Natural State
RENEWABLES

CLASS VI PERMIT INJECTION WELL PLUGGING PLAN

40 CFR 146.92(b)

NATURAL STATE RENEWABLES, INC.
Nimbus ARCCS, Inc.
Ouachita County. Arkansas

Prepared By:
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Geostock Sandia

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1.0 FACILITY INFORMATION

Facility/Project Name: Natural State Renewables Inc.
Nimbus ARCCS Inc.
Class VI Injection Well Nos. 1-4

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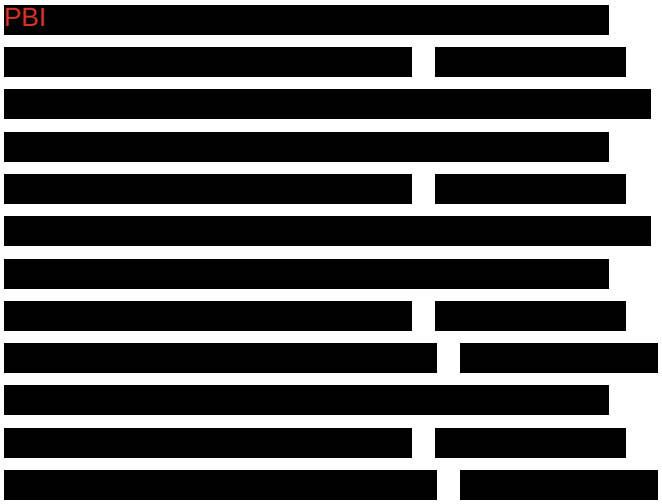
Well Locations: Ouachita County, Arkansas



2.0 INJECTION WELL PLUGGING PLAN

Natural State Renewables (NSR) – Nimbus ARCCS will conduct injection well plugging and abandonment according to the requirements of 40 CFR §146.92. A Notice of Intent to Plug will be provided in writing to the EPA UIC Program Director at least 60 days before commencement of plugging operations, pursuant to 40 CFR §146.92(c). The following sections outline the well plugging plans pursuant to 40 CFR §146.92(b)

3.0 BOTTOMHOLE PRESSURE DETERMINATION

In accordance with 40 CFR §146.92(a), a bottomhole reservoir pressure will be determined prior to commencing plugging operations in any injection well. During the injection well operations, downhole pressure gauges will be installed to continuously monitor the injection pressure. After cessation of injection operations, the downhole gauges will be used to measure the bottomhole pressure of the injection zone at final static conditions (a period after injection operations have ceased) prior to proceeding with the plugging.

If these gauges are damaged or malfunction at the time of well plugging, pressure and temperature gauges will be run down hole via wireline, after the well has been flushed with a brine kill fluid, to record the bottomhole pressure.

3.1 EQUIPMENT DETAILS

If wireline deployed pressure/temperature gauges are used to record bottomhole pressure, the wireline should be corrosion resistant (such as MP-35 line), and the deployed gauges should consist of a surface read-out gauge with a memory backup gauge. Gauge specifications should be as follows or similar in Table 3-1:

Table 3-1: Injection/Falloff Pressure Gauge Information – Wireline Testing Operations

Pressure Gauge	Property	Value
Surface Readout Pressure Gauge	Range Resolution	0 – 10,000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Pressure Gauge	Range Resolution	0 – 10,000 psi/356 °F +/-0.01 psi/0.01 °F
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 °F)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual

4.0 EXTERNAL MECHANICAL INTEGRITY

To confirm external mechanical integrity prior to commencing well plugging operations in any injection well, NSR will conduct a temperature log post-injection to register any fluid movement external to the long string casing in accordance with 40 CFR §146.92(a), and any other logs required by the EPA UIC Program Director at the time of plugging. Prior to testing, the well will be flushed with a brine of sufficient weight to kill the well and force the carbon dioxide into formation. It is recommended that the well be shut-in for a minimum of 36 hours to allow for temperature effects to dissipate prior to conducting the temperature log. The log will include both an absolute temperature curve and a differential temperature curve.

If a distributed temperature sensing fiber is run in the injection/monitor wells, the fiber will be used for the temperature testing, otherwise, a wireline truck will be used.

If wireline operations are used, the temperature will be logged down from the surface to total depth in the well. Recommended line speed for the logging operations is 30 to 40 feet per minute. A correlation log(s) will be presented in track 1, and the two temperature curves will be presented in tracks 2 and 3. The temperature log will be scaled at or about 20° F (or 10° C degrees) per track. The differential curve will be scaled in a manner appropriate to the logging equipment design but will be sensitive enough to readily indicate anomalies. In general, the procedure for wireline operations will be as follows:

1. Attach a temperature probe and casing collar locator (CCL) to the wireline.
2. After a minimum of 36 hours of well static conditions, begin the temperature survey. The tools will be lowered into well at 30 to 40 feet/minute, recording temperature in wellbore. The temperature survey will be run to the deepest attainable depth (top of solids fill) in the wellbore. The wireline may be flagged, if needed, to assist in depth correlation.
3. Following completion of the survey, the wireline tools will be retrieved from the wellbore.

Quality assurance for the planned logs will be provided by the service vendor at time of selection. The quality control will be reviewed and will be documented in the Quality and Assurance Surveillance Plan (contained as an Appendix to the "*E.1. – Testing and Monitoring Plan*").

A successful temperature log will "PASS" if there are no observed, unexplained anomalies outside of the permitted injection zone.

If temperature anomalies are observed outside of the permitted zone, additional logging may be conducted to determine whether a loss of mechanical integrity or containment has occurred. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the EPA UIC Program Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

5.0 PLUG DETAILS

NSR will use the materials and methods noted in Tables 5-1, 5-2, 5-3, and 5-4 to plug the Nimbus ARCSS Inc. Injection Well Nos. 1, 2, 3, and 4, respectively. Tubing and packers will be retrieved at the end of the injection operations as part of the plugging procedure. Casing will remain in the well.

Industry practice has shown that 100 to 200 feet across the hole of good cement is sufficient for permanent isolation. Excess volume should be pumped to account for contamination and uncertainty in placement such as in high angle wells or high expectation of slurry contamination.

The permanent isolation plug positions should be such that the formation fracture pressure exceeds the maximum anticipated pressure under the isolation. This is normally easily met by placing the isolation plugs across a suitable caprock which is an impermeable rock without natural or induced fractures that is continuous over the field. The caprock immediately above the zone of injection is considered suitable caprock.

