Planning, Executing, and Reporting Pressure Transient Tests

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5 -- UNDERGROUND INJECTION CONTROL SECTION
REGIONAL GUIDANCE #6

Revised June 3, 1998

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INDEX

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I. ISSUE

Information about the injection, confining, and other zones penetrated by injection wells is needed in order to assess the capacity of geological reservoirs to accept and contain injected wastes and the ability of geological confining zones to prevent the upward movement of wastes. Pressure transient tests are an effective and commonly used means of obtaining the necessary information. There are numerous test types; some are more appropriate for particular uses than others. The methods and procedures which might be used are limitless. Guidance is needed to assist operators in choosing, performing, and reporting the results of these tests.

II. PURPOSE OF GUIDANCE

This guidance is a major revision of an earlier Guidance #6 which was developed in 1990. In the intervening years, the technical staff of Region 5's Underground Injection Control (UIC) Branch has gained experience and insights which we believe have allowed us to produce a more useful guidance document. The original document was written in response to regulations which required annual reservoir pressure monitoring at all Class I facilities. The Guidance also discussed other pressure transient tests which we believed would be performed in conjunction with the ambient reservoir pressure monitoring.

The Region 5 UIC Branch evaluates all of the test results submitted to the USEPA by operators of facilities located in Michigan, Indiana, and, when requested, states which implement their own UIC programs. In order to receive data which are amenable to evaluation and the information needed to perform evaluations, the technical staff has prepared this guidance to inform operators of facilities in Region 5 about options they have in choosing test methods and equipment, methods which we have found to be efficacious, and information which is necessary to perform valid evaluations. This guidance is intended to address all pressure transient tests commonly run in Region 5. Several pressure transient tests are used to define fracturing pressures. These tests are already discussed in Guidance #7; although those discussions are rather complete, some additional discussion will be given here in order to bring information there up to date.

III. DISCUSSION

A. Regulatory Use of Pressure Transient Test Results

There is a substantial number of pressure transient tests which can be used to derive values for several parameters which are of interest to regulators because they reflect the ability of subsurface reservoirs to accept and store injected wastes in a manner which is protective of underground sources of drinking water (USDWs). Several tests are more frequently used by operators of Class I and much less frequently by operators of Class II wells. These tests will be discussed in some detail in attachments to this guidance. Each attachment can be used as a stand-alone guidance for the test it covers.

The regulatory bases for performing and evaluating test results are found in several sections of 40 Code of Federal Regulations (C.F.R.).

1. For Reservoir Properties

Regulations at &sect 146.12(e)(4)require collection of "physical and chemical characteristics of the injection matrix" for all Class I wells. Similar requirements at &sect 146.22(g)(3) exist for Class II wells and at &sect 146.67(e)(2) for the "injection and confining zones" for Class I hazardous-waste disposal wells. Pumping or injectivity tests are specifically required prior to operation of Class I hazardous-waste injection wells. 40 C.F.R. Part 148 for demonstrations of no migration from the injection zone requires the use of reservoir information which is best gathered by means of pressure transient testing.

Tests most commonly used to determine reservoir properties are:

Pressure Fall-off Test. Typically done following the injectivity test before a well is put on line, or done to determine the effects of injection following long periods of injection. Guidance specific to the pressure fall-off test is provided in Attachment 1.

Interference Test. The interference test is a multi-well test which uses pressure interference in a remote well, called the receptor well, caused by a change in injection rate in an active well to estimate the reservoir properties within the medium between the two wells. Because the measurement point is some distance from the active well, the time required for the passage of a pressure transient between the two wells can be used to increase the amount of information which can be derived from the test. Although the two-well tests are primarily for determining reservoir properties, they can also be used as part of an ambient reservoir pressure monitoring program. Guidance specific to the pressure fall-off test is provided in Attachment 1; Guidance specific to the pressure fall-off test is provided in Attachment 2.

Pulse Test. Similar to the interference test except that multiple rate changes are used. This allows more accurate identification of the beginning of response to rate changes as well as allowing for some disposal during the test. Guidance specific to the pulse test is provided in Attachment 3.

Injectivity Test. Done during drilling or before wells are put on line for injection. Allows longer period tests under more controlled conditions than drill stem tests, but has other important disadvantages. Guidance specific to the injectivity test is provided in Attachment 4.

Drill Stem Test. Done during the drilling of wells, provides both samples of reservoir fluid and estimates of reservoir properties. Guidance specific to conducting drill stem tests is provided in Attachment 5.

Modular Formation Dynamics Tester. The MDT tool is a versatile tool which is lowered into the well on a wire line. The modular aspect refers to the components, packers, sampling vessels and pump. The modules may be configured in various ways to measure reservoir pressures, collect reservoir fluids, or to conduct microfracturing tests. Guidance specific to conducting drill stem tests is provided in Attachment 6.

2. For Ambient Reservoir Pressure Monitoring

Annual ambient reservoir pressure monitoring is required at &sect 146.13(d) for Class I wells and again at 146.68(e) for Class I hazardous-waste disposal wells. A shut-down of the well for sufficient time to make a valid observation of the pressure fall-off curve is the minimum means to perform this pressure monitoring. This implies that a determination of reservoir pressure can be made based on the observation. Where a static pressure in the injection line may be measured, either at reservoir depth or at the surface, a valid observation of the pressure fall-off curve may consist of pressure measurements confirming that the injection pressure has declined and become stable during the fall-off period. Region 5 may require a more complete analysis to determine the reservoir pressure or other parameter values if a condition which may have environmental consequences has been identified.

Although not required for determining an ambient reservoir pressure, an analysis of fall-off data for the determination of reservoir properties is generally good operational practice because it allows the operator to assess the effects of injection on the near-wellbore area of the disposal reservoir.

Pressure Fall-off test. The regulations require, at a minimum, a pressure fall-off test annually for the purpose of monitoring ambient reservoir pressure. For the purposes of this guidance, a fall-off test consists of measurements of pressure response occurring when injection is halted. Guidance specific to the pressure fall-off test is provided in Attachment 1;

Two Rate Test. The two rate test is a pressure fall-off test in which the injection rate is reduced but not brought to zero. It can be an alternative to the pressure fall-off test when wellbore storage makes a fall-off test useless. Because the two-rate test is equivalent to the fall-off test for the purpose of determining reservoir properties, it is not discussed in a separate attachment. Differences are pointed out briefly in Attachment 1. Otherwise, recommendations which are applicable to the fall-off test are appropriate for the two-rate test.

