DIRECTIONAL DRILLING TECHNOLOGY

1. Overview of Directional Drilling Technology

While the use of directional (or horizontal) drilling technology has increased dramatically since the mid-1980's, the technology itself dates back to 1891, when the first patent was granted for equipment to place a horizontal hole from a vertical well. In 1929, the first truly horizontal wells were drilled at Texon, Texas and many horizontal wells were drilled in the USSR and China during the 1950's and 1960's, with limited success. Weakening of oil prices, coupled with the need to reduce finding costs and the development of new downhole devices, resurrected horizontal drilling technology in the late 1970's and early 1980's.

A directionally drilled well is defined as a well bore that intersects a potentially productive formation and does not intentionally exit the formation for the remaining footage drilled. Generally, this means that the well is spudded like a conventional vertical well, and at a predetermined "kick-off" point (KOP), the well is deviated from the vertical so that the well bore enters the formation roughly parallel to the bedding plane. In addition to directionally drilled wells from the surface, some mine operators drill directional wells from within the mine working for degasification and geological control. Currently, there are six different techniques available for drilling horizontal holes, as shown in Figure 1 and outlined in Table 1.

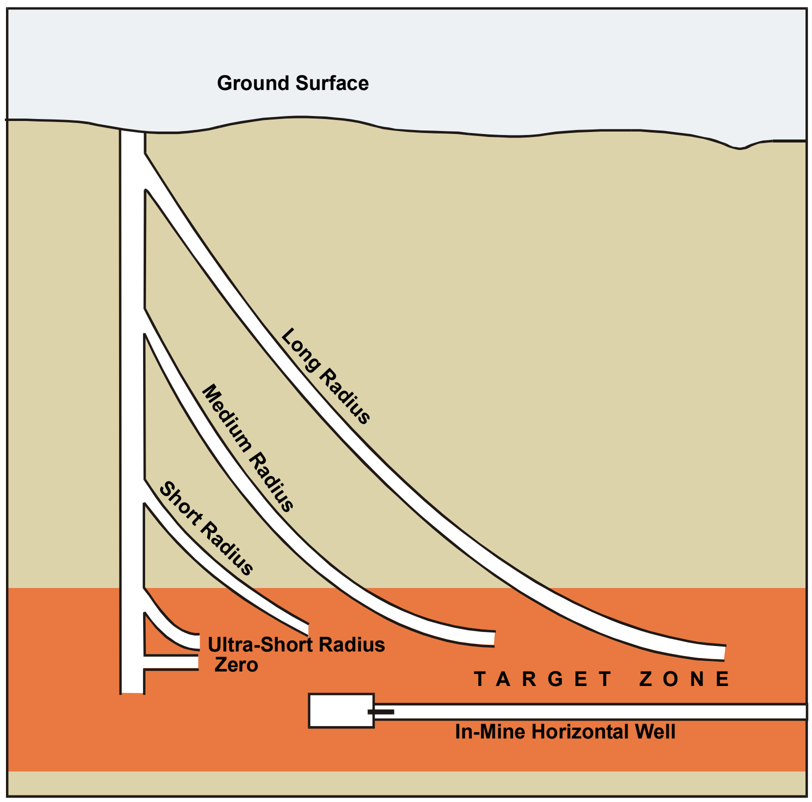

Figure 1. Classification of Directional Wells

Table 1
Classification of Directional Wells

Type Radius	Radius (Feet)	Achievable Lateral Length (Feet)	Method
Zero	0	10	Telescopic probe with hydraulic jet
Ultra-Short	0.5-5.0	200	Coiled tubing with hydraulic jet
Short	35-45	1,500	Curved drilling guide with flexible drill pipe; entire string rotated from surface
Medium	300-500	1,500	Steerable mud motor used with compressive drill pipe; conventional drilling technology can also be used
Long	1,800-2,800	1,500 +	Conventional directional drilling equipment used; very long curve length of 2,800 to 4,400 feet needed to be drilled before achieving horizontal
In-Mine	N/A	5,000	Uses underground drilling rigs with steerable motors and position systems to achieve long, in-seam boreholes

