INJECTION WELL PLUGGING PLAN FOR TB1-2 40 CFR 146.92

Project Name: Tri-State CCS Buckeye 1

Facility Information

Facility Contact: Tri-State CCS, LLC
14302 FNB Parkway
Omaha, NE 68154
402-691-9500

Well Location: Carroll County, Ohio

Well Name	Latitude (WGS84)	Longitude (WGS84)
TB1-2	40.64546393	-81.01533077

Table of Contents

List of Figures

List of Tables

List of Acronyms

22Cr-110	22% Chromium Duplex Stainless Steel with 110,000 Pounds per Square Inch Minimum Yield Strength
BHP	Bottomhole Pressure
BOP	Blowout Preventers
BPV	Back Pressure Valve
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
ft	Feet
gal	Gallon
GL	Ground Level
in	Inch
KIC	Knox Injection Complex
MASP	Maximum Allowable Surface Pressure
MD	Measured Depth
MIC	Medina Injection Complex
MIRU	Move In Rig Up
MIT	Mechanical Integrity Test
N/D	Nipple Down
N/U	Nipple Up
ODNR	Ohio Department of Natural Resources
PBTD	Plug Back Total Depth
PNL	Pulsed Neutron Log
POOH	Pull Out of Hole
PSI	Pounds per Square Inch
PSIG	Pounds per Square Inch, Gauge
R/U	Rig Up
TD	Total Depth
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
U.S. EPA	U.S. Environmental Protection Agency

1. Introduction

The following document describes the procedures that Tri-State CCS, LLC will follow to plug and abandon the proposed carbon dioxide (CO_2) injection well TB1-2 at Tri-State CCS Buckeye 1 in Carroll County, Ohio (the "Project") in accordance with U.S. EPA's requirements under 40 CFR 146.92. Additionally, Tri-State CCS, LLC is working with the Ohio Department of Natural Resources (ODNR) to determine if state requirements will apply to plugging TB1-2.

After completing the planned CO_2 injection into the Knox Injection Complex (KIC), the tubing and completion hardware will be retrieved, and the zone will be plugged off with CO_2 resistant cement. The Medina Injection Complex (MIC) will then be perforated, and the same tubing will be inspected or tested and reused for injection. Once the MIC's injection volume is achieved, the well will be plugged and abandoned. Tri-State CCS, LLC may elect to delay plugging the MIC injection zone for use in monitoring in-zone reservoir conditions post injection. See subsection 5.1 for notifications to the UIC (Underground Injection Control) Program Director regarding plugging or delaying plugging this injection well.

2. Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

During both injection and post-injection phases in the KIC and MIC injection zones, industry-standard downhole pressure gauges will measure and record bottom-hole pressure (BHP). These gauges will be installed either in the injection tubing or the long casing string within the injection zone, enabling continuous real-time surface readout of pressure data. The gauges allow for operational pressures that range from 200 to 10,000 psig with an accuracy of ± 0.015% of range. The bottom-hole reservoir pressure will be obtained prior to plugging each injection zone using the final measurements from the pressure gauges, hydrostatic pressure calculation, or a wireline deployed pressure gauge in both the injection zones after the CO_2 injection period and any post-injection monitoring has ended.

Following the determination of BHP, a buffered fluid (inhibited spacer fluid) will be employed to flush and fill the well, ensuring pressure control. The measured BHP will guide the selection of the appropriate weight of inhibited spacer fluid to stabilize the well and may inform decisions regarding the blend of cement needed to plug the well and address considerations such as preventing leak-off or premature setting.

3. Planned External Mechanical Integrity Test(s)

Verifying external mechanical integrity is necessary for Class VI UIC wells used in the geologic sequestration of CO_2 to prevent potential CO_2 leakage into underground sources of drinking water (USDW). Various methods, including pressure testing, cement bond logs, casing inspections, and other techniques outlined in industry best practices and regulatory guidelines, are employed to monitor integrity. Tri-State CCS, LLC will conduct at least one of the mechanical integrity tests (MIT) specified in Table 1 before plugging the KIC up to the Queenston Shale and, after injection ceases in the MIC, before plugging the remainder of the well to verify external mechanical integrity, as required by 40 CFR 146.92(a). Procedures for each test are outlined in subsections 3.1 to 3.4 below. Surface pressure monitoring during these tests will utilize gauges rated at 0-5,000 psig. This testing aims to ensure that the injection zone remains isolated from USDWs or the ground surface, as mandated by 40 CFR 146.92(b)(2), following the cessation of CO_2 injection.

Table 1: Planned Mechanical Integrity Tests before plugging.

Test Description	Pass	Fail	Logging Interval after KIC Injection	Logging Interval after MIC Injection
Temperature Log	No temperature anomalies found.	Temperature anomalies found.	Long String Casing; Surface to Total Depth (TD)	Long String Casing; Surface to top of Cement Plug below MIC
Oxygen Activation Log	No fluid movement detected outside of casing beyond sequestration zones.	Water movement detected outside of casing beyond sequestration zones.	Long String Casing; Surface to TD	Long String Casing; Surface to top of cement plug below MIC
Noise Log	No flowing noise detected.	Flowing noise detected.	Long String Casing; Surface to TD	Long String Casing; Surface to top of cement plug below MIC
Pulsed Neutron Log	No CO_2 detected outside of casing beyond sequestration zones.	CO_2 detected outside of casing beyond sequestration zones.	Long String Casing; Surface to TD	Long String Casing; Surface to top of cement plug below MIC

3.1 Temperature Log General Procedure

A temperature log would be used to identify temperature anomalies that indicate fluid movement adjacent to the well bore. The general procedure for running a temperature log is as follows:

- Obtain a temperature log using externally mounted fiber optic cable throughout the injection well's depth.
- Evaluate the temperature curve for anomalies indicating fluid migration beyond the injection zone.
- Compare this data with baseline logs taken before CO_2 injection and promptly address any discrepancies between pre- and post-injection logs.

3.2 Activated Oxygen Log General Procedure

An activated oxygen log would be used to identify fluid flow inside and outside casing. The general procedure for running an activated oxygen log is as follows:

- An activated oxygen log throughout the injection well will be conducted immediately prior to cessation of CO_2 injection by utilizing a pulsed neutron spectroscopy tool following the 40 CFR 146.92(b)(2) requirements. This is done to evaluate responses compared to the baseline measurements discussed in subsection 2.2 of the Testing and Monitoring Plan.
- Oxygen (^{16}O) will be activated by high energy neutrons to produce nitrogen (^{16}N), which emits a gamma ray signature during decay read by spaced detectors. Flow rate, velocity, and distance of water flow from the tool can be determined.

- Evaluate log data to determine if any fluid movement is occurring above the confining zone.
- Promptly address any issues related to well casing or cement integrity detected during the activated oxygen log.

3.3 Noise Log General Procedure

A noise log would be used to detect turbulent flow occurring along the well bore. The general procedure for running a noise log is as follows:

- Perform a noise log throughout the injection well immediately prior to cessation of CO_2 injection to detect flow along leakage pathways. Per 40 CFR 146.92(b)(2), a noise log is conducted immediately before cessation of CO_2 injection to evaluate responses compared to baseline measurements and ensure compliance with monitoring standards.
- Evaluate log data to identify any flow outside of confining zone(s), indicating CO_2 leakage through a micro annulus.
- Promptly address any issues related to well casing or cement integrity detected from the noise log.

