GALATI | BLEK LLP

455 Capitol Mall Suite 350
Sacramento CA 95814
Tel· 916.441.6575
Fax· 916.441.6553

DOCKET	
08-AFC-10	
DATE	OCT 19 2009
RECD	OCT 19 2009

October 19, 2009

California Energy Commission
Docket Unit
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY (“EPA”) PUBLIC NOTICE OF INTENT TO ISSUE UIC PERMIT NO. CA10910003**
DOCKET NO. (08-AFC-10)

Enclosed for filing with the California Energy Commission is the original of the **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY (“EPA”) PUBLIC NOTICE OF INTENT TO ISSUE UIC PERMIT NO. CA10910003**, for the Lodi Energy Center Docket No. (08-AFC-10).

Sincerely,

Marie Mills

Marie Mills

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

Mail Code WTR-9

October 16, 2009

Mr. Michael DeBortoli
Electrical / IT Engineer
Northern California Power Agency
651 Commerce Drive
Roseville, CA 95678-6420

Re: Public Notice of Intent to Issue
UIC Permit No. CA10910003
Northern California Power Agency
STIG-1, LEC-1, LEC-2 Class I-NH UIC Injection Wells

Dear Mr. DeBortoli:

This letter is to notify you that the public comment period for the subject permit came to a close with no comments having been submitted. Therefore, the United States Environmental Protection Agency, Region IX ("EPA") is issuing a final Class I-NH Underground Injection Control (UIC) permit in accordance with 40 CFR Part 124.15.

Prior to receiving authorization to drill any new wells permitted by the subject permit, NCPA must submit detailed drilling procedures and proposed well construction specifications for EPA approval in accordance with Part II, Section A, Paragraph 2(a) of the subject permit:

> Prior to each demonstration required in the following sections B through D, 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 E, paragraph 5. No demonstration in these sections may proceed without prior written approval from EPA.

In addition, NCPA must satisfy the requirement described in Part II, Section B, Paragraph 1(a) of the subject permit prior to receiving authorization to drill any new wells permitted by the subject permit:

> Prior to drilling any well, the Permittee must submit proposed field coordinates (Section, Township, Range, with latitude/longitude) for the surface location of that specific well; for subsequent wells, also provide the distance between all wells, along with any justification for the proposed separation distance between the wells, both at the surface and at total depth.

Once NCPA has satisfied the aforementioned and all requirements of the Permitee as outlined in the subject permit, EPA will formally issue NCPA authorization to drill. Please call either Adam Freedman at (415) 972-3845 or me at (415) 972-3971 if you have any questions regarding this letter or any other Underground Injection Control Program issue.

Sincerely,

for DA

David Albright
Manager, Ground Water Office
Date 10/16/09

Enclosure: Final UIC Permit No. CA10910003

Cc w/o enclosure:

Tim Kustic
California Division of Oil, Gas, and Geothermal Resources
District 6 Office
801 K Street, MS 20-22
Sacramento, CA 95814-3530

Diana Messina
California Regional Water Quality Control Board
District 5 Office
11020 Sun Center Drive, Suite 200
Rancho Cordova, CA 95670

U.S. EPA Underground Injection Control Program

FINAL PERMIT

Class I Nonhazardous Waste Injection Wells

Permit No. CA 10910003

Well Names: STIG-1, LEC-1, LEC-2

Lodi, California

Issued to:

Northern California Power Agency
Steam Injected Gas Turbine (STIG) Project #2 & Lodi Energy Center (LEC)
12745 North Thornton Road
Lodi, CA 95242-1478

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,

Northern California Power Agency
STIG Combustion Turbine Project #2 & Lodi Energy Center
12751 North Thornton Road
Lodi, CA 95242-1478

is hereby authorized, contingent upon Permit conditions, to construct and operate a Class I nonhazardous waste injection well facility consisting of two (2) new injection wells, known as the LEC-1 and LEC-2 wells, and one (1) existing well, known as the STIG-1 well, for a maximum of three (3) injection wells. Until this permit is signed, STIG-1 will continue to operate under the authority of the original permit, CA194000002. All three wells are to be located in Section 24, Township 3N, Range 5E, on Northern California Power Agency facilities in San Joaquin County. Exact locations of each new well will be established and approved as outlined in this permit.

Authorization to drill and construct the new wells will be issued by EPA after the requirements of Financial Responsibility in Part II, Section G of this permit have been met. EPA will grant authorization to inject in the new wells 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 Domengine Sand Formation for the purpose of disposal of process wastewater from gas turbine power plants at Northern California Power Agency facilities upon the express condition that the Permittee meet the restrictions set forth herein. The process water supply is treated wastewater from the White Slough Water Pollution Control Facility.

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 **twenty-nine (29)** pages plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by Northern California Power Agency 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 16 October 2009.

Alexis Strauss 16 October 2009
Alexis Strauss, 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 U.S. Environmental Protection Agency Region IX Ground Water Office ("EPA") for discussion and 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 demonstration workplan, in order to allow EPA to arrange to witness if so elected.

(c) The Permittee shall submit results of each demonstration required in this section to EPA within sixty (60) days of completion.

California Division of Oil, Gas, and Geothermal Resources ("CDOGGR") reporting forms (such as a Well Summary Report) may be acceptable provided all information specified by this permit is included.

B. WELL CONSTRUCTION

1. Locations of Injection Wells STIG-1, LEC-1, and LEC-2

Injection wells, LEC-1 and LEC-2, authorized under this permit, will be located at the STIG-LEC facility on 12751 North Thornton Road, in Lodi, California (See Appendix A, Figure 1). The STIG-1 well already exists on site (See Appendix A, Figure B). The proposed general location for the two new wells is found in Appendix A, Figure 3.

(a) Prior to drilling any well, the Permittee must submit proposed field coordinates (Section, Township, Range, with latitude/longitude) for the surface location of that specific well; for subsequent wells, also provide the distance between all wells, along with any justification for the proposed separation distance between the wells, both at the surface and at total depth.

(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 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.

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. Permittee shall conduct Formation Evaluation wireline logging operations and shall provide and use those results to estimate and report values for hydrocarbon saturation, porosity, lithology, rock mechanical properties for both the injection and confining zones identified within the permitted geological sequence.

Before surface, intermediate, and long string casings are set, dual induction/spontaneous potential/gamma ray/caliper (DIL/SP/GR/CAL) logs 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 is completed, a spherically focused cement bond evaluation log (CBL) will be run over the course of the entire cased hole sequence (See Section D.2(a)(iv) of this part).

3. 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. 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.

(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 ("USDW," as defined in 40 CFR §144).

(i) 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 new injection well (LEC-1 or LEC-2) upon its completion. Field measurements of pH, electrical conductance, and temperature will be carried out to confirm that representative Domengine Sand Formation 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 I).

(b) Step-Rate Test ("SRT")

A SRT will be conducted on at least one representative well (STIG-1, LEC-1 or LEC-2) 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 and rate limitations, in accordance with section D, paragraphs 3 and 4 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 thirty (30) days notice before the SRT is conducted.

