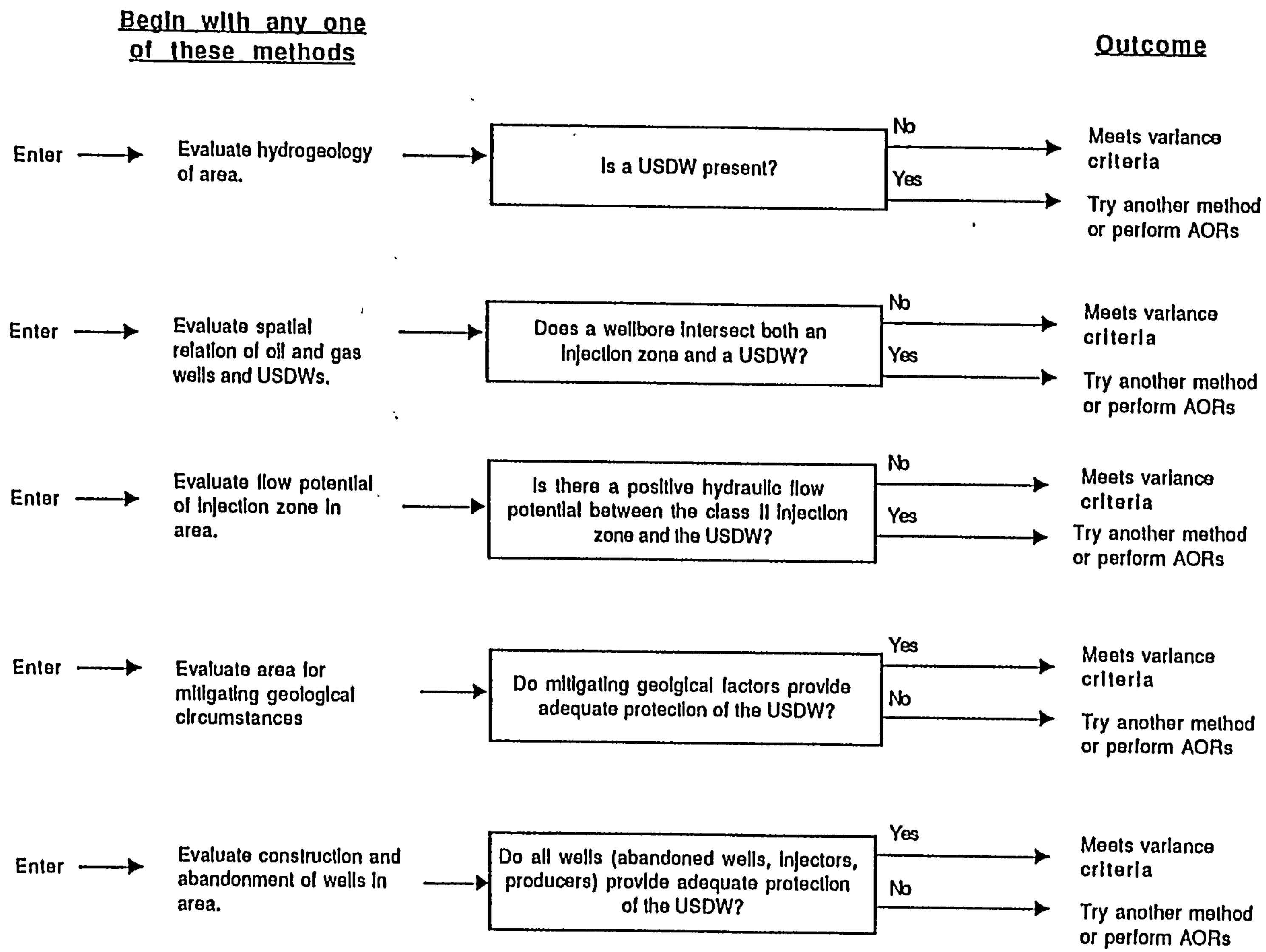

Figure 2. AOR Evaluation Methodology

Five general methods are available for obtaining variance from revised EPA Area of Review requirements. These methods can be used in any order, singly or in combination, to exclude some or all wells from the AOR process. Wells not excluded by variance would be subject to well-by-well AORs.

Variance Based on Absence of USDW. In some oil and gas producing areas there are no USDWs. Any appropriate studies conducted may be used to document this and to justify the granting of a variance from the AOR requirement.

Further, "exempted aquifers" by regulatory definition are not USDWs (40 CFR 146.3) even though ground water total dissolved solids are less than 10,000 mg/l. States have exempted numerous aquifers (40 CFR 146.4 & 146.7) since inception of the UIC program on the basis that the aquifers are hydrocarbon producing, or the total dissolved solids are more than 3,000 mg/l and less than 10,000 mg/l and they are not reasonably expected to support a public water supply system. States should have a list of these exempted aquifers in their records for operators to use in evaluating variance opportunities. In addition, persons in the future may identify aquifers that meet the criteria for exemption under 40 CFR 146.4. In these cases, they may petition the Director to exempt these aquifers under 40 CFR 146.7 for the purpose of either injecting into them or requesting less stringent requirements to protect them.

When injection does not occur into, through or above a USDW, the Director may authorize a well or project with less stringent requirements for AOR, construction, mechanical integrity, operation, monitoring and reporting (40 CFR 144.16).

Variance Based on Lack of Intersection. "No intersection" refers to the situation where a USDW exists and overlies a zone with Class II injection operations, but none of the wells adjacent to the injection well were drilled to a depth which penetrates the injection zone. Hence, in this case there is no connection or fluid pathway between the injection zone and the USDW, and there can be no contamination to the USDW.

Variance Based on Negative Flow Potential. The FAC recommendations contained in Appendix C provide for the possibility of variance from the AOR process where the petroleum reservoir is underpressured relative to the USDW.

a. ***USDW and Petroleum Reservoir Potentiometric Heads.*** Flow potential information is generally available as measured water level (potentiometric head) data from wells completed in USDWs and as petroleum reservoir pressure data from oil and gas wells. Appendix D provides a detailed discussion of the procedure for conversion of petroleum reservoir pressure data to potentiometric head data for comparison with USDW potentiometric head data. Appendix D also describes how comparisons are made of petroleum reservoir head data with USDW head data and discusses the meaning of the comparisons. As discussed in Appendix D, potentiometric head data are reported in feet above a selected datum, usually sea level. The procedures in Appendix D call for subtraction of USDW heads from petroleum reservoir heads to obtain a residual value.

Negative residual heads indicate lack of a potential for upward flow of water from a petroleum reservoir into a USDW while positive residual head data indicate the presence of such a potential.[1] It is recommended however that state directors review head data on a regular basis to ensure an adequate level of protection.

b. ***Procedure for Estimating Flow Potential.*** The idealized step-by-step procedure for evaluation of flow potentials in a geographic area and determination of the availability of a variance is given in Appendix E.

c. ***Effect of Combined Injection and Production Operations.*** For the limited situation where the AOR established by a "zone of endangering influence" could be less than the one-fourth mile fixed radius, the EPA has provided an equation to be used in calculating the "zone of endangering influence." The equation is given in Appendix F, along with a discussion of the limitations of the equation in areas of combined injection and production operations.

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[1] This variance based on negative heads may not be allowed in some states.

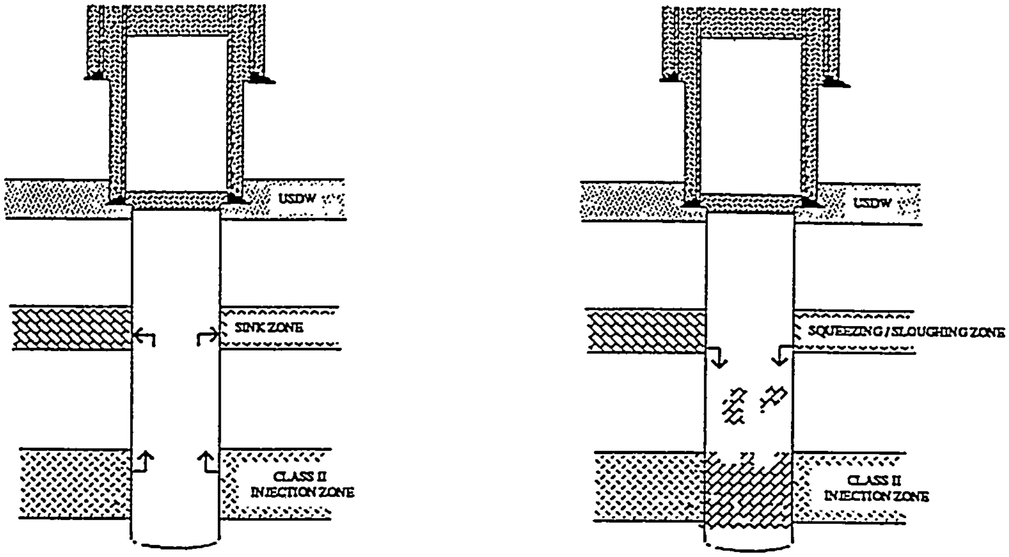
Variance Based on Mitigating Geological Factors. The FAC variance criteria include the availability of local geologic conditions that preclude upward fluid movement that could endanger USDWs. Such mitigating geological factors include, sloughing, squeezing and sink zones.

A sloughing formation refers to any geological horizon which is highly incompetent and tends to fall or cave into the wellbore. With this type of formation, the rock material lost from sloughing could fall into the wellbore, bridge off, and form a solid barrier to flow. Examples of sloughing zones include unconsolidated formations, consolidated bentonitic shales, salt and anhydrite.

A squeezing formation is one with strata that flow plastically under the overburden stress to close an uncased borehole or to close the casing-formation annulus in a cased well. Examples of this type of formation also include unconsolidated shales, consolidated bentonitic shales, salt and anhydrite.

A thief, or sink zone, refers to a geological horizon which has a flow potential less than the overlying USDWs and the petroleum reservoir which contains injection operations. Thief zones, as used in this document, are intermediate formations (located between an injection zone and a USDW) which act to divert the fluids flowing up the wellbore. By acting as a fluid sink, the thief zone prevents contaminating fluids from reaching the USDW. A thief zone can also be a normally-pressured formation that is so permeable and thick that it diverts virtually all upward flowing fluid without experiencing significant pressure increase. The Wilcox Sand in the Lower Tuscaloosa producing trend of Mississippi and Louisiana is an example of such a thief zone.(5)

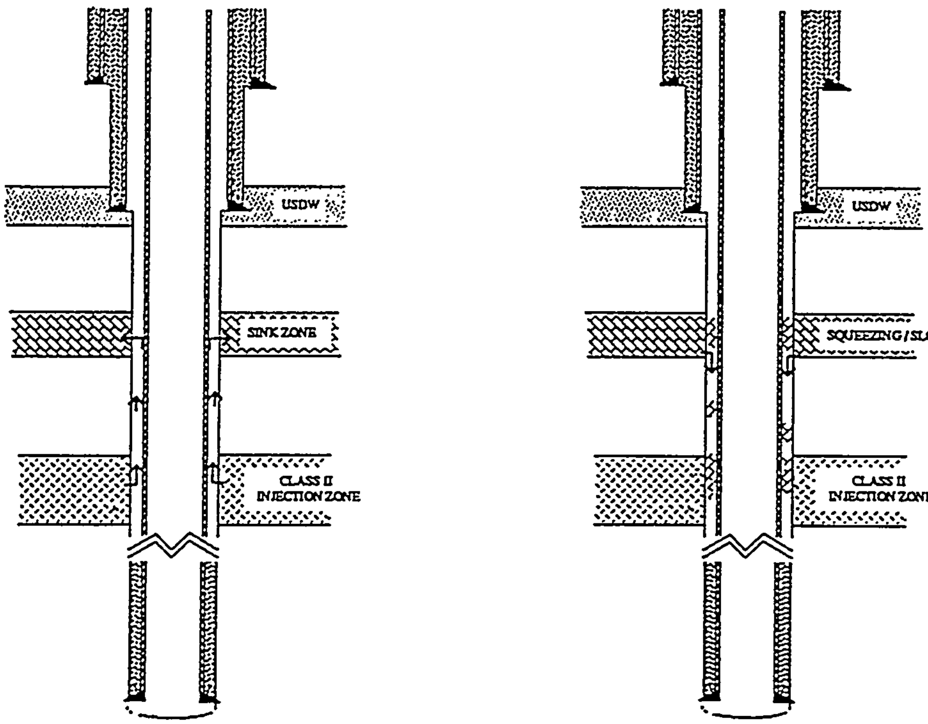
Squeezing, sloughing, and sink zones may or may not prevent USDW contamination. In order for the squeezing, sloughing or sink zone to mitigate the contamination risk, it must be positioned and exposed to the wellbore in the manner shown and discussed in Figure 3. Hence, anyone applying the evaluation methodology must determine not only if the



OPEN HOLE SQUEEZE, SINK AND SLOUGHING ZONE RULES

- SINK ZONE MUST BE LOCATED BETWEEN THE CLASS II INJECTION ZONE AND THE USDW
- THE HYDRUALIC HEAD OF THE SINK ZONE MUST BE LESS THAN THAT OF THE USDW

- SQUEEZING OR SLOUGHING ZONE MUST BE LOCATED BETWEEN THE CLASS II INJECTION ZONE AND THE USDW
- SQUEEZING ZONE MUST CLOSE BOREHOLE OR SUFFICIENT SLOUGHING MATERIAL MUST FALL TO COMPLETELY COVER THE CLASS II INJECTION ZONE



CASED HOLE SQUEEZE, SINK AND SLOUGHING ZONE RULES

- SINK ZONE MUST BE LOCATED BETWEEN THE CLASS II INJECTION ZONE AND THE USDW
- THE HYDRUALIC HEAD OF THE SINK ZONE MUST BE LESS THAN THAT OF THE USDW

- SQUEEZING OR SLOUGHING ZONE MUST BE LOCATED BETWEEN THE CLASS II INJECTION ZONE AND THE USDW
- SQUEEZING ZONE MUST CLOSE BOREHOLE OR SUFFICIENT SLOUGHING MATERIAL MUST FALL TO COMPLETELY COVER THE CLASS II INJECTION ZONE

Figure 3. SINK, SQUEEZE AND SLOUGHING ZONE RULES

mitigating geological zone exists, but assess whether the zone is actually capable of providing the necessary protection.

The only means of assessing the presence and the effectiveness of sloughing or squeezing zones may be qualitative evidence in the form of the experience by operators and of observations by regulatory agency personnel. The presence of sink zones may be known as a result of experience by operators with lost circulation during drilling or such zones may be known to geologists or engineers through basin-wide or regional studies of aquifer/reservoir fluid potentials. Where a sink zone is sufficiently well known for its fluid acceptance characteristics it may be possible to assume that it will effectively divert upward flowing water without further study. Where more quantitative evidence is desired, numerical modeling such as that carried out by Warner and McConnell(5), for the Lower Tuscaloosa trend of Mississippi and Louisiana, may be useful.

Variance Based on Well Construction and Abandonment Methods. Well construction and abandonment methods can also be considered as a factor for an AOR variance. This is because the manner in which a well is constructed or abandoned may preclude fluid migration, even if a positive hydraulic flow potential does exist.

a. *Development of Construction and Abandonment Standards.* States which have oil and gas production have historically set forth standards for well construction and abandonment. These standards detail the correct use or placement of casing, cement, bridge plugs, and other mechanical barriers in a wellbore. The most recent standards, i.e. those in use today, are considered the "current" or "modern day" standards. These standards have generally evolved from a series of accepted practices, adapted over the years to accommodate new technology and new regulatory practice.

Many states have enacted well construction and abandonment standards as regulations which operators are required to follow. Other states present the

standards less formally, as verbal directives or simple written guidelines which the operator is expected to follow. For example, in New Mexico a review of state oil and gas regulations revealed that the well construction and abandonment laws and regulations are written in a general manner, and that specific details with respect to casing setting depth, size and placement of cement plugs, etc., are handled by directives from each district within the State's Oil Conservation Division.

Regardless of whether the historic and current, modern practices are detailed by law, by regulation or by accepted practice, it is necessary to document the practices so that other wells can be judged accordingly. Figures 4 and 5 depict an example of the manner in which current construction and abandonment techniques were formalized in a study of the San Juan Basin.(6) While this is not the only manner in which the regulations can be presented, it was found that a graphical representation is helpful in making comparisons.

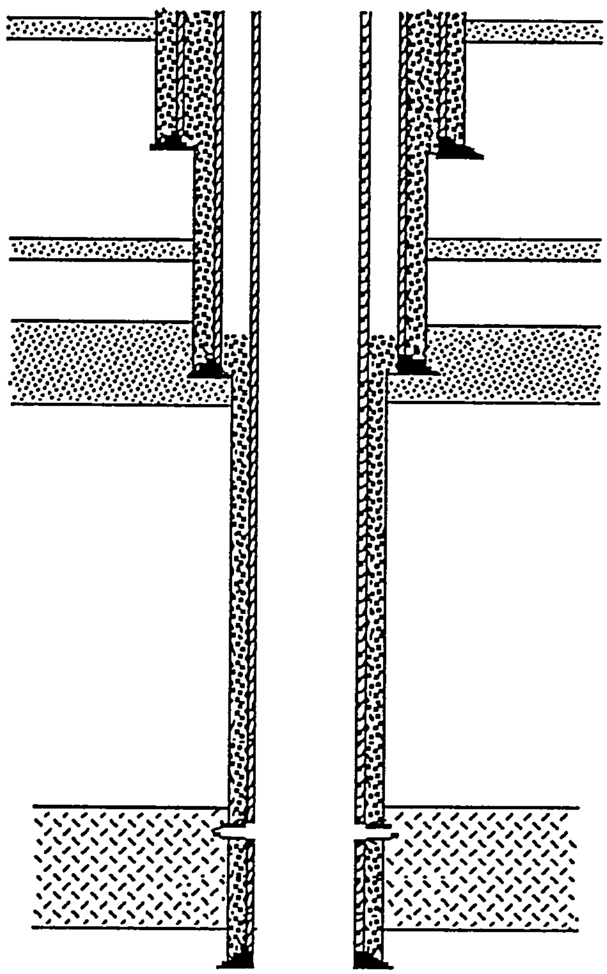
It should be emphasized that past and current construction and abandonment practices will vary from state to state. Therefore, one must document the well construction and abandonment regulations or practices pertinent to the state.

b. *Alternative Variance Approaches.* On the basis of the historic sequence of development of construction and abandonment laws, regulations and practices, it is believed logical that well construction/abandonment based variances should be available through several different approaches, which are:

1. Field discovery and development occurs after promulgation of well construction and abandonment standards that provide adequate USDW protection.
2. Sufficient AORs exist and provide statistical evidence that all wells protect the USDWs.
3. A representative sample of wells is found to provide adequate protection to USDWs. Wells are evaluated with respect to flow barriers and plugs.

FIGURE 4.

EXAMPLE WELL CONSTRUCTION STANDARDS



1. Cement must be circulated around surface pipe. If cement is not circulated, annulus must be filled from surface.

2. All subsequent casing strings shall be cemented a minimum of 100' into the next shallowest string.

   If cement is not circulated, then the top shall be found by temperature survey or CBL.

3. Minimum surface pipe requirements:

Well Depth	Surface Pipe
0-3000'	120'
3-5000'	200'
5-8000	320'
8001'+	call district

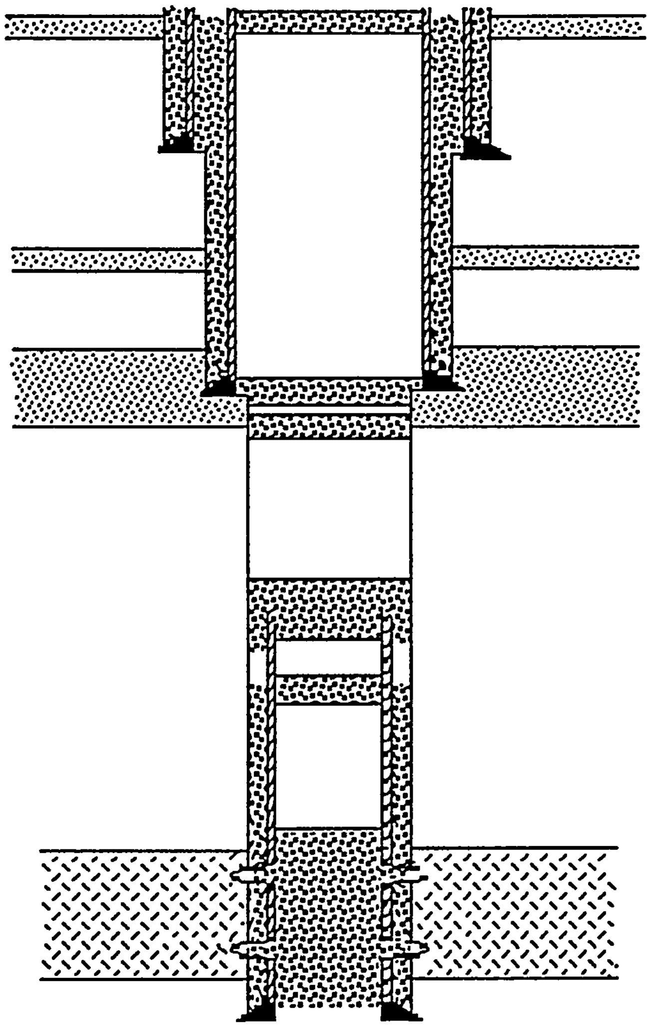
4. Wells drilled in valley fill areas must have surface pipe set at least 50' below the fill.

5. Intermediate casing is optional, but must be cemented according to point #2.

6. Production casing may be set either on top, or through the producing formation.

FIGURE 5.

EXAMPLE WELL ABANDONMENT STANDARDS



1. Minimum 10 sack surface plug should be used.

2. If the surface casing cement was not circulated and the annulus left unfilled, then the annulus should be filled at abandonment.

3. If an intermediate string of casing was run, and cement was not circulated to surface, then a squeeze cement job is required if fresh water or hydrocarbon bearing zones were not originally covered by the primary cement job.

4. In an open hole, cement spacer plugs must be used to cover fresh water and hydrocarbon bearing zone. These plugs should be a minimum of 100' in thickness.

5. In a dry hole with intermediate casing, a cement plug is not routinely required across the shoe of the intermediate string, but may be required depending on formations present at that depth.

6. Cement spacer plugs may be separated by either densified water or mud. The fluid should be greater than or equal to 9 ppg.

7. Pulling casing is optional, but if it is pulled the casing stub should have a minimum of 50' of cement both inside and outside the stub.

8. If production casing cement does not cover all fresh water and hydrocarbon bearing zones, then the casing must be perforated and squeezed in such a manner as to cover these zones.

9. All productive hydrocarbon bearing formations should be abandoned with a plug across the zone. This may be either a CIBP covered with a minimum of 50' of cement, or a cement plug which covers the entire zone.

Variances could be available through each of the approaches for all wells in an area or for only those wells in the area that meet the variance criteria. For example, under the first approach listed, if a field was discovered and entirely developed after the date of adoption of construction and abandonment standards that provide adequate USDW protection, all wells would meet variance criteria. If the field was discovered and partially developed prior to such standards but part of the development occurs after such standards were in place, then those wells constructed/abandoned after standards adoption would meet variance criteria and the older wells would have to be examined through another approach.

Under the second approach, it is conceived that older fields will exist where sufficient new injection wells have been drilled or sufficient production wells converted to injection since promulgation of UIC regulations, to provide an adequate number of AORs and wells within those AORs to statistically characterize the entire field. This basis for the statistical approach used for such a field will depend upon what is known about wells in the field from the AORs that have been performed. The field can possibly be characterized by a random sample of the entire population or may require stratified sampling as is discussed in section titled "Sampling Wells for Evaluation".

The third approach requires that a representative sample of wells be selected from the total population of area wells and that all wells in that sample be evaluated with respect to their construction/abandonment characteristics. This approach will be discussed in greater detail in the following sections.

Sampling Wells for Evaluation. In order to justify an AOR variance based on wellbore construction and abandonment methods, one must be able to verify the quality of well conditions within the area under consideration. There are two ways of accomplishing this. The first method is to actually evaluate the construction and abandonment methods used in all wells

within the zone of endangering influence of each Class II injection well in the area. The second method is to obtain a statistically valid sample of the wells and to evaluate only those wells.

Evaluation of a statistically representative number of wells is recommended as a means of qualifying an area for variance from the current AOR procedure. The EPA Underground Injection Control regulations provide for such a statistical approach in 40 CFR, Part 146, 146.24 where it is stated that, in the AOR process, "In cases where the information would be repetitive and wells are of similar age, type, and construction, the Director may elect to only require data on a representative number of wells."

One prerequisite in applying such a statistical approach, however, is that there must be an agreed method of sampling the wells. There are several different sampling techniques available, such as simple random sampling or stratified random sampling. Simple random sampling refers to a process where a limited, yet representative, number of items are randomly selected from a total population. Stratified random sampling refers to segregating the sample population into sub-populations which share common characteristics or traits. For example, one could segregate a group of wells by age based on spud date or abandonment date. Sub-populations of wells might be grouped by the selected time periods.

It is believed that simple random sampling could be adequate in justifying the AOR exemption in some circumstances. For example, if an operator samples wells in an active waterflood project and cannot find instances of inadequate completion or abandonment methods; then, with a large enough representative sample, one could conclude that all such wells in the project area provide sufficient USDW protection.

Alternatively, suppose that the operator identified four unplugged wells and, therefore, could not conclude that all of the wells provide protection to the USDW. In this case it might be more advantageous to stratify the population based on the age of the wells, in an attempt to determine if there was a particular date after which no unplugged abandoned well exists. For example, if the wells are analyzed by age and one could ascertain that all of the unplugged wells occurred prior to 1940, then there would be a strong argument for allowing a variance for all wells drilled or completed subsequent to that date.

Neither one of these sampling methods is the most desirable method, universally, to apply. One thing to keep in mind is that for any given population, stratified random sampling involves the examination of a greater number of wells than does simple random sampling. While stratified sampling can be very useful in some cases for justifying variances, this approach might not be needed in all cases. In addition, practical issues such as the databases available may preclude the use of stratified sampling.

Appendix G contains additional guidance on the selection of sample well populations for evaluation of well construction and abandonment methods.

Preparation of Wellbore Diagrams. In evaluating wells, it has been found that a wellbore diagram depicting the relevant information about a well's construction and abandonment method (e.g. casing depths, position of cement plugs) it is very helpful to effectively compare the well to past and current construction and abandonment methods. Without such a diagram, it is extremely difficult to visualize the position of barriers with respect to overlying USDWs. For this reason, it is advised that anyone attempting to apply the evaluation methodology prepare wellbore sketches of the

construction and, if applicable, abandonment well conditions.

Several sources of data can be used to prepare wellbore drawings. These sources include both public and private information. Public information is obtained from commercial databases, and state completion and abandonment reports. Private sources of information include the well records of an oil and gas operating company.

It is envisioned that an operator who is applying the evaluation methodology would use primarily the company's private data to prepare wellbore drawings. Many production departments within operating companies already routinely prepare and maintain such diagrams.

