MONITORING FOR ENHANCED GAS AND LIQUIDS RECOVERY FROM A CO_2 'HUFF-AND-PUFF' INJECTION TEST IN A HORIZONTAL CHATTANOOGA SHALE WELL

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ABSTRACT

Permanently sequestering carbon dioxide (CO_2) in gas-bearing shale formations is beneficial in that it can mitigate greenhouse gas emissions as well as enhance gas recovery in production wells. This is possible due to the sorption properties of the organic material within shales and their greater affinity for CO_2 over methane. The phenomenon of preferentially adsorbing CO_2 while desorbing methane has been proven in coalbed reservoirs successfully, and is feasible for shale formations. The objective of this thesis is to explore the potential for enhanced gas recovery from gas-bearing shale formations by injecting CO_2 into a targeted shale formation.

With the advancement of technologies in horizontal drilling combined with hydraulic fracturing, shale gas has become a significant source of energy throughout the United States. With over 6,000 trillion cubic feet (Tcf) of theoretical gas-in-place, Appalachia has proven a major basin for gas production from organic shales. With its extensive shale reserves and lack of conventional reservoirs typically used for CO_2 storage, Appalachia's unconventional reservoirs are favorable candidates for CO_2 storage with enhanced gas recovery. Enhancing gas recovery not only increases reserves, but extends the life of mature wells and fields throughout the basin.

As part of this research, 510 tons of CO_2 were successfully injected into a horizontal production well completed in the Chattanooga shale formation, a late Devonian shale, in Morgan County, Tennessee. An extensive monitoring program was implemented during the pre-injection baseline, injection, soaking, and flowback phases of the test. Multiple fluorinated tracers were used to effectively monitor CO_2 breakthrough at offset production wells and to help account for the CO_2 once the well was flowed back. Results from this test, once the well was put back into normal production state, confirm the injectivity and storage potential of CO_2 in shale formations, as well as an increase in gas production rate and quality of gas produced.

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INTRODUCTION

The main objective of this thesis is to explore the potential of injecting CO_2 in a gas-bearing shale formation to monitor storage capabilities (carbon sequestration) and enhanced gas recovery. Through the funding of the U.S. Department of Energy, current research and development for CO_2 storage in geologic formations include saline aquifers, conventional oil and gas reservoirs, and coal seams (DOE, 2015a). Positive results from this project can update the list of favorable geologic CO_2 storage formations to include unconventional, gas-bearing shale reservoirs.

This thesis is divided into five main sections: 1) a literature review; 2) development of gas chromatography and tracer gas applications for CO_2 sequestration; 3) a CO_2 injection test in an organic shale formation in Tennessee; 4) results from the injection test; and 5) conclusions and recommendations.

The first section of this report is a literature review which summarizes information pertaining to CO_2 injection into organic shale formations. This review will include an analysis of current shale gas production and techniques in the United States. It will also assess the storage potential of CO_2 in organic shale formations, and review previous and ongoing CO_2 injections utilizing the benefit of enhanced oil and gas recovery.

The second section covers the development of analytical chemistry techniques, such as gas chromatography and mass spectroscopy, and their application to CO_2 sequestration in unconventional reservoirs. It will help develop the use of fluorinated tracers as a monitoring, verification, and accounting tool for geologic CO_2 injection, as well as cover sampling techniques used for the injection test.

The third section of this thesis covers a small-scale CO_2 injection test in an organic shale formation, including the design and injection parameters of the CO_2 and tracers. For this test 500 tons of CO_2 will be injected into the Chattanooga shale formation in Morgan County, Tennessee. The test will be broken into four phases: pre-injection baseline, injection, soaking, and flowback. Specific monitoring goals will be implemented in each phase in order to test CO_2 storage and enhanced gas recovery potential.

The fourth section analyzes the results from each phase of the CO_2 injection test. Finally, the last section makes conclusions and recommendations based on the results from the test, as well as provides a brief financial analysis based on the results from the test.

1 LITERATURE REVIEW

1.1. INTRODUCTION

In order to evaluate enhanced gas recovery in organic shale formations using CO_2, a basic understanding of shale gas production, the storage potential of CO_2 in shale formations, and previous and current CO_2 injection tests must be reviewed. The following review is divided into three main parts: 1) U.S., specifically Eastern and Appalachian, shale gas production and techniques; 2) Storage potential of CO_2 in organic shale formations; and 3) previous and current CO_2 – enhanced oil and gas recovery tests.

1.2. SHALE GAS PRODUCTION

Shale gas is natural gas (composed primarily of methane with low levels of ethane, propane, and butane, and trace amounts of CO_2 and N_2) that is found within organic-rich shale formations. During the deposition, very fine-grained clay material and organic-rich material were deposited in thin layers resulting in extremely low permeability formations, often in the nano Darcy range (Kennedy, et al., 2012). Due to this low permeability, shale formations are considered unconventional oil and gas reservoirs. Conventional gas reservoirs, such as sandstones and limestones, are much more porous and allow easier flow of gas through the pore spaces in the reservoir. Other unconventional, low permeability reservoirs include tight sandstones, tight carbonates, and coal seams containing coalbed methane (DOE, 2009).

Shale gas is stored in three different ways within shale formations: 1) as a free gas that is located within the shale matrix and fracture pathways; 2) as physically and chemically adsorbed gas onto the organic matrix within the shale; and 3) as dissolved gas in the liquids present in the shale formation (Kennedy, et al., 2012).

1.2.1. U.S. Shale Gas Production

As of 2013, shale gas has become the largest component in U.S. natural gas production, overtaking conventional gas wells, oil wells, and coalbed methane wells (EIA, 2014a). In 2014, the U.S. has remained the world's largest producer of petroleum and natural gas, mainly in part to due to exploitation of shale formations, especially those in the eastern United States (EIA 2015a). The Marcellus shale, which covers major portions of New York, Pennsylvania, Ohio, and West Virginia, is one of the more area extensive shale formations in the United States. Other significant shale plays in the eastern U.S. include the Antrim, Devonian Ohio, and the

Utica. These four major shale plays account for more than 180,000 square miles of area and over 6,000 trillion cubic feet (Tcf) of gas in place (GIP) (Godec, 2013a). Figure 1.1 displays the shale gas plays in the lower 48 states. Figure 1.2 displays the Marcellus shale gas production as it compare to other major gas plays in the United States.

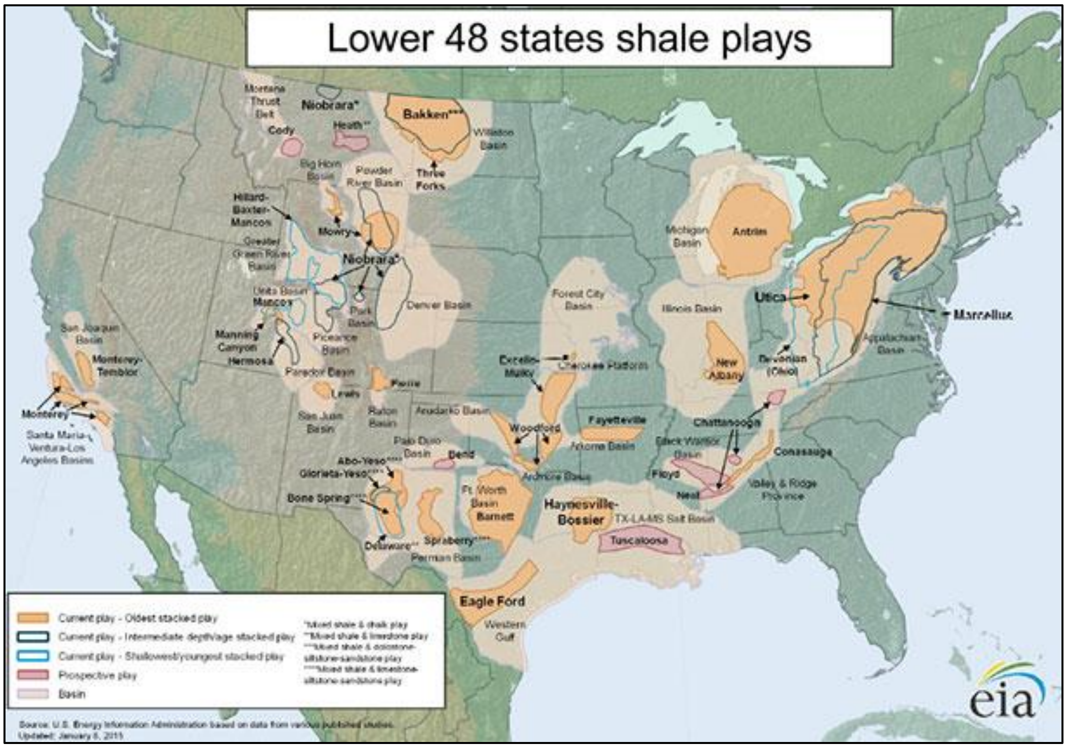

Figure 1.1: Shale Gas Plays in the Lower 48 states (EIA, 2015b)

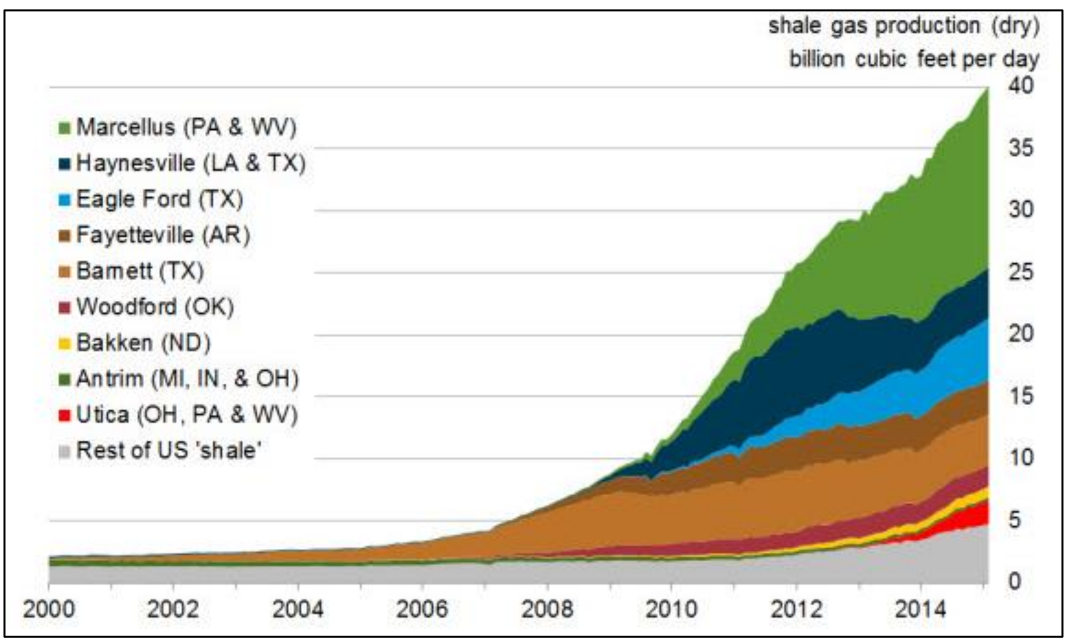

Figure 1.2: Comparison of Production in U.S. Shale Plays (EIA, 2015b)

1.2.2. Shale Gas Production Techniques

One of the main factors that contributed to the rapid success of shale gas production is the technological advances in horizontal drilling and hydraulic fracturing (DOE, 2009). While shale gas wells can either be drilled vertically or horizontally, horizontal wells increase the area of exposure within the reservoir. These horizontal wells are initially drilled vertically, then, at a given distance above the target formation known as the kickoff point (KOP), the wellbore will start to curve to achieve the lateral portion within the shale formation. Once the well is drilled, a series of cement casings will be placed to protect the groundwater and prevent the leakage of natural gas produced from the well. The wellbore is then divided into sections, or stages, and the casing is perforated to target the shale in that stage. Large quantities of water, or nitrogen foam, are then pumped into each stage under extremely high pressure to create fractures within the shale formation. These fractures are the pathways for increasing natural gas flow within the shale to the wellbore. Often sand is mixed in with the fracture fluid to act a proppant, keeping the created fractures open once the pressure within the reservoir decreases (DOE, 2010a).

1.3. CO_2 STORAGE POTENTIAL FOR SHALE RESERVOIRS

Due to their low permeability and ability to store natural gas and CO_2 over millions of years, unconventional shale gas reservoirs lend themselves extremely well to permanent CO_2 storage. (DOE, 2009; Kang, et al., 2011). Another benefit of CO_2 sequestration is the potential for the shale to preferentially adsorb CO_2 while desorbing methane, thus enhancing gas recovery in the formation. This preferential adsorption of CO_2 over methane has been demonstrated in coals at a ratio of 2:1. A study conducted in 2005 concluded that shales will behave similarly to coal and that CO_2 is, in fact, preferentially adsorbed over methane in shales at a ratio of 5:1 (Nuttall, et al., 2005).

One of the more extensive studies published on the storage potential of CO_2 in shale formations was conducted by Advanced Resources International, Inc. (ARI) in 2013 as a report for the U.S. Department of Energy – National Energy Technology Laboratory (Godec, 2013a). This group focused on the storage capacity as well as the enhanced gas potential for eastern shales. Included in their assessment were the Marcellus, Utica, Antrim, and Devonian Ohio shale plays. According to their study, there is over 6,000 Tcf of gas in place within these eastern shales. The maximum theoretical CO_2 storage potential in these shales is over 600 billion metric tonnes. Not all of the gas in place will be able to be technically or economically recovered.

Therefore, reservoir characteristics were modeled to create multiple simulations based on different scenarios. Costing and cash flow analysis were used to evaluate the economic potential for storing CO_2 based on historical natural gas prices, and CO_2 emission reduction credits and carbon taxes. The result is that over 1,300 Tcf (460 of which would be economical at the current gas prices) of enhanced gas recovery is associated with the injection of CO_2 into the eastern shale plays. This would also result in 80 billion metric tonnes of CO_2 storage potential (50 billion metric tonnes economical) which is significant based on the 6,673 million metric tonnes of CO_2 emissions from the U.S. in 2013 (EPA, 2015).

1.4. CO_2 INJECTION TESTS FOR ENHANCED OIL AND GAS RECOVERY

In 2003, the United States Department of Energy (DOE), through the National Energy Technology Laboratory (NETL), developed seven Regional Carbon Sequestration Partnerships (RSCPs) for the research and development of CO_2 sequestration technologies. These RSCPs span 43 states, three Native American Organizations, and four Canadian provinces, representing over 400 state agencies, universities, and private entities. The RCSP Initiative was divided into three phases: I) Characterization; II) Validation; and III) Development. Phase I was developed for initial data collection and characterization of the region's potential to store CO_2. Phase II would validate CO_2 storage potential through small-scale (< 1 million metric tonnes) CO_2 injection tests. Finally, Phase III would implement large-scale (> 1 million metric tonnes) safe, economic, and permanent CO_2 injection tests (DOE, 2015b).

Many injection tests have been conducted throughout the individual RCSP regions to test for the storage potential of CO_2 and the benefit of enhanced oil and gas recovery in different formations. The U.S. DOE has recognized multiple formations favorable for geologic carbon dioxide storage. These formations include: 1) deep saline formations; 2) oil and gas fields; 3) unmineable coal seams; 4) basalts; and of particular interest to the scope of this thesis 5) organic shale formations (DOE, 2015b). This section will briefly cover some of the CO_2 injection tests that have occurred in these different formations. Focus will be directed to projects that are located in the eastern United States with the benefit of enhanced oil and gas recovery.

1.4.1. CO_2 Injection Tests in Shale Formations

CO_2 was used as a treatment for enhancing oil and gas recovery as early as 1963. Due to its solubility in oil and water, CO_2 can greatly reduce the viscosity of oil, reducing the amount of energy needed to produce oil from conventional reservoirs (Praxair, 2013). Hydraulically fracturing with CO_2 first appeared in 1982, when over 40 liquid CO_2/sand fracture treatments were performed in the United States (Lillies and King, 1982). Also during this time, over 40 CO_2/sand fracture treatments were performed in Canada resulting in a 50% increase in well production (King, 1983). By the late 1980s, it is reported that over 450 liquid CO_2/sand fracture treatments had been completed in Canada, the majority of which were natural gas wells (Sinal and Lancaster, 1987).

In1993, five CO_2/sand fracture treatments were successfully performed in the Devonian shale in Kentucky. The amount of CO_2 injected in each well ranged from 120 to 160 tons and the amount of sand proppant ranged from 23,000 to 43,000 pounds. Results from these wells indicated a 56% increase in initial monthly production than wells fractured with the traditional nitrogen treatment in the study area and 4.8 times more production than traditional shot wells in the study area (Yost, et al., 1993).

In September, 2012, the Kentucky Geological Survey conducted a small-scale CO_2 injection test in the Devonian Ohio shale in eastern Kentucky (Godec, 2013b). The plan for the test was to continuously inject between 300 to 500 metric tonnes (331 to 551 short tons) of CO_2 into a vertical well completed in the Devonian Ohio shale at a depth interval of 1,274 and 1,672 feet. After a three day period of injection, the casing pressure reading displayed 590 psig, the same reading as the injection tubing pressure, suggesting communication between the injection tubing and the annulus. Packer failure, fracture communication, or formation communication were determined to be the cause. The injection test was terminated and the well was flowed back. In total, 87 tons of CO_2 were injected during this test.

1.4.2. CO_2 Injection Tests in Coal Seams

In 1995, the world's first CO_2 – enhanced coalbed methane (ECBM) test was performed in the Allison Unit of the San Juan Basin in New Mexico (Reeves, 2001; Stevens, et al., 1999). Burlington resources conducted the test by drilling four new injection wells and using nine previously producing offset wells. The initial injection rate of CO_2 was 5 million cubic feet per day (MMcf/day) for a total of six months. During this time, five of the offset production wells were shut in to allow the methane/CO_2 exchange to occur. Minimum CO_2 breakthrough was experienced at the offset production wells, increasing from 0.4% CO_2 composition, to only 0.6%, supporting the theory of CO_2 sequestration in coal seams.

In 2005, a pilot-scale CO_2 – ECBM injection test was conducted in Russell County, Virginia (Ripepi, 2009; Grimm, et al., 2012). Approximately 1,000 tons of CO_2 was injected into a vertical CBM well intersecting 18 thin, unmineable coal seams in the Pocahontas and Lee formations at a depth of 2,500 feet. Two offset vertical wells were drilled at 90 degree offsets from the designated injection well and in the approximate orientation of the face and butt cleats of the coals, respectively. During this injection test, a perfluorocarbon tracer (PFT) was injected with the CO_2 by the U.S. DOE-NETL to track CO_2 leakage. Analysis during the injection indicated that the PFT had migrated to 10 different offset production wells in the area, indicating communication in the coal matrix between the injection well and the offset wells. While there was detection of tracers at the offset wells, there was no significant increase in CO_2 at these wells, indicating no breakthrough of CO_2. The injection well was flowed back and put into normal operation, resulting in a more productive well than pre-injection.

In 2009, CONSOL Energy commenced a proposed 20,000 ton injection of CO_2 in Marshall County, WV (Winschel, et al., 2010; DOE, 2013; Locke & Winschel, 2014). In 2004, CONSOL drilled four peripheral horizontal CBM wells and two central horizontal CBM wells to later be converted into CO_2 injection wells. Each of the four peripheral wells had two horizontal sections, one completed in the Upper Freeport coal seam and the other in the Pittsburgh coal seam. Injection of CO_2 started in late 2009, with fully automated injection by early 2010. As part of the monitoring program for the injection test, tracer gases were injected with the CO_2 to test for potential CO_2 leakage. A total of less than 5,000 tons of CO_2 were injected. The tracers gases were detected at the offset wells but no results have been published to date (Industry Communications, 2015).