Because of its intrinsic low permeability, carbon dioxide-resistant cement will be used due to the injection of supercritical carbon dioxide and water saturated with carbon dioxide conditions. Accelerated reaction kinetics can lead to a stabilized matrix within days of exposure to the carbon dioxide environment, leading to stabilized mechanical properties. This makes the carbon dioxide-resistant cement applicable for plugging across Injection Zone(s) and at the top of the sequestration complex.

The Plug & Abandonment (P&A) plans are based on the following general placement of plugs:

1. CO_2 resistant cement plug set from the bottom of the perforations in the injection interval to 200 feet above the top perforation in the injection interval.
2. CO_2 resistant cement plug set from 100 feet below the Upper Confining Zone to 100 feet above the Upper Confining Zone.
3. Class “H” cement plug set from 100 feet below the surface casing shoe to surface.

A pressure test of the first plug will be conducted to confirm integrity and isolation of the injection interval. The top of the cement plugs will be tagged and loaded to confirm location and integrity.

A fluid (brine/mud/salt gel) of at least 9.5 lb/gal will be placed throughout the wellbore between the cement plugs. The wellhead and casings will be cut and removed at least 3 feet below ground level and capped with a steel plate. The tables below show preliminary calculations of the proposed plugs.

Table 5-1: Proposed Plugging Details – Nimbus ARCCS Inc. Injection Well No. 1 (INJ-1)

Plug Information	Plug #1 (425 ft)	Plug #2 (340 ft)	Plug #3 (1,100 ft)
Internal Diameter (ID) of boring in which plug will be placed *(inches)*	8.755"	8.755"	8.755"
Sacks of cement to be used (each plug)	153	123	434
Slurry volume to be pumped (ft^3)	178	143	460
Slurry weight (lb./gal)	14.5	14.5	16.4
Calculated top of plug (ft)	5,025	2,950	0
Bottom of plug (ft)	5,450	3,290	1,100
Type of cement or other material	CO_2 Resistant Slurry	CO_2 Resistant Slurry	Class "H"
Method of emplacement (*e.g.*, balance method, retainer method, or two-plug method)	Balanced	Balanced	Balanced

Table 5-2: Proposed Plugging Details – Nimbus ARCCS Inc. Injection Well No. 2 (INJ-2)

Plug Information	Plug #1 (635 ft)	Plug #2 (340 ft)	Plug #3 (1,100 ft)
Internal Diameter (ID) of boring in which plug will be placed *(inches)*	8.755"	8.755"	8.755"
Sacks of cement to be used (each plug)	229	123	434
Slurry volume to be pumped (ft^3)	266	143	460
Slurry weight (lb./gal)	14.5	14.5	16.4
Calculated top of plug (ft)	4,325	2,950	0
Bottom of plug (ft)	4,960	3,290	1,100
Type of cement or other material	CO_2 Resistant Slurry	CO_2 Resistant Slurry	Class "H"
Method of emplacement (*e.g.*, balance method, retainer method, or two-plug method)	Balanced	Balanced	Balanced

Table 5-3: Proposed Plugging Details – Nimbus ARCCS Inc. Injection Well No. 3 (INJ-3)

Plug Information	Plug #1 (540 ft)	Plug #2 (340 ft)	Plug #3 (1,100 ft)
Internal Diameter (ID) of boring in which plug will be placed *(inches)*	8.755"	8.755"	8.755"
Sacks of cement to be used (each plug)	195	123	434
Slurry volume to be pumped (ft^3)	227	143	460
Slurry weight (lb./gal)	14.5	14.5	16.4
Calculated top of plug (ft)	3,900	2,950	0
Bottom of plug (ft)	4,440	3,290	1,100
Type of cement or other material	CO_2 Resistant Slurry	CO_2 Resistant Slurry	Class "H"
Method of emplacement (*e.g.*, balance method, retainer method, or two-plug method)	Balanced	Balanced	Balanced

Table 5-4: Proposed Plugging Details – Nimbus ARCCS Inc. Injection Well No. 4 (INJ-4)

Plug Information	Plug #1 (800 ft)	Plug #2 (1,100 ft)
Internal Diameter (ID) of boring in which plug will be placed *(inches)*	8.755"	8.755"
Sacks of cement to be used (each plug)	288	434
Slurry volume to be pumped (ft^3)	335	460
Slurry weight (lb./gal)	14.5	16.4
Calculated top of plug (ft)	2,950	0
Bottom of plug (ft)	3,750	1,100
Type of cement or other material	CO_2 Resistant Slurry	Class "H"
Method of emplacement (*e.g.*, balance method, retainer method, or two-plug method)	Balanced	Balanced

Prior to plugging any injection well, NSR-Nimbus ARCCS will consider the operational and monitoring history of the sequestration project and identify whether any information or events warrant amendment of the original plugging plan. The final volume and depth of the plug(s) will depend on the final geology and "as built" well completion, in addition to the final conditions of

the well as assessed during mechanical integrity testing prior to closure. Final cement volumes will be calculated and verified using industry accepted equations for cement volumes, using open-hole diameter, casing size, annular areas, and total length of cement plugs. A casing caliper may be utilized to confirm diameters if deemed necessary. Adding extra plugs will be contingent upon the external well integrity status at the time of plugging the well. If well integrity was found to be poorer than expected, then a risk assessment would be conducted to identify if additional plugs are required.

Any final modification to the cement formulation, number and volume(s) of the plug(s), and required certification documents will be submitted to the regulatory agency with the proposed well plugging plan prior to field operations. NSR will include the wet density in the final *"Report of Plugging and Abandonment"* for each well and will retain duplicate samples of the cement used for each plug.

These plans are expected to meet the objective of well plugging, which is minimizing the chance of leaks to the environment and unintended flow of fluid underground. Verification of meeting the objective will be conducted at the end of each plugging operation, by assessing the sealing effectiveness and position of the permanent isolation. Direct verification methods such as tagging the top of the plug, weight testing, dressing-off, inflow testing, pressure testing, or indirect verification methods such as volume/losses records, cementing pressure records, laboratory slurry testing (e.g., compressive strength development), surface cement sampling, logging, and long-term monitoring may be performed.

6.0 PLUGGING PLAN DETAILS

The following plugging and abandonment plans have been developed for the NSR project site in accordance with 40 CFR 146.92(b). The proposed plugging and abandonment plan for the proposed Injection Wells is shown below, subject to modification by the EPA UIC Program Director. The plugging procedure will be implemented if well operations are abandoned or if a well has reached the end of its useful life.

