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Coalbed Methane: Recovery & Utilization in North Western San Juan, Colorado

EME 580 : Integrative Design

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INTRODUCTION:

Natural Gas is a vital component of the world's supply of energy. It is one of the cleanest, safest, and most useful of all energy sources. It is a fossil fuel like coal and oil and a mixture of combustible hydrocarbon gases with methane being the principal component (usually 70-90%). Methane is a greenhouse gas with a global warming potential (GWP) over 100 years of 23. This means that when averaged over 100 years each kilogram of methane warms the Earth 23 times as much as the same mass of carbon dioxide (1). Harnessing this resource will not only help meet the growing energy demands but also help reduce the problem of global warming.

According to the U.S. Energy Information Administration 2008 data, primary energy consumption by source and sector for that year showed that contribution of natural gas to energy consumption was nearly 24% of the total. Majority of this amount is reflected in the residential and commercial sectors. However, over the past decade, a gap between demand and consumption is evident; to fulfill a part of which, United States has been importing natural gas from countries like Canada and New Mexico. However, to be self sufficient in its energy needs, U.S. is looking towards others sources of natural gas like Tight gas, Shale gas, Coal Bed Methane, Landfill gas etc. This project focusses on the development and utilization of Coal Bed Methane, an unconventional source of natural gas.

Unconventional resources are resources that have low permeability and require advanced drilling or stimulation technologies to be produced at commercial flow rates. The role of unconventional gas in the future supply picture is made crucial by the fact that conventional gas basins (where gas flows out naturally when a well is drilled) appear to be becoming increasingly supply challenged. Coal Bed Methane is an unconventional source in which methane is trapped or adsorbed in the coal surface. Today, Coal Bed Methane meets nearly 9% of the energy demands and contributes more than 1.6 Tcf of gas production annually in United States (2). Some of the major development in the extraction of this resource has taken place in basins like San Juan, Powder River, Raton while exploratory work is still in progress in comparatively newer basins like the Northern Appalachian.

This project will focus on the development of coal bed methane using appropriate drilling, water disposal, enhancement, treatment and distribution methods while giving appropriate attention to the environmental challenges and project feasibility issues. The focus of our study will be in the North Western San Juan basin in Colorado. The details about the selection of area and the production and distribution of the natural gas will be discussed in the following sections.

LITERATURE REVIEW:

1. METHODS OF METHANE EXTRACTION FROM COAL:

Coal is a type of rock that contains more than 50% by weight and 70% by volume of organic materials consisting mainly of carbon, hydrogen and oxygen. Methane from coal can be extracted in two ways. One is to extract methane from a mine when mining is in progress and the second is to extract methane from a virgin coal seam or coal bed in which mining has not been started.

1.1 Methane Drainage from Coal Mines:

Methane drainage is the process of removing the methane gas contained in the coal seam and surrounding strata through pipelines. Control techniques for use in coal mines can be divided into three categories: 1. Dilution ventilation, 2. Blocking or diverting gas flow in the coal bed by means of seals, and 3. Removing relatively pure or diluted methane through boreholes. The drained gas is mostly methane. In this study our focus is not on the mining aspect, but more so on just removing methane from vertical coal bed methane wells.

1.1.1 Recovery Techniques for Methane in Coal Mines:

There are four main methods used for methane recovery. These are the vertical degas system, vertical gob degas system, horizontal borehole degas system, and the cross – measure borehole system. In both the horizontal and cross-measure borehole systems, the captured methane has to be transported by way of pipeline to the surface.

Summary of Methods for Recovering Methane from Non-mined areas and Underground Mines has been summarized in Table 1. [3]

1.1.2 Utilizing Drained Methane:

The coal-bed methane that is drained can be used as an energy source to the own company. The methane in most cases is used as a way to generate electrical power for the company. Not only is the gas being recycled but it is kept from re-entering into the atmosphere, which is a great concern to the environment because of it being a dangerous greenhouse gas.

For ventilation air methane (VAM), there is even ways to use VAM as a resource now to further prevent the emission of methane into the atmosphere. Biothermica, a company that specializes in turn-key projects in the fields of gaseous pollutant emissions control, uses what is called a ‘VAMOX’. The VAMOX converts VAM into carbon dioxide and water vapor using the well known principle of regenerative thermal oxidation (RTO). RTO is based on the cyclic reversal of the airflow through multiple vessels filled with heat absorbing media to minimize heat losses during the oxidation process. Each ton of methane oxidized by the VAMOX reduces greenhouse gas emissions by approximately

18 tCO2e. In addition, whenever the VAM concentration is above 0.25%, heat can be recovered as hot water, low grade steam or electricity can be produced from superheated steam [4].

In other cases if the methane is of a very high quality it can be immediately compressed into commercial gas lines and sold. This can be very profitable, especially to coal mine operators who are not only profiting on the sale of coal production but also, selling the methane that must be emitted anyway in order to mine and ventilate properly. For our case, since we were not dealing with the mining aspect of the deal we used this approach of trying to sell our methane, which is later explained in detail in the transportation section.

2. METHANE FROM COAL BED RESERVOIRS:

Methane is present in high concentration in coal reservoirs and can be easily liberated from the coal matrix by reducing the pressure in these coal bed reservoirs. Typically coal bed methane reservoirs are made of fractures and the coal matrix. These fractures are called as cleats and usually have much higher permeability than the matrix [5] .

Coalbed methane reservoirs consist of methane and other heavier components such as ethane and propane in high quantities. The economics of coalbed methane depends upon several important factors such as permeability and porosity, gas content, density of coal and drainage efficiency.

2.1 Permeability and Porosity:

The permeability of this type reservoir is usually low and is in the order of microdarcies. Typically coalbed methane reservoirs have dual porosity system. Dual porosity systems have primary porosity systems and secondary porosity systems.

1. Primary porosity systems: The porosity of matrix is the primary porosity of the system. Since majority of the porosity is in the matrix, it is called as the primary porosity system. The matrix is composed of micro pores which has large internal surface and has high quantities of methane absorbed on it. The permeability is extremely low and is usually of the order of microdarcies. As the reservoir pressure declines, gas is desorbed and released into the fractures surrounding the matrix. The rate of desorption of gas depends upon the temperature and pressure of the reservoir.
2. Secondary porosity systems: The matrix is usually surrounded by fractures. These fractures can be horizontal or vertical and have more or less the same permeability. The permeability of these fractures is usually hundred to thousand times more than the matrix permeability and this fracture network is responsible for transporting the gas till the wellbore. Since the porosity of the fractures is usually much smaller than the matrix, it is called as the secondary porosity systems [6]. **Figure 1** shows the dual porosity system.

The fractures initially are filled with water and can have water saturation as high 99% to 100%. This water must be produced before the gas can flow into the fissure system. It is natural for such reservoirs to have high water production in the initial stage however the gas oil ratio increases at the later stages. The amount of water present in the matrix can be neglected.

The fracture porosity and permeability reduces due to compaction and reduction of net stress but it increases due to coal matrix shrinkage as gas gets desorbed.

2.2 Gas Content Determination:

Gas content estimation is usually done in the laboratory. Freshly cut samples are taken to the lab and the rate of gas desorbed and the time taken is noted. Since some gas is always lost during the transportation of the rock sample, corrections must be applied. The amount of gas lost during the transportation is called lost gas volume; this volume can be quite significant and can be as high as 50% in some high pressured reservoir cases. The relationship of gas content to the pressure at a constant temperature is called sorption isotherm curve (**Figure 2**).

The amount of gas stored depends upon factors such as area, height of the formation, average gas content and density of coal. The equation that relates the factors are given as:

$$G = 1359.7 * A * h * \rho * Gc$$

Where G = initial gas in place Standard cubic feet/ ton

A = Drainage area of the reservoir in acres

ρ = density of the coal in grams/ cubic centimeter

Gc = average gas content in scf/ton.

Coal density varies as the function of mineral matter content, moisture and coal rank, figure 2 shows.

2.3 Deliverability and Drainage Efficiency:

For higher deliverability, it is necessary to have extensive fracture network and its connection to the wellbore. The gas content must be high to make economical sense. A saturated coal seam is the one that holds maximum adsorbed gas as possible for given pressure and temperature conditions. A coal seam will be under-saturated if the reservoir pressure is greater than the critical desorption pressure, this implies an under-saturated coal seam can hold more gas at that reservoir pressure. As seen from the sorption isotherm (figure 2), a coal matrix will store larger amount of gas at higher reservoir pressures. The water is what contributes pressure that keeps methane gas attached to the coal. In order to extract the methane, by way of a well, the well's performance is divided into three main stages: (i) de-watering; (ii) Two-phase gas-water production; (iii) declined production stage.

In de-watering stage there is no gas produced, water is simply being pumped out from the drilled well. This allows the pressure to be decreased and the gas can then detach from the coal and start to flow through the well. Primarily, in this beginning stage the wells will produce mostly water.

In the two-phase gas-water production stage there is a decline of water production while a noticeable increase in gas production. Usually the deeper the coal seams the less water that will be present, and hence the sooner the well will begin to produce gas. This happens because; most of the coal bed is being dewatered. The production in this stage is controlled by the relative permeability of the gas and water. During this stage electric submergible pumps can be employed to pump out water at higher rates.

Lastly in the declined production stage, the decrease in reservoir pressure is now responsible for the shrinking of matrix and further increasing the cleat permeability. The gas production now becomes steady. Coalbed methane reservoirs are often fractured to increase productivity of wells.

2.4 Reserve estimation and economics for Coalbed Methane Reservoirs:

Analytical solution: Analytical solutions provide exact solutions to approximate models. Analytical solutions include production decline analysis and well test analysis:

2.4.1 Production Decline Curve:

It is a plot of production rate versus time at constant drawdown pressure. The period in which the reservoir goes into pseudo steady state is used for decline curve analysis. Under pseudo state conditions, the reservoir pressure behaves linearly with time. The necessary condition for decline curve analysis is there should be no interference from neighboring wells. The decline curve analysis not only gives information about the extent of the reservoir but also gives future production rate versus time; hence this plot is often used to give a forecast of cumulative gas production. We can either estimate the reservoir block pressure given constant production rate or estimate the production rate given constant bottom hole flowing pressure. **Figure 3** shows an example of production decline analysis for a typical reservoir.

2.4.2 Pressure Transient Analysis:

The required date here is pressure versus time for a given stable production rate. The reservoir acts as being infinite in extent till the pressure diffusion hits the boundaries. The duration till the reservoir acts as infinite in extent is called transient behavior. The analysis of this transient behavior gives us information about the permeability and skin of the well. Since well test analysis analyzes transient behavior, the resolution of pressure gauge should be as high possible and time duration should be in seconds preferably. The pressure diffusion in the reservoir depends upon the permeability and porosity of the reservoir. Since both, the permeability and porosity are very low for tight matrix such as coal bed reservoirs, it takes very long time for the pressure to diffuse deeper and further away from the wellbore. Well test analysis can be used not only to detect the boundaries but also the type of boundaries. For special cases such as dual porosity reservoirs, well test analysis can reveal the fracture and matrix permeability. **Figure 4** shows response of pressure versus time for a typical dual porosity reservoir.

Analytical methods could not be employed as there was no production history or pressure versus time data available.

2.5 Reservoir simulation:

Numerical solutions unlike analytical solutions give approximate answers to exact models. It works in exactly the opposite way as the analytical methods. The reservoir parameters such as permeability and porosity are already known and we generate plots for block pressure versus time and production rate versus time. We used CMGGEM for our numerical simulation. The flowing bottom hole pressure was kept at 30 psi for all the wells. The well head pressure could not be computed as the flow in the wellbore is multiphase flow. The estimation of well head pressure becomes more complicated with multiphase flow as we have to consider the slippage between light and heavy phases. Special correlations are required to compute well head pressure accurately.

3. PRODUCTION ENHANCEMENT AND STIMULATION:

Over the life of a field, the productivity will be evaluated. After these evaluations are completed a well may not need to be stimulated or enhanced, however some may need both enhancement and stimulation to become productive.

3.1 Stimulation:

Stimulation is a process to remove damage around the wellbore and formation that impedes productivity. Well or field stimulation is a treatment used to restore and/or enhance the productivity of a field [(7)]. Stimulations are divided into two groups: hydraulic fracturing treatment and matrix treatments. Hydraulic fracturing treatments are performed above the fracture pressure of the formation or zone in question. It involves creating a fracture that would extend from the wellbore and into formation. This creates a very permeable conductive path which allows easy flow of reservoir fluid from the formation to the wellbore [(8)] **Figure 5** shows a simple schematic of the hydraulic fracturing process. After a fracture is created, proppants which are used with the fracturing fluids keep the fracture opened until they expire or breakers are used to dissolve or breakdown the proppants [(9)]. Once the proppants are broken, the fracture closes thus shutting the conductive pathway. Hydraulic fracturing is also used to increase the connectivity of a formation [(10)]. The fracture created would propagate in the direction perpendicular to minimum stress [(8)], this would make the hydraulic fracture created connect other natural fractures thus increasing the connectivity and productivity [(10)].

Another type of hydraulic fracturing treatment is Frac and Packs. Frac and Packs are very similar to hydraulic fracturing, except that they are much shorter and are local around the wellbore. The primary goal of the Frac and Packs is to create a very conductive path through the damage regions around the well bore. The Hydraulic fracturing treatment procedures and methods are applicable to coalbed methane reservoir in the way mentioned here [(11)].

3.2 Enhanced Recovery:

The main goal of enhanced oil recovery is to restore or increase the productivity of a field by displacing the formation fluid from the fractures, cleats and seams and also by pressurizing the formation in this section, focus is given to CO_2 injection above other alternatives. Coal has a very high affinity for CO_2 [(12)] and depending on the grade of coal can absorb really high amounts of CO_2 [(13)] [(14)]. With the CO2 displacing the CO_2 from the cleats, fractures and matrix and also pressurizing the formation the productivity of the field or well is increased. Also, because of the high affinity and capacity for CO_2 by coal, the CO_2 can be sequestrated [13].

4. METHANE TREATMENT:

The natural gas that comes out of the ground is not 100% pure methane but almost always has contaminants that reduce the BTU value of the gas but are also dangerous. Due to this, the natural gas has to be treated to meet but the government standards and the standard of the customer. **Figure 6** shows a generalized natural gas processing schematic.

The Oil-Gas Separator unit and the oil input are optional and not applicable in the coalbed methane application. The Major contaminants of the natural gas are water, CO_2, and sulfur dioxide [15]. The problems associated with the contaminants and some solutions to how to remove them are shown in **Table 2**. Natural gas that contains CO_2 and sulfur dioxide are called sour gas and the process of removing these contaminants is called sweetening [16].

Most of these contaminants though may have a bad influence and the quality of the methane gas, after they have been extracted become valuable themselves. Element sulfur is mainly gotten as a byproduct from the oil and gas industry [17]. From CO_2 injection, some of the gas may get mixed and extracted with the methane; the CO_2 is extracted from the methane during the treatment process and can be reinjected.

Now that the location has been narrowed down to most likely the San Juan basin stimulation, production enhancement techniques and treatments methods that are relevant to the basin would be focused on.

5. WATER MANAGEMENT:

The Production of coal bed methane results in the release of water from the hydrocarbon bearing formation which is subsequently co-produced with gas. This produced water is separated at the wellhead and must be separated from the gas at or near the well head. Produced water accounts for greater than 80 percent by volume of the residual material generated in the natural gas industry. Cost-effective and environmentally acceptable disposal of these waters is critical to the continued economic production and physical sustainability of CBM project [18].

While coal bed methane contributed less than 8% of the1990 gas production volume, coal bed methane operations accounted for 13% of the produced water volume. Moreover stated on a unitized basis, the produced water to gas ratio for coal bed methane averages 0.31 barrels of produced water per 1000 cubic feet of gas (BBL/MCF) whereas the ratio for conventional non-associated gas is 0.023 BBL/MCF. Thus a unit volume of coal bed methane on average produces 13.5 times as much water as a unit volume of conventional non-associated gas. Economic management of produced water is a critical issue for coal bed methane development [19].

For a CBM field, the cost of handling co-produced water varies from a few cents per barrel to more than a dollar per barrel and can add significantly to the cost of gas production. In some areas, the volumes of water produced and the cost of handling may prohibit development of this resource [20].

5.1 Brief History Of CBM Water Management:

Over the last fifteen years there has been an incredible transition in the disposal of CBM produced water. Most of this transition has been led by environmental concerns about the quantity of water that is being drained from our large underground aquifers and the potential environmental impact of this surface discharged water.

When Coal Seam Gas production was first developed, limited environmental and regulatory oversight existed. Initially, Gas Production Companies discharged the CBM produced water to the nearest drainage or into a local waterway. Unfortunately this type of surface discharge is no longer desirable and in most places has become an unacceptable solution. While unmitigated surface discharge was inexpensive, it was not effective at saving usable water for the landowner, and in some cases, there was negative environmental impact on the soil and waterways.

As environmental concerns increased, impoundment ponds became the next step in produced water management. Production costs rose as these structures required long timelines for planning, eighteen month permitting cycles, large reclamation bonds, and large upfront cash outlays for development. With continued regulatory oversight, multi-million dollar treatment facilities were erected to improve the quality of surface discharged water, but the cost per barrel of treated water has become un-economical, and further surface discharge of the water after treatment is either limited or unviable.
Trends indicate that most CBM Production Companies are now closing their treatment facilities, as the ongoing costs of "treating" such enormous quantities of water is not economical and the ability to surface discharge is disappearing [(21)]. This necessitates the need to identify and develop less complicated and more cost effective CBM produced water treatment systems

5.2 Types of Water in Coal Bed Methane:

There are three different mechanisms by which water is stored in Coal Bed Methane:

1. First adherent moisture or bulk moisture which refers to the free water contained in the cleat system and that has a normal vapor pressure. This is the volume of water that must be removed during the dewatering phase to produce gas effectively.

2. Second is the inherent moisture that is water present in the micro pore system that decreases the adsorptive capacity of the coal for methane. Although this type of water storage is inconsequential when considering water disposal it is extremely detrimental to the gas concentration of the coal.

3. The other forms of water found in coal seams include chemically bound water or water of hydration. [(22)].

5.3 Factors Affecting Production of Water:

As shown in **Table 3**, the amount of water produced, as well as the ratio of water to gas, varies widely among basins with Coal Bed Methane Production. Causes of variations include

1. Fracturing ease of cleats present in the coal (face, butt).
2. Thickness, density of coal.
3. Composition of coal in place i.e. whether coal contains sand, clay, or other solids (abrasives) that interfere with the artificial lift systems employed to extract water.
4. The presence of multiple zones in coal and nature of material that separates the zones?
5. Depth of burial.
6. Duration of coal bed methane production in the basin. [23]

5.4 Produced Water and Treatment Technologies:

Typically, water treatment technologies are limited to treating specific constituent types concentrated in water, e.g., dissolved solids, organics, conductive ions, etc. Depending on the eventual use of the water and the desired constituent concentrations, treatment processes are often coupled together to achieve required water use objectives. For this reason, an integral aspect of the treatment process is the performance of water analysis to ascertain the presence of specific constituents for any given water source. The dissolved constituents of produced water are known as total dissolved solid (TDS) concentration.

Table 4 represents CBM produced water data collected in the San Juan Basin by the Marathon Oil Company [24]. This data does not necessarily reflect produced water quality levels for other regions or natural gas facilities.

5.5 Water Treatment Methods:

The quality of water that is produced in association with CBM development will vary from basin to basin, within a particular basin, and over the lifetime of a CBM well [25].There are a variety of potential beneficial uses for CBM produced water that can be implemented by CBM operators to manage this resource but the quality of the produced water can be a deciding criterion for what option is chosen.

1. Electro dialysis
2. Reverse osmosis
3. Ion exchange resin
4. Freeze/Thaw evaporation
5. Artificial wetlands.
6. Ultra-Violet Light

5.6 Conventional Produced Water Disposal Options:

1. Injection of Original Water Produced.
2. Surface Discharge In deeper offshore environment.
3. Surface Discharge for beneficial Use of treated Water e.g. Irrigation
4. No liquid discharge resulting from evaporation of produced water.

5. Surface Discharge in produced Low TDS water in High surface Water Stream Flow Environments.
6. Modification of Hydrocarbon Techniques to reduce Ratio of Water /Hydrocarbon Produced. This Project will attempt to design another disposal option for use as heat transfer fluid for the geothermal generation of energy.

6. METHANE DISTRIBUTION AND STORAGE:

Everyday, close to 70 million customers in the United States depend upon the national natural gas distribution network, which include natural gas distribution companies and pipelines, to deliver natural gas to them. These customers currently consume nearly 20 trillion cubic feet (Tcf) of natural gas per annum, accounting for about 22 percent of the total energy consumed in the United States each year. This end use customer base is 92 percent residential units, 7 percent commercial businesses, and 1 percent large industrial and electric power generation customers. More than 1,500 companies carry out the natural gas distribution process [(26)].

Once the extraction and treatment of methane is complete, there may be several options available to use it efficiently. Distribution will depend on the location of the production site, the distance of the potential consumers from this site and the amount of production. If methane is coming from a mine, it may be used to meet the energy needs of the mine or power plants nearby. If production is higher than the amount being used by the mine or natural gas company itself, then it has to be distributed. Ideally, natural gas has four potential consumers: Residential, Commercial, Industrial and Electric power plants.

Natural Gas is a clean burning fuel compared to other fuels like gasoline or diesel. However, under ambient conditions it is a low density gas and hence there are difficulties with its transportation. Based on its requirements and current demand, there are ways to transport and/or store natural gas which are discussed below.

6.1 Natural Gas Pipeline Transportation:

Transporting natural gas from the production site to the final customer is a multi-step process. A natural gas pipeline system begins at the natural gas field. Once the gas leaves the field (coal bed in this case), a pipeline gathering system directs the flow to a processing plant or mainline depending on its quality. Ideally, gas is gathered by several small diameter pipelines which take the natural gas to a company. Larger diameter pipelines are required when the pipeline company distributes it to a market hub, local distribution companies or sends it to an underground storage reservoir [(27)].

The natural gas main transmission lines are wide-diameter pipelines (20-42 inches), operating on long distances, between production area, natural gas processing plant, other receipt points, and the principal customer service area(s). The mainline branches off into several pipelines of smaller diameter to connect with or serve specific customers. United States has mainly two types of pipelines: Interstate (operating between States) and Intrastate (operating within a State). In 2007, nearly 36 Tcf of gas was transported via the interstate pipelines. Apart from these, smaller diameter (6-24 inches) pipelines belong to the local distribution companies [(27)].

Two important parameters which determine the amount of gas being carried by a pipeline are its diameter (usually kept between 6-42 inches) and operating pressure (usually 500-1500 psi). Those passing through populated areas operate at reduced pressures due to safety reasons. Apart from these parameters, design of pipelines take into account cost estimates for various possible combinations of pipe size, compression equipment, inter-station distances, potential flexibility and expandability, appropriate wall thickness to withstand high pressure and maintain the working pressure rate at a constant value. Pipelines in United States run over distances as long as 2000 miles, feeding as much as 12000 MMcf/d (million cubic feet per day) of gas to states like Texas (the biggest natural gas consumer in U.S.) and priced between $4 to $12 per thousand cubic feet of gas flowing . To maintain the speed and flow rate of gas (nearly 10-20 miles/hr) through them, compressor stations are installed at intervals of approximately 40-100 miles along the line [(27)].

Natural gas transmission via pipelines also puts some quality restrictions on the gas being carried to meet pipeline standards. It must be free from corrosive components like water, carbon dioxide, hydrogen sulfide, nitrogen, oxygen, sulfur etc and solid particulates. The gas should have a certain Btu range (1035±50 Btu) and be delivered at a specified hydrocarbon dew point temperature to avoid it from condensing in the pipes [(28)].

6.2 Underground Natural Gas Storage:

Underground natural gas storage system facilities act as underground pressurized storage vessels in which gas is stored at a high pressure. They provide for inventory management, supply backup, and the access to natural gas to maintain the balance of the system so that pipelines can operate at a constant and efficient rate especially during peak season. Most underground storage facilities, 327 out of 399 at the beginning of 2008, were depleted reservoirs, which were close to consumption centers and relatively easy to convert to storage service. In some areas, however, notably the Midwestern United States, some natural aquifers have been converted to natural gas storage reservoirs [(27)].
Two of the most important characteristics of an underground storage reservoir are the capability to hold natural gas for future use, and the rate at which natural gas inventory can be injected and withdrawn (its deliverability rate) [(27)]. However, gas injection and withdrawal capability declines with time and some enhancement techniques might be necessary.

A pressure differential is required to push the natural gas out of the natural gas reservoir. When this differential reduces, some amount of gas is left behind. Hence, there is always a physically unrecovered amount of gas that remains embedded in the formation. In addition to this unrecoverable gas, underground storage facilities contain some 'base gas' or 'cushion gas'. This is the volume of gas that must remain in the storage facility to provide the required pressurization to extract the remaining gas. In the normal operation of the storage facility, this cushion gas remains underground; however a portion of it may be extracted using compression equipment. Working gas is the volume of natural gas in the storage reservoir that can be extracted during the normal operation of the storage facility. There are three principal types of underground storage sites used in the United

States today: depleted reservoirs in oil and/or gas fields, aquifers, and salt cavern formations [29].

6.2.1 Depleted Reservoirs:

The most common form of underground storage consists of depleted gas reservoirs. Depleted reservoirs are those formations that have already been tapped of all their recoverable natural gas. This leaves an underground formation, geologically capable of holding natural gas. Moreover, using an already developed reservoir for storage purposes allows the use of the extraction and distribution equipment left over from when the field was productive. This reduces the operating costs. Depleted reservoirs are attractive because their geological characteristics are already well known. They are the cheapest and easiest to develop, operate, and maintain. The factors that determine whether or not a depleted reservoir will make a suitable storage facility are both geographic and geologic. Geographically, depleted reservoirs must be relatively close to consuming regions, transportation infrastructure, including trunk pipelines and distribution systems. While depleted reservoirs are numerous in the U.S., they are more abundantly available in producing regions. Geologically, depleted reservoir formations must have high permeability and porosity. The porosity of the formation determines the amount of natural gas that it may hold, while its permeability determines the rate at which natural gas flows through the formation, which in turn determines the rate of injection and withdrawal of working gas. A major limitation of depleted reservoirs would be that in order to maintain pressure in depleted reservoirs, about 50 percent of the natural gas in the formation must be kept as cushion gas [29].

