STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY
SUPERVISOR OF WELLS

IN THE MATTER OF:

THE PETITION OF RIVERSIDE ENERGY MICHIGAN, LLC FOR AN ORDER FROM THE SUPERVISOR OF WELLS APPROVING AN ENHANCED GAS RECOVERY OPERATION BY INJECTION OF CARBON DIOXIDE, AND SUCH OTHER APPROPRIATE SUBSTANCES AS MAY BE APPROVED, INTO THE ANTRIM FORMATION WITHIN THE CHESTONIA/KEARNEY CO_2 UNIFORM SPACING PLAN, IN PARTS OF SECTIONS 5, 6, 7, 8, 17 AND 18 OF CHESTONIA TOWNSHIP AND PARTS OF SECTIONS 1, 11 AND 12 IN KEARNEY TOWNSHIP, ALL IN ANTRIM COUNTY, MICHIGAN. /

CAUSE NO. 02-2020

VERIFIED STATEMENT OF PHILLIP KORO

State of Michigan)
)ss
County of Grand Traverse)

Phillip Koro, after having been duly sworn, deposes and states as follows:

1. My name is Phillip Koro and I am an Engineering and Oil Field Consultant contracted to Riverside Energy Michigan, LLC for this enhanced gas recovery project.

2. I have not testified before the Supervisor of Wells in the past. A summary of my educational background and work experience is summarized as follows:

a. I graduated from Seattle University with a Bachelor of Science Degree in Civil Engineering in 1981. I have worked for various oil and gas related companies over the years. I started with Schlumberger Well Services in Michigan in 1982 and held various engineering positions running and evaluating electric well logs for 13 years. I worked as a Consulting Oil and Gas Engineer and Log Analyst for two years after Schlumberger. I then joined CMS NOMECO in 1996 and worked as a Production and Reservoir Engineer working on the Antrim, Niagaran and PDC wells for four years. I then went to work for DTE Gas & Oil and held various positions as a Production Engineer, Senior Petroleum Engineer and Business Development Manager over the next six years. I moved to the Fort Worth Basin in 2006 as the Engineering Manager and worked on the Barnett Shale for over two years. I then went to work for Atlas Resources and worked various projects ranging from Antrim, New Albany Shale in Indiana and Marcellus Shale. In 2009 I was promoted as President of Atlas Gas & Oil for Michigan and Indiana. Atlas Resources was acquired by Chevron in 2011 and I was assigned the role as Michigan Area Manager through 2016. In 2017 Chevron sold their Michigan asset to Riverside Energy. At that point I became a Consulting Engineer. Over the last 35 years, in my jobs with CMS/NOMECO, DTE, ATLAS and Chevron I have been involved in the drilling, completion, production and reserves analysis of over 1,000 Antrim wells. I am working part time for Riverside Energy in an engineering capacity.

b. I have worked in the oil and gas industry in various engineering roles for over 35 years.

c. I am a member of the following oil and gas associated organizations:

- Michigan Oil & Gas Association Board Member 2009 – present
- Past President, Secretary/Treasurer of Society of Well Log Analysis 1986 – 1990
- Past Business Manager of Michigan Basin Geological Society 1986 – 1988

- Member of Society of Petroleum Engineers, American Petroleum Institute

3. If called upon to testify, I could do so competently with regard to the information contained in this Verified Statement. As part of my responsibilities for the Chestonia/Kearney CO_2 USP Project at Riverside, I am working on a pilot project to determine if we can increase ultimate gas reserves produced from the Antrim by utilizing CO_2, a current waste product from the Antrim, and achieve the additional side benefit of sequestering CO_2.

4. The development history of the Chestonia/Kearney CO_2 USP Field began with an initial well drilled by O.I.L./Lee Petroleum to the Antrim in 1989 as a test well. Project development commenced in 1994 thru 1996 when 23 wells were drilled for Antrim production within the Chestonia/Kearney CO_2 USP unit, and initial production started in 1995 as the Chestonia 18 or sometimes referred to as the Chess Play unit. Four additional wells were added in the Chestonia/Kearney CO_2 USP unit from 2003 thru 2007.

5. There are currently three SWD wells drilled to the Dundee in the Chestonia/Kearney CO_2 USP. The Kafi B4-12 well was plugged in 1998.

6. **Exhibit A** depicts the Chestonia/Kearney CO_2 USP and the location of wells in the USP. As set out on Exhibit A, the Chestonia/Kearney CO_2 USP unit lays within the Chestonia 18 voluntary unit. The Chestonia 18 USP is delineated by the orange outline and the Chestonia/Kearney CO_2 USP is delineated by the dashed blue and white outline. Producing wells are identified by red gas symbols. The wells we plan to convert from producing wells to CO_2 injection wells are identified by green injection well symbols. The Central Production Facility and riverside's CO_2 plant are in Section 17 and marked as CPF.

7. Daily production from Chestonia/Kearney CO_2 USP is monitored on a project-level basis. Individual wells are tested periodically.

8. **Exhibit B** shows that production commenced in the Chestonia 18 unit towards the end of 1995, reaching peak production in 1997 of 1,854 Mcfd. Production has declined at a rate of 6.5%, flattening to 4% over the last several years. Water production peaked in 1996 at 4,980 BWPD and has declined sharply as the field has dewatered. CO_2 percentage in the gas has increased, starting around 3% and increasing to 6.5% today. Current production is 486 Mcfd and 412 BWPD.

9. Based upon my review of Chestonia/Kearney CO_2 USP, it is my opinion that in order to maximize the ultimate recovery from the field, development of the Chestonia/Kearney CO_2 USP Field should occur by injecting CO_2 into the Antrim formation.

10. Riverside owns a CO_2 processing plant located within the boundary of the Chestonia/Kearney CO_2 USP. This plant strips CO_2 from the gas produced from Antrim wells to make the gas sellable and vent the CO_2 to the atmosphere. We plan to capture this CO_2 and reinject back into the Antrim and stimulate additional methane recovery while sequestering CO_2 at the same time. The Antrim rock will adsorb the CO_2 and release additional methane in its place.

11. In forming my opinion regarding the benefits of injecting CO_2, I relied upon two publications which are marked as Exhibits C and D.

12. **Exhibit C** is a paper titled "A Field Study on Simulation of CO_2 Injection and ECBM Production and Prediction of CO2 Storage Capacity in Un-mineable Coal Seam" which was documented in 2012 by the Department of Petroleum and Natural Gas Engineering, West Virginia University. In this study, CO_2 was injected into a coal seam in West Virginia. In this pilot project (summarized on page 7), they injected almost 2,600 tons (an average of 38.7 Mcfd)

of CO_2 over three years and increased methane recovery by 6.7 Mcfd. Riverside is planning to inject about 650 Mcfd of CO2 per day.

Exhibit D is the second paper, titled "The Allison Unit CO_2-ECBM Pilot – A Reservoir and Economic Analysis", which was published by personnel at the Advanced Resources International, Inc. The study (on page 6 of the paper) estimated that CO_2 injection would result in incremental methane recovery over primary recovery of approximately a proportion of one volume of methane for every three volumes of CO_2 injected. Methane recoveries of 17 - 18% of original gas in place were estimated for effectively swept portions of the reservoir.

13. These publications are considered reliable in oil and gas engineering as both West Virginia University and Advanced Resources International are respected institutions in the oil and gas industry.

The program at West Virginia University is one of four ABET (Accreditation Board for Engineering and Technology, Inc.) accredited programs encompassing both petroleum and natural gas engineering in the country.

Advanced Resources International is a consulting, research and development firm providing services related to unconventional gas (gas shales, coalbed methane and tight sands), enhanced oil recovery (EOR), and carbon capture, utilization and storage (CCUS). During the past decades, Advanced Resources has conducted extensive shale studies, R&D and project work on the geology, engineering, economics, and environmental impacts of development in plays and basins through the world, including the Antrim during its early development.

14. In my opinion, these papers are based on factual and accurate data, as both of these pilot projects had actual CO_2 injection results from pilot programs along with simulation to arrive at their conclusions.

15. A review of the benefits of the process of adsorption of CO_2 and the desorption of methane in this Unit is necessary to understand the benefits of injecting CO_2.

Study of the Antrim Shale indicates that the Antrim Shale stores methane gas thru adsorption. The gas was created biogenically by microbes instead of the more conventional thermogenic process. The microbes generated both methane and CO_2, the majority of this gas adsorbed to the rock matrix. As formation pressure is lowered, the rock releases both methane and CO_2. The methane desorbs from the rock at a higher rate than the CO_2 as the shale matrix preferentially desorbs methane and retains CO_2. We know from gas samples as we produce the Antrim; the gas content is much higher in methane versus CO_2 initially. As we produce reserves over time, CO_2 content slowly increases over time. By injecting CO_2, the partial pressure of CO_2 is increased, which creates a driving force for the adsorption of CO_2 and desorption of additional methane to the fracture system and ultimately to the wellbore.

16. Our research indicates that there are similarities between the Antrim and Coal Bed Methane.

Coal bed methane production or CBM is similar to the Antrim where the gas was formed biogenically and the coal cleats act as fractures similar to the fracture system in the Antrim. Based on the previously mentioned studies where CO_2 was injected into CBM reservoirs, the injection of CO_2 resulted in increased methane production. In addition, there was the side benefit of CO_2 sequestration. We want to apply this same enhanced gas recovery method to the Antrim Shale formation.

17. Our study of the Antrim formation indicates that CO_2 injection would increase gas production as the rock matrix wants to preferentially retain CO_2, thus the rock will give up a methane molecule in exchange to adsorb a CO_2 molecule. The fracture network in the Antrim

helps create a large surface area and access to matrix porosity. In tighter rock with less fractures we may not be able to inject as much CO_2 and liberate as much methane.

18. Another reason why we chose the Chestonia/Kearney CO_2 USP for injection is because we have a secure source of CO_2 at the plant located in this Unit.

19. Additional geological data and Exhibits supporting the Petition are as follows:

Exhibit	Description
E	Schematic
F	Cross Section
G	Antrim Structure Map
H	Reservoir Properties
I	Estimated Volumes
J	Economics

20. **Exhibit E** is a schematic of the Chestonia 18 wells and infield gathering system. The wells are currently gathered via the depicted blue lines and sent to the Chestonia 18 Central Processing Facility. Gas and water are separated, water is disposed in an SWD well and gas is compressed, dehydrated and sent to the Chestonia CO_2 Plant. At the plant, CO_2 is removed and vented while the methane gas is sold into DTE's gas transmission system. We plan to add infrastructure to capture the CO_2 instead of venting it, compress and dehydrate the CO_2 and send it back to injection wells depicted in red.

21. With respect to the UIC permits, we have applied for an Underground Injection Control (UIC) Permit from the EPA for injection of CO_2 into the Unitized Formation.

We have applied for the D4-7 and the A3-18 wells to convert them from production to CO_2 injection.

22. **Exhibit F** shows two geologic cross-sections, one is an East-West view and the other is a North-South view. In both cross-sections the thickness of the Glacial Drift, the Ellsworth

Shale and Antrim is illustrated. The Ellsworth Shale provides a confining layer of rock between the Antrim and the Drift. The thickness of the Ellsworth varies from 87 ft to 387 ft, providing a more than adequate barrier to confine CO_2 to the Antrim.

23. **Exhibit G** shows the Antrim to have very low structural relief dipping to the south. Structure has not played a significant role in influencing Antrim production as both structurally low and high areas of the Antrim are productive. Rather, production is more controlled by microbial generated gas and fractures in the rock matrix.

24. **Exhibit H** shows initial reservoir pressure is calculated to have been around 269 psi. Gas gravity is 0.62 with 6.46% CO_2 content. From the literature, porosity in the Antrim ranges from 3 - 10% with an average of 9%. Approximately 60 - 70% of Antrim gas is adsorbed to the rock matrix. The remaining 30 - 40% gas is stored in the porosity and fracture system. By injecting CO_2, we are looking to stimulate the release of the gas that is adsorbed to the rock matrix. We calculate that 80 acres holds 1.1 to 2.7 BCF of gas, based on gas content ranging from 40 - 100 scf/ton. The Chestonia/Kearney unit at 3,860 acres therefore has a range of 51 - 129 BCF of original gas in place.

25. **Exhibit I** shows that Reserve recovery to date thru July 2019 is 8.4 Bcf. Based on our decline curve analysis, we estimate another 3.1 Bcf of remaining primary production to be produced for a total of approximately 11.5 Bcf of total primary production. From Exhibit H, we estimated original gas in place is estimated at 51 Bcf - 129 BCF. If we assume that 60% of this original gas is adsorbed, adsorbed gas will range from 30.1 - 77.7 Bcf. Assuming we can recover an additional 10% of this adsorbed gas through CO2 injection, we could potentially increase gas recovery by 3.1 - 7.7 Bcf.

26. **Exhibit J** represents undiscounted economics of this CO_2 Enhanced Gas Recover Project. Assuming we recover an additional 3.1 Bcf of gas, the low end of our range, at an average price of $2.25/mcf gas at a net NRI of 80% over the next 20 years, we will add additional gross revenues of about $5.5 MM. We estimate we will need capital expenditure of $600,000 to install infrastructure. We expect an annual operating expense of $12,000/year or $240,000 over 20 years. We would generate positive cash flow of $4.75 MM over this time period.

27. The Chestonia/Kearney CO_2 USP is subject to a Unitization Agreement executed or Ratified by all owners in the USP and the Plan of Unitization allocates production to the various tracts in the unit on a mineral acre basis. (Based on the ratio of mineral acres a party owns in a proportion to the total number of mineral acres in the unit).

28. Riverside operates several Antrim units that offset this unit. These units include Kearney 9, Kearney 15 and Chestonia 31. Riverside has 100% working interest in all of these units. In my opinion there is minimal to no impact on surrounding units. The CO_2 injection wells are surrounded by producing wells that should produce any CO_2 that isn't adsorbed and newly liberated methane. In the event any CO_2 or newly liberated gas that might migrate to an offset unit, there are different scenarios by which this would not have a detrimental effect on the offsetting units.

29. Riverside's plans for development of the Chestonia/Kearney CO_2 USP are as follows:

We plan to start with the A3-18 well and convert it for CO_2 injection. We plan to use the D1-7, D4-7, B1-18 and B4-18 to monitor CO_2 levels to get a better feel for the impact of CO_2 injection.

The next well we plan for injection is to convert the D4-7 from production and add this well as an injector. As we learn about the impact of CO_2 injection, we plan to proceed adding the A3-7, A1-7, B3-12 and B1-12 wells over time. All these injection wells are in the center of the Chestonia/Kearney CO_2 USP and will give us producing wells that border the USP to monitor the impact of the CO_2.

All of the CO_2 we plan to inject is sourced from the Antrim itself. The CO_2 is removed from the gas stream at Riverside's Chestonia CO_2 plant located in Section 17. The CO_2 will be compressed, dehydrated and sent via infield lines to the injection wells.

30. At this time we do not plan on drilling additional injection wells as part of unit operations as we would like to see the impact of the CO_2 injection over time before we conclude if additional wells might be beneficial.

31. As part of our study of injecting CO_2, we have reviewed the potential impact on groundwater in this area due to the injection of CO_2.

We find that the Ellsworth Shale is a gray shale known to be impervious and a good hydrocarbon trapping layer. It has a thickness from 87 ft to 387 ft and provides an adequate barrier of rock between the Antrim and the Glacial Drift. Also, the current EGLE regulations require cementing at least 100 ft of surface casing below the base of drift and cementing of the Antrim production string to surface will provide isolation required to keep the CO_2 injected within the Antrim.

