4.0 INJECTION WELL CONSTRUCTION PLAN
40 CFR 146.82(a)(8), 146.87

MARQUIS BIOCARBON PROJECT

Facility Information

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Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

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4.0 Injection Well Construction Plan (40 CFR 146.86 (a)(1)

This section describes how a single, newly drilled injection well (MCI CCS 3) will be constructed at the Marquis BioCarbon Project site near Hennepin, Illinois, to meet the requirements of 40 CFR 146.82(a)(9)(11) and 40 CFR 146.86. The well design is discussed in detail in the following sections, including the drilling phase, materials to be used, and the initial expected design. Formation and casing depths for the injection well were determined using data from the MCI MW 1. Slight deviations in depths and well placement may occur during the drilling process as new information, hazards, or other concerns come to light.

No completion stimulation is planned at this time because the expected reservoir quality is sufficient for the planned injection volumes. The maximum injection volume for this project is anticipated to be 1.5 million tonnes (MT)/year. No oil or gas zones are anticipated to be encountered at this location. The only expected zone that may present corrosion issues during the life of the project is the injection zone itself, the Mt. Simon Sandstone, as carbon dioxide (CO_2) is injected over time and mixes with the connate waters, the saline brine contained within the Mt. Simon, to form carbonic acid.

The reservoir modeling section of this application determined that a single, vertical injection well is sufficient to achieve the target CO_2 injection rate. The approximate location of the well is shown in **Figure 4-2.**

The proposed injection well diagram is shown in **Table 4-1** details the depths of the geological formations of interest at the site. Refer to the Area of Review (AoR) and Corrective Action Plan (Permit **Section 2**) for further details on these formations.

<u>The Class VI wells are designed and will be constructed to:</u>

1) <u>Prevent the movement of fluids into or between USDWs or into any unauthorized zones;</u>
2) <u>Permit the use of appropriate testing devices and workover tools; and</u>
3) <u>Permit continuous monitoring of the annulus space between the injection tubing and long string casing.</u>

Formations	**Depth (ft, MD)**
Bedrock Top	[redacted]
Base of Deepest USDW – Gunter Sandstone	[redacted]
Caprock Formation – Eau Claire Shale	[redacted]
Injection Formation – Lower Elmhurst Sandstone–Mt. Simon Sandstone	[redacted]
Total Depth	[redacted]

Table 4 - 1: Formations of Interest in MCI MW 1 Well.

Confidential, Privileged, or Sensitive Business Information

[redacted]

Figure 4 - 1: MCI CCS 3 injection well schematic & perforation zone locations.

Confidential, Privileged, or Sensitive Business Information

[redacted]

Figure 4 - 2: Plot showing anticipated injection well location for MCI CCS 3.

4.1 Well Design (40 CFR 146.86 (b))

The proposed well design is shown above in **Figure 4-1.** The lithology of the injection and confining zones are shown with the injection depth, hole sizes and casing sizes and depths. These are discussed below.

4.1.1 CO_2 stream and Formation Fluids (146.86 (b)(1)(v)(vi))

4.1.1.1 CO_2 Stream Chemical Composition

The anticipated chemical composition of the CO_2 stream is given in **Table 4-2**. Based on samples collected during normal operations and a fermentation drop at the ethanol-production facility, the injection stream will be composed of nearly pure CO_2, with a composition of 99+% CO_2. A fermentation drop is considered the period during fermentation when the worst-case emissions from the scrubbers would be observed. The chemical balance of the remainder of the injection stream will be composed of trace constituents (nitrogen, oxygen, and triethylene glycol [TEG]) with quantities of approximately 0.1%, 0.05%, and 0.3 gallons (gal)/MMSCF, respectively. Dehydration will be performed to reduce the water vapor content in the injection stream. Confidential, Privileged, or Sensitive Business Information [redacted] The well has been designed with corrosive-resistant materials that contact the injection stream to prevent corrosion of the components caused by the presence of carbonic acid. Hydrogen sulfide (H_2S) is not expected to be present in the injection stream; however, analyses will be performed to confirm this. Confidential, Privileged, or Sensitive Business Information [redacted]

The corrosivity of the injection stream should be limited given the quantities of the minor concentrations of the trace constituents in the injection stream, and the water content will be maintained below Confidential, Privileged, or Sensitive Business Information [redacted] within the plant piping to the injection well.