3. For Determining Minimum Lithostatic Stress

Regulations at 40 C.F.R. &sect.§ 146.13(a)(1) and 146.67(a) require that pressures at the wellhead of all Class I wells and Class I hazardous waste injection wells, respectively, be maintained at levels which are calculated to assure that the pressure in the injection zone will not cause the initiation of new fractures or the extension of existing fractures except during stimulation at Class I injection wells. Regulations at &sect.§ 146.12(e)(1) and 146.66(d)(1)require that the fracture pressure for the injection zone at Class I wells and injection zone and confining zone at Class I hazardous-waste disposal zones, respectively, be determined.

Region 5 has determined that fracture initiation or extension can be reliably prevented if injection pressure is insufficient to allow fracture opening. Because the difference between fracture closure and fracture extension pressures may be very small, fracture closure pressure can usually be measured reliably, and if fractures are not opened they certainly cannot be extended, Region 5 sets maximum injection pressures based on fracture closure pressure. Therefore, testing is required at Class I sites to determine the fracture closure pressure. As an alternative to testing, the permittee may elect to accept a default maximum allowable surface injection pressure (MASIP) based on the lowest fracture closure pressure measured in the Region. This MASIP is equal to depth at the top of the injection interval (which may be higher than the completed interval) x (the appropriate formation fracture closure pressure) - specific gravity of injectate) - 14.7 psi.

Fracture closure pressure is equal to the minimum lithostatic stress. This pressure is determined most reliably by the use of pressure transient tests although other means may be used. These tests include:

Step Rate Tests. Step rate tests are used mostly in existing wells. They involve increasing injection rate in steps of equal duration. A plot of pressure at the end of each step versus rate for that step falls on a straight line below the fracture extension pressure and on a straight line having a lesser slope above the fracture extension pressure. The intersection of the lines marks the pressure at which fracture extension occurs. Guidance specific to conducting step rate tests is provided in Attachment 7.

Microfracture Tests. Are tests of very small intervals of the well bore. They usually involve isolating these small intervals by means of inflatable packers. Injection at a rate sufficient to cause pressure build up through fracture pressures within a few minutes of beginning is used. Following shut in, fracture closure pressure is identified by a change in the curvature of the pressure fall-off curve. Tests using the Modular Formation Dynamics Tester or other such equipment are considered to be variants of this test. Guidance specific to conducting the microfracture test is provided in Attachment 8.

Minifracture Tests. Minifracture tests are similar to microfracture tests except the injection interval includes the entire completion interval. Therefore higher injection rates are normally required to initiate fractures. Analysis is similar to that for microfracture tests. Guidance specific to the minifracture test is provided in Attachment 9.

B. NOTIFICATION

Testing procedures for Class I wells must be approved by the USEPA before testing begins. The UIC Branch technical staff requests an opportunity to review the procedures for tests performed in the States and Michigan for Class I wells. We will try to make suggestions which may result in more accurate determinations. When more critical tests, such as microfracture and step rate tests, are performed, members of the staff will try to be present to assist the operator by evaluating the test results on site.

Alternative procedures which operators may think are more appropriate in specific cases will be considered by the UIC Branch. Methods which can be expected to produce equivalent or better information will be approved.

C. REPORTING THE RESULTS OF PRESSURE TRANSIENT TESTS

There are no set forms for reporting results. When a contractor supplies pressure measurement data, this data normally includes time, pressure and temperature measurements. Additional information is necessary to fully interpret these data. All of the information necessary to achieve the purpose of the test must be available to Agency analysts. Although it is likely that the analyst contracted by the permittee will provide all necessary information along with an interpretation, this is not necessarily so. Therefore, the following guidance is provided.

Required Well Background Information

Well identification - Needed for compliance monitoring;

Well radius - Needed to make quantitative interpretations of reservoir properties for single-well test data. One half of bit size for open-hole completions, and one half of internal diameter of casing for cased-hole completions;

Required Formation Information

Thickness of injection zone - Needed to derive reservoir permeability from transmissivity for all tests. The reported thickness should be the net, tested thickness rather than the gross thickness;

Porosity - Needed to allow derivation of reservoir properties from single and multi-well test data. Porosisity is normally determined based on core or log measurements. The reported porosity should be the thickness-weighted average porosity of the net injection interval;

Formation compressibility - Needed to allow derivation of reservoir characteristics from single-well test data. May be provided only as an element of total compressibility;

Injection Fluid Information

Viscosity of injection fluid at reservoir temperature (as measured by temperature log or estimated from average wellhead temperature adjusted for injection depth) - Needed to allow derivation of reservoir properties from transmissivity values for all tests;

Viscosity of reservoir fluid at reservoir temperature (as measured by temperature log run before injection began or estimated from local geothermal gradient adjusted for injection depth - Needed to allow derivation of reservoir properties from transmissivity values for tests in which the radial flow data is developed in the formation outside the plume of injected waste;

Density of injection fluid - Needed to adjust pressure measurements to reservoir depth datum for all tests at which gauge is not at common datum near the top of the reservoir;

Fluid compressibility - Needed to allow derivation of reservoir properties for all tests. May be provided only as an element of an estimated total compressibility.

