Geology and Oil and Gas Assessment of the Mancos-Menefee Composite Total Petroleum System

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Volume Title Page

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Chapter 4 of 7

Total Petroleum Systems and Geologic Assessment of Undiscovered Oil and Gas Resources in the San Juan Basin Province, Exclusive of Paleozoic Rocks, New Mexico and Colorado

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Geology and Oil and Gas Assessment of the Mancos-Menefee Composite Total Petroleum System

By J.L. Ridgley, S.M. Condon, and J.R. Hatch

Abstract

The Mancos-Menefee Composite Total Petroleum System (TPS) includes all genetically related hydrocarbons generated from organic-rich shales in the Cretaceous Mancos Shale and from carbonaceous shale, coal beds, and humate in the Cretaceous Menefee Formation of the Mesaverde Group. The system is called a composite total petroleum system because the exact source of the hydrocarbons in some of the reservoirs is not known. Reservoir rocks that contain hydrocarbons generated in Mancos and Menefee source beds are found in the Cretaceous Dakota Sandstone, at the base of the composite TPS, through the lower part of the Cliff House Sandstone of the Mesaverde Group, at the top. Source rocks in both the Mancos Shale and Menefee Formation entered the oil generation window in the late Eocene and continued to generate oil or gas into the late Miocene. Near the end of the Miocene in the San Juan Basin, subsidence ceased, hydrocarbon generation ceased, and the basin was uplifted and differentially eroded. Reservoirs are now underpressured.

Eight assessment units were defined in the Mancos-Menefee Composite TPS. Of the eight assessment units, four were assessed as conventional oil or gas accumulations and four as continuous-type accumulations. The conventional assessment units are Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (AU), Gallup Sandstone Conventional Oil and Gas AU, Mancos Sandstones Conventional Oil AU, and the Mesaverde Updip Conventional Oil AU. Continuous-type assessments are Dakota-Greenhorn Continuous Gas AU, Mancos Sandstones Continuous Gas AU, Mesaverde Central-Basin Continuous Gas AU, and Menefee Coalbed Gas AU. The Mesaverde Updip Conventional AU was not quantitatively assessed for undiscovered oil and gas resources, because the producing oil fields were smaller than the 0.5 million barrel cutoff, and the potential of finding fields above this cutoff was considered to be low.

Total oil resources that have the potential for additions to reserves in the next 30 years are estimated at a mean of 16.78 million barrels. Most of this resource will come from reservoirs in the Mancos Sandstones Oil AU. Gas resources that have the potential for additions to reserves in the next 30 years are estimated at a mean of 11.11 trillion cubic feet of gas (TCFG). Of this amount, 11.03 TCFG will come from continuous gas accumulations; the remainder will be gas associated with oil in conventional accumulations.Total natural gas liquids (NGL) that have the potential for additions to reserves in the next 30 years are estimated at a mean of 99.86 million barrels. Of this amount, 96.95 million barrels will come from the continuous gas assessment units, and 78.3 percent of this potential resource will come from the Mancos Sandstones Continuous Gas AU.

Introduction

The boundary of the Mancos-Menefee Composite Total Petroleum System (TPS) coincides with the boundary that delimits the San Juan Basin Province for this assessment (fig. 1). The TPS is defined as including all reservoir rocks and potential source beds from the base of the Dakota Sandstone to the top of the Cliff House Sandstone of the Mesaverde Group or the top of the Allison Member of the Menefee Formation of the Mesaverde Group (fig. 2). Within the TPS, there are two principal hydrocarbon source intervals:

1. Mancos Shale and
2. Menefee Formation (fig. 2).

The composite definition was chosen for the TPS because it was impossible to determine exactly which of the two intervals was the source of oil and gas found in each of the various formations that compose the Mesaverde Group. The hydrocarbons probably represent, in some cases, a mixture of the two sources. The boundary of the TPS was drawn to include the known source rocks of the Mancos and Menefee, and known or potential reservoir rocks as shown in figure 2. There are eight assessment units (AU) in this TPS. These are, in ascending order,

1. Dakota-Greenhorn Conventional Oil and Gas AU,
2. Dakota-Greenhorn Continuous Gas AU,
3. Gallup Sandstone Conventional Oil and Gas AU,
4. Mancos Sandstones Conventional Oil AU,
5. Mancos Sandstones Continuous Gas AU,
6. Mesaverde Updip Conventional Oil AU,
7. Mesaverde Central-Basin Continuous Gas AU, and
8. Menefee Coalbed Gas AU (fig. 2).

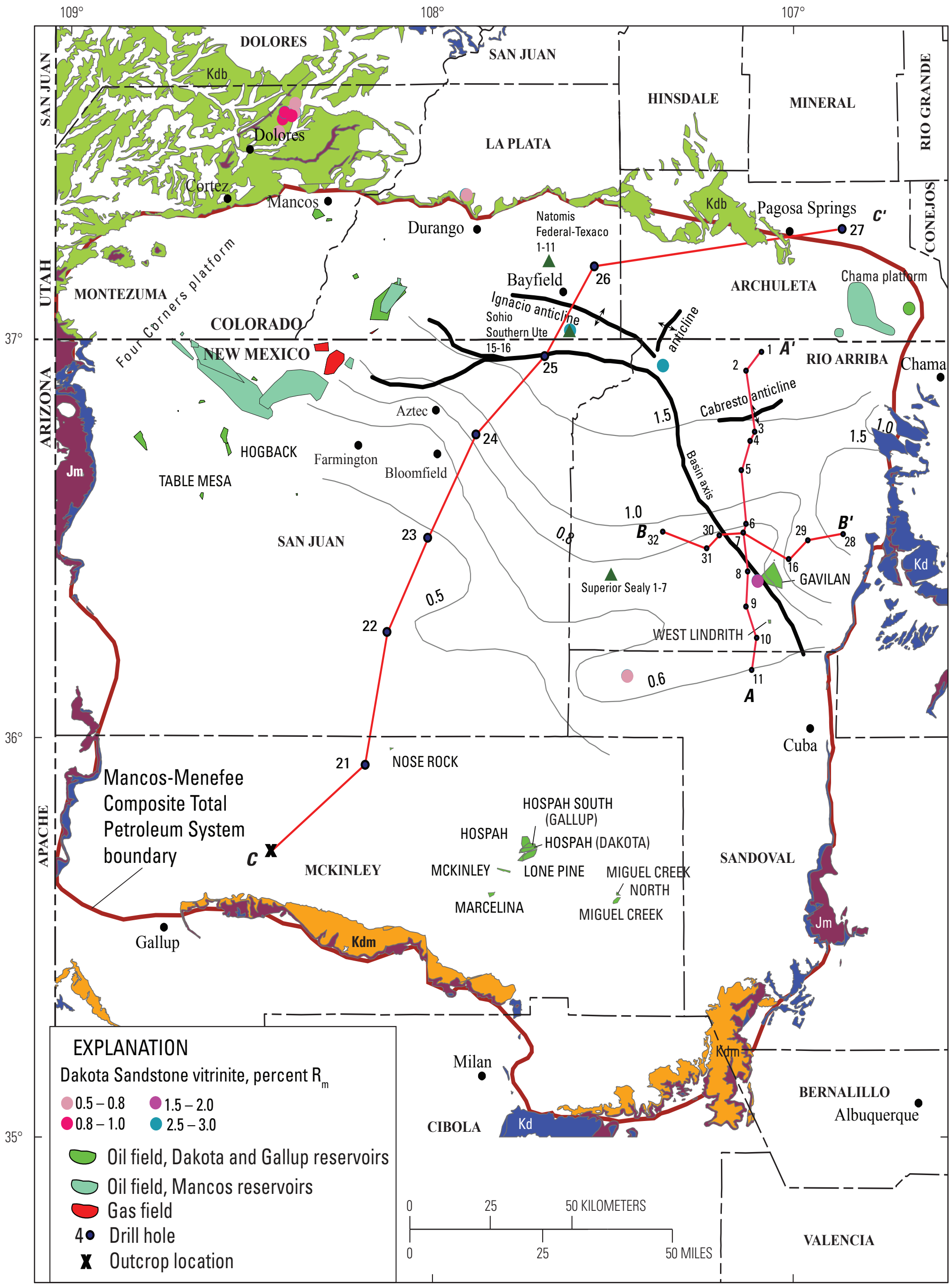


Figure 1. Map showing the boundary (in red) of the Mancos-Menefee Composite Total Petroleum System, San Juan Basin, Colorado and New Mexico. Shown are selected Mancos-sourced oil and gas fields. Menefee maturity contours (in gray) show vitrinite reflectance (R_m) values, in percent, contoured from data in Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Isolated R_m vitrinite data from shale or coal in the Dakota Sandstone (colored dots) are from Fassett and Nuccio (1990) and U.S. Geological Survey unpublished data. Also shown are locations of cross sections *A–A′*, *B–B′* (pls. 1 and 2), and *C–C′* (fig. 9); principal structures in the basin; and locations of the wells (green triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation (Green, 1992; Green and Jones, 1997).

Within the lower part of the Mancos Shale in the TPS, there is a major unconformity that is Coniacian in age (see summary discussion in Ridgley, 2001a). This unconformity separates genetically unrelated (although similar in appearance) strata above and below the unconformity (figs. 2 and 3). The geologic basis for this unconformity has not been identified, but the unconformity is probably tectonically related. The magnitude of erosion below the unconformity increases from south to north across the San Juan Basin (figs. 2 and 3; pls. 1 and 2); at places the unconformity nearly incises into the Juana Lopez Member of the Mancos Shale (Molenaar, 1977b). This unconformity was used to separate the two Dakota-Greenhorn assessment units and the Gallup Sandstone Conventional Oil and Gas AU below the unconformity from the two Mancos sandstone assessment units above the unconformity (fig. 2). Controls on sediment geometry and depositional environments of strata below the unconformity differ from those above it. The Gallup Sandstone Conventional Oil and Gas AU was separated from the Dakota-Greenhorn Conventional Oil and Gas AU because of the very different geometry of the various shorelines and regional distribution of potential reservoir rocks. These differences affect migration pathways for hydrocarbon movement. Seals and traps vary among the five assessment units of the Mancos Shale part of the TPS and are related to

1. facies distributions that reflect variations in depositional environments, and
2. structural control on sandstone-shale geometry and fracture orientation.

The Menefee part of the TPS includes three assessment units from which both oil and gas have been produced, but in different parts of the basin. The lowermost is a conventional oil assessment unit and includes strata in the Menefee Formation and Point Lookout Sandstone. Small amounts of oil have been produced on the updip southern flank of the basin from Menefee and Point Lookout age conventional accumulations. Gas and some condensate are produced from Menefee and Point Lookout reservoirs in the deep, central part of the basin in an accumulation that is considered continuous: Mesaverde Central-Basin Continuous Gas AU. The uppermost assessment unit, Menefee Coalbed Gas AU, is hypothetical and consists of possible coal-bed gas accumulations from thermally immature coal beds within the Menefee.