(i) Injection as proposed in an approved SRT procedure is temporarily authorized while the SRT is completed.

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

(iii) Measure pressures with a down-hole pressure bomb or other approved pressure monitoring system and synchronize the data with 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 (vi) below.

(iv) 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.

(v) Record at least three (3) time steps (data points on pressure vs. flow plot) before reaching the anticipated fracture pressure. Use one (1) barrel per minute rate increments in the early test stages. Larger rate increments may be used later in the test, but justification for this request must be approved.

(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.

(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 after a radial flow regime has been established at an injection rate which is representative of the expected contribution to that well from the facility's total wastewater generation. 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 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 SRT is conducted.

(i) Annually, the FOT test shall be repeated at an interval of not less than nine (9) months nor greater than fifteen (15) months from the previous test. The results of the test shall be included with the quarterly report due each January, as described in Section E paragraph 5 of this part.

(ii) 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 in paragraph (i) above.

(d) Particulate Filters may be used upstream of the well, at the discretion of the operator, 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.

4. Drilling, Work-over, and Plugging Procedures

Drilling, work-over, and plugging procedures must comply with the 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 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; and

(e) Details and justification for any open hole gravel packing.

Procedures provided on reporting forms such as CDOGGR's Well Summary Report may be 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. Casings shall be maintained throughout the operating life of the wells. See Appendix B, Figure 1, for the approximate construction specifications pertaining to the two proposed injection wells LEC-1 and LEC-2. See Appendix B, Figure 2 for the exact specifications of well STIG-1 as built.

EPA may require minor alterations to the construction requirements for wells LEC-1 and LEC-2 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.

Final depths will be determined by the field conditions, sieve analysis, well logs, and other input from the drilling consultant and geologists. EPA approval will be obtained for any revisions prior to installation and these will be documented in the well completion report (See paragraph 9(a) below).

6. Injection Intervals

Injection for wells STIG-1, LEC-1 and LEC-2 shall be permitted for the lower sand member of the Domengine Formation at depths between approximately 4,234 feet bgs and 4,507 feet bgs. The entire injection unit is 831 feet thick at STIG-1, extending from 3,747 feet bgs to 4,578 feet bgs (the unit is not less than 780 feet within the Area of Review). The exact depths of injection zone intervals and casing setting depths are expected to be realized upon drilling. 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). The Permittee must demonstrate that each well has mechanical integrity, in accordance with Section D paragraphs 1(a) and 2 of this part, before any 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 upper confining layer, the Nortonville Shale, is a dark gray marine shale and siltstone. It ranges in thickness from 100 to 200 feet within the Area of Review, with a thickness of 117 feet at the STIG-1 well. The Nortonville Shale confining layer is located between approximately 3,610 and 3,727 feet bgs.

The lower confining layer, the Capay Shale Formation, is a marine shale to silty shale with occasional sand stringers. The estimated thickness of the Capay confining layer is approximately 150 feet, from 4,578 to 4,728 feet bgs.

Field information on the Nortonville Shale formation at the LEC-1 and LEC-2 sites, such as its 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 9(a) 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 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:

(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, and other results, with a schematic diagram and detailed description of construction, including driller's log, materials used (i.e., tubing tally), and cement (and other) volumes, to EPA within sixty (60) days after completion of either of the Injection Wells LEC-1 or LEC-2.

(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.

10. 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 D paragraphs 1(a) and 2 of this part.

C. CORRECTIVE ACTION

Corrective action to 40 CFR §§144.55 and 146.7 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.

No corrective action plan is currently required as all wells within the Area of Review were plugged and abandoned in accordance with CDOGGR review and oversight. See Appendix

A, Figures 4-5, and Appendix B, Figure 3 (excerpted from Attachments B and C to the Permit Application).

1. 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 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 quarterly report due in January, as required in Section E paragraph 5 of this part.

2. 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.

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 stream 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) Operation of the injection facility is temporarily granted for the two (2) weeks following initial operations to allow for sample analyses to be performed and for the results to be submitted to EPA.

(ii) The Permittee will be required to submit a letter to EPA confirming that the "Hazardous Waste Determination" was carried out according to 40 CFR §261 within sixty (60) days of its having been completed.

(iii) 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/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 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 quarterly report to

EPA per Section E paragraph 5 of this part unless more detailed records are requested by EPA.

(iii) Injection profile survey (external MIT)

In conjunction with the annual 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 casing is installed, after conducting a cement squeeze job in an open hole, or after any well cement repair, 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, run after the long-string casing is set and cemented, 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 or recommence injection until it has received written notice from EPA that such a demonstration is satisfactory.

(b) Subsequent MITs

EPA may require that an MIT be conducted at any time during the permitted life of the well. 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 when any loss of mechanical integrity becomes evident during operation, an internal pressure MIT shall be conducted on each injection well authorized under this permit.

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

(iii) At least once every five (5) years during the life of the well, an internal pressure MIT shall be conducted on each injection well authorized under this permit 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 of this part.

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)(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 for wells STIG-1, LEC-1 and LEC-2 shall be based on the Step-Rate Test 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, along with a minor modification of the permit under 40 CFR §144.41(e).

(b) Permittee may continue injection into well STIG-1 at a Maximum Available Injection Pressure (MAIP) at the wellhead of 975 psi, as established while injecting under the authority of the original permit (#CA194000002), only until re-establishing the MAIP for the well by conducting a Step-Rate Test in accordance with 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.

4. Injection Volume (Rate) Limitation

(a) The injection rate for wells LEC-1 and LEC-2 shall not exceed the volume determined 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 conducted after an approved SRT (see Section B.3(b)).

(b) Permittee may continue injection into well STIG-1 at a maximum injection rate of 200 gallons per minute (gpm), as established while injecting under the authority of the original permit (#CA194000002), only until re-establishing the maximum injection rate for the well by conducting a Step-Rate Test in accordance with Section B paragraph 3(b) of this part.

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

(d) 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

Injection fluids in well STIG-1 consist of tertiary-treated makeup water from the City of Lodi's White Slough Water Pollution Control Facility ("WPCF"), brine reject from the ultrafiltration units, brine from the reverse osmosis units, and blowdown from the cooling towers. The remaining fluids consist of both continuous and intermittent blowdowns from the Heat Recovery Boilers.

Injection fluids in wells LEC-1 and LEC-2 will consist of tertiary-treated makeup water from WPCF, other recovered process wastewater that has been concentrated by evaporative losses in the cooling tower, as well as the chemicals added to the circulating water that are used to control scaling and biofouling of the cooling tower and to control corrosion of the circulating water piping and intercooler.

All fluids from WPCF that are injected using STIG-1, LEC-1 and LEC-2 will be used in the power generation processes/sytems identified in this section prior to injection.

In addition,

(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 Northern California Power Agency and White Slough Water Pollution Control facilities. No fluids shall be accepted from other sources.