The well construction information which should be displayed includes:

1. Operator's name
2. Spud date, completion date and status of well at completion
3. Geological tops and thicknesses of any USDWs, zones with Class II injection operations and possible sloughing, squeezing or sink zones
4. Total drilled depth and plugged back depth
5. Casing string sizes and setting depths
6. Casing cementing records, including volume and calculated tops
7. Bradenhead cement operations
8. Cement squeeze volumes and method of placement
9. Depth of perforations of all zones tested or produced and methods of completion
10. Location of temporary or permanent bridge plugs, cement retainers, or any other mechanical devices left in the wellbore
11. Information regarding cement placed on top of any mechanical devices left in the wellbore

12. Any information regarding changes in the status of the well such as conversion to water supply or water injection
13. Information regarding USDW encountered during drilling or completion

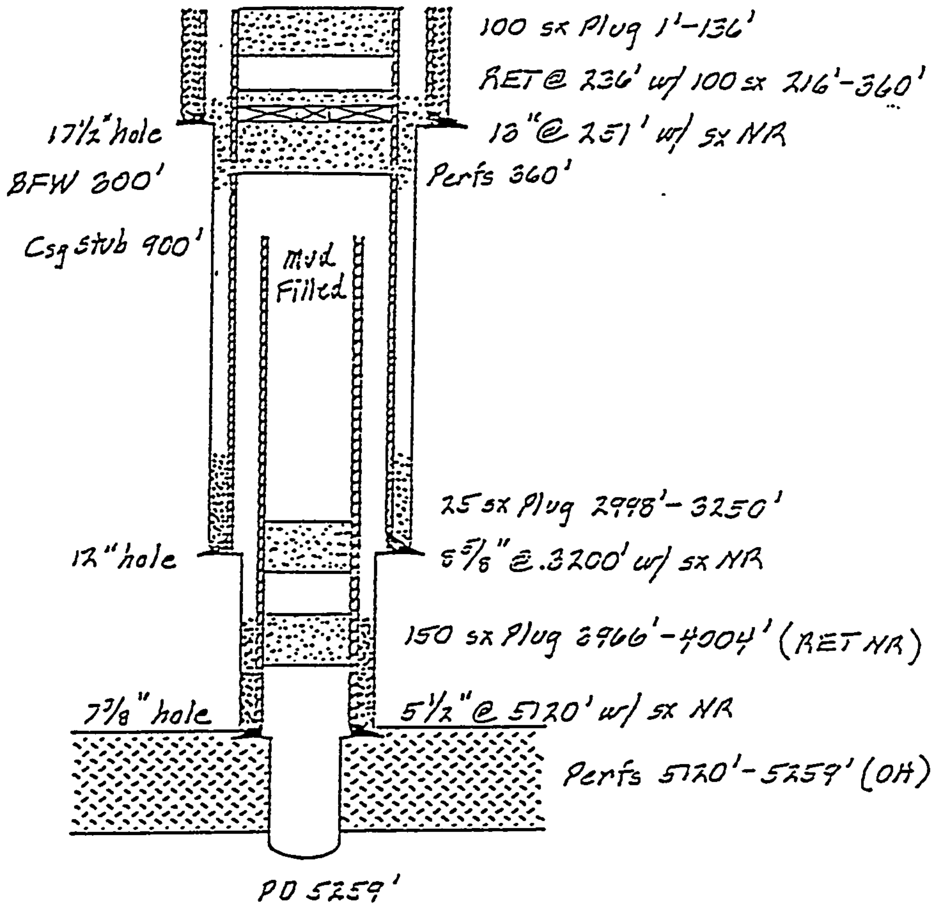
The well abandonment information which should be displayed includes:

1. Date of abandonment
2. Information regarding any casing pulled, e.g. depth where casing was cut and footage of pipe retrieved from the well
3. Cement volumes, depths and thickness of all plugs set in the wellbore
4. Cement squeeze volumes and method of placement
5. Fluids remaining in wellbore
6. Record of any fish left in the hole

A typical well drawing which includes this information is shown in Figure 6. Such drawings should be prepared whenever there are sufficient data available for analysis.

Some older wells may or may not have sufficient data to allow preparation of a wellbore diagram. In these cases, it may be possible to infer the construction and abandonment methods used if data for other wells drilled and/or abandoned in the same time period are available. If this is not the case, then no wellbore drawing can be prepared.

c. Tools Available for AOR Variance Evaluation. Table 1 lists the AOR evaluation methods that have been discussed, the information required for evaluation and the information sources and user tools available to carry out the various evaluations.



Well API # 42-165-01779
Gaines County, Texas

NOTE: USDW at Base of Fresh Water (BFW)

FIGURE 6. EXAMPLE WELLBORE DRAWING

Table 1 is largely self-explanatory with the exception of the ABE program listed as a tool for well analysis under H., 3., 2. ABE, the Automated Borehole Evaluation program, is a computer program which provides a quantitative assessment of the barriers to USDW contamination based on well construction and abandonment methods. While use of the ABE program is not essential to evaluating wells for their flowpath characteristics, the program was developed to help ensure a consistent basis for assessing and comparing flow barriers found in different types of active and abandoned wells. A complete discussion of ABE is presented in Appendix H.

Table 1. AOR Evaluation Methods, Information Required, Information Sources and Available User Tools

AOR EVALUATION METHOD	INFORMATION REQUIRED	INFORMATION SOURCES AND AVAILABLE USER TOOLS
A. No USDW	1. Hydrogeology of Area	1. Federal, State & Local Public Agency Studies & Files
		2. Knowledge of Local Water Users, Water Well Drillers & Oilfield Operators
		3. Oil & Gas Well Logs
B. No USDW Intersection	1. Spatial Relations of Oil and Gas Wells and USDWs	1. State Reports
		2. Operators Completion Records
		3. Oil & Gas Well Logs
C. Hydraulic Flow Potential	1. USDW Head Data	1. Federal, State & Local Public Agency Studies & Files
	2. Injection Zone Head Data	1. State Injection Records
		2. Operator DST Records
		3. Operator Well Tests
	3. Head Comparisons	1. Computerized Databases
		2. Computer-based Mapping Programs

Table 1.
Page 2

AOR EVALUATION METHOD		INFORMATION REQUIRED		INFORMATION SOURCES AND AVAILABLE USER TOOLS
	4.	Reservoir Pressure Buildup During Injection	1.	Reservoir Simulation
D. Mitigating Geological Factors	1.	Presence of Sinks, Sloughing, and/or Squeezing Zones	1.	Knowledge of Geological Characteristics of Formations
			2.	Operator Drilling Records
			3.	Operator Injection Experience
			4.	Oil and Gas Well Logs
	2.	Location of Mitigating Geological Factors with Respect to Injection Zone	1.	Operator Drilling Records
			2.	Operating Flow Models
			3.	Injection Well Tests
	3.	Effectiveness of Sink Zones in Diverting Flow	1.	Computer Flow Models
E. Construction & Abandonment of Wells	1.	Historic and Current Well Construction & Abandonment Laws & Regulations	1.	State Records

Table 1.
Page 3

AOR EVALUATION METHOD	INFORMATION REQUIRED	INFORMATION SOURCES AND AVAILABLE USER TOOLS
F. Field Discovery	1. Date of Adoption of Adequate Regulations	1. State Records
	2. Date of Discovery and Development of Field	1. State Records
		2. Operator Records
		3. Commercial Databases
		4. Society Publications
G. Sufficient Existing AORs	1. Existing AORs	1. State & Federal Records
		2. Operator Records
H. Representative Samples of Wells Analyzed	1. Well Data	1. State Records
		2. Operator Records
		3. Commercial Databases
	2. USDW Data	1. Federal, State & Local Public Agency Studies & Files
	3. Analysis Methods	1. Manual Interpretation
		2. ABE Program
		3. Reservoir Simulation

d. ***Analysis of Well Construction and Abandonment Evaluation Results.*** The evaluation process described in the previous three sections will have provided data on the number of flow barriers in abandoned wells, producing wells and injection wells and the number of plugs in abandoned wells included in the selected sample of wells from the area under study.

In some circumstances, any producing well or injection well with at least one behind-pipe flow barrier and at least one through-pipe flow barrier provides adequate USDW protection. Based on appropriate evaluation, an abandoned well with one cement plug between the injection zone and the USDWs may provide adequate USDW protection. Wells with less than adequate protection require further evaluation.

The wellbore evaluation methodology that has been described can provide "compelling evidence" that will allow for complete or partial variance from AOR requirements.

The evaluation of a statistically representative sample of wells, through the procedures that have been developed, can substitute for the well-by-well process and can provide "compelling evidence" for variance. This methodology can be applied to geographic areas much larger than a single AOR and including a producing basin, trend, region or field or a portion of such areas.

If, for example, evaluation of the statistically selected random sample of wells shows them all to provide adequate protection, then there is compelling evidence for a variance since it would have been demonstrated that it is statistically probable that all wells have been constructed and/or abandoned by acceptable standards.

As a refinement of the variance concept, specific identified categories of wells could be excluded from the AOR process even though a total variance could not be granted. For example, it might be determined that all wells constructed and/or abandoned since a certain historical date have been satisfactorily constructed and/or abandoned whereas earlier wells require further evaluation. Such a partial variance could greatly reduce the level of effort that would be required for complete well-by-well AORs.

Variance Based on Other Compelling Evidence

While this committee has attempted to identify as many bases for qualifying an area for variance as possible, there likely may be others that the committee has overlooked or is unaware of. In developing a variance plan, the Director should remain flexible and not limit the information that he/she will consider in determining whether to grant a variance. This flexibility is needed to ensure variances can be obtained in all areas where injection wells pose sufficiently low risk to USDWs. The plan should allow the use of innovation and creativity to develop acceptable methods of demonstrating nonendangerment of USDWs. Operators should be allowed to negotiate with a Director to identify the most appropriate and cost-effective method, and the Director should reasonably consider all compelling evidence in his/her variance determination.

REFERENCES

1. 40 CFR, Part 146.

2. 40 CFR, Part 146. Subpart C, 146.24.

3. 40 CFR, Part 146, 146.6 (b).

4. Warner, D.L., Koederitz, L.F., Dunn-Norman, S., and Laudon, R.C., 1993, An Area of Review Variance Methodology, Final report from the University of Missouri-Rolla to the American Petroleum Institute, April 1993, 110p., American Petroleum Institute, Washington, D.C.

5. Warner, D.L., and McConnell, C.L., 1993, Assessment of Environmental Implications of Abandoned Oil and Gas Wells, Journal Petroleum Technology, Vol. 45, No. 9, Sept. 1993, p. 874-880.

6. Warner, D.L., Koederitz, L.F., Dunn-Norman, S., and Laudon, R.C., 1993a, Application of an Area of Review Variance Methodology to the San Juan Basin of New Mexico, Interim report from the University of Missouri-Rolla to the American Petroleum Institute, June 1993, 171 p., American Petroleum Institute, Washington, D.C.

7. 40 CFR, Part 146, 146.6 (a) (2).

8. Pressure Buildup and Flow Tests in Wells, C.S. Matthew and D.G. Russell, Society of Petroleum Engineers, Richardson, Texas, 1967, p. 72.

9. The Reservoir Engineering Aspects of Waterflooding, F.F. Craig, Jr., Society of Petroleum Engineers, Richardson, Texas, 1971, p. 48.

10. Sampling Wells for Evaluation of Well Construction and Abandonment Method, P.G. Wakim, American Petroleum Institute - Department of Finance, Accounting and Statistics, 1993.

APPENDIX A

The Underground Injection Practices Research Foundation Committee

for the Development of a Model Variance Plan Guidance

for Use in the Area-of-Reviews for Class II Injection Well Practices

THE UNDERGROUND INJECTION PRACTICES RESEARCH FOUNDATION

VARIANCE PLAN COMMITTEE

COMMITTEE MEMBERS:

Five State Representatives:	Jerry Mullican	Texas
	David Catanach	New Mexico
	Bill Bryson	Kansas
	David Bolin	Alabama
	Ken Henderson	California
Two USEPA Representatives:	Francoise Brasier	Headquarters
	Steve Platt	Region 3
Industry Representative:	Bill Freeman	Shell Oil
UIPRF Representative:	Debra Eno	UIPRF

COMMITTEE SUPPORT:

Committee Facilitator:	Marty Mefferd	Consultant
Technical Advisor:	Dr. Don Warner	UMR
	Dr. Paul Wakim	API
GWPC Liaison:	Michel Paque	GWPC
UIPRF Project Manager:	Ben Grunewald	UIPRF
API Project Manager:	Mark Rubin	API

APPENDIX B

EPA Underground Injection Control

Permit Application and Instructions

Well Class and Type Codes

Class I	Wells used to inject waste below the deepest underground source of drinking water
Type "I"	Nonhazardous industrial disposal well
"M"	Nonhazardous municipal disposal well
"W"	Hazardous waste disposal well injecting below USDWs
"X"	Other Class I wells (not included in Type "I," "M," or "W")
Class II	Oil and gas production and storage related injection wells.
Type "D"	Produced fluid disposal well
"R"	Enhanced recovery well
"H"	Hydrocarbon storage well (excluding natural gas)
"X"	Other Class II wells (not included in Type "D," "R," or "H")
Class III	Special process injection wells.
Type "G"	Solution mining well
"S"	Sulfur mining well by Frasch process
"U"	Uranium mining well (excluding solution mining of conventional mines)
"X"	Other Class III wells (not included in Type "G," "S," or "U")
Other Classes	Wells not included in classes above.
	Class V wells which may be permitted under §144.12
	Wells not currently classified as Class I, II, III, or V.

Attachments to Permit Application

Class	Attachments
I new well	A, B, C, D, F, H — S, U
existing	A, B, C, D, F, H — U
II new well	A, B, C, E, G, H, M, Q, R; optional — I, J, K, O, P, U
existing	A, E, G, H M, Q, R — U; optional — J, K, O, P, Q
III new well	A, B, C, D, F, H, I, J, K, M — S, U
existing	A, B, C, D, F, H, J, K, M — U
Other Classes	To be specified by the permitting authority

EPA Form 7520-6 (2-84) page 2 of 5

INSTRUCTIONS — Form 4 — Underground Injection Control (UIC) Permit Application

Form 4 must be completed by all owners or operators of Class I, II, and III injection wells and others who may be directed to apply for a UIC permit by the Director.

I. EPA I.D. NUMBER — Fill in your EPA Identification Number. If you do not have a number, leave blank.

II. FACILITY NAME AND ADDRESS — Name of well, well field or company and address.

III. OWNER/OPERATOR NAME AND ADDRESS — Name and address of owner/operator of well or well field.

IV. OWNERSHIP STATUS — Mark the appropriate box to indicate the type of ownership.

V. SIC CODES — List at least one and no more than four Standard Industrial Classification (SIC) Codes that best describe the nature of the business in order of priority.

VI. WELL STATUS — Mark Box A if the well(s) were operating as injection wells on the effective date of the UIC Program for the State. Mark Box B if the well(s) existed on the effective date of the UIC Program for the State but were not utilized for injection. Box C should be marked if the application is for an underground injection project not constructed or not completed by the effective date of the UIC Program for the State.

VII. TYPE OF PERMIT — Mark "Individual" or "Area" to indicate the type of permit desired. Note that area permits are at the discretion of the Director and that wells covered by an area permit must be at one site, under the control of one person and do not inject hazardous waste. If an area permit is requested the number of wells to be included in the permit must be specified and the wells described and identified by location. If the area has a commonly used name, such as the "Jay Field," submit the name in the space provided. In the case of a project or field which crosses State lines, it may be possible to consider an area permit if EPA has jurisdiction in both States. Each such case will be considered individually, if the owner/operator elects to seek an area permit.

VIII. CLASS AND TYPE OF WELL — Enter in these two positions the Class and type of injection well for which a permit is requested. Use the most pertinent code selected from the list on the reverse side of Form 4. When selecting type X please explain in the space provided.

IX. LOCATION OF WELL — Enter the latitude and longitude of the existing or proposed well expressed in degrees, minutes, and seconds or the location by township, and range, and section, as required by 40 CFR 146. If an area permit is being requested, give the latitude and longitude of the approximate center of the area.

X. INDIAN LANDS — Place an "X" in the box if any part of the facility is located on Indian lands.

XI. ATTACHMENTS — Note that information requirements vary depending on the injection well class and status. Attachments for Class I, II, and III are described on pages 4 and 5 of this document and listed by Class on page 2. Place EPA ID number in the upper right hand corner of each page.

XII. CERTIFICATION — All permit applications (except Class II) must be signed by a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, and by a principal executive or ranking elected official for a public agency. For Class II, the person described above should sign, or a representative duly authorized in writing.

EPA Form 7520-6 (2-84) Page 3 of 5

INSTRUCTIONS — Attachments to Form 4

Attachments to be submitted with permit application for Class I, II, III and other wells

A. AREA OF REVIEW METHODS — Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review shall be a fixed radius of ¼ mile from the well bore unless the use of an equation is approved in advance by the Director

B. MAPS OF WELLS/AREA AND AREA OF REVIEW — Submit a topographic map, extending one mile beyond the property boundaries, showing the injection well(s) or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste, treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:

Class I

The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located with one quarter mile of the facility property boundary. Only information of public record is required to be included on this map:

Class II

In addition to requirements for Class I, include pertinent information known to the applicant. This requirement does not apply to existing Class II wells:

Class III

In addition to requirements for Class I, include public water systems and pertinent information known to the applicant.

C. CORRECTIVE ACTION PLAN AND WELL DATA — Submit a tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the area of review, including those on the map required in B, which penetrate the proposed injection zone. Such data shall include the following:

Class I

A description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require. In the case of new injection wells, include the corrective action proposed to be taken by the applicant under 40 CFR 144.55

Class II

In addition to requirements for Class I, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review which penetrate formations affected by the increase in pressure. This requirement does not apply to existing Class II wells.

Class III

In addition to requirements for Class I, the corrective action proposed under 40 CFR 144.55 for all Class III wells.

D. MAPS AND CROSS SECTIONS OF USDWs — Submit maps and cross sections indicating the vertical limits of all underground indicating the vertical limits of all underground sources of drinking water within the area of review (both vertical and lateral limits for Class I), their position relative to the injection formation and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection. (Does not apply to Class II wells.)

E. NAME AND DEPTH OF USDWs (CLASS II) — For Class II wells, submit geologic name, and depth to bottom of all underground sources of drinking water which may be affected by the injection.

F. MAPS AND CROSS SECTIONS OF GEOLOGIC STRUCTURE OF AREA — Submit maps and cross sections detailing the geologic structure of the local area (including the lithology of injection and confining intervals) and generalized maps and cross sections illustrating the regional geologic setting. (Does not apply to Class II wells)

G. GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (CLASS II) — For Class II wells, submit appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and fracture pressure.

H. OPERATING DATA — Submit the following proposed operating data for each well (including all those to be covered by area permits).(1) average and maximum daily rate and volume of the fluids to be injected; (2) average and maximum injection pressure. (3) nature of annulus fluid; (4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids; (5) for Class II wells, source and analysis of the physical and chemical characteristics of the injection fluid; (6) for Class III wells, a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

I. FORMATION TESTING PROGRAM — Describe the proposed formation testing program. For Class I wells the program must be designed to obtain data on fluid pressure, temperature, fracture pressure, other physical, chemical, and radiological characteristics of the injection matrix and physical and chemical characteristics of the formation fluids.

For Class II wells the testing program must be designed to obtain data on fluid pressure, estimated fracture pressure, physical and chemical characteristics of the injection zone. (Does not apply to existing Class II wells or projects.)

For Class III wells the program must be designed to obtain data on fluid pressure, fracture pressure, and physical and chemical characteristics of the formation fluids if the formation is naturally water bearing. Only fracture pressure is required if the formation is not water bearing. (Does not apply to existing Class III wells or projects.)

J. STIMULATION PROGRAM — Outline any proposed stimulation program.

K. INJECTION PROCEDURES — Describe the proposed injection procedures including pump, surge, tank, etc.

L. CONSTRUCTION PROCEDURES — Discuss the construction procedures (according to §146.12 for Class I, §146.22 for Class II, and §146.32 for Class III) to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring programs, and proposed annulus fluid. (Request and submission of justifying data must be made to use an alternative to a packer for Class I.)

M. CONSTRUCTION DETAILS — Submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

N. CHANGES IN INJECTED FLUID — Discuss expected changes in pressure, native fluid displacement, and direction of movement of injected fluid. (Class III wells only.)

O. PLANS FOR WELL FAILURES — Outline contingency plans (proposed plans, if any, for Class II) to cope with all shut-ins or well failures, so as to prevent migration of fluids into any USDW.

P. MONITORING PROGRAM — Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and a discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Q. PLUGGING AND ABANDONMENT PLAN — Submit a plan for plugging and abandonment of the well including (1) describe the type, number, and placement (including the elevation of the top and bottom) of plugs to be used, (2) describe the type, grade, and quantity of cement to be used; and (3) describe the method to be used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs. Also for a Class III well that underlies or is in an exempted aquifer, demonstrate adequate protection of USDWs. Submit this information on EPA Form 7520-14, Plugging and Abandonment Plan.

R. NECESSARY RESOURCES — Submit evidence such as a surety bond or financial statement to verify that the resources necessary to close, plug or abandon the well are available.

S. AQUIFER EXEMPTIONS — If an aquifer exemption is requested, submit data necessary to demonstrate that the aquifer meets the following criteria: (1) does not serve as a source of drinking water; (2) cannot now and will not in the future serve as a source of drinking water; and (3) the TDS content of the ground water is more than 3,000 and less than 10,000 mg/l and is not reasonably expected to supply a public water system. Data to demonstrate that the aquifer is expected to be mineral or hydrocarbon producing, such as general description of the mining zone, analysis of the amenability of the mining zone to the proposed method, and time table for proposed development must also be included. For additional information on aquifer exemptions, see 40 CFR 144.7 and 146.04.

T. EXISTING EPA PERMITS — List program and permit number of any existing EPA permits, for example, NPDES, PSD, RCRA, etc

U. DESCRIPTION OF BUSINESS — Give a brief description of the nature of the business.

APPENDIX C

Federal Advisory Committee

Final Document

March 23, 1992

ENVIRONMENTAL PROTECTION AGENCY
CLASS II INJECTION WELL ADVISORY COMMITTEE

FINAL DOCUMENT

INTRODUCTION

The EPA Class II Injection Well Advisory Committee was chartered on June 6, 1991 and subsequently met for a total of seven two-day meetings. The Committee was made up of representatives of major and independent oil production companies, environmental interests, state regulators, the United States Environmental Protection Agency, the United States Department of Energy, and the United States Department of Interior (see the attached list of Committee members).

The Committee was charged with the task of providing recommendations to the Office of Ground Water and Drinking Water regarding possible changes in the Underground Injection Control Program. Over the course of its deliberations, the Committee developed proposals for changes in the following areas: construction requirements, monitoring and testing requirements, "area of review" requirements, abandoned well protocols, actions pursuant to a failure of mechanical integrity, and requirements for commercial disposal facilities. These recommendations are set forth below.

The Committee believes that the implementation of these recommendations will substantially increase the overall effectiveness of the Class II program. Specifically, these recommendations address the concerns raised about the adequacy of the UIC program during the Mid-Course Evaluation of the Class II Program,[1] in the GAO Report[2] (which focussed on the current Area of Review program), and — with respect to construction requirements for Class II wells — the Report to Congress prepared by EPA/OSW.[3]

Except as noted in the Committee Members' Letters of Endorsement,[4] the Committee endorses these recommendations as appropriate Federal requirements for the effective protection of Underground Sources of Drinking Water (USDWs). At the same time, the Committee recognizes that Section 1425 of the Safe Drinking Water Act provides that States may employ alternative requirements if they can demonstrate to USEPA that, in light of any amendments to the Federal requirements, their programs remain effective in protecting USDWs.

The Committee also recognizes that some of its recommendations will place additional administrative burdens on the State programs. In particular, the proposed Area of Review program may necessitate a short–term funding increase for some States if it is to be fully implemented within the recommended timeframe.

CONSTRUCTION REQUIREMENTS FOR NEWLY DRILLED WELLS

1. The regulations should be amended to require that all newly drilled wells be constructed with:

    2. tubing and packer,

    3. long string casing cemented to prevent fluid movement out of the injection zone,

    4. cemented surface casing to 3,000 TDS, unless state requirements for surface casing are currently more stringent (in which case these requirements remain in effect) or cementing surface casing to this depth is technically impractical. Where cementing surface casing to 3,000 TDS is technically impractical:

        5. it must extend at a minimum to below currently–used water and any water which may reasonably be expected to be used in the future, and

        6. cement must be used to isolate the base of 3,000 TDS water.

CONSTRUCTION REQUIREMENTS FOR NEWLY CONVERTED WELLS

7. The regulations should be amended to apply the construction requirements set forth in #1 – #6 above to all converted production wells that are originally constructed after the date these regulations are promulgated.

HISTORICALLY ACCEPTED NON–CONVENTIONAL COMPLETIONS

8. The requirements set forth in #1 – #7 above could be delayed for a maximum of five years for small entities, as defined by the Regulatory Flexibility Act, in those parts of the country where alternative practices have historically been allowed.

MONITORING AND TESTING

9. As is currently required, an MIT must be conducted every 5 years on wells with three layers of protection and surface casing down to at least 3,000 TDS. For wells with less protection, the regulations should be amended to require:

    10. for wells with two layers of protection, an MIT must be conducted at least every three years, and

    11. for wells with only one layer of protection, an MIT must be conducted annually.

AREA OF REVIEW

The regulations should be amended to require that:

12. An AOR be performed within five years of promulgation of the regulations on all existing injection wells except those covered by previously conducted AORs and those located in a field, basin, or project that has been granted a variance as described below.

13. Program Directors have six months from the promulgation of the new regulations to provide EPA with:

    14. a schedule for performing AORs in known high risk areas within two years, and either

    15. a schedule for performing AORs within five years on all wells not covered by previously conducted AORs, or

    16. notice of their intent to establish a variance program.

17. The schedules set forth in #14 and #15 may be adjusted by the Administrator for good cause.

18. Program Directors choosing to establish a variance program would have one year from the promulgation of the new regulations to submit to EPA for approval a variance plan which sets forth the specific types and sources of information that will be considered in making variance determinations.

19. Variances for new and existing wells may be granted only if the Director determines that there is a sufficiently low risk of upward fluid movement from the injection zone that could endanger USDWs.

20. Information indicating any of the following conditions could be considered by a Director in determining whether to grant a variance:

    21. the absence of USDWs,

    22. the reservoir is underpressured relative to the USDW,

    23. local geological conditions preclude upward fluid movement that could endanger USDWs,

    24. other compelling evidence.

25. Directors must provide notice and opportunity for public comment in the development of the variance program plan and in the granting of variances.

GUIDANCES

26. The January 22, 1992 draft of Guidance #75, entitled "Follow-up to Class II Well MIT Failures under Section 40 CFR 146.8," should be signed and implemented, and the regulations should be amended as necessary for the effective implementation of the guidance.

27. The January 22, 1992 draft of Guidance #76, entitled "Operating, Monitoring and Reporting Requirements for Class IID Commercial Salt Water Disposal Wells," should be signed and implemented, and the regulations should be amended as necessary for the effective implementation of the guidance.

28. The January 22, 1992 draft of Guidance #77, entitled "Management and Monitoring Requirements for Class II Wells in Temporary Abandoned Status," should be signed and implemented.

<u>Endnotes</u>:

1. See: "Mid – Course Evaluation of the Class II Injection Control Program: Final Report of the Mid–Course Evaluation Workgroup," dated August 22, 1989.

2. See the GAO report entitled: "Drinking Water: Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wastes," dated July, 1989. GAO/RCED-89-97.

3. See: "Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy," dated December, 1987. Prepared by EPA's Office of Solid Waste. EPA/530/SW-88-003.

4. The State of Ohio and the Independent Petroleum Association of America have indicated that they intend not to endorse Provision #11.

