UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

FINAL PERMIT ID-2D001-A

Class II Disposal Well
DJS 2-14
Payette County, Idaho

Issued To:

Snake River Oil and Gas, LLC
117 East Calhoun – P.O. Box 500
Magnolia, Arkansas 71754-0500

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AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act (SDWA) and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this Permit, Snake River Oil and Gas, LLC, hereinafter referred to as the "Permittee," is authorized to construct and to operate, upon written issuance of authorization to commence injection by EPA, the following Class II well:

DJS 2-14
API Number: 11-705-20-023
NE ¼ of the NW ¼ of Section 14, Township 8N, Range 4W
Latitude: 44.03867, Longitude: -116.78333
Payette County, ID

The Permittee is authorized to engage in underground injection in accordance with the conditions of this Permit. Any underground injection activity not authorized by this Permit is prohibited.

This Permit is based on representations made by the Permittee and other information contained in the administrative record. The names of specific wells are identified by their American Petroleum Institute (API) number. Geologic formations and elements of geologic structure are defined in the Fact Sheet to this permit if not otherwise defined in this document. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit.

Where a state or tribe is not authorized to administer the UIC program under the SDWA, EPA regulates underground injection so that injection does not endanger Underground Sources of Drinking Water (USDWs) as defined in 40 CFR § 144.3. EPA UIC Permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subparts D and E, certain conditions apply to all UIC Permits and must be incorporated either expressly or by reference.

Compliance with the terms of this Permit does not constitute a defense to any action pursuant to the provisions of Section 1431 of the SDWA or any other law governing protection of public health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable laws and regulations.

This Permit is issued for the operating life of the facility or until it expires under the terms of the Permit, unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41. This permit must be reviewed at least once every five years to determine if action is required under 40 CFR § 144.36(a).

Issue Date: **November 3, 2022** Effective Date: **December 19, 2022 at 12:01 AM**

MATHEW MARTINSON
Digitally signed by MATHEW MARTINSON
Date: 2022.11.03 15:12:32 -07'00'

Mathew J. Martinson
CAPT, USPHS
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SECTION A. WELL CONSTRUCTION

These requirements specify the approved minimum construction standards for well casing and cement, injection tubing and packer.

DJS 2-14 is an existing production well that will be converted to an injection well. For the remainder of this Permit, any instances of the word "construction" shall also refer to actions constituting a conversion from a production well to UIC Class II disposal well. An EPA-approved well construction plan is incorporated into this Permit as Appendix A.

1. Casing and Cement

The well must be cased and cemented to prevent the movement of fluids into or between USDWs in accordance with 40 CFR § 146.22 and any other applicable federal, state, or local laws and regulations. The construction must be designed for the life expectancy of the well.

The Permittee is required to submit a Cement Bond Log (CBL) for EPA approval prior to receiving written EPA authorization to commence and continue injection of authorized fluids into this Class II disposal well. This CBL must be run within the long string casing from the shallowest Cast Iron Bridge Plug, or a depth of at least 4,000 feet (ft.) True Vertical Depth (TVD), to surface. Results of the test must demonstrate cement isolation between all USDWs.

2. Injection Tubing and Packer

Injection must only take place through tubing with a packer set within or below the upper confining zone as defined in the Fact Sheet for this permit. The tubing must be of a diameter able to accommodate all well testing and logging tools required to meet requirements of this permit. The Permittee must set the packer no more than 100 ft. above the uppermost perforation in the casing unless the Director[1] provides written approval for a greater offset distance. Tubing and packer specifications are represented in Appendix A of this Permit.

3. Changes to the Approved Well Construction Plan

The Permittee may make changes to the well construction plan that are consistent with existing Permit conditions. Any proposed changes must first be approved via written correspondence from the Director, who will confirm that the new construction falls within existing Permit conditions. If these changes result in changes to the well construction schematic, a proposed schematic must be submitted with the notification for planned changes to the well construction. Based on the nature of the requested change in construction, the Director may determine that a Permit modification is needed. Changes to the approved well construction plan must not be implemented until after the Permittee has received written approval from the Director.

4. Sampling and Monitoring Devices

The Permittee must install and maintain in good operating condition any and all devices required to measure, monitor, and record the parameters required by this Permit in Section D. Installation of specific devices are specified in Appendix A.

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[1] Throughout this Permit, the term "Director" refers to the Director of the EPA Region 10 Water Division; the Chief or the EPA Region 10 Permitting, Drinking Water and Infrastructure Branch; or an equivalent authority delegated UIC permitting actions.

The Permittee must ensure that the devices and methods installed and used are sufficient to represent the activity being measured, monitored, or recorded. Continuous monitoring is required unless primary monitoring devices malfunction or a power outage occurs. In the event of primary monitoring device malfunction or a power outage, injection may only occur if the Permittee records injection pressure, inner annulus pressure, and injection rate once every 30 minutes for the duration of the malfunction or power outage. Record of any injection occuring during device malfunction or a power outage must include the date(s) and time over which each recording is taken, the name and title of the person making the measurements, and information regarding the gauges used to make measurements. Gauge information that must be submitted includes the gauge make, model, and the most-recent calibration dates. Once the device(s) is repaired or power is returned, the Permittee must return to continuously monitoring all injection criteria as required by this permit. The Permittee must ensure all gauges used for monitoring and testing are calibrated, and remain properly calibrated, as appropriate.

5. Postponement of Construction or Conversion to Injection Wells

a) The Permit will expire if well construction has not begun within two years following the Effective Date of the Permit. The Permittee may request a up to two additional two-year extensions, resulting in a maximum waiting period of six total years between the Effective Date of this permit and the start of construction. Each request must be made prior to expiration of the Permit. Notification must be in writing and state the reasons for the delay, provide an estimated completion date, and list additional wells within the area of review (AOR) that were not included in the initial Permit application. For those newly completed AOR wells that penetrate the upper confining zone, a well construction diagram, cement records and cement bond logs are also required.

   Once the Permit has expired, the Permittee will need to reapply for a new UIC Permit.

b) For wells that have begun construction, but for which authorization to inject has not been provided within two years of the Effective Date of the Permit, the Permittee is subject to the conditions found in Section E.5., Wells Not Actively Injecting or may elect to convert the well to a non-UIC well found in Section F.2., Injection Well Conversion.

SECTION B. WELL OPERATION

1. Annular Injection Prohibition

Injection into any annulus formed by casing within the well bore is prohibited. Injection may only occur through tubing in a well exhibiting mechanical integrity (MI).

2. Pre-Injection Requirements

The Permittee must conduct sampling, logging, and testing prior to receiving initial authorization to inject. These requirements are found in Sections C and D. Limited injection is permissible prior to receiving initial authorization to inject only for the purpose of conducting the initial well logs and tests required in Section C.

Well injection may commence only after the Permittee has received written authorization to inject from the Director and has met all well construction and pre-injection requirements in this Permit and the UIC regulations, including the following:

a) The Permittee has:

   i. submitted to the Director a notice of completion of construction and a completed EPA Form 7520-18 and required attachments or its equivalent. If the well construction is different than the approved construction found in Appendix A, the Permittee must also provide a revised well diagram and a description of the previously approved modification(s) to the well construction;

   ii. conducted all applicable logging and testing requirements found in Section C. The logging and testing requirements include demonstration of MI pursuant to 40 CFR § 146.8, in accordance with the conditions found in Section C of this Permit;

   iii. submitted required logging and testing records to the Director;

   iv. completed initial representative sampling of the injection stream as specified in Section D; and

   v. satisfied requirements for corrective action in Appendix D, if applicable.

b) The Director has received and reviewed the documentation associated with the requirements in Paragraph 2(a) of this section and finds the information provided by the Permittee is in compliance with the conditions of the Permit.

c) The Director has inspected the injection well and finds it is in compliance with the conditions of the Permit. Such inspection is waived if the Permittee has not received notice from the Director of intent to inspect the injection well within 21 calendar days from the date of the notice provided in Paragraph 2(a)(i) above.

3. Injection Zone, Perforations, and Fluid Movement

Injection zone means "a geological formation, group of formations, or part of a formation receiving fluids through a well."

The approved injection zone is the portion of the Willow Sand, Sands 3-6, found within Fault Block E, as defined by the Fact Sheet to this Permit. These sands are encountered by well DJS 2-14 between approximate depths 4,900 ft. to 5,500 ft. Measured Depth (MD). All perforations must be within the approved injection zone.

