SELECTION OF BEST DRILLING, COMPLETION AND STIMULATION METHODS FOR COALBED METHANE RESERVOIRS

A Thesis

by

SUNIL RAMASWAMY

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2007

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Walter B. Ayers
Committee Members,	Maria A. Barrufet
	Stephen A. Holditch
	W. John Lee
Head of Department,	Stephen A. Holditch

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ABSTRACT

Selection of Best Drilling, Completion and Stimulation Methods for Coalbed Methane Reservoirs. (December 2007)

Sunil Ramaswamy, B.E, National Institute of Technology Karnataka at Surathkal, India

Chair of Advisory Committee: Dr. Walter B. Ayers

Over the past three decades, coalbed methane (CBM) has moved from a mining hazard and novel unconventional resource to an important fossil fuel that accounts for approximately 10% of the U.S. natural gas production and reserves. The expansion of this industry required development of different drilling, completion and stimulation practices for CBM in specific North American basins, owing to the complex combinations of geologic settings and reservoir parameters encountered. These challenges led to many technology advances and to development of CBM drilling, completion and stimulation technology for specific geologic settings.

The objectives of this study were to (1) determine which geologic parameters affect CBM drilling, completion and stimulation decisions, (2) identify to the engineering best practices for specific geologic settings, and (3) present these

findings in decision charts or advisory systems that could be applied by industry professionals.

To determine best drilling, completion and stimulation practices for CBM reservoirs, I reviewed literature and solicited opinions of industry experts through responses to a questionnaire. I identified thirteen geologic parameters (and their ranges of values) that are assessed when selecting CBM drilling, completion and stimulating applications. These are coal thickness, number of seams, areal extent, dip, depth, rank, gas content, formation pressure, permeability, water saturation, and compressive strength, as well as the vertical distribution of coal beds and distance from coal reservoirs to fracture barriers or aquifers. Next, I identified the optimum CBM drilling, completion and stimulating practices for specific combinations of these geologic parameters. The engineering best practices identified in this project may be applied to new or existing fields, to optimize gas reserves and project economics.

I identified the best engineering practices for the different CBM basins in N.A and combined these results in the form of two decision charts that engineers may use to select best drilling and completion practices, as well as the optimal stimulation methods and fluids for specific geologic settings. The decision charts are presented in a Visual Basic Application software program to facilitate their use by engineers.

DEDICATION

To my FAMILY

ACKNOWLEDGEMENTS

I would like to thank Dr. Walter B. Ayers for his valuable guidance, encouragement, and interest throughout the course of completion of this research project and my advisory committee, Dr. Stephen A. Holditch, Dr. W. John Lee and Dr. Maria A. Barrufet for their support in completing this project.

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Finally, would like to thank my Mother and Father for their continued encouragement and support.

I thank God for empowering and guiding me throughout the completion of the degree.

NOMENCLATURE

CBM	Coalbed Methane
N.A.	North America
U.S.	United States of America
Sub B	Sub Bituminous Coal
HV	High Volatile Bituminous Coal
MV	Medium Volatile Bituminous Coal
LV	Low Volatile Bituminous Coal
PDM	Positive Displacement Motor
LWD	Logging While Drilling
MWD	Measurement While Drilling
LPDP	Lateral Push Drill Pipe
HWDP	Heavy Weight Drill Pipe
DC	Drill Collars
DPFS	Drill Pipe from Surface
LRH	Long Radius Horizontal Drilling
MRH	Medium Radius Horizontal Drilling
SRH	Short Radius Horizontal Drilling
KOP	Kick Off Point
TVD	Total Vertical Depth
C_t	Overall Fluid Loss Co-efficient

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CHAPTER I

INTRODUCTION

Energy Supply

The demand for energy is increasing as conventional oil and gas resources are being depleted. To meet the increasing demand, the oil and gas industry is turning towards unconventional oil and gas reservoirs. Unconventional reservoirs are the oil and gas reservoirs that cannot be produced at an economic rate or cannot produce economic volumes of oil and gas without assistance from massive stimulation treatments, special recovery processes or advanced technologies.[1] Unconventional reservoirs include tight gas reservoirs, coalbed methane (CBM) reservoirs, gas shales, oil shales, tar sands, heavy oil and gas hydrates.[1]

All natural resources, such as gold, zinc, oil, gas, etc., are distributed log normally in nature. John Masters introduced the concept for oil and gas resources in form of a resource triangle (**Fig. 1**).[2] High quality resources that are less abundant but easy to produce occur at the top of the triangle, whereas the unconventional resources that are more abundant but difficult and expensive to produce occur at the base of the triangle.[1]

This thesis follows the style of *Society of Petroleum Engineers*.

With growing demand for energy and depletion of conventional energy supplies, the emphasis is shifting towards the lower part of the triangle, and unconventional gas resources are assuming greater importance worldwide. CBM resources occur in the lower portion of this triangle.

CBM is methane produced from coal beds. Most commonly, a coalbed gas system is a self-sourcing reservoir. The gas generated by thermal maturation of the coal is stored in the coal matrix as adsorbed gas. The hydraulic pressure in the coal keeps the gas adsorbed. Sometimes the coal generates more gas than it can hold, and this gas can be a source for nearby traps in other types of reservoirs. Thus, the coal matrix acts as the primary reservoir rock, with secondary gas storage in cleats as free gas or as solution gas in water.

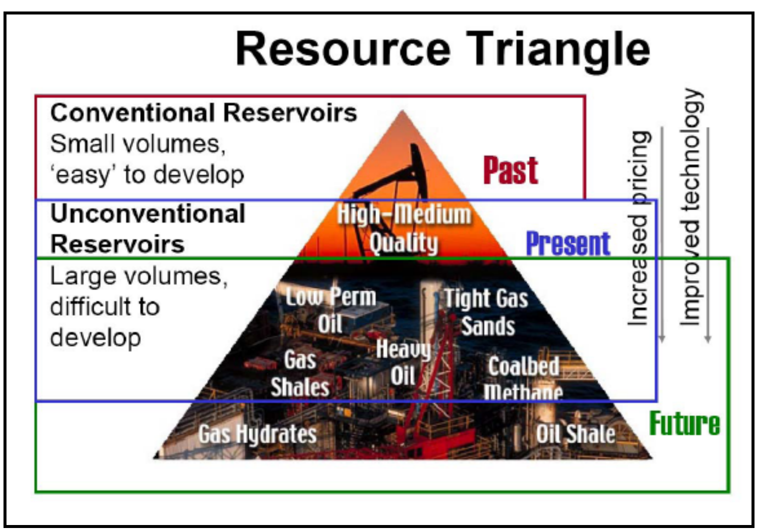


Fig 1: Natural gas resource triangle[1]

Worldwide energy demand is predicted to increase from the current level of 400 quadrillion BTU per year in 2004 to 600 quadrillion BTU by the year 2020 (**Fig. 2**).[3] To help meet this demand, the world is turning to unconventional resources, as the conventional energy resources are depleting. By the year 2020, about 47.5% of the energy demand is expected to be satisfied by gas resources. Of this 47.5%, about 20% is expected to be fulfilled by CBM.[3] Currently, CBM is one of the major unconventional resources fulfilling the demands of U.S. In 2006, CBM contributed about 9.73% of the total dry gas reserves of U.S.[3]

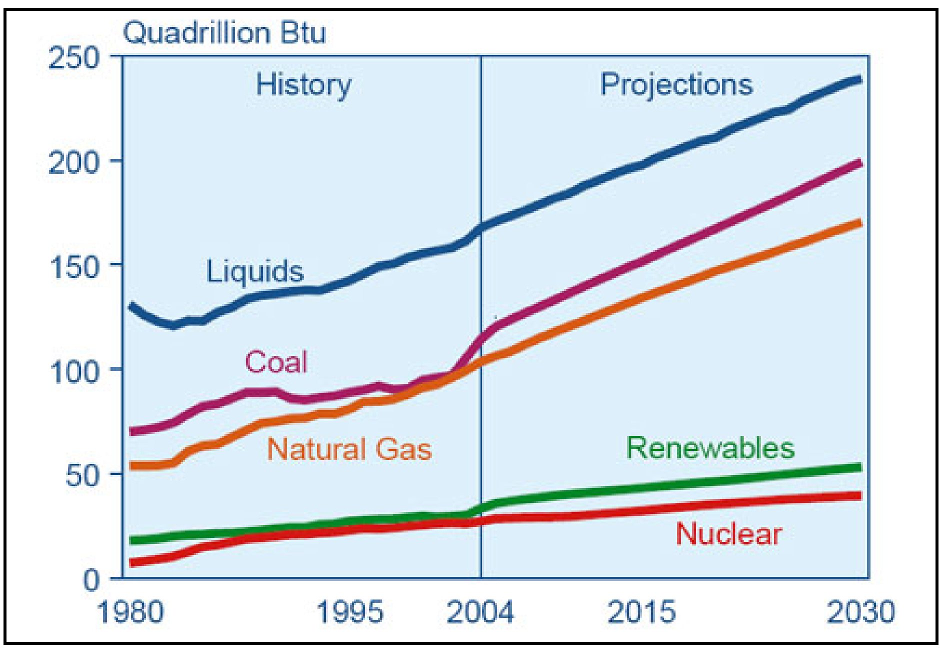


Fig 2: World energy demand[4]

Significant coal reserves underlie approximately 13% of the United States. Of the coal regions (**Fig. 3**), several currently produce CBM, and exploration is active in others. The U.S. is the world leader in coalbed gas exploration, booked reserves, and production. Currently, 12 U.S. basins have commercial coalbed gas production or exploration. The major producing areas are the San Juan, Powder River, Black Warrior, Raton, Central Appalachian, and Uinta basins (Fig. 3). Other U.S. areas with significant exploration or production are the Cherokee, Arkoma, Illinois, Hanna, Gulf Coast, and Greater Green River basins. Internationally, commercial coalbed gas is produced in Canada and the Bowen Basin of Queensland, Australia. Exploration, test wells, or pilot projects are ongoing in several countries, including Russia, the United Kingdom, China, and India.[5]

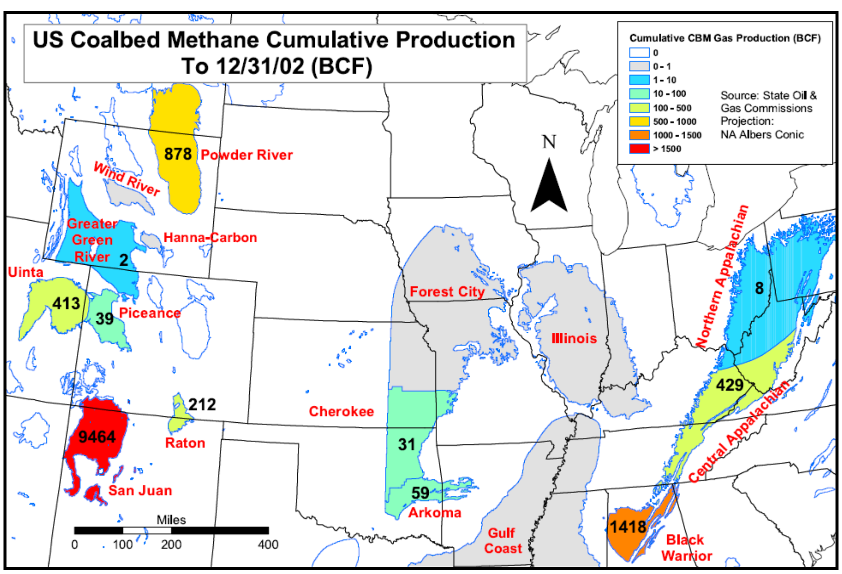


Fig 3: U.S. basins with active CBM wells as of 2002[6]

CBM Production Methods

The methods used for CBM production vary across and basins and from one basin to another, depending on the local geology and reservoir properties (**Fig. 4**). To select optimal engineering applications to maximize well performance, it is crucial to determine the influence of these geologic parameters on the success of specific drilling, completion, or stimulation practices.

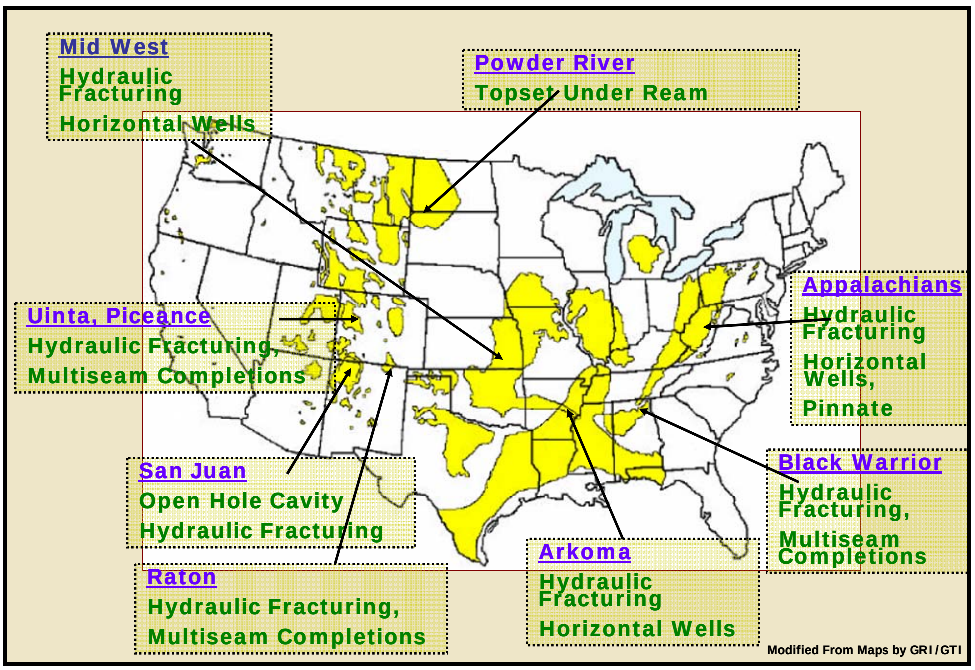


Fig 4: CBM basins and completion and stimulation methods used in the U.S. base map from EIA[6]

Depending on the geologic setting, CBM wells may be vertical or horizontal wells, and selection of completion and stimulation methods will further depend on the number of coal beds to be produced, depth of occurrence, permeability, compressive strength of coal, etc. (**Figs. 5** and **6**). This project aims to clarify how various reservoir properties influence selection of specific drilling, completion, and stimulation applications.

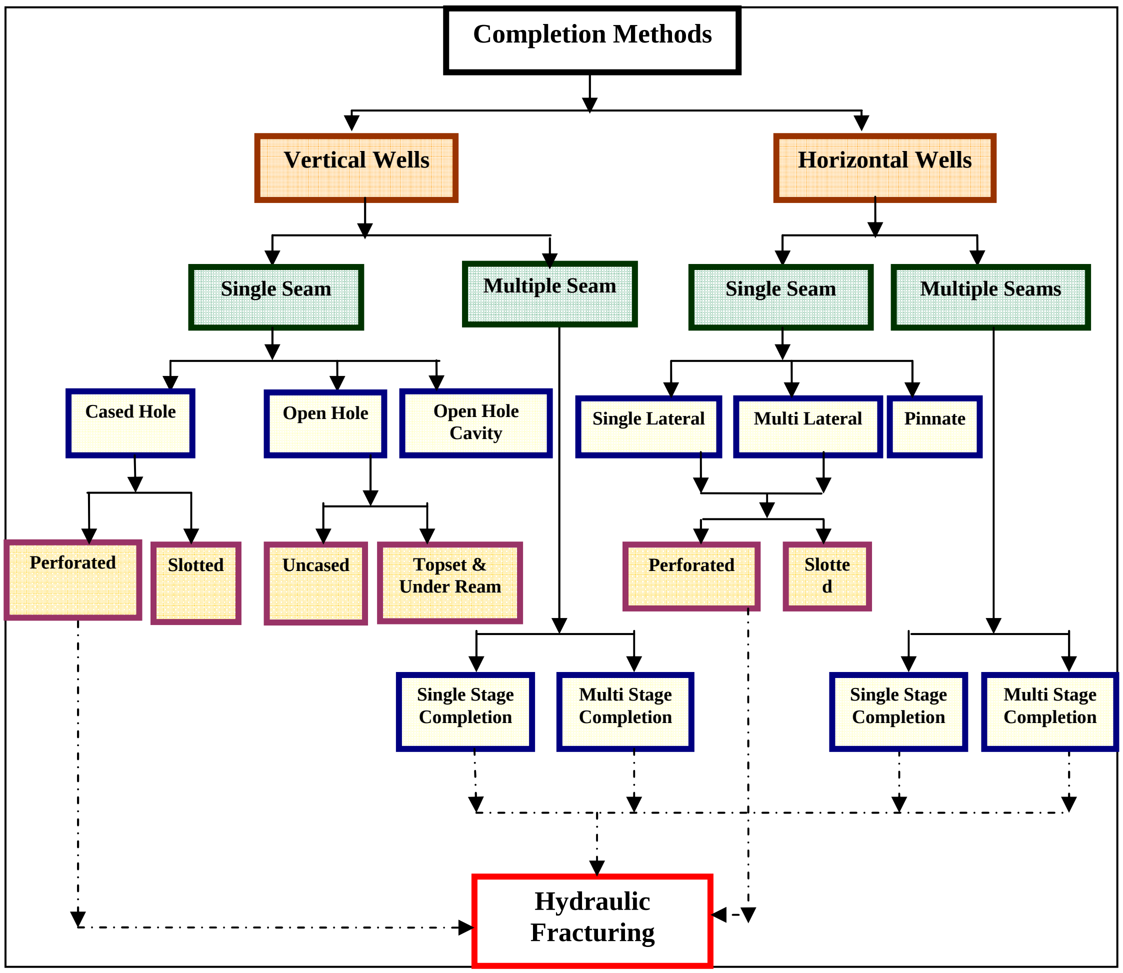


Fig 5: Drilling and completion methods for CBM reservoirs

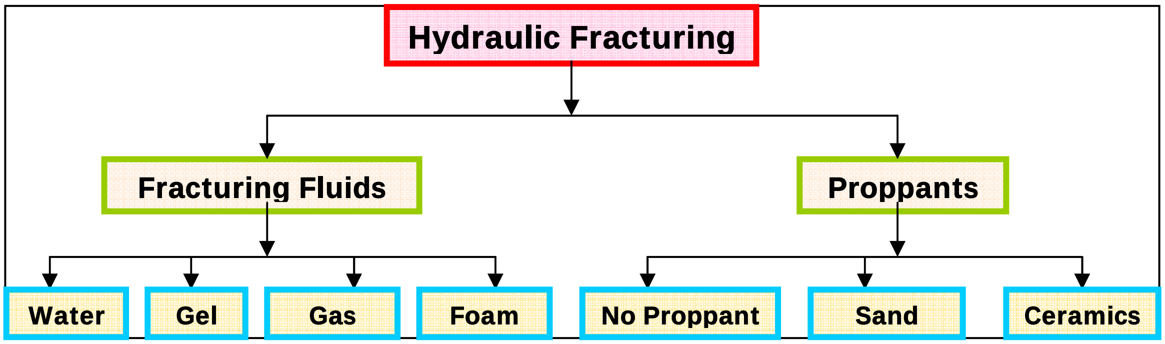


Fig 6: Hydraulic fracture stimulation fluids and proppants used for CBM reservoirs

Evolution of CBM Engineering Practices

Completion Methods

Coalbed methane has been produced for many years in the U.S., and engineering practices have evolved over time. CBM was produced successfully in Oklahoma in 1926, [7] and in the mid 1940's, CBM was produced from Appalachian basin coals.[8] The first commercial CBM well in the San Juan basin was drilled in 1953.[7] In the late 1970's, CBM wells were drilled in the Black Warrior basin as well,[7] and the U.S. CBM industry expanded rapidly in the 1980s to take advantage of the Section 29 tax credit.

Most early CBM wells were vertical wells, and gravel packs were used for completions. Commonly, coal fines plugged the gravel packs, resulting in reduced production. This led to the use of cased-hole completions with hydraulic fracture stimulation of coal beds[7] by the late 1970s in the Black Warrior and San Juan basins. Today, openhole completions are seldom used for coalbed wells.[7]

However, some modified versions of openhole completions, like the openhole cavity completion and the topset under ream method, are still used. The openhole cavity completion method was developed for the San Juan basin "fairway" coals in 1985, by Meridian Resources[7]. This method is one of the most successful methods for producing coalbed gas, but it has been proven to work only in the specific geologic conditions that occur in the San Juan basin fairway. The topset under ream method of coalbed completion was developed in the 1990s for producing gas from the shallow coals of Powder River basin. In this method, wells are drilled to the top of the coal, and casing is set. Then, the well is drilled through the coal and under reamed. Wells are then stimulated by pumping a small quantity of water (approximately 160 bbl) to remove the damage caused to the coal by drilling.[9]

Currently, cased hole completions are the most commonly used completion methods for CBM wells (Fig. 4). Most cased wells are stimulated using hydraulic fracturing techniques.[7] However, the hydraulic fracture designs vary from basin-to-basin and, sometimes, even from place to place within one basin.