ENVIRONMENTAL PROTECTION AGENCY
CLASS II INJECTION WELL ADVISORY COMMITTEE

LIST OF COMMITTEE MEMBERS

Francoise M. Brasier	Environmental Protection Agency
William R. Bryson	Kansas Corporation Commission
James W. Collins	ARCO Oil and Gas Company
Dennis Crist	OH Department of Natural Resources/Division of Oil & Gas
Bill Freeman	American Petroleum Institute
Rob Hauser	CA Department of Conservation Division of Oil & Gas
H. William Hochheiser	Office of Fossil Energy/Department Energy
Frank Lanzeta	Bureau of Land Management/Department of the Interior
David Lennet	National Audubon Society
Ralph S. Moore	Conoco, Inc.
Jerry Mullican	Texas Railroad Commission
Barry Russell	Independent Petroleum Association of America
Velma Smith	Friends of the Earth
Wilma Subra	Subra & Company

FACILITATORS:

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APPENDIX D

Discussion of Potential for Flow Upward

from a Petroleum Reservoir Into a USDW

(From Warner, et al., 1993 (4))

POTENTIAL FOR FLOW OF SALT WATER UPWARD FROM A PETROLEUM RESERVOIR INTO A USDW

Modern groundwater text books begin discussion of subsurface fluid flow by establishing that the total potential to cause flow is comprised of two components, elevation and pressure.[1] Elevation is the distance above some datum, normally expressed in feet, and may be positive or negative with respect to the datum. Sea level is often used as a reference datum, but elevation can be measured with respect to any arbitrary level.

Pressure is the fluid gauge pressure as measured or calculated at the subsurface point of interest. In oil and gas wells pressures are normally measured at a particular depth in the borehole.

The equation for total potential is as follows:

$$H_t = H_p + H_z \qquad (1)$$

where,

H_t = total potential or head, ft
H_p = pressure head at point of pressure measurement, ft
H_z = elevation head, ft

In petroleum reservoir engineering, the pressures reported in a wellbore are usually expressed in psi. Hence, to calculate total head using equation (1) it is first necessary to convert reservoir pressure in psi to feet of head. This is accomplished by dividing the pressure by the density of the fluid column as follows:

$$H_p = \frac{P}{\frac{\rho}{144}} = \frac{P}{\rho}(144) \qquad (2)$$

where,

H_p = pressure head at point of pressure measurement, ft
P = reservoir or measured pressure, psi
ρ = fluid density, lb/ft^3

The constant in equation (2) is 144 in^2/ft^2 and is used to convert the fluid density in lb/ft^3 to a pressure gradient in psi/ft. For example, fresh water has a density of 62.4 lb/ft^3. The pressure gradient in a column of fresh water would therefore be:

---

[1] Freeze, R.A. and Cherry, J. A., 1979, Groundwater, Prentice Hall, Englewood Cliffs, N. J. 604 p.

$$grad = \frac{62.4\ lb/ft^3}{144\ in^2/ft^2} = 0.433\ psi/ft \qquad (3)$$

where,

grad = fluid pressure gradient, psi/ft

In groundwater practice, flow potentials are generally expressed as heads in units of feet. These values can be used directly in calculating total potential (equation 1).

Figure D-1 shows an example of these principles. In the figure, there is a continuous porous medium, saturated with fresh water, which extends from surface to a depth of 2000 feet. A borehole has been drilled completely through the sediments as shown. The reference datum, which is assigned an elevation of 0, is the bottom of the hole.

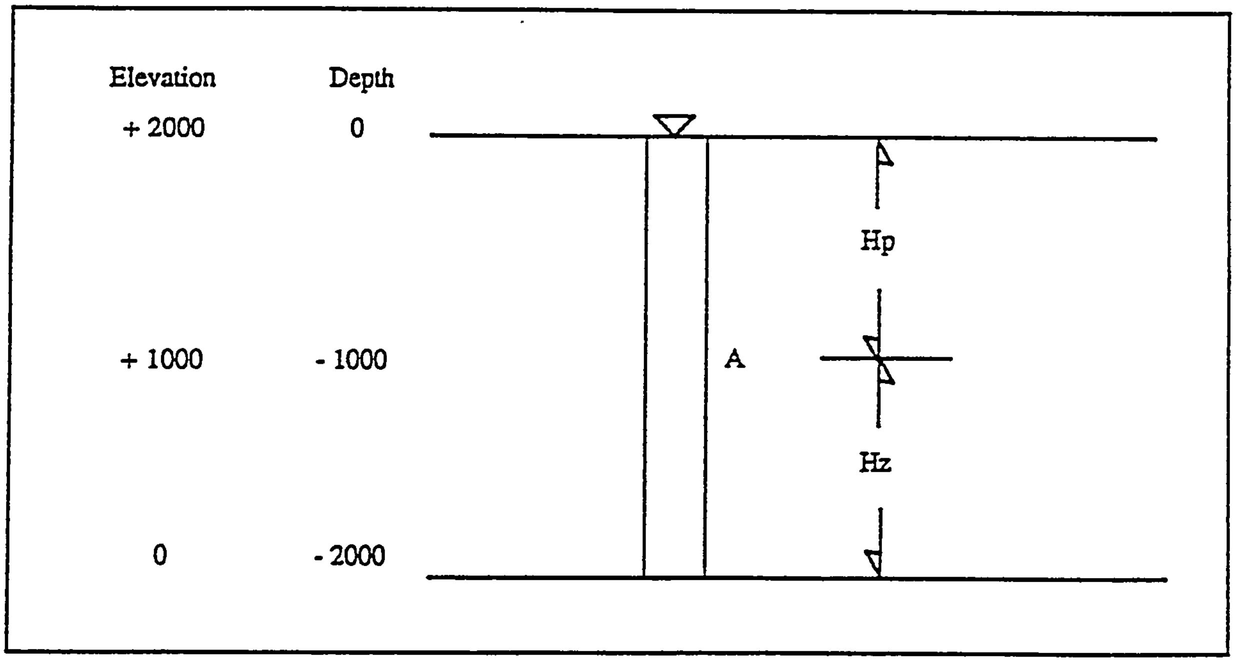

Figure D-1. Pressure (H_p) and Elevation (H_z) head at Reference Point A

The total potential at any point in the borehole can be determined by equation (1), since it is known that the fluid in the medium is fresh water. For example, if a pressure measurement was made at point A 1000 ft below the surface, there would be a hydrostatic pressure at point A of:

$$P = (grad)\ (H_p) = (0.433\ psi/ft)\ (1000\ ft) = 433\ psi \qquad (4)$$

where,

P = hydrostatic fluid pressure, psi
grad = fluid pressure gradient, psi/ft (fresh water = 0.433)
H_p = height of column of water generating the pressure

Converting this pressure to head (H_p), gives the following:

$$H_p = \frac{433}{62.4}(144) = 1000 \text{ ft} \tag{5}$$

The elevation potential (H_z) at point A is equal to:

$$H_z = (1000 \text{ ft}) - (0 \text{ ft}) = 1000 \text{ ft} \tag{6}$$

which represents the elevation of point A minus the elevation of the datum plane. Thus, at point A the total potential is equal to:

$$H_t = 1000 \text{ ft} + 1000 \text{ ft} = 2000 \text{ ft} \tag{7}$$

A similar calculation can be made at any other point in the borehole or for a different formation fluid density. For example, the pressure at a depth of 500 ft would be 217 psi (0.433 psi/ft x 500 ft = 217 psi), and the total potential at this point would be would be:

$$H_t = 500 \text{ ft} + 1500 \text{ ft} = 2000 \text{ ft} \tag{8}$$

The example in Figure D-1 assumes a single homogeneous aquifer containing water of a constant density. In this situation, the flow potentials are equal everywhere so that no flow can occur. Although this case demonstrates the concept of head and potential, the practical problem of interest is that of interaquifer flow, i.e. where fluid from one aquifer or reservoir may flow into another aquifer.

Figure D-2 depicts a USDW which overlies a petroleum reservoir. The USDW contains fresh water with a very low total solids content and its density is approximately 62.4 lb/ft^3 (pressure gradient = 0.433 psi/ft). The petroleum reservoir contains salt water with a total dissolved solids content of 250,000 mg/l. The density of the salt water is shown as 72 lb/ft^3. This extreme density contrast would not normally exist, i.e. most oilfield brines have densities of about

68 lb/ft³. The density contrast is exaggerated here to demonstrate the principles in the following examples.

As shown, there are impermeable strata between the petroleum reservoir and the USDW. In this example and the others discussed herein it is assumed that the zones between the USDW and the petroleum reservoir are of such low permeability that flow through them does not occur.

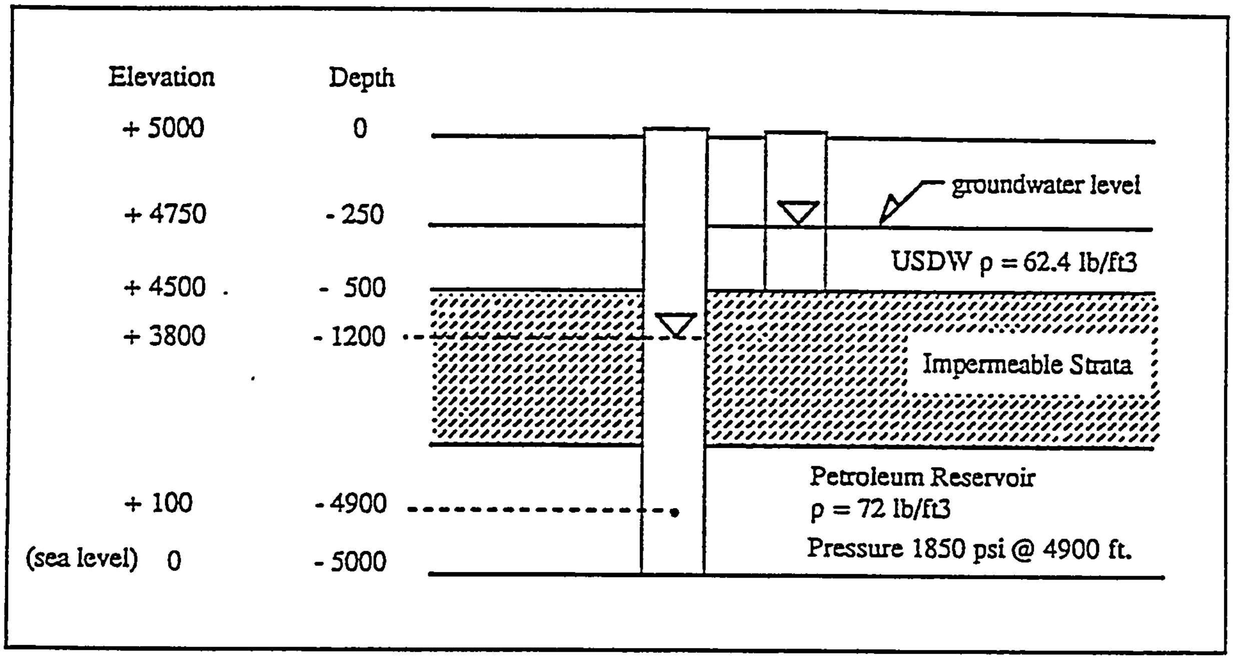

Figure D-2. Diagrammatic Drawing of Flow Potential Conditions in a Petroleum Reservoir and Overlying USDW.

The petroleum reservoir in Figure D-2 has a reservoir pressure of 1850 psi at a depth of 4900 feet. Water from this reservoir can be calculated to have the potential to rise to an elevation of 3800 feet in an open borehole as follows:

$$H_t = \frac{1850 \text{ psi}}{72 \text{ lb/ft}^3}(144 \text{ in}^2/\text{ft}^2) + 100 \text{ ft} = 3800 \text{ ft} \qquad (9)$$

As this example shows, reservoir pressures are normally pressure measurements made at a specified depth. Ground water aquifer potentiometric data are water levels measured in wells and reported with reference to sea level as a datum. To compare these data, reservoir heads must be calculated with reference to the same datum as the groundwater data. Hence, in (9) 100 ft is added to calculate the reservoir head relative to sea level.

The reservoir head data and USDW head data are then compared to determine if fluids from the reservoir have sufficient potential to flow into the USDW. The usual practice is to subtract the USDW head from the reservoir head. If the difference is positive, there is a potential for the reservoir fluid to flow into the USDW. However, in Figure D-2 it can be seen that the height of the fluid column representing the salt water potential is lower than the base of the USDW (deepest point where interaquifer flow can occur). This indicates that no flow can occur from the reservoir into the USDW.

If the reservoir head, i.e. the height of the reservoir fluid column, is above the base of the USDW, there may or may not be potential for interaquifer flow. This depends on the amount of reservoir head relative to the base of the USDW, the density of the reservoir fluid and the potential of the USDW.

Figure D-3 shows an example where there is not a sufficient potential for interaquifer flow, even though the reservoir potential is sufficient to cause a fluid column to rise above the base of the USDW.

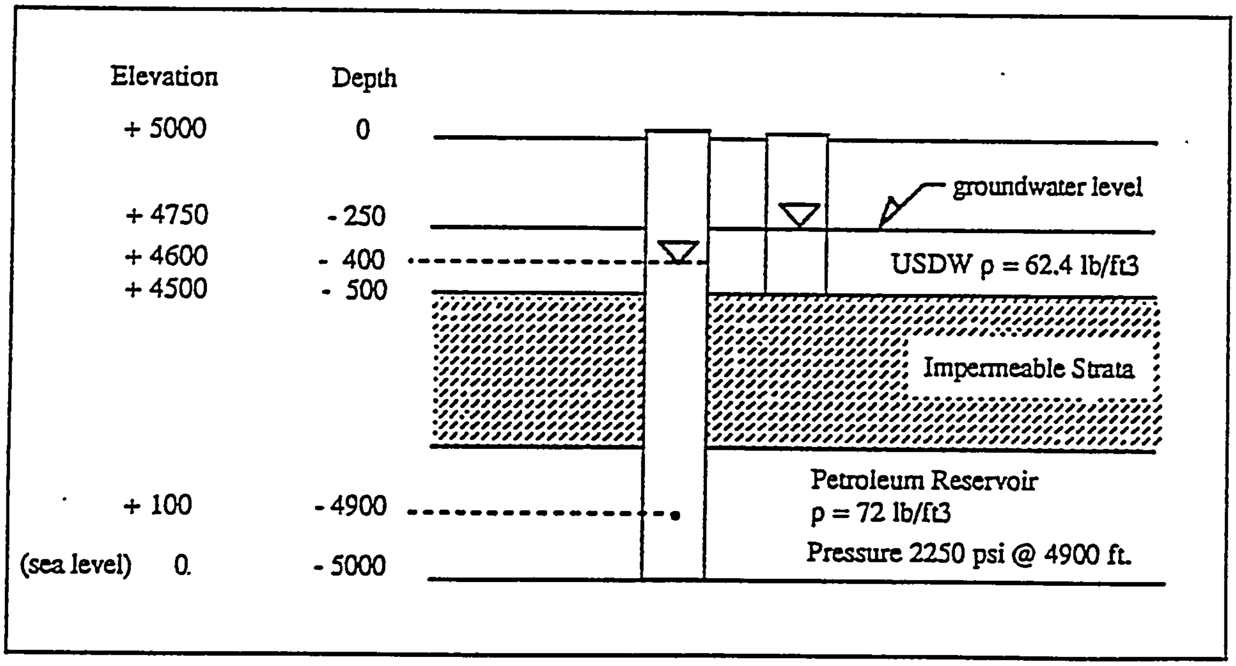

Figure D-3. Diagrammatic Drawing of Flow Potential Conditions in a Petroleum Reservoir and Overlying USDW.

In Figure D-3, the reservoir pressure at a depth of 4900 feet is 2250 psi. The salt water column in this case would rise to an elevation of 4600 feet as shown below:

$$H_t = \frac{2250 \text{ psi}}{72 \text{ lb/ft}^3}(144 \text{ in}^2/\text{ft}^2) + 100 \text{ ft} = 4600 \text{ ft} \qquad (10)$$

In order to determine if the reservoir head would actually be able to overcome the total head potential in the USDW and flow into it, the salt water head above the base of the USDW must be converted into an equivalent fresh water head. In the case shown in Figure D-3, the salt water head is 100 ft greater than the base of the USDW. The equivalent fresh water head above the base of the USDW would therefore be:

$$(100 \text{ ft}) \left(\frac{72 \text{ lb/ft}^3}{62.4 \text{ lb/ft}^3}\right) = 115.4 \text{ ft} \qquad (11)$$

Adding 115.4 ft to the elevation of the base of the USDW yields a total of 4615.4 ft (115.4 + 4500 ft). Since this is less than the USDW head of 4750 ft., the salt water cannot flow into the USDW.

In the third example, Figure D-4, there is sufficient potential for flow. In this case the reservoir pressure at a depth of 4900 ft is 2315 psi.

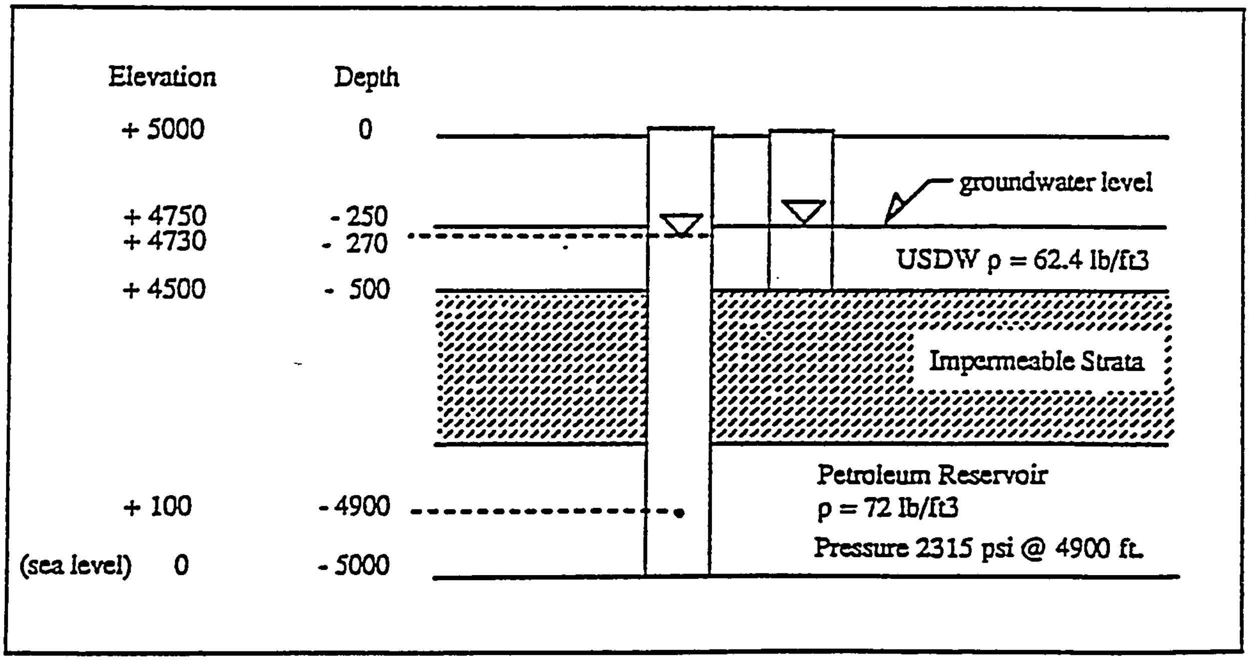

Figure D-4. Diagrammatic Drawing of Flow Potential Conditions in a Petroleum Reservoir and Overlying USDW.

The reservoir pressure of 2315 psi would cause the salt water column to rise to an elevation of 4730 feet as shown below:

$$H_t = \frac{2315 \text{ psi}}{72 \text{ lb/ft}^3} (144 \text{ in}^2/\text{ft}^2) + 100 \text{ ft} = 4730 \text{ ft} \tag{12}$$

The reservoir head (height of the fluid column) in this example is 230 feet above the base of the USDW. The equivalent fresh water head for this fluid column would be:

$$(230 \text{ ft}) \left(\frac{72 \text{ lb/ft}^3}{62.4 \text{ lb/ft}^3}\right) + 4500 \text{ ft} = 4765.4 \text{ ft} \tag{13}$$

Since the total equivalent salt water head of 4765.4 ft would exceed the 4750 ft fresh water head, the salt water would have the potential to flow into the USDW (4765.4 - 4750 = +15.4 ft)

A fourth example is given to illustrate the case where reservoir head is greater than the head of the USDW, i.e. the height of the reservoir fluid column rises above the top of the USDW. This is shown in Figure D-5.

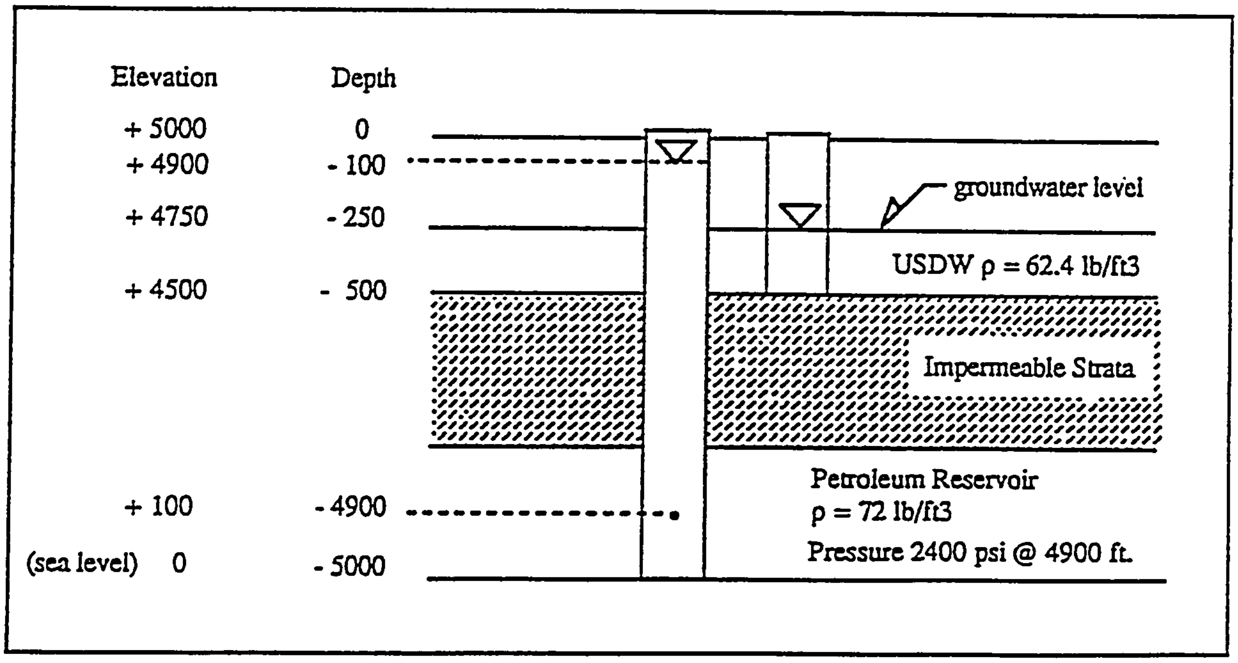

Figure D-5. Diagrammatic Drawing of Flow Potential Conditions in a Petroleum Reservoir and Overlying USDW.

In this case the reservoir pressure at a depth of 4900 ft is 2400 psi and the salt water column would rise to an elevation of 4900 ft. The reservoir head is 400 feet above the bottom of the USDW. Converting this to an equivalent fresh water head, the total potential to cause flow would be:

$$(400\ \text{ft})\left(\frac{72\ \text{lb/ft}^3}{62.4\ \text{lb/ft}^3}\right) + 4500\ \text{ft} = 4961.5\ \text{ft} \tag{14}$$

Since the total equivalent salt water head of 4961.5 ft exceeds the 4750 ft fresh water head, the salt water would have the potential to flow into the USDW (4961.5 - 4750 = +211.5 ft). However, this determination is also obvious from visual inspection of Figure D-5, i.e. when the salt water column rises above the fresh water level in the USDW, there is no question that the salt water potential would be sufficient for flow into the USDW to occur.

POTENTIAL CALCULATIONS WHERE ELEVATION OF THE BASE OF USDW IS UNKNOWN

In all of the four examples cited in Figures D-2 through D-5, a precise determination of the flow potential difference between the petroleum reservoir and the USDW could be calculated because the elevation of the base of the USDW was assumed to be known. In many cases, the USDW fresh water heads will be known but the elevation of the base of the USDW will not. In those cases, the salt water heads can be calculated as was previously shown, but a different procedure must be used to calculate the equivalent fresh water heads. The procedure that has been used in this study is to convert the entire salt water head, above the elevation at which the pressure was measured, to an equivalent fresh water head. This procedure is conservative in that it overestimates the potential for upward flow. For the four examples, the fresh water heads calculated by the procedure are shown in Figure D-6.

Example 1, Figure D-2

$$(3700 \text{ ft}) \left(\frac{72 \text{ lb/ft}^3}{62.4 \text{ lb/ft}^3}\right) + 100 \text{ ft} = 4369 \text{ ft}$$

Example 2, Figure D-3

$$(4500 \text{ ft}) \left(\frac{72 \text{ lb/ft}^3}{62.4 \text{ lb/ft}^3}\right) + 100 \text{ ft} = 5292 \text{ ft}$$

Example 3, Figure D-4

$$(4630 \text{ ft}) \left(\frac{72 \text{ lb/ft}^3}{62.4 \text{ lb/ft}^3}\right) + 100 \text{ ft} = 5442 \text{ ft}$$

Example 5, Figure D-5

$$(4800 \text{ ft}) \left(\frac{72 \text{ lb/ft}^3}{62.4 \text{ lb/ft}^3}\right) + 100 \text{ ft} = 5638 \text{ ft}$$

Figure D-6. Fresh Water Heads Calculated for Examples shown in Figures D-2 through D-5.

Figure D-7 is a summary of the various reservoir heads calculated for the four examples shown in Figures D-2 through D-5. The head values summarized consist of the initial salt water

head (calculations (9), (10), (12)), the equivalent fresh water head relative to the base of the USDW (calculations (11), (13)), the total fresh water equivalent of the reservoir head (Figure III-6), and the USDW heads.

Example 1, Figure D-2

	head, ft
A. Calculated reservoir salt water head	3800
B. Calculated reservoir fresh water head with base of USDW as reference	(*)
C. Calculated reservoir fresh water head with elevation of pressure measurement as reference	4639
D. Measured USDW head	4750

Example 2, Figure D-3

	head, ft
A. Calculated reservoir salt water head	4600
B. Calculated reservoir fresh water head with base of USDW as reference	4615
C. Calculated reservoir fresh water head with elevation of pressure measurement as reference	5292
D. Measured USDW head	4750

Example 3, Figure D-4

	head, ft
A. Calculated reservoir salt water head	4730
B. Calculated reservoir fresh water head with base of USDW as reference	4765
C. Calculated reservoir fresh water head with elevation of pressure measurement as reference	5442
D. Measured USDW head	4750

Example 4, Figure D-5

	head, ft
A. Calculated reservoir salt water head	4900
B. Calculated reservoir fresh water head with base of USDW as reference	4961
C. Calculated reservoir fresh water head with elevation of pressure measurement as reference	5638
D. Measured USDW head	4750

(*) cannot be calculated because salt water does not rise to base of USDW

Figure D-7. All Calculated Heads Calculated for Examples shown in Figures D-2 through D-5.

Conclusions that can be drawn from the above listing of head data are:

1. Only the petroleum reservoir equivalent fresh water heads calculated using the known elevation of the base of the USDW as a datum are accurate representations of the potential for flow of salt water from a petroleum reservoir to a USDW.