Additional injection perforations may be added if (1) perforations are made within the approved injection zone(s), (2) fracture gradient data is submitted and representative of the portion of the injection zone to be perforated, and (3) the Permittee provides notice and reports to the Director in accordance with Section B.8. *Alteration, Workover, and Well Stimulation*. The Permittee must also follow the requirements found in Section B.4 *Injection Pressure Limitation* regarding required changes to the Maximum Allowable Injection Pressure (MAIP).

Injection may only occur within the approved injection zone specified in this section. Injected fluids must remain within the injection zone. If monitoring indicates the movement of fluids from the injection zone, the Permittee must halt injection and notify the Director pursuant with Section I.11.e.

4. Injection Pressure Limitation

a) Injection pressure at the wellhead must not initiate new fractures or propagate existing fractures in either the injection zone or the confining zones as identified in the Fact Sheet. Injection must not result in the movement of injectate or formation fluids into a USDW.

b) The MAIP as measured at the surface must equal 90 percent the calculated formation fracture pressure (FFP**).** The MAIP is calculated using the equation below.

MAIP = **FFP*.90** + **Friction Loss** (if applicable)

Friction Loss (pounds per square inch, psi) is pressure loss between the wellhead and the injection zone due to friction.

Formation Fracture Pressure (**FFP**, psi) (measured at the surface) will be calculated using the following equation:

FFP = [Fracture Gradient - (0.433 psi/ft * (SG + SGFF))] * Depth

Fracture Gradient (psi/ft) is the fracture gradient of the injection zone. This value must be determined by conducting a valid Step Rate Test reviewed and approved by the Director. Alternative methods to determine a representative fracture gradient may be used, if approved by the Director.

Specific Gravity (**SG**, unitless) is the specific gravity of the injection fluid obtained from a representative fluid sample. The specific gravity is a ratio of the density of the injection fluid to the density of water at 4 degrees Celsius.

Specific Gravity Fluctuation Factor (SGFF, unitless) is added to the Specific Gravity to account for potential variations of the actual injected fluid specific gravity. Set at .05 unless otherwise directed by the Director.

Depth (ft) The True Vertical Depth to the shallowest open perforations.

5. Establishing MAIP

The Permittee must submit a letter to the Director proposing an MAIP prior to receiving approval to inject. This request must include a calculation of the MAIP as described in Section B.4., above. The Permittee shall submit the following for review: Step Rate Test results to determine the fracture gradient, fluid analysis from a representative sample of the injectate that provides specific gravity, and a revised well diagram (if construction is different than the approved construction found in Appendix A, that specifies the depth to top perforation). If applicable, the Permittee may request an estimate of tubing friction and perforation friction be added when calculating the MAIP. This request must be supported by a calculation of the effects of friction based on commonly used engineering practices, to be approved by the Director.

The MAIP does not go into effect until the Director provides written notice to the Permittee.

a) Under the following circumstances the Permittee must halt injection, calculate a new MAIP, and submit a request for written authorization of a new MAIP to the Director:

   i. The results of a fluid sample analysis indicate that the injectate specific gravity exceeds the SG + SGFF value used to calculate the current MAIP,

   ii. new perforations are added at depths shallower than the depth used to calculate the current MAIP, or

   iii. the Permittee becomes aware of a more accurate value for the Fracture Gradient of the injection zone that is lower than that used to calculate the current MAIP.

b) The Permittee may request a change to the MAIP at any time. To request a new MAIP, the Permittee shall submit the following for review: Step Rate Test results to determine the fracture gradient, fluid analysis from a representative sample of the injectate that provides specific gravity, and a revised well diagram (if construction is different than the approved construction found in Appendix A, that specifies the depth to top perforation). The MAIP shall be calculated as described above. The Director will review the information and may revise the MAIP in a written authorization.

c) Once a MAIP is requested under this section, the new MAIP will not go into effect until the Director provides written approval stating a new MAIP. The Director will determine whether a Permit modification is needed to implement the requested change.

d) If, during an Internal Mechanical Integrity Test (Internal MIT), the Permittee is unable to achieve a pressure on the inner annulus as measured at the wellhead equal to or exceeding the MAIP, the MAIP will be set at a value equal to the maximum pressure applied to the inner annulus during the test. The Permittee must notify the Director in writing of the new MAIP at the time the results of the MIT are submitted to EPA.

e) If, during an External Mechanical Integrity Test (External MIT), the Permittee is unable to achieve a pressure on the tubing as measured at the wellhead equal to or exceeding the MAIP, the MAIP will be set at a value equal to the maximum pressure applied to the tubing during the test. The

Permittee must notify the Director in writing of the newly requested MAIP at the time the results of the MIT are submitted to EPA.

f) The MAIP must not result in a bottomhole pressure exceeding the sum of the original formation pressure (as measured during pre-injection testing) plus 616 psi. This requirement may be waived by the Director if the Permittee demonstrates through fault slip potential modeling that a higher injection pressure will not result in movement of fluids into USDWs. At no point may injection pressure exceed the calculated value as set by Appendix A.

g) The Director may determine that a lower MAIP is needed for the protection of USDWs. If the Director provides written notification to the Permittee that a new MAIP is required to protect USDWs, the Permittee must halt injection within 24 hours.

6. Injection Volume Limitation

To ensure that injection does not cause migration of fluids into USDWs, the Permittee must not inject more than 7.35 million barrels of fluid into Block E.

7. Injection Fluid Limitation

Injected fluids are limited to those which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection. Fluids that do not fall within the above definition for a Class II fluid defined in 40 CFR § 144.6(b) are not approved for injection.

This permit only allows injection of fluids generated by the Permittee and does not allow injection of fluids generated by any other person, company, entity, etc. This permit does not allow injection of fluids generated outside of Payette County, ID.

This Permit does not allow injection of any hazardous waste as defined in 40 CFR § 261.3.

Examples of fluids which may be approved for injection include, but are not limited to: produced water; drilling fluids; used well completion, treatment, and stimulation fluids; basic sediment, water and other tank bottoms from oil and gas production storage facilities; well workover waste; liquid hydrocarbons removed from the production stream but not from oil refining; gases from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons; waste crude oil from primary field operations; and, materials ejected from a producing well during blowdown.

Examples of prohibited fluids include, but are not limited to: unused fracturing fluids or acids; gas plant cooling tower cleaning wastes; painting wastes; waste solvents; oil and gas service company wastes; vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste; refinery wastes; liquid and solid wastes generated by crude oil and tank bottom reclaimers; used equipment lubricating oils; waste compressor oil, filters, and blowdown; used hydraulic fluids; waste in transportation pipeline related pits; caustic or acid cleaners; boiler cleaning wastes; boiler refractory bricks; boiler scrubber fluids, sludges, and ash; incinerator ash; laboratory wastes; sanitary wastes; pesticide wastes; radioactive tracer wastes; and, groundwater remediation waste.

The Permittee must notify the Director prior to injection of a new fluid source. Fluids produced from a different formation, a different well field, or a different waste stream would constitute a new fluid source. The notification must include a description of the fluid, the process that generated the fluid, and a chemical analysis of a representative sample of the new fluid source that provides an analysis of the constituents found in Section D.1. If results of the fluid analysis indicate a new MAIP is required, the Permittee must submit a request for a new MAIP. See Section B.4 *Injection Pressure Limitation*.

8. Inner Annulus

The inner annulus, or the tubing-casing annulus in the well, must be filled with a non-corrosive fluid. Any valves located on the inner annulus must remain closed during normal operations. Pressure in the inner annulus must not exceed 100 psi or 10% of the tubing pressure, whichever is lower.

If the Permittee cannot maintain an inner annulus pressure within the conditions of this permit, the Permittee must shut-in the well and notify EPA pursuant with Section I.11.e. If MI has been lost, Permittee must comply with the Loss of MI requirements found in Section C.

9. Alteration, Workover, and Well Stimulation

Alterations and workovers must meet all conditions of the Permit. This includes any activity that physically changes the well construction (casing, tubing, packer, perforations) or injection formation. These actions are collectively called “alterations” for the remainder of this section.

The Permittee must notify the Director prior to beginning an alteration. This notice must be provided at least 30 days prior to the date of the planned alteration. At the Director’s discretion, a shorter notification period may be allowed upon written request of the Permittee. The written request must provide a timeline for the requested alteration and along with an explanation as to why this requested timeline is necessary and appropriate. If the alteration would result in a well construction different that the Construction Plan in Appendix A, the Permittee may not make the alteration unless the Director grants approval.

The Permittee must record all alterations and workovers on a Well Rework Record (EPA Form 7520-19) and submit a revised well schematic and plugging and abandonment (P&A) plan, if necessary, when the well construction has been modified. The Permittee must submit these documents and other records of well workover, logging, or test data to the Director within 30 days of completion of the activity.