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

5. 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 quarter of injection operations, the Permittee shall determine the range of fluctuation of annular pressure for the well during periods of normal operation. This normal pressure range shall be submitted with the first quarterly report after injection has commenced. Any annular pressure outside of the normal range shall be considered a loss of mechanical integrity and shall be reported per Paragraph 2(c) of this section.

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program

Injection fluids from different sources and/or of different composition will be analyzed to yield representative data on their physical, chemical, or 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 Constitutents – 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.

alkalinity

(iii) General and Physical Parameters – appropriate USEPA methods for Temperature, Turbidity, pH, Conductivity, Hardness, Specific Gravity, Alkilinity, 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 - USEPA Method 8270.

(b) Analysis of injection fluids.

Quarterly, or whenever there is a significant 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

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. 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:

Monitoring Parameter	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 (degrees Fahrenheit)	Hourly	digital recorder

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

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

Each data line shall include four (4) values separated by a consistent combination of spaces or tabs. The first value contains the date measurement in the format of mm/dd/yy or mm/dd/yyyy , where mm is the number of the month, dd is the number of the day and yy or yyyy is the number of the year. The second value is the time measurement, in the format of hh:mm:ss, where hh is the hour, mm are the minutes and ss are the seconds. Hours should be calculated on a 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 psi. The fourth column is injection rate in gallons per minute.

(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 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;

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

(c) Results of the injectate "Hazardous Waste Determination" according to 40 CFR §262.11. Analyses 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 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 submit accurate reports to EPA containing, at minimum, the following information:

(a) 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) 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 2(a) of this section, unless more detailed records are requested by EPA;

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

(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.

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

(e) 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 B, paragraph 3(c) of this part;

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

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

(v) Annual ZEI recalculation for each well as required in Section B paragraph 3(c) of this part.

(f) To be included in the next quarterly report due in January after completion every five years, an internal MIT as required in Section D.2(a)(i) of this part.

(g) 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:

California Division of Oil, Gas, and Geothermal Resources
District 6 Office
Attn: Tim Kustic
801 K Street, MS 20-22
Sacramento, CA 95814-3530

California Regional Water Quality Control Board
District 5 Office
Attn: Diana Messina
11020 Sun Center Drive, Suite 200
Rancho Cordova, CA 95670

F. 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 CDOGGR 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 or if the well is not consistent with EPA requirements for construction or mechanical integrity. EPA may require the Permittee 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 approved Plugging and Abandonment Plans, or

(b) Where actual plugging differed from the Plugging and Abandonment Plans, a statement specifying 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 maintain a bond rating within the four highest categories of Standard and Poor's (AAA, AA, A, or BBB), Moody's (Aaa, Aa, A, or Baa) or Fitch (AAA, AA, A, or BBB). If the most recent bond rating does not fall within the four highest categories, the the Permitee 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 $314,400 per well, to guarantee closure.

(b) The financial responsibility mechanism and amount 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) The Permitee must provide proof to EPA of its bond rating or renewal every year by March 31.

1. 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 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).

2. 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 up to ten (10) years unless terminated under the conditions set forth in Part II, 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) into underground sources of drinking water (as defined 40 CFR §§144.3, 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 production wells.

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 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. <u>Penalties for Violations of Permit Conditions</u> - 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. <u>Need to Halt or Reduce Activity Not a Defense</u> - 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. <u>Duty to Mitigate</u> - The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this permit.

5. <u>Proper Operation and Maintenance</u> - 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. <u>Property·Rights</u> - This permit does not convey any property rights of any sort, or any exclusive privilege.

7. <u>Duty to Provide Information</u> - 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. <u>Inspection and Entry</u> - 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. 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 noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water; and

(ii) A written submission of all noncompliance as described in paragraph (c)(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(c) 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 Maps

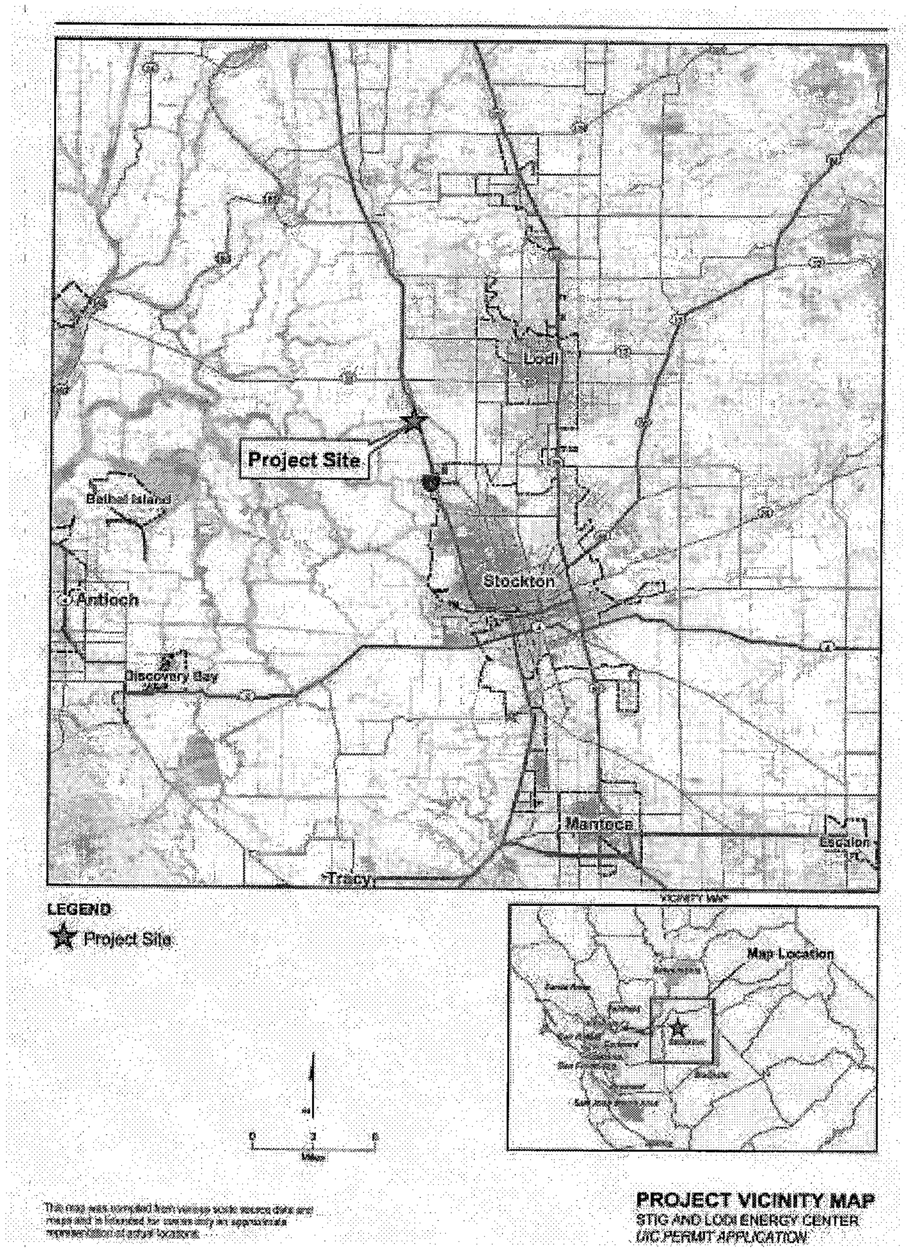

Figure 1. Project vicinity map of the STIG and Lodi Energy Center (from the Introduction to the Permit Application)