2. If the calculated petroleum reservoir salt water head is greater than the measured USDW head there is potential for upward flow. The further calculation of the petroleum equivalent fresh water head will only serve to more accurately quantify the head differential which will

be larger than that between the calculated salt water head and the measured USDW fresh water head.

3. If the petroleum reservoir equivalent fresh water head, calculated without knowledge of the elevation of the base of the USDW and using the elevation of the pressure measurement as the datum, is less than the measured USDW fresh water head, then there is no possibility of there being sufficient potential for upward flow of salt water from the petroleum reservoir to the USDW.

4. When the elevation of the base of the USDW is unknown, then a practical procedure is to calculate the petroleum reservoir salt water head and the equivalent fresh water head using the elevation of the pressure measurement as the datum. These two results provide a range of head which bracket the correct result.

CONCEPT OF HEAD RESIDUALS

In order to provide a readily understandable and easily visualized means of presenting information on the potential for flow of salt water from a petroleum reservoir in to a USDW, the concept of flow potential residuals has been adopted. A flow potential residual is defined as the arithmetic difference obtained by subtracting the measured USDW head from the calculated petroleum reservoir head. A negative residual indicates the absence of sufficient potential for upward flow from a petroleum reservoir to a USDW while a positive residual indicates the presence of sufficient potential for such flow. A listing of the residuals from the four previous examples is as follows:

Example 1, Figure D-2

A. 3800 ft - 4750 ft = -950 ft
B. ——
C. 4369 ft - 4750 ft = -381 ft

Example 2, Figure D-3

A. 4600 ft - 4750 ft = -150 ft
B. 4615 ft - 4750 ft = -135 ft
C. 5292 ft - 4750 ft = 542 ft

Example 3, Figure D-4

A. 4730 ft - 4750 ft = - 20 ft
B. 4765 ft - 4750 ft = 15 ft
C. 5442 ft - 4750 ft = 692 ft

Example 4, Figure D-5

A. 4900 ft - 4750 ft = 150 ft
B. 4961 ft - 4750 ft = 211 ft
C. 5638 ft - 4750 ft = 888 ft

Figure D-8. Residuals Calculated for Examples shown in Figures D-2 through D-5.

From these calculations it is apparent that, in some cases, conflicting residual values can be obtained. The reasons for this are as follows:

- In example 1, there in no potential for upward flow, since the two extreme residual values are both negative.
- In example 2, the range of residuals is from -150 feet to 542 feet and, unless the elevation of the base of the USDW is known, the correct residual of -135 cannot be determined.
- In example 3, the range of residuals is -120 feet to 692 feet. Again, unless the elevation of the base of the USDW is known, the correct residual of 15 feet cannot be determined.
- In example 4, since the two extreme residuals are both positive there is potential for upward flow.

APPENDIX E

Idealized Step-By-Step Procedure

for Evaluation of Flow Potential

(From Warner; et al., 1993 (4))

The idealized step-by-step procedure for evaluation of flow potential in a geographic area and determination of the availability of a variance is as follows:

1. Obtain head data for the USDW or USDWs of concern and adjust data to a base of USDW datum.
2. Plot the data from 1. on a base map (or maps) of an appropriate scale.
3. Hand contour or computer contour the USDW head map of 2. using an appropriate contour interval.
4. Obtain predevelopment petroleum reservoir pressure data for the field or fields of concern.
5. Convert the data from 4 to a common datum, usually sea level, and plot the pressure data on the same base map as used in 2.
6. Hand contour or computer contour the predevelopment petroleum reservoir pressure data.
7. Obtain current petroleum reservoir pressure data and add to the map of 5.
8. Recontour the map resulting from 7.
9. Convert values from the petroleum reservoir pressure map as obtained from 5. to fresh-water heads as described in Appendix D , using the base of the USDW as a datum.
10. Plot and contour petroleum reservoir head data from 9. for visual inspection for consistency with map of 8.
11. Subtract USDW contour head values from 3 from petroleum reservoir map head

values from 10.

12. Plot and contour residual heads from 11.

13. Where residuals from 12. are positive, there is potential for upward flow with no additional imposed injection head. Where residuals from 12. are negative, determine the additional injection pressure head that could be imposed. If imposed head creates a positive residual, then there is potential for upward flow to the USDW. If imposed head leaves a negative residual, the upward flow cannot occur. Such an area of negative residual would be eligible for a variance from well-by-well AOR.

The 13 steps listed above are idealized for a large field, multi-field, basin or sub-basin size area. For a small field or single well, one could start with present-day petroleum reservoir pressure data, convert those data to equivalent fresh-water heads and compare them with local USDW heads in the same manner as in Step 13 without the need for the other steps. The folowing figures provide an example of the application of Steps 1-13, as given above, to a regional area.

USDW DATA				HYDROCARBON RESERVOIR DATA							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
X (EAST)	Y (NORTH)	HEAD ELEV ABOVE SEA LEVEL	HEAD ELEV ABOVE BASE USDW	X (EAST)	Y (NORTH)	RESERVOIR ELEVATIONS ABOVE SEA LEVEL	RESERVOIR PRESSURE	RESERVOIR PRESSURE ADJUSTED TO SEA LEVEL	HEAD ELEV ABOVE SEA LEVEL	HEAD ELEV ABOVE BASE USDW	ADJUSTED HEAD ELEVATION ABOVE BASE USDW (.5/.433)
2.0518	3.3998	4830	330	0.4200	1.5415	100	2405	2455	4910	410	473
4.4632	2.5456	4830	330	0.9456	7.3065	120	2395	2455	4910	410	473
7.9010	1.7134	4820	320	0.9212	4.8642	155	2375	2453	4905	405	468
11.4695	1.3005	4820	320	3.9633	7.7505	-3324	4075	2413	4825	325	375
3.0546	1.5343	4875	375	3.3797	3.9145	-3300	4063	2413	4825	325	375
4.9194	0.1757	4875	375	3.6268	0.6127	-3345	4085	2413	4825	325	375
1.5231	0.5261	4915	415	5.6401	1.4132	-2307	3531	2378	4755	255	294
0.6278	5.9734	4760	260	5.4335	5.1152	1225	1773	2385	4770	270	312
10.4917	2.3784	4792	292	5.5921	7.2919	1275	1753	2390	4780	280	323
5.3903	4.1029	4787	287	6.0642	2.6237	1250	1746	2371	4742	242	279
3.6393	5.9991	4758	258	10.5329	6.4289	-5550	5095	2320	4640	140	162
6.5058	4.1065	4765	265	9.6607	3.1372	-5500	5070	2320	4640	140	162
10.0738	3.3685	4758	258	11.4319	3.1873	-4500	4548	2298	4595	95	110
6.6120	5.7962	4725	225	11.1731	0.7097	-4400	4498	2298	4595	95	110
8.3123	4.9355	4725	225	9.2119	7.7886	1275	1700	2338	4675	175	202
10.2797	4.5477	4725	225	8.8804	5.0445	1250	1713	2338	4675	175	202
5.9753	8.1283	4690	190	8.4129	0.1803	1265	1705	2338	4675	175	202
11.2545	5.7277	4690	190	7.4004	3.8012	1270	1718	2353	4705	205	237
0.6510	8.5459	4695	195								
4.2438	8.4845	4695	195								
11.5580	7.2155	4635	135								
11.1209	8.6338	4592	92								

LAND SURFACE AT +5,000 FEET ABOVE SEA LEVEL.
BASE USDW IS AT +4,500 ABOVE SEA LEVEL.
HYDROCARBON RESERVOIR PRESSURES AND ELEVATIONS ARE VARIABLE.

COLUMN 4 = COLUMN 3 - 4500 FEET.
COLUMN 9 = (COLUMN 7 * 0.5 PSI/FT) + COLUMN 8
COLUMN 10 = COLUMN 7 + (COLUMN 8 / 0.5 PSI/FT)
COLUMN 11 = COLUMN 10 - 4500 FEET
COLUMN 12 = COLUMN 11 * .5 PSI/FT / .433 PSI/FT
THIS ADJUSTMENT IS MADE BECAUSE THE LARGEST PRESSURE (OR HEAD) DIFFERENTIAL OCCURS AT THE BASE OF THE USDW, AND A FRESH WATER HEAD EQUIVALENT (0.433 PSI/FT) MUST BE USED FOR HEADS ABOVE THE BASE OF THE USDW.

TABLE E-1: SPREAD SHEET SHOWING DATA USED IN MAP EXAMPLES.

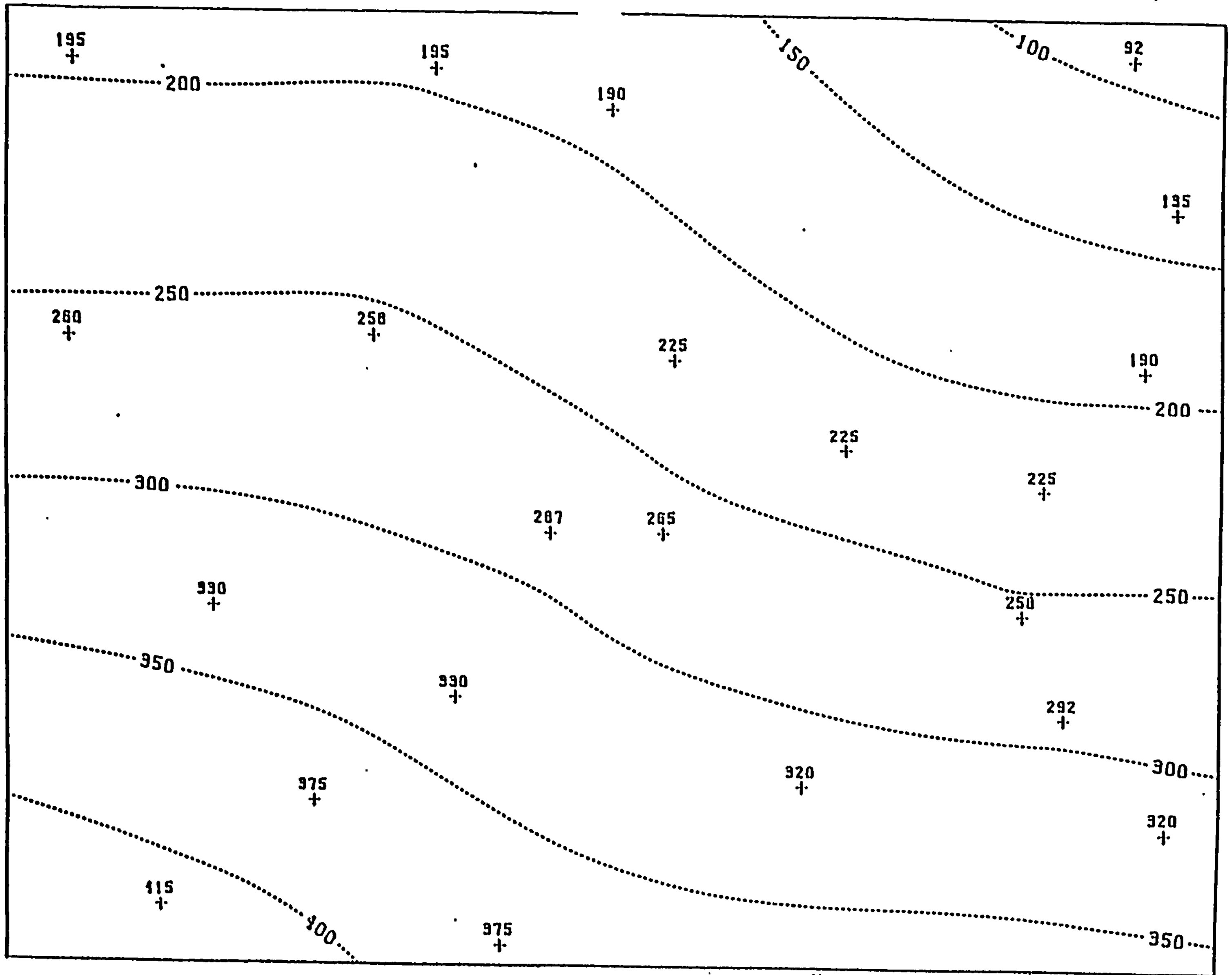

FIGURE E-1 . : VARIANCE EXAMPLE MAP E-1 . : STEPS 1, 2 & 3: OBTAIN, POST AND CONTOUR USDW HEAD DATA. This data should be posted and contoured using the base of the USDW as the datum if possible. If the base of the USDW is not known, use sea level as the datum.

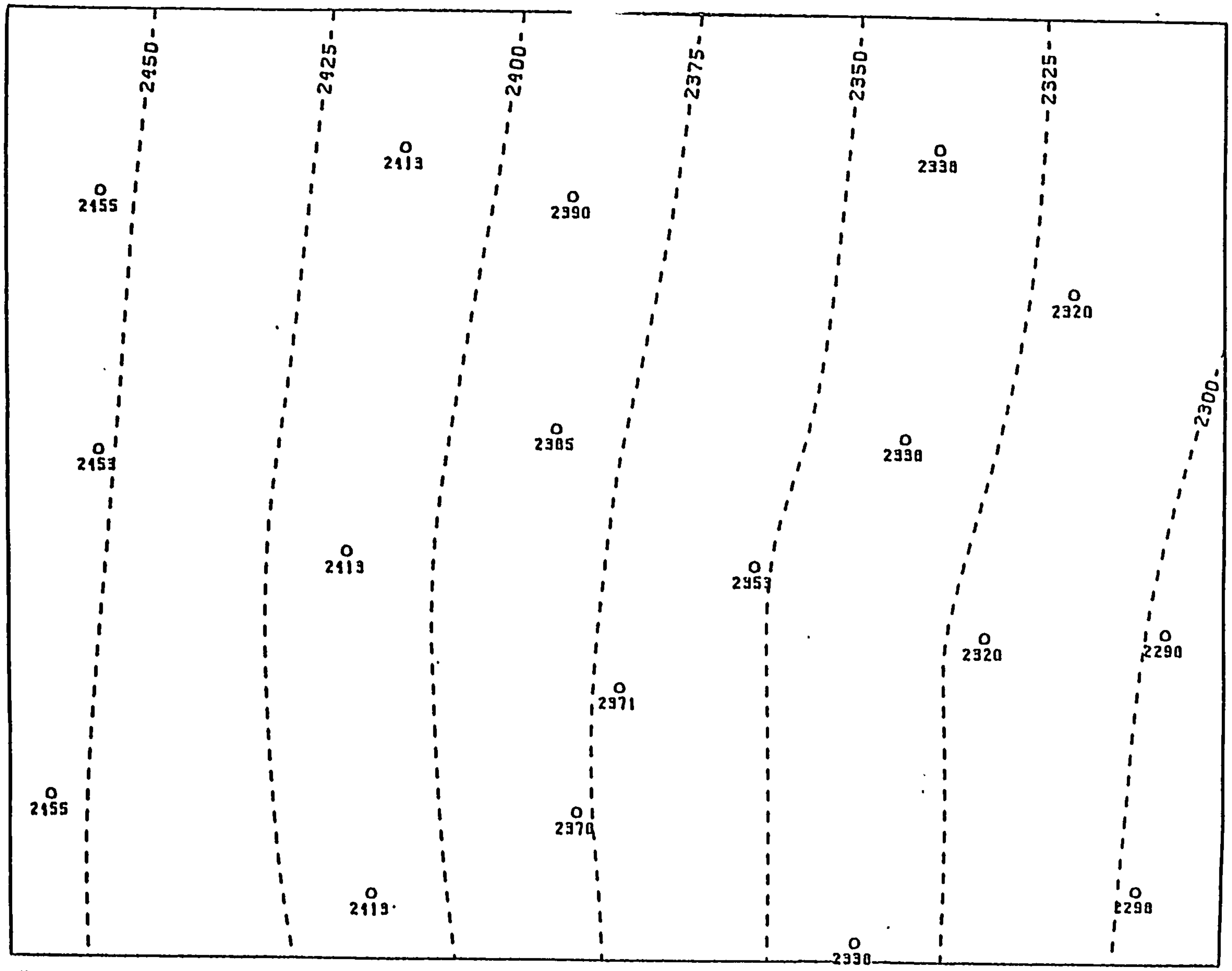

FIGURE E-2 : VARIANCE EXAMPLE MAP E-2 : STEPS 4, 5 & 6, OR STEPS 7 & 8:
OBTAIN, POST AND CONTOUR RESERVOIR PRESSURE DATA: This step is not absolutely necessary.
The adjustment to sea level is made through the following:

$$\text{Pressure}_{(\text{sea level})} = \text{Reservoir pressure} + (\text{Reservoir elevation} * \text{gradient})$$

The gradient is a function of formation water salinity, in this example = 0.5 psi/ft.
Steps 4, 5 & 6 contour original reservoir pressure data.
Steps 7 & 8 contour partially depleted reservoir pressures.
In this example, original reservoir pressure data have been used (Steps 4, 5 & 6).

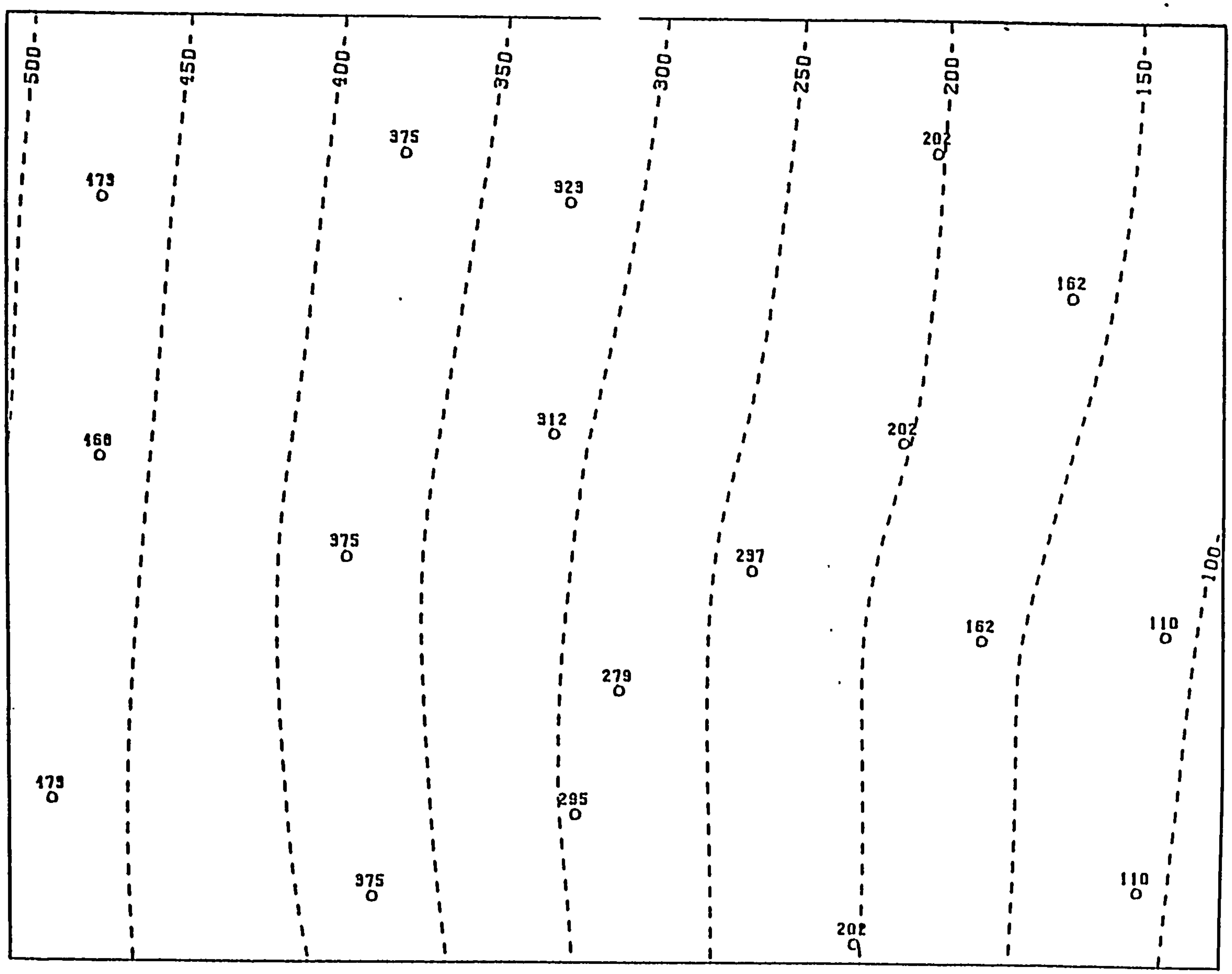

FIGURE E-3 : VARIANCE EXAMPLE MAP E-3 : STEPS 9 & 10 USING FRESH WATER GRADIENT CORRECTION FOR HYDROCARBON HEADS ABOVE THE BASE OF THE USDW.

The conversion used is:

(Hydrocarbon reservoir head above base of USDW) * 0.5 psi/ft / 0.433 psi/ft.

This adjustment is necessary because the maximum pressure (head) differential occurs at the base of the USDW, and the brine gradient (0.5 psi/ft) is operational throughout the wellbore column. See Table III-1 for explanation.

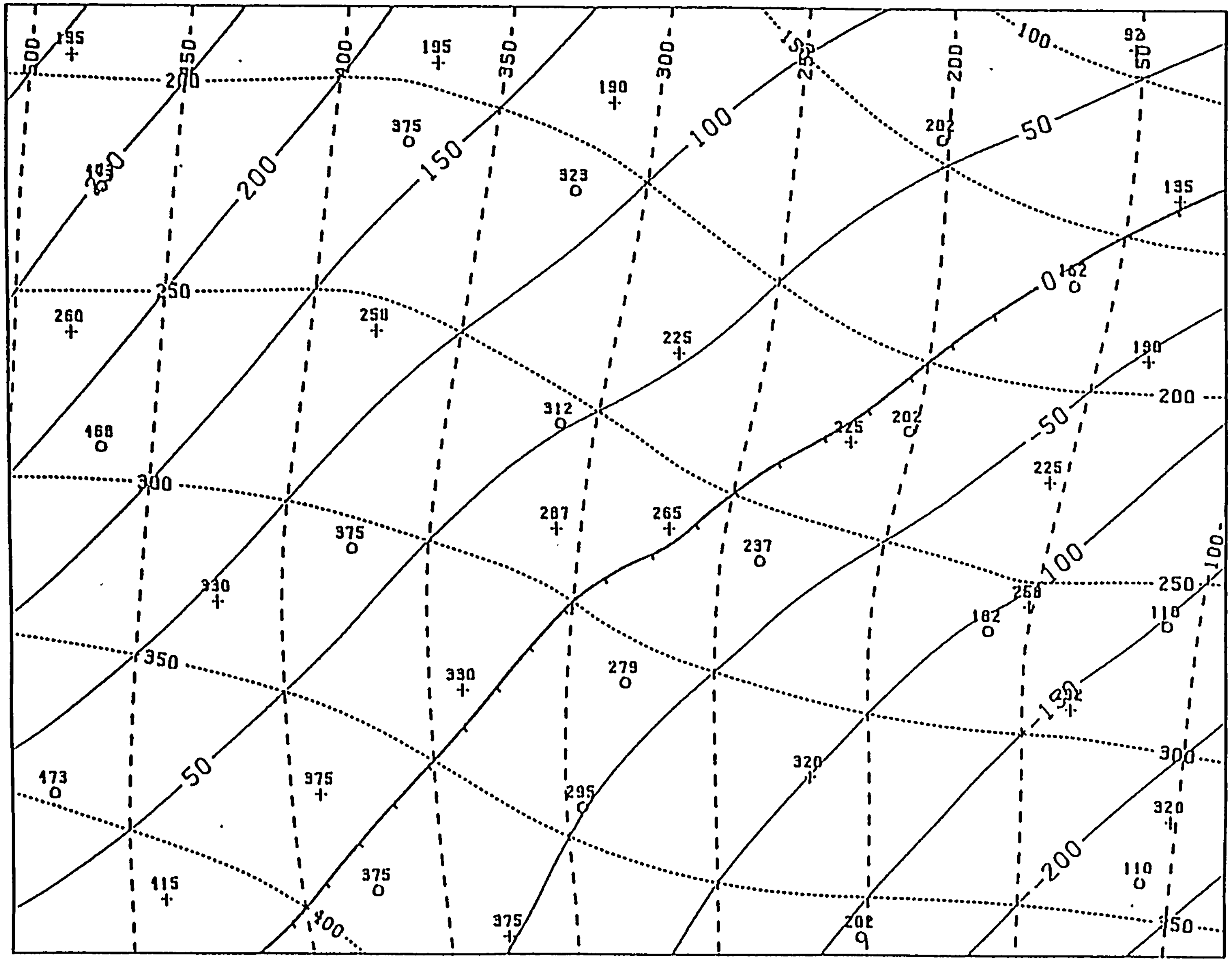

FIGURE E-4 : VARIANCE EXAMPLE MAP E-4 : STEPS 11, 12 & 13 USING HEADS ADJUSTED TO FRESH WATER EQUIVALENT ABOVE THE BASE OF THE USDW.

+ symbols and dotted lines denote USDW head data and contours.

o symbols and dashed lines denote hydrocarbon reservoir head data and contours.

Solid lines are residual contour lines.

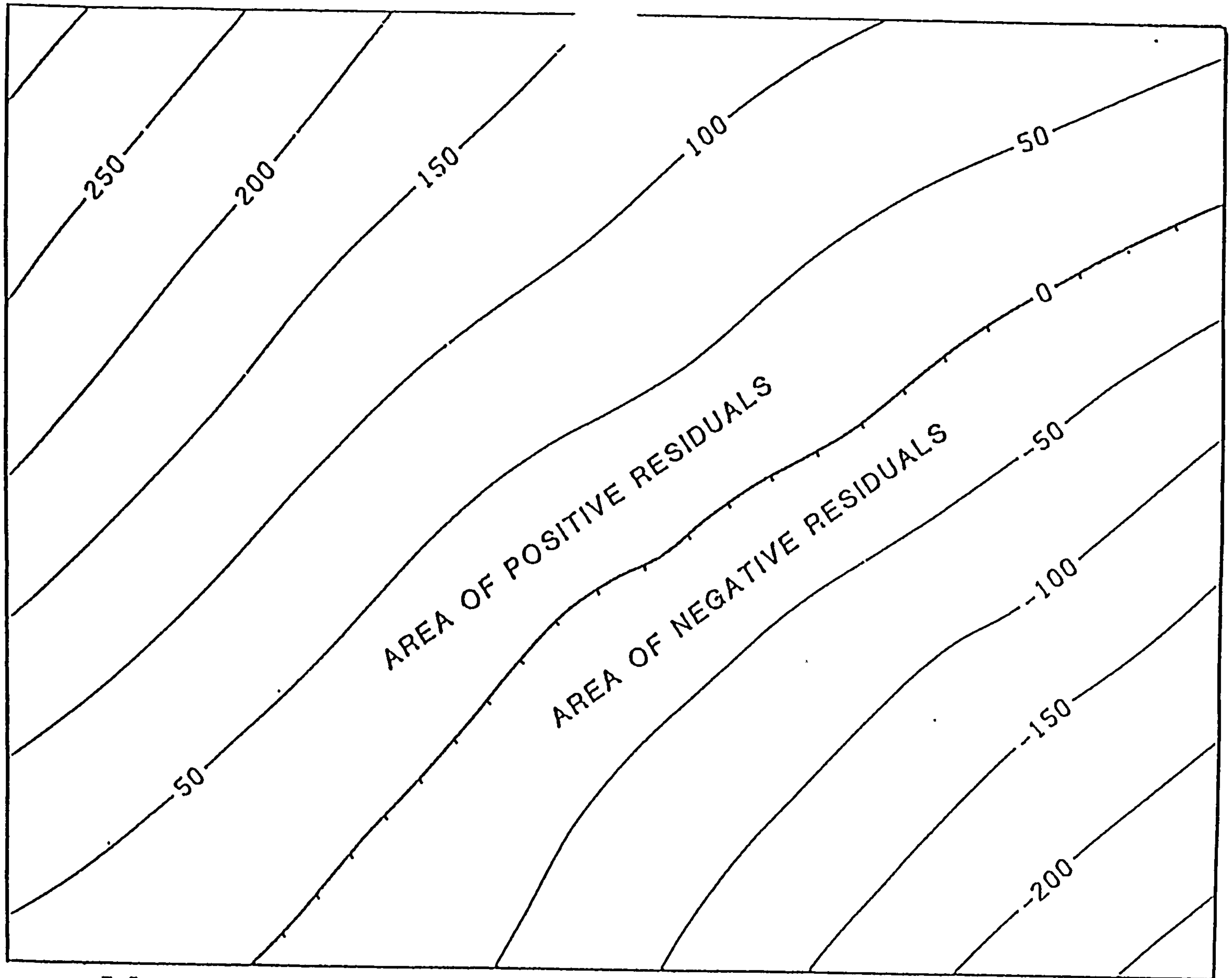

FIGURE E-5 : VARIANCE EXAMPLE MAP E-5 : RESIDUALS CORRECTED TO FRESH WATER HEAD EQUIVALENTS ABOVE THE BASE OF THE USDW.