1.4.3. CO_2 Injection Tests in Saline Formations

CO_2 injection into saline and brine formations are one of the main options for CO_2 sequestration in the eastern United States due to the vast extents these formations cover underneath a large network of power plants in the region. The Southeast Regional Carbon sequestration Partnership (SECARB) estimated that over 1,440 billion metric tons could be stored in saline formations in the southeastern U.S. (SECARB, 2015)

In 2005, a small-scale injection of CO_2 was conducted in the Frio formation of southeastern Texas (Hovorka, 2009). Over 1,850 tons of CO_2 were injected during two phases of the project. Along with the CO_2 multiple suites of perfluorocarbon tracers were injected to monitor flow pathways of the CO_2 within the formation (McCallum, et al., 2005). Perfluoromethylcyclopentane (PMCP), perfluoroethylcyclohexane (PMCH), perfluorodimethylcyclohexane (PDMCH), and perfluorotrimethylcyclohexane (PTMCH) were all injected during three intervals at the beginning and middle of the test. All PFTs were detected at the monitor well at three separate breakthrough times, corresponding to the three separate injection. Concentrations of the PFTs had been diluted between injection and sample collection.

The Early Test, also known as the Cranfield Project, in Cranfield, Mississippi was a CO_2 – Enhanced Oil recovery project carried out by Denbury Onshore, LLC (SECARB, 2015). The CO_2 was from the Jackson Dome and was delivered to the injection site by pipeline. Injection began in April of 2009 and reached the first milestone of 1 million tonnes by August of 2009. The Cranfield Project is the first test in the U.S. to reach this volume of CO_2 injection. Over 5 million tonnes have been injected at the Cranfield site. Tracer gases, including SF_6, noble gases, and perfluorocarbon tracers were injected with the CO_2. The tracers were detected 13 days after injection at the offset monitoring wells drilled specifically for the project. Injection rates were increased and the tracer arrival became faster, indicating a heterogeneous flow system (Hovorka, 2011).

The SECARB Anthropogenic Test, also known as the Citronelle Project, is a demonstration project of CO_2 capture, transport, and storage (Esposito, et al., 2011; Koperna, et al., 2012; Koperna, et al., 2013). In 2011, Southern Company, along with Mitsubishi Heavy Industries, constructed a CO_2 capture facility at Alabama Power's Plant Barry in Mobile County, Alabama. The facility has the ability to capture up to 500 metric tonnes of CO_2 for geologic storage. A 12 mile pipeline was constructed from the power plant to the Citronelle Field, an oilfield located in the deep saline Citronelle formation. Along with the CO_2, perfluorocarbon tracers were injected to monitor for surface leakage. To date, over 110,000 metric tonnes of CO_2 have been injected

2 DEVELOPMENT OF GAS CHROMATOGRAPHY AND TRACERS FOR CO_2 SEQUESTRATION

The objective of this chapter is to develop methods to analyze enhanced gas recovery from a CO_2 injection test. This includes monitoring for increased concentrations of methane and natural gas liquids (ethane, propane, butane, etc.), as well as, increased concentrations of CO_2. This chapter will also develop the use of fluorinated tracers as a monitoring tool for geologic CO_2 sequestration. Multiple fluorinated tracers were injected with the CO_2 in order to detect plume movement from an injection well to offset production monitoring wells. Detection of these tracers at the monitoring wells will confirm communication from well to well through a series of fracture networks within the formation. Development of high sensitivity gas chromatographic equipment and a reliable method for fast analysis were needed to detect changes in natural gas stream composition, as well as trace detection of fluorinated tracers within the CO_2 plume. Contents of this chapter include a brief induction to basic concepts of gas chromatography, an overview of laboratory and field equipment used for this project, sampling techniques implemented out in the field, and finally tracer selected for this project.

2.1. BASIC GAS CHROMATOGRAPHY

Chromatography is a physical method of separation in which the components are partitioned between two phases: a stationary phase and a mobile phase. The sample is carried by the mobile phase through the stationary phase where it separates into individual analytes based on their affinity for the stationary phase (McNair & Miller, 2009; IUPAC, 1993). Chromatography is a critical technology for separating and analyzing volatile, organic and inorganic gases, liquids, and solids.

A gas chromatograph is composed of three main entities: 1) the injection port; 2) the column; and 3) the detector. The injection port is where the collected sample is introduced into the system for analysis. A gas chromatograph can only analyze volatile samples. The injector port is heated in order to ensure complete volatilization of the sample injected. The volume of the sample can then be further reduced using a split that will allow the desired amount of sample to continue to the column, while the rest is purged from the system. An advantage of reducing the sample size through a split is high resolution separation with no dilutions necessary. A disadvantage of using too high of a split is poor sensitivity in trace analysis (McNair & Miller, 2009).

Once the sample passes through the injection port, it is introduced into the column. The column is where the sample is separated into its individual components for analysis. The sample is transported through the column via a mobile phase or carrier gas. In gas chromatography, the carrier gas is typically helium, nitrogen, or hydrogen. The column typically is made of a thin fused silica open tube with internal diameters ranging from 0.250 to 0.320 mm. Inside of the column is a thin film of stationary phase that separates the components of the sample based on their affinities for this phase.

Finally the partition sample moves from the column to the detector. The most common types of detectors are the electron capture detector (ECD), the thermal conductivity detector (TCD), and the flame ionization detector (FID). The main component in an ECD is a Ni^{63} radioactive source that ionizes ultra-pure nitrogen and produces a high standing current. When electronegative molecules are passed through this current, they absorb electrons and produce a loss in signal. The magnitude of the loss in signal is associated with the concentration of the analyte. A TCD is a type of differential detector that measures the difference in thermal conductivity of the carrier and the analytes to the thermal conductivity of just the pure carrier. The difference can be correlated, with extreme accuracy, to the concentration of the analytes. An FID utilizes a small hydrogen flame that, when introduced to partitioned column effluent, produces ions that are collected to create the response signal. This signal is then attributed to the individual components that created the signal. A mass spectrometer (MS) is a special type of detector that allows for the qualitative identity and confirmation of unknown compounds. A mass spectrometer, often coupled with an ECD, is a very powerful tool used for detection and identification of trace analytes (McNair & Miller, 2009).

2.2. EQUIPMENT

Analysis of the natural gas samples and the tracer samples were completed using different laboratory and field equipment. Two GC/MS systems were used to analyze natural gas samples and tracer samples in the laboratory and a portable natural gas chromatograph was used to analyze natural gas samples in the field.

2.2.1. Laboratory Gas Chromatograph and Mass Spectrometer

The analyses for natural gas samples in the laboratory were completed using a Shimadzu GC2010 gas chromatograph (GC) equipped with an electron capture detector (ECD) and coupled with a QP2010S mass spectrometer (MS). An Agilent HP-PLOT/Q column was installed in the GC. This column is a 30 m long, 0.320 mm internal diameter (ID), 20.0 µm film thickness, porous layer open tubular (PLOT) column. The stationary phase inside the column is polystyrene-divinylbenzene which is commonly used in columns that separate C_1 to C_7 hydrocarbons, CO_2, air/CO, water, and sulfur compounds. A particle trap, which helps protect the equipment from any particles that may become dislodged from the column, is also used in this GC/MS system. Utilization of a particle trap is common practice when using a PLOT column with a mass spectrometer (McNair, personal communication, 2015).

The analysis of tracer samples in the laboratory was completed using a separate, but identical model, GC equipped with an ECD and coupled with an MS. For this system, an Agilent HP-AL/S column was installed in the GC. This column is a 30 m long, 0.250 mm ID, 5.00 µm film thickness, capillary column that contains aluminum oxide and is deactivated with sodium sulfate. This column has been extensively used in this work to analyze fluorinated tracers used for previous and current mining ventilation research.

2.2.2. Portable Natural Gas Chromatograph

The analysis for natural gas samples in the field were completed using an ABB NGC8206 Natural Gas Chromatograph equipped with a thermal conductivity detector (TCD). This unit is portable and is typically field mounted on an individual well to provide continuous on-site analysis. The NGC 8206 used for this project was enclosed in a Pelican case to allow portability into the field while protecting it from water, dust, and shock from everyday field exposure.

2.3. TRACER GAS DEVELOPMENT

For this project, multiple tracers were injected with CO_2 as a monitoring, verification, and accounting tool. The tracers were injected with the CO_2 at the injection well and will be sampled at different offset monitoring wells for arrival. Detection at offset monitoring wells can confirm communication through fracture pathways within the reservoir and can help characterize and model CO_2 plume movement through underground reservoirs. Also, once the injection well is put back into normal production, the tracers can help account for any reproduced CO_2. For this project, multiple tracers were injected during different time periods of CO_2 injection to compare arrival times at different stages of the project. Any differences in arrival time between similar tracers can help characterize injection potential and swelling behaviors of the target reservoir.

Characteristics of the selected tracers are such that they must be easily detected at extremely low levels; they must have negligible background concentrations in the test environment making detection and ownership easy; and they must be environmentally safe. Tracer properties such as solubility and vapor pressure, as well as reservoir characteristics are also important in the selection of tracers. Common tracers used are Sulfur hexafluoride (SF_6) and octafluoropropane (C_3F_8), noble gases, and perfluorocarbon tracers (PFTs).

Sulfur hexafluoride and octafluoropropane have a low solubility in water, lower molecular weight compared to other tracers, and exist as gases, making them excellent candidates for a tracer in a CO_2 injection (Mroczek & Glover, 1996). PFTs are also great candidates as they have similar properties compared to each other. It has been noted that as fluorine and carbon content increases, solubility decreases and vapor pressure decreases (Kabal'nov, et al., 1990; Lindner & Leone, n.d.). Therefore, smaller fluorocarbon chain tracers should be taken into consideration such as perfluoromethylcyclopentane (PMCP), perfluoromethylcyclohexane (PMCH), and perfluoroethylcyclohexane (PECH) should be considered as candidate tracers.

As a final result, SF_6, PMCP, and PMCH were chosen as the three tracers to be used during this project. SF_6 was selected based on its existence as a gas and low molecular weight which will most likely simulate CO_2 within the reservoir. PMCP and PMCH were selected based on their existence as a volatile liquid and their comparatively low molecular weight to other PFTs. Also, SF_6, PMCP, and PMCH have been previously used in other CO_2 injection tests and have been extensively studied and developed in the Subsurface Atmospheres Laboratory within the Mining and Minerals Engineering department at Virginia Tech. A detailed description of the injection of these tracers can be found in Chapter 3, Section 3.3.1 of this thesis.

2.4. SAMPLING

2.4.1. Vacutainers

The samples for natural gas analysis and tracer analysis using the GC/MS were collected using 10mL glass BD Vacutainers. These glass vials are commonly used for blood collection in the medical field. Advantages of these vials are that they are cheap, easy to transport, disposable, and allow for easy sample collection and analysis. The vials are uncoated and contain an isobutyl rubber stopper/septum. The vials contain a vacuum allowing for rapid collection of gas and liquid samples. The vials come from the manufacturer with an approximate vacuum of 70%. This is calculated by measuring the volume of a water sample to the total volume of the vial. In order to obtain a more representative sample, the vials are evacuated using a vacuum pump setup in the laboratory. The result is a vial that contains approximately a 98% vacuum. Figure 2.1 shows (from left to right) a picture of an empty vacutainer, one from the manufacturer with a 70% vacuum shown with water, and one that has been evacuated to a 98% vacuum by the user shown with water.

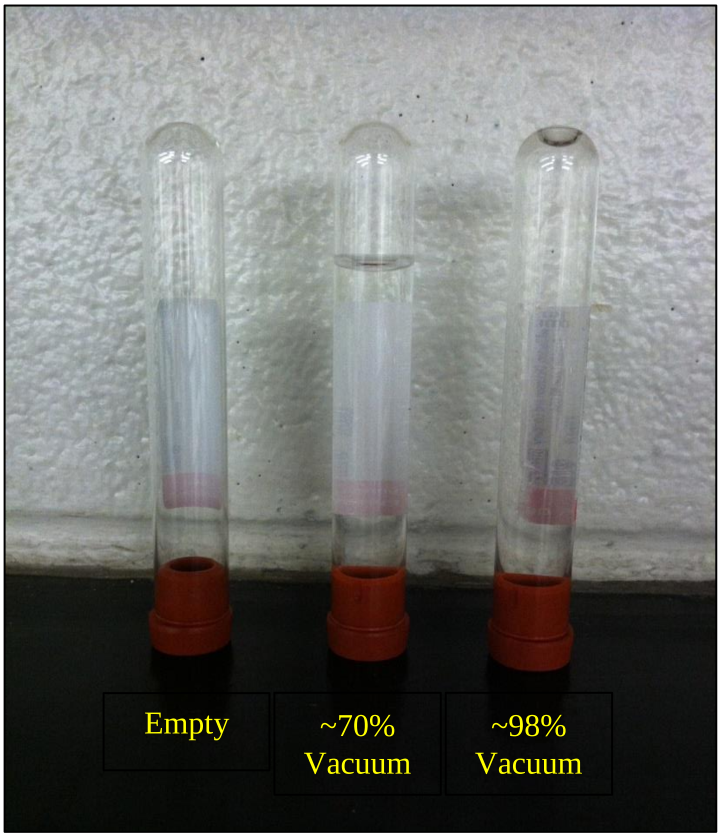

Figure 2.1: Vacutainers

Vacutainer samples were collected at the wellhead using a double-sided needle and plastic holder. Again, advantages of using this system are that the needles and holders are cheap, available in bulk, and disposable. The samples are collected at a ¼ inch, female NPT port located at the wellhead. Prior to sampling from the wellhead, the valve was opened and allowed to flow in order to clear any liquids or grease contaminants from the sample port. An adapter was made using a ¼ inch tube fitting with a rubber septum inserted into the swage nut. The needle could then pierce the rubber septum and grab a sample of the gas stream without any outside air contamination. Figure 2.2 shows the adapter for wellhead gas sample collection using the vacutainers. The left picture shows the tube fitting, the rubber septum (green) and the swage nut. The right picture shows the full assembly. Figure 2.3 shows the author taking a gas sample from a natural gas well using the vacutainer system.

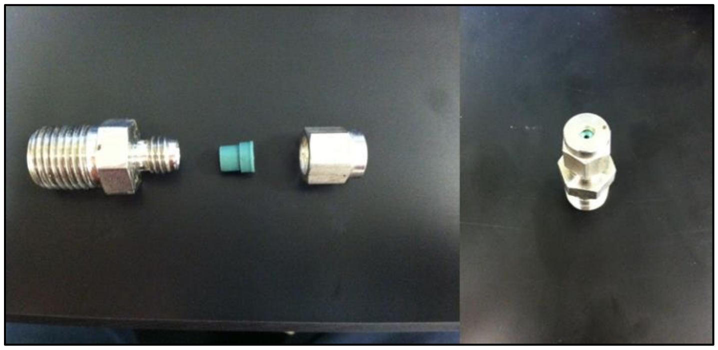

Figure 2.2: Wellhead Adapter for Vacutainer Sampling

Figure 2.3: Vacutainer Sample Being Taken at a Gas Well

2.4.2.   Stainless Steel Gas Cylinder

The samples for natural gas analysis using the portable natural gas chromatograph were collected using stainless steel gas cylinders often referred to as “bombs”. The gas cylinders are double-ended cylinders made of 316L stainless steel and have a maximum pressure rating of 1,800 psig. On each end is a nonrotating-stem needle valve. Each bomb is equipped with one rupture disk unit to remain compliant with the U.S. DOT regulation on pressure relief devices. Figure 2.4 shows a gas cylinder used for sampling the gas stream.

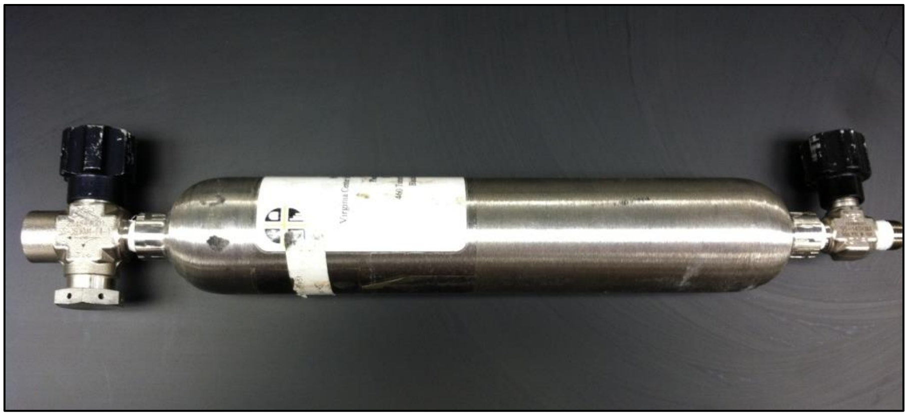

Figure 2.4: Stainless Steel Gas Cylinder

The gas cylinders are filled using the ¼ inch, female NPT port located at the wellhead. Figure 2.5 shows the author taking a gas cylinder sample at a natural gas well. Sampling procedure follows an adaptation of the GPA Standard 2166 for spot sample purging – fill and empty method (GPA, 2005):

1. The well sample port is opened to clear any material (water, grease, etc.) that may be located at the sample port and then closed.
2. The gas cylinder is connected to the sample port and both needle valves are opened.
3. The sample port on the well is fully opened allowing for gas to flow through the gas cylinder.
4. The needle valve farthest from the sample port valve is closed allowing the gas cylinder to fill with gas.
5. The needle valve farthest from the sample port valve is reopened allowing gas to, again, flow through the gas cylinder. This concludes one purge of the gas cylinder.

Steps 4 and 5 are repeated for the minimum number of cycles needed to purge the cylinder (Table 2.1).

Figure 2.5: Gas Cylinder Sample Being Taken at a Gas Well

Table 2.1: Minimum Purge Cycles (GPA, 2005)

Maximum Gas Pressure in Container (psig)	Number of Fill and Purge Cycles
15-29	13
30-59	8
60-89	6
90-149	5
150-500	4
>500	3

2.5. SAMPLE ANALYSIS METHODS

2.5.1. Gas Chromatograph and Mass Spectrometer Method

The method for natural gas analysis for the GC/MS was developed using the ASTM Method D1945-96 (ASTM, 2001). Figure 2.6 displays the ASTM method as well as a typical chromatogram with separated analytes.

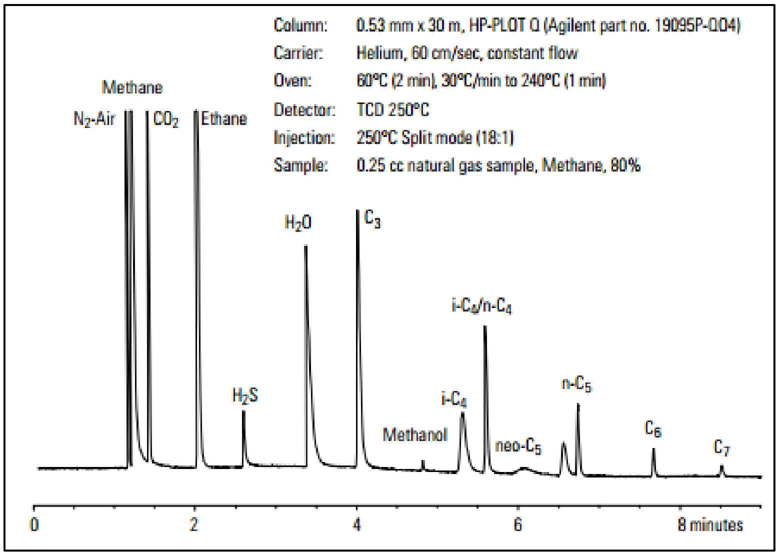

Figure 2.6: ASTM Method D1945-96 Natural Gas Analysis

Table 2.2 displays the constant parameters used to analyze the natural gas samples in the laboratory. Table 2.3 displays the dynamic temperature program utilized to analyze the natural gas samples.

