MONITORING CO_2 PLUME MIGRATION FOR A CARBON STORAGE-ENHANCED COALBED METHANE RECOVERY TEST IN CENTRAL APPALACHIA

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Dissertation submitted to the faculty of the Virginia Polytechnic Institute and State University in partial fulfillment of the requirements for the degree of

Doctor of Philosophy
In
Mining Engineering

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December 7, 2018
Blacksburg, Virginia

Keywords: CO_2 sequestration, coal, enhanced coalbed methane, tracers

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ABSTRACT

A small-scale CO_2 injection test was conducted in 2015 to determine the storage and enhanced coalbed methane (ECBM) recovery potential of CO_2 in a stacked coal reservoir in Buchanan County, Virginia. Phase I of the injection test was conducted from July 2, 2015 to April 15, 2016 when a total of 10,601 tons of CO_2 were injected. Phase II of the injection was conducted from December 14, 2016 to January 30, 2017 when an additional 2,662 tons of CO_2 were injected, for a total of 13,263 total tons of CO_2 injected. The soaking period between the two phases lasted for eight months and the wells were flowed back in early January 2018. A customized monitoring, verification, and accounting (MVA) plan was created to monitor CO_2 injection activities, including surface, near-surface, and subsurface technologies. As part of this MVA plan, chemical tracers were used as a tool to help track CO_2 plume migration within the reservoir and determine interwell connectivity. The work presented in this dissertation will discuss the development and implementation of tracers as a monitoring tool, detail wellbore-scale tests performed to characterize CO_2 breakthrough and interwell connectivity, and present results from both phases of the CO_2 injection test.

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GENERAL AUDIENCE ABSTRACT

During the past decade, carbon capture, utilization, and storage (CCUS) has gained considerable recognition as a viable option to mitigate carbon dioxide (CO_2) emissions. This process involves capturing CO_2 at emission sources such as power plants, refineries, and processing plants, and safely and permanently storing it in underground geologic formations. Many CO_2 injection tests have been successfully conducted to assess the storage potential of CO_2 in saline formations, oil and natural gas reservoirs, organic-rich shales, and unmineable coal reservoirs. Coal seams are an attractive reservoir for CO_2 storage due to coal's large capacity to store gas within its microporous structure, as well as its ability to preferentially adsorb CO_2 over naturally occurring methane resulting in enhanced coalbed methane (ECBM) recovery.

A small-scale CO_2 injection test was conducted in Southwest Virginia to assess the storage and ECBM recovery potential of CO_2 in a coalbed methane reservoir. The goal of this test was to inject up to 20,000 tons of CO_2 into a stacked coal reservoir of approximately 15-20 coal seams. Phase I of the injection test was conducted from July 2, 2015 to April 15, 2016 when a total of 10,601 tons of CO_2 were injected. Phase II of the injection was conducted from December 14, 2016 to January 30, 2017 when an additional 2,662 tons of CO_2 were injected, for a total of 13,263 total tons of CO_2 injected. A customized monitoring, verification, and accounting (MVA) plan was created to monitor CO_2 injection activities, including surface, near-surface, and subsurface technologies. As part of this MVA plan, chemical tracers were used as a tool to help track CO_2 plume migration within the reservoir and determine interwell connectivity. The work presented in this dissertation will discuss the development and implementation of chemical tracers as a monitoring tool, detail wellbore-scale tests performed to characterize CO_2 breakthrough and interwell connectivity, and present results from both phases of the CO_2 injection test.

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DEDICATION

This dissertation is dedicated to my father, Don, and my mother, Leeta.

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ACKNOWLEDGEMENT

First, I would like to thank my advisor and committee chairman, Dr. Nino S. Ripepi, for providing me every opportunity to be successful in completing this dissertation.

I would like to thank my committee members, Dr. Kray Luxbacher, Dr. Ellen Gilliland, and Dr. Michael Karmis for their guidance and support over the past years. I would like to extend a special thanks to Dr. Matthew Hall at the University of Nottingham for providing both a warm welcome while I was studying overseas and his expertise on gas adsorption. I would also like to express my extreme gratitude to Dr. Harold McNair for being a great mentor and sharing his expertise in the field of gas chromatography.

Due to the collaborative nature of this research, there are a number of industrial partners, research partners, and collaborators that I would like to thank: The Virginia Center for Coal and Energy Research (VCCER), the Virginia Tech Mining and Minerals Engineering Department, Marshall Miller and Associates, the Virginia Department of Mines, Minerals, and Energy (DMME), and CNX Gas.

I would like to thank special individuals and great friends within the Mining Engineering Department at Virginia Tech and the Virginia Center for Coal and Energy Research (VCCER) that were involved with this project: Charlie Schlosser, Joseph Amante, Xu Tang, Cigdem Keles, and Scott Jeter.

Finally, I would like to thank my family for their continuous love and support throughout my entire academic journey.

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CHAPTER 1 – INTRODUCTION

Carbon capture, utilization, and storage (CCUS) has recently emerged as a viable option to mitigate anthropogenic carbon dioxide (CO_2) emissions. This process involves capturing CO_2 at point sources such as power plants, refineries, and processing plants, and safely and permanently storing it in underground geologic formations. Under the U.S. Department of Energy's (DOE) Carbon Storage Program, seven Regional Carbon Sequestration Partnerships (RCSPs) were created to research, develop, and test technologies for CO_2 storage for their specific region's geologic reservoirs. Currently, the major types of geologic reservoirs being investigated for CO_2 storage are saline formations, oil and natural gas reservoirs, unmineable coal, organic-rich shale basins, and basalt formations.

Unmineable coal seams are an attractive reservoir for CCUS due to coal's microporous structure which allow it to store large quantities of gas. Coal provides an additional benefit that when introduced to CO_2, it will preferentially adsorb the CO_2 over the naturally occurring methane (CH_4). The release and production of this methane results in enhanced coalbed methane (ECBM) recovery which can extend the life of mature CBM fields and help offset the cost of CO_2 storage.

An award was given by the U.S. DOE through the National Energy Technology Laboratory (NETL) to the Virginia Center for Coal and Energy Research (VCCER) and the Mining and Minerals Engineering Department at Virginia Tech to conduct a small-scale CO_2 injection test in in Buchanan County, Virginia. The objective of this test was to inject up to 20,000 tons of CO_2 to test the injectivity, storage, and ECBM recovery potential of CO_2 in a stacked coal reservoir. Phase I of the test was conducted from July 2, 2015 to April 15, 2016 when a total of 10,601 tons of CO_2 were injected. Phase II was conducted from December 14, 2016 to January 30, 2017 when an additional 2,662 tons of CO_2 were injected. As part of an extensive monitoring, verification, and accounting (MVA) plan, a multi-tracer program was created to help monitor CO_2 plume migration within the reservoir and determine interwell connectivity throughout the study area.

The research presented in this dissertation encompasses multiple aspects of the CO_2 injection test in Buchanan County, Virginia, including the development and implementation of the multi-tracer program and key findings from Phase I and Phase II of CO_2 injection operations.

***Chapter 2 –Development of Fluorinated Tracers as a Qualitative Monitoring Tool for a CO_2 Storage-Enhanced Coalbed Methane Recovery Test**,* presents a background on the uses of tracers as a monitoring tool for CCUS projects, including the implementation of tracers used in previous tests conducted by this research team. The major focus of this chapter will be on the development and implementation of a unique multi-tracer program to track CO_2 plume migration for a CO_2 injection test in Buchanan County, Virginia. The following contributions were made by the co-authors:

Kray Luxbacher	Virginia Tech Department of Mining and Minerals Engineering	Provided funding and oversight for the Subsurface Atmospheres Laboratory
Nino Ripepi	Virginia Tech Department of Mining and Minerals Engineering	Provided funding and oversight for the CO_2 injection test in Buchanan County, Virginia
Ellen Gilliland	Virginia Tech Department of Mining and Minerals Engineering	Oversaw design and implementation of the MVA Plan
Harold McNair	Virginia Tech Department of Chemistry	Provided expertise in gas chromatography and separation techniques

Chapter 3 – An Update of Monitoring Results from a CO_2-ECBM Recovery Test in Buchanan County, Virginia: Phase II and Flowback, provides an overview and results of a designed 20,000-ton CO_2 injection test in a stacked coalbed methane reservoir in Central Appalachia. Phase I of the injection test commenced on July 2, 2015 when a total of 10,601 tons of CO_2 were injected. Phase II commenced on December 14, 2016 when an additional 2,662, tons were injected. This paper highlights key results from Phase I and presents new findings from Phase II of CO_2 injection operations and the flowback of the injection wells into normal production. The following contributions were made by the co-authors:

Ellen Gilliland	Virginia Tech Department of Mining and Minerals Engineering	Oversaw design and implementation of the MVA Plan
Nino Ripepi	Virginia Tech Department of Mining and Minerals Engineering	Provided funding and oversight for the CO_2 injection test in Buchanan County, Virginia
Xu Tang	Virginia Center for Coal and Energy Research	Provided field work assistance, sample analysis, and editing
Charlie Schlosser	Virginia Center for Coal and Energy Research and Virginia Tech Department of Mining and Minerals Engineering	Provided field work assistance and data compilation
Cigdem Keles	Virginia Tech Department of Mining and Minerals Engineering	Constructed pre- and post-injection reservoir model
Michael Karmis	Virginia Center for Coal and Energy Research and Virginia Tech Department of Mining and Minerals Engineering	Provided expertise in CCUS technologies

Chapter 4 – Delineating CO_2 Plume Migration in a Stacked Coalbed Methane Reservoir Using Multiple Wellbore-Scale Tests, describes an effort to determine which seams in a stacked coal reservoir the injected CO_2 plume was migrating through. During Phase I of the CO_2 injection test, increased concentrations of an injected tracer were detected at the closest offset production well from the injection well where the tracer was introduced. Later during Phase I, CO_2 was detected above baseline levels at the same offset well. In order to determine which coal seams or production zones the CO_2 was migrating through, multiple wellbore-scale tests were conducted. A downhole video camera was used as a qualitative method to determine the condition of the perforations created when the well was first drilled and completed. Next, a water injection test used increasing water levels to kill gas production and assign contributions of quantity and quality of gas flow to individual coal seams. After that, a continuous spinner survey was utilized to determine flow profile changes versus depth of the injection wells during CO_2 injection operations. Finally, a downhole Raman spectrometer test was conducted on the injection wells after CO_2 injection operations were completed and the wells were placed back into normal production. Results from this test were used to create a composition profile versus depth in the injection wells.

The following contributions were made by the co-authors:

Nino Ripepi	Virginia Tech Department of Mining and Minerals Engineering	Provided funding and oversight for the CO_2 injection test in Buchanan County, Virginia
Ellen Gilliland	Virginia Tech Department of Mining and Minerals Engineering	Oversaw design and implementation of the MVA Plan
Xu Tang	Virginia Center for Coal and Energy Research	Provided field work assistance on the Well Kill Test
Grant Myers	Carbon GeoCycle Inc.	Provided oversight for the Downhole Raman Spectrometer Test
Ed Diminick	Marshall Miller & Associates	Provided management for the CO_2 injection site in Buchanan County, Virginia
Mike McClure	Marshall Miller & Associates	Provided geologic characterization for the CO_2 injection test in Buchanan County, Virginia
Michael Karmis	Virginia Center for Coal and Energy Research and Virginia Tech Department of Mining and Minerals Engineering	Provided expertise in CCUS technologies

CHAPTER 2 – DEVELOPMENT OF FLUORINATED TRACERS AS A QUALITATIVE MONITORING TOOL FOR A CO_2 STORAGE-ENHANCED COALBED METHANE RECOVERY TEST

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ABSTRACT

A small-scale carbon dioxide (CO_2) injection test was conducted in order to demonstrate the storage and enhanced coalbed methane (ECBM) recovery potential of CO_2 in a stacked coal reservoir in Southwest Virginia. A total of 13,263 tons of CO_2 were injected during two phases. Phase I was conducted from July 2, 2015 to April 15, 2016, when a total of 10,601 tons of CO_2 were injected. After a soaking period of eight months, Phase II was conducted from December 14, 2016 to Jan 30, 2017, when an additional 2,662 tons of CO_2 were injected. As part of an extensive monitoring, verification, and accounting (MVA) plan, a multi-tracer program was developed to track CO_2 plume migration within the reservoir. This paper will provide a brief overview of the CO_2 injection test, detail the tracer program including tracer selection and laboratory development, and finally, give a plan for field implementation of the selected tracers.

2.1 – INTRODUCTION

Tracers have been used in a variety of industries including civil engineering, building construction, environmental management, mining, and oil and gas primarily to understand and measure mass transport in a system of interest. While there is no universally accepted classification for tracers, they can generally be divided into two categories: natural and artificial. Natural tracers, also known as environmental tracers, are substances that are inherently present in the environment. Common natural tracers include elemental isotopes or changes in chemical composition due to the process of interest. Artificial tracers, also known as chemical tracers, are chemical substances that are added to the environment as a proxy for a process variable that cannot be measured directly. In order for chemical tracers to be effective, they must be: 1) non-toxic and non-reactive; 2) easily transported and deployed; and 3) easily sampled and detected.

For these reasons, fluorinated tracers such as sulfur hexafluoride (SF_6), perfluorocarbons tracers (PFTs), and halocarbons are among the most commonly used chemical tracers. A major advantage of fluorinated tracers is their high molecular electronegativity, which allows them to be detected using common analytical techniques such as gas chromatography (GC) coupled with negative-ion chemical ionization mass spectrometry (NICI-MS). Another advantage of fluorinated tracers is their low, almost negligible, background concentrations in the atmosphere and subsurface. This low background presence further increases detection sensitivity by limiting interference caused by environmental contamination. PFTs have the added benefit in that they can be used as a suite of similar-property tracers to be deployed simultaneously within the same study area. SF_6 and PFTs have been successfully used in the past as a qualitative and quantitative tool to help characterize fluid flow in atmospheric, marine, groundwater, and reservoir studies. Major advantages for the use of tracers in these studies are that they can be deployed in areas that are difficult to access (e.g. underground reservoirs, pipes) and areas that span large distances (e.g. geologic basins, oceans, airspaces) [1].

Fluorinated tracers, most commonly SF_6, have been used in the mining industry as early as the mid-1970s in the U.S. as a critical tool in evaluating underground mining ventilation systems [2]-[4]. Underground mining environments are dynamic in nature as daily production causes advancement, and in some cases retreat, of the working face. This causes changes in the requirements of the ventilation system and often the need for new ventilation controls. Evaluating the effectiveness of these controls on air quantity using traditional ventilation surveys involves measuring the air velocity and cross-sectional area of a mine opening. Because this measurement is only valid at a point in space, these traditional surveys are often time and resource intensive, and can sometimes be inaccurate due to a number of environmental factors, such as irregular shaped mine openings, obstructions, and turbulence [5]. Tracer gas surveys are desirable in these environments as air quantity can be measured without the measuring the cross-sectional area. Additionally, tracer gases are currently used in mines for a variety of applications such as: determining air leakages across stoppings, doors, and overcasts, characterizing the exchange of gases between active and sealed areas, understanding airflow within inactive workings and gobbed areas, evaluation of auxiliary ventilation, effectiveness of scrubber and spray systems on mining equipment, and use in inaccessible areas.

Numerous tracers, including SF_6 and PFTs, have been used in the oil and natural gas industry to detect leakage at natural gas facilities such as gathering pipelines, compressor stations, transmission pipelines and processing facilities [6]-[11]. They have also been widely used in reservoir engineering to help optimize production [12]-[14], characterize fluid flow within a reservoir [15]-[18], and reduce uncertainties in flow pathways (both horizontal and vertical) and reservoir continuity [19]-[23]. Tracers are useful in enhanced recovery operations where a fluid is injected into one or multiple wells and the hydrocarbons are produced out of offset production wells. Introducing a chemical tracer with the injected fluid and monitoring the concentration response curve at offset wells can provide information about the reservoir and determine flow pathways and interwell communication [24]-[26]. Using different chemical tracers at multiple injector wells and/or at different timelines over the span of a project can greatly increase the quality of information about the reservoir. While there has been a wide use of tracers in the oil and gas industry since the 1950s [27], many of the tests are qualitative in nature, with little emphasis on choice of tracers, design, and implementation.

Tracers have also been used as a viable monitoring tool in emerging geologic carbon sequestration projects with a focus on the detection and quantification of CO_2 leakage and monitoring CO_2 plume migration within the reservoir. Fluorinated tracers have been used in multiple, large-scale projects throughout the United States including the Cranfield Test site in Mississippi [28],[29], the Frio Injection Test in Texas [30]-[32], the ZERT Injection Project in Montana [33]-[36] and the West Queen Pearl Site in New Mexico [37],[38]. In 2015, an award was given to Virginia Tech and the Virginia Center for Coal and Energy Research (VCCER) by the U.S. Department of Energy through the National Energy Technology Laboratory to conduct a small-scale CO_2 injection test in Southwest Virginia. This paper describes the development and implementation of fluorinated tracers as part of an extensive monitoring plan for this test.

2.2 – BACKGROUND

2.2.1 – Motivation

Carbon capture, utilization, and storage (CCUS) has emerged as a viable option for mitigating CO_2 emissions. In 2003, the U.S. Department of Energy (DOE), under its Carbon

Storage program, created seven Regional Carbon Sequestration Partnerships (RCSPs) tasked to develop and test technologies for CO_2 storage for their specific regions [39],[40]. In 2009, based on a number of successful CO_2 storage tests, the U.S. DOE collaborated with the RCSPs to release its first edition of best practice manuals for geologic CO_2 storage. These manuals were updated in 2013 and again in 2017. Of these manuals, *BEST PRACTICES: Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* was intended to increase awareness of existing and emerging MVA techniques, and ultimately, ensure safe and permanent geologic storage of CO_2 [41]. This MVA manual is broken into three sections, atmospheric, near-surface, and subsurface monitoring which include implemented techniques, and lessons learned from applied research and field demonstrations. Tracers play a role as a viable monitoring tool in all three sections to help detect CO_2 leakage into the atmosphere, soil, and groundwater, and to track CO_2 migration within the reservoir. Table 2.1 below displays monitoring applications of tracers for each section of the best practice manual, including a description, benefits, and challenges for each.

Table 2.1: Atmospheric, near-surface, and subsurface applications for tracers (adapted from [42]).

ATMOSPHERIC	
Atmospheric Tracers	**Description**: Natural and injected chemical compounds that are monitored in air to help detect CO2 released to the atmosphere. **Benefits**: Used as a proxy for CO2, when direct observation of a CO2 release is not adequate. Also used to track potential CO2 plumes. **Challenges**: In some cases, analytical equipment is not available onsite, and samples need to be analyzed offsite. Background/baseline levels must be established. Tracers may not behave the same as CO2 along the migration pathway.
NEAR-SURFACE	
Geochemical Monitoring in the Soil and Vadose Zone	**Description**: Sampling of soil gas for CO2, natural chemical tracers, and introduced tracers. Measurements are made by extracting gas samples from shallow wells or from/with flux accumulation chambers placed on the soil surface and/or with sensors inserted into the soil. **Benefits**: Soil-gas measurements detect shifts in gas ratios or elevated CO2 concentrations above background levels that may provide indications of gas releases from depth. Tracers aid in identification of native vs. injected CO2. Flux chambers can quickly and accurately measure local CO2 fluxes from soil to air. **Challenges**: Potential for interference from surface processes producing false positives as well as missing signal is significant. Significant effort for potential lack of significant results. Relatively late detection of release. Considerable effort is required to avoid cross-contamination of tracer samples. Natural analogs suggest that migration may be focused in small areas and flux chambers provide measurements for a limited area.
Geochemical Monitoring of Shallow Groundwater	**Description**: Geochemical sampling of shallow groundwater above CO2 storage reservoir to demonstrate isolation of the reservoir from USDWs. Chemical analyses may include pH, alkalinity, electrical conductivity, major and minor elements, dissolved gasses, tracers, and many other parameters. Sensor probes/meters, as well as titration test kits, can be used to test/ sample in the field. **Benefits**: Mature technology, samples collected with shallow monitoring wells. Sensors may be inserted into the aquifer. Address major regulatory concern regarding migration reaching USDWs, and may have value in responding to local concerns, which typically elevate concerns about groundwater. **Challenges**: Significant effort for potential lack of significant results. Reactive transport modeling of CO2 migration shows that signal may be retarded and attenuated so that high well density and long sampling periods are required to reach an insignificant result. Many factors other than fluids from depth can change or damage aquifer water quality, and detailed assessment of aquifer flow system may be needed to attribute a change to signal either to migration or to other factors. Gas solubility and associated parameters (pH, alkalinity) are pressure sensitive, so that obtaining samples representative of the aquifer fluids requires careful sampling. Carbon isotopes may be difficult to interpret due to complex interactions with carbonate minerals in shallow formations.
SUBSURFACE	
Emerging Wellbore Tools	**Description**: Emerging wellbore technologies include smart sensors for geologic storage monitoring applications and subsurface tracer applications. Tools include harmonic pulse testing of reservoirs, modular borehole monitoring, and novel tracers. **Benefits**: Demonstrate reservoir integrity through pressure response during pulse testing. The modular borehole monitoring (MBM) concept is a multi-functional suite of instruments designed to optimize subsurface monitoring. Geochemical changes associated with the interaction of injected tracers and supercritical CO2 provide insight concerning migration of CO2 through the reservoir. **Challenges**: Reservoir noise interference and signal-to-noise ratio may be an issue.

Unconventional reservoirs such as organic-rich shale basins and unmineable coal seams are an attractive reservoir for CCUS due to their unique gas storage properties combined with the potential for enhanced gas recovery. The microporous structure of coal allows for large quantities of gases to be adsorbed onto the coal surface. Additionally, when introduced to CO_2, coal will preferentially adsorb the CO_2 over naturally occurring methane, resulting in enhanced coalbed methane (ECBM) recovery [42]-[44]. It is estimated that up to 113 billion tons of CO_2 could be stored in unmineable coal seams in America [45]. Similar to coals, the organic-rich clays found in gas-bearing shale formations have a preferential absorptive capacity of CO_2 approximately 2-5 times higher than that of methane [46],[47]. Advances in horizontal drilling and hydraulic fracturing of gas-bearing shale formations have made the U.S. a worldwide leader in natural gas production. The increasing infrastructure that results from developing plays along with the increased permeability from the induced fractures have made shale formations a viable reservoir for CO_2 storage.

The research team at Virginia Tech and the VCCER has previously conducted two small-scale CO_2 injection tests in order to demonstrate the storage and enhanced gas recovery potential of CO_2 in unconventional reservoirs. The first test injected 1,000 tons of CO_2 into a CBM well is Russell County, Virginia. The second test injected 500 tons of CO_2 into a horizontal shale gas well in Morgan County, Tennessee. For both of these tests, fluorinated tracers were used as a qualitative tool to help monitor CO_2 plume migration.

2.2.2 – 2009 CO_2-ECBM Test in Russell County, Virginia

In 2009, a CO_2-ECBM test was conducted in the Oakwood CBM field in Russell County, Virginia. Approximately 1,000 tons of CO_2 was injected into a depleted CBM well over a one-month period. As part of the monitoring plan, perfluorotrimethylcyclohexane (PTMCH)(C_9F_{18}) was injected with the CO_2 stream within the first week of injection operation to help determine migration pathways within the coal reservoir to offset production wells.

PTMCH was detected at all of the immediate offset production wells and at several peripheral wells up to 3,500 ft. from the injection well (Figure 2.1). Increased CO_2 concentrations were detected at two monitoring wells that were drilled in close proximity to the injection well (135 and 285 ft.) but were not found at any other offset well. Detection of tracers at the offset wells confirms that the wells are interconnected and could provide a network for the CO_2 to migrate if injected at a higher quantity.

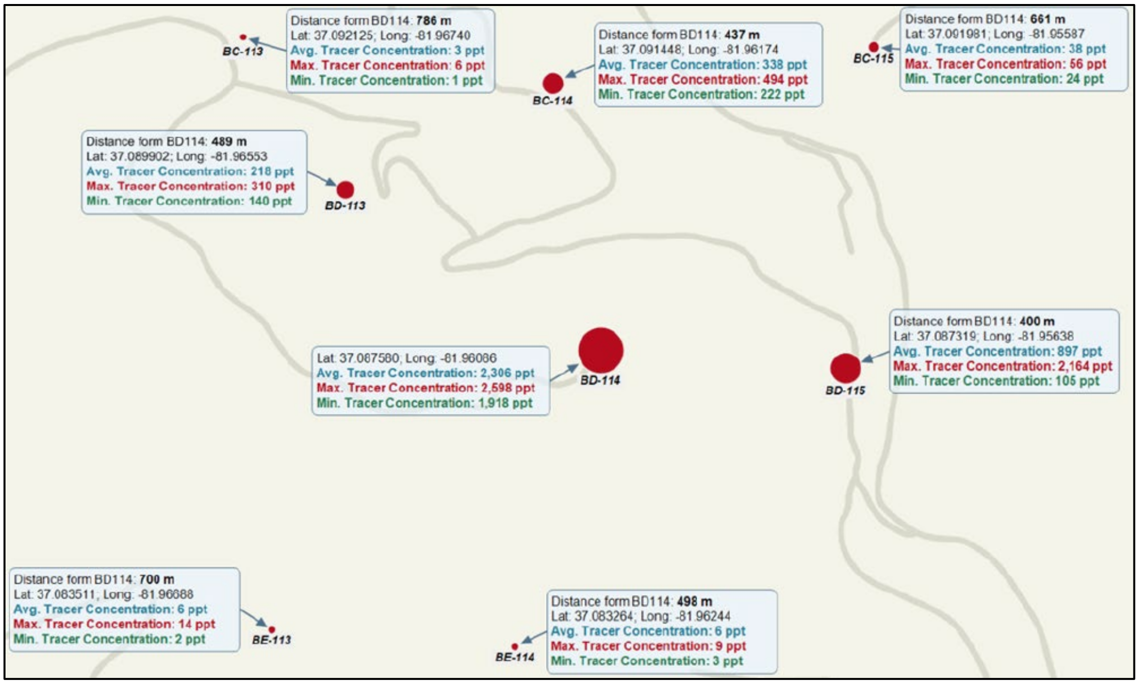

Figure 2.1: Tracer concentrations at offset production wells for the Russell Co., VA CO_2 injection test [48].

To date, it is estimated that 65% of the injected CO_2 has been stored within the reservoir and the estimated ultimate recovery (EUR) for the injection well has increased by 85% (Figure 2.2). Additional details for this test can be found in [49].

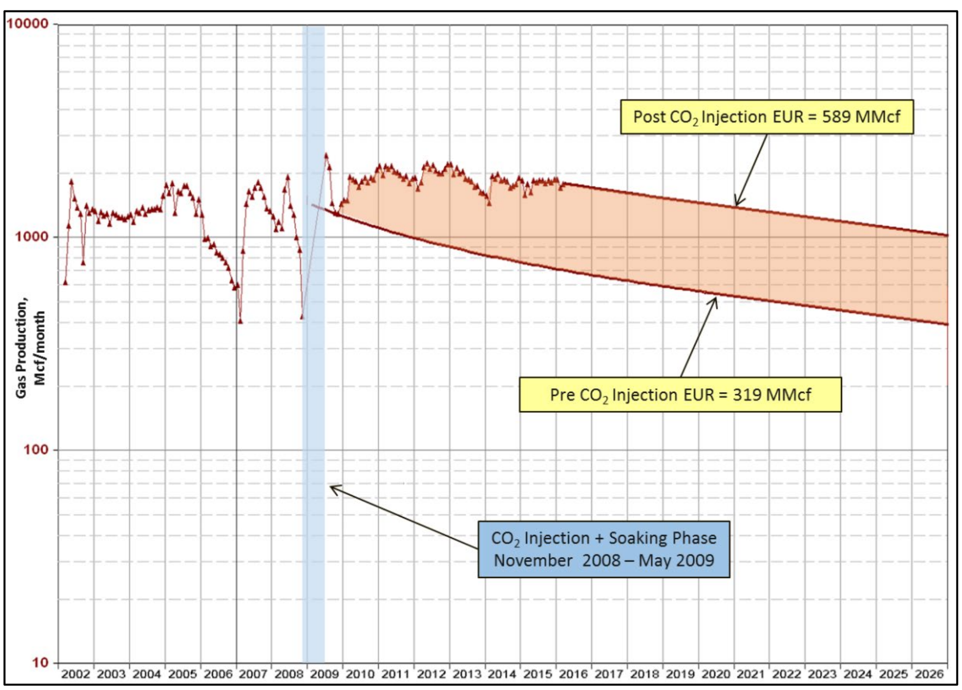

Figure 2.2: Russell County, VA post-injection production and regression analysis [50].

2.2.3 – 2014 CO_2-EGR Test in Morgan County, Tennessee

In March 2014, a small-scale CO_2 injection test was conducted in Morgan County, Tennessee to demonstrate the storage and enhanced gas recovery potential of CO_2 in shale formations (Figure 2.3). Approximately 510 tons of CO_2 were injected over a period of 13 days into a horizontal shale gas well in the Devonian Chattanooga Shale. As part of the CO_2 injection, multiple fluorinated tracers were added at different time periods to help monitor CO_2 plume migration within the reservoir. For this test, sulfur hexafluoride (SF_6) and two PFTs, perfluoromethylcyclopentane (PMCP) (C_6F_{12}), and perfluorometylcyclohexane (PMCH) (C_7F_{14}) were used. SF_6 and PMCP were injected with the first 50 tons of CO_2 to simulate the initial plume movement through the reservoir and to compare the performance of the two tracers. PMCH was injected at the 350 tons of CO_2 mark to compare the two similar PFTs at different phases of the project.

Figure 2.3: Morgan County, TN injection site layout.

Gas samples were collected at thirteen offset production wells in the area and analyzed for composition and tracer concentration and it was determined that there was no increased concentration of CO_2 and no detection of the three tracers at any of the offset wells. Designed as a 'huff-and-puff' test, the injection well was shut in for a soaking period of approximately four months before it was put back into normal production. Gas composition analysis of the injection well once it was put back into normal production concluded an increase in heavier hydrocarbons (C_2H_6, C_3H_8, C_4H_{10}) for a period of seven months before returning to baseline levels (Figure 2.4). Monitoring the gas flow rate of the injection well also concluded a significant increase in production for a period of five months before returning to historical production levels. A regression analysis was performed on the pre- and post-injection flowrates and combined with the CO_2 concentrations in the production stream. It is estimated that greater than 50% of the injected CO_2 has been stored within the reservoir.

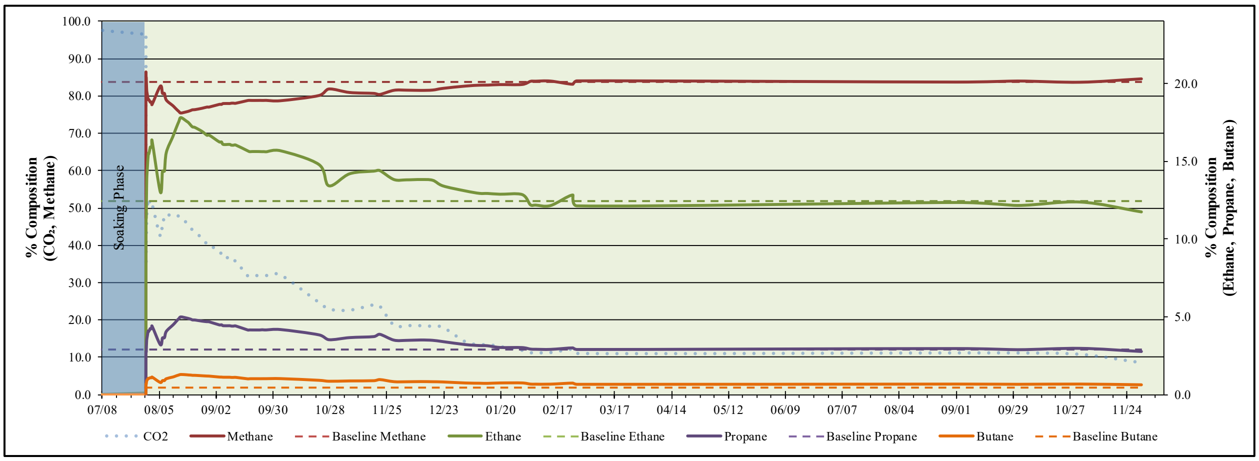

Figure 2.4: Morgan County, TN post injection gas composition [51].

The Morgan County, Tennessee CO_2 injection test represents the first successful injection of CO_2 into an organic shale formation to monitor for storage and enhanced gas recovery potential in Central Appalachia. This test demonstrated the potential for injected CO_2 to enhance gas production and stimulate additional heavier hydrocarbon recovery in shale gas reservoirs. Additional details from this test can be found in [51],[52].

2.3 – TRACER DEVELOPMENT FOR CO_2-ECBM RECOVERY TEST IN BUCHANAN COUNTY, VIRGINIA

2.3.1 – Objective

The objective of this test was to inject 20,000 tons of CO_2 in Southwest Virginia into multiple wells over two distinct phases. An extensive MVA plan was created to select specific monitoring techniques to be implemented during each phase of the test. As part of this MVA plan, a customized tracer program was developed to track CO_2 plume migration within the reservoir. By injecting tracers with the CO_2 and monitoring for breakthrough at offset productions wells, flow pathways and interwell connectivity can be determined. For this test, multiple tracers were needed to differentiate results between: 1) the multiple injection wells; and 2) the multiple injection phases.

All tracer development and analysis was conducted in the Virginia Tech Mining and Minerals Engineering's Subsurface Atmospheres Laboratory. Much of the tracer development for the CO_2-ECBM test has evolved over time stemming from a number of sponsored projects and years of graduate student research in this laboratory.

2.3.2 – Tracer Selection

A number of factors went into selecting the chemicals tracers used to track CO_2 plume migration for this test. Some properties of the tracer itself, such as vaporization pressure, solubility in water, and adsorption characteristics on coal will determine how the tracers will perform within the reservoir. Other factors such as cost and availability will dictate how easily deployable the tracers are. Finally, a major factor will be in the ability to detect and quantify the tracers once deployed. Table 2.2 displays the tracers that were chosen for this test and selected properties.

Table 2.2: Selected tracers.

Formula	Name	CAS No.	M.W.	Density (kg/L)	Vap. Press. (bar)	Solubility (kg/L)
C_6F_{12}	perfluoromethylcyclopentane (PMCP)	1805-22-7	300	1.707	0.368	$1.707\text{x}10^{-6}$ to $1.707\text{x}10^{-10}$
C_6F_{14}	perfluoromeythylpentane (PMP)	355-04-4	338	1.682	0.294	$1.682\text{x}10^{-6}$ to $1.682\text{x}10^{-10}$
C_7F_{14}	perfluoromethylcyclohexane (PMCH)	355-02-2	350	1.788	0.141	$1.788\text{x}10^{-6}$ to $1.788\text{x}10^{-10}$
C_7F_{16}	perfuloroethylpentane (PEP)	2690-05-3	388	1.78	0.092	$1.780\text{x}10^{-6}$ to $1.780\text{x}10^{-10}$
C_8F_{16}	perfluoroethylcyclohexane (PECH)	335-21-7	400	1.829	0.048	$1.829\text{x}10^{-6}$ to $1.829\text{x}10^{-10}$
C_8F_{16}	perfluorodimethylcheclohexane (PDMCH)	306-98-9	400	1.828	0.047	$1.828\text{x}10^{-6}$ to $1.828\text{x}10^{-10}$
SF_6	sulfur hexafluoride	2551-62-4	146	0.006	21.78	$3.78\text{x}10^{-5}$
CHF_3	trifluoromethane	75-46-7	70	0.003	47.09	$4.09\text{x}10^{-3}$
CF_4	tetrafluoromethane	75-73-0	88	0.004	233.32	$1.88\text{x}10^{-5}$
C_3F_8	octafluoropropane	76-19-7	188	0.008	8.82	$5.7\text{x}10^{-6}$

2.3.3 – Perfluorocarbon Tracers

The six PFTs listed were selected as they can be deployed as a suite of similar-property, yet uniquely identifiable tracers. PFTs are classified as perfluoroalkanes with an empirical formula of C_nF_{2n+2}. Cyclic perfluoroalkanes (C_nF_{2n}) form when two fluorine atoms are removed from the chain to form the cyclic structure [53]. Perfluoroalkanes are similar in structure to hydrocarbons (C_nH_{2n+2}), however, since the hydrogen atoms are replaced by fluorine, the molecular weight of PFTs are much higher than their corresponding hydrocarbon, ranging from 300 to 400 g/mol. As fluorine forms one of the strongest bond to carbon, PFTs are very stable. Also, PFTs exhibit very low intermolecular forces, which cause them to have high volatility with a low boiling point. This high volatility allows them to readily vaporize, and makes them difficult to condense once in the vapor state, even at low temperatures (Figure 2.5). As the PFTs increase in molecular weight, their vaporization pressure decreases.

