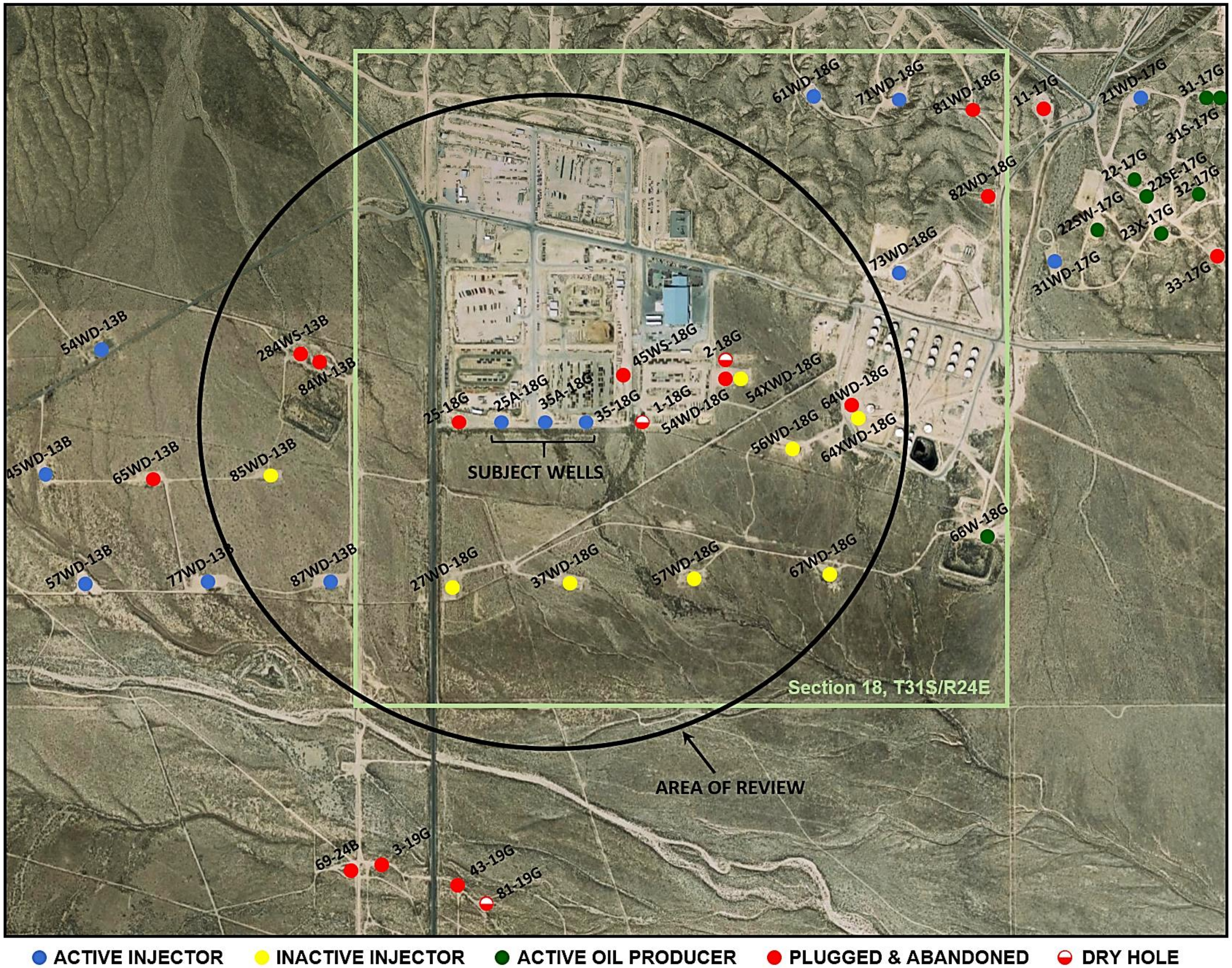
Appendix A

Project Maps

UIC Permit R9UIC-CA5-FY20-3

(Source: California Division of Oil, Gas and Geothermal Resources, online maps 2019: Google Imagery, 2019)



Map of Wells in Area of Review

Appendix B

Well Schematics

UIC Permit R9UIC-CA5-FY20-3

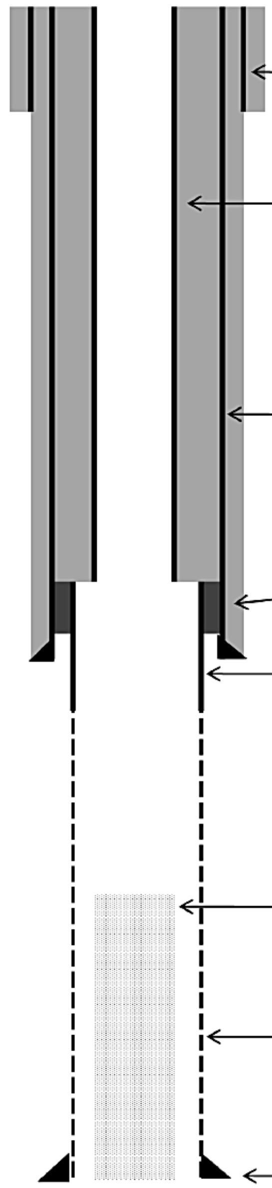
Elk Hills Power, LLC
UIC Well 25A
Well Schematic

Drawing Date: 04/26/2012
Spud Date: 12/12/2003

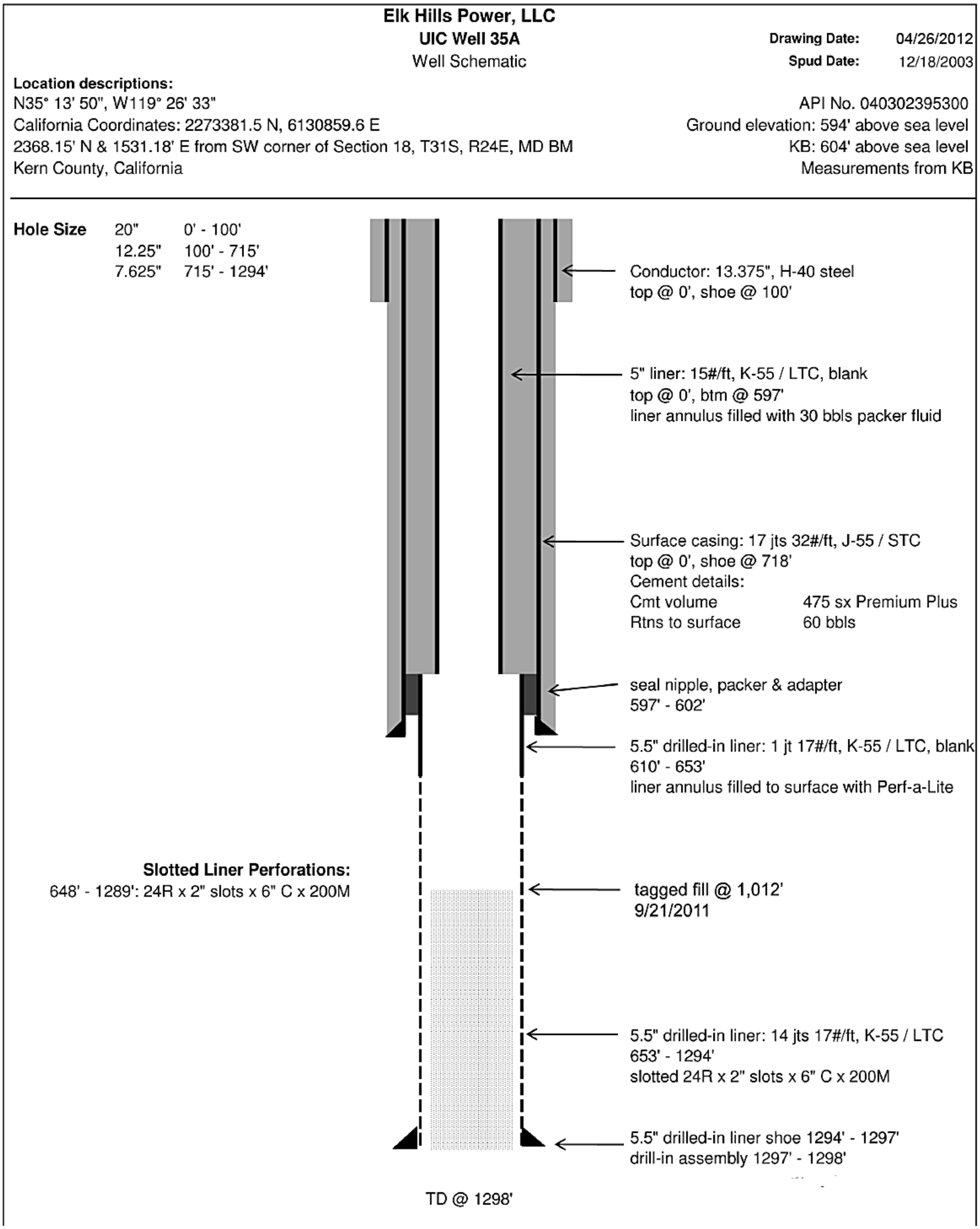
Location descriptions:
N35° 13' 50", W119° 26' 37"
California Coordinates: 2273382.2 N, 6130524.4 E
2364.55' N & 1196.02' E from SW corner of Section 18, T31S, R24E, MD BM
Kern County, California

API No. 040302395200
Ground elevation: 600' above sea level
KB: 610' above sea level
Measurements from KB

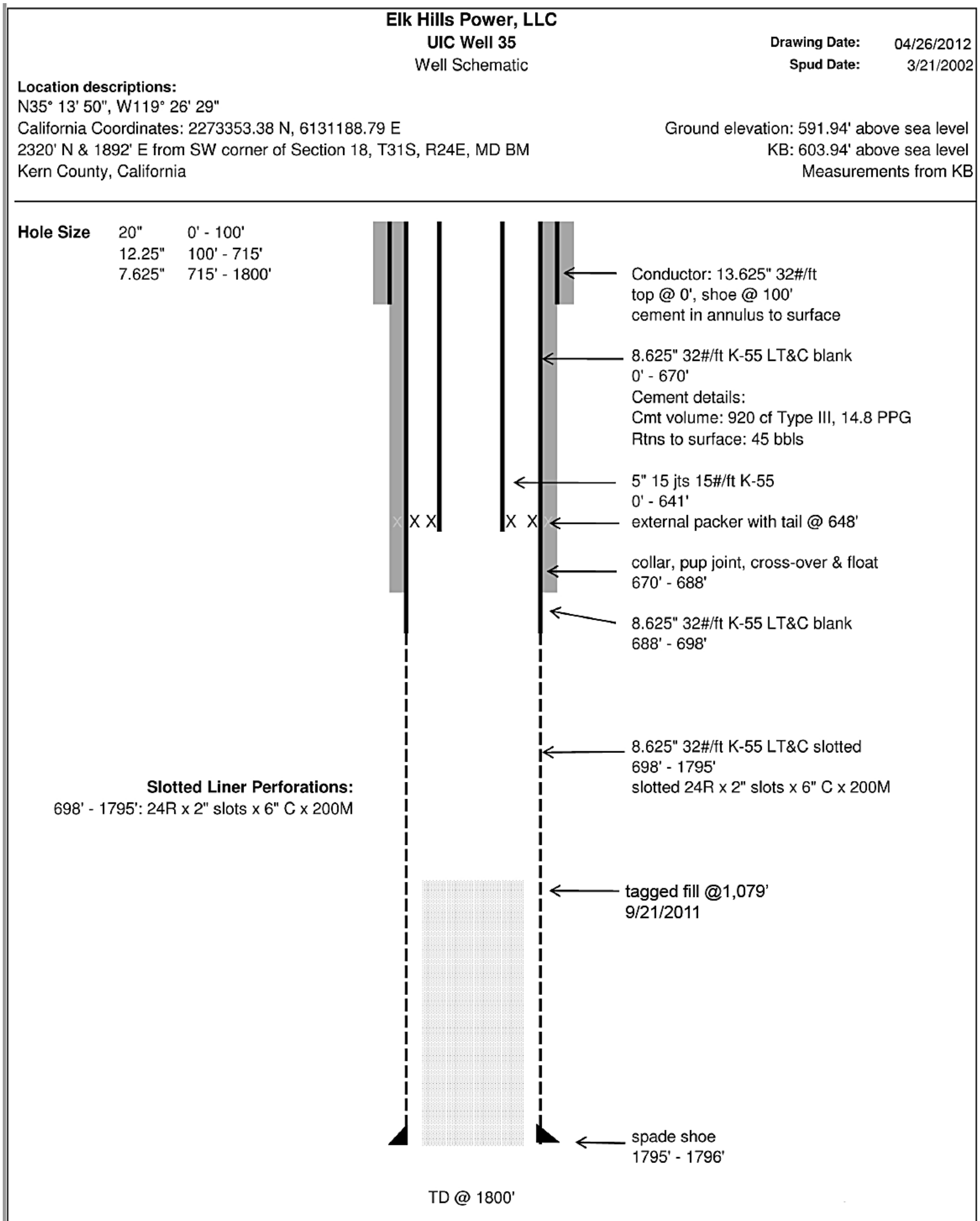
Hole Size		
	20"	0' - 100'
	12.25"	100' - 715'
	7.625"	715' - 1424'



Well 25A-18G Construction Schematic



Well 35A-18G Construction Schematic



Well 35-18G Construction Schematic

Appendix C

EPA Reporting Forms

UIC Permit R9UIC-CA5-FY20-3

APPENDIX C – EPA Reporting Forms

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

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

Quarterly Injection Well Monitoring Report

	Month/Year	Month/Year	Month/Year
Injection Pressure (PSI)			
1. Minimum			
2. Average			
3. Maximum			
Injection Rate (Barrels/Day)			
1. Minimum			
2. Average			
3. Maximum			
Annular Pressure (PSI)			
1. Minimum			
2. Average			
3. Maximum			
Injection Volume (Barrels)			
1. Monthly Total			
2. Yearly Cumulative			
Temperature (F °) - If Specified in UIC Permit			
1. Minimum			
2. Average			
3. Maximum			
pH - If Specified in UIC Permit			
1. Minimum			
2. Average			
3. Maximum			
Other Information Specified in the Permit (Attach Pages if Necessary)			

Permit (or EPA ID) Number		API Number		Full Well Name	

Certification

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

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

INSTRUCTIONS FOR FORM 7520-8

Use this form to submit quarterly injection well monitoring results. Note: owners or operators of Class II wells should use Form 7520-11 to report monitoring results. Please submit a separate form for each well.

On the top row, enter the **MONTH** and **YEAR** for each month of the quarter for which monitoring results are being reported.

INJECTION PRESSURE: Enter the minimum, average, and maximum injection pressure that occurred during each month, in pounds per square inch (psi).

INJECTION RATE: Enter the minimum, average, and maximum injection rate, in barrels per day, that occurred during each month.

ANNULAR PRESSURE: Enter the minimum, average, and maximum pressure on the annulus between the tubing and long string casing that occurred during each month, in pounds per square inch (psi).

INJECTION VOLUME: Enter the monthly total and yearly cumulative volume (in barrels) that has been injected.

TEMPERATURE: If the UIC permit requires monitoring of the temperature of the injectate, provide the minimum, average, and maximum temperature that occurred during each month, in degrees Fahrenheit (F°).

pH: If the UIC permit requires monitoring of the pH of the injectate, provide the minimum, average, and maximum values that occurred during each month.

OTHER INFORMATION: If the UIC permit requires any other monitoring, provide the minimum, average, and maximum values that occurred during each month, as appropriate. (Attach pages to this form if necessary.)

PERMIT OR EPA ID NUMBER: Enter the well identification number or permit number assigned to the injection well by the EPA or the permitting authority.

API NUMBER: Enter the number assigned by the local jurisdiction (usually a State Oil and Gas Agency) using the American Petroleum Institute standard numbering system.

FULL WELL NAME: Enter the full name of the well or project.

CERTIFICATION: This form must be signed and dated by either: a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, or by a principal executive or ranking elected official for a public agency.

PAPERWORK REDUCTION ACT NOTICE: The public reporting and recordkeeping burden for this collection of information is estimated to average 24.7 hours per response for operators of Class I hazardous wells, 14.4 hours per response for operators of Class I non-hazardous wells, and 27.9 hours per response for operators of Class III wells. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

EPA

United States Environmental Protection Agency

COMPLETION REPORT FOR INJECTION WELLS

Name, Address, Phone Number and/or Email of Permittee

State

County

Permit (or EPA ID) Number

API Number

Full Well Name

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

Surface Location

___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

___ ft. from (N/S) ___ Line of quarter section

___ ft. from (E/W) ___ Line of quarter section.

Latitude

Longitude

Anticipated Daily Injection Volume (Bbls)		Injection Interval (Perforated/Open Hole Interval)	
Average	Maximum	Feet	to Feet

Depth to Bottom of Lowermost USDW (Feet)

Date Drilling Began

Date Drilling Completed

Date Well Completed

Name of Injection Zone

Fracture Pressure of Injection Zone

Permeability of Injection Zone

Porosity of Injection Zone

Complete Attachments; See Instructions.

