ATTACHMENT E

Injection Well Plugging Plan

Gulf Coast Sequestration, LLC (G1037)

Project Minerva, Cameron Parish
Minerva South CCS Well Nos. 001 & 002

EPA Project Id: R06-LA-0002

LDENR Appl Nos: 45031 & 45032

Date: November 2024

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FACILITY INFORMATION

Facility Name: Minerva Facility

Injection Wells: Minerva South CCS Well No. 001 (MS CCS 1)
Minerva South CCS Well No. 002 (MS CCS 2)

Facility Contact: David Cook, CEO
5599 San Felipe Street, Suite 1450, Houston, Texas 77056
(713) 419-6808; dcook@gcscarbon.com

Well Locations: Sec 3, T12S, R13W, Cameron Parish, Louisiana

MS CCS 1 (North American Datum (NAD) 1927)
Surface: 30° 02' 34.10"W, -93° 40' 20.63"N
Bottom-Hole: 30° 02' 34.10"W, -93° 40' 20.63"N
MS CCS 2 (NAD 1927)
Surface: 30° 02' 33.84"W, -93° 40' 20.48"N
Bottom-Hole: 30° 02' 13.74"W, -93° 40' 42.07"N

1 INTRODUCTION

Gulf Coast Sequestration (GCS) will conduct injection well plugging and abandonment according to the following sections.

2 PLANNED TESTS OR MEASURES

2.1 BOTTOM-HOLE RESERVOIR PRESSURE (BHP)

GCS will record bottom hole pressure using a downhole pressure gauge and calculate kill fluid density.

2.2 MECHANICAL INTEGRITY TESTING (MIT)

2.2.1 Internal

At the end of injection activities, an (internal) pressure test can be performed with the tubing in-place, still connected to the packer. The pressure inside the 9 ⅝” long string casing can be increased to a value above the standard pressure applied during injection.

The tubing/casing annular pressure will be maintained with a pressure that exceeds the operating injection pressure. These test pressures can be read on the 0-5,000 psi gauges installed on the wing outlets valves for the tubing and tubing-casing annulus.

2.2.2 External

A final DTS MIT will be performed prior to plugging, in accordance with the procedure outlined in the Testing and Monitoring Plan (Attachment D). If there are any temperature anomalies that may indicate a failure of well integrity (i.e. tubing leak or movement of fluid behind the casing), GCS will submit a Form UIC-17 Work Permit within 30 days of identification and propose to run at least one of the alternate tests described in Table E.2.2-1.

3 PLUGGING INFORMATION

GCS will use the materials and methods noted in Table E.3-1 to plug MS CCS 1 and MS CCS 2. The volume and depth of the plug or plugs will depend on the well's final geology and downhole conditions as assessed during construction. The cement(s) formulated for plugging will be compatible with the carbon dioxide stream. The cement formulation and required certification documents will be submitted with the well-plugging plan to the agency. GCS will report the wet density and will retain duplicate samples of the cement used for each plug.

3.1 VOLUME CALCULATION METHODS

The well will be flushed with a brine fluid of a specific weight designed to kill and control the well from any flow or pressure up. The brine fluid will be injected at least three times the volume of the tubing without exceeding the fracture pressure. The specific weight of brine fluid to be used for final displacement will be dictated by final mud weight used to drill to total depth and final observation of pore pressure values. The objective is to keep well on balance. A final external Mechanical Integrity Test (MIT) will be performed to ensure that the well is mechanically plugged.

Before installing bridge plugs and starting the cement plugs operations, the tubing and packer will be pulled out of the well. All the casing in this well will be cemented to the surface and will not be retrieved at abandonment.

Well cementing software will be used to model the sealing and verify the plug designs. Lab test will be conducted before plugging operations. Slurry samples will be kept at the well site as proof of cement / plug quality. All casings will cut off at least 3 feet below the surface, below the plow line. Then, a blanking plate will be welded with the necessary permit information to the top of the cutoff casing.

Volumes will be calculated for specific abandonment of wellbore environments based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

Choose the following:

- Length of the cement plug desired
- Desired setting depth of base of plug
- Amount of spacer necessary to be pumped ahead of the slurry

Determine the following:

- Number of sacks of cement required (yield)
- Volume of spacer to be pumped behind the slurry to balance the plug

- Plug length before the pipe is withdrawn
- Length of mud freefall in drill pipe
- Displacement volume required to spot the plug (depending on the Tubing / Drill pipe specs)

Field cementing and wellsite supervisor will both review calculations prior to spotting any plug.

4 DESCRIPTION OF PLUGGING AND ABANDONMENT PROCEDUES

4.1 NOTICE OF INTENT TO PLUG

In compliance with LAC 43:XVII§3631.A.4, GCS will submit the Form UIC-17, or successor form, to the commissioner and receive written approval from the commissioner before beginning actual well plugging operations. The form will contain information on the procedures to be used in the field to plug and abandon (P&A) the well.

4.2 PLUGGING PROCEDURES

Pre-Closure and Post-Closure Well Schematics for MS CCS1 and MS CCS2 are shown in Figures E.4-1, E.4-2, E.4-3 and E.4-4.

GCS will use the materials and methods noted in Table E.3-1 to plug the injection well. It is assumed there will be three primary intervals perforated for CO_2 injection. The plugging plan will be performed via a bottom-up sequence.

4.2.1 Proposed P&A Procedure for MS CCS 1 and MS CCS 2

Appendices E-I-1 and E-I-2 detail the proposed P&A Procedure for MS CCS 1 and MS CCS 2, process to plug each perforated interval and potential contingencies.

4.2.2 Cementing Protocols

Plug-and-abandonment (P&A) cementing operations should occur when fluids in the wellbore are at balance with the exposed formation (in this case, via perforations in the long string). Water is the major component of the working fluid and is the liquid component of the cement. Water is effectively incompressible. The density difference between the work fluid and fluid cement will not disrupt the placement of cement. A barrel of water introduced into a closed system will cause one barrel of water to be displaced out of the system.

The cement in fluid form will be precisely placed by accurately measuring the volumes of spacer, cement, and work fluid so that the cement height outside the work string will match the height inside the work string. As soon as the cement is in place, the workstring will be slowly pulled from the still-fluid cement mixture, leaving a cement column of a known height.

The interval depths, length, and method to place every cement plug is described in Table

E.3-1. For Plugs #1-#3 (within the Injection Zone), PermaSet™ Cement System (or equivalent) will be used because it is resistant to CO_2 and H_2S. For more details about the PermaSetTM Cement System, refer to Appending E-II. For Plugs #4 and #5 (above the Confining Zone), Class H Cement will be utilized. The following additives will be included to the Class H cement slurry to improve to the resistance to CO_2: Tricalcium Silicate (C_3S), Dicalcium silicate (C_2S), Tricalcium Aluminate (C_3A), Tetra calcium aluminoferrite (C_4AF). Subject to final vendor selection; chemical composition and non-corrosive additives will all be reviewed.

4.2.3 Plugging Protocols

Table E.3-1 details the plugging details for MS CCS 1 and MS CCS 2. For each plug, the relevant perforation interval, retainer depth, volume, placement method and cement type are described.

Each plug will be tagged and seal tested to prove its location and competency. This process will confirm each plug is successfully placed and ensure the future protection of the USDW.

4.2.4 Contingencies

Detailed contingencies are listed for possible scenarios that may occur while implementing various steps listed in Appendices E-I-1 and E-I-2 (Proposed P&A Procedures).

Table E.4.2-1 also lists potential issues and contingent actions.

4.3 ABANDONMENT PROCEDURES

Once plugging placement is completed and pressure tested, work string will be laid down. All equipment will be rigged down and moved out. Casing will be cut 15’ below the ground. Cellar will be cleaned so a plate with relevant well information can be welded on.

5 WELL CLOSURE REPORTS

In compliance with LAC 43:XVII§3631.A.5, GCS will submit a Well Closure Report to the commissioner within 30 days after well plug and abandonment. The report will detail the procedures of the closure operation and specify any differences between the original plan and actual closure. The report will also include relevant state regulatory reporting forms and information related to the closure activity, such as final schematics, tests and monitoring data.

Table E.2.2-1 Planned and Alternate External Mechanical Integrity Tests

	Test	Location	Test Description	Pass/Fail Criteria
Primary	**Distributed Temperature Sensing (DTS)**	9 ⅝" Casing	Fiber Optic Cable used as the primary method to detect fluid movement or integrity issues behind the casing, by monitoring temperature changes over time.	Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.
Alternates (If Required)	**Noise Log**	9 ⅝" Casing	Noise logging is used primarily for channel detection, but has also been used to measure flow rates, identify open perforations. The log may be either a continuous record against depth or a series of stationary readings. The log may indicate the total signal over all frequencies, the signal at a single frequency, or consist of a set of logs for different frequency ranges. Different frequency ranges can be tied to different sources of noise or different flow regimes. This will be run on wireline.	Any high/low frequency change on a continuous or stationary log is an indication of a failure condition,such as fluid movement behind the pipe (tubing/casing) or might infer a leak in the casing or mico annulus.
	Temperature Decay Log	9 ⅝" Casing	A record of the temperature gradient in a well. The temperature log is interpreted by looking for anomalies, or departures, from the reference gradient. This reference might be the geothermal gradient, a log recorded before production started or a log recorded with the well shut-in. Since the temperature is affected by material outside the casing, a temperature log is sensitive to not only the borehole but also the formation and the casing formation annulus. This may be run on wireline or on DTS installed behind casing.	Temperature changes with respect to the geothermal gradient represent anomolies related to the entry of fluids into the borehole or fluid exit in the formation, such as casing integrity issues, channels, micro annulus
	Oxygen Activation Log *Spectral Pulsed Neutron (SPN)*	9 ⅝" Casing	SPN tools can perform a service called HydroLog. HydroLog describes a mode of operation where the neutron generator produces shots or periodic neutron bursts to activate oxygen's nuclear response in reservoir rock and fluids. Multiple detectors spaced vertically with known distance monitor the oxygen spectrum response. If fluids are moving, then a shift in the timing of the oxygen response is detected across the detectors. This method can detect fluid flows as slow as 3-4 ft /min (fluid movement detection is dependent on cross-sectional area of the channel. Assuming fluid velocity is constant, a larger flow area is easier to detect. Oxygen activation testing establishes a "PASS / FAIL" criterion as to whether the fluids are moving or are stationary based on the measurement location and a threshold on velocity.	Lag in the nuclear response between source and detector indicating fluid flowing faster than 4 ft/min above the confining zone will be considered a fail