Required Test Informationu

Date of test - Needed for compliance monitoring;

Depth to pressure gauge - Needed to ensure that comparisons of pressure measurements are valid for all tests at which gauge is not at common datum near the top of the reservoir. Tests at facilities with multiple wells should provide depths below sea level;

Injection rates - Needed to allow derivation of reservoir properties for all tests. Should be provided in gallons per minute format;

Length of flow periods - Needed to produce Horner Plot;

Flow rate data for other wells on site - Needed to explain boundary effects and other pressure anomalies for all multi-well sites;

Attachments

ATTACHMENT 1 THE PRESSURE FALL-OFF TEST (FOT)

A. Theoretical Bases

Increased hydrodynamic pressures are created in geologic reservoirs as a result of the injection of fluids through wells. The distribution of pressure is a result of the rate of injection, viscosity and compressibility of the injected fluid, the permeability, porosity, compressibility, and geometry of the injection reservoir, and the compressibility and viscosity of its contained fluids. If the injection rate is changed, the pressures in the reservoir around the well change in response. The rate and magnitude of pressure change depends upon the change in injection rate and such reservoir qualities as transmissivity and storativity. Transmissivity and storativity, in turn are determined by reservoir and fluid parameters such as permeability and compressibility.

Observations of such pressure changes at the injection well can be used to estimate the total values of the groups of unknown reservoir/fluid properties which may be reported as transmissivity and storativity. Individual parameter values can be obtained from the group values if values for all other parameters in the group are already known. The Horner method can be used to extrapolate pressure measurements made during radial-acting flow to infinite shut-in time. If the values used for the analysis are a valid approximation of the injection well's history, then the extrapolation to infinite shut-in time can be made with fair confidence. In addition, reservoir boundaries can be detected, volumes of small reservoirs determined, and, if fractures are penetrated, the half length can be determined. Well damage or efficiency can be estimated.

Two-rate fall-off test

The two-rate fall-off test does not use a full shut off of injection. This is theoretically equivalent to a full fall-off test with the lower rate being more than zero. The advantage of the two-rate test is that afterflow may be eliminated as a problem because the amount of afterflow is less significant along with the remaining flow than when the rate is zero.

B. Advantages and Disadvantages of the FOT

Informational Advantages

Provides all hydrological information that any other single-well test provides.

Informational Disadvantages

For the two-rate fall-off test, extrapolation of fall-off pressure to infinite shut-in time by means of the Horner method is subject to error as a result of continuing flow. Simulations can project backward to provide an estimate of original reservoir pressure if the well history can be taken into account.

Operational Advantages

Easy to maintain stable injection rate if injection is stopped and well is blocked in;
Requires minimal equipment and procedural changes in active Class I injection wells.

Operational Disadvantages

Subject to wellbore storage effects;
May interfere with production schedules.

C. Primary Applications

Used to test wells which have been on injection for some time in order to estimate: long-term pressure build up, well damage, permeability changes, and to identify and characterize transmissive fractures.

D. Equipment

Pressure measurements must be made with sufficient accuracy and frequency to achieve the purposes of the testing. If gauge reading error is less than 0.5% (0.005) of the maximum pressure recorded, the accuracy is sufficient for regulatory purposes. The pressure measurements for analysis may be recorded using the permanent wellhead pressure monitoring equipment, a surface-readout pressure gauge (SRPG), an electronic memory recorder (EMR), or a Bourdon-tube gauge (B-T gauge). In any case, it is convenient to have pressure measurements available at the surface during the test so that the progress of pressure decline can be evaluated.
The injection pumps may be used at established sites.

If a direct measurement of static reservoir pressure is recorded, a record of measurements spanning sufficient time to indicate stability is required. These pressure measurements should extend over a period of at least six hours and include periods of pressure increase and decrease to confirm that short-term trends are dominant. If the measurements are not made at the injection interval, then the density or specific gravity of the fluid in the well bore must be reported.

E. Procedure for the FOT

There are two phases to the FOT, the pretest injection period and the fall-off test itself. Although the regulations for ambient reservoir pressure monitoring require only that a shut down for a time sufficient to make a valid observation of the pressure fall-off curve be made, some care in preparing for the fall-off period is needed to ensure that a valid observation can be made.

Preinjection flow period

1. Determine the fluid to be used during the test.

   We prefer that the normal injection fluid be used. This may allow longer pretest injection periods and eliminates concerns about changing viscosity within the injection reservoir and the need to shut the well in to switch from waste to fresh water injection. Fresh water may be used if there are good reasons, such as: corrosive injectate, insufficient volume of waste to inject for the time needed to make the necessary observations, or if the reservoir pressure is known to be sufficient to support a column of fresh water, but not of waste, reaching to the surface.

2. Determine injection rate, fall-off and minimum pretest flow periods.

   In general, higher rates are preferred so that the period through which pressure decline is accurately measured is increased. The rate should be based on knowledge of reservoir properties, availability of fluid, pump capacity and flexibility of operation. The time required for collecting representative data from the period during which the pressure decline reflects radial flow in an infinite-acting reservoir must be reached or exceeded. To ensure good data through this period, the length of the flow period should be no less than 150% of the fall-off period. The injection pressure should be essentially stable (below the permitted (MASIP) for at least half of the flow period. If the normal injection pressure is near the MASIP, no special arrangements are necessary. The preceding recommendations should not be taken as maximum time periods; the final flow period preceding the fall-off period should be as long as is practical. In wells which experience a long period of after flow due to formation decompression, a lower injection rate, which will not cause the onset of severe pressure-sensitivity, may allow more accurate measurement of the effects of near-well reservoir properties.

3. Choose gauge type and position.

   If the facility's monitoring equipment records in a digital format with an accuracy of 0.5% of the difference between the injection pressure and final shut-in pressure, measurements from that equipment may be used. Other considerations include: 1) the length of fall-off time expected. If the fall-off occurs within a few hours, the measurements will be substantially affected by fluid density changes along the well bore as the wellbore temperature stabilizes; 2) the consistency of the injectate density. If this cannot be accurately estimated, error in the calculation of the ambient reservoir pressure may occur.

   If considerations about the consistency of injectate density will cast doubt on the results, a down-hole gauge may be appropriate. This gauge may be a SRPG or EMR. If there is real uncertainty about the reservoir properties and no digital information about injection tubing pressures, or if on-site analysis will be used to evaluate the data during the test, then an SRPG may be the better choice.

   If the test can be preprogrammed without possibility of changes being required, an EMR is a more economical choice.

   If a down-hole gauge is to be used, it should be installed and injection continued for at least one more hour after the gauge is at its test depth. This allows adequate time for temperature stabilization, measurement of an average injection pressure, and dissipation of any effects due to flow interruption during installation.

