U.S. EPA Underground Injection Control Program

FINAL PERMIT

Class I Nonhazardous Waste Injection Wells

Permit No. R9UIC-CA1-FY11-4

Well Names: Martinez Wells 1 and 2
Franklin Wells 1 and 2

Issued to:

Newhall Land and Farming Company, Inc.,
a California Corporation
25124 Springfield Court, Suite 300
Valencia, CA 91355

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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), §§124, 144, 145, 146, 147, and 148,

Newhall Land and Farming Company, Inc., a California Corporation
25124 Springfield Court, Suite 300
Valencia, CA 91355

is hereby authorized, contingent upon Permit conditions, to construct and operate a Class I nonhazardous waste injection well facility with a maximum of four (4) injection wells, known as the Martinez Wells 1 and 2 and Franklin Wells 1 and 2. The Martinez wells are located at Section 29, Township 4 North, Range 17 West, Northeast ¼, and the Franklin wells are located at Section 12, Township 4 North, Range 17 West, Southwest ¼, at Newhall Land and Farming Company, Inc. (Newhall Land) facilities in Los Angeles County, California. Exact locations of each well will be established and approved as outlined in this permit.

For each permitted well, EPA will issue authorization to drill and construct only after requirements of Financial Responsibility in Part II, Section G of this permit have been met. EPA will grant authorization to inject only after the requirements of Part II Sections B-D of this permit have been met. Operation of each well will be limited to maximum volume and pressure as stated in this permit. Total amounts must not exceed specified limits.

If approved, injection will be authorized into the Towsley Formation Sands for the purpose of disposal of industrial nonhazardous fluids from the treatment of wastewater at the Valencia Treatment Plant, and subsequently, after build out, also from the Newhall Ranch Treatment plant. The primary injection interval sand sequence is identified as the Towsley Formation, and is expected to contain at least five hundred (500) feet of net sand thickness at the Martinez site, and 200 feet at the Franklin site.

All conditions set forth herein are based on Title 40 §§124, 144, 145, 146, 147 and 148 of the Code of Federal Regulations, and are regulations that are in effect on the date that this permit is effective.

This permit consists of thirty-four (34) pages plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by Newhall Land and on other information contained in the administrative record. It is the responsibility of the Permittee to read, understand, and comply with all terms and conditions of this permit.

This permit and the authorization to construct, test, and inject are issued for a period of ten (10) years unless terminated under the conditions set forth in Part III, Section B.1 of this permit.

This permit is issued and becomes effective on __11/13/13________________

__/signed by/_____________________________
Jane Diamond, Director
Water Division, EPA Region IX

Part II. SPECIFIC PERMIT CONDITIONS

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

1. Financial Assurance

   The Permittee shall supply evidence of financial assurance prior to commencing Injection Well Drilling and Construction, in accordance with Section G of this part.

2. Field Demonstration Submittal, Notification, and Reporting

   a. Prior to each demonstration required in the following sections B through D, the Permittee shall submit plans for procedures and specifications to the EPA Region 9 Ground Water Office for approval. The submittal address is provided in Section E, paragraph 5. No demonstration in these sections may proceed without prior written approval from EPA.

   b. The Permittee must notify EPA at least thirty (30) days prior to performing any required field demonstrations, after EPA approves the plans/procedures for testing, in order to allow EPA to arrange to witness if so elected.

   c. The Permittee shall submit results of each demonstration required in this Part to EPA within sixty (60) days of completion, unless otherwise noted.

      In lieu of using EPA reporting forms in Appendix C, California Division of Oil, Gas, and Geothermal Resources (DOGGR) reporting forms (such as a Well Summary Report) are acceptable provided all information specified by this permit is included.

B. WELL CONSTRUCTION

1. Locations of Injection Wells Martinez 1 and 2 (Martinez wells) and Franklin 1 and 2 (Franklin wells)

   Injection wells authorized under this permit will be located in Valencia, California. The proposed general location for all four wells is found in Appendix A (Permit Application, Introduction, Figure 1). The Martinez 1 and Franklin 1 wells will be drilled directionally and deviated from vertical, as described in the proposed drilling program included in Attachment L of the Permit Application. The Martinez 2 and Franklin 2 well drilling plans will be based on information gathered from the drilling of the primary wells and are subject to EPA review and approval.

a. Prior to drilling any well, the Permittee must submit proposed field coordinates (Section, Township, Range, with latitude/longitude) for the surface and bottom hole locations of that specific well; for subsequent wells, also provide the drilling program details, and the distance between all wells, along with 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

b. After drilling is completed, the Permittee must submit final field surface and bottom hole coordinates (Section, Township, Range, with latitude/longitude) of any well constructed under this permit with the Final Well Construction Report required under paragraph 9(a) of this section. If final well coordinates differ from the proposed coordinates submitted under paragraph (a) above, justification and documentation of any communication with and approval by EPA shall be included.

In addition, the Permittee shall submit final directional survey data and reports upon completion of the drilling operations.

2. Testing during Drilling and Construction

Logs and other tests conducted during drilling and construction shall include, at a minimum, deviation checks, casing logs, and injection formation tests as outlined in 40 CFR §146.12(d). Open Hole logs shall be conducted over the entire open hole sequence below the conductor casing. The Permittee shall conduct formation evaluation wireline logging and testing operations and shall provide and use those results to estimate and report values for hydrocarbon saturation, porosity, lithology, formation water resistivity, Total Dissolved Solids (TDS) concentrations, and rock mechanical properties for both the injection and confining zones identified within the permitted geological sequence, and for selected intervals for identification of any Underground Sources of Drinking Water (USDWs) above the injection zone.

Before surface, intermediate, and long-string casings are set, dual induction/spontaneous potential/gamma ray/caliper (DIL/SP/GR/CAL) logs must be run over the course of the entire open hole sequence after the wellbore is drilled to each respective total depth.

In addition, the Permittee must run a compensated neutron/density/gamma ray/caliper (CN/D/GR/CAL) log to total depth in each wellbore before casings are set. The caliper log may be omitted from the DIL/SP/GR log suite if run with the CN/D/GR/CAL logs.

After each casing is set and cementing is completed, a cement bond evaluation will be conducted over the course of the entire cased hole sequence (See Section

D.2.a.iv of this part). This cement bond log evaluation shall enable the analysis of bond between cement and casing, as well as between cement and formation, and shall allow detection and assessment of any micro-annulus between the casing and cement as well as any cement channeling in the borehole annulus.

The Permittee must also run the Sequential Formation Test Tool (SFTT) or equivalent to evaluate fluid pressures and collect fluid samples in the targeted injection zone and at selected depths above the injection zone for TDS analyses and identification of USDWs.

In addition, the Permittee must collect sidewall core samples in the injection zone and confining zone immediately above the injection zone and provide timely copies of the sample analyses reports to EPA no later than 60 days after the completion of the well (Refer to paragraph 9(a) of this section, for the required report submittal date).

3. Injection Formation Testing

Injection formation information as described in 40 CFR 146.12 (e), shall be determined through well logs, sidewall core samples, and tests and shall include porosity, permeability, static formation pressure, and effective thickness of the injection zone. Reservoir compressibility (typically coefficient "c") must also be computed. A summary of results shall be submitted to EPA with the Final Construction Report required in paragraph 9(a) of this section and updated periodically with subsequent analyses. In addition, a preliminary submittal of the static formation pressure and logging data should be provided to EPA as it is collected, and before the long-string casing is installed and cemented.

a. Ground Water Testing

During construction of the wells, information relating to ground water at these sites shall be obtained and submitted to EPA. This information shall include direct TDS analysis of target injection formation water to demonstrate either the presence or absence of any USDWs, (as defined in 40 CFR §§144.3 and 146.3) and the characteristics of the formation.

The Permittee shall provide well logs and representative water sample analyses from the targeted injection aquifer using method(s) approved by EPA as evidence. These analyses shall be sufficient to confirm compatibility of the injectate with the injection formation. Formation water samples from the injection zone will be collected (swabbed or other approved method) from the first injection well upon its completion. Field measurements of pH, electrical conductance, and temperature will be carried out to confirm that representative Towsley Formation Sands water is being collected. Subsequent laboratory analysis of the samples will include at least Trace Metals, Alkalinity, Conductivity, Hardness, pH, TDS, Specific Gravity (see II.E.1.a), and Oil and Grease (per 40 CFR §136.3, Table IB).

b. Step-Rate Test (SRT)

i. A SRT will be conducted on at least one representative well, at each location (Martinez and Franklin sites) before injection is authorized, to establish the maximum injection pressure in accordance with section D, paragraph 3 of this part. Refer to Society of Petroleum Engineering (SPE) paper #16798 for test design and analysis guidance. Similar testing may be required in other wells, at the discretion of EPA. Detailed plans for conducting the SRT must be submitted to EPA for review, possible editing, and approval. Once approved, The Permittee may schedule the SRT, providing EPA at least thirty (30) days notice before the SRT is conducted. If available, an EPA representative will be present to monitor and evaluate the SRT.

ii. Injection as proposed in an approved SRT procedure will be temporarily authorized while the SRT is completed.

iii. Prior to testing, shut in the well long enough so that the bottom-hole pressure approximates static formation pressure, and record.

iv. Measure pressures with a down-hole pressure bomb and synchronize the data with any available data from a surface pressure recorder. Data sampling rate must allow for observation and analysis of the pressure transient behavior during each rate step as well as during the final pressure falloff period which is discussed in item vii below.

v. Use equal-length time step intervals throughout the test; these should be technically justified and should be sufficiently long to overcome well bore storage and to achieve radial flow. Use thirty (30) minute or longer time intervals unless EPA approves shorter intervals.

vi. Record at least three (3) time steps (data points on pressure vs. flow plot) before and after reaching the anticipated fracture pressure in order to obtain at least six (6) valid data points and the targeted fracture pressure. Larger rate increments may be used later in the test, but justification for this request must be approved. The data should be plotted and monitored as the test proceeds to conclusion. Refer to Appendix F - EPA Step Rate Test Policy.

vii. At the end of the test, shut down pumps and record the instantaneous shut in pressure and observe the pressure falloff for a sufficient time period to observe and later analyze the radial flow portion of the injection zone during the SRT. The length of time for pressure falloff observation must be determined and discussed in the Permittee's submission plans in advance of conducting the SRT.

viii. The Permittee shall report the results to EPA within forty-five (45) days of conducting the SRT. Results shall include analyses of the pressures versus rate and the transmissivity and storativity for the stepped rates throughout the SRT by analyzing the pressure transient data.

c. Fall Off Pressure Test (FOT)

To determine and to monitor formation characteristics, a FOT shall be run in at least one representative well selected by EPA at each of the Martinez and Franklin sites, after a radial flow regime has been established at an injection rate which is representative of the expected wastewater contribution to that well. The FOT will be conducted in accordance with EPA guidance found in Appendix E. The Permittee shall use the test results to recalculate the Zone of Endangering Influence (ZEI, as defined in 40 CFR §146.6) and to evaluate whether any additional corrective action will be required (refer to Section C of this part); a summary of the recalculation shall be included with the FOT report. Detailed plans for conducting the FOT must be submitted to EPA for review and approval. Once approved, the Permittee may schedule the FOT, providing EPA at least thirty (30) days notice before the test is conducted. The final FOT report shall be submitted to EPA within forty-five (45) days of test completion.

i. An initial FOT shall be performed approximately three (3) months after start of injection. The initial FOT report will be submitted to EPA within 45 days of the completion of the test.

ii. Annually thereafter, the FOT test shall be repeated. The results of the test shall be submitted with the report due June 1 each year, but not later than 45 days after the test is performed, whichever date comes first.

iii. The latest static reservoir pressure and its cumulative behavior over time on a graphic plot of the injection zone shall be determined and reported with the FOT report listed above.

d. Particulate Filters may be used upstream of the injection well, at the discretion of the Permittee, to prevent formation plugging or damage from particulate matter. The Permittee shall include any filter specifications in the Final Construction Report required in paragraph 9(a) of this section, including proposed particle size removal with any associated justification for the selected size. For any particulate filters used, follow appropriate waste analysis and disposal practices, and provide documentation of such.

