

U.S. EPA Underground Injection Control Program

**FINAL PERMIT**

Class I Nonhazardous Waste Injection Well

Permit No. CA10910002

(Renewal of CA192000001)

Well Name:

Sousa-1

San Joaquin County, CA

Issued to:

Kruger Foods, Inc. (Owner)  
18632 East Highway 4  
Stockton, CA 95215

and

S.M.S. Briners (Operator)  
17750 East Highway 4  
Stockton, CA 95215

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**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,

Kruger Foods, Inc. (Owner)  
18632 East Highway 4  
Stockton, CA 95215

and

S.M.S. Briners (Operator)  
17750 East Highway 4  
Stockton, CA 95215

is hereby authorized to, contingent upon Permit conditions, operate a Class I nonhazardous waste injection facility with one (1) existing well, known as Sousa-1. Until this permit is signed, Sousa-1 will continue to operate under the authority of the original permit, CA192000001. Sousa-1 is located in Section 22, Township 1N, Range 8E, at the S.M.S. Briners facility in San Joaquin County, California.

Authorization to continue injection operations using Sousa-1 will be issued by EPA after the requirements of Financial Responsibility in Part II, Section G and operational requirements of Part II Sections B-D of this permit have been met. Operation of the well will be limited to maximum volume and pressure as stated in this permit. Total amounts must not exceed specified limits.

If approved, injection for well Sousa-1 will continue to be authorized into the Lower Starkey formation for the purpose of brine disposal upon the express condition that the Permittee meet the restrictions set forth herein. All fluids to be injected consist of a joint waste stream from Kruger Foods, Inc. and S.M.S. Briners.

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-seven (27) pages plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by S.M.S. Briners (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 re-authorization to 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 and becomes effective on 4/12/10.

\_\_\_\_\_/signed/\_\_\_\_\_  
Alexis Strauss, Director, March 16, 2010  
Water Division, EPA Region IX

## PART II. SPECIFIC PERMIT CONDITIONS

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

#### 1. Financial Assurance

The Permittee shall supply evidence of financial assurance in accordance with Section G of this part prior to commencing injection well operation under the authority of this permit.

#### 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 Resource’s (“CDOGGR”) reporting forms (such as a Well Summary Report) may be acceptable provided all information specified by this permit is included.

### B. WELL SPECIFICATIONS

#### 1. Location of Injection Well

The injection well authorized under this permit, Sousa-1, is located on S.M.S. Briners property at 17750 East Highway 4 in Stockton, California. The exact location for the existing well is found in Appendix A.

#### 2. Injection Formation Testing and Operations

- (a) The Permittee shall submit a detailed Prognosis for each drilling or workover operation for EPA review and approval before the work will be allowed to be scheduled and conducted.

(b) Step-Rate Test (“SRT”)

A SRT will be conducted on well Sousa-1 before injection may recommence under the authority of this permit. Refer to Society of Petroleum Engineering (“SPE”) paper #16798 for test design and analysis. The SRT will be used to establish maximum 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 well Sousa-1 after a radial flow regime has been established at an injection

rate which is representative of the expected contribution to that well from the facilities' 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) The FOT shall be repeated annually according to the schedule established during the tenure of the original permit (UIC Permit #CA192000001). Results shall be included with the quarterly report due each January, as described in Section E paragraph 5 of this part. The annual FOT should not be less than 9 months or greater than 15 months from the previous test.

(ii) The latest static reservoir pressure and its cumulative behavior 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 may be used upstream of the well, at the discretion of the operator, to prevent formation plugging or damage from particulate matter. For any particulate filters used, follow appropriate waste analysis and disposal practices.

### 3. Workover and Plugging Procedures

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.

CDOGGR reporting forms such as Well Summary Report, etc. may be accepted provided they contain all information as required within this permit. Otherwise, Permittee must complete and submit Form 7520-14 (provided in Appendix C) after plugging operations are completed.