6.1 NOTIFICATIONS, PERMITS, AND INSPECTIONS

In accordance with 40 CFR §146.92(c), NSR will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable. Inspections will be made available to the regulatory authority at their request.

In accordance with 40 CFR §146.92(d), NSR will submit to the regulatory agency a plugging report within 60 days after plugging. The plugging report will certify that the well was closed in accordance with applicable requirements and will include records for any newly constructed or discovered wells within the Area of Review. NSR will retain a copy of the plugging report for a minimum of 10 years following site closure.

6.2 PLUGGING PROCEDURES

The plugging and abandonment procedures and materials have been designed to contain the sequestered carbon dioxide and prevent movement out of the sequestration complex or into Underground Source(s) of Drinking Water (USDW). The materials to be used will be resistive to the corrosive nature of carbon dioxide and water. The proposed well plugging schematics are included as Figures 1, 2,3, and 4 and are based upon the proposed drilling and completion schematic. Final plan adjustment will be made for “as built” well conditions and penetrated formation tops.

Prior to conducting the following plugging and abandonment procedure, NSR will inject enough brine buffer fluid to displace the carbon dioxide from the immediate wellbore area into the storage reservoir. This volume of fluid will be determined by the plant prior to initiating closure activities using data on the volume of carbon dioxide injected during the lifetime of the well and the results

of previous well formation pressure testing. Specific plugging plans will be updated for the Injection Well(s) after the drilling and completion with "as-built" well specifics and penetrated formation tops. This will be submitted prior to receiving authorization to inject.

6.2.1 Plugging Procedure – Injection Well No. 1 (INJ-1)

A proposed plugging schematic for Injection Well No. 1 (INJ-1) is included as Figure 1. All depths in the outlined procedure are referenced to the kelly bushing (KB), which is estimated at 20.0 ft above ground level. The outline of plugging procedures for Injection Well No. 1 (INJ-1) is as follows:

1. In accordance with 40 CFR 146.92(c), notify the EPA UIC Program Director at least 60 days before plugging the well and provide an updated plugging plan.
2. Bottom hole reservoir pressure will be obtained prior to well plugging.
3. Well will be flushed by brine to displace CO_2 into the reservoir. Normally the well is flushed by pumping 2 times the well volume of brine at pressure lower than 80% of frac pressure.
4. Allow a minimum of 36 hours for temperature stabilization. Conduct a Temperature log and compare with the baseline temperature log in addition to temperature logs obtained during injection and post-injection to assess external mechanical integrity. In addition, either a noise log or oxygen activation log could also be run and evaluated for external mechanical integrity.

   Note: If the external well integrity was found to be poorer than expected then a proper risk assessment will be conducted to assess if the planned plugging program is sufficient to meet well abandonment objectives.
5. Pull out/remove tubing from the well.
6. Pull out/remove the packer from the well. If the packer cannot be removed, a revised plugging plan to leave the packer in place will be submitted and approved prior to moving forward.
7. Run workstring to Plugged Back Total Depth (PBTD) and confirm the injection interval is free of solids. Circulate out fill if necessary.
8. Spot the end of the workstring at the bottom perforation. Rig up cementing equipment. Pump a fluid spacer followed by CO_2 resistant cement mixed at a minimum density of 14.5

pounds per gallon (ppg). Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from the bottom perforation to at least 200 ft above the top perforation.

9. Pull the end of the work string ±250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
10. After waiting enough time for the cement to harden, lower the workstring to the top of cement and load test to confirm competency. Record the top of cement depth. Pressure test the cement plug to confirm integrity.
11. Displace the wellbore with 9.5 lb/gal brine/mud/salt gel.
12. Pick up the workstring to ±3,290 ft (100 ft below the base of the Upper Confining Zone). Pump a fluid spacer followed by CO_2 resistant cement mixed at a minimum density of 14.5 ppg. Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from ±3,290-2,950 ft (100 ft above the top of the Upper Confining Zone).
13. Pull the end of the work string ±250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
14. After waiting for enough time for the cement to harden, lower the workstring to the top of cement and load test to confirm competency. Record the top of cement depth.
15. Pick up the workstring to ±1,100 ft (100 ft below the surface casing shoe). Pump a fluid spacer followed by Class “H” cement mixed at a minimum density of 16.4 ppg. Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from ±1,100 to surface. Confirm cement returns to surface.
16. Lay down the workstring. Top off the 9-5/8-inch casing with Class “H” cement to bring the top of cement to surface.
17. Remove wellhead, cut the casings three feet below the ground surface, and weld steel plate on top of the 13-3/8-inch surface casing.
18. Erect a permanent marker on the well with the permit number, date of plugging and company name identified on the marker.
19. In accordance with the requirements of 40 CFR 146.92(d), within 60 days of plugging and closure, a plugging report will be submitted to the EPA UIC director. This report will be certified as accurate by the owner or operator, and by the person who has performed the plugging operations. The owner / operator will retain the well plugging report for 10 years following the site closure.

6.2.2 Plugging Procedure – Injection Well No. 2 (INJ-2)

A proposed plugging schematic for Injection Well No. 2 (INJ-2) is included as Figure 2. All depths in the outlined procedure are referenced to the kelly bushing (KB), which is estimated at 20.0 ft above ground level. The outline of plugging procedures for Injection Well No. 2 (INJ-2) is as follows:

1. In accordance with 40 CFR 146.92(c), notify the EPA UIC Program Director at least 60 days before plugging the well and provide an updated plugging plan.
2. Bottom hole reservoir pressure will be obtained prior to well plugging.
3. Well will be flushed by brine to displace CO_2 into the reservoir. Normally the well is flushed by pumping 2 times the well volume of brine at pressure lower than 80% of frac pressure.
4. Allow a minimum of 36 hours for temperature stabilization. Conduct a Temperature log and compared with the baseline temperature log in addition to temperature logs obtained during injection and post-injection to assess external mechanical integrity. In addition, either a noise log or oxygen activation log could also be run and evaluated for external mechanical integrity.

   Note: If the external well integrity was found to be poorer than expected then a proper risk assessment will be conducted to assess if the planned plugging program is sufficient to meet well abandonment objectives.
5. Pull out/remove tubing from the well.
6. Pull out/remove the packer from the well. If the packer cannot be removed, a revised plugging plan to leave the packer in place will be submitted and approved prior to moving forward.
7. Run workstring to PBTD and confirm the injection interval is free of solids. Circulate out fill if necessary.
8. Spot the end of the workstring at the bottom perforation. Rig up cementing equipment. Pump a fluid spacer followed by CO_2 resistant cement mixed at a minimum density of 14.5 pounds per gallon (ppg). Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from the bottom perforation to at least 200 ft above the top perforation.