Table 2.2: Natural Gas Analysis Parameters

Parameter	Method
Column	HP-PLOT/Q, 0.320 mm ID, 30 m long, 20.0 µm film
Carrier Gas	Helium - Ultra Pure Carrier
Linear Velocity	58.3 cm/s
Sample Size	50 µL
Injector Temperature	250°C
Split	10:1
Detector Temperature	200°C

Table 2.3: Natural Gas Dynamic Temperature Program

Parameter	Method
Initial Column Temperature	60°C
Hold Time (Initial Temperature)	2 min
Temperature Gradient	30°C/min for 6 min
Final Temperature	240°C
Hold Time (Final Temperature)	1.25 min
Total Sample Runtime	9.25 min

Figure 2.7 displays a sample chromatogram of a natural gas analysis with the individual analytes labeled. It is important to note is the clean separation of the nitrogen and methane peak at the beginning of the chromatogram.

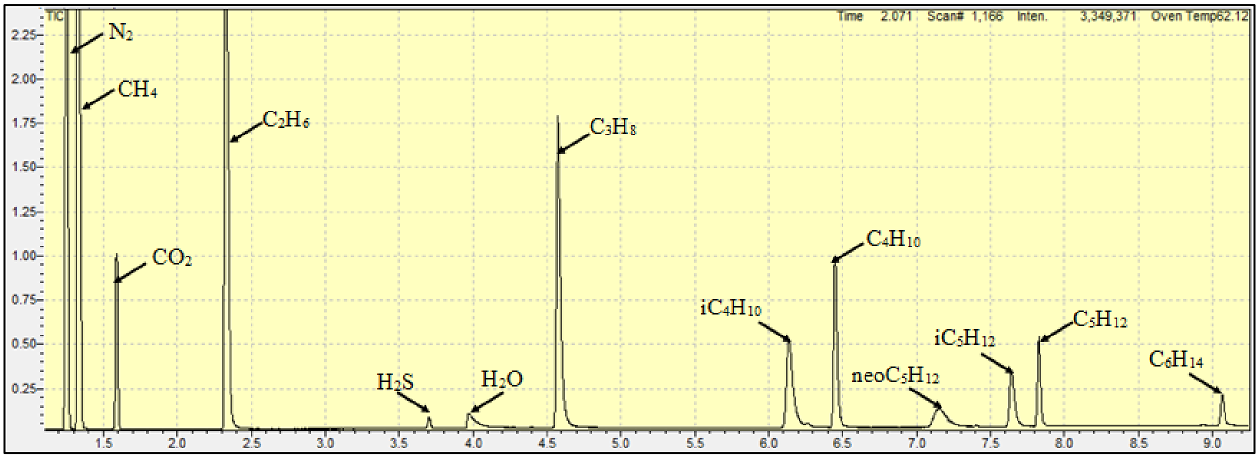

Figure 2.7: Sample Natural Gas Chromatogram

A separate method was developed for tracer gas analysis using the GC/MS. Table 2.4 displays the constant parameters for analyzing the tracers using the GC/MS in the laboratory. Table 2.5 displays the dynamic temperature program used to analyze the tracers. Figure 2.8 displays a sample chromatogram with the individual analytes labeled.

Table 2.4: Tracer Analysis Parameters

Parameter	Method
Column	HP-AL/S, 0.25mm ID, 30 m long, 5 µm film thickness
Carrier Gas	Helium – Ultra Pure Carrier
Linear Velocity	45.0 cm/s
Sample Size	50 µL
Injector Temperature	150°C
Split	50:1
Detector Temperature	200°C

Table 2.5: Tracer Dynamic Temperature Program

Parameter	Method
Initial Column Temperature	175°C
Hold Time (Initial Temperature)	3.75 min
Total Sample Runtime	3.75 min

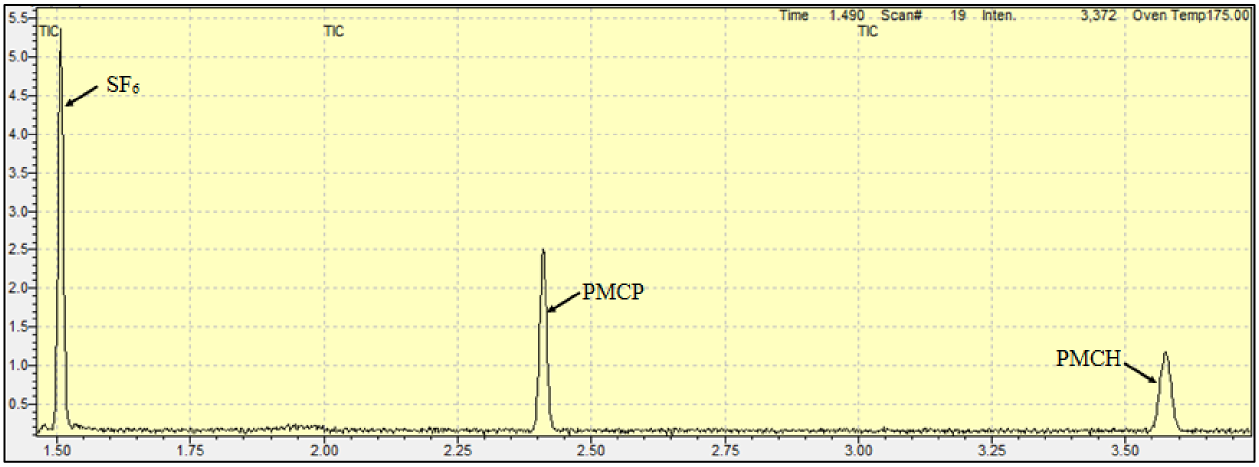

Figure 2.8: Sample Tracer Chromatogram

2.5.2. Natural Gas Chromatograph Method

The carrier gas for the portable natural gas chromatograph (NGC) is helium. A calibration gas is used to verify peak retention times and to normalize the stream components. The inlet pressure range for the NGC is between 5 and 15 psig, so the carrier gas and calibration gas are regulated out of the tank to 10 ± 2 psig. In order to run a sample, the gas cylinder is connected to an inlet hose adapter. A two stage regulator and a water filter were retrofitted before the inlet of the chromatograph. This allows for the pressure of the sample to be reduced to the operating range, and any water in the sample to be filter, which can cause damage to the equipment. The sample analysis time is just over 5 minutes. Figure 2.9 show a sample run report, including the calculated % gas stream, the calorific value, and relative density for each individual component. It also calculates the compressibility, density, and wet, dry, and ideal CV values for the entire gas stream based on the individual chromatographic results. Figure 2.10 shows the NGC system in the back of a truck ready for field deployment.

Comp	UnNorm %	Normal %	Liquids (USgal/MCF)	Ideal (Btu/SCF)	Rel. Density
Propane	3.20718	3.15353	0.87117	79.34592	0.04801
Hydrogen Sulfide	0.00000	0.00000	0.00000	0.00000	0.00000
IsoButane	0.15290	0.15034	0.04933	4.88903	0.00302
Butane	0.49659	0.48829	0.15436	15.92939	0.00980
NeoPentane	0.00086	0.00084	0.00031	0.03368	0.00002
IsoPentane	0.04490	0.04414	0.01619	1.76619	0.00110
Pentane	0.07186	0.07065	0.02568	2.83232	0.00176
Hexane+	0.11180	0.10993	0.00000	0.00000	0.00000
Nitrogen	2.21188	2.17488	0.23993	0.00000	0.02104
Methane	81.46175	80.09897	13.61639	808.99957	0.44367
CarbonDioxide	0.00055	0.00054	0.00009	0.00000	0.00001
Ethane	13.94111	13.70788	3.67604	242.58842	0.14232
Hexane	0.00000	0.10993	0.04533	5.22816	0.00327
Heptane+	0.00000	0.00000	0.00000	0.00000	0.00000
Heptane	0.00000	0.00000	0.00000	0.00000	0.00000
Octane	0.00000	0.00000	0.00000	0.00000	0.00000
Nonane+	0.00000	0.00000	0.00000	0.00000	0.00000
Nonane	0.00000	0.00000	0.00000	0.00000	0.00000
Decane	0.00000	0.00000	0.00000	0.00000	0.00000
Undecane	0.00000	0.00000	0.00000	0.00000	0.00000
Dodecane	0.00000	0.00000	0.00000	0.00000	0.00000
Ethane-	0.00000	0.00000	0.00000	0.00000	0.00000
Propane +	0.00000	0.00000	0.00000	0.00000	0.00000
Oxygen	0.00000	0.00000	0.00000	0.00000	0.00000
Water	0.00000	1.74067	0.00000	0.00000	0.00000
Total	101.70138	100.00000	18.69483	1161.61267	0.67578

Inferior Wobbe	1408.1687 (Btu/SCF)	Superior Wobbe	1420.5601 (Btu/SCF)
Compressibility	0.9970	Density	0.0517 (lbm/ft3)
Real Rel. Density	0.6758	Ideal CV	1161.6127 (Btu/SCF)
Wet CV	1147.5020 (Btu/SCF)	Dry CV	1167.7859 (Btu/SCF)

Figure 2.9: Sample NGC Chromatographic Report

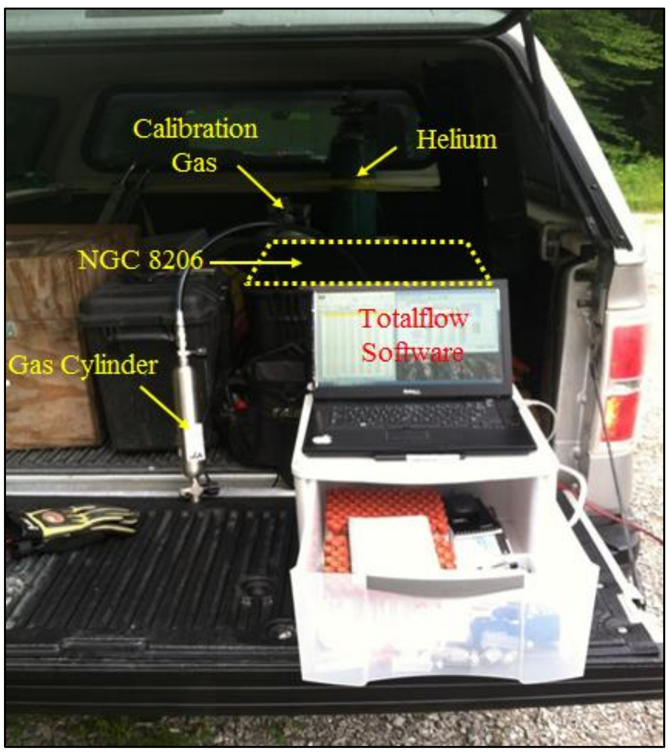

Figure 2.10: Field Deployment of NGC 8206

As a result, high sensitivity gas chromatographic equipment was identified and developed in order to analyze natural gas and tracer samples in the field and in the laboratory. Tracers were selected to be injected with the CO_2 and sampling methods for both natural gas samples and tracer samples were created. Finally, analysis methods were developed for both natural gas samples and tracer samples with excellent precision, separation, and analysis time.

3 CO_2 – ENHANCED GAS RECOVERY VALIDATION TEST IN THE CHATTANOOGA SHALE

The primary goal of this project is to inject 500 tons of CO_2 in order to assess the injection and storage potential of CO_2 in an organic shale formation while monitoring for enhanced gas recovery. Site characterization and selection was previously carried out by researchers at the Virginia Center for Coal and Energy Research (VCCER), engineers at Cardno Marshall Miller & Associates, and industry partners. Ultimately, the Chattanooga shale formation located in north-central Tennessee was selected as the target formation for CO_2 injection. The Chattanooga shale formation lends itself nicely to CO_2 sequestration based on reservoir characteristics such as thickness, gas production, and regional geologic seals above the target formation. Figure 3.1 displays the Chattanooga shale study area located in Morgan, Anderson, Campbell, and Scott Counties, Tennessee. Figure 3.2 displays a generalized stratigraphic column of the study area including the Chattanooga shale and the overlaying seals, including the Ft. Payne, Warsaw, St. Louis, and Monteagle limestones.

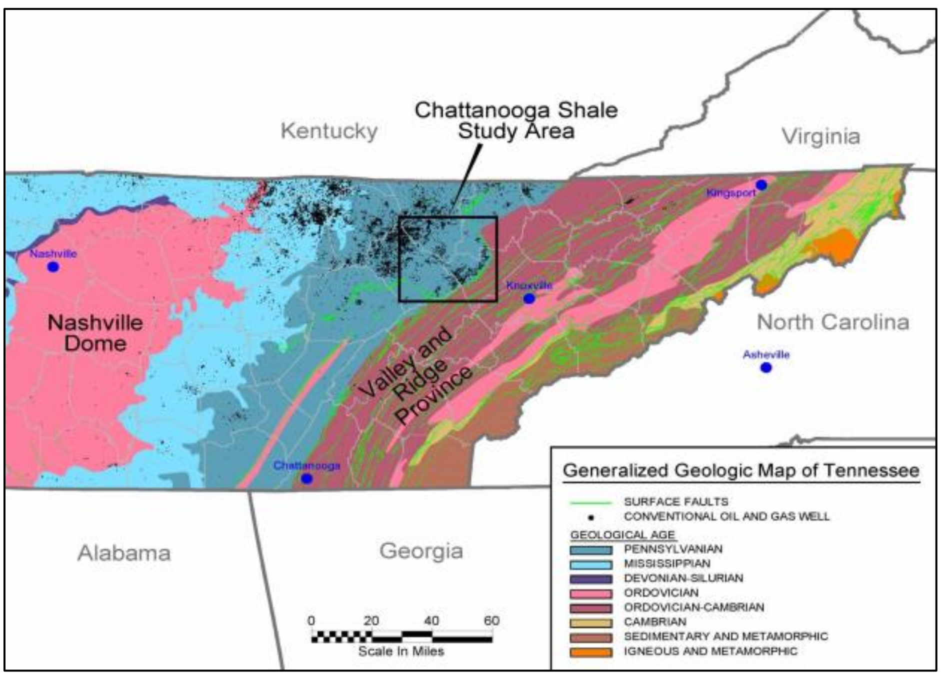

Figure 3.1: Chattanooga Shale Study Area (VCCER, 2012)

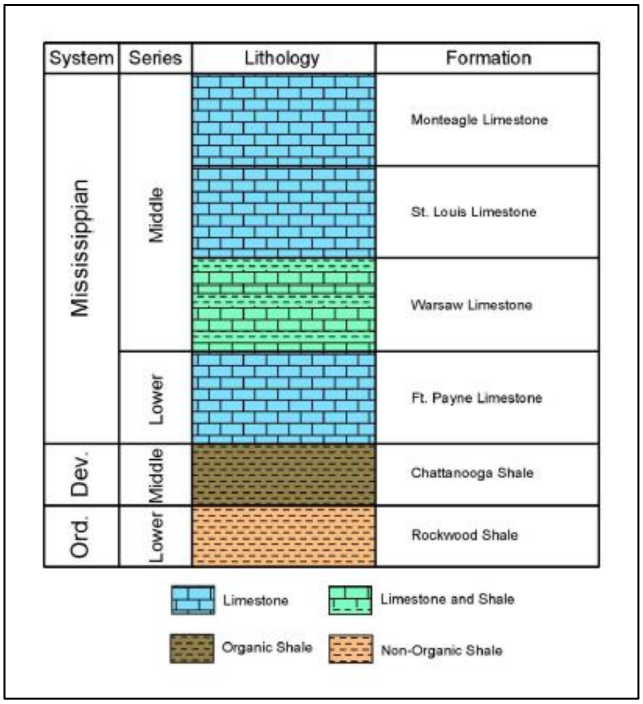

Figure 3.2: Chattanooga Shale Generalized Stratigraphic Column (VCCER, 2012)

3.1. SITE OVERVIEW

As part of the injection and monitoring program for this test, fourteen natural gas production wells were chosen in the gas fields to the northeast of Wartburg, Tennessee and bordering the Frozen Head State Park in Morgan County, Tennessee. The wells in this area are primarily owned and operated by CNX Gas and Atlas Energy. CNX has donated horizontal well HW-1003 to be used as the injection well for CO_2. HW-1003 was previously hydraulically fractured in four stages in the Chattanooga shale. There are three other horizontally drilled wells in the area that were also completed in the Chattanooga shale formation and chosen as monitoring wells for the test: HH-1003, HH-1006, and HH-1008. There are eight vertically drilled wells that were completed in the Chattanooga shale formation chosen as monitoring wells for the test: HW-1005, HW-1010, HW-1012, HW-1032, HW-1035, HW-1100, HW-1101, and HW-1102. Lastly, there are two vertically drilled wells in the area that were completed above the Chattanooga shale formation that were chosen to monitor for CO_2 plume migration out of formation: HW-1002 and HW-1007. Figure 3.3 displays the map of the production wells in the area. The injection well, HW-1003, is denoted by a black symbol. The wells that were completed in the Chattanooga shale formation are denoted by a blue symbol while those completed out of formation are denoted by a red symbol. The grey lines connected to HW-1003, HH-1003, HH-1006, and HH-1008 demonstrate the length and orientation of the horizontal segment of these wells.

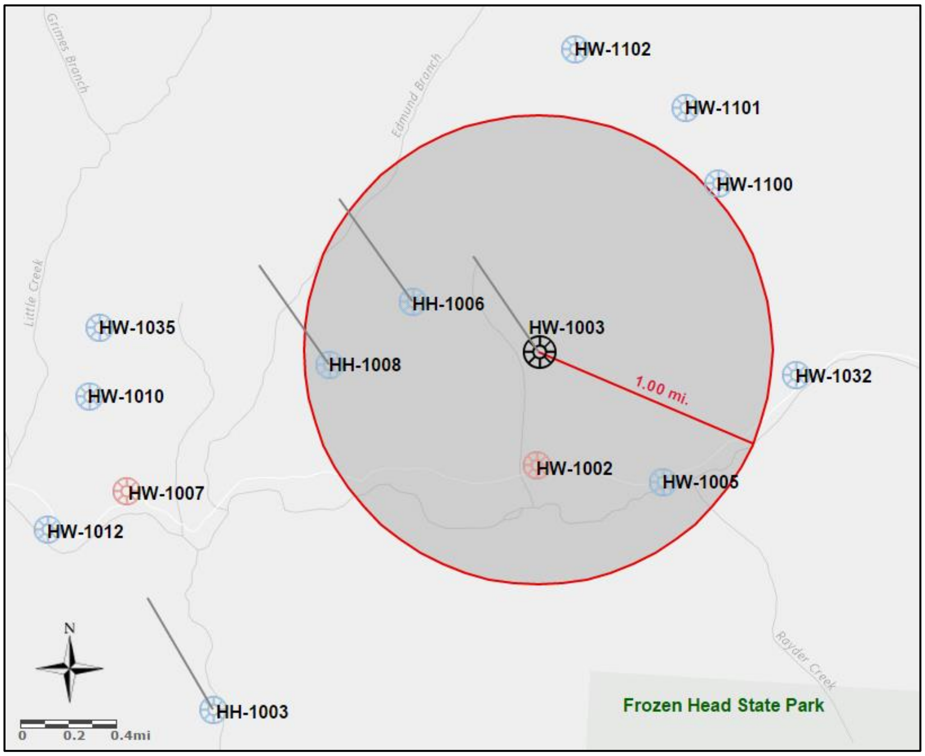

Figure 3.3: Area of Study (ESRI, 2015)

3.2. INJECTION WELL

3.2.1. Drilling and Completion

HW-1003 was drilled on December 2, 2008 to a kickoff point (KOP) depth of 2,029 feet. The lateral portion of the well extends from a depth of 2,817 feet to 4,985 feet. The casing data for the injection well HW-1003 show that a 7-inch surface casing was set to a depth of 3,003 feet. A 4 ½-inch production casing was set to a depth of 4,985 feet.

