San Juan North CBM Play

Jim O’Leary
Dec, 2006
San Juan North Asset

- Unique situation in Durango; tourism, resort living, environmental activism, tribal ownership
- 1020 BP wells producing 650mmcmd gross
- BP operates 52% of rate in the county
- Potential to stay above 80mbd net for 8 more yrs
- 95% of activity geared toward CBM
- One rig drilling program to infill to 160 acre well density; ~54 wells/yr, 3.5 yrs remaining
- Potential exists for 800 BP 80 acre wells
- Own and operate 650mmcmd of midstream infrastructure, including 850 miles of P/L, 200k hp, 420 mmcmd plant
- Capex spend 70mm$/yr
- Infill program delivers 30% IRR at $3.50/mcf
- Cost of supply $4.70/boe, 40% ROACE
Unique Asset, Unique Challenges

Terrain and topography

Working in populated areas

Regulatory & Permitting

Environmentally sensitive area
La Plata County Significant Operators

Note: Significant Conventional operators w/ no CBM production:
Williams (21mmcfd, 194 wells), Apache (4mmcfd, 38 wells), Murchison (2mmcfd, 71 wells)
**Production Statistics, La Plata County**

- **Industry Statistics:**
  - Avg Prod’n, mmcfd
    - CBM: 1180
    - Conv: 80
    - Total: 1260
  - # of Producing wells
    - CBM: 1300
    - Conv: 900
    - Total: 2200
  - Avg Rate per well, mcfd
    - CBM: 900
    - Conv: 90
    - Total: 570
  - # of Significant Operators
    - CBM: 12
    - Conv: 3
    - Total: 15

- **BP Statistics:**
  - Avg Prod’n, mmcfd
    - CBM: 642
    - Conv: 8
    - Total: 650
  - # of Producing wells
    - CBM: 890
    - Conv: 130
    - Total: 1020
  - Avg Rate per well, mcfd
    - CBM: 720
    - Conv: 60
    - Total: 780
  - % of Operatorship, by rate
    - CBM: 55%  
    - Conv: 10%
    - Total: 52%
**Long Term Outlook**

**Development Options**

**Base:** Production declines (15-18% pa) with minimal capital spend.

**LTP Wedge:** consists of expense wellwork, capital wellwork, facilities spend, and infill drilling (1 rig @ 54 wells/yr).

**80-acre Opportunity:** adding a second rig to double the number of wells (a total of 108) drilled per year to access 80-acre density in a shorter period of time.
Environment - Resource Sensitivities

**Air**
- Visibility/Regional Haze (emission control strategies)
- Permitting (Minor and Major Source Permitting)
  - Fee Lands
  - Tribal/Federal Lands

**Water**
- Beneficial Use of Produced Water/Surface Discharge/POTW
- UIC Permitting
- Stormwater permits (currently 5 acres threshold; could potentially be reduced to 1 acre)
- Wetlands Issues (increased density challenges avoidance strategy)
- Water Well Monitoring—will continue per HSW Plan

**Wildlife**
- Big game seasonal restrictions (deer, elk habitat management)
- T&E species (i.e., Knowlton’s cactus, flycatcher)
  - Water Depletion Affecting Listed Aquatic Species
- Raptor Species (bald eagles)

**NGO Outreach**
- Must assess degree of outreach
- Regional vs. National focus
Environment - Agency Interaction

**County/Local Issues (Fee Land Actions)**
- Visual/ Noise
- Permitting (Major Facilities)
- Future Stricter Land Use Regulation
- Infill/Health Safety Welfare (HSW) Outreach Effort

**COGCC Infill Hearing**
- HSW Plan (noise)
- Outcrop Issues

**Southern Ute Tribe (Tribal Lands)**
- ROW
- Land Use Approvals/Permits
- New Minor Permitting Program (smaller emission sources, i.e., pumps, pumpjack engines, small compressors)

**BIA (Tribal Lands)**
- Possible delays in obtaining surface use activities permit approval (rights of way, tribal occupancy)

**U.S. Forest Service (National Forest Lands)**
- Sauls Creek, areas northeast of Bayfield (eastern flank of HD Mountain area)
- Activities require current EIS approvals
• On an overall average basis:
  – Working Interest = 85%  Net Interest = 72%