To compare pressures through time, a fixed reference datum is necessary. We have chosen the top of the open injection interval as this point. If down-hole pressure measurements are made, the gauge depth should be at this point. In other cases, the ambient reservoir pressure should be adjusted to this depth.

4. Stabilize injection rate.

   Stabilize the injection rate at the test well in accordance with the program designed based on the preceding steps. At multi-well sites, stabilize the injection rates for all wells. Rates should be chosen which can be maintained throughout the entire injection and fall-off periods. If this is impossible, attempt to minimize interference by altering rates for most distant well(s) and do so when the change is least likely to be relatively significant, ie: when the rate of change at the test well is high.

Fall-off Period

1. Shut in injection as nearly instantaneously as possible. As soon as the pumps are shut off, the injection line should be shut in as near to the well head as possible, certainly down stream from the pumps;
2. Measure reservoir pressure at frequent intervals, decreasing the frequency as the rate of pressure decline decreases. For instance: 0 to 5 minutes at maximum possible frequency, to 30 minutes at no less frequently than at 30-second intervals, and beyond that time determinations can be made as necessary to maintain a record of pressure including change of no more than 1% of the difference between highest and lowest recorded pressures;
3. End pressure measurements when pressure is relatively stable, when operational necessity dictates, or when an extrapolation of pressure response due to radial flow to infinite shut-in time is possible, or if boundary effects are observed. The period of radial flow will be marked by a near-constant derivative value and must proceed long enough to allow extrapolation of a best fit line with a high degree of confidence.

F. Interpretation

Region 5 uses a computer-assisted analysis which emphasizes interpretation of reservoir condition. Results are evaluated to determine whether flow is radial, linear, or bilinear, and whether the fabric of the reservoir is being affected by injection pressures. The interpretation uses plots of pressure changes through time during the test with the derivative of the pressure change plotted on logarithmic axes, against both the square and fourth roots of time, and the Horner plot. The Horner plot is used to determine an extrapolated shut-in pressure.

The regulations establish no criterion for failure, and we have not developed any. We look for conditions which might have environmental consequences. When conditions which are unusual are observed, we bring these to the attention of the operator and discuss whether the condition should be incorporated into the model used for test analysis, and, if it appears that the condition might require changes to the model used to simulate waste movement through the 10,000-year period of concern for the landban demonstration, new simulations must be performed.

Although we track the results of the extrapolations of infinite shut-in pressure, we believe that most variations are a result of our inability to incorporate the entire history of injection rate changes into our calculations. Our main concern is a steady trend of increasing pressure which might be due to limited reservoir volume. This will not be a problem for operators who inject into the Mt. Simon Sandstone. If the rate of pressure increase is substantially lower than projected, a loss of fluid from the injection reservoir is a possibility.

Two-rate Test

Pressure response during the two-rate test is not affected when the effects of fluid decompression are insignificant relative to the effects of the rate reduction. The procedures for running the two-rate test are identical to those for running the pressure fall-off test. In fact, the pressure fall-off test is a special case of the two-rate test in which the reduced rate is zero.

If the apparent wellbore storage effects are due to formation decompression rather than to fluid decompression, the two-rate test offers no advantages over the fall-off test. After flow due to formation decompression normally occurs in a fixed pressure range just below fracturing pressure. Because raising the reduced injection rate from zero to some small value is unlikely to affect the pressure response at a higher pressures, the two-rate test cannot avoid the effects of such after flow.

Informational Advantages Relative to other Demonstrations

May allow quantitative evaluation of reservoir properties using wells which are not amenable to evaluation by means of the pressure fall-off test as a result of high wellbore storage.

Informational Disadvantages Relative to Other Demonstrations

The p* value reflects pressure at the lower flow rate rather than for a cessation of all injection.

Operational Advantages Relative to other Demonstrations

None.

Operational Disadvantages Relative to Other Demonstrations

Adequate rate control at two rates may be difficult to achieve.

ATTACHMENT 2
INTERFERENCE TESTS

A. Theoretical Bases

The bases of the interference test are the same as those of the fall-off test. The difference between the two tests is the location of the point at which response to rate change is measured. The interference test utilizes a second (observation) well near enough to the injection (active) well that pressure responses resulting from rate changes at the active well can be identified and measured. The time required for the pressure transient to move between the wells can be measured. This gives a basis for calculating storativity. Knowledge of the value of storativity allows the refinement of the permeability value and, as a result, more accurate prediction of reservoir pressurization due to injection.

B. Advantages and Disadvantages

Informational Advantages Relative to Single Well Tests

The speed of travel from well to well may be measured, allowing derivation of a value for a group of parameters linked to storativity;

A larger body of rock, unaffected by injection effects, may be tested than is possible using a single well, thereby allowing better estimates of far-field reservoir characteristics to be made;

If more than two wells (not in line) are available, directional differences in reservoir properties can be measured.

Informational Disadvantages Relative to Other Demonstrations

None

Operational Advantages Relative to other Demonstrations

Well bore damage and storage effects present in the active well do not affect the measurements at the observation well to the extent they do the active well.

Operational Disadvantages Relative to Other Demonstrations

Two wells are involved, and planning may be more difficult.

The measurement of pressure change at the observation well may require a more sensitive pressure gauge than is used for routine monitoring.

Time synchronization between the two wells is more difficult to establish.

C. Primary Applications

For the determination of reservoir properties at facilities with more than one well. In addition to reservoir quality information, directional information is obtained if more than two wells can be involved. An interference test, by itself, does not satisfy the requirement for annual ambient reservoir pressure measurement. However, the records from the active well can usually be used to satisfy the requirement.

D. Equipment

Plant facilities may be used to inject as necessary. Plant monitoring equipment may be used to document rate and pressure at the active well. In the event that the reservoir pressure will not support a column of liquid reaching to the surface, then it is almost certain that a down-hole gauge will be required in the observation well.

The records of pressures measured at both the active and observation wells, correlated to each other, must be submitted.