6.2.2 Aquifers:

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs. But, in certain situations, they may be reconditioned and used as natural gas storage facilities. They are one of the least desirable and most expensive storage facilities in that they demand time and money to discover their geology and a lot of infrastructure development in terms of pipelines, wells, extraction equipment etc. They require nearly 80% cushion gas and cause underground water contamination. Upon extraction from a water bearing aquifer formation, the gas typically needs further dehydration prior to transportation, which requires specialized equipment near the wellhead. Aquifer formations do not have the same natural gas retention capabilities as depleted reservoirs. Therefore, natural gas that is injected escapes from the formation, and must be gathered and extracted by 'collector' wells, designed specially to pick up gas that may escape from the formation [29].

6.2.3 Salt Caverns:

Underground salt formations are well suited to natural gas storage in that salt caverns, once formed, allow little injected natural gas to escape from the formation unless extracted. The walls of a salt cavern also have the structural strength of steel, which makes it very resilient against reservoir degradation. In addition, cushion gas requirements are the lowest of all three storage types, with salt caverns only requiring about 33 percent of total gas capacity to be used as cushion gas [29].

Developing a salt cavern consists of using water to dissolve and extract a certain amount of salt from the deposit by drilling a well, leaving a large empty space in the formation. This process is known as 'salt cavern leaching'. Salt cavern storage facilities are primarily located along the Gulf Coast, as well as in the northern states, and are best suited for peak load storage. Salt caverns are typically much smaller than depleted gas reservoirs and aquifers. As such, salt caverns cannot hold the volume of gas necessary to meet base load storage requirements. However, deliverability from salt caverns is much higher than for either aquifers or depleted reservoirs and they can start providing natural gas in few hours notice in case of emergencies [29].

Essentially, salt caverns are formed out of existing salt deposits. These underground salt deposits may exist in two forms: salt domes, and salt beds. Salt domes are thick formations that can be as large as a mile in diameter, and 30,000 feet in height. Typically, salt domes used for natural gas storage are between 6,000 and 1,500 feet beneath the surface. Salt beds are shallower, thinner formations usually within 1,000 feet in height. Because salt beds are wide, thin formations, once a salt cavern is introduced, they are more prone to deterioration, and may also be more expensive to develop than salt domes [29].

6.3 Natural Gas Transportation in Compressed, Liquified or Adsorbed Forms:

6.3.1 Compressed Natural Gas:

One way of transporting natural gas or methane is to store it in vessels and distribute via tankers or containers designed specifically to carry it under high pressure. One such form of natural gas is the compressed natural gas or the CNG which is currently being used to some extent in the automobile industry for vehicles like buses and trucks. However, lack of an effective, economic and safe on-board storage system is one of the major technical barriers preventing methane-driven automobiles from competing with the traditional ones [30].

Methane has a high energy per unit mass but it cannot be stored at a density as high as other fuels, and thus has an energy density approximately one-third that of gasoline (11 MJ/L for compressed natural gas at 24.8 MPa or 3600 psi compared with 32 MJ/L for gasoline). Thus a compressed natural gas (CNG) fuel tank would need to be approximately three times larger than a gasoline tank to allow a vehicle the same driving range. The use of CNG has its disadvantages. The CNG storage tanks must be pressure vessels constrained in their geometry (typically cylindrical), and are also rather heavy (much more than 1 kg/L for steel tanks).

Moreover, attainment of high pressures nearing 20.7 MPa (3000 psi) requires costly multi-stage compression [31].

6.3.2 Liquified Natural Gas:

Liquified form of natural gas is one that has been converted temporarily to liquid form (at the boiling point of methane at -161^{o} C) for ease of storage or transport. Liquefied natural gas takes up about 1/600th the volume of natural gas in the gaseous state. However, due to costly equipment and infrastructure required, so far LNG transportation has been restricted mostly to import and exports. This requires a liquifaction infrastructure at the exporting end and a regasification equipment at the receiving end [32]. Moreover, LNG transport has not yet been realized widely for passenger vehicles due to safety and leakage reasons as LNG storage demands specially built cryogenic containers [33].

6.3.3 Adsorbed Natural Gas:

Methane can be stored in a physically adsorbed state at a pressure of 3.5 MPa (500 psi) at energy densities comparable to methane compressed at 24.8 MPa (3600 psi) [31]. However, a number of practical problems need to be considered in the ANG technology like presence of higher hydrocarbons and impurities in the natural gas, mass transfer and heat transfer effects. Approriate sorbent development with characteristics like high micropore volume, packing density and surface areas is also a big challenge in this upcoming field [33]. However, once this technology is commercialized, it can solve the methane storage problem by aiding pressure savings in storage vessels and bring them down to pressures at which pipelines ideally operate.

7. ENVIRONMENTAL ISSUES IN COAL BED METHANE:

Coal Bed Methane (CBM) wells are being developed extensively in the areas of United States in the past two to three decades for meeting the demands of Natural Gas in the country. So as in developing any type of reservoir, there exist the environmental issues and challenges. The core issues related to environment in the case of Coal Bed Methane are as follows:

- Disposal of Produced Water
- Underground Water table drawdown
- Methane contamination
- Noise Pollution
- Air Pollution
- Surface Disturbances

7.1 Produced Water Disposal:

During the production of gas from Coal Bed Methane, large volumes of water are produced from the reservoir. The ratio of water to gas is very high generally in any reservoir but still the numbers vary according to the location of the reservoir and many other factors including the duration of production of the reservoir , type of coal, etc.

The major issue in the development of CBM reservoir is the disposal of water as it is large in volume. The common practices of the water disposal are discussed in the previous part of the review in the water management section.

7.2 Groundwater Withdrawal:

One of the substantial environmental issues of CBM production is the underground water withdrawal from the aquifer. In some of the basins coal is present in the aquifer, as a result of which during production we need to pull out the water in the aquifer which leads to drawdown of shallow groundwater. This affects the landowners and farmers who are benefitted with the use of groundwater for irrigation, livestock and other household purposes.

Another ancillary impact of groundwater withdrawal is occurrence of coal fires. In some of the basins, this happens to be a major problem. Coal is most susceptible to self-heating which is characterized by high intrinsic moisture and oxygen content. If the coal exists in the aquifer, there would be water removal to extract gas which fluctuates the water table in the aquifer. Due to this fluctuation, the heat of wetting potential increases. When the water level drops in the aquifer, ambient air is drawn into the aquifer resulting in combustion of the coals. This leads to massive fire inside the reservoir which vents out steam and other sulfurous gases. The coal-seam fires are difficult to extinguish and has an adverse impact on the quality of the coal inside the reservoir.

7.3 Venting:

The mobility of methane gas to the surface from the reservoir is a significant environmental concern. The seepage of methane takes place mostly in the uncemented annular spaces, natural fractures, through water wells and some abandoned oil and gas wells. This seepage can lead to contamination of groundwater, kill vegetation and may also result in fire and explosion hazards.

For an instance several pump houses exploded due to accumulation of methane gas in some confined spaces which got ignited by a spark. The high content of methane gas in the water samples leads to destruction of vegetation like plants, crops, trees and even the wildlife which might depend on drinking the disposed water in the ponds.

7.4 Noise Pollution:

Coal Bed Methane producers are faced with challenging another environmental concern of noise pollution which also has an adverse affect on the environment. To reduce the concerns of landlords, industries need to deal with this problem quiet effectively.

The major sources of noise pollution in the course of development of CBM reservoir are the compressors and pumps. The noise coming especially from the compressors can be very loud and it might affect the hearing ability of the field officers working in the basin. “Depending on wind direction, the roar of a field compressor can be heard three to four miles from the site. Near the compressor stations, people need to shout to make themselves heard over the sound of the engines." [34]

7.5 Air Pollution:

During the production from the CBM reservoir, there are many pollutant gases and other air pollutants that come across leading to formation of a cloud of pollutant gases. The major gases which are emitted are nitrogen oxides, sulfur oxides, carbon monoxide, carbon dioxide, hydrocarbons and the particulate matter.

One of the sources due to which these gases are emitted is from the internal combustion machines used for drilling and completion, compression of gas and transportation of gas. Also the traffic at the well site increases the pollution and leaves a significant impact on the air quality.

7.6 Surface Disturbances:

The CBM reservoir developments experiences continuous chain of constructions & operations of wells, vehicle traffic, construction of pipelines, compressor stations and many other small surface activities. All these factors add up to the disturbances created on the surface which is also considered to be one of the potential environmental concerns.

The major impacts of the surface disturbances are the soil erosion, wildlife habitat disturbance, destruction of agricultural fields and growth of weeds & other unnecessary plants.

7.7 Remedies for Environmental Issues:

1. For the Produced Water disposal issue, we can adapt certain methods through which we can dispose off, keeping in mind the economic feasibility of each process, which are discussed in detail in the section of water management techniques.
2. For Groundwater withdrawal issue, we need to come out with a better solution so as to not decline the groundwater table in the aquifer or else we can issue some regulations of what limit of water we can dispose of for the production of gas so that we do not disturb the needs of farmers or landlords for using groundwater for various purposes.
    a. Also to control the coal-seam fire inside reservoir, we need to adapt proper safety and health regulations and practice better techniques of improving productivity without any explosion hazards.
3. For the Methane contamination issue, we should put an acceptable limit of seepage of methane in the reservoir which can happen when we employ better drilling techniques.
4. For the Noise Pollution issue, we can come up with construction of noise arresting obstacles around the noise-causing equipments like compressors and pumps, also keeping in mind the cost. Also we can use high grade mufflers on the compressors and pumps which minimizes the sound to certain limit (35).
5. For the Air Pollution issue, we need to incorporate regulations laid by the state government on the limits of gas emissions. In order to reduce particulate matter we can use the suppressants which arrest the particulate matter.

6. For the Surface Disturbances issue, we need to adapt proper planning activities [35] and also we need to put up traffic regulations in whole of the reservoir area so as to control the vehicular traffic.

8. ECONOMIC FACTORS IN THE DEVELOPMENT OF COAL BED METHANE RESERVOIRS:

The major factor affecting the economics of coal bed reservoirs are discussed as follows:

- Natural Gas Price
- Capital Costs
- Cost of Implementation
- Transportation Costs
- Others

8.1 Natural Gas Pricing:

In the recent past there have been a lot of discrepancies in the price of natural gas. For the development of CBM reservoir and to make an economic model, we need to make a proper forecast of Natural Gas price for a considerable amount of time so as "to project the cash flows which acts as the basis of most financial measures applied to proposed coal bed methane development projects" [36].

The economic model is a Discounted Cash Flow Model (DCF) which is used by most of the companies which provides both an internal rate of return & NPV of an investment at various discount rates.

8.2 Capital Costs:

For the initial start up of the reservoir production we need to have the capital costs which include costs of land purchasing, permit issuing, drilling & completion methods, equipment infrastructure and also the last but not the least the water management costs.

These costs depend on many factors like the number of wells to be drilled at the site and at what depth the gas is present, etc. The costs also changes depending on the well head price of Natural Gas at the basin [37].

8.3 Cost of Implementation:

Implementation costs include the operations & maintenance costs. These costs comprises of labor, power fuel, repairs, field organization & supervision and other maintenance costs [36]. These costs keep on varying with time like in initial stages; the costs will be higher because of well enhancements and pump replacements and other related problems and slowly gets normalized when the system is in control.

8.4 Transportation Costs:

These include the costs required to transport the gas through different modes of transport, either by pipelines or by diesel transport.

8.5 Others:

The costs in the others section include the income taxes which has both State & Federal Taxes. "Typical oil & gas investments often involve complex division of ownership interest" [(38)]

ENGINEERING DESIGN:

1. Selection of Location:

Table 5 displays six popular coal bed methane basins. Based on the compilation of each basin's characteristics, we chose the San Juan Basin. Even though the square miles of the area was less than Powder River Basin and Northern Appalachian, the San Juan Basin proved to have more reserve estimates at least 50 TFC. Along with the large amount of reserves, coal thickness on average was around 40 to 50 feet. The coal bed methane mainly occurs in the Fruitland Formation, with some methane trapped in the underlying and adjacent Pictured Cliffs Sandstone. The rank of the coal is considered to be both 'High- Volatile A Bituminous' and 'Medium-Volatile Bituminous'. This is a good quality, considering the methane in a coal seam will depend on the quality and depth of the coal. In essence, the higher the energy value of coal and the deeper the coal bed, the more methane in the deposit. In our specific area, well depth for our wells was approximately 3,300 feet. San Juan basin is the most productive coal bed methane basin in the world with resources of approximately 50 TCF. Coal bed methane wells with the highest production (initial potential greater than 10 MCF day) occur in the over pressured, north-central part of the basin. Highly permeable, laterally continuous coal beds override abandoned shoreline Pictured Cliffs Sandstones and extend to the elevated recharge area in the northern basin to form a dynamic, regionally interconnected aquifer system [39].

The specific area of interest was in the northern part of the basin in Colorado. **Figure 7** illustrates the boundaries of the San Juan Basin. We are looking to drill the wells slightly southeast of Durango.

1.1 San Juan basin characteristics:

The basin selected for our project is located near the Colorado-New Mexico border. The properties of the reservoir are listed **Table 6** [40]

A block within area E was selected **(Figure 7)**. The block is situated between 32N-33N and 6W-5W. This block is approximately 60 miles in length and breadth.

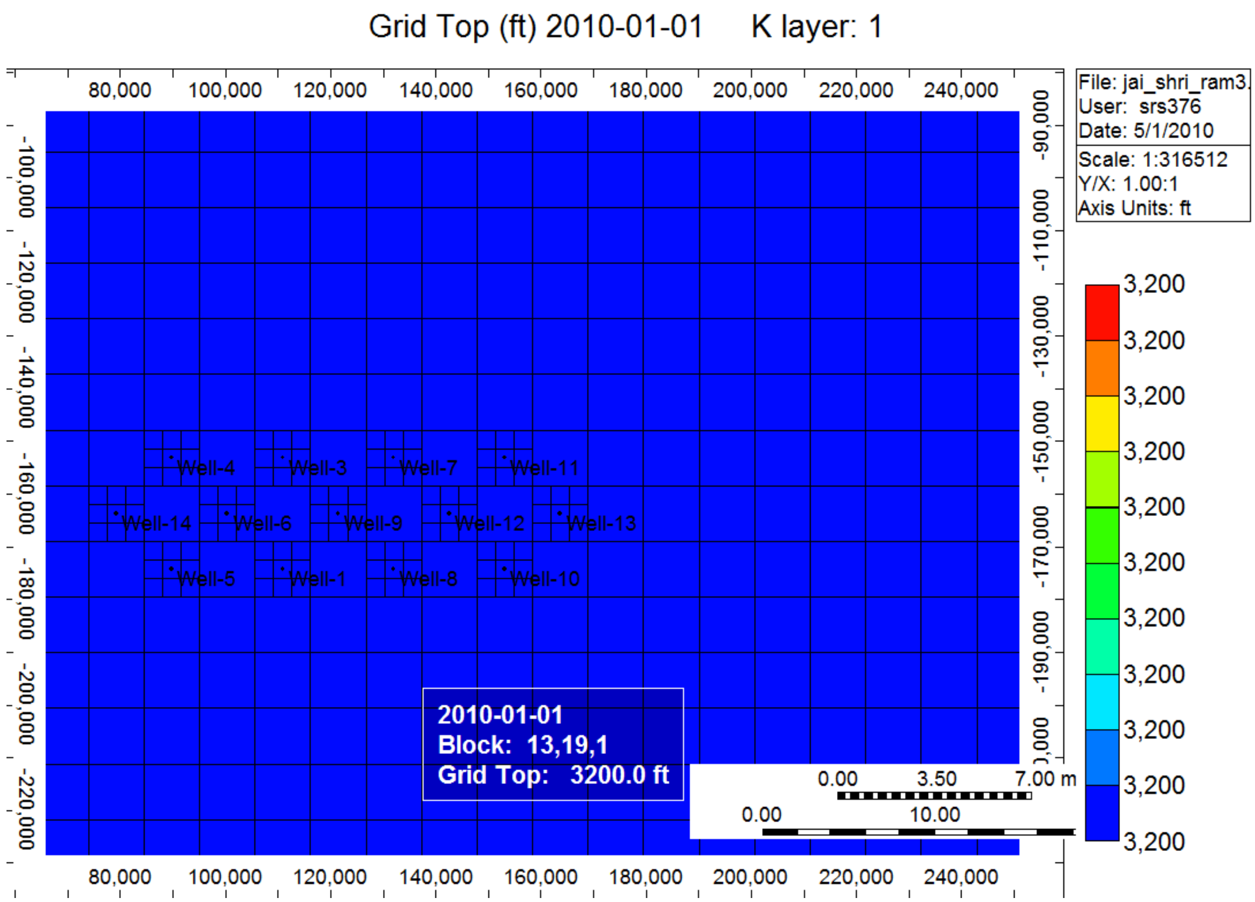
2. Reservoir Simulation:

We used CMG GEM software for our numerical simulation. The flowing bottom hole pressure was kept at 30 psia for all the wells. The well head pressure could not be computed as the flow in the wellbore is multiphase flow. The estimation of well head pressure becomes more complicated with multiphase flow as we have to consider the slippage between light and heavy phases. Special correlations are required to compute well head pressure accurately.

CMG GEM reservoir simulator was used for reservoir simulations. The input for the model is shown in **Table 7** and the thermodynamic properties are shown in **Table 8**.

Drilling pattern and well spacing: Grid of 30 X 30 blocks was considered. Each block has length and breadth of 10560 feet. From other literature, most coal bed methane wells, especially being drilled into a virgin coal seam, are vertical wells. **Figure 8** illustrates the use of a five-star drilling pattern with four conventional vertical gas wells bordering a single injection well, with a total of nine conventional vertical gas wells and 4 injector wells. From this initial set up we shortly found through simulation, that injection wells were not feasible with our design. Consequently, we used a simple pattern of 13 conventional vertical gas wells for production to begin our simulation process. Each well was on average 3,200 feet in depth.

The well spacing between adjacent wells is at least 2 miles. The well configuration for thirteen wells and configuration is shown below.



Initially only thirteen wells were drilled for the first year. Thirteen new wells were added each year for next nine years. Total of one hundred and thirty wells were drilled in a span of ten years. The smaller blocks within each block represents grid refinement. This helps us further to define reservoir properties more accurately. The drainage area for each well is assumed to be around 100 acres. This drainage area is used to calculate lease cost for the land. The boundaries considered are sealing fault, which means there is no communication with wells or aquifer outside the block. Since the height of the formation is quite high (about 45 feet), we had taken only vertical wells for consideration.

2.1 Results of Simulation Run:

The simulation results shown are for wells without any stimulation.

As shown in **Figure 9**, the initial water production is very high. It starts with 185 barrels of water per day and starts to decline slowly. After the end of ten years, the water production reaches 55 barrels of water per day. The gas rate rises steadily until it reaches steady state and produces at around 320 MScf/ day.

The results show that as the water production declines steadily, the gas production increases. The gas production is low to make any economical sense.

As seen from **Figure 10**, the cumulative water production for the field tends to flatten a bit at later stages since the water production declines constantly. The cumulative gas production for each year on the other hand rises steadily since the daily gas production rate rises.

The **Figure 11** shows there is hardly any influence from the adjacent wells. We assumed this condition to be true for the remaining one hundred and thirty wells. The cumulative gas and water production for each year were calculated based on this assumption.

Figure 12 shows the block pressure for each well, it declines to 1500 psi approximately at the end of ten years.

2.2 Conclusions:

1. The production from wells without stimulation is very low and is not economically feasible.
2. The production of gas rises steadily as the reservoir is de-watered
3. The well spacing of 2 miles is enough to avoid any well interference between and two neighboring wells and this assumption can be extended to one hundred and thirty wells.

2.3 Recommendations:

3. 1Recent studies showed, multilateral wells can improve productivity significantly and also cut down the cost of operation and maintenance.
3. 2Such wells can be used to simulateneously discharge water into deeper formations.
3. 3Multilateral wells have smaller foot print.

3. Overview of Stimulation and Enhancement

It is often required to fracture reservoirs for higher productivity. Mechanical properties of coal are significantly different from conventional rocks. The young's modulus for coal is ranges between 100,000 psi to 10,000,000 psi. Such low of young's modulus means very wide and complex network of hydraulic fractures. Fractures are created in multiple directions including vertical directions possibly to cleat system. Hydraulic fracturing basically connects the cleat system to the wellbore increasing productivity of the well. The fracture pressure for San Juan basin as reported in literature is about 5000 psi and it requires at least about 200,000 barrels of water to fracture. **Figure 13** shows the plot of fracturing pressure and amount of fluid required to fracture the reservoir. The high pressure required fracturing San Juan basin could be because of entry friction; entry friction is the friction in the perforations, perforation friction junction and flow constriction near the well bore region can contribute to significant fracture resistance pressure [(41)].

The field evaluated was put up for evaluation for stimulation and enhancement due to the low permeability of 0.0001 and initial low production. Stimulation and enhancement implementation was done through the simulation. The model had to be edited to apply the stimulation and enhancement methods of choice. To observe the effectiveness of the stimulation and enhancement methods, the production behavior of 13 wells were observed over 10 years.

3.1 Enhancement:

The initial plan for the project was to perform enhancement through gas injection by the means of CO_2 injection. Carbon Dioxide injection was the favorable choice for many reasons including the high affinity coal has for carbon dioxide in coalbed methane formations, the opportunity to perform carbon dioxide sequestration which allowed help to the reduction of green house gas. Literature also indicated good results through this process. However, after setting up the model to accept the injection of carbon dioxide into the system, it was discovered that the model could not process gas injection. It was difficult to inject CO_2 into the reservoir without exceeding fracturing pressure.

The model had difficulties with the numerical calculations converging. We believe that the main problem is that the system is too tight due to the low permeability and model cannot handle gas injection under low permeability. Because of this alternative methods were searched in stimulation to treat the low permeability around the wellbore.

3.2 Stimulation:

Hydraulic fracturing was used as the stimulation method because it would allow us to treat the low permeability around the wellbore and create a highly conductive path from deep in the formation to the wellbore allowing a huge improvement in the flow of gas [(42)]. Along with these benefits, literature also shows improvement in recovery due to hydraulic fracturing in the San Juan region [(42)]. It was also discovered that the model created could not simulate the hydraulic fracturing process. Despite this, the effects of a hydraulic fracture were implemented into the model. The first thing in modeling the effect of a hydraulic fracture was creating a fracture that would extend from the wellbore to the formation. This was done by implementing local grid refinement that allowed the creation of a plane through the wellbore that would act as the fracture. Next, to simulate the highly conductive nature of the fracture the permeability within the created plane was given a much higher permeability compared to the formation. Because the model could not perform hydraulic fracturing the method employed to simulate the effects of the hydraulic fracture has some limitations. The assumptions made about the nature of the fracture due to this method are listed below:

1. All the wells are fractured
2. Constant conductivity throughout the fracture
3. Constant permeability throughout the fracture
4. The height of the fracture is equal to the thickness of the formation.
5. The fracture orientation is a constantly perpendicular to the vertical wellbore.
6. The fracture has no tip, and tip effects are not simulated.

Also, because the model could not compute the hydraulic fracture process, assumption had to be made on the treatment size and results from hydraulic fracturing. In other to make the most accurate assumptions literature was searched to find a formation with properties very similar the field here and use their treatment schedule and the results they obtained. A paper was found that had a field in the same San Juan region with properties extremely close to this field [43]. Based on this, the treatment size and resulting fracture length created are shown below [43]:

1. Fracture fluid is nitrogen foam (75% gas and 25% water)
2. 300,000 barrels of fracture fluid is used
3. 200,000lb of 40/70 mesh proppant sand is used.
4. Resulting fracture length is about 2300ft.
5. Permeability increased to 2md in the created conductive path.

Figure 14 shows the well distribution and the effects of hydraulic fracturing on permeability. Nitrogen foam is used because of the great success it has in this region and the non-swelling effect it has on coal. The benefits of the hydraulic fracture are shown below:

1. A 1450MMSCF increase in gas production
2. A 0.6MM barrels decrease in water production.

Since there is less water produced money is saved in water production and more money is made since there is an increase in gas production. The hydraulic fracture allowed us to more than 4 times increase gas production after the first year as shown in **Figure 15**. Cumulative gas and water production is shown in **Figure 16** and F**igure 17** respectively. Water rate is shown in figure 13. The hydraulic fracture is considered to be a success, because we reduce water production and increase gas production, we also increase gas production rate 4 folds as shown in F**igure 15** and reduce water rate by almost 50% as shown in F**igure 18** in the first year of production.

4. Overview of Gas Treatment:

The natural gas produced cannot be sold raw without treatment due to the presence of impurities and standards. **Table 9** below shows the general component make-up of raw natural gas. There are impurities local in this region present in the natural gas, some of which are dangerous and possess health risks like hydrogen sulfide others which can damage equipment and reduce the BTU value of the gas like water. The major impurities in the natural gas are shown below:

- CO_2
- SO2
- Water
- Fracture fluids

Government has described the standard of natural gas to be considered to have an average standard of heating units not less than 1000btu per cubic foot of gas under the following condition [44]:

- At a temperature of 60° F.
- Under a pressure of 30in of mercury.

4.1 Treatment of Gas:

Due to high initial capital cost of installing a gas treatment facility, the treatment of the gas is subcontracted to a treatment facility called the Ignacio treatment facility owned by Williams LLP in Ignacio about 20miles from the field location.

5. WATER PRODUCTION AND DISPOSAL

Water production and disposal assume a greater degree of importance in coalbed methane (CBM) projects than in conventional oil or gas operations. In marginally economic coalbed projects, the water disposal costs and the attendant environmental accounting are critical factors in the investment decision; water disposal costs economically make or break a marginal project [45].

Normally, water must be removed from the coal to lower the pressure and to initiate methane desorption; however, near mining operations there may be only small amounts of water to produce. The operator can also anticipate large amounts of water being produced early in the process but decreasing thereafter to an eventual low level. Therefore, water disposal problems decrease with time, and the greatest economic burden is placed on the operator in the first few years.