Key elements that define the Mancos-Menefee TPS are

1. source rocks of sufficient thermal maturity to generate hydrocarbons,
2. reservoir rocks to host the accumulations,
3. migration pathways that allow the hydrocarbons to move into reservoirs,
4. structural or stratigraphic traps in which hydrocarbons could accumulate, and
5. seals to contain the accumulations.

These key elements are described more fully below and in each assessment unit discussion. Methodologies for assessing continuous-type and conventional accumulations are discussed in Schmoker (2003) and Schmoker and Klett (2003).

Mancos-Menefee Composite Total Petroleum System

Geologic Framework

Stratigraphy

Cretaceous rocks, beginning with deposition of the Dakota Sandstone, consist of wedges of marine-to-continental transgressive and regressive strata (fig. 2) that occupy the broader San Juan Basin (as shown in figure 4) (Baltz, 1967; Fassett, 1974, 1977, 2000; Molenaar, 1977b; Owen and Siemers, 1977; Posamentier and others, 1992; Nummedal and Molenaar, 1995; Wright Dunbar, 2001). Figure 3 is a generalized time-stratigraphic cross section through the San Juan Basin and shows the relation of the various reservoir units discussed below. Except for the Dakota Sandstone, shoreline geometry of strata within these wedges generally has a northwest–southeast orientation that may be controlled by basement structural blocks (fig. 4). Shoreline geometry in the Dakota was much more complex and was influenced by a large embayment centered over the southern part of the basin. The Dakota shorelines tend to be oriented west–east to slightly northwest–southeast in Colorado and New Mexico around this embayment (Seboyeta Bay) (fig. 5). Fluvial rocks in the basal part of the Dakota are found throughout the TPS and fill valleys incised into the underlying Jurassic rock. During the Cretaceous, deposition in the basin area was open-ended to the northeast in the direction of deeper marine sedimentation.

The base of the TPS is unconformable with underlying strata throughout the extent of the San Juan Basin Province. The Dakota Sandstone rests unconformably on the Upper Jurassic Morrison Formation throughout the southern part of the San Juan Basin and on the Lower Cretaceous Burro Canyon Formation in the northern part of the basin (Saucier, 1974; Molenaar, 1977b; Owen and Siemers, 1977). Hydrocarbons have been reported from the Morrison Formation (some of these hydrocarbons intervals are in the Burro Canyon Formation based on subsurface analysis of well logs) in a few isolated wells in the northern part of the TPS. These isolated occurrences of hydrocarbons in strata older than those assigned to the TPS may be related to lateral migration of hydrocarbons across faults, where the older rocks have been displaced upward along a fault, thus, juxtaposing them with potential source rock. In this way hydrocarbons may have leaked laterally from the Dakota into the older strata. Alternatively, hydrocarbons may have migrated through channels in the basal Dakota Sandstone that have cut into the Burro Canyon or Morrison Formations, and from there laterally into sandstones of the latter formations.

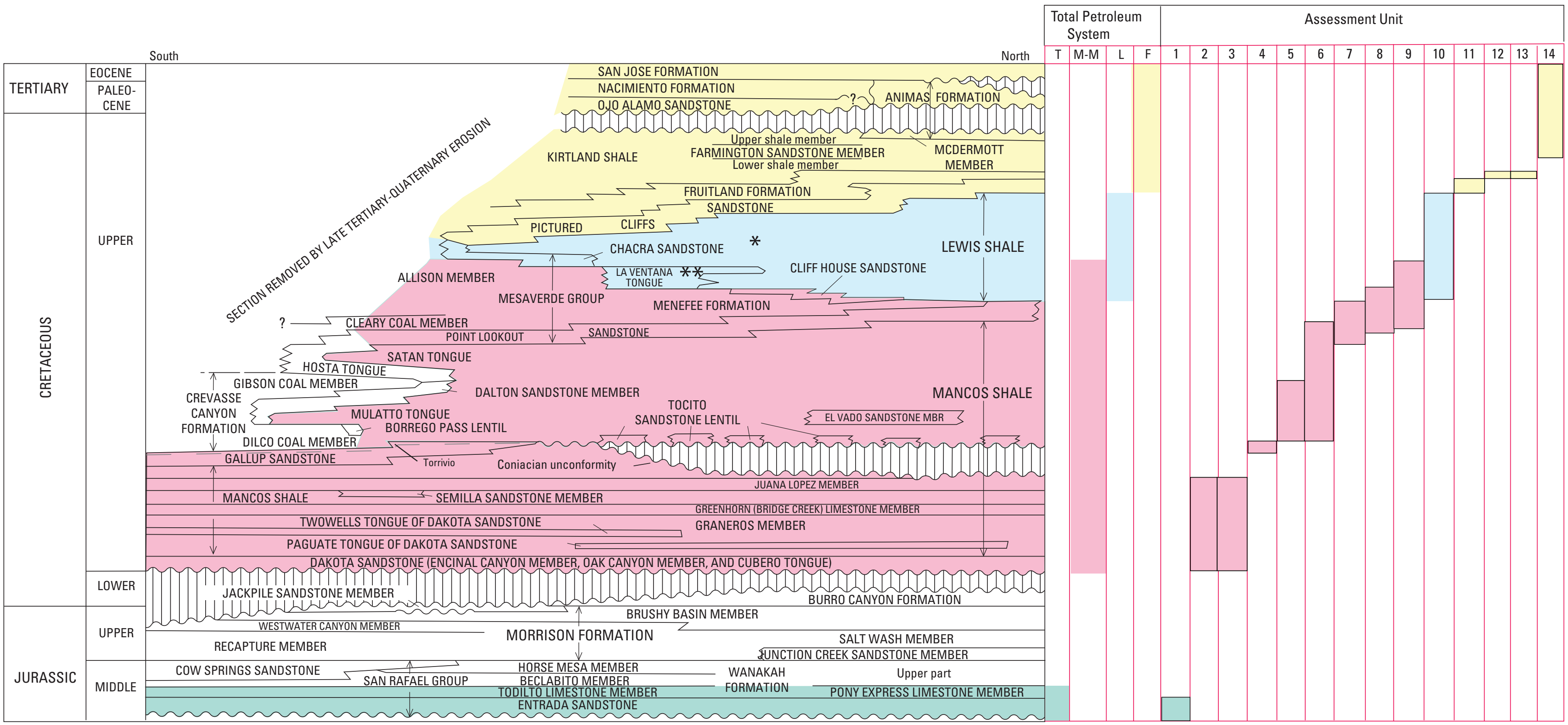


Figure 2. Chart showing regional chronostratigraphic correlations in the San Juan Basin (modified from Molenaar, 1977a) from the Tertiary to the base of the Jurassic, and the extent of the total petroleum systems and assessment units defined in the 2002 National Oil and Gas Assessment of the San Juan Basin Province (5022), New Mexico and Colorado. Total petroleum systems: F, Fruitland; L, Lewis Shale; M-M, Mancos-Menefee composite, and T, Todilto. Assessment units: 1, Entrada Sandstone Conventional Oil; 2, Dakota-Greenhorn Conventional Oil and Gas; 3, Dakota-Greenhorn Continuous Gas; 4, Gallup Sandstone Conventional Oil and Gas; 5, Mancos Sandstones Conventional Oil; 6, Mancos Sandstones Continuous Gas; 7, Mesaverde Updip Conventional Oil; 8, Mesaverde Central-Basin Continuous Gas; 9, Menefee Coalbed Gas; 10, Lewis Continuous Gas; 11, Pictured Cliffs Continuous Gas; 12, Basin Fruitland Coalbed Gas; 13, Fruitland Fairway Coalbed Gas; and 14, Tertiary Conventional Gas. *Chacra sandstone, an informal term used by drillers and geologists in the basin; **La Ventana Tongue of the Cliff House Sandstone. Vertical lines, unconformities.