• BP is subject to a 35% corporate income tax on field revenues

• State taxes include:
  – 2% income tax
  – 6.5% severance tax
  – 3% ad valorem tax

• Cessation of production is modeled at ~2050
La Plata County Economy

• O&G portion of total property tax accounts for 62% of county budget

• Tourism = 27.5% of local economy
  – Major attractions: Durango Mountain Resort, D&SNG train, Mesa Verde National Park

• Fort Lewis College
  – more than 4,000 faculty and students

• Mercy Medical: due open in 2006
  – New regional hospital: 320m sq. ft.
  – Associated medical office bldg: 375m sq. ft.
The San Juan Basin, located in southwest Colorado and northwest New Mexico, contains the second largest gas deposit in the United States. It covers an area of 6,500 square miles as defined by the Cretaceous outcrops rimming the basin. Most of the BP acreage is focused in the northern half, northeast of Farmington.
Aggressive development began in the 1930’s, after the first pipeline
was constructed. Until the 1990’s the primary production was from the
Cretaceous age Dakota, Mesaverde, and Pictured Cliffs sandstones.
For over 50 years the Fruitland “Fairway” coals were considered a
nuisance because water influx and high pressures required casing to be
set before drilling to the deeper reservoirs. Over 20,000 wells
penetrated the Fruitland before it was first recognized by Amoco as a
potential gas resource in the 1970’s.

The San Juan Basin is very asymmetric. The east and north flanks are
steep and faulted. The southwest is much gentler. Structure within the
basin is simple. Faults are probably numerous but have small offsets
and are hard to recognize. Fracture enhanced permeability is important
in all of the producing horizons, especially the Fruitland.
The Upper Cretaceous Fruitland Formation is the shallowest producing horizon in the basin. Average depth for productive coals is 2,500 feet. Coal is concentrated in the lower 400 feet of the formation, and is present everywhere. The coals are part of a well-preserved sequence of shoreline deposits. This shoreline moved back and forth through time along the western edge of the Cretaceous seaway. BP has recognized five seam “packages” within the Fruitland as mappable units which resulted from these cyclic shoreline movements. The thickest total coals are found where three or more of these units overlap.
Large quantities of gas can be produced at very low reservoir pressures
- Reservoir/production chokes significantly affect rates
- Proper production configuration is essential
• Rig utilization is currently at 100%

• Operators are looking to bring more rigs into the basin to meet growing rig demands
Capital Productivity of Infill Drilling

Infill Program Well Cost Structure

- 2001: $826 M (120 $M, 100 $M, 288 $M)
- 2004: $726 M (25 $M, 115 $M, 147 $M)
- 2005 Est: $810 M (45 $M, 111 $M, 250 $M)

Colors represent different cost structures:
- Restore
- Pipeline
- Equip
- Complete
- Drill
- Road & Pad
- Land
• Majority of wells drilled to date are vertical (99% of 680 320-acre “parent” wells and 80% of 250 160-acre “infill” wells). All vertical wells are drilled from individual locations.

  ★ There are no issues with drilling or completing vertical wells ★

• Directional wells drilled to date were driven by topographical and cultural constraints. Only a very few are drilled from shared locations.

• Remaining 160-acre infills (approximately 170 wells) will be drilled from individual locations with about 70% of the wells vertical.

• Regulatory and reputational drivers will most likely force the proposed 80-acre infills (500 – 800 wells) to be drilled from existing locations (“pad drilling” – 100% directional)

  ★ There are minimal issues with drilling directional wells ★

  ★ There can be serious issues with completing and producing directional wells ★
“Pad Drilling” the 80-Acre Infill Locations

Assumptions:

Reduce 990’ offset from external (320 acre) boundary to 660’ (requires regulatory change)

Eliminate internal (between well) boundary offset of 130’ (requires regulatory change)

Maximize distance from existing well

Result:

1200’ – 1500’ step-out
“Pad Drilling” the 80-Acre Infill Locations

High angles are needed to achieve necessary step-out at shallow depths

Estimate of Hole Angle

Kick-off Point = 500 feet
Build Angle = 4 degrees per 100'

- 50 Deg. Max. Angle
- 40 Deg. Max. Angle
- 30 Deg. Max. Angle
- 20 Deg. Max. Angle
- 10 Deg. Max. Angle

80-acre well from existing 160-acre pad
“Pad Drilling” the 80-Acre Infill Locations

High angles can be achieved from a drilling standpoint...