Horizontal coalbed wells have long been successfully drilled inside mines for degasifying the coals before mining operation. In late 1980s, horizontal CBM wells drilled from the surface were tried in Black Warrior basin, but they were considered uneconomic. However, with advances in drilling technology in the early 2000s, horizontal coalbed wells have become more common. These horizontal CBM wells are drilled in thin coal seams to enable the wellbore to contact the maximum possible reservoir area. Today, even multi-lateral wells are being successfully used in the Arkoma and Appalachian basins.

Stimulation Methods

Several types of hydraulic fracturing methods have been used to stimulate CBM wells (Fig. 6). These stimulation methods and the types of fracture fluids and proppants have also evolved over time. Hydraulic fracturing of coal beds was tried first in the San Juan and Black Warrior basins, in the late 1970s. The initial fracture stimulation treatments in the Black Warrior basin utilized slick water with proppant.[10] Later, linear gel fluids with proppant were used during fracture treatments.[10] However, the increase in production observed by the use of linear gels was insignificant, owing to the damage caused to the formation by the gels.[10] As the gel fracs were not very successful, operators returned to slick water, but it was used without proppant. However, even this method was not found to be very successful. With further improvements in technology and development of cross-linked fluids, better gel breakers, and cleaning agents, currently, cross-linked fluids are accepted to be the most suitable fluids.[10]

Research Objectives

Drilling, completion and stimulation methods in CBM reservoirs vary with the different geological parameters. Seam thickness affects the decision of whether to drill a vertical well or a horizontal well. The depth of occurrence and formation permeability further affect engineering decisions, such as whether to complete the well openhole with under reaming, as an openhole cavity, or as a cased-hole completion. If one selects a cased-hole completion, then further choices must be made concerning the type and volume of hydraulic fracturing fluid and proppant to be used. Similarly, in horizontal wells, coalbed permeability and the number of coal seams to be completed affect the decision of whether to drill a single lateral or multilateral well.

As more CBM fields are developed in diverse geologic settings, we face tough decisions concerning the optimum drilling, completion and stimulation methods. Moreover, the development of new technology further complicates the selection process. Based on the geology of the CBM reservoir, one must select the best engineering practices to maximize gas recovery and profits. The objectives of this research were to (1) identify the geologic parameters that affect drilling, completion, and stimulation decisions, (2) clarify the best drilling, completion, and stimulation practices to optimize CBM recovery and project economics in various geologic settings, and (3) present these findings in decision chart or advisory system that can be applied by industry professionals.

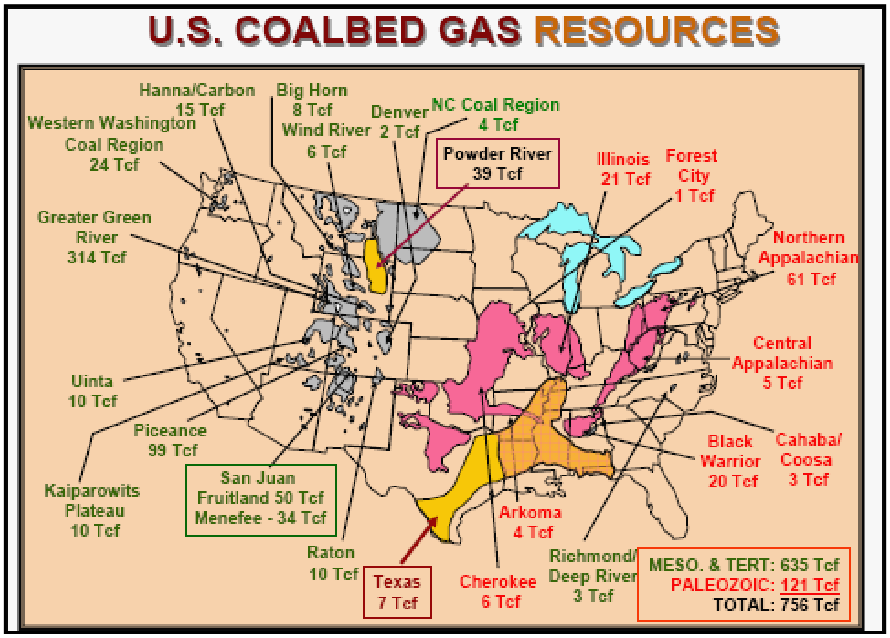
The engineering best practices identified in this project will apply to both new and existing fields. By evaluating the geologic setting of producing areas, we can reassess, and possibly increase, reserves on the basis of best technology applications.

CHAPTER II

METHODOLOGY

This research aims to determine the best drilling and completion practices for given sets of CBM reservoir conditions. To accomplish these research objectives, the following tasks were performed.

- A review of CBM literature was conducted to determine the important CBM reservoir properties that influence the CBM engineering practices. In conducting this study, only North American (N.A.) CBM basins were considered, because the CBM industry started in N.A. and this area has been the site of most advancements in CBM technology (**Fig. 7a and 7b**);
- The different drilling, completion, and stimulation practices used in CBM reservoirs were analyzed.
- Best engineering practices for the N.A. CBM basins and the geological parameters that contribute to the success of these practices were identified.
- Based on the literature review, I prepared and circulated a questionnaire among industry experts to determine the different geological conditions that affect the selection of specific drilling, completion, and stimulation methods in coal beds and the current best practices for these geologic conditions.



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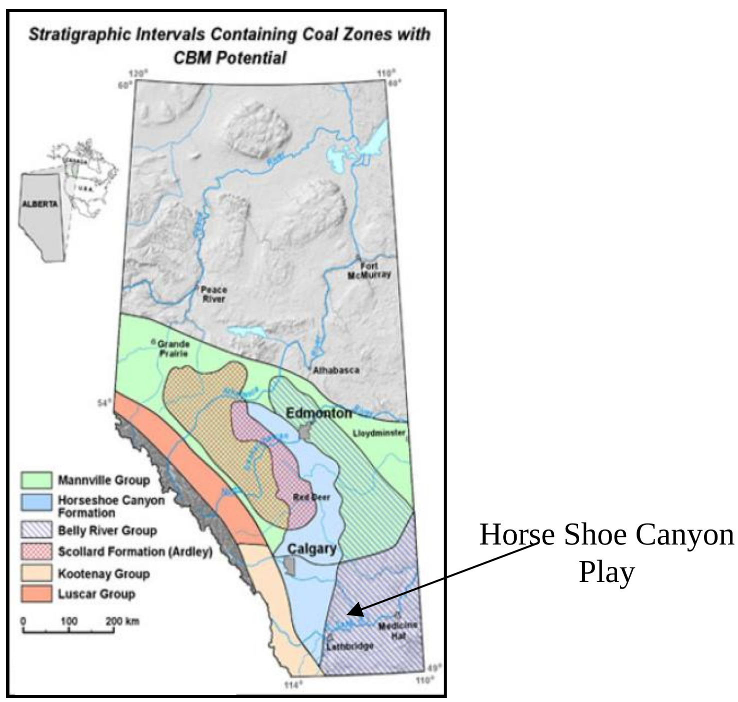


(b)

Fig. 7: Basins with CBM resource in N.A (a) U.S. basins, [11]
(b) Horseshoe Canyon CBM play in the Western Canada Sedimentary basin[12]

- On the basis of the industry response and the literature review, I developed a decision chart to help engineers select the appropriate drilling, completion, and stimulation methods for developing CBM reservoirs in various geologic settings.
- Finally, I built advisory software to simplify the process of identifying the best drilling, completion and stimulation practices.

Overview of Coalbed Gas Systems

Owing to differences in reservoir quality, coalbed gas production varies across individual basins; commonly, only part of a basin is productive, and the fairways or sweetspot areas that have the most productive wells, comprise less than 10% of the area of producing basins.[9] An economic coalbed methane project requires convergence of several geologic factors, as well as acceptable gas prices and operational and environmental conditions.[9] CBM reservoir properties are determined by a number of factors, including the coal properties, depositional setting, and the geological processes that occur over time. An understanding of coalbed gas systems helps clarify the complexity and variability of coalbed reservoirs.

A petroleum system is defined as a natural system that encompasses a pod of active source rock and all related oil and gas, and that includes all the geologic elements and processes that are essential if for a hydrocarbon accumulation to exist.[13] The most important elements of a petroleum system are hydrocarbon source rock, reservoir, seal rocks, and the geological process that occur over time. Many CBM petroleum systems differ from conventional petroleum systems in a number of ways. Most commonly, a coalbed gas system is a self-sourcing reservoir.[14] Gas generated by the thermal maturation of the coal is stored on the coal matrix, as adsorbed gas.[14] The hydraulic pressure in the coal cleats (fractures) assists in keeping the gas adsorbed.[14] Thus, the coal matrix acts as the primary reservoir rock, with secondary gas storage in cleats as free gas or as solution gas in water.[14]

Coalbed gas is classified on the basis of origin as primary biogenic gas, secondary biogenic gas, early thermogenic, thermogenic, migrated thermogenic or mixed gas.[14] Primary biogenic gas is generated in peat at relatively low temperature and shallow burial depth. Most primary biogenic gas is lost during burial and compaction. Early thermogenic gas is generated by the thermal maturation of the coal, generally, at vitrinite reflectance < 0.78%. Thermogenic gas is generated by further burial and thermal maturation of coal, at vitrinite reflectance > 0.78%. Thermogenic gas is the source of most gas in thermally mature coals. Secondary biogenic is generated by activity of methanogenic microbes present in meteoric water moving through the coal cleat system. These microbes are introduced in the coal after the formation of coal. Migrated thermogenic gas is transported to a location in the coal from other places in the coal bed by hydrologic flow. Alternatively, it may be transported to the coal from other source rock, such as shales or other coals. Mixed gas is a mixture of gas from 2 or more thermogenic or biogenic sources.[14]

The majority of coalbed gas is adsorbed on the surface of organic matter in pores of the coal matrix. However, some coalbed gas is stored in the cleats as solution gas in water or as free gas, in the absence of water. Seals in coalbed gas systems maintain formation pressure, and formation pressure holds gas in an adsorbed state, preventing gas desorption and escape. Although conventional traps may be present in coalbed gas systems, their presence is unnecessary, because gravity separation of gas and water is not required. Thus, coalbed gas may be produced from structurally low sites, such as synclines.[9]

The structural complexity of coal basins may affect CBM project economics. In small basins that are highly faulted, for example, reservoir properties may vary markedly from one fault compartment to the next. In some cases, it may be difficult to develop projects with sufficient number of well to support the required infrastructure.

Review of CBM Reservoir Properties

Among the CBM reservoir properties that play important roles in determining engineering best practices are the depth of coal occurrence, thickness of individual coal seams and net coal thickness, number of coal seams and their vertical distribution, lateral extent of the coal, thermal maturity, structural dip, and adjacent formations (e.g., aquifer sandstones, fracture barriers, etc.) .

The number of effective coal seams and their vertical distribution affect the type of completion to be used. The completion could be single zone completion or multizone, the aerial extent of the coal also plays an important role in selecting well locations and in deciding whether to drill a vertical or horizontal well. If the dip of the coal is greater than 15 degrees, then keeping a horizontal wellbore inside the coal seam is very difficult, and drilling a horizontal well may be uneconomical.[15]

The distance to fracture barriers aquifers above or below coal beds influences the selection of fluids when hydraulic fracture stimulation is being used.[16] Values of reservoir fluid compressibility and formation compressibility are also important when selecting the type of hydraulic fracture stimulation.

Depth of Occurrence

Depth of coal occurrence is important to the selection of completion and stimulation methods. With increase in depth of coal occurrence, overburden stress, formation pressure, and thermal maturity of coal increase, and gas content may increase, also. Depth determines the drilling cost, and it is an important factor in determining the surface injection pressure and the bottomhole pressure when designing a fracture treatment.[16]

Gas Content

Thermal maturity, moisture and ash contents, and maceral composition of coal directly affect the coals ability to adsorb gas. Gas content of coal is governed by the adsorption capacity and formation pressure.[17] **Fig. 8** shows the gas generation during the coalification process from peat to anthracite. The amount of gas retained depends on the reservoir pressure and coal properties.

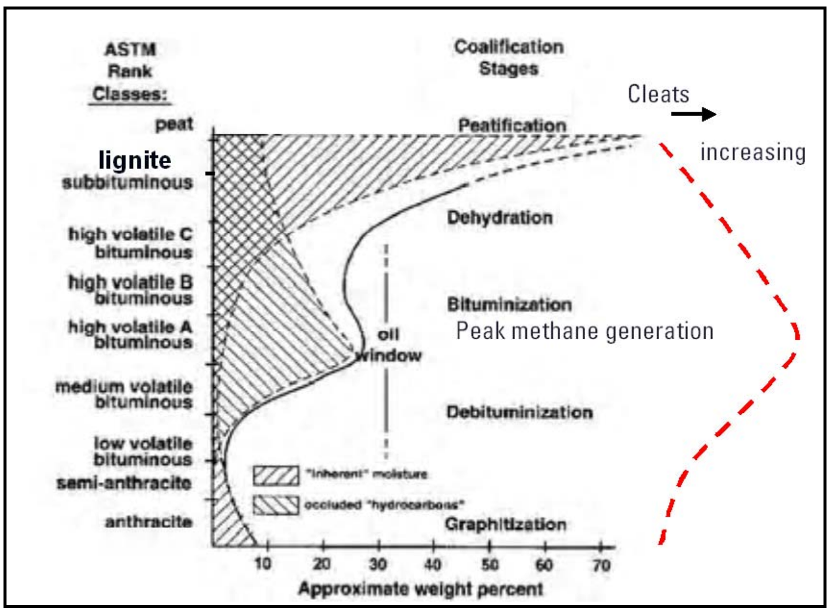


Fig. 8: Coalification, cleats and hydrocarbon generation[17]

Coal Rank

Coal rank or thermal maturity may be described on the basis of the percentage of carbon or moisture in the coal, vitrinite reflectance, or other measures (**Table 1**). The amount of gas that may be stored in coal is directly dependent on coal rank.[17] Low-volatile bituminous (LV) may be better suited for CBM gas production than high-volatile bituminous (HV) coals, as LV coals have potential to adsorb greater amounts of gas and are more highly cleated than HV coal.[17] Although the gas content of semi-anthracite and anthracite coals may be very high, there are no economical coalbed gas projects in these coals, owing to low permeability and very slow rates of gas desorption.[18]

Table 1: Carbon percentage, heating value, and vitrinite reflectance on basis of coal rank[19]

Coal Rank	% Carbon	Specific Energy (MJ/kg)	Vitrinite Reflectance (Max %)
Anthracite	95	35.2	up to 7.0
Semi-Anthracite	92	36	2.83
Low-Volatile Bituminous Coal	91	36.4	1.97
Medium-Volatile Bituminous Coal	90	36	1.58
High-Volatile Bituminous Coal	86	35.6	1.03
Sub-Bituminous Coal	80	33.5	0.63
Brown Coal	71	23	0.42

Reservoir Pressure

Reservoir pressure affects the gas storage capacity, the amount of depressurization required to initiation gas desorption (critical desorption pressure), effective in-situ stress, leakoff coefficient and well productivity. Where coal cleats are water saturated, it is necessary to dewater the coal bed to allow desorption and gas production (**Fig. 9**).[9]

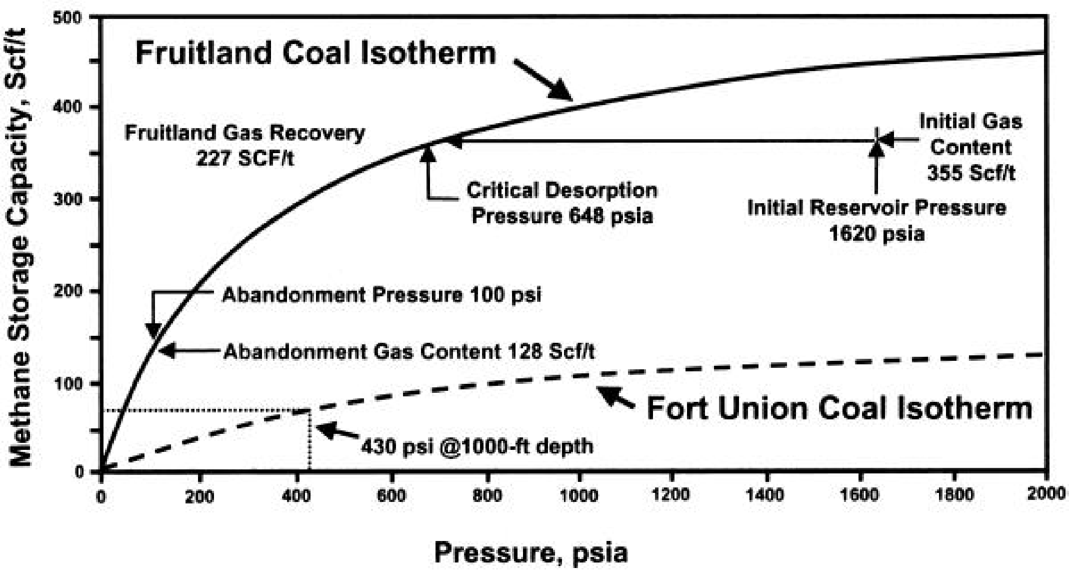


Fig. 9: Effect of pressure on methane storage for San Juan Basin Fruitland coal and Powder River Basin Fort Union coals[21]

When depressurization progresses to the Critical Desorption Pressure, gas desorbs from the coal matrix adjacent to the cleat and moves by Darcy flow to the well-bore (**Fig. 9**). Desorption of coalbed gas from the coal matrix adjacent to the cleat creates a concentration gradient, and gas within the matrix diffuses to the cleat.[22] Over time, water production declines and gas production increases.[22]

Thus the fluid flow in CBM formations is controlled by two flow mechanisms, Darcy flow and diffusion.[22]

Any pressure gradient in the reservoir caused by low permeability or poor reservoir access causes a reduction in the amount of gas released.[16] Reservoir pressure is important factor when selecting the completion and stimulation method, as it affects the selection of the fracturing fluid to be used.

Reservoir Fluid Saturation

In most coals, the cleat is water saturated. Coalbed water is important because it (1) may contribute microbes that generate biogenic gas, (2) may cause artesian overpressure, (3) reduces the relative permeability to gas in the coal cleats,[5] (4) must be removed to allow coalbed gas desorption, and (5) must be disposed, which adds to operation costs. The quantity of water to be pumped is one of the most important factors in determining the economics of a coalbed gas well.[10]

In-situ Stress

Coal is highly compressible, and the in-situ stress acting on coal affects reservoir permeability and production.[9] Generally, permeability decreases with depth owing to increased in-situ stress, and most coalbed gas production is from coals less than 4000 ft deep.[9] Knowledge of the in-situ stress is used in calculating the surface injection pressure and the bottom hole treatment pressure when designing fracture stimulation treatments.[16]

In-situ stress orientation may also impact CBM production. The orientation of the horizontal stress relative to cleat orientation may affect coalbed permeability. Moreover, in-situ stress orientation determines the orientation of induced fractures.