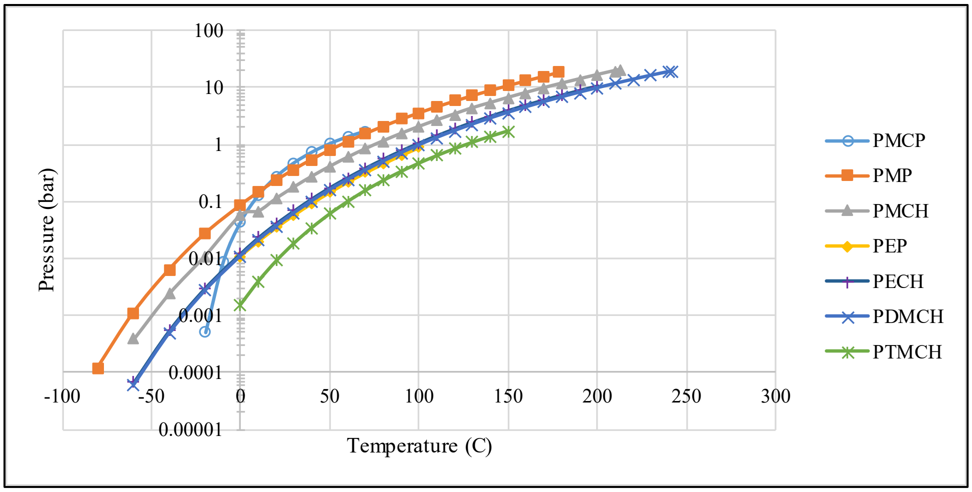

Figure 2.5: Phase diagram for perfluorocarbon tracers.

Along with phase change data, PFTs solubility in water can determine how the tracer will partition in waters naturally found in coal reservoirs. While there is not much literature on the solubility of PFTs in water, it is estimated to be about 10^{-6} to 10^{-10} mL/mL [54],[55]. It is also generalized that solubility in water decreases with the addition of each normal CF_2 group and increases with branching and ring formations for the same number of carbons. The PFTs selected are non-polar, non-toxic, non-flammable, colorless, and odorless. Logistically, PFTs are relatively inexpensive, readily available, stored as a liquid at room temperature and pressure, and easily deployable through a number of systems.

2.3.4 – Sulfur Hexafluoride

SF_6 was selected due to its detectability at very low concentrations and its demonstrated reliability in multiple field tests. SF_6 is artificially produced which results in naturally low background concentrations in the atmosphere and subsurface. Like the PFTs, the fluorine bond with sulfur is very strong creating weak intermolecular forces, which allows SF_6 to exist as a gas at room temperature and pressure. It is odorless, colorless, and non-toxic. SF_6 is inexpensive and readily available as a liquefied compressed gas in a number of sizes of standardized gas cylinders.

2.3.5 – Halocarbons

Trifluoromethane (CHF_3) (also known as halocarbon 23), tetrafluoromethane (CF_4) (also known as halocarbon 14), and octafluoropropane (C_3F_8) (also known as halocarbon 218) were selected for their differing molecular weight from the previous selected tracers. The fluorine compounds increase their electronegativity which will enhance detection and quantification. Similar to SF_6, the halocarbons are colorless, odorless, non-toxic, and are readily available in compressed gas cylinders.

2.3.6 – Equipment Selection and Analysis Method Development

For this study, a Shimadzu GC/MS QP2010 equipped with a NICI source was used. NICI was selected due to the high electronegativity of PFTs, SF_6, and halocarbons, and their tendency to form negative ions [56]. NICI was also selected as it has been demonstrated to detect and quantify fluorinated compounds at the ultra-trace level [57]-[60]. This system utilizes research grade (99.999%) CH_4 as the reagent gas and ultra-high purity (99.9995%) helium as the carrier gas.

The main goal in developing the method for tracer detection will be timely separation of all ten of the tracers. This will help decrease the costs of analyzing a large number of samples taken over a long projected timeline. Two methods were developed to analyze the multiple tracers implemented in the CO_2 injection test. The first method uses an Agilent J&W HP-Al/S column (30m., 0.32mm, 5 μm.) to separate the six PFTs (Table 2.3). This column is a porous layer open tubular (PLOT) column with an aluminum oxide (Al_2O_3) stationary phase deactivated with sodium sulfate. The second method used an Agilent J&W GS-GASPRO column (30m., 0.32mm) to separate SF_6 and the three halocarbon tracers (Table 2.4). This column is also a PLOT column with a proprietary bonded silica-based stationary phase. Figures 2.6 and 2.7 display sample chromatograms with the individual tracer separation for each methods.

Table 2.3: GC and MS method parameters for HP-AL/S column.

Column oven temperature	80°C, isothermal
Injection port temperature	185°C
Injection mode	Split
Split ratio	50
Pressure	153.2 kPa
Total Flow	104.0 mL/min
Column flow	2.00 mL/min
Linear velocity	52.1 cm/sec
Purge flow	2 mL/min
Ion source temperature	200°C
Interface temperature	185°C
Ionization mode	NCI

Table 2.4: GC and MS method parameters for GS-GASPRO column.

Column oven temperature	150°C, isothermal
Injection port temperature	150°C
Injection mode	Split
Split ratio	50
Pressure	194.5 kPa
Total Flow	103.9 mL/min
Column flow	2.00 mL/min
Linear velocity	53.7 cm/sec
Purge flow	2 mL/min
Ion source temperature	200°C
Interface temperature	185°C
Ionization mode	NCI

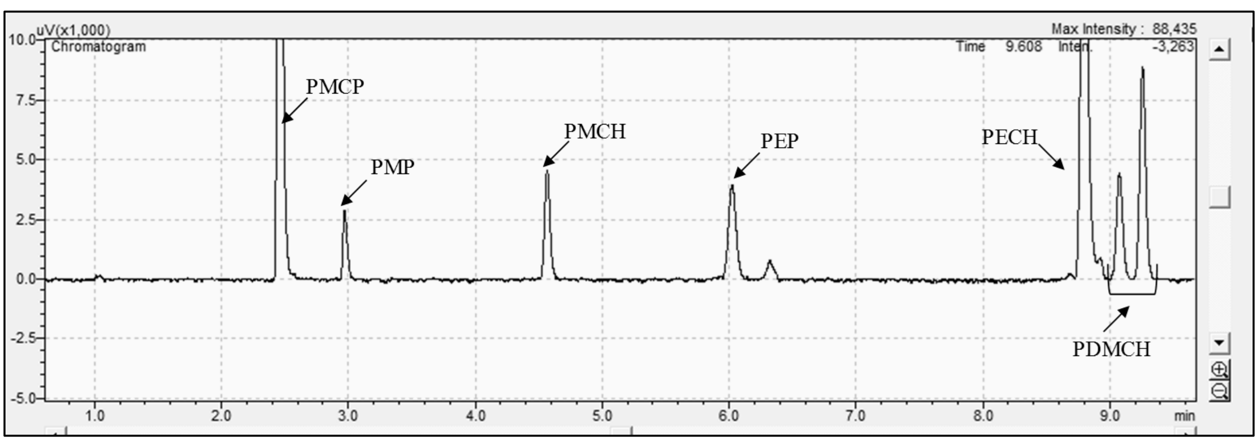

Figure 2.6: Chromatogram displaying PFTs using HP-AL/S column.

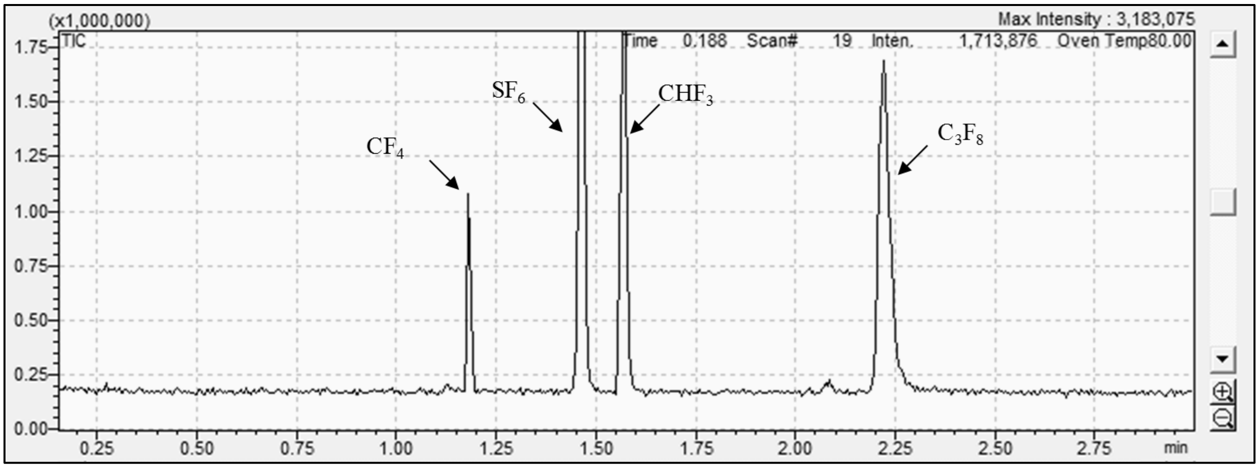

Figure 2.7: Chromatogram displaying SF_6 and halocarbon tracers using GS-GASPRO column.

2.3.7 – Field Sampling Methods

Gas composition sample were collected using DOT-compliant stainless steel gas cylinders. The gas cylinders are equipped at both end with a nonrotating-stem needle valve. Gas samples are collected by connecting one end to the sampling port located at the wellhead and following the GPA Standard 2166 for natural gas spot sampling [61]. Tracer concentration samples were collected using 10mL glass BD Vacutainers. These glass vials have a rubber septum and come from the manufacturer with a vacuum to allow for rapid collection of gas or liquid samples. Tracer samples were collected at the wellhead using a double-sided needle and a plastic holder (Figure 2.8). An adapter was made for the wellhead sampling port using a fitting and a rubber septum (Figure 2.9). The needle could then pierce this rubber septum on the wellhead and the rubber septum on the glass vial to collect a sample without any outside contamination. More details on the sampling procedures for gas composition and tracer sampling can be found in [52].

Figure 2.8: Tracer concentration sample being collected using Vacutainer.

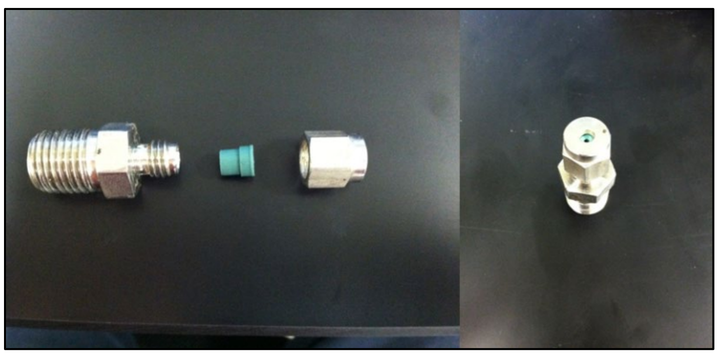

Figure 2.9: Wellhead adapter for tracer concentration sampling.

2.4 – CO_2-ECBM RECOVERY TEST IN BUCHANAN COUNTY, VIRGINIA

2.4.1 – Overview

In July, 2015, a small-scale CO_2 injection test was conducted to demonstrate the storage and ECBM recovery potential in a stacked coal reservoir. The test site is located in Buchanan County, Virginia, approximately 7.5 miles from the 2009 Russell County CO_2 injection test (Figure 2.10). The injection site is located within the Oakwood CBM field, one of the largest in Central Appalachia. The coal reservoir within the Oakwood CBM field consists of 15 to 20

Pennsylvanian-aged coal seams distributed from a depth of approximately 1,000 to 2,000 ft. and averaging 1.0 ft. in thickness.

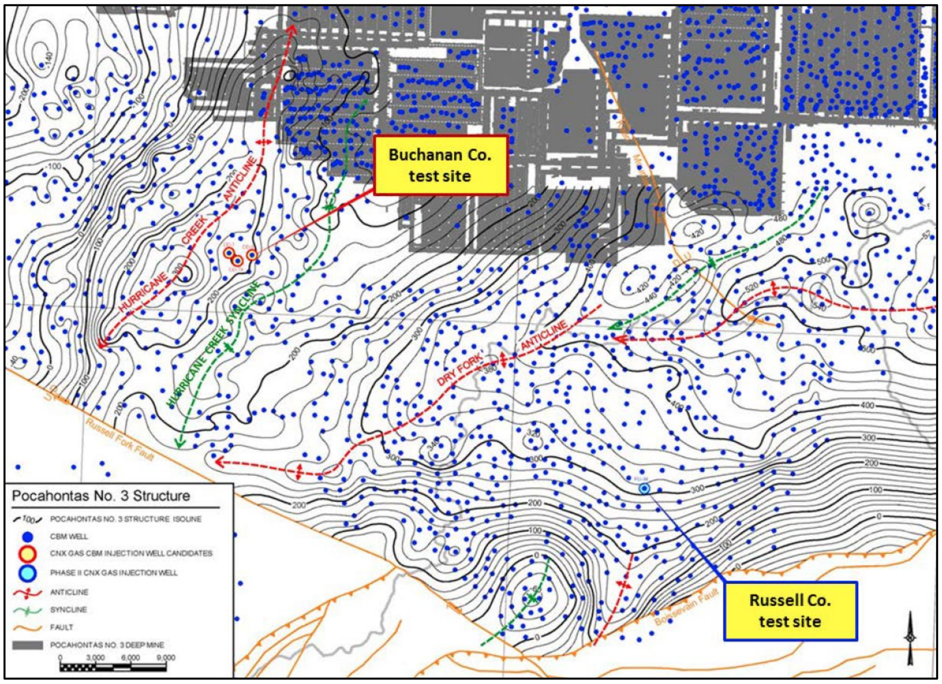

Figure 2.10: Buchanan County CO_2 injection test study area.

Three wells, DD-7, DD-7A, and DD-8, were selected as injection well candidates (Figure 2.11). Three monitoring wells, M-1, M-2, and C-1, were drilled prior to the test for additional reservoir characterization. An overlapping ¼-mile radius boundary from each well was established where a majority of the monitoring efforts would take place. This boundary was based on the results of a preliminary model which simulated the extents of the CO_2 plume at the target 20,000 tons [62]. A ½-mile radius boundary was extended beyond this initial boundary to include all monitoring activities for the test. More details on the MVA plan can be found in [63].

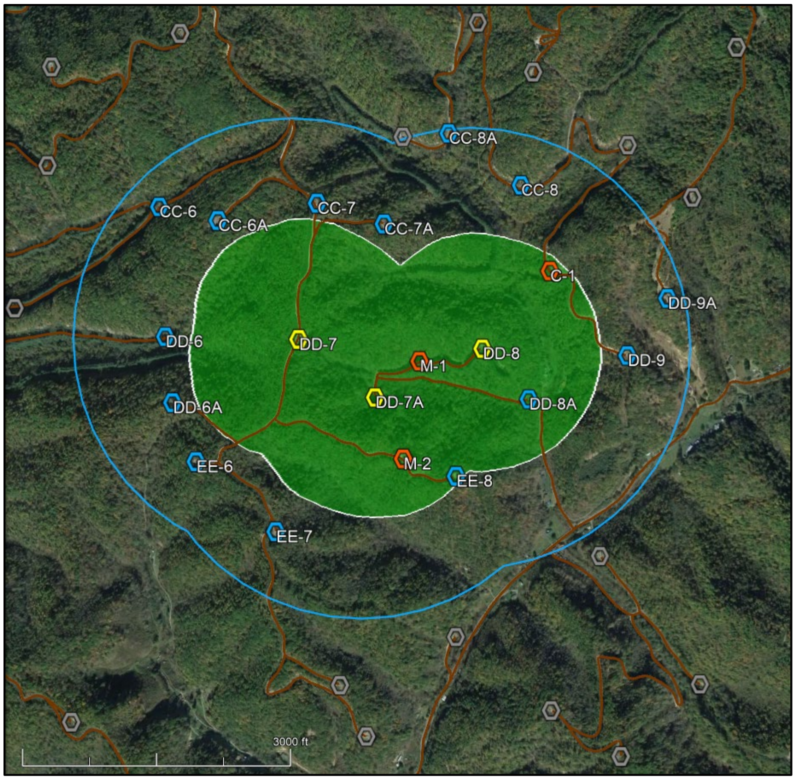

Figure 2.11: Buchanan County CO_2 injection test site. The three injection wells are denoted by a yellow symbol. The three monitoring wells are denoted by an orange symbol. The ¼-mile boundary is denoted by a white line and shaded green. The ½ mile boundary is denoted by a blue line. The offset production wells located within this boundary that were used as monitoring wells for this test are denoted by a blue symbol.

2.4.2 – CO_2 injection Operations

The three CO_2 injection wells were issued an EPA Class II Underground Injection Control (UIC) permit. The wells were converted for CO_2 injection operations by first removing the 2.375-inch tubing, sucker rods, and pumps used for dewatering. Next, a downhole camera was run in each well to assess the condition of the perforations created during the initial drilling and completion of the wells. Finally, a new 2.375-inch tubing and inflatable packer assembly was installed just above the first perforations in each well to assure CO_2 injection into the target formations.

CO_2 injection operations were conducted on the DD-7 well pad (Figure 2.12). CO_2 was delivered by truck and stored on site in 70-ton storage vessels. An injection skid was constructed on site to be able to control the CO_2 injection operations at each well separately. The injection skid connected directly to the DD-7 wellhead, and to the DD-7A and DD-8 wells via pipeline. Each line of the skid contained motorized valves to control flowrates, Coriolis flowmeters to measure injection rates, and a supervisory control and data acquisition (SCADA) system to record data continuously every 60 seconds and be able to monitor and control injection parameters remotely.

Figure 2.12: Injection operations at the DD-7 well pad. Background: CO_2 storage tanks. Middleground: Injection skid. Foreground (Left): DD-7 wellhead. Foreground (Right): Pipeline to DD-7A and DD-8.

CO_2 injection operations were conducted over two phases. Phase I was conducted from July 2, 2015 to April 15, 2016 when a total of 10,601 tons of CO_2 was injected. The injection wells were shut in for a period of eight months to allow the reservoir to equilibrate. Phase II commenced on December 14, 2016 and was completed on January 30, 2017. During Phase II a total of 2,662 tons of CO_2 was injected. The wells were again allowed to soak for a period of eight months. The wells were put back into normal production and flowed back on September 5, 2017.

2.5 – TRACER IMPLEMENTATION FOR CO_2-ECBM RECOVERY TEST IN BUCHANAN COUNTY, VIRGINIA

The chemical tracers were deployed at different stages during the CO_2 injection test to accurately track plume migration throughout both phases of CO_2 injection operations and to simulate changing reservoir conditions across both phases. In total, tracers were injected at 4 different stages:

1) prior to/start of Phase I CO_2 injection to track the initial CO_2 plume migration;
2) during Phase I to simulate reservoir conditions when CO_2 injection pressures were relatively low;
3) during Phase I to simulate reservoir conditions when CO_2 injection pressures were relatively high; and
4) start of Phase II CO_2 injection to compare initial CO_2 plume migration at the start of each Phase.

Prior to the start of CO_2 injection, the three injection wells were shut-in so they could be converted for CO_2 injection operations. During this time, the wells filled with natural water from the formation. The liquid PFTs were added to the water in these wells using a PVC pipe filled with the tracer and dropped to the bottom of each wells. The PVC pipes were capped at one end with a brass fitting drilled with holes. The assembly was filled with a small volume of water and frozen to create an ice plug. The liquid PFT was measured and filled offsite to reduce contamination at the site. The other end of the assembly was capped with a brass fitting. Once lowered into the wellbore, the ice will melt and the liquid PFTs will mix with the water at the bottom of the well through the drilled holes (Figure 2.13). On July 2, 2015, 150 mL of perfluoromethylcyclohexane (PMCH) was added to the DD-7A injection well. On July 8, 2015 150 mL of perfluoromethylcyclopentane (PMCP) was added to DD-7 and 250 mL of perfluoroethylcyclohexane (PECH) was added to DD-8.

Figure 2.13: PVC assembly for PFT added to wellbore fluid.

On July 17, 2015, 15 days after the start of Phase I CO_2 injection operations, 2,000 cm^3 of sulfur hexafluoride (SF_6) was added to the CO_2 stream in the DD-8 injection well. At this point in the project 132 tons of CO_2 had been injected into DD-8 and a total of 663 tons in all three wells. SF_6 was injected using 500 cm^3 DOT-compliant stainless steel gas sampling cylinders. The tracer was transferred from its gas cylinder into multiple stainless steel cylinders in a laboratory to reduce contamination at the site. These individual cylinders were connected to the CO_2 stream at the wellhead and were flushed with a high-pressure compressed air tank regulated at a pressure higher than the CO_2 injection pressure to ensure successful injection of the tracer (Figure 2.14). These cylinders were flushed and cleaned after the tracer injection before they were put back to use for gas composition samples.

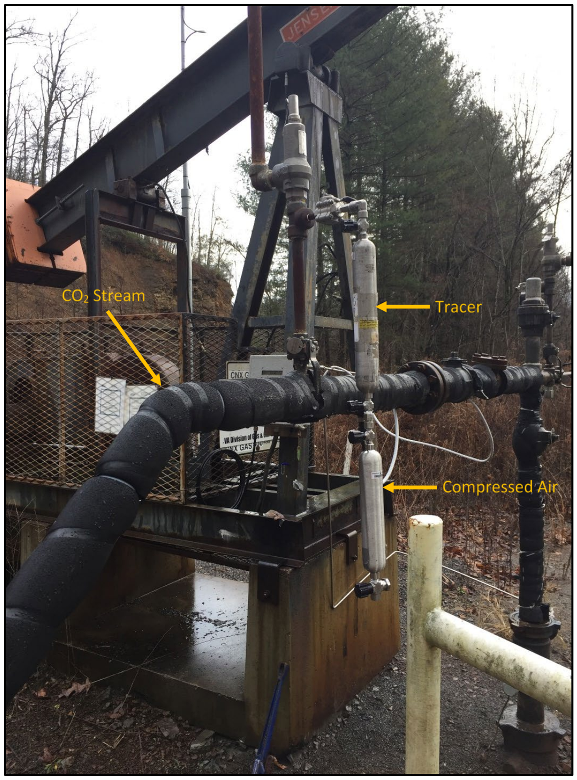

Figure 2.14: Gaseous tracer injection method.

The second round of tracers were administered on October 14, 2015. A volume of 2,500 cm^3 of trifluoromethane (CHF_3) was added with the CO_2 stream at DD-7. A volume of 2,000 cm^3 of tetrafluoromethane (CF_4) was added with the CO_2 stream at DD-7A. A volume of 4,000 cm^3 of octafluoropropane (C_3F_8) was injected with the CO_2 stream at DD-8. At this stage in the CO_2 injection test, 913, 1,031, and 1,070 tons of CO_2 had been injected into DD-7, DD-7A, and DD-8, respectively. These gaseous tracers were injected the same way SF_6 was injected as previously mentioned.

The third round of tracers was injected on March 29, 2016. A volume of 500mL of perfluoromethylpentane (PMP) was added with the CO_2 stream at DD-7. A volume of 500mL perfluoroethylpentane (PEP) was added with the CO_2 stream at DD-7A. A volume of 500 mL of perfluorodimethylcyclohexane (PDMCH) was injected with the CO_2 stream at DD-8. These PFTs were chosen to correspond to their cyclic perfluoroalkane counterpart injected at the start of CO_2

injection operations and expected to behave similarly within the reservoir. At this stage in the CO_2 injection test, 3,306, 3,030, and 3,478 tons of CO_2 had been injected into DD-7, DD-7A, and DD-8, respectively. This round of liquid PFTs were injected using a Teledyne Isco 500D Syringe Pump (Figure 2.15). This pump has a 500 mL capacity and can be programmed to inject at a constant flow rate or a constant pressure. For this test, constant flow rate was selected. More information can be found in [52].

Figure 2.15: Teledyne Isco syringe pump.

Finally, on January 11, 2017, 28 days after the start of Phase II CO_2 injection operations, a volume of 5,000 cm^3 of SF_6 was injected with the CO_2 stream at DD-8. At this stage in the CO_2 injection test, 4,326 tons of CO_2 had been injected into DD-8 and 12,361 total tons of CO_2 had been injected in all three wells for the entire test.

2.6 – RESULTS

Gas samples were routinely collected at the offset monitoring and production wells and analyzed for tracer concentrations. The samples were analyzed in triplicate to determine percent relative standard deviation (%RSD). A %RSD of 5% or less was used as a standard to ensure GC analysis precision. Only two tracers from the first stage of tracer injections were discovered at offset wells. SF_6, which was added at the start of injection at DD-8, was discovered at five offset wells. PMCP, which was added to DD-7 prior to the start of injection, was discovered at three offset production wells. Figure 2.16 displays the tracer arrival at the offset wells and the number of days between tracer injection and detection. It is important to note that these arrival times are estimates, as it is possible that the tracers could have arrived earlier, but due to sampling frequency, were detected at a later date. It is also important to note that negative findings of tracer arrival at offset wells could have been due to the sampling frequency, where the tracer arrived earlier and was undetected when sampled at a later date. Lastly, negative findings of tracer arrival could be due to concentrations lower than the limits of detection for the equipment and analysis method selected.

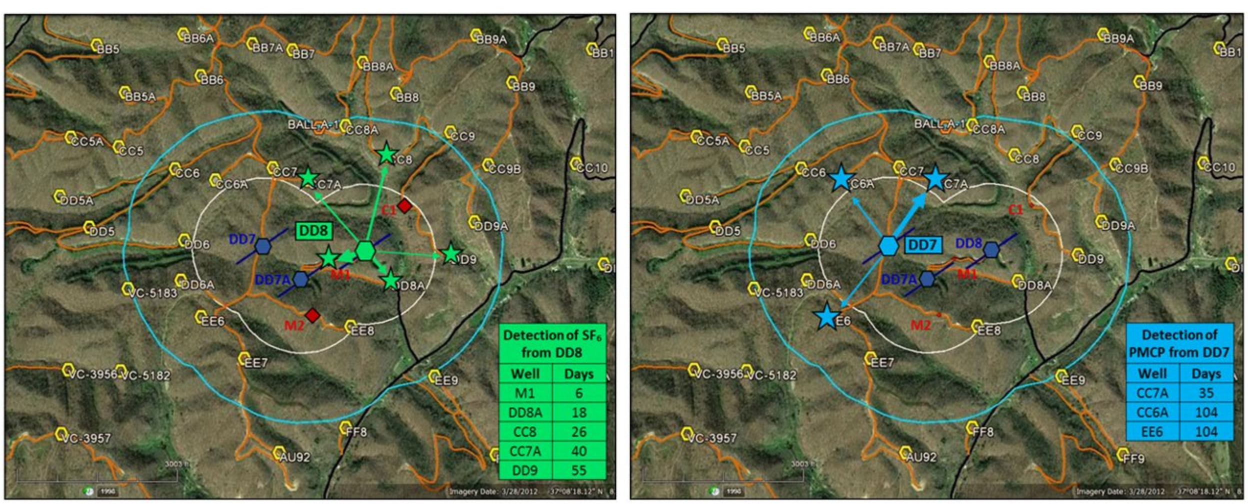

Figure 2.16: Tracer arrival at offset monitoring and production wells.

The SF_6 that was injected in the DD-8 well was detected at M-1 to the southwest, DD-8A to the southeast, CC-8 to the northeast, CC-7A to the northwest, and DD-9 to the east. The pattern and extent of tracer detection coincides with the extent of the ¼-mile MVA boundary associated with the DD-8 injection well, which was established based on the pre-injection simulation of the extents of the CO_2 plume. One likely explanation for this outward trend could be the influence of the overlapping pressure fronts created by the CO_2 injection at all three wells. Assuming that the tracer moved as a uniform plume outwards from the DD-8 injection well, the pressure fronts from DD-7A and DD-7 would have kept SF_6 from moving to wells such as EE-8, M-2, and other wells to the West. The detection of SF_6 at M-1 does not support this explanation, however, it is important to note that SF_6 was detected almost immediately (6 days) after CO_2 injection, when injection pressures would have been relatively low. Also, M-1 is located in the typical hydraulic fracture direction and fracture length for CBM wells in this area which would increase the direct pathway for the tracer to migrate. This explanation is further supported when the PMCP that was injected in the DD-7 well was detected at CC-7A to the northeast, CC-6A to the northwest, and EE-6 to the northwest. This pattern also coincides with the extent of the ¼-mile boundary associated with the DD-7 injection well. Factors such as missed arrival due to sampling frequency or undetectable concentrations could explain why PMCP was not found at other wells along this pattern such as CC-7, DD-6, and DD-6A.

2.7 – CONCLUSIONS

As part of an extensive MVA plan for a CO_2-ECBM recovery test in Buchanan County, Virginia, a unique multi-tracer program was developed to track CO_2 plume migration within a stacked coalbed methane reservoir. For this test, ten fluorinated tracers (Six PFTS, SF_6, and three halocarbon tracers) were selected based on a number of physical properties as well as their demonstration as viable tracers in a number of other CCUS projects.

Due to the high electronegativity of fluorinated compounds, GC-NICI-MS was utilized to successfully develop two trace analytical methods to detect the selected tracers simultaneously. Both methods successfully separate the tracers in a timely manner which can help reduce the analysis costs of running numerous samples.

The selected fluorinated tracers were successfully injected at four distinct phases during the CO_2 injection test to track CO_2 plume migration under changing injection operations and reservoir conditions. Three PFTs were introduced with the water in the injection wells prior to the start of Phase I CO_2 injection operation to simulate the initial plume movement. One of these tracers, PMCP, which was injected into the DD-7 well, was detected at three offset production wells. SF_6 was also injected with the CO_2 stream in DD-8 at the start of Phase I. SF_6 was detected at five offset production wells. The outward pattern of detection for both tracers suggests a major influence from the overlapping CO_2 plume from the three injection wells. None of the tracers introduced during the second, third, or fourth round of tracer injection were detected at any of the offset wells. This could be due to a number of factors including, missed breakthrough due to sampling frequency, detectability too low due to insufficient amount of tracer injected, complex reservoir conditions resulting from CO_2 injection operations such as adsorption or coal matrix swelling. The breakthrough of multiple fluorinated tracers at multiple offset wells prove them to be a viable monitoring tool to detect interwell connectivity. Monitoring for subsequent CO_2 breakthrough at these offset wells where tracers were detected will further validate them as a tool to predict migration pathways within the reservoir.

It is recommended for future tests that similar property tracers be used to reduce uncertainty in field results. For this test, three types of fluorinated tracers were injected: PFTs, halocarbons, and SF_6. Two different types were detected at offset wells, a PFT (PMCP) and SF_6. Had two different tracers of the same type been injected into different wells at the same time, the breakthrough results could be more easily compared. Likewise, had two different tracers of the same type been injected into the same well but at different times (e.g. Phase I and II) during the project, breakthrough results for each phase could be more easily compared. Therefore it is recommended that PFTs be used for future tests as they exist as a suite of similar property, relatively inexpensive, easily deployed, and easily detectible tracers.

A number of implementation techniques were also used to administer the tracers. By selecting one type of tracer such as PFTs, one single method of implementation can be used to further reduce uncertainty in results. The Teledyne Isco Syringe Pump is an easy to operate pump that can be programmed to create customized tracer injection operations. Its capability to inject liquids make it one of the best options to inject PFTs and its range of models can be selected for larger volume capacity and higher injection pressures.

Selection of one type of tracer will also reduce the requirements of the analysis method used for detection, as all six PFTs were detected using one GC/NICI/MS method. Reducing analysis to one method will cut down on analysis time and therefore the costs associated with analysis. It is recommended that future work be conducted to determine the limits of detection for the tracers that were selected for this test. This could eliminate the uncertainty in negative findings of breakthrough at offset wells due to too low of concentration. This could also aid in predicting the amount of tracer needed during injection to have successful detection of breakthrough at offset wells.

ACKNOWLEDGEMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the National Energy Technology Laboratory's program under contract no. DE-FE0006827.

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CHAPTER 3 – AN UPDATE OF MONITORING RESULTS FROM A CO_2-ECBM RECOVERY TEST IN BUCHANAN COUNTY, VIRGINIA: PHASE I, PHASE II, AND FLOWBACK

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ABSTRACT

In 2015, a small-scale carbon dioxide (CO_2) injection test was conducted in a stacked coal reservoir Buchanan County, Virginia. The objective of this test was to determine the storage and enhanced coalbed methane (ECBM) recovery potential of CO_2 in Central Appalachian coals. The design of this test was to inject up to 20,000 tons of CO_2 over two phases. Phase I was conducted from July 2, 2015 to April 15, 2016 when a total of 10,601 tons of CO_2 were injected into three wells. The injection wells were shut in for a period of eight months when Phase II commenced on December 14, 2016. A number of monitoring, verification, and accounting (MVA) technologies were implemented to track CO_2 plume migration and determine interwell connectivity, as well as to determine any changes caused by CO_2 injection operations. This paper will provide a brief overview of this injection test and the implemented MVA plan, highlight key results from Phase I, and present findings from Phase II of CO_2 injection operations and the flowback of the injections wells into normal production.

3.1 – INTRODUCTION

Carbon capture, utilization, and storage (CCUS) technologies have the potential to effectively reduce greenhouse gas emissions and mitigate anthropogenic climate change by capturing CO_2 at emission sources and permanently sequestering it in underground geologic formations. In 1997, the U.S. Department of Energy (DOE) created its Carbon Storage program tasked to advance CCUS technologies through applied research projects. In 2003, as part of this program, seven Regional Carbon Sequestration Partnerships (RCSPs) were created to develop approaches to safely and effectively store CO_2 in their specific region. As a result of these partnerships, over 17 million tons of CO_2 have been injected in the U.S. in a number of target reservoirs including saline formations, oil and natural gas reservoirs, unmineable coal seams, organic-rich shale basins, and basalt formations.

Because of their unique storage properties and potential for enhanced gas recovery, unconventional reservoirs such as coalbed methane (CBM) and organic shale reservoirs are a viable option for CO_2 storage. Coal's microporous structure allows it to store large quantities of gases and its preferential affinity for CO_2 over naturally occurring methane allow it to enhance coalbed methane (ECBM) recovery [1]. Multiple tests have been conducted to determine the storage and ECBM recovery potential of CO_2 in coal seams, including the Pump Canyon Project in the San Juan Basin, New Mexico, CONSOL Energy's CO_2 injection test in Marshall County, West Virginia, SECARB's CO_2 injection test in the Black Warrior Basin, Alabama, and Virginia Tech's CO_2 injection test in Russell County, Virginia [2]-[5].

An award was given to the Virginia Center for Coal and Energy Research (VCCER) and the Mining and Minerals Engineering Department at Virginia Tech by the U.S. DOE through the National Energy Technology Laboratory (NETL) to conduct a small-scale CO_2 injection test in unconventional reservoirs in Central Appalachia. This paper will provide an overview of this injection test, highlight key results from Phase I of CO_2 injection operations, and present findings from Phase II of CO_2 injection operations and from the flowback of the injection wells into normal production.

3.2 – CO_2-ECBM TEST IN BUCHANAN COUNTY, VA

3.2.1 – Overview

Central Appalachian CBM fields are among the highest producing fields in the U.S. and have approximately 2,000 BCF of proven reserves left and an estimated 2.4 TCF of estimated recoverable resource [6]. The CO_2 injection test study area is located in the Oakwood CBM field (Figure 3.1). The Oakwood CBM field is one of the largest in Central Appalachia and spans portions of Buchanan, Russell, and Tazewell Counties. The coal reservoir in the Oakwood field is composed of 15-20 stacked coal seams from the Pennsylvanian aged Pocahontas and Lee formations. Gas production in the Oakwood CBM field began in the early 1990s by CNX Gas Company and Equitable Gas Company.

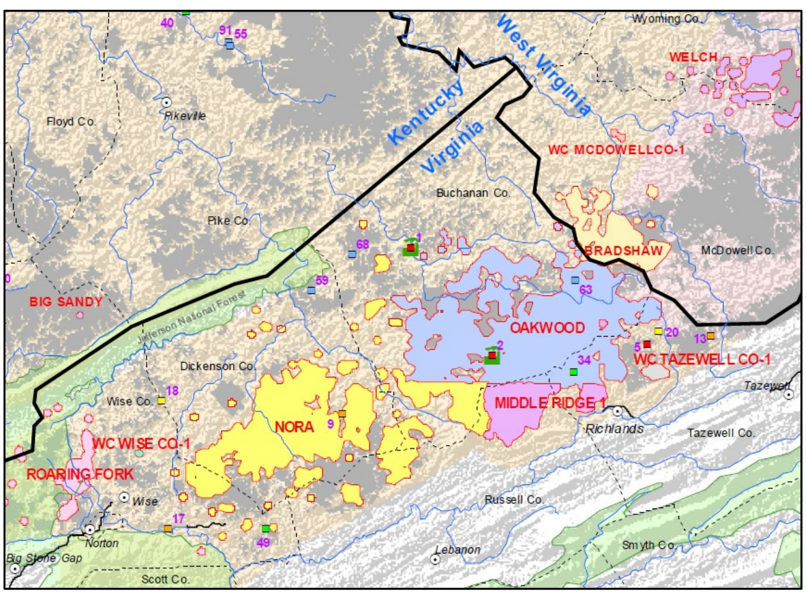

Figure 3.1: Central Appalachia coalbed methane fields [7].

