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CO_2 well construction: Lessons learned from United States Department of Energy sponsored projects

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Abstract

The objective of a carbon capture and storage (CCS) project is long term storage of CO_2 with no migration outside of the storage zone. To meet this objective, CO_2 injection wells should meet a higher construction standard than conventional oil and gas wells. Over the last decade multiple injection and monitoring wells have been constructed as part of the United States Department of Energy's (US DOE's) regional carbon sequestration partnership and other federally funded programs. These wells provide information and lessons learned that can be applied to future projects as CCS moves from the pilot and demonstration phase to the commercial phase. As part of the US DOE funded *Establishing an Early Carbon Dioxide Storage Complex in Kemper County, Mississippi* (Project ECO_2S) project a study was conducted to collect and compare data from monitoring wells drilled as part of the project and at wells drilled from as part of the *Illinois Basin – Decatur Project* and the *Ohio River Valley CO_2 Storage Project / American Electric Power Product Validation Facility Project*. The set of wells in this study used a variety of materials and methods for construction. Cements used included common Portland well cement, Portland cement with pozzolan additives to provide CO_2 resistance, and highly engineered CO_2-resistant cements. Results showed microannuli, cement contamination, and formation breakdown in portions of the wells. Analyses of the operational details of the cementing operations give insight into how these conditions occurred. Each of the wells encountered problems that are common within conventional oil and gas wells. Lessons identified during the study highlight the need to emphasize a successful cement job at every point in the construction of the well from laboratory testing through drilling, cementing, and completion.

Keywords: CO_2; CCS; well integrity; cement; microannulus; leakage

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1. Introduction

The objective of a carbon capture and storage (CCS) project is long term storage of CO_2 with no migration outside of the storage zone. To meet this objective, wells constructed for CCS are required to meet a higher standard than conventional oil and gas production wells. Additionally, CCS injection wells are regulated in the United States by the Underground Injection Control (UIC) geologic sequestration wells (Class VI) program developed by the US Environmental Protection Agency (EPA). The program specifies strict well construction standards including CO_2 resistant materials and cement to surface. Technology and equipment used to construct CCS wells comes from the oil and gas industry and construction is normally supervised by oilfield personnel.

Over the last decade multiple injection and monitoring wells have been constructed as part of United States Department of Energy's (US DOE) regional carbon sequestration partnership and other US DOE funded programs. These wells provide information and lessons learned that can be applied as CCS moves from the pilot and demonstration phase to the commercial phase. As part of the US DOE funded *Establishing an Early Carbon Dioxide Storage (ECO_2S) Complex in Kemper County, Mississippi* (Project ECO_2S) project a study was conducted to collect and compare data from monitoring wells drilled as part of the project and at wells drilled from as part of *Illinois Basin Decatur Project* and the *Ohio River Valley CO_2 Storage Project / American Electric Power Product Validation Facility Project* (Mountaineer Project).

2. Background

Under the Clean Water Act in the US, the EPA regulates the construction, operation, permitting, and closure of injection wells used to place fluids underground for storage or disposal. There are six different classes divided based on the type of fluid being injected and the location in the subsurface of the injection [1].

Class I: Class I wells are divided into two subgroups: hazardous and nonhazardous waste injection wells. Class I hazardous waste injection wells are used to inject hazardous waste into non-drinking water geologic units. Class I non-hazardous wells are used to inject non-hazardous industrial waste into non-drinking water geologic units. Prior to the adoption of Class VI this class included some CO_2 injection wells that were not injecting into oilfields.

Class II: Class II wells are used to inject fluids related to oil and gas production. The fluids can be waste, typically brine produced with oil and gas, injected into non-drinking water geologic units, fluids such as CO_2, water, or other fluids injected into producing reservoirs for enhanced oil recovery (EOR), or liquid hydrocarbons injected into geologic formations for storage. Class II permits have been issued to CO_2 storage study wells associated with oil and gas projects.

Class III: Class III wells are used for solution mining of minerals and are not used for CO_2 injection

Class IV: Class IV wells are used for shallow hazardous and radioactive waste injection into or above underground sources of drinking water (USDWs). This class of wells has been banned

Class V: Class V wells are used for many different types of injection operations, including shallow non-hazardous waste injection, aquifer storage and recovery, and geothermal power production. Class V was used to permit some geologic storage wells prior to the adoption of Class VI.

Class VI: Class VI was adopted at the end of 2010 for permitting CO_2 storage injection into deep saline formations. Class I and Class V wells designed and constructed for CO_2 storage demonstrations during the rule making process relied heavily on the draft Class VI rules. With the adoption of Class VI, the US EPA has prohibited permitting of CO_2 injection wells for saline storage projects, including small studies, under Class I and Class V. The Class VI program is partially based on the Class I non-hazardous well program. The long string-casing, and surface casing(s) must be cemented to the surface. However, the Class VI program requires more detailed logging, modeling, and planning than Class I nonhazardous; with detailed open-hole logs and radial cement integrity logs,

detailed reservoir modeling to establish the area of review (AOR), and multiple plans for operation and post injection being required. Class VI requires monitoring to ensure that stored CO_2 behaves as expected in the subsurface and does not pose a risk to underground sources of drinking water (USDW)

Class II and Class VI are the only current classes of injection wells that can be used to permit CO_2 injection for carbon capture, utilization, and storage (CCUS) projects. The construction requirements for Class II wells are more flexible than those of Class VI; the injection casing is not required to be cemented to surface and radial cement integrity logs are not required. However, all classes of US EPA wells are required to protect USDWs.

