INTRODUCTION

The Jicarilla Apache Indian Reservation covers approximately one million acres in north-central New Mexico on the eastern edge of the San Juan Basin, comprising parts of townships 22 to 32 north and ranges 1 east to 5 west (Figures J-1 and J-3). The San Juan Basin contains the second largest natural gas field in the conterminous United States and has produced more oil from fractured Mancos shale than any other basin in the Rocky Mountain province. The Jicarilla Apache Tribe is the single largest mineral owner in the basin, excluding the United States government. During more than 35 years of gas and oil activity within the Reservation, over 2,700 wells were drilled, predominantly on the southern half. The 1993 production from 2,200 active wells was nearly 900,000 barrels of oil (BBO) and 30 billion cubic feet of gas (BFC).

Two recent discoveries highlight the new potential in this mature basin. Fruitland coal seam gas has more than doubled the basin's gas production. Additionally, a 1992 horizontal Mancos oil well has tapped an estimated 5-10 million barrel oil (MMBO) reservoir on the relatively unexplored northern half of the Reservation.

The Jicarilla Apache Indian Tribe has successfully financed, drilled, produced and marketed oil and gas resources from Tribal properties for more than 15 years. The Tribe plans to continue to expand its own operations and participation as a working interest owner. For entities interested in working with the Tribe, Tribal oil and gas exploration and development agreements are negotiated and structured individually to address the needs of the outside parties and the Tribe and the specific concerns relative to the reservoir. Agreements will follow basic industry standards as applicable and are governed by federal laws protecting all parties.

The basin contains a complete infrastructure of gas gathering and delivery systems, oil pipelines, and refineries to process, market and deliver oil and gas. Gas transportation systems such as the Williams Company, El Paso Natural Gas, West Gas and The Gas Company of New Mexico provide competitive markets in almost all directions.

RESERVATION PRODUCTION OVERVIEW

Figures J-2 and J-3 shows the outline of the Jicarilla Apache Reservation, on the eastern side of the San Juan Basin, and the general distribution of the primary producing fields. A stratigraphic chart of the eastern part of the San Juan Basin is shown in Figure J-4. General, the producing formations are Cretaceous-age fluvial, deltaic, and nearshore sandstones, offshore siltstones and shales and coal deposits during numerous transgressive and regressive cycles. Typically, land was to the west and southwest shedding sediment toward the sea, and open to the east and northeast.

Most of the gas in the sandstones are stratigraphically trapped against shales in a structural setting of regional west dip. However, localized structures may enhance trapping and productivity. Oil producing sandstones such as the Dakota may require more structural closure. The Mancos Shale occurs in fractures along the steeply dip
The Dakota Sandstone is a transgressive marine unit formed as the Late Cretaceous sea moved from east to west across the land. It contains coastal barrier marine sandstones and continental fluvial sandstone units. It is a dominantly stratigraphic gas play in the basin and a structural and stratigraphic oil and gas play along the basin’s flanks. The rocks represent a wide variety of depositional environments, ranging from braced and meandering stream complexes to nearshore deposits. Lithologies vary considerably, as do reservoir quality and trapping mechanisms.

The first Dakota discoveries were made in the early 1920’s on the northwestern flank of the basin and a central basin discovery well was drilled in 1947 south of Bloomfield, New Mexico in the Angel Peak area. A few additional discoveries were made in the 1950’s. In 1961 several fields were combined to form the Basin Dakota field, which by the end of 1976 contained 2,400 producing wells that had produced over 2.7 trillion cubic feet (TCF) of gas with an estimated total production of over 5 TCF. The field produces from a combination of hydrodynamic and stratigraphic traps. Dakota fields range in size from 40 to 10,000 acres with most production from fields of 100 to 2,000 acres (Huffman, 1987). Production of oil ranges from field totals of 1-7 MMBO. Over 14 BCF of associated gas has been produced.

Potential still exists for future discoveries in the Dakota interval and the limits of the Basin Dakota field have not yet been defined. Exploration in the Dakota is challenging and demands an understanding of basin structure and complex Dakota depositional patterns. New production techniques for tight gas sandstones and new interpretive tools such as 3-D seismic and the application of sequence stratigraphy will be critical in the development of future Dakota reserves.

The monocline flexure surrounding the east, north and west flank of the San Juan Basin concentrates most of the Mancos oil production in fractured dolomite siliciclastics sandwiched by marine shale. The Jicarilla Apache Indian Reservation lies along the east rim of the basin and the southeastern part of the central basin.
Tectonic activity associated with the Laramide Orogeny in late Cretaceous to early Tertiary time resulted in the subsidence of the central basin, uplifts of the surrounding rim and associated fracturing of bristle beds (Bussey, 1985 and 1991; Baltz, 1967). Figure J-5 is an east-west section through the San Juan Basin showing the central basin and marginal steeply dipping strata.

Mancos oil production in the San Juan Basin is nearly 30 MMBO. Seventy-five percent of the total or 23.3 MMBO comes from the four Mancos fields that lie within and just outside the Reservation boundary. Mancos oil production on the Reservation has been 5.1 MMBO. The unexplored northern part of the Reservation lies on the same geologic and structural trend of this prolific Mancos production. Hence the potential is quite high for additional Mancos discoveries in the area.

