Southern Ute Indian Reservation

General Setting

The Southern Ute Indian Reservation is in southwestern Colorado adjacent to the New Mexico border (Figs. SU-1 and -2). The reservation encompasses an area about 15 miles (24 km) wide by 72 miles (116 km) long; total area is approximately 818,000 acres (331,000 ha). Of the Indian land, 301,867 acres (122,256 ha) are tribally owned and 4,966 acres (2,011 ha) are allotted lands; 277 acres (112 ha) are federally owned (U.S. Department of Commerce, 1974). The rest is either privately owned or National Forest Service Lands. The Tribal land is fairly concentrated in two blocks; one in T 32-33 N, R 1-6 W, and the other in T 32 N, R 8-13 W and T 33 N, R 11 W. Most of the allotted land is along or near Los Pinos River. This "checker-boarding" has had a profound effect on the development of the Southern Ute people. Unlike many tribes where they are isolated from outside influence, the Southern Utes have lived alongside non-Indians since the late 1800's.

The Tribal headquarters are located 1 mile north of the town of Ignacio (Fig. SU-2). The city of Durango is located just outside the north boundary of the Reservation, 24 miles northwest of Ignacio.

The population of the Tribe is currently 1,135 people. The Tribe is growing rapidly with over half of the population under the age of 25. Approximately 25 percent of the membership lives off the Reservation, mostly in larger metropolitan areas such as Denver, Albuquerque, and Phoenix. There are 300 Tribal members in the local work force. In addition to Tribal Members, there are approximately 30,000 people living in La Plata County.

Topography of the reservation is generally rugged. West of Animas River, the eastern flank of Mesa Verde is cut by numerous small canyons. Eastward the hills become more rounded and timber covered. Elevations range from about 6,000 feet along La Plata River near the southwest corner and along the San Juan River near Arboles, to 8,551 feet at Piedra Peak (sec 24, T33N, R6W). Principal streams on the Reservation are the San Juan, Piedra, Animas, Florida, and La Plata Rivers. The Navajo Reservoir, formed by Navajo Dam in New Mexico, forms a significant body of water on the San Juan River and the lower Piedra River in the eastern part of the reservation (Fig. SU-2); water surface is at an elevation of about 6,100 feet.

Ignacio, with a population of 613 in 1970, is the largest town on the reservation, and site of the Southern Ute Indian Agency. The nearest large town is Durango, Colorado with a population of 10,333. It is about 5 miles north of the reservation (Fig. SU-2). Farmington, New Mexico, with a population of 21,979 (1980), lies to the south about 29 miles from the reservation boundary.

The climate is temperate with an annual average of 16 inches of rainfall. The growing season is about 109 frost free days between May and September.

The Southern Ute Indian Tribe is blessed with an abundance of valuable natural resources. A major source of revenue for the Tribe is the production of oil and natural gas. Recent drilling and production activity has focused on coal-bed methane gas which occurs throughout the coal seams underlying the Reservation. The coal, estimated to be in excess of 200 million tons of strippable coal, is high quality (10,000 BTUs per lb.) and with low sulfur content.

Leasing of minerals and development agreements on the Southern Ute Indian Reservation are designed in accordance with the Indian Mineral Development Act of 1982, and the rules and regulations contained in 25 CFR, Part 225 (published in the Federal Register, March 30, 1994). The Tribe no longer performs lease agreements under the old 1938 Act (since 1977).

The 1982 Act provides increased flexibility to the Tribe and developer to tailor their agreements to the specific needs of each party. It also allows the parties to draft agreements based on state-of-the-art oil and gas agreements used in industry rather than standard Bureau of Indian Affairs forms. The Act also contains sections which set forth the responsibilities of BLM and MMS offices. The regulations contain a 21 point check list for matters which should be considered, and if appropriate, included in any mineral agreement.

Inquiries regarding new leasing should be directed to Robert Santistevan, Director of Energy Resources, Red Willow Production Company at:

Red Willow Production CO
Production Operating/Acquisition
P.O. Box 737
Tribal Annex bldg., 2nd Fl
Ignacio, CO 81137

Tel: (970) 563-0140
Fax: (970) 563-0398

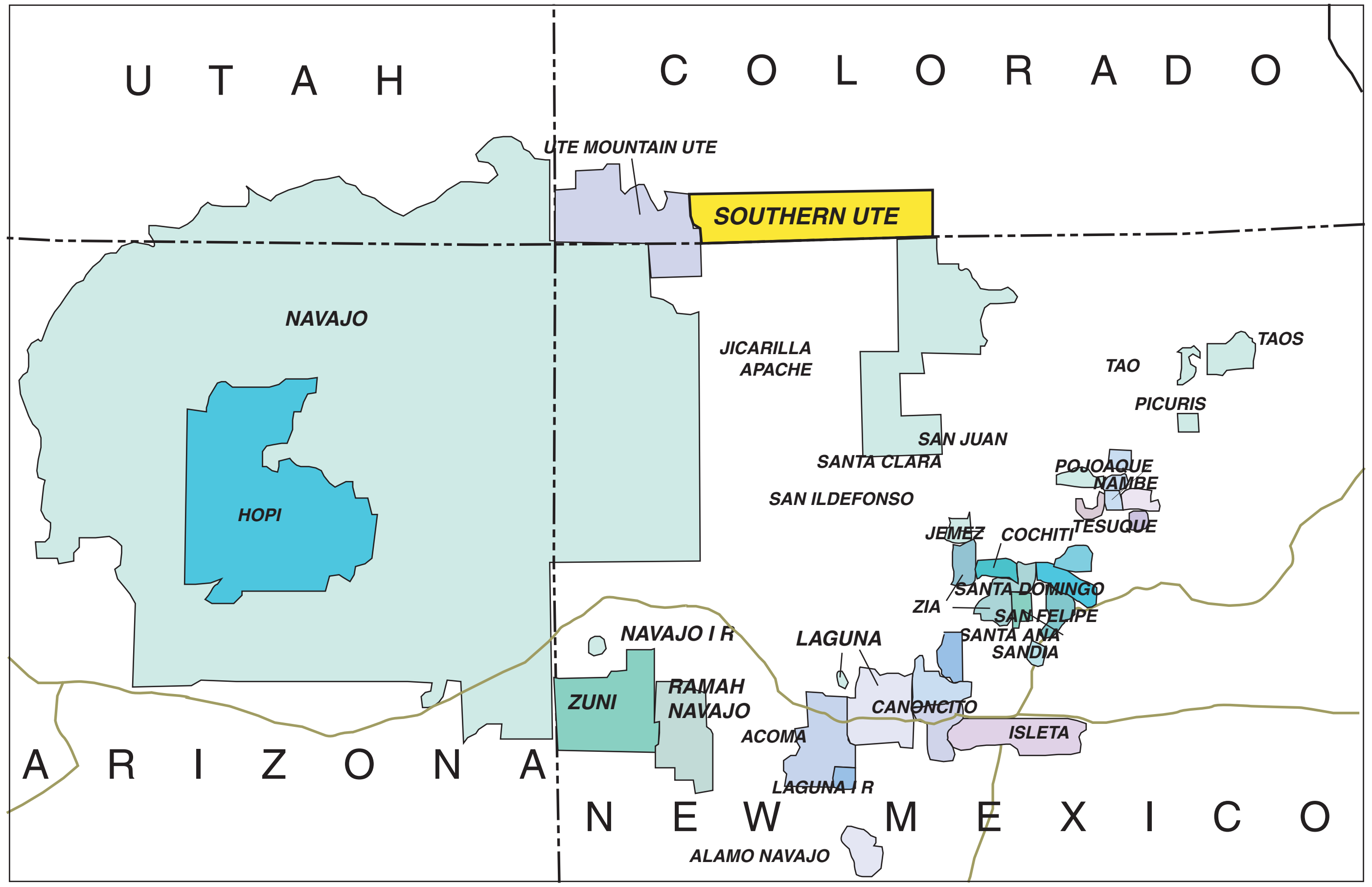


Figure SU-1. Location of Southern Ute Indian Reservation with respect to other Indian Reservations (modified after Indian Land Areas, 1993).

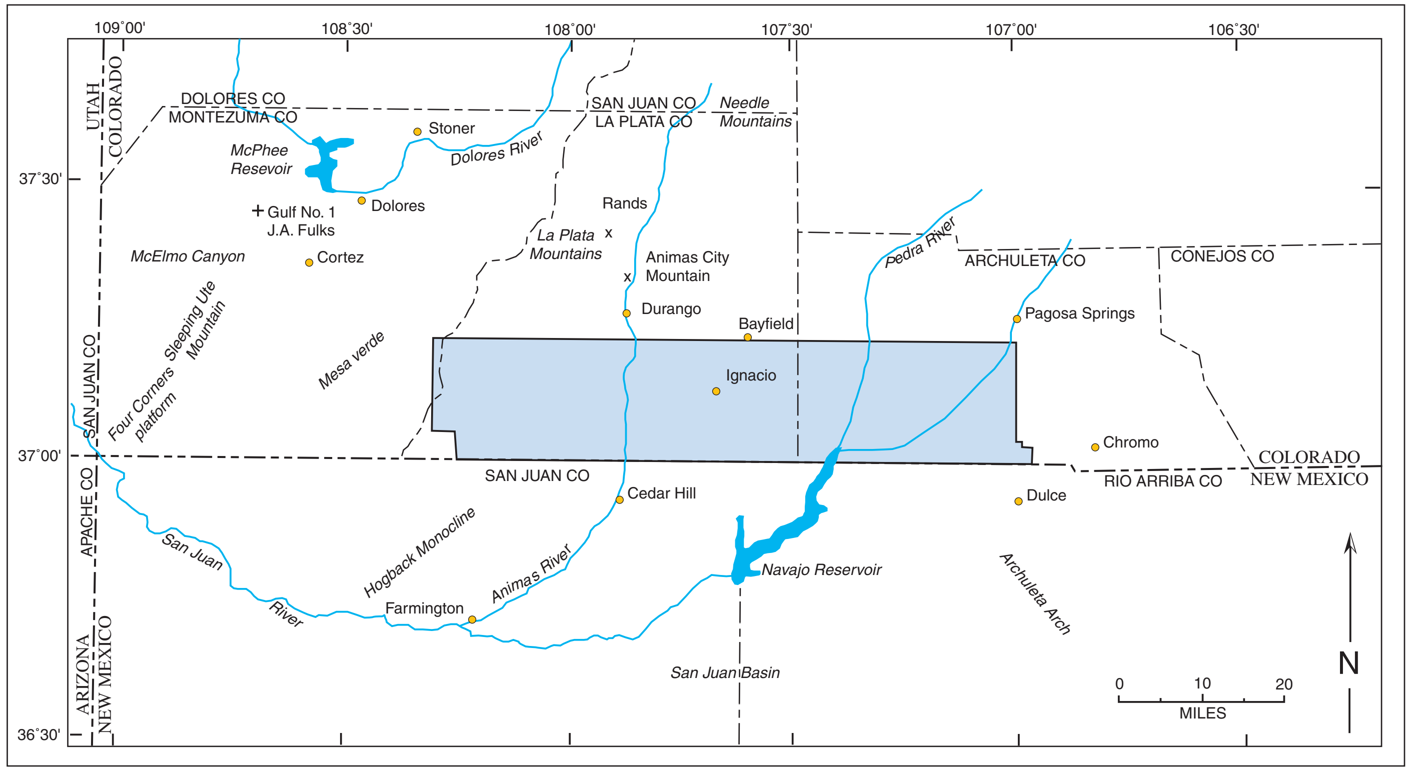


Figure SU-2. Index map showing the Southern Ute Indian Reservation and adjacent areas (modified after Condon, 1992).

Geology

The Southern Ute Indian Reservation is on the northern margin of the San Juan Basin, a large circular structural depression whose center is some 50 miles southeast of Durango (Fig. SU-3). The sedimentary layers that fill the San Juan Basin dip gently toward its center. Their outcrop pattern around the basin is a series of concentric bands, with the younger rocks toward the center and the older rocks toward the margin. Nearly all the rocks exposed at the surface on the Reservation are sedimentary rocks of Late Cretaceous or Early Tertiary age (Fig. SU-4).

Geologic Structure

The Southern Ute Indian Reservation is located in the northern part of the structural and sedimentary San Juan Basin. The present structure was largely shaped by Laramide (Late Cretaceous through Eocene) and later tectonic activity. The area was also on the edge of the older Paleozoic Paradox Basin during deposition of the sediments of the Pennsylvanian Hermosa Group (Condon, S.M., 1992)

Figures SU-3, -4, and -5 show various structural elements in southwestern Colorado and northwestern New Mexico. The structure contours in Figures SU-4 and -5 show effects of Laramide deformation. The San Juan Basin is flanked on the west by the Hogback Monocline and on the east by the Archuleta Arch. The monocline rim extends unbroken around the northern rim of the basin. Superimposed on these major structures are several smaller ones: the Barker anticline and Red Horse syncline in the southwest corner of the Reservation, the Ignacio anticline and H-D Hills syncline in the central part, and several northwest-trending anticlines, synclines and faults at the east end.

A structural bench, the Four Corners Platform, lies between the San Juan Basin and the Blanding Basin (Fig. SU-3). Upper Cretaceous to Tertiary laccolith intrusions of Ute dome and the La Plata dome are evident (Fig. SU-3). The northern rim of the San Juan Basin is defined by the uplift of the San Juan Dome. The Chama basin and the San Juan sag are low structural features on the east and northeast sides, respectively, of the Archuleta arc (Fig. SU-5).

The principal structures of economic significance are the Barker anticline, which produces gas from the Dakota and Hermosa Groups, and the Ignacio anticline, which produces gas mainly from the Mesaverde and subordinately from several other formations from the Fruitland down to the Morrison (Fig. SU-4).

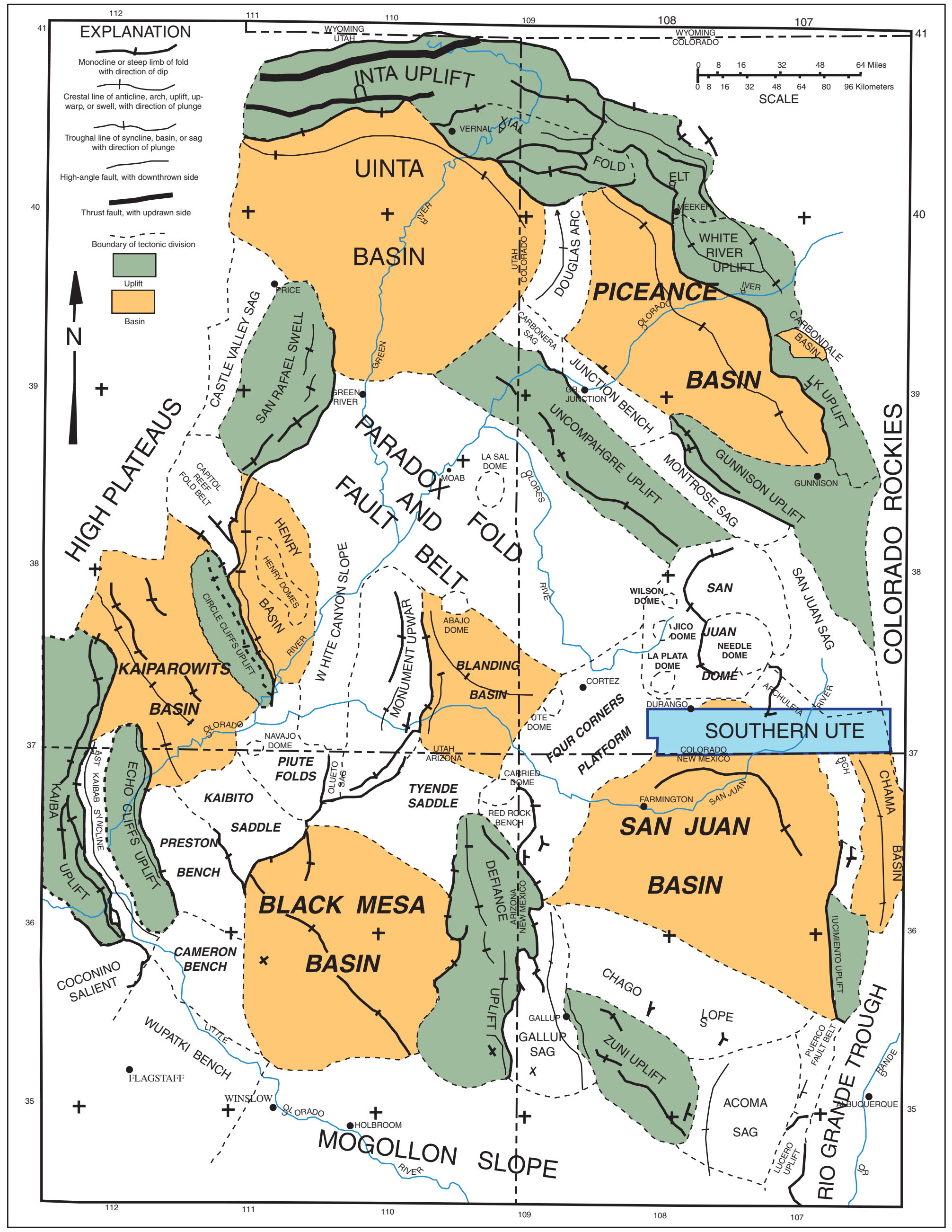


Figure SU-3. Tectonic divisions of the Colorado Plateau (modified after Kelley, 1958).

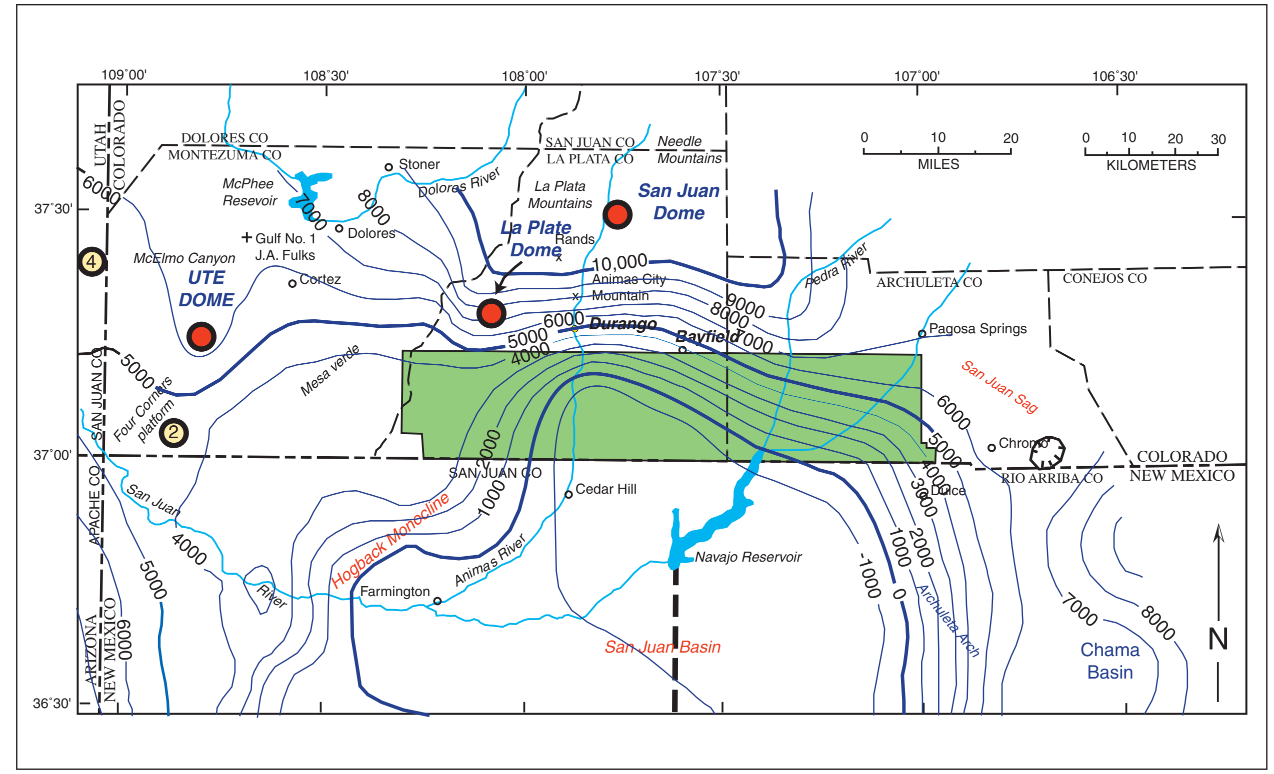


Figure SU-5. Structure Contour map under and adjacent to the Southern Ute Indian Reservation. Structure contours are drawn on the top of the Jurassic with a contour interval of 1000 feet. Major structural features are labeled (modified after Condon, 1992).

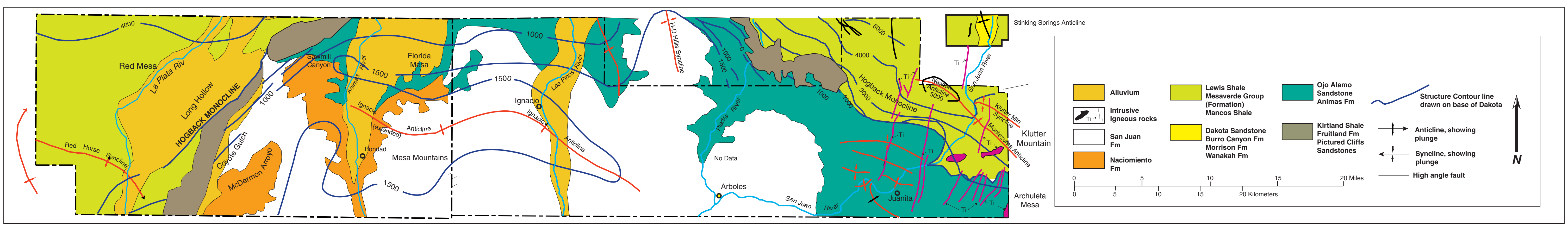


Figure SU-4. Generalized geologic and structure map of the Southern Ute Indian Reservation. Structure lines are drawn on the base of the Dakota Sandstone (modified after Anderson, 1995).

Stratigraphic Overview

The following is a brief description of the stratigraphy under the Southern Ute Indian Reservation. The formations of oil and gas significance will be discussed in more detail in the "Play Summary Overview". Please refer to Figures SU-4, 5, 6, and 7.

Older Paleozoic Systems

The oldest formation in the subsurface of the Southern Ute Indian Reservation is the Upper Cambrian Ignacio Quartzite which unconformably overlies Precambrian metamorphic and igneous rocks (Fig. SU-6). The Ignacio is as thick as 150 feet in the northwest part of the Reservation and thins to about 30 feet in the Piedra River canyon about 20 miles west of Pagosa Springs. It consists mainly of white, reddish-brown, and light-brown conglomerate; feldspathic and quartzoes sandstone; purple to green, burrowed, micaceous mudstone and siltstone; and minor dolomite. The sandstone is very coarse to fine grained. Bedding is thin to thick in tabular layers with small to medium scale crossbeds. The lower Ignacio Quartzite was deposited subaerially in streams and on alluvial fans. The upper Ingacio Quartzite is a shallow-shelf assemblage of strata that was deposited by the eastward transgressing sea. There is no production of hydrocarbons or any other economic resource from the Ignacio in the vicinity of the Reservation.

The Cambrian-Devonian McCracken Sandstone Member and Upper Member of the Elbert Formation unconformably overly the Ignacio Quartzite and basement rocks (Fig. SU-6). The McCracken Sandstone Member ranges from 0 -140 feet thick on the Reservation. The McCracken consists of gray to brown sandstone, brown and gray dolomite, and greenish-gray shale. The dominant lithology is very fine to coarse grained sandstone. It is composed of shallow marine, nearshore sediments that were deposited during a eustatic sea-level rise in the Late Devonian. The Upper Member of the Elbert Formation ranges from 150 to 250 feet thick on the Reservation. It consists of poorly exposed, thinly bedded, brownish-gray, sandy dolomite and sandstone; green to red shale; and minor anhydrite. The sediments were deposited in a shallow, tidal-flat environment.

The Devonian Ouray Limestone conformably overlies the Elbert Formation (Fig. SU-6). The Ouray is 100 feet thick in the western part of the Reservation and pinches out in the eastern part of the Reservation. It is composed of dark-brown to light-gray, dense, argillaceous limestone with local green clay partings.

The Lower Mississippian Leadville Limestone unconformably overlies the Ouray Limestone. The Leadville ranges in thickness from nearly zero on the east side of the Reservation to about 250 feet on the west side. The Leadville is composed of yellowish-brown and light to dark-gray finely to coarsely crystalline, fossiliferous dolomite and limestone. The Leadville formed during two transgressive episodes in the Mississippian. The sediments were deposited under a variety of depositional environments ranging from shallow water tidal flats to low-energy stable-shelf conditions to high-energy shoals. Another unconformity separates the Leadville Limestone from the Lower Pennsylvanian Molas Formation.

Pennsylvanian System

The Molas Formation averages 60 feet thick on the Reservation. The Molas Formation is composed of three members. They are the Coabank Hill Member, the Middle Member, and the Upper Member. They range from shale to conglomerate with some fossiliferous limestone.

The Hermosa Group conformably overlies the Molas Formation. It ranges in thickness from 400 feet on the southeast side to thicker than 2,000 feet. The Hermosa Group consists of (from oldest to youngest) the Pinkerton Trail Formation, the salt-bearing Paradox Formation and the Honaker Trail Formation. The Paradox Formation is composed of four main cycles of Desmoinian deposition. The cycles are the Ismay, Desert Creek, Akah, and Barker Creek Stages. These are cyclic deposits of dolomite, limestone, and black, carbonaceous shale. Porosity is 10% and more, which has made these cycles important as an oil and gas reservoir.

Pennsylvanian and Permian Systems

The Rico Formation averages about 200 feet thick on the Reservation. It is composed of conglomeratic sandstone and arkose interbedded with greenish-, reddish-, and brownish- gray shale and sandy fossiliferous limestone. The Rico Formation represents the transition between the Cutler Group and the Hermosa Group.

Lower Permian System

The Cutler Group ranges from 1,200 to 1,700 feet thick on the Reservation. It is mostly nonmarine red shale, siltstone, mudstone, sandstone, and conglomerate. It is composed of (from oldest to youngest) the Halgaito Formation, Ceder Mesa Formation, Organ Rock Shale, and the De Chelley Sandstone (Fig. SU-6).

Triassic System

The Dolores Formation ranges in thickness from about 900-1,200 feet on the west side of the Reservation. It is composed mostly of interbedded red to purplish-red, very fine to coarse grained sandstone, conglomerate, siltstone, and mudstone. The Dolores is interpreted to be fluvial-channel, flood plain, lacustrine, and eolian sand-sheet deposits.

Jurassic System

The Entrada Sandstone unconformably overlies the Dolores Formation and is composed of light-gray, cross-bedded sandstone. Maximum thickness is about 250 feet. The overlying Morrison Formation is composed of two members, the Salt Wash Member which is mostly sandstone with interbedded claystone and mudstone, and the overlying Brushy Basin Member which is mostly varicolored claystone and mudstone. Maximum thickness of the Morrison Formation is about 800 feet.

Cretaceous System

The Early Cretaceous Burro Canyon Formation disconformably overlies the Morrison Formation. Like the Jurassic rocks, the Burro Canyon is exposed only at the northeast corner of the reservation. It is about 1000 feet thick in the Reservation and consists of lenticular conglomerate and conglomeratic fluvial-channel sandstone bodies.

The Late Cretaceous (Cenomanian) Dakota Sandstone lies either disconformably over the Burrow Canyon Formation or unconformably over the Morrison Formation Fig. SU-6). It is exposed only in the valley of the San Juan River in the northeast corner of the Reservation, but it underlies the entire Reservation in the subsurface. It was deposited in response to the initial transgression of the upper Cretaceous epeiric sea. The Dakota formed in a variety of environments and consists of a basal alluvial unit that is overlain by deltaic, marginal-marine, and marine rocks in different parts of the region. Its thickness on the Reservation is not known, but nearby to the north it is 177-270 feet thick.

The Late Cretaceous Mancos Shale conformably overlies the Dakota Sandstone and intertongues with the overlying Point Lookout Sandstone. It underlies the entire Reservation and outcrops in the northeast corner. It is mostly a dark gray marine shale and its maximum subsurface thickness on the Reservation is about 2,400 feet. The lower part, about 500 feet thick, contains thin limy shale and limestone in the lower 150 feet. The upper part, about 1,900 feet thick, has sandy limestone and clayey sandstone at its base and contains some limestone or limy beds in its lower 600 feet; it grades upward into fine-grained shaly sandstone.

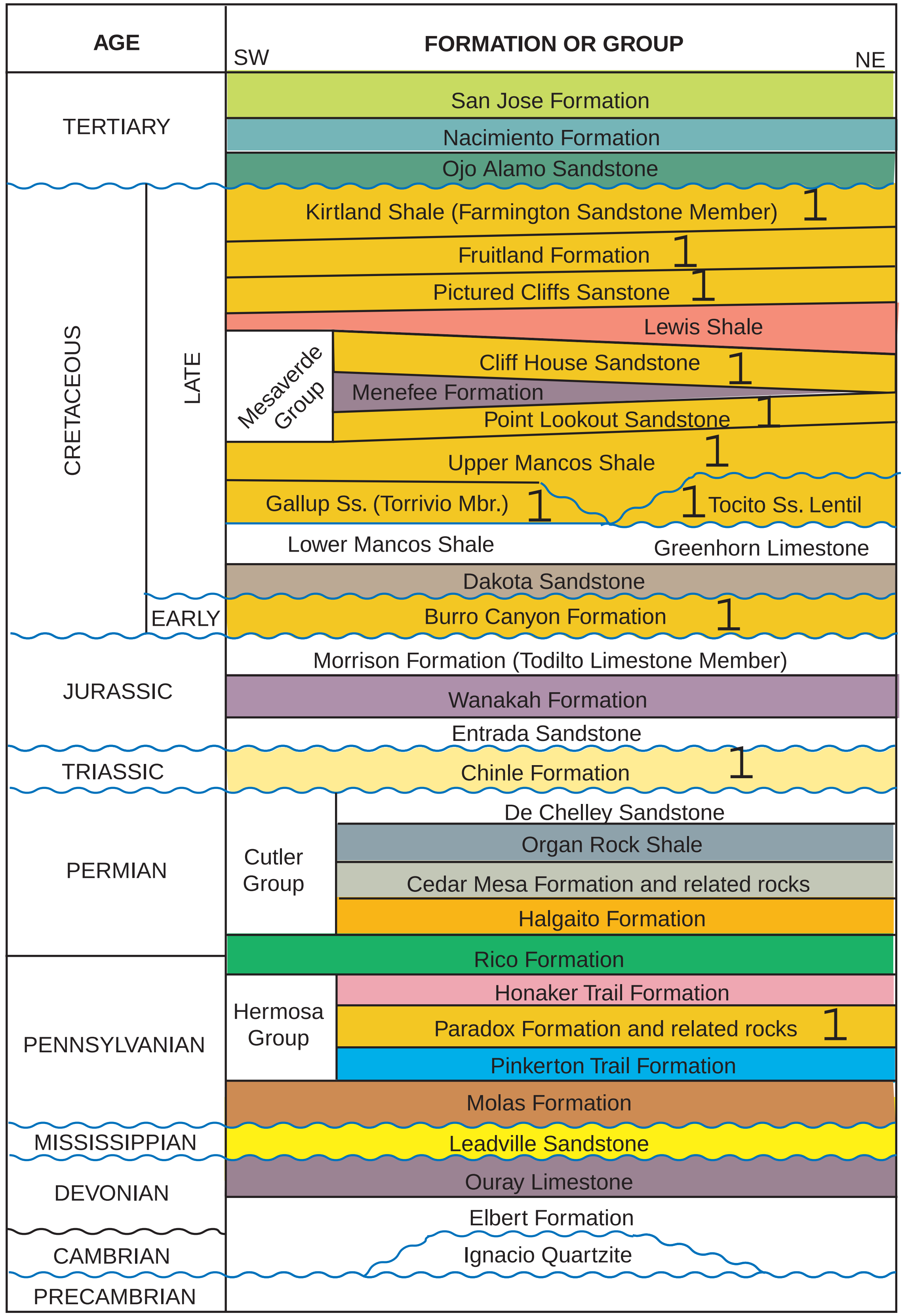


Figure SU-6. Geochronologic chart for the San Juan Basin. Yellow units are productive in the Southern Ute Indian Reservation (modified after Gautier et al., 1996).

Overlying the Mancos Shale is the series of interbedded sandstones of the Late Cretaceous Mesaverde Group. It is composed of the Point Lookout Sandstone, the Menefee Formation, and the Cliff House Sandstone (Fig. SU-6). The Mesaverde Group forms several small mesas in the northeastern part of the reservation. The outcrop continues to the west in an arc north of the reservation, and reenters it on the west side, where the Cliff House Sandstone lies at the surface of nearly all the reservation west of the La Plata River.

The Point Lookout Sandstone, at the base of the Mesaverde Group, conformably overlies and is transitional with the Mancos Shale. In the area of the Reservation, the Point Lookout Sandstone is divided into a lower sandstone and shale member and an upper massive sandstone member. The sandstone and shale member is about 80-125 feet thick and is composed of interbedded yellowish gray, fine-grained, cross-laminated sandstone and sandy dark-olive-gray, fossiliferous shale; the amount of sandstone in the member increases upward toward the overlying massive sandstone member. The upper massive sandstone member is about 200-250 feet thick and is composed of thick to massive beds of light-gray to yellowish-gray, crossbedded, fine- to medium-grained sandstone. The contact with the overlying Menefee Formation is conformable and sharp in most places.

