SAN JUAN BASIN PROVINCE (022)

By A. Curtis Huffman, Jr.

INTRODUCTION

The San Juan Basin province incorporates much of the area from latitude 35û to 38û N. and from longitude 106û to 109û W. and comprises all or parts of four counties in northwest New Mexico and six counties in southwestern Colorado. It covers an area of about 22,000 sq mi.

Almost all hydrocarbon production and available subsurface data are restricted to the topographic San Juan Basin. Also included in the province, but separated from the structural and topographic San Juan Basin by the Hogback monocline and Archuleta arch, respectively, are the San Juan dome and Chama Basin, which contain sedimentary sequences similar to those of the San Juan Basin. In much of the San Juan dome area the sedimentary section is covered by variable thicknesses of volcanic rocks surrounding numerous caldera structures. The stratigraphic section of the San Juan Basin attains a maximum thickness of approximately 15,000 ft in the northeast part of the structural basin where the Upper Devonian Elbert Formation lies on Precambrian basement. Elsewhere in the province Cambrian, Mississippian, Pennsylvanian, or Permian rocks may overlie the Precambrian.

Plays were defined primarily on the basis of stratigraphy because of the strong stratigraphic controls on the occurrence of hydrocarbons throughout the province. In general, the plays correspond to lithostratigraphic units containing good quality reservoir rocks and having access to source beds. In the central part of the basin, porosity, permeability, stratigraphy, and hydrodynamic forces control almost all production, whereas around the flanks structure and stratigraphy are key trapping factors. Although most Pennsylvanian-age oil and gas is on structures around the northwestern margin, it commonly accumulates only in highly porous limestone buildups. Jurassic oil on the southern margin of the basin is stratigraphically trapped in eolian dunes at the top of the Entrada Sandstone. Almost all oil and gas in Upper Cretaceous sandstones of the central basin is produced from stratigraphic traps. Around the flanks of the basin, some of the same Cretaceous units produce oil on many of the structures.

Seven conventional plays were defined and individually assessed in the province; Porous Carbonate Buildup (2201), Marginal Clastics (2203), Entrada (2204), Basin Margin Dakota Oil (2206), Tocito / Gallup Sandstone Oil (2207), Basin Margin Mesaverde Oil (2210), and Fruitland-Kirtland Fluvial Sandstone Gas (2212). The Porous Carbonate Buildup Play (2201) is assessed as part of play 2102 in the Paradox Basin; similary, Permian–Pennsylvanian Marginal Clastics Gas Play (2203) is assessed as part of play 2104 in the Paradox Basin.

Eight unconventional plays were also assessed--five continuous-type plays and three coalbed gas plays. Continuous-type plays are Fractured Interbed (2202), Dakota Central Basin Gas (2205), Mancos Fractured

Shale (2208), Central Basin Mesaverde Gas (2209), and Pictured Cliffs Gas (2211). Also present is the continuous-type Fractured Interbed Play (2103) which is described and assessed in Paradox Basin Province (021). Coal-bed gas plays are San Juan Basin–Overpressured (2250), San Juan Basin–Underpressured Discharge (2252), and San Juan Basin–Underpressured (2253).

ACKNOWLEDGMENTS

Scientists affiliated with the American Association of Petroleum Geologists and from various State geological surveys contributed significantly to play concepts and definitions. Their contributions are gratefully acknowledged.

CONVENTIONAL PLAYS

2201. POROUS CARBONATE BUILDUP PLAY

(Assessed with play 2102, in Paradox Basin Province, 021)

This Porous Carbonate Buildup Play in this province is primarily a gas play and is characterized by oil and gas accumulations in mounds of algal (Ivanovia) limestone associated with organic-rich black shale rimming the evaporite sequences of the Paradox Formation of the Hermosa Group. Most developed fields within the play produce from combination traps on the Four Corners platform or in the Paradox Basin province, but for this analysis, the play was extended southeast to the limit of the black shale facies, roughly corresponding to the limit of the central San Juan Basin.

Reservoirs: Almost all hydrocarbon production has been from vuggy limestone and dolomite reservoirs in five zones of the Hermosa Group: (in ascending order) the Alkali Gulch, Barker Creek, Akah, Desert Creek, and Ismay. The zones gradually become less distinct toward the central part of the San Juan Basin. Net pay thicknesses generally vary from 10 to 50 ft and have porosities of 5-20 percent.

Source rocks: Source beds for Pennsylvanian oil and gas are believed to be organic-rich shale and laterally equivalent carbonate rocks within the Paradox Formation. The presence of hydrogen sulfide (H_2S) and appreciable amounts of CO_2 at the Barker Creek and Ute Dome fields probably indicates high-temperature decomposition of carbonates, (Rice, 1983). Correlation of black dolomitic shale and mudstone units of the Paradox Formation with prodelta facies in clastic cycles present in a proposed fan delta complex on the northeastern edge of the Paradox evaporite basin helps to account for the high percentage of kerogen from terrestrial plant material in black shale source rocks.

Timing and migration: In the central part of the San Juan Basin, Pennsylvanian sediments entered the thermal zone of oil generation during the Late Cretaceous to Paleocene and the dry gas zone during the Eocene to Oligocene. It also is probable that Pennsylvanian source rocks entered the zone of oil generation during the Oligocene throughout most of the Four Corners Platform. Updip migration and local migration from laterally equivalent carbonates and shale beds in areas of favorable reservoir beds predominate, and remigration may have occurred in areas of faulting and fracturing.

Traps: Combination stratigraphic and structural trapping mechanisms are dominant among Pennsylvanian fields of the San Juan Basin and Four Corners platform. Most fields are located on structures, although not all of these structures demonstrate closure. The structures themselves may have been a critical factor in the deposition of bioclastic limestone reservoir rocks. Seals are provided by a variety of mechanisms including porosity differences in the reservoir rock, overlying evaporites, and interbedded shale. Most production on the Four Corners platform is from depths of 5,100 to 8,500 ft, but minor production and shows in the central part of the San Juan Basin are from as deep as 11,000 ft.

