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Attachment F: Testing and Monitoring Plan

SYD Denova 1

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(40 CFR 146.90)

Revision	Date	Notes	Written By	Approved By
A	11/27/2023	Issued for Approval		R. Keeling

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1. Facility Information

- [redacted]
- [redacted] [redacted]
- [redacted]
- [redacted] [redacted]

This Testing and Monitoring Plan describes how [redacted] will monitor the site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide (CO_2) plume and pressure front are moving as predicted, and that there is no endangerment to underground sources of drinking water (USDWs), the monitoring data will also be used to validate and adjust the computational models used to predict the distribution of the CO_2 within the injection zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

2. Overall Strategy and Approach for Testing and Monitoring

CO_2 plume and pressure front tracking will be conducted at the project site and will be based on the computational modeling results described in **Attachment A: Area of Review and Corrective Action Plan**. Injection and environmental testing and monitoring methods are presented in Tables F-2, F-6, F-9, and F-10. As the project progresses, the Testing and Monitoring Plan will be amended if appropriate and in accordance with testing and monitoring data that is collected during the injection and post-injection site care (PISC) phases of the project. The primary objective of this Testing and Monitoring Plan is to continuously ensure that the pressure front and CO_2 plume are aligning with model predictions and are sufficiently monitored to prevent endangerment to USDWs. Below is a brief summary of the testing and monitoring methods that will be employed at the project site, with further elaboration of each method presented in Sections 3 through 9 of this document.

2.1 Pre-Operational, Operational, and PISC Testing and Monitoring Summary

2.1.a Groundwater

Pre-operational, or baseline, groundwater monitoring will occur prior to injection. Groundwater chemistry will be monitored in the lowermost USDW, [redacted], and the public use aquifer, the [redacted] in the project AoR. A baseline fluid sample has been acquired in the [redacted] from the [redacted] and is reported in Appendix F-1.

Groundwater chemistry for the [redacted] has been documented in two surrounding historical water wells outside of the AoR and is presented in the **Permit Application Narrative, Appendix 7**.

Additionally, [redacted] water wells within the project AoR that penetrate the [redacted] have been identified for sampling during the pre-operational phase of the project. Refer to Figure F-1 for wells locations and Appendix F-2 for well details. Wells were selected to capture a representative spatial distribution and sampling depth within the project AoR. Pre-operational sampling results will be reported when acquired and

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analyzed. If at any time during the project the list of selected groundwater wells needs to be amended, [redacted] will seek approval from the U.S. Environmental Protection Agency (EPA) prior to any amendment.

During the operational and PISC phases of the project, groundwater chemistry will continue to be sampled for the [redacted] fluid chemistry will be sampled [redacted] located approximately [redacted] (Figure F-1). The [redacted] well will be used as the [redacted] well. [redacted] fluid chemistry samples will continue to be obtained from the [redacted] existing water wells listed in Appendix F-2.

2.1.b Geophysical Methods

The [redacted], will be acquired prior to injection, and will include the [redacted]

[redacted]

2.1.c Well Methods

Testing and monitoring methods that will occur in the injection and/or monitoring wells include those intended for plume and pressure front tracking, injection rate and volume monitoring, as well as mechanical integrity verification. In summary, these methods are:

- [redacted]
- [redacted]
- Pressure fall-off testing (PFOT)
- Internal and external mechanical integrity testing (MIT)
- Flowmeter

For CO_2 plume tracking, a [redacted] listed in Table F-9. This frequency will be increased if abnormal plume behavior is expected or observed based on computational modeling and/or testing and monitoring data.

[redacted] injection design is shown in **Attachment B: Construction Details**, Figure B-2. [redacted] wellbore diagrams (WBDs) [redacted] are displayed in Appendix F-3. Baseline reservoir pressures will be established in [redacted] prior to injection and will be monitored continuously during the operational phase of the project. Once [redacted] is plugged at the end of its injection life, [redacted] will continue to monitor reservoir pressure during the PISC period. These wells will also be equipped with annulus P/T gauges to monitor annular pressure.

Upon completion of the injection well, a baseline PFOT will be conducted to verify pressure behavior and fracture gradient of the injection zone. During the operational phase of the project, a PFOT will be acquired once every 5 years to assess reservoir behavior.

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Internal mechanical integrity testing (IMIT) will be conducted prior to injection and no less than once every 5 years during the operational phase of the project. Annulus pressure testing (APT) will be used as the primary IMIT method and will support other methods of verifying internal mechanical integrity, including monitoring injection pressure, injection rate, injected volume, pressure on the annulus between the tubing and long-string casing, and annulus fluid volume. External mechanical integrity testing (EMIT) will be conducted prior to injection, no less than once every year until the injection well is plugged, and prior to injection well plugging after the cessation of injection. [redacted] will be used as the primary EMIT method.

[redacted] flowmeters will be used to continuously monitor injection rate and volume. [redacted] flowmeters will be located at surface facilities: [redacted] will notify EPA if the flowmeter design and/or type is changed during the facilities detailed design process.

2.1.d Corrosion Monitoring

During the operations phase, injection well materials will be monitored for loss of mass, thickness, cracking, or pitting to ensure that well components meet minimum standards for mechanical integrity. A [redacted] will be utilized over the life of the project, and is further characterized in Section 5 of this document.

2.2 Quality Assurance Procedures

A Quality Assurance and Surveillance Plan (QASP) for testing and monitoring activities described in this attachment is provided as **Attachment G: QASP**.

2.3 Reporting Procedures

[redacted] will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91. Data will be submitted in electronic format. Additionally, [redacted] will notify the EPA Director at least 30 days prior to conducting any testing.

3. Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

[redacted] will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

Injectate composition is discussed in the **Permit Application Narrative, Section 4.8.3**. The injectate is predicted to be [redacted] from the ethanol fermenting process.

3.1 Sampling Location and Frequency

The CO_2 stream, or injectate, will be sampled quarterly and sent to a third-party laboratory for analysis. Quarterly sampling is deemed to be sufficient to yield representative physical and chemical CO_2 stream characteristics due to the predictable nature of the ethanol fermentation process. Samples will be collected at a quarterly frequency for [redacted] prior to injection and will serve as a baseline characterization. During injection, quarterly sampling will occur by the following dates each year: 3 months after injection begins, 6 months after injection begins, 9 months after injection begins, and 12 months after injection begins.

Laboratory samples will be extracted from a sample point [redacted] and permitted to decompress into a gaseous phase within a sample holder or other device for analysis. Standard methods will be used to calculate chemical and physical properties at in situ pressure and temperature from the results of the decompressed sample analysis (U.S. EPA, 2013). Once a chemical baseline characterization has been made, a statistically significant deviation threshold will be established that will prompt [redacted] to increase sampling frequency in the event of anomalous CO_2 concentrations. [redacted] will notify EPA if the sampling location is changed during the facilities detailed design process.

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3.2 Analytical Parameters

[redacted] will sample the CO_2 stream for the constituents identified in Table F-1. Samples will be sent to a third-party for analysis using the methods listed in the table.

Table F-1. Summary of Analytical Parameters for CO_2 Stream

Parameter	Analytical Method(s)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes: (1) An equivalent method may be employed with the prior approval of the Underground Injection Control (UIC) Program Director.

[redacted]

3.3 Sampling Methods

Laboratory samples will be extracted from a sample point [redacted] A sampling station will be installed that will allow for sample purging and collection. The sample container will be sealed and sent to an authorized laboratory for chemical and physical analysis.

3.4 Laboratory to be Used/Chain of Custody and Analysis Procedures

Samples will be sent to and analyzed by a third-party laboratory that utilizes standard procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The chain-of-custody procedures described in **Attachment G: QASP, Section 2.3** will be employed.

CO_2 injectate analysis will be submitted in semiannual reports, which include a list of chemical analyses, third-party laboratory reports, chain-of-custody forms, tabular testing results, sampling description, and data interpretation.

4. Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

[redacted] will install and use continuous recording devices to monitor injection pressure, rate, and volume, the pressure on the annulus between the tubing and the long string casing, the annulus fluid volume added, and the temperature of the CO_2 stream, as required at 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

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4.1 Monitoring Location and Frequency

[redacted] will perform the activities identified in Table F-2 to monitor operational parameters and verify internal mechanical integrity of the injection well as required at 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b). All monitoring will take place at the locations and frequencies shown in the table.

Table F-2. Sampling Devices, Locations, and Frequencies for Continuous Monitoring

Parameter	Device(s)	Location	Minimum Sampling Frequency	Minimum Recording Frequency
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted] [redacted]	[redacted] [redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.

Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

(1) Fluid volume added or removed to maintain annular pressure will be recorded on the date performed and submitted to the regulatory authority

4.2 Monitoring Details

4.2.a Continuous Monitoring of Injection Pressure and Rate

[redacted] will monitor injection pressure continuously using [redacted] (Table F-2). [redacted] specifications and calibration standards are listed in **Attachment G: QASP, Section 1.4.** [redacted] will be calibrated at least annually according to its calibration standards. [redacted] once deployed and will therefore be deployed with [redacted].

