Selected Field Practices for ECBM Recovery and CO_2 Sequestration in Coals based on Experience Gained at the Allison and Tiffany Units, San Juan Basin

Topical Report

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Executive Summary

In October, 2000, the U.S. Department of Energy, through contractor Advanced Resources International, launched a multi-year government-industry R&D collaboration called the Coal-Seq project. The Coal-Seq project is investigating the feasibility of CO_2 sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operating by BP America, into which N_2 is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, an engineering capability to simulate them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, coal permeability changes due to swelling with CO_2 injection. This report describes the results of an important component of the overall project, the documentation of selected field practices at the Allison & Tiffany Units based on operator experience.

Experience gained from the CO_2/N_2 injection operations at the Allison and Tiffany Units has provided valuable first-of-a-kind experience that will be useful as other companies begin to evaluate CO_2 sequestration in coalseams or ECBM recovery projects. Injection operations at both sites were reliable and safe, and achieved the (operational) objectives required. While future projects in new areas will undoubtably require modification and customization of the procedures presented in this report, it will serve as a useful starting point for facility and operational design.

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1.0 Introduction

In October, 2000, the U.S. Department of Energy (DOE), through contractor Advanced Resources International (ARI), launched a multi-year government-industry R&D collaboration called the Coal-Seq project[1]. The Coal-Seq project is investigating the feasibility of CO_2 sequestration in deep, unmineable coalseams, by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operating by BP America, into which N_2 is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, an engineering capability to simulate them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, coal permeability changes due to swelling with CO_2 injection, and geochemical reactions between injected CO_2 and coal formation water. This report describes the results of an important component of the overall project, the documentation of selected field practices at Allison & Tiffany based on operator experience.

2.0 Allison Unit

2.1 Field Background

The Allison Unit is located in the northern New Mexico portion of the San Juan Basin (Figure 1). The study area of the field, which consists of 16 producer wells, four CO_2 injector wells, and one pressure observation well (Figure 2), began production in July 1989 (Figure 3). Injection operations at the field began in April 1995 and continued almost continuously until August 2001. Operations were suspended at that time to study the results of the pilot.