9. Pull the end of the work string ±250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
10. After waiting enough time for the cement to harden, lower the workstring to the top of cement and load test to confirm competency. Record the top of cement depth. Pressure test the cement plug to confirm integrity.
11. Displace the wellbore with 9.5 lb/gal brine/mud/salt gel.
12. Pick up the workstring to ±3,290 ft (100 ft below the base of the Upper Confining Zone). Pump a fluid spacer followed by CO_2 resistant cement mixed at a minimum density of 14.5 ppg. Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from ±3,290-2,950 ft (100 ft above the top of the Upper Confining Zone).
13. Pull the end of the work string ±250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
14. After waiting for enough time for the cement to harden, lower the workstring to the top of cement and load test to confirm competency. Record the top of cement depth.
15. Pick up the workstring to ±1,100 ft (100 ft below the surface casing shoe). Pump a fluid spacer followed by Class "H" cement mixed at a minimum density of 16.4 ppg. Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from ±1,100 to surface. Confirm cement returns to surface.
16. Lay down the workstring. Top off the 9-5/8-inch casing with Class "H" cement to bring the top of cement to surface.
17. Remove wellhead, cut the casings three feet below the ground surface, and weld steel plate on top of the 13-3/8-inch surface casing.
18. Erect a permanent marker on the well with the permit number, date of plugging and company name identified on the marker.
19. In accordance with the requirements of 40 CFR 146.92(d), within 60 days of plugging and closure, a plugging report will be submitted to the EPA UIC Director. This report will be certified as accurate by the owner or operator, and by the person who has performed the plugging operations. The owner / operator will retain the well plugging report for 10 years following the site closure.

6.2.3 Plugging Procedure – Injection Well No. 3 (INJ-3)

A proposed plugging schematic for Injection Well No. 3 (INJ-3) is included as Figure 3. All depths in the outlined procedure are referenced to the kelly bushing (KB), which is estimated at 20.0 ft above ground level. The outline of plugging procedures for Injection Well No. 3 (INJ-3) is as follows:

1. In accordance with 40 CFR 146.92(c), notify the EPA UIC Program Director at least 60 days before plugging the well and provide an updated plugging plan.
2. Bottom hole reservoir pressure will be obtained prior to well plugging.
3. Well will be flushed by brine to displace CO_2 into the reservoir. Normally the well is flushed by pumping 2 times the well volume of brine at pressure lower than 80% of frac pressure.
4. Allow a minimum of 36 hours for temperature stabilization. Conduct a Temperature log and compared with the baseline temperature log in addition to temperature logs obtained during injection and post-injection to assess external mechanical integrity. In addition, either a noise log or oxygen activation log could also be run and evaluated for external mechanical integrity.

   Note: If the external well integrity was found to be poorer than expected then a proper risk assessment will be conducted to assess if the planned plugging program is sufficient to meet well abandonment objectives.
5. Pull out/remove tubing from the well.
6. Pull out/remove the packer from the well. If the packer cannot be removed, a revised plugging plan to leave the packer in place will be submitted and approved prior to moving forward.
7. Run workstring to PBTD and confirm the injection interval is free of solids. Circulate out fill if necessary.
8. Spot the end of the workstring at the bottom perforation. Rig up cementing equipment. Pump a fluid spacer followed by CO_2 resistant cement mixed at a minimum density of 14.5 pounds per gallon (ppg). Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from the bottom perforation to at least 200 ft above the top perforation.
9. Pull the end of the work string ±250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.

10. After waiting enough time for the cement to harden, lower the workstring to the top of cement and load test to confirm competency. Record the top of cement depth. Pressure test the cement plug to confirm integrity.
11. Displace the wellbore with 9.5 lb/gal brine/mud/salt gel.
12. Pick up the workstring to ±3,290 ft (100 ft below the base of the Upper Confining Zone). Pump a fluid spacer followed by CO_2 resistant cement mixed at a minimum density of 14.5 ppg. Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from ±3,290-2,950 ft (100 ft above the top of the Upper Confining Zone).
13. Pull the end of the work string ±250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
14. After waiting for enough time for the cement to harden, lower the workstring to the top of cement and load test to confirm competency. Record the top of cement depth.
15. Pick up the workstring to ±1,100 ft (100 ft below the surface casing shoe). Pump a fluid spacer followed by Class "H" cement mixed at a minimum density of 16.4 ppg. Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from ±1,100 to surface. Confirm cement returns to surface.
16. Lay down the workstring. Top off the 9-5/8-inch casing with Class "H" cement to bring the top of cement to surface.
17. Remove wellhead, cut the casings three feet below the ground surface, and weld steel plate on top of the 13-3/8-inch surface casing.
18. Erect a permanent marker on the well with the permit number, date of plugging and company name identified on the marker.
19. In accordance with the requirements of 40 CFR 146.92(d), within 60 days of plugging and closure, a plugging report will be submitted to the EPA UIC Program Director. This report will be certified as accurate by the owner or operator, and by the person who has performed the plugging operations. The owner / operator will retain the well plugging report for 10 years following the site closure.

6.2.4 Plugging Procedure – Injection Well No. 4 (INJ-4)

A proposed plugging schematic for Injection Well No. 4 (INJ-4) is included as Figure 4. All depths in the outlined procedure are referenced to the kelly bushing (KB), which is estimated at 20.0 ft above ground level. The outline of plugging procedures for Injection Well No. 4 (INJ-4) is as follows:

1. In accordance with 40 CFR 146.92(c), notify the EPA UIC Program Director at least 60 days before plugging the well and provide an updated plugging plan.
2. Bottom hole reservoir pressure will be obtained prior to well plugging.
3. Well will be flushed by brine to displace CO_2 into the reservoir. Normally the well is flushed by pumping 2 times the well volume of brine at pressure lower than 80% of frac pressure.
4. Allow a minimum of 36 hours for temperature stabilization. Conduct a Temperature log and compared with the baseline temperature log in addition to temperature logs obtained during injection and post-injection to assess external mechanical integrity. In addition, either a noise log or oxygen activation log could also be run and evaluated for external mechanical integrity.