E. Procedures for Conducting Interference Tests

1. Choosing the injection rate.
   The injection rate should be chosen to allow for production of the largest pressure pulse possible within the limits of the permit.
2. Stabilize injection rates at the site.
   All injection rates except that of the active well should be maintained constant throughout the test. If possible, all injection wells except the active well should be shut in. The observation well itself should be shut in for as long as practical preceding the interference test.
3. Install the the pressure gauge in the observation well.
   The gauge should be installed several hours before injection into the active well is halted in order to allow establishment of a background noise level. The gauge can be installed at any depth because the absolute measurement of the pressure is not critical, instead, the relative magnitude of pressure readings and the time elapsing between pressure change at the active and response at the observation well is important.
4. Shut in the active well.
   The shut-in procedure is not so critical for the success of the interference test as for the fall-off test. Because the pressure response at the active well will be analyzed as a fall-off test, equivalent precautions should be taken.
5. If the liquid level is at the surface or if a surface-reading pressure gauge is being used, observe pressures in the observation well. Pressure measurements should be made until the pressures become essentially stable following arrival of the pressure transient. The active well can be restarted as this condition approaches, or is calculated to approach.
6. End the Interference Test.

The interference test should not be ended until the pressure in the observation well is apparently stable. If a shut-in period of such length is not practical, then a pulse test may be more appropriate.

Interpretation

Region 5 uses the results from interference tests to investigate reservoir properties over a larger area than is usually possible using a single-well test with the purpose of eliminating near-wellbore effects. This should provide a better measure of original conditions, reducing the effects of injection.

Normally records from the active well are analyzed first to provide a starting-point permeability value for the area. Then the interference test is analyzed using a type curve matching method.

ATTACHMENT 3
PULSE TEST

A. Theoretical Basis

The pulse test is similar to the interference test in that it includes the advantages of a multi-well test. In addition, a cyclic pattern of pressure change is developed by turning injection on and off at the transmitter well. This makes the determination of travel time easier and allows intermittent injection through at least one of the two wells involved in the test.

B. Advantages and Disadvantages

Informational Advantages Relative to the Interference Test

Cyclic pattern makes matching correlative events easier and thus enhances accuracy of determinations.

Informational Disadvantages Relative to the Interference Test

None.

Operational Advantages Relative to the Interference Test

Intermittent injection occurs during the test allowing for some disposal of waste to occur.

Operational Disadvantages Relative to the Interference Test

None.

C. Primary Applications

Same as interference test, particularly where long shut-in periods are not practical.

D. Equipment and Forms

The equipment and forms are identical to those required for interference testing.

E. Procedures for Pulse Testing

1. Choosing the length of the injection cycle
   The length of the injection cycle should allow pressure to fall from a near maximum to a near minimum. If the well responses at the receptor well are known, then this length can be pre-planned. If not, the first cycle can be used to determine the optimum cycle time. A slightly irregular pattern will help to ensure that correct correlation between the two wells' responses is made.
2. Stabilize injection rates at the site.
   All injection rates except that of the transmitter well should be maintained constant throughout the remainder of the test. If possible, all injection wells except the injector should be shut in.

3. Install the pressure gauge in the receptor well.
   The gauge should be installed several hours before the first cycle is begun in order to allow establishment of a background noise level. The gauge can be installed at any depth because the absolute measurement of the pressure is not critical, instead, the relative magnitude of pressure readings and the time elapsing between pressure change at the transmitter and response at the receptor well is important.
4. Begin the test cycle.
   The cycle will probably begin with the injector well being shut in. The shut-in procedure is not so critical as for the fall-off test. The cycle restarts when the well is again put on injection. This can be at any convenient time after the pressure measured at the injector well has become semi-stable.
5. Complete the pulse test. At least three cycles of injection and pressure fall-off should be completed.

F. Interpretation

Interpretation of the pulse test is identical to that of the interference test.

ATTACHMENT 4
INJECTIVITY TEST

A. Basis

As fluid is injected into a porous medium, fluid pressure within the medium increases. The rate and magnitude of the pressure increase are functions of reservoir and fluid properties. Analysis of the pattern of pressure increase, therefore, can be used to estimate values for important reservoir parameters.

B. Advantages and Disadvantages

Informational Advantages Relative to other Demonstrations
Similar to other single-well tests

Informational Disadvantages Relative to Other Demonstrations

Similar to other single-well tests

Operational Advantages Relative to other Demonstrations

Not subject to wellbore storage effects
Often easier to obtain water for injection than to dispose of produced water.

Operational Disadvantages Relative to Other Demonstrations

Formation damage may not be overcome without reaching fracturing pressures during injection.
Rate control may be difficult as reservoir pressure increases.

Pressure differentials achievable through injection (without fracturing) are likely to be less than those achieved by pressure draw down.

C. Primary Applications

The injectivity test is used primarily during the drilling or completion of new wells in order to determine formation properties. Although drawdown tests have theoretical advantages, the practicality of injectivity tests often results in their use.

When injectivity tests are run, the opportunity to append a fall-off test should not be missed. Problems which might compromise the results of injectivity test analysis are likely not to affect the fall-off test. Apparently some formations, especially highly permeable formations, suffer significant "formation damage" as a result of the formation of wall cake during drilling. When injection is attempted, the resistance to flow offered by the wall cake may necessitate injection pressures high enough to cause fracturing. The results of both the injectivity and fall-off portions of the test are compromised. However, the results of the fall-off test are more likely to reflect the nature of the tested formation than are the results of the injectivity test. Even better than a fall-off test is the use of a pressure-drawdown test. Therefore we prefer a pressure draw-down/pressure build-up couplet. However, if disposing of produced fluid is a problem, the injectivity/fall-off test package may be necessary.

D. Equipment and Forms

Either casing set to allow injection into the zone to be tested or drill string with inflatable packers above and below the tested zone;
Pumping equipment, usually mobile and supplied by oil field service companies;
Pressure measurement equipment, usually positioned near the zone being tested.

There are no standard forms. Information including: test interval; injection rate; density of injected fluid; time, pressure, and temperature measurements; must be submitted.