3.4 Pulsed Neutron Log General Procedure

A pulsed neutron log (PNL) would be used to detect CO_2 saturation changes at the well bore. The general procedure for a PNL is as follows:

- Run PNL in cased hole immediately prior to cessation of injection and compared to previous annual PNL logs.
- Evaluate CO_2 saturations, derived from water saturation less than 100%, above baseline outside of storage reservoir.
- Promptly address any issues related to well casing, cement integrity, or CO_2 leakage detected during the PNL.

4. <u>Information on Plugs</u>

Tri-State CCS, LLC will use the materials and methods noted in **Error! Reference source not found.** after completing the planned CO_2 injection into the KIC, and those in **Error! Reference source not found.** after completing the planned CO_2 injection into the MIC, to plug the TB1-2 injection well in compliance with 40 CFR 146.92 (b)(3)-(6). The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging across the storage intervals and across the confining zones will be compatible with the CO_2 stream. Shallower plugs, above the MIC confining zone, will consist of class A neat cement or equivalent.

The cement formulation and required certification documents will be submitted to the UIC Program Director with the 60-day notification described in subsection 5.1 below and an updated Injection Well Plugging Plan prior to beginning plugging activities. Tri-State CCS, LLC will report the wet density and will retain duplicate samples of the cement used for each plug.

Table 2: Plugging details for TB1-2 to plug the KIC through Queenston Shale [1]

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in)	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft TVD)	8,055	8,055	5,865	5,865
Sacks of cement to be used	183	8	77	8
Slurry volume to be pumped (bbl)	45.7	1.9	19.2	1.9
Slurry weight (lb/gal)	14.8	14.8	14.8	14.8
Calculated top of plug (ft TVD)	8,055	8,005	5,865	5,815
Bottom of plug (ft TVD)	9,249	8,055	6,365	5,865
Type of cement or other material	CO_2 resistant	CO_2 resistant	CO_2 resistant	CO_2 resistant
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balanced	Retainer	Balanced

[1] Cement volumes were determined by volumetric calculations.

Table 3: Plugging details for TB1-2 to plug the MIC to surface [1]

Plug Information	Plug #5	Plug #6	Plug #7	Plug #8
Diameter of boring in which plug will be placed (in)	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft TVD)	5,215	5,215	2,090	1,015
Sacks of cement to be used	92	8	74	151
Slurry volume to be pumped (bbl)	23.0	1.9	19.2	38.9
Slurry weight (lb./gal)	14.8	13.5	13.5	13.5
Calculated top of plug (ft TVD)	5,215	5,165	1,590	Surface
Bottom of plug (ft TVD)	5,815	5,215	2,090	1,015
Type of cement or other material	CO_2 resistant	Class A	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balanced	Balanced	Balanced

[1] Cement volumes were determined by volumetric calculations.

5. Narrative Description of Plugging Procedures

5.1 Notifications, Permits, and Inspections

The following are the federal notifications and reporting required for injection well plugging. These will be submitted separately for each well:

- 60-Day Notification: Tri-State CCS, LLC will notify the UIC Program Director in writing at least 60 days prior to the plugging of either the KIC or MIC injection zones in TB1-2. Any changes to this plan shall be submitted no later than the notification period deadline specified in 40 CFR 146.92(c).

- Well Plugging Report: Within 60 days of plugging either the KIC or MIC injection zones in TB1-2, Tri-State CCS, LLC will submit a Well Plugging Report to the UIC Program Director as outlined in 40 CFR 146.92(d). The Well Plugging Report should include the following information:

    - Pumping charts and all lab information;
    - Plug emplacement type, depth range (top/bottom), cement type, grade, weight, and quantities used for each plug;
    - Notes on plug tagging;
    - Construction/plugging schematics with USDW depths;
    - Certification of 10-year report retention;
    - Certification as accurate by Tri-State CCS, LLC and plugging contractor;
    - Well flushing and kill fluids description along with fluids and volumes;
    - Notes on debris or tight restrictions;
    - Documentation of removed completion equipment (tubing, control lines, packers, gauges); and
    - Squeeze cementing descriptions (if applicable).

Tri-State CCS, LLC will work with ODNR to determine any state reporting requirements.

5.2 Plugging Procedures

Upon cessation of injection into the KIC, TB1-2 will be plugged from the KIC through the Queenston Shale so that injection into the MIC can begin. Upon cessation of injection into the MIC, TB1-2 will be plugged and abandoned to meet the requirements of 40 CFR 146.92. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive effects of CO_2 and water mixtures, and to protect any USDWs. Any necessary revisions to this plan to address new information collected during logging and testing of the well will be made after construction, logging, and testing of the well have been completed and will be submitted to the UIC Program Director for approval.

Prior to plugging either injection zone, based on BHP measurements, the well will be flushed with a kill weight brine fluid with corrosion inhibitor. The brine composition will be selected to minimize corrosion risk over the post-injection site care period. A minimum of two tubing volumes will be injected without exceeding fracture pressure. An external MIT will be conducted prior to plugging as outlined in Table 1. If a loss of mechanical integrity is discovered, the well will be repaired prior to proceeding with the plugging operations. The detailed plugging procedure is provided in subsection 5.2.1 below.

All casing in the well will be cemented to surface at the time of well construction and will not be retrievable at abandonment. After injection is permanently terminated into the KIC, the injection tubing and packer will be removed. Figure 1 and Figure 2 show the wellbore schematic before plugging the KIC. A retainer squeeze will be used to plug off perforations in the Rose Run Sandstone injection interval using CO_2 resistant cement (Plug #1). The pressure used to squeeze the cement will be determined from the BHP data measured before beginning the plugging and abandonment process. However, the injection pressure (hydrostatic weight of column plus applied surface pressure) of the cement will not exceed 90% of the fracture pressure of the section being squeezed or any underlying previously squeezed zone unless a casing test is conducted to validate the integrity of the casing, and any isolation plugs below the zone being abandoned to confirm a higher-pressure limitation. If it appears that the injection pressure will exceed the fracture or test pressure and the planned volume of cement has not been pumped into the injection interval, cement pumping will cease. If the pressure does not dissipate, the tubing will be un-strung from the cement retainer and reversed or circulated clean. After allowing sufficient time for cement to reach appropriate compressive strength, the tubing will be re-strung into the cement retainer, and the squeeze will be tested to 90% fracture pressure, or re-squeezed if injectivity is established. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement. 50 ft of CO_2 resistant cement balanced plug will be placed on top of the retainer, converted to a mechanical plug, to provide an additional seal (Plug #2).

Inhibited spacer fluid will be pumped, and mechanical plug will be set approximately 400 ft below the bottom of the planned section mill interval. Approximately 50 ft of the long string casing will be milled at the crossover from 22Cr-110 grade duplex stainless steel (22Cr-110) to L80 grade steel (L80), covering 10-20 ft of the 22Cr-110 section. Once milled, this interval will be squeezed and plugged off with CO_2 resistant cement (Plug #3) as outlined in **Error! Reference source not found.** and illustrated in Figure 3 and Figure 4. 50 ft of CO_2 resistant cement balanced plug will be placed at the top of the retainer, converted to a mechanical plug (Plug #4), and the Medina Group injection interval will be perforated to begin injection.

