Tight Gas Sands Development—How to Dramatically Improve Recovery Efficiency

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Integrated application of joint DOE/NETL and industry-sponsored intensive resource development technology could double the volume of natural gas considered technically recoverable from tight gas sands in Rocky Mountain basins. This is the first of a three-part series.

Three case studies are presented in this article to demonstrate the application of Intensive Resource Development (IRD). The first case study discusses how IRD is converting the Williams Fork/Mesaverde gas play in the **Rulison** field of the southern Piceance Basin of Colorado from a modest 100 Bcf accumulation into what is potentially a multi-Tcf gas field. The second case study examines the application of IRD in the **Jonah** field of the Greater Green River Basin of Wyoming, a field once labeled uneconomic and now the No. 1 producing field in the basin. The third case study describes how application of the lessons learned from the IRD experience in the Rulison field has helped change the **Cave Gulch/Waltman** field in the eastern Wind River Basin of Wyoming from a "four-well prospect" into a major gas field. One common thread in these examples is that the technologies and insights applied in each grew out of research and development (R&D) efforts supported by the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) during the 1980s and early 1990s.

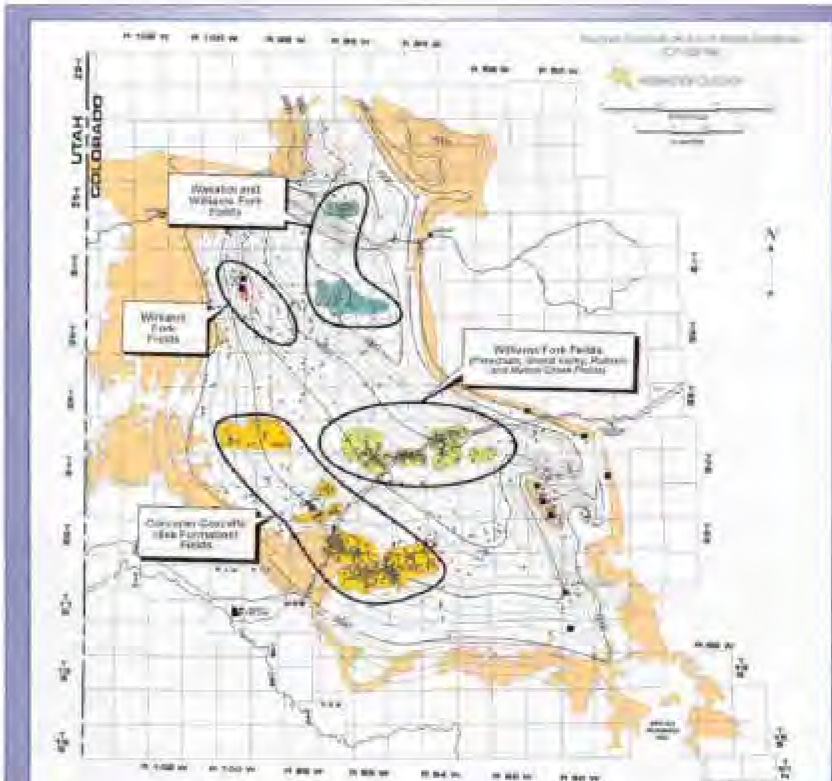

Figure 1. Gas fields in the southern portion of the Piceance Basin are experiencing active tight gas sands drilling.

This three-part series of GasTIPS articles on tight gas sand resource development focuses on the application of advanced exploration and production technology in low-permeability sandstone reservoirs to increase domestic natural gas supplies and lower their finding and production costs. IRD is the integrated application of a series of complementary resource assessment, reservoir characterization and field development technologies designed to optimize recovery. It is particularly applicable to low-permeability reservoirs with thick but discontinuous pay zones and anisotropic flow behavior – settings where a well's drainage area is low but numerous productive intervals are penetrated.

The suite of technologies IRD encompasses includes:

- *natural fracture identification technologies* to delineate high-productivity sections within a multi-township tight gas accumulation;
- *well logging technologies* that reliably distinguish between gas- and water-bearing sands, and can identify and quantify volumes of secondary porosity;
- *multi-zone completion technologies* that can efficiently stimulate multiple zones without damaging a formation; and
- *well testing technologies* to establish drainage volumes, well-to-well communication and anisotropic flow patterns.

