DETERMINATION OF THE MECHANICAL INTEGRITY OF INJECTION WELLS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5 -- UNDERGROUND INJECTION CONTROL (UIC) BRANCH
REGIONAL GUIDANCE #5

Revised February, 2008

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5 -- UNDERGROUND INJECTION CONTROL (UIC) SECTION
REGIONAL GUIDANCE #5

DETERMINATION OF THE MECHANICAL INTEGRITY
OF INJECTION WELLS

Revised February, 2008

1 ISSUE

Demonstrations of mechanical integrity (MI) are the most common means of demonstrating that there is no movement of fluids into or between underground sources of drinking water (USDWs) associated with injection wells. Although relatively simple in theory, MI tests (MITs) must be conducted so that their validity as well as their outcome is evident. The Underground Injection Control (UIC) Branch of the Water Division in Region 5, United States Environmental Protection Agency (USEPA), as the authority in matters of MI in Region 5, should establish guidelines which will assist operators and regulators of injection wells in Region 5 subject to demonstrations of MI to conduct those demonstrations such that the results will be useful.

2 PURPOSE OF GUIDANCE

The guidelines were developed by the UIC Branch of Region 5 USEPA, to assist owner/operators of injection wells in Region 5 to demonstrate MI. Procedures varying from these guidelines may be accepted if first approved by the Director of the USEPA.

Pursuant to 40 C.F.R. &sect 146.8(a) "an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing, or packer; and (2) there is no significant fluid movement into an USDW through vertical channels adjacent to the injection well bore". The absence of significant leaks is demonstrated through the use of tests which have been approved for that purpose by the Administrator (MI tests). The methods presently accepted for establishing MI pursuant to 40 C.F.R. &sect 146.8(a)(1) [part 1] of MI for wells operating in states in which the UIC Branch implements the UIC regulations, include: 1) the standard annulus pressure test (SAPT), 2) the standard annulus monitoring test (SAMT), 3) the radioactive tracer survey (RTS), and for certain Class III wells: the water-brine interface test (W-BIT. Other methods, including the Ada pressure test(AT) and the cementing pressure/single point resistivity test, are approved for national use under certain circumstances, but are not used in Region 5. In addition, the dual completion monitoring test (DCMT) is used by a few wells in Michigan and Indiana although interim approval has expired. The procedures for this test are under review. Accepted methods for demonstrating MI pursuant to 40 C.F.R. &sect 146.8(a)(2) [part 2] include: 1) the results of a temperature log, 2) noise log, 3) oxygen activation log, 4) the re.sults of a radioactive tracer survey (RTS) (when the injection zone is separated from the lowermost USDW by a single confining layer), or 5) for all Class II wells and for Class III wells in which the casing precludes the use of logging techniques, cementing records demonstrating the presence of adequate cementto prevent fluid migration into USDWs pursuant to 40 C.F.R. &sect 146.8(c)(2) and (c)(3) respectively. Demonstrations of both part 1 and part 2 of MI must be made before injection can be authorized.

The procedures which are recommended in the attachments to this document will, in most cases, result in development of valid data which Region 5 will be able to interpret with confidence. Deviations from these procedures may result in anomalies which will complicate or even invalidate test results. If the recommended test results do not result in definitive information, any anomalies noted should be investigated immediately, including re-doing the tests. Results which provide demonstrations of MI are the purpose of this guidance, but adherence to guidance may not ensure development of acceptable results in all cases. In such cases, mere adherence to guidance does not absolve the operator from the requirement to demonstrate MI. In cases in which there is doubt about the certainty of outcomes, reference to and comparison with previous tests can often be used to clarify the test results. In this vein, comparison of tests through time, especially the comparison of temperature and radioactive tracer logs can make interpretation easier and make progressive change apparent. In all cases, operators should submit proposed testing procedures to the UIC Branch's Direct Implementation (DI) Section for approval before the testing is done. This can prevent misunderstandings and possible retesting.

3 DISCUSSION

3.1 Mechanical Integrity Pursuant to 40 C.F.R. &sect 146.8(a)(1)

There are a limited number of means by which part 1 of MI (the absence of significant leaks in tubing, casing, and packer) may be demonstrated. Therefore, little discussion of the relative merits of the various tests is necessary.

3.1.1 The Standard Annulus Pressure Test (SAPT)
The SAPT is the most common means used to demonstrate part 1 of MI. This test is based on the principle that a pressure applied to fluids filling a sealed vessel will persist. A well's annulus system, though closed to transfer of matter, is not closed to energy transfer because it is not isolated from transfer of heat from its surroundings, therefore an allowance for small pressure changes is necessary. The test provides an immediate demonstration of whether or not leaks, detectable by these means, exist. A discussion of and procedures for the SAPT are outlined in Attachment 1.

3.1.2 The Standard Annulus Monitoring Test (SAMT)
Pursuant to 40 C.F.R. &sect 146.8(b), monitoring of the annulus pressure is an approved method for establishing part 1 of MI for all wells. Annulus pressure monitoring for Class I wells required at &sect 146.13(b)(2) to verify the maintenance of a minimum pressure differential is not the SAMT, because changes in pressure due to loss of annulus liquid are attenuated by the presence of a gas blanket which is replenished as pressure decreases. If annulus monitoring is used to demonstrate MI, an initial SAPT is required. Annulus monitoring may continue throughout the life of the well or the operator may choose, at any time, to conduct a SAPT every five years and after well reworks (on rule authorized Class II wells and on permitted wells if the particular UIC permit allows it), thereby discontinuing the SAMT. A discussion of the merits and procedures for the SAMT is provided in Attachment 2.

3.1.3 The Radioactive Tracer Survey (RTS)
On September 18, 1987, the USEPA published a Federal Register (FR) notice at 35324 et seq. FR 52, No. 181, giving interim approval for the use of the RTS as an alternative MIT. In a FR Notice at 46837 et seq. FR 52, No. 237 on December 10, 1987, the USEPA announced final approval of the RTS as a demonstration of part 1 and 2 (as limited), and provided clarifications and additional information based on comments received and the use of the test during the interim approval period. A discussion of and procedures for conducting the RTS as a demonstration of part 1 of MI in Region 5 are outlined in Attachment 3.

3.1.4 Water-Brine Interface Test (W-BIT)
On January 10, 1992, approval of the W-BIT was announced in the Federal Register at 1109 et seq FR 57, No. 7. The test is valid only for Class III wells and only when construction and operating conditions make testing with the SAPT impractical. Although there are no special recommendations applicable in Region 5, additional explanation of the basis for the test is provided in Attachment 4, and a full description of the procedures for conducting the W-BIT is available in the above referenced FR Notice.

3.1.5 Ada Pressure Test
The Ada test is a variant of the SAPT. It is used to test wells which have perforations above the injection zone. It can be used to test the integrity of the casing above the perforations. To conduct the test gas pressure is used to depress the liquid level to a point just above the perforations. The

pressure is measured over a period of time. If the pressure change is less than the established limit, the well has mechanical integrity.

3.1.6 Water-in-Annulus Test (WIAT)
The WIAT was announced at 14678 et seq 54 FR No. 19 on April 12, 1989, for existing Class II wells for enhanced oil recovery in the counties in which the Bradford oil field is located in New York and Pennsylvania. Approval of the test was extended to similar wells in the Redhaw oil field in Ashland County, Ohio. The test is used for wells which are constructed without long string casing. The level of water near the top of the annulus between the surface casing, which protects all USDWs, and the injection tubing which is set on a formation packer and may have some cement on the top of the packer, is observed under specified conditions. The presence and nature of relatively small leaks can be determined.

3.2 Mechanical Integrity Pursuant to 40 C.F.R. &sect 146.8(a)(2)

Owner/operators have a choice of a number of methods for demonstrating that wells have part 2 of MI (no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore). The conditions under which these tests can be used to best effect differ significantly; therefore, a listing of relative advantages and disadvantages of the various options is provided in the attachments concerning each of the approved methods for demonstrating part 2 of MI.

3.2.1 Temperature Logs (TL)
Temperature logs are a very versatile and sensitive means of identifying fluids which have moved along channels adjacent to the well bore. In addition to demonstrations of part 2 of MI, temperature logs can be used to monitor fluid movement through the confining zone adjacent to the well bore and can often locate small casing leaks. To be effective for demonstrations of MI, there must be adequate time available for short-term temperature effects along the well bore to dissipate. Background information and general procedures for running t emperature logs are provided in Attachment 5.

3.2.2 Noise Logs (NL)
The use of noise logs is based on the observation that flow behind the casing in the well bore will, at some points, be turbulent. Turbulent flow causes noise which may travel for significant distances along the well bore. Noise logs are appropriate where it is impractical for injection operations to be suspended for the length of time needed to allow temperature stabilization to proceed to the point at which a temperature log can be run with good results. They can also be used to locate some tubing or casing leaks. Background information and procedures for using noise logs to demonstrate part 2 of MI are found in Attachment 6.