Flow rate will be monitored with an [redacted] flowmeter located [redacted]. The flowmeter will be calibrated for the entire expected range of flow rates and will be accurate to within [redacted] (**Attachment G: QASP, Table G-7**).

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Injection operations will be monitored using a supervisory control and data acquisition (SCADA) system. Injection operations will be continuously monitored by [redacted] staff using the SCADA system. Critical systems parameters (i.e., pressure, temperature, and flow rate) will be continuously monitored and integrated with SCADA, allowing SCADA to alarm and shutdown if any control parameters demonstrate anomalous changes outside of their normal operating range. The master control room in which SCADA will continuously be monitored will be located at the [redacted]

4.2.b Injection Volume Monitoring

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Table F-3. [redacted]

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

4.2.c Continuous Monitoring of Annular Pressure

[redacted] will use the following procedure to continuously monitor annular pressure and ensure the integrity of the wellbore annulus:

1. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

An annular pressure gauge will be mounted on the wing valve of the [redacted] (Figure F-2). Annular fluid volume, if added, will be monitored and recorded. Any changes in the composition of the annular fluid will be reported to the Region 8 UIC Program Director.

5. Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), [redacted] will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

[redacted] according to the description in the following subsections.

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5.1 Monitoring Location and Frequency

This monitoring will occur quarterly, by the following dates each year: 3 months after injection begins, 6 months after injection begins, 9 months after injection begins, and 12 months after injection begins.

5.2 Sample Description

Materials that encounter the CO_2 stream will have samples included in the [redacted] system. The samples are listed in Table F-5 and include the [redacted]

Table F-5. List of Equipment with Material of Construction

Equipment Coupon	Material of Construction
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

5.3 Monitoring Details

[redacted]

[redacted]

6. [redacted]

[redacted]

- [redacted]
- [redacted]

[redacted] Groundwater chemistry analysis will be conducted in accordance with **Attachment G: QASP, Table G-4**.

6.1 Monitoring Location and Frequency

Table F-6 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring [redacted]

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Table F-6. Monitoring of Groundwater Quality and Geochemical Changes [redacted]

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]

6.1.a [redacted] Lowermost USDW Monitoring

[redacted]

6.1.b Shallow USDW Monitoring

A total of [redacted] shallow ([redacted]) groundwater wells within the AoR have been identified to monitor the public use aquifer, the [redacted]. Figure F-1 presents the AoR and groundwater wells identified for [redacted] monitoring (selected well has permit number displayed on map). Well permit information is available on Colorado's Department of Natural Resources (DNR) website and is provided in Appendix F-4. All shallow groundwater wells are owned by private parties or state agencies. Access agreements will be made with all parties to ensure compliance with the monitoring program summarized in Tables F-6 and F-7.

Fluid samples frequencies are listed in Table F-6. Fluid samples will be obtained at a [redacted] in the shallow groundwater wells prior to injection. Fluid samples will be analyzed for the parameters listed in Table F-7.

Fluid samples will be collected after the well has been purged to ensure stabilization of field parameters (i.e., pH, temperature, dissolved oxygen, specific conductivity). Samples will be collected in sample bottles provided by a third-party laboratory and proper chain of custody protocols will be followed per the selected laboratory. QA/QC samples will also be obtained including one duplicate, one equipment rinsate/blank, one matrix spike (if needed based on analytical method) and one trip blank.

6.1.c Sampling, Data Interpretation, and Reporting

[redacted] will maintain an electronic database of all monitoring results. Sampling will be performed as described in **Attachment G: QASP**, including sampling standard operating procedures (SOPs), chain of custody procedures, and QA/QC measures.

Baseline groundwater data, in combination with historical data, will be analyzed to establish expected statistical ranges for each analyte. Deviations from this range may be statistically significant and signify an anomaly, prompting an investigation by [redacted]. All groundwater quality analyses will be compared to baseline analysis collected prior to injection for potential leakage signatures, including:

[redacted]

Groundwater analysis will be reported to the EPA in semiannual reports and in an electronic format, including all recent results, laboratory reports, data interpretation, description of sampling activities, data quality evaluation, and identification of any data gaps if present.

6.2 Analytical Parameters

Table F-7 identifies the analytical parameters to be monitored and their corresponding analytical methods.

Table F-7. Summary of Analytical and Field Parameters for Groundwater Samples

Parameters	Analytical Methods
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

6.3 Sampling Methods

Sample collection procedures are described above in Sections 6.1.a and 6.1.b and will be performed as described in **Attachment G: QASP**, including sampling SOPs, chain of custody procedures, and QA/QC measures.

6.4 Laboratory to be Used/Chain of Custody Procedures

Detection limits for analytical methods and chain of custody procedures are described in **Attachment G: QASP**. The sample chain-of-custody procedures described in **Attachment G: QASP, Section 2.3** will be employed.

7. External Mechanical Integrity Testing

7.1 Testing Location and Frequency

[redacted] will conduct at least one of the tests presented in Table F-8 periodically (at least once per year until the injection well is plugged as required at 146.90(e)) during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90.

Table F-8. Mechanical Integrity Tests

Test Description	Location
[redacted]	[redacted]
[redacted]	[redacted]

7.2 Testing Details

MITs will be performed annually up to 45 days before the anniversary date of first injection each year. Additionally, during normal operations (i.e., no shut-in period or workover activities), a deviation of [redacted] from

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normal operating annular pressure will trigger a mechanical integrity investigation. If the annular pressure is returned to its operating pressure and the deviation persists, mechanical integrity will be verified.

[redacted] will be conducted in accordance with EPA guidance (U.S. EPA, 2013). [redacted] procedures per are provided in Appendix F-5. [redacted] will be conducted using wireline techniques and the following procedure:

[redacted]

[redacted] will only be conducted if [redacted] results were inconclusive. [redacted] procedures are provided in Appendix F-6.

All EMIT results will be submitted to EPA in an electronic format within 30 days of completion of each test. MIT reports will include charts and/or tabular results of each log including a comparison of background or baseline conditions, injection conditions, shut-in conditions, and a description of each test including date and time of the test.

8. Pressure Fall-Off Testing

[redacted] will perform PFOTs during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

8.1 Testing Location and Fequency

PFOTs will be conducted upon initial completion of the [redacted] well and every five years thereafter to confirm reservoir and well conditions unless more frequent testing is required by the UIC Director.

8.2 Testing Details

EPA Region 6 guidelines that will be followed for PFOTs are provided in Appendix F-7. A summary of the PFOT testing procedure is as follows:

- Maintain continuous, normal injection operations for at least one week prior to shutting in the well
- Shut-in the well at the wellhead and monitor pressure decay
- Conduct test until radial flow can be observed and characterized. If radial flow is not observed after reasonable attempts are made, attempt to type curve match the falloff data.
- Conduct PFOT analysis for identification of reservoir parameters.
- Submit analysis and results to the EPA

Continuous pressure measurements will be made [redacted]. Pressure gauge specifications are included in Table F-2.

PFOT results will be submitted to the EPA within 30 days of the completion of each test. Results will be submitted in a tabular format, including the date and duration of the test, bottomhole pressure and temperature, gauge specifications, injection rates and pressures prior to the PFOT, various pressure plots, changes to any AoR model parameters, if necessary, calculated reservoir parameters (permeability, transmissivity, skin factor), and identification of any data omissions or anomalies.

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9. Carbon Dioxide Plume and Pressure Front Tracking

[redacted] will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

9.1 Plume Monitoring Location and Frequency

Table F-9 presents the methods that [redacted] will use to monitor the position of the CO_2 plume, including activities, locations, and frequencies. Quality assurance procedures for these methods are presented in **Attachment G: QASP, Section 2**.

Table F-9. Plume Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Indirect Plume Monitoring				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Plume monitoring within the injection zone will include the following:

- [redacted]
- [redacted]

[redacted]

[redacted]

9.2 Plume Monitoring Details

[redacted]

9.3 Pressure-Front Monitoring Location and Frequency

Table F-10 presents the methods that [redacted] will use to monitor the position of the pressure front, including the activities, locations, and frequencies. Quality assurance procedures for these methods are presented in **Attachment G: QASP, Section 2**.

[redacted] will install [redacted] (Tables F-2 and F-10). [redacted] as discussed in Section 4, above. [redacted] Appendix F-3 provides the [redacted].

Table F-10. Pressure-Front Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]

9.4 Pressure-Front Monitoring Details

[redacted]

Pressure monitoring data will be submitted to the EPA in semiannual reports, including raw pressure data, gauge calibration reports, time-series graphs of measured pressure versus modeled pressure, and identification of any data omissions or anomalies.