### 4. Casing and Cementing Specifications

Notwithstanding any other provisions of this permit, the Permittee shall have cased and cemented the well to prevent the movement of fluids into or between Underground Sources of Drinking Water ("USDW," as defined in 40 CFR §144.3).

- (a) The following specifications from the permit renewal application apply to injection well Sousa-1 (see Appendix B for the Wellbore Schematic):
- (i) Surface Casing: 9-5/8 inch O.D., K-55 steel, 36 pounds per foot (ppf). 13-3/4 inch borehole cemented from 1,424 feet below ground surface (bgs) to surface.
  - (ii) Long-String Casing: 5-1/2 inch O.D., J-55 steel, 17 ppf. 8-3/4 inch borehole cemented from 5,468 feet bgs to surface. Perforations exist between 3,332 and 3,378 feet bgs.
- (b) 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 well.
- (c) A casing inspection log (CIL) to 3,306' bgs (below the packer) was completed prior to permit reissuance. Subsequent CILs will be conducted at a frequency dependent upon the results of the most recent log in accordance with the following guidelines with respect to casing thickness above the tubing-packer setting depth (see Appendix G for Casing Inspection Log Guidance), or when otherwise requested by EPA:
- (i) If metal loss of nominal casing thickness is greater than 70%, Permittee shall repair the casing or plug and abandon the well. After the casing is repaired, Permittee shall verify the integrity of the casing by conducting an MIT and an additional CIL subject to EPA approval prior to recommencing injection in the repaired well. The required MIT consists of a casing pressure test at maximum operating pressure.
  - (ii) If metal loss of nominal casing thickness is between 40 and 70%, Permittee shall conduct an MIT as described in the previous paragraph and shall monitor casing loss by conducting additional CILs every three (3) years.
  - (iii) If the metal loss of nominal casing thickness is between 20 and 40%, Permittee shall monitor casing loss by conducting additional CILs every 5 years.
  - (iv) If the metal loss of nominal casing thickness is 20% or less, Permittee may continue normal injection operations.

## 6. Tubing and Packer Specifications

The tubing and packer for well Sousa-1 were set according to the specifications indicated in the permit application and in subsequent communications to EPA. These



specifications are summarized in this section (See Appendix B for a Wellbore Schematic). The tubing and packer are coated with fusion-bonded epoxy to prevent corrosion from injection fluid.

- (i) Tubing: 2-3/8 inch O.D., J-55 steel, 4.7 ppf from ground surface to approximately 2,989 feet bgs.
- (ii) Packer: 5-1/2" Baker Lok-Set Tension Packer, located from 2,989 to 3,010 feet bgs.

7. Injection Intervals

Injection shall be permitted and restricted to the Starkey Sands formation for the Sousa-1 well. The Sousa-1 well has four (4) perforations per foot between 3,332 and 3,378 feet bgs.

8. Confining Layer

The confining layer, the 'K1 Shale,' separates the Upper and Lower Starkey Sands. It consists of a low resistivity mudstone to shale bed which is about 176 feet in total thickness at the S.M.S. Briners facility. However, the K1 Shale is split by a thin interbed of sand. Therefore the lower 86 foot portion of the K1 Shale is considered the confining zone. The confining layer is located between approximately 2,558 and 2734 feet bgs.

9. 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.

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 well. 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, including EPA Form 7520-9, "Completion Form for Injection Wells." 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 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, since no known wells located within the AOR penetrate the confining or injection zones.

1. Annual ZEI Review

Annually, the ZEI calculation shall be reviewed and modified if based on any new data obtained from the FOT(s) and static reservoir pressure tests required in Section B, paragraph 2(c) of this part. A copy of the reviewed 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 with the quarterly report or within 60 days whichever is sooner.
- (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 recommence injection operations under the authority of this permit until the Permittee has complied with following paragraphs (a) and (b):

#### (a) Mechanical Integrity

The Permittee shall demonstrate that well Sousa-1 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 recommence injection after a workover which has compromised well integrity until it has received notice from EPA that such a demonstration is satisfactory. Permittee may cite a recent test as demonstrating integrity if conducted in the last year according to the schedule established by the original permit or due to workover operations.