32. We have prepared **Exhibit K**, which depicts the location of the Ellsworth Shale and the cementing of the production string to the surface.

This Exhibit depicts the cement, casing and tubing string used for a CO_2 injection well. Surface Casing, depicted in yellow, is set at least 100' below the base of drift as required by rule.

A second string of casing, depicted in red, is set to TD, usually several hundred feet below the base of the Antrim. Both strings of casing are cemented to surface shown in purple. The casing is perforated in the Antrim show in black. An injection string will be set on a packer just above the top of the Antrim depicted in blue. The annulus between the tubing and casing is filled to surface with a corrosion inhibitor and monitored for any pressure or fluid level changes to ensure there are no leaks. These systems along with the Ellsworth Shale above the Antrim provide isolation for both the Antrim gas reservoir and the CO_2 we plan to inject.

33. It is our opinion that the injection of CO_2 results in recovery of hydrocarbons that would not otherwise be produced.

34. In addition, instead of continuing to vent CO_2 from the Chestonia Plant, we will be capturing a portion of the CO_2 and sequestering it in the Antrim where it originated.

This concludes my Verified Statement.

Respectfully submitted,

RIVERSIDE ENERGY MICHIGAN, LLC

Dated: May 14, 2020

By: Phillip Koro

VERIFICATION

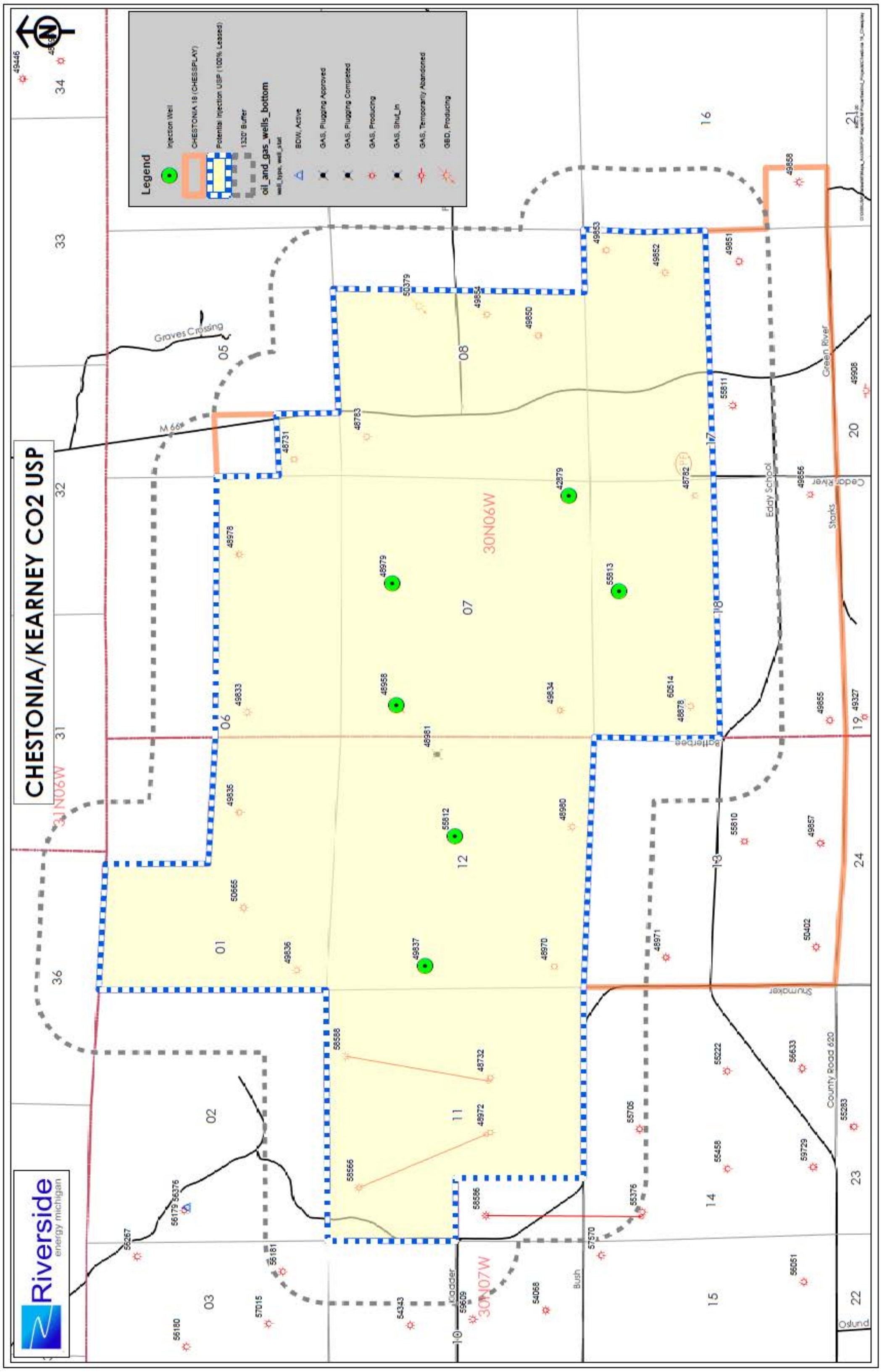
State of Michigan)
)ss
County of Leelanau)

Phillip Koro, being first duly sworn, states that he is Agent for Riverside Energy Michigan, LLC, that he has read the foregoing Verified Statement and is knowledgeable of its contents and that the contents are true based upon his own knowledge, information and belief.

JOANNE MULDER
Notary Public – State of Michigan
County of Grand Traverse
My Commission Expires May 7, 2024
Acting in the County of Leelanau

Joanne Mulder, Notary Public
County, Michigan
Acting in Leelanau County, Michigan
My Commission Expires: May 7, 2024

Exhibit A – Chestonia/Kearney Unit Area and Wells Map



<u>Exhibit B</u> – Primary Production

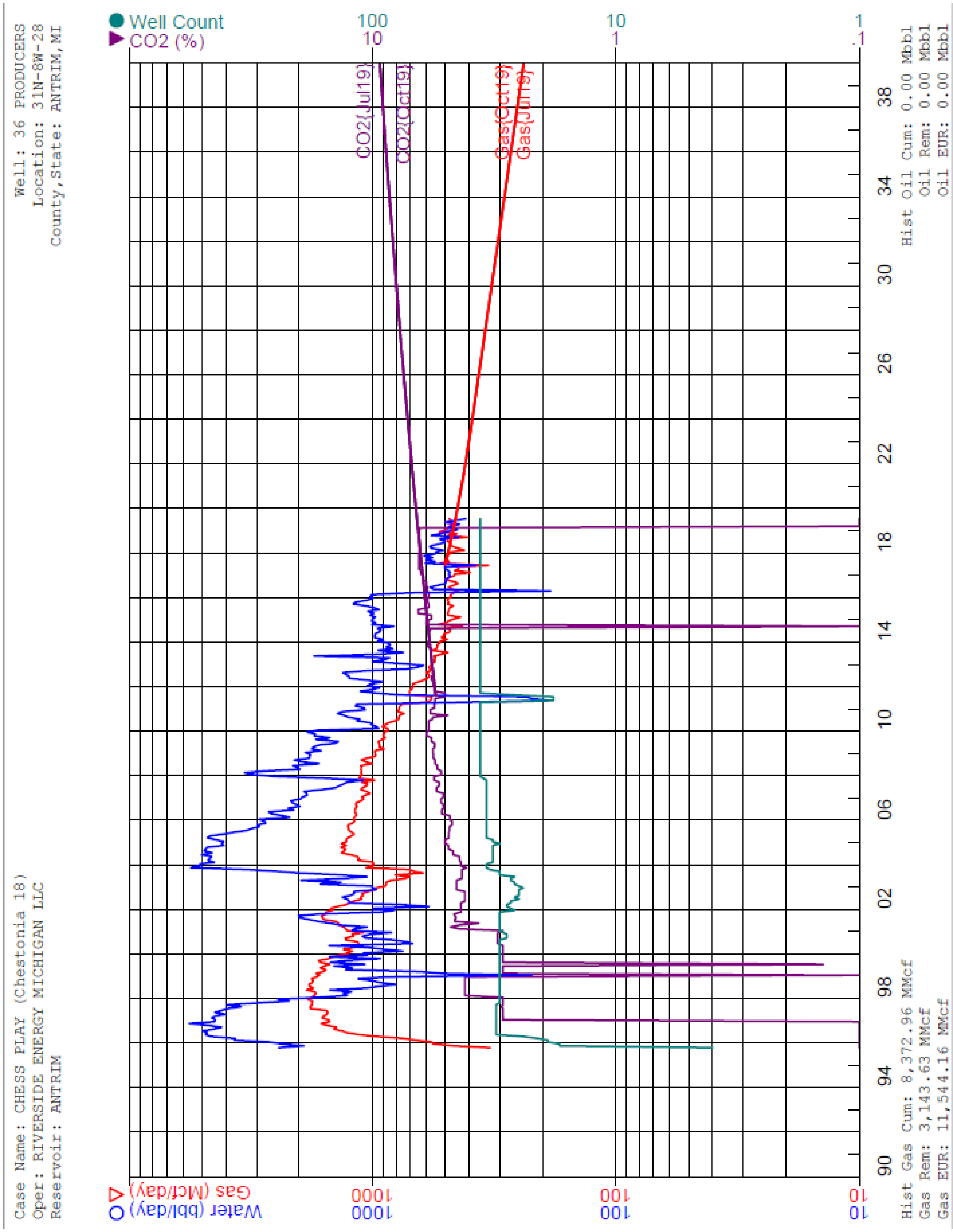


Exhibit C

Hindawi Publishing Corporation
Journal of Petroleum Engineering
Volume 2013, Article ID 803706, 8 pages
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Research Article

A Field Study on Simulation of CO_2 Injection and ECBM Production and Prediction of CO_2 Storage Capacity in Unmineable Coal Seam

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CO_2 sequestration into a coal seam project was studied and a numerical model was developed in this paper to simulate the primary and secondary coal bed methane production (CBM/ECBM) and carbon dioxide (CO_2) injection. The key geological and reservoir parameters, which are germane to driving enhanced coal bed methane (ECBM) and CO_2 sequestration processes, including cleat permeability, cleat porosity, CH_4 adsorption time, CO_2 adsorption time, CH_4 Langmuir isotherm, CO_2 Langmuir isotherm, and Palmer and Mansoori parameters, have been analyzed within a reasonable range. The model simulation results showed good matches for both CBM/ECBM production and CO_2 injection compared with the field data. The history-matched model was used to estimate the total CO_2 sequestration capacity in the field. The model forecast showed that the total CO_2 injection capacity in the coal seam could be 22,817 tons, which is in agreement with the initial estimations based on the Langmuir isotherm experiment. Total CO_2 injected in the first three years was 2,600 tons, which according to the model has increased methane recovery (due to ECBM) by 6,700 scf/d.

1. Introduction

Fossil fuels are currently playing a significant role in the whole world's energy supply. However, its damage to the environment, especially the CO_2 emission resulting in the green house effect, has gotten more and more attention. At present, several geological CO_2 sequestration technologies, such as CO_2 injection into saline aquifer, CO_2-EOR, CO_2-ECBM, and so forth, have been studied to minimize the CO_2 release into the atmosphere, and these projects have been operating all over the world [1–6]. Studies have shown that unmineable coal seams (seams too deep or too thin to be mined economically) are pretty attractive as one of the promising options for CO_2 sequestration because of their large CO_2 sequestration capacity, long time CO_2 trapping, and extra enhanced coalbed methane (ECBM) production benefits [1, 7–10]. Field experience with CO_2 injection into coal seam is limited, although field tests are planned or are being conducted in the USA, Canada, Poland, Australia, and Japan [3].

However, unlike conventional reservoirs, gas flow in the coal seams can cause the cleat permeability and porosity variation during the injection/production process. Once gas is injected and adsorbed on the coal matrix, the matrix will swell, and correspondently decrease the cleat permeability and porosity [11, 12]. Due to its special features and the nature of gas retention in CBM reservoirs, simulating the production and injection will have more complexity compared to conventional resources.

Similar to conventional naturally fractured reservoirs, coal is characterized as a dual-porosity system consisting of matrix and cleat, in which majority of the gas is stored within the coal matrix by a process of adsorption and a small amount of free gas exists in the cleats or fractures [13]. Once CO_2 is injected into the coal seam, it will be held by coal surface because of its higher affinity to the coal matrix than methane, and then displaces the methane to boost extra natural gas production. Figure 1 shows a schematic representation of the CO_2 sequestration-ECBM process. It is estimated by

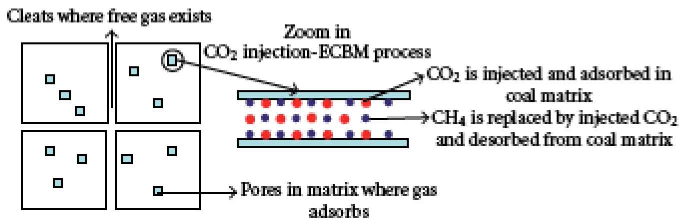


Figure 1: A schematic representation of CO_2 sequestration-ECBM production.

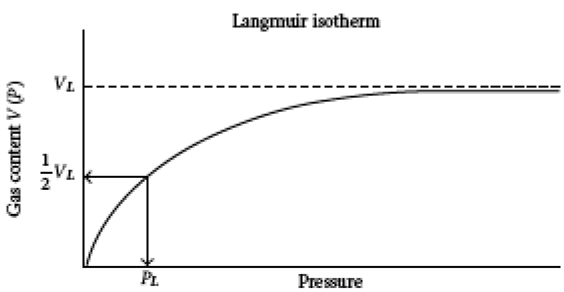


Figure 2: Langmuir isotherm function.

laboratory measurements that this process, known as CO_2-enhanced coal bed methane, can store twice as much CO_2 as the methane desorbed or even more [14].

The entire gas flow mechanism can be summarized in three steps: (1) desorption: once free gas or water is produced from fracture systems in coal seams, pressure starts to be released, then the adsorbed gas will be desorbed from the matrix surface, which can be described by Langmuir isotherm equation; (2) diffusion: due to the gas molecular concentration difference, gas will diffuse from matrix surface to cleats/micro-pores; (3) Darcy's flow: gas in the cleats and natural fractures will flow to the wellbore by Darcy's flow [15]. Recently, the numerical reservoir simulator have become the most popular tool to predict coal seam performance and provides a good understanding of gas flow from the reservoir to the wellbore [16].

1.1. Langmuir Isotherm. The gas adsorption/desorption process can be described by the typical formulation of Langmuir isotherm:

$$V(P) = \frac{V_L P}{P_L + P}. \tag{1}$$

As shown in Figure 2, Langmuir volume (V_L) is the maximum amount of gas that can be adsorbed on a piece of coal at infinite pressure. Langmuir pressure (P_L) is the pressure at which the Langmuir volume can be adsorbed. $V(P)$ is the amount of gas at different pressure, also known as gas content (scf/ton). Whenever the Langmuir volume and Langmuir pressure are known, the adsorbed gas amount can be calculated at any pressure.