If an alteration results in loss of MI, the Permittee must complete the alteration and provide demonstration of Internal MI within 90 days of beginning the alteration. If the Permittee is unable to complete work within the specified time, the Permittee must propose an alternative schedule in writing to EPA including a timeline for finishing the alteration. Injection operations must not resume until the well has successfully demonstrated mechanical integrity. The Permittee must receive written approval from the Director to recommence injection in accordance with Section C of this Permit.

10. Seismic Events

The Permittee must monitor active and publicly posted USGS earthquake data. If an earthquake of any magnitude is detected within five miles of the surface location of the injection well, the Permittee must shut-in the well and submit a notice of the event to the Director as stipulated by Section I.11.e. This notice must list the date, time, and magnitude of the event. It must also include a comparison between injection well depth and depth of the hypocenter, and the distance between the epicenter and the surface location of the injection well. Injection may resume only at such time and under such restrictions as determined by the Director to be protective of USDWs. Actions required prior to resumption of injection may include additional testing and/or monitoring if needed to confirm protection of USDWs. The Director may require the modification, revocation and reissuance, or termination of this Permit if needed to protect USDWs.

SECTION C. LOGGING AND TESTING

1. Notification Prior to Testing

The Permittee must notify the Director at least 30 calendar days prior to conducting any logs or tests required by this Permit. This notification must include a description of the proposed method(s) for any logs or tests. The Director may allow a shorter notification period if it would be sufficient to enable EPA or a designated representative to witness the test. EPA may also decline to witness certain the logs and/or tests. Notification to EPA may be in the form of a yearly or quarterly schedule of planned MI tests, or it may be on an individual case-by-case basis.

2. Requirement to Maintain Mechanical Integrity

The Permittee is required to ensure the injection well always maintains MI[2]. Injection into this well if it lacks MI, or if any testing or logs indicate that this well may lack MI, is prohibited unless written approval from EPA to restart and continue injections is received by the Permittee. An injection well must satisfy two parts of:

> **Internal MI -** There is no significant leak in the casing, tubing, or packer; and
>
> **External MI -** There is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

3. Demonstration of Mechanical Integrity

The Permittee must demonstrate that the injection well meets the criteria for Internal and External MI. Well-specific conditions dictate the methods and the frequency for demonstrating Internal and External MI and are specified in this Section. The Permittee must demonstrate Internal and External MI on the following occasions:

a) Prior to receiving authorization to commence injection and periodically thereafter as specified in this Section,

b) After any alteration that compromises the MI of the well or after a loss or suspected loss of Internal and/or External MI per Paragraph 5 of this Section, and

c) Upon request of the Director.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director in demonstrating Internal and/or External MI.

4. Specific Test Methods and Criteria

Test methods must follow those proposed in the Notification Prior to Testing subsection, above, unless otherwise specified by the Director. The Director has established specific testing requirements for the following tests:

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[2] 40 CFR 146.8(a)

a) **INTERNAL MIT -** EPA requires demonstration of Internal MI by conducting an MIT of the inner annulus. The Permittee must pressure test the inner annulus with a fluid approved by EPA. This pressure must equal the current MAIP. If the Permittee cannot reach the MAIP, the test should be carried out at the highest achievable pressure. In no case should the test pressure exceed 70% of the yield strength of the well components (tubing, casing, wellhead, packer). The Permittee must observe the pressure in the tubing, inner annulus, and (if present) outer annulus of the well for 30 minutes. The results of the test must satisfy either (i) or (ii) below:

   i. At the end of the 30-minute test, the inner annulus pressure does not decline by more than 10% of the starting pressure and the loss in the second half of the test period is less than 50% of the loss in the first half of the test period, or,
   ii. At the end of the 30-minute test, the inner annulus pressure does not decline by more than 2% of the starting pressure and the loss in the second half of the test period is less than the loss in the first half of the test period.

   If the well fails to satisfy (i) or (ii) during the first 30-minute test period, the test may be re-run up to three times.

b) **EXTERNAL MIT -** EPA requires demonstration of External MI by conducting a temperature log, radioactive tracer survey, or water flow log. Use of tests other than those listed in this section must be approved in writing by the Director. The Director will consider alternative tests methods that evaluate whether injected fluids are being emplaced within the approved injection zone. The Director may require additional or alternative test methods when appropriate or required to ensure that there is no movement of fluid into or between USDWs resulting from injection activity. The Director may stipulate specific testing methods when needed to evaluate inadequate cementing operations. After the performance of the first test satisfying the requirements of this Section, and at the discretion of the Director, EPA may accept an evaluation of cement records in place of a fluid movement test to satisfy this requirement.

c) **PRESSURE FALL-OFF TEST (PFOT) -** A PFOT must be conducted annually for the life of this well. The procedure and testing methods for this test must be submitted to EPA at least 30 days prior to testing. Unless alternative conditions are approved in writing by EPA, the test procedure must match the EPA Region 6 UIC Pressure Falloff Testing Guideline (Third Revision) with necessary changes made for site-specific conditions. Testing protocol must be designed to produce all data needed to prepare a Boundary Effects Analysis Report (BEAR) (Appendix B).

   All PFOTs must be planned and performed by an individual who has attained:

   i. at least a bachelor’s degree in petroleum engineering or a field closely related to petroleum engineering;
   ii. a professional geologist or professional engineer licensure; and
   iii. at least 5 years of experience performing and analyzing PFOTs.

   These qualifications must be demonstrated in the Notification Prior to Testing (Section C.1.). EPA reserves the right to disapprove the submitted procedure and testing methods if the testing entity does not meet the above requirements.

   Following completion of the initial PFOT to be performed within 30 days after beginning injection, the Permittee shall halt injection and shall not inject until test results have been submitted to EPA and the Director has approved the well to commence injection. Following the initial PFOT, injection need not be halted following completion of annual PFOTs unless 60 days has passed since completion of the test and the BEAR has not been submitted to EPA. For tests other than the initial PFOT, the Permittee may resume injection after submitting the BEAR to EPA unless the Director otherwise requires the Permittee to cease injection based on BEAR results.

d) **STEP-RATE TEST -** The Step Rate test must follow the Step Rate Test Procedure issued by EPA Region 8, approved January 12, 1999[3], unless the Director approves alternative testing measures in writing. The SRT must be conducted with both surface and bottom-hole pressure gauges. This requirement may be waived with a written approval from the Director.

e) **STATIC RESERVOIR PRESSURE MEASUREMENTS**

i. Reservoir Pressure of the Willow Sands Block E must be measured in well DJS 2-14 by use of a downhole pressure gauge. Measurement must be taken for a period of no less than 20 minutes, and measured pressure must not change by more than 10 psi over the course of the measurement. Submission of test results must identify which Sands (i.e., Sands 1, 2, etc.) are open, based on the downhole completion.

ii. Static Reservoir Pressure of the Willow Sands Block B must be measured in well ML 1-114. Submission of test results must identify which Sands (i.e., Sands 1, 2, etc.) are open, based on the downhole completion. Downhole pressure gauge and fluid level measurement(s) must be performed for initial measurement. Subsequent reservoir pressure measurements may be made by fluid level correlation.

f) **PRESSURE BUILT-UP TESTS (PBUT)** – PBUT within the Willow Sands Blocks A and B must be performed in wells ML 3-10[5] and ML 2-10[6], respectively. Pressure measurements must be made by a wireline-conveyed gauge and a wellhead pressure gauge. Proposed testing protocols must establish a minimum length of time over which constant production rate must occur prior to shutting in the well. Tests must be designed and performed for a length of time sufficient to identify wellbore effects, identify reservoir type (i.e., faulted, bounded, etc.), and determine average reservoir pressure near wellbore.