4. Drilling, Work-over, and Plugging Procedures

Drilling, work-over, and plugging procedures must comply with the DOGGR "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Section 1722-1723. Drilling procedures shall also include the following:

a. Details for staging long-string cementing or justification for cementing without staging;

b. Records of daily Drilling Reports (electronic and hard copies);

c. Blowout Preventer (BOP) System testing on recorder charts including complete explanatory notes during the test(s);

d. Casing and other tubular and accessory measurement tallies;

e. Details and justification for any open hole gravel packing; and

f. Directional drilling records and reports.

Procedures provided on reporting forms such as DOGGR's Well Summary Report are acceptable provided all required information as specified above is included.

5. Casing and Completion Specifications

Notwithstanding any other provisions of this permit, the Permittee shall case and cement the wells to prevent the movement of fluids into or between USDWs. Cement evaluation analyses shall be performed as described in Section D paragraph 2.a.iv of this part. Casing shall be maintained until the wells are plugged and abandoned. Refer to Appendix B, Attachment M, Figures M1 and M2 for planned casing and completion specifications for each of the injection wells.

EPA may require minor alterations to the construction requirements based upon information obtained during well drilling and related operations, for example, if the proposed casing setting depths will not completely cover the base of the

USDWs and the confining formation located immediately above the injection zone.

Final casing setting depths will be determined by the field conditions, sieve analysis, well logs, formation fluid samples and other input from the drilling consultant and hydrogeologists. EPA approval will be obtained for any revisions prior to installation and these will be documented in the Final Well Construction Report (See paragraph 9(a) below).

6. Injection Interval

Injection for all wells shall be permitted for the Towsley Formation Sands at depths estimated from about 7,200 to 7,700 feet in the Martinez wells and 10,600 to 10,800 feet bgs in the Franklin wells measured from the Kelly bushing on the drill rig.

Minor alterations of the depths of injection zone intervals and the casing setting depths are expected to be realized upon drilling. These alterations and other rework operations that may occur later in the course of well operation are considered minor for this permit and must be reported (refer to EPA Form 7520-12 listed in Appendix C). The Permittee must demonstrate that each well has mechanical integrity, in accordance with Section D paragraphs 1.a and 2 of this part, before initial injection is authorized or before injection is recommenced after a workover has compromised the seal (see Part II.D.2.b.i).

7. Confining Layer

The confining layer at the Martinez site is a 400-foot thick claystone/mudstone bed with very few sandy interbeds within the upper Towsley Formation immediately above the proposed injection target interval.

The confining layer at the Franklin site is a 1,000 to 1,400-foot thick sequence of fine-grained mudstone/claystone with very few interbeds of sand in an interval correlated to the upper Towsley Formation and located immediately above the proposed injection zone.

Field information on the upper Towsley Formation confining layer, including its geophysical characteristics, thickness, and local structure will be obtained and updated during drilling of the injection wells and shall be included in the Final Well Construction Report required in paragraph 9a of this section.

8. Monitoring Devices

The Permittee shall install and maintain in good operating condition:

a. A tap on the discharge line between the injection pump and the wellhead for the purpose of obtaining representative samples of injection fluid; and

b. Devices to continuously measure and record injection pressure, annulus pressure, flow rate, and injection volumes, subject to the following:

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

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

2) 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.

9. Final Well Construction Report and Completion of Construction Notice

a. 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 completion of any of the permitted injection wells.

b. The Permittee must also submit a notice of completion of construction to EPA (Form 7520-9 listed in Appendix C). Injection operations may not commence until EPA has inspected or otherwise reviewed the injection wells and notified the Permittee that it is in compliance with the conditions of the permit.

10. Proposed Changes and Workovers

a. The Permittee shall give advance notice to EPA, as soon as possible, of any planned physical alterations or additions to the permitted injection wells. Any changes in well construction require prior approval by EPA and may require a permit modification under the requirements of 40 CFR §§144.39 and 144.41.

b. In addition, the Permittee shall provide all records of well workovers, logging, or other subsequent test data, including required mechanical integrity testing, to EPA within sixty (60) days of completion of the activity.

c. Appendix C contains a list of the appropriate reporting forms.

d. Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Section D paragraphs 1.a and 2 of this part.

C. CORRECTIVE ACTION

Corrective action in accordance with 40 CFR §§144.55 and 146.7 will be necessary in two existing abandoned wells in the Area of Review (AOR, defined in 40 CFR §146.6) These wells penetrate the injection zone within the Franklin well AOR and could cause movement of fluids into USDWs if not properly plugged and abandoned. The wells are identified as the NL&F B-1 and Newhall D-2 and their current status and proposed Plugging Programs are described in Attachment H.

The wells will be re-entered and cement plugs placed to isolate USDWs from potential fluid entry. Geophysical logs shall be run and formation fluid samples obtained from selected intervals for analysis of TDS concentrations and determination of the USDW base in those wells. If log analyses are inconclusive with respect to the USDW base and formation pressure determinations, the Permittee shall run a SFTT or equivalent wireline tool for fluid sampling and pressure testing zones of interest, as described in section B.2 above. The Plugging Program will be reviewed and modified, if necessary, based on the log evaluations, fluid sample analyses, and pressure measurements.

1. Initial Zone of Endangering Influence (ZEI) re-evaluation with Field Data

   Data resulting from testing performed under Section B paragraphs 2 and 3, and Section C, in this part, will be used by the Permittee to confirm or modify assumptions used to calculate the original ZEI (see Section II.B.3.c). If new field data results in a ZEI larger than the AOR, and there are wells within the expanded area that penetrate the proposed zones of injection, a corrective action plan shall be proposed to EPA for approval and implemented as described in paragraph 3 of this section.

2. Annual ZEI Review

   Annually, the Permittee shall review the ZEI calculation based on any new data obtained from the FOT and static reservoir pressure tests required in Section B, paragraph 3(c) of this part. A copy of the modified ZEI calculations, along with all associated assumptions or justifications, shall be provided to EPA with the report due in January, as required in Section E, paragraph 5.e. of this part.

3. Implementation of Corrective Actions

a. If any additional wells requiring corrective action are found within the modified ZEI, a list of these 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 to re-enter, plug, and abandon the wells listed in paragraph a above in a way that prevents the migration of fluids into a USDW.

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

D. WELL OPERATION

1. Demonstrations Required Prior to Injection

For each well, injection operations may not commence until construction is complete and the Permittee has complied with following paragraphs a and b:

a. Mechanical Integrity

The Permittee shall demonstrate that each well has and maintains mechanical integrity consistent with CFR §146.8 and with paragraph 2 of this section. The Permittee shall demonstrate that there are not significant leaks in the casing and tubing and that there is not significant fluid movement into or between USDWs through the casing wellbore annulus or vertical channels adjacent to the injection wellbore. The Permittee may not commence initial injection into a well nor recommence injection after a workover which has compromised well integrity until it has received written notice from EPA that such a demonstration is satisfactory.

b. Injectate Hazardous Waste Determination

The Permittee shall perform an Injectate Hazardous Waste Determination of each unique waste steam injected into any of the wells authorized by this permit, according to 40 CFR §262.11. The results of the analyses shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR §261.

i. The Permittee will be required to submit a letter to EPA confirming that the "Hazardous Waste Determination" was carried out according to 40 CFR §262.11 within sixty (60) days of its having been completed.

ii. The Permittee shall perform an additional "Hazardous Waste Determination" whenever there is a process change or a change in fluid chemical constituents or characteristics. Also refer to injectate testing requirements in Section D, paragraph 5 below.

2. Mechanical Integrity

a. Mechanical Integrity Tests (MITs)

Mechanical integrity testing shall conform to the following requirements throughout the life of the injection wells:

i. Casing/tubing annular pressure (internal MIT)

A demonstration of the absence of significant leaks in the casing, tubing and/or liner shall be made by performing a pressure test on the annular space between the tubing and long string casing. This test shall be for a minimum of thirty (30) minutes at a pressure equal to or greater than the maximum allowable injection pressure. 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) pounds per square inch (psi) between the tubing and annular pressures shall be maintained throughout the MIT.

ii. Continuous pressure monitoring

The tubing/casing annulus pressure and injection pressure shall be monitored and recorded continuously by a digital instrument with a resolution of one tenth (0.1) psi. The average, maximum, and minimum monthly results shall be included in the next report to EPA per Section E paragraph 5.b of this part unless more detailed records are requested by EPA.

iii. Injection profile survey (external MIT)

In conjunction with the initial FOT required in Section B paragraph 3.c, a demonstration that the injectate is confined to the proper zone shall be conducted and presented by the Permittee and subsequently approved by EPA. This demonstration shall consist of a radioactive tracer and a temperature log (as specified in Appendix D) or other 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 schedule the external MIT, providing EPA at least thirty (30) days notice before the external MIT is conducted.

iv. Cement Evaluation Analysis

After installing and cementing casing, conducting a cement squeeze job, or any well cement repair, for any well constructed under this permit, the Permittee shall submit 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 casing, and long string casing well bore annuli shall be cemented to surface. Analysis shall include cement evaluation performed after each casing is set and cemented. Cement evaluation must assess the following four objectives:

1) Bond between casing and cement;
2) Bond between cement and formation;
3) Detection and assessment of any micro-annulus (small gaps between casing and cement); and
4) Identification of any cement channeling in the borehole annulus.

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

b. Schedule for MITs

EPA may require that an MIT be conducted at any time during the permitted life of any well authorized by this permit. The Permittee shall also arrange and conduct MITs according to the following requirements:

i. Within thirty (30) days from completion of any work-over where well integrity is compromised, or within 30 days when any loss of mechanical integrity becomes evident during operation. An internal pressure MIT shall be conducted on the well which lost mechanical integrity.

ii. At least annually, an injection profile survey external MIT shall be conducted on each permitted well in accordance with 40 CFR §146.8 and paragraph a.iii above.

iii. At least once every five (5) years, an internal pressure MIT shall be conducted on each permitted well in accordance with 40 CFR §146.8 and paragraph a.i above.

c. Loss of Mechanical Integrity

The Permittee shall notify EPA, in accordance with Part III, Section E paragraph 10 of this permit, under any of the following circumstances:

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. See Section D.6.b of this part.