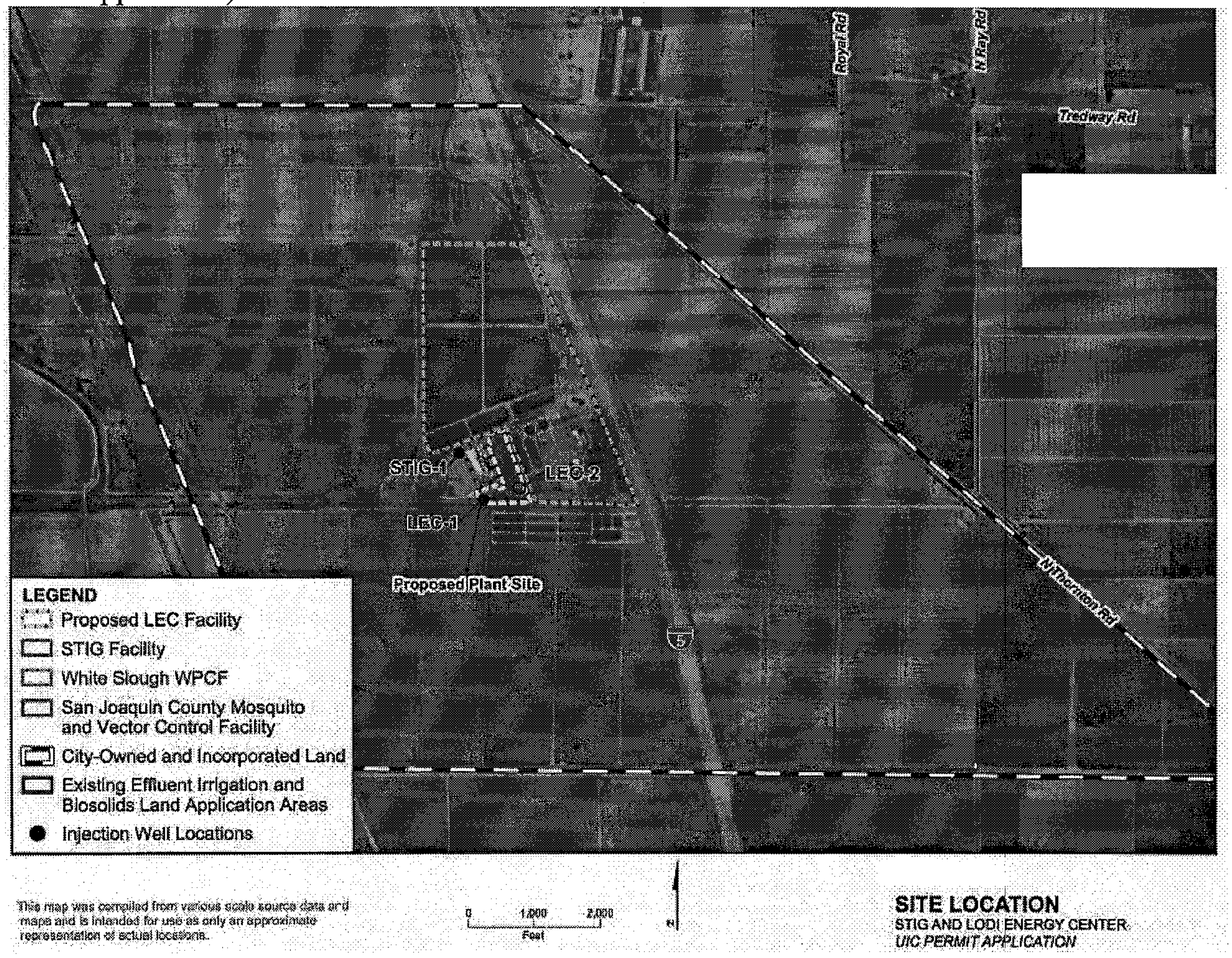

Figure 2. Site location of the STIG and Lodi Energy Center, showing the site of the proposed power plant, well STIG-1, and the proposed locations of wells LEC-1 and LEC-2 (from the Introduction to the Permit Application).