NETL Intensive Resource Development R&D

The DOE/NETL sponsored three major research and development (R&D) activities in the Piceance Basin during the 1980s that helped establish a foundation for IRD technology. First was a series of resource assessments for the Piceance, Greater Green River and Wind River basins completed during a 15-year period (1980 to 1995). These assessments drew attention to large, high-concentration, Cretaceous-age unconventional gas accumulations and established the need for their thorough characterization. The National Energy Technology Laboratory (NETL) recently completed reassessments of the Greater Green River and Wind River basins, and is working on the Uinta and Anadarko basins (see *GasTIPS* Summer 2002, Vol. 8 No. 3).

Second was the Multiwell Experiment (MWX) in the southern Piceance Basin. This R&D project produced a comprehensive, well-documented description of the geologic controls on gas productivity in the Williams Fork and Iles Formations of the Mesaverde Group.

The third effort was an initial field test and demonstration of geomechanical-based natural fracture prediction technology in the **Rulison** field of the southern Piceance Basin. This test drew on prior work at the MWX site to develop technology for locating the higher productivity areas within tight gas sand accumulations. While these U.S. Department of Energy (DOE)-fostered research efforts were not the only drivers for the development of IRD technology, they were important catalysts.

The MWX in the Rulison field in Garfield County, Colo., began in 1980 and was completed in 1988. Three vertical wells, (MWX-1, 2 and 3) were drilled only a few hundred feet apart to provide a "laboratory" for production and stimulation experiments. The bulk of the work was performed in MWX-1, with holes two and three serving as observation wells for interference tests. An additional slant hole well was completed in 1990 as part of a joint DOE/Gas Research Institute (GRI) field research project.

The wells targeted the Mesaverde Group, Iles and Williams Fork Formations, which together encompass four different depositional environments. A geologic characterization of the Williams Fork Formation established that the sand bodies are compartmentalized fluvial point bars, with extremely tight matrix permeability (<0.0001 millidarcies) with an abundant system of micro-scale natural fractures and a less frequent set of macro-scale natural fractures, requiring hydraulic stimulation to interconnect this dual-fracture system with a wellbore. To obtain more reliable data on the natural fractures – defining vertical fractures is difficult with a vertical well because of the low probability of intercepting a vertical plane with a vertical hole – the DOE/GRI slant well was drilled at an angle of 60° to 85° from vertical. Two interval were cored, and the strike, dip and spacing of 65 fractures were recorded in the 381ft of retrieved core. These natural fractures, oriented west-northwest, were vertical and terminated within or at the boundaries of the sandstone beds. Well tests showed flow was primarily through these natural fractures with little occurring transverse to the fracture orientation.

Present-day stress conditions in the Mesaverde dictate hydraulic fractures initiated from a wellbore will have the same general orientation as existing micro-scale natural fractures, thereby lessening the chance of linking the wellbore with this system of natural fractures. However, areas where local faulting has tectonically altered the stress field and created large-scale natural fractures orthogonal to the micro-scale fractures will contain more favorable flow paths from reservoir to well.

The MWX also established a full set of reservoir properties for the Mesaverde Group formations, an achievement that went a long way toward improving methods for completing and stimulating these tight gas reservoirs. Continuous core and a full suite of logs and well tests across the stacked pay zones provided detailed pressure, porosity, permeability and saturation data. The well tests showed limited well-to-well communication, and modeling of the pressure response suggested permeability anisotropy ratios of 50:1 with bulk permeabilities of 1 microdarcy to 15 microdarcies.

The composite reservoir model that emerged from the MWX field experiment revealed a complex geologic and reservoir setting with vertically stacked point-bar deposits separated by alternating layers of shale that naturally isolated individual reservoirs. The combination of isolated point bars and the preferred natural fracture distribution could be shown to lead to elliptical drainage patterns.