After injection is permanently terminated into the MIC, the injection tubing and packer will be removed. Figure 5 and Figure 6 show the wellbore schematic before plugging the MIC. A retainer squeeze will be used to plug off perforations in the Medina Group injection interval using CO_2 resistant cement (Plug #5). Class A balanced plugs (Plug #6, #7 and #8) and inhibited spacer fluid will be used to isolate the remainder of the well to surface as outlined in **Error! Reference source not found.** and illustrated in Figure 7 and Figure 8. Each cement plug will be pressure tested after setting to verify integrity. All the casing strings will be cut off at least 5 ft below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing.

The remainder of this page intentionally left blank.

TB 1-2 Proposed Well Schematic (Before Plugging KIC)

Well Name	Prepared By	Prepared Date	Completion Fluid	Final TVD (ft)
TB1-2	M.S. Langseth	01/20/2025	Brine	9249
Coordinates	**Wellhead**		**RKB (ft)**	
40.64546393, -81.01533077	TBD		TBD	
County	**State**		**GL (ft)**	
Carroll County	Ohio		TBD	

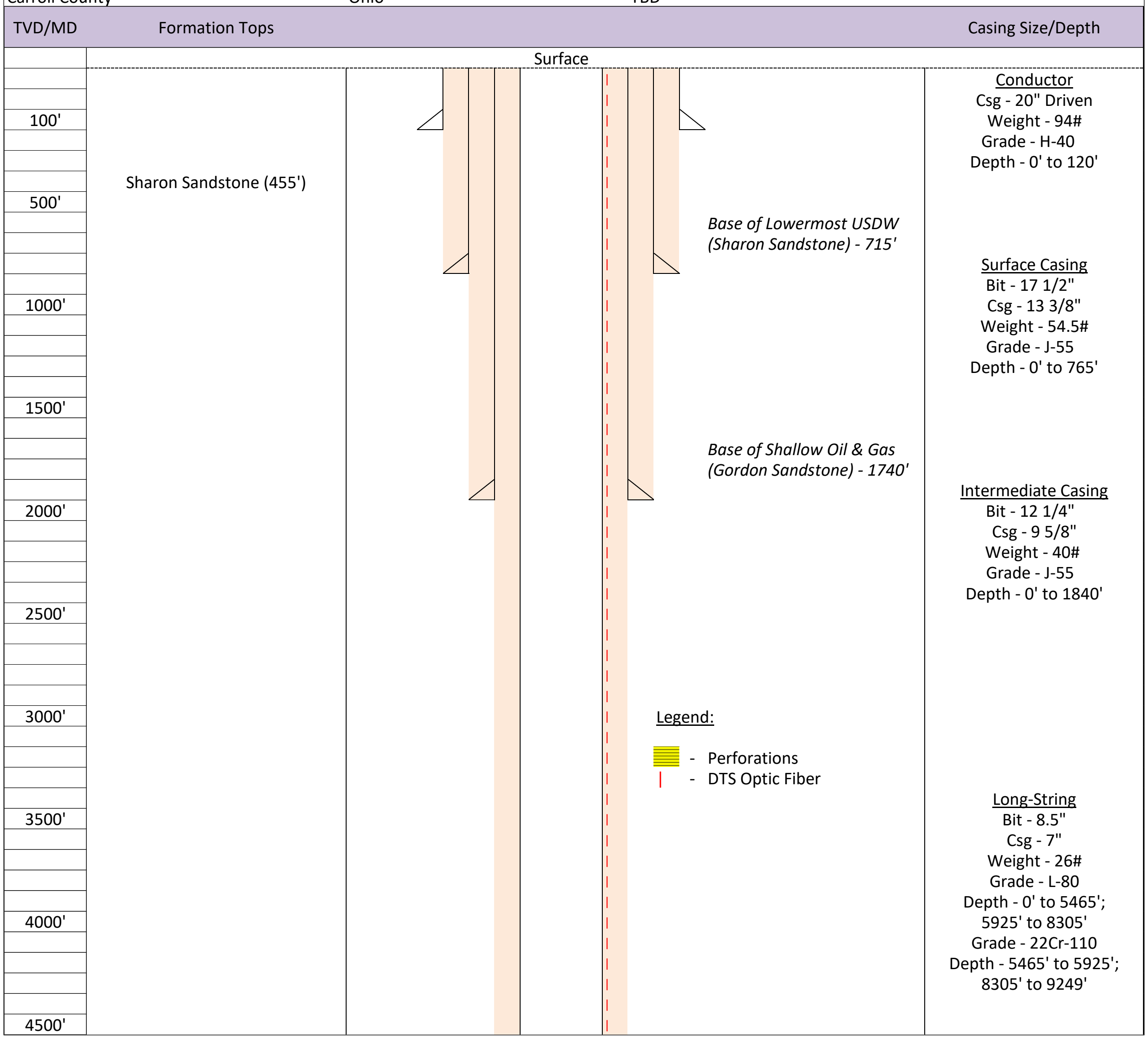

Figure 1: Proposed well schematic for TB1-2 after pulling the completion and before plugging the KIC. Well schematic split in two for illustration purposes, 1/2: Surface to 4,500 ft.

