U.S. EPA Underground Injection Control Program

FINAL PERMIT

Class I Non-Hazardous Waste Injection Wells

Permit No. CA10710001

Well Names: La Paloma WD-1, WD-2, WD-3, WD-4, WD-5

Kern County, CA

Issued to:

La Paloma Generating Company, LLC
1760 W. Skyline Road, P.O. Box 175
McKittrick, CA 93251

TABLE OF CONTENTS

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,

La Paloma Generating Company, LLC
1760 W. Skyline Road, P.O. Box 175
McKittrick, CA 93251

is hereby authorized to, contingent upon Permit conditions, construct and operate a Class I nonhazardous waste injection well facility with up to five (5) new wells to be drilled, known as the La Paloma WD-1, WD-2, WD-3, WD-4, and WD-5 wells. Wells to be drilled are located in Section 27, Township 30S, Range 22E, at 35 degrees, 17 minutes, 34 seconds Latitude and 119 degrees, 35 minutes, and 39 seconds Longitude, on La Paloma Generating Company, LLC facilities in Kern County, California. Exact locations of each well will be established and approved as outlined in this permit.

Authorization to drill and construct up to five (5) new wells will be issued by EPA after the requirements of Financial Responsibility in Part II, Section F of this permit have been met. EPA will grant authorization to inject after the requirements of Part II Sections A-C of this permit have been met. Operation of the wells will be limited to maximum volume and pressure as stated in this permit. Total amounts must not exceed specified limits. If approved, injection for wells WD-1, WD-2, WD-3, WD-4, and WD-5 will be authorized into the Olig sand zone of the Reef Ridge Formation for the purpose of disposal of industrial nonhazardous wastewater fluids. These fluids consist primarily of cooling tower blowdown from the power plant cooling process, but also include boiler and evaporative cooler blowdown, wash water, filter backwash, equipment drains, and stormwater from equipment containment areas at the La Paloma Generating Plant facility in Kern County, California.

All conditions set forth herein are based on Title 40 §§124, 144, 145, 146, 147 and 148 of the Code of Federal Regulations.

This permit consists of thirty-one (31) pages plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by La Paloma Generating Company, LLC (Permittee) 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, paragraph 1 of this permit.

This permit is issued on and becomes effective on March 6, 2008.

/Signed by/
Alexis Strauss, Director

Water Division, EPA Region IX

PART II. SPECIFIC PERMIT CONDITIONS

Prior to each demonstration required in the following sections A through C, the Permittee shall submit plans for procedures and specifications to the U.S. Environmental Protection Agency Region IX Ground Water Office ("EPA") for discussion and approval. The submittal address is provided in Section D, paragraph 5. No demonstration in these sections may proceed without prior written approval from EPA. The Permittee shall submit results of each demonstration required in this section to EPA within sixty (60) days of completion.

A. WELL CONSTRUCTION

1. Requirement for Prior Written Permission to Drill, Test, Construct, or Operate

   (a) Financial Assurance

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

   (b) No drilling or construction activities of Injection Wells WD-1, WD-2, WD-3, WD-4, or WD-5 may commence without adherence to the conditions in this section and written permission from the EPA Region IX Water Division Director (Director).

   (c) Pre-notification

   After approval for any of the approved field demonstrations is provided, notification to EPA at least 30 days prior to performing the demonstration is required, to allow EPA to arrange to witness if so elected.

2. Locations of Injection Wells

   Injection wells authorized under this permit will be located near the La Paloma Generating Company, LLC property on W. Skyline Road in McKittrick, California. The proposed general location for the wells is found in Appendix A, Figures 1-2.

   (a) Prior to drilling any well, the Permittee must submit proposed field coordinates (Section, Township, Range, with latitude/longitude).

   (b) After drilling is completed, the Permittee must submit final field coordinates (Section, Township, Range, with latitude/longitude) of any well constructed under this permit with the Final Well Construction Report required under paragraph 12 of this section. If final well coordinates differ from the proposed coordinates submitted under paragraph (a), justification and documentation of any communication with and approval by EPA shall be included.

3. 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). Before surface, intermediate, and long string casings are set, a dual induction/spontaneous potential/gamma ray log will be run over the course of the entire open hole sequence after the well is drilled to each respective terminal depth. After each casing is set and cementing complete, a spherically focused cement bond evaluation log will be run over the course of the entire cased hole sequence.

4. Injection Formation Testing

Injection formation information as described in 40 CFR 146.12 (e), shall be determined through well logs and tests and shall include porosity, permeability, static formation pressure, and effective thickness of the injection zone. The reservoir compressibility coefficient c (units of psi^{-1}) characterizing the total compressibility of water and rock must also be computed. A summary of results shall be submitted to EPA with the Final Construction Report required in paragraph 12 of this section and updated periodically with subsequent analyses.

(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 Total Dissolved Solids (TDS) analysis of target injection formation water to demonstrate either the presence and characteristics of, or the lack of, any Underground Sources of Drinking Water (USDWs). A USDW is defined as an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 milligrams per liter TDS; and which is not an exempted aquifer (40 CFR §§144.3, 146.4).

(i) The Permittee shall provide well logs and representative ground water sample analyses from the targeted injection aquifer using method(s) approved by EPA as evidence. These anlayses shall be sufficient to confirm compatibility of the injectate with the injection formation. Formation water samples from the injection zone will be collected for subsequent analyses from the first injection well upon its completion. Field measurements of pH, electrical conductance, and temperature will be carried out to confirm that representative Olig formation water is being collected. Subsequent laboratory analysis of the samples will include various elemental concentrations, alkalinity components, conductivity, hardness, pH, TDS, specific gravity, and oil and grease among others.

(ii) EPA may require minor alterations to the construction requirements based upon the information obtained during well drilling and related operations 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.

(b) Step-Rate Test (SRT)

An SRT will be conducted on at least one representative well before injection is authorized, to establish maximum injection pressure. Refer to Society of Petroleum Engineering (SPE) paper #16798 for test design and analysis. Similar testing may be required in other wells, at the discretion of EPA. The SRT will be used to establish the injection pressure limitation, in accordance with Section C, paragraph 3 of this part. Detailed plans for conducting the SRT must be submitted to EPA for review, possible editing, and approval. Once approved, Permittee may schedule the SRT, providing EPA at least 30 days notice before the SRT is conducted.

(i) Prior to testing, shut in the well long enough so that the bottom-hole pressure approximates shut-in formation pressure.

(ii) Measure pressures with a down-hole pressure bomb and coordinate with a surface pressure recorder throughout the course of the SRT.

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

(iv) Use 1 (one) bbl per min rate increments in the early stages, commencing at an initial injection rate of 1.0 bbl per min. Larger rate increments up to 2 bbl per min may be used later in the test, though the reasons for this request must be approved. This also allows for the requirement to record at least three (3) time steps (data points on pressure vs. flow plot) before reaching the anticipated fracture pressure without wellbore storage or other effects interfering with the results.

(v) Fracture pressure need not necessarily be achieved. The SRT must only continue until reaching 120% of the maximum requested operating pressure or until fracture pressure is reached. If SRT is terminated upon reaching 120% of the maximum requested operating pressure, the SRT results must clearly demonstrate that fracture pressure has not been reached. If fracture pressure is achieved before reaching 120% of the maximum requested operating pressure then the maximum operating pressure of the injection well will be equal to the surface pressure that corresponds to 80% of this bottom hole pressure.

(vi) 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.

(vii) Supplementary SRT may be authorized by EPA if well WD-3 injection pressure reaches approximately 770 psi measured at the wellhead, operational data indicate that injection pressure is within 80 percent of the calculated fracture pressure, or if operational data indicate that fracture pressure is realized prior to reaching 770 psi.

(c) Fall Off Pressure Test (FOT)

To determine and to monitor formation characteristics, a FOT shall be run in the representative well determined by EPA after a radial flow regime has been established. 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 corrective action is now required (refer to Section B 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, possible editing, and approval. Once approved, Permittee may schedule the FOT, providing EPA at least 30 days notice before the FOT is conducted.

(i) Initially, the FOT shall be performed approximately six months after start of injection.

(ii) Annually thereafter, the FOT test shall be repeated and results shall be included with the quarterly report due each January, as described in Section D paragraph 5 of this part. The annual FOT should not be less than 9 months or greater than 15 months from the previous test.

(iii) The latest static reservoir pressure and its cumulative pressure behavior from previous reservoir pressure measurements on a graphic plot of the injection zone shall be determined and reported with the FOT report in paragraphs (i) and (ii) above.

(d) Particulate Filters should be used upstream of the well, at the discretion of the operator, to prevent formation plugging or damage from particulate matter. Permittee shall include any filter specifications in the Final Construction Report required in paragraph 11 of this section, including proposed particle removal size along with any associated justification for the selected size. For any particulate filters used, follow appropriate waste analysis and disposal practices.

5. <u>Drilling, Workover, and Plugging Procedures</u>

Drilling, workover, and plugging procedures must comply with the California Division of Oil, Gas, and Geothermal Resource's (CDOGGR) "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 details for:

(a) 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; and

(d) Casing and other tubular and accessory measurement tallies.

CDOGGR reporting forms such as Well Summary Report, etc. may be accepted provided they contain all information as required within this permit.

6. <u>Casing and Cementing</u>

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 C paragraph 2(a)(iv) of this part. Casings shall be maintained throughout the operating life of the wells. The following approximate specifications from the permit application apply to proposed injection wells WD-1, WD-2, WD-3, WD-4, and WD-5:

(a) Conductor casing: 40' long by 14" or 16" diameter steel conductor pipe with at least 1/4" wall thickness placed in an augured hole and the annulus backfilled with concrete. An 8' square by 5' deep cellar is dug out around the conductor pipe.

