Directional Drilling: The Key to the Smart Growth of Oil and Gas Development in the Rocky Mountain Region

By Ken Kreckel

Over the past few years, the Rocky Mountain region has experienced explosive growth in drilling, especially in the number of natural gas wells. Benefiting from increases in gas price and new technologies, operators have embarked on a wave of development of gas resources that is breathtaking in magnitude, comprising increases of thousands of wells. While the region has previously experienced booms in drilling, this one has a different character. Natural gas resources are being developed at an unprecedented density, with wells spaced every 20, 10 or even 5 acres. Gas fields now consisting of 64 or even 128 wells per mile are being developed, rather than the one or two wells per square mile which previously characterized such fields. With each well site typically comprising 2 to 4 acres, such drilling densities leave little area of a gas field untouched by development. Since such fields can be comprised of hundreds, or even thousands of wells, and there are many such fields, extensive areas of the West are being affected. This increase in drilling and order of magnitude increase in density is resulting in impacts to the surface that were until recently unforeseen.

The application of one technology, directional drilling, can significantly mitigate these impacts. Long established in the drilling industry, this method has widespread applications in the fields currently under development. By allowing the concentration of many wells in a single pad, directional drilling can greatly decrease the density of drilling on the surface, thereby dramatically reducing the environmental impacts of gas developments.

In the field of city planning, there is a concept called "Smart Growth", which is now providing new guidelines for urban planning and zoning. Its goal is to manage growth through a rational approach, one that seeks to eliminate the often unplanned growth which has bequeathed massive traffic problems, suburban sprawl and blighted neighborhoods. Smart Growth solves these problems in two major ways. One is remedial, by redesigning existing streetscapes. The other, one that is more applicable to oil and gas developments, attempts to get it right in the first place, by "creating environments that nurture the well being of people" working and living within them.[1] The creation of livable high density communities are a major part of this effort.

This paper borrows the phrase, "smart growth", and applies it to the management of the unprecedented growth in oil and gas drilling that is currently underway across the Rocky Mountain region. Much of this is essentially unplanned, that is, individual companies are drilling their acreage to maximize production, with massive impacts to the environment. The accompanying unprecedented boom in drilling densities requires a new approach to manage its impact. Directional drilling has been shown to be an excellent means of reducing the impacts of these densely drilled gas developments. Unfortunately, this

[1] Zelinka, Al, "6th Annual New Partners for Smart Growth," conference announcement, 2006.

advantageous technology has only been partially adopted as a primary means of reducing surface impacts. Largely due to the perception of higher costs, industry has been reluctant to embrace this technology. BLM, the main steward of our federal lands, has likewise been slow to require, or even properly analyze, its use, despite the obvious environmental benefits. This paper will show that directional drilling should be adopted as a major means of reducing these impacts. 'Smart growth' of Rocky Mountain gas production must include a large role for directional drilling, especially in the areas of intense drilling of our unconventional gas resources.

THE PROBLEM: UNPRECEDENTED GROWTH IN BOTH THE NUMBER AND DENSITY OF GAS WELLS

This large increase in Rocky Mountain drilling activity has resulted in a significant increase in production [see Figure 1]. According to one industry source, IHS reported gas well completions increased from 5700 in 2002 to 8100 in 2005.[2] Much of this increase comprised wells completed in tight gas sand reservoirs in Colorado, Utah and Wyoming. This activity continued to increase during 2006. Colorado saw their annual permits increase to 5848 in 2006 over the pervious year total of 4323. Half of these wells were permitted in the tight gas sand play of the Piceance Basin.[3] Utah saw its 2006 drilling increase to 1054 wells from 889 in 2005. Over 90% of these were concentrated in the tight gas fields of the Uinta Basin.[4] Wyoming projected a total of 4200 wells for 2006, up from 3640 in 2005.[5] Much of this increase was due to the very active drilling for tight formations in the Green River Basin, and the Powder River Basin coalbed methane play. Across the Rocky Mountains, coalbed methane wells comprised over 4000 wells in 2005, up from just over 3000 in 2002.[6]

These new developments are exploiting two unconventional sources of gas: tight gas sands and coalbed methane. Total ultimate reserves from unconventional gas sources in the Rocky Mountains is estimated at 60 trillion cubic feet (Tcf) from tight gas formations and an additional 30 Tcf from coalbed methane.[7] Both of these estimates far exceed the totals from any other region of the United States. With reserves of this magnitude for the taking, it is clear the current high levels of drilling activity can continue for many years.

This paper will focus first on tight gas sand wells, which comprise the bulk of the most recent drilling increase. Coalbed methane [CBM] will be discussed in a separate section.

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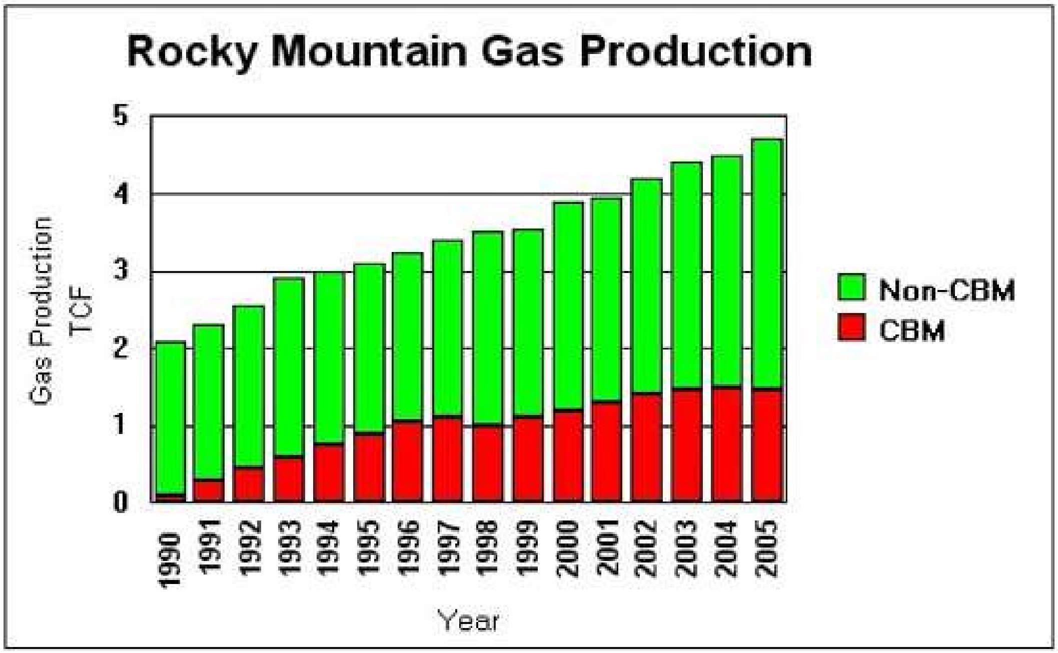
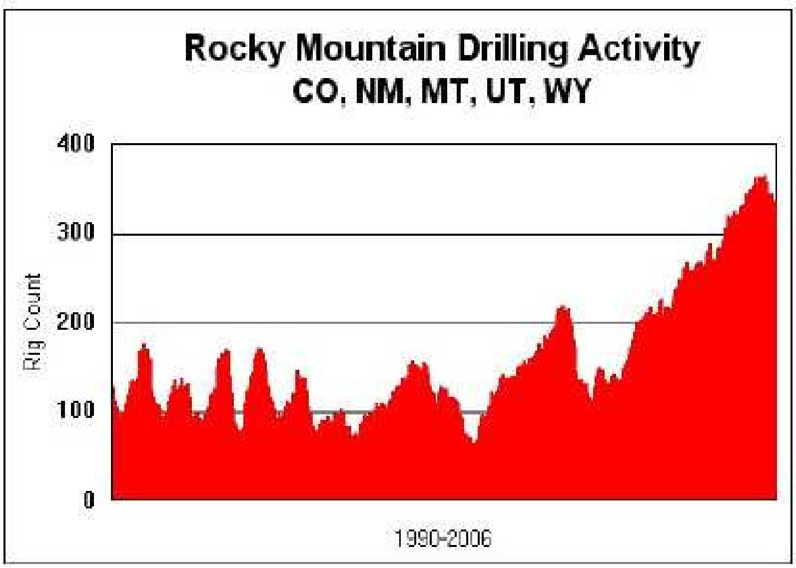
[2] Trammel, Stephen, Senior Product Manager, IHS, Inc., "Rocky Mountains…Cooking With Gas and Oil," presentation, May 18, 2006.
http://energy.ihs.com/NR/rdonlyres/949AEE0D-E1F5-4522-B95C-096D0CE6F3DE/0/Trammel.pdf
[3] Colorado Oil and Gas Conservation Commission, data, 2007. http://www.oil-gas.state.co.us/
[4] State of Utah, Division of Oil, Gas and Mining, data, 2007. http://www.ogm.utah.gov/
[5] World Oil, statistics, 2006. http://www.worldoil.com/
[6] Trammel 2006.
[7] Oil and Gas Investor, "A Supplement to Oil & Gas Investor: Tight Gas," March 2006.
http://www.oilandgasinvestor.com/pdf/TightGas.pdf

FIGURE 1





Increase in natural gas production in the Rocky Mountains for CBM and other, mostly tight gas. Drilling activity is for states with major unconventional gas resources. [Sources: IHS and Baker Hughes].

In numbers alone, the increases in tight gas sand drilling activity cited above are significant, but this recent upsurge has an additional unforeseen characteristic, one that impacts the environment to a greater extent than the sheer numbers imply. The density of drilling, that is, how many wells are drilled in a square mile, has reached unprecedented numbers.

In the past, a typical gas well was thought to drain an area of about 640 acres. Accordingly, natural gas reservoirs had been developed with wells usually spaced at one per square mile. Now, an improved understanding of tight gas sands has resulted in those reservoirs being developed with incredibly dense spacing, up to and including one well per 5 acres, or 128 wells to the square mile. Speaking of just one of these developments [Roan Plateau], an Encana geologist wrote, this represents "the greatest gas well spacing density in Colorado (and probably the world)."[8]

Understanding the current growth in the development of tight gas sands

There are primarily two reasons for this explosive growth:

1. Increase in the price of natural gas
2. Impact of new technology[9]

Before examining these factors in detail, a brief look at the geology of tight gas sand reservoirs will be useful Then, we will examine the chief factors driving this activity: the rise in gas price resulting from increased demand, and the new understanding of the nature of tight gas reservoirs, which revealed the typical well drains only a very small area, paving the way for the very dense drilling we're experiencing today.

Geology of tight gas sand reservoirs

In short, tight gas sands are defined as sandstone formations with less than 0.1 millidarcy permeability.[10] Due to the tight, low permeability nature of these reservoirs, artificial fracturing techniques are required for wells to be productive.

These formations occur in most of the gas productive basins in the Rocky Mountain region [see Figure 2]. Although composed of various geologic formations, they share common characteristics:[11]

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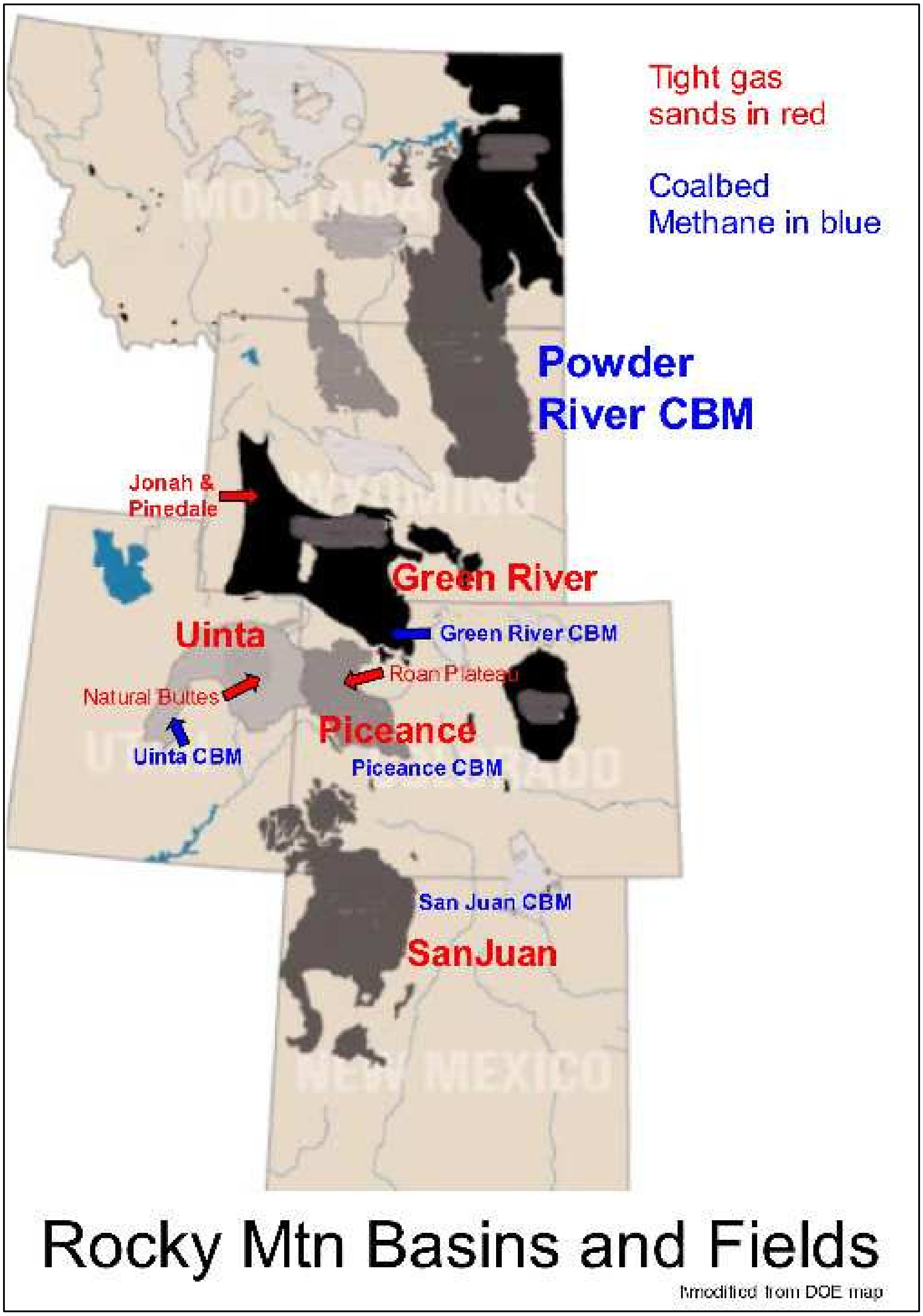
[8] Uhi, David, EnCana O&G Inc., "Mamm Creek (Mesaverde) Field: Exploiting a Giant Basin-Center Resource," Joint CSPG/CSEG Convention Abstracts, 2003.
http://www.cspg.org/conventions/abstracts/2003abstracts_author.htm
http://www.cspg.org/conventions/abstracts/2003abstracts/483S0207.pdf

[9] Perry, Kent F., Michael P. Cleary, and John B. Cleary, New Technology for Tight Gas Sands, World Energy Council, 2005.
http://217.206.197.194:8190/wec-geis/publications/default/tech_papers/17th_congress/2_1_16.asp

[10] Perry 2005.

[11] U.S. Energy Information Agency, U.S. Department of Energy, "Characterization of Utah's Natural Gas Reservoirs and Potential New Reserves," 2003.
http://geology.utah.gov/emp/gas_research/pdf/resource_character.pdf

FIGURE 2



Principal Rocky Mountain sources of unconventional gas

- Moderate drilling depths
- Multiple, stacked, channel reservoirs
- Continuous, deep-basin gas
- Multiple reservoirs and in-situ source rocks
- Tertiary and Cretaceous age

The key characteristic is the nature of the reservoirs. These reservoirs are often composed of multiple gas charged 'channel sands' that are individually discontinuous, and lenticular in shape. These sands are distributed both vertically [stacked] and horizontally within a particular formation. Any one gas well drilled through the formation is likely to encounter a number of these individual sands, but a nearby offsetting well may encounter similar, and but quite separate sands. Even two closely spaced wells may produce from entirely separate reservoirs. Thus gas wells must be drilled very closely together to adequately drain a given reservoir, frequently at 20, 10, or 5 acre spacing. Instead of the situation that prevailed in the past, that of one to four gas wells per square mile, we now have fields being drilled with 32 to 128 wells per square mile.

Although the individual sands within the formation are discontinuous, the formation as a whole, consisting of a large number of these separate bodies, can be considered a continuous reservoir. As described by the Colorado School of Mines:

> tight gas sand reservoirs differ from conventional reservoirs in that tight gas sands are continuous, consisting of a stacking of sedimentary layers that are charged with oil or gas much in the same way that an aquifer is charged with water.[12]

Hence, the risk in drilling tight gas sands lies not in discovering gas, but finding it in economic quantities. Limits to fields can become defined by economics rather than geology. However, that is not to say all tight gas sand reservoirs are equally prolific:

> There are "sweet spots" where wells of greater productivity may be found.[13]

Hence some portions of a field may be developed with a tighter well spacing than other areas.