3.2.2 – CO_2 Injection Operations

The goal of this test was to inject 20,000 tons of CO_2 into multiple CBM wells over two phases. Three wells that are owned and operated by CNX Gas were selected for CO_2 injection. DD-7 and DD-8 were initially drilled on 80-acre grids in 2000 and 2001, respectively. DD-7A was drilled as an infill well on the DD-7 unit in 2007. Historic and projected gas production for the three injection wells is shown in Figure 3.2.

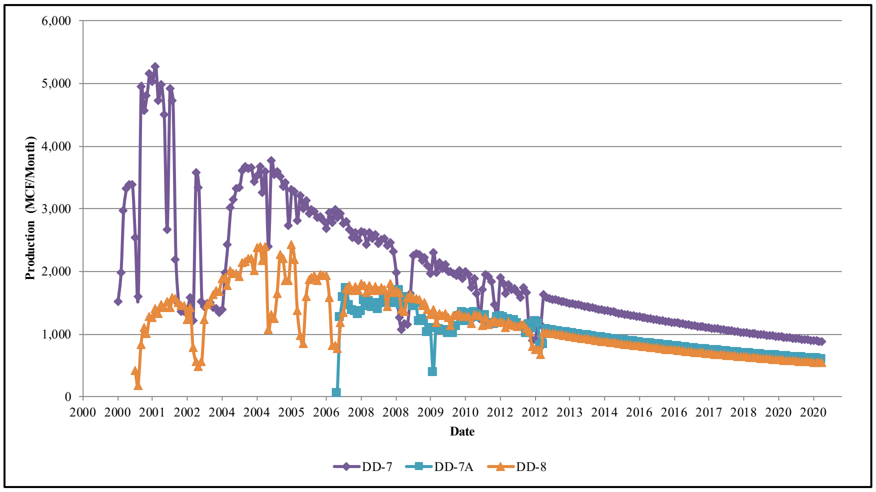

Figure 3.2: Historical and projected gas production for the three injection wells DD-7, DD-7A, and DD-8.

The three injection wells were issued an EPA Underground Injection Control (UIC) permit which regulates the maximum flow rate and pressure of the CO_2 injection. The wells were taken offline and converted for CO_2 injection operations by removing the water production tubing and pumps and running a downhole camera in each well to assess the condition of the perforations. A bridge plug was installed at the bottom of the wells to create an open-hole injection and a packer and tubing assembly was installed just above the first perforations to ensure direct CO_2 injection into the target coals seams (Figure 3.3). Each injection wellhead was outfitted with an assembly for pressure and temperature sensors, a tracer injection port, and sampling ports (Figure 3.4).

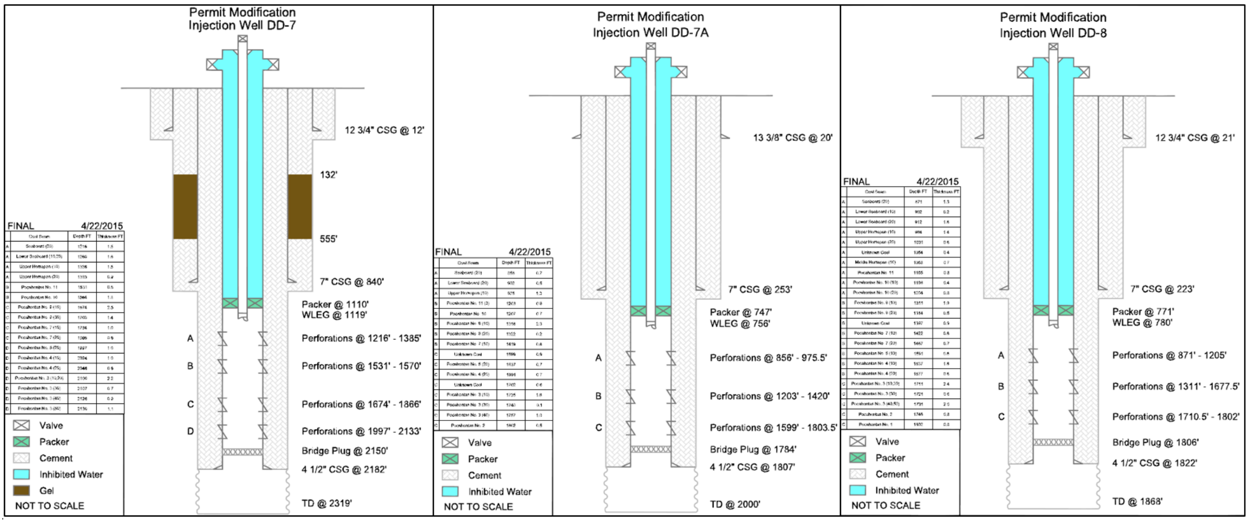

Figure 3.3: Well schematic of the three injection wells after conversion for CO_2 injection operations.

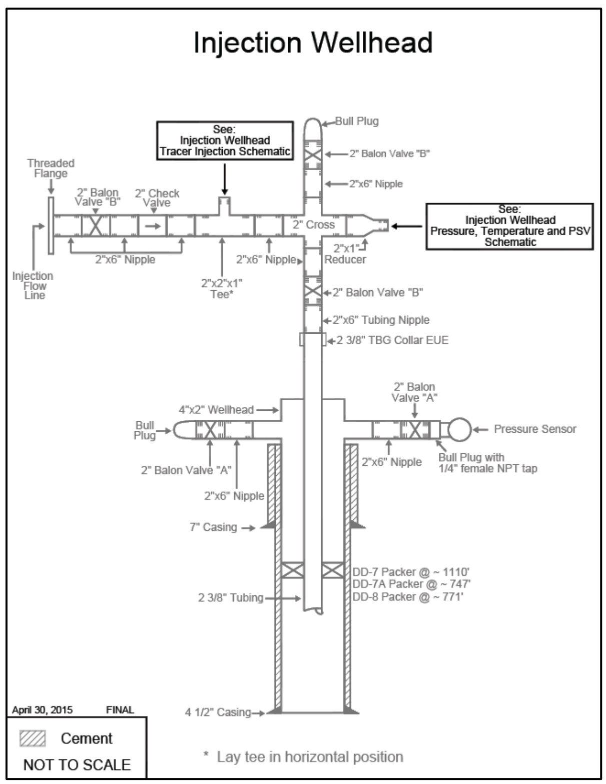

Figure 3.4: Injection wellhead schematic.

All CO_2 injection operations were conducted on the DD-7 well pad (Figure 3.5). CO_2 was delivered by truck and stored in 70-ton storage vessels on site. An injection skid specifically built to inject CO_2 into the three wells was located on site and connected directly to the DD-7 wellhead and to DD-7A and DD-8 via pipeline. Located on each injection line of the skid are Coriolis flowmeters to measure flowrate, motorized pumps to control flowrate, and a supervisory control and data acquisition (SCADA) system to record data continuously and control injection operations remotely.

Figure 3.5: Injection operations at the DD-7 well pad. Background: CO_2 storage tanks. Middleground: Injection skid. Foreground (Left): DD-7 wellhead. Foreground (Right): Pipeline to DD-7A and DD-8.

3.2.3 – Monitoring, Verification, and Accounting (MVA)

An extensive monitoring, verification, and accounting (MVA) plan was created combining atmospheric, near-surface, and subsurface technologies to identify and quantify any changes caused by CO_2 injection operations [8]. Table 3.1 summarizes the MVA technologies deployed during this test. Atmospheric monitoring technologies include pre- and post-injection ambient air sampling. Near surface technologies include CO_2 soil flux, groundwater sampling, and geospatial monitoring including interferometric synthetic aperture radar (InSAR) and GPS stations. Subsurface technologies include using three monitoring and characterization wells for reservoir pressure and temperature monitoring, gas composition, and well logging. Offset production wells will be monitored for any flow rate and gas composition changes. A buried array of geophone stations will monitor for any passive microseismic activity. Finally, a multi-tracer program will be implemented to track CO_2 plume migration and monitor interwell connectivity.

Table 3.1: Overview of atmospheric, near-surface, and subsurface technologies. The bolded techniques were selected as part of the MVA plan for the Buchanan County injection test [9].

	Techniques	Advantages	Disadvantages
Atmosphere	**CO2 detectors**	Inexpensive; portable; mature technology	Difficult to detect CO2 above ambient levels (signal to noise)
	Eddy covariance	Mature technology; high accuracy	Highly specialized; data processing requirement; signal to noise
	Advanced leak detection system	Accurate for CO2 soil flux measurement	Null result if no CO2
	Laser systems and LIDAR	High accuracy; large spatial range; non-intrusive	Requires favorable weather; requires time-lapse; interference from vegetation
	Tracers (isotopes)	Can determine flow direction, early leakage	Samples often require off-site analysis
Near-surface	Ecosystem Stress Monitoring	Easy deployment; effective	Detection after leakage has occurred; false positives; difficult to quantify leaks
	Tracers	Can determine hydrologic properties, flow direction	GHGs often used as tracers, adding to risk profile
	Groundwater monitoring	Early detection of leakage; mature technology	Large effort if no leakage
	Thermal hyperspectral imaging	Covers large areas; detects CO2 and CH4	Little experience in CCS applications
	Synthetic Aperature Radar (SAR & InSAR)	Large-scale monitoring; easy deployment by satellites	Requires time-lapse; compromised by topography, vegetation, other land use
	Color infrared transparency films	Vegetative stress indicates CO2 or brine leakage	Detection after leakage has occurred
	Tiltmeters	Mature technology for injection processes	Land access requirements; remote data collection
	Flux accumulation chamber	Accurate for CO2 soil flux measurement	Limited area; only instantaneous measurements
	Induced polarization	Effective for identifying metallic minerals	Inaccurate for non-metal material
	Spontaneous (self) potential	Fast and inexpensive metal detection	Must be used in conjunction with other technologies
	Soil and vadose zone gas monitoring	Indicates leakage or migration of CO2, possibly before reaching atmosphere	Large effort if no leakage
	Shallow 2-D seismic	Potential to image multiple gases in subsurface	Imaging limited to a line; resolution limits
Subsurface	Multi-component 3-D surface seismic time-lapse survey	3-D imaging of subsurface; can provide information on distribution and migration of CO2	Resolution limits; not sensitive to gas/fluid concentration; signal to noise
	Vertical seismic profile	Improved resolution over surface seismic	Limited imaging geometry
	Magnetotelluric sounding	Large depth range	Low resolution; immature for CO2 detection
	Electromagnetic resistivity	Rapid data collection	Strong response to metal
	Electrical resistance tomography (ERT)	High resolution	Poor resolution for CO2 movement; not proven for CCS applications
	Electromagnetic induction tomography (EMIT)	High resolution (better than electrical resistivity tomography)	Difficult to execute; not proven for CCS applications
	Pulsed neutron capture	High resolution; CO2 saturation in time-lapse	Limited to near-wellbore area
	Sonic (acoustic) logging	Produces high-accuracy seismic velocity data	Used in conjunction with other (seismic) technologies
	2-D seismic survey	Potential to image multiple gases in subsurface	Imaging limited to a line; resolution limits
	Time-lapse gravity	Effective	Sensitivity limits; non-unique results
	Cement bond log	Integrity test; can detect or prevent leakage	Needs to be repeated; not quantitative
	Gamma ray logging	inexpensive; provides formation characterization	Prone to error in certain geologic conditions
	Microseismic (passive) survey	large area of investigation, high resolution, often installed for easy repeatability	Indirect detection of CO2 (by fracturing or faulting); data processing requirement
	Crosswell seismic survey	Higher resolution than surface seismic methods	Very limited imaging area
	Aqueous geochemistry	Can provide mass-balance and dissolution/mineral trapping information	Cannot image CO2 directly, often requires repeat measurement
	Resistivity log	Sensitive to fluid changes	Requires specific casing materials
	Injection well (wireline) logging	Easily deployed; detection of wellbore leakage	Detection limited to near-wellbore area
	Annulus pressure monitoring	Reliable measurements; simple equipment	Requires periodic mechanical integrity testing
	Density logging (RHOB Log)	Formation density and porosity data	Low resolution compared to other logging tests
	Optical logging	Inexpensive; simple; effective; depth range	Qualitative assessment; only images inside casing

Figure 3.6 displays a map of the injection test site and the location of deployed technologies in the MVA plan. The white boundary (shaded green) is where monitoring efforts were concentrated. This roughly ¼-mile radius, overlapping boundary was based on a preliminary reservoir model that simulated the extents of the CO_2 plume for the total 20,000 ton target injection. This reservoir model will be discussed in a following section. The blue boundary, which extends

roughly ½ mile from the injection wells, defines the overall project boundary where all monitoring activities occurred.

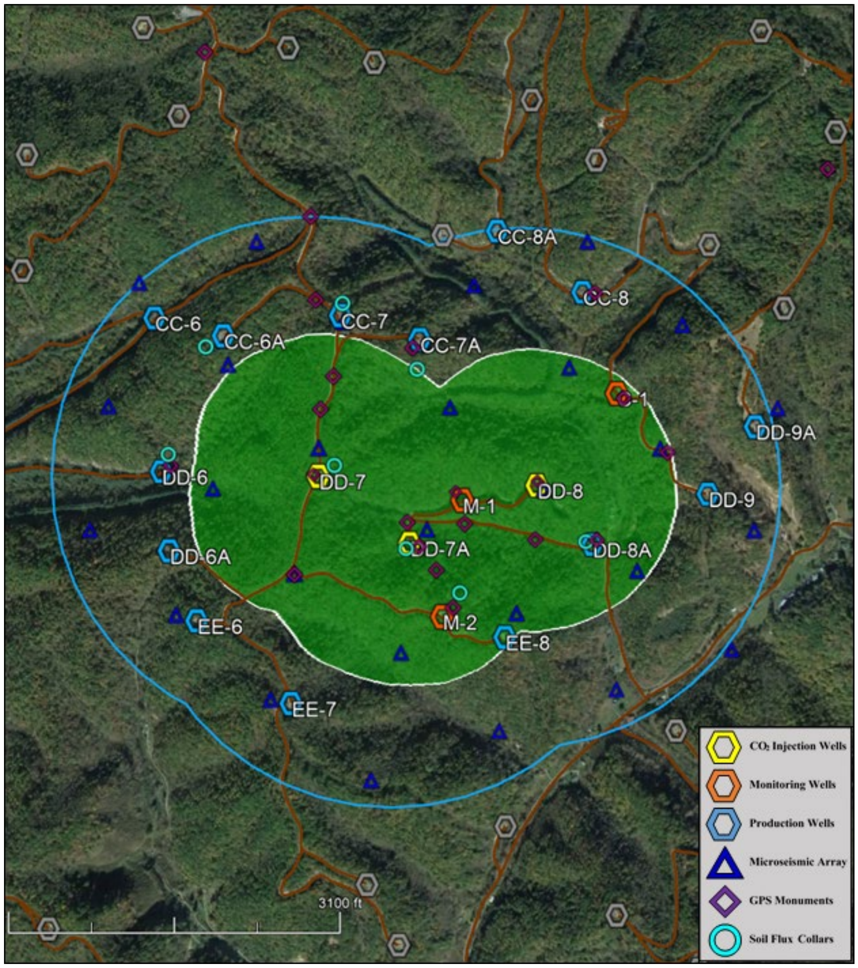

Figure 3.6: Overview map of MVA Plan.

Three offset monitoring wells, M-1, M-2, and C-1, were drilled prior to CO_2 injection operations. The locations of these wells were carefully selected based on proximity to the injection wells and surrounding offset wells, orientation to the typical direction and length of hydraulic fractures of the injection wells, and monitoring needs and predicted outcomes. These wells were outfitted with a tubing and packer assembly to divide the wells into two zones: deep and shallow producing coal seams (Figure 3.7). Surface and downhole pressure and temperature gauges were installed for each zone and set to continuously monitor any changes that may occur during CO_2 injection operations. Sampling ports were installed at the surface for both zones so that gas samples could be collected and analyzed for composition changes that may occur. It is important to note that the packer was set at the same reference location (within the Basal Lee Sandstone, below the Pocahontas 7 coal seam) in each well not only to compare the two zones to each other, but to also compare the two zones to their corresponding zone in each monitoring well.

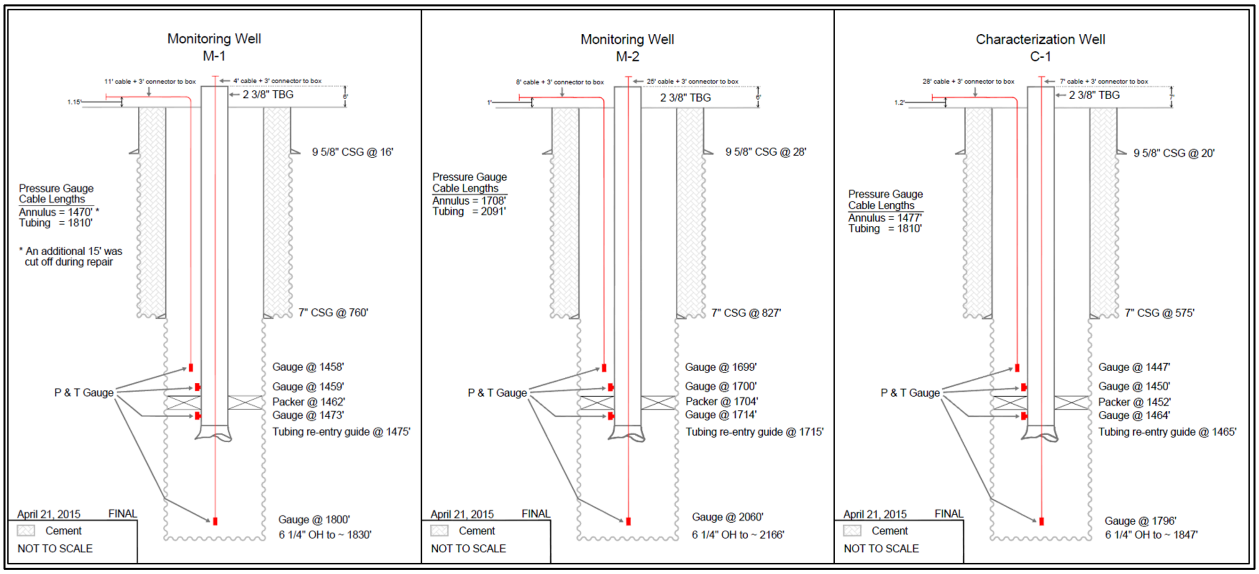

Figure 3.7: Well Schematic of M-1, M-2, and C-1, showing location of packer and downhole pressure and temperature gauges.

3.2.4 – Pre-Injection Reservoir Modeling

Preliminary reservoir modeling was completed using CMG's GEM software to build three different dual porosity-single permeability models. The first model used data from a CO_2 injection test conducted in 2009 in Russell County, Virginia. This data was used to gain experience with the software as well as to help build an initial model with similar reservoir parameters to those expected in Buchanan County. Once this initial model was build the next two models involved CO_2 injection simulations for Buchanan County.

The first model used data from the 2009 SECARB CO_2 injection test in Russell County, Virginia. The geology and extraction operations in this area (7.5 miles from the Buchanan County test) are expected to be the same with vertically drilled wells intersecting 15-20 thin coal seams completed in multiple stages (typically 3-5). This model included three scenarios: the first was a base model, the second included a skin factor defined for each well to simulate enhanced gas flow around the wellbore, and the third introduced a hydraulic fracture effect by assigning matrix permeability in the typical orientation and length of the fractures.

The second model was developed as a single-well model to identify how the variation of selected reservoir parameters and properties affected the model results. This sensitivity analysis focused on: 1) the effect of selected initial conditions (e.g. pressure gradient, adsorption isotherms, and porosity); 2) the influence of production mechanisms (e.g. permeability, relative permeability, and compressibility); and 3) the contribution of well characteristics (e.g. hydraulically stimulated wells versus skin factors). The primary goal for each variation was to match historic water and gas production for one of the selected injection wells.

The third model consisted of two scenarios, a 20-well scenario including the three selected injection wells and the surrounding offset production wells, and a smaller 4-well scenario including the three injection wells and the closest offset production well. The primary focus of these scenarios was to predict the amount of CO_2 that can be stored in multiple stacked coal seams, the extent of the CO_2 plume, the potential for breakthrough at offset wells, and the amount of CO_2 stored after the wells were put back into normal production. Each scenario was based on pre-injection inputs such as historic gas and water production, a simulated 1-year/20,000-ton CO_2 injection, and a flowback after a 1-year soaking period. For the smaller, 4-well scenario, 3 cases were considered. The first case (a) assumed that all 18 of the coal seams were perforated but not hydraulically fractured. In the second case (b), a negative skin was assigned to each well to account for enhanced flow around the wellbore. Finally, in the third case (c), the hydraulic fractures were explicitly modeled. For all cases in this third model, CO_2 breakthrough is predicted at the nearest offset production well (Figure 3.8). More details about the pre-injection modeling can be found in [10]-[12].

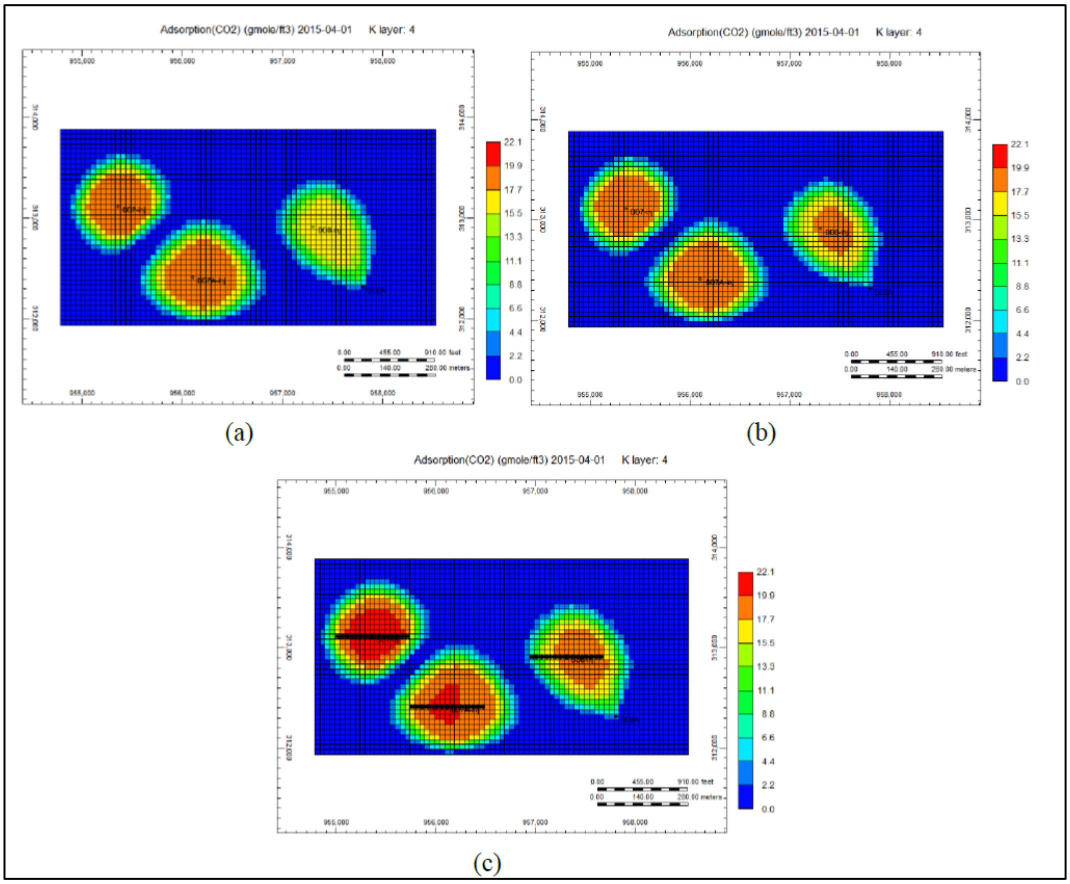

Figure 3.8: Adsorption profile (gmole/ft^3) for four-well scenario with three cases (a), (b), and (c).

3.3 – PHASE I RESULTS

Phase I of CO_2 injection operations began on July 2, 2015. Injection operations were staggered such that each wells was brought online at different times. CO_2 injection began with DD-7A on July 2, and followed with DD-7 and DD-8 on July 8 and 9, respectively. A total of 10,601 tons of CO_2 were injected during Phase I.

Multiple fluorinated chemical tracers were injected to help monitor CO_2 plume migration within the reservoir. Sampling for concentration increases at offset production wells can help identify interwell connectivity and predict migration pathways for the injected CO_2. The tracers were deployed at different stages during the CO_2 injection to simulate the changing reservoir conditions. Tracer were deployed at three different stages during Phase I: 1) prior to/start of CO_2 injection to track the initial CO_2 plume migration; 2) when CO_2 volumes reached 3,000 total tons (approximately 15% of proposed 20,000 tons) and injection pressures were relatively low; and 3) when CO_2 volumes reached 9,800 total tons (approximately 50% of proposed 20,000 tons) and injection pressures were relatively high.

Prior to the start of CO_2 injection, the three injection wells were shut-in so they could be converted for CO_2 injection operations. During this time, the wells filled with natural water from the formation. Liquid PFTs were added to the water in these wells using a PVC pipe filled with the tracer and dropped to the bottom of each wells. Approximately 150 mL of perfluoromethylcyclopentane (PMCP), 150 mL of perfluoromethylcyclohexane (PMCH), and 250 mL of perfluoroethylcyclohexane (PECH) was added to DD-7, DD-7A, and DD-8, respectively. The second round of tracers were administered on October 14, 2015. A volume of 2,500 cm^3 of trifluoromethane (CHF_3), 2,000 cm^3 of tetrafluoromethane (CF_4), and 4,000 cm^3 of octafluoropropane (C_3F_8) was injected with the CO_2 stream at DD-7, DD-7A, and DD-8, respectively. The third round of tracers was injected on March 29, 2016. A volume of 500mL of perfluoromethylpentane (PMP), 500 mL perfluoroethylpentane (PEP), and 500 mL of perfluorodimethylcyclohexane (PDMCH) was injected with the CO_2 stream at DD-7, DD-7A, and DD-8, respectively.

The SF_6 that was injected in the DD-8 well was detected at five offset wells: M-1 to the southwest, DD-8A to the southeast, CC-8 to the northeast, CC-7A to the northwest, and DD-9 to the east. The PMCP that was injected in the DD-7 well was detected at three offset wells: CC-7A to the northeast, CC-6A to the northwest, and EE-6 to the northwest (Figure 3.9). The outward pattern and extents of breakthrough for both tracers coincides with the shape of the overlapping

¼-mile MVA boundary that simulates the extents of the CO_2 plume. One likely explanation for this outward trend could be the influence of the overlapping pressure fronts created by the CO_2 injection operations at all three wells. SF_6 detection at M-1 does not support this explanation, but it is important to note that SF_6 was detected almost immediately (6 days) after CO_2 injection, when injection pressures would have been relatively low. Also, M-1 is located in the typical hydraulic fracture direction and fracture length for CBM wells in this area which would increase the pathways for the tracer to migrate.

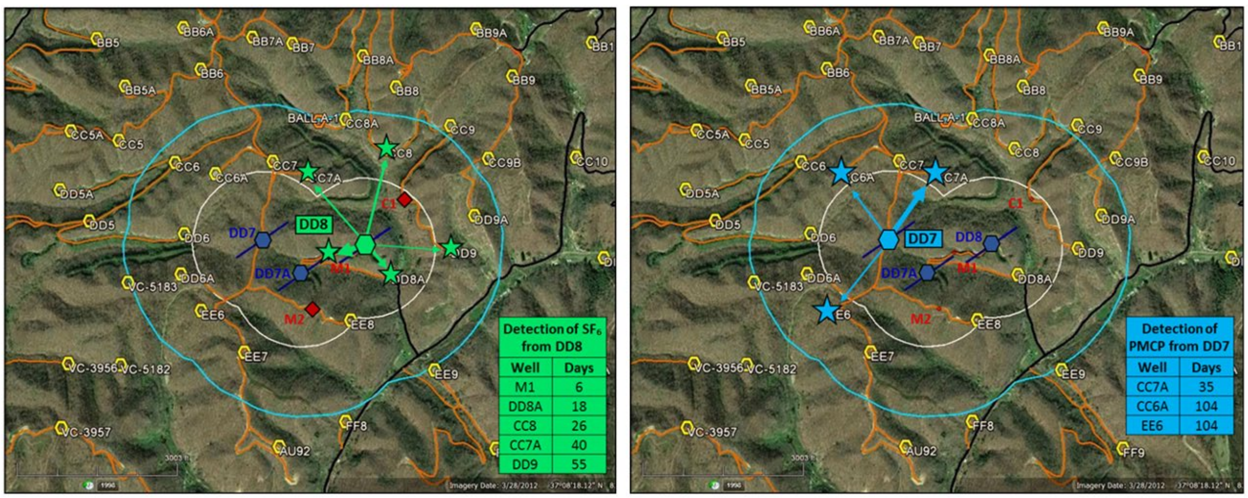

Figure 3.9: SF_6 and PMCP tracer arrival at offset monitoring and production wells.

Gas samples were collected and analyzed for composition at all of the offset monitoring and production wells within the ½-mile MVA boundary. On November 10, 2015, approximately four months after the start of CO_2 injection operations, increased concentrations of CO_2 were detected at DD-8A (Figure 3.10). CO_2 concentrations continued to increase reaching a maximum of 12.9%.

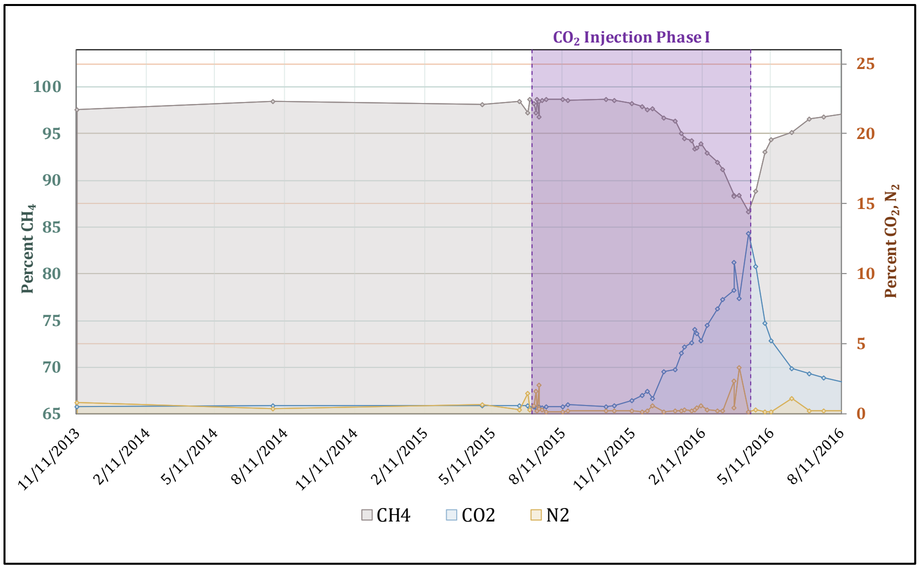

Figure 3.10: CH_4 (grey), CO_2 (blue), and N_2 (gold) gas composition of the DD-8A offset production well for Phase I (purple) of the CO_2 injection test.

3.4 – PHASE II AND FLOWBACK RESULTS

3.4.1 – CO_2 Injection

Phase II of CO_2 injection operations was conducted from December 14, 2016 to Jan 30, 2017 when an additional 2,662 tons of CO_2 were injected. All three injection wells behaved very similarly with respect to pressure, injection rate, and cumulative volume of CO2 injected during both phases (Figure 3.11). After each injection phase, wellhead pressure rapidly decreased and leveled off at approximately 100 psi. Injection temperatures follow a seasonal trend with the higher temperatures occurring from May to August and the lower temperatures occurring from November through February. During these low temperature months, there is an uptick in temperature which is due to the use of a propane heater in accordance to the standard operating procedures of Praxair and to reduce equipment malfunction.

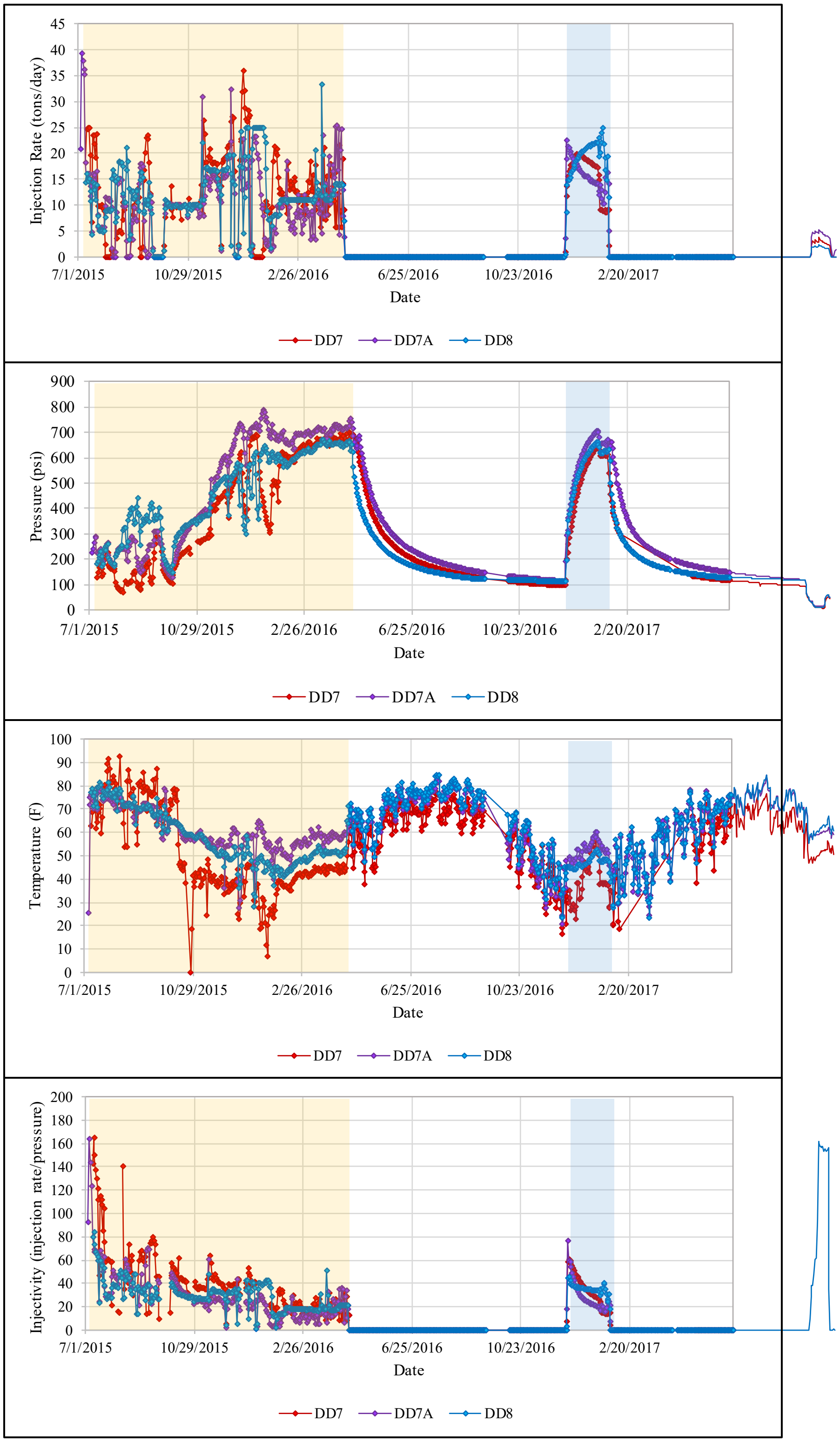

Figure 3.11: Phase I (yellow) and II (blue) CO_2 injection parameters.