Permeability

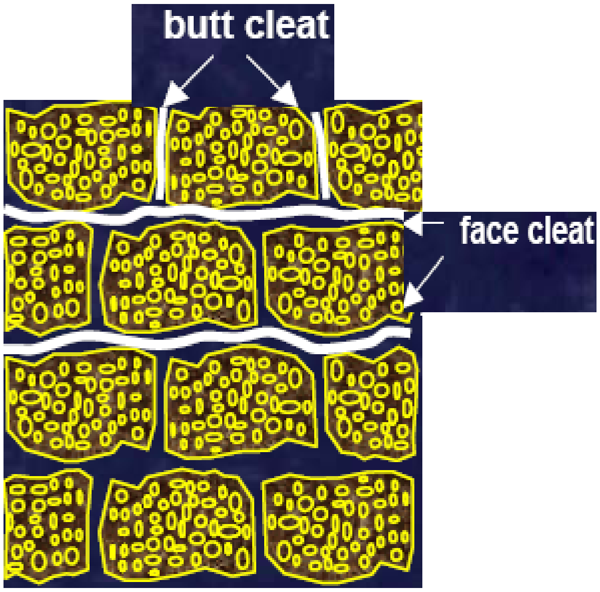
Coal has very low matrix permeability (< 1 mD). Fluid and pressure transmission in CBM reservoirs is dependent on the coal cleats[15]. Thus, cleat properties affect the type of completion to be used. Cleats in the coal seam are thought to form as a result of coal dehydration, local and regional stresses, and unloading of overburden. Two orthogonal sets of cleats develop perpendicular to bedding in coals (**Fig. 10).**[15] Face cleats are the dominant fracture set, and they are more continuous and laterally extensive; face cleats form parallel to maximum compressive stress and perpendicular to fold axes.[15] Butt cleats are secondary and terminate against face cleats. Butt cleats are strain release fractures that form parallel to fold axes.[9]

Cleat spacing is related to coal rank, bed thickness, maceral composition, and ash (inorganic) content.[15] Coals with well-developed cleat sets are brittle. In general, cleats are more closely spaced with increasing coal rank. One study suggests that average cleat spacing values for three coal ranks are: sub-bituminous (2 to 15 cm), high-volatile bituminous (0.3 to 2 cm), and medium- to low-volatile bituminous (<1 cm).[21] Cleat spacing is tighter in thin coals, in vitrinite-rich coals, and in low-ash coals. Where biogenic gas is present, cleats serve multiple purposes of conveying microbes to the coal-water interface, sweeping microbial gas along the groundwater flow paths, and during production, transporting water and gas to the wellbore. The fact that face cleat is more continuous than the subordinate butt cleat leads to permeability anisotropy and elliptical reservoir drainage patterns.[17]

Permeability influences the type and the design of the stimulation treatment[16]. Coal seam permeability is used to calculate the leakoff coefficient, the size of the pad volume, and injection rate of a fracture treatment.[16]

Coalbed Thickness

Coal seam thickness affects the quantity of coalbed gas.[16] Also, thickness affects the decision of whether to drill a vertical or horizontal well. If the coal seam is thick, then drilling a horizontal well is not considered to be the best economic choice, as the wellbore may not access all parts of the reservoir.[16]



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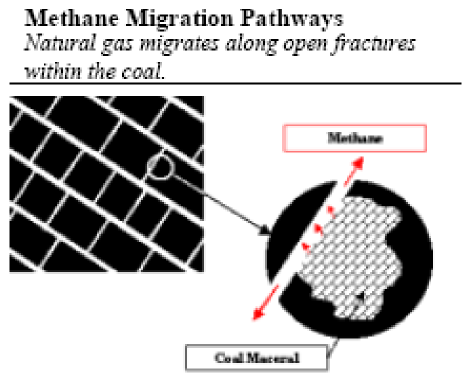

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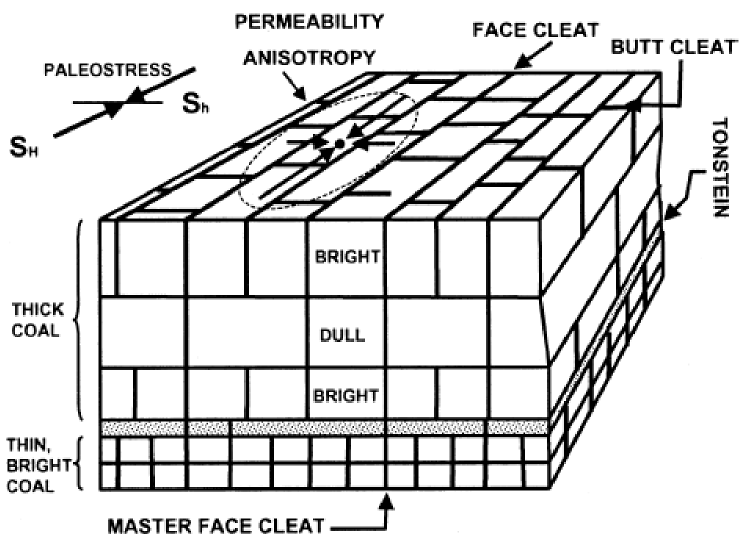


(c)

Fig. 10: Cleats in coal (a) shows face and butt cleats, [22] (b) shows methane migration pathways through coal, [15] (c) shows permeability anisotropy in coal[9]

Reservoir Temperature

Reservoir temperature is important in selection of the stimulation design to be used for hydraulic fracturing. The fracturing fluid to be used is directly dependent on the reservoir temperature, as temperature affects the fluid stability.[16]

Coal Porosity

Typically, coal seams have a macroporosity of 1-2%, due to the presence of cleats.[16] The value assigned to coal seam porosity is not critical to the selection of completion and stimulation type.[16]

CBM Production Practices

CBM wells are drilled, completed and stimulated similar to conventional reservoirs. However, engineering practices differ somewhat because of the differences in the reservoir properties between conventional and coalbed reservoirs, and because of differences in coalbed properties from one case to the next. Identifying and understanding the geological and reservoir parameters of coal are necessary for the optimum design of the drilling, completion, stimulation, and production operations. The appropriate completion technique depends upon the specific reservoir characteristics, and each technique requires a different drilling procedure.

After completion, coal reservoirs typically undergo dewatering to reduce reservoir pressure and allow gas to desorb. Therefore, the well bore configuration and completion technique must be designed to accommodate water and gas production needs. The types of drilling, completion and stimulation methods that are currently used for producing CBM gas are discussed below.

Drilling Methods

The primary concerns in selecting the appropriate coalbed drilling method are formation damage, lost circulation because of high permeability, overpressure, gas/water flow, and wellbore stability. To address these problems, the following factors and data are considered when designing the drilling program:

- formation depth, pressure and production;
- type of coal and non-coal formations;
- well logs;
- drilling fluid specifications;
- casing program;
- drilling problems encountered; and
- stimulation and the completion method that will be used.[23]

Any depleted zones or other conditions that can cause circulation loss must be determined. Also, other potential problem zones, like the sloughing shale zones and fresh water aquifers, must be identified.

The selection of the casing setting depth is an important factor in determining the casing string and drilling equipment. Some factors that affect drilling depth are fracture gradient of the coal seams and adjacent formations, regulatory requirements, and drilling problems.

To determine the hole size for drilling the following factors are considered:

- expected production rates of water and gas;
- type of artificial lift method to be used;
- tubing size;
- completion method to be used;
- stimulation method to be used;
- type of drilling fluid that is to be used; and
- expected future workover and recompletion requirements.[23]

Vertical Drilling

Most CBM wells are vertical. The commonly used methods for drilling vertical CBM wells are rotary percussion drilling and the conventional rotary drilling. The formation hardness determines the type of drilling method to be used. For softer formations the rotary method is used, whereas for harder formation, rotary percussion drilling is used for a faster rate of penetration. The most commonly used drilling fluids in coal are air/mist, aerated mud and formation water. The selection of fluid is dependent on the coal seam reservoir properties.

To prevent formation damage while drilling, the coal is drilled underbalanced. This prevents the drilling fluid, chemical additives, and drilling solids from being injected into and plugging the cleat system of the coal. In the case of overpressured reservoirs, a slightly overbalanced, water-based drilling fluid is used to maintain well control.[23]

Horizontal Drilling

Horizontal drilling is used to increase the footage of the production zone contacted by the borehole. Horizontal drilling increases the production rate and ultimate reserves recovered.[24] The drilling equipment used for most horizontal wells is comprised of a drilling bit, positive-displacement motor (PDM), logging while drilling (LWD), measurement while drilling (MWD), non-magnetic drill collars, lateral “push” drill pipe (LPDP), heavy-weight drill pipe (HWDP) or drill collars (DC) used for weight, and drill pipe from surface (DPFS).[24]

Types of horizontal drilling are:

- Long Radius (LRH);
- Medium Radius (MRH); and
- Short Radius (SRH).[24]

Horizontal wells have a kick-off point (KOP), a directionally drilled curve section to an inclination within the range of 70° to 110°, depending on the dip of the coal, and a lateral section. The lateral section is drilled while changing the true vertical depth (TVD) of the well and the wellbore direction by adjusting the inclination and azimuth, respectively. Several types of CBM horizontal wells may be drilled (**Table 2**).

MRH profiles are generally the design of choice, with the exception of smaller hole sizes and drilling tools that can accommodate an SRH curve. MRH designs cover the widest range of build rates (6°/100’ to 40°/100’) and can be drilled using most common drilling tool sizes.[24]

Table 2: Classification of horizontal wells and well specifications[24]

Horizontal Class	Horizontal Class Identifier	Horizontal Build Rate deg. / 100’	Hole Radius (feet)	Wellbore Size Diameter
Long Radius	LRH2	2°/100'	2865	
(Up to 6°/100')	LRH4	4°/100'	1432	
	LRH6	6°/100'	955	8-1/2"
Medium Radius	MRH8	8°/100’	716	6-1/2"
(7°/100' to	MRH12	12°/100’	477	4-3/4"
40°/100')	MRH16	16°/100’	358	
	MRH20	20°/100’	286	
	MRH25	25°/100’	229	6-1/2"
	MRH30	30°/100’	143	4-3/4"
	MRH35	35°/100'	164	
	MRH40	40°/100’	143	
Short Radius	SRH45	45°/100’	127	4-3/4"
(40°/100' to	SRH50	50°/100’	115	
60°/100')	SRH55	55°/100’	104	
	SRH60	60°/100’	95	

LRH design is not suitable for CBM and many other unconventional horizontal drilling applications, because the KOP above the desired lateral TVD is in excess of 950 feet, as is the distance from the surface location to the start of the lateral section in the desired reservoir zone (**Fig. 11**). This excessive distance impacts the well's ability to produce and limits the lateral footage able to be drilled because of additional geological zones exposed in the curve. In addition, the extra distance on the build portion of the well is much longer. This increases the section of high contact forces on the drilling assembly.[24]

Ultra SRH wells have curve build rates greater than 60°/100' (radius less than 95 feet), and are not used for CBM wells because of the limited lateral section achievable. Ultra SRH profiles are complex and are expensive to drill, requiring specialized equipment.[24]

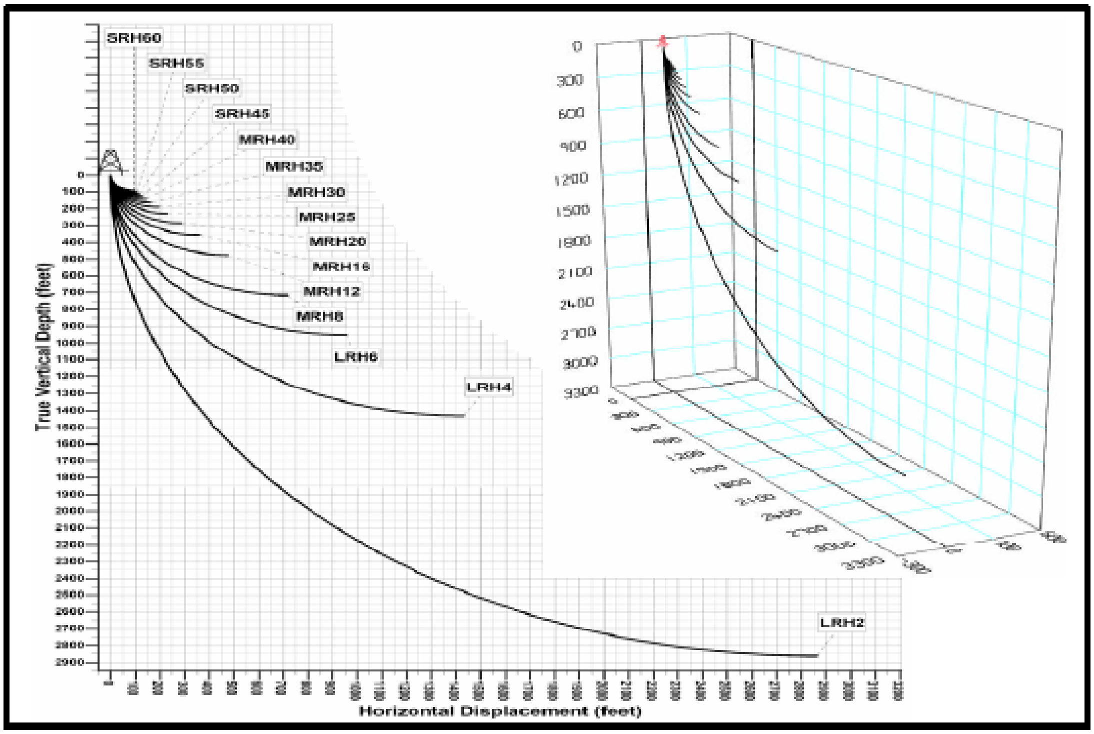


Fig. 11: Horizontal well profiles[24]

Completion Methods

Before selecting a completion method for a CBM well, nine factors should be considered.[16] These are: investment required; number of coal seams encountered by the borehole; expected production rate; reserves in the various coal intervals; coal seam permeability and gas content; type of stimulation treatment expected; wellbore stability problems; future workover requirements; and artificial lift requirements.

Well completion design should be coordinated with the stimulation strategy. The need for and the type of pumping equipment must be considered. Besides efficiently removing liquids from the borehole, pump selection should recognize the effects of coal fines and fracturing sand that may migrate back to the wellbore. The estimation of gas production rates expected after stimulation is also important. In most coalbed reservoirs, early flow rates are small. However, flow rates increase with time, as gas desorbs from the coal. The tubing in the well must be designed to maximize the lifting of liquids early in the life of the well, to help dewater the coal.[16]

To help decide the zones to complete, a reserve analysis should be performed on each potential interval to determine the commercial value of the well. The effect of various sizes of stimulation treatments, type of artificial lift, and the size of the tubular have to be determined on the basis of reserves and the expected commercial value.[16]

Other factors, such as surface injection pressures for the different wellbore configurations and the volumes of fluids required for stimulation, must be estimated. Pumping fluids affects stresses in the tubular goods, and the changes in stress caused by the stimulation treatment must be computed to design the tubing and casing.[16]

The choice of completion type can be made on the basis of the above factors. After the completion type has been chosen, the number of completions within the wellbore is determined, and the final tubing and casing configurations are designed. The different completion methods that are used in CBM are described below.

Cased Hole Completion

The cased-hole completion is the most commonly used coalbed completion type. It is used somewhere in most producing basins, and it is the most common completion in medium-to-low permeability coal beds. This completion is successful because it gives the best control over coal integrity and the stimulation of individual seams. Cased-hole completions replaced openhole completions to solve the coal sloughing problems and to allow fracture stimulation treatments.[7]

In most CBM cased-hole completions, the casing is perforated, and the coal is hydraulically stimulated. Thus, the hydraulic fracture design is an integral part of the cased-hole completion design. The aspects of hydraulic fracture completion are discussed later in the section on Stimulation Methods (page 42).

The cased-hole completion is suitable for almost all types of coal seams, other than high permeability coal seams. The most important factors in selecting a cased-hole completion is the economics involved and the type of stimulation treatment. Depending on the number of seams to be produced, the cased-hole completion could be single seam or multi-seam completion.

Multi-seam Completions

Some disadvantages associated with the single-seam completion are:

- it may cause thin coal seams to be ignored, and thus, cause large areas in the basin to remain uneconomic;[25] and
- it requires a much larger number of CBM wells, with increased capital costs and land disturbance, to produce the same quantity of gas as can be produced from fewer wells using multi-seam completions.[25]

Multi-seam completions are used in Black Warrior, Raton, and Uinta basins. The wells may be stimulated in a single fracture treatment or several treatments, depending on the distance between the seams.

Multi-seam technology for completing numerous coals was developed in the Black Warrior basin. This technology improved the economics of CBM recovery, and also, it increased the EUR of wells, as even the thin coal seams were accessed.[25]

Openhole Cavity Completion

CBM wells completed by the openhole cavity technique in the fairway of the Fruitland formation in the San Juan basin have gas production rates nearly ten times greater than those from wells completed by fracture stimulation of vertical wells in the same area (**Fig. 12**). However, the openhole cavity completion method works only under favorable reservoir, geologic, and geo-mechanical conditions.[26]

The openhole cavity technique involves setting the casing only to the top of the coal formation with the drilling rig. Then, the coal is drilled out using a special completion rig (**Fig. 12**). To enhance the flow back and to encourage coal sloughing in the wellbore, compressed air is injected into the reservoir. Then, the well is allowed to rapidly flow back water, gas and coal. This results in the formation of a cavity in the coal. The generated coal fines may be removed out by circulating the drill bit to the total depth from time to time. This process is repeated till the cavity is stable. Once stability is attained, the well is left openhole, or it is completed using a perforated, uncemented liner.[27]

The cavitation process affects the wellbore in the following ways. It

- removes the drilling skin damage and increases the connectivity of the reservoir to the wellbore;
- removes stress damage, due to stress concentration around the wellbore;

- o enlarges the physical wellbore radius; and
- o enhances the permeability in a zone beyond the cavity surface by up to 5 times the actual cavity radius in very weak coals.[28]

This process has been successful only in the San Juan basin coalbed fairway region in the U.S. and in a limited region of the Bowen basin, Australia.[29] The specific geologic conditions of the fairway region that make this method successful are highly compressible coal, high permeability, formation overpressure, and high gas content coal. The mechanism and the processes involved in openhole completions are further described in Appendix A.

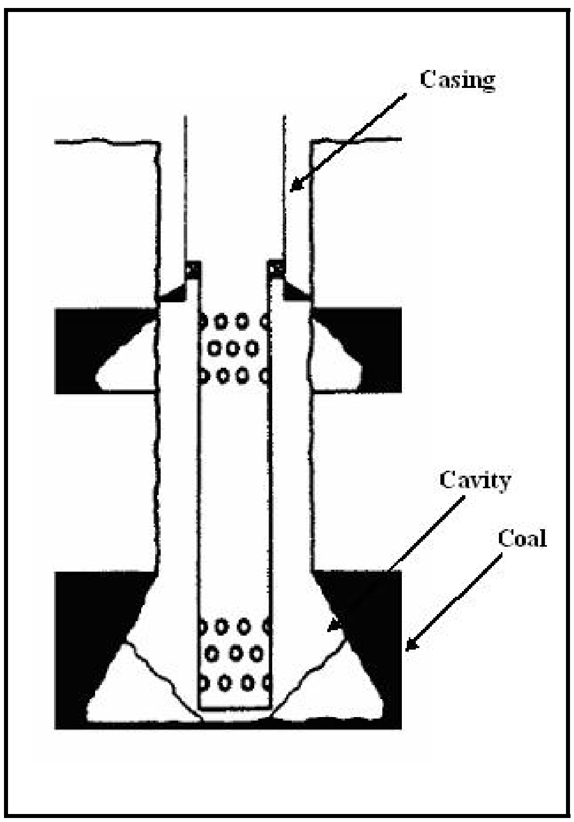


Fig. 12: Schematic of cavity completed method[26]

Topset and Under Ream

A modified version of the openhole completion is the topset and under ream method that is used to produce coalbed gas from shallow coal seams in the Powder River basin **(Fig. 13**). In this method, wells are drilled to the top of the coal and casing is set. Then, the well is drilled through the coal and under reamed to enlarge the borehole to enhance production and to remove permeability damage caused by drilling.[29]

Wells are then stimulated by pumping a small quantity of water (approximately 160 bbl) to remove the damage caused to the formation by drilling.[30] No proppant is used, as the permeability of the reservoir is already very high.[30]

Topset and under ream wells in the Powder River basin are successful because:

- permeability of the coal bed is very high;
- coal beds are thick and continuous;
- coals are shallow, and as a result the cost of drilling involved is low;
- completions are very simple; and
- the stimulation treatment used is simple and inexpensive.[30]

Some disadvantages of this method are that the gas decline rate is very steep as the reservoir permeability falls because fines cause plugging, as there is no proppant trap them.[29] The total cost for completing topset and under reamed wells in 2003 ranged from $65,000 to $135,000, thus making these wells very economical and easy to drill.[29]

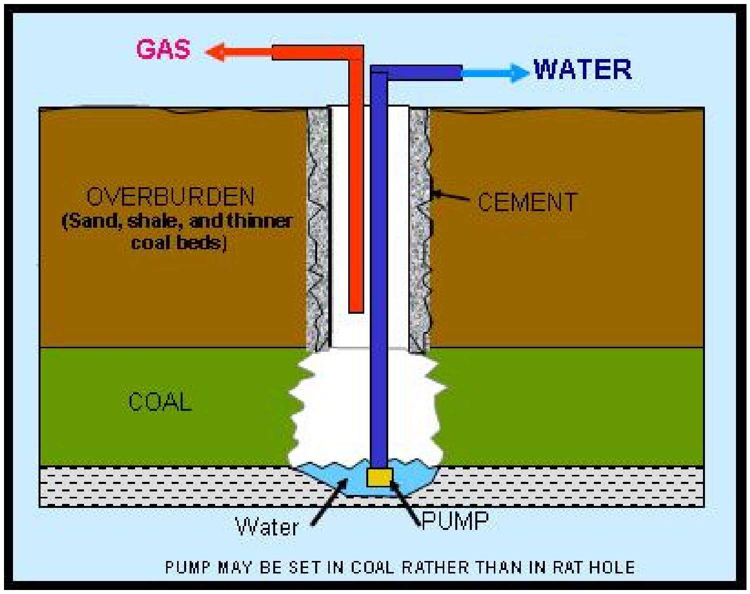


Fig.13: Schematic of topset under reamed well[9]

Horizontal Wells`

Horizontal wells are drilled to maximize borehole contact with the reservoir. Fracturing wings in vertical CBM wells in have average half lengths of less than 200 ft. The reason for such short half lengths is associated with the creation of complex fracture geometries, such as multi-stranded, jointed, and T-shaped fractures.[31]

