THIRTY YEARS OF LESSONS LEARNED – TIPS AND TRICKS FOR FINDING, DEVELOPING AND OPERATING A COALBED METHANE FIELD

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Introduction
Coalbed Methane (CBM) has been developed and operated by BP in the San Juan Basin of the United States since 1977. This development pioneered the CBM business by initiating the first commercial CBM field in the world. These 30 years of operation represent a significant learning opportunity and during this time we have accumulated numerous lessons about finding, developing and operating CBM fields.

This paper is by no means a highly technical dissertation on CBM. Rather, it is intended as a high-level discussion where the lessons we have learned can be compiled and shared. A common theme throughout will be a comparison between CBM and “conventional” gas fields, highlighting both the similarities and the differences, identifying the source of those differences and examining the impacts those differences will introduce into the exploration and production process.

There are many similarities between a CBM field and a conventional gas field. On the surface, they can be indistinguishable from each other, with subtle differences that only an expert might discern. Many of the same methods used in conventional oil and gas are used to find, develop and operate CBM fields. One might travel past similar looking surface production equipment and even peer into a wellbore without noticing anything unusual.

However, as one leaves the wellbore and enters the reservoir, it quickly becomes apparent that there are fundamental differences between coal and the rocks that typically make up conventional reservoirs. These differences provide coal with several unique properties, which in turn impact all aspects of the CBM business, from exploration through field development and production.

Coal's Unique Reservoir Properties
The differences between CBM and conventional gas reservoirs can primarily be traced back to two physical properties of coal: the unique storage mechanism of methane in coal and the naturally fractured nature of the coal. These two characteristics will drive important reservoir behaviors like the trapping mechanism, pressure depletion and production profiles, ultimately having a significant impact on exploration methods, subsurface operations and surface operations.

Adsorption  The storage mechanism, known as adsorption, is fundamentally different from the storage mechanism in conventional reservoirs, where gas is stored in a compressed but gaseous state in the pore spaces between sand grains. Adsorption allows methane to adhere to the surface of the infinitesimally small coal particles at near-liquid densities. That mechanism, coupled with the incredibly large aggregated surface area of the coal particles, yields a storage mechanism that can be many times more efficient than that of conventional reservoirs.

Adsorption provides a storage mechanism not only for methane, but for other gases as well. The most common secondary gas that is associated with CBM is carbon dioxide (CO$_2$). In fact, coal has a higher affinity for CO$_2$ than for methane. Consequently, CO$_2$ concentrations typically start out low, as methane is preferentially released from the surface of the coal, and rise over time, particularly late in the life of a CBM reservoir. Coal's affinity for CO$_2$ provides a potential future opportunity to utilize depleted CBM fields for CO$_2$ sequestration or possibly even pursue enhanced CBM recovery through CO$_2$ injection.

Isotherms and Saturation  Coal's highly efficient storage mechanism for methane comes with a price – coal is very stingy about giving up its methane. Adsorption of the methane to the coal is maintained by pressure. Decreasing that pressure allows the methane to “de-sorb” from the coal and become mobile. Desorption of the methane from the coal can be described by a curve known as a Langmuir isotherm (or more commonly, just isotherm). In effect, the isotherm describes the gas storage capacity of a coal as a function of pressure. A coal whose gas content equals the storage capacity at a given pressure (i.e. the point exists on the isotherm) is said to be saturated. A coal whose gas content is below the isotherm at a given pressure is under-saturated. (Hint: if your gas content at a given pressure exists above the isotherm, you have bad data). The isotherm establishes the relationship between the abandonment pressure of the reservoir and the ultimate recovery. The shape of the isotherm curve dictates that the abandonment pressure in coal must be much lower than in conventional reservoirs to achieve the same recovery. [Figure 1]
Isotherms can be constructed for composite gases or for particular gas constituents, such as methane or CO$_2$. Under the same conditions, the shapes of the isotherms for methane and CO$_2$ are different. The isotherm for CO$_2$ is flatter at high pressures and steeper at low pressures. This shape corresponds with coal’s greater affinity for CO$_2$ and explains how CO$_2$ concentrations in the produced gas stream are lower in early life and much greater in late life.

**Diffusion**  As the methane de-sorbs from the surface of the coal particles, it travels through the micro-porosity of the coal matrix via diffusion. This relatively slow diffusion process occurs only over short distances before being overshadowed by coal’s second important physical characteristic – natural fractures.

**The Cleat System**  The natural fracture system in coal is known as the cleat system and it provides the primary flow path for the methane to travel through the reservoir to the wellbore. The cleat system is typically composed of two sets of vertical fractures that are perpendicular to each other, with one set (the face cleats) tending to be more through-going. The cleats form during the coalification process as peat is cooked into coal and shrinks. Flow through the cleat system can generally be described using Darcy’s flow
equation, just as in conventional reservoirs. So, the concept of permeability that is used to characterize flow through porous media in conventional reservoirs can be applied to coal.

**De-watering** Although there are a few exceptions, the cleat system is almost always filled with water and this water is typically fairly fresh. The hydrostatic head of this water provides the pressure that keeps the methane adsorbed to the coal. For gas production to take place this pressure must be reduced, typically by “de-watering” the cleat system. De-watering is simply the production of the water located within the cleat system. As water is a highly incompressible fluid, the removal of large volumes of water from the cleat system causes a rapid drop in reservoir pressure, allowing the methane to de-sorb from the surface of the coal particles, diffuse through the matrix and ultimately find its way into the cleat system. [Figure 2] This phenomenon can also be seen in the flat slope of the isotherm near initial pressure, which represents significant pressure reduction without much gas production.