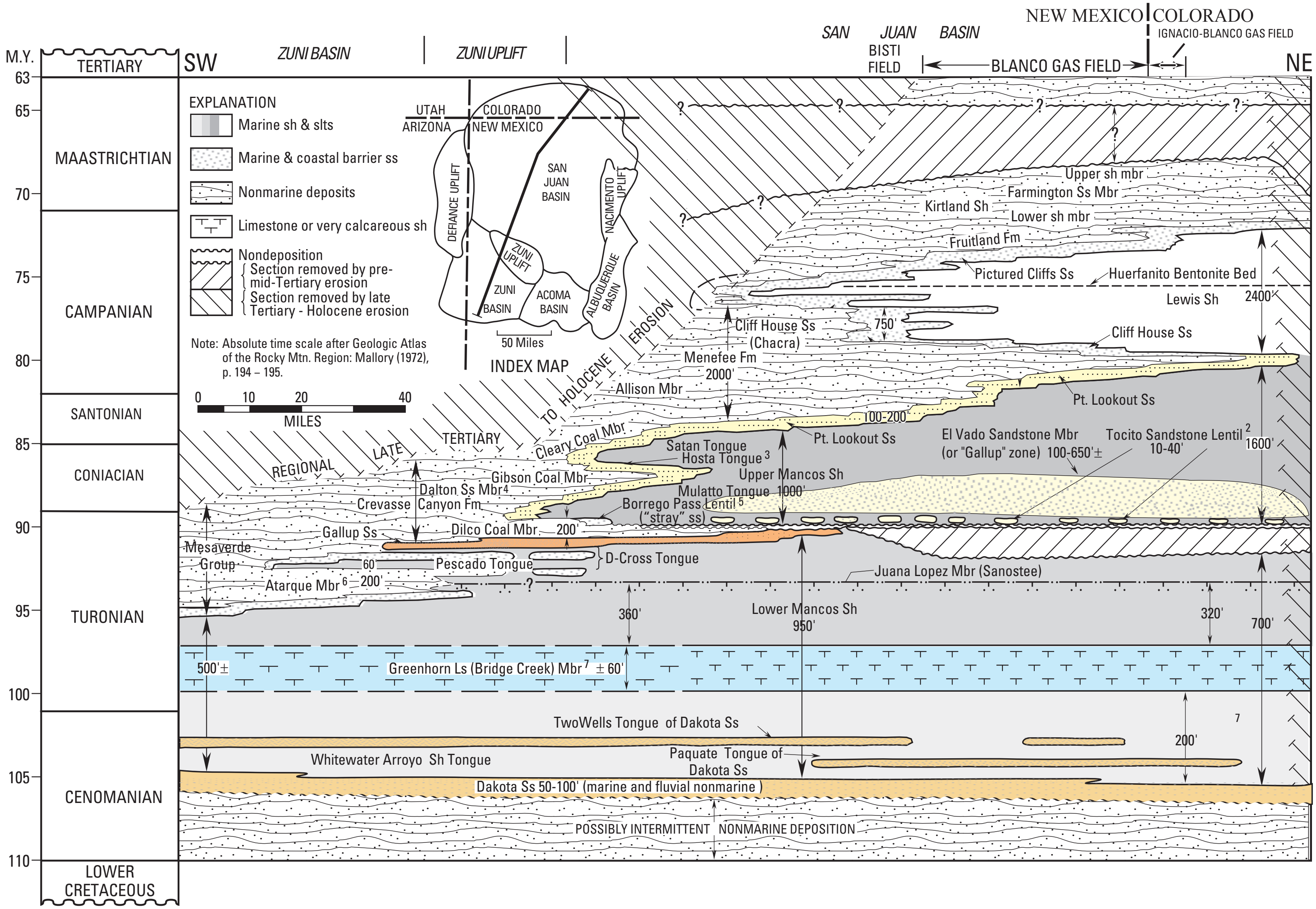


Figure 3. Time-stratigraphic cross section of Upper Cretaceous and Tertiary rocks in the Zuni and San Juan Basins, Colorado and New Mexico. Modified from Pentilla (1964) and Molenaar (1977a). Members shown by footnotes: [1]of Cliff House Sandstone , [2]of Mancos Shale, [3]of Point Lookout Sandstone, [4]of Crevasse Canyon Formation, [5]of Tres Hermanos Formation, [6]of Mancos Shale, [7]of Mancos Shale. Shale, sh; siltstone, slts; sandstone, ss; member, mbr; formation, fm.

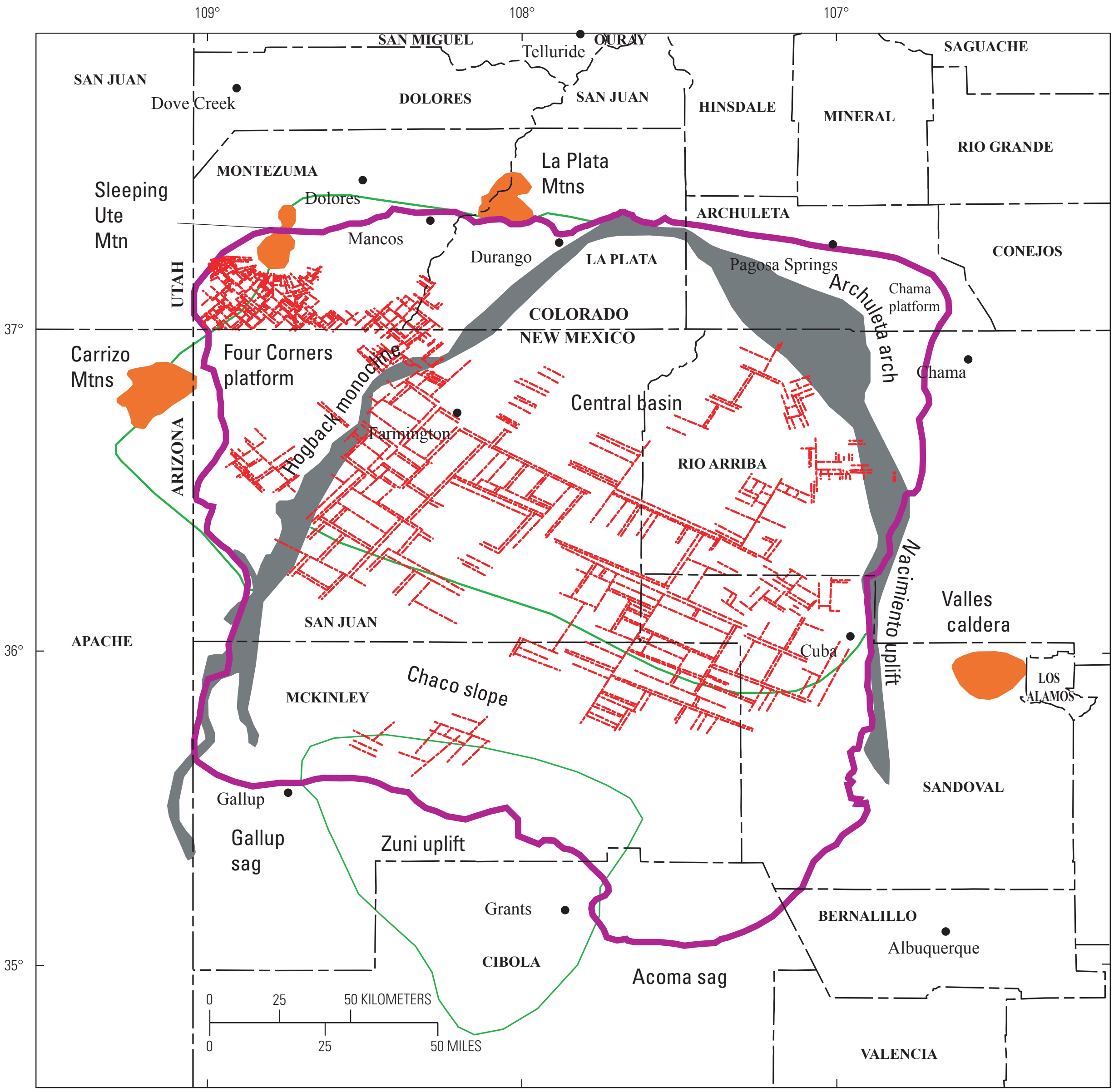


Figure 4. Map showing the location of inferred basement structural blocks (dashed red lines) and other structural elements in the San Juan Basin. Modified from Taylor and Huffman (1998, 2001), Fassett (2000), and Huffman and Taylor (2002). San Juan Basin Province (5022) boundary (purple line). Orange polygons are Late Cretaceous and Tertiary intrusive and extrusive igneous centers; gray polygons are areas of steep dip along monoclines; green line outlines some of the main structural elements.

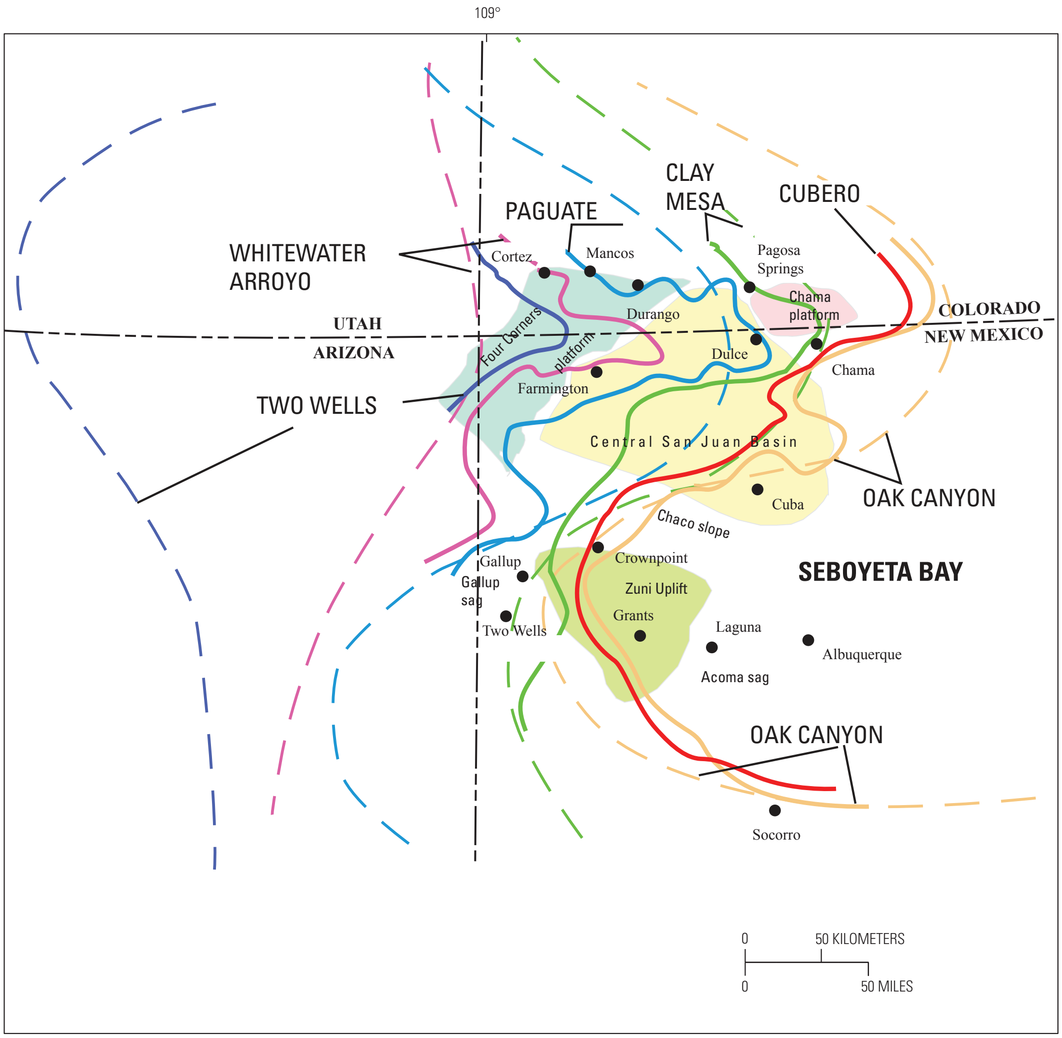


Figure 5. Map showing location of shorelines and location of Seboyeta Bay during deposition of the Dakota Sandstone and Mancos Shale. Members of Dakota and Mancos are, in ascending order: Oak Canyon Member of Dakota, Cubero Sandstone Tongue of Dakota, Clay Mesa Tongue of Mancos, Paguate Tongue of Dakota, Whitewater Arroyo Tongue of Mancos, and Twowells Tongue of Dakota. Dashed lines indicate shorelines based on ammonite data collected from outcrops around the San Juan Basin (Cobban and Hook, 1984). Solid lines are from J.L. Ridgley (unpublished data, 2002).