This study evaluates wells from three different projects permitted under Class I, Class V, and Class VI of the UIC program. The analysis presented relied on the construction records and details of the well and well logs collected after construction to identify issues during and after construction that can affect well integrity. The objective of this study is to identify the types of flaws that can occur in CO_2 wells and their root causes as lessons learned that can be applied to future projects. The dataset includes two wells that injected CO_2 and four wells that were constructed as project monitoring wells but designed to Class VI standards. The projects and wells in this study include:

- Project ECO_2S: three monitoring wells designed to Class VI specifications
- IBDP: one Class VI (initially Class I) injection well and one monitoring well designed to Class VI specifications
- Mountaineer: one injection well designed as a Class V well

Each of the wells evaluated in this study employed sonic and ultrasonic mapping methods for cement and casing integrity evaluation that are more sophisticated than methods typically used for conventional oil and gas wells. In addition to the detailed logging (mapping), open-hole logs, hole conditions, casing setting and centralization details, and cement pumping data were used to assess the integrity of each of the wells.

The logging tools created maps of the casing, cement-casing bond, and cement quality that provided detail on the success of cement placement and the quality of cement behind the long-string casing in the study wells. Open-hole logs provided information on specific geologic factors that may have affected cement placement. Hole conditions, casing and centralization details, cement slurry formulation, and cement job pumping data provided insight into how well design and field execution affected the final cement placement.

3. Wells

The set of wells in this study used a variety of materials and methods for construction. Cements used included common Portland well cement, Portland cement with pozzolan additives to provide CO_2 resistance, and highly engineered CO_2-resistant cements. Casing material included mild steel and 13-chrome alloy. Cementing techniques included single- and two-stage methods that brought the cement either into the surface casing or all the way to the surface. Results of the integrity assessment showed microannuli, cement contamination, and formation breakdown in portions of the wells. Analyses of the operational details of the cementing operations give insight into how these conditions occurred.

3.1 Establishing an Early Carbon Dioxide Storage (ECO_2S) Complex in Kemper County, Mississippi

Three wells, MPC 26-5#1, MPC 34-1#1, and MPC 10-4#1, were drilled to allow detailed characterization of the subsurface at the site. The wells were then completed as monitoring wells following the UIC regulations (Part 146 in the US Code of Federal Regulations) for the construction of Class VI injection wells as a guideline. The UIC Class VI regulations call for casing, cement, and other materials to be compatible with stored CO_2 and subsurface conditions. The casing and cementing program must prevent movement into or between USDWs. A cement isolation log must be run to radially evaluate the location and quality of cement after construction. The wells were logged with ultrasonic

Isolation Scanner* Cement Evaluation Service (note: * denotes the mark of Schlumberger). The Isolation Scanner provided radial maps of the casing and cement to assess quality and placement.

The wells were designed to meet the UIC Class VI construction requirements with both the surface and long string casings cemented to surface. The long string sections of the well were designed with chrome casing and CO_2 resistant cement across the potential storage zones and through the caprock. The wells were drilled to approximately 5,400 to 5,700 ft. Table 1 presents the construction details for the Project ECO_2S wells. To simplify cementing operations, each well was cemented in a single stage. Single-stage cementing required balancing the slurry properties and density with set cement properties and CO_2 resistance.

Table 1 Project ECO_2S well construction details. Note ppg is pounds per gallon.

Well	**MPC 26-5 #1**	**MPC 34-1 #1**	**MPC 10-4 #1**
Surface Casing	12.25-in Open hole with 9-5/8-in 40lb/ft LTC J-55 set at 2489'. Cemented to surface	12.25-in Open hole with 9-5/8-in 40lb/ft LTC J-55 set at 2495'. Cemented to surface	13.5-in Open hole 10-3/4-in 45.5lb/ft BTC J-55 set at 2505'. Cemented to surface
Surface Cement	50 bbls 10.5 ppg Spacer	30 bbls 10.5 ppg Spacer	30 bbls 10.5 ppg Spacer
	Lead: 210 bbls 65/35 cmt-poz 6% gel 1.97 cu.ft/sk 12.4 ppg	Lead: 246 bbls 65/35 cmt-poz 6% gel 2.1 cu.ft/sk 12.0 ppg	Lead: 233 bbls 65/35 cmt-poz 6% gel 2.1 cu.ft/sk 12.0 ppg
	Tail Cement: 69 bbls Class A 1.18 cu ft/sk 15.6 ppg	Tail Cement: 59 bbls Class A 1.18 cu ft/sk 15.6 ppg	Tail: 65 bbls Class A 1.18 cu ft/sk 15.6 ppg
	Logging confirmed cement to surface	Logging confirmed cement to surface	Logging confirmed cement to surface
Long String Hole Size	8.5-in	8.5-in	9.875-in
Total Depth	5,877 ft	5,748 ft	5,440 ft
Mud Weight	9.4 ppg	9.4 ppg	9.1 ppg
BHST	135 °F	140 °F	128 °F
Long String Casing	5-1/2-in 17lb/ft Cr13-85 JFE-Bear 5865 ft -3,002 ft and 5-1/2-in 17lb/ft L-80 LTC 3,002 ft-surface	5-1/2-in17lb/ft Cr13-85 JFE Bear 5705 ft -2,846 ft and 5-1/2-in 17lb/ft L-80 LTC 2,846 ft-surface	7-in 29lb/ft Cr13-85 JFE Bear 5,440-2,792 ft and 7-in 26lb/ft N-80 LTC 2792 ft-surface
Centralization	Centralization: One centralizer every joint for first 66 joints (3,140ft), every other joint to 2,435ft and every third joint to surface	Centralizer every joint for first 68 joints (2,906ft), every other joint to 2287 ft and every third joint to surface	Centralizer every joint for first 65 jts (2,792ft), every other joint to 2,531ft and every third joint to surface
Primary Cement	well cemented to surface in one stage	well cemented to surface in one stage	well cemented to surface in one stage
	50 bbls 11.0 ppg spacer	50 bbls 10.5 ppg spacer	60 bbls 11.0 ppg spacer
	Lead: 65/35 cmt-poz 6% gel 1.92 cu ft/sk,12.7 ppg	Lead: 160 bbls 65/35 cmt-poz 6% gel 1.95 cu ft/sk 12.5 ppg	Lead: 327 bbls LiteCRETE lead at 11.5 ppg,
	Tail Cement: NeoCEM 1.13 cu ft/sk, 14.5 ppg	Tail Cement: 182 bbls 50/50 cmt-poz, 1.27 cu ft/sk, 14.5 ppg	Tail: 155 bbls 50/50 cmt-poz 1.27 cu ft/sk 14.5 ppg
	Displaced with 134 bbls fresh water	Displaced with 131 bbls fresh water.	Displaced with 202 bbls fresh water
	Note: Mixability problems with tail cement causing rates to be very low, poor mud removal as result.	Note: Lost returns after dropping the plug. Final lift pressure 800 psi	Note: Full returns. 140 bbls mud-cement mix and 60 bbls good cement to surf
	Held 500 psi on casing while logging	Held 500 psi on casing while logging. Log indicated cement top at 3100 top of tail at approximately 4,100 ft	Held 500-1,000 psi on casing while logging. Held 1,500 while logging inside surface casing
Remedial Cement		Perforated 2,939-40ft with 4 shots.	
		Cemented through tubing below retainer	
		50 bbls Mud Flush	
		Lead: 110 bbls 65/35 cmt-poz 1.95 cu ft/sk, 12.5 ppg	
		Tail 55: bbls 50/50 cmt-poz, 1.27 cu ft/sk, 14.5 ppg and 10 bbls Class A, 1.18 cu ft/sk, 15.8 ppg	
		Circulated 20 bbls to surface	
		logging confirmed cement to surface	

