United States Environmental Protection Agency
Underground Injection Control Program

FINAL PERMIT

Class I Non-hazardous Waste Injection Wells

Permit No. R9UIC-CA1-FY17-2R (the Permit)

Well Names: IW1, IW2, IW3, IW4, IW5, and IW6

Issued to:

Panoche Energy Center, LLC
43883 West Panoche Road
Firebaugh, CA 93622

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APPENDICES

PART I. AUTHORIZATION TO INJECT

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

Panoche Energy Center, LLC (PEC or the Permittee)
43883 West Panoche Road
Firebaugh, CA 93622

is hereby authorized, as owner and operator, and contingent upon Permit conditions, to operate an existing injection well facility. In April 2008, EPA issued UIC Program Permit CA10600001, authorizing the construction and operation of up to six (6) injection wells (IW1, IW2, IW3, IW4, IW5, and IW6). IW1, IW2, IW3, and IW4 were installed at the PEC site in 2009. This Permit authorizes continued operation of wells IW1, IW2, IW3, and IW4. The Permit also authorizes the construction and operation of up to two (2) potential additional wells, IW5 and IW6, with no change in injection volume or maximum allowable injection pressure.

The facility is in the southwest quarter of Section 5, Township 15 South, Range 13 East, approximately 16 miles southwest of the City of Firebaugh, California.

EPA authorizes the Permittee to continue operating the four (4) Class I wells conditioned upon the Permittee meeting the Monitoring Requirements set forth in Section II.E.2 of this Permit, and the Financial Assurance requirements set forth in Section II.G of this Permit. Injection operation of the permitted wells will continue to be limited to the maximum volume and pressure as established by the previously conducted Step-Rate Test under EPA Permit No. CA10600001, and in accordance with terms and conditions in this Permit. If potential additional wells IW5 and/or IW6 are constructed during the term of the Permit, Financial Assurance requirements must be met prior to construction. No changes to the operating conditions or total volume injected and pressure limitations will be authorized if the additional wells are constructed.

The Permittee is limited to injecting into the four (4) wells fluids that consist of cooling tower blowdown water, reverse osmosis system reject water, evaporative cooler blowdown water, combustion turbine intercooler condensate, enhanced wastewater system (EWS) water, and oil/water separator discharge water associated with operations of a simple cycle power generation plant that consists of four natural gas-fired combustion turbine generators. If authorized, the fluids authorized to be injected into IW5 and/or IW6 will be identical to those listed above.

This Permit authorizes injection by Wells IW1, IW2, IW3, IW4 and potential additional Wells IW5 and IW6 to dispose of these wastewaters into the Panoche Formation at depths ranging between approximately 7,199 to 8,897 feet below ground surface. The Panoche Formation at the location of the wells has greater than 10,000 mg/L total dissolved solids and is confined above by the approximately 1,148-foot-thick Tierra

Loma Member of the Moreno Formation and the 308 foot-thick Marca Member of the Moreno Formation.

All conditions set forth herein are based on 40 CFR Parts 124, 144, 145, 146, 147 and 148, and are regulations that are in effect on the date that this Permit is effective.

This Permit consists of thirty-three (33) pages plus the appendices, and includes all items listed in the Table of Contents of the Permit. Further, the Permit is based upon representations made by PEC 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 is issued for a period of ten (10) years unless the Permit is terminated under the conditions set forth in Section III.B.1 or administratively extended under the conditions set forth in Section III.E.12 of this Permit.

This Permit is issued on September 30, 2022, and becomes effective on October 31, 2022.

Tomás Torres, Director
Water Division, EPA Region 9

PART II. SPECIFIC PERMIT CONDITIONS

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

1. Financial Assurance

   The Permittee's plugging and abandonment cost estimate and chosen financial assurance mechanism for the wells authorized by this Permit meet the requirements of 40 CFR § 144.52(a)(7).

2. Field Demonstration Submittal, Notification, and Reporting

   a. Prior to each field demonstration required by and described in the following Section II.B.3.a., and the initial mechanical integrity tests required in Sections II.D.1.a., 2.a., and 2.b., the Permittee shall submit plans for procedures and specifications to the EPA Region 9 Groundwater Protection Section for approval at a minimum of sixty (60) days prior to the planned demonstration. Submittals shall be made in accordance with Section III.E.9 of this Permit. No demonstration in the Sections listed above may proceed without prior written approval from EPA.

   b. After receipt of approval of the Permittee's proposed field demonstrations in writing from EPA, the Permittee must provide notice to EPA in accordance with Section E.9.b. of this Permit at least thirty (30) days prior to performing any required field demonstrations.

   c. Unless otherwise specified elsewhere in this Permit, the Permittee shall submit results of each such field demonstration required by Sections II.B. through D. to EPA within sixty (60) days of completion, unless otherwise directed by EPA (Refer to Part III.E.9.b).

B. CONDITIONS FOR EXISTING WELL AND FUTURE WELL CONSTRUCTION

1. Surface Location

   The four (4) injection wells authorized by this Permit are located as follows:

   Well IW1: Located at 36° 39' 2.321" N, 120° 35' 1.777" W
   Well IW2: Located at 36° 39' 2.164" N, 120° 35' 5.637" W
   Well IW3: Located at 36° 39' 2.264" N, 120° 35' 0.170" W
   Well IW4: Located at 36° 39' 3.372" N, 120° 35' 9.076" W

   The two (2) potential additional wells authorized by this Permit are proposed to be located as follows:

Well IW5: Located at 36° 39' 0.201" N, 120° 35' 1.069" W
Well IW6: Located at 36° 39' 0.248" N, 120° 35' 8.834" W

The facility is in the southwest quarter of Section 5, Township 15 South, Range 13 East, approximately 16 miles south-southwest of the City of Firebaugh, California.

2. Well Construction Details

Well schematics for the four (4) existing wells authorized by this Permit are contained in Appendix B of this Permit. The Permittee shall at all times maintain the wells consistent with these Well Schematics.

The Permittee shall submit updated Well Schematics for the proposed additional wells, IW5 and/or IW6, and must receive EPA approval prior to commencing drilling and construction of each of the wells. Appendix B contains draft Well Schematics for these potential additional wells, for informational purposes only.

3. Injection Formation Testing

a. Pressure Fall Off Test (FOT)

A. A FOT shall be performed approximately six (6) months after the permit becomes effective, if an FOT has not been conducted within the last six (6) months under the prior permit. If an FOT has been performed within six (6) months under the prior permit, the next FOT shall be performed one year after the prior FOT.

B. The Permittee shall conduct this FOT in either Well IW1, IW2, IW3, or IW4 as proposed in procedures submitted to EPA for approval to determine and monitor formation characteristics. The Permittee shall conduct the FOT after a radial flow regime has been established at an injection rate that is representative of the wastewater contribution to the well. The other injection wells shall either be inactive, or operated at a constant rate, prior to and during the FOT, in order to obtain reliable pressure data and accurate results. The Permittee shall conduct the FOT in accordance with EPA Region 9 guidance found in Appendix E, and as follows.

C. The Permittee shall submit to EPA for review and approval a detailed plan for the FOT that is developed in accordance with EPA Region 9 guidance in Appendix E. Once EPA provides written approval of the test plan, the Permittee may schedule the FOT, providing EPA at least thirty (30) days' notice before the test is conducted. The final FOT report shall be submitted to EPA within sixty (60) days of test completion.

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

E. After conducting the FOT required in Section II.B.4.b.1 above, the Permittee shall conduct a FOT within 9 to 15 months of the previous FOT thereafter following the same procedures described in Sections II.B.4.b.i. and ii. The Permittee may conduct the annual FOT in conjunction with the annual External Mechanical Integrity Test (MIT) demonstration, as required by Section II.D.2.a.iii.

F. The Permittee shall create a plot/graph of the latest static reservoir pressure of the injection zone and its cumulative behavior over time, the plot shall be included with the annual FOT report each year.

4. Injection Interval

Wells IW1, IW2, IW3, and IW4 are currently authorized to inject into the Panoche Formation, which has greater than 10,000 mg/L total dissolved solids. Injection by the wells is only permitted into the Panoche Formation, within the depth range as depicted in the well schematics in Appendix B (i.e., at depths ranging between 7,199 and 8,897 feet below ground surface). Potential Wells IW5 and IW6 may be authorized to inject into the Panoche Formation, within the depth range as depicted in the draft well schematics in Appendix B (i.e., at depths ranging between approximately 7,500 and 9,000 feet below ground surface).

5. Monitoring Devices

The Permittee shall maintain in good operating condition at all times during operation of Wells IW1, IW2, IW3, and IW4, and the potential additional wells IW5 and IW6, the following monitoring devices:

a. A tap on the discharge line line shall be located to provide for representative sampling of all wastewaters being injected downstream of any chemical or physical water treatment and as approved in writing by the EPA Director or their delegated representative; and

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

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

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

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

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

6. Proposed Changes and Workovers

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

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

c. The Permittee shall submit all reports required by this Permit using the appropriate reporting forms (see Appendix C).

d. The Permittee shall perform a MIT on each well authorized by this Permit using the procedures set forth in Sections II.D.1.a. and II.D.2. within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Section II.D.1. The Permittee shall provide results of the MIT to EPA within sixty (60) days of completion.

C. CORRECTIVE ACTION

Prior to granting authorization to inject under this Permit, the Permittee is not required to conduct any corrective action, in accordance with 40 CFR §§144.55 and 146.7. Determination of future corrective action and implementation is discussed below:

Determination and Implementation of Future Corrective Action

1. Annual Zone of Endangering Influence Review

   Annually, beginning with the first FOT conducted under this Permit, the Permittee shall review the ZEI calculation based on any new data obtained from the FOT and static reservoir pressure observations required by Section II.B.3.a. The Permittee shall provide to EPA a copy of the modified ZEI calculations, along with all associated assumptions and justifications, with the next Quarterly Report, as required by Section II.E.6.c. This review shall address the Permittee's interpretation of the pressure and specific conductance monitoring and chemical analyses in the report required in Section II.E.6.e.

2. Implementation of Future Corrective Actions

   a. If any additional wells are found within the modified ZEI referenced above, a list of the wells along with their locations and construction data shall be provided to EPA within thirty (30) days of their identification.

   b. If required by EPA, the Permittee shall submit a plan for approval by EPA to re-enter, plug, and abandon the wells listed in Section II.B.1., above, in a way that prevents the migration of fluids into a USDW. The Permittee may submit an alternative plan to address the potential for fluid migration in any of these wells to EPA.

   c. Corrective action may be required after permit issuance to address any wells within the area of review that may allow migration of fluids into underground sources of drinking water. EPA will use the annual FOT results and re-calculation of the ZEI, along with USDW monitoring results from the monitoring well, as described in Section V. Monitoring, Recordkeeping, and Reporting of Results below, to determine the potential need for any future corrective action.

   d. The Permittee shall not commence corrective action activities without prior written approval from EPA.

D. WELL OPERATION

1. Required Demonstrations

   a. Mechanical Integrity

      i. Within one (1) year of the most recent mechanical integrity testing conducted under the existing EPA Permit No. CA10600001, the Permittee shall conduct an MIT to demonstrate that each well authorized by this Permit has mechanical integrity consistent with 40 CFR § 146.8 and with Section II.D.2.a. The Permittee shall demonstrate that there are not significant leaks in the casing and tubing (internal mechanical integrity) 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 (external mechanical integrity).

b. Injectate Hazardous Waste Determination

i. Within sixty (60) days of the effective date of this Permit, the Permittee shall certify as unchanged, the existing Injectate "Hazardous Waste Determination" of each unique waste stream source injected into each well authorized by this Permit, as listed in Section II.D.5.a, in accordance with 40 CFR § 262.11. If a change is identified, a new determination must be performed within sixty (60) days of the effective date of this Permit.

ii. Whenever there is a process change or a change in fluid chemical constituents or characteristics of the injectate at the power generating plant, the Permittee shall perform an additional "Hazardous Waste Determination" for each unique waste stream source listed in Section II.D.5.a. The Permittee should also refer to injectate testing requirements set forth in Section II.E.1., below. A letter with the results of the analyses shall be submitted to EPA within sixty (60) days of the "Hazardous Waste Determination" completion.

2. Mechanical Integrity

a. Mechanical Integrity Tests

Mechanical integrity testing shall conform to the following requirements throughout the life of each well authorized by this Permit and in accordance with the requirements set forth at 40 CFR §§ 144.51(q) and 146.8:

i. Casing/Tubing Annular Pressure (Internal MIT)

In accordance with the timing requirements defined in Section II.D.2.b., below, the Permittee shall perform a pressure test on the annular space between the tubing and long string casing to demonstrate the absence of significant leaks in the casing, tubing and/or liner. This test shall be for a minimum of thirty (30) minutes at a pressure equal to or greater than the maximum allowable surface injection pressure (MAIP). A well passes the MIT if there is less than a five (5) percent change in pressure over the thirty (30) minute period. A pressure differential of at least three hundred and fifty (350) pounds per square inch (psig) between the tubing and annular pressures shall be maintained throughout the MIT. This test shall be performed on each well authorized by this Permit initially as described in Section II. D.1.a.

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

ii. Continuous Pressure Monitoring

The Permittee shall continuously monitor and record the tubing/casing annulus pressure and injection pressure by a digital instrument with a resolution of one tenth (0.1) psig. The average, maximum, and minimum monthly results shall be included in the next Quarterly Report submitted to EPA pursuant to Section II.E.6.b., along with any additional records or data requested by EPA regarding the continuous monitoring data described in this Section.

iii. Injection Profile Survey (External MIT)

In conjunction with and consistent with the deadlines for the first FOT conducted under this Permit, as required in Section II.B.4.b., the Permittee shall conduct a demonstration that the injectate is confined to the proper zone and submit the results of the demonstration to EPA for approval.

This demonstration shall consist of a radioactive tracer survey 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. The final test report shall be submitted to EPA within sixty (60) days of test completion.

b. Schedule for MITs

EPA may require that an Internal and/or External MIT be conducted, upon written request, at any time during the permitted life of each well authorized by this Permit. The Permittee shall also arrange and conduct MITs in each well authorized by this Permit according to the following requirements and schedule:

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

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

iii. At least once every five (5) years, an Internal MIT shall be conducted in accordance with 40 CFR § 146.8 and Section II.D.2.a.i., above.

c. If Well IW5 and/or IW6 are constructed, the Permittee must conduct internal and extermal MITs in accordance with the procedures and schedules outlined in Part II.D.2, above.

d. <u>Loss of Mechanical Integrity</u>

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

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

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

iii. A significant change in the annulus or injection pressure occurs during normal operating conditions. See Section II.D.6.b.

