U.S. EPA Underground Injection Control Program

FINAL PERMIT

Class V Experimental
Permit No. R9UIC-CA5-FY18-1R (the Permit)

Well Names:
SFI-1, SFI-2, SFI-3, and SFI-4
Los Angeles County, California

Issued to:
City of Los Angeles
LA Sanitation & Environment
445 Ferry St.
San Pedro, California 90731

TABLE OF CONTENTS

Appendices

Part I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control (UIC) regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (CFR), Parts 124, 144, 145, 146, 147, and 148,

City of Los Angeles, LA Sanitation & Environment (LASAN or the Permittee)
Terminal Island Water Reclamation Plant (the Facility)
445 Ferry Street
San Pedro, California 90731

is hereby authorized, as owner and operator, and contingent upon Permit conditions, to operate an existing injection facility. The Facility has been permitted since November 2006 by EPA as a Class V Experimental municipal biosolids waste injection facility. EPA issued the current Permit on December 23, 2013, with an expiration date of December 23, 2018. In May 2018, prior to the expiration date of the Permit, the Permittee submitted an application to renew its UIC Class V Experimental waste injection Permit for four (4) existing wells: SFI-1, SFI-2, SFI-3, and SFI-4 (the Existing Wells), and four (4) proposed replacement injection wells (the Proposed Replacement Wells). Per 40 CFR § 144.37, until this Permit is issued and effective, the Existing Wells will continue to operate under the authority of the current UIC Permit, No. R9-CA5-FY11-3R.

All Existing and Proposed Replacement Wells are located in Section 8, Township 5 South, Range 13 West, at the Terminal Island Wastewater Reclamation Plant (the Facility) in San Pedro, California. Exact locations of existing wells are provided in Part II.B.1. The Proposed Replacement Wells' tentative location is described below; exact locations will be established by the Permittee and approved by EPA as outlined in this Permit.

The Permittee will inject wastewater collected from various process units at the Facility including: Slurry mixtures of treated, non-hazardous municipal sludge, brine, and plant effluent. The Permit allows continued injection at pressures sufficient to create hydraulic fractures to demonstrate an experimental technology whereby the municipal waste slurry undergoes high-temperature anaerobic biodegradation. Extensive field monitoring, sampling, and analysis from monitoring wells is mandated by the Permit to quantify numerous parameters, including slurry placement, biodegradation rates, carbon dioxide and methane separation, carbon sequestration and saturation in formation brine, free gas migration, commercial methane production potential and timeframes.

In this Permit, EPA authorizes the Permittee to operate the Existing Wells because the Permittee has met the requirements of Title 40 of the CFR Parts 124, 144, 145, 146, 147, and 148, as set forth in this Permit, to operate UIC Class V Experimental wells.

Pursuant to the terms of this Permit, the Permittee will be authorized to drill, construct, and inject into four (4) Proposed Replacement Wells after it has met the requirements of Part II Sections A-D and the Financial Assurance requirements described in Part II.G.1. and has received approval from EPA to construct and operate the Proposed Replacement Wells pursuant to the terms of this Permit.

This Permit authorizes injection of specific types of wastewater from Terminal Island Wastewater Treatment Plant operations into the Repetto and Puente sands at an approximate depth between 3,800 and 7,500 feet below ground surface (bgs). Existing Wells SFI-1,SFI-3 are authorized for injection, with the potential for SFI-2 to be converted to an injection well with EPA approval. The Permittee is authorized to inject into only one well at a time. Wells that are not injecting will be used for monitoring. Existing well SFI-4 is authorized for monitoring purposes only. The Repetto and Puente sands at the Existing Wells has greater than 10,000 mg/L total dissolved solids and is confined above by approximately 900 feet of shale in the Repetto and Pico Formations.

All Conditions set forth in this Permit are based on Title 40 of the CFR Parts 124, 144, 145, 146, 147, and 148, which are regulations in effect as of the effective date of this Permit.

This Permit consists of forty-one (41) pages plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by the Permittee and on other information contained in the administrative record. It is the sole responsibility of the Permittee to read, understand, and comply with all terms and conditions of this Permit.

This Permit is issued for a period of ten (10) years unless terminated under the conditions set forth in Part III.B.1 of this Permit or administratively extended under the conditions set forth in Part III.E.12 and 40 CFR § 144.37.

This Permit is issued on 7/28/2022 and becomes effective on 8/31/2022.

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Tomás Torres, Director
Water Division, EPA Region 9

Part II. SPECIFIC PERMIT CONDITIONS

A. REQUIREMENTS PRIOR TO DRILLING, TESTING, CONSTRUCTING, OR OPERATING

1. Financial Assurance

The Permittee's plugging and abandonment cost estimate and chosen financial assurance mechanism for the Existing Wells meets the requirements of 40 CFR § 144.52(a)(7). Prior to authorization for constructing, drilling, or injecting into the Proposed Replacement Wells, the Permittee shall submit to EPA, and receive EPA's approval in writing for, the chosen financial assurance mechanism for the plugging and abandonment cost estimate for the Proposed Replacement Wells, in accordance with Section G of this Part.

2. Field Demonstration Submittal, Notification, and Reporting

   a. Prior to each demonstration required by and described in Part II.B.5, and Part II.D.1.a, 2.a, and 2.b., the Permittee shall submit plans for procedures and specifications to the EPA Region 9 Groundwater Protection Section for approval at least sixty (60) days prior to the planned demonstration. Submittals shall be made in accordance with Part III.E.9. No demonstration in this Permit may proceed without prior written approval from EPA.

   b. After receipt of approval of the Permittee's proposed field demonstrations in writing from EPA, the Permittee must provide at least thirty (30) days' notice prior to performing any required field demonstrations.

   c. Unless otherwise specified in this Permit, or otherwise directed by EPA, the Permittee shall submit results of each such field demonstration required by Part II.B. through D. to EPA within sixty (60) days of completion.

3. Approval Requirements for Proposed Replacement Wells

Prior to commencing construction, drilling, testing, or operating, or any other activities for the Proposed Replacement Wells, the Permittee must (i) satisfy the Financial Assurance requirements set forth in Section G of this Part, (ii) submit the information and plans to EPA required by Part II.B.3. of this Permit, and (iii) receive written approval of its Financial Assurance and other deliverables by EPA.

B. CONDITIONS FOR EXISTING AND PROPOSED REPLACEMENT WELLS

1. Surface Location

The Existing Wells are located as follows:

Existing Well SFI-1: Located at latitude 33 deg, 74 min, 39.91 sec, and longitude 118 deg, 26 min, 46.55 sec of Section 8, Township 5 South, Range 13 West.

Existing Well SFI-2: Located at latitude 33 deg, 74 min, 59.13 sec, and longitude 118 deg, 26 min, 48.16 sec of Section 8, Township 5 South, Range 13 West.

Existing Well SFI-3: Located at latitude 33 deg, 74 min, 40.45 sec, and longitude 118 deg, 26 min, 29.75 sec of Section 8, Township 5 South, Range 13 West.

Existing Well SFI-4: Located at latitude 33 deg, 74 min, 55 sec, and longitude 118 deg, 26 min, 22.3 sec of Section 8, Township 5 South, Range 13 West.

Proposed Replacement Wells (SFI-5, SFI-6, SFI-7, SFI-8): The Proposed Replacement Wells may be authorized for UIC Class V Experimental nonhazardous municipal biosolids injection and monitoring activities under this Permit when the Permittee satisfies the requirements and receives approval from EPA in writing to commence construction, drilling, and injection activities. The location of the Proposed Replacement Wells will be located on the Terminal Island Water Reclamation Plant in Section 8, Township 5 South, Range 13 West. If the Proposed Replacement Wells are determined to be necessary, Permittee shall submit a proposed exact location to EPA for approval.

2. Existing Well Construction Details

Well Schematics for the Existing Wells are contained in Appendix B of this Permit. The Permittee shall at all time maintain the wells consistent with these Well Schematics.

Wells SFI-1, SFI-2, SFI-3, and SFI-4 shall be equipped with retrievable or permanent monitoring systems depending on the role these wells play, i.e. monitoring versus injection.

The following specifications apply to the wells:

a. Monitoring/Injection Well SFI-1

Injection well SFI-I was constructed in July 2007. SFI-1 started receiving bioslurry material (brine, effluent, digested sludge and biosolids) in July 2008. SFI-1 will remain classified as an injection well in this permit and will also be utilized to gather monitoring data while injection operations occur in SFI-2. This permit allows for injection into Wells SFI-1,SFI-3, and the potential to convert SFI-2 to an injection well with EPA approval. Only one injection well is authorized to inject at a time. Wells that are not used for injecting will be used to collect monitoring data.

Perforations in SFI-1 are set at 4,868 ft. – 4,888 ft., and 4,893 ft. – 4,913 ft. These perforation intervals reflect a portion of the injection zone that is currently authorized in this permit per Part II.B.6. Perforations may be systematically extended uphole within the permitted portions of the Repetto formation which are between the well depths 3,800 - 7,500 ft TVD (True Vertical Depth). These interval changes must be requested in writing 60 days in advance, including detailed proposed procedures for construction and for properly isolating the lower perforation interval, and perforating the upper interval. These perforation interval changes must be approved by EPA before they are conducted and are considered minor in this permit.

The Permittee must also provide at least 30 days advance notice of operations, including a timeline of operations after receipt of approval of those proposed procedures from EPA.

b. Monitoring/Injection Well SFI-2:

SFI-2 was constructed in July 2007 as a monitoring well. This Permit allows for converting SFI-2 from a monitoring well to an injection well. SFI-2 may be converted to an injection well only with EPA approval. The Permittee must submit to EPA, for review and approval, detailed construction plans and procedures for the conversion of the well. This permit allows for injecting in both Wells SFI-SFI-2, and SFI-3 but solely on an alternating basis, i.e. one well injecting and two wells are monitoring at any given time.

Monitoring of microseismicity and temperature in SFI-2 began in November 2008. Microseismic monitoring was discontinued in SFI-2 and began in SFI-3 in May 2011. Temperature and bottom hole pressure monitoring continues in SFI-2.

Perforations at SFI-2 are set at 4,730 - 5,002 ft. This perforation interval reflects a portion of the injection zone that is currently authorized in this permit per Part II.B.6. SFI-2 may be deepened to 7500 feet TVD if the deeper geological interval encountered during the drilling of SFI-4 is determined to be advantageous. Any such deepening of SFI-2 requires advance notice in writing, including detailed proposed procedures for construction for EPA's review and approval. The permittee must also provide at least 30 days advance notice of operations, including a timeline of operations after receipt of approval of those proposed procedures from EPA.

c. Monitoring/Injection Well SFI-3:

SFI-3 was constructed in April 2011 and is currently used as a monitoring well since May 2011. Temperature, bottom hole pressure, and microseismic data are being monitored. SFI-3 may also be used as an injection well in this permit and will also be utilized to gather monitoring data while injection operations occur in SFI-1 or SFI-2. This permit allows for injection into Wells SFI-1, SFI-3, and the potential to convert SFI-2 to an injection well with EPA approval. Only one injection well is authorized to inject at a time. Wells that are not used for injecting will be used to collect monitoring data. Before the initial injection begins in SFI-3 Mechanical Integrity Testing will be required per Part II.D.2.a.

The Permittee shall obtain and test representative formation fluid samples from SFI-3 annually at a minimum, once pressure data and reservoir modeling show injection fluid has reached the monitoring well location. The Permittee shall obtain and test representative formation gas samples from SFI-3, at periodic intervals, quarterly at a minimum.

Well SFI-3 is currently perforated at 5086-5106 ft. This perforation interval reflects a portion of the injection zone that is currently authorized in this permit per Part II.B.6. Perforations may be systematically extended uphole within the permitted portions of the Repetto formation which are between depth interval 3,800 - 5,300 ft TVD. Additionally, SFI-3 may be deepened to 7500 feet TVD. Construction plans and schematic are included in Appendix B. Any such deepening of SFI-3 requires advance notice in writing, including detailed proposed procedures for construction for EPA's review and approval. The permittee must also provide at least 30 days advance notice of operations, including a timeline of operations after receipt of approval of those proposed procedures from EPA.

d. Monitoring Well SFI-4:

SFI-4 was constructed in 2014 as a monitoring well and will continue to be used in that capacity. Temperature and bottomhole pressure will continue to be monitored at SFI-4. The Permittee shall obtain and test representative formation fluid samples from SFI-4 annually at a minimum, once pressure data and fluid modeling show injection fluid has reached the monitoring well location. The Permittee shall obtain and test representative formation gas samples from SFI-4, at periodic intervals, quarterly at a minimum, once there is evidence of gas accumulation at SFI-4. SFI-4 will remain a monitoring well under this permit.

Perforations at SFI-4 are set at 4,655 - 4695 ft. This perforation interval reflects a portion of the injection zone that is currently authorized in this permit per Part II.B.6.

3. Proposed Replacement Well Construction Details

The Permittee shall submit an updated Well Schematic for the Proposed Replacement Wells and must receive written EPA approval prior to commencing drilling and construction of the well. All drilling, workover, and plugging procedures must comply with the California Geologic Energy Management Division (CalGEM)'s "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Sections 1722-1723

4. Future Well Construction Beyond the Proposed Replacement Well Identified in this Permit

   Prior to drilling any new injection well(s) not covered by this Permit, the Permittee must submit to EPA, for review and approval, a permit application with detailed construction plans and procedures, including proposed field coordinates (Section, Township, Range, with latitude/longitude) for the surface and bottom hole locations of the proposed well(s). The Permittee shall also provide the drilling program details, and the distance between all wells, and any justification for the proposed separation distance between the wells, both at the surface and at the true vertical depth of the top of the injection interval.

   Construction on any such new injection well may only commence after the Permittee receives a modified or new permit, consistent with 40 CFR § 144.52(a)(1), that covers the construction and operation of any new injection well. All drilling, workover, and plugging procedures must comply with CalGEM's "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Sections 1722-1723. Additional requirements may be applied upon EPA's review and issuance of a modified or a new permit.

5. Formation Testing Program for Proposed Replacement Well

   The Permittee shall submit a detailed proposed formation testing program for the Proposed Replacement Well for EPA review as part of the proposed drilling program for the Proposed Replacement Well. The Permittee shall not commence construction of the Proposed Replacement Well until EPA has approved the proposed formation testing program for the well.