1.2. Diffusion. Diffusion is the fact that particles move/spread from high concentration to low concentration region. Diffusion of gas out of the coal matrix can be expressed by a simple diffusion equation. The diffusion process in coal seams can be described by either diffusion coefficient or coal desorption time input in the simulator [16]:

$$\frac{\partial C}{\partial t} = \frac{1}{\tau}\left[\overline{C} - C\left(P_f\right)\right]. \tag{2}$$

1.3. Coal Shrinkage and Swelling. One of the unique characteristics of coal seam is the phenomenon of pressure dependent permeability. As the production from the reservoir takes places, two distinct phenomena occur. First, the reservoir pressure declines, which causes the pressure in the fractures to decline as well, which in turn leads to an increase in the effective stress within the cleats causing the cleats to be more compactable, so the cleat permeability will decrease. At the same time, the gas that has been desorbed is coming out of the matrix, which causes the matrix to shrink and the cleats to open-up; thereby the cleat permeability will be increased. As a function of the pressure drop, compressibility dominates in early time and shrinkage dominates in the late time [16]. Palmer and Mansoori model [17] is used to simulate the permeability change process during production/injection in this model:

$$\frac{\varnothing}{\varnothing_0} = 1 + C_f\left(\frac{P-P_0}{\varnothing_0}\right) + \frac{\varepsilon_\alpha}{\varnothing_0}\left(\frac{K}{M}-1\right)\left(\frac{P}{P+P_L} - \frac{P_0}{P_0+P_L}\right),$$
$$\frac{K}{K_0} = \left(\frac{\varnothing}{\varnothing_0}\right)^3. \tag{3}$$

2. Project Description

From 2009, the CO_2 sequestration with ECBM production project began in Marshall County, West Virginia. The objective of this project was to help mitigate climate change by providing an effective and economic way to permanently store CO_2 in un-minable coal seams. In advance of CO_2 injection, four horizontal coalbed methane wells (MH5, MH11, MH18, and MH20) were drilled into the un-minable Upper Freeport coal seam, which are 1,200 to 1,800 feet below the ground. These wells have been producing coalbed methane since 2004. The center located wells (MH18 and MH20) have been converted to CO_2 injection wells since

Table 1: Initial reservoir parameters used in the model.

Input parameters	Value	Unit	Input parameters	Value	Unit
Average reservoir depth	1200	ft	Poisson ratio	0.3	
Average formation thickness	4	ft	Young's Modulus	125,000	psia
Fracture spacing I/J/K	0.02	ft	CO_2 Strain	0.0065	
Perm I-Matrix	0.01	md	CH_4 Strain	0.0045	
Perm J-Matrix	0.01	md	Palmer/Mansoori exponent	3	
Perm K-Matrix	0.001	md	CO_2 Langmuir Pressure	240	psia
Perm I-Fracture	0.2	md	CO_2 Langmuir Volume	890	scf/ton
Perm J-Fracture	0.2	md	CH_4 Langmuir Pressure	402	psia
Perm K-Fracture	0.02	md	CH_4 Langmuir Volume	452	scf/ton
Porosity-Matrix	0.004		CO_2 Sorption time	100	days
Porosity-Fracture	0.001		CH_4 Sorption time	100	days
Rock compressibility-Matrix	$1.00E-06$	1/psi	Rock compressibility-Fracture	$1.00E-06$	1/psi

September 2009 [18]. 20,000 short tons are planned to be injected through well MH18 and MH20 in two years.

Several questions come with this project and need to be investigated: how much CO_2 can be stored in this coal seam? How long does the injection process take? Which parameters affect the injection and production the most? These questions could be answered by an effective coal seam model, which was represented by a dual-porosity system to show the fluid flow through both matrix and cleat under the particular conditions in this site. The following assumptions were considered for the modeling and simulation purpose.

(1) The initial seam pressure is hydrostatic pressure, which is 0.28 psi/ft after water is produced.

(2) The flow in the coal seam is single phase including only CH_4 and CO_2.

(3) The fluid flow in the cleat system is a laminar flow due to the larger pore size and it is governed by Darcy's Law, while the flow in the matrix is a diffusional flow due to smaller pore size and governed by Fick's Law.

(4) Palmer and Mansoori equation is used to allow the natural permeability and porosity to vary as a function of pressure.

In most cases, the actual in situ seam data is unavailable, which leads to the requirements of some assumptions on certain parameters, such as, in this case, matrix/cleat permeability, matrix/cleat porosity, geo-mechanical properties (Young's modulus, Poisson ratio), and so forth. Table 1 summarizes the initial physical parameters in the model.

3. History-Matching Results and Discussion

As indicated before, the CO_2 sequestration-ECBM production project went through three stages: primary methane (CBM) recovery, CO_2 injection, and secondary methane (ECBM) recovery. MH18 and MH20 were firstly performed as production wells from January 2005 to July 2007 with a following two-year shut in period; thereafter, they were transferred into CO_2 injection wells since September 2009. MH5 and MH11 keep on methane production from the all the way from beginning to present. All well productions and injection were simulated starting from the start day until the date the most updated data have been recorded and reported (August 2012 in this paper).

However, different performance of MH18 and MH20 in different time periods introduced a lot of complexity on the history matching process. A key factor should be respected in the history matching: either for initial methane production or the following CO_2 injection, well properties (MH18 or MH20) must stay the same in the model; thereby what was changed is only the operation type.

The results of sensitivity analysis were very valuable in back and forth model parameter adjustment. Sensitivity analysis is known as the study of how the variation (uncertainty) in the output of a mathematical model can be apportioned, qualitatively or quantitatively affected by the change of different variations in the input of the model [19]. Sensitivity analysis of coal modeling properties is widely studied and is addressed that it will be an important tool in future decision making [19–21]. In this case, related coal parameters, including cleat permeability, porosity, CH_4 desorption time, CO_2 desorption time, CH_4 Langmuir volume, CO_2 Langmuir volume, and Palmer and Mansoori parameters have been tested in the model. The comparison of coal physical property influences can be concluded based on the study result as: Young's modulus and Poisson ratio have little effect, while sorption time, cleat permeability, strain, and Langmuir isotherm are the key parameters that affect CH_4 production and CO_2 injection most.

The actual in-seam data for both methane production and CO_2 injection in Upper Freeport coal seam were reported daily as shown in Figure 3. The average minimum bottom hole pressure in production wells is 20 psia, and the average maximum BHP in injection wells is 900 psia. The daily injection rate is set as constraint. The trend could be observed in the production; the methane production rate has clearly increased in MH5 and MH11 after July 2009 due to the CO_2 injection. A gradual decline trend in injection rate can be noticed in the injection wells, especially in MH18, which can be a consequence of the permeability changes occurring during desorption/adsorption process on coal.

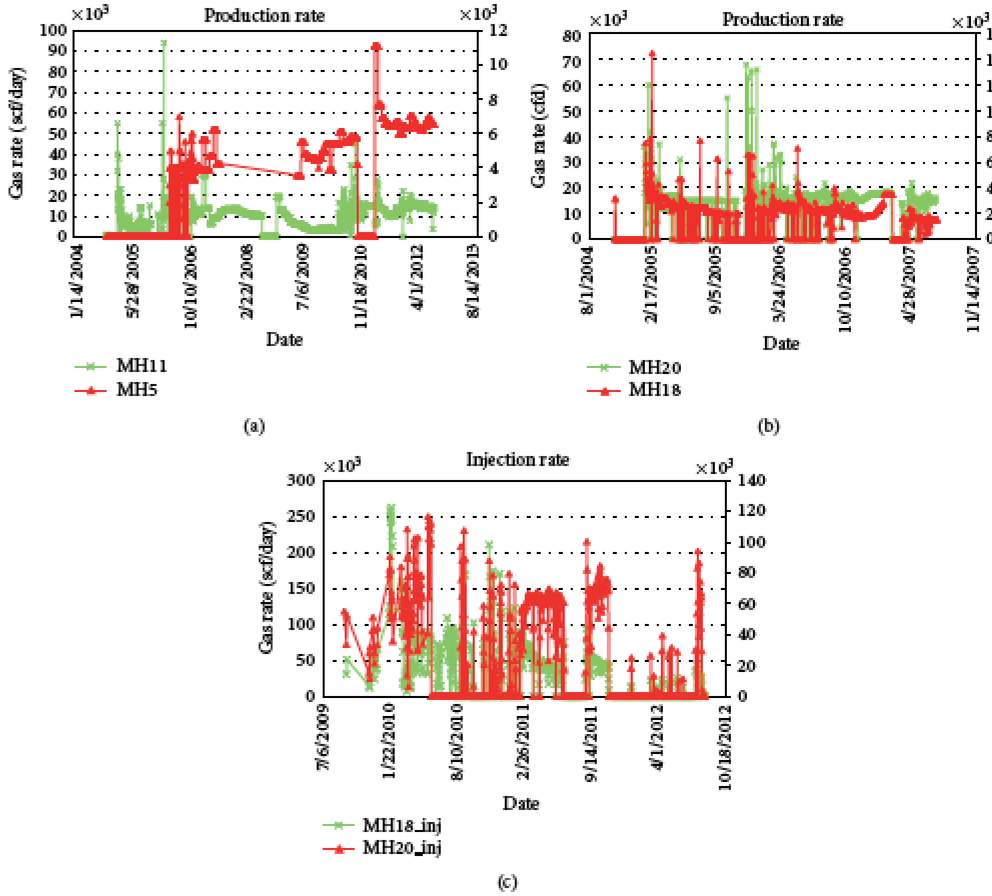


FIGURE 3: Actual CH_4 production rate/CO_2 injection rate in Upper Freeport coal seam. (a) CH_4 production rate in MH11 and MH5, (b) CH_4 production rate in MH18 and MH20, (c) CO_2 injection rate in MH18_inj and MH20_inj (MH18 and MH20 after conversion to Injection wells).

No regular tracking pattern of daily rate was observed because of frequent shut-in operations due to weather, equipment damage, or other unpredictable reasons during the injection process. Therefore, cumulative rates are considered to be the history matching target by setting bottom hole pressure as constraints in the model. History matching was performed for six wells, and final existing reservoir properties, including permeability, porosity, Langmuir isotherm parameter, sorption time, and so forth, as appropriate, were determined by history matching. The history matching results are illustrated in Figures 4 and 5 and the coal parameters are listed in Table 2. It is important to note that the degree of component isotherm and sorption time at any given in-situ condition is directly related to the rank of the coal. Values may change in a large range from different coal seams.

Figure 4 shows the fairly good history matching result of CH_4 cumulative production for all production wells. Green line and red line represents the simulated result and actual data, respectively. As shown in Figure 4(a), well5 was shut in from July 2007 to April 2009 and October 2010 to March 2011, which can be seen from two short straight lines in red cumulative curves. 7×10^6 ft^3 CH_4 could be produced from well5 by August 2012 with a stable increase. As illustrated in Figure 4(b), well11 had a short shut-in period of three months; that is why no production increase is shown in October 2005 and from July 2008 to November 2008. Totally, 2×10^7 ft^3 CH_4 were produced from well11 by August 2012, a sharp build-up could be observed after the start of large CO_2 injection on September 2009, which is because of ECBM production. Figures 4(c) and 4(d) show the cumulative CH_4 production of well18 and well20 from January 2005 to July 2007, respectively, before they were shut-in and transferred to CO_2 injection well. MH18 produced 1.6×10^7 ft^3 CH_4, while MH20 had a total of 1×10^7 ft^3 CH_4 production at the end of production period.

Figure 5 shows cumulative CO_2 injection history matching in MH18 and MH20 after they were converted into injection wells. Red dashed line represents actual CO_2 injection

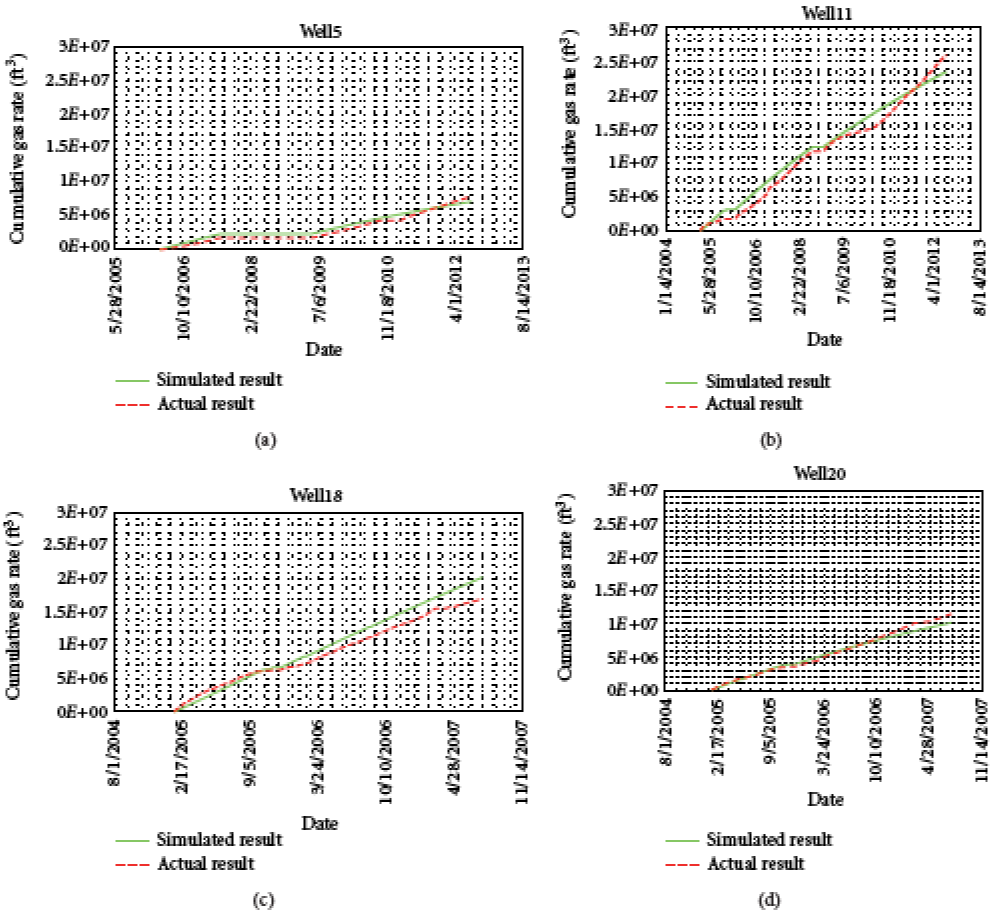


FIGURE 4: CH_4 cumulative production history matching. (a) CH_4 cumulative production in MH5, (b) CH_4 cumulative production in MH11, (c) CH_4 cumulative production in MH18, (d) CH_4 cumulative production in MH20.

data from September 2009 to August 2012, while green line shows simulation results for both wells. Certain plateaus could be seen in the curves during the whole injection periods, which is because of the shut-in times resulting from operational reasons, such as weather affects, equipment damage, and so forth. More CO_2 was injected through well18 (maximum amount of 2.5×10^7 ft^3 CO_2), compared to 2.5×10^7 ft^3 CO_2 injection in well20. The total amount of injected CO_2 through MH18 and MH20 has been almost 3,000 tons in the first three years, with an average ECBM increase of an approximation of 6,700 scf/day.

4. CO_2 Sequestration Capacity in Coal Seam

There are four main CO_2 storage mechanisms in coal seams: (a) stratigraphic and structural trapping, (b) hydrodynamic trapping, (c) mineral trapping, and (d) adsorption trapping. In un-mineable coal seams, adsorption trapping is the main sequestration method. This is the process of accumulation of injected gases which is adsorbed on the surface of micropores within the coal matrix. The adsorption capacity will mostly depend upon Langmuir isotherm factors [22]. Figure 6 illustrates the final Langmuir Isotherm in Upper Freeport coal seam in this case.

Two assumptions have been made in order to simplify the calculation here.

(1) No water production data was reported in this case; the coal reservoir was simulated with single phase production with only CH_4 and CO_2.

(2) Adsorption trapping is the main sequestration method in un-mineable coal seam, which was considered as the only storage mechanism without including free gas in the fractures in this study.