Water purity ranges from nearly fresh around the edges to marginally saline in the deepest coals of the San Juan basin. Water purity and the quantity produced determine the means of disposal and the costs of disposal. Suspended solids, total dissolved solids, and oxygen demand of produced waters have the most impact on water treatment.

Before investing in a CBM process, a multiplicity of questions are to be answered concerning the water to be produced—questions concerning quantity, flow rates, chemical content, disposal means, monitoring, and environmental regulations. Perhaps no other factor affects the economics and feasibility of CBM projects as much as water removal and disposal. It has been suggested [45] that a truer indicator of the value of a well would be a plot of gas/water ratio rather than gas production alone. As a whole, CBM operations result in 0.31 barrels of water produced per 1,000 cu ft of methane [46].

5.1 Produced Water Disposal In San Juan Basin:

The San Juan Basin is located in southwestern corner of Colorado and extends into the northwestern corner of New Mexico. The basin encompasses parts of Archuleta and La Plata counties in Colorado and into parts of San Juan, Rio Arriba, Sandoval and McKinley counties in New Mexico.

On the Colorado side of the basin, the Ignacio Blanco Field is where the vast majority of wells are producing gas and water. In 2000, an estimated 1,790 wells generated conservatively 25,293,071 barrels of produced water with 403,025,158 mcf gas [(47)].On the New Mexico side, producers reported that the Basin Fruitland Coal gas pool produced the highest volume of water associated with gas in the basin, in the amount of 6,033,799 barrels of water associated with 491,374,058 mcf gas. High volumes of water (over 1 million barrels each) were also reported at the Blanco-Mesa Verde pool and the Basin Dakota Pool [(48).]

5.1.1 Concerns and Issues of Produced Water Disposal In San Juan Basin

Produced water management and disposal is a major issue in the San Juan basin. Firstly, Produced water associated with production of Coal Bed methane incurs close to 50% of the capital and operating costs associated with production of methane from unmineable coal bed seams .The methane produced in the San Juan Basin has an average water to gas ratio of 0.031 barrels per 1000 cubic feet of gas (Bbl/MCF). Economic management of produced water is an especially critical issue for coal bed methane development as producers look for treatment alternatives in an effort to find economic competitive disposal alternatives [(49)].

Secondly, Deep injection which is the predominant disposal technique in the San Juan Basin is a costly practice as operators must consider capital expenditures, direct operating costs, and gathering costs involved. Total disposal costs can vary widely from about $0.12/bbl in SE New Mexico to more than $5.00/bbl in some Colorado basins. (at $5.00/bbl that’s over $38,000/ac-ft) [(50)].

Finally, treatment of produced water for beneficial use has significant appeal in most arid western states because of the need to conserve valuable water and as a way to reduce costs but this basin lacks the infrastructure needed for most management options. This places emphasis on the need to identify and develop less complicated and more cost effective CBM produced water disposal options.

5.2 Produced Water Project Objective:

The objective of this aspect of the project was to develop an alternative water disposal technique by using produced water generated from the modeled field as water supply for a Geothermal Power Generation Plant located in the same area (60 Miles from field).

5.2.1 Project Benefits:

The benefits of this aspect of the project include:

1. Conserve river water for other beneficial uses in New Mexico.

2. Reduce the diversion of water from the San Juan River for cooling at San Juan geothermal power generation Station.
3. Reduce the volume of water that must be handled and injected by producers.
4. Reduce producers' water handling and injection costs.
5. Establish an infrastructure to significantly minimize produced water injection in the San Juan Basin.
6. Establish area-wide opportunities to reduce produced water handling and injection costs.

5.3 Produced Water Characterization:

5.3.1 Water Production Rates From Methane Wells:

The amount of water produced from CBM wells typically starts at a high volume and declines significantly once the coal seam becomes depressurized. In the San Juan Basin the typical initial rate of produced water is 400 barrels per day per well. But, over the 10-20 year life of a well, it will average less than 100 barrels per day [51].

Table 10 shows typical water production rates and water to gas ratios for the San Juan basin. The actual amount of water produced, as well as the ratio of water to gas, varies widely from area to area within a basin. The variations are due to the original depositional environment, depth of the coal seam, type of coal, and means of CBM production [51]. **Figure 19** gives the Water production schedule of the modeled area of the Fruitland formation.

In this simulation, the water production rates showed a significant decrease by the end of the first month of production. **Figure 20** shows the production rate of water for a single well for the simulated area.

5.3.2 Water Decline Rates And Estimates From Model:

The anticipated schedule of water production throughout the life of the project is needed for an accurate economic evaluation. Water disposal and operating costs depend upon knowing the water production rate from an entire field. The water production with time data of a production unit in the field may be described with decline curve analysis if the subject production unit does not experience interference. Then, it would be appropriate to have either a field or an isolated well as a unit.

If the data points are treated as an exponential decline, then the resulting straight line can be extrapolated to any later time which represents the water production schedule of a single well in the field without interference from other wells. If the decline rate can be established for all production units or for the field as a whole, the total load schedule can be determined for the water treatment facilities, discharge into surface streams, or injection into disposal wells.

From the results of the modeled area (**Figure 21**), a decline curve was created treating the water production data as an exponential decline. This was used to determine an average production rate from a single well. A steady rate of

65bbl/day was calculated and this was used as a base average value throughout the production life of the well. The Water Production rate is shown in **Table 11.**

5.3.3 Chemical Content:

Quantity and chemical content are the two important considerations of waters produced from coal seams. Some treatment at the surface is necessary regardless of the disposal method. A representative analysis of coalbed water is given in **Table 12**, which is a compilation by Lee-Ryan [52] for waters in the San Juan Basin.

Perhaps the single most critical parameter which can serve as a surrogate parameter for produced water quality is total dissolved solids (TDS). This is true because TDS is usually associated with undesirable environmental impacts on aquatic organisms and potential drinking water sources, and, may also influence injection formation fluid chemistry compatibility.

5.4 Produced Water Management Options:

This project has identified two water disposal management options to reduce operation cost and put waste water for beneficial use based on the disposal regulations and infrastructure in the San Juan Basin.

Produced water from the model will be treated for use as heat transfer fluid and fracture fluid for use in a nearby Geothermal Power Plant.

The Remaining excess will be deep injected according to the provisions set by the National Pollutant Discharge Elimination System (NPDES)

1. The design of produced disposal and treatment options in this project is dependent on three important factors:

2. The quantity of produced water to be treated in barrels per day (bbls /day),

3. The chemical quality of the produced water (concentrations in mg/L of chemical constituents-of-concern), and

4. The disposal requirements in terms of mode and quality issues (usually determined by the government regulations).

For this project, the design criteria for the treatment of water for geothermal purposes include:

1. Requirement of 7,253,357 Barrels of water for an operational period of 10 years, as determined by the Geothermal Energy Design Group. The breakdown of this volume of water and their uses is given in **Table 13**.

2. A total dissolved solids (TDS) concentration of about 5,000 mg/L as set by the NPDES as the TDS limits for Surface Discharge of Produced water. This criterion fits use of water for Hydraulic fracturing and use as heat transfer fluid.

Water estimates is based on a 10-year operating life of the power plant

5.5 Treatment Process Selection:

Three different treatment process systems for removal of specific types of water quality constituents were evaluated. The three process systems include:

1. Deoiling

2. Organic Removal

3. Partial Demineralization

These three systems have been identified by the Gas Research Institute as the process systems that would meet the NPDES permit requirements for beneficial use discharges for the San Juan Basin [(49)].

The treatment process systems and the unit equipments required are listed in **Table 14**. The selection of these three treatment process systems for this analysis is based on the water quality data presented in **Table 15** and discharge permit requirements set by NPDES for surface discharge. Different combinations of unit treatment processes within each treatment process system were varied to determine which were the most cost-effective.

The Process flow sheet for the water treatment plant for produced water is given in **Figure 22**. The plant is designed with a basis of 3 gallons per minute of untreated produced water and treated water effluent of 1.25 gallons per minute. The Plant has 75% overall efficiency, with the Reverse Osmosis units having an efficiency of 33%.

5.6 Deep Well Injection:

5.6.1 Underground Injection:

One management option for produced water is to inject it underground in accordance with the state and federal laws. Injection wells have over the time become popular amongst the oil and gas industries especially CBM reservoirs as in some cases it is the only disposal mode available.

Injection is dependent on a variety of factors mainly hovering around the availability of formation; quality of water being injected, quality of water in the receiving formation, storage capacity of the receiving formation. Injection basically refers to emplacement of water into an aquifer or reservoir by pumping the water into an injection well completed in a zone or formation that is capable of receiving and storing water. [(53)]

Injection wells are regulated by Underground Injection Control Program (UIC), which was initiated under the Safe Water Drinking Act (SDWA) to prevent contamination of all USDWs (Underground Sources of Drinking Water).The program although is overseen by EPA the final say is in the hands of state.

5.6.2 Well Classification:

EPA has provided definitions, regulations which divide the injection wells into five different categories. EPA's definition depends on several criteria, such as purpose, quality of injecting fluid, location of USDW with respect to injection wells.

Class II wells have been identified for the Oil and Gas industries including CBM. Injection is basically carried out in a formation which is not an underground source of water that is TDS content is greater than 10,000 mg/liter. Class II wells have been further divided into three subclasses which are explained as follows.

1. Class II-R: - These wells are used to inject water or other fluids into producing horizons in order to enhance production.
2. Class II-D: - These wells are used for disposal purpose's that is pumping fluids into zones other than producing zones for disposal purposes.
3. Class II-H: - These wells are used to inject and store oil and natural gas in order to extract it later.

   Hence for CBM purposes we fall under the second option.

5.6.3 Factors Affecting Deep Injection:

There are certain technical considerations which have to be incorporated such as the geology, economy, engineering considerations. Some set of issues that need to be focused upon are as follows.

1. Formation Suitability-Various factors such as depth, relative location with respect to producing wells, from USDW, effects of faulting and fracturing have to be considered.
2. Isolation- The formation must be vertically, laterally either be separated or confined from all other underground sources of drinking water and other zones which are not permitted for disposal.
3. Porosity-Porosity refers to the percentage of void spaces hence the receiving formation should have sufficiently high porosity whereas the confining zones should have none.
4. Permeability-Permeability refers to the relative ease with which fluids can be transmitted under a potential gradient. Receiving formation should have high permeability whereas the confining zones should have low in order to prevent seepages from occurring.
5. Storage Capacity- Storage capacity limits the volume of fluids that can be stored. Laboratory tests can be carried out in order to calculate porosity, bulk volume and in turn the pore volume which can be extrapolated in order to attain the big picture.
6. Reservoir Pressure- Reservoir pressures limit the rate at which fluids can be injected.
7. Water Quality- The quality of water both inside the formation and the one to be pumped should be monitored in terms of chemical compatibility.

Once injection is done testing criteria's are assigned in order to assure that the injection wells are mechanically sound. Mechanical Integrity Tests (MITs) are performed on all injection wells in order to assure the integrity of wells internal components such as casing, tubing, and packers. Timely reporting to EPA is mandatory. Once the capacity of an injection well is met it must be plugged and abandoned in a routinely manner with guidelines issued by EPA.

5.6.4 Alternative Injection Methods

1. Produced water can be injected into coal seams above or below the producing zone. Injection of water will most definitely not have any detrimental effects on gas production. Also the seam can be a depleted one hence can and should be used to save costs of drilling and completing an injection well.
2. Aquifer Storage/Recovery-ASR refers to the process of injecting water into an active aquifer for subsequent retrieval later. The water quality should be in accordance with non exempted aquifer that is less than 10,000 mg/liter hence certain pretreatment procedures needed to be carried out.

For our CBM development and considering our economics and resources we will be emplacing all the excess produced water into class II-D wells.

5.7 Predicted Economics Of Water Management Options:

5.7.1 Key Economic Factors:

The economics of coalbed methane produced water management in the San Juan Basin are influenced by four key factors:

1. Future natural gas prices and, most critical today, the "basin differential." While natural gas prices at the Henry Hub have recently ranged from $4 to $4.069 per Mcf, the prices paid at the White River hubs have ranged from $3.8 to $3.9 per Mcf, for a persistent "basin differential" of $0.219 per Mcf.
2. The volume and timing of gas and water production from individual coal seams in distinct portions of the basin. Expected gas recovery from a CBM well ranges by order of magnitude, from 0.1 Bcf to 1 Bcf per well; and, water recovery varies twenty-fold, from 100,000 to 2,000,000 barrels per well.

3. The capital and O&M costs for drilling and operating wells of different gas and water productivity and at depths of 300 to 3,000 feet.

4. The coalbed methane produced water management option selected by the operator, as discussed below.

5.7.2 Water Disposal Alternatives:

In this project, the two water disposal alternatives implemented include:

1. Actively treated water for use in geothermal electricity power generation

2. Deep re-injection of untreated produced coal-bed methane water.

5.7.3 Capital And Operating Costs Of Actively Treated Water:

This alternative involves constructing water holding and residual concentration storage impoundments, installing a water treatment system involving reverse osmosis (RO), surface discharging the treated water, and either trucking or deep re-injecting the residual concentrate.

Capital Costs. The capital costs are for a large, central unit able to service 96-producing CBM wells.

1. The cost of three surface discharge points is estimated at $24,000 (from above), plus $100,000 for water piping and $110,000 for studies and permits, for a total of $234,000 for a 130-well unit.

2. The cost of one 3-acre (20 acre-foot) infiltration impoundment (with a capacity of 150,000 barrels) is estimated at $92,250 (from above). This would provide storage for about 5 days of water production from a 130-well unit. Two such impoundments are required to provide 10 days of produced water storage capacity. The cost of a third smaller (10 acre-foot) lined impoundment for storing the reject water (concentrate) from the RO unit is estimated at $151,900, plus piping. This would provide storage for up to one month of reject water. The total cost for impoundments is estimated at $336,400.

3. Assuming a 130-well unit and 320 barrels of water per day per well (average water rate for first 2 years), 3 300-gpm (10,286 barrel per day) units are required with capacity to treat 30,000 barrels per day.

4. The cost for 3 RO units (from Filter Tech) is $2,212,000. Assuming 20% for site preparation, the electrical system, building, etc., plus 10% for contingency, insurance and other, the cost for three units is $2, 880,000.

5. Two options, trucking and deep disposal exist for disposing of the residual concentrate, estimated at 10% of the treated water or 3,000 barrels per day.

6. If trucking is the option, these costs are included in O&M costs, presented in the next section. The total capital costs for using active water treatment (with RO) are as follows for a 900-gpm (30,860 barrel per day) facility:

The cost for the RO unit and associated facilities, assuming trucking of the residual concentrate to disposal, is $3,450,000 or $26,538.5 per well for a 96-well unit. Adding a deep disposal well and injection facilities would eliminate the costs of trucking the residual concentrate, but would raise the capital costs to $4,380,000 or $33,693 per well for a 130-well unit [54].

Operating and Maintenance Costs:

Operating costs for the 3 RO units are estimated at $233,100 per year for a 130-well unit, or $0.03 per barrel of water treated (assuming a capacity of 30,000 barrels per day) and an operating factor of 95%, as shown below. Adding the costs of maintaining the discharge points and impoundments, and providing electricity and maintenance for the pumps, brings operating costs to $0.04 per barrel of water produced. If trucking is the option, the costs for operating the RO unit, pumping the water, operating the discharge points, and disposing of the residual concentrate are estimated at $0.24 per barrel of water produced assuming water trucking costs of $2.00 per barrel of residual concentrate and 10% residual concentrate [(54)].

5.7.4 Transport Costs of Actively Treated Water:

Two alternatives are available to transport water to the geothermal plant that is located at about 60 miles away from the central treating facility. They include:

1. Trucking, this utilizes trucks with a capacity of about 4,500 gallons to transport water. This mode requires low capital cost, a high operating cost and major risk involved are road accidents.

2. Pipeline, this requires a huge capital investment, low operating cost and the risk involved is line failures.

The trade-off between both choices is never clear or obvious but operators usually prefer trucking as the preferred option if produced water is less than 225 bbl/day. This option was chosen for this project as the average daily production was 65 bbl/day.

Prior to this project, transportation cost analyses of produced water have focused on the cost per barrel transported. Katz *et al* (2006) estimated that between $0.40 and $0.90 is spent transporting each barrel (42 gallons) of produced water based on assumptions stated in **Table 16**. The assumptions were based on the following figures: diesel costs $2.50/gallon, truck fuel mileage equals 10 miles/gallon, driver's pay equals $19.50/hr, driver travels 40 miles/hr, and the central facility operator's pay equals $22.50/hr. Maintenance includes oil changes, tires, and other mechanical needs, and central facility represents the operator required to run the central reinjection facility [(55)].

Therefore, approximately $1.35 is spent for every mile the produced water is transported. The distance from power plant to the central facility (60 miles) was multiplied by $1.35 in order to determine the total transportation cost per trip from the facility. The total cost incurred over a 10-year period is given in **Table 17**.

5.7.5 Cost Analysis for Deep Injection:

The cost analysis for deep injection includes the cost for drilling one injection well, cost of transporting to the well and maintenance of the well [(56)]. The cost estimates for this project is given in **Table 18**. They include both capital and maintenance costs for operating the injection well for a period of 10 years.

5.7.6 Cost Summary:

The total cost incurred in management of produced water is summarized in **Table 19**.

6. NATURAL GAS DISTRIBUTION:

6.1 Overview of Colorado's Resources:

Colorado is substantially rich in fossil fuels and other sources of energy. It has ten of the Nation's 100 largest natural gas fields and three of its 100 largest oil fields. Conventional and unconventional output from several Colorado basins typically accounts for more than 5 percent of U.S. natural gas production. Coalbed methane accounts for over forty percent of Colorado's natural gas production, and almost thirty percent of all coalbed methane produced in the United States. Coalbed methane production is active in the San Juan and Raton Basins, and further development is possible in northwest Colorado's Piceance Basin, which holds the second-largest proven reserves in the Nation [57].

6.2 Natural Gas Consumption Trends in Colorado:

Colorado has a population of around 5 million with 20 gas utilities. State profile data from Energy Information Administration database for Colorado for the year 2008 suggests that the residential sector contributed the most (68%) to the total gas utility revenues followed by commercial (30%), electric power (1.7%) and industrial sectors (0.3%). The annual state consumption was nearly 342 Bcf the same year [58]. Natural gas consumption by the electric power sector has been increasing since 2003, with a dramatic increase in 2007 putting the sector second only to the residential as the leading natural gas-consuming sector in Colorado. About three-fourths of Colorado households use natural gas as their primary energy source for home heating, one of the highest shares in the Nation. [57]

Colorado uses only about two-fifths of its natural gas production. The remainder is transported to markets in the West and Midwest. Colorado is part of the transportation corridor for shipping gas from the Rocky Mountain supply region to the Midwest and West markets. Its natural gas production is growing, and construction of a new pipeline, known as the Rockies Express Pipeline, was recently completed to help move the rapidly increasing output to the Midwest [57].

6.3 Destinations for Natural Gas from the North Western San Juan Basin:

6.3.1 Interstate Pipelines:

In Colorado, the Rocky Mountain Natural Gas Company provides interconnections between natural gas producers in the western part of the State and the TransColorado Gas Transmission Company, which travels southward into New Mexico en route to the California market, through the Transwestern Gas Company and El Paso Natural Gas

Pipeline Company systems. In addition, in 2006, the TransColorado Gas Transmission Company installed a capability to reverse flow on its system, providing natural gas producers operating in the developing Unita/Piceance Basins of eastern Utah and western Colorado the opportunity to also transport their product eastward to the Cheyenne Hub in eastern Colorado via other regional natural gas pipelines to access transportation services to Midwest markets. TransColorado Transmission also further expanded its northern flow capacity out of the San Juan Basin in southern Colorado in 2008 to give producers in that area greater access to these Midwest markets, in addition to their traditional Western regional market.

Also providing transporation is the western portion of the Rockies Express Pipeline system. Completed in February 2007, the 328-mile Rockies Express-Entrega system has the capability to transport 1.5 Bcf per day of natural gas supplies from northwestern Colorado and southwestern Wyoming to the Cheyenne Hub located in northeastern Colorado. A major LDC (Local Distribution Company) in the western part of this region is Questar Gas Company. The Public Service Company of Colorado is the major distributor of gas in Colorado, with more end-use customers in a single State than any other company in the region. Colorado Interstate Gas Company provides nearly all of the gas to this LDC [(59)].

The expanding development of natural gas resources in Colorado, especially for coal bed methane and tight-sands natural gas, has greatly increased the amount of natural gas pipeline capacity built within and exiting the area in recent years. Header laterals have been built to transport natural gas from local gathering systems to interconnections with major interstate natural gas pipelines such as Colorado Interstate Gas Company. In addition to these laterals, several existing intrastate natural gas pipelines have also provided support to producers needing natural gas transportation services in the area [(59)].

Looking at the overall spread of the interstate pipelines, there is a possibility to construct and connect a new gas pipeline from our production area to the Colorado Interstate Gas Pipeline. Colorado Interstate Gas (CIG) consists of approximately 4,200 miles of pipeline with a design capacity of approximately 3,750 million cubic feet per day. CIG is comprised of pipelines that deliver natural gas from production areas in the U.S. Rocky Mountains and the Anadarko Basin directly to customers in Colorado and Wyoming and indirectly to the midwest, southwest, California and Pacific northwest. CIG also owns interests in five storage facilities located in Colorado and Kansas, which collectively have approximately 35 billion cubic feet of underground working natural gas storage capacity and one natural gas processing plant located in Wyoming [(60)].

6.3.2 Local Distribution Companies:

Distribution is the final step in delivering natural gas to end users. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity interstate and intrastate pipelines (usually contracted through natural gas marketing companies), most other users receive natural gas from a local distribution company (LDC). LDCs are companies involved in the delivery of natural gas to consumers within a specific geographic area. With the expansion in the gas pipeline network, the local distribution companies have expanded their network as well. There are two basic types of local distribution companies: those owned by investors, and public gas systems owned by local governments.

Local distribution companies typically transport natural gas from delivery points along interstate and intrastate pipelines through thousands of miles of small-diameter distribution pipe. Delivery points to LDCs, especially for large municipal areas, are often termed 'citygates', and are important market centers for the pricing of natural gas. Typically, LDCs take ownership of the natural gas at the citygate, and deliver it to each individual customer's location of use. This requires an extensive network of small-diameter distribution pipe [61].

6.3.3 Market Centers/Hubs:

6.3.3.1 *Importance of Hubs*:

Since 1980's, market centers have become a key component of the North American natural gas transportation. Located at strategic points on the pipeline grids, these centers offer essential transportation service for shippers between pipeline interconnections, as well as provide these shippers with many of the physical and administrative support services formerly handled by the natural gas pipeline company as "bundled" sales services. [62]

Figure 23 shows Natural gas market centers or hubs with respect to natural gas transportation corridors.

6.3.3.2 *Hubs in Colorado*:

Colorado has two market hubs each operating at capacities greater than 2000 MMcf a day. The market center White River Hub became active during the past seven years. Located in western Colorado, it is owned by a partnership between Enterprise Products Partners, LP and Questar Gas Company. The White River Hub was created to provide natural gas producers in the Piceance and Uinta basins access to the multiple intrastate and interstate pipelines that now serve the expanding production fields located within the surrounding area. The hub operates an 11-mile header system pipeline and offers market center services to producers and pipelines located primarily in the Piceance Basin area of western Colorado. Natural gas production in this area of Colorado increased from 14 percent of total Colorado production in 2003 to 28 percent in 2007, supporting development of the White River Hub [62].

The Cheyenne Hub, located in eastern Colorado, has not only profited from the increased natural gas production in the Green River Basin that flows eastward, it has been the destination of a large portion of the natural gas coming out of the Uinta/Piceance Basin expansion. These new flows into the

Cheyenne Hub have more than compensated for the one-third decrease in Wyoming's Powder River Basin coalbed methane production, much of which is directed toward the hub. The Cheyenne Hub began operations in 2000 to support the growing need for natural gas transportation out of the Powder River Basin and to provide trading services for eastern Wyoming and northern Colorado area producers and other market makers [62]. **Figure 24** shows the location of the important hubs in the Rocky Mountain region and also the White River and Cheyenne Hubs.

6.3.4 Storage Sites:

6.3.4.1 *Importance*:

At the end of the mainline transmission system, and sometimes at its beginning and in between, underground natural gas storage facilities provide for inventory management, supply backup, and the access to natural gas to maintain the balance of the system. There are three principal types of underground storage sites used in the United States today: depleted reservoirs in oil and/or gas fields, aquifers, and salt cavern formations. In one or two cases mine caverns have been used. Two of the most important characteristics of an underground storage reservoir are the capability to hold natural gas for future use, and the rate at which natural gas inventory can be injected and withdrawn (its deliverability rate). Underground natural gas storage provides pipelines, local distribution companies, producers, and pipeline shippers with an inventory management tool, seasonal supply backup, and access to natural gas needed to avoid imbalances between receipts and deliveries on a pipeline network [63]. **Figure 25** shows types of underground natural gas storage facilities and **Figure 26** shows the location of the different storage sites in US.

6.3.4.2 *Owners and Operators*:

The principal owner/operators of underground storage facilities are (1) interstate pipeline companies; (2) local distribution companies (LDCs) and intrastate pipeline companies, and (3) independent storage service providers. If the facility serves the interstate market it is subject to Federal Energy Regulatory Commission (FERC) regulations; otherwise, it is State-regulated. Owners and operators of storage facilities are not necessarily the owners of the gas held in storage. Indeed, most working gas held in storage facilities is held under lease with shippers, LDCs, or end users who own the gas [64].

6.3.4.3 *Natural Gas Storage Sites in Central Region*:

Many of the 49 storage facilities located in the region are used to store excess production rather than to serve as a supply source for local markets. Production is stored to allow a stable flow rate despite temporary demand fluctuations. The region has the Nation's largest storage site, the Baker/Cedar Creek Field in Montana, with a total capacity of 287 billion cubic feet (Bcf) and a working gas capacity of 164 Bcf. The total regional working gas storage capacity (approximately 557 billion cubic feet) is 14 percent of the U.S. total, while daily deliverability from storage is only 6.2 billion cubic feet per day, or 7 percent of the U.S. total [(64)]. **Figure 27** shows the natural gas storage capacity for the central region. It shows that Colorado has 8 depleted gas fields for this purpose. The storage fields in Colorado and portions of Wyoming service the Denver area through the Colorado Interstate Gas Company system. The local distribution companies serving these markets account for about 16 percent of the total storage deliverability in the region.