Structure

A generalized regional structure map, contoured on the top of the Mancos Shale, shows the present-day structural configuration of the San Juan Basin (fig. 6). The Mancos Shale is less than 1,000-ft subsea level in the deeper part of the San Juan Basin; overburden thickness in this area ranges between 6,000 and 7,000 ft. Structure contours on top of the Menefee (fig. 7) also generally parallel structural interpretations of the underlying Dakota Sandstone (Thaden and Zech, 1984; pl. 3) and the overlying Huerfanito Bentonite Bed of the Lewis Shale (Fassett, 2000). The top of the Menefee dips gently northward to an elevation of about 1,000 ft above sea level (6,500 ft below the land surface) at the basin axis, and then reverses dip at a steep angle toward the outcrops along the north basin rim. This northward rise is interrupted by the Ignacio anticline in southern Colorado (fig. 1), which has about 200 ft of closure (Harr, 1988).

Current overburden on the Menefee ranges from 0 to about 6,500 ft (IHS Energy Group, 2001). Overburden shows a gradual thickening from southwest to northeast on the Chaco slope (fig. 4), with maximum overburden along the basin axis. Overburden thicknesses decrease markedly over short distances as the outcrops are approached on the northwest, north, and northeast sides of the basin.

Structure contours drawn on the tops of the Dakota Sandstone (Thaden and Zech, 1984; pl. 3), Mancos Shale (fig. 6), and Menefee Formation (fig. 7) show the gradual northward dip from the Chaco slope (fig. 4) to the basin axis on the north and northeastern sides of the basin (fig. 1). North of the basin

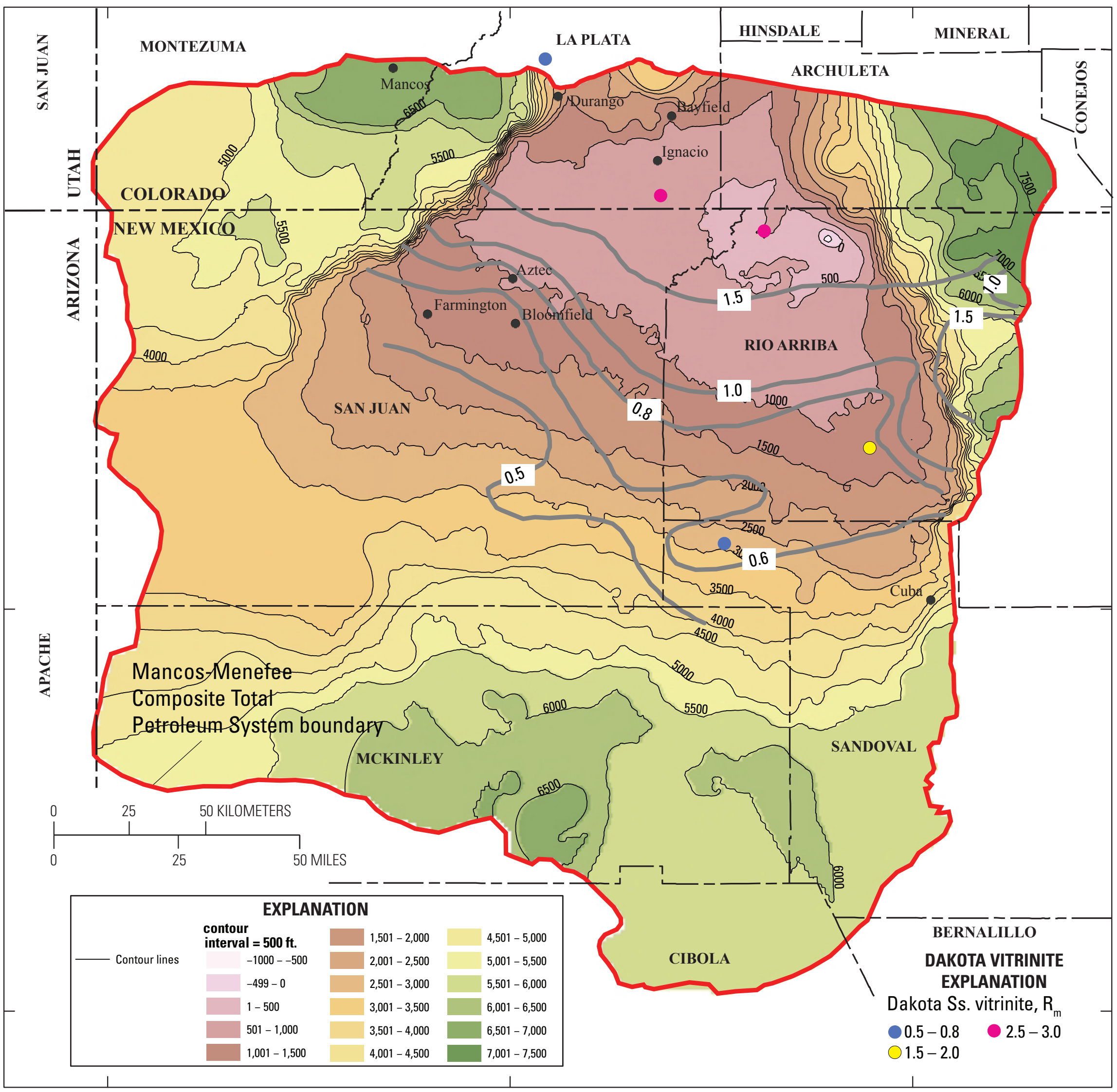


Figure 6. Structure contour map drawn on top of the Mancos Shale, San Juan Basin, Colorado and New Mexico, using data from IHS Energy Group (2002). Contour interval, 500 ft; datum is mean sea level. Menefee maturity contours (in gray) show vitrinite reflectance (R_m) values in percent using data from Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Isolated R_m vitrinite data from shale or coal in the Dakota Sandstone (colored dots) are from Fassett and Nuccio (1990) and C. Threlkeld (written commun., 2001).

Figure 7. Structure contour map drawn on top of the Menefee Formation using data from IHS Energy Group (2001). Contour interval, 500 ft; datum is mean sea level. Menefee maturity contours (in gray) show vitrinite reflectance values, in percent, using data from Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Also shown are locations of the wells (green triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*) and the pod of thermally mature source rocks in the Mancos Shale and Menefee Formation (shaded green). Geologic units are from Green (1992) and Green and Jones (1997): Tc, Tertiary Chuska Sandstone; Tnv, Tertiary Neogene volcanics; Tmb, Tertiary Miocene volcanics; Kcc, Crevasse Canyon Formation; Kmp, Menefee Formation and Point Lookout Sandstone; Kmv, Mesaverde Group; Kpl, Point Lookout Sandstone.

axis, the dip reverses, and the Dakota and other units rise to the surface in southern Colorado. The rise to the north is modified by the Ignacio anticline, just north of the axis, and another unnamed anticline that trends northeastward (fig. 1). The Cabresto anticline (fig. 7), as designated in this study, was determined by contouring the top of the Paleocene Ojo Alamo Sandstone. This small anticline trends east-northeast, perpendicular to the basin axis (fig. 1). The Four Corner platform is a structural bench off the northwest side of the basin (fig. 4). Faults at the level of the Dakota Sandstone are common on the southern and southeastern sides of the basin, but are not identified in most of the central or northern parts (Thaden and Zech, 1984; pl. 3), probably due to a lack of data. Taylor and Huffman (1998, 2001) and Huffman and Taylor (2002) mapped basement faults in parts of the basin (fig. 4), including basin-directed thrust faults underlying the Hogback monocline, at points along the northern and northeastern basin margin, and along the eastern side of the basin at the Nacimiento fault (Baltz, 1967). The various structural elements of the basin have been summarized by Lorenz and Cooper (2001).

Hydrocarbon Reservoir Rocks

Reservoir rocks that have hydrocarbons sourced from the Mancos Shale include the stratigraphic interval bounded by the Dakota at the base and the Lewis Shale at the top (figs. 2 and 3). In the Mancos, isolated limestone or sandstone reservoir units are confined to the lower two-thirds of the formation and are described below. The stratal relations of these reservoir units are shown in plates 1 and 2. Reservoir properties of the main producing reservoirs are shown in table 1.

Dakota Sandstone

The Upper Cretaceous Dakota Sandstone is a complex sequence of fluvial, marginal marine (deltaic and strandplain shoreface sandstones), and marine shelf sandstones (Landis and others, 1973; Owen, 1973; Molenaar, 1977b; Owen and Siemers, 1977; Ridgley, 1977, 1990; Berg, 1979; Aubrey, 1988). The Dakota has been divided into five members, in ascending order:

Table 1. Properties of Dakota Sandstone, Gallup (main) and Gallup (Torrivio Sandstone Member) Sandstone, Tocito Sandstone Lentil, and "Gallup" sandstone (Ridgley, 2001a) oil and gas reservoirs in the Dakota-Greenhorn Conventional Oil and Gas, Dakota-Greenhorn Continuous Gas, Gallup Sandstone Conventional Oil and Gas, Mancos Sandstones Conventional Oil, and Mancos Sandstones Continuous Gas Assessment Units. Data summarized from field descriptions in Fassett (1978a,b, 1983a).

[Conv, conventional; cont, continuous; %, percent; md, millidarcy; min, minimum; max, maximum; frac, fracture]

Rock unit	Net pay (ft)	Porosity (%)	Permeability (md)	Water saturation (%)	API gravity (degrees)	Type of accumulation
"Gallup"	min 7 max 278	min 1 max 15	min 0.06 max 22	min 25 max 50	min 34 max 46	Conv oil
"Gallup"	min 11 max 30	16	min ? max frac	40		Conv gas
"Gallup"	min 25 max 400	min 6 max frac	min 0.02 max frac	max 49 unreliable		Cont gas
Tocito	min 5 max 40	min 8 max 20	min 6 max 250	min 23 max 40	min 35 max 51	Conv oil
Tocito	min 6 max 15	min 10 max 15	min 82 max 83	min 31 max 40		Cont gas
Gallup (main)	27	38	110	39	24	Conv oil
Gallup (Torrivio)	min 8 max 35	min 22 max 30	min 10 max 600	min 10 max 50	min 29 max 40	Conv oil
Dakota	min 8 max 100	min 9 max 22	min 0.1 max 700	min 28 max 90	min 35 max 76	Conv oil
Dakota	min 8 max 40	min 14 max 19	min 10 max 83	min 35 max 57		Conv gas
Dakota	min 40 max 65	min 7 max 8	min 0.2 max 0.4	40		Cont gas

1. Encinal Canyon Member,
2. Oak Canyon Member,
3. Cubero Tongue,
4. Paguate Tongue, and
5. Twowells Tongue

(Landis and others, 1973; Owen, 1973; Aubrey, 1988). The Paguate and Twowells are underlain and overlain by tongues of the Mancos Shale. The Dakota rests on a regional unconformity (Aubrey, 1988; Ridgley, 1989) and is conformable with the Mancos Shale with which it intertongues (figs. 2 and 4; pls. 1 and 2). The Dakota was deposited during an overall transgression of the sea into the area of the San Juan Basin. Most of the nearshore and shelf sandstones were deposited as highstand deposits during periods of higher clastic input. Distribution of facies, and hence sandstone reservoirs in the Dakota, were controlled by the positions of the various shorelines that defined the limit of Dakota deposition in the basin (fig. 5). Unlike the northwest–southeast trend to shorelines of the overlying Upper Cretaceous formations, shorelines in the Dakota were arcuate as a result of a major embayment (Seboyeta Bay) in the San Juan Basin (Cobban and Hook, 1984; Ridgley, 1992).