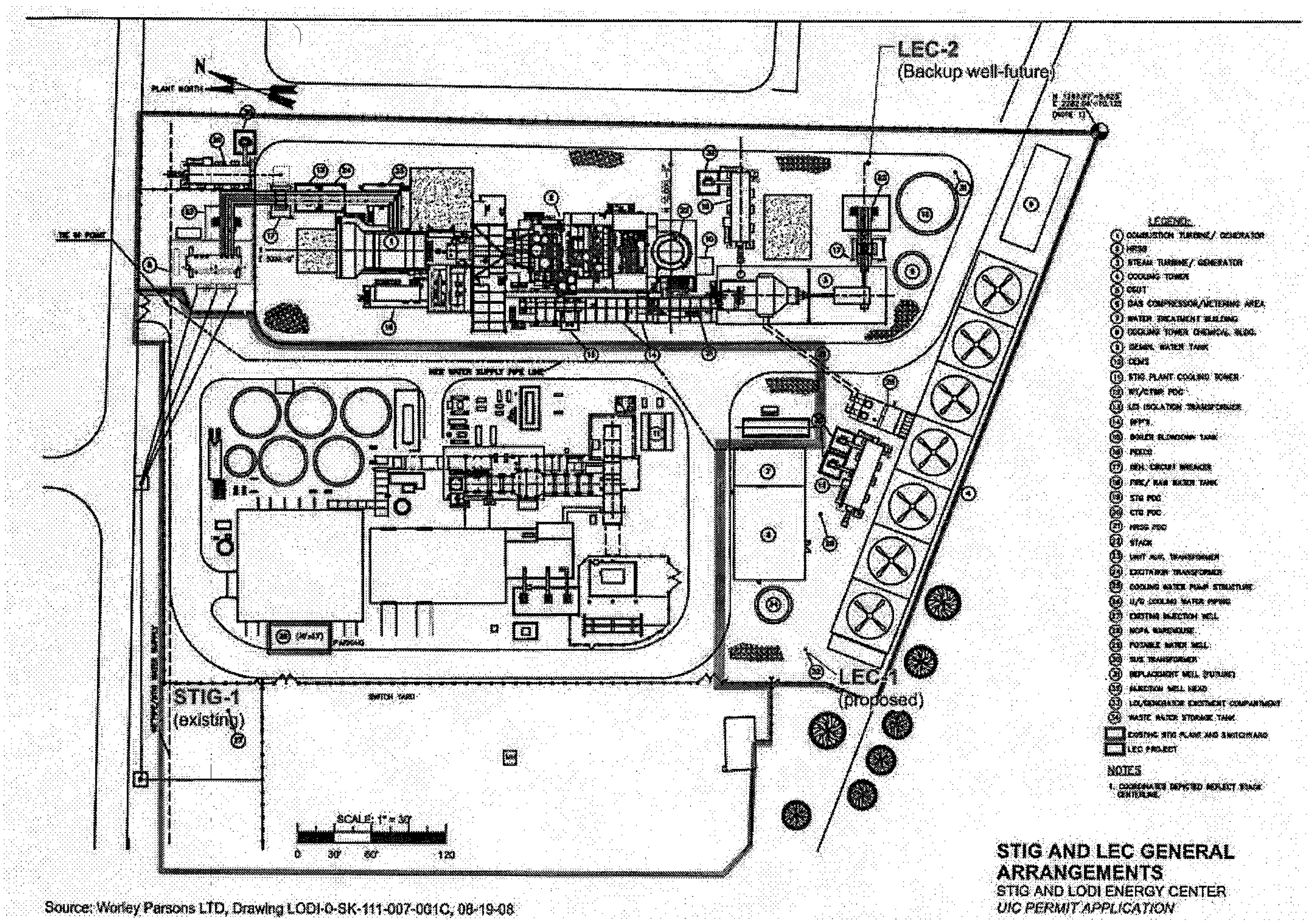

Figure 3. STIG and Lodi Energy Center general arrangements, showing the site of currently existing well STIG-1, and the proposed locations for wells LEC-1 and LEC-2 (from the Introduction to the Permit Application).

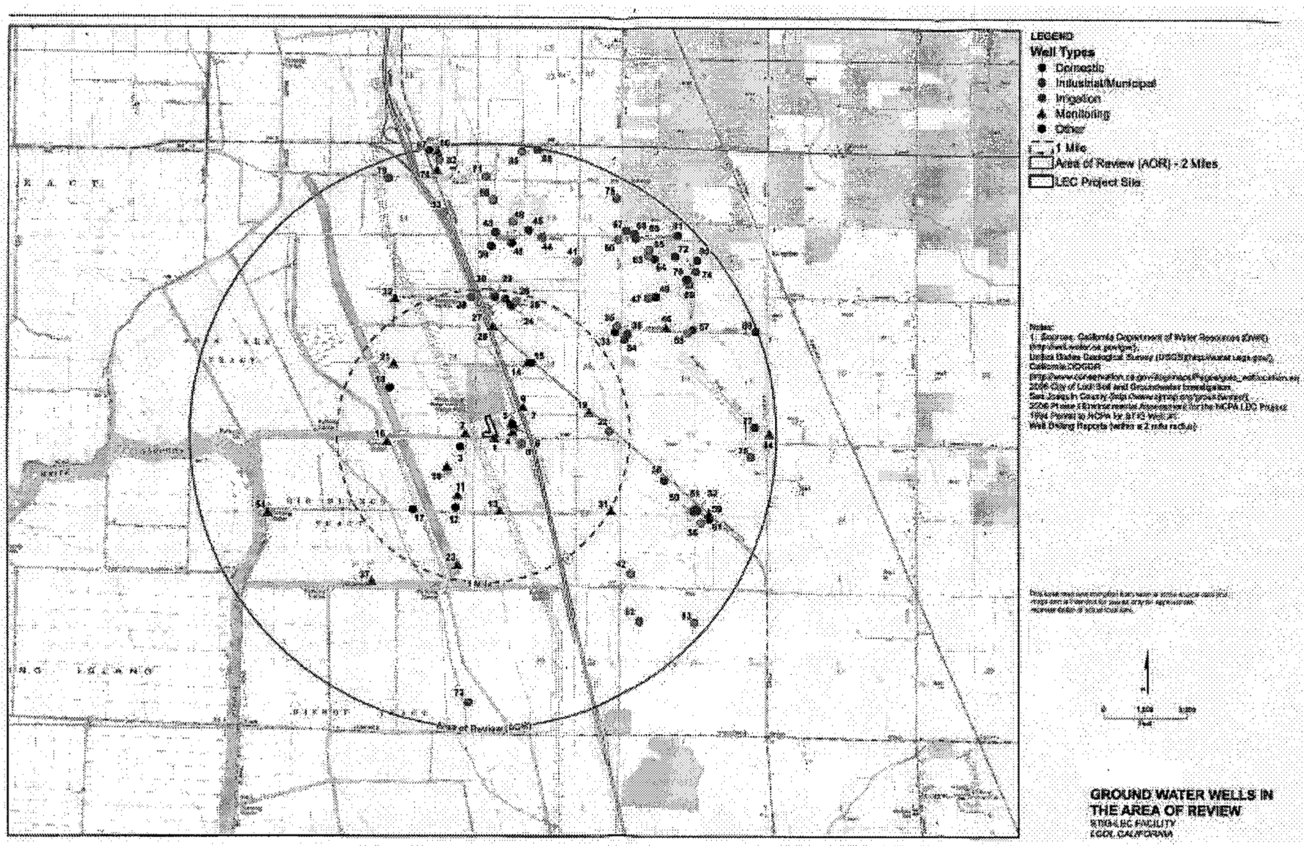

Figure 4. Map showing ground water wells within the two-mile Area of Review (from Attachment B of the Permit Application).