Exploration status and resource potential: Field sizes in the play vary considerably; most oil discoveries are in the 1–100 MMBO size range and include associated gas production. The largest fields, Tocito Dome and Tocito Dome North, have produced a total of about 13 MMBO and 26 BCFG. Eight significant nonassociated and associated gas fields have been developed in the play, the largest of which, Barker Creek, has produced 205 BCFG. The Pennsylvanian is basically a gas play and has a moderate future potential for medium-size fields.

2203. PERMIAN–PENNSYLVANIAN MARGINAL CLASTICS PLAY (HYPOTHETICAL)
(Assessed with play 2014 in Paradox Basin Province 021)

The Permian–Pennsylvanian Marginal Clastics hypothetical gas play extends from the Paradox Basin province into the northwestern parts of the San Juan Basin province. It was formerly known as the Silverton Delta Play but has been renamed to more accurately reflect the geometry and depositional environment of the reservoir rocks.

Reservoirs: Gas shows have been encountered in porous and permeable sandstone intervals within the generally arkosic Cutler Group in the vicinity of the ancestral Uncompahgre uplift. In these intervals, feldspar and clay were winnowed out by wave action or fluvial stream flows. In most of the area, the lower part of the Pennsylvanian interval is more likely to contain these beds than the upper part because of its lower original feldspar content. In the northwestern San Juan Basin province and southeastern Paradox Basin province, however, the upper part of the Pennsylvanian interval is more likely to contain such beds due to the presence of a large fan delta complex, which would have provided the necessary depositional environments to clean up the sandstone.

Source rocks, timing and migration: This play is dependent on the presence of the Desmoinesian organic-rich dolomitic shale and mudstone in contact or close proximity to the reservoir lithologies. Because this juxtaposition is necessarily close to the ancestral Uncompahgre uplift, the play is gas prone due to the preponderance of type III kerogen from the uplift as well as the depth of burial in the deep trough along the basin margin.

Traps: Trap types are expected to be dominantly combinations of updip pinchouts of permeable sandstone lenses localized on folded and faulted structures. Seals are provided by shale beds as well as by reduction of permeability due to clay. More details on this play are given in the Paradox Basin province description (2104).

Exploration status and resource potential: Little exploration has taken place within this play with no production to date, but shows reported from the Permian Cutler Group sandstone bodies and the presence of excellent source rocks and structures are strong factors in its favor.

2204. ENTRADA PLAY

The Entrada play is associated with relict dune topography on top of the eolian Middle Jurassic Entrada Sandstone in the southeastern part of the San Juan Basin and is based on the presence of organic-rich limestone source rocks and anhydrite in the overlying Todilto Limestone Member of the Wanakah Formation. North of the present producing area, in the deeper, northeastern part of the San Juan Basin, porosity in the Entrada decreases rapidly (Vincelette and Chittum, 1981). Compaction and silica cement make the Entrada very tight below a depth of 9,000 ft. No eolian sandstone buildups have been found south and west of the producing area.

Reservoirs: Some of the relict dunes are as thick as 100 ft but have flanks that dip only 2 degrees. Dune reservoirs are composed of fine-grained, well-sorted sandstone, massive or horizontally bedded in the upper part and thinly laminated, with steeply dipping crossbedding, in the lower part. Porosity (23 percent average) and permeability (370 millidarcies average) are very good throughout. Average net pay in developed fields is 23 ft.

Source rocks: Limestone in the Todilto Limestone Member has been identified as the source of Entrada oil (Ross, 1980). There is a reported correlation between the presence of organic material in the Todilto Limestone and the presence of the overlying Todilto anhydrite (Vincelette and Chittum, 1981). This association limits the source rock potential of the Todilto to the deeper parts of the depositional basin in the eastern San Juan Basin. Elsewhere in the basin, the limestone was oxygenated during deposition and much of the organic material destroyed.

Timing and migration: Maximum depth of burial throughout most of the San Juan Basin occurred at this time. In the eastern part of the basin the Todilto entered the oil generation window during the Oligocene. Migration into Entrada reservoirs either locally or updip to the south probably occurred almost immediately; however, in some fields, remigration of the original accumulations has occurred subsequent to original emplacement.

Traps: All traps so far discovered in the Entrada Sandstone are stratigraphic and are sealed by the Todilto limestone and anhydrite. Local faulting and drape over deep-seated faults has enhanced, modified, or destroyed the potential closures of the Entrada sand ridges. Hydrodynamic tilting of oil-water contacts and (or) "base of movable oil" interfaces has had a destructive influence on the oil accumulations because the direction of tilt typically has an updip component. All fields developed to date have been at depths of 5,000–6,000 ft. Because of increase in cementation with depth, the maximum depth at which suitable reservoir quality can be found is approximately 9,000 ft.

Exploration status and resource potential: The initial Entrada discovery, the Media field, was made in 1953. Development was inhibited by problems of high water cut and high pour point of the oil, problems common to all subsequent Entrada field development. Between 1972 and 1977, seven fields similar to Media were discovered, primarily using seismic techniques. Areal sizes of fields range from 100 to 400 acres, and total estimated production of each varies from 150,000 BO to 2 MMBO. A number of areas of anomalously thick Entrada in the southeastern part of the San Juan Basin have yet to be tested, and there is a good probability that at least a few of these areas have adequate trapping conditions for undiscovered oil accumulations, but with similar development problems as the present fields. Limiting factors to the moderate future oil potential of the play include the presence of sufficient paleotopographic relief on top of the Entrada, local structural conditions, hydrodynamics, source-rock and oil migration history, and local porosity and permeability variations.