Throughout the basin, the Dakota is of variable thickness, owing to the presence or absence of the Twowells Tongue. The formation is as thick as 500 ft but averages 200–300 ft (Craigg, 2001). Sandstones, conglomerates, and thin coal and carbonaceous sandstone of the Encinal Canyon Member fill valleys incised into the underlying Burro Canyon Formation in the northern part of the basin and the Morrison Formation in the southern part. Facies in the overlying Oak Canyon Member were deposited as the sea transgressed over the fluvial facies of the Encinal Canyon. In places, facies of the Oak Canyon comprise a heterolithic sequence of sandstone, siltstone, and carbonaceous sandstone deposited in estuaries and coastal marine environments (Nummedal and Swift, 1987). Sandstones of this member tend to be fine grained, burrowed, and bioturbated. Sandstones of the overlying Cubero, Paguate, and Twowells are fine to medium grained, poor to moderately well sorted, locally burrowed and bioturbated, cross stratified, and contain ripple laminations. Each of these sandstones grade into the underlying shaly unit of the Mancos Shale. They consist of stacked, upward coarsening parasequences of variable thickness. The upper sandstone in each parasequence tends to be cleaner and locally crossbedded (Franklin and Tieh, 1989).

Petrographic studies of the Dakota in the Lone Pine field (Berg, 1979) and West Lindrith field (fig. 1) (Franklin and Tieh, 1989) indicate significant variation in grain size, nature and degree of cementation, porosity, and permeability throughout the formation. Variation was observed within and between discrete sandstone bodies. The cementation history is complex; major cements are quartz, calcite, and clay. Natural fractures are especially prevalent in the West Lindrith field (fig. 1) where they are associated with small-scale folds. Fractures have been identified elsewhere in the Dakota, from outcrop and core studies, and are important in production (table 1) (Lorenz and others, 1999; Cooper and others, 2000; Jaramillo and others, 2000).

Greenhorn Limestone Member of Mancos Shale

The Greenhorn (Bridge Creek) Limestone Member of the Mancos Shale is found throughout the San Juan Basin (fig. 3; pls.1 and 2) where it consists of 30 to 70 ft of limestone, silty limestone, and calcareous shale. The member thickens from east to west across the basin; it thins to the southwest and is an excellent subsurface marker unit. The Greenhorn appears to rest conformably on the underlying Graneros Shale Member of the Mancos Shale and is conformably overlain by shale of the lower part of the Mancos Shale (fig. 3; pls.1 and 2). A persistent bentonite or a low-resistivity shale of undetermined composition marks the base of the unit. The term Greenhorn, rather than Bridge Creek, is used in this report because it is the term used by industry when reporting tops and production. A few wells produce oil from the Greenhorn; most of which are in the Gavilan field (fig. 1). Most production from the Greenhorn is commingled with production from the Dakota. Fracturing of the Greenhorn, especially on the northeast side of the basin where isolated oil production occurs, may be important to production.

Gallup Sandstone

In the San Juan Basin, the Gallup Sandstone (fig. 3) was deposited as a northeast-prograding wedge of conglomerate, sandstone, thin coal, and shale making up a complex intertonguing sequence of sediments deposited in shoreface, estuarine, and fluvial environments (Molenaar, 1973, 1977b; Nummedal and Molenaar, 1995). At the outcrop and in the subsurface where sandstone is the dominant lithology, the Gallup has been subdivided into six principal sandstone units labeled A–F, with F being the oldest (fig. 8) (Molenaar, 1973, 1983; Craigg, 2001). Each of the sandstone units prograded slightly more to the northeast than the preceding unit. The northeast pinchout of the A-sandstone unit marks the maximum northeast progradation of thick sandstone in the main Gallup. The northeast limit of each of the sandstone units has been used to define the approximate orientation and position of the various shorelines throughout Gallup deposition (fig. 8). Basinward (to the northeast), each sandstone unit of the Gallup changes facies laterally into a vertically stacked, interbedded sequence of thin sandstone and shale. This thin sandstone and shale sequence changes basinward into predominantly silty shale, and the units in the sequence are referred to as distal Gallup equivalent. These rocks are generally included in the middle unit of the Mancos Shale (pls.1, and 2) below the Coniacian unconformity (fig. 2).

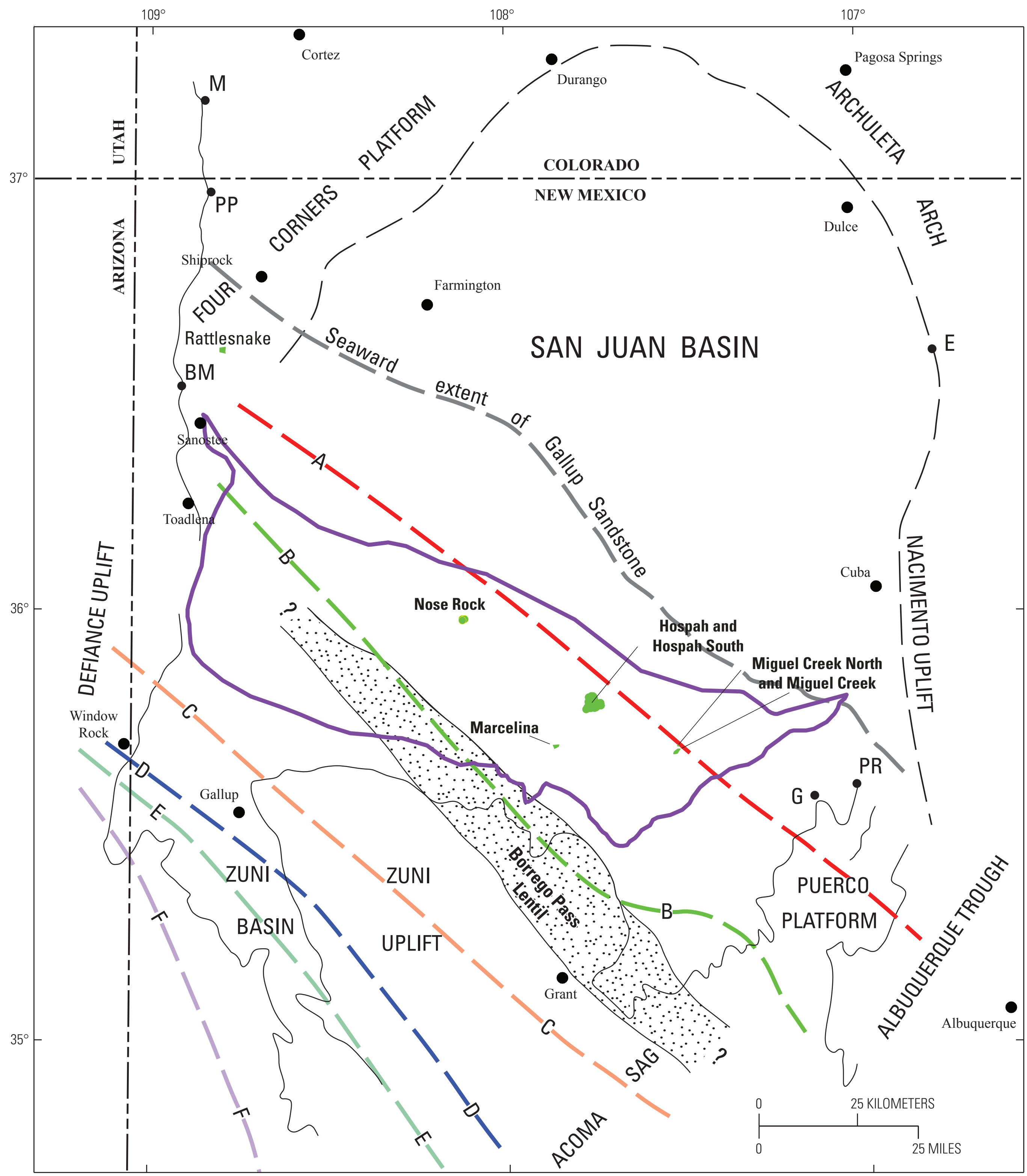


Figure 8. Map of the San Juan Basin showing the position of the Gallup Sandstone A–F shorelines (dashed lines), Borrego Pass Lentil of Crevasse Canyon Formation (dots), and outcrop locations (single black dots) of the Tocito Sandstone Lentil-"–"Gallup"sandstone interval. Outcrop locations are: M, Mounds; PP, Plunge pool; BM, Beautiful Mountain; G, Guadalupe; PR, pipeline road; and E, El Vado Reservoir. Modified from Molenaar (1973, 1983). Also shown is the outline of the Gallup Sandstone Conventional Oil and Gas Assessment Unit (purple) and oil fields that reportedly produce from the Gallup (Hospah) or Gallup Sandstone (green).

In the San Juan Basin, the Gallup is conformable with the underlying lower part of the Mancos Shale and also with members of the overlying Crevasse Canyon Formation (figs. 2 and 3) in the southwest part of the basin. Sandstone facies of the Gallup vary in thickness up to as much as 300 ft and are commonly fine to medium grained and moderately to well sorted (Stone, 1981). Shoreface facies are composed of amalgamated sandstones that coarsen upward. Hummocky cross stratification, horizontal laminations, and rare trough cross beds are the dominant sedimentary structures. Coastal facies, which include estuarine, tidal flats and deltas, and tidal channels, are heterolithic and vary laterally in extent. The sandstones are commonly bioturbated and burrowed; flaser bedding, herringbone cross stratification, and double mud drapes are common sedimentary structures (Nummedal and Molenaar, 1995). The upper part of the Gallup A sandstone and distal Gallup equivalents (included in middle of the Mancos unit below the unconformity on pl. 1) are truncated progressively from southwest to northeast across the San Juan Basin below a regional unconformity of Coniacian age (fig. 3; pl. 1) (Pentilla, 1964; Molenaar, 1977b; Nummedal and Swift, 1987; Craigg, 2001; Ridgley, 2001a). A thick, marine nearshore-bar sandstone of the main Gallup produces oil only in the Hospah South field (fig. 1), where it is called “lower Hospah” (the Hospah sandstone is an informal name used by industry) (Luce, 1978; Struna and Poettmann, 1988). Reservoir properties of the main Gallup sandstone in the Hospah South field are in table 1.