Certification

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

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

INSTRUCTIONS FOR FORM 7520-18

This form must be completed for each injection well. This form is appropriate for all injection well classes, and replaces the previous Form 7520-9 and Form 7520-10. While reports or other information developed by contractors or service companies may be attached, this form must be signed by a responsible entity as described at 40 CFR 144.32.

NAME, ADDRESS, PHONE AND/OR EMAIL OF PERMITTEE: Enter the name and street address, city/town, state, and ZIP code of the permittee. Also provide an email address (if available) and/or a phone number.

Enter the **STATE** and **COUNTY** where the well is located. For States that do not have counties, use the name of that State's equivalent jurisdiction at a more local level.

PERMIT OR EPA ID NUMBER: Enter the well identification number or permit number assigned to the injection well by the EPA or the permitting authority.

API NUMBER: Enter the number assigned by the local jurisdiction (usually a State Oil and Gas Agency) using the American Petroleum Institute standard numbering system.

FULL WELL NAME: Enter the full name of the well or project.

WELL LOCATION: Fill in the complete township, range, and section to the nearest quarter-quarter section. A township is north or south of the baseline, and a range is east or west of the principal meridian (e.g., T12N, R34W). Also include the distance, in feet, from the nearest north or south line and nearest east or west line of the quarter-section. Also, enter the **latitude** and **longitude** of the well in decimal degrees, to five or six places if possible; be sure to include a negative sign for the longitude of a well in the Western Hemisphere and a negative sign for the latitude of a well in the Southern Hemisphere.

ANTICIPATED DAILY INJECTION VOLUME: Enter the anticipated **average** and **maximum** daily volume of fluid to be injected, in barrels.

INJECTION INTERVAL: Enter the depths, in feet, to the top and bottom of the perforated hole/open interval of the well through which injected fluids will exit the well. (Note: this is different from the depth of the injection zone.) Provide information about how these were derived, e.g., by attaching a step-rate test or other test results. (See the description of attachments below.)

Enter the **DEPTH TO BOTTOM OF THE LOWERMOST USDW** (i.e., formation containing less than 10,000 mg/L total dissolved solids), in feet.

Enter the **DATE DRILLING BEGAN**, the **DATE DRILLING WAS COMPLETED**, and the **DATE THE WELL WAS COMPLETED** in the appropriate blanks.

Enter information about the permitted injection formation, including the **NAME OF THE INJECTION ZONE**, the calculated **FRACTURE PRESSURE**, and the **PERMEABILITY** and **POROSITY** of the injection zone in the appropriate blanks.

CERTIFICATION: This form must be signed and dated by either: a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, or by a principal executive or ranking elected official for a public agency.

INSTRUCTIONS FOR COMPLETING ATTACHMENTS TO FORM 7520-18

Please attach the following information to the completion report. Reports prepared by contractors or service companies may be submitted, provided they are clear and legible and the requested information is accessible. Please be sure to specify units as needed, e.g., of depth, pressure, temperature, etc.

I. Geologic Information

1. Provide a geologic description of the rock units penetrated by name, age, depth, thickness, and lithology of each rock unit penetrated.

2. Provide information about the injection formation that supports the information provided on the form, for example: (1) name; (2) depth (drilled); (3) thickness; (4) formation fluid pressure; (5) age of unit; (6) bottom hole temperature; (7) lithology; and (8) bottom hole pressure.

3. Provide chemical characteristics of formation fluid, including a chemical analysis.

4. Provide a description of all USDWs, including: (1) depth below ground surface to base of fresh water (less than 10,000 mg/L TDS); and (2) a geologic description of aquifer units with name, age, depth, thickness, lithology, and average total dissolved solids.

II. Well Design and Construction

1. Provide information on the surface, intermediate, and long string casing and tubing. Describe: the materials used; outside diameter size; weight/foot, grade, and whether new or used; and the depth to which each casing string is set (include appropriate units, e.g., below ground surface, below Kelly bushing, etc.).

2. Provide data on the holes drilled for each casing string, including the bit diameter and depth of hole.

3. Provide data on the well cement for each casing string, such as type/class, additives, amount, method of emplacement, and depth to top of cement.

4. Describe the packer (if used) such as type, name and model, setting depth, and type of annular fluid used.

5. Provide data on centralizers, including number, type, and depth.

6. Provide data on bottom hole completions, including the depth and diameter of the hole.

III. Monitoring Systems. Describe the recording and nonrecording injection pressure gauges, casing-tubing annulus pressure gauges, injection rate meters, temperature meters, and other meters or gauges. Also provide information on constructed monitoring wells such as location, depth, casing diameter, method of cementing, etc.

IV. Logging and Testing Results. Provide a report describing the types of geophysical logs, cores, and other tests performed; date of the logs; the intervals logged; and interpretation of the results. Include a description and the results of deviation checks run during drilling. If requested, provide a final print of all geophysical logs run.

V. As-built Schematic. Provide a diagrammatic sketch of the surface and subsurface construction details of the injection well as-built, showing casing, cement, tubing, packer, etc., with proper setting depths. The sketch should include the well head and gauges.

VI. Mechanical Integrity Testing. Provide data demonstrating mechanical integrity pursuant to 40 CFR 146.08. Describe the method and results of mechanical integrity testing.

VII. Report on the compatibility of injected wastes with fluids and minerals in both the injection zone and the confining zone.

VIII. Report the status of corrective action on deficient wells in the area of review.

IX. Include the anticipated maximum pressure and flow rate at which injection will operate.

X. Stimulation. Describe any stimulation performed, including the interval treated and the materials and amounts used.

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Permit or EPA ID Number	API Number	Full Well Name

State	County

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

Surface Location

___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

___ ft. from (N/S) ___ Line of quarter section

___ ft. from (E/W) ___ Line of quarter section.

Latitude

Longitude

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ☐ Class V	☐ Notice Prior to Work Date Expected to Commence ☐ Report After Work Date Work Ended	☐ Well Rework ☐ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Certification

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

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

INSTRUCTIONS FOR FORM 7520-19

This form replaces forms 7520-12 and 7520-14. Use this form only when work is planned or has occurred that affects the well's construction or operation as an injection well, including work on the casing, tubing or packer (or for shallow Class V wells, the subsurface fluid emplacement network). Use one form per injection well. While reports or other information developed by contractors or service companies may be attached, this form must be signed by a responsible entity as described at 40 CFR 144.32. Note: operators closing Class V wells should use Form 7520-17.

NAME, ADDRESS, PHONE AND/OR EMAIL OF PERMITTEE: Enter the name and street address, city/town, state, and ZIP code of the permittee. Also provide an email address (if available) and/or a phone number.

PERMIT OR EPA ID NUMBER: Enter the well identification number or permit number assigned to the well by the EPA or the permitting authority.

API NUMBER: Enter the number assigned by the local jurisdiction (usually a State Oil and Gas Agency) using the American Petroleum Institute standard numbering system.

FULL WELL NAME: Enter the full name of the well or project.

Enter the **STATE** and **COUNTY** where the well is located. For States that do not have counties, use the name of that State's equivalent jurisdiction at a more local level.

WELL LOCATION: Fill in the complete township, range, and section to the nearest quarter-quarter section. A township is north or south of the baseline, and a range is east or west of the principal meridian (e.g., T12N, R34W). Also include the distance, in feet, from the nearest north or south line and nearest east or west line of the quarter-section. Also, enter the **latitude** and **longitude** of the well in decimal degrees, to five or six places if possible; be sure to include a negative sign for the longitude of a well in the Western Hemisphere and a negative sign for the latitude of a well in the Southern Hemisphere.

Enter the **WELL CLASS,** i.e., the class of injection well as defined in 40 CFR 144.6.

TIMING OF THE ACTION: Check ***Notice prior to work*** if the activity has not yet occurred (i.e., is planned). Check ***Report after work*** if the activity described has already occurred. As appropriate, include the date the activity is expected to start or the date the activity was completed. (Note this may not be available, e.g., for a plugging plan submitted with a permit application.)

TYPE OF ACTION: Check the appropriate box to describe the kind of activity being reported. Check ***Well Rework*** for work that was/will be performed on the well after it has already been in operation as an injection well. Check ***Plugging and Abandonment*** to report on plans for or descriptions of final closure/plugging after use as an injection well. Check ***Conversion to a Non-Injection Well*** if the well is to be converted to something other than an injection well.

Provide a **NARRATIVE DESCRIPTION** of the work planned to be performed, or that was performed. The narrative should include a description of the main procedures planned or that occurred during the work activity. A service company report, daily report, or similar document may be attached if it includes all the requested information and is clear and legible.

For well reworks, include the following information: The reason for the well rework; depths of activity; type of activity; changes to injection well configuration, well casing, or cement behind casing; any plug added to the well and its depth; any newly drilled interval and its depth; method(s) to demonstrate that the well has mechanical integrity (as applicable); and any deviations from the approved rework plan (as applicable).

For a well plugging plan, include the following information: Reason for the well plugging; number of plugs placed, and their depths; materials used as plugs (e.g., cast iron bridge plug, cement, cement retainer); method to set plugs; and wait-on-cement times, if any. Also provide one or more cost estimates from an independent firm in the business of plugging and abandoning wells to plug the well as described in the plan.

For well plugging affidavit, include the following information: Reason for the well plugging; number of plugs placed, and their depths; materials used as plugs (e.g., cast iron bridge plug, cement, cement retainer); method to set plugs; wait-on-cement times, if any; and any deviations from the approved plugging plan (if applicable).

For conversion to a non-injection well, include the following information: Depths of activity; type of activity; changes to injection well configuration, well casing, or cement behind casing; any plug added to the well and its depth; any newly drilled interval and its depth; depths of new perforations; and method(s) to demonstrate that the well has mechanical integrity (as applicable).

For all of the above activities, include a well sketch depicting the work, results of well tests/logging performed, service company tickets, and any other available information demonstrating how the work was/is to be performed. Also, specify whether depths are below ground surface, relative to Kelly bushing, etc.

CERTIFICATION: This form must be signed and dated by either: a responsible corporate officer for a corporation, by a general partner for a partnership, by the proprietor of a sole proprietorship, or by a principal executive or ranking elected official for a public agency.

PAPERWORK REDUCTION ACT NOTICE: The public reporting and recordkeeping burden for this collection of information is estimated to average between 6.0 and 7.9 hours per response, depending on the injection well class. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

Appendix D

Logging Requirements

UIC Permit R9UIC-CA5-FY20-3

APPENDIX D – EPA Region 9 Temperature Logging Requirements

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

1. With the printed log, also provide raw data for both logging runs (at least one data reading per foot depth) unless the logging truck is equipped with an analog panel as the processing device.
2. The heading on the log must be complete and include all the pertinent information, such as correct well name, location, elevations, etc.
3. The total shut-in times must be clearly shown in the heading. Minimum shut-in time for active injectors is 12 hours for running the initial temperature log, followed by a second log, a minimum of 4 hours later. These two log runs will be superimposed on the same track for final presentation.
4. The logging speed must be kept between 20 and 50 ft. per minute (30 ft/min optimum) for both logs. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).
5. The vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs (see 7(b)). The horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.
6. The right hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.
7. The left hand tracks must contain (unless impractical, but EPA must pre-approve any deviations):
   (a) a collar locator log,
   (b) a lithology log, 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 SP curve from either the subject well or from a representative, nearby well.
   (c) a clear identification on the log showing the base of the lowermost Underground Source of Drinking Water ("USDW"). A USDW is basically a formation that contains less than 10,000 ppm Total Dissolved Solids ("TDS") and is further defined in 40 CFR §144.3.

Appendix E

EPA Region 9 UIC Pressure Falloff Requirements

UIC Permit R9UIC-CA5-FY20-3

EPA Region 9
UIC PRESSURE FALLOFF REQUIREMENTS

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

August 8, 2002

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6.0 Conducting the Falloff Test
7.0 Evaluation of the Falloff Test
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    Characteristics of Individual Test Flow Regimes
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        Spherical Flow
        Linear Flow
        Hydraulically Fractured Well
        Naturally Fractured Rock
        Layered Reservoir

Semilog Plot Determination of the Appropriate Time Function for the Semilog Plot
Parameter Calculations and Considerations
Skin
Radius of Investigation
Effective Wellbore Radius
Reservoir Injection Pressure Corrected for Skin Effects
Determination of the Appropriate Fluid Viscosity
Reservoir Thickness
Use of Computer Software
Common Sense Check

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. **<u>Graphs:</u>**
  - 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 **<u>radial flow portion</u>** 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.

<u>General Operational Concerns</u>

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 at the wellhead 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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8. "Well Testing: Interpretation Methods," Bourdarot, 1996
9. "A New Method To Account For Producing Time Effects When Drawdown Type Curves Are Used To Analyze Pressure Buildup And Other Test Data," SPE Paper 9289, Agarwal, 1980
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24. “Selecting a Reservoir Model For Well Test Interpretation,” Hart’s Petroleum Engineer International, Spivey, Ayers, Pursell,and Lee, December 1997
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APPENDIX

Pressure Gauge Usage and Selection

Usage

- 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.

Selection

- 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

General Operational Considerations

- 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:

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

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.

<u>Cartesian Plot</u>

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.

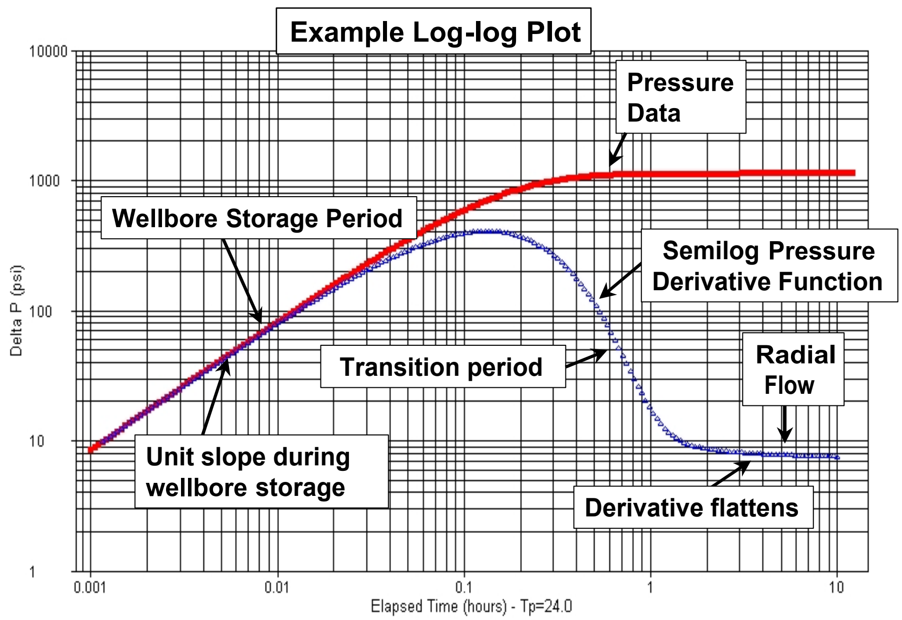
X A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to 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)

Semilog Plot

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:

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

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.

<u>Reservoir Thickness</u>

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

Plugging and Abandonment Plans

UIC Permit R9UIC-CA5-FY20-3

Abandonment Program for Well 25A-18G, Section 18G, T31S, R24E.