3.2.3 Oxygen Activation Method (OAL)
On February 1, 1991, the USEPA published a FR Notice (FRN)granting final approval, effective March 4, 1991, for use of the oxygen activation method or log (OAL) as a means of demonstrating part 2 of MI. Details of the operation and conditions under which the OAL can be used can be found at 4063 et seq. FR 56, No. 22 which is included in this guidance as Attachment 7.

3.2.4 Radioactive Tracer Survey
The same FRNs which describe how the RTS can be used for demonstrating part 1 of MI also describe its use for demonstrating part 2 of MI. This method may be used only where there is only a single confining formation separating the lowermost USDW from the injection zone with no aquifers within it. Additional requirements and limitations of the RTS are described in the previously mentioned FR Notices (See III.C.). The use of the RTS as a means of demonstrating part 2 of MI is described in Attachment 8.

3.2.5 Cement Records
The most common demonstration of part 2 of MI for Class II wells is based on cementing records. Demonstrations of MI for Class III wells can also be based on cementing records if the configuration of

wells prevents the use of logging methods. If records show that casings are cemented in a way which will prevent the movement of liquids into or between USDWs, the well has part 2 of MI. A discussion of the use of cementing records is provided in Attachment 9.

3.3 Additional Mechanical Integrity Tests

Other alternative MITs will be added to this guidance if approved by the Administrator of the EPA for use in Region 5. In order for a test to be approved, it must be submitted to the Water Division Director in Region 5 with all supporting evidence. If the proposal is approved by the Director, then it will be submitted to the Administrator, and will be evaluated by the national UIC Technical Workgroup which will evaluate its effectiveness. If approved by the Administrator, the approval and any limitations placed on the test will be promulgated in the Federal Register. In addition, specific procedures outlined in this guidance may be modified after additional data are obtained or to accommodate a particular type of well construction. National UIC Guidances #15 and #34 include information relating to approval of alternate methods of testing mechanical integrity.

3.4 Tests which are not MI Tests but are Specifically Required by Regulation

3.4.1 Radioactive Tracer Survey
The regulations at 40 C.F.R. 146.68(d)(2) require annual demonstrations of the integrity of cement at the top of the injection interval in Class I hazardous-waste injection wells. The RTS is more often used for that purpose than to demonstrate either part 1 or 2 of MI. The procedures for demonstrating cement integrity using the RTS are presented in Attachment 10*.

3.4.2 Casing Inspection Logs (CIL)
The regulations at 40 C.F.R. 146.68(d)(4)require periodic monitoring of change in casing thickness for Class I wells injecting hazardous wastes. The procedures for running the logs and presentation of the results are set by the logging company. Because the standards adopted by the logging companies are appropriate, no additional information is provided for running casing inspection logs.

4 CONDUCTING TESTS WITHOUT A REPRESENTATIVE OF THE USEPA

It is, and has been, the policy of Region 5 to witness mechanical integrity testing to the extent practicable. Tests for which a mechanical or third-party record is produced may be conducted without an Agency witness when it proves impossible to resolve scheduling conflicts with both the USEPA contract inspectors and the Regional technical staff.

In order to conduct testing without an USEPA representative the following procedures should be followed:

1. The owner/operator must submit proposed procedures including the information that no USEPA representative is available, and receive permission from the DI Section of the UIC Branch to proceed;
2. The test must be documented using either a mechanical device which records the value of the parameter of interest, or by a service company job record;
3. A report of the testing including all data available at the conclusion of the test and a certification of accuracy which is signed by an authorized representative of the company must be submitted to the DI Section within 10 c alendar days of the completion of testing; and
4. A final report, including any additional interpretation necessary for evaluation of the testing, must be submitted prior to or with the next regularly scheduled monitoring report or as required under the appropriate permit for the injection well.

NOTE: Pursuant to &sect 146.8(f) of the UIC regulations, Region 5 may, at any time, require a test witnessed by a USEPA representative to verify the results of an unwitnessed test. This is possible if results are ambiguous or if documentation is lacking.

5 ACTIONS TO BE TAKEN IN THE EVENT OF A FAILURE TO DEMONSTRATE MI OR LOSS OF MI DURING OPERATIONS

If upon investigation, the well appears to be lacking MI, the operator should cease injection immediately and attempt to mitigate any environmental effects of the loss of MI. The Director may allow up to 48 hours of injection if necessary to allow for a smooth shut down of operations. Pursuant to 144.28(b) or 144.51(l)(6), owners/operators are required to report any known loss of MI which might endanger health or the environment to Region 5 within 24 hours. To report a failure, operators may call Region 5 at (312) 353-4148; during nonbusiness hours a message can be left on the voice mail system. Also, pursuant to 144.28(b) or 144.51(l)(6) a written submission shall be prepared and sent to Region 5 within five days of the time the operator becomes aware of a loss of MI.

Injection into wells which have lost MI can be resumed only after a letter authorizing injection is received from the Director. The Director will prepare such a letter only if: 1) the well is repaired, a report detailing the means used to effect the repair is submitted, and MI is demonstrated or 2) the owner/operator demonstrates, by means acceptable to the Director, an absence of flow into or between USDWs pursuant to 40 C.F.R. &sect 144.28(f)(4) or 40 C.F.R. 144.51(q)(3). As an alternative, the well can be plugged in accordance with 40 C.F.R. &sect 146.10. The plugging procedures must remove any threat posed by the absence of MI. If the failure is of part 1 of MI, this is usually accomplished through cementing the leaking portion. If the failure is of part 2 the means required to eliminate the fluid movement might be more demanding.

Falsification of MI testing is a violation of 18 USC &sect 1001 and violators may be subject to criminal penalties.

ATTACHMENT 1
STANDARD ANNULUS PRESSURE TEST (SAPT)

1 Basis

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted, undiminished, throughout the vessel. This fact is the basis for the selection of the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. To fully test the well bore, the pressure applied to the annulus system must be transmitted through the entire well bore. Therefore, no mechanical plug may be placed above the packer in any well subject to testing by means of the SAPT.

Because the annulus system is not an isolated system (e.g. it transmits energy, but not matter), the measured pressure applied may not be constant through time. The temperatures along the well bore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding rock. When the well is shut in part of the well bore may cool and part may become warmer. As this happens, the liquid in the annulus contracts or expands. Because liquids are only very slightly compressible, it is very unlikely that the pressure will appear to remain absolutely stable either while the well is shut in or being used for injection.

2 Advantages and Disadvantages of the SAPT

<u>Advantages of the SAPT</u>

1. Easy to interpret
2. Inexpensive to perform

<u>Disadvantage of the SAPT</u>

Provides a demonstration at a single point in time

3 Equipment and Forms

Pressure measurements must be made using a gauge which can be read with sufficient accuracy to identify pressure change which would result in failure of the test and to record accurate intervening values required per the procedures in Part D below. If the test pressure is 300 pounds per square inch, gauge (psig), then the gauge face should be marked in increments of 5 pounds per square inch (psi) or less. A gauge measuring injection pressure should be available.

The "Annulus Pressure Test" form (Attachment 11) is used to record SAPTs. Pressure measurements at intervals through the test period and the signature of an authorized witness are essential for acceptance. The most recent record of calibration for the gauge used for the MI test must be submitted along with the Annulus Pressure Test form. If authorization has been granted to conduct the test without a USEPA witness, the mechanical record of the test must be submitted as well.

4 Procedure for the SAPT:

To properly conduct the SAPT:

1. The tubing/casing annulus (annulus) must be completely filled with liquid (variations must be approved by Region 5). Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test. This may be achieved by filling the annulus with liquid and either ceasing injection or maintaining stabilized injection (i.e., continuous injection at a constant rate and constant injection fluid temperature) before and through the test;

   No unapproved substances may be added to the annulus liquid. Use of any substance which might affect the outcome of testing may constitute falsification of the test procedure, invalidate the test, and may subject the owner/operator to civil or criminal prosecution;
2. After stabilization, the annuluses of Class II wells should be pressurized to a surface pressure of no less than 300 psig. The annuluses of Class I wells should be pressurized to the greater of 300 psig or a pressure which exceeds the maximum allowable injection pressure by 100 psi, unless an alternate pressure is approved by Region 5. A positive pressure differential between the pressure in the annular space and the injection tubing pressure of at least 100 psi should be maintained throughout the entire annulus (from the top of the packer to the surface) of all Class I and II wells. Specific gravity differences between liquids in the annulus and the tubing should be accounted for when determining the appropriate test pressure. Following pressurization, the annular system must be isolated from the source of pressure and the sealpot (if present) by a closed valve. If not inconvenient, the connection to the pressure source should be disconnected entirely;
3. The annulus system must remain isolated for a period of no less than 30 minutes for Class II, III, and V wells. The isolation must be maintained for one hour for Class I wells. During the period of isolation measurements of pressure should be made at ten-minute intervals; and
4. After the SAPT test period has been completed, the valve to the annulus should be opened and liquid returns from the annulus observed and measured. This may be done by allowing liquid to flow into a sealpot assembly and measuring the volume of the returns or by opening a valve and catching the liquid flowback in a container. The volume of annulus liquid returns recovered is proportional to the volume of the annulus and the amount of pressurization. The liquid return test can serve as an indication as to whether the full length of the annulus has been tested. As an alternative, the amount of liquid needed to increase the pressure can be measured. If the entire length of the annulus, from the wellhead to the packer, set at the approved depth, is not tested, then the test is void.