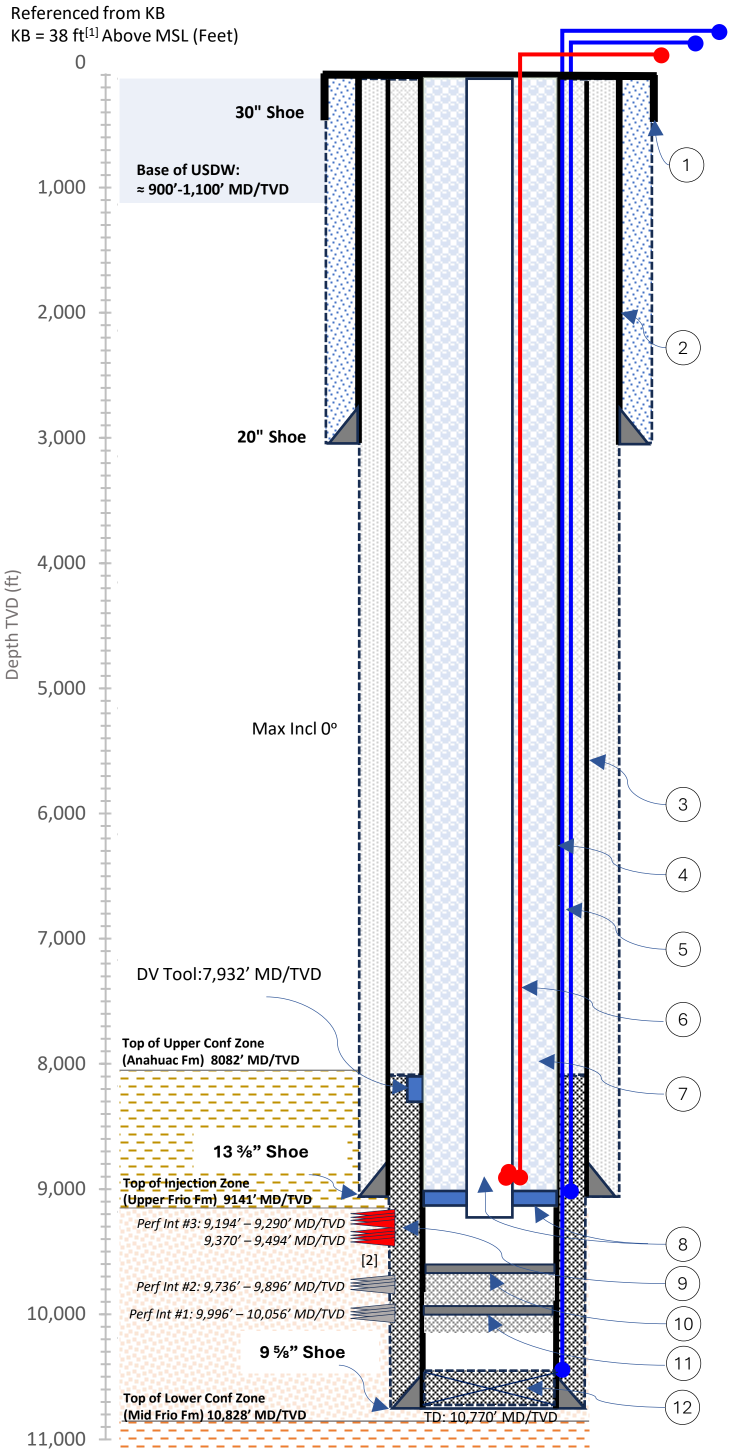
Table E.3-1 Plugging Details for MS CCS 1 and MS CCS 2

Plug Details		MS CCS 1	MS CCS 2
Plug #1 Inside 9 ⅝" Casing - 8.681" ID	Perf Interval	9,996' MD–10,056' MD/TVD	10,662' MD -10,722' MD 9.870' TVD – 9.930' TVD
	Retainer Depth	≈ 9,996' MD/TVD	≈ 10,662' MD / 9,870' TVD
	Top of Cement	≈ 9,926' MD/TVD	≈10,592' MD ≈ 9,800' TVD
	Volume	13.8 bbls / 77.4 cuft / 70 sacks	13.8 bbls / 77.4 cuft / 70 sacks
	Placement Method	Squeezed below and above Packer	Squeezed below and above Packer
	Cement Type	14.8 ppg PermaSet System Cement (or equivalent CO_2 corrosion-resistant cement) + 0.07% bwoc Static Free (Aids cement bulk delivery & prevent caking/clumping) + 1 gps BA-86L (provides fluid loss control, low viscosity, enhanced bonding, and acid resistance) + 0.02 gps FP-6L (foam prevention) + 0.2% bwoc ASA-301 (reduce or eliminate free water and settling in cement slurries) + 0.8% bwoc FL-66 (fluid loss control across rage on temperatures) + 0.35% bwoc R-21 (cement retarder used to control the thickening time of a cement slurry) + 36.4% Fresh Water. Volume ft^3 / 1.12 Sacks Volume Factor	
Plug #2 Inside 9 ⅝" Casing - 8.681" ID	Perf Interval	9,736' MD/TVD – 9,896' MD/TVD	10,385' MD – 10,562' MD 9,593' TVD – 9,770' TVD
	Retainer Depth	≈ 9,734' MD/TVD	≈10,383' MD / 9,591' TVD
	Top of Cement	≈ 9,734' MD/TVD	≈ 10,383' MD / 9,591' TVD
	Volume	23.7 bbls / 133.2 cuft / 119 sacks	26.2 bbls / 147.2 cuft / 131 sacks
	Placement Method	Squeezed below Packer	Squeezed below Packer
	Cement Type	14.8 ppg CO_2 corrosion-resistant cement slurry + 0.07% bwoc Static Free (Aids cement bulk delivery & prevent caking/clumping) + 1 gps BA-86L (provides fluid loss control, low viscosity, enhanced bonding, and acid resistance) + 0.02 gps FP-6L (foam prevention) + 0.2% bwoc ASA-301 (reduce or eliminate free water and settling in cement slurries) + 0.8% bwoc FL-66 (fluid loss control across rage on temperatures) + 0.35% bwoc R-21 (cement retarder used to control the thickening time of a cement slurry) + 36.4% Fresh Water. Volume ft^3 / 1.12 Sacks Volume Factor	
Plug #3 Inside 9 ⅝" Casing - 8.681" ID	Perf Interval	9,194' MD/TVD – 9,290' MD/TVD and 9,370' MD/TVD – 9,494' MD/TVD	10,024' MD –10,142' MD, 9,232' TVD – 9,350' TVD and 9,833' MD –9,944' MD, 9,041' TVD – 9,152' TVD
	Retainer Depth	≈ 9,192' MD/TVD	≈ 9,831' MD / 9,039' TVD
	Top of Cement	≈ 7,870' MD/TVD	≈ 8,440' MD / 7,648' TVD
	Volume	141 bbls / 791.6 cuft / 707 sacks	141 bbls / 791.6 cuft / 707 sacks
	Placement Method	Squeezed below and above Packer	Squeezed below and above Packer
	Cement Type	14.8 ppg CO_2 corrosion-resistant cement slurry + 0.07% bwoc Static Free (Aids cement bulk delivery & prevent caking/clumping) + 1 gps BA-86L (provides fluid loss control, low viscosity, enhanced bonding, and acid resistance) + 0.02 gps FP-6L (foam prevention) + 0.2% bwoc ASA-301 (reduce or eliminate free water and settling in cement slurries) + 0.8% bwoc FL-66 (fluid loss control across rage on temperatures) + 0.35% bwoc R-21 (cement retarder used to control the thickening time of a cement slurry) + 36.4% Fresh Water. Volume ft^3 / 1.12 Sacks Volume Factor	
Plug #4 Inside 9 ⅝" Casing - 8.681" ID	Plug Interval	1,500' MD/TVD –3,000' MD/TVD	1,500' MD/TVD –3,000' MD / 2,991' TVD
	Retainer Depth	≈ 3,100' MD/TVD	≈ 3,100' MD / 3,087' TVD
	Top of Cement	≈ 1,600' MD/TVD	≈ 1,600' MD/TVD
	Volume	117.1 bbls / 658 cuft / 619 sacks	117.1 bbls / 658 cuft / 619 sacks
	Placement Method	Spotted above Cast Iron Bridge Plug	Spotted above Cast Iron Bridge Plug
	Cement Type	16.4 ppg Class H Cement + 0.07% bwoc Static Free (Aids cement bulk delivery & prevent caking/clumping) + 0.3% bwoc R-3 (retarder) + 0.02 gps FP-6L (foam prevention) + 60.1% Fresh Water. Volume ft^3 / 1.06 Sacks Volume Factor	
Plug #5 Inside 9 ⅝" Casing - 8.681" ID	Perf Interval	0' MD/TVD –1,500' MD/TVD	0' MD/TVD –1,500' MD/TVD
	Top of Cement	0' MD/TVD	0' MD/TVD
	Volume	109.8 bbls / 617 cuft / 581 sacks	109.8 bbls / 617 cuft / 581 sacks
	Placement Method	Spotted above TOC	Spotted above TOC
	Cement Type	16.4 ppg Class H Cement + 0.07% bwoc Static Free (Aids cement bulk delivery & prevent caking/clumping) + 0.3% bwoc R-3 (retarder) + 0.02 gps FP-6L (foam prevention) + 60.1% Fresh Water. Volume ft^3 / 1.06 Sacks Volume Factor	

Table E.4.2-1 Potential Issues during P&A and Contingent Actions

Issue	Contingent Action
Encounter perforation interval blocked or unable to pass while calibration (before placing retainer)	POOH tubing, install and run 8 ¾" mill with cleanout BHA and run to well TD or previous TOC to ensure interval free and have control of volume to pump.
No admission on intervals during injection test (before squeezing cement)	Set up a cement plug filling the casing along the interval with a control volume and set up a retainer on the top. Retainer at the top of every interval is already on the plan. Cement on top of the retainer will be possible only if the is enough length to the base of the next interval above.
Encounter TOC between intervals too high in the well, blocking the interval above	Install and run 8 ¾" mill and clean out BHA to mill, cement up to the required depth. Important to run the casing scrapper to ensure the casing wall is clean to set the packer without issues.
Well flow back due to unbalanced conditions	Before P&A operations, ensure to collect site specific data of formation pressure, bottom hole pressure, and temperature to utilize proper control fluid (ppg)

Figure E.4-1 Proposed Pre-Closure Well Schematic - Minerva South CCS Well No. 001



[1] Assumed KB height of 38' above MSL, value will be updated when rig is selected

1. 30" Conductor Pipe: 1.0" WT, 28" ID, 310.3 lb/ft, X-56 Welded, plain-end, beveled conductor with drive shoe driven to refusal at 150' MD/TVD

2. 20" Surface Casing: 133 lb/ft, L-80, ER at 3,000' MD/TVD. 26" Hole. Expected MW 9.00 ppg WBM. Cemented with Type-1 cement up to the surface; Lead slurry 11.80 ppg (2,618 sacks, 2.71 cuft/sack); Tail slurry 14.8 ppg (1,427 sacks, 1.33 cuft/sack). Assumed 100% excess volume.

3. 13 ⅜" Intermediate Casing: 13 ⅜", 68 lb/ft, L-80 BTC from section TD to surface. 17 ½" Hole at 8,991' MD/TVD. Expected MW 10.00 ppg SBM. Cemented with Class H cement up to surface; Lead slurry 12.80 ppg (3,354 sacks; 2.10 cuft/sack); Tail slurry 14.8 ppg (1,437 sacks; 1.33 cuft/sack). Assumed 50% excess volume in open hole section.

4. 9 ⅝" Injection Casing: 9 ⅝", 53.5 lb/ft, 25CRW-125 VAM-21, Prem Connection from 10,770' MD/TVD (Well TD) to 7,932' MD/TVD (150' above Top of Confining zone) & 53.5 lb/ft, L-80 VAM-21, Premium connection from 7,932' MD/TVD to surface. 12 ¼" Hole to 10,770' MD/TVD. Expected MW 13.50 ppg SBM.

Cemented in two stages:
Stage #1: CO_2 corrosion-resistant cement slurry (PermaSet or equivalent), 14.8 ppg (1,011 sacks; 1.12 cuft/sack). Expected TOC at 7,932' MD/TVD. (DV tool). Assumed 20% excess.

Stage #2: 12.5 ppg (2,053 sacks; 1.24 cuft/sack) Class H cement lead slurry + 14.8 ppg (100 sacks; 1.12 cuft/sack) CO_2 corrosion-resistant cement tail slurry. Cement up to the surface. No volume excess is assumed.

5. DTS/DAS Fiber Optic Cable: Downhole cable with a 150 ºC temperature rating, 2 single-mode fiber acrylate clamped outside the 9 ⅝" casing from surface to TD.

Back-up fiber optic cable will be set up from surface to the depth of the intermediate casing shoe.

6. TEC (Electrical Cables): Downhole cable attached outside of the tubing, with pressure/temperature gauge carriers. Downhole measurements in two locations – annulus and tubing; minimum pressure and temperature ratings of 10k psi and 150º C.

7. Packer fluid: 8.5 ppg $CaCl_2$ inhibited brine with corrosion control (98% MgO, magnesium oxide).

8. Tubing and Packer: 4 ½" Tubing, 15.1 lb/ft, 25CRW-125, VAM-21. End of tail at 9,100' MD/TVD; Removable Production packer at 9,050' MD/TVD; if required a SCSSV 4 ½" with a 7.403" OD, 3.688" ID at base of USDW ≈ 1,100' MD/TVD; Tubing hanger at ground level.