E. Procedures for Conducting the Injectivity Test

1. Establish injection interval. This is done by setting packer depths in uncompleted wells, or by recording the completion interval in completed wells.
2. Measure initial reservoir pressure. Pressure should be static. It can be measured at the reservoir level by means of a downhole gauge, or by measurement of pressure at the surface or near the surface and addition of the pressure exerted by the column of liquid in the well.
3. Begin pressure measurements at high rate.
4. Establish injection rate. A short pretest at a low rate may be used to determine an appropriate rate for testing. The testing rate should be high enough to cause a pressure which is equal to the depth of the top of the tested zone times 0.75 psi/ft.
5. Continue injection until pressure measurements become near stable unless this is impossible due to slow increase, insufficient injection fluid, or high injection pressure.
6. Shut in the injection well.

7. Continue to collect pressure measurements for a period equal in length to the injection portion of the test. The resulting data will constitute a pressure fall-off test.
8. Remove test tools from the well.

F. Interpretation

The injectivity and fall-off tests are interpreted as are all other pressure transient tests run in Region 5 for the purpose of determining reservoir properties.

ATTACHMENT 5
DRILL STEM TESTS

A. Basis

Drill stem tests are used during the construction of wells to test the reservoir qualities of formations. In addition, reservoir fluids can be brought to the surface for analysis. Drill stem tests are often described as temporary well completions. The well is tubed by means of the drill string which carries packer and valve assemblies to the interval to be tested. The packer is made to expand against the well bore by compressing a rubber sleeve using the weight of the drill string or by hydraulic inflation of an inflatable sleeve. The valve assembly controls flow into the drill string which may be run into the well completely empty.

The drill stem test uses one or more flow periods to cause a disturbance in the reservoir, and shut-in periods (pressure build-up tests) to gather data for analysis. The pressure build-up tests are analogous to the pressure fall-off test. In its simplest form, the analysis is the same as for the fall-off test.

Generally there are two flow periods and two shut-in periods with the initial periods being much shorter than the final shut-in periods. During the second shut-in period the flow time and rate may be regulated by swabbing or nitrogen jetting. If reservoir qualities are to be determined, it is necessary that the flow rate be relatively constant. If the rate is not relatively constant, the analysis is more complex and subject to error.

B. Advantages and Disadvantages

The advantages of this test should be compared to injectivity (pressure build-up) tests because these are the logical alternatives to each other.

<u>Informational Advantages Relative to Injectivity Tests</u>
Samples of formation fluids may be brought to the surface for analysis;
Test results will not be complicated by possible fracturing occurring during injection;

<u>Informational Disadvantages Relative to Injectivity Tests</u>

None

Operational Advantages Relative to Injectivity Tests

Flow direction is into the well bore and wall cake is less likely to impede flow than in an injectivity test;
Larger differentials between well bore and reservoir pressures can be developed to clean up wall cake and lengthen period during which meaningful data are collected;

Operational Disadvantages Relative to Injectivity Tests

Fluids brought to the surface must be managed in compliance with legal and practical considerations;
Equipment for swabbing or nitrogen jetting is likely to be more awkward, expensive, and more difficult to rig up.

C. Equipment and Forms

Necessary equipment includes the downhole assembly and surface manifolds and connections which are usually readily available from oil field sources. If more flow control than can be had by means of natural reservoir pressure is needed, a swabbing unit must be rigged up within the drilling rig or nitrogen bulk trucks and pumping equipment must be procured. All of this equipment is also widely available.

The forms are usually provided by the service companies. They include records of activities and time-pressure records.

D. Procedures for Conducting the Drill Stem Test The procedures become more complex if sample recovery is critical. If not, a sample of the last fluid to enter the downhole assembly, or no sample at all, may be collected using a tap on the flow line or by diverting part of the flow stream to a sample container. If a relatively representative sample of formation fluids is needed, then enough fluid must be produced to flush out drilling fluid which has infiltrated the formation to be tested. This normally requires flowing more than a single drill string's volume of fluid. If the reservoir will not support a column of formation fluid with enough energy to maintain fairly rapid flow, then flow must be enhanced by means of relieving hydrostatic pressure due to the mounting column of fluid in the drill string. This can be done by swabbing or jetting. Swabbing uses a tool which can be lowered down the drill string below the top of the fluid in the drill string and which then can be used to lift the portion of the fluid above the tool out of the drill string. Jetting uses nitrogen which is injected through a smaller tubing to a depth below the top of the fluid and mixes with the fluid, lightening and lifting it out of the drill string. Jetting allows a more stable flow rate to be established than does swabbing but either method can be successfully used to establish a pressure draw down preceding a pressure buildup test.

E. Interpretation

If the flow period preceding the pressure build-up period is relatively constant, analysis is simple. Equations have been developed to simplify the use of the pressure drawdown-buildup couplets. The UIC Branch technical staff uses the same program for all tests. After data are entered into the program a Cartesian plot of pressure versus time is produced. This has little actual use, but shows the trained eye gross trends and effects. The log-log plot of pressure change and its derivative are the primary diagnostic tool. They are examined to identify reservoir features such as fractures, skin, boundaries, and small reservoir volume. Usually radial flow is clearly defined in these tests and the derivative is used to pick the beginning and end of radial flow. When these are defined, a best-fit line is constructed to fit the data points within the selected interval when plotted against the Horner time function. The slope of this line is used to calculate a value for transmissivity. As a check of the accuracy of the fit, the extrapolations to infinite shut-in time for the two couplets are compared. Often the second value is less than the first, but this normally does not mean that reservoir volume is limited, rather it is on account of the residual draw down occurring in the first flow period.

ATTACHMENT 6
MODULAR FORMATION TESTER

A. Basis

Stress tests done using the Modular Formation Dynamics Tester (MDT) are similar to microfracture tests in that a small interval is tested, but are done using a wireline tool. The injection pressures are generated by pumping drilling fluid from outside a small packed-off interval into the packed-off interval.