(All depths are referenced to kelly bushing (+10'), not ground level, unless otherwise specified)

1.e MIRU work over or coiled tubing rig, pump, portable tank. Bring in 50 joints of 2-7/8"e tubing for the work string in the event the job will use a work-over rig. Fill the tank withe fresh water. Prepare the wellhead with a riser/valve to the 8-5/8" x 13-3/8" annulus.e Install and function test a Class II 2M BOPE.e

2.e Release the tubing/liner, POOH and lay down 5" tubing. PU and RIH with 2-7/8" worke string or coiled tubing to ED of 1424'.e

3.e Circulate the hole clean (hole volume about 80 barrels) to 1424'.e

4.e Pull tubing tail 10' above the bottom tag depth. MIRU cementers. Lay a balanced, Classe A (15.6 ppg) with 2% CaCl2 cement plug (about 80 barrels) from ED to surface.e Cementing operations are to be witnessed by an EPA representative. RD cementerse and POOH. WOC for 12 hours.e

5.e Remove BOPE. Pour cement to surface from the top if the cement level dropped moree than five (5) feet. RD cementers/coiled tubing unit/work over rig. DOGGR to witness thee plug.e

6.e Cut and retrieve both the 8-5/8" and 13-3/8" casings from 5' to no deeper than 10' belowe the surface.e

7.e Weld a steel cap (on which the API number 03023952 is engraved) of at least 0.70e inches thick on the top of the cut 13-3/8" casing.e

8.e Within 60 days following plugging of the well, remove the cellar, refill it with earth ande compact the ground to prevent settling, restore the grade and remove oil field equipmente and debris (enclosure, trash, waste materials, & cement).e

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Elk Hills Power, LLC
4026 Skyline Road
Tupman, CA 93276
(661) 763-2730

Permit or EPA ID Number	API Number	Full Well Name
R9UIC-CA1-FY20-3	03023952	Elk Hills Power LLC 25A-18G

State	County
CA	Kern

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

Latitude 35.230615

Surface Location

NW 1/4 of SW 1/4 of Section 18G Township 31S Range 24E

Longitude -119.443503

2364.55 ft. from (N/S) N Line of quarter section

1196.02 ft. from (E/W) E Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ☑ Class V	☑ Notice Prior to Work Date Expected to Commence: Not known at this time ☐ Report After Work Date Work Ended:	☐ Well Rework ☑ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

(All depths are referenced to Kelly bushing (+10′), not ground level, unless otherwise specified)

1. MIRU work over or coiled tubing rig, pump, portable tank. Bring in 50 joints of 2-7/8″ tubing for the work string in the event the job will use a work-over rig. Fill the tank with fresh water. Prepare the wellhead with a riser/valve to the 8-5/8" x 13-3/8" annulus. Install and function test a Class II 2M BOPE.
2. Release the tubing/liner, POOH and lay down 5″ tubing. PU and RIH with 2-7/8″ work string or coiled tubing to ED of 1424′.
3. Circulate the hole clean (hole volume about 80 barrels) to 1424'.
4. Pull tubing tail 10′ above the bottom tag depth. MIRU cementers. Lay a balanced, Class A (15.6 ppg) with 2% $CaCl_2$ cement plug (about 80 barrels) from ED to surface. Cementing operations are to be witnessed by an EPA representative. RD cementers and POOH. WOC for 12 hours.
5. Remove BOPE. Pour cement to surface from the top if the cement level dropped more than five (5) feet. RD cementers/coiled tubing unit/work over rig. CalGEM to witness the plug.
6. Cut and retrieve both the 8-5/8″ and 13-3/8" casings from 5′ to no deeper than 10′ below the surface.
7. Weld a steel cap (on which the API number 03023952 is engraved) of at least 0.70 inches thick on the top of the cut 13-3/8″ casing.
8. Within 60 days following plugging of the well, remove the cellar, refill it with earth and compact the ground to prevent settling, restore the grade and remove oil field equipment and debris (enclosure, trash, waste materials, & cement.

Certification

Name and Official Title (Please type or print)	Signature	Date Signed
BRANDON MYERS / PLANT MANAGER		8/27/2020

EPA Form 7520-19 for EHP Well 25A-18G

Abandonment Program for Well 35A-18G, Section 18G, T31S, R24E.

(All depths are referenced to kelly bushing (+10'), not ground level, unless otherwise specified)

1. MIRU work over or coiled tubing rig, pump, portable tank. Bring in 45 joints of 2-7/8" tubing for the work string in the event the job will use a work-over rig. Fill the tank with fresh water. Prepare the wellhead with a riser/valve to the 8-5/8" x 13-3/8" annulus. Install and function test a Class II 2M BOPE.

2. Release the tubing/liner, POOH and lay down 5" tubing. PU and RIH with 2-7/8" work string or coiled tubing to ED of 1298'.

3. Circulate the hole clean (hole volume about 73 barrels) to 1298'.

4. Pull tubing tail 10' above the bottom tag depth. MIRU cementers. Lay a balanced, Class A (15.6 ppg) with 2% CaCl2 cement plug (about 73 barrels) from ED to surface. Cementing operations are to be witnessed by an EPA representative. RD cementers and POOH. WOC for 12 hours.

5. Remove BOPE. Pour cement to surface from the top if the cement level dropped more than five (5) feet. RD cementers/coiled tubing unit/work over rig. DOGGR to witness the plug.

6. Cut and retrieve both the 8-5/8" and 13-3/8" casings from 5' to no deeper than 10' below the surface.

7. Weld a steel cap (on which the API number 03023953 is engraved) of at least 0.70 inches thick on the top of the cut 13-3/8" casing.

8. Within 60 days following plugging of the well, remove the cellar, refill it with earth and compact the ground to prevent settling, restore the grade and remove oil field equipment and debris (enclosure, trash, waste materials, & cement).

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Elk Hills Power, LLC
4026 Skyline Road
Tupman, CA 93276
(661) 763-2730

Permit or EPA ID Number	API Number	Full Well Name
R9UIC-CA1-FY20-3	03023953	Elk Hills Power LLC 35A-18G

State	County
CA	Kern

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

Surface Location

NW 1/4 of SW 1/4 of Section 18G Township 31S Range 24E

Latitude 35.230621

Longitude -119.442383

2368.15 ft. from (N/S) N Line of quarter section
1513.18 ft. from (E/W) E Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I ☐ Class II ☐ Class III ✔ Class V	✔ Notice Prior to Work Date Expected to Commence: Not known at this time ☐ Report After Work Date Work Ended:	☐ Well Rework ✔ Plugging and Abandonment ☐ Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

(All depths are referenced to Kelly bushing (+10′), not ground level, unless otherwise specified)

1. MIRU work over or coiled tubing rig, pump, portable tank. Bring in 45 joints of 2-7/8″ tubing for the work string in the event the job will use a work-over rig. Fill the tank with fresh water. Prepare the wellhead with a riser/valve to the 8-5/8" x 13-3/8" annulus. Install and function test a Class II 2M BOPE.
2. Release the tubing/liner, POOH and lay down 5″ tubing. PU and RIH with 2-7/8″ work string or coiled tubing to ED of 1298′.
3. Circulate the hole clean (hole volume about 73 barrels) to 1298'.
4. Pull tubing tail 10′ above the bottom tag depth. MIRU cementers. Lay a balanced, Class A (15.6 ppg) with 2% CaCl2 cement plug (about 73 barrels) from ED to surface. Cementing operations are to be witnessed by an EPA representative. RD cementers and POOH. WOC for 12 hours.
5. Remove BOPE. Pour cement to surface from the top if the cement level dropped more than five (5) feet. RD cementers/coiled tubing unit/work over rig. CalGEM to witness the plug.
6. Cut and retrieve both the 8-5/8″ and 13-3/8" casings from 5′ to no deeper than 10′ below the surface.
7. Weld a steel cap (on which the API number 03023953 is engraved) of at least 0.70 inches thick on the top of the cut 13-3/8″ casing.
8. Within 60 days following plugging of the well, remove the cellar, refill it with earth and compact the ground to prevent settling, restore the grade and remove oil field equipment and debris (enclosure, trash, waste materials, & cement).

Certification

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

Name and Official Title *(Please type or print)*	Signature	Date Signed
BRANDON MYERS / PLANT MANAGER		8/27/2020

EPA Form 7520-19 for Well 35A-18G

Abandonment Program for Well 35-18G, Section 18G, T31S, R24E.

(All depths are referenced to kelly bushing (+12'), not ground level, unless otherwise specified)

1. MIRU work over or coiled tubing rig, pump, portable tank. Bring in 60 joints of 2-7/8" tubing for the work string in the event the job will use a work-over rig. Fill the tank with fresh water. Prepare the wellhead with a riser/valve to the 8-5/8" x 13-3/8" annulus. Install and function test a Class II 2M BOPE.
2. Release the tubing and packer, POOH and lay down 5" tubing. PU and RIH with 2-7/8" work string or coiled tubing to ED of 1800'.
3. Circulate the hole clean (hole volume about 72 barrels) to 1800'.
4. Pull tubing tail 10' above the bottom tag depth. MIRU cementers. Lay a balanced, Class A (15.6 ppg) with 2% CaCl2 cement plug (about 72 barrels) from ED to surface. Cementing operations are to be witnessed by an EPA representative. RD cementers and POOH. WOC for 12 hours.
5. Remove BOPE. Pour cement to surface from the top if the cement level dropped more than five (5) feet. RD cementers/coiled tubing unit/work over rig. DOGGR to witness the plug.
6. Cut and retrieve both the 8-5/8" and 13-3/8" casings from 5' to no deeper than 10' below the surface.
7. Weld a steel cap (on which the well name 35-18G is engraved) of at least 0.70 inches thick on the top of the cut 13-3/8" casing.
8. Within 60 days following plugging of the well, remove the cellar, refill it with earth and compact the ground to prevent settling, restore the grade and remove oil field equipment and debris (enclosure, trash, waste materials, & cement).

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency

EPA

WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN, OR PLUGGING AND ABANDONMENT AFFIDAVIT

Name and Address, Phone Number and/or Email of Permittee

Elk Hills Power, LLC
4026 Skyline Road
Tupman, CA 93276
(661) 763-2730

Permit or EPA ID Number	API Number	Full Well Name
R9UIC-CA1-FY20-3	None	Elk Hills Power LLC 35-18G

State	County
CA	Kern

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

Latitude 35.230615

Longitude -119.443503

Surface Location

NW 1/4 of SW 1/4 of Section 18G Township 31S Range 24E

2320.3 ft. from (N/S) S Line of quarter section
1890.5 ft. from (E/W) W Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
☐ Class I	☑ Notice Prior to Work	☐ Well Rework
☐ Class II	Date Expected to Commence: Not known at this time	☑ Plugging and Abandonment
☐ Class III	☐ Report After Work	☐ Conversion to a Non-Injection Well
☑ Class V	Date Work Ended:	

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See Instructions.

(All depths are referenced to Kelly bushing (+12′), not ground level, unless otherwise specified)

1. MIRU work over or coiled tubing rig, pump, portable tank. Bring in 60 joints of 2-7/8″ tubing for the work string in the event the job will use a work-over rig. Fill the tank with fresh water. Prepare the wellhead with a riser/valve to the 8-5/8" x 13-3/8" annulus. Install and function test a Class II 2M BOPE.
2. Release the tubing and packer, POOH and lay down 5″ tubing. PU and RIH with 2-7/8″ work string or coiled tubing to ED of 1800′.
3. Circulate the hole clean (hole volume about 72 barrels) to 1800'.
4. Pull tubing tail 10′ above the bottom tag depth. MIRU cementers. Lay a balanced, Class A (15.6 ppg) with 2% $CaCl_2$ cement plug (about 72 barrels) from ED to surface. Cementing operations are to be witnessed by an EPA representative. RD cementers and POOH. WOC for 12 hours.
5. Remove BOPE. Pour cement to surface from the top if the cement level dropped more than five (5) feet. RD cementers/coiled tubing unit/work over rig. CalGEM to witness the plug.
6. Cut and retrieve both the 8-5/8″ and 13-3/8" casings from 5′ to no deeper than 10′ below the surface.
7. Weld a steel cap (on which the well name 35-18G is engraved) of at least 0.70 inches thick on the top of the cut 13-3/8″ casing.
8. Within 60 days following plugging of the well, remove the cellar, refill it with earth and compact the ground to prevent settling, restore the grade and remove oil field equipment and debris (enclosure, trash, waste materials, & cement).

Certification

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

Name and Official Title *(Please type or print)*	Signature	Date Signed
BRANDON MYERS / PLANT MANAGER		8/27/2020

EPA Form 7520-19 (Rev. 4-19)

EPA Form 7520-19 for Well 35-18G

Appendix G

Operating Data

UIC Permit R9UIC-CA5-FY20-3

INJECTION OPERATION AND MONITORING PROGRAM (40 CFR § 144.54)

Historical Operating Data

As discussed previously, the EHP site has been generating and disposing of plant wastewater since April 2003 under EPA UIC Permit No. CA200002. The operating data for the three active injection wells has been reported to the EPA on a quarterly schedule per the permit requirements. The most recent quarterly report is for the second quarter of 2020, which is included in Exhibit D-1**.** The yearly injection volumes, as reported to the EPA, by injection well are summarized below in Table D-1.

Historical Injection Volumes

Historical Injection Volumes by Year through June 30, 2020 (bbls)						
Year	**25-18G**	**25A-18G**	**35-18G**	**35A-18G**	**Total**	**Cumulative**
2003	289,344	0	2,022,900	0	2,312,244	2,312,244
2004	142	1,340,687	98,990	2,365,038	3,804,857	6,117,101
2005	0	1,163,891	0	2,624,547	3,788,437	9,905,538
2006	0	760,559	0	3,118,717	3,879,276	13,784,814
2007	0	1,221,832	3	2,788,980	4,010,815	17,795,629
2008	0	1,850,369	2	2,129,415	3,979,786	21,775,415
2009	1	387,686	27	2,723,489	3,111,203	24,886,618
2010	0	1,484,761	1,234	1,223,112	2,709,106	27,595,725
2011	0	1,499,791	459	805,411	2,305,661	29,901,385
2012	0	2,283,762	0	87,867	2,371,629	32,273,015
2013	0	2,240,459	375	203,427	2,444,262	34,717,276
2014	0	246,423	536	1,567,264	1,814,222	36,531,499
2015	0	1,895,678	340	1,302,786	3,198,804	39,730,303
2016	0	1,312,091	274	1,349,280	2,661,645	42,391,948
2017	0	1,231,601	672	1,456,264	2,688,537	45,080,485
2018	0	963,305	78,539	1,836,553	2,878,397	47,958,883
2019	0	1,091,602	136,186	1,381,218	2,609,005	50,567,888
2020	0	105,805	200,966	705,256	1,012,026	51,579,914
Total	**289,487**	**20,974,497**	**2,340,537**	**26,963,367**	**50,567,888**	**50,567,888**
% of Total	**0.6%**	**41.5%**	**4.6%**	**53.3%**	**100.0%**	

The cumulative injection volume is about 50.6 million bbls through June 30, 2020, of which about 95% has historically been disposed of in two wells, the 25A-18G and the 35A-18G. A summary of injection and rate data for the first two quarters of 2020 are shown in Table D-2 below.

2020 Injection Data for EHP Wells

Minimum Injection Pressure, psig						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	137	0	0	84	149	93
35-18G	136	0	0	81	145	91
35A-18G	138	0	0	76	134	77
Average Injection Pressure, psig						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	155	46	50	107	159	166
35-18G	153	47	46	103	155	166
35A-18G	155	46	31	95	145	140
Maximum Injection Pressure, psig						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	175	191	141	147	179	196
35-18G	173	187	137	143	172	190
35A-18G	176	191	97	135	155	156
Minimum Injection Rate, gpm						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	56	0	0	0	0	0
35-18G	43	0	0	0	27	36
35A-18G	67	0	0	151	147	67
Average Injection Rate, gpm						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	65	20	3	1	1	11
35-18G	52	15	15	1	57	61
35A-18G	73	22	102	173	157	153
Total	**190**	**57**	**120**	**175**	**215**	**225**
Maximum Injection Rate, gpm						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	79	94	32	14	11	38
35-18G	62	85	88	11	87	90
35A-18G	83	96	222	187	186	180
Monthly Total Injection, gals						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	2,895,935	849,017	116,819	41,866	47,465	492,704
35-18G	2,324,162	603,197	427,110	16,628	2,451,090	2,617,660
35A-18G	3,260,671	930,800	4,569,824	7,455,941	6,797,011	6,606,493
Total	**5,584,833**	**1,533,997**	**4,996,934**	**7,472,569**	**9,248,101**	**9,224,153**
Yearly Cumulative Injection, gals						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	2,895,935	3,744,952	3,861,771	3,903,637	3,951,102	4,443,805
35-18G	2,324,162	2,928,079	3,355,189	3,371,817	5,822,907	8,440,567
35A-18G	3,260,671	4,191,471	8,761,295	16,217,236	23,014,248	29,620,740
Total	**8,480,768**	**19,345,270**	**35,323,525**	**58,816,215**	**91,604,472**	**134,109,584**
Yearly Cumulative Volume, bbls						
Well	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
25A-18G	68,951	89,166	91,947	92,944	94,074	105,805
35-18G	55,337	69,716	79,885	80,281	138,641	200,966
35A-18G	77,635	99,797	208,602	386,125	547,958	705,256
Total	**201,923**	**258,679**	**380,435**	**559,350**	**780,673**	**1,012,026**

Source: 1st &2nd Quarter 2020 Injection Well Monitoring Reports

These actual operating data are representative of the operating conditions expected to be encountered for the three Class V injection wells in this permit application. It is anticipated that approximately 150 to 435 gpm of injectate (average month) will be generated at the EHP site for injection under normal operating conditions. The injection wells will be operated so as not initiate or propagate fractures in the formation. The maximum injection surface pressure is discussed under Attachment B, Part II.