During this second phase of CO_2 injection, a fourth round of tracers were injected. On January 11, 2017, 28 days after the start of Phase II CO_2 injection operations, a volume of 5,000 cm^3 of SF_6 was injected with the CO_2 stream at DD-8. At this stage in the CO_2 injection test, 4,326 tons of CO_2 had been injected into DD-8 and 12,361 total tons of CO_2 had been injected in all three wells for the entire test. Gas samples were collected at the offset monitoring and production wells and analyzed for tracer concentrations. This round of tracers was not detected at any of the offset wells.

The gas samples collected were also analyzed for composition. As expected, CO_2 was again detected at DD-8A (Figure 3.12). CO_2 composition had decreased to less than 2.0% after the end of Phase I. Shortly after the beginning of Phase II, CO_2 concentrations increased reaching a maximum of 3.7% by the end of Phase II. CO_2 was not detected at any of the other offset wells.

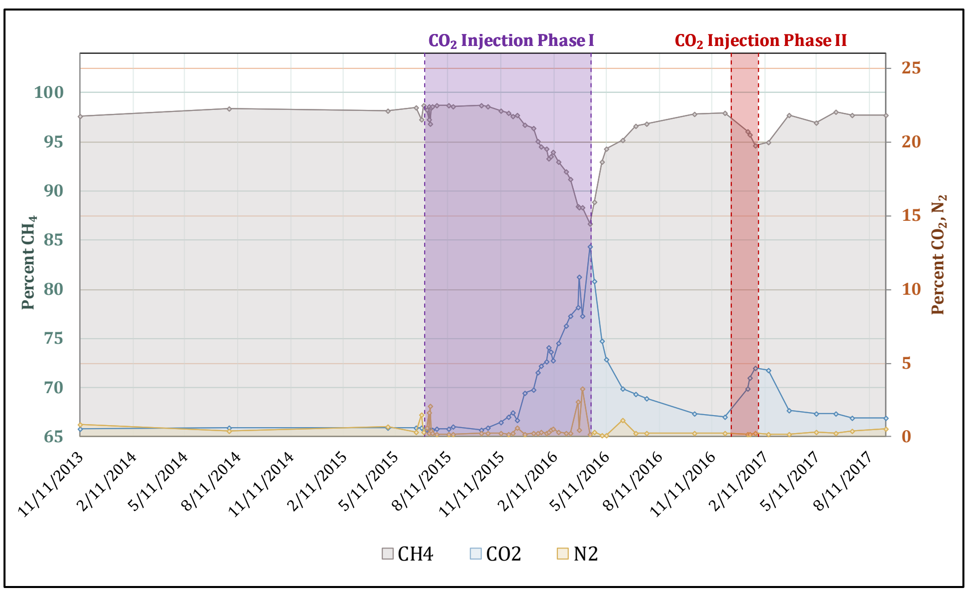

Figure 3.12: CH_4 (grey), CO_2 (blue), and N_2 (gold) gas composition of the DD-8A offset production well for Phase I (purple) and Phase II (red) of the CO_2 injection test.

3.4.2 – Flowback Results

The three injection were put back into normal production on January 9, 2018, after a soaking period of 12 months. Daily flow rates were recorded and gas composition samples were collected periodically and analyzed for CO_2 and methane composition (Figure 3.13). CO_2 dominated the methane stream in all three wells at 79.6, 76.4, and 79.3% for DD-7, DD-7A, and DD-8, respectively. CO_2 composition reached a maximum of 83.5, 85.7, and 86.3% for the three wells, respectively. The last gas composition sample was collected on December 7, 2018. At this point, the CO_2 composition were similar but decreasing at 70.6, 71.5, and 77.9%, respectively. To estimate the amount of CO_2 that has been produced by this date, flow rates were projected using decline curve analysis. On December 7, 2018, a total of 1,740 tons of CO_2 had been flowed back out of the three injection wells. This represents 13.1% of the total CO_2 injected. In order to calculate the amount of CO_2 that has been flowed back from each well, the flow rate was multiplied by the CO_2 composition. Figure 3.14 displays the amount of CO_2 retained within the reservoir for each well. On December 7, 2018, approximately 81.5, 87.9, and 90.9% of the injected volume of CO_2 for DD-7, DD-A, and DD-8 had been retained within the reservoir, respectively.

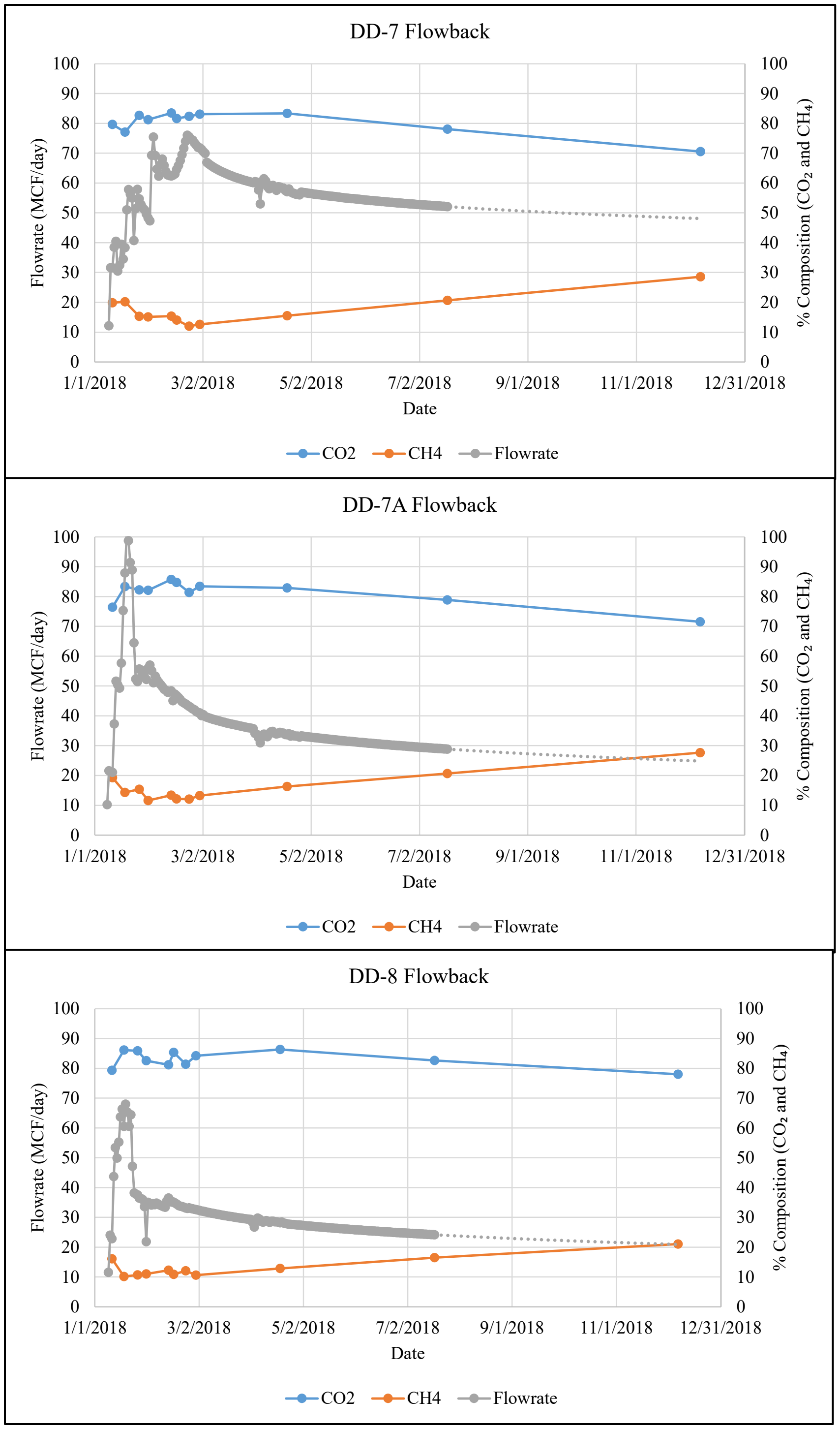

Figure 3.13: DD-7, DD-7A, and DD-8 flowback.

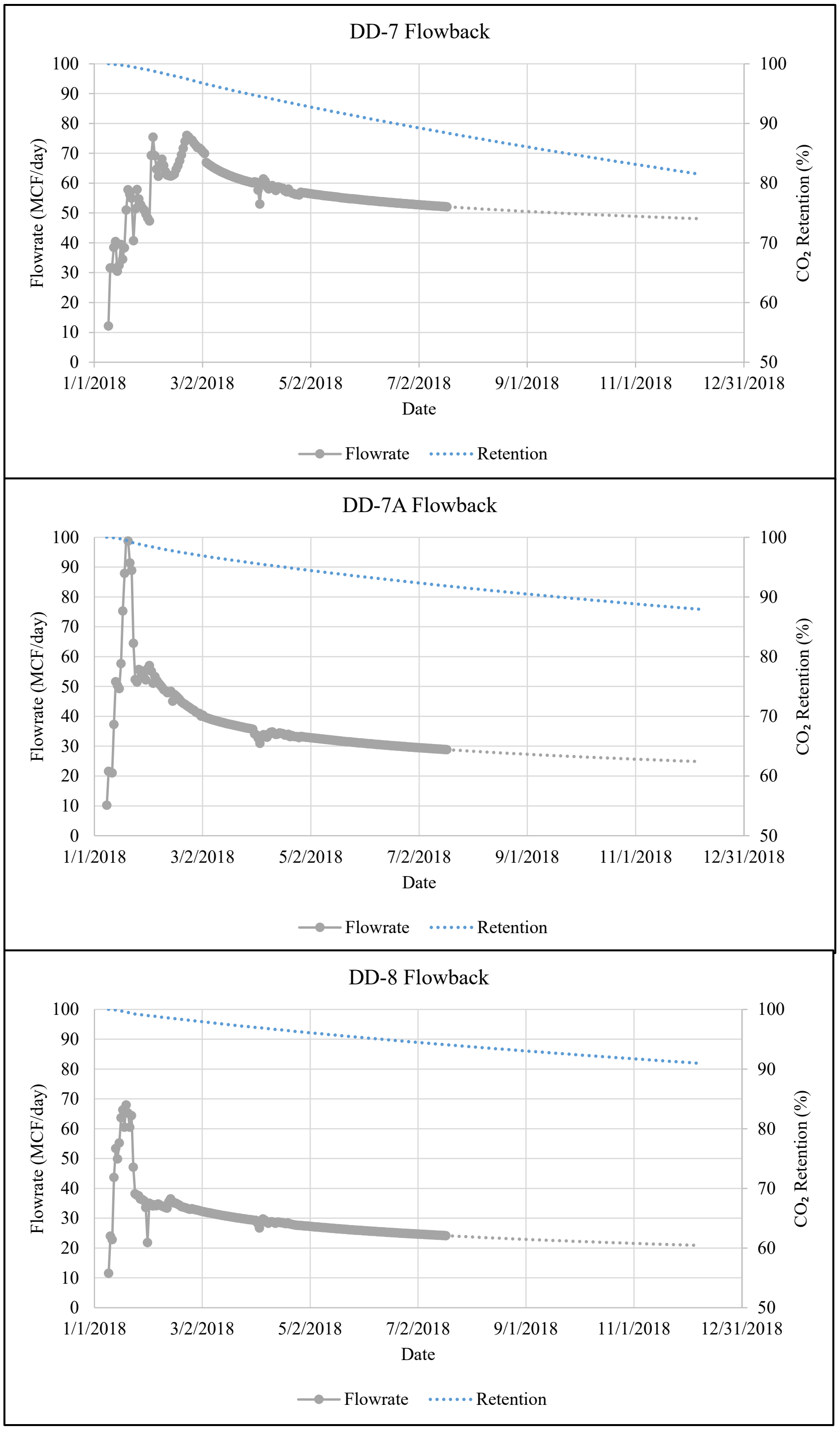

Figure 3.14: DD-7, DD-7A, and DD-8 CO_2 Retention

3.4.3 – Adsorption Isotherm of SF_6 on Coal

To understand how the tracers will behave within the reservoir, adsorption tests were conducted with SF_6 and CO_2 on crushed coal samples. The tests were conducted at the University of Nottingham using a Hiden Isochema's Xemis gravimetric sorption analyzer. The following isotherms (Figure 3.16) show a comparison of CO_2 and SF_6 at different temperatures on the Pocahontas 3 coal seam. The results conclude that CO_2 has a higher excess adsorption on coal approximately 3 to 3.5 times that of SF_6. Currently, there is no literature on the adsorptive behaviors of fluorinated tracers on coal.

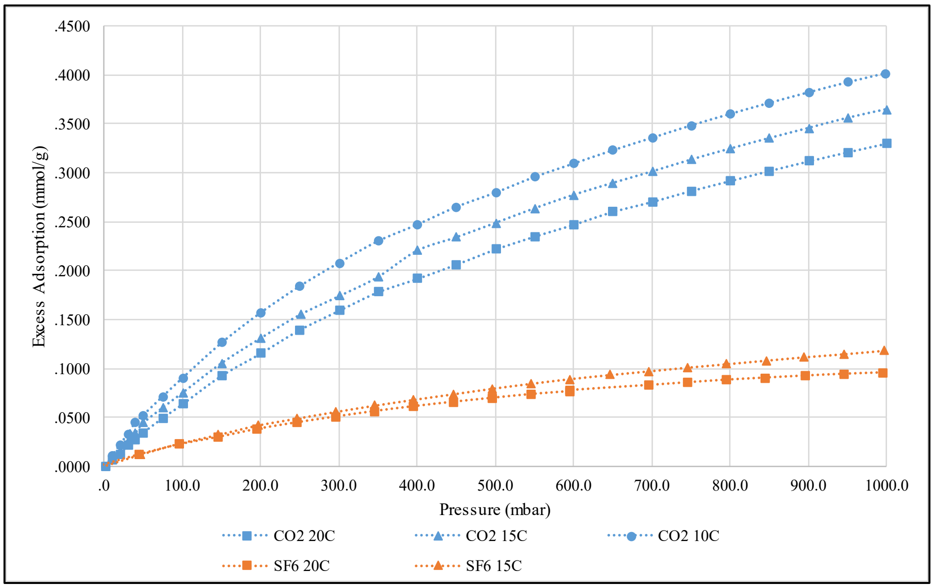

Figure 3.16: Adsorption isotherms of CO_2 and SF_6 on the Pocahontas 3 coal seam.

The Langmuir volume and pressure were calculated using both SF_6 isotherm curves to be used as input for the post-injection reservoir modeling. The Langmuir volume is the maximum amount of gas that can adsorb onto the coal. The Langmuir pressure is the pressure at which the storage capacity of coal is equal to one-half the Langmuir volume. Langmuir isotherms assume adsorption as a monolayer on the surface of the coal. The equation can be calculated as follows:

$$GC = \frac{V_L p}{p_L + p}$$

Where GC is the gas content, V_L is the Langmuir volume and p_L is the Langmuir pressure. Based on the SF_6 isotherms, the following Langmuir constants were used as input parameters for the post-injection reservoir model (Table 3.2).

Table 3.2: Langmuir constants for SF_6 on Pocahontas 3 coal.

Pocahontas 3		
T	V_L	P_L
59°F (15°C)	155 scf/ton	12.5 psi
68°F (20°C)	107 scf/ton	8.3 psi

3.4.4 – Post-Injection Reservoir Modeling

Similar to the pre-injection reservoir modeling, CMG's GEM software was used to simulate the dual porosity-single permeability post-injection reservoir models. For the post-injection simulation, two complex models were developed based on regional geologic data, historic gas and water production, and the CO_2 injection data. The first model included all of the gas wells within the ½-mile radius overlapping MVA boundary around the injection wells. The second model focused on the wells within the ¼-mile MVA boundary. Sensitivity studies were conducted for both post-injection models to assess the CO_2 plume behavior under different conditions.

The first post-injection reservoir model was constructed with the three CO_2 injection wells and 17 offset production wells within the ½-mile MVA boundary. This model consists of 16 coal seams layers using elevation and thickness data from the wells' drilling and completion reports. For this model, a number of cases were created with differing injection parameters such as number of injection wells, different injection well candidates, and time and rate of CO_2 injection (Figure 3.17). In cases 1, 2, and 3 the injection rates were higher for DD-7, DD-8, and DD-7A, respectfully. In cases 4, 5, and 6, the CO_2 was only injected into one well. In cases 7, 8, and 9, the CO_2 was injected into two wells. Cases 10, 11, and 12 had the same injection had the same amount of CO_2 injection with different injection periods (longer). The last four cases (13-16) simulated the CO_2 injection in different wells in the area.

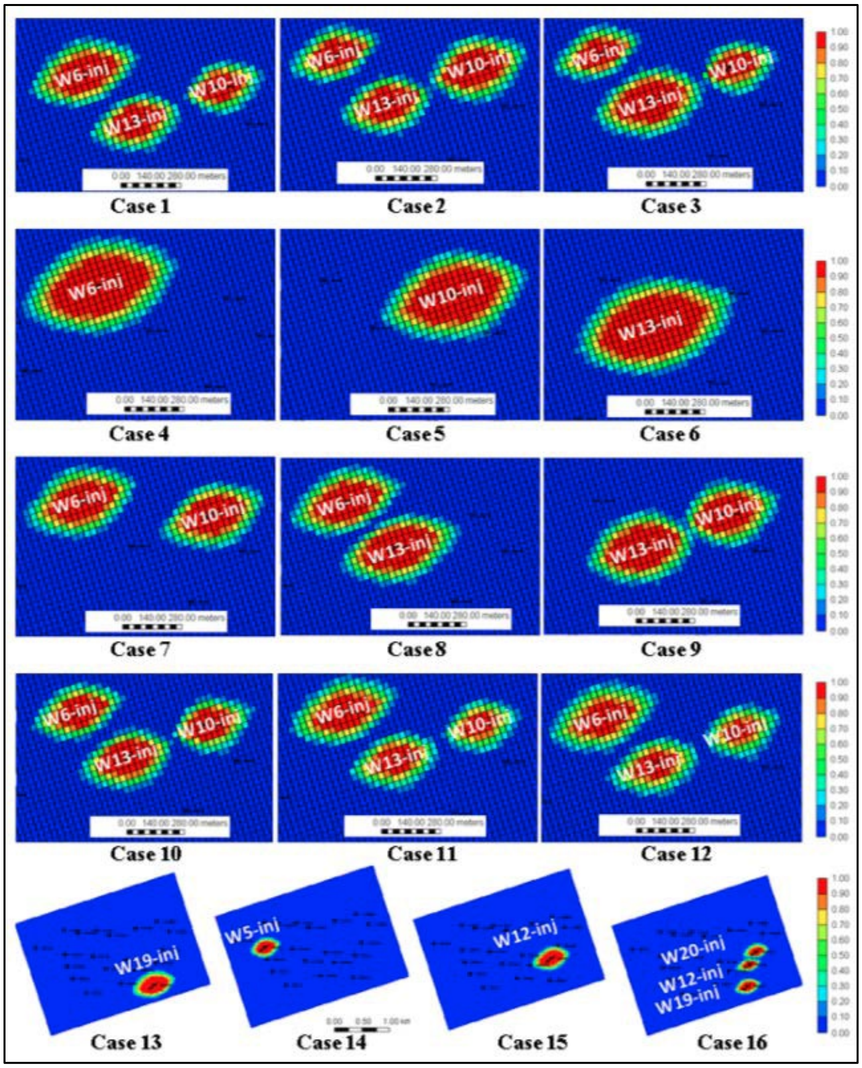

Figure 3.17: Reservoir model with varying injection wells, injection rates, and injection periods.

The second post-injection model included the three injection wells and the two offset production wells within the ¼-mile MVA boundary. This model consists of the same 16 layers used in the previous model, but for this model, only the perforated seams from the drilling and completion report were included for each well. Gas composition data (CH_4, C_2H_6, N_2, and CO_2) was also used in this model. The gas composition samples taken at the offset production wells was comingled (mixed from each coal seam producing in that well) so gas composition could not be attributed to each coal seam. For this model two different values for gas composition were assigned to shallow and deep coal seams based on the results from the deep and shallow coal zones in the monitoring and characterization wells M-1, M-2, and C-1. The permeability in the cleats was also varied in wells and coal seams based on active fracture network results from the tomographic fracture imaging conducted (Figure 3.18).

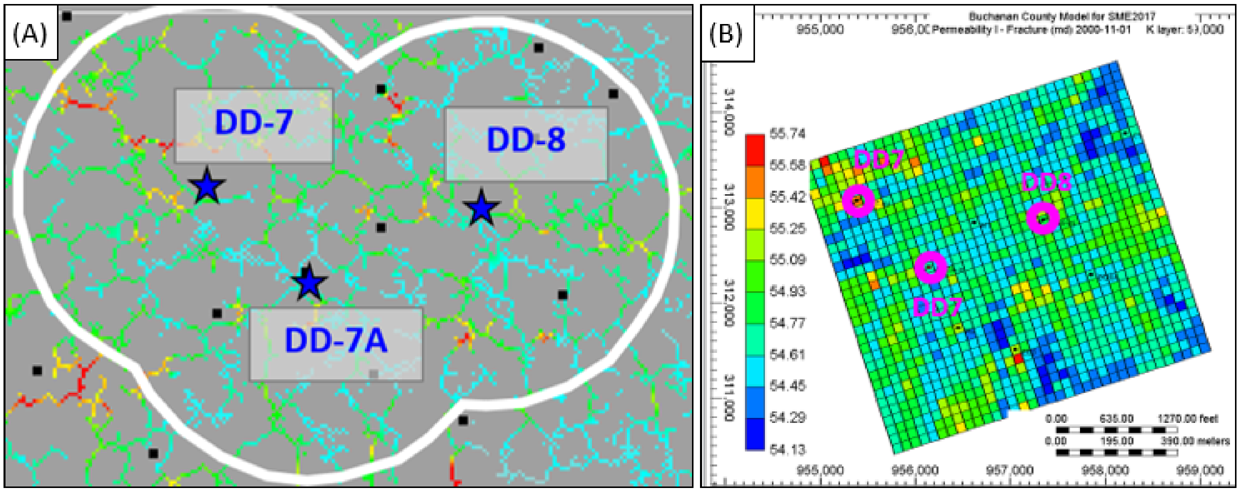

Figure 3.18: Active fracture network from tomographic imaging (A) and associated permeability values (B) for post-injection modeling.

For this model, both CO_2 and the SF_6 tracer injection were modeled together using the Langmuir constants (volume and pressure) calculated from the isotherms as an input to simulate the tracer plume migration for different layers. Based on the field and lab results, SF_6 reached M-1 and DD-8A after 6 and 18 days, respectively. Snapshots taken of the model after 1 hour, 6 days, 10 days, and 18 days show the same results (Figure 3.19). The injection of CO_2 into DD-7A cause a buildup of SF_6 concentration at M-1 and cause the SF_6 plume to radiate outwards from DD-8. Using the adsorption characteristics of the injected gases, the well perforations, and the fracture network as inputs significantly increased the accuracy of the model. Creating a model with a smaller area allowed for parameters to be changed easily and reduced computational time and energy. More details on the post-injection reservoir model can be found in [13],[14].

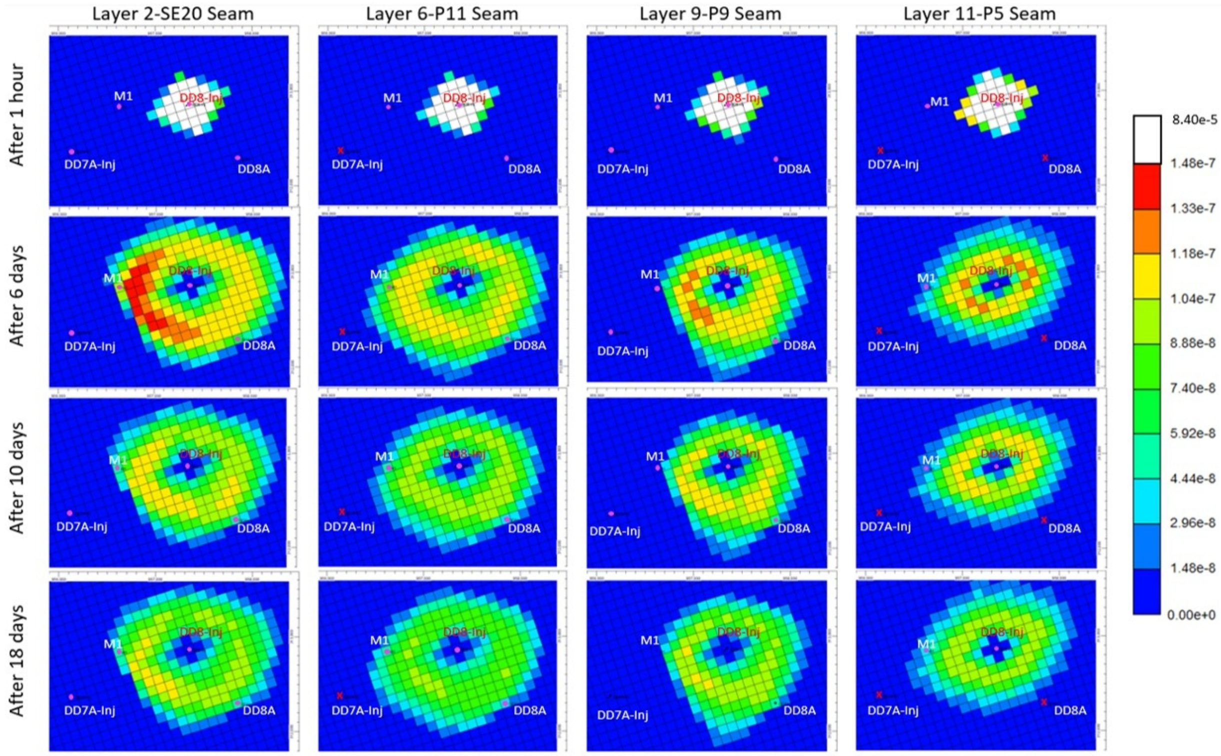

Figure 3.19: SF_6 plume migration for four coal layers 1 hour, 6 days, 10 days, and 18 days after tracer injection.

3.5 – CONCLUSIONS

A total of 13,263 tons of CO_2 were injected into three vertical coalbed methane wells over two distinct injection phases. Phase I was conducted from July 2, 2015 to April 15, 2016 when a total of 10,601 tons of CO_2 were injected. Phase II was conducted from December 14, 2016 to January 30, 2017 when an additional 2,662 tons of CO_2 were injected. During both phases, all three wells behaved similarly with respect to pressure, temperature, and cumulative volume of CO_2 injected. After both injection phases, pressures decreased and leveled off at approximately 100 psi. This pressure fall-off suggests that injectivity for the reservoir was restored during both of the soaking phases.

The pre-injection reservoir model that was created to predict the extents of the CO_2 plume was refined and additional inputs such as completion information, gas composition, and fracture network. Adsorption tests were conducted for SF_6 on crushed coal samples and the resulting isotherms were also used as an input parameter for the model. A literature review concluded that this is the first known test for SF_6 adsorption on coals. The resulting model showed significant breakthrough of SF_6 at M-1 after 6 days, confirming field results. This model shows the SF_6 plume moving as a ring outward from the DD-8 injection well. This plume appears to have a confining barrier to the Southwest in the Seaboard (20) and Pocahontas 9 coal seams, but not the Pocahontas 11 and Pocahontas 5 coal seam. The completion report for DD-7A shows the completion of the entire Seaboard (20) and Pocahontas 9 coal seams, but only partial completion of the Pocahontas 11 (Pocahontas 11 (30)) and Pocahontas 5 (Pocahontas 5 (30)). This barrier confirms the influence of injected CO_2 from the other two injection wells on the direction of SF_6 breakthrough at offset wells.

The three injection wells were flowed back into normal production on January 9, 2018. On December 7, 2018, 11 months after flowback, approximately 1,740 tons of CO_2 had been flowed back out of the wells. This represents approximately 13% of the injected CO_2 volume. By comparison, the 2009 Russell County injection test reached 15% flowback after 10 months. DD-7, DD-7A, and DD-8 have retained approximately 81.5, 87.9, and 90.9% of their injected volume of CO_2, respectively.

ACKNOWLEDGEMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the National Energy Technology Laboratory's program under contract no. DE-FE0006827.

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CHAPTER 4 – DELINEATING CO_2 PLUME MIGRATION IN A STACKED COALBED METHANE RERVOIR USING MULTIPLE WELLBORE-SCALE TESTS

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ABSTRACT

A small-scale carbon dioxide (CO_2) injection test was designed to store up to 20,000 tons of CO_2 to demonstrate the storage and enhanced coalbed methane (ECBM) recovery potential in a stacked coal reservoir in Southwest Virginia. Phase I of the injection test was conducted from July 2, 2015, to April 15, 2016, when a total of 10,601 tons of CO_2 were injected into three coalbed methane wells. As part of the monitoring, verification, and accounting (MVA) plan for the project, a tracer gas, sulfur hexafluoride (SF_6), was introduced with the CO_2 in one of the injection wells to help track CO_2 plume migration. Shortly after the beginning of Phase I injection operations, both CO_2 and SF_6 were detected at a nearby production well. To delineate which coal seams the CO_2 was migrating through, four unique, wellbore-scale tests were performed; a downhole video camera, a well kill test, a downhole injection logging test, and a downhole Raman spectrometer test. This paper will give an overview of the CO_2 injection test, as well as a description of each test performed, including the methodology and results.

4.1 – INTRODUCTION

During the past decade, carbon capture, utilization, and storage (CCUS) has gained considerable recognition as a viable option to mitigate CO_2 emissions. This process involves capturing CO_2 at emission sources such as power plants, refineries, and processing plants, and securely and permanently storing it in underground geologic formations. The United States Department of Energy (DOE) has created a Carbon Storage Program, whose aim is to develop and advance CCUS technologies to make them more cost effective for widespread commercial deployment [1].

In 2003, as part of the Carbon Storage program, seven Regional Carbon Sequestration Partnerships (RCSPs) were created to research and determine the best technologies to store CO_2 for their specific regions [2]. As a result of these partnerships, many injection tests have been conducted to assess the storage potential of CO_2 in saline formations, oil and natural gas reservoirs, organic rich shales, and unmineable coal seams. Large-scale CO_2 injection projects for storage in saline aquifers include the Kevin Dome Project in Montana, the Citronelle Project in Alabama, and the Illinois Basin-Decatur Project in Illinois [3]-[5]. Additionally, injection projects for CO_2-enhanced oil recovery (EOR) include the Bell Creek Field Project in Montana, the Michigan Basin Project in Michigan, the Cranfield Project in Mississippi, and the Farnsworth Unit Project in Texas [6]-[9].

Unmineable coal seams are also an attractive reservoir for CO_2 storage due to coal's microporous structure and ability to adsorb CO_2 in large capacities. The DOE has estimated a total of 54 to 113 billion metric tons of CO_2 could be stored in unmineable coal seams [10]. Coal also provides an additional benefit in that, when introduced to CO_2, it will preferentially adsorb CO_2 over the naturally occurring methane (CH_4) at a ratio of 2:1 or higher [11]-[14]. Injecting CO_2 into unmineable coal seams can enhance coalbed methane (ECBM) recovery which could help offset the cost of CO_2 storage. Injection projects to test the CO_2 storage and ECBM recovery potential of coal seams include the Pump Canyon Project in the San Juan Basin, New Mexico, CONSOL Energy's CO_2 injection test in Marshall County, West Virginia, SECARB's CO_2 injection test in the Black Warrior Basin, Alabama, and Virginia Tech's CO_2 injection test in Russell County, Virginia [15]-[18]. In 2015, an award was granted to Virginia Tech and the Virginia Center for Coal and Energy Research (VCCER) by the U.S. Department of Energy through the National Energy Technology Laboratory to conduct a small-scale CO_2 injection test in Buchanan County, Virginia. The following section will describe this CO_2 injection test and provide initial Phase I results.

4.2 – CO_2 INJECTION TEST IN BUCHANAN COUNTY, VIRGINIA: PHASE I

4.2.1 – Overview

Up to 20,000 tons of CO_2 will be injected into three coalbed methane wells to test the injectivity, storage, and ECBM recovery potential of CO_2 in a stacked coal reservoir. The test site is located in Buchanan County, Virginia, approximately 7.5 miles from the aforementioned 2009 Russell County CO_2 injection site (Figure 4.1). The injection site is located within the Oakwood coalbed methane field, one of the largest fields in Central Appalachia. The Oakwood CBM field spans portions of Buchanan, Russell, and Tazewell Counties. Gas production in the Oakwood CBM field began in the early 1990s primarily by CNX Gas Company and Equitable Gas Company. Initial drilling began on 80-acre units with infill wells being drilled in the early- to mid-2000s [19]. The majority of wells in this area are vertically drilled and cased and are typically perforated and hydraulically fractured in several zones using nitrogen foam and sand proppant. Each zone can contain anywhere from 2 to 10 coals.

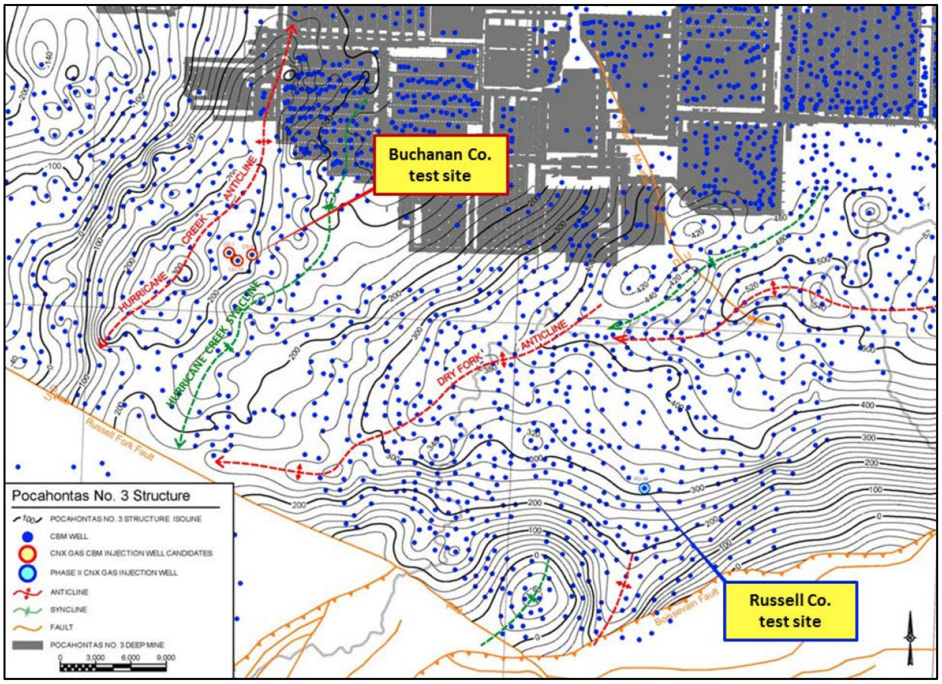

Figure 4.1: Map of CO_2 injection study area. The grey shaded area is an active underground coal mine.

4.2.2 – Geologic Characterization

The Oakwood CBM field is located within the Cumberland Overthrust Block, a large, well-defined northeast-southwest trending geologic feature that covers parts of Tennessee, Kentucky, West Virginia, and Virginia. Development of the block involved differential movement of up to seven miles along the Pine Mountain thrust fault, an extensive plane-derived fault, which resulted in complex internal structures characterized by the presence of thrust, strike-slip, and normal faults, as well as anticlinal and synclinal features [20]. The study area is located on the northeastern edge of the block and is defined to the south by the Russell Fork and Boissevain faults. The CO_2 injection site is positioned between the Hurricane Creek Anticline and Syncline.

Site-specific geologic cross sections were developed for the study area (Appendix A). Information garnered from these cross sections includes the identification of lithological features within the CBM-producing intervals such as individual coal seams, confining units, and regional seals. Also important is individual well-specific information such as drilling and completion dates, perforated and completed coal seams, total depth of wells, and geophysical logs performed including gamma, density, and/or caliper.

The coal reservoir in the study area consist of 15 to 25 individual, stacked coal seams from the Pennsylvanian-aged Pocahontas and Lee formations. The average coal thickness in the study area is 1.0 ft. and the coal seams are distributed from a depth of 1,000 ft. to over 2,000 ft. Significant coal seams in the area include the Seaboard, Horsepen and Pocahontas 1-11 coal seams. Interbeds consists of low permeability sandstones and shales. One key geologic feature in the study area is the Basal Lee Sandstone. The Basal Lee Sandstone is a well-cemented, low permeability sandstone that divides the deeper Pocahontas coal seams from the shallower Pocahontas, Horsepen, and Seaboard coal seams. The Basal Lee sandstone is approximately 200 ft. thick in the study area and acts as a confining unit between the deep and shallow injection target coal seams. Another key feature in the study area are three low permeability shales, including the Hensley Shale, that overlie the shallowest coal seams in the area. The Hensley shale has been identified as an effective regional seal due to its low permeability (0.001 to 0.1 md), its thickness (30 ft.), and its lateral continuity throughout the entire study area [21]. A generalized stratigraphic column for the study area is shown in Figure 4.2.