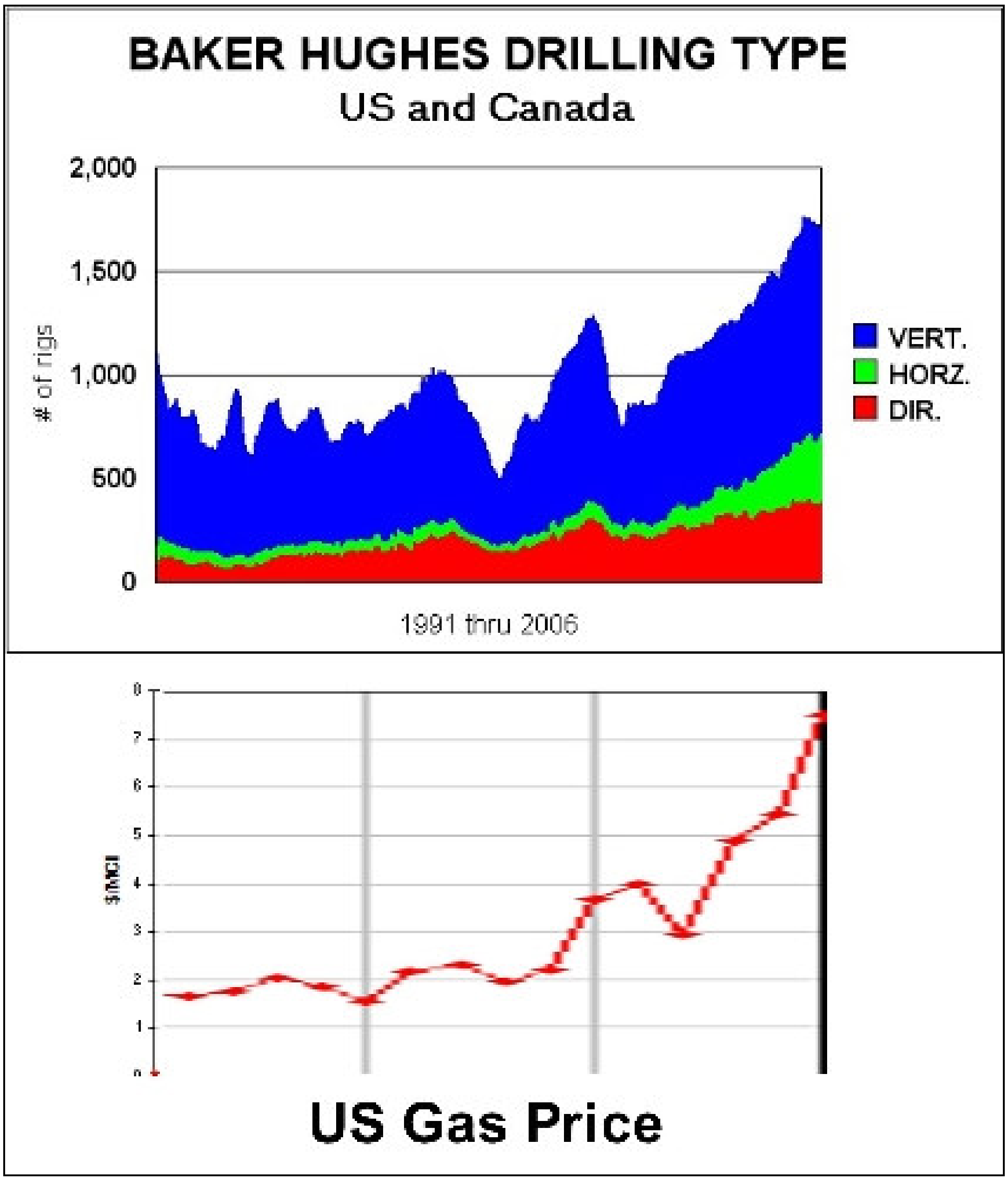
Increases in gas price have driven increased drilling in the Rocky Mountains

One of the major factors driving the recent increase in gas well drilling is price. Over the last several years, the price of natural gas, responding to increasing demand and lowered supply, has increased dramatically. Therefore, gas wells that were uneconomic to drill as recently as the 1990s, are now very profitable to drill.

[12] Baughman, Gary, "Tight Gas Sands," Colorado School of Mines, 2006.
[13] Baughman 2006.

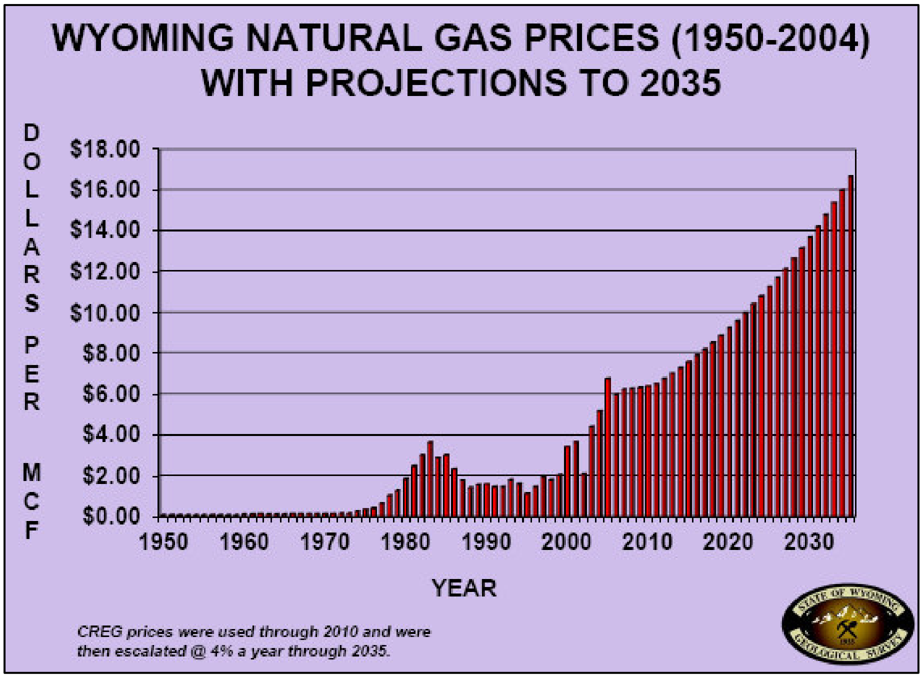
Figure 3 shows the close relationship between gas price and the number of active drilling rigs in the U.S. There is widespread agreement that these product price increases are projected to continue far into the future. Predictions of a continued rise in price made by the Wyoming State Geological Survey are illustrated on Figure 4.

FIGURE 3



Relationship of gas price to drilling, showing the magnitude of recent increases in each. [Source: DOE and Baker Hughes data]

FIGURE 4



Historical and projected price of natural gas

This rise in prices has had a dramatic impact on the Rocky Mountain region. A prominent geophysicist, Rhett Bridges, in a recent article published by the Society of Exploration Geophysicists, explains:

> The National Petroleum Council estimates that the Rockies hold 41% of proven and potential U.S. onshore gas reserves, versus 36% for the Midcontinent and 23% for the Gulf Coast. Between 1972 and 1999, the Rocky Mountain region increased gas production more than fivefold while the Gulf Coast dropped 24% and Midcontinent went down 36%. The Energy Information Administration's "Annual Energy Outlook" for January 2005 predicts that the Rockies will become the No. 1 onshore producing region by 2008.[14]

He goes on to show that world demand will continue to increase and competing energy sources are unlikely to make up the supply shortfall. He concludes:

[14] Bridges, Rhett, "The next ten years in the Rockies: Oil and gas prices, technology, and politics," The Leading Edge, SEG, February 2007.

> The United States will definitely need to expand its investment in both renewable energy and conservation to get through the coming decades without significantly higher gas prices.[15]

A wide range of industry experts supports the view that worldwide supply and demand considerations will mandate a continuing increase in price.

Increased density of drilling is due to improvements in reservoir engineering

Both improvements in technology and significant increases in gas prices during the latter part of the 1970s resulted in rapid development of tight gas sands in several sectors of the country. Tax credits and advancing technologies in the 1980s further increased development, with production reaching 2.5 Tcf per year. There are now over 40,000 tight gas wells producing from 1600 reservoirs in 900 fields.[16]

Recent improvements in reservoir engineering have taken two forms. One centers on artificial fracturing technology, which has increased the productivity of an individual gas well. The other is the recognition that a individual tight gas sand well drains only a very limited area around the wellbore.

It is widely acknowledged that advances in artificial fracturing techniques have been a major factor in allowing the economic exploitation of tight gas sands. The application of this improved technology essentially began in the Rocky Mountain region:

> Tight gas production first developed in the Western United States San Juan Basin, fueled by improvements in hydraulic fracturing technology.[17]

By 1970, approximately 1 Tcf per year were being produced nationwide.[18] Improvements continued, slowly at first. At Jonah, although the field was discovered in 1975, development did not begin in earnest until the 1990s. Montgomery et al attribute this to advancements in artificial fracturing technology.[19] Now, essentially all tight gas sand wells undergo extensive artificial fracturing during their completion.

However, new advances in the recognition of the nature of tight gas sand reservoirs have played an even greater role. Geologic and reservoir studies have resulted in the understanding that tight gas sand reservoirs are composed of the individual, discrete, reservoir packages described above. Accordingly, any given well may intersect and produce from only a small number of these. Another well, even one quite close, is likely to encounter reservoirs that were untapped by the first. Many reservoir studies support this idea.

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[15] Bridges 2007.
[16] Perry 2005.
[17] U.S. Agency, "Characterization of Utah's Natural Gas Reservoirs and Potential New Reserves," 2003.
[18] Perry 2005.
[19] Montgomery, Scott L. and John W. Robinson, "Jonah Field, Sublette County, Wyoming; gas production from overpressured Upper Cretaceous Lance sandstones of the Green River basin," AAPG Bulletin, July 1997, v. 81, no. 7, pp. 1049-1062.

An early study performed at the DOE's MWX field research site involved the successful recompletion and stimulation of several uphole zones in the Mesaverde, a major tight gas sand. Later a more extensive recompletion program was performed in the mid-90s by Barrett Resources. Focusing on the Mesaverde in the Piceance Basin, this work featured advanced fracturing techniques that enabled "completing and independently stimulating each of the sand packages, increasing the size of the proppant load, and using more sophisticated fracturing fluids and procedures." The program added reserves of 80 Bcf. Barrett followed up with an infill drilling program in Rulison Field [Piceance Basin], successively going from 160- to 40-acre spacing, ultimately drilling a pilot project of four wells at 20-acre spacing in one particular square mile area [Section 20]. Results were as good for the 20-acre wells as the 160-acre well. Additional 20-acre infill wells were drilled, with the result that "the reserves per well remained relatively constant as the well density in Section 20 has progressively increased, indicating additional gas is being recovered vs. faster depletion." Williams followed up with a 10-acre program with encouraging results. "Based on estimates by Williams, gas recovery in this section [10-acre spacing] may reach 75% of gas-in-place vs. less than 10% on the previous 160-acre spacing."[20]

Similar studies were performed in several other tight gas sand fields across the Rockies, with much the same results. With the case for increased drilling density proven, operators across the region embarked on large infill programs in many tight gas sand fields, going to the very dense spacing described. Some of these will be discussed in detail in a subsequent portion of this report.

However, the production characteristics of these reservoirs also bear examination. The initial production from these wells is high, but it declines rapidly to level off at a relatively low number. Although the increased number of wells has resulted in a steady increase in daily production, that production, if drilling is halted, declines rapidly. This results in a situation that, in the words of one exploration Vice-President, is like "eating crawfish", that is, "you can't eat them fast enough to fill up." Charles Stanley, Executive Vice-President of Questar, a major oil and gas operator in the Rocky Mountain region, agrees:

> This unconventional gas resource is like a treadmill. We are running hard just to stay in place. …they come on at a fairly high rate, declining very rapidly, with about a 40% to 50% decline in the first year. After about 5 or 6 years, we have recovered about half of the gas that that individual well will recover. We then go into a fairly long, low-rate, flat production profile. Because of the nature of these wells and these reservoirs, a very high amount of capital reinvestment is required just to stay at flat. High

[20] Kuuskraa, Vello, Advanced Resources Intl. Inc. and J. Ammer, National Energy Technology Laboratory (NETL), "Tight Gas Sands Development–How to Dramatically Improve Recovery Efficiency," Unconventional Resources, GasTIPS, Vol. 10, Number 1, Winter 2004. http://204.154.137.14/technologies/oil-gas/publications/GasTIPS/GasTIPS-Winter04.pdf

> capital reinvestment corresponds with a large number of wells that we need to drill each year.[21]

Thus as production rises, an ever increasing number of wells must be drilled just to keep production at the current level. This effect contributes to the large increase in number of wells currently being drilled in the region.

This growth has resulted in unprecedented impacts to the surface.

This unprecedented increase in the number of wells per square mile of development has resulted in significant impacts to the surface. Using a typical BLM estimate for the area of a single well pad of 1.9 acres, and 10-acre spacing, we have 122 acres of direct surface impacts per square mile.[22] This is obviously much greater than the 1.9 acre per square mile that the older 640-acre spacing generated. To this, the effect of the accompanying roads and pipelines must be added. Estimating road and pipeline impact at another 2 acres per well, we have another 128 acres, for a total impact to the surface of 250 acres, or fully 40% of the square mile under development. Given a gas well may have a life of twenty years or more, clearly this density of well pads has an enormous and lasting impact to the surface. When even denser spacing of 5 acres is utilized, it is easy to see that the entire area of a gas field can be impacted.

The effects of this increased well density can be readily seen in Landsat photos. In Figure 5, Jonah Field's growth is graphically chronicled from the situation in 1989 with few wells drilled to 1999 when the field was developed on 160- to 80-acre spacing. The 2005 photos show the field after infilling at 40-acre spacing [16 wells per square mile]. Approval has since been granted for an additional 3100 wells, spaced at 20, 10 and 5 acres. This translates to an average of 4 additional well pads to each well shown. Virtually none of the surface will remain unaffected.

The case of Rulison Field, a part of the overall development of the Roan Plateau area in western Colorado, is similar. Figure 6 shows the field in 1989 and after development at 160-acre spacing in 2004. Drilling continues to reduce this spacing to 40 acres and less. [Both this and Jonah Field will be examined in detail later in this report].

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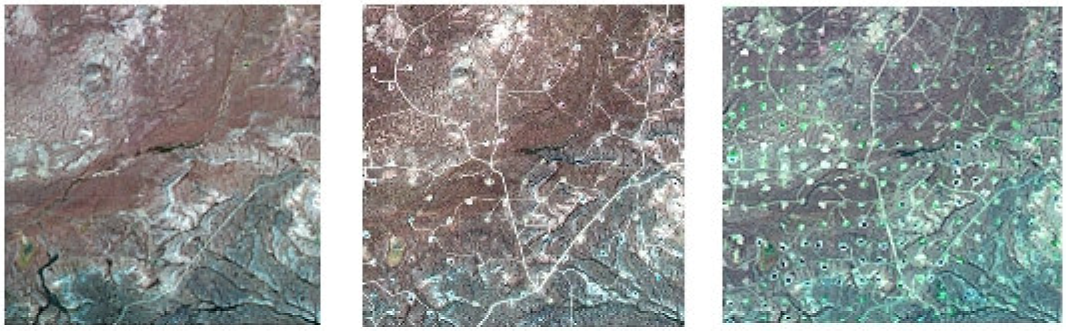
[21] Stanley, Charles, Executive Vice President and Director, Questar Corporation, "U.S. Natural Gas Supply: Time for Compromise," speech, Interstate Oil and Gas Compact Commission (IOGCC) Annual Meeting, Jackson Hole, 2005.
http://iogccdev.phase2online.com/Meetings/Annual_meeting/Jackson_Hole_2005/Charles_Stanleys_Speech.pdf

[22] Bureau of Land Management (BLM), "Roan Plateau Resource Management Plan (RMP) Amendment, Oil and Gas Development Summary," August, 2006.
http://www.blm.gov/rmp/co/roanplateau/documents/Oil_and_Gas_Development Summary.pdf

FIGURE 5



1989 1999 2005

Development of Jonah Field, Wyoming

Source: Skytruth

FIGURE 6

1989 2004

Rulison Field, Roan Plateau Area, Piceance Basin, Colorado

Source: Skytruth

Besides the obvious visual evidence, the impacts of this density of drilling are numerous. Among them are:

- Increases in air pollution caused by emissions from vehicles, drill rigs, compressors and other engines, and dust caused by vehicular traffic;
- The introduction of noxious weed species and invasive alien species;
- Ground and surface water pollution caused by hydraulic fracturing operations and the disposal of drilling fluids and produced water;
- Noise and light pollution;
- Changes in the foraging behavior, breeding success, and migration patterns of wildlife; and
- Aesthetic loss resulting from the industrialization of essentially wild or pastoral landscapes.[23]

But these impacts can be minimized simply by reducing the number of well pads. Pinedale Field, due to a better utilization of directional drilling, has seen much less impact [Figure 7—compare with Jonah, Figure 5]. A recent study of the mule deer population in this field concluded that "Efforts to minimize habitat losses should focus on reducing numbers and size of well pads."[24] As John Amos stated in his testimony before Congress, "Much of this impact could be reduced by applying well-demonstrated technologies to shrink the direct surface footprint of oil and gas operations."[25] One of the most effect ways of doing this, without reducing the amount of oil and gas developed, is the widespread application of a proven technology--directional drilling. This technology, by allowing the drilling of numerous wells from a single well pad, can dramatically reduce the number of well pads, and therefore, the undesirable impacts to the surface.