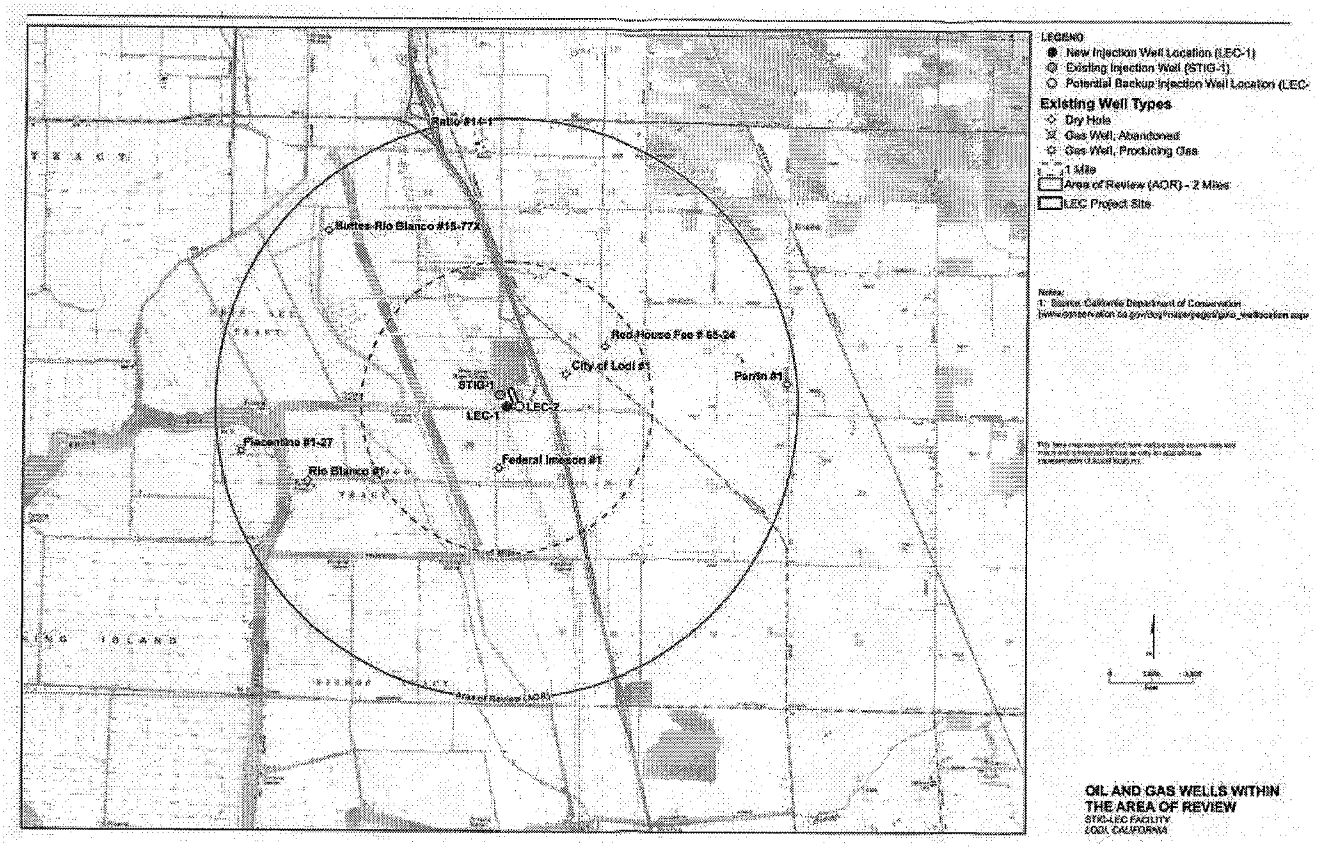

Figure 5. Map showing oil and gas wells within the two-mile Area of Review (from Attachment B of the Permit Application).

APPENDIX B – Well Schematics

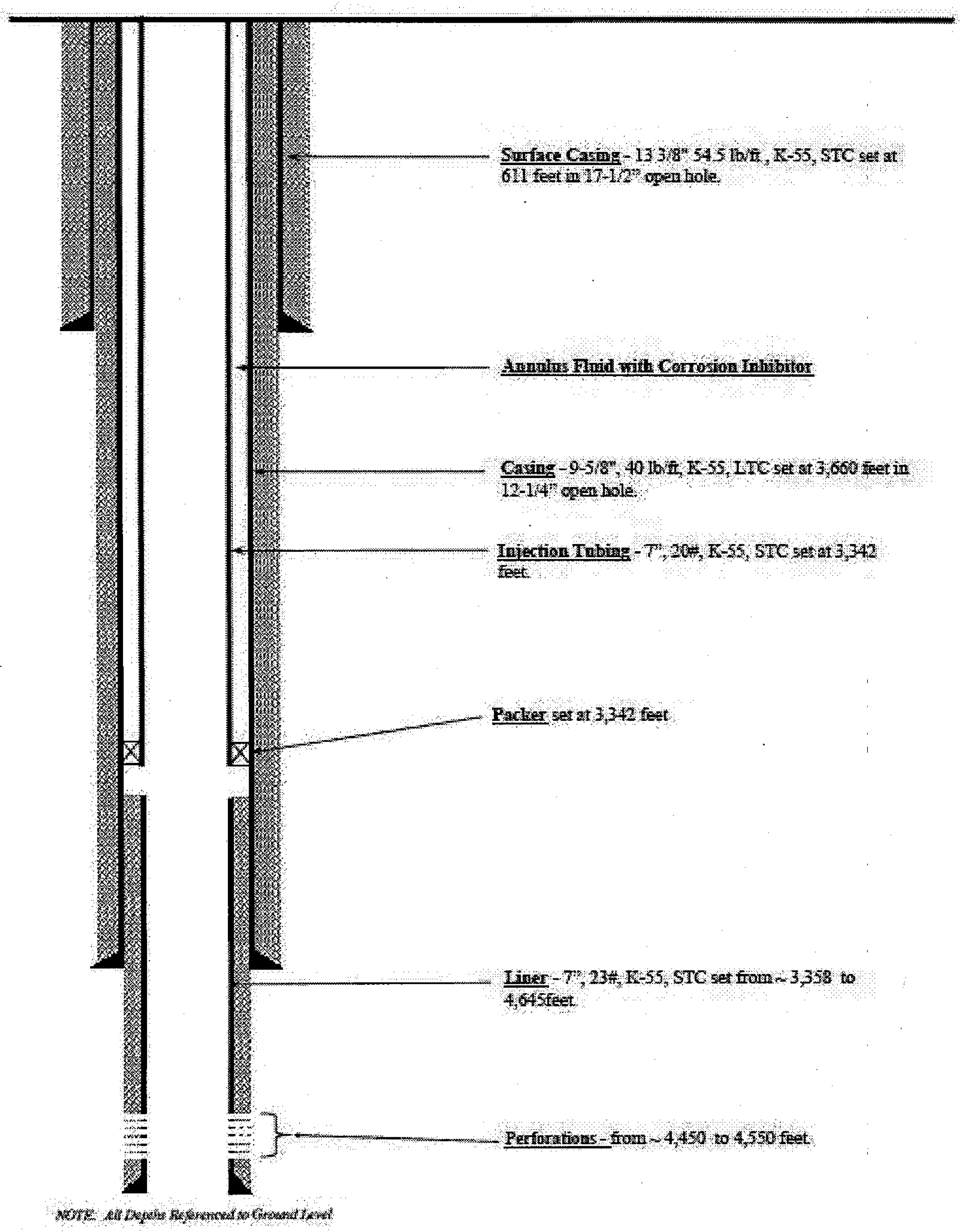

Figure 1. Proposed constuction specifications for wells LEC-1 and LEC-2.