Directional drilling for coalbed degasification is an outgrowth of the techniques developed for degasification through the use of in-mine horizontal holes and surface vertical, stimulated wells ("conventional" CBM wells) using modified oilfield technology. In-mine horizontal holes have the advantage of relatively low drilling costs and the ability to intersect the coalbed cleat or fracture system at right angles to the dominant fracture direction. However, in-mine drilling requires underground access to the coal and facilities that often interfere with the mining cycle (Diamond and Oyler, 1986). Additionally, the requirement of access to the coal can limit the value of the horizontal degasification holes, because of the limited time and/or distance they can be drilled ahead of mining. Generally, horizontal wells only produce for a three to six-month period before being mined through.

The various difficulties associated with degasifying coal seams via in-mine drainage horizontal wells led the industry to the use of hydraulically fractured vertical wells drilled from the surface to degasify the coal seam in advance of mining. At first, many mining companies expressed concern that the hydraulic fracturing process would damage the integrity of the mine roof, thus creating hazardous mining conditions. These fears were largely put to rest after the publication of a U.S. Bureau of Mines Report (RI 9083) which found no significant roof damage in 22 mined-through stimulations.

The concept of directionally drilled degasification holes has been considered as a means of combining the best elements of vertical boreholes and underground horizontal drilling techniques.

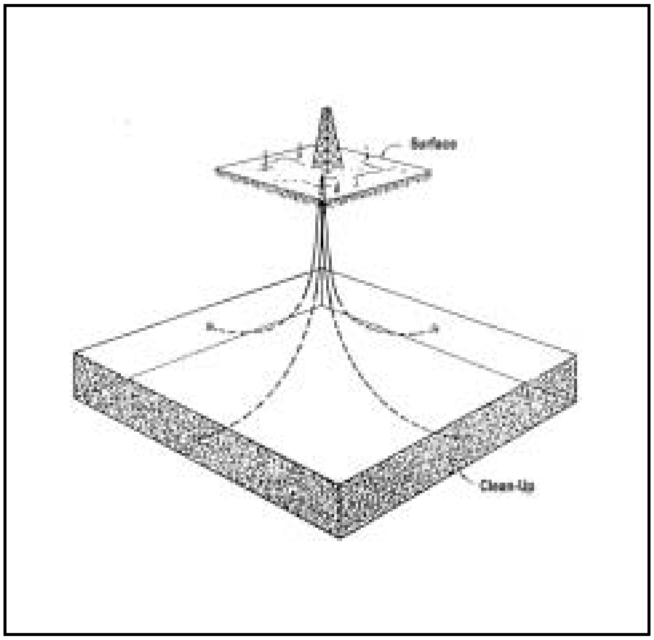

Figure 2: Schematic Diagram of a Directionally Drilled Pre-Mine Degasification.

From a single surface site, a vertical or near-vertical well could be progressively deviated to intersect a coalbed horizontally. Several horizontal gas collection holes could then be sidetracked from the original well bore into the coalbed. The drill rig could be oriented in several other directions on the same surface site, where a succession of directional degasification holes could be drilled. The cost of site preparation and production facilities would be significantly reduced by having the entire gas flow from a large degasification area centralized at one location (Figure 2).

Thus, directional drilling would eliminate the need for underground gas piping systems, would make entry into mines unnecessary, and could degasify large areas of coal far ahead of mining. The directional degasification hole could be used at sites where in-mine horizontal or vertical holes are not feasible and at sites that are unsatisfactory for other types of methane drainage (Diamond and Oyler, 1986).

2. Current Status and Research Projects

2.1 Surface Directional Wells

To date, there are limited published data on attempts at using directional wells drilled from the surface to produce gas from coal. CDX Gas, LLC is currently conducting a directional drilling project at the Pinnacle Mine in West Virginia. The project targets the Pocahontas #3 and #4 coalbeds. Reported production in 2000 from ten wells was 884 million cubic feet (MMcf).