As Questar's Charles Stanley recently stated: "How can you minimize surface disturbance? We had technology readily available to do that using directional drilling from pads."[26]

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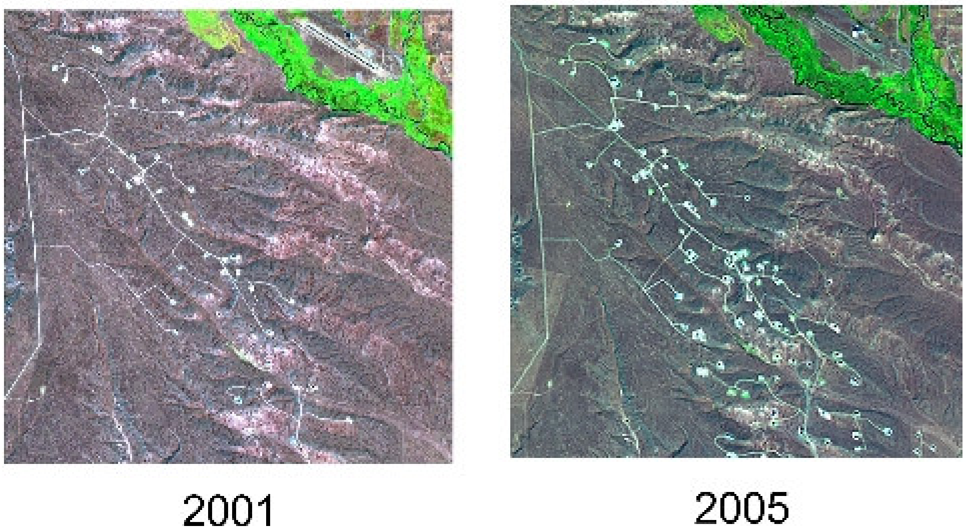
[23] Amos, John, President, SkyTruth, "Environmental Aspects of Modern Onshore Oil and Gas Development," witness statement, testimony to the Committee on Resources of the United States House of Representatives, Subcommittee on Energy and Mineral Resources, September 17, 2003. http://www.skytruth.org/pdfiles/Amos%20testimony%2017sep03.pdf

[24] Royster, Whitney, "Report: Deer numbers stabilize," Casper Star Tribune, Dec. 12, 2006.

[25] Amos 2003.

[26] Stanley 2006.

FIGURE 7



Development of Pinedale
Field, Wyoming

Source: Skytruth

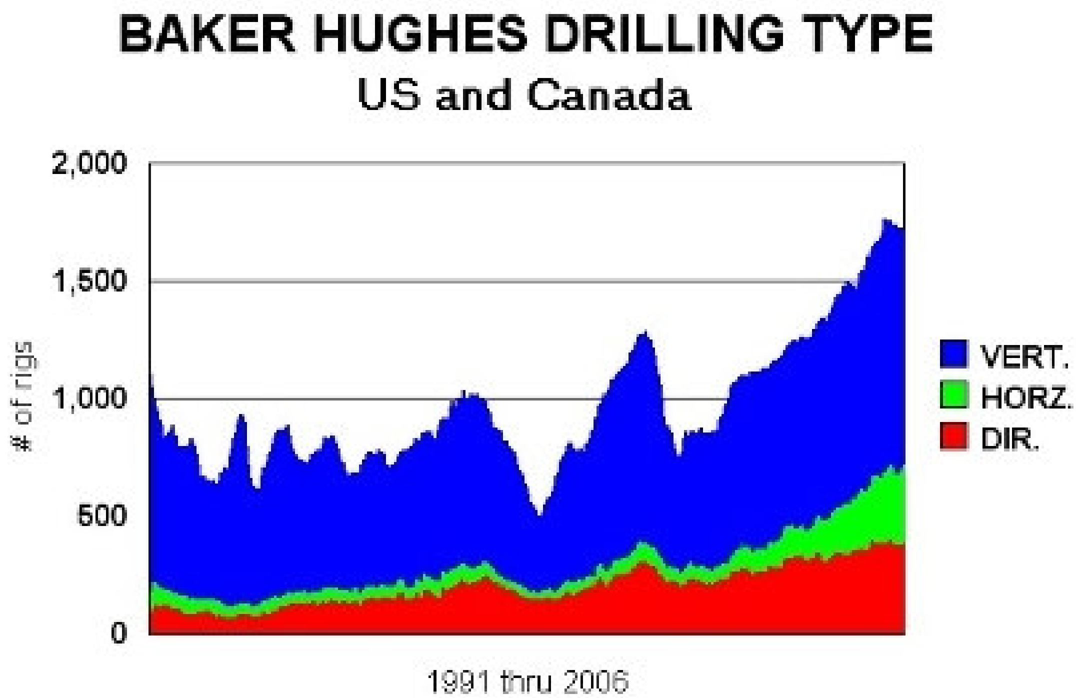
Directional Drilling: the major technology to reduce impacts

Directional drilling technology is routinely utilized in the United States

In the past, most oil and gas wells were drilled vertically, despite the fact that most oil and gas reservoirs are many times larger horizontally than vertically. However, since the last half of the Twentieth Century, directional drilling, that is, drilling wells at an angle other than vertical, has become commomplace. In recent years, [see Figure 8] directional wells accounted for nearly 40% of the total wells drilled in the United States and has been increasing by a factor of 2% per year. Directional wells of 90 degrees [known as horizontal wells] accounted for a third of the total.[27] Assuming that rate of growth continues, the next twenty years will see directional wells become the dominant form of drilling.

[27] Baker Hughes, drilling data, 2007. http://www.bakerhughes.com/investor/rig/rig_na.htm

FIGURE 8



Number and distribution of drilling in the United States

In terms of horizontal displacement, that is, how far a wellbore can reach laterally away from its surface location, incredible distances have been achieved. Routinely achievable horizontal displacements have rapidly climbed from 400 feet to over 8,000 feet.[28] In directional drilling, it is now common for the horizontal displacement of the bottom hole location to be twice the vertical depth of the well.[29]

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[28] U.S. Energy Information Administration, Office of Oil and Gas, U.S. Department of Energy, "Drilling Sideways -- A Review of Horizontal Well Technology and Its Domestic Application," DOE/EIA-TR-0565 Distribution Category UC-950, April 1993. http://tonto.eia.doe.gov/ftproot/petroleum/tr0565.pdf

[29] Alaska Department of Natural Resources, Division of Oil and Gas, Final Best Interest Finding, Beaufort Sea Areawide Sale: Appendix E: Directional and Extended-Reach Drilling Current and Projected Uses of the Sale 86 Area, 1999. http://www.dog.dnr.state.ak.us/oil/products/publications/beaufortsea/bsa1999_final_finding/appe.pdf

Extended reach technology have allowed operators to go even farther, reaching targets up to 35,000 feet horizontal displacement.[30] At England's Wytch Farm, wells drilled from surface locations onshore have set records:

> This record extended-reach well, M-11, at the BP Exploration Operating Co. Ltd. Wytch Farm development in southern England, has a horizontal displacement of 10,114 m [33,182 ft] at a true vertical depth (TVD) of only 1605 m [5266 ft]. Well M-11 is the second extended-reach record well at Wytch Farm.[31]

For the typical Rocky Mountain tight gas sand field, directional drilling has been much more modest. Utilizing a geometry called an S-curve after its distinctive profile, these wells have usually been drilled with horizontal displacements of less than 2500 feet. A typical S-curve well from the Roan Plateau area is shown on Figure 9.

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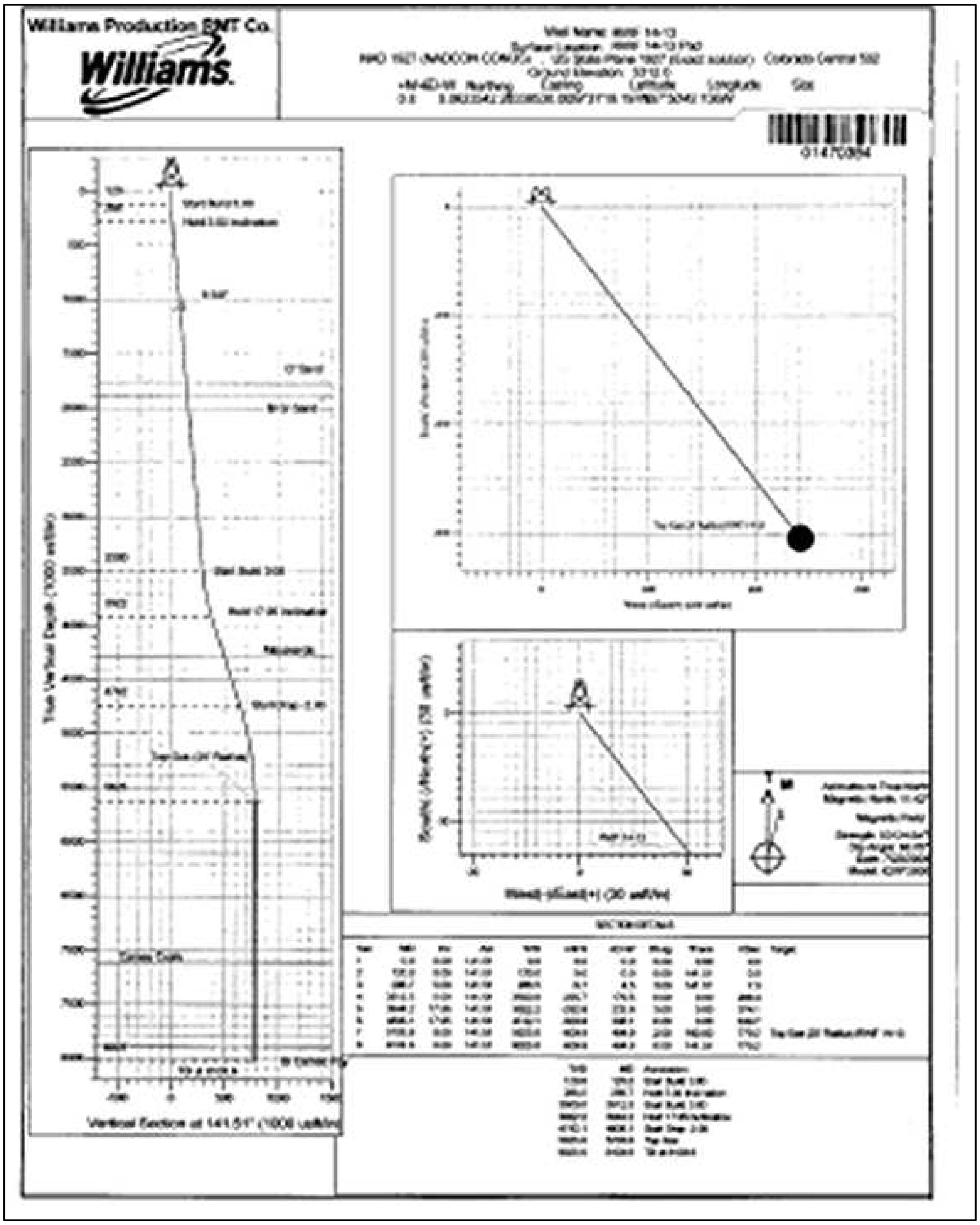
[30] Schubert, Jerome J., Assistant Professor, University of Texas and Texas A&M, "2001-2002 Offshore Technology Research Center [OTRC] Project: Workshop on Multilateral and Extended Reach Wells," December 2002 Progress Report, TAMU [University of Texas and Texas A&M], 2002. http://otrc.tamu.edu/Pages/wellworkshop.htm

[31] Allen, Frank et al, BP Exploration Operating Company Ltd., "Extended-Reach Drilling: Breaking the 10-km Barrier," Oilfield Review, Winter 1997. http://www.oilfield.slb.com/media/services/resources/oilfieldreview/ors97/win97/ex_drilling.pdf

FIGURE 9



Typical directional well from the Roan Plateau, showing the S-curve in profile and plan views. [Source: Colorado Oil & Gas Commission]

Directional drilling has allowed operators to drill multiple wells from a single well pad, presenting the obvious benefit of reducing the number of surface well pads. In fields undergoing increased drilling density, this results in a greatly decreased surface impact. For example, well pads could be spaced 160 acres apart, while drilling eight 20-acre spaced wells, or sixteen 10-acre wells, from each single pad.

This technology is currently being applied in a few tight gas sand fields:

- At Pinedale, Questar has utilized well pads comprising up to 30 subsurface wells to develop gas reserves within the Lance and Mesaverde, at depths of 9,000-14000 feet. Horizontal displacements average 2100 feet.[32]

- In the Piceance Basin, Exxon plans "the drilling of 200 new wells in the next two years. That includes drilling nine wells, 15 feet apart, from a single well pad.[33] Other operators such as Encana are planning 28 directional wells per pad.[34]

These and other examples will be explored further.

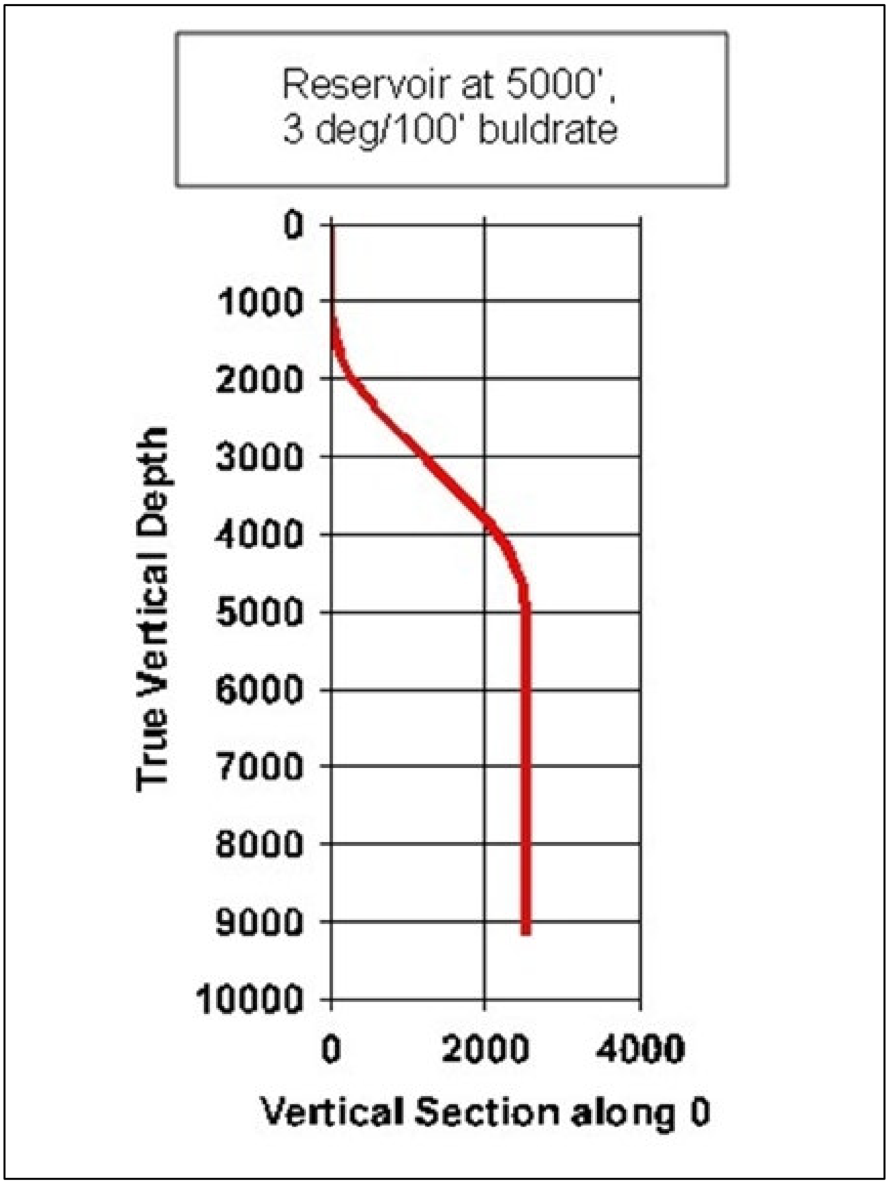
Applying directional drilling

In applying this technology, there are three broad parameters which are important:

1. Well design. In drilling tight gas sand reservoirs, operators currently prefer to penetrate the reservoir vertically. This is done both to increase the probability of intersecting a large number of the individual channel sand gas compartments, as well as to simplify the subsequent completion and fracturing. To do this directionally, an S-curve well is required.
2. Horizontal reach of the well. After consulting industry experts, the BLM in Colorado recently acknowledged that the industry has the capability of drilling an S-cure well with a horizontal displacement, that is, how far a well can extend out, of 2500 feet in the tight gas sand fields of the Roan Plateau.[35] Since the geology and depths at the Roan are similar to that of most Rocky Mountain tight gas fields, this 2500 feet can be considered to be a standard. An example of an S-curve well with the these parameters is presented on Figure 10.
3. Well pads comprising multiple wells. At Pinedale, Questar has been capable of fitting up to thirty wells per well pad. [see Figure 11] They can drill up to three of these simultaneously, while also producing or completing other wells on the same pad. As the individual well heads are placed as close to 16 feet on the surface, many more such wells could be accommodated by these multi-well pads. A