(b) Surface casing: 9-7/8 inch OD (40.5 lb J-55) from ground surface to approximately 500 feet bgs cemented to surface.

(c) Long String Casing: 7 inch OD (23 lb J-55) from ground surface to the top of the target Olig Sand injection zone approximately 4,400 feet bgs, cemented to surface.

7. Tubing, Liner and Well Completion Specifications

For the five (5) proposed wells, injection will take place through tubing strings and a liner, subject to the following approximate specifications from the permit application:

(a) Tubing: 5-1/2 inch OD (17 lb L-80) from ground surface to approximately 4,300 feet bgs; 4.25-inch OD x 3.000-inch ID x 20-ft L seal (assembly to 4,350 ft bgs).

(b) Well WD-3 Liner: 5-1/2 inch 17 lb, L-80 liner from 4,350-5,300 ft bgs contains a polish bore receptacle that accepts a seal section on the end of the tubing string equipped with a series of chevron seals rated to ~10,000 psi differential pressure; slotted 2-inch x 200M, 48R, 6-inch C from 4,400-5,300 ft bgs. Setting collar is 3 feet in length, Liner hanger device is approximately 8 feet long, and polished bore receptacle extends 20 feet below that, resulting in a 31’ long liner hanger (5-1/2 inch top liner hanger will extend from 4,350-4,381 feet bgs). See Appendix B, Figures 7a, 7b, and 8.

(c) Well WD-3 Sand Control Liner: 3-1/2 inch (2.99 inch ID), 17 lb. L-80 base pipe with 132 holes (3/8 inch diameter) per foot, 0.010-inch diameter slot, 316L stainless steel wire wrap (4.0 inch OD) from approximately 4,346-4,720 ft bgs. The liner hanger is approximately 4 feet long. The sand control liner contains the polish bore receptacle that accepts a seal section on the end of the tubing string equipped with a series of chevron seals rated to ~10,000 psi differential pressure. See Appendix B, Figure 7a.

(d) Integrated Sand Control Liner: 5-1/2 inch, 17 lb. L-80 base pipe with 146 holes (3/8 inch diameter) per foot, 0.010-inch diameter slot, 316L stainless steel wire wrap (6.050 inch OD) from 4,400-5,300 ft bgs. The liner hanger is approximately 4 feet long. The sand control liner contains the polish bore receptacle that accepts a seal section on the end of the tubing string equipped with a series of chevron seals rated to ~10,000 psi differential pressure. See Appendix B, Figure 7b.

Final depths will be determined by the field conditions, pilot boring cuttings, sieve analysis, well logs and other input from the drilling consultant and hydrogeologist. EPA approval will be obtained for any revisions prior to installation.

8. Injection Intervals

Injection for each of the five (5) wells shall be permitted for the Miocene Olig sand zone of the Reef Ridge Formation, expected to occur at depths estimated from about 4,150 feet bgs to about 5,250 feet (900 feet). Casing setting depths are expected to be affected by minor alterations of the depths at which the injection zone intervals are actually encountered. These alterations and other rework operations that may occur later in the course of operation of the wells are considered minor for this permit and must be properly reported (use EPA Form 7520-12), and the Permittee must demonstrate that each well has mechanical integrity, in accordance with Section C paragraphs 1(a) and 2 of this part, before any injection is authorized.

9. Confining Layer

Field information on the Pliocene San Joaquin-Etchegoin confining layer that directly overlies the Olig sand injection zone, such as its characteristics, its thickness and its local structure will be obtained during drilling of the injection wells and shall be included in the Final Well Construction Report required in paragraph 12 of this section.

10. 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 fluids; 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:

a. A full pressure range of 100 percent greater than the anticipated operating pressure; and

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

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

11. 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 and casing tallies), and cement (and other) volumes, to EPA within sixty (60) days after completion of each new injection well (WD-1, WD-2, WD-3, WD-4, WD-5).

(b) The Permittee must also submit a notice of completion of construction to EPA (see EPA Form 7520-9 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.

12. Proposed Changes and Workovers

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 of EPA and may require a permit modification under the requirements of 40 CFR §§144.39 and 144.41. 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. Appendix C contains samples of the appropriate reporting forms. 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 C paragraphs 1(a) and 2 of this part.

B. CORRECTIVE ACTION

Corrective action may be necessary for existing wells in the Area of Review (AOR), defined in 40 CFR §146.6) that penetrate the injection zone, or which may otherwise cause movement of fluids into USDWs (see 40 CFR §§144.55 and 146.7). No corrective action plan is currently required, since all known wells located within the AOR have been deemed to either be properly plugged and abandoned or sufficiently confined geologically such that hydraulic communication between the proposed wells and nearby producing wells will not occur throughout the duration of this permit as specified in Section G. See Appendix A, Figures 1, 5 and 6 and Table 1.

1. Initial ZEI re-evaluation with Field Data

Data resulting from testing performed under Section A paragraphs 3 and 4, or Section C paragraph 2, in this part will be used by the Permittee to confirm or modify assumptions used to calculate the original ZEI and to set the AOR. If new field data results in a ZEI larger than the AOR which includes wells penetrating the proposed zones of injection, a corrective action plan shall accordingly be proposed for approval and implemented as described in paragraph 3 of this section.

2. Annual ZEI Review

Annually, the ZEI calculation shall be reviewed by the Permittee, based on any new data obtained from the FOT and static reservoir pressure tests required in Section A, paragraph 4(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 quarterly report due in January, as required in Section D paragraph 5 of this part.

3. Implementation of Corrective Actions

(a) If any wells requiring corrective action are found within the modified ZEI, a list of these wells along with their locations shall be provided to EPA as soon as possible.

(b) If requested by EPA, the Permittee shall submit a plan to re-enter, plug, and abandon the wells listed in paragraph (a) above in such a manner to prevent the migration of fluids into a USDW.

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

C. WELL OPERATION

1. Demonstrations Required Prior to Injection

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 all wells have and maintain 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 injection until it has received written notice from EPA that such a demonstration is satisfactory.

(b) Hazardous Waste Determination

The Permittee shall perform a "Hazardous Waste Determination" according to 40 CFR §262.11. The results of the waste determination shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR §§ 146.3 and 261. In addition:

(i) The Permittee shall maintain copies (or originals) of all records relating to the "Hazardous Waste Determination" and make such records available for inspection. In addition, 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.

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 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 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 to an accuracy within one tenth (0.1) of a psi. The average, maximum, and minimum monthly results shall be included in the quarterly report to EPA (as specified in Section D paragraph 5(a) 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 A paragraph 4(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, possible editing, and approval. Once approved, Permittee may schedule the external MIT, providing EPA at least 30 days notice before the external MIT is conducted.

(iv) Cement Evaluation Analysis

After casing is installed, or after conducting a cement squeeze job in an open hole, for any well constructed under this permit, the Permittee shall submit cementing records and cement evaluation logs that demonstrate the isolation of the injection interval and other formations from underground sources of drinking water by means of cementing the surface casing and the long string casing well bore annuli to surface. The analysis shall include a spherically-focused tool which enables the evaluation of the bond between cement and casing as well as of the bond between cement and formation. The Permittee may not commence injection until it has received written notice from EPA that such a demonstration is satisfactory.

(b) Subsequent MITs

It is the Permittee's responsibility to arrange and conduct MITs.

(i) At least once every five (5) years during the life of the well, in accordance with 40 CFR §146.8 and paragraph (a)(i) above**,** an internal pressure MIT shall be conducted on each injection well authorized under this permit. An MIT shall also be conducted within thirty (30) days from completion of any workover, if the liner hanger is unseated, if the seal is broken in the tubing/casing annulus, if the seal is broken at the wellhead assembly, if the construction of the well is modified, or when any loss of mechanical integrity becomes evident during operation. In addition, EPA may require that a MIT be conducted at any time during the permitted life of the wells.

(ii) At least annually for the life of the well, an injection profile survey external MIT, in accordance with 40 CFR §146.8 and paragraph (a)(iii) above, shall be conducted on each injection well authorized under this permit.

At least annually for the life of the best representative well, a FOT shall be conducted in accordance with Section A paragraph 4(c) of this part, unless other information demonstrates the need for additional tests and/or an increased frequency of tests. The proposed procedures must generally conform to EPA regional guidance for conducting pressure falloff tests but must be adapted for the specific conditions at this facility. Detailed plans for conducting the FOT must be submitted to EPA for review, possible editing, and approval. Once approved, Permittee may schedule the FOT, providing EPA at least 30 days notice before the external MIT is conducted. Appendix E contains Region 9 UIC pressure falloff testing requirements.

(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.

Furthermore, in the event of (i), (ii), or (iii), injection activities shall be terminated immediately and operation shall not be resumed until the Permittee has taken necessary actions to restore mechanical integrity to 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) 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) The initial wellhead injection operating pressure for well WD-3 will be 100 pounds per square inch (psi) or less. Injection pressures for the well will be evaluated at 100 psi increments to monitor reservoir pressure increases. The Permittee will provide immediate verbal notification and written notification within five (5) days to EPA when surface pressures reach successive 100 psi increments and an evaluation report will be submitted to EPA within thirty (30) days of reaching these increments. Each report will contain digital injection rate and wellhead injection pressure data collected by the installed monitoring devices (including date, time, injection pressure, and injection rate data) in accordance with Section D, paragraph 3(a) of this part. Permittee will not inject at pressures greater than 770 psi measured at the wellhead without written authorization by EPA in accordance with Section C, paragraph 3 of this part.