Increasing the footage of the production zone increases production and ultimate reserves recovered. Horizontal wells contact the main fracture system of the coal, as they are drilled perpendicularly to the face cleats. This significantly increases production and ultimate gas recovery because of the large drainage area connected with the lateral. In conventional reservoirs, horizontal wells are most commonly used in formations that are somewhat flat, with thicknesses ranging from less than one foot up to tens or hundreds of feet. However, in the CBM, horizontal wells are drilled in seams ranging from 3 ft to about 20 ft thick.[32] In thicker coal seams, horizontal wells are not effective, as the well bore is not able to contact the complete reservoir. To increase the connectivity to the reservoir, the well must be hydraulically fractured, or more laterals must be drilled. To date, hydraulic fracturing has not been very successful in horizontal CBM wells, because the costs are not been justified by the limited increase in production. Drilling multilateral wells increases the drilling cost, and the chances of the wells collapsing during drilling and production is very high.[29]

Advantages of horizontal wells over vertical fracture stimulated wells that are they:

- can be drilled to a length of 8000 ft, whereas the effective CBM fracture lengths are usually less than 200 ft, tip-to-tip;
- can be oriented in the direction of maximum horizontal stress to intersect face cleats, to provide maximum wellbore stability;
- are better in reservoirs having high permeability anisotropy
- can be better controlled to stay in seam (to avoid wet zones) than can induced fractures;
- may provide accelerated cash flow and small foot-print; and

- can be expanded to various combinations (multilateral or pinnate designs, and multiple fracturing options).[15]

Some disadvantages of horizontal wells are that they are costly when there are many seams that require drilling multiple horizontals, and the chances of horizontals collapsing during drilling and production are high. A liner is highly recommended to prevent borehole collapse. In most cases, pre-perforated liner is used.[15]

Multilateral Horizontal Wells

Multilateral horizontal wells are drilled in cases where the ratio of horizontal well gas production rate and vertical well gas production rate is less than one.[15] In these cases, the total contact area for a vertical well is more than that for a single horizontal well. In cases where a number of thin coal seams are to be accessed, multiple lateral wells will provide greater production than a vertical well.[15]

Pinnate Wells

Pinnate pattern, multilateral wells have proved very successful in producing coalbed gas from low-permeability coals (**Fig. 14**). Pinnate wells may have a 20-fold increase in production rate, compared to fracture-stimulated vertical wells.[33]

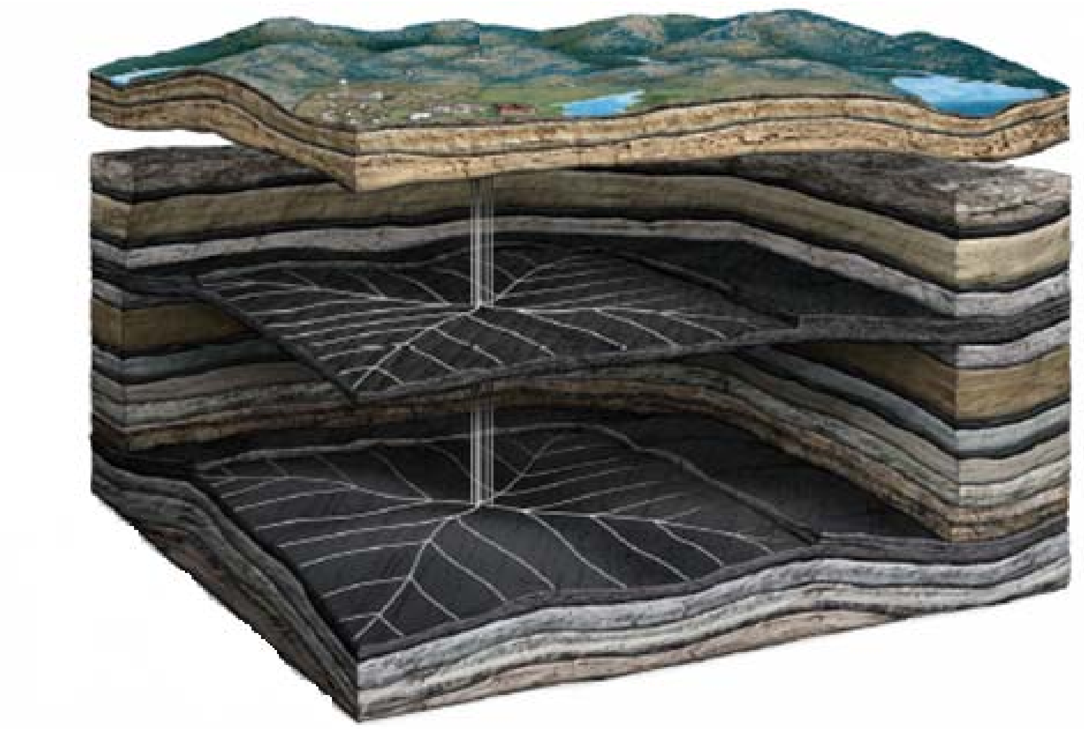


Fig. 14: Pinnate pattern drilling[33]

The pinnate well pattern was developed by CDX drilling Inc. to produce CBM from low-permeability coals (**Fig. 14**). This method is extensively used in the Arkoma basin. Some advantages of pinnate wells are that:

- wells can drain up to 2000 acres from a single drill pad;
- gas is produced immediately;
- peak gas production is reached quickly, unlike a vertical wells in CBM reservoir;
- wells can drain a reservoir in 2 to 4 years;
- gas recovery is high (80 to 90%); and

- o high gas flow rates (1 to 5 MMcfd) can be achieved. [34]

These wells are not suitable in high permeability coals, as many cases of lateral collapses have occurred.[34] Further details of pinnate wells are discussed in Appendix C.

Fracture Stimulation

Hydraulic fracturing is the most commonly used stimulation method in the CBM industry. The stimulation design depends on the reservoir properties. Four major reasons that stimulation treatments are used in cased-hole wells are to (1) bypass near wellbore formation damage, (2) stimulate production and accelerate dewatering by creating a high-conductivity path in the reservoir, (3) distribute the pressure drawdown and thus reduce coal fines production, and (4) to effectively connect the wellbore to the natural fracture system of the coal reservoir. Various fracturing techniques, fluid types, and procedures have been developed for coals.[16]

Coal seam fracturing can be compared to hydraulic fracturing of a naturally fractured carbonate reservoir. In such a reservoir, the matrix permeability is very low, and virtually all of the productive capacity of the formation is controlled by the natural fracture system.[16] To stimulate a naturally fractured carbonate reservoir properly, one must interconnect the natural fracture system to the wellbore. In a coal seam reservoir, the same goal must be achieved. We must connect the cleat system to the wellbore. [16]

The complex stratigraphy of many coal seams complicates completion and stimulation procedures. In some areas, coal seams are relatively thick, uniform layers that are bounded by formations that are barriers to fracture growth. In other cases, however, coal seams occur in thin, multiple layers with essentially no barriers to vertical fracture growth between the seams.[16]

The fracturing procedures and fluids used to stimulate CBM wells differ from operator to operator in a single basin due to local characteristics of geology and to perceived advantages of cost, effectiveness, production characteristics, or other factors. Moreover, CBM projects in different basins may share common rock types and characteristics, but the fracture stimulations treatment and fracture behavior may differ significantly.[16]

Aspects of induced fractures, such as fracture dimensions (height, length, and width), are affected by the different fracturing approaches taken by the operator. Generally, the larger the volume of fracturing fluids injected, the greater the potential fracture dimensions. Fluid injection rates and viscosity also affect fracture dimensions. The interconnected cleat system may cause the volume of fluid leakoff to be very large during a fracture treatment. In a permeable coal seam, high injection rates, large pad volumes, and solid fluid-loss additives are needed to pump a fracture treatment successfully.

If a hydraulically induced fracture has a relatively constant height due to a geologic layer acting as a barrier to fracture propagation, and if the fracture is forced to grow and increase in volume (through an increased volume of fracturing fluid), the fracture will mainly grow in length. Increasing fluid viscosity can increase the injection pressure, resulting in greater fracture width, and thus often shorter fractures. The type of stimulation treatment selected is a function of the depth, thickness, and permeability of a coal seam.[16] The different scenarios and the aspects of hydraulic design process are further discussed in Appendix B.

Fracture fluid selection is an important part of hydraulic fracture design. Fracture fluid selection is based on site-specific characteristics, including formation geology, field production characteristics, and economics. The fracture fluid should be able carry high proppant concentrations, and it should not damage the formation. Hydraulic fracturing operations vary widely with the types of fracturing fluids used, the volumes of fluid required, and the pump rates at which they are injected. We can classify hydraulic fracturing fluids used for coal bed methane wells as:

- plain water and potassium chloride (KCl) water;

- gelled fluids;
- foam;
- acids;
- gas; and
- hybrid (any combination of 2 or more of the aforementioned fluids).[10]

Water Fracturing

Either groundwater pumped directly from the formation or treated water is used for fracturing CBM wells. In some CBM well stimulations, proppants are not needed to prop the fractures, so simple water or slightly thickened water can be a cost-effective substitute for an expensive polymer or foam-based fracturing fluid with proppant. Plain water has a lower viscosity than gelled water, and thus, plain water has proppant transport capacity.[10] Hydraulic fracturing performance is not exceptional with plain water, but, in some cases, the production rates achieved are adequate and the lower costs make the well economical to produce. The proppant carrying capacity of water ranges from 1 to 2 ppg. The fracture conductivity attained by using water is good but not better than gelled fluids. The biggest advantage of using water fracturing is that it is cheap to use.[16]

Gelled Fluids

Two types of gelled fluids commonly used in coalbed methane wells are linear gels and cross-linked gels. Gelled fracturing fluids are used because they have a much better proppant carrying capacity than water and can thus attain better fracture conductivity. The most common problem faced with gelled fracturing fluids is the polymer residue left behind. This residue causes permeability damage to the coal.[10] To solve this problem, newer and better cleaning agents are being used with gelled fluids. These cleaning agents suppress the fines movement and plugging of the proppant packs due to coal fines production during CBM production. The disadvantage of using gelled fluid is that it is very expensive to use. The proppant carrying capacity of gelled fluid ranges from 5 to 12 ppg. Linear gel can carry up to 8 ppg, whereas cross-linked gel can carry as much as 12 ppg.[16]

Linear Gels

The most commonly used gelling agents in fracturing fluids are guar gum, guar derivatives such as hydroxypropylguar (HPG), and carboxymethylhydroxyprop-ylguar (CMHPG), or cellulose derivatives such as carboxymethylguar or hydroxyethylcellulose (HEC). Gelling agents are biodegradable in nature.[11]

Cross-linked Gels

Cross-linking agents may be added to linear gels to form high-viscosity fracturing fluids called cross-linked gels. Cross-linked gels provide higher proppant transport performance than do linear gels. Cross-linking reduces the need for fluid thickener and extends the viscous life of the fluid indefinitely. The fracturing fluid remains viscous until a breaking agent is introduced to break the cross-linker and, eventually, the polymer. [11] Cross-linked gels are normally metal ion-cross-linked guar. Metal ions such as chromium, aluminum, titanium, and others are used to achieve cross-linking.[11]

Foam

Foam fracturing technology uses foam bubbles to transport and place proppant in fractures. The most widely used foam fracturing fluids employ nitrogen or carbon dioxide as their base gas. Incorporating inert gases with foaming agents and water reduces the amount of fracturing liquid required. Foamed gels use fracturing fluids with higher proppant concentrations to achieve highly effective fracturing. The gas bubbles in the foam fill voids that would otherwise be filled by fracturing fluid. The high concentrations of proppant allow for an approximately 75-percent reduction in the overall amount of fluid that would be necessary using a conventional linear or cross-linked gel. Foaming agents can be used in conjunction with gelled fluids to achieve an extremely effective fracturing fluid. They are more generally used in cases where there is low water content in the coal cleats and low reservoir pressure gradients (less than 0.2 psi/ft).[10] Gelled foams have a proppant carrying capacity of up to 8 ppg. Some of the advantages of using foam as fracturing fluid are that it causes less permeability damage because less fluid is involved, and it has better cleanup than gelled fracturing fluids. Foam fracturing is expensive, and thus, the use has to be justified economically.

Acid Fracturing

Acids are used in limestone formations that overlay or are inter-bedded within coals to dissolve the rock and create a conduit through which formation water and CBM can travel.[11] The stimulation fluid is hydrochloric acid or a combination of hydrochloric and acetic or formic acid. For acid fracturing to be successful, thousands of gallons of acid must be pumped far into the formation to etch the face of the fracture. Some of the cellulose derivatives used as gelling agents in water and water/methanol fluids can be used in acidic fluids to increase treatment distance. Acids may also be used as a component of breaker fluids, and they can be used to clean up perforations of the cement surrounding the well casing prior to fracture fluid injection.[10]

Gas Fracturing

When coal comes in contact with water it may swell, closing the cleats and causing the formation to loose permeability. Therefore, CO_2 or N_2 may be used as the fracturing fluid in CBM reservoirs that have water-sensitive coal.[35] A coiled tube is usually used to pump these fluids. All these variations of hydraulic fracturing fluids are used in North American coal basins **(Table 3).**

CBM Drilling, Completion and Stimulation Practices in N.A. Basins

In this section, I summarize the drilling, completion, and stimulation practices that are used in N.A. basins. Also, I describe the geological characteristics that influence the selection of drilling, completion and stimulation methods in each basin.

Black Warrior Basin

Estimated CBM reserves in the Black Warrior Basin are approximately 20 Tcf, with approximately 4.35 Tcf technically recoverable gas.[38] CBM production in the Black Warrior Basin is from the Pennsylvanian age Pottsville formation. Most CBM wells are completed in the Black Creek, Mary Lee, and/ Pratt cycles, and well depths range from 350 to 2,500 feet deep.[40] Net coal thickness varies from 6 to 30 ft. The distance between the coal seams and coal cycles varies from place to place in the basin (**Table 4**).

Table 3: Fracturing fluids used in CBM operations in N.A. basins[5,6, 7,10, 26,36,37,38.39,40]

Basin	Formation	Thickness (ft) of coal (all formations)	Completion Depths (ft)	Fracturing Fluids Used
San Juan	Fruitland	20-40	500-5000	Slick Water, Cross Linked Gels, N_2 and CO_2 Foam
Black Warrior	Pottsville (Mary Lee/Pratt/Black Creek)	2-20	800-3500	Water, Linear Gel, Cross Linked Gel
Piceance	Mesaverde	5.5-12.1	2300-6500	Water, Linear Gel
Uinta	Mesaverde	10-50	1200-4400	Cross-Linked Gel
Powder River	Wasatch, Fort Union	15-100	0-1000 400-1800	Water
Central Appalachian	Pocahontas		100-.3500	Foam, Water
North Appalachian	Pottsville, Allegheny, Monongahela	<1-8	1030-6570	Water, N_2 Foam
Arkoma	Hartshorne, McAllister	2-12	611-2300	Linear Gel, N_2 Foam
Cherokee	Weir-Pittsburgh, Riverton	2-5	400-1350	Linear Gel, N_2 Foam
Raton	Vermejo, Raton	5-35	1500-2500	Linear Gel, Water
Alberta	Horseshoe Canyon	1.5-9.8	490-2800	N_2 & CO_2 Gas

CBM wells in this basin are mostly vertical, and the completions are cased hole.[7] Hydraulic fracturing is used for stimulation in all wells.[14] Depending on the distance between the seams, fracture treatments are either single stage or multi-stage. When the distance between the seams is more than 40 ft, then multiple stage completion is preferred.[25]

Horizontal wells have been tried in Black Warrior basin but were not found to be economical[7]. CBM production began in Black Warrior basin as an attempt to degasify coals in advance of mining. By the early 1980s, CBM development was advanced in the basin. In the early 1980's slick water fracturing was performed to produce CBM in Brookwood field[5]. In the late 1980s, linear gel was tried in the basin but it was not successful. This was attributed to the gel damage caused to the coals. Until the beginning of 2000s, water fracturing was considered to be the best fracturing method in the Warrior basin. But with the development of better gel cleaning agents, like SandWedge, gel has become the most commonly used fracturing fluid.[15] The most effective fracturing fluid in Black Warrior basin is cross linked gel with gel-cleaning agent.[30] Stimulation treatments may be designed for single seam or multiple seams, based on the distance between the seams.[30] The geological parameters that make cased hole completion successful in this basin are the depth of occurrence, the thickness of the coal seams, the gas content, and the permeability of the coal seams **(Table 5)**.

Table 4: CBM reservoir properties of N.A. basins [16,18,36,37,38,39,40,41,42,43,44,45,46,47,48,49,5

Basin	WCSB (Hs. Canyon)	Black Warrior Basin	Central Appalachian Basin	North Appalachian Basin	Cahaba Basin	Arkoma Basin	Cherokee Basin	Forest City Basin	Powder River Basin	San Juan Basin	Uinta Basin	Piceance Basin	Raton Basin
Depth (ft) (Min)	490	800	100	1030	2500	611	400	720	400	500	1200	2300	1500
Depth (ft)(Max)	2800	3500	3500	6570	9000	2300	1350	2096	1800	5000	4400	6500	2500
Thickness of coal formation (ft) (Min)	10	1	2	2	7	3	2	2.1	70		4	80	2
Thickness of coal formation (ft) (Max)	66	10	12	20	45	7	25	22	150		48	150	35
Coal Rank (Min)	Sub Bit	HV	MV	HV	HV	MV	HV	HV	Lignite	Sub Bit	HV	HV	HV
Coal Rank (Max)	HV	LV	LV	LV	LV	LV	MV	MV	Sub Bit	LV	LV	Anthracite	LV
Gas Content (scf/tn) (Min)	64	125	285	26		73	28	50	25	100	187	25	4
Gas Content (scf/tn) (Max)	448	680	573	445	380	570	444	435	75	600	443	750	810
Porosity (Min)	1	1	1	1						1	1	1	1
Porosity (Max)	3	2	3	3.5						3	2	3	3
Permeability(md) (Min)	1	0.01	0.01	0.01	0.01	1	0.01	0.01	1	1	0.01	0.01	0.01
Permeability(md) (Max)	15	40	40	40	40	30	500	500	1000	60	100	50	120
Reservoir Fluid Saturation (%) (Min)	0	80	50	50		50	50	50	100	100	50	50	50
Reservoir Fluid Saturation (%) (Max)	10	100	100	100		100	100	100	100	100	100	100	100
Reservoir Pressure (psi)/(psi/ft) (Min)	0.18	70	0.35	0.3		205	0.4	0.4		1500	0.45	0.45	< .43
Reservoir Pressure (psi)/(psi/ft) (Max)	0.5	420	0.43			600				2000			
No of coal seams	4	3	9	6		7	6	13	6	2	2	3	3

Table 5: U.S. CBM basins and engineering practices [9,10, 15, 16, 24, 25, 32,33, 34, 35, 36, 37,44,48]