5 Interpretation

The interpretation and confirmation of the SAPT include:

1. Comparison of the pressure change through the test period to 3% of the test pressure (0.03 X test pressure). If the annulus test pressure changes by this amount or more (gain or loss), the well has failed to demonstrate MI (for all wells), and operation may constitute a violation

of the UIC regulations. If the annulus test pressure changes by less than 3 percent (gain or loss) over the test period, the well has demonstrated MI, pursuant to 40 C.F.R. &sect 146.8(a)(1); and

2. Evaluation of the amount of liquid returned. If less than a cup of liquid is returned, the annulus may be blocked at a shallow depth. In the past criminal charges have been brought as a result of investigations inspired by the observation that very little liquid was returned. The owing formula can be used to find how much liquid should be returned:

$$dV = (P_t - P_f) \times V_f \times h \times 0.0000032$$

where:
dV = the amount returned, gals;
P_t = the pressure used to test the annulus, psi;
P_f = annulus pressure after depressurization, psi;
V_f = the volume of one foot of the annulus from Halliburton table 221-B, gals;
h = length of the annulus, ft; and
0.0000032 gal/gal/psi = the compressibility of water.

The result is the number of gallons of liquid which should be returned. It is also the amount of liquid needed to pressurize the annulus to the test pressure once the annulus is filled with liquid. For a small annulus which might be typical of a Class II well (4-1/2 inch, 11.6 lb/ft. casing and 2-3/8 inch tubing, pressurized to 300 psi), just under one half gallon of liquid should be returned for each 1,000 feet of depth to the packer. If several gallons of liquid are returned, it is fairly certain that the entire length of the casing and tubing have been tested.

ATTACHMENT 2
STANDARD ANNULUS MONITORING TEST (SAMT)

1 Basis

The SAMT is essentially a continuing SAPT; however, interpretation is complicated by operational effects, principally: 1) injection tubing expansion or contraction as a result of injection pressure changes and 2) well bore temperature changes associated with a) starting or stopping injection or b) daily and seasonal changes of injectate temperature. To eliminate additional complexities, the regulations now require that the pressure be greater than atmospheric pressure.

This means that the annulus pressure should be raised to some pressure and the annulus should then be sealed. The pressure will change in response to temperature changes or even pressure changes in the injection tubing. Allowing for some seasonal variation, the range of temperature change should be consistent. In the event of a casing leak opposite a permeable zone, the pressure will normally fall, probably to zero and, if not, the range of pressure change will be much diminished because the aquifer with which the leak communicates will buffer volumetric changes in the annulus. In the event of a tubing or packer leak, the annulus pressure will track injection pressure. These two pressures will probably not be equal because of pressure loss due to friction in the injection tubing and density differences.

Region 5 Class I UIC permits require that a positive pressure differential be maintained between the annulus and injection tubing in Class I wells. The purpose of this requirement is to ensure that any leak in the injection tubing will result in an inward leak so that the injectate will not leak into the annulus. This is an important safeguard when the injectate is corrosive or very dangerous. Compliance with this requirement is not equivalent to use of SAMT if the pressure is artificially maintained through the addition of gas to a seal pot.

Unless any leak will result in an unimpeded pressure change, leaks might not be evident. To enhance the value of maintaining a positive pressure differential, Region 5 permits require volume measurement of all liquid additions and subtractions from the annulus systems of Class I wells. The results of these measurements are accumulated and a continuing need to add or remove fluid to maintain a set pressure is evidence of a leak in the well, although not necessarily an absence of MI. When a loss becomes evident, the Director may require a SAPT to confirm MI. If the well demonstrates MI, the Director may allow continued use if the leak does not cause violation of any UIC regulation.

2 Advantages and Disadvantages of the SAMT

Advantages

1. Provides a continuous demonstration of MI
2. Inexpensive for simple annulus systems
3. Easy to interpret for simple annulus systems

Disadvantages

Is difficult or impossible to interpret for wells with annulus pressure maintenance systems

3 Equipment and Forms

In order to make determinations quickly and simply, measurements of both the annulus and injection pressures should be made. Operators of Class I wells must use either an analog chart recorder or electronic equipment recording in a digital format at short intervals. Class II operators must record these pressure measurements at a frequency set by permit conditions. Other arrangements are possible, but must be established as permit conditions.

There is no set form for reporting the results of the SAMT. Each operator using the SAMT proposes a monthly reporting form to the DI Section. To effectively use the SAMT, the form must list not only the annulus pressure as measured at least once in any 24 hour period, but also the injection pressure measured at the same time. In addition, information about the injection rate, the temperature of the injection fluid, and the injection pressure may be useful. Changes in any of these parameters can affect the annulus pressure.

4 Procedure for the SAMT:

For Class I wells and other wells having a sealpot assembly and pressure maintenance the operator must:

1. Establish a positive pressure differential between the annulus and injection tubing sufficient to avoid changes which impinge on the required pressure differential (most Class I permits require at least a 100 psi pressure differential);
2. Isolate the annulus from any source of pressure maintenance;
3. Perform an SAPT, recording pressure at ten-minute intervals. If the pressure change is less than 3% in 30 minutes for Class II and III wells or 3% in 60 minutes for Class I wells, the test is passed and the SAMT begins;
4. Report the results of near-continuous measurements of annulus pressure and injection pressure in tabular and graphical formats along with tabulations of injection rate and pressure and injectate temperature as required by permit; and
5. Report the volume (in gallons) of any liquid added to or removed from the well's annulus system.

For wells not using a sealpot assembly the operator must:

1. Establish a pressure greater than atmospheric on the casing/tubing annulus;
2. Isolate the annulus from any source of pressure maintenance;

3. Perform an SAPT, recording pressure at ten-minute intervals. If the pressure change is less than 3% in 30 minutes for Class II or III wells or 60 minutes for Class I wells, the test is passed and the SAMT begins;
4. Report the results of periodic measurements of annulus and injection pressures and conditions under which pressure measurements are made, e.g. injecting or not injecting, and approximate injectate temperature; and
5. Report the volume (in gallons) of liquid added to or removed from the well's annulus system.

After any well failure, MI must be confirmed using the SAPT before resuming the SAMT.

5 Interpretation

The standard used for evaluating SAMT demonstrations is the same as that used for the SAPT, i.e., 3% pressure loss in either 30 or 60 minutes. However, it is only possible to apply this standard when external factors which might affect the annulus pressure are stable and a change in annulus pressure is established. Otherwise, liquid property changes occurring in response to change in ambient conditions make determination of a leak-induced pressure change impossible.

To provide an effective, real-time demonstration of MI, frequent inspection of pressure records is needed. This review should focus on the pressure in the annulus relative to: 1) atmospheric pressure, 2) the injection pressure measured at the surface, and 3) pressure in aquifers along the well bore. The following occurrences may indicate a loss of MI:

5.1 For wells with injection pressure greater than the annulus pressure

1. Annulus pressure increases and tracks injection pressure - probable tubing or packer leak;
2. Annulus pressure decreases:
    a. and goes to near zero - probable casing leak;
    b. stabilizes and returns to normal behavior - possible packer slip;
3. Annulus pressure is very stable regardless of injection - probable deep casing leak in well with light annulus liquid;
4. Annulus pressure fluctuates - probable temperature effects due to operational effects of injectate temperature changes;

5.2 For wells with injection pressure greater than zero but less than annulus pressure

1. Annulus pressure increases - if the well is deep, penetrates high pressure zones, and the annulus liquid is light it may indicate a deep casing leak, possibly due to an increase in injectate temperature;
2. Annulus pressure decreases:
    a. to near zero and/or becomes very stable - probable deep casing leak in well with lighter annulus liquid;
    b. and tracks injection pressure - probable tubing leak;
    c. stabilizes, and resumes normal behavior - could be a decrease in average injectate temperature or packer slip;
3. Annulus pressure fluctuates - probable temperature effects due to operational effects of injectate temperature changes;

5.3 <u>For wells which inject on a vacuum</u>

1. Annulus pressure decreases - could be either a casing, tubing, or packer leak;
2. Annulus pressure increases: and
    a. stabilizes - if the well is deep, penetrates high pressure zones, and the annulus liquid is light it may indicate a deep casing leak;
    b. begins to behave normally at a higher pressure - possibly due to an increase in injectate temperature.