(b) In event that the Permittee conducts a subsequent Step-Rate Test according to Section A paragraph 4(b) of this part for well WD-3, EPA will provide the Permittee written notification of the modified maximum allowable injection pressure for well WD-3, along with a minor modification of the permit under 40 CFR §144.41(e). 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.

(c) For proposed wells WD-1, WD-2, WD-4 and WD-5, Maximum allowable injection pressure measured at the wellhead shall be based on the Step-Rate

Test conducted under Section A paragraph 4(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, along with a minor modification of the permit under 40 CFR §144.41(e). 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.

4. Injection Volume (Rate) Limitation

(a) The injection rate for well WD-3 shall not exceed 14.28 bbls/min. This volume limitation was determined to be appropriate through the demonstrations conducted in this section and justified by measured friction factors. EPA will provide written notification of the maximum injection volume allowed under this permit prior to any injection activities, along with a minor modification of the permit under 40 CFR §144.41(e).

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

(c) Any request for an increase in injection rate shall demonstrate to the satisfaction of EPA that the increase in volume will not interfere with the operation of the facility, its ability to meet conditions described in this permit, change its well classification, or cause migration of injectate or pressure buildup to occur beyond the Area of Review.

5. Injection Fluid Limitation

(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 at the La Paloma Generating Company facility. No fluids shall be accepted from other sources.

(c) Any well stimulation procedures, performed at the discretion of the operator, including all anticipated types of stimulation fluids and methods of injection, shall be proposed and submitted to EPA for approval no less than thirty (30) days prior to implementation. EPA may expedite approval in less than thirty (30) days prior to implementation in the event that requested well stimulation procedures are justified.

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.

(b) A minimum pressure of 100 psi at shut-in conditions shall be maintained on the tubing/casing annulus. Within the first quarter of injection operations, Permittee shall determine the range of fluctuation of annular pressure that shall be considered normal for each well configuration during periods of injection. The results of this determination shall be submitted with the first quarterly report after injection operations have commenced. Any annular pressure behavior outside of the normal range of fluctuation shall be considered indicative of a loss of mechanical integrity (MI) and shall be reported as per Section C, paragraph C of this part.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program

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 - USEPA Methods 160.1 and 160.2 for Total Dissolved Solids and Total Suspended Solids.

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

(iv) Trace Metals - USEPA Method 200.8 for trace metals analysis.

(v) Volatile Organic Compounds ("VOCs") - USEPA Methods 8010/8020 or 8240.

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

(b) Analysis of injection fluids.

A sample of the injectate shall be taken by an individual with the proper expertise and sent to a laboratory with proof of certification from the State of California. Sampling and injectate analysis performed as outlined in paragraph (a) above, must occur quarterly and every time there is a significant change in injection fluid, and shall be reported per section D paragraphs 5(a) through 5(d)(i) of this part.

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 and Specifications

(a) Continuous monitoring devices

Temperature, annular pressure, and injection pressure shall be measured at the wellhead using equipment of sufficient sensitivity and accuracy. All measurements must be recorded at minimum to a precision of one tenth of the unit of measure (e.g. injection rate and volume must be recorded to a precision of a tenth of a gallon; pressure must be recorded to a precision of a tenth of a psig; injection fluid temperature must be recorded to a precision of a tenth of a degree Fahrenheit). Exact dates and times of measurements, when taken, must be recorded and submitted. Injection rate, well head injection pressure, annular pressure and injection fluid temperature specifically must be recorded on an hourly basis. Injection rate shall be measured in the supply line immediately before the wellhead. The Permittee shall continuously monitor and record the following parameters at the prescribed frequency:

Continuously Monitored Parameter	**Recording Frequency**	**Instrument**
Injection rate (gallons per minute)	Hourly	digital recorder
Daily Injection Volume (gallons)	Daily	digital totalizer
Total Cumulative Volume (gallons)	Daily	digital totalizer
Well head injection pressure (psig)	Hourly	digital recorder
Annular pressure (psig)	Hourly	digital recorder
Injection fluid temperature (°F)	Hourly	digital recorder

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

DATE	TIME	INJ. PRESS (PSIG)	INJ. RATE (GPM)
06/27/07	16:33:16	1525.6	65.8
06/27/07	17:33:16	1525.4	66.3

Each line with data has to include 4 values separated by any consistent combination of spaces and tabs. The first column contains information about the measurement date in the format mm/dd/yy or mm/dd/yyyy , where mm is the month, dd is the day of the month and yy or yyyy is the year. The second column is the measurement time, in the format hh:mm:ss, where hh is the hour, mm are the minutes and ss are the seconds. Hours should be calculated on a 24 hours basis, i.e. 6 PM should be entered as 18. Seconds are optional. The third column is the well head injection pressure in psi. The fourth column is injection rate in gallons per minute.

(b) Injection Fluid Monitoring

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. The results of the tests shall be submitted to EPA on a quarterly basis.

(c) 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 have them available at all times for examination by an EPA inspector:

(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; and

(b) Information on the nature and composition of all injected fluids;

(c) The results of performing the "Hazardous Waste Determination" on the injectate 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.

(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 either delivered to the Regional Administrator, or

(ii) written approval from the Regional Administrator to discard the records is obtained.

5. Reporting

Quarterly, the Permittee shall electronically submit accurate reports to EPA containing, at minimum, the following information:

(a) Hourly and daily values for all continuously monitored parameters specified for the injection wells in paragraph 3(a) of this section, unless more detailed records are requested by EPA;

(b) Monthly average, maximum, and minimum values of all hourly and daily monitored parameters specified in paragraph 3(a) of this section for the injection wells, unless more detailed records are requested by EPA;

(c) Total cumulative injected volume over the course of the life of the well to date, unless more detailed records are requested by EPA;

(d) Quarterly analyses, to be included in the next quarterly report following completion:

    (i) Injection fluid characteristics for parameters specified in paragraph 3(b) of this section;

    (ii) When appropriate, hazardous waste injectate determination, according to Section C, paragraph 1(b)(i) of this part

(e) To be included with the next quarterly report immediately following completion of each well, results of any additional MITs or other tests required by EPA, and any well workovers completed; and

(f) To be included in the quarterly report due in January each year, the following annual analyses,:

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

    (ii) FOT results as required in Section A, paragraph 4(c) of this part;

    (iii) Shut-in static reservoir pressure cumulative behavior plot of the injection zone, as required in Section A, paragraph 4(c)(iii) of this part;

    (iv) Annual injection profile survey results as required in Section C paragraph 2(a)(iii) of this part; and

    (v) Annual ZEI recalculation as required in Section B paragraph 2 of this part.

(g) To be included in the quarterly report due in January every five years, an internal MIT as required in Section C paragraph 2(a)(i) of this part.

(h) A narrative description of all non-compliance that occurred during the reporting period.

Quarterly report forms as specified in Appendix C 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 IX
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:

Doug Patteson
California Regional Water Quality Control Board
Central Valley Region, Fresno Branch Office
1685 E Street
Fresno, CA 93706

California Division of Oil, Gas, and Geothermal Resources
District 4 Office
Attn: Rich Thesken, Randy Adams
4800 Stockdale Hwy., Suite 417
Bakersfield, CA 93309-0279

E. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

The Permittee shall notify EPA no less than sixty (60) days before conversion, workover, or abandonment of any well authorized by this permit. EPA may require that the plugging and abandonment be witnessed by an EPA representative.

2. Plugging and Abandonment Plans

The Permittee shall plug and abandon the well(s) as provided in Appendix F, the general Plugging and Abandonment Program submitted as Attachment Q to the application, and consistent with 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 or if the well is not consistent with EPA requirements for construction or mechanical integrity. EPA may require the Permittee to estimate and to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the wells, including mud and disposal costs, with appropriate contingencies.

3. Cessation of Injection Activities

After a cessation of injection operations for two (2) years, 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; and

(c) Has described actions or procedures, satisfactory to EPA, that will be taken to ensure that the well(s) will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging any well, the Permittee shall submit a report on Form 7520-13, 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 Plugging and Abandonment Plans, or

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

F. FINANCIAL RESPONSIBILITY

1. <u>Demonstration of Financial Responsibility</u>

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 a financial instrument such as a surety bond with a standby trust agreement or arrange other financial assurance for each well constructed in the amount of $127,500 per well, to guarantee closure. Authority to drill and construct any well will not be given until 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 which names EPA as the beneficiary. Any such change must be approved in writing by EPA prior to the change.

2. <u>Insolvency of Financial Institution</u>

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 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 will result in the termination of this permit pursuant to 40 CFR '144.40(a)(1).

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

An owner or operator must notify EPA by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days. 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.

G. DURATION OF PERMIT

This permit and the authorization to inject are issued for a period of up to ten (10) years unless terminated under the conditions set forth in Part III, Section B, paragraph 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) into underground sources of drinking water (as defined 40 CFR §§144.3, 146.4), if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons.

Furthermore, 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 144, 145, 146, and 124. 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. <u>Modification, Revocation and Reissuance, or Termination</u>

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 non-compliance 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 non-compliance is authorized by an emergency permit issued in accordance with 40 CFR §144.34. Any permit non-compliance 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 non-compliance 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 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 non-compliance 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 Non-compliance - The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in non-compliance with permit requirements.