![Diagram](image)

**Methane stored at near-liquid density in mono-molecular layer on surface of coal particle. De-sorption occurs as pressure decreases.**

**Methane diffuses through micro-porosity of coal matrix towards lower methane concentrations (pressure sink).**

**Methane reaches water-filled cleat system and enters two-phase Darcy-like flow.**

**Fig. 2 – Movement of methane in coal (at increasing scale)** Modified from Kuuskraa and Brandenburg (1969)

**Production Profile** Early time production typically consists almost entirely of water, driven by the fact that there is little (if any) free gas in the cleat system to produce, but also by the relative permeability effect, which favors flow of the predominant phase. Only over time, as gas saturation (and therefore relative permeability to gas) in the cleat system increases, will the gas rate begin to reach commercial levels. Water rate will drop as the gas rate climbs. In fact, the shapes of the gas and water production curves mimic a gas-water relative permeability curve. [Figure 3] This behavior is almost the exact opposite of the production performance from conventional gas wells, where gas rate is highest and water production is lowest in early life.
Dry Coals  Those few exceptions where the cleat system is not filled with water are known as “dry” coals. Dry coals have some advantages over wet coals. The biggest advantage is that gas production is immediate (no de-watering) and there is no water production to lift, gather and dispose. However, there are disadvantages as well – namely that dry coals are often sensitive to water and this makes them difficult to drill and complete. Also, dry coals are often under-saturated. Because of the rarity of dry coals, the remainder of this paper will address the more commonly occurring coals with water-filled cleat systems.

Exploring for CBM
From a chronological standpoint, the first practical aspect of CBM that is controlled by coal’s unique properties is exploration. As with any exploration prospect, the scale of the potential development is important. However, as will be seen, the development of a CBM field can involve significant infrastructure compared to most onshore fields. In addition, per-well production rates and recoveries tend to be relatively low. Consequently, scale is a particularly important factor when screening potential CBM exploration prospects. Successful CBM fields tend to cover large areas and contain hundreds of wells – there are no five-well CBM developments that are considered to be economic successes.
Conventional Exploration Screening and Testing  Conventional exploration usually starts with screening work designed to establish the presence of suitable reservoir rock and a source of hydrocarbons. Next, a structural or stratigraphic trap (or combination of the two) that will allow the hydrocarbons to accumulate must be identified. A migration path from the source to the potential trap along with the appropriate timing must then be established. [Figure 6 – upper half] Once a conventional exploratory play has been defined, an exploratory well is drilled to confirm the presence of hydrocarbons and reservoir quality rock. Often, only a single well is needed to confirm or condemn the play. Follow-up appraisal drilling is sometimes needed to understand the extent and heterogeneity of the discovery.

CBM Exploration Screening and Testing  CBM exploration also starts with a screening process, but the process is different as it focuses on different geologic elements. Instead of focusing on reservoir quality, source and trap as in a conventional play, CBM screening focuses on coal extent, gas content, degree of saturation and whether the coal is wet or dry. Rather than drilling a single exploratory well, as is usually done in a conventional play, testing a CBM exploratory play typically involves drilling multiple core holes and conducting at least one, but probably several extended flow tests.

Coal Extent  Large coal deposits, long recognized as a commercial resource, have not been ignored over time, so their presence has usually already been established by mining (or attempted mining) in the area. This is often augmented by the presence of outcrops located near the prospective CBM play. Also, drilling for conventional oil and gas reservoirs often penetrates the typically shallower CBM targets and can provide useful data on coal presence and extent.

Gas Content  Traditional petroleum systems studies, conducted to establish the presence of hydrocarbons in immature or new exploration basins, are not needed in CBM exploration, as the coal acts as its own source of hydrocarbons. Gas in coal can be sourced by either thermogenic processes (produced through the action of heat and pressure on the organic material in the coal) or biogenic processes (produced by microorganisms living within the coal). Thermogenic gas is the more common of the two, although biogenic gas can be an important component in shallower CBM plays.

Coal is categorized into ranks, which represent the thermal maturity of the coal. The ranks of coal - from least mature to most mature - are peat, lignite, sub-bituminous, bituminous, anthracite and graphite. There is a strong link between a coal’s rank and its gas content. [Figure 4] Therefore, a primary screening mechanism for coal is to identify its rank.

![Fig. 4 – The relationship of coal rank and gas content](Modified from Boyer (1989))
Coal rank can often be identified visually but the definitive test is to measure the amount of vitrinite in the coal — the higher the vitrinite, the higher the rank. Vitrinite content is usually measured and reported as the vitrinite reflectance ($R_o$) of the coal material. Coal samples for use in this type of analysis are often readily available from both surface and subsurface mines and can be supplemented by data gathered at the outcrop, if present. Reconstructing the burial history of a coal can also be a useful tool in predicting the thermal maturity, and thus rank and gas content of coal. Mining records can also give indications, or possibly direct measurement, of gas content.