   Note: If the external well integrity was found to be poorer than expected then a proper risk assessment will be conducted to assess if the planned plugging program is sufficient to meet well abandonment objectives.
5. Pull out/remove tubing from the well.
6. Pull out/remove the packer from the well. If the packer cannot be removed, a revised plugging plan to leave the packer in place will be submitted and approved prior to moving forward.
7. Run workstring to PBTD and confirm the injection interval is free of solids. Circulate out fill if necessary.
8. Spot the end of the workstring at the bottom perforation. Rig up cementing equipment. Pump a fluid spacer followed by CO_2 resistant cement mixed at a minimum density of 14.5 pounds per gallon (ppg). Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from the bottom perforation to at least 100 ft above the top of the Upper Confining Zone.

9. Pull the end of the work string ±250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
10. After waiting enough time for the cement to harden, lower the workstring to the top of cement and load test to confirm competency. Record the top of cement depth. Pressure test the cement plug to confirm integrity.
11. Displace the wellbore with 9.5 lb/gal brine/mud/salt gel.
12. Pick up the workstring to ±1,100 ft (100 ft below the surface casing shoe). Pump a fluid spacer followed by Class "H" cement mixed at a minimum density of 16.4 ppg. Circulate cement and displace to spot a balanced plug in the 9-5/8-inch casing from ±1,100 to surface. Confirm cement returns to surface.
13. Lay down the workstring. Top off the 9-5/8-inch casing with Class "H" cement to bring the top of cement to surface.
14. Remove wellhead, cut the casings three feet below the ground surface, and weld steel plate on top of the 13-3/8-inch surface casing.
15. Erect a permanent marker on the well with the permit number, date of plugging and company name identified on the marker.
16. In accordance with the requirements of 40 CFR 146.92(d), within 60 days of plugging and closure, a plugging report will be submitted to the EPA UIC Program Director. This report will be certified as accurate by the owner or operator, and by the person who has performed the plugging operations. The owner / operator will retain the well plugging report for 10 years following the site closure.

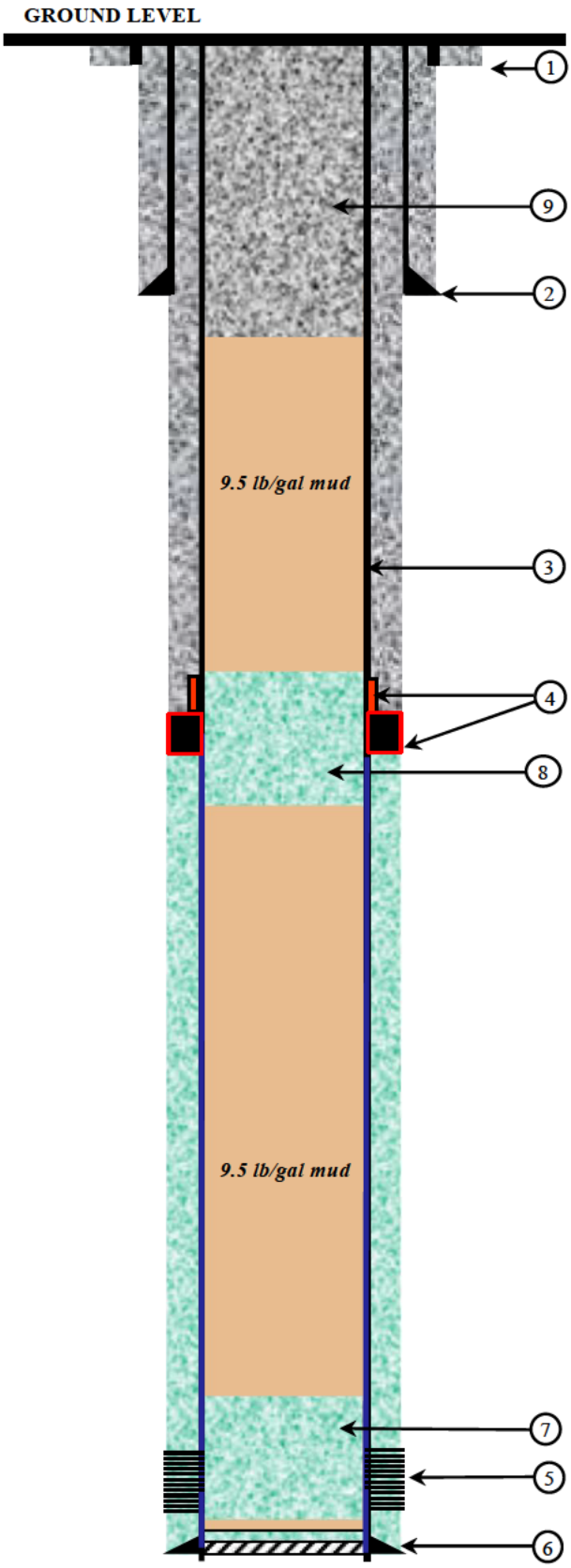
6.3 CONTINGENCY PLANS

Should any of the cement plugs not pass the integrity pressure test, a sample of the retained slurry will be sent to the cementing company's laboratory for root-cause analysis to identify failure mechanism of the slurry. Cement pumping and mixing equipment will be inspected for equipment malfunction or cement contamination sources. Corrective actions will be applied prior to resetting the failed cement plug. The failed cement plug will be drilled out and the well will be recirculated down to the previous plug depth, before spotting a new plug.

Nimbus ARCCS Inc. – Injection Well No. 1 (Nimbus INJ-1)

Permit No. XXXXXX

Proposed P&A Well Schematic



All depths reference Rig Kelly Bushing
Rig Kelly Bushing = 20 above GL
Ground Level ~250' (TBD)

COMPLETION DETAILS

1. Conductor Casing: 20-inch, set from surface to ±100, driven to refusal.
2. Surface Casing: 13-3/8", 54.5 lb/ft, J-55, BTC. Set from surface to ±1,000' in a 17-1/2" hole. Cemented to surface with 370 sx (700', 1.972 ft^3/sx, 730 ft^3, 130 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 291 sx (300', 1.196 ft^3/sx, 348 ft^3, 62 bbl) tail premium cement mixed at 15.0 lb/gal.
3. Protection Casing: 9-5/8" mixed string set from surface to ±5,950' in 12-1/4" hole.
   - 0' to ±3,050': 43.5 lb/ft, L-80, LT&C
   - ±3,050' to ±3,066': 9-5/8" stage tool from ±3,050' to ±-3,056' and 9-5/8" external casing packer from ±3,056' to ±3,066'. L80, LTC with premium gas tight bottom pin.
   - ±3,066' to ±5,950': 43.5 lb/ft, 13Cr80, premium gas tight connections.