The specific nature of the annulus fluid introduced during initial wellbore construction in each permitted well is unknown other than what is reported in the well histories under Attachment A, Part IV. In the case of wells 25A-18G and 35A-18G, the annulus was filled with a fluid described as 'packer fluid' (35 bbls in 25A-18G and 30 bbls in 35A-18G). There is no record of any fluid being placed in the annulus of well 35-18G.

Hall Plots

Injection well operations are monitored through the use of Hall plots in the quarterly UIC Well Monitoring Reports. The Hall plot is a useful tool for evaluating performance of injection wells. The Hall method is a steady-state analysis method, whereas fall-off tests and injection tests are transient methods. Transient pressure analysis, such as the annual pressure fall-off test, determines the reservoir properties at a given point in time. The Hall plot is a continuous monitoring method whereby reservoir properties are measured over a period of months and years. The Hall plot, therefore, can help identify changes in injection characteristics that may occur over extended periods of time. For example, if an injection well is stimulated, the slope of the line on the Hall plot decreases with time, and if the well is damaged, the slope increases with time. The spreadsheets for the Hall plot calculations for all EHP wells are included in Exhibit D-2.

The typical industry application of the Hall method is a graphical form of Cumulative Surface Pressure-Days (psig-days) versus Cumulative Injection Volume (bbls). These conventional plots are included in Exhibit D-2 for the three permitted wells. However, for this conventional application to work there must be a constant fluid head and surface injection pressure greater than zero. In addition, the boundary reservoir pressure must be close to the weight of a full fluid column in order for the Hall approximation to Darcy's law to be valid. There is a significant portion of the injection that takes place at zero tubing pressures in wells 25A-18G and 35A-18G. As a result, the traditional form of the Hall plot is not suitable; rather, a better procedure is one that takes the integral of the difference between bottom-hole injection pressure (Pwf) and reservoir boundary pressure (Pe) with respect to time. Integrating the pressure data with the Hall integral,

$$\{Pwf - Pe\}\ dt,$$

will give the desired slope and have a smoothing effect on the data (Buell, Kazemi and Puettmann, 1990). Static reservoir boundary pressures are measured annually as part of the UIC fall-off testing program as discussed in the “Formation Testing Program” section of Attachment B, Part II). Bottom-hole pressure, Pwf, necessary to the integral {Pwf – Pe} dt, is estimated by correcting the recorded surface wellhead pressure for hydrostatic head and friction loss (considered negligible). In the case when surface injection pressure is zero, it is necessary to make a couple of additional simplifying assumptions for this analysis. If the surface pressure is zero and the injection fluid rate is greater than a selected minimum rate (5 gpm), it is assumed that the fluid level is near the surface and therefore Pwf is approximately equivalent to the weight of the fluid column (i.e., 0.433 psi/ft times datum depth).

The permitted injection wells are capable of operating at a surface wellhead injection pressures well below the 200 psi limit. A graphical presentation of the surface wellhead pressures and rates versus time also is included in Exhibit D-1, as are the modified Hall plots with the new integral of {Pwf minus Pe} dt for wells 25A-18G and 35A-18G. The modified Hall plots now look like the conventional Hall plot and may be used to observe changes in the line slopes as part of monitoring injection characteristics.

As discussed previously, since 2004, plant wastewater has been disposed of principally in two wells, 25A-18G and 35A-18G. The following conclusions are based on the data in Exhibit D-2 for the three EHP wells:

Well 25A – 18G: The average surface injection pressure of all of the injection-days through December 31, 2011, is 14.7 psig. During its operational history starting in January 2004, there are only a handful of surface pressures readings greater than 125 psig. These high pressures are not sustained, and subsequent pressure readings return to zero or less than 75 psi. There is no trend in the surface pressure data over the operational history. However, the average surface pressure of the injection-days in 2011 increased to 37.5 psig.

Well 35A – 18G: The average surface pressure of all of the injection-days through October 31, 2019, is 30 psig. During its operational history starting in January 2004 through 2011, there are only a handful of surface pressures readings greater than 125 psig. These high pressures were not sustained, and subsequent pressure readings returned to zero or less than 75 psi.

Well 35 – 18G: The average surface pressure of the injection-days through December 31, 2011, is 158 psig. This well has a history of high surface injection pressures (150-190 psig), especially during 2003 when it was on full-time injection. Since the construction of wells 25A-18G and 35A-18G in January 2004, well 35-18G is not used on a regular basis but is kept as a backup injection well in the event of a 25A or 35A well failure.

Quarterly Reporting

The EHP injection wells are equipped with pressure and rate monitoring devices that allow for continuous recording of the injection pressure and injection rate. The minimum, maximum, and monthly averages of injection pressure and annular pressure have been and will continue to be submitted in quarterly reports in the format used in Exhibit D-1. In addition, the flow rate and volume of injectate also was and will be monitored and reported to the EPA on a quarterly schedule. The flow rate will be measured in the supply line immediately before the wellhead. All monitoring equipment shall be calibrated and maintained on a regular basis to ensure proper working order of all equipment. The monitoring program will maintain all the information previously prepared to meet the requirements of UIC Permit No. CA200002.

The monitoring program includes sampling the injectate on a quarterly schedule and testing the fluid for CAM metals, geochemical constituents and associated physical data, volatile organic compounds, semi-volatile organic compounds, corrosivity, and toxicity, the results of which will be reported to the EPA on a quarterly schedule. The most recent injectate analyses for chemical and physical parameters included in the 2020 Second Quarter Underground Injection Well Performance Monitoring Report, dated July 9, 2020 (Exhibit D-1).

Procedures followed for injectate sampling and analysis are described in Section 9.03 E1 of the EHP Policies and Procedures Manual (Exhibit D-3).

Annual Well Logging and Testing

To ensure that the injectate is moving into the injection zone only, an annual, cased-hole logging program will be conducted. Temperature and natural radioactive logs will be run to evaluate possible fluid migration above the casing shoe or around the packer.

A pressure fall-off test will be conducted annually to evaluate the pressure buildup in the injection zone. The results of previous fall-off tests conducted to measure the static formation pressure are discussed in Attachment B, Part II.

Mechanical Integrity Testing

Mechanical integrity tests (RTS method) to demonstrate the absence of significant leaks in the tubing and packer will be conducted annually on the three injection wells. Mechanical integrity of the casing will be investigated every five years using Standard

Annulus Pressure Testing (SAPT) or after well reworks, and test results will be sent to the US EPA.

Injection Procedures

Injection of plant wastewater into the EHP injection wells is automated. The controls for the water supply and injection systems are provided in Exhibit D-4.

Characterization of Injectate

EHP's non-hazardous injectate consists of: turbine wash wastewater; cooling tower blowdown wastewater; plant area wash wastewater; reverse osmosis regeneration wastewater; wastewater from plant and equipment drains; filter backwash wastewater; and non-oil-contaminated storm runoff wastewater. Analyses of EHPP injectate are conducted and reported quarterly in its monitoring reports for the facility, the most recent of which is included in Exhibit D-1.

EHP injectate has been tested quarterly for the following analyses:

1. Characteristics of hazardous waste using EPA SW-846 methodology, as described under CCR Title 22, Article 3, §66261.20 for:
   - §66261.21: Ignitability
   - §66261.22(a)(1): Corrosivity (aqueous, dealing with pH 2-12.5)
   - §66261.23: Reactivity (explosives, sulfides-cyanides)
   - §66261.24(a)(1): Toxicity (TCLP-metals, organics, WET extraction, STLC-TTLC CAM metals), and
2. Geochemical water analyses.

The data reviewed for this application consisted of 38 quarterly samplings of EHP injectate, which were analyzed for 18 CAM metals, for a total of 684 CAM metal analyses (Exhibit D-5). The sampling review period was from the first quarter of 2011 through the second quarter of 2020. In some instances, the PQL of a constituent was higher than the federal or California MCL for drinking water, so the absolute determination of that constituent's relation to a MCL could not be evaluated. As discussed below, some of these samples were collected during a plant shut-down and were not representative of the injectate. Based on the statistical analyses, the injectate has not exceeded MCLs.

EHP injectate has never tested positive for any characteristics of hazardous waste. Of the total 684 CAM metal analyses reviewed, only 23 sampling events, or about 3% of the total, were determined to have exceeded either federal or California MCLs for drinking water. As discussed below, some of these samples were collected during a plant shut-down, and the samples were not representative of the injectate. Based on the statistical analyses, the injectate has not exceeded MCLs. Additionally, background concentrations in Upper Tulare groundwater in the south flank Elk Hills area also exceed drinking water standards for some constituents.

Appendix H

Well Treatment Program

UIC Permit R9UIC-CA5-FY20-3

Proposed Well Treatment Program

In recent years, the EHP wells are experiencing backfill, and acid treatment is conducted along with coil-tube cleaning. A proposed acid treatment procedure for each well is provided in Exhibit C-5. This procedure will be revised as necessary and subject to EPA approval whenever an acid job needs to be performed. An acid treatment will be performed when the well injection pressure reaches 175 psig or above.

ACID WORK PROGRAM

WELL#: **25A-18G**	API 10: 0403023952	RMT: EHPP
PROJECT/TASK:	1110178 / 01030304	Date: TBD
WELL CONDITION:	**Injecting Water**	

WELL INFORMATION:

Current Well Head Pressure: **172** PSIG

PBMD:	N/A'	Tubing ID:	N/A"
BMD:	N/A'	No Go ID:	N/A"
PERF/SLOTS:	724'-1415'	**Max Treating PSI (MTP):**	**135 PSI**
Last Tag Depth:	**1185'** (07-23-19)		

ACID WORK INFORMATION:

ACID NAME	QUANTITY	UNIT	DESCRIPTION	PENETRATION
15% HCl	1000	Gals.	Hydrochloric Acid	3.82 in
12-3% HCl-HF	3000	Gals	Mud Acid	8.39 in
NH4Cl (2%)	500	Gals.	Displacement Fluid	2.20 in

JOB PROCEDURE:

1. Obtain the permit from the EHPP Control Room Operator 765-1810 (Power Plant). Notify the operator of the work to be performed on the injector.
2. MIRU acid transport truck containing 1000 gal of 15% HCl, 3000 gal of 12-3% HCl-Hf & 500 gal of NH4Cl (2%) w/ inhibitor.
   Install HP hoses and pressure test, check for leaks.
   Open valve to well to establish injection @ ½ bbl/min without exceeding MTP

If injection cannot be established below MTP, contact and consult with ENGINEER before ANY further action is taken. Engineer will provide a safety factor maximum allowable PSI.

3. Once injection is established and confirmed, begin injecting 1000 gal of 15% HCl at any allowable rate under MTP.
4. Switch over to 12-3% HCl-Hf and inject 3000 gal at any allowable rate under MTP.
5. Switch over to NH4Cl and inject 500 gal to displace acid to top perforation.
   Close valves, bleed pressure from equipment and disconnect.
   RDMO.
6. Contact EHPP Control Room (765.1810) and notify operator that well is ready to RTI
7. RTI well.

CONTACTS:

Supervisor:	Office: N/A	Cell:
Well Analyst:	Office:	Cell:
Engineer:	Office:	Cell:

WELL CONFIGURATION:

ELK HILLS, INC.

Current Well Configuration

25A-18G

API-10:	0403023952	Battery:		Original KB Elev:		Spud Date/Time:	12/12/2003
Field Name:	ELK HILLS	Test Facility:		Ground elevation:	600.10 (ft)	Last Well Status:	
Country:	USA	Coord E/W:	1,868,587.58 (m)	KB To Ground:		Well Class.:	Injector - Class I
State:	CALIFORNIA	Coord N/S:	692,928.27 (m)	Ref. Datum: Original KB @610.10ft (above Mean Sea Level)			
County:	KERN			Casing Flange:			

Wellbores/Sidetracks

Wellbore No.	Wellbore label	Start Date	Parent wellbore	Top MD (ft)	Top TVD (ft)	Btm MD (ft)	Btm TVD (ft)	PBMD (ft)	PBTVD (ft)	BH Coord X (m)	BH Coord Y (m)
00	ORIGINAL HOLE	12/12/2003	--None--	0.0	0.0	1,424.0	1,423.9	1,415.0		1,868,587.64	692,932.53

Casing and Liner

	Jts	Length (ft)	Nominal OD (in)	Nominal ID (in)	Drift ID (in)	Weight (ppf)	Grade	Connection	Top MD (ft)	Btm MD (ft)
PRE-SET CONDUCTOR	**Installed:**	12/12/2003		**Wellbore No.**	00					
Casing	2	90.00	13.375						10.0	100.0
SURFACE CASING	**Installed:**	12/13/2003		**Wellbore No.**	00					
Casing	18	704.00	8.625			32.00	J-55		10.0	714.0
SCREEN / SLOTTED LINER	**Installed:**	12/13/2003		**Wellbore No.**	00					
LINER HANGER	1	10.00							684.0	694.0
BLANK	1	30.00							694.0	724.0
SLOTTED LINER	15	691.00							724.0	1,415.0
DRILL-IN SHOE	1	4.00							1,415.0	1,419.0

Other Wellbore Equipment

	Jts	Nominal OD (in)	Nominal ID (in)	Weight (ppf)	Grade	Connection	Top MD (ft)	Btm MD (ft)	Length (ft)	Additional Description
TUBING STRING			**Installed:**	12/14/2003		**Wellbore No.**	00			
Tubing	20	5.000	4.408	15.00	J-55	LTC	10.0	660.0	650.00	
Retrievable	1	8.625		32.00	J-55	LTC	660.0	670.0	10.00	Weatherford 8-5/8" sump packer

Event Work History

Event Name	Start date	End date	Prim. Reason	Sec. Reason	End Status	Field Cost	Total Hrs
INJECTION WELL MAINT - RIGLESS	01/12/2017	01/12/2017	WIRELINE - INJ	MECHANICAL SERVICI	FINISHED - SUCCESS	654.00	3.25
INJECTION WELL MAINT - RIGLESS	04/07/2016	04/07/2016	WELLBORE CLEANOUT - COIL TE		FINISHED - SUCCESS	2,260.00	6.50
INJECTION WELL MAINT - RIGLESS	03/16/2016	03/16/2016	WIRELINE - INJ	MECHANICAL SERVICI	FINISHED - SUCCESS	508.00	2.75
WELL MAINT - RIGLESS	08/24/2015	08/24/2015	WIRELINE - MECHANICAL SERVI		FINISHED - SUCCESS	541.60	3.00
HISTORY	12/12/2003					0.00	

ACID WORK PROGRAM

WELL#: **35-18G**	API 10: 0403023953	RMT: EHPP
PROJECT/TASK:	1110178 / 01030304	Date: TBD
WELL CONDITION:	**Injecting Water**	

WELL INFORMATION:

Current Well Head Pressure: **<u>172</u>** PSIG

PBMD:	N/A'	Tubing ID:	N/A"
BMD:	N/A'	No Go ID:	N/A"
PERF/SLOTS:	688'-1795'	**Max Treating PSI (MTP):**	**<u>122</u> PSI**
Last Tag Depth:	**<u>1091'</u>** (07-23-19)		

ACID WORK INFORMATION:

ACID NAME	QUANTITY	UNIT	DESCRIPTION	PENETRATION
15% HCl	1000	Gals.	Hydrochloric Acid	3.82 in
12-3% HCl-HF	3000	Gals	Mud Acid	8.39 in
NH4Cl (2%)	500	Gals.	Displacement Fluid	2.20 in

JOB PROCEDURE:

1. Obtain the permit from the EHPP Control Room Operator 765-1810 (Power Plant). Notify the operator of the work to be performed on the injector.
2. MIRU acid transport truck containing <u>1000</u> gal of 15% HCl, <u>3000</u> gal of 12-3% HCl-Hf & <u>500</u> gal of NH4Cl (2%) w/ inhibitor.
   Install HP hoses and pressure test, check for leaks.
   Open valve to well to establish injection @ ½ bbl/min without exceeding MTP

If injection cannot be established below MTP, contact and consult with <u>ENGINEER</u> before ANY further action is taken. Engineer will provide a safety factor maximum allowable PSI.

3. Once injection is established and confirmed, begin injecting 1000 gal of 15% HCl at any allowable rate under MTP.
4. Switch over to 12-3% HCl-Hf and inject 3000 gal at any allowable rate under MTP.
5. Switch over to NH4Cl and inject 500 gal to displace acid to top perforation.
   Close valves, bleed pressure from equipment and disconnect.
   RDMO.
6. Contact EHPP Control Room (765.1810) and notify operator that well is ready to RTI
7. RTI well.