2206. BASIN MARGIN DAKOTA OIL PLAY

The Basin Margin Dakota Oil Play is both a structural and stratigraphic play on the northern, southern, and western sides of the central San Juan Basin. Because of the variability of depositional environments in the transgressive Dakota Sandstone, it is difficult to characterize a typical reservoir lithology. Most production has been from the upper marine part of the interval but significant amounts of both oil and gas also have been produced from the nonmarine section.

Reservoirs: The Late Cretaceous Dakota Sandstone varies from dominantly nonmarine channel deposits and interbedded coal and conglomerate in the northwest to dominantly shallow marine, commonly burrowed deposits in the southeast. Net pay thicknesses range from 10 to 100 ft; porosities are as high as 20 percent and permeabilities as high as 400 millidarcies.

Source rocks: Along the southern margin of the play, the Cretaceous marine Mancos Shale was the source of the Dakota oil. API gravities range from 44û to 59û. On the Four Corners platform to the west, nonmarine source rocks of the Menefee Formation were identified as the source (Ross, 1980). The stratigraphically higher Menefee is brought into close proximity with the Dakota across the Hogback monocline.

Timing and migration : Depending on location, the Dakota Sandstone and lower Mancos Shale entered the oil window during the Oligocene to Miocene. In the southern part of the area, migration was still taking place in the late Miocene or even more recently.

Traps: Fields range in size from 40 to 10,000 acres and most production is from fields of 100-2,000 acres. Stratigraphic traps are typically formed by updip pinchout of porous sandstone into shale or coal. Structural traps on faulted anticlines sealed by shale form some of the larger fields in the play. Oil production ranges in depth from 1,000 to 3,000 ft.

Exploration status and resource potential: The first discoveries in the Dakota play were made in the early 1920's on small anticlinal structures on the Four Corners platform. Approximately 30 percent of the oil fields have an estimated total production exceeding 1 MMBO, and the largest field (Price Gramps) has production of 7 MMBO. Future Dakota oil discoveries are likely as basin structure and Dakota depositional patterns are more fully understood.

2207. TOCITO-GALLUP SANDSTONE OIL PLAY

The Tocito-Gallup Sandstone Oil Play is an oil and associated gas play in lenticular sandstone bodies of the Upper Cretaceous Gallup Sandstone and Tocito Sandstone Lentil associated with Mancos Shale source rocks lying immediately above an unconformity. The play covers almost the entire area of the province. Most of the producing fields are stratigraphic traps along a northwest-trending belt near the southern margin of the central part of the San Juan Basin. Almost all production has been from the Tocito Sandstone Lentil of the Mancos Shale and the Torrivio Member of the Gallup Sandstone.

Reservoirs: The Tocito Sandstone Lentil of the Mancos Shale is the major oil producing reservoir in the San Juan Basin. The name is applied to a number of lenticular sandstone bodies, commonly less than 50 ft thick, that lie on or just above an unconformity and are of undetermined origin. Reservoir porosities in producing fields range from 4 to 20 percent and average about 15 percent. Permeabilities range from 0.5 to 150 Md and are typically 5–100 Md. The only significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above and in some places scouring into the top of the main marine Gallup Sandstone.

Source rocks: Source beds for Gallup oil are the marine Upper Cretaceous Mancos Shale. The Mancos contains 1-3 weight percent organic carbon and produces a sweet, low-sulfur, paraffin-base oil that ranges from 38û to 43û API gravity in the Tocito fields and from 24û to 32û API gravity farther to the south in the Hospah and Hospah South fields.

Timing and migration: The upper Mancos Shale of the central part of the San Juan Basin entered the thermal zone of oil generation in the late Eocene and gas generation in the Oligocene. Migration updip to reservoirs in the Tocito Sandstone Lentil and regressive Gallup followed pathways similar to those determined by present structure because basin configuration has changed little since that time.

Traps: Almost all Gallup production is from stratigraphic traps at depths between 1,500 and 5,500 ft. Hospah and Hospah South, the largest fields in the regressive Gallup Sandstone, are combination stratigraphic and structural traps. The Tocito sandstone stratigraphic traps are sealed by, encased in, and intertongue with the marine Mancos Shale. Similarly, the fluvial channel Torrivio Member of the Gallup is encased in and intertongues with finer grained, organic-rich coastal-plain shales.

Exploration status and resource potential: Initial Gallup field discoveries were made in the mid 1920's; however, the major discoveries were not made until the late 1950's and early 1960's in the deeper Tocito fields, the largest of which, Bisti, covers 37,500 acres and has estimated total ultimate recovery of 51 MMBO. Gallup producing fields are typically 1,000–10,000 acres in area and have 15–30 ft of pay. About one-third of these fields have an estimated cumulative production exceeding 1 MMBO and 1 BCF of associated gas. All of the larger fields produce from the Tocito Sandstone Lentil of the Mancos Shale and are stratigraphically controlled. South of the zone of sandstone buildups of the Tocito, the regressive Gallup Sandstone produces primarily from the fluvial channel sandstone of the Torrivio Member. The only large field producing from the Torrivio are the Hospah and Hospah South fields, which are combination traps. Similar, undiscovered traps of small size may be present in the southern half of the basin. The future potential for oil and gas is low to moderate.

2210. BASIN MARGIN MESAVERDE OIL PLAY

The Basin Margin Mesaverde Oil Play is a confirmed oil play around the margins of the central San Juan Basin. Except for the Red Mesa field on the Four Corners platform, field sizes are very small. The play depends on intertonguing of porous marine sandstone at the base of the Upper Cretaceous Point Lookout Sandstone with the organic-rich upper Mancos Shale.

Reservoirs: Porous and permeable marine sandstone beds of the basal Point Lookout Sandstone provide the principal reservoirs. The thickness of this interval and of the beds themselves may be controlled to some extent by underlying structures oriented in a northwesterly direction.

Source rocks: The upper Mancos Shale intertongues with the basal Point Lookout Sandstone and has been positively correlated with oil produced from this interval (Ross, 1980). API gravity of Mesaverde oil ranges from 37û to 50û.