9. Perforations Interval #3: 9,194' – 9,290' MD/TVD and 9,370 – 9,494' MD/TVD. Oriented perforation system.

P&A Perforation Interval #2 (9,736' MD/TVD – 9,896' MD/TVD)

10. Plug #2: 9 ⅝" Squeeze Packer assumed at ≈ 9,734' MD/TVD 14.88 ppg CO_2 corrosion-resistant cement squeezed below packer to isolate Interval #2; 133.2 cuft/23.7 bbls/119 sacks.

P&A Perforation Interval #1 (9,996' MD/TVD–10,056' MD/TVD)

11. Plug #1: 9 ⅝" Squeeze Packer assumed at ≈ 9,996' MD/TVD. 14.88 ppg CO_2 corrosion-resistant cement squeezed below packer to isolate Interval #1; 49.4 cuft/8.8 bbls/45 sacks. Sting out of Squeeze Packer. Squeeze cement above Packer, 28 cuft/5 bbls/25 sacks.

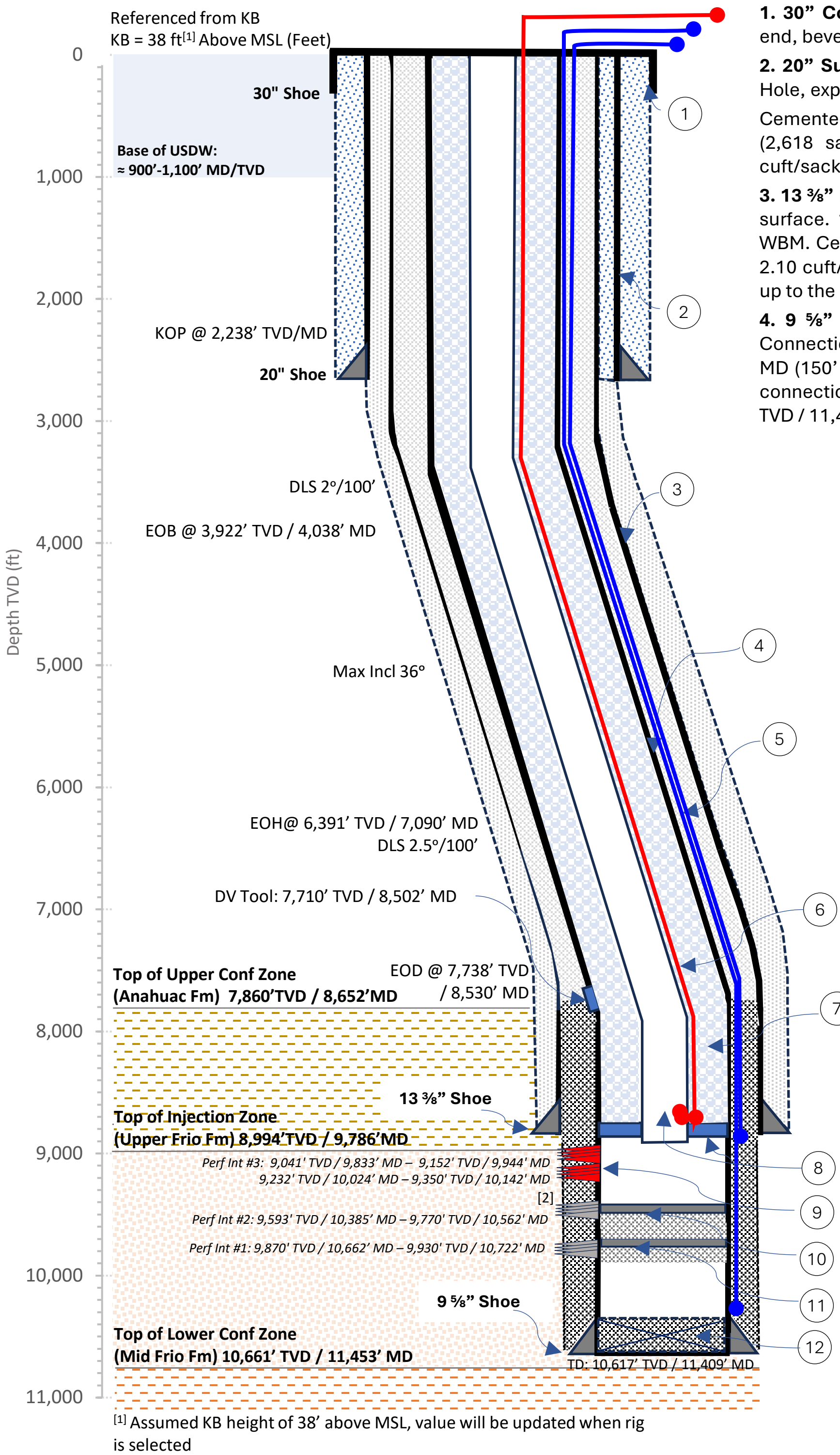
12. Plug back TD: From 10,770' MD/TVD (Shoe Depth) to 10,690' MD/TVD (Float Collar). Shoe Track

LEGEND

USDW	Type 1 Cement
Upper Confining Zone (Anahuac Fm)	Class H Cement
Injection Zone (Upper Frio Fm)	CO_2 Corrosion-Resistant Cement
Lower Confining Zone (Mid Frio Fm)	CO_2 Corrosion-Resistant Cement and Class H Cement
	$CaCl_2$ Inhibited Brine with Corrosion Control

[2] Oriented Perforation System, included to avoid damage to fiber optic cable

Figure E.4-2 Proposed Pre-Closure Well Schematic - Minerva South CCS Well No. 002



[1] Assumed KB height of 38' above MSL, value will be updated when rig is selected

1. 30" Conductor Pipe: 1.0" WT, 28" ID, 310.3 lb/ft, X-56 Welded, plain-end, beveled conductor with drive shoe driven to refusal at 150' MD/TVD.

2. 20" Surface Casing: 133 lb/ft, L-80, ER at 2,991' TVD /3,000' MD. 26" Hole, expected MW 9.00 ppg WBM.

Cemented with Type-1 cement up to the surface. Lead slurry 11.80 ppg (2,618 sacks; 2.71 cuft/sack); Tail slurry 14.8 ppg (1,427 sacks; 1.33 cuft/sack). Assumed 100% volume excess.

3. 13 ⅜" Intermediate Casing: 13 ⅜", 68 lb/ft, L-80 BTC from section TD to surface. 17 ½" Hole at 8,844' TVD / 9,636' MD. Expected MW 10.00 ppg WBM. Cemented with Class H cement. Lead slurry 12.80 ppg (3,608 sacks; 2.10 cuft/sack) + Tail slurry 14.8 ppg (1,542 sacks; 1.33 cuft/sack). Cement up to the surface. Assumed 50% excess volume in open hole section.

4. 9 ⅝" Injection Casing: 9 ⅝", 53.5 lb/ft, 25CRW-125 VAM-21, Prem Connection from 10,617' TVD / 11,409' MD (Well TD) to 7,710' TVD / 8,502' MD (150' above Top of Confining zone) & 53.5 lb/ft, L-80 VAM-21, Premium connection from 7,710' TVD / 8,502' MD to surface. 12 ¼" Hole to 10,617' TVD / 11,409' MD. Expected MW 13.50 ppg WBM.

Cemented in two stages:
Stage #1: CO_2 corrosion-resistant cement slurry (PermaSet or equivalent) 14.8 ppg (1,027 sacks; 1.12 cuft/sack). Expected TOC at 7,710' TVD / 8,502' MD. (DV tool). Assumed 20% excess volume in open hole section.
Stage #2: 12.5 ppg (2,207 sacks; 1.24 cuft/sack) Class H cement lead slurry + 14.8 ppg (100sacks; 1.12 cuft/sack) CO_2 corrosion-resistant cement tail slurry. Cement up to the surface. No excess volume was considered.

5. DTS/DAS Fiber Optic Cable: Downhole cable with a 150 ºC temperature rating, 2 single-mode fiber acrylate clamped outside the 9 ⅝" casing from surface to TD.
Back-up fiber optic cable will be set up from the surface to the depth of the intermediate casing shoe.

6. TEC (Electrical Cables): Downhole cable attached outside of the tubing, with pressure/temperature gauge carriers. Downhole measurements in two locations – annulus and tubing; minimum pressure and temperature ratings of 10k psi and 150º C.

7. Packer fluid: 8.5 ppg $CaCl_2$ inhibited brine with corrosion control (98% MgO, magnesium oxide).

8. Tubing and Packer: 4 ½" Tubing, 15.1 lb/ft, 25CRW-125, VAM-21, End of tail at 8,938' TVD / 9,730' MD; Removable Production packer at 8,888' TVD / 9,680' MD; if required a SCSSV 4 ½" with a 7.403" OD, 3.688" ID at base of USDW ≈ 1,100' MD/TVD; Tubing hanger at ground level.

9. Perforations Interval #3: 9,041' TVD / 9,833' MD – 9,152' TVD / 9,944' MD and 9,232' TVD / 10,024' MD – 9,350' TVD / 10,142' MD. Oriented perforation system.

P&A Perforation Interval #2
(9,593' TVD / 10,385' MD – 9,770' TVD / 10,562' MD)

10. Plug #2: 9 ⅝" Squeeze Packer assumed at ≈ 9,552' TVD/10,345' MD. 14.88 ppg CO_2 corrosion-resistant cement squeezed below Packer to isolate Interval #2; 147.2 cuft/26.2 bbls/131 sacks.

P&A Perforation Interval #1
(9,870' TVD / 10,662' MD – 9,930' TVD / 10,722' MD)

11. Plug #1: 9 ⅝" Squeeze Packer assumed at ≈ 9,832' TVD/ 10,624'MD. 14.88 ppg CO_2 corrosion-resistant cement squeezed squeezed below packer to isolate Interval #1; 49.4 cuft/8.8 bbls/45 sacks. Sting out of Squeeze Packer. Squeeze cement above Packer, 28 cuft/5 bbls/25 sacks.