Component	Quantity
CO_2	99%+
Oxygen	<0.05%
Nitrogen	<1%
Water Vapor	<30 lb/MMSCF
Hydrogen sulfide (H_2S) (not expected)	<0.002%
Total Hydrocarbons	<0.005%
TEG	<0.0005%

Table 4 - 2: Chemical Composition of CO2 Stream

4.1.1.2 Formation Fluids

Aquifer samples were collected from various geologic formations in MCI MW-1. The samples from the Mt. Simon aquifer were analyzed for elemental concentrations, isotopic parameters, and general parameters (pH, total dissolved solids, etc.). The laboratory analytical results are included in **Appendix G.** A table compiling the geochemical analytical data obtained from the Mt. Simon is included in **Appendix I.** The analytical data detailing the chemical composition of the Mt. Simon injection zone was utilized for purposes of MCI CCS 3 Well corrosion modeling and metallurgy review to determine the potential corrosion risk of the 13Cr material. In response to recent industry lessons learned, 25Cr was the material selected for injection well construction due to its higher corrosion resistance.

Corrosivity of Construction Materials

Table 4-3 presents a condensed list of the chemical parameters and concentrations from the Mt. Simon aquifer samples that were used to evaluate the potential corrosion risk of the 13Cr well construction material within the injection zone. See Table 5 in the Viking Engineering 13Cr Corrosion Modeling Report in **Appendix Y.**

Aquifer Chemical Parameters (Note 1)	Concentrations	Units
pH	[redacted]	
Calcium	[redacted]	mg/L
Chloride	[redacted]	mg/L
Density	[redacted]	g/cm^3
Iron	[redacted]	mg/L

Aquifer Chemical Parameters (Note 1)	Concentrations	Units
Sodium	[redacted]	mg/L
Total Dissolved Solids (calculated)	[redacted]	mg/L
Sulfate	[redacted]	mg/L
Note: (1) For complete list of Mt. Simon Chemicals used in the Modeling, see Table 5 of Appendix Y.		

Table 4 - 3: Chemical Parameters of Mt. Simon Brine Used for 13Cr Corrosivity Evaluation

Viking Engineering conducted a thermohydraulic analysis and corrosion assessment to evaluate the fitness for service of 13Cr metallurgy based on the material properties, the in-situ conditions, and laboratory analytical test data for the water from the MCI MW-1 well. Viking considered normal injection conditions as well as worst-case upset injection conditions where the injected CO_2 mixed with brine water in the Mt. Simon flowed back into the well. Viking also considered the potential for sulfide stress cracking. [redacted] the service life for the materials under those conditions exceeds the duration of the project. MCI CCS3 and the deep monitoring wells (MCI MW-1 and MCI MW-2) will be constructed with Super 25Cr casing and tubing material within the Mt. Simon. The exposed components of the packer will be specially constructed from CO_2-resistant materials including 25Cr in addition to specially designed polymers for the elements. Super 25Cr is a highly corrosion resistant material. By utilizing the Super Chrome material grade, which is a Super Duplex Stainless Steel, these well designs have increased pitting and corrosion resistance to formation fluids combined with CO_2 over the recommended 13Cr material.

4.1.2 Casing/Tubing

The well will be designed using carbon steel for the casing and tubulars that are not expected to be in contact with a mixture of the injectate (CO_2) and water. That is, the conductor, surface, and intermediate casing sections will all be carbon steel. The deep casing string will be constructed with corrosion-resistant chrome (25Cr) across the reservoir and caprock to total depth (TD) and carbon steel from above the caprock to surface. This section of the wellbore is expected to have intermittent exposure to CO_2-formation water mixed fluids especially in the initial phases of injection and intermittently when well workovers are performed throughout the life of the project. [redacted] the injection tubing string will be composed of corrosion resistant material.