6. Injection Interval

   The Existing Wells are currently injecting into the sand member of the Repetto (Pliocene Age) and Puente (Miocene Age). Injection by any Existing Wells, or potential future injection from the Proposed Replacement Wells, is only permitted into the sand member of the Repetto and Puente Formation, (i.e., at a depth of approximately 3,800 to 7,500 feet bgs).

   The sequence of formations that are considered to be possibly suitable for use as injection zones shall be evaluated for their ability to provide containment of slurry fracture injection, their volumetric and areal extent of zonal reservoir continuity, their cumulative performance and response to slurry fracture injection, and their pressure influence at the location of the three improperly plugged and abandoned wells (Superior Well B-1, Apex Hards-Warnock Well 1, and SP LA Harbor Well 301) (See Part II.C.1.b.).

The top of the portion of the Repetto Formation that is approved for injection can be found at approximately 3,800 feet TVD, and the top of Puente Formation can be found at approximately 6,000 feet TVD. The current approved injection zone occurs in Well SFI-1 from 4,800 to 5,210 feet TVD. However, if this injection interval proves not usable as an injection zone, other injection zones within the Repetto and Puente formations may be systematically considered for injection by the Permittee. A written request to change the injection interval shall be submitted to EPA for review as described in Part II.B.2. These perforation interval or injection zone changes shall be requested in writing and proposed procedures will include plans for placement of cement, cement squeezing or via another isolation mechanism for the perforated injection interval, testing of the isolated interval (if cleaned out) or the plugged interval (if not cleaned out), and perforating the next injection interval. These alterations and other rework operations that may occur later in the course of operation of the wells must be properly and thoroughly reported, including submittal of EPA Form 7520-12. The Permittee must demonstrate that each well has mechanical integrity in accordance with Part II, Section D.1 before any injection is authorized.

7. Monitoring Devices

The Permittee shall install and maintain in good operating condition at all times during the operation of the Existing Wells, or the Proposed Replacement Wells (if authorized), the following monitoring devices:

Monitoring Devices for Injection Wells:

The permittee is required to maintain a tap on the discharge line between the injection pump and the wellhead or an alternative location proposed in a detailed written request by the Permittee and approved in writing by EPA for the purpose of obtaining representative samples of injection fluid; and

a. Devices to continuously measure and record injection pressure, bottom hole pressure, annulus pressure, flow rate, and injection volume, subject to the following:

    i. Pressure gauges shall be of a design to provide:

        (a) A full pressure range of at least fifty (50) percent greater than the anticipated operating pressure; and

(b) A certified deviation accuracy of five (5) percent or less throughout the operating pressure range.

ii. Flow meters shall measure cumulative volumes and be certified for a deviation accuracy of five (5) percent or less throughout the range of injection rates allowed by the Permit.

b. Once operational changes in Part II.D.4 have been made, The Permittee may provide a written request with relevant data and evidence to EPA for approval to discontinue continuous bottomhole pressure monitoring.

Monitoring Devices for Monitoring Wells:

A permanently installed device to measure and record bottom hole temperature and bottom hole pressure. Once operational changes in Part II.D.4 have been made, the Permittee may provide a written request with relevant data and evidence to EPA for approval to discontinue continuous bottomhole pressure monitoring.

8. Proposed Changes and Workovers

a. The Permittee shall give advance notice to EPA as soon as possible, pursuant to and in accordance with 40 CFR § 144.51(l)(1), of any planned physical alterations or additions to the Existing Wells or the Proposed Replacement Well (after becoming operational) authorized by this Permit, including sidetracking and deepening or perforating additional intervals. Any changes in well construction, including changes in casing, tubing, packers, and/or perforations other than minor changes, require prior written approval by EPA and may require a permit modification under the requirements of 40 CFR § 144.39 or 144.41. Modifications that are considered routine in well construction details, such as tubing dimensions and strengths, packer models, types and setting depths, and perforation interval changes within the permitted injection zone may be processed by EPA as minor permit modifications consistent with 40 CFR § 144.41 and Part III.B.1

b. For each operational well, the Permittee shall provide all records of well workovers, logging, or other subsequent test data to EPA within sixty (60) days of completion of the activity.

c. The Permittee shall submit all reports required by this Permit using the appropriate reporting forms contained in Appendix C.

d. The Permittee shall perform a Mechanical Integrity Test (MIT), using the procedures set forth in Part II.D.1.a. and II.D.2., within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Part II.D.1. The Permittee shall provide results of the MIT to EPA within sixty (60) days of completion.

9. Testing during Drilling and Construction of Proposed Replacement Well

   a. The Permittee shall include logs and other tests conducted during drilling and construction including, at a minimum, deviation checks, casing logs, and injection formation tests as outlined in 40 CFR § 146.12(d).

   b. The Permittee shall conduct Open Hole logs over the entire open hole sequence below the conductor casing.

   c. The Permittee shall conduct formation evaluation logs and tests and shall provide and use those results to estimate and report values for porosity, permeability, compressibility, static formation pressure, effective thickness, lithology, and rock mechanical properties for both the injection and confining zones identified within the permitted geological sequence.

   d. The Permittee shall collect and analyze full-diameter cores from the overlying confining unit (Pico Formation) and within the Repetto and Puente Formation during drilling of the Proposed Replacement Well.

   e. Before surface, intermediate, and long string casings are set, the Permittee shall run dual induction/spontaneous potential/gamma ray/caliper (DIL/SP/GR/CAL) logs over the course of the entire open hole sequence after the well is drilled to each respective terminal depth. After each casing is set and cementing is completed, the Permittee shall conduct a cement bond evaluation over the course of the entire cased hole sequence (see Part II.D.2.a.iv). The cement bond evaluation shall enable the analysis of bond between cement and casing as well as any cement channeling in the borehole annulus.

   f. During construction of the Proposed Replacement Well, the Permittee shall obtain information relating to ground water at the site and submit to EPA. This information shall include a direct Total Dissolved Solids analysis of the target injection formation water to demonstrate the presence and characteristics of, or the absence of, any Underground Sources of Drinking Water (USDWs, as defined in 40 CFR Part 144).

C. CORRECTIVE ACTION

The Permittee is not required to conduct any corrective action, in accordance with 40 CFR §§ 144.55 and 146.7, prior to EPA granting authorization to inject under this Permit.

1. Annual Zone of Endangering Influence Review

a. The Permittee shall annually review the ZEI calculation based on any new data obtained from the FOT and static reservoir pressure observations required by Part II.D.8.d. The Permittee shall provide to EPA a copy of the modified ZEI calculations, along with all associated assumptions and justifications, with the next Quarterly Report due in accordance with the schedule, set forth in Part II.E.5.b.

b. The sequence of formations (Repetto and Puente Formation) that are authorized for use as injection zones shall be evaluated for their ability to provide containment of slurry fracture injection, their volumetric and areal extent of zonal reservoir continuity, their cumulative performance and response to slurry fracture injection, and their pressure influence at the location of the three improperly plugged and abandoned wells (Superior Well B-1, Apex Hards-Warnock Well 1, and SP LA Harbor Well 301).

c. Numeric gas modeling shall be conducted annually and included in the annual report to estimate the change in pressure at the location of the three improperly plugged and abandoned wells.

2. Implementation of Corrective Actions

a. If any wells requiring corrective action, in accordance with 40 CFR §§ 144.55 and 146.7, are found within the modified ZEI referenced in Part II.C.1., above, a list of the wells along with their locations and construction data shall be provided to EPA within thirty (30) days of their identification.

b. The Permittee shall submit a plan for approval by EPA to re-enter, plug, and abandon the wells listed in Part II.C.2.a., above, in a way that prevents the migration of fluids into any USDWs. The Permittee may submit an alternative plan to address the potential for fluid migration in any of these wells to EPA.

c. The Permittee may not commence corrective action activities without prior written approval from EPA.

D. WELL OPERATION

1. Required Demonstrations

a. Mechanical Integrity

Within ninety (90) days of the effective date of this Permit, the Permittee shall propose a schedule to conduct a MIT to demonstrate that each existing active injection well authorized by this Permit has mechanical integrity consistent with 40 CFR § 146.8 and with Section II.D.2.a. The test should be planned for no more than 365 days after the prior well tests were conducted under the previous permit.

Prior to the approval to inject in the Proposed Replacement Well, the Permittee shall conduct a MIT to demonstrate that the well has mechanical integrity consistent with 40 CFR § 146.8 and with Part II.D.2.a. The Permittee shall demonstrate that there are no significant leaks in the casing and tubing (internal mechanical integrity) and that there is no significant fluid movement into or between USDWs through the casing wellbore annulus or vertical channels adjacent to the injection wellbore (external mechanical integrity).

2. Mechanical Integrity Tests

a. Mechanical Integrity Tests

Mechanical integrity testing shall conform to the following requirements throughout the life of any injection wells currently or in the future authorized by EPA under this Permit and in accordance with the requirements set forth at 40 CFR §§ 144.51(q) and 146.8:

i. Casing/Tubing Annular Pressure (Internal MIT)

In accordance with the timing requirements defined in Part II.D.2.b., below, the Permittee shall perform a pressure test on the annular space between the tubing and long string casing to demonstrate the absence of significant leaks in the casing, tubing, and/or liner. This test shall be for a minimum of thirty (30) minutes at a pressure equal to or greater than the operating injection pressure. If greater than the operating injection pressure, it should be no greater than one hundred (100) pounds per square inch gauge (psig) or 10% of the operating injection pressure, whichever is less. A well passes the MIT if there is less than a five (5) percent change in pressure over the thirty (30) minute period. A pressure differential of at least three hundred and fifty (350) psig between the tubing and annular pressures shall be maintained throughout the MIT. This test shall be performed on the existing active injection wells and the Proposed Replacement Wells that are used for injection initially as described in Part II.D.1.a. and once every year thereafter.

Detailed plans for conducting the Internal MIT must be submitted to EPA for review and approval. Once approved, the Permittee may schedule the Internal MIT, providing EPA at least thirty (30) days' notice before the Internal MIT is conducted. The final test report shall be submitted to EPA within sixty (60) days of test completion.

ii. Continuous Pressure Monitoring of Injection Wells

The Permittee shall continuously monitor and record the tubing/casing annulus pressure and injection pressure by a digital instrument with a resolution of one tenth (0.1) psig. The average, maximum, and minimum monthly results shall be included in the next Quarterly Report submitted to EPA pursuant to Part II.E.5.b., along with any additional records or data requested by EPA regarding the continuous monitoring data described in this Section.

iii. Injection Profile Survey (External MIT)

The Permittee shall conduct a demonstration that the injectate is confined to the proper zone and submit the results of the demonstration to EPA for approval.

This shall be demonstrated with temperature surveys conducted on active injection wells (as specified in Appendix D) and using Fall Off Testing Data to conduct the Advanced Pressure Analysis (Part II D.8.d) or another diagnostic tool or procedure as approved by EPA.

Detailed plans for conducting the external MIT must be submitted to EPA for review and approval. Once approved, the Permittee may conduct the External MIT. Any changes in procedure or schedule to the External MIT shall be requested in writing to EPA.

iv. Cement Evaluation Analysis

After installing and cementing casing, conducting a cement squeeze job, or any well cement repair, for any approved injection well under this Permit, the Permittee shall submit to EPA cementing records and cement evaluation logs that demonstrate isolation of the injection interval and other formations from underground sources of drinking water. Surface casing, intermediate, and long string casing well bore annuli shall be cemented to ground surface. Analysis shall include cement evaluation performed after each casing is set and cemented. Cement evaluation must assess the following four objectives:

(a) Bond between casing and cement;
(b) Bond between cement and formation;
(c) Detection and assessment of any micro-annulus (small gaps between casing and cement); and
(d) Identification of any cement channeling in the borehole

annulus.

If the cement bond logs indicate a lack of sufficient cement or poor bonding at the base of USDWs and/or other critical intervals in any approved injection well under this Permit, remedial cementing may be required to place additional cement in the casing/wellbore annulus.

The Permittee may not commence or recommence injection on that well until it has received written notice from EPA that the cement evaluation/demonstration is satisfactory.

b. Schedule for MITs

EPA may require that an Internal and/or External MIT be conducted within thirty (30) days of a written request from EPA during the permitted life of any well authorized by this Permit. The Permittee shall also arrange and conduct MITs according to the following requirements and schedule:

i. Within thirty (30) days from completion of any workover operation where well integrity is compromised, an Internal MIT shall be conducted and submitted to EPA for approval to verify that the well has mechanical integrity. Prior to this field demonstration, the Permittee shall submit testing plans to EPA, as described in Part II.A.2.

ii. At least quarterly, an injection profile survey External MIT shall be conducted in accordance with 40 CFR § 146.8 and Part II.D.2.a.iii.

iii. At least annually, a pressure test on the annular space between the tubing and long string casing shall be conducted in accordance with 40 CFR § 146.8 and Part II.D.2.a.i.

c. Loss of Mechanical Integrity

Within twenty-four (24) hours from the time the Permittee becomes aware of any loss of mechanical integrity of any well authorized by this Permit, the Permittee shall notify EPA of the situation and specify which of the following circumstances apply:

i. The well fails to demonstrate mechanical integrity during a test; or

ii. A loss of mechanical integrity becomes evident during operation; or

iii. A significant change in the annulus or injection pressure occurs during normal operating conditions.

The Permittee shall send any notifications of loss of mechanical integrity in writing, by electronic mail to: Albright.David@epa.gov

In the event of a loss of mechanical integrity, the Permittee shall immediately suspend injection activities in the affected well and shall not resume operation until it has taken necessary actions to restore and confirm mechanical integrity of the affected well and not until EPA has provided written approval prior to the recommencing of injection into the affected well.

The Permittee may not recommence injection after a workover which has compromised well integrity (such as unseating the packer, etc.) until it has received written approval from EPA that the demonstration of mechanical integrity is satisfactory.