Residuals are derived from intersections on Figure 12.

Area to the northwest of the heavy zero line shows positive residuals. In this northwest area the potential exists for flow from the hydrocarbon reservoir to the USDW.

Area to the southeast of the heavy zero line shows negative residuals. In this southeast area no potential exists for flow from the hydrocarbon reservoir to the USDW.

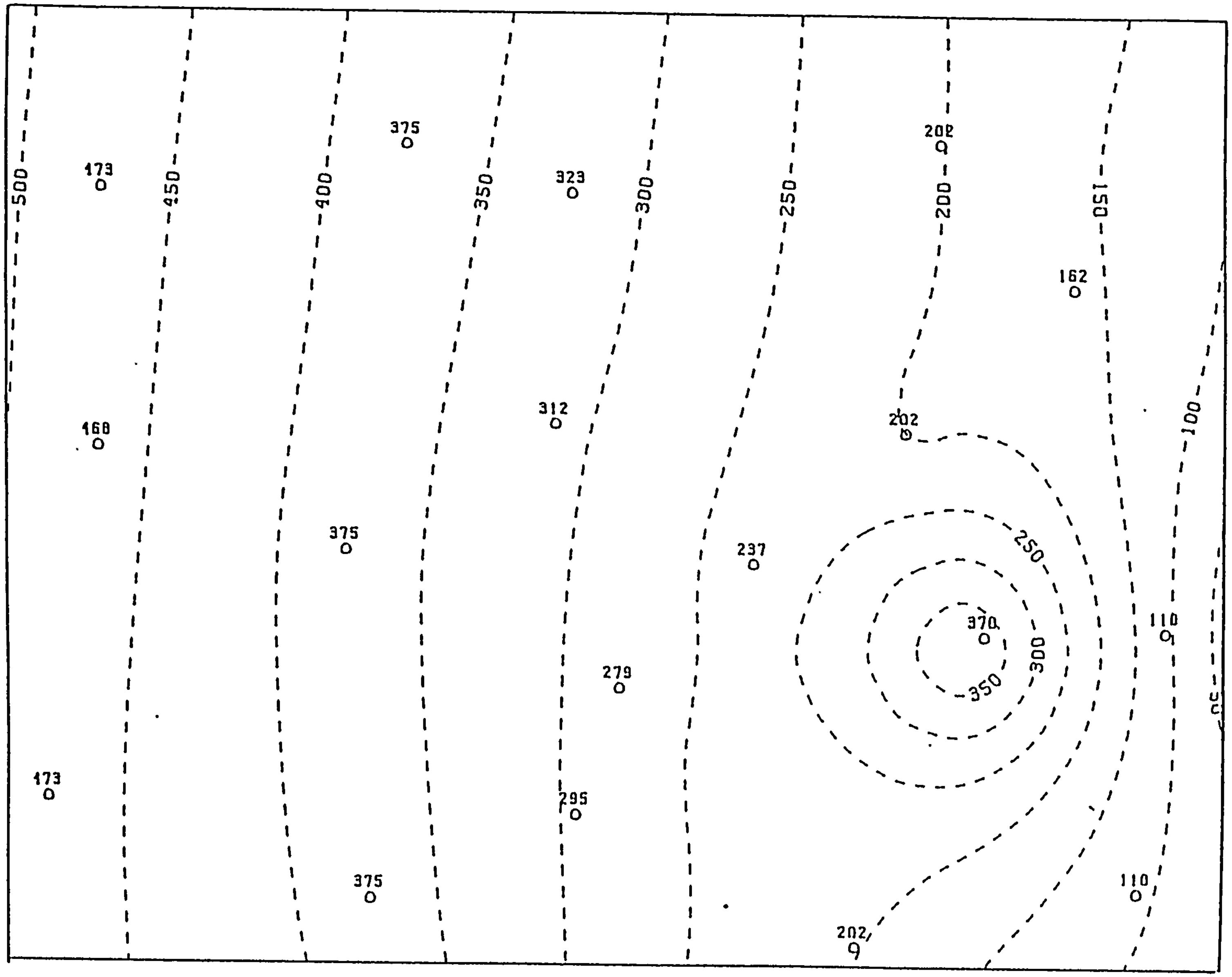

FIGURE E-6 : VARIANCE EXAMPLE MAP E-6 : STEPS 9 & 10 REPEATED WITH INJECTION WELL PRESENT.
Maximum pressure from the injection well is converted to fresh water equivalent heads above the base of the USDW as in steps 9 & 10.

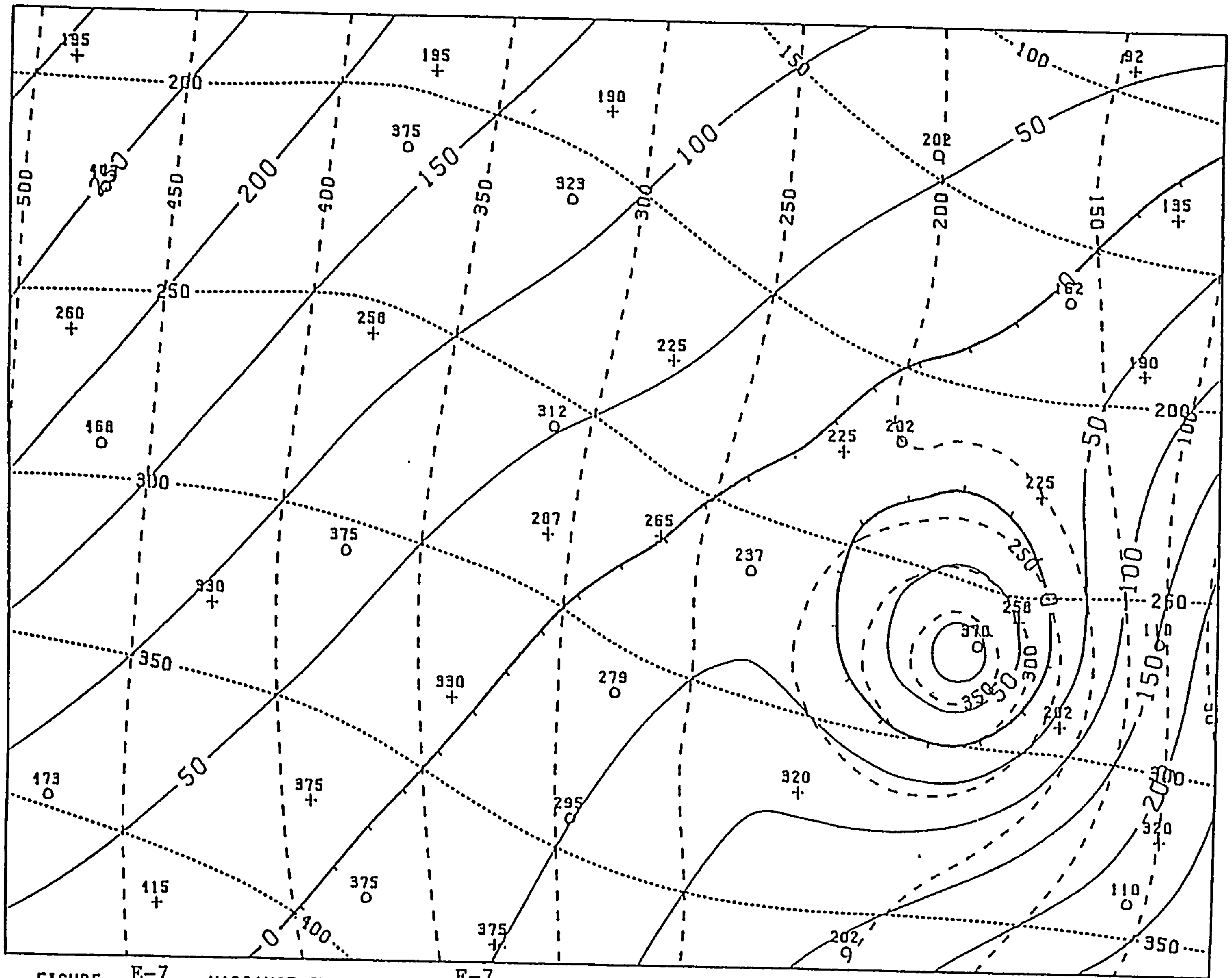

FIGURE E-7 : VARIANCE EXAMPLE MAP E-7 : STEPS 11, 12 & 13 REPEATED WITH INJECTION WELL INCLUDED.
+ symbols and dotted lines denote USDW head data and contours.
o symbols and dashed lines denote hydrocarbon reservoir head data and contours.
Solid lines are residual contour lines.

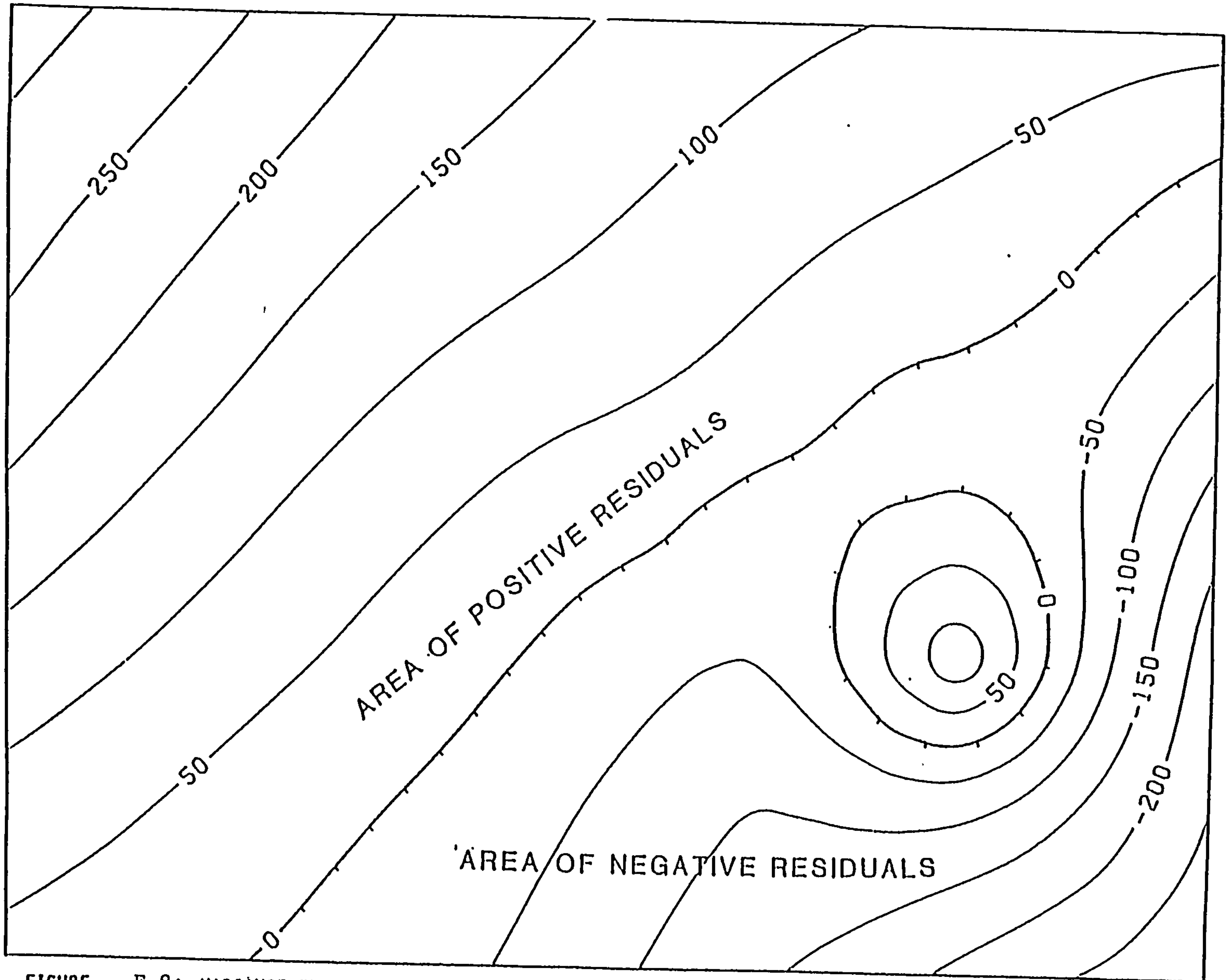

FIGURE E-8: VARIANCE EXAMPLE MAP E-8 : RESIDUALS CORRECTED TO FRESH WATER HEAD EQUIVALENTS ABOVE THE BASE OF THE USDW.

Residuals are derived from intersections on Figure E-7.

Area to the northwest of the heavy zero line shows positive residuals. In this northwest area the potential exists for flow from the hydrocarbon reservoir to the USDW.

Area to the southeast of the heavy zero line shows negative residuals. In this southeast area no potential exists for flow from the hydrocarbon reservoir to the USDW except in the vicinity of the injection well where a closed positive residual is shown.

APPENDIX F

Effect of Combined Injection and Production Operation

(From Warner, et al., 1993 (4))

For the limited situation where the AOR established by a "zone of endangering influence" could be less than the one-fourth mile fixed radius, the EPA has provided an equation to be used in calculating the "zone of endangering influence." The equation, as given by the EPA (7), is:

$$r = \left(\frac{2.25\ KHt}{S10^{x}}\right)^{\frac{1}{2}}$$

where:

$$X = \left(\frac{4\pi KH\,(h_w - h_{bo} * S_p G_b)}{2.3Q}\right)$$

r	=	Radius of endangering influence from injection well (length)
K	=	Hydraulic conductivity of the injection zone (length/time)
H	=	Thickness of the injection zone (length)
t	=	Time of injection (time)
S	=	Storage coefficient (dimensionless)
Q	=	Injection rate (volume/time)
h_{bo}	=	Observed original hydrostatic head of injection zone (length) measured from the base of the lowermost underground source of drinking water
h_w	=	Hydrostatic head of underground source of drinking water (length) measured from the base of the lowest underground source of drinking water
S_pG_b	=	Specific gravity of fluid in the injection zone (dimensionless)
π	=	3.142 (dimensionless)

According to the EPA , the above equation is based on the following assumptions:

1. the injection zone is homogeneous and isotropic;
2. the injection zone has infinite area extent;
3. the injection well penetrates the entire thickness of the injection zone;
4. the well diameter is infinitesimal compared to "r" when injection time is longer than a few minutes; and
5. the emplacement of fluid into the injection zone creates instantaneous increase in pressure.

In addition to the limitations established by the assumptions listed above, additional important limitations are:

1. The equation is for single-phase flow of water and, thus, may apply to wells injecting brine into a water-filled reservoir. It may, however, apply only poorly or not at all to enhanced recovery injection wells where multiphase flow is involved.

2. The equation is for a single injection well and does not consider that adjacent production wells will limit the radius of endangering influence by virtue of their pressure drawdown effects.

As pointed out above, except in the case of a brine injection well injecting into a water-filled reservoir, the equation provided by the EPA will likely not apply. In enhanced recovery operations, both injection and production wells are present in one or more of a variety of geometric configurations as shown in Figure F-1. Of those configurations, the most commonly used is the five-spot pattern.

In the case of a balanced five-spot pattern (injection = production, on a reservoir volume basis), equipressure contours exist as shown in Figure F-1. The maximum pressure will exist in the reservoir at the injection well and the minimum pressure will exist at the producing well. The 50% equipressure contour separates the injection well affected area from the producing well affected area. Very simply, the injection pressure pushes fluids from the injector to the 50% equipressure contour, and the producing pressure draws fluids from the 50% equipressure contour to the producing well. For this reason, the area enclosed by the 50% equipressure contours encloses a diamond-shaped square area surrounding the injector. As noted by Matthews and Russell,(8)

> "We may closely approximate the pressure behavior in this square by finding the pressure behavior in a circle of equivalent area...we choose the radius of the equivalent circle from $\pi r_e^2=A$, where A is the area inside the 50 percent equipressure contour..."

From Figure F-2 it is readily apparent that the area affected by the injector is one-half of the pattern spacing and the following table may be employed for affected radial distances using the equivalent circle concept for a balanced five-spot pattern.

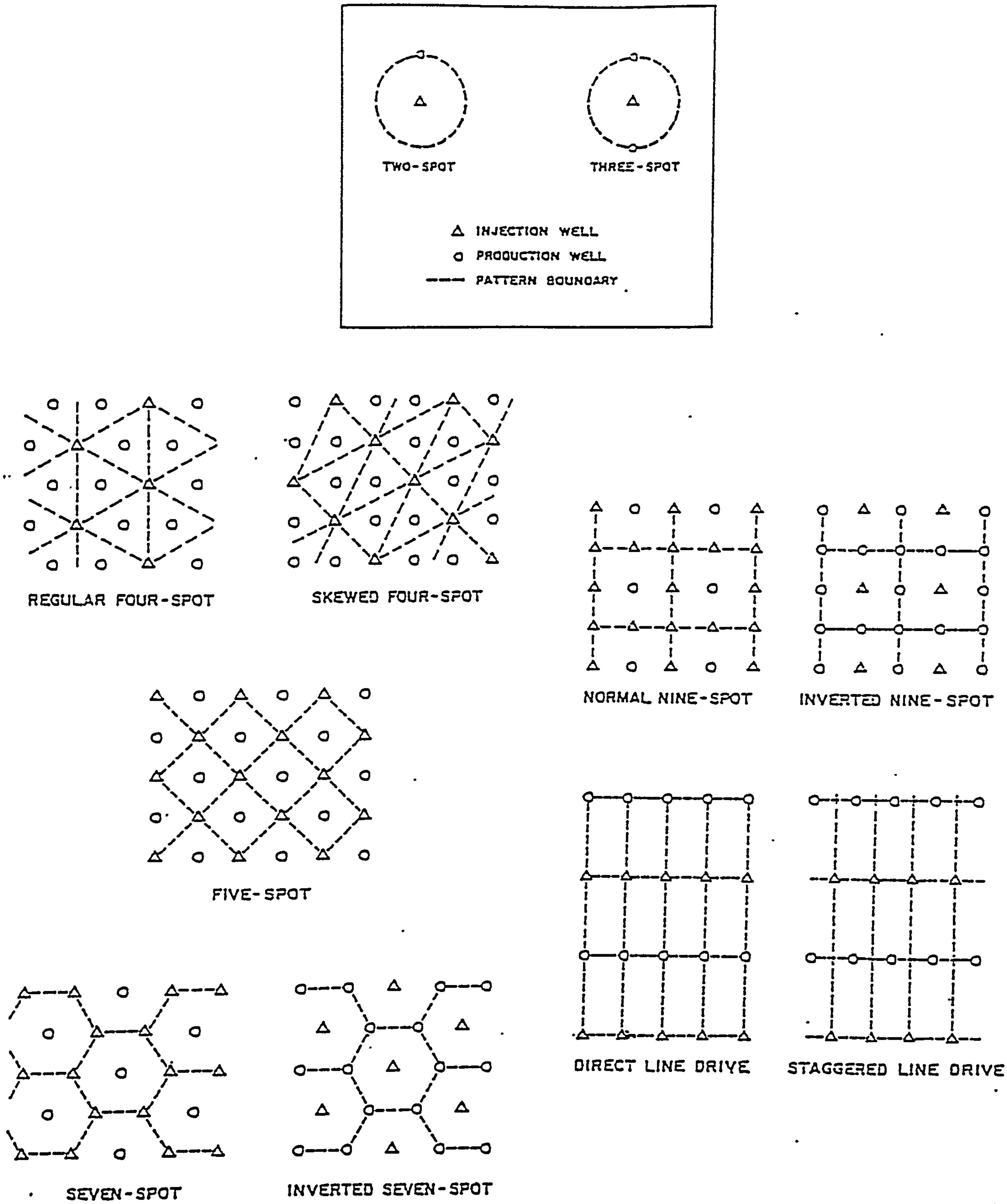

Figure F-1. Injection/production well patterns used in enhanced petroleum recovery operations. (9)

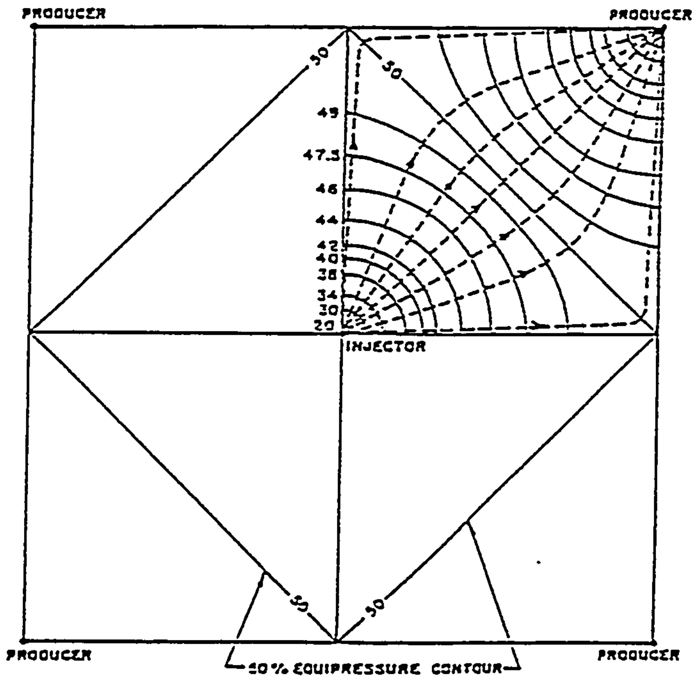

Figure F-2. Equipressure contours and streamlines in a five-spot pattern. (8)

Pattern Area (acres)	Affected Radius (ft.)
5	186
10	263
20	372
40	527
80	745
160	1053

One of the methods of determining the "zone of endangering influence" according to the EPA is to employ a fixed radius of one-fourth mile (1320 feet); for patterns of less than 250 acres, the actual affected radius is less than one-fourth mile. Many waterfloods consist of patterns of 80 acres or less while other types of enhanced recovery projects usually employ much smaller patterns.

For an Area of Review, the maximum pressure exists at the injection well. If the injection well pressure is not sufficient to cause fluids to migrate from the petroleum reservoir to the USDW, no contamination can occur as pressures elsewhere will be lower than at the injection well and thus will also not allow migration to the USDW. If the injection well pressure will allow fluids to flow from the reservoir to the USDW, the pressure distribution in the injection affected area will require an analysis as shown in the matrix in Figure F-3.

Operations involving non-repeating or irregular patterns, rate variations, multiphase flow, severe mobility ratio variations, or reservoir heterogeneities will require an operating model or development plan for review rather than using any simplified analysis. Such a plan can only be prepared by an operator with full knowledge of the geologic and operational parameters needed for the analysis.

POTENTIAL FOR FLOW TO USDW	Pressure is Sufficient Prior to Injection	With Added Injection Pressure	Required Analysis
	NO	NO	None
	NO	YES	Maximum of Affected Radius within the "zone of endangering influence"
	YES	YES	Total Area

Figure F-3. Analysis Requirements for Various Flow Potential Scenarios.

APPENDIX G

Sampling Wells for Evaluation

of Well Construction and Abandonment Method

(From Wakim, 1993, (10))

SAMPLING WELLS FOR EVALUATION OF WELL CONSTRUCTION AND ABANDONMENT METHOD

INTRODUCTION

Contained in this appendix is a discussion of statistical methods recommended for selecting samples[1] from well populations[2]. This discussion is intended to provide guidance to Underground Injection Control (UIC) Directors for ensuring a sample is representative of the total well population. The selection of well samples for evaluation of construction and abandonment methods is recommended for justification of AOR variance areas.

The existing AOR requirements under the federal UIC regulatory program provide for such a statistical sampling approach. Prior to the issuance of a permit for a Class II injection well (or the injection wells in a project area) to operate, the Director shall consider data available on all wells within the applicable area of review and penetrating the injection zone. Such data include a description of each well's type, construction, date drilled, location, depth, and record of plugging and completion. Pursuant to 40 CFR 146.24 (a) (3), in cases where the information would be repetitive and the wells are of similar age, type, and construction, the Director may elect to require data only on a representative sample of the population.

The purpose of reviewing such data is to help ensure wells are properly completed or abandoned to prevent movement of fluid into underground sources of drinking water (USDWs). The applicant must submit a corrective action plan for wells found to be improperly completed or abandoned. In allowing examination of only a statistically

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[1] Throughout this appendix, the term "sample" denotes a randomly selected subgroup of the population.

[2] Throughout this appendix, the term "population" represents the group of wells being considered for an Area-of-Review (AOR) variance.

representative sample of the population, EPA agrees that every well in the population need not be examined, and, therefore, that a 100 % guarantee of protection is not necessary.

While a less-than-100% guarantee is acceptable under the UIC program, how much less has never before been specified. Information contained in the following sections provides guidance on the quantification of assurance and the relationship between confidence levels and sample size.

DEFINITION OF ASSURANCE

Assurance is defined here as the probability that the proportion of "bad" wells in the population is less than or equal to some specified number (in percent).

For example, say that 237 wells are randomly sampled from a population of 1000 wells. Based on the review of the wells in the sample, only one well is found to be "bad". If that group of 1000 wells (the population) is granted a variance, then the assurance can be calculated using acceptable statistical methods[3] and stated as follows:

> There is a 78% chance that the proportion of "bad" wells in the population is less than or equal to 1%.

Or in short,

$$P(\text{proportion of "bad" wells in the population} \leq 1\%) = 0.78.$$

As illustrated by the above example, assurance consists to two components: the allowed proportion of "bad" wells (1%) and the confidence level (0.78). In the example, 1% was

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[3] See Section 6 for a description of the statistical methodology.

chosen arbitrarily. In reality, the interested parties will first need to agree on and specify the maximum proportion of "bad" wells and then the level of confidence.

SAMPLE SIZE

Since no "bad" wells are expected to be found in most samples, the sample size determination is based on that premise.