(c) Compliance Schedules - Reports of compliance or non-compliance 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) <u>Twenty-four Hour Reporting</u>

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

(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 non-compliance 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 non-compliance as described in paragraph (d)(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 non-compliance and its cause; the period of non-compliance, including exact dates and times; if the non-compliance 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 non-compliance.

(e) <u>Other Non-compliance</u> - At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of non-compliance not otherwise reported. The Permittee shall submit the information listed in Part III, Section E, paragraph 10(d) of this permit.

(f) <u>Other Information</u> - 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. <u>Continuation of Expiring Permit</u>

(a) <u>Duty to Reapply</u> - 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 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 MAPS

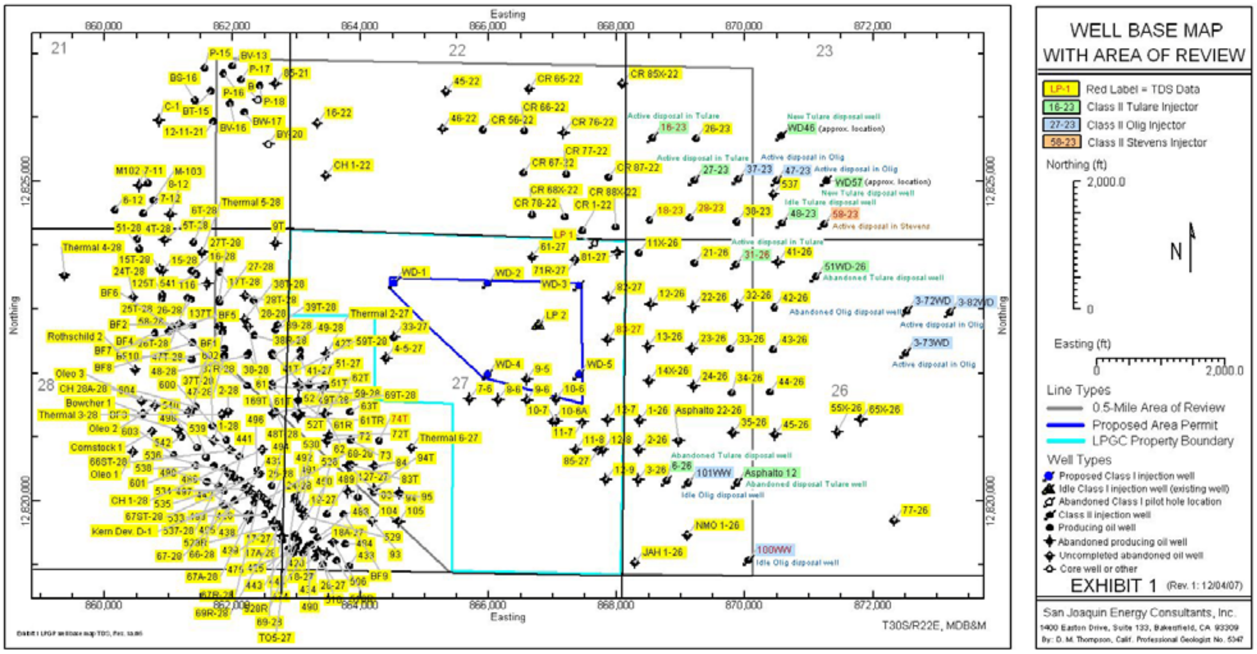

Figure 1. Well base map with area of review.

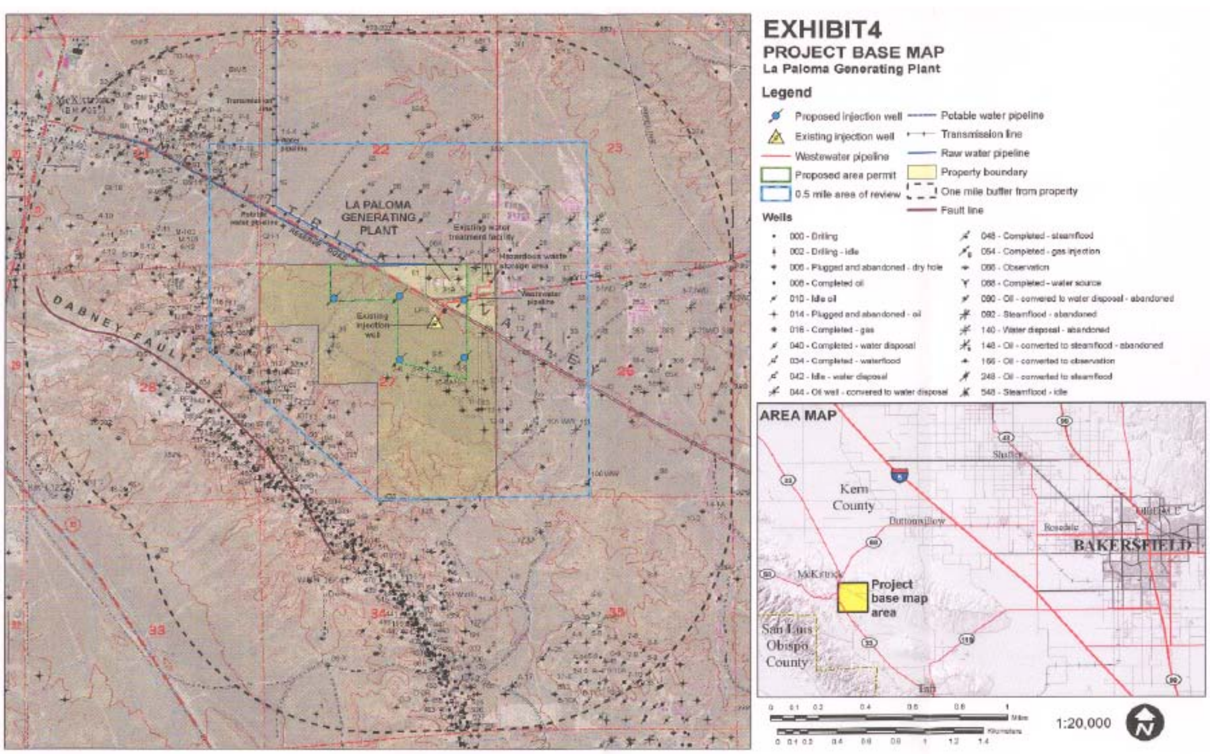

Figure 2. Project base map.

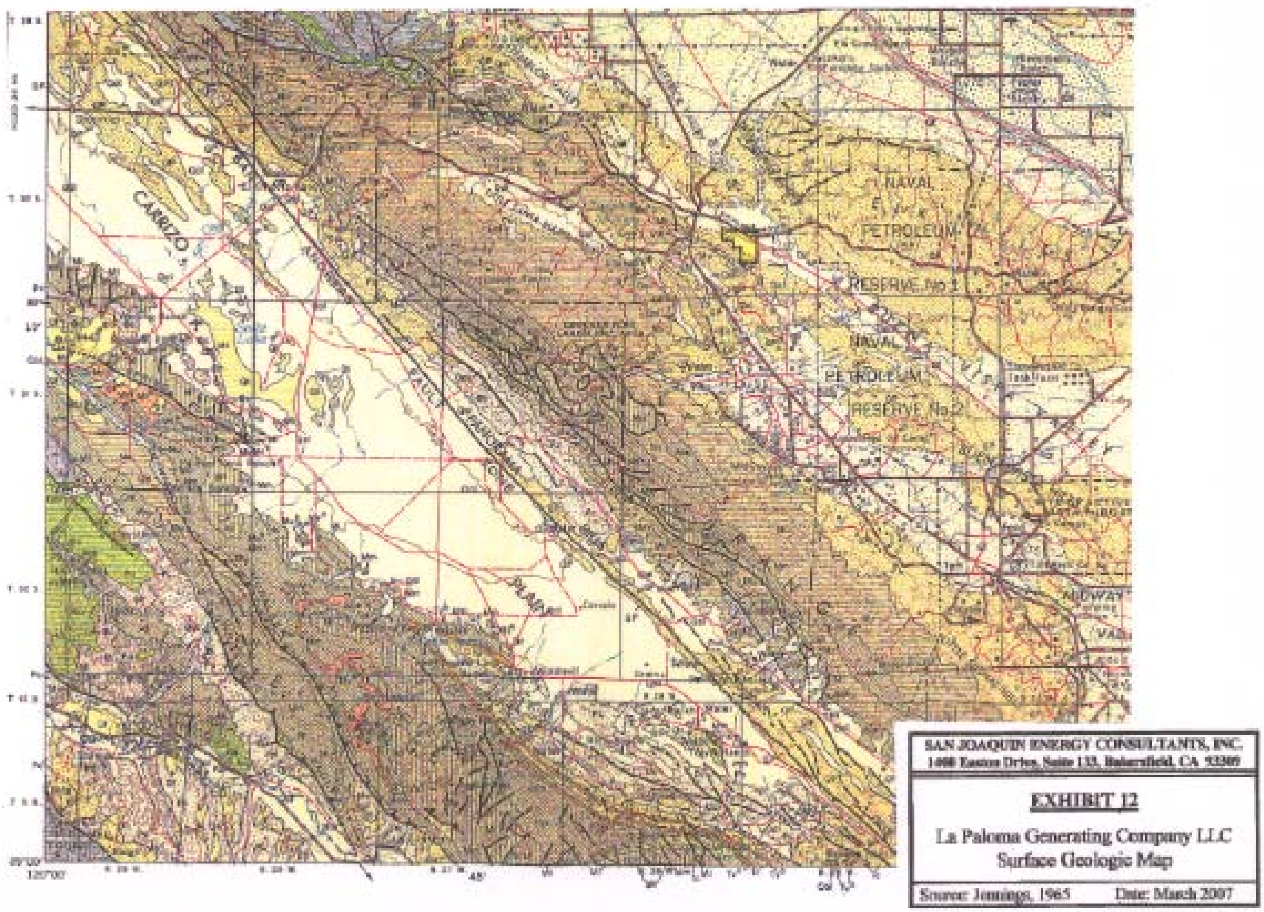

Figure 3. Surface geologic Map.