The MWX project provided key insights to the nature of the tight gas sand reservoirs in the Rulison field that helped establish the foundation for the IRD technologies being applied in tight gas sand reservoirs of the Southern Piceance Basin – particularly those in the Williams Fork Formation – and elsewhere in the Rockies. Williams Production RMT is using the results from the MWX site to obtain Colorado Oil and Gas Conservation Commission approval for 10-acre and 20-acre per well spacing rules at Rulison and adjacent fields. The MWX project is a good example of the DOE-sponsored research providing the basic data and analytical foundation for interpretations the industry would not otherwise make the investment to acquire. ●

Case Study No. 1—Southern Piceance Basin, Colorado

The Piceance Basin is in northwest Colorado. Gas fields in the southern portion of the basin (Rulison, Grand Valley, Parachute and Mamm Creek) are experiencing active drilling for tight gas sands in the Upper Cretaceous-age Mesaverde Group (Figure 1). Historically, the tight lenticular Mesaverde sands in the Williams Fork have been viewed as a massive but low-productivity natural gas resource. However, field-based research has provided a more rigorous geologic understanding of these tight gas reservoirs and the appropriate technologies for producing them.

The Mesaverde tight gas sands in the Piceance Basin are estimated to hold more than 300 Tcf of gas. This resource is most highly concentrated in the southern portion of the basin, particularly in the stacked, lenticular sands of the Williams Fork Formation being developed in the Rulison field. In recent presentations to the Colorado Oil and Gas Commission (COGC), Williams RMT concluded the gas-in-place per section was 135 Bcf at Rulison, 120 Bcf at Parachute and 105 Bcf at Grand Valley. At traditional well spacings of 160 acres per well (four wells per section), 5% to 6% of this resource is in contact with a wellbore and recoverable. Based on the results of the MWX research (see sidebar), two new IRD strategies have been pursued in the Rulison field: intensive infill drilling and extensive vertical sand development. As documented in Barrett Resources and Williams RMT submissions to the COGC, these companies credit the DOE/NETL-sponsored MWX and its other R&D projects for developing the knowledge base and science for much of the IRD technology at Rulison field.

Geologic Basis for IRD Strategy—Outcrop studies of the lenticular Mesaverde sands have shown that wells separated by only 1,000ft will not be in communication, except in a handful of the more continuous sand intervals. Wells spaced as close as 1,100ft (28 acres per well) show little to no pay correlation from well to well (Figures 2 and 3). Even the three closely spaced MWX wells

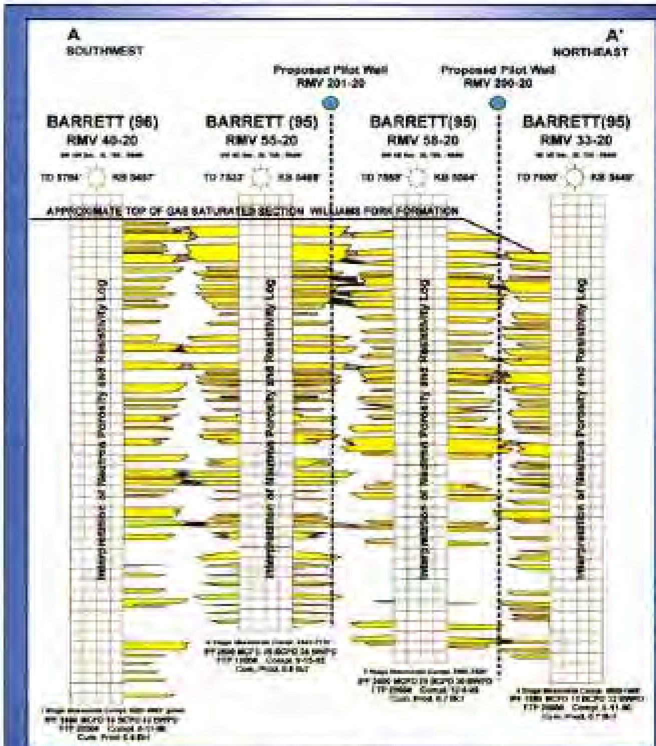

Figure 2. Even closely spaced wells often show little continuity.