Basin	Key Reservoir Parameters	Value Range	Drilling Method	Completion Methods	Stimulation Methods
Black Warrior	No. of Seams	3	Vertical	Cased Hole Completion Single Seam Single Stage, Cased Hole Completion Multi Seam Multi Stage	Cross Linked Gels Fracturing with Proppant,
	Net Seam Thickness (ft)	1- 10			Water Fracturing with Proppant,
	Depth of Occurrence (ft)	800 - 3500			Linear Gels with Proppant
	Gas Content (scf/t)	125 - 680			
	Permeability (mD)	0.01 - 10			
	Vertical Separation (ft)	20 - 100			
Central Appalachian	Net Seam Thickness (ft)	2 - 12	Vertical,	Cased Hole Completion Single Seam Single Stage,	Water Fracturing with Proppant,
	Depth of Occurrence (ft)	100 - 3500	Horizontal	Single Lateral with liner,	Foam Fracturing with Proppant
	Gas Content (scf/t)	285 - 573		Single Lateral without liner, Multi Lateral Pinnate Pattern	
	Water Saturation (%)	80 - 100			
	Coal Rank	MV - LV			
	Permeability (mD)	0.01 - 40			
	Reservoir Pressure (psi)	0.35 - 0.43			
Northern Appalachian	Net Seam Thickness (ft)	2 - 20	Vertical,	Cased Hole Completion Single Seam Single Stage,	Water Fracturing with Proppant,
	Depth of Occurrence (ft)	1030 - 6570	Horizontal	Single Lateral with liner,	Foam Fracturing with Proppant
	Gas Content (scf/t)	26 - 445		Single Lateral without liner, Multi Lateral	
	Water Saturation (%)	50 - 100			
	Coal Rank	HV - LV			
	Permeability (mD)	0.01 - 40			
	Reservoir Pressure	0.3 - 0.45			
Arkoma	Net Seam Thickness (ft)	3 - 7	Vertical,	Cased Hole Completion Single Seam Single Stage,	Cross Linked Gel Fracturing,
	Depth of Occurrence (ft)	611 - 2300		Single Lateral with liner,	Foam Fracturing with Proppant
	Gas Content (scf/t)	73 - 570		Single Lateral without liner, Multi Lateral, Pinnate Pattern	
	Water Saturation (%)	50 - 100	Horizontal		
	Coal Rank	MV - LV			
	Permeability	1 - 30			
	Reservoir Pressure (psi)	< 0.4			
Cherokee	Depth of Occurrence (ft)	400 - 1350	Vertical	Cased Hole Completion Single Seam Single Stage	Water Fracturing with Proppant,
	Gas Content (scf/t)	28 - 444			Foam Fracturing
	Water Saturation (%)	50 - 100			
	Coal Rank	HV - LV			
	Permeability (mD)	0.01 - 100			
	Reservoir Pressure (psi)	< 0.4			
Forest City	Depth of Occurrence (ft)	720 - 2096	Vertical	Cased hole Completion Single Seam Single Stage,	Water Fracturing with Proppant,
	Gas Content	50 - 435			Foam, Fracturing with Proppant
	Water Saturation (%)	50 - 100			
	Coal Rank	HV - LV			
	Permeability (mD)	0.01 - 100			
	Reservoir Pressure (psi)	< 0.4			
Powder River	Depth of Occurrence (ft)	400 - 1800	Vertical	Topset Under Ream,	Water without Proppant,
	Net Seam Thickness (ft)	70 - 150			
	Permeability	1 - 1000			
	Coal Rank	Sub Bit - LV			
	Gas Content (scf/t)	25 - 70			
San Juan	Depth of Occurrence (ft)	500 - 5000	Vertical,	Cased Hole Completion Single Seam Single Stage, Cased Hole Completion Multi Seam Single Stage, Open Hole Cavity, Single Lateral	Cross Linked Gel with Proppant,
	Permeability (mD)	1 - 60			
	Coal Rank	Sub Bit			
	Gas Content (scf/t)	LV	Horizontal		
	Compressive Strength of Coal	0 - 2000			
	No. of Seams	2			
	Net Seam Thickness	20 - 80			
	Vertical Separation (ft)	10 - 50			
Uinta and Piceance	Depth of Occurrence (ft)	2000 - 6000	Vertical	Cased Hole Completion Single Seam Single Stage, Cased Hole Completion Multi Seam Single Stage, Cased Hole Completion Multi Seam Multi Stage,	Cross Linked Gels Fracturing with Proppant,
	Permeability (mD)	0.01 - 100			Water Fracturing with Proppant,
	Coal Rank	HV - Anthracite			
	Gas Content (scf/t)	25 - 750			
	No. of Seams	3			
	Vertical Separation (ft)	3 -30			
Raton	Depth of Occurrence (ft)	1500 - 2500	Vertical	Cased Hole Completion Single Seam Single Stage, Cased Hole Completion Multi Seam Single Stage, Cased Hole Completion Multi Seam Multi Stage	Cross Linked Gels Fracturing with Proppant,
	Permeability (mD)	0.01 - 120			Foam Fracturing with Proppant
	Coal Rank	HV - LV			
	Gas Content (scf/t)	4 - 810			
	No. of Seams	3			
	Vertical Separation (ft)	10 - 50			
Western Canada Sedimentary	Depth of Occurrence (ft)	490 - 2800	Vertical	Cased Hole Completion Single Seam Single Stage, Cased Hole Completion Multi Seam Multi Stage	Gas (CO2 or N2) without Proppant,
	Permeability (mD)	1 - 15			Gas(N2) with Proppant
	Coal Rank	Sub Bit - HV			
	Gas Content (scf/t)	64 - 448			
	Water Saturation (%)	0 - 5			
	Reservoir Pressure	0.18 - 0.5			
	No. of Coal Seams	10 - 30			

Central Appalachian Basin

For the Central Appalachian basin the estimated recoverable gas is 2.4 Tcf.[36] The Central Appalachian coal basin has six Pennsylvanian age coal formations.[41] Coal typically occurs in multiple coal bed that are widely distributed. Most of the CBM occurs in Pocahontas formation coal seams.[39] The Pocahontas No. 3 and 4 seams are the most targeted coal seams for CBM production in the Central Appalachian basin. Both horizontal and vertical CBM wells are common in this basin (Table 4).

The most common CBM completion method in the Central Appalachian coal basin is the cased-hole completion with hydraulic fracture stimulation.[15] Horizontal wells have also been successful in parts of the basin.[15] Also, some pinnate wells have been drilled by CDX gas.[33] The selection of completion method depends on the local geology and vintage of the wells. Horizontal or pinnate wells are more likely to be recent wells.

The type of fracturing fluid used in the Central Appalachian Basin varies with depth of the targeted coal seam, In the shallow regions of the north side of the basin, where the depth of the coal seam is less than 500 ft, water saturation of the seams is high, and the most common fracturing fluid is used is slick water.[30] The fracture treatment includes proppant. However, in the deeper part of the basin, where the water saturation of the seams is lower, foam with proppant is the most common method used for fracturing.[30] The geological parameters that contribute to the selection of the completion and stimulation method in this basin are the depth of the coal seam, water saturation, coal rank, gas content, and the thickness of the formation (Table 5).

Northern Appalachian Basin

The coal zones in the Northern Appalachian basin are the Brookville-Clarion, Kittanning, Freeport, Pittsburgh, Sewickley, and Waynesburg.[41] CBM is produced from Kittanning and the Pittsburgh groups.[36] The geology of the Northern Appalachian basin suits the drilling of both horizontal and vertical wells (Table 4).

The completion and stimulation methods used in the Northern Appalachian basin are similar to those of the Central Appalachian basin, as the geologic parameters are quite similar. Currently, a number of horizontal wells have been drilled in Northern Appalachian basin.[30] Both lined and unlined horizontal wells have been drilled, based on the operator preference, but lined wells have been more stable and thus more productive in the longer run.[34] The geological parameters that contribute to the selection of the completion and stimulation method in this basin are the depth of the coal seam, water saturation, coal rank, gas content, and the thickness of the formation (Table 5).

Arkoma Basin

In the Arkoma Basin, major coal beds occur in the Hartshorne, McAlester, Savanna, and Boggy formations.[42] The Hartshorne coals are the most important for methane production in the Arkoma Basin. Their depth ranges from 600 to 2300 ft.[36] Coal reservoir geology in the Arkoma basin is amenable to drilling either vertical or horizontal wells (Table 4).

Most wells drilled during the early development of CBM in this basin were vertical wells.[15] The cased hole completion type was used to complete these wells, and they were stimulated using hydraulic fracturing. Cross linked gel is the most common fluid used for hydraulic fracturing in the Arkoma basin.[15] Foam fracturing has been successful used in some CBM wells.

Recently, horizontal CBM wells with liners have become the most successful method of completion in the Arkoma basin.[34] More than 200 horizontal wells have been drilled in the basin. Gas recovery ranges from 50% to 80% for these wells.[32] Horizontal wells drilled in the pinnate pattern have also been successful in the Arkoma basin.[33] The thin coal seams have made horizontal wells the most suitable method of CBM production in this basin. The depth of occurrence coal seams and low coal permeability (Table 5) also make horizontal drilling the favored method in this basin.

Cherokee Basin

In the Cherokee Basin, targeted coal seams are the Riverton Coal of the Krebs formation and the Weir-Pittsburg and Mulky coals of the Cabaniss formation.[43] The Pittsburg coals and the Mulky coals are the primary contributors to CBM. The geology of the basin favors the drilling of vertical wells for CBM production (Table 4).

CBM wells in the Cherokee Basin are vertical, cased-hole completions. Well spacing in the basin is 80 acres. Hydraulic fracturing is used for stimulation in all CBM wells.[10] The most common hydraulic fracturing technique uses foam and slick water as fracturing fluids.[10] The choice of the fluid depends on the water saturation of the target coal seam. Some other key reservoir parameters that make cased hole completion with hydraulic fracturing as the method of choice in this basin are rank of coal, depth of occurrence, gas content and permeability of the formation (Table 5).

Forest City Basin

The Cherokee group coals are the primary targets for CBM wells in the Forest City basin. Individual coal seams in the Cherokee Group are commonly a few inches to about 4 ft thick, with some seams as much as 6 ft thick.[43] The drilling, completion and stimulation methods used are quite similar to those of the Cherokee basin. In this basin, geologic parameters (Table 4) favor the drilling of vertical wells. The cased-hole completion is used in almost all wells. The wells are fracture stimulated using foam and slick water.[36] The key reservoir parameters that make cased hole completion with hydraulic fracturing as the method of choice in this basin are rank of coal, depth of occurrence, gas content and permeability of the formation (Table 5).

Powder River Basin

CBM development in the Powder River basin started in the late 1980s in the Wyoming part of the basin, and production slowly expanded to Montana in the early 1990s.[9] The CBM gas reserves in the Powder River basin have been estimated to be as much as 90 TCF in the Montana portion of the basin.[11] The Wasatch and Fort Union formations are the major CBM producing formations in Powder River basin.[9] The geology of the basin favors the drilling of shallow, vertical wells (Table 4). The Powder River basin is one of the few basins where the major quantity of the CBM produced is biogenic gas.

All the wells drilled in Powder River basin have been vertical. The completion method used in this basin is typically topset and under ream.[9] The gas reserves of individual wells is low, as the gas is mostly biogenic and coalbed gas content is low (30 to 70 scf/t).[50] Wells are drilled at a spacing of about 80 acres, and the coal seams are very shallow and economical to drill.[15] To stimulate the CBM wells, a small quantity of water is used without proppant, to remove the skin created by drilling. Some hydraulic fracture treatments have been tried in Powder River basin with insignificant improvement in the production.

Some of the unique geologic characteristics of this basin are the shallow depth of production, very thick coal seams, high coal permeability, low coal rank, and the low coalbed gas content (Table 5). The top set and under ream method has proven to be the most successful method of completion in this basin.

San Juan Basin

CBM has been identified as an economic resource for nearly 100 years, and it has been exploited in the San Juan basin since the 1950's.[9] The most important coal-bearing unit in the San Juan Basin is the Fruitland Formation.[44] CBM production is almost entirely from Fruitland formation coals, but CBM is also present in the Menefee formation.[44]

The San Juan basin is the greatest producer of CBM gas in the U.S. Wells is the fairway regions in the northern part of San Juan basin have the highest CBM production rates in the world. The unique geology of this region accounts for the exceptional CBM well performance of the fairway area (**Table 6).** CBM is produced from the other parts of the basin as well. Vertical wells are most common types of wells in the basin, but some horizontal wells have been successful.

Table 6: CBM reservoir properties of San Juan basin "Fairway" region [9, 39, 43, 44]

Parameter	Minimum	Maximum
Depth of formation (ft)	1000	3000
Net thickness of coal (ft)	50	70
Number of effective coal beds	2	
Water saturation (%)	100	
Gas Content (scf/t)	500	600
In-situ stress (psi)	2000	4000
Coal rank	High-Volatile A Bituminous	Medium-Volatile Bituminous
Cleat properties		
Permeability (mD)	10	60
Porosity (%)	1	3
Bottom hole pressure (psi)	92	3120
Natural fracture orientation	Northwest -Northeast	

In terms of completion types, the San Juan Basin can be divided into two main regions: the fairway region and the rest of the basin. Cased-hole well completions with single-stage fracture stimulation are the most common completion in most of the basin. Casing is cemented in place over the coal section. Every coal seam in the coal interval is perforated. The entire coal section is hydraulically stimulated using single-stage stimulation. The stimulation consists typically of 90,000 gallons of a high viscosity gel, and 200,000 pounds of sand.[26]

Openhole cavity well completions are the most common completion type in the fairway. Casing is set and cemented in place at the top of the coal interval. The coal interval is drilled out and left open. The well is stimulated using a cavitation process, in which air and water are injected into the well under high pressure.[44]

The pressure is rapidly released, causing the open-hole section to surge large volumes of gas, water and coal. The process is repeated until a stable cavity forms and maximum flow rates are achieved.[45]

The key reservoir parameters that influence the selection of completion method in San Juan basin include the reservoir pressure, rank of coal, permeability of the formation, depth of occurrence, distance between the seams, number of seams, and compressive strength of coal (Table 5).[45]

Uinta and Piceance Basins

The estimated total recoverable CBM reserves in the Uinta basin are approximately 10 Tcf.[47] Two major formations that contain CBM are the Ferron Sandstone member, which includes most of the present CBM production, and the Mesaverde Blackhawk formation, which has about 14 coal zones.[43]

In the Piceance basin, CBM reservoirs occur in the Upper Cretaceous Mesaverde Group.[47] Two-thirds of the CBM in this basin occurs in coals deeper than 5,000 ft.[47]

Similar drilling and completion practices are used in both basins. The reservoir properties favor vertical wells in these basins (Table 4). The Piceance basin has some of the deepest CBM wells in N.A.

CBM wells in these basins are completed using cased-hole completion and hydraulic fracturing. Both slick water and cross linked gel have been used for fracturing these wells. However, in regions of high permeability (> 10 mD), cross-linked gels have shown to perform better than slick water.

The primary CBM well completion practice in the Uinta Basin is a cased-hole completion with one or two stages of stimulations. CBM wells are drilled with air to total depth, with a 5.5 inch casing string cemented in place across the coal interval. Each coal seam is perforated. The wells are hydraulically stimulated using a high viscosity, cross-linked gel. A single well has one or two such treatments across a relatively large formation interval. Hydraulic fracture volumes are typically 50,000 gallons of gel and 50,000 to 90,000 pounds of sand per treatment.[26] The key reservoir parameters that influence the selection of engineering practices in this basin are the depth of the coal, the number of seams, the distance between the seams, water saturation and rank of coal (Table 5).

Raton Basin

The basin contains coal in the Upper Cretaceous Vermejo and Paleocene Raton formations.[10] The Vermejo formation has individual coal seams as thick as 14 ft, with cumulative coal thickness ranging from 5 to 35 ft; the Raton formation has net coal thickness from 10 to 120 ft.[44] The geology of this basin favors the drilling of vertical wells (Table 4).

The cased-hole completion is used with hydraulic fracturing to stimulate the wells. The most effective fluid used for fracturing in the Raton formation has been cross-linked gel.[30] All of the fracture stimulation is done with sand or resin-coated sand proppant. However, a small quantity of foamed gel is pumped in the formation in the early stages before using cross linked gel. This combination of the two treatments was found to be very effective. Thus, the basin uses a hybrid fracturing treatment. [15]

CBM wells are drilled underbalanced to limit formation damage. A 5½ -inch casing string is cemented in place to total well depth. Each coal seam is selectively perforated. Single coal seams and small intervals containing multiple coal seams are hydraulically stimulated. A single well will have between three and six stimulation stages, depending on the extent of coal development. The stimulation begins with a small acid break down. This is followed with a larger nitrogen foam breakdown and sand.[30] Cross-linked gel and sand are used in the last stimulation stage. The final stimulation stage consists of 200 to 400 barrels of gel and 20,000 to 40,000 pounds of sand.[30] The key reservoir parameters that influence the selection of engineering practices in this basin are the depth of the coal, the number of seams, the distance between the seams, and rank of coal (Table 5).

Western Canada Sedimentary Basin

The main CBM activity in the Western Canada Sedimentary (Alberta) basin is concentrated in the coals of Horseshoe Canyon, Ardley, Mannville, and the Mist Mountains formations.[48] In the Alberta plains region, CBM resources are estimated to be nearly 668.6 Tcf in the Mannville formation.[49] Horseshoe Canyon coals have an estimated 550 Tcf of gas.[49] These two formations are the most targeted for CBM production in this region. The unique feature of the Horseshoe Canyon coals is that they are very dry (Table 4). This property affects the drilling and completion design in this formation.

Wells drilled in the Western Canada Sedimentary basin are vertical wells. The completion method used is cased-hole completion. Gas fracturing has the most successful method of stimulating the wells.[15] No proppant is pumped with the gas. About 20 fracture stimulation treatments are performed for each well.[15] The different drilling and completion methods used and the key reservoir parameters that influence the selection of these methods are summarized in Table 6.

Industry Survey of CBM Drilling, Completion and Stimulation Best Practices

To clarify relations among the selection of drilling, completion and stimulation methods and geologic characteristics of coal beds, we reviewed pertinent literature and we queried industry experts. This approach assured that we were incorporating the latest engineering practices in our study. Industry experts from operating, service and consulting companies were selected on the basis of their expertise and the CBM basins in which they worked.

Questionnaire

A questionnaire was used to gather input from industry experts (Appendix D). To design the questionnaire, we used knowledge gained through literature review of the CBM drilling, completion and stimulation practices in different basins. We identified the critical geologic properties that influence these engineering decisions for CBM reservoirs. We asked the industry experts to rank the parameters that they feel influence their decisions to select drilling, completion and stimulation methods.

By asking participants to rank the parameters, we were able to identify a short list the critical geological parameters that should be considered when selecting the appropriate engineering technologies for CBM reservoirs. To determine the importance of the each parameter, we averaged the ranks assigned by experts.

Also, we also asked the experts to add any other parameter that they find important to consider when select appropriate drilling or completion methods.

Next, we listed the different CBM drilling, completion, and stimulation practices, and we asked the experts to rank the geological parameters they felt are important in selecting each. Also, we asked them to assign a range of values for the critical geological parameters.

Using the expert's responses, we made a list of the critical geologic parameters and the range of values suggested by them. In the questionnaire, we included a separate section to determine the geologic factors that influence the selection of hydraulic fracturing fluids for CBM wells. The questionnaire was sent to 22 industry experts; 6 experts completed and returned the questionnaire. The questionnaire is in Appendix D.

Experts' Opinions

The results of the survey indicate that, when selecting drilling, completion and stimulation types and stimulation fluids, most of the experts consider all the 13 factors that we listed in the questionnaire. The most important geologic parameters are depth of coal occurrence, thickness of coal seams, permeability, gas content and reservoir pressure. Some factors, such as dip of the coal seam, areal extent of the coal seam, and vertical offset of coal beds from aquifers, were added to our list of parameters, based on feedback from the experts.

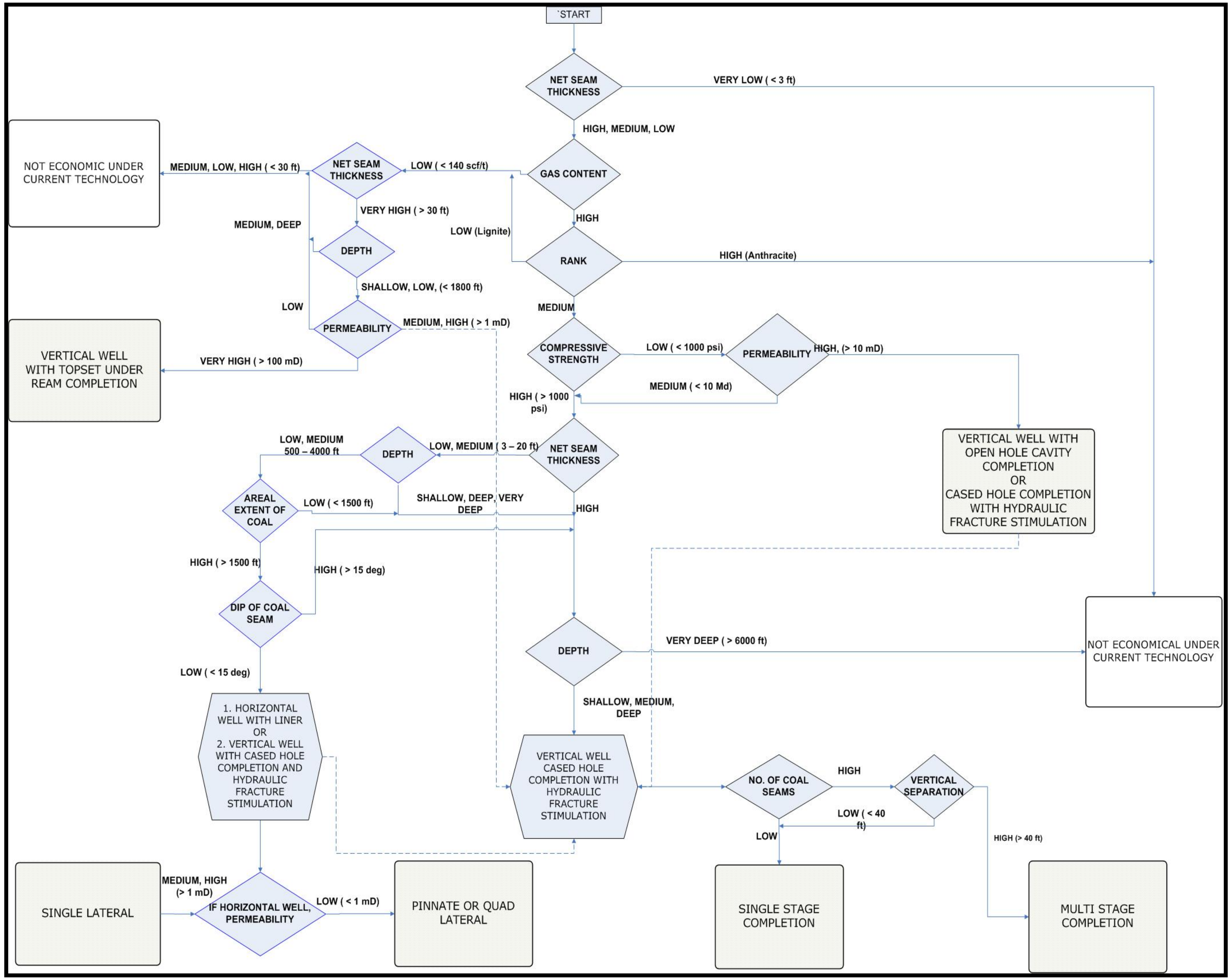
CHAPTER III

DISCUSSION AND RESULTS

Based on the industry response to our questionnaire and review of literature, I identified the drilling, completion and stimulation methods used in CBM reservoirs in North America. Also, I identified the geologic parameters that influence industry experts' decisions concerning the best CBM engineering practices for specific geologic settings. Using this knowledge, I made two decision charts. One chart is used to select the best drilling, completion and stimulation methods for CBM wells (**Fig. 15**), and the other is used to select the best fracture stimulation fluids to use in specific geologic settings (**Fig. 16**). These decision charts were captured in a software routine to facilitate their use (Appendix E).