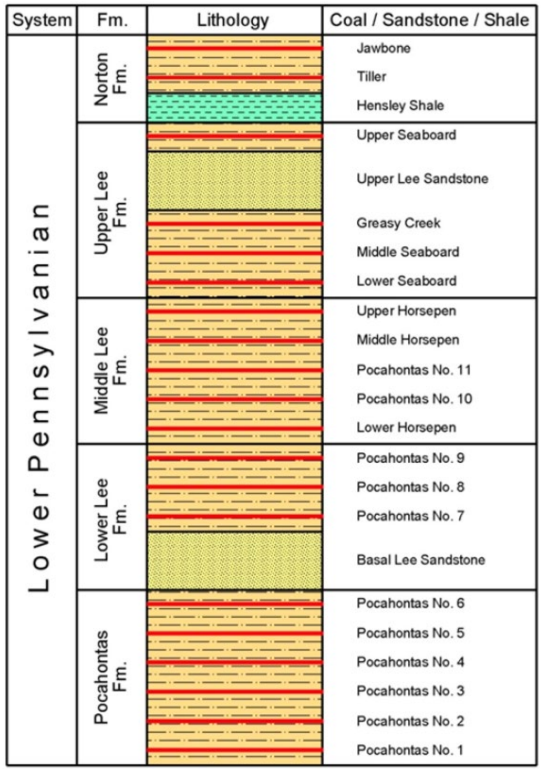

Figure 4.2: Generalized stratigraphic column for the Oakwood CBM field.

4.2.3 – Monitoring Verification and Accounting (MVA) Plan

A map of the injection site is shown in Figure 4.4. The three wells selected for CO_2 injection, DD-7, DD-7A, and DD-8, are indicated with yellow symbols. DD-7 and DD-8 were both drilled as initial wells in 2000 and 2001, respectively. DD-7A was drilled as an infill well on the DD-7 unit in 2007. These three wells were taken offline and converted for CO_2 injection operations. The production tubing was taken out of each injection well and a bridge plug was inserted at the bottom of the well to create an open-hole injection of the CO_2. A packer was set just above the first perforation to ensure injection of CO_2 into the target formations.

A customized monitoring, verification, and accounting (MVA) program was created for this injection test to monitor atmospheric, near-surface, and subsurface changes that may occur during CO_2 injection operations [22]. The white (shaded), ¼-mile overlapping boundary is where monitoring efforts were concentrated. This boundary was based on a preliminary model that simulated the extents of the CO_2 plume for the total target injection volume for the test. The blue, ½-mile boundary, which was extended beyond the white boundary, defines the overall project site where all monitoring activities will occur.

Three monitoring wells, M-1, M-2, and C-1, indicated with orange symbols, were drilled prior to CO_2 injection. Gas samples were collected routinely at these wells and analyzed for composition. These wells were also outfitted with surface and downhole temperature and pressure gauges, which were set up to record continuously. Gas samples were also routinely collected and analyzed at offset production wells within the MVA boundary, denoted by blue symbols, to detect any changes in gas composition over time and gas flow rates and pressures were recorded to monitor for any changes during CO_2 injection operations. More details on the sampling program can be found in [23].

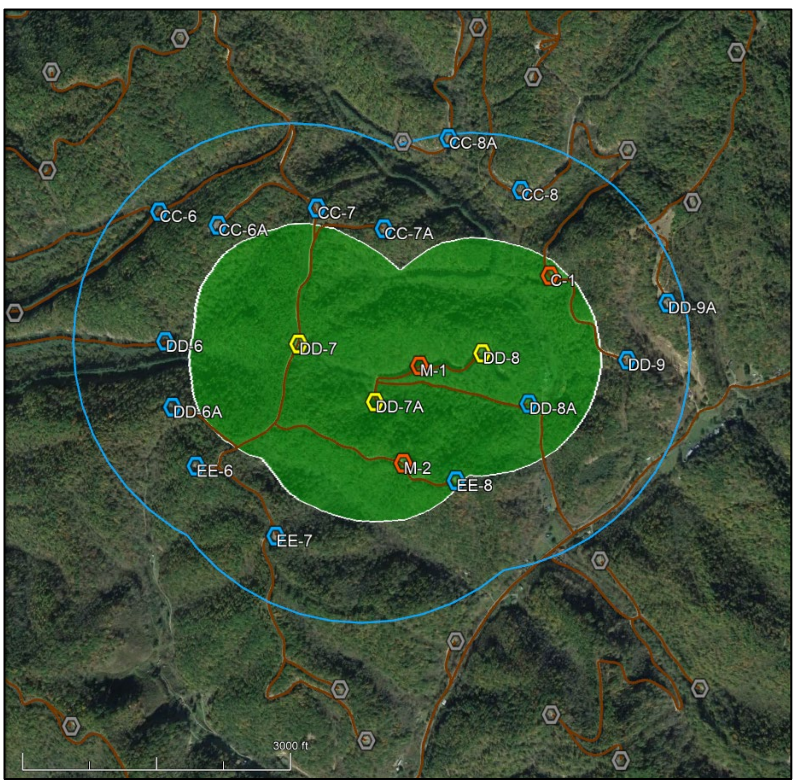

Figure 4.3: Map of CO_2 injection test site. Injection wells are denoted by a yellow symbol. Offset monitoring wells are denoted by an orange symbol. Offset production wells located inside of the monitoring boundary that were sampled are denoted by a blue symbol. Offset production wells located outside of the monitoring boundary that were not sampled are denoted by a grey symbol.

4.2.4 – Phase I Results

Phase I of the CO_2 injection test was conducted from July 2, 2015, to April 15, 2016, when a total of 10,601 tons of CO_2 were injected. As part of the MVA plan, multiple fluorinated tracers were added with the CO_2 stream at different times in each injection well to help determine interwell connectivity and migration pathways within the coal reservoir [24]. On July 17, 2015, 15 days after the start of CO_2 injection, sulfur hexafluoride (SF_6), was injected with the CO_2 stream at the DD-8 injection well.

On August 4, 18 days after tracer injection, SF_6 was detected at the nearest offset production well, DD-8A. Analysis of comingled gas composition at the surface of the DD-8A showed subsequent breakthrough of CO_2 approximately four months after the start of CO_2 injection (Figure 4.4). Baseline CO_2 concentrations taken up to 20 months prior to CO_2 injection at this offset well were less than 1.0%. On, November 10, 2015, CO_2 concentrations showed the first significant increase above 1.0% and steadily increased until the end of Phase I injection. On April 12, 2016, the concentration of CO_2 at DD-8A was measured at its peak of 12.9%.

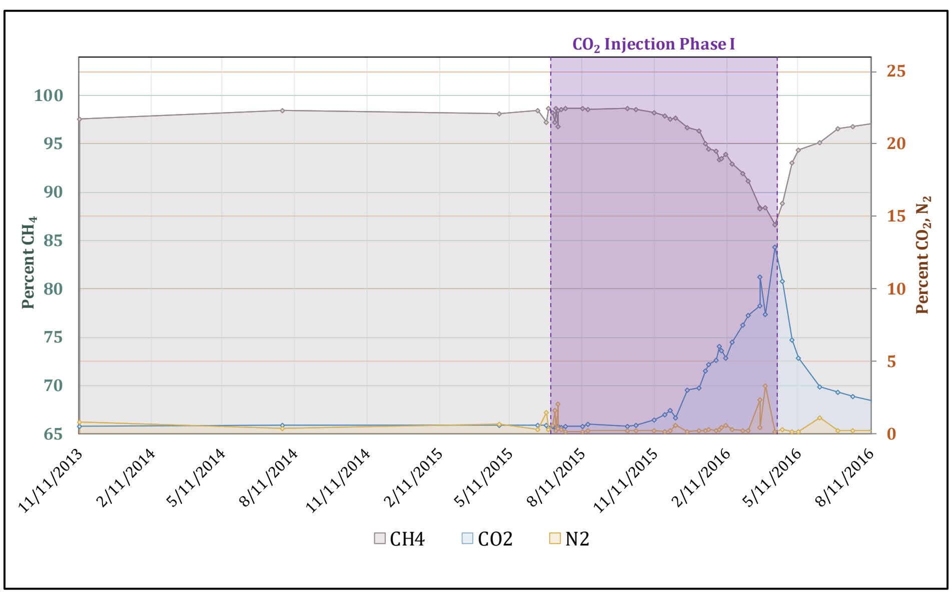

Figure 4.4: CH_4 (grey), CO_2 (blue), and N_2 (gold) gas composition of the DD-8A offset production well for Phase I (purple) of the CO_2 injection test.

Analysis of gas composition and tracer samples taken at the offset wells were successful in detecting the breakthrough of the CO_2 and SF_6, but because the samples taken were comingled gas at the surface, it was not able to be determined which coal seams or perforation zones the CO_2 was migrating through. The tests described in the following sections were performed to understand the connectivity between DD-8 and DD-8A and to delineate the CO_2 plume migration by coal seams or zones.

4.3 – DOWNHOLE VIDEO CAMERA

4.3.1 – Background

A downhole video camera was utilized in the injection wells as a qualitative method to determine the condition of the perforations created when the well was initially drilled and completed. It was important to assess whether the perforations were open or closed to determine which coal seams had successfully been completed and could potentially accept the injected CO_2.

4.3.2 – Methodology

The downhole video camera test was performed while the wells were being converted for CO_2 injection. Each well had 2-3/8" tubing installed with a downhole pump and sucker rod to remove water. The pumps and rods were removed and the wells were swabbed to remove any additional water. Once as much water as possible was removed via swabbing, the tubing was pulled out of the well and the camera was then lowered down to the bottom of the well and raised to inspect the perforations on the side wall of the casing. Perforations were determined to be open or closed based on visual inspection of the video log. Open perforations were indicated by a hole in the casing roughly 0.5" in diameter. The hole was also smooth and rounded along its edge, likely due to abrasion from the sand proppant entering the perforation. In many of the perforations deemed open, sand could also be observed indicating that individual perforation had accepted the completion treatment.

4.3.3 – Results

Table 4.1 displays the number of open perforations viewed vs. total perforations for each coal seam (and bench) based on visual inspection. In total, of the perforations that could be viewed, 64 of 70 were determined to be open.

Table 4.1: Assessment of DD-8 perforations from downhole camera.

Coal Seam	Depth (ft.)	No. of Open Perfs Viewed	No. of Perfs Viewed	No. of Perfs Viewed/Total Perfs*
Seaboard (20)	871	7	7	36/64
L. Seaboard (20)	912	4	4	
U. Horsepen (10)	984	4	4	
U. Horsepen (20)	1031	5	6	
Middle Horsepen	1068	6	6	
Pocahontas 11	1165	4	5	
Pocahontas 10 (10)	1198	4	4	
Pocahontas 9 (10)	1311	2	4	34/56
Unknown Coal	1397	5	5	
Pocahontas 7 (10)	1422	3	4	
Pocahontas 5 (10)	1591	4	5	
Pocahontas 4 (10)	1637	8	8	
Pocahontas 4 (20)	1677	8	8	
Pocahontas 3 (10, 20)	1711	Unable to view		0/32
Pocahontas 3 (30)	1721	Unable to view		
Pocahontas 3 (40, 50)	1731	Unable to view		
Pocahontas 2	1746	Unable to view		
Pocahontas 1	1802	Unable to view		
* from drilling and completion report				

Using the downhole camera log in DD-8 and the drilling and completion reports in DD-8 and DD-8A, perforated and completed coal seams were determined in each well. It is important to note that the perforations in the bottommost completion zone in DD-8 (Pocahontas 3 (10, 20) down to Pocahontas 1 coal seams) could not be viewed due to water build up in the well. Although visual confirmation was not achieved, it is assumed that all of the coals listed on the completion report were successfully completed. Likewise, although a downhole camera was not used in DD-8A, it is assumed that all of the coals listed as completed in the report were successfully completed. Coal seams that were successfully perforated and completed in both wells have the potential to provide favorable connectivity over coal seams that were not. Figure 4.5 shows the coal seams present in each well, and which coal seams were successfully completed in each well. There are 23 coal seams present in the DD-8 injection well, 20 of which were perforated and completed. There are only 16 coal seams present in DD-8A, 10 of which were perforated and completed. Of the 10 completed coals in DD-8A, all 10 were also perforated and completed in DD-8 suggesting favorable connectivity.

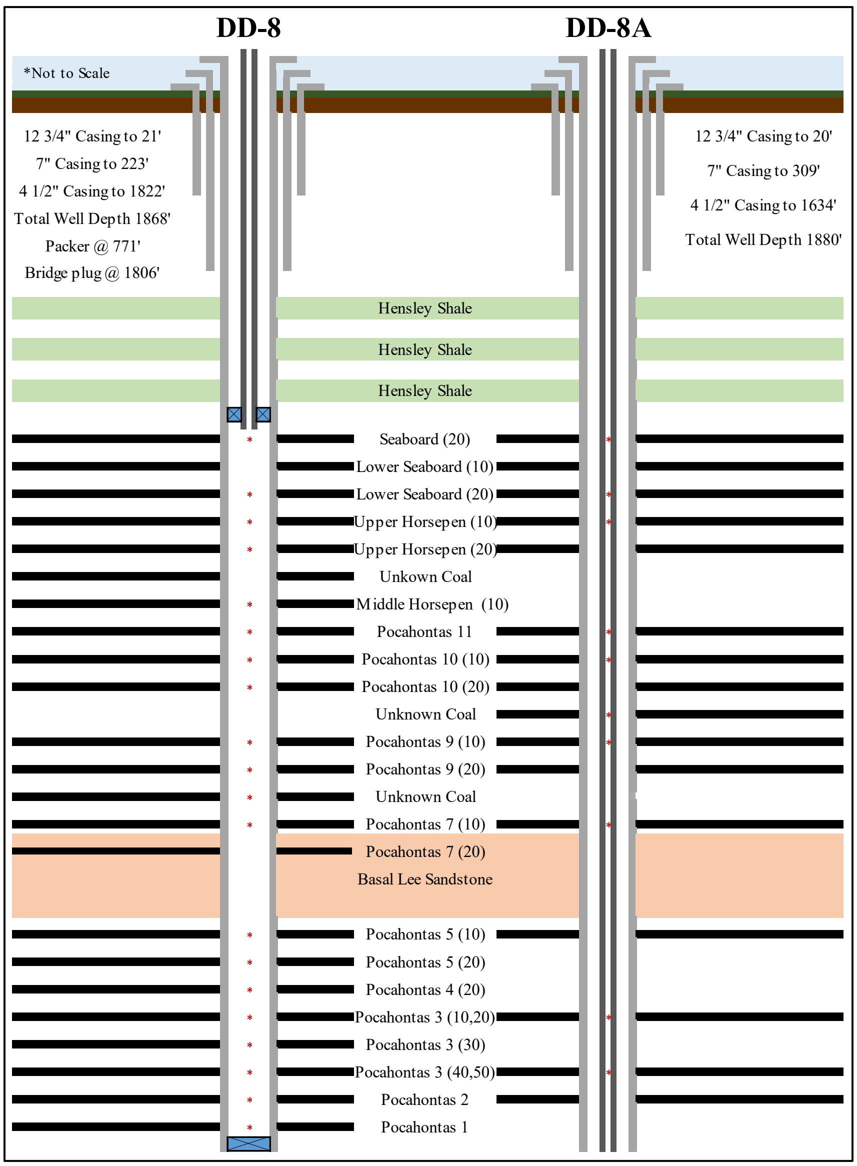

Figure 4.5: DD-8 and DD-8A interwell connectivity. Completed coals seams denoted by asterisk (red).

4.4 – WELL KILL TEST

4.4.1 – Background

Most coalbeds are naturally saturated with water [25],[26]. The presence of water significantly hinders gas transport through coal seams and contributes to pressure in coal seams that keeps methane adsorbed on coal surfaces [27],[28]. Water exists in coal seams in different states including bulk water in coal cleats and fractures, chemical-bonded water in clay minerals, and adsorbed water on coal surfaces within the coal matrix [29]. Because hydrocarbons are poorly soluble in water, cleats and fractures filled with water are poor transport pathways. For water-saturated coal seams, the removal of bulk water in cleats and fractures will create more flow pathways and improve gas flow by increasing relative permeability [30]. Therefore, coalbed methane production relies heavily on the dewatering of the coal seams to lower the water pressure head below the gas desorption pressure of the reservoir. Over time, the production of CBM can increase as the coal seams become more dewatered.

The goal of this specific test is to inject a volume of water on the annulus of the DD-8A well, covering individual coal seams or known perforation zones at different intervals. By injecting water at multiple intervals in the wellbore, gas production from coal seams that are below the water level will be terminated due to the increased hydraulic pressure created by the water column, which will be higher than the low desorption pressures typically found in coal seams [31].

4.4.2 – Methodology

The well kill test was conducted on December 16, 2015 approximately five months after CO_2 injection operations began. At this point in the project, a total of 5,804 tons of CO_2 had been injected into the three-injection wells. A total of 1,960 tons of CO_2 had been injected into DD-8 at an average rate of 16.2 tons/day. The CO_2 concentration at the DD-8A well was approximately 2.5%.

The test is designed to inject water directly on the annulus of the DD-8A well. At each water injection level, flow rates will be measured and gas samples will be collected and analyzed for composition. This general process is illustrated in Figure 4.6 below. In step 1, the depth of the water, d_1, is measured and the gas flowrate, Q_1, and comingled gas composition, c_1, for this interval is contributed from coal seams A, B, and C. In step 2, a volume of water is injected and the depth of the water, d_2, is measured. The gas flowrate, Q_2, and comingled gas composition, c_2, for this interval and contributed from coal seams A and B. In step 3, more water is injected and the depth of the water, d_3, is measured. The gas flowrate, Q_3, and gas composition, c_3, for this interval is contributed from only coal seam A. Finally, in step 4, water is injected to cover up all coal seams. At this step, the gas flowrate, Q_4, is expected to equal zero.

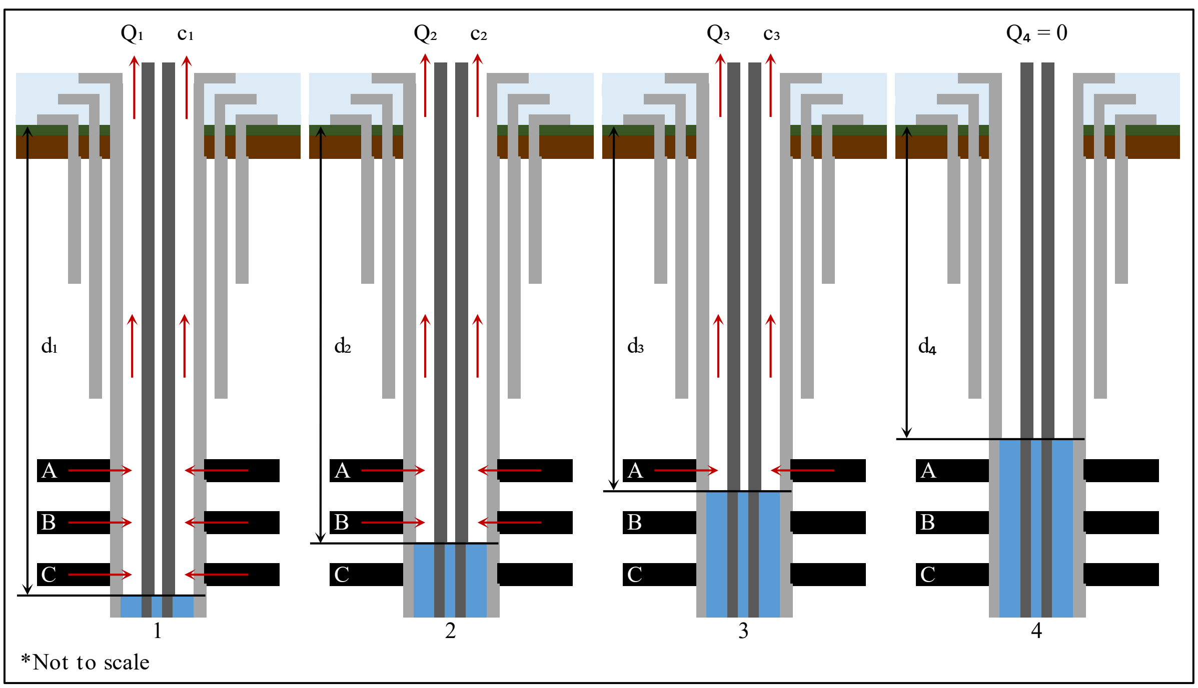

Figure 4.6: Water injection test to determine gas production from individual coal seams.

To determine the downhole liquid level in the wellbore after each water injection, an Echometer Remote Fire Gas Gun coupled with the Total Well Management (TWM) software was used. The Echometer gun generates a pressure pulse that travels down the annulus of the wellbore and reflects off each individual collar and the liquid level. The reflected pulse is picked up by a microphone located in the gun and transmitted via electric signal to the TWM software. The software then counts the number of collar reflections detected, and with the input of known collar lengths, can calculate the depth of the liquid level.

4.4.3 – Results

A total of eight water injections were performed for this test. Figure 4.7 below shows a generalized schematic of the DD-8A well, including the depth of each water injection level (blue lines) with respect to the location of each coal seam and geologic feature found in the well. Six zones, Z1-Z6, were created by the injected water, some of which contain multiple perforated coal seams. It is important to note that the water injections with measurements at 1,341 ft. and 963 ft. did not cover any additional perforated coals from the level below. For these water levels, the gas flow rate did not change, as there was no change in perforated coal seams contributing to those zones. Therefore, data from these water levels were not considered in the analysis of this test.

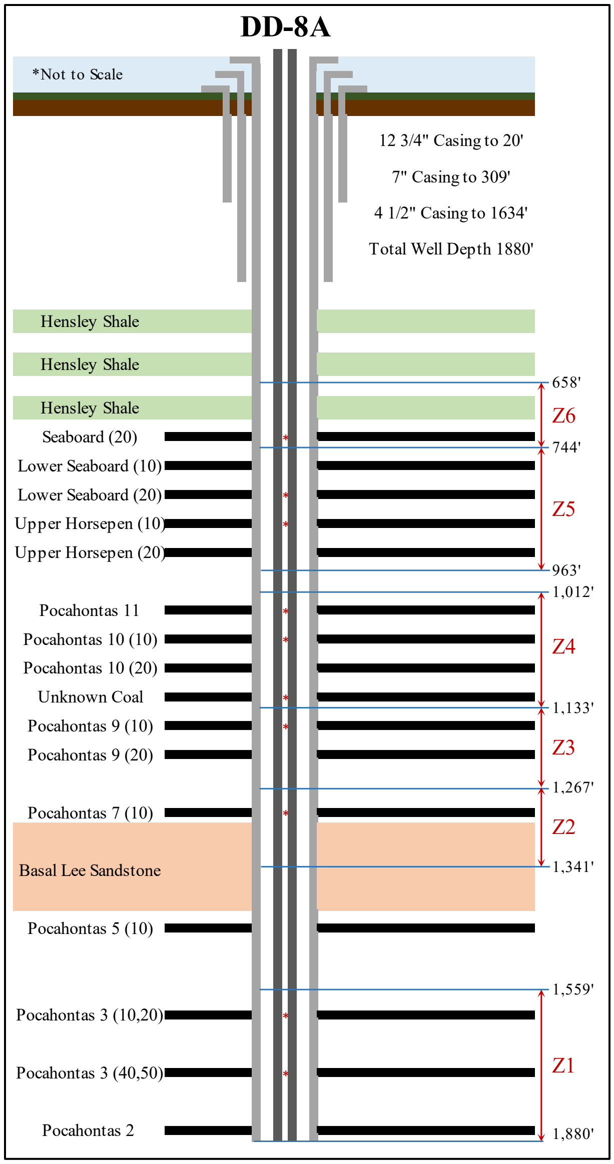

Figure 4.7: Echometer results from the DD-8A water injection test.

To determine individual flow rates for each zone, flow rates were measured at the surface for each water interval. These surface measurements are comingled, meaning as gas flows from each zone, it mixes with the gas from the zones above. As each water interval was added the production from the submerged zone is terminated, assuming the hydrostatic head exceeds the desorption pressure of gases in the submerged seams. Therefore, the measured total rate of gas exiting the well decreases by the rate of the submerged zones. This relationship is represented in the equations below with zones n=1 to N, where n=1 is the deepest zone and n=N is the shallowest zone, and individual flow rates given by r_n and total flow rate measures at the surface given by Q_n:

$$Q_n = \sum_{i=n}^{N} r_i$$

Thus, the first flow rate measurement of the test, where none of the zones have been submerged, Q_1 is the sum of the individual flow rates of all N zones:

$$Q_1 = \sum_{i=1}^{N} r_i = r_1 + r_2 + \ldots + r_N$$

Similarly, the final flow rate measurement of the test, where production from all but the shallowest zone has been stopped, Q_N, is simply the flow rate of the shallowest zone:

$$Q_N = \sum_{i=N}^{N} r_i = r_N$$

It can be shown that the individual flow rate of the n^th zone for n<N is given by:

$$r_n = Q_n - Q_{n+1}$$

Where:

$$r_n = \sum_{i=n}^{N} r_i - \sum_{i=n+1}^{N} r_i$$

$$= (r_n + r_{n+1} + r_{n+2} + \ldots + r_N) - (r_{n+1} + r_{n+2} + \ldots + r_N) = r_n$$

Figure 4.8a displays the raw data for the total comingled flow rates measured at the surface for each water level. Using this raw data and the above calculations, it was determined that Zone 6, which contains gas solely produced from the Seaboard (20) coal seam, and Zone 1, which contains gas produced solely from the Pocahontas 3 coal seam, have the highest individual gas production (Figure 4.8b). In order to compare gas production per zone, each zone was normalized by the thickness of completed coal for each zone (Figure 4.8c). While Zone 6 contained the highest rate of gas produced, it also contained the least amount of coal. Gas production per unit of coal thickness (Figure 4.8d) shows that Zone 6 has the highest gas production per foot of coal thickness.

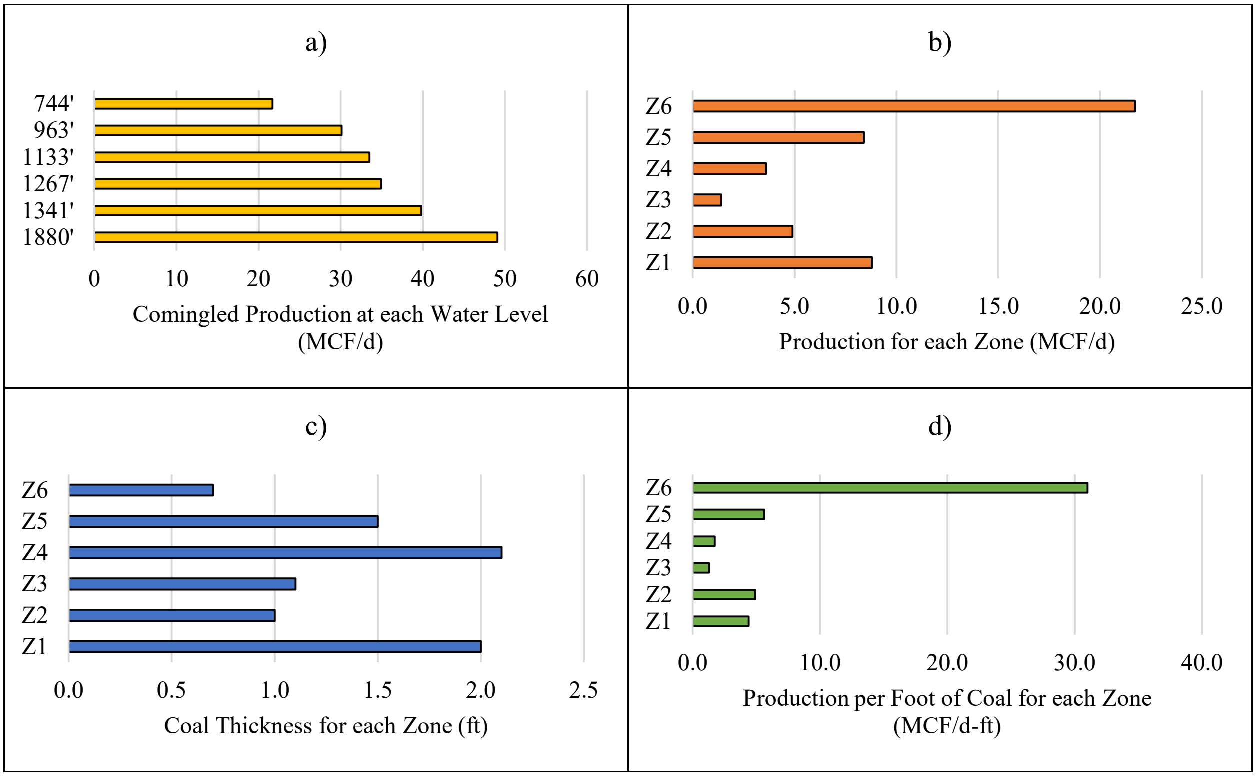

Figure 4.8: a) total comingled gas production. b) gas production by zone. c) coal thickness by zone. d) gas production per foot of coal thickness by zone.

For each water injection level, comingled gas samples were taken at the surface and analyzed for composition. Samples were collected in high pressure rated stainless steel gas cylinders. Samples were analyzed using an ABB NGC8206 natural gas chromatograph. Based on the results, methane dominates the content of the gas at each water level (Figure 4.9a). By considering the smaller components of the gas stream (Figure 4.9b), it was determined that CO_2 compositions increased after each water injection. The CO_2 concentration was the highest (6.9%) at the 744 ft. water level. This trend suggests that the majority of CO_2 is being produced from the shallowest zone and that the concentration is being diluted by comingled gas from the zones below.

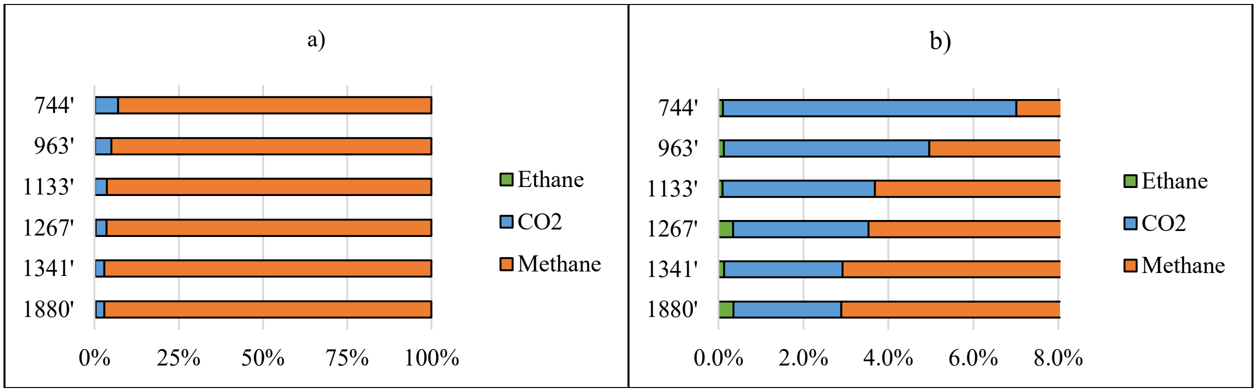

Figure 4.9: a) Comingled gas composition at each water injection level. b) CO_2 composition at each water injection level.

The comingled gas samples taken at the surface for each water level were also analyzed for tracer composition. The samples were analyzed on a Shimadzu QP2010 gas chromatograph with a negative-ion chemical ionization mass spectrometer (GC-NICI-MS). The resulting peak areas are counted (Table 4.2) and a calibration curve with known concentrations is created. The resulting peak areas are fit to the calibration curve to determine concentration (Figure 4.10). Similar to the CO_2 composition trend, SF_6 concentrations increased after each water injection (Figure 4.11). The highest concentration of SF_6 was measured at the 744 ft. water level, which is solely attributed to the Seaboard (20) coal seam. This trend again suggests that a majority of the tracer being produced by the shallowest zone and that the tracer concentration is being diluted by comingled gas from zones below.

Table 4.2: NICI analysis results.

Water Level	Peak Area	Avg	%RSD
744'	142380	141677	0.67
	142050		
	140601		
963'	56961	55310.3	4.62
	55885		
	53085		
1133'	36292	36024	0.68
	35813		
	35967		
1267'	22939	22306.3	2.79
	22283		
	21697		
1341'	22756	21618.7	4.56
	21016		
	21084		
1880'	16626	17290	4.35
	17690		
	17554		

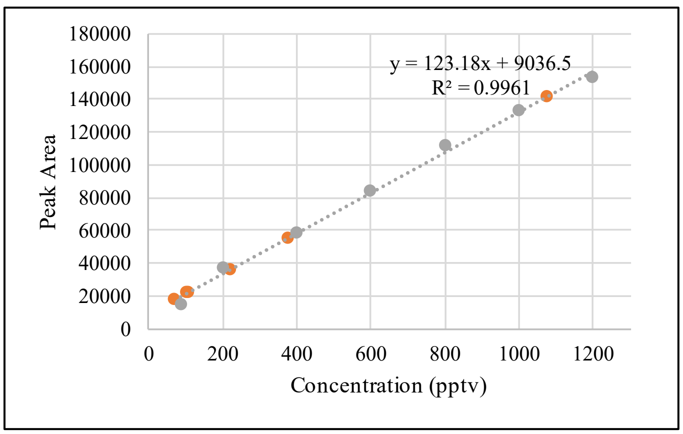

Figure 4.10: SF_6 calibration curve.

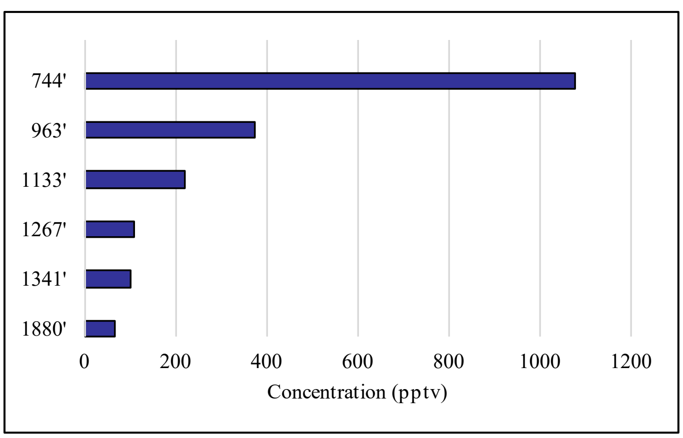

Figure 4.11: SF_6 concentration at each water injection level.

4.5 – DOWNHOLE INJECTION LOGGING

4.5.1 – Background

A continuous spinner survey is a common method used to determine fluid-flow profiles in natural gas wells. The spinner tool consists of rotating elements that, when placed in a flowing gas stream, will rotate at a rate proportional to the velocity of the gas stream. The spinner tool is moved up and down the well at a constant rate to provide a continuous flow profile of the entire well. Any change in gas flow will cause a change in rotation rate, which is recorded versus the depth of the tool. Spinner tools are often deployed on a wireline and are usually accompanied with other production logging tools.

4.5.2 – Methodology

On March 23, 2016, approximately eight months after CO_2 injection operations began and four months after the breakthrough of CO_2 was observed in the offset production well DD-8A, Weatherford Wireline Services conducted and logging test on the injection wells to determine the injection zones for the CO_2. The logging tool string consisted of a full-bore spinner tool, a gamma ray density tool, a casing collar locator, a temperature gauge, a pressure gauge, and a radioactive density tool.

At the time of logging, approximately 3,385 tons of CO_2 had been injected in the DD-8 well. Two round trip logging passes from 820 ft. to 1,806 ft. were conducted at different logging speeds, 100 and 150 ft. per minute (fpm). A calibration pass from 1,205 ft. to 1,311 and back was conducted at 50 fpm. All passes were run while CO_2 was being injected. The average CO_2 injection rate during logging was 61 tons/day.

4.5.3 – Results

A Weatherford engineer prepared the report by filtering and analyzing the flow meter data to compute the injection profile, to determine the injection zones, and estimate the flow per injection zone based on the surface flow rate. The down pass at 150 feet per minute (fpm) was used to estimate the injection profile due to its average consistency in the overall data. The injection zones were determined by the deflection in the spinner curves. The percent flow to each zone was calculated by the change in revolutions per second on the spinner as it passed each coal seam.