CONTACTS:

Supervisor:	Office:	Cell:
Well Analyst:	Office:	Cell:
Engineer:	Office:	Cell:

WELL CONFIGURATION:

OCCIDENTAL OF ELK HILLS INC

Current Well Configuration

35EHP-WD-18G

API-10:	0403023953	Battery:		Original KB Elev: Spud Date/Time:	03/21/2002
Field Name:	ELK HILLS	Test Facility:		Ground elevation: 591.90 (ft) Last Well Status:	-
Country:	USA	Coord E/W:	6,131,353.32 (usft)	KB To Ground: Well Class.:	Water Disposal
State:	CALIFORNIA	Coord N/S:	2,273,371.75 (usft)	Ref. Datum: Original KB @603.90ft (above Mean Sea Level)	
County:	KERN			Casing Flange: ELCO, C-22, 11.000, 2000	

Wellbores/Sidetracks

Wellbore No.	Wellbore label	Start Date	Parent wellbore	Top MD (ft)	Top TVD (ft)	Btm MD (ft)	Btm TVD (ft)	PBMD (ft)	PBTVD (ft)	BH Coord X (usft)	BH Coord Y (usft)
00	ORIGINAL HOLE	03/21/2002	--None--	0.0	0.0	1,800.0	1,797.3	1,284.0		6,131,328.75	2,273,294.57

Casing and Liner

	Jts	Length (ft)	Nominal OD (in)	Nominal ID (in)	Drift ID (in)	Weight (ppf)	Grade	Connection	Top MD (ft)	Btm MD (ft)
CONDUCTOR CASING Installed: 03/20/2002 **Wellbore No.** 00										
CASING JOINT(S)	1	100.00	13.375						12.0	112.0
PRODUCTION CASING Installed: 03/26/2002 **Wellbore No.** 00										
CASING JOINT(S)	8	336.43	8.625			32.00	K-55	LTC	12.0	348.5
Casing	1	5.00	8.625			32.00	K-55	LTC	348.5	353.5
CASING JOINT(S)	1	45.46	8.625			32.00	K-55	LTC	353.5	398.9
Casing	1	20.02	8.625			32.00	K-55	LTC	398.9	418.9
CASING JOINT(S)	1	45.22	8.625			32.00	K-55	LTC	418.9	464.2
Casing	1	10.02	8.625			32.00	K-55	LTC	464.2	474.2
CASING JOINT(S)	1	41.75	8.625			32.00	K-55	LTC	474.2	515.9
Casing	1	10.00	8.625			32.00	K-55	LTC	515.9	525.9
CASING JOINT(S)	2	83.49	8.625			32.00	K-55	LTC	525.9	609.4
Casing	1	9.99	8.625			32.00	K-55	LTC	609.4	619.4
CASING JOINT(S)	1	44.66	8.625			32.00	K-55	LTC	619.4	664.1
CROSSOVER	1	5.95	8.625			32.00	K-55	LTC	664.1	670.0
CEMENT STAGE TOOL	1	2.56	8.625			40.00		LTC	670.0	672.6
ECP	1	7.37	8.625						672.6	679.9
FLOAT COLLAR	1	5.66	8.625			32.00		LTC	679.9	685.6
CROSSOVER	1	1.30	8.625			32.00	K-55	LTC	685.6	686.9
Casing	1	10.00	8.625			32.00	K-55	LTC	686.9	696.9
SLOTTED CASING	29	1,096.78	8.625			32.00	K-55	LTC	696.9	1,793.7
GUIDE SHOE	1	0.61	8.625			32.00	K-55	LTC	1,793.7	1,794.3
SCREEN / SLOTTED LINER Installed: 02/25/2014 **Wellbore No.** 00										
PACKER (SINGLE)	1	6.23	7.625	5.500			N-80		603.4	609.6
DRIVE-ON ADAPTER	1	1.25	7.500	5.495			N-80		609.6	610.9
BLANK	1	32.28	5.500	4.892		17.00	K-55	LTC	610.9	643.2
SLOTTED LINER	1	640.72	5.500	4.892		17.00	K-55	LTC	643.2	1,283.9
DRILL-IN ADAPTER	1	3.35	5.500	2.375			K-55	LTC	1,283.9	1,287.2
DRILL BIT	1	0.65	7.875						1,287.2	1,287.9

Non-Perforated Intervals

Wellbore No.	Top MD (ft)	Btm MD (ft)	Type	Reason/Comments	Status	Status date
00	697.0	1,794.0	SLOTTED	200M x 24R x 2" x 6"C (1097' overall)	OPEN	03/06/2002

Other Wellbore Equipment

	Jts	Nominal OD (in)	Nominal ID (in)	Weight (ppf)	Grade	Connection	Top MD (ft)	Btm MD (ft)	Length (ft)	Additional Description
TUBING STRING Installed: 02/27/2014 **Wellbore No.** 00										
TUBING HANGER (SINGLE)	1	11.000	4.408	15.00	TCM		1.9	4.2	2.31	Cameron 11" x 5" single hanger
PUP JOINT	4	5.000	4.408	15.00	N-80		4.2	39.3	35.12	5" 15# N80 LT&C pup joints
Tubing	14	5.000	4.408	15.00	N-80		39.3	601.3	561.95	5" 15# N80 LT&C Production tubing
SEAL ASSEMBLY	1	5.500	4.408		N-80		601.3	603.4	2.14	Weatherford 5-1/2" Tie Back Stem

Notes / Recommended Work

Effective date	Category	Comments
02/08/2014	Wellbore Note	This is an Elk Hills Power, water disposal well (Regulated by the EPA, not DOGGR) no API #

Event Work History

Event Name	Start date	End date	Prim. Reason	Sec. Reason	End Status	Field Cost	Total Hrs
INJECTION WELL MAINT - RIGLESS	07/23/2019	07/23/2019	WIRELINE	MECHANICAL SERVIC	FINISHED - SUCCESS	628.00	3.00

Event Work History

Event Name	Start date	End date	Prim. Reason	Sec. Reason	End Status	Field Cost	Total Hrs
INJECTION WELL MAINT - RIGLESS	01/10/2019	01/10/2019	WIRELINE	MECHANICAL SERVIC	FINISHED - SUCCESS	764.00	2.00
INJECTION WELL MAINT - RIGLESS	10/20/2018	10/21/2018	WELLBORE CLEANOUT - COIL T	WATER INJECTION SU	FINISHED - SUCCESS	27,503.96	19.00
INJECTION WELL MAINT - RIGLESS	09/12/2018	09/12/2018	DOGGR REGULATORY	MECHANICAL SERVIC	FINISHED - SUCCESS	2,200.00	2.75
INJECTION WELL MAINT - RIGLESS	07/31/2018	07/31/2018	WIRELINE	MECHANICAL SERVIC	FINISHED - SUCCESS	575.00	2.50
INJECTION WELL MAINT - RIGLESS	07/21/2016	07/21/2016	WIRELINE - INJ		FINISHED - SUCCESS	580.00	3.50
WELL MAINT - RIGLESS	08/06/2015	08/06/2015	WELLBORE CLEANOUT - COIL T		FINISHED - SUCCESS	22,591.00	9.00
WELL MAINT - RIGLESS	07/01/2014	07/01/2014	WIRELINE - MECHANICAL SERVI		FINISHED - SUCCESS	1,092.15	2.98
WELL MAINT - RIG	02/08/2014	02/27/2014	TUBING CHANGE		FINISHED - SUCCESS	161,504.71	85.00
DEV DRILLING	03/20/2002	04/24/2002	ORIG DRILL DIR			280,267.77	281.50

ACID WORK PROGRAM

WELL#: **35A-18G**	API 10: 0403023953	RMT:	EHPP
PROJECT/TASK:	1110178 / 01030304	Date:	TBD
WELL CONDITION:	**Injecting Water**		

WELL INFORMATION:

Current Well Head Pressure: **172** PSIG

PBMD:	N/A'	Tubing ID:	N/A"
BMD:	N/A'	No Go ID:	N/A"
PERF/SLOTS:	653'-1294'	**Max Treating PSI (MTP):**	**122 PSI**
Last Tag Depth:	**1287'** (7-23-19)		

ACID WORK INFORMATION:

ACID NAME	QUANTITY	UNIT	DESCRIPTION	PENETRATION
15% HCl	1000	Gals.	Hydrochloric Acid	3.82 in
12-3% HCl-HF	3000	Gals	Mud Acid	8.39 in
NH4Cl (2%)	500	Gals.	Displacement Fluid	2.20 in

JOB PROCEDURE:

1. Obtain the permit from the EHPP Control Room Operator 765-1810 (Power Plant). Notify the operator of the work to be performed on the injector.
2. MIRU acid transport truck containing 1000 gal of 15% HCl, 3000 gal of 12-3% HCl-Hf & 500 gal of NH4Cl (2%) w/ inhibitor.
   Install HP hoses and pressure test, check for leaks.
   Open valve to well to establish injection @ ½ bbl/min without exceeding MTP

If injection cannot be established below MTP, contact and consult with ENGINEER before ANY further action is taken. Engineer will provide a safety factor maximum allowable PSI.

3. Once injection is established and confirmed, begin injecting 1000 gal of 15% HCl at any allowable rate under MTP.
4. Switch over to 12-3% HCl-Hf and inject 3000 gal at any allowable rate under MTP.
5. Switch over to NH4Cl and inject 500 gal to displace acid to top perforation.
   Close valves, bleed pressure from equipment and disconnect.
   RDMO.
6. Contact EHPP Control Room (765.1810) and notify operator that well is ready to RTI
7. RTI well.

CONTACTS:

Supervisor:	Office:	Cell:
Well Analyst:	Office:	Cell:
Engineer:	Office:	Cell:

WELL CONFIGURATION:

OCCIDENTAL OF ELK HILLS, INC.

Current Well Configuration

35A-18G

API-10:	0403023953	Battery:		Original KB Elev:		Spud Date/Time:	12/18/2003
Field Name:	ELK HILLS	Test Facility:		Ground elevation:	604.00 (ft)	Last Well Status:	
Country:	USA	Coord E/W:	1,868,689.74 (m)	KB To Ground:		Well Class.:	Water Disposal
State:	CALIFORNIA	Coord N/S:	692,928.07 (m)	Ref. Datum: Original DF @614.00ft (above Mean Sea Level)			
County:	KERN			Casing Flange:			

Wellbores/Sidetracks

Wellbore No.	Wellbore label	Start Date	Parent wellbore	Top MD (ft)	Top TVD (ft)	Btm MD (ft)	Btm TVD (ft)	PBMD (ft)	PBTVD (ft)	BH Coord X (m)	BH Coord Y (m)
00	ORIGINAL HOLE	12/18/2003	--None--	0.0	0.0	1,298.0	1,298.0	1,294.0		1,868,689.74	692,928.07

Casing and Liner

	Jts	Length (ft)	Nominal OD (in)	Nominal ID (in)	Drift ID (in)	Weight (ppf)	Grade	Connection	Top MD (ft)	Btm MD (ft)
CONDUCTOR CASING	**Installed:**	12/16/2003		**Wellbore No.**	00					
Casing	2	90.00	13.375						10.0	100.0
SURFACE CASING	**Installed:**	12/18/2003		**Wellbore No.**	00					
Casing	17	708.00	8.625						10.0	718.0
SCREEN / SLOTTED LINER	**Installed:**	12/24/2003		**Wellbore No.**	00					
Casing	1	33.00	5.500			17.00	K-55		620.0	653.0
SLOTTED CASING	15	641.00	5.500			17.00	K-55		653.0	1,294.0
DRILL-IN SHOE	1	4.00	5.500						1,294.0	1,298.0

Non-Perforated Intervals

Wellbore No.	Top MD (ft)	Btm MD (ft)	Type	Reason/Comments	Status	Status date
00	653.0	717.0	SLOTTED	200M x 24R x 2" x 6"C slots (641' over all)	ISOLATED	12/24/2003

Other Wellbore Equipment

	Jts	Nominal OD (in)	Nominal ID (in)	Weight (ppf)	Grade	Connection	Top MD (ft)	Btm MD (ft)	Length (ft)	Additional Description
TUBING STRING			**Installed:**	02/27/2014		**Wellbore No.**	00			
TUBING HANGER (SINGLE)	1	11.000	4.408	15.00	TCM		10.0	12.3	2.31	Cameron 11" x 5" single hanger
PUP JOINT	4	5.000	4.408	15.00	N-80		12.3	47.4	35.12	5" 15# N80 LT&C pup joints
Tubing	14	5.000	4.408	15.00	N-80		47.4	617.9	570.45	5" 15# N80 LT&C Production tubing
SEAL ASSEMBLY	1	5.500	4.408		N-80		617.9	620.0	2.14	Weatherford 5-1/2" Tie Back Stem

Event Work History

Event Name	Start date	End date	Prim. Reason	Sec. Reason	End Status	Field Cost	Total Hrs
INJECTION WELL MAINT - RIGLESS	01/12/2017	01/12/2017	WIRELINE - INJ	MECHANICAL SERVICI	FINISHED - SUCCESS	648.00	3.50
INJECTION WELL MAINT - RIGLESS	03/16/2016	03/16/2016	WIRELINE - INJ	MECHANICAL SERVICI	FINISHED - SUCCESS	520.00	1.75
WELL MAINT - RIGLESS	08/24/2015	08/24/2015	WIRELINE - MECHANICAL SERVI		FINISHED - SUCCESS	580.00	3.00
WELL MAINT - RIGLESS	06/24/2014	06/24/2014	WIRELINE - MECHANICAL SERVI		FINISHED - SUCCESS	643.95	2.25
WELL MAINT - RIG	02/08/2014	02/27/2014	TUBING CHANGE		FINISHED - SUCCESS	161,504.71	85.00
DEV DRILLING	03/20/2002		ORIG DRILL VERT	WATER DISPOSAL		0.00	

HYDROCHLORIC ACID SDS

Hydrochloric Acid

Safety Data Sheet

according to Federal Register / Vol. 77, No. 58 / Monday, March 26, 2012 / Rules and Regulations

Date of issue: 05/27/2016 Version: 1.0

SECTION 1: Identification

1.1. Identification

Product form	:	Mixture
Product name	:	Hydrochloric Acid

1.2. Relevant identified uses of the substance or mixture and uses advised against

No additional information available

1.3. Details of the supplier of the safety data sheet

Cal Coast Acidizing
PO Box 2050
Orcutt, CA 93457
T 661-746-4713

1.4. Emergency telephone number

Emergency number	:	Chemtrec : +1 800-424-9300 (Within USA)

SECTION 2: Hazard(s) identification

2.1. Classification of the substance or mixture

GHS-US classification

Met. Corr. 1	H290 -	May be corrosive to metals
Skin Corr. 1B	H314 -	Causes severe skin burns and eye damage
Eye Dam. 1	H318 -	Causes serious eye damage
STOT SE 3	H335 -	May cause respiratory irritation

Full text of H statements : see section 16

2.2. Label elements

GHS-US labeling

Hazard pictograms (GHS-US) :

GHS05 GHS07

Signal word (GHS-US) : Danger

Contains : Hydrochloric acid

Hazard statements (GHS-US) :
H290 - May be corrosive to metals
H302 - Harmful if swallowed
H314 - Causes severe skin burns and eye damage
H335 - May cause respiratory irritation

Precautionary statements (GHS-US) :
P234 - Keep only in original container
P260 - Do not breathe vapors, spray, mist
P261 - Avoid breathing vapors, spray, mist
P264 - Wash hands thoroughly after handling
P270 - Do not eat, drink or smoke when using this product
P271 - Use only outdoors or in a well-ventilated area
P280 - Wear protective gloves, protective clothing, eye protection
P301+P312 - If swallowed: Call a POISON CENTER if you feel unwell
P301+P330+P331 - If swallowed: rinse mouth. Do NOT induce vomiting
P303+P361+P353 - If on skin (or hair): Take off immediately all contaminated clothing. Rinse skin with water/shower
P304+P340 - If inhaled: Remove person to fresh air and keep comfortable for breathing
P305+P351+P338 - If in eyes: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing
P310 - Immediately call a doctor
P312 - Call a doctor if you feel unwell
P321 - Specific treatment (see on this label)
P330 - Rinse mouth
P363 - Wash contaminated clothing before reuse
P390 - Absorb spillage to prevent material damage
P403+P233 - Store in a well-ventilated place. Keep container tightly closed
P405 - Store locked up

P406 - Store in corrosive resistant container with a resistant inner liner
P501 - Dispose of contents/container to hazardous or special waste collection point, in accordance with local, regional, national and/or international regulation

2.3. Other hazards

Other hazards not contributing to the classification : None.