10. References

U.S. Environmental Protection Agency (EPA), 2013. Underground Injection Control (UIC) Program Class Six Well Testing and Monitoring Guidance. Office of Water (4606M) EPA 816-R-13-001, March 2013.

Ouyang, 2011. New Correlations for Predicting the Density and Viscosity of Supercritical Carbon Dioxide Under Conditions Expected in Carbon Capture and Sequestration Operations. *The Open Petroleum Engineering Journal* 4: 13-21.

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Figures

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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Appendix F-5

Temperature Logging Guidelines

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http://www.epa.gov/region08

TEMPERATURE LOGGING FOR MECHANICAL INTEGRITY

Approved January 12, 1999

PURPOSE:

The purpose of this document is to provide a guideline for the acquisition of temperature surveys, a procedure that may be used to determine the internal mechanical integrity of tubing and casing in an injection well. A temperature survey may be used to verify confinement of injected fluids within the injection formation.

Test results must be documented with service company or other appropriate (acceptable) records and/or charts, and the test should be witnessed by an EPA inspector. Arrangements may be made by contacting the EPA Region 8 Underground Injection Control (UIC) offices using the EPA toll-free number 1-800-227-8917

LOGGING PROCEDURE

1. Run the temperature survey while going into the hole, with the temperature sensor located as close to the bottom of the tool as possible. The tool need not be centralized.

2. Record temperatures a 1-5 ^{o}F per inch, on a 5 inches per 100 feet log scale.

3. Logging speed should be within 20 - 30 feet per minute.

4. Run the log from ground level to total depth (or plug-back depth) of the well.

5. When using digital logging equipment, use the highest digital sampling rate as possible. Filtering should be kept to a minimum so that small scale results are obtained and preserved.

6. Record the first log trace while injecting at up to the maximum allowed injection pressure. Subsequent to the temperature survey, the maximum injection pressure will be limited to the pressure used during the survey.

Log the first log trace while the well is actively injecting, and record traces for gamma ray, temperature, and differential temperature. Shut-in (not injecting) temperature curves should be recorded at intervals depending on the length of time that the injection well has been active.

Preferred time intervals are shown in the following table:

Active Injection	Record Curves at These Times (In Hours)				
1 month	1	3	6	12	
6 months	1	6	10-122	22-24	
1 year	1	10-12	22-24	45-48	
5 years	1	10-12	22-24	45-48	90-96
10 years or more	1	22-24	45-48	90-96	186-192

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Appendix F-6
Radioactive Tracer Survey Guidance

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Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations

PURPOSE:

The purpose of this document is to provide EPA staff with guidelines to assist operators in planning and conducting a Radioactive Tracer Survey (RTS). When used properly, a RTS can identify the presence or absence of vertical fluid movement behind the casing near injection perforations. With the exception of very specific circumstances, the RTS is not approved as a stand-alone method for demonstrating Part II (external) Mechanical Integrity (MI). However, a RTS can be used to supplement data from approved Part II demonstrations. If channeling behind casing is detected, a RTS can also be used to evaluate the vertical extent of fluid movement.

As with any logging or testing method, planning a RTS should begin with a clearly stated objective and should identify consequences and follow-up actions based on the results anticipated. It is important to understand the site-specific geologic, construction, and operational factors that may influence the test. Remind the operator that RTS results must be analyzed and interpreted by a knowledgeable log analyst and must be documented with the appropriate narrative descriptions, log records, schematics, and charts, and that advance notification is required 30 days prior to conducting a RTS when it is expected that the Maximum Allowable Injection Pressure (MAIP) will be exceeded. Discussing the RTS procedure with the operator and the logging service company prior to conducting the RTS is strongly recommended.

PLANNING THE TEST

The operator should consider many factors when planning a RTS: wellbore construction, any drilling or completion problems encountered, fracture and acid treatments, proximity of USDWs and confining zones, and the adequacy of the confining zone all play a role in the success of the test. Planning the RTS should include discussion of the following items with the operator and the logging service company:

- LOGGING EQUIPMENT: Determine any limitations of the logging equipment to be used in conducting the RTS.
- THE LOGGING TOOL: The RTS tool should include a collar locator for depth control with at least one ejector and one gamma-ray detector located below the ejector.
- TRACER MATERIAL: The tracer material, typically Iodine 131, should be dated less than one half-life at the time of use.
- TEST PRESSURE: Discuss the test pressure with the operator and the service company prior to conducting the RTS. The results obtained are only valid at (or below) the pressure obtained while conducting the RTS. Therefore, the RTS should be conducted at the MAIP when possible. The MAIP may be reduced in cases where a RTS is conducted at a lower pressure.

- WORKOVERS: Any anticipated workover or treatment operations should be performed prior to conducting the RTS. Workover and treatment operations occurring *after* the RTS may necessitate an additional RTS to reconfirm the presence of adequate cement near injection perforations.
- SEQUENCE OF LOGGING: Because tracer material ejected during early logging runs can interfere with later logging passes, the RTS should be designed to begin in the deepest portion of the well, moving progressively shallower. Alternatively, sufficient water should be injected between logging runs to flush tracer material out of the casing and away from the wellbore where it will not interfere with subsequent tracer runs.
- DETECTOR GAIN: During the pre- and post-tracer logging runs, tool gain should be set to detect changes in lithology and to correlate with other well logs. When logging full-strength tracer slugs, tool gain should be set to deflect nearly full scale at the slug's peak.
- FOR EACH LOG PASS: Operator should record the beginning and ending clock times, the tool location, injection pressure, and injection rate.
- LOG SCALE: Depth scale should be scaled 5 inches per 100 ft to facilitate correlation with other logs. Logs run on time drive should be scaled at 1 inch (or more) per minute.
- LOGGING SPEED: On depth-drive, logging speed should be no greater than 60 ft/min.

SURVEY ELEMENTS

The RTS used to investigate channeling behind casing should include several elements. These are:

- Tool calibration and gain settings
- Pre-tracer background gamma ray log
- Injectivity Profile
- Channel Check (two parts)
- Post-tracer gamma ray log

1) **Tool calibration and setting instrument gain:** Tool gain settings typically vary between different types of logging runs. During the pre- and post-tracer gamma ray log runs, the tool gain should be set so that lithological effects are easily identifiable, background noise is minimized, and correlation with other well logs can be made. This is often about 40 API units or equivalent per inch. To aid in choosing gain settings for the pre- and post-tracer curves, background gamma readings should be made in both a sand and shale to show the magnitude of "noise" measured at the proposed logging sensitivity. The readings should be taken while holding the tool stationary and recording gamma radiation in time drive for a period of 3 to 5 minutes each. This is a statistical check in a shale and sand to set the gain appropriately. The gain on the pre- and post-tracer runs should be set equally to allow the two log runs to be overlaid for comparison. When logging the radioactive slugs on time drive, the tool gain should be set to deflect nearly full scale at the slug peak.

2) **Pre-tracer baseline gamma ray log:** This log provides the baseline gamma ray response through the injection interval and confining zones prior to release of *any* recent radioactive tracer material into the wellbore. This log will be compared to the post-tracer gamma ray log made at the conclusion of the RTS.

- Logging speed should be no greater than 60 ft/min.
- Tool gain should be set to detect changes in lithology and to correlate with other well logs.
- Operator should begin the pre-tracer gamma ray log 200 ft below the lowermost perforation (or at PBTD) and continue to a point at least 200 ft above the top of the uppermost confining zone.

3) **Injectivity Profile:** The injectivity profile will determine the percentage of fluid entering each set of perforations and to confirm no-flow below all perforations. The percentage of fluid entering any set of perforations can be determined by comparing the fluid velocity at points above and below the perforations. Two methods are often used to determine fluid velocity: Method 1) by holding the tool stationary and running the tool on time drive and recording the time needed for the slug to move a fixed distance between the ejector and the detector, or Method 2) by placing the tool on depth drive and logging through a moving slug. In either case, the fluid velocity is determined by comparing the distance the slug has moved with the time required to move that distance. Determining which method to use at each point will depend on the distance between perforated intervals, and the anticipated fluid speed at that point. Consult with the logging service company regarding the appropriate method for each set of perforations. Here are some other factors for the operator to consider:
   - This log pass should be conducted with the well injecting at a test pressure corresponding to the MAIP and with the injection rate stabilized.
   - Fluid velocities should be determined at points 1) below all perforations, 2) between each set of perforations, and 3) at one point above all perforations (moving from deeper to shallower, if possible).
   - Logging below the lowermost perforation should confirm no-flow. Any fluid moving below the lowest set of perforations may indicate injection into an unpermitted interval. **NOTE:** *If the RTS is being used to confirm that no fluid is moving behind pipe vertically below the lowermost perforations, the velocity shot that is made below all perforations should be conducted last (following the post-gamma ray log) in order to prevent the appearance of a 'hot spot' on the post-gamma ray log.*
   - Show the injectivity profile by determining the percentage of injected fluid entering each set of perforations.