Figure J-5: East-west cross-section through the San Juan Basin (see Figure J-2 for line of section) showing lithologies and structure. The Jicarilla Apache Indian Reservation is located on the steeply dipping eastern flank, west of the Nacimiento uplift (after Peterson, 1985, p. 2088).
The three primary oil-bearing reservoirs of the Manos occur in fractured dolomitic siltstones beds (London, 1972) within a 300 foot interval of the Niobrara called the “A”, “B” and “C” zones. The more brittle rocks, such as the calcareous siltstones of the Niobrara A, B and C zones, fractured more easily when bent or folded than the more plastic encasing shales. The zones are 20-60 feet thick with individual siltstone beds within the zones 5-20 feet thick. The A and B zones are the main productive intervals near the study area, as found in East Puerto Chiquito field and the northern part of West Puerto Chiquito field. The C zone produces the most oil in the southern part of West Puerto Chiquito field. Increased resistivity in the Niobrara zones may be due to the tightly cemented dolomitic siltstone and/or oil in the fractures. The abrupt bending of the rocks along the monoclinal rim resulted in many north-south trending faults and fractures. Eissen dorfier (1989) showed a prevailing north to south fracture orientation in the greater Puerto Chiquito/Gaviñan area based on wireline dip meter fracture logs (Figure J-4). This trend extends into the Jicarilla Apache Reservation. Remote sensing data such as satellite, radar and photo images and surface mapping also show similar linear and fracture orientations in the eastern San Juan Basin. The larger features appear to be reactivated basement fault zones that control magmatic, uplift, fracturing and folding throughout geologic time (Dart, 1992).

Five structural settings of fracture intensity and associated oil production have been recognized in the central Jicarilla Apache Indian Reservation area. These include: monoclinal flexure, basal monoclinal flexure, antecinal nose, synclinal trough and central basin structures. The central basin structures contain low relief anticlines and synclines but are west of the monoclinal. The common structural traits of these five settings are maximum curvature of the brittle beds and a sudden change in the rate of dip. The four Manos fields in the area (23.3 MMBO) are: Boulder, East Puerto Chiquito, West Puerto Chiquito and Gaviñan (see Figure 3). The structural settings of these fields have been classified in the following manner: Boulder Field, monoclinal flexure; East Puerto Chiquito Field, antecinal nose and synclinal trough; West Puerto Chiquito Field, basal monoclinal flexure; Gaviñan Field, central basin structures of low relief anticlines and synclines. The American Hunter Exploration, Jicarilla 3-F well discovered a new Manos field in 1992. This horizontal well flowed at rates up to 600 BOPD and has produced over 150 MMBO. The Jicarilla 3-F well lies on the basal monoclinal flexure along structural strike with West Puerto Chiquito field, hence this new discovery field has the potential to produce over 5 MMBO. The 3- F well also sets up for further exploration to the north along undrilled segments of the monoclinal flexure.

Five key factors control the occurrence and quality of Manos oil production in these fields and provide the framework for successful exploration and development.

1. Reservoir rock consisting of a primary open fracture set and secondary conjugate fracture set in brittle dolomitic siltstones of the Niobrara Member of the Niobrara Formation.

2. Top seal of impermeable shale which traps the oil in the fractured reservoir beds.

3. Black organic rich shales within the lower Manos which provided a local source of hydrocarbons (see Griss, et. al., 1997, p. 1133, for an excellent discussion of the source rock characteristics of the Manos in the adjacent San Juan Sag).

4. Structural features such as anticlines, synclines, monoclinal and faults which have enhanced both the fracturing of the rock and the migration and trapping of oil.

5. Gravity drainage drive mechanism which maximizes oil recovery compared to solution gas drive.

Mesaverde Group

The Late Cretaceous Mesaverde Group lies stratigraphically above the Manos Formation. It consists of three basic units – The Upper Cliff House Sandstone, the middle shales, coals, sandstones and siltstones of the Menefee Formation and the lower Point Lookout Sandstone. The Mesaverde Group produces predominantly gas with some related oil. Gas bearing sandstones in all three members of the Mesaverde Group have been selectively perforated and produced. Volumetrically most gas comes from the Point Lookout. Geologically it is a regressive coastal barrier beach deposit, developed as the Cretaceous sea moved eastward away from the land. The Menefee consists of rocks laid down on the continent under swampy, nearshore conditions. The uppermost unit, the Cliff House Sandstone, records a time when once more the sea inundated the land and sandstones formed in primarily barrier island beach front environments. The Mesaverde Group is the largest producer of natural gas (excluding coalbed gas) of all geologic units in the San Juan Basin, followed by the Dakota Sandstone and the Pictured Cliff Sandstone. The Mesaverde has furnished energy to Native Americans in the region for several hundreds of years, beginning with oil and gas seeps. Oil production was established from these rocks in 1911 on the Chaco Slope, on the southwestern side of the Point Lookout and the Cliff House over long distances, but on a local scale the sandstones are quite variable. The coarser, cleaner sandstones readily produce oil and gas, while the siltstones and shales do not. Along the eastern San Juan Basin, the Pickett Lookout Sandstone. The Group produces pre cumulative and over 1.1 million barrels of associated oil. Oil is also produced in the Blanco Mesaverde trend. Research supports a model in which gas is trapped in stratigraphic features, often along faulted zones.

Research supports a model in which gas is trapped in stratigraphic traps developed by localized changes in the sandstone reservoir rocks and by the existence of permeability barriers. One can correlate the Point Lookout and the Cliff House over long distances, but on a local scale the sandstones are quite variable. The coarser, cleaner sandstones readily produce oil and gas, while the siltstones and shales do not. Along the eastern San Juan Basin, the Pickett Lookout Sandstone. The Group produces pre cumulative and over 1.1 million barrels of associated oil. Oil is also produced in the Blanco Mesaverde trend. Research supports a model in which gas is trapped in stratigraphic features, often along faulted zones.