Consol Energy, with support from the U.S. Department of Energy (DOE), will be conducting a pioneering pilot project in northern West Virginia that combines directional drilling technology with enhanced methane recovery methods via CO_2 injection. Consol will drill deviated slant wells with multi-laterals from the surface and will inject CO_2 into the Pittsburgh coal seam after producing methane from the seam for about nine months. The project will monitor the enhanced recovery for a two-year period.

While there is a general lack of published data on current directional drilling projects in coalbeds, several projects were conducted in the 1980's that provide some indication of the potential of this technique:

- **Upper Freeport Coal**. A 3-inch pilot degasification hole, sponsored by the USBM, was drilled to a near-horizontal position in the Upper Freeport coal horizon in Greene County, Pennsylvania.

- **Pittsburgh Coalbed**. Another attempt at using horizontal drilling technology for degasification in advance of mining was made by the USBM in the Pittsburgh coalbed in Greene County, Pennsylvania. In this project, a 3-inch pilot hole was drilled to a vertical depth of 1,000 feet with a total footage of 1,652 feet and a deviation of 5^{o} to 6^{o} per 100 feet.

- **Cameo Coal Group**. In 1986, the Gas Research Institute sponsored a short-radius horizontal drilling project in a deeply buried coal seam, the Cameo "D" seam, in the Piceance basin of Colorado. The well was drilled to a depth of 5,645 feet and a whipstock was set to kick-off the radial portion of the hole.

- **Hanna Coal Seam**. DOE funded a medium radius drilling project at the Rocky Mountain No. 1 site in the Hanna Basin, Wyoming in 1987. In this project, three horizontal wells were successfully drilled into the Hanna coal seam.

2.2 In-Mine Horizontal Wells

One of the biggest advances in CMM recovery has been the increased use of in-mine drilling techniques. The ability to accurately steer boreholes as long as 5,000 feet in advance of the mine face is the result of steerable motors coupled with precision borehole survey systems, both technologies developed during the 1980's.

In-mine directional drilling systems improve efficiency and lower costs by enabling fewer wells to contact the same quantity coal. For example, instead of having to drill a series of relatively short horizontal wells across the width of a longwall panel, several long holes can be drilled down the length of the panel to achieve the same degasification effect. Studies have shown that horizontal wells in a long wall panel can reduce methane levels in the panel by up to 50% within a six to nine month period.

Drilling fewer wells also reduces the amount of time required for inter-hole moves and allows for fewer gas gathering lines within the mine workings. Producing the gas via in-mine techniques can therefore improve project economics and minimize environmental impacts.

3. Technical Limitations and Barriers to Implementation

To date, the main beneficiary of direction drilling technology has been the U.S. offshore industry, where multiple directional wells must be drilled from a fixed platform location. In addition, the highly fractured Austin Chalk has seen prolific use of horizontal wells. On a less extensive basis, operators have been evaluating and using directional drilling in Prudhoe Bay in Alaska, the Bakken shale in North Dakota and Montana, and extended reach drilling projects in coastal California, where offshore prospects are produced using directional wells drilled from onshore.

On an even move case-specific basis, directional wells have been found to be economically successful in the following types of reservoirs:

- Naturally fractured reservoirs
- Oil reservoirs with water or gas coning characteristics
- Thin and/or marginal - sized reservoirs
- Heavy oil reservoirs.

Equally important is understanding what types of reservoirs are not amenable to directional drilling:

- Reservoirs with poor vertical permeability or separation due to impermeable streaks
- Multiple zones with pressure differences
- Unconformities caused by igneous intrusions
- Mineralized fractures
- Areas of high tectonic stress
- Reservoirs which fluctuate greatly in reference to true vertical depth.