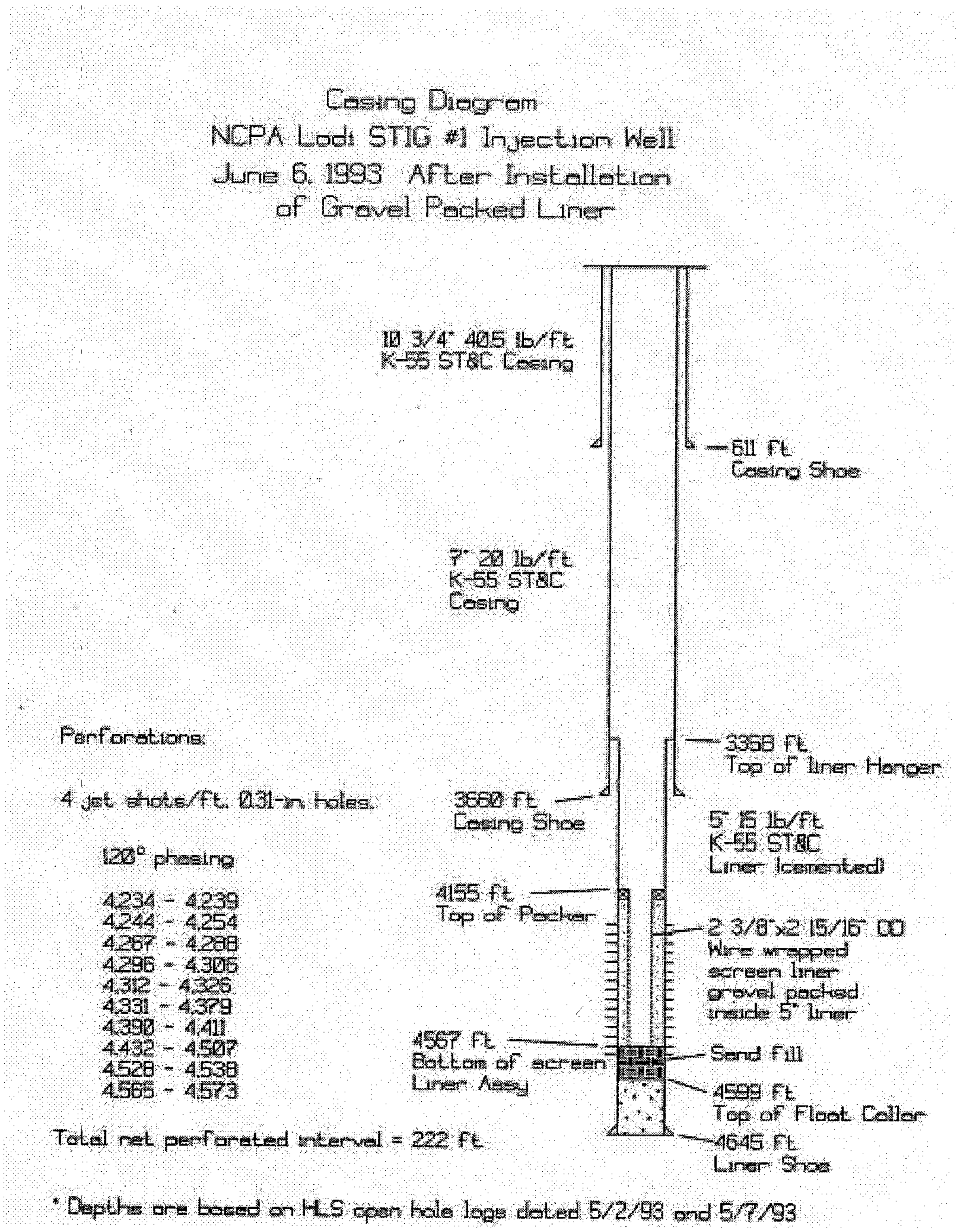

Figure 2. As-built constuction specifications for well STIG-1 (from Appendix 10 of the Permit Application).

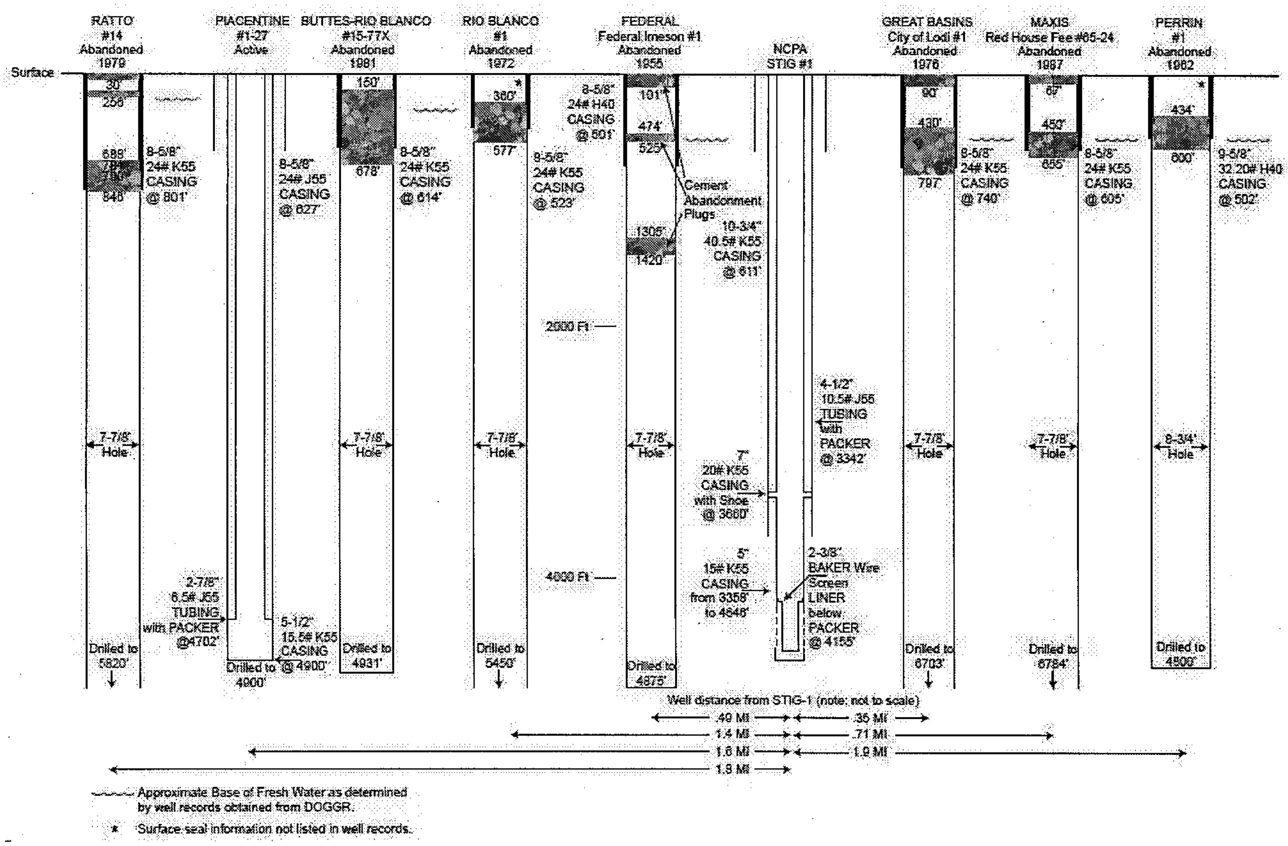

Figure 3. Wellbore schematics of the active and abandoned exploratory gas wells in the Area of Review.