HW-1003 was completed in four stages using a 70Q nitrogen foam fracture fluid. Table 3.1 displays the details of the completion report for each stage, including the volume of nitrogen used as a fracture fluid and the amount of sand used as a proppant, as well as the breakdown pressure and the initial shut in pressure (ISIP).

Table 3.1: Completion Data for HW-1003 (Knox, 2008)

	Stage 1	Stage 2	Stage 3	Stage 4
Perforation Range (feet)	4772-4752	4455-4415	4092-4064	3376-3346
Number of Perforations	6	6	6	6
Total Slurry Volume (gallons)	700	691	718	689
Total Nitrogen Volume (gallons)	1543000	1605000	1647000	1560000
Total Sand (sacks)	1000	1000	1000	1000
Breakdown Pressure (psi)	3929	1975	1885	4121
Initial Shut In Pressure (psi)	2492	2132	2144	3071

3.2.2. Production Data

HW-1003 was brought online as a natural gas producer in January of 2009 and over its lifetime has averaged 40 thousand cubic feet (Mcf) per day. Before the well was taken offline and converted into a CO_2 injection well, HW-1003 had produced over 75.1 MMcf of gas. The average daily production for the last year of production before the well was taken offline was 14.7 Mcf/day. Figure 3.4 displays the historical production data for HW-1003.

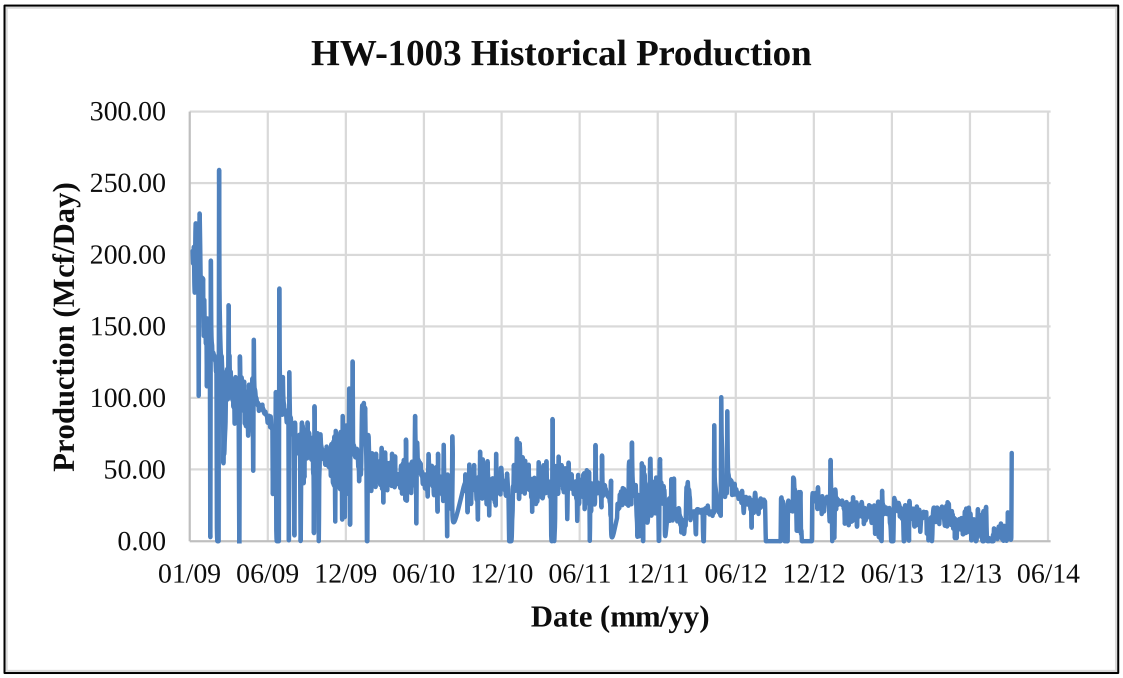

Figure 3.4: HW-1003 Historical Production Data

3.3. INJECTION DESIGN

3.3.1. Site Layout

The well pad was cleared and graveled prior to moving equipment on site. A 70-ton CO_2 storage vessel was located permanently on site and refilled periodically by 20-ton tankers. The skid pump with all the controls and monitors, as well as the propane tank and heater to heat the CO_2, was also located on the well pad. The wellhead of HW-1003 was also converted in order to inject the CO_2 and the tracers simultaneously. The traditional "Christmas tree" on the wellhead was replaced with a gate valve, an inlet for the CO_2 line, and a tee for tracer injections. Figure 3.5 shows the site layout of the HW-1003 well pad. Figure 3.6 shows the HW-1003 wellhead configuration.

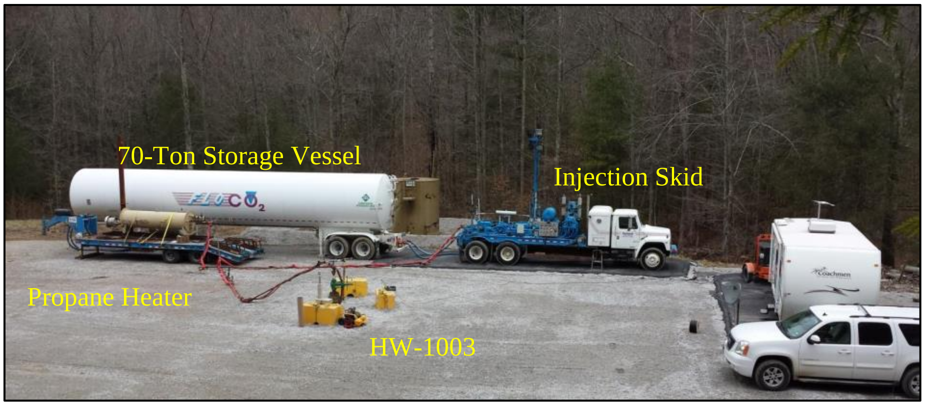

Figure 3.5: HW-1003 Site Layout

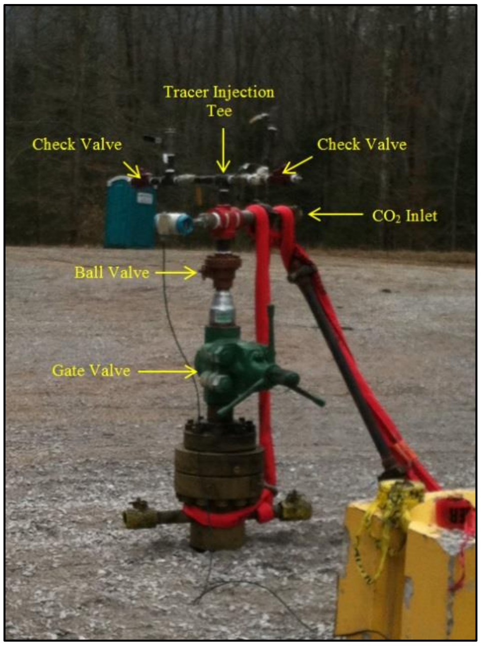

Figure 3.6: HW-1003 Wellhead Configuration

3.3.2. CO_2 Injection

The CO_2 injection was carried out by the oilfield service company, FloCO_2. Up to 500 tons of CO_2 will be injected to test the storage potential and enhanced gas recovery of gas-bearing shales. This injection is significant when compared to the amount of nitrogen and water used to initially fracture the well (Figure 3.7). The injected CO_2 would nearly equal the amount of nitrogen and water used to hydraulically fracture the well and is equivalent to 8,595 Mcf which is approximately 11.4% of the total gas produced from the well.

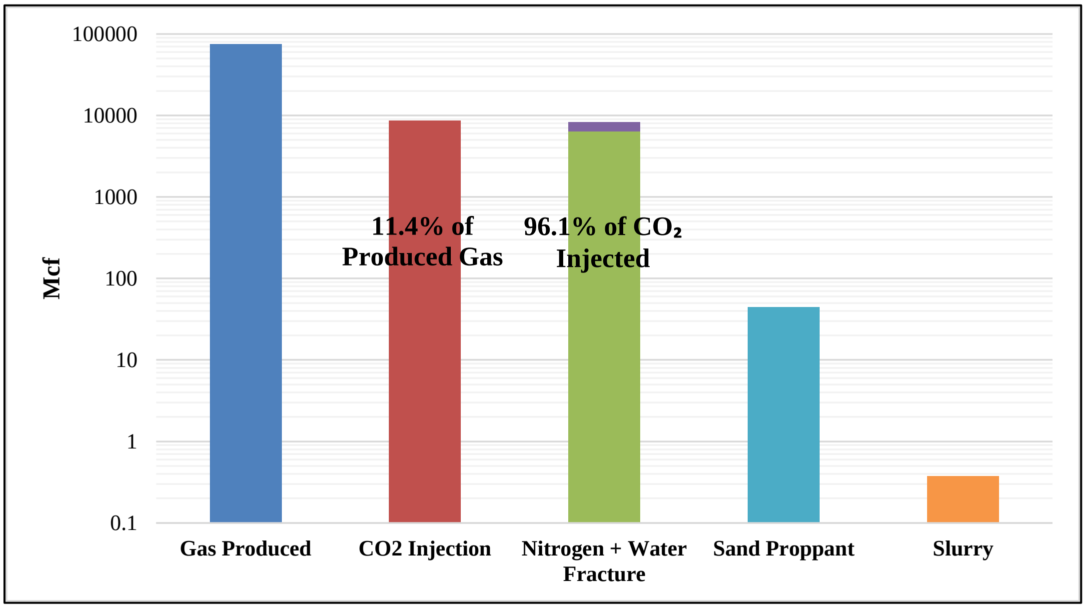

Figure 3.7: CO_2 Injection Comparison

3.3.3. Tracer Injection

As part of the injection, fluorinated tracers were also added to help detect CO_2 plume migration to offset production wells, and to account for the CO_2 during the flowback of the well following the injection and soaking phase. Advantages of using tracers are that they have a negligible concentration in the environment, making ownership identifiable, they are detectable in extremely low concentrations (often in parts per trillion), and they also are nontoxic. Finally, multiple tracer suites are easily deployed and commercially available (Heiser & Sullivan, 2002).

For this test Sulfur Hexafluoride (SF_6) and two perfluorocarbon tracers (PFTs), perfluoromethylcyclopentane (PMCP) and perfluoromethylcyclohexane (PMCH) were chosen as the tracers injected with the CO_2. SF_6 was chosen as a tracer for this project due to its previous use in other CO_2 injection tests, its low solubility in water, and its ability to exist as a gas

(Lindner and Leone, n.d.). PMCP and PMCH were chosen because they have minimal solubility in water and have a higher vapor pressure relative to other PFTs (Lindner and Leone, n.d.).

Sulfur Hexafluoride and PMCP were injected with the first 50 tons of CO_2 in order to help detect the initial plume movement through the reservoir and arrival at any of the offset production wells. By injecting two tracers simultaneously, it will also help model the movement of the smaller SF_6 molecule compared the PFT. PMCH was injected later in the test near the 350 ton mark of CO_2 injected in order to help compare arrival times of similar PFTs at the offset production wells. Due to the fact that SF_6 exists as a gas and the PFTs exist as volatile liquid, different injection methods were developed and implemented to introduce the tracer with the CO_2 stream. The following sections will discuss the injection design and method for the tracers.

Sulfur Hexafluoride

On March 20, 2014 at 12:00PM, 5,500 mL of SF_6 were injected with CO_2 at HW-1003. At this time, the cumulative amount of CO_2 injected downhole totaled 20 tons, the wellhead pressure was 216 psig, the flow rate of the CO_2 was 28 tons/day, and the heater output for the CO_2 was 50 degrees Fahrenheit.

The SF_6 gas cylinder was connected to a dual stage pressure regulator and then connected to an Alicat mass flow controller using 1/8th inch stainless steel tubing. From the flow controller, the gas went into a Sprague booster pump system. In order for the SF_6 to overcome the pressure of the CO_2, a higher pressure needed to be achieved. The booster pump was used to effectively utilize air from a standard air compressor to drive a compression piston in the pump allowing the input gas, SF_6 in this case, to be compressed to a higher pressure. The maximum pressure the booster pump can achieve is 1,100 psig with a drive air pressure of only 200 psig. A pressure gauge was connected to the outlet port to measure the boosted pressure before the SF_6 was introduced to the CO_2. Figure 3.8 shows a schematic of the SF_6 injection system and Figure 3.9 shows the actual well head setup.

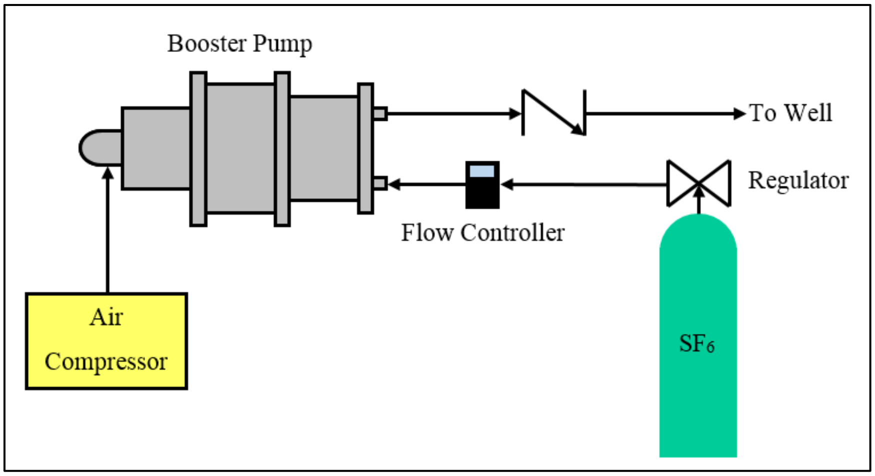

Figure 3.8: Sulfur Hexafluoride Injection Schematic

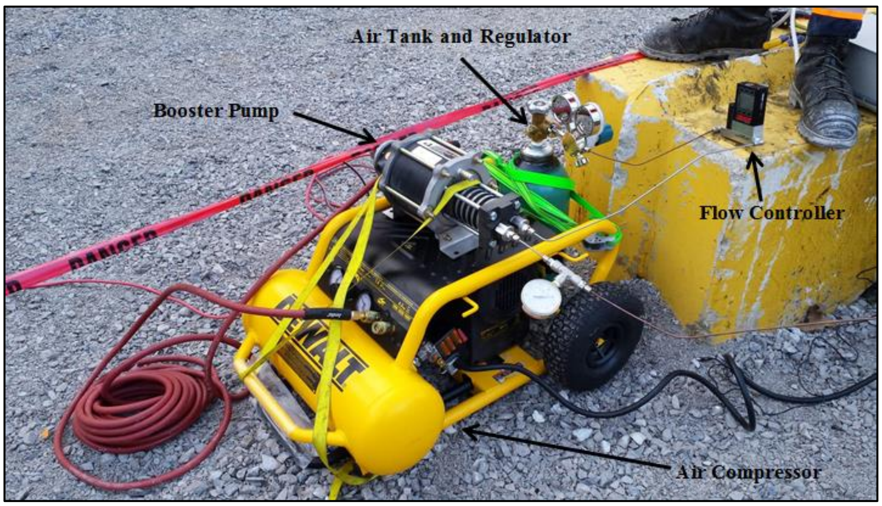

Figure 3.9: Sulfur Hexafluoride Injection Wellhead Setup

Perfluorocarbon Tracers

The perfluorocarbon tracers were injected using a Teledyne Isco 500D Syringe Pump. This pump has a 500 mL capacity and a maximum injection pressure of 3,750 psig. The pump can be programmed to inject at a constant flow rate or a constant pressure. For this test, constant flow rate was selected.

On March 20, 2014 at 12:07 PM, 500 mL (0.85 kg) of PMCP were injected at a constant flow rate of 62.5 mL/hr. At this time, the cumulative amount of CO_2 injected downhole totaled 20 tons, the wellhead pressure was 216 psig, the flow rate of the CO_2 was 28 tons/day, and the heater output for the CO_2 was 50 degrees Fahrenheit. The total 500 mL of PMCP was completed at 8:07 PM the same day. At this time, cumulative tons of CO_2 injected totaled 46 tons, the wellhead pressure was 260 psig, the flow rate of CO_2 was 41 tons/day, and the heater output was 50 degrees Fahrenheit.

The flow rate was adjusted for the second PFT injection due to the higher injection rate of the CO_2 at the time. This adjustment allowed for the concentration of tracer versus CO_2 to remain the same for both PFT injections. On March 28th, 2014 at 1:30PM, 500 mL (0.89 kg) of PMCH were injected at a constant flow rate of 85.5 mL/hr. At this time, the cumulative amount of CO_2 injected downhole totaled 337 tons, the wellhead pressure was 463 psig, the flow rate of the CO_2 was 49 tons/day, and the heater output for the CO_2 was 50 degrees Fahrenheit. The total 500 mL of PMCH was completed at 7:21 PM the same day. At this time, the cumulative amount of CO_2 injected downhole totaled 350 tons, the wellhead pressure was 468 psig, the flow rate of the CO_2 was 50 tons/day, and the heater output for the CO_2 was 50 degrees Fahrenheit.

The pump cylinder is equipped with an inlet for filling and refilling, and an outlet for discharge. 1/8th inch tubing was placed on the inlet of the pump to fill the cylinder with the tracers. Once filled, the inlet was plugged and 1/8th inch stainless steel tubing was assembled to the pump outlet. Just past the outlet, a quarter turn plug valve was placed in-line so the pump could be shut off, disassembled, and cleaned. The tubing was connected to the check valves on the wellhead where the PFTs were introduced to the CO_2 injection system. After each PFT injection, the pump was filled twice with 500 mL of ethanol (C_2H_6O) and allowed to pump in order to clean the pump cylinder, tubing, and wellhead assembly of any remaining tracer. Figure 3.10 shows a schematic of the PFT injection system and Figure 3.11 shows the actual well head setup.