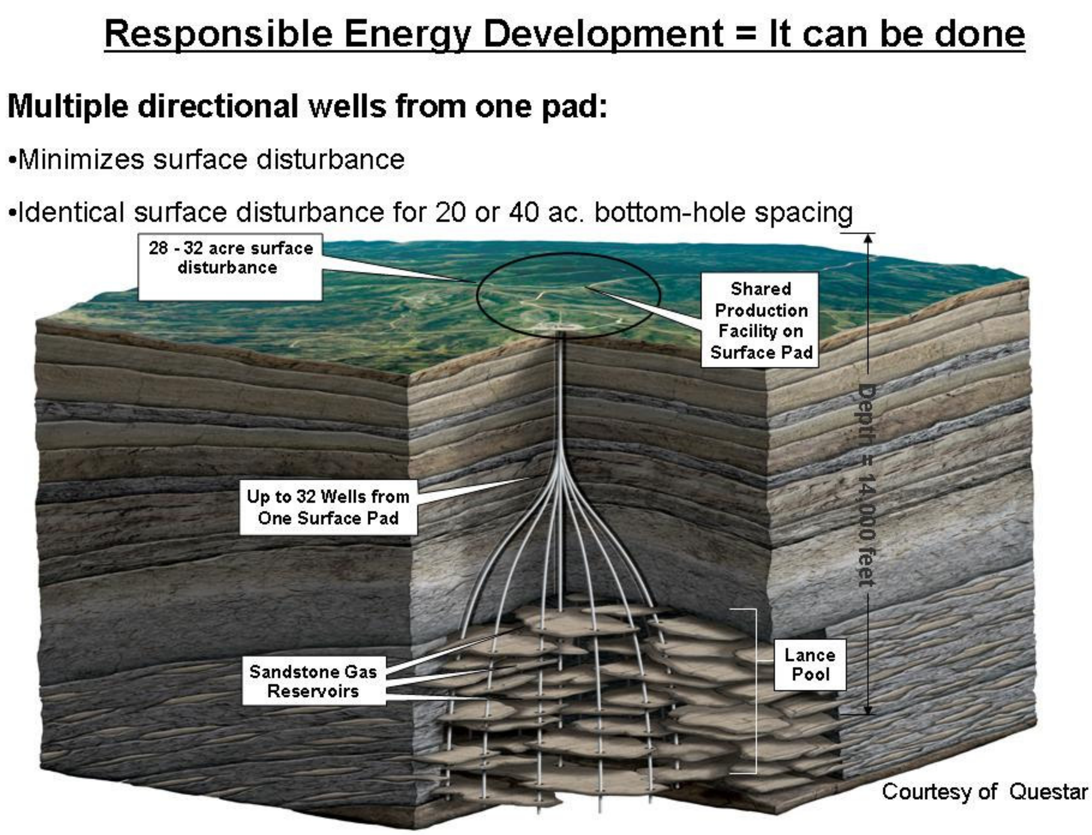
[32] Shawler, C., Questar, "The Rockies – A Key Source of Future Gas Supply?" presentation before the Independent Petroleum Association of America (IPAA), Houston, February 11, 2004.
[33] Chakrabarty, Gargi, "Exxon puts the squeeze on gas," Rocky Mountain News, June 24, 2006.
[34] Chakrabarty, Gargi, "Treading Lightly," Rocky Mountain News, November 18, 2006.
[35] BLM, August, 2006.

FIGURE 10



S-curve well with 2500 feet displacement. This configuration could produce from reservoirs as shallow as 5000 feet. Angle build rates do not exceed 3 degrees per 100 feet.

FIGURE 11



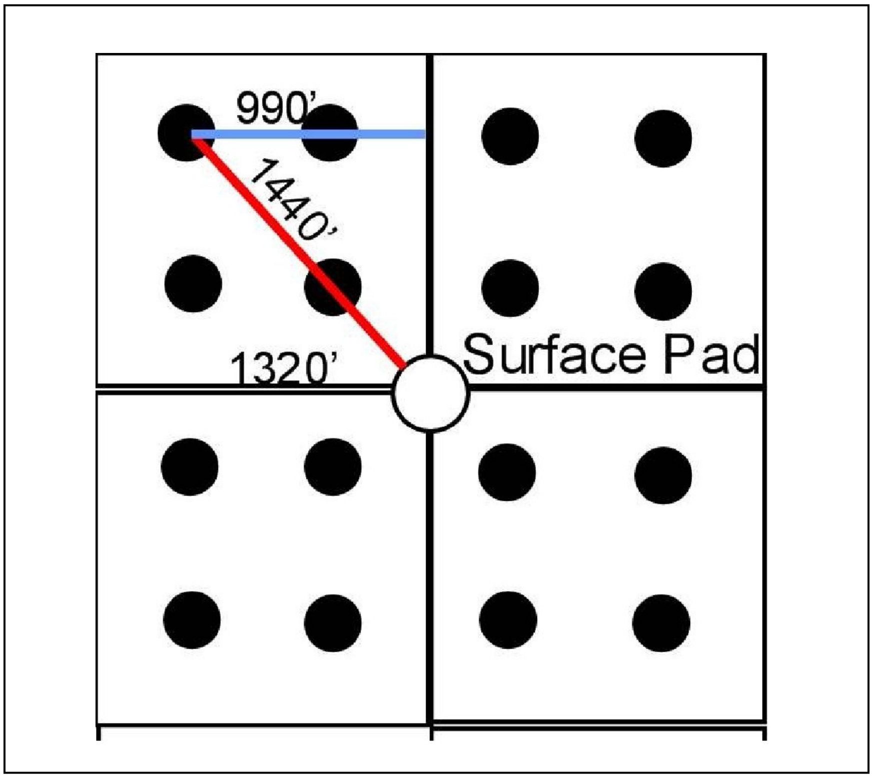
Graphical representation of Questar's directional, multi-well pad approach at Pinedale.

typical 20-acre well pad disturbs an area from 14 acres, to as much as 20 acres, which reduces the disturbance to about 0.7 to 1 acre per well.[36] Contrast this against single well pads which disturb 2 to 4 acres each. The net savings in surface disturbance is significant: 1 to 3.3 acres per well or 50 to 85%.

Figure 12 presents a plan view of one example which makes use of the above parameters. This is a simple case of 10-acre well spacing drilled from pads placed at 160-acre intervals. Using only 16 wells per pad and a rather modest maximum horizontal reach of less than 1500 feet, this configuration has been successfully utilized, most notably in the Roan Plateau area.

[36] Questar, "Pinedale Field Trip," presentation, September 7, 2006.

FIGURE 12

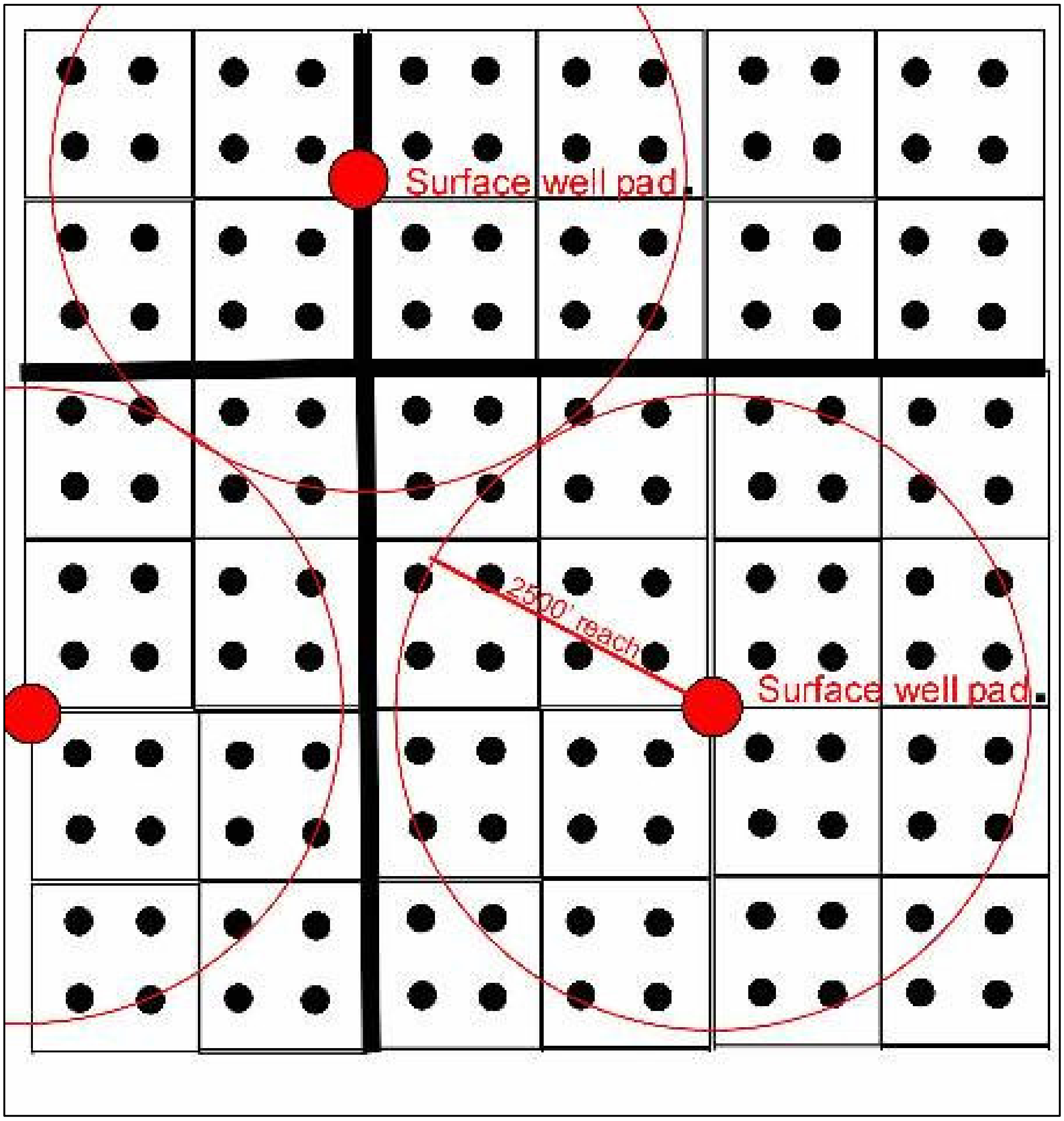


Plan view diagram illustrating a well pad spaced at 160 ac producing from 16 wells spaced at 10 acres at the reservoir level. Note the maximum displacement is 1440 feet, using parameters much more modest than the directional well shown on Figure 11.

Potential parameters for tight gas sand directional drilling

Utilizing the same drilling parameters as the above, a much greater reduction in the number of surface well pads could be achieved. Figure 13 reveals what is ultimately possible using the 2500 feet horizontal displacement. It illustrates a 10-acre downhole well spacing [each small square is a 40-acre tract] with a well pad placed at approximately one mile intervals, or close to a 640-acre spacing. The departure from current practice lies only in the number of wells per pad, requiring 52 wellheads per pad. With current developments exceeding 30 wells per pad, increasing the number of wells to 52 will likely not present a serious problem.

FIGURE 13



Plan view showing well pad spaced at one mile producing from downhole wells spaced at 10 acres. Note maximum horizontal displacement does not exceed 2500 feet.

However, the above configuration is confined to a 2500 feet horizontal displacement. As noted previously, industry has the capability to reach much farther. Recent advances in S-curve drilling technology have enabled operators to drill faster and cheaper, due to: "reduced drilling/completion time, minimized hole enlargements, reduced torque/drag to help deliver smooth high quality wellbores and increased efficiency of cementing operations. This has allowed the operator to log and set tubulars easily and quickly, leading to early production."[37] It appears that greater displacements may be possible. Regarding tight gas sand wells, what is a reasonable limit?

Fortunately, a recent paper published by the Society of Petroleum Engineers provides a clue. In it, the authors cited a 3 degree per 100 feet angle as standard for S-curve wells in tight gas sand reservoirs.[38] Taking a typical Rocky Mountain tight gas field producing from below 5000 feet, there is at least 3000 feet available to accommodate the S-curve portion of a well. Using these parameters, a maximum horizontal displacement can then be calculated.

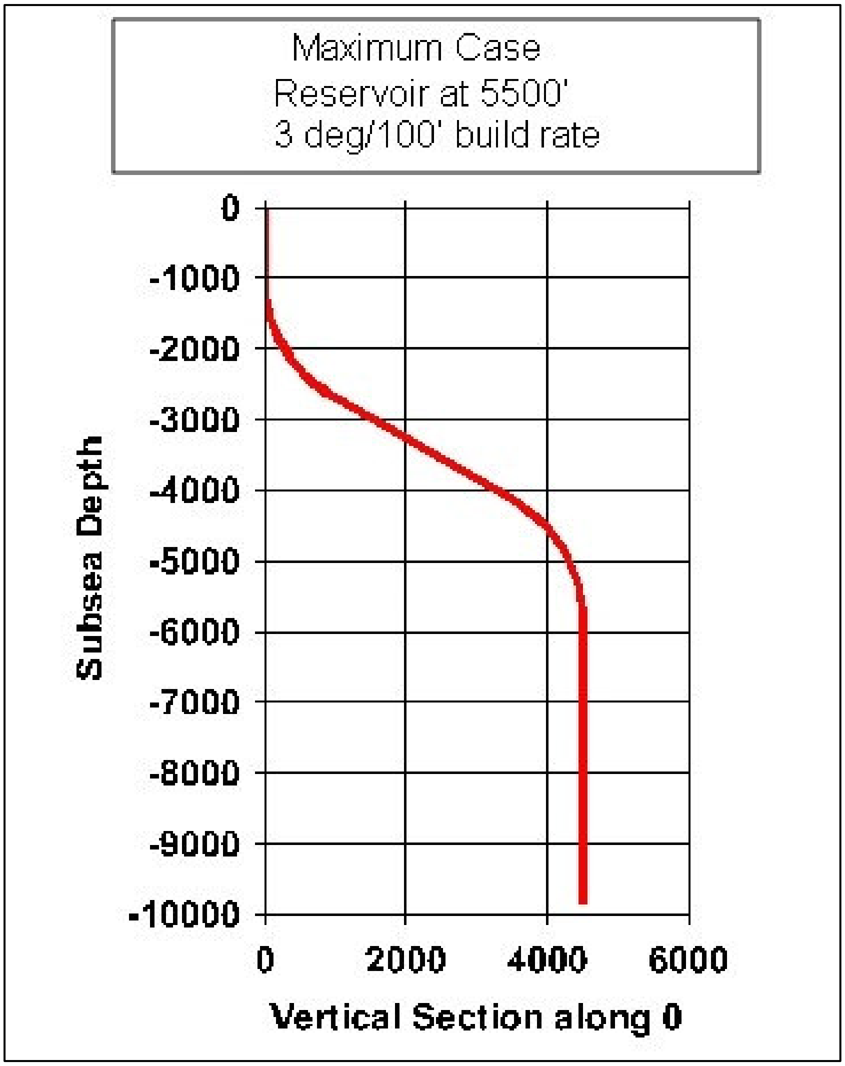
The result, presented on Figure 14, shows a potential horizontal displacement of 4300 feet. This reach allows the drilling of a tight gas sand S-curve well from a pad over three quarters of a mile away. This makes well pads spaced at more than one mile, or at least one well pad per section [which requires only a 3267 feet reach] feasible for many tight gas sand fields in the Rocky Mountains.

Note these numbers are for S-curve wells, a relatively unique design which is the dominant form in the Rockies. In a more normal directional well, where a return to vertical is not required, much greater displacements are possible.

[37] Janwadkar, S., Baker Hughes, INTEQ, D. Fortenberry, B. Dawkins, and M. Kramer, Devon Energy Corp., M. Kurella, B. Welch, Baker Hughes INTEQ, and M. Reich, SPE, "Pioneering Advanced Directional Drilling Technologies Overcome Challenges Of S and J Type Wells in North America," Society of Petroleum Engineers, SPE 103198, 2006. http://www.spe.org/atce/2006/technical/documents/spe1031981.pdf

[38] Janwadkar 2006.

FIGURE 14



Maximum case for a reservoir below 5000 feet and a build rate not exceeding 3 degrees per 100 feet.

Directional drilling dramatically decreases impacts

Directional drilling is important in reducing impacts to the surface because:

1. A single well pad on the surface can support wells drilled to many widely spaced points in a given reservoir. This allows the reservoir to be effectively drained without a correspondingly large number of surface well pads.
2. These pads can be optimally placed to cause the least damage to the surface.
3. Pads allow the concentration of facilities, a reduced need for roads, pipelines, and other subsidiary equipment.