Drilling and Completions Decision Chart

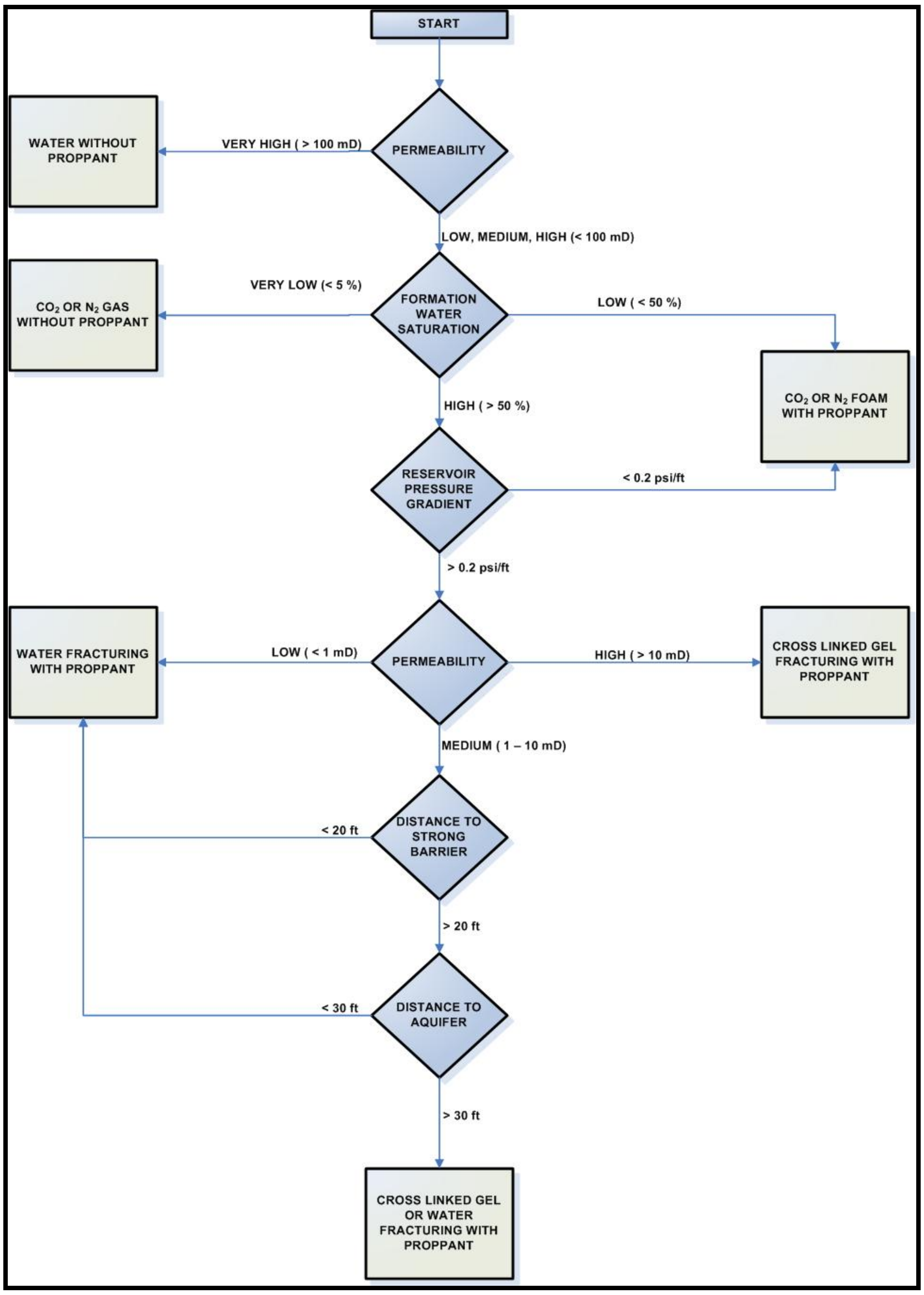
The decision chart for selecting the optimum drilling and the completion practices for CBM reservoirs (Fig. 15) used the following key reservoir parameters: net seam thickness; gas content of the coal seam; coal rank; coal seam depth; permeability; areal extent of coal; dip of the coal; number of coal seams; and vertical distribution of coal. Below is a brief explanation of importance of some of these key geologic parameters.



Decision Parameter Values Used in the Decision Chart

No. of Coal Seams	
Less	< 2
More	> 2
Dip of Coal Seam	
Low	< 15 deg
High	> 15 deg
Extent of Coal	
Low	1500 ft
High	> 1500 ft
Compressive Strength	
Low	0 – 1000 psi
High	> 1000 psi
Gas Content	
Low	0-140 scf/t
High	> 140 scf/t
Rank (Vitrinite Reflectance)	
Low	Lignite, Sub B (< 0.63 %)
Medium	HV, MV, LV (0.63 – 1.97 %)
High	Semi Anthracite, Anthracite (1.97 – 7 %)
Net Seam Thickness	
Very low	< 3 ft
Low	3 ft – 10 ft
Medium	10 ft – 20 ft
High	> 20 ft
Very High	> 30 ft
Permeability	
Low	< 1 mD
Medium	1 mD – 10 mD
High	10 mD- 100 mD
Very High	> 100 mD
Depth	
Shallow	0-500 ft
Low	500 ft – 1800 ft
Medium	1800 ft – 4000 ft
Deep	4000 ft – 6000 ft
Very Deep	> 6000 ft

Fig. 15: Decision chart for selecting the drilling and completion method



Reservoir Parameter Values used in the decision chart.

Permeability		**Formation Water Saturation**		**Reservoir Pressure**	
Low	-< 1mD	Very Low	-< 5 %	Low	< 0.2 psi/ft
Medium	-1mD – 10mD	Low	5 - 50 %	Normal/ High	>0.2 psi/ ft
High	- 10mD- 100mD	High	50 - 100 %		
Very High	- > 100mD				

Fig. 16: Decision chart for selecting the stimulation method

Net Seam Thickness

The net seam thickness influences the decision of whether to drill a horizontal well or a vertical well. It also influences in the decision of selecting some of the completion methods, such as the topset under ream method used in Powder River Basin (net seam thickness > 30 ft). For drilling horizontal wells, the industry response indicated that net seam thickness should range from 3 to 20 ft.

Gas Content of the Coal Seam

The gas content of the coal seam is important to the commercial success of the well. Only the Fort Union coals of the Powder River basin and Horseshoe Canyon coals of the Western Canada Sedimentary basin have successful CBM plays with gas content less than 140 scf /t. In both cases, coal seam permeability is high, the depth is shallow, and net seam thickness is very high. These factors help reducing the completion and stimulation costs, thus making these projects successful. We selected the value of 140 scf/t as the boundary between high and low CBM content on the basis of industry response to our questionnaire.

Coal Rank

Coal rank plays an important role in the gas content and cleats development, and thus permeability, of coal seam. Most CBM production is from high-volatile bituminous to low-volatile bituminous coals. Anthracitic coals have not had economic CBM production, to date. Only Powder River basin coals have had economic production from subbituminous rank coals.

Coal Seam Depth

Coal seam depth influences a number of decisions in drilling and completion of coal seams. To date, all CBM horizontal wells that have been drilled were in coal seams between of 500 and 4000 ft deep. Similarly, topset under ream, have been demonstrated successful only at depths less than 1800 ft. CBM has not been successfully produced from seams deeper that 6000 ft because of very low coalbed permeability.[15] CBM can be economically produced from depths greater than 6000 ft only if sweet spots can be identified.[15]

Permeability

Permeability is the most important factor in deciding whether to complete a CBM well. Also, it is important in deciding the type of completion and stimulation methods to be used.

Areal Extent and Dip

The areal extent and dip of the coal are important parameters to consider when deciding whether to drill horizontal wells. We selected cutoff values for these factors on the basis of industry responses.

Number and Vertical Separation of Seams

Knowledge of the number of coal seams and the vertical separation between them are used to decide between single-stage (single/ multi-seam), and multistage completion. The cutoff values of these key geological parameters for the different CBM practices are summarized in Table 7.

Table 7: CBM engineering practices cutoff values

Engineering Practice	Key Geologic Parameters	Cutoff - Values
Topset Under Ream	Depth of Coal Seam	< 1800 ft
	Coal Seam Thickness	> 30 ft
	Permeability	> 100 mD
Open Hole Cavity	Compressive Strength of Coal	< 1000 psi
	Permeability	> 10 mD
	Rank of Coal	HV - LV
Horizontal Well	Thickness of Coal Seam	3 - 20 ft
	Extent of Coal	> 1500 ft
	Dip of Coal	< 15 deg
	Depth of Coal Seam	500 - 4000 ft
Cased Hole Completion with Hydraulic Fracture Stimulation	Depth of Coal Seam	< 6000 ft
	Rank of Coal	HV - LV
Cased Hole Completion with Hydraulic Fracture Stimulation (Multi-Stage)	No of Coal Seams	> 2
	Vertical Separation	> 40 ft
Fracturing Fluids		
Water without Proppant	Permeability	> 100 mD
Gas with/ without Proppant	Water Saturation	< 5%
Foam with Proppant	Water Saturation	< 50 %
	Reservoir Pressure Gradient	< 0.2 psi/ft
Water with Proppant	Permeability	< 10 mD
Cross Linked Gel with Proppant	Permeability	> 1 mD
	Distance to Strong Barrier	> 20 ft
	Distance to Aquifer	> 30 ft

Application of the Drilling, Completions and Stimulation Decision Charts and Description of the Completion and Stimulation Methods

In the following discussion, I describe application of the Drilling and Completions Decision Chart (Fig. 15). Enter the chart at the top, with coal seam thickness. There have been no cases of economic CBM production where net coal thickness is less than 3 ft. Hence, there are no recommended completion methods for this case.

Next, the decision chart leads us to check gas content of the coal. For cases where gas content is less than 140 scf/t and the rank of coal is less than high-volatile bituminous, only the Powder River basin and Horseshoe Canyon CBM plays have been successful. Hence, where geologic conditions are not similar to those plays, we concluded that CBM gas cannot be economically produced.

If the gas content is low (<140 scf/t), we checks the net coal thickness and the depth of the coal. If the net seam thickness exceeds 30 ft and coal depth is less than 1800 ft, we evaluate coalbed permeability. If the permeability exceeds 100 mD, then Powder River basin conditions are satisfied, and we conclude that topset under ream completions are appropriate. If the permeability exceeds 1 mD but is less than 100 mD, then Horseshoe Canyon conditions are satisfied, and we concluded that a vertical well with cased-hole completion is an option.

If net coal thickness is less than 30 ft or the depth exceeds 1800 ft where gas content is less than 140 scf/t, then we conclude that the economic gas production cannot be achieved.

Topset Under Ream

The topset under ream CBM completion is used exclusively in the Powder River Basin. Powder River basin is characterized by high permeable, low rank, low gas content, shallow and thick coals (Table 5). As the coals are shallow the drilling cost is less. The wells are left openhole. As the coals are highly permeable the coals the cost of stimulation involved is also less. The average coal thickness in the basin is more than 30 ft, which makes it economical to produce (high gas volume) even though the gas content is very low. The main geological parameters that effect the selection of this method are depth of the coal seam, thickness of the coal seam and permeability (Fig.15). This method is successful in developing low rank and low gas content coals.

The low drilling, completion and stimulation costs associated with this method make this method successful even though the gas content and the rank of coal are low. We conclude that when the gas content and the rank of coal are low, hence topset under ream method is most successful if the reservoir is shallow, thick and highly permeable (permeability > 100 mD).

Semi-Anthracite and Anthracite

For the cases where coal rank is semi-anthracite or anthracite, gas content may be high, but the rates of gas desorption rates and permeability are very low. To date, there been no successful CBM projects from these high rank coals. Hence, we conclude that it is not economical to complete CBM wells under these conditions.

Moving down the Decision Chart (Fig. 15), we check the compressive strength of the coal. If it is less than 1000 psi, we check the permeability. If permeability exceeds 10 md, then San Juan basin fairway conditions are satisfied, and openhole completions should be considered.

Openhole Cavity Completion

The main geologic factors that make the open hole cavity completion successful have been identified as the low compressive strength of coal, high permeability, high gas content and reservoir overpressure (Tables 4 and 5). Apart from the fairway of the San Juan basin, this completion type has been successful in one part of the Bowen basin, Australia. In all cases it has been successful where compressive strength of the coal is less than 1000 psi and permeability was greater than 10 mD (Fig.15).

We conclude that, if the compressive strength of coal is less than 1000 psi and permeability ranges from 10 mD to 100 mD, cavity completion method is an option (Fig. 15). In cases where cavity completion is successful, cased-hole completions with hydraulic fracture stimulation are a viable option for completing the CBM well. The decision to select either openhole cavity completion or cased-hole completion is based on the operator choice, availability of equipment, and the cost involved.

Where the permeability is less than 10 mD and the compressive strength is greater than 1000 psi, we check net coal thickness (Fig.15). If net coal thickness ranges from 3 to 20 ft, we check depth and areal extent of the coal and the dip of the coal seam. If the depth ranges between 500 and 4000 ft, areal extent of the coal is greater than 1500 ft, and dip is less than 15 degrees, then the conditions are good for drilling horizontal wells.

Horizontal wells

Horizontal CBM wells have been used successfully in the Appalachian, Arkoma, and some parts of San Juan basin. Coal seam thickness varies from 3 to 20 ft in both the Appalachian and the Arkoma basin (Table 4). Depth ranges from 500 to 4000 ft, and gas content exceeds 140 scf/t in both basins. From the industry response to the questionnaire, we conclude that coal should extend at least 1500 ft from a well, and coal seam dip should be less than 15 degrees. Thus, depth, thickness, areal extent, and dip of the coal seam are the main geologic factors that decide the selection of drilling horizontal wells.

We conclude that a horizontal well completion is an option when the thickness of the coal ranges from 2 to 20 ft, the areal extent of the coal is more than 1500 ft, the depth ranges from 500 ft to 4000 ft, and the coal seam dip is less than 15 degrees (Fig.15).

Horizontal well production rates are 5 to 10 times greater than those of vertical wells. However, in cases where cases horizontal well are successful, vertical wells with cased holes and hydraulic fracture stimulation have been found to be successful also in San Juan basin, Arkoma basin and the Appalachian basins.

If the decision has been made to drill a horizontal well, then further decisions may be made concerning whether to drill a single lateral or multilateral well, based on the permeability of the coal.

Multilateral/Pinnate Wells

Multilateral wells in pinnate pattern have been drilled in Arkoma and Appalachian basins. In addition to the conditions that are needed for drilling horizontal wells, multilateral wells have been drilled in low-permeability coals (< 1 mD). Other geologic conditions to consider when selecting pinnate wells are coal that is free of intrusions and other geological structures, such as folds and faults. We conclude that, if the conditions for horizontal wells are satisfied and the permeability of the coal is less than 1 mD, then drilling multilateral wells is the best option.

For cases where coal depth exceeds 4000 ft or is less than 500 ft, areal extent of coal is less than 1500 ft, and/or coalbed dip is greater than 15 degrees, we check whether coal depth exceeds 6000 ft, and if so, we conclude that CBM production is not economical, based on experience to date (Fig.15). For all the other remaining conditions, cased-hole completions with hydraulic fracturing are the best completion and stimulation method.

Cased Hole Completion

From previous chapter it is clear that the case hole method is used in all the CBM producing basins, other than the Powder River basin. This method has been used for producing gas from all types of coal seams other than low- and high-rank coals, high permeability coal seams (> 100 mD), and low gas content coals (< 140 scf/t) (Fig.15). It is used with hydraulic fracture stimulation. The type of hydraulic fracture design differs from basin to basin. The geologic parameters that influence selection of hydraulic fracture design are discussed later.

The cased-hole completion can be either a single-stage or a multi-stage completion. Multi-stage completion is used when stimulating more than one coal seam when seams are separated by more than 40 ft, such as in the Black Warrior, Raton and Uinta basins. Hence, we conclude that the cased-hole completion with hydraulic fracturing is a completion option when the gas content of the coal is more than 140 scf /t and permeability is less than 100 mD.

Stimulation Decision Chart

The decision chart for selecting the stimulation fluid for CBM reservoirs (Fig. 16) is based on the following reservoir parameters: permeability; water saturation; reservoir pressure; distance to aquifer; and distance to strong fracture barrier.

Water Saturation

Water saturation of the coal is important when deciding the selections of fracturing fluids. Foam fracturing is used for coals having low water saturation, such as those in the Western Canada Sedimentary (Alberta) basin. We selected the water saturation cutoff values (Fig 16 and Table 7) based on industry response.

Distance to Aquifer

Knowledge of distance to aquifer and distance to strong barrier are used to decide between the use of water fracturing or gelled fracturing. Again, the industry responses were used to select cutoff values for these parameters.

Cutoff values for the different fracturing fluids are summarized in Table 7. First, we check the Fluid Decision Chart for the permeability of the reservoir. If the permeability of the reservoir is very high (> 100 mD) then fracturing without proppant is the best option.

Fracturing without Proppant

This method of completion is used in the Powder River Basin to stimulate the wells when using Topset Under Ream completion method. It is used to improve the connectivity of the reservoir to the wellbore in very high permeability (> 100 mD) reservoirs. Permeability is the main deciding factor for using of this method. (Fig. 16)

Next, we check the Fluid Decision Chart for formation water saturation. If it is less than 5 %, then fracturing with gas is the best option. If the formation water saturation is less than 50 % but more than 5 %, then fracturing with foam and proppant is the best option (Fig. 16). Fracturing with foam and proppant is also the best option when the reservoir pressure gradient is less than 0.2 psi/ft.

Fracturing with Gas

Water saturation of the coal is the most important factor in deciding to use gas as the stimulation fluid. It is used in dry coals or coals that swell when they come in contact with water or other liquids. Fracturing with gas is used in the Horseshoe Canyon coals in the Western Canada Sedimentary Basin. These coals have zero to very low water saturation (Table 4).

Foam

Foam fracturing is used in the Appalachian, Arkoma, Cherokee, Forest City, and Raton basins. All of these basins are characterized by low formation pressure and low water saturation (Table 4), which are the two major factors in determining the use of foam as the fracturing fluid.

Where water saturation of coal reservoirs is high (> 50 %) and the reservoir pressure gradient is more than 0.2 psi/ ft, then fracturing with water or gelled fluids with proppant are both options (Table 7).

Water

Slick water has been used as a fracturing fluid in the Appalachian, Arkoma, Cherokee, Forest City, Black Warrior, Raton, and San Juan basins. In the zones where water is used for fracture stimulation in these basins, the reservoir is normally pressured or overpressured, water saturation is high, and permeability is less than 10 mD.

Cross-Linked Gels

Cross-linked gel has been used as a fracturing fluid in Appalachian, Arkoma, Cherokee, Forest City, Black Warrior, Raton, San Juan, Uinta, and Piceance basins. In the zones where cross linked gel fracturing is used in these basins, the reservoir is normally pressured or over pressured. Also, water saturation is high and permeability exceeds 1 mD. Also, other factors, such as distance to a strong fracture barrier and distance to the nearest aquifer are considered before using cross-linked gel as the fracturing fluid.

For cases where permeability of the formation is 1 to 10 mD, both water and cross-linked gel fracturing can be used as fracturing fluids (Fig. 16). Some other factors, such as distance to the nearest aquifer and distance to strong barrier, also influence selection of water or cross-linked gel as the fracturing fluid. However, the decision of selecting a fracturing fluid is dependent on the operator in these cases.