The results of the cementing varied greatly between the wells. Two wells successfully had cement returns to surface. One well lost much of the cement due to breakdown in the surrounding formations and had no returns to surface. This well was remediated by a perforation and squeeze operation. The well integrity assessment showed each well has integrity across the planned storage formation. The assessment identifies the likely reasons cement failed to reach the surface in one well including hole conditions, casing location, and slurry density.

MPC 26-5#1: The cementing service provider recommended a new system for use in CCS wells, with its physical makeup a proprietary blend. Lab testing prior to cementing the well indicated that the system was very viscous and could pose mixing problems. The service provider altered the system and improved the mixability so that the lab report rated it adequate. On the actual job, the system was very difficult to mix, and the pump rate had to be slowed to an average rate of 2.3 barrels per minute to achieve proper density control. This lowering and variation of the rate had a negative effect on mud removal and sections of the well show mud contamination in the cement sheath (Fig. 1).

Lesson learned: Lab testing is very important, and results should be monitored closely to ensure the lab results can be repeated in a field setting. Cement systems should be selected with care and ensure simplicity with full understanding of field operations.

MPC 34-1#1: This well experienced a loss of returns during cementing just as the leading edge of the spacer system was entering the surface casing and pumping was shut down to launch the wiper plug. The hole likely bridged to the point that the equivalent circulating density was raised enough to break down the natural fracture system encountered in a Paleozoic unit beneath the storage reservoirs; causing the cement to enter the formations. As a result, the cement top was lower than expected and as required by Class VI requirements (Fig. 2), which is to surface. The bridge was likely created by debris carried out of a deeper than usual sump below the casing (43 ft off bottom) when cementing commenced. A sump this deep would not likely be cleaned out by normal circulation prior to cementing and the addition of the material in the sump to the spacer and lead portions of the cement slurry would raise the effective circulating density leading to higher than expected pressures at the bottom of the cement column. This well was remediated some months later by perforating the casing, circulating cement to surface, and squeezing the perforations.

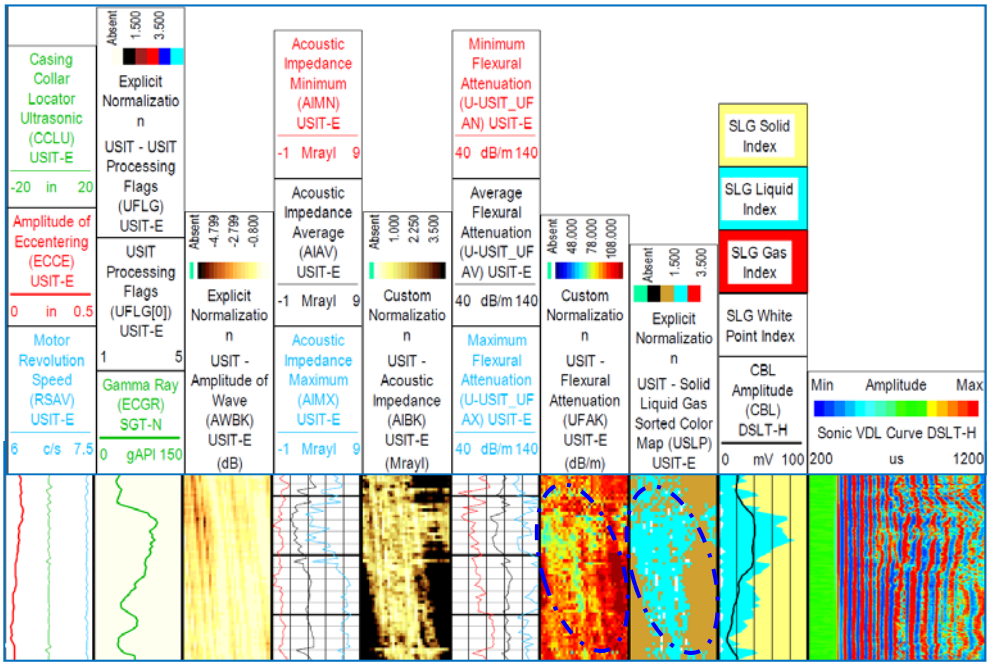

Fig. 1 Isolation Scanner log showing mud contamination in MPC 26-5#1. The contaminated zone is inside the dotted oval in the USIT - Flexural Attenuation track and the USIT - Solid Liquid Gas track.