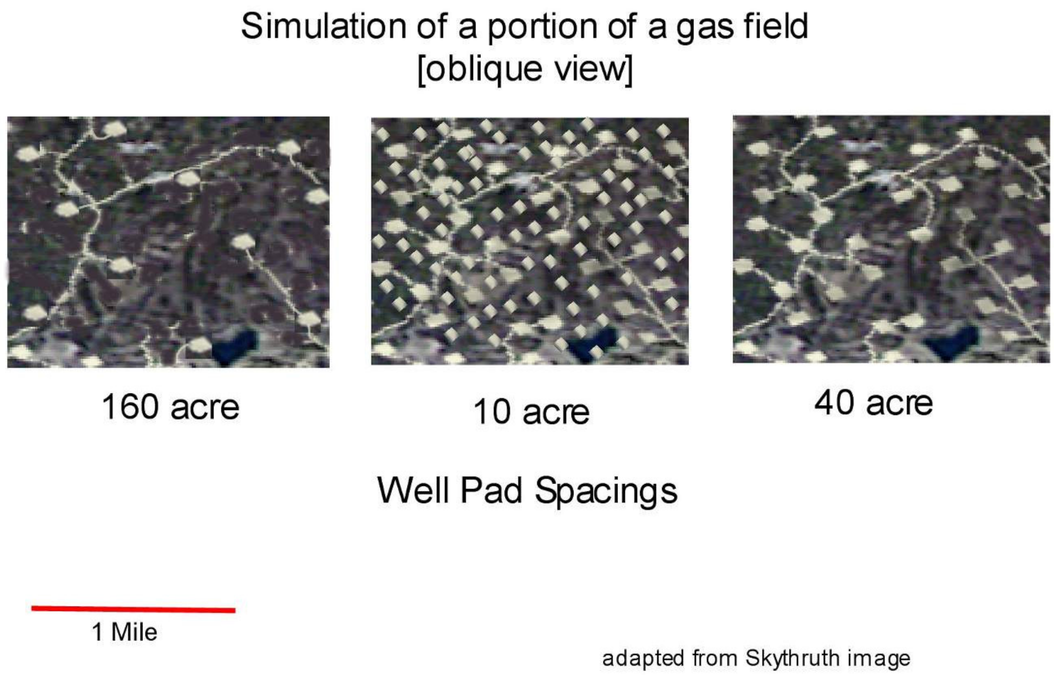
The potential for directional drilling to reduce impacts is substantial. The previous example from Pinedale revealed an impact reduction of 50% to 85%. At the lower rim of the Roan Plateau, 10-acre drilling densities are being achieved with a surface pad every 160 acres. Using BLM estimates of 1.9 acres for single well pads, and 2.5 acres for multi-well pads, this translates into the replacement of 30.4 disturbed acres by 2.5 acres, representing a reduction of 27.9 acres or 92%.[39]

Using the parameters outlined in the section above, even greater savings are possible. Utilizing a maximum reach of only 2500 feet, surface pads could be reduced to one every 320 acres, providing 32 wells per pad. Even if one doubles the size of the multi-well pad to 5 acres to accommodate the additional wells, the savings will be 55.8 acres, again 92%. To this, comparable reductions in pipelines and roads will add to the reduction in impacts.

This effect is even more dramatic when shown graphically. Figure 15 compares a typical field drilled at a 160-acre surface spacing, with simulations of wells drilled at 10- and 40-acre spacing. Unquestionably, the 160-acre surface spacing is preferable. The example presented in the previous section, using a 55-well pad, would yield even greater results. Reducing the 160-acre case to one well pad per 640 acres, or one per section, which is, as shown above, perfectly feasible, the impacts could be further reduced.

[39] BLM August 2006.

FIGURE 15



Typical gas field shown at various simulated spacings.

Economics

Although directional drilling is being employed in some tight gas sand developments, it use could be increased substantially. However, industry usually resists using the technology, based on the question of cost. Unfortunately cost figures are usually considered to be proprietary information by operators and hence operators' concerns are rarely quantified. The published data that is available usually falls into one of three categories: incremental cost of directional drilling; offsetting cost savings; and Finding and Development [F&D] cost.

Incremental costs are not a deterrent to drilling directionally

Costs, like price, vary. Published data can only provide a snapshot of costs at any particular time. However, the incremental costs, that is, the amount directional drilling costs over the that of a vertical well, when expressed as a percentage, should be more stable.

There are some reported incremental costs of drilling directionally in tight gas sand fields:

1. Encana, at Jonah Field, reported an average incremental cost of $244,000 over a completed well cost of $2,186,684, or about 11%.[40]
2. At Pinedale Field, Questar published an incremental cost of $500,000 over a well cost of $4,000,000, or about 12.5%.[41]
3. Ecos Consulting compared costs of vertical and directional drilling in a Piceance basin development program operated by Barrett Resources, reporting a cost premium in the range of 4% to 15%.[42]
4. Laramie Energy quoted an incremental cost of $100,000 for directional wells in the Piceance. Considering the average cost of a vertical well at that time was $600,000, this yields a 16% increase.[43]

Thus published reports support a range of 4% to 16% for the incremental cost of drilling directional wells in tight gas fields.

However, there is another effect which serves to lower this ratio with time. As a given set of directional parameters are used in well after well in a particular area, operators become more efficient. In short, with practice, drillers get better. Having conquered the initial learning curve, costs fall. This has been my personal experience with drilling horizontal wells, a far more complex directional undertaking. Historically, this has been the case as well:

> By 1990, the cost premium associated with horizontal wells had shrunk from the 300-percent level experienced with some early experimental wells to an annual average of 17 percent. Also, the industry *Joint Association Survey on 1990 Drilling Costs* reported that average horizontal drilling cost per foot was $88.16 as compared to $75.40 for wells not drilled horizontally, a 17-percent cost premium.[44]

In a similar way, it is expected that the average cost premium associated with directional drilling will decrease with time.

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[40] Reservoir Management Services, Inc., “Analysis of Respondent’s Comments to the JIPD [Jonah Infill Drilling Project] DEIS Questioning BLM’s Estimate of Unrecovered Resource,” prepared for Encana, Inc., August 2005.
[41] Shawler 2004.
[42] Dunmire, Carolyn et al, Ecos Consulting, “Directional Drilling and the Roan Plateau,” a report for The Wilderness Society, October 2002.
[43] Toal, Brian, “Piceance Basin: with as much as an estimated 300-plus trillion cubic feet of gas resource in place, Colorado's Piceance Basin may well be the biggest natural gas play in North America,” cover story,” Oil & Gas Investor, August, 2005.
http://www.accessmylibrary.com/coms2/summary_0286-9603668_ITM
[44] U.S. Energy Information Administration, April 1993.

Costs are offset by cost savings associated with located multiple wells on a single pad.

There are cost savings associated with directional drilling from multi-well pads, which may offset a portion or even all of the above incremental cost increases. Several companies involved in gas well drilling in tight gas sand have commented:

Keith Rattie, CEO of Questar, which utilizes a directional multi-well pad approach at Pinedale field states:

> With pad drilling, we also need fewer roads and fewer gathering lines, production separators and other surface facilities.[45]

Oil and Gas Investor reports on Encana's experience in the Piceance Basin :

> Another efficiency on the completion side: since the operator can directionally drill 12 to 16 Piceance wells from just one pad, as is the case of its North Parachute project, and each well undergoes an average of seven fracs, that's 84 to 112 fracs that can be accomplished without moving any frac equipment.[46]

Laramie Energy's Jim Schroeder, whose company plans to drill 100 Piceance Basin wells per year, states:

> While it may cost more to drill wells directionally than vertically, perhaps $100,000 more per well, that expense is more than offset by the cost savings an operator achieves by having all his wells and production facilities on one pad—plus he doesn't have to lay as many gathering lines or construct as many access roads.[47]

The Garfield County Oil and Gas liaison agrees, stating that:

> Although directional drilling increases the cost of a well, much of this cost is recouped through reduced pad construction and co-locating facilities on one pad.[48]

However these cost savings are difficult to quantify. They impact production costs, which are often accounted for differently than drilling and completion well costs. But it is apparent they are significant. Economies of scale, as well as the benefits accruing from the concentration of facilities can have a significant impact.

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[45] Wall Street Transcripts, "Company Interview with Keith Rattie, CEO, Questar," Wall Street Transcripts, May 2004. http://www.twst.com/pdf/TAF217.pdf
[46] Toal 2005.
[47] Toal 2005.
[48] Dennison, Doug, Garfield County Oil & Gas Liaison, "Drilling 101: Drilling of a Natural Gas Well and Natural Gas Production in the Piceance Basin," presentation, October, 2005. http://www.garfield-county.com/Modules/ShowDocument.aspx?documentid=2185

Operators' Finding and Development [F&D] costs indicate tight gas sand economics are robust.

One available economic parameter is a company's Finding and Development [F&D] costs. Expressed as a cost per Mcf of gas produced, it provides a normalized parameter by which costs can be compared among companies and geologic plays. It also provides a rule-of-thumb measure of the economic viability of a play. My own experience is that a given play is considered economic if the F & D costs are at or below a third of the product price. Thus if the price of natural gas is $6 per million cubic feet (Mcf), F&D costs must be below $2 to be economic. Some published sources corroborate this. For example, Ultra Petroleum stated in 2003: "Finding and development costs for all Pinedale wells average between $0.50 - $0.60 / Mcfe." Although prices at the time were around $3 to $4 per Mcf, [making their F&D costs about an eighth of the price], they stated this level of activity would be economic even at $1.50 per Mcf. Again, this is about a third of the product price.[49]

A comparison of the finding costs among the top 15 natural gas producers in the United States indicates that F& D costs for the period 2003 to 2005 averaged a low of less than $1 per Mcf to a high of just over $2 per Mcf. Natural gas prices during this same period increased from $3 to $7 per Mcf, for an average of $5 per Mcf.[50] Thus, F&D costs were running about 20 to 40% of product price, or about an average of 30%. However, as prices continue to rise, operators report improved F&D costs. For example, Williams is projecting F & D costs of $0.92 per Mcf against prices of $5.55 over the period 2006-2008.[51] [They also reported a F&D cost of $0.89 per Mcf in 2003 for the Piceance Basin.][52] Thus typically, an operator's F & D costs for tight gas sand reservoirs are averaging less than a third of the price of natural gas, indicating the play can be considered economic.

Some F&D costs for directional developments are available as well. For their 30-well per pad directional drilling program at Pinedale, Questar reported in 2006 F&D costs of $1.00 per Mcf on costs that were 16% higher for directional wells over vertical.[53] Prices in 2006 were approximately $6 per Mcf. Thus, their F&D costs were far better than the required one third of price. Even in this case, when they reported incremental directional costs that were higher than vertical wells, economics were still favorable.

A few conclusions can be drawn from these numbers:

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[49] Thomasson, M. Ray et al, "Rocky Mountain Giants: Rockies Dominate U.S. Onshore 'Discovery' of 1990s Giants," Adapted for online presentation of "Rocky Mountain Giants," Oil and Gas Journal, v. 99.49, December 3, 2001. http://www.searchanddiscovery.net/documents/2003/thomasson/index.htm.
[50] Williams Corp., "2006 1st Quarter Earnings," Internet presentation for investors, Thursday, May 4, 2006.
[51] Williams Corp. 2006.
[52] Guderian, Bryan, Vice President of Exploration and Production, Williams Corp., "Williams Exploration & Production," presentation to Rocky Mountain Natural Gas Investment Forum Colorado Oil and Gas Association (COGA), August 5, 2003.
[53] Questar 2006.

1. Economics for tight gas sand wells are robust and profitable. Note that a comparison of the two quotes for Williams in the above paragraph, comparing the situation in 2003 against projections for 2006-8 indicate a minimal rise in costs [$0.89 to $0.92] against a large increase in price [$3.00 to $5.55]. Economics for other operators are expected to be similar.
2. Even an incremental cost increase of 10% for directional drilling would not substantially change these numbers. For example, a 10% increase would bring the Williams development cost quoted above to an F&D of $1.01 per Mcf [very similar to Questar's Pinedale directional numbers] Considering their projected price of $5.55, this would still leave the costs of the play at about 20% of price, far better than the rule-of-thumb profitability requirement of no more than 33%.
3. Directional drilling, even when relatively costly, need not negatively impact the economics. Questar's recent experience at Pinedale cited above, which had a directional cost premium of 16% over vertical wells, resulted in F&D costs of only $1 per Mcfe, still well within favorable economics.[54]

Operator's assertions of high costs of directional drilling should be properly analyzed

It should be apparent that recent economics of tight gas sand plays do not preclude the use of directional drilling. However, that very argument is often used to discourage the BLM from mandating its use, even in spite of substantial demonstrated environmental benefit. Why?

One problem is that operator's assertions of costs are seldom, if ever, documented in any EIS, DEIS, EA, or other BLM report. Thus there are no means for other stakeholders in our federal lands to evaluate these claims. As a result, operator's assertions of prohibitively high costs due to directional technology are seldom challenged, or even analyzed. I submit that these assertions should never be accepted by BLM or others without full and public analysis.

In addition, BLM needs to realize, as a guiding principle, that a major goal of oil & gas operators is to keep costs to a minimum. This may lead an operator to overstate difficulties, misrepresent costs, and fail to apply environmentally beneficial technologies that may be more costly. There is a distinction between costs that are simply higher, versus costs that are uneconomic.

In some cases, the BLM has allowed operators to simply assert that 'directional drilling won't work here'. Instead, convincing evidence should be required and evaluated by the BLM to show that it is not technologically feasible. This evidence should then be available for public comment.

A final note is that one operator's difficulties with directional drilling do not necessarily mean the technology is not applicable. It is possible that the particular operator's inability to apply technology is the problem. Over time, major companies developing reserves in

[54] Questar 2006.

the Rockies have been replaced by smaller, lower cost, and sometimes under capitalized entities. This places an additional burden on regulating agencies, especially the BLM, to ensure that these operators are fully capable of responsibly developing oil and gas reserves.

Specific examples: the current situation in the Rocky Mountains

There are a number of large fields currently under development in the Rocky Mountain region [see Figure 2]. To gain an appreciation of the magnitude of these developments, I have profiled several below. However, one should keep two things in mind:

1. These fields are some of the most significant, but by no means, the only tight gas sand developments currently underway.
2. The fields, though widely spaced geographically, share similar geology and producing characteristics [depth, thickness, etc.].

Jonah

Jonah field, located in the northwestern Green River basin, Wyoming, produces gas from overpressured fluvial channel sandstones of the Upper Cretaceous Lance Formation. This overpressuring substantially enhances production, making individual wells very prolific. Ultimate recoverable reserves from the field are estimated at 7.9 Tcf. Since the gas reservoirs are also tight, with very low permeabilities of .01-0.9 millidarcys, artificial fracturing must be performed. Structurally, faults have partly controlled the level of overpressuring. This faulting has resulted in the Lance being 2500 feet (758 m) higher at Jonah field than in surrounding parts of the basin.[55] The gross thickness of the Lance Formation increases toward the downdip limit (northeastern edge) of the field. Near the updip termination, the Lance is 2000 feet thick, while at the northeastern side of the field it attains a thickness in excess of 3000 feet.[56] Both the variable thickness and depth make the use of directional wells somewhat more difficult than in the case of nearby Pinedale Anticline, which has an active directional program, but certainly does not preclude the use of this technology at Jonah. Productive intervals at Jonah have been divided into five pay intervals. Only one (Jonah interval) displays continuity across most of the field. Due to the discontinuous nature of these sands, producing well bores need to be placed close together to effectively drain the reservoir.

Encana and other operators' recent proposal for a 5-acre infill well program was approved by the BLM. As the final EIS states:

> The Operators propose to expand development of natural gas and condensate reserves from the Lance and other formations at depths of approximately 11,000 feet by drilling as many as 3,100 additional wells on

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[55] Montgomery and Robinson 1997.

[56] DuBois, Dean P. et al, "Geology of Jonah Field," Canadian Society of Exploration Geophysicists (CSEG) conference, 2003 abstracts. http://www.cseg.ca/conferences/2003/2003abstracts/245S0130.pdf

> up to 16,200 acres of new surface disturbance during the development (drilling) phase. Specific features include the following: a minimum of 64 well pads per 640-acre section, downhole well spacing from 1 bottomhole/5 acres to 1 bottomhole/40 acres; up to 465 miles of new resource roads with associated pipelines; 8 miles of new collector/local roads; 41 acres of new surface disturbance for ancillary facilities; and 100 acres of new surface disturbance for exploration of other formations.[57]

The impact of this infill program is enormous. With well spacing as tight as 5 acres and well pads comprising over 4 acres each, the entire area is disturbed. Mitigation efforts have virtually no effect. The governor of Wyoming characterized these efforts as follows: "To attempt to minimize any additional surface disturbance or completely mitigate impacts onsite is a futile attempt to "perfume the pig."[58]

Previous to this decision, over fifty directional wells were undertaken by Encana. Based on that experience, the operator argued that directional drilling was too costly, in spite of their average cost being only 11% greater than a vertical well, or $244,000 per well. Although the excellent economics of these wells are beyond dispute, BLM elected to rely on mitigation measures other than directional drilling.

Pinedale

Situated on an obvious large structure, Pinedale Field is another tight gas field essentially rediscovered by technology. As at the neighboring Jonah Field, it produces from the same tight Lance and Mesaverde formations, only deeper, from 9000 to 14000 feet. Total hydrocarbon bearing column is 5000 feet. Ultimate recoverable reserves have been estimated at over 25 Tcf. It is likely this field will eventually link up with Jonah as development continues to the south, resulting in a single giant gas field.