In other words, given that there are no "bad" wells in the sample, what should the sample size be so that:

$$P(\text{proportion of "bad" wells in the population} \le Ⓐ\%) = Ⓑ$$

where Ⓐ is the maximum acceptable proportion of "bad" wells in the population, and Ⓑ is the confidence level at which the proportion of "bad" wells in the population is believed not to exceed Ⓐ%. Again, Ⓐ and Ⓑ would need to be determined by the interested parties. As was mentioned in the previous section, Ⓐ should be determined first because it is the more important component in meeting an acceptable assurance. Ⓐ remains the same throughout the calculations of sample sizes and confidence levels. Ⓑ, on the other hand, is set initially to calculate the appropriate sample size assuming no "bad" wells in the sample. However, Ⓑ will change and must be recalculated if some "bad" wells are actually found in the sample.

Table G-1 shows sample sizes for Ⓐ=1%, 2% and 5%, for Ⓑ=0.90 and 0.95, and for different population sizes. The values of Ⓐ were selected only for illustration purposes. They do not represent recommended values. On the other hand, the values of Ⓑ represent the confidence levels that are most commonly used in statistical analyses. They also may be set to other values if deemed appropriate.

Table G-1 shows, for example, that for a population size of 500, a goal of 2% maximum

proportion of "bad" wells, and a confidence level of 0.90, 93 wells should be randomly selected for evaluation.

It is clear from Table G-1 that the sample size does not increase proportionately to the population size. For example, according to Table G-1 and based on Ⓐ=1% and Ⓑ=0.90, a population of 500 wells would require a sample of 158 wells, whereas a population of twice that size would require a sample of only 187 wells.

STEP-BY-STEP PROCEDURE

The sequence of steps necessary for sampling wells and justifying an AOR variance is summarized as follows:

(1) Set the value of Ⓐ, the maximum acceptable proportion of "bad" wells in the population. That value may be different for different geographical areas or well types. For example, less assurance may be required in remote unpopulated areas.

(2) Determine the value of Ⓑ, the confidence level at which the proportion of "bad" wells in the population does not exceed Ⓐ%. This value could be 0.90 or 0.95. Since 0.95 is the more commonly used confidence level, it is the recommended level.

(3) Based on the values set for Ⓐ and Ⓑ and the size of the population being considered for an AOR variance, use Table G-1 (or a more extensive table that could be developed) to find the sample size needed.

(4) Randomly[4] select wells from the population, and evaluate their construction and abandonment method.

(5) Determine the number of "bad" wells in the sample.

(6) Based on the set value of A, use the appropriate table (from Tables G-2 to G-4, or a more extensive table that could be developed) to find the probability that the proportion of "bad" wells in the population is less than or equal to A%, given the number of "bad" wells found in the sample.

(7) Determine whether this probability is acceptable. If it is, then the population is granted an AOR variance. If it is not, then either further sampling[5] or AOR would need to be performed.

SPECIAL ISSUES

- Prioritizing according to level of confidence:
  The probabilities determined in Step 6 of the above described procedure can be used to rank the severity of the situation.

- Sampling as large an area as possible:
  Table G-1 shows that the larger the population, the smaller the sample size in relative terms. In other words, instead of sampling a total of 2x158=316 wells from

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[4] One way of randomly selecting a sample is by assigning a number to each well in the population and using a computer number generator to choose the sample wells. For example, one way of selecting a sample of 158 wells from a population of 500 wells is by assigning a number (from 1 to 500) to each well in the population, and using a computer random number generator to select 158 numbers from among the numbers 1 to 500.

[5] See Sequential Sampling in Section 5 for further details.

two populations of 500 wells, one may sample 187 wells from the combined population of 1000 wells (based on Ⓐ=1% and Ⓑ=0.90). Consequently, it is more efficient to sample as large a population as possible, as long as that population is expected to include almost no "bad" wells.

- Wells already examined:

  Question: Can an AOR variance be granted to a population of wells if a subgroup of that population has already had AOR performed?

  Answer: The subgroup of wells already examined can be used (1) if the number of wells already examined is sufficiently large (as defined by the sample sizes in Table G-1), and (2) if the selection of those wells was reasonably random, in the sense that particular geographical areas or age groups (or other subgroups determined by factors that may affect the existence of "bad" wells) were not undersampled.

- Stratified sampling:

  Stratification (e.g. according to age) is advisable when the population consists of two or more well-defined groups of wells that are expected to contain different proportions of "bad" wells. This would avoid condemning a big population because of a small subgroup that contains an unacceptable number of "bad" wells. For example, say a population of 1500 wells is known to include 500 "old" and 1000 "new" wells; moreover, say it is expected that all the "new" wells would likely pass the review, and that some of the "old" wells may be "bad". Then, it is more efficient to take a random sample of 158 wells from the group of "old" wells and 187 wells from the group of "new" wells (based on Ⓐ=1% and Ⓑ=0.90) rather than 200 wells[6] from the whole population of 1500 wells. The reason is that with stratification, the 1000 "new" wells may be granted an AOR variance and the 342 (=500-158) "old" wells that were not examined may be required to be evaluated. Whereas without stratification, 1300 (=1500-200) wells may be required to be examined.

[6] Somewhere between 187 and 219 wells according to Table G-1.

- Sequential sampling:

  Question: What if the sample is found to contain enough "bad" wells to reject the granting of an AOR variance. Instead of examining all the wells that were not reviewed, can the sample be expanded?

  Answer: A second sample from the remaining wells can be randomly selected and examined. Based on the size of the total sample (1st+2nd sample) and the total number of "bad" wells in the total sample, the probability that the proportion of "bad" wells in the population is less than or equal to A% would be re-calculated. The next step would be to determine whether this new probability is now acceptable.

STATISTICAL METHODOLOGY

This section briefly describes the statistical approach used to calculate the sample sizes and probabilities shown in Tables G-1 to G-4. But first, some notation needs to be defined:

N = the population size,

n_∞= the sample size for a large population ($N > 5000$),

n = the sample size for a finite population ($N \leq 5000$),

p = the unknown proportion of "bad" wells in the population,

X = the number of "bad" wells in the sample.

In the large population case ($N > 5000$), the sample size shown in Table G-1 can be calculated as follows:

$$n_\infty = \frac{\log\left(1-B\right)}{\log\left(1-A\right)}.$$

As for obtaining the probabilities shown in Tables G-2 to G-4, the prior distribution of p is assumed to be Uniform (0,1) which is equivalent to a Beta (1,1) distribution. Using

Bayes theorem, the posterior distribution of p is Beta (1+X,1+n-X). Because the formulas for calculating these probabilities are extensive, they are not presented here.

In the finite population case ($N \leq 5000$), the sample size shown in Table G-1 can be approximately[7] calculated as follows:

$$n = \frac{n_\infty}{1+\frac{n_\infty - 1}{N}}$$

As for obtaining the probabilities shown in Tables G-2 to G-4, the posterior distribution of p is calculated using Bayes theorem, the fact that X has a hypergeometric distribution, and the assumption that the prior distribution of p is discrete Uniform (0,1/N,2/N,....,1). Because the formulas for computing these probabilities are extensive and therefore not presented here.

[7] The exact formula for calculating the sample size for finite populations is more complicated and is not presented here.

TABLE G-1

SAMPLE SIZE NEEDED

so that:

P(proportion of "bad" wells in the population ≤ Ⓐ%) = Ⓑ

assuming that no "bad" wells are found in the sample

Ⓐ	Ⓑ	Population Size					
		100	250	500	1000	5000	>5000
1%	0.90	68	133	158	187	219	230
	0.95	77	157	195	237	283	299
2%	0.90	53	79	93	102	111	114
	0.95	63	97	117	131	144	149
5%	0.90	31	39	41	42	44	45
	0.95	38	50	52	55	57	59

TABLE G-2

Probability that the proportion of "bad" wells in the population ≤ 1%

based on the number of "bad" wells found in the sample
and for different population and sample sizes

POPULATION SIZE	SAMPLE SIZE	# OF "BAD" WELLS FOUND IN THE SAMPLE			
		0	1	2	3
100	68	0.90	0.46	0	0
	77	0.95	0.59	0	0
250	133	0.90	0.55	0.15	0
	157	0.95	0.69	0.25	0
500	158	0.90	0.62	0.29	0.08
	195	0.95	0.75	0.44	0.17
1000	187	0.90	0.64	0.34	0.13
	237	0.95	0.78	0.51	0.25
5000	219	0.90	0.66	0.39	0.18
	283	0.95	0.80	0.56	0.33
>5000	230	0.90	0.67	0.41	0.20
	299	0.95	0.80	0.58	0.35

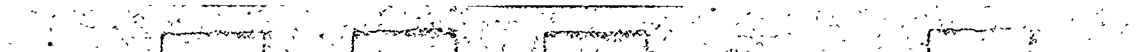


TABLE G-3

Probability that the proportion of "bad" wells in the population ≤ 2%

based on the number of "bad" wells found in the sample
and for different population and sample sizes

POPULATION SIZE	SAMPLE SIZE	# OF "BAD" WELLS FOUND IN THE SAMPLE			
		0	1	2	3
100	53	0.90	0.55	0.15	0
	63	0.95	0.70	0.25	0
250	79	0.90	0.62	0.29	0.08
	97	0.95	0.75	0.44	0.16
500	93	0.90	0.64	0.34	0.13
	117	0.95	0.77	0.50	0.25
1000	102	0.90	0.65	0.37	0.16
	131	0.95	0.79	0.54	0.30
5000	111	0.90	0.67	0.40	0.19
	144	0.95	0.80	0.57	0.34
>5000	114	0.90	0.67	0.40	0.20
	149	0.95	0.80	0.58	0.35

TABLE G-4

Probability that the proportion of "bad" wells in the population ≤ 5%

based on the number of "bad" wells found in the sample
and for different population and sample sizes

POPULATION SIZE	SAMPLE SIZE	# OF "BAD" WELLS FOUND IN THE SAMPLE			
		0	1	2	3
100	31	0.90	0.62	0.28	0.08
	38	0.95	0.75	0.43	0.15
250	39	0.90	0.64	0.34	0.13
	50	0.95	0.78	0.51	0.26
500	41	0.90	0.66	0.37	0.16
	52	0.95	0.79	0.53	0.29
1000	42	0.90	0.66	0.38	0.17
	55	0.95	0.79	0.55	0.32
5000	44	0.90	0.67	0.39	0.19
	57	0.95	0.80	0.56	0.33
>5000	45	0.90	0.68	0.41	0.20
	59	0.95	0.81	0.58	0.35

APPENDIX H

Wellbore Barrier Evaluation Program "ABE"

(From Warner, et al., 1993 (4))

WELLBORE BARRIER EVALUATION PROGRAM "ABE"

ABE, the Automated Borehole Evaluation program, is a computer program which provides a quantitative assessment of the barriers to USDW contamination based on well construction and abandonment methods. While use of the ABE program is not essential to evaluating wells for their flowpath characteristics, the program was developed to help ensure a consistent basis for assessing and comparing flow barriers found in different types of active and abandoned wells. Active wells include producers, injectors and disposal wells. A listing of the program code is found in Appendix IV.

The flow path evaluation within ABE is based on an algorithm which determines the number and types of barriers to flow in a wellbore, and then assigns each barrier a factor indicating that barrier's probable level of protection. Barriers to flow in the program include casing, primary cement behind casing, cast iron bridge plugs, cement across casing stub, cement plugs, and remedial cement squeezes. These barriers are introduced in the wellbore during completion and abandonment. Some barriers may also be removed during abandonment, e.g. pulling casing.

Each barrier which ABE identifies in the well is assigned a value based on its expected level of protection. As the scale in Figure H-1 indicates, each barrier is assigned a level of protection based on a numeric scale which ranges from -1 to +1, where the negative value indicates enhancement of flow and a positive value indicates barriers to flow. In the actual assigning of these flow path rules in the ABE program, values were employed as shown in the "barriers assigned" columns of Figure H-1 for the actual wellbore conditions. The sum of the numerical assignments for each barrier constitutes the overall barrier assessment for the well.

Factors which could potentially enhance flow, such as perforating and fracturing the well, were identified for completeness in assessing wellbore construction but were not included in the evaluations. Negative values were assigned only where barriers which had been

	BARRIERS ASSIGNED Through Pipe	BARRIERS ASSIGNED Behind Pipe
Surface Casing (above USDW)	0	0
(covers USDW)	1	0
Surface Casing Cemented (at USDW)	0	1
(covers USDW)	1	1
Int. Casing (above USDW)	0 /string	0 /string
(covers USDW)	1 /string	0 /string
Int. Cas. Cement (not to USDW)	0 /string	1 /string
Int. Cas. Cement (covers USDW)	1 /string	1 /string
Production Casing or Liner	1	0
Prod. Cas. Cement (not to USDW)	0	1
(covers USDW)	1	1
Tubing w/ Packer (isolates USDW)	1	0
Cement Squeeze (isolates USDW)	0	1
(covers USDW)	1	1
Cement &/or Plug @ abandonment	1	1
Casing/Liner Pulled	-1 /string	0
Cement across Stub	1	1
Number of Plugs	1 /plug	0

FLOW PATH RULES for BARRIER ASSIGNMENT

1 Retards flow
0 Neutral -- No Effect
-1 Increases potential for flow

FIGURE H-1 ABE PROGRAM EVALUATION SCHEME

introduced at the time of completion were subsequently removed in abandoning the well. In these cases, the negative value assigned offsets the initial positive value for a 'O' net effect. For example, if casing covers a USDW at the time of completion it is assigned a +1. If the same casing is pulled at abandonment and the casing stub is not plugged, a -1 is assigned. The sum is 0, indicating that the barrier has no effect, i.e., after removal the casing can no longer retard flow into the USDW.

The barrier factors given in Figure H-1 are further differentiated based on the flow path which the contaminating fluids are expected to follow. Within ABE, there are two flowpaths, designated "through pipe" and "behind pipe". Through pipe refers to a pathway through the inside of the main wellbore, either through casing or an uncased borehole. Behind pipe refers to flow in the annular space behind casing in a cased hole. For both of these flowpaths, it is assumed that the contaminating fluids are flowing upward, from an injection zone which is located some distance below a USDW. Differentiating the contamination pathways is believed to be significant because each pathway has unique types of barriers to flow.

For active wells, both the through pipe and behind pipe barriers should be examined. Depending on the method of construction, either of these possible contamination pathways may exhibit a minimal protection; obviously, the lower of either the through pipe or behind pipe barrier factor from ABE should be selected as the well's USDW contamination possibility. Wells injecting into the petroleum reservoir under study need not be evaluated if they have previously been permitted; however, other active wells penetrating the reservoir require analysis if they have not been previously eliminated based on the variance methodology.

In evaluating abandoned wells, the primary flow preventer is the presence of plugs although both the through pipe and behind pipe barriers should be examined. The USDW contamination possibility is determined by the number of plugs between the injection zone and the USDW, and this basis was adopted for characterizing abandoned wells. It is interesting to note that after analyzing a large number of abandoned wells, it was found

that the behind pipe flow path consistently yields similar ABE results, indicating that this pathway has similar flow barriers for many abandoned wells. This is logical since the primary cement behind pipe is normally the principal behind pipe flow barrier. Drilling mud, squeezing zones, and the materials from sloughing zones are other possible behind pipe barriers; however, since these are assessed as mitigating geological factors they were not included in the ABE program.

When a well (either active or abandoned) penetrates to another petroleum reservoir deeper than the zone of injection under consideration, if required, the well should be analyzed from the level of the injection zone under consideration to the applicable USDW(s). In performing this evaluation, only construction and abandonment details from the injection zone under consideration upward to the USDW should be employed in the analysis and only the behind pipe barrier factors are applicable in this situation for cased boreholes.

Figures H-2 and H-3 depict the evaluation logic of the ABE program. As these diagrams show, the user is questioned about the presence of mechanical barriers to flow and their position with respect to USDWs in a wellbore. Depending on the response given at each decision point, barrier factors for each flowpath are assigned, and the program may make a further "intelligent" decision regarding the assignment of other flow barrier factors. For example, an early question posed is whether surface casing covers the USDW. If the response is "yes", the program assigns a "+1" factor for the barrier and continues to query the user with respect to surface casing cement. If the user indicates that surface pipe does not cover the USDW (even though it may be present in the wellbore), the program assigns a "O" barrier factor, meaning the casing cannot retard flow into the USDW since it is set above the zone. In this case, the logic also intelligently assigns a "O" factor for cement behind the pipe. This is due to the fact that there can be no protection from surface casing cement if the surface casing itself does not cover the USDW.

Since multiple USDWs may be present in a single well, ABE was designed to evaluate each USDW present. The program initially requests that the user state the number of USDWs found within the well, and then uses this number to iterate the questions

FIGURE H-2
ABE PROGRAM LOGIC
FOR ABANDONED WELLS

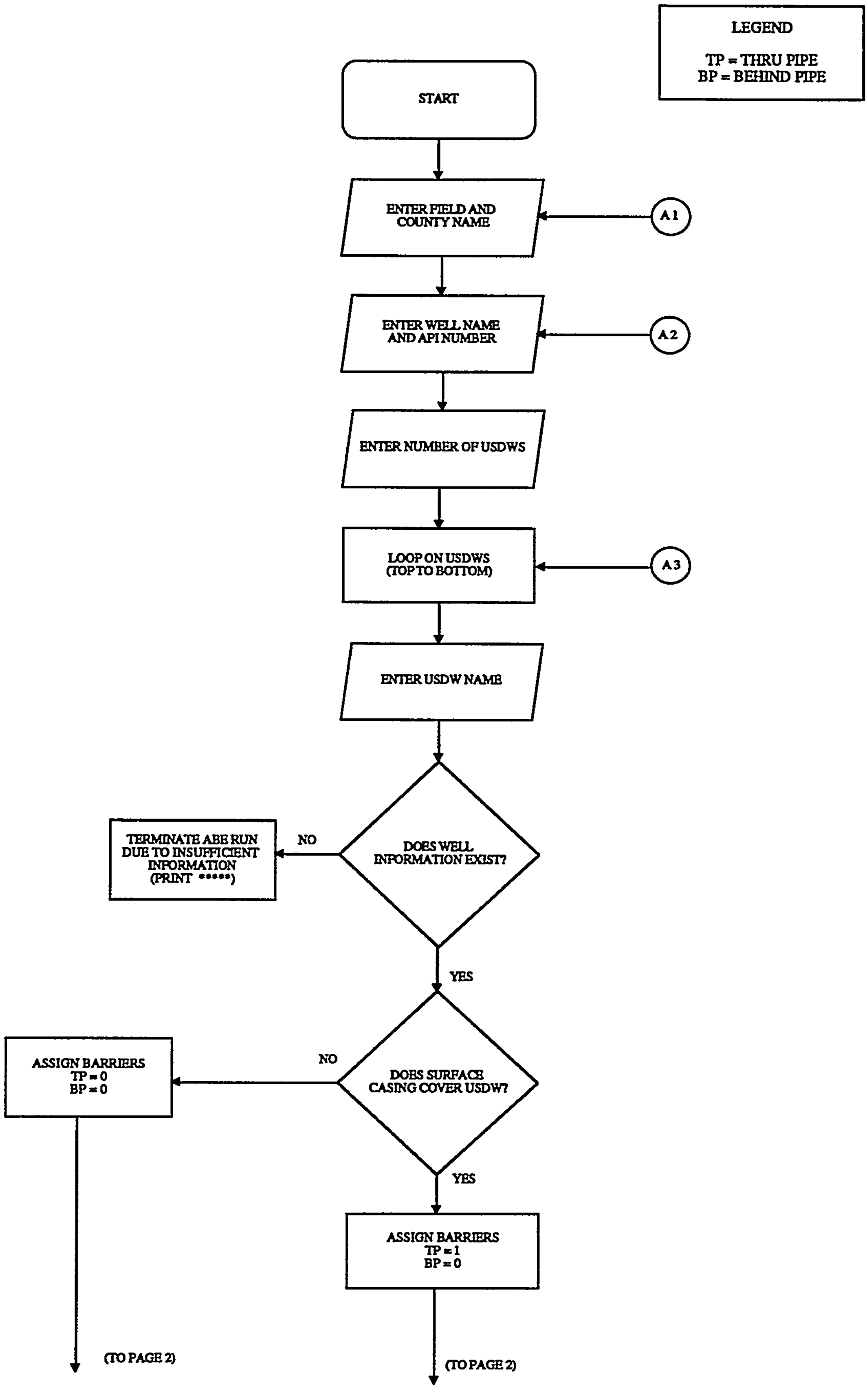


FIGURE H-2
ABE PROGRAM LOGIC
FOR ABANDONED WELLS
(page 2)

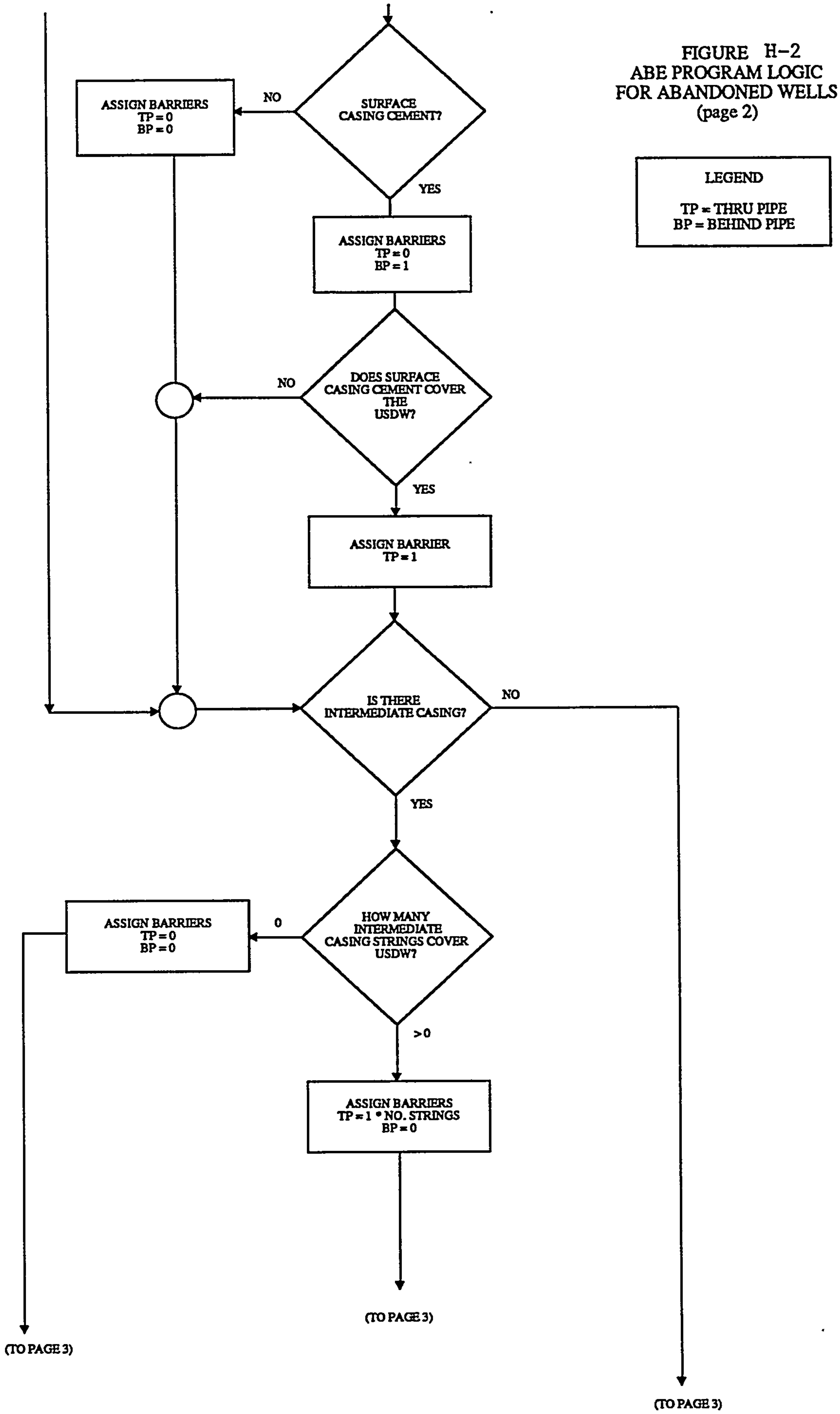


FIGURE H-2
ABE PROGRAM LOGIC
FOR ABANDONED WELLS
(page 3)