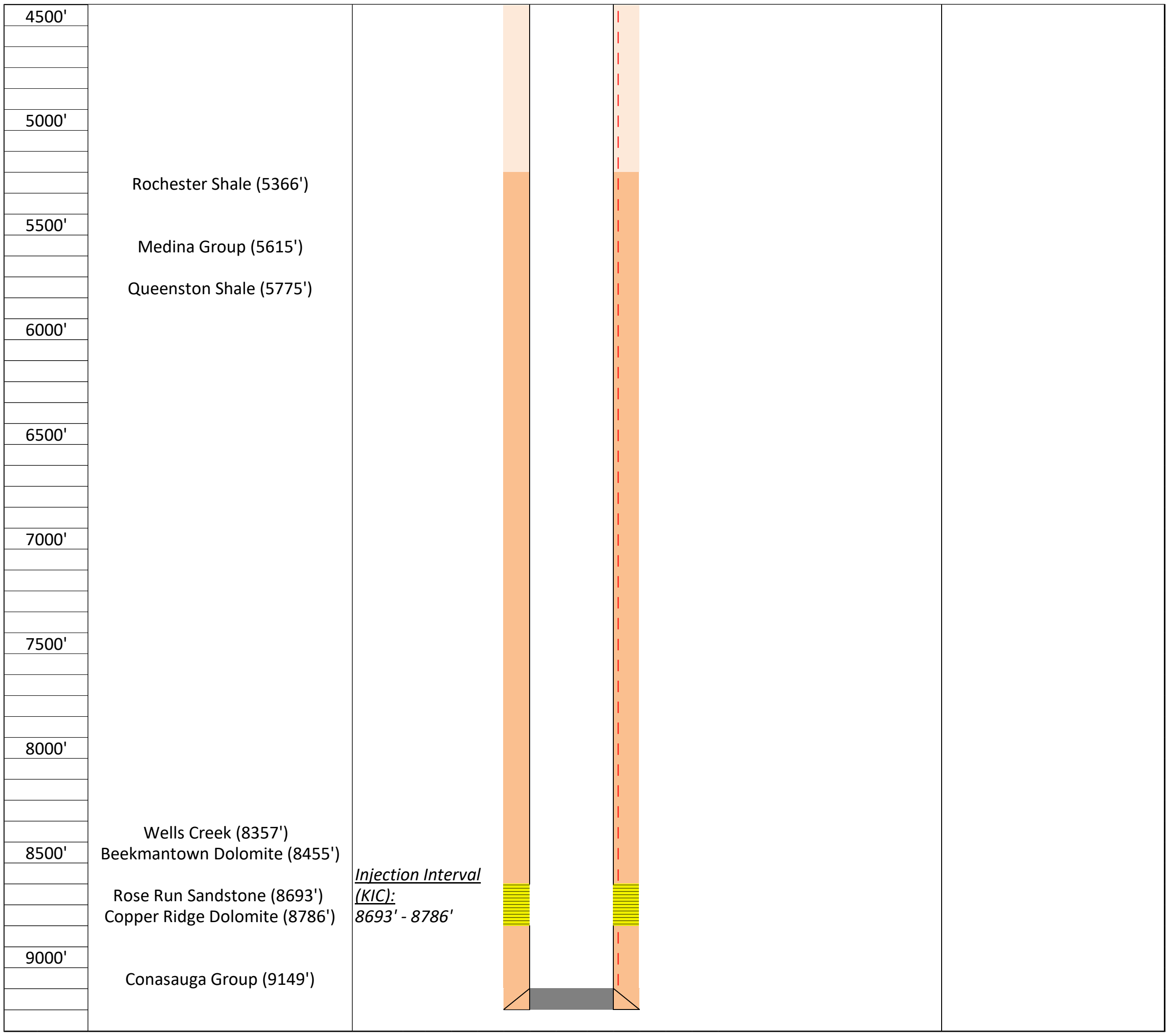

Figure 2: Proposed well schematic for TB1-2 after pulling the completion and before plugging the KIC. Well schematic split in two for illustration purposes, 2/2: 4,500 ft to 9,300 ft.

TB 1-2 Proposed Well Schematic (After Plugging KIC)

Well Name	Prepared By	Prepared Date	Completion Fluid	Final TVD (ft)
TB1-2	M.S. Langseth	01/20/2025	Brine	9249
Coordinates	**Wellhead**		**RKB (ft)**	**PBTD TVD (ft)**
40.64546393, -81.01533077	TBD		TBD	5815
County	**State**		**GL (ft)**	
Carroll County	Ohio		TBD	

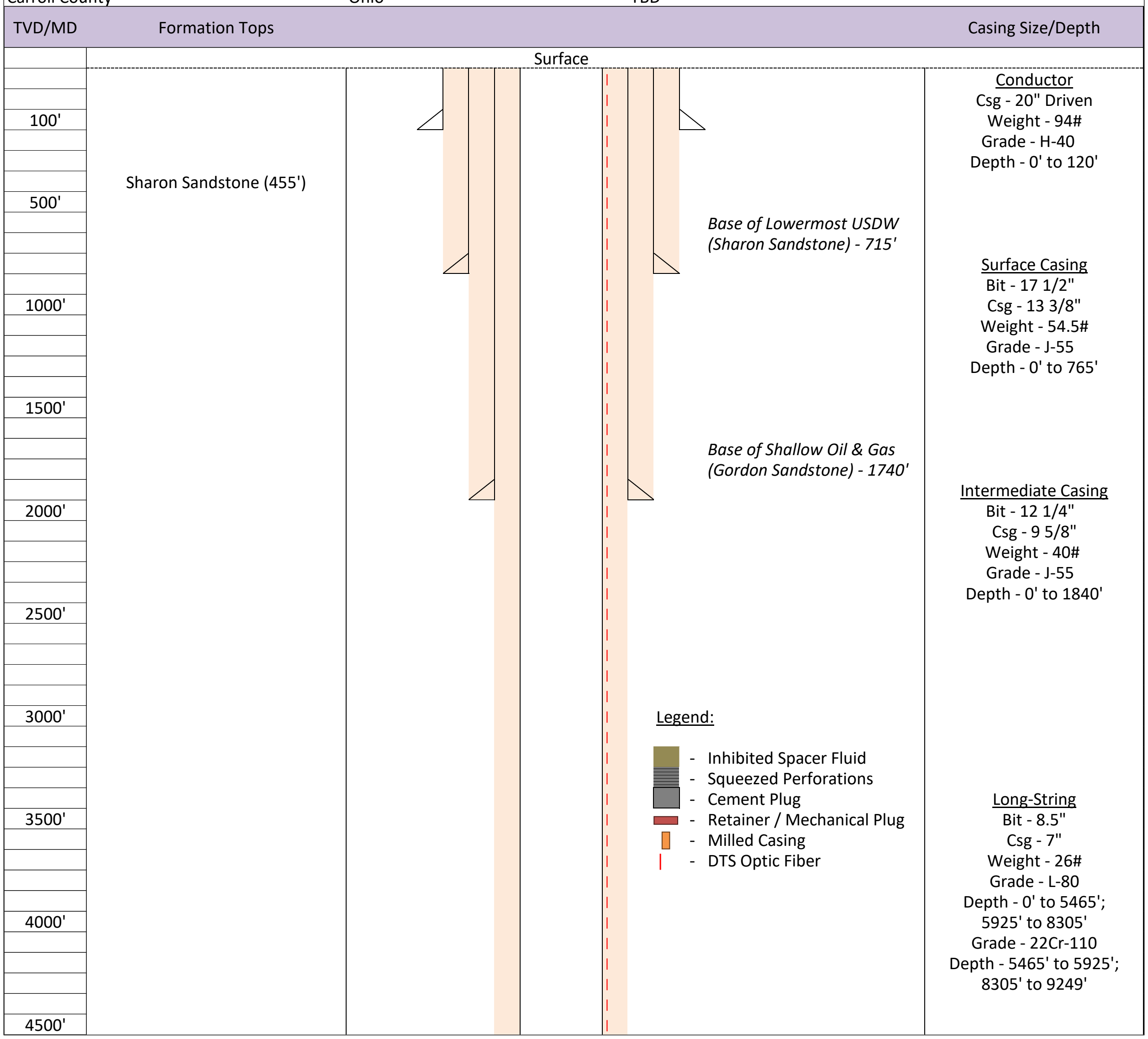

Figure 3: Proposed well schematic for TB1-2 after plugging from the KIC to the Queenston Shale (lower confining zone of MIC). Well schematic split in two for illustration purposes, 1/2: Surface to 4,500 ft.