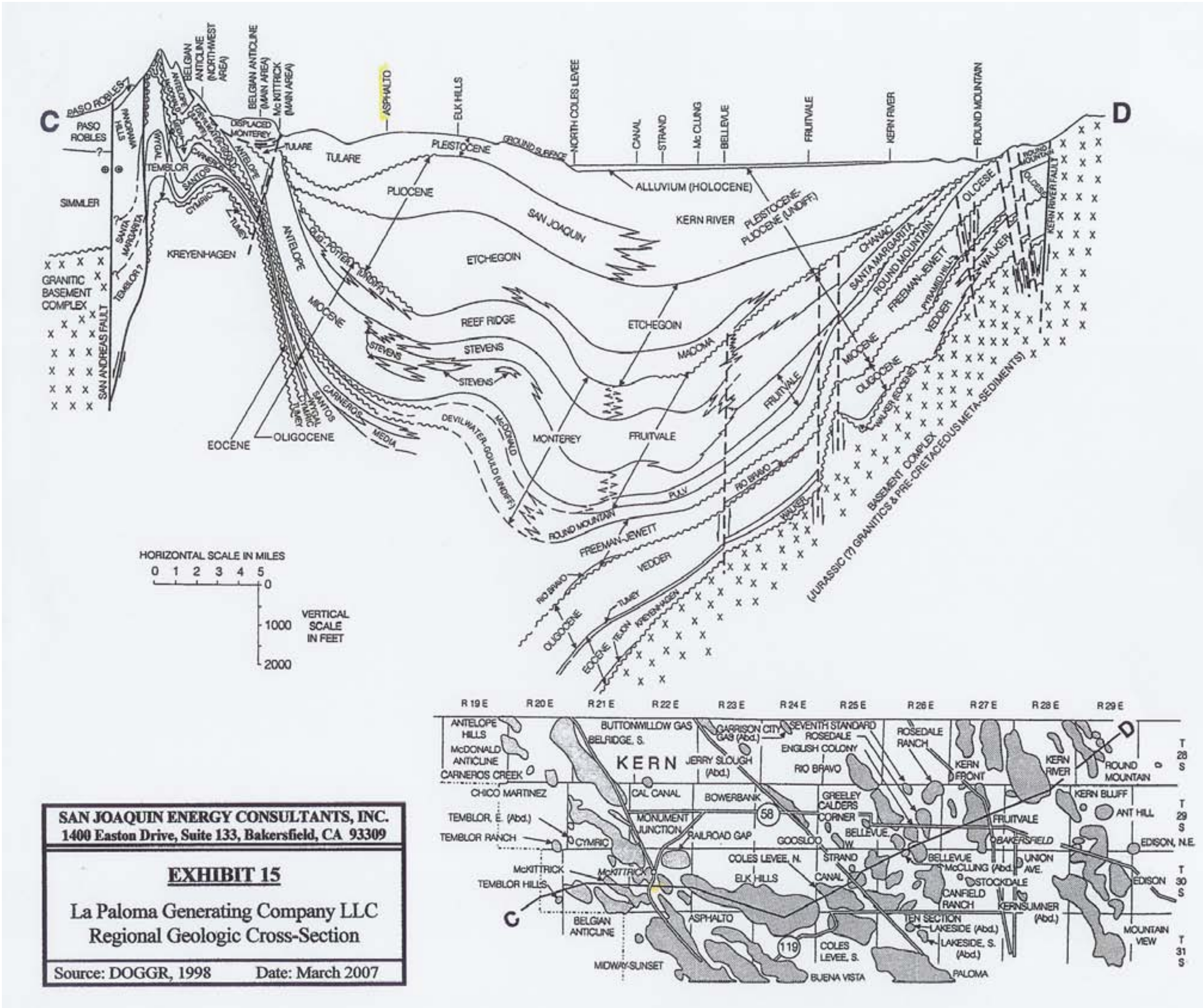

Figure 4. Regional Geologic Cross-Section

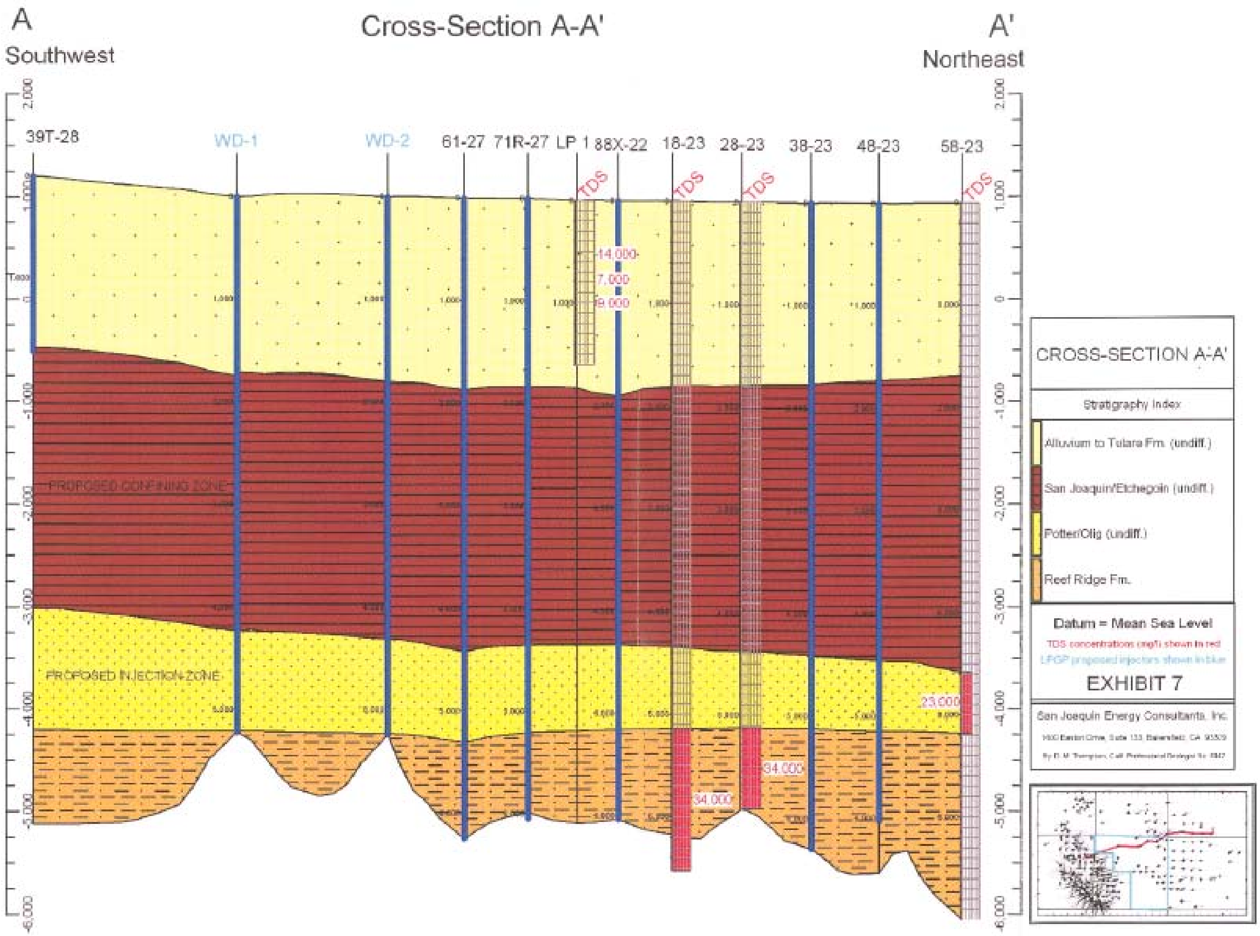

Figure 5. Approximately east-west running representative strike and dip cross-section within the project area, which includes TDS values in various zones and proposed locations of WD-1 relative to nearby existing wells.