Coal seam reservoirs are complex, and as such have elements which are both favorable and unfavorable for successful directional well development. Two critical coal characteristics could compromise the effectiveness of directional wells:

- **Poor vertical permeability or impermeable streaks.** Compositionally, coal is often heterogeneous with the different coal types generally segregated into bands, which can range in thickness from several millimeters up to several to tens of centimeters. The degree of cleat development varies greatly between these coal types; for example vitrain bands tend to be well cleated, while durain bands tend to be poorly cleated. The alternation of well cleated/poorly cleated bands can substantially reduce vertical permeability. Additionally, coalbeds often contain thin shale beds or stringers which would further limit vertical permeability.

- **Variable formation depth and thickness.** Some coalbeds were formed in depositional systems which resulted in erratic or uneven coal seam deposition. In such cases, it would be difficult to keep a horizontal or near-horizontal hole in the seam while drilling. Problems experienced in the Upper Freeport project (see previous section) were primarily due to erratic coal thickness.

In addition to possible reservoir limitations, there are also several operational constraints which may limit the effectiveness of directional drilling for pre-mine drainage. In every actively mined coalfield in the U.S., there are at least several (and up to dozens) of thinner, unminable seams located above and below the mined seam. These associated seams are an important source of methane emissions (i.e., gob gas emissions) and as such, need to be targeted in any pre-mining drainage scheme. While it is technically feasible to drill multiple horizontal legs at different depths, there are some unique characteristics of how coalbed methane wells are produced which must be considered:

- First, only one leg of a horizontal well with multiple legs can be cased. Because coal is often friable, uncased horizontal wellbores will be prone to sloughing and collapse. The loss of wellbore integrity will inhibit both the dewatering process and gas production.

- Second, dewatering operations in horizontal wells are more complicated than vertical well operations. The majority of coalbed methane wells in the U.S. are dewatered using conventional "beam" or "sucker rod" pumps. Formation water is produced by a down-hole pump, which is operated via an up and down motion imparted to the rods by the pump jack on the surface. Because the pumping system is designed to operate in a vertical plane, the connecting rods tend to break when flexed, as would be the case in a horizontal wellbore. However, provided the build angle is not too great (<20º/100 feet), rod guides and other equipment can be installed to allow beam pumps to be used efficiently. However, a down-hole pump could only be installed in one horizontal leg at a time, which would leave the other horizontal legs full of water, thus limiting their effectiveness. Some operators have tried to overcome these limitations by letting the water from the horizontal legs dewater naturally via gravity into the vertical portion of the wellbore and then pumping out the water.

4. Comparison of Vertical and Horizontal Well Performance

As discussed in the introduction, the decision to employ directional wells is primarily an economic one. Horizontal well costs are generally 20% to 25% higher than vertical well costs; because of this, they must produce commensurately more gas to compete economically. Because there are limited published data on the performance of directionally drilled wells in coal seams, reservoir simulation must be used to compare the recovery efficiencies of vertical and horizontal wells.

Data for this reservoir modeling study were taken from the Rock Creek Field test site near the Oak Grove mine in the Warrior Basin of Alabama. The Rock Creek site, funded by the Gas Research Institute, represents the most intensively studied coalbed methane project in the world (see GRI Topical Report 93/0179 entitled "Reservoir Characterization of Mary Lee and Black Creek coals at the Rock Creek Field Laboratory, Black Warrior Basin" for detailed data). Additionally, the close proximity of the Rock Creek Site to extensive active mining operations (i.e., the Oak Grove mine) allows for the close simulation of an actual mine setting.

The vertical well case modeled was a multi-seam completion in the Mary Lee seam (9 feet thick at a depth of 2,200 feet) and the Black Creek coal seams (a combined thickness of 7 feet thick at 2,500 feet depth). Both the Mary Lee and Black Creek intervals were modeled using 100 foot fracture half-length for a typical, fractured vertical well. It was assumed that the pump was set below the Black Creek interval to maintain a bottom hole pressure of 25 psia.