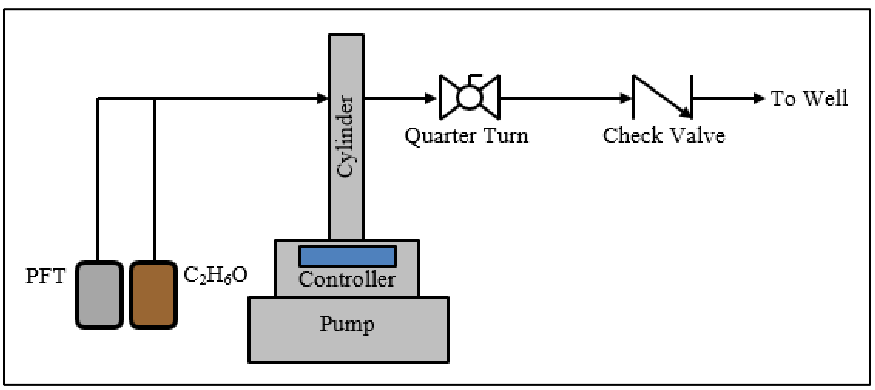

Figure 3.10: Perfluorocarbon Tracer Injection Schematic

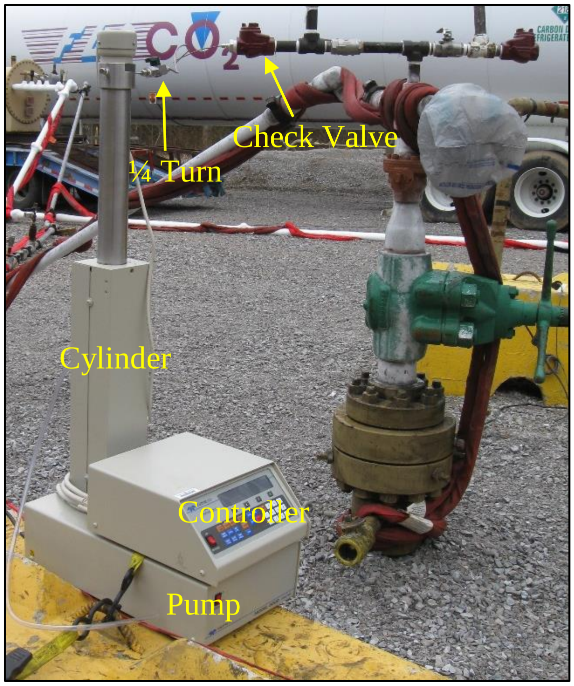

Figure 3.11: Perfluorocarbon Tracer Injection Wellhead Setup

4 CO_2 INJECTION TEST RESULTS

The test was split up into four distinct phases: Pre-Injection Baseline, Injection, Soaking, and Flowback. Specific monitoring goals were set up for each phase at the injection well and the offset production wells. The results for the test will be split up into each phase of the test.

4.1. PRE-INJECTION BASELINE PHASE

As part of the pre-injection baseline monitoring, composition and pressure data from the injection and offset production wells were collected five months prior to injection. Table 4.1 displays the composition data of HW-1003 for the five month baseline samples collected. Complete composition data for the injection well can be found in Appendix A.

Table 4.1 HW-1003 Baseline Composition Data (% of Total Gas Stream)

		10/17/2013	10/18/2013	12/14/2013	1/17/2014	3/17/2014
N_2	Nitrogen	3.80330	3.05620	3.05629	3.14406	2.17135
CO_2	Carbon Dioxide	0.00690	0.00795	0.01519	0.01118	0.00050
CH_4	Methane	80.96793	81.64435	82.04221	81.75309	80.09227
C_2H_6	Ethane	11.70470	11.75960	11.43995	11.59842	13.71568
C_3H_8	Propane	2.72853	2.74685	2.69221	2.72135	3.15733
C_4H_{10}	Butane	0.45390	0.45520	0.43194	0.44473	0.48833
iC_4H_{10}	IsoButane	0.14497	0.14560	0.13976	0.14311	0.15040
C_5H_{12}	Pentane	0.07710	0.07690	0.07288	0.07546	0.06877
$neoC_5H_{12}$	NeoPentane	0.00107	0.00105	0.00103	0.00105	0.00079
iC_5H_{12}	IsoPentane	0.04773	0.04810	0.04579	0.04703	0.04378
C_6H_{14}	Hexane	0.05727	0.05810	0.06278	0.06061	0.11078

4.2. INJECTION PHASE

In total, 510 tons of CO_2 were successfully injected into HW-1003 over a period of 13 days. Injection commenced on March 19^{th}, 2014 at 7:41 AM and concluded on March 31^{st}, 2014 at 3:58 PM. During injection, flow rate, temperature, wellhead pressure, and total cumulative tons were collected every 30 seconds by the operator (Figure 5.1). The average flow rate was 40.95 tons/day and the average heater output was 48.59 degrees Fahrenheit. Heater output was the parameter that was held constant by the operator in order to keep CO_2 above the freezing point throughout the injection period. Heater output also had the largest effect on flow rate, which tended to decrease at night due to outside temperature drop which required more propane to heat the CO_2. Figure 4.1 displays the CO_2 injection data. Complete injection data can be found in Appendix B.

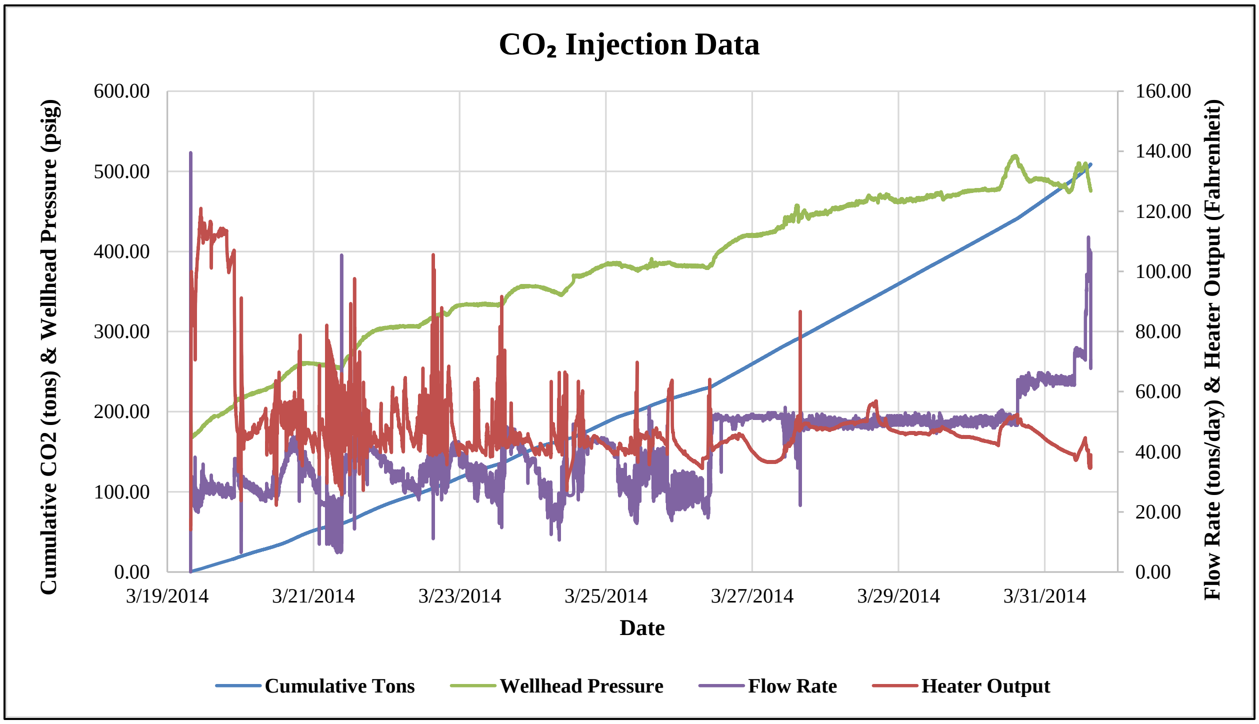

Figure 4.1: CO_2 Injection Data

Based on the injection pressure and temperature, the phase of the CO_2 and the tracers can be graphed. Figure 4.2 shows the phase diagrams for CO_2 (black), SF_6 (blue), PMCP (red), and PMCH (Green). The CO_2 injection is represented by the light blue line. The purple segment of the line represents the injection of SF_6 and PMCP with the CO_2. The orange segment of the line represents the injection of PMCH with the CO_2. From this plot it can be determined that the CO_2 was injected as a gas for the entirety of the injection. While a liquid CO_2 injection was attempted, an increased injection pressure was difficult to achieve due to the ease of injectivity in the reservoir. It can also be determined that the PFTs were injected entirely as liquids. SF_6 experienced phase change during injection but likely returned as a gas once in the reservoir.

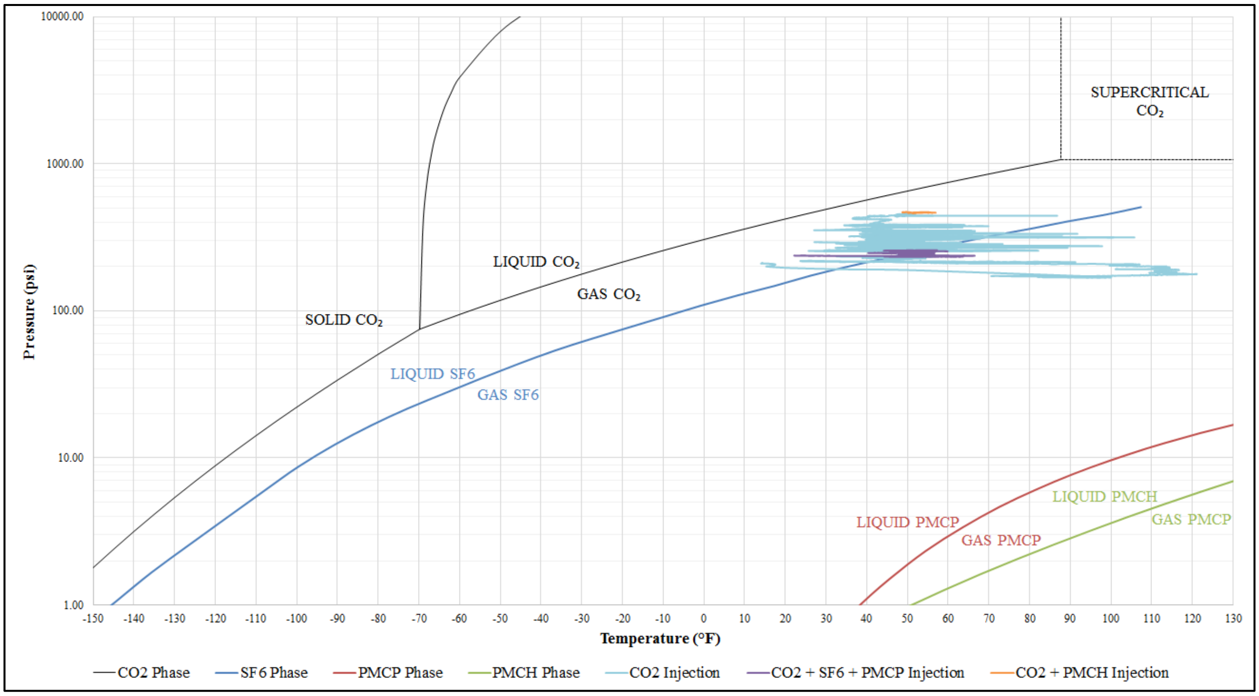

Figure 4.2: CO_2 and Tracer Phase Diagram

During the injection of the fluorinated tracers with the CO_2, periodic atmospheric samples were taken around the wellhead to make sure no tracers leaked during the setup, injection, or breakdown of the systems. Analysis of these atmospheric samples resulted in none having any concentration of tracers, rendering a successful injection of tracers with no stray contamination.

Also during the injection phase, pressure readings, composition analysis, and tracer samples were conducted periodically at the offset production wells. The naturally occurring CO_2 in this formation is in the thousandths of a percent, making any migration of CO_2 into the offset production wells apparent with any significant increase in CO_2 composition. During the injection phase, there was no significant change in wellhead pressures at the offset wells. After analysis, it was determined that there was also no tracer detection at any of the offset wells. Finally, composition analysis of the offset well during injection resulted in no significant increase in CO_2 concentration at any of the offset wells, including the closet horizontal well HH-1006.

4.3. SOAKING PHASE

After the injection phase was completed, HW-1003 was shut in for a period of four months to allow the CO_2 absorb within the reservoir. During this soaking phase, composition and tracer samples were collected periodically at the offset production wells. Analysis of these samples, once again, concluded that no significant increase in CO_2 concentration and no tracer detection had occurred at any of the offset wells.

Gas composition samples were taken from HW-1003 periodically during the soaking phase. Analysis of these samples indicated the gas stream averaged over 95% CO_2. Pressure readings were also taken during the soaking phase of the project (Figure 4.3). The wellhead pressure after CO_2 injection was just above 500 psig. This pressure quickly decreased and then leveled out between 250 and 260 psig for a period of about three months

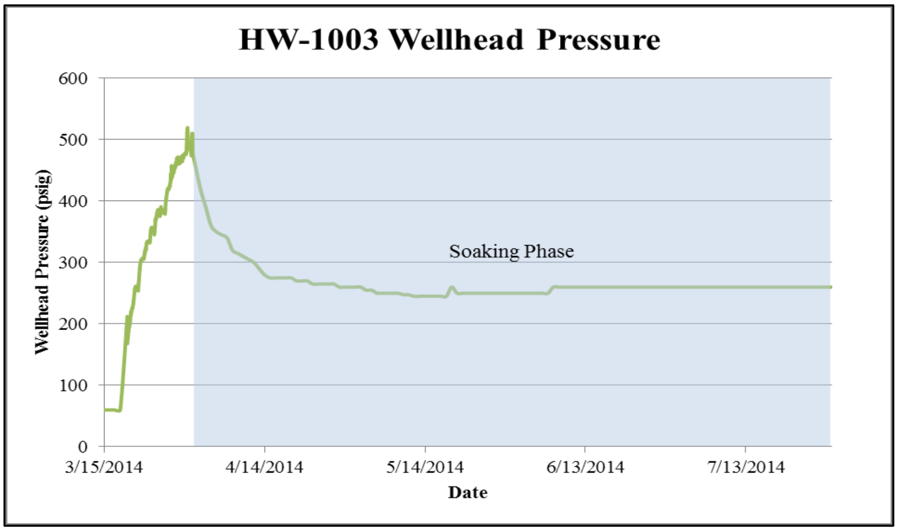

Figure 4.3: HW-1003 Wellhead Pressure during Soaking Phase

4.4. FLOWBACK PHASE

During the flowback phase of the project, the well was opened back up and put back into normal pipeline operation. Flowback commenced on July 29th, 2014 at 8:40 AM. Gas composition and tracer samples were collected every 30 minutes to 1 hour during the first week of flowback, then once per day by the well tending service company, P&C Well Service. Figure 4.4 shows the gas compositions of HW-1003 during the flowback phase, including CO_2 (blue), total hydrocarbons (black), and nitrogen (gold). The dashed gold line represents the average baseline composition for comparison.

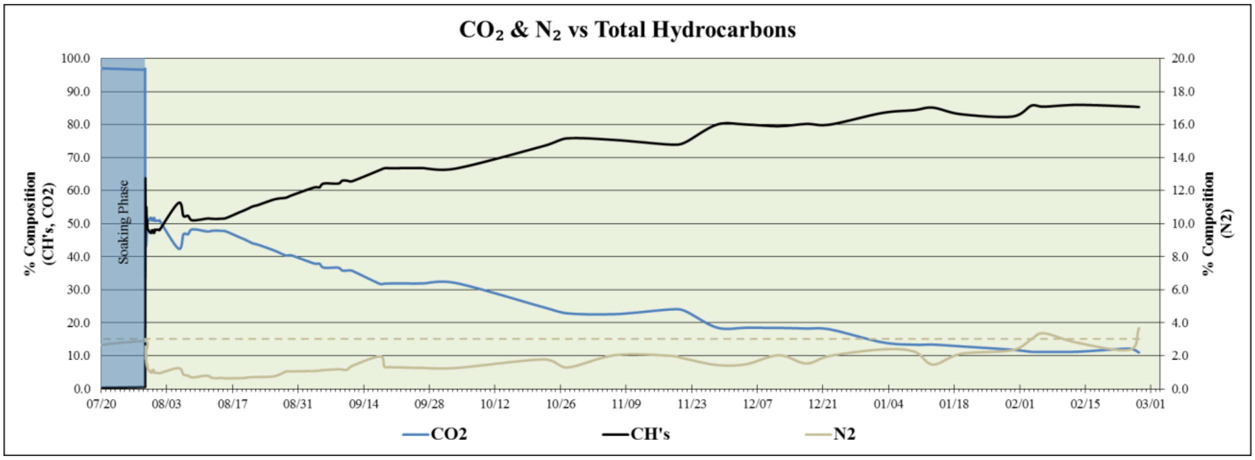

Figure 4.4 HW-1003 Gas Composition during Flowback Phase

In order to evaluate enhanced gas recovery, the quality of the total hydrocarbon composition during flowback was evaluated. Figure 4.5 displays the individual hydrocarbon chains and their relative percentage of the total hydrocarbon composition during the flowback phase, including methane (red), ethane (green), propane (purple), and butane (orange). The dashed lines corresponding to the matching colors represent the baseline averages for each component for comparison. CO_2 (dotted blue) composition is also displayed for comparison.

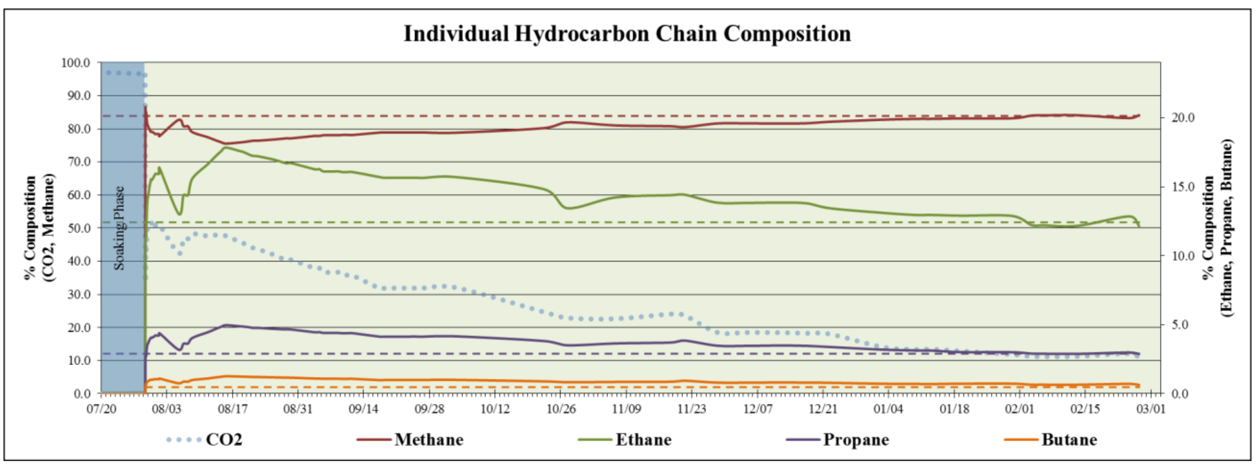

Figure 4.5 Individual Hydrocarbon Chain Composition

Flow data from the ABB Totalflow XFC G4 meter located at HW-1003 was collected daily. This unit uses an orifice plate in the meter run to measure static pressure, differential pressure on both sides of the plate, temperature, and gas density to measure flow rate in Mcf/day. A standard density input is programmed in the meter to calculate the flow rate in Mcf/day. The flowrate data was adjusted to the actual density of the gas stream, which was calculated from the compositional analysis from each day collected. Figures 4.6 and 4.7 display the historical production (red shaded area), the injection and soaking period (green shaded area), and the flowback (blue shaded area). The red dotted line represents the projected decline curve based on the historical production data. The blue solid line represents the total gas produced during flowback and the blue dotted line represents the total hydrocarbons produced during flowback.