In the event that a loss of MI is suspected an SAPT should be performed to ensure that the well has MI. If the SAPT confirms MI, then the operator may resume the use of the SAMT.

ATTACHMENT 3
RADIOACTIVE TRACER SURVEY (RTS)
FOR DEMONSTRATION OF 146.8(a)(1)

1 Basis

During injection, radioactive (RA) tracers can be added to injected liquids at a point above the interval to be checked for leaks. The RA material will mix with a portion of the injectate so that a slug of RA injectate passes through the section of the well to be tested. Any leak of the mixed injectate will be marked with some RA tracer. The leaked tracer material may be traced using a detector device on a wire line. The movement of the leaked tracer material is unlikely to keep pace with the movement of the slug of marked injectate which continues down the well and will be identifiable.

When tracer material is observed to split, the movement of the portion which appears to have separated should be carefully traced. The most accurate way to do this is by positioning the detector ahead of the moving tracer and observing its passage. When the tracer fails to arrive at the detector, the upper limit of movement is fixed. This method is superior to chasing the slug because it appears to be more sensitive and the record does not distort the shape of the slug as a result of tool movement. However, great care is needed to identify small increases in gamma ray activity.

2 Advantages and Disadvantages of the Radioactive Tracer Survey

<u>Advantage</u>
Locates the depth of the leak within the well bore

<u>Disadvantages</u>
1. Expensive relative to SAPT
2. Approved testing methods always require injection. Velocity shots used for the location of very small leaks may be used without injection, but require long periods of investigation

3 Equipment and Reporting Forms

The equipment required is readily available. In the past, almost any company engaged in geophysical logging was able to conduct RA tracer surveys. Some companies have discontinued the service due to restrictions imposed on the handling of RA material. The equipment consists of a sonde (tool) which is lowered into the well on a cable which allows transmission of data from the tool to receivers in a winch/instrument truck on the surface. The tool consists of an injector stage, one or more gamma radiation detector devices, and a collar locator.

The relative positions of the injector and detectors are variable. If only one detector is used, it must be located below the ejector. If more than one is used, it is common and advantageous for one detector to be located above the ejector. Three detectors are sometimes used with two being below the detector. This allows very accurate measurement of the speed of the injectate to be made. It also simplifies the location of the upward limit of leaking by eliminating some repositioning of the tool.

The purpose of the collar locator is to pinpoint the location of leaks in reference to permanent markers. This may also be done by means of correlation to a gamma ray trace which is scaled to show lithologic effects. Using a collar locator immediately lets the analyst know whether an identified leak is at a collar, while using a gamma ray correlation log clarifies the stratigraphic location of the leak.

The RA tracer is usually Iodine 131, because of its short (eight day) half life. Other tracers may be used for special applications. In any case, the tracer material used must be anionic to minimize its molecular attraction to well and rock materials.

In addition to the log of the test as presented bythe service company which performed the test, the digital data from which the log was produced must also be submitted. Information which is helpful to interpretation should be reocrded on the log form, including: 1) a schematic drawing or description of the configuration of the tool, 2) the injection rate, 3) the time at the beginning and end of each logging run, and 4) the time at which any peak is recorded. It is also helpful to use time markers on the logs to accurately fix the times at which changes in radioactivity are recorded.

We request that logging engineers review the information sheet which will be returned to permittees along with approval of procedures so that they will provide the informatiion needed to fully interpret the logs. The information sheets need not be filled out and returned.

Further testing may be necessary if possible migration out of an authorized injection interval is noted. This may include a series of time drives and slug chases to determine the extent of the leak or channel.

4 Procedures for Running the Radioactive Tracer Survey (RTS) as a Demonstration of Part 1 of MI

The demonstration can be effective for locating leaks in both the tubing and the casing. However, the RTS is useful for demonstrating an absence of leaks only in tubing strings through which the tracer material may flow. A demonstration that there are no leaks in the tubing requires that steps 1 through 8 listed below be followed. To test the casing, the tubing may be removed and the same steps followed, or the packer may be unseated and the method used to check cement integrity, described in Attachment 10, may be followed.

Testing is always conducted while injecting, and the operator should ensure that adequate water can be supplied for the test. The injection rate may be governed by the ability of the winch operator to track the RA slug as it moves downward. However, the injection rate should be as close to the maximum injection rate as practical. The following practices usually result in interpretable results:

1. Ensure that there is a significant pressure differential across the tubing wall to be tested. If the tubing is to be tested, special permission may be needed to perform the test with excess pressure in the tubing, because permits may require a positive pressure differential within the annulus. Although introduction of tracer material into the annulus can allow testing while maintaining a positive pressure differential, testing within the range of USDWs defeats the purpose of the positive pressure differential, because a casing leak would allow a release of radioactive material into an USDW. Further, practical difficulties make testing with the tracer in the annulus a complex operation;
2. Set the gamma ray (GR) detector sensitivity so that lithologic effects are just identifiable, usually 25 to 50 counts per second per inch. This ensures maximum sensitivity to leaked RA material. Noisy logs are much more difficult to interpret;
3. Make a background GR log over the interval to be tested before any RA material is introduced into the well;
4. Record measurements over a period of three to five minutes with the tool stationary at two points which are representative of the extremes of natural radiation within the interval to be tested. This will allow the interpreter to observe the effects of natural variations of GR emission on the record;
5. Release a slug of RA material above the interval to be tested. The greater the intensity of radioactivity of the slug the more resolution the method will have. Deflections caused by the slug should be 50 times greater than those caused by lithologic effects;
6. Follow the slug with the logging tool or make repeated passes upward through the slug as it moves down the well. Any increase in radioactivity which remains behind the slug should be investigated by supplementary passes through the interval as needed to determine whether

it is a result of material adhering to the tubing or of a leak. All logging should be done at a single logging speed which is appropriate for the injection rate to allow quantitative measurements of deflections to be evaluated

7. If repeated passes are used, the logs resulting from the slug-tracking exercise should overlap so that the return of radioactivity to the level which existed before the slug's passing is demonstrated for the entire length of the section of the well being tested. The logs of all passes should be presented as a composite log on a common depth track. If means to differentiate the log traces are available no other presentation is required. If the traces cannot be differentiated on the composite log, they should also be presented individually;
8. After any ejection, the slug should be followed until it has moved below the interval being tested. If the slug splits, both slug portions must be accounted for. This can be accomplished by concentrating first on the upward moving portion, and resuming tracking of the downward moving slug after the upward moving slug is tracked to its final destination; and
9. After completion of the passes, a final log should be made through the entire tested interval to check for residual radioactivity which might be associated with exit of tracer material from the well bore.

If the tubing has been removed from the well and the casing is being tested, leaked RA material will exit the well bore into a porous, permeable zone or fracture or move along the well bore to a porous, permeable zone or fracture. The movement of the tracer should be followed and the depth at which it exits the well bore recorded.

Leaks in the casing can be located with the tubing in the well by monitoring for upward movement at the base of the tubing with the packer released, as described in Attachment 8. Except in the unlikely case that the pressure in the aquifer with which a leak allows communication is higher than the injection pressure at the same depth less the friction loss from the leak to the end of the tubing, an absence of upward movement when the top of the annulus is sealed, means that there is no leak in the casing. However extreme care must be taken to ensure that upward movement will be identified. A release of a longer- period slug may increase the strength of the upward moving slug. Any upward movement of RA tracer will continue until the tracer reaches the leak and exits the well bore.

If the operator wishes, the portions of the injection interval which accept waste may be determined by making more frequent passes while the slug is within the injection interval. The sensitivity may be reset so that the log trace remains on scale.

5 Interpretation

1. Where a measurable amount of RA tracer material leaks from the tubing, it will be observed as a small area of increased radioactivity after the slug has passed;
2. If an area of elevated radioactivity is observed, additional runs should clarify what becomes of the RA material responsible. This will demonstrate whether only the tubing is leaking, or both the tubing and casing lack integrity. In most cases, if a well's casing has integrity but a tubing leak exists, pressure equalization and cessation of leaking will occur until a change in injection pressure allows the leak to resume. This is why it is important to ensure a pressure differential between the injection tubing and annulus.

   If annulus pressure is lower than injection pressure and both the tubing and casing are leaking, any tracer material that leaks out of the tubing will generally move toward and out through the casing leak. This is because the annulus pressure normally will be higher than the hydrostatic pressures within adjacent formations at all depths.

   If only the tubing is leaking, the tracer material will remain near the leak, spreading slowly both up and down from the leak location.

   Adherence of tracer material to the tubing can be differentiated from a tubing leak because any material adhering to the tubing will eventually be washed away with no movement evident.

If no evidence of leaking is observed, the well has demonstrated part 1 of MI. Be aware that demonstrations of MI using the RTS will be examined very closely, and any conditions which threaten the ability to interpret them accurately must be removed.