Large relatively unexplored areas exist on the Reservation which are underlain by rocks of the Mesaverde Formation. Stratigraphic changes can occur over very short distances and relatively good wells can lie close to marginal producers or dry holes. Most of the exploration in the Mesaverde reservoirs occurred in the 1950’s and again in the 1970’s. Several detailed studies by recent workers illustrate the stratigraphic complexity of the Mesaverde rocks when interpreted in light of sequence stratigraphy. The potential for additional Mesaverde production on the Jicarilla Apache Reservation needs to be thoughtfully analyzed in light of new ideas and application of seismic data and interpretation.
Pictured Cliffs

Hydrocarbon production in the Pictured Cliffs has been primarily gas trapped in sandstone beds which are enclosed in shales or coals at the top of the unit. The Pictured Cliffs Sandstone is similar to the Cliff House Sandstone in that it is a regressive marine sandstone, consisting of two steps or benches which record stillstands or buildups of the sandstone bodies. Stillstands in the regression of the sea produced thicker shoreline sandstones and the best reservoirs. Thickness of the formation ranges from 0 to 400 feet and it is conformable with both the underlying marine Lewis Shale and the overlying nonmarine Fort Union Formation.

Gas was first discovered in the Pictured Cliffs in 1927 at the Blanco and Fulcher Kutz fields of northwest New Mexico. Most of the Pictured Cliffs fields were discovered early, with only a few having been discovered in recent years. Discoveries since the mid-1950’s have averaged 3,000 acres in size and 11 BCF estimated ultimate recovery. In the central basin and on the Jicarilla Reservation Pictured Cliffs production, while perhaps not outstanding in its own, is commingled with the Mesaverde (or other horizons) and can mate recovery. In the central basin and on the Jicarilla Reservation, gas from tight sandstones. Stratigraphic traps which result from the landward pinchout of nearshore and foreshore sandstones into siltstones, shales or coals of the Fruitland produce most of the hydrocarbons, especially in areas of stratigraphic rises. These rises are concentrated along a north-south trend in the central part of the basin, genetically coinciding with similar trends in the Gallup and Mesa Verde sections (Huffman, 1987). The most important factor in reservoir quality is the abundance of authigenic clay in the sandstones, limit ing porosity and permeability. Average porosity is about 15 percent and permeability averages 5.5 millidarcies, although many fields have porosities less than 1 millidarcy. Thickness of pay ranges from 5 to 150 feet and is often less than 40 feet.

Fruitland Formation Coal Seam Gas

Currently the Fruitland Formation coals produce more than half of the daily gas volume from the San Juan Basin and are currently the thickest gas producing in the San Juan Basin. The most prolific gas wells in both Colorado and New Mexico are Fruitland coal gas wells. All depths of less than 4,000 ft, this unconventional gas resource has been the primary objective of the San Juan Basin in the last five years. The expired “Section 29” tax credit provided an economic incentive to invest in this giant resource. However, with improved technology and good geology, commercial wells will continue to be discovered.

The goals of the Fruitland Formation were deposited landward and stratigraphically above the Pictured Cliffs Sandstone. Regionally, Fruitland coals thin to the east and southeast in the basin, providing limited gas potential on the Jicarilla Apache Reservation. However, conventional traps and localized thickening are likely to occur behind the regressing Pictured Cliffs marine sands, creating potential drilling targets. The Fruitland is the shallowest of the San Juan Basin reservoirs. Therefore, reconfiguring wells in the coals can add reserves at minimal cost.

JICARRILLA APACHE INDIAN RESERVATION
NEW MEXICO

Geology Overview

The Jicarilla Apache Reservation is located on the east side of the San Juan Basin in northeastern New Mexico (Figure J-3), comprising parts of Townships 22 to 32 N and Ranges 1 to 5 W (Figure J-1). The outcrop of the Cretaceous Fruitland formation is generally accepted as the outer limit of the geologic San Juan Basin and the outcrop trends generally north to south along the east side of the Reservation (Figure J-7). The east edge of the basin marks the approximate eastern edge of the Colorado Plateau physiographic province. Formations present in the eastern part of the San Juan Basin and under the Reservation range in age from Mississippian to recent as shown in Figure J-4.

The eastern part of the San Juan Basin was an area of erosion non-deposition during Mississippian time. Even then, sediments deposited during the Mississippian and Pennsylvanian range from 0 to a few hundred feet thick beneath the Jicarilla Apache Indian Reservation. The first formation that appears to be present under all parts of the Reservation is the Permian Canyon. From the unit level upward there can be units that reach zero thickness, such as the Cretaceous Pictured Cliffs Sandstone, but it is more likely that the pinchouts represent true depositional edges rather than erosional truncation. Thickness variations and pinch-outs in the pre-Pennsylvanian section seem to be a result of the San Juan Basin depositional area being on the northwest flank of the early Paleozoic Transcontinental Arch (Peterson, 1965, p. 2087).

Cambrian and Ordovician

A very thin section of Ignacio Quartzite is present in the west side of the basin. It rests nonconformably on Precambrian rocks in equivalent in age to the Belt Supergroup and is overlain disconformably by Devonian rocks (Loehman-Bahi, 1972, p. 68).

Devonian

Up to 300 feet of lower Devonian Elbert Formation carbonates are present in the Four Corners area and these thin eastward into the San Juan Basin where they disconformably overlie both the Cambrian Ignacio Quartzite and Precambrian rocks. According to Baars (1972, p. 96) the overlying McCracken sandstone is areally restricted to the east side of the basin and the best reservoirs. The McCracken sandstone is Upper Cretaceous in age, but up to 200 feet of Lower Cretaceous Burro Canyon Formation were deposited downstream and aligned approximately with the younger Jurassic depositional trend (McGeeley, 1977, p. 197). These were trapped behind the advancing Jurassic sea.