The Menefee Formation consists of a series of interbedded lenses of sandstone, siltstone, shale, and coal. Irregular bedding and rapid lateral changes of lithology are characteristic of the formation. The sandstones and siltstones are various shades of light gray and yellowish gray and range in grain size from coarse sand to very fine silt. The shales are mostly shades of dark gray or brown. The coal beds are lenticular and in many places grade both horizontally and vertically into carbonaceous clay shale and carbonaceous shaly sandstone. Thin coal beds occur throughout the formation, but most coal beds more that 1.2 feet thick are in the lowermost 50-60 feet of the formation, and a few are immediately below the top. The Menefee thins to the northeast and pinches out in the eastern part of the Reservation.

The Cliff House Sandstone is a sandstone and shale sequence in the vicinity of the Reservation. The unit consists of sandstone, siltstone, and shale in varying proportions, with sandstone becoming thicker toward the southwest. On Weber Mountain, a few miles northwest of the Reservation, the Cliff House consists of an upper sandstone unit 65 feet thick, a middle shaly unit 210 feet thick, and a lower sandy unit 70 feet thick. The shaly unit wedges out within a few miles southward; as a result, the subsurface Cliff House Sandstone at and beneath the surface in the western part of the Reservation may be presumed to be predominantly sandstone. The total thickness is about 400 feet, but some of this has been eroded where the formation is at the surface. The Cliff House Sandstone interfingers laterally and vertically with the overlying marine Lewis Shale and with the underlying deltaic deposits of the upper member of the Menefee Formation.

The Late Cretaceous Lewis Shale is a marine shale that was deposited in late Campanian time (Figs. SU-6, SU-7). It consists primarily of light-to dark-gray and black shale with interbeds of fine-grained sandstone, limestone, calcareous concretions, and bentonite. It crops out on the west side of the Reservation in a northeast-trending band marked by Long Hollow, and on the east side in a wide sinuous zone that trends northwest from Archuleta Mesa. Thickness of the Lewis ranges from 1,440 to 1,825 feet on the west side if the Reservation, and increases eastward to about 2,400 feet on the east side.

The Late Cretaceous Pictured Cliffs Sandstone was deposited during the final regression of the epeiric Cretaceous sea during Campanian time (Figs SU-6, SU-7). It forms a hogback from Cinder Buttes to Bridge Timber Mountain on the west side of the Reservation, and on the east side forms the lower part of the steep northeast-facing slopes that extend form Archuleta Mesa to the Piedra River. In its western exposures the formation is from about 215 feet to 285 feet thick. The Pictured Cliffs is divided into an upper part that consists of one or more massive sandstone beds interbedded with some thin shale beds and a lower transitional zone composed of relatively thin intercalations of sandstone and shale. The lower transitional zone consists of thin, grayish-orange and light-olive-gray, very fine grained sandstone, interbedded with subordinate amounts of gray shale and siltstone. The upper part is composed primarily of dark-yellowish-orange and light-gray, medium- to thick-bedded, ledge-forming sandstone. The formation thins eastward to 90 feet on Klutter Mountain just east of the Reservation, but the general lithology remains the same. The contact with the overlying Fruitland Formation is conformable, with local intertonguing.

The Late Cretaceous Fruitland Formation is a sequence of interbedded and locally carbonaceous sandstones, siltstones, shales, coal and locally in the lower part of the formation, thin limestone beds. The lithology of the formation is characterized by lateral discontinuity, most individual beds pinching out within a few hundreds of feet. The coal beds, are more continuous and may be traced for several miles. Although coal beds occur throughout the formation, the thickest and most persistent beds are in its lower part. The limestone beds are found only in the lowermost part of the formation, sandstone is usually more abundant in the lower part than in the upper part, and siltstone and shale predominate the upper part. The formation ranges form about 300 to 500 feet thick on the west side of the Reservation, but thins eastward to about 300 feet in its outcrop area on the east side. The contact with the Kirtland is gradational, and most geologists place the top at the highest bed of coal or carbonaceous shale.

The Late Cretaceous Kirtland Shale is divided into a lower shale member, a middle sandstone unit called the Farmington Sandstone Member, and an upper shale member. In the western part of the Reservation, the lower shale member consists of olive- to medium-gray sandy shale that commonly contains lenses of nonresistant olive-gray, fine grained sandstone. The lower member also contains thin lenses of carbonaceous shale and abundant amounts of silicified wood at various horizons. The Farmington Member on the western part of the Reservation is a sequence of resistant sandstones that are separated by beds of shale. The upper shale member on the western part of the Reservation consists of shale and interbedded lenses of nonresistant, friable sandstone. The age of the Kirtland is Late Cretaceous (Campanian to Maastrichtian). The contact between the Kirtland Shale and the Animas Formation, which overlies it on most of the Reservation, is transitional and arbitrary.

Cretaceous and Tertiary Systems

Immediately overlying the Kirtland shale over most of the Reservation is the Animas Formation. It ranges in age form Late Cretaceous-Early Paleocene but in the southeastern part of the Reservation it is only Paleocene. The Animas Formation crops out in a band of variable width forming an east-west arc across the Reservation. The Animas is characterized by conglomerate beds, containing boulders and pebbles of andesite in a tuffaceous matrix. Interbedded with variegated shale and sandstone. On the west side of the Reservation the McDermott Member (Late Cretaceous) has a maximum thickness of 290 feet, which thins to the south and east. The upper member (Paleocene) has a maximum of 2,670 feet near the La Plata-Archuleta County line (north of the Reservation), and thins to 1,840 feet on Cat Creek.

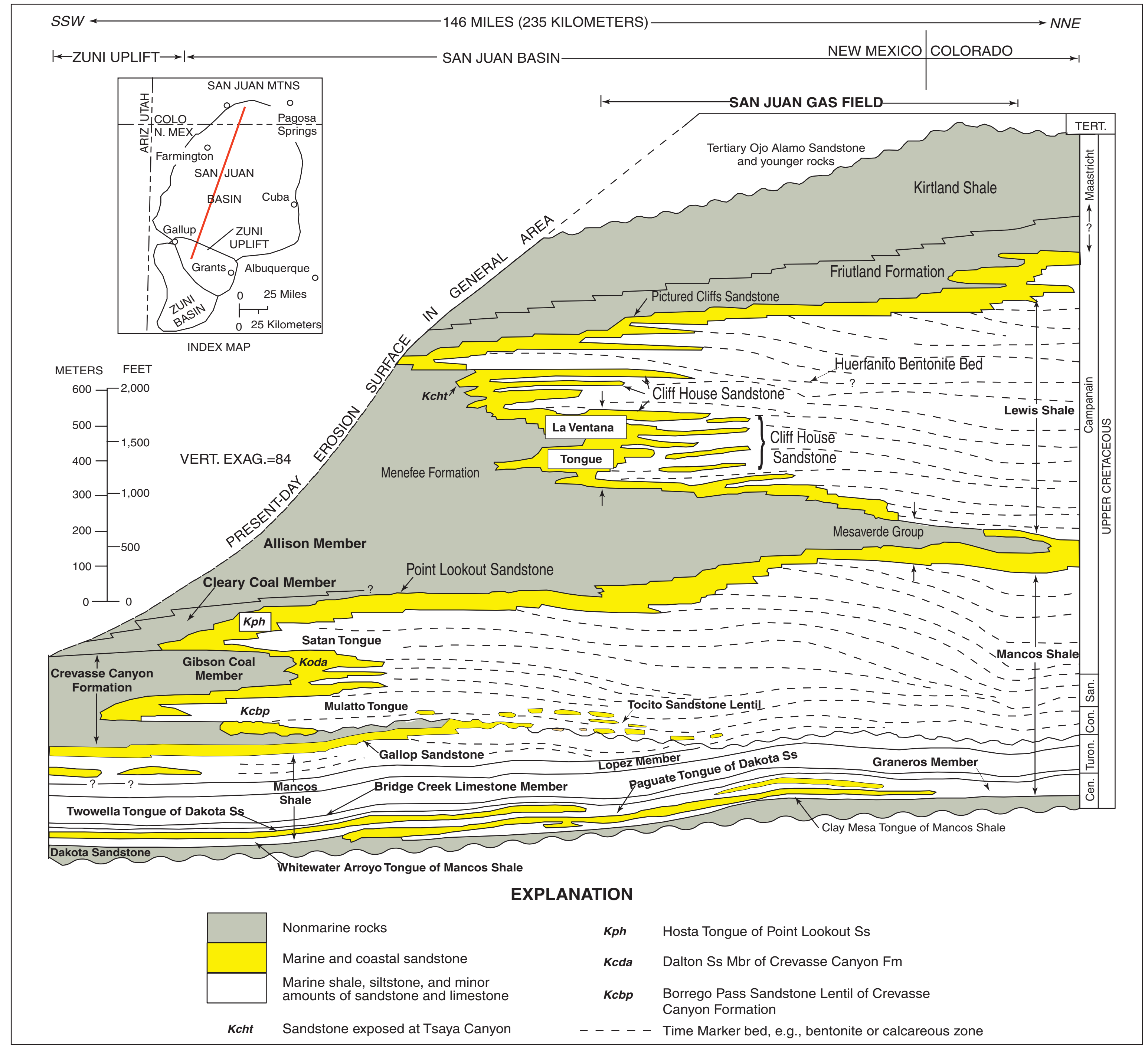


Figure SU-7. Stratigraphic cross section showing upper Cretaceous rocks across the San Juan Basin, New Mexico and Colorado (modified after Nummedal and Molenaar, 1995).

Production Overview

Oil and gas production in the San Juan Basin was described in the "*1995 National Assessment of United States Oil and Gas Resources*" (Gautier, D.L., et al., 1996). All plays discussed in the "Play Summary Overview" are defined by that publication. The "Play Summary Overview" combines the research from that publication along with other recent publications in the Southern Ute Indian Reservation. The following is a summary of the San Juan Basin Province as described in "1995 National Assessment of United States Oil and Gas Resources"

San Juan Basin Province

The San Juan Basin province incorporates much of the area from latitude 35˚ to 38˚ N. and from longitude 106˚ to 109˚ W. and comprises all or parts of four counties in northwest New Mexico and six counties in southwestern Colorado (Huffman, 1996). It covers an area of about 22,000 sq mi (Fig. SU-8).

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 with connections to source beds. In the central part of the basin, porosity, permeability, stratigraphy, and subsurface hydrodynamics 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, hydrocarbons commonly accumulate only in highly porous limestone buildups. Jurassic oil on the southern margin of the basin is stratigraphically trapped in eolian strata 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; similarly, Permian–Pennsylvanian Marginal Clastics Gas Play (2203) is assessed as part of play 2104 in the Paradox Basin, so is not discussed further here.

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). The plays of interest to the Southern Ute Indian Reservation are described in the "Play Summary Overview".

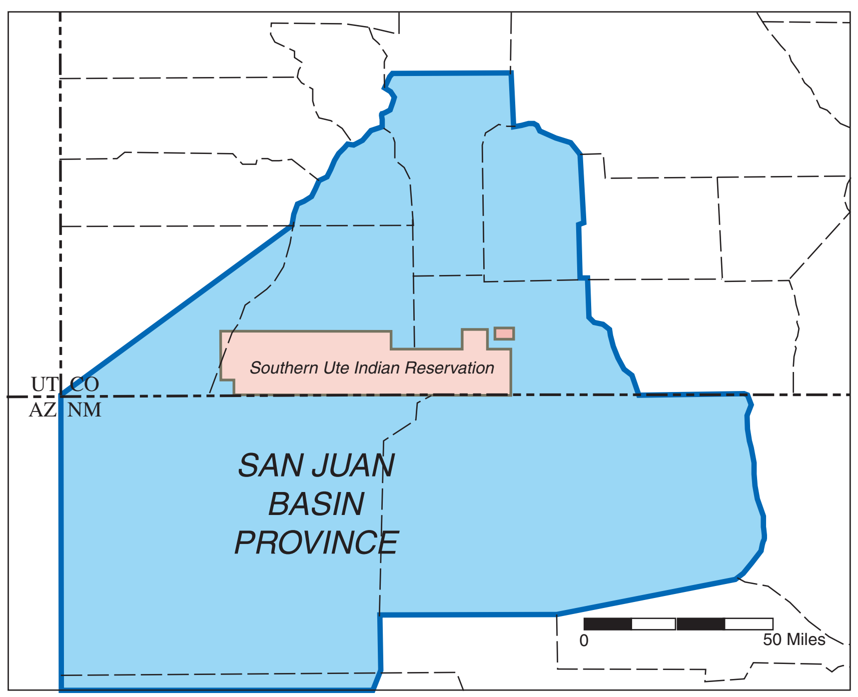


Figure SU-8. Location of U.S.G.S. San Juan Basin Province with respect to the Southern Ute Indian Reservation (modified after Gautier et al., 1996).

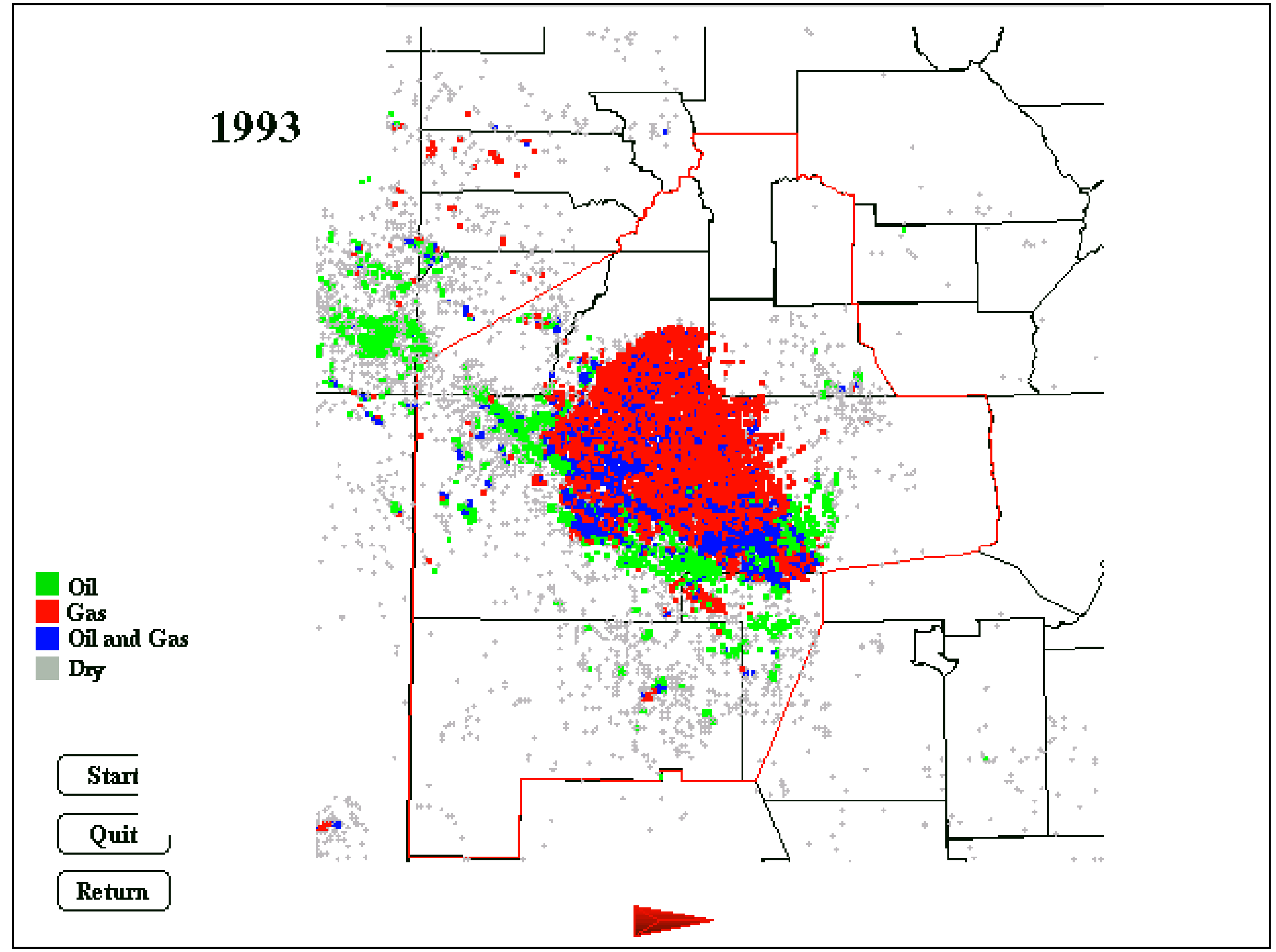


Figure SU-9. Locations of oil and gas production wells, cumulative through 1993 (modified after Gautier et al., 1996).

Summary of Plays

The United States Geological Survey identifies several petroleum plays in the San Juan Basin Province and classifies them as Conventional or Unconventional. The discussions that follow are limited to those with direct significance for future petroleum development in the Southern Ute Indian Reservation.

Play Types

Conventional Plays- Discrete Deposits, usually bounded by a downdip water contact, from which oil, gas or NGL can be extracted using traditional development practices, including production at the surface from a well as a consequence of natural pressure within the subsurface reservoir, artificial lifting of oil from the reservoir to the surface where applicable, and the maintenance of reservoir pressure by means of water or gas injection

Unconventional Plays- A broad class of hydrocarbon deposits of a type (such as gas in "tight" sandstones, gas shales, and coal-bed gas) that historically has not been produced using traditional development practices. Such accumulations include most continuous-type deposits.

Reservation: Southern Ute
Geologic Province: Paradox & San Juan Basin
Province Area: Paradox Basin (33,000 sq. miles) San Juan Basin (22,000 sq. miles)
Reservation Area: 553,008 acres

Total Production

San Juan Basin Cumulative Totals
Oil: >240,000,000 BO
Gas: >18,000,000,000 CFG
NGL: Included
(figures from NMOGA, 1997 & FCGS, 1983)

Undiscovered resources and numbers of fields are for Province-wide plays. No attempt has been made to estimate number of undiscovered fields within the Southern Ute Indian Reservation.

Play Type	USGS Designation	Description of Play	Oil or Gas	Known Accumulations	Undiscovered Resource (MMBOE) Field Size (> 1 MMBOE) median, mean	Play Probability (chance of success)	Drilling depths (feet)
1 Porous Carbonate Buildup Play	2102,2201	Mounds of algal limestone in the Paradox Formation of the Hermosa group.	Both	Gas (448,740 MMCFG) Oil (521,090 MBO)	Gas (10 BCFG, 131 BCFG) Oil (4 MMBO, 6.3 MMBO)	1.0	Gas (4000, 6000, 14000) Oil (2500, 6000, 14000)
2 Entrada Play	2204	Associated with relict dune deposits on top of the Jurassic Entrada Sandstone.	Oil	Oil (4,360 MBO)	Oil (2 MMBO, 1.8 MMBO)	1.0	Oil (3000, 6000, 9000)
3 Basin Margin Dakota Oil Play	2206	Mostly upper marine part of the Dakota sandstone.	Both	Gas (62,100 MMCFG) Oil (22,589 MBO)	Gas (10 BCFG, 12.1 BCFG) Oil (2 MMB0, 2.8 MMBO)	1.0	Gas (1000, 2000, 2000) Oil (600, 2000, 5000)
4 Tocito-Gallup Sandstone Oil Play	2207	Lenticular sandstone bodies of Upper Cretaceous Tocito and Gallup Sandstones.	Both	Gas (199,800 MMCFG) Oil (174,135 MBO)	Gas (30 BCFG, 38.0 BCFG) Oil (4 MMBO, 6.3 MMBO)	1.0	Gas (4000, 6000, 8000) Oil (1000, 5000, 8000)
5 Basin Margin Mesa Verde Oil Play	2210	Intertonguing of porous marine sandstone at base of the Upper Cretaceous Point Lookout Sandstone with the organic rich upper Mancos Shale.	Oil	Gas (7.8 BCFG, estimated mean) Oil (7.8 MMBO, estimated mean)	Oil (2 MMBO, 1.9 MMCO)	0.8	Oil (300, 2000, 4000)
6 Fruitland-Kirtland Fluvial Sandstone Gas Play	2212	Lenticular fluvial sandstone bodies enclosed in shale source rocks and (or) coal.	Gas	Gas (1,505,520 MMCFG)	Gas (18 BCFG, 23.2 BCFG)	1.0	Gas (1000, 2000, 4000)

Table 1. Play summary chart.

Reservation: Southern Ute
Geologic Province: Paradox & San Juan Basin
Province Area: Paradox Basin (33,000 sq. miles) San Juan Basin (22,000 sq. miles)
Reservation Area: 553,008 acres

Total Production

San Juan Basin Cumulative Totals
Oil: >240,000,000 BO
Gas: >18,000,000,000 CFG
NGL: Included
(figures from NMOGA, 1997 & FCGS, 1983)

Undiscovered resources and numbers of fields are for Province-wide plays. No attempt has been made to estimate number of undiscovered fields within the Southern Ute Indian Reservation

Play Type	USGS Designation	Description of Play	Oil or Gas	Known Accumulations	Undiscovered Resource (MMBOE) Field Size (> 1 MMBOE) median, mean	Play Probability (chance of success)	Drilling depths (feet)		
7 Dakota Central Basin Gas Play	2205	Coastal marine barrier-bar sandstone and continental fluvial sandstone units, primarily within the transgressive Dakota Sandstone.	Gas	Gas (8211.28 BCFG) (estimated mean)	N / A	1.0	Gas (5000, 6900, 8000)		
8 Mancos Fractured Shale Play	2208	Fractured organic rich marine Mancos Shale.	Oil	Gas (94.42 BCFG) (estimated mean) Oil (188.85 MMBO) (estimated mean)	N / A	1.0	Oil (1000, 3000, 7000)		
9 Central Basin Mesaverde Gas Play	2209	Sandstone buildups associated with stratigraphic rises in the Upper Cretaeous Point Lookout and Cliff House Sandstones.	Gas	Gas (7,000 BCFG)	N / A	1.0	Gas (1000, 2600, 5000)		
10 Pictured Cliffs Gas Play	2211	Sandstone reservoirs enclosed in shale or coal at the top of the Pictured Cliffs Sandstone.	Gas	Gas (3264.04 BCFG) (estimated mean)	N / A	1.0	Gas (1000, 2100, 3600)		
11 Coal Bed Gas Play: Overpressured Play	2250	North-Central part of the basin and north of the structural hingeline where recharge of fresh water takes place.	Gas	Gas (4165.41 BCFG) (estimated mean)	N / A	1.0	Gas (500, 2809, 4200)		
12 Coal Bed Gas Play: Underpressured Discharge Play	2252	South of the structural hingeline of the basin where coal beds are underpressured.	Gas	Gas (2143.84 BCFG) (estimated mean)	N / A	1.0	Gas (500, 1402, 4000)		
13 Coal Bed Gas Play: Underpressured Play	2253	Eastern part of the basin where ground water flow is sluggish.	Gas	Gas (1223.78 BCFG) (estimated mean)	N / A	1.0	Gas (500, 2446, 4000)		

Table 2. Play summary chart - *continued*

Two logs were chosen to represent the stratigraphy of the Southern Ute Indian Reservation. Their locations are marked on the figure below. Together they represent the stratigraphy from Devonian - Tertiary. The logs show the SP/Gamma and Resistivity profile of their respective rock units.

Well #1 **ARCO S. Ute 33-11 No. 10-1**
Sec 10, T33N, R11W
(Molenaar, C.M., and Baird, J.K., 1989)

Well #2 **GENERAL PETROLEUM CORP. No. 55-17 Kikel**
Sec 17, T34N, R11W,
(Condon, S.M., and Huffman, A.C., 1994)

EXPLANATION

unconformity

depositional contact

0
300
600 feet

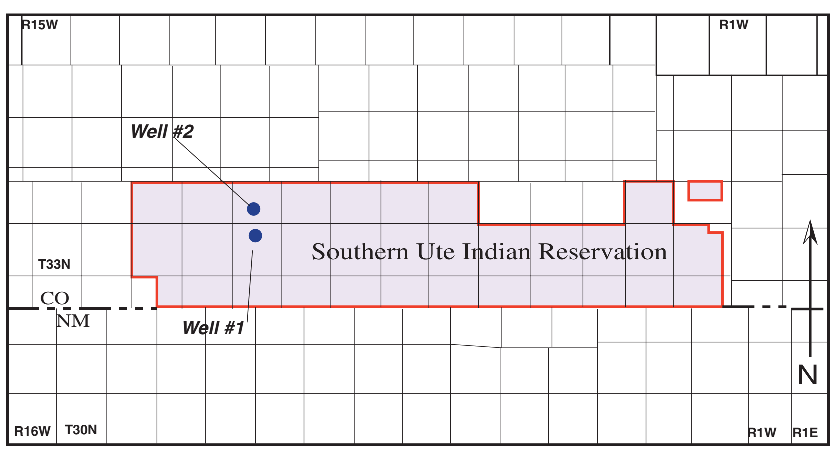
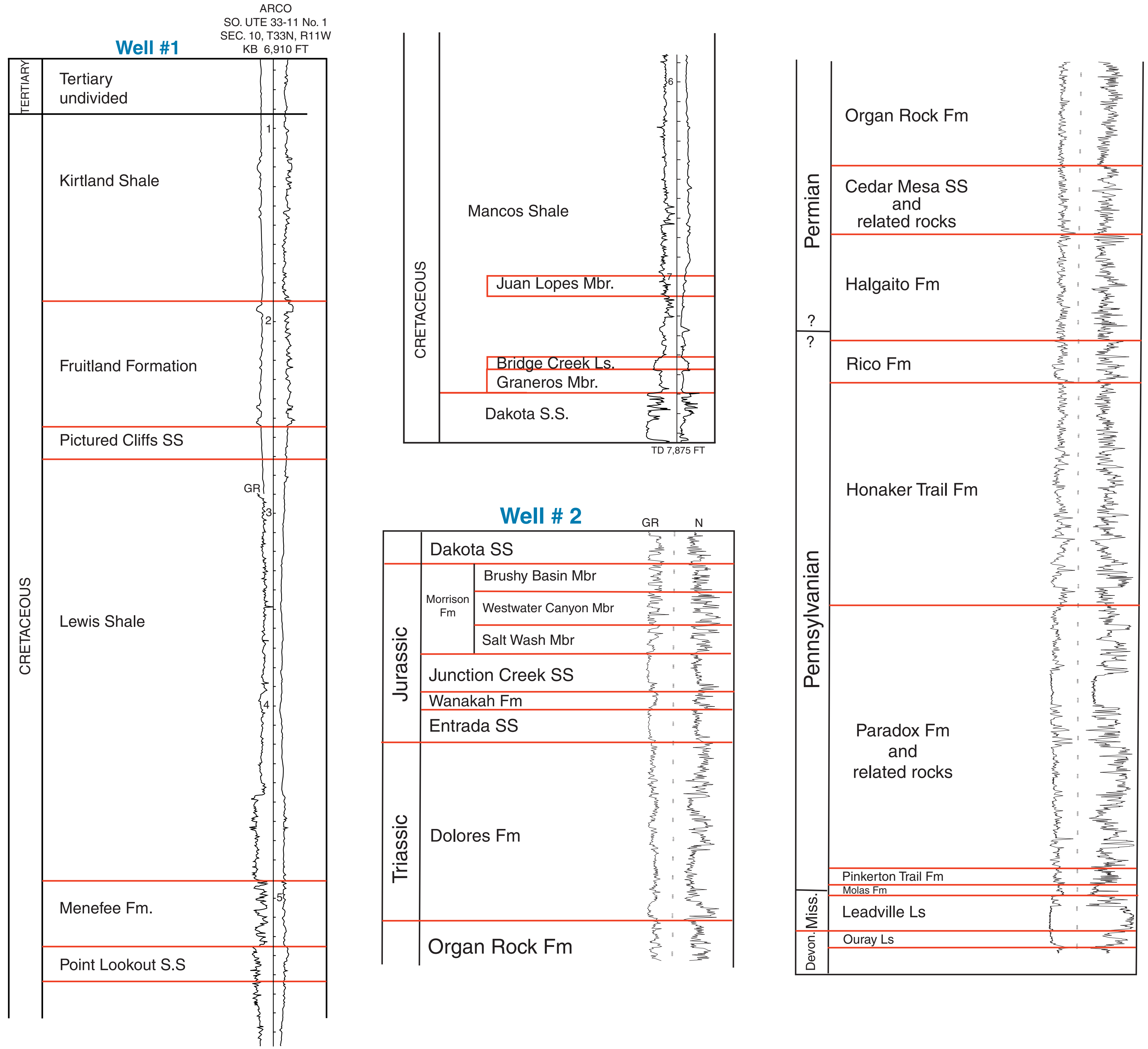


Fig. SU-10 Location of Type Logs in Southern Ute Indian Reservation.



Porous Carbonate Buildup Play

(USGS 2201)

General Characteristics

The 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. 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.

Characteristics of the Porous Carbonate Buildup Play

In the Southern Ute Indian Reservation, the Paradox Formation is conformably bounded by the Pinkerton Trail Formation at its base and the Honaker Trail Formation at its top (Fig. SU-3). It ranges from 800 feet thick in the south to 1700 feet thick in the north. The Paradox Formation was deposited during Desmoinesian age of the Pennsylvanian Period under strong cyclic conditions involving transgressive and regressive movements of the Pennsylvanian sea. The transgressive phase is represented by black organic rich dolomitic muds while the regressive phase is represented by carbonate mounds. Reservoirs within the reservation are biogenic/bioclastic carbonate mounds deposited in shoaling areas of an evaporite basin. The four main cycles of Desmoinesian deposition are the Barker Creek, Akah, Desert Creek, and Ismay Stages (Fig. SU-10).

Barker Creek Stage strata have a gross thickness of 500 feet. It is a fossiliferous, algal, dolomitic limestone with vuggy, secondary dolomite. Most reservoir rock is algal, dolomitic limestone with enhanced porosity and permeability due to dolomitization and weathering. The Barker Creek was deposited on paleostructural features related to the Hogback lineament.

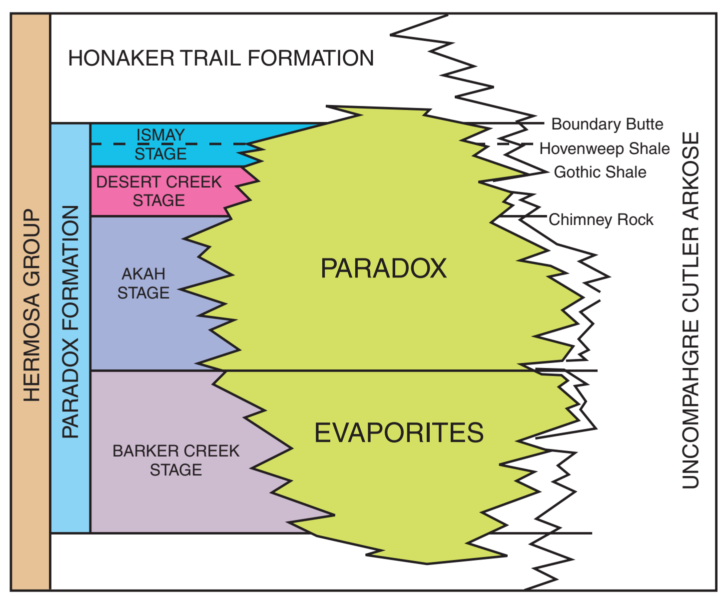


Figure SU-10. Stratigraphic chart of the Pennsylvanian Hermosa Group illustrating the Paradox Formation facies changes across the basin. Each stage is bounded by a time stratigraphic marker bed of sapropelic, dolomitic mudstone. These markers are continuous and mappable throughout the basin (modified after Harr, 1996).

Akah Stage rocks are not considered to be an exploration objective within the reservation because salt and anhydrite deposition was dominate at this time. The Akah Stage represents the maximum extent of evaporite limits (Fig. SU-10).

Desert Creek Stage carbonates were deposited in a definable arcuate trend around the southeast terminus of the basin. The Desert Creek is bounded by the Chimney Rock and Gothic Shales which represent transgressions. Growth of the Desert Creek carbonate bank occurred during slow subsidence of the Paradox Basin. Source rocks for hydrocarbons are the Chimney Rock and Gothic Shales (Fig. SU-10).

The Ismay Stage is divided into lower and upper units. The lower unit is bounded by the Gothic and Hovenweep Shales (Fig. SU-10). During the Ismay Stage the southern part of the basin was slowly subsiding. Oil is produced from algal carbonate buildups. The upper unit is bounded by the Hovenweep and Boundary Butte Shales (Fig. SU-10). Production is from algal or bioclastic/biogenic reservoirs. The source rocks for Ismay rocks are the Gothic, Hovenweep, and Boundary Butte Shales.

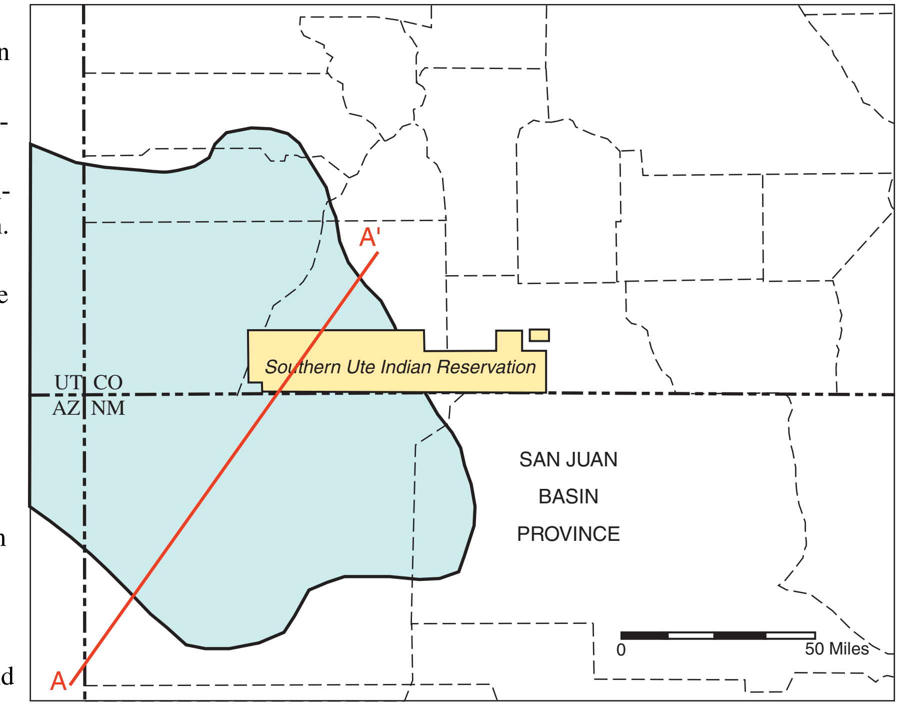


Figure SU-11. Location of the Porous Carbonate Buildup Play (modified after Gautier et al., 1996).

