ATTACHMENT D: INJECTION WELL PLUGGING PLAN

Facility Information

Facility name:	Archer Daniels Midland, CCS#1 Well IL-115-6A-0002
Facility contact:	Mr. Mark Burau, Plant Manager, 4666 Faries Parkway, Decatur, IL, (217) 424-5750, mark.burau@adm.com
Well location:	Decatur, Macon County, IL; 39º 52' 37.06469" N, 88 º 53' 36.25685" W

Injection well plugging and abandonment will be conducted according to the procedures below, which are based on information submitted by ADM in December 2011.

Upon completion of the project, or at the end of the life of the CCS #1 injection well, the well will be plugged and abandoned to meet the requirements at 40 CFR 146.92. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, to resist the corrosive aspects of carbon dioxide/water mixtures, and to protect any USDWs. Prior to plugging the well, any necessary revisions to this approved well plugging plan to address new information will be submitted to the UIC Program Director for review and approval. The final plugging plan will be submitted to the UIC Program Director no later than 60 days prior to the plugging of the well.

Following receipt of the approved plugging plan, the well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure. Bottom hole pressure measurements will be made and the well will be logged and pressure tested to ensure mechanical integrity inside and outside the casing prior to plugging. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with the plugging operations. The detailed plugging procedure is provided below. All casing in this well will be cemented to surface at the time of construction and will not be retrievable at abandonment. The injection tubing and packer will be removed. After the tubing and packer are removed, the balanced-plug placement method will be used to plug the well. If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer and the packer will be left in the well, and the cement retainer method will be used for plugging the injection formation below the abandoned packer.

All of the casing strings will be cut off at least 3 feet 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.

Planned Tests or Measures to Determine Bottom-hole Reservoir Pressure

ADM will record bottom hole pressure from a down hole pressure gauge and calculate kill fluid density.

Planned External Mechanical Integrity Test(s)

ADM will conduct at least one of the following tests to verify external MI prior to plugging the injection well as required in 40 CFR 146.92(a).

Test Description	Location
Temperature Log	Along wellbore using DTS or wireline well log
Noise Log	Wireline Well Log
Oxygen Activation Log	Wireline Well Log

Information on Plugs

The cement(s) formulated for plugging will be compatible with the carbon dioxide stream. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The operator will report the wet density and will retain duplicate samples of the cement used for each plug. Figure 1 presents a plugging schematic.

	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5	Plug #6	Plug #7
Diameter of Boring in Which Plug Will be Placed (inches)	8.681	8.835					
Depth to Bottom of Tubing or Drill Pipe (ft)	7136	4000					
Sacks of Cement to be Used (each plug)	1161	1443					
Slurry Volume to be Pumped (cu. ft)	1289	1702					
Slurry Weight (lb/gal)	15.9	15.9					
Calculated Top of Plug (ft)	4000	Surface					
Bottom of Plug (ft)	7000	4000					
Type of Cement or Other Material	CO_2 resistant	Class A					
Method of Emplacement (e.g., balance method, retainer method, or two-plug method)						Balance Method	

Narrative Description of Plugging Procedures

Notifications, Permits, and Inspections

Notifications, permits, and inspections procedures will include:

1. In compliance with 40 CFR 146.92(c), notify the regulatory agency at least 60 days before plugging the well and provide updated plugging plan, if applicable.

2. Move-in (MI) Rig onto CCS #1 and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI. Ensure all overhead restrictions (e.g., power lines, telephone lines) have been previewed and managed prior to MI and RU.

3. Conduct and document a safety meeting for entire crew. Document date and time of safety meeting and retain records on site.

4. Record bottom hole pressure from down hole gauge and calculate kill fluid density.

5. Open up all valves on the vertical run of the tree and check pressures.

6. Test the pump and line to 2,500 psi. Fill tubing with kill weight brine (9.5 ppg or determined by bottom hole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system. Test casing annulus to 1000 psi and monitor as in annual MIT. If there is pressure remaining on tubing rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.

7. If the well is not dead or the pressure cannot be bled off of tubing, rig up (RU) slickline and set plug in lower profile nipple below packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, nipple down tree, nipple up blow-out preventers (BOPs), and perform a function test. BOP's should have 4 ½ inch single pipe rams on top and blind rams in the bottom ram for tubing. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all Texas Iron Works (pressure valve), BOP's choke and kill lines, and choke manifold to 250 psi low and 3,000 psi high. NOTE: Make sure casing valve is open during all BOP tests**.** After testing BOPs pick up tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and circulate until well is dead.

8. RU 4 ½" rig hydraulic tubing tongs for handling of production tubing. Pick back up on tubing string and pull seal assembly from seal bore. Pull hanger to floor and remove same. Circulate bottoms up with packer fluid.

9. Pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are at least 2 well control barriers in place at all times. Cut and remove control lines while pulling out of hole. Lay down all downhole equipment including PS3, gauge mandrel, and seal assembly.

10. Pick up workstring, and trip in hole (TIH) with the packer retrieving tools. Latch onto the packer and pull out of hole laying down same. Next, confirm the well's mechanical integrity by performing one of the permitted external mechanical integrity tests presented in the table under "Planned External Mechanical Integrity Test(s)" above.

    Contingency: If unable to pull seal assembly, RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. If unable to pull the packer, pull the work string out of hole and proceed to next step. If problems are noted, update cement remediation plan (if needed) and execute prior to plugging operations.

11. TIH with work string to total depth (TD). Keep the hole full at all times. Circulate the well and prepare for cement plugging operations.