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

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

3. Injection Pressure Limitation

   For each well authorized by this Permit:

   a. MAIP measured at the wellhead shall not exceed the values listed below at each well for injection into the Panoche Formation.

      IW1: 2,478 psi
      IW2: 2,416 psi
      IW3: 2,478 psi
      IW4: 2,478 psi

   b. In no case shall the Permittee inject at pressures that (i) initiate new fractures or propagate existing fractures in the injection zone or the confining zone, (ii) cause the movement of injection or formation fluids into or between USDWs, or (iii) allow injection fluids to migrate to oilfield production wells.

   c. Step Rate Testing (SRT), in accordance with EPA guidance is required prior to final establishment of injection presssure limits for the potential additional wells IW5 and/or IW6. Initial injection pressure(s) will not be greater than those set for the existing wells (as above).

4. Injection Volume (Rate) Limitation

   For each well authorized by this Permit:

   a. The daily injection rate at each well shall not exceed the values listed below at any time. This rate will be subject to an annual review based on the annual ZEI determinations performed as described in Section II.C.2. If IW5 and/or IW6 are constructed, no increase in the total volume authorized to be injected under this Permit is authorized.

      IW1: 144,039 gallons
      IW2: 172,041 gallons
      IW3: 155,147 gallons
      IW4: 164,002 gallons

   b. The Permittee may request an increase in the maximum rate allowed in Section II.D.4.a., above. Any such request shall be made in writing, along with a justification for the proposed increase, to EPA for its review and approval.

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

d. The injection rate shall not cause an exceedance of the injection pressure limitation established pursuant to Section II.D.3.a.

5. Injection Fluid Limitation

a. This Permit authorizes injection of the following fluids into the wells authorized by this Permit: cooling tower blowdown water, reverse osmosis system reject water, evaporative cooler blowdown water, combustion turbine intercooler condensate, enhanced wastewater system (EWS) water, and oil/water separator discharge water generated from the power generating plant.

b. The Permittee shall not inject any hazardous waste, as defined by 40 CFR § 261, at any time. See also Section II.D.1.b.

c. Injection fluids shall be limited to those authorized by this Permit, which includes those fluids produced by the Permittee as described in Section II.D.5.a., above.

d. Particulate Filters may be used upstream of any well authorized by this Permit, at the discretion of the Permittee, to prevent formation plugging or damage from particulate matter. The Permittee shall include any filter specifications in the Quarterly Report due annually in January as required in Section II.E.6.c., including proposed particle size removal with any associated justification for the selected size. For any particulate filters used, the Permittee shall follow appropriate waste analysis and disposal practices consistent with local, state, and federal law, and provide documentation to EPA.

e. Any well stimulation or treatment procedure (e.g., acidizing) performed at the discretion of the Permittee shall be proposed and submitted to EPA for approval. After approval is granted, notification to EPA is required at least thirty (30) days prior to performing the approved procedure. This requirement may be modified if the Permittee submits, within sixty (60) days after the effective date of the permit, a standard operating procedure for well stimulation or treatment for EPA approval. If the standard operating procedure plan is approved by EPA in writing, the Permittee may notify EPA within fifteen (15) days of the proposed well stimulation or treatment procedure, provided the procedure does not deviate in any way from the EPA-approved plan.

6. Tubing/Casing Annulus Requirements

For any well authorized by this Permit:

a. The Permittee shall use and maintain corrosion-inhibiting annular fluid during well operation. See Appendix H for a complete, generic description and characterization of the annular fluid.

b. The Permittee shall maintain a minimum pressure of one hundred (100) psig at shut-in conditions on the tubing/casing annulus.

c. Any annular pressure measured outside of the established normal pressure range, as previously determined under existing EPA Permit No. CA10600001, regardless of whether it otherwise meets the requirements of this Permit, shall be reported orally to EPA within twenty-four (24) hours, followed by a written submission within five (5) days, as a potential loss of mechanical integrity. In the submission, the Permittee must describe the event and include details, such as associated injection pressures and temperatures. The Permittee shall provide any additional information regarding the reported annular pressure event requested by EPA within sixty (60) days of receipt of a written request from EPA, or such other time frame established in writing by EPA.

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Fluid Monitoring Program

The Permittee shall sample and analyze injection fluids to yield representative data on their physical, chemical, and other relevant characteristics. Test results shall be submitted by the Permittee to EPA on a quarterly basis (see Section II.E.6., 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," and as described below, unless other methods have been approved by EPA or additional approved methods or updates to the methods listed below become available.

a. Summary of Acceptable Analytic Methods

i. Inorganic Constituents – USEPA Method 300.0, Part A for Major Anions (with the exception of Fluoride, which may be analyzed by SM-4500-F), and USEPA Method 200.8 or USEPA Method 200.7 for Cations and Trace Metals.

ii. Solids – Standard Methods 2540C and 2540D for Total Dissolved Solids (TDS) and Total Suspended Solids (TSS).

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

iv. Volatile Organic Compounds (VOCs) – USEPA Method 8260B or the most recently-approved EPA method.

v. Semi-Volatile Organic Compounds (SVOCs) – USEPA Method 8270C or the most recently-approved EPA method.

b. <u>Timing of Analysis of Injection Fluids</u>

Injection fluid sampling and analyses as outlined in Section II.E.1.a. above shall be performed, at the required timing or frequency:

i) Within thirty (30) days after the effective date of this Permit. If no change in injection fluid has occurred from the prior permit, the Permittee shall certify there has been no change within the specified timeframe; and

ii) On a quarterly basis; and

iii) Whenever there is a change in injection fluids such as whenever the injection fluid is no longer representative of previous samples and measurements that have been submitted and approved.

2. <u>USDW Monitoring</u>

<u>Monitoring Well Installation – pursuant to 40 CFR §§ 146.13 (b) and (d) :</u>

a. The Permittee shall install one (1) monitoring well to perform chemical analysis and measure specific conductance and formation pressure in order to identify potential changes in the USDW in the vicinity of one (1) nearby abandoned well, as described below in Monitoring Requirements. The one (1) monitoring well shall be located within 100 feet to the south-southwest of the Silver Creek 18 Well.

b. Within 60 days of the effective date of this Permit, and prior to drilling the monitoring well, the Permittee shall submit to EPA, for review and approval, a detailed construction plan and procedures, including the proposed field coordinates (Section, Township, Range, with latitude/longitude) for the surface location of the proposed monitoring well. The plans and procedures must describe how the Permittee will:

i. Drill the wellbore to the base of the USDW, located at the stratigraphic contact between the Kreyenhagen Shale and the sandy interval in the overlying Tumey Formation;

ii. Equip the well with a transducer to monitor pressure and specific conductance within the USDW, and with water quality monitoring equipment to allow sampling of the USDW; and

iii. Perform baseline characterization of ground water chemistry, to meet the analytical requirements in Part II.E.2., below.

c. Drilling for the installation of the monitoring well must commence within 120 days of the approval of the construction plans and procedures as described in (b) above. Proposed financial assurance for the plugging and abandonment of the monitoring well must also be provided to EPA within 60 days of the effective date of the Permit. Financial assurance is described in Part II.G. 1, below.

d. The Permittee must submit a final well construction report, including logging, and other results, with a schematic diagram and detailed description of construction, including geophysical logs, driller's log, materials used (i.e., tubing tally), and cement (and other) volumes to EPA within sixty (60) days after completion of the monitoring well.

e. The Permittee must also submit a notice of completion of construction to EPA (using EPA Form 7520-18; see Appendix C) within sixty (60) days after completion of the well.

Monitoring Requirements

The Permittee shall perform the following chemical analysis and measure specific conductance and formation pressure in the monitoring well to be installed as described in Part II.E.2.a, in order to identify potential changes within the lowest USDW. The lowest USDW is defined by the sandy interval in the Tumey Formation, overlying the stratigraphic contact with the Kreyenhagen Shale:

a. Record pressure and specific conductance measurements via transducers daily;

b. Sample and perform chemical analysis for the following parameters using the Analytical Methods in Section E.1.a: TDS, alkalinity, anions and cations, trace metals, hardness, pH, specific gravity, total sulfide, oil and grease, and total metals. This analysis shall be performed monthly for the first year of monitoring, and quarterly thereafter; and

c. Report the results to EPA as described in Section II.E.6.

3. Monitoring Information

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

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

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

c. Exact sampling method(s) used;

d. Date(s) laboratory analyses were performed;

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

f. Types of analyses; and

g. Results of analyses.

4. Monitoring Devices

a. Continuous Monitoring Devices

During all periods of operation of any authorized well, the Permittee shall measure the following wellhead parameters: (i) injectate rate/volume, (ii) injectate temperature, (iii) annular pressure, and (iv) injection pressure. The Permittee shall also measure pressure and specific conductance as described in Section II.E.2 at the monitoring well to be installed pursuant to Section II.E.2.a. All measurements must be recorded at minimum to a resolution of one tenth (0.1) of the unit of measure as shown in the table below (i.e., injection rate and volume must be recorded to a resolution of one tenth (0.1) of a gallon; pressure must be recorded to a resolution of one tenth (0.1) of a psig; injection fluid temperature must be recorded to a resolution of one tenth (0.1) of a degree Fahrenheit; and specific conductance must be recorded to a resolution of one tenth (0.1) of a micromhos/cm). Exact dates and times of measurements, when taken, must be recorded and submitted. Each injection well shall have a dedicated flow meter, installed so it records all injection flow. To meet the requirements of this Section, the Permittee shall monitor the following parameters, at the prescribed frequency, and record the measurements at this required frequency, using the prescribed instruments (continuous monitoring requires a minimum frequency of at least one (1) data point every thirty (30) seconds):

Monitoring Parameter	Frequency	Instrument
Injection Rate (gallons per minute)	Continuous	Digital recorder
Daily Injection Volume (gallons)	Daily	Digital totalizer
Total Cumulative Volume (gallons)	Continuous	Digital totalizer
Well Head Injection Pressure (psig)	Continuous	Digital recorder
Annular Pressure (psig)	Continuous	Digital recorder
Injection Fluid Temperature (degrees Fahrenheit)	Continuous	Digital recorder
Pressure in USDW (psig)	Daily	Digital recorder
Specific conductance in the USDW (micromhos/cm)	Daily	Digital recorder

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

<u>DATE</u>	<u>TIME</u>	<u>INJ. PRESS (PSIG)</u>	<u>INJ. RATE (GPM)</u>
mm/dd/yy	hh:mm:ss	XXXX.X	XXXX.X

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

b. <u>Calibration and Maintenance of Equipment</u>

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

5. <u>Recordkeeping</u>

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

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

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

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

iv. The geophysical logging and results of the chemical analyses of the USDW from the monitoring well pursuant to Section II.E.2.a;

v. Pressure and specific conductance readings recorded pursuant to Section II.E.2; and

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

b. The Permittee shall maintain copies (or originals) of all records described in Sections II.E.5.a.i. through vi., above, during the operating life of any well authorized by this Permit and shall make such records available at all times for inspection at the facility. The Permittee shall only discard the records described in Sections II.E.5.a.i. through vi., if:

i. The records are delivered to the EPA Region 9 Groundwater Protection Section; or

ii. Written approval from EPA to discard the records is obtained.

6. <u>Reporting</u>

a. The Permittee shall submit to EPA Quarterly Reports containing, at minimum, the following information gathered during the Reporting Period identified in Section II.E.6.b.:

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

ii. The results of pressure and specific conductance monitoring and chemical analyses required in Section II.E.6.d.ii;

iii. When appropriate, Injectate Hazardous Waste Determination according to Section II.D.1.b.;

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

v. Any pressure tests, as required by Section II.D.2.a.i.;

vi. Shut-in static reservoir pressure cumulative behavior plot of the injection zone, as required by Section II.B.3.a.F.;

vii. Hourly and daily values, submitted in electronic format, for the continuously monitored parameters specified for the injection wells in Section II.E.4.a.; and

viii. 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 Section II.E.4.a., unless more detailed records are requested by EPA.

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

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

c. For the Quarterly Report covering the reporting period of January, February, and March, the Permittee shall also include in that Report the following information collected during the prior year covering January through December:

i. Annual reporting summary;

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

iii. The report on the results of pressure and specific conductance monitoring and chemical analyses required in Section II.E.6.e; and

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

d. The Permittee shall also submit to EPA reports of the results of formation pressure and specific conductance monitoring and chemical analyses performed pursuant to Section II.E.2. The reports shall include pressure and specific conductance measurements and the results of chemical analyses, and means and standard deviations of these values in a tabular (i.e., spreadsheet) format, along with graphical representations of the data, and be submitted as follows:

i. For the first year following the commencement of monitoring activities required under this Permit, the Permittee shall submit this information to EPA monthly, on the 15th day of the month.

ii. Following one (1) year of monthly monitoring reporting, the Permittee shall submit this information to EPA with the quarterly reports required in Section II.E.6.a.

e. At the end of each year, the Permittee shall submit a report that summarizes the pressure, specific conductance, and water quality monitoring data collected that includes: a cumulative tabulation of the measurements/analytical results (since the commencement of monitoring activities), a description of trends in the measurements over time, and an interpretation regarding whether the data demonstrate that there is no hydraulic communication between the injection zone and the USDW via abandoned wells in the AOR and that USDWs are not endangered.

f. In addition to meeting the submittal requirements of Section III.E.9., digital e-copies of all Quarterly Reports shall also be provided to the following:

California Geologic Energy Management Division
Inland District
Attention: Supervising Oil and Gas Engineer
William.Long@conservation.ca.gov

Central Valley Regional Water Quality Control Board
Attention: Permit Section
Dale.Harvey@waterboards.ca.gov

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

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

2. Plugging and Abandonment Plans

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

3. Cessation of Injection Activities

After a cessation of injection operations for two (2) years for any wells authorized by this Permit, a well is considered inactive. In this case, the Permittee shall plug and abandon the inactive well in accordance with the approved Plugging and Abandonment Plans, contained in Appendix G, unless the Permittee:

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

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

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

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

4. Plugging and Abandonment Report

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

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

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

G. FINANCIAL ASSURANCE REQUIREMENTS

1. Demonstration of Financial Assurance

The Permittee is required to demonstrate and maintain financial assurance and resources sufficient to close, plug, and abandon any authorized underground injection operations by this Permit, as provided in the Plugging and Abandonment Plan contained in Appendix G and consistent with 40 CFR § 144 Subpart D.

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

a. Prior to the issuance of this Permit, the Permittee provided, and EPA approved in writing, a financial assurance instrument, consistent with Section II.A.1 of this Permit, to guarantee closure of the wells authorized by this Permit, as follows, in the amount of:

Well IW1: $302,627
Well IW2: $348,156
Well IW3: $273,787
Well IW4: $270,431

These values were determined by the Permittee and have factored in the cost for an independent third party to plug and abandon the wells, plus a 20% contingency.