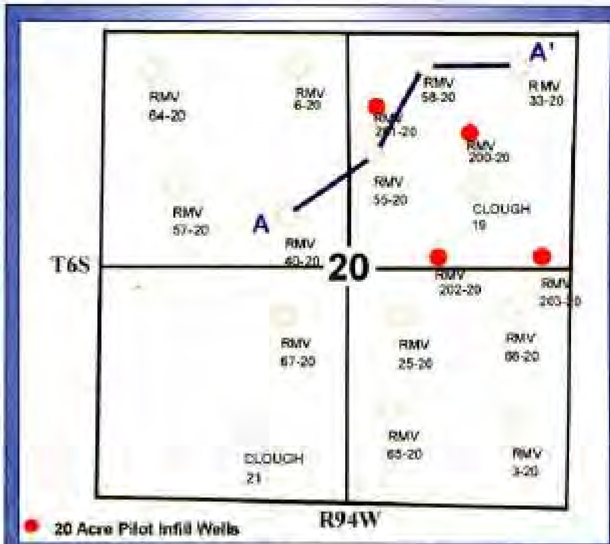

Figure 3. This figure shows the location of the cross-section outlined in Figure 2.

(about 150ft apart) showed poor well-to-well log correlation for the Williams Fork lenticular sands (Figure 4). Reservoir simulation (by Barrett Resources and Advanced Resources International) incorporating the low magnitude, anisotropic permeability and compartmentalized geometry of the lenticular Williams Fork sand bodies, has shown such wells have limited areal drainage. These studies helped operators view the Williams Fork as primarily a vertical rather than areal reservoir. This led operators to pursue more intensive development – closer well spacing and completion of all potentially productive sand intervals – than had been traditional in the Piceance Basin.

Infill Well Tests Support Tighter Spacing—Well tests also supported the idea of limited communication. During the initial infill-drilling program at Rulison, bottomhole pressure tests on new wells drilled adjacent to highly productive older wells showed essentially no communication-related depletion. More recent bottomhole pressure build-up data Barrett Resources performed on 80-acre and 40-acre spaced wells in 1994 and 1995, and subsequently on 20-acre spaced wells drilled in 1996 at Rulison and Grand Valley fields, indicated essentially no well-to-well pressure communication.

Reservoir Simulation and Analyses Quantifies Benefit—Type curve matching performed on a series of representative Mesaverde tight sand wells in different portions of the Rulison field showed the average outer limit of pressure depletion for a typical 1.8 Bcf well in the Williams Fork, after 20 years of production, is about 12 acres. Reservoir simulation and production data showed that traditional 160-acre spacing wells would only recover about 7% of the gas-in-place, but this value would climb to 21% at 40-acre spacing. Modeling also showed that when permeability, anisotropy and depositional direction are accounted for, drainage takes on a preferential east-west direction, calling for wells to be spaced on a rectangular rather than a square grid.

Barrett Infill Program Shows IRD Benefit—The traditional field development practice for the Williams Fork (Mesaverde) Formation had been to space wells at 160 acres or more. In 1994, Barrett Resources took the initial steps toward IRD, requesting approval for first 80-acre and then 40-acre spacing from the COGC. In 1996, Barrett requested approval to drill four wells in a 20-acre spacing pilot. The 20-acre spaced wells performed as well as the older, more widely spaced offset wells. Based on these promising results, the field operator continued with its intensive infill-drilling program. Twelve new infill wells were drilled in Section 20 of the Rulison field between 1998 and 2000, bringing the section total to 30 wells (effectively 20-acre spacing). The performance of these wells continued to be encouraging, with initial gas rates of 1 MMcf/d to 2 MMcf/d and estimated ultimate recoveries of 1.4 Bcf to 2.5 Bcf per well. Analysis of currently available data shows:

- 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; and
- intensive development of the Williams Fork sands at 20 acres per well may result in the recovery of 50 Bcf to 60 Bcf of gas reserves from this single section. Based on previous experience, bottomhole pressure testing on the 20-acre spaced wells at Rulison revealed that

only three of the 72 sands tested in the four wells exhibited pressure communication and possible partial pressure depletion.