12. Plug back TD: From 11,409' MD / 10,617' TVD (Shoe Depth) to 11,329' MD / 10,537' TVD (Float Collar). Shoe Track

LEGEND

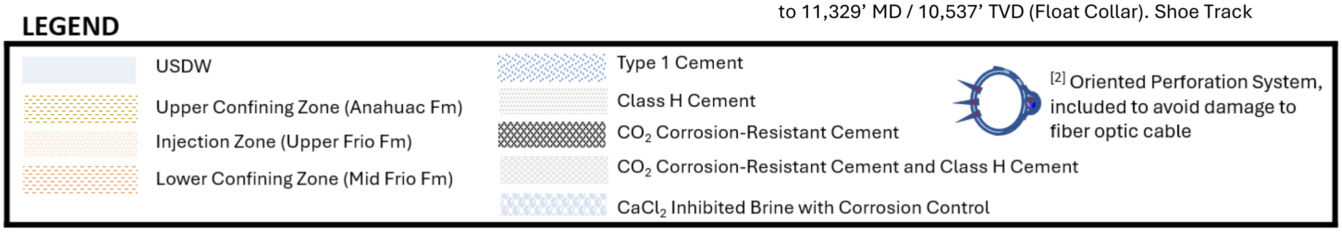
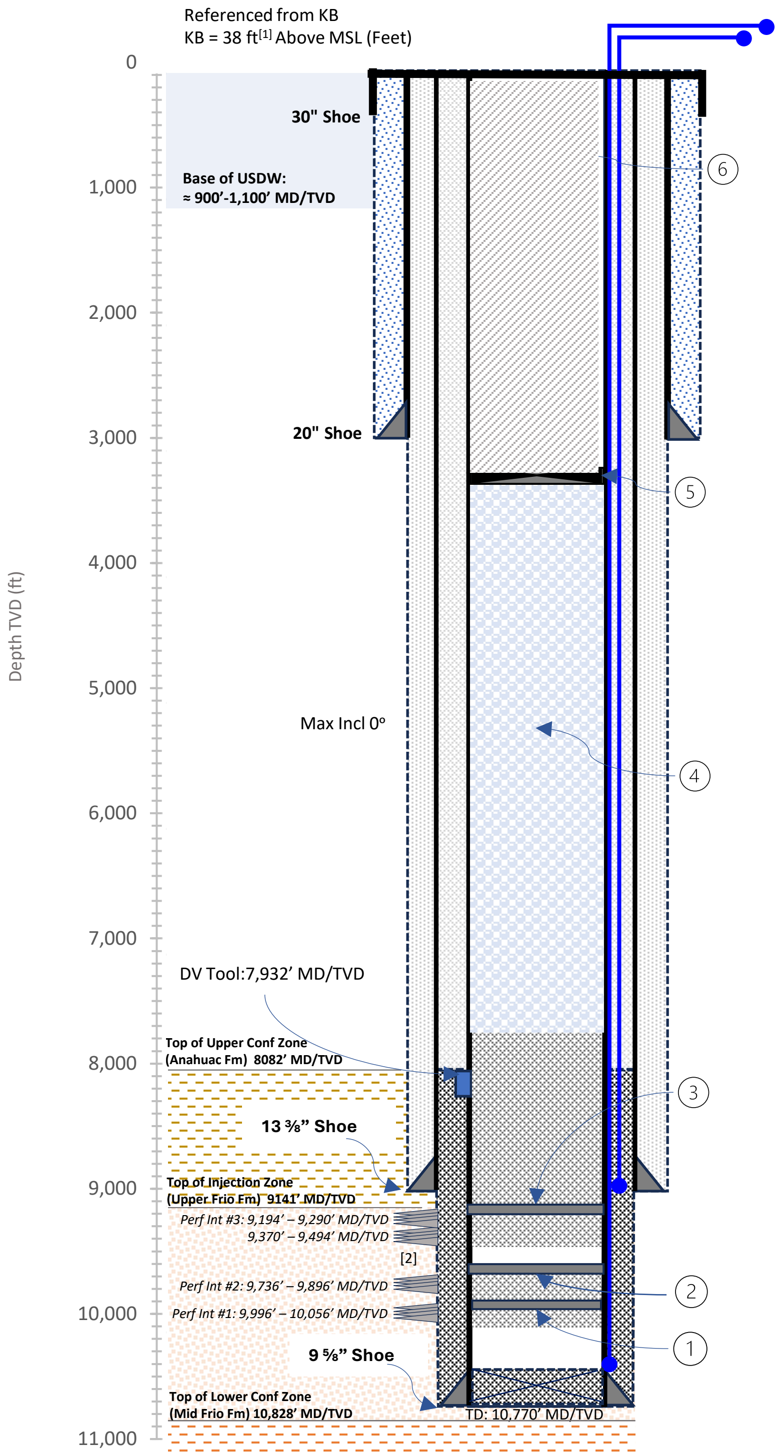


Figure E.4-3 Proposed Post-Closure Well Schematic - Minerva South CCS Well No. 001



[1] Assumed KB height of 38' above MSL, value will be updated when rig is selected

P&A Perforation Interval #1
(9,996' MD/TVD – 10,056' MD/TVD)

1. Plug #1: 9 ⅝" Squeeze Packer assumed at ≈ 9,996' MD/TVD. 14.88 ppg CO_2 corrosion-resistant cement slurry PermaSet System Cement (or equivalent) squeezed below packer to isolate Interval #1; 49.4 cuft/8.8 bbls/45 sacks. Sting out of Squeeze Packer. Squeeze cement above Packer, 28 cuft/5 bbls/25 sacks.

P&A Perforation Interval #2
(9,736' MD/TVD – 9,896' MD/TVD)

2. Plug #2: 9 ⅝" Squeeze Packer assumed at ≈ 9,734' MD/TVD 14.88 ppg CO_2 corrosion-resistant cement slurry squeezed below packer to isolate Interval #2; 133.2 cuft/23.7 bbls/119 sacks.

P&A Perforation Interval #3
(9,194' MD/TVD – 9,290' MD/TVD and 9,370' MD/TVD – 9,494' MD/TVD)

3. Plug #3: 9 ⅝" Squeeze Packer assumed at ≈ 9,192' MD/TVD. 14.88 ppg CO_2 corrosion-resistant cement slurry squeezed below packer to isolate Interval #1; 248.2 cuft/44.2 bbls/222 sacks. Sting out of Squeeze Packer. Squeeze cement above Packer, 543.4 cuft/96.8 bbls/485 sacks.

4. Buffer Fluid: 8.5 ppg $CaCl_2$ inhibited brine with corrosion control (98% MgO, magnesium oxide).

Surface Casing Shoe/USDW Isolation
(1,600' MD/TVD – 3,100' MD/TVD)

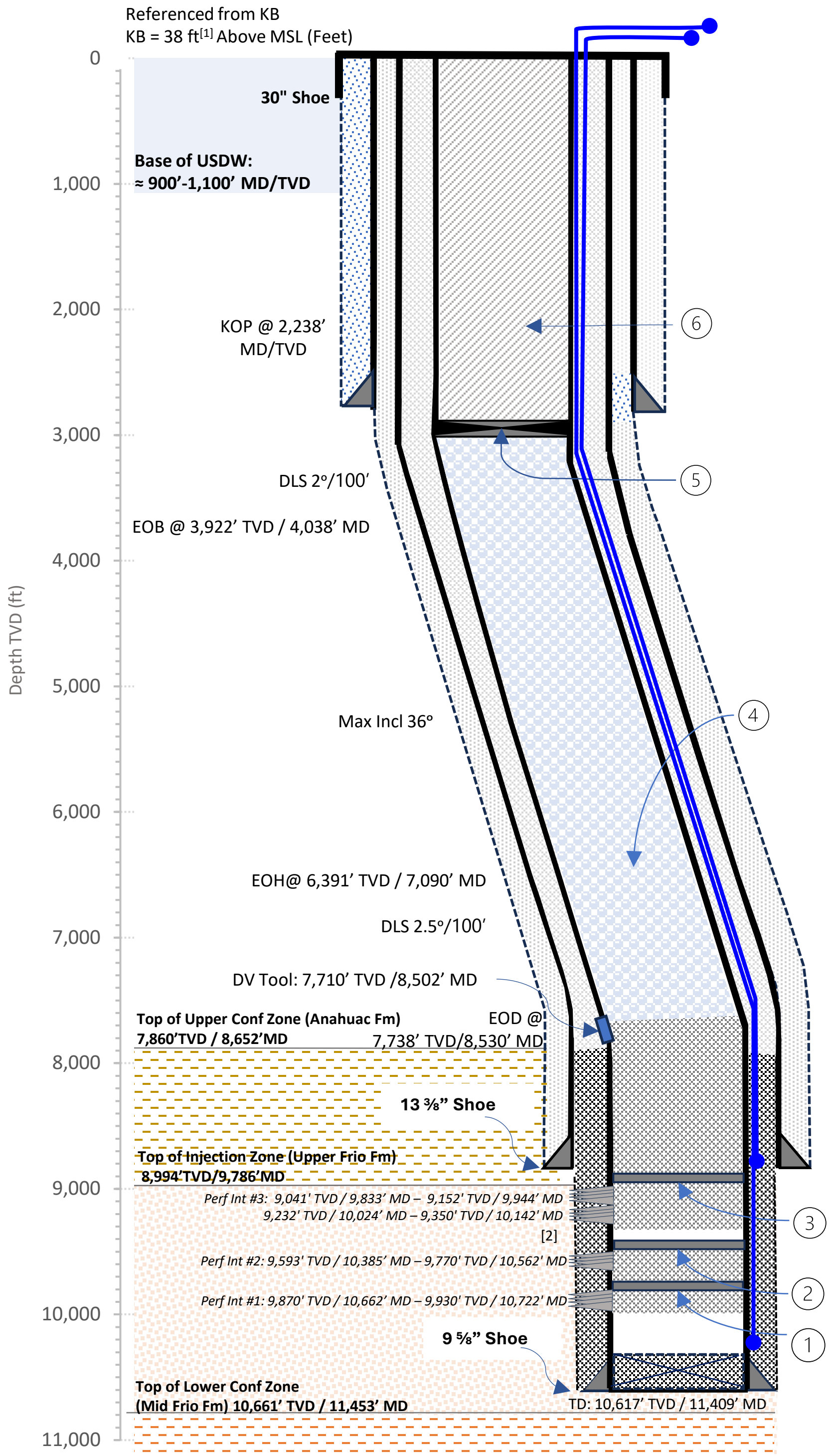
5. Plug #4: 9 ⅝" Cast Iron Bridge Plug (CIBP) assumed at ≈ 3,100' MD/TVD, 100' below the surface casing depth. ≈ 1,600' of 16.4 ppg Class H Cement spotted above the CIBP, 658 cuft/117.1 bbls/619 sacks.

6. Plug #5: ≈ 1,500' 16.4 ppg Class H Cement up to surface, 617 cuft/109.8 bbls/581 sacks.

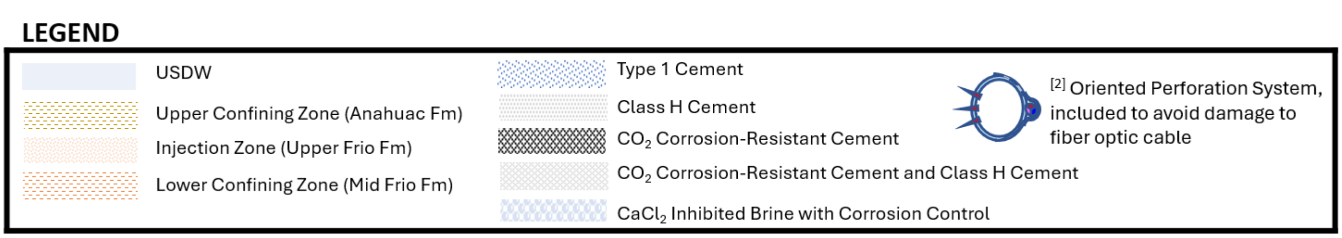
LEGEND

- USDW
- Upper Confining Zone (Anahuac Fm)
- Injection Zone (Upper Frio Fm)
- Lower Confining Zone (Mid Frio Fm)
- Type 1 Cement
- Class H Cement
- CO_2 Corrosion-Resistant Cement
- CO_2 Corrosion-Resistant Cement and Class H Cement
- $CaCl_2$ Inhibited Brine with Corrosion Control
- [2] Oriented Perforation System, included to avoid damage to fiber optic cable

Figure E.4-4 Proposed Post-Closure Well Schematic - Minerva South CCS Well No. 002



[1] Assumed KB height of 38' above MSL, value will be updated when rig is selected



P&A Perforation Interval #1
(9,870' TVD / 10,662' MD – 9,930' TVD / 10,722' MD)

1. Plug #1: 9 ⅝" Squeeze Packer assumed at ≈ 9,832' TVD/ 10,624' MD. 14.88 ppg PermaSet System Cement (or equivalent) squeezed below packer to isolate Interval #1; 49.4 cuft/8.8 bbls/45 sacks. Sting out of Squeeze Packer. Squeeze cement above Packer, 28 cuft/5 bbls/25 sacks.

P&A Perforation Interval #2
(9,593' TVD / 10,385' MD – 9,770' TVD / 10,562' MD)

2. Plug #2: 9 ⅝" Squeeze Packer assumed at ≈ 9,590' TVD/10,383' MD. 14.88 ppg CO_2 corrosion-resistant cement slurry squeezed below Packer to isolate Interval #2; 147.2 cuft/26.2 bbls/131 sacks.

P&A Perforation Interval #3
(9,232' TVD / 10,024' MD – 9,350' TVD / 10,142' MD) and (9,041' TVD / 9,833' MD – 9,152' TVD / 9,944' MD)

3. Plug #3: 9 ⅝" Squeeze Packer assumed at ≈ 9,038' TVD/ 9,831' MD. 14.88 ppg CO_2 corrosion-resistant cement slurry squeezed below packer to isolate Interval #3; 255.6 cuft/45.5 bbls/228 sacks. Sting out of Squeeze Packer. Squeeze cement above Packer, 571.7 cuft/101.8 bbls/510 sacks.