Lessons learned: Good hole cleaning practices and surface execution are important for obtaining a good cement job. Setting the casing deeper would likely have allowed better cleanout during circulation prior to cementing.

MPC 10-4#1: A larger hole was drilled (13.5-in) and larger casing was run (7-in) compared to the MPC 26-5#1 and 34-1#1 wells. A caliper log run in the well indicated severe washouts and hole enlargement over a large portion of the open hole. Although the spacer volume was increased and the pipe was centralized, mud removal was compromised due to the number of washouts. This was detected during the cementing operation when cement contaminated mud was encountered at the surface very early in the cementing process. Pump rates were maximized and the lower section of the well has good bonding but inside the surface casing and in the area just below there is evidence of mud contamination and a microannulus.

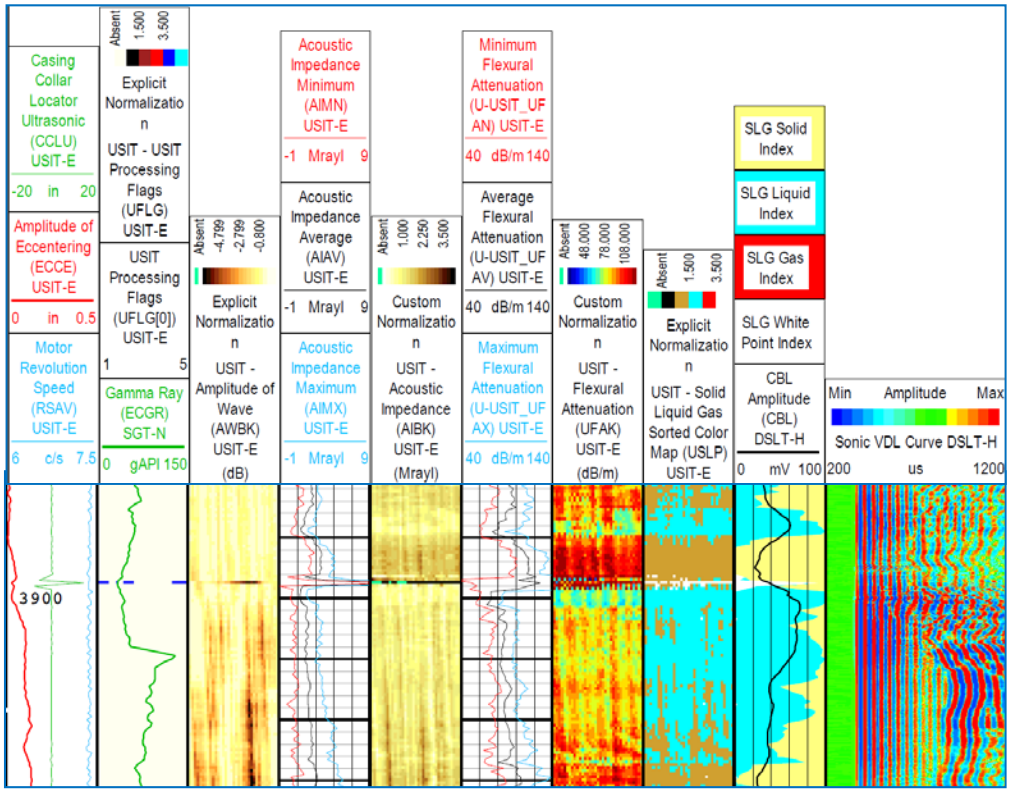

Fig. 2 Isolation Scanner log section showing patchy cement near the original top of cement in MPC-34-1 prior to remediation.

Lessons learned: Close attention is required during drilling to achieve adequate penetration rates and good hole cleaning without encountering hole enlargement. It is virtually impossible to obtain good mud removal in a highly washed out wellbore. This likely led to the mud contamination and microannulus seen inside of the surface casing.

3.2 Illinois Basin Decatur Project

The Midwest Geological Sequestration Consortium (MGSC) established the Illinois Basin - Decatur (IBDP) CCS project at the Archer Daniels Midland Company (ADM) ethanol fermentation facility in Decatur, Illinois, USA [2]. The objective of the project was to validate the capacity, injectivity, and containment of the Mt. Simon sandstone, which represents the primary carbon storage formation in the Illinois Basin. The CO_2 injection operations began on November 4, 2011, and were completed successfully on November 26, 2014, with a total injection mass of 999,215 tonnes of CO_2.