Torrivio Sandstone Member of Gallup Sandstone

In the southern part of the basin, fluvial sandstones that lie landward (to the southwest) of the Gallup sandstones are referred to as the Torrivio Sandstone Member of the Gallup Sandstone (fig. 2) (Molenaar, 1977b,c; Nummedal and Molenaar, 1995, their figs. 4 and 5). The Torrivio was deposited in braided river depositional environments (Molenaar, 1977b,c; Valasek, 1995). From outcrop studies, the Torrivio is conformable, in part, with the different Gallup shorelines and may have been the fluvial feeder system for these strandplain deposits. However, there is also some evidence that the youngest sandstone assigned to the Torrivio overlies a regional erosional surface (Nummedal and Molenaar, 1995; Valasek, 1995). Nummedal and Molenaar (1995) suggested making the Torrivio a member of the Crevasse Canyon Formation. They did not, however, change the stratigraphic position of the Torrivio in relation to the Gallup A–D sandstones. For the purposes of this report, the Torrivio is left in the Gallup because of the way industry has historically identified this sandstone.

The Torrivio Member is described as medium- to fine-grained sandstone that was deposited in continental or marine strandline settings (see field descriptions in Fassett, 1978a; Struna and Poettmann, 1988). Elsewhere, it has been documented as containing mud clasts at the base and characterized by trough cross beds (Nummedal and Swift, 1987). It has been suggested that the Torrivio of the Gallup, N. Mex., area is the same lithostratigraphic unit as the “upper Hospah” sandstone in the oil-producing Hospah and Hospah South fields (Molenaar, 1977b; Huffman, 1996). In the Hospah South field, the Torrivio is separated from the underlying main Gallup (“lower Hospah”) by a thin coal bed that was deposited during continued regression that produced the Torrivio. The producing Gallup reservoirs in the Marcelina, Miguel Creek, Miguel Creek North, and Nose Rock fields (fig. 1) (see field descriptions in Fassett, 1978a,b, 1983a) are also called “upper Hospah,” and thus correlate with the Torrivio. Using geophysical logs, the Torrivio was correlated between the Hospah and Hospah South, Marcelina, Miguel Creek, Miguel Creek North, McKinley, and Nose Rock fields; in these fields it consists of one or more sandstone beds separated by shale. Reservoir properties of the Torrivio (“upper Hospah”) Sandstone Member are summarized in table 1.

Semilla Sandstone Member of Mancos Shale

Oil has been produced from only one well in the Semilla Sandstone Member of the Mancos Shale, and it was co-produced with oil from the Dakota Sandstone. The member crops out on the east side of the San Juan Basin. At the type section, the Semilla consists of 70 ft (21.3 m) of sandstone deposited as an offshore marine bar (Dane and others, 1968; Molenaar, 1977b), and it is very fine to fine grained, becoming locally medium grained and crossbedded in the upper part. In the subsurface, the Semilla forms elongate northwest- to southeast-trending sandstone bodies that average 10 ft in thickness, but may be as much as 20 ft thick. The Semilla pinches out somewhere between T. 25 and 26 N. (wells 7 and 8, pl. 1). In the subsurface, the Semilla forms a persistent marker bed located 10 to 20 ft below the base of the Juana Lopez Member of the Mancos Shale.

Juana Lopez Member of Mancos Shale

The Juana Lopez Member (often called Sanostee, especially in drilling completion reports) crops out on the east side and is found throughout the San Juan Basin (fig. 3; pls.1 and 2) where it consists of 90 to 125 ft of dark-gray to very dark gray shale, calcarenite, and thin sandstone (Molenaar, 1977b). The base and top of the member are delineated by beds of hard, very fine grained, orange- to yellow-brown weathering, fossiliferous calcarenite (Landis and Dane, 1967). The Juana Lopez was deposited in marine environments in a shallow sea of low clastic input (Molenaar, 1973). Throughout the subsurface in the study area, the Juana Lopez forms a prominent marker interval characterized by more resistant calcarenite beds at the base and top (pls. 1 and 2). Because of its persistent character, it likely represents a time line over much of the study area and thus is used as the datum in the cross sections (pls.1 and 2). On the west side of the basin, the Juana Lopez is truncated below the Coniacian age regional unconformity (see Gallup description above). Oil and gas have been produced from the Juana Lopez in a few wells and production is usually commingled with production from the Dakota.

Sandstone Reservoirs in the Mancos Shale

At the outcrop and in the subsurface, the Mancos Shale above the Coniacian age unconformity and below the Point Lookout Sandstone of the Mesaverde Group consists of, in ascending order:

1. shale with discrete sandstone lenses (Tocito Sandstone Lentil) (the basal Niobrara sandstones of Molenaar, 1977b);
2. interbedded thin sandstone, siltstone, and shale (El Vado Sandstone Member interval of Fassett and Jentgen, 1978); and
3. shale with scattered thin sandstone and siltstone laminae in a gradational sequence with the overlying Point Lookout Sandstone of the Mesaverde Group (fig. 3; pls.1 and 2).

The Mancos sandstone reservoirs are described below.

Tocito Sandstone Lentil of Mancos Shale

The Tocito sandstones are the primary oil reservoirs in the basin, rest at different positions on the Coniacian unconformity, and become younger from north to south (Molenaar, 1973; Molenaar, 1977a; Nummedal and Molenaar, 1995; Jennette and Jones, 1995; Nummedal and Riley, 1999). Some of the sandstone beds appear to be composites, with upper and lower sandstone separated by an unconformity (Nummedal and Riley, 1999; Valasek, 1995). The depositional history of Tocito sandstones is quite complex and controversial. The sandstones form elongate northwest- to southeast-trending sandstone lenses (pls. 1 and 2) and are found mostly in the central and northern part of the basin east and north of the line that defines the regional truncation of the Gallup Sandstone (fig. 3). They have been interpreted as lowstand sandstones (Hart, 1997), remnants of tidal deltas, transgressive sand ridges (Valasek, 1995; Nummedal and Riley, 1999), and incised valley fill (Jennette and Jones, 1995).

Tocito reservoirs consist of heterolithic facies that may be as much as 45 ft thick in the subsurface. The lowermost lithofacies consist of bioturbated, muddy, glauconitic, fine-grained sandstone; burrowed and bioturbated sandstone; and crossbedded sandstone (Nummedal and Riley, 1999). The uppermost lithofacies comprise burrowed fine-grained sandstone; crossbedded sandstone; ripple-bedded sandstone; and poorly sorted, medium- to coarse-grained, glauconitic, and locally, pebbly sandstone (Tillman, 1985; Jennette and others, 1991; Jennette and Jones, 1995; Nummedal and Riley, 1999). Reservoir properties of Tocito sandstones are summarized in table 1.

"Gallup" Sandstone of Mancos Shale

The interbedded sandstone, siltstone, and shale sequence that overlies the Tocito has been called the El Vado Sandstone Member of the Mancos Shale by Fassett and Jentgen (1978) and Fassett (1991) and the "Gallup" sandstone by industry; it ranges between 100 and 700 feet thick in the basin. This "Gallup" interval, which lies above the regional Coniacian age unconformity, is not genetically equivalent to the type Gallup Sandstone, which lies below that unconformity. However, industry and IHS Energy (2001) use this term for these beds when reporting formation tops and production data in the basin. The type El Vado, as originally defined on the east side of the San Juan by Landis and Dane (1967), is a more restricted unit than that defined in the subsurface (Fassett and Jentgen, 1978; Fassett, 1991). The El Vado used in this report (pls. 1 and 2) follows the definition of Landis and Dane (1967).

The "Gallup" sequence was reinterpreted to comprise a lower transgressive wedge of sediment that is overlain by a regressive wedge of sediment (fig. 3; pls. 1 and 2) (Ridgley, 2001a). The units within the transgressive wedge were deposited during an overall sea-level rise. Although the stratal relations of the rocks in the transgressive wedge reflect deposition during transgression, the individual genetic packages were deposited during periods of regression as fluvially derived sediment from the south was deposited and redistributed in the marine environment. The overall rise in sea level that accompanied transgression appeared to have been punctuated by periodic stillstands during which greater concentrations of sandstone or sandstone mixed with shale accumulated in neritic environments closer to the shoreline. Therefore, these stillstands can be used to define areas of greater sandstone concentration that might be better reservoirs. In the northeastern part of the San Juan Basin, these sandstone trends are elongate northwest–southeast and subparallel to the inferred paleoshorelines, which overstepped each other in a southerly direction. This overstepping results in a thicker wedge of transgressive sediments in the northern part of the study area and a thinner wedge of transgressive sediments in the southern part of the study area. Cores from the transgressive wedge of sediment show this sequence to consist of stacked parasequences comprising interbedded black shale, silty mudstone, and fine-grained, carbonaceous, very bioturbated, fossiliferous sandstone (Ridgley, 2001a). Locally, "dead" oil coats fossil fragments.

The regressive wedge of sediments includes the El Vado Sandstone Member of the Mancos Shale (pls. 1 and 2) in the lower part and an unnamed sandy and silty sequence above. Sandstones in the type El Vado are fine grained, calcareous, and locally rippled or crossbedded. Sandstone is most prominent in the upper half of the member, whereas siltstone is more abundant in the lower half where it is interbedded with shale. Sandstone beds in the upper half, as observed in core, tend to be thicker compared to those of the underlying transgressive wedge, which are more carbonaceous, and the sedimentary structures are better developed. The increased sand content in the El Vado, compared to that in the underlying transgressive wedge, suggests a closer proximity to the sediment source. The El Vado was deposited as offshore sandstones during progradation of part of the Dalton Sandstone Member of the Crevasse Canyon Formation (fig. 3) (Ridgley, 2001a).

Overlying the El Vado Member is 300 to 400 ft of thin sandstone and siltstone interbedded with shale, making up the upper part of the subsurface El Vado of Fassett and Jentgen (1978) or "Gallup" of industry. These units lie stratigraphically below the deeper water facies of the marine Satan Tongue of the Mancos Shale (fig. 3). Core from the lower half of this interval shows the Mancos Shale to consist of carbonaceous, wavy to hummocky crossbedded sandstone that is interbedded with thin black shale. This sandstone sequence is similar to the sandstones found in the underlying El Vado Sandstone Member. The pattern of deposition of this sandstone succession indicates deposition in distal marine environments probably during continued regression of the Dalton Sandstone Member. The upper part of the basal 300 to 400 ft contains less sandstone and proportionally more shale. The change from greater sand to less sand marks the turn-around point between the regressive Dalton and the transgressive Hosta Tongue of the Point Lookout Sandstone. This unnamed part of the Mancos produces both oil and gas (pls. 1 and 2) (Ridgley, 2001a). Fractures are important in production of oil and gas in this interval of the Mancos as well as in other "Gallup" units (Gorham and others, 1977; Emmendorfer, 1992). Table 1 contains a summary of reservoir properties of "Gallup" reservoirs.