#### (b) Injectate Hazardous Waste Determination

The Permittee shall perform an injectate Hazardous Waste Determination of the waste stream injected into well Sousa-1, 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.

(a) 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.

(b) 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 packer 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 FOT required in Section B paragraph 2(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 conducting a cement squeeze job and/or cement repair, 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 recommence injection after the squeeze job or repair 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. It is also the Permittee's responsibility to 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 operations, an internal pressure MIT shall be conducted on the 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 in accordance with 40 CFR §146.8 and paragraph (a)(ii) above.
- (iii) At least once every five (5) years during the life of the well an internal pressure MIT shall be conducted on the 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.

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 the well 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 well Sousa-1 shall be based on the Step-Rate Test conducted under Section B paragraph 2(b) of this part. The Step-Rate Test shall be conducted prior to recommencing injection under the authority of this permit. EPA will provide the Permittee written notification of the maximum allowable injection pressure for well Sousa-1, along with a minor modification of the permit under 40 CFR §144.41(e).
- (b) Permittee may continue injection into well Sousa-1 at a Maximum Available Injection Pressure (MAIP) at the wellhead of 1200 psi, as established while injecting under the authority of the original permit (#CA192000001), only until re-establishing the MAIP for the well by conducting a Step-Rate Test in accordance with Section B paragraph 2(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) Permittee may continue injection into well Sousa-1 at a maximum injection rate of 100 gallons per minute (gpm), or 3,428 barrels per day, as established while injecting under the authority of the original permit (#CA192000001), only until re-establishing the maximum injection rate for the well by conducting a Step-Rate Test in accordance with Section B paragraph 2(b) of this part.
- (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, or as determined by an injectate Hazardous Waste Determination as described in paragraph 1(b) of this section, at any time.
- (b) Injection fluids shall be limited to only waste fluids authorized by this permit and produced at the S.M.S. Briners and Kruger Foods, Inc. facilities. All injectate is combined into one waste stream upstream of the wellhead. No fluids shall be accepted from other sources.
- (c) Any well stimulation, performed at the discretion of the operator, shall be proposed and submitted to EPA for approval prior to implementation.

6. Tubing/Casing Annulus Requirements

- (a) Corrosion-inhibiting annular fluid shall be used and maintained during well operation. A complete description and characterization has been submitted to EPA for approval before use.
- (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 the 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 and shall be reported per Section C, Paragraph 2(c) of this part.

**E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS**

1. Injection Well Monitoring Program

Injection fluids will be analyzed to yield representative data on their physical, chemical, and other relevant characteristics. The Permittee shall take samples at or before the wellhead for analysis. The results of the tests shall be submitted to EPA on a quarterly basis.

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

- (a) Summary of acceptable analytic Methods:
  - (i) Inorganic Constituents – appropriate USEPA methods for Major Anions and Cations (including an anion/cation balance).
  - (ii) Solids - Standard Methods 2540C and 2540D for Total Dissolved Solids and Total Suspended Solids.
  - (iii) General and Physical Parameters – appropriate USEPA methods for 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.
  - (v) Volatile Organic Compounds (“VOCs”) - USEPA Methods 8260C.
  - (vi) Semi-Volatile Organic Compounds - USEPA Method 8270.
- (b) Analysis of injection fluids.

Quarterly, whenever there is a significant change in injection fluids, or a whenever there is a change in the source of injection fluids, injectate sampling and analyses shall be performed as outlined in paragraph (a) above and reported per section E paragraphs 5(c) 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.



2. 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:

Monitored 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 (°F)	Hourly	digital recorder

The Permittee is required to adhere to the preferred format below for reporting injection rate and wellhead 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 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.