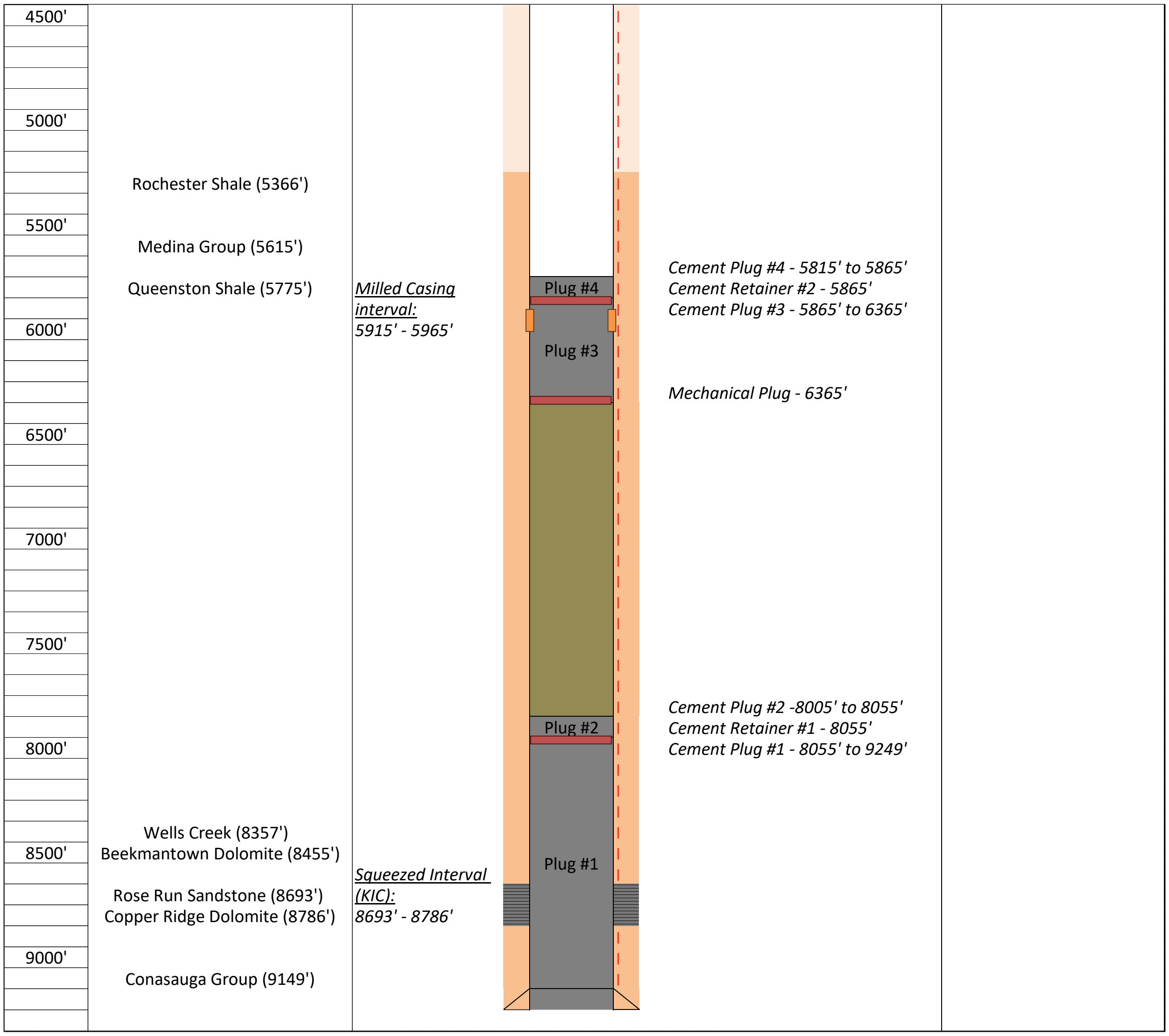

Figure 4: Proposed well schematic for TB1-2 after plugging from the KIC to the Queenston Shale (lower confining zone of MIC). Well schematic split in two for illustration purposes, 2/2: 4,500 ft to 9,300 ft.

TB 1-2 Proposed Well Schematic (Before Plugging MIC)

Well Name	Prepared By	Prepared Date	Completion Fluid	Final TVD (ft)
TB1-2	M.S. Langseth	01/20/2025	Brine	9249
Coordinates	**Wellhead**		**RKB (ft)**	**PBTD TVD (ft)**
40.64546393, -81.01533077	TBD		TBD	5815
County	**State**		**GL (ft)**	
Carroll County	Ohio		TBD	