**Saturation**  In addition to predicting the thermal maturity of a coal, a properly constructed burial history can assess the risk that gas has been lost during a "reburial" event and left an under-saturated coal. This phenomenon, analogous to the breach of a trap in a conventional reservoir, occurs when a saturated coal is lifted to shallower depth and then later reburied. During uplift, as the coal becomes shallower and is exposed to lower hydrostatic pressures, the coal "rides" the isotherm down to a lower gas storage value. Methane is de-sorbed from the coal and escapes. When the coal is reburied, the hydrostatic pressure increases and the gas storage capacity returns to a higher value. However, unless the coal has been returned to conditions that allow for the generation of new gas, there is no additional gas to fill the restored capacity. The coal now exists below the isotherm and is under-saturated. [Figure 5]

![Fig. 5 – Reburial event leading to under-saturation of coal](image)

There are two practical considerations to under-saturation. First, the coal contains less gas than would normally be expected under current conditions. Second, no gas will be de-sorbed until the reservoir pressure declines and reaches the isotherm. Until this point is reached, the only production from the coal will be water.

**Traps and Wet or Dry Coals**  Because only hydrostatic pressure is needed to hold the methane in the coal, there is not always a need to define a "trap" as in a conventional gas play. The coal is not only self-sourcing but also serves as its own trap. [Figure 6 – lower half] Consequently, there may not be the need to embark on an extensive seismic acquisition program (although existing 2-D seismic lines can be useful in determining the distribution of the coal). CBM fields that exist due to a hydrostatic trap are clearly "wet" coals. However, not all wet coals rely on a hydrostatic trap but contain at least some structural or stratigraphic component. In these more complex cases, attention will have to be paid to identifying and mapping a trap. Dry coals, by definition, will rely on a structural or stratigraphic trap.
Exploratory Activity  “Exploratory” drilling in a CBM play often commences earlier in the process than in a conventional exploration play. This is due in part to the inexpensive nature of the typically shallow CBM wells relative to other types of pre-drilling evaluation work (e.g. seismic). Also, CBM “exploratory” drilling will usually consist of a multi-well drilling program, once again driven by the inexpensive nature of shallow CBM wells, but also driven by the limited amount of data that comes out of a single CBM well.

Open-hole Well Logs As in a conventional play, the intent is to confirm the presence of commercial hydrocarbons and reservoir quality rock. To establish the gas content of a conventional exploration target, one would normally drill a single exploration well and run a suite of “open-hole” well logging tools. The data from the well logs would then be analyzed to calculate the storage capacity (porosity) and fluid content (water saturation) of the exploration target. In favorable circumstances, it is possible to infer permeability from the open-hole log data. Coal’s gas storage mechanism is so different from that of conventional reservoirs that traditional well log analysis does not work at identifying the storage capacity and fluid content of a coal. In fact, porosity and water saturation do not usually enter into reserve calculations for CBM. Therefore, well logs are of somewhat limited use in CBM.

That’s not to say that open-hole well logs are not useful. Only open-hole logs can provide coal density, a critical parameter in calculating gas-in-place and very useful for inferring coal quality. Additionally open-hole logs can provide insight into conventional formations that adjoin the coal. Special imaging logs, only capable of working in the open-hole, can determine cleat density (which can be correlated to permeability) and cleat orientation. So, valuable information about a CBM play can be gathered from open-hole logs – just not as much as is typically gathered in a conventional play.

Cores Because of the limitations with open-hole well logs, CBM exploration relies heavily on the gathering of cores, much more so than conventional gas exploration. However, as with well logging, the type of data that can be extracted from a CBM core is different than that from cores in conventional reservoirs. Permeability, an extremely critical factor in assessing a CBM play, is almost impossible to measure in the incompetent coals that usually make a good CBM play. Porosity is equally difficult to measure.

So, what useful information can cores provide in evaluating a CBM exploration play? Cores provide the almost exclusive source for gas content data. This data, measured in gas volume/mass of coal (e.g. scf/ton), when combined with coal density (g/cc), net pay thickness and productive (or prospective) area provides a
good estimate of gas-in-place and therefore an indication of the scale of the CBM play. Of equal importance is the data provided by cores from which the isotherm curve is constructed.

Ideally, a core recovered and maintained at reservoir pressure will yield the best gas content data. However, recovery of pressurized cores can be problematic. We have found wireline-retrievable cores to be a good alternative. Due to the speed at which the core sample can be brought to the surface and properly stored, gas lost from the core is minimized.

Gathering good core samples is important, but equally important is securing the services of a qualified and capable laboratory. This laboratory will be responsible for conducting gas content measurement analyses and constructing isotherm curves. Also of significant value is a company who will provide proper handling of core samples and accurate core descriptions.

**Permeability Determination** As in conventional reservoirs, permeability continues to be the elusive parameter that is essentially unknowable through well logs. However, it may be the most important indicator of commercial success. Consequently, CBM "exploratory" wells should include some kind of test to confirm the presence of permeability. There are several types of tests to choose from, but not all are suitable for tests in coal. In theory, open-hole tests are less complicated and can give better results, but in reality are subject to problems associated with poor hole conditions, like stuck tools or ineffective zonal isolation. Cased-hole tests avoid those problems, but formation damage from the cementing operation can limit or prohibit communication with the reservoir, negating the validity of the test. Consequently, cased-hole tests might require some type of stimulation treatment.

In addition to the question of open-hole versus cased-hole tests, there is also the question of production versus injection tests. Production tests can range all the way from the extremely short-term tests performed by wireline conveyed tools to long-term tests involving stimulation, artificial lift and surface production equipment. Injection tests do not have a practical wireline conveyed option so they tend towards medium and longer durations. However, they do have the advantage of not requiring artificial lift and surface production equipment. Whether a production or injection test is chosen (or some combination of the two), the test will typically incorporate bottom-hole pressure measurement both during the production/injection period and subsequent build-up/fall-off period.