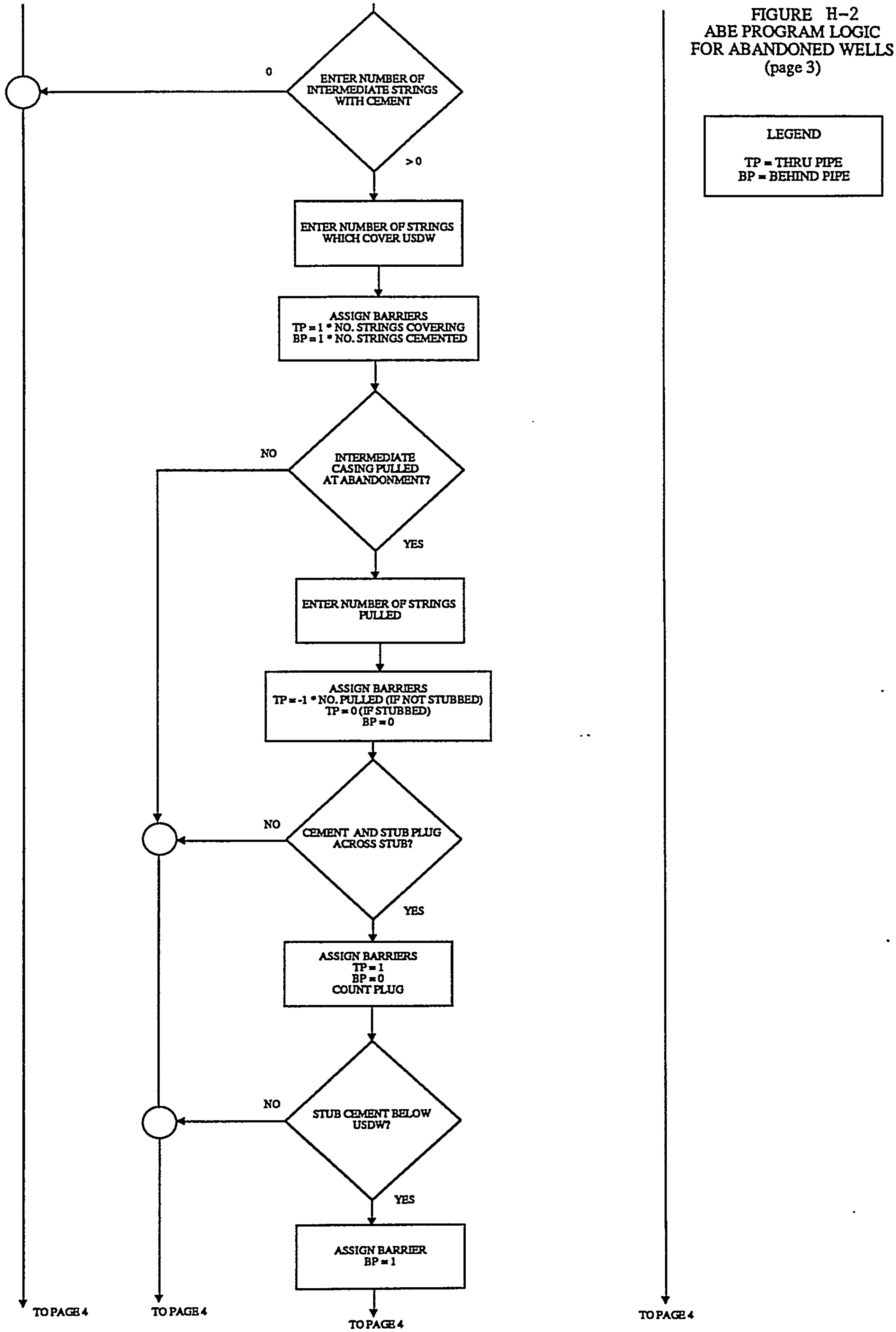
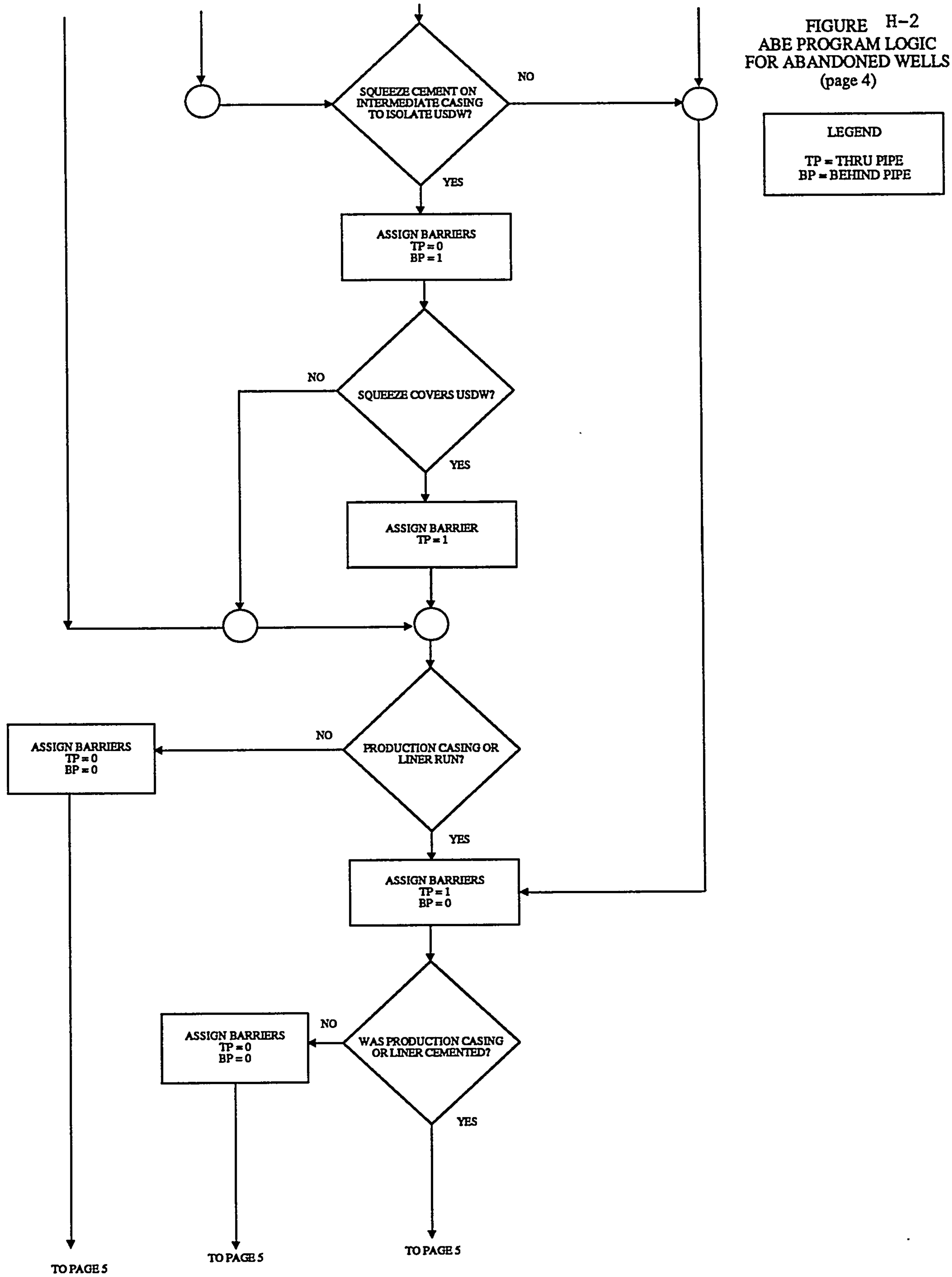


FIGURE H-2
ABE PROGRAM LOGIC
FOR ABANDONED WELLS
(page 4)



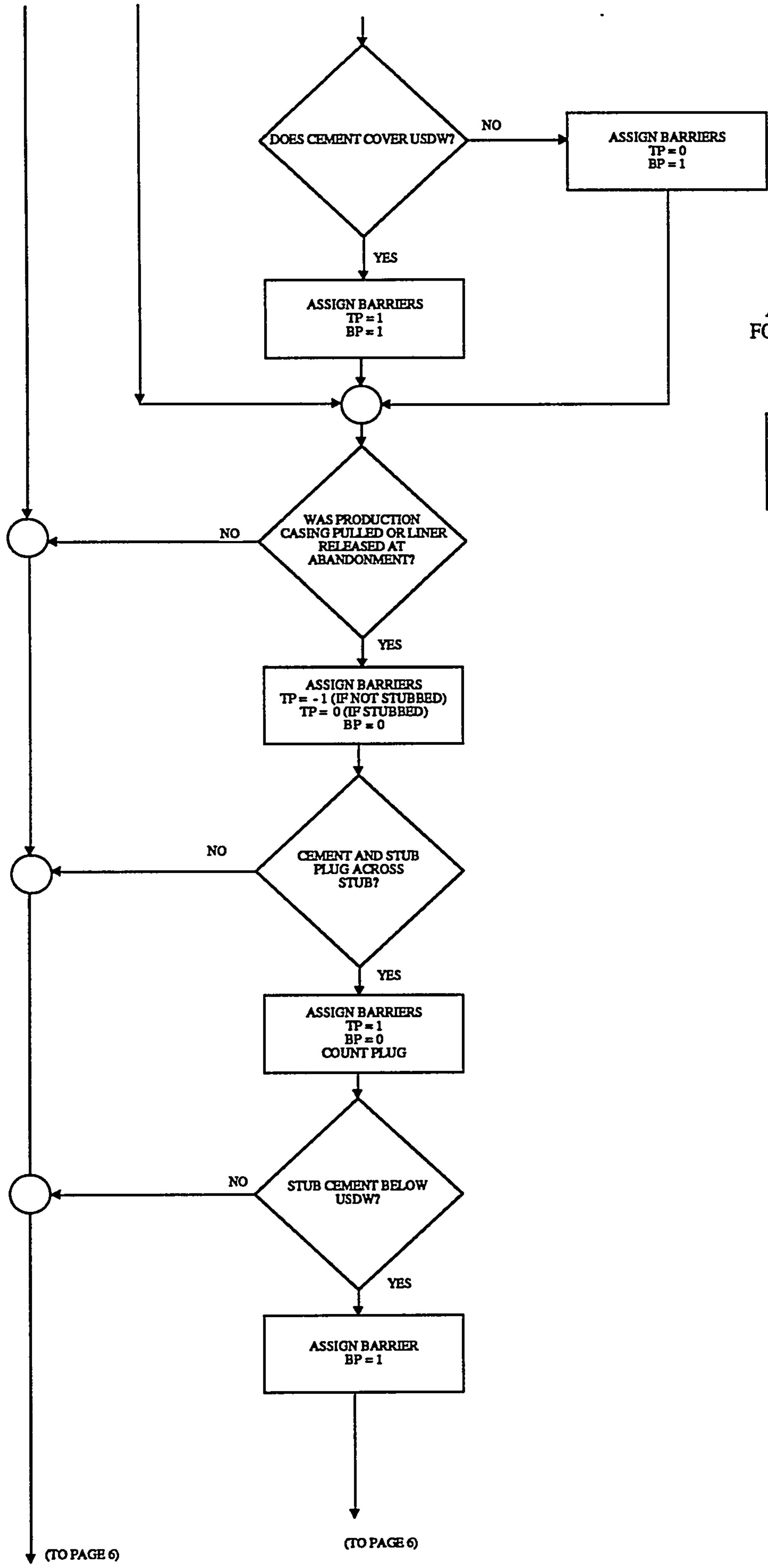


FIGURE H-2
ABE PROGRAM LOGIC
FOR ABANDONED WELLS
(page 5)

LEGEND
TP = THRU PIPE BP = BEHIND PIPE

FIGURE H-2
ABE PROGRAM LOGIC
FOR ABANDONED WELLS
(page 6)

LEGEND

TP = THRU PIPE
BP = BEHIND PIPE

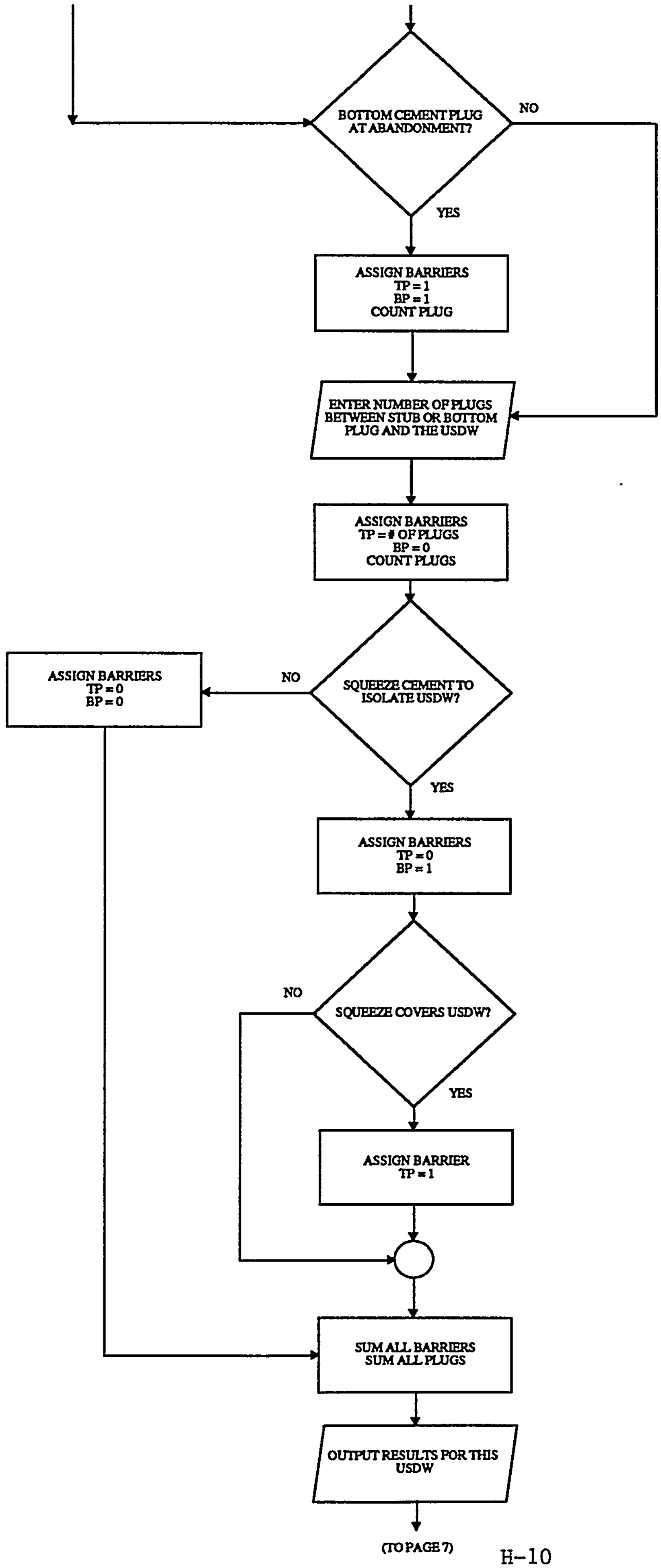


FIGURE H-2
ABE PROGRAM LOGIC
FOR ABANDONED WELLS
(page 7)

LEGEND
TP = THRU PIPE BP = BEHIND PIPE

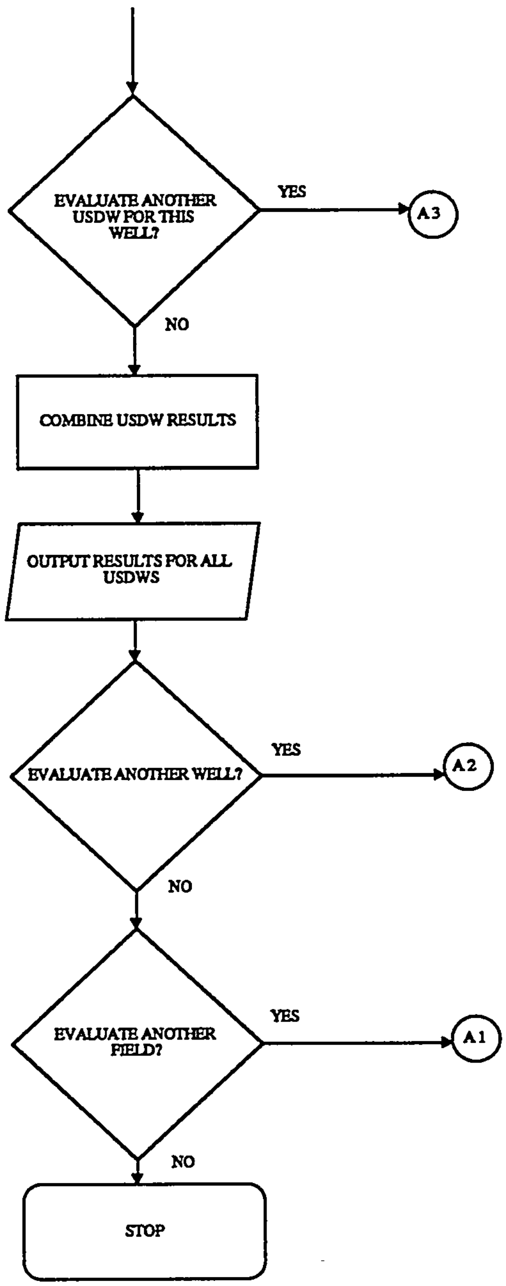


FIGURE H-3
ABE PROGRAM LOGIC
FOR ACTIVE WELLS

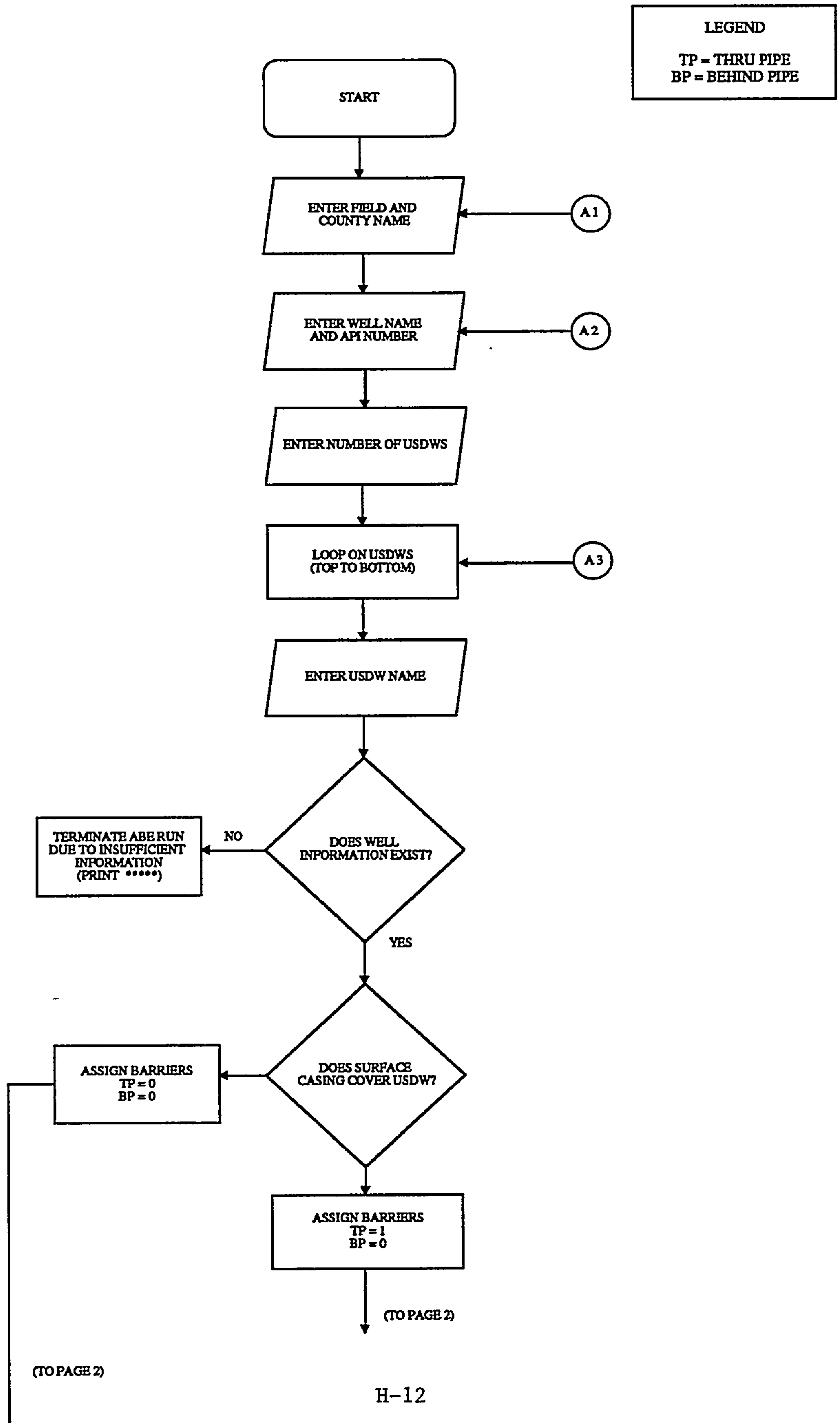


FIGURE H-3
ABE PROGRAM LOGIC
FOR ACTIVE WELLS
(page 2)

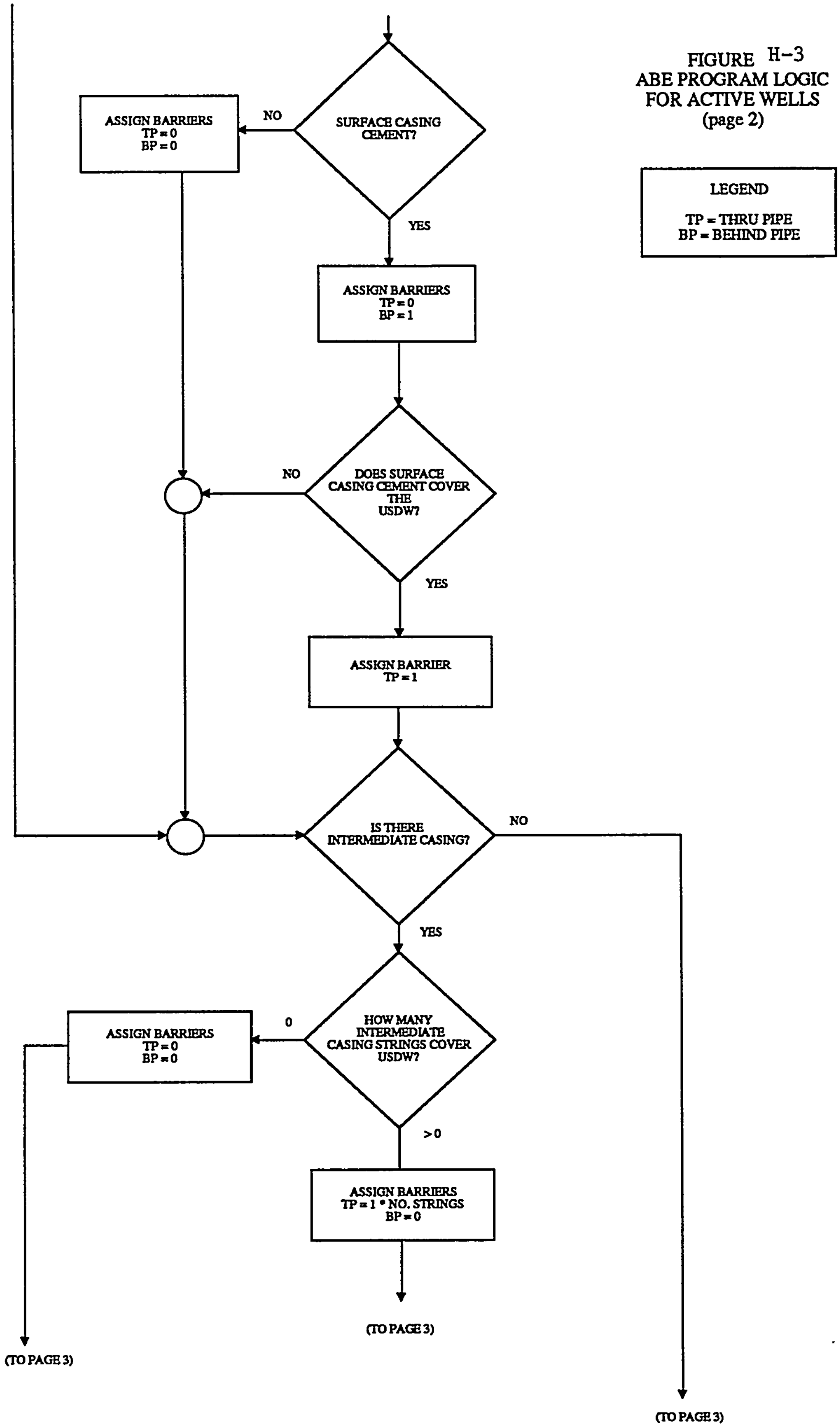


FIGURE H-3
ABE PROGRAM LOGIC
FOR ACTIVE WELLS
(page 3)

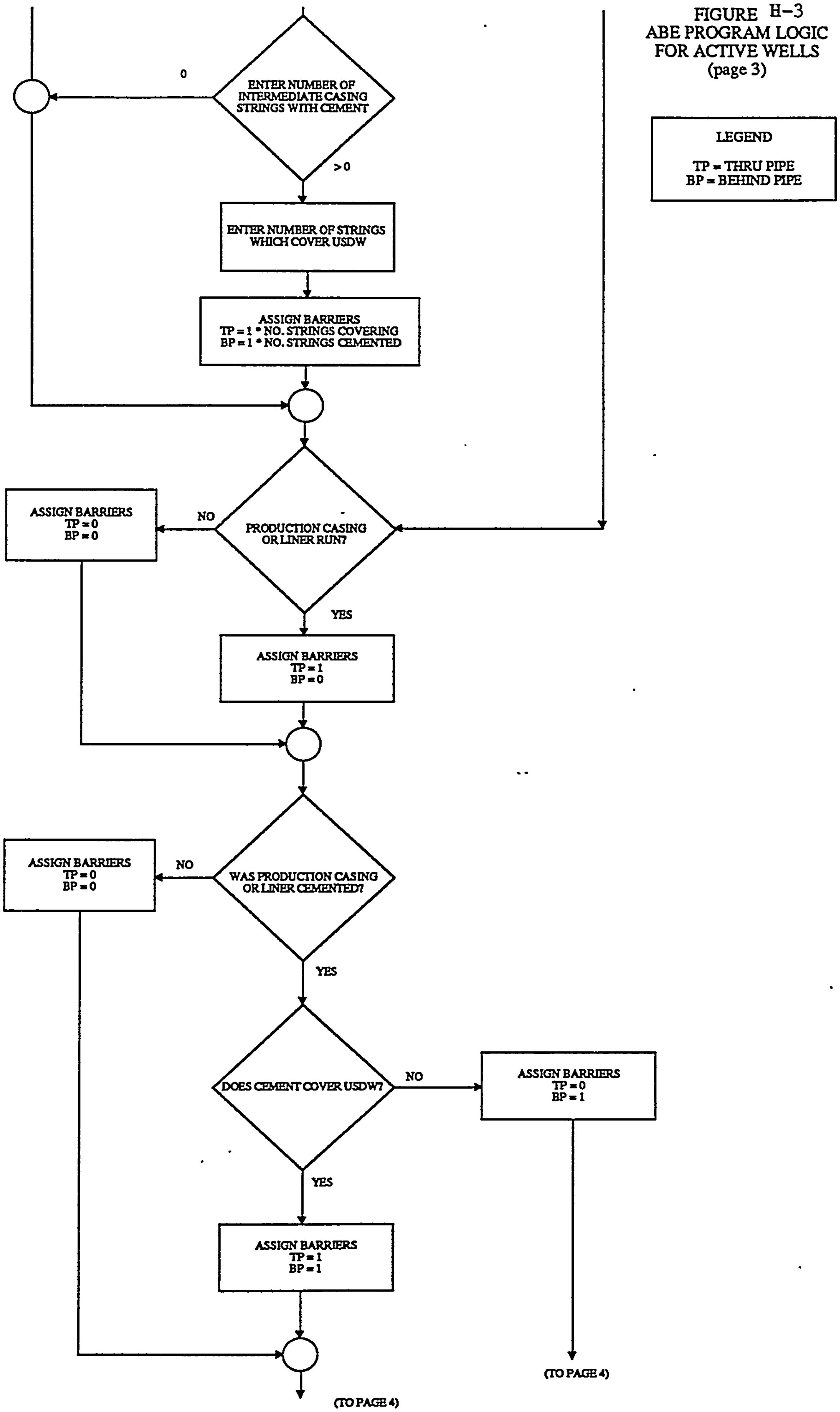
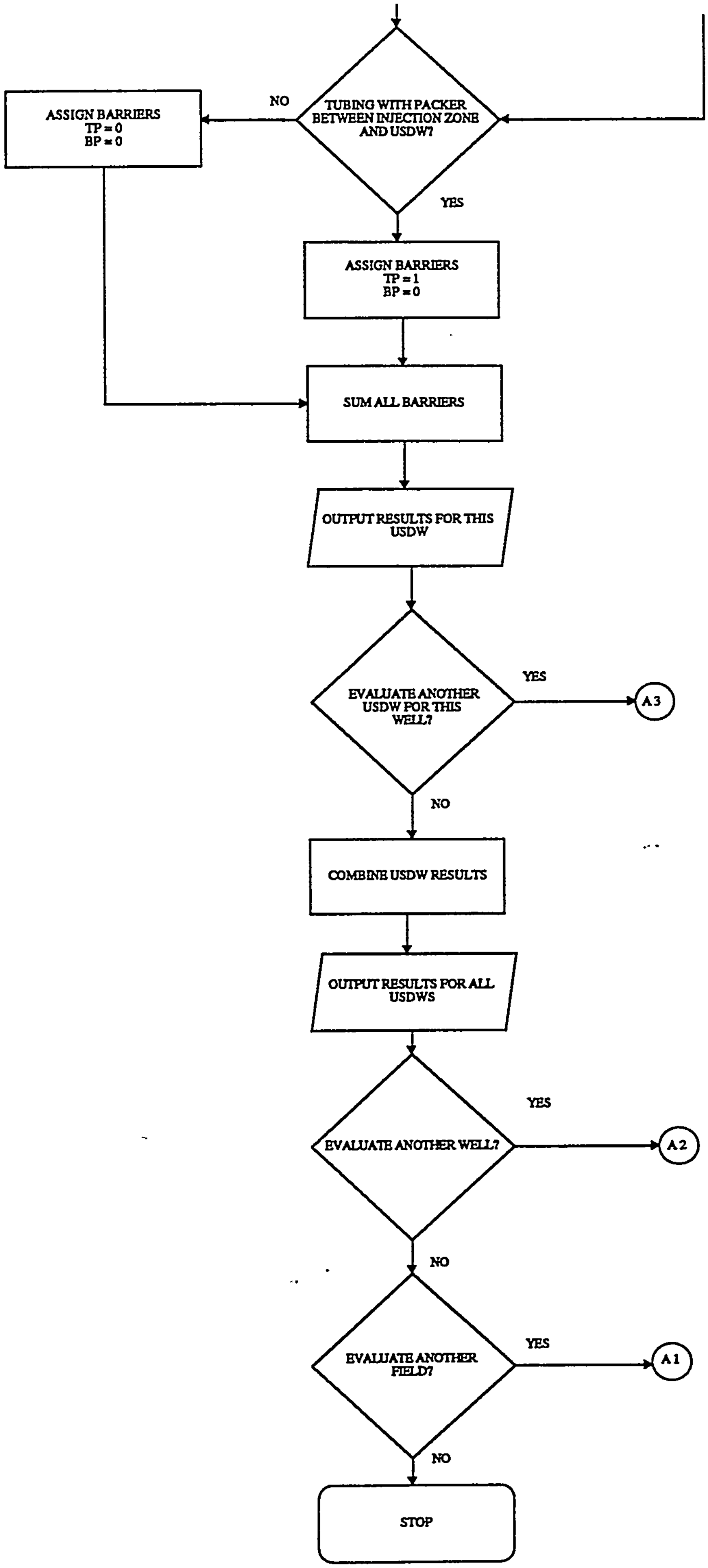