All casing strings will be centralized with bow type centralizers. Confidential, Privileged, or Sensitive Business Information [redacted]

Specific pressure ratings for the tubulars are provided in Permit **Section 4.1.2** and in **Appendix X** *Marquis_Injector_TDAS-Simulation 6-30-2023*. However, all selected casing and tubing grades and weights will be adequate for handling anticipated stress loads and pressures throughout the life of the project. The downhole tubulars were analyzed to ensure their ability to withstand the anticipated loads. This analysis reviewed loads during installation, drilling, injection, workover, and subsequent abandonment. Additionally, effects due to cyclical loading, temperatures and temperature fluctuations, and exposure to wellbore fluids were also assessed. **Figure 4-5** details the minimum recommended tubulars and descriptions of key loads that were assessed. The design is robust, meeting industry accepted minimum safety factors with a significant margin. See **Section 4.1.3** for design standards and safety factors.

The injection well will include the following casing strings: Confidential, Privileged, or Sensitive Business Information [redacted] All casing strings will be cemented to surface**. Figures**, **4-5 ,** and **4-6** summarize the casing and tubing/packer program for the injection well. Any potential changes to the final well design will be discussed with the UIC Director or representative.

The deepest underground source of drinking water (USDW) was confirmed from the fluid sampling program during the characterization phase and was determined to be the Gunter Sandstone formation. Intermediate casing will be set through the Gunter and into the top of the Eau Claire caprock which will provide an additional layer of protection to the USDW.

Casing String Name	Open Hole Size	Outside Diameter (in.)	Setting Depth (ft MD)	Weight (lb/ft)	Wall Thickness (in.)	Grade	Connection
Conductor	Confidential, Privileged, or Sensitive Business Information [redacted]						
Surface							
Intermediate							
Long String							
Injection Tubing							

Casing String Name	Outside Diameter (in.)	Weight (lb/ft)	Grade	Connection	Burst Rating (psi)	Collapse Rating (psi)	Tensile Yield (klbf)
Surface	Confidential, Privileged, or Sensitive Business Information [redacted]						
Intermediate							
Long String							
Injection Tubing							

Table 4 - 5: Tubular Performance Details

4.1.3 Tubular Stress Conditions (40 CFR 146.86 (c))

In compliance with Casing Performance and Mechanical standards listed in API Technical Report 5C3, the information reviewed for the casing design of the MCI CCS 3 resulted in all strings exceeding the minimum design factors derived from the design methods of API Recommended Practice 1171 (Underground Natural Gas Storage). Safety factors are the ratio of material strength, ultimate strength, yield strength, or endurance strength to the working or allowable strength or stress of the same type. Factor of safety = material strength / design stress. Marquis' third-party engineering firm (Tres Management) took the pipe vendor's published strengths for Burst (Internal Yield Strength), Collapse Resistance Pressure and Joint or Body Strength (Axial Load Limit) and divided this value by the anticipated loads. Minimum calculation design factors are in **Table 4-6**.

Design Criteria	Minimum Design Factor
Burst Resistance	[redacted]
Collapse Resistance	[redacted]
Axial Resistance	[redacted]

Table 4 - 6: Minimum Design Factors for Casing

4.1.3.1 Surface Casing

The surface casing will be the first string of casing installed by the drilling rig. The surface casing will be isolated behind two casing strings during injection operations, so the only applicable load conditions are: (1) during the installation of the surface casing and (2) during drilling of the intermediate hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a [redacted] and meets design criteria. [redacted]

Design Criteria	Worst Case Load	Load Condition	Safety Factor
Tension	Pressure Test	[redacted]	[redacted]
Burst	Pressure Test	[redacted]	[redacted]
Collapse	Cementing	[redacted]	[redacted]
Collapse	Full Evacuated	[redacted]	[redacted]

Table 4 - 7: Surface Safety Factor Summary

4.1.3.2 Intermediate Casing

The intermediate casing will be the second string of casing installed by the drilling rig. The intermediate casing will not be exposed to injected fluids due to being isolated behind the long string. All applicable load conditions occur during the installation of the intermediate casing and during drilling of the production hole section. The highest evaluated burst load occurs when pressure testing the casing, which [redacted] meets design criteria. Axial loading will be minimal due to relatively shallow setting depth and will be the highest during pressure testing. During the pressure test, the evaluated load [redacted] The worst-case collapse loading for the intermediate casing would be if returns are lost while drilling the long string hole interval; however, this still [redacted], which meets design criteria. Operationally, the highest risked planned collapse scenario is during cementing operations resulting [redacted].