2.4. Unknown acute toxicity (GHS US)

Not applicable

SECTION 3: Composition/Information on ingredients

3.1. Substance

Not applicable

3.2. Mixture

Name	Product identifier	%	GHS-US classification
Hydrochloric acid	(CAS No) 7647-01-0	1 - 30	Acute Tox. 3 (Inhalation:gas), H331 Skin Corr. 1A, H314

Full text of H-phrases: see section 16

SECTION 4: First aid measures

4.1. Description of first aid measures

First-aid measures general : Call a physician immediately. If medical advice is needed, have product container or label at hand.

First-aid measures after inhalation : Remove person to fresh air and keep comfortable for breathing. Give oxygen or artificial respiration if necessary. Call a poison center/doctor/physician if you feel unwell.

First-aid measures after skin contact : Wash skin with plenty of water. Remove affected clothing and wash all exposed skin area with mild soap and water, followed by warm water rinse. Seek medical attention if burns develop.

First-aid measures after eye contact : Immediately rinse with water for a prolonged period while holding the eyelids wide open. Remove contact lenses, if present and easy to do. Continue rinsing. Call a physician immediately.

First-aid measures after ingestion : Rinse mouth. Do NOT induce vomiting. Call a physician immediately.

4.2. Most important symptoms and effects, both acute and delayed

Symptoms/injuries : Causes severe skin burns and eye damage.

Symptoms/injuries after inhalation : May cause respiratory irritation.

Symptoms/injuries after skin contact : Burns.

Symptoms/injuries after eye contact : Serious damage to eyes.

Symptoms/injuries after ingestion : Burns.

4.3. Indication of any immediate medical attention and special treatment needed

Not applicable.

SECTION 5: Firefighting measures

5.1. Extinguishing media

Suitable extinguishing media : Water spray. Dry powder. Foam. Carbon dioxide.

5.2. Special hazards arising from the substance or mixture

Reactivity : The product is non-reactive under normal conditions of use, storage and transport.

5.3. Advice for firefighters

Protection during firefighting : Do not attempt to take action without suitable protective equipment. Self-contained breathing apparatus. Complete protective clothing.

SECTION 6: Accidental release measures

6.1. Personal precautions, protective equipment and emergency procedures

6.1.1. For non-emergency personnel

Emergency procedures : Avoid contact with skin and eyes. Do not breathe vapors, spray, mist. Evacuate unnecessary personnel.

6.1.2. For emergency responders

Protective equipment : Do not attempt to take action without suitable protective equipment. For further information refer to section 8: "Exposure controls/personal protection".

6.2. Environmental precautions

Avoid release to the environment.

6.3. Methods and material for containment and cleaning up

Methods for cleaning up : In case of large spillages: Soak up spills with inert solids, such as clay or diatomaceous earth as soon as possible. Shovel or sweep up and put in a closed container for disposal. Small quantities of liquid spill: take up in non-combustible absorbent material and shovel into container for disposal. Notify authorities if product enters sewers or public waters.

Other information : Dispose of materials or solid residues at an authorized site.

6.4. Reference to other sections

For further information refer to section 13.

SECTION 7: Handling and storage

7.1. Precautions for safe handling

Additional hazards when processed : May be corrosive to metals. Never add water to the acid. Add acid to water to dilute.

Precautions for safe handling : Use only outdoors or in a well-ventilated area. Avoid breathing vapors, spray, mist. Avoid contact with skin and eyes. Wear personal protective equipment. Do not handle until all safety precautions have been read and understood. Do not breathe vapors.

Hygiene measures : Separate work clothes from street clothes. Wash contaminated clothing before reuse. Launder separately. Do not eat, drink or smoke when using this product. Always wash hands after handling the product.

7.2. Conditions for safe storage, including any incompatibilities

Storage conditions : Store in corrosive resistant container with a resistant inner liner. Keep only in original container. Store locked up. Store in a well-ventilated place. Keep container tightly closed. Keep cool.

Incompatible materials : Metals.

SECTION 8: Exposure controls/personal protection

8.1. Control parameters

Hydrochloric acid (7647-01-0)		
ACGIH	ACGIH Ceiling (ppm)	2 ppm
OSHA	OSHA PEL (Ceiling) (mg/m^3)	7 mg/m^3
OSHA	OSHA PEL (Ceiling) (ppm)	5 ppm

Water (7732-18-5)
Not applicable

8.2. Exposure controls

Appropriate engineering controls : Ensure good ventilation of the work station.

Hand protection : Chemically resistant protective gloves.

Eye protection : Chemical goggles or safety glasses. Eye protection, including both chemical splash goggles and face shield, must be worn when possibility exists for eye contact due to spraying liquid or airborne particles.

Skin and body protection : Wear suitable protective clothing.

Respiratory protection : In case of insufficient ventilation, wear suitable respiratory equipment.

Environmental exposure controls : Avoid release to the environment.

SECTION 9: Physical and chemical properties

9.1. Information on basic physical and chemical properties

Physical state : Liquid

Appearance : Clear.

Color : Colorless

Odor : Pungent

Odor threshold : No data available

pH : No data available

Melting point : Not applicable

Freezing point : No data available

Boiling point	: No data available
Flash point	: No data available
Relative evaporation rate (butyl acetate=1)	: No data available
Flammability (solid, gas)	: No data available
Explosion limits	: No data available
Explosive properties	: No data available
Oxidizing properties	: No data available
Vapor pressure	: No data available
Relative density	: No data available
Relative vapor density at 20 °C	: No data available
Solubility	: Water: Solubility in water of component(s) of the mixture : • Hydrochloric acid: 823 g/l (at 0 °C)
Log Pow	: No data available
Auto-ignition temperature	: No data available
Decomposition temperature	: No data available
Viscosity	: No data available
Viscosity, kinematic	: No data available
Viscosity, dynamic	: No data available

9.2. Other information

No additional information available

SECTION 10: Stability and reactivity

10.1. Reactivity

The product is non-reactive under normal conditions of use, storage and transport.

10.2. Chemical stability

Stable under normal conditions.

10.3. Possibility of hazardous reactions

No dangerous reactions known under normal conditions of use.

10.4. Conditions to avoid

None under recommended storage and handling conditions (see section 7).

10.5. Incompatible materials

Strong bases. metals. Amines. Alkali metals. Permanganates.

10.6. Hazardous decomposition products

Under normal conditions of storage and use, hazardous decomposition products should not be produced. On combustion, forms: carbon oxides (CO and CO2). Corrosive vapors. Chlorine.

SECTION 11: Toxicological information

11.1. Information on toxicological effects

Acute toxicity : Not classified

Hydrochloric Acid	
ATE US (oral)	793.333 mg/kg body weight

Hydrochloric acid (7647-01-0)	
LD50 oral rat	238 - 277 mg/kg
LD50 dermal rabbit	> 5010 mg/kg
LC50 inhalation rat (mg/l)	1.68 mg/l (Exposure time: 1 h)
ATE US (oral)	238.000 mg/kg body weight
ATE US (gases)	700.000 ppmV/4h
ATE US (vapors)	1.680 mg/l/4h
ATE US (dust, mist)	1.680 mg/l/4h

Skin corrosion/irritation	: Causes severe skin burns and eye damage.
Serious eye damage/irritation	: Causes serious eye damage.
Respiratory or skin sensitization	: Not classified

Germ cell mutagenicity : Not classified
Carcinogenicity : Not classified

Hydrochloric acid (7647-01-0)	
IARC group	3 - Not classifiable

Reproductive toxicity : Not classified
Specific target organ toxicity (single exposure) : May cause respiratory irritation.
Specific target organ toxicity (repeated exposure) : Not classified
Aspiration hazard : Not classified
Symptoms/injuries after inhalation : May cause respiratory irritation.
Symptoms/injuries after skin contact : Burns.
Symptoms/injuries after eye contact : Serious damage to eyes.
Symptoms/injuries after ingestion : Burns.

SECTION 12: Ecological information

12.1. Toxicity

Ecology - general : Before neutralisation, the product may represent a danger to aquatic organisms.

12.2. Persistence and degradability

Hydrochloric Acid	
Persistence and degradability	Not established.

12.3. Bioaccumulative potential

Hydrochloric Acid	
Bioaccumulative potential	Not established.

12.4. Mobility in soil

Hydrochloric Acid	
Ecology - soil	Not established.

12.5. Other adverse effects

Effect on global warming : No known ecological damage caused by this product.
Not established

SECTION 13: Disposal considerations

13.1. Waste treatment methods

Waste treatment methods : Dispose of contents/container in accordance with licensed collector's sorting instructions.
Waste disposal recommendations : Dispose in a safe manner in accordance with local/national regulations.

SECTION 14: Transport information

Department of Transportation (DOT)

In accordance with DOT
Transport document description : UN1789 Hydrochloric acid (Solution), 8, II
UN-No.(DOT) : UN1789
Proper Shipping Name (DOT) : Hydrochloric acid
Solution
Class (DOT) : 8 - Class 8 - Corrosive material 49 CFR 173.136
Hazard labels (DOT) : 8 - Corrosive

Packing group (DOT)	: II - Medium Danger
DOT Packaging Non Bulk (49 CFR 173.xxx)	: 202
DOT Packaging Bulk (49 CFR 173.xxx)	: 242
DOT Special Provisions (49 CFR 172.102)	: A3 - For combination packaging, if glass inner packaging (including ampoules) are used, they must be packed with absorbent material in tightly closed metal receptacles before packing in outer packaging A6 - For combination packaging, if plastic inner packaging are used, they must be packed in tightly closed metal receptacles before packing in outer packaging B3 - MC 300, MC 301, MC 302, MC 303, MC 305, and MC 306 and DOT 406 cargo tanks and DOT 57 portable tanks are not authorized B15 - Packaging must be protected with non-metallic linings impervious to the lading or have a suitable corrosion allowance IB2 - Authorized IBCs: Metal (31A, 31B and 31N); Rigid plastics (31H1 and 31H2); Composite (31HZ1). Additional Requirement: Only liquids with a vapor pressure less than or equal to 110 kPa at 50 C (1.1 bar at 122 F), or 130 kPa at 55 C (1.3 bar at 131 F) are authorized N41 - Metal construction materials are not authorized for any part of a packaging which is normally in contact with the hazardous material T8 - 4 178.274(d)(2) Normal............. Prohibited TP2 - a. The maximum degree of filling must not exceed the degree of filling determined by the following: (image) Where: tr is the maximum mean bulk temperature during transport, tf is the temperature in degrees celsius of the liquid during filling, and a is the mean coefficient of cubical expansion of the liquid between the mean temperature of the liquid during filling (tf) and the maximum mean bulk temperature during transportation (tr) both in degrees celsius. b. For liquids transported under ambient conditions may be calculated using the formula: (image) Where: d15 and d50 are the densities (in units of mass per unit volume) of the liquid at 15 C (59 F) and 50 C (122 F), respectively TP12 - This material is considered highly corrosive to steel
DOT Packaging Exceptions (49 CFR 173.xxx)	: 154
DOT Quantity Limitations Passenger aircraft/rail (49 CFR 173.27)	: 1 L
DOT Quantity Limitations Cargo aircraft only (49 CFR 175.75)	: 30 L
DOT Vessel Stowage Location	: C - The material must be stowed "on deck only" on a cargo vessel and on a passenger vessel
Emergency Response Guide (ERG) Number	: 157
Other information	: Product RQ: 16,667 lbs. Hydrochloric acid.

TDG

No additional information available

Transport by sea

UN-No. (IMDG)	: 1789
Proper Shipping Name (IMDG)	: HYDROCHLORIC ACID
Class (IMDG)	: 8 - Corrosive substances
Packing group (IMDG)	: II - substances presenting medium danger

Air transport

UN-No. (IATA)	: 1789
Proper Shipping Name (IATA)	: Hydrochloric acid
Class (IATA)	: 8 - Corrosives
Packing group (IATA)	: II - Medium Danger

SECTION 15: Regulatory information

15.1. US Federal regulations

Chemical(s) subject to the reporting requirements of Section 313 or Title III of the Superfund Amendments and Reauthorization Act (SARA) of 1986 and 40 CFR Part 372.

Hydrochloric acid	CAS No 7647-01-0	1 - 30%

Hydrochloric acid (7647-01-0)	
Listed on the United States TSCA (Toxic Substances Control Act) inventory Listed on the United States SARA Section 302	
SARA Section 302 Threshold Planning Quantity (TPQ)	500 (gas only)
SARA Section 313 - Emission Reporting	1.0 % (acid aerosols including mists, vapors, gas, fog, and other airborne forms of any particle size)

Water (7732-18-5)
Listed on the United States TSCA (Toxic Substances Control Act) inventory

15.2. International regulations

National regulations

Hydrochloric Acid
All chemical substances in this product are listed in the EPA (Environment Protection Agency) TSCA (Toxic Substances Control Act) Inventory

Hydrochloric acid (7647-01-0)
Listed on the AICS (Australian Inventory of Chemical Substances) Listed on IECSC (Inventory of Existing Chemical Substances Produced or Imported in China) Listed on the Japanese ENCS (Existing & New Chemical Substances) inventory Listed on the Korean ECL (Existing Chemicals List) Listed on NZIoC (New Zealand Inventory of Chemicals) Listed on PICCS (Philippines Inventory of Chemicals and Chemical Substances) Japanese Poisonous and Deleterious Substances Control Law Listed on the Canadian IDL (Ingredient Disclosure List) Listed on INSQ (Mexican National Inventory of Chemical Substances) Listed on CICR (Turkish Inventory and Control of Chemicals)

Water (7732-18-5)
Listed on the AICS (Australian Inventory of Chemical Substances) Listed on IECSC (Inventory of Existing Chemical Substances Produced or Imported in China) Listed on the Korean ECL (Existing Chemicals List) Listed on NZIoC (New Zealand Inventory of Chemicals) Listed on PICCS (Philippines Inventory of Chemicals and Chemical Substances) Listed on INSQ (Mexican National Inventory of Chemical Substances)

15.3. US State regulations

California Proposition 65 - This product does not contain any substances known to the state of California to cause cancer, developmental and/or reproductive harm

Hydrochloric acid (7647-01-0)
U.S. - Massachusetts - Right To Know List U.S. - New Jersey - Right to Know Hazardous Substance List U.S. - Pennsylvania - RTK (Right to Know) - Environmental Hazard List U.S. - Pennsylvania - RTK (Right to Know) List

SECTION 16: Other information

Full text of H-phrases:

H290	May be corrosive to metals
H314	Causes severe skin burns and eye damage
H318	Causes serious eye damage
H331	Toxic if inhaled
H335	May cause respiratory irritation

SDS GHS US CUSTOM BLUE

MUD ACID (HCl-Hf) SDS

HCl-HF Acid Blend

Safety Data Sheet

according to Federal Register / Vol. 77, No. 58 / Monday, March 26, 2012 / Rules and Regulations
Date of issue: 05/27/2016 Version: 1.0

SECTION 1: Identification

1.1. Identification

Product form : Mixture

Product name : HCl-HF Acid Blend

1.2. Relevant identified uses of the substance or mixture and uses advised against

No additional information available

1.3. Details of the supplier of the safety data sheet

Cal Coast Acidizing
PO Box 2050
Orcutt, CA 93457
T 661-746-4713

1.4. Emergency telephone number

Emergency number : Chemtrec : +1 800-424-9300 (Within USA)

SECTION 2: Hazard(s) identification

2.1. Classification of the substance or mixture

GHS-US classification

Met. Corr. 1	H290 -	May be corrosive to metals
Acute Tox. 2 (Dermal)	H310 -	Fatal in contact with skin
Acute Tox. 3 (Inhalation:dust,mist)	H331 -	Toxic if inhaled
Skin Corr. 1A	H314 -	Causes severe skin burns and eye damage
Eye Dam. 1	H318 -	Causes serious eye damage
STOT SE 3	H335 -	May cause respiratory irritation

Full text of H statements : see section 16

2.2. Label elements

GHS-US labeling

Hazard pictograms (GHS-US) :

GHS05 GHS06 GHS07

Signal word (GHS-US) : Danger

Contains : Hydrochloric acid; Hydrofluoric acid

Hazard statements (GHS-US) : H290 - May be corrosive to metals
H310 - Fatal in contact with skin
H314 - Causes severe skin burns and eye damage
H331 - Toxic if inhaled
H335 - May cause respiratory irritation

Precautionary statements (GHS-US) : P234 - Keep only in original container
P260 - Do not breathe mist, spray, vapors
P262 - Do not get in eyes, on skin, or on clothing
P264 - Wash clothing, face, hands thoroughly after handling
P270 - Do not eat, drink or smoke when using this product
P271 - Use only outdoors or in a well-ventilated area
P280 - Wear eye protection, face protection, protective clothing, protective gloves
P301+P330+P331 - If swallowed: rinse mouth. Do NOT induce vomiting
P303+P361+P353 - If on skin (or hair): Take off immediately all contaminated clothing. Rinse skin with water/shower
P304+P340 - If inhaled: Remove person to fresh air and keep comfortable for breathing
P305+P351+P338 - If in eyes: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing
P310 - Immediately call a POISON CENTER
P321 - Specific treatment (see Labeling on this label)
P361 - Take off immediately all contaminated clothing
P363 - Wash contaminated clothing before reuse
P390 - Absorb spillage to prevent material damage
P403+P233 - Store in a well-ventilated place. Keep container tightly closed

P405 - Store locked up
P406 - Store in corrosive resistant container with a resistant inner liner
P501 - Dispose of contents/container to hazardous or special waste collection point, in accordance with local, regional, national and/or international regulation

2.3. Other hazards

Other hazards not contributing to the classification : None.