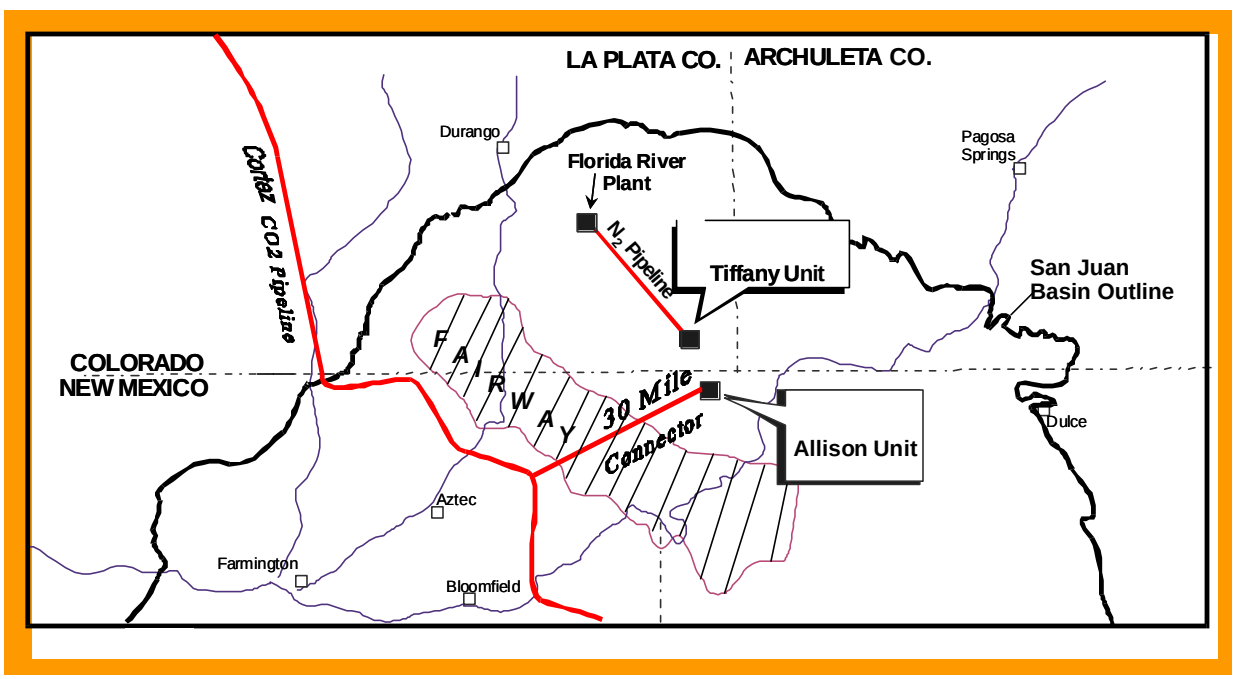

Figure 1: Location of Allison Unit, San Juan Basin

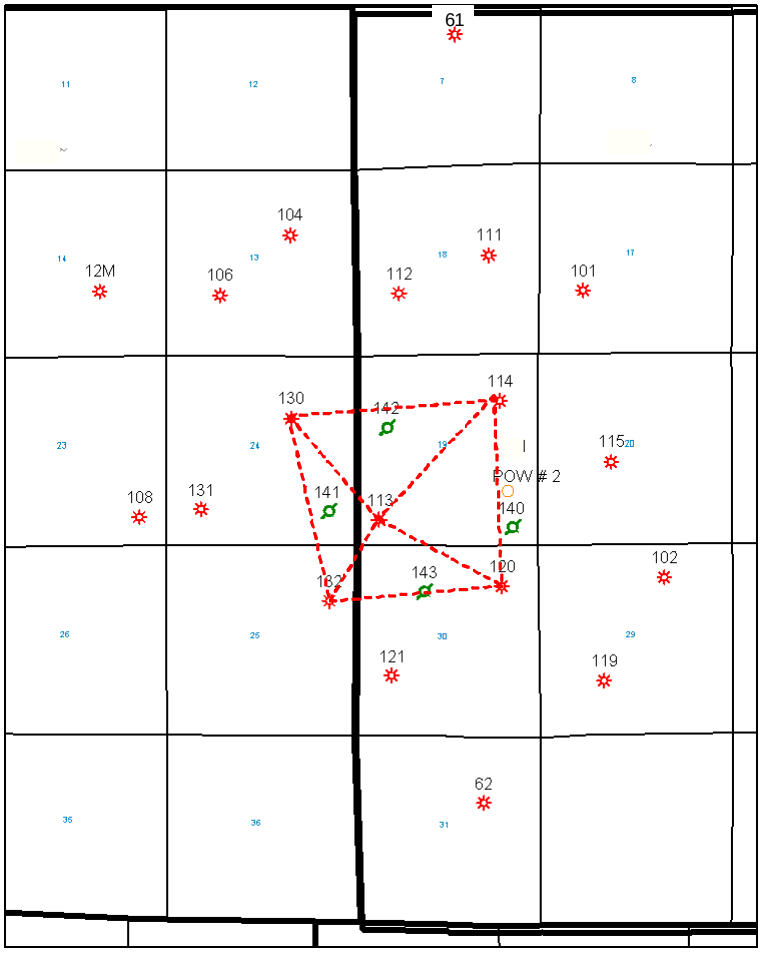

Figure 2: CO_2 Pilot Area, Allison Unit

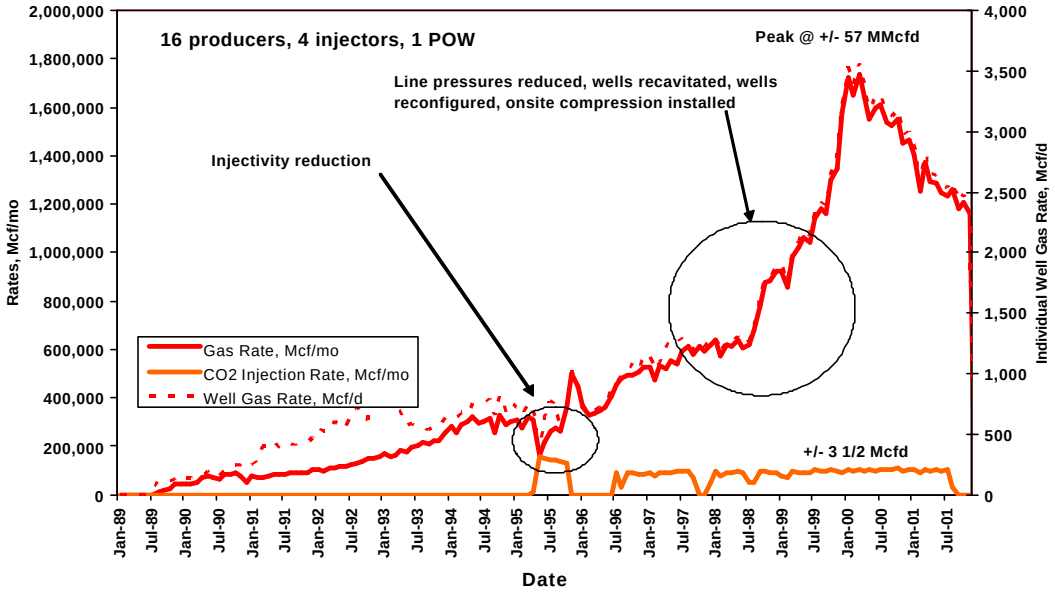

Figure 3: Production/Injection History, Allison CO_2 Flood Pilot

2.2 CO_2 Source & Field Reticulation

The source of the injected CO_2 is the natural CO_2 deposits of McElmo Dome in southwest Colorado. These deposits are tapped by 44 CO_2 producer wells that have a combined capacity to deliver 1.1 Bcfd of nearly-pure CO_2. Kinder Morgan CO_2 operates the 30-inch, 500-mile Cortez pipeline from McElmo Dome to the oilfields of West Texas via the Denver City hub, where it is used for enhanced oil recovery operations. Conveniently, the pipeline passes within 30 miles of the Allison Unit.

Burlington Resources constructed a 4-inch, 36-mile spur to the Allison Unit from the main pipeline. At the tap point, the main line pressure is about 2,200 psi. No compression or flow control facilities are required on the pipeline spur; at the CO_2 injection volumes injected at Allison, which have varied between 2.9 and 5.2 MMcfd in total, the gas can be delivered to the wells at a pressure of about 1,800 psi – greater than that desired (pressure reduction is required at the wellsite) – without compression.

In the field, the gas is delivered to the individual wells by a system of 4-inch steel pipes. This system was originally laid on the surface, however this resulted in a large variability in injection rates with temperature fluctuations (in cold periods, the gas would contract, reducing line pressures and injection volumes; hot periods would produce the opposite effect). Therefore the system was buried in October and November 1997 to eliminate this problem.

2.3 Injection Well Configurations

2.3.1 Well Drilling, Completion & Stimulation

The injection wells were drilled vertically with a standard mud system to a diameter of 7-7/8 inches. The wells were drilled to total depth (though all the target coalseams), and then cased and cemented with 5-1/2 inch steel casing. No special metal alloys were used for the casing, and the cementing practices were standard.

The wells were then perforated in the coal seams, and perforation cleanup treatments performed. Hydraulic fracture nor any other type of massive stimulation was performed to avoid the potential connection with and CO_2 injection into non-coal strata.

2.3.2 Downhole Configuration

The injection wells were configured with 2-7/8 inch steel tubing, internally coated with fiberglass to prevent corrosion, and landed 30-60 feet above the perforations. A seating nipple was installed on the end of the tubing, as were packers that were set prior to injection. The tubing/casing annulus was then filled with a corrosion inhibitor, with a fluid reservoir on the surface to capture overflow and refill voidage with tubing expansion/contraction. A typical downhole wellbore schematic is shown in Figure 4.