Design Criteria	Worst Case Load	Load Condition	Safety Factor
Tension	Pressure Test	[redacted]	[redacted]
Burst	Pressure Test	[redacted]	[redacted]
Collapse	Cementing	[redacted]	[redacted]
Collapse	Full Evacuated	[redacted]	[redacted]

Table 4 - 8: Intermediate Safety Factor Summary

4.1.3.3 Long String Casing

The long string is the final casing string that will be installed and will be exposed to installation and injection load cases. The upper portion of the string will be isolated by a tubing and packer completion allowing for use of carbon steel. The lower portion of the string that will be across the injection zone and caprock will use a corrosion resistant alloy (25Cr) as this string will be providing long term well integrity after the injection phase is completed and the well will be plugged. The highest evaluated burst load occurs when pressure testing the casing, which results [redacted] and meets design criteria. However, due to the limit of Maximum Injection Pressure from the Confining Zone Fracture Pressure (90%), the Long String Pressure test should be limited to the Maximum Injection Pressure; Resulting in a Burst [redacted] Axial loading will be minimal due to shallow setting depth and minimal temperature fluctuations. Worst case for axial loading would be an unlikely scenario of casing stuck on bottom. The worst-case collapse loading for the long string casing is a full evacuation to air which results in a [redacted] which meets design criteria. This annulus will be filled with packer fluid (to minimize corrosion) and will be monitored to check for leaks; thus, this evacuated load case is extremely unlikely.

Design Criteria	Worst Case Load	Load Condition	Safety Factor
Tension	Stuck Pipe	[redacted]	[redacted]
Burst	Pressure Test	[redacted]	[redacted]
Collapse	Cementing	[redacted]	[redacted]
Collapse	Full Evacuated	[redacted]	[redacted]

Table 4 - 9: Long String Safety Factor Summary

4.1.3.4 Injection Tubing

The injection tubing will be the final string of tubulars installed. The injection tubing will be the primary tubular in contact with injected fluids. During a workover event, the tubing may be removed from the well and can be replaced if any wall loss or damage has taken place. The highest burst load evaluated occurs when the tubing is pressure tested. This load results [redacted] SF, which meets design criteria. Burst load during normal injection operations (maximum injection pressure, low annular pressure) results [redacted]. Burst load during injection with an annular pressure loss event results in a [redacted] The highest collapse load assessed assumes that the tubing is evacuated during a high annular pressure event, but still results [redacted] and meets design criteria. Axial loading will be minimal due to shallow setting depth, low temperatures and all evaluated axial load cases result in [redacted] Furthermore, axial modeling (WELLCAT^{TM} Temperature & Pressure) analysis indicated that both pressure testing and operational conditions are in the working envelope of the tubing-packer design limits (See **Figure 4-3**: Packer-Tubing Axial Loading).

[redacted]

Figure 4 - 3: Packer-Tubing Axial Loading

4.1.4 Cement (40 CFR 146.86 (b))

The cemented casing strings (four in total) for the proposed injection well will all be cemented back to surface. The surface strings will be cemented using Class A, H, or G cement while the intermediate string will be cemented using Class H or G cement. The injection string will be installed using Schlumberger's EverCRETE (or equivalent) as the tail mix across the injection reservoir and caprock intervals with Class G or H as the lead above the caprock. **Table 4-10** gives a summary of the cement types to be used for each casing string.

Casing String	Appx. Depth Range (MD ft)	Cement Type
Surface	[redacted]	Class A, G, or H
Intermediate	[redacted]	Class G or H
Deep	[redacted]	CO_2-Resistant tail slurry /Class G or H: Pozzolan 50:50 lead slurry

Table 4 - 10: Summary of Cement Types and Corresponding Casing Strings

Class A cements are adequate for providing zonal isolation in behind-pipe environments to prevent the movement of formation fluids between zones. Class A cements have been applied in shallow oil and gas wells and water disposal wells for many decades and are an accepted best practice. In a typical, non-corrosive subsurface environment (i.e., aquifer or oil/gas reservoirs) Class A cement will perform well throughout the service life of the well.

Class G or H cements are generally intended for use in deeper onshore wells and will have improved performance characteristics under higher temperature and pressure conditions, as compared to Class A cements (Guner & Ozturk, 2015).

The deep casing string will be cemented with CO_2-resistant cement where appropriate. Casing sections which have potential to come in contact with the CO_2 will be designed as a "No-Portland" slurry.