The reservoir and operating parameters used for modeling the horizontal wells were assumed to be identical to the established vertical well parameters, with the following exceptions:

- Two horizontal legs were required to access both the Mary Lee and Black Creek seams. Mary Lee coal thickness was modeled using 9 feet (same as the vertical well case). For the Black Creek coal, a thickness of only 2 feet was modeled (compared to 7 feet in the vertical case). Because the Black Creek coal group is comprised of a number of thin coal seams spread out over a 20 to 30 foot interval, it would be uneconomic to drill horizontal legs into coal seams less than 2 feet in thickness.

- Three different horizontal wellbore lengths were simulated; 500 foot, 1,000 foot and 1,500 foot. The horizontal wells are assumed to be short radius wells with a radius of 40 feet.

- No hydraulic fracturing was assumed for the horizontal laterals.

- An electric submersible pump is set below the Black Creek lateral which results in a back pressure of 40 psia on both coal seams; this higher back pressure is the result of water remaining in the radial portion of the well.

Table 2 presents the results of the production simulation for the vertical and horizontal well cases. For this example, horizontal wells recover from about 50% to 300% more gas by the first year than a vertical well: a vertical well will only recover about 68 MMcf versus 93.4 MMcf, 169.6 MMcf, and 238.7 MMcf for the 500 foot, 1,000 foot, and 1,500 foot horizontal cases, respectively. This should be an important consideration to a mining company if they were interested in pre-mine degasification and had limited lead time before mining were to take place.

Table 2
Comparison of Vertical and Horizontal Well Recoveries

	Cumulative Gas Recovery (MMCF)			
	1 Year	3 Year	5 Year	10 Year
Vertical Well	67.9	237.5	321.0	431.0
Horizontal Well, 500' Lateral	93.4	212.0	275.5	351.4
Horizontal Well, 1,000' Lateral	169.6	300.3	354.2	411.3
Horizontal Well, 1,500' Lateral	238.7	362.2	405.2	445.6

On the other hand, ten-year recoveries vary by 30% or less, with the vertical well producing 431 MMcf, the 500-foot horizontal case - 351.4 MMcf, the 1,000-foot horizontal case - 411.3 MMcf, and the 1,500-foot horizontal well case - 445.6 MMcf. These results indicate that if a mining company has the ability to install pre-mine degasification wells 10 years or more in advance of mining, the incremental degasification effect between horizontal and vertical fractured wells would be somewhat limited. Therefore, given the higher costs and greater risks (hole stability, etc.) associated with horizontal wells, companies would opt for vertical wells, (except for certain situations, described in Section 6). This conclusion is supported by the fact that all of the pre-mine degasification wells drilled to date in Alabama and Virginia are vertical wells.

5. Economic Analysis

The results of a cash-flow analysis of the gas production streams for the vertical and horizontal well cases considered here is presented in Table 3. The analysis assumed a vertical well cost of $250,000. Based on published data, horizontal well costs run from 15% to 30% higher than vertical wells, depending on the length of the horizontal leg. In this study, we assumed a 500 foot horizontal would be 15% higher, a 1,000 foot horizontal 25% higher, and a 1,500 foot horizontal 30% higher. These percentages were then doubled to account for the fact that two horizontal (one in the Mary Lee/Blue Creek and one in the Black Creek) legs were modeled. This resulted in horizontal well costs shown in Table 3. A $2.00/Mcf gas price was assumed for the economic analyses for all cases.

Table 3
Cash-Flow Analysis of Vertical and Horizontal Well Production

Case	NPV (@10% Discount Rate)	Well Costs
Vertical Well	$83,121	$250,000
Horizontal Well, 500'	($7,397)	$575,000
Horizontal Well, 1,000'	$118,430	$625,000
Horizontal Well, 1,500'	$229,151	$650,000

The results of the analyses show that the 1,500-foot horizontal well has the highest NPV at $229,151 (Table 3). Only one case, the 500-foot horizontal case, has a negative NPV. The vertical well and 1,000-foot horizontal well have similar NPV's $83,121 and $118,430, respectively. Therefore, from a financial perspective, there is not a big incentive to select a 1,000-foot horizontal well over a vertical and, given that vertical wells are proven and lower risk, companies would tend to continue drilling vertical degasification wells.