3. 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;
- (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. Refer to section D, paragraph 1(b) of this part;
- (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 in hard copy and electronic format as specified 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 well in paragraph 3(a) of this section;
- (b) Cumulative total volumes over the life of the well, monthly total values, as well as monthly average, maximum, and minimum values for the continuously monitored rate, pressure and temperature parameters specified for the injection well in paragraph 3(a) of this section, unless more detailed records

are requested by EPA;

- (a) Quarterly analyses, to be included in the next quarterly report following permit renewal:
  - (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.
- (b) Results of any additional MITs, CILs or other tests required by EPA, and any well workovers completed;
- (c) 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 2(c) of this part;
  - (iii) Shut-in static reservoir pressure behavior plot of the injection zone, as required in Section B, paragraph 2(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 as required in Section B, paragraph 2(c)(i) 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, paragraph 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:

<u>Reporting Period</u>	<u>Report Due</u>
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

Hard or electronic copies of all reports shall also be provided to the following:

California Division of Oil, Gas, and Geothermal Resources  
 District 4 Office  
 4800 Stockdale Hwy. Ste. 417  
 Bakersfield, CA 93309

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

**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 the well. 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 according to the the Plugging and Abandonment (P&A) Program and provided in Appendix F. The P&A program must also be consistent with CDOGGR requirements and 40 CFR §146.10. EPA reserves the right to change the manner in which the 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 well, 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 in accordance with the Plugging and Abandonment Plans, unless it:

- (a) Provides notice to EPA;
- (b) Has demonstrated that the well 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 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 the well, the Permittee shall submit a report on Form 7520-14, provided in Appendix C, to EPA. The report shall be certified as accurate by the person who performed the plugging operation and shall consist of either:

- (a) A statement that the well was plugged in accordance with the EPA-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 post an approved financial instrument in the amount of \$307,800 to guarantee closure. Continued authority to inject and operate Sousa-1 under the authority of this permit will be granted only after the financial instrument had been posted and approved by EPA.
- (b) The financial responsibility mechanism shall be reviewed and updated periodically, upon request of EPA. The permittee may also 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.

2. Insolvency of Financial Institution

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

- (a) The institution issuing the bond or other financial instrument files for bankruptcy; or
- (b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

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

3. Insolvency of Owner or Operator

An owner or operator must notify EPA by certified mail within ten (10) business days of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor. 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 renewal 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 operation in accordance with the conditions of this permit. The Permittee shall not 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 USDWs.

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. Modification, Revocation and Reissuance, or Termination

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

2. Transfers

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

**C. SEVERABILITY**

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

**D. CONFIDENTIALITY**

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

1. Name and address of the Permittee, or
2. Information dealing with the existence, absence, or level of contaminants in drinking water.

**E. GENERAL DUTIES AND REQUIREMENTS**

1. Duty to Comply - The Permittee shall comply with all applicable UIC Program regulations and all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 CFR §144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (“RCRA”).
2. Penalties for Violations of Permit Conditions - Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to enforcement actions pursuant to RCRA. Any person who willfully violates a permit condition may be subject to criminal prosecution.
3. Need to Halt or Reduce Activity Not a Defense - It shall not be a defense, for the Permittee in an enforcement action, that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
4. Duty to Mitigate - The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this permit.
5. Proper Operation and Maintenance - The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.
6. Property Rights - This permit does not convey any property rights of any sort, or any exclusive privilege.
7. Duty to Provide Information - The Permittee shall furnish to EPA, within a time specified, any information which EPA may request to determine whether cause



exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to EPA, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry - The Permittee shall allow EPA, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:
  - (a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;
  - (b) Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
  - (c) Inspect and photograph at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
  - (d) Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.
9. Signatory Requirements - All applications, reports, or other information submitted to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative according to 40 CFR §§122.22 and 144.32.
10. Additional Reporting
  - (a) Planned Changes – The Permittee shall give notice to EPA as soon as possible of any planned physical alterations or additions to the permitted facility.
  - (b) Anticipated Noncompliance - The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
  - (c) Compliance Schedules - Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted to EPA no later than thirty (30) days following each schedule date.
  - (d) Twenty-four Hour Reporting
    - (i) The Permittee shall report to EPA any noncompliance which may endanger health or the environment. 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:

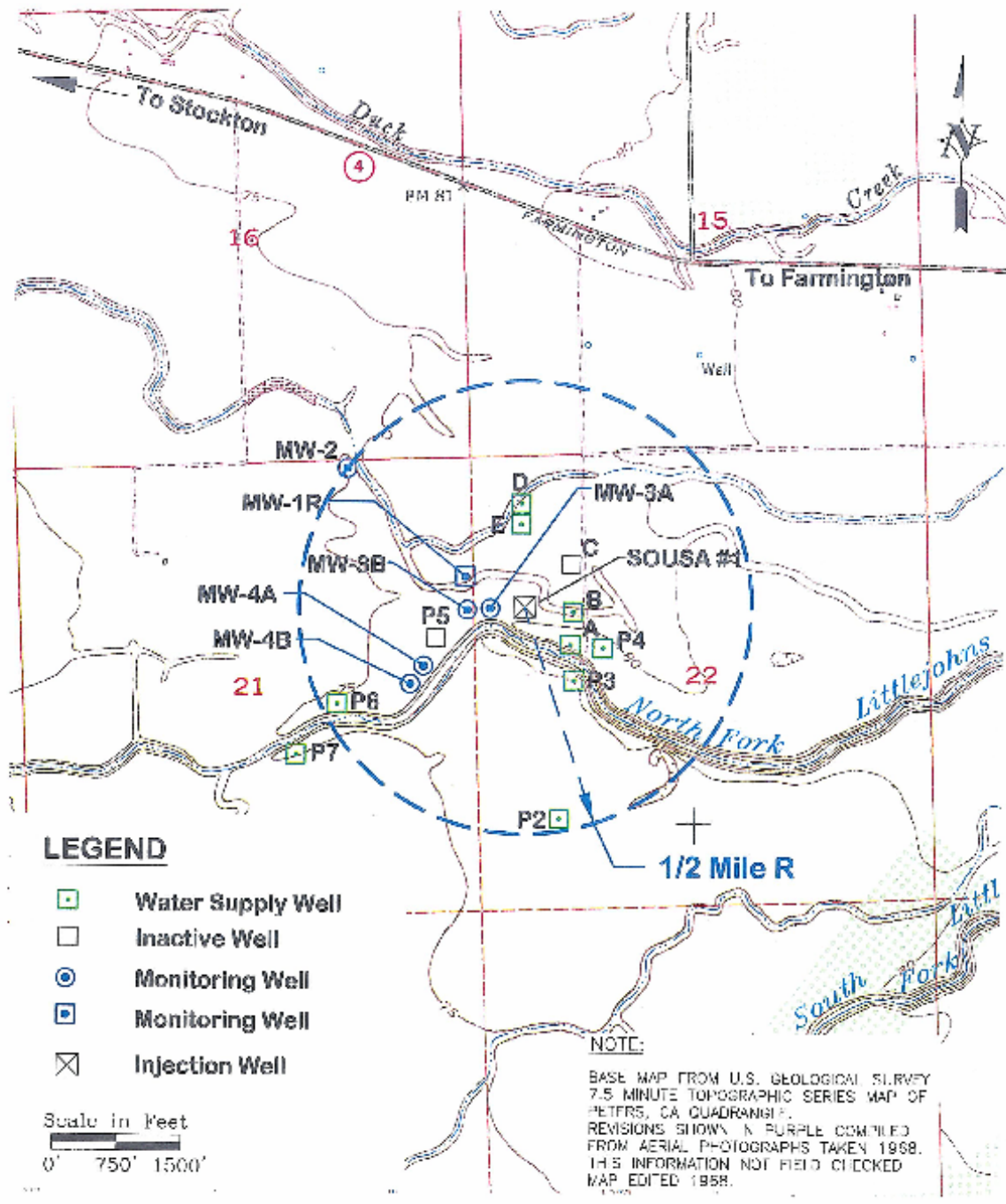
- (1) Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water; and
  - (2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water.
- (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 180 days before this permit expires.
- (b) Permit Extensions - The conditions and requirements of an expired permit continue in force and effect in accordance with 5 U.S.C. §558(c) until the effective date of a new permit, if:
  - (i) The Permittee has submitted a timely and complete application for a new permit; and