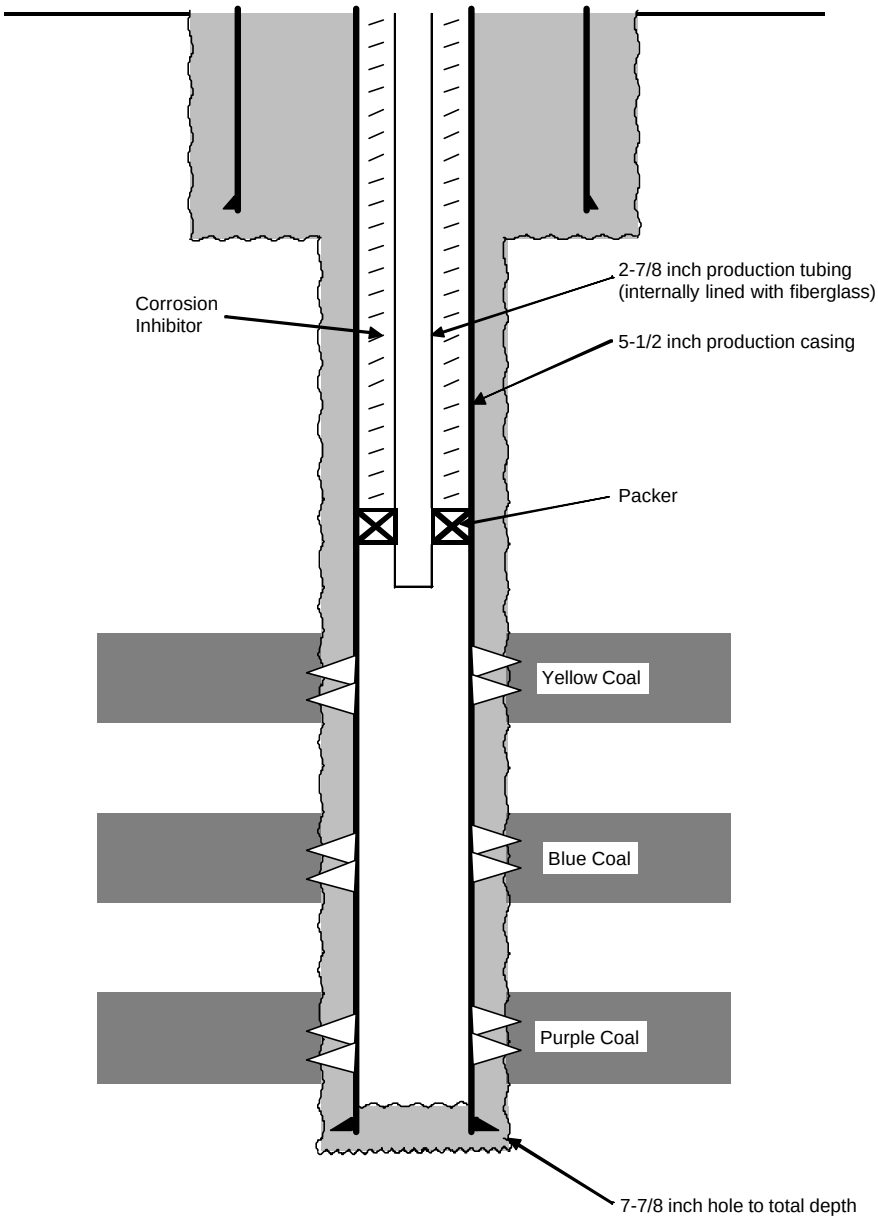

Figure 4: Schematic of Typical Injection Well, Allison Unit

2.3.3 Surface Configuration

A typical surface configuration is shown in Figure 5. The first event that occurs when the CO_2 arrives at the wellsite is that it is passed through an ethylene glycol heating unit that heats the CO_2 to reservoir temperature (about 120 degrees Fahrenheit). This is performed to minimize tubing contraction/expansion during shut-down periods. The heating unit is operated at an elevated pressure, as governed by the pressure regulator located downstream of the unit. The heater is equipped with various safety devices to shut itself down in the case of high pressure, temperature and/or other unsafe conditions (Figure 6). Fuel to the unit comes from a 2-inch line connected to the gas gathering system; each unit requires about 10 Mcfd of gas to operate.

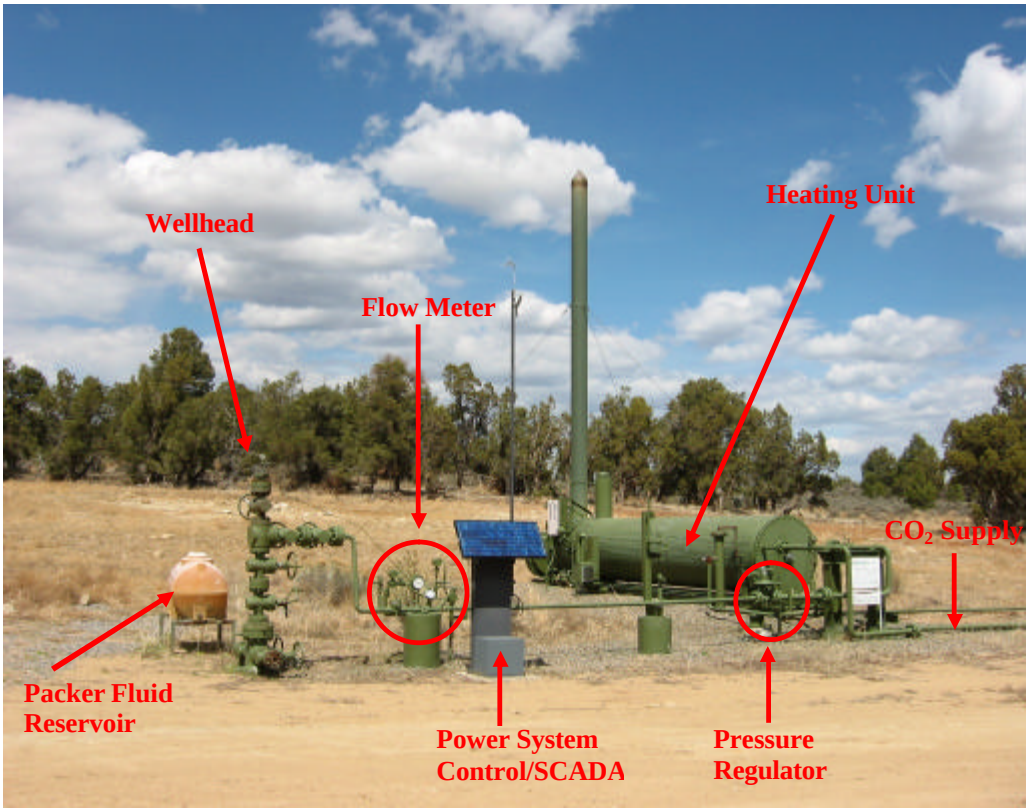

Figure 5: Typical Injection Well Surface Configuration, Allison Unit

Figure 6: Alarm Panel on the CO_2 Heating Unit, Allison Unit

The pressure regulator maintains downstream pressure at a constant level, consistent with the gas injection objectives for each individual well. Typically they are set to maintain downstream (wellhead) pressure in the 1,300 – 1,600 psi range. Based on downhole pressure measurements taken just prior to the wells being shut-in in August 2001, bottomhole pressures at a depth of about 3,100 feet were close to 2,500 psi. Hence, injection is achieved at a constant bottomhole pressure, with injection rate being allowed to vary. This approach is much easier operationally than trying to maintain a constant injection rate. A plot of computed bottomhole injection pressure and injection rate for one of the CO_2 injectors is provided in Figure 7. Note the significant decline in injection rate in early time due to matrix swelling and permeability reduction, and then increasing again at later times as this effect is gradually reversed with reservoir pressure depletion.