Wireline conveyed, open-hole formation testers are generally not suitable in coals due to the difficulty in establishing isolation between the tool-reservoir interface and the wellbore fluid. However, there are wireline tools for use in cased-holes (in conjunction with perforating tools) that have yielded good results. Of course, tests conducted with these wireline conveyed tools are of extremely short duration and contact only a small vertical section of the coal. Consequently, they test only a minute portion of the reservoir and their results may not be representative. An open-hole drill-stem test (DST) can yield more representative results, as it is of longer duration and contacts a much larger vertical section of the coal. However, it is subject to the same drawbacks shared by all open-hole tests. Running a DST in cased-hole will eliminate those problems but introduce issues with formation damage. Ultimately, the best option may be to complete the well, including some type of stimulation and artificial lift, and run a long-term production test.

Assuming representative permeability data has been gathered, there still remains one significant set of data to acquire – a relative permeability curve. Relative permeability is a critical mechanism in CBM production because it controls the de-watering of the cleat system. Unfortunately, it is extremely difficult to measure CBM relative permeability using cores, as is done with conventional reservoirs. The types of cores suitable for relative permeability measurements (i.e. competent and consolidated) are not usually representative of a high quality productive coal. Ultimately, the best way to construct a relative permeability curve may be through numerical modeling of a long-term production test in which the production has transitioned from 100% water to a high percentage of gas. It normally takes years for a producing well to experience this range of conditions, but a properly designed pilot can achieve this in weeks to months.

**Appraisal** After the exploratory phase of drilling has been completed there should be enough data available to understand the magnitude of the resource and describe the geographic distribution of the resource and permeability. An appraisal stage is then needed to define what the full-field development might look like and to confirm the commerciality of that development. Appraisal might consist of several multi-well production pilots distributed throughout the prospective field area. The primary goal of these pilots is to determine the geographic distribution of permeability, from which will be derived drainage area. Multi-well pilots allow a small area to be de-watered relatively quickly and for gas production to be initiated. Technically, initiating gas production is not necessary to determine permeability. However, one must be quite confident in the gas content, isotherm curve and degree of saturation to move forward with field development without having established gas production.
Developing and Producing a CBM Field

Once a CBM field has been discovered, development and operation are also shaped by coal's unique properties. The two properties that have the most impact are the water-filled cleat system and the shape of the isotherm curve. These two properties impact every aspect of field development, both subsurface and surface.

The cleat system must be de-watered to initiate gas production, and this often requires the use of artificial lift (e.g., down-hole pumps) to help bring the water to the surface. Once at the surface, this produced water must be separated from the gas, gathered and disposed (or put to beneficial use). These operational requirements associated with de-watering the cleat system drive the design of the wellbore and wellsite production equipment and the need for artificial lift and a water gathering/handling system.

The shape of the isotherm curve dictates that the reservoir pressure be drawn to a minimum in order to achieve desirable gas recoveries. In fact, field development can be thought of as a series of efforts to eliminate or minimize every pressure loss between the plant tailgate and the edge of each well's drainage radius, ultimately resulting in a minimized abandonment pressure. The need to eliminate pressure losses in the subsurface will drive well-spacing, stimulation design and artificial lift selection. The need to eliminate pressure losses in the surface will drive the design of the wellsite production equipment, gas gathering system and gas plant.

Well Spacing The effort to minimize pressure losses in the system starts in the reservoir, with the identification of the proper well spacing. Ignoring for a moment several other factors, well spacing and permeability will ultimately dictate the reservoir abandonment pressure, and therefore the per-well reserves. Economic analysis can be performed to determine the spacing that yields the optimum abandonment pressure for a given permeability. Of course, permeability will likely vary across the field, so the optimum well spacing will also vary.

Stimulation In truth, it is not permeability alone that controls well spacing. Instead it is a combination of permeability and stimulation design. Coal, like many conventional reservoirs, often requires some type of stimulation to provide an effective flow path from deep in the reservoir to the wellbore. However, the need for stimulation in coal is increased not only by the shape of the isotherm but also by the natural fractures of the cleat system which are very sensitive to damage by drilling and cementing operations. Depending on the permeability of the coal and the methods used in drilling the well, stimulation requirements may be minimal or massive. [Figure 7]

![Typical CBM Completions](image)

**Fig. 7 – Typical CBM completion options** Modified from Eckstein (2009)
Types of stimulation In high permeability coals, it is common to set casing above the coal, drill through the coal with mist or air and leave the coal section uncased. Stimulation techniques in this case consist of under-reaming or cavitation. Cavitation consists of a cyclic and repeated pressuring and de-pressuring of the near-wellbore region which results in mechanical failure of the coal and the formation of a cavity in the coal that can be up to many feet in diameter. Open-hole completions such as this are relatively inexpensive but can lead to problems in the future as the incompetent coal starts to slough into the wellbore.

In medium to low permeability coals, it is common to drill through the coal, set casing and pump a hydraulic fracture stimulation. This method has been shown to be highly effective at bypassing near-wellbore damage and establishing a flow path into the reservoir. Numerous types of “fracs” have been used to stimulate coal. Most include some type of proppant to maintain conductivity in the fracture after pumping has ceased. Resin-coated proppant has been shown to be effective at controlling proppant flow back, and possibly exhibiting some control of coal solids production (important points to be discussed later in the artificial lift section). Different types of fluid have been used to transmit hydraulic energy to the coal and to transport the proppant. “Slick” water has the advantage of causing minimal damage to the coal but has had limited success at proppant transport and placement. Foamed fluids place less liquid into the coal and provide energy to assist in post-stimulation flow back but have shown some indications of incompatibility with the coal. The most common, and probably most successful, fluid system is a borate cross-linked guar gel. Though somewhat damaging to the coal, it seems to provide the best compromise between damage and proppant placement.