The field operator (now Williams Production RMT) took the IRD concept to the next level by applying for permission to drill Section 20 in the Rulison field, and an additional section at Grand Valley field, at a spacing of 10 acres per well. Starting in late 2001 and continuing through early 2003, the operator added 10 additional infill wells to Section 20, bringing the total to 40 wells. While production data are still limited and several of the wells are still cleaning up, preliminary analysis shows the most recent group of wells have exhibited initial production rates of 1 MMcf/d to 2 MMcf/d, comparable or superior to the previously drilled 20-acre and 40-acre spaced wells. Seven of the 10 wells, after about 1 year of production, have performed such that their ultimate recoveries can be estimated in the range of 2 Bcf per well. Pressure testing in the newly drilled 10-acre spaced infill wells detected partial reservoir pressure depletion in six of 98 individually tested sand bodies. The total gas recovery from this section of the field, albeit with favorable reservoir properties and a high concentration of gas in-place, is expected to be more than 100 Bcf per section if fully developed with 64 wells (Table 1). Based on estimates by Williams, gas recovery in this section may reach 75% of gas-in-place vs. less than 10% on 160-acre spacing.

Vertical Completion and Restimulation—The lenticular sands in the Rulison field are separated into a series of packages, each of which comprise 400ft to 500ft of gross interval, and most wells penetrate four to six packages across more than 3,000ft of gas-saturated interval. Historical practice, given the difficulties with then-current log interpretation technology, had been to complete one or two sand packages to avoid wet, unproductive sands. This conventional practice resulted in per-well reserves averaging 0.5 Bcf, effectively rendering the wells and the gas play uneconomic.

Starting in 1994, Barrett Resources began to aggressively develop the total stack of lenticular sands intersected by each wellbore. The new approach included completing and independently stimulating each of the sand packages, increasing the size of the proppant load, and using more sophisticated fracturing fluids and procedures.

With improved core and log data, and a better understanding of lenticular sands, and basin-centered gas plays, Barrett also began to re-examine the potential for recompleting these older wells. An early recompletion demonstration took place in 1990 in the No. 1 well at the DOE's MWX field research site. The recompletion, which involved perforating and stimulating three additional uphole Williams Fork/Mesaverde sand

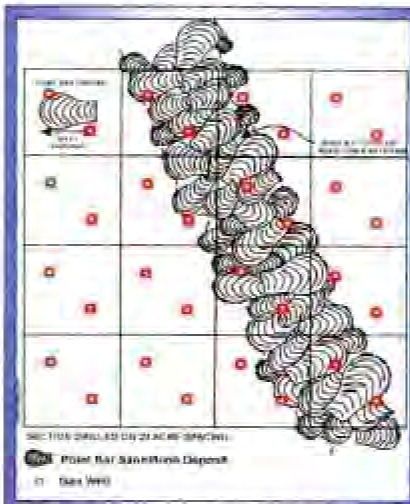

Figure 4. Outcrop studies have indicated the individual point bar deposits are in irregular vertical contact with the sequence of deposits that comprise the larger sand lenses in the fluvial channel.

packages, exhibited an excellent initial production response. As of early 2003, it had produced 1.4 Bcf of incremental production, validating this more aggressive recompletion approach. Following this demonstration, the operator launched a program to recomplete bypassed sands in older wells. Overall, the recompletion program has been successful, adding more than 80 Bcf of low-cost natural gas reserves. The cumulative effect of completing four to five pay zones in a single well and recompleting the older wells has been to raise the average well performance for new and old wells in Rulison field to 1.5 Bcf per well.