Sandstone Reservoirs in Upper Part of Mancos Shale

The Mancos Shale above the El Vado ranges in thickness from 700 ft in the southern part of the basin to over 1,100 ft in the northern part (fig. 3). The increase in thickness is related to the stratigraphic rise of the base of the Point Lookout Sandstone of the Mesaverde Group. Regionally, the top of the Mancos Shale is transitional with the overlying Point Lookout Sandstone of the Mesaverde Group, with sandstones gradually increasing in thickness up to the base of the Point Lookout Sandstone described below. This transition interval represents distal equivalents to Point Lookout shoreface sandstones that were deposited farther to the southwest, and could be prospective targets for gas in the deeper part of the basin where the Point Lookout is also productive.

Mesaverde Group

Reservoir rocks that could have had their gas or oil accumulations sourced from the Menefee Formation of the Mesaverde Group include from oldest to youngest, sandstones in the Point Lookout Sandstone, sandstones and coal in the Menefee Formation, and sandstones in the Cliff House Sandstone (figs. 2, 3, and 9), which together compose the Mesaverde Group. The lower half of the Mesaverde Group (Point Lookout and lower part of Menefee) was deposited as a generally progradational package of terrestrial, coastline, and shallow marine sediments that shifted from southwest to northeast. The upper half of the Mesaverde (upper part of the Menefee and the shallow-marine Cliff House Sandstone) was deposited in a time of overall southwestward transgression.

Although the Cliff House Sandstone interfingers with the Lewis Shale (of the Lewis Shale TPS) (fig. 2), most of the production in the Cliff House is reported (IHS Energy, 2002) as Mesaverde. For this reason, it was impossible to separate Cliff House production from that of other formations of the Mesaverde Group. Therefore, in the 2002 National Oil and Gas Assessment of the San Juan Basin, reservoirs and production in the Cliff House have been included in the Mancos-Menefee TPS. However, production from the Chacra sandstone (unit of industry usage that is part of the Cliff House Sandstone) and La Ventana Tongue of the Cliff House Sandstone (figs. 2 and 3) are reported separately (IHS Energy, 2002), and thus, those units were arbitrarily included in the Lewis Shale TPS, even though the units are considered part of the Cliff House Sandstone.

Point Lookout Sandstone

The Point Lookout Sandstone transitionally overlies the Mancos Shale; thin sandstone beds in the transition interval gradually become thicker, coarser grained, and more abundant upward, and the contact is placed where sandstone becomes the dominant lithology. The upper part of the Point Lookout consists of massive, lenticular sandstone beds. A sequence stratigraphic model applied to the Mesaverde has shown that the Point Lookout is composed of a complex assemblage of depositional units, some more favorable than others as hydrocarbon reservoirs (Katzman and Wright-Dunbar, 1992; Wright-Dunbar and others, 1992; Wright Dunbar, 2001). Reservoir quality is thought to be best in shoreface, foreshore, and estuarine sandstones that

1. have the highest original porosity and permeability,
2. pinch out landward into nonmarine mudrocks, and
3. are capped by a sequence boundary (Wright Dunbar, 2001).

The Point Lookout is present across most of the study area, ranging in thickness from about 40 to over 400 ft (Craigg, 2001). It is composed of very fine to medium-grained sandstone beds occurring in NW.–SE. aligned lenses 30–50 ft thick, cemented with calcite and iron oxide (Wright Dunbar, 2001). Calcite cement is present in amounts as much as 25 percent (Loomis and Crossey, 1993) and is a major control on porosity. The Point Lookout appears to be absent, either from nondeposition or by post-depositional erosion, in some places, especially in an oblong area extending from T. 33 N., R. 11 W. in Colorado to T. 31 N., R. 6 W. in New Mexico. Cross sections by Molenaar and others (2002) show thickening and thinning of the unit (fig. 9). In general, beds of the Point Lookout Sandstone are thinner, have higher shale content, and are poorer hydrocarbon reservoirs than sandstones of the Cliff House, which are discussed below (Raynolds and Pasternack, 1994).

STAGE	part	MOLLUSCAN FOSSIL-ZONE
Maas. (part)	upper	1 *Jeletzkytes nebrascensis*
		2 *Hoploscaphites nicolletii*
		3 *Hoploscaphites birkelundi*
	lower	4 *Baculites clinolobatus*
		5 *Baculites grandis*
		6 *Baculites baculus*
		7 *Baculites eliasi*
Campanian	upper	8 B*aculites jenseni*
		9 *Baculites reesidei*
		10 *Baculites cuneatus*
		11 *Baculites compressus*
		12 *Didymoceras cheyennense*
		13 *Exiteloceras jenneyi*
		14 *Didymoceras stevensoni*
		15 *Didymoceras nebrascense*
	middle	16 *Baculites scotti*
		17 *Baculites reduncus*
		18 *Baculites gregoryensis*
		19 *Baculites perplexus*
		20 *Baculites sp.* (smooth)
		21 *Baculites asperiformis*
		22 *Bacuiltes mclearni*
		23 *Baculites obtusus*
	lower	24 *Baculites sp.* (weak flank ribs)
		25 *Baculites sp.* (smooth)
		26 *Scaphites hippocrepis* III
		27 *Scaphites hippocrepis* II
		28 *Scaphites hippocrepis* I
		29 *Scaphites leei* III
Santonian	upper	30 *Desmoscaphites bassleri*
		31 *Desmoscaphites erdmanni*
		32 *Clioscaphites choteauensis*
	mid.	33 *Clioscaphites vermiformis*
	low.	34 *Clioscaphites saxitonianus*
Coniacian	up.	35 *Scaphites depressus*
	mid.	36 *Scaphites ventricosus*
	low.	37 *Forresteria alluaudi*
		38 *Forresteria hobsoni*

STAGE	part	MOLLUSCAN FOSSIL-ZONE
Turonian	upper	39 *Prionocyclus germari*
		40 *Scaphites nigricollensis*
		41 *Scaphites whitfieldi*
	middle	42 *Scaphites ferronensis*
		43 *Scaphites warreni*
		44 *Prionocyclus macombi*
		45 *Prionocyclus hyatti*
		46 *Prionocyclus praecox*
		47 *Collignoniceras woollgari*
	lower	48 *Mammites nodosoides*
		49 *Vascoceras birchbyi*
		50 *Pseudaspidoceras flexuosum*
		51 *Watinoceras devonense*
Cenomanian	upper	52 *Nigericeras scotti*
		53 *Neocardioceras juddii*
		54 *Burroceras clydense*
		55 *Euomphaloceras septemseriatum*
		56 *Vascoceras diartianum*
		57 *Dunveganoceras conditum*
		58 *Dunveganoceras albertense*
		59 *Dunveganoceras problematicum*
		60 *Dunveganoceras pondi*
	middle	61 *Plesiacanthoceras wyomingense*
		62 *Acanthoceras amphibolum*
		63 *Acanthoceras bellense*
		64 *Acanthoceras muldoonense*
		65 *Acanthoceras granerosense*
		66 *Conlinoceras tarrantense*
		(Gap in biostratigraphic record)
	lower	67 *Neogastroplites maclearni*
		68 *Neogastroplites americanus*
		69 *Neogastroplites muelleri*
		70 *Neogastroplites cornutus*
	?	71 *Neogastroplites haasi*
Albian (pt)	upper	72 *Inoceramus bellvuensis*
		73 *Inoceramus comancheanus*

[Maas. = Maastrichtian; low. = lower; mid. = middle; up. = upper; pt = part]

EXPLANATION

Formation or member contact

Contact that rises (uniformly or abruptly) in stratigraphic position. Queried where uncertain

Contact, position is uncertain

Unconformity—Queried where uncertain

SP Spontaneous-potential curve

GR Gamma-ray curve

R Resistivity curve

KB Kelly bushing

(proj) Projected position of macrofossil from nearest outcrop

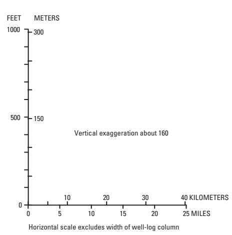
Borehole depths shown are in thousands of feet below altitude of Kelly bushing except for boreholes where igneous sills have been removed. Also note that only partial logs of boreholes are shown; upper and lower parts of logs are omitted where they are not applicable to this study.

FACIES COLORS FOR CRETACEOUS ROCKS

Nonmarine strata (various formations)

Marine and coastal sandstone

Dominantly marine shale and siltstone

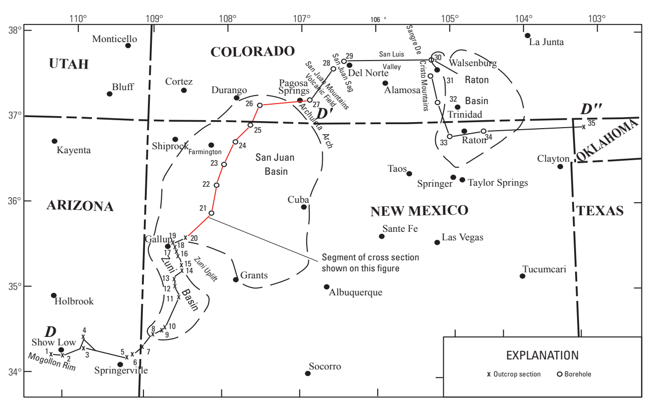


SCALE

Percent Ro values in red

ABBREVIATIONS FOR STRATIGRAPHIC UNITS

Kk Kirtland Shale
Kl Lewis Shale
Kch Cliff House Sandstone
Kpl Point Lookout Sandstone
Km Mancos Shale