Prior to the installation of the monitoring well described in Part II.E.2.a, financial assurance must also be provided, for EPA approval, consistent with the schedule set forth in Part II.C.1 (c).

If the Permittee requests to construct IW5 and/or IW6, the Permittee is required to provide for EPA approval adequate financial assurance to guarantee closure of the well(s) before construction may be authorized.

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

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

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

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

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

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

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

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

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

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

H. DURATION OF PERMIT

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

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

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

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

Any underground injection activity not specifically authorized in this Permit is prohibited (40 CFR § 144.11). The Permittee must comply with all applicable provisions of the Safe Drinking Water Act (SDWA) and 40 CFR Parts 124, 144, 145, 146, 147 and 148. 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, including future, laws or regulations.

B. PERMIT ACTIONS

1. Modification, Revocation and Reissuance, or Termination

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

2. Transfers

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

C. SEVERABILITY

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

D. CONFIDENTIALITY

In accordance with 40 CFR §§ 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

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

1. Duty to Comply

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

2. Penalties for Violations of Permit Conditions

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

3. Need to Halt or Reduce Activity Not a Defense

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

4. Duty to Mitigate

   The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from non-compliance with this Permit.

5. Proper Operation and Maintenance

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

6. Property Rights

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

7. Duty to Provide Information

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

8. Inspection and Entry

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

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

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

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

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

9. Submittal Requirements

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

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

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

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

and by e-mail to: albright.david@epa.gov.

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

10. Additional Reporting Requirements

a. Planned Changes

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

b. Anticipated Non-compliance

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

c. Compliance Schedules

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

d. Monitoring Reports

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

e. Twenty-four Hour Reporting

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

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

(b) Any non-compliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs.

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

f. Other Non-compliance

At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of non-compliance not otherwise reported pursuant to other reporting requirements outlined in this Permit. The Permittee shall submit the information listed in Section III.E.10.d.

g. Other Information

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

11. Requirements Prior to Commencing Injection, Plugging and Abandonment Report, Duty to Establish and Maintain Mechanical Integrity

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

12. Continuation of Expiring Permit

a. Duty to Re-apply

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

e. 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.

13. Records of Permit Application

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

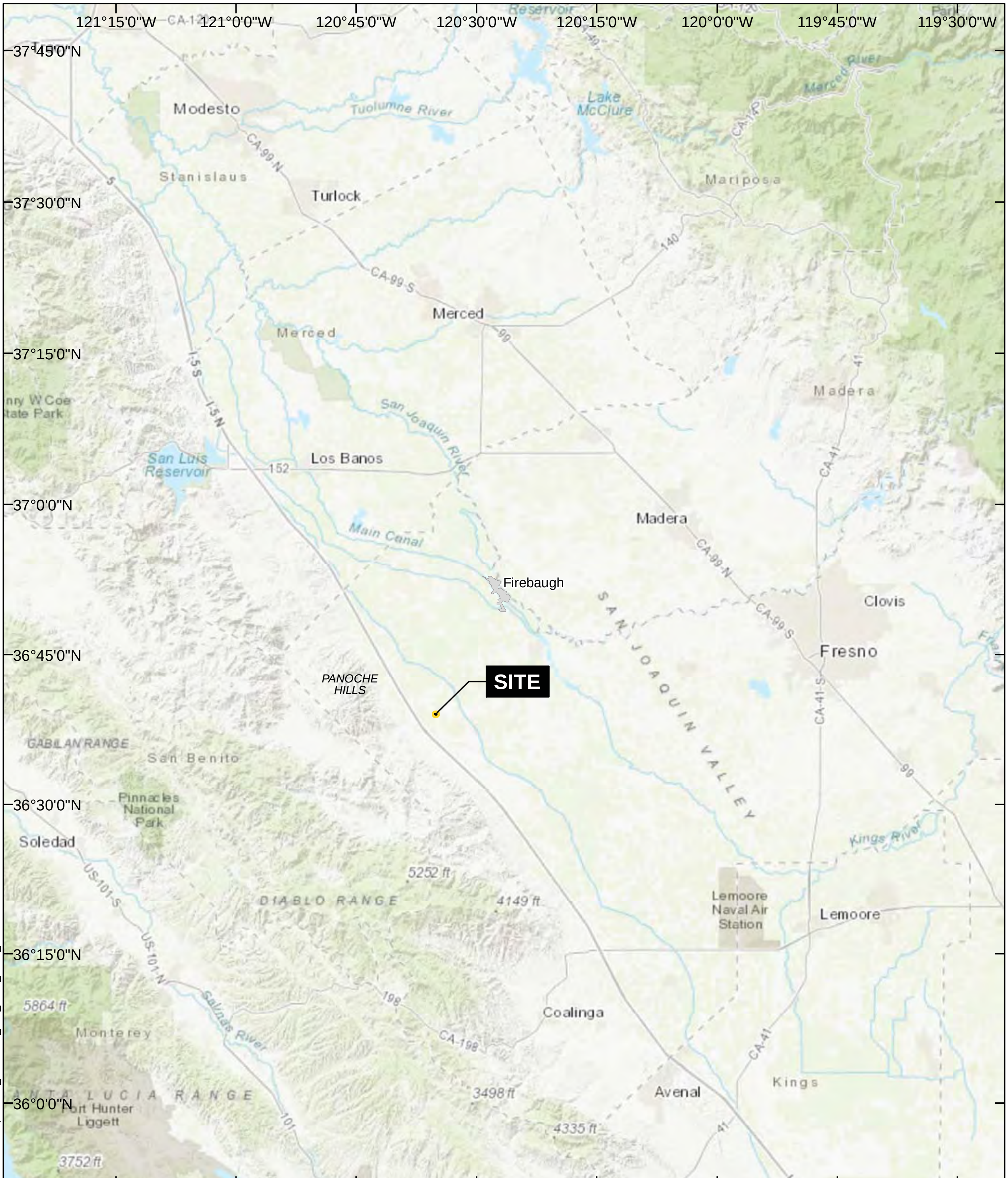
14. Availability of Reports

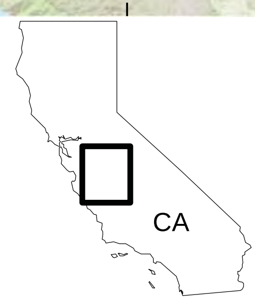
Except for information determined to be confidential under 40 C.F.R. Part 2, Subpart B, all permit applications, permits, reports, and well operation data prepared in accordance with the conditions of this Permit shall be available for public inspection at appropriate offices of the EPA.

Appendix A

Project Maps

UIC Permit R9UIC-CA1-FY17-2R





N

0 10 20

SCALE IN MILES

MAP SOURCE: ESRI
SITE COORDINATES: 36°39'3"N, 120°35'4"W

HALEY ALDRICH

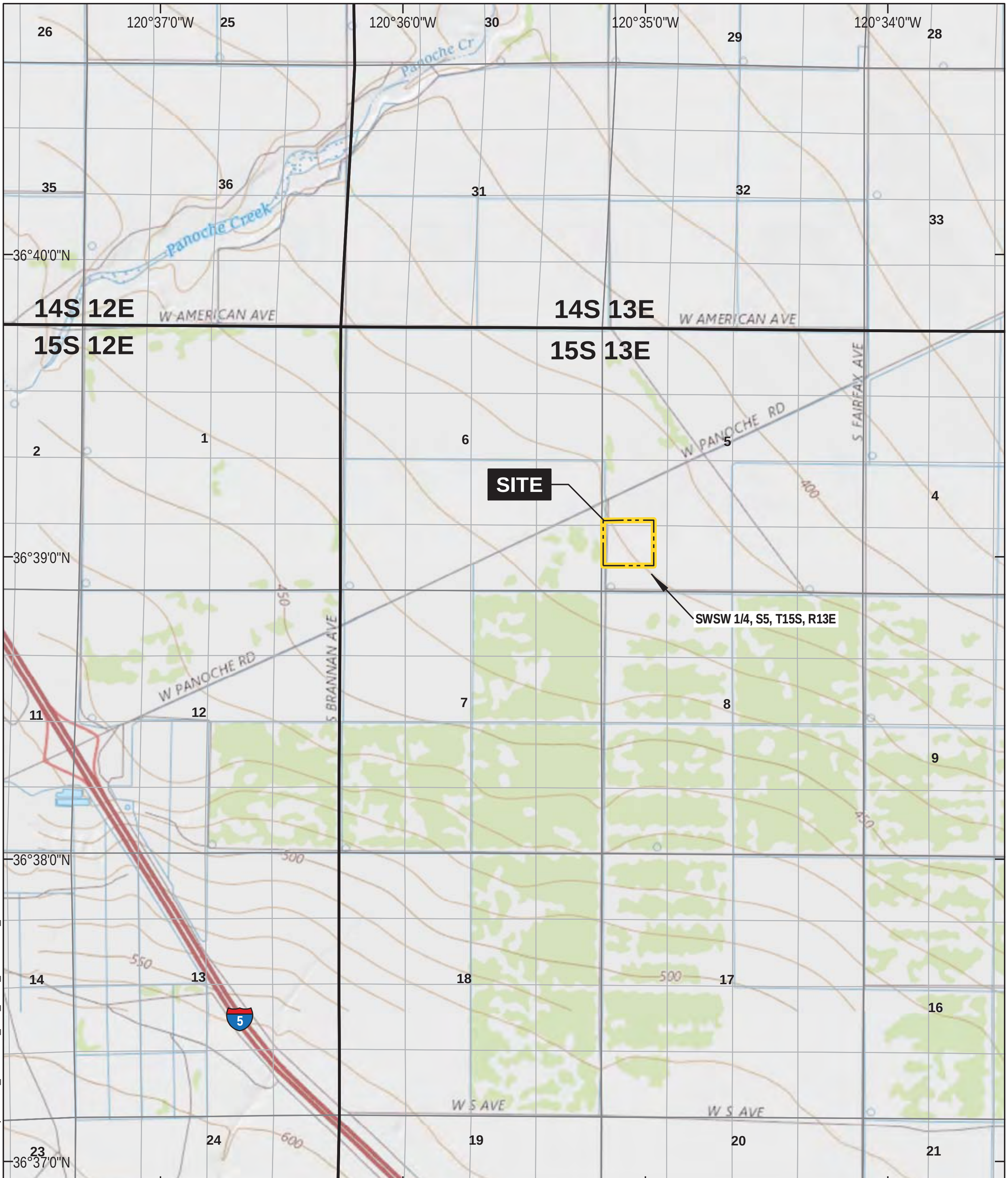
PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

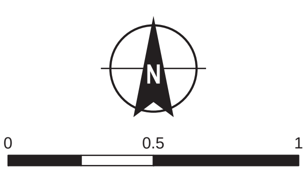
SITE VICINITY

APPROXIMATE SCALE: 1 IN = 20 MI
OCTOBER 2017

FIGURE 1

GIS FILE PATH: G:\39073_Panoche_Compliance\GIS\Maps\2017_08\39073_007_0001_SITE_VICINITY.mxd — USER: ibruce — LAST SAVED: 10/17/2017 5:12:17 PM





MAP SOURCE: ESRI
SITE COORDINATES: 36°39'5"N, 120°35'7"W

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

PROJECT LOCUS

APPROXIMATE SCALE: 1 IN = 1 MI
SEPTEMBER 2017

FIGURE 2

GIS FILE PATH: G:\39073_Panoche_Compliance\GIS\Maps\2017_08\39073_007_0002_PROJECT_LOCUS.mxd — USER: ibruce — LAST SAVED: 9/1/2017 12:05:00 PM

Appendix B

Well Schematics

UIC Permit R9UIC-CA1-FY17-2R

FIGURE M-1

Panoche Energy Center
Well IW1

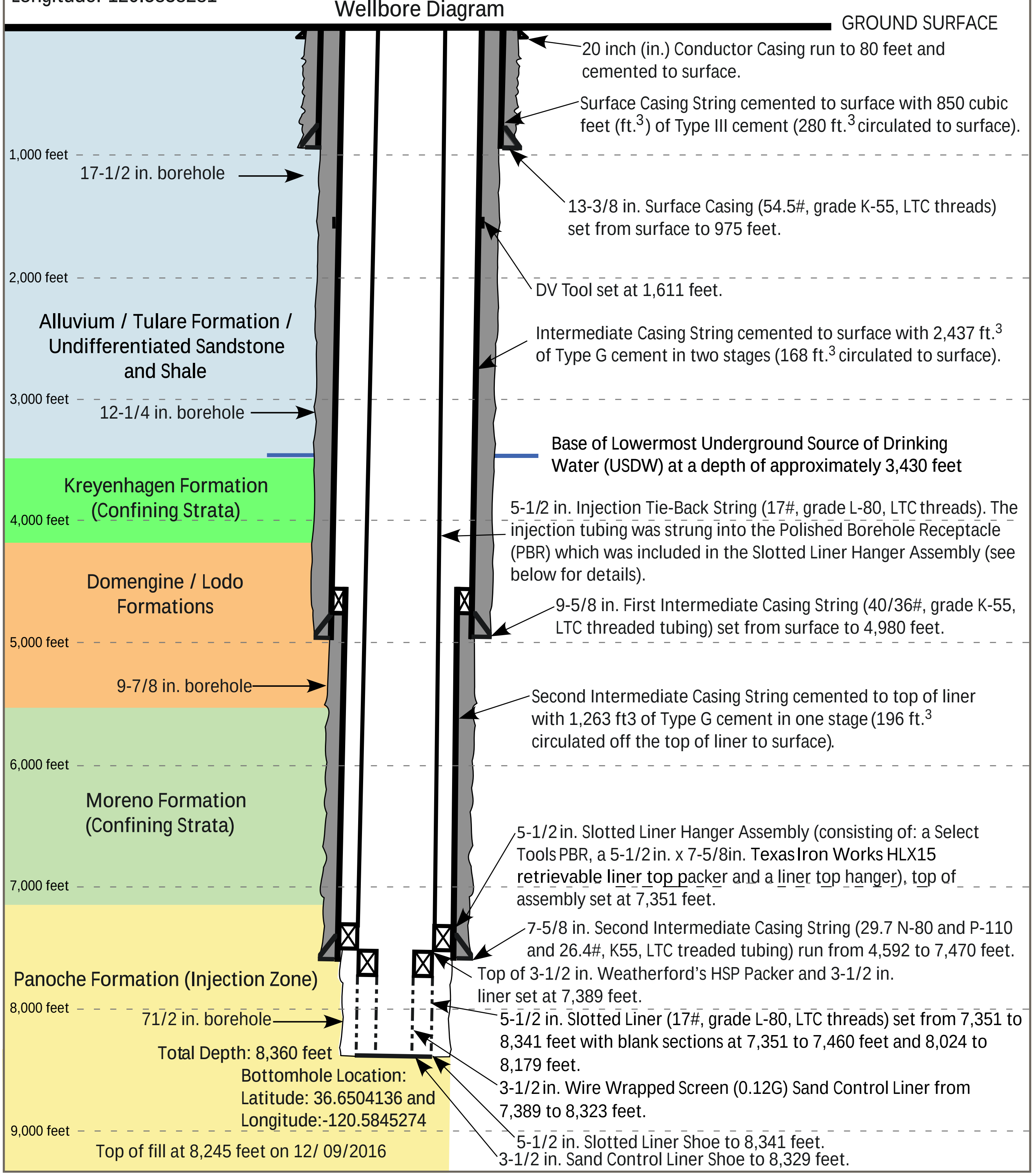
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.650645 and
Longitude:-120.5838281