Based on the Rulison field example, IRD technology, with 10-acre well spacings and vertical completion of the full stack of sand, offers the promise of providing about 100 Bcf of recoverable resource per section and recovery of 80% of gas-in-place. IRD could transform a township-sized, basin-centered tight gas field from a 100-Bcf prospect into a major field with multiple Tcf of reserves. Other operators in the Southern Piceance Basin are applying the lessons learned at Rulison for optimally developing massively stacked tight sand accumulations in other Williams Fork Formation tight gas fields. Successful application of this technology holds

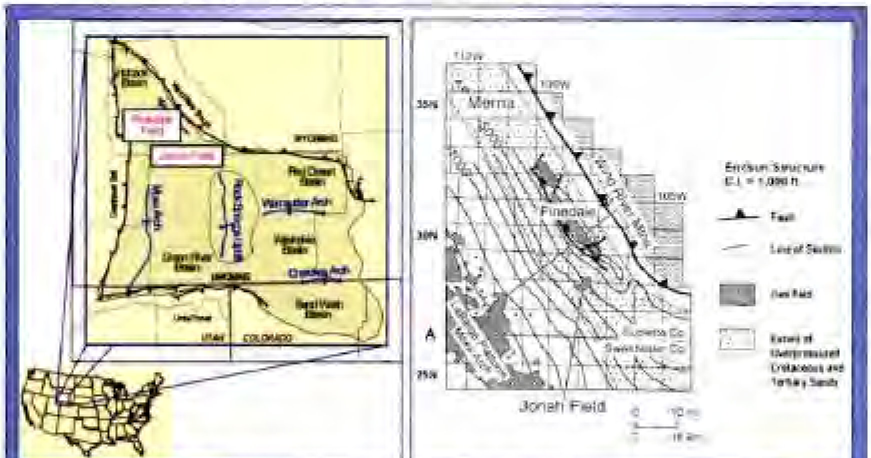

Figure 5. The Lance Formation is emerging as a significant producing horizon in the Jonah and Pinedale fields in the Greater Green River Basin.

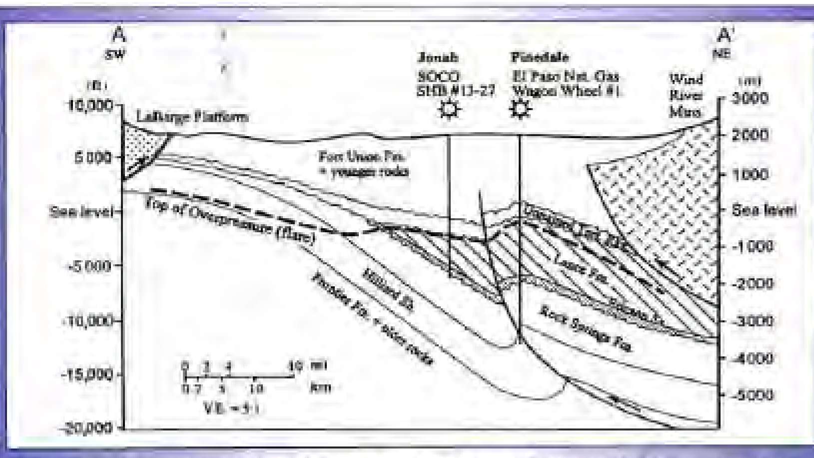

Figure 6. This cross-section shows the Jonah and Pinedale fields relative to the surrounding tectonic features.

the potential for converting this previously uneconomic tight gas play into a world class natural gas accumulation.

Case Study No. 2— Northwestern Greater Green River Basin, Wyoming

The Greater Green River Basin (GGRB) is the dominant natural gas-producing basin in the Rocky Mountains. Gas in this basin is found in the Tertiary and Cretaceous-age Fort Union, Lance, Mesaverde Group, Frontier, Muddy and Dakota formations. Recently, the 8,000-ft to 12,000-ft Lance Formation has emerged as a significant producing horizon in the Jonah and Pinedale fields in the northwestern portion of the GGRB. Development of an extensive stack of tight, over-pressured sandstones is underway in both fields (Figure 5).

The township-sized Jonah field is estimated (by industry) to hold nearly 10 Tcf of gas-in-place; a resource concentration of 250-Bcf to 300-Bcf per section. A unique geologic setting involving the local uplift of the over-pressured Lance section and a series of lateral sealing faults has enabled gas to accumulate and remain trapped in the Jonah field area (Figure 6).