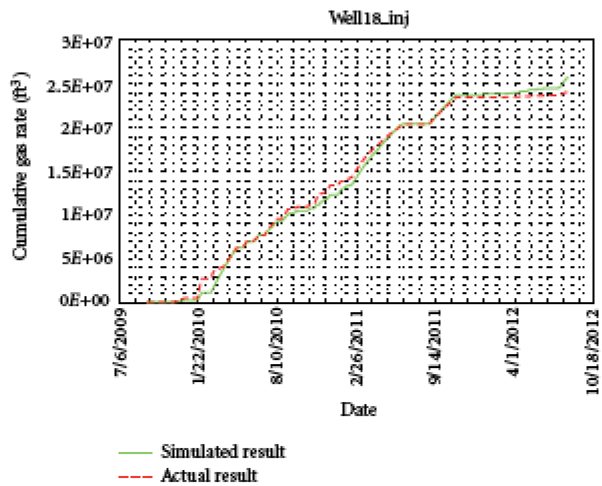
The CO_2 adsorption capacity in the coal seam can be calculated as

$$\mathrm{OGIP} = A \times h \times \rho_b \times G_{\mathrm{ci}} = V \times \rho_b \times G_{\mathrm{ci}}, \tag{4}$$

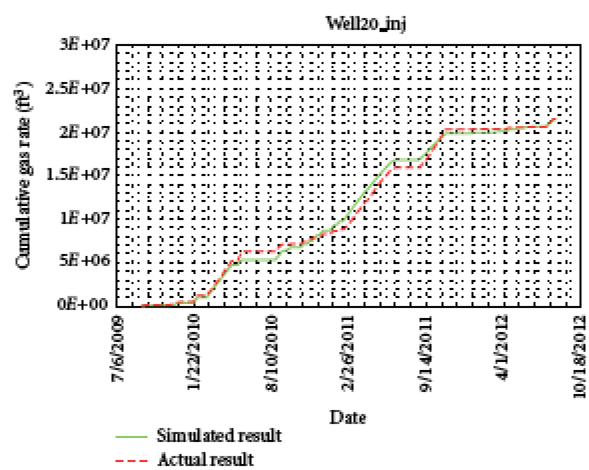
where $V_L = 800$ scf/ton, $P_L = 412$ psia, $P = 0.28$ psi/ft $\times$ 1200 ft = 360 psi, and $V(P) = G_{\mathrm{ci}} = V_L P/(P_L + P) = 800 \times$

Table 2: History matched reservoir parameter setting.

Input parameters	Value	Unit	Input parameters	Value	Unit
Average reservoir depth	1200	ft	Poisson ratio	0.3	
Average formation thickness	4	ft	Young's Modulus	125,000	psia
Fracture spacing I/J/K	0.015	ft	CO_2 Strain	0.0025	
Perm I-Matrix	0.01–0.02	md	CH_4 Strain	0.0045	
Perm J-Matrix	0.01–0.02	md	Palmer/Mansoori exponent	3	
Perm K-Matrix	0.001–0.002	md	CO_2 Langmuir Pressure	412	psia
Perm I-Fracture	0.2–0.4	md	CO_2 Langmuir Volume	800	scf/ton
Perm J-Fracture	0.2–0.4	md	CH_4 Langmuir Pressure	628	psia
Perm K-Fracture	0.02–0.04	md	CH_4 Langmuir Volume	652	scf/ton
Porosity-Matrix	0.002–0.004		CO_2 Sorption time	140	days
Porosity-Fracture	0.001–0.002		CH_4 Sorption time	350	days
Rock compressibility-Matrix	$1.00E-06$	1/psi	Rock compressibility-Fracture	$1.00E-06$	1/psi



(a)



(b)

Figure 5: Cumulative CO_2 injection history matching. (a) Cumulative CO_2 injection in MH18_inj, (b) Cumulative CO_2 injection in MH20_inj.

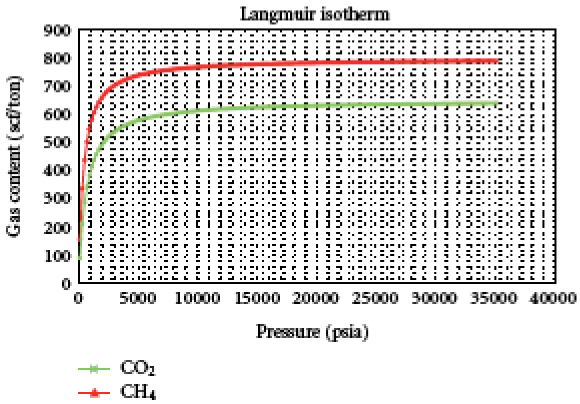


Figure 6: Existing Langmuir isotherm for CO_2 and CH_4 in Upper Freeport Coal seam.

$360/(412 + 360) = 373$ scf/ton, where, $\rho_b = 85$ lbs/ft^3, $V = 25{,}193{,}558$ ft^3, 1 ton = 2,000 lbs, Coal tonnage = 85 × 25,193,558/2,000 = 1,069,466 tons, OGIP = 1,069,466 tons × 373 scf/ton/17,483 ton/scf = 22,817 tons (coal seam volume and coal density were provided and were used directly).

5. Summary and Conclusions

The modeling and history matching process of methane production and ECBM as well as CO_2 injection in a coal bed seam was explained in this work. This process was performed using conducting actual data analysis and sensitivity analysis of related coal seam physical properties on four horizontal wells drilled in Upper Freeport coal seam. Results of history matching were compiled to show the initial and existing condition in the coal seam. CO_2 sequestration capacity prediction was completed according to the Langmuir isotherm properties obtained from the history matched reservoir model.

The simulation of CH_4 gasification and CO_2 injection process was quite complicated. The special swelling and shrinkage features and the nature of gas retention in CBM reservoirs make the modeling and history matching of production and injection data in coal bed methane more complex because of the permeability and porosity variations compared to conventional resources.

Sensitivity analysis results suggested that sorption time, cleat permeability, strain, and Langmuir isotherm are the most influential parameters during CH_4 production and CO_2 injection process. It is concluded by the Langmuir isotherm parameters from history matched model that the total CO_2 sequestration capacity is about 22,817 tons excluding the free gas part in the cleat system. The total CO_2 injection amount in the first three years was 4.5×10^7 ft^3 or 2,600 tons, which caused an increase of 6,700 scf/day in CH_4 production rate from other two wells.

Nomenclature

D: Diffusion coefficient

$\overline{C}$: Average gas concentration in the matrix

τ: Desorption time, days

$C_f((P-P_0)/\varnothing_0)$: Stress-dependent permeability term

$(K/M-1)(P/(P+P_\varepsilon)-P_0/(P_0+P_\varepsilon)(K/M-1)(P/(P+P_\varepsilon)-(P_0/(P_0+P_\varepsilon))))$: Matrix shrinkage term

Φ_i: Initial fracture porosity, %

C_f: Pore volume compressibility, 1/psi

P: Initial pressure, psi

M: Axial modulus, psi

K: Bulk modulus, psi

ε: Langmuir strain

P_L: Langmuir pressure, psi

V_L: Langmuir volume, scf/ton

A: Drainage area, ft^2

h: Net pay, ft

ρ_b: Bulk density, lbs/ft^3

G_{ci}: Gas Content, scf/ton

$\varnothing_i$: Porosity, %

B_{gi}: Initial formation volume factor, STB/scf

OGIP: Original gas in place, tons

V: Coal volume, ft^3.

Acknowledgments

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Exhibit D

0522

The Allison Unit CO_2-ECBM Pilot – A Reservoir and Economic Analysis

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ABSTRACT

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 investigated the feasibility of CO_2 sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane (ECBM) recovery field projects in the San Juan basin. The two sites were the Allison Unit, operated by Burlington Resources, into which CO_2 was injected, and the Tiffany Unit, operating by BP America, into which N_2 was injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The objectives of the field studies were to understand the reservoir mechanisms associated with CO_2 and N_2 injection into coalseams, demonstrate the effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate ECBM/sequestration economics. In support of these efforts, laboratory and theoretical studies were also performed to understand multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This paper presents the results of The Allison Unit study, in which a detailed reservoir characterization of the field was developed, the field history was matched using the COMET2 reservoir simulator, future field performance was forecast under various operating conditions, and an economic analysis performed.

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 investigated 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 were the Allison Unit, operated by Burlington Resources, into which CO_2 was injected, and the Tiffany Unit, operated by BP America, into which N_2 was injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The objectives of the field studies were to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate ECBM/sequestration economics. In support of these efforts, laboratory and theoretical studies were also performed to understand multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This paper presents the results of The Allison Unit study, in which a detailed reservoir characterization of the field was developed, the field history was matched using the COMET2 reservoir simulator, future field performance was forecast under various operating conditions, and an economic analysis performed.

SITE DESCRIPTION

The Allison Unit ECBM pilot is located in San Juan County, southern New Mexico, in close proximity to the border with Colorado (Figure 1). While the Unit consists of many wells, the pilot area for CO_2 injection consisted of 16 coalbed methane (CBM) producer wells, 4 CO_2 injectors, and one pressure observation well (POW #2). The study area well pattern is illustrated in Figure 2. At the center of the study area is a five-spot of CBM producers on nominal 320 acre spacing (wells 130, 114, 132 and 120 at the corners, and well 113 in the center), with the four CO_2 injectors roughly positioned on the sides of the five-spot between the corner producer wells (creating a nominal 160 acre spacing between injectors and producers). POW #2 is located on the eastern border of the central pattern, and the remaining CBM producers surround this central pattern.

The producing history for the study area is shown in Figure 3. The field originally began production in 1989, with CO_2 injection occurring between April, 1995 and August, 2001. Several points are worth making regarding the producing history:

- Upon commencement of the injection operations, the five producer wells in the central five-spot pattern were shut in. The purpose was to facilitate CH_4/CO_2 exchange in the reservoir. After about six months, CO_2 injection was suspended for about another six months, during which time the five shut-in producers were re-opened. These activities can be clearly identified in Figure 3; their impact on long-term production performance however, if any, is unclear.

- Shortly after CO_2 injection began, a program of production enhancement activities unrelated to the CO_2-ECBM pilot was implemented. Those activities included well recavitations, well reconfigurations (conversion from tubing/packer completions to annular flow with a pump installed for well dewatering), line pressure reductions due to centralized compression, and also the installation of on-site compression. These activities largely coincided with the dramatic increase in production observed beginning in mid-1998.

In addition, a plot of injection rate and pressure history for injector well # 143 is shown in Figure 4. Injection was performed at a constant surface pressure, and rate was allowed to vary. Note the reduction in injection rate during early time, presumably due to coal swelling and permeability reduction. The rebound in injectivity during later times is believed due to overall reservoir pressure reduction and resulting matrix shrinkage that occurred near the injector wells.

RESERVOIR DESCRIPTION

The Allison Unit wells produce from three Upper Cretaceous Fruitland Formation coal seams, named the Yellow, Blue and Purple (from shallowest to deepest) using Burlington Resources' terminology. A summary of basic coal depth, distribution, thickness, pressure, and temperature information is provided in Table 1.

Sorption isotherms for both CH_4 and CO_2 were measured for six coal samples taken from three wells within the study area. Average CH_4 and CO_2 isotherms based on these data for each coal interval, on a raw basis and at an average density of 1.5 grams per cubic centimeter (g/cc), are shown in Figures 5 and 6.

In May, 2000, pressure buildup tests were performed on 12 wells in the Allison Unit, eight of which were inside the study area. Analysis of these data provided estimates of effective gas permeability, skin factor, and reservoir pressure. Two adjustments of the results were made to 1) derive absolute permeability from the effective gas permeability results and 2) correct to initial conditions – accounting for both pressure-dependent permeability and matrix shrinkage. The resulting permeability map of the field is shown in Figure 7. Permeability values ranged from 30-150 millidarcies (md), with higher permeabilities concentrated within the central 5-spot pattern. No permeability anisotropy appeared to exist for the study area.

A novel technique was also used to estimate relative permeability and porosity for the study area based on historical gas and water production. This technique, described in a detailed report on the Allison Unit[2], provided average relative permeability curves for the study area, as well as a porosity map.

RESERVOIR MODEL CONSTRUCTION

The reservoir simulator used for the study was ARI's COMET2 (binary isotherm – CH_4 and CO_2) model. Details on the model theory are provided in the references[3,4].

A three-layer (Yellow, Blue, Purple), full-field model was constructed. The coal structure and thickness information for each layer was directly input per the maps generated. Coal permeability and porosity maps were similarly employed. Relative permeability curves from the analysis mentioned previously, as well as the laboratory isotherms, were also used.

Additionally, well completion and operating parameters were examined for input into the model, such as recavitations, well reconfigurations and producing pressure adjustments. This was particularly important given the complexity of the field history, and the desire to isolate and study the effects of CO_2 injection.

The model gridblock dimensions were 33 x 32 x 3 (approximately 3,200 total grid blocks, 2,600 of which were active), and covered an active area of about 7,100 acres (Figure 8). On average, the gridblock dimensions were 560 feet x 525 feet x 14 feet. The corners of the model were isolated using no-flow barriers to account for producing wells immediately adjacent to these portions of the study area.

HISTORY MATCH RESULTS

The independent parameter used for the simulator was gas production (and injection) rate to maintain material balance, and the dependent (history match) parameters were water production rate, flowing pressure (producing and injecting), and gas composition. Note that only some of these data were available for some periods for some wells; whatever was available was used. In addition, the pressure history at POW #2 was available.

All parameters were modified globally to obtain the best overall match for the field. The objective of the study was to understand the mechanisms of the CO_2-ECBM process by matching general trends, and not necessarily to make regional changes to the reservoir characterization to achieve matches on an individual well basis. While a large number of simulation trials were performed varying almost all significant reservoir parameters, it was ultimately found that the original reservoir characterization seemed to provide the best overall result.

A comparison of the actual versus simulated field gas rate is presented in Figure 9. The only conclusion that can be derived from this result, since the model was "driven" on gas rate, is that model (as constructed) was capable of delivering the gas volumes required.

The actual versus simulated pressure at POW#2 is presented in Figure 10. Actual pressure data is only available after the commencement of CO_2 injection. At that particular point in time (April, 1995), there appears to be excellent agreement between actual and predicted pressure, suggesting that material balance (at least during primary production) was achieved, and hence values for original gas/water storage capacities, as well as depletion characteristics, were reasonable. After that, however, there is considerable difference in pressure values. Of note is that the estimated pressure at the location of POW #2 based on the May, 2000 pressure transient analysis (PTA) is reasonably close to the simulated value. After considerable analysis of the discrepancy it is believed that the pressure data recorded at POW#2 may have been influenced by severe restrictions in wellbore-reservoir connectivity, and therefore may not have been valid.

Comparison plots of gas and water rates, flowing pressures, and produced gas compositions, for well 113 are presented in Figure 11. This well was selected because it was the central well of the 5-spot, it had data for comparison in all categories, and it had observable CO_2 breakthrough. In addition, this well typifies the differences in simulated versus actual results for the other wells. Several general comments can be made regarding the results:

- The quality of the water rate predictions varied, with some being too high and some too low. However, on balance the predictions were considered within reason (and that could be easily "fixed" with regional variations in porosity and/or water relative permeability).

- In all cases, the predicted bottomhole flowing pressures were higher than the measured values – which were actually surface casing pressure data – usually by 200-300 psi. While some difference might be expected due to the different types of data being compared (surface vs. downhole), the magnitude of the difference seems large. (The wells were believed to be pumped-off with little water head existing above the coal seam.) In most cases the predicted flowing pressures appear smooth through the period when the recavitation operations were performed. This result was per the model design.