Spud: September 26, 2008 Final Drilling Rig (Kenai #5)
Report: December 17, 2008 Final Completion Rig (Rival #9)
URS Completion Report: February 19, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =13 feet (ft.) above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 10/20/2020

Panoche Energy Center
Well IW2

FIGURE M-2

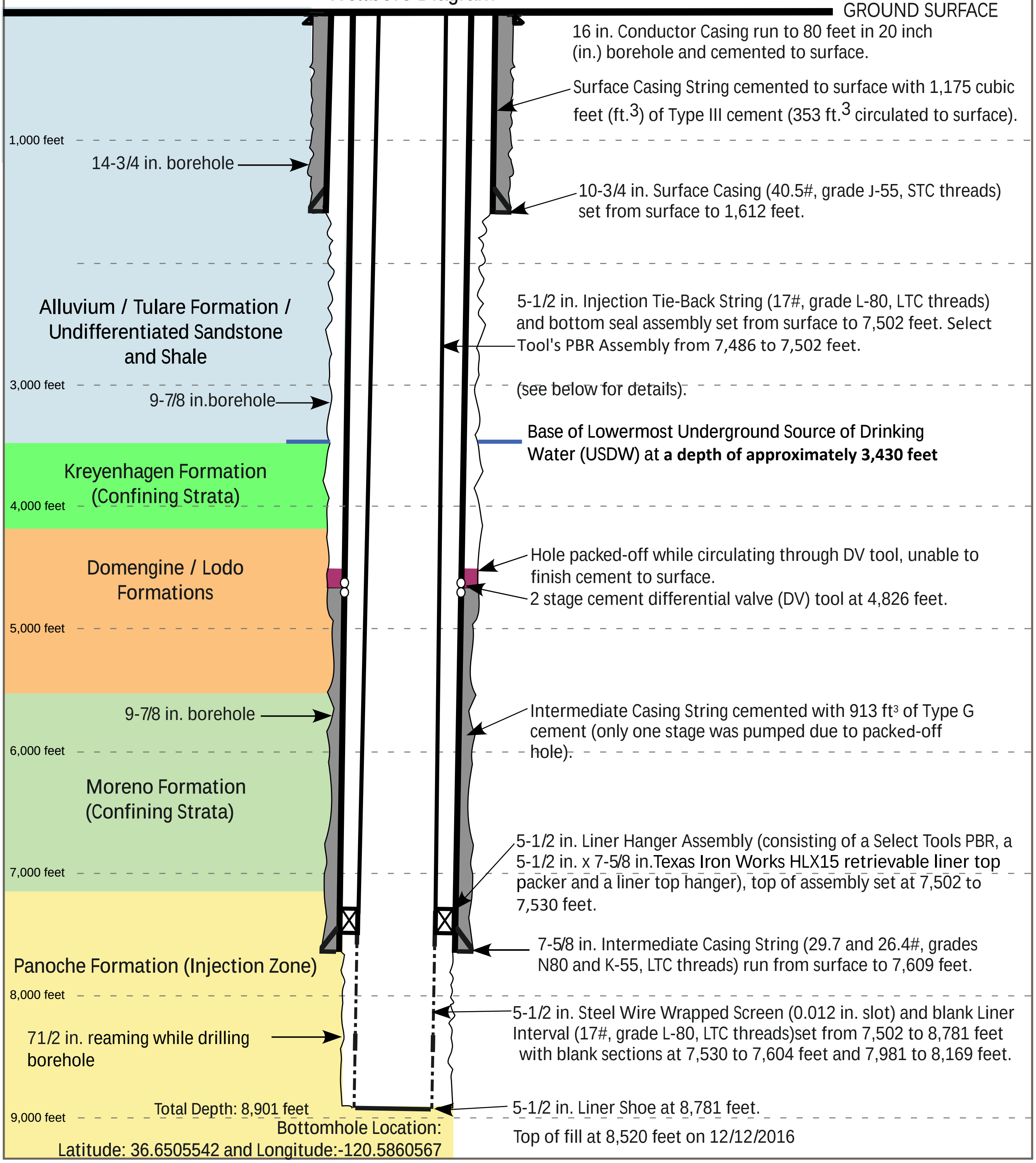
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.650588 and
Longitude:-120.5849399

Spud: December 19, 2008 Final Drilling Rig (Kenai #5)
Report: January 17, 2008 Final Completion Rig (Rival #9)
Report: January 29, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =13 feet (ft.) above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 11/05/2020

Panoche Energy Center
Well IW3

FIGURE M-3

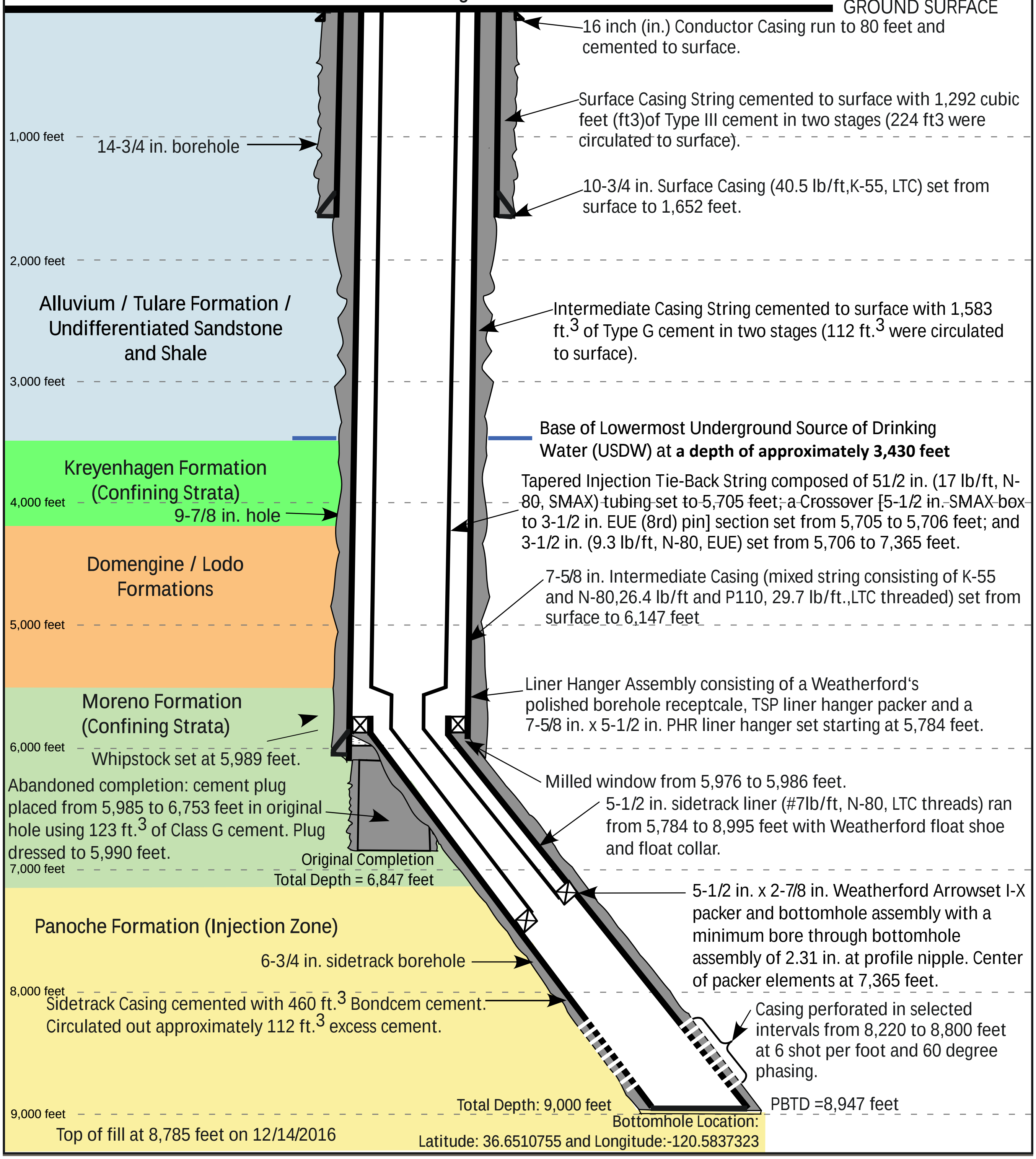
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.6506313 and
Longitude:-120.5833801

Spud: April 30, 2009
Final Original Hole Drilling Rig Report : May 25, 2009
Start of Well Deepening Sidetrack: October 19, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth = 19 feet (ft.) above Ground Surface (KB =427 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2018

FIGURE M-4

Panoche Energy Center
Well IW4

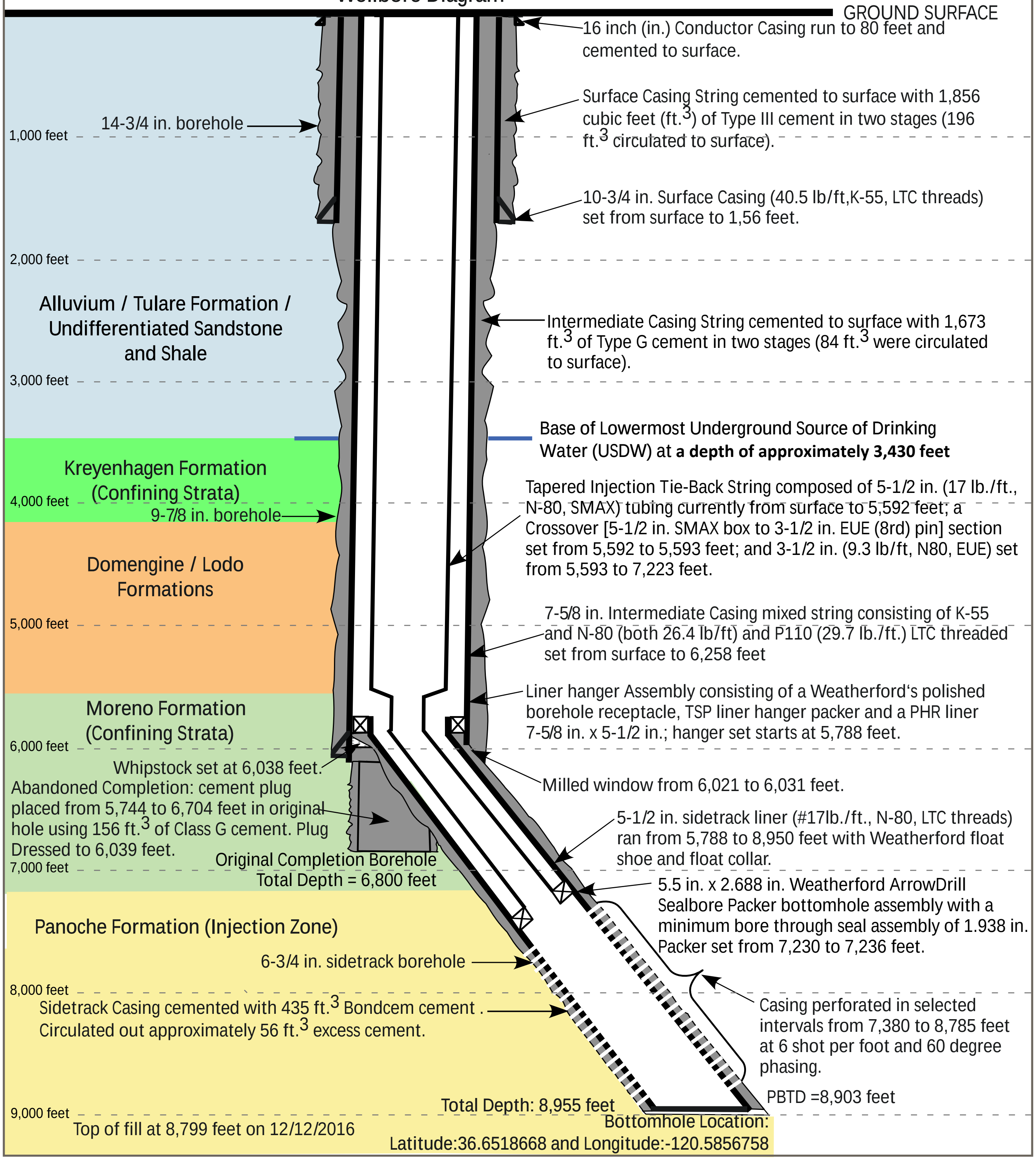
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.6509366 and
Longitude:-120.585846

Spud: May 6, 2009
Final Original Hole Drilling Rig Report: June 4, 2009
Start of Well Deepening Sidetrack: October 20, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 410 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =19 feet (ft.) above Ground Surface (KB =429 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2017

Appendix C

EPA Reporting Forms

UIC Permit R9UIC-CA1-FY17-2R

EPA Reporting Forms List

Form 7520-7: Application to Transfer Permit

Form 7520-8: Quarterly Injection Well Monitoring Report

Form 7520-18: Completion Report for Injection Wells

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

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

Appendix D

Logging Requirements

UIC Permit R9UIC-CA1-FY17-2R

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 9

RADIOACTIVE TRACER SURVEY (RTS) GUIDELINES

Introduction:
The intent of this guideline document is to provide general guidance to owners and operators of Class I non-hazardous underground injection wells for performing radioactive tracer surveys (RTS) used as a means of testing and measuring the external mechanical integrity of these wells as defined in 40 CFR Part 146.8(a)(2). These guidelines are general in nature and individual well conditions may require deviations from these procedures. All proposed plans and any deviations from these guidelines to conduct radioactive tracer surveys must be approved in advance by the EPA Region 9 Drinking Water Protection Section.