Furthermore, in the event of i, ii, or iii, injection activities shall be suspended immediately and operation shall not be resumed until the Permittee has taken necessary actions to restore and confirm mechanical integrity of the well and EPA gives approval to recommence injection.

d. Prohibition without Demonstration

After the permit effective date, injection into wells may continue only if:

i. The well has passed an internal pressure MIT in accordance with paragraph 2.a.i of this section; and

ii. The Permittee has received written notice from EPA that the internal pressure MIT demonstration is satisfactory.

3. Injection Pressure Limitation

a. Maximum allowable injection pressure measured at the wellhead, to be applied to each permitted injection well, shall be based on results of the SRT conducted under Section B, paragraph 3(b) of this part. EPA will provide the Permittee written notification of the maximum allowable injection pressure for each injection well constructed and operated under this permit, and the established limits will be incorporated into the permit using minor modification procedures (see 40 CFR §144.41).

b. The Permittee may request an increase in the maximum injection pressure allowed under the provisions of paragraph 3(a) above. Any such request shall be made in writing and justified to EPA with the results of a SRT conducted as described in Section B, paragraph 3(b) of this part.

c. In no case shall pressure in the injection zone during injection initiate new fractures or propagate existing fractures in the injection zone or the confining zone. In no case shall injection pressure cause the movement of injection or formation fluids into or between underground sources of drinking water. In no case shall injection fluids be allowed to migrate to oilfield production wells.

d. Any approval granted by the Director for increased injection pressure as stated in paragraph 3(b), above, shall be made part of this permit by minor modification procedures (see 40 CFR §144.41)

4. Injection Volume (Rate) Limitation

a. The injection rate for each well site (Martinez and Franklin) shall not exceed five hundred thousand (500,000) gallons per day (gpd) at any time and the actual injection volume shall not exceed seventy-six (76) million gallons per year cumulative at the Martinez site and 76 million gallons per year cumulative at the Franklin site. The rate and cumulative injection volumes will be subject to a review of the initial and annual ZEI determinations performed as described in Section C.1 and 2.

b. The Permittee may request an increase in the maximum rate(s) allowed in paragraph a above. Any such request shall be made in writing and justified to EPA.

c. Should any increase in 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 AOR.

d. The injection rate shall not cause an exceedance of the injection pressure limitation established under item 3(a) of this section.

5. Injection Fluid Limitation

Injection fluids will consist of brine generated from reverse osmosis (RO), or equivalent, demineralization of effluent from the existing Valencia Water Reclamation Plant (Valencia WRP) operated by the Santa Clarita Valley Sanitation District, and later, in addition, from the planned Newhall Ranch Water Reclamation Plant (Newhall Ranch WRP).

a. The Permittee shall not inject any hazardous waste, as defined by 40 CFR Part 261, at any time. See also paragraph 1.b of this section.

b. Injection fluids shall be limited to only waste fluids authorized by this permit and produced by the Newhall Ranch WRP or the Valencia WRP. Brine generated from the Newhall Ranch WRP and the Valencia WRP may be individually sent or commingled for disposal at the Franklin or alternatively at the Martinez Class I injection well facility, as needed, to facilitate operational flexibility between the two plants. No fluids shall be accepted from other sources for injection into the permitted wells.

The Permittee is required to notify EPA in writing at least ninety (90) days prior to its planned injection of fluid from the Newhall Ranch WRP. In addition, the Permittee must submit to EPA, prior to initial injection of fluids from the Newhall Ranch WRP, analytical results of this fluid in accordance with the conditions under Section D, paragraph 1b, and the test method requirements in permit condition Section E, paragraph 1. Once injection of the Newhall Ranch WRP fluid is approved, analytical results shall be reported to EPA within 30 days of testing, and shall be included in the next report in accordance with reporting requirements under Section E, paragraph 5c. below. The testing of the injection fluids shall be conducted in accordance with the requirements under Section E, paragraph 5.c.

c. Any well stimulation or treatment procedure performed at the discretion of the Permittee shall be proposed and submitted to EPA for approval prior to implementation.

6. Tubing/Casing Annulus Requirements

a. Corrosion-inhibiting annular fluid shall be used and maintained during well operation. A complete description and characterization shall be submitted to EPA for approval before use.

b. A minimum pressure of one hundred (100) psi at shut-in conditions shall be maintained on the tubing/casing annulus. Within the first three (3) months of normal injection operations, the Permittee shall monitor and determine the cyclic range of annular pressure fluctuation for the well. This pressure range shall be submitted with the first quarterly report due after injection commences. Any annular pressure measured outside of this established normal pressure range shall be reported orally within twenty-four (24) hours, followed by a written submission within five (5) days, as a potential loss of mechanical integrity and per Paragraph 2.c of this section and Part III. E. 10. Event details, including associated injection pressures and temperatures shall be submitted to EPA for review and consultation as to whether a loss of mechanical integrity occurred.

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Fluid Monitoring Program

   Injection fluids will be analyzed to yield representative data on their physical, chemical, and other relevant characteristics. The Permittee shall take samples at or before the wellhead for analysis. Test results shall be submitted to EPA on at least a quarterly basis (see paragraph 5 below).

   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," unless other methods have been approved by EPA.

   a. Summary of acceptable analytic Methods:

      i. Inorganic Constituents – appropriate USEPA methods for Major Anions and Cations (including an anion/cation balance).

      ii. Solids - Standard Methods 2540C and 2540D for Total Dissolved Solids and Total Suspended Solids.

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

      iv. Trace Metals - USEPA Method 200.8.

      v. Volatile Organic Compounds (VOCs) - USEPA Method 8260C.

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

   b. Analysis of injection fluids.

      Within 30 days after the start of injection, or whenever there is a change in injection fluids, injectate sampling and analyses shall be performed as outlined in paragraph a above.

2. Monitoring Information

Records of monitoring activity required under this permit shall include:

a. Date, exact location, and time of sampling or field 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

Injectate rate/volume, injectate temperature, annular pressure, and injection pressure shall be measured at the wellhead using equipment of sufficient precision and accuracy. All measurements must be recorded at minimum to a resolution of one tenth of the unit of measure (e.g. injection rate and volume must be recorded to a resolution of a tenth of a gallon; pressure must be recorded to a resolution of a tenth of a psig; injection fluid temperature must be recorded to a resolution of a tenth of a degree Fahrenheit). Exact dates and times of measurements, when taken, must be recorded and submitted. Each well shall have a dedicated flow meter, installed so as to record all injection flow. The Permittee shall monitor the following parameters, at the prescribed frequency, and record the measurements at this required frequency, using the prescribed instruments. For this permit, continuous monitoring requires a minimum frequency of at least one data point every thirty (30) 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
Injection fluid temperature (degrees Fahrenheit)	Continuous	digital recorder

The 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)
06/27/10	16:33:16	1525.6	65.8
06/27/10	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 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 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

All monitoring and recording equipment shall be calibrated and maintained on a regular basis to ensure proper working order of all equipment.

4. Recordkeeping

The Permittee shall retain the following records and shall have them available at all times for examination by EPA personnel, in accordance with the following:

a. 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;

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

c. Results of the injectate “Hazardous Waste Determination” according to 40 CFR §262.11 (See Section II.D.1.b). Results shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR §261; and

d. Records and results of MITs, any other tests required by EPA, and any well workovers completed.

e. The Permittee shall maintain copies (or originals) of all records described in paragraphs a through d above during the operating life of the well and shall make such records available at all times for inspection at the facility.

f. The Permittee shall only discard the records described in paragraphs a through d if:

i. The records are delivered to the EPA Region 9 Ground Water Office, or

ii. Written approval from the Regional Administrator to discard the records is obtained.

5. Reporting

The Permittee shall submit, in accordance with the required schedule, accurate reports to EPA containing, at minimum, the following information:

a. Annually, by June 1, hourly and daily values, submitted in electronic format, for the continuously monitored parameters specified for the injection wells in paragraph 3.a of this section;

b. Annually, by June 1, 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 paragraph 3.a of this section, unless more detailed records are requested by EPA;

c. Quarterly analyses, to be included in the next quarterly report, as specified below:

i. Injection fluid characteristics for parameters specified in paragraph 1.a of this section.

ii. When appropriate, Injectate Hazardous Waste Determination according to Section D, paragraph 1.b of this part, within 30 days of the sampling dates.

d. To be included with the next report immediately following the test, but no later than 45 days after completion of the test/workover, the results of any additional MITs or other tests required by EPA, and any well workovers completed; and

i. FOT results as required in Section B, paragraph 3.c.ii of this part

ii. Shut-in static reservoir pressure cumulative behavior plot of the injection zone, as required in Section B, paragraph 3.c.iii of this part.

e. To be included in the report due in January each year, the following annual analyses:

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

ii. Annual injection profile survey results as required in Section D paragraph 2.a.iii of this part; and

iii. Annual ZEI recalculation as required in Section C paragraph 2 of this part.

f. To be included in the next quarterly report , but no later than 45 days after completion of the test, results of an internal MIT (every five years) as required in Section D.2.2.i. of this part.

g. A narrative description of all non-compliance that occurred during the reporting period.

Reports as specified, 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

Monitoring results and all other reports required by this permit shall be submitted to the following address:

U.S. Environmental Protection Agency, Region 9
Water Division
Ground Water Office (Mail Code WTR-9)
75 Hawthorne St.
San Francisco, CA 94105-3901

Copies of all reports shall also be provided to the following:

California Division of Oil, Gas, and Geothermal Resources, District 2
Attention: District Engineer
1000 S. Hill road, Suite 116
Ventura, CA 93003-4458

California Regional Water Quality Control Board
Attention: Permit Section
320 W. Fourth Street, Suite 200
Los Angeles, CA 90013

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. EPA may require that plugging and abandonment activities be witnessed by an EPA representative.

2. Plugging and Abandonment Plans

   The Permittee shall plug and abandon the well(s) as provided in Appendix G (Permit Application Attachment Q and Figures Q1 and Q2), consistent with State of California requirements and 40 CFR §146.10. EPA reserves the right to change the manner in which a well will be plugged if the well is modified during its permitted life, if the well is not consistent with EPA requirements for construction or mechanical integrity, or otherwise at EPA's discretion.