6. Potential Methane Emission Reduction from Directional Drilling

The use of horizontal wells, instead of more traditional fractured vertical wells, will generally result in small increases in CMM recovery over the life of the well. However, with horizontal wells, CMM would be recovered much more rapidly. This would generally lead to more rapid project payback times (although horizontal wells cost more than vertical wells). On the other hand, the use of horizontal wells would, in most instances, probably be perceived as more risky.

Consequently, the relative economic viability of horizontal or directional wells to enhance CMM recovery will be very site-specific, depending on a variety of factors, including:

- The development schedule and strategy of mining operations, and the relative lead times associated with degasification activities (if substantial lead times between degasification and mining are possible, vertical wells may be more cost-effective).

- The general topography at the mine location. (In many cases, there may be only limited sites from which vertical wells could be drilled, which would necessitate the use of multiple directional wells from a single well site).

- The relative contribution of methane recovery and sale to the profitability of mining operations. Based on relative coal and natural gas prices, rapid recovery of methane from the coal seam may present considerable economic advantages.

- The willingness of the mine operator to accept the possible risks associated with applying horizontal drilling technology.

Given the site-specific potential costs and benefits associated with the utilization of horizontal wells in place of traditional, vertical wells with fracture stimulations, it is impossible to make blanket assumptions to estimate the methane emissions reduction potential associated with the use of horizontal wells to enhance CMM recovery. However, several broad assumptions could provide some guidance into the order of magnitude of potential benefits:

- If 10% to 25% of the gassiest mine sites (those emitting more than 5 MMcf per day) have topography that restricts the use of vertical wells, and CMM recovery would not be realized otherwise, then roughly 1.9 to 4.8 Bcf per year of methane emissions reductions could be realized from the use of horizontal wells. This assumes that horizontal wells reduce the methane emissions from mining by 30%, similar to that assumed to be achievable by fractured vertical wells.

- Similarly, if 10% to 25% of the gassiest mine sites choose to use horizontal wells because they provide, at their specific sites, indisputable economic advantage from more rapid methane recovery, then comparable methane emission reductions - - from 1.9 to 4.8 Bcf annually - - could be realized.

7. Summary

Pre-drainage of methane from mineable coal seams, either via the use of horizontal wells or standard vertical wells, offer the most economic options for reducing methane emissions from coal mines. Studies at the Oak Grove mine in Alabama have shown that up to 79% of the initial gas-in-place can be produced prior to mining (Diamond and others, 1989). Pre-drainage wells offer significant advantages over other degasification methods (i.e., in-mine horizontal wells and gob wells) which require mining to take place before gas production can occur. These advantages are:

- The quality of the gas produced meets or is close to pipeline specifications, thus limiting gas processing costs.

- Pre-drainage of the methane will lower mining costs through reduced ventilation costs and less down time due to gas-outs.

Directional drilling for pre-mine degasification exhibits some potential for lowering methane emissions associated with coal mining. However, mining companies (as well as coalbed methane producers) have been reluctant to attempt horizontal drilling because of it's higher costs, greater technical risks, and relatively unproven performance in coal seams. It is important to remember that it took about 8 years for the mining industry to accept hydraulic fracturing in minable coal seams. Just as it took the 22 successful mined-through stimulations to convince the mining community of the efficacy of hydraulic fracturing, it may require several successful directionally drilled pilot demonstrations projects (like those underway at the Pinnacle Mine) to persuade the industry to consider this approach for CMM recovery.

R&D efforts in directional drilling need to concentrate on lowering costs and maintaining hole stability.

References

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