6.4 Treatment Plants:

Treatment plants in Colorado near the producing regions handle the job of gas gathering, treatment and transportation from the area of production. Some of the companies which work over the gathering and treatment of the natural gas from the San Juan basin include William Partners L.P, Red Willow Production Company, Red Cedar Gathering Company. These companies gather and treat gas from all of the geological formations and coal seams within the San Juan Basin and deliver high quality, treated gas to Intrastate and Interstate pipelines [(65)]. **Figure 28** shows the concentration of natural gas processing plants in the US. Note the region near the San Juan Basin.

6.5 Natural Gas Fired Power Plants:

6.5.1 Why Natural Gas Fired Plants:

Natural gas, because of its clean burning nature, has become a very popular fuel for the generation of electricity. In the 70's and 80's, the choices for most electric utility generators were large coal or nuclear powered plants; but, due to economic, environmental, and technological changes, natural gas has become the fuel of choice for new power plants. In 2009, 23,475 MW of new generation capacity are planned in the U.S. Of this, over 50% will be natural gas fired additions. Natural gas fired electricity generation is expected to increase dramatically over the next 20 years. There are many reasons for this increased reliance on natural gas to generate our electricity. While coal is the cheapest fossil fuel for generating electricity, it is also the dirtiest, releasing the highest levels of pollutants. Regulations surrounding the emissions of power plants have forced them to come up with new methods of generating power, while lessening environmental damage. New technology has allowed natural gas to play an important role in the clean generation of electricity [(61)].

6.5.2 Natural Gas Fired Plants in Colorado:

Colorado has 14 natural gas fired power plants which operate from 200-700 MW capacity. All of these plants are within 300-500 miles road distance of operation of this project. The different plants with their operating capacity are listed below:

6.5.2.1 Front Range Power Project , 480 MW
6.5.2.2 Fountain Valley, 234 MW
6.5.2.3 Limon Generating Station, 134 MW
6.5.2.4 Arapahoe Combustion Turbine Project, 122 MW
6.5.2.5 Blue Apruce Energy Center, 276 MW
6.5.2.6 Plains End, 120MW
6.5.2.7 Frank Knutson, 134 MW
6.5.2.8 Rocky Mountain Energy Center, 608 MW
6.5.2.9 Spindle Hill Energy Center, 270 MW
6.5.2.10 TCP 272, 264 MW
6.5.2.11 Fort St. Vrain, 695 MW
6.5.2.12 Manchief Electric Generating Station, 264 MW
6.5.2.13 Brush IV, 115 MW
6.5.2.14 Rawhide, 260 MW.

These capacites translate to nearly 11,000 to 40, 000 Mcf/day of gas requirement considering them to be operating at 50-60% efficiency. **Figure 29** shows the map of Colorado with the inverted orange triangles depicting the locations of the natural gas fired plants and orange stars the location of the market hubs.

6.6 Compressed Natural Gas Stations:

The relative abundance and clean burning characteristics of natural gas make it an attractive vehicular fuel, especially for urban areas. Compared to gasoline, natural gas combustion produces less hydrocarbon emission as well as less emissions of sulfur and nitrogen oxides. Today, there are more than a million NGV's operating worldwide. These vehicles use compressed natural gas at about 3000 psig (200 bar) and ambient temperature. However, for the same driving range, the size of the CNG vessel is at least three times the volume of a gasoline tank. Compression to 200 bar necessitates a four stage compression unit and costly infrastructure [(66)].

The state of Colorado has several fueling stations of Clean Energy and Xcel Energy spread over the cities of Arvada, Aurora, Boulder, Denver, Colorado Springs etc [(67)]. These stations need atleast 80,000 to 90,000 MMcf/d of gas to run around 2000 buses a day.

6.7 Deciding Potential Customers:

Looking at the above options, there are a few things that can be done with the natural gas produced from our location. We can sell our natural gas in the following ways:

6.7.1 Sell our natural gas to a treatment plant who will then direct the treated gas to an interstate or intrastate pipeline.
6.7.2 Treat the gas by sending it to a treatment plant and spend money and then direct it to an interstate/intrastate pipeline.
6.7.3 Construct a pipeline to be sent to the market/ hub, local distribution companies or storage companies after spending on its treatment.
6.7.4 Construct a pipeline to the natural gas fired plants or CNG stations. Spend money on the treatment of the gas before sending them to these customers.

In the first three scenarios, we will end up selling gas at the well head price. On the other hand, the electric power plants and the stations buy gas from the market hub at a price much higher than the well head price. If we decide to sell the gas to these customers after treatment via pipelines, we can be advantaged by selling it to them at higher price than the well head price but at a price lower than the hub price. So for this project, we plan to have a pipeline from our production location to the nearest natural gas fired power plant which is aprroximately 300-400 miles away or a CNG station which is also nearly the same distance away. This can be done since the market for wellhead natural gas purchases is unregulated; that is, producers may negotiate prices and delivery terms with consumers or with other firms, such as marketers and LDCs etc, for the sale of their products [(68)]. Another advantage of sending gas to these customers is that there demands are not season dependent. It remains more or less constant. So our production team will not have to worry hard on where to store excess gas during off season.

6.8 Pipeline Delivery:

The efficient and effective movement of natural gas from producing regions to consumption regions requires an extensive and elaborate transportation system. In many instances, natural gas produced from a particular well will have to travel a great distance to reach its point of use. The transportation system for natural gas consists of a complex network of pipelines, designed to quickly and efficiently transport natural gas from its origin, to areas of high natural gas demand.

6.8.1 *Pipeline Construction/Infrastructure*:

The pipeline network is a complicated system build to efficiently move the gas to the delivery point. The overall infrastructure demands huge investments in terms of materials, labor requirements, compressor stations, remote controls for maintaining gas flow and systems to detect leakage along the way.

6.8.1.1 *Pipes*:

Pipelines can measure anywhere from 6 to 48 inches in diameter, although certain component pipe sections can consist of small diameter pipe, as small as 0.5 inches in diameter. The small diameter pipe is usually used only in gathering and distribution systems. Mainline pipes or the principle pipelines are usually between

16 and 48 inches in diameter. Lateral pipelines, which deliver natural gas to or from the mainline, are typically between 6 and 16 inches in diameter. Most major interstate pipelines are between 24 and 36 inches in diameter. The actual pipeline consists of a strong carbon steel material, engineered to meet standards set by the American Petroleum Institute (API).

Pipelines are produced in steel mills and there are two different production techniques, one for small diameter pipes and one for large diameter pipes. For large diameter pipes, from 20 to 42 inches in diameter, the pipes are produced from sheets of metal which are folded into a tube shape, with the ends welded together to form a pipe section. Small diameter pipe, can be produced seamlessly. This involves heating a metal bar to very high temperatures, then punching a hole through the middle of the bar to produce a hollow tube. In either case, the pipe is tested before being shipped from the steel mill, to ensure that it can meet the pressure and strength standards for transporting natural gas [(69)].

Line pipe is also covered with a specialized coating to ensure that it does not corrode once placed in the ground. The purpose of the coating is to protect the pipe from moisture, which causes corrosion and rusting. There are a number of different coating techniques. Pipes are often protected with what is known as a fusion bond epoxy. In addition, cathodic protection is often used; which is a technique of running an electric current through the pipe to ward off corrosion and rusting [(69)].

6.8.1.2 *Compressor Stations/Equipment*:

The natural gas is periodically compressed to ensure pipeline flow, although local compressor stations are typically much smaller than those used for interstate transportation. Because of the smaller volumes of natural gas to be moved, as well as the small-diameter pipe that is used, the pressure required to move natural gas through the distribution network is much lower than that found in the transmission pipelines. In addition, Mercaptan is added by the LDCs prior to distribution. This is added because natural gas is odorless and colorless, and the familiar odor of Mercaptan makes the detection of leaks much easier [(69)].

Basic components of such a station include compressor units, scrubber/filters, cooling facilities, emergency shutdown systems, and an on-site computerized flow control and dispatch system that maintains the operational integrity of the station [(70)].

Compressor units that are used on a natural gas mainline transmission system are usually rated at 1,000 horsepower or more and are of the centrifugal (turbine) or reciprocating (piston) type. The larger compressor stations may have as many as 10-16 units with an overall horsepower rating of from 50,000 to 80,000 HP and a throughput capacity exceeding three billion cubic feet of natural gas per day [69].

Compressor stations are “pumping” facilities that advance the flow of natural gas. They are usually situated between 50 and 100 miles apart along the length of a natural gas pipeline system and are designed to operate on a nonstop basis. The average station is capable of moving about 700 million cubic feet (MMcf) of natural gas per day. The scope of this project requires transportation of not more than 100 million cubic feet of gas so the design requirements will be much relaxed in terms of horse power requirement. The compression of the produced gas and set up of the paraphernalia can be outsourced to American Gas Compression Inc. which charges a fixed cost per annum to compress one Mcf of gas. Based on production and the duration of operation of the project it turns out to be nearly $ 0.3/Mcf.

Figure 30 shows the location of main compressor stations on the US Interstate pipeline network.

6.9 Pipeline Specifications:

The flow of gas through pipeline distribution network has been described in the previous section in literature review and has been elaborated in **Figure 31.** The pressure of the flowing gas depends on the diameter of the pipeline and the point of delivery. The pipe pressure for local distribution companies at the city gate could be as low as 3 psi but the pressure in the interstate and intrastate pipelines can be as high as 1500 psi to boost the volume of gas carried.

The quality of gas required and the thermal energy content of gas required have also been discussed previously. The natural gas to be distributed is typically depressurized at or near the city gate, as well as scrubbed and filtered (even though it has already been processed prior to distribution through interstate pipelines) to ensure low moisture and particulate content.

The typical length of pipelining involved in this project will be 300-600 miles which include small diametered (<6 inches) gathering lines from the production wells to the mail line. The mainline from the production site to the end use customer will have 16-24 inch diameter operating at pressure between 500-1000 psi. With these values, the gas will travel at about 10-20 miles an hour through the pipe.

6.10 Pipeline Costs:

Pipeline construction entails the following costs based on the diameter and length of the pipe(s) used [71]:

6.10.1 Materials cost which account for nearly 25% of the total. It can vary from $50,000 - $ 300,000 per inch-mile if diameter varies from 5 to 35 inches.

6.10.2 Labor cost which accounts for the lion's share of 40-50% can vary from \$200,000 to \$400,000 per inch mile (upper limits) for 6 to 36 inches diameter pipes.
6.10.3 Miscellaneous costs account for 20-30% and can vary from \$80,000 to \$300,000 per inch mile.
6.10.4 Right of way costs which are a small fraction, varying between \$20,000 to \$80,000 per inch mile.

There are maintenance costs as well for pipeline integrity which are incurred annually. These can be high as \$300,000 per year.

6.11 Pipeline Safety and Regulations:

There are a variety of problems and challenges associated with the operation of pipeline network. Compressor stations run continuously and are very noisy. Pipelines cut through forests, farms and residential neighborhoods and even run under rivers and lakes, disturbing a variety of environments, sometimes in very damaging ways. Pipeline routes are frequently established through the process of eminent domain. The aging pipeline infrastructure leads to frequent leaks, which regularly produce explosions that are costly in property damage and lives lost [72].

Safety parameters require that all pipelines passing through populated areas reduce their maximum operating pressure. Nominal pipe diameter but increased wall thickness are common where a line has to be derated for its surroundings (change in external stresses due to earth or traffic loads) in order to keep the working pressure rating more constant along the line. Increasing the pipe wall thickness or strength of the pipe will enable the pipe to withstand a greater pressure between operating and design pressure to adhere to safety requirements. To address the potential for pipeline rupture, safety cutoff meters are installed along a mainline transmission system route. Devices located at strategic points are designed to detect a drop in pressure that would result from a downstream or upstream pipeline rupture and automatically stop the flow of natural gas beyond its location. Monitoring the pipeline as a whole are apparatus known as (SCADA Systems Control and Data Acquisition) systems. SCADA systems provide monitoring staff the ability to direct and control pipeline flows, maintaining pipeline integrity and pressures as natural gas is received and delivered along numerous points on the system, including flows into and out of storage facilities [73].

As far as regulations are concerned, the Federal Energy Regulatory Commission (FERC) has a major control over the way natural gas transoprtation is handled in United States. FERC determines the rate setting methods for interstate and intrastate pipeline companies, sets rules for business practices, and has the sole responsibility for authorizing the siting, construction, and operations of interstate/intrastate pipelines, natural gas storage fields, and liquefied natural gas (LNG) facilities [73].

6.12 Future Work:

The application of adsorbed natural gas development for the construction of an onsite ANG fuel station may be considered. This requires tight control over the sorbent thermodynamics, mass and heat transfer rates, sorbent packing density, micropore volume, surface area and other parameters. So far, research has been restricted to laboratories with very little commercialization of this technology because of uncertainties with involved costs for the development of a suitable sorbent on a commercial scale. Till date, research on methane storage has been performed on materials like superactivated carbons, zeolites, Silica, Metal Organic Frameworkds etc. to be able to meet the DOE target of 180 V/V (V stands for volume) uptake of adsorbent. This means that a unit volume of adsorbent should be capable of storing atleast 180 times of methane its own volume. Using such sorbents will reduce the compression requirement to store gas in cylinders by approximately four times and hence the reduction in cost is apparent. However, a major cost factor which is the sorbent development on a commercial scale, has not been explored in great details in the literature which has been a major limitation to the exploration of the application of this technology in this project. [(66)]

However, lietrature reports some overwhelming advances made in this field. Using corncob waste as a starting material, researchers **at the University of Missouri-Columbia and the Midwest Research Institute in Kansas City** have created carbon briquettes with complex nanopores capable of storing natural gas at an unprecedented density of 180 times their own volume and at one seventh the pressure of conventional natural gas tanks. This breakthrough may lead to a flat and compact tank that would fit under the floor of a passenger car, similar to current gasoline tanks.

The carbon briquettes contain networks of pores and channels (**Figure 32**) that can hold methane at a high density without the cost of extreme compression, ultimately storing the fuel at a pressure of only 500 pounds per square inch, the pressure found in natural gas pipelines. This would lead to tremendous pressure savings. The low pressure of 500 pounds per square inch is central for crafting the tank into any desired shape, so ultimately, fuel storage tanks could be thin-walled, slim, rectangular structures affixed to the underside of the car, not taking up room in the vehicle. It was also discovered that fractal pore spaces (spaces created by repetition of similar patterns at different scales) are remarkably efficient at storing natural gas. Researchers are trying to figure out ways of reducing the cost associated with the development of such briquettes [(74)].

7. ENVIRONMENTAL ISSUES:

Some of the major potential environmental issues relating to San Juan Basin, Colorado can be listed as follows:

7.1 Methane Seepage:

As major portion of San Juan Basin is methane rich region, methane has always leaked to the surface. Seeps often are easily discovered near water because seeping gas must bubble through the water to dissipate into the air. Seeps occur all around the San Juan Basin regardless of the proximity to water. Seeps pose the greatest potential safety hazard and engender the greatest fear among residents.

Litigators too easily explain the origin of dissolved methane in water wells and methane seeps as being from coal bed methane operations that lower the hydrostatic pressure and cause large quantities of gas to be released into the subsurface. Implied in this explanation is the idea that gas released from a coal bed methane reservoir has easy access to the surface and surrounding aquifers.

"Gas migration along access paths are provided by wellbore conduits. In the San Juan basin, for example, well installation practices conducted prior to the 1950s left the production casing annulus of deep oil and gas wells uncemented across both the shallower Fruitland formation and overlying strata.
Consequently, when CBM operations began in the 1980s, desorbed gas was free to migrate vertically from the Fruitland coal along the wellbore annulus and into shallow aquifer horizons." Methane liberated during production could migrate up dip until it emanates from the outcrop or shallow sub crop, near basin margins where gas seeps emerge along the outcrop belt of producing coal seams. (75)

"The first documentation of vegetation death due to methane seeps was in 1901, long before natural gas production began in the area. Methane displaces oxygen, eventually killing affected trees and grasses. The methane seeping into the soil eventually dissipates into the air. Methane seeps naturally migrate from one location to another." (76)

7.2 Sound Pollution:

For the coal bed methane development, there are many types of equipment which produce sound like compressors, pumps or safety valves. Some of the loud and inconsistent sounds produced are through the safety valves which pop-up when the valve releases gas so that equipment and surrounding areas are protected from a gas build-up that could become dangerous if contained or unattended for long periods of time.

Some pumps other than the electric pumps, are used during drilling process which use natural gas as the fuel whose engine results in louder noise than the electric pumps.

Similarly in the case of compressors, there are electric driven compressors and also gas engine driven compressors. They can be present on-site or centralized facility. "The type of compression and the power source are dependent on the closeness of a well site to centralized facilities and/or electric power sources. Centralized compression creates the lowest sound impact because it removes onsite compression at various well locations to one central facility, which can be located and built to significantly diminish sound. On-site compression utilizing an electric power source may lower sound impacts, if a well site is not near a central compression facility. However, some remote locations do not have electric power available to them and must utilize natural gas." (76)

"On-site natural gas-powered compressors can be equipped with mufflers to lessen the sound. In appropriate circumstances, sound walls or buildings are sometimes installed to further reduce sound emissions." (76)

7.3 Water Quality:

In the nearby residential areas of San Juan Basin, people complain about the methane gas in the domestic water wells in the early 1980's and 1990's. With this the Colorado Oil and Gas Conservation Commission (COGCC) began a water testing program to determine what type of methane is seeping in the water. After some laboratory tests, it was found that the domestic water contained "biogenic" gas which is caused by a bacteria which is not caused by natural gas development. "One third of the methane gas in groundwater was found to have thermogenic gas, which could be related to natural conditions or development or both. Water separators can mitigate thermogenic gas problems". (76)

Hence the presence of methane in the domestic residential wells can lead to serious health problems. "Residents should take precautions to ensure safe drinking water from domestic wells. San Juan Basin Heath Department and water well contractors can test for water problems. Wells should be regularly disinfected to guard against bacteria." (76)

7.4 Ground Water Impacts:

Due to the presence of coal seams in the aquifer, the withdrawal of ground water is a major issue in the San Juan Basin. This affects the landowners and farmers who are benefitted with the use of groundwater for irrigation, livestock and other household purposes. (77)

"Also due to the seepage of methane gas, the number of shallow domestic wells and springs may increase. Drought and the gas desorbing effects of the domestic wells themselves, may also contribute to groundwater impacts, both in terms of quantity and quality of water produced from domestic wells." (78)

7.5 Coal Fires:

"Partial removal of water from the coal seam near the coal outcrop depressurizes the coal seam and could leave it in a condition where oxygen could replace water in the coal seam and increase the risk of spontaneous combustion. The risk of coal fires would increase with additional wells close to the Fruitland outcrop. Therefore, it is anticipated that the potential for coal fires may increase but should be mitigated by proper operation of the wells." (78)

7.6 Air Quality:

"There have been questions about natural gas flaring affects to air quality in the area. Reflective of gas pressure in formations, the flow of gas can be uneven, sometimes resulting in a gas pressure buildup. Flares safely release gas pressure to avoid a potentially explosive event. Flares do burn natural gas in the process, but natural gas is one of the cleanest burning fuels in use today. Infrequent flaring is temporary and transient in nature with insignificant effects to air quality.

Some on-site gas compressors use natural gas powered engines, producing some air pollution. However, many compressor engines are equipped with state-of-the-art emission controls. These emission controls can consist of internal modifications built into the engine or exhaust treatment utilizing catalytic technology. Both types of controls are very effective at reducing emissions from 60% to 90%. If a threshold of emissions is exceeded at a given site, the State of Colorado or the EPA requires permits. When possible, some companies power compressors using electric motors to reduce air emissions at well sites and at larger facilities.

The overwhelming majority of air pollution in the San Juan Basin is due to automobile exhaust emissions. The remaining air pollution sources in our area include coal-burning electrical power plants, road dust, residential wood burning stoves and fireplaces. Recent studies show that electric power plants that use natural gas instead of coal, dramatically reduce emissions." [(76)]

7.7 Contamination Of Soil:

Contaminated soil is not an issue in the case of natural gas production facilities due to the relatively clean nature of methane production. But sometimes the produced water spillage on the surface can lead to the contamination of soil as the water may contain high amount of TDS. Also at the areas where there are pumps and compressors, there is an issue of spillage of lube oil while refilling it on to the required equipments. So for these, proper rules and regulations need to be issued by the COGCC for proper removal and clean up.

Even though there are not many complaints about the methane gas seepage in the soil, we need to undertake frequent well tests to guard against the potential of methane leaks.

7.8 Wildlife Impacts:

Wildlife impacts are mainly due to the surface disturbances at the time production. Surface disturbance associated with CBM development consists mainly of sites and roads for producing wells, compressor facilities and pipelines. Wildlife is also disturbed by activity but wells are unmanned and require only minimal visits. Some wells are automated requiring even less activity that might disturb wildlife. [(79)]

"In response to increased human activity, equipment operation, vehicular traffic, and noise associated with all phases of each alternative, wildlife may avoid CBM development and production activities and displace to other locations. This avoidance would result in the under-utilization of otherwise suitable habitats. Therefore, the effectiveness of these habitats in supporting wildlife would be diminished and wildlife distribution patterns would be altered. The degree of habitat avoidance would vary between species and among individuals of any particular species."[78]

7.9 Surface Disturbances:

"Natural gas production operations use county and state roads in several ways. The first way roads are used to transport construction equipment. This is a temporary road use that is limited to once or twice in the life of a well or facility -- just like construction equipment used for building a home or commercial facility. Some wells require water trucks to haul produced water to a treatment plant or disposal well. Depending upon site-specific circumstances, some wells are connected to a water gathering pipeline system, which eliminates the need for water trucks.

The most common road use is periodic visits to wells by operation personnel. These visits can be daily (one trip in and one trip out per day), weekly or even monthly. The main purpose for well visits is to monitor operations such as the production flow of natural gas and checking equipment. These trips are typically made in one-ton pickup trucks, commonly used by ranchers, contractors and county personnel.

Many people point out that gas wells utilize heavy equipment during construction, which damages the road. Heavy construction equipment is only needed during initial construction and then averages only once every five to ten years and only for a few days. In comparison, residential construction requires weeks of heavy equipment such as graders, backhoes, cement trucks, cranes, and lumber trucks."[76]

7.9.1 Traffic:

The industry regularly stresses traffic safety and traffic law obedience. Most companies have strict policies that severely punish or dismiss employees who disobey traffic laws while operating company equipment.

8. RULES AND REGULATIONS:

Any oil/gas reservoirs face the adverse affects of their respective production on the environment and also the surroundings. In order to reduce these problems to some extent, we need to lay some rules and regulations and follow them wisely so that we don't any further complex the situation to deal with. Below we present some of the regulations to be placed on each of the activities taking place in the CBM production in the San Juan Basin. These rules and regulations are presented keeping the environmental issues in consideration.

8.1 DRILLING, DEVELOPMENT & COMPLETION:

8.1.1 Approval

Before commencing the operations of drilling, one must sign up an application with the director for a permit-to-drill and get the approval to carry on the drilling operations.

8.1.2 Distance

All wells shall be so drilled that the horizontal distance between the bottom of the hole and the location at the top of the hole shall be at all times a practical minimum.

8.1.3 Permit Display

As a general practice, a permit for drilling should be posted on the rig and should also specify the number of days the permit is valid for, having the proper approval from the director concerned with these operations.

8.1.4 Surface Casing

In areas where pressure and formations are unknown, sufficient surface casing shall be run to reach a depth below all known or reasonably estimated utilizable domestic fresh water levels and to prevent blowouts or uncontrolled flows, and shall be of sufficient size to permit the use of an intermediate string or strings of casings. Surface casing shall be set in or through an impervious formation and shall be cemented by pump and plug or displacement or other approved method with sufficient cement to fill the annulus to the top of the hole, all in accordance with reasonable requirements of the Director. [80]

8.1.5 Underground Water Degradation

The casing program adopted for each well must be so planned and maintained as to protect any potential oil or gas bearing horizons penetrated during drilling from infiltration of injurious waters from other sources, and to prevent the migration of oil, gas or water from one horizon to another, that may result in the degradation of ground water.

8.1.6 Aquifer Protection

In areas where fresh water aquifers are of such depth as to make it impractical or uneconomical to set the full amount of surface casing necessary to comply fully with the requirement to cover or isolate all fresh water aquifers, the owner may, at its option, comply with this requirement by stage cementing the intermediate and/or production string so as to accomplish the required result. If unanticipated fresh water aquifers are encountered after setting the surface pipe they shall be protected or isolated by stage cementing the intermediate and/or production string with a solid cement plug extending from fifty feet below each fresh water aquifer to fifty feet above said fresh water aquifer or by other methods approved by the Director in each case.

8.1.7 Flaring of Gas during Drilling

Any gas escaping from the well during drilling operations shall be, so far as practicable, conducted to a safe distance from the well site and burned. The operator shall notify the local emergency dispatch as provided by the local governmental designee of any such flaring. Such notice shall be given prior to the flaring if the flaring can be reasonably anticipated, and in all other cases as soon as possible but in no event more than two (2) hours after the flaring occurs.

8.1.8 Requirement to log well

For all new drilling operations, the operator shall be required to run a minimum of a resistivity log with gamma-ray or other petrophysical log(s) approved by the Director that adequately describe the stratigraphy of the wellbore.

SAFETY REGULATIONS

8.1.9 Vehicle Distance

The Vehicles of persons which are not involved in drilling, production, servicing, or seismic operations should be located at a minimum distance of one hundred (100) feet from the wellbore. Equivalent safety measures shall be taken where terrain, location or other conditions do not permit these minimum distance requirements.

8.1.10 Control of fire hazards

Any material not in use that might constitute a fire hazard shall be removed a minimum of twenty-five (25) feet from the wellhead, tanks and separator. Personnel shall be familiarized with the location of fire control equipment such as drilling fluid guns, water hoses and fire extinguishers and trained in the use of such equipment. They shall also be familiar with the procedure for requesting emergency assistance as terrain and location configuration permit."[(80)]

8.1.11 Removal of surface trash

All surface trash, debris, scrap or discarded material connected with the operations of the property shall be removed from the premises or disposed of in a legal manner.