3. Cessation of Injection Activities

   After a cessation of injection operations for two (2) years, a well is considered inactive. In this case, the Permittee shall plug and abandon the inactive well(s) in accordance with the Plugging and Abandonment Plans, unless it:

   a. Provides notice to EPA;

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

   c. Has described actions or procedures, satisfactory to EPA, which will be taken to ensure that the well(s) will not endanger underground sources of drinking water during the period of inactivity, including annually demonstrating external mechanical integrity of the well(s);

d. Conducts an internal MIT every two years while the well remains inactive; mechanical integrity must be restored if the well fails the MIT.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging any well, the Permittee shall submit a report on Form 7520-14, provided in Appendix C, 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, or

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

G. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility

The Permittee is required to demonstrate and maintain financial responsibility and resources sufficient to close, plug, and abandon the underground injection operation as provided in the Plugging and Abandonment Plans and consistent with 40 CFR §144 Subpart D, which the Director has chosen to apply.

a. The Permittee shall post an approved financial instrument in the amount of \$500,000 each, for a toal of \$1,000,000 to guarantee closure of Martinez Wells 1 and 2 and \$500,000 each for a total of \$1,000,000 to guarantee closure of Franklin Wells 1 and 2. -Authority to inject and operate each of these wells under the authority of this permit will be granted only after the financial instrument has been posted and approved by EPA.

b. The financial responsibility mechanism shall be reviewed and updated periodically, upon request of EPA. The Permittee may be required to change to an alternate method of demonstrating financial responsibility. Any such change must be approved in writing by EPA prior to the change.

c. EPA may require the Permittee to estimate and to update the estimated plugging cost periodically. Such estimates shall be based upon costs that a third party would incur to plug the wells, including mud and disposal costs, with appropriate contingencies.

2. Insolvency of Financial Institution

The Permittee must submit an alternate instrument of financial responsibility acceptable to EPA within sixty (60) days after either of the following events occurs:

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

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.

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

3. Insolvency of Owner or Operator

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. 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, Section B.1 of this permit.

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 other injection activity in a manner that allows the movement of fluid containing any contaminant (as defined by 40 CFR §144.3 and 146.3) into USDWs (as defined 40 CFR §§144.3 and 146.3).

No injection fluids are allowed to migrate to any nearby oilfield 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 migrate to oilfield operation or geothermal production wells.

Any underground injection activity not specifically authorized in this permit is prohibited. 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. § 300(i), 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 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, and 144.40. 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. 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 §§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 §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

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. 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.

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 includes 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 a time specified, 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. Signatory Requirements

All applications, reports, or other information submitted to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative according to 40 CFR §§122.22 and 144.32.

10. Additional Reporting

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. Twenty-four Hour Reporting

i. The Permittee shall report to EPA any noncompliance which may endanger health or the environment. The following information shall be provided orally within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances:

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

2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water.

ii. A written submission of all noncompliance as described in paragraph (i) 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.

e. Other Noncompliance - At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of noncompliance not otherwise reported. The Permittee shall submit the information listed in Part III, Section E.10.d of this permit.

f. 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. 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 for a new permit at least one hundred and eighty (180) days before this permit expires.

b. Permit Extensions - The conditions and requirements of an expired permit continue in force and effect in accordance with 5 U.S.C. §558(c) 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.

APPENDIX A - Project Map

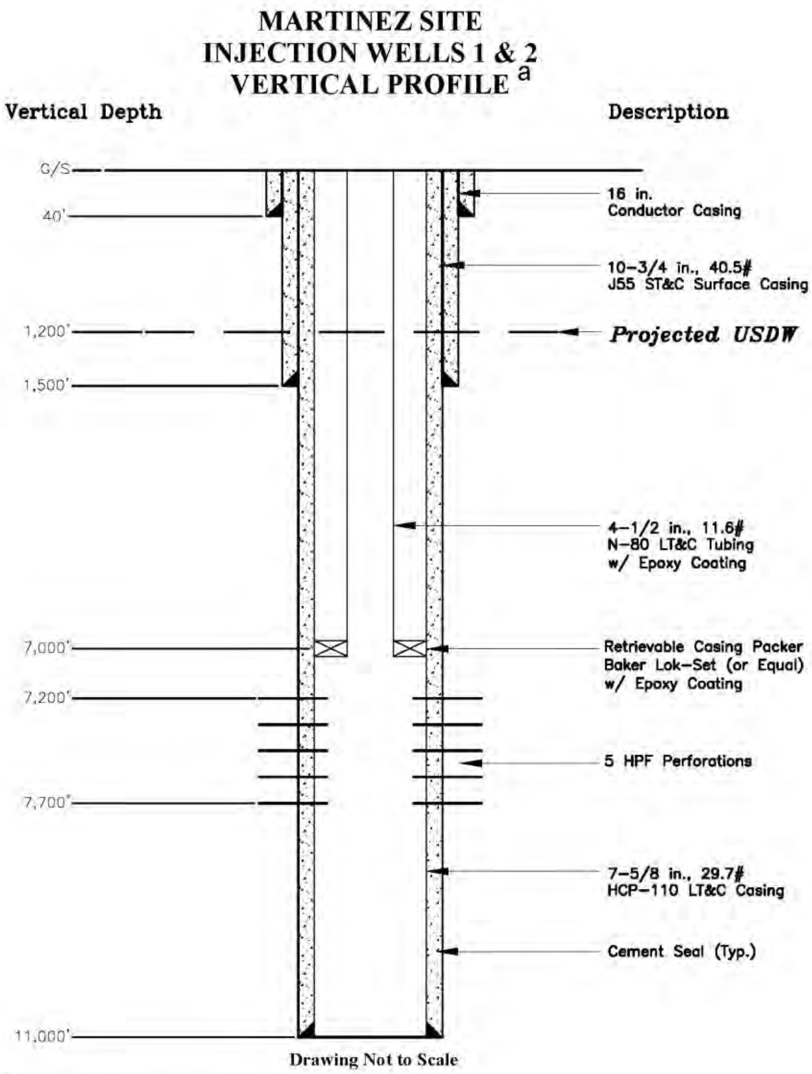
Application Introduction, Figure 1 – Project Location Map

LUHDORFF & SCALMANINI
CONSULTING ENGINEERS

Figure 1
Project Location Map

APPENDIX B –Proposed Well Schematics

Application Attachment M, Figure M1



Note

a. **See Directional Well Path and Coordinates.**

CAD FILE: G:/Projects/Newhall Land/10-2-129/M-1.dwg CFG FILE: LSCE2500.PCP_MRG DATE: 12-01-11 2:13pm

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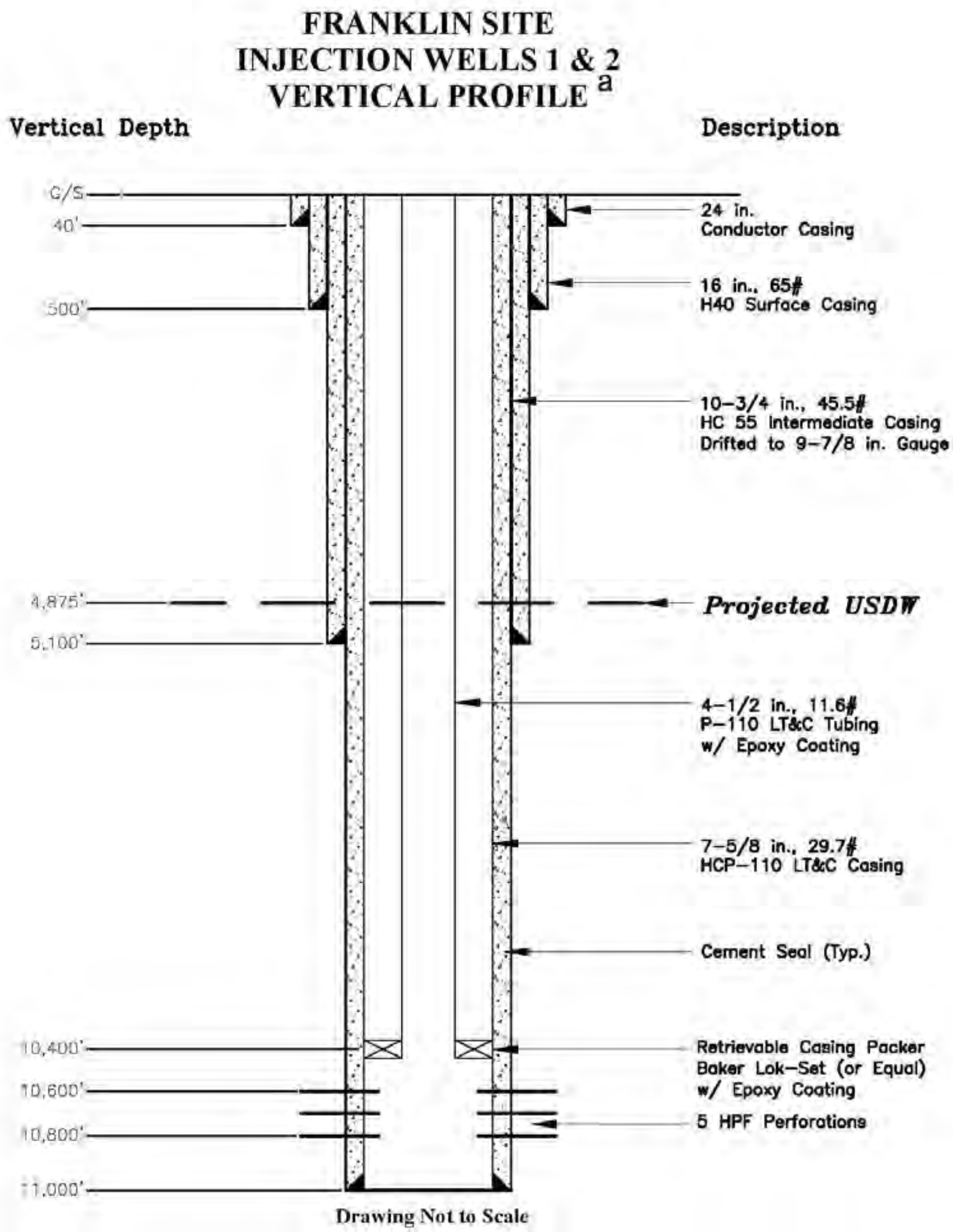
Figure M-1
Preliminary Profile for Martinez Site Wells



Note

a See Directional Well Path and Coordinates.

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Figure M-2
Preliminary Profile for Franklin Site Wells

APPENDIX C – EPA Reporting Forms

Form 7520-7	Application to Transfer Permit
Form 7520-9	Completion of Construction
Form 7520-11	Annual Well Monitoring Report
Form 75200-12	Well Rework Record
Form 7520-14	Plugging and Abandonment Plan(s)

APPENDIX D – Logging Requirements

Region 9 Temperature Logging Requirements

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 - Region 9 UIC Pressure Falloff Requirements

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

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

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

- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- 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:
   - Review previous welltests, if available
   - Simulate the test using measured or estimated reservoir and well completion parameters
   - 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)
   - 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
   - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
   - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
   - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

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

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

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

7.0 Evaluation of the Falloff Test

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

2. Prepare a **log-log diagnostic plot** of the pressure and semilog derivative. Identify the

flow regimes present in the welltest. (See Appendix, page A-6 for additional information.)

- Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff (See Appendix, page A-10 for details on time functions.)
- **Mark the various flow regimes -** particularly the radial flow period
- Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
- If there is no radial flow period, attempt to type curve match the data

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

- EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- **Downhole pressure measurements** are less noisy and are required.
- 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.
- The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.
- Mechanical gauges should be **calibrated** before and after each test using a dead weight tester.
- Electronic gauges should also be **calibrated** according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

Selection

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

Test Design

General Operational Considerations

- The injection period controls what is seen on the falloff since the falloff is replay of the injection period. Therefore, the injection period must reach radial flow prior to shut-in of the well in order for the falloff test to reach radial flow
- Ideally to determine the optimal lengths of the injection and falloff periods, the test should be simulated using measured or estimated reservoir parameters. Alternatively, injection and falloff period lengths can be estimated from empirical equations using assumed reservoir and well parameters.