Timing: Around the margin of the San Juan Basin the upper Mancos Shale entered the thermal zone of oil generation during the Oligocene.

Traps: Structural or combination traps account for most of oil production from the Mesaverde. Seals are typically provided by marine shale, but paludal sediments or even coal of the Menefee Formation may also act as the seal.

Exploration status and resource potential: The first oil-producing area in the State of New Mexico, the Seven Lakes Field, was discovered by accident in 1911 when a well being drilled for water produced oil from the Menefee Formation at a depth of approximately 350 ft. The only significant Mesaverde oil field , Red Mesa, was discovered in 1924. Future discoveries are likely to be small.

2212. FRUITLAND-KIRTLAND FLUVIAL SANDSTONE GAS PLAY

The Fruitland-Kirtland Fluvial Sandstone Gas Play covers the central part of the basin and is characterized by gas production from stratigraphic traps in lenticular fluvial sandstone bodies enclosed in shale source rocks and (or) coal. Production of coalbed methane from the lower part of the Fruitland has been known since the 1950's. The Upper Cretaceous Fruitland Formation and Kirtland Shale are continental deposits and have a maximum combined thickness of more than 2,000 ft. The Fruitland is composed of interbedded sandstone, siltstone, shale, carbonaceous shale, and coal. Sandstone is primarily in northerly trending channel deposits in the lower part of the unit. The lower part of the overlying Kirtland Shale is dominantly siltstone and shale, and differs from the upper Fruitland mainly in its lack of carbonaceous shale and coal. The upper two-thirds or more of the Farmington Sandstone Member of the Kirtland Shale is composed of interbedded sandstone lenses and shale.

Reservoirs are predominantly lenticular fluvial channel sandstone bodies, most of which are considered tight gas sands. They are commonly cemented with calcite and have an average porosity of 10-18 percent and low permeability (0.1–1.0 millidarcy). Pay thickness ranges from 15 to 50 ft. The Farmington Sandstone Member is typically fine grained and has porosity of from 3 to 20 percent and permeability of from 0.6 to 9 millidarcies. Pay thicknesses are generally 10–20 ft.

Source rocks: The Fruitland-Kirtland interval produces nonassociated gas and very little condensate. Its chemical composition (C_1 / C_{1-5}) ranges from 0.99 to 0.87 and its isotopic ($d^{13}C_1$) compositions range from -43.5 to -38.5 per mil (Rice, 1983). Source rocks are thought to be primarily organic-rich nonmarine shales encasing sandstone bodies.

Timing and migration: In the northern part of the basin, the Fruitland Formation and Kirtland Shale entered the thermal zone of oil generation during the latest Eocene and the zone of wet gas generation probably during the Oligocene. Migration of hydrocarbons updip through fluvial channel sandstone is suggested by gas production from immature reservoirs and by the areal distribution of production from the Fruitland.

Traps: The discontinuous lenticular channel sandstone bodies that form the reservoirs in both the Fruitland Formation and Kirtland Shale intertongue with overbank mudstone and shale and paludal coals and carbonaceous shale in the lower part of the Fruitland. Although some producing fields are on structures, the actual traps are predominantly stratigraphic and are at updip pinchouts of sandstone into the fine-grained sediments that form the seals. Most production is from depths of 1,500–2,700 ft. Production from the Farmington Sandstone Member is from depths of 1,100–2,300 ft.

Exploration status and resource potential: The first commercially produced gas in New Mexico was discovered in 1921 in the Farmington Sandstone Member at a depth of 900 ft in what later became part of the Aztec field. Areal field sizes range from 160 to 32,000 acres, and almost 50 percent of the fields are 1,000–3,000 acres in size. The almost linear northeasterly alignment of fields along the western side of the basin suggests a paleofluvial channel system of northeasterly flowing streams. Similar channel systems may be present in other parts of the basin and are likely to contain similar amounts of hydrocarbons. Future potential for gas is good, and undiscovered fields will probably be in the 2–5 sq mi size range at depths between 1,000 and 3,000 ft. Because most of the large structures have probably been tested, future gas resources probably will be found in updip stratigraphic pinchout traps of channel sandstone into coal or shale in traps of moderate size.

UNCONVENTIONAL PLAYS

Continuous-Type Plays

2205. DAKOTA CENTRAL BASIN GAS PLAY

The Dakota Central Basin unconventional continuous-type play is contained in coastal marine barrier-bar sandstone and continental fluvial sandstone units, primarily within the transgressive Dakota Sandstone.

Reservoirs: Reservoir quality is highly variable. Most of the marine sandstone reservoirs within the Basin field are considered tight, in that porosities range from 5 to 15 percent and permeabilities from 0.1 to 0.25 millidarcies. Fracturing, both natural and induced, is essential for effective field development.

Source rocks: Quality of source beds for oil and gas is also variable. Nonassociated gas in the Dakota pool of the Basin field was generated during late mature and postmature stages and probably had a marine Mancos Shale source (Rice, 1983).

Timing and migration: In the northern part of the central San Juan Basin, the Dakota Sandstone and Mancos Shale entered the oil generation window in the Eocene and were elevated to temperatures appropriate for the generation of dry gas by the late Oligocene. Along the southern margin of the central basin, the Dakota and lower Mancos entered the thermal zone of oil generation during the late Miocene (Huffman, 1987). It is not known at what point hydrodynamic forces reached sufficient strength to act as a trapping mechanism, but early Miocene time is likely for the establishment of the present-day uplift and erosion pattern throughout most of the basin. Migration of oil in the Dakota was still taking place in the late Miocene, or even more recently, in the southern part of the San Juan Basin.

Traps: The Dakota gas accumulation in the Basin field is on the flanks and bottom of a large depression and is not localized by structural trapping. The fluid transmissibility characteristics of Dakota sandstones are generally consistent from the central basin to the outcrop. Hydrodynamic forces, acting in a basinward direction, have been suggested as the trapping mechanism, but these forces are still poorly understood. The seal is commonly provided by either marine shale or paludal carbonaceous shale and coal. Production is primarily at depths ranging from 6,500 to 7,500 ft.