3. Injection Pressure and Fracture Limitation

For any injection wells authorized pursuant to this Permit:

a. In the event that pressure in any authorized injection zone initiates a newly identified fracture, the permittee shall notify EPA. Permittee shall obtain authorization from EPA to continue slurry fracture injection in the overlying, sequential injection zone in those cases when the fractures migrate out of the currently authorized zone. Permittee's request for such authorization shall include a detailed analysis and determination of the fracture propagation. A newly identified fracture is defined in this permit as a fracture that is created in a zone other than the perforated interval as a result of pressure changes due to fluid injection that causes vertical fracture that is not currently being used as a location for injection fluid containment or a pre-existing fracture that is identified during the injection operations. A fracture that is created as a result of pressure changes due to fluid injection that is not currently being used as a location for injection fluid containment or a pre-existing fracture that is identified during the course of injection operations.

b. In no case shall the Permittee inject at pressures that (i) initiate new fractures or propagate existing fractures in the confining zone, (ii) cause the movement of injection or formation fluids into or between USDWs, or (iii) allow injection fluids to migrate to any oil, gas, or geothermal field operations or production wells.
    i. The fracture pressure of the confining layer (Repetto Formation Shale) is estimated to be 4,780 psi. Bottom hole pressure at the Injection Wells shall not exceed 4,541 psi, or 95% of the estimated confining layer fracture pressure.

4. Injection Volume (Rate) Limitation

For any injection wells authorized pursuant to this Permit:

a. The injection rate limitation is the operational pump capacity, currently 10 bpm.

b. The Permittee may request a change in the maximum rate allowed in Part II.D.4.a., above when the operation pump capacity is planned to increase. Any such request shall be made in writing to EPA for its review and approval, along with a justification for the proposed increase and a schedule for gradually increasing the injection rate.

c. Should any increase in injection rate be requested, the Permittee shall demonstrate to the satisfaction of EPA that the proposed increase will not interfere with the operation of the facility, its ability to meet conditions described in this Permit, change its well classification, or cause migration of injectate or pressure buildup to occur beyond the Area of Review.

d. The request shall also include modeling of the predicted change in bottom hole pressure due to the increased rate. If the increased rate is approved, the following Quarterly Report shall include a discussion of any differences between the observed and modeled bottom hole pressure.

e. The injection rate shall not cause an exceedance of the injection pressure limitation established pursuant to Part II.D.3.

5. Injection Fluid Limitation

a. This Permit authorizes the following injection fluids into the Injection Wells (SFI-1 SFI-2, and SFI-3): wastewater plant fluid and biosolids from the Hyperion Treatment Plant, Terminal Island Water Reclamation Plant, Reclamation Plant No. 1: Fountain Valley, Orange County,, Treatment Plant No. 2: Huntington Beach, Orange County, and Los Angeles County Sanitation District Joint Water Pollution Control Plant (JWPCP).. The amounts of wastewater treatment fluids and biosolids from each plant shall be reported in the Quarterly Report.

b. The Permittee shall not inject any hazardous waste, as defined by 40 CFR § 261.3, at any time.

c. Injection fluids shall be limited to those authorized by this Permit, which are those fluids produced by the Permittee as described in Part II.D.5.a., above. No fluids other fluids shall be injected.

d. Any well stimulation or treatment procedure (such as acidizing, etc.) performed at the discretion of the Permittee shall be proposed and submitted to

EPA for approval. After approval is granted, notification to EPA is required at least thirty (30) days prior to performing the approved procedure. This requirement may be modified if the Permittee submits a standard operating procedure for well stimulation or treatment for EPA approval after the effective date of this Permit. If the standard operating procedure plan is approved by EPA in writing, the Permittee shall notify EPA within fifteen (15) days of the proposed well stimulation or treatment procedure, provided the procedure does not deviate in any way from the EPA-approved plan.

6. Tubing/Casing Annulus Requirements

For any injection wells authorized pursuant to this Permit:

a. The Permittee shall use and maintain annular fluid during well operation. The annular fluid used in the Injection wells is corrosion inhibiting KCl brine.

b. Thirty (30) days prior to workovers or maintenance in which shut-in shall occur, the Permittee shall request in writing for EPA approval to maintain less than one hundred (100) psig on the tubing/casing annulus.

c. If the historic cyclic range of annular pressure fluctuation is not already known, then within the first three (3) months of normal injection operations after the effective date of this Permit, the Permittee shall monitor and record to determine that range. The pressure fluctuation data shall be submitted with the first Quarterly Report due after the effective date of the Permit.

d. Any annular pressure measured outside of the established normal pressure range, regardless of whether it otherwise meets the requirements of this Permit, shall be reported orally to EPA within twenty-four (24) hours, followed by a written submission within five (5) days, as a potential loss of mechanical integrity. In the submission, the Permittee must describe the event and include details, such as associated injection pressures and temperatures. The Permittee shall provide any additional information regarding the reported annular pressure event requested by EPA within sixty (60) days of receipt of a written request from EPA.

7. Final Well Construction Report and Completion of Construction Notice

a. In the event the Proposed Replacement Well is approved to be drilled, the Permittee must submit a final well construction report, including logging, coring, and other results, with a schematic diagram and detailed description of construction, including driller's log, materials used (i.e., tubing tally, and particulate filters, if any), and cement (and other) volumes, to EPA within sixty (60) days after well construction completion.

b. The Permittee must also submit a notice of completion of construction to EPA

(Form 7520-18 listed in Appendix C). Injection operations may not commence until EPA has inspected or otherwise reviewed the injection wells and notified the Permittee that they are authorized to commence injection, in accordance with the conditions of the Permit.

8. Slurry Fracture Injection and Operation Process

a. Operational Schedule and Requirements

i. Injection operations are authorized under this Permit for up to 24 hours a day 5 days a week with a shut-in time of 2 days a week. Bottom hole pressure at the end of the 2-day shut-in time is required to be within 10% of the previous week's start up bottom hole pressure.

ii. Injection operation time may be increased as follows:

(a) The Permittee may request in writing injection operations to increase from 5 days a week to 7 days a week. The required consecutive shut-in time required will be once a quarter for a minimum of 20% of the cumulative injection time. Bottom hole pressure at the end of the quarterly shut-in time is required to be within 10% of the previous start up bottom hole pressure.

(b) The Permittee must demonstrate with a Step Rate Test for the request to increase operations from 5 days a week to 7 days a week that increased operation time will not cause the bottom hole pressure to exceed the limit established in Part II D.3.b, and formation parting pressure and changes in in situ stresses are consistent with model predictions.

iii. Alternating Injection Between SFI-1,SFI-2 and SFI-3

(a) If the alternation of injection wells occurs on a basis of a monthly or quarterly schedule, the Permittee shall provide 30-day notice to EPA of the anticipated alternation between injection wells.

(b) If the alternation between injection wells occurs on a daily or weekly schedule, the Permittee shall provide 30-day notice to EPA of the initial anticipated alternating operation, including the start of operations and the anticipated injection schedule for both wells.

b. Project Summary Reports

Project summary reports shall be prepared and distributed on a quarterly basis, in addition to the regulatory reporting in the quarterly EPA report. Project summary reports will include at a minimum records of daily injection volumes, cumulative volume, rates, bio-slurry solids concentration of injectate, and monitoring and injection well pressures (bottom hole and wellhead pressure).

c. Step Rate Tests (SRTs)

i. SRT Procedures

(a) The Permittee shall conduct SRTs at the operating injection well to evaluate formation parting (fracture) pressure and changes in in-situ stresses. The SRTs consist of a series of stepped increases of rate followed by a period of slurry injection, then a shorter series of stepped rate decreases. The SRT may be conducted up to the maximum allowable injection rate. Modifications to the SRT procedures must be requested in writing in advance and justified based on field observations.

The following SRT procedures shall be implemented:

RATE (bbl/min)	DURATION (min)	WASTEWATER TREATMENT FLUIDS
1.0	60	Digested sludge/HPE (High Pressure Effluent)
2.0	60	Digested sludge/HPE
3.0	60	Digested sludge/HPE
5.0	60	Digested sludge/HPE
7.0	60	Digested sludge/HPE
9.0	60	Digested sludge/HPE
8.0	60 or longer	Digested sludge/HPE
8.0	15	HPE
4.0	15	HPE
2.0	15	HPE
Shut-in period	Refer to Appendix F – SRT Guidelines	

(b) Injection rate is gradually increased between steps over a 5-minute interval.

(c) Injection rates are not varied during the 60-minute duration at each step.

(d) Injected volumes and rates are recorded for each step at 15-minute intervals

(e) Scan rate for BHP monitoring is twenty readings per minute through the duration of the SRT and the extended falloff period that follows.

(f) The valve at the surface, in between the pump and pressure gauge, is closed just as the pump is stopping to prevent flow-back

(g) SRTs are to be analyzed using conventional and multi-rate methods to analyze the BHP that was measured. The results from these two methods of analysis shall be provided in the Quarterly Reports. The Permittee shall provide a narrative description of the results and compare the results of the two methods. The main purpose of the narrative description is for EPA to understand and for the permittee to demonstrate their ability to determine the fracturing dynamics and fracture development over time to develop a better understanding of the data patterns and behavior. Refer to Appendix F – Step Rate Test Procedure Guidelines. Refer also to Society of Petroleum Engineers (SPE) Paper #16798 for test design and analysis guidance.

ii. SRT Frequency

(a) SRTs shall be conducted on a quarterly basis when the maximum allowable injection rate is 10 bpm.

(b) If an increase in allowable injection rate is approved by EPA, then SRTs shall be conducted monthly for the first six months of the increased injection rate. After six months of monthly SRTs at the increased injection rate the Permittee may request in writing for EPA approval to reduce SRTs back to the quarterly frequency.

d. Pressure Fall Off Test (FOT)

i. The Permittee shall conduct the FOT after a radial flow regime has been established at an injection rate which is representative of the wastewater contribution to the well. The Permittee shall conduct the FOT in accordance with EPA Region 9 guidance found in Appendix E, and as follows.

ii. The Permittee shall use the test results to calculate the Zone of Endangering Influence (ZEI), consistent with procedures set forth at 40 CFR § 146.6, and to evaluate whether any additional corrective action will be required (refer to Part II.C.). The Permittee shall include a summary of the ZEI recalculation with the FOT report.

iii. The Permittee shall create a plot/graph of the latest static reservoir pressure of the injection zone and its cumulative behavior over time, starting with the FOT conducted after the initial FOT; the plot shall be included with the Project Summary Report.

iv. The Permittee shall use @IPT or a similar advanced commercial well testing software to conduct the Advanced Pressure Fall Off Test. The Advanced Pressure Fall Off Test results shall include the following:

(a) Long term fracturing injection operations
(b) Estimate of reservoir and fracture parameters (length, height) through both standard well testing methods and type-curve matching of closing and shrinking fractures
(c) Model the shrinkage of the fracture after shut-in as it progressively recedes from containment layers and its length decreases
(d) Estimation of the stress contrast between the injection and containment layers based on the shape of differential pressure and its derivative plots after shut-in
(e) Analyze pressure fall off data in a dual-mobility zone, resulting from difference in rock permeability and fluid viscosity

v. The Schedule for FOT shall be as follows:

(a) FOTs shall be conducted on a quarterly basis when the maximum allowable injection rate is 10 bpm.
(b) If an increase in allowable injection rate is approved by EPA, then FOTs shall be conducted monthly for the first six months of the increased injection rate. After six months of monthly FOTs at the increased injection rate the Permittee may request in writing for EPA approval to reduce FOTs back to the quarterly frequency.

e. Microseismic Monitoring

The permittee shall install and operate a downhole microseismic monitoring system with best available technology to provide a determination of the dimensions and orientation of the fractures. Downhole monitoring shall be performed as follows, subject to EPA review and approval.

i. Microseismic monitoring shall be conducted once every two (2) years during regular injection operations, defined as an injection rate not exceeding ten (10) barrels per minute (bpm). The microseismic monitoring shall be conducted during a step rate test (SRT) within the two (2)-year timeframe

ii. If a continuous injection rate greater than ten (10) bpm is used, microseismic monitoring shall be conducted once every month for the first six (6) months during operation at the increased injection rate. The microseismic monitoring shall be conducted during an SRT. The following conditions shall also apply during times when the permittee is injecting at an increased injection rate.

(a) After the six (6) month monitoring period, microseismic monitoring frequency shall be reduced to once every six (6) months, also to be conducted during an SRT. This monitoring frequency shall remain in effect until the Permittee can demonstrate that fracture growth has reached a static condition and microseismic behavior is normal.

(b) Once the Permittee has demonstrated the conditions in Part II D.8.e.i.(a) of this permit, microseismic monitoring frequency can be reduced to once every two (2) years during an SRT.

iii. Microseismic monitoring discussed in Part II D.8.e.i, and Part II D.8e.ii of this permit must be conducted for at least twenty-four (24) hours before and after each SRT to allow for baseline data acquisition and the monitoring of residual microseismic behavior, if any.

9. Modeling and Analysis

a. Fracture Geometry

Slurry Fracture Injection simulation modeling and analysis shall be performed to provide estimates on general fracture geometry, including at a minimum, fracture-pattern azimuth, location, thickness and length. The permittee shall perform analyses using industry standard best available technology software. A detailed written analysis shall be provided by the permittee to demonstrate the fracturing dynamics and development, and over passage of time, establishing better confidence in the understanding of the data patterns and behavior. The results from these analyses shall be discussed in the Quarterly Reports.

b. Biodegradation Process Evaluation

Samples of standing gas and samples of formation fluids representing the current state and qualities of the formation's fluid at each monitoring well's location shall be obtained once a quarter when data show gas is present. Reports shall be submitted with the Quarterly Report (Part II.E.5) regarding details of the sampling program, to include the sampling and data quality, methods used, and updated results. Samples from Monitoring Wells SFI-3 and SFI-4 shall be extracted and tested for geochemical and biological properties in efforts to quantify and identify at a minimum:

i. Gas water ratio
ii. Salinity
iii. Hydrogen, Carbon Dioxide, Hydrogen Sulfide, Oxygen, Nitrogen Methane and Ethane content.

c. Experimental Objectives

The Class V Experimental classification of this permit is based on the high level of investigation and analyses of the complex in situ processes that are fully expected to continue well beyond the period of injection and emplacement of biosolids within distinct geological formations. Progress is likewise expected throughout this project regarding theoretical predictive analysis and application techniques as new data are acquired and various reservoir and geological characteristics and properties are obtained and confirmed. Reports addressing the experimental objectives, including the ongoing development of experimental theories/hypotheses shall be submitted quarterly. Further, these Quarterly Reports must reflect any previous related dialogue between EPA and the permittee, to assure continuity in the discussion of the experimental objectives. The experimental objectives include:

i. Demonstrate with assurance, to EPA's satisfaction, the technical, practical, conceptual, and environmental understanding of slurry fracture injection disposal at a scale sufficient for application at large municipalities in the U.S., such as at the Los Angeles Terminal Island facility.

ii. Apply advanced geophysical monitoring tools and numerical simulation to determine and verify the vertical and azimuthal placement of the slurrified biosolids material in the permitted intervals, below USDWs.

iii. Timely and representative formation sampling, analysis using EPA-approved laboratory methods, and computer modeling using EPA-approved techniques to quantify CH_4 and CO_2 generation, migration and geologic stratigraphic accumulation of CH_4.

iv. Document the subsurface biodegradation process through microbial studies.