- In general, the trend in gas composition was reasonably well replicated. In some cases (most noteworthy well #113), the increase in CO_2 content of the produced gas occurs more rapidly than that actually observed.

A comparison of actual to simulated bottomhole injection pressures for CO_2 injector well #142 is provided in Figure 12. Note that the results for the other three injector wells were very similar. The actual bottomhole pressure history data was computed using long-term surface pressure data, and flowing pressure gradients obtained during the August, 2001 injection/falloff tests. The simulated pressures are considerably lower than the actual values. While simulated bottomhole pressures could be increased substantially to better match the actual data by assuming lower initial permeability values for the injector well gridblocks, the objective was to see if the coal swelling formulation in the simulator could adequately account for sufficient permeability reduction to achieve the high injection pressures observed. The result suggests that the answer is negative. Therefore, coal swelling models with CO_2 injection may require further development to adequately replicate field data.

Pressure transient tests performed in August, 2001 in the CO_2 injection wells indicated near-well permeabilities of <1 md, considerably less than the estimated initial values. However, at most injectivity was only cut in half. The apparent discrepancy between the high permeability reduction and comparatively modest injectivity loss was investigated by examining the permeability profile that extended radially from one of the injector wells (#142) at about the time when injectivity was at its lowest value. The result is shown in Figure 13. This plot suggests that the permeability reduction effect is decreased radially from the well, and reached a distance of about 1000 feet. Simple analytic modeling confirmed that this type of permeability reduction profile would yield a reduction in injectivity by about a factor of two, all else being equal.

PERFORMANCE FORECASTS

In order to evaluate the long-term performance of the ECBM pilot, performance prediction cases were simulated using the history match result as the starting point. The specific cases evaluated were:

1. No CO_2 injection (i.e., primary production only).
2. Current conditions (i.e., CO_2 injection until August 2001).
3. Aggressive injection (i.e., CO_2 injection at four times actual rate until August, 2001)

For each ECBM forecast case, an economic limit of 50 Mcfd of methane per well and 50% CO_2 content per well was imposed; reaching those thresholds prompted the well in question to be shut-in in the model. Results of the forecast for the actual pilot conditions indicated that of the 6.4 Bcf of CO_2 injected in the pilot area, 1.6 would ultimately be reproduced. The incremental methane recovery was 1.6 Bcf, yielding a net CO_2/CH_4 ratio of 3.0. Figure 14 presents the simulated sweep of the CO_2 at the end of the forecast period for the pilot. Note that excellent sweep appears to have been achieved in the northern, western, and southern quadrants of the five-spot. However, due to the location of injection well #140, poor sweep was achieved in the eastern quadrant.

Since the model area was so large compared to the actual flooded area, the incremental recovery results were examined for each quadrant of the central 5-spot pattern. Methane recoveries with and without CO_2 injection were computed for each quadrant and are presented in Table 3. This analysis indicates that CO_2-ECBM was highly effective at recovering incremental methane, providing on the order of 17 – 18% of original-gas-in-place where the patterns were configured for effective sweep.

Two additional interesting observations were made regarding the modeling results:

- The stabilized CO_2/CH_4 ratio of about 3:1 is higher than normally cited for San Juan basin coals. However, if one examines the ratio as a function of pressure (based on the isotherms) the results are as expected (Figure 15). At an abandonment pressure of ~50 psi, the CO_2/CH_4 ratio is close to 3:1.

- It appears that some time was required after CO_2 injection ceased for the CO_2 to migrate through the reservoir and displace the "equilibrium" volume of methane. Figure 16 illustrates the CO_2/CH_4 ratio over time for the pilot. Note that the ratio increases during injection periods (and for some time afterwards), and then begins a gradual decline to the equilibrium value.

ECONOMIC ASSESSMENT

The final element of the study was to evaluate the economic performance of the pilot. The capital, operating and financial assumptions are presented in Table 3. Note that all economics were performed on an incremental basis (i.e., only the incremental production and costs were considered). Further, the effect of Section 29 tax credits was not considered.

The analysis first evaluated the performance of the existing pilot, with no future CO_2 injection considered. Note that the hot-tap and pipeline capital costs are included for this case, but only allocated at 25% of the total since the working assumption was that it would also be used for additional pilots and/or large-scale CO_2 flood implementation. The results are presented in Figure 17. There are several points worth making. First, at the prevailing gas price at the time of the pilot (~ \$2.20/Mcf), the project had a negative net present value (NPV), not accounting for Section 29 tax credits. At \$4.00/Mcf however, it would have yielded a peak NPV of \$2 – 3 million. The breakeven gas price for the pilot was \$2.57/Mcf.

Secondly, a peak in NPV occurs approximately five-years after CO_2 injection began. Examination of the incremental methane recovery profile provides insight into this finding, shown in Figure 18. The CO_2 injection resulted in some acceleration of methane recovery, and when the incremental methane rate became negative at later times, the NPV began to drop. This point in time also corresponds to the peak CO_2/CH_4 ratio in Figure 16. The implication is that there may be a fixed, optimum CO_2 volume that should be injected to a given pattern, probably corresponding to the volume of methane in place and the equilibrium CO_2/CH_4 ratio, and any further injection in addition to that volume merely represents additional cost without additional methane recovery. At the Allison Unit pilot, that optimum CO_2 injection volume appears to have been exceeded.

Finally, since the CO_2 injection rate was constrained by pressure limitations and coal swelling. The impact of a higher injection rate was examined. These cases, at \$2.20/Mcf and \$4.00/Mcf, are also shown on Figure 17. It is clear that higher injection rates substantially improves CO_2-ECBM economic performance. Therefore strategies for mitigating coal swelling and injectivity reduction should be a priority consideration for CO_2-ECBM projects.

CONCLUSIONS

Based on the results of this study, the following conclusions have been drawn:

- The injection of CO_2 at the Allison Unit has resulted in incremental methane recovery over estimated ultimate primary recovery, in approximately a proportion of one volume of methane for every three volumes of CO_2 injected. Methane recoveries of 17 - 18% of original-gas-in-place were estimated for effectively swept portions of the 5-spot.

- At the prevailing gas prices at the time the project was implemented (~$2.20/Mcf), and not considering any tax credit benefits, the pilot itself was uneconomic. However, with today's gas prices of ~$4.00/Mcf, CO_2-ECBM appears economically attractive. The breakeven gas price for the conditions at Allison was estimated to be ~ $2.60/Mcf.

- There appears to be clear evidence of significant coal permeability reduction with CO_2 injection. This permeability reduction, and the associated impact on CO_2 injectivity, compromised incremental methane recoveries and project economics. Finding ways to overcome and/or prevent this effect is therefore an important topic for future research.

ACKNOWLEDGEMENTS

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2) Reeves, S.R., Taillefert, A. Pekot, L., and Clarkson, C.: "The Allison Unit CO_2 – ECBM Pilot: A Reservoir Modeling Study", Topical Report, DOE Contract No. DE-FC26-00NT40924, February, 2003.

3) Reeves, S. and Pekot, L.: "Advanced Reservoir Modeling in Desorption-Controlled Reservoirs," SPE 71090, presented at the SPE Rocky Mountain Petroleum Technology Conference, Keystone, May 21-23, 2001.

4) Sawyer, W.K., Paul, G.W., Schraufnagel, R.A., "Development and Application of a 3D Coalbed Simulator," CIM/SPE 90-119, presented at the CIM/SPE International Technical Conference, Calgary, June 10-13, 1990.

Table 1: Basic Coal Reservoir Data, Allison Unit

Property	Value
Average Depth to Top Coal	3,100 feet
Number of Coal Intervals	3 (Yellow, Blue, Purple)
Average Total Net Thickness	43 feet Yellow - 22 ft Blue - 10 ft Purple - 11 ft
Initial Pressure	1,650 psi
Temperature	120° F

Table 2: Incremental Recovery by Quadrant, Case 2 vs. Case 1

Quadrant	Recovery (% OGIP)		
	w/o CO_2	w/ CO_2	Incremental
North	77%	94%	17%
West	77%	95%	18%
South	77%	95%	18%

Table 3: Economic Analysis Assumptions

Capex	
CO_2 Hot Tap:	$175,000 } Allocated @ 25%
36 mi (4 inch) Pipeline:	$3.5 million ($24,000/in-mi) } Allocated @ 25%
Field Distribution:	$80,000 ($20,000/in-mi)
Wells	$1.6 million ($400,000/ea; fully equipped)
Total	$5.355 million
Opex	
Injector Well Operating:	$1,000/mo (active only)
CO_2 Cost	$0.30/Mcf
Produced Gas Processing	$0.25/Mcf
Financial	
Gas Price:	$2.20/MMBTU (ex-field)
Methane BTU Content	1.04 MMBTU/Mcf
Net Revenue Interest:	87.5%
Production Taxes:	8%
Discount Rate:	12%