Exploration status and resource potential: The Dakota discovery well in the central basin was drilled in 1947 southeast of Farmington, New Mexico, and the Basin field, containing the Dakota gas pool, was formed February 1, 1961 by combining several existing fields. By the end of 1993 it had produced over 4.0 TCFG and 38 MMB condensate. Almost all of the Dakota interval in the central part of the basin is saturated with gas, and additional future gas discoveries within the Basin field and around its margins are probable.

2208. MANCOS FRACTURED SHALE PLAY

The Manco Fractured Shale Play Play is a confirmed, unconventional, continuous-type play. It is dependent on extensive fracturing in the organic-rich marine Mancos Shale. Most developed fields in the play are associated with anticlinal and monoclinal structures around the eastern, northern, and western margins of the San Juan Basin.

Reservoirs: Reservoirs comprise fractured shale and interbedded coarser clastic intervals at approximately the Tocito Lentil stratigraphic level.

Source rocks: The Mancos Shale contains 1-3 weight percent organic carbon and produces a sweet, low-sulfur, paraffin-base oil that ranges from 33û to 43û API gravity.

Timing: The upper Mancos Shale of the central part of the San Juan Basin entered the thermal zone of oil generation in the late Eocene and of gas generation in the Oligocene.

Traps: Combination traps predominate; Traps formed by fracturing of shale and by interbedded coarser clastics on structures are common.

Exploration status and resource potential: Most of the larger discoveries such as Verde and Puerto Chiquito were made prior to 1970, but directional drilling along the flanks of some of the poorly explored structures could result in renewed interest in this play.

2209. CENTRAL BASIN MESAVERDE GAS PLAY

The unconventional continuous-type Central Basin Mesaverde Gas Play is in sandstone buildups associated with stratigraphic rises in the Upper Cretaceous Point Lookout and Cliff House Sandstones. The major gas-producing interval in the San Juan Basin , the Upper Cretaceous Mesaverde Group, comprises the regressive marine Point Lookout Sandstone, the nonmarine Menefee Formation, and the transgressive marine Cliff House Sandstone. Total thickness of the interval ranges from about 500 to 2,500 ft , of which 20–50 percent is sandstone. The Mesaverde interval is enclosed by marine shale; the Mancos Shale is beneath the interval and the Lewis Shale above.

Reservoirs: Principal gas reservoirs productive in the Mesaverde interval are the Point Lookout and Cliff House marine sandstones. Smaller amounts of dry, nonassociated gas are produced from thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. Much of this play is designated as tight, and reservoir quality depends mostly on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for almost half of the total nonassociated gas and condensate production from the San Juan Basin. Within these two fields porosity averages about 10 percent and permeability less than 2 Md; total pay thickness is 20–200 ft. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 Md, with 6–25 ft of pay thickness.

Source rocks: The carbon composition (C_1 / C_{1-5}) of 0.99-0.79 and isotopic carbon ($d^{13}C_1$) range of -33.4 to -46.7 per mil of the nonassociated gas suggest a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Rice, 1983).

Timing and migration: In the central part of the basin, the Mancos Shale entered the thermal zone of oil generation in the Eocene and of gas generation in the Oligocene. The Menefee Formation also entered the gas generation zone in the Oligocene. Because basin configuration was similar to that of today, updip migration would have been toward the south. Migration was impeded by hydrodynamic pressures directed toward the central basin, as well as by the deposition of authigenic swelling clays due to dewatering of Menefee coals.

Traps: Trapping mechanisms for the largest fields in the central part of the San Juan Basin are not well understood. In both of these fields, the Blanco Mesaverde and Ignacio Blanco, hydrodynamic forces are believed to contain gas in structurally lower parts of the basin, but other factors such as cementation and swelling clays may also play a role. Production depths are most commonly from 4,000 to 5,300 ft. Updip pinchouts of marine sandstone into finer grained paludal or marine sediments account for almost all of the stratigraphic traps with a shale or coal seal.

Exploration status and resource potential: The Blanco Mesaverde field discovery well was completed in 1927, and the Ignacio Blanco Mesaverde field discovery well was completed in 1952. Areally, these two closely adjacent fields cover more than 1,000,000 acres, encompass much of the central part of the San Juan Basin, and have produced almost 7,000 BCFG and more than 30 MMB of condensate, approximately half of their estimated total recovery. Most of the recent gas discoveries range in areal size from 2,000 to 10,000 acres and have estimated total recoveries of from 10 to 35 BCFG.

2211. PICTURED CLIFFS GAS PLAY

The Pictured Cliffs unconventional continuous-type play is defined primarily by gas production from stratigraphic traps in sandstone reservoirs enclosed in shale or coal at the top of the Upper Cretaceous Pictured Cliffs Sandstone and is confined to the central part of the basin. Thicker shoreline sandstones produced by stillstands, or brief reversals in the regression of the Cretaceous sea to the northeast have been the most productive. The Pictured Cliffs is the uppermost regressive marine sandstone in the San Juan Basin. It ranges in thickness from 0 to 400 ft and is conformable with both the underlying marine Lewis Shale and the overlying nonmarine Fruitland Formation.

Reservoirs: Reservoir quality is determined to a large extent by the abundance of authigenic clay. Cementing material averages 60 percent calcite, 30 percent clay, and 10 percent silica. Average porosity is about 15 percent and permeability averages 5.5 millidarcies, although many field reservoirs have permeabilities of less than 1 Md. Pay thicknesses range from 5 to 150 ft but typically are less than 40 ft.

Reservoir quality improves southward from the deepest parts of the basin due to secondary diagenetic effects.