   Cemented in two stages:
   - Stage 1: Cement from ±5,950' to ±3,050' with 955 sx (1.163 ft^3/sx, 1,110 ft^3, 198 bbl) CO_2 resistant cement slurry mixed at 14.5 lb/gal.
   - Stage 2: Cement from ±3,050' to surface with 555 sx (2,550', 1.712 ft^3/sx, 950 ft^3, 169 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 160 sx (500', 1.203 ft^3/sx, 193 ft^3, 34 bbl) tail premium cement mixed at 15.0 lb/gal.
4. 9-5/8" Stage Tool (L-80) and External Casing Packer set from ±3,050' to ±3,066'.
5. Injection Perforations: Smackover formation from ±5,225' to ±5,450' with 4 SPF 90-degree phasing -or- 6 SPF 120 deg phasing.
6. Planned Total Depth: ±5,950' ; PBTD ±5,900'.
7. Cement Plug #1: ±5,450' (bottom perforation) to ±5,025' (200' above perforations); 178 ft^3 CO_2 resistant cement at 14.5 lb/gal.
8. Cement Plug #2: ±3,290' (100' below U. Confining Zone) to ±2,950' (100' above U. Confining Zone); 143 ft^3 CO_2 resistant cement at 14.5 lb/gal.
9. Cement Plug #3: ±1,100' (100' below surface casing shoe) to surface; 460 ft^3 Class "H" at 16.4 lb/gal (1.06 ft^3/sx).

Geostock Sandia

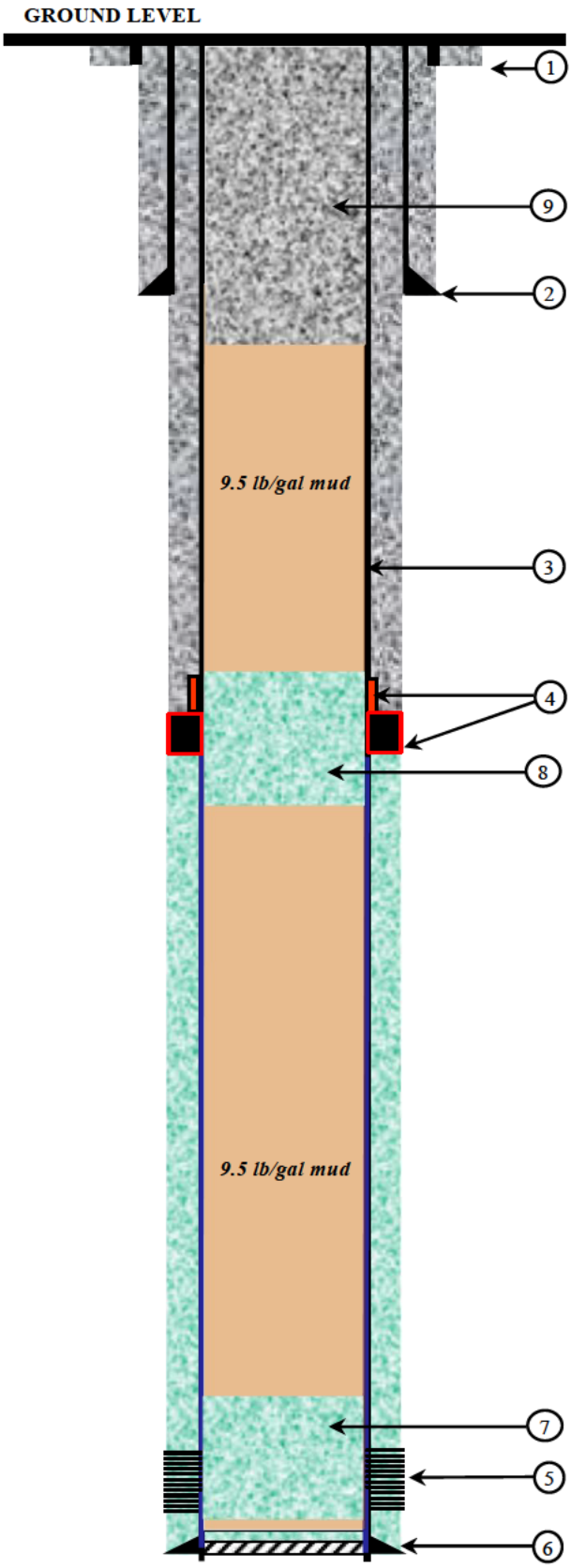
Drawn by: BH	Date: March 2025	*Drawing not to scale*

Figure 1: Nimbus INJ-1 P&A

Nimbus ARCCS Inc. – Injection Well No. 2 (Nimbus INJ-2)

Permit No. XXXXXX

Proposed P&A Well Schematic



All depths reference Rig Kelly Bushing
Rig Kelly Bushing = 20 above GL
Ground Level ~250' (TBD)

COMPLETION DETAILS

1. Conductor Casing: 20-inch, set from surface to ±100, driven to refusal.
2. Surface Casing: 13-3/8", 54.5 lb/ft, J-55, BTC. Set from surface to ±1,000' in a 17-1/2" hole. Cemented to surface with 370 sx (700', 1.972 ft^3/sx, 730 ft^3, 130 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 291 sx (300', 1.196 ft^3/sx, 348 ft^3, 62 bbl) tail premium cement mixed at 15.0 lb/gal.
3. Protection Casing: 9-5/8" mixed string set from surface to ±5,110' in 12-1/4" hole.
   - 0' to ±3,050': 43.5 lb/ft, L-80, LT&C
   - ±3,050' to ±3,066': 9-5/8" stage tool from ±3,050' to ±3,056' and 9-5/8" external casing packer from ±3,056' to ±3,066'. L-80, LTC with premium gas tight bottom pin.
   - ±3,066' to ±5,110': 43.5 lb/ft, 13Cr80, premium gas tight connections.