Directional drilling has had a greater impact on Pinedale. One major operator, Questar, has publicized much of their effort. In 2003, the company had 75 producing wells drilled from 52 existing well pads. With the addition of only 9 new pads, they envisioned developing their acreage at 20 to 40 acre spacing, eventually encompassing 250 to 430 wells, utilizing well pads consisting of 16 to 20 wells.[59] Another operator, Ultra, is likewise drilling directionally from pads comprising 16 wells each. They envision the field will be eventually developed on a 10-acre spacing, with the drilling of approximately 5000 wells.[60] Questar now sees this downhole spacing being developed

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[57] Bureau of Land Management, "Final Environmental Impact Statement, Jonah Field Infill Project," January, 2006. http://www.blm.gov/wy/st/en/info/NEPA/pfodocs/jonah.html

[58] Baldwin, Chad, "Governor backs industry plan", Casper Star-Tribune, April 13, 2005. http://www.casperstartribune.net/articles/2005/04/13/news/wyoming/6387f6c82ff6920887256fe20009f06f.txt

[59] Shawler 2004.

[60] Freeman, Diane, "Pinedale: Tight Gas, Tight Rules"; American Association of Petroleum Geologists (AAPG) Explorer, June 2006. http://www.aapg.org/explorer/2006/06jun/pinedale.cfm

with up to 30 wells per pad.[61] As previously mentioned, they report excellent economics, with F&D costs of $1 per Mcfe.

Contrasting directional drilling at Jonah and Pinedale

As noted above, it is expected that Jonah and Pinedale will eventually link up to become a single giant gas field. The ultimate number of wells for Pinedale field is expected to be similar to Jonah. However, the widespread use of directional wells at Pinedale will result in a greatly reduced impact over the very similar development at Jonah. Why, then, is the application of directional drilling so different?

It is a difficult question to answer. To begin with, the fields are remarkably similar. They are geographically close, and they produce from the same horizons. The productive interval at Jonah is shallower, by about 1500 feet at its top, and the field is structurally more complex, but neither of these factors precludes directional drilling. Like the geology, the directional characteristics of each are markedly similar:

1. As noted above, both fields have seen the successful application of directional drilling [over 50 wells at Jonah].
2. The shallower depths at Jonah are still sufficient to allow S-curve wells of the type exhibited in this report. As will be seen in the Piceance Basin, such wells can be drilled with a horizontal reach of 2500 feet for reservoirs at comparable depths.
3. Documented average costs for directional wells at Pinedale and Jonah are similar: Questar at Pinedale reports 12.5% increase over a vertical well and Encana at Jonah 11%. More recently, Questar has seen costs go to about 16%, but their economics remain robust with overall costs at about $1.00 per Mcf.

The answer apparently lies in arenas other than technology. Politics, timing of development, different operators all might play a role, but technological differences do not appear to provide an explanation.

Greater Natural Buttes

This is a large tight gas sand field composed of Natural Buttes Field proper and several adjacent fields. Together they represent a significant portion of the Uinta Basin. Production is from two formations: the Wasatch and Mesaverde. These formations share similar characteristics with the tight gas sands already described in the Green River Basin:

Tertiary Wasatch
- Moderate drilling depths in most of the play area.
- Proven to be a major producer in the Greater Natural Buttes field.
- Multiple, stacked, channel reservoirs.
- Continuous, deep-basin gas potential exists.

[61] Questar 2006.

• Classified as tight gas sand play (< 0.1 md).
• Cap faulting and fracturing necessary for migration from underlying source beds.
• Geological assessment could result in a large increase in the total gas reserves.

Cretaceous Mesaverde Group Play
• Large undiscovered gas potential, 8.5 to 14.4 TcfG.
• Actively being drilled in the Great Natural Buttes.
• Multiple reservoirs and in-situ source rocks.
• Continuous, deep-basin gas potential could be very large.
• Classified as tight gas sand play (< 0.1 md).
• Geological assessment could result in a large increase in the total gas reserves.[62]

In the largest field, Natural Buttes, the Wasatch is generally productive at 5000 feet to 6000 feet. Mesaverde produces from 6000 feet to 8500 feet.[63] Typical per well reserves are 1.25 Bcf for the Wasatch and 1.4 Bcf for the Mesaverde.[64]

Several operators are actively drilling this field. Kerr McGee had been infilling the existing production at a 40-acre spacing. Anadarko, who recently purchased Kerr McGee's interests in the Rocky Mountains, reports having 237,000 acres leased in the area. In 2006, they had 12 drilling rigs engaged in a 270-well program. These locations are part of a total of 4900 potential drill sites the company has identified in Natural Buttes.[65] EDG has been pursuing a 7 rig/170 well program. Questar, Dominion and Gasco have identified thousands of additional drill sites.[66] By any measure, this activity ranks as a major gas development. It can be reasonably foreseen that this field, like many Rocky Mountain tight gas sand fields, may eventually be drilled at 20- or even 10-acre spacing.

Thus far, directional drilling has played only a minor role.

Roan Plateau

The Roan Plateau area, one of several gas developments currently underway in the Rocky Mountains, is experiencing an unprecedented wave of development drilling. Like other tight gas sand fields, this has been driven by advances in the multistage fracturing completion techniques, which exploits the geologic recognition that the gas reservoirs are composed of a multitude of discrete compartments. These require closely spaced wells to be effectively drained. This has resulted in the permitting of very large well densities

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[62] US Energy Information Agency, "Characterization of Utah's Natural Gas Reservoirs and Potential New Reserves," 2003. http://geology.utah.gov/emp/gas_research/pdf/resource_character.pdf
[63] State of Utah 2007.
[64] Williams Corp. 2006.
[65] Anadarko Petroleum Corporation website: http://www.anadarko.com/operations_by_region/us_rockies/utah_greater_natural.asp
[66] Houston Exploration Company, "Onshore Review," July 2006. http://sec.edgar-online.com/2006/07/10/0000950129-06-007062/Section5.asp

[one well per 10 to 20 acres] which represents, in the words of an Encana geologist, "the greatest gas well spacing density in Colorado (and probably the world)."[67]

These wells are targeted for the Wasatch and Mesaverde, the very same formations being developed in the geologically identical Uinta Basin. Here the formations are slightly shallower, from 4,500 feet to 8,000 feet.

This development is occurring over an extremely large area, consisting of two parts. One is the traditional area of gas drilling below the rim of the plateau. Several fields, stretching out along I-70, have been under development for some time. The other portion is the mostly pristine, relatively undrilled plateau itself. The ultimate number of wells projected for the overall Roan Plateau is 13,000 over a surface area of 127,000 acres. Contrast this with Jonah in Wyoming, which will see the drilling of about 3,600 wells on 30,500 acres. While each of these is similar in density, about 10 acres per well, the Roan is much greater in magnitude, essentially comprising, in terms of potential surface impact, about four Jonah Fields. However, with the maximum possible use of clustered directional wells at the Roan, it will be possible to significantly reduce the surface impacts relative to Jonah.

Directional drilling in the lower rim of Roan Plateau area has become routine. After a protracted debate over the cost and appropriateness of the technology, the BLM reached the conclusion that industry was capable of drilling directional wells with a horizontal reach up to 2500 feet. This made possible the establishment of a maximum surface spacing of 160 acres on the lower rim, from which gas wells of 10 to 40 acre spacing could be drilled.[68] Operators are currently drilling 16 wells per pad, with plans to go beyond these BLM specifications, increasing this to 28 wells per pad.[69]

These comments apply only to the area below the rim of the Roan Plateau. On the upper rim, development is restricted. According to the latest proposal, drilling will occur in a phased manner, with surface disturbance limited to 350 acres [about 1% of the total area] at any given time.[70] Due to both terrain and protection issues, many of these wells, if they are drilled at all, will have to be directional. Even with the application of directional drilling, the development on the upper rim of the plateau itself remains controversial.

Contrasting Natural Buttes with the Roan Plateau

Even more inexplicable than the situation at Jonah-Pinedale, is the contrast between directional drilling in the Piceance versus the Uinta Basins. As shown above, the geology of the two basins is virtually identical. Reservoir formations are the same, and production is from comparable depths and at similar volumes. Directional well parameters would be the same. Economic parameters are similar as well. The Uinta Basin tight gas fields, the Greater Natural Buttes Field and others, could be developed utilizing directional wells

[67] Uhi 2003.
[68] BLM 2006.
[69] Chakrabarty November 2006.
[70] Colorado Oil and Gas Conservation Commission 2007.

from multi-well pads just as in the area below the rim of the Roan Plateau in the Piceance.

Again, technology is not the reason for the apparent dichotomy. The initial proposals for denser infill drilling and extensions to the development over the more pristine Roan Plateau itself originally met with a storm of protest. Calls for greatly reducing surface impacts led to the consideration of directional drilling. Although operators fought against this notion for several years, eventually the BLM crafted a plan featuring the extensive use of directional drilling to mitigate surface damages. While by no means optimal, the plan was a significant advancement, in recognizing and utilizing directional drilling as a major means to reduce impacts.

There remains no technical or economic reason for the lack of similar plans in the Uinta basin tight gas sand fields. Indeed, the application of directional drilling in the lower areas of the Roan Plateau could serve as an example for the development of tight gas sand fields across the Rockies. ***The key component is the recognition that directional drilling allows the establishment of a maximum surface spacing, independent of the much denser downhole spacing, thereby significantly reducing the impacts of development drilling.*** Comparable developments throughout the greater Rocky Mountain Region, especially in areas that exhibit markedly similar geology and production characteristics, such as the Uinta and Green River Basins, could benefit greatly if the BLM would apply this approach on a regional basis.

In addition, the application of directional drilling could be made early in the development process, before unnecessary damage is done. Jonah is an example of operators going to 5-acre spacing without directional drilling. At Pinedale, directional drilling was prescribed much earlier in the process, thereby avoiding the massive impacts seen at Jonah. The Roan Plateau is an attempt to utilize directional technology even earlier in the development process. The large substantially similar areas in the Uinta and Green River Basins are now in the early stages of higher-density gas development. These areas, like the Roan, will benefit greatly if directional drilling is required now, before infill drilling results in irreversible and largely unnecessary damage.

Large are- wide assessments do not utilize directional drilling at all

In recent years, BLM has allowed industry to pursue the development of large tracts of land with the issuance of broad area-wide environmental impact statements and assessments, particularly in the Greater Green River Basin of Wyoming and Colorado. These include:

Area	**Acres**	**Wells**
Great Divide	4,600,000	8822
Desolation Flats	233,542	592
Hiawatha	157,361	4208
Little Snake	2,400,000	3031

These studies, although wide in scope, do not include specific provisions for directional drilling. However all include major tight gas sand developments which produce from the Mesaverde group. With production characteristics similar to the examples provided above, many of these fields are excellent candidates for directional drilling, yet the EIS for each is largely silent on the issue.

Summary of tight gas sand activity

Note the similarities in the above examples:

1. Producing formations are dominantly in the Upper Cretaceous Mesaverde, including the Lance, and the Tertiary Wasatch.
2. Depths and thickness are similar.
3. Activity levels are large, potentially comprising thousands of wells per area.
4. Reserve numbers are huge, measuring in the trillions of cubic feet [Tcf].
5. Well spacing is extremely dense, from 5 to 40 acres per well.

If directional drilling was applied to all these developments, their parameters would be similar as well:

1. 20 to 30 wells per pad.
2. Horizontal reaches up to 2500 feet.

These two broad characteristics can be considered to be well within industry capabilities for a wide range of applications.

Perhaps the most obvious fact, and the biggest mystery, is that the use of directional drilling varies so dramatically. In some cases, such as the Roan Plateau and Pinedale, the technology has been embraced. In others, it is virtually non-existent. Jonah, for instance, has seen little impact from directional wells although its close neighbor, Pinedale, has. The case of Natural Buttes is even more striking. Despite having production from formations and reservoirs that are geologically virtually identical to the Roan Plateau, there has been little directional drilling thus far at Natural Buttes.

These factors extend to developments that are currently occurring across entire basins in the Rocky Mountains. As noted in the previously in this paper, the number of gas wells drilled in the Rockies exceeded 8000 in 2005 and is growing at a rate of about 1000 wells per year. These exploration and development activities are taking place in many areas across the Uinta, Piceance, and Green River Basins, as well as other areas in the Rockies. Disturbingly, as is the case of the larger examples, the application of directional drilling in these areas is spotty, uncoordinated and illogical. A more unified, coherent approach to all Rocky Mountain tight gas developments is long overdue.

Coalbed methane-- Rocky Mountain CBM

Another drilling boom

The other "unconventional" gas resource that has been intensely developed during the past several years is coalbed methane. Essentially no more than a minor contributor to Rockies gas production in 1990, with less than 200 Bcf, production has increased dramatically to around 1500 Bcf per year in 2005.[71] This spectacular seven-fold increase has required a boom in drilling, especially in the Powder River Basin of Wyoming. Here the number of CBM wells has grown from a handful in the 1990s to several thousand by 2003. In that year, in the midst of the boom, the Powder River Basin Oil & Gas final environmental impact statement (EIS) anticipated the addition of 39,400 new wells within the 8-million acre planning area during the next 10 years.[72] As one might expect, this level of activity has had a major impact across the entire northeastern portion of Wyoming.

The notion of producing gas from coal seams is not a new one in the Rockies. Wells have been producing from coal seams of the Fruitland and Menefee formations in the San Juan Basin since the 1950s. As described in the Oil and Gas Investor:

> "Annual production from the world's leading coalbed gas field peaked at 1trillion cubic feet (Tcf) of gas in 1999. Since then, output has been declining slightly while the number of producing wells has climbed from 3,300 to 3,950. Cumulative production topped 10 Tcf in early 2003. In-place gas resources for the Fruitland coal-gas pool are estimated at 50 Tcf."[73]

Remaining potential centers on the lesser developed underpressured "low productivity area", where efforts are now underway to infill the current 320-acre spacing units to 160 acres, or 4 wells per square mile.[74]

More recently, the Powder River Basin has become the dominant area of coalbed methane activity. The bulk of this is in Wyoming where the state is projecting production to grow from 350 Bcf in 2006 to 400 Bcf by 2010.[75] Other predictions reach as high as 600 Bcf from as many as 20,900 wells.[76] At present, over 12,000 wells are producing about 350 Bcf from an area that encompasses 12,500 square miles.[77] Estimated ultimate

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[71] Trammel 2006.
[72] Oil and Gas Investor, "A Supplement to Oil and Gas Investor: Coalbed Methane," December 2003. http://www.oilandgasinvestor.com/pdf/Coalbed_Methane.pdf
[73] Oil & Gas Investor 2003.
[74] Oil & Gas Investor 2003.
[75] Wyoming State Geological Survey website: http://www.wsgs.uwyo.edu/
[76] DeBruin, Rodney et al; "Coalbed Methane in Wyoming"; Wyoming State Geological Survey; 2004. http://blackdiamondenergy.com/coalbed.html
[77] Oil and Gas Investor, "A Supplement to Oil and Gas Investor: An Investor's Guide to Coalbed Methane," December 2006. http://www.oilandgasinvestor.com/pdf/CoalbedMethane2006.pdf

recovery is 25.2 Tcf.[78] Williams, the most active of the over 72 companies involved in the play, expects to have completed 440 wells in 2006.[79]

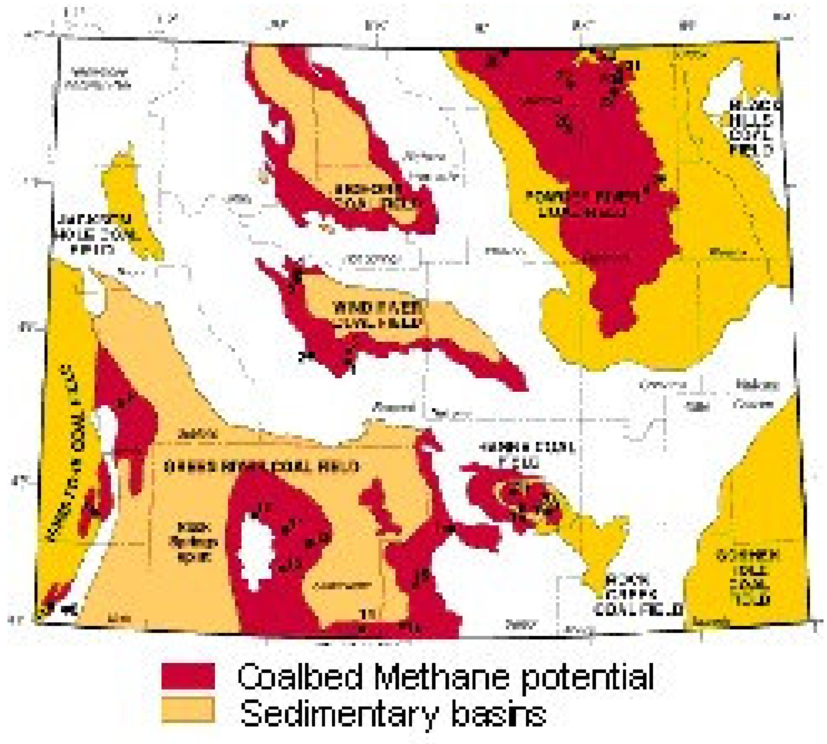
CBM production differs from tight gas sand development as the producing coal formations are comparatively shallow and thin. Producing coal beds in the San Juan are found from 1,000 to 4,000 feet. In the Powder, production is principally from wells producing from less than 3,000 feet; many as shallow to 100 feet to 2100 feet. Rather than the thousands of feet thickness common in tight gas reservoirs, CBM thicknesses are more on the order of 40 feet to 60 feet. The production characteristics of these wells are also quite different. Tight gas sand wells come on strong and rapidly decline. In contrast, CBM wells initially produce mostly water with some gas. Eventually, as the water decreases, gas desorbs from the coal, resulting in gas production which increases to a peak and gradually declines. This period before reaching peak production, the initial dewatering phase, can take from a few months to two years. Thus production volumes can be difficult to predict.