Modeling of Hydraulic Fracture Stimulation The initiation and propagation of hydraulic fractures in coal is not well understood from a physics and mathematical standpoint. Consequently, prediction and modeling, which has reached a high degree of sophistication in conventional reservoirs, is relatively ineffective at this time. It has been shown through “mine-back” and other mapping experiments that hydraulic fracture geometry in coal is complex and that the hydraulic fractures only reach into the CBM reservoir a fraction of what they can achieve in conventional reservoirs. There are some commercially available computer programs that are beginning to address this shortfall, but no solid solutions have been reached yet. In the meantime, optimization of hydraulic fracture stimulation design in coals will be something of a trial-and-error exercise.

Horizontal Completions Horizontal drilling and completion has been successfully applied in a number of areas but has by no means been shown to be universally applicable. Most success has occurred in single coal seams with low permeability and limited water production. Particularly successful, at least from a producing rate and drainage standpoint, has been the application of complex lateral geometry to a single seam. However, even these successes have experienced problems with wellbore collapse and de-watering of the laterals. Additionally, even within a single seam, horizontal completions may not be applicable if the vertical permeability within that seam is limited.

Multiple Coal Seams Many CBM fields are comprised of multiple coal seams, often spread out over a large vertical section. Development of an entire coal section like this is problematic. The primary issue is that large, segregated coal sections are extremely difficult to stimulate effectively. Under-reaming, cavitation and hydraulic fracture stimulation are all difficult to apply over large vertical sections, but for differing reasons. It can be done, but the cost increases dramatically. Developing multiple coal seams with horizontal completions can be especially expensive, involving either multiple laterals or hydraulic fracture treatments designed to cross intervening shale layers and contact several seams. A common mistake in the appraisal phase of a CBM play is to include every seam in the calculation of developable reserves. In reality, seams that are impractical to access and stimulate should not be included in the reserve calculation.

Artificial Lift As stated earlier, lifting water from the wellbore actually addresses both the need to de-water the reservoir and the need to minimize back-pressure on the reservoir. Multiple factors will dictate whether a well will be able to lift water to the surface without assistance. These factors include the initial reservoir pressure, permeability, the operating pressure of the surface equipment and the gas-to-water ratio of the produced fluid. Initial reservoir pressures in CBM tend to range from slightly over-pressured to slightly under-pressured. Consequently, even in the best case, reservoir pressure will usually not lift a full column of water for prolonged periods.

During the early phase of a field development, while water saturation in the cleat system is still high, there will be limited gas production to help lift the water from the wellbore. So, even though the reservoir pressure is at its highest, artificial lift will most likely be needed at initial completion of a well. As field development matures, when the cleat system has been partially or fully de-watered, initial gas production can be substantial and artificial lift might not be needed at initial completion of a well. Occasionally, there can be
circumstances where the cleat system contains free gas at initial conditions. This situation not only provides for immediate gas production but also lessens the likelihood that artificial lift will be needed initially.

Just as the need for artificial lift at initial completion of a well may vary, the need for artificial lift later in a well’s life may also vary. The declining water rate typically seen in CBM wells can often generate conditions where artificial lift is no longer needed in a particular well. Or, sometimes the declining reservoir pressure seen later in a well’s life can necessitate artificial lift even though the water rate is extremely low. Despite these different scenarios, the general trend will be for CBM wells to need artificial lift early in life and for that need to decrease as the well matures. This is opposite to wells in conventional reservoirs, which usually need artificial lift later in a well’s life.

**Types of Artificial Lift** While there are numerous types of artificial lift, the two most common types are beam pumps (also known as sucker-rod pumps) and progressing cavity (PC) pumps. Both employ the use of a moving rod string to impart mechanical energy to the down-hole pump. Beam pumps use a reciprocating rod string to move a plunger within a barrel and utilize a series of check valves to provide positive displacement for the liquid. PC pumps use a rotating rod string to spin a rotor within a stator. As the rotor spins, the cavities between the rotor and stator travel, or progress, upward, providing positive displacement for the liquid, in an action similar to that of an Archimedes screw.

BP’s experience in the San Juan Basin has demonstrated that both types have their advantages and disadvantages. Beam pumps have been highly reliable and have shown to be amazingly resistant to plugging by coal fines. However, the pump-jack that typically drives a beam pump at the surface is a relatively expensive piece of equipment and can require visual and noise mitigation. PC pumps have been somewhat less reliable and surprisingly susceptible to coal fines. However, the surface drive-head is much less expensive than a pump-jack and is a very low-profile piece of equipment. Both types will suffer from serious inefficiency if gas is allowed to enter the pumps.

Numerous other types of artificial lift can and have been applied to CBM. Gas lift has been used very successfully in the early life of a field when water rates and reservoir pressure are high, but a source of high-pressure gas must be available. Plungers can be used later in the life of a field when water rates and reservoir pressure have both declined. Electrical submersible pumps (ESPs) may be appropriate for some applications, but they are quite expensive and may be susceptible to erosion by coal fines.