ATTACHMENT 4
WATER-BRINE INTERFACE TEST (W-BIT)

1 Basis

The water-brine interface test is based on:

1. The differences in liquid pressure gradients of the brine filling salt solution mining caverns and fresh water;
2. Pressurization of the cavern resulting from salt-solution mining; and
3. Pascal's Law, the transmission of pressure throughout a closed vessel.

The strategy governing the test is that a decrease in wellhead pressure will be observed in the event of loss of a fluid of lower density filling a standpipe open to a reservoir filled with a fluid of higher density. In practice, this situation is produced by:

1. Flushing the well to be tested with sufficient fresh water to dissolve any salt precipitated on the interior of the casing;
2. Withdrawing water until cavern brine is brought to the surface; and
3. Depressing the cavern brine to the base of the well casing by the injection of a volume of fresh water sufficient to fill the casing to within 25 feet of the casing shoe.

Because the cavern is pressurized sufficiently to cause the heavy brine to flow to the surface, the pressure within the well filled with fresh water is greater than the hydrostatic pressures in any aquifer through which the well passes. Therefore, any leak will allow fresh water to flow outward, to be replaced by dense brine flowing into the well from the cavern. Because the liquid pressure gradient of the brine from the cavern which replaces the leaked fresh water is greater than that of the freshwater, less pressure is transmitted from the cavern upward through the well to the well head.

It has been found that pressure within the cavern is not constant. To avoid the possibility that this variation might mask any change due to leakage, a reference well is used. This well, which is often the tubing within the well being tested, is filled with a static fluid column. If there is a leak in either the tubing or the casing, fresh water will be lost from the annulus. While the rate of leakage into the tubing is likely to be less than would be leakage from the casing, due to a lower pressure differential, particularly if the leak is near the base of the casing, the resultant emplacement of fresh water into the tubing will increase the wellhead pressure so that the effect is doubled.

The loss of one foot of annulus liquid during the W-BIT will cause a wellhead pressure reduction of approximately 0.11 psi:

$dP = dL \times (0.433 \text{ psi/ft.} - SG_c \times 0.433)$

$-0.11 \text{ psi} = 1 \text{ ft.} \times (0.433 \text{ psi/ft.} - 1.25 \times 0.433 \text{ psi/ft.})$,

where:
dP = pressure change resulting from fluid loss,
0.433 psi/ft. = pressure gradient of fresh water (SG = 1.0),
and
SG_c = specific gravity of cavern fluid = 1.25,

while the loss of one foot of pressurized annulus liquid from an annulus 1,000 feet in length will cause a loss of 312.5 psi:

dP = dV/V/0.0000032 ft./ft./psi

-312.5 psi = -1 ft./1000 ft./0.0000032 ft./ft/psi.

where:
dP = pressure change,
dV = volume leaked = -1 ft.,
V = annulus volume = 1000 ft., and
0.0000032 ft./ft./psi = the compressibility of water.

The test must be run for a longer period than the SAPT and measurements must be much more accurate to compensate for the lesser pressure change associated with leaked volume.

2 Advantages and Disadvantages

Advantages

1. Does not require removal of tubing and installation of a packer for wells used for injection and withdrawal of liquids;
2. Inexpensive for simple annulus systems.

Disadvantages

1. The W-BIT is approved only for Class III wells which cannot be tested by means of the SAPT
2. Requires use of a deadweight pressure gauge, which may be expensive to acquire;
3. Requires a 36-hour interval between initial and final pressure measurements.

3 Equipment and Forms

A dead weight pressure gauges and an operator trained in its use are needed. A convenient worksheet has been developed by members of the Salt Institute.

4 Procedures

The UIC Branch has not identified any common errors in conducting the W-BIT, and we believe that no additional guidance is needed beyond that provided in the Federal Register notices announcing its approval. A schematic drawing of the well construction must be submitted with a description of the proposed test procedures.

5 Interpretation

The calculations which are part of the test result in the calculation of a rate of pressure change. If this pressure change is less than 0.05 psi/hr., then the test demonstrates the MI of the tested well. If the rate of change is more than the standard, the well lacks MI.

ATTACHMENT 5
TEMPERATURE LOG (TL)

1 Basis

In almost every case, an aquifer into which water has flowed in the recent past is heated or cooled because the earth's temperature increases steadily with depth. This makes it unlikely that the water moving into a reservoir is the same temperature as that which is displaced. Given sensors of sufficient sensitivity, the change in temperature is identifiable. In addition, the zone from which the water came is likely to be identifiable if flow is continuing. Temperature logs can also confirm that there is no flow of injectate through the rock surrounding the well bore and often will identify small casing leaks.

During injection the ability of the injectate flowing through the well to maintain its own temperature dominates all other effects so that, for the purpose of establishing MI, the well must be shut in during temperature logging. The principal requirement for running temperature logs is that the well be shut in long enough so that temperature effects related to well construction can dissipate, leaving a relatively simple temperature profile. Experience has shown that 36 hours is usually sufficient in Region 5.

In new wells, baseline temperature logs should be made as long as possible after drilling the well, but before injection begins, because temperature effects due to circulation of drilling fluid will persist for several weeks after drilling is completed and infiltration of drilling fluids causes temperature anomalies which may persist for several months. A;though these anomalies can makr permeable zones, the existence of a temperature log which reflects the natural geothermal gradient can be of great value in assisting later analyses and for understanding other geophysical effects.

2 Advantages and Disadvantages of Temperature Logging

<u>Advantages:</u>

1. Continuous log with high vertical resolution
2. The most sensitive indicator of part 2 of MI
3. In addition to fluid movement within the well bore, fluid migration through the confining layers may be identified
4. Water-filled porosity can be determined if sufficient information is available
5. Injection pressure need not be maintained to ensure identification of well bore flow near the injection interval
6. Flow need not be occurring at the time of logging for its effects to be identifiable
7. Low cost per single survey covering entire well bore

<u>Disadvantages:</u>

1. Gas entry may be marked by cooling, but movement and exit may be obscure
2. Interpretation for complete understanding requires a greater degree of expertise than other logging methods
3. Fluid-filled well bore through interval to be tested may be required
4. Well must be shut in long enough to remove most construction and near-well bore effects

3 Equipment and Reporting Forms

The temperature logging tool is a wireline sonde operated from a winch truck. Temperature logging tools contain circuitry which responds to temperature change by changing resistance to current flow. The response is linear and temperature logs can distinguish very small changes in temperatures. Calibration of logging tools is often poor because the effects they are normally expected to measure have importance as relative rather than absolute values, although correct absolute temperatures also have value for other purposes. To be effective, temperature logging tools must have good thermal coupling to the borehole environment, which means that they are not generally useful in air-filled holes. Sampling is done at short intervals as the sonde is lowered into the well, so that a record of the entire well bore is produced. Because the tool does not react to temperature change instantaneously and the tool is continuously moving, the measured temperature changes lag actual wellbore temperature changes by a consistent amount. The more slowly the tool moves, the closer are the measured temperatures to actual temperatures. If the tool speed is erratic, the recorded temperature profile will also be irregular. Despite the possible inaccuracies due to poor calibration and tool response time, the absolute values recorded can generally be compared with some confidence.

A reporting form has been developed to accompany the log to assure that other information useful for interpretation is submitted. Alternatively, all the information requested on the reporting form can be placed on the log. This includes: average and amximum logging speed, time since the last injection, temperature of the liquid most recently injected (average temperatures for the most recent year, month, and day) and calibration information. If there are frequent changes in the temperature of the injectate or if process changes have caused a significant change in the temperature of the injectate, it is very important to record the average temperatures of the injectate before existing logs were made and the date of the change in injectate temperature and the volume of liquid injected before and since that time. In the case of Class III wells, it is important to note whether the well was last used for injection or production.

The scaling of logs is a matter of importance. Features of significance are emphasized by compressing the depth scale and expanding the temperature scale. A depth scale of one or two inches per 100 feet, and a temperature scale of one inch to two degrees Fahrenheit are appropriate in almost every case.

If multiple logs are run while shut in, they should be displayed on the same axes (depth scale) for comparison. To avoid confusion, it may be necessary to reduce the temperature scale, but reducing it to less than four degrees per inch should be done only when necessary to avoid superimposing logging traces which cannot then be followed.

Gamma ray logs must be run simultaneously with the temperature log. Gamma ray logs provide depth control and important information about the rock types along the well bore. The digital logging data must also be submitted. We request submission of data collected at intervals of one foot. More frequent readings increase the volume of data, but increased resolution serves no purpose.