5. Well Logging and Testing Schedule

The Permittee shall ensure that logs and tests occur within the required timeframes specified, below. Well logs and tests shall be performed according to current EPA-approved procedures. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

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[3] https://www.epa.gov/sites/default/files/2015-08/documents/r8_guideline_-_step_rate_testing.pdf
[4] API Number 11-075-20-025
[5] API Number 11-075-20-033
[6] API Number 11-075-20-022

TYPE OF LOG OR TEST	DATE DUE
Internal Mechanical Integrity Test (Internal MIT)	• Prior to receiving authorization to inject. • Within three years of the most recent test for the life of the Permit thereafter. • Prior to injection after a loss of MI.
External Mechanical Integrity Test (External MIT)	• A baseline temperature log is required prior to receiving authorization to inject. • Initial fluid movement test required prior to receiving authorization to inject. • Within one year after injection begins. • Within three years of the most recent test.
Cement Evaluation Log (CBL)	• Prior to receiving authorization to inject (2,000 ft. TVD to surface). • Within 60 days after the completion of any workover involving remedial cementing.
Step Rate Test	• Prior to receiving authorization to inject. • Following perforation of new injection intervals.
Static Reservoir Pressure in Block E (DJS 2-14)	• Prior to receiving authorization to inject.
Static Reservoir Pressure in Block B (ML 1-11)	• Prior to receiving authorization to inject. • Then, within one year of the most recent measurement for the life of the Permit thereafter.
Pressure Build-Up Test (ML 2-10 and ML 3-10)	• Prior to receiving authorization to inject. • Then, within one year of the most recent test for the life of the Permit thereafter.
Pressure Fall-Off Test (PFOT)	• With the first 30 days after injection begins. • Then, within one year of the most recent test for the life of the Permit thereafter.

6. Submission of Test Results

All well logging and testing results other than those generated from a PFOT must be submitted to the Director within 30 calendar days of completion of the logging or testing activity. Results must be submitted as a report describing the methods used during logging or testing and an interpretation of the log or test results. When applicable, the report must include a descriptive report. Reports must address the results of logging or testing to possible endangerments of USDWs, particularly those near the injection zone.

The results of all static reservoir pressure tests and pressure build-up tests must compare the measured reservoir pressure against any prior reservoir pressure measurements required by this Permit, identifying any trends in pressure change over time. This includes reservoir pressure measurements made prior to receiving authorization to inject.

The results of a PFOT are required to be submitted to the Director within 60 days after completion of the test(s). Results must be submitted as a component of a BEAR. See Appendix B for a description of all information that must be reported in a BEAR. These results must be analyzed by an entity meeting the requirements of Section C.4.c and certified as such during the submission of the test results. EPA may, on the basis of test results inadequately demonstrating isolation of Block E, require the Permittee to halt injection and perform additional actions needed to confirm the presence of fault boundaries and isolation of injected fluids to Block E of the Willow Sands, including but not being limited to substantiating and/or clarifying test results and performing subsequent PFOTs.

7. Loss of Mechanical Integrity

Loss of MI may include any malfunction of the injection well including but not limited to a failed MI test, fluids flowing at the surface, wellhead malfunctions, loss of fluids during annulus fill-ups, or a change in the inner annulus pressure or injection pressure during normal operating conditions. Any well rework/workover that has the potential to compromise MI will constitute a loss of MI. This will include but is not limited to any time the tubing or packer is removed from the well, moved within the well, reset or replaced.

If a downhole pressure measurement in well ML 1-11, ML 2-10, or ML 3-10 required by this Permit indicates that average reservoir pressure in each well's respective Block has increased since the last measurement required by this Permit, the Permittee must stop injection, notify the Director pursuant with Section I.11.e., and evaluate the cause of the increase in reservoir pressure. The well must remain shut-in until the Permittee receives written approval from the Director to resume injection.

Additionally, during the life of this Permit, the Permittee must cease injection immediately upon becoming aware that the well lacks or is suspected of lacking MI. Within 24 hours of the event, the Permittee must notify the Director of the circumstances in accordance with Section I.11(e). The Permittee must also cease injection immediately upon receiving notification from the Director that the well lacks or is suspected of lacking MI.

The Permittee must restore MI within the timeframe established by the Director. The Director may allow plugging of the well pursuant to 40 CFR § 146.10, or require the Permittee to perform such additional construction, operation, monitoring, reporting or corrective action as necessary to prevent the movement of fluid into or between USDWs.

The Permittee must notify the Director at least 30 calendar days prior to conducting well repair and a MI demonstration. The Director may allow a shorter timeframe if it allows EPA sufficient time to review and comment on the proposed repair and arrange on-site inspections. The well must remain shut-in until the Permittee receives written approval from the Director to resume injection.

SECTION D. SAMPLING, MONITORING, AND RECORDKEEPING

1. Sampling Frequency

The Permittee shall monitor the nature and composition of the injected fluid. This shall be performed by sampling the injection stream in a manner representative of injectate characteristics and analyzing collected sample(s) by chemical analysis. Sampling of the injection stream must occur at a sampling port at a location that ensures a representative sample. The results of sampling must be submitted in the annual report, unless otherwise stated by this Permit. Sampling and analysis must occur:

a) prior to receiving authorization to inject, the Permitee must take a representative sample of the proposed injection stream and analyze the sample for the following constituents:

   i. Total Dissolved Solids
   ii. pH by Method
   iii. Specific gravity
   iv. Conductivity/Specific Conductance
   v. Cations (B, Ba, Ca, Fe, K, Li, Mn, Mg, Na, and Sr)
   vi. Anions (Br, Cl, F, SO4)
   vii. Alkalinity as CaCO3
   viii. Ammonia as N
   ix. Uranium and Radium

b) annually (on a date no more than one year after the most recent sampling of the injection stream), the Permittee must sample the injection stream and analyze the sample for the following constituents:

   i. Total Dissolved Solids
   ii. pH by Method
   iii. Specific gravity

In addition, the Permittee must take a representative sample of any new source and analyze the sample for the set of constituents listed in Section D.1.a. A new source includes, but is not limited to, fluids from a different production formation, well field, or waste stream. Sampling and analysis must take place prior to introduction of a new source. Sampling a new source is not considered sampling of the injection stream. If it is unclear whether a fluid is considered a new source, the Permittee must contact EPA for clarification.

The Director may request sampling and analysis of additional constituents other than those listed in this section on a case-by-case basis.

If the Permittee has not injected during the reporting period (defined in Section D.6.), sampling of the injection stream is not required. The Permittee must sample the injection stream prior to resuming injection. See Section D.6. for more information.

2. Sampling Methods

Methods must comply with those specified below, or otherwise found in 40 CFR § 136.3, Table 1 and Appendix I of 40 CFR 261. The Permittee may submit a written request to the Director for written approval to use alternative methods.

i. Total Dissolved Solids by Method 2540 C-2015
ii. pH by Method 4500-H+ B-2011
iii. Specific gravity by Method SM 2710 F
iv. Conductivity/Specific Conductance by Method 2510 B-2011
v. Cations (B, Ba, Ca, Fe, K, Li, Mn, Mg, Na, and Sr) by Methods EPA 200.7, 200.8
vi. Anions (Br, Cl, F, SO_4)) by Method 300.0
vii. Alkalinity as $CaCO_3$ by Method SM 2320 B-2011, Method 310.1
viii. Ammonia as N by Methods 350.1, 350.2, or 350.3
ix. Uranium and Radium by Method 7500

3. Sampling Records

The following information must be collected during all sampling and measurements taken for the purpose of monitoring:

a) the date, exact place, and time of the sampling or measurements;
b) the names of the individual(s) who performed the sampling or measurements;
c) the date(s) of analyses and the names of individuals who performed the analyses;
d) the analytical technique(s) or method(s) used; and
e) the results of such analyses.

4. Monitoring Methods

The Permittee must monitor the injection well and associated components at a set frequency to ensure integrity of the injection system. Observations, measurements, and data collection taken for the purpose of monitoring must be representative of the monitored activity. Pressure monitoring (e.g. injection tubing, inner annulus, etc.), injection rate, injected volume, and cumulative injected volume must be observed and recorded at the wellhead unless explicitly stated otherwise by this permit or by the Director.

Flow meter differential monitoring must occur at two points across the flowline: 1) at a point as near the injection pump as possible considering construction limitations, and 2) at the injection wellhead. This activity must demonstrate that all fluids departing the waste facility are injected into the injection well. The differential shall be determined by subtracting the daily injection volume recorded by the meter nearest the injection wellhead from the daily volume recorded by the flow meter immediately downstream of the injection pump.

Other than during periods of well alterations in which the tubing-casing annulus is disassembled for maintenance or corrective procedures, the Permittee must monitor for the parameters specified below:

Monitoring Requirement	Monitoring Frequency	Minimum Recording Frequency
Tubing Pressure (psi)	Continuously	One datum per minute
Inner Annulus Pressure (psi)	Continuously	One datum per minute
Outer Annulus Pressure (psi)	Daily	Daily
Injection Rate (bbls/day)	Continuously	One datum per minute
Monthly Injection Volume (bbls)	n/a	Monthly
Lifetime Injection Volume (bbls)	n/a	n/a
Flow Meter Differential (bbls)	Daily	Monthly

Monitoring frequency refers to the frequency at which data must be measured and documented in record for the given requirement (e.g., inner annulus pressure must be monitored continuously, or “in real time”). Minimum Recording Frequency refers to the frequency at which data must be recorded and retained (e.g., a reading of inner annulus pressure must be recorded every minute).