Completion Inefficiencies Set the Stage for IRD—Prior to 1992, completion attempts employed relatively small amounts of proppant (80,000 lb to 200,000 lb) and cross-linked water-based gel or carbon dioxide foam as the transport fluid. These ineffective fracturing fluids, coupled with poor proppant placement, failed to establish commercial production. Between 1992 and 1995, nine wells were stimulated with high-quality nitrate (N_2) foam and an average proppant load of 550,000 lb. Most of these new stimulations, limited to the thicker (250ft to 300ft) sandstone intervals, resulted in successful wells but with steep annual declines in gas production. Engineering analyses of the wells completed using N_2 foam highlighted several factors that potentially limited well performance:

- significant vertical growth of hydraulic fractures outside of the pay interval;
- creation of multiple fractures with a resultant reduction in propped fracture length; and
- inefficient lateral transfer of proppant away from the wellbore.

Beginning in 1994, a new completion approach was initiated using water-based fluids with borate cross-linkers and a modified perforation technique designed for flexible treatment of multiple intervals. Wells where this new approach was employed exhibited initial gas flow rates comparable to the earlier completions but with shallower gas production declines, which, from improved lateral and vertical proppant placement, have led to greater ultimate gas recoveries.

With new well completion practices, gas production rates have improved significantly from an average of 2 MMcf/d to 3 MMcf/d, to 5 MMcf/d to 7 MMcf/d. One of the best "early" wells was found to be productive from as many as 17 separate sandstones distributed across all four lower pay intervals (Lower-Middle Lance) and has been completed in an additional 11 zones in the Upper Lance.

Evolution of IRD in Jonah Field—Aggressive vertical completion of the full stack of gas-charged net pay in the Lance Formation has

Table 1: *Expected results from intensive field development (Sec. 20, T6S, 94W, Rulison).*

Date	Wells and Spacing	Reserves/Well[1] (Bcf)	Total Gas Recovery (Bcf)
Initial	First 2 wells @320A/W	2.1	4
1994	Next 2 wells @160 A/W	2.2	4
1995	Next 4 wells @80 A/W	1.9	8
1996-1997	Next 8 wells @40 A/W	1.8	14
1997	Pilot 4 wells @20A/W	1.7	7
1998-2000	Next 12 wells @20 A/W	1.7	20
Latest	Next 32 wells @ 10 A/W	1.7	55
TOTAL (64 wells)		1.75	112

1. Estimated based on history matching with ARI-tight type curve model for wells drilled through 1997.

Table 2: *Evolution of well completion practices, Jonah field, Greater Green River Basin.*

	First Generation	Second Generation	Third Generation	Current
	Pre-1990	1992-1993	1994-1995	2000+
Pay Selection	Bottom 40%	Bottom 20-50%	50%	50% to 100%
Frac Stages	1	1	3	Up to 10
Frac Fluid	X-Link Gel	N_2	N_2/Gel	Borate Gel
IP (MMcf/d)	1.4	1 to 4	3 to 5	5 to 15
EUR (Bcf)	1.5	2.0	3.0	5 to 10+

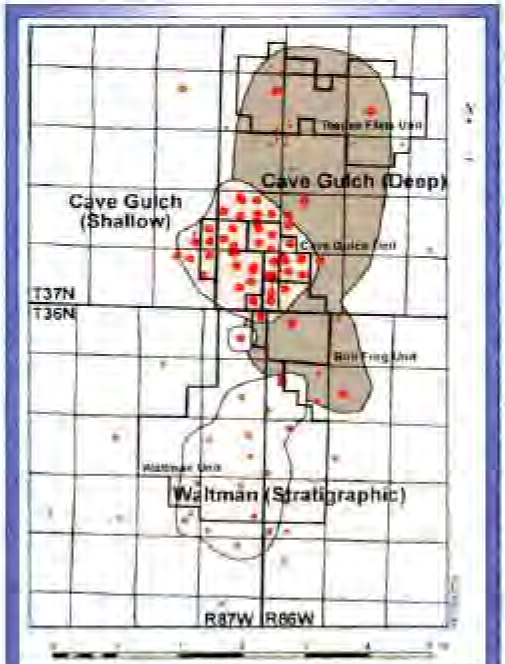

Figure 7. Although the Cave Gulch field was discovered in 1959, only recently has it been recognized as a significant gas accumulation.