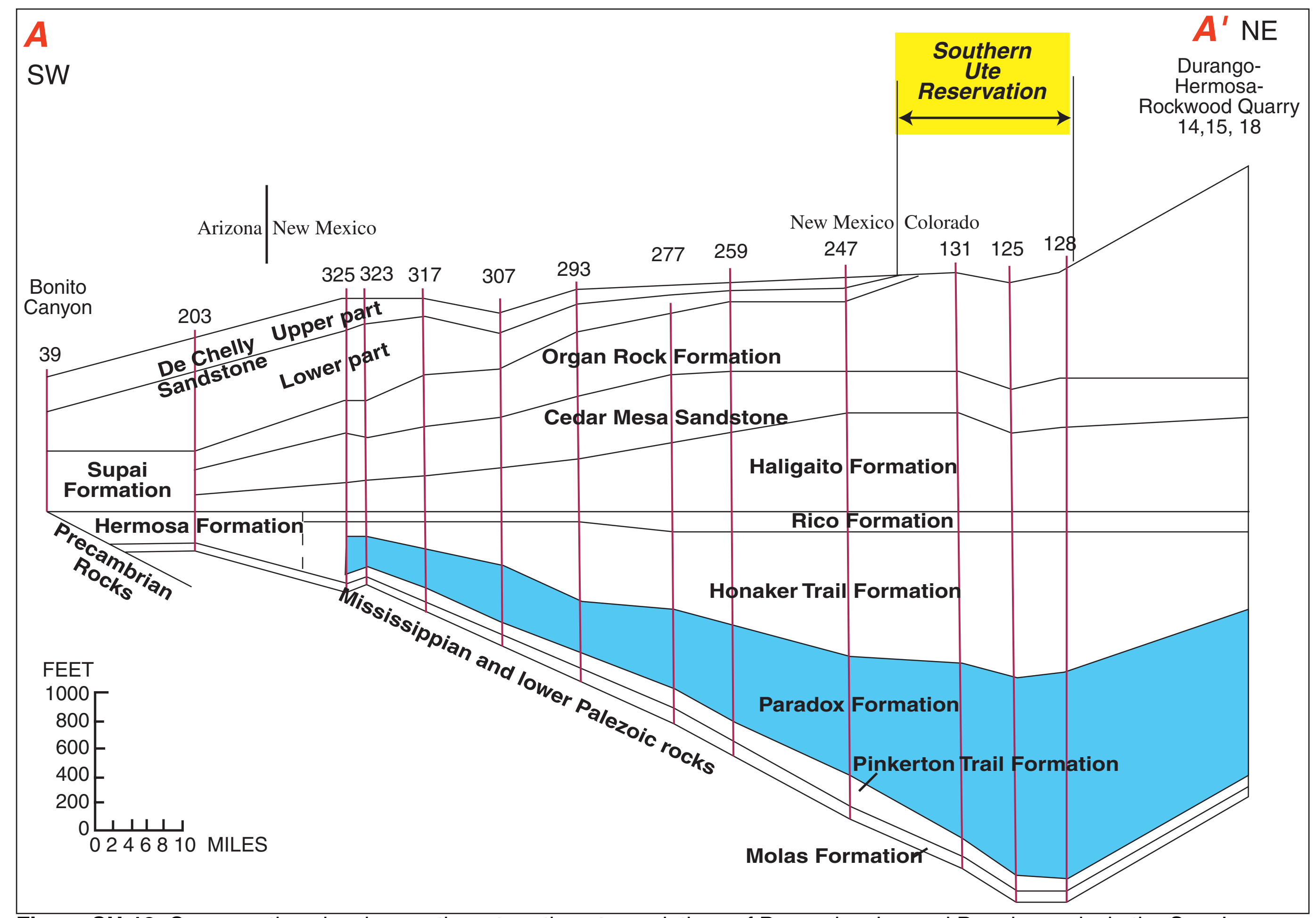


Figure SU-12. Cross section showing southwest-northeast correlations of Pennsylvanian and Permian rocks in the San Juan Basin and adjacent areas. Line of section is shown in Figure SU-11 (modified after Condon, 1992).

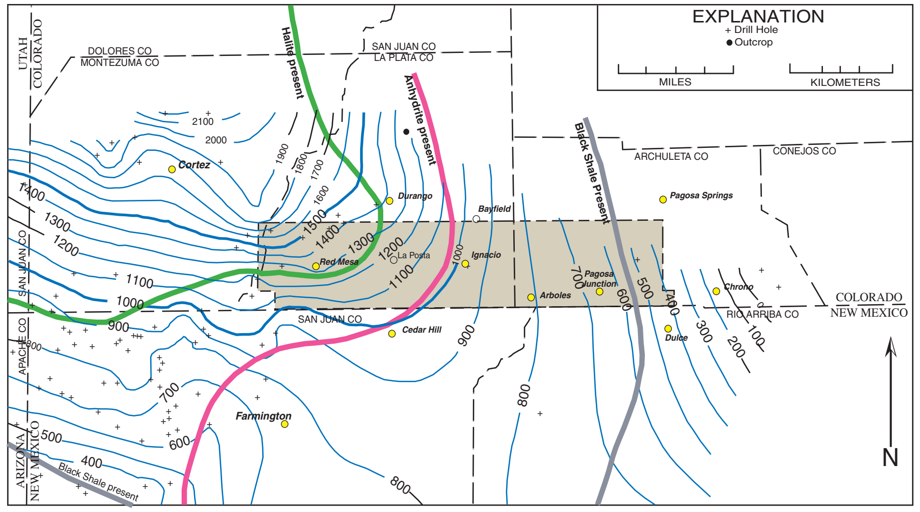


Figure SU-13. Isopach map of the Paradox Formation and equivalent rocks of the Hermosa Group. Contour interval is 100 feet (modified after Condon, 1992).

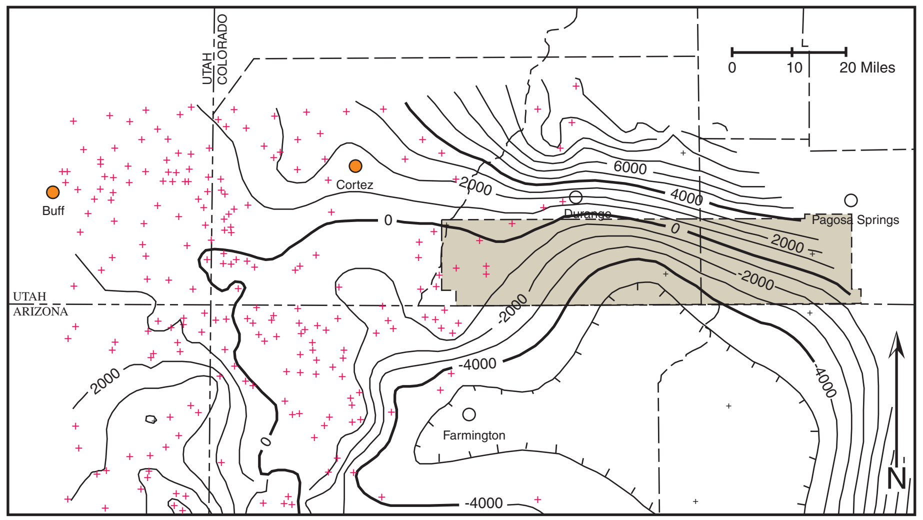


Figure SU-14. Structure contour map of the top of the Rico Formation. Contour interval is 1000 feet (modified after Huffman and Condon, 1993).

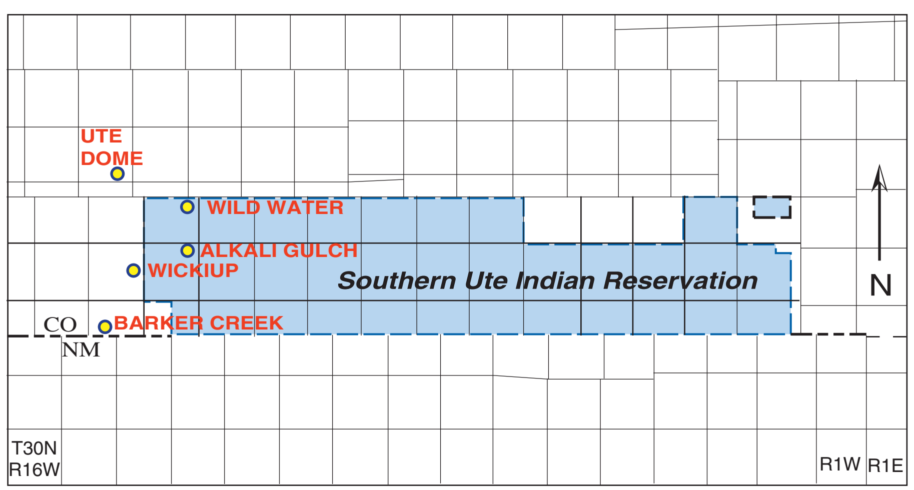


Figure SU-15. Location of oil and gas field discovery wells for fields producing from the Porous Carbonate Buildup Play.

Analog Fields In and Near Reservation

(*) denotes field lies within the reservation boundaries

* Wildwater

(see Figure SU-16)

Location of discovery well:	ne, sw, sec 2, T34N, R13W (1974)
Producing formation:	Paradox Formation
Type of trap:	Structure-Stratigraphic
Number of producing wells:	1 (1977)
Initial production:	1040 MCFGD
Cumulative Production:	N/A
Gas characteristics:	BTU 1,165
Oil characteristics:	63˚ API gravity, light, yellowish green
Type of drive:	Gas expansion
Average net pay:	13 feet
Porosity:	6.6 %
Permeability:	N/A

* Alkali Gulch West

Location of discovery well:	c, new,sw, sec 2, T33N, R13W (1981)
Producing formation:	Ismay Zone of the Paradox Formation
Type of trap:	Stratigraphic
Number of producing wells:	1 (1992)
Initial production:	1.152 MCFGD, 6BWD
Cumulative Production:	369,633 MCFG, 423 B condensate (1992)
Gas characteristics:	97.75% methane, 1.23 % ethane, 0.32 % propane
Type of drive:	Gas expansion
Average net pay:	66 feet
Porosity:	8%
Permeability:	N/A

Wickiup

Location of discovery well:	sw se sec 24, T33N, R14W (1972)
Producing formation:	Barker Creek Zone of the Paradox Formation
Type of trap:	Stratigraphic
Number of producing wells:	1 (1977)
Initial production:	1,970 MCFGD, 842 BWD
Cumulative Production:	20,603 MCFG (1982)
Gas characteristics:	BTU 914
Type of drive:	Gas expansion
Average net pay:	10 feet
Porosity:	8%
Permeability:	N/A

Barker Creek

Location of discovery well:	se, se, nw, sec 21, T32N, R14W (1945)
Producing formation:	Paradox Formation
Type of trap:	Structural
Number of producing wells:	5 (1977)
Initial production:	42,000 MCFGD
Cumulative Production:	115,237,890 MCFG, 109,462, B condensate (1994)
Gas characteristics:	BTU 1,026 sweet gas, BTU 875 sour gas
Type of drive:	Solution gas, fluid expansion
Average net pay:	± 100 feet (individual pay zones range 10-80 ft)
Porosity:	2-10 % (vugs and fractures)
Permeability:	extremely variable due to vugs and fractures)

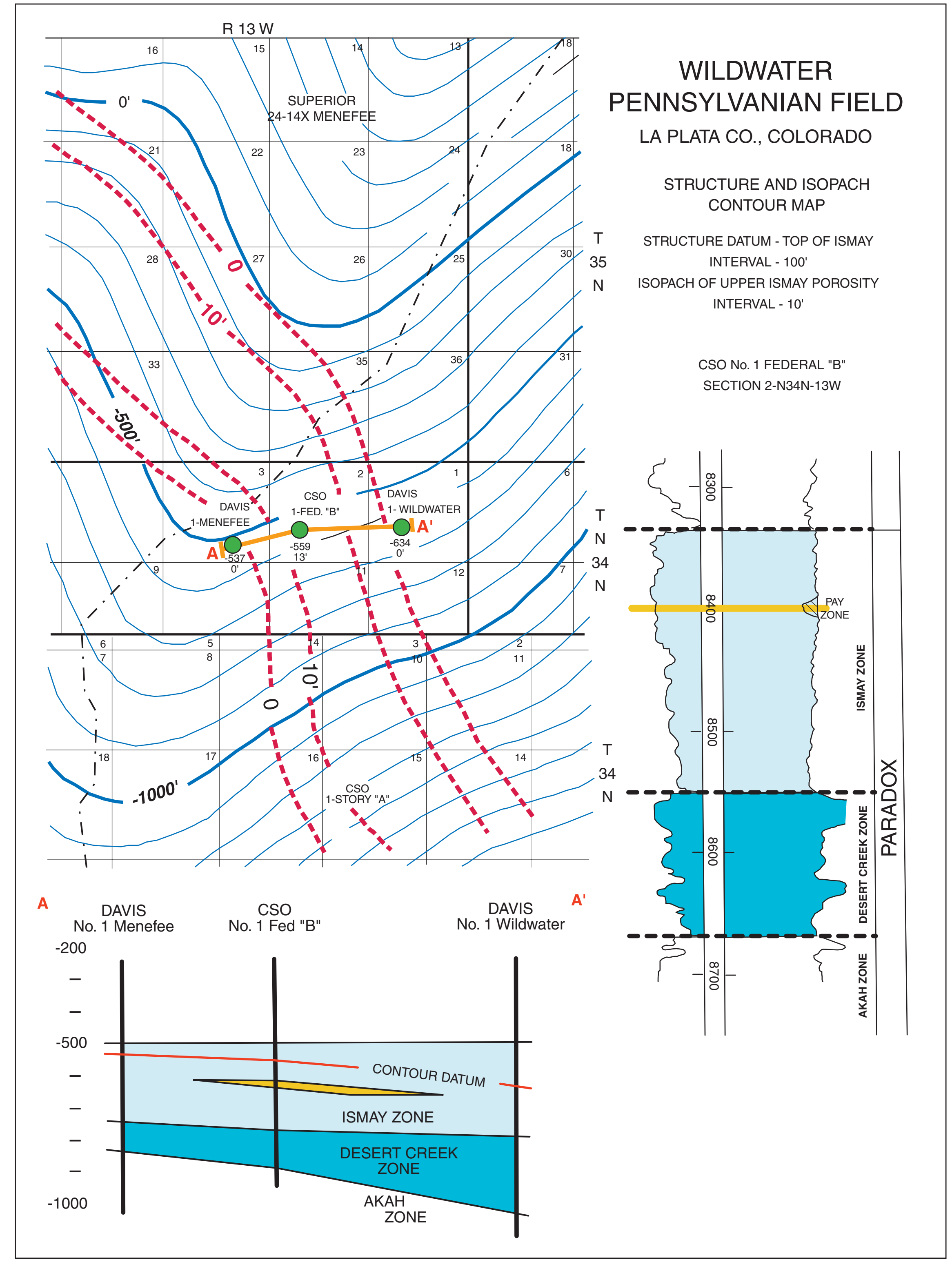


Figure SU-16. Structure contour map, structural cross section, and type log from the Wildwater Pennsylvanian field (modified after Bevacqua, 1983).

Entrada Play

(USGS 2204)

General Characteristics

The Entrada play in the southeastern part of the San Juan Basin, is based on relict dune topography on top of the eolian Middle Jurassic Entrada Sandstone, associated with 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. 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 cross-bedding in the lower part. Porosity (23 percent average) and permeability (370 md 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. There is a reported correlation between the presence of organic material in the Todilto Limestone and the presence of the overlying Todilto anhydrite. This association limits the source rock potential of the Todilto to the deeper parts of 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 have 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 (Gautier, et al, 1996). 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

Characteristics of the Entrada Play

The Entrada Play does not yet produce in the Southern Ute Indian Reservation. The Entrada Sandstone and Wanakah Formation are present in the subsurface of the Reservation (Figs. SU-19 & -20).

The Entrada Formation is composed of two members, the Dewey Bridge Member and the Slick Rock Member (Condon, 1992). The Dewey Bridge member is 25-35 feet thick in the western side of the Reservation; it pinches out eastward. The Dewey Bridge Member is composed of brick-red to reddish-brown, very fine grained, argillaceous sandstone and siltstone. The sediments of the Dewey Bridge were deposited in a sabkah environment that bordered the Jurassic sea, which was present to the north and west of Colorado. The Slick Rock Member consists of white, pinkish-orange, and reddish-orange, very fine to fine grained, locally medium grained sandstone. Bedding is medium to thick with alternating cosets of cross bedded and flat-bedded strata. The Slick Rock averages 70-100 feet in thickness in the subsurface of the Reservation. The sediments of the Slick Rock were deposited in an extensive area of eolian dunes and interdunes that bordered the Jurassic sea.

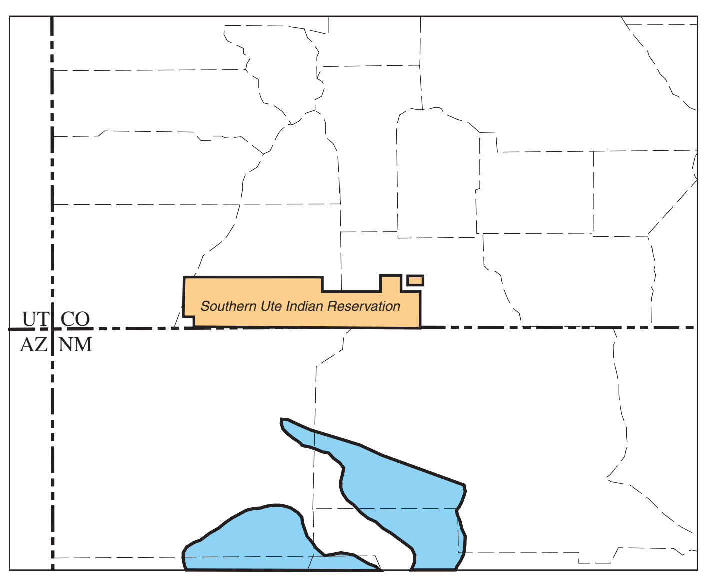


Figure SU-17. Location of the Entrada Play (modified after Gautier, Dolton, Takahashi, and Varnes, 1996).

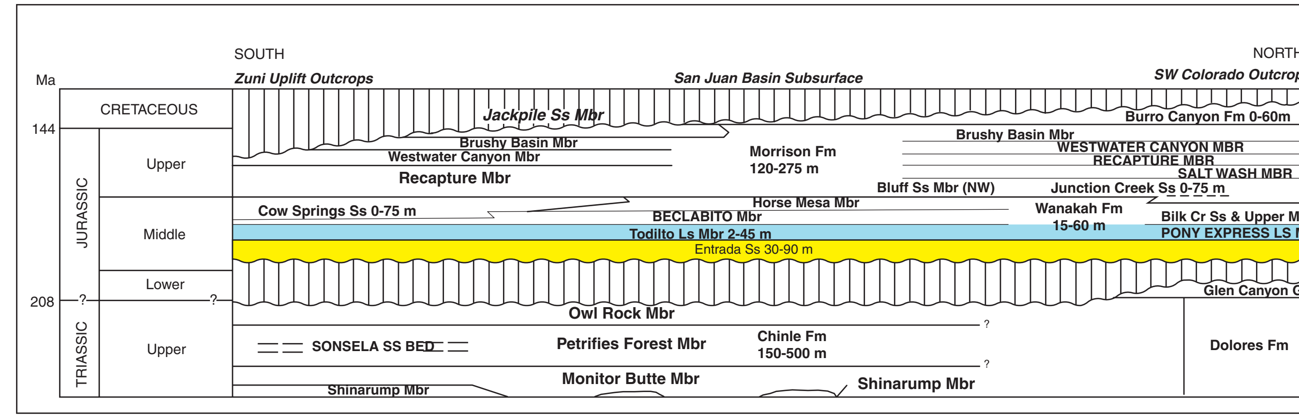


Figure SU-18. Time-stratigraphic chart of stratigraphic units on the Southern Ute Indian Reservation and adjacent areas (modified after Condon, 1992).

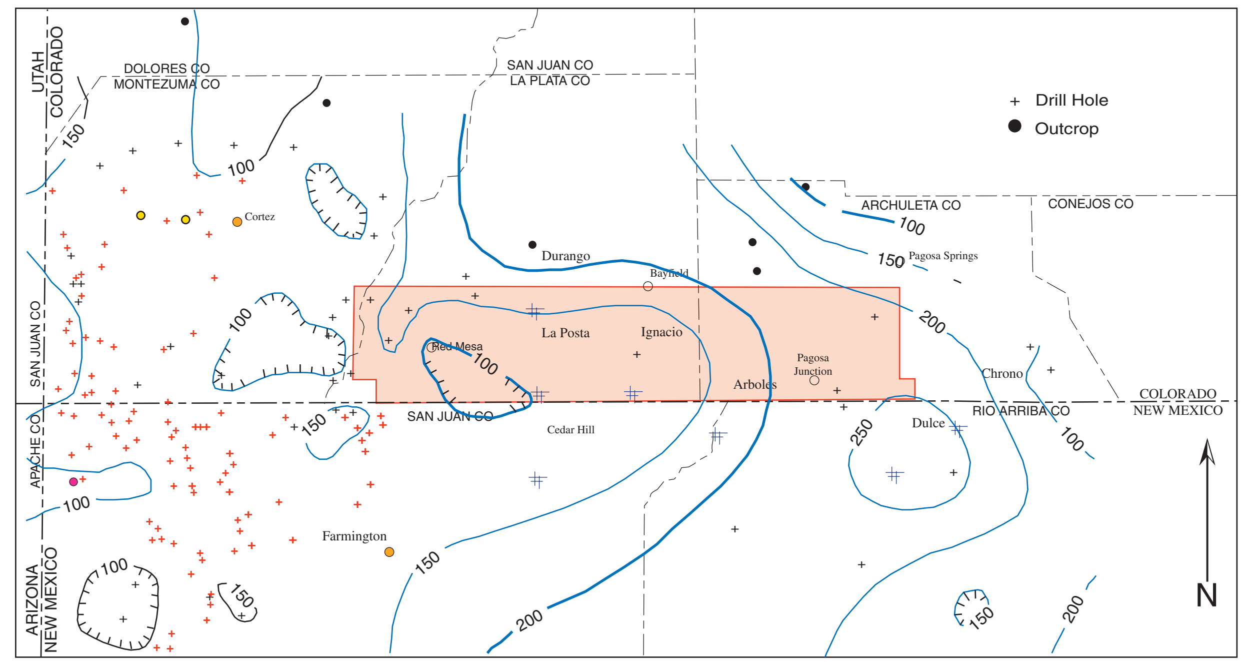


Figure SU-19. Isopach map of the Entrada Sandstone. Contour interval is 50 feet (modified after Condon, 1992).

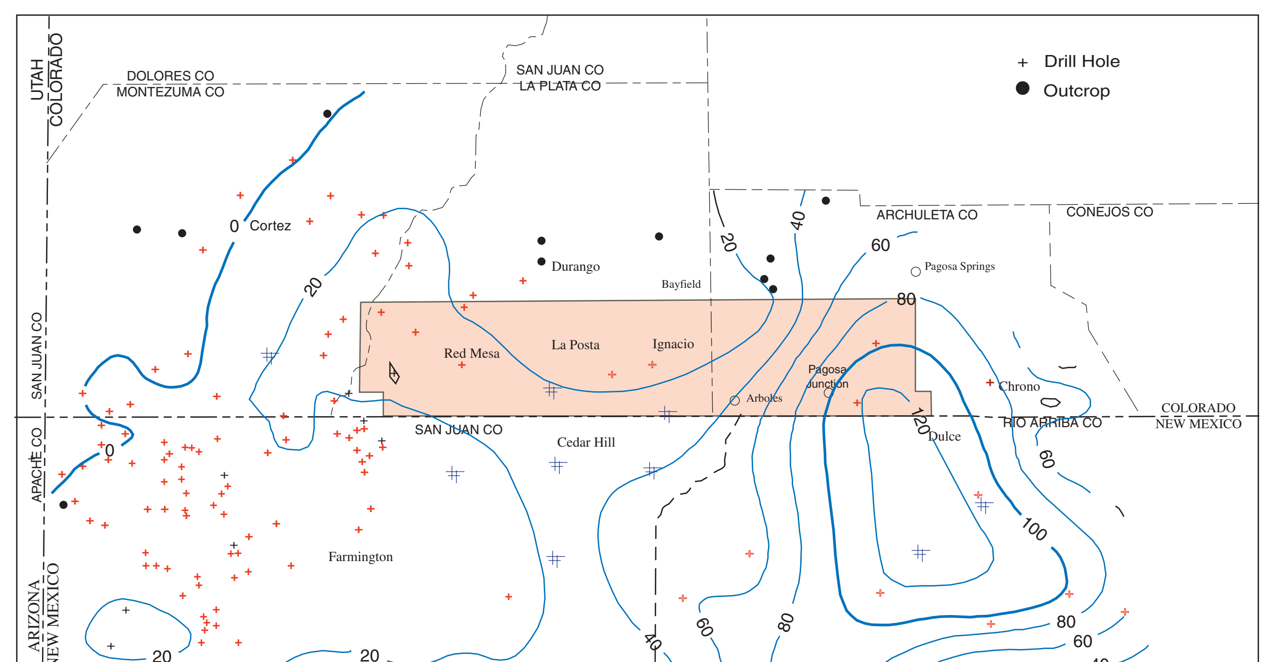


Figure SU-20. Isopach map of the Todilto Limestone Member of the Wanakah Formation and Equivalent rocks. Contour interval is 20 feet (modified after Condon, 1992).

Basin Margin Dakota Oil Play

(USGS 2206)

General Characteristics

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 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 are as high as 400 md.

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 44˚ to 59˚. On the Four Corners Platform to the west, nonmarine source rocks of the Menefee Formation were identified as the source. 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 Oligocene to Miocene. In the southern part of the area, migration was still taking place in the late Miocene time 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.

The Basin Margin Dakota Oil Play

The Dakota Sandstone is a coastal plain deposit laid down in front of the advancing Mancos Sea. The oldest unit of the Dakota Sandstone on the Southern Ute Indian Reservation is the lower Cenomanian Encinal Canyon Member (Fig. SU-24). It consists of alluvial deposits that fill the valleys at the sub-Dakota unconformity. It was deposited by aggradation of Dakota streams in response to rising base level during the earliest stages of the T-1 transgression.

The Encinal Canyon Member is characteristically a trough-cross bedded, fine- to medium-grained sandstone that is commonly conglomeratic at its base. Tabular-planar crossbeds and, more rarely, horizontal or low-angle laminations also occur at some locations. The Encinal Canyon member is overlain by delta-plain deposits in the Four Corners and Durango areas, by shore-zone deposits in the Coldwater Creek and Durango areas (north of the Reservation on the eastern side), and by marine deposits in northwestern New Mexico.

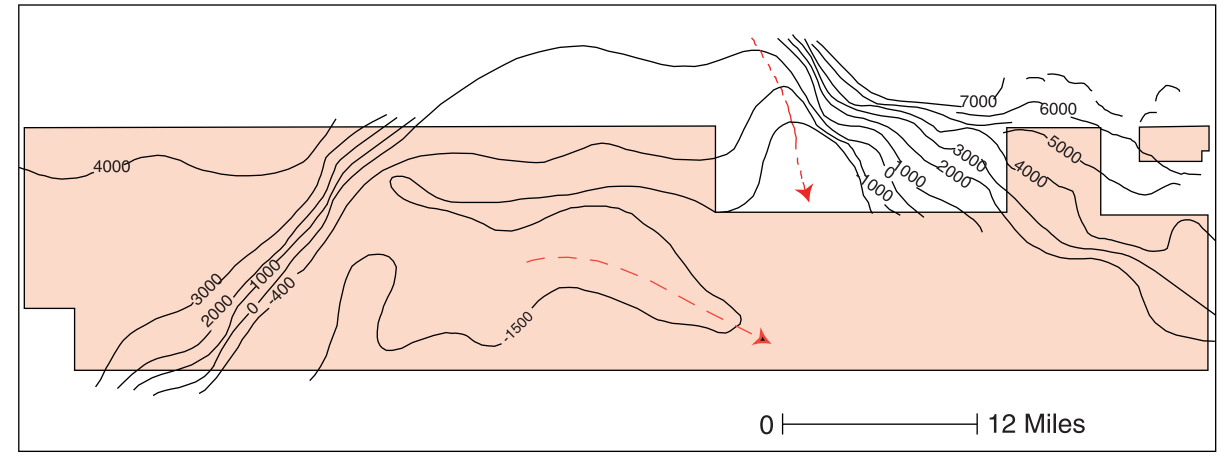


Figure SU-21. Structure contour map of the base of the Dakota Sandstone in the Southern Ute Indian Reservation. Contour interval is 1000 feet except for -1500 foot contour. Southeastern part of the Reservation has no data (modified after Andersen, 1992).

This distribution of depositional environments is consistent with shoreline trends (Fig.25). North-south shoreline trends suggest that depositional environments in the subsurface on the Reservation are similar to those in the Durango and Coldwater Creek areas north of the Reservation.

The shore-zone deposits that overly the Encinal Canyon Member in the Coldwater Creek and Durango areas are composed of fine grained, bioturbated, and flat-bedded or ripple-laminated sandstone probably deposited in tidal-flat, shoreface, or offshore-bar environments. Coal may have been deposited in coastal swamps, and siltstone and mudstone may represent lagoonal or offshore environments. Deltaic rocks on the western part of the Reservation and shore-zone rocks in the eastern part are probably lateral equivalents, deposited during a stillstand of the shoreline. The Dakota is a transgressive unit in the Reservation area; the fluvial rocks of the Encinal Canyon are overlain by deltaic rocks and shore zone rocks that are, in turn, overlain by the marine Mancos Shale.

Reservoirs on the Dakota Sandstone are controlled by stratigraphic and structural trapping. Successful exploration for lower Dakota Sandstone production is obtained by careful mapping of channel sandstones and close attention to oil and gas shows in the thin, porous sandstone that may develop in channels.

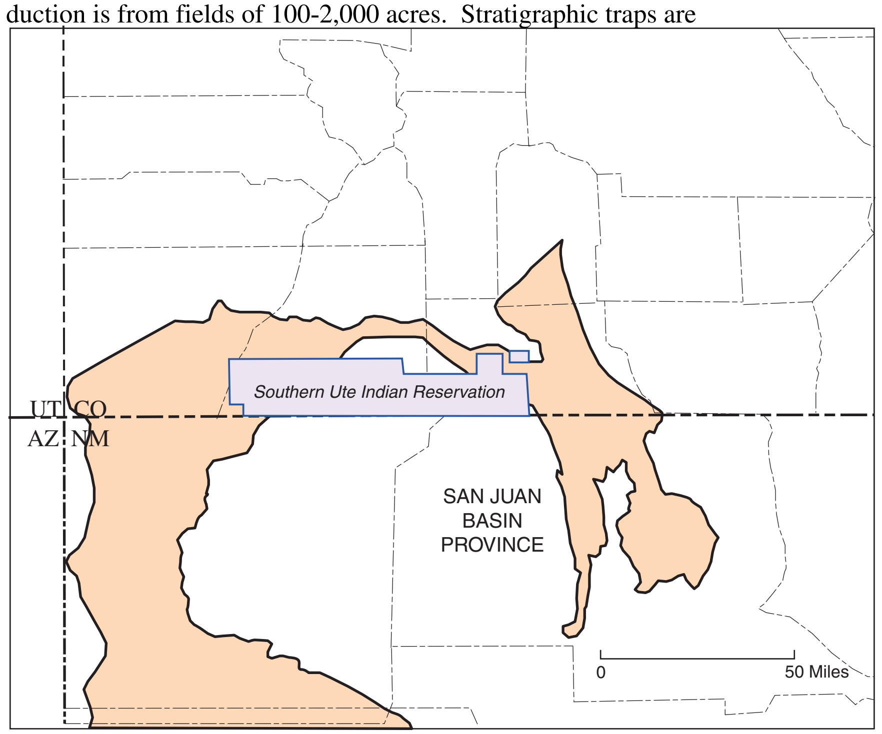


Figure SU-22. Location of the Basin Margin Dakota Oil Play (modified after Gautier, et al., 1996).