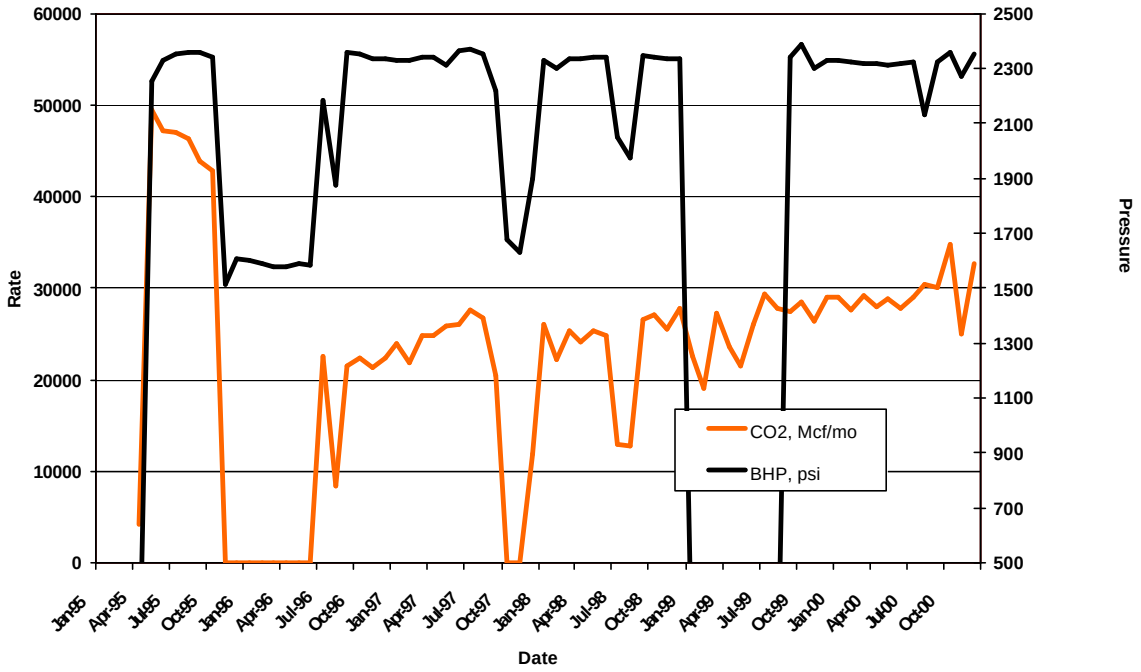

Figure 7: Computed Bottomhole Injection Pressure and Injection Rate History for a CO_2 Injector Well, Allison Unit

Downstream of the pressure regulator is the flow metering device. A SCADA system, solar powered with battery backup, transmits flow rate, pressure and temperature information at regular intervals to a central data gathering facility. Pressure regulation is also remotely enabled via the SCADA system, as are the alarms to immediately alert the operator of any critical events at the well.

2.4 Production Well Configurations

The production wells were drilled, completed, stimulated and equipped similar to many other coalbed methane wells in the San Juan Basin. At Allison, for the most part the coal intervals were top-set with 7-inch casing cemented into place, then the coals drilled underbalanced (with water) with a 6-¼ inch bit. Upon reaching total depth, the wells were stimulated via cavitation and pre-perforated, 5-½ inch liners set (but not cemented) into place. A typical downhole well schematic for a production well is provided in Figure 8. Originally the wells were configured with a tubing/packer arrangement and produced on natural flow, but later downhole rod pumps and pump jacks were installed for more effective well dewatering (as shown in Figure 9).

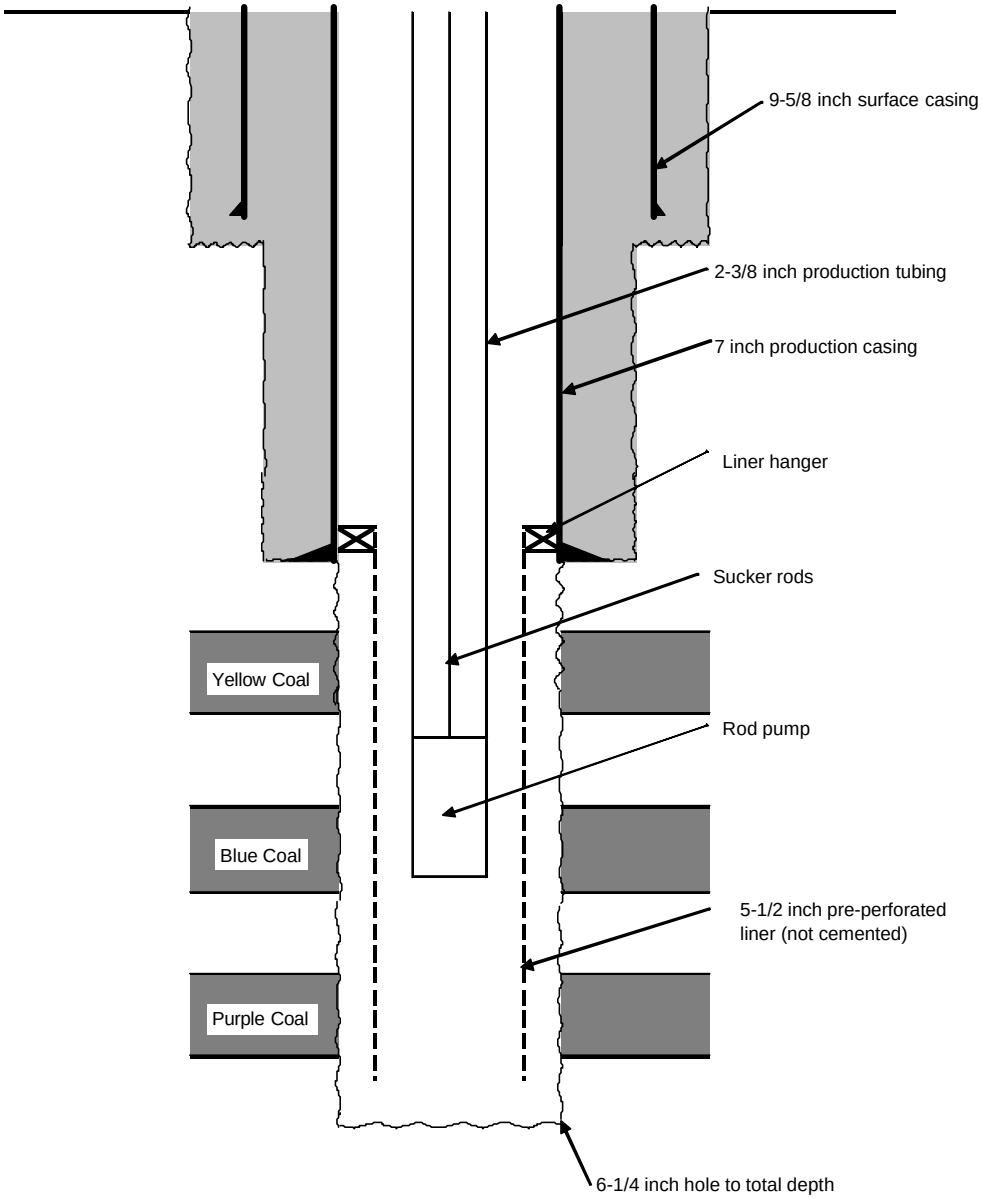

Figure 8: Schematic of Production Well, Allison Unit

Figure 9: Typical Production Well Surface Configuration, Allison Unit

Surface production equipment includes a gas/water separator (Figure 10), surface pressure regulation, gas flow meter (also connected to a central data gathering facility via a SCADA system), Figure 11, produced water storage (the water was periodically trucked off-site to a disposal well), Figure 12, and in some cases on-site compression is employed (Figure 13).