Directional Wells in 160-Acre Infill Program

... but lead to completion and production issues
Completion and Production Issues in High-Angle Wells

- Increased screen-out frequency of hydraulic fracture stimulations (resolved with redesign)
- Wellbore de-liquification more difficult at higher angles (requires increased use of artificial lift)
- Poor production performance from higher angle wells (currently avoiding the drilling of wells with angles > 30°)
Industry Firsts

First Time CT will Drill > 6 ¼” hole
First Time large bore directional work will be done on CT
First Time Rotary Steerable tools will be run on CT
BP’s First Hybrid Rig

- 9 Wells
  - Two 6 ¼” hole with 4 ½” Casing
  - Three 8 ¾” hole set 7” Intermediates.
  - Two 8 ¾” hole set 5 ½” casing (shaped wells)
  - Two re-entries of 2 existing 5 ½” cased wells to conduct 1500ft horizontal sidetracks.
SJN 3rd Multilateral – First Fish Bone Design

• **High Lights**
  - Longest laterals drilled to date
  - Proved ability to effectively conduct openhole sidetracks.
  - First Fish bone design proven feasible

Luchini GU 32-6-11 #2 Upper and Lower Ignacio Laterals

• **Low Lights**
  - Reservoir press 1 ppg > than predicted
  - 5 day delay to swap mud system
  - Drilling Rig expensive for completion

---

**Luchini 32-6-11 No.2**

**Additional Laterals Drilled in less than 1.5days/lateral**

- Mother Bore
- LATERAL #01
- LAT #01 ST #01
- LAT #02
- LAT #02 ST #1
- LAT #02 ST #2
- LAT #02 ST #3
- LAT #02 ST #4

---

**Well Bore Times**

- Lateral # 1 ST1
- Lateral # 2 ST1
- Lateral # 1 ST2
- Lateral # 2 ST2
- Lateral # 1 ST3
- Lateral # 2 ST3
- Lateral # #1
Current Development

- >1000 Vertical wells
- Frac stimulated wells

Why is Piloting Multilaterals a cornerstone of the Major Project Wells Technology plan?

- Investigate opportunity to develop reserves more economically.

- 80 acre application to double density of wells was approved by Colorado Oil & Gas commission on provision that additional wells are drilled from existing pads.
**San Juan North Multilateral Pilot Program Update**

**Production of the Knight E2 Multilateral Relative to its Neighbouring Wells**

- **Knight GU# E 2 Well – Spudded 2Q 2005**
- Multilateral production 5 times neighboring vertical producers

Well offline for tubing upsize

**Vertical Offset Wells**

**Well Time / Cost Analysis**

<table>
<thead>
<tr>
<th></th>
<th>Days</th>
<th>$M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pilot</td>
<td>17.9</td>
<td>803</td>
</tr>
<tr>
<td>Lateral #1</td>
<td>9.3</td>
<td>420</td>
</tr>
<tr>
<td>Lateral #2</td>
<td>5.5</td>
<td>249</td>
</tr>
<tr>
<td>Lateral #3</td>
<td>5.3</td>
<td>239</td>
</tr>
<tr>
<td>Completion</td>
<td>4.7</td>
<td>157</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>43.1</td>
<td>1868</td>
</tr>
</tbody>
</table>

**NPT**

- **14.2%**

**AFE**

- **Total D&C**
  - **$1601**
  - **$1868**
  - **$514**

**Duration**

- **29.5 days**
- **43.1 days**
- **5.9 days**

**IRR**

- **35%**
- **25%**

**Notes:**

- **Cased and cemented Motherbore**
- **6 ¼” laterals with 3 ½” slotted liners**
- **8ft seam**
- **1800ft**
- **2000ft**
- **36ft seam**
San Juan North Major Project
San Juan North Multilateral Pilot Program Update