4 Procedures for Running the Temperature Log

The following steps should be followed for effective temperature logging:

1. Shut well in for sufficient time for temperature effects resulting from well construction features to dissipate. This typically requires at least 36 hours in Region 5. If 36 hours prior to logging are not available, proof that sufficient time has elapsed can be demonstrated by comparison with another log of a well at the same site. The second log may have been made previously or a second log may be made six hours after the first;
2. Calibrate the log if at all possible. This can be done by comparing measurements made using the tool in any two liquids to the known temperatures of those liquids. For instance, both a thermometer and the thermistor to be used for the logging may be used to measure the temperature of water at ambient conditions and a bucket of ice water. Even a single measurement made in a well-mixed bucket of ice water may be very helpful;
3. Log the well from the surface downward, lowering the tool at a rate of no more than 30 feet per minute. The 30 feet per minute limitation is a practical balance between the tool response time and normal time constraints, slower speeds provide increasing detail. Time coding of the log, either a tick or gap in the log grid at one minute intervals or a logging-speed trace, should be used to confirm the tool speed;
4. If the well has not been shut in for at least 36 hours before the log is run, comparison with either a second log run six hours before the time the log of record is started or a log from another well at the same site showing no anomalies should be available to demonstrate normal patterns of temperature change.

5. The log data on a disc in either LAS or ASCII format is needed for ease of interpretation. A gamma ray log, made at the time of logging, or from a previous logging, and correlated to the temperature data is needed for accurate interpretation.

5 Interpretation

Confirm the validity of the log at the well site by comparing two logs made at the same site. When lithology and injectate characteristics are similar, then thermal effects along the well bore should also be very similar. After the temperature effects caused by casing joints, packers, well diameter, casing string differences, and cement have dissipated, the temperature profiles should be similar, although not identical. If construction features are evident, a longer shut-in period is probably needed.

Identification of flow is based on relative differences between logs of nearby wells if such logs exist. Although the gradients may be quite different as a result of differing injection history, their relative positions should be obviously consistent. Lithologic effects which show up on one log should show up similarly in other wells at the same site. Failure of logs made at the same site under conditions which should result in thermal stability to compare coherently constitutes an anomaly.

If there are no logs suitable for comparison, then deviations from a predictable geothermal gradient, modified by the effects of injection, are anomalies. These may take the form of a nearly constant temperature between reservoir strata. When more than one log is run, these anomalies are likely to grow (be left behind) as the profile returns toward the natural geothermal while relative differences between the traces elsewhere decrease. In addition areas with active flow will reach a stable temperature more quickly than other areas. If the movement is not related to injection, this temperature should be that of the natural geothermal gradient at the depth of the source reservoir.

If there are anomalies, a failure of MI may be indicated. In such a case, an additional new log may be necessary to show whether forms apparent on the log just made are evolving toward the forms established on the log from another well. Comparison of these two new logs should show increasing parallelism along the cased well bore, if not, then there may be flow along a channel adjacent to the well bore. If this flow results in the movement of liquid into or between USDWs, then the well does not have part 2 of MI. If the well is used to inject hazardous wastes and flow results in movement of fluid from the injection zone into the confining zone, then a release from the solid waste management unit is indicated. In the event that there are unresolved anomalies which might indicate an absence of part 2 of MI, another approved method must be used to confirm the absence of flow into or between USDWs.

Depending on the nature of the liquid movement, radioactive tracer, noise, oxygen activation, or other logs approved by the Region may be used to further define the nature of the fluid movement.

Identification of flow behind the casing is always made from long-term shut-in logs. The resolution of long-term shut-in logs for identifying the presence of flow is greater than that of logs made during injection. The temperature gradient within a well which has been injecting for some time is very shallow. The temperature at the injection zone may be only a few degrees different from that at the surface. The presence of a flow behind the casing will result in a fractional change in this gradient which will be proportional to the ratio of the flow rates within and outside the tubing. Therefore, only a rather substantial flow can be identified using logs made during injection.

ATTACHMENT 6
NOISE LOG (NL)

1 Basis

Channels along well bores are very rarely uniform. When flow is occurring, irregularities in channel cross section usually result in generation of some turbulence which occurs in audible ranges. Sonic energy travels for considerable distances through solids, allowing sensitive microphones to detect the effects of turbulent fluid flow at considerable distances. Different types of turbulence result in sounds having different frequencies. Single phase turbulence results in low frequency sounds, while two phase turbulence usually results in high frequency sounds. High pass filters are used to determine the intensity of detected noise within various frequency ranges.

2 Advantages and Disadvantages of Noise Logs

Advantages:

1. Relative to oxygen activation log, it is practical to increase vertical resolution by increasing spacing density
2. Can identify flow of gas and differentiate it from liquid flow
3. Relative to temperature logs, cannot be used to demonstrate confinement

Disadvantages:

1. Can identify only turbulent flow
2. Relative to temperature logs, cannot be used to demonstrate confinement
3. Requires liquid in well bore through the interval to be tested
4. Injection pressure must be maintained to ensure identification of fluid flow near the injection zone
5. Actual logging time and cost are usually greater than for temperature logging

3 Equipment and Forms

Noise logging tools are wireline tools which are essentially sensitive microphones. Sampling is done in a stationary mode and the time required at each station is approximately 3-4 minutes. Any sounds detected are transmitted to recorders which measure the amount (loudness) of sonic energy received over a period of time. A cumulative measure of the sound energy which has been received is recorded.

Sonic energy travels considerable distances through solids so sampling can be done in a reconnaissance mode, with additional stations run where increases in energy are detected so that exact locations of conditions which cause sonic events can be found. Sonic logs are similar to temperature logs in that they are much more effective in liquid-filled holes because of improved coupling.

The log is the only form which must be submitted. When the level of sound is low, a linear scale is used, and when there are intervals with higher sound, a logarithmic form is used. Either is acceptable. The vertical scale should be small, one or two inches per 100 feet. In addition to the graphical log, a tabulation of sound energy is normally included on the log form and it should also be submitted.

4 Procedure for Producing the Noise Log:

Noise logging may be carried out while injection is occurring in many wells because flow restriction caused by the logging tool is often insufficient to cause turbulence. It is especially desirable to log while injecting when looking for flow resulting from pressure increase near the top of the injection zone. If ambient noise while injecting is greater than 10 mv, injection should be halted. Logging procedures should include the following steps:

1. Make noise measurements at intervals of 100 feet to create a log on a coarse grid;

2. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels;
3. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing: 1) the base of the lowermost bleed-off zone above the injectioninterval, 2) the base of the lowermost USDW, and 3) in the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval;
4. Additional measurements may be made to pinpoint depths at which noise is produced; and
5. Use a vertical scale of 1 or 2 inches per 100 feet.

5 Interpretation

The interpretation of noise logs for the purpose of demonstrating part 2 of MI is quite straightforward. The following steps are used:

1. Determine the base noise level in the well (dead well level);
2. Identify departures from this level. An increase in noise near the surface due to equipment operating at the surface is to be expected in many situations;
3. Attempt to determine the extent of any movement, this may be difficult when there are few flow constrictions;
4. If flow is into or between USDWs, a lack of mechanical integrity is indicated. If flow is from the injection zone of a hazardous-waste disposal well into or above the confining zone, failure of containment is indicated.

If the log measurements are ambiguous, the determination should be confirmed using another method.

ATTACHMENT 7
OXYGEN ACTIVATION METHOD

1 Basis

The oxygen activation method is based on the ability of the tool to convert oxygen into Nitrogen 16 (N16) within a short distance of the tool. This is accomplished by emitting high energy neutrons from the tool's neutron source. N16 is an unstable isotope of nitrogen which is referred to as activated oxygen. The half life of activated oxygen is just 7.13 seconds, and the release of gamma rays as the activated oxygen decays into oxygen can be measured. If the tool is stationary and oxygen is activated, detectors placed near the activator device will detect increased gamma radiation. The intensity of the additional radiation will be inversely proportional to the square of the distance of the activated oxygen from the detector. Much of the oxygen near the tool occurs in water. If water containing activated oxygen moves, the measured intensity of radiation will be greater if the slug of activated oxygen moves closer to the detector, and less if it moves away. By comparison of intensity of gamma radiation measured as a result of activation at two detectors, the direction and velocity of water movement can be determined. Studies under controlled conditions have shown that water velocities between two and 120 feet per minute can be measured.

2 Advantages and Disadvantages

<u>Advantages:</u>

1. Interpretation is a simple comparison of a calculated velocity to a minimum velocity which the tool is able to identify reliably
2. Relative to temperature logs, little or no shut-in time is required
3. Does not require a liquid-filled well bore
4. Numerical result eliminates the need for qualitative interpretation

<u>Disadvantages:</u>

1. Can identify flow in a broad, but fixed, velocity range
2. Has a very small range of investigation, smaller than very large well bores

3. Cannot be used to demonstrate the absence of liquid movement through confining layers
4. It is not practical to increase vertical resolution by increasing spacing density
5. Calibration errors may affect tool accuracy, perhaps accounting for false positive indications
6. History includes false positives and missed MIT failures confirmed by one or more other tools
7. Injection pressure must be maintained to ensure identification of fluid flow near the injection zone
8. Actual logging time and cost are usually greater than for other logs

3 Equipment and Forms

The equipment consists of a wireline sonde containing a high- energy neutron generator and gamma ray detectors. By spacing several detectors at increasing distances from the oxygen activation area interpretational accuracy is increased. Although the oxygen which is activated may be present in water which may be moving along the well bore, oxygen is also present in rock and cement. Some of this oxygen is also activated, and its decay products become background radiation which must be accounted for in order to reach a valid measurement of the movement of activated atoms in the fluid passing along the well bore.