Permian

Mississippian carbonates equivalent to the Redwall (Madison, Leadville) limestone are present in the northwest portion of the San Juan Basin and in the far southeast part where they are known as the Arroyo-Penacoo Formation. Thickness of the section is less than 200 feet (Craig, 1972, p. 103). Pennsylvanian rocks overlie an erosional surface developed on Devonian, Cambrian and Precambrian rocks. All of the present day San Juan Basin was emergent at the end of Mississippian time (Peterson, 1965, p. 2097).

Uplift of the Anchorage Rocks led to deposition of thick arkose and sandstone sequences adjacent to local structures. During this time, the incipient San Juan Basin was bounded on the north east by the Uncompahgre Uplift and on the south west by the Zuni-Defiance Uplift and formed a shallow swale that accumulated mostly limy shale and shaly carbonates. From the base of the section upward, the three main Pennsylvanian units in the Basin are the Molas Shale, Hermosa Formation and Rino Formation. Pennsylvanian rocks are disconformably on the Mississippian section (Childs, et al., 1988). The section in the San Juan Basin reaches about 2,500 feet in thickness in the far northwest (Mallyor, 1972, p. 115).

There are over 2,000 feet of Pennsylvanian-age rocks in the deepest part of the San Juan Basin (Rancer and Bays, 1972, p. 146) that lie conformably on Pennsylvania sands (Peterson, 1965, p. 2094). By this time, the Zuni-Defiance Uplift was of minor importance and a majority of the sediments came from the north and northeast off the Uncompahgre Uplift, Archuleta Uplift and Navajo Uplift. The influx of clastics from the Navajo Uplift to the east caused almost total regression of marine depositional systems (Peterson, 1965, p. 2092). On the southeast, Cretaceous arkose are the predominant lithology and these are overlain southward by the Coconino and De Chelly Sandstones. There is an erosional hiatus at the top of the Permain section (Childs, et al., 1988).

Triassic

During the Lower Triassic, parts of the far south San Juan Basin became elevated as seen in thinning of the section from about 1,500 feet at the edge of the basin to less than 750 feet on the northeast (Peterson, 1965, p. 2099). In Middle Triassic the basin had high and became a source area, experiencing active erosion. By the Late Triassic time, the area was low and was accumulating shales and sands which we now call the Chinle and Dolores Formations. These appear to be about 1,500 to 2,000 feet of Triassic rocks in the present San Juan Basin (MacAinch, 1972, p. 169), thickening to the southwest. A proto San Juan Basin south of the Central Colorado Uplift was open to the northeast into the Utah-Idaho trough and was the site of deposition of about 1,250 feet of Jurassic rocks (Peterson, 1972, p. 180) thinning to about 1,000 feet to the north and south (Peterson, 1965, p. 2108). From the base of the Jurassic section upward, these are the Entrada Sandstone, To- dito Formation and Morrison Formation. The Entrada is a prod nesum reservoir in parts of the basin where it is overlain by the completions of the Toadcl.

Cretaceous

The present San Juan Basin was on the west side of the Western Interior Cretaceous Sea (Figure J-8) and received a thick section of sedimentary rocks related to transgression and final regression of the west eastern shoreline. Most of the section is Upper Cretaceous in age, but up to 200 feet of Lower Cretaceous Burro Canyon Formation were deposited within and aligned approximately with the older Jurassic depositional trend (McGeeley, 1972, p. 197). These were trapped behind the advancing Jurassic sea.
Upper Cretaceous rocks are more than 6,000 feet thick and comprise all the rocks shown in Figure J-9. The vast majority of petroleum in the San Juan Basin is from rocks of upper Cretaceous age. The present San Juan Basin did not form until the Laramide orogeny. However, a pre-Laramide low aligned approximately north-south allowed accumulation and preservation of the Cretaceous sediments (McGookey, 1972, p. 207).

The Paleocene saw deposition of the continental San Jose and Nacimiento formations and these are the surface formations through most of the San Juan Basin today. There is as much as 2,300 feet of San Jose Formation present in the northern parts of the basin (Peterson, 1972, p. 249). There was much volcanic activity north and northwest of the San Juan Basin starting in late Eocene time, peaking during the Oligocene and tapering off in the Miocene. Surficial deposits derived from this activity are present in much of the basin.

Structural Geology

Structurally, the Jicarilla Apache Reservation extends over and east of the deepest part of the asymmetric San Juan basin and up onto the westward dipping eastern flank as defined by structure contours on the Huerfanito Bentonite of the Lewis Shale (Figure J-10). Figure J-11 is an east-west cross section through the Basin showing the shape of units above the Huerfanito Bentonite. Major structural features of the basin are shown in Figures J-1, J-2 and J-12. Until Pennsylvanian time, the San Juan Basin depositional area was located on the northwest flank of the southwestward trending Transcontinental Arch. The entire area was emergent in late Mississippian time (Peterson, 1965, p. 2087). For most of the period between the end of the Mississippian and beginning of the Tertiary, the area was a low adjacent to a series of uplifts to the north, northwest, southwest and east and received most of its fill during this time.
The San Juan Basin as we know it today is a Laramide age feature that resulted as the North American plate drifted westward and impinged on an eastward dipping subduction zone (Woodward and Callender, 1977, p. 209). Because of the bend in the Cordillera fold belt in southern California, the predominant stress direction was to the northeast, creating the dominant northwest-trending folds and northeast-trending normal faults we see today. Several northwest-plunging, en echelon, open folds and northeast-trending, high-angle faults of small displacement occur along the eastern margin of the San Juan Basin. Erdlev (1997, p. 2) suggests that later activity along the Sevier thrust belt imposed a northwest-southeast compression on the basin. Evidence for this is found on the north side of the basin near Durango where northwest-southeast dikes swarms show extension, not compression. Condon (1997, p.85) thinks that clockwise rotation during the main Laramide event may have been responsible for the observed extension.