5. *Records Retention*

The Permittee must retain recorded information, including the following:

a) calibration and maintenance records for all monitoring devices;
b) copies of all sampling, monitoring, logging, and testing records required by this permit;
c) records and results of MITs or any other tests or logs required by the Director;
d) records of all data used to complete the application for this permit; and
e) other records related to the construction, operation, and closure of a well.

These records must be retained for a period of at least three years from the date of the sample, measurement, report, or application. This period may be extended by written request of the Director at any time.

The Permittee must retain records of the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures in accordance with Appendix C of this permit. The Permittee must continue to retain the records after the three-year retention period unless the Permittee delivers the records to the Regional Administrator, or the Director, or obtains written approval from the Regional Administrator, or the Director, to discard the records.

6. *Annual Reporting*

Regardless of whether the well is operating, the Permittee must submit an Annual Report to the Director including:

a) the results of the sampling and analysis required by Section D, including the written laboratory analytical results and a summary of any major changes in characteristics or sources of injected fluid. The report must identify each new fluid source by well name and location, and the field name or facility name,

b) a summary of all monitoring listed in the table in Section D.4., including all data recorded at the applicable minimum reporting frequency,

c) a summary of all logging and testing that occurred in the reporting year; and

d) description(s) any wells located within the area of review that have not previously been submitted to EPA. For those wells that penetrate the injection zone, a well construction diagram, cement records, and cement bond logs are also required.

The annual report must include all required data collected over the reporting period. The initial reporting period begins upon the effective date of this Permit and extends until December 31. In subsequent years, the reporting period is from January 1 through December 31. Annual reports must be submitted to EPA by February 15 of the year following the reporting year. EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report; however, the monitoring requirements specified in this permit are mandatory even if the EPA form indicates otherwise.

SECTION E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment

The Permittee must notify the Director in writing at least 30 days prior to plugging and abandonment of an injection well. If the Permittee intends on deviating from the previously approved P&A plan, EPA must be notified no less than 45 days prior to the start of the work.

2. Well Plugging Requirements

Plugging and abandonment must be made in accordance with 40 CFR § 146.10 and follow the procedures outlined in the approved P&A Plan incorporated in Appendix C. Additionally, the following conditions must be satisfied to complete plugging and abandonment:

- Prior to plugging a well, mechanical integrity must be established unless the P&A plan will address any known mechanical integrity issues.
- Cement plugs must have sufficient compressive strength to maintain adequate plugging effectiveness.
- Each plug placement, unless above a retainer or bridge plug, must be verified by tagging the top of the plug after the cement has had adequate time to set.
- A minimum 50 ft. surface plug is required inside and, if necessary, outside of the surface casing, to seal all potential pathways for fluid migration into the subsurface.
- Plan must prevent vertical fluid movement into and between USDWs.

Prior to abandonment, the well must be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids into or between USDWs. Additional federal, state, or local laws or regulations may also apply.

3. Approved Plugging and Abandonment Plan

The approved P&A Plan is included as Appendix C. Any requested changes to the approved P&A Plan must be submitted using EPA Form 7520-19 at least 45 days prior to plugging unless a shorter time period is approved by the Director. If the Permittee requests a revised P&A Plan, plugging work cannot commence without first receiving written approval from the Director. A modified P&A Plan must be incorporated into the Permit as a modification prior to beginning plugging operations. Upon revision to the P&A Plan, the Permittee may be required to solicit a new cost estimate.

The Director also may require revision of the approved P&A Plan at any time prior to plugging the well.

4. Plugging and Abandonment Report

Within 60 days after plugging a well, the Permittee must submit a completed EPA Form 7520-19 to the Regional Administrator or his/her authorized representative. The plugging report must be certified as accurate by the person(s) who performed the plugging operation. Such report must consist of either:

a) a statement that the well was plugged in accordance with the approved P&A Plan; or

b) where actual plugging differed from the approved P&A Plan found in Appendix C, an updated version of the plan, specifying the differences.

5. *Wells Not Actively Injecting*

After the effective date of this Permit, following any period of two years during which there is no injection the Permittee must plug and abandon the well in accordance with Section E.2 and Appendix C within 90 days. This includes wells that have not been converted to an injection well under the conditions of this Permit. The Permittee may request an extension to this deadline if the Permittee:

a) Provides a written notice to the Director prior to the end of this two-year period;

b) Describes actions or procedures, satisfactory to the Director by receiving written approval, that the Permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. This must include an Internal and External MI demonstrations. These actions and procedures must include compliance with the technical requirements applicable to active injection wells, unless waived in writing by the Regional Administrator or his/her authorized representative; and

c) Receives written notice by the Director to temporarily waive plugging and abandonment requirements.

The Permittee of a well that has been temporarily abandoned must notify the Director prior to resuming operation of the well.

SECTION F. CHANGES TO PERMIT STATUS

1. Modification, Revocation and Reissuance, or Termination

The Director may, for cause, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Well Conversion

The Permittee may convert this well to a non-UIC well upon which time this Permit will expire due to the end of the intended purpose of the well. The Permittee must provide a 30-day notice prior to planned well conversion to another type of UIC or non-UIC well. The notification must include the following:

i. The type of well to which the authorized well will be converted, and

ii. A completed 7520-19 form or its equivalent.

The Permittee must receive prior written approval from the Director to proceed with any type of well conversion. After well conversion work has been completed, the Permittee must provide to the Director:

i. Demonstration of Internal and External MI, and

ii. Documentation that another agency has regulatory authority over the proposed type of well.

The Director will provide written confirmation of Permit expiration after review and approval of submitted documents.

The Permittee must convert the well in a manner which will not allow the movement of fluids into or between USDWs during or after well conversion. The Permittee must also ensure that the conversion meets any and all applicable federal, state, and local requirements. The Permittee must continue to meet all Permit requirements until the Permit expires unless the Permittee receives written approval from the Director waiving such requirements.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit may be transferred by the Permittee to a new owner and/or operator only if:

a) the Permit has been modified or revoked and reissued (under 40 CFR § 144.39(b)(2)), or a minor modification made (under 40 CFR § 144.41(d)), to identify the new Permittee and incorporate such other requirements as may be necessary under the SDWA, or

b) the Permittee provides written notification (EPA Form 7520-7) to the Director at least 30 days in advance of the proposed transfer date and submits a written agreement between the existing and proposed new Permittees containing a specific date for transfer or Permit responsibility, coverage, and liability between them, and demonstrates that the financial responsibility requirements of 40 CFR § 144.52(a)(7) have been met by the proposed new Permittee. If the Director does not notify the Permittee and the proposed new Permittee its intent to modify or revoke and reissue, the transfer is effective on the date specified in the written agreement.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

SECTION G. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit will not be affected thereby. Additionally, in a Permit modification, only those conditions to be modified will be reopened. All other aspects of the existing Permit will remain in effect for the duration of the Permit.

SECTION H. CONFIDENTIALITY

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

i. the name and address of the Permittee; and

ii. information which deals with the existence, absence, or level of contaminants in drinking water and/or USDWs.

SECTION I. CONDITIONS APPLICABLE TO ALL PERMITS

1. Prohibition of Movement of Fluid Into a USDW

The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of any fluid containing any contaminant into USDWs, except as authorized by 40 CFR part 146. If at any point, including prior to receiving approval to inject, the Permittee or EPA becomes aware of conditions under which injection may result in fluid movement into a USDW, injection may not occur. The Permittee must report these conditions to EPA within the time span specified in Section I.11.e.

2. Duty to Comply

The Permittee must comply with all conditions of this Permit. Any Permit noncompliance constitutes a violation of the SDWA and is grounds for an enforcement action(s); for Permit termination, revocation and reissuance, and/or modification; or for denial of a Permit renewal application. However, there may be an exception when the Permittee need not comply with a provisions of this Permit to the extent and for the duration as such noncompliance is authorized in an emergency Permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

3. Need to Halt or Reduce Activity Not a Defense

It will not be a defense in an enforcement action to allege that the Permittee found it necessary to halt, reduce, or disregard the required and/or permitted activities in the Permit, Regulations, or SDWA in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate

The Permittee must take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance

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

6. Permit Actions

This Permit may be modified, revoked and reissued, or terminated for cause as Described in Section F. The filing of a request by the Permittee for a Permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any Permit condition.

7. Property and Private Rights; Other Laws

This Permit does not convey property rights of any sort. Additionally, this Permit does not confer any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other federal, state or local laws or regulations.