Well planning for the CCS#1 injection well started in 2008. The well was to be permitted through the Illinois Environmental Protection Agency as a Class I nonhazardous injection well. During this time the US EPA was finalizing plans for introducing the Class VI regulations for carbon dioxide injection wells. With an eye toward the impending Class VI regulations and to meet the Illinois EPA requirements, the CCS#1 injection well was constructed in such a manner that it would meet future Class VI requirements [3]. A 20-in surface casing was set through all fresh water bearing strata to a depth of 360 ft. A 17-1/2-in open hole was then planned to be drilled to the top of the Eau Claire formation with 13-3/8-in casing run to this depth and cemented to surface. Drilling proceeded without too many issues to a depth of 4,562 ft where complete circulation was lost. It was known that in gas storage wells some distance away that circulation had been lost in the Potosi formation, but the severity at the site of the CCS#1 well was unexpected. Attempts to regain circulation with the use of traditional lost circulation materials and methods was unsuccessful. As a result, cement plugs were placed to regain circulation. A total of five plugs were set and full circulation was regained. The well then continued to a depth of 5,336 where 13-3/8-in casing was run and successfully cemented back to surface in two stages. A 12-1/4-in open hole was then drilled to 7,230 ft using a KCl based polymer mud system. After an extensive logging program, 9-5/8-in casing was run and the well cemented to surface in a single stage. Casing for the well consisted of 9-5/8-in 47 lb/ft Cr13-80 from TD to 5,272 ft and 9-5/8-in 40 lb/ft N-80 casing from 5,272 ft to surface. The CCS#1 was to be the injection well for the largest CO_2 injection for carbon sequestration performed to date so the cementing of the long string casing was given high priority. The slurry design called for a tail slurry consisting of CO_2 resistant cement to be placed from TD back to a depth of approximately 5,000 ft and filler slurry of a cement-pozzolan blend from 5,000 ft to surface. Design included the use of simulation software to simulate mud removal and aid in centralizer placement. Numerous lab tests were performed to tweak both the lead and tail slurry performance. The mud spacer system was formulated and tested. The well was cemented with 1,100 sacks lead cement, 65/35 cement-pozzolan at 12.5 ppg and 950 sacks of CO_2 resistant cement at 15.84 ppg. The well was displaced with fresh water and full circulation was achieved. Surface execution was excellent.

Cement evaluation logs were run approximately four months later. The well was logged with a cement bond logging tool and the Isolation Scanner ultrasonic cement evaluation tool. Overall cement integrity was very good, but areas of micro-annuli were seen from 5,500 ft to the bottom of the well between the cement and the casing (Fig. 3). This micro-annulus was so small it posed no threat to wellbore integrity, but a thorough investigation was taken to fully understand the causes.

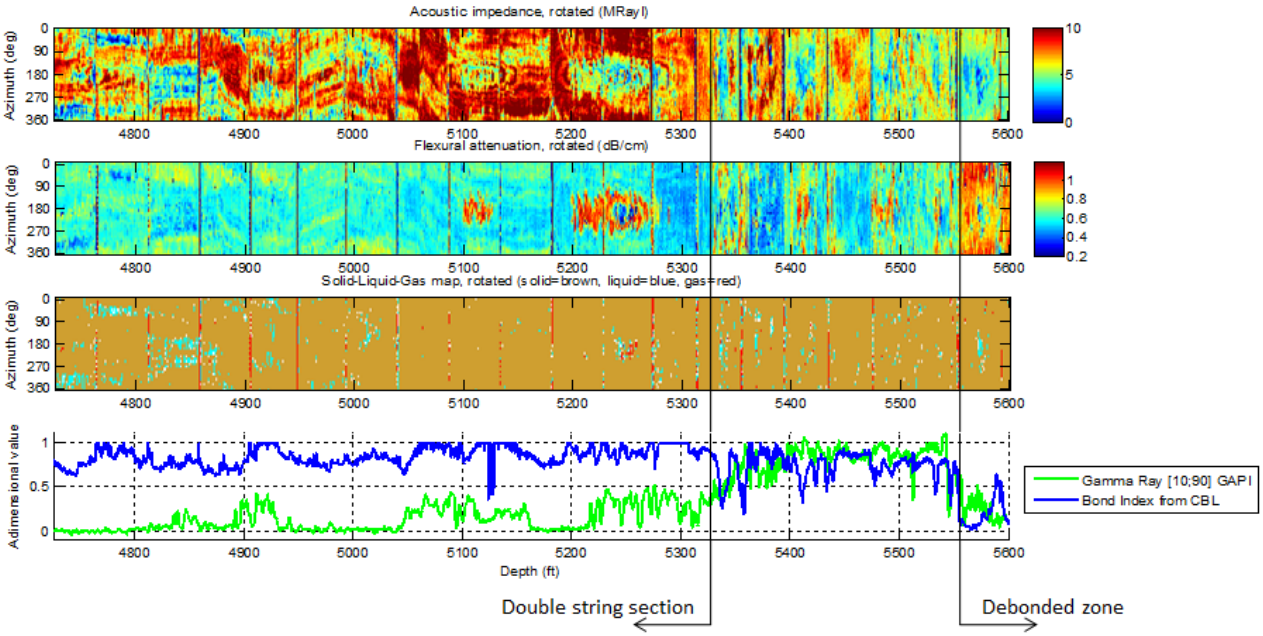

Fig. 3 log sections showing where microannulus (debonding) starts in CCS#1.

During the course of the investigation, several things were identified that would be addressed before the first monitor well, the VW#1, would be drilled and cased. The density of the CO_2 resistant cement going into the batch mixer was lower (0.4 ppg) than the slurry exiting the batch mixer. This suggests that during the batch mixing process the hollow micro spheres were being damaged or crushed by the centrifugal pumps of the batch mixer. Crushing of the microspheres would alter the solid volume fraction of the cement and alter the rheological properties of the cement by increasing the viscosity. The changing of the viscosity would alter the mixing front between the lead and tail cements which was observed in the cement evaluation logs. The Mt. Simon formation is a strong brine aquifer with a static gradient of 0.46 psi/ft in the lower section. It is possible that during the very short transition time of the cement or soon after taking a set, formation brine tried to flow upward separating the cement from the casing. This bond may have been weak due to the smoothness of the Cr13-80 casing. Lastly the bottom hole temperature at the time of cementing was elevated above the bottom hole static temperature. This was due to the high shear applied to the KCl polymer mud at the surface to maintain fluid properties. A temperature log run in conjunction with the open hole logging indicated a temperature of 131°F but after completion the temperature in the lower Mt. Simon was determined to be 123°F. The "cooling off" of the formation after cementing could have contributed to the creation of the micro-annulus observed in the cement evaluation logs.