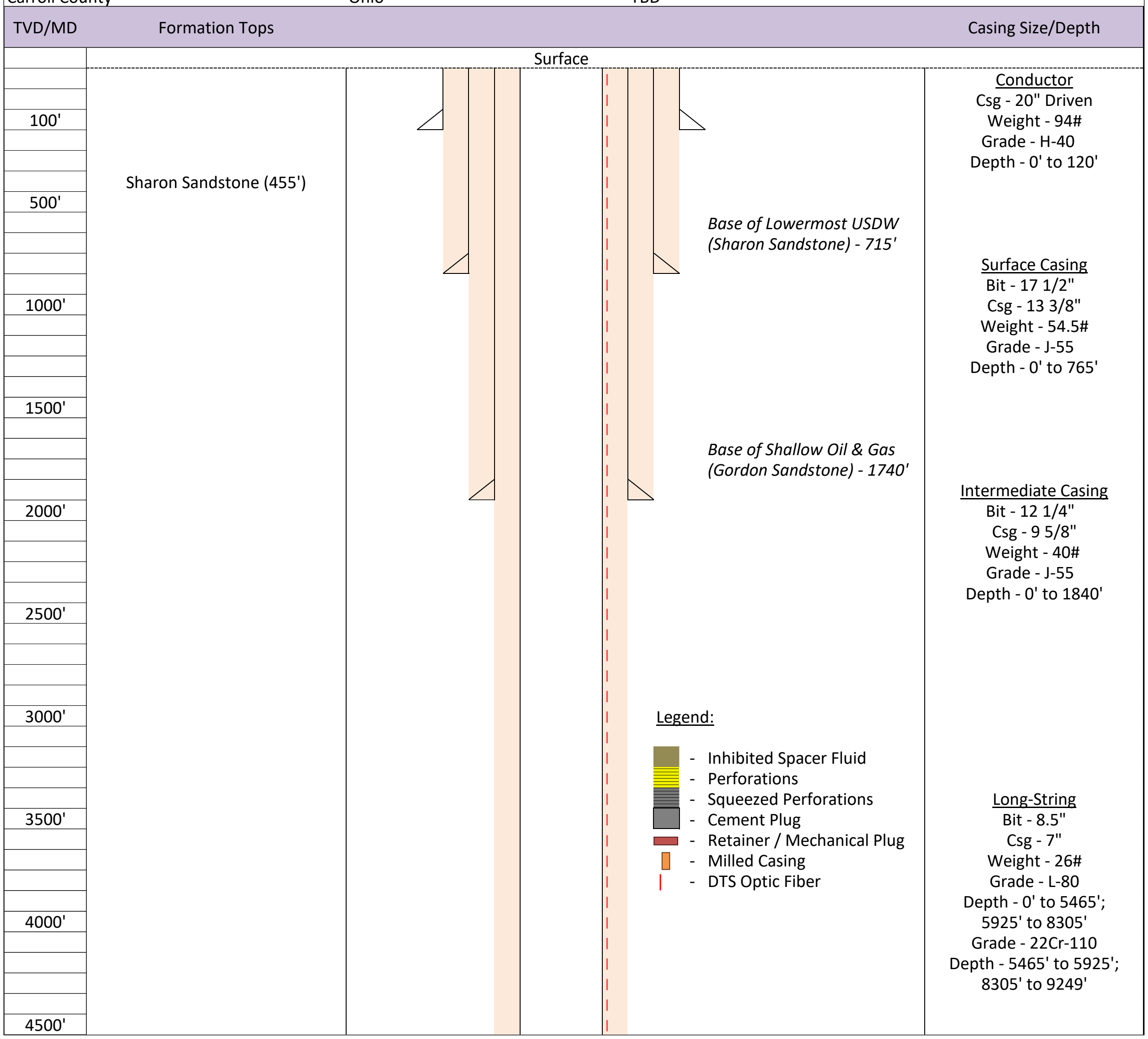

Figure 5: Proposed well schematic for TB1-2 after pulling the completion and before plugging the MIC. Well schematic split in two for illustration purposes, 1/2: Surface to 4,500 ft.

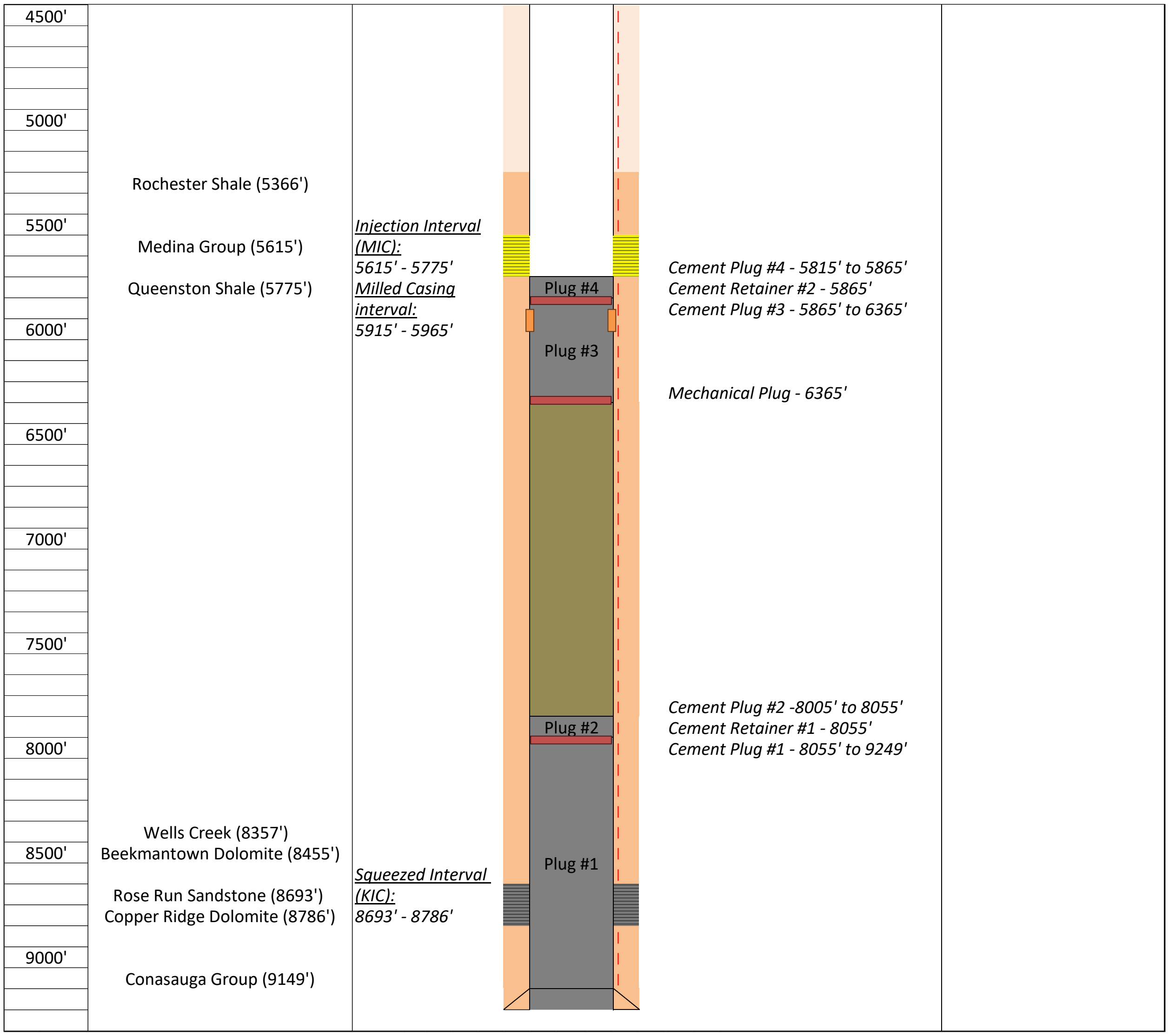

Figure 6: Proposed well schematic for TB1-2 after pulling the completion and before plugging the MIC. Well schematic split in two for illustration purposes, 2/2: 4,500 ft to 9,300 ft.

TB 1-2 Proposed Well Schematic (After Plugging MIC)

Well Name	Prepared By	Prepared Date	Completion Fluid	Final TVD (ft)
TB1-2	M.S. Langseth	01/20/2025	Brine	9249
Coordinates	**Wellhead**		**RKB (ft)**	**PBTD TVD (ft)**
40.64546393, -81.01533077	TBD		TBD	0
County	**State**		**GL (ft)**	
Carroll County	Ohio		TBD	