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

# APPENDIX A - PROJECT MAP

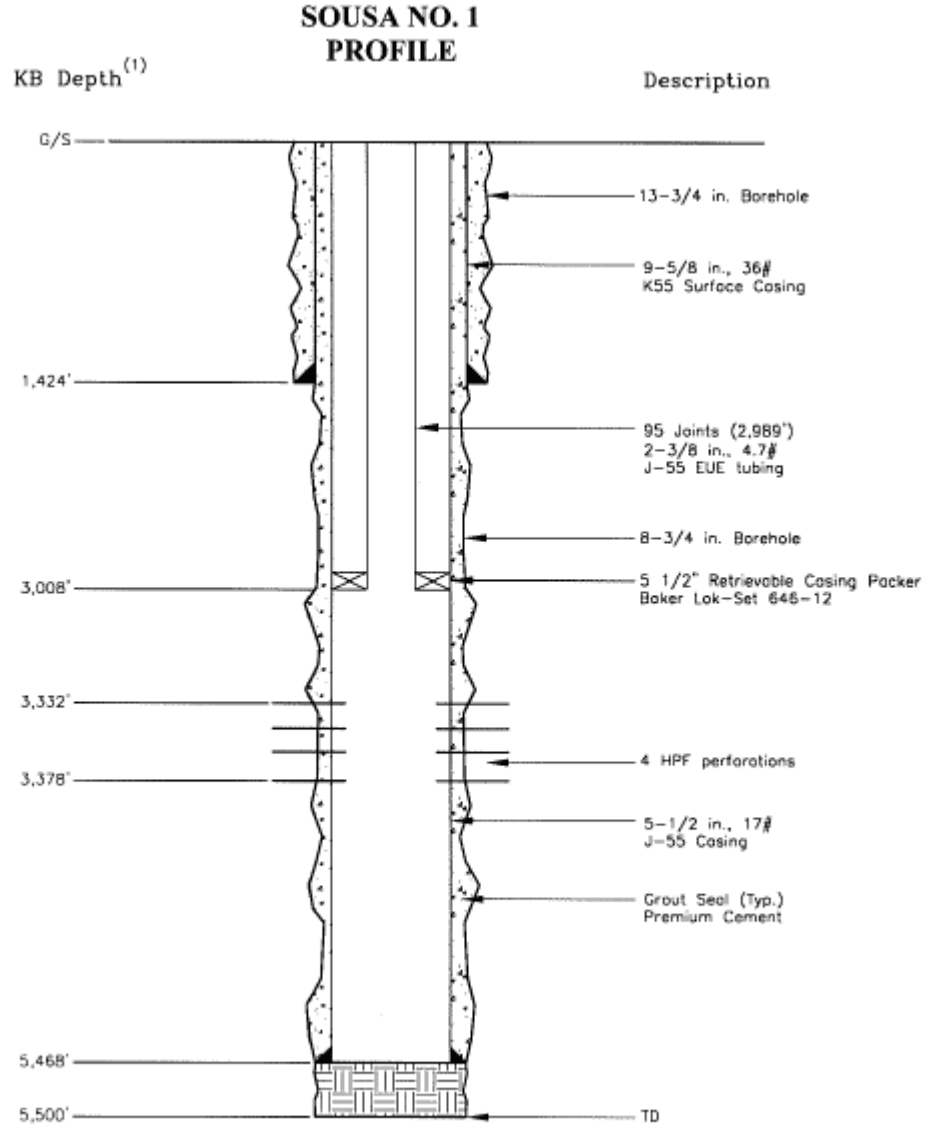


SAC FILE: G:\Projects\999 Bhaas\01\_2 GRV\Well Location 1.mxd DFC FILE: 15CF29M1101.MXD UNL: 02-17-06 8:43am

**LS** LILJEHRF & SCALMANINI  
 CONSULTING ENGINEERS

**Site and Well Location Map**  
**SMS Briners, Inc.**

## APPENDIX B – WELL SCHEMATIC



**Notes;**

(1) KB = G/S + 12'