Although management of the prodigious volumes of water produced by these wells remains the key issue, well spacing is also a major concern, especially as exploration seeks to establish new CBM production in additional areas of the Rockies, such as on the Atlantic Rim in the Greater Green River Basin, the Piceance and Uinta Basins, and others. Well spacing in the Powder River Basin currently varies from 40 to 160 acres, with 80 acres being common.

Figure 16 depicts the major CBM producing areas.

[78] O'Connor, Leslie et al; "Revenge of the Powder River Basin"; Sproule Associates Inc. [presentation]; August 9, 2004.
[79] Oil & Gas Investor 2006.

FIGURE 16



Potential areas of CBM production in Wyoming

Horizontal wells—technical feasibility

Horizontal techniques have been demonstrated to be effective in the development of CBM reserves. Coal beds in the Appalachian Basin and Oklahoma are being actively developed using horizontal technology. The case of the Hartshorne coal in Oklahoma is particularly instructive. Vertical completions in this thin coal typically range from 256 feet to 3756 feet deep and yield average initial rates of 10 to 120 thousand cubic feet per day [Mcf]. Since 1997, horizontal drilling has been used extensively. Between 1998 and 2002, six operators drilled 110 horizontal wells. Laterals reached up to 5300 feet at true vertical depths [TVD] of 752 feet to 3031 feet. Initial production [IP] from half of these wells performed at better than twice the average of the vertical wells, between 200 to 400 Mcf per day. Seven came in at well over a million cubic feet per day. The highest IP, 1152 Mcfd, came from a horizontal lateral of 1604 feet length.[80] The improvement in initial production is because:

> higher initial gas rates are possible in a horizontal well than in a single-bed vertical well by drilling at a high angle (perpendicular to oblique) to the face cleat to drain a larger area.[81]

In this play, Williams Exploration and Production reports that their "superior economics are due to their horizontal drilling and completion techniques." Net cash of $2.92 per Mcf are reported from wells drilled to an average depth of 2000 feet. A success rate of 94% was reported by the operator.[82]

Unfortunately, there is a major hurdle to horizontal CBM drilling in the Rocky Mountain states. As reported in Gas TIPS:

> Eastern hard coals, which contain less water, are often developed using multiple horizontal drains from a single borehole. Horizontal wells have a drawback for CBM production in most western states in that they work best when limited to a single coal seam per well, which would make horizontal drilling prohibitively expensive in the multi-level western basin coal seams. Attempts at multi-laterals into more than one reservoir often fail because it is not possible to lower the water level in individual coals independent of each other. However, horizontal wellbores have been successfully used to produce coalbed natural gas from bituminous coal seams in the San Juan Basin of New Mexico.[83]

San Juan Basin

Horizontal techniques have been applied in the San Juan Basin with some degree of success. Responding to comments submitted in connection with the Northern San Juan Basin Coalbed Methane DEIS, the BLM conducted a study of horizontal drilling in the basin. Their study focused on about 20 horizontal wells that had been drilled through mid-2005. Some important findings are:

1. There are significant problems with hole stability in this area.
2. There is wide variability in the characteristics of the Fruitland coals and their depths, which adds to risk.
3. Fruitland coals consist of multiple seams:

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[80] Haines, Leslie, ed., "Opportunities in Coalbed Methane"; Hart's Oil & Gas Investor, December, 2002. http://www.oilandgasinvestor.com/pdf/HartPubCoalbed.pdf
[81] Logan, Terry, "Horizontal Drainhole Drilling Techniques Used in Rocky Mountain Coal Seams," Coalbed Methane, San Juan Basin, Rocky Mountain Association of Geologists (RMAG), 1988.
[82] Guderian 2003.
[83] Arthur, Dan and Bruce Langhus, ALL Consulting, and Viola Rawn-Schatzinger, RMC Consultants, "Coalbed Natural Gas Resources and Produced Water Management," GasTIPS, Summer 2003. http://www.all-llc.com/CBM/pdf/CoalbedMeth-ProducedWtrMgmt.pdf

"There are multiple coal seams over the net coal thickness within the Fruitland; for example there may be seven or eight seams representing a total of 40 feet of net coal within a 150 foot gross interval. Horizontal drilling technology allows a lateral to be placed within a five foot coal seam; however, unlike a vertical well that can complete and drain the multiple coal seams a horizontal well will effectively drain only the coal(s) which it traverses. Therefore, while the horizontal well may effectively drain larger areas of particular coals it will leave other coals undepleted."[84] [Of course, multiple horizontal laterals could be drilled to compensate for this.]

4. "Horizontal wells appear to perform about twice as well as offsetting vertical wells."[85]
5. Costs are uncertain, due largely to limited experience. Reported costs range from 2 to 3 times that of a vertical well.[86]

However, the more recent experience of two operators in the basin's CBM is encouraging. BP drilled three wells during 2005, each testing a different portion of the CBM fairway. The wells had multiple laterals [from 2 to 3 each] accessing different coal seams going about 2000 feet from the vertical wellbore. Results were encouraging. All achieved production rates that from 2 to 7 times that of comparable vertical wells. These initial rates will likely correspond to similar increases in estimated ultimate recoveries [EURs].[87] If so, then it is possible horizontal drilling will become more prominent in the basin.

Another operator, CDX, has been experimenting with their proprietary technology, pinnate horizontal wells. This technique, involving the use of multiple laterals branching out in a fan shaped fashion from a horizontal well, has been successfully applied by the operator in other areas, most notably the Appalachian Basin and Hartshorne. In West Virginia, a single pinnate well can drain up to 1400 acres, resulting in the replacement of 16 vertical wells. In the Hartshorne, they report production improvements of 10 times a vertical well in initial rate and EUR. This accelerated rate as well as the greater ultimate recoveries both favorably impact the economics of the venture. While still under evaluation in the San Juan Fruitland coals, the operator maintains their technique will prove superior to single lateral horizontal wells. They are projecting initial rates of 2700 Mcf versus 150 Mcf for a vertical well, and EURs of 2.1 Bcf per coal seam versus 0.154 Bcf for the average vertical well.[88]

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[84] MHA Petroleum Consultants, Inc., "Northern San Juan Final Environmental Impact Statement: Appendix D: Evaluation of Coalbed Methane Well Types In The San Juan Basin (November 2005 And March 2004), ***Draft Report*** Prepared For Bureau Of Land Management," November 2005. http://www.nsjb-eis.net/Data/Appdx-D1.pdf
[85] MHA Petroleum Consultants, Inc. 2005.
[86] MHA Petroleum Consultants, Inc. 2005.
[87] MHA Petroleum Consultants, Inc. 2005.
[88] Wright, Doug, CDX Gas, "Unconventional Plays: Enhancing Performance with New Technologies," Summer NAPE (North American Prospects Expo) 2005, August 23, 2005. http://energy.ihs.com/NR/rdonlyres/4EA9831E-99AA-4F1D-A09B-EEDF75212610/0/wight.pdf

Powder River Basin

Because of the relatively shallower, 'easy to reach' nature of the coal seams on the eastern side of the Powder River Basin, where much of the activity has been focused, this basin has seen little horizontal well activity. Instead the focus has been on multi-seam completions [MSC].
As in the tight gas sand case, the use of multi-well pads is a strategy for mitigating the effects of dense spacing. This has been identified as a best practice in the Montana portion of the Powder River Basin:

> Operators who have leases with multiple gas producing coal seams can reduce surface disturbances by completing multiple wells in the different coal seams, called well pods. Well pods can utilize the same operation resources such as access roads, compressors, and utility corridors. [There are examples in Montana of] three wells are currently sharing operation equipment. Each well produces from a separate coal seam so spacing requirements are met. The centralizing of operations equipment around well pods helps to minimize the footprint [on the surface].[89]

This technique addresses wells producing from different zones on a single pad. As in the tight gas sand fields, multiple wells could also be drilled directionally from multi-well pads into the same reservoir horizon.

According to one DOE study in the Powder River Basin, "MSC technology can help improve the outlook for CBM in the Powder River Basin by improving the reserves-per-well, and by reducing environmental impact due to drilling fewer wells."[90]

In addition, there is a promising technology under development in Canada which stands to impact horizontal CBM drilling. In an attempt to improve on their horizontal drilling performance in thin coal seams, Quicksilver recently drilled "two horizontals into thin layers of coal, employing a combination of the Schlumberger PeriScope 15 bed boundary detector, and a PowerDrive X5 rotary steerable system."[91] Utilizing high tech approaches such as these, horizontal drilling may become economic even for areas consisting of thin coal seams, such as the western side of the Powder River Basin and other Rocky Mountain CBM plays.

Other Rocky Mountain CBM Areas

There are other basins which have CBM potential. Many of these have seen some amount of CBM drilling.

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[89] Department of Energy, "Handbook on Best Management Practices and Mitigation Strategies for Coalbed Methane in the Montana Portion of the Powder River Basin," April 2002. http://www.fossil.energy.gov/programs/oilgas/environment/publications/BMPHandbookFinal.pdf
[90] Department of Energy, National Energy Technology Center, Strategic Center for Natural Gas, "Multi-Seam Well Completion Technology: Implications for Powder River Basin Coalbed Methane Production," DOE/NETL-2003/1193, September, 2003. http://www.netl.doe.gov/publications/EPreports/MSCreport.pdf
[91] Oil & Gas Investor 2006.

These basins, unlike the Powder River Basin, may represent an opportunity for horizontal drilling. According to the Petroleum Technology Transfer Council [PTTC]:

> Horizontal and directional drilling has been a tremendous advance in two significant ways; it improves recovery and reduces environmental impact. The technology could be a boon to production from many reservoirs where it not extensively applied now including CBM, especially in deeper tight CBM reservoirs such as the Green River Basin.[92]

Figure 15 reveals the location of these potential CBM producing areas in Wyoming.

Summary of CBM production

CBM production from all sources totaled over 1500 Bcf in 2005, accounting for about a third of all Rocky Mountain gas production [4600 Bcf].[93] This has grown from insignificant volumes in 1990, a time when overall gas production totaled less than half of today [2100 Bcf].[94] As important as this growth has been, significant CBM potential remains in multiple Rocky Mountain Basins, each comprising thousands of wells, representing a large potential impact to the environment.

CBM Economics

Coalbed methane economics in general have been variable. An in-depth study of the economics of the most significant CBM play, the Powder River Basin, by Sproule & Associates, Inc. concluded:

1. Initial economics [prior to 2002] were marginal.
2. Recent rise in gas price from 2002 to 2004 made the play economic.
3. Some areas proved to be better than others, with economics varying by as much as a factor of 3.[95]

In other words, CBM economics are both price sensitive and area dependent. As we have seen in the tight gas sands, current prices allow the overall play to have very favorable economics. However, the factor of three variability shows that even the conventional vertical development can be fairly risky. In addition, results from one area do not necessarily apply to the play as a whole.

[92] Petroleum Technology Transfer Council (PTTC) Rockies Newsletter; Third Quarter, 2004.
[93] Trammel 2006.
[94] Trammel 2006.
[95] O'Connor 2004.

So what of horizontal drilling? In general, the economics of horizontal drilling for coalbed methane depends on:

1. Increased production rates.
2. Favorable cost per Mcf relative to vertical wells.

In the San Juan Basin example, we have seen the early results of horizontal drilling suggested that horizontal wells were economic, if not spectacular. Since they produced about twice that of a vertical well, while costing about twice as well, their cost per Mcf is similar to the vertical case.

Even in the Powder River Basin, PTTC concludes:

> A PRB CBM completion costs about $150,000. If four horizontal wells could be drilled from one site for under $400,000 or $500,000 it may be feasible to begin using this technology to help solve both environmental and technical challenges.[96]

Thus for every CBM play, the economics should be analyzed. However, early evaluations of the economics of horizontal wells can often be misleading, for several reasons:

1. It depends on estimated ultimate recoveries, which can only be reliably calculated after a production history is compiled. Often EURs are initially under-estimated.
2. There is a steep learning curve, so that initial costs will be artificially high.
3. The proper vertical well comparison should be used. In practice, a horizontal well may replace more than one vertical well. The costs and production of all of such vertical wells should be summed.
4. As we have seen, the play greatly benefits from rising prices. As gas prices are projected to continue to rise over the long term, this factor must be recognized.
5. Cost savings accruing from concentration of facilities, economies of scale, reduction in roads and pipelines, etc, are usually not included.
6. The reduction in surface impacts has a value, which is often not taken into account.

Thus it is likely that initial estimates of horizontal economics will be unduly pessimistic relative to vertical drilling. I submit that if the analysis is close, it may be reasonably concluded that the horizontal program under consideration will prove to be economic. As shown by the Sproule analysis, rising prices will favorably impact the overall economics. A decrease in costs arising from a more routine use of the technology will likewise have the same positive effect.

[96] PTTC Rockies Newsletter 2004.

Note on CBM directional wells

Besides horizontal drilling, directional wells should also be considered to mitigate surface impacts. Although the shallow depths involved make this more difficult than in the deeper tight gas sands, the possibilities of directional wells should not be overlooked. As CBM development progresses to deeper depths, these possibilities will become more numerous. Again, a thorough analysis should be undertaken.

Looking ahead; promising advances in technology

Horizontal drilling in tight gas sands

In East Texas, GMX Resources [GMXR] has begun drilling horizontal wells in tight gas sand formations. The company is targeting the Travis Peak and Cotton Valley sands, Cretaceous age tight gas formations that are comparable to the Mesaverde in the Rockies. Composed of thousands of feet of discrete, discontinuous pay sands, these formations have traditionally been drilled vertically, each well making completions in several zones, each of which is then subjected to a massive frac. GMXR is proposing to drill the best of these pay zones horizontally. A several stage fracture stimulation follows, each stage separately treating some 300 to 500 feet of the horizontal lateral. The idea is that the artificial fractures will travel 300 feet vertically away from the wellbore, thereby increasing gas communication from the scattered reservoir pockets to the wellbore. The company expects that each stage will produce the equivalent of one vertical well. Potentially a single horizontal well could replace five or more vertical wells.[97]

The company recently completed the drilling of the Baldwin 5H in the Carthage Field. Targeting the Cotton Valley Taylor sands, the well achieved a horizontal lateral of 1695 feet. A five-stage fracture treatment was then performed. The well came on for 16mMcfg and produced 0.25 Bcf in a single month. Although the well cost was high, $5.5MM versus about $2MM for a vertical well, the expected EUR is 4 to 6 Bcf, far superior to the 1.6 Bcf for a vertical well, thus resulting in a F&D cost that is actually lower than the average vertical well.[98]

This project is significant because it:

1. Demonstrates the feasibility of drilling horizontal wells in tight gas formations.
2. Provides a successful example of multi-stage artificial fracturing in a horizontal well.
3. Opens the possibility that horizontal completions may provide production superior to vertical wells in tight gas sands.
4. May provide a means for reducing the number of wells required to drain a tight gas reservoir.

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[97] GMX Resources, Inc. (GMXR), Presentation at the Dec 4, 2006 Capital One Conference, materials dated November 29, 2006. http://www.secinfo.com/d14D5a.v7G3e.d.htm

[98] GMXR presentation 2006.

5. Is portable to the Rocky Mountain region, due to the similarity of the East Texas tight formations to their counterparts in the Rockies.

GMXR is currently pursuing multiple horizontal drilling locations.

LINGO

The US DOE has created a program called LINGO, or Low Impact Natural Gas and Oil, which seeks to encourage environmentally responsible technologies and innovative practices, such as:

- Directional drilling to reduce the number of drilling pads.
- Use of natural gas-fired drilling rigs to reduce air emissions.
- Installation of water pipelines to eliminate truck traffic.
- Deployment of mat systems on drilling pads to reduce surface impact.
- Elimination of gas flaring during well tests and completions to reduce air emissions and noise.
- Development of centralized fracturing and production facilities.
- Partial site restoration during the production phase.
- Low-impact road construction.
- Recycling of produced water.