Figure 10: Gas/Water Separator, Allison Unit Production Well

Figure 11: Gas Flow Meter, Allison Unit Production Well

Figure 12: Produced Water Storage, Allison Unit Production Well

Figure 13: On-Site Compressor, Allison Unit Production Well

Gas is transported from the wellsite to a central gathering and processing facility where it is dehydrated, CO_2 removed, and compressed for transmission. Since the in-situ CO_2 content of the adsorbed gas for the reservoir coals in the Allison Unit area is on the order of 15%, and increasing volumes of CO_2 production are being routinely handled (via amine separation) as a by-product of primary production, no new or special facilities were required to handle any CO_2 produced as a result of CO_2 injection.

3.0 Tiffany Unit

3.1 Field Background

The Tiffany Unit is located in the southern Colorado portion of the San Juan Basin (Figure 1). The study area of the field, which consists of 34 producer wells and 12 nitrogen injector wells (Figure 14), began production in September 1983 (Figure 15). Injection operations at the field began in February 1998 and continued intermittently until January 2002. Operations were suspended at that time to study the results of the pilot.

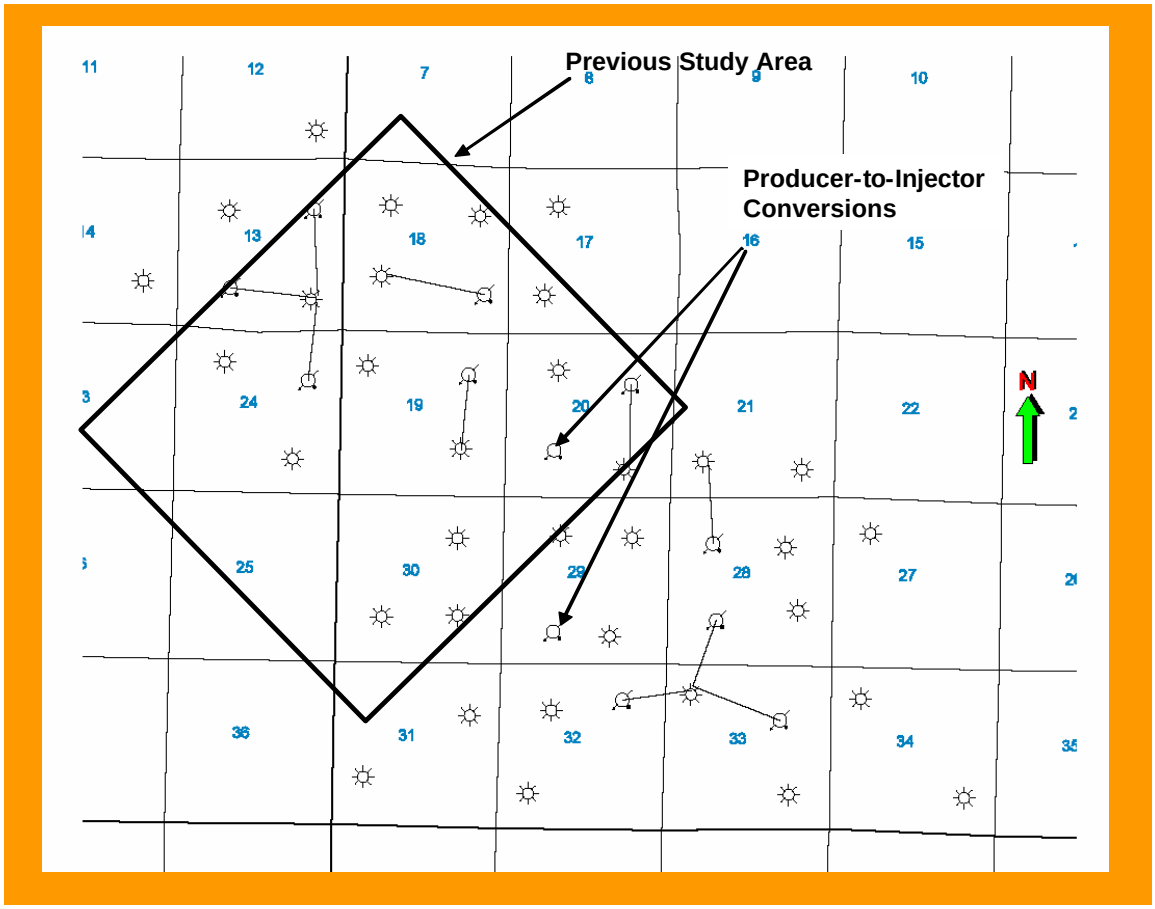

Figure 14: N_2 Pilot Area, Tiffany Unit

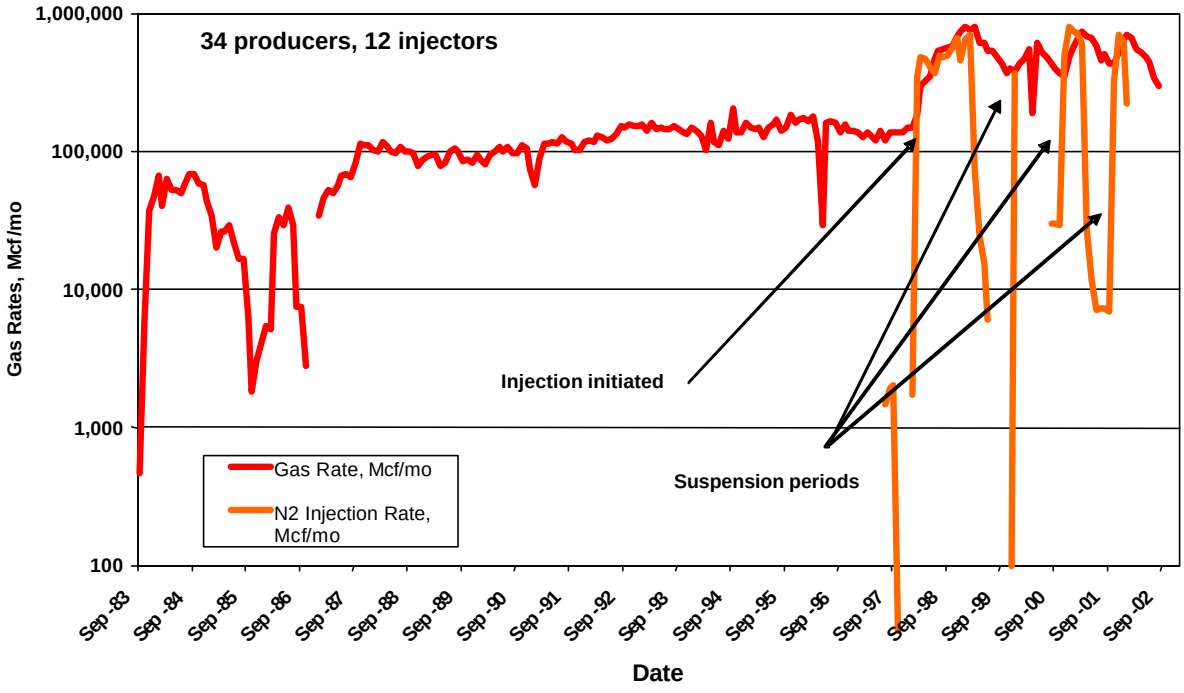

Figure 15: Production/Injection History, Tiffany N_2 Flood Pilot

3.2 N_2 Source & Field Reticulation

The source of the injected N_2 is a cryogenic air separation plant located at BP's Florida River gas processing facility. The plant has the capacity to generate about 28 MMcfd of nitrogen under optimum conditions. However, generation costs become prohibitively high when the ambient temperature is greater than 65 degrees Fahrenheit, therefore BP adopted the strategy of injecting primarily during the cooler (winter) months. This is the reason for the intermittent injection profile in Figure 15.

After generation, the nitrogen is compressed to 1,050 - 1,100 psi and put into a 16-mile, 10-12 inch pipeline for delivery to Tiffany. En-route, the nitrogen is recompressed to 1,900 – 2,000 psi at the Salvador compressor station. The nitrogen reaches the Tiffany Unit at a pressure of 1,700 – 1,900 psi, where it is reticulated to the individual wells via a system of 6-inch steel, buried, distribution lines.

3.3 Injection Well Configurations

3.3.1 *Well Drilling, Completion & Stimulation*

Ten of the twelve injection wells were drilled directionally from existing production well pads, as indicated in Figure 14. In some cases multiple wells were drilled from one pad and the injector wellheads are located about 20 – 30 feet apart, as shown in Figure 16. This strategy minimized the surface footprint associated with the injection wells, and virtually eliminated the costs associated with new roads and well locations, which can be costly and time-consuming to permit and construct in this area. The remaining two injection wells were producer wells that were converted to injector service.

Figure 16: Proximity of Injector Wellheads to One Another, Tiffany Unit

The directional wells were drilled such that immediately under the surface casing shoe, they were deviated and extended close to their desired geographic location, then realigned (close to) vertically before penetrating the coal horizons (Figure 17). Lateral offset of the bottomhole locations were 2,300-2,600 feet from the surface locations. They were drilled, cased and cemented with 4-1/2 inch casing.

The wells were then perforated in the coal seams, and perforation cleanup treatments performed. Hydraulic fracture nor any other type of massive stimulation was performed to avoid the potential connection with and N_2 injection into non-coal strata.

The two vertical producer-to-injector conversions were originally cased with 5-1/2 inch casing though the coals, perforated and hydraulically fracture stimulated. No changes were made to this configuration when converted to injection service.

3.3.2 Downhole Configuration

The injection wells were configured with 2-3/8 inch steel tubing (2-7/8 inch in the case of the vertical conversions) and landed about 50 feet above the perforations. A seating nipple was installed on the end of the tubing, as were packers that were set prior to injection. The tubing/casing annulus was filled with a corrosion inhibitor. A typical downhole wellbore schematic is shown in Figure 17.