8. Duty to Provide Information

The Permittee must furnish to the Director, within a time the specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this Permit, or to determine compliance with this Permit. Failure to respond to a request for information needed to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit may result in termination of this permit or other actions as necessary to protect USDWs. The Permittee must also furnish to the Director, upon request, copies of records required to be kept by this Permit.

9. Inspection and Entry

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

a) enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records will be kept under the conditions of this Permit;

b) have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

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

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

10. Signatory and Certification Requirements

All applications, reports or other information submitted to the Regional Administrator, or his/her authorized representative, must be signed and certified according to 40 CFR § 144.32. This regulation explains the requirements for persons duly authorized to sign documents and provides required wording for certification.

Any person signing and submitting a report require by the Permit or other information requested by the Director must make the following certification:

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

11. Reporting Requirements

Copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Section D.10. of this Permit. All correspondence must reference the well name and location and include the EPA Permit number. All reports must be submitted to EPA at the following address:

U.S. Environmental Protection Agency Region 10
Attn: Water Division, Groundwater and Drinking Water Section
1200 6th Ave., Suite 155
MS 19-CO4
Seattle, WA 98101

EPA may request, and the Permittee must provide, electronic submissions (i.e., email) of all reports required under this Section in a manner EPA prescribes. This must occur within 30 calendar days of EPA making such a request. The following reporting requirements apply:

a) *Recurring Report Submission.* The Permittee is required to submit recurring reports including, but not necessarily limited to, Annual Reports, logging/testing results, and BEARs.

b) *Planned changes.* The Permittee must give notice to the Director of any planned changes, alterations, or additions to the permitted well, and, where applicable or expressly required in this Permit, must receive written approval, prior to commencing such changes. This notice must be provided at least 30 days prior to the date of the planned alteration. At the Director's discretion, a shorter notification period may be allowed upon written request of the Permittee.

c) *Anticipated noncompliance.* The Permittee must give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements, as soon as Permittee becomes aware of potential noncompliance occurring.

d) *Monitoring Reports.* Monitoring results shall be reported at the intervals specified elsewhere in this permit.

e) *Compliance schedules.* Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit must be submitted no later than 30 calendar days following each schedule date.

f) *Twenty-four hour reporting and five day reporting.* The Permittee must report to the Director any circumstance which may endanger human health or the environment, including but not limited to:

    i) any monitoring or other information, which indicates that any contaminant may cause an endangerment to a USDW, including any loss or suspected loss of MI or any information indicating faults forming Block E of the Willow Sands may allow movement of fluids outside the injection zone,

    ii) any noncompliance with a Permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs,

    iii) injection of any fluid not approved for injection, and

    iv) occurrence of an earthquake within 5 miles of the injection well as documented by the USGS earthquake monitoring program.

Information must be provided within twenty-four hours from the time the Permittee becomes aware of the circumstances by telephoning an active UIC permit writer working for EPA Region 10 and sharing the information via live communication. If such person cannot be reached, the Permittee must telephone EPA Region 10 (1-800-424-4372) and request the EPA Region 10 Groundwater and Drinking Water Section Chief or the EPA Region 10 Emergency Operations Center. If no person can be reached as instructed in the previous sentence, the Permittee shall leave a voicemail with the EPA Region 10 Groundwater and Drinking Water Section Chief.

In addition, a follow up written report must be provided to the Director within five calendar days of the time the Permittee becomes aware of the circumstances. The written submission must contain a description of the event and its cause, the period of the event including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time the circumstances at issue are expected to continue; and, the steps taken by the Permittee or its agents and/or those steps planned to reduce, eliminate, and prevent recurrence.

g) *Other Noncompliance.* The Permittee must report all instances of noncompliance not reported under Paragraphs 11(a), 11(d), or 11(e) of this Section at the time the monitoring reports are submitted. The reports must contain the information listed in Paragraph 11(e) of this Section.

h) *Other information.* Where the Permittee becomes aware that it failed to submit any relevant facts in a Permit application or submitted incorrect information in a Permit application or subsequent information submission in response to a request by EPA related to a Permit application or in any report to the Director, the Permittee must submit such facts or information to the Director within 30 days of discovery of failure.

i) *Annual Reports.* The Permittee must submit annual reports pursuant with Section D.6.

j) *Oil Spill and Chemical Release Reporting.* The Permittee must comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802 or NRC@uscg.mil.

SECTION J. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

The Permittee is required to demonstrate and maintain financial responsibility (FR) and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

i. The well has been plugged and abandoned in accordance with the approved plugging and abandonment plan in Appendix C, and the Permittee has submitted a plugging and abandonment report according to Section E.4.; or

ii. The well has been converted in compliance with the requirements of Section F.2.; or

iii. The Permittee has received notice from the Director that the owner and/or operator receiving transfer of the Permit has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility will become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable.

The Regional Administrator, or his/her authorized representative, may on a periodic basis, require the holder of a Permit to revise the estimate of the resources needed to plug and abandon the well revised to reflect inflation of such costs and a revised demonstration of financial responsibility, if necessary.

When Financial Statement Coverage is used as the financial mechanism, this coverage must be updated on an annual basis.

2. Types of Adequate Financial Responsibility.

The Permittee must show evidence of financial responsibility to the Director by the submission of a financial instrument listed under 40 CFR § 144 Subpart F, which the Director has chosen to apply.

3. Determining How Much Coverage is Needed

The Permittee may be required by the Director to submit an estimate of the resources needed to plug and abandon the well revised to reflect inflation of such costs or for other reasons identified by the Director, and a revised demonstration of financial responsibility, if necessary.

4. Bankruptcy and/or Insolvency of the Permittee

The Permittee must notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner and/or operator as debtor, within 10 business days after commencement of the proceeding. A guarantor of a corporate guarantee must make such a notification if he is named as debtor, as required under the terms of the guarantee. See 40 CFR §§ 144.28(d)(5) & 144.64(a).

5. Bankruptcy, Insolvency, Suspension, or Loss of Authority (Issuing Financial Institution)

In the event of insolvency or bankruptcy of the trustee or issuing institution of the financial mechanism; the suspension or revocation of the authority of the trustee institution to act as trustee; or the issuing institution's losing its authority to issue such an instrument, the Permittee must notify the Director, within 10 business days of the Permittee's receiving notice of such event by certified mail. See 40 CFR §§ 144.28(d)(5) & 144.64(a).

An owner and/or operator who obtains a letter of credit or surety bond will be deemed to be without the required FR or liability coverage in the event of bankruptcy, insolvency, or a suspension or revocation of the license or charter of the issuing institution. The owner and/or operator must establish other FR or liability coverage acceptable to the Director, within 60 calendar days after such an event. See 40 CFR §§ 144.28(d)(6) & 144.64(b). If financial assurance is not provided within 60 days following bankruptcy, insolvency, or a suspension or revocation of the license or charter of the issuing institution, the owner and/or operator must immediately halt injection until a new FR demonstration is made.

APPENDIX A - WELL CONSTRUCTION REQUIREMENTS

Construction Requirements

The following well construction requirements apply:

a) The well must be completed with at least two cemented casing strings set within a drilled hole, in addition to either a driven or cemented conductor pipe.

b) Cemented casing must be cemented as follows:

   i. Surface casing is cemented from the casing shoe to the surface,

   ii. Additional casing strings must either be cemented from the casing shoe to the surface or care must be taken to maximize cement fill and bond in the annulus behind the casing to achieve external mechanical integrity to prevent fluid movement in the annulus behind the casing. Section C describes the potential for additional external mechanical integrity requirements based on cement bond quality. Cement must prevent the movement of fluids between USDWs.

c) The casing and cement used in the construction of the well must be designed for the life expectancy of the well, including the natural and applied pressures expected during the life of the well.

d) The well must be completed with injection tubing and a packer.

e) The uppermost packer must be set within 100 ft. of the uppermost open perforation. The Director may approve a greater distance between the packer and the uppermost open perforation upon request and to their discretion.

f) Perforations must be made only within the approved injection zone.

To meet the requirements of Section A, the Permittee proposes to convert the existing wellbore (6/4/2019 schematic, below) into an injection well (proposed wellbore schematic, below).

Permittee must drill out current plugs, install tubing and packer to convert this well to an injection well. Installed tubing must be previously unused and meet industry-standard specifications. A packer must be installed adjacent to, or below, the upper confining zone. The Permittee must install a casing patch or equivalent device to isolate existing perforations at 4,306 ft. to 4,330 ft. and 4,354 ft. to 4,374 ft.

No well stimulation program is proposed during well completion.