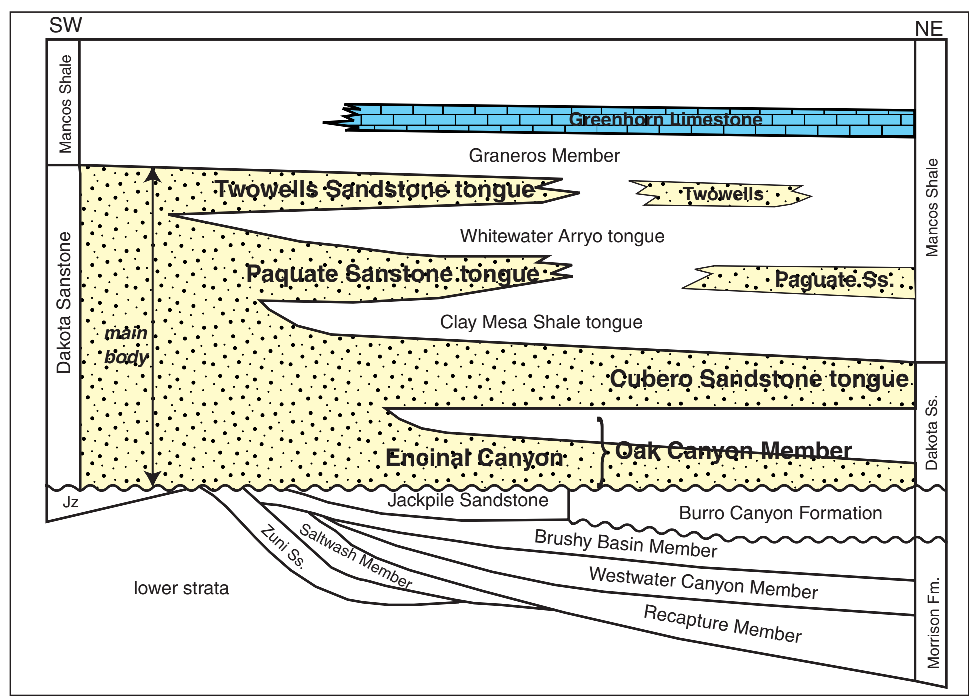


Figure SU-23. Southwest - northeast schematic stratigraphic cross section relating members of the Dakota Sandstone and Mancos Shale and adjacent units in the San Juan Basin (modified after Whitehead, 1993).

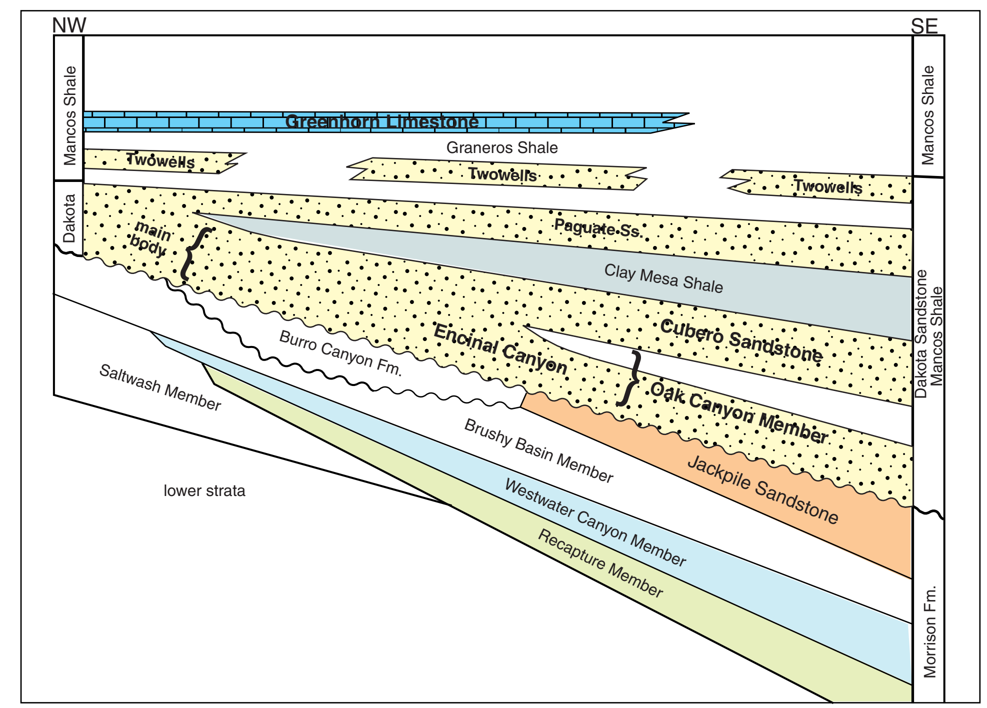
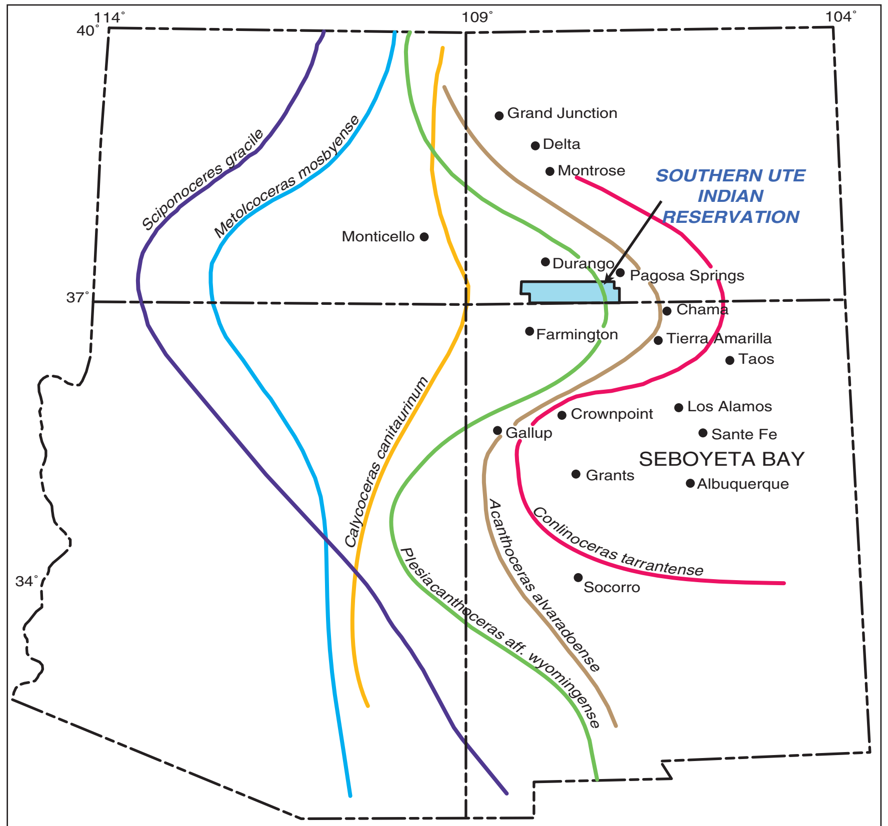


Figure SU-24. Northwest - southeast schematic stratigraphic cross section relating members of the Dakota Sandstone and Mancos Shale and adjacent units in the San Juan Basin (modified after Whitehead, 1993).



T-1 TRANSGRESSION
Dakota Shorelines

Ages	Ammonite Range Zones	Dakota Shelf Sandstones
Late Cenomanian	*Sciponoceres gracile*	
	Metolcoceras mosbyense	Two Wells Sandstone
	Calycoceras canitaurinum	Two Wells Sandstone
Middle Cenomanian	*Plesiacanthoceras aff. wyomingense*	Paguate Sandstone
	Acanthoceras alvaradoense	
	Conlinoceras tarrantense	Cubero Sandstone
Early Cenomanian - Encinal Canyon Member		

Figure SU-25. Map showing positions of the western shoreline of the Western Interior Seaway during deposition of the upper part of the Dakota Sandstone during the middle and late Cenomanian. Shoreline trends are based on the distribution of ammonite fossils found in the lower part of the Mancos Shale, which interfingers with the Dakota Sandstone (modified after Aubrey, 1991).

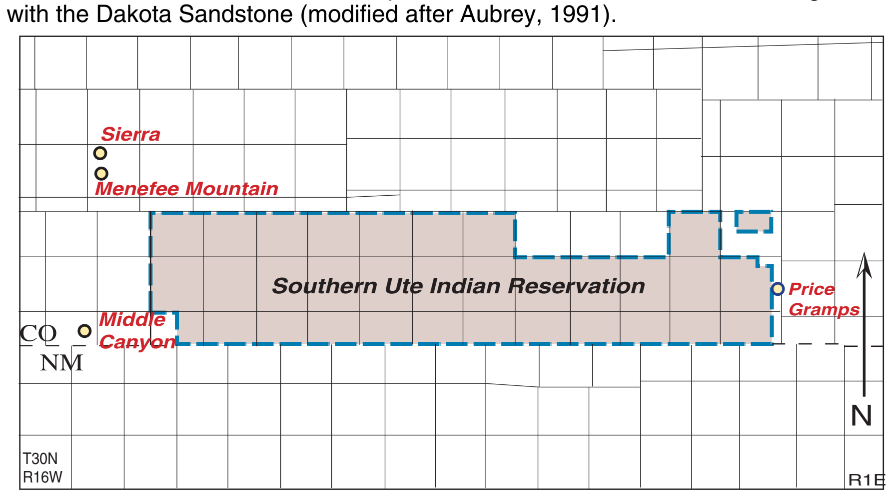


Figure SU-26. Location of oil and gas field discovery wells for fields producing from the Basin Margin Dakota Oil Play.

Analog Fields In and Near Reservation

(*) denotes field lies within the reservation boundaries

Price Gramps

(see figure SU-27)

Location of discovery well:	SE, SE, sec24, T33N, R2E (1935)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Faulted asymmetric anticline
Number of producing wells:	24 (1977)
Initial production:	217 BOD
Cumulative Production:	6, 716,434 BO (1992)
Oil characteristics:	c, 60˚ pour point
Type of drive:	Partial water drive
Average net pay:	30 feet
Porosity:	14.6 % ave., 4% min., 21.1% max.
Permeability:	100 mD

Middle Canyon Dakota

Location of discovery well:	NE, SW, sec 14, T32N, R15W (1969)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Stratigraphic
Number of producing wells:	1 (1977)
Initial production:	122.64 BOD, 7BWD
Cumulative Production:	4886 BO (1977)
Oil characteristics:	N/A
Type of drive:	Water drive
Average net pay:	20 feet
Porosity:	12.1% ave.
Permeability:	0.30 mD ave.

Sierra

Location of discovery well:	SE, NW, sec 5, T35N, R13W (1957)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Stratigraphic
Number of producing wells:	12 (1992)
Initial production:	969 MCFGD
Cumulative Production:	1,299,016 BO (1992), 29,021 MCFG
Oil characteristics:	35˚ API gravity
Type of drive:	solution gas, downdip water encroachment
Average net pay:	22 feet
Porosity:	18-20%
Permeability:	700 mD

Menefee Mountain

Location of discovery well:	NW, NE, NW, sec 16, T35N, R13W
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Structural, stratigraphic
Number of producing wells:	3 (1983)
Initial production:	26 BOD, 11 BWD
Cumulative Production:	49,230 BO, 255 MCFG (1992)
Oil characteristics:	34.0˚ API gravity
Type of drive:	water
Average net pay:	15 feet
Porosity:	12-14%
Permeability:	unknown

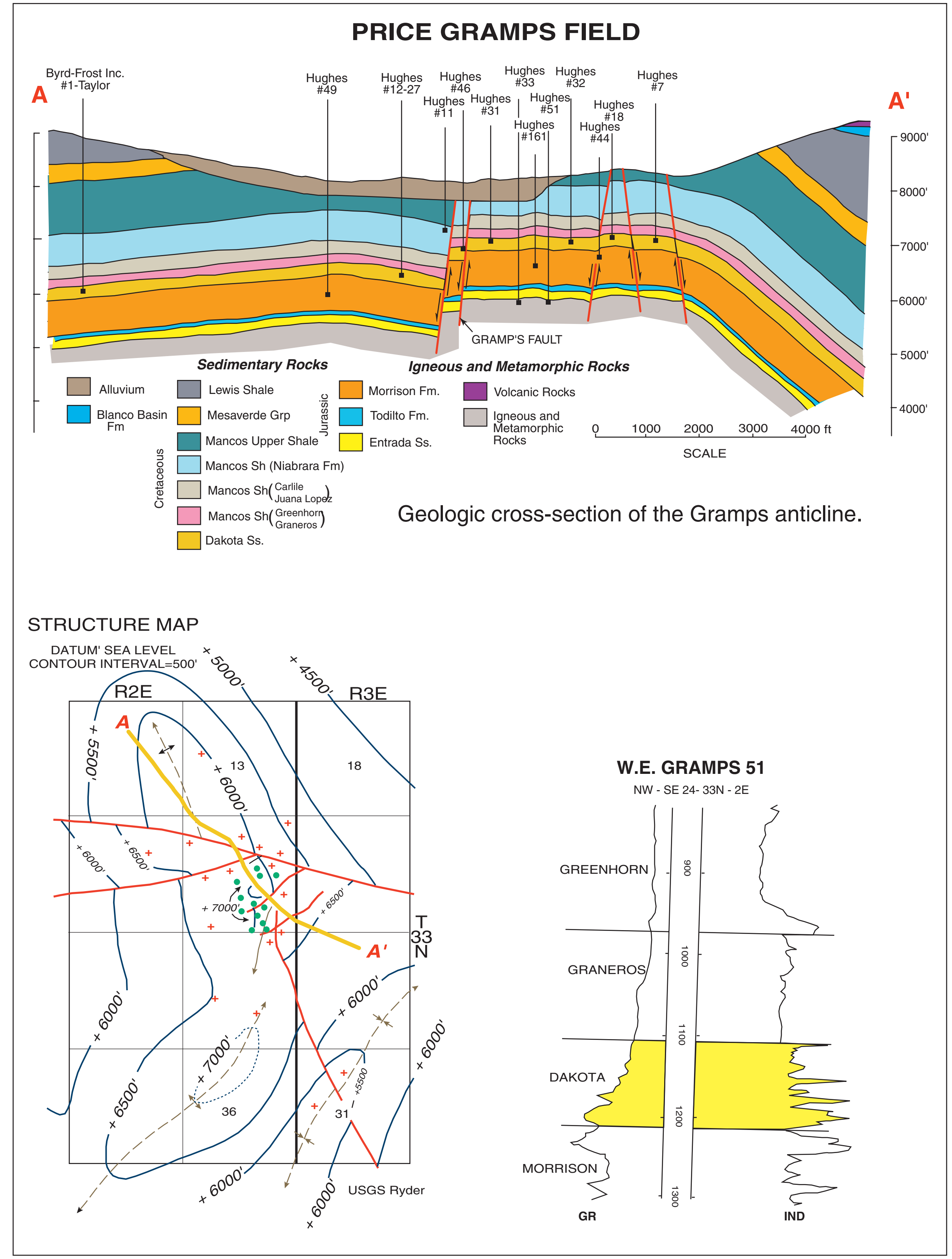


Figure SU-27. Structural cross section, structure contour map, and type log for the Price Gramps Field (modified after Donovan, 1978).

Tocito-Gallup Sandstone Oil Play
(USGS 2207)

General Characteristics

The Tocito-Gallup Sandstone Oil Play is associated with lenticular sandstone bodies of the Upper Cretaceous Gallup Sandstone and Tocito Sandstone Lentil, and 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% and average about 15%. Permeabilities range from 0.5 to 150 md and are typically 5 to 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 38˚ to 43˚ API gravity in the Tocito fields and from 24˚ to 32˚ 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 late Eocene time and gas generation in Oligocene time. 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 to 10,000 acres in area and have 15 to 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 fields 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 thought to be low to moderate.

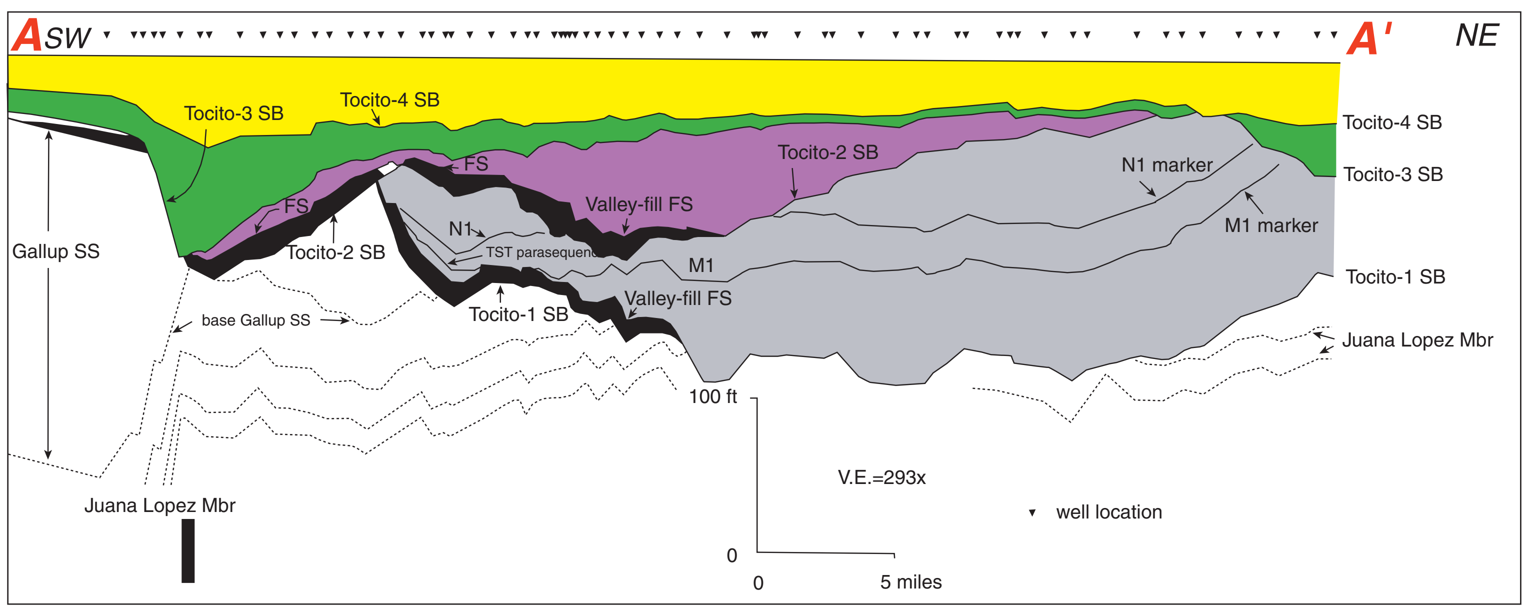


Figure SU-28. Detailed regional cross section showing high-resolution stratal geometries defined by the key stratigraphic surfaces of the Tocito Sandstone. Position of the cross section is shown in Fig. SU-29 (modified after Jennette and Jones, 1995).

Characteristics of the Tocito-Gallup Oil Play

In recent years a sequence stratigraphic framework has been applied to the Tocito and Gallup Sandstones near the Southern Ute Indian Reservation (Fig. SU-30). This framework helps explain hydrocarbon occurrence and the stratigraphic traps associated with these units. The northern extent of the Gallup Sandstone production is several miles south of the Indian reservation where the unit is truncated by the Tocito Sandstone. For this reason, the Gallup Sandstone will not be included in the following description.

Since the late 1950's, 130 MMBOE have been produced from the Tocito. The Tocito Sandstone marks a significant change from shoreface/coastal plain depositional systems which prevailed throughout Gallup deposition. The Tocito Sandstone is a transgressive sequence set internally composed of four high-frequency sequences. In ascending order, they are Tocito-1, Tocito-2, Tocito-3 and Tocito-4 (Fig. SU-30). In the subsurface, the Tocito is distributed into narrow and elongate bodies which trend northwest-southeast (Figs. SU-31 and SU-32). Isopach maps of the Tocito units show that the Tocito-3 and Tocito-4 are the only units beneath the southern Ute Indian Reservation.

The high-frequency sequences of the Tocito Sandstone contain the lowstand, transgressive, and usually highstand systems tracts. There are sequence boundaries at the base of each high-frequency sequence represented by irregular erosional surfaces that truncate into the underlying units. Above the erosional surfaces are incised valley fill deposits representing the lowstand systems tracts. The top of the valley fills represent transgressive flooding surfaces and the passage from valley-filling sedimentation to open-marine/shelfal sedimentation and the onset of the transgressive systems tracts. The transgressive systems tracts are overlain by distal marine shales of the highstand systems tracts (Tocito-1 and Tocito-2 only). Due to their close vertical juxtaposition, the four Tocito sequences are collectively interpreted as components of a sequence set. The four sequences are thought to reflect higher-order cycles in relative sea level which were superimposed on a longer term cycle.

The hydrocarbon trapping is the result of stratigraphic relationships. Structural dip is uniformly toward the northeast and consequently provides only minor influence on the pooling of hydrocarbons. The four main trapping elements are: truncation by younger sequence boundary, arcuate bends in valleys, up-dip valley termination, and

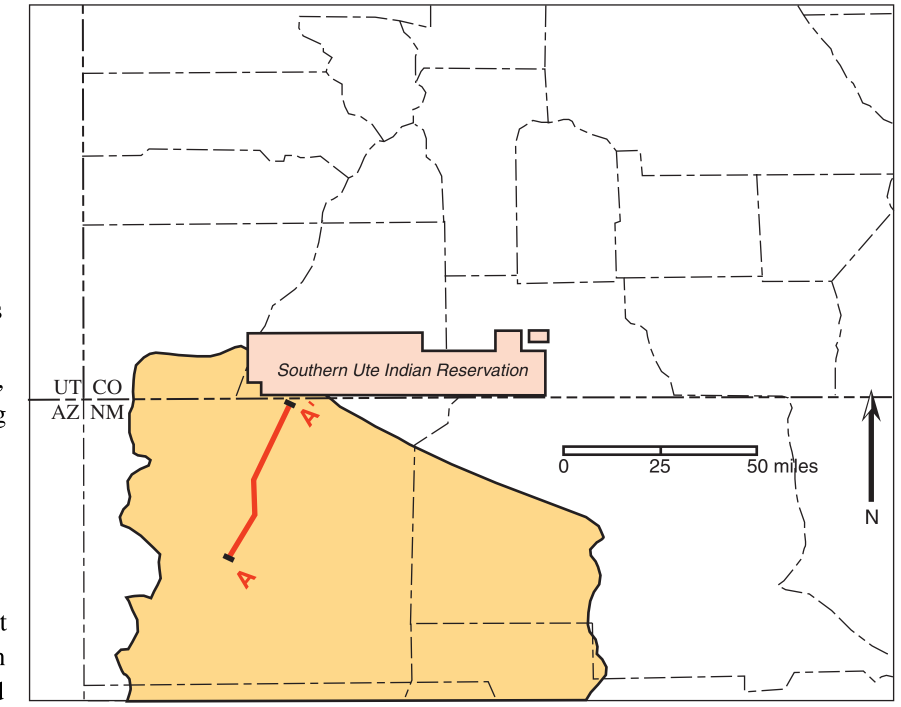


Figure SU-29. Location of the Tocito-Gallup Sandstone Oil Play. Cross section A-A' is shown in Fig. SU-28. (modified after Gautier, et al., 1996).

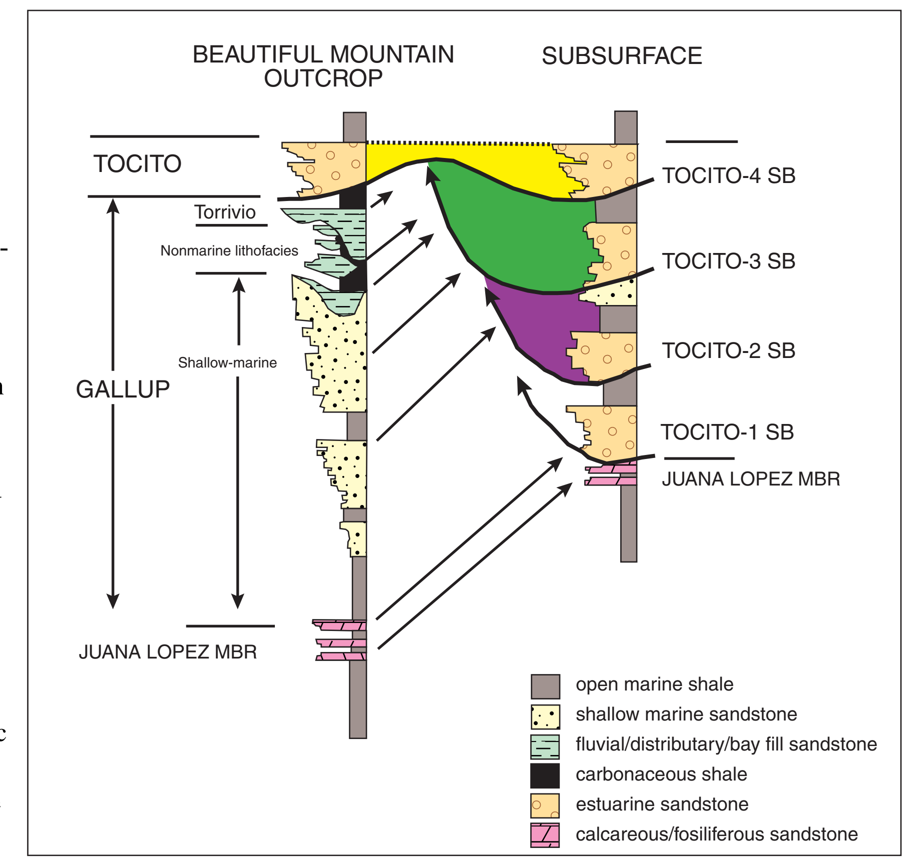


Figure SU-30. Composite stratigraphic summary comparing the outcrop and the subsurface expression of the Gallup and Tocito interval (modified after Jennette and Jones, 1995).

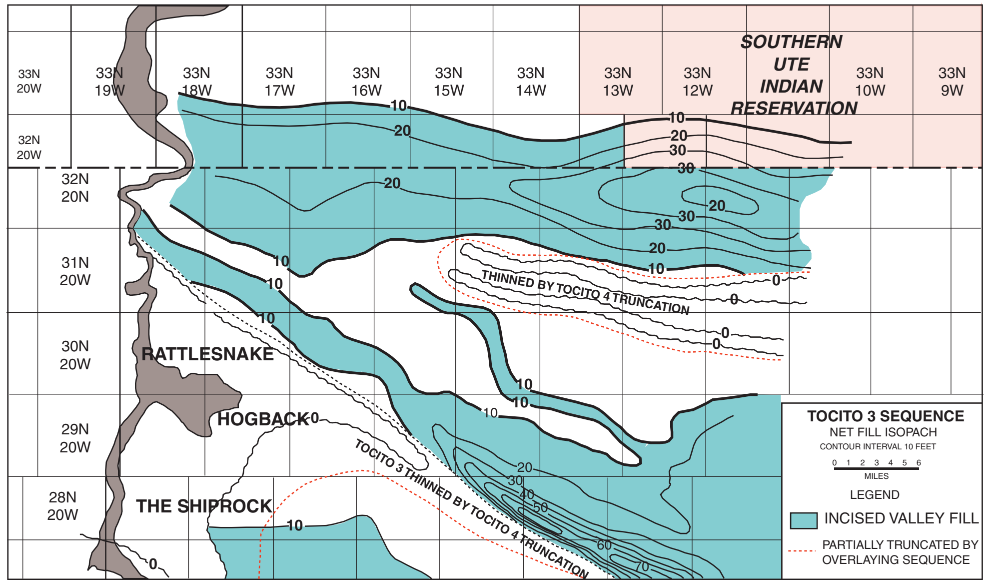


Figure SU-31. Isopach map and cross section of the Tocito-3 sequence. The contoured interval of the Isopach Map is the Tocito-3 sequence boundary to the Tocito-4 sequence boundary. Interval thickness of ten feet and greater is highlighted. The cross section is a transverse section across the Tocito-3 Waterflow Valley (modified after Jennette and Jones, 1995).

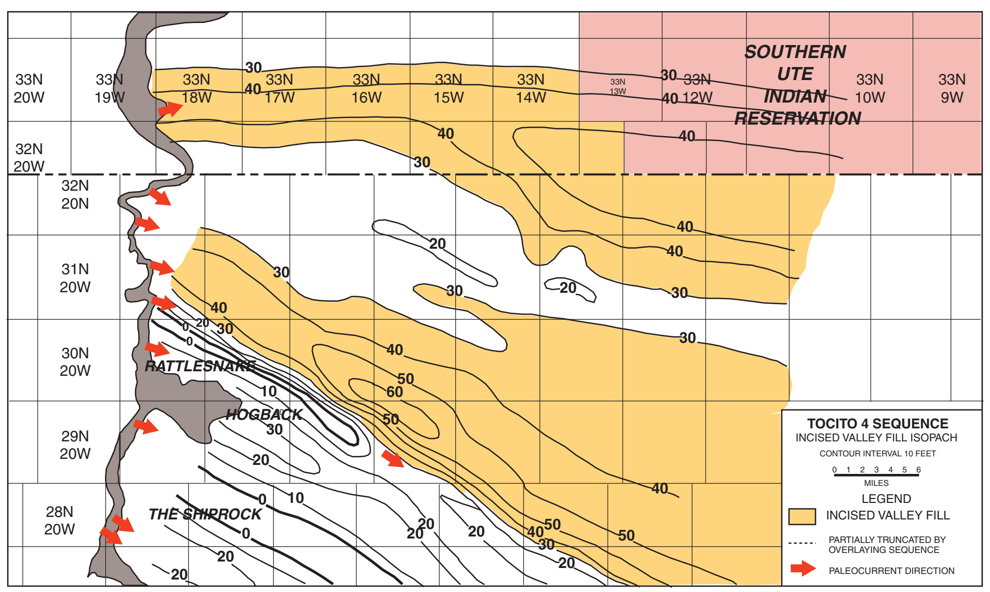


Figure SU-32. Isopach map and cross section of the Tocito-4 sequence. The contoured interval of the Isopach Map is the Tocito-4 sequence boundary to the overlying flooding surface. Interval thickness of thirty feet and greater is highlighted. The cross section is a transverse section across the Tocito-4 Rattlesnake Valley (modified after Jennette and Jones, 1995).

Analog Fields In and Near Reservation

(*) denotes field lies within the reservation boundaries

Albino Gallup (see figure SU-34)

Location of discovery well:	NC, NE, sec 26, T32N, R8W (1974)
Producing formation:	Gallup sandstone of the Mancos Shale
Type of trap:	Structural, Stratigraphic
Number of producing wells:	1 (1994)
Initial production:	2.9 MMCFGD
Cumulative Production:	254,377 MCFG (1994)
Gas characteristics:	N/A
Type of drive:	Gas expansion
Average net pay:	up to 900 feet of fractured interval
Porosity:	3-8%, and fractures
Permeability:	fracture permeability

Cinder Buttes

Location of discovery well:	SE, SE, SW, sec 13, T32N, R12W (1966)
Producing formation:	Cretaceous Gallup Sandstone
Type of trap:	Fractured sandstone, structural-stratigraphic
Number of producing wells:	3 (1987)
Initial production:	302 MCFGD
Cumulative Production:	42,130 MCFG (shut in 1987)
Gas characteristics:	1,176 BTU
Type of drive:	Depletion
Average net pay:	30 feet (divided among 6-8 thin sandstone beds)
Porosity:	16% estimated
Permeability:	unknown

Verde Gallup

Location of discovery well:	SE, SE, sec 14, T31N, R15W (1955)
Producing formation:	Fractured interval, Cret. Gallup Sandstone
Type of trap:	Fractured shale, stratigraphic
Number of producing wells:	27 (1977)
Initial production:	180 BOD
Cumulative Production:	7,963,004 BO, 174,956 MCFG (1994)
Oil characteristics:	38° -42° API gravity
Gas characteristics:	sweet high BTU
Type of drive:	Gravity drainage
Average net pay:	Variable
Porosity:	Fracture
Permeability:	Unknown

Flora Vista Gallup

Location of discovery well:	SE, SW, sec 2, T30N, R12W (1961)
Producing formation:	Cretaceous Gallup Sandstone
Type of trap:	Stratigraphic
Number of producing wells:	3 (1977)
Initial production:	1,070 MCFGD
Cumulative Production:	11,114,501 MCFG, 133,026 B condensate (1994)
Oil characteristics:	BTU 1,303
Type of drive:	Solution gas
Average net pay:	9 feet
Porosity:	9-12%, 10% ave. (sonic log calculated)
Permeability:	unknown

***Red Mesa (poor historical data)**
***Chromo (poor historical data)**

(Fassett, 1978,1983; Wells and Lay, 1997)

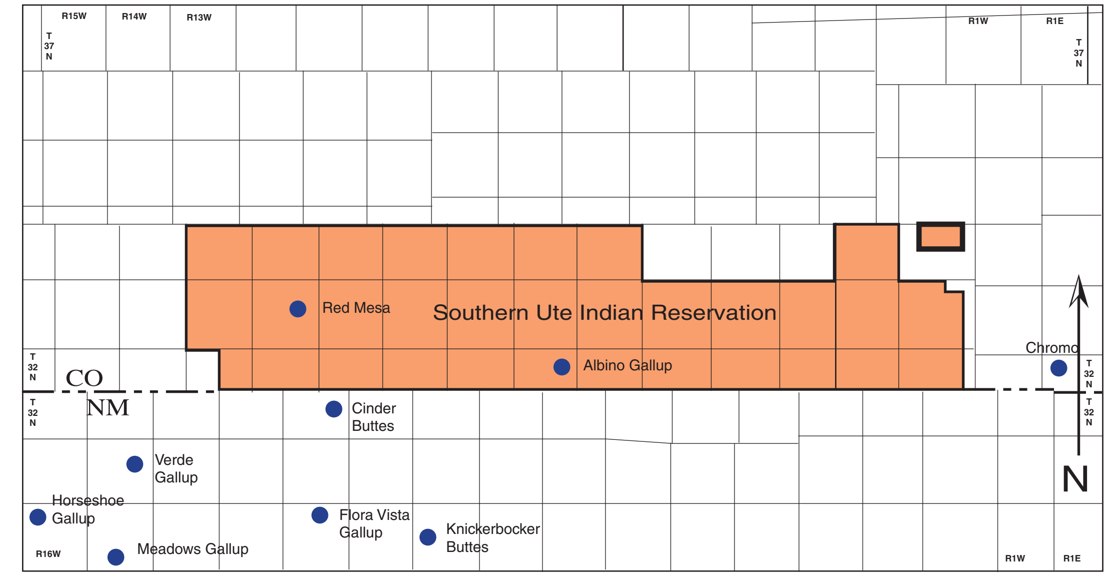


Figure SU-33. Location of oil and gas field discovery wells for fields producing from the Tocito-Gallup Sandstone Oil Play.