Source rocks: The source of gas was probably marine shale of the underlying Lewis Shale and nonmarine shale of the Fruitland Formation. The gas is nonassociated and contains very little condensate (0.006 gal / MCFG). It has a carbon composition (C_1 / C_{1-5}) of 0.85-0.95 and an isotopic carbon ($d^{13}C_1$) range of -43.5 to -38.5 per mil (Rice, 1983).

Timing and migration: Gas generation was probably at a maximum during the late Oligocene and the Miocene. Updip gas migration was predominantly toward the southwest because the basin configuration was similar to that of today.

Traps: Stratigraphic traps resulting from landward pinchout of nearshore and foreshore marine sandstone bodies into finer grained silty, shaly, and coaly facies of the Fruitland Formation (especially in the areas of stratigraphic rises) contain most of the hydrocarbons. Seals are formed by finer grained back-beach and paludal sediments into which marine sandstone intertongues throughout most of the central part of the basin. The Pictured Cliffs Sandstone is sealed off from any connection with other underlying Upper Cretaceous reservoirs by the Lewis Shale. The Pictured Cliffs crops out around the perimeter of the central part of the San Juan Basin and is present at depths of as much as 4,300 ft. Most production has been from depths of 1,000–3,000 ft.

Exploration status and resource potential: Gas was discovered in the play in 1927 at the Blanco and Fulcher Kutz fields of northwest New Mexico. Most Pictured Cliffs fields were discovered before 1954, and only nine relatively small fields have come into production since then. Discoveries since 1954 average about 11 BCFG estimated ultimate recovery. A large quantity of gas is held in tight sandstone reservoirs north of the currently producing areas. Stratigraphic traps and excellent source rocks are present in the deeper parts of the basin, but low permeabilities due to authigenic illite-smectite clay have thus far limited production.

COAL-BED GAS PLAYS

By Dudley D. Rice and Thomas M. Finn

Geologic and hydrologic controls and resource potential of coalbed gas in the San Juan Basin, northwestern New Mexico and southwestern Colorado are given by Kelso and others (1988), Crist and others (1990), Ayers and others (1991), and Ayers and Kaiser (1992). The effects of coal reservoir properties on productivity as determined by reservoir simulation are reported by Paul and Young (1993).

In the San Juan Basin, significant resources of both coal and coalbed gas are in the Upper Cretaceous Fruitland Formation. The occurrence, thickness, and geometry of Fruitland coal deposits are strongly influenced by depositional environment. Coal deposits resulted from peat that accumulated on sandstone platforms of the underlying Pictured Cliffs Sandstone, which were deposited along the coast of a northeast-prograding shoreline. Individual coal beds are as much as 40 ft thick. The greatest net coal thickness, up to 100 ft, is in a northwest-trending belt in the northern part of the basin where thick coal deposits occur in both northwest- and northeast-trending deposits, with the thickest deposits in the northwest-trend. In the northwest-trend, individual coal beds average more than 9 ft in thickness, which resulted from standstills in the Pictured Cliffs Sandstone shoreline. Average thickness of coal beds in the northeast-trend is 6 ft. They occur in floodplain facies between channel-fill sandstone deposits. Depths of burial for the Fruitland coal beds are as much as 4,200 ft in the northeastern part of the basin.

Coal beds in the Upper Cretaceous Menefee Formation are an additional target for gas. The Menefee is older and deeper than the Fruitland and is in the middle part of the Mesaverde Group. Although as much as 35 net ft of coal occur in the Menefee, the coals are generally thinner, more discontinuous, and dispersed over a greater stratigraphic interval than those of the overlying Fruitland Formation. The Menefee coals are as deep as 6,500 ft.

Across the central basin, the rank of Fruitland coal increases northeastward from subbituminous C to medium-volatile bituminous. Coal rank generally conforms with the structural configuration of the basin and abruptly decreases along the steeply dipping north flank. Rank trends for Menefee coals are similar, but somewhat higher because of greater burial depth. Present-day depths of burial do not coincide with the maximum levels of thermal maturity in the northern part of the basin. This is partly the result of significant uplift and erosion that has taken place since about 10 Ma. However, maximum depth of burial and present-day heat flow cannot account for the high rank present at the north end of the basin. In addition to maximum burial depths, this high rank is interpreted to be the result of (1) convective heat transfer associated with a deeply buried heat source located directly below the northern part of the basin, and (or) (2) the circulation of relatively hot fluids into the basin from a heat source located in the vicinity of the San Juan Mountains to the north. Thermogenic gases were probably generated in the coals during time of maximum heat flow and (or) depth of burial in Tertiary time.

Produced Fruitland coalbed gases are variable in their composition. Although methane is the major component, significant amounts of heavier hydrocarbon gases (as much as 23 percent), CO_2 (as much as 13 percent), and nitrogen (as much as 11 percent) are also present. The producing part of the basin can be divided into two areas based on coalbed gas composition. The boundary between the two areas is rather abrupt and coincides with the structural hingeline, which is discussed later. In the southern part, the gases are generally wet (heavier hydrocarbons generally greater than 6 percent) with minor amounts of CO_2 (generally less than 1 percent). Waxy oil is produced in association with wet gases in this part. In contrast, gases in the north part are dry (heavier hydrocarbons generally less than 3 percent) but contain significant amounts of CO_2 (generally greater than 6 percent). On the basis of chemical and isotopic composition, the hydrocarbon gases are interpreted to be mainly thermogenic in origin. The heavier hydrocarbon gases and oils, which are restricted to coals of high-volatile B bituminous and lower ranks, were probably generated from hydrogen-rich coals. In the northern part of the basin, active groundwater flow has probably led, relatively recently, to intensified microbial activity resulting in aerobic consumption of the heavier hydrocarbons and mixing of biogenic methane-rich gas. Isotopic data suggest that the large amounts of CO_2 in the north part of the basin are also the result of recent bacterial activity.