4. Buffer Fluid: 8.5 ppg $CaCl_2$ inhibited brine with corrosion control (98% MgO, magnesium oxide).

Surface Casing Shoe/USDW Isolation
(1,500' MD/TVD – 3,100' MD/TVD)

5. Plug #4: 9 ⅝" Cast Iron Bridge Plug (CIBP) assumed at ≈ 3,100' MD/TVD, 100' below the surface casing depth. ≈ 1,600' of 16.4 ppg Class H Cement spotted above the CIBP, 658 cuft/117.1 bbls/619 sacks.

6. Plug #5: ≈ 1500' 16.4 ppg Class H Cement up to surface, 617 cuft/109.8 bbls/581 sacks.

APPENDIX E-I

Plug and Abandonment Procedures

APPENDIX E-I-1

Plug and Abandonment Procedure for Minerva South CCS No. 001

FACILITY INFORMATION

Facility Name: Minerva Facility

Injector Wells: Minerva South CCS Well No. 001 (MS CCS 1)
Minerva South CCS Well No. 002 (MS CCS 2)

Facility Contact: David Cook, CEO
5599 San Felipe St., Ste. 1450, Houston, Texas 77056
(713) 419-6808; dcook@gcscarbon.com

Well Locations: Sec 3, T12S, R13W, Cameron Parish, Louisiana
MS CCS 1 (NAD 1927)
Surface: 30° 02' 34.10"W, -93° 40' 20.63"N
Bottom-Hole: 30° 02' 34.10"W, -93° 40' 20.63"N
MS CCS 2 (NAD 1927)
Surface: 30° 02' 33.84"W, -93° 40' 20.48"N
Bottom-Hole: 30° 02' 13.74"W, -93° 40' 42.07"N

PROPOSED PLUG AND ABANDONMENT (P&A) PROCEDURE FOR MS CCS 1

The plugging procedure is planned to be executed in the following plugging sequence, but the proposed volumes and depths will vary based on final perforated interval depths.

1. Move the rig to Minerva South CCS Well No. 001 (MS CCS 1) and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor before move-in.
2. Conduct and document a safety meeting.
3. Shut well in and obtain static pressure.
4. Record static bottom hole pressure from the downhole gauge and calculate the kill fluid density.
5. Test the cement pump and flowline to 5,000 psi.
6. Pump kill fluid (weight determined by bottom hole pressure measurement) volume and fill injection tubing. Monitor tubing pressure.
7. Verify the tubing-casing annulus is filled to the surface with inhibited packer fluid and test to 1,500 psi, or NDIC-approved test pressure, and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.
   - **Note**: If failure of pressure test is identified, the operator will prepare a plan to repair the well prior to the P&A.
8. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).
   - **Contingency:** If the well is not dead, RU slickline, and set plug in lower-profile nipple below the packer. Circulate tubing and annulus with kill-weight fluid

until the well is static. After the well is dead, nipple down X-mas tree, NU BOPs, and perform a function test. Prepare to recover the packer with the work string.

9. Pull out of the hole (POOH) and lay down tubing, packer, cable, and sensors.
    - **Contingency**: If unable to release tubing and retrieve packer and if the plug is already set in the nipple, RU electric line, and prepare to cut tubing string just above packer. Cut above the packer at least 5 – 10' MD, POOH, and proceed to the next step. If problems are noted, update the cement remediation plan. The squeeze packer might be used to force cement in case the packer cannot be removed.
10. Pick up work string, and round trip in hole (TIH) with bit and scraper to condition wellbore.
11. RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options in Table E.2.2-1 (Attachment E – Injection Well Plugging Plan).

P&A PERFORATION INTERVAL #1 (9,996' MD/TVD– 10,056' MD/TVD)

1. Rig down logging wireline equipment and tools.
2. TIH work string with squeeze packer to the top of the interval at ~ 9,996' MD/TVD. Circulate well, set squeeze packer, and pump injection rate to establish cement pump rate. RU equipment for cementing operations.
3. Mix and pump Plug #1; 8.8 bbls of 14.88 ppg CO_2-corrosion resistant slurry to squeeze into Interval #1 and isolate it from the upper formation. The volume to inject below the Cement squeeze packer is 49.4 cuft/8.8 bbls/45 sacks with a reduced pump rate. Once completed the volume of a 500psi pressure over the injection pressure, stop injecting. Unlatch from the squeeze packer and circulate.
4. Spot 28 cuft/5 bbls/25 sacks of CO_2-corrosion resistant 14.88 ppg slurry at the top squeeze packer. TOC ~ 9,926' MD/TVD.
5. WOC and RIH to tag the top of the cement and pressure test.
6. To confirm TOC depth, install a slick line unit and run a ring gasket to tag the top of the cement/retainer.
    - **Note:** The plan and sequence of the P&A will depend on the number of intervals perforated at the time. If interval #1 is the only interval perforated and abandoned, then the plan would be to continue to perforate, test, and injection plan to interval #2. Once Interval # 2 is confirmed to plug and abandon, the following process will be followed.

P&A PERFORATION INTERVAL #2 (9,736' MD/TVD – 9,896' MD/TVD)

1. Before running a second cement retainer, it is recommended to run a ring gasket to calibrate the interior of the casing and ensure the well is free of restriction up to the top of the cement plug #1 at ~ 9,926' MD/TVD.
2. Confirm free access through the interval #2: 9,736' MD/TVD – 9,896' MD/TVD. The depth of the cement retainer will be ~ 9,734' MD/TVD, 2' above the top of perforated interval #2.
3. Install the cement retainer and setting tool in a working string pipe, RIH, space out, and set the second cement retainer. Perform an injection test to measure injection pressure and rate.
4. Sting out the cement retainer and pump 133.2 cuft/23.7 bbls/119 sacks of 14.88 ppg CO_2 corrosion-resistant cement slurry in between freshwater as spacer pills of 8.40 ppg down the string followed by displacement. When the cement is close to the end of the pipe, sting in and inject cement down the retainer observing injection pressure.
5. Once completed the volume to inject, sting-out and circulate out. POOH and wait on cement.
6. To confirm the Top of the retainer / TOC depth, install a slick line unit and run a ring gasket to tag the top of the cement/retainer. Top of retainer ~ 9,734' MD/TVD.
    - **Note**: The plan and sequence of the P&A will depend on the number of intervals perforated at the time. If no other interval is perforated above, then the plan would be to continue to perforate, test, and injection plan to interval #3. Once Interval # 3 is confirmed to plug and abandon, then the plan would be as follows:

P&A PERFORATION INTERVAL #3 (9,194' MD/TVD – 9,290' MD/TVD AND 9,370' – 9,494' MD/TVD)

1. Before running a third cement retainer, it is recommended to run a ring gasket to calibrate the interior of the casing and ensure the well is free of restriction up to the top of the cement retainer #2 at ~ 9,734' MD/TVD.
2. Confirm free access through interval #3: 9,194' – 9,290' MD/TVD and 9,370' – 9,494' MD/TVD. The depth of the cement retainer will be ~ 9,192' MD/TVD, 2' above the top of perforated interval #3.
3. Install the Cement retainer and setting tool in a working string pipe, RIH, space out, and set the third cement retainer at 9,192' MD/TVD. Perform an injection test to measure injection pressure and rate.
4. Sting out the cement retainer and pump the 248.2 cuft/44.2 bbls/222 sacks of 14.88 ppg CO_2-corrosion resistant cement slurry in between freshwater as spacer pills of

8.40 ppg down the string followed by displacement. Once completed the volume verifies the final injection pressure. Unlatch from the retainer. Circulate out above the retainer.

5. Mix and pump 543.4 cuft/96.8 bbls/485 sacks of CO_2-corrosion resistant 14.88 ppg slurry and spot at the top squeeze retainer. TOC ~ 7,870' MD/TVD.
6. POOH work string at a controlled speed. POOH at +/- 5,000' MD/TVD. Wait on cement.
7. RIH the work string and tag the top of cement to be ~ 7,870' MD/TVD. POOH.

SURFACE PLUGS (PLUG #4: 1,500' – 3,000' MD/TVD & PLUG #5: 0 MD/TVD – 1,500' MD/TVD)

1. In preparation for Plug #4 across the surface casing shoe and the base of USDW, PU/MU Cast Iron Cement Retainer (CIBP) for 9 ⅝" casing using a Slick line equipment, RIH and set about 3,100' MD/TVD.
2. MU and RIH mule shoe work string pipe to the top of the CIBP. Circulate bottoms-up. Prepare and Mix 658 cuft/117.1 bbls/619 sacks of 16.40 ppg Class H Cement slurry. Pump down string followed by Spacer and water as displacement. Spot at the top of CIBP. POOH and wait for cement.
3. Trip into the hole and tag TOC ~ 1500' MD/TVD. Mix and pump 617 cuft/109.8 bbls/581 sacks of 16.40 ppg of Class H cement slurry balanced and confirm cement at the surface. POOH and wait for cement.
4. Lay down the work string. Rig down all the equipment and move out. Cut the casing at 5' below the ground. Clean cellar to where a plate can be welded with well information.
5. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

APPENDIX E-I-2

Plug and Abandonment Procedure for

Minerva South CCS No.002

FACILITY INFORMATION

Facility Name:	Minerva Facility
Injector Wells:	Minerva South CCS Well No. 001 (MS CCS 1) Minerva South CCS Well No. 002 (MS CCS 2)
Facility Contact:	David Cook, CEO 5599 San Felipe St., Ste. 1450, Houston, Texas 77056 (713) 419-6808; dcook@gcscarbon.com
Well Locations:	Sec 3, T12S, R13W, Cameron Parish, Louisiana MS CCS 1 (NAD 1927) Surface: 30° 02' 34.10"W, -93° 40' 20.63"N Bottom-Hole: 30° 02' 34.10"W, -93° 40' 20.63"N MS CCS 2 (NAD 1927) Surface: 30° 02' 33.84"W, -93° 40' 20.48"N Bottom-Hole: 30° 02' 13.74"W, -93° 40' 42.07"N

PROPOSED PLUG AND ABANDONMENT (P&A) PROCEDURE FOR MS CCS 2

The plugging procedure is planned to be executed in the following plugging sequence, but the proposed volumes and depths will vary based on final perforated interval depths.

1. Move the rig to Minerva South CCS Well No. 002 (MS CCS 2) and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor before move-in.
2. Conduct and document a safety meeting.
3. Shut well in and obtain static pressure.
4. Record static bottom hole pressure from the downhole gauge and calculate the kill fluid density.
5. Test the cement pump and flowline to 5,000 psi.
6. Pump kill fluid (weight determined by bottom hole pressure measurement) volume and fill injection tubing. Monitor tubing pressure.
7. Verify the tubing-casing annulus is filled to the surface with inhibited packer fluid and test to 1,500 psi, or NDIC-approved test pressure, and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.
    - **Note**: If failure of pressure test is identified, the operator will prepare a plan to repair the well prior to the P&A.

8. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).
    - **Contingency:** If the well is not dead, RU slickline, and set plug in lower-profile nipple below the packer. Circulate tubing and annulus with kill-weight fluid until the well is static. After the well is dead, nipple down X-mas tree, NU BOPs, and perform a function test. Prepare to recover the packer with the work string.
9. Pull out of the hole (POOH) and lay down tubing, packer, cable, and sensors.
    - **Contingency**: If unable to release tubing and retrieve packer and if the plug is already set in the nipple, RU electric line, and prepare to cut tubing string just above packer. Cut above the packer at least 5 – 10' MD, POOH, and proceed to the next step. If problems are noted, update the cement remediation plan. The squeeze packer might be used to force cement in case the packer cannot be removed.
10. Pick up work string, and round trip in hole (TIH) with bit and scraper to condition wellbore.
11. RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options in Table E.2.2-1 (Attachment E – Injection Well Plugging Plan).