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

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

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

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

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

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

- The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period.
- The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

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

- Wellbore radius, r_w - from wellbore schematic

- Net thickness, h - See Appendix, page A-15
- Porosity, φ - log or core data
- Viscosity of formation fluid, μ_f - direct measurement or correlations
- Viscosity of waste, μ_{waste} - direct measurement or correlations
- Total system compressibility, c_t - correlations, core measurement, or well test
- Permeability, k - previous welltests or core data
- Specific gravity of injection fluid, s.g. - direct measurement
- Injection rate, q - direct measurement

Design Calculations

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

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

   $C = V_w \cdot c_{waste}$ where, V_w is the total wellbore volume, bbls
   c_{waste} is the compressibility of the injectate, psi^{-1}

   b. Well goes on a vacuum:

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

   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:

- Shut-in all offset wells prior to the test
- If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
- Obtain accurate injection records of offset injection prior to and during the test
- At least one of the real time points corresponding to an injection rate in an offset well should be synchronized to a specific time relating to the test well
- **Following the falloff test in the test well, send at least two pulses from the offset well to the test well by fluctuating the rate in the offset well.** The pressure pulses can confirm communication between the wells and can be simulated in the analysis if observed at the test well. The pulses can also be analyzed as an interference test using an Ei type curve.

- If time permits, conduct an interference test to allow evaluation of the reservoir without the wellbore effects observed during a falloff test.

Falloff Test Analysis

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

Cartesian Plot

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

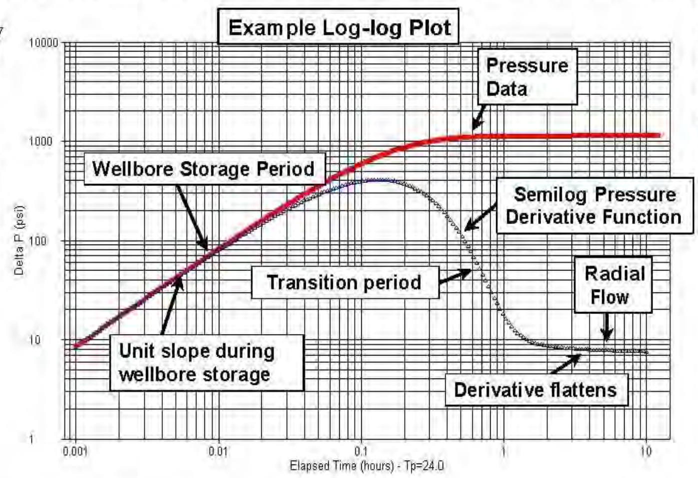
- A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to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

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

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

Log-log Diagnostic Plot

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



Identification of Test Flow Regimes

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

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

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

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

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

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

Characteristics of Individual Test Flow Regimes

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

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

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

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

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

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

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

<u>Semilog Plot</u>

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

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

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

Determination of the Appropriate Time Function for the Semilog Plot

The following four different semilog plots are used in pressure transient analysis:

1. Miller Dyes Hutchinson (MDH) Plot
2. Horner Plot
3. Agarwal Equivalent Time Plot
4. Superposition Time Plot

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

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

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

  2. The Horner plot can result in significant analysis error if the injection rate varies prior to the falloff.

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

- 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

- 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

- 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.

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

Skin Factor

- 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.

- 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.

- 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.

Radius of Investigation

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

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

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

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

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

Effective Wellbore Radius

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

- The effective wellbore radius is calculated from the following:

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

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

Reservoir Injection Pressure Corrected for Skin Effects

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

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

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

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

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

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

Determination of the Appropriate Fluid Viscosity

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

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

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

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

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

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

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

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

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}

- 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.

Reservoir Thickness

- 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.

- 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.

- 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.

- 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

- 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.

- 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

- 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.

- 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.

- 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.

- 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.

- 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.

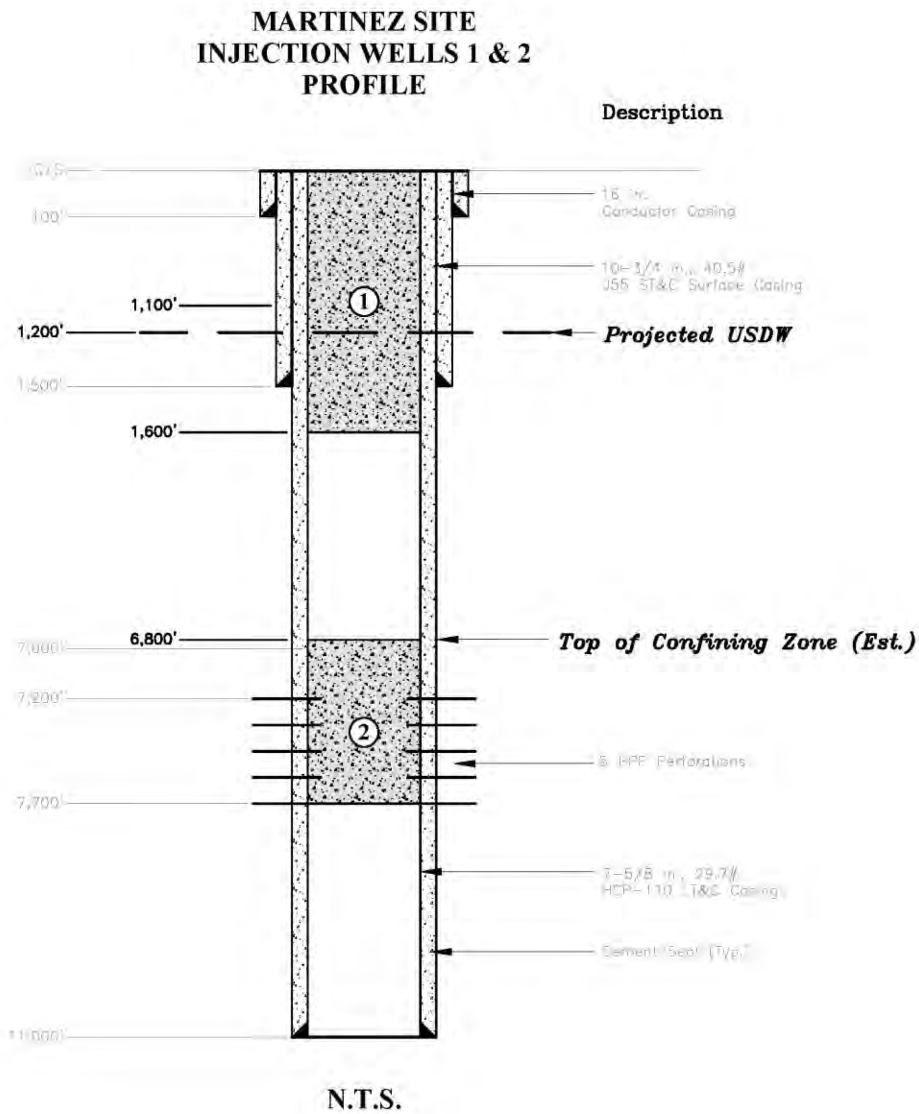
APPENDIX F – Region 9 Step Rate Test Policy

For reference please refer to:
Society of Petroleum Engineers (SPE) Paper #16798,
Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure
(This paper may be obtained from the SPE)

APPENDIX G - Plugging and Abandonment Plans

Application Attachment Q, Figure 1

Upon completion of injection activities the well(s) shall be abandoned according to State and Federal regulations to ensure protection of Underground Sources of Drinking Water.



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LUHDORFF & SCALMANINI CONSULTING ENGINEERS

Figure Q-1
Plugs for Martinez Site Wells

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Martinez Site 04N 17W Section 29 Wells 1 and 2	Newhall Land 25124 Springfield Court, Suite 300, Valencia

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State	County	Permit Number
CA	Los Angeles	

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section 29 Township 4N Range 17

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

Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 2

Lease Name NA

WELL ACTIVITY

- [x] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number 1 and 2

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
10-3/4	45.5		1,500	14
7-5/8	29.7		11,000	9-5/8

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	7-5/8	7-5/8	7-5/8	7-5/8			
Depth to Bottom of Tubing or Drill Pipe (ft	7,700	7,300	1,600	800			
Sacks of Cement To Be Used (each plug)	83	104	165	159			
Slurry Volume To Be Pumped (cu. ft.)	17.1	21.3	34.1	34.1			
Calculated Top of Plug (ft.)	7,300	6,800	800	0			
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.8	15.8	15.8	15.8			
Type Cement or Other Material (Class III)	Class G	Class G	Class G	Class G			

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
7,200	7,700		

Estimated Cost to Plug Wells

Cementing services approx. $67,000 each well (Halliburton Spetember 7, 2012) and related well services $100,000 each well (Irani Engineering (November 13, 2012). Total Wells 1 and 2: $334,000.

Certification

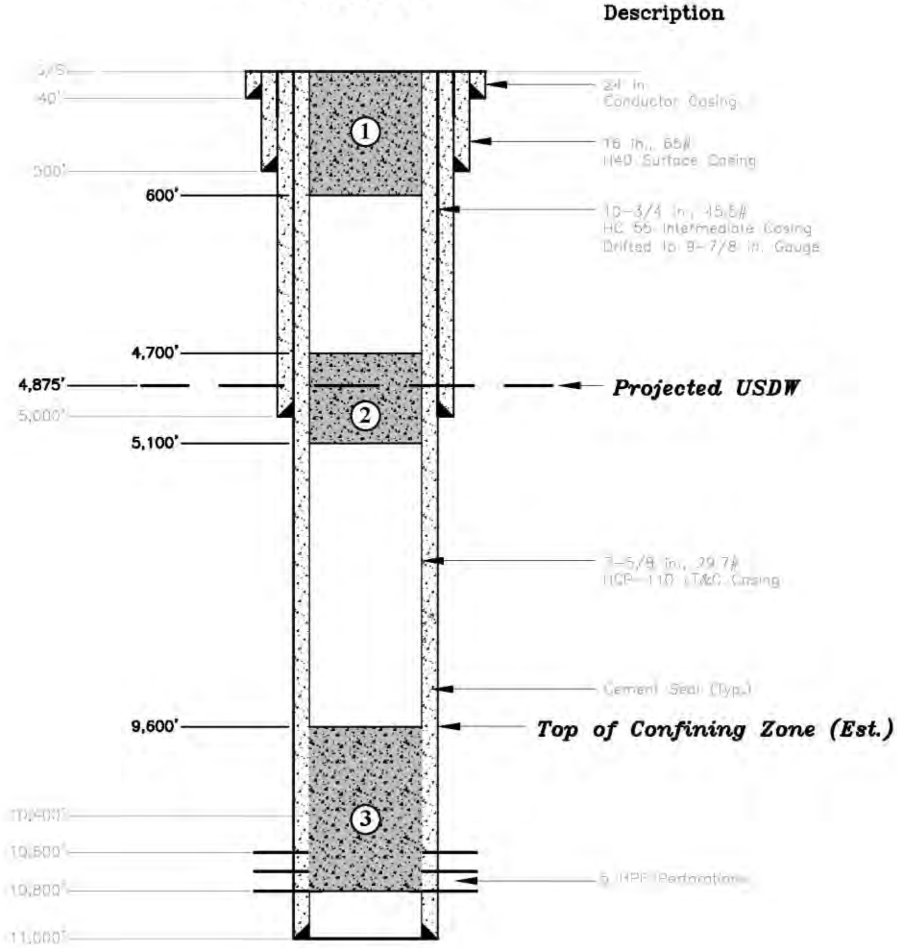
I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate,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

Name and Official Title *(Please type or print)*	Signature	Date Signed
Newhall Land		

EPA Form 7520-14 (Rev. 12-08)

Application Attachment Q, Figure 2

FRANKLIN SITE
INJECTION WELLS 1 & 2
PROFILE



N.T.S.