4. **Channel Check:** The Channel Check consists of two parts. 1) a time-drive portion where the tool is held stationary inside the casing, watching for vertical flow behind casing, and 2) a depth-drive portion where the interval above and/or below the perforations is logged on depth drive, making note of any fluid that has moved vertically from the perforations.

   a) **Time Drive:** This log is used to detect fluid moving vertically behind casing after entering the perforations. This log should be run with the well injecting at the MAIP, with the tool on time-drive, and with the stationary detector located just above the uppermost set of perforations that are shown to be accepting fluid (uppermost effective perforations). The detector should be located so that it is as close as possible to the top set of effective perforations but at a depth that will allow the radioactive slug to pass entirely below the lower detector before entering the perforations. If the detector is located too close to the perforations, the tool may detect tracer material inside and outside of the casing at the same time, obscuring the results of the test.

Once the tool is positioned, a tracer slug is ejected into the wellbore where it mixes with injected fluid and begins moving downward inside the casing, past the lower detector as it continues toward the perforations. The tool should remain on time-drive as the tracer slug enters the perforations and continue recording for some predetermined time, waiting for evidence of any tracer material moving vertically outside of the casing.

Calculating an appropriate wait-time is crucial for using the RTS to determine if fluid is moving vertically behind casing. The wait-time depends on several factors: 1) the injection rate, 2) the distance between the detector and the perforations, 3) the percentage of fluid moving into the perforations, and 4) the size of any cement channel (which cannot be predetermined). No single wait-time will fit every case, but one hour is the safest default for the majority of injection wells in Region 8. Another method for determining the appropriate wait-time is to use a value of $3t$, where t is the time for fluid inside casing to flow between the detector and the uppermost set of effective perforations. A full discussion of the methodology used to determine an appropriate wait-time should be included as part of the submitted results. In addition, a written justification of the chosen wait-time may be in the operator's interest, particularly if the selection methodology differs from those outlined in these guidelines.

The following considerations apply for a Channel Check utilizing Time Drive:

- The results of the Injectivity profile should be used to determine the uppermost set of perforations accepting fluid and the fraction of fluid entering those perforations.
- The log trace during this first portion of the Channel Check should be made with the tool stationary on time-drive, and with the tool located so that the lower detector is as close as possible to the uppermost set of effective perforations, but at a sufficient distance that will allow the radioactive slug to pass entirely below the lower detector before entering the perforations. It may be preferable to position the tool at a specific depth (the confining zone, for example, if it is close enough to the perforations).
- The operator should use a default wait-time of one hour or calculate $3t$. If site-specific conditions appear to call for longer or shorter test times, discuss this with the operator and with the service company prior to running the RTS.
-

b) **Depth Drive:** Immediately following the time-drive portion of the channel check, the tool should be switched to depth-drive and the interval between the tool's current depth and the perforations should be logged. If the detector indicates any tracer material moving vertically away from the perforations, the operator should wait briefly and then repeat this pass, tracking the slug as it continues to move vertically. Several passes may be required in order to determine the depth where the slug appears to moves no further. If movement of the slug is detected behind casing in the depth-drive mode, the operator will include a full written description of the extent and the probable causes for the fluid movement, including any justification of why the results indicate the presence of adequate cement despite observed channeling may be in the operator's interest.

6) **Post-tracer gamma ray log:** This log provides a post-tracer gamma ray log to be compared with the pre-tracer baseline gamma ray log recorded prior to running the RTS. Evidence of behind-pipe fluid movement can be evaluated by overlaying and comparing these two log traces, noting any differences or 'hot spots'.

    - Logging speed, gain, and depths run should duplicate settings used for the pre-tracer baseline gamma ray log

SUBMITTING THE RESULTS:

The operator should provide an analytical interpretation of the logging results performed by a qualified analyst. This should include a written description of the procedure including the methodology used to calculate the wait-time, and conclusions drawn from the test. The submittal should include a fluid loss profile across the perforations and a schematic diagram of the RTS tool and well construction on or with the log. The diagram should show:

- Tool layout
- Casing diameters and depths
- Tubing diameter and depth
- Perforated interval(s)
- Open hole intervals
- Packer location(s)
- Total depth and/or plugged back total depth
- The location of the tool when the tracer material was ejected.
- The distance the tracer slug appears to have moved.
- All stationary tests conducted.
- Detector depth and the amount of time elapsed during the test.

ADDITIONAL CONSIDERATIONS:

Ejection of tracer material should occur as close to the perforations as possible. This may help to minimize the occurrence of radioactive material adhering to the inside casing wall or recirculating below a packer, creating 'hot spots' which could be misinterpreted as evidence of fluid movement. In most cases, there is no UIC Permit requirement to use the RTS for a packer check, so eliminate the packer check whenever possible to prevent misinterpretation.

Appendix F-7
PFOT Guidance

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EPA Region 6

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision

August 8, 2002

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APPENDIX

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EPA Region 6

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision
August 8, 2002

1.0 Background

The Hazardous and Solid Waste Amendments of 1984 to the Resource Conservation and Recovery Act mandated prohibitions on the land disposal of hazardous waste. These prohibitions are known as the land disposal restrictions and EPA promulgated regulations to implement these requirements for injection wells on July 26, 1988. The land disposal restrictions for injection wells are codified in 40 CFR Part 148. In addition to specifying the effective dates of the restrictions on injection of specific hazardous wastes, these regulations outline the requirements for obtaining an exemption to the restrictions.

Facilities that have received an exemption to the land disposal restrictions under 40 CFR Part 148 have demonstrated that, to a reasonable degree of certainty, there will be no migration of hazardous constituents from the injection zone for as long as the waste remains hazardous. As part of this approval, facilities are required by Region 6 to meet approval conditions including annual monitoring in accordance with 40 CFR 148.20(d)(2).

Region 6 has adopted the 40 CFR 146.68(e)(1) requirements for monitoring Class 1 hazardous waste disposal wells. Under 40 CFR 146.68(e)(1), operators are required annually to monitor the pressure buildup in the injection zone, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

A falloff test is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff period is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing analysis provides transmissibility, skin factor, and well flowing and static pressures. All of these parameters are critical for evaluation of technical adequacy of no migration demonstrations and UIC permits.

2.0 Purpose of Guideline

This guideline has been developed by the Region 6 office of the Evironmental Protection Agency (EPA) to assist operators in planning and conducting the falloff test and preparing the annual monitoring report. Typically, this report should consist of a falloff test and a comparison of the reservoir parameters derived from the test with those of the petition demonstration. Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well. Both the reservoir parameters and pressure data are necessary for no migration and UIC permit demonstrations. Additionally, a valid falloff test is a requirement of a no migration petition condition as well as a monitoring requirement under 40 CFR Part 146 for all Class I injection wells. For no migration purposes, the annual report is viewed not as an enforcement tool, but as an annual confirmation that the petition demonstration continues to be valid.

The main body of this guideline contains general information that pertains to the majority of the facilities impacted. Because each site is unique, one guideline cannot be written to encompass all situations. A more detailed discussion of many topics and equations is included in the attached Appendix.

The ultimate responsibility of conducting a valid falloff test is the task of the operator. Operators should QA/QC the pressure data and test results to confirm that the results "make sense" prior to submission of the report to the EPA for review.

3.0 Timing of Falloff Tests and Report Submission

Falloff tests must be conducted within one year from the date of the original petition approval and annually thereafter. The time interval for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals throughout the duration of the petition approval period. Operators can, at their discretion, plan these tests to coincide with the performance of their annual state MIT requirements as long as the time requirements are met. The falloff testing report should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the applicable petition condition and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

4.0 Falloff Test Report Requirements

In general, the report to EPA should provide general information and an overview of the falloff test, an analysis of the pressure data obtained during the test, a summary of the test results, and a comparison of the results with the parameters used in the no migration demonstration. Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The falloff test report should include the following information:

1. Company name and address
2. Test well name and location
3. The name and phone number of the facility contact person. The contractor contact may be included if approved by the facility <u>in addition</u> to a facility contact person.