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Fluid Monitoring Program

On a quarterly basis or whenever there is a change in injection fluids such as whenever the injection fluid is no longer representative of previous samples and measurements that have been submitted and approved, the Permittee shall sample and analyze injection fluids to yield representative data on their physical, chemical, and other relevant characteristics. Test results shall be submitted by the Permittee to EPA on a quarterly basis.

Samples and measurements shall be representative of the monitored activity. The Permittee shall utilize applicable analytical methods described in Table I of 40 CFR § 136.3 or in EPA Publication SW-846, “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” and as described below, unless other methods have been approved by EPA or additional approved methods or updates to the methods become available.

a. Summary of Acceptable Analytical Methods

i. Inorganic Constituents –USEPA Method 300.0, Part A for Major Anions and USEPA Method 200.8 for Cations and Trace Metals.

ii. General and Physical Parameters – appropriate USEPA methods for Temperature, pH, Hardness, Specific Gravity, and Alkalinity; and Density and Viscosity (See EPA Bulletin 712-C-96-032) under standard conditions.

iii. Volatile Organic Compounds (VOCs) - USEPA Method 8260D.

iv. Semi-Volatile Organic Compounds (SVOCs) - USEPA Method 8270E.

2. Monitoring Information

The Permittee shall maintain records of monitoring activity required under this Permit, including the following information and data:

a. Date, exact location, and time of sampling or measurements;

b. Name(s) of individual(s) who performed sampling or measuring;

c. Exact sampling method(s) used;

d. Date(s) laboratory analyses were performed;

e. Name(s) of individual(s) who performed laboratory analyses;

f. Types of analyses; and

g. Results of analyses.

3. Monitoring Devices

a. Continuous Monitoring Devices

During all periods of operation of any injection well authorized by this Permit, the Permittee shall measure the following wellhead parameters: (i) injectate rate/volume, (ii) injectate temperature, (iii) annular pressure, and (iv) injection pressure. All measurements must be recorded at minimum to a resolution of one tenth (0.1) of the unit of measure (e.g. injection rate and volume must be recorded to a resolution of one tenth (0.1) gallon; pressure must be recorded to a resolution of one tenth (0.1) psig; injection fluid temperature must be recorded to a resolution of one tenth (0.1) degree Fahrenheit. Exact dates and times of measurements, when taken, must be recorded and submitted. The well shall have a dedicated flow meter, installed at or near the wellhead so it records all injection flow. To meet the requirements of this Section, the Permittee shall monitor the following parameters, at the prescribed frequency, and record the measurements at this required frequency, using the prescribed instruments (continuous monitoring requires a minimum frequency of at least one (1) data point every sixty (60) seconds):

Monitoring Parameter	Frequency	Instrument
Injection rate (gallons per minute)	Continuous	Digital recorder
Daily Injection Volume (gallons)	Daily	Digital totalizer

Total Cumulative Volume (gallons)	Continuous	Digital totalizer
Well head injection pressure (psig)	Continuous	Digital recorder
Annular pressure (psig)	Continuous	Digital recorder
Bottom hole temperature (degrees Fahrenheit)	Continuous	Digital recorder

Permittee must adhere to the required format below for reporting injection rate and well head injection pressure. An example of the required electronic data format:

DATE	TIME	INJ. PRESS (PSIG)	INJ. RATE (GPM)
06/27/09	16:33:16	1525.6	65.8
06/27/09	17:33:16	1525.4	66.3

Each data line shall include four (4) values separated by a consistent combination of spaces or tabs. The first value contains the date measurement in the format of mm/dd/yy or mm/dd/yyyy, where mm is the number of the month, dd is the number of the day, and yy or yyyy is the number of the year. The second value is the time measurement, in the format of hh:mm:ss, where hh is the hour, mm are the minutes, and ss are the seconds. Hours should be calculated on a twenty-four (24)-hour basis, i.e. 6 PM is entered as 18:00:00. Seconds are optional. The third value is the well head injection pressure in psig. The fourth column is injection rate in gallons per minute (gpm).

b. Calibration and Maintenance of Equipment

The Permittee shall calibrate and maintain on a regular basis all monitoring and recording equipment to ensure proper working order of all equipment.

4. Recordkeeping

a. The Permittee shall retain the following records and shall have them available at the facility at all times for inspection by EPA or other authorized personnel, in accordance with the following:

i. All monitoring information, including required observations, calibration and maintenance records, recordings for continuous monitoring instrumentation, copies of all reports required by this Permit, and records of all data used to complete the Permit application;

ii. Information on the physical nature and chemical composition of all injected fluids; and

iii. Records and results of MITs, FOTs, and any other tests and logs required by EPA, and any well work and workovers completed.

b. The Permittee shall maintain copies (or originals) of all records described in Part II.E.4.a.i. through iv., above, during the operating life of the well and shall make such records available at all times for inspection at the facility. The Permittee shall only discard the records described in Part II.E.4.a.i. through iv., if written approval from EPA to discard the records is obtained.

5. <u>Quarterly Reports</u>

a. The Permittee shall submit to EPA Quarterly Reports containing, at minimum, the following information gathered during the Reporting Period identified in this Part (below):

i. Injection fluid characteristics for parameters specified in Part II.E.1.a.;

ii. The results of any additional MITs, FOTs, logging or other tests, as required by EPA;

iii. Any pressure tests, as required by Part II.D.2.a.i.;

iv. Shut-in static reservoir pressure cumulative behavior plot of the injection zone, as required by Part II.D.8.d.;

v. Results and discussion of the Slurry Fracture Injection Process, Related operations and analysis as described in Part II.D.8

vi. The Permittee shall include fracture simulation and gas migration modeling results. The modeling results shall include the ongoing discussion being developed of the justification and identification of the parameters and theoretical bases used in the modeling, their values and their accuracy sufficient for a level of understanding that is satisfactory to EPA and for EPA's approval. The report must also interpret any deviation or discrepancy between predicted and measured data.

vii. Hourly and daily values, submitted in electronic format, for the continuously monitored parameters specified for the injection wells in Part II.E.3.a.; and

ix. Monthly cumulative total volumes, as well as monthly average, minimum, and maximum values for the continuously monitored rate, pressure, and temperature parameters specified for the injection wells in Part II.E.3.a., unless more detailed records are requested by EPA.

a. Quarterly Reports, with the applicable Appendix C forms, shall be submitted for the reporting periods by the respective due dates as listed below:

Reporting Period	Report Due
Jan, Feb, Mar	Apr 28
Apr, May, June	July 28
July, Aug, Sept	Oct 28
Oct, Nov, Dec	Jan 28

b. For the Quarterly Report due January 28, the Permittee shall also include in that Report the following information collected during the prior year covering January through December:

i. Annual reporting summary (7520-11 in Appendix C);

ii. Annual injection profile survey results as required in Part II.D.2.a.iii.;

iii. Annual ZEI recalculation as required in Part II.C.1.; and

iv. A narrative description of all non-compliance that occurred during the past year.

c. For the Quarterly report due April 28, the Permittee shall also include the Annual Financial Statement for the City of Los Angeles, California Sewer Construction and Maintenance Fund with Independent Auditors Report.

d. In addition to meeting the submittal requirements of Part III.E.9., copies of all Quarterly Reports shall also be provided to the following:

California Geologic Energy Management Division
Southern District
Attn: District Engineer
Via email: CalGEMSouthern@conservation.ca.gov

California Regional Water Quality Control Board
Los Angeles Branch
Attn: Underground Injection Control Unit
Via email: Jeong-heelim@waterboards.ca.gov

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

   The Permittee shall notify EPA no less than sixty (60) days before abandonment of any well authorized by this Permit and shall not perform the plugging and abandonment activities until the Permittee receives written notice of approval by EPA.

2. Plugging and Abandonment Plans

   The Permittee shall plug and abandon the well(s) as provided by the Plugging and Abandonment Plan submitted by the Permittee (see Appendix G) and approved by EPA, consistent with CalGEM's "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Sections 1722-1723 and 40 CFR § 146.10. Upon written notice to the Permittee, EPA may change the manner in which a well will be plugged, based upon but not limited to the following reasons: (a) if the well is modified during its permitted life, (b) if the proposed Plugging and Abandonment Plan for the well is not consistent with EPA requirements for construction or mechanical integrity, or (c) otherwise at EPA's discretion. Upon written notice, EPA may periodically require the Permittee to estimate and to update the estimated plugging cost. To determine the appropriate level of financial assurance for the Plugging and Abandonment Plan, the Permittee shall obtain a cost estimate from an independent third-party firm in the business of plugging wells. The estimate shall include the costs of all the materials and activities necessary to pay an independent third-party contractor to completely plug and abandon the well as established in the Plugging and Abandonment Plan.

3. Cessation of Injection Activities

   After a cessation of injection operations for two (2) years for any well that is not being utilized as a monitoring well authorized by this Permit, a well is considered inactive. In this case, the Permittee shall plug and abandon the inactive well in accordance with the approved Plugging and
   Abandonment Plans contained in Appendix G, unless the Permittee:

   a. Provides notice to EPA of an intent to re-activate the well;

b. Has demonstrated that the well(s) will be used in the future;

c. Has described actions or procedures, satisfactory to EPA and approved in writing by EPA, which will be taken to ensure that the well(s) will not endanger USDWs during the period of inactivity, including annually demonstrating external mechanical integrity of the well(s); and

d. Conducts an initial Internal MIT and every two (2) years thereafter while the well remains inactive, demonstrating no loss of mechanical integrity. Note that the Permittee must restore mechanical integrity of the inactive well if the well fails the MIT.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging any well, or at the time of the next Quarterly Report (whichever occurs first), the Permittee shall submit a report on Form 7520-19, provided in Appendix C, as well as the detailed procedural activity of engineer's log and daily rig log to EPA. The report shall be certified as accurate by the person who performed the plugging operation and shall consist of either:

a. A statement that the well was plugged in accordance with the approved Plugging and Abandonment Plans contained in Appendix G; or

b. Where actual plugging differed from the Plugging and Abandonment Plans contained in Appendix G, a statement specifying and justifying the different procedures followed.

G. FINANCIAL ASSURANCE REQUIREMENTS

1. Demonstration of Financial Assurance

The Permittee is required to demonstrate and maintain financial assurance and resources sufficient to close, plug, and abandon any existing or future-permitted underground injection operations approved pursuant to this Permit, as provided in the Plugging and Abandonment Plans contained in Appendix G and consistent with 40 CFR Part 144 Subpart E.

In addition, the Permittee shall meet the following specific financial assurance requirements:

a. The Permittee established financial assurance for the plugging and abandonment of the Existing Wells in the amounts of $182,352 per well, by demonstrating that it passed the financial test as specified in 40 CFR §

144.63(f)(1)(ii). The plugging and abandonment amounts factored in the cost for an independent third party to plug and abandon the Existing Wells.

b. Pursuant to Part II.A.1. of this Permit, should the Permittee seek to operate a Proposed Replacement Well, the Permittee is required to provide evidence of financial assurance (see Part II.G.1.) for each well. The Permittee must receive approval in writing of any such financial assurance evidence.

c. For each well authorized by this Permit, the financial assurance mechanism shall be reviewed and updated annually, if necessary, and a description of that review and any updates shall be set forth in the Quarterly Report required in Part II.E.5., due on January 28 of each year. At its discretion, and upon written request, EPA may require the Permittee to change to an alternate method of financial assurance. Any such change must be approved in writing by EPA prior to the change.

d. EPA may periodically require the Permittee to update the estimated Plugging and Abandonment Plans (see Appendix G) and/or the cost associated with it, and the Permittee shall make such an adjustment within sixty (60) days of notice from EPA. Alternately, EPA may independently adjust the required financial assurance amount, as warranted.

2. <u>Failure of Financial Assurance</u>

The Permittee must notify EPA of the insolvency of a financial institution supporting the financial assurance as soon as possible, but no later than ten (10) calendar days after the Permittee becomes aware of the insolvency. The Permittee shall submit to EPA a revised and/or new instrument of financial assurance, consistent with the terms of this Permit and 40 CFR § 144.52(a)(7)(ii), within sixty (60) days after any of the following events occurs:

a. The institution issuing the bond or other financial instrument files for bankruptcy;

b. The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked; or

c. The institution issuing the financial instrument lets it lapse or decides not to extend it.

Failure to submit an acceptable financial assurance demonstration may result in the termination of this Permit pursuant to 40 CFR § 144.40(a)(1).

3. <u>Insolvency of Owner or Operator</u>

An owner or operator must notify EPA by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days after such an event occurs. A guarantor of a corporate guarantee must make such a notification if he/she is named as debtor, as required under the terms of the guarantee.

H. DURATION OF PERMIT

This Permit and the authorization to inject are issued for a period of ten (10) years unless terminated under the conditions set forth in Part III.B.1. or administratively extended under the conditions set forth in Part III.E.12.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection well construction and operation in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any injection activity not otherwise allowed by this Permit, as such activities may allow the movement of fluid containing any contaminant into USDWs (as defined by 40 CFR §§ 144.3 and 146.3).

No injection fluids are allowed to migrate to any nearby oil, gas, or geothermal field operations or production wells. Further, this Permit requires systematic and predictive documentation over the facility's operational life to ensure that no injection fluids, either presently or in the future, will so migrate.

Any underground injection activity not authorized by this Permit is prohibited. 40 CFR § 144.11. The Permittee must comply with all applicable provisions of the Safe Drinking Water Act (SDWA) and 40 CFR Parts 124, 144, 145, and 146. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, 42 U.S.C. § 300i, or any other common law, statute, or regulation other than Part C of the SDWA. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege, nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Nothing in this Permit shall be construed to relieve the Permittee of any duties under all applicable, including future, laws or regulations.