The need to account for oxygen which is not in flowing water can be addressed in either of two ways: 1) by making calibration measurements in a representative area of the well bore in which there is thought to be no flow behind the casing, or 2) by extending the measurement period at each station beyond the time during which the activated oxygen in flowing water has been carried away. The rate of decay indicated by the late measurements is used to calculate the theoretical levels of gamma radiation which would have been measured if there were no water movement. The difference between the calculated and measured values is assumed to be the effect of the decay of activated oxygen carried to the vicinity of the detectors as part of moving water.

The first method is used by Western Atlas and the second by Schlumberger. These are the only companies which provide oxygen activation logging service in Region 5.

4 Procedures for Running the Oxygen Activation Log (OAL):

All measurements should be taken for periods of at least five minutes with the well injecting at the maximum normal rate. A total of at least 15 minutes measurement time is required at each station. This total time may be accumulated in one, two, or three episodes. If open-hole caliper logs are available, care should be taken to obtain all readings at depths where the well bore is in gauge. The method for obtaining measurements shall conform to optimum procedures contained in the operator's manual for the tool being used. The following steps are recommended for demonstrating part 2 of MI using the OAL:

1. Secure a log for lithology determination. If no such log is available, run a gamma ray-neutron log to identify porous intervals;
2. If required for tool calibration, background checks will be run with no injection occurring in an interval where no flow is thought to occur. Background calibration should be run for each interval of varying well construction;
3. Take measurements at stations at least 10 feet above the open injection interval;
4. Take measurements at the top of the confining zone and at two or three formation changes between the confining zone and the base of the USDW;
5. Take measurements within 50 feet below the base of each USDW, within 50 feet of the top of the first underlying aquifer, and at least one measurement between these two points;
6. If anomalies are found, additional readings, including readings made while the well is injecting if the original measurements were made while not injecting, or not injecting if the original measurements were made while injecting, should be made above and below the depth of the anomaly to confirm the anomalous reading and discover the extent of fluid movement; and
7. If flow is indicated, another log may be used to confirm the measurement and define the extent of flow. The choice for the confirmation log should be based on all wellbore and

environmental factors, and the tool choice must be approved by Region 5 prior to commencing testing operations.

5 Interpretation

A ratio of the short-spaced flow indicator result to standard deviation of 3-4:1 indicates flow. Indicated water-flow velocities should be in excess of two feet per minute, lower values should be viewed with skepticism. Velocities near and above two feet per minute have been measured at several depths at several sites in Region 5 and other logs did not indicate flow. In some cases the occurrences were repeatable, at least during the period of one logging episode. Although the cause of the false measurements is not known, it is assumed that the logging tool was not properly calibrated for the interval being tested.

To minimize false positives, it is recommended that all measurements be confirmed at several nearby depths and/or measurements be taken under a minimum of 3 varying injection rates, i.e.: 75%, 50%, and 25% of maximum permitted injection rates. Before costly measures are taken to remedy problems, their existence should be confirmed using another approved log.

ATTACHMENT 8
RADIOACTIVE TRACER SURVEYS
FOR DEMONSTRATING PART 2 OF MI

1 Basis

Acceptance of the test as a means for demonstrating part 2 of MI is limited to those wells where there is no aquifer between the injection zone and the base of the lowermost USDW and where there is no significant water quality difference between individual USDWs.

The basis of the test is that flow will follow the well bore upward if the cement seal is poor at and above the base of the casing for open-hole completions or above the uppermost perforation for perforated completions. If the cement at the top of the injection interval is sound and there is no movement upward along the casing at that point, it is assumed that there is no alternate conduit which might allow injected liquids to reach the well bore at a shallower depth and then travel upward through either an uncemented or ineffectively cemented well bore. The analyst is primarily concerned with identifying the uppermost depth at which tracer material can be seen to be moving within and then exiting the well bore.

2 Advantages and Disadvantages

Advantages:

1. Can be run with the well injecting

Disadvantages:

1. Only valid for part 2 when there are no aquifers between the base of the casing and the base of the lowermost USDW and no significant differences between quality of the USDWs
2. Cannot be used to determine interformational flow where the tracer material cannot be introduced into the flow stream outside the casing

3 Equipment and Forms

These are identical to those described for the RTS in Attachment 3.

4 Procedures for Running the Radioactive Tracer Survey (RTS)as a Demonstration of Part 2 of MI

The demonstration of mechanical integrity requires that the packer be seated or the tubing be removed from the well.

Three different test methods are usually employed at each instance of testing: 1) slug tracking, 2) stationary testing, and 3) comparison of logs run before and after the other testing methods are used. Either slug tracking or the stationary tests are adequate tests, but the comparison of logs run before and after the injection is only supplementary, and its use is in identifying the intervals along the well bore where RA material has adhered to the walls as it exited the well bore.

4.1 Recommended procedures for the use of the slug tracking method are:

1. Inject at the maximum rate used for injection unless it is impossible for the tool can be effectively used at that rate. Otherwise inject at the maximum rate at which the winch operator can track the slug;
2. Release a slug of RA tracer far enough above the base of the casing or perforations to allow it to be logged within the casing at least once;
3. Drop the tool down through the slug and then log upward through the slug;
4. Drop the tool down to within 20 feet below the top of the perforations or base of the casing (or tubing tailpipe, if that is lower). Hold the tool at that point until the slug reaches it. As soon as the slug is detected, begin to log upward so that the logging tool passes the top of perforations or the base of the deeper of the casing or tubing just after the slug has passed the same point. This helps to ensure that any upward movement is detected;
5. Drop the tool below the slug, but no more than 50 feet below the perforations/casing/tubing if a split was observed during the previous logging run, and again log upward;
6. Continue making passes to show the upward movement of the slug as long as it is measurable;
7. The procedure (Steps 1 though 6) should be repeated until the highest point to which injectate moved upward is identifiable; and
8. If any slugs are seen to split, the tracer material remaining after all of the planned testing is done should be ejected just above the casing shoe and the resulting slug followed upward as far as possible.

4.2 Recommended procedures for the use of the stationary method are:

1. Injection should be at the maximum rate used to inject waste. The slug of RA material should be ejected some distance above the depth at which the stationary test will be made in order to eliminate electrical effects associated with the ejection which sometimes mask or distort the detection of the downward moving slug. The greater deflection caused by the slug, the better. However, the length of the ejection should not be over a few seconds to avoid producing a long slug.
2. With at least two detectors, one above and one below the ejector, recording in time drive, position the logging tool with the lower detector four feet above the top of the perforations or the deeper of the base of the casing or tubing. When used with slug tracking, position the upper detector about two feet above the highest point reached by the tracked slug;

   The use of at least two detectors has two important advantages: 1) it allows the test to be, in effect, run at two or more depths and may cut the time required to run a test which completely defines the upward distance a slug travels and, more importantly, 2) confirms the direction of travel of any RA material observed after the slug is ejected. Often ejectors leak a small amount of tracer. The direction of movement of extraneous slugs passing by a single detector cannot be determined and may confuse interpretation.

   The scaling should allow the easy calculation of time period and deflections should not be smeared out over so much paper that they are difficult to identify. The time scale should not be compressed so much that determining the time, to at least the minute, at which the increase in radioactivity begins is questionable;
3. The tool is run in time drive for a period sufficient to allow the RA material to reach the perforations, casing shoe, or end of the tailpipe and travel upward to the detectors assuming upward movement at a rate of no more than two feet per minute;

4. If upward moving RA material is detected, following the detection of the slug at the top detector, move the tool upward a short distance and again record in time drive until the RA material is detected. Record the times at which the RA material reaches the detectors to help evaluate how far the detectors should be moved;
5. Continue to monitor the upward movement of the slug until the limit of upward movement is reached. The limit can be considered to be the elevation of a detector which did not record passage of the slug after allowing travel time of two minutes per foot from the point of last detection.

4.3 Recommendations for producing the logs before and after testing are:

1. The log should cover the interval between at least 100 feet below the bottom of the deeper of the casing or tailpipe depth and 200 feet above the shallower of the casing or tailpipe depth.
2. A gamma ray log should be on hand to ensure that the new log reflects background conditions. Occasionally tool leaks cause anomalous results which can be avoided simply by repeating the logging.
3. A presentation including both logs on the same depth scale is helpful. The traces must be coded so as to be clearly identifiable.
4. The log data on disk should be submitted. Having these data allow us to plot various combinations of logging runs at scales which show us what we think we need to see.

5 Interpretation

Each of the three testing methods is interpreted individually.