The San Juan Basin is a strongly asymmetric basin with a gently dipping southern flank and steeply dipping northern flank. It has two axes in the northeastern part of the basin, which are separated by the Ignacio Anticline. A structural hingeline has been interpreted to occur where the gently dipping southern monocline meets the basin floor. This hingeline is probably a zone of northwest trending, en-echelon normal faults and divides the basin into two distinct areas relative to coalbed gas productivity.

The Colorado-New Mexico border roughly marks the division of the basin into two areas of distinctly different face-cleat orientations. North of the border the cleats are oriented northwestward; however, south of the border they are oriented northward or northeastward. Along the State border, interference of the two sets may result in increased permeability, which has lead to the success of vertical open-hole cavity completions. Increased permeability may also result from compaction-induced fractures in areas where the Fruitland coal beds overlie upper Pictured Cliffs sandstone tongues. In addition, compaction-induced fractures may be present where coal beds split and interfinger with fluvial channel-sandstones. In the Cedar Hill coal field area of northern New Mexico, multicomponent 3D seismic surveys indicate that movement on basement-controlled faults with strike-slip displacement has opened natural fractures in the coal.

Fruitland coal beds are major aquifers in the San Juan Basin. In the northern part of the basin, they are commonly thick, well cleated, and more permeable than the adjacent sandstones that serve as aquitards. Recharge is mainly along the wet, northern margin of the basin in the foothills of the San Juan Mountains with limited recharge along the other margins. A sharp steepening of the potentiometric surface occurs along the structural hingeline and divides the basin into two hydrologic provinces. This steepening indicates an area of reduced permeability and is a no-flow boundary.

Groundwater movement and associated reservoir characteristics can be tracked by water composition, in particular the chloride content. Lobes of relatively fresh, low-chloride water extend into the basin from the northern margin. The hydrochemical boundary between low chloride, $NaHCO_3$-type water and high chloride NaCl-type water coincides with the structural hingeline. Water production rates for individual wells are highly variable and range from essentially nothing to more than 2,000 barrels per day. The production rates are strongly controlled by hydrodynamics, and the highest rates are north of the hingeline and along the northern margin. Most of the water is currently being injected into deep wells. However, the disposal capacity is rapidly being approached and alternate, cost-effective methods of disposal will be required.

The Fruitland coal beds are both abnormally pressured and underpressured relative to fresh-water hydrostatic pressure. Overpressuring occurs in north-central part of the basin and coincides with the area of relatively fresh water. The overpressuring is interpreted to be artesian in origin as evidenced by the flowing artesian coalbed gas wells. However, most of the basin is underpressured. The transition from overpressured to underpressured is abrupt and takes place along the structural hingeline.

Gas contents in the San Juan Basin are highly variable and range from less than 100 to more than 800 Scf/t. As expected, there is a general relation between gas content, depth, and rank. However, the gas content also strongly correlates with the pressure regime. In dealing with coals of similar rank, the highest gas contents are usually reported from the overpressured north-central part of the basin.

On the basis of resources and a range of gas contents, in-place coalbed gas resources of the Fruitland Formation are estimated to be about 50 TCF. An additional 38 TCF have been estimated for the Menefee coal beds resulting in a total of 88 TCF for the basin.

New Mexico ranked 14th among the States in 1991 for the production of coal. Most of this coal was mined on the surface from the Fruitland along the western flank of the basin. The New Mexico counties of San Juan and McKinley, located on the west flank of the basin, were ranked 7th and 10th in the nation in terms of production from surface mining. Some coal is also mined in the Colorado part of the basin. Because the coal in the basin is mostly mined on the surface, methane emissions are minor.

The San Juan Basin has been the most productive coalbed gas basin in the United States since 1988. In 1992, more than 436 BCF of coalbed gas were produced from about 2,000 wells. In 1993, more than 480 BCF were produced from about 1980 wells in only the New Mexico part of the basin. Most of the coalbed gas wells in the basin have been drilled since 1987 and the largest number was completed in 1990. Although the Black Warrior Basin has the largest number of producing wells, more than four times as much coalbed gas was produced in the San Juan Basin in 1992 (436 BCF versus 92 BCF). Production rates for individual wells are highly variable and range from 50 to 15,000 MCFPD. About one-third of the total producing wells are vertical open-hole cavity wells, which accounted for about 75 percent of the gas production in 1992. These cavity wells commonly produce 10 times more gas than those completed by hydraulic fracturing. However, successful, open-hole cavity completions are generally restricted to a northwest-trending area referred to as the "fairway," located north of the structural hingeline. Cavity wells in the "fairway" are successful because of artesian overpressuring and high permeability; open-hole cavity completions have not been successful in other basins.

The first coalbed gas well (Cahn No. 1) was drilled in the New Mexico part of the basin in late 1970's. The well is part of the Cedar Hills coal field. Most of the production in New Mexico is assigned to the Basin Fruitland coal field, and all the production in Colorado is assigned to the Ignacio-Blanco coal field. The reserves in the basin as of 1993 are about 7.8 TCF, which represents about 70 percent of the coalbed gas reserves in the country.

The San Juan Basin has had major gas pipelines to southern California since the 1950's when gas was first produced from Cretaceous sandstones. With the rapid development of coalbed gas, pipeline capacity was insufficient in the late 1980's. Since 1990, major expansion projects have resulted in increased capacity for transmitting the gas to interstate markets.