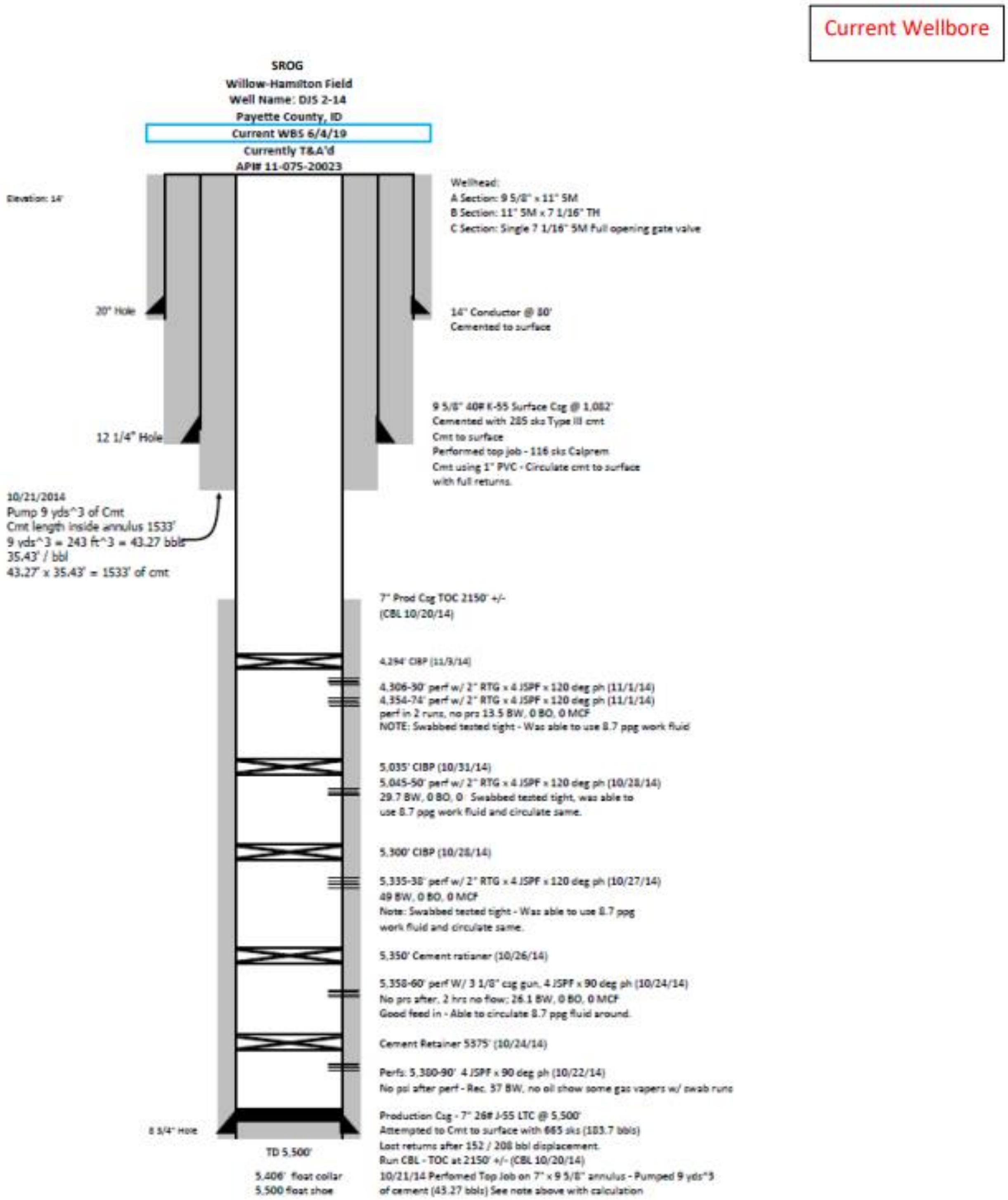
Required Monitoring Devices

The following sampling and monitoring devices are required:

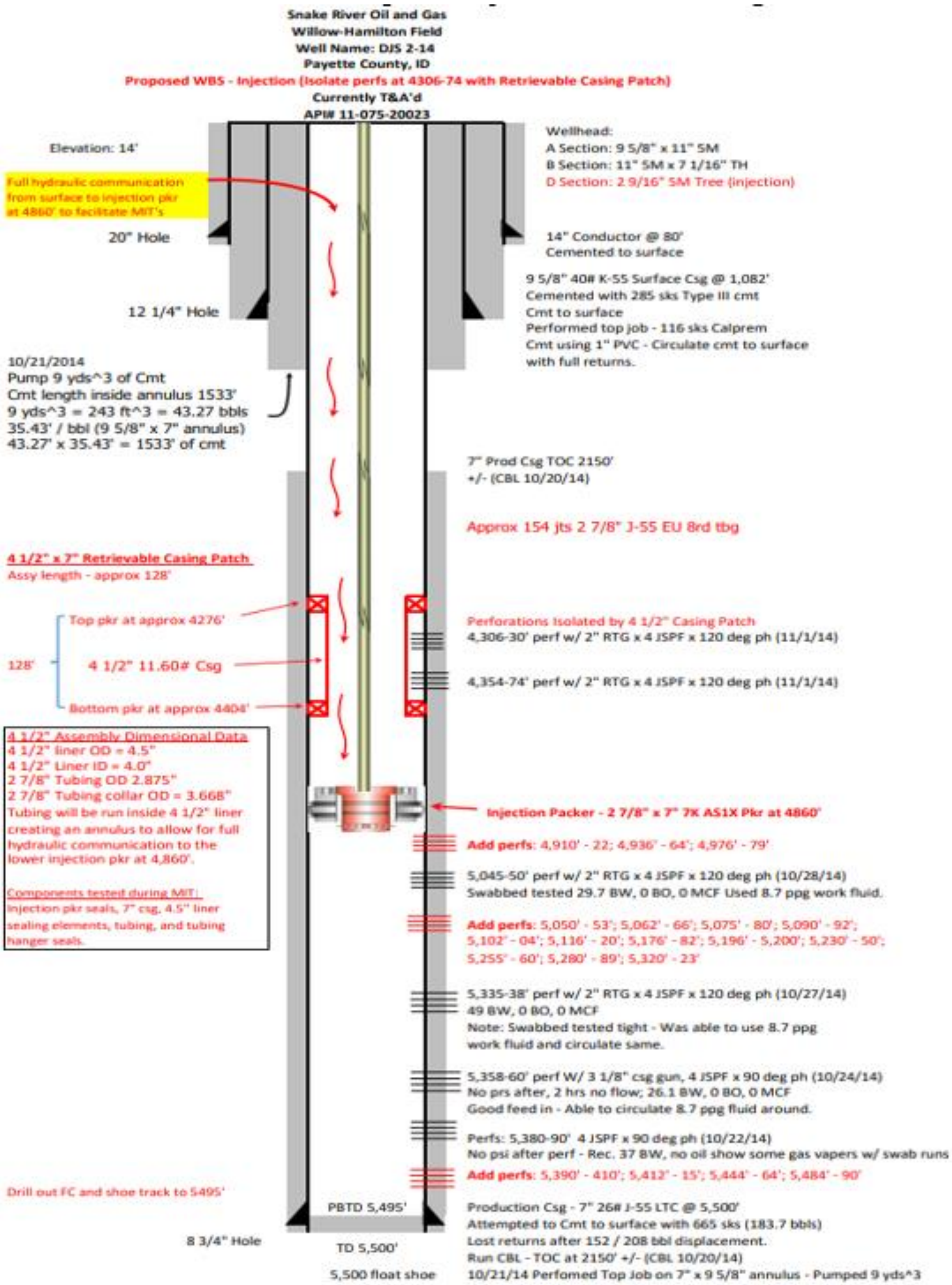
- A pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump before MAIP is exceeded at the wellhead;
- Multiple iron pipe fittings for attachment to a pressure gauge capable of monitoring pressures ranging from zero up to a value 500 psi greater than the MAIP. The fittings must be isolated by shut-off valves and conveniently accessible near the wellhead. Fittings must be present at these locations:
  - on the injection tubing string(s);
  - on the inner annulus; and
  - on the outer annulus (surface casing-production casing annulus);
- A sampling port such that samples can be collected at a location that ensures they are representative of the injected stream; and
- Two flow meters, each capable of recording instantaneous flow rate. One must be installed

immediately downstream of the injection pump and the other must be installed at the wellhead.