   Cemented in two stages:
   - Stage 1: Cement from ±5,110' to ±3,050' with 685 sx (1.163 ft^3/sx, 797 ft^3, 142 bbl) CO_2 resistant cement slurry mixed at 14.5 lb/gal.
   - Stage 2: Cement from ±3,050' to surface with 555 sx (2,550', 1.712 ft^3/sx, 950 ft^3, 169 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 160 sx (500', 1.203 ft^3/sx, 193 ft^3, 34 bbl) tail premium cement mixed at 15.0 lb/gal.
4. 9-5/8" Stage Tool (L-80) and External Casing Packer set from ±3,050' to ±3,066'.
5. Injection Perforations: Cotton Valley "A" formation from ±4,525' to ±4,960' with 4 SPF 90-degree phasing -or- 6 SPF 120 deg phasing.
6. Planned Total Depth: ±5,110' ; PBTD ±5,060'.
7. Cement Plug #1: ±4,960' (bottom perforation) to ±4,325' (200' above perforations); 266 ft^3 CO_2 resistant cement at 14.5 lb/gal
8. Cement Plug #2: ±3,290' (100' below U. Confining Zone) to ±2,950' (100' above U. Confining Zone); 143 ft^3 CO_2 resistant cement at 14.5 lb/gal.
9. Cement Plug #3: ±1,100' (100' below surface casing shoe) to surface; 460 ft^3 Class "H" at 16.4 lb/gal (1.06 ft^3/sx).

Geostock Sandia

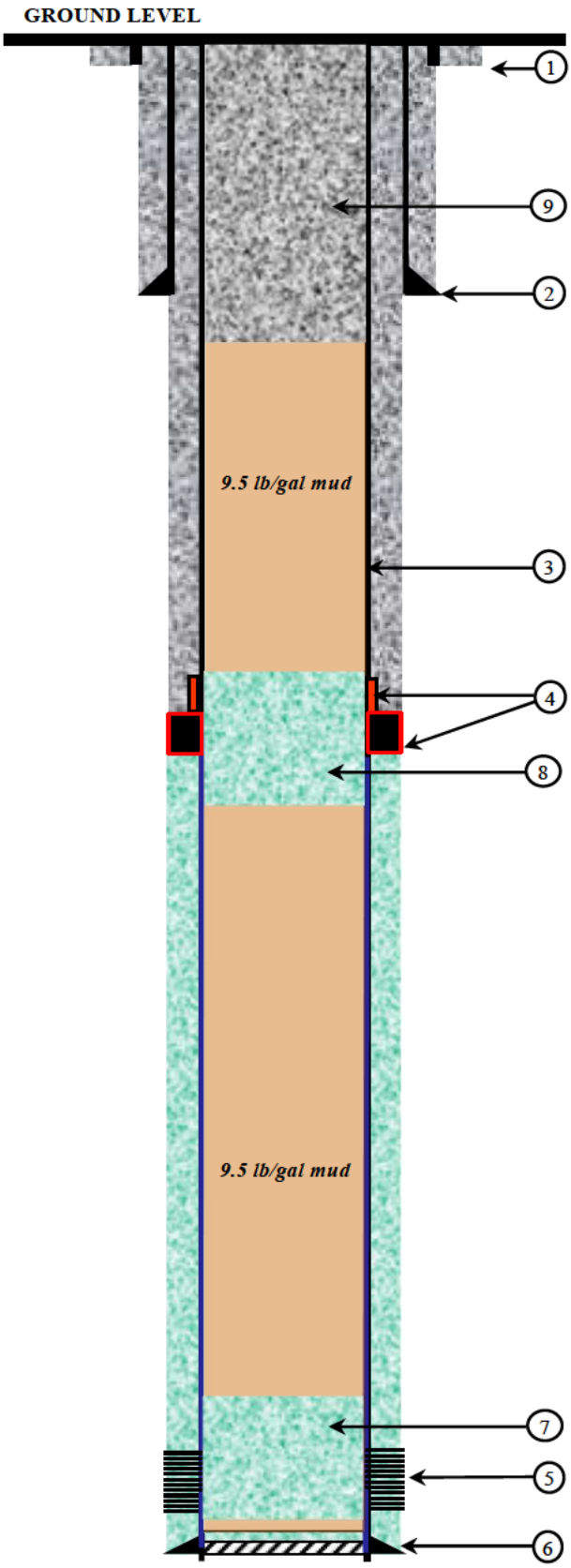
Drawn by: BH	Date: March 2025	*Drawing not to scale*

Figure 2: Nimbus INJ-2 P&A

Nimbus ARCCS Inc. – Injection Well No. 3 (Nimbus INJ-3)

Permit No. XXXXXX

Proposed P&A Well Schematic



All depths reference Rig Kelly Bushing
Rig Kelly Bushing = 20 above GL
Ground Level ~250' (TBD)

COMPLETION DETAILS

1. Conductor Casing: 20-inch, set from surface to ±100, driven to refusal.

2. Surface Casing: 13-3/8", 54.5 lb/ft, J-55, BTC. Set from surface to ±1,000' in a 17-1/2" hole. Cemented to surface with 370 sx (700', 1.972 ft^3/sx, 730 ft^3, 130 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 291 sx (300', 1.196 ft^3/sx, 348 ft^3, 62 bbl) tail premium cement mixed at 15.0 lb/gal.

3. Protection Casing: 9-5/8" mixed string set from surface to ±4,590' in 12-1/4" hole.
   - 0' to ±3,050': 43.5 lb/ft, L-80, LT&C
   - ±3,050' to ±3,066': 9-5/8" stage tool from ±3,050' to ±3,056' and 9-5/8" external casing packer from ±3,056' to ±3,066'. L-80, LTC with premium gas tight bottom pin.
   - ±3,066' to ±4,590': 43.5 lb/ft, 13Cr80, premium gas tight connections.

   Cemented in two stages:
   - Stage 1: Cement from ±4,590' to ±3,050' with 515 sx (1.163 ft^3/sx, 599 ft^3, 107 bbl) CO_2 resistant cement slurry mixed at 14.5 lb/gal.
   - Stage 2: Cement from ±3,050' to surface with 555 sx (2,550', 1.712 ft^3/sx, 950 ft^3, 169 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 160 sx (500', 1.203 ft^3/sx, 193 ft^3, 34 bbl) tail premium cement mixed at 15.0 lb/gal.

4. 9-5/8" Stage Tool (L-80) and External Casing Packer set from ±3,050' to ±3,066'.

5. Injection Perforations: Cotton Valley "B" formation from ±4,000' to ±4,440' with 4 SPF 90-degree phasing -or- 6 SPF 120 deg phasing.