The Jicarilla Apache Indian Reservation is on the east side of the San Juan Basin and according to Woodward and Callender (1977, p. 210):

The eastern boundary of the San Juan Basin is marked by a monocline along the west side of the Gallina-Archuleta Arch and by range-margin upthrust and reverse faults on the west side of the Nacimiento Uplift. A sharp synclinal bend that is locally overturned occurs west of the upthrust and reverse faults. There is at least 10,000 feet of structural relief between the highest part of the Nacimiento Uplift and the adjacent part of the San Juan Basin. Structural relief between the Basin and the Gallina-Archuleta Arch is at least 13,000 feet.

Verbeek and Groat (1997, p. 7) indicate that post-Laramide uplift and regional extension associated with basin and range faulting have created a significant joint network that is locally more important than those resulting from Laramide movements. Significance of these most likely northwest-southeast trending extensional fractures to subsurface fluid migration is not known, although they may have an influence on coal cleat orientation and subsequent effect on coal bed methane recovery.
### Summary of Play Types

#### Total Production

- **San Juan Basin Cumulative Totals**
  - Oil: >2,000,000,000 BO
  - Gas: >18,000,000,000 CFG

**Jicarilla Apache Indian Basin**

- Undiscovered resources and numbers of fields are for Province-wide plays. No attempt has been made to estimate number of undiscovered fields within the Jicarilla Apache Indian Reservation (figures from NMOGA, 1997 & FCGS, 1983).

#### Play Summary Chart

<table>
<thead>
<tr>
<th>Play Type</th>
<th>USGS Designation</th>
<th>Description of Play</th>
<th>Oil or Gas</th>
<th>Known Accumulations</th>
<th>Undiscovered Resource (MMBOE)</th>
<th>Play Probability</th>
<th>Drilling depths</th>
<th>Favorable factors</th>
<th>Unfavorable factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2204</td>
<td>Entrada Sandstone</td>
<td>Oil</td>
<td>0.360 MMBO (1996)</td>
<td>27.3 MMBO (mean)</td>
<td>1.0 5,000-6,000 ft.</td>
<td>1) productive fault of reservation 2) excellent porosity and permeability 3) trends in southeast part of basin 4) reservation location favorable structurally</td>
<td>1) no Entrada production on reservation 2) sand rapidly loses permeability below 9,000 ft 3) requires favorable paleo-topography and paleo-relief 4) must lie within depositional area of overlying Todilto</td>
<td>1.030.5 MMBO (91.6 BCFG associated) 29.3 BCFG non-associated (mean)</td>
</tr>
<tr>
<td>2</td>
<td>2206</td>
<td>Basin Margin Dakota Oil</td>
<td>Both</td>
<td>23.6 MMBO 61.1 BCFP</td>
<td>25.6 MMBO (associated) 26.1 BCFP (non-associated (mean))</td>
<td>1.0 1,800-3,000 ft.</td>
<td>1) possible multiple plays 2) high gas BTUs (1275) 3) relatively shallow on east 4) broad sand/reservoir distribution</td>
<td>1) stratigraphic traps 2) low volume recoveries 3) stratigraphic/hydrodynamic traps 4) comingled production</td>
<td>1) future discoveries likely to be small 2) stratigraphic/hydrodynamic traps 3) low volume recoveries 4) drilled with natural gas</td>
</tr>
<tr>
<td>3</td>
<td>2207</td>
<td>Tolito Gallup Sandstone Oil</td>
<td>Both</td>
<td>176 MMBO 200 BCFP</td>
<td>51.4 MMBO 80.4 BCFP (associated) 80.1 BCFP (non-associated (mean))</td>
<td>1.0 1,100-4,000 ft.</td>
<td>1) possible multiple plays 2) high oil gravities 3) thick pay sections 4) ready market</td>
<td>1) possible multiple plays 2) high gas BTUs (1275) 3) relatively shallow on east 4) broad sand/reservoir distribution</td>
<td>1) stratigraphic traps 2) low volume recoveries 3) stratigraphic/hydrodynamic traps 4) comingled production</td>
</tr>
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<td>4</td>
<td>2210</td>
<td>Basin Margin Mesaverde Oil</td>
<td>Oil</td>
<td>Unknown</td>
<td>7.4 MMBO 7.8 BCFP (associated)</td>
<td>0.00 1,000-3,000 ft.</td>
<td>1) possible multiple plays 2) high oil gravities 3) thick pay sections 4) ready market</td>
<td>1) possible multiple plays 2) high oil gravities 3) thick pay sections 4) ready market</td>
<td>1) possible multiple plays 2) high oil gravities 3) thick pay sections 4) ready market</td>
</tr>
<tr>
<td>5</td>
<td>2212</td>
<td>Fruitland-Kirkland Fluvial Sandstone Gas</td>
<td>Gas</td>
<td>1.8 TCFP</td>
<td>281.1 TCFP</td>
<td>1.0 1,600-3,700 ft.</td>
<td>1) wide fault distribution in San Juan Basin 2) productive faulted tight gas sands 3) high porosity 4) productive Mesaverde methane from San Juan Fruitland</td>
<td>1) large fields are already found 2) thick pay sections 3) stratigraphic traps 4) losing gas noted above the Devonian</td>
<td>1) large fields are already found 2) thick pay sections 3) stratigraphic traps 4) losing gas noted above the Devonian</td>
</tr>
</tbody>
</table>

Table 1. Play summary chart.
### Total Production

- **Reservation:** Jicarilla Apache
- **San Juan Basin Cumulative Totals**
  - **Oil:** >240,000,000 BO
  - **Gas:** >18,000,000,000 CFG