converted the Jonah field from a bypassed area with low productivity wells to a highly productive giant gas field. The realization that past pay selection procedures were inadequate and past well stimulation practices were damaging led to changes in well completion practices (Table 2). The current IRD approach is to attempt to link a wellbore to as much of the vertical net pay as possible, using a dozen or more stimulations in individual Lance zones. With IRD, the estimated reserves per well in the Jonah field have increased from 1 Bcf to 2 Bcf per well in the early 1990s to 5 Bcf to 10 Bcf per well currently. As of mid-2003, Jonah is the largest natural gas field in the GGRB, producing 670 MMcf/d from 484 wells, compared with 15 MMcf/d in 1995. The field has produced more than 800 Bcf and is on its way to becoming a multi-Tcf gas field. Recently, the operators in the Jonah field and in the adjoining Pinedale area have begun development on 40-acre spacing, with indications of closer spacings to come. The coupling of intensive areal resource development with successful intensive vertical resource development should continue to improve the size and economics of this major new tight gas sand field.

Case Study No. 3—Eastern Wind River Basin, Wyoming

The Wind River Basin is one of the least developed of the high-potential natural gas basins in the Rocky Mountains. Gas in this basin exists in an extensive stack of Tertiary- through Cretaceous-age formations. Recently, the tight gas sands in the Fort Union/Lance Formation have become targets of active tight gas development. The primary Fort Union/Lance Formation natural gas fields in the Wind River Basin are Frenchie Draw, Madden, Muddy Ridge/Pavilion and Waltman/Cave Gulch. The largest of these, Waltman/Cave Gulch, is on the northeast flank of the basin, about 50 miles west-northwest of Casper, Wyo. (Figure 7). Although the field was discovered in 1959, the Cave Gulch Unit remained undeveloped and its true potential unrealized until Barrett Resources rediscovered it. For nearly 35 years, the Cave Gulch Unit was judged to be a modest, marginally productive natural gas field, having recovered less than 5 Bcf and producing only a few MMcf/d. Recognition that the Cave Gulch Unit held a massive stack of gas-saturated sands led to the application of IRD in this field starting in 1994.

The Bureau of Land Management (BLM) estimates the Waltman/Cave Gulch field area contains at least 1.6 Tcf of gas-in-place, primarily in a four-section area on the western edge of the field and in two sections on the eastern edge of the field. The BLM estimates the Fort Union and Lance Formations in this area contain an average 885ft of net pay within a 4,000-ft gross interval, holding from 450 Bcf to 680 Bcf per section. Assuming the reservoir sands are truly gas- (instead of water-) saturated, this would make the area one of the most highly concentrated natural gas accumulations in the Rocky Mountain region.

Evolution of Intensive Vertical Resource Development at Cave Gulch—Intensive vertical resource development, completing as much of the vertical sand interval as possible (between four and five stimulation stages per well on average) using large volumes of proppant (about 200,000 lb of sand per stage on average) has improved the performance of Cave Gulch wells. A total of 28 IRD wells completed between 1994 and 1998 exhibited initial flow rates as high as 10 MMcf/d, some with estimated reserves of 20 Bcf per well. Although there is considerable variability in the performance of the wells, particularly recent wells drilled along the edge of the Cave Gulch Unit, the average ultimate recovery for 43 successful Lance Formation IRD completions (excluding three economic dry holes) is estimated at 9 Bcf per well. The average of 18 successful, shallower Fort Union IRD completions in the Cave Gulch Unit is an estimated 5 Bcf per well, excluding four dry holes.

This example illustrates how the combined use of vertical development of the full stack of tight sands and optimum well spacing can lead to recovery of large volumes of natural gas from a relatively limited portion of the tight gas resource base. Together, these examples show how fundamental research and careful characterization of an apparently uneconomic resource by government and industry can reveal opportunities for new approaches to unlocking tight gas. ❖

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