6. Planned Total Depth: ±4,590' ; PBTD ±4,540'.

7. Cement Plug #1: ±4,440' (bottom perforation) to ±3,900' (200' above perforations); 227 ft^3 CO_2 resistant cement at 14.5 lb/gal.

8. Cement Plug #2: ±3,290' (100' below U. Confining Zone) to ±2,950' (100' above U. Confining Zone); 143 ft^3 CO_2 resistant cement at 14.5 lb/gal.

9. Cement Plug #3: ±1,100' (100' below surface casing shoe) to surface; 460 ft^3 Class "H" at 16.4 lb/gal (1.06 ft^3/sx).

Geostock Sandia

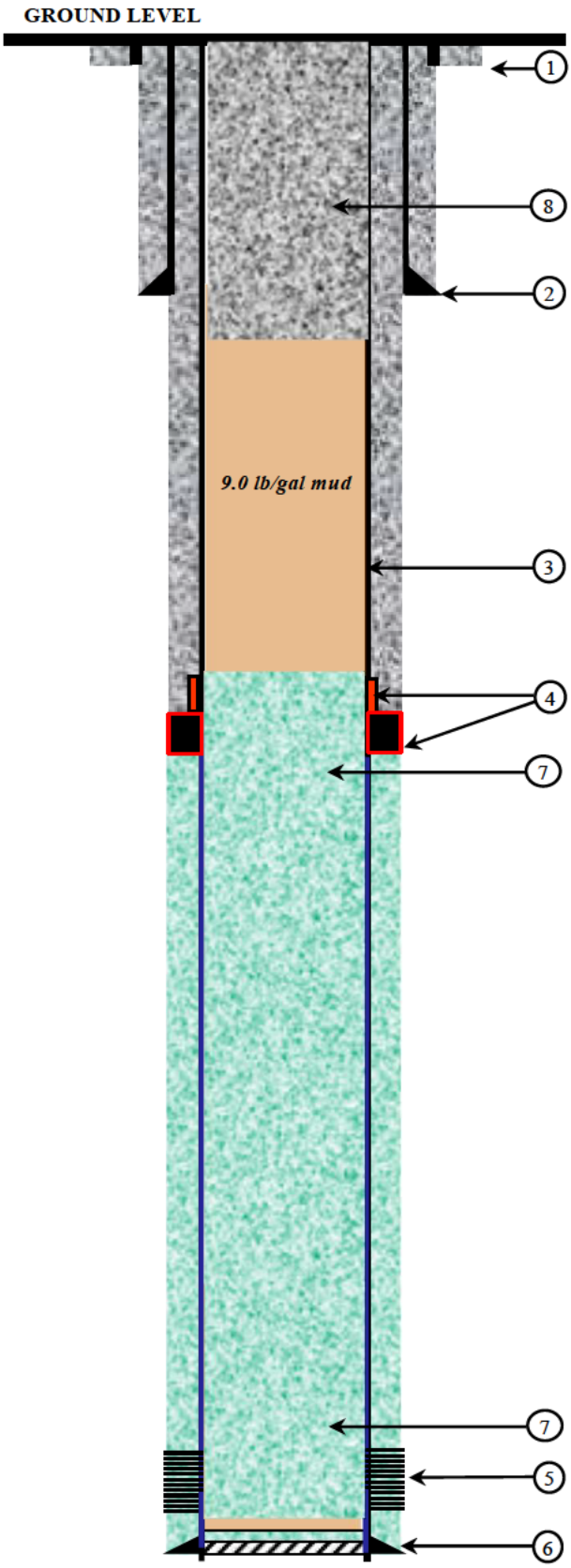
Drawn by: BH	Date: March 2025	*Drawing not to scale*

Figure 3: Nimbus INJ-3 P&A

Nimbus ARCCS Inc. – Injection Well No. 4 (Nimbus INJ-4)

Permit No. XXXXXX

Proposed P&A Well Schematic



All depths reference Rig Kelly Bushing
Rig Kelly Bushing = 20 above GL
Ground Level ~250' (TBD)

COMPLETION DETAILS

1. Conductor Casing: 20-inch, set from surface to ±100, driven to refusal.

2. Surface Casing: 13-3/8", 54.5 lb/ft, J-55, BTC. Set from surface to ±1,000' in a 17-1/2" hole. Cemented to surface with 370 sx (700', 1.972 ft^3/sx, 730 ft^3, 130 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 291 sx (300', 1.196 ft^3/sx, 348 ft^3, 62 bbl) tail premium cement mixed at 15.0 lb/gal.

3. Protection Casing: 9-5/8" mixed string set from surface to ±3,900' in 12-1/4" hole.
   - 0' to ±3,050': 43.5 lb/ft, L-80, LT&C
   - ±3,050' to ±3,066': 9-5/8" stage tool from ±3,050' to ±3,056' and 9-5/8" external casing packer from ±3,056' to ±3,066'. L-80, LTC with premium gas tight bottom pin.
   - ±3,066' to ±3,900': 43.5 lb/ft, 25Cr80, premium gas tight connections.

   Cemented in two stages:
   Stage 1: Cement from ±3,900' to ±3,050' with
   - Stage 1: Cement from ±3,900' to ±3,050' with 290 sx (1.163 ft^3/sx, 337 ft^3, 60 bbl) CO_2 resistant cement slurry mixed at 14.5 lb/gal.
   - Stage 2: Cement from ±3,050' to surface with 555 sx (2,550', 1.712 ft^3/sx, 950 ft^3, 169 bbl) lead "lightweight" cement mixed at 12.4 lb/gal and 160 sx (500', 1.203 ft^3/sx, 193 ft^3, 34 bbl) tail premium cement mixed at 15.0 lb/gal.

4. 9-5/8" Stage Tool (L-80) and External Casing Packer set from ±3,050' to ±3,066'.

5. Injection Perforations: L. Hosston formation from ±3,230' to ±3,750' with 4 SPF 90-degree phasing -or- 6 SPF 120 deg phasing.

6. Planned Total Depth: ±3,900' ; PBTD ±3,850'.

7. Cement Plug #1: ±3,750' (bottom perforation) to ±2,950' (100' above U. Confining Zone); 335 ft^3 CO_2 resistant cement at 14.5 lb/gal.

8. Cement Plug #2: ±1,100' (100' below surface casing shoe) to surface; 460 ft^3 Class "H" at 16.4 lb/gal (1.06 ft^3/sx).

Geostock Sandia

Drawn by: BH	Date: March 2025	*Drawing not to scale*

Figure 4: Nimbus INJ-4 P&A