### Undiscovered resources and numbers of fields are for Province-wide plays. No attempt has been made to estimate number of undiscovered fields within the Jicarilla Apache Indian Basin

### Geologic Province:
- **San Juan Basin (022)**
- **Province Area:** Approximately 8,000 sq miles (basin only)
- **Reservation Area:** Approximately 1,000,000 acres

### Field Size (MMBOE)
- **Oil:** >240,000,000 BO
- **Gas:** >18,000,000,000 CFG
- **NGL:**

### Play Types

#### Jicarilla Apache Indian Reservation, New Mexico

<table>
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<tr>
<th>Play Type</th>
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<th>Favorable factors</th>
<th>Unfavorable factors</th>
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</thead>
<tbody>
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<td>6</td>
<td>Dakota Central Basin Gas</td>
<td>Stratigraphic trap with coastal marine barriers and non-marine fluvial sands.</td>
<td>Gas</td>
<td>Unknown</td>
<td>6.1 TCFG (mean)</td>
<td>1.0</td>
<td>6,500-7,500 ft.</td>
<td>1) multiple plays 2) natural fractures enhance low permeability</td>
<td>1) stratigraphic traps 2) low matrix permeability 3) need fracture enhancement 4) source rock quality variable</td>
</tr>
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<td>7</td>
<td>Mancos Fractured Shale</td>
<td>Structural, interbedded, marine and non-marine, fractured shale play on San Juan margin.</td>
<td>Oil</td>
<td>58 MMBO total on basin 29.3 MMBO on reservation</td>
<td>186.9 MMBO 91.4 BCFG (mean)</td>
<td>1.0</td>
<td>1,000/1,000 BCFG</td>
<td>1) shallow drilling depths 2) fracture-enhanced permeability 3) nearby market 4) gravity drainage</td>
<td>1) new reserves will require directional drilling 2) expensive and more complex completion 3) small volume of gas produced at each well 4) must scale multiple fracture treatments</td>
</tr>
<tr>
<td>8</td>
<td>Central Basin Mesaverde Gas</td>
<td>Comprises the Point Lookout and Cliffhouse members of the Mesaverde formation in sandstone reservoirs with good porosity and permeability.</td>
<td>Gas</td>
<td>Unknown</td>
<td>9.8 TCFG (mean)</td>
<td>1.0</td>
<td>4,500-6,300 ft.</td>
<td>1) multiple plays 2) high oil gravities 3) ready market 4) well pay sandstones</td>
<td>1) future discoveries likely to be small 2) commonly drilled with natural fractures 3) short pay sandstones 4) low recovery</td>
</tr>
<tr>
<td>9</td>
<td>Pictured Cliffs Gas</td>
<td>Gas production is from stratigraphic traps in sandstone reservoirs encased in shale or coal at the top of the Upper Cretaceous Pictured Cliffs sandstone and is confirmed to the central part of the basin. Thicker shoreline sandstones are most productive.</td>
<td>Gas</td>
<td>9 fields average 11 BCFG</td>
<td>5.3 TCFG (mean)</td>
<td>1.0</td>
<td>1,000-3,000 ft.</td>
<td>1) high oil gravities and permeabilities 2) ready market 3) high flow rates 4) higher than average BTU content (11,700)</td>
<td>1) variable litho poro-perm in deeper areas 2) high gas gravity 3) non-associated gas contains little condensate 4) highly variable thickness up to 400 feet</td>
</tr>
</tbody>
</table>

Table 2. Play summary chart (continued).

- **Conventional play type**
- **Unconventional/Hypothetical play type**
SUMMARY OF PLAY TYPES

The United States Geological Survey identifies several petroleum plays in the San Juan Basin Province and classifies them as Conventional and Unconventional. The discussions that follow are limited to those with direct significance for future petroleum development in the Jicarilla Apache Indian Reservation. Much of the following is extracted from USGS CD-ROM DDS-30, Release 2 (Gautier, et al., 1995). Table 1 is a summary of USGS plays in the San Juan Basin.

DEFINITION OF A CONVENTIONAL PLAY

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.

ENTRADA PLAY

USGS 2304

The Entrada sandstone produces south and west of the Jicarilla Apache Indian Reservation. This discussion is included here because of the possibility that Entrada production may develop on the Reservation in the future. The Entrada play is associated with relict dune topography on top of the coquina Middle Jurassic Todilto Sandstone in the southeastern part of the San Juan Basin and is based on the presence of organic-rich limestone source rocks and anhydrite in the overlying Todilto Limestone Member of the Wainakak Formation. North of the present producing area, in the deeper, northeastern part of the San Juan 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 drapes over deep-seated faults has enhanced, modified, or destroyed the potential closures of the Entrada sandstone ridges. Hydrodynamic tilting of oil-water contacts and for "base of movable oil" interfaces has had a destructive influence on the oil accumulations because the direction of tilt typically has an updip component. All fields developed to date have been at depths of 5,000 - 6,000 ft. Because of increase in cementation with depth, the maximum depth at which suitable reservoir quality can be found is approximately 9,000 ft.

Exploration status and resource potential: The initial Entrada discovery, the Media field (Figs. J-13, J-14, J-15), was made in 1953. Development was inhibited by problems of high water cut and high pour point of the oil, problems common to all subsequent Entrada field development. Between 1972 and 1977, seven fields similar to the 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 fields discovered and 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.

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 drapes over deep-seated faults has enhanced, modified, or destroyed the potential closures of the Entrada sandstone ridges. Hydrodynamic tilting of oil-water contacts and for "base of movable oil" interfaces has had a destructive influence on the oil accumulations because the direction of tilt typically has an updip component. All fields developed to date have been at depths of 5,000 - 6,000 ft. Because of increase in cementation with depth, the maximum depth at which suitable reservoir quality can be found is approximately 9,000 ft.