Under this program, the Texas A&M University, in conjunction with Maurer Technology and the Houston Advanced Research Center, is researching new exploration and production technologies. Among these are:

- Advances in extended-reach drilling to expand the limit from the current seven miles to 15-20 miles.
- Lightweight drillpipe, floating drillpipe, and rotary-steerable tools to reduce friction and allow greater length horizontal drilling.
- More-efficient, lower impact rigs through DOE's Microhole Initiative.
- Modifications in drilling fluids leading to lightweight, gasified, and hollow-sphere drilling fluids to improve borehole cleaning and reduce lost circulation problems.
- Expandable casing, making smaller holes possible, reducing environmental impacts, and lowering costs.
- Dual-gradient drilling systems to reduce bottonhole pressures.
- Development of retractable bits and motors, long-life bits, and drilling systems that allow drilling with casing to eliminate trips in and out of the hole, allow longer-reach drilling.[99]

[99] Department of Energy, Office of Fossil Energy, "Eye on the Environment: LINGO [Low Impact Natural Gas and Oil," Winter 2006, vol. 11, no. 1. http://204.154.137.14/technologies/oil-gas/publications/newsletters/eoe/EyeWin2006.pdf

Other programs

Other government sponsored programs are seeking to improve drilling technology. These initiatives seek to drill:

> Faster - increasing efficiency through "reductions in equipment failure, extension of drill bit life, and reaching the target zone with the fewest number of course corrections possible."[100]
>
> Deeper - developing "unique drilling strategies that use the specific characteristics of the geologic formation itself."[101]
>
> Cheaper - promoting "cost-effective" drilling, measuring costs in terms of the "least impact on the environment, the longevity of the wellbore and all its components, and the long term productivity of the well bore."[102]
>
> Cleaner - developing drilling technologies that are environmentally "neutral," or even "friendly." These range from reducing the amount of surface disturbance that results from the drilling phase of energy production, to dealing with the final disposition of used drilling fluids, drill cuttings, and other waste generated by drilling activities.[103]

A good example of the above in action is the use of small bore "slimhole" wells which "has led to a 75 percent reduction in the amount of surface disturbed and the amount of waste generated. Operating costs are also reduced by up to 50 percent. Furthermore, reduced volume and weight of equipment favors slimhole drilling use in sensitive environments, such as wetlands."[104]

Nearly all these technologies have the goal of reducing the impact of drilling, either directly or indirectly. Significantly, a major focus of many of these programs involves the use of directional or horizontal drilling. These and the accompanying technologies will obviously favorably impact surface impacts, *if they are applied*.

Impediments to increased use of directional well techniques

Industry goal of keeping costs to a minimum restricts the application of directional drilling

An operator, in developing oil and gas reserves, has a major goal of keeping finding and development costs as low as possible in order to maximize profits for the company and

[100] Department of Energy, Office of Natural Gas And Petroleum Technology, "Advanced Drilling, Completion, and Stimulation Systems Program," 1999.
[101] DOE, Office Of Natural Gas And Petroleum Technology 1999.
[102] DOE, Office Of Natural Gas And Petroleum Technology 1999.
[103] DOE, Office Of Natural Gas And Petroleum Technology 1999.
[104] DOE, Office Of Natural Gas And Petroleum Technology 1999.

its stockholders. This is, of course, in our economic system, entirely proper. However, it sometimes prevents the utilization of directional drilling, for several reasons:

- Costs, whether real or perceived, might be higher with directional drilling.
- Vertical drilling is tried and true, directional drilling might be considered a risk.
- Directional drilling certainly requires better trained and qualified workers and contractors, which may not be readily available, especially in times of increased activity. This can impact the pace of development.
- Operators vary widely in ability. Some smaller, under-capitalized companies may not possess the required expertise.

As a result, operating companies will often argue against directional techniques, using high costs as the justification.

A few examples will illustrate the point:

In the Roan Plateau area, the oil and gas industry proposed not only increasing its area of operations to include the mostly undrilled upper Roan Plateau itself, but also increasing the drilling density from 640 acres to 20 acres (and in places, 10 acres) for the entire producing area. In spite of the massive impacts to the surface that this proposal entailed, operators argued for years that directional techniques were either not appropriate or too costly. As late as 2003, in preparing the draft EIS for the area, the BLM agreed, concluding that directional drilling on top of the plateau was “infeasible”, citing the poor drilling history of some dated and mostly irrelevant vertical wells. Largely due to a significant public outcry, which pointed out that directional drilling was an appropriate technology, the BLM reversed this opinion in the EIS presented in 2006, coming out in favor of multi-well pad directional drilling. Today, industry is actively pursuing developing the area below the rim utilizing multi-well pads with directional drilling.

Likewise, Encana mounted an effort to prevent the BLM from mandating directional drilling in the Jonah Field. Basing their argument largely on cost, Encana convinced BLM that the costs of directional drilling were unacceptably high, and would render the play ‘uneconomic’. As discussed previously in this paper, this seemed to be overstating the facts, as the average cost premium was only 11%, and the economics remained robust. Several industry experts disagreed as well. Most telling, the nearby analogous Pinedale field continued to be developed with directional techniques. Nevertheless, BLM allowed the operators to continue infilling the field to an unprecedented well density of 5 acres.

The successful application of new technology is often operator dependent. Also in the Roan area, Exxon recently announced plans to drill about 200 tight gas sand wells, using “patented new” drilling and completion techniques, a feature of which is an improved hydraulic fracture technique. “About the technology: Exxon says it will help improve the productivity of wells by 25 percent and reduce surface damage since up to nine wells can be drilled in a single pad in less time."[105] Williams, one of the major operators in the area, "said it tried the new technology while drilling in Garfield County and didn't see much savings."[106] Williams did not comment on the potential environmental benefit.

In the cases above, it was difficult to determine first, if the costs were truly "high," and second, if the "high" costs of directional drilling really unfavorably impacted the economics, or if they merely reduced the play's profitability by a small amount. This uncertainty reduces the ability to properly apply directional drilling technology.

Failure of BLM to properly analyze directional drilling alternatives reduces the application of directional drilling

When cost is cited as a reason for not employing directional or other techniques designed to reduce impacts, it is up to the appropriate governing body, usually the BLM, to balance that cost with the resulting environmental benefit. To be sure, the BLM attempts to manage the large number of development proposals brought before it, but this oversight is fragmented into countless small Environmental Impact Statements [EIS] or Environmental Assessments [EA] created by the local BLM offices, with little overall guidance. Even when a field-wide EIS is done, it is again a local affair. There is unfortunately little coordination among BLM offices, so the work of one may not be applied to a similar one in an adjacent area. As a result, the beneficial aspects of a new technology used in one area are seldom applied to another.

Overwhelmed by the current growth, and under great pressure to allow operators to increase production, the BLM makes an effort at applying mitigation such as directional drilling. However, all too often, as a claim of high costs by an operator goes unchallenged, directional drilling is not properly addressed and the environmental benefit goes unrealized. There are several reasons why this situation occurs:

1. Claims of high cost are not properly analyzed and vetted in a public arena. Often operator assertions are taken at face value and little real analysis is done. Documentation is often lacking.
2. The cost analysis that is performed is often flawed. The burden of proof is seldom on the operator making the claim. Cost-saving attributes of directional drilling, such as economies of scale, reduction in surface facilities, and others, are not taken into account.
3. Higher costs in themselves are used as a reason to reject directional drilling, without an attempt at balancing the benefits of reducing impacts, as if environmental benefits have no value in the calculation. To the contrary, the application of directional drilling, by preventing damage to the environment in the first place, may have the effect of reducing the need for other costly and uncertain mitigation measures meant to restore damaged ecosystems after the fact.

[105] Chakrabarty June 2006.
[106] Chakrabarty June 2006.

4. BLM investigations are uncoordinated, sometimes resulting in the "re-inventing of the wheel." For example, the office handling the Uinta Basin has not incorporated the decisions of the Piceance Basin office, despite the fact that the two geologic areas are substantially similar. Directional drilling is mandated in the Piceance, but not in the Uinta, in fields that are essentially identical.

Government and industry seem to support protecting the environment through the use of directional drilling

The reluctance of the BLM and other regulatory bodies to fully utilize directional drilling is even more inexplicable when one looks at what government and industry are saying about directional drilling to reduce impacts to the environment.

National Energy Policies encourage directional drilling

Directional drilling technologies are cited in several government policies. For example, the President's National Energy Policy contains a section titled, "21st Century Technology: The Key to Environmental Protection and New Energy Production," which states:

> Producing oil and gas from geologically challenging areas while protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques will allow for sophisticated energy production as well as enhanced environmental protection.... Smaller, lighter drilling rigs coupled with advances in directional and extended reach drilling significantly increase protection of the environment [...] highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site[.][107]

Likewise, the Secretary of the Interior, who is responsible for implementing much of the National Energy Policy, has emphasized the need to utilize directional drilling technology:

> We must also harness 21st Century technology to help our environment. Where we once needed scores of wells to tap underground reserves, today in some areas we can use one hole on the surface to drill for oil in a circle extending seven miles. We can use the resources below ground while we preserve the landscape and habitat above. [Presentation of Gale Norton,

[107] National Energy Policy Development Group, "National Energy Policy: Reliable, Affordable, and Environmentally Sound Energy for America's Future: Report of the National Energy Policy Development Group," p. 5.5, May 2001. http://www.whitehouse.gov/energy/2001/index.html

> Secretary of Interior, to the National Newspaper Association (Washington, DC, March 23, 2001).[108]

More recently, in December 2006, directional drilling technologies were included in the Appendices to the Energy Policy Act of 2005 – Section 1835 Split Estate Federal Oil and Gas Leasing and Development Practices. It specifically mentioned the following:

- More prescription of directional and pitless drilling.
- Directional drilling should be used in Watersheds and Wildlife areas.
- Decrease density of drilling sites.
- Use multiple well pads.[109]

The Secretary of the Interior, referring to industry's ability in directional drilling in a speech delivered in July of 2006, quipped:

> The industry also has advanced the technology of directional drilling to the point where if a rig were on the site of the Washington Monument, it could produce oil from an area the size of the entire city of Washington. If I had known about that technology when I was governor of Idaho, I would have tapped some of Wyoming's oil and gas.[110]

In the real world, it has proved difficult to require industry to use such techniques, even where the directional parameters are far more modest than those cited above. This is difficult to understand since undeniably, the federal government is well aware of both the capability of industry to drill directionally, and the need to apply the technology to reduce impacts to the environment. Industry, too, shares this awareness.

Oil and gas industry routinely asserts it possesses the means to mitigate environmental damage through the use of directional drilling

The Society of Petroleum Engineers, in a section of their website entitled "How is the Industry Working to Protect the Environment" explains:

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[108] Norton, Gale, Secretary of Interior, Presentation to the National Newspaper Association, Washington, DC, March 23, 2001.

[109] Perry, J., Bureau of Land Management, "Appendices to the Energy Policy Act of 2005 – Section 1835 Split Estate Federal Oil and Gas Leasing and Development Practices," December, 2006. http://209.85.173.104/search?q=cache:jl8WYdUCsK4J:www.blm.gov/style/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/bmps.Par.86645.File.dat/2-Appendix%2520-%2520Split-Estate%2520Report%2520to%2520Congress%25202006.pdf+Appendices+to+the+Energy+Policy+Act+of+2005+%E2%80%93+Section+1835+Split+Estate+Federal+Oil+and+Gas+Leasing+and+Development+Practices&hl=en&ct=clnk&cd=1&gl=us

[110] Kempthorne, Dirk, Secretary of the Interior, "Remarks Prepared for Delivery to the U.S. Chamber of Commerce," Washington, D.C., July 19, 2006. http://www.doi.gov/secretary/speeches/060719_speech.html

- "Improvements in technology enable us to conduct many aspects of our operations far more efficiently than just a decade ago. This efficiency translates to smaller "footprints" (the amount of surface area disturbed), less waste generated, cleaner and safer operations, and greater compatibility with the environment."

- "Directional drilling technology provides access to oil and gas resources that underlie sensitive areas, such as wetlands, from an area nearby where a drilling site can be constructed with minimal effect on the environment."

- "Companies have substantially reduced the amount of land disturbance required for drilling a well, and by drilling several wells from a single location (with directional or multilateral technology) fewer sites are required to achieve the same level of production."[111]

The Natural Gas Supply Association website states: "innovative technologies have lessened the effect that natural gas exploration and production have on the environment." Among the technologies cited are: "Directional and horizontal drilling allow for less surface impact as a greater number of wells may be drilled from a single location, and drilling rig placement is more flexible."[112]

It is apparent that there is widespread agreement that the oil and gas industry has the ability to use directional drilling techniques, including the use of multi-well pads and horizontal wells, to reduce impacts to the environment. With the apparent support of both government and industry, one is left to wonder why these techniques are not in more widespread use.

I submit it is time to move beyond the sound bite and more fully apply this technology.

<u>Summary</u>

The Rocky Mountain region is currently experiencing a large increase in the drilling of gas wells, especially from two unconventional sources: tight gas sands and coalbed methane. This increase is projected to continue for many years. With this unprecedented increase in both the number of gas wells, and more importantly, the density of those wells, directional drilling can significantly reduce the environmental impacts. To sum up:

1. The use of directional drilling to reduce environmental impacts is recognized as a best practice by the U.S. Government, as well as numerous industry organizations.
2. Directional drilling, accounting for over 40% of all wells drilled in the Untied States and growing, is an established technology that is used routinely by industry.

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[111] Society of Petroleum Engineers, "How is the Industry Working to Protect the Environment", Society of Petroleum Engineers website: http://www.spe.org/spe-app/spe/index.jsp
[112] Natural Gas Supply Association website: http://www.ngsa.org/

3. Directional wells with horizontal displacements of 2500 feet can be drilled commercially in the majority of Rocky Mountain tight gas fields.
4. Widespread use of well pad spacing of 160 acres [half mile] is feasible.
5. Using drilling parameters currently recognized by industry as appropriate for tight gas fields, spacing of one well pad per section may be possible, thereby reducing impacts even more.
6. In tight gas sand fields, directional wells utilizing these parameters can reduce direct surface impacts by a large factor, from 65% to over 92%.
7. Directional drilling is economic. Additional costs in most cases result in only minor increases to an operator's finding and development costs, and fail to render the play uneconomic.
8. The inconsistent and uneven application of directional drilling, across gas fields which are remarkably similar, is not due to the technology. Politics, timing of development, different operators and regulating offices all might play a role, but technological differences often do not.
9. Directional drilling and other technologies can reduce the number of required well pads in some coalbed methane developments.
10. Rising gas prices over time will continue to enhance the economics of these ventures over the long term.

<u>Recommendations</u>

Directional drilling is an established, stable, cost-effective technology that allows the full development of the nation's natural gas resources while simultaneously greatly reducing environmental impacts. The technology provides this benefit primarily by keeping the number of surface well pads to an absolute minimum, thus minimizing impacts at their source, the drilling site. However, in order to maximize this benefit, several steps need to be taken by those who are stewards of our public lands:

1. The reduction in surface impacts should become a major goal in the development of the nation's gas fields.
2. Directional drilling should be routinely required by the government and utilized by operators as a 'best practice' to accomplish this, in all high density tight gas sand developments. In other oil and gas developments, directional alternatives should always be considered and required when appropriate.
3. In coalbed methane developments, horizontal and, where applicable, directional drilling should be analyzed. Other technologies which reduce surface impacts, such as multi-stage completions, should be considered.
4. A clear, comprehensive, and public cost-benefit analysis should be performed when any gas development is proposed.

5. When ‘high costs’ are cited by an operator as a reason to reject directional drilling, the burden of proof should be placed on the operator. A full and public economic analysis should be undertaken.
6. In this analysis, the reduction in surface impacts should be quantified to properly balance it against any increase in cost. The application of directional drilling, by preventing damage to the environment in the first place, may have the effect of reducing the need for other costly, and uncertain mitigation measures meant to restore damaged ecosystems after the fact.
7. The analysis should include the savings in operational costs, such as reduced number of pipelines and roads, benefits of concentration of facilities, etc.
8. This use of technology to reduce impacts should be reviewed at a high level to ensure its uniform application. The Uinta-Piceance and Jonah-Pinedale areas are obvious examples of a failure to do this.

Growth can be managed, but only if it is done intelligently, using the full complement of technologies to mitigate its undesirable effects, while at the same time enjoying the full fruit of its benefits. The nation requires energy, but it also has a responsibility to acquire this energy in a way that least damages the environment. The technology is available to do both. We have the means to manage the required growth in our energy resources, but only through the intelligent application of the full suite of our technological tools. I submit we need not just growth, but ‘smart growth’ of our energy resources. This smarter approach needs to be taken early in the development of these fields, before the accompanying environmental damage is done. As in the case of city planning, let’s prevent the sprawl before it takes place. Even more importantly, directional technology needs to be applied in a widespread and systematic way, to all such developments.

With directional drilling, we possess the means to prevent a great deal of environmental harm, without jeopardizing the production of much needed energy. We lack only the will to do it.

Ken Kreckel is a professional geo-scientist with over thirty years experience in the exploration and development of oil and gas reserves in North America and Europe. He managed Marathon's exploration and development efforts in variety of producing basins, including many years in the Rocky Mountain region. Of particular note is his eight years as Exploitation Manager of Marathon's Southern region, where he led the company's participation in hundreds of wells, many in tight gas sand formations similar to the Wasatch and Mesaverde of the Rockies. He also gained a great deal of experience with directional wells, especially horizontal wells in the Austin Chalk play. More recently, he has been reviewing gas developments throughout the Rocky Mountain region.