P&A PERFORATION INTERVAL #1 (10,662' MD / 9,870' TVD – 10,722' MD / 9,930' TVD)

1. Rig down logging Wireline equipment and tools.
2. TIH work string with squeeze packer to the top of the interval at 10,662' MD / 9,870' TVD. Circulate well, set squeeze packer, and pump injection rate to establish cement pump rate. RU equipment for cementing operations.
3. Mix and pump Plug #1; 8.8 bbls of 14.88 CO_2 corrosion-resistant slurry to squeeze into Interval #1 and isolate it from the upper formations. The total volume to inject below the Cement retainer is 49.4 cuft/8.8 bbls/45 sacks of with a reduced pump rate. Once completed the volume of a 500psi pressure over the injection pressure Stop injecting. Unlatch from the squeeze packer and circulate. Assumed ~5 bbls of slurry injected into the perforations.
4. Spot 28 cuft/5 bbls/25 sacks of CO_2 corrosion-resistant 14.88 ppg slurry at the top squeeze packer. Top of cement (TOC) ~ 10,592' MD / 9,800' TVD.
5. WOC and RIH to tag the top of the cement and pressure test.
6. To confirm TOC depth, install a slick line unit and run a ring gasket to tag the top of the cement/retainer.
    a. **Note**: The plan and sequence of the P&A will depend on the number of intervals perforated at the time. If interval #1 is the only interval perforated and abandoned, then the plan would be to continue to perforate, test, and injection plan to interval #2. Once Interval # 2 is confirmed to plug and

abandon, then the plan would be as follows:

P&A PERFORATION INTERVAL #2 (10,385' MD / 9,593' TVD – 10,562' MD / 9,770' TVD)

1. Before running a second cement retainer, it is recommended to run a ring gasket to calibrate the interior of the casing and ensure the well is free of restriction up to the top of the cement plug #1 at ~ 10,592' MD / 9,800' TVD.
2. Confirm free access through the interval #2: 10,385' MD / 9,593' TVD – 10,562' MD / 9,770' TVD. The depth of the cement retainer will be ~ 10,383' MD / 9,591' TVD, 2' above the top of perforated interval #2.
3. Install the Cement retainer and setting tool in a working string pipe, RIH, space out, and set the second cement retainer. Perform an injection test to measure injection pressure and rate.
4. Sting out the cement retainer, mix and pump 147.2 cuft/26.2 bbls/131 sacks) of 14.88 ppg CO_2 corrosion-resistant cement slurry in between freshwater as spacer pills of 8.40 ppg down the string followed by displacement. When the cement is close to the end of the pipe, sting in and inject cement down the retainer observing injection pressure.
5. Once completed the volume to inject, sting-out and circulate out. POOH and wait on cement.
6. To confirm the Top of the retainer / TOC depth, install a slick line unit and run a ring gasket to tag the top of the cement/retainer. Top of retainer ~ 10,383' MD / 9,591' TVD.
   - **Note**: The plan and sequence of the P&A will depend on the number of intervals perforated at the time. If no other interval is perforated above, then the plan would be to continue to perforate, test, and injection plan to interval #3. Once Interval # 3 is confirmed to plug and abandon, then the plan would be as follows:

P&A PERFORATION INTERVAL #3 (9,833' MD / 9,041' TVD TO 9,944' MD / 9,152' TVD AND 10,024' MD / 9,232' TVD TO 10,142' MD / 9,350' TVD)

1. Before running a second cement retainer, it is recommended to run a ring gasket to calibrate the interior of the casing and ensure the well is free of restriction up to the top of the cement retainer #2 at ~ 10,383' MD / 9,591' TVD.
2. Confirm free access through interval #3: from 9,833' MD / 9,041' TVD to 10,142' MD / 9,350' TVD. The depth of the cement retainer will be ~ 9,831' MD / 9,039' TVD, 2' above the top of perforated interval #3.

3. Install the Cement retainer and setting tool in a working string pipe, RIH, space out, and set the third cement retainer. Perform an injection test to measure injection pressure and rate.
4. Sting out the cement retainer and pump the 255.6 cuft/45.5 bbls/228 sacks of 14.88 ppg CO_2 corrosion-resistant cement slurry in between freshwater as spacer pills of 8.40 ppg down the string followed by displacement. Once completed the volume verifies the final injection pressure. Unlatch from the retainer. Circulate out above the retainer.
5. Mix and pump 571.7 cuft/101.8 bbls/510 sacks of CO_2 corrosion-resistant 14.88 ppg slurry and spot at the top squeeze retainer. TOC ~ 8,440' MD / 7,648' TVD
6. POOH work string at a controlled speed. POOH at +/- 5,000' MD / 4,700' TVD. Wait on cement.
7. RIH the work string and tag the top of cement to be ~ 8,440' MD / 7,648' TVD. POOH.

SURFACE PLUGS (PLUG #4: 1,500' MD/TVD – 3,000' MD / 2,991' TVD & PLUG #5: 0 MD/TVD – 1,500' MD/TVD)

1. In preparation for Plug #4 across the surface casing shoe and the base of USDW, PU/MU Cast Iron Cement Retainer (CIBP) for 9 ⅝" casing using a Slick line equipment, RIH and set about 3,100' MD / 3,087' TVD.
2. MU and RIH mule shoe work string pipe to the top of the CIBP. Circulate bottoms-up. Prepare and Mix 658 cuft/117.1 bbls/619 sacks of 16.40 ppg Class H Cement slurry. Pump down string followed by Spacer and water as displacement. Spot at the top of CIBP. POOH and wait for cement.
3. Trip into the hole and tag TOC ~ 1500' MD/TVD. Mix and pump 617 cuft/109.8 bbls/581 sacks of 16.40 ppg of Class H cement slurry balanced and confirm cement at the surface. POOH and wait for cement.
4. Lay down the work string. Rig down all equipment and move out. Cut the casing at 5' below the ground. Clean cellar to where a plate can be welded with well information.
5. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

PermaSet cement system

Applications

Conventional Primary and remedial cementing operations in CO_2 and H_2S environments

Features and Benefits

- Improves the cement's resistance to attacks from CO_2, H_2S, magnesium, and sulfate
- Provides minimal permeability and improved mechanical properties
- Offers fit-for-purpose designs for specific applications
- Zero Portlandite content eliminates weak points and reduces carbonation (see Fig. 1)
- Lower heat evolution during setting (less shrinkage and cracking)
- Good mechanical properties
- Real-time well conditions determine the final slurry composition
- Compatible with virtually all API and ASTM cements and most Baker Hughes cement additives

The Baker Hughes **PermaSet™ cement slurries** are fit-for-purpose, carbon dioxide (CO_2)- and hydrogen sulphide (H_2S)-resistant cement systems for use in virtually any well condition around the world. These blends have excellent free fluid control and are compatible with most Baker Hughes additives.

Baker Hughes prides itself on solving potential problems at the wellhead, understanding that a single slurry does not fit all applications. This approach allows unlimited design flexibility and takes CO_2- and H_2S-resistant cement systems out of the lab and into the real world. Our cementing philosophy utilizes state-of-the-art cement pumping equipment, such as the Baker Hughes **Seahawk™ cement unit**, to help ensure a quality cement job.

PermaSet cement slurries are part of the Baker Hughes **Set for Life™ family of cement systems**, which are designed to isolate and protect the targeted zone for the life of the well. These slurries can be blended with other systems in this family to help ensure long-term zonal isolation.

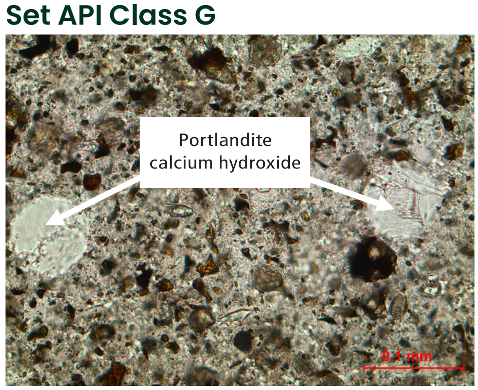
Safety Precautions

Refer to system component material safety data sheets (MSDS) for handling, transport, environmental information, and first aid.

References

- MSDS
- Set for Life systems brochure
- Set for Life cement systems overview

Set API Class G



PermaSet System

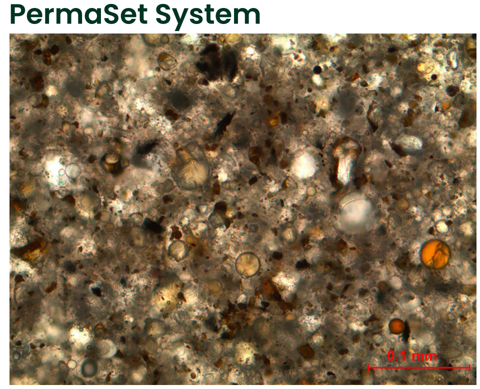


Fig. 1: Thin sections of set samples at 15.8 ppg (1893 kg/m³) under a light microscope.

Technical data

Typical Properties	
Typical temperature range	70 to 450°F (21 to 232°C) BHCT
Typical slurry density range	9 to 20 ppg (1078 to 2397 kg/m^3)

API Class G versus PermaSet cement slurries	Slurry density		Water permeability** (microdarcy)	$Ca(OH)^2$ Portlandite Content*** (%)	Compressive strength		Tensile strength	
	ppg	kg/m^3			psi	MPa	psi	MPa
Set API Class G*	15.8	1893	2.1	9.5	4,807	33.14	378	2.61
PermaSet system*	15.8	1893	0.002	Not detectable	4,674	32.23	459	3.16
Set API Class G* extended with 4% bwoc bentonite	14.0	1678	10.8	9.2	1,633	11.26	170	1.17
PermaSet system* extended	14.0	1678	0.15	Not detectable	2,529	17.44	272	1.88

* Cement slurries were prepared according to API specification 10B using fresh water. Cement specimens were cured at 200°F (93°C) and 3,000 psi (20.68 MPa) for 72 hrs.

** Water permeabilities were measured under a confining pressure of 4,500 psi (31.03 MPa) with a water injection pressure of 3,000 psi (20.68 MPa) at 200°F (93°C).

*** Quantities were determined by X-ray powder diffraction using the reference intensity ratio method.

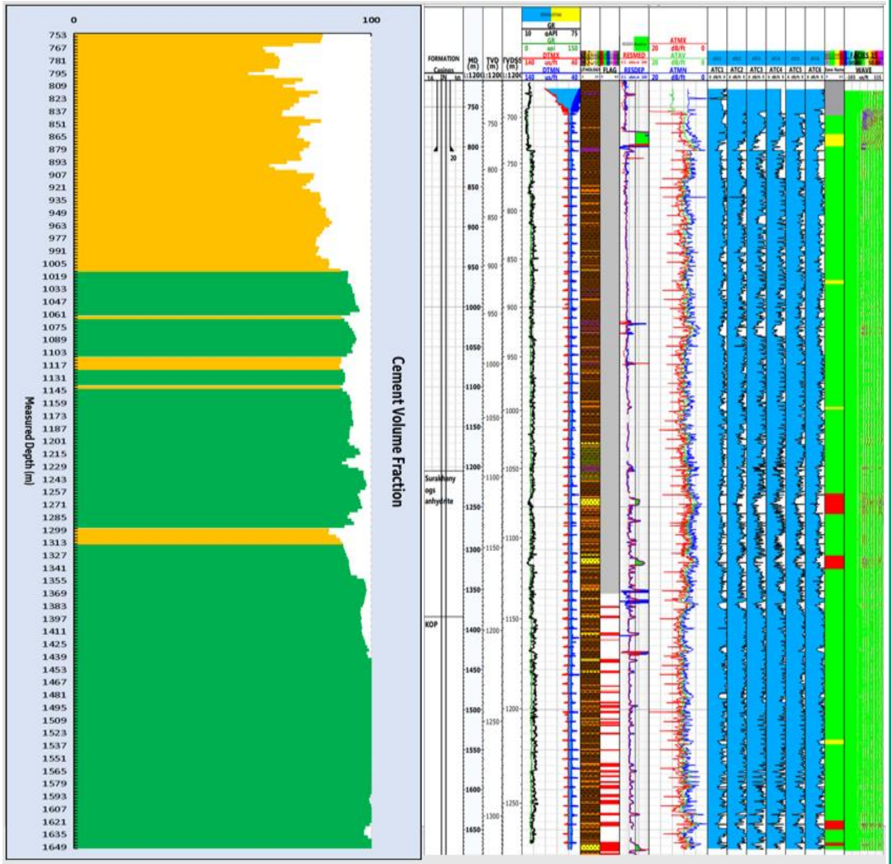
Baker Hughes

Baker Hughes
CCS Cementing Technology

- 30-June 2021

Baker Hughes Zonal Isolation Solutions Executed with Efficiency, Set for Life

DESIGN	• CemMaster – Hydraulic simulation, Set cement stress analysis, Specialty simulations • Standard API Tests • HPHT Tensiometer, Wettability Apparatus, Expansion and Shrinkage, In-situ Shear Bond Tester and Self-Sealing Apparatus
EQUIPMENT	• SeaHawk • Hawk (previously Falcon)
SYSTEMS	• LiteSet - High Performance Light Weight system • DuraSet – Enhanced Mech. Properties • XtremeSet – High Temp. • EnsurSet – Self Sealing system • PermaSet – CO_2 and H_2S resistant • FoamSet/AFCS Lite – Foam System
SPACERS	• SealBond family – Loss Control • XtremeBond – High Temp. • SurfSet – Surfactant in slurry • MCS-NS – North Sea approved
EXECUTION	• Training, Competency, X-PL roles and collaboration (F-PRO), Remote Operations
EVALUATION	• Determining top of cement utilizing CemMaster • PQI