Basic Guidelines:
Prior to commencing performance of the RTS, the operator must have available onsite the following:

- EPA approved plan for conducting the RTS
- Reference Gamma Ray (GR) or Open Hole logs and complete well construction details

The logging company must provide a drawing of their tool configuration with tool diameter, tool length, spacing between detectors, ejector location, casing collar log (CCL), a sketch of the well to be tested construction details and equipment details as part of the logging record.

Tool must include dual GR detectors spaced below the ejector port, centralized with a bow spring centralizer (or motorized centralizer) and be run in conjunction with a CCL.

GR logs are usually run at approximately 60 ft /min. at a time constant of 1 second or 30 ft/min. at a time constant of 2 seconds. Indicate the logging speed and time constant on the logging record. The log scale should preferably correspond with that of the Reference lithology logs that are made available for onsite correlation.

The radioisotope typically utilized for tracer surveys in injection wells is sodium iodine 131 with a half-life of 8.05 days. It is important that the isotope be completely soluble with the injectate fluid.

Example Procedure:

Indicate the beginning and ending clock times on each log pass. Indicate the volume of water injected between log passes. Indicate the volume and concentration of each slug of tracer material and the depth and location of each slug. Where possible, the tracer survey should be conducted utilizing the facility's permitted injectate. If that is not possible, the injected water should have a specific gravity equivalent to that of the facility wastewater and be compatible with the formation and previously injected wastewater. A hydraulically actuated packoff (lubricator) should be utilized even when high well pressures are not expected.

Install the RTS tool with an upper and lower detector and CCL. The RTS tool should be configured to run a standard RTS and to conduct velocity shots. Place the RTS tool in the lubricator and mount lubricator onto the injection wellhead. Open the master valve and slowly start pumping into the well until the desired flow rate is reached.

<u>Radioactive Baseline Survey</u>

1. Run a Correlation GR log with a CCL for 200 to 400 feet at or near the injection interval, provided lithology changes are sufficient for correlation purposes. This will allow equipment to be set on proper depths with the Reference Open Hole or GR logs for the well. The CCL should be run through the packer setting depth and preferably past a short casing joint to collect reference depth information.

2. Run a Base GR log from total depth to approximately 400 feet above the packer setting depth. The log sensitivity should be set such that the slug trace response will take up the entire horizontal log scale in API units. The Base log need not be sensitive enough to show lithology. Record the Total Depth for this initial Base log.

3. Record the injection rate and pressure on the well log record for each log pass. The test should be conducted at the rate corresponding to the Maximum Authorized Injection Pressure (MAIP); however, where the well has been operating at a pressure and rate that are lower than the MAIP, the operator may request approval in advance that the RTS should be run at those operating pressures and rates in which the well normally operates (lower than the MAIP).

<u>Radioactive Tracer Depth Drive Survey</u>

4. Initiate the first slug/ejection with the ejector situated approximately 200 feet above the packer. Record the depth and time, verify ejection of the slug, then drop below the slug and record the time, logging speed, time constant, flow rate, etc. Proceed to make the first logging run up through the slug to above where the slug was initially ejected. Note the time when logging terminated, then again drop past the slug and repeat the logging procedure, each time overlapping the previous log and up to a point where the log returns to baseline. Repeat the

logging sequence until all tracer material has exited the wellbore or has diminished substantial amounts.

Radioactive Tracer Time Drive Survey

5. Initiate a second ejection with the tool set 2 to 5 feet above the injection interval and on time drive. Wait for the pre-calculated Wait-Time to observe whether any vertical migration is occurring. Increase the pump rate to the anticipated operating injection rate and leave on time drive for another 10 to 15 minutes. Note times, flow rates, pressures, and slug depth.

Radioactive Tracer Vertical Migration Survey

6. Initiate a third ejection approximately 200 feet above the packer, then follow the slug to the injection zone using multiple log passes as with the first slug/ejection to check for leakage around the packer.

Radioactive Tracer Velocity Survey

7. These can be performed at this juncture of the testing. First, run a velocity profile over the injection horizon noting injection rate. Make velocity shots of tracer material at recorded intervals while injection is occurring at less than normal or peak pumping rates. Run the gamma ray tool through the injection zone and record injectate across the intervals injected. Increase the well injection rate to maximum or normal pumping rate and repeat velocity shots of tracer material at recorded intervals. Run the GR tool through the injection zone and record injectate across the intervals injected at the higher well pumping rate. The information gathered from the two passes made at different pumping rates will allow flow distribution to be compared at the different rates.

Radioactive Post Tracer Survey

8. After sufficient testing has been done to determine the exit point of the tracer material and for indications of vertical migration, drop to and record this second total depth and run a final Base GR log from total depth to approximately 400 feet above the packer at the same logging speed and sensitivity as with initial base log. These two logs should overlay each other with all the "hot spots" being explainable.

Post Survey Requirements

9. Interpretation of the log must be provided by the logging company on the log itself. The well log heading should be completely filled out with all essential information provided such as well name and number, coordinates, well owner/operator, reference logs, and elevations, etc. documented. The log should

be depicted in a manner that fully describes the operations conducted with explanations inserted to minimize the possibility of misinterpretation. Three copies of the final prints must be forwarded to the EPA Region 9 Groundwater Office within 30 days of the survey. The electronic copy may be provided via mailed storage disk, email or a web accessed site. Courtesy field copies provided to the onsite EPA Inspector are not official records.

10. The operator provides an analytical interpretation of the logging results performed by a qualified analyst. This must include a written description of the procedure, the methodology used to calculate the Wait-Time and conclusions drawn from the test. The submittal must also include a fluid loss profile across the injection interval.

NOTE: The above referenced method for performing a Radioactive Tracer Survey (RTS) is not necessarily prescriptive of how all tests are to be conducted. Each underground injection well presents unique subsurface geological, pressure and injection rate situations which must be properly accounted for when designing specific RTS plans and procedures and approved in advance.

References and Additional Information:

Refer to the following EPA publications for additional information and guidance on running and interpreting radioactive tracer and temperature logs for evaluation of injection well integrity:

- Dr. R. M. McKinley's publication EPA/600/R-94/124, *Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity*.
  It is out of print, but can be downloaded (searched as "600R94124") from the National Service Center for Environmental Publications (NSCEP) site:

  https://www.epa.gov/nscep

- EPA Region 8 UIC Program Staff Guidance Document at:
  http://www2.epa.gov/sites/production/files/documents/INFO-RATS.pdf

Special acknowledgments for additional consultation with:
Texas World Operations, Inc.
Dr. R.M. McKinley

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 9

TEMPERATURE LOGGING GUIDELINES

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

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

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

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

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

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

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

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

(a) a collar locator log,

(b) a lithology log which includes either:

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

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

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

Appendix E

EPA Region 9 UIC Pressure Falloff Requirements

UIC Permit R9UIC-CA1-FY17-2R

EPA Region 9
UIC PRESSURE FALLOFF REQUIREMENTS

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

August 8, 2002

TABLE OF CONTENTS

APPENDIX

REQUIREMENTS

UIC PRESSURE FALLOFF TESTING GUIDELINE
Third Revision
August 8, 2002

1.0 Background

Region 9 has adopted the Region 6 UIC Pressure Falloff Testing Guideline requirements for monitoring Class 1 Non Hazardous waste disposal wells. Under 40 CFR 146.13(d)(1), operators are required annually to monitor the pressure buildup in the injection zone, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

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

A falloff **test** is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff **period** is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing **analysis** provides transmissibility, skin factor, and well flowing and static pressures.

2.0 Purpose of Guideline

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

Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well. Both the reservoir parameters and pressure data are necessary for UIC permit demonstrations. Additionally, a valid falloff test is a monitoring requirement under 40 CFR Part 146 for all Class I injection wells.

The ultimate responsibility of conducting a valid falloff test is the task of the operator. Operators should QA/QC the pressure data and test results to confirm that the results "make sense" prior to submission of the report to the EPA for review.

3.0 Timing of Falloff Tests and Report Submission

Falloff **tests** must be conducted annually. The time **interval** for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals.

The falloff testing **report** should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

4.0 Falloff Test Report Requirements

In general, the **report** to EPA should provide:

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

Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The **falloff test report** should include the following information:

1. **Company name and address**
2. **Test well name and location**
3. The name and phone number of **the facility contact person**. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. **A photocopy of an openhole log** (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. **Well schematic** showing the current wellbore configuration and completion information:
   - X Wellbore radius
   - X Completed interval depths
   - X Type of completion (perforated, screen and gravel packed, openhole)
6. **Depth of fill depth and date tagged.**
7. **Offset well information:**
   - X Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
   - X Simple illustration of locations of the injection and offset wells
8. **Chronological listing of daily testing activities.**
9. **Electronic submission of the raw data (time, pressure, and temperature)** from all pressure gauges utilized on CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any

edited data used in the analysis can be submitted as an additional file.

10. **Tabular summary of the injection rate or rates preceding the falloff test.** At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. **Rate information from any offset wells completed in the same interval.** At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. **Hard copy of the time and pressure data** analyzed in the report.
13. **Pressure gauge information:** (See Appendix, page A-1 for more information on pressure gauges)
    - X List all the gauges utilized to test the well
    - X Depth of each gauge
    - X Manufacturer and type of gauge. Include the full range of the gauge.
    - X Resolution and accuracy of the gauge as a % of full range.
    - X Calibration certificate and manufacturer's recommended frequency of calibration
14. **General test information:**
    - X Date of the test
    - X Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well <u>and any offset wells</u>.
    - X Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. **Reservoir parameters (determination):**
    - X Formation fluid viscosity, μ_f cp (direct measurement or correlation)
    - X Porosity, φ fraction (well log correlation or core data)
    - X Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
    - X Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - X Initial formation reservoir pressure - See Appendix, page A-1
    - X Date reservoir pressure was last stabilized (injection history)
    - X Justified interval thickness, h ft - See Appendix, page A-15
16. **Waste plume:**
    - X Cumulative injection volume into the completed interval
    - X Calculated radial distance to the waste front, r_{waste} ft
    - X Average historical waste fluid viscosity, if used in the analysis, μ_{waste} cp

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

5.0 Planning

The **radial flow portion** of the test is the basis for all pressure transient calculations. Therefore the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns

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

- X Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- X Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- X The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- X The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- X Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- X Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- X Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- X If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be **analyzed as an interference test** to obtain interwell reservoir parameters.

Site Specific Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
    - X Review previous welltests, if available
    - X Simulate the test using measured or estimated reservoir and well completion parameters
    - X Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
    - X Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.

2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to

produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/μ) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are required. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)

4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

6.0 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well

2. Simplify the pressure transients in the reservoir
   - X Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
   - X Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
   - X Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

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

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

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

7.0 Evaluation of the Falloff Test

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

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

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

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

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

4. Explain any anomalous results.

8.0 Technical References

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APPENDIX

Pressure Gauge Usage and Selection

<u>Usage</u>

- X EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- X **Downhole pressure measurements** are less noisy and are required.
- X A bottomhole surface readout gauge (SRO) allows tracking of pressures in real time. Analysis of this data can be performed in the field to confirm that the well has reached radial flow prior to ending the test.
- X The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.
- X Mechanical gauges should be **calibrated** before and after each test using a dead weight tester.
- X Electronic gauges should also be **calibrated** according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

<u>Selection</u>

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

Test Design

<u>General Operational Considerations</u>

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

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

X Waste storage and other operational issues require preplanning and need to be addressed prior to the test date. If brine must be brought in for the injection portion of the test, operators should insure that the fluid injected has a consistent viscosity and that there is adequate fluid available to obtain a valid falloff test. The use of the wastestream as the injection fluid affords several distinct advantages:

1. Brine does not have to be purchased or stored prior to use.
2. Onsite waste storage tanks may be used.
3. Plant wastestreams are generally consistent, i.e., no viscosity variations

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

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

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

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

X The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period.

X The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

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

X Wellbore radius, r_w - from wellbore schematic

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

Design Calculations

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

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

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

   b. Well goes on a vacuum:

   $$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot g_c}}$$ where, V_u is the wellbore volume per unit length, bbls/ft
   ρ is the injectate density, psi/ft
   g and g_c are gravitational constants

2. Calculate the time to reach radial flow for both the injection and falloff periods. Two different empirically-derived equations are used to calculate the time to reach radial flow, $t_{radial\ flow}$, for the injectivity and falloff periods:
   a. Injectivity period:

   $$t_{radial\,flow} > \frac{(200000 + 12000s) \cdot C}{\frac{k \cdot h}{\mu}} \quad hours$$

   b. Falloff period:

   $$t_{radial\,flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \quad hours$$

   The wellbore storage coefficient is assumed to be the same for both the injectivity and falloff periods. The skin factor, s, influences the falloff more than the injection period. Use these equations with caution, as they tend to fall apart for a well with a large permeability or a high skin factor. Also remember, the welltest should not only reach radial flow, but also sustain radial flow for a timeframe sufficient for analysis of the radial flow period. As a rule of thumb, a timeframe sufficient for analysis is 3 to 5 times the time needed to reach radial flow.

3. As an alternative to steps 1 and 2, to look a specific distance "L" into the reservoir and possibly confirm the absence or existence of a boundary, the following equation can be used to estimate the time to reach that distance:

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

where, $L_{boundary}$ = feet to boundary
$t_{boundary}$ = time to boundary, hrs

Again, this is the time to reach a distance "L" in the reservoir. Additional test time is required to observe a fully developed boundary past the time needed to just reach the boundary. As a rule of thumb, to see a fully developed boundary on a log-log plot, allow at least 5 times the time to reach it. Additionally, for a boundary to show up on the falloff, it must first be encountered during the injection period.