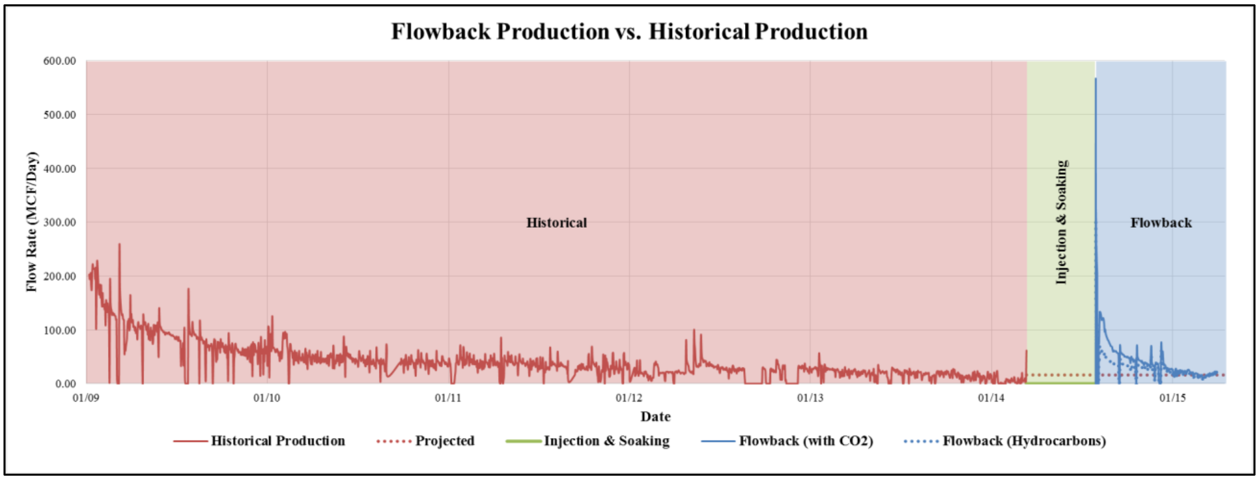

Figure 4.6 Flowback Production vs. Historical Production

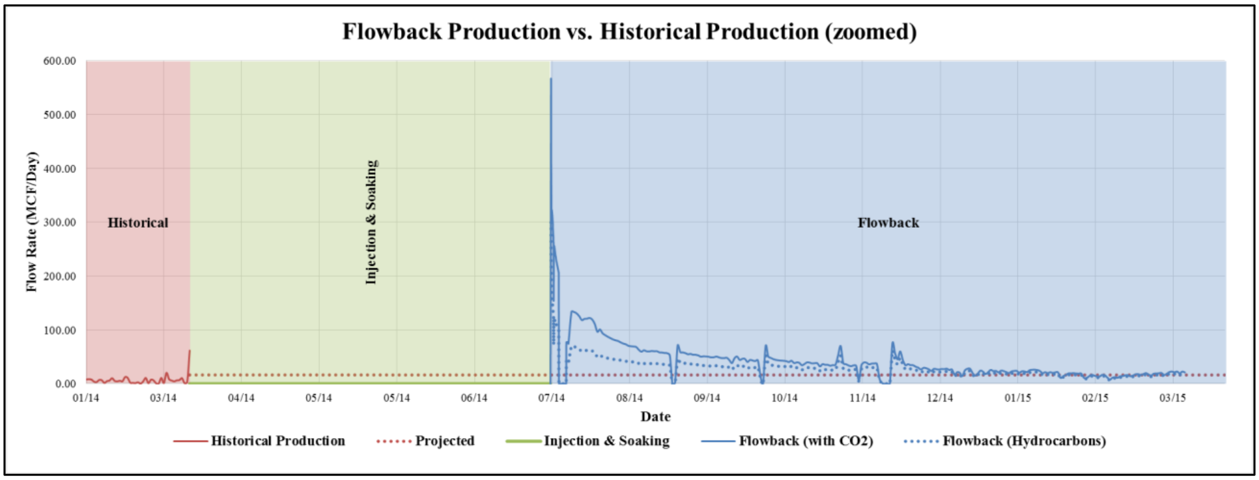

Figure 4.7 Flowback Production vs. Historical Production (zoomed)

To date, a total of 10,044 Mcf of gas has been produced from HW-1003. A total of 6,756 Mcf of hydrocarbons have been produced to date. The difference represents the amount of CO_2 produced back from HW-1003, which is equivalent to 180 tons, or approximately 35.5% of the CO_2 injected. The average daily flow rate for the past month of production to date is 16.9 Mcf/day.

During the flowback, tracer samples were collected and analyze for flowback concentrations. Figure 4.8 displays the concentrations of all three tracers detected in the flowback.

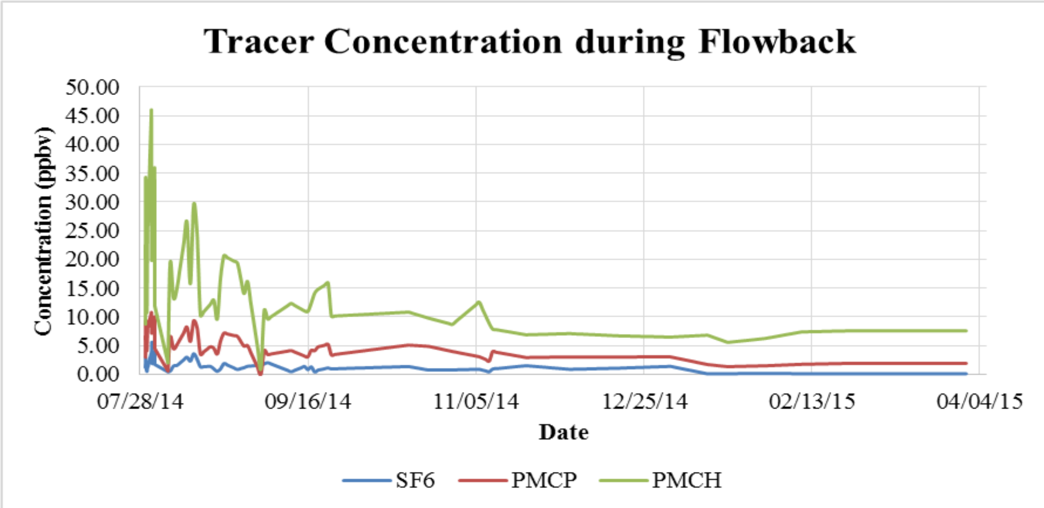

Figure 4.8: SF_6 and PFT Concentrations during Flowback

While the overall trend in concentration for all three tracers is consistent, the concentration of PMCH during flowback was higher than PMCP and SF_6, respectively. To date, 35.1% of the PMCH, 12.0% of the PMCP, and 3.28% of the SF_6 injected has been recovered.

4.5. FINANCIAL ANALYSIS

A brief financial analysis was conducted to determine the value of the CO_2 injected. For this analysis, the Henry Hub Natural Gas Spot Price ($/Mcf) was averaged over the past five years (EIA, 2015c). The 90th percentile and 10th percentile were also included in the analysis. Industry communication indicated that natural gas liquids (NGLs), including ethane, propane, butane, pentane, and hexane, are typically sold at 50% of the West Texas Intermediate (WTI) Spot Price ($/Bbl) (EIA, 2015d). Table 5.1 displays the average, 90th percentile, and 10th percentile spot prices for the last five years for natural gas and NGLs.

Table 5.1 Natural Gas and NGLs Spot Prices

Natural Gas $/Mcf			Petroleum & NGLs $/Bbl		
90%	Average	10%	90%	Average	10%
$4.59	$3.74	$2.71	$104.89	$90.48	$74.58

In order to associate a sales price to the NGLs, they first must be converted from Mcf to barrels (Bbl). Table 5.2 displays the conversion factors for NGLs.

Table 5.2 NGLs Conversion Factors (EIA, 2014b)

Component	Conversion Factor (Mcf/Bbl)
Methane*	2.468
Ethane	1.558
Propane	1.499
Isobutane	1.245
Normal Butane	1.288
Isopentane	1.095
Natural Gasoline	0.940
Plant Condensate	0.940
Other Products	0.940
*Not an NGL	

The individual flow rates for methane and NGLs were calculated using the flow and gas composition data collected during the flowback phase. Table 5.3 displays the value of the flowback for methane and total NGLs.

Table 5.3: Total Methane and NGLs in Flowback

Total Flowback					
Total Methane (Mcf)			Total NGL (Bbl)		
5072.69			832.61		
90%	Average	10%	90%	Average	10%
$23,283.63	$18,969.71	$13,746.98	$43,666.33	$37,666.91	$31,046.43

Once the value of the flowback was determined, two different scenarios were conducted; one that deducted the value of gas that would have been produced while the injection well was shut in during the four month soaking phase, and one that did not include the four month soaking phase. For both scenarios, the assumption that the well would have produced saleable gas at the projected decline curve flow rate, had the test not occurred, was made (red dotted line, Figures 5.6 and 5.7). In order to associate a value to this projected production rate, the flow rate was combined with the average pre-injection baseline gas composition of HW-1003 to find what the individual methane and NGL flow rates were for the well before it was taken offline for the CO_2

injection. Table 5.4 displays the first scenario where the soaking phase was not taken into account. Table 5.5 displays the second scenario where the soaking phase was taken into account.

Table 5.4: Flowback Value without the Soaking Phase

Not Including Soaking					
Total Methane Flowback (Mcf)			Total NGL Flowback (Bbl)		
2275.97			479.84		
90%	Average	10%	90%	Average	10%
\$10,446.69	\$8,511.16	\$6,167.87	\$25,165.01	\$21,707.53	\$17,892.13

Table 5.5: Flowback Value with the Soaking Phase

Including Soaking					
Total Methane Flowback (Mcf)			Total NGL Flowback (Bbl)		
715.01			282.94		
90%	Average	10%	90%	Average	10%
\$3,281.88	\$2,673.83	\$1,937.67	\$14,838.69	\$12,799.97	\$10,550.20

Tables 5.6 and 5.7 display the total summed value of the CO_2 injection test with and without the soaking phase, respectively, as well as a dollar per ton of CO_2 injected value.

Table 5.6: Total Flowback Value without the Soaking Phase

Not Including Soaking Phase		
90%	Average	10%
\$35,611.70	\$30,218.69	\$24,060.00
\$69.82/ton	\$59.25/ton	\$47.17/ton

Table 5.7: Total Flowback Value with the Soaking Phase

Including Soaking Phase		
90%	Average	10%
\$18,120.58	\$15,473.80	\$12,487.87
\$35.53/ton	\$30.34/ton	\$24.48/ton

Common to CO_2 – EOR projects is the recycling of the CO_2 that is reproduced with the oil in order to minimize the amount needed to be purchase in the future for the next project. On a commercial scale, the purchase cost is typically \$2.00/Mcf of CO_2 and the recycle cost \$0.70/Mcf of CO_2 (DOE, 2010b). Table 5.8 displays the net value associated to the CO_2

injection by including the purchase cost to the 510 tons of CO_2 injected for this project and the recycling cost to the 35.5% of CO_2 reproduced. This net value was only conducted for the scenario not including the soaking phase as a commercial 'huff-and-puff' injection can have a soaking phase as little as 10 days (Industry Communication).

Table 5.8: Total Net Flowback Value

Purchase of CO_2 ($2.00/Mcf)		
$17,533.80		
Cost of Recycling ($0.70/Mcf)		
$2,147.89		
Net Value		
90%	Average	10%
$15,930.01	$10,537.00	$4,378.31
$31.24/ton	$20.66/ton	$8.58/ton

5 CONCLUSIONS AND RECCOMENDATIONS

The injection of 510 tons of CO_2 during this test demonstrates the first successful injection of CO_2 in an organic shale formation to monitor for storage and enhanced gas recovery potential in Central Appalachia. This chapter will draw conclusions based on the results from the CO_2 injection test and make recommendations for future research.

5.1. INJECTION

Based on the significant flow rates and relatively low injection pressures from the injection data, the injectivity of CO_2 into organic shale reservoirs is confirmed. By increasing injection pressure, the CO_2 could be injected as a liquid, therefore achieving a higher weight to volume ratio.

Many of the results from the monitoring program indicate that there is no communication in the fracture network between HW-1003 and the thirteen offset production wells, including HH-1006, the closest horizontal well. Factors that are indicative of a closed system at HW-1003 include:

- No significant increase of CO_2 concentration at the offset production wells
- No detection of any fluorinated tracers at the offset production wells
- No increased pressure and flow rate at the offset production wells
- 95% CO_2 in HW-1003 during soaking phase, indicative of a full wellbore
- Leveled pressure in HW-1003 during soaking phase

Based on these results, it can be assumed that if the injection well HW-1003 were shut in after the CO_2 injection, complete and permanent geologic CO_2 sequestration could have been achieved.

5.2. GAS FLOWRATE

Once the well was brought back online after the soaking period, a significant increase in gas production occurred. During the first month of flowback, the average daily production rate was 123.9 Mcf/day, which is over 8 times the average production for the last month before the well was taken offline for injection. The well is still flowing back at an increased production rate but is close to the projected historical production rate. Had a higher wellhead pressure been achieved during the CO_2 injection phase, a more sustained period of increased gas flow rate might have been achieved.

5.3. GAS COMPOSITION

The CO_2 concentration in the production gas has steadily declined during the flowback of HW-1003. The average daily production of CO_2 for the past month of data is 0.11 tons/day and declining. At this rate, it would take a minimum of over eight years to produce all of the CO_2 injected.

One important trend that was discovered during the flowback was that the natural gas liquids (NGLs) (ethane, propane, butane, etc.) composition was correlated to the CO_2 composition, while methane composition had the opposite effect (Figure 4.5). As CO_2 composition decreased, methane composition increased and the heavier hydrocarbon decreased. It would appear that the CO_2 is mobilizing the increased concentrations of NGLs in the gas stream.

5.4. TRACER GASES

Detection of all three injected tracers in the flowback stream indicates a successful injection of tracers to monitor CO_2 injection. The flowback concentrations of the PFTs follow nearly the same trends, but they vary in magnitude. At first glance, it would appear that flow rate has a major impact of the concentration of the tracers, as the concentration over time curve follows a typical flow rate decline curve. However, using standard statistical data analysis to correlate all three tracer concentrations to flow rate, CO_2 flow rate, %CO_2 composition, and %CH_4 composition had negative results. Using a nonparametric test such as the Spearman's rank (rho) correlation determined that, while there is no correlation of tracer concentration to flow rate, there is a positive trend.

The amount of PMCH recovered in the flowback stream most nearly matches the 35% of the CO_2 that has been reproduced. The amount of PMCP and SF_6 recovered is much lower. This could be due to the fact that those tracers are smaller and were injected early during the test. Therefore, they could have made it farther into the reservoir and could more adsorbed within the system. This could also be due to the fact that SF_6 and PFTs are much more soluble in CO_2 than water. The fact that the PMCH closely matches the CO_2 reproduced during flowback could be due to the fact that this tracer was injected at the end of the project and had less CO_2 pushed behind it to dilute it, unlike the PMCP and SF_6. More research on the adsorptive properties of fluorinated tracers on the organic matrix of coals and shales needs to be conducted. By understanding this interaction between the two, more detailed and predictive behaviors can be estimated about CO_2 plume movement within the reservoir. Also, more research needs to be done on the solubility properties of fluorinated tracers in CO_2 and CH_4. Finally, more tracers need to be researched to more closely represent the properties and behaviors of the CO_2 molecule within the reservoir of interest.

5.5. FINAL COMMENTS

In conclusion the successful injection and monitoring of a CO_2 injection in an organic shale reservoir is a great accomplishment and milestone for CO_2 – EGR as well as geologic CO_2 storage in unconventional reservoirs. Based on the results from this test, larger scale CO_2 injection tests should be conducted to further test the storage and EGR potential of CO_2 in shale formations. Alternative tests could include a CO_2 injection in an NGL and oil rich shale formation, such as the Utica play in Pennsylvania and Ohio, to test the interaction between CO_2 and liquid condensates. Also, with the advancements in hydraulic fracturing technology, research on using CO_2 as a fracturing medium to enhance initial gas production could be conducted.

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APPENDIX A – WELL COMPOSITION DATA

		HW-1003								
		N2	CO2	Methane	Ethane	Propane	Butane Total	Pentane Total	Hexane	% CH's
	10/17/13 12:00 PM	3.80330	0.00690	80.96793	11.70470	2.72853	0.59887	0.12590	0.05727	96.18321
	10/18/13 12:00 PM	3.05620	0.00795	81.64435	11.75960	2.74685	0.60080	0.12605	0.05810	96.93575
Baseline	12/14/13 12:00 PM	3.05629	0.01519	82.04221	11.43995	2.69221	0.57170	0.11970	0.06278	96.92855
	1/17/14 12:00 PM	3.14406	0.01118	81.75309	11.59842	2.72135	0.58784	0.12230	0.06061	96.84361
	3/17/14 12:00 PM	2.17135	0.00050	80.09227	13.71568	3.15733	0.63873	0.11334	0.11078	97.82813
	4/1/14 12:00 PM	0.45883	99.39046	0.00000	0.85170	0.00000	0.01036	0.00557	0.00000	0.86763
	4/3/14 12:00 PM	1.26788	98.66450	0.00000	0.03405	0.00000	0.00149	0.00000	0.00000	0.03554
	4/4/14 12:00 PM	1.27057	98.37734	0.00000	0.26631	0.02116	0.02112	0.00657	0.00000	0.31516
	4/23/14 12:00 PM	0.36388	99.57924	0.00000	0.02666	0.00000	0.00072	0.00000	0.00000	0.02738
	4/28/14 12:00 PM	0.56251	99.27085	0.00000	0.12157	0.00000	0.00990	0.00365	0.00000	0.13512
	5/1/14 12:00 PM	0.12298	99.84242	0.00000	0.00753	0.00000	0.00000	0.00000	0.00000	0.00753
Soaking	5/2/14 12:00 PM	0.10634	99.85603	0.00000	0.00879	0.00000	0.00101	0.00000	0.00000	0.00980
	5/5/14 12:00 PM	0.13491	99.82160	0.00000	0.01144	0.00000	0.00136	0.00000	0.00000	0.01280
	5/7/14 12:00 PM	0.58144	99.25418	0.00000	0.09590	0.00000	0.01520	0.00889	0.00000	0.11999
	6/23/14 12:00 PM	1.30869	98.67314	0.00000	0.00750	0.00000	0.00000	0.00000	0.00000	0.00750
	6/25/14 12:00 PM	0.21504	99.76517	0.00000	0.00994	0.00000	0.00000	0.00000	0.00000	0.00994
	6/30/14 12:00 PM	0.86895	99.10453	0.00000	0.01438	0.00000	0.00118	0.00000	0.00000	0.01556
	7/2/14 12:00 PM	1.94707	97.99815	0.00000	0.04162	0.00000	0.00380	0.00000	0.00000	0.04542
Flowback	7/29/14 8:45 AM	2.89875	96.60768	0.00000	0.41359	0.03726	0.06818	0.00570	0.00000	0.52473
	7/29/14 9:00 AM	2.18448	96.93302	0.00000	0.71320	0.10534	0.03903	0.00923	0.00000	0.86680