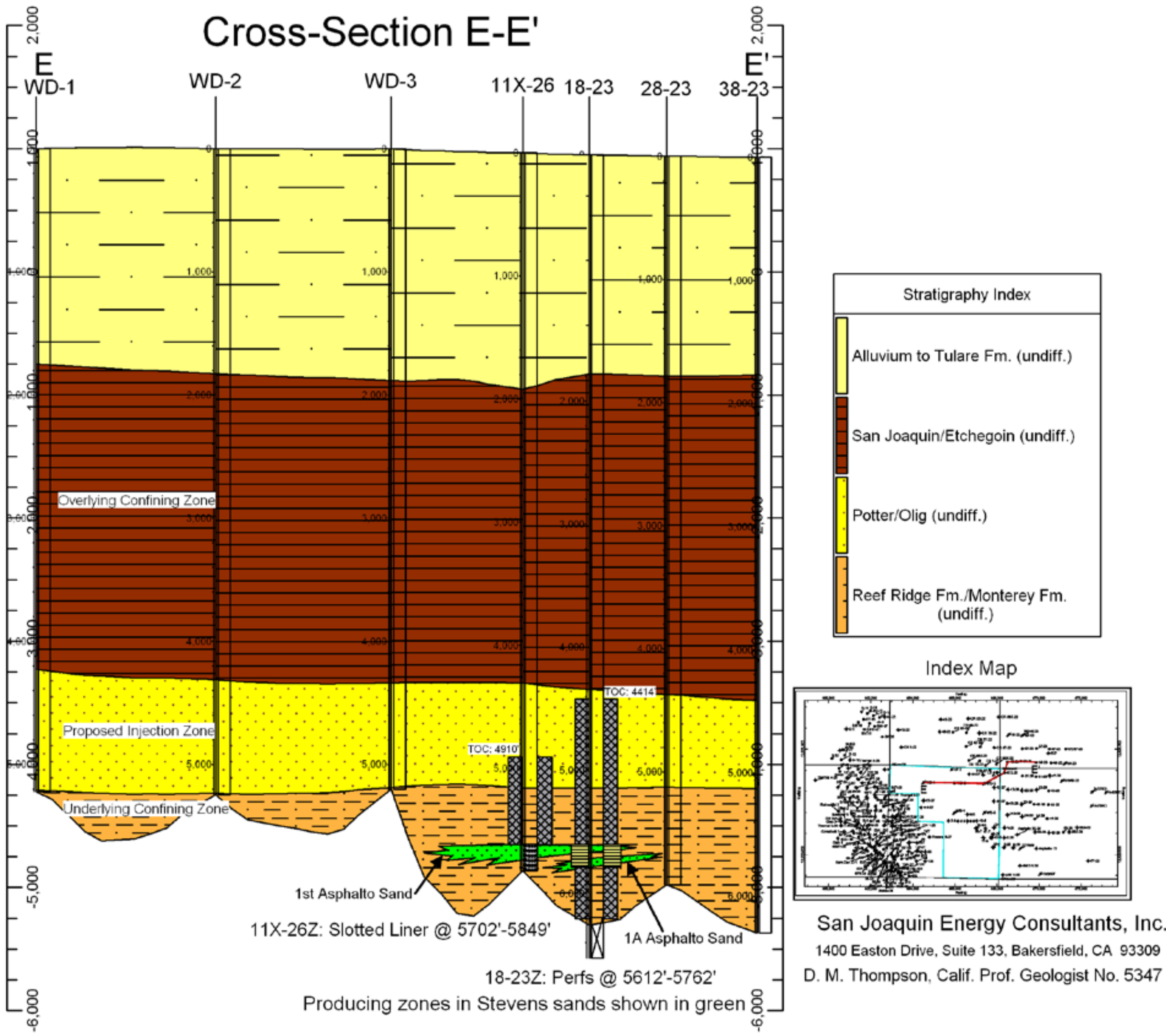

Figure 6. Representative strike and dip cross-section within the project area, which includes the boundary between the Olig sand injection zone and the underlying Reef Ridge Formation/Antelope shale member of the Monterey Formation (undiff.) in the vicinity of producing wells 11X-26Z and 18-23Z.

Table 1. Offset wells potentially impacted by injection based on 20-year waste/pressure front calculations. None of these wells were deemed to pose a significant risk.

Well	API #	Depth to Olig Top	Distance to Closest Injector	Waste Front Impact after 20 Years Inj @ 3,543 BDP/Well	Pressure Front Impact after 20 Years Inj. @ 3,543 BPD/Well	Remarks
Probable Impact: Well within 100' of Waste Front						
71R-27Z	029-01480	4340'	WD #3 410' S	284' inside front	+31 psi	P&A 1-00; cemented above Olig top. **No significant risk.**
82-27Z	029-01482	4307'	WD #3 500' W	194' inside front	+31 psi	P&A 6-00; cemented above Olig top. **No significant risk.**
83-27Z	029-01483	4325'	WD #5 705' SW	11' outside front	+31 psi	P&A 6-00; cemented above Olig top. **No significant risk.**
Possible Impact: Well within +25 psi Pressure Front						
1-22Z	029-37546	4334'	WD #3 850' S	156' outside front	+ 26 psi	SIUE; annulus cemented above Olig top. **No significant risk.**
68X-22Z	029-37551	4396'	WD #2 1275' SW	581' outside front	+26 psi	SIUE; annulus cemented 18' below Olig top. **No significant risk.**
78-22Z	029-37554	5220'	WD #2 1270' S	576' outside front	+26 psi	SIUE; annulus cemented above Olig top. **No significant risk.**
88X-22Z	029-37557	4325'	WD #3 1080' SW	386' outside front	+25 psi	SIUE; annulus cemented above Olig top. **No significant risk.**
18-23Z	029-37559	4342'	WD #3 1500' SW	806' outside front	+24 psi	Active produer; annulus cemented above Olig top. **No significant risk.**
11X-26Z	029-37446	4306'	WD #3 1070' SW	376' outside front	+26 psi	Active produer; annulus cemented 605' below Olig top. **No significant risk.**
12-26Z	029-37447	4260'	WD #3 1160' W	466' outside front	+27 psi	P&A 9-97, annulus cement 820' below Oligl top. **No significant risk.**
13-26Z	029-37535	4266'	WD #5 1170' SW	476' outside front	+27 psi	P&A 10-96, annulus cement 132' below Oligl top. **No significant risk.**
14X-26Z	029-37536	4250'	WD #5 1100' W	406' outside front	+27 psi	P&A 8-95; annulus cement 250' below Olig top. **No significant risk.**
22-26Z	029-37449	4271'	WD #3 1815' W	1121' outside front	+25 psi	P&A 10-96, annulus cement 687' below Oligl top. No significant risk.
23-26Z	029-37537	4230'	WD #5 1800' W	1106' outside front	+25 psi	P&A 4-89; mudded hole, no cement across Olig top. **No significant risk.**
33-27Z	029-05339	4273'	WD #1 855' N	161' outside front	+28 psi	P&A 2-98; cemented across Olig & potential BFW above. **No significant risk.**
61-27Z	029-01479	4419'	WD #2 820' SW	126' outside front	+30 psi	P&A 7-63; cemented above Olig top. **No significant risk.**
81-27Z	029-01481	4306'	WD #3 800' SW	106' outside front	+27 psi	P&A 1-00; cemented above Olig top. **No significant risk.**

APPENDIX B – WELL SCHEMATICS

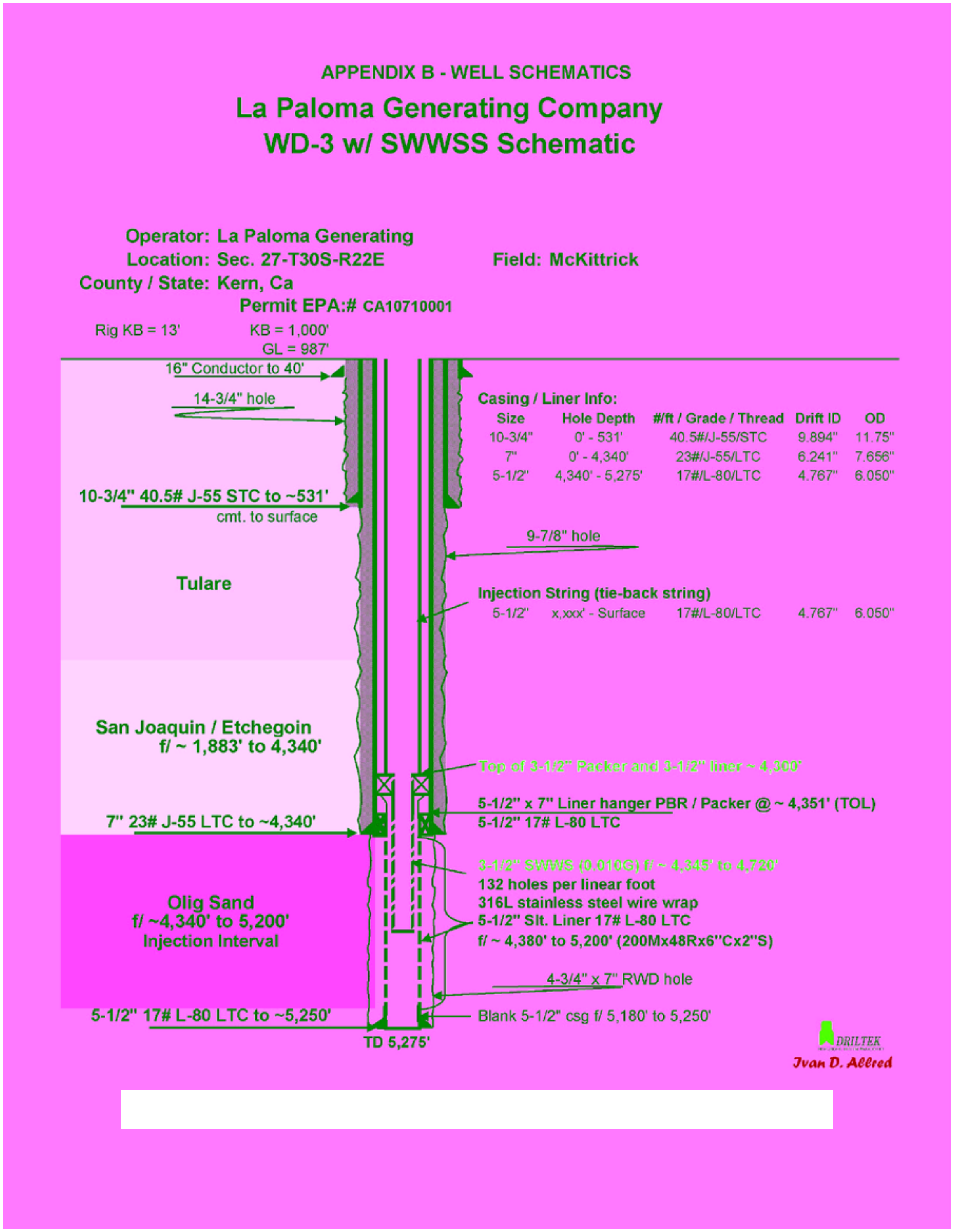

Figure 7a. Well construction schematic typical of proposed well WD-3 with single wire wrap sand screen liner.