4. Calculate the expected slope of the semilog plot during radial flow to see if gauge resolution will be adequate using the following equation:

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

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

Considerations for Offset Wells Completed in the Same Interval

Rate fluctuations in offset wells create additional pressure transients in the reservoir and complicate the analysis. Always try to simplify the pressure transients in the reservoir. Do not simultaneously shut-in an offset well and the test well. The following items are key considerations in dealing with the impact of offset wells on a falloff test:

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

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

Falloff Test Analysis

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

Cartesian Plot

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

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

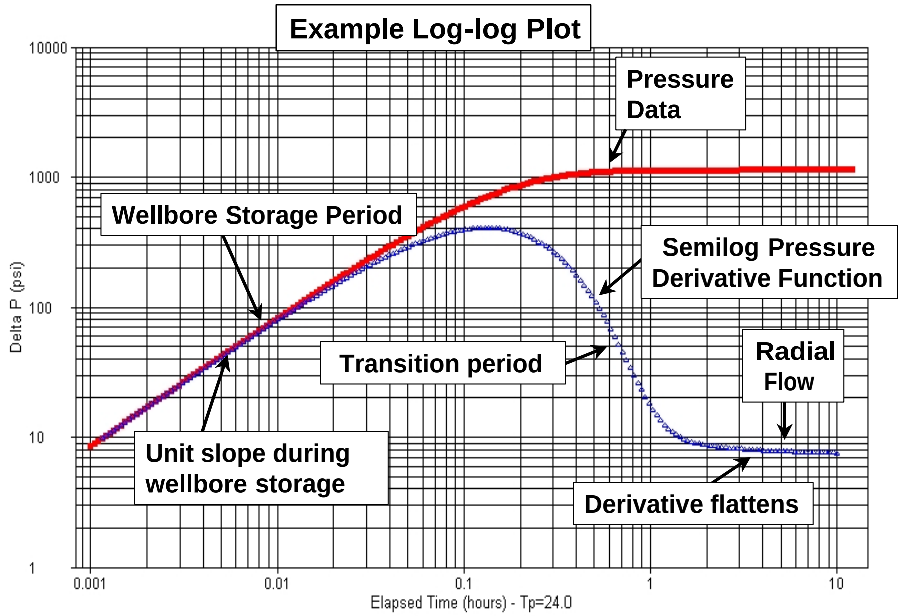
X **Falloff tests conducted in highly transmissive reservoirs** may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for by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

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

Log-log Diagnostic Plot

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

An example log-log plot is shown below:



Identification of Test Flow Regimes

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

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

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

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

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

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

Characteristics of Individual Test Flow Regimes

X **Wellbore Storage:**

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

X **Radial Flow:**

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

X **Spherical Flow:**

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

X **Linear Flow:**

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

X **Hydraulically Fractured Well:**

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

X **Naturally Fractured Rock:**

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

X **Layered Reservoir:**

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

<u>Semilog Plot</u>

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

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

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

Determination of the Appropriate Time Function for the Semilog Plot

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

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

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

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

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

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

X The **superposition time function** accounts for variable rate conditions preceding the falloff.

1. It is the most rigorous of all the time functions and is usually calculated using welltest software.
2. The use of the superposition time function requires the operator to accurately track the rate history. As a rule of thumb, at a minimum, the rate history for twice the length of the falloff test should be included in the analysis.

The determination of which time function is appropriate for the plotting the welltest on semilog and log-log plots depends on available rate information, injection period length, and software:

1. If there is not a rate history other than a single rate and cumulative injection, use a Horner time function
2. If the injection period is shorter than the falloff test and only a single rate is available, use the Agarwal equivalent time function
3. If you have a variable rate history use superposition when possible. As an alternative to superposition, use Agarwal equivalent time on the log-log plot to identify radial flow. The semilog plot can be plotted in either Horner or Agarwal time if radial flow is observed on the log-log plot.

Parameter Calculations and Considerations

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

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

where, q = injection rate, bpd (negative for injection)
B = formation volume factor, rvb/stb (Assumed to be 1 for formation fluid)
m = slope of the semilog straight line through the radial flow portion of the plot in psi/log cycle
k = permeability, md
h = thickness, ft (See Appendix, page A-15)
μ = viscosity, cp

X The viscosity, μ , is usually that of the formation fluid. However, if the waste plume size is massive, the radial flow portion of the test may remain within the waste plume. (See Appendix, page A-14)

1. The waste and formation fluid viscosity values usually are similar, however, if the wastestream has a significant viscosity difference, the size of the waste plume and distance to the radial flow period should be calculated.
2. The mobility, k/μ, differences between the fluids may be observed on the derivative curve.

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

Skin Factor

X In theory, wellbore skin is treated as an infinitesimally thin sheath surrounding the wellbore, through which a pressure drop occurs due to either damage or stimulation. Industrial injection wells deal with a variety of waste streams that alter the near wellbore environment due to precipitation, fines migration, ion exchange, bacteriological processes, and other mechanisms. It is reasonable to expect that this alteration often exists as a zone surrounding the wellbore and not a skin. Therefore, at least in the case of industrial injection wells, the assumption that skin exists as a thin sheath is not always valid. This does not pose a serious problem to the correct interpretation of falloff testing except in the case of a large zone of alteration, or in the calculation of the flowing bottomhole pressure. Region 6 has seen instances in which large zones of alteration were suspected of being present.

X The skin factor is the measurement of the completion condition of the well. The skin factor is quantified by a positive value indicating a damaged completion and a negative value indicating a stimulated completion.

1. The magnitude of the positive value indicating a damaged completion is dictated by the transmissibility of the formation.
2. A negative value of -4 to -6 generally indicates a hydraulically fractured completion, whereas a negative value of -1 to -3 is typical of an acid stimulation in a sandstone reservoir.
3. The skin factor can be used to calculate the effective wellbore radius, r_{wa} also referred to the apparent wellbore radius. (See Appendix, page A-13)
4. The skin factor can also be used to correct the injection pressure for the effects of wellbore damage to get the actual reservoir pressure from the measured pressure.

X The skin factor is calculated from the following equation:

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

where, s = skin factor, dimensionless

P_{1hr} = pressure intercept along the semilog straight line at a shut-in time of 1 hour, psi

P_{wf} = measured injection pressure prior to shut-in, psi

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

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

k = permeability, md

φ = porosity, fraction

c_t = total compressibility, psi^{-1}

r_w = wellbore radius, feet

t_p = injection time, hours

Note that the term $t_p/(t_p + \Delta t)$, where Δt=1 hr, appears in the log term. This term is usually assumed to result in a negligible contribution and typically is taken as 1 for large t. However, for relatively short injection periods, as in the case of a drill stem test (DST), this term can be significant.

Radius of Investigation

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

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

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

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

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

Effective Wellbore Radius

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

X The effective wellbore radius is calculated from the following:

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

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

Reservoir Injection Pressure Corrected for Skin Effects

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

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

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

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

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

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

Determination of the Appropriate Fluid Viscosity

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

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

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

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

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

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

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

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

where, t_w= time to exit waste front, hrs
$V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
h = interval thickness, ft
k = permeability, md
μ_w = viscosity of the historic waste plume at reservoir conditions, cp
c_t = total system compressibility, psi^{-1}

X The **time should be plotted on both the log-log and semilog plots** to see if this time corresponds to any changes in the derivative curve or semilog pressure plot. If the time estimated to exit the waste front occurs before the start of radial flow, the assumption that the pressure transients were propagating through the reservoir fluid during the radial flow period was correct. Therefore, the viscosity of the reservoir fluid is the appropriate viscosity to use in analyzing the well test. If not, the viscosity of the historic waste plume should be used in the calculations. If the mobility ratio is extreme between the wastestream and formation fluid, adequate information should be included in the report to verify the appropriate fluid viscosity was utilized in the analysis.

Reservoir Thickness

X The thickness used for determination of the permeability should be justified by the operator. The net thickness of the defined injection interval is not always appropriate.

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

X Selecting an interval thickness is dependent on several factors such as whether or not the injection interval is composed of hydraulically isolated units or a single massive unit and wellbore conditions such as the depth to wellbore fill. When hydraulically isolated sands are present, it may be helpful to define the amount of injection entering each interval by conducting a flow profile survey. Temperature logs can also be reviewed to evaluate the intervals receiving fluid. Cross-sections may provide a quick look at the continuity of the injection interval around the injection well.

- X A copy of a SP/Gamma Ray well log over the injection interval, the depth to any fill, and the log and interpretation of available flow profile surveys run should be submitted with the falloff test to verify the reservoir thickness value assumed for the permeability calculation.

Use of Computer Software

- X To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.

- X All data should be submitted on a CD-ROM with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the CD, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

- X After analyzing any test, always look at the results to see if they “make sense” based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.

- X If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.

- X Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data acquisition hardware such as a faulty gauge. An anomalous response can often be traced to a brief, but significant rate change in either the test well or an offset well.

X Anomalous data trends have also been caused by such things as ambient temperature changes in surface gauges or a faulty pressure gauge. Explanations for data trends may be facilitated through an examination of the backup pressure gauge data, or the temperature data. It is often helpful to qualitatively examine the pressure and/or temperature channels from both gauges. The pressure data should overlay during the falloff after being corrected for the difference in gauge depths. On occasion, abrupt temperature changes can be seen to correspond to trends in the pressure data. Although the source of the temperature changes may remain unexplainable, the apparent correlation of the temperature anomaly to the pressure anomaly can be sufficient reason to question the validity of the test and eliminate it from further analysis.

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

APPENDIX F

EPA Region 9 Step Rate Test Procedure Guidelines

UIC Permit R9UIC-CA1-FY17-2R

Refer also to:

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

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

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
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STEP-RATE TEST PROCEDURE GUIDELINES

PURPOSE:

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

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

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

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

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

RECOMMENDED TEST PROCEDURES:

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

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

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

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

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

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

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

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

APPENDIX G

Plugging and Abandonment Plan

UIC Permit R9UIC-CA1-FY17-2R

Panoche Energy Center
Well IW1

FIGURE Q-1

Plug and Abandonment Plan

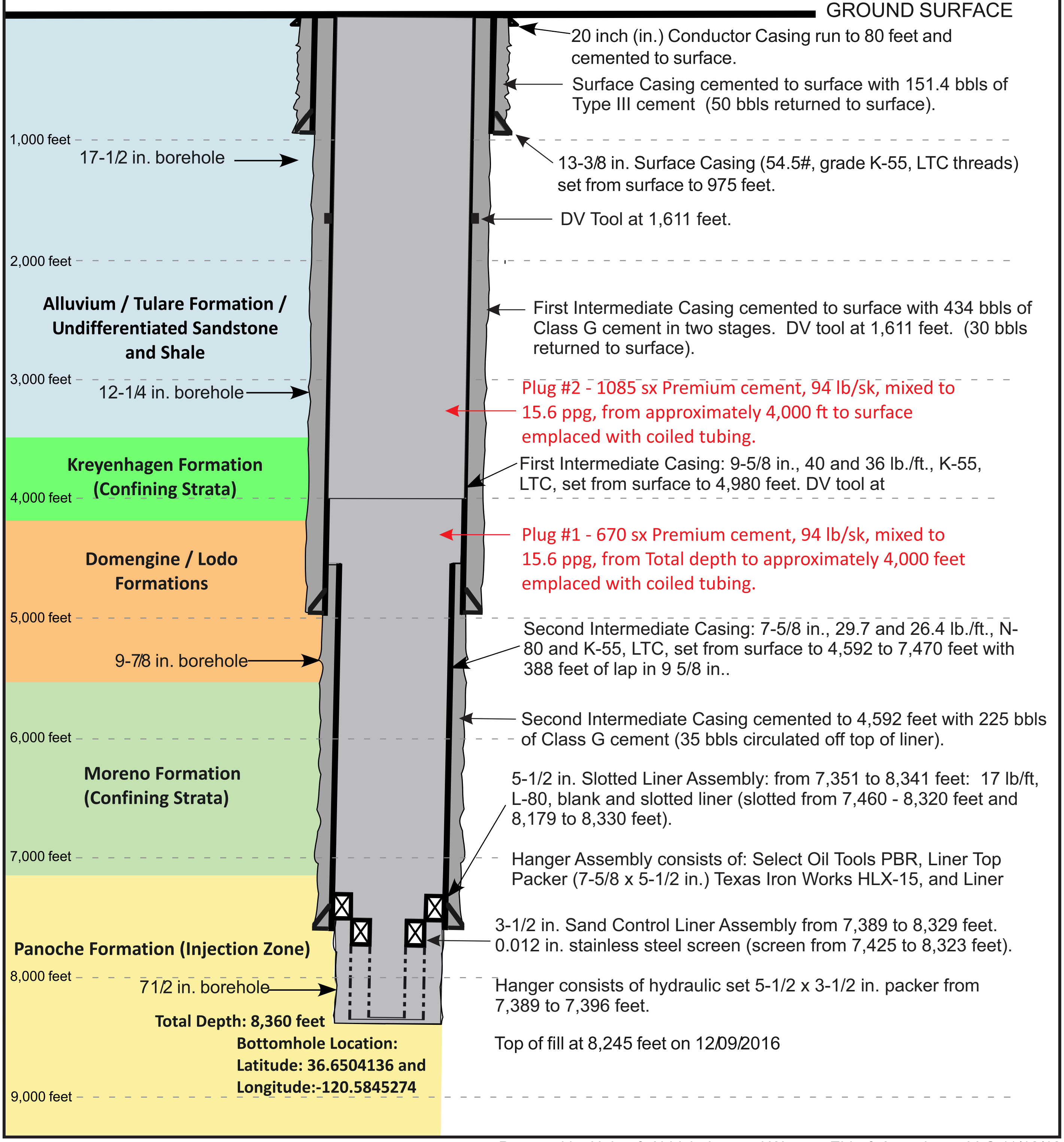
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.650645 and
Longitude:-120.5838281

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION

Spud: September 26, 2008 Final Drilling Rig (Kenai #5)
Report: December 17, 2008 Final Completion Rig (Rival #9)
URS Completion Report: February 19, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-1

IW1 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 220 bbls to kill tubing & 510 bbls to kill well with tubing removed)
4	e.	Rig up for laying down injection tubing. Kill injection tubing.
	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW1* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 185 bbls or approximately 670 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW1* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 306 bbls or approximately 1085 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	p.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