Although present, the micro-annulus did not contribute to any loss of wellbore integrity. The injection pressure inside the casing was more than enough to close the micro-annulus during injection of the one million metric tonnes of CO_2 over a three-year period. Time lapse pulsed neutron logging was used to confirm that the injected CO_2 was only present in the intended injection zone.

Lesson Learned: Temperature changes can cause stresses in a well that can break the cement-casing bond causing a microannulus. The elevated temperature in the Mt Simon from circulating the KCl polymer drilling mud may have contributed to the formation of a microannulus on portions of the injection casing.

Lesson Learned: Differences in density and rheology between the field and lab can affect the quality of the cement job. Differences in density and viscosity between the planned and actual cement slurries may have led to mixing between the lead and tail slurries.

Two years later in the fall of 2011 the VW#1 well, the in zone and above zone monitoring well was drilled. This well was constructed with 13-3/8-in surface casing, 9-5/8-in intermediate casing, and 5-1/2-in long string casing. Again, the loss circulation zone was encountered in the Potsosi formation. Based on the CCS#1 experience the loss zone was sealed up with two lost circulation plugs. The 12-1/4-in intermediate hole was drilled to 5,322 ft. The 9-5/8-in intermediate casing was run to 5,320 ft and cemented to surface in two stages. An 8.5-in open hole was then drilled to TD of 7264'. After logging the 5-1/2-in long string casing was run. The casing string consisted of 5-1/2-in 17lb/ft Cr13-80 casing from TD to 5,054 ft and 5-1/2-in 17 lb/ft N-80 casing from 5,054 ft to surface. The cement design was changed from the CCS#1 well by eliminating the hollow microspheres and adding an expansion agent. Again, computer simulation of the actual hole trajectory was used to guide centralizer placement. The displacing fluid was changed from fresh water to an 8.8 ppg NaCl brine. The well was cemented in a single stage with 30 bbls mud flush, 725 sacks 65/35 cement-pozzolan lead mixed at 12.5 ppg and 800 sacks of CO_2 resistant cement mixed at 15.82 ppg. Cement was displaced with the previously mentioned 8.8 ppg brine. Surface execution of the cementing operation was again excellent. The cement evaluation logs were run four months later using the same logging tools (cement bond logging tool and Isolation Scanner). The results were very good with almost total cement coverage across all of the open hole section and no micro-annulus present.

3.3 Mountaineer

American Electric Power (AEP) conducted a carbon dioxide (CO_2) capture and storage demonstration project at its Appalachian Power Company (APCO) Mountaineer Plant, located near New Haven, West Virginia between October 2009 and May 2011. The project injected 10,219 metric tons of CO_2 into the Rose Run sandstone and 27,184 metric tons of CO_2 were injected into the Copper Ridge dolomite. Injection stopped on May 28, 2011. The injection

wells were permitted under the West Virginia Department of Environmental Protection (WVDEP) UIC Program as Class V injection wells. The permit authorized the injection of CO_2 through two deep wells (AEP-1 and AEP-2) at the Mountaineer site for a period of five years. The AEP-1 well is discussed here.

The AEP-1 injection well was part of the American Electric Power (AEP) Product Validation Facility (PVF) project at the Mountaineer Plant. The injection well was used for the CCS test project for CO_2 injection into the Copper Ridge dolomite. The well was drilled as a stratigraphic test well as part of CCS project feasibility study from 2002 to 2003 and completed as part of the AEP PVF project in 2009 and injection started in 2009 and lasted into 2011. The construction details of the well are presented in Table 2. The well was cemented in two stages. AEP-1 was designed with the surface casing and injection strings with cement planned from TD to surface and two intermediate strings with cement at the bottom and open annuli above the cement. The first stage of cement on the injection casing was designed to run from TD to the stage collar at 5,432 ft. The second stage was designed to run from the stage collar to the surface.

Table 2 AEP-1 construction details

Tubular Name	Borehole Total Depth (ft)	Sacks of cement	Type of cement
30-in Conductor	42	--	Class A
26-in Conductor	102	250	Class A
20-in Shallow Surface	259	490	Class A
13-3/8-in Shallow Intermediate	1,818	940, 120	50/50 poz mix lead, Class A tail
9-5/8-in Intermediate	3,906	300	Class A
7-in Deep Intermediate	6,288	294, 120	65/35 poz mix lead, Class A tail
4-1/2-in Injection Casing	9,190 plugged to 8,552	360, 320	Stage 2: 65/35 poz mix lead with Class A tail Stage 1: C-poz. Stage collar at 5,432 ft.

The cement job was conducted for the injection casing on April 3, 2009 and went smoothly with returns to surface. At the end of the first stage an external casing packer was inflated. After cementing and prior to injection, well integrity logs using USI* Ultrasonic Imager (USIT) were run (April 27, 2009 and May 15, 2009) to collect data on the quality of cement behind the 4-1/2-in injection string casing in AEP-1. Initially, logs were run with less than 800 pounds per square inch (psi) at the surface. The logs show that the cement top of the first stage is located at a depth of 7,280 ft instead of at the stage collar at 5,432 ft. The zone above stage collar, the second stage, showed little to no cement. A second set of logs was run on 2010. Repeat logging runs were conducted (October 3, 2010) at 0, 1,500, and 3,000 psi. The repeat logs confirmed lack of cement in the first stage. The logs at 1,500 and 3,000 psi show some improvement between 7,280 and 7,100 ft (Fig. 4). There was little cement between 7,100 and 6,430 ft and good to patchy cement between 6,430 and 6,000 ft. Between 6,000 ft to the stage collar there was poor, patchy cement in the 3,000 psi logs. Above the stage collar 3,000 psi log shows the cement is good to 5,380 ft and then patchy to good between 5,380 to 3,950 ft. Above 3,950 ft to the top of the log, 500 ft, the cement was good.