8.1.12 "Air and Gas Drilling

"Drilling compressors (air or gas) shall be located at least one hundred twenty five (125) feet from the wellbore and in a direction away from the air or gas discharge line.

All combustible material shall be kept at least one hundred (100) feet away from the air and gas discharge line and burn pit." [80]

8.1.13 Water Quality

People should be aware of the quality of water being used in their domestic household purposes as the probability of methane seeping in the domestic water is higher. If the water is tested to contain methane in high proportion, they need to take the initiative to complain against the company and force them to take appropriate steps.

8.2 WILDLIFE RESOURCES PROTECTION

8.2.1 Education

Informing and educating employees and contractors on wildlife conservation practices, including no harassment or feeding of wildlife.

8.2.2 Mobilization & Demobilization

We need to minimize rig mobilization and demobilization where practicable by completing or recompleting all wells from a given well pad before moving rigs to a new location.

8.2.3 Road Transport Limitation

Limiting access to oil and gas access roads where approved by surface owners, surface managing agencies, or local government, as appropriate.

8.2.4 Trench Construction During pipeline construction for trenches that are left open for more than five (5) days and are greater than five (5) feet in width, install wildlife crossovers and escape ramps where the trench crosses well-defined game trails and at a minimum of one quarter (1/4) mile intervals where the trench parallels well-defined game trails.

8.2.5 Traffic Control

Reducing traffic associated with transporting drilling water and produced liquids through the use of pipelines, large tanks, or other measures where technically feasible and economically practicable. [80]

8.2.6 General Regulations

To minimize adverse impacts to wildlife resources, plan new transportation networks and new oil and gas facilities to minimize surface disturbance and the number and length of oil and gas roads and utilize common roads, rights of way, and access points to the extent practicable, consistent with these rules, an operator's operational requirements, and any requirements imposed by federal and state land management agencies, local government regulations, and surface use agreements and other surface owner requirements, and taking into account cost effectiveness and technical feasibility. [80]

9. ECONOMIC ANALYSIS

For the economic evaluation, we have obtained the values for various parameters through different literature reviews which are clearly referenced and for some parameters, we have made some logical assumptions, the values of which could not be obtained from the literature and are also mentioned in this part of the report.

9.1 Exploration Costs:

The costs for exploring are neglected as we assume that the land is already explored and we are working from the drilling process.

9.2 Drilling, Completion & Fracturing Costs:

The base-case capital investments for the production wells for drilling is calculated depending on the depth of the reservoir. The depth for this part of the San Juan Basin, the depth is about 3000 ft. The cost for drilling is taken as $100/ft. [81].For the completion and fracturing, the costs are taken as $1000/month.

So, accounting for each well the investment for the drilling, completion and fracturing would be about $2 Million.

9.3 Lease Costs:

The lease costs are assumed as $1500/acre. This cost varies according to the price of the natural gas.

9.4 Administrative Costs:

The administrative costs are taken as 10% of total gas revenue costs. These costs include the salaries for the employees, workers and other general services.

9.5 Equipment Costs:

According to the EIA data available, the equipment costs for San Juan basin are $912,000 for 10 wells annually. So, for 13 wells we calibrated the costs to be about $1,200,000 annually. [82]

9.6 Operating Costs:

The operating costs for compression are taken as 0.30/Mcf and the pumping costs are taken as $2/ton. (81). Other additional miscellaneous costs like maintenance costs are included in these calculations. [82]

9.7 Transportation Costs:

The pipeline transportation costs for capital investment will be based as $20000/acre-mile. For operations, the costs would be $0.01/Mcf. [81]

The transportation costs are included in the capital costs are included from the fifth year of production as the break-even obtained for this project is about 7 years. So the constructions of pipelines are assumed to be started from the fifth year, so that when the break- even price is obtained we can start transporting gas from the seventh year onwards.

9.8 Royalty Costs:

This amount is calculated on the basis of the production sale costs. It is assumed to be 12.5% for this project.

9.9 Gas Price:

The present gas price is very much fluctuating with time. However for the 10 years of gas production, we have obtained the forecast prices which are listed in the **Table 20**. [83]

9.10 Revenue Costs:

The total gas production from the wells are calculated per year for 10 years which is listed in the **Table 21** and are then multiplied with the respective year's forecasted gas price to get the total Revenue Costs.

9.11 Total Capital Investment & Gross Revenue:

The total capital investment for this project is projected to be about $350,000,000. According to the production rate obtained after 10 years of operation, the total gas revenue costs are about $580,000,000. According to the numbers we obtained from the simulation, we are able to make profit only after 7 years, i.e. the break even time obtained is about 7-8 years.

9.12 Sensitivity Analysis:

The sensitivity analysis was done for two main parameters of Gas Price and the lease costs, as these vary very frequently for a particular period of time. The values were varied from 40% & 20% of the increase and decrease of the present values taken into consideration and also their percentage increase and decrease were calculated. These are listed in the appendices section in **Tables 22** and **23**.

Summary:

The scope of this project included finding out the feasibility of the development of production design and distribution of natural gas produced from coal bed methane basin on a certain block area of the North Western region in San Juan basin.

The project planning included drilling rate of 13 wells in one year with one rig and continue the project for 10 years. From calculations, the break even to recover production costs appears at about 6-7 year period.

Simulation results proved that the formation was too tight to allow for CO_2 injection. Rather hydraulic fracturing was tried on all the wells drilled and they show to increase the production of gas.

Throughout the course of the project, it has been made clear on why effective, safe and economic disposal of produced water is necessary to sustain the project both physically as well as environmentally. The best part was transporting the water for the purpose of geothermal power generation in order to prevent depletion of resource as the nearby area is pretty arid and depends heavily on ground water as a source of drinking water. Also it was decided to supply water at minimal rates initially so that exact information about the quality of water can be attained and from there on cost issues can be worked out. Trucks were decided to be used as the volume of water considerably reduces after initial requirements are met and also our flow rate is much less than the industry set limit for the use of pipeline. TDS content is a huge problem in the San Juan basin hence we selected technologies which provided maximum efficiency and reduced the TDS content to surface discharge quality. Excessive water was deep injected safely into an underground reservoir without treatment. Economic analysis of the overall costs involved in various aspects of the project was thoroughly carried out and is mentioned in our report. Last but not least once we start making profits and have more money at our disposal we may use the water for certain benevolent issues such as development of rangelands, water parks, aquatic habitat etc.

The break even analysis was carried out to evaluate an estimated time when the production investments made could be recovered. It was decided that approximately two to three years before this period arrives, investments will be made in terms of treatment of gas and development of pipelining infrastructure. This would involve selling off the gas produced at the well head price in the initial recovery period and then after the completion of the transportation infrastructure, selling it to a natural gas fired plant or a compressed natural gas station at a price higher than the well head price but lower than the price at which these customers buy gas from the market centers. The margin or profit would increase by nearly \$2-\$3 per Mcf of gas. Targeting such customers would be beneficial since their demands are not goverened by season. Over the last decade, EIA reports have shown that power plants consume almost a constant amount of natural gas for their operations.

Although the project economics encourages investors to make investments to harness the coalbed methane resource in the area that was selected, there were few measures which could not be

practiced due to lack of knowledge and time. Future work to enhance the benefits associated with this project may include the following:

1. Increasing the number of wells. By changing the amount invested in drilling and the number of rigs used, the production could be enhanced. The idea here was to look at a number that was low and yet productive.
2. Refracturing of existing wells was not simulated due to software limitations. However, in practice, the same wells can be fractured two to three times to enhance production with the cost being nearly the same.
3. Multilateral Drilling has not been explored in excruciating detail. However, it would be interesting to understand and apply this method of extraction since it apparently prevents formation damage and creates greater reservoir exposure through a single well. Gas production, dewatering and disposal can be combined in a single well with this technique which makes it economical in terms of preventing large infrastructure and long term maintenance investments. It also reduces surface disturbances and reduces impact on environment.

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FIGURES:

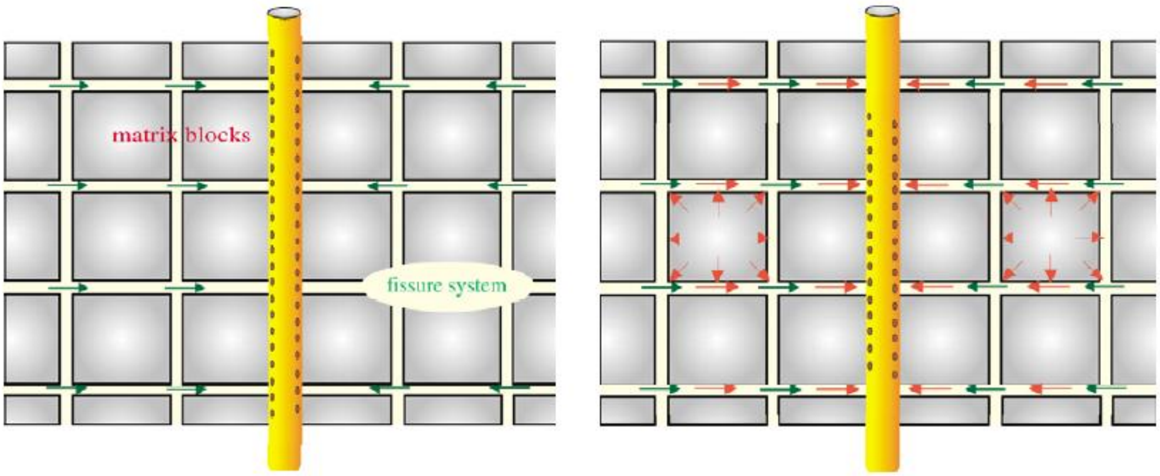


Figure 1. Dual Porosity System [84]

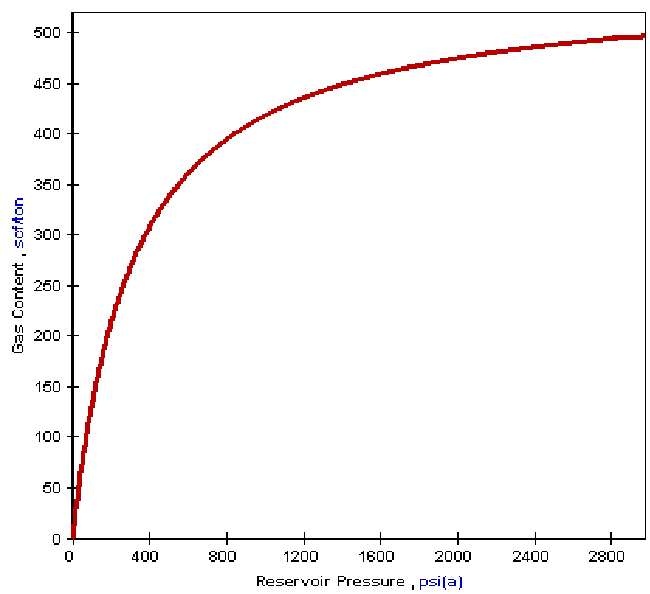


Figure 2. Sorption Isotherm-shows gas content versus pressure at constant temperature. [85]

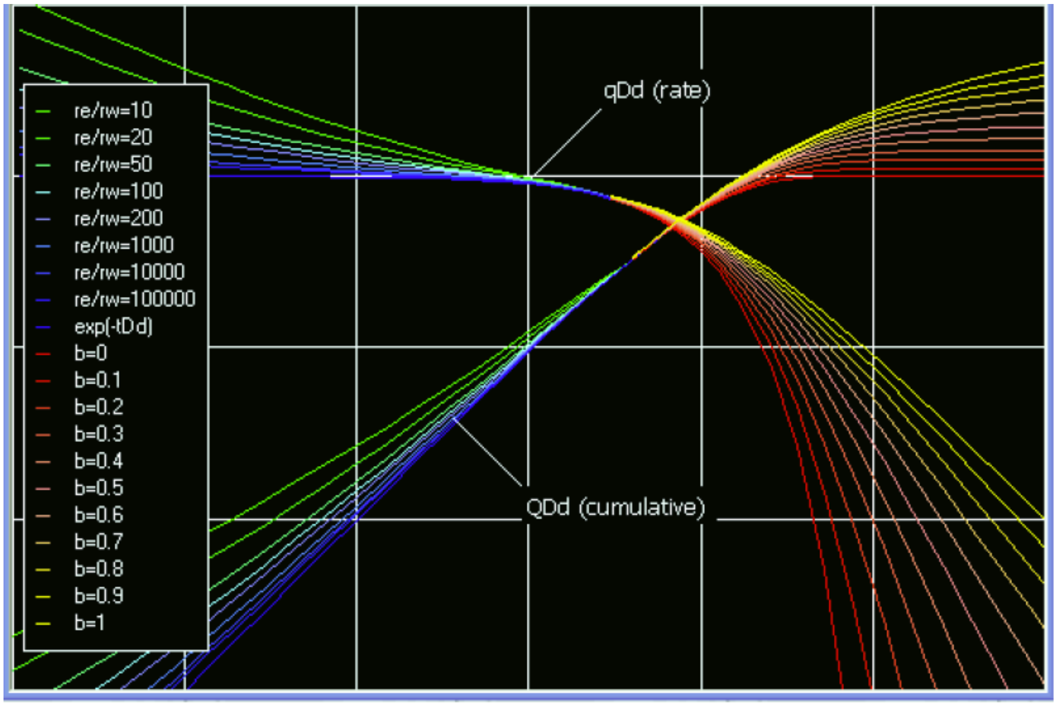


Figure 3. Production Decline Analysis for a Typical Reservoir.

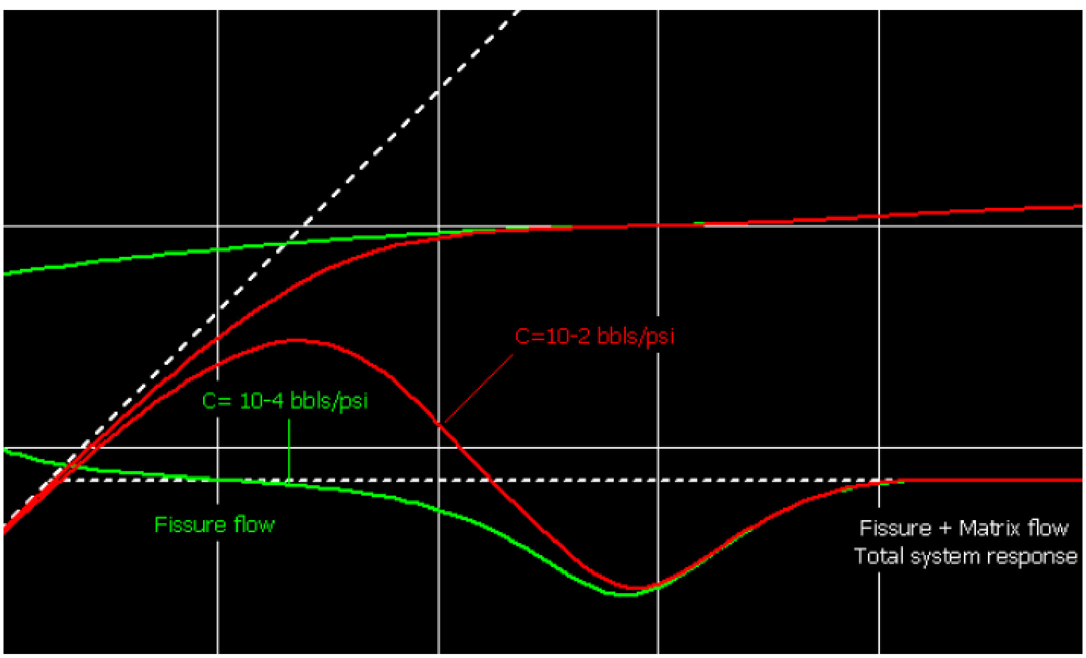


Figure 4. Response of Pressure versus Time for a Typical Dual Porosity Reservoir.

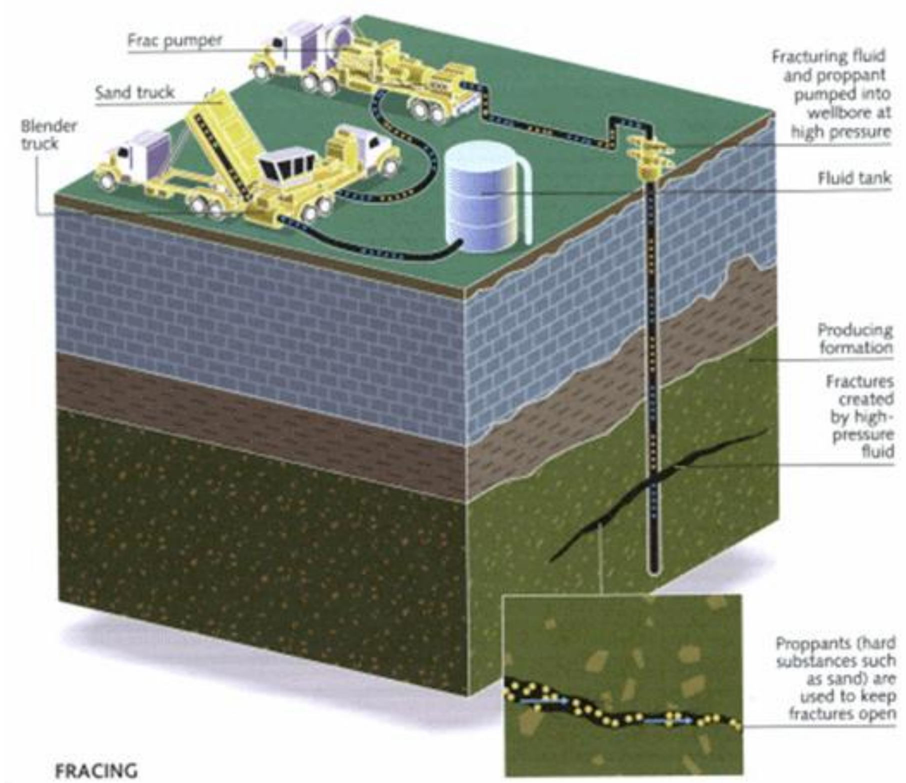


Figure 5. Hydraulic Fracturing Schematic.

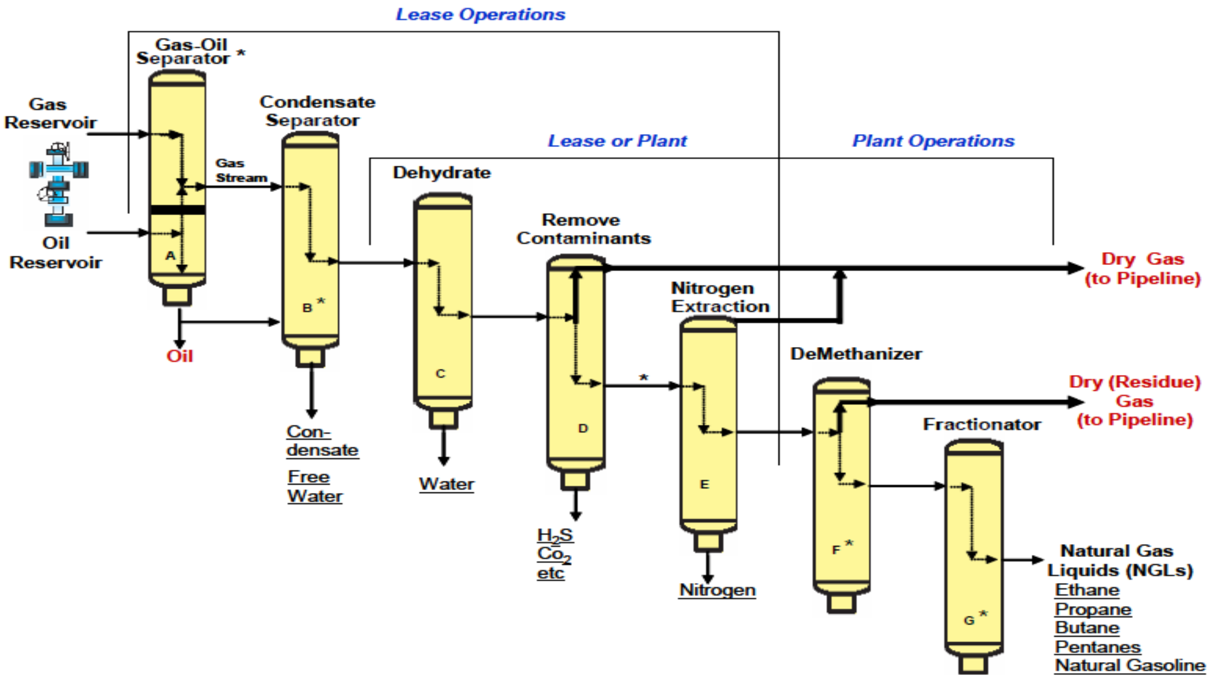


Figure 6. Natural Processing Schematic.

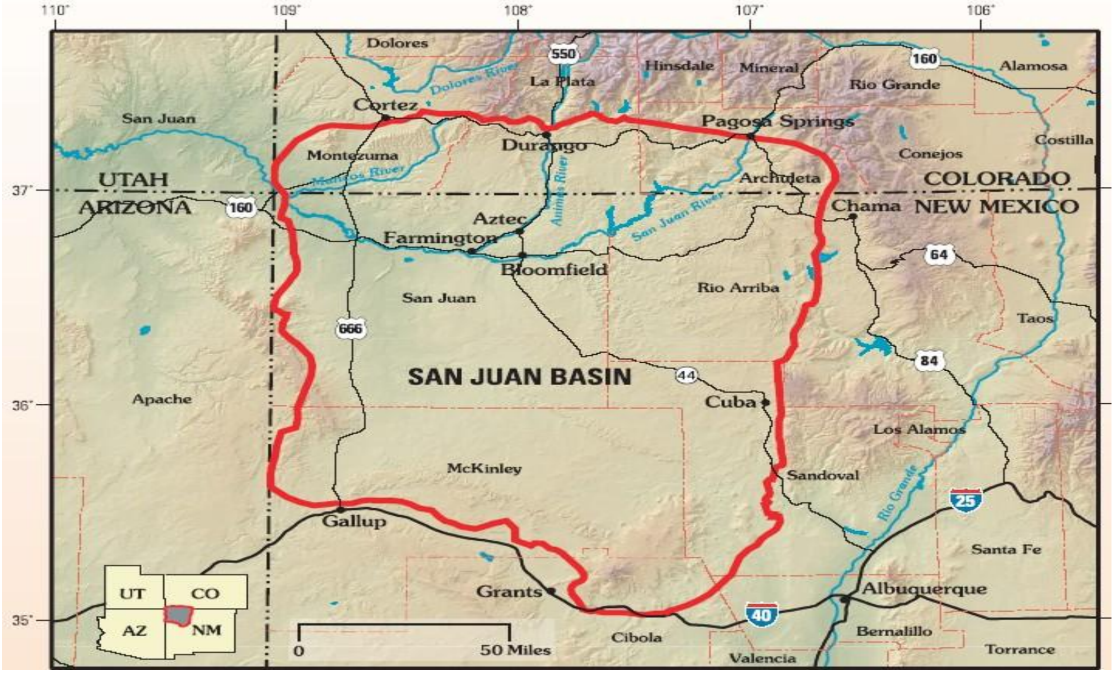
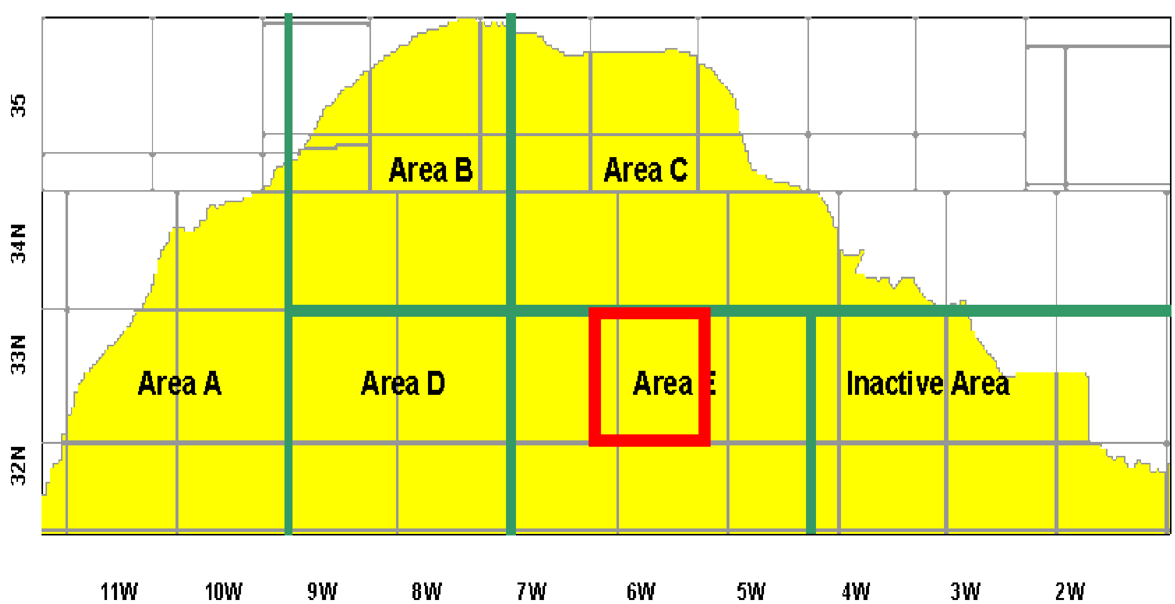


Figure 7. Shown above in the First Picture are the Boundaries of the San Juan Basin in Colorado and in New Mexico. While below is an Enlarged Portion of the Basin in Colorado with the Selected Area Highlighted in Area E.