BAKER HUGHES' ENERGY TRANSITION THEMES

- 1st in Oil and Gas Industry to make a net-zero carbon commitment
- Advancing long-term energy technology solutions needed for decarbonization -
  - Carbon capture and storage
  - Geothermal solutions
  - Hydrogen energy

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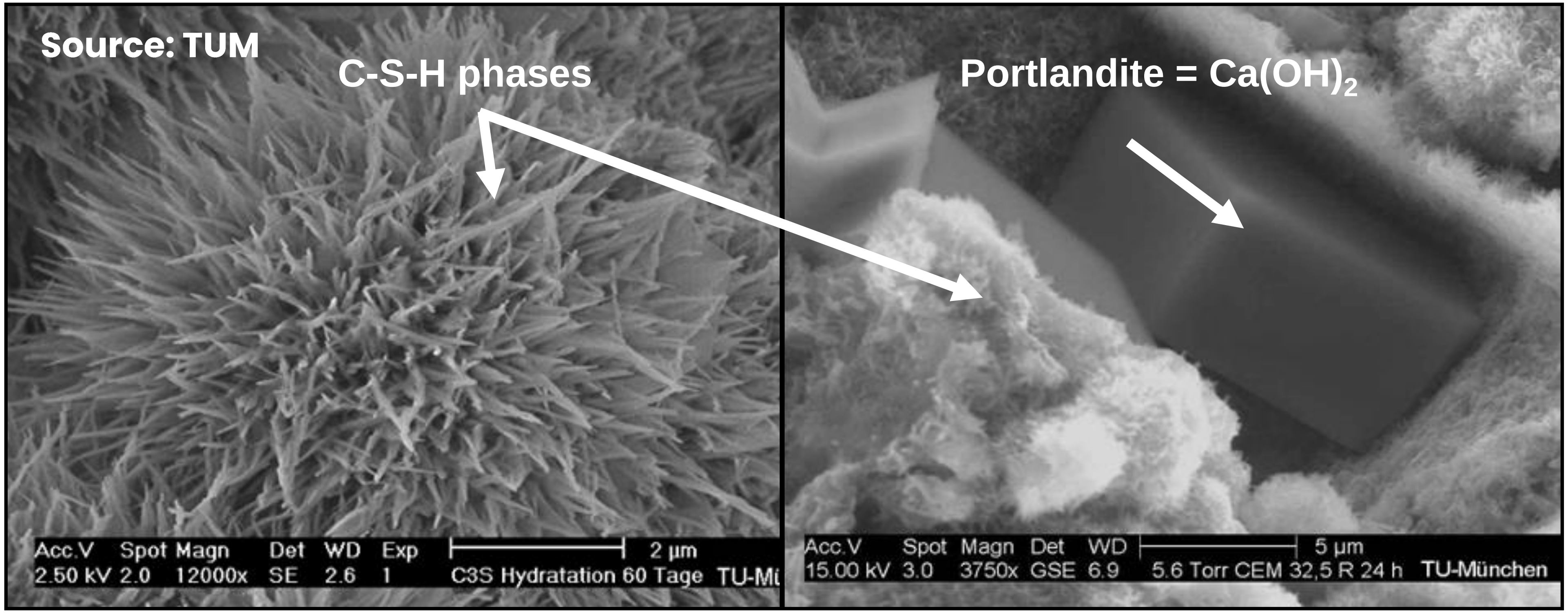
CO_2 & H_2S Resistant Cement

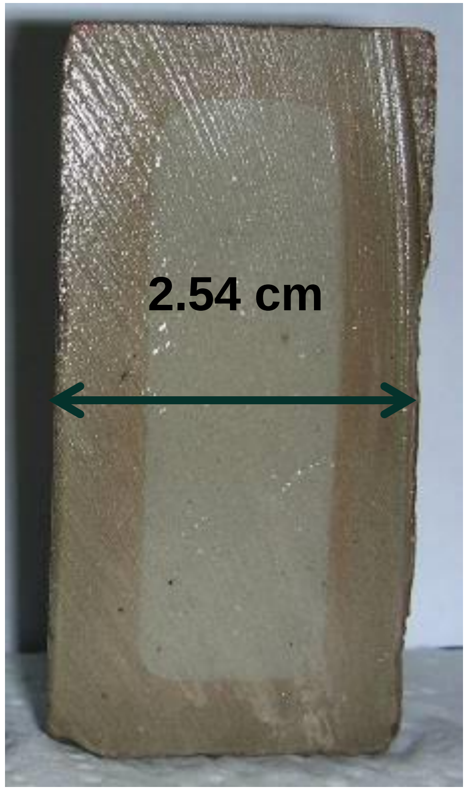
Main Minerals of Set API Cement



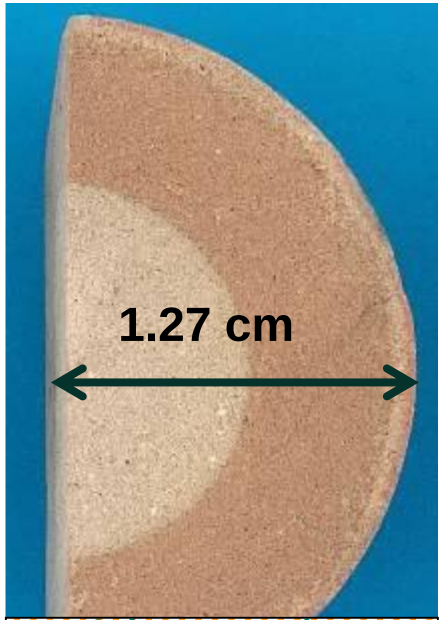
- C-S-H grab onto another (e.g. zipper) causing high strength
- Portlandite does not contribute to the strength (weak point):
  - Disruptive, easy to be leached out & increase brittleness

CO_2 Attack in conventional API Cement

Sliced into half



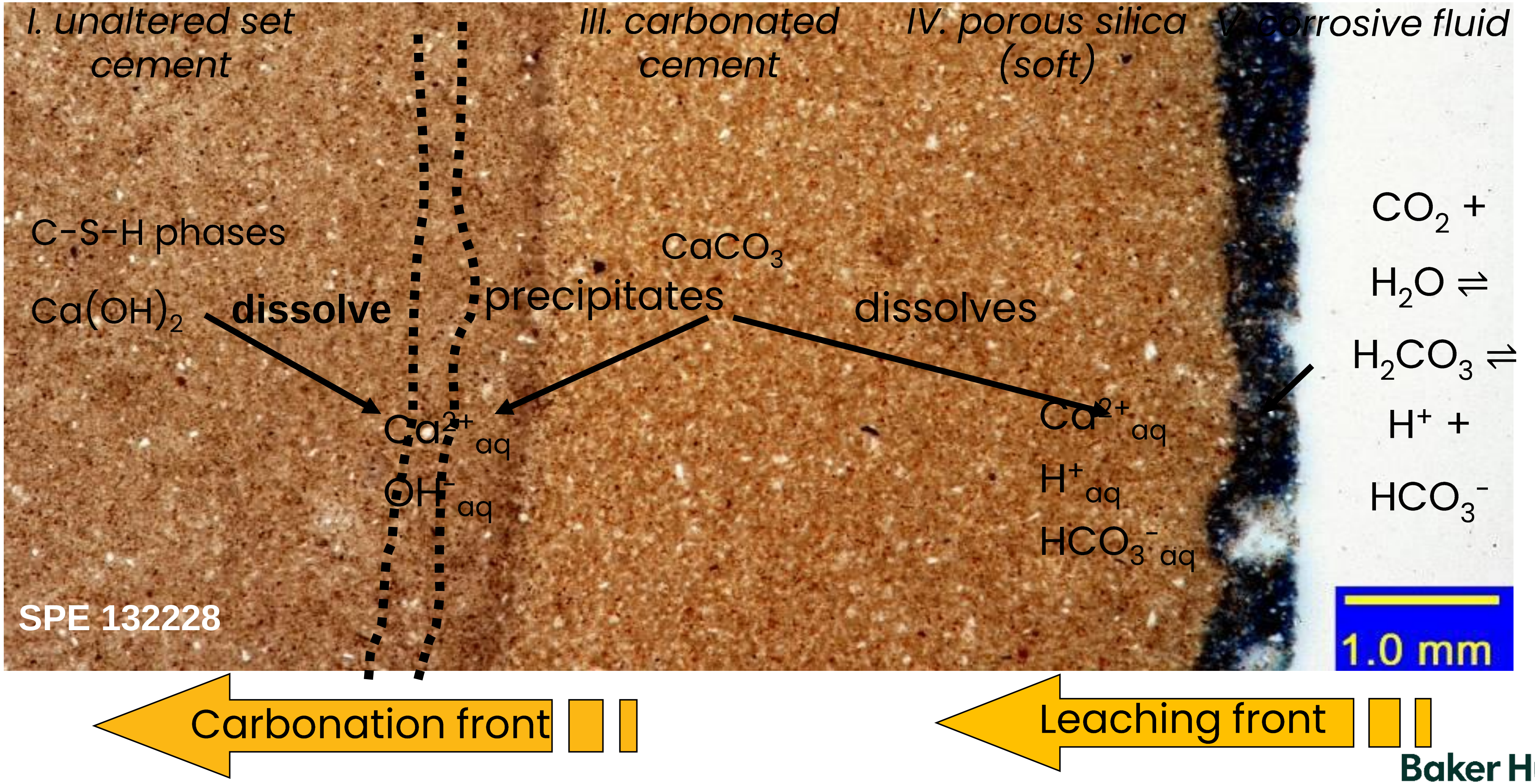
Cut into half



Thin section
See next slide

- API class G / silica flour (15.8 ppg)
- Exposed to CO_2-loaded water (250°F)
- continuous injection (30 days)

CO_2 Attack in conventional API Cement



CO_2 Attack in conventional API Cement

Conventional API cement

- After 6 mo. exposure. to CO2 water
- Specimen flaked off
- Reduction of diameter Δ=-0.6 mm
- Loss of integrity
- Potential bond failure
- Migration pathway
- => Loss of zonal isolation