All casing strings will be cemented to surface. **Table 4-11** describes the type of cement, estimated volumes, and weight of the mixture in pounds-per-gallon (ppg). Additives may change slightly based on laboratory testing. Volumes will be adjusted based on wireline logs or fluid caliper.

Casing String	Casing Depth (MD ft)	Cement Description
Surface	[redacted]	Lead, Class A w/gel 13.2ppg 104bbls (50% excess) Class A, 15.6 ppg, 54bbls (50% excess)
Intermediate	[redacted]	Lead, 50/50 Poz:Class H w/gel, 13.2 ppg, 400bbls (25% excess) Tail, Class H, 16.4 ppg, 50bbls (25% excess)
Deep	[redacted]	Lead, 50/50 Poz:Class H w/gel, 13.2 ppg, 174bbls Tail, CO_2-Resistant, 15.2 ppg, TOC 2700', 165bbls (25% excess)

Table 4 - 11: Cement Program for the CO2 Injection Well

4.1.5 Downhole Completion Equipment (40 CFR 146.86 (a)(2, 3)

Completion equipment will exceed the ratings of the injection tubing and will be suitable for downhole conditions. The downhole completion equipment will include:

- [redacted]

[redacted] which will be below the top of the Eau Claire Caprock. Tubing tail pipe will be present below the packer to allow installation of a tubing plug. [redacted] Positive external pressure will be applied to and monitored in the annulus throughout the service life of the well fluid system (**Section 4.7**).

The final packer selection for this well will be determined prior to completion. However, the preliminary selection is a Halliburton X-Treive hydraulic set production packer. Although a high-pressure differential will not be observed in this well, the design of this packer provides additional assurance of a positive seal. The exposed components of the packer will be specially constructed from CO_2-resistant materials including <u>25Cr</u> in addition to specially designed polymers for the elements. [redacted]

4.1.6 Perforation Strategy

The perforated interval of the injection well will encompass selected targets throughout the Mt. Simon. See **Figure 4-1** which identifies the perforation zones. The perforated zones will range from one to six shots per foot (SPF) depending on the evaluation of the wireline logs of the MCI CCS 3. Perforated zones will be selected to balance well performance (i.e., injection pressure) with plume development. Because the Mt. Simon is expected to have some level of heterogeneity, the final selected perforation intervals will largely depend on interpreted permeability layers within the Mt. Simon. Modeled perforation intervals are based on data from MCI MW 1 well.

The perforation strategy has been designed to purposely avoid perforation and injection into the shallowest and deepest portions of the Mt. Simon. The deepest sections were avoided in order to give a buffer zone between injection and the basement granite, as injecting too close to the basement has been shown to cause microseismic activity in other injection projects. Omitting this zone from the perforation and injection strategy adequately mitigates that risk. The shallowest layers of the Mt. Simon are not being perforated for several reasons. First, it gives an additional buffer for vertical migration of the CO_2. This will allow the plume to occupy more of the vertical space before it hits the seal and buoyancy spreads it further. Second, it will also allow a pressure buffer zone to allow the injection pressure to dissipate prior to hitting the seal. Third, the upper Mt. Simon has some very prolific permeable zones. If these zones were perforated, the CO_2

plume would preferentially flow into these zones and quickly migrate horizontally creating an even larger plume footprint and AoR.

4.2 Drilling Contingencies

The largest drilling issue is anticipated to be the Potosi Dolomite [redacted]. This formation is widely known for its vugular, secondary porosity zones that can lead to lost circulation while drilling. Generally, it is thought to be more problematic deeper into the Illinois Basin to the south and east, away from the Marquis Biocarbon Project site. However, it is a risk that the project will plan to manage at the project site. The Potosi formation did not present drilling problems during the installation of the MCI MW 1 well. However, in the event circulation is nearly or completely lost, the plan is to drill ahead without drilling fluid returns through the remainder of the formation if possible. Then, a thixotropic cement slurry will be pumped, likely several slurries, to seal off the lost circulation zones. Once circulation has been fully restored, drilling will proceed as planned.

In the event of severe lost circulation issues, a two-stage cement job may be implemented. The differential valve (DV) tool will be set just above the uppermost encountered lost circulation zone.