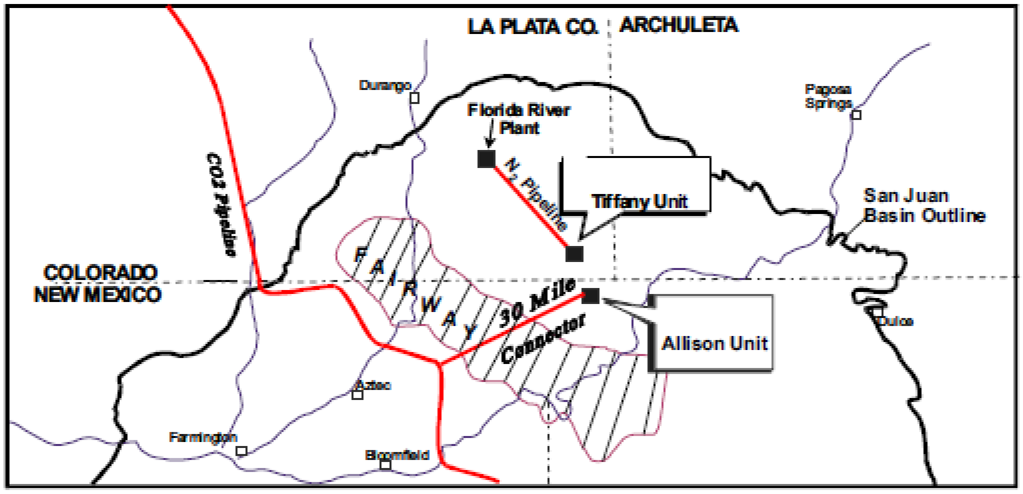


Figure 1: Location of the Allison Unit, San Juan Basin

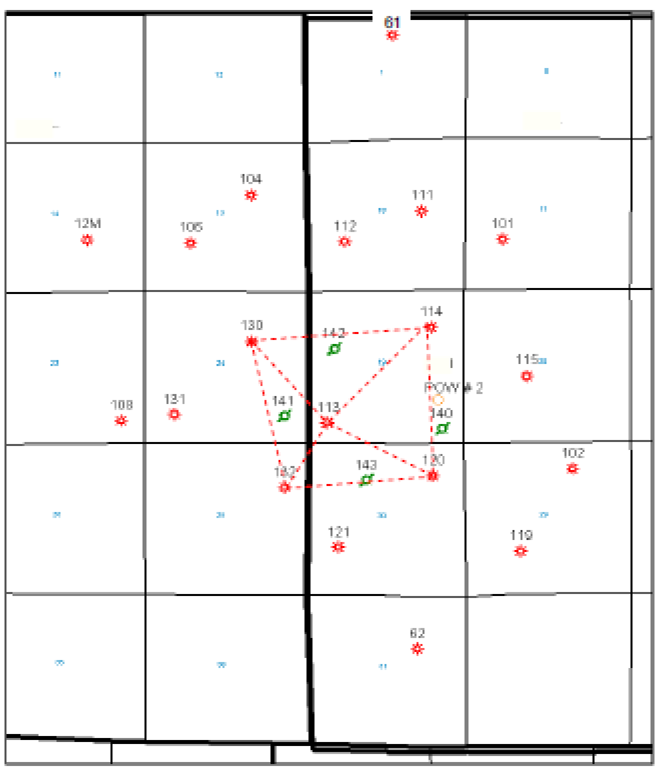


Figure 2: Producer/Injector Well Pattern, Allison Unit Study Area

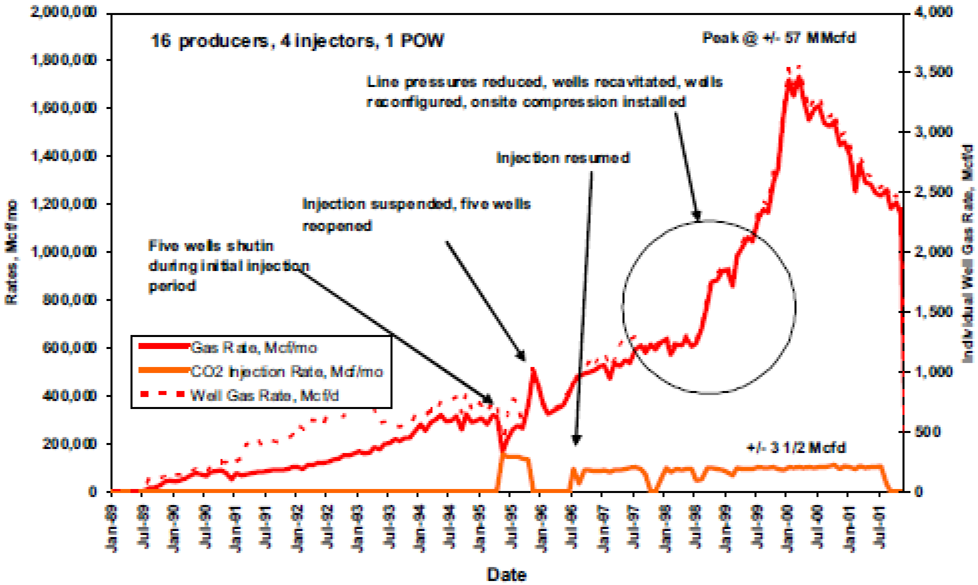


Figure 3: Producing History, Allison Unit Study Area

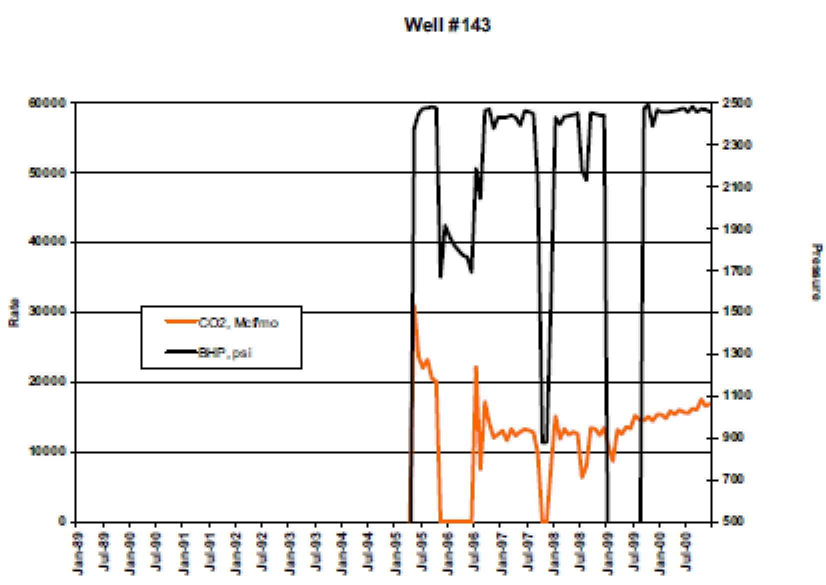


Figure 4: Injector Well # 143 Injection and Pressure History

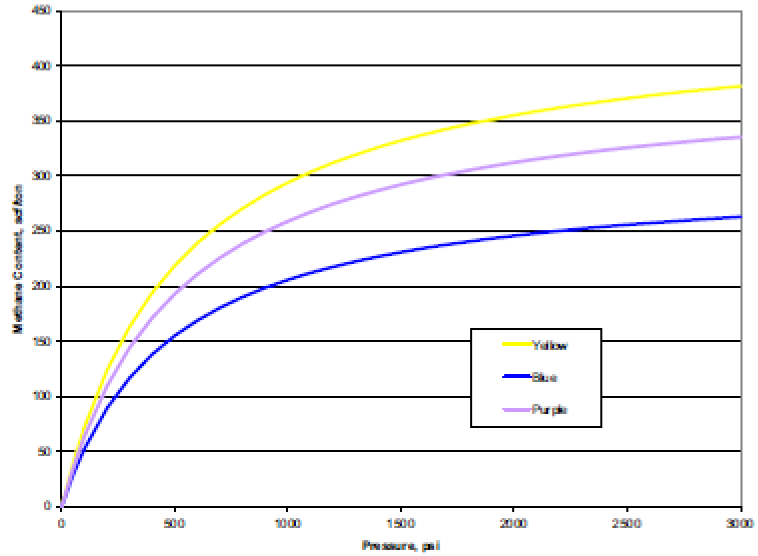


Figure 5: Methane Sorption Isotherms, Allison Unit Study Area

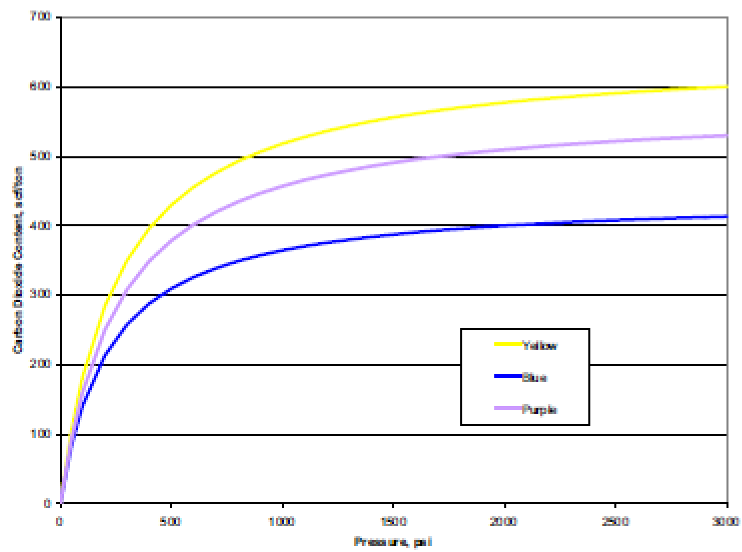


Figure 6: Carbon Dioxide Sorption Isotherms, Allison Unit Study Area

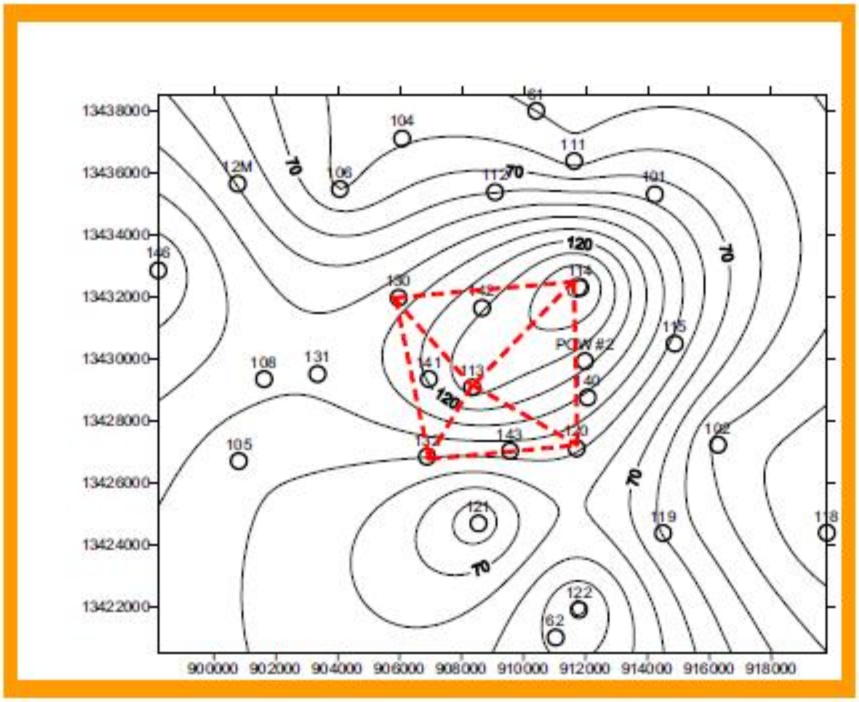


Figure 7: Permeability Map for Allison Unit Study Area

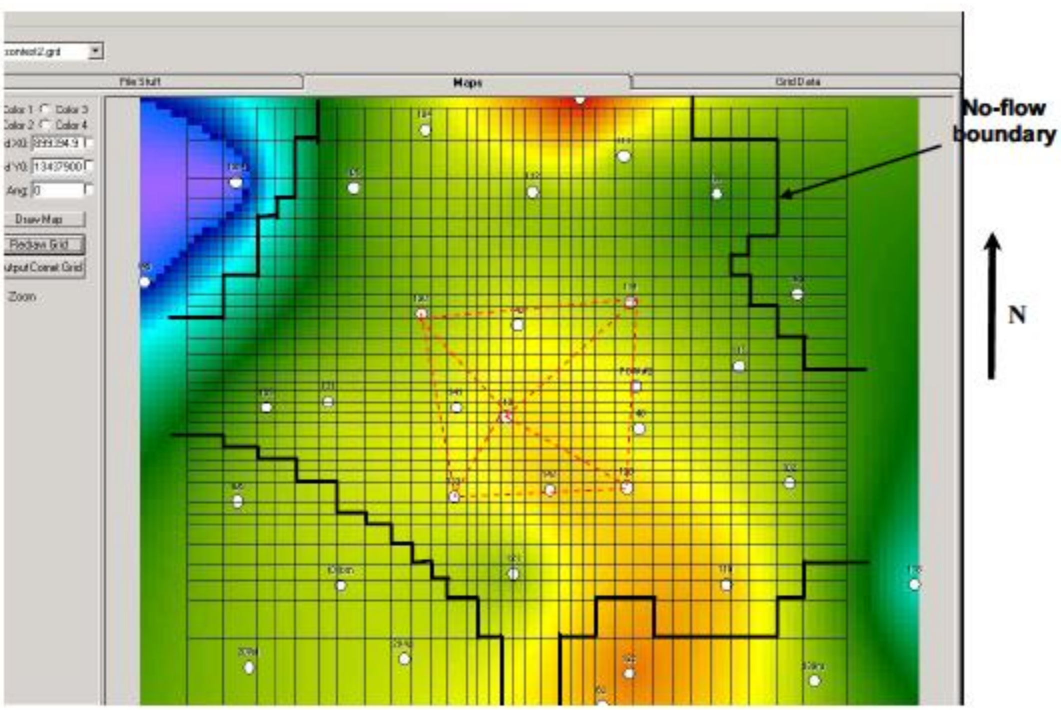


Figure 8: Map View of the Middle Layer of the Simulation Model

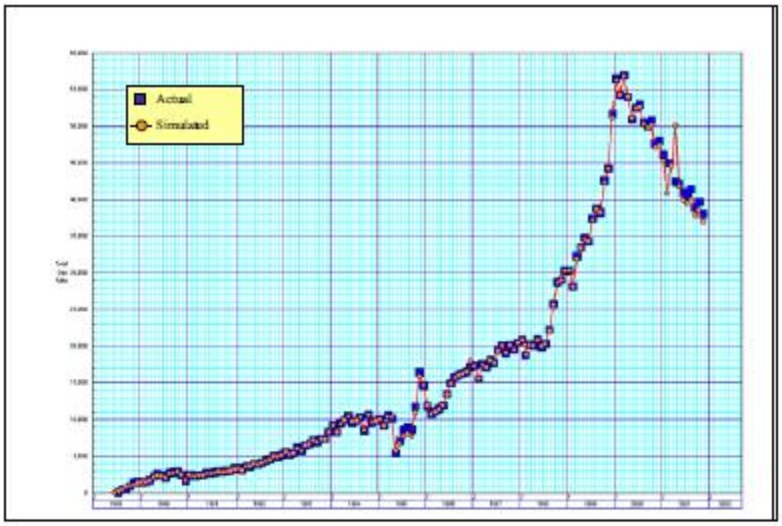


Figure 9: Actual versus Simulated Field Gas Rate, Allison

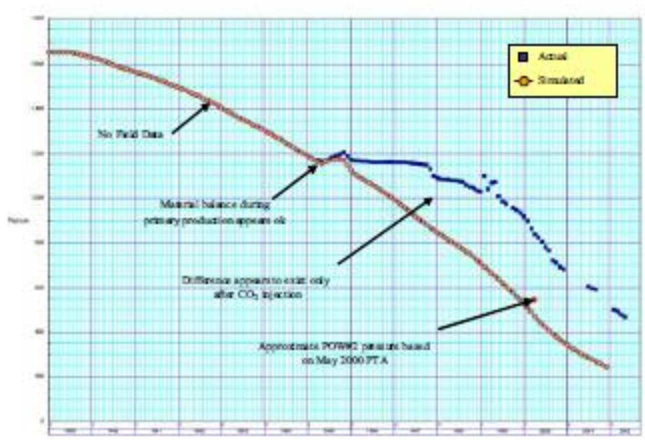


Figure 10: Actual versus Simulated Pressure at POW#2

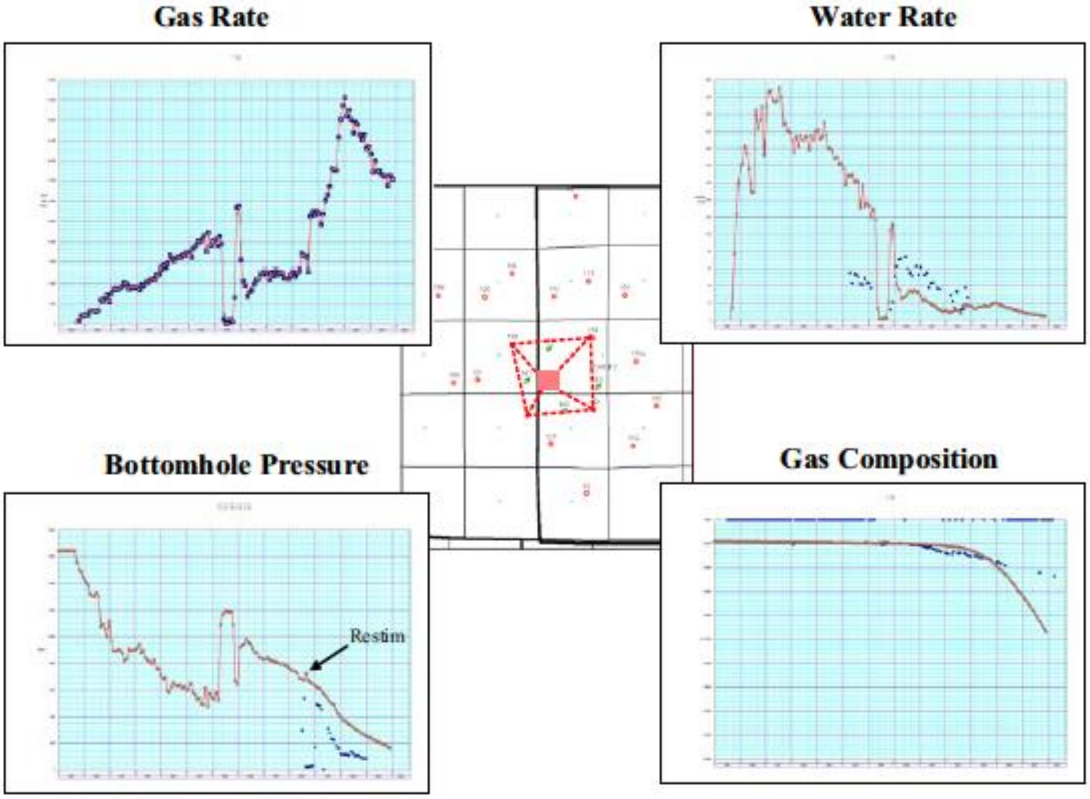


Figure 11: Comparison of Predicted to Actual Well Performance, Well 113

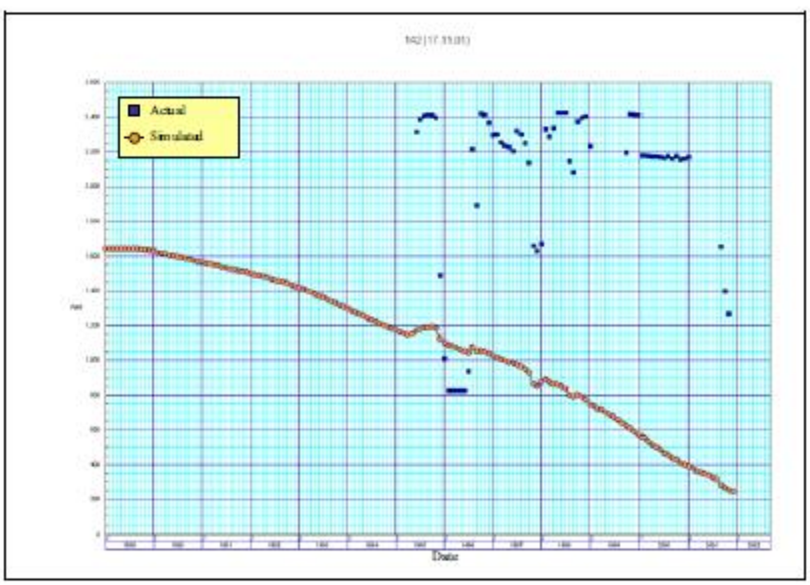


Figure 12: Comparison of Predicted to Actual Bottomhole Injection Pressures, Injection Well #142