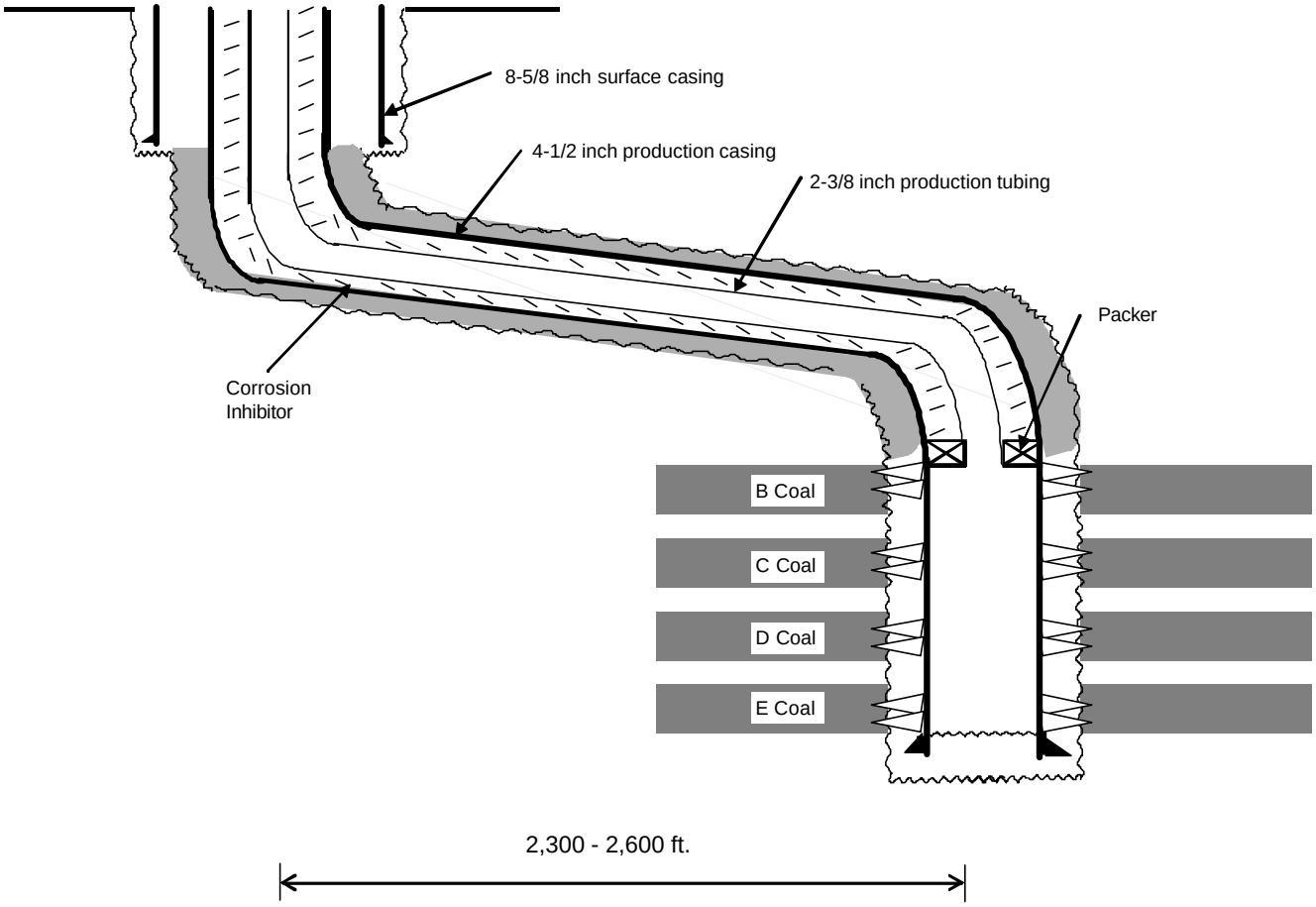

Figure 17: Schematic of Typical Directional Injection Well, Tiffany Unit

3.3.3 Surface Configuration

A typical surface configuration is shown in Figure 18. When nitrogen is delivered to the well site, it is injected into the well based on either constant rate or constant pressure control, based on individual well characteristics. Electronic flow controllers perform this function, which can be operated remotely, and are powered by solar units with battery backup (Figure 19). Nitrogen injection rates and pressures are monitored and recorded to a central database continuously using a SCADA system.