Although elevated pressures or hydrocarbons are not expected, Blow Out Prevention Equipment (BOPE) will be installed prior to drilling below the surface casing. Periodic drills and training will be performed to ensure the crews are educated in how to react to a well control event.

Other planned contingencies include standard oilfield practices for preventing excessive borehole deviation and a lost drill string. A stiff bottom-hole assembly (BHA), including stabilizers and/or drill collars, will be used to prevent significant deviation from vertical and to minimize the corkscrew tendency of the drill string. Intermittent deviation checks using single shot surveys will be used to verify that wellbore deviation stays below five degrees from vertical. Directional drillers will be contracted in the event consecutive deviation surveys show to be greater than five degrees from vertical to bring the wellbore back to near zero degrees.

Periodically throughout the drilling process the drill string will be pulled back up through the wellbore to ensure the hole is in good working condition, known as “wiper trips.” These short trips can prevent the buildup of formation cuttings around the outside of the drill string which can cause the string to become stuck in the hole in the worst cases. They also ensure the formation of an even mud-cake layer along the walls of the wellbore which aids in better data collection with wireline tools in addition to a smoother installation of casings later in the process.

4.3 Annular Fluid System

All project wells will have annular fluid when tubing and packers are installed. MCI CCS3 will have an active annular pressure monitoring system. The space between the casing long string and the injection tubing (i.e., annulus) is filled with a pressurized brine fluid, and is sealed at the bottom by the packer. The active annular system monitors the annulus pressure and the fluid volume. Confidential, Privileged, or Sensitive Business Information [redacted]

The annular monitoring system will have a continuous annular pressure gauge, pressure regulators, a brine water storage tank, a low-volume/high-pressure pump, and tank fluid volume level indicator. Confidential, Privileged, or Sensitive Business Information [redacted]

Confidential, Privileged, or Sensitive Business Information [redacted]

The annulus fluid will contain additives and inhibitors including: a corrosion inhibitor, biocide (prevent growth of harmful bacteria), and an oxygen scavenger. Example additives and inhibitors are listed below along with approximate mix rates:

- Confidential, Privileged, or Sensitive Business Information [redacted]
- [redacted]
- [redacted]
- [redacted]

These products were recommended by and are provided by Tetra Technologies, Inc., of Houston, TX. Actual comparable products and providers may be used other than those described above.

The annular system pressures are provided in **Table 4-12** below. Confidential, Privileged, or Sensitive Business Information [redacted].

Type	**Pressure** (Note 1)	**Units**
Maximum Anticipated Injection Pressure (MAIP)	[redacted]	psi
Annular Pressures		
Operational Packer Differential (Note 2)	[redacted]	psi

Type	Pressure (Note 1)	Units
Annular Fluid Hydrostatic Pressure	[redacted]	psi
Maximum Annular Pressure (MAP)	[redacted]	psi
Maximum Surface Pressure Applied (Note 3)	[redacted]	psi

Notes:
(1) The low and high [redacted] be set to engage the annulus pump or shut the pump down and relieve pressure, respectively.
(2) When not injecting, the system will maintain the [redacted] the pressure of the CO_2 in the injection tubing at the depth of the packer, which will be monitored by the WAMS control system.
(3) Maximum surface pressure applied is delivered from [redacted] injection pressure, which is 90% of the fracture pressure.

Table 4 - 12: Injection and Annular System Pressures

4.4 Stimulation Program

No stimulation program is being planned as the expected injectivity of the Mt. Simon Sandstone should be adequate for the planned injection volumes. A small volume of acid may be required to “clean the perforations” prior to injection but formation breakdown pressure will not be reached during the activity.

4.5 Demonstration of Mechanical Integrity

Pressure testing and logging will be performed to confirm the casing was installed correctly and cemented appropriately.

Please refer to the Pre-Operational Testing Plan (Permit **Section 5**) and the Testing and Monitoring Plan (Permit **Section 7**) for additional details on the demonstration of mechanical integrity.

4.6 References

Guner, D., Ozturk, H., 2015. Comparison of Mechanical Behavior of G Class Cements for Different Curing Time. Presented at 24th International Mining Congress and Exhibition of Turkey, 2015.

Schlumberger. EverCRETE system: https://www.slb.com/drilling/drilling-fluids-and-well-cementing/well-cementing/cemcrete-cementing-technology/evercrete-co2-resistant-cement-system.