Cementing records indicate that cement was successfully circulated to surface. The poor cement quality was initially attributed to unset cement; not enough time between the cement installation and logging for the cement to completely hydrate. Additionally, an acid treatment was performed after the cementing but prior to cement logging. The timing of the acid treatment is important because the maximum observed surface pressure during the acid job was approximately 3,550 psi, higher than the 800-psi logging pressure for the initial logs. It is possible that the high treatment pressure caused a microannulus in the cement. A microannulus is confirmed by the improvement in the logs between the initial logging and the pressure passes in 2010. However, this does not explain the missing sections of cement and poor cement in the first stage between 7,100 and 6,500 ft. The missing cement may be explained by gas intrusion. The shale and limestone running between 7,100 and 6,450 ft show gas in the open hole logs, this lines up with the location of the poorest cement in the first stage. The inflation of the ECP at the end of the first stage may could have caused or exacerbated the problem by reducing the hydrostatic pressure in the cement column as it

transitioned from a liquid into a solid, allowing gas intrusion. Gas may have accumulated under the ECP pushing cement into the surrounding formations. Little gas was visible in the log, the annulus instead shows water/brine where there is missing cement. However, the microannulus would allow the escape of gas from this zone.

The CO_2 stream was sampled prior to and during injection; detailed analyses of the injected CO_2 show the CO_2 is approximately 97% pure. During the project the annulus between the 4-1/2-in and the 7-in casings showed a pressure buildup. Samples of the gas were collected from that annulus at the wellhead on December 15, 2009 and April 28, 2010 and analyzed to determine its composition. Results of these analyses indicated that the gas was between 85% (2009) and 88% (2010) methane, one percent nitrogen, and the remainder comprised other hydrocarbon gases. No CO_2 was detected. This implies that the cement between the perforations at 8,144 and 7,300 ft is providing isolation not allowing CO_2 leakage but the cement above 7,100 ft cement may be allowing sufficient gas to migrate to pressurize the annulus.

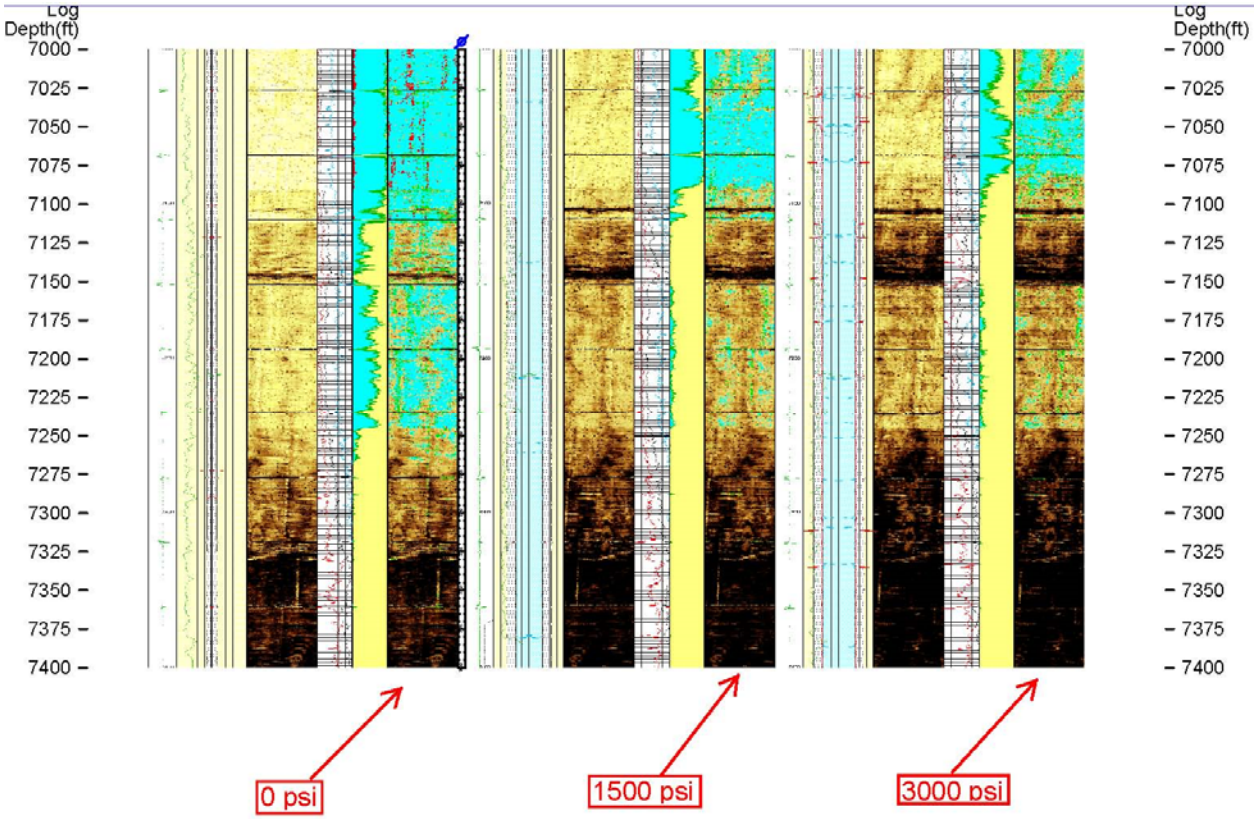

Fig. 4 Change in USIT response in AEP-1 at 0, 1500, and 3000 psi.