**Artificial Lift Operation** Regardless of the type of pump used, the water is typically pumped up the tubing and the gas is produced up the tubing-casing annulus. Obviously, this dictates that the tubing is run without a packer. There are trade-offs in picking the landing depth of the pump relative to the perforations. To prevent gas from entering the pump and to minimize the back-pressure on the reservoir, the pump is landed below the perforations. However, this can lead to plugging of the pump by coal fines or proppant. BP’s philosophy has been to land the pump below the perforations and attempt to mitigate the solids plugging problem.

Rod-on-tubing wear can be a problem in any artificial lift installation that uses a moving rod string, especially in a deviated wellbore. BP has found that the use of continuous rod (instead of traditional jointed rods) and a harder grade of tubing (e.g. P-110) have dramatically reduced tubing wear. In addition, the use of insert pumps on the beam pump installations, which are retrievable without pulling the tubing from the wellbore, has reduced intervention time and cost.

**Fluid Level Management** As water is pumped from the well, hydrostatic back-pressure on the reservoir is reduced, allowing reservoir fluids to enter the wellbore. To make any progress at eliminating back-pressure on the reservoir, the withdrawal rate must be higher than the influx, which allows the fluid level in the tubing-casing annulus to fall. This fluid level must be carefully monitored and managed for several reasons. First, the fluid level cannot be lowered too rapidly, or the drawdown on the reservoir may cause excessive solids production. Second, the fluid level cannot be lowered too far, or gas will enter the pump and drastically reduce its efficiency. Both of these concerns must be balanced against the need to minimize the fluid level, and thus the back-pressure on the reservoir, and to do so quickly so gas production can ramp up in a reasonable amount of time.

Fluid levels in the casing-tubing annulus are typically measured using a device that sends an acoustic signal down the annulus which reflects off of the gas-liquid interface and returns to the surface. The signal also reflects off of casing collars in a fairly distinctive way. By comparing the roundtrip travel times of these various signals, the depth to the fluid level (and the corresponding height above the pump inlet) can be easily calculated. During early production time, the water rates and fluid levels can change dramatically, so it is advisable to measure fluid levels with some frequency.
A more sophisticated tool to help manage the fluid level is a pump-off controller (POC). These devices work differently for different types of pumps, but regardless of the pump type the intent is to maintain higher pump speed while the fluid level is high and slower pump speed when the fluid level drops below (or near) the pump inlet (i.e. the well is “pumped off”). The most common types of POCs do not actually measure the fluid level, but infer a low fluid level from other measurements. POCs for beam pumps measure load on the rod string to determine if the pump is filling completely or only partially. POCs for PC pumps utilize flow measurement at the surface to determine when the water rate begins dropping. Other more sophisticated devices use downhole sensors to measure fluid level, but these are quite expensive and do not always fit into the low cost world of CBM.

**Pad Drilling** There may be factors, either economic or regulatory, that drive the use of pad drilling, where multiple directional wells are drilled from a shared location. This concept has proven successful in many circumstances, not the least of which are offshore and the Arctic. However, there are special problems with pad drilling in CBM that must be addressed before embarking down this path. Most of the problems stem from the fact that CBM usually occurs at shallow depths, and achieving a reasonable bottom-hole well separation requires high-angle directional wells. For example, in the northern San Juan Basin, to achieve a separation of 1320’ (80-acre well spacing) at a depth of 2500’ requires a hole angle of 35° (assuming a build-and-hold well geometry).

High-angle wells lead to several complications in CBM. The first of these appears when fracture stimulating the already naturally fractured coal. A complex interaction between hole-angle, well azimuth and hydraulic fracture azimuth can lead to poor alignment between the wellbore and the plane of the hydraulic fracture, resulting in premature screen-out and ineffective flow back of the permeability-reducing frac gel. [Figure 8]

![Diagram](image.png)

**Fig. 8** – Complex relationship between orientation of stress field, azimuth of wellbore and deviation angle of wellbore can lead to ineffective hydraulic fracture stimulation.

Under most circumstances, hydraulic fractures will typically grow parallel to the face cleats, which are in turn parallel to the plane of maximum stress. For a well that penetrates the coal in a near-vertical orientation (either a vertical well or an “S-shaped” well), the wellbore is aligned with the plane of the hydraulic fracture and there is no negative impact on the quality or effectiveness of the stimulation. In a directional well where the well azimuth is near-parallel with the azimuth of the face cleats, the alignment is also favorable and there
is essentially no negative impact. However, when the azimuth of a directional well is more than about 10° away from the azimuth of the face cleats, problems start to emerge with both the execution and the quality of the fracture treatment. Multiple transverse fractures form along the wellbore. These multiple fractures tend to interfere with each other, limiting the propagation of the fractures into wellbore. Also, the connection between the wellbore and the multiple fractures can become tortuous, yielding an ineffective flow path. Both of these situations can lead to screen-outs and poor post-frac clean up. These problems are magnified with increases in either the hole-angle or the difference in azimuth.

Another complication associated with utilizing directional wells in coal involves artificial lift. All other conditions being equal, a directional well will need artificial lift more often than a comparable vertical well. In a vertical well, all of the gas velocity is acting to lift the water out of the wellbore, whereas in a directional well only a portion of the gas velocity is acting in the vertical direction to lift the water. Once artificial lift is installed, failures of the equipment can be much more frequent in a directional well. If a rod-driven pump is installed, rod-on-tubing wear is much more severe in a directional well. Also, solids transport through the angled section of the well is less efficient so solids tend to fall out of suspension and build up, leading to stuck pumps.