The interpretation of the logging suggests that the most active perforations are in the shallowest interval, which was originally stimulated from 871 ft. to 1,205 ft. Based on these results, the spinner survey suggests that a majority of the CO_2 injection occurred into the Seaboard (20) coal seam. It is likely that deflections in the spinner curves due to the low rates of flow of injected gas into deeper seams fall short of the instrument sensitivity limit. The pressure and temperature recorded at all depths below the tubing indicate the wellbore was filled with supercritical CO_2. More details about the injection logging can be found in Appendix B.

4.6 – DOWNHOLE RAMAN SPECTROMETER

4.6.1 – Background

Raman spectroscopy is a widely used, analytical chemistry technique that uses monochromatic illumination, usually by an intense laser beam in the ultraviolet-to-visible region, to illuminate a sample. Interactions between photons and molecules in the sample result in Rayleigh scattering (elastic) and Raman scattering (inelastic). Inelastic scattering is associated with a change in the scattered photon energy, which indicates a change in photon frequency (and thus color). This change in frequency, or Raman shift, with respect to the original frequency of the excitation laser provides information about the vibrational, rotational, and other low frequency properties of the illuminated sample. These properties provide a unique rovibrational fingerprint by which the molecules within a sample can be identified, differentiated, and quantified.

Raman spectroscopy is extremely useful not only to identify multiple components in a chemical mixture, but also to precisely quantify the amount of each component in the mixture. A major advantage of Raman spectroscopy is that unlike the related infrared-absorption spectroscopy, it is not overly sensitive to water. This is useful in the natural gas industry to be able to analyze mixtures containing solubilized gas (hydrocarbon and non-hydrocarbon) and other liquid hydrocarbons, and especially in coalbed methane reservoirs where the system contains water.

Laser excitation and sensitive detector requirements for Raman spectroscopy historically confined application of the technique to a laboratory setting. Recent advances in miniaturization have enabled compact, portable, and even hand-held systems for field work. A novel, downhole reservoir Raman system (DRRS) was developed by Welldog Inc. to measure the concentration of various gases, including natural gas liquids, as well as higher hydrocarbons solubilized or diluted in fluids extracted from carbonaceous strata including coal seams and shale [32],[33]. The DRRS incorporates a full spectrum Raman spectrometer and an analog sensor package to measure fluid conductivity, temperature, and pressure. The instrument package is integrated into a single housing and is deployed downhole on multi-core wireline to acquire real-time borehole fluid concentration profiles. Unlike a typical logging tool, the DRRS functions both while moving through the wellbore as well as when held stationary. Thus, a conventional log of the borehole gas composition versus depth can be measured, as well as a temporal log of the dynamics of borehole gas composition while the system is held in place during stationary scanning mode. Data is collected in-situ and communicated to the surface for near-real-time analysis. The DRRS has been historically used for determining gas saturation and gas content of coal seams. [34]-[36]. This test represents the first ever application of the DRRS to characterize dry gasses flowing out of individual coal seams. The goal of the test was to the use the DRRS to identify changes in CH_4 and CO_2 vs. depth in the three injection wells post-injection to help determine which individual coal seams or zones the CO_2 is migrating through.

4.6.2 – Methodology

The downhole Raman spectrometer test was conducted on November 10-11, 2017 during the flowback phase of the project, approximately 10 months after being in normal production. Prior to this test, the packer used to isolate the coal seams was retrieved and consequently, packer fluid was released and fell to the bridge plug at the bottom of the well. This plug was drilled out and the wellbore cleaned out using compressed air to remove as much fluid as possible.

The logging program for DD-8 included: an initial run of the DRRS to log the gas composition, pressure, and temperature for the entire length of the well from surface to the drilled-out bridge plug just above the rathole; to perform stationary scans above the perforation zones (for DD-8, three zones consisting of 5-6 coals); and then the instrument was pulled out of hole. Data collection rate was nominally 2.5 Raman spectra collected per minute continuously from entry in hole until pulled out of hole. After the entire well was logged, a temporary bridge plug was set to block production from the bottommost zone. The DRRS was then redeployed to log from surface to the temporary plug, to perform stationary scans again above the perforation zones, and then pulled out of hole. This process was repeated two more times, as two more temporary plugs were placed to block production from underlying coal seams and similar logs were performed. A total of four runs of the DRRS were performed in DD-8.

An important concept to understand borehole composition logs is that gas flows out of lower active seams and upwards, comingling with gases that flow from active seams above. When a change in gas composition is recorded as the DRRS is moved past a seam during a logging run, it can be inferred that the seam is actively producing gases that are different from those flowing up from below. However, unless that seam is the lowest active seam, it is impossible to tell the exact composition of gases being produced from that seam because of comingling. It is only possible to tell if that seam is producing more or less CO_2 or CH_4 than the aggregate of seams below. On the other hand, if no change in gas composition is recorded upon moving past a seam, then there are two possibilities: Either that seam is negligibly active, or it is producing a composition of gases that are indistinguishable from those flowing upwards from active seams below. Ideally, the gas composition change when logging past a seam would be combined with a measurement of the net flow contribution from that individual seam to determine the actual composition of gases produces from the seam.

4.6.3 – Results

During the initial log of DD-8, the DRRS was lowered to 1,805 feet below surface, performing stationary scans at 870, 1,160, 1,310, and 1,590 ft. on the way down. The tool was then raised to perform scans at each station again and then pulled out of the hole. It was determined that there was a buildup of water over the Pocahontas 4 (20) coal seam at 1,677 ft. There was also a buildup of "foam" on top of the water column to 1,585 ft., covering the Pocahontas 5 (10) coal seam at 1591 ft. Due to the water and foam layer obscuring results from the DRRS, the first temporary bridge plug was set just above these layers at 1,490 ft. The second temporary bridge plug was set at 1,288 ft. (just above the second perforation zone and the Pocahontas 9 (10) coal seam). The third temporary bridge plug was set at 1,132 ft. (above the Pocahontas 11 coal seam and below the Middle Horsepen (10) coal seam). Data from all four runs was compiled and general observations and conclusion are compiled in Table 4.3 below. More details about the downhole Raman spectrometer test can be found in Appendix C.

Table 4.3: Summary of DD-8 testing with downhole Raman Spectroscopy.

Coal Seam	**Zone / Depth FT / Thickness FT / Active? / Composition of gases exiting seam: Delta %CO2**
Surface	- / 88% CO_2: - / After plug @1132
Seaboard-20	A / 871 / 1.3 / Yes >CO_2 / >UH-20 CO_2 : +10%
Lower Seaboard	A / 902 / 0.2 (LS-10) / No or Eq. / - : -
	A / 912 / 1.6 (LS-20) / Yes >CO_2 / >UH-20 CO_2 : +7%
Upper Horsepen	A / 984 / 1.4 (UH-10) / Yes >CO_2 / >UH-20 CO_2 : +26%
	A / 1031 / 0.6 (UH-20) / Yes >CH_4 / <79% CO_2 : -24%
Unknown	A / 1054 / 0.4 / No or Eq. / 79% CO_2 : -
Middle Horsepen-10	A / 1068 / 0.7 / No or Eq. / 79% CO_2 : -
Temporary Plug	Prior to this plug at 1132, composition at surface was 88% CO_2
Pocahontas 11	A / 1165 / 0.8 / No or Eq. / - : - / -
Pocahontas 10	A / 1198 / 0.4 (P10-10) / No or Eq. / - : -
	A / 1204 / 0.8 (P10-20) / No or Eq. / - : -
Temporary Plug	Prior to this plug at 1288, composition at surface was 84% CO_2
Pocahontas 9	B / 1311 / 1.9 (P9-10) / No or Eq. / - : -
	B / 1314 / 0.5 (P9-20) / No or Eq. / - : -
Unknown	B / 1397 / 0.9 / Yes >CH_4 / ~86% CO_2 : -2%
Pocahontas 7	B / 1422 / 0.6 (P7-10) / Yes >CO_2 / >86% CO_2: +2%
	B / 1467 / 0.7 (P7-20) / No or Eq. / 86% CO_2 : -
Temporary Plug	Prior to this plug at 1490 composition at surface was 87% CO_2
Pocahontas 5	B / 1591 / 0.6 (P5-10) / Unknown / - : - / Obscured by foam
Pocahontas 4	B / 1637 / 1.6 (P4-10) / Unknown / - : - / Obscured by foam
	B / 1677 / 0.6 (P4-20) / Unknown / - : - / Obscured by water
Pocahontas 3	C / 1711 / 2.4 (P3-10,20) / Unknown / - : - / Obscured by water
	C / 1721 / 0.6 (P3-30) / Unknown / - : - / Obscured by water
	C / 1731 / 2.0 (P3-40) / Unknown / - : - / Obscured by water
Pocahontas 2	C / 1746 / 0.8 (P3-50) / Unknown / - : - / Obscured by water
Pocahontas 1	C / 1802 / 0.8 Unknown / - : - / Obscured by water
Seams below	1806 Bridge plug / 1822 to 1868 / end of casing to TD

Color Code
Division: Surface, plug, etc.
Uncertain composition and activity : No change in composition on logs past the seam
Uncertain: obscured by water/foam
Active Seam producing more CO_2 than flowing seams below
Active Seam producing more CH_4 than flowing seams below

4.7 - CONCLUSIONS

Phase I of a CO_2 injection test to demonstrate the storage and ECBM recovery potential in a stacked coal reservoir was successful in injecting approximately 10,600 tons of CO_2 into three coalbed methane wells. As part of a multiple tracer program to help track CO_2 plume migration, the tracer gas SF_6 was added with the CO_2 stream at the DD-8 injection well. Shortly after the start of CO_2 injection operations, increased concentrations of both SF_6 and CO_2 were detected at the closest offset production well, DD-8A. To delineate which coal seams the CO_2 was migrating through, four unique, wellbore-scale tests were performed successfully during different timelines of the CO_2 injection test.

A downhole video camera was used on the three injection wells while they were being converted for CO_2 injection operations. The perforations were visually inspected to assess their condition and determine which coal seams had been successfully completed. This test confirmed that over 90% (64/70) of perforations that were viewed in the DD-8 injection well were successfully completed. It was determined that all 10 perforated and completed coals that are present in DD-8A, are also present and completed in the DD-8 injection well. Assuming the same rate of success for perforations in DD-8A as in DD-8, it can be concluded that there is evidence suggesting favorable connectivity between DD-8 and DD-8A. This connectivity was confirmed later by the breakthrough of CO_2 and SF_6 at DD-8A shortly after injection operations began.

Approximately five months after CO_2 injection began, a well kill test was conducted on the DD-8A well. Water was injected on the annulus of the well at multiple intervals to detect changes in flow rate and gas composition at each interval. Individual flow rates were attributed to each zone created by the water injection levels and it was determined that the shallowest zone containing the Seaboard (20) coal seam had the highest rate of gas production. Composition analysis of the comingled production at each water level also concluded that the Seaboard (20) coal seam was the largest overall contributor to CO_2 composition. Tracer analysis confirmed the same results that the shallowest zone containing the Seaboard (20) coal seam had the highest concentrations of SF_6. These result was later supported when Weatherford Wireline Services conducted a continuous spinner survey to determine injection zones for the CO_2. Results from this test for the DD-8 injection well concluded the based on the higher active flow profile, most of the

CO_2 was injected into the top perforations from 871 ft. to 1,205 ft. It was also observed that within this profile, there was higher activity from 871 ft. to 1,040 ft. This is from the Seaboard (20) coal seam down to, and including, the Upper Horsepen (20) coal seam.

Ten months after the end of CO_2 injection operations, the DD-8 well was logged using the DRRS a total of four times downhole over two days in conjunction with the setting of three temporary bridge plugs to stop flow from underlying seams. Relatively small changes in gas composition were observed when logging past the Pocahontas 7 (10) (>CO_2 than aggregate of seams below) and the unnamed coal seam just above (>CH_4 than aggregate of seams below). Most other perforations in the well registered insignificant changes in gas composition during logs. The most dramatic activity in the well was observed from the shallowest coal seams. Activity from seams above the Upper Horsepen (20) dilute that methane from ~55% down to ~30% (Upper Horsepen (10)), then 20% (Lower Seaboard (20)) and 13% methane (Seaboard (20)), successively, with the balance of CO_2. It should be noted that this dramatic spike in methane was muted to some extent by comingling with the production of gases from seams below the Upper Horsepen (20) prior to the setting of the temporary bridge plug at 1,132 ft. To draw definitive conclusions about the sequestration of carbon dioxide it would be important to combine the gas composition changes observed during DRRS logs with measurements of the net flow contributions from individual seams.

Analyzing the results from the four wellbore-scale tests, in conjunction with the overall Phase I and II results, the following can be concluded:

1. Breakthrough of SF_6 during Phase I, and CO_2 during both phases at the nearest offset production well DD-8A confirm interwell connectivity in stacked coal reservoirs.

2. Fluorinated tracers such as SF_6 can be used to help monitor CO_2 plume migration and even predict migration pathways within a stacked coal reservoir as CO_2 was detected shortly after the arrival of SF_6 at the same offset production well.
3. Multiple intervals of injected water on the annulus of DD-8A was successful in determining individual flow rates from zones containing multiple perforated coal seams and determining which zones contributed the highest concentrations of CO_2 and SF_6.
4. Downhole Raman spectroscopy is a viable option to verify CO_2 sequestration in stacked coal reservoirs by characterizing gas composition from individual coal seams.
5. A majority of the CO_2 and SF_6 were being injected into, and migrating through, the shallowest coal seams, predominantly the Seaboard (20) coal seam.

ACKNOWLEDGEMENTS

Financial assistance for this work was provided by the U.S. Department of Energy through the National Energy Technology Laboratory's program under contract no. DE-FE0006827.

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CHAPTER 5 – CONCLUSIONS

A CO_2 injection test in Buchanan County, Virginia was successful in injecting 13,263 tons of CO_2 into multiple coalbed methane (CBM) wells. The objective of this test was to determine the storage and ECBM recovery potential of CO_2 in a stacked coal reservoir in Central Appalachia. Three CBM wells were taken offline and converted for CO_2 injection operations. Phase I of CO_2 injection operations began on July 2, 2015 when 10,601 tons of CO_2 were injected. Phase I ended on April 15, 2016 and the three wells were shut in for a soaking period of eight months. Phase II of CO_2 injection operations were conducted from December 14, 2016 to January 30, 2017 when an additional 2,662 tons of CO_2 were injected.

As part of the monitoring, verification, and accounting (MVA) plan, chemical tracers were used to track the CO_2 plume migration and determine flow pathways and interwell connectivity for the study area. In order to distinguish results from the multiple injection wells over multiple injection phases, a multi-tracer program was created. For this test, ten fluorinated tracers were selected: six perfluorocarbon tracers (PFTs), three halocarbon tracers, and sulfur hexafluoride (SF_6). These tracers were successfully injected at four distinct phases throughout the project. Two unique analytical methods were developed using gas chromatography coupled with negative-ion chemical ionization mass spectrometry (GC-NICI-MS) to detect and separate the tracers in a timely manner.

During Phase I of CO_2 injection operations, two of the chemical tracers injected were detected at multiple offset production and monitoring wells. PMCP that was injected in DD-7 prior to CO_2 injection was detected at three offset wells: CC-7A, CC-6A, and EE-6. SF_6 that was injected at the start of Phase I was detected at five offset wells: M-1, DD-8A, CC-8, CC-7A, and DD-9. Detection of these tracers at multiple offset wells confirms interwell connectivity in coalbed methane reservoirs. The detection of SF_6 at DD-8A before the arrival of CO_2 makes tracers a viable option to predict migration pathways. The detection of only two out of the ten injected tracers could be due to a number of factors including insufficient amount of tracer injected such that it could not be detected, missed breakthrough due to sampling frequency, or the tracer was unable to move through the reservoir due to adsorbed CO_2 or coal swelling. The two tracers that were detected were injected at the beginning of CO_2 injection operations making them a viable tool for the initial plume movement and migration prediction. It is recommended that future tests implement a multi-tracer program such as the one presented, and consider multi-zone injection of tracers to determine differences in migration pathways and times for deep and shallow coal seams/zones. It is recommended that for future tests only one type of tracer be used to reduce uncertainties in results. PFTs are a great option as they can be selected as a suite of similar-property tracers that are relatively inexpensive, easily deployed, and easily detected. Another advantages of selecting one type of chemical tracers, such as PFTs, are that a single, reliable method can be developed for analysis of these tracers which can reduce the costs and resources associated with analysis.

Approximately four months after the start of injection, CO_2 was detected above baseline levels and one of the nearest offset well, DD-8A. CO_2 concentrations in this well reached a maximum of 12.9% at the end of Phase I. During the first soaking phase, these concentrations decreased. As expected, CO_2 concentrations increased in DD-8A at the beginning of Phase II, reaching a maximum of 4.7% at the end of Phase II. Detection of a tracer at this offset well followed by the breakthrough of CO_2 confirms tracers as a viable tool to predict migration pathways for CO_2 injection tests. Based on this result, had more CO_2 been injected, breakthrough of CO_2 could be expected at the other wells where SF_6 was detected and likely in the order in which it was detected.

In order to delineate which coal seams the CO_2 was migrating through, multiple wellbore-scale tests were conducted on the DD-8A well where CO_2 breakthrough was detected and the DD-8 injection well where the CO_2 was determined to originate. A downhole camera was successfully lowered into the three injection wells while they were being converted for CO_2 injection operations to assess the condition of the perforations created during the initial drilling and completion. Inspection of the DD-8 video concluded that over 90% of the perforations that were able to be viewed were determined to be open and successfully completed. It was also determined that all of the coal seams that were completed in DD-8A were also successfully completed in DD-8, creating favorable connectivity between the two wells. A well kill test was conducted on the DD-8A well. Water was injected into the annulus of the well at multiple interval to detect changes in flow rate and composition, and attribute those to zones containing multiple coal seams. Results from this test conclude that a majority of the CO_2 was migrating through the shallowest zone containing the Seaboard (20) coal seam. Next, a downhole injection log was conducted in the injection wells using a continuous spinner tool. Interpretation of these logs concluded that a majority of the CO_2 injection occurred in the shallowest interval from 871-1,205 ft., including the Seaboard (20) coal seam. Finally, a downhole Raman spectrometer test was conducted to create a composition versus depth profile for the injection wells. Results from this test conclude that three coal seams were producing more CO_2 than the aggregate of the seams below them: Upper Horsepen (10), Lower Seaboard (20), and Seaboard (20).

The three injection wells were put back into normal production in January, 2018. Gas composition samples collected and analyzed at these wells up to December 7, 2018 determine that the gas stream is primarily CO_2 (>~70%). It is estimated that a total of 1,740 tons of CO_2 have been produced out of the three injection wells. This represents approximately 13.1% of the total CO_2 injected. By comparison, the 2009 Russell County injection test reached 15% flowback after 10 months and the Morgan County injection test reached 15% flowback after only 4 months. DD-7, DD-7A, and DD-8 have retained approximately 81.5, 87.9, and 90.9% of their injected volume of CO_2, respectively. It is recommended that further monitoring of the flowback be conducted on both the flowrates of the injection wells and the gas composition. Analysis of the flowback should be conducted to determine how much CO_2 has been stored during this test.

Based on the successful injection of over 13,000 tons of CO_2 into three coalbed methane wells during this test, it is recommended that a larger-scale test be performed in Central Appalachia to validate the potential for CO_2 storage and ECBM recovery in stacked coal seams at the regional/field level. The U.S. Department of Energy has estimated a total of 54-113 billion tons of CO_2 can be stored in coal seams in the U.S. Based on current EPA estimates this could mitigate up to 20 years' worth of CO_2 emissions in the U.S., with over 1.3 billion tons of CO_2 able to be stored in Central Appalachia alone. ECBM recovery can also extend the life of the mature fields typically found in Central Appalachia by adding recoverable reserves.

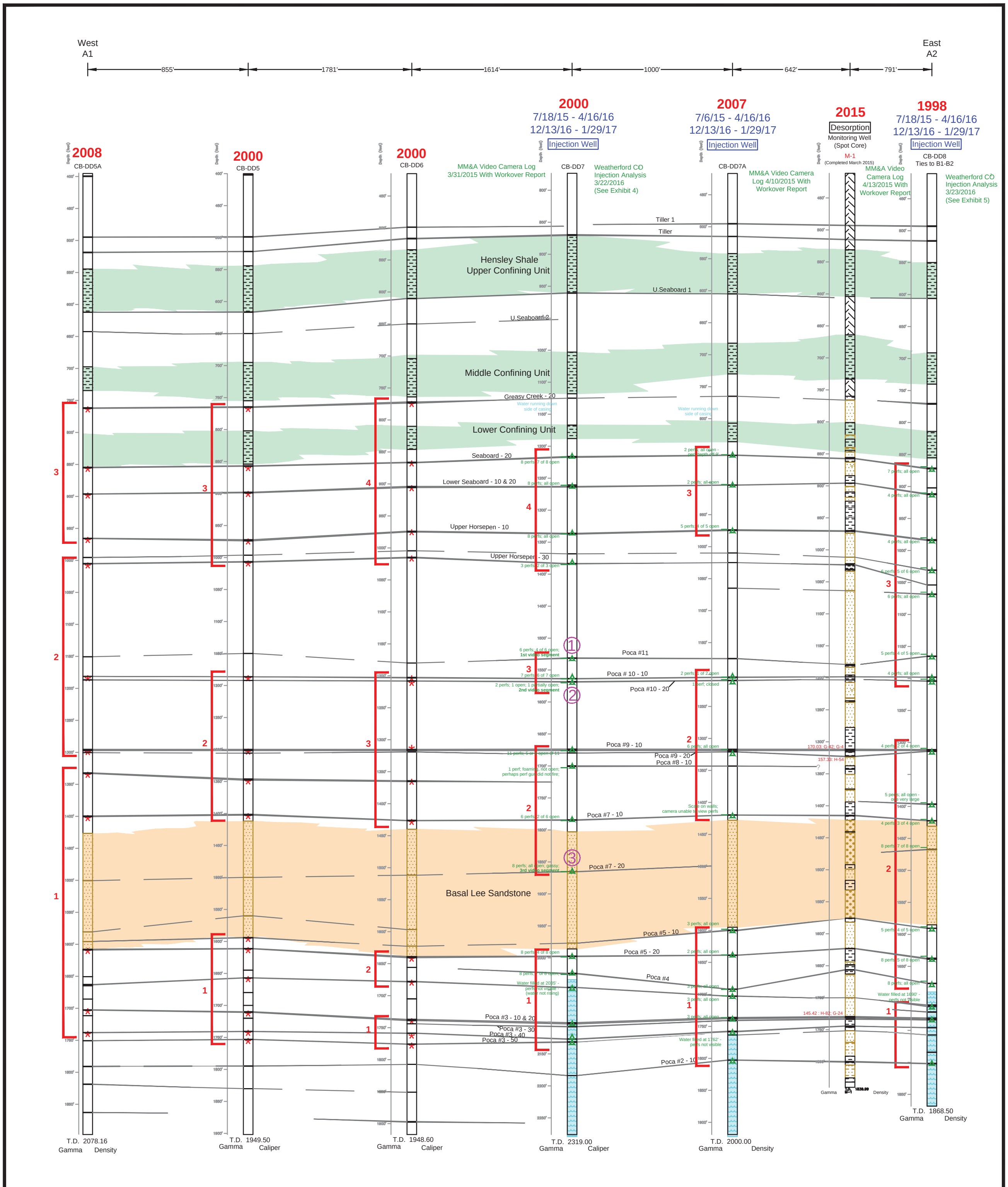
A larger-scale test should utilize varying injection schemes in order to maximize the storage and ECBM recovery potential at the field level. From a storage perspective, the breakthrough of CO_2 at offset wells is cause for concern. However, a larger test could be designed to reduce or eliminate the breakthrough of CO_2. For this test, it was determined that the CO_2 was migrating through the shallow, and likely more depleted, coal seams. Multi-zone injection of CO_2 would allow for a higher quantity and more even distribution of CO_2 injection. For this test, the three injection wells were located next to each other. For a larger test, the injection well candidates should be spaced based on the estimated extent of the CO_2 plume for the target amount of CO_2 to be injected into each well. Reservoir modeling could be used to estimate the extents of this CO_2 plume and determine which offset wells could be affected by the plume migration. The injection well candidates could be selected based on drilling schedule (initial vs infill), historic gas and water production for an area, or individual wells known to have a high depletion percentage. Wells that have a higher depletion could be more readily taken offline and plugged after CO_2 injection operations, ensuring CO_2 storage. From an ECBM recovery perspective, multi-zone CO_2 injections would allow for the recovery of heavier hydrocarbons that are typically found in deeper coal seams. The initial completion of a well with CO_2 could yield a higher initial recovery and increase the estimated ultimate recovery.

In order to determine the commercial potential for CO_2-ECBM recovery in Central Appalachia, an in-depth economic analysis should be conducted using results from this test and compared with results from previous tests such as the 2009 Russell County test and the 2014 Morgan County test. Continued monitoring of flow rates and CO_2 concentrations from the injections wells will determine the amount of CO_2 that was successfully stored underground the enhanced coalbed methane production due to CO_2 injection. Flow rate and gas composition should also be collected at surrounding offset production wells to see any changes to peripheral wells due to CO_2 injection operations. Results of the ECBM recovery and the amount of CO_2 injected/stored should be compared and the injection volumes should be optimized for future tests.

Ultimately the proceeds must outweigh the costs for a future test to be commercially viable. Reducing the cost of CO_2 and operating costs is critical. Applicable tax credits such as 45Q for carbon capture and storage could help alleviate the cost of CO_2 injection operations. Market factors such as higher gas prices will also provide favorable conditions for commercial viability.

The research team at the Virginia Center for Coal and Energy Research has now partnered with the Southeast Regional Carbon Sequestration Partnership (SECARB) on two CO_2 injection tests in Central Appalachia (2009) and the Black Warrior Basin (2010) and has recently conducted two small-scale CO_2 injections, one in an organic shale reservoir in Morgan County, Tennessee (2014) and another in a coalbed methane reservoir in Buchanan County, Virginia (2015). Results from each of these tests have concluded that CO_2 can stimulate hydrocarbon production in coal and shale reservoirs and the trapping mechanisms of unconventional reservoirs can retain the bulk of injected CO_2 for long-term storage. While much information is garnered from these CO_2 injection field tests, additional field laboratory research will reduced existing gaps in data and information related to enhanced coalbed methane and shale gas recovery associated with CO_2 storage.

APPENDIX A



Cross Section Exhibit E1

A1 - A2 (Injection Site)

Notes:

1. See Map A1 for location.
2. See Exhibit E4 video segments for CB-DD7.
3. Datum: Pocahontas No. 9 Seam

Lithologies

- Blank
- Bone
- Coal
- Coal with Shale
- Dark Shale
- Fireclay
- Hard Sandstone
- Sandstone
- Sandstone with Coal Spar(s)
- Sandstone with Shale Streak(s)
- Sandy Shale
- Shale With Sandstone Streak(s)
- Unknown
- Unknown Lithology

2007 — CBM Well Completion Year

1 — CBM Well Completion Zone

7/18/15 - 4/16/16 — CO_2 Injection Dates

* — Completed Coal Seam

8 perfs; all open — CO_2 Injection Zone With Description of Perforations

1 — Location of 2015 Video Segment

Water Observed By Video Camera in 2015

Quartz Arenite

Shale Confining Unit

Desorption

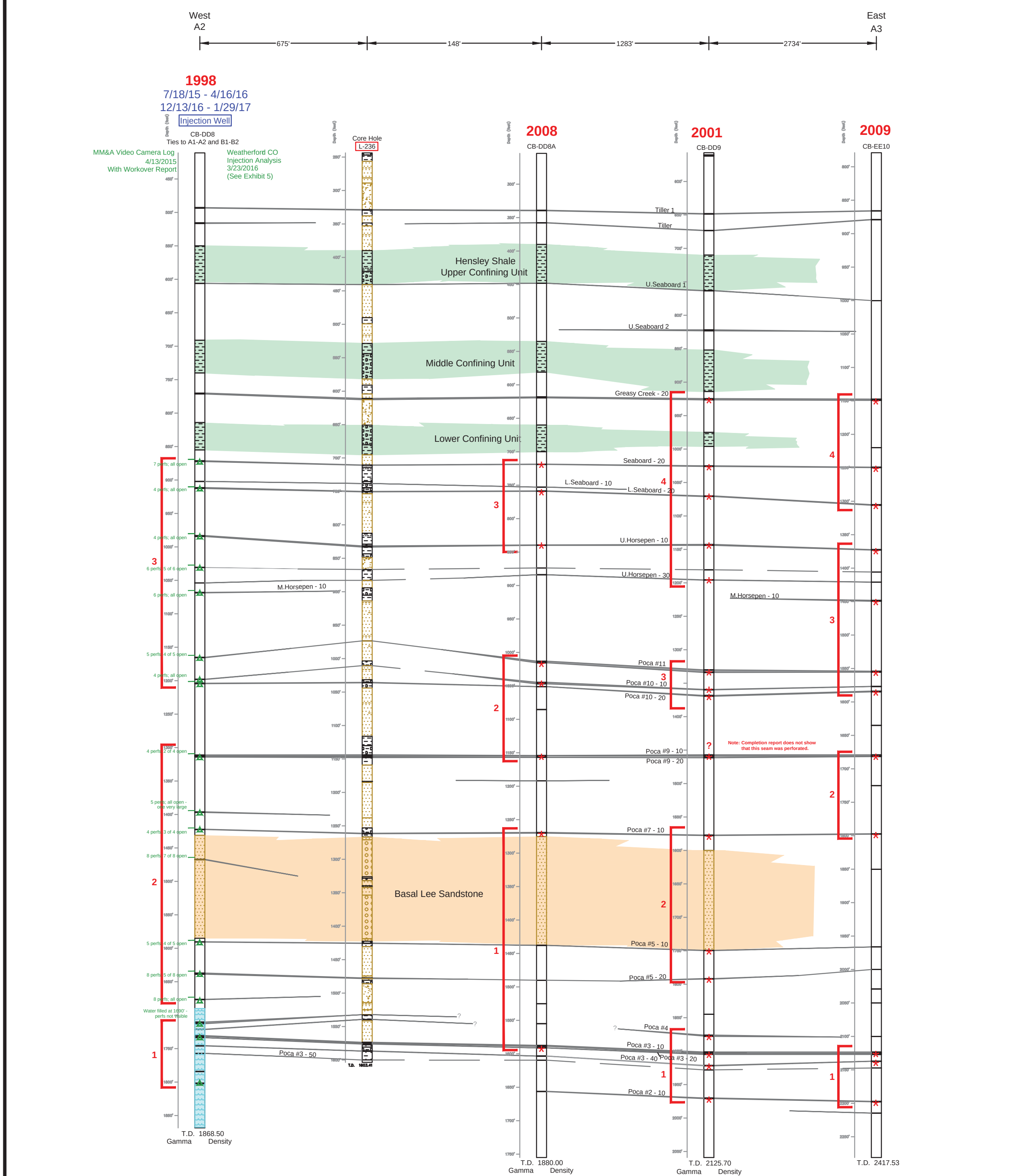
Gas Content Test	
scf/t	Canister ID
204.3	212

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17

E1—E3 Xsecs ABC.dwg

mh



Cross Section Exhibit E2

A2 - A3 (Injection Site)

Notes:

1. See Map A1 for location.
2. Datum: Pocahontas No. 9 Seam

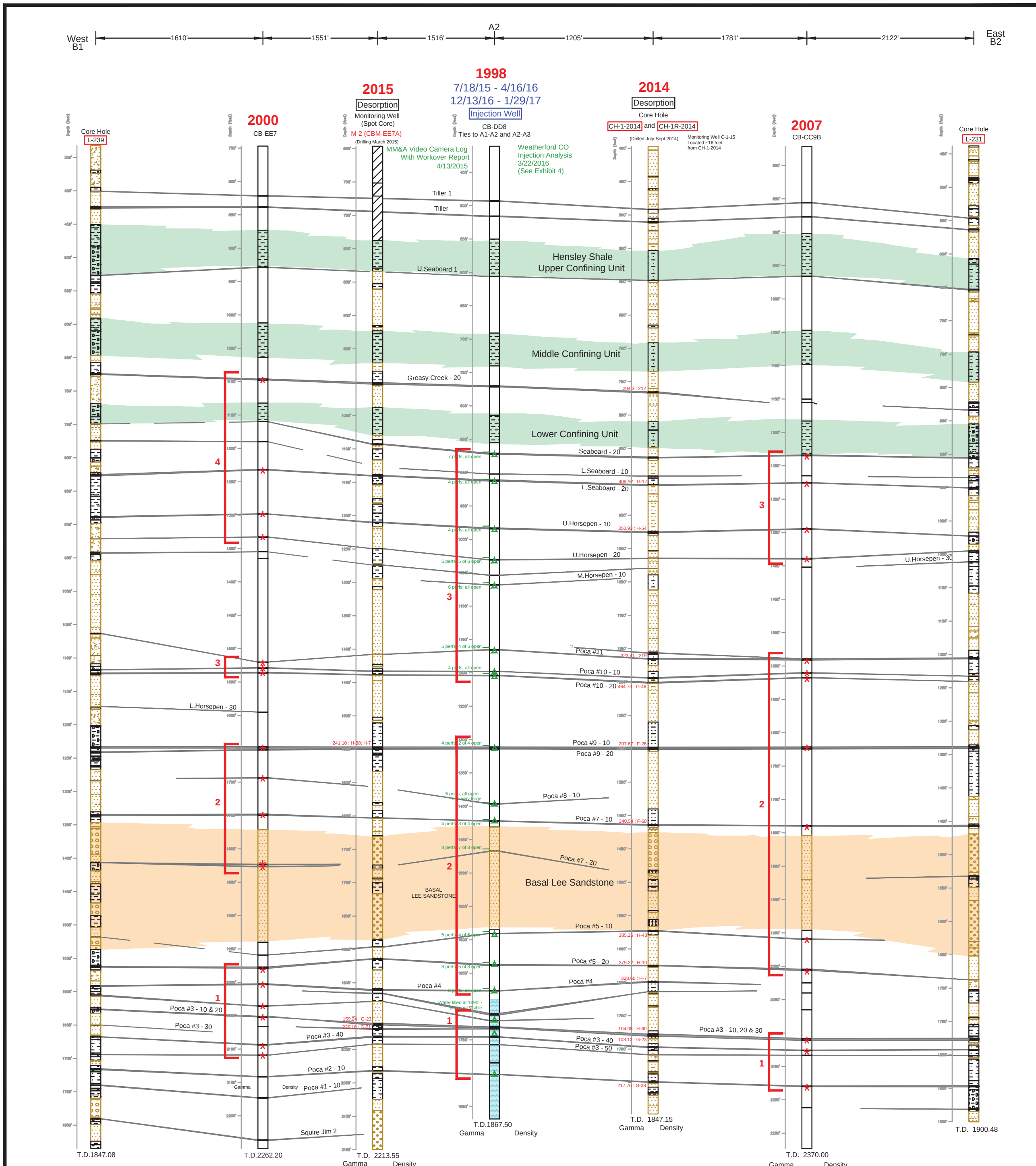
Lithologies

Blank	Sandstone
Bone	Sandstone with Coal Spar(s)
Coal	Sandstone with Shale Streak(s)
Coal with Shale	Sandy Shale
Dark Shale	Shale With Sandstone Streak(s)
Fireclay	Unknown
Hard Sandstone	Unknown Lithology

2007	CBM Well Completion Year
1	CBM Well Completion Zone
7/18/15 - 4/16/16	CO_2 Injection Dates
*	Completed Coal Seam
8 perfs; all open	CO_2 Injection Zone With Description of Perforations
	Water Observed By Video Camera in 2015
	Quartz Arenite
	Shale Confining Unit
L-236	Core Hole

MARSHALL MILLER & ASSOCIATES

VCER101 Bluefield, VA 11/17
E1-E3 Xsecs ABC.dwg mh



Cross Section Exhibit E3

B1 - B2 (Injection Site)

Notes:

1. See Map A1 for location.
2. Datum: Pocahontas No. 9 Seam

Lithologies

- Black Shale
- Blank
- Bone
- Bone with Coal
- Boney Coal
- Coal
- Coal With Bone
- Coal With Shale
- Crystallized Sandstone
- Dark Shale
- Fireclay
- Hard Sandstone
- Sandstone
- Sandstone with Coal Spar(s)
- Sandstone with Shale Streak(s)
- Sandy Shale
- Shale
- Shale with Coal Streak(s)
- Shale with Sandstone Streak(s)
- Unknown Lithology

2007 — CBM Well Completion Year

1 — CBM Well Completion Zone

7/18/15 - 4/16/16 — CO_2 Injection Dates

* — Completed Coal Seam

8 perfs, all open — CO_2 Injection Zone With Description of Perforations

Water Observed By Video Camera in 2015

Quartz Arenite

Shale Confining Unit

L-239 — Core Hole

Desorption — Gas Content Test

scf/t	Canister ID
204.3	212

MARSHALL MILLER & ASSOCIATES®

VCER101 Bluefield, VA 11/17

E1–E3 Xsecs ABC.dwg mh

APPENDIX B

Weatherford

Production Log Interpretation

Well Report Review Copy

CARDNO
DD-8
Field: OAKWOOD

3/29/2016

Prepared by:
Dahiana Mejia
15710 JFK Blvd, Houston TX, 77032
832.284.3731

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LIST OF FIGURES

CUSTOMER	:	CARDNO	WELL No.	:	DD8
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

1. EXECUTIVE SUMMARY

Weatherford Wireline Services were commissioned to perform an injection log (PLT) survey on DD8 for Cardno on March 23, 2016. The objective of the survey was to determine injecting zones.