B. PERMIT ACTIONS

1. Modification, Revocation and Reissuance, or Termination

EPA may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.51(f). The Permit is also subject to minor modifications for cause as specified in 40 CFR § 144.41. The filing of a request for a Permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance by the Permittee, does not stay the applicability or enforceability of any Permit condition. EPA may also modify, revoke and reissue, or terminate this Permit in accordance with any amendments to the SDWA if the amendments have applicability to this Permit.

2. Transfers

This Permit is not transferable to any person unless notice is first provided to EPA and the Permittee complies with requirements of 40 CFR § 144.38. See also 40 CFR § 144.51(l)(3). EPA may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

C. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this Permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and § 144.5, any information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures contained in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

1. Name and address of the Permittee; or

2. Information dealing with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

The provisions of 40 CFR § 144.51 are incorporated by reference into this Permit, except as modified by specific provisions in this Permit. In addition, the following general duties and requirements apply to this Permit and the Permittee.

1. Duty to Comply

The Permittee shall comply with all applicable UIC Program regulations and all conditions of this Permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 CFR § 144.34. Any Permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, Permit termination, revocation and reissuance, or modification, or denial of a Permit renewal application. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions

Any person who violates a Permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may also be subject to enforcement actions pursuant to RCRA or other actionable authorities. Any person who willfully violates a Permit condition may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate

The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this Permit. The Permittee shall notify EPA twenty-four (24) hours prior to initiating any mitigation steps as required in Part III.E.10.e.

5. Proper Operation and Maintenance

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance include effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Property Rights

This Permit does not convey any property rights of any sort, or any exclusive privilege.

7. Duty to Provide Information

The Permittee shall furnish to EPA, within 30 days of a request, any information which EPA may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this Permit, or to determine compliance with this Permit. The Permittee shall also furnish to EPA, upon request, copies of records required to be kept by this Permit.

8. Inspection and Entry

The Permittee shall allow EPA, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

a. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this Permit;

b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this Permit;

c. Inspect and photograph, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and

d. Sample or monitor at reasonable times, for the purposes of assuring Permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

9. Submittal Requirements

The Permittee shall follow the procedures set forth below for all submittals made to EPA under this Permit, including all notices and reports:

a. All submittals to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative consistent with the requirements of 40 CFR §§ 122.22, 144.32, and 144.51(k).

b. Unless otherwise authorized, or required by this Permit or rule, all submissions (including correspondence, reports, records and notifications) required under this Permit shall be in writing, sent by electronic mail and mailed first class mail to the following address:

U.S. Environmental Protection Agency, Region 9
Water Division
UIC Program
Groundwater Protection Section (WTR-4-2)
75 Hawthorne St.
San Francisco, CA 94105-3901
Email: Albright.David@epa.gov

c. The compliance date for submittal of a report is the day it is postmarked.

10. Additional Reporting Requirements

a. Planned Changes

The Permittee shall give notice to EPA as soon as possible of any planned physical alterations or additions to the permitted facility.

b. Anticipated Noncompliance

The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

c. Compliance Schedules

Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted to EPA no later than thirty (30) days following each schedule date.

d. Monitoring Reports

Monitoring results shall be reported at the intervals specified elsewhere in this Permit.

e. Twenty-four Hour Reporting

i. The Permittee shall report to EPA any noncompliance which may endanger health or the environment, including:

(a) Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water (USDW); or

(b) Any noncompliance with a Permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs.

ii. Any information shall be provided orally within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances. A written submission of all noncompliance as described in Part III.E.10.e.i., above, shall also be provided to EPA within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

f. Other Noncompliance

At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of noncompliance not otherwise reported pursuant to other reporting requirements outlined in this Permit.

g. Other Information

If the Permittee becomes aware that it failed to submit all relevant facts in the Permit application, or submitted incorrect information in the Permit application or in any report to EPA, the Permittee shall submit such facts or information within two (2) weeks of the time such facts or information becomes known.

11. Requirements prior to commencing injection, Plugging and abandonment report, Duty to establish and maintain mechanical integrity.

The Permittee shall comply with all applicable requirements set forth at 40 CFR § 144.51(m)-(q) and as outlined throughout this Permit.

12. Continuation of Expiring Permit

a. Duty to Reapply

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, the Permittee must submit a complete application to EPA for a new permit at least three hundred and sixty-five (365) days before this Permit expires.

b. Permit Extensions

The conditions and requirements of an expired permit continue in force and effect in accordance with 40 CFR 144.37(a) until the effective date of a new permit, if:

i. The Permittee has submitted a timely and complete application for a new permit; and

ii. EPA, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

13. Records of Permit Application

The Permittee shall maintain records of all data required to complete the Permit application and any supplemental information submitted with the Permit application for the duration of the permit.

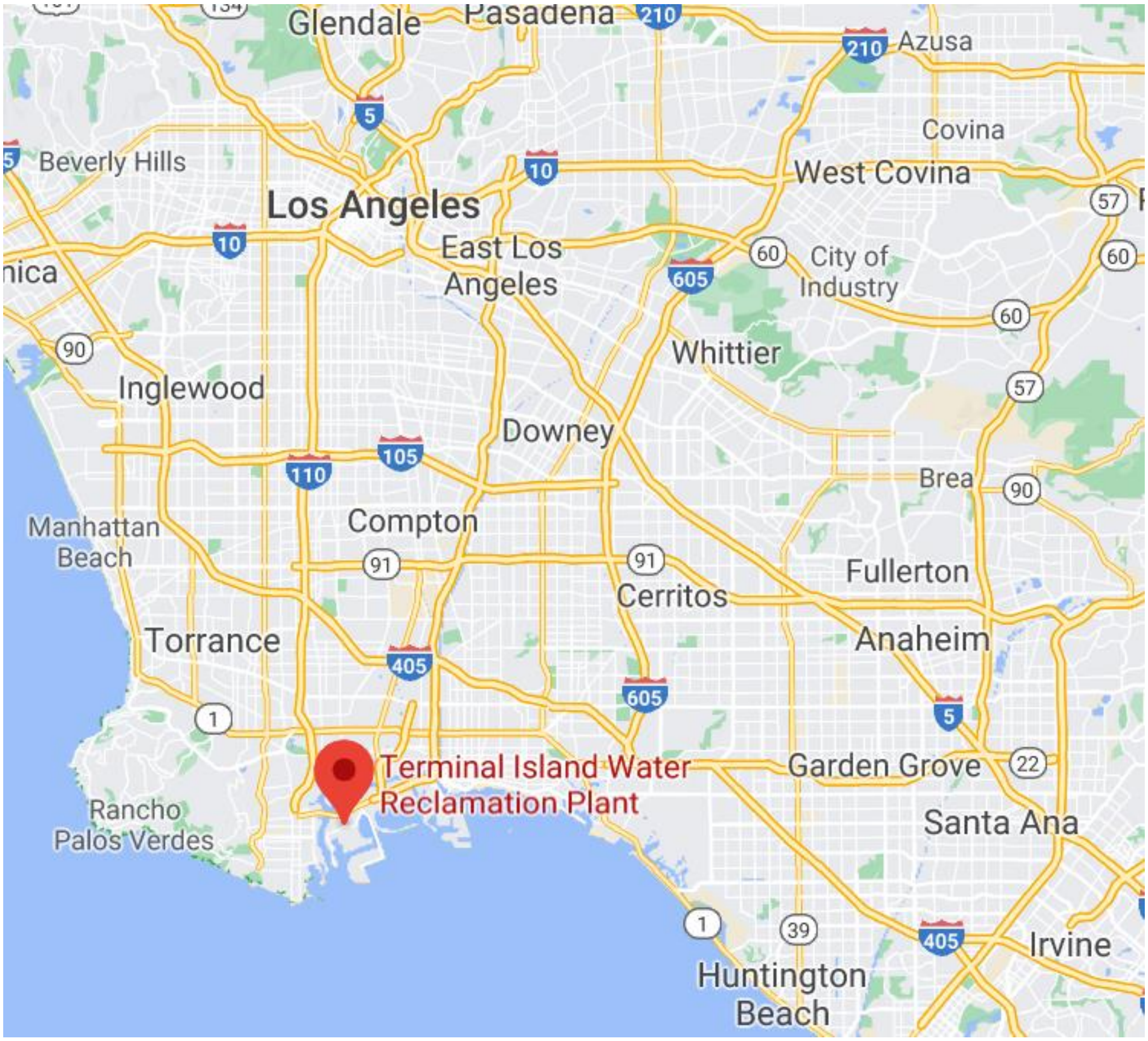
14. Availability of Reports

Except for information identified as confidential under the procedures of 40 CFR Part 2, all reports prepared in accordance with the conditions of this Permit shall be available for public inspection at appropriate offices of the EPA. Permit applications, Permits, and well operation data shall not be considered confidential.