4. A photocopy of an openhole log (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. Well schematic showing the current wellbore configuration and completion information:
    - Wellbore radius
    - Completed interval depths
    - Type of completion (perforated, screen and gravel packed, openhole)
6. Depth of fill depth and date tagged.
7. Offset well information:
    - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
    - Simple illustration of locations of the injection and offset wells
8. Chronological listing of daily testing activities.
9. Electronic submission of the raw data (time, pressure, and temperature) from <u>all</u> pressure gauges utilized on a floppy disk or CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any edited data used in the analysis can be submitted as an additional file.
10. Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. Rate information from any offset wells completed in the same interval. At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. Hard copy of the time and pressure data analyzed in the report.
13. Pressure gauge information: (See Appendix, page A-1 for more information on pressure gauges)
    - List all the gauges utilized to test the well
    - Depth of each gauge
    - Manufacturer and type of gauge. Include the full range of the gauge.
    - Resolution and accuracy of the gauge as a % of full range.
    - Calibration certificate and manufacturer's recommended frequency of calibration
14. General test information:
    - Date of the test
    - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
    - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)

15. Reservoir parameters (determination):
    - Formation fluid viscosity, μ_f cp (direct measurement or correlation)
    - Porosity, ϕ fraction (well log correlation or core data)
    - Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
    - Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - Initial formation reservoir pressure - See Appendix, page A-1
    - Date reservoir pressure was last stabilized (injection history)
    - Justified interval thickness, h ft - See Appendix, page A-15
16. Waste plume:
    - Cumulative injection volume into the completed interval
    - Calculated radial distance to the waste front, r_{waste} ft
    - Average historical waste fluid viscosity, if used in the analysis, μ_{waste} cp
17. Injection period:
    - Time of injection period
    - Type of test fluid
    - Type of pump used for the test (e.g., plant or pump truck)
    - Type of rate meter used
    - Final injection pressure and temperature
18. Falloff period:
    - Total shut-in time, expressed in real time and Δt, elapsed time
    - Final shut-in pressure and temperature
    - Time well went on vacuum, if applicable
19. Pressure gradient:
    - Gradient stops - for depth correction
20. Calculated test data: include all equations used and the parameter values assigned for each variable within the report
    - Radius of investigation, r_i ft
    - Slope or slopes from the semilog plot
    - Transmissibility, kh/μ md-ft/cp
    - Permeability (range based on values of h)
    - Calculation of skin, s
    - Calculation of skin pressure drop, ΔP_{skin}
    - Discussion and justification of any reservoir or outer boundary models used to simulate the test
    - Explanation for any pressure or temperature anomaly if observed
21. Graphs:
    - Cartesian plot: pressure and temperature vs. time
    - Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. A comparison of all parameters with those used in the petition demonstration, including references where the parameters can be found in the petition.

23. A copy of the latest radioactive tracer run to fulfill the annual mechanical integrity testing requirement for the State and a brief discussion of the results.
24. Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

5.0 Planning

The radial flow portion of the test is the basis for all pressure transient calculations. Therefore the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns
Successful well testing involves the consideration of many factors, most of which are within the operator's control. Some considerations in the planning of a test include:

- Adequate storage for the waste should be ensured for the duration of the test
- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- Other pressure transient tests may be used in conjunction or in place of a falloff test in some situations. For example, if surface pressure measurements must be used because of a corrosive wastestream and the well will go on vacuum following shut-in, a multi-rate test may be used so that a positive surface pressure is maintained at the well.

C If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

<u>Site Specific Pretest Planning</u>

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
    - C Review previous welltests, if available
    - C Simulate the test using measured or estimated reservoir and well completion parameters
    - C Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
    - C Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.

2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/:) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are usually superior to surface pressure measurements because bottomhole measurements tend to be less noisy. Surface pressure measurements can be used if positive pressure is maintained at the surface throughout the falloff portion of the test. The surface pressure gauge should be located at the wellhead. A surface pressure gauge may also serve as a backup to a downhole gauge and provide a monitoring tool for tracking the test progress. Surface gauge data can be plotted during the falloff in a log-log plot format with the pressure derivative function to determine if the test has reached radial flow and can be terminated. Note: Surface pressure measurements are not adequate if the well goes on a vacuum during the test. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)

4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

6.0 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well

2. Simplify the pressure transients in the reservoir
   - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
   - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
   - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

3. The test well should be shut-in <u>at the wellhead</u> in order to minimize wellbore storage and afterflow. (See Appendix, page A-3 for additional information.)

4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.

5. Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.

7.0 Evaluation of the Falloff Test

1. Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
   - Confirm pressure stabilization prior to shut-in of the test well
   - Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution

2. Prepare a log-log diagnostic plot of the pressure and semilog derivative. Identify the flow regimes present in the welltest. (See Appendix, page A-6 for additional information.)
   - Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff (See Appendix, page A-10 for details on time functions.)
   - Mark the various flow regimes - particularly the radial flow period
   - Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
   - If there is no radial flow period, attempt to type curve match the data

3. Prepare a semilog plot.
   - C Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
   - C Draw the semilog straight line through the radial flow portion of the plot and obtain the slope of the line
   - C Calculate the transmissibility, kh/:
   - C Calculate the skin factor, s, and skin pressure drop, ΔP_{skin}
   - C Calculate the radius of investigation, r_i

4. Explain any anomalous results.

8.0 Comparison of Falloff Results to No Migration Petition Data

A comparison between the falloff test results and the parameters used in the no migration petition demonstration should be made. Specifically, the following should be demonstrated:

- C Both the flowing and static bottom hole pressures measured during the test should be corrected for skin and be at or below those which were predicted to occur by the pressure buildup model in the approvided no migration petition for the same point in time. (See Appendix, page A-13)

- C It should be shown that the (kh/:) parameter group calculated from the current falloff data is the same or greater than that employed in the pressure buildup modeling.

9.0 Technical References

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APPENDIX

Initial Formation Reservoir Pressure from Falloff Testing

For use in the no migration demonstration pressure buildup modeling:

- Some predictive models calculate a pressure buildup while other models calculate a specific pressure based on an initial reservoir pressure assigned to the model. No wellbore skin should be assumed in the demonstration. Historical falloff flowing pressure data used for comparison with model results should be corrected for skin effects
- The initial pressure should represent the initial reservoir pressure prior to initiation of injection in the model.
- Direct bottomhole static measurements are best. If no measurements are available, or are questionable, attempt to correct static surface pressures to bottomhole conditions. Use site specific information if available. Alternatively, the facility can reference a technical paper that may discuss the initial pressure of the injection interval at another location in the same area or an initial static pressure measurement from an offset injection well.
- Review historical measured static pressures. The initial reservoir pressure should be lower than the measured static pressures following injection at the well.

For use in Cone of Influence (COI) calculations in both no migration demonstrations and UIC permits:

- P^* is the false extrapolated pressure obtained from the semilog straight line at a time of 1 hour and is often used as the average reservoir pressure
- P^* is only applicable for a new well in an infinite acting reservoir
- EPA Region 6 does not recommend using P^* for the average reservoir pressure. For long injection periods, P^* will differ significantly from $\overline{P}$, the average reservoir pressure
- Use the final shut-in pressure, if the well reaches radial flow, for the cone of influence calculation

Pressure Gauge Usage and Selection

<u>Usage</u>

- EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- As a general rule, downhole pressure measurements are less noisy and are preferred. Surface pressure measurements can be employed if positive pressure is maintained at the surface throughout the test. Surface gauges are insufficient if the well goes on a vacuum.
- Surface pressure gauges may be impacted by the fluctuations in ambient temperature that can occur over the course of a normal day. If unchecked, this aspect of these gauges can result in erroneous pressure readings. Insulating the gauges appears to be an effective countermeasure for temperature fluctuations in many instances.

- A surface or bottomhole surface readout gauge (SRO) allows tracking of pressures in real time. Analysis of this data can be performed in the field to confirm that the well has reached radial flow prior to ending the test.
- The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.
- Mechanical gauges should be calibrated before and after each test using a dead weight tester.
- Electronic gauges should also be calibrated according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

Selection

- The pressures must remain within the range of the pressure gauge. The larger percent of the gauge range utilized in the test, the better. Typical pressure gauge limits are 2000, 5000, and 10000 psi. Note that gauge accuracy and resolution are typically a function of percent of the full gauge range.
- Electronic downhole gauges generally offer much better resolution and sensitivity than a mechanical gauge but cost more. Additionally, the electronic gauge can generally run for a longer period of time, be programmed to measure pressure more frequently at various intervals for improved data density, and store data in digital form.
- Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.
- The type of wastestream injected may prevent the use of a downhole gauge unless brine from offsite is brought in and used for the test. This may be cost prohibitive.

Test Design

General Operational Considerations

- The injection period controls what is seen on the falloff since the falloff is replay of the injection period. Therefore, the injection period must reach radial flow prior to shut-in of the well in order for the falloff test to reach radial flow

- Ideally to determine the optimal lengths of the injection and falloff periods, the test should be simulated using measured or estimated reservoir parameters. Alternatively, injection and falloff period lengths can be estimated from empirical equations using assumed reservoir and well parameters.

- The injection rate dictates the pressure buildup at the injection well. The pressure buildup from injection must be sufficient so that the pressure change during radial flow, usually occurring toward the end of the test, is large enough to measure with the pressure gauge selected.

- Waste storage and other operational issues require preplanning and need to be addressed prior to the test date. If brine must be brought in for the injection portion of the test, operators should insure that the fluid injected has a consistent viscosity and that there is adequate fluid available to obtain a valid falloff test. The use of the wastestream as the injection fluid affords several distinct advantages:
  1. Brine does not have to be purchased or stored prior to use.
  2. Onsite waste storage tanks may be used.
  3. Plant wastestreams are generally consistent, i.e., no viscosity variations

- Rate changes cause pressure transients in the reservoir. Constant rate injection in the test well and any offset wells completed in the same reservoir are critical to simplify the pressure transients in the reservoir. Any significant injection rate fluctuations at the test well or offsets must be recorded and accounted for in the analysis using superposition.