Separation, Measurement and SCADA In addition to artificial lift, wells site equipment usually includes separation, measurement and some type of supervisory, control and data acquisition (SCADA) system. Because only gas and water are produced, a simple two-phase separator is sufficient. Separation at the wellsite is highly advantageous for two reasons. First, it allows for single-phase gathering, which is much more efficient than a two-phase system. Second, it allows for measurement of both gas and water on an individual well basis. This can be critical to optimizing well performance, especially if a well is producing on artificial lift. At a minimum, the SCADA system provides the capability for telemetry of the rate and pressure data to a central location, where performance can be monitored and troubleshooting can occur. A more sophisticated system can allow for remote operation of flow control valves and artificial lift equipment. An even more sophisticated system can provide a wide range of real-time artificial lift and POC data and allow for remote troubleshooting and optimization of the artificial lift.

Gas Gathering and Compression The primary goal of the surface development will be to get the gas from wellsite to export pipeline while minimizing the pressure at the wellhead. This is usually accomplished through the installation of compression and a large-diameter, low-pressure gas gathering system. This system should be a single-phase gathering system, as two-phase systems are subject to considerably more pressure losses and do not allow for compression. Compression can be installed at a centralized facility (e.g. the gas plant) or distributed out in the field. A typical field probably includes some combination of both.

From a theoretical standpoint, the most optimum design would include compression at every wellsite (known as wellhead compression). This provides the lowest operating pressure at the wellhead while allowing for a high-pressure gathering system, which is more efficient than a low-pressure gathering system and allows for smaller diameter pipe. However, it is not always practical or cost effective to place compression at every wellsite. Often, a hybrid system is implemented where several “nodal” compressor stations, each serving multiple wellsites, feed into centralized compression located at the gas plant. The gathering system upstream of the nodes will consist of large diameter pipe operated at low pressure while the pipelines between the nodes and the central plant will be operated at medium pressure. [Figure 9] Despite the cost and associated operational requirements, wellhead compression may be needed late in the life of the field in order to achieve the desired abandonment pressure.
Even in a properly designed gas gathering system, eventually some water will either enter the system or condense within it. This water will gather in low spots and add pressure losses that can become significant. This problem is exacerbated if the field has any topographic relief. Some provision will need to be made to remove that water from the system, either through pigging or pipeline drip systems or both.

Gas Plants
Due to the nature of coalbed methane, the gas processing plant tends to be a relatively simple facility. If a hybrid centralized-decentralized compression scheme has been implemented, gas will be entering the plant at medium pressure. The outlet, or tailgate, of the plant will usually be the entry point into a major third-party export pipeline, operating at high pressure and subject to CO$_2$, water vapor and BTU specifications. In between will be the equipment designed to remove water vapor and CO$_2$ from the gas and to compress the gas to the export pipeline pressure. Dehydration and CO$_2$ removal are more efficient at higher pressures but will most likely be performed at medium pressure to minimize the exposure of the compressors to water vapor and high-pressure CO$_2$. Depending on the export pipeline’s BTU specification, blending of the methane with richer gas may be required prior to entry. Dehydration and CO$_2$ removal may also be installed at any of the nodal compression sites.

Water Gathering and Handling
As in many conventional oil and gas fields, water is an unwanted but unavoidable byproduct of gas production in most CBM fields. While water production can be stored in tanks on each wellsite and gathered with trucks, the volume of water that is produced in a typical CBM field normally necessitates the installation of a water gathering system. This system will most likely mirror the gas gathering system. The energy to move the water through the gathering system will typically be provided by reservoir pressure (as expressed in the operating pressure of the separator on each wellsite). This is especially true in the early life of a field, when reservoir pressure is still high. Later in the field life, when every pressure loss is critical, transfer pumps can be added to lower the back-pressure on the system. Just as with water in the gas gathering system, gas will find its way into the water gathering system, collect in high spots and add back-pressure to the system. Some provision will need to be made to address this issue.

Once gathered to a centralized location (or locations), the water will need to be disposed or put to beneficial use. Two common types of disposal are surface discharge and subsurface injection. The most common beneficial use is irrigation. Surface discharge can be the least expensive option but may be prohibited or impractical, depending on water quality, applicable regulations and treatment requirements. Subsurface injection is expensive but highly effective, especially if water quality is too poor for treatment. However, a suitable injection formation must be available, preferably deeper than the productive coal. Beneficial use is
obviously the preferred solution but may not be achievable due to issues around water rights, regulations and economic factors.

**Computer Models** There are numerous commercial computer programs available to aid in the development and optimization of conventional oil and gas fields. These programs can be applied to model the behavior of the reservoir, individual wellbores or the gathering system. An ideal program would model all three components and dynamically link them together. While some commercial programs can be applied with varying degrees of success to CBM fields, there are few programs that are specifically written for CBM.

When considering reservoir simulators, one must weigh the advantages and disadvantages of numerical models versus analytical models. Numerical, or gridded, simulators are rigorous and can be highly effective at evaluating important issues such as proper well spacing and abandonment pressure. However, a numerical simulator requires in-depth knowledge of reservoir properties (like permeability) and their spatial distribution. This type of data is often not known to any degree of certainty in a highly heterogeneous CBM field. In addition, CBM fields tend to be extensive, and it is highly impractical to build a full-field numerical model for a field that could span hundreds of square miles. The best application for numerical simulators in a CBM field is to build several small models that cover the range of reservoir variation seen throughout the field and use the results to represent the entire field. This is basically the same approach used when conducting several multiple-well pilots in the appraisal stage. In fact, the logical locations for the numerical models coincide with the locations of the pilots.