Based on the above decision charts, we developed a visual basic program for selection of drilling, completion and stimulation best practices for CBM reservoirs. The subroutine for this program is given in Appendix E.
On the basis of the experts' responses we note the following additional general practices that are common when stimulating vertical wells:

- the pre-pad volume pumped before a fracture job is approximately 30 to 40% of the total volume of the pad;
- the pad volume is about 10 to 20% of the total treatment volume;
- the total volume of fracturing fluid pumped is approximately 50 bbl/ft of net coal thickness;
- The injection rate of treatments ranges from 1 to 2 bpm/ft of net coal thickness;
- the type of proppant pumped is normally determined on the basis of targeted fracture conductivity value; and
- the size of the proppant normally used is 20/40 mesh, unless the permeability value is greater than 30 mD, in which case the mesh size used is 12/20.

Limitations of the Study

The data used for this study were from North American CBM drilling, completion and stimulation activities conducted primarily over the past decade. Therefore, the decision charts are applicable only to regions where the gas prices and engineering costs are similar to those in N.A. Because project economics are sensitive to gas prices, engineering practices and availability of technology that changes with time and location, the cutoff values used in the decision charts may have to be changed to fit specific projects.

CHAPTER IV

CONCLUSIONS

On the basis of the research results described in the thesis I offer the following conclusions.

- Drilling, completion and stimulation methods used in the CBM reservoirs differ from basin to basin, and areally within basins, owing to variations in geologic setting and coal seam properties.
- The key geologic parameters that affect selection and success of CBM drilling, completion and stimulation practices in CBM reservoirs are coal depth, thickness, areal extent, dip, permeability, rank, gas content, formation pressure, water saturation, and compressive strength, as well as vertical distribution of coal beds and distance to fracture barriers and aquifers.
- Review of literature and feedback from industry experts clarify which geologic parameters affect specific drilling, completions and stimulation decisions.
- The literature review and the industry opinions were used to identify engineering best practices for drilling, completing and stimulating CBM wells in specific geologic settings.
- The results of this research were used to develop decision charts to help engineers select the appropriate CBM drilling and completion methods for specific of CBM reservoir conditions.

- Topset under reamed openhole wells exist primarily in the Powder River basin. Key reservoir parameters and the associated range of values that influence the selection and the success of this method are:
  - depth <1800 ft;
  - permeability > 100 mD; and
  - thickness > 30 ft.
- The openhole cavity completion method is successful primarily in the fairway region of San Juan basin. Key reservoir parameters and the corresponding range of values that influence the selection and the success of this method are:
  - compressive strength < 1000 psi;
  - permeability > 10 mD; and
  - coal rank: high- to medium-volatile bituminous.
- Horizontal wells are successful in the Arkoma, Appalachian and San Juan basins. Key reservoir parameters and the corresponding range of values, that influence the selection and the success of this method are:
  - thickness of 3 ft - 20 ft;
  - areal extent of the coal ≥ 1500 ft;
  - dip of the coal seam < 15 degrees; and
  - depth of 500 ft – 4000 ft.
- Multilateral wells are successful in Arkoma and Appalachian basins. The key reservoir parameters that influence the selection of this method are

similar to those of horizontal wells. A key factor is that multilateral wells are successful where permeability is less than 1 mD.

- Multilateral horizontal wells drilled in pinnate pattern have the highest recovery efficiency of any type of CBM completion method with more than 85% recovery.
- The cased-hole completion with hydraulic fracture stimulation is the most commonly used completion and stimulation method and is applicable to all coalbed reservoirs having permeability value less than 100 mD.
- Results of the research were used to develop a decision chart for selection of fracture fluids for specific CBM reservoir conditions. The following are geologic parameters and the recommended stimulations method.
  - For coal beds having permeability greater than 100 mD – water fracturing without proppant.
  - For dry coals – gas fracturing is the best stimulation method.
  - For coal beds having low water saturation and low reservoir pressure – foam fracturing.
  - For coal bed reservoirs having permeability of 10 to 100 mD – cross-linked gel fracturing with proppant.
  - For coal beds having permeability less than 1 mD – water fracturing with proppant.

- For CBM wells that encounter more than one coal bed, multi-stage fracturing is the best stimulation method, if the seams are separated by a distance of more than 40 ft.

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APPENDIX A

OPENHOLE CAVITY COMPLETION

A conventional truck mounted drilling rig is used to drill a hole to 20-50 ft above the top of the reservoir using natural mud as the drilling fluid. Casing is set and cemented. Then, 200-500 ft of openhole interval is drilled with a conventional drill rig or a modified drilling rig. Drilling mud is not used in order to avoid chemical and physical damage to the coal seam. [43]

Four air compressors and two dual-stage air boosters are used to inject air for stimulation. A triplex pump is used to inject small volumes of water. To stimulate the well, 2000-3000 scf/min of air and air water mixture is injected into the well bore at a surface pressure of approximately 1500 psi. Then, a surface valve is opened to rapidly reduce the pressure and blow out water, coal, and gas (blowdown). The procedure is repeated until the wellbore is full of rock. Then, the wellbore is cleaned out. [44]

Then, the surface values are closed and the surface pressure is allowed to increase to a value less than about 1000 psi of the reservoir pressure and the well is shut in for about 15 to 30 min. Again, the valves are opened so that a blowdown occurs in the well. Air and water are swept in through the well to maintain the pressure in the wellbore.

Air-water mixture is continuously injected into the open-hole interval after every one to six hours. This is followed by a sudden release of pressure during production. This process causes tensile fractures extending from the wellbore. These fractures intersect the natural fractures (**Fig. A-1**).

The apertures of the induced fractures do not close as a result of partial propping of material due to the sudden changes in flow directions from the blowdown operation. Thus the improved conductivity is due to the increased linkage between the cavity and the natural fracture system. [43,44]

The natural limits to cavity size are the maximum pressure gradient that can be achieved with the available injection rate, and the decreasing depressurization rate on blowdown as the cavity enlarges. The geometry of cavity development is strongly influenced by the natural fracture system of the coal and the in-situ stress state. The anisotropic principal stresses produce less stable conditions and assists in cavity development (Fig. A-1).[43]

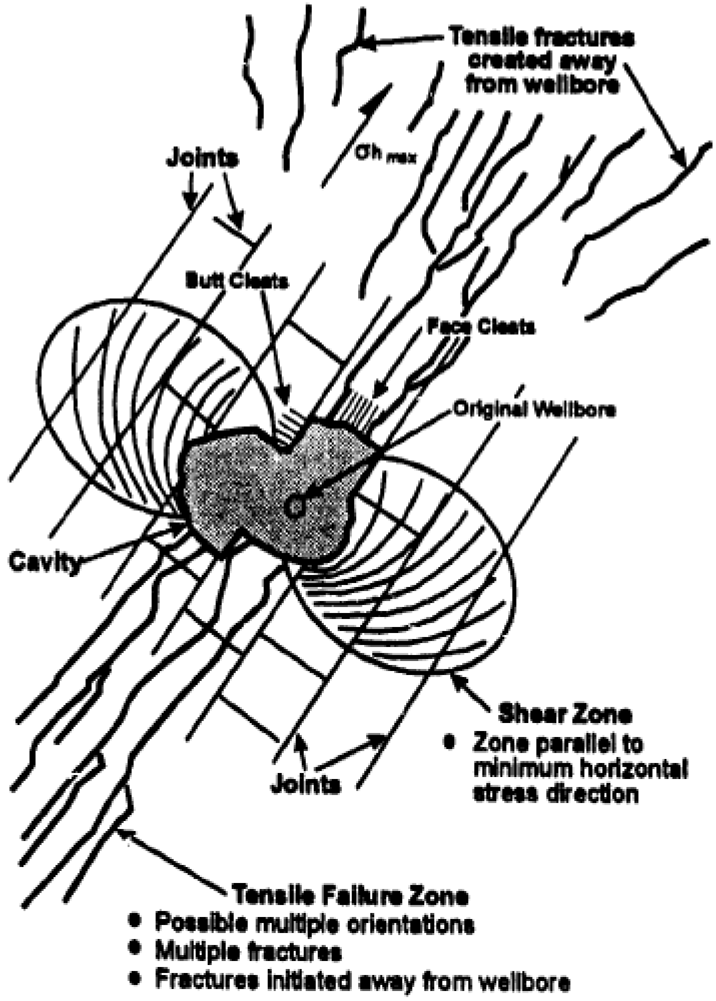

Fig. A-1: Orientation of shear and tensile stress during cavity creation. [43]

Cavity formation increases the kinematic degrees of freedom for displacements on structures around the cavity during cyclic injection and blowdown.[43] In highly permeable coals that are more naturally fractured and friable, dynamic energy release during blowdown assists the loosening of structures in the near region, and also in the removal of fines.[29] The fracture displacement extends far beyond the boundaries of the cavity. Since conductivity of fractures is highly sensitive to fracture aperture, potential exists for significant enhancement of permeability by this mechanism.[29]

APPENDIX B

HYDRAULIC FRACTURE DESIGN

Fracture Scenarios

Four fracture stimulations scenarios are commonly observed. These are:

Scenario 1 - A shallow coal seam where the fracture will be horizontal;

Scenario 2 - A series of thin coal seams in a depth range where a single, planar, vertical fracture will be created;

Scenario 3 - A single, thick coal seam in which the hydraulic fracture will be confined entirely in the coal and a complex fracture system (multiple vertical or T-shaped fractures) will be created; and

Scenario 4 - A hydraulic fracture treatment in which the fracture initially will be confined within a single coal seam but later will propagate vertically into the bounding layers. [16]

Scenario 1 - Horizontal Fracture in Shallow Coal Seam

For this situation, the least principal stress is vertical. Therefore, the hydraulic fracture is initiated in the horizontal plane or parallel to bedding when the strata dip. Young's modulus for coal is approximately 100,000 to 500,000 psi as opposed to 2,000,000 psi or more in the surrounding strata. When abundant natural fractures are present in the coal, the "effective" Young's modulus of the coal seam is even lower. This results in a very wide fracture at early times in the treatment. However, because of the higher values of Young's modulus in the boundary layers, the effective modulus controlling fracture width in the coal increases as the fracture extends.[25]

Scenario 2 - A Single Vertical Fracture through a Series of Thin Coal Seams

Scenario 2 is analogous to a vertical hydraulic fracture in a layered clastic or carbonate reservoir. The presence of the coal will have little effect on the actual fracture treatment design other than the possibility of high leakoff into coal seams that have well developed cleat systems.[25]

When rapid height growth is expected early in the treatment, the location of the perforations is usually not critical. The hydraulic fracture propagates through the coal seam layers and interconnects the wellbore to the coal.[25]

Scenario 3 - A Complex Hydraulic Fracture Contained in a Single Thick Coal Seam

The most significant characteristic observed when a complex fracture is contained in a single, thick coal seam is the high treating pressure. Commonly, the pressure in the fracture increases rapidly when pumping begins and remains high during the treatment. The high treating pressure causes the creation of multiple vertical or T-shaped fractures near the wellbore.

This phenomenon can be summarized as described below.

1. Slip zones - Slip zones are created in the highly cleated areas immediately ahead of the fracture tip. Because of stress concentrations near the fracture tip, slip can occur that tends to absorb energy that otherwise would be used to propagate the fracture. The formation of a slip zone will result in increased injection pressures.[16]

2. Poroelastic effects - Because of the high fluid leakoff that can occur in a cleated coal, a significant backstress can develop during the treatment. As backstress increases, the injection pressure also increases.[16]

3. Coal fines plugging the fracture tip - If large volumes of coal fines are generated, fines may concentrate at the fracture tip and inhibit propagation.[16]

4. Coal fines entrainment in fluid - Coal fines will also remain entrained in the fluid and will cause the apparent viscosity to increase. Although this is a minor effect, the result will be a small increase in injection pressure.[16]

Scenario 4 - A Complex Hydraulic Fracture in a Thick Coal Seam That Propagates into Bounding Layers

Scenario 4 is a special case of either Scenario 3 or Scenario 1 and includes any of the complex fracture geometries previously described. As excess pressure increases because of complex fracture geometry, a vertical component could be initiated into the boundary layers at a point of weakness at the boundary interface. If this happens, the fluid escaping to the boundary layer could cause the fracture(s) in the coal to decrease in width, that could lead to a screenout if high concentrations of sand are being pumped when the vertical growth begins.[16]

Fracture Design

Fracture design parameters that can be controlled to affect the results of the fracture treatment are listed below.[16]

- Tubular goods
- Pad volume
- Fluid viscosity
- Injection volume
- Fracture fluid density
- Injection rate
- Fluid loss additives
- Proppant schedule
- Wellbore access to the coal through perforations, slotting or open-hole cleanout operations

Other properties that cannot be controlled but that must be measured or estimated for fracture treatment design are listed below.[16]

- Formation depth
- Reservoir pressure
- In-situ stress
- Formation modulus

- Formation porosity
- Created fracture height
- Formation permeability
- Net coal pay thickness
- Formation compressibility

Before designing the fracture the following approach is suggested.[16]

- Determine the most likely fracture scenario and orientation
- Estimate the most probable value of each design parameter
- Run a fracture treatment design model for a range of injection rates and volumes
- Determine the formation properties most likely to be in error and establish a range for each parameter
- Run the fracture design model, changing one parameter at a time

Data concerning the coal seam reservoirs are needed to estimate in-situ stress and fluid leakoff characteristics and to characterize the ability of the coal seam to produce.

General reservoir data needed to design a stimulation treatment include the depth to the coal seam reservoir, reservoir pressure, permeability, porosity, reservoir fluid saturations, reservoir fluid compressibility, formation compressibility, reservoir temperature, and well spacing.[16]

These reservoir parameters are used to calculate or estimate values of in-situ stress, fracture fluid leakoff coefficient or the productivity index increase ratio. The importance of these properties with respect to CBM production is discussed in Chapter II (Page No 17). These values need to be determined for fracture treatment design, including selection of the optimum propping agent and optimum size fracture treatment for a given coal seam. These "optimum" values are computed by using a reservoir model to predict post-fracture well performance and the economic benefit of various fracture treatment designs.[16]

Fluid loss control is critical to the success of a treatment when the coal contains abundant cleats. In the field, fluid loss control is achieved by using particulate fluid loss additives. Large pad volumes and high injection rates also improve the probability of success when high leakoff is a problem. The size of the pad used during a treatment is selected based on the expected fluid loss. In coals containing a well developed cleat system, large pad volumes are needed. As the amount of leakoff expected decreases, the size of the pad volume can also be decreased.[16]

Fracture Fluid Selection Criteria

The primary criteria used to select a fracturing fluid are the orientation of the natural fractures and proppant transport considerations. In shallow coal seams, horizontal fractures can sometimes be created. In deep coal seams, a single, vertical fracture or multiple, vertical fractures are usually created.

Horizontal Fractures

Horizontal fractures are generally created at depths less than 2000 ft.[16] In coal seams, the created fracture system is generally complex.[16] For horizontal fracture systems, a linear gel is the preferred fracture fluid.[16] A linear gel with moderate viscosity is better than ungelled water when considering only proppant transport; i.e., the ability to carry proppants deeply into the fracture from the wellbore.[26] Because of low gas content and low gas recovery in most of the shallow, low productivity coals, the gelling agent may not be affordable, and ungelled water is sometimes used by the operator.[16]

Cross-linked fracturing fluids are not recommended when horizontal fractures are expected.[16] Thick, viscous, crosslinked fluid tends to create a very wide fracture that reduces fracture penetration into the reservoir. If the fracture penetration distance is limited, the productivity of the well is limited, also. The best fluid in this case is linear gel that creates a fracture of moderate width.[16]

In most cases, medium-size pad volumes are used when one expects to create a horizontal fracture using linear gel. The size of the pad volume is dictated by the permeability of the coal and the volume of leakoff that is expected to occur in the cleat system.[16]

Vertical Fractures

When a vertical fracture is expected, a high viscosity fluid is needed to ensure that adequate proppant transport is achieved. Usually, a cross-linked gel is the best option. Commonly, guar or HPG fracturing fluids, cross-linked with borate or a time delayed cross-linking system are used.[16]

Cross-linked fluids minimize the detrimental effects of proppant settling, especially in cases when a vertical fracture is created that cuts through more than a single coal seam.[16] In a high-permeability coal system, high leakoff occurs, even when a cross-linked fluid is used. To combat high leakoff, pad volumes of 40-60% are recommended.[16] High injection rates improve results when high leakoff is expected. Usually, bridging fluid loss additives, in combination with a cross-linked fluid and a high pump rate, must be combined to fracture treat permeable coals successfully.[25]

Fluid Loss

Conventional fluid loss data for hydraulic fracturing fluids are not particularly applicable to fracturing of coal seams. Since the matrix of coal is basically impermeable, there is no appreciable leakoff into the matrix. Leakoff occurs in the cleat system in the coal. In highly cleated, high-permeability coal seams, the best method to minimize leakoff is to use very large injection rates. In permeable coals that are less fractured, bridging fluid loss additives and moderate injection rates is used to minimize the detrimental effects of fluid leakoff. In many cases, 100-mesh sand can be used effectively.[16]

C_t (Overall Fluid Loss Co-efficient) values in the range of 0.001 to 0.01 ft/sqrt(min) are normally used for coal. The value of C_t used in fracture design is affected by the expected value of permeability. If the coal appears to be relatively tight and with low permeability, the value of C_t = 0.0005 ft/sqrt(min) is appropriate.[16] For a high permeability coal, the value of C would increase. Spurt loss is also very high in permeable, cleated coals. Large pad volumes and 100 mesh sand are used to minimize the effects of high spurt loss.[16] Excessive leakoff usually occurs when the hydraulic fracture is completely contained with the coal seam. If the fracture breaks out of the coal vertically, then lower leakoff occurs as the vertical component propagates through less permeable formations.

Proppant Selection

The selection and use of proppants in coal seams involves different criteria than for fracturing sandstone or limestone formations. The main objective when fracturing a coal seam is to interconnect the cleat system with the wellbore. In a typical coal seam, there is little or no permeability in the coal matrix. Therefore, the gas flows to the wellbore through the cleat system. An extremely high conductivity fracture is not necessarily needed; rather, a proppant pack that interconnects as many of the cleats as possible is needed. Even though large diameter proppants are more permeable than smaller mesh proppants, the "extra" conductivity is not beneficial if the proppant cannot be placed in the fracture properly.[16]

It is better to use smaller mesh proppants in coal beds, that can be transported further into the formation and connect more cleats to the well than to use large mesh proppants that cannot be properly placed in the fracture. Therefore, small diameter proppants are preferred, particularly in the early stages of the treatment, to achieve deep penetration and to interconnect the cleat system with the wellbore.[16]

The closure stress on the proppant in shallow coal seams is usually very small. Therefore, proppant crushing or embedment is not a cause for concern. The major considerations in proppant selection for coal seams include (1) problems with proppant flow back, (2) achieving deep penetration into the coal seam and (3) minimizing the flow back of coal fines. [16]

Proppant sizes of 12/20 mesh or larger have been pumped to allow the coal fines to migrate through the proppant pack and be produced. The small mesh proppants can be used to minimize the movement of fines. For example, 100 mesh proppant, followed by 40/70 mesh, then 20/40 mesh have been used. The 100 mesh sand penetrates deeply into the coal. The 40/70 mesh prevents flow back of the 100 mesh. The 20/40 mesh proppant provides high conductivity near the wellbore. In areas where proppant production is a problem, curable resin coated 20/40 mesh sand works well in keeping the proppant from being produced into the wellbore.[16]

When low viscosity fracturing fluids are used, smaller mesh proppants are recommended.[16] To achieve deep penetration of proppants using low viscosity fluids, 100 mesh, 40/70 mesh or 20/40 mesh proppants can be used.[16] When low viscosity fluids are used, proppant settling occurs rapidly, and a proppant bed is created near the wellbore. [16]

APPENDIX C

PINNATE WELLS

The Z-Pinnate Drilling and Completion Technology™ (pinnate technology) employs horizontal drilling techniques in a multi-well pattern that creates an efficient and environmentally friendly recovery method. CDX pinnate technology makes CBM production from challenging reservoirs viable.[33]

CDX Technology

In pinnate technology, first, a "cavity" well is drilled. That is, a conventional vertical well that is enlarged at the coal seam level to a diameter of 8 feet[12]. The second well is directionally drilled to intersect the cavity at a predetermined point and extended to a length of up to 1 mile in the seam. From this main lateral, numerous horizontal laterals are drilled to roughly cover a square area (**Fig. D-1**: single pinnate). The pinnate system is the multilateral horizontal drainage network configured in the shape of a leaf. A single pinnate can cover an area of up to 320 acres. A single pinnate pattern can be drilled in 4 directions offset by 90° each to cover an area of up to 1,200 acres over 360°. (**Fig. D-2**: quad pinnate). In the ongoing effort to reduce drilling cost, more advanced horizontal drilling patterns have also been developed. [34]

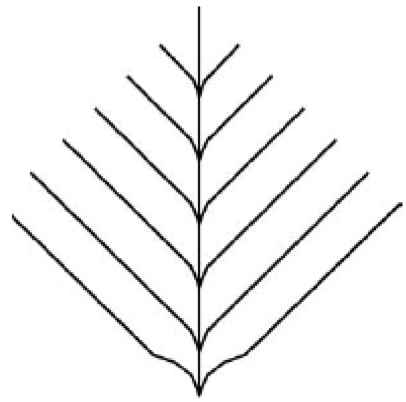

Fig. D-1: The single pinnate drilling pattern[33]

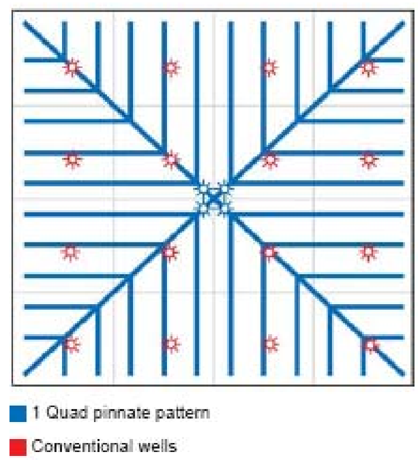

Fig. D-2: The quad pinnate drilling pattern[33]

Production Characteristic of Pinnate Wells

In the CDX pinnate drilling system, the gas production is accelerated and increased ultimate resource recovery compared with conventionally completed wells.[34] **Fig.D-3** shows production decline curves for a horizontal pinnate well and conventionally completed vertical wells in the Central Appalachian Basin. The decline curve for the vertical (conventional) well represents the total production from 15 wells drilled on 80-acre spacing needed to cover the 1,200-acre area.