2.4. Unknown acute toxicity (GHS US)

Not applicable

SECTION 3: Composition/Information on ingredients

3.1. Substance

Not applicable

3.2. Mixture

Name	Product identifier	%	GHS-US classification
Hydrochloric acid	(CAS No) 7647-01-0	5 - 15	Acute Tox. 3 (Inhalation:gas), H331 Skin Corr. 1A, H314
Hydrofluoric acid	(CAS No) 7664-39-3	0.5 - 5	Acute Tox. 2 (Oral), H300 Acute Tox. 1 (Dermal), H310 Acute Tox. 2 (Inhalation:dust,mist), H330 Skin Corr. 1A, H314

Full text of H-phrases: see section 16

SECTION 4: First aid measures

4.1. Description of first aid measures

First-aid measures general : Call a physician immediately. If you feel unwell, seek medical advice (show the label where possible).

First-aid measures after inhalation : Remove person to fresh air and keep comfortable for breathing. Call a doctor.

First-aid measures after skin contact : Remove/Take off immediately all contaminated clothing. Call a physician immediately. Immediately remove contaminated clothing or footwear. Seek medical attention if burns develop. Wash skin with plenty of water.

First-aid measures after eye contact : Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing. Call a physician immediately. Consult an ophtalmologist if irritation persists.

First-aid measures after ingestion : Rinse mouth. Do not induce vomiting. Call a physician immediately.

4.2. Most important symptoms and effects, both acute and delayed

Symptoms/injuries : Not expected to present a significant hazard under anticipated conditions of normal use.

Symptoms/injuries after inhalation : May cause respiratory irritation.

Symptoms/injuries after skin contact : Burns.

Symptoms/injuries after eye contact : Serious damage to eyes.

Symptoms/injuries after ingestion : Burns.

4.3. Indication of any immediate medical attention and special treatment needed

Not applicable.

SECTION 5: Firefighting measures

5.1. Extinguishing media

Suitable extinguishing media : Water spray. Dry powder. Foam. Carbon dioxide.

5.2. Special hazards arising from the substance or mixture

Reactivity : The product is non-reactive under normal conditions of use, storage and transport.

5.3. Advice for firefighters

Protection during firefighting : Do not attempt to take action without suitable protective equipment. Self-contained breathing apparatus. Complete protective clothing.

SECTION 6: Accidental release measures

6.1. Personal precautions, protective equipment and emergency procedures

6.1.1. For non-emergency personnel

Emergency procedures : Only qualified personnel equipped with suitable protective equipment may intervene. Do not breathe dust/fume/gas/mist/vapors/spray. Evacuate unnecessary personnel.

6.1.2. For emergency responders

Protective equipment : Do not attempt to take action without suitable protective equipment. For further information refer to section 8: "Exposure controls/personal protection".

6.2. Environmental precautions

Avoid release to the environment.

6.3. Methods and material for containment and cleaning up

Methods for cleaning up : In case of large spillages: Soak up spills with inert solids, such as clay or diatomaceous earth as soon as possible. Shovel or sweep up and put in a closed container for disposal. Small quantities of liquid spill: take up in non-combustible absorbent material and shovel into container for disposal. Notify authorities if product enters sewers or public waters.

Other information : Dispose of materials or solid residues at an authorized site.

6.4. Reference to other sections

For further information refer to section 13.

SECTION 7: Handling and storage

7.1. Precautions for safe handling

Precautions for safe handling : Use only outdoors or in a well-ventilated area. Avoid breathing dust/fume/gas/mist/vapors/spray. Do not get in eyes, on skin, or on clothing. Wear personal protective equipment.

Hygiene measures : Wash contaminated clothing before reuse. Separate work clothes from street clothes. Launder separately. Do not eat, drink or smoke when using this product. Always wash hands after handling the product.

7.2. Conditions for safe storage, including any incompatibilities

Storage conditions : Store in corrosive resistant container with a resistant inner liner. Keep only in original container. Store locked up. Store in a well-ventilated place. Keep container tightly closed. Keep cool.

Incompatible materials : Metals.

SECTION 8: Exposure controls/personal protection

8.1. Control parameters

Hydrofluoric acid (7664-39-3)		
ACGIH	ACGIH TWA (ppm)	0.5 ppm
ACGIH	ACGIH Ceiling (ppm)	2 ppm
OSHA	OSHA PEL (TWA) (ppm)	3 ppm

Hydrochloric acid (7647-01-0)		
ACGIH	ACGIH Ceiling (ppm)	2 ppm
OSHA	OSHA PEL (Ceiling) (mg/m^3)	7 mg/m^3
OSHA	OSHA PEL (Ceiling) (ppm)	5 ppm

Water (7732-18-5)
Not applicable

8.2. Exposure controls

Appropriate engineering controls : Ensure good ventilation of the work station.

Hand protection : Chemically resistant protective gloves.

Eye protection : Chemical goggles or safety glasses. Eye protection, including both chemical splash goggles and face shield, must be worn when possibility exists for eye contact due to spraying liquid or airborne particles. Safety glasses.

Skin and body protection : Wear suitable protective clothing.

Respiratory protection : Wear respiratory protection.

Environmental exposure controls	: Avoid release to the environment.

SECTION 9: Physical and chemical properties

9.1. Information on basic physical and chemical properties

Physical state	: Liquid
Color	: Mixture contains one or more component(s) which have the following colour(s): Colorless
Odor	: There may be no odour warning properties, odour is subjective and inadequate to warn of overexposure. Mixture contains one or more component(s) which have the following odour(s): choking sharp
Odor threshold	: No data available
pH	: No data available
Melting point	: Not applicable
Freezing point	: No data available
Boiling point	: No data available
Flash point	: No data available
Relative evaporation rate (butyl acetate=1)	: No data available
Flammability (solid, gas)	: No data available
Explosion limits	: No data available
Explosive properties	: No data available
Oxidizing properties	: No data available
Vapor pressure	: No data available
Relative density	: No data available
Relative vapor density at 20 °C	: No data available
Solubility	: Water: Solubility in water of component(s) of the mixture : • Hydrochloric acid: 823 g/l (at 0 °C) • Hydrofluoric acid: 719.8 g/l (at 20 °C)
Log Pow	: No data available
Auto-ignition temperature	: No data available
Decomposition temperature	: No data available
Viscosity	: No data available
Viscosity, kinematic	: No data available
Viscosity, dynamic	: No data available

9.2. Other information

No additional information available

SECTION 10: Stability and reactivity

10.1. Reactivity

The product is non-reactive under normal conditions of use, storage and transport.

10.2. Chemical stability

Stable under normal conditions.

10.3. Possibility of hazardous reactions

No dangerous reactions known under normal conditions of use.

10.4. Conditions to avoid

None under recommended storage and handling conditions (see section 7).

10.5. Incompatible materials

metals.

10.6. Hazardous decomposition products

Under normal conditions of storage and use, hazardous decomposition products should not be produced. On combustion, forms: carbon oxides (CO and CO_2).

SECTION 11: Toxicological information

11.1. Information on toxicological effects

Acute toxicity : Oral: Not classified. Dermal: Fatal in contact with skin. Inhalation:dust,mist: Toxic if inhaled.

HCl-HF Acid Blend	
ATE US (dermal)	100.000 mg/kg body weight
ATE US (dust, mist)	0.918 mg/l/4h

Hydrofluoric acid (7664-39-3)	
LC50 inhalation rat (mg/l)	0.79 mg/l (Exposure time: 1 h)
ATE US (oral)	5.000 mg/kg body weight
ATE US (dermal)	5.000 mg/kg body weight
ATE US (vapors)	0.790 mg/l/4h
ATE US (dust, mist)	0.050 mg/l/4h

Hydrochloric acid (7647-01-0)	
LD50 oral rat	238 - 277 mg/kg
LD50 dermal rabbit	> 5010 mg/kg
LC50 inhalation rat (mg/l)	1.68 mg/l (Exposure time: 1 h)
ATE US (oral)	238.000 mg/kg body weight
ATE US (gases)	700.000 ppmV/4h
ATE US (vapors)	1.680 mg/l/4h
ATE US (dust, mist)	1.680 mg/l/4h

Skin corrosion/irritation : Causes severe skin burns and eye damage.

Serious eye damage/irritation : Causes serious eye damage.

Respiratory or skin sensitization : Not classified

Germ cell mutagenicity : Not classified

Carcinogenicity : Not classified

Hydrochloric acid (7647-01-0)	
IARC group	3 - Not classifiable

Reproductive toxicity : Not classified

Specific target organ toxicity (single exposure) : May cause respiratory irritation.

Specific target organ toxicity (repeated exposure) : Not classified

Aspiration hazard : Not classified

Symptoms/injuries after inhalation : May cause respiratory irritation.

Symptoms/injuries after skin contact : Burns.

Symptoms/injuries after eye contact : Serious damage to eyes.

Symptoms/injuries after ingestion : Burns.

SECTION 12: Ecological information

12.1. Toxicity

Ecology - general : Before neutralisation, the product may represent a danger to aquatic organisms.

Hydrofluoric acid (7664-39-3)	
EC50 Daphnia 1	270 mg/l (Exposure time: 48 h - Species: Daphnia species)

12.2. Persistence and degradability

HCl-HF Acid Blend	
Persistence and degradability	Not established.

12.3. Bioaccumulative potential

HCl-HF Acid Blend	
Bioaccumulative potential	Not established.

Hydrofluoric acid (7664-39-3)	
BCF fish 1	(no bioaccumulation)
Log Pow	-1.4

12.4. Mobility in soil

HCl-HF Acid Blend	
Ecology - soil	Not established.

12.5. Other adverse effects

Effect on global warming : No known ecological damage caused by this product.
Not established

SECTION 13: Disposal considerations

13.1. Waste treatment methods

Waste treatment methods : Dispose of contents/container in accordance with licensed collector's sorting instructions.

Waste disposal recommendations : Dispose in a safe manner in accordance with local/national regulations.

SECTION 14: Transport information

Department of Transportation (DOT)

In accordance with DOT

Transport document description : UN2922 Corrosive liquids, toxic, n.o.s. (Hydrofluoric acid, Hydrochloric acid solution), 8 (6.1), II

UN-No.(DOT) : UN2922

Proper Shipping Name (DOT) : Corrosive liquids, toxic, n.o.s.
Hydrofluoric acid, Hydrochloric acid solution

Class (DOT) : 8 - Class 8 - Corrosive material 49 CFR 173.136

Subsidiary risk (DOT) : 6.1 - Class 6.1 - Poisonous materials 49 CFR 173.132

Hazard labels (DOT) : 8 - Corrosive
6.1 - Poison

Packing group (DOT) : II - Medium Danger

DOT Packaging Non Bulk (49 CFR 173.xxx) : 202

DOT Packaging Bulk (49 CFR 173.xxx) : 243

DOT Symbols : G - Identifies PSN requiring a technical name

DOT Special Provisions (49 CFR 172.102) : B3 - MC 300, MC 301, MC 302, MC 303, MC 305, and MC 306 and DOT 406 cargo tanks and DOT 57 portable tanks are not authorized
IB2 - Authorized IBCs: Metal (31A, 31B and 31N); Rigid plastics (31H1 and 31H2); Composite (31HZ1). Additional Requirement: Only liquids with a vapor pressure less than or equal to 110 kPa at 50 C (1.1 bar at 122 F), or 130 kPa at 55 C (1.3 bar at 131 F) are authorized
T7 - 4 178.274(d)(2) Normal............ 178.275(d)(3)
TP2 - a. The maximum degree of filling must not exceed the degree of filling determined by the following: (image) Where: tr is the maximum mean bulk temperature during transport, tf is the temperature in degrees celsius of the liquid during filling, and a is the mean coefficient of cubical expansion of the liquid between the mean temperature of the liquid during filling (tf) and the maximum mean bulk temperature during transportation (tr) both in degrees celsius. b. For liquids transported under ambient conditions may be calculated using the formula: (image) Where: d15 and d50 are the densities (in units of mass per unit volume) of the liquid at 15 C (59 F) and 50 C (122 F), respectively

DOT Packaging Exceptions (49 CFR 173.xxx) : 154

DOT Quantity Limitations Passenger aircraft/rail (49 CFR 173.27) : 1 L

DOT Quantity Limitations Cargo aircraft only (49 CFR 175.75) : 30 L

DOT Vessel Stowage Location : B - (i) The material may be stowed "on deck" or "under deck" on a cargo vessel and on a passenger vessel carrying a number of passengers limited to not more than the larger of 25 passengers, or one passenger per each 3 m of overall vessel length; and (ii) "On deck only" on passenger vessels in which the number of passengers specified in paragraph (k)(2)(i) of this section is exceeded

DOT Vessel Stowage Other : 40 - Stow "clear of living quarters"

Emergency Response Guide (ERG) Number	: 154
Other information	: Product RQ: 33,333 lbs. Hydrochloric acid. 2,000 lbs. Hydrofluoric Acid.

TDG

No additional information available

Transport by sea

UN-No. (IMDG)	: 2922
Proper Shipping Name (IMDG)	: CORROSIVE LIQUID, TOXIC, N.O.S.
Class (IMDG)	: 8 - Corrosive substances
Packing group (IMDG)	: II - substances presenting medium danger

Air transport

UN-No. (IATA)	: 2922
Proper Shipping Name (IATA)	: Corrosive liquid, toxic, n.o.s.
Class (IATA)	: 8 - Corrosives
Packing group (IATA)	: II - Medium Danger

SECTION 15: Regulatory information

15.1. US Federal regulations

Chemical(s) subject to the reporting requirements of Section 313 or Title III of the Superfund Amendments and Reauthorization Act (SARA) of 1986 and 40 CFR Part 372.