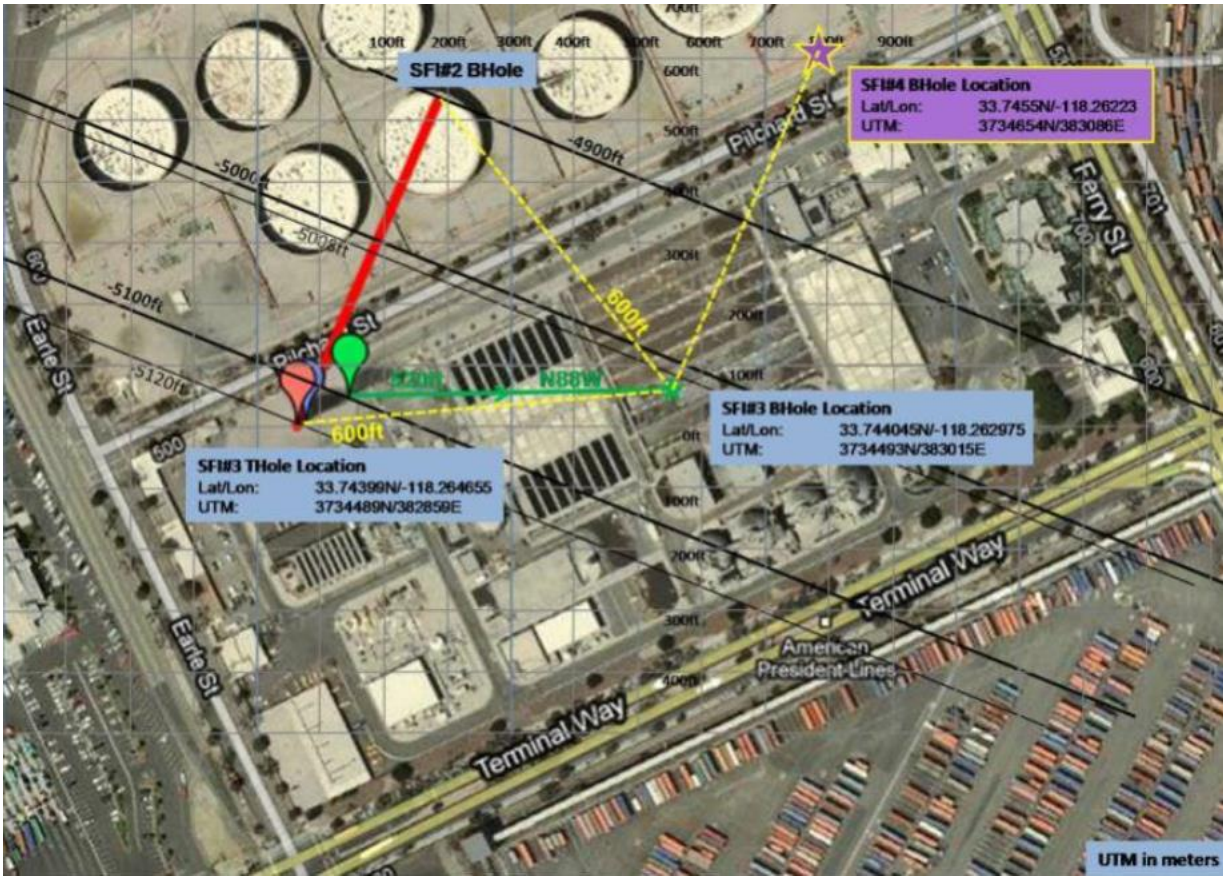
APPENDIX A

Project Location Maps

UIC Permit No. R9UIC-CA5-FY18-1R



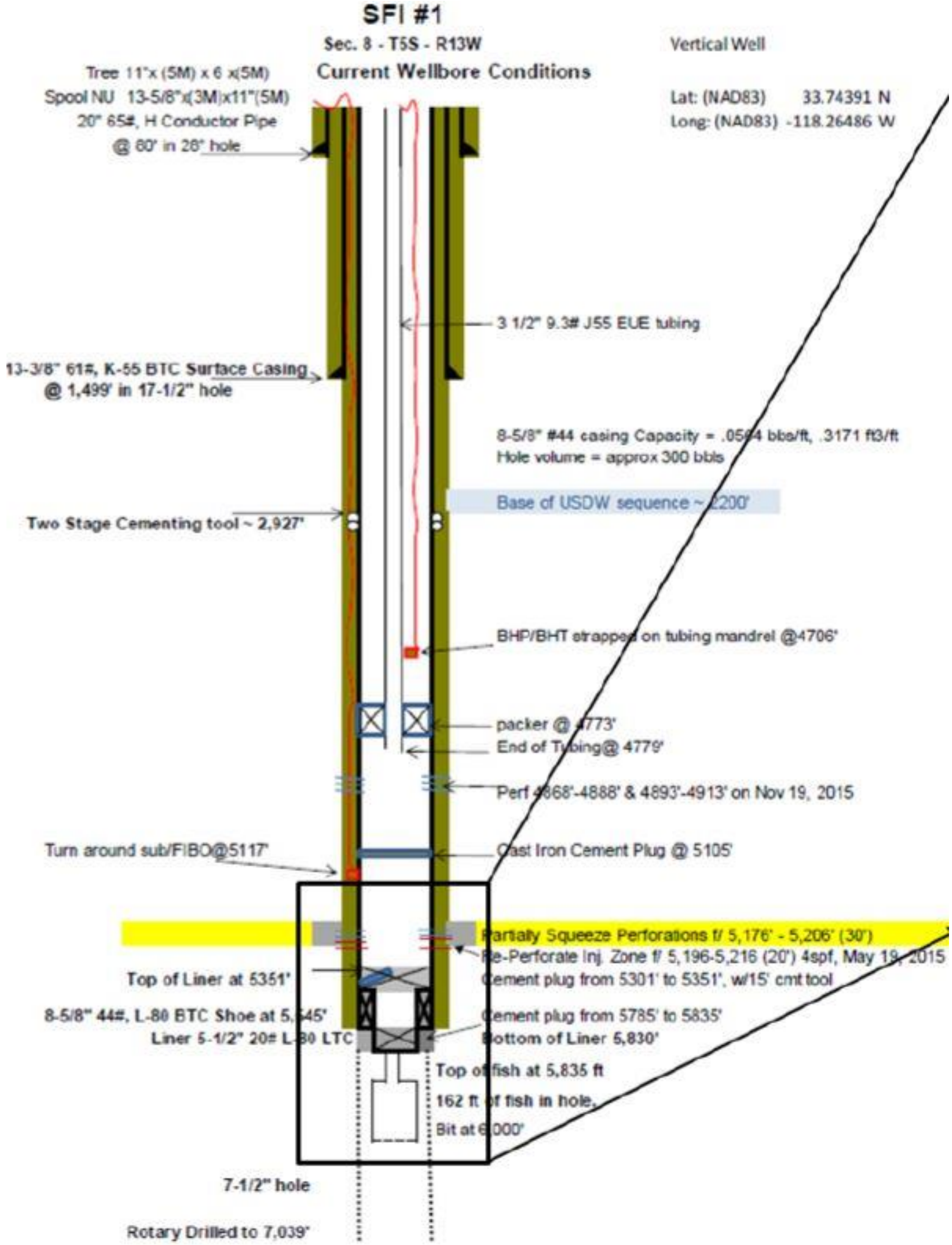
Glendale
Pasadena
Azusa
Covina
Beverly Hills
Los Angeles
West Covina
East Los Angeles
City of Industry
Whittier
Inglewood
Downey
Brea
Manhattan Beach
Compton
Fullerton
Cerritos
Torrance
Anaheim
Garden Grove
Terminal Island Water Reclamation Plant
Rancho Palos Verdes
Santa Ana
Irvine
Huntington Beach


SFI#2 BHole
SFI#4 BHole Location
Lat/Lon: 33.7455N/-118.26223
UTM: 3734654N/383086E
SFI#3 BHole Location
Lat/Lon: 33.744045N/-118.262975
UTM: 3734493N/383015E
SFI#3 THole Location
Lat/Lon: 33.74399N/-118.264655
UTM: 3734489N/382859E
600ft
600ft
N88W
-4900ft
-5000ft
-5008ft
-5100ft
-5120ft
Pilchard St
Ferry St
Earle St
Terminal Way
American President Lines
UTM in meters

APPENDIX B

Well Schematics

UIC Permit No. R9UIC-CA5-FY18-1R



Drilled to 7,039'

TTI

SFI # 2

Section 8 - T5S - R13W

Monitoring Well

Kick Off @1600ft, max build angle 10 degree @ 1degree/100ft

Surface:

Lat: 33.743852 N

Long: -118.26403 W

KB (above sea level) 31

GL (above sea level) 10

Wellhead Assembly 5K

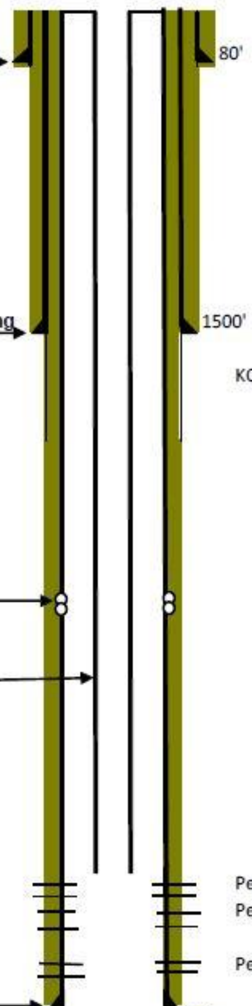
20" 65#, H Conductor Pipe
@80' ft 26" hole

10 3/4" 40.5#, J-55 Surface Casing
@1533' in 14 3/4" hole
w/920 sacks of cement
cement return to surface

BFW app. 2200'

Two stage Cementing Tool
DV tool @2922'

2 3/8" 4.7# J-55 EUE tubing
end @ 4605'



Perf:4730' to 4750' .49" dia 6spf 11/23/09
Perf:4755' to 4775' .49" dia 6spf 11/23/09

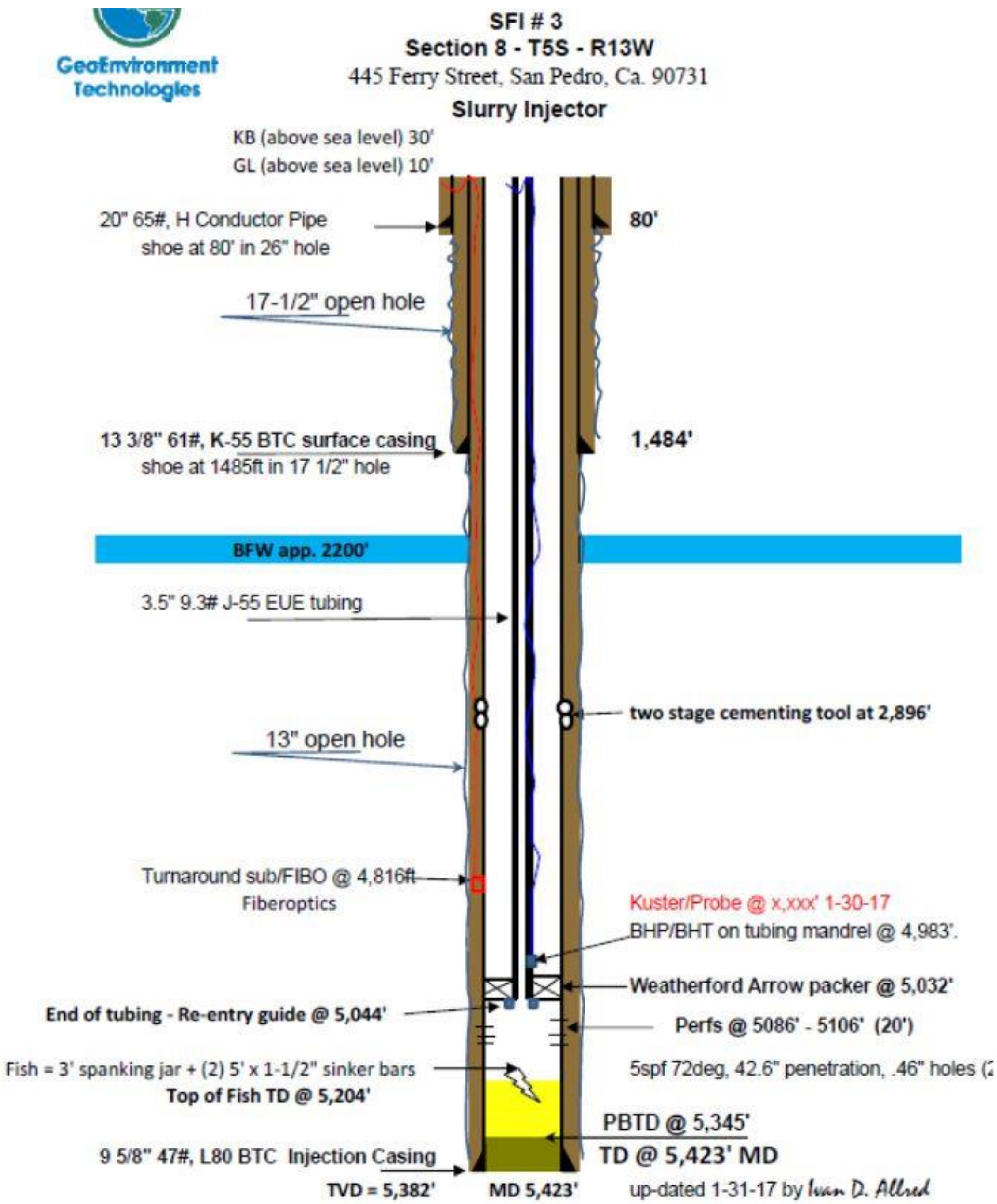
Perf:4982' to 5002' .49" dia 6spf 11/23/09

7" 29#, L80 Injection Casing
@5431' in 9 7/8" hole
w/575 sacks of cement for top
w/700 sacks of cement for bottom
cement return to surface

TD 5431'

MD	TVD (from deviation survey)
1500	1499.81
1939	1938.46
2607	2597.49
3147	3129.65
3625	3600.86
4005	3975.96
4482	4446.52
4767	4726.82
4927	4883.97
5118	5071.32
5300	5250.29

BH Location: 559'N & 559'E


GeoEnvironment Technologies
SFI # 3
Section 8 - T5S - R13W
445 Ferry Street, San Pedro, Ca. 90731
Slurry Injector
KB (above sea level) 30'
GL (above sea level) 10'
20" 65#, H Conductor Pipe
shoe at 80' in 26" hole
80'
17-1/2" open hole
13 3/8" 61#, K-55 BTC surface casing
shoe at 1485ft in 17 1/2" hole
1,484'
BFW app. 2200'
3.5" 9.3# J-55 EUE tubing
two stage cementing tool at 2,896'
13" open hole
Turnaround sub/FIBO @ 4,816ft
Fiberoptics
Kuster/Probe @ x,xxx' 1-30-17
BHP/BHT on tubing mandrel @ 4,983'.
Weatherford Arrow packer @ 5,032'
End of tubing - Re-entry guide @ 5,044'
Perfs @ 5086' - 5106' (20')
Fish = 3' spanking jar + (2) 5' x 1-1/2" sinker bars
5spf 72deg, 42.6" penetration, .46" holes
Top of Fish TD @ 5,204'
PBTD @ 5,345'
9 5/8" 47#, L80 BTC Injection Casing
TD @ 5,423' MD
TVD = 5,382'
MD 5,423'
up-dated 1-31-17 by Ivan D. Allred

Terminal Island Facility

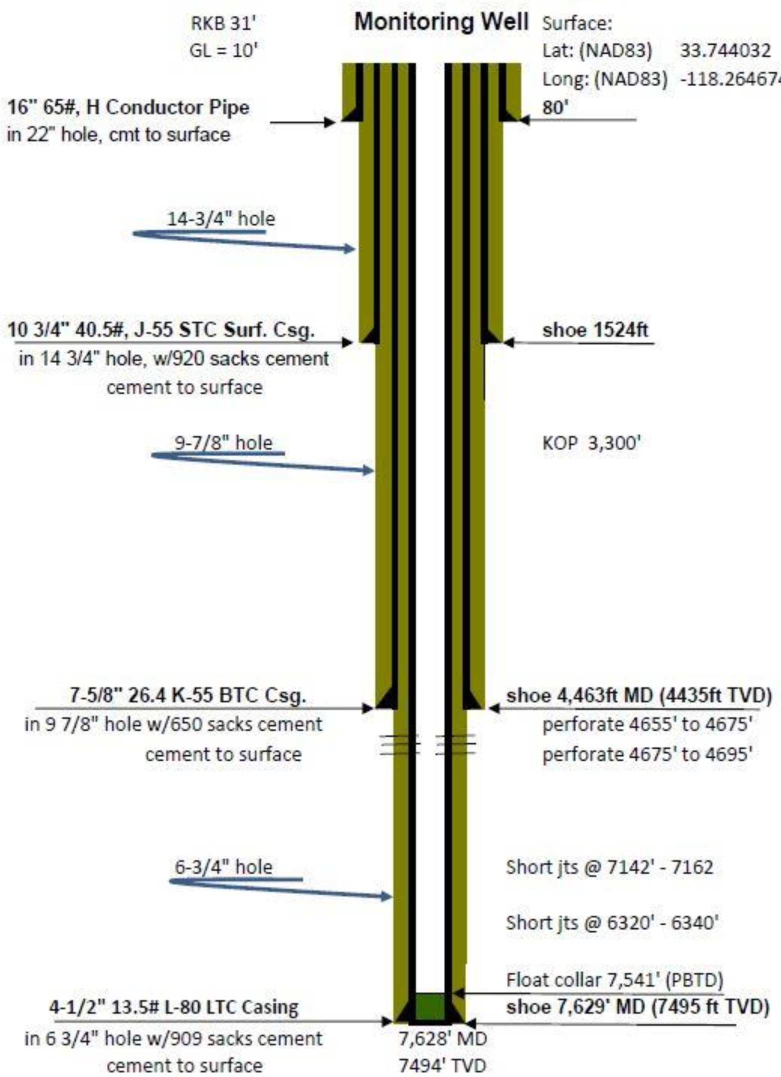
DOE #2 (aka SFI#4)

Section 8 - T5S - R13W

Monitoring Well

Surface:
Lat: (NAD83) 33.744032 N
Long: (NAD83) -118.264674 W

Bottom:
634ft N of surface
864ft E of surface



Directional Well: 634'N & 864' E

Deviation Survey

MD	TVD
3303	3303
4157	4140
4577	4547
5051	5003
5460	5399
5937	5859
6380	6288
6887	6776
7077	6958
6360	7233
7590	7456

APPENDIX C

EPA Reporting Forms

UIC Permit No. R9UIC-CA5-FY18-1R

EPA Reporting Forms List

Form 7520-7: Application to Transfer Permit

Form 7520-8: Quarterly Injection Well Monitoring Report

Form 7520-11: Annual Class II Disposal/Injection Well Monitoring Report

Form 7520-18: Owner and Operator Completion Report for Injection Wells EPA

Form 7520-19: Well Rework Record, Plugging and Abandonment Plan, or Plugging and Abandonment Affidavit

These forms are available for downloading at:
https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators

APPENDIX D

Logging Requirements

UIC Permit No. R9UIC-CA5-FY18-1R

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 9
TEMPERATURE LOGGING GUIDELINES

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid MIT as specified by 40 CFR §146.8(c)(1). Variances to these requirements are expected for certain circumstances, but they must be approved prior to running the log. As a general rule, the well shall inject for approximately six (6) months prior to running a temperature decay progression sequence of logs.

1. With the printed log, also provide raw data for both logging runs (at least one data reading per foot depth) unless the logging truck is equipped with an analog panel as the processing device.