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LUHDORFF & SCALMANINI CONSULTING ENGINEERS

Figure Q-2
Plugs for Franklin Site Wells

OMB No. 2040-0042 Approval Expires 12/31/2011

United States Environmental Protection Agency
Washington, DC 20460

EPA

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Franklin Site 04N 17W Section 12 Wells 1 and 2	Newhall Land 25124 Springfield Court, Suite 300, Valencia

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State	County	Permit Number
CA	Los Angeles	

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section 12 Township 4N Range 17

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

Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- ☑ Individual Permit
- ☐ Area Permit
- ☐ Rule

Number of Wells 2

Lease Name NA

WELL ACTIVITY

- ☑ CLASS I
- ☐ CLASS II
  - ☐ Brine Disposal
  - ☐ Enhanced Recovery
  - ☐ Hydrocarbon Storage
- ☐ CLASS III

Well Number 1 and 2

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
10-3/4	45.5		5,000	14
7-5/8	29.7		11,000	9-5/8

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- ☑ The Balance Method
- ☐ The Dump Bailer Method
- ☐ The Two-Plug Method
- ☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	7-5/8	7-5/8	7-5/8	7-5/8			
Depth to Bottom of Tubing or Drill Pipe (ft	10,800	10,200	5,100	600			
Sacks of Cement To Be Used (each plug)	125	125	83	119			
Slurry Volume To Be Pumped (cu. ft.)	25.6	25.6	17	25.5			
Calculated Top of Plug (ft.)	10,200	9,600	4,700	0			
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.8	15.8	15.8	15.8			
Type Cement or Other Material (Class III)	Class G	Class G	Class G	Class G			

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
10,600	10,800		

Estimated Cost to Plug Wells

Cementing services approx. $68,000 each well (Halliburton Spetember 7, 2012) and related well services $100,000 each well (Irani Engineering (November 13, 2012). Total Wells 1 and 2: $336,000.

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 possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Newhall Land		

EPA Form 7520-14 (Rev. 12-08)

ATTACHMENT C – CORRECTIVE ACTION PLAN

Area of Review

Each well site was evaluated to determine whether corrective action is required. Within the one-half mile Area of Review for the Franklin site, two abandoned oil and gas wells were identified that penetrate the target injection zone and are candidates for corrective action under 40 CFR 144.55. No wells penetrating the target injection zone were found within the AOR for the Martinez site.

The abandoned wells located within the Franklin site AOR are shown on Figure C-1. The distances between the bottomhole locations for the proposed project injection wells and the abandoned oil and gas wells in Figure C-1 are listed below:

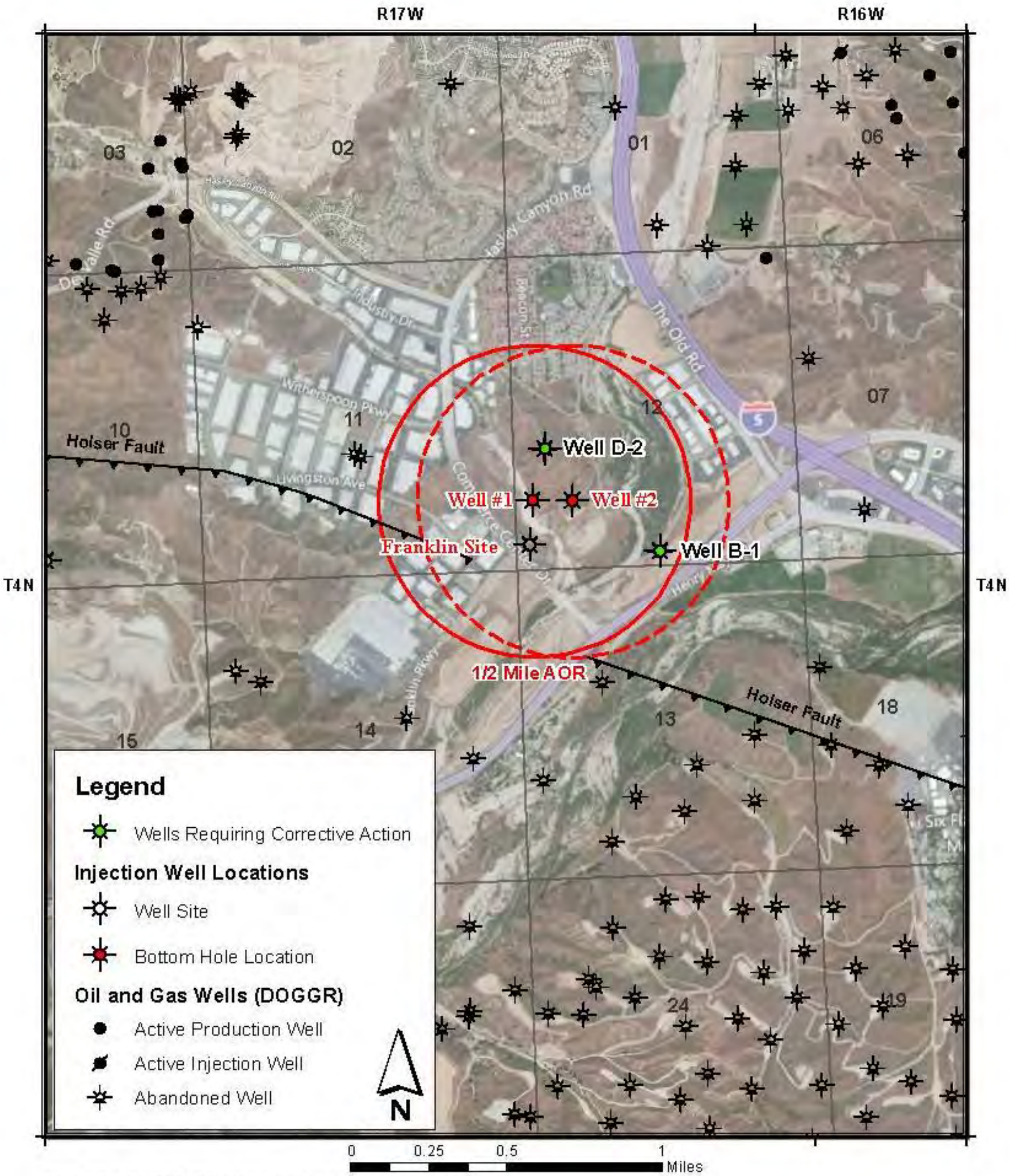
	Distance to Abandoned Oil and Gas Well (feet)	
Injection Well	**Well D-2**	**Well B-1**
Franklin Well 1	880	2,325
Franklin Well 2	990	1,720

Well Data

Data for the abandoned wells within the Franklin site Area of Review were obtained from the California Division of Oil and Gas (DOGGR) online mapping system. Partial well records are included with this attachment and complete records from DOGGR are in Appendix 1. Relevant information on these wells with respect to corrective action planning is summarized below:

Well Name	API No.	Date Abandoned	USDW Depth[1]	Seals[2]	Corr. Action Required?
NL&F B-1	03705490	1951	Approx. 5,000 ft	23-35 ft 585-850 ft 2,650-2,850 ft 4,300-4,800 ft	Yes
Newhall D-2	03706109	1957	Approx. 4,800 ft	0-16 ft 800-1,050 ft 1,634-2,220 ft 2 seals below 7,471 ft	Yes

1. See TDS Determination Worksheet in Attachment D.
2. Measured depth.



File: X:\2010 Job Files\10-129\GIS\Figure C-1 - AOR and Corrective Action.mxd Date: 11/23/2011

LUHDORFF & SCALMANINI CONSULTING ENGINEERS

Figure C-1
Areas of Review and Wells Requiring Corrective Action
Franklin Site

Corrective Action Plan

In accordance with 40 CFR 146.7, Corrective action, the Director shall consider various factors in determining the adequacy of proposed corrective actions. These criteria are listed below and discussed in terms of the wells requiring corrective action at the Franklin site.

i. Nature and Volume of Injected Fluid

The injected fluids will consist of non-hazardous brine concentrate from reverse osmosis treatment of municipal waste water.

ii. Nature of Native Fluids or By-Products of Injection

Native, or connate, fluids in the targeted injection zone are marine in origin and are anticipated to be compatible with the brine injectate. Fluid compatibility will be tested under Formation Testing to determine if any unforeseen reactions or by-products would be produced.

iii. Potentially Affected Population

The largest city near the project sites is the City of Santa Clarita. The population of the City of Santa Clarita and surrounding areas is estimated at greater than 200,000. The Newhall Ranch project will add 21,000 new homes and 19,000 jobs to the area.

iv. Geology

A detailed geologic description is provided in Attachment F. Significant regional structural features provide the traps for oil and gas accumulation and accounts for the presence of numerous well fields in the area. The abandoned wells within the Franklin AOR were dry exploratory holes targeting oil and gas accumulations.

v. Hydrology

The project area is situated in the Upper Santa Clara River Hydrologic Area, as defined by the California Department of Water Resources, and is located almost entirely in northwestern Los Angeles County. The area encompasses about 654 square miles comprised of flat valley land (about 6 percent of the total area) and hills and mountains (about 94 percent of the total area) that border the valley. Elevations range from about 800 feet on the valley floor to about 6,500 feet in the San Gabriel Mountains. The headwaters of the Santa Clara River are at an elevation of about 3,200 feet. The Santa Clara River and its tributaries flow intermittently through the project area to the Pacific Ocean.

The Santa Clarita Valley is characterized as having an arid climate. Historically, intermittent periods of below-average precipitation have typically been followed by periods of above-average precipitation in a cyclical pattern, with each wetter or drier period typically lasting from one to five years. Long-term average precipitation from a local precipitation gage is 17.9 inches.

Groundwater in the Santa Clarita Valley occurs in the Santa Clara River Valley Groundwater Basin, East Subbasin (Department of Water Resources Bulletin 118 Basin No. 4-4.07) and is comprised of two aquifer systems. The Alluvium generally underlies the Santa Clara River and its tributaries and the Saugus Formation underlies most of the Upper Santa Clara River area. The East Subbasin is the source of most groundwater used for water supply in the Santa Clarita Valley. Since 1980, local groundwater supplies have been supplemented with imported water supplies from the State Water Project.