**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 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 – 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, provide also raw data for both logging runs (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**

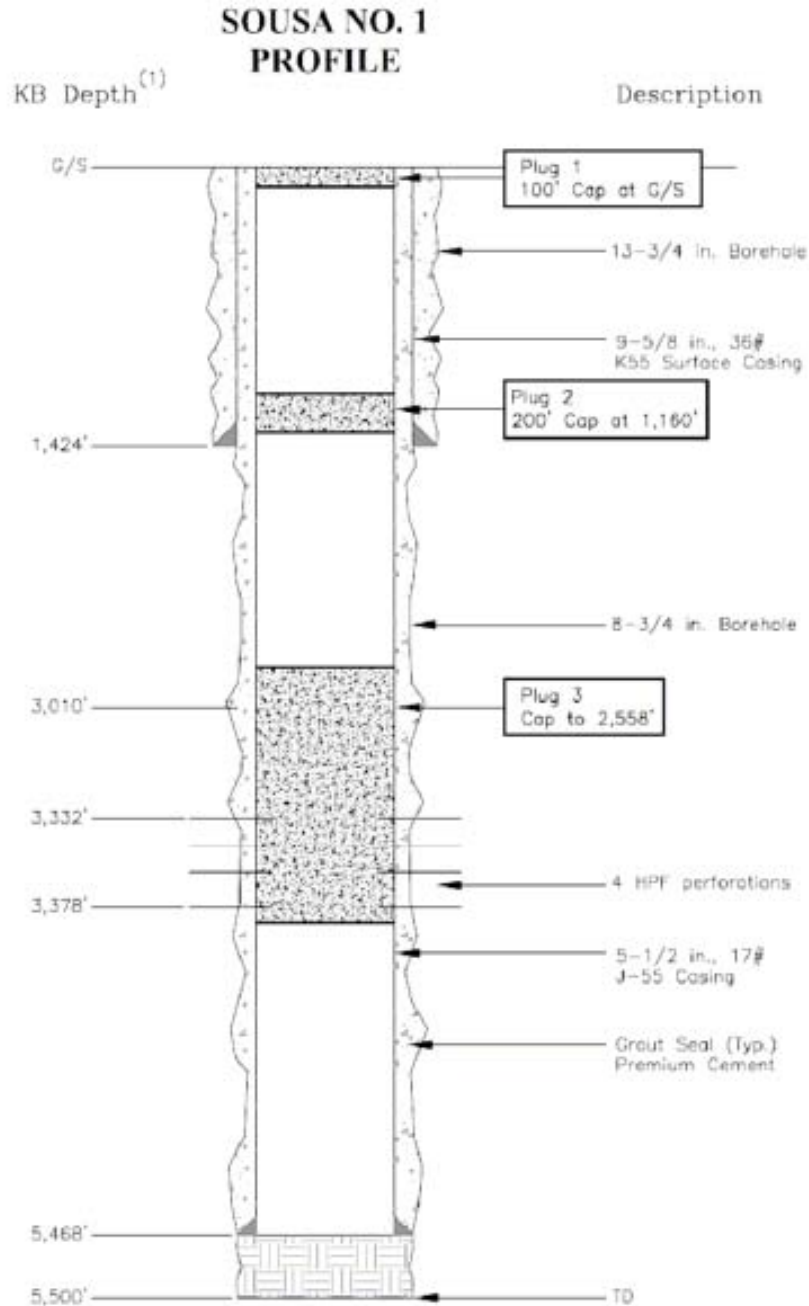
**The website for downloading this forms is at:**