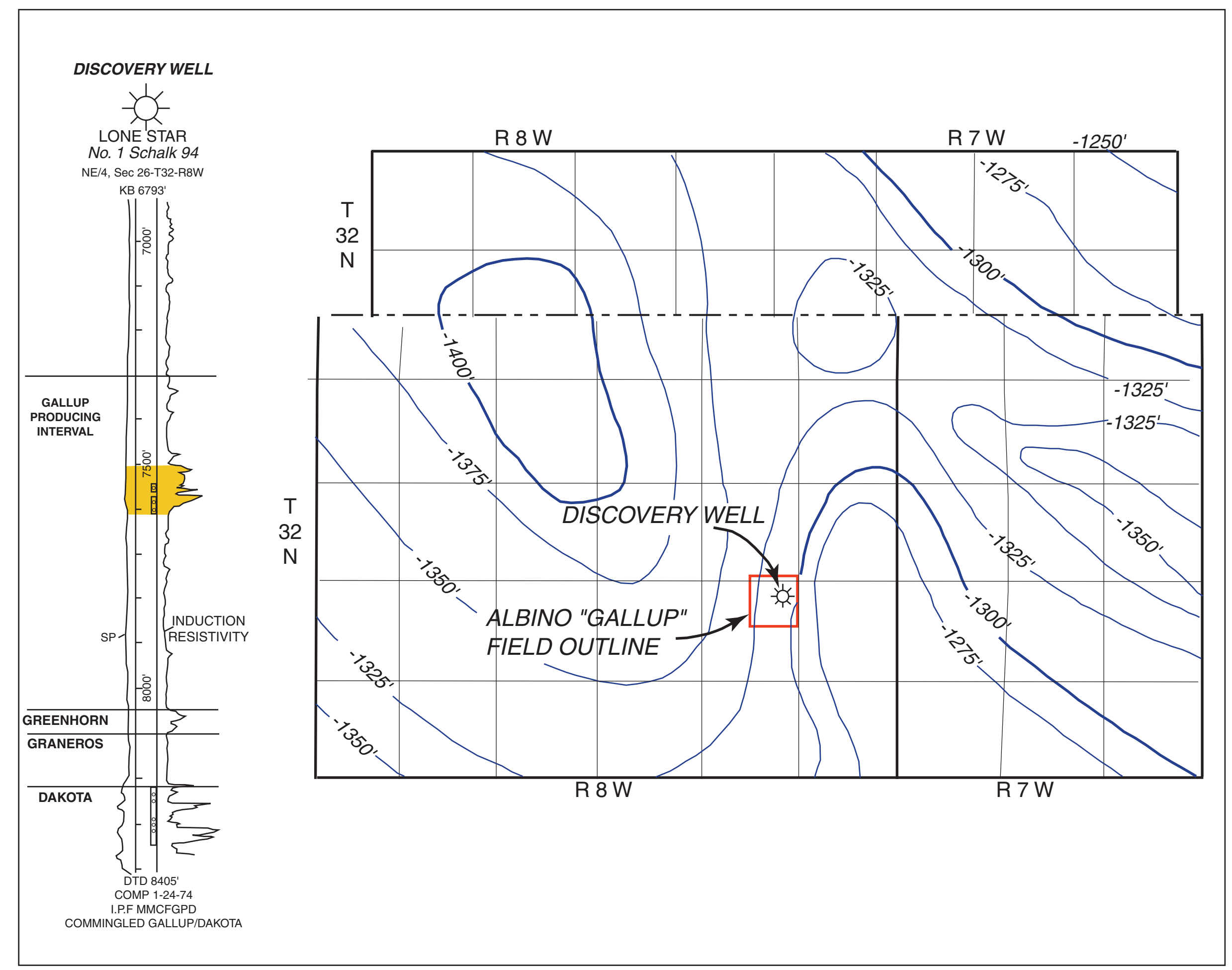


Figure SU-34. Structure contour map, and type log from Albino Gallup Field (modified after Middleman, 1983).

Basin Margin Mesaverde Oil Play

(USGS 2210)

General Characteristics

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. API gravity of Mesaverde oil ranges from 37˚ to 50˚.

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.

The Basin Margin Mesaverde Oil Play in Southern Ute Indian Reservation

The Cliff House and Point Lookout Sandstones are the producers in the Basin Margin Mesaverde Oil Play in the Southern Ute Indian Reservation (Fig. SU-37). The Point Lookout shoreface prograded in a staircase fashion across the basin, as a series of steps and risers until it reached its seaward depositional limit (Fig. SU-36). At this limit, there is a change in the stacking pattern of genetic sequences from seaward-stepping to landward-stepping. This marks the beginning of the Cliff House shoreface aggradation (Fig. SU-36). Reservoir-quality sandstones in the two vertically stacked shorefaces at the turn-around position are 70 m thick.

The Point Lookout Sandstone is the most extensive regressive marine Cretaceous sandstone in the San Juan Basin. Formed during shoreline regression, it covers virtually the entire basin. Its shoreline trended northwest-southeast and prograded toward the northeast in a series of thick, imbricated, sandstone units. Straight, wave dominated shoreface and delta-front deposits form the bulk of the sandstone; tidal, foreshore, and offshore sandstones are lesser constituents. Cores 1HCMS and 2 HCMS (Figs. SU-38 thru 40) show fluvial/estuarine, shoreface, and delta-front deposits of the Point Lookout Sandstone. The best reservoir sandstones, in terms of porosity and permeability, are found in zones in the upper and lower shoreface environments and the shoreface/delta front environments. These sandstones are least influenced by carbonate cementation, and appear least sensitive to increased confining stress. Reservoir characteristics of the Point Lookout show that the sandstones are conventional rather than tight. Measured porosity in the 1HCMS well range from 4.2-20.5 percent and 6.6-20.4 percent in the 2HCMS well. Measured ambient permeabilities are 0.0003-56.3 md for the 1HCMS well and 0.0007 to 59.3 md in the 2HCMS well. Higher permeabilities are more common in the upper shoreface and shoreface/delta-front depositional environments. Diagenesis also influence reservoir quality. The highest amounts of carbonate cement are generally in the lower to middle shoreface environment. There is a general increase in carbonate cement directly above and below many of the shale breaks.

The Cliff House Sandstone consists of several linear sandstone complexes (Fig. SU-36). The thicker parts are connected by thin sandstone sheets; where these sheets are absent, the Lewis Shale rests directly on the Menefee Formation. The depositional environments present in the Cliff House Sandstone are fluvial/estuarine, shoreface, and delta front. The Cliff House Sandstone benches are composed of homogeneous, mud-free sandstone dominated by amalgamated hummocky and swaley cross stratification.)

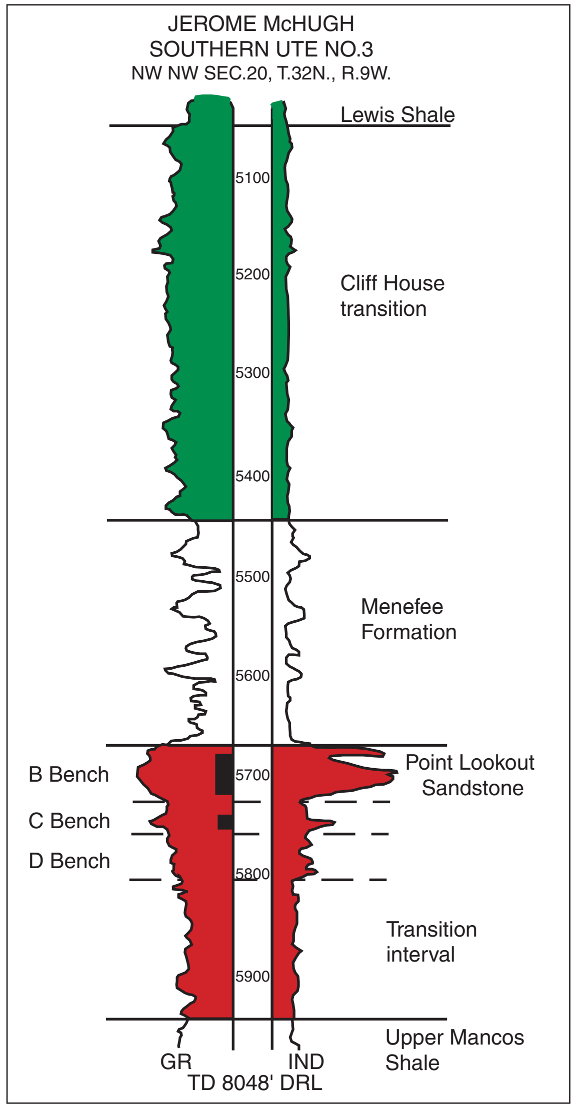


Figure SU-37. Log of the Mesaverde pool stratigraphic units showing perforated and producing "B" bench reservoir of the Point Lookout Sandstone. The "A" bench is absent by non-deposition and the "C" and "D" benches are shaley. Well is the Jerome McHugh Southern Ute No. 3, NW, NW, sec. 20, T32N, R9W, La Plata Co., CO (modified after Keighin, et al., 1993).

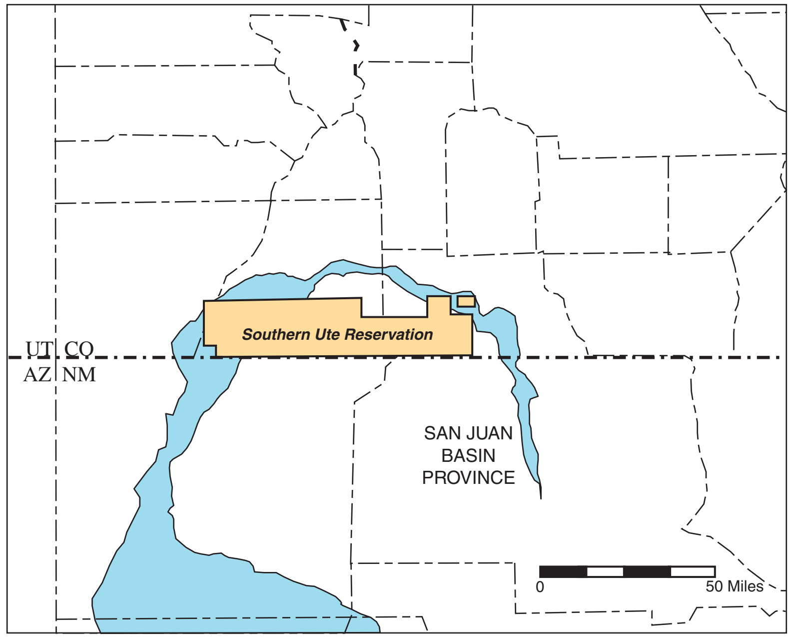


Figure SU-35. Location of the Basin Margin Mesaverde Oil Play (modified after Gautier, et al., 1996).

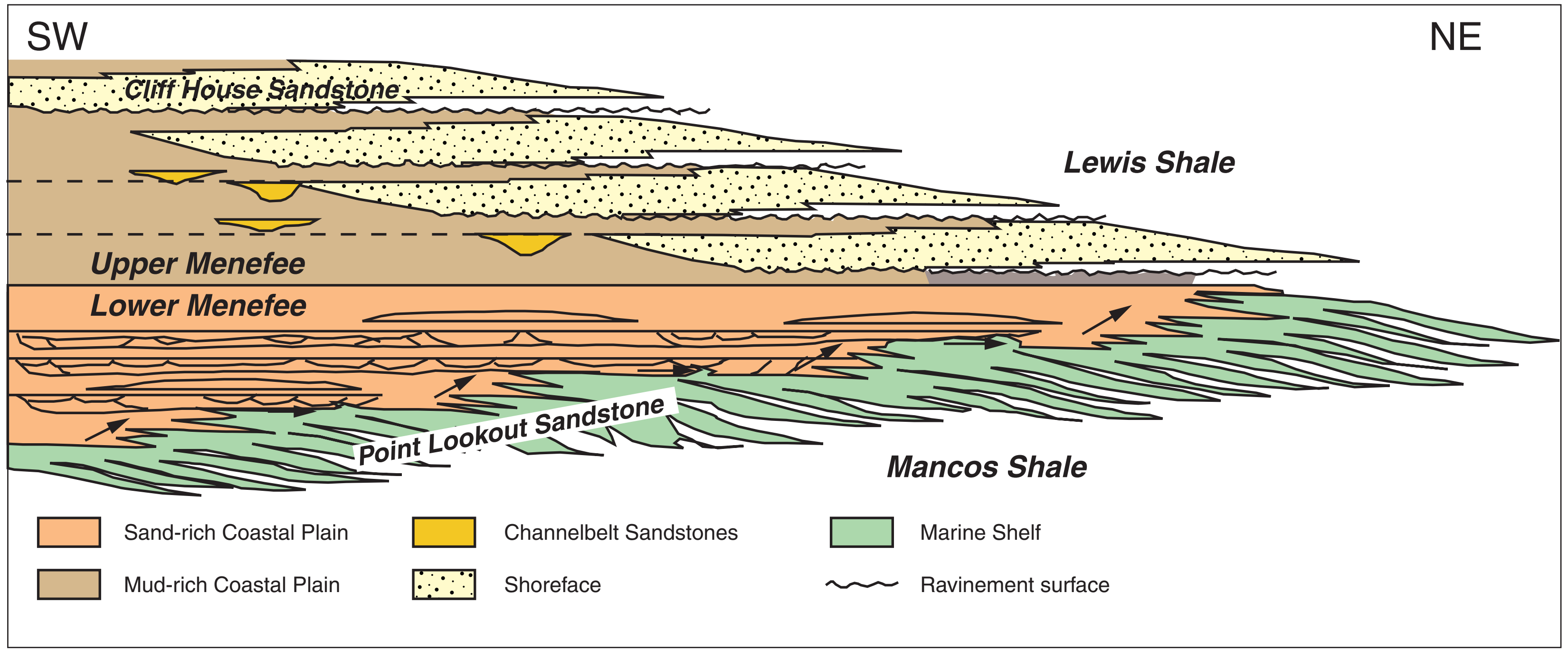


Figure SU-36. Diagram of the stacking patterns of genetic sequences in the Mesaverde Group, and the temporal relations among the five formations that encompass them (modified after Cross and Lessenger, 1997).

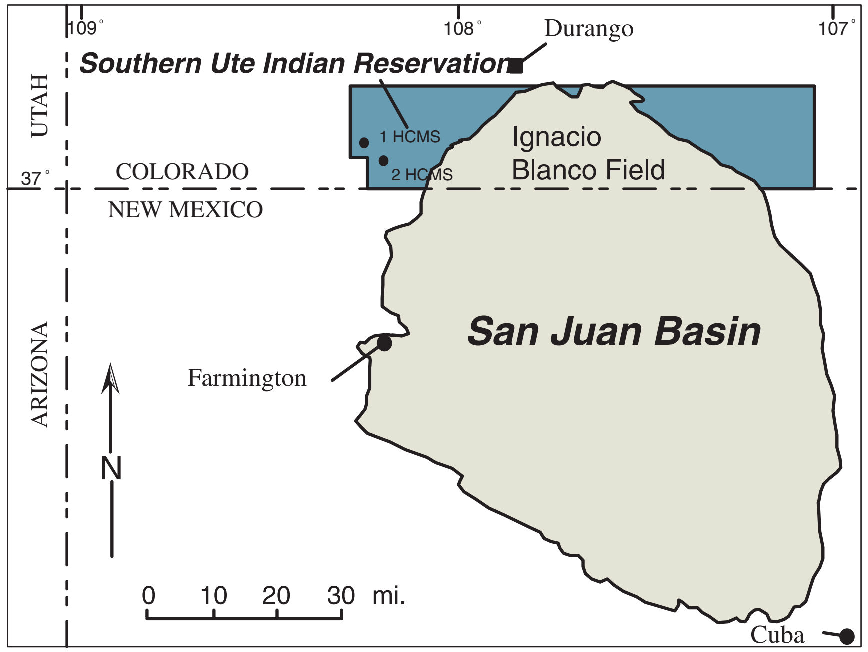


Figure SU-38. Index map showing location of the San Juan Basin as defined by the Fruitland-Pictured Cliffs contact, Ignacio-Blanco gas field, Southern Ute Indian Reservation, and drill holes 1HCMS (sec 30, T33N, R13W) and 2HCMS (sec 5, T32N, R13W) (modified after Keighin, et al., 1993).

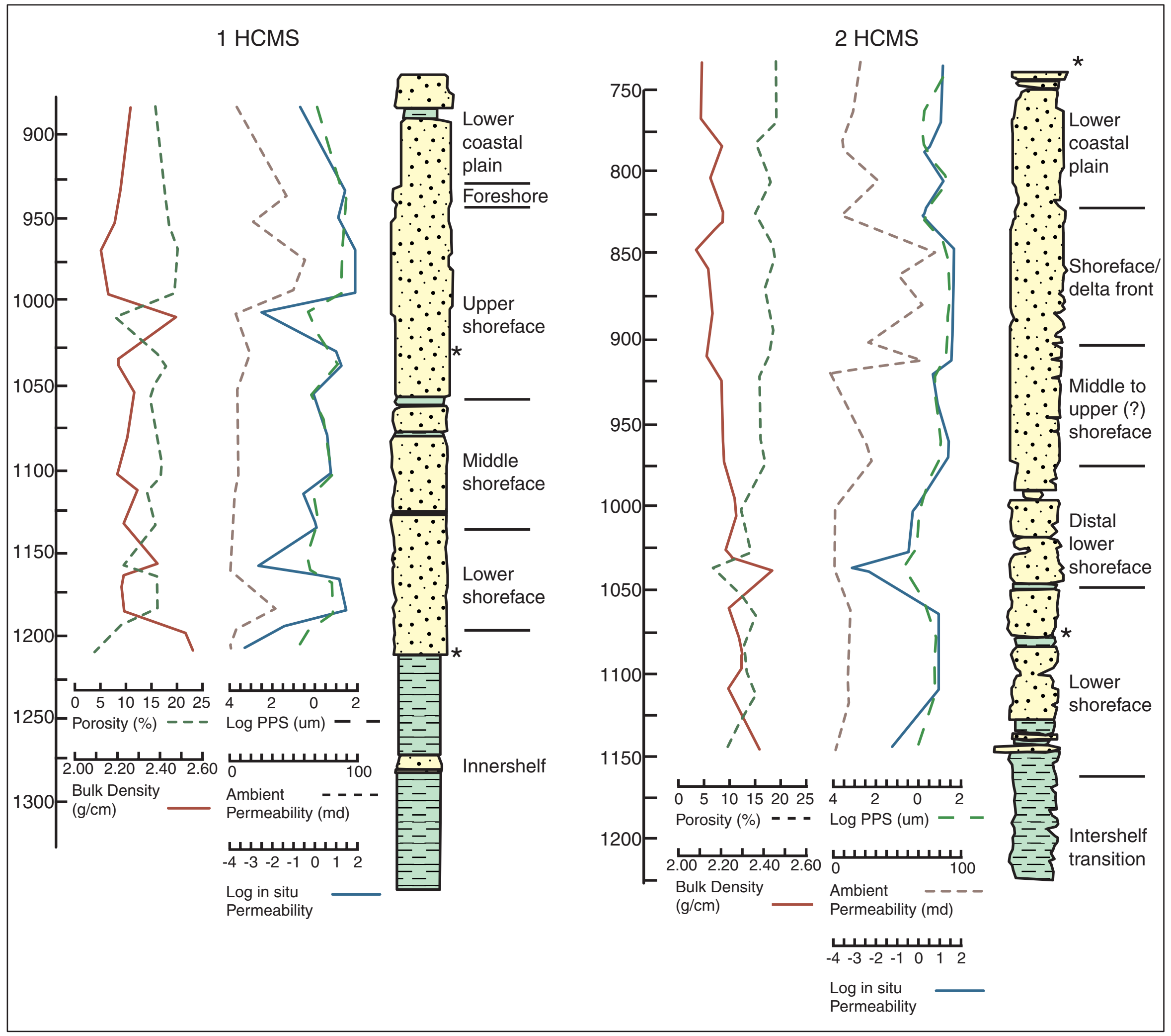


Figure SU-39. Relationship in the Point Lookout Sandstone between measured porosity, bulk density, ambient and in-situ permeability, calculated principle pore size (PPS), observed lithology of cores, and interpreted depositional environments (modified after Keighin, et al., 1993).

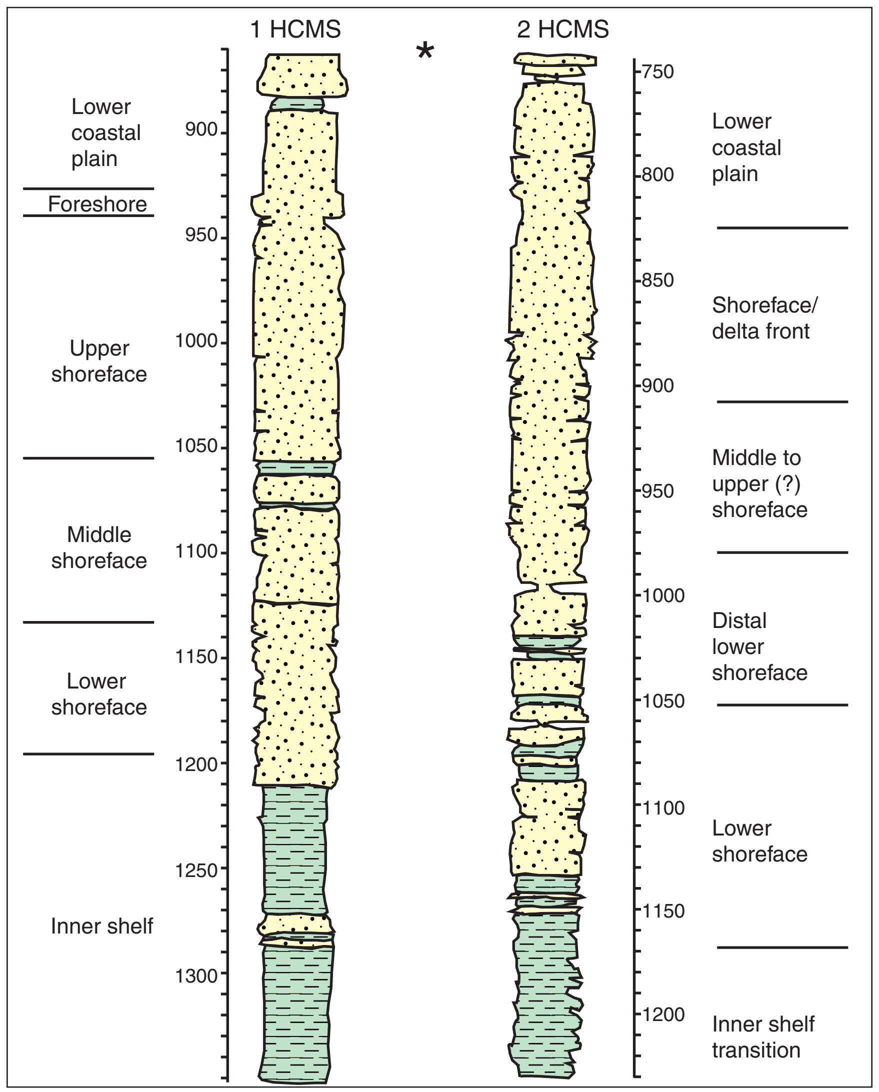


Figure SU-40. Comparison of depositional facies in the Point Lookout Sandstone, as determined from cores; for core holes 1HCMS and 2HCMS (modified after Keighin, et al., 1993).

Analog Fields In and Near Reservation

The Basin Margin Mesaverde Oil Play only produces from one field in or near the Southern Ute Indian Reservation. That field is the Red Mesa field. Figure SU-41 is a location map of the field. There is no data available for Mesaverde production, oil characteristics, reservoir quality, etc. in the Red Mesa field. The Central Basin Mesaverde Play provides additional information about Mesaverde Production in the Southern Ute Indian Reservation. (Lauth, 1983)

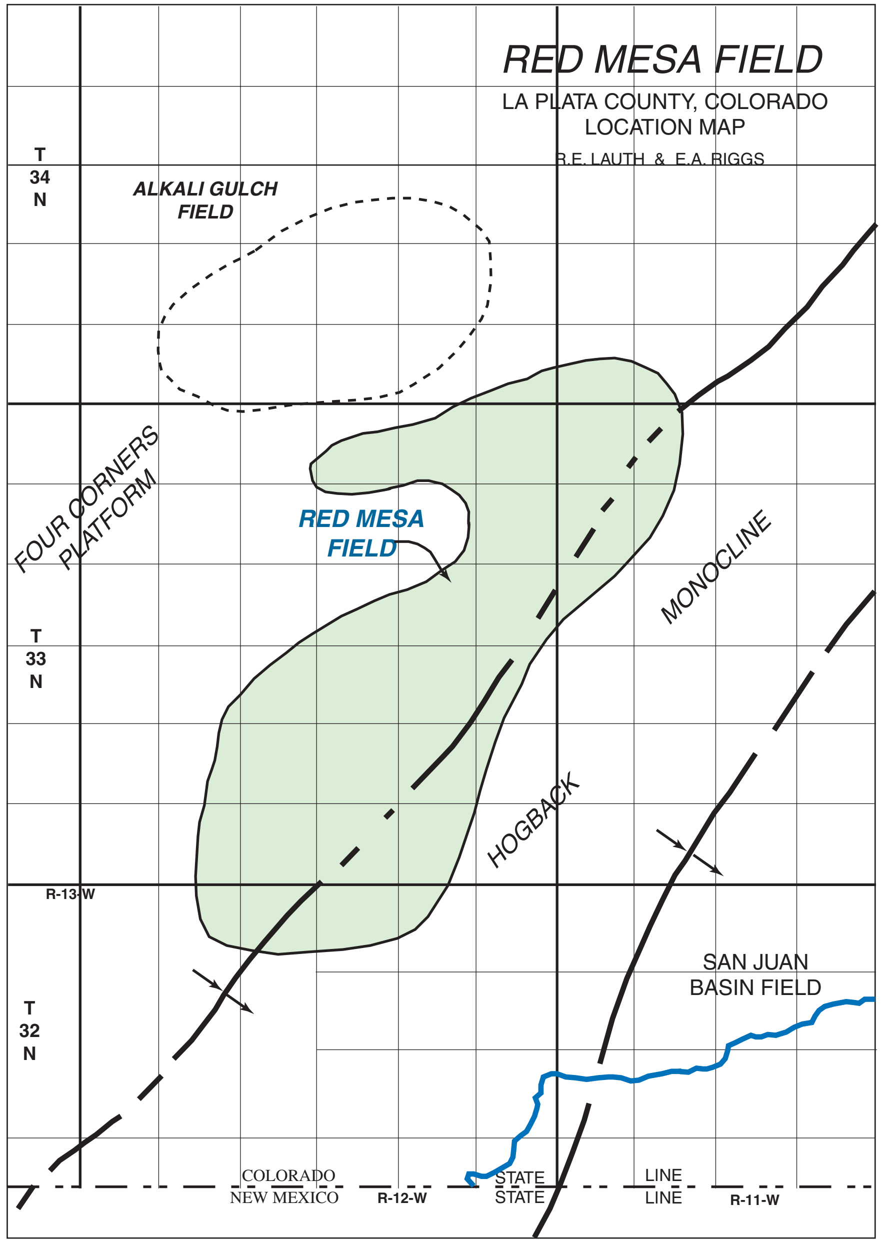


Figure SU-41. Location map of the Red Mesa Field (modified after Lauth, 1983).

Fruitland-Kirtland Fluvial Sandstone Gas Play

(USGS 2212)

General Characteristics

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 that 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 md). Pay thickness ranges from 15 to 50 ft. The Farmington Sandstone Member is typically fine grained and has porosity of 3 to 20 percent and permeability of 0.6 to 9 md. Pay thicknesses are generally 10–20 ft.

Source rocks: The Fruitland-Kirtland interval produces nonassociated gas and very little condensate. Its chemical composition (C1/C1-5) ranges from 0.99 to 0.87 and its isotopic (d13C1) compositions range from -43.5 to -38.5 per mil (Rice et al., 1988). 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 (Gautier et al., 1996).

Characteristics of the Fruitland-Kirtland Fluvial Sandstone Gas Play

Many studies have focused on the Fruitland-Kirtland Fluvial Sandstone Gas Play in the past ten years (Harr, 1988; Bland, 1992; and Hoppe, 1992). For this reason, the following should be considered an extremely brief overview.

The Fruitland Formation contains up to 50 TCF of coalbed methane in place. Half of this may be producible reserves. The Fruitland pore system ranges from overpressured to underpressured. The Fruitland Formation lies stratigraphically above the Pictured Cliffs Sandstone. The Fruitland consists of sandstone, limestone, shale, carbonaceous shale, coal, and volcanic ash. It represents numerous environments on the coastal plain. Environments change quickly laterally and include stream, overbank, floodplain, swamp, and tidal deposits. Production from the Fruitland is highly dependent on finding areas where cleating is preserved or in locating natural fractures. Production is also controlled by net thickness of coals.

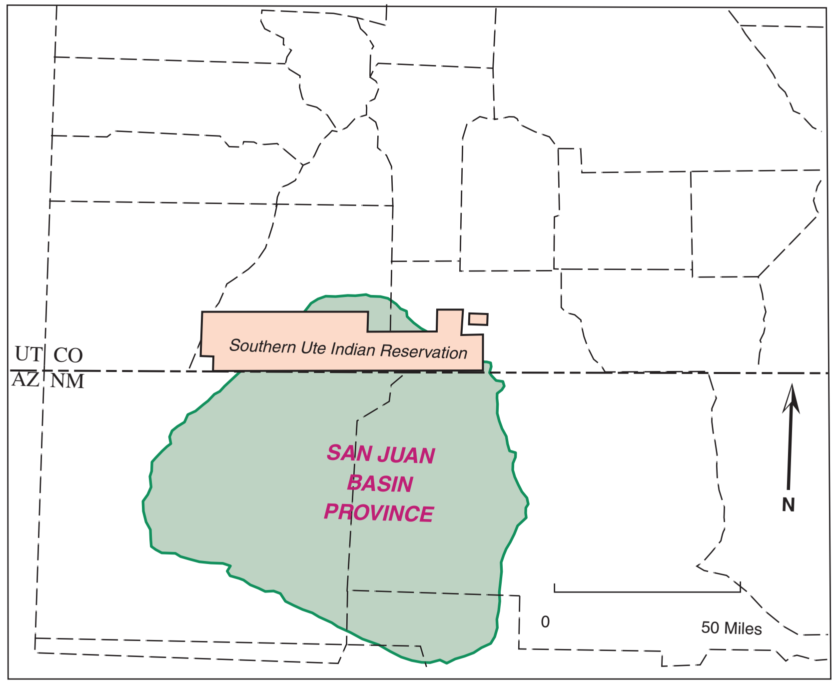


Figure SU-42. Location of the Fruitland-Kirtland Fluvial Sandstone Gas Play (modified after Gautier et al., 1996).

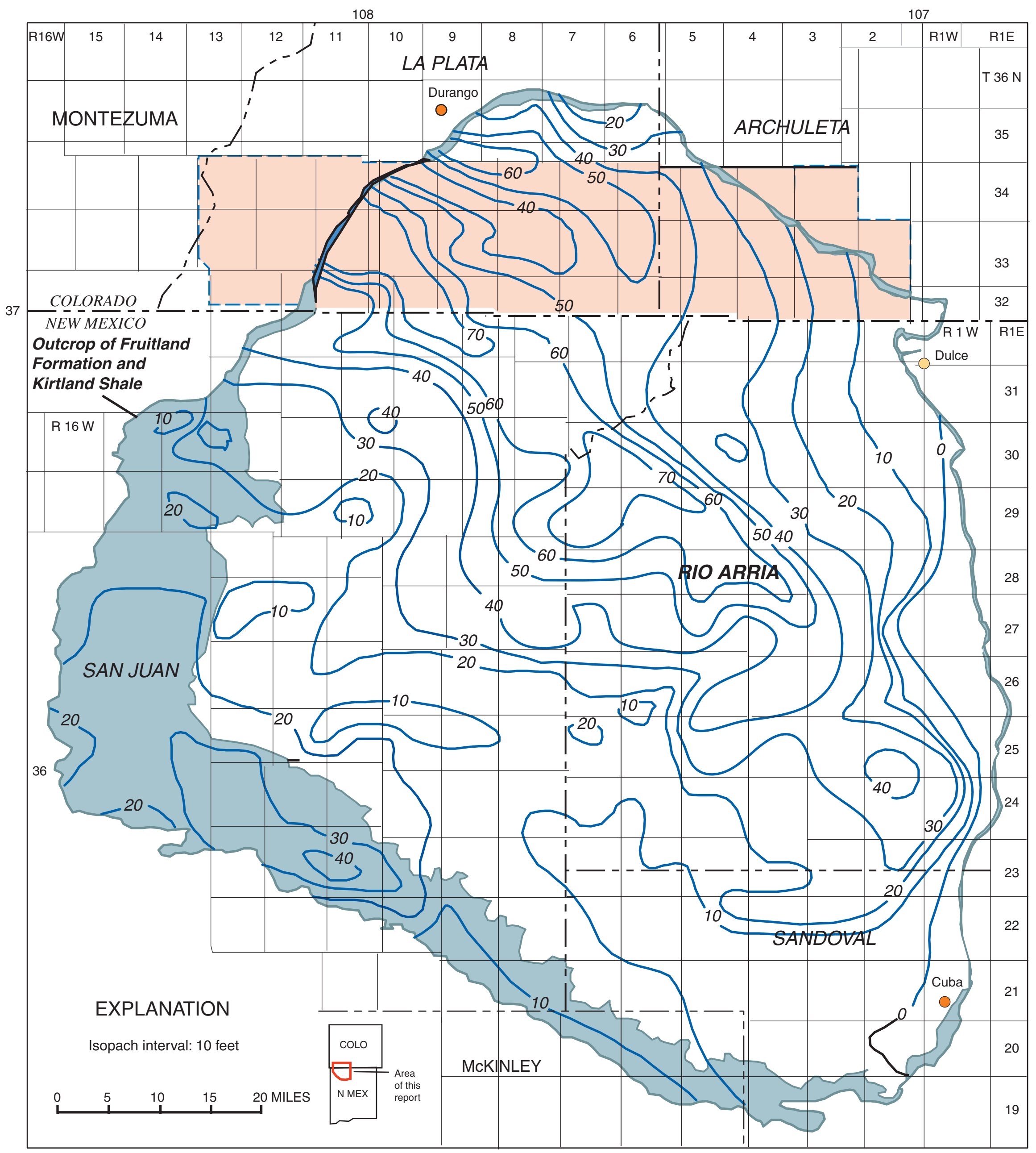


Figure SU-43. Gas-in-place contour map for the Fruitland Formation. Contour interval is 10 BCFG / mi^2. (modified after Kelso and Wicks, 1988).