	7/29/14 10:00 AM	2.55859	34.34177	54.60373	6.54319	1.50678	0.34342	0.06701	0.03552	63.09965
	7/29/14 11:00 AM	2.10156	41.29845	48.61678	6.04825	1.45408	0.35326	0.07503	0.05259	56.59999
	7/29/14 11:30 AM	1.79018	43.50862	46.54453	6.17450	1.49680	0.36511	0.07695	0.04329	54.70118
	7/29/14 2:00 PM	2.24860	43.43091	46.19206	6.17971	1.47846	0.35532	0.07686	0.03817	54.32058
	7/29/14 2:30 PM	1.63225	43.30987	46.37785	6.55091	1.60327	0.39075	0.08771	0.04740	55.05789
	7/29/14 3:00 PM	1.60997	44.29565	46.19206	6.57321	1.62315	0.39930	0.08983	0.04868	54.92623
	7/29/14 3:30 PM	1.56533	44.65918	44.97284	6.62264	1.64013	0.40206	0.08994	0.04787	53.77548
	7/29/14 4:00 PM	1.48819	45.79215	43.88902	6.63254	1.65607	0.40429	0.08989	0.04721	52.71902
	7/29/14 4:30 PM	1.46766	46.13385	43.48252	6.68949	1.67802	0.41098	0.09110	0.04637	52.39848
	7/29/14 5:00 PM	1.42596	46.58606	42.98304	6.75215	1.69312	0.41860	0.09329	0.04778	51.98798
	7/29/14 5:30 PM	1.40966	46.95986	42.52888	6.81205	1.72398	0.42369	0.09444	0.04745	51.63049
	7/29/14 6:00 PM	1.37266	47.27083	42.17428	6.86997	1.73880	0.43032	0.09586	0.04728	51.35651
	7/29/14 7:00 PM	1.31613	47.78743	41.56243	6.96552	1.78446	0.43981	0.09752	0.04670	50.89644
	7/29/14 8:00 PM	1.46811	50.13479	39.38328	6.75313	1.70395	0.41967	0.09114	0.04594	48.39711
	7/29/14 10:00 PM	1.20262	50.44552	39.17551	6.85682	1.74603	0.43126	0.09417	0.04806	48.35185
	7/30/14 2:00 AM	1.12504	50.81804	38.69213	6.98127	1.79255	0.44587	0.09731	0.04777	48.05690
	7/30/14 7:00 AM	1.05686	51.34948	37.97933	7.13707	1.85745	0.46420	0.10213	0.05348	47.59366
	7/30/14 9:00 AM	1.05993	51.49281	37.74348	7.19148	1.87977	0.46970	0.10298	0.05985	47.44726
	7/30/14 11:00 AM	1.03141	51.63962	37.56964	7.23542	1.88537	0.47470	0.10432	0.05951	47.32896
	7/30/14 12:00 PM	1.02428	51.69974	37.48285	7.25715	1.89369	0.47681	0.10488	0.06059	47.27597
	7/30/14 1:00 PM	1.00358	51.78706	37.36985	7.28062	1.90604	0.48113	0.10611	0.06560	47.20935
	7/30/14 1:30 PM	0.99781	51.83794	37.33851	7.29159	1.89833	0.47467	0.10239	0.05876	47.16425
	7/30/14 2:00 PM	1.01434	51.81408	37.30088	7.32134	1.91334	0.47526	0.10325	0.05750	47.17157
	7/30/14 3:00 PM	0.99077	51.79635	37.32425	7.32718	1.92141	0.47780	0.10399	0.05825	47.21288
	7/30/14 4:00 PM	0.98249	51.74448	37.37148	7.34831	1.91379	0.47755	0.10401	0.05790	47.27304
	7/30/14 5:00 PM	0.98915	51.63718	37.46905	7.34972	1.91529	0.47875	0.10391	0.05694	47.37366
	7/30/14 6:00 PM	0.98598	51.58401	37.51533	7.35594	1.91779	0.47990	0.10425	0.05680	47.43001
	7/30/14 8:00 PM	1.12383	50.89613	37.94522	7.43807	1.95902	0.48618	0.10594	0.04561	47.98004
	7/30/14 9:00 PM	0.99857	50.96889	37.98285	7.46039	1.95236	0.48787	0.10623	0.04285	48.03255
	7/30/14 10:00 PM	0.99192	50.99100	37.95641	7.46878	1.95553	0.48893	0.10579	0.04162	48.01706
	7/30/14 11:00 PM	1.00159	50.97940	37.93946	7.47944	1.95925	0.49079	0.10678	0.04329	48.01901
	7/31/14 3:00 AM	1.15470	51.57651	37.26962	7.40747	1.94544	0.48804	0.10665	0.05157	47.26879
	7/31/14 8:00 AM	0.99353	51.73776	37.17371	7.47448	1.96490	0.49528	0.10822	0.05213	47.26872
	7/31/14 10:00 AM	1.00360	50.80729	37.85612	7.63824	2.02230	0.50534	0.10958	0.05753	48.18911

	7/31/14 11:00 AM	0.97143	50.85292	37.83012	7.64850	2.02030	0.50509	0.10964	0.06199	48.17564
	7/31/14 12:00 PM	0.96273	50.84900	37.80657	7.67043	2.02926	0.50771	0.10987	0.06443	48.18827
	7/31/14 2:00 PM	0.96689	50.82863	37.80150	7.68518	2.03470	0.50897	0.11000	0.06414	48.20449
	7/31/14 4:00 PM	0.96399	50.89322	37.75079	7.67939	2.03191	0.50822	0.11023	0.06224	48.14278
	8/1/14 8:00 AM	0.95318	50.87628	37.76730	7.68225	2.03639	0.51046	0.11054	0.06716	48.17410
	8/1/14 10:00 AM	0.93860	51.04375	37.35345	7.85765	2.10542	0.52932	0.11536	0.05644	48.01764
	8/5/14 12:00 PM	1.25640	42.43414	46.58014	7.34441	1.79663	0.42533	0.09060	0.07235	56.30946
	8/6/14 1:08 PM	0.86299	46.79152	42.29018	7.52992	1.89511	0.45878	0.09865	0.07285	52.34549
	8/7/14 12:15 PM	0.80461	46.80235	42.31601	7.54103	1.90599	0.45932	0.10476	0.07152	52.39863
	8/8/14 10:30 AM	0.69103	48.29517	40.29744	7.95530	2.06169	0.50737	0.11049	0.08150	51.01379
	8/11/14 2:30 PM	0.80230	47.64083	39.96545	8.55646	2.28971	0.56734	0.12395	0.05395	51.55686
	8/12/14 12:00 PM	0.67810	47.82016	39.67541	8.70643	2.34889	0.58631	0.12894	0.05576	51.50174
	8/13/14 2:00 PM	0.64464	47.91433	39.32203	8.88307	2.42937	0.61285	0.13611	0.05760	51.44103
	8/14/14 2:30 PM	0.66602	47.82801	39.11084	9.05827	2.50167	0.63425	0.14139	0.05954	51.50596
	8/15/14 2:00 PM	0.63711	47.68963	39.02830	9.21789	2.56694	0.65364	0.14575	0.06074	51.67326
	8/18/14 1:00 PM	0.64741	45.86581	40.58229	9.40988	2.61668	0.66555	0.14946	0.06293	53.48679
	8/19/14 9:00 AM	0.65494	45.39198	41.00408	9.44852	2.62460	0.66534	0.14865	0.06190	53.95309
	8/20/14 12:40 PM	0.69739	44.61165	41.68839	9.48250	2.63553	0.67051	0.15049	0.06353	54.69095
	8/21/14 8:30 AM	0.71426	44.03856	42.20534	9.52293	2.63710	0.66880	0.14959	0.06342	55.24718
	8/22/14 11:50 AM	0.71361	43.62225	42.54272	9.57693	2.65583	0.67381	0.15151	0.06333	55.66413
	8/26/14 12:30 AM	0.76604	41.83334	44.08069	9.72870	2.69623	0.67922	0.15150	0.06401	57.40035
	8/28/14 11:11 AM	1.05085	40.31460	44.63094	9.66364	2.69777	0.67438	0.13645	0.06887	57.87205
	8/29/14 12:52 PM	1.05434	40.41612	45.13952	9.78016	2.72378	0.67918	0.13708	0.06981	58.52953
	9/3/14 12:00 PM	1.07712	37.91961	47.48338	9.92663	2.71841	0.67210	0.13419	0.06859	61.00330
	9/4/14 1:45 PM	1.10640	37.90854	47.46722	9.92417	2.72235	0.67015	0.13407	0.06711	60.98507
	9/5/14 10:30 AM	1.13544	36.70472	48.52399	10.01433	2.73784	0.67691	0.13621	0.07057	62.15985
	9/8/14 2:25 PM	1.18620	36.67345	48.51332	10.01229	2.73669	0.67585	0.13517	0.06701	62.14033
	9/9/14 9:30 AM	1.16862	35.82395	49.24431	10.12192	2.76101	0.67926	0.13515	0.06577	63.00742
	9/10/14 11:45 AM	1.15547	35.80996	49.26894	10.12411	2.76109	0.67914	0.13498	0.06629	63.03455
	9/11/14 12:50 PM	1.38808	35.74907	49.11671	10.10419	2.75982	0.67987	0.13584	0.06642	62.86285
	9/17/14 11:45 AM	1.96630	31.76030	52.27251	10.40200	2.73798	0.65379	0.13470	0.07243	66.27341
	9/18/14 9:30 AM	1.35190	31.86322	52.69746	10.44860	2.76139	0.66387	0.13928	0.07426	66.78486
	9/19/14 1:45 PM	1.31389	31.88671	52.70332	10.45699	2.76087	0.66571	0.14070	0.07830	66.80589
	9/22/14 8:50 AM	1.29358	31.88826	52.71686	10.45906	2.76085	0.66551	0.14072	0.07516	66.81816

	9/23/14 11:30 AM	1.28257	31.90040	52.72152	10.45672	2.76106	0.66506	0.14045	0.07221	66.81702
	9/24/14 2:00 PM	1.27318	31.88598	52.73251	10.45738	2.77052	0.66609	0.14113	0.07321	66.84084
	9/25/14 1:30 PM	1.26868	31.89464	52.73260	10.45760	2.76398	0.66677	0.14193	0.07382	66.83670
	9/26/14 1:40 PM	1.26714	31.89037	52.74528	10.45237	2.76363	0.66654	0.14215	0.07252	66.84249
	10/3/14 2:00 PM	1.26100	32.06908	52.54573	10.46972	2.77298	0.66768	0.14172	0.07210	66.66993
	10/22/14 11:45 AM	1.77865	24.65641	59.00529	10.89983	2.81017	0.65786	0.13605	0.05574	73.56494
	10/27/14 9:30 AM	1.28976	22.87969	62.15087	10.19683	2.66177	0.63212	0.13149	0.05747	75.83055
	11/6/14 2:30 PM	2.03894	22.61915	61.04594	10.71445	2.74498	0.64336	0.13500	0.05818	75.34191
	11/18/14 11:00 AM	2.00183	24.04358	59.74129	10.64201	2.74260	0.64234	0.13274	0.05361	73.95459
	11/21/14 10:00 AM	1.83576	23.67693	59.95631	10.74602	2.87099	0.70022	0.15034	0.06343	74.48731
	11/28/14 9:25 AM	1.44073	18.53571	65.30653	11.08262	2.78597	0.64472	0.13729	0.06429	80.02142
	12/4/14 12:45 PM	1.48613	18.48124	65.34370	11.06822	2.77512	0.64119	0.13797	0.06608	80.03228
	12/11/14 1:45 PM	2.03724	18.45062	64.87125	11.01221	2.77631	0.64612	0.13871	0.06755	79.51215
	12/17/14 10:20 AM	1.53516	18.25673	65.51170	11.07057	2.78271	0.64435	0.13724	0.06197	80.20854
	12/22/14 11:45 AM	1.99382	18.00011	65.70611	10.75263	2.70939	0.63111	0.13709	0.06974	80.00607
	1/2/15 1:50 PM	2.38628	14.10555	69.09844	10.95129	2.66924	0.60385	0.12595	0.05940	83.50817
	1/9/15 10:30 AM	2.26298	13.36345	70.01159	10.93392	2.64497	0.59698	0.12595	0.06016	84.37357
	1/13/15 11:00 AM	1.46970	13.39531	70.66689	11.02704	2.65664	0.59562	0.12571	0.06308	85.13498
	1/19/15 11:45 AM	2.12113	12.85876	69.12334	10.72860	2.50563	0.60317	0.15433	0.02662	83.14169
	1/30/15 10:00 AM	2.34128	11.84142	68.55697	10.61839	2.47768	0.59887	0.15364	0.02656	82.43211
	2/3/15 12:30 PM	3.01464	11.20856	72.06176	10.48164	2.49500	0.55942	0.11556	0.06342	85.77680
	2/6/15 1:45 AM	3.36807	11.18104	71.80258	10.42409	2.47491	0.55387	0.11283	0.05505	85.42333
	2/13/15 9:30 AM	2.78606	11.23934	72.29026	10.46513	2.48502	0.55844	0.11495	0.06081	85.97461
	2/24/15 9:45 AM	2.36557	12.15121	71.14771	10.98736	2.55220	0.61177	0.15698	0.02718	85.48320
	2/26/15 10:30 AM	3.67086	11.00215	71.78806	10.37072	2.46033	0.54500	0.11067	0.05221	85.32699

APPENDIX B – CO_2 INJECTION DATA

Date & Time	Flow Rate (Tons/Day)	Heater Output (°F)	Cumulative Tons	Wellhead Pressure (psig)
3/19/14 6:00 AM	0	72.55794767	0	0.904409755
3/19/14 7:00 AM	11.63935594	68.84379457	0.448717952	128.1819902

3/19/14 8:00 AM	26.50740215	87.22212294	1.55128932	168.2077235
3/19/14 9:00 AM	24.62001149	94.97468864	2.598288298	171.4614214
3/19/14 10:00 AM	23.55342017	111.9310202	3.581173658	174.4803277
3/19/14 11:00 AM	27.64436602	112.2482728	4.76063633	176.2230358
3/19/14 12:00 PM	28.62369521	88.46297248	5.961465836	183.0484527
3/19/14 1:00 PM	27.40305211	111.8011763	7.115287781	186.5718902
3/19/14 2:00 PM	27.85586712	111.4305724	8.286203384	189.8673589
3/19/14 3:00 PM	8.31035355	31.90700399	9.042597771	56.36755655
3/19/14 4:00 PM	19.36536024	79.00770377	9.457118988	136.9955316
3/19/14 5:00 PM	26.93692972	112.2499005	10.58957386	194.8171506
3/19/14 6:00 PM	26.34861554	112.3029548	11.69638824	196.784286
3/19/14 7:00 PM	26.81243472	108.3221606	12.81602287	199.2510048
3/19/14 8:00 PM	26.66964203	100.7844525	13.9356575	202.3032964
3/19/14 9:00 PM	25.97973572	104.6025357	15.02965164	204.3768902
3/19/14 10:00 PM	35.32034168	57.37690868	16.51264	210.4659527
3/19/14 11:00 PM	29.55913734	26.11606596	17.75648117	213.7707964
3/20/14 12:00 AM	28.03461369	58.68098674	18.94048119	214.5366298
3/20/14 1:00 AM	29.49260342	44.43193107	20.18432236	216.8083485
3/20/14 2:00 AM	28.80410437	44.47132969	21.38969421	218.6619943
3/20/14 3:00 AM	28.03640482	45.18679824	22.56941986	220.0927235
3/20/14 4:00 AM	27.44015751	47.37575172	23.72777367	221.4607964
3/20/14 5:00 AM	26.49946846	46.83980633	24.83910942	222.6653277
3/20/14 6:00 AM	25.62659396	48.85815057	25.91625023	223.7809527
3/20/14 7:00 AM	24.7336316	51.08714542	26.95919609	224.9578798
3/20/14 8:00 AM	25.72716268	48.0866009	28.04061127	226.3548068
3/20/14 9:00 AM	26.09143599	44.8974754	29.13912392	228.3400152
3/20/14 10:00 AM	28.18508274	48.44542896	30.3273983	229.6378277
3/20/14 11:00 AM	30.77491882	48.84663226	31.61825752	232.3787652
3/20/14 12:00 PM	27.01395552	55.70981728	32.75490189	235.2477756
3/20/14 1:00 PM	32.12133698	52.40226792	34.10499954	238.6268902
3/20/14 2:00 PM	35.15298304	52.18970543	35.58327103	242.4522027
3/20/14 3:00 PM	38.63386345	46.74129088	37.20680618	246.5149631
3/20/14 4:00 PM	41.00541692	51.11177305	38.92433548	249.3583485
3/20/14 5:00 PM	42.17552023	52.57951264	40.69740677	252.489964
3/20/14 6:00 PM	41.86319389	52.17156995	42.45338821	254.7086739
3/20/14 7:00 PM	40.25882862	53.74756743	44.14955521	256.5741448
3/20/14 8:00 PM	38.57961194	47.71533779	45.7688179	257.8575302
3/20/14 9:00 PM	36.25847105	45.1342281	47.29408646	258.5272178
3/20/14 10:00 PM	34.1744217	45.83107437	48.72963333	258.2812802
3/20/14 11:00 PM	32.6211096	42.2192202	50.10536575	258.1875302
3/21/14 12:00 AM	29.28161404	43.72343918	51.34010696	257.8104469

3/21/14 1:00 AM	26.96712641	41.81565792	52.47658157	257.1141969
3/21/14 2:00 AM	22.62795807	48.91739532	53.4250679	256.4645094
3/21/14 3:00 AM	22.11091235	44.08930629	54.36500931	251.9685193
3/21/14 4:00 AM	21.36509162	49.55789267	55.26649857	255.2734671
3/21/14 5:00 AM	20.58242155	50.9669162	56.12953568	254.5956001
3/21/14 6:00 AM	20.52868243	44.3922387	56.98830032	254.0483057
3/21/14 7:00 AM	19.21310031	43.08661098	57.79579544	253.5890286
3/21/14 8:00 AM	18.89117807	40.11683493	58.59474564	253.2244943
3/21/14 9:00 AM	26.89995291	47.57161663	59.71840286	254.8793988
3/21/14 10:00 AM	35.25380768	48.15681963	61.20521927	261.9033636
3/21/14 11:00 AM	35.20761747	49.31747085	62.67921829	266.2839886
3/21/14 12:00 PM	38.07984023	55.03509602	64.28566742	269.2464365
3/21/14 1:00 PM	40.90830286	53.94806479	66.00746918	275.3848219
3/21/14 2:00 PM	42.04641818	53.2739346	67.77199554	280.0112802
3/21/14 3:00 PM	45.16379223	45.98028279	69.67324066	285.0357594
3/21/14 4:00 PM	43.45732293	45.432697	71.49330902	289.4210198
3/21/14 5:00 PM	39.02449504	46.51128295	73.13393402	292.4433636
3/21/14 6:00 PM	41.52182318	45.55426726	74.87709808	295.1519052
3/21/14 7:00 PM	40.41403111	43.78101728	76.57753754	297.5284677
3/21/14 8:00 PM	39.31430266	43.42572292	78.22670746	299.3265407
3/21/14 9:00 PM	38.27598644	42.00471518	79.83742523	300.4499261
3/21/14 10:00 PM	36.70463275	46.50638449	81.37978363	301.1013844
3/21/14 11:00 PM	36.16250887	42.91882964	82.90077972	302.2258115
3/22/14 12:00 AM	34.33538272	45.31616824	84.34059906	302.3716969
3/22/14 1:00 AM	32.74496503	46.91431432	85.72060394	302.8777386
3/22/14 2:00 AM	31.47007101	55.33191377	87.04506683	302.9815407
3/22/14 3:00 AM	31.49412576	53.55971329	88.36952972	303.2865927
3/22/14 4:00 AM	31.4131335	47.17332185	89.68972015	303.8814365
3/22/14 5:00 AM	29.95667813	48.96536133	90.94582367	304.2033636
3/22/14 6:00 AM	28.74140908	55.68614822	92.15493011	303.7677386
3/22/14 7:00 AM	28.82022617	47.28539528	93.36830902	304.2474261
3/22/14 8:00 AM	28.27682279	43.25179577	94.56032562	304.1020094
3/22/14 9:00 AM	27.36185204	44.56755889	95.70961761	303.9733115
3/22/14 10:00 AM	27.39524695	47.95027024	96.86318207	304.277374
3/22/14 11:00 AM	31.99082756	49.57368952	98.2047348	306.5078427
3/22/14 12:00 PM	33.50396446	49.01506442	99.61464691	308.9331552
3/22/14 1:00 PM	34.61111527	46.36397318	101.0715561	311.2532594
3/22/14 2:00 PM	35.37395293	45.58444165	102.5583725	313.3943011
3/22/14 3:00 PM	34.81417201	57.76192155	104.0195541	314.4630511
3/22/14 4:00 PM	36.43721721	45.63990542	105.5576401	317.4285198
3/22/14 5:00 PM	36.61276492	43.49355604	107.0871811	319.4083636