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Analog Field

SOUTHWEST MEDIA ENTRADA

Location: T19N, R3W, south of Reservation
Formation: Entrada
Lithology: Sandstone
Average Depth: 5,300 ft
Pore: 23.8%
Permeability: 361 md
Oil/Gas Column: 30 feet
Average Net Pay Thickness: 30 feet
Estimated Ultimate Recovery: 1,600,000 BO
Other Information: Oil gravity 33.5 degrees API, asphaltic base with high pour point. Reservoir is in structurally enhanced stratigraphic trap.

Figure J-13. Southwest Media Entrada Field section along A-A' - see Figure J-14 (after Reese, 1978).

Figure J-15. Southwest Media Entrada Field example electric log (from Reese, 1978).
The Basin Margin Dakota Oil Play is both a structural and stratigraphic play on the northern, southern, and western sides of the central San Juan Basin. Because of the variability of depositional environments in the transgressive Dakota Sandstone, it is difficult to characterize a typical reservoir geology. Most production has been from the upper marine part of the interval, but significant amounts of both oil and gas have also been produced from the nonmarine section.

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

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

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

Traps: Fields range in size from 40 to 10,000 acres and most production is from fields of 100-2,000 acres. Stratigraphic traps are typically formed by updip pinchouts 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 MMBD, and the largest field (Price Gramps) has production of 7 MMBD. Future Dakota oil discoveries are likely as basin structure and Dakota depositional patterns are more fully understood.

**Analog Field**

**LINDRITH GALLUP-DAKOTA SOUTH**

| Location: | T23-24N, R4W, on Reservation |
| Formation: | Dakota |
| Lithology: | Sandstone |
| Average Depth: | 7200 feet |
| Porosity: | 12% |
| Permeability: | 0.1 to 0.5 md, fracture enhanced |
| Oil/Gas Column: | 200 feet |
| Average Net Pay Thickness: | 40 feet |
| Other Information: | Estimated ultimate recovery 80,000 BO per well, comingled. Oil averages 43 degrees API and is a sweet crude. |

**Figure J-16.** South Lindrith Gallup-Dakota Field, structure map and example log (from Matheny, 1978, p. 982).
The Tocito-Gallup Sandstone Oil Play is an oil and associated gas play in lenticular sandstone bodies of the Upper Cretaceous Gallup Sandstone and Tocito Sandstone Lentil associated with Mancos Shale source rocks lying immediately above an unconformity. The play covers almost the entire area of the province. Most of the producing fields involve stratigraphic traps along a northeast-trending belt near the southern margin of the central part of the San Juan Basin. Almost all production has been from the Tocito Sandstone Lentil of the Mancos Shale and the Torrivio Member of the Gallup Sandstone. Reservoirs: The Tocito Sandstone Lentil of the Mancos Shale is the major oil producing reservoir in the San Juan Basin. The name is applied to a number of lenticular sandstone bodies, commonly less than 50 ft thick, that lie on or just above an unconformity and are of undetermined origin. Reservoir porosities in producing fields range from 4 to 20 percent and average about 15 percent. Permeabilities range from 0.5 to 150 mD and are typically 5 - 100 mD. The only significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above cant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above. The only significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above. Timing and migration: The upper Mancos Shale of the central part of the San Juan Basin entered the thermal zone of oil generation in the late Eocene and gas generation in the Oligocene. Migration updip to reservoirs in the Tocito Sandstone Lentil and regressive Gallup fodiellowed 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 5,800 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 intermarine Mancos Shale. Similarly, the fluvial channel Torrivio Member of the Gallup is encased in and intertongues with finer grained, organic-rich coastal-plain shales.

Figure J-17. South Linford Gallup-Dakota Field, cross section along A-A' (Figure J-16) (from Matheny, 1978, p. 983).

Figure J-18. Bianco Tocito South Field structure map and cross section (from Fassett and Jerjen, 1978, p. 234).
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 northwest direction.

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

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 the 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. It produced oil from the Menefee Formation at a depth of approximately 350 ft. The only significant Mesaverde oil field, Red Mesa, was discovered in 1924. Future discoveries are likely to be small.
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 1950s. The Upper Cretaceous Fruitland Formation and Kirtland Shale are continental deposits and have a maximum combined thickness of more than 2,000 ft. The Fruitland is composed of interbedded sandstone, siltstone, carbonaceous shale, and coal. Sandstone is primarily in meandering 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 shales.

Reservoirs: Reservoirs are predominantly lenticular fluvial channel sandstone bodies, most of which are considered tight gas sandstones. They are commonly cemented with calcite and have an average porosity of 10–18 percent and low permeability (0.1–1.0 millidarcies). Pay thickness ranges from 15 to 50 ft. The Farmington Sandstone Member is typically fine grained and has a porosity of from 5 to 20 percent and permeability of from 0.6 to 9 millidarcies. Pay thicknesses are generally less than 20 ft.

Source rocks: The Fruitland-Kirtland interval produces non-associ gas and very little condensate. Its chemical composition (C1/C1-5) ranges from 0.59 to 0.87 and its isotopic (δ13C1) compositions range from -41.5 to -38.5 per mil (Rice, 1983). Source rocks are thought to be primarily organic-rich non-marine shales enclosing 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 through fluvial channel sandstone is suggested by gas production from immatures reservoirs and by the areal distribution of production from the Fruitland.