FIGURE H-3
ABE PROGRAM LOGIC
FOR ACTIVE WELLS
(page 4)



LEGEND

TP = THRU PIPE
BP = BEHIND PIPE

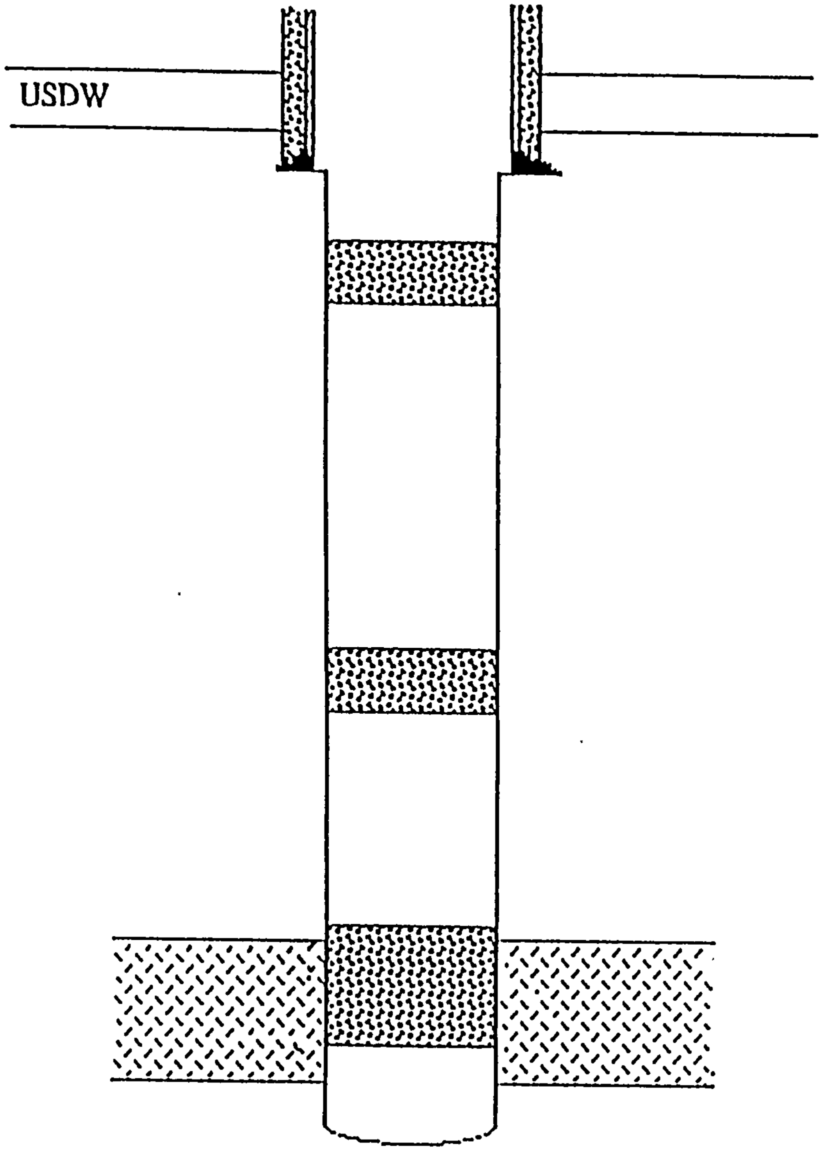
regarding barriers to flow. Based on current program logic, the user must evaluate multiple USDWs in descending order, i.e. from shallowest to deepest. At the end of an ABE evaluation, all of the barrier factors assigned to mechanical barriers are summed, and an overall barrier factor for each USDW is calculated. Values generated may range from O to essentially any positive number.

It is important to note that the ABE evaluations shown in Figures H-4 through H-9 depict a well with only one USDW. When multiple USDWs are present in a well, the overall barrier factor for each USDW is reported separately. Then, the most conservative barrier factor should be selected as the well's USDW contamination possibility. That is, the USDW which had the lowest ABE value (highest USDW contamination possibility) should be reported as the overall USDW barrier factor for the well.

The program ABE must evaluate a single well at a time because the wellbore construction and abandonment techniques will most likely be unique to a single well. If multiple wells are to be examined, then ABE runs must be created for all wells.

The results generated by ABE provide a basis for comparing wells and for identifying wells with less than adequate protection. The program does not calculate actual mathematical probabilities of leakage within a given wellbore. Rather, the purpose of the ABE program is to provide a numerical framework for comparing wells with different construction and abandonment configurations.

In Open Hole Example #1 as shown in Figure H-4, an abandoned open hole is evaluated using the ABE program. Although this is an open hole example, the terms "through pipe" and "behind pipe" (as previously defined) will be employed to evaluate flow in and behind the casing that is present in the hole. Both the surface casing and surface casing cement protect the USDW from through pipe flow and there is a bottom cement plug in addition to two additional plugs between the injection zone and the USDW, resulting in five through pipe barriers and three plugs. Behind pipe flow has only two barriers in this example, the surface casing cement and the bottom cement plug located at the injection



Date: 3/25/1993
Field:
County:
USDW:

Analyst: Koederitz
Well: Open Hole Example #1
API #:

ABANDONED WELL	BARRIERS ASSIGNED Through Pipe	Behind Pipe
Surface Casing	1	0
Surface Cas. Cement	1	1
Intermediate Casing	0	0
Int. Cas. Cement	0	0
Int. Cas. Pulled	0	0
Cmt. across Int Stub	0	0
Cement Squeeze - Int	0	0
Production Casing/ Liner/Open Hole	0	0
Prod. Cas. Cement	0	0
Cement Squeeze - Prd	0	0
Sqz. Cmt/Plug @ abd.	1	1
Prod. Cas. Pulled	0	0
Cement across Stub	0	0
Plugs(Inj.Zone to USDW)	2	0
TOTAL BARRIERS	5	2
TOTAL NO. of PLUGS	3	

Computed using UMRs ABE Version: 93.083

Figure H-4. EXAMPLE #1 - ABE EVALUATION FOR AN OPEN HOLE ABANDONED WELL

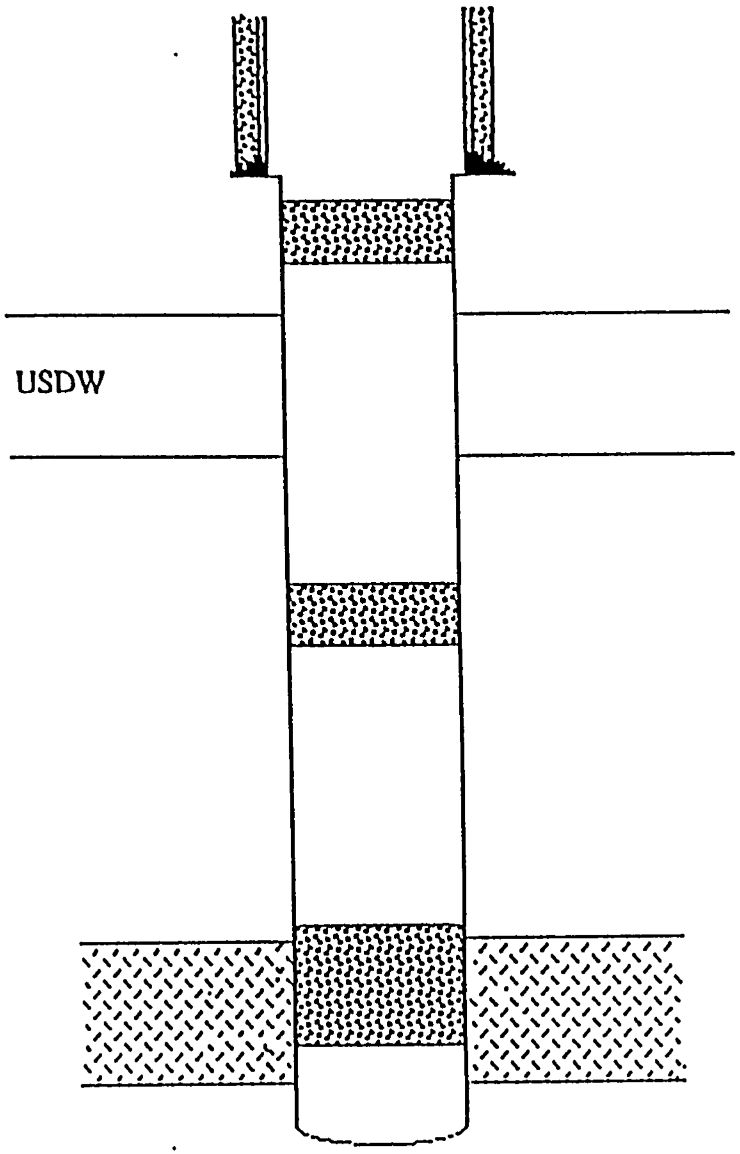
zone. Open Hole Example #2 (Figure H-5) differs in that the USDW is now located below the surface casing and below the top plug. In this example, only the bottom plug and one additional plug prevent through pipe flow resulting in two through pipe barriers and two plugs. The only barrier to flow behind pipe is the bottom plug at the injection zone.

Figure H-6 illustrates an abandoned cased hole wellbore with a bottom plug. Through pipe flow from the injection zone to the USDW is prevented by the production casing and the bottom plug. Behind pipe flow also has two barriers: the production casing cement and the bottom plug squeeze cement. A second example of an abandoned cased hole is depicted in Figure H-7; in this example, there are clearly two plugs and six through pipe barriers to flow from the injection zone to the USDW.

The through pipe barriers consist of the surface casing, the surface casing cement, the production casing, the cement squeeze at the USDW, the bottom plug with a squeeze at the injection zone, and the second plug located opposite the USDW. Four barriers to flow exist behind pipe in this example. They are the surface casing cement, the production casing cement, the squeeze cement at the USDW, and the squeeze cement at the injection zone.

Figure H-8 shows an abandoned well with the production casing pulled and stubbed off. Since the USDW is below the surface casing, there is only one barrier to through pipe flow: the stub plug; obviously, there is only one plug. The two behind pipe flow barriers consist of the production casing cement and the stub cement.

The last example indicates a producing well (Figure H-9). Two through pipe flow barriers can be found in this example: the production casing and the tubing which is isolated by a packer. The only behind pipe barrier to flow is the production casing/cement.



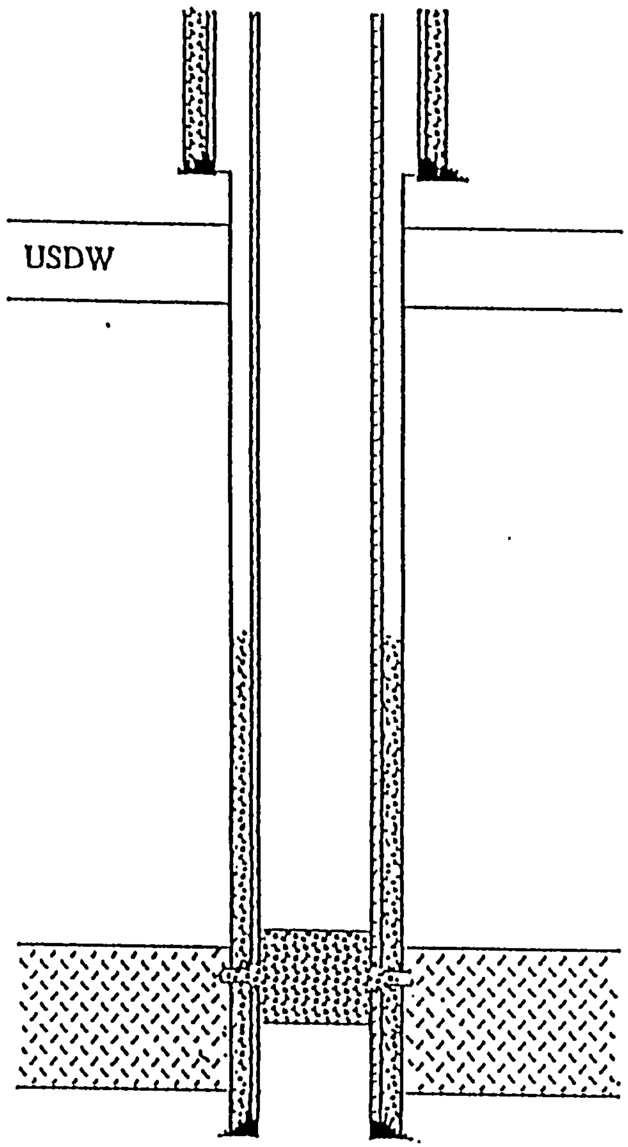
Date: 3/24/1993
Field:
County:
USDW:

Analyst: Koederitz
Well: Open Hole Example #2
API #:

ABANDONED WELL	BARRIERS ASSIGNED Through Pipe	Behind Pipe
Surface Casing	0	0
Surface Cas. Cement	0	0
Intermediate Casing	0	0
Int. Cas. Cement	0	0
Int. Cas. Pulled	0	0
Cmt. across Int Stub	0	0
Cement Squeeze - Int	0	0
Production Casing/ Liner/Open Hole	0	0
Prod. Cas. Cement	0	0
Cement Squeeze - Prd	0	0
Sqz. Cmt/Plug @ abd.	1	1
Prod. Cas. Pulled	0	0
Cement across Stub	0	0
Plugs(Inj.Zone to USDW)	1	0
TOTAL BARRIERS	2	1
TOTAL NO. of PLUGS	2	

Computed using UMRs ABE Version: 93.083

Figure H-5. EXAMPLE #2 - ABE EVALUATION FOR AN OPEN HOLE ABANDONED WELL



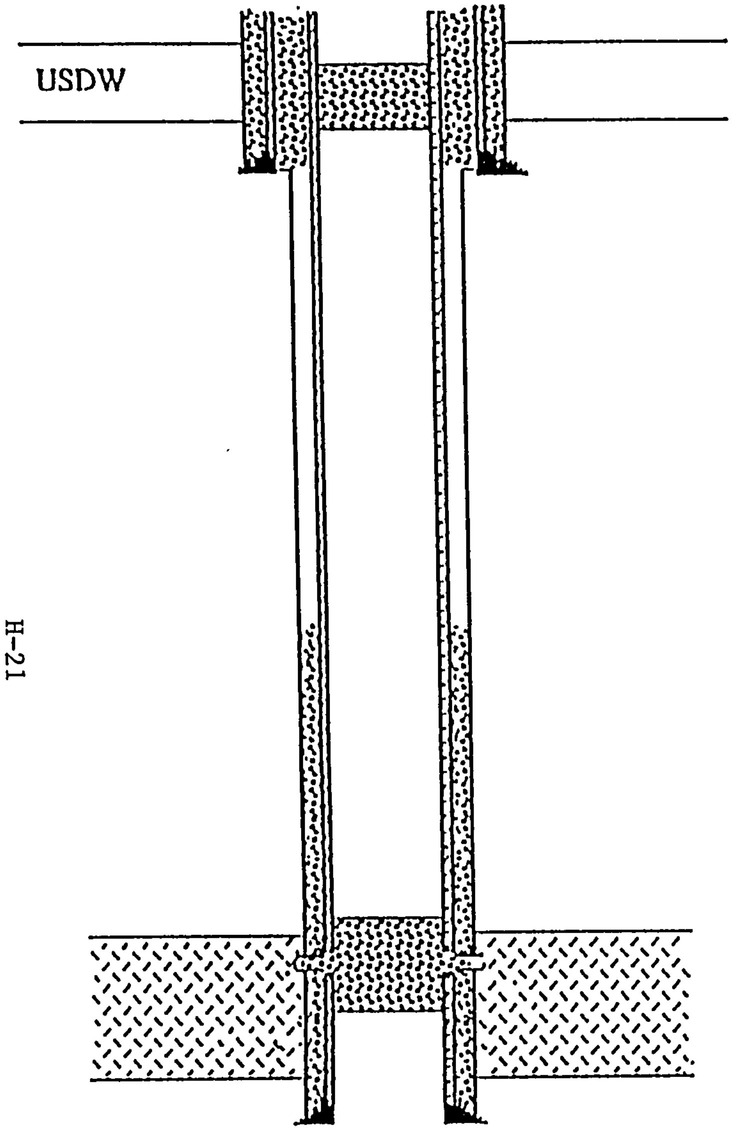
Date: 3/24/1993
Field:
County:
USDW:

Analyst: Koederitz
Well: Cased Hole Abd. #1
API #:

ABANDONED WELL	BARRIERS ASSIGNED Through Pipe	Behind Pipe
Surface Casing	0	0
Surface Cas. Cement	0	0
Intermediate Casing	0	0
Int. Cas. Cement	0	0
Int. Cas. Pulled	0	0
Cmt. across Int Stub	0	0
Cement Squeeze - Int	0	0
Production Casing/ Liner/Open Hole	1	0
Prod. Cas. Cement	0	1
Cement Squeeze - Prd	0	0
Sqz. Cmt/Plug @ abd.	1	1
Prod. Cas. Pulled	0	0
Cement across Stub	0	0
Plugs(Inj.Zone to USDW)	0	0
TOTAL BARRIERS	2	2
TOTAL NO. of PLUGS	1	

Computed using UMRs ABE Version: 93.083

Figure H-6. EXAMPLE #1 - ABE EVALUATION FOR A CASED HOLE ABANDONED WELL



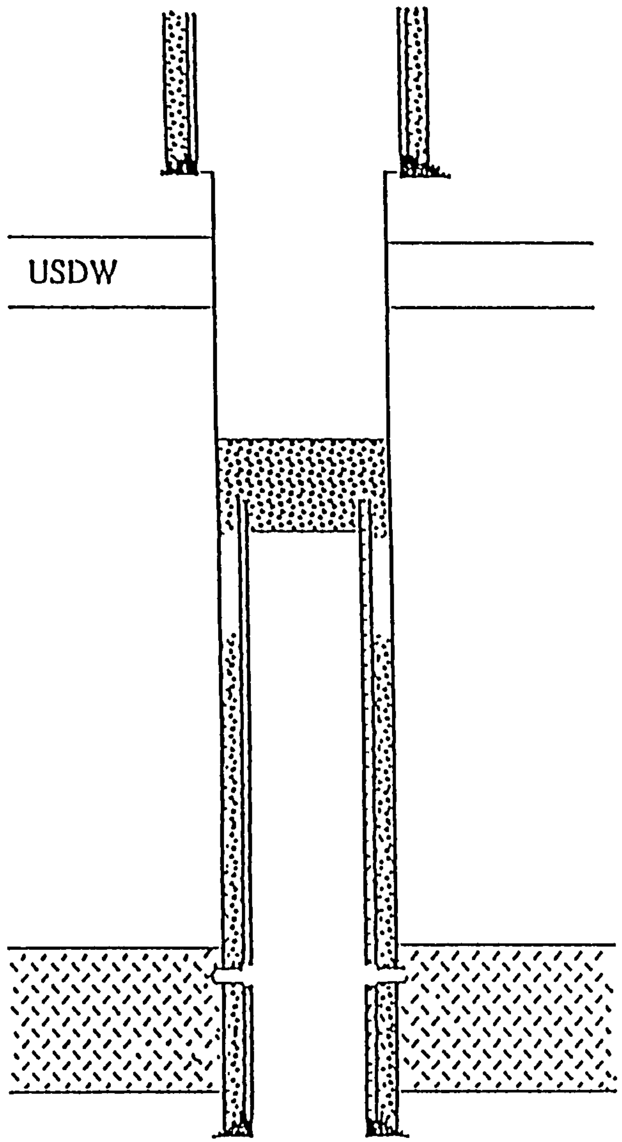
Date: 3/25/1993
Field:
County:
USDW:

Analyst: Koederitz
Well: Cased Hole Abd. #2
API #:

ABANDONED WELL	BARRIERS ASSIGNED Through Pipe	Behind Pipe
Surface Casing	1	0
Surface Cas. Cement	1	1
Intermediate Casing	0	0
Int. Cas. Cement	0	0
Int. Cas. Pulled	0	0
Cmt. across Int Stub	0	0
Cement Squeeze - Int	0	0
Production Casing/ Liner/Open Hole	1	0
Prod. Cas. Cement	0	1
Cement Squeeze - Prd	1	1
Sqz. Cmt/Plug @ abd.	1	1
Prod. Cas. Pulled	0	0
Cement across Stub	0	0
Plugs(Inj.Zone to USDW)	1	0
TOTAL BARRIERS	6	4
TOTAL NO. of PLUGS	2	

Computed using UMRs ABE Version: 93.083

Figure H-7. EXAMPLE #2 - ABE EVALUATION FOR A CASED HOLE ABANDONED WELL



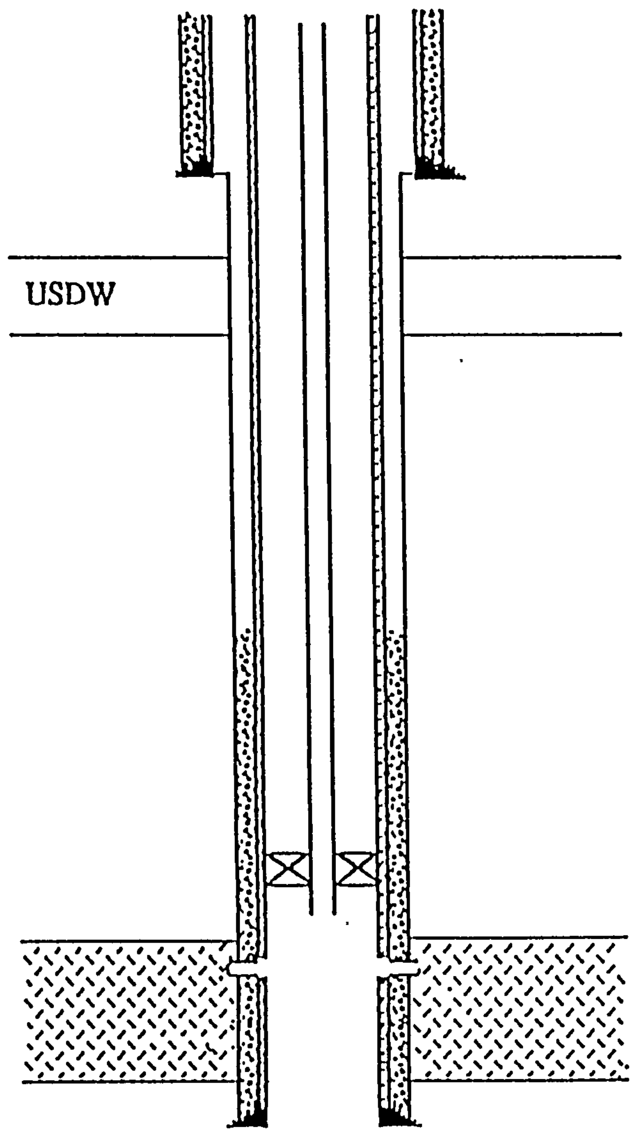
Date: 4/13/1993
Field:
County:
USDW:

Analyst: Koederitz
Well: Casing Pulled
API #:

ABANDONED WELL	BARRIERS ASSIGNED Through Pipe	Behind Pipe
Surface Casing	0	0
Surface Cas. Cement	0	0
Intermediate Casing	0	0
Int. Cas. Cement	0	0
Int. Cas. Pulled	0	0
Cmt. across Int Stub	0	0
Cement Squeeze - Int	0	0
Production Casing/ Liner/Open Hole	1	0
Prod. Cas. Cement	0	1
Cement Squeeze - Prd	0	0
Sqz. Cmt/Plug @ abd.	0	0
Prod. Cas. Pulled	-1	0
Cement across Stub	1	1
Plugs(Inj.Zone to USDW)	0	0
TOTAL BARRIERS	1	2
TOTAL NO. of PLUGS	1	

Computed using UMRs ABE Version: 93.097

Figure H-8. EXAMPLE ABE EVALUATION FOR AN ABANDONED WELL WITH CASING PULLED



Date: 3/24/1993
Field:
County:
USDW:

Analyst: Koederitz
Well: Producing Example
API #:

ACTIVE WELL (Producer)	BARRIERS ASSIGNED Through Pipe	Behind Pipe
Surface Casing	0	0
Surface Cas. Cement	0	0
Intermediate Casing	0	0
Int. Cas. Cement	0	0
Production Casing/ Liner/Open Hole	1	0
Prod. Cas. Cement	0	1
Tubing w/ Packer	1	0
TOTAL BARRIERS	2	1

Computed using UMRs ABE Version: 93.083

Figure H-9. EXAMPLE ABE EVALUATION FOR A PRODUCING WELL

The idealized step-by-step procedure for evaluation of flow potential in a geographic area and determination of the availability of a variance is as follows:

1. Obtain head data for the USDW or USDWs of concern and adjust data to a base of USDW datum.
2. Plot the data from 1. on a base map (or maps) of an appropriate scale.
3. Hand contour or computer contour the USDW head map of 2. using an appropriate contour interval.
4. Obtain predevelopment petroleum reservoir pressure data for the field or fields of concern.
5. Convert the data from 4 to a common datum, usually sea level, and plot the pressure data on the same base map as used in 2.
6. Hand contour or computer contour the predevelopment petroleum reservoir pressure data.
7. Obtain current petroleum reservoir pressure data and add to the map of 5.
8. Recontour the map resulting from 7.
9. Convert values from the petroleum reservoir pressure map as obtained from 5. to fresh-water heads as described in Appendix III, using the base of the USDW as a datum.
10. Plot and contour petroleum reservoir head data from 9. for visual inspection for consistency with map of 8.
11. Subtract USDW contour head values from 3 from petroleum reservoir map head values from 10.
12. Plot and contour residual heads from 11.
13. Where residuals from 12. are positive, there is potential for upward flow with no additional imposed injection head. Where residuals from 12. are negative, determine the additional injection pressure head that could be imposed. If imposed head creates a positive residual, then there is potential for upward flow to the USDW. If imposed head leaves a negative residual, the upward flow cannot occur. Such an area of negative residual would be eligible for a variance from well-by-well AOR.

The 13 steps listed above are idealized for a large field, multi-field, basin or sub-basin size area. For a small field or single well, one could start with present-day petroleum reservoir pressure data, convert those data to equivalent fresh-water heads and compare them with local USDW heads in the same manner as in Step 13 without the need for the other steps. The following figures provide an example of the application of Steps 1-13, as given above, to a regional area.