- Unless an injectivity test is to be conducted, shutting in the well for an extend period of time prior to conducting the falloff test reduces the pressure buildup in the reservoir and is not recommended.

- Prior to conducting a test, a crown valve should be installed on the wellhead to allow the pressure gauge to be installed and lowered into the well without any interruption of the injection rate.

- The wellbore schematic should be reviewed for possible obstructions located in the well that may prevent the use or affect the setting depth of a downhole pressure gauge. The fill depth in the well should also be reported. The fill depth may not only impact the depth of the gauge, but usually prolongs the wellbore storage period and depending on the type of fill, may limit the interval thickness by isolating some of the injection intervals. A wellbore cleanout or stimulation may be needed prior to conducting the test for the test to reach radial flow and obtain valid results.

- The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period. The injection pipeline leading to the well can act as an extension to the well if the shut-in valve is not located near the wellhead. Operators should report the location of the shut-in valve and its distance from the wellhead, in the test report.

- The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

Wellbore and Reservoir Data Needed to Simulate or Analyze the Falloff Test

- Wellbore radius, r_w - from wellbore schematic
- Net thickness, h - See Appendix, page A-15
- Porosity, N - log or core data
- Viscosity of formation fluid, $:_f$ - direct measurement or correlations
- Viscosity of waste, $:_{waste}$ - direct measurement or correlations
- Total system compressibility, c_t - correlations, core measurement, or well test
- Permeability, k - previous welltests or core data
- Specific gravity of injection fluid, s.g. - direct measurement
- Injection rate, q - direct measurement

Design Calculations

When simulation software is unavailable the test periods can be estimated from empirical equations. The following are set of steps to calculate the time to reach radial flow from empirically-derived equations:

1. Estimate the wellbore storage coefficient, C (bbl/psi). There are two equations to calculate the wellbore storage coefficient depending on if the well remains fluid filled (positive surface pressure) or if the well goes on a vacuum (falling fluid level in the well):

   a. Well remains fluid filled:

   $$C = V_w \cdot c_{waste}$$

   where, V_w is the total wellbore volume, bbls

   c_{waste} is the compressibility of the injectate, psi^{-1}

   b. Well goes on a vacuum:

   $$C = \frac{V_u}{\frac{r \cdot g}{144 \cdot g_c}}$$

   where, V_u is the wellbore volume per unit length, bbls/ft

   D is the injectate density, psi/ft

   g and g_c are gravitational constants

2. Calculate the time to reach radial flow for both the injection and falloff periods. Two different empirically-derived equations are used to calculate the time to reach radial flow, $t_{radial\ flow}$, for the injectivity and falloff periods:

   a. Injectivity period:

   $$t_{radial\ flow} > \frac{(200000 + 12000s) \cdot C}{\frac{k \cdot h}{m}} \quad hours$$

   b. Falloff period:

   $$t_{radial\ flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{m}} \quad hours$$

   The wellbore storage coefficient is assumed to be the same for both the injectivity and falloff periods. The skin factor, s, influences the falloff more than the injection period.

Use these equations with caution, as they tend to fall apart for a well with a large permeability or a high skin factor. Also remember, the welltest should not only reach radial flow, but also sustain radial flow for a timeframe sufficient for analysis of the radial flow period. As a rule of thumb, a timeframe sufficient for analysis is 3 to 5 times the time needed to reach radial flow.

3. As an alternative to steps 1 and 2, to look a specific distance “L” into the reservoir and possibly confirm the absence or existence of a boundary, the following equation can be used to estimate the time to reach that distance:

$$t_{boundary} = \frac{948 \cdot f \cdot m \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

where, $L_{boundary}$ = feet to boundary
$t_{boundary}$ = time to boundary, hrs

Again, this is the time to reach a distance “L” in the reservoir. Additional test time is required to observe a fully developed boundary past the time needed to just reach the boundary. As a rule of thumb, to see a fully developed boundary on a log-log plot, allow at least 5 times the time to reach it. Additionally, for a boundary to show up on the falloff, it must first be encountered during the injection period.

4. Calculate the expected slope of the semilog plot during radial flow to see if gauge resolution will be adequate using the following equation:

$$m_{semi\log} = \frac{162.6 \cdot q \cdot B}{\frac{k \cdot h}{m}}$$

where, q = the injection rate preceding the falloff test, bpd
B = formation volume factor for water, rvb/stb (usually assumed to be 1)

<u>Considerations for Offset Wells Completed in the Same Interval</u>

Rate fluctuations in offset wells create additional pressure transients in the reservoir and complicate the analysis. Always try to simplify the pressure transients in the reservoir. Do not simultaneously shut-in an offset well and the test well. The following items are key considerations in dealing with the impact of offset wells on a falloff test:

- Shut-in all offset wells prior to the test
- If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
- Obtain accurate injection records of offset injection prior to and during the test
- At least one of the real time points corresponding to an injection rate in an offset well should be synchronized to a specific time relating to the test well

- Following the falloff test in the test well, send at least two pulses from the offset well to the test well by fluctuating the rate in the offset well. The pressure pulses can confirm communication between the wells and can be simulated in the analysis if observed at the test well. The pulses can also be analyzed as an interference test using an Ei type curve.
- If time permits, conduct an interference test to allow evaluation of the reservoir without the wellbore effects observed during a falloff test.

Falloff Test Analysis

In performing a falloff test analysis, a series of plots and calculations should be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. Individual plots, flow regime signatures, and calculations are discussed in the following sections.

Cartesian Plot

- The pressure data prior to shut-in of the well should be reviewed on a Cartesian plot to confirm pressure stabilization prior to the test. A well that has reached radial flow during the injectivity portion of the test should have a consistent injection pressure.

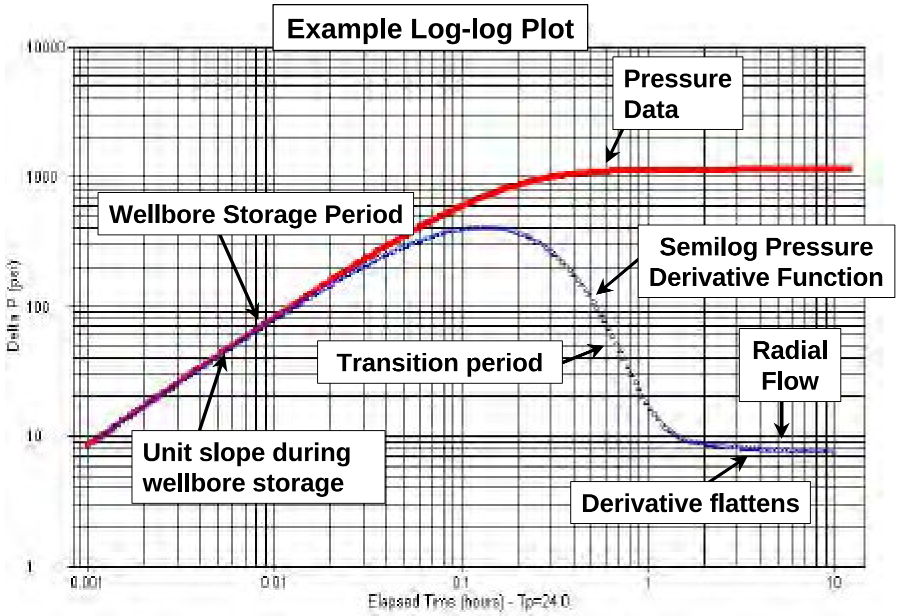
- A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to the pressure gauges used to confirm adequate gauge resolution existed throughout the test. If the gauge resolution limit was reached, this timeframe should be identified to determine if radial flow was reached prior to reaching the resolution of the pressure gauge. Pressure data obtained after reaching the resolution of the gauge should be treated as suspect and may need to be discounted in the analysis.

- Falloff tests conducted in highly transmissive reservoirs may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for by the pressure gauge, resulting in erroneous pressure data and an incorrect analysis. For this reason, the Cartesian plot of the temperature data should be reviewed. Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.

- Include the injection rate(s) of the test well 48 hours prior to shut-in on the Cartesian plot to illustrate the consistency of the injection rate prior to shut-in and to determine the appropriate time function to use on the log-log and semilog plots. (See Appendix, page A10 for time function selection)

Log-log Diagnostic Plot

- Plot the pressure and semilog derivative versus time on a log-log diagnostic plot. Use the appropriate time function based on the rate history of the injection period preceding the falloff. (See Appendix, page A-10 for time function selection) The log-log plot is used to identify the flow regimes present in the welltest. An example log-log plot is shown below:



Identification of Test Flow Regimes

- Flow regimes are mathematical relationships between pressure, rate, and time. Flow regimes provide a visualization of what goes on in the reservoir. Individual flow regimes have characteristic slopes and a sequencing order on the log-log plot.