Water delivered by area water purveyors consistently meets drinking water standards set by the Environmental Protection Agency and the California Department of Public Health. Perchlorate was detected in 1997 in four supply wells in the eastern part of the Saugus Formation, near the former Whittaker-Bermite facility. The state Department of Toxic Substances Control is the lead agency responsible for regulatory oversight of the site.

The above information is summarized from the 2009 annual report to water purveyors by Luhdorff and Scalmanini (2010).

vi. <u>History of the Injection Operation</u>
Injection has not been initiated for the project. The project is part of a sustainability measure to reclaim waste water for irrigation. During low irrigation demand, RO treated waste water will be discharged to the Santa Clara River under an NPDES permit and the RO brine concentrate will be injected into the project wells.

vii. <u>Completion and Plugging Records</u>
Detailed records are available for the two abandoned wells that are located within the Franklin site AOR. Complete DOGGR records are reprinted in Appendix 1.

viii. <u>Abandonment Procedures in Effect at the Time the Well was Abandoned</u>
The subject corrective action wells were abandoned following accepted DOGGR standards in effect at the time. A difference between DOGGR requirements for protection of fresh water sources exists due to USEPA's definition for a USDW.

ix. Hydraulic Connections with Underground Sources of Drinking Water

The subject oil and gas wells within the Franklin site AOR have the potential to provide a conduit for migration of injected brine to the USDW because they penetrate the USDW and the injection zone. Additionally, they do not have a seal across the interval where the interpreted USDW occurs locally. The threat that migration would occur without corrective action is estimated to be low because of the conservative selection of a one-half mile AOR. As indicated in Attachment A, the estimated ZEI is limited to a very small distance away from the injection wells, much smaller than the distances between the injection wells and the abandoned wells.

Plugging Program

Both abandoned wells were dry holes with no intermediate or production (long-string) casings installed. The proposed plugging would consist of reentering the boreholes to depths below the USDW and installing plugs that extend a minimum 100 feet above and below the USDW. A second plug in each wellbore would be installed at least 50 feet into the surface casings per local practices and requirements by DOGGR.

Each borehole will be re-entered to a target of 500 feet below the estimated USDW. The USDW will be evaluated in each borehole by running Dual Induction Laterolog and a Compensated Density-Neutron logging suite (with a caliper log). If the USDW determinations from logs are inconclusive, fluid samples using a formation testing tool will be obtained as specified in the reentry programs (see Step 5). Sufficient margin in the cement plug volumes will be employed to provide the required plugging across the USDW. With approval by USEPA, plug depths and extent will be finalized based on the USDW determinations. As appropriate to ensure that all USDWs are protected, consideration will be given to completely cementing the boreholes to surface rather than using discrete plugs. USEPA will be notified to witness each plug.

A detailed program was prepared by Irani Engineering, a California petroleum engineering consulting firm. The proposed programs for each well are attached.

Final Surface Casing Depth for Franklin Injection Wells

The final depth of surface casing in the Franklin injection wells will be based on the USDW determination in the CAP wells. All corrective action activities will be completed prior to injection operations.

References

California Division of Oil and Gas (DOGGR). 2011. *DOGGR online mapping system* *http://maps.conservation.ca.gov/doms/doms-app.html*. Accessed various dates.

Luhdorff and Scalmanini, Consulting Engineers. 2010. *2009 Santa Clarita Valley water report.*

Attachments

1. Reentry and plugging programs prepared by Irani Engineering for each corrective action.
2. Partial records for wells identified within the Franklin AOR that require corrective action (complete DOGGR records are included in Appendix 1).

Reentry Program – Irani Engineering
NL&F B-1
API No. 03705490

IRANI
ENGINEERING
CONSULTING PETROLEUM ENGINEERS

Newhall Land
NL&F B-1 Redrill No. 1

Location: 5920 North and 10645' East from Southwest corner of
Section 11, T 4N, R 17W, Los Angeles County, California.
The well is in Section 12.
Elevation: +996′ ground. +1012' KB (assume 16')
Take all measurements from KB which is 16' above ground.
Keep hole full at all times.
Check operation of BOE daily.

Present Condition
TD: 4452' PD: Surface, cement plug
Casing: 12-3/4″, 49.56#, B-line surface casing cemented at 748'.
11" hole from 748' to 3752'
7-5/8" hole from 3752' to 4452'
Cement plugs: 1) From 23' to 35'.
2) From 585' to 850'.
4) From 2650' to 2850'.
Note: There is mud between cement plugs.

Reentry Program
1. Move in Drilling rig. Install 3000 BOE and test. Notify EPA to witness. Use recorded chart for BOE testing.

2. Pick up 11" mill tooth bit and 11" stabilizer, 2DC, 11" stabilizer, 30 HW's. Drill cement plugs from 23' to 35' and from 585' to 850'.

3. Ream open hole to top of cement plug at 2650'. Circulate and condition mud to 10#, 45 viscosity. POH.

4. Run one joint of 8-5/8" wash pipe with 11" washover shoe, 11" stabilizer, 2DC's, 11" stabilizer, 30 Hw's. Wash over the cement plug from 2650' to 2850'. Clean hole to TD and drill out to 5500′. Circulate and condition mud. Wiped hole to shoe. POH.

5. Run DIL/Neutron/Density/Caliper logs from TD to 748'. Identify the base of USDW. If USDW determination is inconclusive and as permitted by hole conditions, run repeat, or sequential, formation tester (e.g., Halliburton SFTT or equal) to obtain fluid samples for USDW verification. With approval from EPA, abandon well as follows.

6. Equalize 400' lineal feet of Class G cement premixed 3% CaCl2 100' below the base of USDW. WOC for 4 hours. Locate top of cement plug which must be 100' above the base of USDW. Notify EPA to witness.

7. Equalize 200 sacks of Class G cement premixed 3% CaCl2 at 800'. WOC for 4 hours. Locate top of cement plug which must be above 698'. Notify EPA to witness.

November 27, 2011
Rev. November 2012

8. Cut casing 5' below ground. Plug casing with 30 lineal feet of cement. Weld steel plate on stub. Notify EPA to witness.

November 27, 2011
Rev. November 2012

Reentry Program – Irani Engineering
Newhall D-2
API No. 03706109

IRANI

ENGINEERING

CONSULTING PETROLEUM ENGINEERS

Newhall Land
Newhall D-2 Redrill No. 2

Location: From Rancho San Francisco Cor. #10 SW'ly along the Rancho line 11,839' thence SE'ly at 90 degrees thereto 2903'. Section 12, T 4N, R 17W, Los Angeles County, California.
Elevation: +1049′ ground. +1060' KB
Take all measurements from KB which is 11' above ground.
Keep hole full at all times.
Check operation of BOE daily.

Present Condition
TD: 11833' PD: Surface, cement plug
Casing: 11-3/4″, 47# & 54#,J-55 surface casing cemented at 988'.
9-7/8" hole from 988' to 11833'
Cement plugs: 1) From surface to 16'.
2) From 800' to 1050'.
4) From ~1610' (estimated, did not tag) to 2220'.
Note: There is 80# mud below cement plugs and between cement plugs.
Junk in hole from 11721' to 11833'.

Reentry Program
1. Move in Drilling rig. Install 3000 BOE and test. Notify EPA to witness. Use recorded chart for BOE testing.

2. Pick up 9-7/8" mill tooth bit and 9-7/8" stab, 2DC, 9-7/8" stab, 30 HW's. Drill cement plugs from surface to 16' and from 800' to 1050'.

3. Ream open hole to top of cement plug at around 1610'. Circulate and condition mud to 10.7#, 45 viscosity. POH.

4. Run one joint of 7-5/8" wash pipe with 9-7/8" washover shoe, 9-7/8" stabilizer, 2DC's, 9-7/8" stabilizer, 30 Hw's. Wash over the cement plug from ~1610' to 2220'. Clean hole to 5500'. Circulate and condition mud. Wiped hole to shoe. POH.

5. Run DIL/Neutron/Density/Caliper logs from TD to 748'. Identify the base of USDW. If USDW determination is inconclusive and as permitted by hole conditions, run repeat, or sequential, formation tester (e.g., Halliburton SFTT or equal) to obtain fluid samples for USDW verification. With approval from EPA, abandon well as follows.

6. Equalize 400' lineal feet of Class G cement premixed 3% CaCl2 100' below the base of USDW. WOC for 4 hours. Locate top of cement plug which must be 100' above the base of USDW. Notify EPA to witness.

7. Equalize 140 sacks of Class G cement premixed 3% CaCl2 at 1050'. WOC for 4 hours. Locate top of cement plug which must be above 838'. Notify EPA to witness.

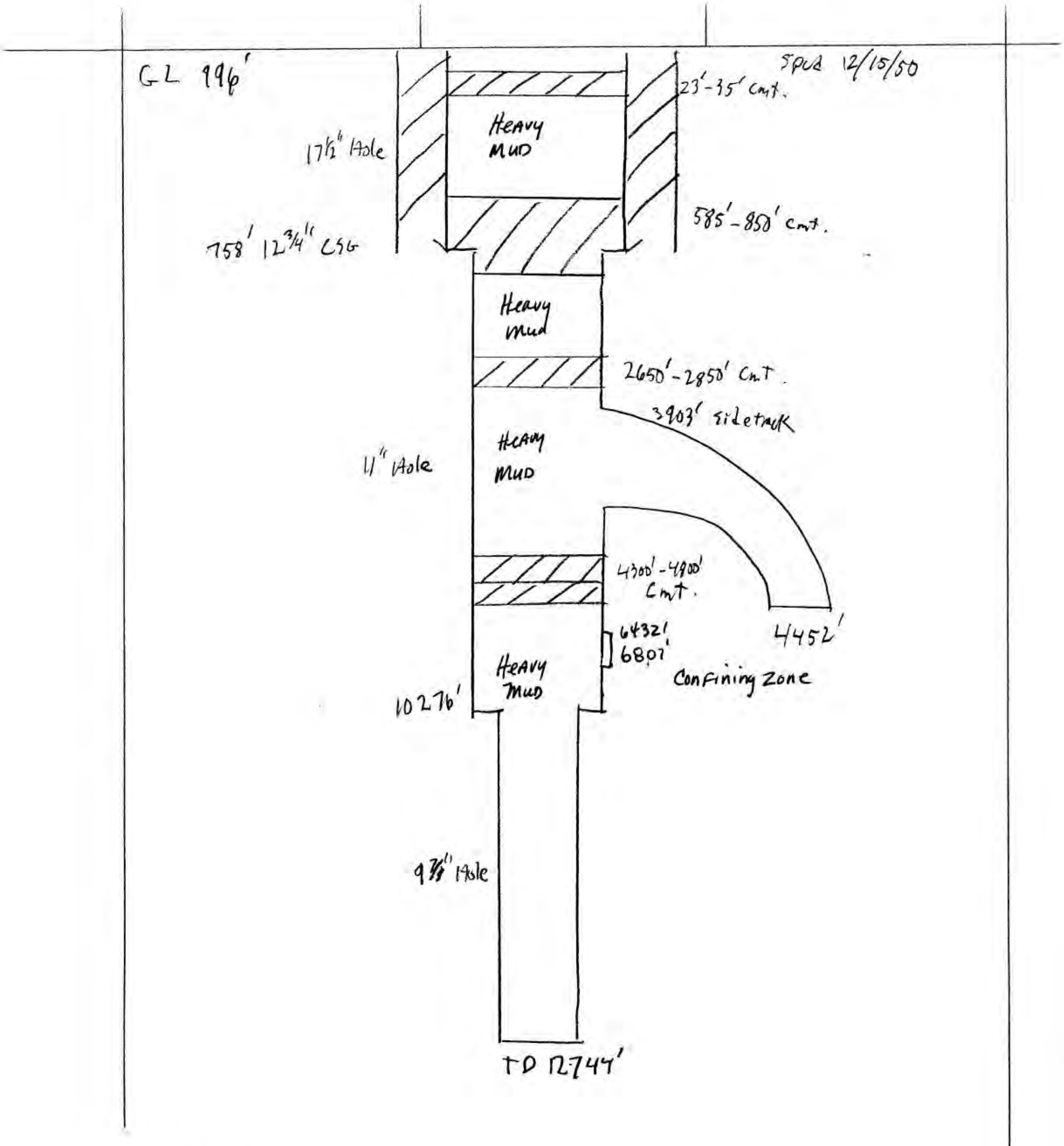
November 28, 2011
Rev. November 2012

IRANI
ENGINEERING
CONSULTING PETROLEUM ENGINEERS

8. Cut casing 5' below ground. Plug casing with 30 lineal feet of cement. Weld steel plate on stub. Notify EPA to witness.