A Weatherford PLT tool string consisting of GR, CCL, temperature, pressure, radioactive density, 1.69" jewel spinner was used in the logging job.

Conclusions:

- Raw data shows qualitatively active perforations between 871ft and 1040ft.
- Majority of CO_2 went to the top of perforation at (871-1205)ft (had the highest change in injection profile).
- Spinner data was affected by yo-yo making difficult to detect injecting zones with low injection rate at the time of logging.
- Density curve is provided from surface to the bottom of the logging interval to show CO_2 density changes against pressure and temperature. See figure 7.
- Bottom perforation was partially logged due to the tag depth.
- The injection profile was calculated from the 150B down pass.

Perforations (ft)		DW_150 (RPS)	%_DW 150B	Tons/day
871	1205	1.3	100	58
1311	1677	0	0	0
1710	1802	0	0	0

Table 1: Total Injection rate

2. LOGGING OBJECTIVES FOR PLT

The aim of the survey was to identify injection zones

3. LOGGING PROCEDURE

The tool string was composed as follows from top to bottom of E-line:

- Weight bars
- CCL
- GR
- Pressure Gauge
- Density
- Temperature sensor/ Jewel Flowmeter.

Job Procedure

String	Direction	Cable Speed	Interval	Well condition	BH contents	Remarks
PLT	Down	RIH	Surface to 820ft_MD	Injecting	CO_2	Looking for interfaces
Take a 5 minutes station at 820ft						
PLT	Down	100	820ft_MD (EOT) to 1806ft_MD	Injecting	CO_2	Check spinner response, if necessary repeat the pass
PLT	Up	100	1806ft_MD to 820ft (EOT)_MD	Injecting	CO_2	Check spinner response, if necessary repeat the pass
PLT	Down	150	820ft_MD (EOT) to 1806ft_MD	Injecting	CO_2	Check spinner response, if necessary repeat the pass
PLT	Up	150	1806ft_MD to 820ft (EOT)_MD	Injecting	CO_2	Check spinner response, if necessary repeat the pass
Calibration Passes						
PLT	Down	50	1205ft_MD to 1311ft_MD	Injecting	CO_2	
PLT	Up	50	1311ft_MD to 1205ft_MD	Injecting	CO_2	
Take a 5 minutes station at 1700ft and 1800ft						

Figure 1: Injection log procedure

CUSTOMER	:	CARDNO	WELL No.	:	DD8
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

4. SEQUENCE OF EVENTS

(Provided by T. Pawliuk, Weatherford US Specialty Engineer)

Production Logging Job Notes

Company	Cardno
Well Name	DD-8
Field	OAKWOOD
Date	23-Mar-16
Field Engineer	T. PAWLIUK
Correlation Log Used	Geological Logging Systems Gamma-Caliper Log dated 12/16/2001

	Pressure Tested
Lubricator Test	650

	Gas (TPD)	Oil (BPD)	Water (BPD)	Pressure (PSI)	Temperature (F)
Flow Rates	58				

Surface Pressure while logging	650
Hours well was flowing before logging	

PL RAW DATA file name shall be of the form XX_YY_ZZ.LAS, where:
XX: well condition, SI (shut in) or absent if flowing conditions
YY= logging direction DN (down pass) or UP (up pass)
ZZ= Cable speed in feet per minute (fpm)

Flowing Passes — Times are in Texas time because it matches up with the laptop

Passes	Time	Date	
150 DOWN			
150 UP	14:05		
RATE CHANGE 58 TON/DAY			
150 DOWN b	14:53		
150 up c	15:02		
100 down			REDUCED LOGGING INTERVAL TO A MAX DEPTH OF 1740' BECAUSE WE HAD ISSUES WITH THE FM PICKING UP STUFF AND DYING
150 UP D			
100 DOWN B	15:33		
100 UP			NO FM 1720-1400, AND FM NOT TURNING WHILE STATIONARY AT TOP OF INTERVAL. PULL INTO TUBING TO TRY TO CLEAN
70 DOWN	15:58		
100 UP B	16:15		

Stationary Data

Depth (ft)	Time	Date
820	13:50	23-Mar-16
RATE CHANGE		
820	14:42	
1700		
1800	17:00	

Remarks (Include any issues while logging)

DENSITY CALS BEFORE: AIR-15188.5 WATER-6352.1, AFTER: AIR-15157.2WATER-6339.9

11:45	dummy run	
12:43	power up to fdt in prep of cal	
12:53	cal fluid density	
13:08	TEST TOOL	
13:13	STAB ON	
13:15	EQUILIZE	650PSI
13:22	RIH	
13:35	AT 820	INJECTING ABOUT 60 TONS, TRY TO GET THEM TO BUMP IT UP TO 80, 858PSI, .67G/CC,0.6RPS
13:50	STAT820	
14:15	THEY HAD TO DROP INJECTION RATE	
	MY SPINNER HAD STALLED DURING THE UP PASS AS WELL SO I CAME INTO TUBING ANYWAYS TO GIVE IT A CLEANING	
14:40	RESTART LOGGING PASSES ATT NEW INJECTION RATE	

Figure 2: Sequence of Events

5. TOOL DIAGRAM

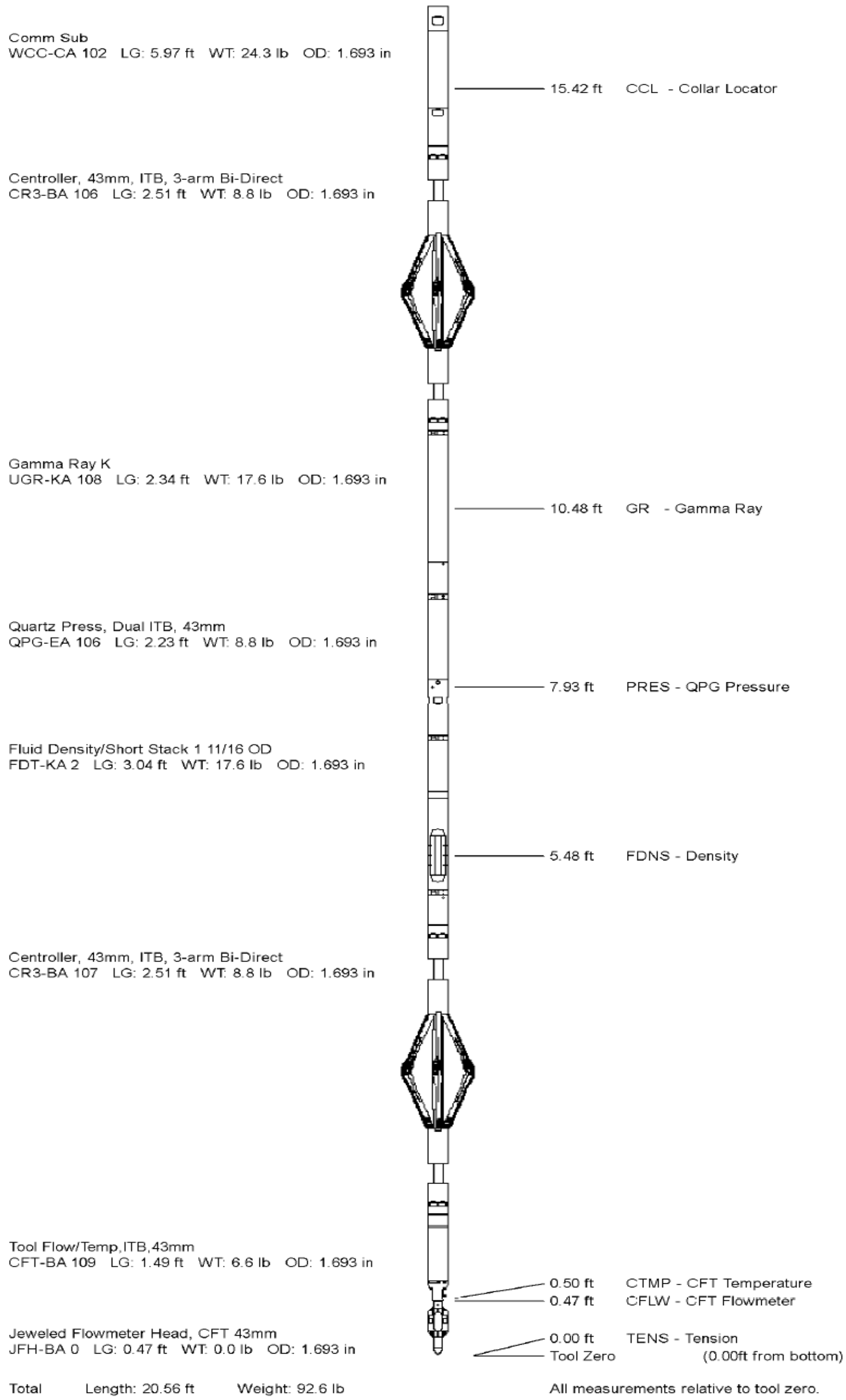

Figure 3: Tool String Diagram Tool OD: 1.693”

6. INJECTION LOG INTERPRETATION

OVERVIEW

The analysis was performed as follow:

- The data preparation to filter the data.
- The flow meter analysis to compute the injection profile.
- The profile determination to identify the potential injecting zones.
- The computation of percentage per injecting zones based on surface flow rate reported by client.

6.1 DATA QUALITY CONTROL AND DISCUSSION

The main sensors are:

- *Spinner flowmeter*: for an estimate of mixture flow rate.
- *Temperature*: mainly for qualitative interpretation, but is sometimes very useful and can confirm or deny conclusions drawn from other measurements.
- *Pressure*: needed for calculation of fluid properties and can be used to compute fluid density in wellbore.
- *Caliper, CCL and Gamma Ray*: needed for depth control or casing ID. The gamma ray curve can additionally help identify reservoir zones and scaling problems.

Log Quality Check –**Figure 4**: Injection passes- DD8

- **Gamma Ray:** The curves generally stack.
- **Pressure:** Repeatability pass to pass.
- **Spinner:** The spinner data was affected by yo-yo, seem in the erratic motion of the tension, making difficult to identify low injecting zones.
- **Line Speed:** Line speed data was very spiky.
- **Density:** Density remains consistent over whole logging interval. Good repeatability pass to pass.
- **Temperature:** Cannot be determined from temperature data clear injecting zones.

CUSTOMER	:	CARDNO	WELL No.	:	DD8
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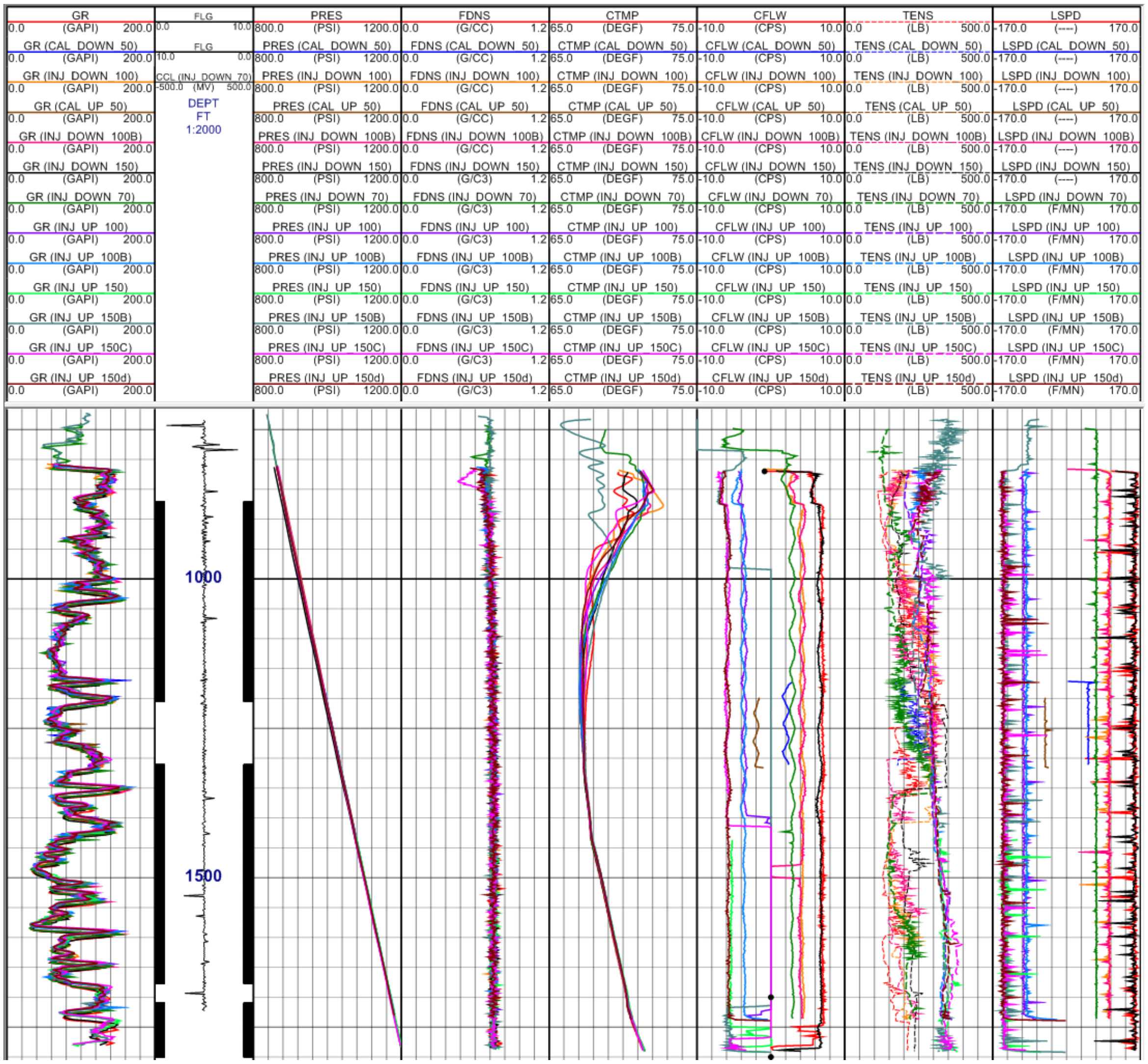


Figure 4: Injection passes- DD8

CUSTOMER	:	CARDNO	WELL No.	:	DD8
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

6.2 PROFILE CALCULATION

The down pass at 150B was used to get the injection profile. Where the spinner is showing the minimum value is the total flow rate, 100% flow. The maximum value for spinner is 0% flow.

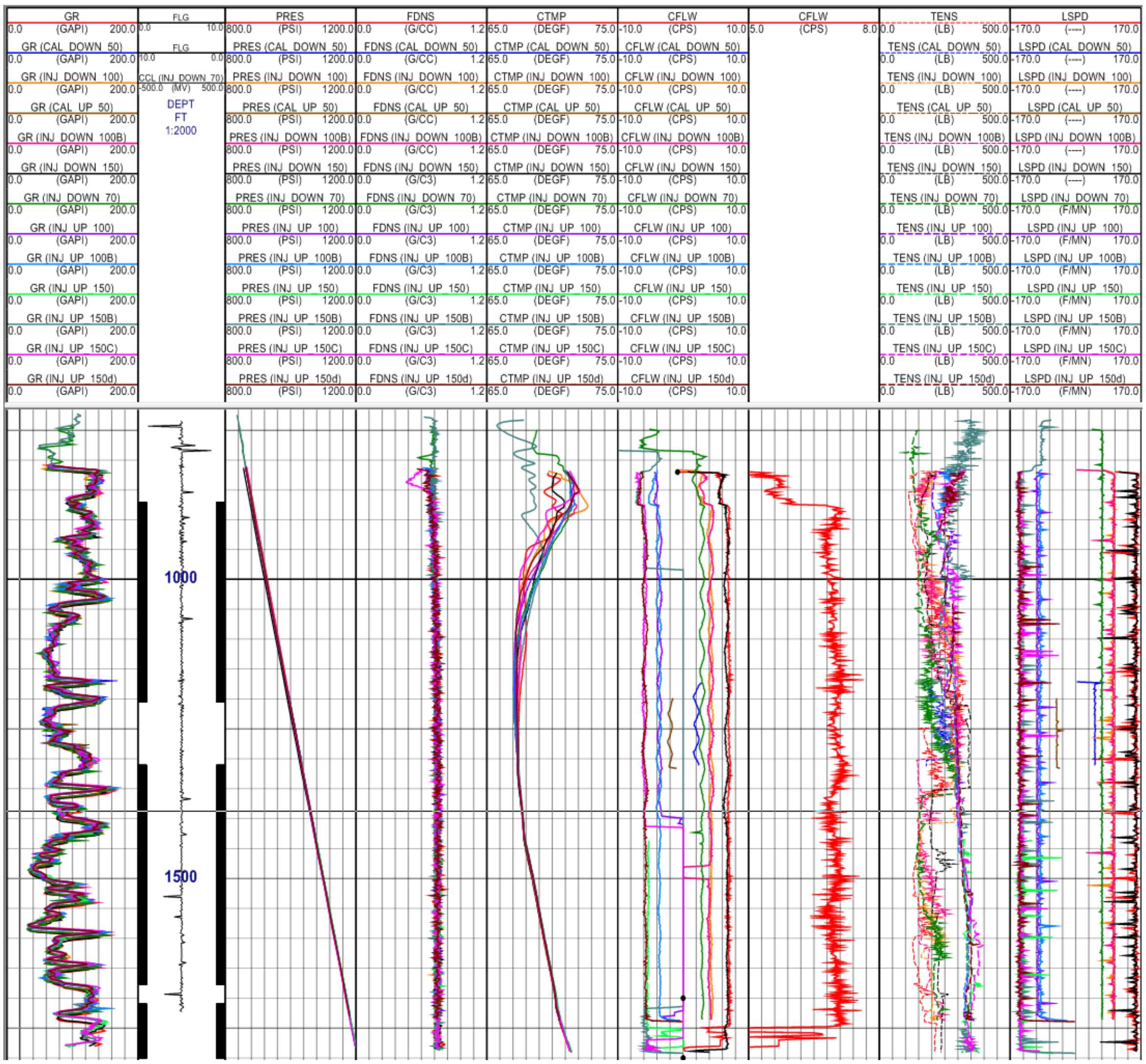


Figure 5: Injection Profile Computed

CUSTOMER	:	CARDNO	WELL No.	:	DD8
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

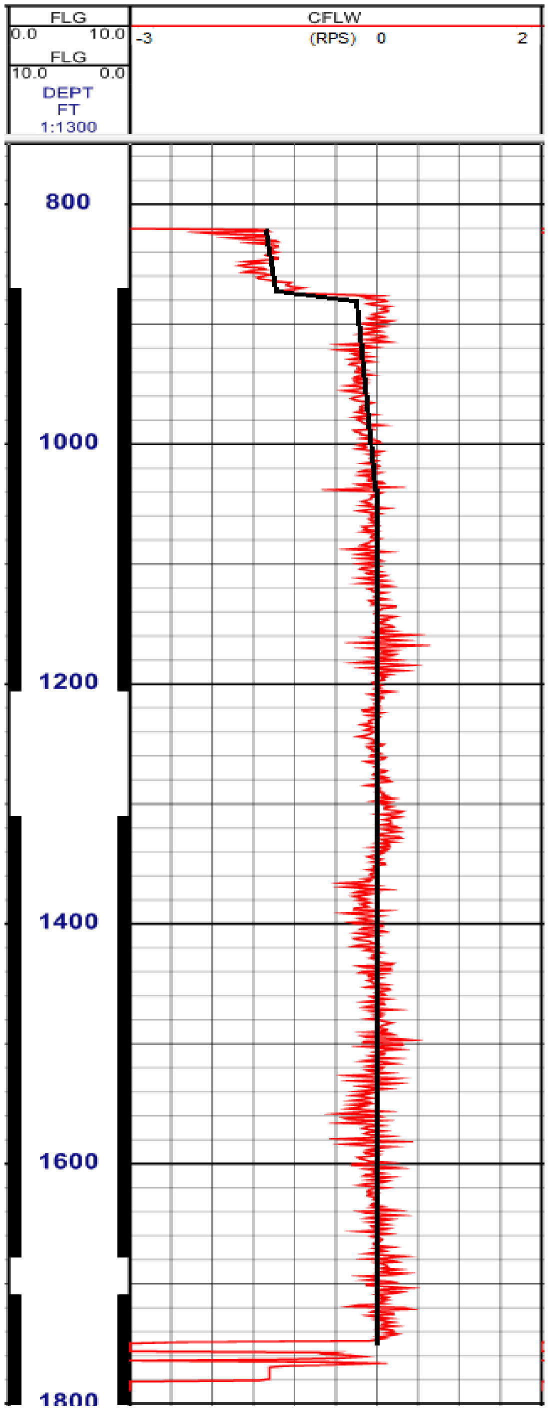


Figure 6: Injection flow profile

Perforations (ft)		DW_150 (RPS)	%_DW 150B	Tons/day
871	1205	1.3	100	58
1311	1677	0	0	0
1710	1802	0	0	0

Table 2: Percentage Injecting Zones

7. DENSITY PROFILE

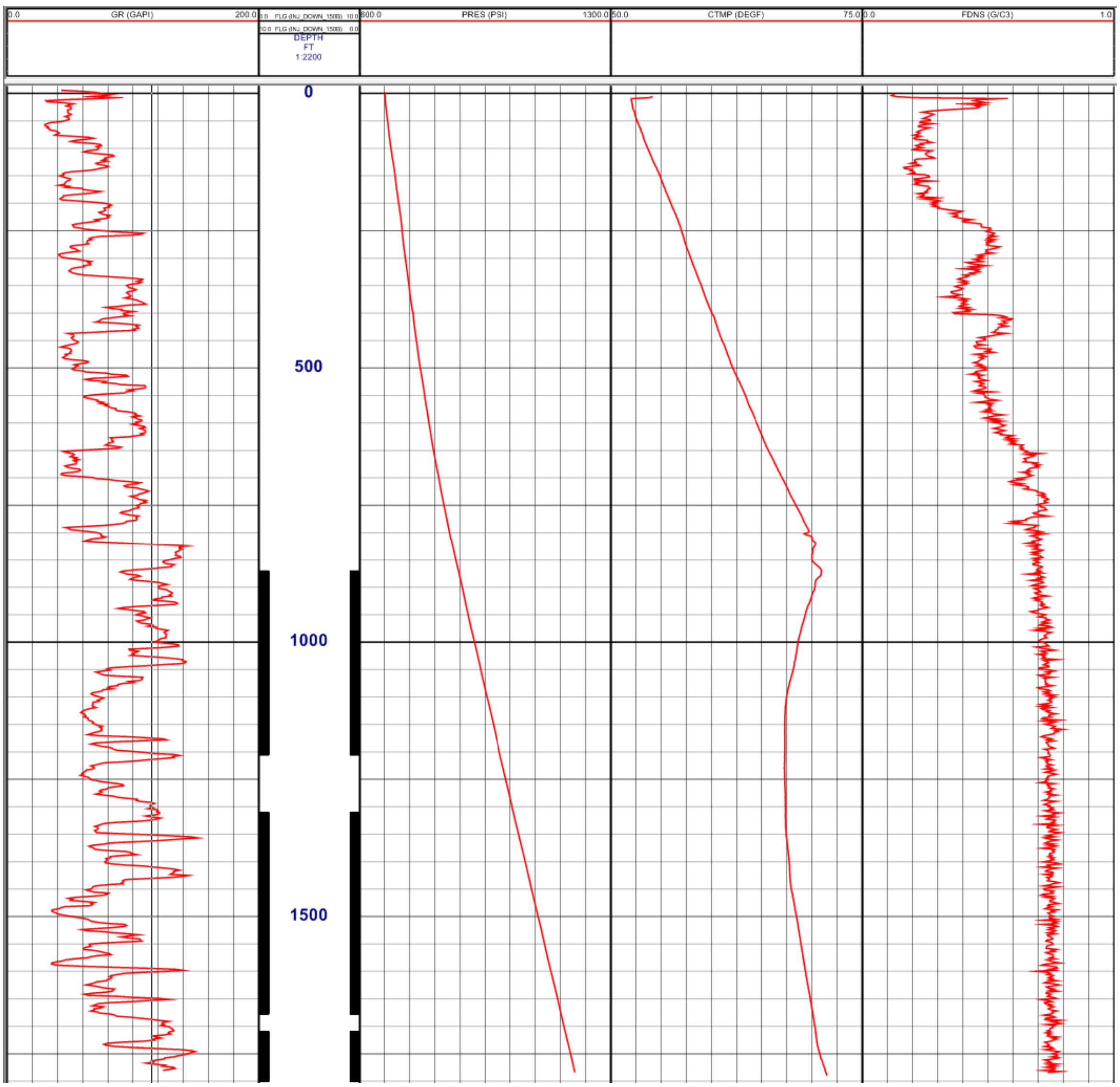
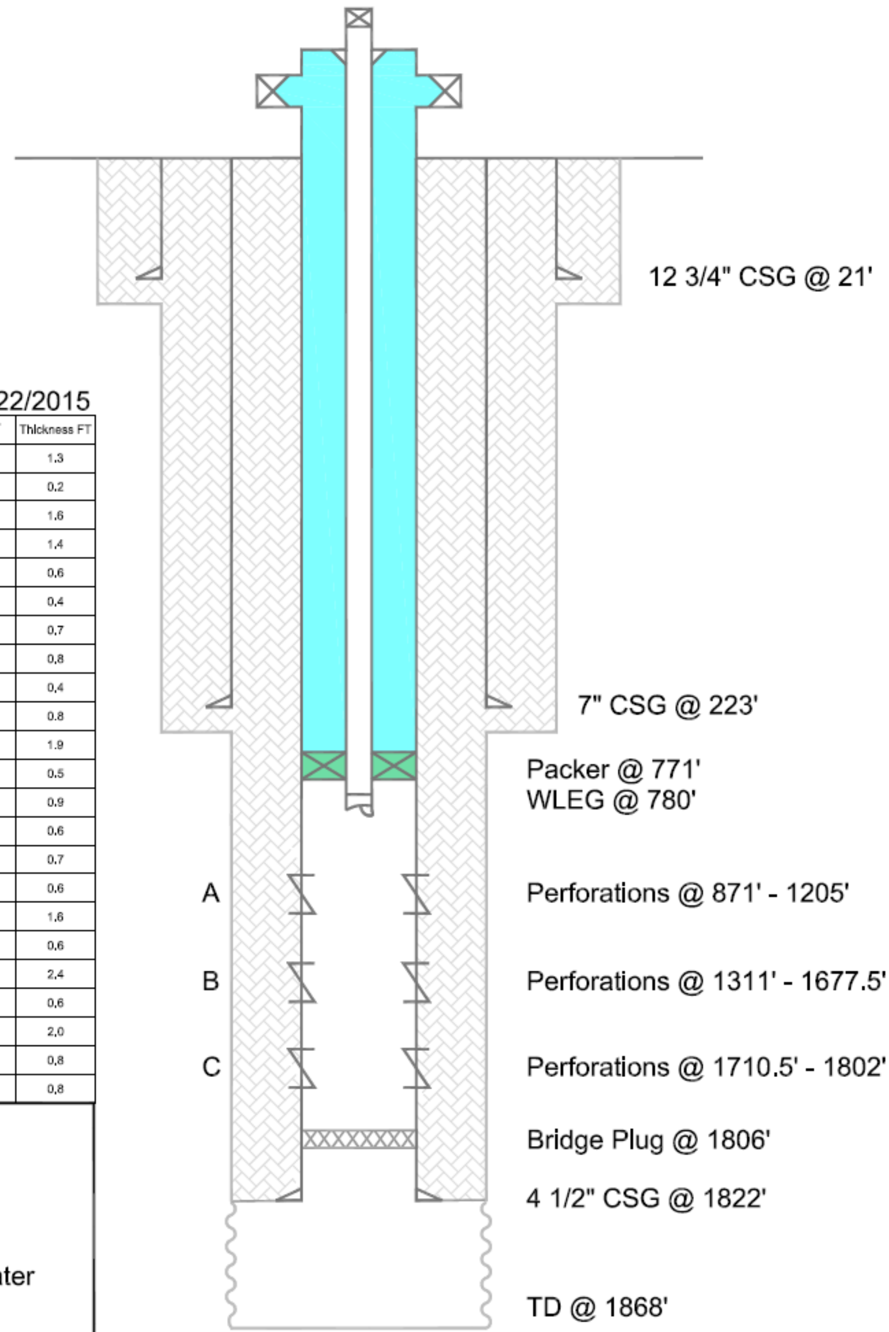


Figure 7: Density Curve from 1800ft to surface

CUSTOMER	:	CARDNO	WELL No.	:	DD8
FIELD	:	OAKWOOD	LOCATION	:	VIRGINIA
DATE	:	MARCH 23, 2016	REPORT NO.	:	2016-006

APPENDIX I: Well Diagram

Permit Modification
Injection Well DD-8



FINAL 4/22/2015

	Coal Seam	Depth FT	Thickness FT
A	Seaboard (20)	871	1.3
A	Lower Seaboard (10)	902	0.2
A	Lower Seaboard (20)	912	1.6
A	Upper Horsepen (10)	984	1.4
A	Upper Horsepen (20)	1031	0.6
A	Unknown Coal	1054	0.4
A	Middle Horsepen (10)	1068	0.7
A	Pocahontas No. 11	1165	0.8
A	Pocahontas No. 10 (10)	1198	0.4
A	Pocahontas No. 10 (20)	1204	0.8
B	Pocahontas No. 9 (10)	1311	1.9
B	Pocahontas No. 9 (20)	1314	0.5
B	Unknown Coal	1397	0.9
B	Pocahontas No. 7 (10)	1422	0.6
B	Pocahontas No. 7 (20)	1467	0.7
B	Pocahontas No. 5 (10)	1591	0.6
B	Pocahontas No. 4 (10)	1637	1.6
B	Pocahontas No. 4 (20)	1677	0.6
C	Pocahontas No. 3 (10,20)	1711	2.4
C	Pocahontas No. 3 (30)	1721	0.6
C	Pocahontas No. 3 (40,50)	1731	2.0
C	Pocahontas No. 2	1746	0.8
C	Pocahontas No. 1	1802	0.8

Valve
Packer
Cement
Inhibited Water
NOT TO SCALE

APPENDIX II – Curve Mnemonics

MNEMONICS	UNITS	DESCRIPTION
DEPTH	FT	LOGGED DEPTH
CCL	MV	COLLAR LOCATOR
GR	GAPI	GAMMA RAY
PRES	PSI	PRESSURE
FDNS	C/CC	RADIOACTIVE DENSITY
CTMP	DEGF	TEMPERATURE
CFLW	RPS	FLOWMETER/SPINNER
TENS	LB	TENSION
LSPD	FPM	LINE SPEED

APPENDIX C

Carbon Tracker Services: Injection Well DD8

10-11 November 2017

Near Grundy VA

Comprehensive Summary

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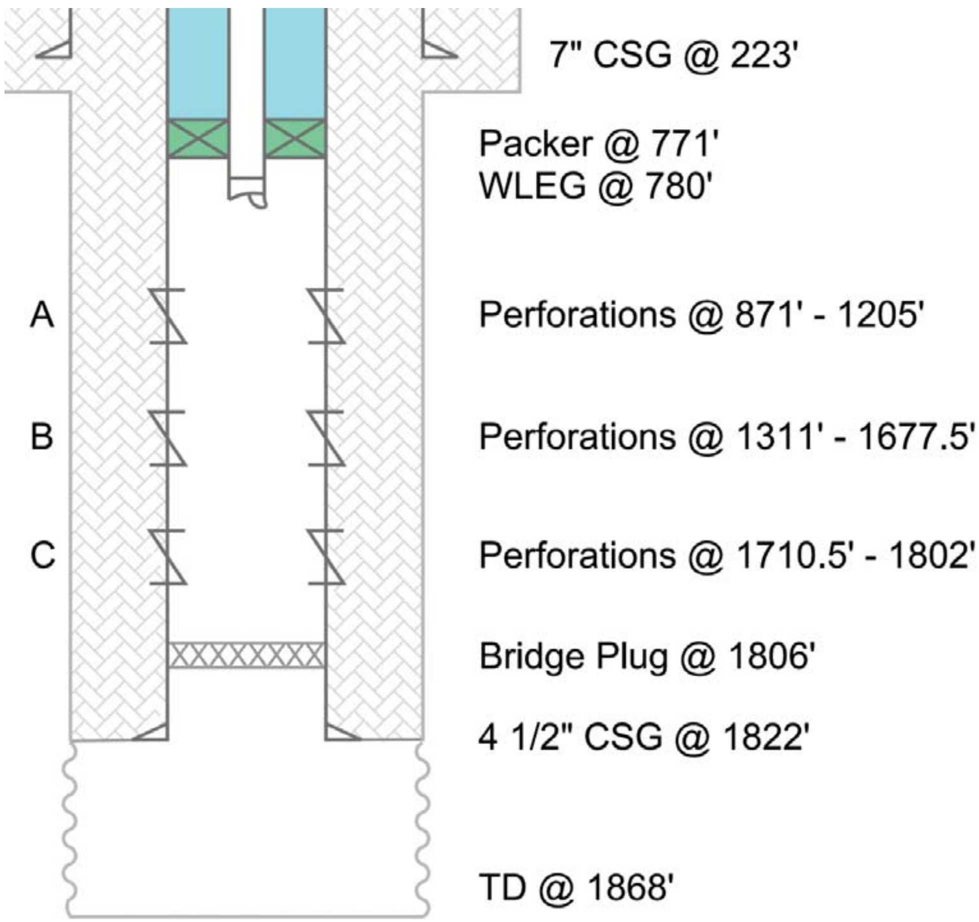
Comprehensive Summary of Days 5 and 6: analysis of Well DD8

- Over two days, a total of four runs of the DRRS instrument downhole were accomplished including: an initial run in hole to characterize the well from surface to the drilled-out bridge plug at 1806 ft-below surface (FBS), a run after setting a bridge plug at 1490 FBS, a run after setting a second bridge plug at 1288 FBS, and a final run after setting a bridge plug at 1132 FBS. As in Well DD7, logged a few days previous, this well consisted a column of mixed gases atop a column of foam atop a column of liquid water. In this case the foam layer was 100 ft. high, and the salinity of the liquid water read at 100 mS. The foam and underlying water obscured half of perforation zone B and all of zone C as identified in the well completion report.
- The logs downhole on the first day indicated an average gas composition consisting of 87% CO_2 and remainder CH_4 with a moderate increase in methane, up to 20% of total, associated with the upper seams in perforation zone A, between 984 and 870 FBS. After setting a bridge plug above zone B overnight, on the next day's logs, a dramatic increase in methane was observed to be associated with the coal seams between 1031 and 870 FBS, where the methane fraction was as high as 50%. Composition above and below these seams was 85-87% CO_2, with the remainder CH_4. A careful 10-ft/min log from 1100 to 800 FBS on pull-out of hole indicates that the seam at 1031 emits increased methane relative to the average borehole composition, which is successively diluted by CO_2 emitted from the subsequent seams at 984, 912 and 871 FBS.