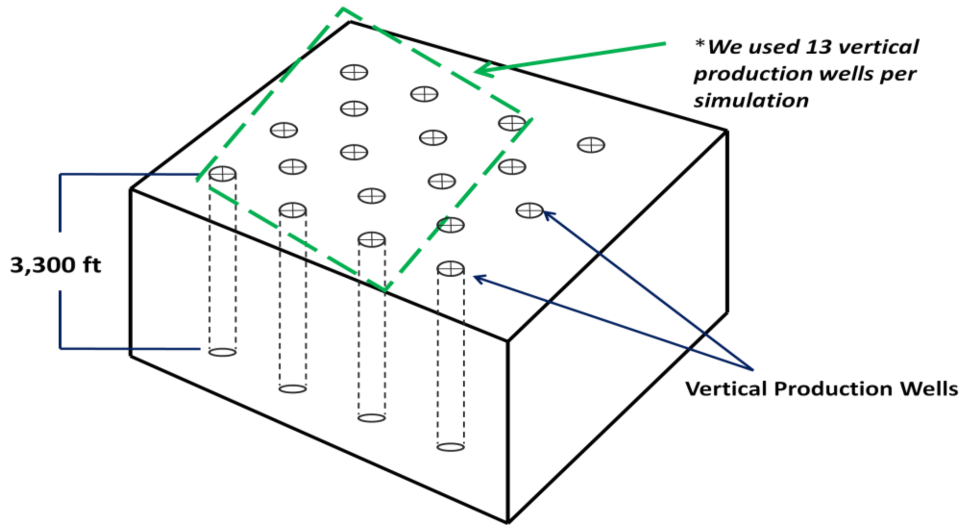


Figure 8. Shows the Five Spot Drilling Pattern for Producer Wells.

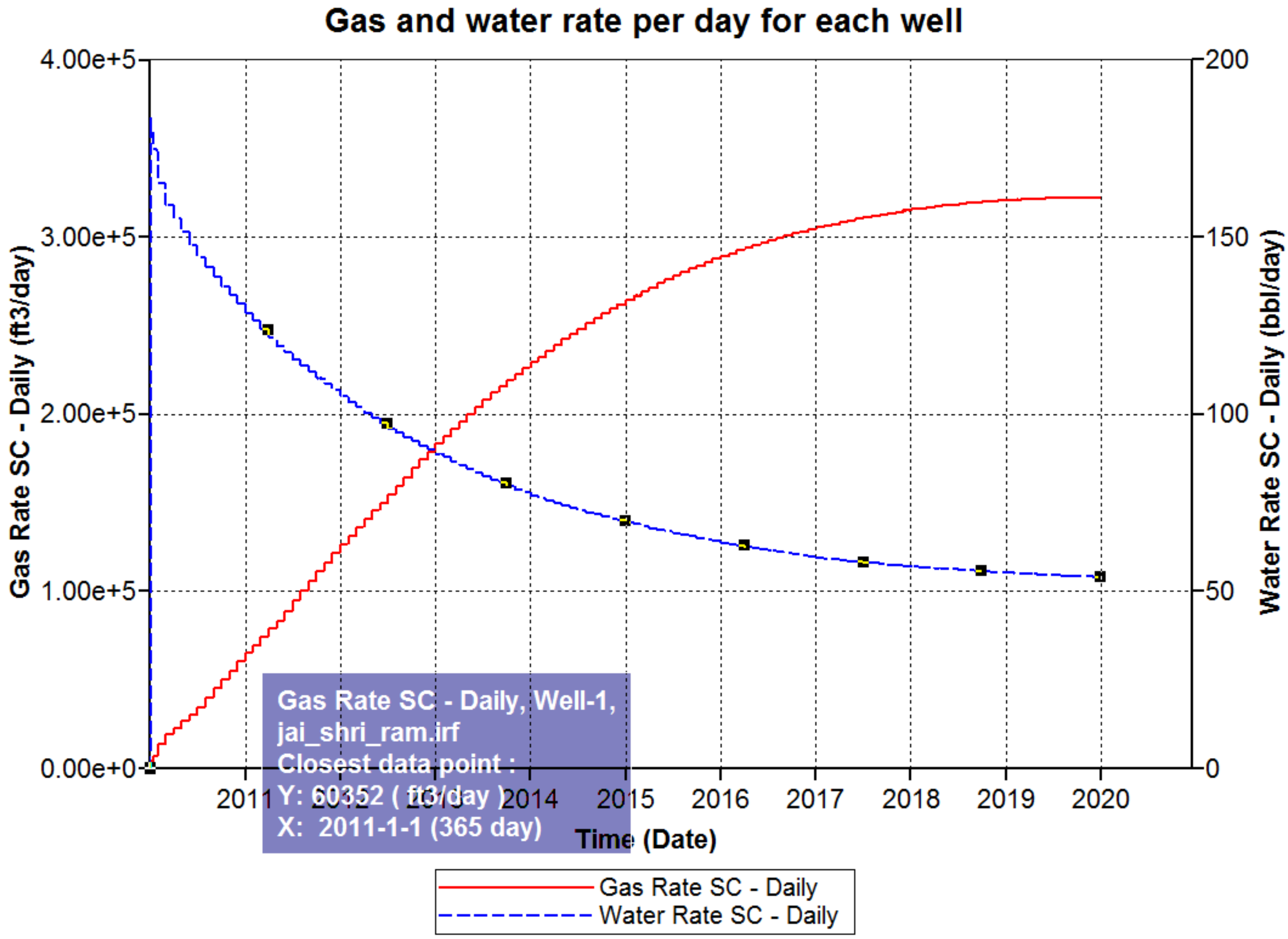


Figure 9. Shows Daily Gas and Water Production for Each Well.

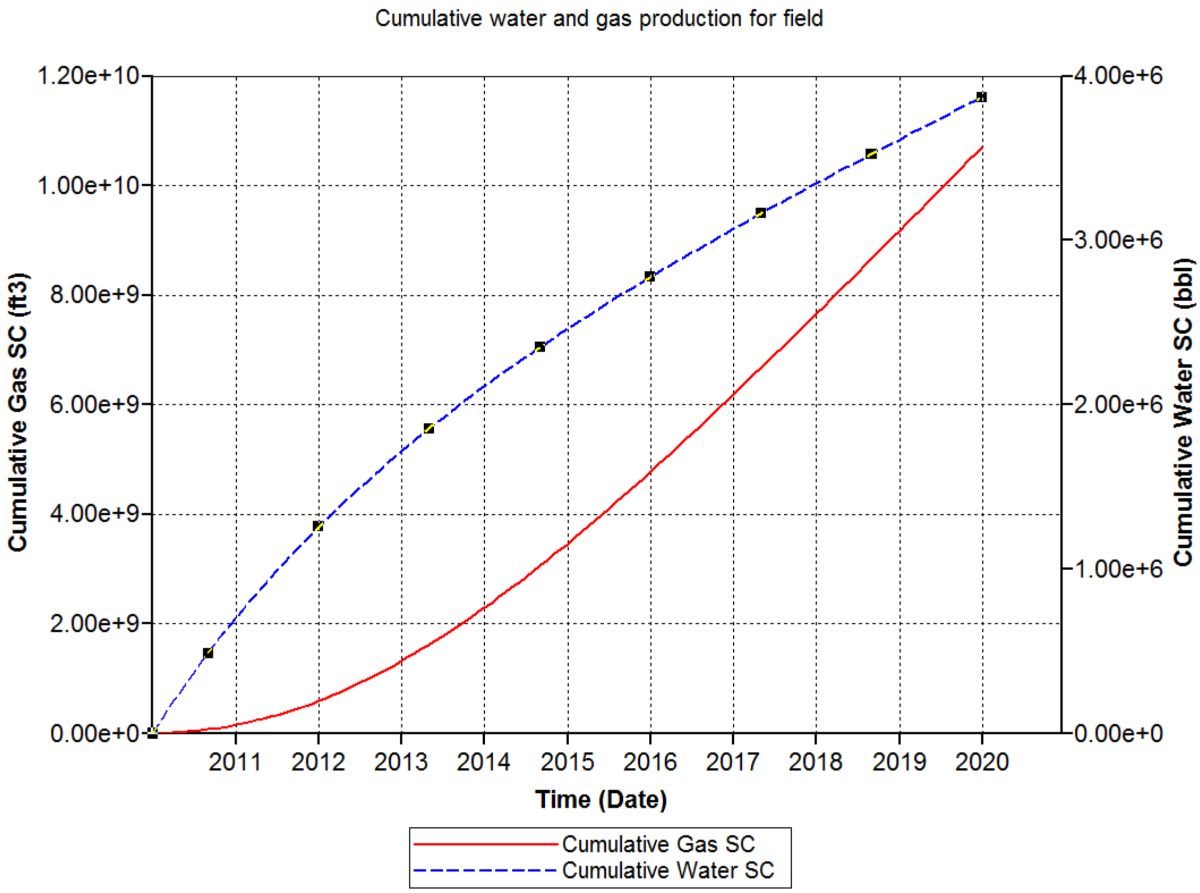


Figure 10. Shows Cumulative Gas and Water Production for 13 Wells.

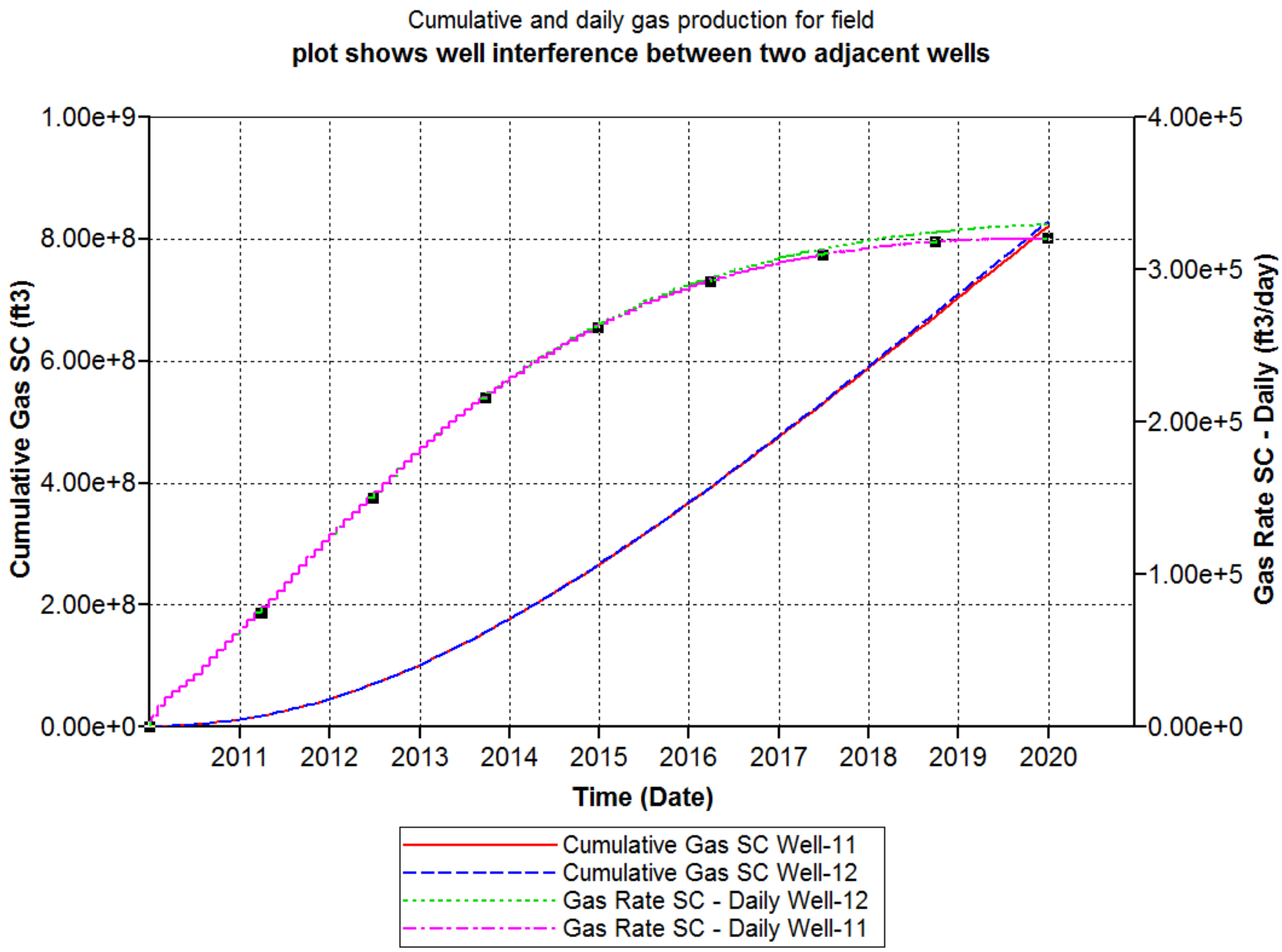


Figure 11. Showing the Impact of Interference from Other Wells.

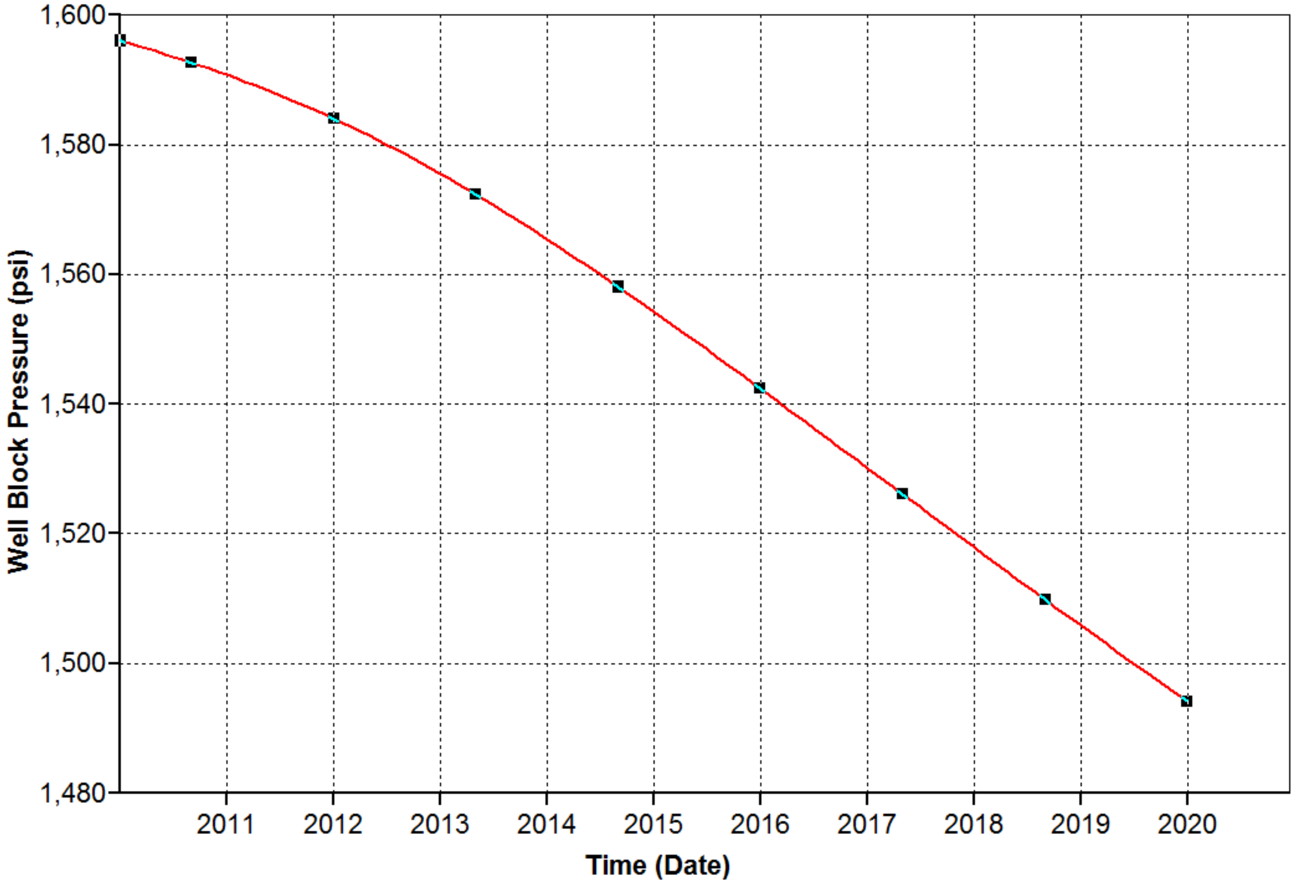


Figure 12. Block Pressure for each Well for Ten Years

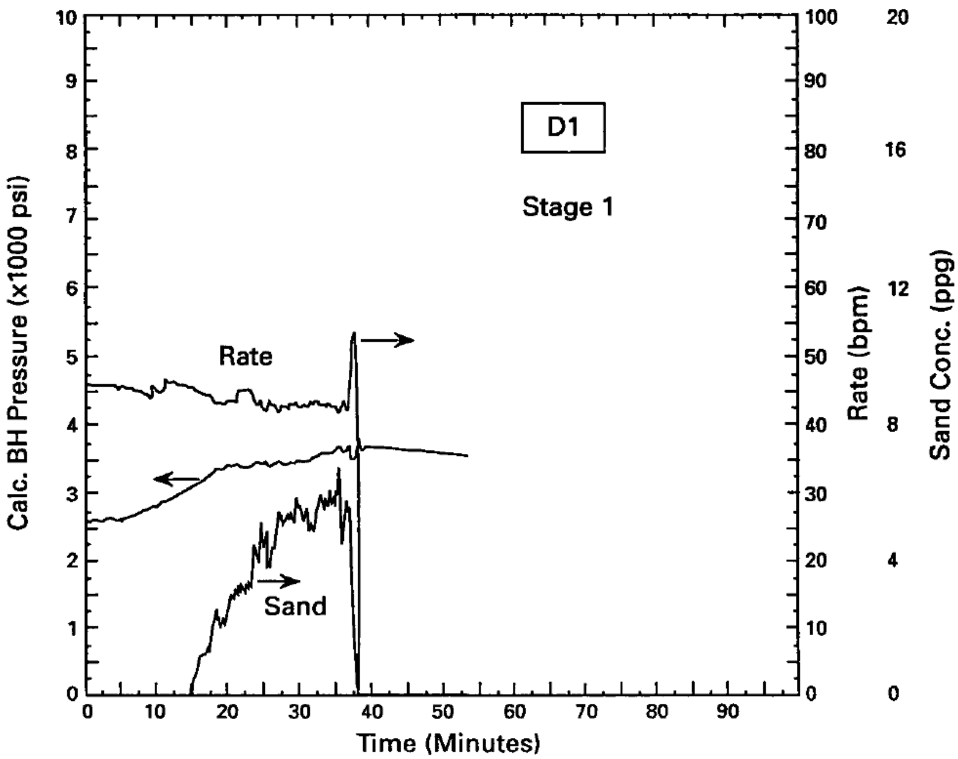


Figure 13. Fracture Pressure and Rate of Injection for San Juan Basin.

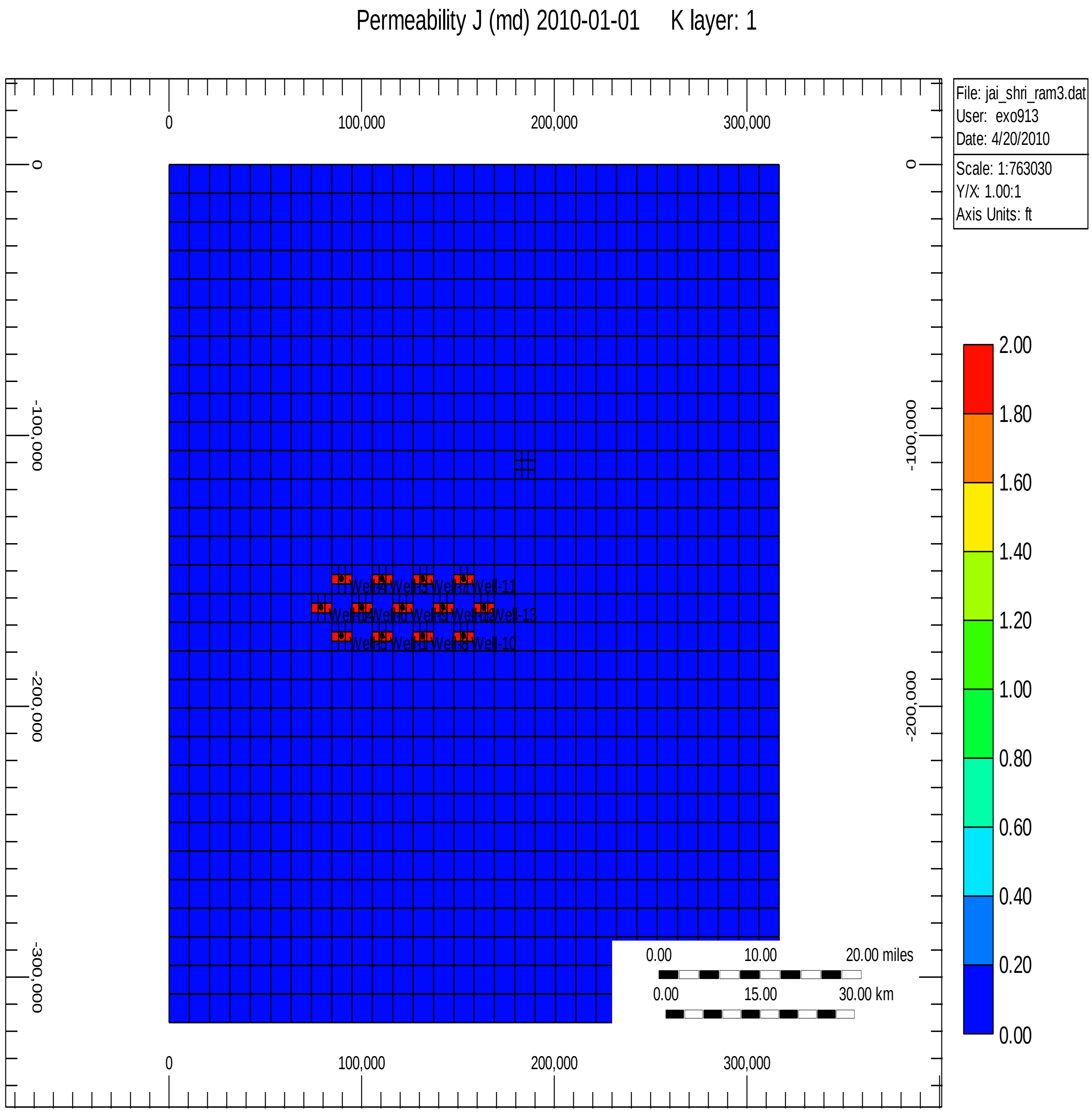


Figure 14. Well Distribution and Permeability Change after Fracturing.

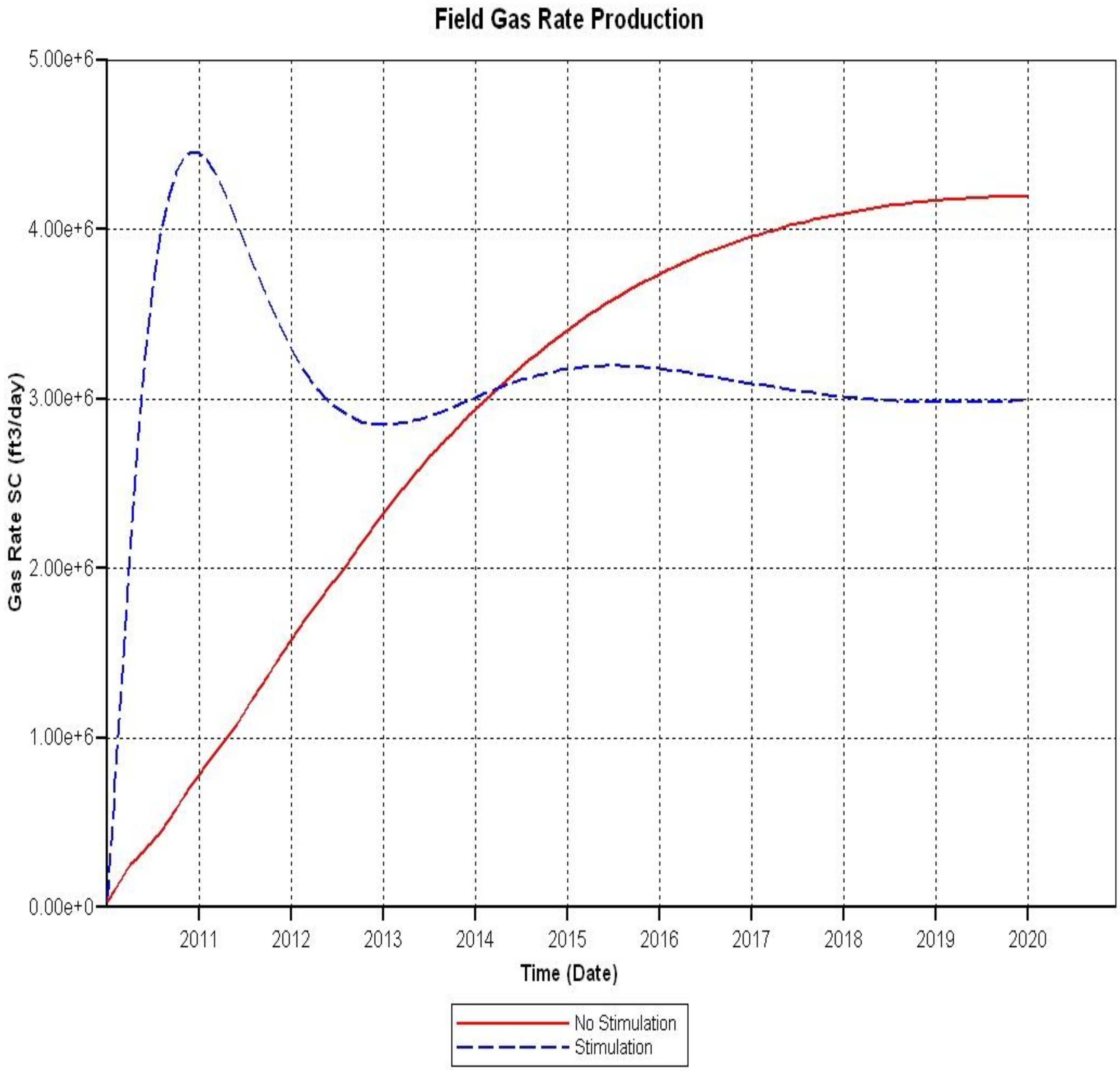


Figure 15. Gas Rate for 10 Wells in 10 years.