Panoche Energy Center
Well IW2

FIGURE Q-2
Plug and Abandonment Plan

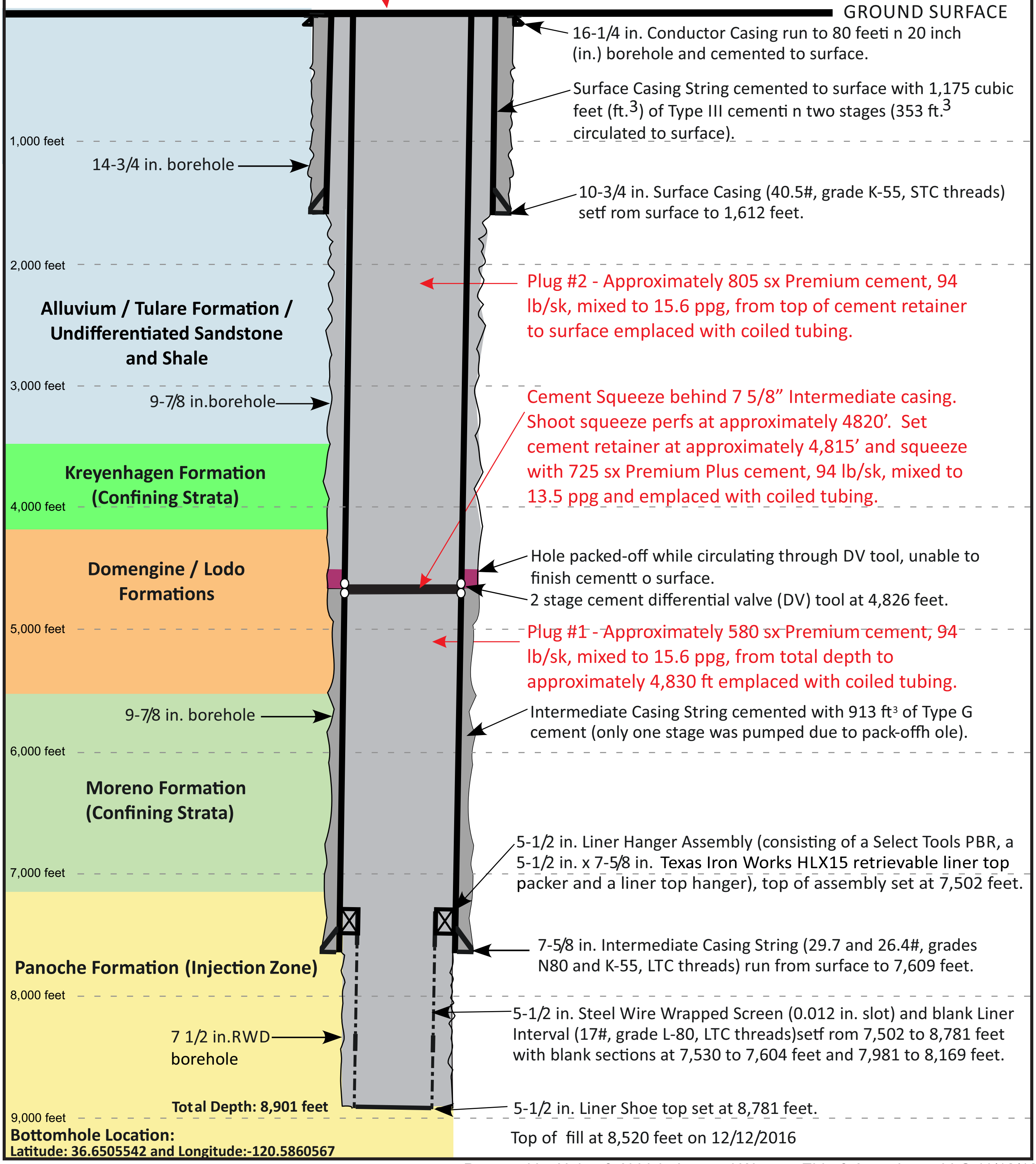
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.650588 and
Longitude:-120.5849399

Spud: December 19, 2008 Final Drilling Rig (Kenai #5)
Report: January 17, 2008 Final Completion Rig (Rival #9)
Report: January 29, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-2

IW2 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 225 bbls to kill tubing & 385 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW2* through 2-inch coiled tubing from PBTD to approximately 4,830 ft. Plug to consists of approximately 175 bbls or approximately 630 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Rig up wireline and shoot approximately 5 feet of perforations at 4,820 ft. for squeeze cementing of 7 5/8-inch longstring casing.
	o.	POOH with perforating guns and run in hole with 7 5/8-inch cement retainer to set at approximately 4,805 feet.
	p.	Run in hole with coiled tubing and sting into retainer. Open backside and squeeze cement 7 5/8-inch x 9 7/8-inch hole and 7 5/8-inch x 10 3/4-inch casing with 725 sx premium cement mixed to 13.5 ppg as per squeeze cementing program for IW2*. Unsting from retainer and leave 20 feet of cement on top of retainer and reverse clean. Pull out of hole and wait on cement to cure.
8	q.	Rig up wireline and run CBL on squeezed interval.
	r.	Run in hole with CT to bottom.
	s.	Pump second plug per cementing program for IW2* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 224 bbls or approximately 805 sx premium cement.
	t.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
9	u.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	v.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	w.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

Panoche Energy Center
Well IW3

FIGURE Q-3
Plug and Abandonment Plan

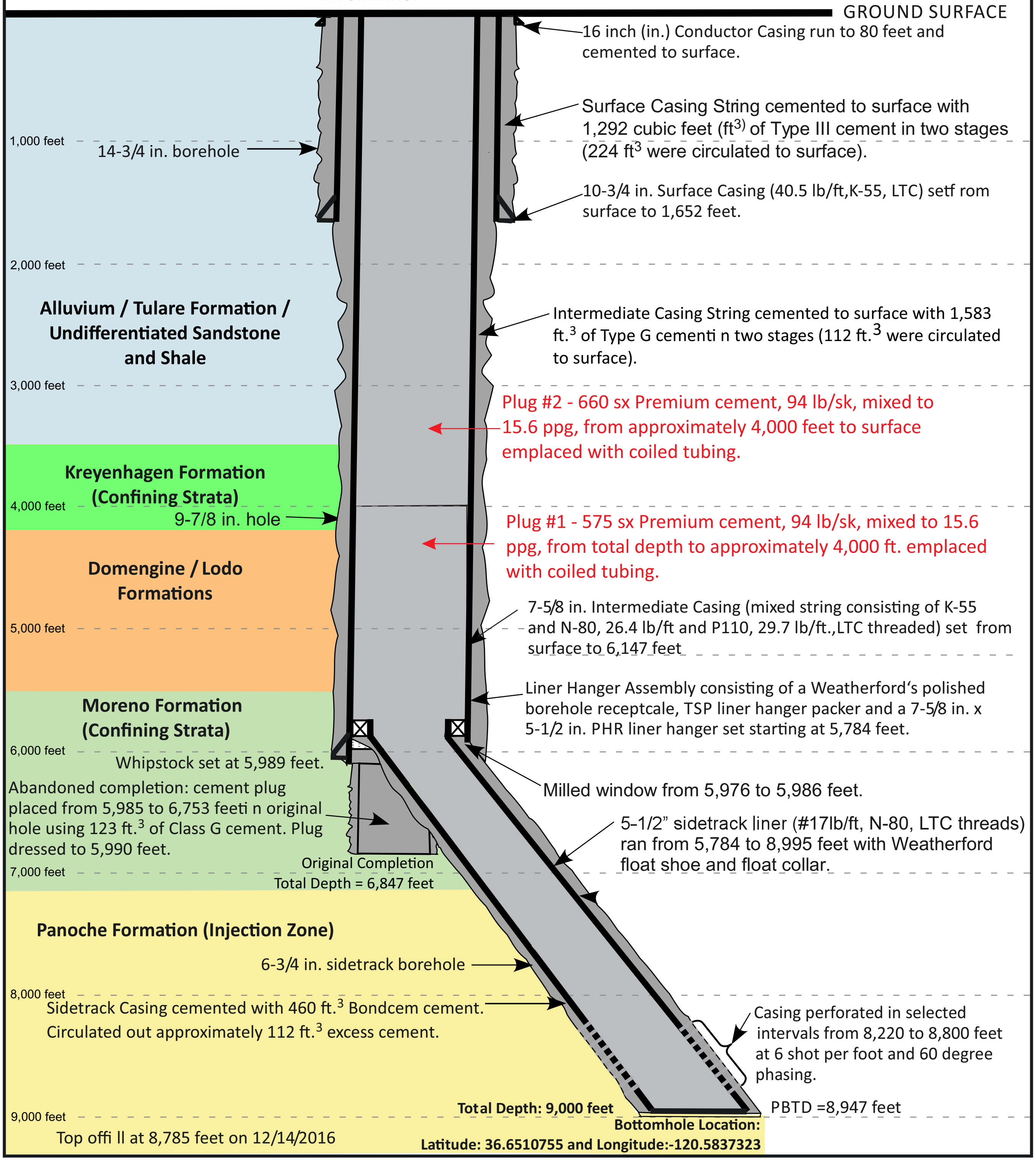
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.6506313 and
Longitude:-120.5833801

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION

Spud: April 30, 2009
Final Original Hole Drilling Rig Report : May 25, 2009
Start of Well Deepening Sidetrack: October 19, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =427 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-3

IW3 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 184 bbls to kill tubing & 346 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5 x 3.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW3* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 159 bbls or approximately 575 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW3* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	p.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

Panoche Energy Center
Well IW4

FIGURE Q-4
Plug and Abandonment Plan

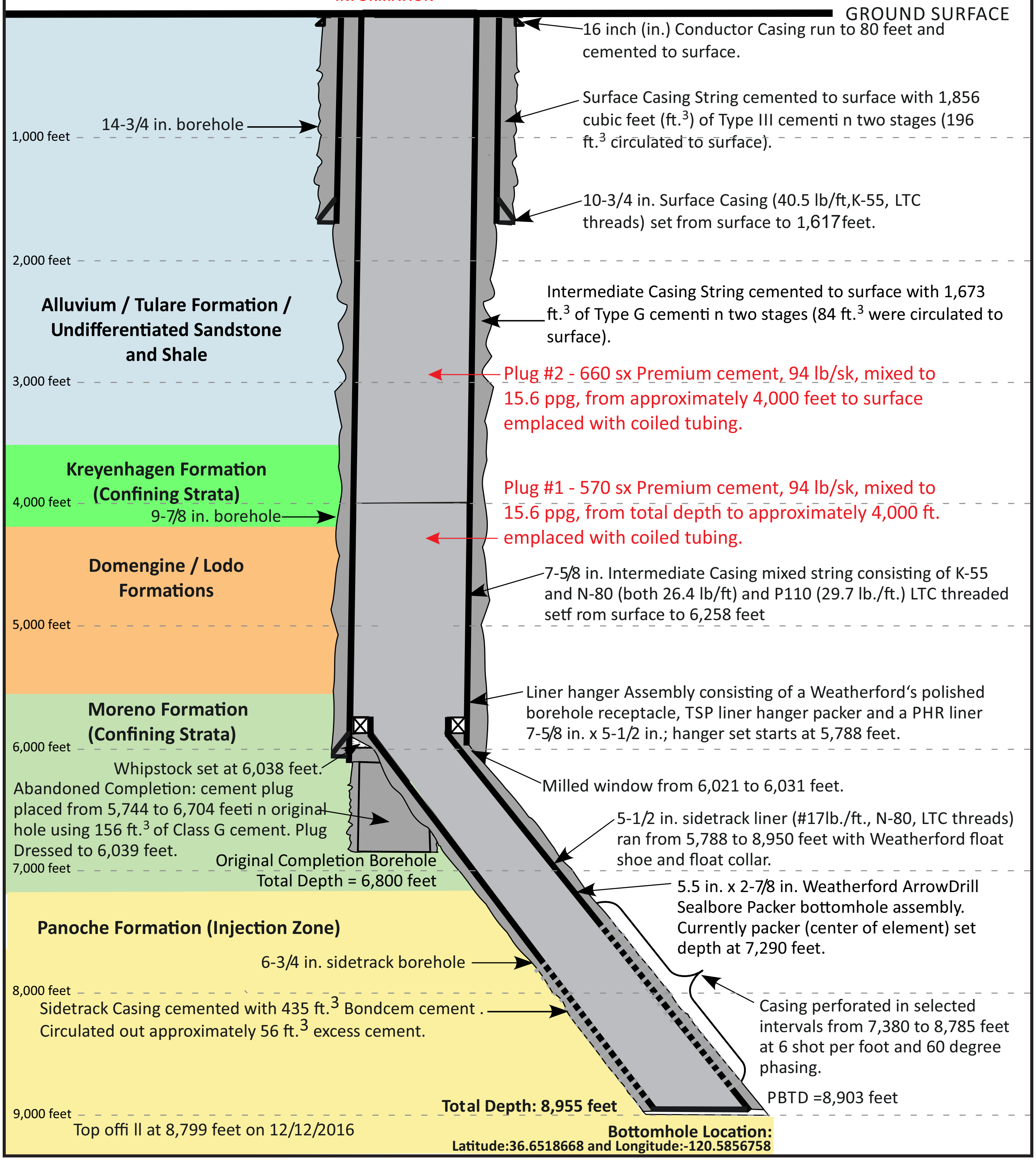
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.6509366 and
Longitude:-120.585846

Spud: May 6, 2009
Final Original Hole Drilling Rig Report: June 4, 2009
Start of Well Deepening Sidetrack: October 20, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 410 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =429 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-4

IW4 Proposed Plugging Program

Day	Task	Task Description
1	**a.**	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	**b.**	Radioactive Tracer Survey.
3	**c.**	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 182 bbls to kill tubing & 346 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	**f.**	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5 x 3.5-inch injection tie-back string and lay out to pipe racks.
5	**i.**	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	**k.**	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW4* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 158 bbls or approximately 570 sx premium cement. Wait appropriate amount of time for plug to cure.
7	**m.**	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	**p.**	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

APPENDIX H

Operating Data

UIC Permit R9UIC-CA1-FY17-2R

ATTACHMENT H – OPERATING DATA

PERMIT REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment H requires the applicant to submit the following proposed “operating data for each well (including all those to be covered by area permits):

(1) average and maximum daily rate and volume of the fluids to be injected;

(2) average and maximum injection pressure;

(3) nature of annulus fluid;

(4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids.”

AVERAGE AND MAXIMUM FLUID INJECTION RATES, VOLUMES, AND OPERATING PRESSURE

As described in Attachment P, all quarterly data can be found in the Quarterly Injection monitoring reports (tables and raw data spreadsheets) and in the Annual Monitoring Reports (USEPA Form 7520-11) submitted to USEPA for the last 10 years (See Exhibits folder on compact disc). A summary of an example set of consecutive four quarters of submitted operating data, including the average and maximum injection rate, daily volume of injectate, and injection pressure, are presented for each injection well in Table H-1. As the wells operate on an intermittent basis (only a few hours at a time) and thus, injection rates are presented in gallons per minute (gpm) as measure just during these injection periods rather than daily rates.

As described in Attachment K and previously discussed in Attachment A, the construction of the enhanced wastewater system (EWS) caused a decrease in wastewater injection at the Panoche Energy Center (PEC) facility starting in June 2016 (Haley & Aldrich, 2016). As a result, the anticipated wastewater injection rate is expected to be less between 2018 and 2027 than the wastewater injection rate that occurred between 2009 and 2016. Therefore, the data shown in Table H-1 was aggregated from the four most recent quarters of monitoring data (Haley & Aldrich, 2016, Haley & Aldrich, 2017a, Haley & Aldrich, 2017b, Haley & Aldrich, 2017c).