DD8 Well Completion



FINAL 4/22/2015

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C	Pocahontas No. 3 (30)	1721	0.6
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Days 5-6 : 10-11 Nov – DD8: Logging programs

9-Nov

- Bridge plug was drilled out and blowing down from bottom of casing
- Rathole is short on this well relative to the other two injection wells logged previously

10 Nov

- To depth
  - Stationary scans at 870, 1160, 1310, 1590, and 1805
- Then plug at 1490, repeat stations, set plug at 1288

11 Nov

- 1288 Plug
  - Log to 870 ft-below surface (FBS) at 60 ft-per-minute (fpm)
  - then 1250 at 30 fpm, stationary
  - Up to 870 at 30 fpm, stationary
  - Down to 1160 FBS at 10 fpm, stationary
  - Pull out of hole (POOH) at 60 fpm
- 1132 plug
  - Log to down 870 at 60 fpm, then to 1100 at 30 fpm, stationary
  - Log up to 400 at 30 fpm
  - Log down to 100 at 60 fpm, station
  - Log to 800 at 10 fpm, station
  - POOH at 60 fpm

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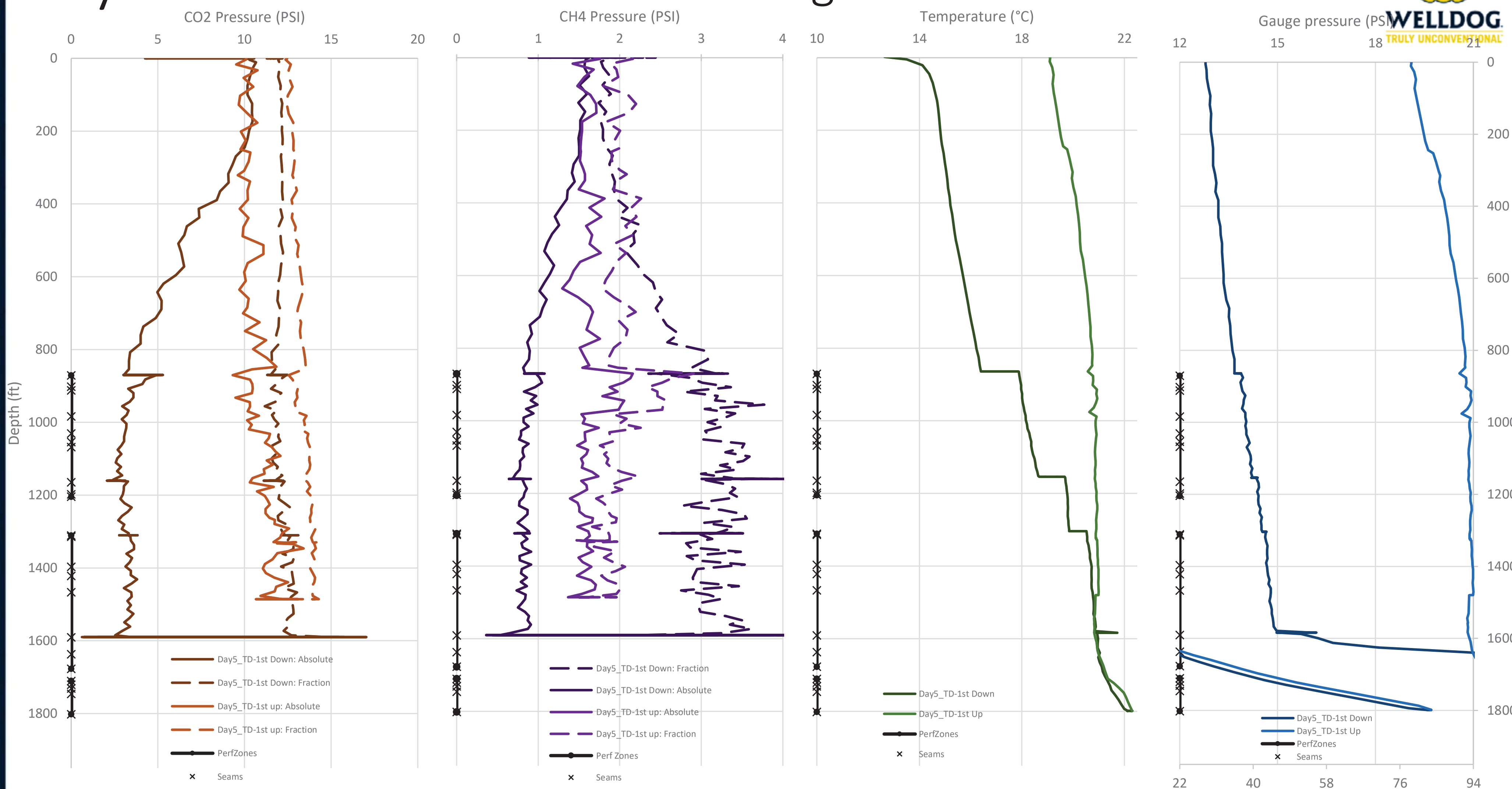
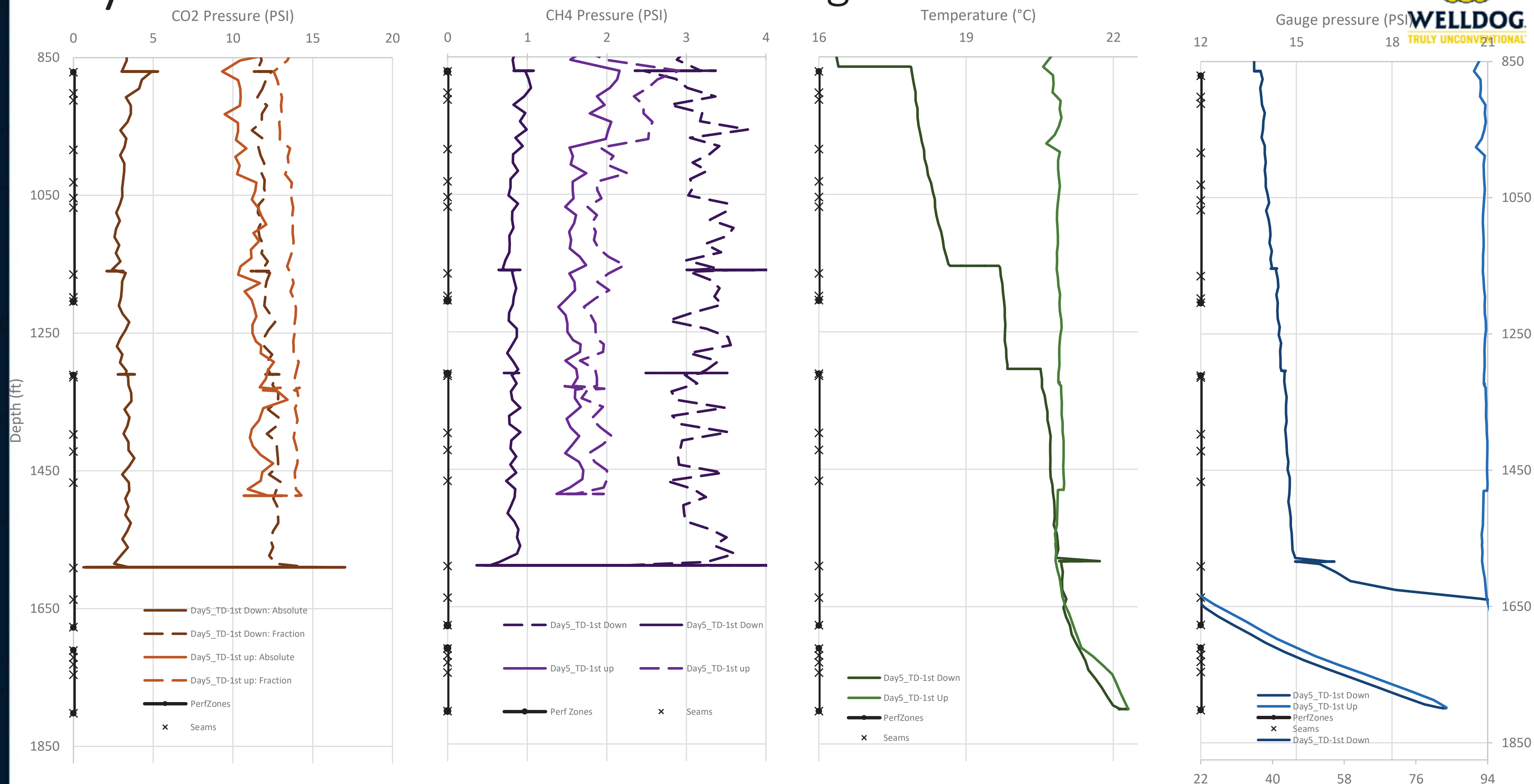
Day 5 : 10 Nov – DD8- First log to TD

- Summary: Surface to stations and TD and POOH
  - **Column of Gas:** At surface, produced gas composition measured 87% CO_2 and 13% CH_4 and on log to first station above zone A, fog was encountered at 200 FBS, where Absolute gas composition showed an apparent decline down to the zone and below. Fraction gas composition was relatively steady except on approach to zone where methane began to fall below the limit of detection. In general, during the logs down to the other stations, CO_2 Absolute measured between 2-3 PSI and CH_4 less than 1 PSI (or below the limit of detection), which renders Fraction composition inaccurate. As the log downwards was continued, a foam layer was encountered at 1585 FB5, and during stationary scans at 1590 FBS, spectra indicate a highly fluorescent or highly scattering medium with sporadic indications of CH_4 and CO_2 that weren't quantifiable. On log to final station at 1805 FBS, liquid water was encountered at 1670 FBS, which the onboard conductivity meter measured at ~100 mS. Spectra indicated a highly fluorescent or highly scattering medium with CH_4 and CO_2 sporadically visible but not quantifiable atop a varying water background. In contrast to well DD7, there did not appear to be active high-pressure gas bubbles in the fluid.
    During the log to depth and stationary scans, onboard temperature meter reading rose from 15 to 21°C. Onboard pressure meter reading increased steadily from 13 to 15 PSI above the foam and then up to 80 PSI during the stationary scans in fluid at 1805 FBS. Interestingly upon exiting the fluid layers, onboard pressure registered at 21 PSI. On pull out of hole, after exiting the foam layers, spectra indicate fluorescent residue but quantifiable levels of CO_2 and CH_4: CO_2 around 10 PSI and CH_4 1.5 PSI or more in Absolute composition measurements. When moving up past the coal seam at 984 FBS (Upper Horsepen-10) methane increased, and then above the top coal seam of zone A at 871 FBS (Seaboard-20), methane decreased and CO_2 increased slightly. Both were then steady up to surface.

Day 5 : 10 Nov – DD8- First log to TD



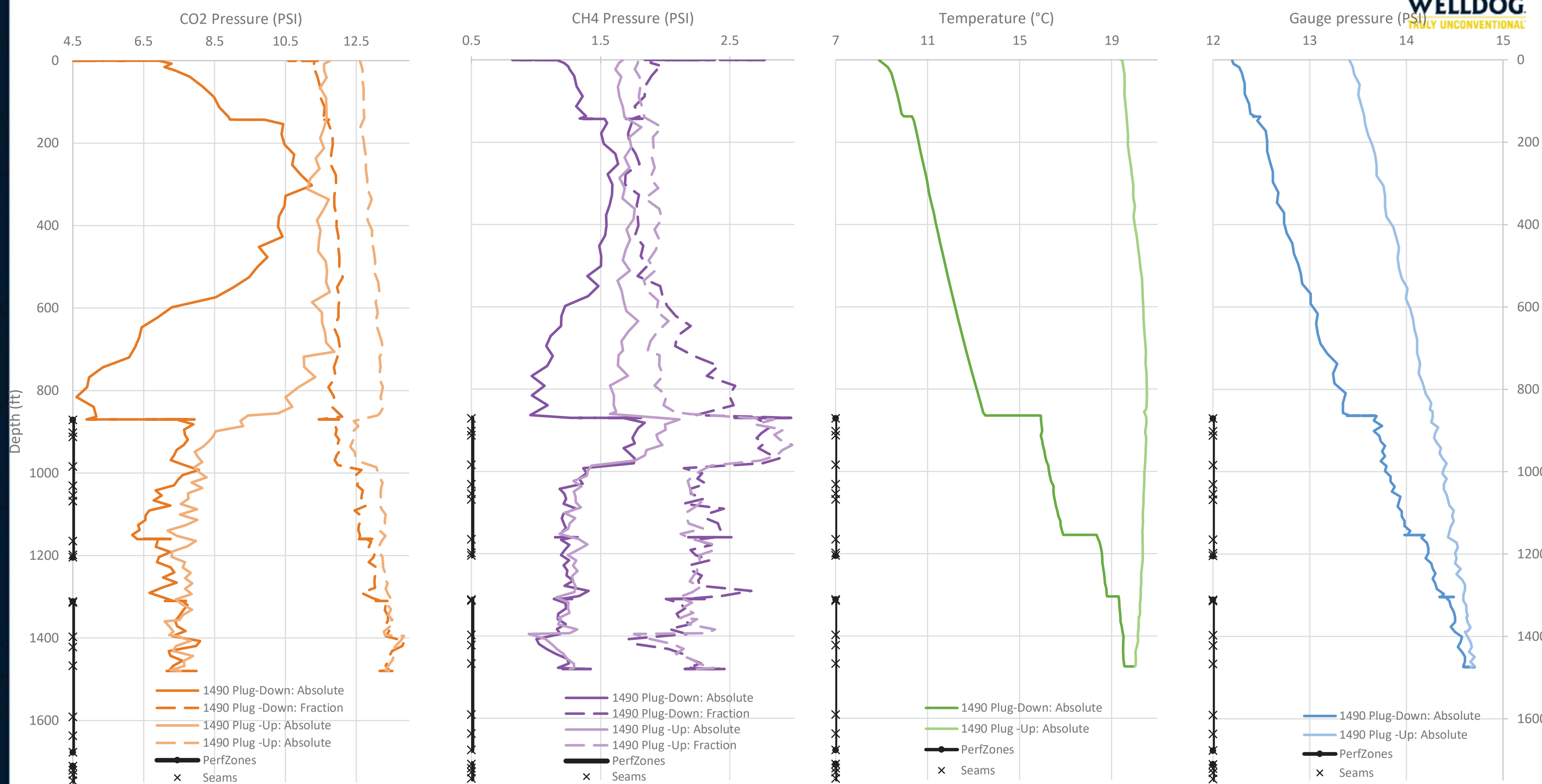
Day 5 : 10 Nov – DD8- First log to TD: Zones



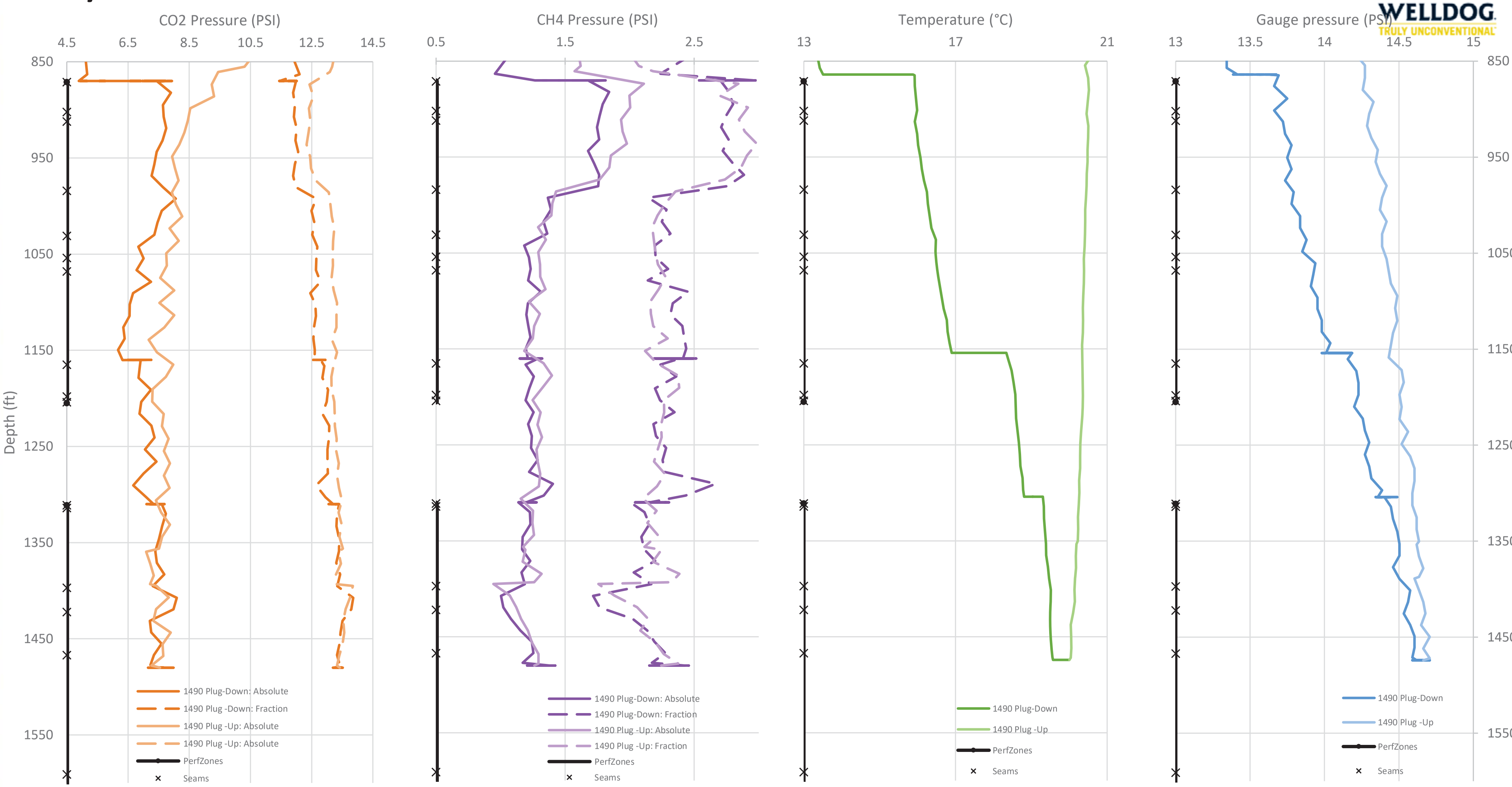
Day 5 : 10 Nov – DD8- 1490 Plug

- Summary: Surface to stations and TD and POOH
  - **Column of Gas:** At surface, produced gas composition measured 84% CO_2 and 16% CH_4. On downward log, the fog effect was observed between 300 FBS and to the station at 870 FBS, where CO_2 dropped from 10 PSI down to 4.5 and CH_4 from 1.7 down to 1 PSI in Absolute composition but Fraction composition showed little change over the same interval. During the stationary scans at 870 FBS, the fog was partially cleared. On moving down to the next station at 1154 FBS, upon moving below the seam at 984 FBS, methane dropped. The rest of the log downwards and stationary scans were nondescript, the exception of a possible dip in CH_4 after moving down past the seam at 1422 FBS (Pocohontas #7-10) and then a spike again after moving down past the seam at 1467 FBS (Pocohontas #7-20). Pull out of hole confirmed these trends in methane over these seams in zone B, as well as the upper seams in zone A. No fluid was observed accumulated on top of the bridge plug at 1490 FBS.

Day 5 : 10 Nov – DD8- 1490 plug



Day 5 : 10 Nov – DD8- 1490 plug - Stations



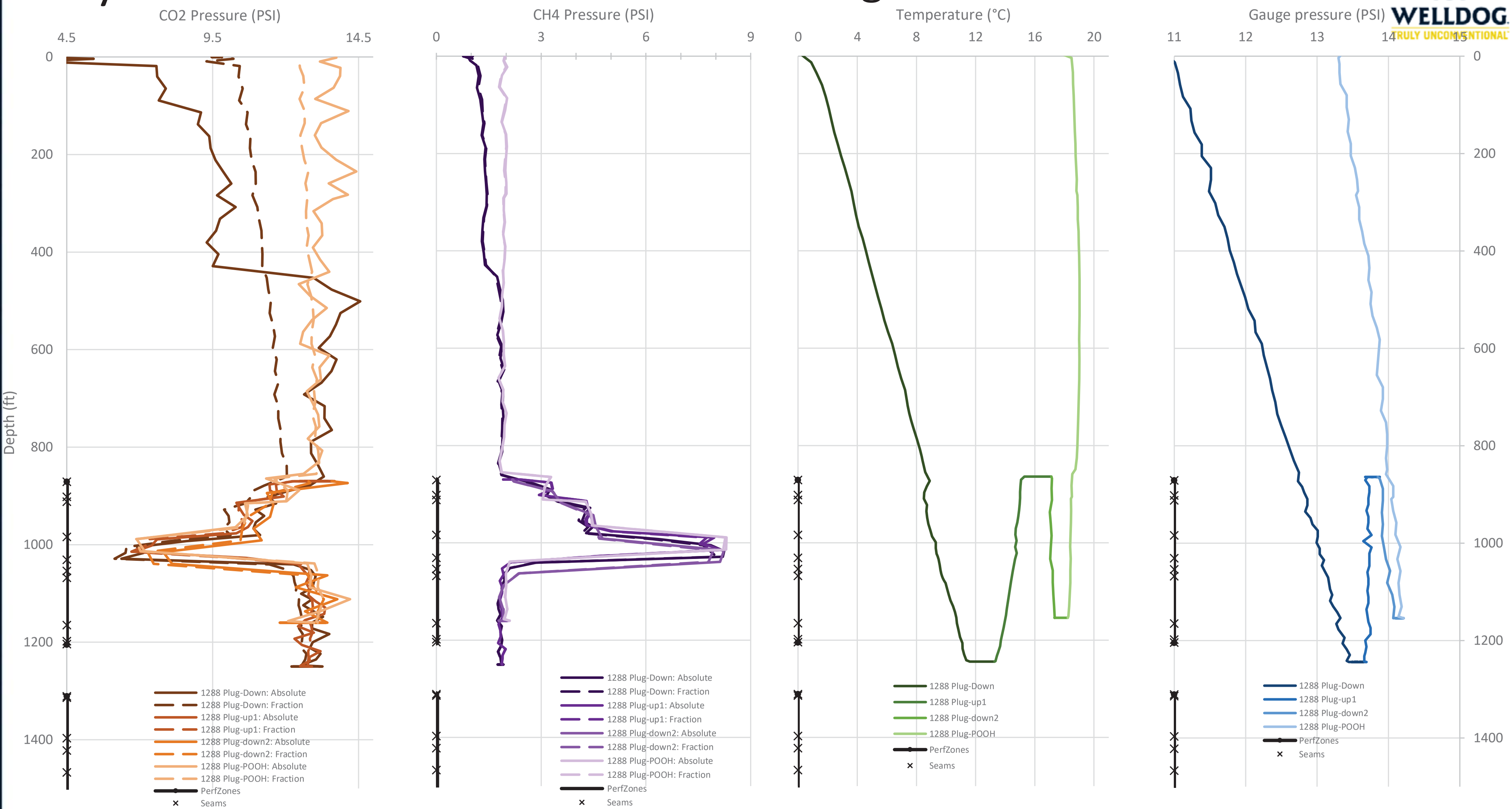
Day 6 : 11 Nov – DD8: Plug at 1288 and 1132

- Plug was set at 1288 FBS last night
  - Log to 870 FBS at 60 fpm,
  - then 1250 at 30 fpm, stationary
  - Up to 870 at 30 fpm, stationary
  - Down to 1160 FBS at 10 fpm, stationary
  - POOH at 60 fpm
- Plug set at 1132, back in the hole at noon
  - Log to down 870 at 60 fpm, then to 1100 at 30 fpm, stationary
  - Log up to 400 at 30 fpm
  - Log down to 100 at 60 fpm, station
  - Log to 800 at 10 fpm, station
  - POOH at 60 fpm

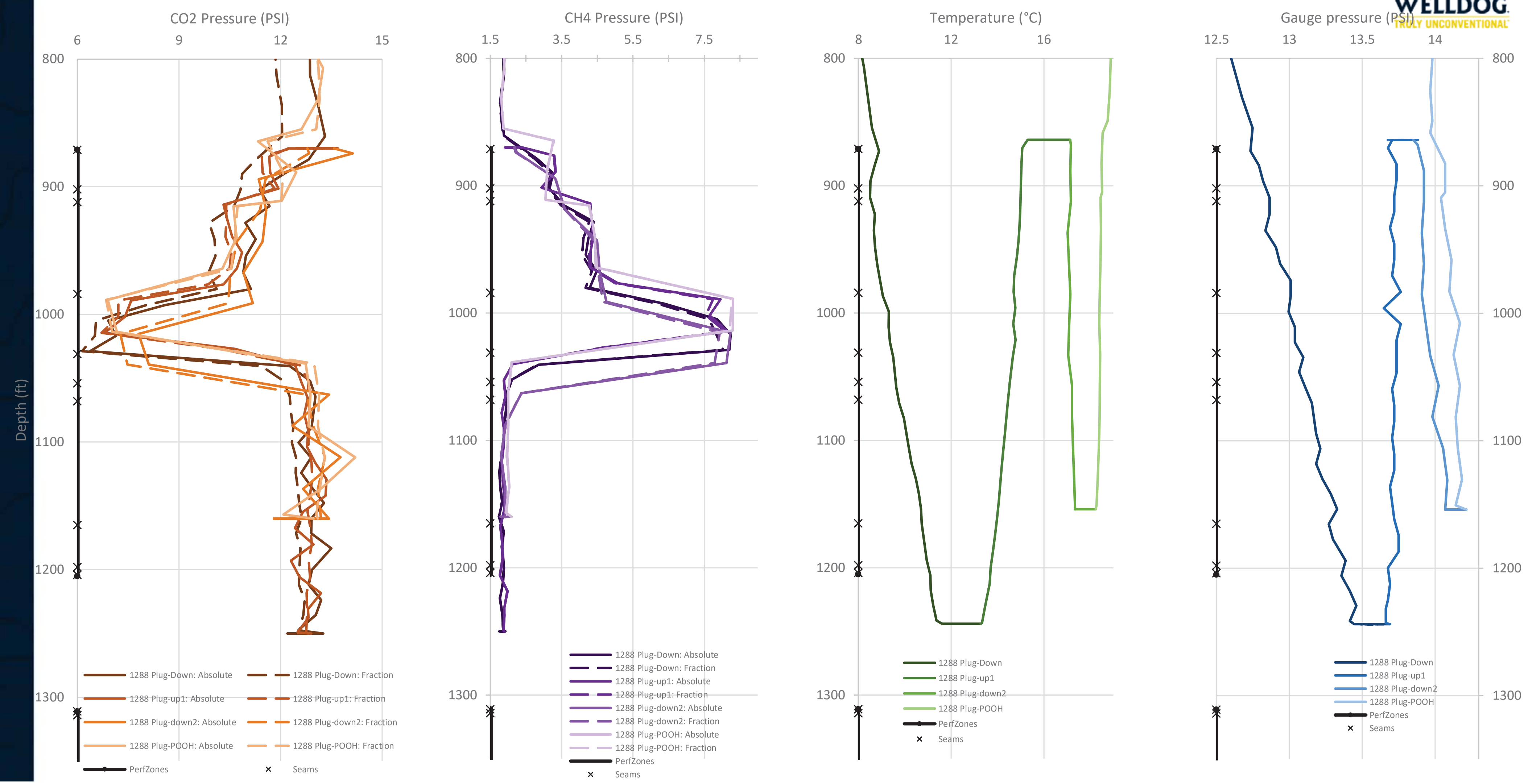
Day 6 : 11 Nov – DD8- 1288 Plug

- Summary: Surface to depth, stations and POOH
  - **Column of Gas:** At surface, gas composition measured 88% CO_2 and 12% CH_4. During the log to depth, Absolute gas compositions showed a sudden increased at 450 FBS, though relative Fraction composition showed only a steady gradual increase from surface to just above the first perforation zone. Upon passing downwards the coal seam at 871 FBS, CO_2 dipped and CH_4 increased. CH_4 again traded with CO_2 upon passing the coal seam at 912 FBS and again after passing the seam at 984 FBS. Remarkably, the composition of gases at this point was 50/50 CO_2/CH_4. Continuing downwards, after passing the seam at 1031, CO_2 increased and methane decreased. The composition below this point was back to the norm, 87% CO_2 and remainder CH_4, as it averaged during the stationary scans at 1250 FBS. During the ascent to 870 FBS for stationary scans, the pocket of high methane gas composition was confirmed, as were the steps in methane upon passing above the upper seams of zone A. Two more passes of the methane spike were accomplished upon moving downwards to stationary scans at 1154 FBS and then on the log to surface.

Day 6 : 11 Nov – DD8- 1288 Plug



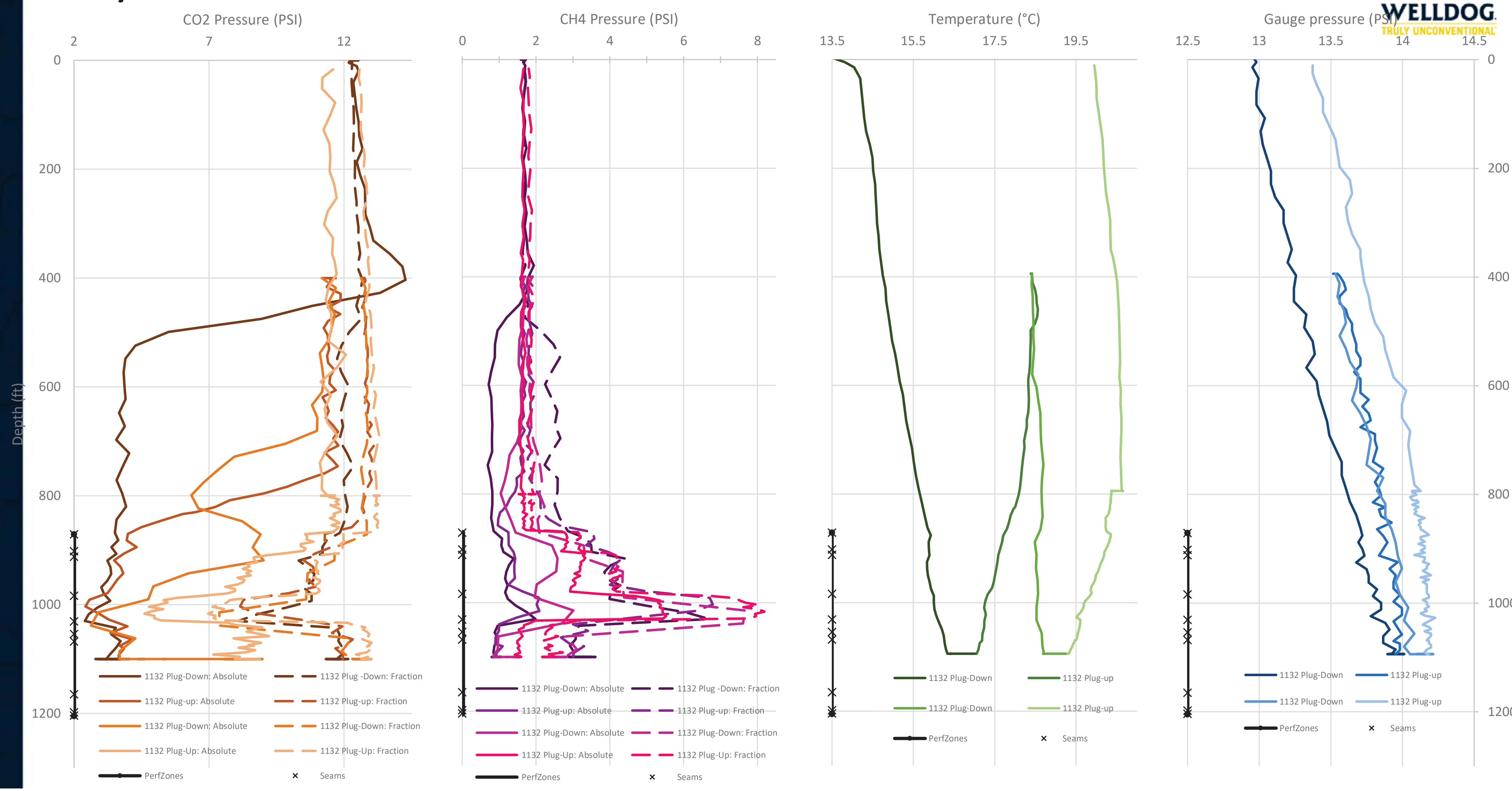
Day 6 : 11 Nov – DD8- 1288 Plug: Stations



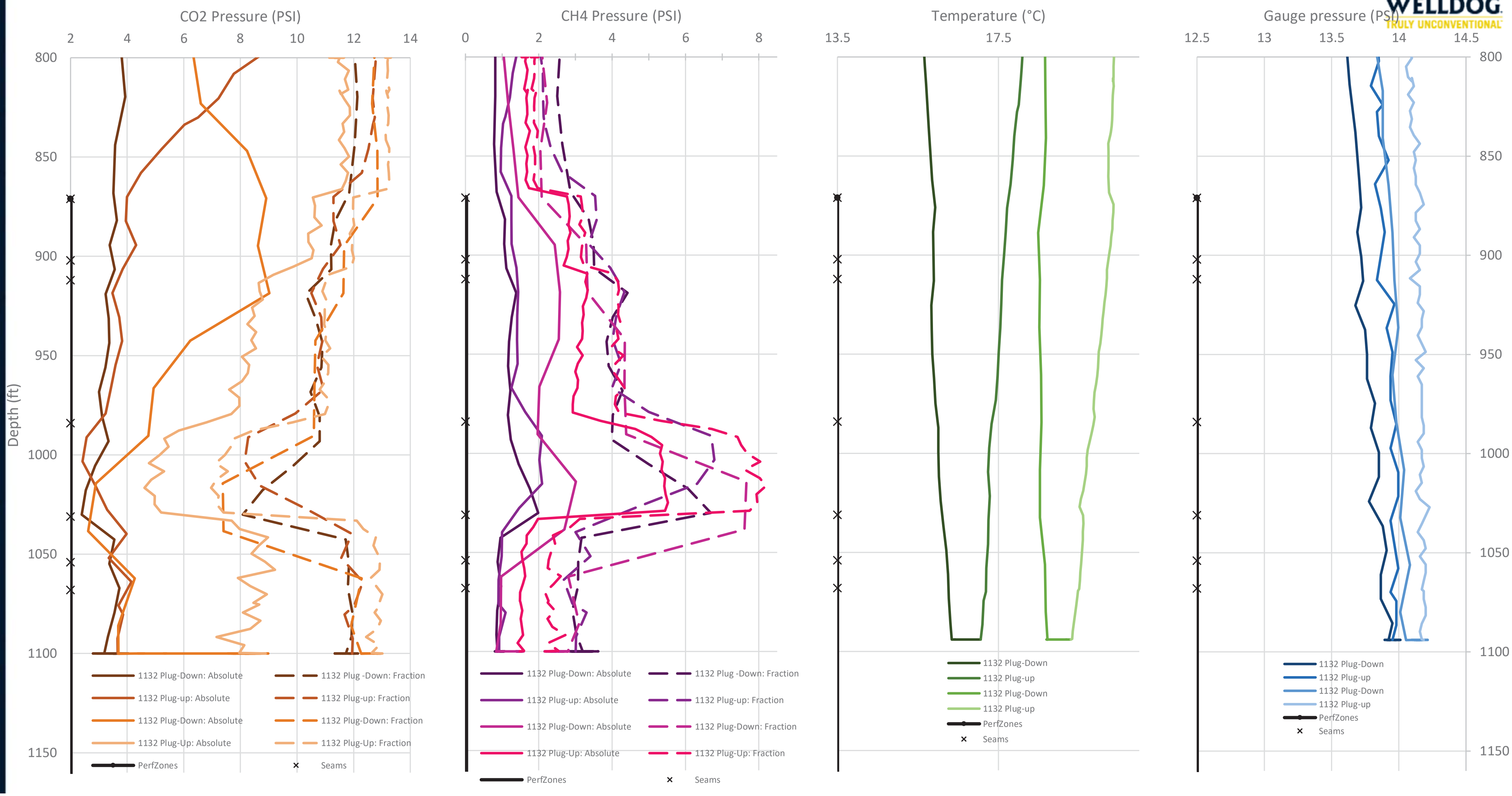
Day 6 : 11 Nov – DD8- 1132 Plug

- Summary: Surface to depth, stations and POOH
  - **Column of Gas:** At surface, gas composition measured 88% CO_2 and 12% CH_4. During the log to depth, Absolute gas compositions declined steeply below 400 FBS due to the fog effect. Fraction composition was relatively steady. Upon passing downwards the coal seam at 871 FBS, the Fraction CO_2 dipped and CH_4 increased as in the morning run downhole. Again the methane Fraction increased and CO_2 decreased in steps upon passing downwards past the upper seams of zone A. Beyond the pocket of methane and down to the plug, average gas composition was 80% CO_2 and 20% CH_4. In multiple passes across the upper seams of zone A, the profile of increased methane was confirmed, including on pull-out of hole, a deliberate, 10 ft/min log from the plug to 800 FBS. In this final log, CO_2:CH_4 was 84%:16% between 1100 and 1046 FBS, then after passing above the seam at 1031 FBS (Upper Horsepen-20), the CH_4 content increased and the composition was 48%:52% up until passing the seam at 984, when CH_4 dropped and the composition was 72%:28% until passing the seam at 912 FBS (Lower Seaboard-20), when CH_4 dropped again and the composition was 80%:20% until finally passing above the seam at 871 FBS (Seaboard-20), when CH_4 dropped and the composition was 87%:13% up to surface.

Day 6 : 11 Nov – DD8- 1132 Plug



Day 6 : 11 Nov – DD8- 1132 Plug: Stations



Day 6 : 11 Nov – DD8- 1132 Plug: Final 10 fpm log