Analytical reservoir models (also known as “tank” models) are much more suitable for constructing a full-field model, mainly because the data requirements are much simpler and are more aligned with actual knowledge about the reservoir. Clearly there are reservoir behaviors that analytical models do not address, like well-to-well interference. Analytical models are best applied after some fundamental questions about the reservoir have been answered by numerical models and are more suited to predicting well performance, rather than the behavior of the reservoir as a whole. When preceded by proper numerical modeling and combined with a wellbore hydraulics model and a surface facilities model, analytical reservoir models can provide a practical foundation for an integrated full-field model.

**Infill Drilling** In a perfect world, the proper well spacing would be identified prior to the initiation of development drilling. However, this does not always happen, so there could be a need for an infill drilling program sometime in the middle life of a CBM field. To account for this possibility, it could be very cost effective to oversize the pipelines in the gathering system and to design the compression and other facilities to be modular for easy expansion. Infill drilling can be more amenable to pad drilling than initial development drilling, as the inter-well spacing is generally less. However, directional wells will still be subject to all the drawbacks previously discussed, although to maybe a lesser degree.

To account for the possibility that the proper well spacing may not be identified initially, a plan should be devised to ensure that appropriate data is gathered during field development and operation. This can be difficult to justify at the time, because the value of this type of data is not always apparent in the early stages of field development. However, it is time and money well spent. For example, the measurement of initial and subsequent reservoir pressures, combined with material balance analysis, has proven invaluable in determining and demonstrating the need for infill drilling in the San Juan Basin. Regulatory approval for 80-acre infill drilling was granted primarily based upon this data and associated analysis.

While open-hole logs will likely be run as part of any CBM exploration program and subsequent development drilling, they are not necessarily required as development drilling progresses, and certainly not once an infill program commences. Once a thorough understanding has been gained regarding coal quality and coal distribution, most (if not all) necessary information for a well can be measured using cased-hole logs. If chosen correctly, and especially if supported by correlation against open-hole logs, cased-hole logs can identify coal seams, provide net pay counts and even give an indication of coal quality (density). This can result in significant per-well savings on both logging costs and rig time.

**Economic Considerations of CBM Exploration and Development** In general, CBM exploration and development are less expensive than many other types of plays. First, CBM is an onshore play, at least it has been to date, and onshore exploration and development is typically less expensive than conducting those operations offshore. Second, CBM is by nature a shallow play. Therefore well costs are low and there is no need for high-pressure / high-temperature (HPHT) equipment. Finally, the products of CBM production – methane, water and CO₂ – are relatively benign, at least in the concentrations and pressures typically associated with CBM operations.
However, CBM developments can be surprisingly expensive compared to other onshore gas developments because of the amount of infrastructure required for CBM. A low pressure gathering system, artificial lift and water gathering and disposal are all necessary and fairly capital intensive components of a CBM development. In addition, many of these investments must be made earlier in the field life than is common for conventional gas fields.

In addition to possessing the capital wherewithal to install this significant infrastructure, the developer of a CBM field must also possess patience. As mentioned earlier, CBM wells typically produce large volumes of water before yielding any commercial gas volumes. The combination of the upfront capital requirement and the delay before commercial gas rates are achieved yields a cumulative cash flow curve that can stay negative for quite some time. Due to this, it can be tempting to develop a CBM field “on the cheap” by cutting corners at every turn. While there are definitely financial benefits to controlling the upfront capital costs, cutting too many corners can lead to unintended operational problems and unexpectedly high operating costs that can destroy the long-term project economics.

Summary

Thirty years of conducting CBM operations in the San Juan Basin of the USA have provided ample opportunity for learning how to find, develop and operate CBM fields. As is often the case, some of the best lessons learned were based on the discovery of how not to do some things.

Fundamental to the learning process was the realization that, despite the many similarities between a CBM field and a conventional gas field, there are a number of highly important differences as well. These differences are driven by several properties of coal that are distinctive from those of the rocks that form conventional reservoirs. These distinctive properties shape the way that exploration, development and operations activities are conducted in a CBM development.

The two key properties of coal that impact CBM development are the storage mechanism and the water-filled cleat system. When combined, these two properties provide a trapping mechanism that is so dissimilar from that of conventional reservoirs that exploration methods differ significantly. Consequently, exploration screening for CBM focuses on a different set of geologic attributes and exploration drilling usually consists of multiple core-holes and production tests instead of a single exploratory well.

Coal’s unique storage mechanism provides pressure depletion behavior that is also dissimilar from that of conventional gas reservoirs. This behavior is governed by the isotherm curve, the shape of which drives a need to eliminate or minimize all pressure losses between the edge of the reservoir and the tailgate of the plant. This need will impact both subsurface and surface equipment and operations and dictate that most developments will require a significant investment in artificial lift and compression.

The cleat system itself is not unique, in that there are numerous conventional gas plays that are naturally fractured. As in other naturally fractured plays, there will be impacts on drilling, stimulation and reservoir modeling. However, a water-filled cleat system introduces several important factors. The water-filled cleat system is a strong driver in the need for artificial lift and a water gathering and disposal system. More importantly, the water-filled cleat system, when combined with the shape of the isotherm, generates a production profile that is initially dominated by high water production with commercial gas production only appearing over time.

This typical production profile, along with the significant and early capital requirements, can generate challenging economics hurdles and a long wait for positive cash flow. So, what has been the biggest lesson learned? Perhaps that patience is indeed a virtue in CBM development.

References