Production of the Bonifacio Gallegos GU A2 Relative to its Neighbouring Wells

**Gallegos, Bonifacio#2 Well – Spudded 3Q ’05**

- Multilateral production
- 6-7 times neighboring vertical producers

**Well Time / Cost Analysis**

<table>
<thead>
<tr>
<th>Well Stage</th>
<th>Days</th>
<th>$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pilot</td>
<td>11.5</td>
<td>507</td>
</tr>
<tr>
<td>Lateral #1</td>
<td>10.1</td>
<td>545</td>
</tr>
<tr>
<td>Lateral #2</td>
<td>8.7</td>
<td>382</td>
</tr>
<tr>
<td>Lateral #3</td>
<td>6.4</td>
<td>369</td>
</tr>
<tr>
<td>Completion</td>
<td>1.1</td>
<td>77</td>
</tr>
<tr>
<td>Total</td>
<td>39</td>
<td>1871</td>
</tr>
</tbody>
</table>

| NPT           | 11.5% |

**Total D&C**

AFE $1543
Actual $1871
Vertical Offset $514

**Duration**

31.6 days
39 days
59 days

**IRR**

25%
18%
Luchini – SJN 3rd Multilateral

Vertical Section

Plan View
Lower Lateral

Plan View
Upper Lateral
George – Jean – Dickens Cross Section

Horizontal Tests - 2006

Pictured Cliffs Tongue
Pictured Cliffs main body
Pictured Cliffs Tongue 2

05067076860000
ELEV_KB : 6,948
TD : 2,550
SPUD_DATE : 10/29/1990
FRUITLAND COAL

05067076980000
ELEV_KB : 6,786
TD : 2,700
SPUD_DATE : 10/21/1990
FRUITLAND COAL

05067079280000
ELEV_KB : 6,773
TD : 2,720
SPUD_DATE : 12/7/1992
FRUITLAND COAL

BP AMERICA PRODUCTION COMPANY
GEORGE GU 11-11 #1
T34N R8W S11
SE NW NW

BP AMERICA PRODUCTION COMPANY
JEAN GU 21-13 #1
T34N R8W S13
NE SW NW

BP AMERICA PRODUCTION COMPANY
DICKENS GU 44-14 #1
T34N R8W S14
NE SE SE
Completions

Completion types, hydraulic fracturing, other methods, horizontal completions, issues
Coalbed methane wells have been traditionally completed in one of two fashions: either by fracture stimulation or by open-hole cavitation. In the San Juan basin, open-hole cavity completions have been concentrated in the highly productive Fairway (high perm sweet spot), while fracture stimulations generally are employed elsewhere. In the current drilling program, all of the completions employ the fracture stimulation type of completion (the last cavitation completion was made in 2003 and no more are expected).
Coal (or “activated carbon”, a primary component in many air filters), tends to adsorb liquids and gasses. As the coal adsorbs these fluids, its bulk swells, which tends to shrink the size of the cleats within the coal matrix. In CBM operations swollen coals result in skin damage that significantly reduces a well’s ability to produce. This damage typically occurs during the drilling operation and can also occur during the completion phase, especially if some type of stimulation is performed. For this reason, the advances in technology for designing fracture stimulations in coal wells have been geared toward clean, non-damaging fluids. The fluids used in today’s fracture treatments are different, and much better, than five years ago and those were different than the ones five years before.

Because the San Juan Basin Type II coals have moderate permeability (0.1 to 10 md), fracture stimulations are not designed to be massive, as is the case in conventional tight gas (micro-Darcy) reservoirs, but are designed to bypass drilling damage and ensure good communication with the reservoir. Rock properties unique to coal tend to generate complex fracture geometries that are not well understood, making it almost impossible to model fracture completions and their associated performance. Consequently, optimization of fracture completions in coal is accomplished through trial and error. Despite this handicap, fracture stimulations have proved highly effective and will continue to be our mainstay completion type. In 2005, we have committed to evaluate a number of variations on fracture stimulations including coil tubing frac’s, propellant frac’s and BJ’s EXCAPE technology. In addition, we plan to enlist the help of EPTG to bring a higher level of engineering design to the process through the identification / development of engineering tools suitable for use in coal.
Cavitations

Cavity completions employ the imposition of significant induced stresses on the coal with the goals of bypassing near-wellbore skin damage and increasing conductivity. Through the process of cavitation, the diameter of the borehole is enlarged and a zone of enhanced near-wellbore permeability is created, typically displaying a radial impact of approximately 50’.