Following the completion of injection in 2011, the AEP-1 well entered the post-injection monitoring phase. During this phase of the project, the injection reservoir was monitored for CO_2 plume location and pressure stabilization, and groundwater monitoring was conducted to ensure injected CO_2 did not pose a risk to groundwater.

Initially the UIC permits called for a 20-year post injection period with an allowance to shorten it if the carbon dioxide plume has stabilized, the pressure front has stabilized, and there is no endangerment to USDWs. Based on these requirements requests were made in early 2013 for authorization to close the site and an updated post injection site care and closure was accepted in fall 2013 because monitoring and modeling showed the plume and pressure to be stable. AEP-1 and its sister injection well, AEP-2, and the monitoring well MW-3 were plugged in 2014. Two other monitoring wells for the project, MW-1, MW-2 continued to monitor until they were plugged and abandoned in 2017. No monitoring data during or after the injection provided any indication of CO_2 leakage during the project.

Lesson Learned: Design and implementation must be considered in tandem to allow for successful cementing. The open hole logs and mud logs indicated gas in the limestone formation above 7,300 ft and this was taken into account by adding a gas blocking agent to the first stage slurry. However, the inflation of the external casing packer may have reduced the hydraulic head on the cement column allowing gas to compromise the cement.

Lesson Learned: High-pressure well operations can damage the cement-casing bond at any point in the well's life. The high-pressure acid job after cementing likely created the microannulus above 7,200 ft. In addition, the high-pressure logging runs could have further damaged the bond.

4. Discussion

In each of the project wells, issues were identified that caused defects that could affect well integrity. At each project, conditions were identified that led to microannuli. These conditions include high pressure in AEP-1, higher-than-reservoir temperatures in CCS#1 and poor hole cleanout and mud contamination in MPC 10-4#1. Nelson and Guillot [4] note that all of these conditions can cause debonding of the casing and cement. Microannuli are common and can lead to the transmission of pressure and gas as in the case of AEP-1. Bellabarba et al. [5] described the need to achieve proper spacer rheology and hole cleanout to achieve casing-cement bond. In several instances, conditions were identified where proper hole cleanout or rheology problems affected cement quality. Differences in field behavior and laboratory behavior of cement slurries were identified as an issue that can affect the quality of cement jobs; as was the case in CCS#1 and MPC 26-5#1. Drilling and hole conditions including breakouts, hole cleanout, and gas zones affected the cement in AEP-1, MPC 34-1#1 and MPC 10-4#1. All of these issues are related to cultural differences in planning and operations between oil and gas and CCS projects.

Within oil and gas projects, it has been known that proper hole cleanout and hole conditioning leads to a better cement job. However, it is common in oil and gas drilling operations to rush cement jobs to finish wells and get the drill rig off the site. For CCS wells, from the initial well planning all the way through the well construction process, it should be emphasized that the goal of the well drilling is to drill a hole that will facilitate CO_2 storage. This requires a successful cementing operation; i.e., as straight and as close to gauge as possible followed by carefully planned completion operations. A slight change in penetration rate or different pump pressures can adversely affect the borehole as well as the cement integrity for the entire well by affecting hole cleanout. Changes in pressure and temperature during and after cementing can lead to the development of a microannulus. Slurry designs in the laboratory setting that can be difficult to implement in the field leading to defects in the cement and should be avoided.

Lessons learned during this study show how cultural differences, cement operations, and hole conditions can affect well integrity and these lessons may lead to more careful design and operations to reduce poor cementing outcomes for CO_2 wells. Lessons from this study also provide insight on how to balance operational needs for successful cementing with long term requirements of the well and overall storage objectives. One additional lesson can be drawn from the success of the two injection wells in this study; cement configurations that differ from the required Class VI configuration can still be successful. It is important to note that although defects were identified in both AEP-1 and CCS#1 both wells performed as needed and kept injected CO_2 isolated in the intended injection formations. This is particularly important because the AEP-1 well and the CCS#1 well had very different planned designs and were even more different in execution. AEP-1 was permitted as a Class V well and did not look like a Class VI well in initial planning, as some annuli were open between the formation and surface. In execution the injection string was not cemented from TD to surface looking more similar to a Class II injection well than a Class VI or Class I well. The CCS#1 well was initially permitted as a Class I nonhazardous well and eventually permitted as a Class VI well. The design and execution of the cement job had cement from TD to surface with no annuli open between any formations and the surface. The success of these two different well implies that multiple well designs can successfully implement CCS projects and protect USDWs.

5. Conclusion

The lessons learned from the wells discussed as part of this study are intended to inform future projects on ways to reduce the potential of future well integrity issues. The construction of the wells for Project ECO_2S, the IBDP, and Mountaineer provided an opportunity to identify and document problems that may affect the construction of CCS wells at future projects. Each of the wells had sections of the cemented annulus capable of providing isolation sufficient for CO_2 storage. Each of the wells encountered problems that are common within conventional oil and gas wells. CCS wells are constructed using standard oilfield equipment and generally supervised by oilfield personnel; however, the goals of CCS wells are much different than a typical oil and gas well. The standard to which wellbore integrity is held in CCS wells is higher than the standard for a conventional oil and gas well. The methods used for evaluation are also generally more sophisticated as well. From the initial well planning and all the way through the construction process it has to be emphasized that the goal of the well drilling is to drill a hole that will facilitate a successful cementing operation; i.e., as straight and as close to gauge as possible. A slight change in penetration rate or different pump pressures can adversely affect the borehole as well as the cement integrity for the entire well. Additionally, cement slurries need to meet project needs while still being placeable in a field setting. Post cementing well operations need to consider well integrity at every point in the well's life. Successful well planning requires attention to the cultural attitudes as well as the technical issues.

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