2. The heading on the log must be complete and include all the pertinent information, such as correct well name, location, elevations, etc.

3. The total shut-in times must be clearly shown in the heading. Minimum shut-in time for active injectors is twelve (12) hours for running the initial temperature log, followed by a second log, a minimum of four (4) hours later. These two log runs will be superimposed on the same track for final presentation.

4. The logging speed must be kept between twenty (20) and fifty (50) feet per minute (30 ft/min optimum) for both logs. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).

5. The vertical depth scale of the log should be one (1) or two (2) inches per one-hundred (100) feet to match lithology logs (see 7(b)). The horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

6. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

7. The left hand tracks must contain (unless impractical, but EPA must pre-approve any deviations):

(a) a collar locator log,

(b) a lithology log which includes either:

(i) an historic Gamma Ray that is "readable", i.e. one that demonstrates lithologic changes without either excessive activity by the needle or severely dampened responses; or

(ii) a copy of an original spontaneous potential (SP) curve from either the subject well or from a representative, nearby well.

(c) A clear identification on the log showing the base of the lowermost Underground Source of Drinking Water (USDW). A USDW is basically a formation that contains less than ten thousand (10,000) parts per million (ppm) Total Dissolved Solids (TDS) and is further defined in 40 CFR §144.3.

APPENDIX E

EPA UIC Pressure Falloff Requirements

UIC Permit No. R9UIC-CA5-FY18-1R

EPA Region 9
UIC PRESSURE FALLOFF REQUIREMENTS

Condensed version of the
EPA Region 6
UIC PRESSURE FALLOFF TESTING GUIDELINE
Third Revision

August 8, 2002

TABLE OF CONTENTS

APPENDIX

REQUIREMENTS

UIC PRESSURE FALLOFF TESTING GUIDELINE
Third Revision
August 8, 2002

1.0 Background

Region 9 has adopted the Region 6 UIC Pressure Falloff Testing Guideline requirements for monitoring Class 1 Non Hazardous waste disposal wells. Under 40 CFR 146.13(d)(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.

All of the following parameters (Test, Period, Analysis) are critical for evaluation of technical adequacy of UIC permits:

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.

2.0 Purpose of Guideline

This guideline has been adopted by the Region 9 office of the Evironmental Protection Agency (EPA) to assist operators in **planning and conducting** the falloff test and preparing the **annual monitoring report**.

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 UIC permit demonstrations. Additionally, a valid falloff test is a monitoring requirement under 40 CFR Part 146 for all Class I injection wells.

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 annually. 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.

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 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:

(1) general information and an overview of the falloff test,
(2) an analysis of the pressure data obtained during the test,
(3) a summary of the test results, and
(4) a comparison of those results with previously used parameters.

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 in addition 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:
   - X Wellbore radius
   - X Completed interval depths
   - X Type of completion (perforated, screen and gravel packed, openhole)
6. **Depth of fill depth and date tagged.**
7. **Offset well information:**
   - X Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
   - X 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 all pressure gauges utilized on 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)
    - X List all the gauges utilized to test the well
    - X Depth of each gauge
    - X Manufacturer and type of gauge. Include the full range of the gauge.
    - X Resolution and accuracy of the gauge as a % of full range.
    - X Calibration certificate and manufacturer's recommended frequency of calibration
14. **General test information:**
    - X Date of the test
    - X 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 <u>and any offset wells</u>.
    - X Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. **Reservoir parameters (determination):**
    - X Formation fluid viscosity, μ_f cp (direct measurement or correlation)
    - X Porosity, φ fraction (well log correlation or core data)
    - X Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
    - X Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - X Initial formation reservoir pressure - See Appendix, page A-1
    - X Date reservoir pressure was last stabilized (injection history)
    - X Justified interval thickness, h ft - See Appendix, page A-15
16. **Waste plume:**
    - X Cumulative injection volume into the completed interval
    - X Calculated radial distance to the waste front, r_{waste} ft
    - X Average historical waste fluid viscosity, if used in the analysis, μ_{waste} cp

17. **Injection period:**
    - X Time of injection period
    - X Type of test fluid
    - X Type of pump used for the test (e.g., plant or pump truck)
    - X Type of rate meter used
    - X Final injection pressure and temperature
18. **Falloff period:**
    - X Total shut-in time, expressed in real time and Δt, elapsed time
    - X Final shut-in pressure and temperature
    - X Time well went on vacuum, if applicable
19. **Pressure gradient:**
    - X Gradient stops - for depth correction
20. **Calculated test data:** include all equations used and the parameter values assigned for each variable within the report
    - X Radius of investigation, r_i ft
    - X Slope or slopes from the semilog plot
    - X Transmissibility, kh/μ md-ft/cp
    - X Permeability (range based on values of h)
    - X Calculation of skin, s
    - X Calculation of skin pressure drop, ΔP_{skin}
    - X Discussion and justification of any reservoir or outer boundary models used to simulate the test
    - X Explanation for any pressure or temperature anomaly if observed
21. **Graphs:**
    - X Cartesian plot: pressure and temperature vs. time
    - X Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - X Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - X Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. **A copy of the latest radioactive tracer run** and a brief discussion of the results.

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

X Adequate storage for the waste should be ensured for the duration of the test

X 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

X 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

X The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period

X 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.

X Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well

X 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.

X 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.

X 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.

Site Specific Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:

   X Review previous welltests, if available

   X Simulate the test using measured or estimated reservoir and well completion parameters

   X 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)

   X 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/μ) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are required. (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
   - X 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.
   - X 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.
   - X 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 at the wellhead 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.
   - X Confirm pressure stabilization prior to shut-in of the test well
   - X 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.)

X 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.)

X **Mark the various flow regimes** - particularly the radial flow period

X Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)

X If there is no radial flow period, attempt to type curve match the data

3. Prepare a **semilog plot**.

X Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff

X Draw the semilog straight line through the radial flow portion of the plot and obtain the slope of the line

X Calculate the transmissibility, kh/μ

X Calculate the skin factor, s, and skin pressure drop, ΔP_{skin}

X Calculate the radius of investigation, r_i

4. Explain any anomalous results.

8.0 Technical References

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APPENDIX

Pressure Gauge Usage and Selection

Usage

- X EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- X **Downhole pressure measurements** are less noisy and are required.
- X A 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.
- X 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.
- X Mechanical gauges should be **calibrated** before and after each test using a dead weight tester.
- X 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

- X 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.
- X 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.
- X Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.

Test Design

General Operational Considerations

- X 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
- X 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.

- X 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.

- X 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

- X 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.

- X 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.

- X 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.

- X 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.

- X 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.
- X 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

- X Wellbore radius, r_w - from wellbore schematic

X Net thickness, h - See Appendix, page A-15
X Porosity, φ - log or core data
X Viscosity of formation fluid, μ_f - direct measurement or correlations
X Viscosity of waste, μ_{waste} - direct measurement or correlations
X Total system compressibility, c_t - correlations, core measurement, or well test
X Permeability, k - previous welltests or core data
X Specific gravity of injection fluid, s.g. - direct measurement
X 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:
      $$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot g_c}}$$
      where, V_u is the wellbore volume per unit length, bbls/ft
      ρ 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:
      $$t_{radial\,flow} > \frac{(200000 + 12000s) \cdot C}{\frac{k \cdot h}{\mu}} \quad hours$$
   b. Falloff period:
      $$t_{radial\,flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \quad hours$$

   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:

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

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:

$$m_{semilog} = \frac{162.6 \cdot q \cdot B}{\frac{k \cdot h}{\mu}}$$

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

Considerations for Offset Wells Completed in the Same Interval

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:

X Shut-in all offset wells prior to the test
X If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
X Obtain accurate injection records of offset injection prior to and during the test
X 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
X **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.

- X 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

- X 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.

- X 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.

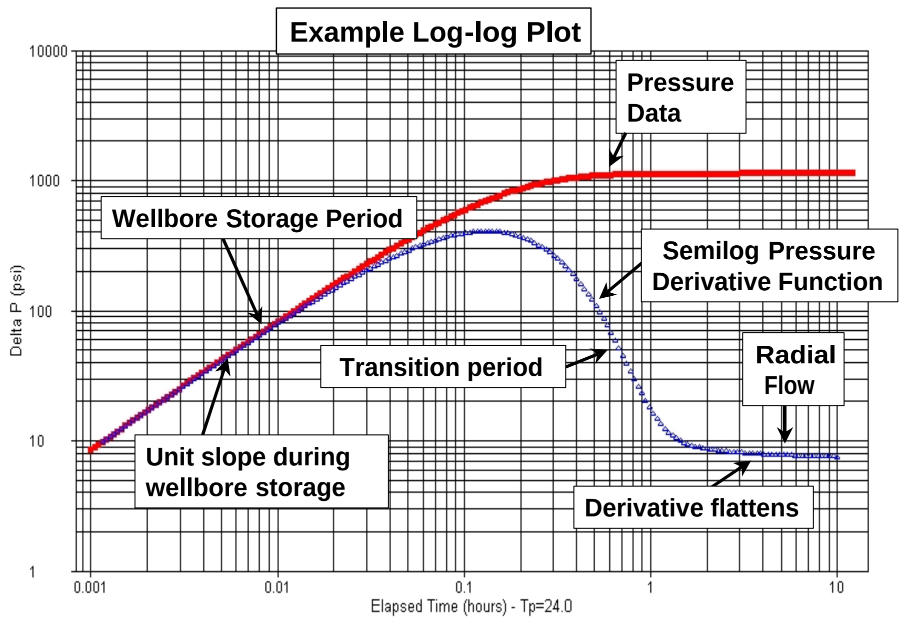
- X **Falloff tests conducted in highly transmissive reservoirs** may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for 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.**

- X 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

X 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

X 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.

X 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.

X 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.

X 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.

X **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

X **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

X **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

X **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

X **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

X **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

X **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.

X **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)

Semilog Plot

X 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.

X 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.

X 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.

X The **<u>MDH plot</u>** 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.

X The **<u>Horner plot</u>** 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.

X The **<u>Agarwal equivalent time plot</u>** 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.

X 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.

Parameter Calculations and Considerations

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

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

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)

μ = viscosity, cp

X The viscosity, μ , 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/μ, differences between the fluids may be observed on the derivative curve.

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

Skin Factor

- X 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. Region 6 has seen instances in which large zones of alteration were suspected of being present.

- X 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.

- X The skin factor is calculated from the following equation:

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

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

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

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

k = permeability, md

φ = 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>

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

X 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).

X 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.

X 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>

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

X The effective wellbore radius is calculated from the following:

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

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

Reservoir Injection Pressure Corrected for Skin Effects

X 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

X 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:

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

X 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.

Determination of the Appropriate Fluid Viscosity

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

X 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.

X 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.

X 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

X 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
μ_w = viscosity of the historic waste plume at reservoir conditions, cp
c_t = total system compressibility, psi^{-1}

X 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>

X 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.

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

X 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.

X 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.

Use of Computer Software

X 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.

X All data should be submitted on a CD-ROM 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 CD, 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

X 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.

X 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.

X 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.

X 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.

X The data that is obtained from pressure transient testing should be compared to permit parameters. Test derived transmissibilities and static pressures can confirm compliance with non-endangerment (Area Of Review) conditions.

APPENDIX F

EPA Region 9 Step Rate Test Procedure Guidelines

UIC Permit No. R9UIC-CA5-FY18-1R

Refer also to:

Society of Petroleum Engineers (SPE) Paper #16798, Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure

(This paper can be ordered from the SPE website.)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
DRINKING WATER PROTECTION
75 HAWTHORNE STREET
SAN FRANCISCO, CA 94105
STEP-RATE TEST PROCEDURE GUIDELINES

PURPOSE:

The purpose of the document is to provide guidelines for performing a Step-Rate Test (SRT). Test results shall be used by the EPA Region 9 (EPA) Underground Injection Control (UIC) offices to determine a Maximum Allowable Injection Pressure (MAIP) at the wellhead that will provide for the protection of underground sources of drinking water (USDW) at injections wells.

A detailed work plan proposal must be submitted to EPA for review and approval prior to the SRT being performed. The work plan must include detailed plans, supporting justifications and associated calculations for conducting the SRT. Refer to the Society of Petroleum Engineers ("SPE") paper 16798 for supporting test design and analysis guidance (1987, Society of Petroleum Engineers).

Dialogue is expected and encouraged during the actual development of the work plan. EPA will review the work plan proposal and will send written communications either to request clarification or changes to the proposed work, or grant approval of the proposed work. Once the SRT plan is approved, we require at least 30 days' notice in advance of SRT operations so we may schedule an EPA representative to witness the SRT.

Test results will be used by Region 9's Underground Injection Control permitting program to determine a Maximum Allowable Injection Pressure (MAIP) which is the surface pressure that correlates to (a) 80 percent of the bottom hole pressure (BHP) that represents the Formation Parting Pressure (FPP) of the permitted injection zone, or, (b) 80 percent of the maximum pressure applied during SRTs in which the FPP was not achieved. This determination serves to provide for the protection of the Underground Sources of Drinking Water (USDWs) as required by the regulations at 40 CFR §§ 146.12(e)(3) (fracture pressure) and 146.14(b)(3) (the anticipated maximum pressure and flow rate at which the permittee will operate).

SRT results must be documented and the test should be witnessed by an EPA inspector who can assist in approving real-time modifications.

<u>RECOMMENDED TEST PROCEDURES:</u>

1) The well should be shut in long enough prior to testing such that the BHP approximates static formation pressures.

2) It is important to use equipment that will be capable of accurately controlled pumping rates at varying amounts and exceeding the estimated Formation Parting Pressure (FPP) or alternately,

equipment that will exceed the operator's equipment limitations by 120%. Operator must also ensure that sufficient water will be available onsite to complete the SRT. The water used for the SRT may be the operator's permitted wastewater or other water with known specific gravity.

3) Measure and record test pressures with both down-hole and surface pressure recorders. Observe, record, and synchronize surface and BHP pressures, times, dates, and injection rates for each increment (step) of the test. The BHP behavior will be the basis for the determination of FPP. Surface pressures will also be observed to monitor pressure versus rate behavior during the SRT and to determine pressure losses due to friction and other factors that affect the MAIP.