Cavity completions have outperformed fracs within some parts of the Fairway, but beyond the Fairway, have not proven to be as effective as fracs. Even though a cavitation does not introduce ‘damaging’ fluids to the coal, in non-Fairway regions the coal physical properties may not allow cavitations to create the network of near wellbore fractures. In addition, cavitation completions introduce a significant amount of flaring to the completion operation, generating both HSE and reputational issues.

Horizontal Completions

Although in its infancy, the application of horizontal completions to coal holds great promise. Horizontal tests by other operators have met with mixed success, but when successful have demonstrated that the technology could be highly applicable. Horizontal completions (especially multi-lateral completions) offer the possibility of contacting large areas of the reservoir from only one surface location, reducing the surface footprint of our operation. Challenges associated with the application of horizontal completions to San Juan Basin coals include wellbore stability, wellbore de-liquefaction and a fully contacting a vertically segmented reservoir. There are multiple “flavors” of horizontal technology to be applied and evaluated, each with its own pros and cons. BP conducted two horizontal pilots in 2004 (one each in San Juan North and San Juan South) using one of these “flavors”. While both were operationally successful, production results have been somewhat disappointing to date, although it is too early in the evaluation stage to make any judgments. Additional piloting of other horizontal completion technologies will be conducted in 2005.
Key Observations

• Transwestern SJ Expansion (Jun 05) expected to stabilize differentials.
• Overall San Juan production decline and Rockies export into San Juan are key variables for 2006+
• Long-term differential target (~$0.40 tied to $3.50 HH) needs to be re-visited for higher price environment.
Production Engineering and Operations
Production Operations

- On the surface, coalbed methane production looks just like any other oilfield production. There are flowing wells, pumping wells, and gas-lift wells. Production goes through typical facilities such as separators, meters, and processing plants. Liquid transfer stations and disposal wells handle waste fluids.

- What makes coal production unique is the manner in which the reservoir releases its contents and how the production behaves with time. As has been discussed earlier, coal does not release gas in direct proportion to reduction in reservoir pressures (isotherm). A reservoir pressure drop of 20 psi will yield far more gas in a mature (low pressure) well than will a 20 psi drop in a new (high pressure) well. Coal does not release the majority of its stored gas at high reservoir pressures. As a result, lowering the reservoir pressure of a coal formation is of utmost importance in production operations.

- Also unique to coal is the aspect of stress dependent permeability. Because natural gas is contained within the matrix of the coal, the rock loses bulk volume as gas is produced. As the coal loses bulk volume, it shrinks, and the cleats within the coal matrix enlarge. This cleat enlargement results in an increase of reservoir permeability. As mentioned before, the coal, through its isotherm behavior, releases more gas at lower reservoir pressures. The positive ‘double whammy’ of these two processes helps to explain why a coal well’s gas production can continue at high rates with time even as reservoir pressure drops.

- As an operator, we can influence the reservoir pressure decline through our facility designs and production methods. Compressor stations, wellsite compression, pipeline layouts, and artificial lift are all designed to provide the lowest possible producing pressures at the formation face of each well.
• A typical coal well in the San Juan basin does not come with many associated production problems. Produced water is fairly fresh, scale formation in tubulars is not common, the gas is not sour, paraffin is rare, and natural gas liquids do not drop out in the reservoir. As a result, production facilities are simple. Two phase separators and a nearly pure methane gas stream minimize the amount of treatment necessary to provide pipeline quality gas.

• For the most part, production maintenance is as simple as keeping artificial lift equipment and tubulars sound. Certain areas of the reservoir do respond favorably to acid treatments, and when propped fractures become plugged with coal fines, stimulations such as re-fracs are conducted. Also, re-fracs are often performed on some older wells that may have received a damaging fracture stimulation during the initial completion.

• For younger wells, the nature of production is typically high water rate and low gas rate. Since water is not stored in the coal matrix, but instead within the cleat system, its production declines from day one. Because of isotherm behavior, poor initial relative permeability to gas, and low initial base permeability, gas rates are typically low. Consequently, a large percentage of young wells (high reservoir pressure) are on artificial lift. As the gas rate inclines and the water rate declines, a typical well will reach a point where it can dewater itself and artificial lift is removed. As a well matures, gas production will decline and at some point may need to have artificial lift reinstated.