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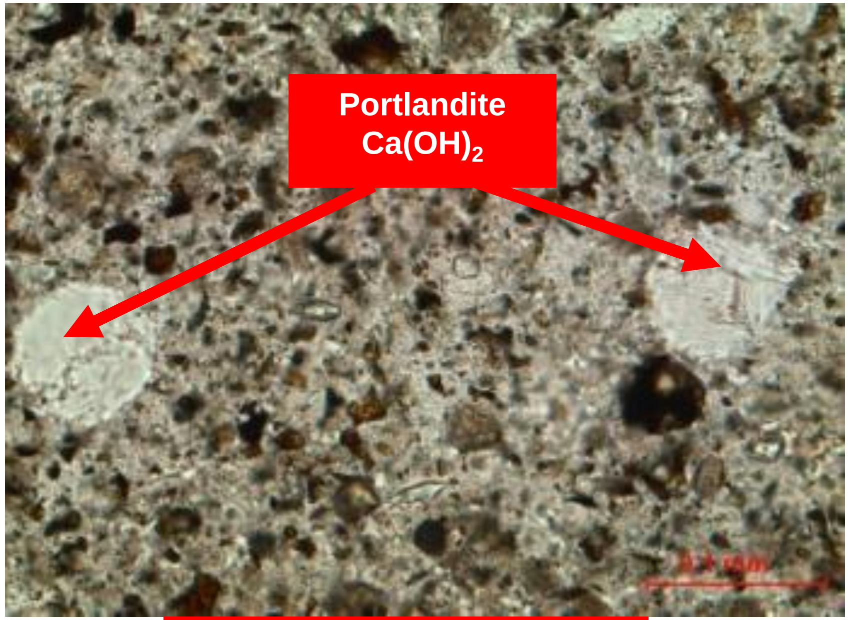
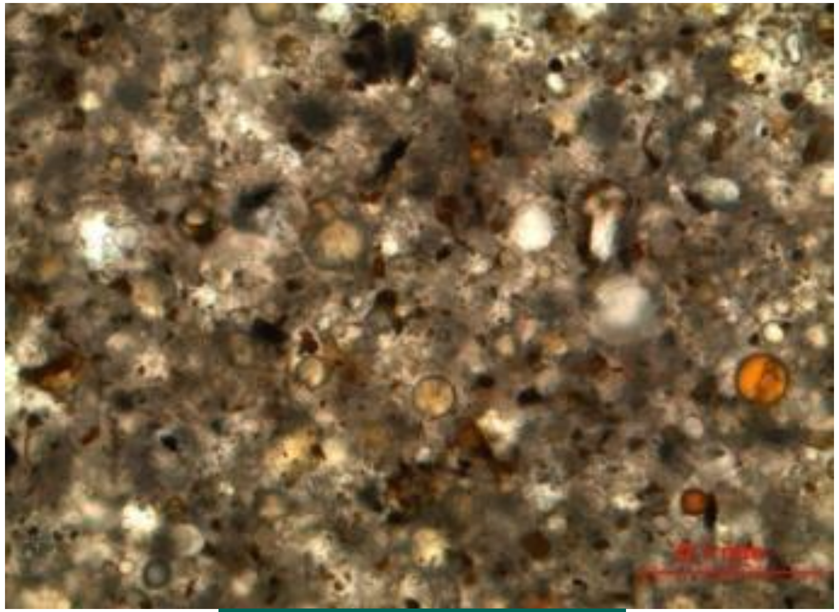
Design criteria to improve the cement's durability

- Corrosive fluids preferentially react with the Portlandite
  - Eliminate the Portlandite in set cement
- Corrosion of C-S-H phases also takes place
  - Partly substitution of API cement with inert material
- Corrosion reactions are diffusion controlled processes (Lower permeability of set cement = slower corrosion)
  - Reduce the permeability

Design Criteria



Set API Class G



PermaSet™

- Reducing $Ca(OH)_2$ by adding selected "amorphous alumo-silicates":

  $Ca(OH)_2$ + "SiO_2 / Al_2O_3" → C-S-H / C-A-S-H phases

- Cement matrix will become densified

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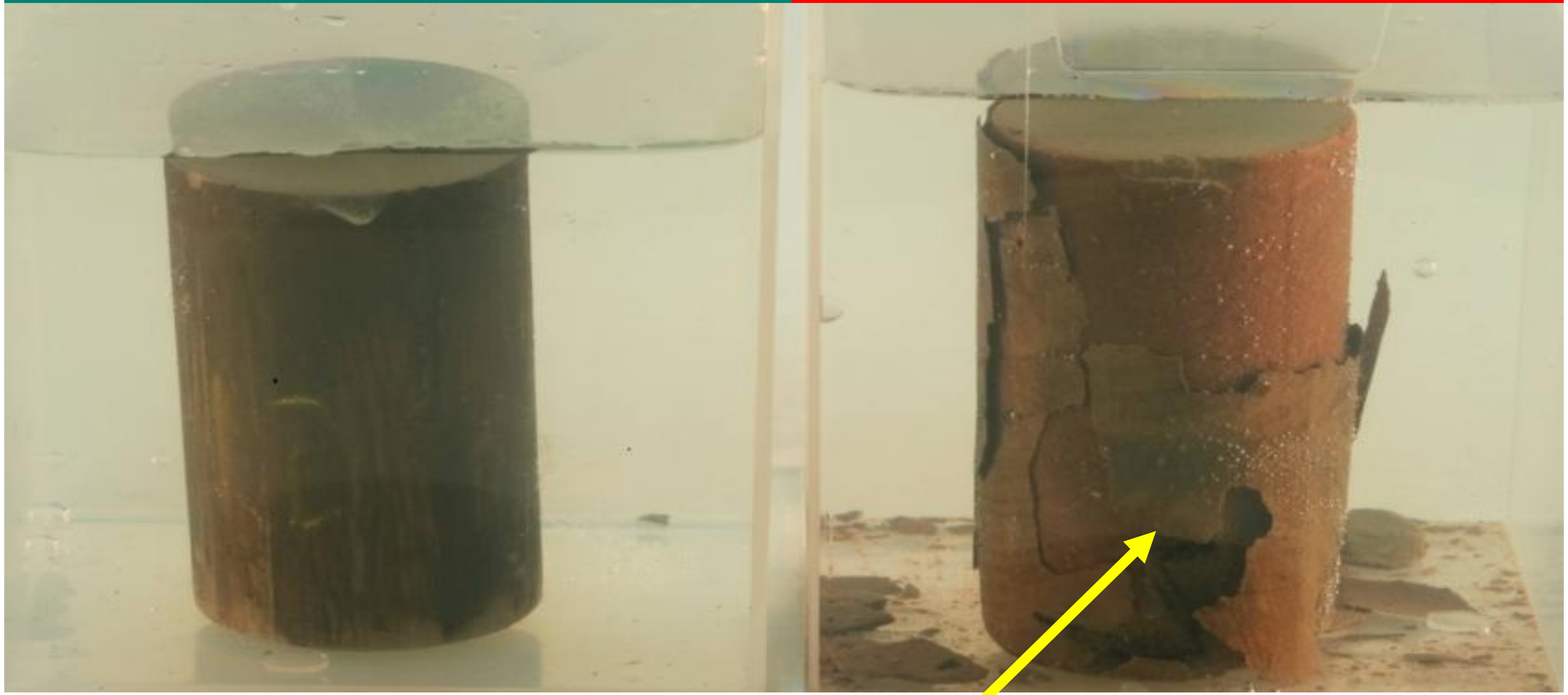
After 6 Months Exposure to CO_2

PermaSet	API class G + 40% S.F.



- No flaking
- No reduction in dimensions
- Integrity

- Flakings (diameter Δ=-0.6 mm)
- Reduced dimensions
- Potential bond failure

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PermaSet™ – CO_2 & H_2S Resistant

Part of the Baker Hughes "Set for Life ™ " family of cement systems, which are designed to isolate and protect the target zone for the life of the well .

Benefits

- Improves cement resistance to attacks from CO_2, H_2S, magnesium and sulfate
- Provides minimal permeability and improves mechanical properties
- Offers fit-for-purpose design for specific applications
- Reduced Portlandite content eliminates weak points and reduces carbonation (see Fig. 1)
- Lower heat evolution during setting (less shrinkage and cracking)
- Good mechanical properties
- Real-time well conditions determine the final slurry composition
- Compatible with virtually all API and ASTM cements and most Baker Hughes cement additives

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Case History – Malaysia

- 7” Production liner at 2,373 m
- BHST: 291ºF

– Objective / Challenges:

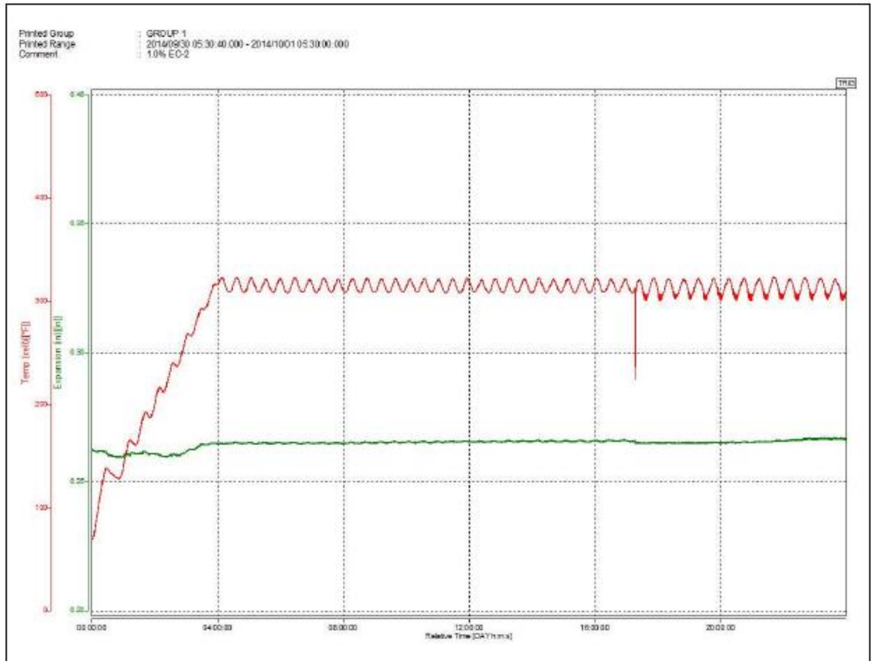
- Long term zonal isolation along production zone
- Delivering exploratory & DST objective

– Solution

- Single 16.6 ppg expanding gas-control cementing system
    - CO2 corrosion tolerant
    - Self-sealing and resilient

Results:

- Controlled linear expansion of set cement
- Accomplished zonal isolation objective



Publication: IPTC-18749

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Case History – Middle East

- 7" liner for an EOR-CO_2 project
- BHST: 250 ºF

– Objective / Challenges:

- Long term zonal isolation by improving cement bonding
- Non-damaging fluid (NDF)

– Solution

- Expanding PermaSet cement system

Results:

- Excellent slurry properties
- 7" liner USIT LOG with excellent cement bond results confirming zonal isolation
- Customer satisfied with BKR solution

More than 27 wells executed flawlessly in UAE all in gas injection wells with success.

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References

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2. Brandl, S. Bray, C. Magelky, R. Dajani, *Cementing Strategies for Effective Zonal Isolation of CO_2 Wells*, 1st Combined Network Meeting on Modelling and Wellbore Integrity, the IEA Greenhouse Gas R&D Programme (IEAGHG), Perth (Australia), April 27-29, 2011

3. A. Brandl, R. Dajani, *Performance of Portland Cement Systems in HTHP CO_2 Environment,* presented at the 6th Wellbore Integrity Network Meeting, the IEA Greenhouse Gas R&D Programme (IEAGHG), The Hague (Netherlands) 28-29 April, 2010

4. A. Brandl, *Cementing in Corrosive Environments*, TechLine - a publication of BJ Services Company, Volume 10, 2009

5. A. Brandl, *Permian Basin: Cementing Solutions for CO_2 and Other Corrosive Environments,* presented at the SPE Gulf Coast Section Study Group, Houston, TX October 12th, 2009

6. A. Brandl, S. Bray, D. Doherty, *Technically and Economically Improved Cementing System with Sustainable Components*, paper IADC/SPE 136276

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Supporting published studies from other experts

1. C. Tiemeyer, D. Bülichen, J. Plank „CO_2-Beständigkeit von Zementsystemen unter den Bedingungen einer geologischen Endlagerung von CO_2 (CCS-Technologie)“, 18. Ibausil, Tagungsbericht Band 2, F. A. Finger-Institut für Baustoffkunde, Bauhaus-Universität Weimar, 419 - 426 (2012)

2. Crow, W., Williams, D.B., Carey, J.W., Celia, M., Gasda, S., Wellbore integrity analysis of a natural CO_2 producer, Energy Procedia 1 (2009), 3561–3569

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