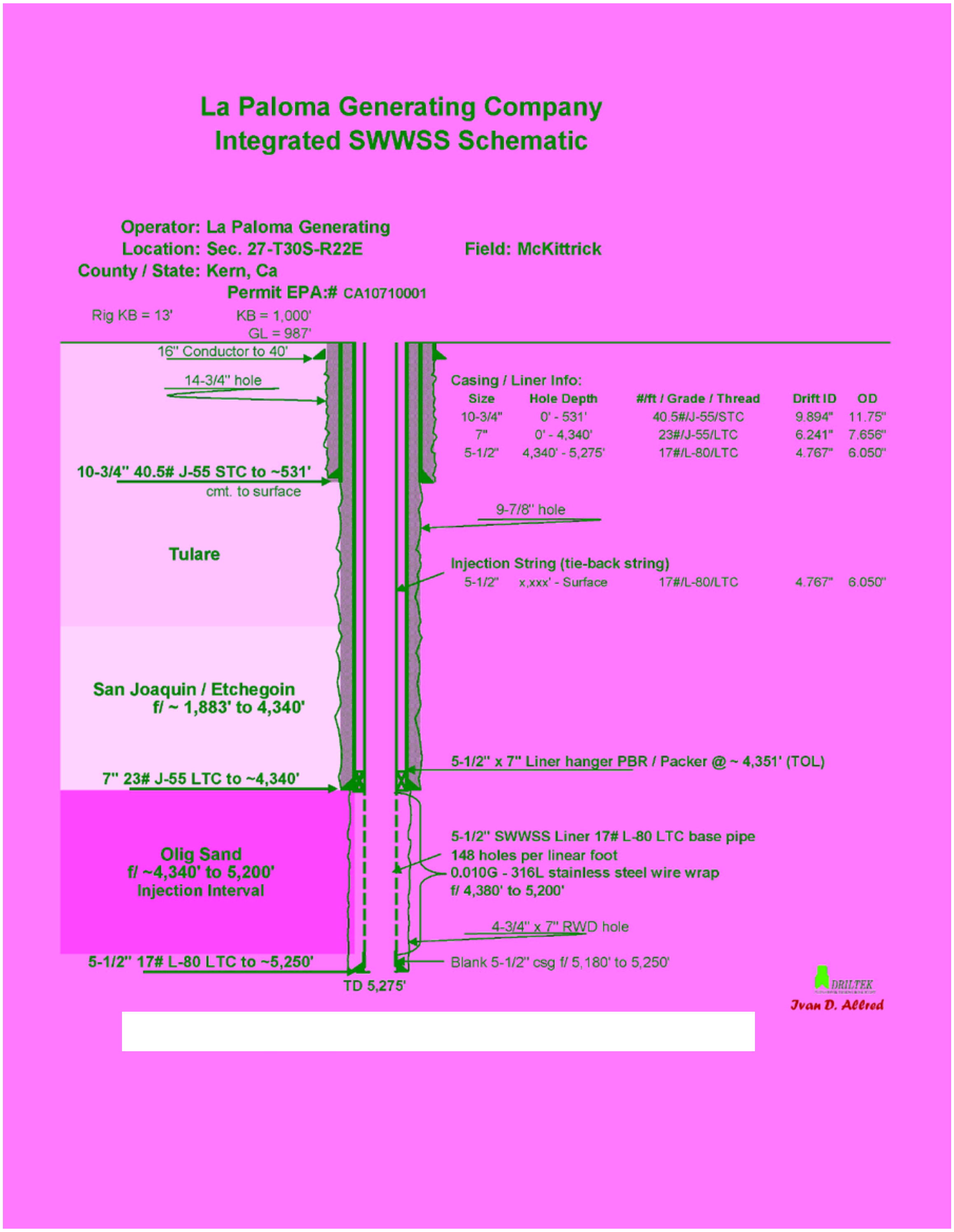

Figure 7b. Well construction schematic typical of proposed wells WD-1, WD-2, WD-4 and WD-5 with integrated single wire wrap sand screen.

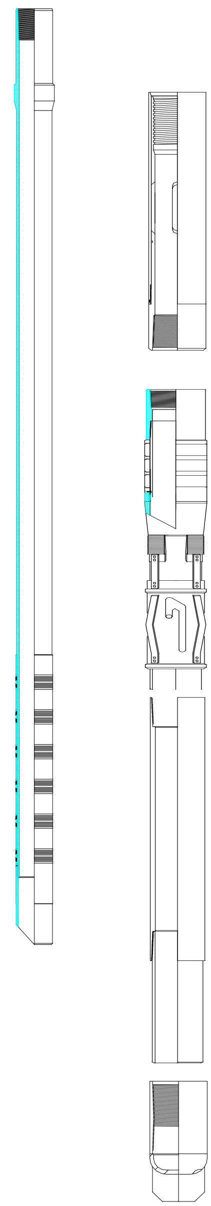

Figure 8. Bottom-hole assembly detail typical of proposed wells WD-1 – WD-5.

APPENDIX C – EPA REPORTING FORMS

(The website for downloading these forms is at: http://www.epa.gov/safewater/uic/7520s.html)

Form 7520-7:	**Application toTransfer Permit**
Form 7520-9:	**Completion of Construction**
Form 7520-10:	**Well Completion Report**
Form 7520-11:	**Annual Well Monitoring Report**
Form 7520-12:	**Well Rework Record**
Form 7520-14:	**Plugging and Abandonment Plan**

APPENDIX D – RADIOACTIVE TRACER STUDY AND TEMPERATURE LOGGING REQUIREMENTS

U.S.E.P.A. REGION IX

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid Mechanical Integrity Test ("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 12 hours for running the initial temperature log, followed by a second log, a minimum of 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 20 and 50 ft. 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 1 or 2 in. per 100 ft. 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:
      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 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 10,000 ppm Total Dissolved Solids ("TDS") and is further defined in 40 CFR §144.3.

APPENDIX E - REGION 9 UIC PRESSURE FALLOFF TEST REQUIREMENTS

For reference please refer to:

http://www.epa.gov/region09/water/groundwater/uic-docs/falloff-testing-guidlines.pdf

APPENDIX F - PLUGGING AND ABANDONMENT PLANS

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.

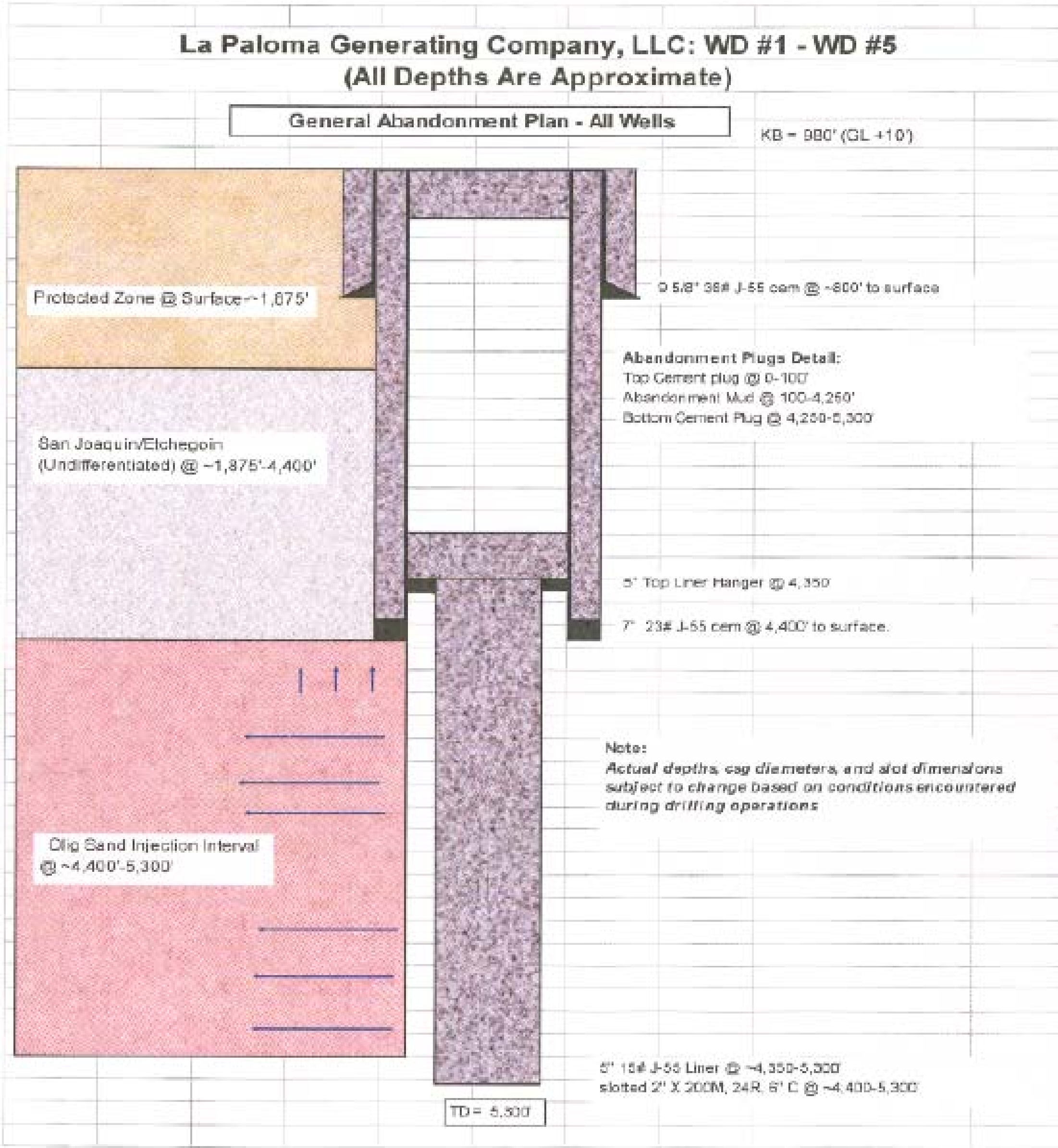

Figure 9a. Schematic of general plugging and abandonment plan for proposed wells WD-1, WD-2, WD-4 and WD-5.