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 7520-12: **Well Rework Record**

Form 7520-14: **Plugging and Abandonment Plan**

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 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 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.

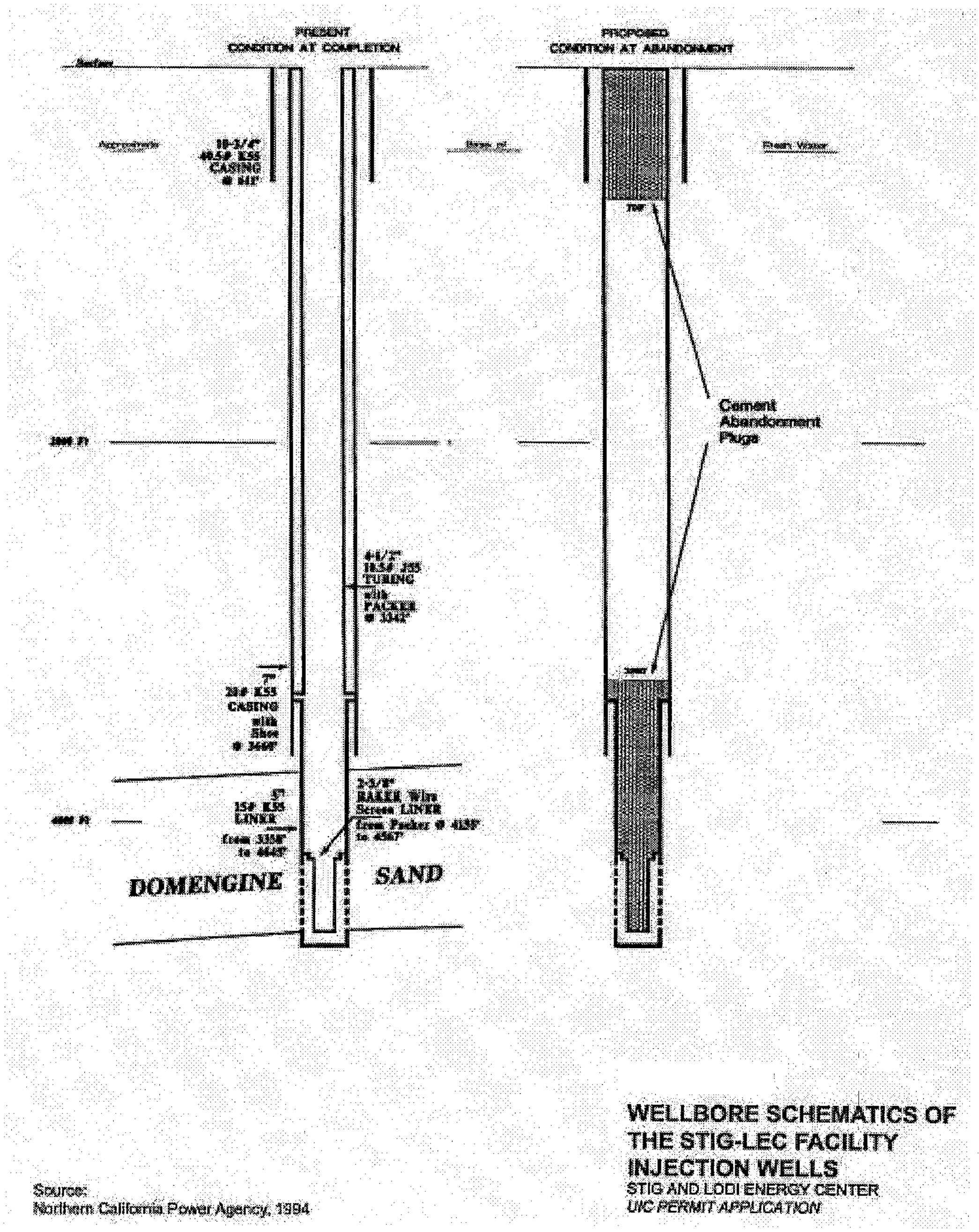

Figure 1. General Plugging and Abandonment plan schematics for wells STIG-1, LEC-1 and LEC-2 (from Attachment Q of the Permit Application).

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.)

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228- WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION
FOR THE *Lodi Energy Center*

Docket No. 08-AFC-10

PROOF OF SERVICE
(Revised 2/17/09)

APPLICANT

Ken Speer
Assistant General Manager
Northern California
Power Agency
651 Commerce Drive
Roseville, CA 95678
ken.speer@ncpagen.com

Ed Warner
Project Manager
Northern California
Power Agency
P.O. Box 1478
Lodi, CA 95241
ed.warner@ncpagen.com

APPLICANT'S COUNSEL

Scott Galati
Galati Blek
455 Capitol Avenue, Ste. 350
Sacramento, CA 95814
sgalati@gb-llp.com

APPLICANT'S CONSULTANT

Andrea Grenier
Grenier & Associates, Inc.
1420 E. Roseville Pkwy,
Ste. 140-377
Roseville, CA 95661
andrea@agrenier.com

Sarah Madams
CH2MHILL
2485 Natomas Park Drive,
Ste. 600
Sacramento, CA 95833
smadams@ch2m.com

APPLICANT'S ENGINEER

Steven Blue
Project Manager
Worley Parsons
2330 E. Bidwell, Ste. 150
Folsom, CA 95630
Steven.Blue@WorleyParsons.com

INTERESTED AGENCIES

California ISO
e-recipient@caiso.com

INTERVENORS

ENERGY COMMISSION

KAREN DOUGLAS
Chairman and Presiding
Member
kldougla@energy.state.ca.us

JEFFREY D. BYRON
Commissioner and Associate
Member
jbyron@energy.state.ca.us

Kenneth Celli
Hearing Officer
kcelli@energy.state.ca.us

Rod Jones
Project Manager
rjones@energy.state.ca.us

Melanie Moultry
Staff Counsel
MMoultry@energy.state.ca.us

Public Adviser
publicadviser@energy.state.ca.us

<u>DECLARATION OF SERVICE</u>

I, Marie Mills, declare that on October 19, 2009, I served and filed copies of the attached UNITED STATES ENVIRONMENTAL PROTECTION AGENCY ("EPA") PUBLIC NOTICE OF INTENT TO ISSUE UIC PERMIT NO. CA10910003 dated October 16, 2009. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: [www.energy.ca.gov/sitingcases/lodi]. The document has been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:

(*Check all that Apply*)

For service to all other parties:

__X__ sent electronically to all email addresses on the Proof of Service list;

__X__ by personal delivery or by depositing in the United States mail at <u>Sacramento, California</u> with first-class postage thereon fully prepaid and addressed as provided on the Proof of Service list above to those addresses NOT marked "email preferred."

AND

For filing with the Energy Commission:

__X__ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (*preferred method*);

OR

____ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 08-AFC-10
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

I declare under penalty of perjury that the foregoing is true and correct.

Marie Mills

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