4) The step intervals must be of equal duration and their duration must be of no less than the minimum 30 minutes. Engineering based justification of the planned duration for the steps is required. Steps must be sufficiently long to overcome well bore storage effects and achieve or clearly demonstrate a stabilized pressure (radial flow) at the end of each timed step.

5) The SRT should proceed continuously and uninterrupted, with minimally delayed transition between steps. The SRT must be planned to provide at least 3 to 5 steps before reaching the expected FPP and at least 3 additional steps after exceeding the FPP. Alternatively, the SRT must exceed the BHP that occurs at the operator's maximum equipment surface pressure limitation by at least 120 percent of that corresponding BHP.

6) Because a surface readout of the BHP is employed, the duration of the planned injection rate increments may be modified during the initial part of the test. This will allow, for instance, an initial determination whether modification of the subsequent rate increments may be necessary to obtain at least three BHP data points above the FPP or to adequately exceed the proposed operator's maximum equipment limitation before concluding the test. The well operator shall consult and receive approval from the onsite EPA inspector before any modifications to the plan are implemented during ongoing SRT operations.

7) After pumping stops, observe and record (a) the instantaneous shut-in pressure (ISIP) and (b) the injection zone's pressure fall-off decline for a sufficient time to allow a pressure transient analysis which shall be included in the operator's report. The length of time for pressure fall-off observation will be determined in consultation with EPA prior to conducting the SRT, but may be modified by EPA depending on the actual BHP fall-off behavior observed at the conclusion of the test.

APPENDIX G

Plugging and Abandonment Plans

UIC Permit No. R9UIC-CA5-FY18-1R

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Enrique C. Zaldivar, Director and General Manager
Bureau of Sanitation, City of Los Angeles
1149 S. Broadway, Suite 900, Los Angeles, CA 90015
(213)485-2210
Enrique.zaldivar@lacity.org

Permit or EPA ID Number	API Number	Full Well Name
CA 5060001	N/A	TIRE SFI #1

State	County
California	Los Angeles

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location

NW 1/4 of NE 1/4 of Section 8 Township 5S Range 13W

Latitude 33.74388 N

Longitude -118.26497 W

N/A ft. from (N/S) N/A Line of quarter section

N/A ft. from (E/W) N/A Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
Class I	Notice Prior to Work	Well Rework
Class II	Date Expected to Commence N/A	✓ Plugging and Abandonment
Class III	Report After Work	Conversion to a Non-Injection Well
✓ Class V	Date Work Ended N/A	

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See Instructions.

The City of Los Angeles has prepared this updated Plugging and Abandonment Affidavit as per one of EPA's recommendation to renew existing UIC permit No. R9UIC-CA5-FY11-3R.

A well is plugged by setting mechanical or cement plugs in the wellbore at specific intervals to prevent fluid flow. The plugging process usually requires a workover rig and cement pumped into the wellbore. The plugging process can take two days to a week, depending on the number of plugs to be set in the well.

In the case of this well, the EPA has recommended to place a 200-foot plug from 100 feet above to 100 feet below the base of Underground Source of Drinking Water (USDW) since it is not clear that the USDW base is identical to the Base of Fresh Water (BFW). Multiple cement plugs will be set including but not limited to:

- Sealing of the injection perforations and formation
- Sealing of the base of USDW
- Sealing the top of the wellbore

The Diagram attached to this form will identify the plugs and depths. It is estimated the cost of this work would range from $100-150K per well.

Certification

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

Name and Official Title (Please type or print)	Signature	Date Signed
Enrique C. Zaldivar, Director & General Manager	[signature] for	5/8/20

Well Abandonment Plan, Schedule, and Cost Analysis

This document presents an estimate the cost per **WELL** to plug and abandonment biosolid injection or monitoring well located at 445 Ferry St. San Pedro, Ca., as per the requirements of the Environmental Protection Agency (EPA).

Estimate includes Mobilizing of Rig and all equipment, installing BOPE, pulling injection packer, cleaning out to total depth, running CBL and cementing well per EPA permit to surface, and Demobilizing rig and equipment.

Abandonment and plugging can be conducted in 12 working days per well. The schedule can be summarized as follows:

- Two days mobilizing rig and equipment and to install BOPE
- Two days releasing packer and pulling injection string
- Two days cleaning out to well bottom and running CBL
- Five days cementing well to surface
- One day mobilizing rig and equipment

Plugging Procedures

1- Move in and rig up. Unset packer and pull out of the hole with injection tubing and packer
2- Rig up a wireline unit and run in the hole with a gauge ring for the 5-1/2" casing to check for obstruction, Pull out to the hole.
3- Run in the hole with the tubing string to 5,105 ft. Pull up slightly and circulate the hole with an appropriate presflush to clean hole.
4- Circulate one-hole volume (288 bbl.) of plugging fluid to establish static well conditions and prepare well for plugging. Observe fluid level to ensure that the hole is in a static condition.
5- Emplace the bottom cement plug (81 sacks). Using the balance method, pump a spacer followed by the cement slurry, spacer, and a displacement fluid.
6- Pull tubing slowly out of the cement by about 200 ft. Reverse circulate any excess cement out of the tubing using plugging fluid as a circulating fluid
7- Pull up to 2,400 ft and emplace 1,100 ft cement plug (250 sacks) using same technique.
8- After waiting 12 hours for cement to set, run in the hole with the tubing and tag the base of USDW plug. Assuming that the plug has been successfully tagged, run pressure test.
9- Pull up to 50' and emplace the surface cement plug (12 sacks) at ground surface
10-Mark and restore the well site according to State requirements. Rig down and move off the site.

The location and extent (by depth) of the plugs

Three cement plugs will be set as shown by **Figure 1** including:

- Sealing of the injection perforations and formation (4,748 – 5,105 ft)
- Sealing of the base of USDW (1,300 – 2,400 ft)
- Sealing the top of the wellbore (0 – 50 ft)

The nature and quantity and material to be used in plugging

The wellbore fluid system used in the plugging operation should be one exhibits the following characteristics:

1- Sufficient hydrostatic head or weight to prevent any fluid flow into borehole
2- Ability of the fluid to remain in place over indefinite period of time
3- Chemical and physical stability of material for unlimited period of time

In fully cased wells where pressure control does not appear to be a problem, a specially prepared plugging fluid may not be considered a necessity. In this case, pressure control may be provided by using 9.6 ppg abandonment mud that is composed of water and a mixture of: barite, gel, and soda ash.

The cement slurry used to plug and abandon a wellbore must be designed so that:

1- It provides sealing to prevent fluid movement between intervals
2- It possesses good bonding characteristics to the pipe or formation
3- It demonstrates durability
4- A long life may be expected

These conditions can generally be met using a densified cement such as API classes A, C, G, and H. Class G cement is used among the West Coast and Rocky Mountain areas.

Plugging fluid calculations for the job design depicted in **Figure 1** are presented below:

- Plugging Fluid Calculations

(0.0565 bbl./ft) . (1,300' – 50')	=	70.625	bbl.
(0.0565 bbl./ft) . (4,748' – 2,400')	=	132.662	bbl.
Approximate Mud Required	=	**203.3**	**bbl.**

- Cement Plug Calculations

Top of the Wellbore Plug	(0.317224 cu.ft/ft) . (50' – 0')	=	15.8612	cu.ft
	15.8612 cu.ft / 1.4 cu.ft/sk.	=	11.3 ≈ 12	sks. cement
Base of USDW Plug	(0.317224 cu.ft/ft) . (2,400' – 1,300')	=	348.9464	cu.ft
	348.9464 cu.ft / 1.4 cu.ft/sk.	=	249.2 ≈ 250	sks. cement
Injection Perforations Plug	(0.317224 cu.ft/ft) . (5,105' – 4,748')	=	113.249	cu.ft
	113.249 cu.ft / 1.4 cu.ft/sk.	=	80.9 ≈ 81	sks. cement
Approximate Cement Required		=	**243**	**sks. cement**

Proposed test or measurement to be made

Tagging test, which consists of running pipe into the hole to locate the plug. After the cement has set up, the pipe is run into the hole to the plug depth and weight is applied to check the position of the plug.

Pressure test, where the plug is tested for proper shut-off by pressure-testing the plug and injection casing to 1000 psi for at least 10 minutes.

The amount, size, and location (by depth) of casing to be left in the well

All casing will be left in the wellbore since casing strings are cemented all the way to the surface. Casing to be left in the well are:

- Conductor casing 0 - 50
- Surface casing 0 – 1,499
- Injection casing 0 – 5,545

The estimated cost of plugging the well.

The estimated plugging cost is $182,352 per well as shown by **Table 1**. This estimate includes a 20% contingency. Cost excludes submitting for EPA permits to conduct well work

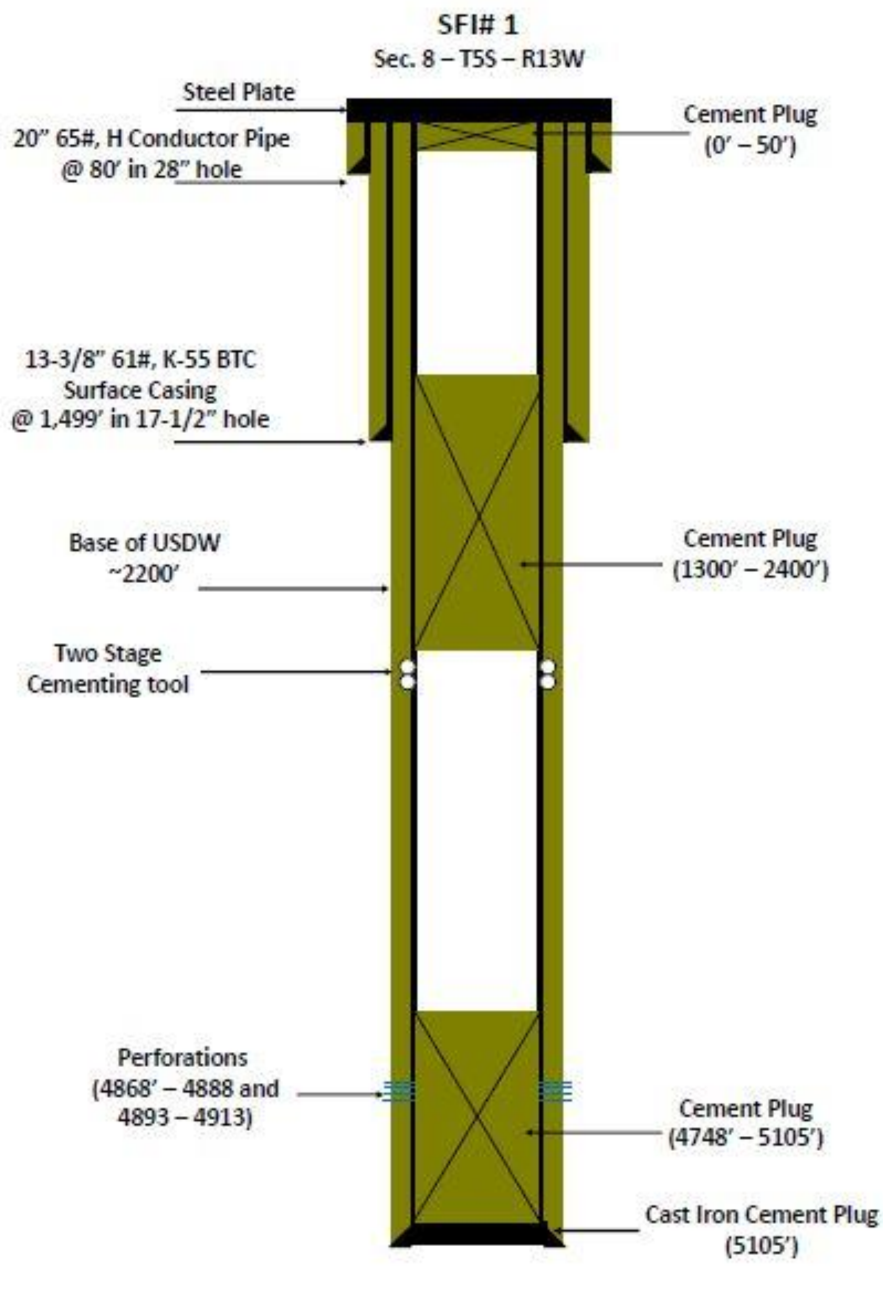

SFI# 1
Sec. 8 – T5S – R13W
Steel Plate
20" 65#, H Conductor Pipe
@ 80' in 28" hole
Cement Plug
(0' – 50')
13-3/8" 61#, K-55 BTC
Surface Casing
@ 1,499' in 17-1/2" hole
Base of USDW
~2200'
Cement Plug
(1300' – 2400')
Two Stage
Cementing tool
Perforations
(4868' – 4888 and
4893 – 4913)
Cement Plug
(4748' – 5105')
Cast Iron Cement Plug
(5105')

TABLE 1: ABANDONMENT AND PLUGGING SCHEDULE AND COST ANALYSIS PER WELL

	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12		Total
Rig and crew ($425/hr)	4,250	4,250	4,250	4,250	4,250	4,250	4,250	4,250	4,250	4,250	4,250	4,250		51,000
Fuel	150	150	150	150	150	150	150	150	150	150	150	150		1,800
Circulating pump ($980/d)				980	980	980	980	980	980	980				6,860
B.O.P.E ($500/d)	500	500	500	500	500	500	500	500	500	500	500			5,500
Vacuum Truck ($105/hr)		1,050	1,260	1,260	1,260	1,260	1,260	1,260	1,050	1,050	1,050			11,760
CBL					8,000									8,000
Cement Services								10,000	10,000	10,000	5,000			35,000
Abandonment Mud ($25/bbl)			1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250				10,000
Wellhead Flange ($50/d)	50	50	50	50	50	50	50	50	50	50	50			550
Waste Disposal ($20/bbl)							1,000	1,000	1,000	1,000	1,000	1,000		6,000
Trucking ($105/hr)	1,260	1,260									1,260	1,260		5,040
Shale Pit ($50/hr)			50	50	50	50	50	50	50	50	50			450
Injection Packer/Field Tech				5,000										5,000
Work String ($500/d)			500	500	500	500	500	500	500	500	500	500		5,000
Estimated Daily Total	6,210	7,260	8,010	13,990	16,990	8,990	9,990	19,990	19,780	19,780	13,810	7,160		151,960
Contingency (20%)														30,392
Total Cost Analysis per well														**182,352**