    The lower section of the well will be plugged using CO_2 resistant cement from TD at 7136 ft to 1000 ft above the top of the Eau Claire formation (4000 ft). This will be accomplished by placing plugs in 500 ft incremental lifts. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 1326 sacks of cement will be required. The 9 5/8 inch casing is 47#/ft to 5272 ft and 40#/ft from 5272 ft to surface. It is anticipated that at least six plugs of 522 feet in length will be necessary. No more than two plugs will be set before cement is allowed to set and plugs verified by setting work string weight down onto the plug. (Calculations are as follows: PBTD 7136-5272=1864 ft X .4110 cu. ft./ft/ 1.11 cu. ft/sk=690 sacks; 5272-4000=1272 X .4110 cu. ft./ft. / 1.11 cu. ft. /sk = 471 sks; Total amount of CO_2 resistant cement = 690 + 471 = 1161 sacks.)

12. Circulate the well and ensure it is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 9 5/8 inch casing (approximately 190 sacks Class A/H mixed at 15.9 ppg with yield 1.18 cu ft/sk). Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 8 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. After waiting overnight, trip back in hole and tag plug and continue. After ten plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. *Calculate volume for final plug*. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (min 3 feet below ground level or per local policies/standards and ADM requirements). Trip in well and set final cement plug. Total of approximately 1,443 sacks total cement used in all remaining plugs above 4000 feet. 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 onto lowest casing string at 3 feet, or as per permitting agency directive. (Calculations assume 40#/ft casing and no excess because

this section is inside the intermediate casing 4000 ft x .4257 cu ft/ft / 1.18 cu ft/sk = 1443 sacks Class A cement.)

13. The procedures described above are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect USDWs, and any significant modifications due to unforeseen circumstances will be described in the Plugging report. Complete plugging forms and submit with charts and all lab information to the regulatory agency as required by permit. Plugging report shall be certified as accurate by ADM and plugging contractor, and shall be submitted within 60 days after plugging is completed.

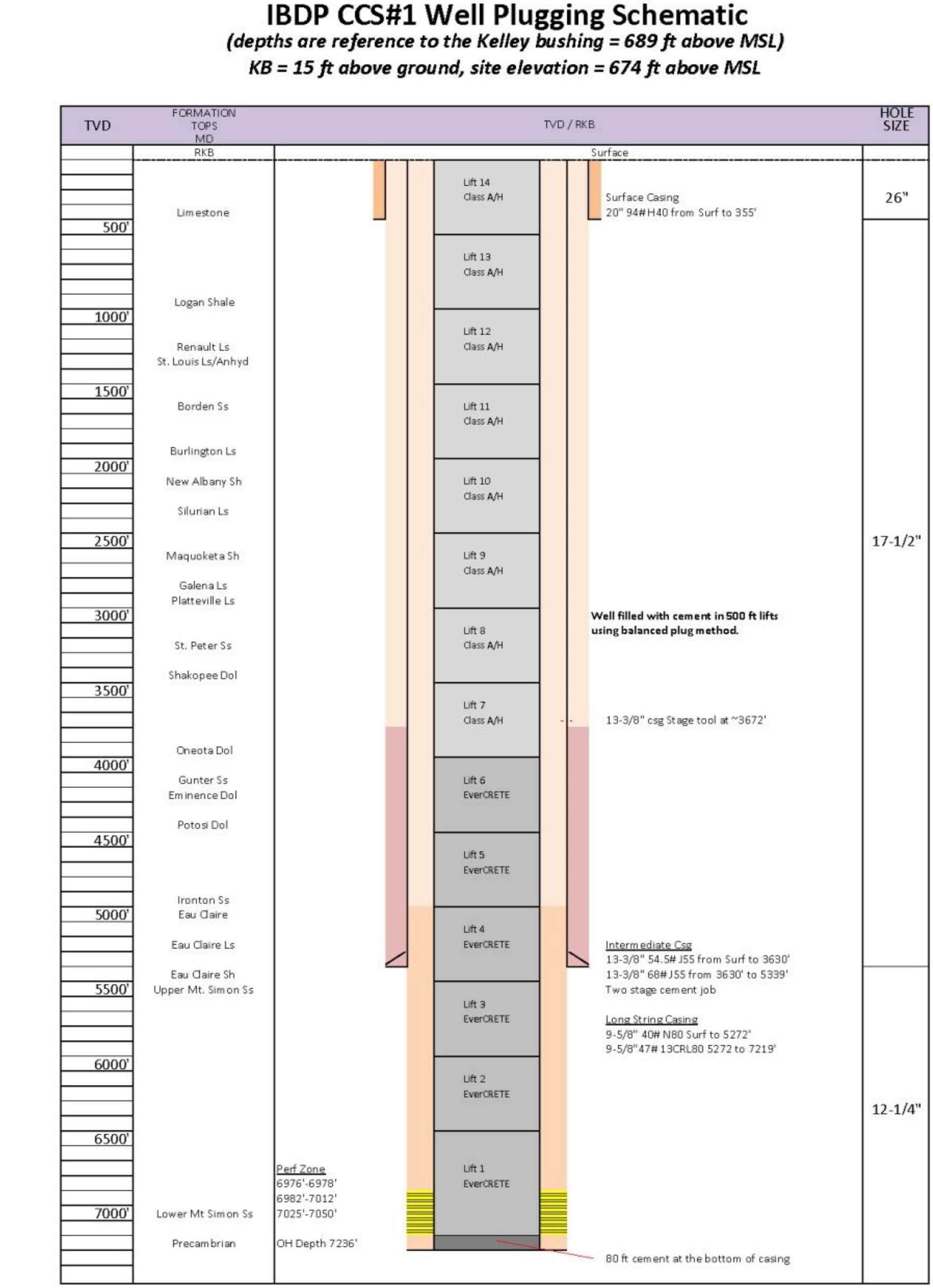

Figure 1. CCS#1 Injection Well Plugging Schematic.