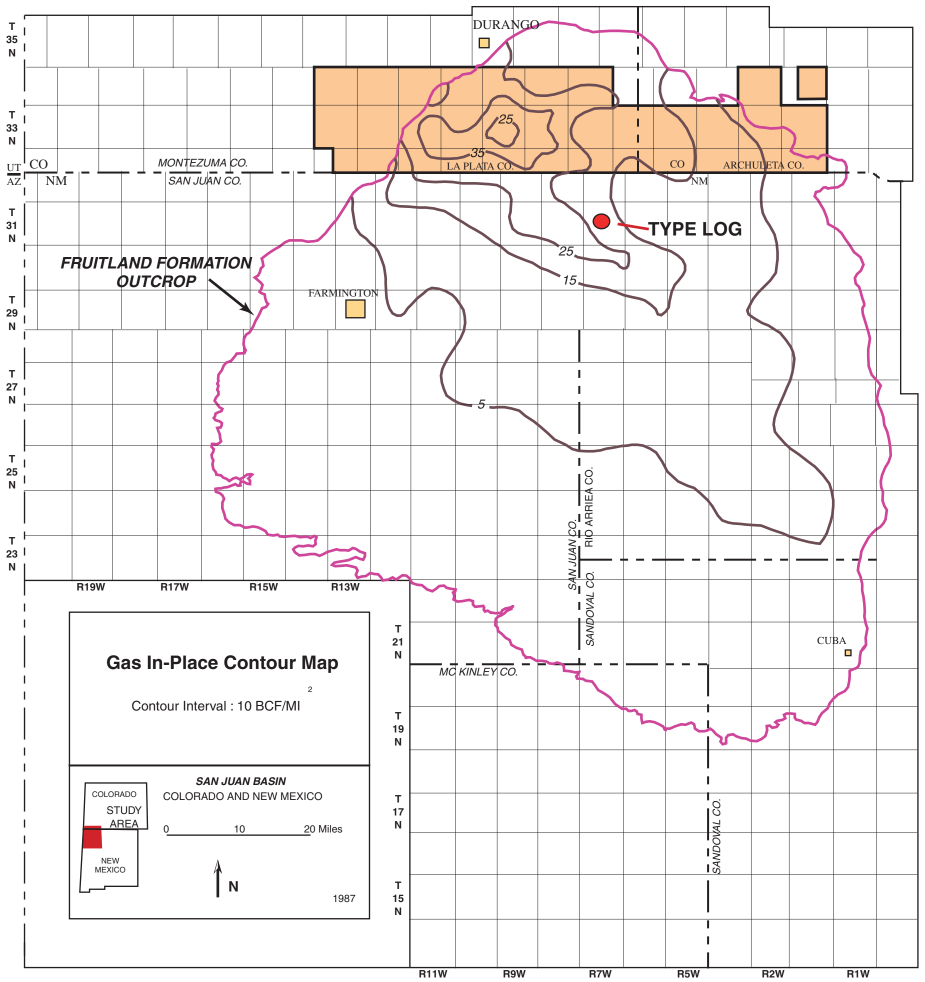


Figure SU-44. Isopach map of total thickness of coal in the Fruitland Formation. Contour interval is 10 feet (modified after Fassett, 1988).

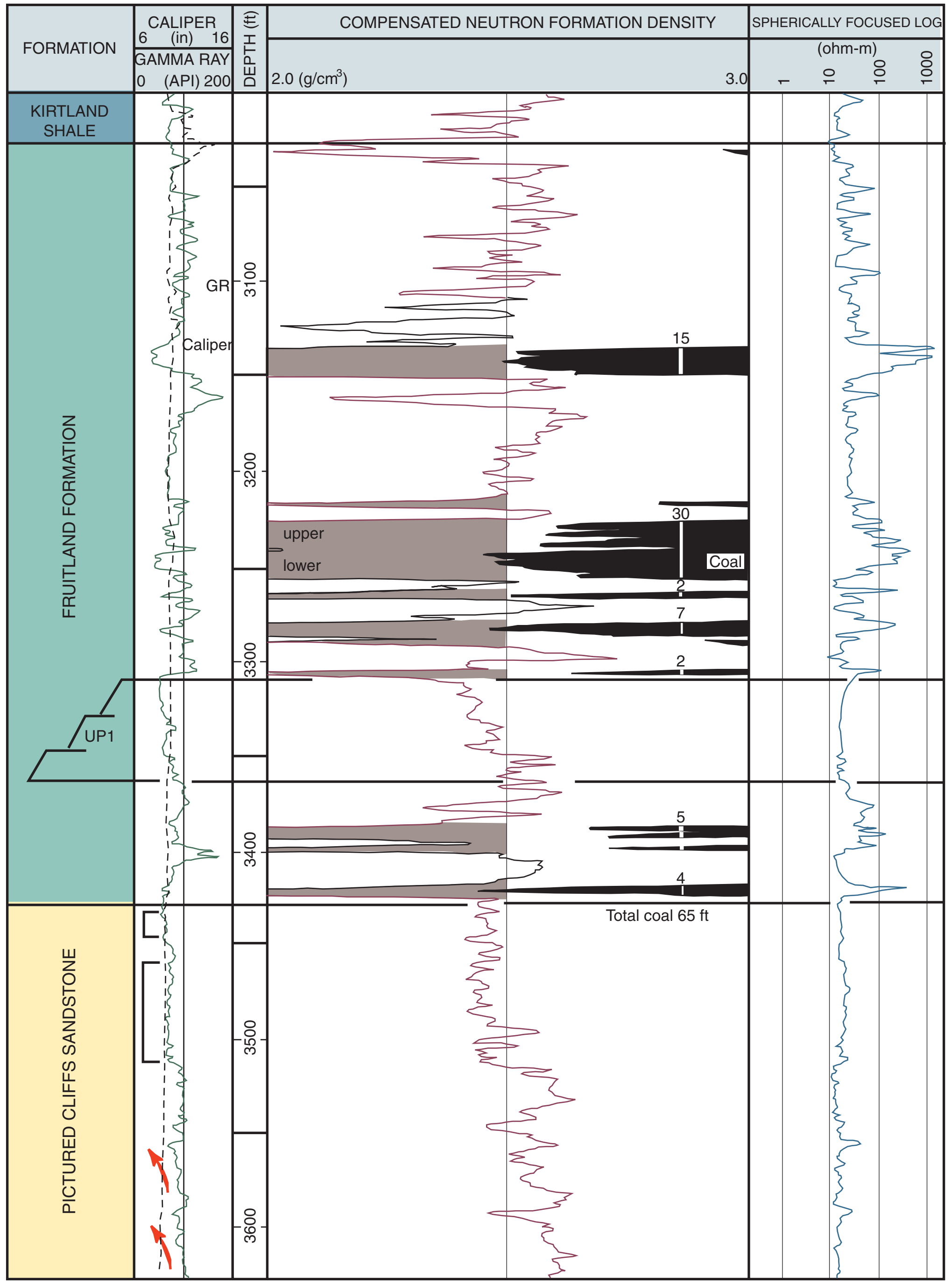


Figure SU-45. Identification and measurement of Fruitland Coal in type log (location is labeled in figure 44). High natural gamma response, indicated by arrows, are attributed to volcanic ash beds and to organically bound radioactive elements in coal seams (modified after Ayers et al., 1994).

Analog Fields In and Near Reservation

(*) denotes field lies within the reservation boundaries

*Ignacio Blanco (see Fig. SU-47)

Location of discovery well:	NE ¼, NW ¼, sec 7, T33N, R7W (1951)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Structural / Stratigraphic
Number of producing wells:	115 (1986)
Initial Production:	2,200 MCFGD
Cumulative Production:	26,750,352 MCFG (1986)
Gas characteristics:	990 BTU
Type of drive:	Solution gas
Average net pay:	16-205 feet, 70 feet average
Porosity:	4.4%
Permeability:	0 - 1500 md

Glades Fruitland

Location of discovery well:	NW ¼, MW ¼, sec 36, T32N, R12W (1978)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Stratigraphic
Number of producing wells:	12 (1994)
Initial Production:	1,002 MCFGD
Cumulative Production:	1,478,106 MCFG (1994)
Gas characteristics:	1,177 BTU
Average net pay:	20 feet average
Porosity:	8-15%
Permeability:	NA

Los Pinos Fruitland, North

Location of discovery well:	NE ¼, NE ¼, sec 18, T32N, R7W (1953)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Stratigraphic
Number of producing wells:	8 (1994)
Initial Production:	1,310 MCFGD
Cumulative Production:	2,111,682 MCFG (1994)
Gas characteristics:	1,071 BTU
Type of drive:	Gas expansion
Average net pay:	50 feet average
Porosity:	12-14% estimated
Permeability:	NA

Los Pinos Fruitland, South

Location of discovery well:	NE ¼, NE ¼, sec 17, T31N, R7W (1953)
Producing formation:	Cretaceous Fruitland Formation
Type of trap:	Stratigraphic, enhanced by fractures
Number of producing wells:	1 (1994)
Initial Production:	1,790 MCFGD
Cumulative Production:	947,221 MCFG (1994)
Gas characteristics:	980 BTU
Type of drive:	Gas expansion
Average net pay:	41 feet average
Porosity:	11.9% estimated
Permeability:	0.96 md

(Fassett, 1978,1983; Lay, 1997)

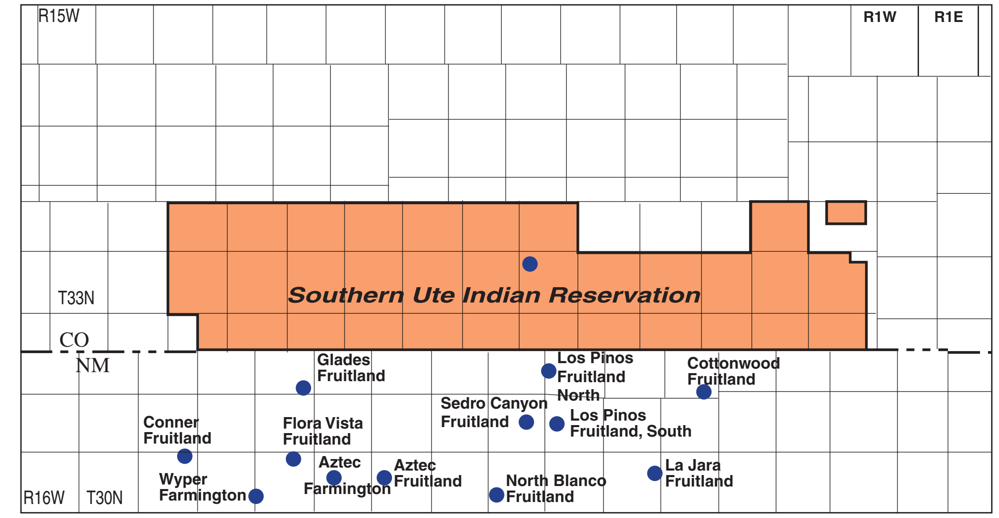


Figure SU-46. Location of discovery wells for fields that produce from the Fruitland-Kirtland Fluvial Sandstone Gas Play in and near the Southern Ute Indian Reservation.

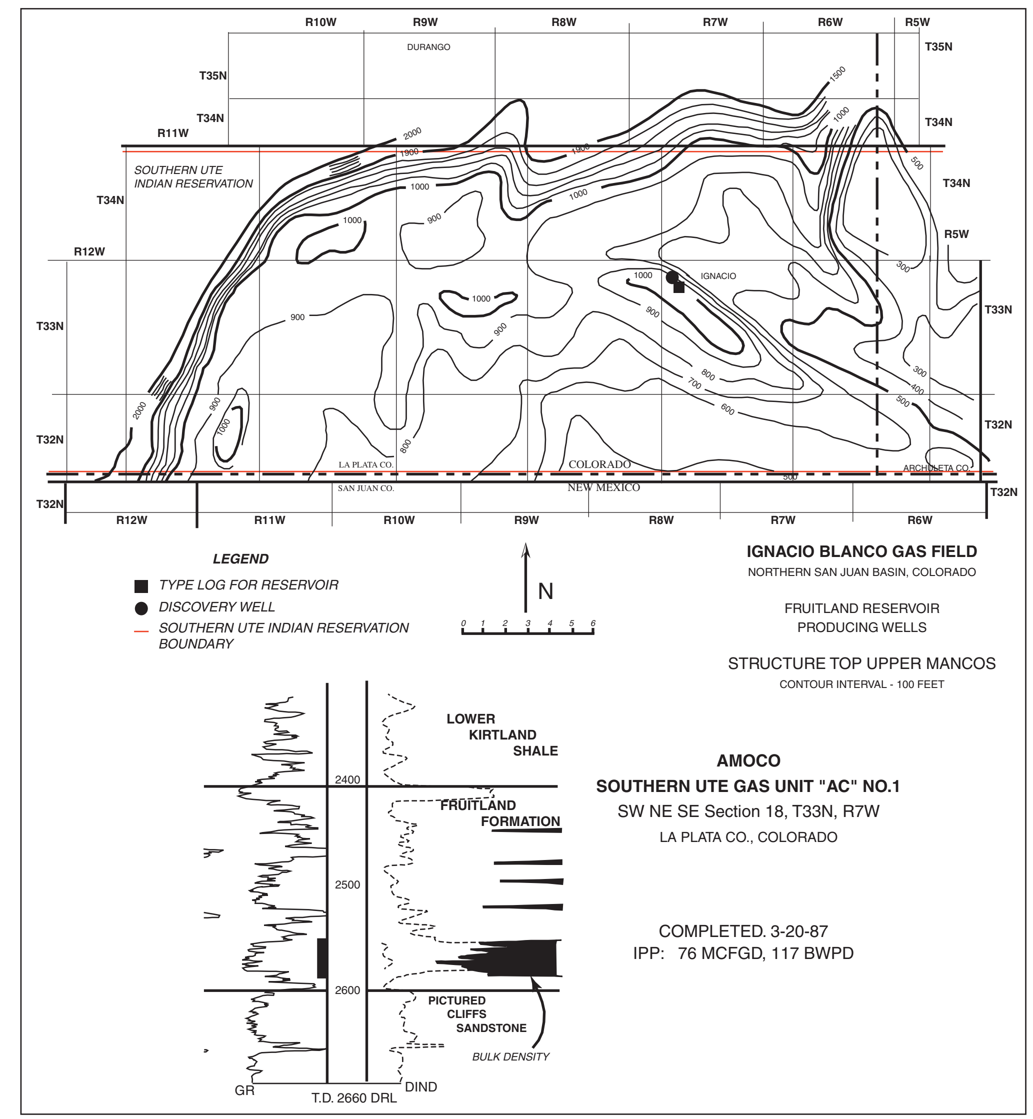


Figure SU-47. Structure contour map and log for the Ignacio Blanco gas field. Structure contours are drawn on the top of the upper Mancos Shale, contour interval is 100 feet. (modified after Harr, 1988).

Dakota Central Basin Gas Play

(USGS 2205)

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

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

Source rocks: Quality of source beds for oil and gas is also variable. Non-associated 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, 1988).

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 Eocene time and were elevated to temperatures appropriate for the generation of dry gas by late Oligocene time. Along the southern margin of the central basin, the Dakota and lower Mancos entered the thermal zone of oil generation during the late Miocene. 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 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. (Gautier et al. 1996)

Analog Fields In and Near Reservation

(* field lies within the reservation boundaries)

*** Ignacio Blanco Dakota (see figure SU-50)**

Location of discovery well:	SE, NE, sec 18, T33N, R7W (1950)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Stratigraphic and Structural
Number of producing wells:	193 (1992)
Initial production:	3,780 MCFGD
Cumulative Production:	219,443,282 MCFG (1992)
Gas characteristics:	BTU 950-990
Type of drive:	Gas expansion, possible water drive
Average net pay:	Variable 10-60 feet
Porosity:	7.5% ave.
Permeability:	0.02-0.7 md intergranular and natural fracturing

Ute Dome Dakota

Location of discovery well:	SE, sec 35, T32N, R14W (1921)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Faulted anticline
Number of producing wells:	14 (1978)
Initial production:	12,000 MCFGD
Cumulative Production:	18,767,726 MCFG (1994)
Gas characteristics:	Sweet, BTU 1000+
Type of drive:	Combination water and volumetric
Average net pay:	30 feet
Porosity:	15%
Permeability:	10 md

(Fassett, 1978,1983; Well and Lay, 1997)

Barker Creek Dakota

Location of discovery well:	SE, NE, sec 16, T32N, R19W (1925)
Producing formation:	Upper Cretaceous Dakota
Type of trap:	Structural
Number of producing wells:	5 (1977)
Initial production:	Estimated 10,000-30,000 MCFGD
Cumulative Production:	22,542,303 MCFG (1994)
Gas characteristics:	Sweet gas, 1,125 BTU
Type of drive:	Gas expansion
Average net pay:	40 feet
Porosity:	14%
Permeability:	0-1500 md, 16.5 md ave.

Strait Canyon Dakota

Location of discovery well:	NW, SW, sec 14, T31N, R16W (1975)
Producing formation:	Cretaceous Dakota Sandstone
Type of trap:	Structural
Number of producing wells:	N/A
Initial production:	303 MCFGD
Cumulative Production:	114,155 MCFG (1994)
Gas characteristics:	BTU 1031.0
Type of drive:	Water
Average net pay:	12 feet
Porosity:	15%
Permeability:	0.66-17 md, 10 md avg.

***Red Mesa**

(poor historical data)

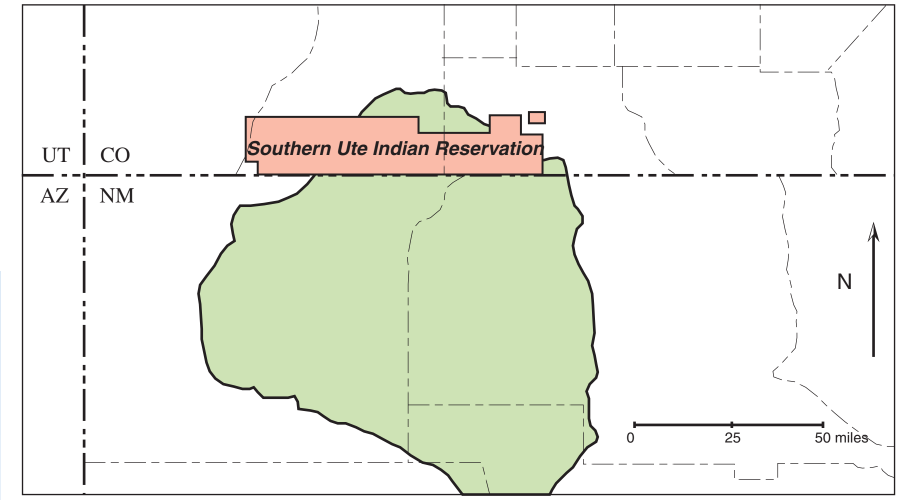


Figure SU-49. Location of the Dakota Central Basin Gas Play (modified after Gautier et al., 1996).

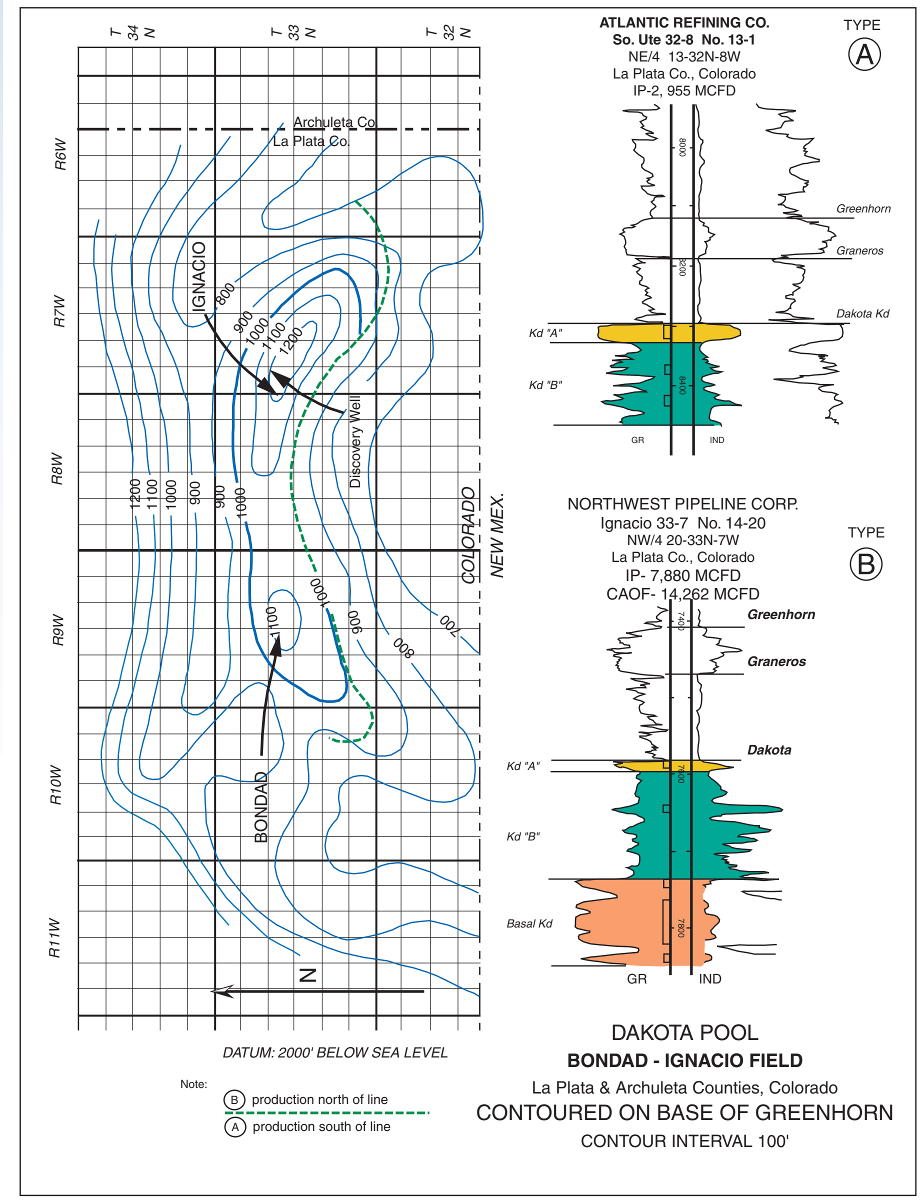


Figure SU-50. Structure map and logs for the Ignacio Blanco Gas Field. Structure Contours are drawn on the base of the Greenhorn. Kd "A" is littoral marine sandstones while Kd "B" is paludal-fluvial sandstones (modified after Bowman, 1978).

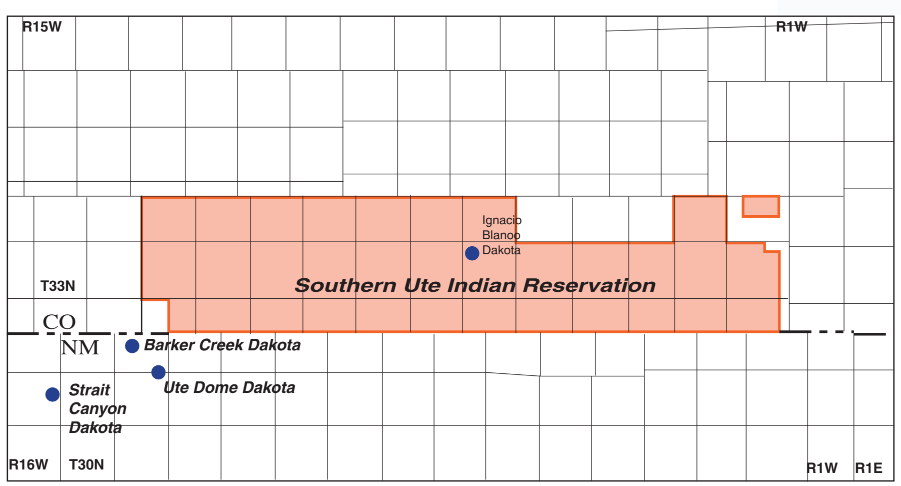


Figure SU-48. Location of discovery wells for fields producing from the Dakota Central Basin Gas Play.

Mancos Fractured Shale Play

(USGS 2208)

General Characteristics

The Mancos Fractured Shale Play (Fig. SU-51) is a confirmed, unconventional, continuous-type play (Gautier et al., 1996). 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 (Fig. SU-52).

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 33˚ to 43˚ 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.

Characteristics of Mancos Fractured Shale Play

The Mancos Fractured Shale play produces oil from fractures in the Niobrara-Carlile age clastic sediments (Fig. SU-53) which represent the first regressive wedge in the San Juan Basin (Gorhman et al.,1978; DuChene, 1989). These sediments have little or no effective porosity and permeability except that associated with fractures. The units of interest to oil exploration are the basal Niobrara (lower Tocito Sandstone), Niobrara-Carlile unconformity (upper Carlile Shale-Tocito Sandstone contact), and Carlile Shale/siltstone interval above the Juana Lopez (Fig. S-53). The Niobrara-Carlile stage is laterally consistent with respect to siltstone content, cement content, and other observable stratigraphic phenomenon.

The Hogback Monocline (Fig. SU-52) is the structural feature associated with the fractures in the Mancos Shale. It is located in the northwest flank of the San Juan Basin, southwest part of the Southern Ute Indian Reservation. It has a dip as great as 60˚ and has up to 8,000 feet of structural relief. Fractures are mostly associated with areas of maximum flexure and where anticlines and synclines intersect the monocline. The fractures are best developed parallel to the trend of the fold. Fracture apertures range from 1 ¾ inches to hairline cracks.

Oil reservoirs associated with the Mancos Fractured Shale Play depend on secondary porosity and permeability provided by the fractures. The reservoirs are lithologically controlled only to the extent that brittle competent interbeds capable of fracturing are present. The fractures have greater lateral, than vertical continuity. The basic tools used in exploration for fracture permeability are structure contour maps and lithofacies maps showing brittle interbeds in dominantly shaly sequences.

Trap types are structural/stratigraphic - fracture traps. The reservoirs are primarily driven by gravity drainage.

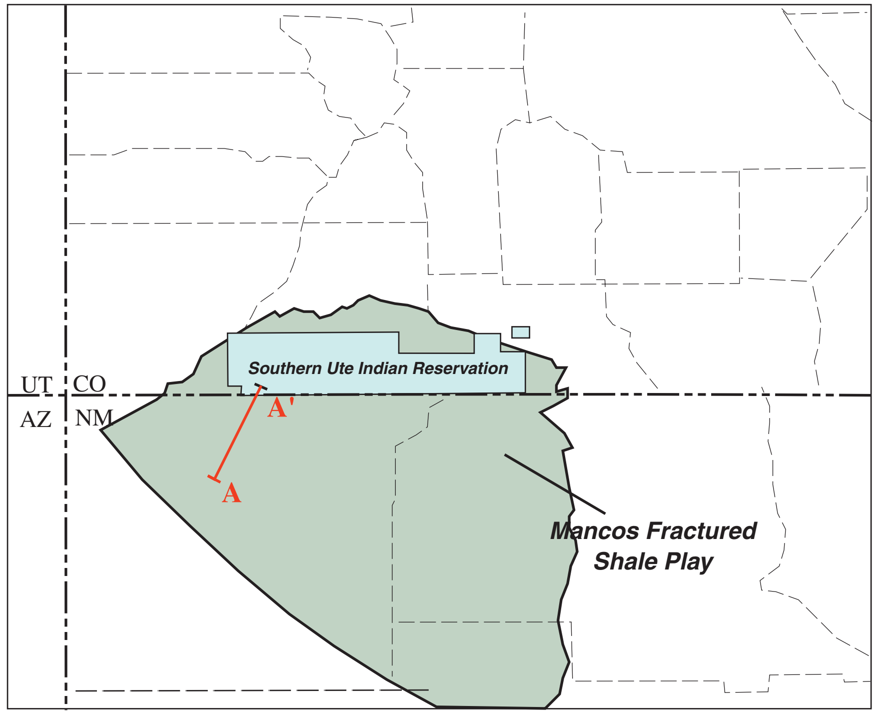


Figure SU-51 Location of the Mancos Fractured Shale Play (modified after Gautier et al., 1996).

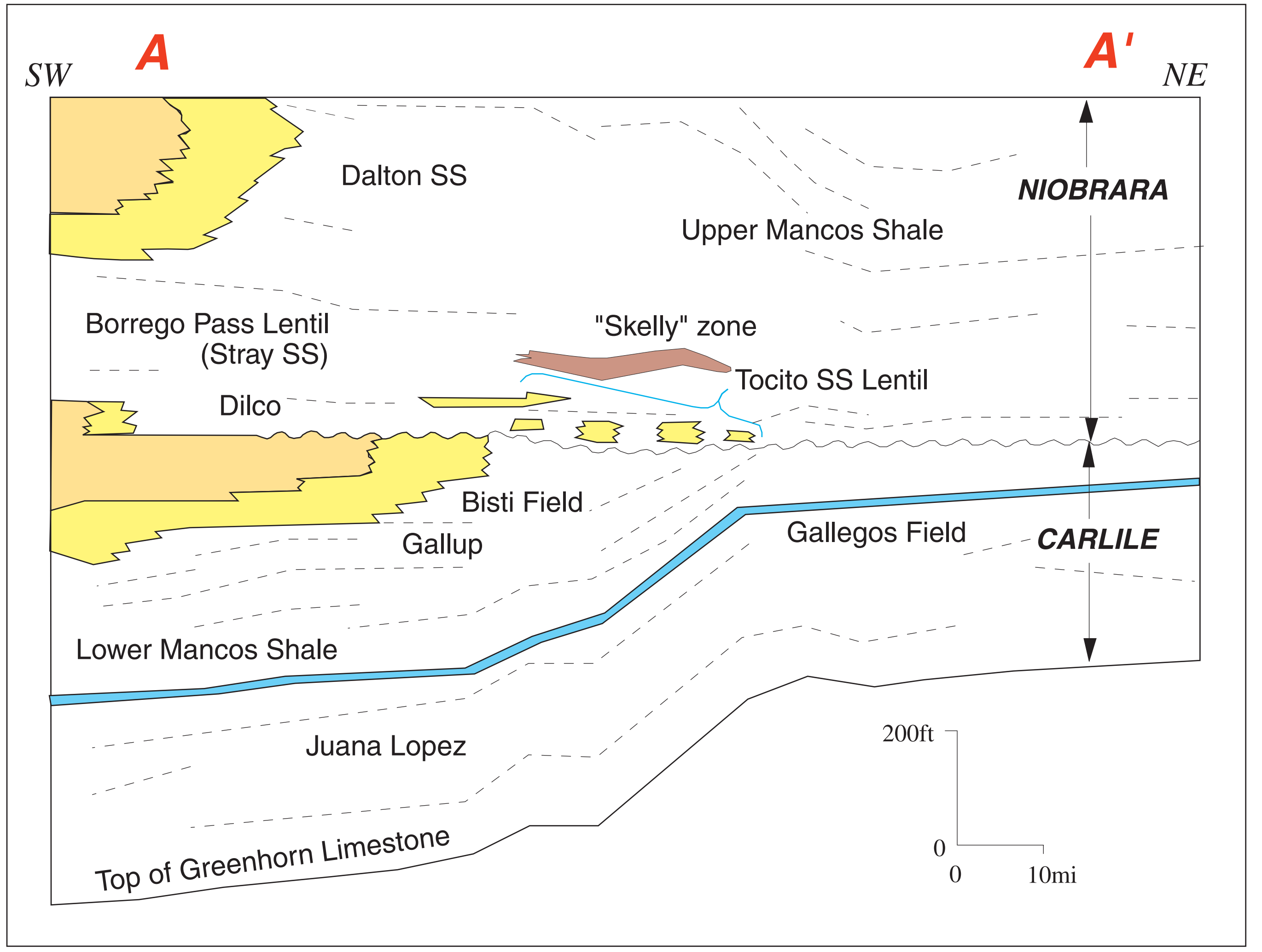


Figure SU-53 Subsurface stratigraphic cross section across the central San Juan Basin. Dashed lines are time marker bentonites or calcareous silty zones. Approximate location of section is labeled in Figure SU-51 (modified after Molenaar, 1973 and Tillman, 1985).