• CBM production does come with a few challenges. Primary production problems include the handling of produced water, the handling of solids (mainly coal fines), the control of erosional velocities, and the handling of corrosion associated with CO2 in produced water (carbonic acid). Teams are formed and operational practices are in place to evaluate and control these production challenges.

• A separate aspect of the production operations in the Colorado portion of the San Juan basin concerns our presence within the local community. Residences are often built close to well locations. As a result, a considerable amount of effort is directed towards cleanliness, noise, land impact (area) and visual. Our operations in the San Juan are some of the cleanest in the oil patch. Given the conditions and the beauty of the area, they have to be.
Coalbed Methane Recovery Mechanism & Primary Production

- Characteristics of coalbed methane primary production are:
  - Inclining production rate during early time
  - Majority of reserves at low reservoir pressure
  - Significant volumes of water produced
  - Long life
  - Inexpensive well, expensive completion, and significant associated facility costs
  - Unlike conventional reservoirs in which gas is trapped in voids or pore space in the rock, with coal the majority of the gas is adsorbed onto the surface of the coal. The gas is held in place by pressure. The Langmuir isotherm relates the volume of gas adsorbed as a function of pressure.

CBM Isotherm
Reducing reservoir pressure allows some gas to desorb and diffuse into the conventional porosity system. Better SJB coals often hold over 600 scf/ton coal, a number comparable to a 30 per cent porosity sandstone on a bulk rock volume basis. A fundamental difference between CBM and conventional reservoirs is illustrated by the isotherm. In a conventional reservoir, a reduction in average reservoir pressure from 1,600 psia to 300 psia will result in over 80% recovery of original gas in place, represented by the dashed line on the preceding plot. The same pressure reduction in a CBM reservoir results in less than 45% recovery of original gas in place, red line on plot. The implication is that significant amounts of compression will be required for much of the life of the reservoir. This will result in significant capital expenditures and operating costs.

The conventional porosity and permeability system in coal reservoirs is in the form of cleats. These cleats are very small fractures, often several per inch. The cleat development, i.e. permeability system, is by far the most critical factor required to have a productive CBM prospect. In addition to rank, other factors that control cleat formation include plant material type, ash content (non-organic), depth (rock stress), and factors that may induce natural fracturing. The porosity in this cleat system is usually less than 1 per cent and, in most cases, initially saturated with water. Because of the presence of water many CBM wells require artificial lift.

The Fruitland Coal formation typically has 40 feet of net coal concentrated in 2 or 3 coal seams/sequences in a 250 foot gross interval. Nominally the Fruitland is 2,500 to 3,500 feet deep although it is shallower around the edge of the basin near the outcrop. Initial permeability of the coal ranges from 0.1 to 20 md requiring stimulation to enhance productivity. The coal is easily damaged because of its highly adsorptive and easily friable nature. Currently, the preferred completion technique is the hydraulic fracture stimulation. In the past, open hole cavitation completions were conducted, mainly in the highly prolific ‘fairway’ region. All current drilling operations today are outside the ‘fairway’ so cavitations are rare.
An aspect of the high initial water saturation is the very poor initial relative permeability to gas as illustrated by the Southern Ute 9-1,32-10 in the following graph:

The high initial water production rate and inclining gas rate is typical of SJB “Fairway” wells. As water is depleted, the relative permeability to gas increases. Shrinkage of the coal matrix appears to occur with the desorption of gas, further enhancing the absolute permeability of the matrix. Note in this well the gas production does not begin inclining for 18 months. The plot illustrates the early time dewatering behavior of the well. The peak rate (not depicted on the above graph) for the Southern Ute 9-1,32-10 is in excess of 6 MMCF/D occurring 7 years after initial production.
The Lemon Gas Unit F 2 is typical of the current infill program wells. Its performance is depicted in the graph below. The reservoir is partially dewatered resulting in somewhat lower initial water rates than the “parent” well. The production for these wells typically reaches peak rate of 500 to 1,000 MCF/D in 6 to 18 months. These wells will have a long life and relatively flat production profile with ultimate reserves in the 4 BCF/well range.