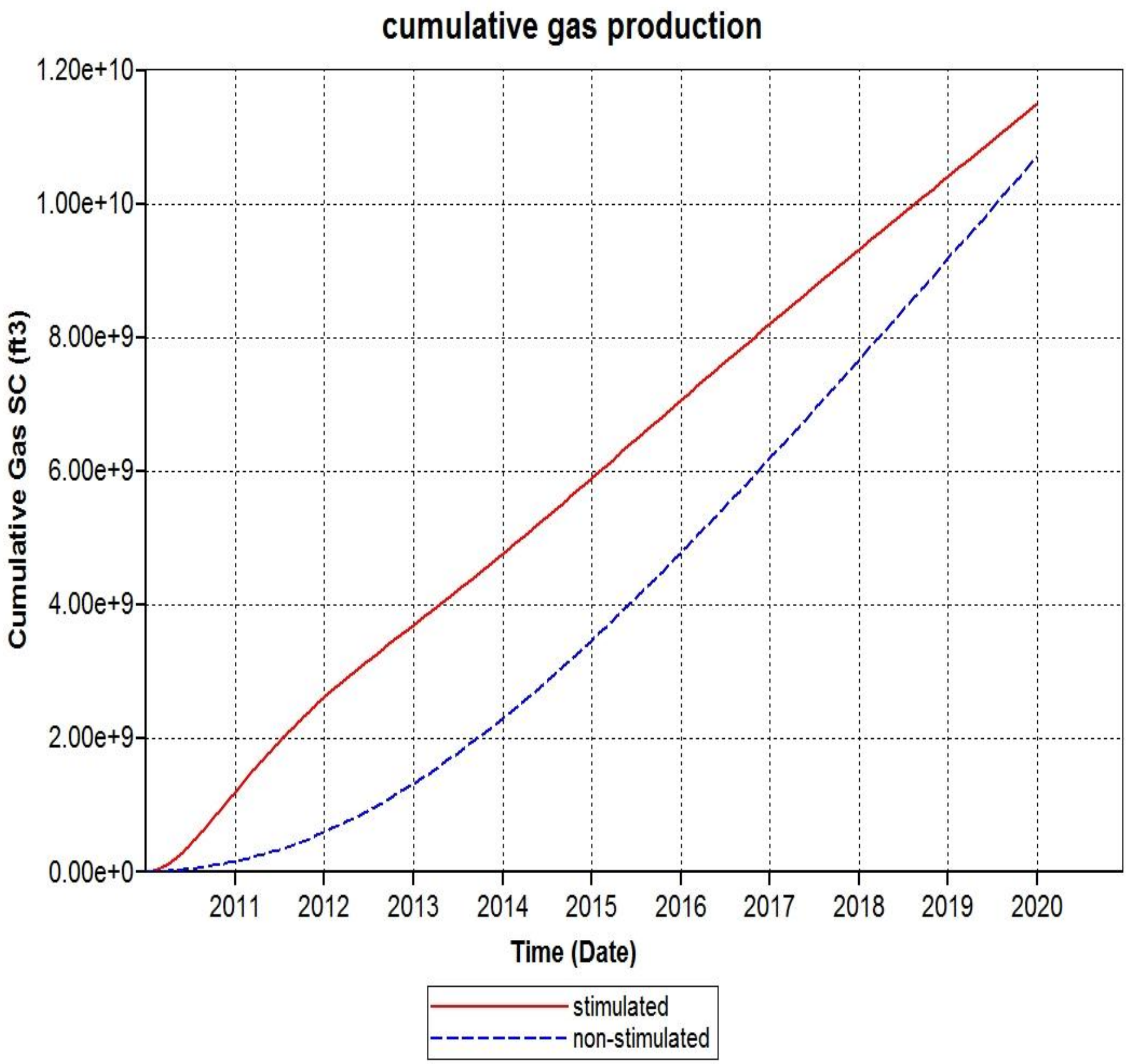


Figure 16. Cumulative Gas Production for 10 Wells in 10 years.

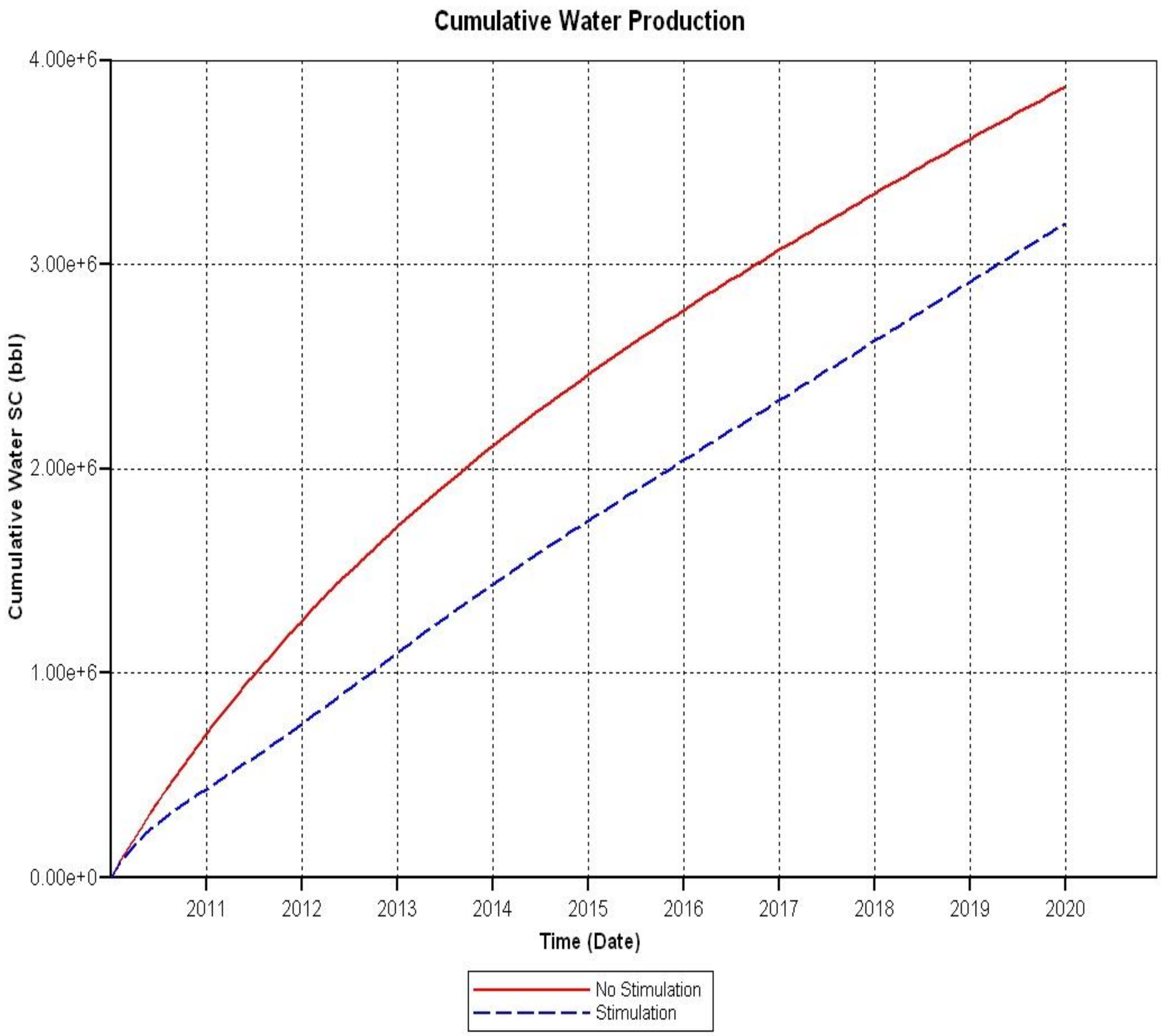


Figure 17. Cumulative Water Production for 10 Wells in 10 years.

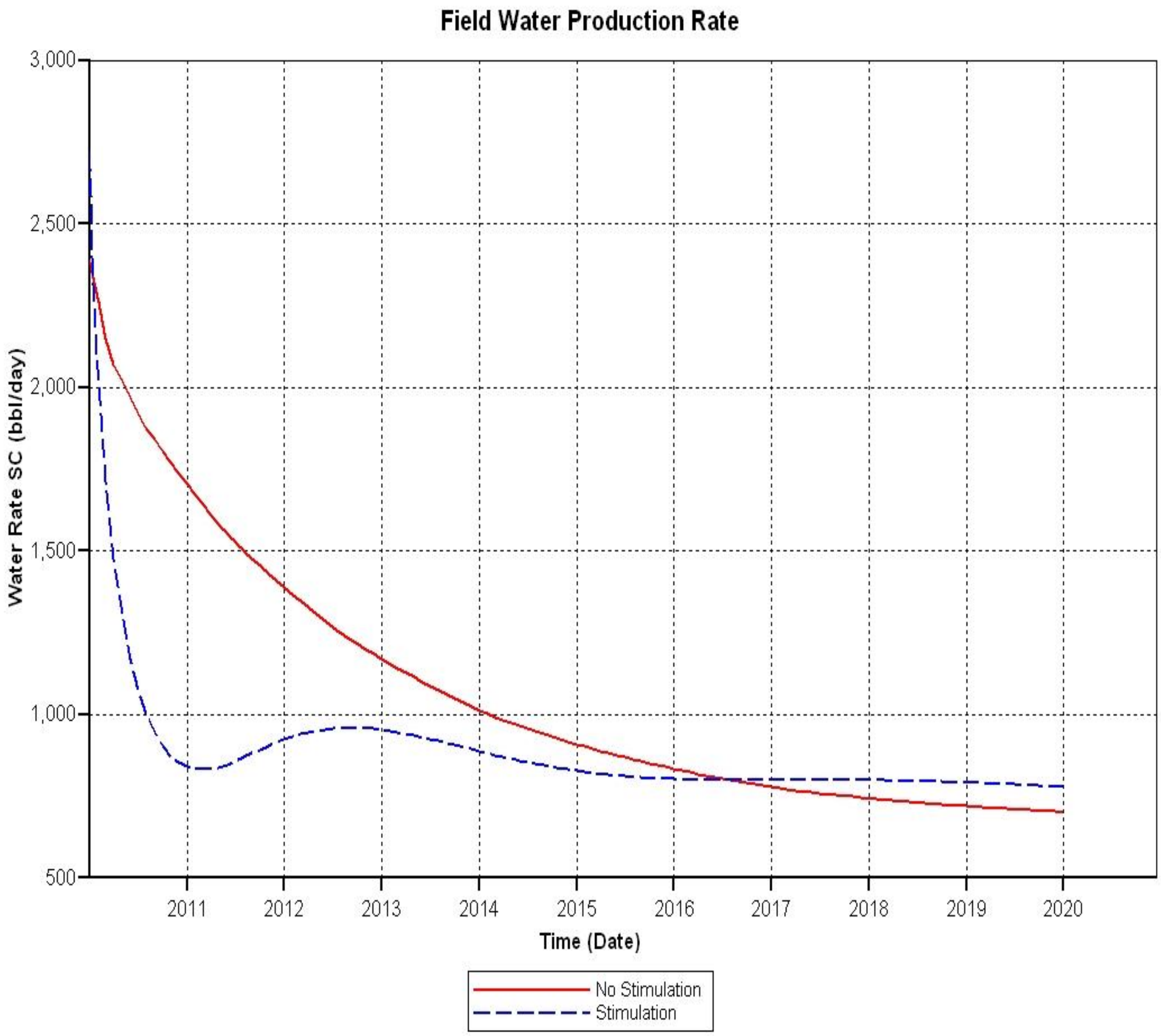


Figure 18. Water Rate for 10 Wells in 10 years.

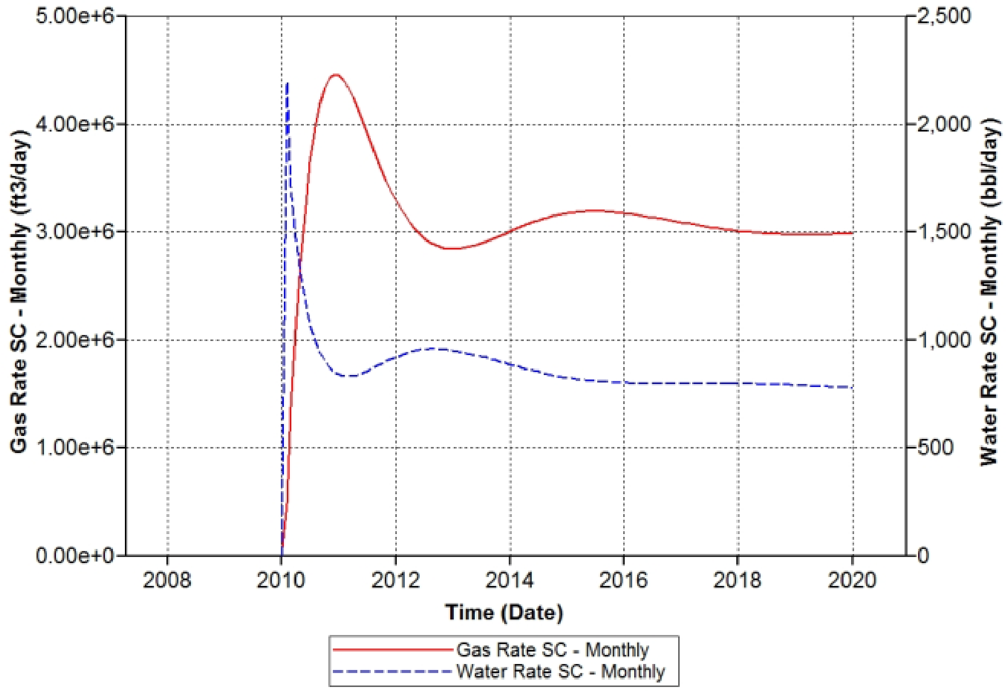


Figure 19. Water Production from Simulated Area.

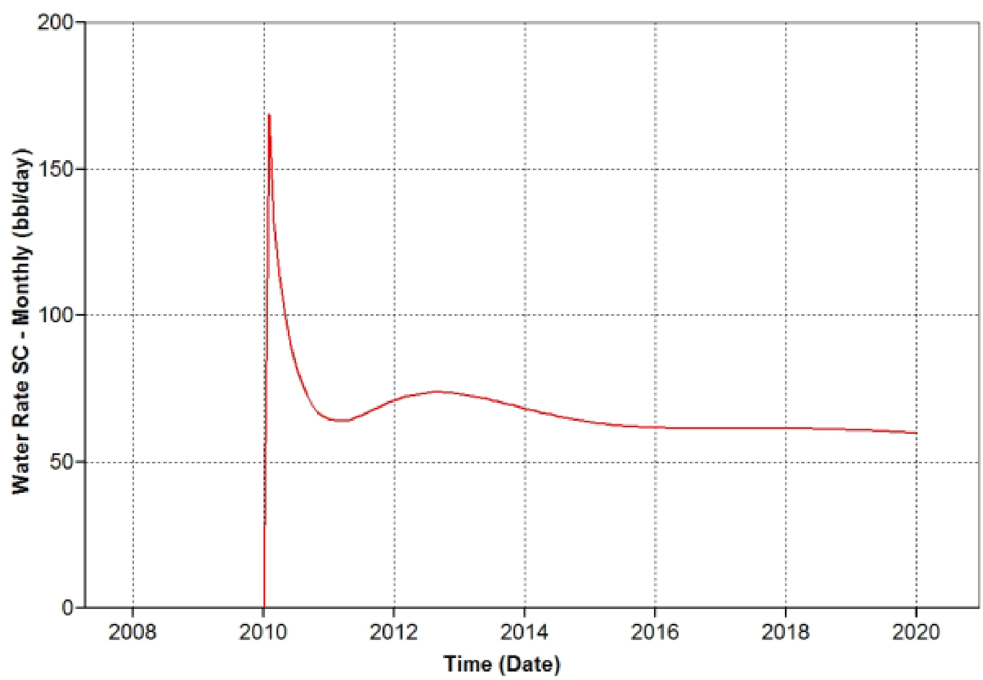


Figure 20. Water Production from a Single Well in Simulated Area.

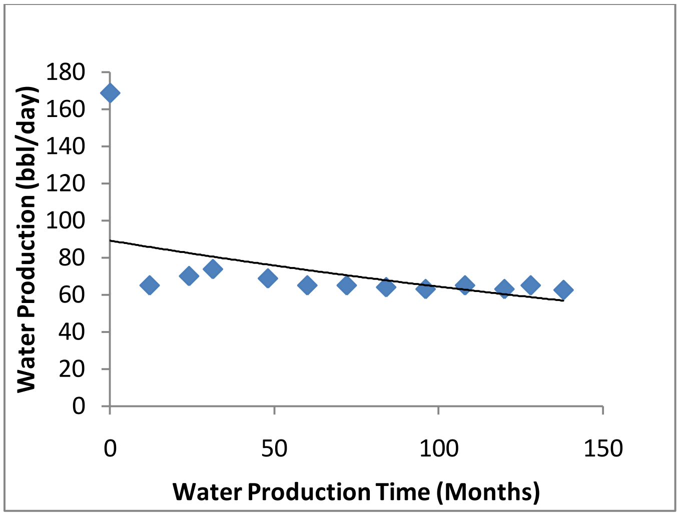


Figure 21. Exponential Decline of Water in a Single Well.

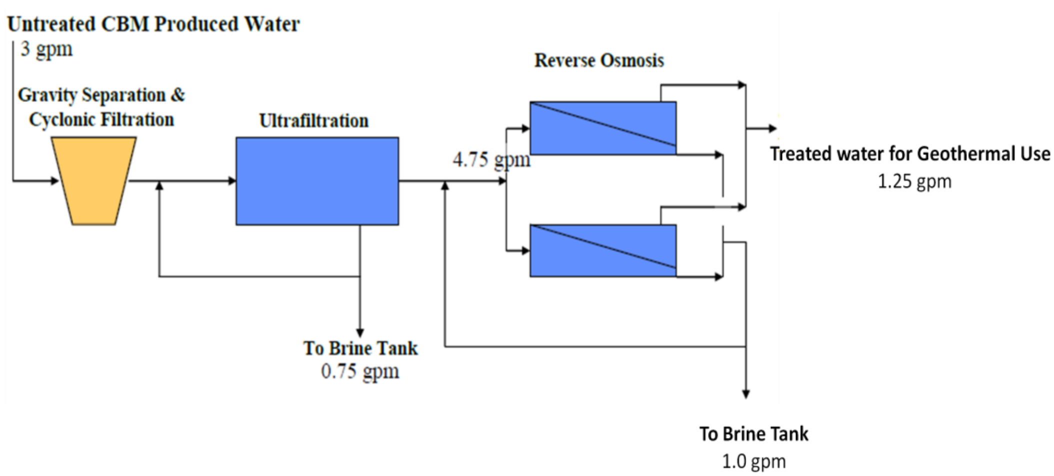
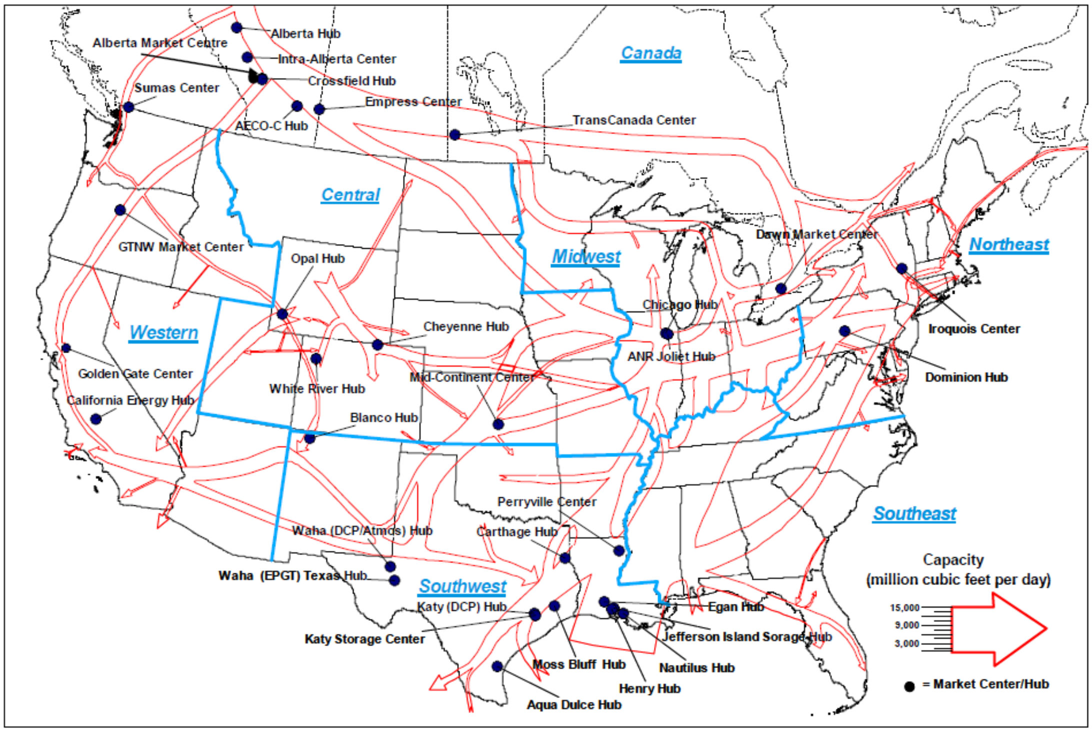
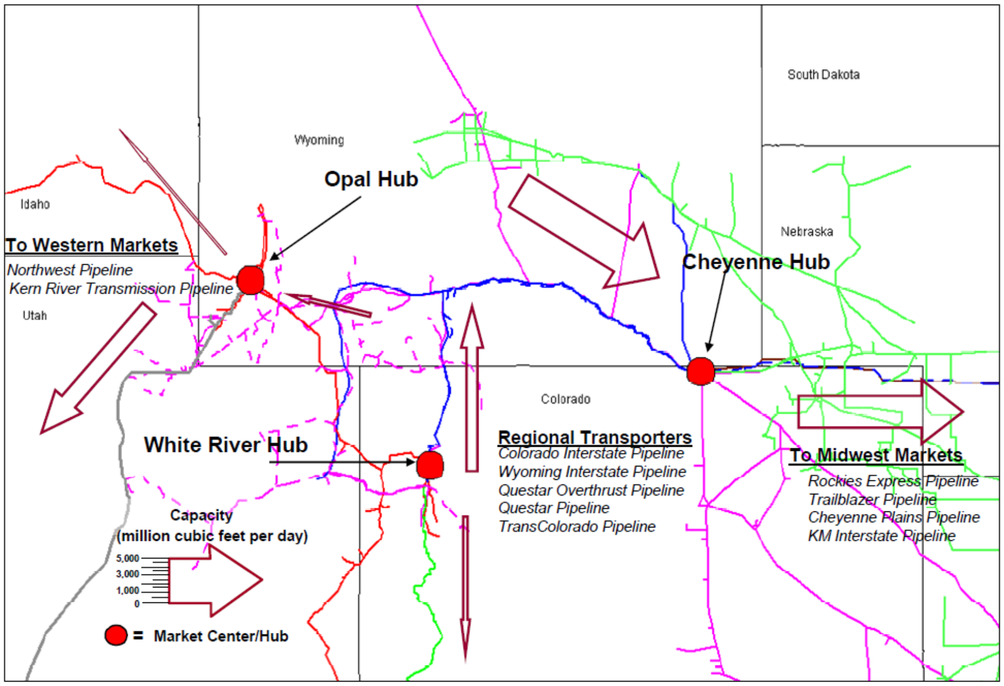


Figure 22. Simplified Flow Diagram for Produced Water Treatment.



DCP = DCP Midstream Partners LP; EPGT = Enterprise Products Texas Pipeline Company.
Note: The relative widths of the various transportation corridors are based upon the total level of interstate pipeline capacity (2008) for the combined pipelines that operate on the generalized route shown.
Source: Energy Information Administration, GasTran Gas Transportation Information System, Natural Gas Market Hubs Database, December 2008.

Figure 23. Natural gas market centers or hubs with respect to natural gas transportation corridors.



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, Natural Gas Market Hubs Database, December 2008.

Figure 24. Location of Hubs in Rocky Mountain Region.

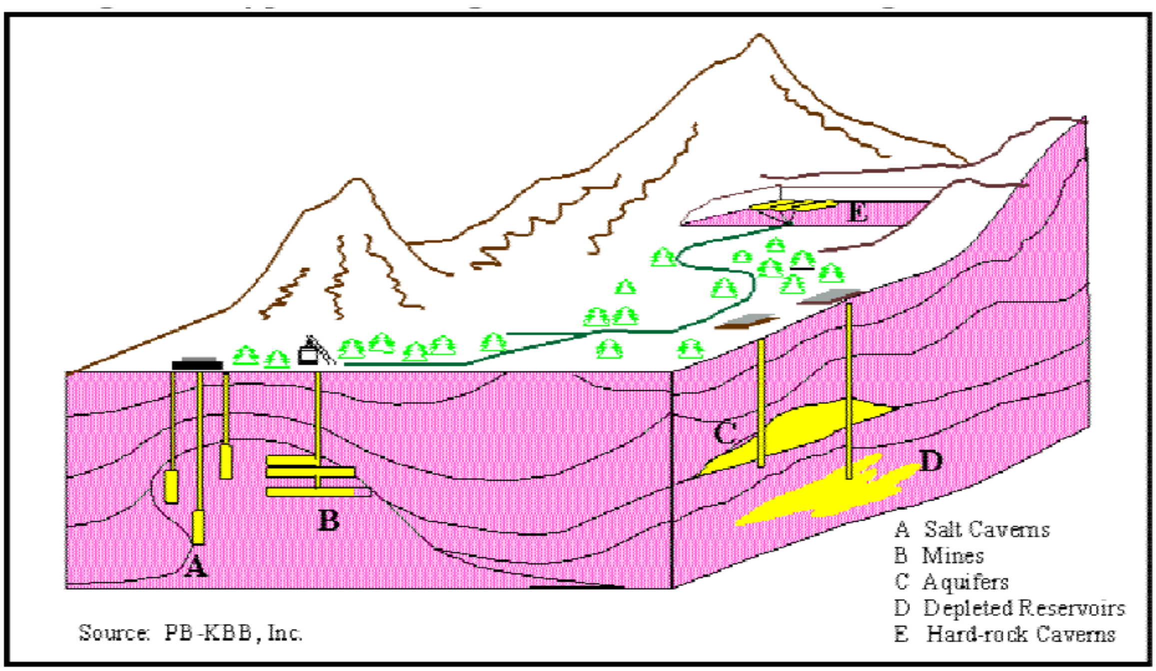


Figure 25. Types of Underground Natural Gas Storage.