- Various flow regimes will be present during the falloff test, however, not all flow regimes are observed on every falloff test. The late time responses correlate to distances further from the test well. The critical flow regime is radial flow from which all analysis calculations are performed. During radial flow, the pressure responses recorded are representative of the reservoir, not the wellbore.

- The derivative function amplifies reservoir signatures by calculating a running slope of a designated plot. The derivative plot allows a more accurate determination of the radial flow portion of the test, in comparison with the old method of simply proceeding 1½ log cycles from the end of the unit slope line of the pressure curve.

- The derivative is usually based on the semilog plot, but it can also be calculated based on other plots such as a Cartesian plot, a square root of time plot, a quarter root of time plot, and the 1/square root of time plot. Each of these plots are used to identify specific flow regimes. If the flow regime characterized by a specialized plot is present then when the derivative calculated from that plot is displayed on the log-log plot, it will appear as a "flat spot" during the portion of the falloff corresponding to the flow regime.

- Typical flow regimes observed on the log-log plot and their semilog derivative patterns are listed below:

Flow Regime	Semilog Derivative Pattern
Wellbore Storage	Unit slope
Radial Flow	Flat plateau
Linear Flow	Half slope
Bilinear Flow	Quarter slope
Partial Penetration	Negative half slope
Layering	Derivative trough
Dual Porosity	Derivative trough
Boundaries	Upswing followed by plateau
Constant Pressure	Sharp derivative plunge

Characteristics of Individual Test Flow Regimes

- Wellbore Storage:
  1. Occurs during the early portion of the test and is caused by the well being shut-in at the surface instead of the sandface
  2. Measured pressure responses are governed by well conditions and are not representative of reservoir behavior and are characterized by both the pressure and semilog derivative curves overlying a unit slope on the log-log plot
  3. Wellbore skin or a low permeability reservoir results in a slower transfer of fluid from the well to the formation, extending the duration of the wellbore storage period
  4. A wellbore storage dominated test is unanalyzable

- Radial Flow:
  1. The pressure responses are from the reservoir, not the wellbore
  2. The critical flow regime from which key reservoir parameters and completion conditions calculations are performed
  3. Characterized by a flattening of the semilog plot derivative curve on the log-log plot and a straight line on the semilog plot

- Spherical Flow:
  1. Identifies partial penetration of the injection interval at the wellbore
  2. Characterized by the semilog derivative trending along a negative half slope on the log-log plot and a straight line on the 1/square root of time plot
  3. The log-log plot derivative of the pressure vs 1/square root of time plot is flat

- Linear Flow
  1. May result from flow in a channel, parallel faults, or a highly conductive fracture
  2. Characterized by a half slope on both the log-log plot pressure and semilog derivative curves with the derivative curve approximately 1/3 of a log cycle lower than the pressure curve and a straight line on the square root of time plot.
  3. The log-log plot derivative of the pressure vs square root of time plot is flat

- Hydraulically Fractured Well
  1. Multiple flow regimes present including wellbore storage, fracture linear flow, bilinear flow, pseudo-linear flow, formation linear flow, and pseudo-radial flow
  2. Fracture linear flow is usually hidden by wellbore storage
  3. Bilinear flow results from simultaneous linear flows in the fracture and from the formation into the fracture, occurs in low conductivity fractures, and is characterized by a quarter slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus quarter root of time plot
  4. Formation linear flow is identified by a half slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus square root of time plot
  5. Psuedo-radial flow is analogous to radial flow in an unfractured well and is characterized by flattening of semilog derivative curve on the log-log plot and a straight line on a semilog pressure plot

- Naturally Fractured Rock
  1. The fracture system will be observed first on the falloff test followed by the total system consisting of the fractures and matrix.
  2. The falloff analysis is complex. The characteristics of the semilog derivative trough on the log-log plot indicate the level of communication between the fractures and the matrix rock.

- Layered Reservoir
  1. Analysis of a layered system is complex because of the different flow regimes, skin factors or boundaries that may be present in each layer.
  2. The falloff test objective is to get a total tranmissibility from the whole reservoir system.
  3. Typically described as commingled (2 intervals with vertical separation) or crossflow (2 intervals with hydraulic vertical communication)

<u>Semilog Plot</u>

- The semilog plot is a plot of the pressure versus the log of time. There are typically four different semilog plots used in pressure transient and falloff testing analysis. After plotting the appropriate semilog plot, a straight line should be drawn through the points located within the equivalent radial flow portion of the plot identified from the log-log plot.

- Each plot uses a different time function depending on the length and variation of the injection rate preceding the falloff. These plots can give different results for the same test, so it is important that the appropriate plot with the correct time function is used for the analysis. Determination of the appropriate time function is discussed below.

- The slope of the semilog straight line is then used to calculate the reservoir transmissibility - kh/μ, the completion condition of the well via the skin factor - s, and also the radius of investigation - r_i of the test.

<u>Determination of the Appropriate Time Function for the Semilog Plot</u>
The following four different semilog plots are used in pressure transient analysis:
1. Miller Dyes Hutchinson (MDH) Plot
2. Horner Plot
3. Agarwal Equivalent Time Plot
4. Superposition Time Plot

These plots can give different results for the same test. Use of the appropriate plot with the correct time function is critical for the analysis.

- The MDH plot is a semilog plot of pressure versus Δt, where Δt is the elapsed shut-in time of the falloff.
    1. The MDH plot only applies to wells that reach psuedo-steady state during injection. Psuedo-steady state means the pressure response from the well has encountered all the boundaries around the well.
    2. The MDH plot is only applicable to injection wells with a *very* long injection period at a constant rate. This plot is not recommended for use by EPA Region 6.

- The Horner plot is a semilog plot of pressure versus $(t_p+\Delta t)/\Delta t$. The Horner plot is only used for a falloff preceded by a single constant rate injection period.
    1. The injection time, $t_p=V_p/q$ in hours, where V_p=injection volume since the last pressure equalization and q is the injection rate prior to shut-in for the falloff test. The injection volume is often taken as the cumulative injection since completion.
    2. The Horner plot can result in significant analysis error if the injection rate varies prior to the falloff.

- The Agarwal equivalent time plot is a semilog plot of the pressure versus Agarwal equivalent time, Δt_e.
    1. The Agarwal equivalent time function is similar to the Horner plot, but scales the falloff to make it look like an injectivity test.
    2. It is used when the injection period is a short, constant rate compared to the length of the falloff period.
    3. The Agarwal equivalent time is defined as: $\Delta t_e=\log(t_p\,\Delta t)/(t_p+\Delta t)$, where t_p is calculated the same as with the Horner plot.

C The superposition time function accounts for variable rate conditions preceding the falloff.
1. It is the most rigorous of all the time functions and is usually calculated using welltest software.
2. The use of the superposition time function requires the operator to accurately track the rate history. As a rule of thumb, at a minimum, the rate history for twice the length of the falloff test should be included in the analysis.

The determination of which time function is appropriate for the plotting the welltest on semilog and log-log plots depends on available rate information, injection period length, and software:

1. If there is not a rate history other than a single rate and cumulative injection, use a Horner time function
2. If the injection period is shorter than the falloff test and only a single rate is available, use the Agarwal equivalent time function
3. If you have a variable rate history use superposition when possible. As an alternative to superposition, use Agarwal equivalent time on the log-log plot to identify radial flow. The semilog plot can be plotted in either Horner or Agarwal time if radial flow is observed on the log-log plot.

<u>Parameter Calculations and Considerations</u>

C Transmissibility - The slope of the semilog straight line, m, is used to determine the transmissibility (kh/:) parameter group from the following equation:

$$\frac{k \cdot h}{m} = \frac{162.6 \cdot q \cdot \mathrm{B}}{m}$$

where, q = injection rate, bpd (negative for injection)
B = formation volume factor, rvb/stb (Assumed to be 1 for formation fluid)
m = slope of the semilog straight line through the radial flow portion of the plot in psi/log cycle
k = permeability, md
h = thickness, ft (See Appendix, page A-15)
: = viscosity, cp

C The viscosity, :, is usually that of the formation fluid. However, if the waste plume size is massive, the radial flow portion of the test may remain within the waste plume. (See Appendix, page A-14)
1. The waste and formation fluid viscosity values usually are similar, however, if the wastestream has a significant viscosity difference, the size of the waste plume and distance to the radial flow period should be calculated.
2. The mobility, k/:, differences between the fluids may be observed on the derivative curve.

C The permeability, k, can be obtained from the calculated transmissibility (kh/:) by substituting the appropriate thickness, h, and viscosity, :, values.