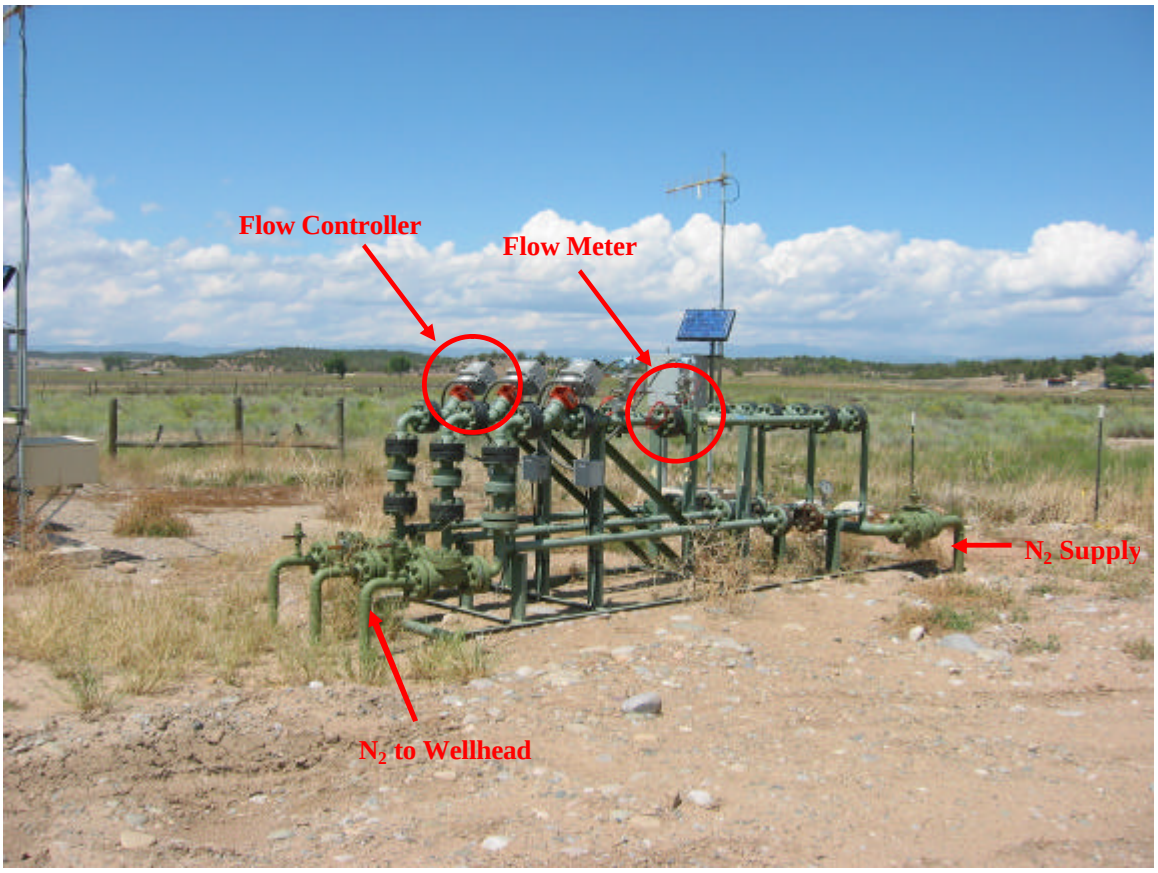

Figure 18: Typical Injection Well Surface Configuration, Tiffany Unit (three wells)

Figure 19: Onsite Power Source and SCADA Transmission System, Tiffany Injection Wells (three wells)

A plot of surface injection pressure and injection rate for one of the directional N_2 injectors is provided in Figure 20.

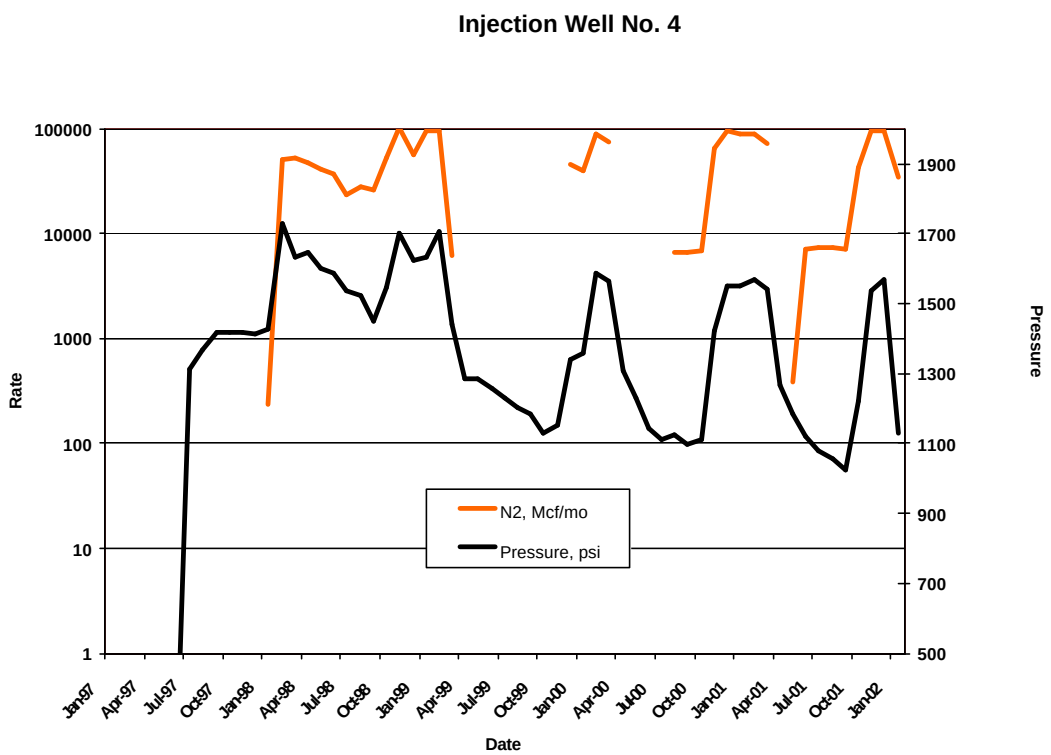

Figure 20: Surface Injection Pressure and Injection Rate History for a Directional N_2 Injector Well, Tiffany Unit