B. Advantages and Disadvantages

<u>Informational Advantages Relative to other Demonstrations</u>
Results are identical to microfracturing results;

<u>Informational Disadvantages Relative to Other Demonstrations</u>

Usually tests only a small fraction of the injection zone;

<u>Operational Advantages Relative to other Demonstrations</u>

Can be moved about within the bore hole even more quickly than microfracturing equipment;
Pressure drawdown tests, injectivity tests, and even fluid samples can be gathered with the same equipment on a single run into the well (savings in rig time will probably be greater than costs to have the tool delivered and used;

<u>Operational Disadvantages Relative to Other Demonstrations</u>

In large holes, high injection pressures may damage the tool;

Equipment may not be readily available.

C. Equipment and Forms

The equipment is available through Schlumberger Well Services. The results are presented in a log form. An engineer's record of activities clarifying the conditions under which each test was run is very helpful.

D. Procedures for Using the MDT for Gathering Fracture Pressure Data

The tool is operated by a trained technician. The intervals to be tested will be listed in the Regional Class I UIC permit. Each formation or part of a formation should be tested at least twice to confirm measurements. Before any injection is begun, the ambient hydrostatic pressure should be measured.

E. Interpretation Interpretation is similar to that for microfracture tests. The data are always available in digital format.

ATTACHMENT 7
STEP RATE TEST

A. Basis

Injection in a series of increasing rate steps results in increasing injection pressure. When injection pressure is sufficient to cause fracture opening, the apparent wellbore radius appears to increase significantly. Because wellbore radius is a factor controlling the rate of pressure increase, the trend of pressure increases caused by subsequent rate increases is not linear with respect to those occurring before the change in wellbore geometry. As a result, the test can be used to determine the pressure at which linear flow begins.

B. Advantages and Disadvantages

Step rate tests (SRTs) should be compared to other tests used to determine formation fracturing pressures, including mechanical properties logging as well as microfracture and minifracture tests.

Informational Advantages Relative to other Demonstrations
Tests a broad interval relative to microfracture tests.

Informational Disadvantages Relative to Other Demonstrations

Delivers a measure of fracture extension pressure, not closure pressure.

Operational Advantages Relative to other Demonstrations

Is relatively simple to conduct and interpret.

Operational Disadvantages Relative to Other Demonstrations

Best suited to completed wells;
May require hundreds to thousands of barrels of temporary tank room on site.

C. Equipment and Forms

Pump trucks, pressure and rate recording equipment and a large supply of water.

The information needed to interpret the test includes:
Depth to the top of the tested interval;
Depth to pressure gauge;
Density of injected liquid;
Pressure at start of the test;
Rates of injection for each rate step; and
Time and pressure at the end of each rate step.

D. Procedures for Step Rate Tests

The pressure in the zone to be tested should be quite stable at the time the test is begun. For best results, the water level should be at or very near the surface. This means that if a heavy brine has been used to kill the well, then fresh water should be added sometime before the tests begins until the water level reaches the surface. If the pressure in the reservoir is so low that it will not support a column of fresh water reaching to the surface then injection at a rate which is low but sufficient cause a pressure increase which will support a column of water to the surface should be maintained until the injection pressure becomes stable before the test begins. This eliminates the problem of changing injection rate as the well bore fills during early steps.

Because pressure due to friction will be a very important factor in pressures measured at the surface during injection at high rates, it is strongly recommended that downhole pressure gauges be used. In either case, friction reducers may be used.

Magnitude of Rate Increases
The test should be planned to include at least three rates below the fracture opening pressure, not including the zero-rate step. A leak-off test should be conducted before the SRT in order to determine the rates required for the test. This test is useful in determining the relation of pressure increase below fracture pressure so that appropriate injection rates can be chosen.

Length of Rate Steps
The lengths of the rate steps must be equal. The length should be planned so that the pressure at the

end of each rate step will be fairly constant. This makes timing less critical than if rate steps are ended while the injection pressure is still increasing rapidly. The UIC Branch also recommends that the final step be twice as long as preceding steps so that a fall-off test can be run following the SRT. The effects of rate changes will make interpretation of pressure change difficult after a very short time. The fall-off test may be able to identify fracture closure pressure if measurements are made very frequently at the time the final step is ended.

<u>Number of Rate Steps Above Fracture Opening Pressure</u>
At least two steps beyond fracture opening are required to confirm opening and three steps are recommended. The magnitude of rate increases following fracture opening need not be great, but they should be at least 120% of the preceding rate.

E. Interpretation

The pressure at the end of each step is plotted against the injection rate at the end of the same step. Best-fit lines are constructed using the points before and after fracture opening. The pressure at the point of intersection is the fracture opening pressure.

If a fall-off test is performed using the last injection period and the succeeding shut-in period, the results should be analyzed similarly to a fall-off test. In particular the relationship of time and pressure data recorded before the pressure fell below the fracture opening pressure might be important. If the points based on these data indicate linear flow, the fracture closure pressure can be determined. Usually the fracture closes before enough data can be gathered to define a time of linear flow.

In order to properly interpret the SRT, a plot of pressures versus rates is constructed. In either case, the desired result is a surface pressure level at which injection can occur without the initiation or propagation of fractures. The pressures may be measured at the surface and corrected for friction for the construction of the chart, or measured at the injection zone. Because friction increases with increased rate, failure to correct for friction may mask the inflection of the time-pressure plot at fracture extension pressure.

Region 5 uses a spreadsheet program to make the friction correction, produce the plot, construct best fit lines for pressures below and above the inflection point, and then determine the point at which the two lines intersect. The analyst can choose which points to consider for matching. This allows points very near the intersection to be used on either line segment or neither of them.

Interpretation may not be straightforward. It may be necessary to alter the scale to identify the inflection point. In a number of tests there has been no discrete inflection point despite injection at very high rates and surface pressures. There may be a relatively tight curve indicated between relatively linear plots. In the case of the appearance of a tight curve, or even a single point which appears to be on neither line segment, we tend to believe that pressure-sensitive permeability rather than fracture opening is responsible. We have results of two tests in which heated water was used to confirm that fracture opening did not occur in previous tests. Theoretically, the injection of heated water will increase near-wellbore stresses due to thermal expansion and the fracture opening pressure will be increased. In the two cases, the pressures at which inflection occurred were lower than when cool water was used. Because of the few data sets we have examined, we have many questions about the entire process. However, we have confidence that fracture opening is not always the cause for increased injectivity.