Hydrofluoric acid	CAS No 7664-39-3	0.5 - 5%
Hydrochloric acid	CAS No 7647-01-0	5 - 15%

Hydrofluoric acid (7664-39-3)	
Listed on the United States TSCA (Toxic Substances Control Act) inventory Listed on the United States SARA Section 302	
SARA Section 302 Threshold Planning Quantity (TPQ)	100
SARA Section 313 - Emission Reporting	1.0 %

Hydrochloric acid (7647-01-0)	
Listed on the United States TSCA (Toxic Substances Control Act) inventory Listed on the United States SARA Section 302	
SARA Section 302 Threshold Planning Quantity (TPQ)	500 (gas only)
SARA Section 313 - Emission Reporting	1.0 % (acid aerosols including mists, vapors, gas, fog, and other airborne forms of any particle size)

Water (7732-18-5)
Listed on the United States TSCA (Toxic Substances Control Act) inventory

15.2. International regulations

National regulations

HCI-HF Acid Blend
All chemical substances in this product are listed in the EPA (Environment Protection Agency) TSCA (Toxic Substances Control Act) Inventory

Hydrofluoric acid (7664-39-3)
Listed on the AICS (Australian Inventory of Chemical Substances) Listed on IECSC (Inventory of Existing Chemical Substances Produced or Imported in China) Listed on the Japanese ENCS (Existing & New Chemical Substances) inventory Listed on the Korean ECL (Existing Chemicals List) Listed on NZIoC (New Zealand Inventory of Chemicals) Listed on PICCS (Philippines Inventory of Chemicals and Chemical Substances) Japanese Poisonous and Deleterious Substances Control Law Japanese Pollutant Release and Transfer Register Law (PRTR Law) Listed on the Canadian IDL (Ingredient Disclosure List) Listed on INSQ (Mexican National Inventory of Chemical Substances) Listed on CICR (Turkish Inventory and Control of Chemicals)

Hydrochloric acid (7647-01-0)
Listed on the AICS (Australian Inventory of Chemical Substances) Listed on IECSC (Inventory of Existing Chemical Substances Produced or Imported in China) Listed on the Japanese ENCS (Existing & New Chemical Substances) inventory Listed on the Korean ECL (Existing Chemicals List) Listed on NZIoC (New Zealand Inventory of Chemicals) Listed on PICCS (Philippines Inventory of Chemicals and Chemical Substances) Japanese Poisonous and Deleterious Substances Control Law Listed on the Canadian IDL (Ingredient Disclosure List) Listed on INSQ (Mexican National Inventory of Chemical Substances) Listed on CICR (Turkish Inventory and Control of Chemicals)

Water (7732-18-5)
Listed on the AICS (Australian Inventory of Chemical Substances) Listed on IECSC (Inventory of Existing Chemical Substances Produced or Imported in China) Listed on the Korean ECL (Existing Chemicals List) Listed on NZIoC (New Zealand Inventory of Chemicals) Listed on PICCS (Philippines Inventory of Chemicals and Chemical Substances) Listed on INSQ (Mexican National Inventory of Chemical Substances)

15.3. US State regulations

California Proposition 65 - This product does not contain any substances known to the state of California to cause cancer, developmental and/or reproductive harm

Hydrofluoric acid (7664-39-3)
U.S. - Massachusetts - Right To Know List U.S. - New Jersey - Right to Know Hazardous Substance List U.S. - Pennsylvania - RTK (Right to Know) - Environmental Hazard List U.S. - Pennsylvania - RTK (Right to Know) List

Hydrochloric acid (7647-01-0)
U.S. - Massachusetts - Right To Know List U.S. - New Jersey - Right to Know Hazardous Substance List U.S. - Pennsylvania - RTK (Right to Know) - Environmental Hazard List U.S. - Pennsylvania - RTK (Right to Know) List

SECTION 16: Other information

Full text of H-phrases:

H290	May be corrosive to metals
H300	Fatal if swallowed
H310	Fatal in contact with skin
H314	Causes severe skin burns and eye damage
H318	Causes serious eye damage
H330	Fatal if inhaled
H331	Toxic if inhaled
H335	May cause respiratory irritation

SDS GHS US CUSTOM BLUE

This information is based on our current knowledge and is intended to describe the product for the purposes of health, safety and environmental requirements only. It should not therefore be construed as guaranteeing any specific property of the product

NH4CL (DISPLACEMENT FLUID)

HALLIBURTON

SAFETY DATA SHEET

Product Trade Name: **DCA-32005**

Revision Date: 08-Aug-2016 **Revision Number:** 8

1. Identification

1.1. Product Identifier

Product Trade Name:	DCA-32005
Synonyms	None
Chemical Family:	Surfactant
Internal ID Code	HM007686

1.2 Recommended use and restrictions on use

Application:	Surfactant
Uses advised against	No information available

1.3 Manufacturer's Name and Contact Details

Manufacturer/Supplier
Halliburton Energy Services, Inc.
P.O. Box 1431
Duncan, Oklahoma 73536-0431
Emergency Telephone: (1-866-519-4752 (US, Canada, Mexico) or 1-760-476-3962

Halliburton Energy Services
645 - 7th Ave SW Suite 1800
Calgary, AB
T2P 4G8
Canada

Prepared By Chemical Stewardship
Telephone: 1-281-871-6107
e-mail: fdunexchem@halliburton.com

1.4. Emergency telephone number

Emergency Telephone Number: 1-866-519-4752 or 1-760-476-3962

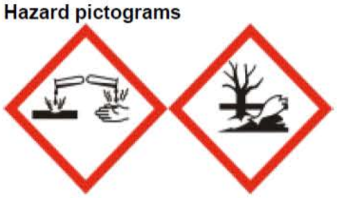
2. Hazard(s) Identification

2.1 Classification in accordance with paragraph (d) of §1910.1200

Serious Eye Damage/Irritation	Category 1 - H318
Chronic Aquatic Toxicity	Category 2 - H411

2.2. Label Elements

Hazard pictograms



Signal Word: Danger

Hazard Statements
H318 - Causes serious eye damage
H411 - Toxic to aquatic life with long lasting effects

Precautionary Statements

Prevention
P264 - Wash face, hands and any exposed skin thoroughly after handling
P273 - Avoid release to the environment
P280 - Wear eye protection/face protection

Response
P305 + P351 + P338 - IF IN EYES: Rinse cautiously with water for several minutes. Remove contact lenses, if present and easy to do. Continue rinsing
P310 - Immediately call a POISON CENTER or doctor/physician
P391 - Collect spillage

Storage
None

Disposal
P501 - Dispose of contents/container in accordance with local/regional/national/international regulations

2.3 Hazards not otherwise classified
None known

3. Composition/information on Ingredients

Substances	CAS Number	PERCENT (w/w)	GHS Classification - US
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	30 - 60%	Eye Corr. 1 (H318) Aquatic Acute 2 (H401) Aquatic Chronic 2 (H411)

The exact percentage (concentration) of the composition has been withheld as proprietary.

4. First-Aid Measures

4.1. Description of first aid measures

Inhalation
If inhaled, remove from area to fresh air. Get medical attention if respiratory irritation develops or if breathing becomes difficult.

Eyes
In case of contact, immediately flush eyes with plenty of water for at least 15 minutes and get medical attention if irritation persists.

Skin
Wash with soap and water. Get medical attention if irritation persists. Remove contaminated clothing and launder before reuse.

Ingestion
Do NOT induce vomiting. Give nothing by mouth. Obtain immediate medical attention.

4.2 Most important symptoms/effects, acute and delayed
Causes severe eye irritation which may damage tissue.

4.3. Indication of any immediate medical attention and special treatment needed
Notes to Physician Treat symptomatically.

5. Fire-fighting measures

5.1. Extinguishing media
Suitable Extinguishing Media
All standard fire fighting media
Extinguishing media which must not be used for safety reasons

None known.

5.2 Specific hazards arising from the substance or mixture

Special exposure hazards in a fire
Not applicable

5.3 Special protective equipment and precautions for fire-fighters

Special protective equipment for firefighters
Not applicable

6. Accidental release measures

6.1. Personal precautions, protective equipment and emergency procedures

Use appropriate protective equipment. Avoid contact with skin, eyes and clothing. Avoid breathing vapors. Ensure adequate ventilation.
See Section 8 for additional information

6.2. Environmental precautions

Prevent from entering sewers, waterways, or low areas.

6.3. Methods and material for containment and cleaning up

Isolate spill and stop leak where safe. Contain spill with sand or other inert materials. Scoop up and remove.

7. Handling and storage

7.1. Precautions for safe handling

Handling Precautions
Use appropriate protective equipment. Avoid contact with eyes, skin, or clothing. Avoid breathing mist. Ensure adequate ventilation. Wash hands after use. Launder contaminated clothing before reuse. Material is slippery underfoot.
Hygiene Measures
Handle in accordance with good industrial hygiene and safety practice.

7.2. Conditions for safe storage, including any incompatibilities

Storage Information
Store in a cool well ventilated area. Keep container closed when not in use. Product has a shelf life of 12 months.

8. Exposure Controls/Personal Protection

8.1 Occupational Exposure Limits

Substances	CAS Number	OSHA PEL-TWA	ACGIH TLV-TWA
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Not applicable	Not applicable

8.2 Appropriate engineering controls

Engineering Controls Use in a well ventilated area.

8.3 Individual protection measures, such as personal protective equipment

Personal Protective Equipment If engineering controls and work practices cannot prevent excessive exposures, the selection and proper use of personal protective equipment should be determined by an industrial hygienist or other qualified professional based on the specific application of this product.

Respiratory Protection Not normally needed. But if significant exposures are possible then the following respirator is recommended:
Dust/mist respirator. (N95, P2/P3)

Hand Protection	Impervious rubber gloves. Butyl rubber gloves. Nitrile gloves. Neoprene gloves. Polyvinylchloride gloves.
Skin Protection	Normal work coveralls.
Eye Protection	Chemical goggles; also wear a face shield if splashing hazard exists.
Other Precautions	Eyewash fountains and safety showers must be easily accessible.

9. Physical and Chemical Properties

9.1. Information on basic physical and chemical properties

Physical State:	Liquid	**Color**	Clear to Light Amber to Dark Amber
Odor:	Mild	**Odor Threshold:**	No information available

Property Remarks/ - Method	Values
pH:	No data available
Freezing Point / Range	No data available
Melting Point / Range	No data available
Boiling Point / Range	No data available
Flash Point	> 93.3 °C / > 200 °F Closed cup
Flammability (solid, gas)	No data available
Upper flammability limit	No data available
Lower flammability limit	No data available
Evaporation rate	No data available
Vapor Pressure	No data available
Vapor Density	No data available
Specific Gravity	1.0802 - 1.1052
Water Solubility	Soluble in water
Solubility in other solvents	No data available
Partition coefficient: n-octanol/water	No data available
Autoignition Temperature	No data available
Decomposition Temperature	No data available
Viscosity	No data available
Explosive Properties	No information available
Oxidizing Properties	No information available

9.2. Other information

VOC Content (%)	No data available

10. Stability and Reactivity

10.1. Reactivity
Not expected to be reactive.

10.2. Chemical stability
Stable

10.3. Possibility of hazardous reactions
Will Not Occur

10.4. Conditions to avoid
Excessive heat

10.5. Incompatible materials
Strong oxidizers. Strong alkalis.

10.6. Hazardous decomposition products
Oxides of nitrogen. Ammonia.

11. Toxicological Information

11.1 Information on likely routes of exposure

Principle Route of Exposure Eye or skin contact, inhalation.

11.2 Symptoms related to the physical, chemical and toxicological characteristics

Acute Toxicity

Inhalation	May cause mild respiratory irritation.
Eye Contact	Causes severe eye irritation which may damage tissue.
Skin Contact	May cause mild skin irritation.
Ingestion	Irritation of the mouth, throat, and stomach.

Chronic Effects/Carcinogenicity No data available to indicate product or components present at greater than 0.1% are chronic health hazards.

11.3 Toxicity data

Toxicology data for the components

Substances	CAS Number	LD50 Oral	LD50 Dermal	LC50 Inhalation
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	> 560-640 mg/kg bw (rat) 4900 mg/kg bw (rat, similar substance) 5000 mg/kg bw (rat, similar substance) 7900 mg/kg bw (rat, similar substance) >10000 mg/kg bw (rat, similar substance)	> 2000 mg/kg bw (rat)	No data available

Substances	CAS Number	Skin corrosion/irritation
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Non-irritating to the skin (Rabbit) (similar substances)

Substances	CAS Number	Serious eye damage/irritation
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Causes severe eye irritation which may damage tissue. (Rabbit) (similar substances)

Substances	CAS Number	Skin Sensitization
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Did not cause sensitization on laboratory animals (guinea pig) (similar substances)

Substances	CAS Number	Respiratory Sensitization
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	No information available

Substances	CAS Number	Mutagenic Effects
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	In vitro tests did not show mutagenic effects. In vivo tests did not show mutagenic effects. (similar substances)

Substances	CAS Number	Carcinogenic Effects
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Did not show carcinogenic effects in animal experiments (similar substances)

Substances	CAS Number	Reproductive toxicity
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Animal testing did not show any effects on fertility. Did not show teratogenic effects in animal experiments. (similar substances)

Substances	CAS Number	STOT - single exposure
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	No significant toxicity observed in animal studies at concentration requiring classification. (similar substances)

Substances	CAS Number	STOT - repeated exposure
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	No significant toxicity observed in animal studies at concentration requiring classification. (similar substances)

Substances	CAS Number	Aspiration hazard
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Not applicable

12. Ecological Information

12.1. Toxicity

Ecotoxicity effects
Toxic to aquatic life with long lasting effects.

Product Ecotoxicity Data
No data available

Substance Ecotoxicity Data

Substances	CAS Number	Toxicity to Algae	Toxicity to Fish	Toxicity to Microorganisms	Toxicity to Invertebrates
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	No information available	EC50(96h): 2.6 mg/L (Oncorhynchus mykiss) EC50(96h): 36.8 mg/L (Brachydanio rerio)	No information available	EC50(48h): 3.2 mg/L (Daphnia magna)

12.2. Persistence and degradability

Readily biodegradable

Substances	CAS Number	Persistence and Degradability
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Readily biodegradable (90% @ 28d)

12.3. Bioaccumulative potential

Substances	CAS Number	Log Pow
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	1.65

12.4. Mobility in soil

Substances	CAS Number	Mobility
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	No information available

12.5 Other adverse effects

No information available

13. Disposal Considerations

13.1. Waste treatment methods

Disposal methods Disposal should be made in accordance with federal, state, and local regulations.
Contaminated Packaging Follow all applicable national or local regulations.

14. Transport Information

US DOT

UN Number UN3082
UN proper shipping name: Environmentally Hazardous Substance, Liquid, N.O.S. (Contains Betaine)
Transport Hazard Class(es): 9
Packing Group: III
Environmental Hazards: Marine Pollutant
NAERG: NAERG 171

Canadian TDG

UN Number	UN3082
UN proper shipping name:	Not restricted Environmentally Hazardous Substance, Liquid, N.O.S. (Contains Betaine)
Transport Hazard Class(es):	9
Packing Group:	III
Environmental Hazards:	Not applicable

IMDG/IMO

UN Number	UN3082
UN proper shipping name:	Environmentally Hazardous Substance, Liquid, N.O.S. (Contains Betaine)
Transport Hazard Class(es):	9
Packing Group:	III
Environmental Hazards:	Marine Pollutant
EMS:	EmS F-A, S-F

IATA/ICAO

UN Number	UN3082
UN proper shipping name:	Environmentally Hazardous Substance, Liquid, N.O.S. (Contains Betaine)
Transport Hazard Class(es):	9
Packing Group:	III
Environmental Hazards:	Marine Pollutant

Transport in bulk according to Annex II of MARPOL 73/78 and the IBC Code Not applicable
Special Precautions for User None

15. Regulatory Information

US Regulations

US TSCA Inventory All components listed on inventory or are exempt.

TSCA Significant New Use Rules - S5A2

Substances	CAS Number	TSCA Significant New Use Rules - S5A2
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Not applicable

EPA SARA Title III Extremely Hazardous Substances

Substances	CAS Number	EPA SARA Title III Extremely Hazardous Substances
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Not applicable

EPA SARA (311,312) Hazard Class
Acute Health Hazard

EPA SARA (313) Chemicals

Substances	CAS Number	Toxic Release Inventory (TRI) - Group I	Toxic Release Inventory (TRI) - Group II
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Not applicable	Not applicable

EPA CERCLA/Superfund Reportable Spill Quantity

Substances	CAS Number	CERCLA RQ
Lauryl dimethyl hydroxysulfobetaine	13197-76-7	Not applicable

EPA RCRA Hazardous Waste Classification
If product becomes a waste, it does NOT meet the criteria of a hazardous waste as defined by the US EPA.

California Proposition 65	All components listed do not apply to the California Proposition 65 Regulation.
MA Right-to-Know Law	Does not apply.
NJ Right-to-Know Law	Does not apply.
PA Right-to-Know Law	Does not apply.
NFPA Ratings:	Health 3, Flammability 1, Reactivity 0
HMIS Ratings:	Health 3, Flammability 1, Physical Hazard 0 , PPE: D

Canadian Regulations

Canadian Domestic Substances List (DSL)	All components listed on inventory or are exempt.

16. Other information

Preparation Information

Prepared By	Chemical Stewardship Telephone: 1-281-871-6107 e-mail: fdunexchem@halliburton.com
Revision Date:	08-Aug-2016
Reason for Revision	SDS sections updated: 14

Additional information
For additional information on the use of this product, contact your local Halliburton representative.

For questions about the Safety Data Sheet for this or other Halliburton products, contact Chemical Stewardship at 1-580-251-4335.

Key or legend to abbreviations and acronyms used in the safety data sheet
bw – body weight
CAS – Chemical Abstracts Service
d - day
EC50 – Effective Concentration 50%
ErC50 – Effective Concentration growth rate 50%
h - hour
LC50 – Lethal Concentration 50%
LD50 – Lethal Dose 50%
LL50 – Lethal Loading 50%
mg/kg – milligram/kilogram
mg/L – milligram/liter
mg/m^3 - milligram/cubic meter
mm - millimeter
mmHg - millimeter mercury
NIOSH – National Institute for Occupational Safety and Health
NTP – National Toxicology Program
OEL – Occupational Exposure Limit
PEL – Permissible Exposure Limit
ppm – parts per million
STEL – Short Term Exposure Limit
TWA – Time-Weighted Average
UN – United Nations

w/w - weight/weight

Key literature references and sources for data
www.ChemADVISOR.com/

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End of Safety Data Sheet