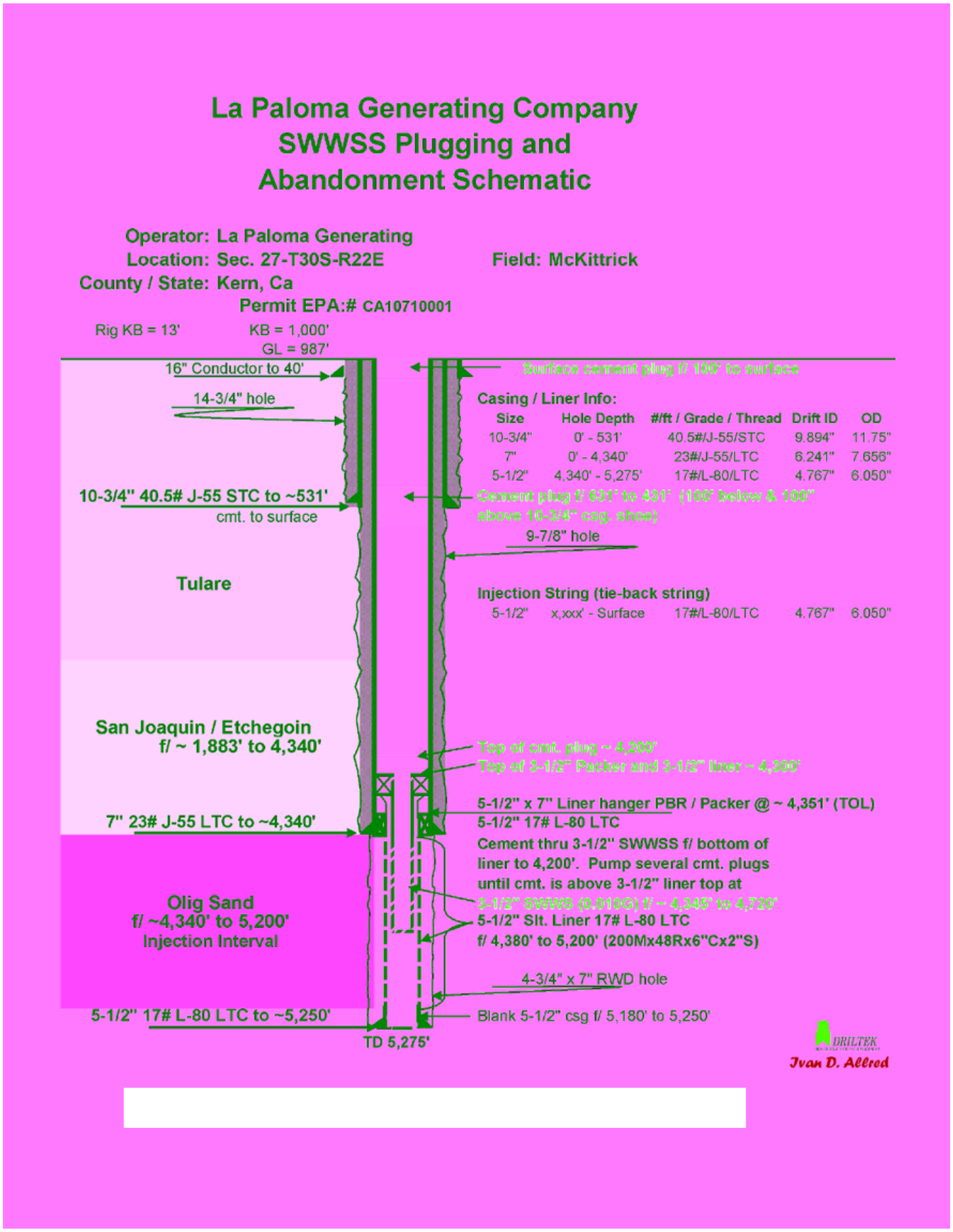

Figure 9b. Schematic of general plugging and abandonment plan for well WD-3.

Abandonment Procedure for Injection Well WD-3 with Sand Control Liner

Note: Notify DOGGR and EPA at least 60 days before scheduled abandonment.

Submit a Notice of Intention to Abandon and obtain an Abandonment Permit from DOGGR prior to prior to commencing abandonment activities.

DOGGR and EPA to approve final abandonment procedure and witness abandonment work.

Referenced depths are below Kelly bushing (KB). KB is approximately 13 feet above ground level (GL).

See Figure 9b for general plugging and abandonment schematic of well WD-3.

Casing / Liner Info:

Size (inch)	Approximate Hole Depth (feet)	#/ft / Grade / Thread	Drift ID (inch)	OD (inch)
10-3/4	0 – 531	40.5#/J-55/STC	9.894	11.75
7	0 - 4,381	23#/J-55/LTC	6.241	7.656
5-1/2	4,381 – 5,275	17#/L-80/LTC	4.767	6.050
3-1/2 SWWS	4,346 – 4,720	17#/L-80/LTC w/ 316L stainless steel wire wrap	2.998	4.000

1. MIRU workover rig, pump, portable tank and joints of 2-3/8 inch (in.) work string. Fill tank with fresh water. Remove wellhead, unland tubing (tbg), install and function test BOPE.

2. POOH and lay down 5-1/2 in. tie-back injection tubing and seal assembly. Pick up and RIH with 2-3/8 in. work string to bottom of 3-1/2 in. SWWSS. (EPA to witness cleanout tag.)

3. Circulate or bail hole clean and necessary. Pull tbg tail 10 feet (ft.) off bottom.

4. MIRU cementers. Lay as many as necessary cement plugs to plug and abandon lower liner interval from bottom of SWWSS to 4,200 ft. (to at least 100 ft. above 3-1/2 in. liner top) follows:
   a. Pump 5 barrels (bbls) fresh water pre-flush at 3 barrels per minute (BPM).
   b. Pump class “G” neat cement at 1-2 BPM.
   c. Displace cement with 16 bbls fresh water.

5. Slowly pull tbg to 4,100 ft. Reverse circulate hole clean with 100 bbls fresh water, SDFN. (ETOC @ 4,200’)
6. RIH, tag TOC (EPA to witness). If cement found below 4,200’, consult engineering and prepare to pump additional cement to bring TOC to 4,200’ continue step #6 until TOC is at or above 4,200’, (EPA to witness and approve cement tag).

7. Circulate ~140 bbls EPA-approved abandonment mud down to tbg from 4,200 ft to approximately 631 ft.

8. POOH with 2-3/8 in. workstring to 631 ft.

9. MIRU cementers. Lay a cement plug from 631 ft. to 431 ft. (100 ft. above and 100 ft. below 7 in. 23# csg.) as follows:
    a. Pump 5 bbls fresh water preflush at 3 BPM.
    b. Pump ~ 43 ft^3 (8 bbls) + of class “G” neat cement at 1-2 BPM.
    c. Displace cement with 2 bbls fresh water.
10. Slowly pull tbg to 350 ft. Reverse circulate hole clean with at least 20 bbls fresh water, SDFN. (TOC @ 421 ft.)
11. RIH, tag TOC (EPA to witness). If cement found below 421 ft, consult engineering and prepare to pump additional cement to bring TOC to 421 ft, (EPA to witness and approve cement tag).
12. Circulate ~12 bbls EPA-approved abandonment mud down to tbg from 421 ft. to 100 ft.
13. POOH to 100 ft.
14. MIRU cementers. Lay a cement plugs from 100 ft. to surface in 7 in. as follows:
    a. Pump 5 bbls fresh water preflush at 3 BPM.
    b. Pump 22 ft^3 (4 bbls) + of class “G” neat cement at 1-2 BPM.
    c. Displace cement with 2 bbls fresh water.
15. Pull tbg tail to surface (EPA to witness) cement to surface.
16. Cut and retrieve 7 in. casing head and 7 in. casing from 5 ft. below GL.
17. Remove cellar. Surface pour cement in all exposed annuli. Weld cap on well and install abandonment marker. (EPA to witness). Proper capping and marking of well.

Notes:
SWWSS – single wire wrap sand screen
BOPE – blowout preventer equipment
BPM – barrels per minute
MIRU – move in and rig up
POOH – pull out of hole
RIH – run in hole
SDFN – shut down for night
TOC – top of cement
TTOC – tag top of cement
ETOC – top of cement

APPENDIX G – 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.)