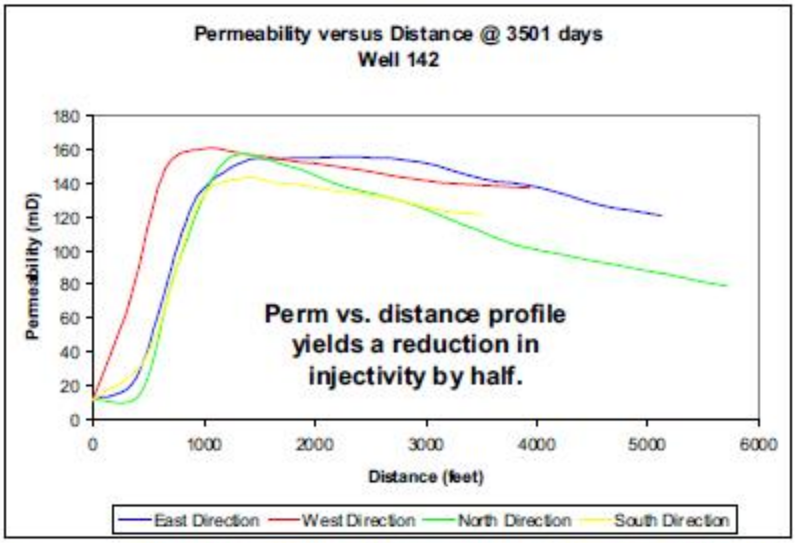


Figure 13: Simulated Permeability Profile from Injector Well #142

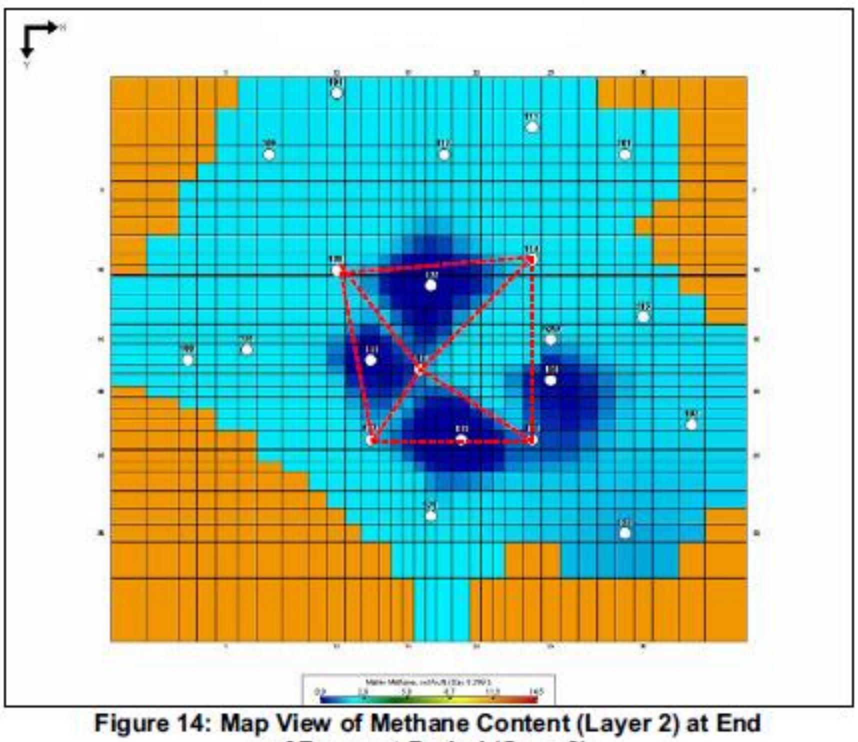


Figure 14: Map View of Methane Content (Layer 2) at End of Forecast Period (Case 2)

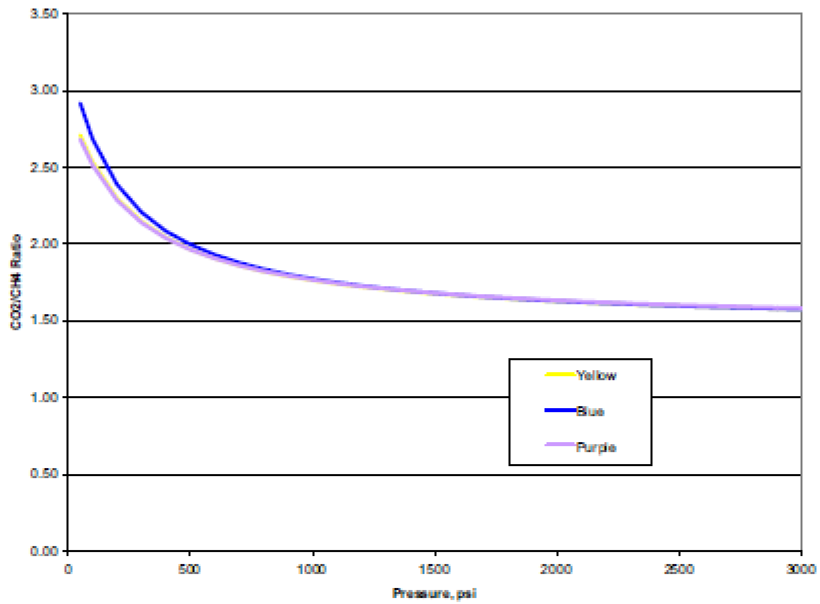


Figure 15: CO_2/CH_4 Ratio vs. Pressure

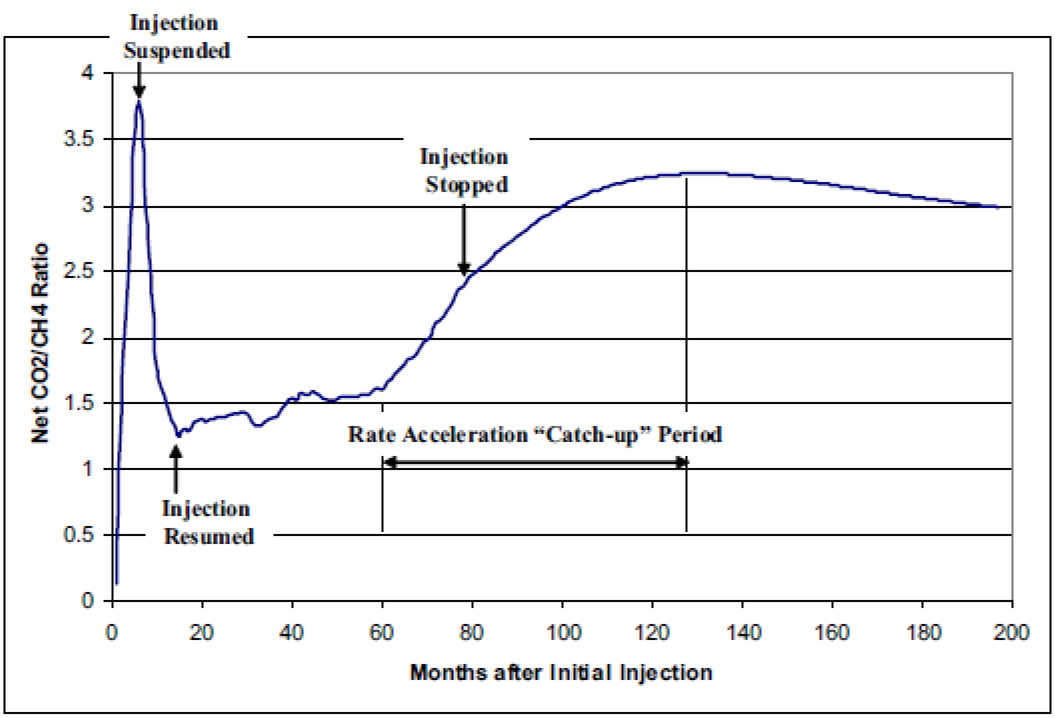


Figure 16: CO_2/CH_4 Ratio vs. Time, Allison Unit Pilot

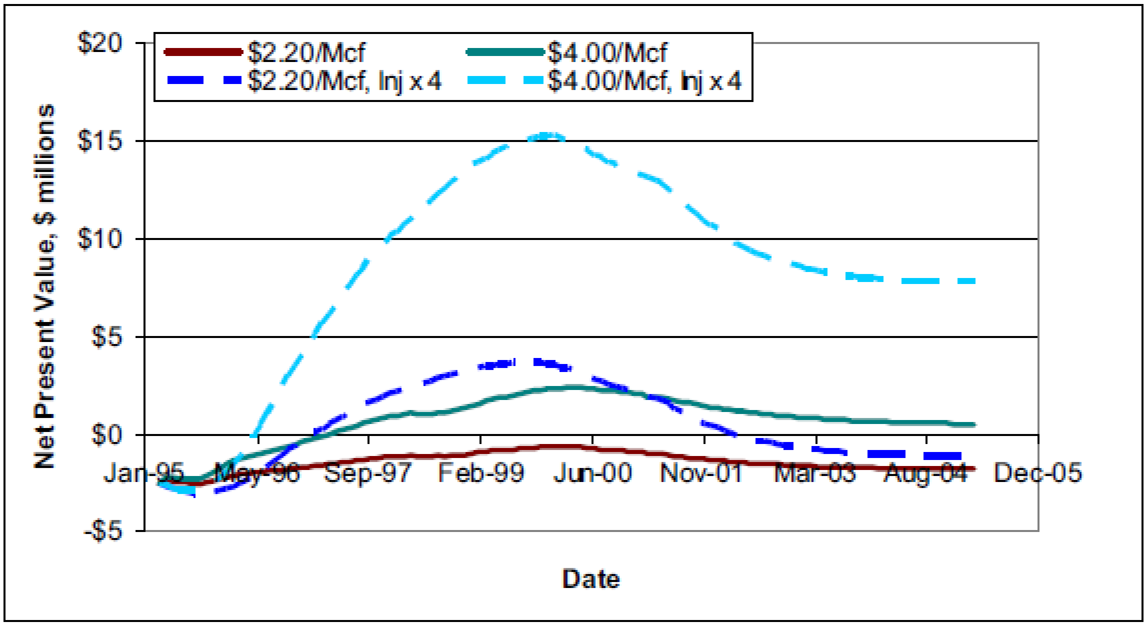


Figure 17: Economic Analysis Results, Case 2 vs. Case 1

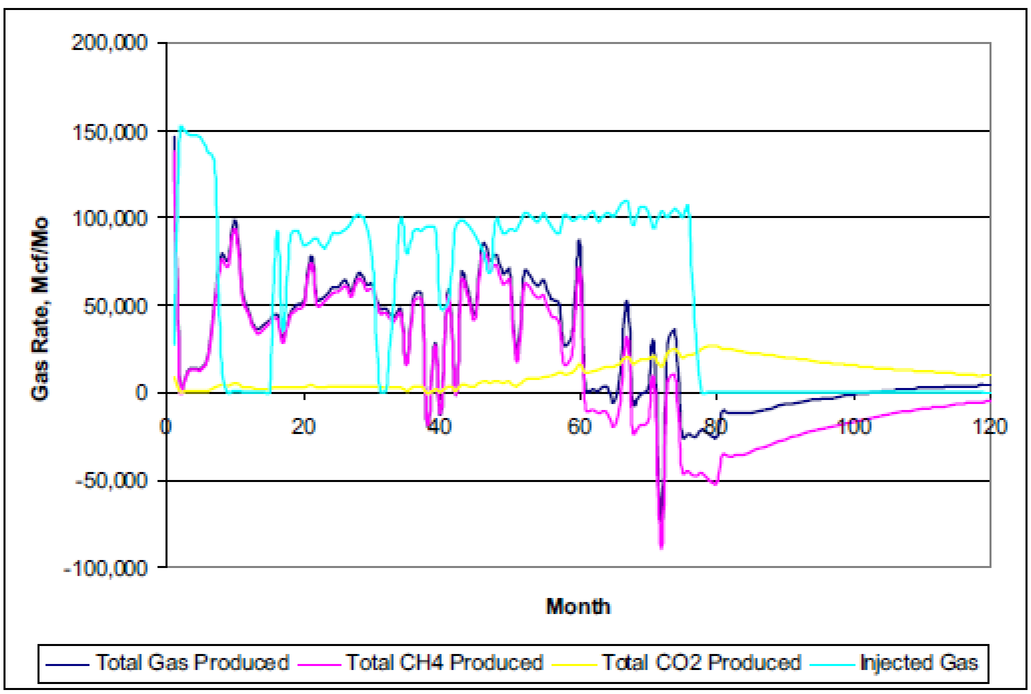
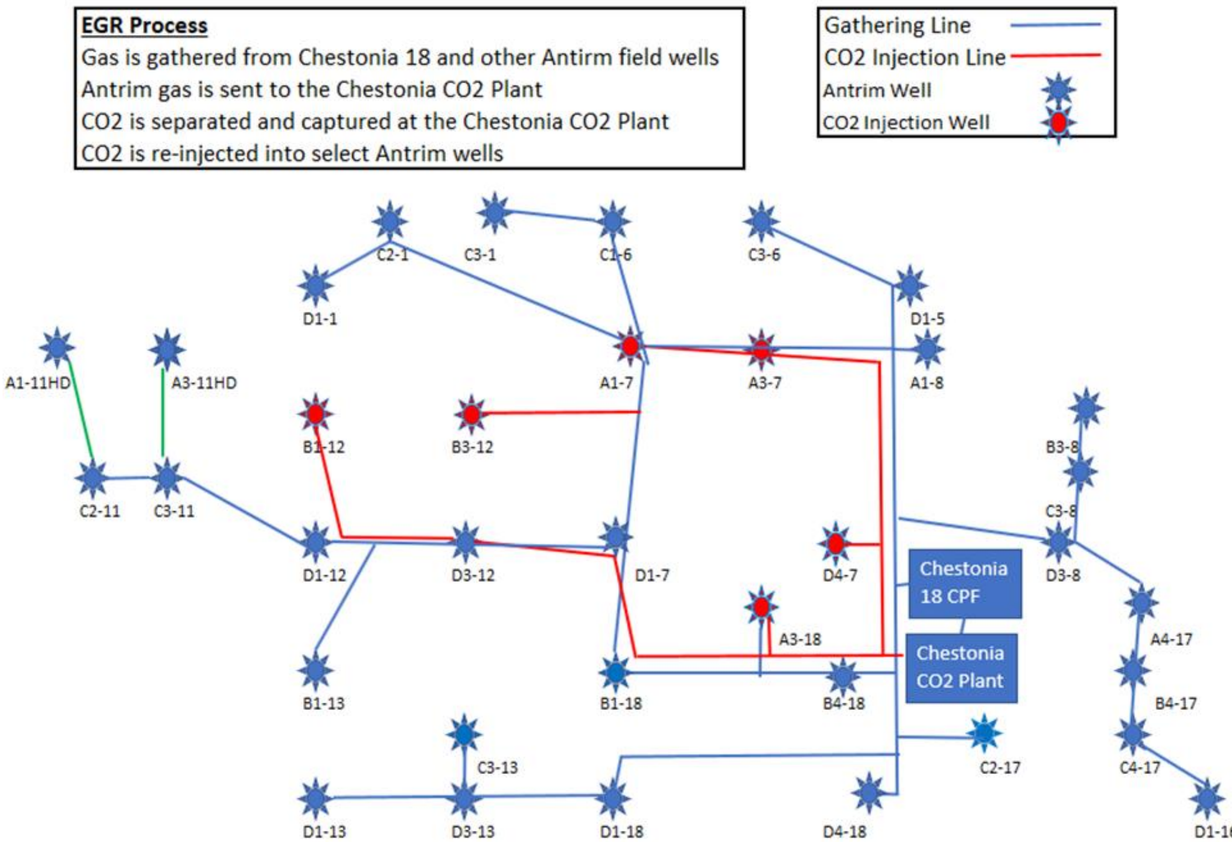


Figure 18: Incremental Gas Rates, Case 2 vs. Case 1

Exhibit E

CO2 Injection Process Diagram (Not to Scale)