November 28, 2011
Rev. November 2012

NL&F B-1
API No. 03705490



Field: Any Field
S12 T4N R17W, SB
Well Name: NL&F B-1
ExxonMobil Corp.
API #: 03705490
Well Type: OG Spud Date:1951
Status: Plugged Abandon Date:1951
Abandonment DOG Witness Date: 4-14-51

Field north of Castaic + Del Valle

FORM 109-D

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

Special Report on Operations Witnessed

No. T 1-52775

Los Angeles 15, Calif. April 25, 1951.

Mr. John S. Bell,
Los Angeles 17, Calif.
Agent for HUMBLE OIL & REFINING COMPANY

DEAR SIR:

Operations at your well No. "Newhall Land & Farming Co." B-1 Sec. 12, T. 4 N., R. 17 W., S. B. B. & M., xx Field, in Los Angeles County, were witnessed by Paul Betts, Inspector, representative of the supervisor, on April 14, 1951. There was also present J. Ortega, Drilling Foreman; and B. Borge, Driller.

Casing Record 12-3/4" cem. 748'. T.D. (present hole), 4452', plugged with cement 2850'-2650', 850'-585' and 23'-16'.

Junk (T. D., 1st hole, 12,744', plugged with cement 4800'-3752'.)

The operations were performed for the purpose of inspecting a cement plug placed from 23' to 16' in the process of abandonment.

The inspector arrived at the well at 8:00 a. m. and Mr. Ortega reported:

1. The hole was bridged with cement sacks at 12' below the cellar floor (11' below the surface of the ground).
2. The hole was filled with cement to the cellar floor.

THE INSPECTOR NOTED THAT the hole was filled with set cement to 5' below the cellar floor.

(The operator decided to dump another sack of cement into the hole calculated to fill to 3' from the cellar floor.)

The operations were completed at 8:15 a. m.

THE LOCATION AND HARDNESS OF THE CEMENT PLUG AT 16' ARE APPROVED.

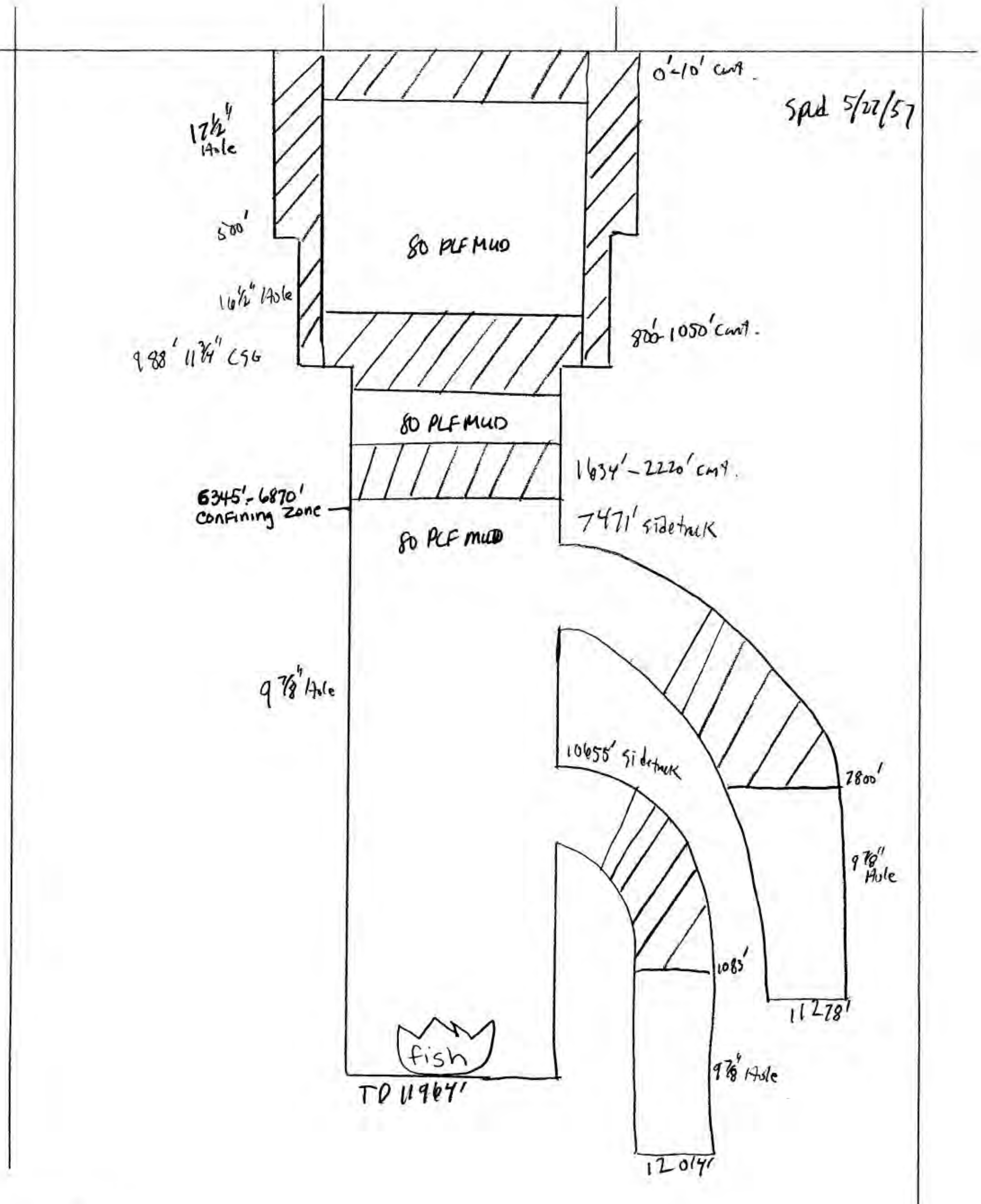
PWB:my
2 cc - Company

R. D. BUSH
State Oil and Gas Supervisor
By R. H. Mussey Deputy

16330 10-49 17,500 SPO

Final

Newhall D-2
API No. 03706109



Field: Any Field
S12 T4N R17W, SB
Well Name: Newhall D-2
Marathon Oil Co.
API #: 03706109
Well Type: OG Spud Date:1957
Status: Plugged Abandon Date:1957
Abandonment DOG Witness Date 11-29-57

Field North of Castaic + Del Valle

FORM 109-D

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

Special Report on Operations Witnessed

No. T 157-1368

Mr. T R Beauchamp
P O Box 7221
Long Beach 7 California
Agent for THE TEXAS COMPANY

Inglewood 3 Calif.
December 4 1957

DEAR SIR:

Operations at your well No. "Newhall" D-2, Sec. 12, T. 4 N., R. 17 W., S.B. B & M. Beacon Anticline Area Field, in Los Angeles County, were witnessed on November 29, 1957. Mr. R. Johnson, Engineer, representative of the supervisor was present from 9:45 to 10:00 a.m.. There were also present M. McBee, Drilling Foreman
T. Bolton, Driller

Present condition of well: 11-3/4" cem. 988', Junk (in hole) bit at 7663', top of drill collars at 11,715', T.D. (present hole) 11,946' plugged with cement 2220'-1610'±, 1050'-791', 16'-6', T.D. 1st hole 11,278', T.D. 2nd hole 12,064'.

The operations were performed for the purpose of witnessing the plugging operations in the process of abandonment.

~~Mxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxreportedx~~
ENGINEER, M. DOSCH, VISITED THE WELL FROM 7:30 TO 8:30 A.M., ON NOVEMBER 28, 1957, AND MR. McBEE REPORTED

1. A 9-7/8" hole was drilled from 988' to 11,278'.
2. On July 28, 1957, 100 sacks of cement was pumped into the hole through 4-1/2" drill pipe hanging at 7600', filling to 6950'.
3. The cement was drilled out to 7488' and a removable whipstock was set at that depth.
4. A 9-7/8" hole was redrilled from 7488' to 12,064'.
5. On October 3, 1957, 150 sacks of cement plus 75 sacks of sand was pumped into the hole through 4-1/2" drill pipe hanging at 10,832', filling to 10,675'.
6. The cement was drilled out of the hole from 10,675' to 10,680' and a removable whipstock was set at that depth.
7. A 9-7/8" hole was redrilled from 10,680' to 11,946'.
8. Junk consisting of 6-1/2" drill collars and a 9-7/8" bit was left in the hole from 11,715' to 11,827'.
9. A 9-7/8" bit was later lost at 7663'.
10. On July 27, 1957, 300 sacks of cement was pumped into the hole through 4-1/2" drill pipe hanging at 2220', calculated to fill to 1610'.
11. On July 27, 1957, 150 sacks of cement was pumped into the hole through 4-1/2" drill pipe hanging at 1050'.

THE ENGINEER NOTED the cement plug at the reported depth of 791' supported 4 points of the weight of the drill pipe.

ENGINEER, R. JOHNSON, VISITED THE WELL FROM 9:45 TO 10:00 A.M., ON NOVEMBER 29, 1957, AND MR. McBEE REPORTED

1. The hole was bridged at 16' with cement sacks.
2. Thirteen sacks of cement was dumped into the hole.

THE ENGINEER NOTED THAT the top of the cement in the 11-3/4" casing was at the cellar floor, 6' below the ground surface.

THE PLUGGING OPERATIONS AS WITNESSED AND REPORTED ARE APPROVED.

RJ:yk
cc- Company

D/J

Orig Mr P O Giddens

E. H. MUSSER
State Oil and Gas Supervisor
By Wm C. Bailey Deputy
DER

63193 9-57 17M SPO

Final