5.1 The slug tracking records are evaluated by:

1. Reviewing the statistical check performed before testing began to check the sensitivity of the log display, check to be sure the scaling used for the logging is the same as was used for the statistical check;
2. Checking the deflection caused by the slug within the tubing or casing. It should be at least 50 times greater than that caused by lithological background;
3. Checking to see if a slug split occurred at the base of the tubing or casing. Identify any increases of radioactivity along the well bore above the base of the tubing or casing;
4. Evaluating the slug split for upward movement. Turbulence at the base of the tubing often causes some tracer to remain. If only a slow dissipation of the resulting hot spot, with no upward movement, is observed, the split has no significance;
5. If the tubing extends below the casing, upward movement to the base of the casing commonly occurs, this also has no environmental significance;
6. If movement above the base of the casing occurs, its extent must be very carefully determined and recorded. It is not uncommon or of concern if there is some limited movement, particularly where the base of the casing is within a porous, permeable interval. The extent of upward movement should be compared with previous measurements to confirm that the cement seal is not deteriorating.

5.2 The stationary tests are evaluated by:

1. Checking the strength of the slug, often the detector cannot react quickly enough to measure the entire distance of the deflection. The deflection should appear sharp if the total deflection is not measured;
2. Checking the record from the lower detector to see if any increase occurred after the initial passage of the slug;
3. If a second increase in radiation was detected, check the record from the upper detector (above the ejector) to check whether an increase occurred at that detector before the detection of the slug by the lower detector, if so, the detection may be due to an extraneous slug, previously ejected, moving downward past the tool;
4. If no increase in radiation is detected by the upper detector, then the tracer exited the well bore between the lower detector and the upper detector. The maximum upward movement identified through this test is the elevation of the upper detector;
5. If an increase in gamma ray radiation is detected by the upper detector after the detection by the lower detector, the tool should have been moved upward so that the slug had the

opportunity to pass both of the detectors again. If so, repeat steps 2, 3, and 4 until the maximum upward extent of movement of the tracer is established. This depth should be recorded and compared with that for the slug tracking and tests conducted in previous years;

5.3 To evaluate the logs run before and after all other tests are performed:

1. The logs should be printed overlain on the same depth scale. If not, on a light table, light box or back-lighted window, overlay the initial log above the final log. Focus on the interval just above the top of the injection interval;
2.
3. After matching depth and/or collar log features, check to be sure that the gamma ray traces overlay. If they do not, shift one log to the left or right until they generally overlay;
4. Identify regions in which the final log indicates apparent increased radiation. If the magnitude of the increased radiation is greater than the statistical variation, then radioactive tracer material has probably adhered to either the well construction materials or the borehole walls where the waste exited the well bore; and
5. Try to relate all instances of increased radiation above the casing shoe to the results of the previous testing. If unexplained occurrences persist, the results of a recent part 2 MI test should be carefully reviewed to see if upward movement is indicated.

5.4 The result of the testing should be determination of a depth above which no upward movement occurs. The result should be at or below the casing shoe. If it is above the casing shoe, the extent should be tracked and significance determined.

ATTACHMENT 9
CEMENTING RECORDS

1 Basis

A very small span of sound cement surrounding the casing will prevent movement between the well bore and the casing or between casings.

The use of cementing records as a demonstration of part 2 of MI is limited to all Class II wells and those Class III wells in which the nature of the construction precludes the use of temperature or noise logs. The cementing records must indicate that cement is present along the well bore between the injection zone and the base of the lowermost USDW.

2 Advantages and Disadvantages

<u>Advantages:</u>

1. Usually based on existing information
2. A one-time demonstration

<u>Disadvantages:</u>

1. This is an indirect demonstration. The presence of cement does not assure us that it is sound
2. If paper records are not available, they cannot be reconstructed
3. Either the CBL or CET requires that the well bore be water filled to the upper limit of the logged interval

3 Equipment and Forms

1. Forms of Cementing Records
   Cementing records include any acceptable records containing information which allows the calculation of cement placement behind the casings of wells. Cementing records may include

cement bond logs, cement evaluation logs, and temperature logs which give evidence of the location and/or quality of cement along well bores. The most reliable cementing records are job reports from cementing companies, but any records of construction containing information about the placement of cement may be acceptable. Either the original or copies of t hese cementing records must be submitted.

2. Cement Bond and Cement Evaluation Logs

   Cement bond logs (CBLs) use sonic attenuation and travel time to determine whether casing is cemented or free. The more cement which is bonded to casing, the greater will be the attenuation of sounds transmitted along the casing. The Cement Evaluation Tool (CET) operates on a principle similar to the CBL except that the tool uses many sound transmitters and receptors to evaluate the cement in various sectors of the well bore. Instead of an average bond index accounting for the entire circumference of the well bore, the log can identify poor bonding in single 60o segments. This increases the ability to confirm the presence of channels tremendously.

   The logs should include a gamma ray curve, casing collar log, acoustic amplitude and travel time curves, and CBLs should include an acoustic variable density log (VDL). The left hand track should contain the gamma ray and casing collar log. The right hand tracks should contain the acoustic amplitude and travel-time curves in track 2 and the acoustic VDL in track 3. CETs include a graphical depiction of the cemented area of the well bore in track 3. If available, a shop calibration record should be attached. The surface pressure under which the log was run should be noted on the log form.

   In new wells, the cement should be allowed to set for at least 72 hours before logging.

4 Procedures for Recording the Cement Bond Log (CBL) or Logs made Using Cement Evaluation Tool (CET)

1. Centralize the tool. Be sure that the part of the hole to be logged is liquid filled. Calibrate the tool;
2. Record the amplitude and travel time measured by the short- spaced receiver in the fixed gate mode;
3. Run the CBL over the entire cemented length of the casing and through at least two joints of the uncemented portion, if any;
4. Check the travel time. If intervals are found having four microseconds less than travel time in free pipe, check the tool centralization and relog the well if necessary;
5. If the log indicates poor bond, the log can be run under pressure to eliminate any micro-annulus effect. The pressure used should be minimal to prevent enlargement of the micro-annulus. Often reproduction of the pressure used during cement setting is sufficient. For Class I wells (although cement logs are occasionally required at Class I sites, they are not a demonstration of part 2 of MI) pressurizing to the normal annulus pressure may be sufficient to eliminate the micro- annulus; and
6. Check the tool calibration. If significant tool drift has occurred, relog the well with the back-up tool.

5 Interpretation

1. Interpretation of records

   Most cement records document the volume of cement emplaced between the casing and the well bore. For demonstrations of MI for Class II wells, the records must indicate that cement was emplaced at locations which will prevent upward movement from the injection zone. For demonstrations of MI for Class III wells, the records must indicate that cement was emplaced at locations which will prevent upward movement from the injection zone and into or between USDWs.

2. Interpretation of CBLs

   The log is examined to identify the location of cement along the casing. Only a few feet of sound cement are required to prevent flow along the well bore, but in most cases making judgements about the adequacy of a few feet of cement will not be required because there will be more than 10 feet of cement indicated to be sound, or there will be no indications of sound cement in critical areas. If an initial cement bond log does not indicate the presence of cement, often a second log will be run with pressure on the casing. This may show cement while the earlier log does not. In this case, a microannulus has developed due to past expansion of the casing while it was pressurized during operations or testing. It is sometimes necessary to pressurize the casing above the highest pressure to which it has been subjected. The presence of a microannulus does not indicate a lack of part 2 of MI. Microannuli are very minute. By definition, while they may allow the passage of gas but not liquids.

If there is a question about the adequacy of cement to prevent the movement of liquids into USDWs, then one of the previously described logs, pre-approved by Region 5, should be utilized to demonstrate MI.

ATTACHMENT 10
RADIOACTIVE TRACER SURVEYS FOR
THE INTEGRITY OF CEMENT AT THE TOP OF THE INJECTION INTERVAL

1 Basis

The basis of the use of the RTS for confirming the integrity of the cement at the top of the injection interval is identical to that of demonstrating part 2 of MI. In fact, if there are no aquifers above the injection interval from which the waters might degrade any USDW, the demonstration of cement integrity becomes a demonstration of part 2 of MI.

2 Advantages and Disadvantages

This test is required annually for Class I wells which are used to inject hazardous waste; there is no alternative test. The logs used to demonstrate part 2 of MI may also make a similar demonstration, but such a demonstration cannot be substituted for the RTS for this purpose. Because there is no alternative, and the advantages and disadvantages of the log have been previously listed in Attachment 8, they are not listed here.

3 Equipment and Forms

These are identical to the equipment and forms listed in Attachment 3 for the RTS.

4 Procedures

The procedures for using the RTS to confirm the integrity of cement are identical to those used for the demonstration of part 2 of MI.

5 Interpretation

The interpretation of the RTS used for confirming the integrity of cement is similar to that for demonstrating part 2. If any upward movement is observed, it becomes critical to determine the exact amount of upward movement. The upper limits of upward movement are recorded and compared from year to year to check for any increase.