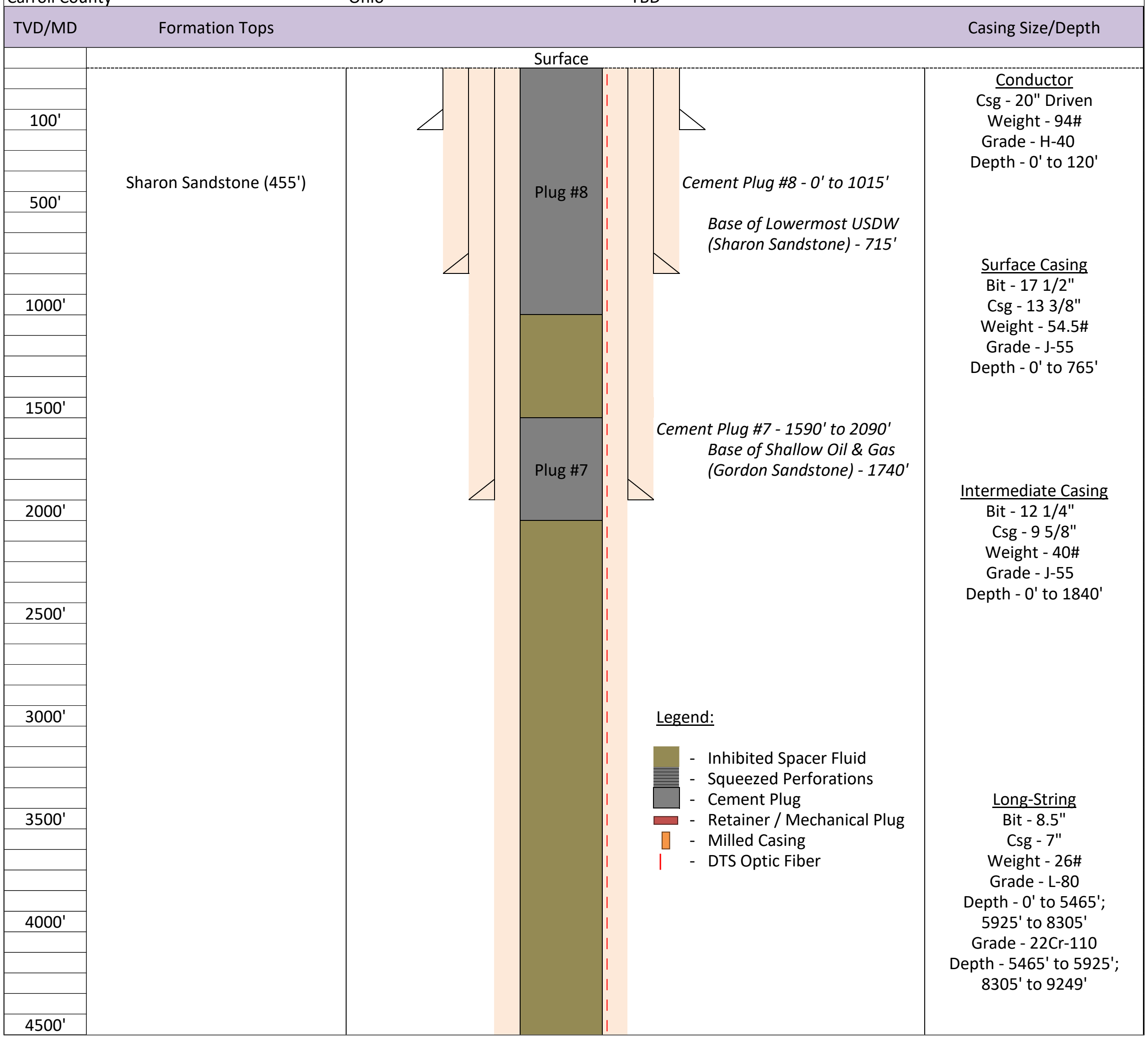

Figure 7: Proposed well schematic for TB1-2 after plugging the MIC to surface. Well schematic split in two for illustration purposes, 1/2: Surface to 4,500 ft.

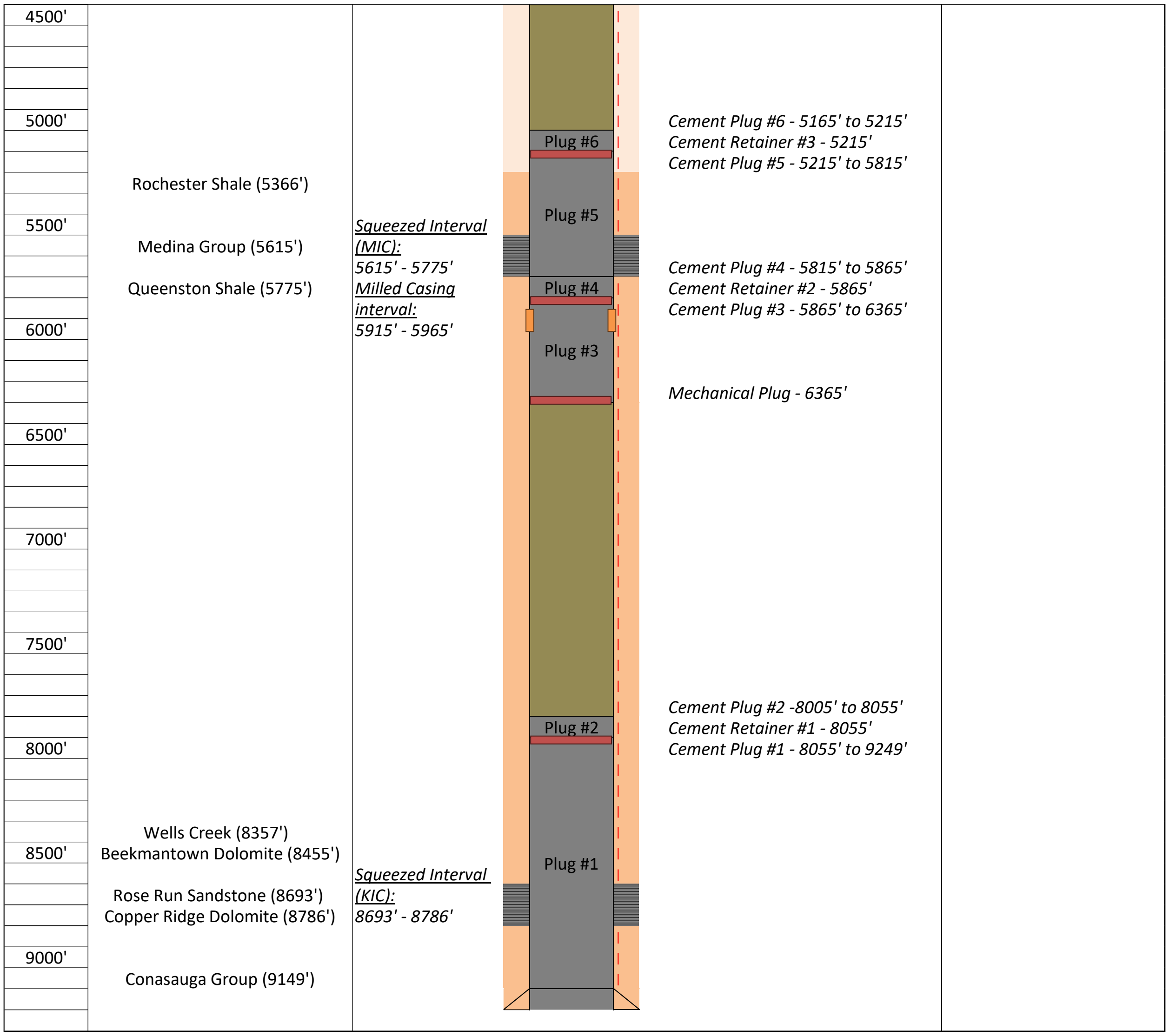

Figure 8: Proposed well schematic for TB1-2 after plugging the MIC to surface. Well schematic split in two for illustration purposes, 2/2: 4,500 ft to 9,300 ft.

5.2.1 Detailed Procedure

The following is a step-by-step procedure for plugging that includes MITs and operations to place cement in the necessary intervals at critical points in the wellbore to ensure no vertical communication of fluids from the injection zone outside of the primary confining zones. This procedure is subject to change to utilize the latest technology and best practices.