Existing Well Schematic



Proposed Well Schematic



APPENDIX B - BOUNDARY EFFECTS ANALYSIS REPORT (BEAR)

The Permittee must submit a Boundary Effects Analysis Report (BEAR) to the Director within 60 days after the completion of a PFOT. It must include the following information:

a) Electronic submission of the raw data (time, pressure, and temperature) from all pressure gauges utilized on CD-ROM, email, or file share.

b) Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information must be provided for a period 48 hours prior to the falloff or for a time equal to twice the time of the falloff test, whichever is longer.

c) Pressure gauge information, including, for all gauges used: the manufacturer, type, pressure range, resolution as a percentage of the pressure range, calibration certificate and manufacture's recommended frequency of calibration, and depth of deployment.

d) Location of the shut-in valve.

e) Reservoir parameters, including:

   i. Formation fluid viscosity.
   ii. Porosity.
   iii. Total compressibility.
   iv. Formation volume factor.
   v. Initial formation reservoir pressure.
   vi. Date reservoir pressure was last stabilized (injection history).
   vii. Injection interval thickness.

f) A description of the PFOT injection period, including:

   i. Time of injection period.
   ii. Type of test fluid.
   iii. Type of pump used for the test (e.g., plant or pump truck).
   iv. Type of rate meter used,
   v. Final injection pressure and temperature.

g) A description of the falloff period, including:

   i. Total shut-in time,
   ii. Final shut-in pressure and temperature, and
   iii. Time well went on vacuum, if applicable.

h) An update on the size of the injectate plume, including:

   i. Cumulative volume injected into the completed interval (i.e. lifetime injection).
   ii. Calculated radial distance to the waste front, taking reservoir heterogeneities (i.e., fault boundaries) into account.
   iii. An arial map showing extent of emplaced fluid based on reservoir geometry.

i) A description of pressure gradient stops for depth correction, if performed.

j) A summary of calculated test data. Include all equations used to generate the following parameters.

   i. Radius of investigation, including a brief description of methods used to determine,
   ii. Slope or slopes from the semilog plot,
   iii. Transmissibility,
   iv. Permeability,
   v. Calculation of skin,
   vi. Calculation of reservoir injection pressure corrected for skin effects,
   vii. Discussion and justification of any reservoir or outer boundary models used to simulate the test, and,
   viii. Explanation for any pressure or temperature anomaly if observed.

k) Provide the following graphical plots. As applicable, identify flow regimes and boundary effects:

   i. A cartesian plot of pressure and temperature vs. time.
   ii. A log-log diagnostic plot with pressure and semilog derivative curves. Identify wellbore storage period, transition period, radial flow period, and boundary effects, as applicable.
   iii. Semilog plot of the pressure versus the log of time. Identify which plot is used for analysis (e.g., Miller Dyes Hutchinson, Horner, Agarwal Equivalent Time, or Superposition Time) and reasoning for selection of plot type.
   iv. Injection rate(s) vs time
   v. A Hall Plot and derivative Hall Plot. Must identify any apparent changes in flow regime and assign probable causes for such changes. Data should be cumulative for the well's life.

l) A narrative analysis of PFOT results focusing on flow boundaries identified. Analysis must identify a sealing boundary(-ies) encountered withing the radius of investigation along the semilog derivative plot as an upswing followed by a plateau. If the radius of investigation encounters both the southwest and northern fault, plots should demonstrate a response expected of a well between two intersection sealing faults or similar multi-boundary response[7].

m) A comparison of actual reservoir pressure measured from the PFOT versus reservoir pressure expected from cumulative injection in a bound reservoir. Discussion should include an evaluation of whether the lifetime volume limit (7.35 million barrels) will be protective of USDWs.

[7] See, *Harts Petroleum Engineer International* November, 1997., Pages 81-89.

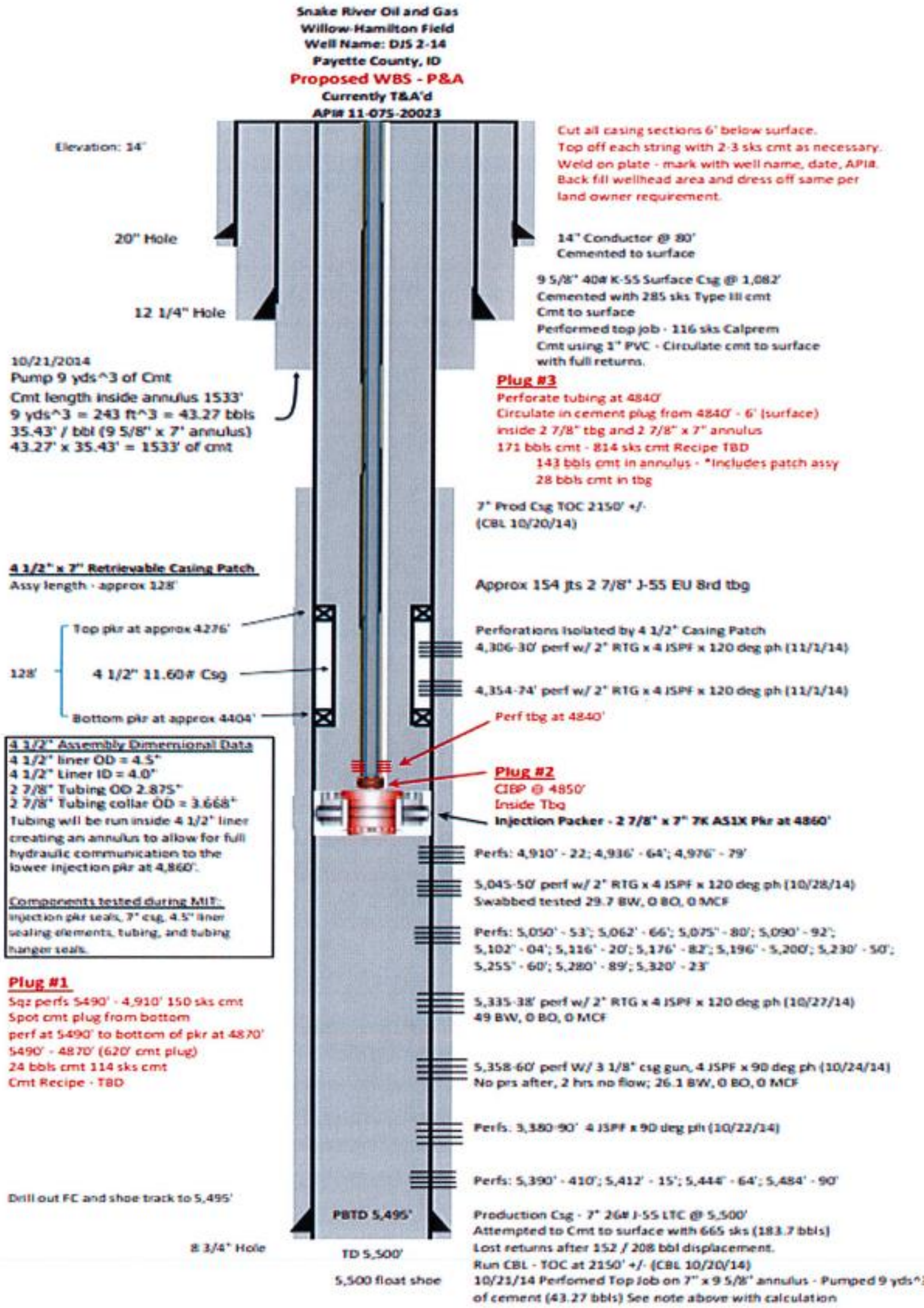
APPENDIX C - PLUGGING AND ABANDONMENT PLAN

The proposed P&A plan and schematic are included in this Appendix.

Procedure Summary:

1. MIRU wireline unit and cement unit.
2. Squeeze perfs and spot cement plug from 5,490' - 4,870' (Plug #1).
3. Set CIBP inside tubing at 4,850' (Plug #2).
4. Perforate tubing at 4,840'.
5. Mix 814 sks cement and spot long balanced plug from 4,840' - 6'. Cement will be inside tubing and inside tubing / casing annulus (Plug #3).
6. RD Cement unit and wireline unit.
7. Move in backhoe and welder. Nipple down 2 9/16" wellhead and dig bell hole 8' below surface.
8. Cut all casing strings down to 6'. Weld on plate to conductor.
9. Backfill bell hole and dress off same.

Attachment Q-1 Proposed Post-Injection Plug and Abandon Wellbore Diagram



APPENDIX D - CORRECTIVE ACTION PLAN

No corrective action is required at this time because EPA's evaluation of the information provided in the Permit application or otherwise available to the agency did not identify migration pathways within the area of review.