Chestonia 18 Pool
CO2 EGR Project Process Diagram

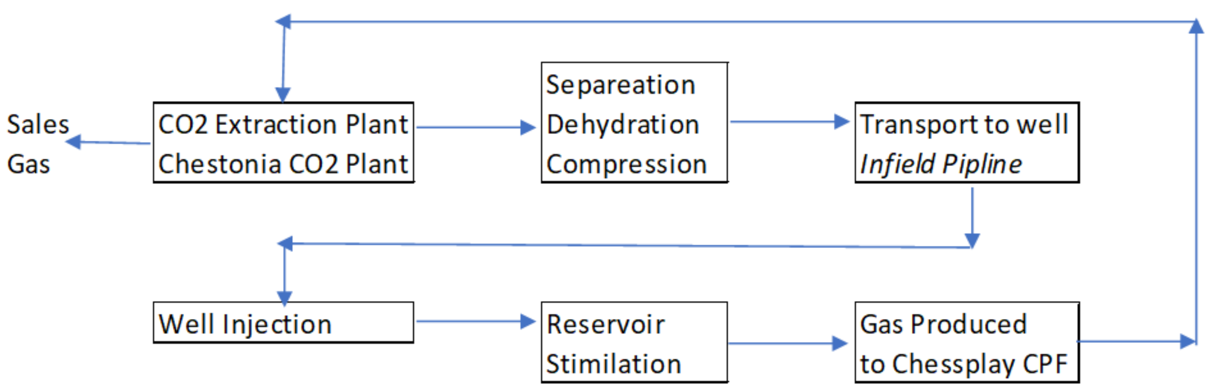


Exhibit F – Cross Section Diagram

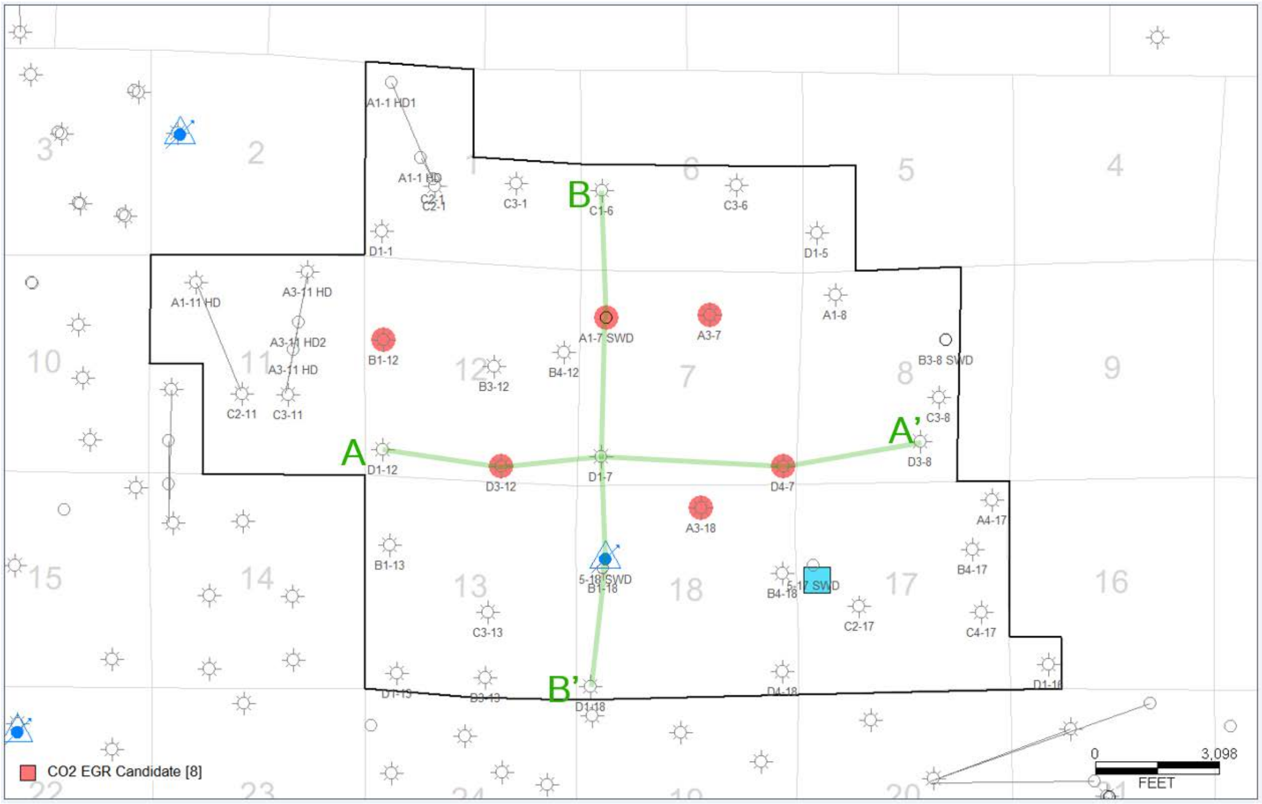


Figure 1. Base map of the Chestonia 18 Project, showing the project boundary outline (black), candidate wells for CO2 injection (red), the Chestonia CO2 processing plant (blue), and locations of two geologic cross-sections (green, A-A' and B-B', see figures 3 and 4).

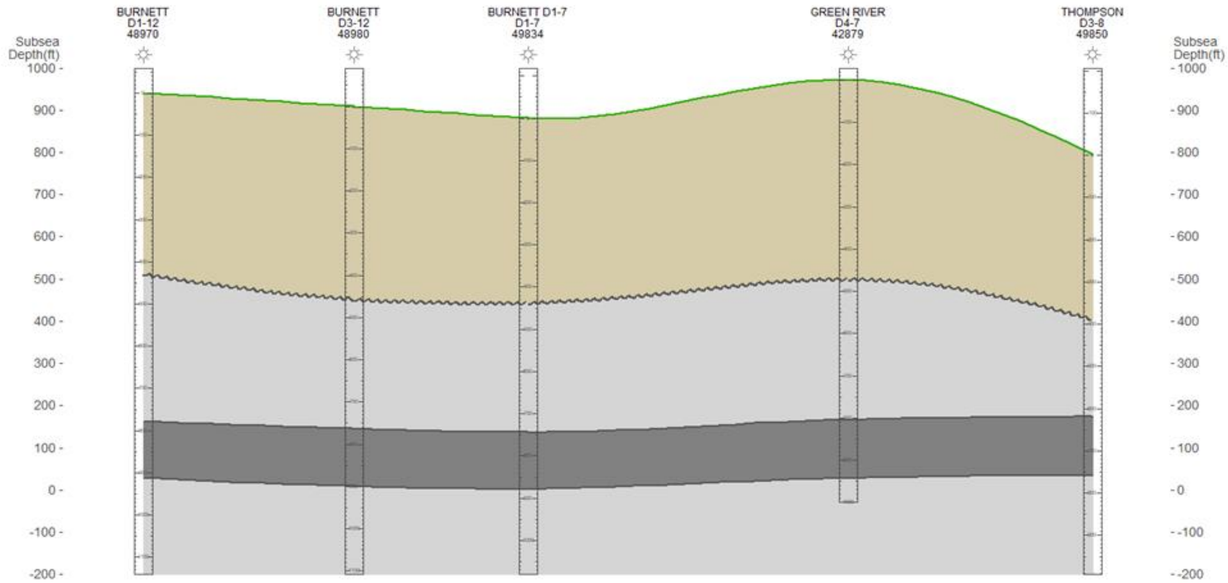


Figure 2. East-west cross-section of the Antrim Shale and overlaying strata at the Chestonia 18 Project.

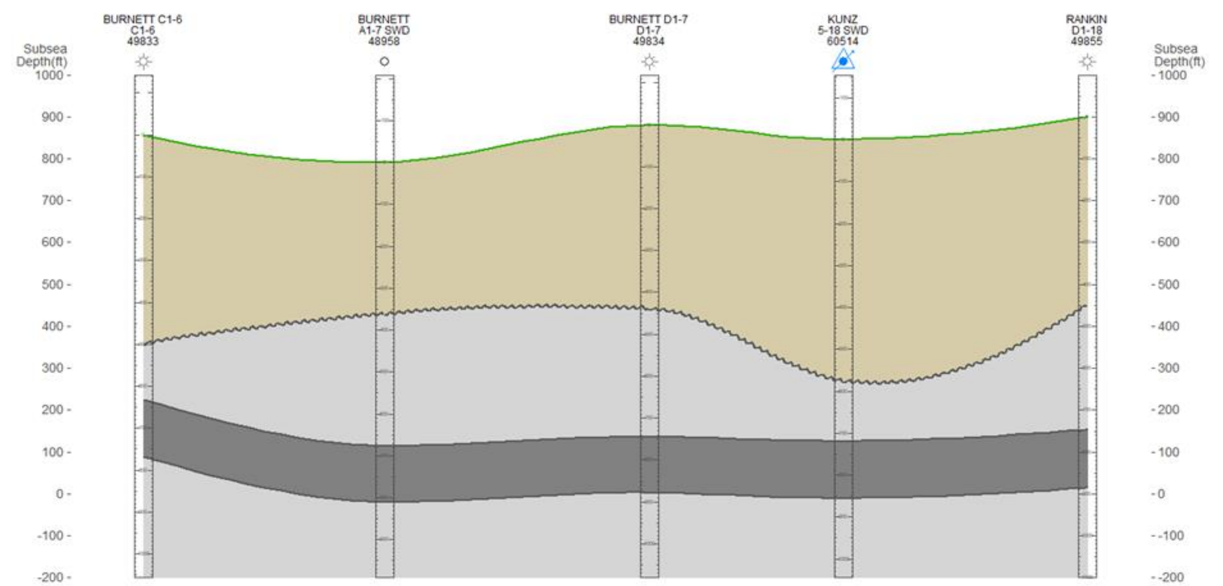
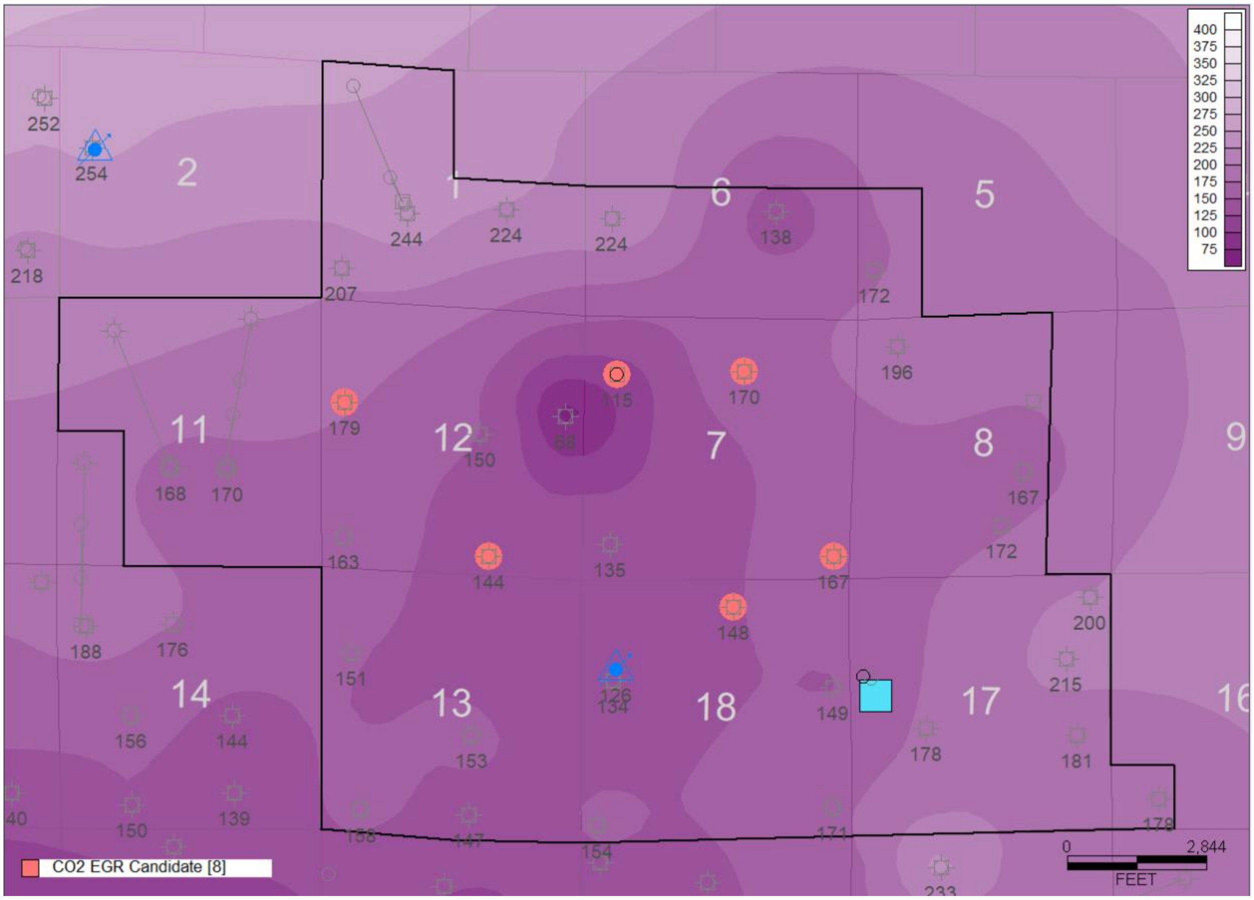


Figure 3. North-south cross-section of the Antrim Shale and overlaying strata at the Chestonia 18 Project.

Exhibit G - Structural Diagram



Chestonia 18 Unit - Structure map of the top of the Antrim Shale (C.I. = 25 ft). Structure data determined from well logs and driller's reports are posted at well symbols. Also shown are candidate wells for CO2 EGR injection (red), and the Chestonia 18 CO2 processing facility (blue).

Exhibit H – Reservoir Properties

Chestonia 18 Unit

Initial Reservoir Pressure

- **Antrim Shale pressure gradient range is .35 -.38 psi/ft, average .365**
- **Average depth mid- perf 737**
- **Calculated pressure = 269 psi**

Initial Gas Formation Volume Factor

Gas Gravity

- **Specific gravity - 0.62**
- **CO_2 content – 6.46 %**

Porosity Range

- **3 – 10% (A. Agrawal, 2010)**

Average Porosity

- **9% (A. Agrawal, 2010)**

Gas Content

- **Approximately 60 – 70% of Antrim gas is absorbed to the rock matrix (A. Agrawal, 2010).**
- **Gas content for the Antrim ranges between 40 SCF/ton to 100 SCF/ton (Phasis Consulting, 2008)**
- **80 acre unit = 26,840,051 tons of rock or 1,073.602 to 2,684.005 MMcf**
- **The Chestonia/Kearney Unit is 3,860 acres or 1,295,032,461 tons of rock = 51,801 – 129,503 MMcf in place**

<u>Exhibit I</u> – Estimated In-Place Volumes & Recoveries

Chestonia 18 Unit

Estimated In-Place Volumes & Recoveries

Original Gas in Place (OGIP) Estimate:

- **51,801 – 129,503 MMcf in place**

Recoveries from Primary Production:

- Produced thru July 2019 - 8,372.96 MMcf
- Estimated Remaining Primary - 3,143.63 MMcf
- Total - 11,544.16 MMcf

Estimates Ultimate Recover (EGR) from CO2 EGR:

- Assuming 60% of original gas in place is absorbed to the rock 31,080 – 77,701 MMcf
- Assuming an additional 10% recovery of absorted gas could be achieved by CO2 injection/absorption
- Potential additional gas recovered 3,108 MMcf to 7,770 MMcf

Total Potential EUR of Gas (Primary + CO2 EGR):

14,652 MMcf to 19,314 MMcf

Exhibit J – Estimated Economics of EGR Project

Chestonia/Kearney Unit

Estimated Economics of EGR Project

Undiscounted Economics	MM$
Gross Net Revenue = 3,108,000 (lower end EGR) X $2.25/mcf X 80% NRI	$ 5.594
Estimated CAPEX =	$ 0.600
EGR Operating LOE = $12,000/year * 20 years	$ 0.240
Total	$ 4.754

<u>Exhibit K</u> – Injection Well Construction

The Drift and Ground Water are protected by two strings of casing and two cement jobs.
Surface Casing is set at least 100' beyond the base of Drift
Production/Injection Casing is cemented to surface
Packer and Tubing are Set and monitored