1. In compliance with 40 CFR 146.92(c), the UIC Program Director will be notified at least 60 days before plugging commences for the KIC injection zone, after cessation of the planned 30-year injection period and will be provided an updated Injection Well Plugging Plan, if applicable. This notification will include details on historic MIT data and remedial work on the well since inception.

2. Move In Rig Up (MIRU) onto well. All CO_2 pipelines will be marked, locked, and tagged out and noted with rig supervisor prior to mobilization of equipment onto location. Other surface hazards will be marked, removed, or barricaded as appropriate.
3. Conduct and document a safety meeting.
4. Record BHP from downhole gauge and calculate kill fluid density.
5. Open all valves on the vertical run of the tree and check pressures.
6. Rig Up (R/U) to tubing wing valve on tree.
7. Pressure test the pump and line to 5,000 psi against master valve and wing valve at a minimum.
8. Kill Well
    a. Fill tubing with kill weight brine (as determined by BHP measurement). Bleeding off tubing occasionally may be necessary to remove all air from the system. With tubing open to atmosphere, test tubing annulus to 1.1 times anticipated injection pressure and monitor. If there is pressure remaining on tubing, rig to pump down tubing and inject two tubing volumes of kill weight inhibited spacer fluid. Monitor tubing and annulus pressure for 1 hour.
    b. If the well is not dead or the pressure cannot be bled from the tubing, consider heavier kill fluid or displacement using coiled tubing. R/U (Rig Up) slickline and set a plug-in profile nipple. Punch tubing and circulate tubing and annulus with kill weight fluid until the well is dead.
9. R/U slickline and set a plug in profile nipple.
10. Install two-way check valve in tubing hanger and nipple down (N/D) the tree.
11. Nipple up (N/U) BOPs and perform a function test on the BOPs. BOPs should have appropriately sized single pipe rams on top and blind rams in the bottom ram for tubing. Close and pressure test blind rams through BOP side outlet valve. Open blind rams and use tubing pup or joint to test pipe rams. Conduct all tests with fresh water to 250 psi low and the lower of rated working pressure of ram preventer or wellhead component for high pressure test. Low pressure test cannot exceed 350 psi, and both tests must be held for five minutes. Test annular preventer around tubing to 250 psi low and the lower of 70% rated working pressure or maximum allowable surface pressure (MASP) for the high-pressure test. Do not test annular closed over open hole. Test all full open safety valves (TIWs), BOPs choke and kill lines, and choke manifold to 250 psi low and MASP. NOTE: Make sure a casing valve is open during all BOP tests.
12. Remove two-way check valve. Install Back Pressure Valve (BPV) if further kill operations are required.
13. Pull hanger to surface, confirm tubing is dead, and remove BPV.
14. R/U slickline and remove plug from tubing (if previously installed in step 9). Pump kill fluid if needed.
15. Retrieve tubing and completion assembly.
16. Pull out of hole (POOH) with tubing and control lines, laying down as tubing is removed. Record size and amount of tubing, packers, and any other well construction material removed from the well. NOTE: Ensure that the well remains over-balanced for the duration of abandonment. Pump continuously through fill up line and ensure hole fill tracks with displacement. If weighted slug is required to avoid pulling wet, ensure displacement is calculated and accounted for, and sufficient time is allowed for equalization before continuing to POOH.

17. Contingency: If unable to pull packer, R/U wireline to cut the tubing if required. NOTE: Ensure clear and timely communication with UIC Program Director to acquire approval of modified plugging plan if needed.
18. Run in hole (RIH) work string to TD with bit and scraper across long string. Fill tubing every 5 stands, break circulation periodically, and keep the hole full at all times. Work scraper across any tight spots. Ensure well is in static equilibrium by circulating the well and prepare for cement plugging operations. POOH.
19. Perform a retainer squeeze to plug off perforations in the Rose Run Sandstone injection interval using CO_2 resistant cement as discussed in subsection 5.2 above (Plug#1). The CO_2 resistant cement plugs are anticipated to be 14.8 ppg, but final weight will be determined depending on additives used and other desirable cement properties determined by well conditions. Lost Circulation Material may need to be added in the event of losses during cementing. After curing, each cement plug will be pressure tested after setting to verify integrity. The test pressure should not decline by more than ten percent during a thirty-minute test period.
20. Spot 50 ft of CO_2 resistant cement as a balanced plug above the cement retainer to provide an additional seal (Plug #2).
21. Pump inhibited spacer fluid and set a permanent CO_2 corrosion resistant mechanical plug with drill pipe or wireline approximately 400 ft below the bottom of the planned section mill interval.
22. RIH with milling assembly to section mill approximately 50 ft of long string casing from 5,915 ft to 5,965 ft. Mill at least 10 to 20 ft of 22Cr-110 pipe section along with 30 to 40 ft of L80 pipe section. POOH.
23. Set a cement retainer above the milled casing interval. Spot CO_2 resistant cement through the retainer to squeeze and isolate the milled section (Plug #3).
24. Spot 50 ft of CO_2 resistant cement as a balanced plug above the cement retainer, converted to a mechanical plug, to provide an additional seal (Plug #4).
25. Recomplete the well for CO_2 injection into the MIC. Perforate Medina Group injection interval from 5,615 ft to 5,775 ft as discussed in subsection 2.7.3 of the Construction Details for TB1-2. RIH with injection tubing and packer as discussed in subsection 2.5.5 and 2.6 of the Construction Details for TB1-2. N/D BOPs and N/U the tree.
26. Repeat steps 1-18 for pulling tubing and completion after cessation of injection into the MIC.
27. Perform a retainer squeeze to plug off perforations in the Medina Group injection interval using CO_2 resistant cement as discussed in subsection 5.2 above (Plug#5).
28. Spot 50 ft of Class A cement as a balanced plug above the cement retainer, converted to a mechanical plug, to provide an additional seal (Plug #6). Standard oilfield cement (i.e., Class A) will likely be used for a balanced plug. It is anticipated that this will be mixed neat with a slurry weight of 13.5 ppg. Actual cement volume for each plug will depend upon well conditions, completed depths, and finalized casing diameters. Each balanced plug will be tagged after the required wait on cement (WOC) time and topped off if needed.
29. Pump inhibited spacer fluid and spot 500 ft of Class A cement as a balanced plug across the intermediate casing shoe (Plug #7).
30. Pump inhibited spacer fluid and spot 1,015 ft of Class A cement as a balanced plug across the USDW and surface casing to ground level (GL).

31. N/D BOPs and cut all casing strings below plow line (minimum of 5 ft below GL or per local policies/standards and other identified requirements) prior to pumping top plug. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name, well API# and other required information onto lowest casing string at 5 ft below GL, or as per permitting agency directive.
32. Within 60 days after plugging, Tri-State CCS, LLC will submit the plugging report to the UIC Program Director in compliance with 40 CFR 146.92(d) as described in subsection 5.1 above. The Plugging Report will be retained for the following 10 years after site closure.

The procedures described above may be modified during execution as necessary to ensure a plugging operation that prevents any vertical fluid movement, protects worker safety, and protects all identified USDWs. Anticipated changes will be submitted to the UIC Program Director for approval, and any significant modifications due to unforeseen circumstances will be detailed in the Plugging Report as described in subsection 5.1 above.