An unusual characteristic of the CDX decline curve is its almost immediate gas production. This eliminates the typical lengthy dewatering period of conventional CBM wells prior to significant gas production. Furthermore, the production decline is steep; usually 75 per cent to 85 per cent of the recoverable gas is produced in only two to three years.[34] CDX reports that with their drilling and completion system it is possible to accurately control direction and length of the horizontal laterals in the coal seam.[34]

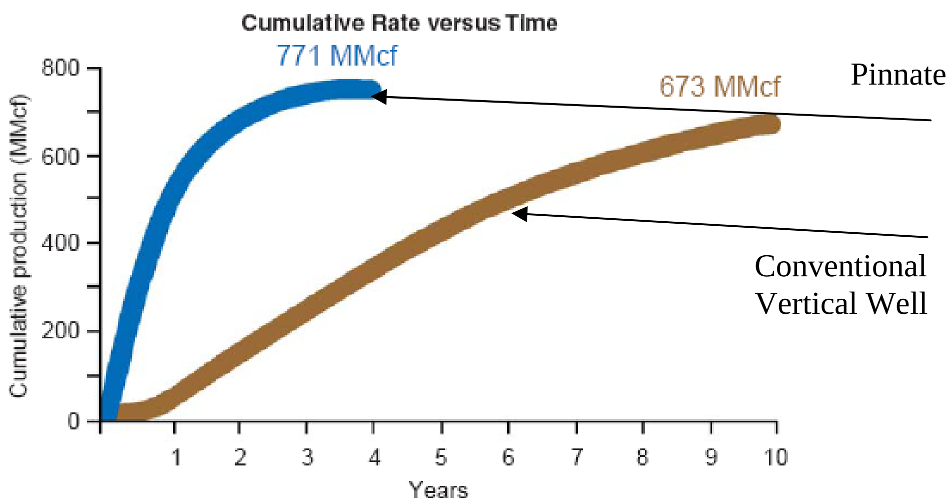

Fig. D-3: Comparison of production from a vertical well and a pinnate well in the North Appalachian Basin[34]

APPENDIX D

QUESTIONNAIRE

Part A: Information Concerning Your Professional Background

1. Your name and the name of your company (optional):

Name:
Company:

This information will not be released. I will assign a letter (A, B, ….) to each company to refer to the answers.

2. If you prefer to not give your name or that of your company, please indicate the following.
My company is a
   - ☐ major operator.
   - ☐ large independent operator.
   - ☐ small independent operator.
   - ☐ consulting company.
   - ☐ service company.
   - ☐ governmental or educational agency.
   - ☐ Other. Type: [ ]

3. My expertise:
   - ☐ Geologist
   - ☐ Geophysicist
   - ☐ Engineer
   - ☐ Other [ ]

My Industry experience: [ ] years.

4. My company is involved in the following basins for coal bed resources.

Countries

a. U.S. and Canada (North America)
Basins

1.	4.
2.	5.
3.	6.

b. International
Country:
1. [ ]
Basins

1.
2.

2. [ ]
Basins

1.
2.

Part B: Geological Parameters for Determining Completion and Stimulation Methods.
Check all factors that you consider when selecting completion and stimulation methods, and then, rank the top five factors in order of importance. More detailed questions concerning completions and stimulation will follow.

Table 1: Coalbed Reservoir Parameters.

No.	**Parameters**	**Check all that apply**	**Top five** (1 = most important)	
			Completions	**Stimulations**
1	Depth of formation	☐		
2	Net thickness of coal	☐		
3	Vertical distribution of coal	☐		
4	Number of effective coal beds	☐		
5	Water saturation	☐		
6	Gas content	☐		
7	Surrounding formation barriers	☐		
8	In-situ stress	☐		
9	Coal rank	☐		
10	Cleat properties			
A	Permeability	☐		
B	Porosity	☐		
C	Dimensions	☐		
11	Reservoir pressure	☐		
12	Reservoir temperature	☐		
13	Anticipated water production	☐		
	Others			
		☐		
		☐		
		☐		
		☐		
		☐		
		☐		

Part C : Selection of Completion Types

What combination of parameters and values do you consider when selecting each of the following seven completion methods? In the left column, rank the parameters in order of their importance for selecting the completion type. (1 = MOST IMPORTANT, IN ALL CASES)

1. **Vertical well, cased hole completion, single seam**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

2. **Vertical well, cased hole completion, multi-seam**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

3. **Vertical well, openhole cavity completion**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				

	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

4. **Vertical well, top set and under ream**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

5**. Horizontal well, single lateral completion**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

6. **Horizontal well, multilateral completion**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

7. **Horizontal well, pinnate pattern completion**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

8.**Other completion practices**____

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				

	Permeability				
	Other Parameters				

9.**Other completion practices**____________________________________

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

Part D: Stimulation Types

What combination of parameters and values do you consider when selecting each of the following 3 stimulation methods? In the left column, rank the parameters in order of their importance for selecting the type. (1 = MOST IMPORTANT, IN ALL CASES)

1.**Hydraulic fracture, vertical wells**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

2.**Hydraulic fracture, horizontal wells**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

3.**Small water fracture, (Like Powder River basin completions)**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				

	Porosity				
	Permeability				
	Other Parameters				

4. **Other**

Rank	**Parameters**	**Minimum**	**Maximum**	**Average**	**Units**
	Depth				
	Thickness of coal formation				
	Coal rank				
	In-situ stress				
	Gas content				
	Porosity				
	Permeability				
	Other Parameters				

Part E: Hydraulic Fracturing

1. Check all parameters that you consider when selecting a fracturing fluid and then rank the top five factors in order of importance. (1 = MOST IMPORTANT, IN ALL CASES)

Table 2: Formation parameters

No.	**Parameters**	**Check all that apply**	**Number (rank)**
1	Depth of formation	☐	
2	Bottomhole temperature	☐	
3	Bottomhole pressure	☐	
4	Fracture gradient	☐	
5	Net pay thickness	☐	
6	Formation permeability	☐	
7	Coal maceral composition	☐	
8	Formation porosity	☐	
9	Formation modulus	☐	
10	Gross fracture height	☐	
11	Single or multiple coal seams	☐	
12	Expected flowrate	☐	
13	Location of well	☐	
14	Cost of fracturing fluid	☐	
15	Well trajectory	☐	
16	Natural fracture orientation	☐	
17	Face cleat Dimensions	☐	
18	Butt cleat Dimensions	☐	
19	Strong barrier on top	☐	
20	Strong barrier at the bottom	☐	
21	Nearby aquifer	☐	
22	Desired fracture length	☐	
23	Desired fracture conductivity	☐	
24	Water Saturation	☐	
25		☐	
26		☐	
27		☐	
28		☐	
29		☐	
30		☐	

2. For the top 5 parameters in Table 2, what are the values that you consider when selecting a fracturing fluid?

a. X-linked gel

No.	Parameters (from Table 2)	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

b. Water

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

c. Hybrid

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

d. Foam

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

e. Other

____

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

3. Hydraulic fracturing options.

a. How do you determine the amount of **pre-pad** needed for a treatment?
☐Pre-pad should be about__________ % of pad, **or**
☐Pre-pad is _________ times the volume of the wellbore.
Other:
____
____
_
____
_

b. How do you determine the amount of **pad** to be pumped?
☐Pad should be about__________ % of total treatment volume, **or**
☐The fracture width at the wellbore should be ___________ inch.
Other:
____
____
_
____
_

c. How do you determine the **total volume of fracturing fluid** to be pumped?
____
_
____
_
____
_
____
_
____
_
____
_

d. How do you determine the **injection rate** (Q)?
☐ Maximum, based upon maximum allowable surface injection pressure, or
☐ Optimize to control out of zone fracture growth.
Other:
____
____
_

____
_

e. How do you decide upon the **type** of proppant to be pumped? I decide on the basis of:
☐ total proppant volume.
☐ closure pressure.
☐ targeted fracture conductivity value.
☐ cost.
Other:
____
____
_
____
_

f. How do you determine the **grain size** of the proppant? I choose it based on
☐ viscosity of fracturing fluid.
☐ type of coal.
☐ fracture width.
☐ depth
☐ proppant transport.
☐ required conductivity.
Other:
____
____
_
g. When do you consider **multi-stage** fracturing?
______When multiple zones are over ___________ ft apart.
Other:
____
____
_
____
_

Part F: Pumps Selection

1. Check all factors that you consider when selecting a pump, and then rank the top five factors in order of importance. (1= MOST IMPORTANT)

Table 3: Pump selection parameters

No.	Factors	Check all that apply	Rank
1	Expected water production	☐	
2	Depth of well	☐	
3	Production flexibility	☐	
4	Amount of solids to be pumped	☐	
5	Water quality	☐	
6	Type of well, horizontal/ vertical	☐	
7	Type of power supply	☐	
8	Proximity to residential areas	☐	
9	Environmental concerns	☐	
10	Life of the well	☐	
11	Others		
		☐	
		☐	
		☐	
		☐	
		☐	
		☐	
		☐	

2. What ideal combinations and values of your top five factors from Table 3 do you consider when you to select a pump?

a. Progressive cavity pump

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

b. Rod pump

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

c. Jet pump

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

d. Electric submersible pump

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

e.
Others____
______

No.	Parameters	Minimum	Maximum	Average	Units
1					
2					
3					
4					
5					

3. Under what conditions do you use gas lift in CBM wells?

____
_
____
_
____
_
____
_

_

4. Under what conditions do you drill rat holes in CBM wells?

_

_

_

Any other suggestions or comments:

APPENDIX E

BEST PRACTICES SUBROUTINE

```
Public VERY_LOW, LOW, MEDIUM, HIGH, VERY_HIGH, SHALLOW, DEEP, VERY_DEEP, LESS, MORE As Integer
Public netSeamThickness, gasContent, rank, compressiveStrength, depth, permeability, extentOfCoal, dipOfCoal, noOfCoalSeams,
distanceBetweenSeams, individualSeamThickness, verticalDistribution As Integer
Public formationWaterSaturation, distanceToLowerBarrier, distanceToAquifer As Integer

Sub Validate()

    VERY_LOW = 1
    LOW = 2
    MEDIUM = 3
    HIGH = 4
    VERY_HIGH = 5
    SHALLOW = 6
    DEEP = 7
    VERY_DEEP = 8
    LESS = 9
    MORE = 10

    If Range("B1") >= 0 And Range("B1") < 2 Then
        netSeamThickness = VERY_LOW
    ElseIf Range("B1") >= 2 And Range("B1") < 10 Then
        netSeamThickness = LOW
    ElseIf Range("B1") >= 10 And Range("B1") < 30 Then
        netSeamThickness = MEDIUM
    ElseIf Range("B1") >= 30 Then
        netSeamThickness = HIGH
    Else
        MsgBox ("Error in Net Seam Thickness")
        End
    End If

    If Range("B2") >= 0 And Range("B2") < 200 Then
        gasContent = LOW
    ElseIf Range("B2") >= 200 Then
        gasContent = HIGH
    Else
        MsgBox ("Error in Gas Content")
        End
    End If

    If StrComp(Range("B3"), "Lignite") = 0 Or StrComp(Range("B3"), "Sub B") = 0 Then
        rank = LOW
    ElseIf StrComp(Range("B3"), "HV") = 0 Or StrComp(Range("B3"), "LV") = 0 Or StrComp(Range("B3"), "MV") = 0 Or
StrComp(Range("B3"), "Bituminous") = 0 Then
        rank = MEDIUM
    ElseIf StrComp(Range("B3"), "Semi Anthracite") = 0 Or StrComp(Range("B3"), "Anthracite") = 0 Then
        rank = HIGH
    Else
        MsgBox ("Error in Rank")
        End
    End If

    If Range("B4") >= 0 And Range("B4") < 2000 Then
        compressiveStrength = LOW
    ElseIf Range("B4") >= 2000 Then
        compressiveStrength = HIGH
    Else
        MsgBox ("Error in Compressive Strength")
        End
```

```
End If

If Range("B5") >= 0 And Range("B5") < 1500 Then
   depth = SHALLOW
ElseIf Range("B5") >= 1500 And Range("B5") < 4000 Then
   depth = MEDIUM
ElseIf Range("B5") >= 4000 And Range("B5") < 6000 Then
   depth = DEEP
ElseIf Range("B5") >= 6000 Then
   depth = VERY_DEEP
Else
   MsgBox ("Error in Depth")
   End
End If

If Range("B6") >= 0 And Range("B6") < 1 Then
   permeability = LOW
ElseIf Range("B6") >= 1 And Range("B6") < 10 Then
   permeability = MEDIUM
ElseIf Range("B6") >= 10 And Range("B6") < 100 Then
   permeability = HIGH
ElseIf Range("B6") >= 100 Then
   permeability = VERY_HIGH
Else
   MsgBox ("Error in Permeability")
   End
End If

If Range("B7") >= 0 And Range("B7") < 1500 Then
   extentOfCoal = LOW
ElseIf Range("B7") >= 1500 Then
   extentOfCoal = HIGH
Else
   MsgBox ("Error in Extent of Coal")
   End
End If

If Range("B8") >= 0 And Range("B8") < 15 Then
   dipOfCoal = LOW
ElseIf Range("B8") >= 15 Then
   dipOfCoal = HIGH
Else
   MsgBox ("Error in Dip of Coal")
   End
End If

If Range("B9") >= 0 And Range("B9") < 2 Then
   noOfCoalSeams = LESS
ElseIf Range("B9") >= 2 Then
   noOfCoalSeams = MORE
Else
   MsgBox ("Error in Number of Coal Seams")
   End
End If

If Range("B10") >= 0 And Range("B10") < 100 Then
   distanceBetweenSeams = LESS
ElseIf Range("B10") >= 100 Then
   distanceBetweenSeams = MORE
Else
   MsgBox ("Error in Distance between Seams")
   End
End If

If StrComp(Range("B12"), "More than 100ft") = 0 Then
   verticalDistribution = MORE
```

```
    ElseIf StrComp(Range("B12"), "Less than 100ft") = 0 Then
        verticalDistribution = LESS
    Else
        MsgBox ("Error in Vertical Distribution")
        End
    End If

    If Range("B13") < 5 And Range("B13") >= 0 Then
        formationWaterSaturation = VERY_LOW
    ElseIf Range("B13") >= 5 And Range("B13") <= 50 Then
        formationWaterSaturation = LOW
    ElseIf Range("B13") > 50 And Range("B13") <= 100 Then
        formationWaterSaturation = HIGH
    Else
        MsgBox ("Error in Formation Water Saturation")
        End
    End If

    If StrComp(Range("B14"), "More than 30ft") = 0 Then
        distanceToLowerBarrier = MORE
    ElseIf StrComp(Range("B12"), "Less than 30ft") = 0 Then
        distanceToLowerBarrier = LESS
    Else
        MsgBox ("Error in Distance to Lower Barrier")
        End
    End If

    If StrComp(Range("B15"), "More than 50ft") = 0 Then
        distanceToAquifer = MORE
    ElseIf StrComp(Range("B15"), "Less than 50ft") = 0 Then
        distanceToAquifer = LESS
    Else
        MsgBox ("Error in Distance to Aquifer")
        End
    End If

End Sub

Sub Macro1()
'
' Macro1 Macro
' Macro recorded 7/14/2007 by sunil.ramaswamy
'
    Call Macro2

    If permeability = VERY_HIGH Then
        Range("B23").FormulaR1C1 = "Water Without Proppant"
        End
    Else
        If formationWaterSaturation = VERY_LOW Then
            Range("B23").FormulaR1C1 = "Gas Without Proppant"
            End
        ElseIf formationWaterSaturation = LOW Then
            Range("B23").FormulaR1C1 = "CO2/N2 Foam With Proppant"
            End
        Else
            If permeability = LOW Then
                Range("B23").FormulaR1C1 = "Water With Proppant"
            ElseIf permeability = MEDIUM Then
                Range("B23").FormulaR1C1 = "Cross Linked Gel With Proppant"
            Else
                If distanceToLowerBarrier = LESS Then
                    Range("B23").FormulaR1C1 = "Water With Proppant"
                Else
                    Range("B23").FormulaR1C1 = "Water With Proppant Or Cross Linked Gel With Proppant"
                End If
```

```
            If distanceToAquifer = LESS Then
               Range("B23").FormulaR1C1 = "Water With Proppant"
            Else
               Range("B23").FormulaR1C1 = "Water With Proppant Or Cross Linked Gel With Proppant"
            End If
         End If
      End If
   End If
'
End Sub

Sub Macro2()
'
' Macro1 Macro
' Macro recorded 7/14/2007 by sunil.ramaswamy

   Call Validate

   If netSeamThickness = VERY_LOW Then
      Range("B19").FormulaR1C1 = "Not a viable option 1"
      End
   Else
      If gasContent = LOW Then
         If netSeamThickness = HIGH Then
            If depth = SHALLOW Then
               If permeability = VERY_HIGH Then
                  Range("B20").FormulaR1C1 = "Top Set under Ream"
                  End
               End If
            End If
         Else
            Range("B19").FormulaR1C1 = "Not a viable option 2"
            End
         End If
      Else
         If rank = LOW Then
            If netSeamThickness = HIGH Then
               If depth = SHALLOW Then
                  If permeability = VERY_HIGH Then
                     Range("B20").FormulaR1C1 = "Top Set under Ream"
                     End
                  End If
               End If
            Else
               Range("B19").FormulaR1C1 = "Not a viable option 3"
               End
            End If
         ElseIf rank = HIGH Then
            Range("B19").FormulaR1C1 = "Not a viable option 4"
            End
         Else
            If compressiveStrength = LOW Then
               If permeability = HIGH Then
                  Range("B20").FormulaR1C1 = "Open Hole Cavity Completion Or Cased Hole Completion with Hydraulic Fracture
Stimulation"
               Else
                  GoTo nst2
               End If
            Else
nst2:          If netSeamThickness = LOW Then
                  If depth = MEDIUM And extentOfCoal = HIGH And dipOfCoal = LOW And permeability <> VERY_HIGH Then
                     If noOfCoalSeams = HIGH And distanceBetweenSeams = MORE Then
                        Range("B20").FormulaR1C1 = "Multilateral Horizontal Wells Or Cased Hole Completion with Hydraulic
Fracture Stimulation"
                     ElseIf permeability = LOW Then
                        Range("B20").FormulaR1C1 = "Pinnate Wells Or Cased Hole Completion with Hydraulic Fracture Stimulation"
```

```
                        Else
                            Range("B20").FormulaR1C1 = "Single Lateral Horizontal Wells Or Cased Hole Completion with Hydraulic
Fracture Stimulation"
                        End If
                    Else
                        GoTo nst
                    End If
                Else
nst:
                    If depth = VERY_DEEP Then
                        Range("B19").FormulaR1C1 = "Not a viable option 5"
                    Else
                        If noOfCoalSeams = HIGH And verticalDistribution = MORE Then
                            Range("B20").FormulaR1C1 = "Cased Hole Completion with Multiple Stage Hydraulic Fracture Stimulation"
                        Else
                            Range("B20").FormulaR1C1 = "Cased Hole Completion with Single Stage Hydraulic Fracture Stimulation"
                        End If
                    End If
                End If
            End If
        End If
    End If
End If

'  Range("C5").Select
End Sub
```

VITA

Name:	Sunil Ramaswamy
Address:	16 Yogekshema Layout, Sneh Nagar Nagpur, Maharashtra, India 440015
Email Address:	sunil_gcr@yahoo.co.in
Education:	B.E., Mining Engineering, National Institute of Technology, Karnataka, Surathkal 2003 M.S., Petroleum Engineering, Texas A&M University, 2007