Traps: The discontinuous lenticular channel sandstone bodies that form the reservoirs in the Fruitland Formation and Kirtland Shale anastomose with overbank marlstone and siltstone 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 Arco field. Areal field sizes range from 100 to 12,000 acres, and almost 50 percent of the fields are 1,000-3,000 acres in size. The almost linear northeast-southwest alignment of fields along the western side of the basin suggests a palaeoflow channel system of northeasternly 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 25 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 pinchouts of channel sandstone into or shale in traps of moderate size.
Unconventional Plays — Definition

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.

**DAKOTA CENTRAL BASIN GAS PLAY**

**USGS 2205**

The Jicarilla Apache Indian Reservation is on the east flank of the San Juan Basin but extends sufficiently westward that there is a possibility of finding unconventional Dakota formation gas reservoirs. The preceding discussion on the conventional Basin Margin Dakota Play, USGS Play 2206, characterizes existing Reservation Dakota production on the Reservation. The Dakota Central Basin unconventional continuous-type play is contained in coastal marine barrier-bar sandstone and continental fluvial sandstone units, primarily within the transgressive Dakota Sandstone.

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

**Source rocks:** Quality of source beds for oil and gas is also variable. Non-associated gas in the Dakota pool of the Basin field was generated during late maturity and postmature stages and probably had a marine Mancos Shale source (Rice, 1983). The preceding discussion on the conventional Basin Margin Dakota Play, USGS Play 2206, characterizes existing Reservation Dakota production on the Reservation. The Dakota Central Basin unconventional continuous-type play is contained in coastal marine barrier-bar sandstone and continental fluvial sandstone units, primarily within the transgressive Dakota Sandstone.

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

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

**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 38.2 BOPD. By the end of 1993 it had produced over 4.0 TCFG and 38.2 BOPD. The 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 38.2 BOPD. The 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 38.2 BOPD.
**Mancos Fractured Shale Play**

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

**Reservoirs:** Reservoirs are comprised of fractured shale and interbedded coarser clastic intervals at approximately the Tocito Lentil 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 degrees to 43 degrees 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.

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**Analog Field**

**PUERTO CHIQUITO MANCOS, WEST**

(Figure J-25)

- **Location:** T25–27N, R1E and R1W, partly on Reservation
- **Formation:** Mancos, Niobrara equivalent section
- **Lithology:** Shale
- **Average Depth:** 5,400 feet
- **Porosity:** Indefinite, fracture porosity
- **Permeability:** Unknown, transmissibility up to 6 darcy-feet
- **Oil/Gas Column:** 250 feet
- **Average Net Pay Thickness:** Unknown, less than 50 feet
- **Other Information:** The Canada Ojitos Units lies totally within the Puerto Chiquito West Field. Originally a gravity drainage field, final stages of development will include expansion gas drive and reinjection of produced gas. Oil gravity is 39 to 40 degrees API.
The unconventional continuous-type Central Basin Mesaverde Gas Play is in sandstone buildups associated with stratigraphic rises in the Upper Cretaceous Point Lookout and Cliff House Sandstones. The major gas-producing interval in the San Juan Basin, the Upper Cretaceous Mesaverde Group, is comprised of 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 20-30 percent is sandstone. The Mesaverde interval is enclosed by marine shale; the Menefee Shale is beneath the interval and the Lewis Shale above.

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

**Source rocks:** The carbon composition (Cl/Cl-5) of 0.99-0.79 and isotopic carbon (dl3Cl) range of -33.4 to -46.7 per mil of the nonassociated gas suggest a mixture of source rocks including coal and carbonaceous shale in the Menefee Formation (Rice, 1983).

**Timing and migration:** In the central part of the basin, the Menefee Shale entered the thermal zone of oil generation in the Eocene and the transgressive marine Cliff House Sandstone. Total gas discoveries range in areal size from 2,000 to 10,000 acres and have estimated total recoveries of 10 to 35 BCFG. Areally, these two closely adjacent fields cover more than 1,000,000 acres, encompass much of the central part of the San Juan Basin, and have produced almost 7,000 BCFG and more than 30 MMB of condensate, approximately half of their estimated total recovery. Most of the recent gas discoveries range in areal size from 2,000 to 10,000 acres and have estimated total recoveries of 10 to 35 BCFG.

**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 fields produce almost 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 10 to 35 BCFG.

**Traps:** Trapping mechanisms for the largest fields in the central part of the San Juan Basin are not well understood. In both the Blanco Mesaverde and Ignacio Blanco fields, 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.

**ANALOG FIELD BLANCO MESAVERDE FIELD**

- **Location:** T25S-32N, R3-12W, on Reservation
- **Formation:** Mesaverde, Cliff House and Point Lookout members
- **Lithology:** Sandstone
- **Average Depth:** 4,500 feet
- **Porosity:** 10 to 16%
- **Permeability:** Cliff House 0.5 md, Point Lookout 2.0 md
- **Oil/Gas Column:** 400 feet
- **Average Net Pay Thickness:** 80 to 200 feet
- **Other Information:** Gas carries 1,194 Btu per CF, about 1% inert (carbon dioxide and nitrogen). Associated oil ranges between 33 and 60 degrees API. Estimated field ultimate recovery 12 TCFG. In 1975 field spacing was changed to 1 well per 320 acre spacing unit.

**STRUCTURE CONTOUR ON GREEN MARKER HORIZON**

**CROSS SECTION A’-A’ OF THE MAJOR MESAVERDE BENCHES**
PICTURED CLIFFS GAS PLAY - USGS 2211

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

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

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

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

Exploration status and resource potential: Gas was discovered in 1927 at the Blanco and Fulcher 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.

Analog Field: Blanco Pictured Cliffs, South

Environment of Fruitland Formation Coal Beds

Blanco Pictured Cliffs South Field

Figure J-27. Blanco Pictured Cliffs Field map with isopach of net pay (from Brown, 1978, p. 230).