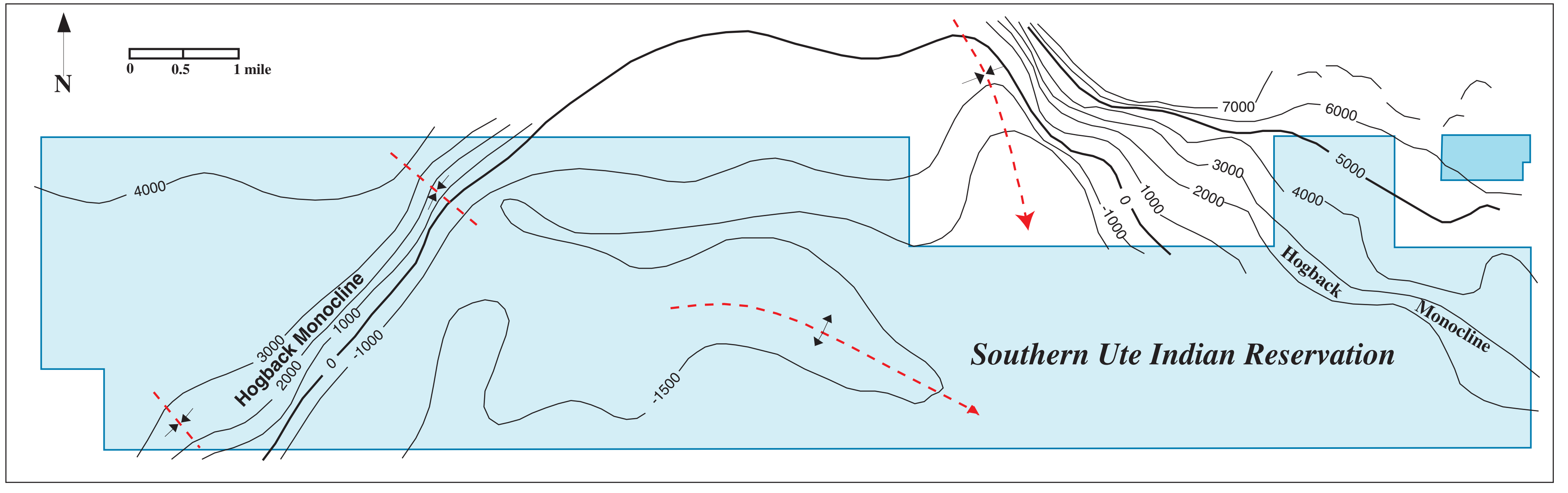


Figure SU-52 Structure contour map of the Dakota Sandstone showing the Hogback Monocline and associated anticlines and synclines (modified after Anderson, 1995).

Analog Fields in and near Reservation

(*) denotes that field lies within the reservation boundaries

La Plata Gallup

(Figs. SU-54 & SU-55)

Location of discovery well:	SE, SW, sec 5, T31N, R13W (1959)
Producing formation:	Cretaceous Mancos Shale
Type of trap:	Stratigraphic, Fractured Shale
Number of producing wells:	4 (1978)
Initial production:	241 BOD
Cumulative Production:	635,144 BO and 539, 607 MCGG (1994)
Oil characteristics:	Sweet, yellow-green, 38˚ API gravity
Type of drive:	Combination gravity drainage and solution gas
Average net pay:	uncertain, probably less than 30 feet
Porosity:	uncertain, probably on the order of 1%
Permeability:	Unknown

Verde Gallup

(Fig SU-54)

Location of discovery well:	SE, SE, sec 14, T31N R15W (1955)
Producing formation:	Fractured interval in Cretaceous "Gallup" sandstone (basal Niobrara age rocks)
Type of trap:	Fractured shale, structural
Number of producing wells:	27 (1978)
Initial production:	180 BOD
Cumulative Production:	7,963,004 BO and 174,956 MCFG (1994)
Oil characteristics:	38-42˚ API gravity
Type of drive:	Gravity drainage
Average net pay:	Variable
Porosity:	Fracture
Permeability:	Unlimited

Chromo (poor historical data)

Ref: Fassett, 1983, 1978; Wells and Lay, 1996

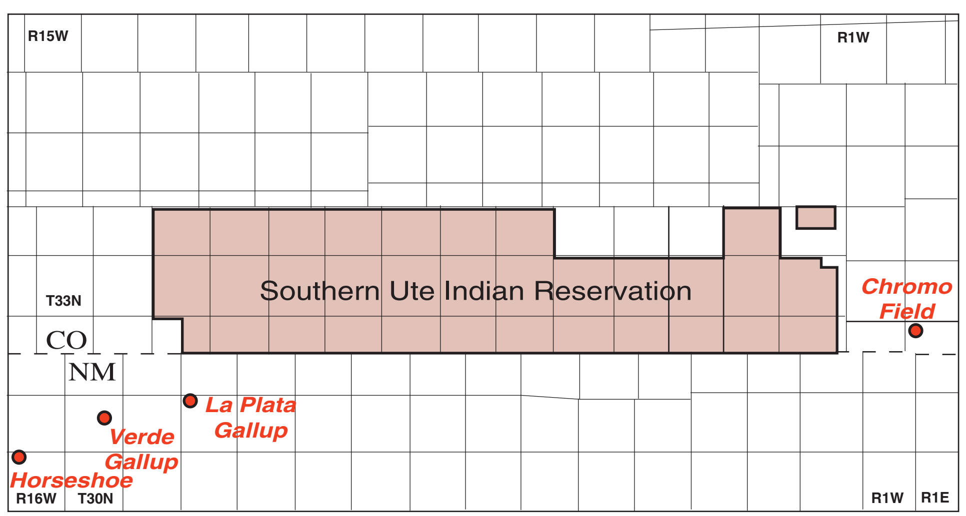


Figure SU-54 Location of oil field discovery wells for fields producing from the Mancos Fractured Shale Play.

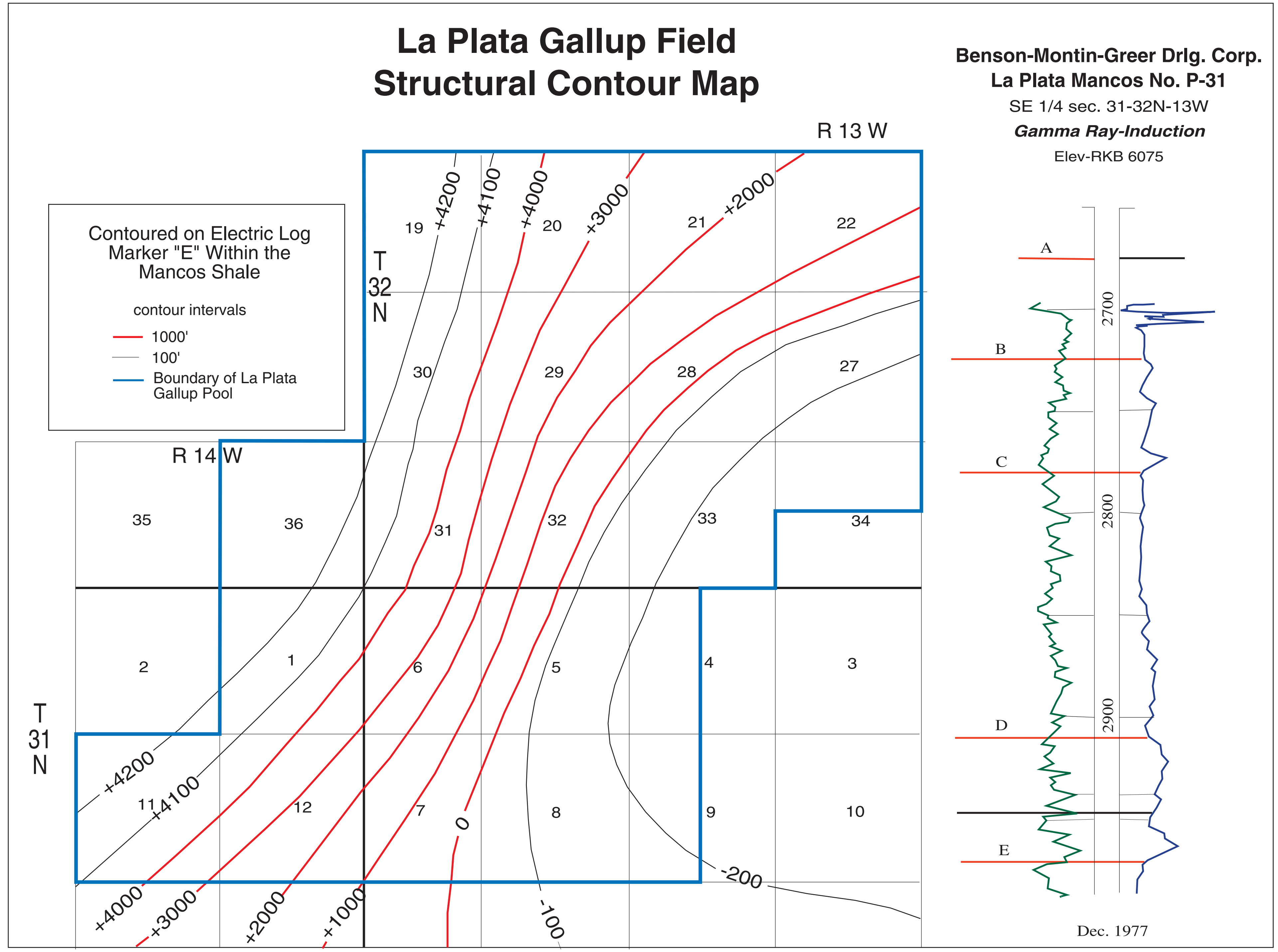


Figure SU-55 Structure contour map and type log for the La Plata Gallup field. Structure contour lines are drawn on the "E" marker which is the top of the Niobrara Stage, which generally produces highest electrical resistivities in the Mancos Shale. Contour interval is 100 feet. (modified after Greer, 1978).

Central Basin Mesaverde Gas Play

(USGS 2209)

General Characteristics

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 (Gautier et al, 1996). 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, non-associated 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 non-associated 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 (C1/C1-5) of 0.99-0.79 and isotopic carbon (d13C1) range of -33.4 to -46.7 per mil of the non-associated gas suggest a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Rice, 1988).
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 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.

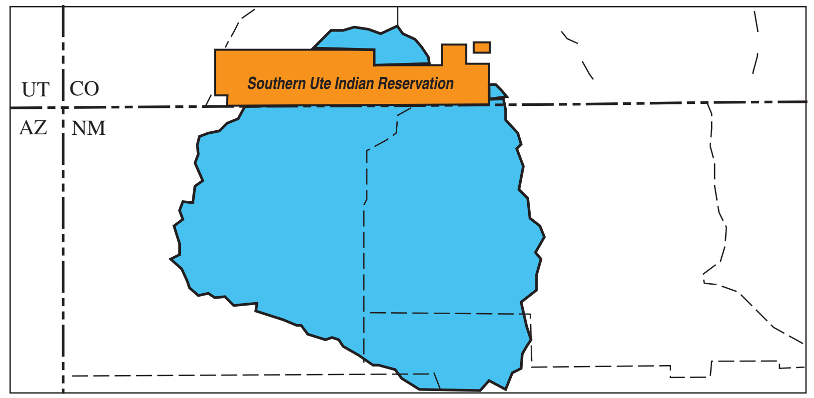


Figure SU-56. Location of the Central Basin Mesaverde Gas Play (modified after Gautier et al., 1996).

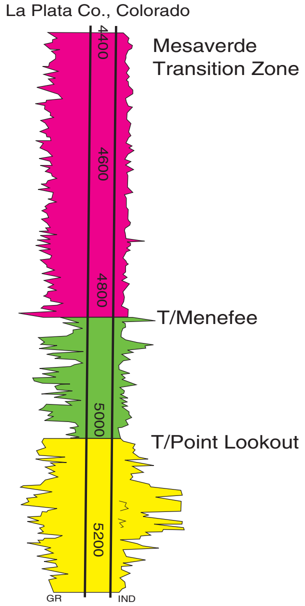
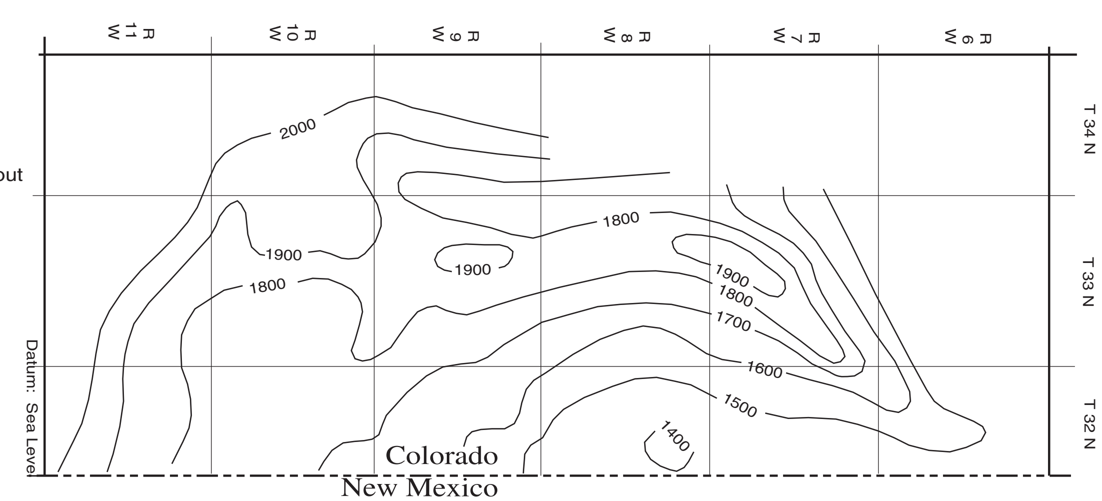


Figure SU-58 Structure contour map and log for the Mesaverde pool of the Ignacio Blanco Gas field. Structure contours are drawn on the Mesaverde transition zone, contour interval is 100 feet (modified after Bowman, 1978).



Analog Fields in and near Reservation

(*) denotes field lies within the reservation boundaries)

* Ignacio Blanco (see Fig SU-58)

Location of discovery well:	SE, SW, sec 15, T32N, R11W (1952)
Producing formation:	Cretaceous Mesaverde
Type of trap:	Stratigraphic, basinal hydrodynamic trapping
Number of producing wells:	825 (1992)
Initial production:	1,710 MCFGD
Cumulative Production:	625,860,995 MCFG, 257,988 B Condensate (1992)
Gas characteristics:	BTU 970-1040 range
Type of drive:	Gas expansion, dry gas reservoir
Average net pay:	20 - 150 feet
Porosity:	9.1% ave.
Permeability:	0.02-0.5 mD intergranular, enhanced by natural fractures

Animas Chacra

Location of discovery well:	NW, NW, sec 6, T31N, R10W (1975)
Producing formation:	Cretaceous Chacra: sandstone (tongue of La Ventana Member, Cliff House ss)
Type of trap:	Stratigraphic
Number of producing wells:	1 (1994)
Initial production:	3,300 MCFG
Cumulative Production:	8,086,233 MCFG and 1,988 B Condensate
Gas characteristics:	Unknown
Type of drive:	Gas expansion
Average net pay:	42 feet
Porosity:	4-6%
Permeability:	Unknown

Flora Vista Mesaverde

Location of discovery well:	SW, SW, sec 22, T30N, R12W (1961)
Producing formation:	Cretaceous Cliff House Sandstone
Type of trap:	Stratigraphic
Number of producing wells:	9 (19994)
Initial production:	5,988 MCFGD
Cumulative Production:	20,267,279 MCFG and 96,159 B Condensate
Gas characteristics:	BTU 1,252
Type of drive:	Solution Gas
Average net pay:	18.5 feet
Porosity:	14-17%
Permeability:	2-3 md

Navajo City Chacra

Location of discovery well:	SW, NW, sec 35, T30N, R8W (1974)
Producing formation:	Lewis Shale above "Chacra" tongue of Cliff House Sandstone
Type of trap:	Natural Fractures
Number of producing wells:	2 (1994)
Initial production:	3,433 MCFGD
Cumulative Production:	9,862,944 MCFG (1994)
Gas characteristics:	Unknown
Type of drive:	Gas expansion
Average net pay:	15 feet
Porosity:	3-4% matrix, probably fracture
Permeability:	Fracture, unknown

*Red Mesa (poor historical data)

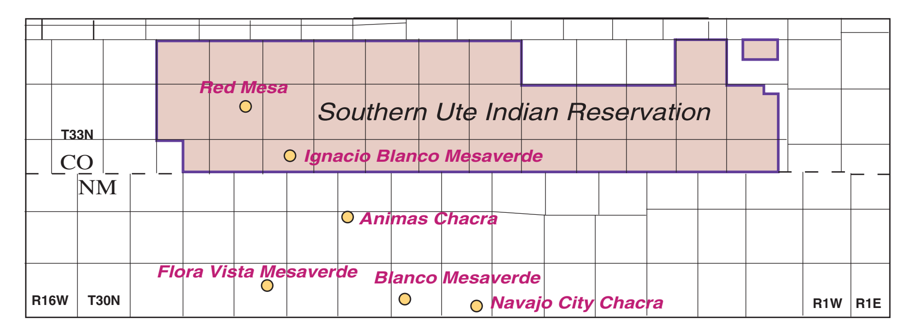


Figure SU-57. Location of discovery wells for fields producing from Central Basin Mesaverde Gas Play.

Pictured Cliffs Gas Play

(USGS 2211)

General Characteristics

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 (Gautier et al., 1996). 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 md, 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 (C1/C1-5) of 0.85-0.95 and an isotopic carbon (d13C1) range of -43.5 to -38.5 per mil (Rice, 1988).

Timing and migration: Gas generation was probably at a maximum during the late Oligocene and the Miocene. Up-dip 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 near-shore 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 sandstones intertongue throughout most of the central part of the basin. The Pictured Cliffs Sandstone is sealed off from 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.

Characteristics of the Pictured Cliffs Gas Play on the Southern Ute Indian Reservation

Numerous studies have focused on the Pictured Cliffs Sandstone in the Southern Ute Indian Reservation in the past ten years. For this reason, the following should be considered an extremely brief overview.

The Pictured Cliffs Sandstone represents a littoral deposit in a wave dominated system during the final northeasterly regression of the Cretaceous sea. The Lewis Shale is stratigraphically below and intertongues with the Pictured Cliffs (Fig. SU-61). In recent years, Pictured Cliffs gas development has shifted from a depleted structural accumulation to a stratigraphically trapped accumulation (Harr, 1988, and Hoppe, 1992). Two interpretations for high gas production exist in the literature. The first is that gas production is controlled by local sandstone lenticularity and permeability barriers (shales) developed along the shore-side slope of coastal barriers. Higher yield wells are attributed to individual thicker sandstone lenses which are least shaley. The second interpretation is that the Pictured Cliffs is characterized as a low-permeability, gas saturated reservoir with production dependent on fractures. Fractures play a crucial role in production. The highest producing wells in the Pictured Cliffs show communication between them, which is explained by fractures. For this reason, fracture identification is important in identifying new reservoirs. Landsat imagery (Fig. SU-62) and multi-component 3-D seismic are being used to interpret fracture orientations and frequencies in the subsurface.

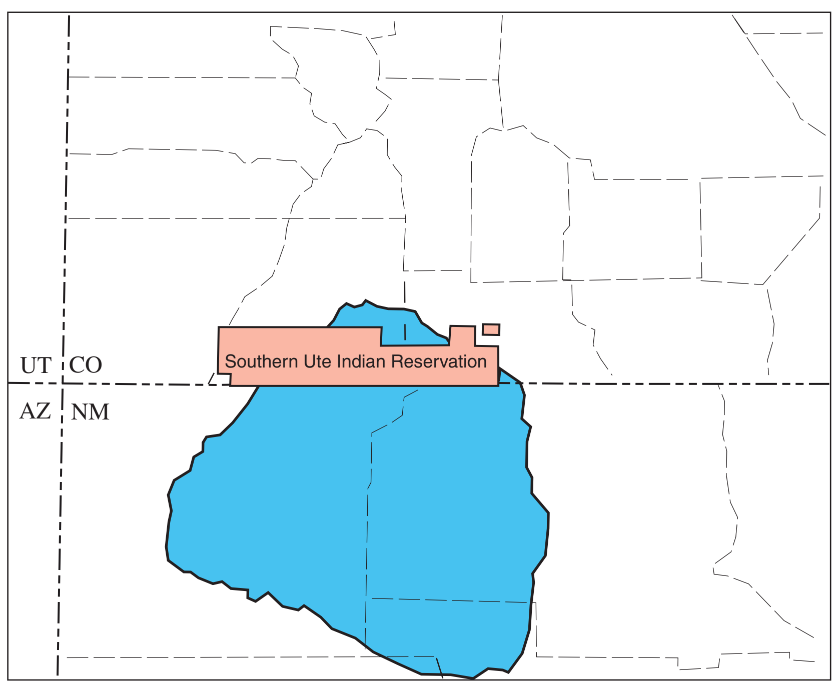


Figure SU-59. Location of the Pictured Cliffs Gas Play (modified after Gautier et al., 1996)

Figure SU-60. Structure contour map of the Pictured Cliffs Sandstone and major structural features (modified after Kelso and Wicks, 1988).

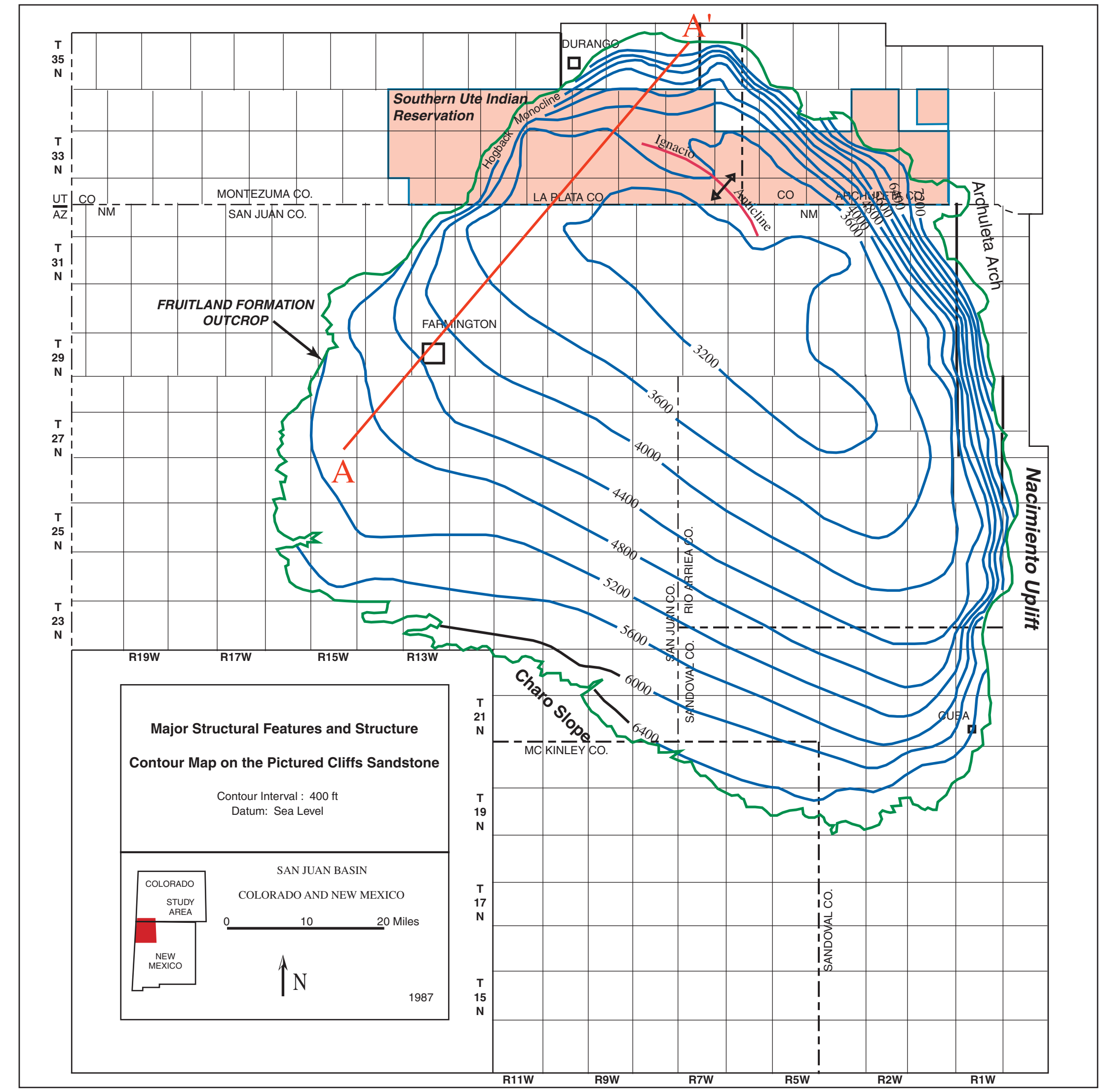
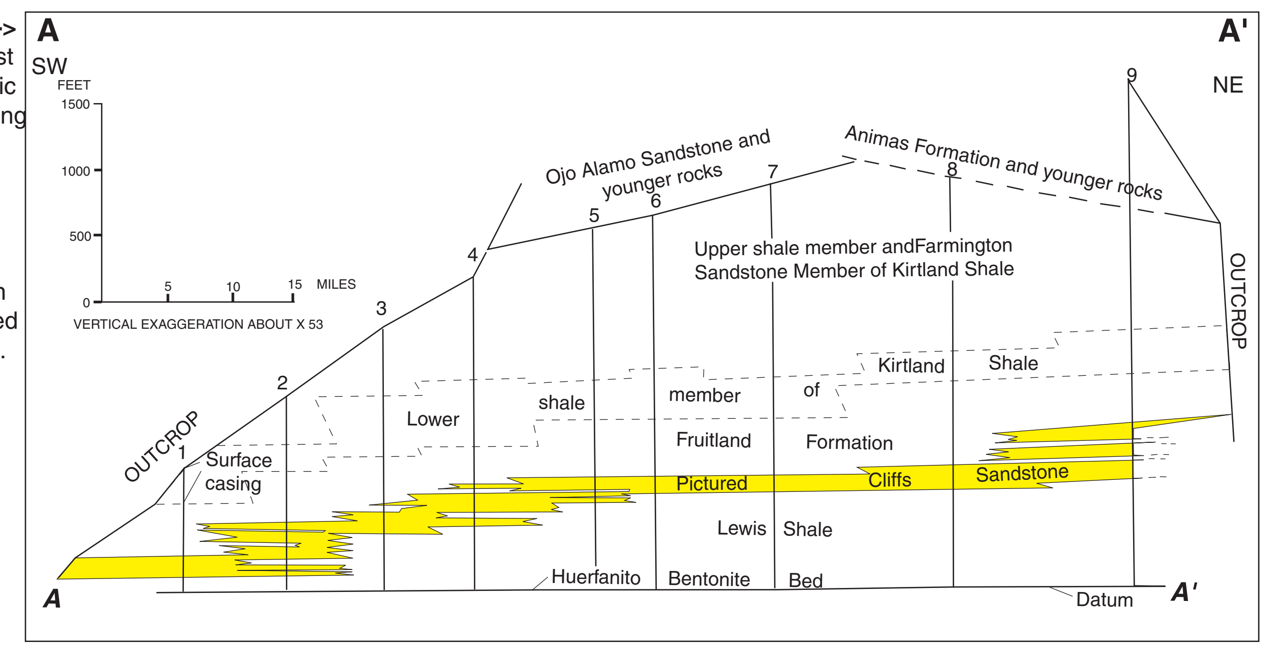


Figure SU-61. --> Southwest-northeast trending stratigraphic cross section showing the northeast stratigraphic rise of the Pictured Cliffs Sandstone and associated rocks. Section is located in Fig. SU-60 (modified after Fassett, 1988).



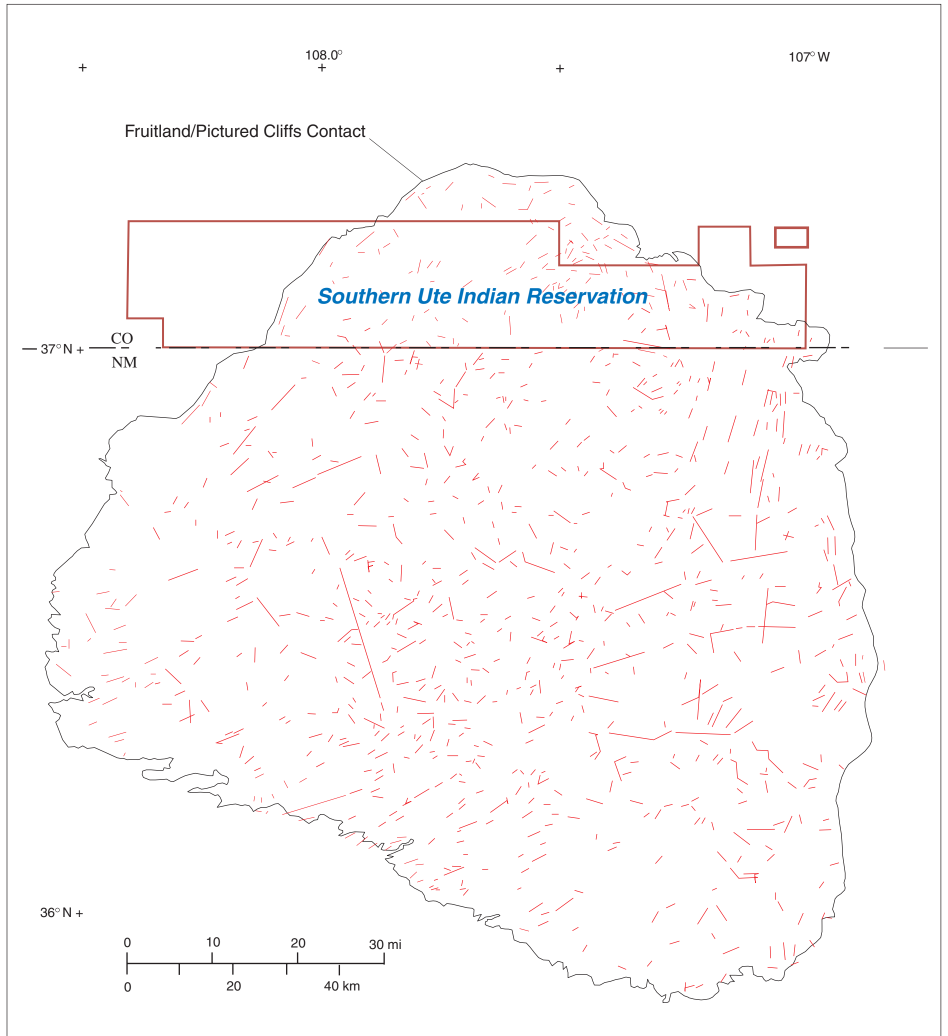


Figure SU-62. Landsat lineaments in the San Juan Basin (modified after Baumgardner, 1994).

Analog Fields within and near Reservation

(*) denotes field lies within the reservation boundaries)

*Ignacio Blanco (see Figs. 63 and 64)

Location of discovery well:	NE ¼, NW ¼, sec 7, T33N, R7W (1951)
·Producing formation:	Cretaceous Pictured Cliffs Sandstone
·Type of trap:	Structural / Stratigraphic
·Number of producing wells:	115 (1986)
·Initial Production:	2,200 MCFGD
·Cumulative Production:	26,750,352 MCFG (1986)
·Gas characteristics:	990 BTU
·Type of drive:	Solution gas
·Average net pay:	16-205 feet, 70 feet average
·Porosity:	4.4%
·Permeability: 0 - 1500 mD	

Albino Pictured Cliffs

·Location of discovery well:	SE ¼, SW ¼, sec 26, T32N, R8W (1974)
·Producing formation:	Cretaceous Pictured Cliffs Sandstone
·Type of trap:	Stratigraphic
·Number of producing wells:	15 (1994)
·Initial Production:	556 MCFGD
·Cumulative Production:	7,260,895 MCFG (1994)
·Gas characteristics: 1,074 BTU	
·Type of drive: Gas Expansion	
·Average net pay: 40 feet average	
·Porosity: 12%	
·Permeability: NA	

Aztec Pictured Cliffs

·Location of discovery well:	SE ¼, SW ¼, sec 10, T30N, R11W (1951)
·Producing formation:	Cretaceous Pictured Cliffs Sandstone
·Type of trap:	Stratigraphic
·Number of producing wells:	559 (1994)
·Initial Production:	180 MCFGD
·Cumulative Production:	340,024,535 MCFG (1994)
·Gas characteristics:	1,169 BTU
·Type of drive:	Gas expansion with water encroachment
·Average net pay:	40 feet average
·Porosity:	15%
·Permeability:	545 mD

Twin Mounds Pictured Cliffs

Location of discovery well:	SE ¼, SW ¼, sec 33, T30N, R14W (1951)
Producing formation:	Cretaceous Pictured Cliffs Sandstone
Type of trap:	Sratigraphic, up-dip gradation sand to shale
Number of producing wells:	7 (1994)
Initial Production:	1,875 MCFGD
Cumulative Production:	2,288,169 MCFG (1986)
Gas characteristics:	1,153 BTU
Type of drive:	Volumetric gas reservoir
Average net pay:	10 feet average
Porosity:	24%
Permeability:	65 mD

(Fassett, 1983, 1978; Wells and Lay, 1996)

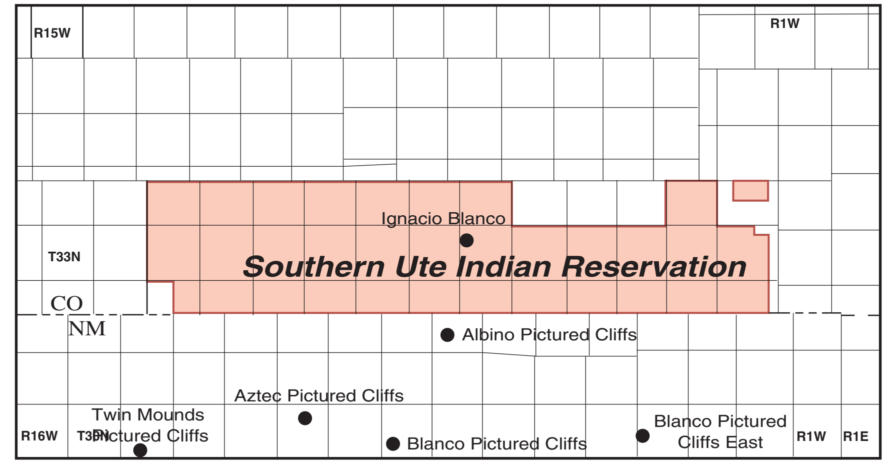


Figure SU-63. Location of discovery well for fields that produce from the Pictured Cliffs Gas Play in and near the Southern Ute Indian Reservation.