2250. SAN JUAN BASIN–OVERPRESSURED PLAY
2252. SAN JUAN BASIN–UNDERPRESSURED DISCHARGE PLAY
2253. SAN JUAN BASIN–UNDERPRESSURED PLAY

On the basis of hydrology, pressure regime, reservoir properties, and hydrocarbon composition, three plays are identified for the Fruitland coalbed gas: (1) San Juan–Overpressured Play, (2) San Juan--Underpressured Discharge Play, and (3) San Juan–Underpressured Play. The San Juan–Overpressured Play (2250) is in the north-central part of the basin and north of the structural hingeline where recharge of relatively fresh water takes place. The coals are generally thick (>10 ft) and laterally extensive in northwest-trending bands. The coals are generally of high rank (as much as medium-volatile bituminous), have high gas contents, and are characterized by high formation pressures (greater than 0.5 psi/ft). The coalbed gases are relatively dry (heavier hydrocarbons less than 3 percent) and contain significant amounts of CO_2 (3–12 percent). Although depths of burial extend to 4,200 ft, the Fruitland

Coal in a large part of the play is at depths of less than 3,000 ft. Within this play is the very productive "fairway" trend. The average daily gas production for wells in this play during their most productive year ranges from less than 30 MCF/D to more than 3,000 MCF/D, and the highest rates were in the "fairway" trend. Because of recharge of fresh water on the north margin, most wells produce water at rates as high as 2,000 bbl/D and must be dewatered to initiate desorption and production. Because of the high productive capacity of wells in this play, the prime areas have been explored and developed (Cedar Hills, Ignacio-Blanco, and Basin Fruitland coal fields). The potential for additional reserves from this play is considered to be good; however, the areal extent of this potential is limited because of previous development.

The San Juan–Underpressured Discharge Play (2252) is south of the structural hingeline in the southwest part of the basin where the coal beds are underpressured (0.3 to 0.4 psi/ft). The area is characterized by regional groundwater convergence and discharge. The groundwater is a NaCl type and has a higher chloride content than that of the overpressure play. Coals may be as thick as 10 ft and the thickest coals are in northeast trends. Compared to the overpressured play, coal rank is lower (high-volatile B bituminous and lower) and gas contents are lower. The gas is chemically wet (heavier hydrocarbons generally more than 5 percent) and contains less than 1.5 percent CO_2. During early months of production, the coals of high-volatile B bituminous rank produce some waxy oil. Depths of burial are less than 3,000 ft, and production is commonly water free. The average daily production of wells in this play during their most productive year ranges from 30 to 300 MCF/D. The potential for undiscovered coalbed gas in this play is good to fair. Similar to the overpressured play, extensive drilling and production (Basin Fruitland coalbed gas field) have taken place in this play, and the remaining potential for reserves is mainly at shallower depths (less than 1,500 ft) in the southwestern part of the play.

The San Juan–Underpressured play (2253) is in the eastern part of the basin where groundwater flow is sluggish. The produced waters are a NaCl type and similar to seawater. Coal beds are generally thin and gas content is low, particularly in the eastern part. Minor production has been established and rates are low (average annual production in the range of 1 to 3 MMCF) with little or no water production. Depths of burial (500–4,000 ft) and coal rank (subbituminous to medium-volatile bituminous) are variable and generally increase to the north. The potential for additional reserves from this play is only fair because of underpressuring and low permeability.

REFERENCES

(References for coalbed gas are shown in Rice, D.D., Geologic framework and description of coalbed gas plays, this CD-ROM)

Huffman, A.C., Jr., 1987, Petroleum geology and hydrocarbon plays of the San Juan Basin Petroleum Province: U.S. Geological Survey Open-File Report 87-450B, 67 p.

Rice, D.D., 1983, Relation of natural gas composition to thermal maturity and source rock type in San Juan Basin, northwestern New Mexico and southwestern Colorado: American Association of Petroleum Geologists Bulletin, v. 67, p. 1199-1218.

Ross, L.M., 1980, Geochemical correlation of San Juan Basin oils--A study: Oil and Gas Journal, v. 78, p. 102-110.

Vincelette, R.R., and Chittum, W.E., 1981, Exploration for oil accumulations in Entrada Sandstone, San Juan Basin, New Mexico: American Association of Petroleum Geologists Bulletin, v. 65, p. 2546-2570.

AGE		FORMATION OR GROUP (SW)		(NE)
TERTIARY		San Jose Formation		
TERTIARY		Nacimiento Formation		
TERTIARY		Ojo Alamo Sandstone		
CRETACEOUS	LATE	Kirtland Shale (Farmington Sandstone Member)		
CRETACEOUS	LATE	Fruitland Formation		
CRETACEOUS	LATE	Pictured Cliffs Sandstone		
CRETACEOUS	LATE	Lewis Shale		
CRETACEOUS	LATE	Mesaverde Group	Cliff House Sandstone	
CRETACEOUS	LATE	Mesaverde Group	Menefee Formation	
CRETACEOUS	LATE	Mesaverde Group	Point Lookout Sandstone	
CRETACEOUS	LATE	Upper Mancos Shale		
CRETACEOUS	LATE	Gallup Ss. (Torrivio Mbr.)		Tocito Ss. Lentil
CRETACEOUS	LATE	Lower Mancos Shale		Greenhorn Limestone
CRETACEOUS	LATE	Dakota Sandstone		
CRETACEOUS	EARLY	Burro Canyon Formation		
JURASSIC		Morrison Formation (Todilto Limestone Member)		
JURASSIC		Wanakah Formation		
JURASSIC		Entrada Sandstone		
TRIASSIC		Chinle Formation		
PERMIAN		Cutler Group	De Chelley Sandstone	
PERMIAN		Cutler Group	Organ Rock Shale	
PERMIAN		Cutler Group	Cedar Mesa Formation and related rocks	
PERMIAN		Cutler Group	Halgaito Formation	
PENNSYLVANIAN		Rico Formation		
PENNSYLVANIAN		Hermosa Group	Honaker Trail Formation	
PENNSYLVANIAN		Hermosa Group	Paradox Formation and related rocks	
PENNSYLVANIAN		Hermosa Group	Pinkerton Trail Formation	
PENNSYLVANIAN		Molas Formation		
MISSISSIPPIAN		Leadville Limestone		
DEVONIAN		Ouray Limestone		
DEVONIAN		Elbert Formation		
CAMBRIAN		Ignacio Quartzite		
PRECAMBRIAN				