If pressure measurements made at the injection zone have been used, when the inflection point has been identified, the pressure is adjusted to the surface by calculating the force which will be exerted by the column of water between the gauge depth and the surface and subtracting it from the appropriate pressure.

This reversal of the theoretical response, a decrease rather than an increase in injection pressure with warmer waste, is believed to be due to decreased viscosity at higher temperatures.

ATTACHMENT 8
MICROFRACTURE TESTS

A. Basis

Microfracture tests make use of injection over a very short section of the well bore to induce failure in rocks. As a result, the injection rates necessary to induce fracturing pressures in the tested formations are low, often a few gallons per minute and fracturing pressures are reached within a minute or two of the time injection begins. After fracture opening occurs, injection at the same rate continues for several minutes and then the pumps are stopped and a pressure fall-off test methods are used to find the fracture closure pressure.

B. Advantages and Disadvantages

Informational Advantages Relative to other Demonstrations

Measurements are made in situ with actual fracture opening occurring, and are more representative of actual conditions than determinations made through core or log measurements;

Fall-off data can be used to estimate hydrostatic pressure; thereby allowing collection of a number of hydrostatic pressure measurements;

Informational Disadvantages Relative to Other Demonstrations

None;

Operational Advantages Relative to other Demonstrations

Require a short time and numerous tests can be run in a matter of hours.
Require very little water and low horsepower pumping equipment.

Operational Disadvantages Relative to Other Demonstrations

Pumping equipment normally available is more suited to pumping at higher rates. Pump trucks may need modifications.

C. Equipment and Forms

The equipment is that which is normally used for pumping fluids for stimulation in oil or gas producing wells. There is no standard form for reporting data. Digital time and pressure data should be submitted if recorded, along with injection interval, rate, date and time.

D. Procedures for Conducting a Microfracture Test

Microfracture tests were developed as a means to measure near-surface lithostatic stresses, and the techniques used may not provide good data when transferred directly to the deep subsurface. Downhole pressure measurement is a real advantage. Inflatable packers are set with about four feet of perforated pipe between them. An electronic memory gauge (EMR) may be used to measure pressure within the packed-off interval and an EMR should be used to measure pressure below the packed-off interval to allow investigation of packer by pass. The primary pressure recorder may be a wireline SRPG mounted above a ported standing valve which seats above the upper packer to shut in the test zone. This arrangement produces very good data. It is most important to collect pressure data frequently. Because of the small amount of fluid injected, the temperature changes during injection are usually small, so pressure measurements can be substituted for temperature measurements for transmission. If pressure measurements can be made more frequently using an EMR than a SRPG, then an EMR should be used.

Injection of only a few gallons per minute may be sufficient to induce high pressure and fracturing within the test interval. The rate should be high enough so that pressure rises very rapidly past fracture opening pressure. After the rock fractures and the pressure stabilizes, injection should continue for at least one minute before the pumps are stopped and the well is shut in. Pressure fall off should be allowed to continue until the pressure approaches stability. This cycle should be repeated three times.

E. Interpretation

Analog recordings show sharp changes in curvature upon fracture opening and closure. When analog measurements are made, the only interpretation is picking the pressures at which fracture opening and closing occur. If digital data are recorded, the tests can be analyzed as other pressure transient tests are. Upon fracture opening, radial flow ends and linear flow begins. These points can be picked using the derivative of pressure change. Similarly, when fracture closure occurs, the end of linear flow can be identified. The real advantage of using digital recorders down hole is that some reservoir parameters, such as permeability and hydrostatic pressure, may be determined, even in lithologies with low permeabilities.

ATTACHMENT 9
MINIFRACTURE TEST

A. Basis

Minifracture tests are used to test an entire injection interval in a completed well. The minimum horizontal stress existing in the interval to be tested is exceeded by injecting at a relatively high rate. The pressure records are used to determine the pressures at which failure, fracture extension, and fracture closure occur. The minifrac lasts long enough for fracture growth to occur. The records of pressures, rates, and fluids used during the test are analyzed to allow characterization of the fracture which is created. This information is frequently used to plan well stimulations.

B. Advantages and Disadvantages

Informational Advantages
Relative to step rate testing, closure pressure is determined rather than fracture extension pressure;
Relative to microfracs, the entire injection interval is tested;

Informational Disadvantages

None;

Operational Advantages

Relative to step rate testing, requires a limited amount of water;
Relative to microfracs, requires less time and equipment;

Operational Disadvantages

None.

C. Equipment and Forms

Equipment includes pump trucks, wellhead equipment, and pressure measurement devices. The pressure record may be an analogue pressure recording, but is more likely to be a digital recording which may be presented in an apparently analogue form. The pressures recorded will probably have been measured at the surface.

D. Procedures for Performing a Minifrac

The primary purpose of minifrac tests is to determine how rock and frac fluids will interact during well stimulations. This includes leak-off behavior as well as mechanical properties. Because we are interested only in mechanical properties and (for the most part) use minifrac data because it is already available, this guidance does not include detailed procedures for running minifracs. If a minifrac is proposed for the purpose of determining closure pressure, we suggest it be run similarly to a microfrac, the difference being the injection rate. Whereas minifracs are usually run through only one cycle of injection and fall-off, we would require several cycles to be sure that good data are collected, just as is done during a microfrac.

E. Interpretation For our purposes, the minifrac would be analyzed in the same way that a microfrac is analyzed.

ATTACHMENT 10
REQUIRED DATA FORM

<u>Required Well Background Information</u>

Well identification

Well radius

<u>Required Injection Formation Information</u>

Net thickness of injection zone

Porosity

Formation compressibility

<u>Required Injection Fluid Information</u>

Viscosity of injected fluid

Density of injection fluid

Viscosity of reservoir fluid

Fluid compressibility

<u>Required Test Information</u>

Date of test

Depth to pressure gauge

Injection rates

Length of flow period

Flow rate data for other wells

The following data may be provided in printed and/or in computer readable format as agreed upon:

> Time data in decimal format to three decimal places for time in hours,
> Pressure data to two decimal places for pressure in psi, and
> Temperature data to one decimal place in degrees Fahrenheit.