Skin Factor

C In theory, wellbore skin is treated as an infinitesimally thin sheath surrounding the wellbore, through which a pressure drop occurs due to either damage or stimulation. Industrial injection wells deal with a variety of waste streams that alter the near wellbore environment due to precipitation, fines migration, ion exchange, bacteriological processes, and other mechanisms. It is reasonable to expect that this alteration often exists as a zone surrounding the wellbore and not a skin. Therefore, at least in the case of industrial injection wells, the assumption that skin exists as a thin sheath is not always valid. This does not pose a serious problem to the correct interpretation of falloff testing except in the case of a large zone of alteration, or in the calculation of the flowing bottomhole pressure. The Region has seen instances in which large zones of alteration were suspected of being present.

C The skin factor is the measurement of the completion condition of the well. The skin factor is quantified by a positive value indicating a damaged completion and a negative value indicating a stimulated completion.

1. The magnitude of the positive value indicating a damaged completion is dictated by the transmissibility of the formation.
2. A negative value of -4 to -6 generally indicates a hydraulically fractured completion, whereas a negative value of -1 to -3 is typical of an acid stimulation in a sandstone reservoir.
3. The skin factor can be used to calculate the effective wellbore radius, r_{wa} also referred to the apparent wellbore radius. (See Appendix, page A-13)
4. The skin factor can also be used to correct the injection pressure for the effects of wellbore damage to get the actual reservoir pressure from the measured pressure.

C The skin factor is calculated from the following equation:

$$s = 1.1513\left[\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k \cdot t_p}{(t_p + 1) \cdot f \cdot m \cdot c_t \cdot r_w^2}\right) + 3.23\right]$$

where, s = skin factor, dimensionless

P_{1hr} = pressure intercept along the semilog straight line at a shut-in time of 1 hour, psi

P_{wf} = measured injection pressure prior to shut-in, psi

: = appropriate viscosity at reservoir conditions, cp (See Appendix, page A-14)

m = slope of the semilog straight line, psi/cycle

k = permeability, md

N = porosity, fraction

c_t = total compressibility, psi^{-1}

r_w = wellbore radius, feet

t_p = injection time, hours

Note that the term $t_p/(t_p + \Delta t)$, where Δt=1 hr, appears in the log term. This term is usually assumed to result in a negligible contribution and typically is taken as 1 for large t. However, for relatively short injection periods, as in the case of a drill stem test (DST), this term can be significant.

<u>Radius of Investigation</u>

- The radius of investigation, r_i, is the distance the pressure transient has moved into a formation following a rate change in a well.

- There are several equations that exist to calculate the radius of investigation. All the equations are square root equations based on cylindrical geometry, but each has its own coefficient that results in slightly different results, (See Oil and Gas Journal, Van Poollen, 1964).

- Use of the appropriate time is necessary to obtain a useful value of r_i. For a falloff time shorter than the injection period, use Agarwal equivalent time function, Δt_e, at the end of the falloff as the length of the injection period preceding the shut-in to calculate r_i.

- The following two equivalent equations for calculating r_i were taken from SPE Monograph 1, (Equation 11.2) and Well Testing by Lee (Equation 1.47), respectively:

$$r_i = \sqrt{0.00105 \frac{k \cdot t}{\phi \cdot \mu \cdot c_t}} \equiv \sqrt{\frac{k \cdot t}{948 \cdot \phi \cdot \mu \cdot c_t}}$$

<u>Effective Wellbore Radius</u>

- The effective wellbore radius relates the wellbore radius and skin factor to show the effects of skin on wellbore size and consequently, injectivity.

- The effective wellbore radius is calculated from the following:

$$r_{wa} = r_w e^{-s}$$

- A negative skin will result in a larger effective wellbore radius and therefore a lower injection pressure.

<u>Reservoir Injection Pressure Corrected for Skin Effects</u>

- The pressure correction for wellbore skin effects, ΔP_{skin}, is calculated by the following:

$$\Delta P_{skin} = 0.868 \cdot m \cdot s$$

where, m = slope of the semilog straight line, psi/cycle
s = wellbore skin, dimensionless

- The adjusted injection pressure, P_{wfa} is calculated by subtracting the ΔP_{skin} from the measured injection pressure prior to shut-in, P_{wf}. This adjusted pressure is the calculated reservoir pressure prior to shutting in the well, Δt=0, and is determined by the following:

$$P_{wfa} = P_{wf} - \Delta P_{skin}$$

- From the previous equations, it can be seen that the adjusted bottomhole pressure is directly dependent on a single point, the last injection pressure recorded prior to shut-in. Therefore, an accurate recording of this pressure prior to shut-in is important. Anything that impacts the pressure response, e.g., rate change, near the shut-in of the well should be avoided.

<u>Determination of the Appropriate Fluid Viscosity</u>

- If the wastestream and formation fluid have similar viscosities, this process is not necessary.

- This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/\mu)_w$, and formation fluid, $(k/\mu)_f$. Depending on when the test reaches radial flow, these cases with extreme mobility differences could cause the derivative curve to change and level to another value. Eliminating alternative geologic causes, such as a sealing fault, multiple layers, dual porosity, etc., leads to the interpretation that this change may represent the boundary of the two fluid banks.

- First assume that the pressure transients were propagating through the formation fluid during the radial flow portion of the test, and then verify if this assumption is correct. This is generally a good strategy except for a few facilities with exceptionally long injection histories, and consequently, large waste plumes. The time for the pressure transient to exit the waste front is calculated. This time is then identified on both the log-log and semilog plots. The radial flow period is then compared to this time.

- The radial distance to the waste front can then be estimated volumetrically using the following equation:

$$r_{waste\ plume} = \sqrt{\frac{0.13368 \cdot V_{waste\ injected}}{\pi \cdot h \cdot \phi}}$$

where, $V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
$r_{waste\ plume}$ = estimated distance to waste front, ft
h = interval thickness, ft
ϕ = porosity, fraction

- The time necessary for a pressure transient to exit the waste front can be calculated using the following equation:

$$t_w = \frac{126.73 \cdot \mu_w \cdot c_t \cdot V_{waste\ injected}}{\pi \cdot k \cdot h}$$

where, t_w = time to exit waste front, hrs
$V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
h = interval thickness, ft

k = permeability, md
:$_w$ = viscosity of the historic waste plume at reservoir conditions, cp
c_t = total system compressibility, psi^{-1}

C The time should be plotted on both the log-log and semilog plots to see if this time corresponds to any changes in the derivative curve or semilog pressure plot. If the time estimated to exit the waste front occurs before the start of radial flow, the assumption that the pressure transients were propagating through the reservoir fluid during the radial flow period was correct. Therefore, the viscosity of the reservoir fluid is the appropriate viscosity to use in analyzing the well test. If not, the viscosity of the historic waste plume should be used in the calculations. If the mobility ratio is extreme between the wastestream and formation fluid, adequate information should be included in the report to verify the appropriate fluid viscosity was utilized in the analysis.

<u>Reservoir Thickness</u>

C The thickness used for determination of the permeability should be justified by the operator. The net thickness of the defined injection interval is not always appropriate.

C The permeability value is necessary for plume modeling, but the transmissibility value, kh/:, can be used to calculate the pressure buildup in the reservoir without specifying values for each parameter value of k, h, and :.

C Selecting an interval thickness is dependent on several factors such as whether or not the injection interval is composed of hydraulically isolated units or a single massive unit and wellbore conditions such as the depth to wellbore fill. When hydraulically isolated sands are present, it may be helpful to define the amount of injection entering each interval by conducting a flow profile survey. Temperature logs can also be reviewed to evaluate the intervals receiving fluid. Cross-sections may provide a quick look at the continuity of the injection interval around the injection well.

C A copy of a SP/Gamma Ray well log over the injection interval, the depth to any fill, and the log and interpretation of available flow profile surveys run should be submitted with the falloff test to verify the reservoir thickness value assumed for the permeability calculation.

<u>Use of Computer Software</u>

C To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.

C All data should be submitted electronically with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the diskette, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

- C After analyzing any test, always look at the results to see if they "make sense" based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.

- C If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.

- C Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data acquisition hardware such as a faulty gauge. An anomalous response can often be traced to a brief, but significant rate change in either the test well or an offset well.

- C Anomalous data trends have also been caused by such things as ambient temperature changes in surface gauges or a faulty pressure gauge. Explanations for data trends may be facilitated through an examination of the backup pressure gauge data, or the temperature data. It is often helpful to qualitatively examine the pressure and/or temperature channels from both gauges. The pressure data should overlay during the falloff after being corrected for the difference in gauge depths. On occasion, abrupt temperature changes can be seen to correspond to trends in the pressure data. Although the source of the temperature changes may remain unexplainable, the apparent correlation of the temperature anomaly to the pressure anomaly can be sufficient reason to question the validity of the test and eliminate it from further analysis.

- C The data that is obtained from pressure transient testing should not collect dust, but be compared to petition or permit parameters. Test derived transmissibilities and static pressures can confirm compliance with no migration and non-endangerment (AOR) conditions.