**<http://www.epa.gov/region09/water/groundwater/uic-docs/falloff-testing-guidlines-07.pdf>**



## APPENDIX F - PLUGGING AND ABANDONMENT SCHEMATIC

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.

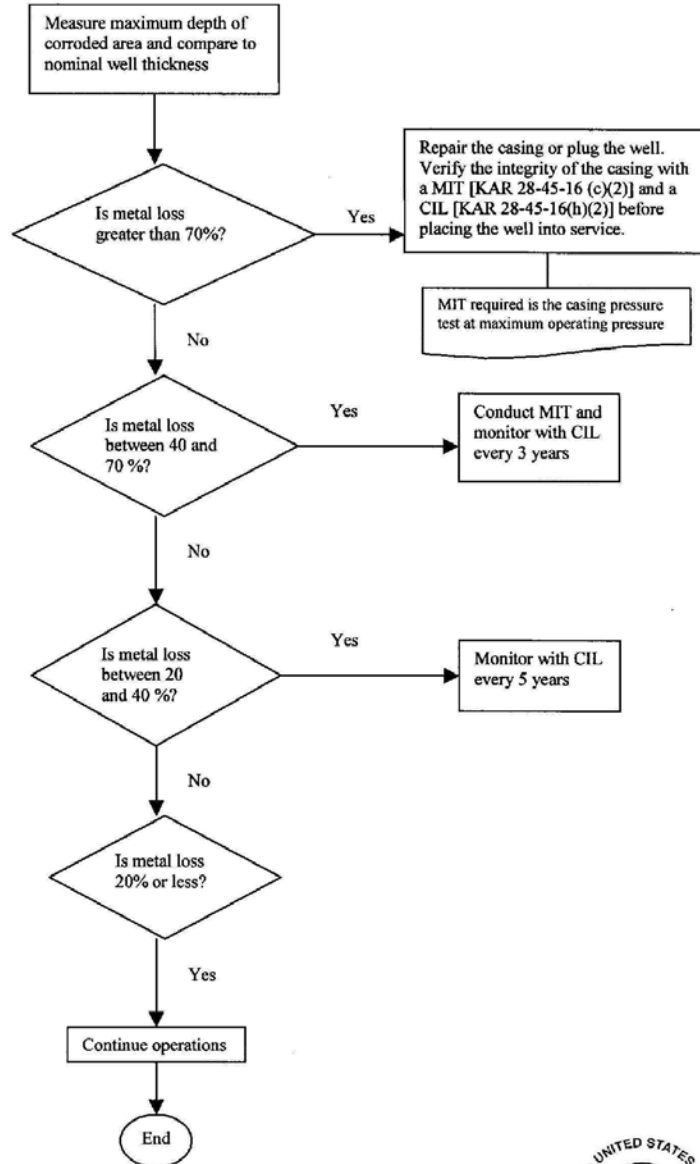


**Notes:**

(1) KB = G/S + 12'

# APPENDIX G - CASING INSPECTION LOG GUIDANCE

## EPA Region 9 Guidance for Casing Inspection Log Results UIC Underground Injection Wells



U.S. Environmental Protection Agency, Region 9  
Underground Injection Control Program  
October 2008

Adapted from Kansas Dept. of Health and Environment  
Bureau of Water/Geology Section, July 2003