Maximum historic recorded daily injection volumes for each well are as follows: 144,039 gallons in IW1 during August 2013; 172,041 gallons in IW2 during September 2014; 155,147 gallons in IW3 during July 2013; and 164,002 gallons in IW4 during October 2014 (Haley & Aldrich, 2013b, Haley & Aldrich, 2014b, Haley & Aldrich, 2014c). While it is anticipated that future injection rates will be significantly lower most of the time due to the installation of the EWS, similar maximum daily injection volumes may occur when the EWS maintenance is required during a high electricity demand season. Therefore, we propose that the maximum daily injection volumes for the next permit period are set to be the same as the previous historic daily maximums. Similarly, the highest historical daily average volumes and maximum daily injection rates for individual wells reported in the quarterly reports are used as the proposed future values. The proposed average daily injection rates are estimated by the ratios of the proposed maximum daily volumes (in gallons) to 1,440 minutes; these estimates represent potential daily average rates that may occur when the EWS maintenance is required during a high electricity demand season.

Based on Attachment I, the proposed maximum injection pressures at well head are 2,478 pounds per square inch (psi) for IW1, IW3, and IW4; and 2,416 psi for IW2. The proposed average injection pressure at well head is 2,065 psi based on the historical maximum injection pressure for all wells. Note that the current injection pressure is limited by the capability of injection pumps (approximately 2,000 psi). The injection pumps can be upgraded to have the capability of performing injection at around 2,400 psi at well head.

The proposed average and maximum injection pressures, as well as the proposed average and maximum daily rate and volume of the fluids to be injected, are summarized in Table H-2.

NATURE OF ANNULUS FLUID

The annular fluid used in wells IW1 and IW2 consists of Amber Chemical's corrosion inhibitor packer fluid, which is composed of sodium bisulfite with a bio-filming amine (URS, 2009a; URS, 2009b). On 21 May 2013, IW3 was topped off with 10 pounds per gallon (ppg) inhibited fluid, and a packer was set in-place during the re-installation of injection tubing after fracture stimulation of this well (Haley & Aldrich, 2013a). On 16 June 2014, during the well repair of IW4, approximately 150 barrels (bbls) of 10.5 ppg calcium chloride inhibited with Geo Drilling Fluids, Inc.'s Amberguard COS and CAP was emplaced down the backside of the injection tube prior to setting the tubing sting packer (Haley & Aldrich, 2014a).

INJECTION FLUID CHARACTERISTICS

When it became operational, PEC performed a hazardous waste determination of the injection fluids on 28 April 2009, per the requirements of Code of Federal Regulations Title 40 (40 CFR) §262.11. The results of that determination indicated that the injection fluids did not meet the definition of hazardous waste as defined in 40 CFR §146.3 and §261. In addition, PEC performed a new hazardous waste injectate determination in the third quarter of 2016, per the above listed requirements and according to Section C, paragraph 1(b)(ii) of the Underground Injection Control (UIC) Permit, once an on-demand wastewater treatment system became operational and began contributing to the combined injectate flow. This Hazardous Waste Determination document concludes that the injectate still does not meet the definition of hazardous waste as defined in 40 CFR §146.3 and §261 and demonstrates that PEC continues to comply with the injection fluid limitations as required by Section C, paragraph 5(a) of the current UIC Permit. The Hazardous Waste Determination document prepared by PEC is presented as Appendix C of the Third Quarter 2016 Injection Monitoring Report (Haley & Aldrich, 2016).

In accordance with the Permit, injection fluid is analyzed on a quarterly basis (See Attachment P for details). The injection fluids for wells IW1 through IW4 originate from the same wastewater storage tank. Therefore, a single sample of injection fluid (a composite of all the wells) is collected and analyzed. A summary of the past four quarters of analytical results for injection fluids is presented in Table H-3. This time frame (previous four quarters) was selected because, as described above, the EWS system is in operation and the future injectate is expected to closely match the analytical results from the last four quarters.

References

1. Haley & Aldrich, Inc. (Haley & Aldrich). 2013a. IW3 Fracture Stimulation Report and Request to Operate Well IW3, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Fresno County, California. July.

2. Haley & Aldrich. 2013b. Third Quarter 2013 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

3. Haley & Aldrich. 2014a. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

4. Haley & Aldrich. 2014b. Third Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

5. Haley & Aldrich. 2014c. Fourth Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

6. Haley & Aldrich. 2016. Third Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

7. Haley & Aldrich. 2017a. Fourth Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

8. Haley & Aldrich. 2017b. First Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

9. Haley & Aldrich. 2017c. Second Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

10. URS. 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California. March.

11. URS. 2009b. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

TABLES

TABLE H-1
INJECTION WELL OPERATIONAL DATA
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Month	IW1						IW2						IW3						IW4					
	Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)	
	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
July, 2016	17,698.0	90,730.0	1,856.6	1,993.4	104.0	156.0	19,472.4	108,765.0	1,849.7	1,994.3	140.2	234.9	7,910.9	52,917.0	1,840.7	1,913.3	88.6	179.6	5,298.5	70,769.0	1,814.9	1,935.9	134.6	162.8
August, 2016	27,265.3	87,759.0	1,889.1	2,004.8	99.1	145.1	28,235.3	88,500.0	1,885.9	1,993.4	132.0	186.6	13,983.4	42,859.0	1,893.7	1,949.7	82.0	111.8	--	--	--	--	--	--
September, 2016	6,709.2	46,000.0	1,837.6	1,922.2	103.8	143.9	13,915.4	129,051.0	1,862.1	2,001.2	140.5	253.1	7,266.0	71,004.0	1,887.2	1,998.0	89.5	150.2	11,598.9	59,125.0	1,857.4	1,953.3	150.4	230.7
October, 2016	5,994.1	107,000.0	1,885.1	1,998.6	106.3	147.5	11,792.6	113,046.0	1,862.8	1,997.7	143.3	186.7	5,510.1	32,101.0	1,878.1	1,978.3	90.0	124.4	10,302.0	61,830.0	1,867.8	1,977.4	145.6	203.3
November, 2016	2,367.6	31,110.0	1,849.7	1,955.6	112.7	131.9	7,888.2	56,495.0	1,873.3	1,979.9	143.5	204.6	3,991.0	33,940.0	1,870.4	1,976.9	94.3	130.3	5,474.0	58,842.0	1,852.7	1,909.6	142.4	163.9
November, 2016	7,311.0	93,612.0	1,885.6	1,972.8	106.6	234.7	7,792.3	102,000.0	1,779.2	1,977.1	125.9	199.4	6,130.9	67,002.0	1,923.3	1,978.3	87.2	111.8	6,157.8	49,913.0	1,895.1	1,977.1	143.3	181.9
January, 2017	5,987.9	45,472.0	1,879.6	1,989.5	101.6	178.0	13,849.9	62,445.0	1,906.5	1,999.3	134.3	166.0	4,359.7	21,170.0	1,899.5	1,991.3	96.0	135.9	16,041.7	65,650.0	1,922.9	1,996.6	141.4	206.9
February, 2017	2,440.9	33,221.0	1,942.6	1,989.7	118.5	139.5	6,202.1	42,502.0	1,931.6	1,977.4	144.0	197.8	--	--	--	--	--	--	9,677.9	47,244.0	1,952.4	1,992.2	146.0	186.3
March, 2017	1,859.1	39,582.0	1,860.0	1,902.1	103.4	126.3	7,898.2	43,213.0	1,907.2	1,988.8	146.8	251.3	--	--	--	--	--	--	8,994.0	44,583.0	1,930.7	1,998.0	143.6	182.5
April, 2017	5,963.4	33,000.0	1,884.7	1,981.0	99.6	121.6	9,839.6	54,463.0	1,891.9	1,984.0	139.0	174.2	2,353.6	21,768.0	1,859.1	1,897.7	103.4	151.2	10,779.5	61,731.0	1,903.4	1,991.5	140.3	161.3
May, 2017	4,888.6	37,627.0	1,855.7	1,968.4	98.8	139.2	7,713.9	34,002.0	1,857.0	1,969.6	140.6	200.1	1,762.3	33,009.0	1,949.5	1,991.3	104.8	117.2	12,133.0	41,989.0	1,908.8	1,990.9	141.6	168.1
June, 2017	13,922.5	71,285.0	1,856.0	1,958.1	74.2	141.6	25,292.4	97,581.0	1,879.6	2,000.7	113.7	172.5	5,803.4	44,981.0	1,867.8	1,919.0	89.6	122.3	27,859.0	97,792.0	1,898.9	1,998.6	121.3	170.3
Historical Operating Parameters (12-month average, 12-month maximum)	8,534.0	107,000.0	1,873.5	2,004.8	102.4	234.7	13,324.4	129,051.0	1,873.9	2,001.2	137.0	253.1	5,907.1	71,004.0	1,886.9	1,998.0	92.5	179.6	11,301.5	97,792.0	1,891.4	1,998.6	141.0	230.7

Abbreviations:
-- = not applicable
gal = gallons
gpm = gallons per minute

TABLE H-2
PROPOSED INJECTION PRESSURES, RATES, AND VOLUMES
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Operation Parameter		Proposed Quantity			
		IW1	IW2	IW3	IW4
Injection Pressure (psi)	Average	2,065	2,065	2,065	2,065
	Maximum	2,478	2,416	2,478	2,478
Injection Rate (gpm)	Average	98	119	108	114
	Maximum	240	224	181	253
Daily Volume (gallons)	Average	7,808	149,555	99,458	123,890
	Maximum	141,039	172,041	155,147	164,002

Operation Parameter		Rationale fofr Proposed Quantity			
		IW1	IW2	IW3	Iw4
Injection Pressure (psi)	Average	Historical Maximum Pressure			
	Maximum	See Attachment I			
Injection Rate (gpm)	Average	Based on maximum daily volume (÷1440)			
	Maximum*	2Q-2016	2Q-2016	4Q-2014	3Q-2014
Daily Volume (gallons)	Average*	3Q-2015	3Q-2015	3Q-2013	3Q-2015
	Maximum*	3Q-2013	3Q-2014	3Q-2013	3Q-2015

Notes:
* = based on the historical values reported in a quarterly report (2Q2016 = second quarter 2016 monitoring report)
gpm = gallons per minute
psi = pounds per square inch

TABLE H-3
LABORATORY ANALYTICAL RESULTS FOR INJECTION FLUIDS
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Sample Date:		17-Aug-16	9-Dec-16	1-Mar-17	12-May-17
	Units	Results	Results	Results	Results
Physical/Chemical Properties					
pH	pH Units	8.0	7.4 J	7.3 J[1]	7.2 J [1]
Specific Conductivity	µmhos/cm @ 25°C[1]	13,000	9,900	14,000	15,000
Specific Gravity	@ 60/60°F[2]	1.008	1.0054	1.0107	1.011
Density	g/mL @ 60°F[3]	1.007	1.0054	1.0097	1.01
Viscosity	cSt @ 100°F[4]	0.7	0.71	1.1	0.76
Total Dissolved Solid	mg/L[5]	8,900	5,400	10,000	8,300
Total Suspended Solid	mg/L	17	21	32	22
Turbidity	NTU[6]	0.31	2.7	7.4	0.86
Alkalinity, as $CaCO_3$[7]	mg/L	410	270	280	260
Inorganic Analytes - Cations/Metals					
Aluminum	mg/L	< 0.050	< 0.050	< 0.050[9]	< 0.050[9]
Antimony	mg/L	< 0.0020	< 0.0040	< 0.0040	< 0.0020
Arsenic	mg/L	0.190	0.079	0.150	0.210
Barium	mg/L	0.019	0.019	0.037	0.021
Beryllium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Cadmium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Calcium	mg/L	37	61	18	15
Chromium	mg/L	< 0.010	< 0.020	< 0.020	0.010
Cobalt	mg/L	0.011	0.32	0.081	0.087
Copper	mg/L	0.041	0.050	0.200	0.130
Fluoride	mg/L	2.2	1.6	2.3	2.7
Iron	mg/L	0.60	3.1	23	1.9
Lead	mg/L	< 0.0050	< 0.010	< 0.002	< 0.001
Magnesium	mg/L	14	21	5.2	7.2
Manganese	mg/L	0.023	0.054	0.29	0.029
Mercury	mg/L	< 0.00020 J	< 0.0010	< 0.0002	< 0.0002
Molybdenum	mg/L	0.490	0.44	0.390	0.650
Nickel	mg/L	< 0.010	< 0.020	0.020	0.010
Phosphorus	mg/L	1.2	0.79	1.9	0.59
Potassium	mg/L	25	100	70	50
Selenium	mg/L	0.180	0.084	0.079	0.150
Silica (SiO_2)[9], total	mg/L	180	150	170	180
Silica (SiO_2), dissolved	mg/L	190	140	150	180
Silver	mg/L	< 0.010	< 0.020	< 0.020	< 0.010
Sodium	mg/L	3,900	2,600	3,900	4,900
Strontium	mg/L	0.500	0.70	0.660	0.460
Thallium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010 UJ [14]
Thorium	mg/L	< 0.00050	< 0.00050	< 0.00050	< 0.00050
Uranium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Vanadium	mg/L	0.013	< 0.0060	< 0.0060	0.010
Zinc	mg/L	0.067	0.160	< 0.100	0.058
Inorganic Analytes - Anions					
Bicarbonate, as $CaCO_3$	mg/L	410	270	280	260
Carbonate, as $CaCO_3$	mg/L	< 3.0	< 3.0	< 3.0	< 3.0
Hydroxide, as $CaCO_3$	mg/L	< 3.0	< 3.0	< 3.0	< 3.0
Chloride	mg/L	810	650	1,100	940
Sulfate, as SO_4[10]	mg/L	4,900	3,900	6,400	6,500
Nitrate, as NO_3[11]	mg/L	< 20	< 1.0	< 50	< 100
Orthophosphate, as P [12]	mg/L	< 4.0	< 0.20	< 10	< 20
Mass Balance					
Anions	meq/L[13]	130	110	170	170
Cations	meq/L	170	120	170	220
Non-Ionic Analytes					
Biochemical Oxygen Demand	mg/L	2.0	47 J	17 J	8.0
Detected Organic Analytes					
Acetone	mg/L	0.022	0.035	0.080	0.064
Dibromomethane	mg/L	< 0.00050	0.0086	0.0026	0.0022
Dibromochloromethane	mg/L	< 0.00050	0.0014	< 0.00050	0.0011
Bromoform	mg/L	0.0086	0.057	0.015	< 0.00050

Notes:
µmhos/cm @ 25°C = micromhos per centimeter at 25 degrees Celsius
g/mL @ 60°F = grams per milliliter at standadization temperture in degrees Fahrenheit
meq/L = milliequivalents per liter
mg/L = milligrams per liter
@ 60/60°F = standardization temperature in degrees Fahrenheit
< = not detected at or above the reporting limit shown
$CaCO_3$ = calcium carbonate
cSt @ 100°F = centistokes at 100 degrees Fahrenheit
NO_3 = nitrate
NTU = nephelometric turbidity units
P = phosphorus
SiO_2 = silicon dioxide
SO_4 = sulfate