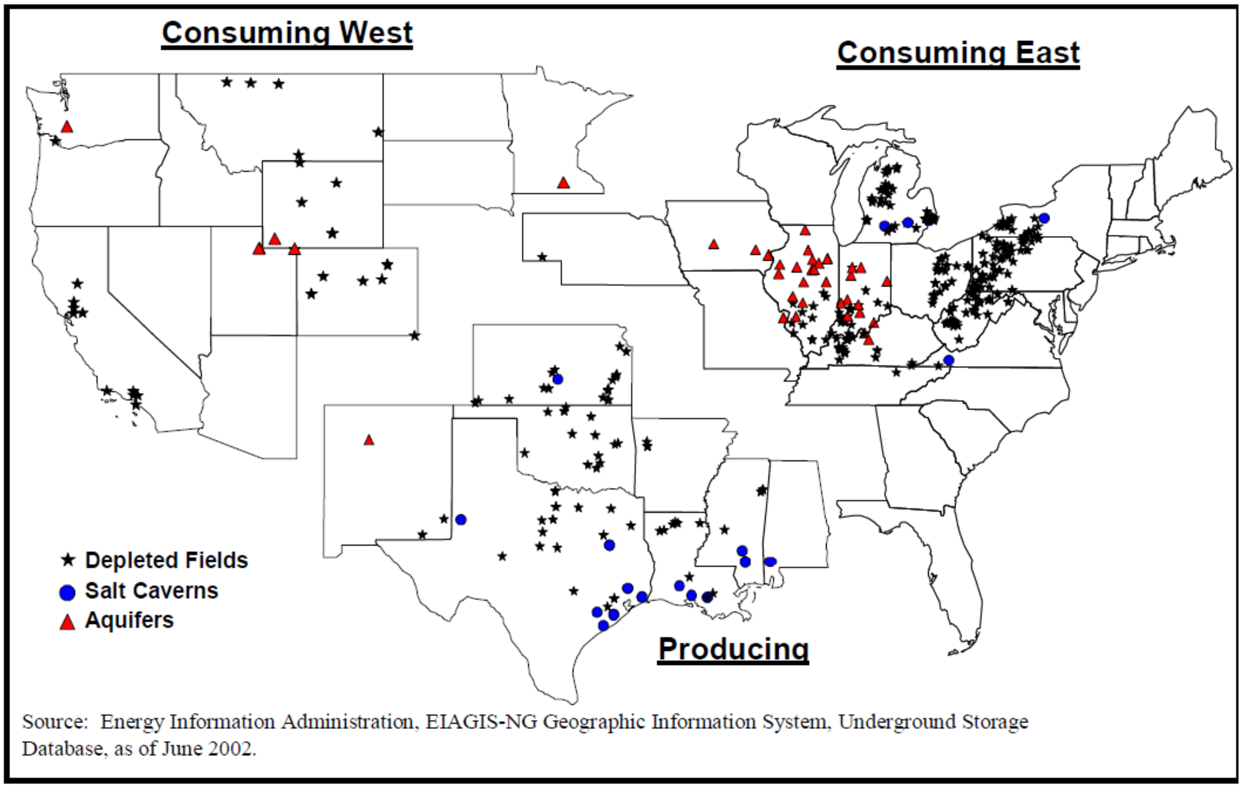


Figure 26. Location of Underground Storage Sites in US.

Central Region -- Underground Natural Gas Storage, by State and Reservoir Type, Close of 2007

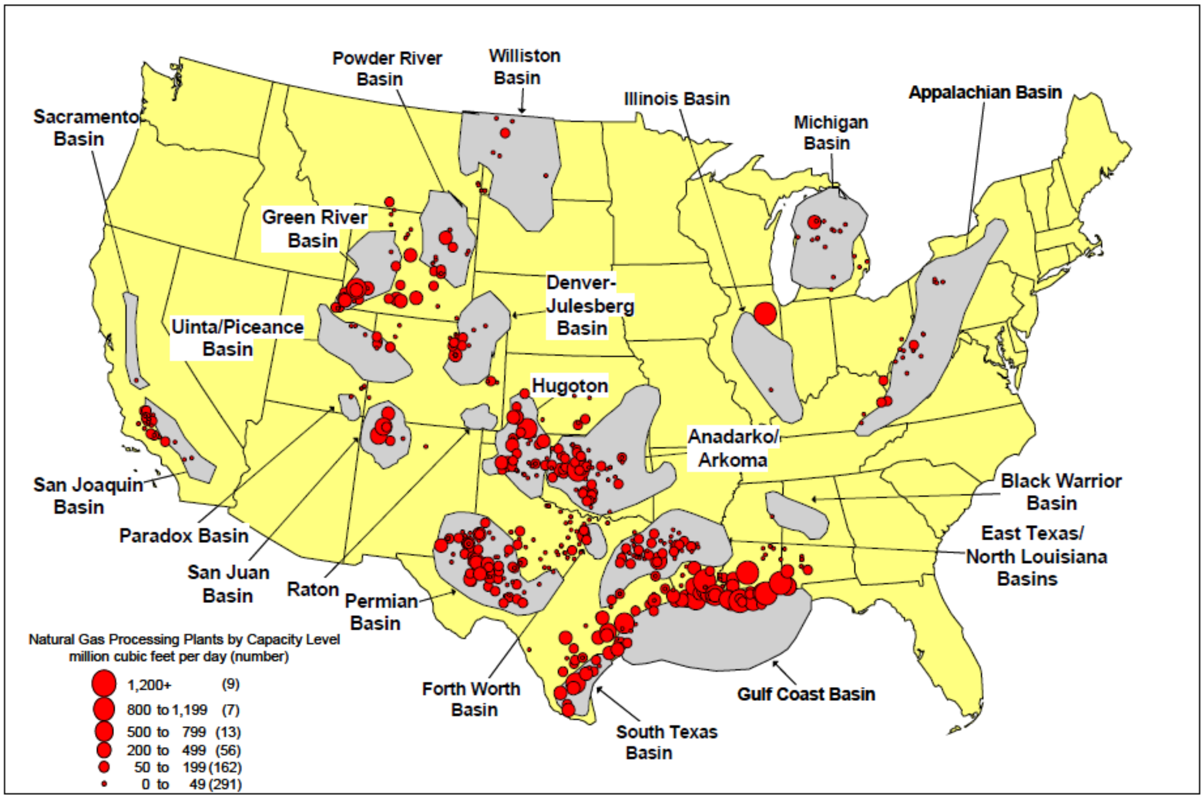
	Depleted Gas/Oil Fields			Aquifer Storage			Salt Cavern Storage			Total		
Region/ State	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capability (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capability (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capability (MMcf)	Sites	Working Gas Capacity (Bcf)	Daily Withdrawal Capability (MMcf)
Central Region												
Colorado	8	42	1,088	0	0	0	0	0	0	8	42	1,088
Iowa	0	0	0	4	77	1,060	0	0	0	4	77	1,060
Kansas	18	116	2,418	0	0	0	1	1	0	19	117	2,418
Missouri	0	0	0	1	11	350	0	0	0	1	11	350
Montana	5	196	310	0	0	0	0	0	0	5	196	310
Nebraska	1	16	169	0	0	0	0	0	0	1	16	169
North Dakota	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
South Dakota	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Utah	1	51	427	2	1	100	0	0	0	3	52	527
Wyoming	7	45	227	1	1	75	0	0	0	8	46	302
Total Sites	40	466	4,639	8	90	1,585	1	1	0	49	557	6,224
(Marginal Sites)[1]	(5)	(2)	(186)	(0)	(0)	(0)	(1)	(1)	(0)	(6)	(3)	(186)
Percent of U.S.	12	13	7	19	23	19	3	1	0	12	14	7

[1]**Marginal sites: very little or no activity reported during the 2007 calendar year. Marginal sites included in State/Regional total.**

Note: Bcf = Billion cubic feet. MMcf = Million cubic feet. States with no underground storage facilities are shown in *Italics*.

Source: Energy Information Administration, Gas Transportation Information System, December 2008.

Figure 27. Underground Storage Sites for Central Region.



Note: Eight Alaska plants not displayed, but count is reflected in the legend.
Source: Energy Information Administration, Gas Transportation Information System, Natural Gas Processing Plant Database.

Figure 28. Natural Gas Processing Plant Concentration in US.

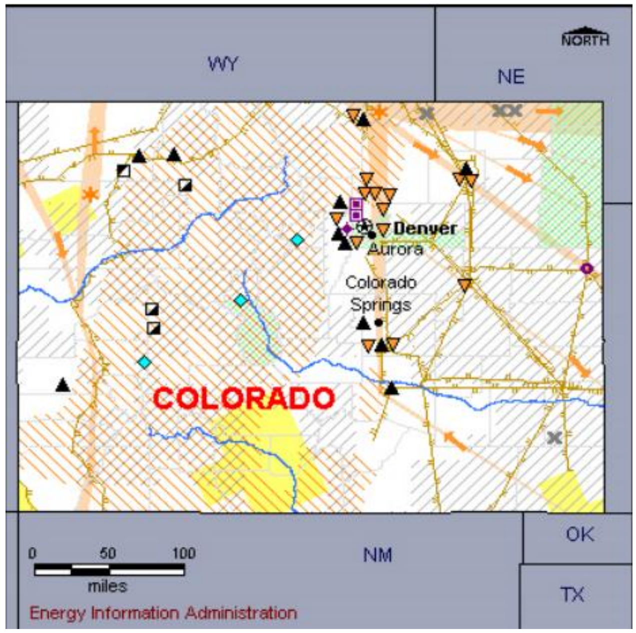
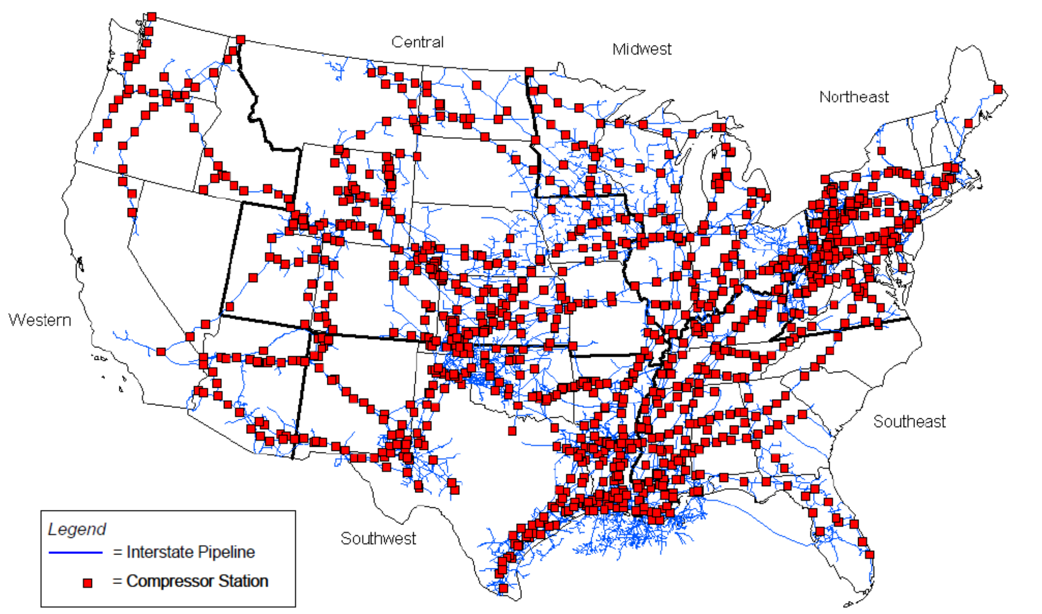


Figure 29. Location of Natural Gas Fired power plants (inverted orange triangles) and Market centers (orange stars) in Colorado.



Note: EIA has determined that publication of this figure does not raise security concerns, based on the application of Federal Geographic Data Committee's *Guidelines for Providing Appropriate Access to Geospatial Data in Response to Security Concerns*.
Source: Energy Information Administration, Natural Gas Division, Natural Gas Transportation Information System, Compressor Station Database.

Figure 30. Compressor Stations on the Interstate pipeline networks.

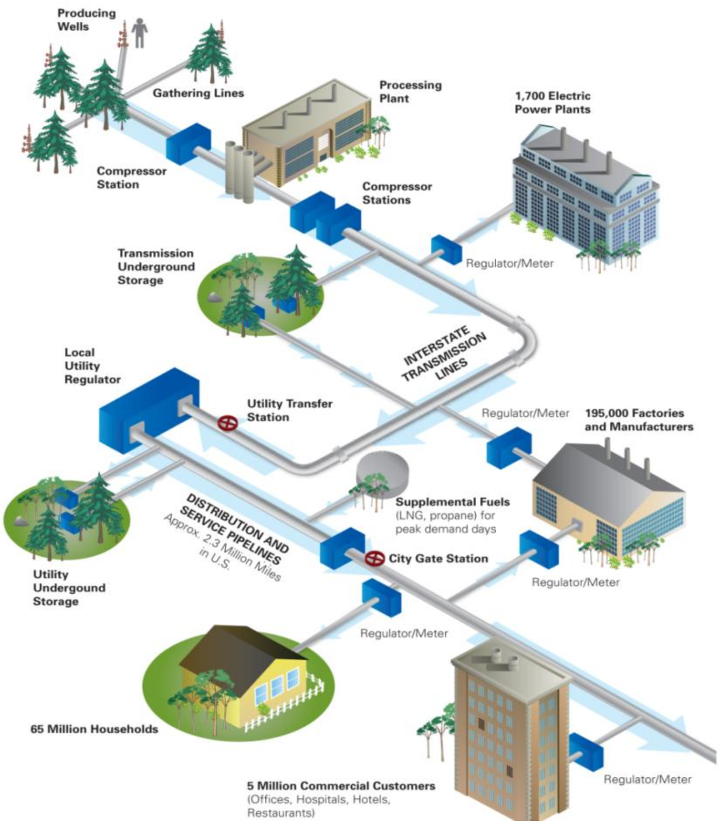


Figure 31. An Ideal Natural Gas Distribution Network.

Figure 32. Development of Nanoporous Carbon Material from Corncob waste to Store Methane.

TABLES:

Table 1. Summary of Methods for Recovering Methane from Non-mined areas and Underground.

Method	Description	Methane Quality	Recovery Efficiency*	Mine or Non-Mine
Vertical Wells	Drilled from surface to coal seam	Recovers nearly pure methane	≤ 70%	Mine and Non-mine
Gob Wells	Drilled from surface to a few feet above coal seam just prior to mining	Recovers methane that is sometimes contaminated with mine air	≤ 50%	Mine
Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam	Recovers nearly pure methane	≤ 20%	Mine or Non-Mine
Cross-Measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata	Recovers methane that is sometimes contaminated with mine air	≤ 20%	Mine or Non-Mine

Table 2. Removing Contaminants.

Contaminants	Problem	Solution
Water	1. Reduces calorific value of gas 2. Corrosive in the presence of acid gas 3. Can damage pipeline and equipment when hydrates form.	1. Use of heater treaters 2. Use of glycol treaters 3. Use of Dessicants and other chemicals
Hydrogen Sulfide (S_2O)	1. Can be toxic 2. Causes corrosion to pipelines and other equipments. 3. Reduces calorific value of gas	1. Use of sulfide scavenger 2. Solid bed absorption processes (e.g Iron Sponge) 3. Direct conversion to sulfur processes (e.g IFP
Carbon Dioxide (CO_2)	1. Can cause corrosion to pipes and other equipment. 2. Can be dangerous to health. 3. Reduces caloric value of gas	1. Ryan Holms Distillation 2. Gas permeation (Membrane treatment)

Table 3. Water Production In Some Major Producing Coal-Bed-Methane Areas. [21]

BASIN	STATE	NO OF WELLS	AVERAGE WATER PRODUCTION (BBL/DAY)	WATER/GAS RATIO (Bbl/Mscf)	WATER DISPOSAL METHOD
Black warrior	Alabama	2917	58	0.55	Surface discharge
Powder river	Wyoming/ Montana	2737	400	2.75	Surface discharge
Raton	Colorado	459	266	1.34	Injection
San juan	Colarado/ New mexico	3089	25	0.031	Injection
Uinta	Utah	393	215	0.42	Injection

Table 4. Typical San Juan Basin CBM Produced Water Constituents and Concentrations.

CONSTITUENT	CONCENTRATION
Sodium	619 mg/L
Potassuim	7 mg/L
Calcium	25 mg/L
Magnesuim	12 mg/L
Carbonate	0 mg/L
Bicarbonate	1920 mg/L
Chloride	18 mg/L
Sulfate	18 mg/L
Nitrite	4 mg/L
Iron	2080 µg/L
Manganese	20 µg/L

Table 5. The Six Most Popular Coalbed Methane Basins within the United States.

BASIN	AREA (sq. miles)	FORMATION OF INTEREST	THICKNESS & DEPTH	PROVED RESERVES	PIPELINES/ UGSTORAGE	OTHER QUALITIES/PROBLEMS
SAN JUAN	7500	Fruitland	Thickness: 20-80 ft depth: 550 to 4000 ft	50TCF	Rockies Express Pipeline, Northwest Pipeline Corp., UG storage: Aquifer in NM, Depleted Reservoirs in Colorado	Thickness, high, overpressuring, premeability (avg 5md), gas content, depth, high rank. Thermally mature coal, CH_4 ~97% of the HC.
BLACK WARRIOR	23000	Pottsville	Thickness: 10-65 ft depth: 350 to 2500 ft	2068 BCF	Natural Gas Co. • Tennessee Gas Pipeline Co. • Texas Eastern Transmission Co. UG storage: Salt Caverns	High to medium volatile bituminous coal. High CH_4 content. Wells have been hydraulically fractured 2-6 times.
PICEANCE	7225	Williams Fork	Thickness: 30-50 ft depth > 5000 ft	750 BCF	Rockies Express Pipeline. Underground Storage: depleted reservoirs	Too deep. Formation inhibits permeability
POWDER RIVER	25800	Wasatch & Fort Union	Thickness: >200 ft depth > 450-6500 ft	2418 BCF	Northern Natural Gas Co, Northern Border Pipeline Co. Depleted Reservoirs and some Aquifers.	Lignite to sub-bituminous coal. Water problems. Deficient pipeline systems.
NORTHERN APPALACHIAN	43700	Pottsville, Allegheny, and the Monongahela Groups	Thickness: ~25 ft depth: 1000-2000 ft	64 BCF	Columbia Gas Transmission Corp, Tennessee Gas Pipeline Co Lots of depleted reservoirs.	insufficient reservoir knowledge, inadequate well-completion techniques, and coalbed methane ownership issues
RATON	2200	Vermejo and Raton	Thickness: 10-140 ft depth >2500 ft	2786 BCF	Rockies Express Pipeline. Lot of depleted reservoirs.	Bituminous . Small Basin, Coal, fracturing issues- less NG & more H_2O

Table 6. San Juan Basin Reservoir Properties.

Property	Value
Number of coal seams	5 (Area A, B, C, D, E)
Total coal thickness	40-50 feet
Depth	3200 feet
Initial reservoir pressure	1400-1620 psi
Reservoir temperature	120 ^{o} F
Coal seam porosity	0.01-0.02
Permeability	1-3 mD

Table 7. Input Data for Numerical Simulation.

Property	Value
Grid top depth	3200 feet
Initial reservoir pressure	1600 psi
Thickness	45 feet
Porosity (matrix)	1%
Permeability (matrix)	0.1 µD
Porosity(fracture)	.8%
Permeability(fracture)	2 mD
Temperature	120^{o} F
Fracture spacing(I,j,k)	0.02 feet
Water saturation (matrix)	0.0001
Water saturation (fracture)	.99
CH_4 molar fraction	0.96
CO_2 molar fraction	.03
N_2 molar fraction	.01

Table 8. Thermodynamic Properties of the Components.

Component	Pc (critical pressure) Psia	Tc (critical Temperature) in ^{O} F	Langmuir volume Constant (scf/ton)	Langmuir pressure constant (psia)
CH_4	667.2	-116.6	450	294
CO_2	1069.9	87.9	707.5	151.15
N_2	493	-232.4	222	588

Table 9. General Raw Natural Gas Component make-up.

Component	Typical Analysis (mole %)	Range (mole %)
Methane	94.9	87.0 - 96.0
Ethane	2.5	1.8 - 5.1
Propane	0.2	0.1 - 1.5
iso - Butane	0.03	0.01 - 0.3
normal - Butane	0.03	0.01 - 0.3
iso - Pentane	0.01	trace - 0.14
normal - Pentane	0.01	trace - 0.04
Hexanes plus	0.01	trace - 0.06
Nitrogen	1.6	1.3 - 5.6
Carbon Dioxide	0.7	0.1 - 1.0
Oxygen	0.02	0.01 - 0.1
Hydrogen	trace	trace - 0.02

Table 10. Typical Water Production Rates in San Juan Basin.

Basin	No of wells	Average water Production (bbl/day/well)	Water: Gas ratio (bbl/MCF)
San Juan Basin	3089	25	0.03

Data Source: USGS 2000.

Table 11. Water Production Rates from the Simulated Case Study.

Basin (Fruitland Formation)	No of wells	Average water Production (bbl/day/well)	Cumulative Water Production for 10 yrs (bbls)
San Juan Basin	**130**	**65**	**17,000,000**

Table 12. Chemical Composition of Coalbed Water.

	SAN JUAN BASIN	
PARAMETERS	RANGE	AVERAGE
pH	6.5 – 9.2	7.8
ANIONS (mg/L)		
Bicarbonate	76 to 12,000	596.5
Chloride	19 to 15,000	2,000
Fluoride	ND to 20	2.6
Sulfate	ND to 650	12.9
METALS (mg/L)		
Barium	0.2 to 37	2.78
Cadmium	ND to 0.026	0.005
Calcium	ND to 620	89
Iron	0.005 to 246	9.8
Lithium	0.18 to 3.3	0.49
Manganese	0.3 to 420	33.1
Magnesium	0.005 to 3.8	0.25
Potassium	0.3 to 24	7.5
Silicon	0.2 to 14	7.3
Sodium	0 to 6800	1905
Strontium	0 to 56	5.8
Zinc	0 to 0.38	0.1
TDS	550 to 26,700	14,700
BOD	100 to 300	20
Hydrocarbon	21 to 62	3

Table 13. Water Requirements for Geothermal Energy Generation.

Water Use (bbls)	**Volume Of Water Required (bbls)**
Fracture Requirements	3,1746.03
Initial Water For Heat Transfer Fluid	2,1621.224
Yearly Makeup Water	7,891,746.76
Total	7,945,114

Table 14. Water Treatment Process System & Capital Costs for Active Water Treatment.

TREATMENT PROCESS SYSTEM	TREATMENT PROCESS UNITS
Deoiling, Organic removal and Partial Demineralization	Hydrocyclone, FBR w/Sand Filter, Ultra Filtration and Reverse Osmosis
TREATMENT UNIT	**COST ($)**
Three RO Unit (installed)	2,880,000
Deep Disposal Well and Facilities	-
Three Impoundments	336,400
Three Surface Discharge Points	234,000
Total	3,450,400

Table 15. Annual Operating Costs for Treating Water (For a 130-well unit).

Unit Operation	Annual Operating Costs
Electric Power	$352,000
Chemicals	
Anti-Scalant	$73,000
Cleaning	$5,000
Iron Removal	$3,500
Membrane replacement (after 5 years annualized)	$33,500
Reject Disposal (10% residual concentrate)	-
Annual labor	$22,000
	$194,200
G & A of 20%	$38,800
Total	$233,000

Table 16. Estimated Transport Costs.

	Cost ($/mile)
Fuel	0.25
Driver	0.49
Maintenance	0.05
Central Facility	0.56
TOTAL	**1.35**

Table 17. Projected Transport Costs over a 10 year Operating Period.

Volume of Water Transported (Bbls)	Distance (Miles)	Cost of Transportation ($/Miles/Trips)	Number of Trips Required	Total Cost of Transportation ($)	Cost Of Transportation ($/Bbl)
7945114	60	1.35	55,608	4,504316	0.567

Table 18. Cost of Deep Injection of Produced Water.

Component	Cost ($)
Drilling	**600,000**
Transporting/Maintenance	**960,000**
Total Cost	**1,560,000**

Table 19. Total Cost for Management of Produced Water.

	Activity	**Costs**
Active Water Treatment	**Operating and Maintenance**	**$ 233,000**
	Capital	**$ 3,450,400**
	Transportation	**$ 4,504,316**
	Deep injection	**$ 1,560,000**
	Total Costs	**$ 9,747,716**
	Cost per Barrel	**$ 0.57**
	Cost per Barrel per Mcf	**$ 0.0171**

Table 20. Forecasted Gas Prices for next 10 Years.[83]

Year	Gas Price ($/Mcf)
2011	6.5
2012	6.85
2013	6.95
2014	7
2015	7.5
2016	7.75
2017	8.25
2018	8.55
2019	8.875
2020	9.25

Table 21. Total gas production from wells for 10 years.

Year	Production(Mcf)	Total Revenue Costs ($)
1	1200485	7803153
2	3358365	23004800
3	4450080	30928056
4	5518070	38626490
5	6657235	49929263
6	7820125	60605969
7	8959290	73914143
8	10074730	86138942
9	11166445	99102199
10	12258160	113387980

Table 22. Sensitivity Analyses as per NPV.

% Change	Lease Costs($)	Gas Price($)
+40	-34,698,742.7	105010306.9
+20	-17,421,671.3	52432853
-40	17,132,471.6	-105299508.6
-20	34,409,543.1	-69,999,126.2

Table 23. Sensitivity Analyses as per % NPV Change.

% Change	Lease Costs($)	Gas Price($)
+40	-14.93%	45.20%
+20	-7.499%	22.57%
-40	14.811%	-45.32%
-20	7.374%	-22.69%