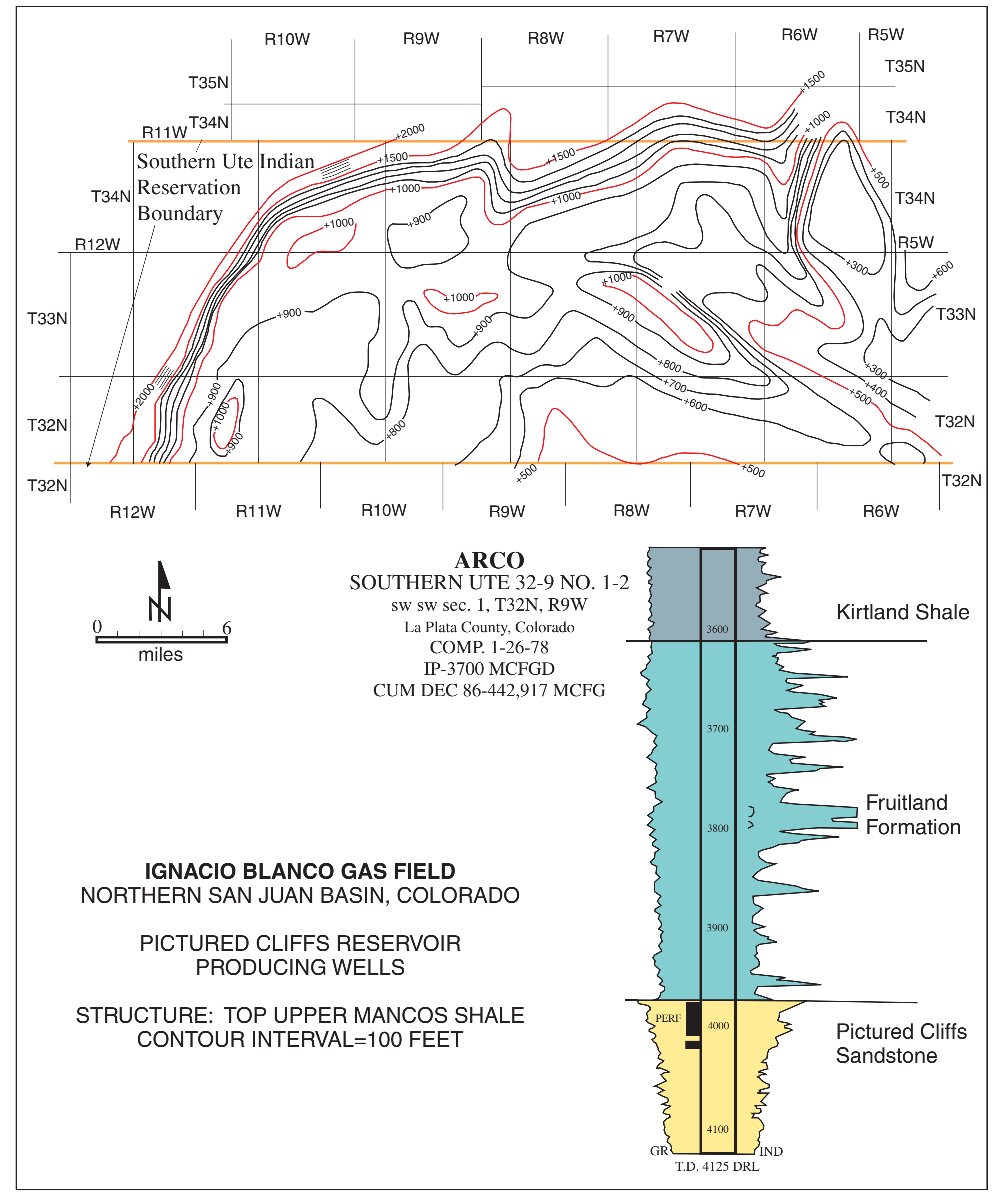


Figure SU-64. Structure contour map and log for the Ignacio Blanco Gas Field (modified after Harr, 1988).

COAL BED GAS PLAYS

Overpressured Play

(USGS 2250)

Underpressured Discharge Play

(USGS 2252)

Underpressured Play

(USGS 2253)

General Characteristics

On the basis of hydrology, pressure regime, reservoir properties, and hydrocarbon composition, three plays are identified for the Fruitland coal-bed gas: (1) San Juan-Overpressured Play, (2) San Juan-Underpressured Discharge Play, and (3) San Juan-Underpressured Play (Gautier et al., 1996).

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 (greater than 10 feet) 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 coal-bed 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 feet, the Fruitland Coal in a large part of the play is at depths of less than 3,000 feet. 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 overpressured play. Coals may be as thick as 10 feet 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 feet, 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 MCFPD. The potential for undiscovered coal-bed gas in this play is good to fair. Similar to the Overpressured Play, extensive drilling and production (Basin Fruitland Coal-Bed Gas Field) have taken place in this play, and the remaining potential for reserves is mainly at shallower depths (less than 1,500 feet) 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 feet) 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.

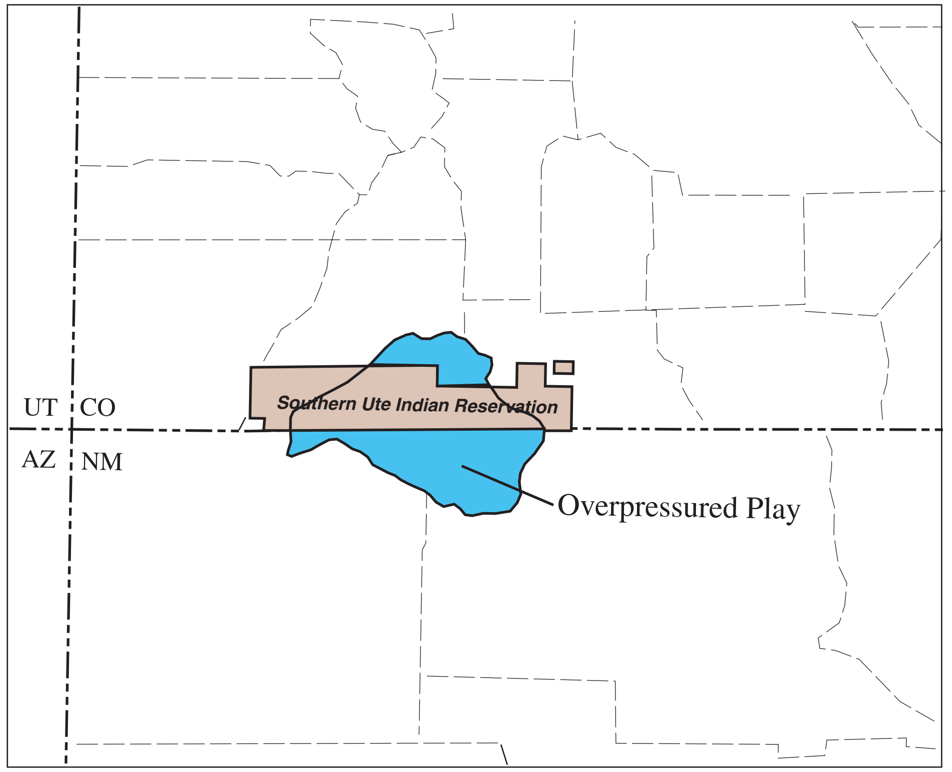


Figure SU-65. Location of the Overpressured Play (modified after Gautier et al., 1996).

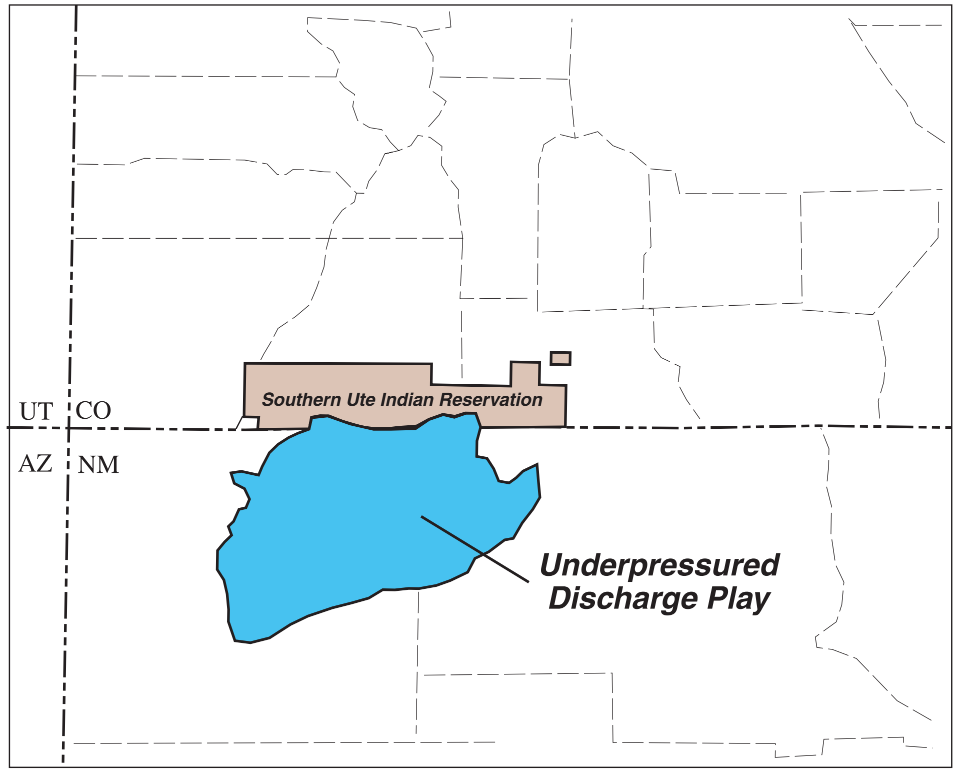


Figure SU-66. Location of the Underpressured Discharge Play (modified after Gautier et al., 1996).

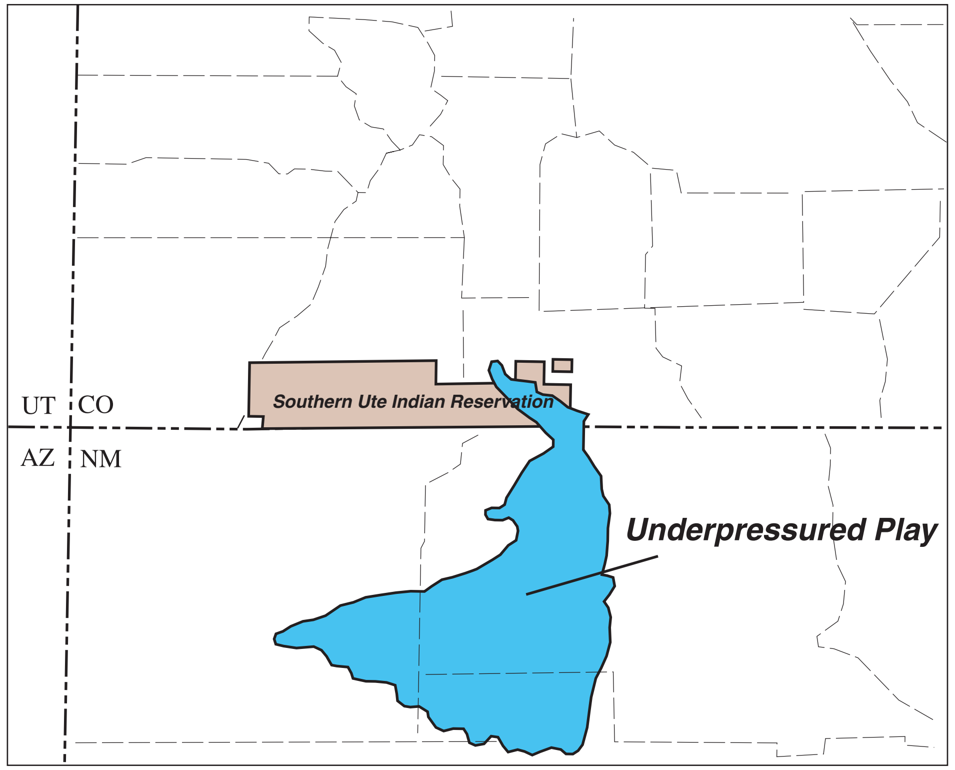


Figure SU-67. Location of the Underpressured Play (modified after Gautier et al., 1996).

Coal-Bed Gas Plays

In the San Juan Basin, significant resources of both coal and coalbed gas are in the Upper Cretaceous Fruitland Formation (Rice and Finn, 1996) . 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. 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 led 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 the 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 MCFGPD. 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 the 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.

REFERENCES

Anderson, R., ed., 1995, Southern Ute Indian Reservation, in Anderson, R., ed., The Oil and Gas Opportunity on Indian Lands: Exploration Policies and Procedures, 1995 edition, Bureau of Indian Affairs, p. 78-92.

Aubrey, W.M., 1992, New interpretations of the stratigraphy and sedimentology of uppermost Jurassic to lowermost Cretaceous strata in the San Juan Basin of northwestern New Mexico: U.S. Geological Survey Bulletin 1808-J.

Aubrey, W.M., 1991, Geologic framework of Cretaceous and Tertiary Rocks in the Southern Ute Indian Reservation and adjacent areas in the northern San Juan Basin, Southwestern Colorado, in Zech, R.S., Geology and Mineral Resources of the Southern Ute Indian Reservation: U.S. Geological Survey Professional Paper 1505-B.

Aubrey, W.M., 1991, Stratigraphic architecture and deformational history of Early Cretaceous foreland basin, eastern Utah and southwestern Colorado, in Huffman, Jr., A.C., Lund, R.W., Godwin, L.H., eds., Geology and Resources of the Paradox Basin, 1996 Special Symposium, Utah Geological Association and Four Corners Geological Society, p. 211-220.

Ayers, W.B., Jr., W.A. Ambrose, and J.S. Yeh, 1994, Coalbed methane in the Fruitland Formation, San Juan basin: depositional and structural controls on occurrence and resources, in W.B. Ayers, Jr., and W.R. Kaiser, eds., Coalbed methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado, New Mexico Bureau of Mines and Mineral Resources, Bulletin 146, Socorro, p. 13-61.

Ayers, W.B., and S.D. Zellers, 1994, Coalbed methane in the Fruitland Formation, Navajo Lake area: geologic controls on occurrence and producibility, in W.B. Ayers, Jr., and W.R. Kaiser, eds., Coalbed methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado, New Mexico Bureau of Mines and Mineral Resources, Bulletin 146, Socorro, p. 63-85.

Baumgardner, R.W., Jr., 1994, Use of lineament attributes to predict coalbed methane production in the northern San Juan Basin, in W.B. Ayers, Jr., and W.R. Kaiser, eds., Coalbed methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado, New Mexico Bureau of Mines and Mineral Resources, Bulletin 146, Socorro, p. 119-132.

Bell, G.J., 1989, Pressurized Coal Core Desorption Measurement Southern Ute Mobil 36-1 Well, San Juan Basin, Colorado: Resource Enterprises, INC., Grand Junction, Colorado.

Bevacqua, L.J., 1983, Wildwater, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 907-908.

Bland, D.M., 1992, Coalbed methane from the Fruitland Formation, San Juan Basin, New Mexico, in Lucas, S.G., et al., eds., San Juan Basin IV, New Mexico Geological Society forty-third annual field conference, p. 373-383

Bowman, K.C., 1978, Ignacio Blanco Dakota, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 131, 137, 390, 393.

Boyce, B.C., and L.C. Burch, 1988, The Southern Utes: An economically and socially successful Indian nation building upon its history and challenging the future, in Fassett, J.E., ed., Geology and coal-bed methane resources of the northern San Juan basin, Colorado and New Mexico, Rocky Mountain Association of Geologists, Denver, Colorado, p. 11-18.

Bircher, J.E., 1978, Glades Fruitland, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 966.

Broadhead, R.F., 1989, Petroleum production and frontier exploration in New Mexico, in Lorenz, J.C, Lucas, S.G. eds., Energy Frontiers in the Rockies, AAPG-SEPM-IMD Rocky Mountain Section, p. 35-46.

Brown, C.F., 1978, Aztec Pictured Cliffs, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 192.

Brown, C.F., 1978, Blanco Pictured Cliffs, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 225.

Brown, C.F., 1978, Blanco Pictured Cliffs, East, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 228.

Chidsey, T.C., D.E. Eby, and D.M. Lorenz, 1996, Geological reservoir characterization of small shallow-shelf carbonate fields, southern Paradox Basin, in Huffman, Jr., A.C., Lund, R.W., Godwin, L.H., eds., Geology and Resources of the Paradox Basin, 1996 Special Symposium, Utah Geological Association and Four Corners Geological Society, p. 39-56.

Clark, W.R., et. al, 1989, Frontier Exploration Plays in Colorado, in Lorenz, J.C, Lucas, S.G. eds., Energy Frontiers in the Rockies, AAPG-SEPM-IMD Rocky Mountain Section, p. 57-68.

Close, J.C., et al., 1991, Western Cretaceous Coal Seam Project, Measurement and Analysis of Sorption Isotherm Data: Gas Research Institute Topical Report GRI-91/0335, Chicago Illinois.

Close, J.C., T.J. Pratt, M.J. Mavor, 1991, Western Cretaceous Coal Seam Project, Preliminary Evaluation of the Co-operative Research Well Valencia Canyon 32-1: Gas Research Institute Topical Report GRI-92/0129, Chicago, Illinois.

Condon, S.M., 1992, Geologic and Structure Contour Map of the Southern Ute Indian Reservation and Adjacent Areas, Southwestern Colorado and Northeastern New Mexico, U.S. Department of the Interior, U.S. Geological Survey, scale 1:100,000.

Condon, S.M., 1992, Geologic framework of Pre-Cretaceous rocks in the Southern Ute Indian Reservation and adjacent areas, southwestern Colorado and Northwestern New Mexico, in Zech ed., Geology and Mineral Resources of the Southern Ute Indian Reservation: U.S. Geological Survey Professional Paper 1505-A.

Condon, S.M., and A.C. Huffman Jr., 1994, Northwest-southeast-oriented stratigraphic cross sections of Jurassic through Paleozoic rocks, San Juan Basin and vicinity, Colorado, Arizona, and New Mexico: Oil and Gas Investigations Chart, U.S. Geological Survey.

Conway, M.W., 1994, Is it time to put the final nail in the fraccing coffin?: Methane from Coal Seams Technology, April, 1994, p. 7-12.

Craney, D.L., 1978, Ignacio Blanco Fruitland-Pictured Cliffs, East, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 134.

Cross, T.A., and M.A. Lessenger, 1997, Correlation strategies for clastic wedges, in RMAG special publication.

Davis, T.L., and G.M. Jackson, 1988, Seismic stratigraphy study of algal mound reservoirs, Patterson and Nancy fields, Paradox Basin, San Juan County, Utah: Geophysics, V. 53, No. 7, p. 875-880.

Doneselaar, M. E., 1989, The Cliff House Sandstone, San Juan Basin, New Mexico: Model for the stacking of 'transgressive' barrier complexes: Journal of Sedimentary Petrology, Vol. 59, No. 1, p. 13-27.

Donovan, W., 1978, Price Gramps, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 157.

DuChene, H.R., 1989, Fractured Reservoirs in the San Juan Basin, Colorado and New Mexico, in Lorenz, J.C, Lucas, S.G. eds., Energy Frontiers in the Rockies, AAPG-SEPM-IMD Rocky Mountain Section, p. 101-109.

Dunbar, R.W., et al., 1992, Strandplain and deltaic depositional models for the Point Lookout Sandstone, San Juan basin and Four corners platform, New Mexico and Colorado, in Lucas, S.G., et al., eds., San Juan Basin IV, New Mexico Geological Society forty-third annual field conference, p. 199-206.

Edmister, J.A., 1983, Cottonwood Fruitland, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 946.

Fassett, J.E., 1988, Geometry and depositional environment of Fruitland Formation coal beds, San Juan basin, New Mexico and Colorado: Anatomy of a giant coal-bed methane deposit, in Fassett, J.E., ed., Geology and coal-bed methane resources of the northern San Juan basin, Colorado and New Mexico, Rocky Mountain Association of Geologists, Denver, Colorado, p. 23-38.

Fassett, J.E. ed., 1983, Oil and gas fields of the Four Corners area, Volume III, Four Corners Geological Society, 727 p.

Fassett, J.E. ed., 1978, Oil and gas fields of the Four Corners area, Volumes I and II, Four Corners Geological Society, 727 p.

Gautier, D.L., G.L. Dolton, K.I. Takahashi, and K.L. Varnes, eds., 1996, 1995 National Assessment of United States Oil and Gas Resources-Results, Methodology, and Supporting Data: U.S. Geological Survey Digital Data Series DDS-30, Release 2.

Gorhman, Jr., F.D., et al., 1979, Fractures in Cretaceous rocks from selected areas of San Juan Basin, New Mexico-Exploration Implications: AAPG Bulletin V. 63, No. 4, P. 598-607.

Gorhman, Jr., F.D., and L.A. Woodward, J.F. Callender, and A.R. Greer, 1977, Fracture permeability in Cretaceous rocks of the San Juan Basin, in Fasset, J.E., James, H.L., and Hodgson, H.E., eds., San Juan Basin III, New Mexico Geological Survey, p. 235-241.

Greer, A.R., 1978, La Plata Gallup, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 371.

Hamilton, D.P, 1983, Twin Mounds Pictured Cliffs, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 540.

Harr, C.L., 1996, Paradox Oil and Gas Potential of the Ute Mountain Ute Indian Reservation, in Huffman, Jr., A.C., Lund, R.W., Godwin, L.H., eds., Geology and Resources of the Paradox Basin, 1996 Special Symposium, Utah Geological Association and Four Corners Geological Society, p. 13-28.

Harr, C.L., 1988, The Ignacio Blanco gas field northern San Juan basin, Colorado, in Fassett, J.E., ed., Geology and coal-bed methane resources of the northern San Juan basin, Colorado and New Mexico, Rocky Mountain Association of Geologists, Denver, Colorado, p. 205-219.

Hart, A.W., and E.G. Mickel, 1983, Wickiup, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 904.

Hoppe, W.F., 1992, Hydrocarbon potential and stratigraphy of the Pictured Cliffs, Fruitland, and Ojo Alamo Formations in the northeastern San Juan basin, New Mexico, in Lucas, S.G., et al., eds., San Juan Basin IV, New Mexico Geological Society forty-third annual field conference, p. 359-371.

Hoppe, W.F., 1978, Animas Chacra, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 184.

Hornbeck, J. M., 1978, Flora Vista Gallup, in Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 294.

Huffman, Jr., A.C., 1996, San Juan Basin Province (022), in Gautier, D.L., et al., 1995 National assessment of United States oil and gas resources-results, methodology, and supporting data, U.S Geological Survey Digital Data Series DDS-30 Release 2.

Huffman, Jr., A.C., and S.M. Condon, 1993, Stratigraphy, Structure, and Paleography of Pennsylvanian and Permian rocks, San Juan Basin and adjacent areas, Utah, Colorado, Arizona, and New Mexico: U.S. Geological Survey Bulletin 1808-O, plates, p. 9.

Huffman, Jr., A.C., and S.M. Condon, 1994, Southwest-northeast-oriented stratigraphic cross sections of Jurassic through Paleozoic rocks, San Juan Basin and vicinity, Colorado, Arizona, and New Mexico: Oil and Gas Investigations Chart, U.S. Geological Survey.

Hunt, A.P., and L.G. Spencer, 1992, Stratigraphy, paleontology and age of the Fruitland and Kirtland Formations (Upper Cretaceous), San Juan basin, New Mexico, in Lucas, S.G., et al., eds., San Juan Basin IV, New Mexico Geological Society forty-third annual field conference, p. 217-239.

Indian Land Areas: U. S. Department of the Interior Bureau of Indian Affairs, 1993.

Jennette, D.C., and C.R. Jones, 1995, Sequence stratigraphy of the Upper Cretaceous Tocito Sandstone: A model for tidally influenced incised valleys, Sand Juan Basin, New Mexico, in Van Wagoner, J.C., Bertram, G.T., eds., Sequence Stratigraphy of Foreland Basin Deposits, Outcrop and subsurface examples from the Cretaceous of North America, AAPG Memoir 64, p. 311-348.

Kaiser, W.R., and W.B. Ayers, Jr., 1994, Coalbed methane production, Fruitland Formation, San Juan basin: Geologic and hydrologic controls, in W.B. Ayers, Jr., and W.R. Kaiser, eds., Coalbed methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado, New Mexico Bureau of Mines and Mineral Resources, Bulletin 146, Socorro, p. 187-207.

Katzman, D., and R. Write-Dunbar, 1992, Parasequence geometry and facies architecture in the upper Cretaceous Point Lookout Sandstone, Four Corners Platform, southwestern Colorado, in Lucas, S.G., et al., eds., San Juan Basin IV, New Mexico Geological Society forty-third annual field conference, p. 187-197.

Keighin, C.W., 1996, Petroleum geology and hydrocarbon potential of pre-Dakota strata, western portion of the Southern Ute Indian Reservation, Colorado, *in* Huffman, Jr., A.C., Lund, R.W., Godwin, L.H., eds., Ge-
Malone, T.L., 1978, La Jara Fruitland, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 369.
Marvin, L, and J.P. Matheny, 1978, Cha Cha Gallup, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 256.
Matheny, M.L., 1983, Cinder Buttes, *in* Fassett, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 873.
Matheny, M.L., 1978, Barker Creek Dakota, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 198.
Matheny, M.L., 1978, Barker Creek Paradox, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 201.
Matheny, M.L., and C.J. Little, 1978, Many Rocks Gallup, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 398.
Matheny, M.L., and C.J. Little, 1978, Many Rocks Gallup, North, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 403.
Mavor, M.J., 1994, Well testing for San Juan Basin open-hole completion evaluation: Methane from Coal Seams Technology, April, 1994, p. 19-26.
Mavor, M.J., et al., 1992, Western Cretaceous Coal Seam Project Summary of the Vertical COAL Site, San Juan Basin: Gas Research Topical Report GRI-92/0504, Chicago Illinois.
Mavor, M.J., et al., 1990, Western Cretaceous Coal Seam Project, Preliminary Evaluation of the Co-operative Research Well FC Federal #12, Gas Research Institute Topical Report, Chicago Illinois.
McEachin, W.D., and R.M. Royce, 1978, Horseshoe Gallup, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 335.
Meibos, L.C., 1983, Navajo City Chacra, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 989.
Meibos, L.C., 1983, Nenahnezad Mesaverde, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 992.
Middleman, A.A., 1983, Albino Gallup, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 924.
Middleman, A.A., 1983, Albino Pictured Cliffs, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 927.
Molenaar, C.M., D. Nummedal, and W.A. Cobban, 1996, Regional stratigraphic cross sections of the Gallup Sandstone and associated strata around the Sand Juan Basin, New Mexico, and parts of adjoining Arizona and Colorado: Oil and Gas Investigations Chart, U. S. Geological Survey.
Molenaar, C.M., and J.K. Baird, 1991, Stratigraphic cross sections of Upper Cretaceous rocks in the Northern San Juan Basin, Southern Ute Indian Reservation, southwestern Colorado, *in* Zech ed., Geology and Mineral Resources of the Southern Ute Indian Reservation: U.S. Geological Survey Professional Paper 1505-C
Molenaar, C.M., and J.K. Baird, 1989, North-south stratigraphic cross sections of Upper Cretaceous rocks, northern San Juan Basin, southwestern Colorado: Miscellaneous Field Studies Map, U.S. Geological Survey.
Molenaar, C.M., 1988, Stratigraphic cross section showing upper Cretaceous rocks across the San Juan basin, New Mexico and Colorado, *in* Fassett, J.E., ed., Geology and coal-bed methane resources of the northern San Juan basin, Colorado and New Mexico, Rocky Mountain Association of Geologists, Denver, Colorado, p. 21.
Nuccio, V.R., and S.M. Condon, 1996, Burial and thermal history of the Paradox Basin, Utah and Colorado, and petroleum potential of the middle Pennsylvanian Paradox Formation, *in* Huffman, Jr., A.C., Lund, R.W., Godwin, L.H., eds., Geology and Resources of the Paradox Basin, 1996 Special Symposium, Utah Geological Association and Four Corners Geological Society, p. 57-76.
Nummedal, D., 1992, Sequence stratigraphy in ramp settings-with application to upper Cretaceous rocks in the San Juan basin, *in* Lucas, S.G., et al., eds., San Juan Basin IV, New Mexico Geological Society forty-third annual field conference, p. 185-186.
Nummedal, D., and C.M. Molenaar, 1995, Sequence stratigraphy of ramp-setting strand plain successions: the Gallup Sandstone, New Mexico, *in* Van Wagner, J.C., Bertram, G.T., eds., Sequence Stratigraphy of Foreland Basin Deposits, Outcrop and subsurface examples from the Cretaceous of North America, AAPG Memoir 64, p. 277-310.
Olszewski, A.J., and R.A. Schraufnagel, 1993, Development of formation evaluation technology for coalbed methane development: Methane from Coal Seams Technology, February 1993, P. 32-36.
Olszewski, A.J., and J.D. McLennan, 1992, Development of formation evaluation technology for coalbed methane development: Methane from Coal Seams Technology, July 1992, P. 25-29.
Osterhoudt, W., 1978, Chromo, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 111.
Pritchard, R.L., 1987, Flora Vista Mesaverde, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 131.
Raup, O.B, and R.J. Hite, 1992, Lithology of evaporite cycles and cycle boundaries in the upper part of the Paradox Formation of the Hermosa Group of Pennsylvanian Age in the Paradox Basin, Utah and Colorado: U.S. Geological Survey Bulletin 2000-B.
Rice, D.R., and T.M. Finn, 1996, Coal-bed gas plays, *in* Gautier, D.L., et al., eds., 1995 National assessment of United States oil and gas resources-results, methodology, and supporting data, U.S. Geological Survey Digital Data Series DDS-30 Release 2.
Rice, D.D., et al., 1988, Identification and significance of coal-bed gas, San Juan basin, northwestern New Mexico and southwestern Colorado, *in* Fassett, J.E., ed., Geology and coal-bed methane resources of the northern San Juan basin, Colorado and New Mexico, Rocky Mountain Association of Geologists, Denver, Colorado, p. 51-59.
Riggs, E.A., 1983, Wyper Farmington, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 1059.
Riggs, E.A., 1978, Verde Gallup, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 550.
Roth, G., and R.E. Lauth, 1983, Alkali Gulch, West, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 867.
Roth, G., and R.E. Lauth, 1983, Menefee Mountain, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 884.
Rueger, B.F., 1996, Palynology and its relationship to climatically induced depositional cycles in the Middle Pennsylvanian (Desmoinesian) Paradox Formation of southeastern Utah: U.S. Geological Survey Bulletin 2000-K.
Sandberg, D.T., 1990, Coal resources of Upper Cretaceous Fruitland Formation in the Southern Ute Indian Reservation, Southwestern Colorado *in* Zech R.S. ed., Geology and Mineral Resources of the Southern Ute Indian Reservation, U.S. Geological Survey Professional Paper 1505-D.
Scott, A.R., W.R. Kaiser, and W.B. Ayers, Jr., 1994, Thermal maturity of Fruitland coal and composition of Fruitland Formation and Pictured Cliffs Sandstone gases, *in* W.B. Ayers, Jr., and W.R. Kaiser, eds., Coalbed methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado, New Mexico Bureau of Mines and Mineral Resources, Bulletin 146, Socorro, p. 165-186.
Sperandio, R.J., 1983, Sedro Canyon Fruitland, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volume III, Four Corners Geological Survey, p. 1029.
Stevenson, G.M., 1989, Petroleum Exploration in southwestern Colorado: Paradox Basin, *in* Lorenz, J.C, Lucas, S.G. eds., Energy Frontiers in the Rockies, AAPG-SEPM-IMD Rocky Mountain Section, p. 85-89.
Stevenson, G.M., 1978, Middle Canyon Dakota, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 421.
Tezak, M.A., 1978, Ute Dome Dakota, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 543.
Tezak, M.A., 1978, Ute Dome Paradox, *in* Fasset, J.E., ed., Oil and Gas Fields of the Four Corners Area, Volumes I and II, Four Corners Geological Survey, p. 546.
Tremain, C.M., S.E. Laubach, and N.H. Whitehead III, 1994, Fracture (cleat) patterns in Upper Cretaceous Fruitland Formation coal seams, San Juan basin, *in* W.B. Ayers, Jr., and W.R. Kaiser, eds., Coalbed methane in the Upper Cretaceous Fruitland Formation, San Juan Basin, New Mexico and Colorado, New Mexico Bureau of Mines and Mineral Resources, Bulletin 146, Socorro, p. 87-102.
Turner-Peterson, C.E. 1989, Recent geologic studies in the San Juan Basin: Highlights and new directions, *in* Lorenz, J.C, Lucas, S.G. eds., Energy Frontiers in the Rockies, AAPG-SEPM-IMD Rocky Mountain Section, p. 177-188.
Valasek, D. 1995, The Tocito Sandstone in a sequence stratigraphic framework: An example of landward-stepping small-scale genetic sequences, *in* Van Wagner, J.C., Bertram, G.T., eds., Sequence Stratigraphy of Foreland Basin Deposits, Outcrop and subsurface examples from the Cretaceous of North America, AAPG Memoir 64, p. 349-370.
White, J.V., and B.L. Kirkland, 1996, Diagenesis and porosity distribution of Pennsylvanian Paradox Formation Carbonates (Upper Ismay), Southeastern Utah, *in* Huffman, Jr., A.C., Lund, R.W., Godwin, L.H., eds., Geology and Resources of the Paradox Basin, 1996 Special Symposium, Utah Geological Association and Four Corners Geological Society, p. 151-160.
Whitehead III, N.H. 1993, San Juan Basin Plays-Overview, *in* Hjellming C.A. ed., Atlas of Major Rocky Mountain Gas Reservoirs: available from New Mexico Bureau of Mines and Mineral Resources, Socorro, NM 878801
Young, G.B.C., 1994, Parametric study of open-hole cavity performance: Methane from Coal Seams Technology, April, 1994, p. 35-38