3/22/14 6:00 PM	34.74917296	49.7497673	108.5440903	319.7234677
3/22/14 7:00 PM	30.22588494	43.36132979	109.8172836	319.0706552
3/22/14 8:00 PM	34.31209599	61.65068982	111.257103	320.6200823
3/22/14 9:00 PM	40.13740347	50.25223376	112.944725	325.1364365
3/22/14 10:00 PM	40.58778781	43.67953016	114.6537094	328.2765407
3/22/14 11:00 PM	40.46418806	39.76172012	116.3498764	329.8083636
3/23/14 12:00 AM	36.85215907	41.52468927	117.8922348	330.2448219
3/23/14 1:00 AM	36.41828048	40.65518885	119.4260483	330.9229469
3/23/14 2:00 AM	34.32425114	41.20255615	120.8658676	331.0612802
3/23/14 3:00 AM	32.62955374	41.48910318	122.2373276	330.9865927
3/23/14 4:00 AM	31.0843017	42.69242083	123.5447006	330.9494573
3/23/14 5:00 AM	30.08258101	47.76882982	124.8093491	330.6328427
3/23/14 6:00 AM	31.10362232	45.56208504	126.125267	330.9115927
3/23/14 7:00 AM	31.93017917	40.06663684	127.4710922	331.6588323
3/23/14 8:00 AM	30.03434395	41.34392607	128.7314758	331.4831032
3/23/14 9:00 AM	27.63847975	44.48424384	129.8850403	331.1866448
3/23/14 10:00 AM	27.74160774	42.82982979	131.0556946	330.8019052
3/23/14 11:00 AM	26.83009164	47.00018142	132.1836243	330.7281032
3/23/14 12:00 PM	26.98081697	51.65013234	133.3158264	330.9250302
3/23/14 1:00 PM	28.42805958	56.92721602	134.5163879	331.5496657
3/23/14 2:00 PM	35.2799098	54.60104357	135.9989319	334.0868011
3/23/14 3:00 PM	46.25008672	41.74113682	137.9429016	340.6172177
3/23/14 4:00 PM	43.9743689	46.08164755	139.7928772	344.9157073
3/23/14 5:00 PM	44.91851152	44.49536874	141.6813049	348.0214365
3/23/14 6:00 PM	44.54208327	43.72610301	143.5526428	350.7890928
3/23/14 7:00 PM	41.58400639	44.96220998	145.3000793	352.2003427
3/23/14 8:00 PM	41.54894891	43.28578793	147.0475159	353.2096136
3/23/14 9:00 PM	38.57270281	43.55554565	148.6667786	353.756749
3/23/14 10:00 PM	36.52371157	43.71213442	150.2048645	353.6672698
3/23/14 11:00 PM	36.51552296	41.88289216	151.738678	353.5376865
3/24/14 12:00 AM	35.94895981	39.06710569	153.2639465	347.6681027
3/24/14 1:00 AM	33.59071493	39.91711102	154.6695862	353.2234677
3/24/14 2:00 AM	28.93077499	41.12617366	155.8829651	352.4922177
3/24/14 3:00 AM	27.771036	40.4390248	157.0365295	351.5495094
3/24/14 4:00 AM	26.07928088	39.46778791	158.1430969	350.0875302
3/24/14 5:00 AM	24.96790757	39.32386586	159.1898499	348.9822698
3/24/14 6:00 AM	19.54116384	48.4731454	160.0016174	347.5314365
3/24/14 7:00 AM	19.85118693	43.60473056	160.8304749	346.0685719
3/24/14 8:00 AM	18.81069744	46.04802003	161.6208801	344.6363844
3/24/14 9:00 AM	22.40877956	45.74547836	162.565094	343.7547177
3/24/14 10:00 AM	27.46869039	48.906088	163.7186584	347.2883115

3/24/14 11:00 AM	0	-11.95464362	163.7186584	-166.1465247
3/24/14 12:00 PM	0	-0.003320734	163.7186584	-0.046151812
3/24/14 1:00 PM	28.775572	30.69271981	165.9446106	256.8131983
3/24/14 2:00 PM	33.96317635	50.56651275	167.375885	366.1127386
3/24/14 3:00 PM	39.88930875	44.91205134	169.0506897	366.4606032
3/24/14 4:00 PM	37.9540651	50.51478589	170.6528625	369.8485721
3/24/14 5:00 PM	42.30602894	41.76325926	172.4430237	362.6858631
3/24/14 6:00 PM	42.44613431	42.45750151	174.2331848	370.1562802
3/24/14 7:00 PM	43.5170749	43.14843893	176.0617981	372.6437802
3/24/14 8:00 PM	43.55661132	44.69494176	177.8904114	375.2758636
3/24/14 9:00 PM	43.32143965	43.64534801	179.7104797	376.6159157
3/24/14 10:00 PM	43.45322794	42.74508477	181.5348206	378.5271657
3/24/14 11:00 PM	43.48252853	41.97818882	183.3634338	379.7777386
3/25/14 12:00 AM	42.53314055	41.12994441	185.153595	381.1075302
3/25/14 1:00 AM	41.71387734	40.32326457	186.905304	381.2450823
3/25/14 2:00 AM	41.08461923	39.29119682	188.6271057	381.6750302
3/25/14 3:00 AM	38.3239686	39.30958739	190.2378235	381.8350302
3/25/14 4:00 AM	31.19139554	41.54015253	191.549469	381.2804469
3/25/14 5:00 AM	31.0854531	40.4820953	192.8525696	378.7111761
3/25/14 6:00 AM	29.67134977	39.99374621	194.0958557	378.7369052
3/25/14 7:00 AM	27.77577062	39.79288158	195.2494202	378.1230511
3/25/14 8:00 AM	20.04848598	42.17432449	196.1039124	376.5445615
3/25/14 9:00 AM	18.36914198	45.44952767	196.8943176	375.2322698
3/25/14 10:00 AM	25.80930683	46.51979865	198.0179749	374.1900302
3/25/14 11:00 AM	34.24325894	44.34861083	199.4663391	375.5940927
3/25/14 12:00 PM	34.58910775	44.58193909	200.9275208	377.2123219
3/25/14 1:00 PM	34.27153573	44.92461103	202.3673401	377.3613323
3/25/14 2:00 PM	42.40941198	39.90350395	204.1446838	380.4852907
3/25/14 3:00 PM	35.1376295	44.06799122	205.6101379	380.8628427
3/25/14 4:00 PM	32.61240812	46.07212634	206.9858704	380.9789886
3/25/14 5:00 PM	33.27621305	45.03882196	208.3829651	381.7791448
3/25/14 6:00 PM	33.82447888	43.92592348	209.7971497	381.644249
3/25/14 7:00 PM	33.72915603	42.64534247	211.2198792	382.2388844
3/25/14 8:00 PM	25.79382465	53.26242126	212.3093567	383.0138323
3/25/14 9:00 PM	23.36482191	57.63042142	213.2877502	381.6464365
3/25/14 10:00 PM	25.93265056	43.86343141	214.4114075	380.3027907
3/25/14 11:00 PM	26.74283	41.69889198	215.5393372	378.8531552
3/26/14 12:00 AM	27.13589252	40.40732965	216.6715393	378.9281552
3/26/14 1:00 AM	26.81998401	39.36495729	217.8037415	379.0318011
3/26/14 2:00 AM	26.51482303	38.52176714	218.9273987	378.7154469
3/26/14 3:00 AM	27.58640421	37.48329314	220.0809631	378.797999

3/26/14 4:00 AM	27.74928507	36.78432199	221.2430725	378.8726344
3/26/14 5:00 AM	27.56401323	36.22044945	222.4051819	378.5244052
3/26/14 6:00 AM	27.8043033	35.32111624	223.5758362	378.4882594
3/26/14 7:00 AM	26.26097042	35.34740521	224.686676	378.627374
3/26/14 8:00 AM	21.93229375	37.59228527	225.6095276	377.3616969
3/26/14 9:00 AM	23.97859821	41.80752769	226.6092834	376.9341969
3/26/14 10:00 AM	39.56777011	44.69447546	228.2712708	380.0878427
3/26/14 11:00 AM	51.08646836	40.72628544	230.4203186	386.9968011
3/26/14 12:00 PM	51.27685922	41.52213183	232.5736389	393.6739365
3/26/14 1:00 PM	49.70806384	42.44546769	234.6671448	397.0430511
3/26/14 2:00 PM	50.53692309	42.88009542	236.7905579	400.1874261
3/26/14 3:00 PM	50.8278819	43.09945458	238.9267883	402.9453427
3/26/14 4:00 PM	50.38312802	43.92701977	241.045929	406.1900823
3/26/14 5:00 PM	49.7602685	44.41166045	243.1351624	408.4539365
3/26/14 6:00 PM	49.43412395	44.64066297	245.2073059	410.7326865
3/26/14 7:00 PM	50.64644834	44.88862147	247.3392639	412.5995094
3/26/14 8:00 PM	50.18199084	44.90203271	249.4498596	414.6521136
3/26/14 9:00 PM	50.59808308	43.85555605	251.5775452	416.2226344
3/26/14 10:00 PM	50.9011962	42.27267333	253.7137756	416.3944052
3/26/14 11:00 PM	51.27737074	40.57672799	255.8713684	416.4231552
3/27/14 12:00 AM	51.27762644	39.41394677	258.0246887	416.6014365
3/27/14 1:00 AM	51.15185089	38.26735562	260.178009	416.6760719
3/27/14 2:00 AM	51.24013694	37.35009503	262.3313293	417.2419052
3/27/14 3:00 AM	50.90887319	36.79814462	264.4718323	418.4510719
3/27/14 4:00 AM	50.97822206	36.43801976	266.6166077	418.9020615
3/27/14 5:00 AM	51.63934151	36.32959804	268.7870178	419.6205511
3/27/14 6:00 AM	51.75859147	36.34504855	270.957428	420.8201344
3/27/14 7:00 AM	51.81361032	36.32229838	273.1321106	421.9712802
3/27/14 8:00 AM	51.05051392	36.72003792	275.2811584	425.4238323
3/27/14 9:00 AM	51.31690776	37.37136874	277.4387512	426.6437802
3/27/14 10:00 AM	46.91350863	39.60530097	279.4126282	431.764874
3/27/14 11:00 AM	47.30912925	41.20743646	281.39505	435.9896657
3/27/14 12:00 PM	48.43828869	42.38337655	283.4415588	437.5329469
3/27/14 1:00 PM	49.1389424	44.04757973	285.5051575	438.2743011
3/27/14 2:00 PM	41.51888029	49.30632493	287.2440491	450.2249261
3/27/14 3:00 PM	48.59694592	48.55167365	289.2991028	439.3326865
3/27/14 4:00 PM	49.60109884	48.22745785	291.3883362	442.2656032
3/27/14 5:00 PM	48.80345938	48.94237741	293.4391174	444.6726344
3/27/14 6:00 PM	48.92833736	48.58403875	295.4984436	438.9615927
3/27/14 7:00 PM	49.73685411	47.90859086	297.587677	442.3016448
3/27/14 8:00 PM	48.99474484	47.72999434	299.6512756	442.9302386

3/27/14 9:00 PM	48.82137088	46.08157977	301.7319641	432.6501337
3/27/14 10:00 PM	49.67019228	47.40984519	303.8211975	443.8844052
3/27/14 11:00 PM	50.11161868	47.26711067	305.9275208	444.2797177
3/28/14 12:00 AM	49.53686829	47.27180877	308.0124817	444.955499
3/28/14 1:00 AM	49.55107089	46.94418366	310.1017151	446.133624
3/28/14 2:00 AM	49.59751676	47.22514458	312.1824036	449.2802907
3/28/14 3:00 AM	49.38256122	47.6636738	314.263092	450.064249
3/28/14 4:00 AM	49.09083522	48.16621053	316.3309631	449.6731552
3/28/14 5:00 AM	49.12487046	48.71505955	318.3945618	451.0786761
3/28/14 6:00 AM	48.92629167	49.02140076	320.4496155	452.678624
3/28/14 7:00 AM	48.77889274	49.18016651	322.5003967	453.9781552
3/28/14 8:00 AM	48.63725212	49.33847099	324.5469055	454.571124
3/28/14 9:00 AM	49.2334994	49.17238267	326.6147766	454.8890407
3/28/14 10:00 AM	49.44832726	49.29090335	328.6911926	456.7215927
3/28/14 11:00 AM	48.9752967	49.67383815	330.7505188	458.0753428
3/28/14 12:00 PM	48.86538743	49.76127823	332.809845	457.7818011
3/28/14 1:00 PM	48.8090892	50.17712453	334.8606262	460.1443011
3/28/14 2:00 PM	48.6554208	54.39519228	336.9028625	464.707374
3/28/14 3:00 PM	48.94778739	55.39698664	338.9621887	461.5090927
3/28/14 4:00 PM	49.81605508	55.31486168	341.0556946	461.4537802
3/28/14 5:00 PM	49.22966141	50.60129932	343.1235657	462.7418011
3/28/14 6:00 PM	49.42248142	48.83966886	345.2042542	464.5493011
3/28/14 7:00 PM	49.66520192	49.12795534	347.2849426	464.5571657
3/28/14 8:00 PM	49.62515397	47.98403856	349.374176	466.0091969
3/28/14 9:00 PM	49.82654675	46.96228279	351.4676819	462.1485719
3/28/14 10:00 PM	49.93555993	46.63918656	353.5611877	460.2347698
3/28/14 11:00 PM	50.05557674	46.26489217	355.6632385	459.0481552
3/29/14 12:00 AM	50.19452995	45.93461853	357.7738342	459.2744052
3/29/14 1:00 AM	49.9763757	45.83576701	359.875885	459.9078948
3/29/14 2:00 AM	50.56712068	45.5763297	361.9992981	459.6068011
3/29/14 3:00 AM	49.85955785	45.80614754	364.0885315	460.7557594
3/29/14 4:00 AM	50.1349053	45.9175977	366.1948547	460.552999
3/29/14 5:00 AM	50.94598028	45.6912384	368.3310852	460.1658636
3/29/14 6:00 AM	50.45541961	45.80426995	370.4544983	461.949874
3/29/14 7:00 AM	50.0371517	45.81542316	372.5565491	461.6297177
3/29/14 8:00 AM	50.13311405	45.67456418	374.6628723	462.5800302
3/29/14 9:00 AM	50.30891732	45.57307201	376.7777405	464.6795615
3/29/14 10:00 AM	49.03287193	45.90524633	378.8413391	465.3168011
3/29/14 11:00 AM	48.26913834	46.58331924	380.8750305	465.041124
3/29/14 12:00 PM	47.99686048	46.74949891	382.8916321	468.0593532
3/29/14 1:00 PM	49.67940317	46.77570466	384.976593	468.0590927

3/29/14 2:00 PM	48.79398952	47.5377625	387.0316467	464.4887803
3/29/14 3:00 PM	48.67410167	47.12871243	389.082428	463.7312802
3/29/14 4:00 PM	49.02148743	46.65679838	391.1417542	465.5640927
3/29/14 5:00 PM	49.13126801	46.19872543	393.2096252	466.0924261
3/29/14 6:00 PM	49.50539296	45.60132961	395.2903137	466.5575302
3/29/14 7:00 PM	49.63948441	44.97302241	397.3795471	466.9608636
3/29/14 8:00 PM	49.9885309	44.65378264	399.4773254	469.3047178
3/29/14 9:00 PM	49.74261181	44.56363175	401.5708313	470.4120615
3/29/14 10:00 PM	49.63500565	44.52228791	403.6515198	471.4375823
3/29/14 11:00 PM	49.45293346	44.46389215	405.7322083	471.7581552
3/30/14 12:00 AM	49.2494938	44.30336093	407.8043518	472.0884677
3/30/14 1:00 AM	49.82795426	44.09338171	409.9021301	472.6990407
3/30/14 2:00 AM	50.26899662	43.79274108	412.0127258	472.4875302
3/30/14 3:00 AM	50.35101243	43.42865276	414.127594	473.0994573
3/30/14 4:00 AM	49.98507636	43.21178038	416.2296448	473.7569573
3/30/14 5:00 AM	49.94912245	43.00047034	418.3274231	472.4588844
3/30/14 6:00 AM	49.82117269	42.72260558	420.420929	472.7458636
3/30/14 7:00 AM	49.43578815	42.55524363	422.497345	473.0262803
3/30/14 8:00 AM	50.38722297	42.22611067	424.6122131	473.714249
3/30/14 9:00 AM	51.39278179	46.59351991	426.7740784	477.067374
3/30/14 10:00 AM	50.86038238	48.63702305	428.9103088	486.6952386
3/30/14 11:00 AM	50.54997439	49.64113758	431.0379944	496.1698219
3/30/14 12:00 PM	50.56801552	50.85057522	433.1614075	506.0156621
3/30/14 1:00 PM	49.89666278	50.89647621	435.2591858	511.9856334
3/30/14 2:00 PM	49.79993311	51.59636695	437.3484192	513.9639147
3/30/14 3:00 PM	60.35887831	49.97881464	439.886261	505.2419117
3/30/14 4:00 PM	62.8285697	49.07553361	442.5266418	500.3681552
3/30/14 5:00 PM	62.8478898	48.23708038	445.1712952	492.6383115
3/30/14 6:00 PM	63.57643675	47.94854398	447.8458557	485.7510719
3/30/14 7:00 PM	62.73516592	47.58752795	450.4862366	483.7083636
3/30/14 8:00 PM	62.1192144	46.86991818	453.1009827	486.1888844
3/30/14 9:00 PM	62.47235588	46.13480872	455.7285461	486.7676344
3/30/14 10:00 PM	64.51174892	45.40421256	458.4372864	487.0116969
3/30/14 11:00 PM	63.91524804	44.53766555	461.1246643	485.9456552
3/31/14 12:00 AM	63.36826272	43.65576712	463.7906799	484.8314365
3/31/14 1:00 AM	63.96783494	42.92810032	466.4780579	483.8193532
3/31/14 2:00 AM	63.20832564	42.25363681	469.1355286	481.0158636
3/31/14 3:00 AM	63.03994331	41.69308492	471.7844543	479.7344052
3/31/14 4:00 AM	63.2712771	41.05488179	474.441925	479.6503948
3/31/14 5:00 AM	63.31183726	40.44084284	477.1079407	477.7564365
3/31/14 6:00 AM	62.17999112	39.26522028	479.7397766	469.6316443

3/31/14 7:00 AM	62.99208995	39.50713957	482.3887024	472.7410719
3/31/14 8:00 AM	62.94756289	39.07007968	485.0376282	471.8750302
3/31/14 9:00 AM	64.34068247	38.69459258	487.7463684	482.9057594
3/31/14 10:00 AM	72.51285058	37.40184272	490.801178	496.6423219
3/31/14 11:00 AM	72.66280886	39.7696265	493.8517151	502.2916969
3/31/14 12:00 PM	71.83471525	41.95968628	496.8680725	499.3432594
3/31/14 1:00 PM	82.71174531	42.47621492	500.3544006	502.9626344
3/31/14 2:00 PM	102.1038456	37.34912132	504.6482239	484.0388844