3.4 Production Well Configurations

The production wells were drilled, completed, stimulated and equipped similar to many coalbed methane wells in the San Juan Basin. At Tiffany, for the most part the wells were drilled to total depth and cased and cemented with 5-1/2 inch casing. The wells were then stimulated via hydraulic fracturing. Originally the wells were configured with downhole rod pumps and pump jacks for well dewatering, but now with low water rates this has been replaced with a tubing/packer arrangement and produced on natural flow. A typical downhole well schematic for a production well is provided in Figure 21. Most of the wells were also restimulated in the mid-1990's.

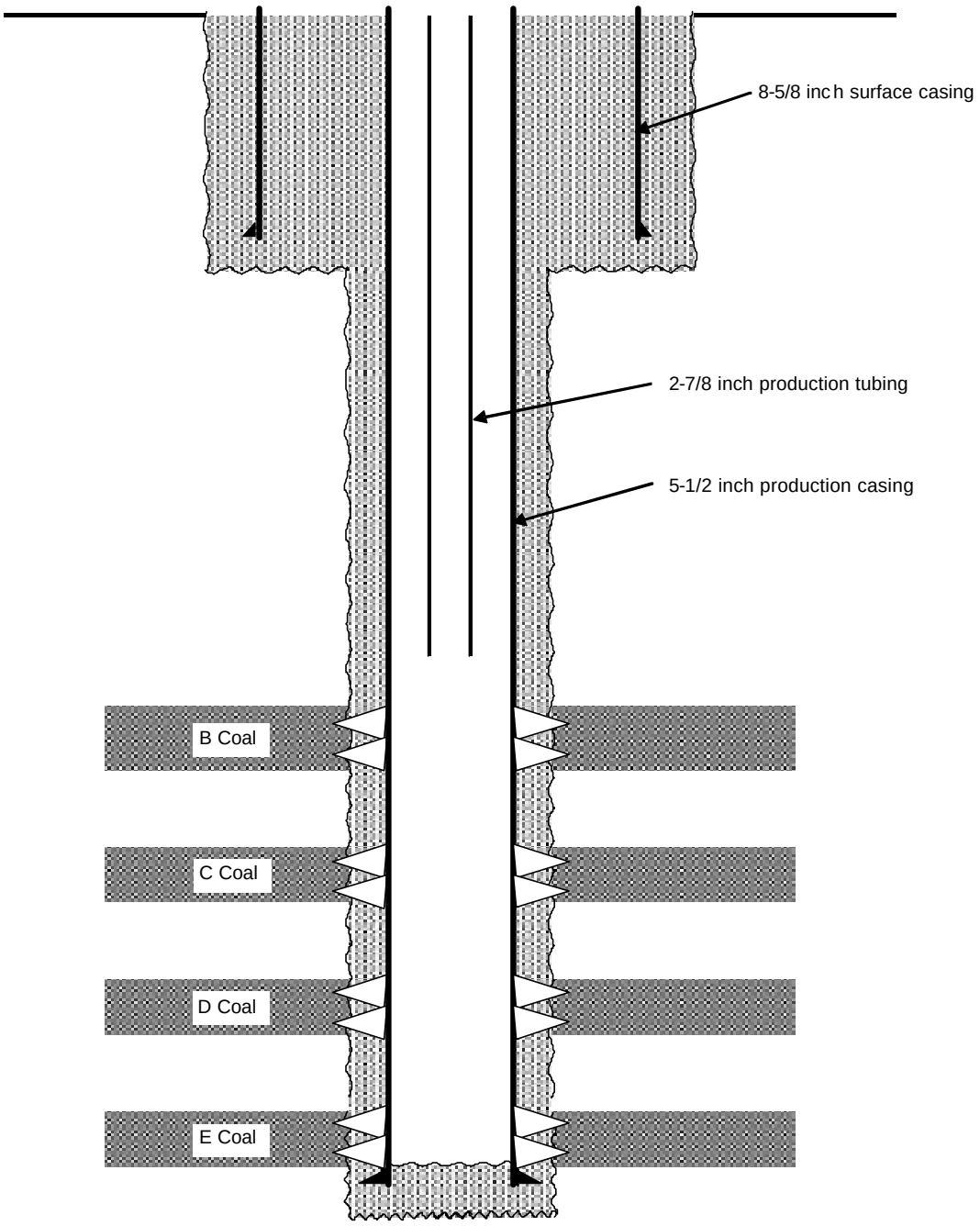

Figure 21: Downhole Schematic of Production Well, Allison Unit

The wellhead configuration for a production well is shown in Figure 22. Note the absence of any pumping equipment, as mentioned above. The fence around the wellhead was for protection against damage when the drilling rig was on-site drilling the injector wells.

Figure 22: Production Wellhead, Tiffany Unit

Surface production equipment included a gas/water separator, surface pressure regulation, gas flow meter (also connected to a central data gathering facility via a SCADA system), and produced water storage (the water was periodically trucked off-site to an approved disposal well), Figure 23.

Figure 23: Production Well Surface Equipment Configuration, Tiffany Unit

Gas is transported from the wellsite to the Florida River processing facility where it is dehydrated, CO_2 removed, and compressed for transmission. Due to the large volumes of hydrocarbon gases being processed through the facility, nitrogen is not separated out from the produced gas, but rather diluted to pipeline specifications with the gas production from other fields. Therefore, no new or special facilities were required to handle any N_2 produced as a result of N_2 injection. However, larger scale operations of this type may necessitate such separation facilities as N_2 volumes increase.

4.0 Discussion

Experience gained from the CO_2/N_2 injection operations at the Allison and Tiffany Units has provided valuable first-of-a-kind experience that will be useful as other companies begin to evaluate CO_2 sequestration in coalseams or ECBM recovery projects. Injection operations at both sites were reliable and safe, and achieved the (operational) objectives required. While future projects in new areas will undoubtably require modification and customization of the procedures presented in this report, it will serve as a useful starting point for facility and operational design.

5.0 Acknowledgement

The authors express their gratitude to the US Department of Energy, which provided funding for the research and preparation of this publication (Cooperative Agreement No. DE-FC26-00NT40924). We also thank Burlington Resources and BP America for permission to present their San Juan basin field information.

6.0 References

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