INDEX MAP SHOWING LOCATION OF CROSS SECTIONS

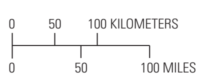
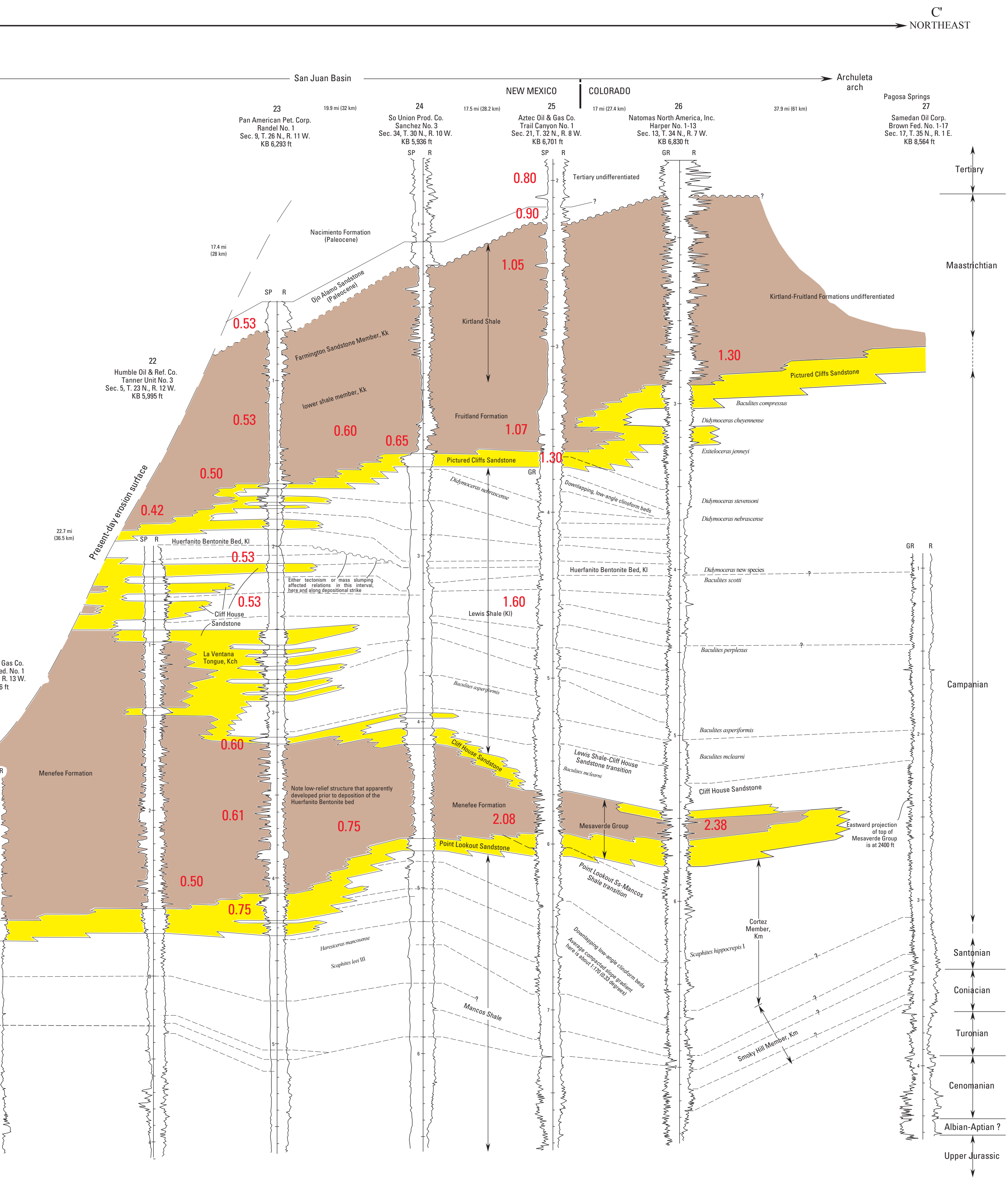


Figure 9. Cross section extending from southwest to northeast across the central part of the San Juan Basin, Colorado and New Mexico (modified from Molenaar and others, 2002).



C'
NORTHEAST
San Juan Basin
Archuleta arch
NEW MEXICO
COLORADO
Pagosa Springs
23
Pan American Pet. Corp.
Randel No. 1
Sec. 9, T. 26 N., R. 11 W.
KB 6,293 ft
19.9 mi (32 km)
24
So Union Prod. Co.
Sanchez No. 3
Sec. 34, T. 30 N., R. 10 W.
KB 5,936 ft
17.5 mi (28.2 km)
25
Aztec Oil & Gas Co.
Trail Canyon No. 1
Sec. 21, T. 32 N., R. 8 W.
KB 6,701 ft
17 mi (27.4 km)
26
Natomas North America, Inc.
Harper No. 1-13
Sec. 13, T. 34 N., R. 7 W.
KB 6,830 ft
37.9 mi (61 km)
27
Samedan Oil Corp.
Brown Fed. No. 1-17
Sec. 17, T. 35 N., R. 1 E.
KB 8,564 ft
22
Humble Oil & Ref. Co.
Tanner Unit No. 3
Sec. 5, T. 23 N., R. 12 W.
KB 5,995 ft
17.4 mi (28 km)
22.7 mi (36.5 km)
Gas Co.
ed. No. 1
R. 13 W.
6 ft
Tertiary
Maastrichtian
Campanian
Santonian
Coniacian
Turonian
Cenomanian
Albian-Aptian ?
Upper Jurassic
Tertiary undifferentiated
Nacimiento Formation (Paleocene)
Ojo Alamo Sandstone (Paleocene)
Farmington Sandstone Member, Kk
lower shale member, Kk
Kirtland Shale
Fruitland Formation
Kirtland-Fruitland Formations undifferentiated
Pictured Cliffs Sandstone
Present-day erosion surface
Huerfanito Bentonite Bed, Kl
Either tectonism or mass slumping affected relations in this interval, here and along depositional strike
Cliff House Sandstone
La Ventana Tongue, Kch
Lewis Shale (Kl)
Downlapping, low-angle clinoform beds
Lewis Shale-Cliff House Sandstone transition
Menefee Formation
Note low-relief structure that apparently developed prior to deposition of the Huerfanito Bentonite bed
Mesaverde Group
Point Lookout Sandstone
Point Lookout Ss-Mancos Shale transition
Eastward projection of top of Mesaverde Group is at 2400 ft
Cortez Member, Km
Smoky Hill Member, Km
Mancos Shale
Downlapping low-angle clinoform beds
Average compacted slope gradient here is about 1:170 (0.33 degrees)
Baculites compressus
Didymoceras cheyennense
Exiteloceras jenneyi
Didymoceras stevensoni
Didymoceras nebrascense
Didymoceras new species
Baculites scotti
Baculites perplexus
Baculites asperiformis
Baculites mclearni
Scaphites hippocrepis I
Haresiceras mancosense
Scaphites leei III
0.80
0.90
1.05
0.53
0.53
0.60
0.65
1.07
1.30
1.30
0.50
0.42
0.53
0.53
1.60
0.60
0.61
0.75
2.08
2.38
0.50
0.75
SP
R
GR

Menefee Formation

The Menefee Formation overlies the Point Lookout conformably in places, but in other places this contact is an unconformable sequence boundary (Wright Dunbar, 2001). The Menefee is over 2,000 ft thick (fig. 4) just north of its outcrop belt, and it thins northeastward and pinches out between the Point Lookout and Cliff House Sandstones in the Pagosa Springs area (Zapp, 1949). It was probably originally thicker in some areas in the south part of the basin, but late Cenozoic erosion has removed much of the unit there. The formation crops out around the perimeter of the San Juan Basin, except on the far northeast side, where it pinches out between the Cliff House and Point Lookout Sandstones (Aubrey, 1991). Coal beds and other carbonaceous strata (including humate) in the Menefee acted as source rocks for at least some of the gas in the Mesaverde. Coal may also serve as reservoir rocks. Isolated and amalgamated sandstone beds formed in fluvial channels occur throughout the formation and are also potential reservoir rocks. Some fluvial-channel sandstone units at the base of the Menefee were deposited in back-filled valleys incised into the Point Lookout Sandstone (Wright Dunbar, 2001). Most channels were deposited on alluvial plains in a meandering fluvial system (Siemers and Wadell, 1977); these sandstones are encased in overbank mudrocks. Fluvial channel sandstones are typically fine to coarse grained, have a clay matrix, and are variously cemented with calcite, iron oxide, or silica (Craigg, 2001). Channel sandstone thickness ranges from 6–15 ft (Siemers and Wadell, 1977).

Cliff House Sandstone

The Cliff House Sandstone disconformably overlies the Menefee, although some intertonguing has been noted (Fassett, 1977; Beaumont and Hoffman, 1992). The transgressive flooding surface that separates the Menefee and Cliff House is marked by a lag deposit containing sharks' teeth, shells, wood fragments, and rip-up clasts cemented with silica (Wright Dunbar, 2001). Above the lag deposit, the Cliff House consists of very fine to fine-grained, very well to well-sorted, calcite- or silica-cemented sandstone and common mudrock interbeds (Craigg, 2001). The Cliff House is poorly developed in some areas of the basin, especially in the north-central part. Molenaar and others (2002) (see well 25 on figure 9) consider it missing in some wells in the northern part of the basin, and this was verified for this report by examining well logs in that area. Thicknesses as much as 400 ft are reported in Mesaverde National Park (Aubrey, 1991). In much of the New Mexico part of the basin, the Cliff House is well developed. Upper tongues of the Cliff House (La Ventana Tongue and Chacra sandstone of industry usage, fig. 2) are thick units that are included in the assessment of the Lewis Shale TPS. Table 2 shows characteristics of Mesaverde reservoir rocks.

Hydrocarbon Source Rocks

The Mancos-Menefee TPS contains two potential hydrocarbon source rock intervals. These are carbonaceous shale in the Mancos Shale and carbonaceous shale, coal, and humate beds in the Menefee Formation. Carbonaceous shale and coal beds in the Dakota Sandstone may locally contribute to hydrocarbon generation, but these are considered to be of minor importance.

Mancos Shale Source Rock Characterization

The Upper Cretaceous Mancos Shale is the source of most of the oil and gas found in reservoir rocks in the stratigraphic interval bounded by the nonmarine Dakota Sandstone at the base and the Point Lookout Sandstone of the Mesaverde Group at the top (figs. 2 and 3) (Ross, 1980; Rice, 1983). Deposition of the Mancos Shale extended far beyond the area of the San Juan Basin. In this 2002 assessment of the San Juan Basin, the extent of Mancos source beds has been limited to coincide with the San Juan Basin Province boundary

Table 2. Characteristics of Mesaverde Group reservoir rocks and oil and gas data compiled from Prichard (1973) and from field descriptions in Fassett (1978a,b, 1983a) for units assigned to the Mesaverde Updip Conventional Oil Assessment Unit and Mesaverde Central-Basin Continuous Gas Assessment Unit. Reported minimums (min) and maximums (max) are shown; calculated averages (avg) are not shown when there were fewer than five values reported. Fluid pressure gradients were calculated from bottom-hole pressures and bottom-perforated depth.

[%, percent; psi, pounds per square inch; ft, feet; --, not applicable]

		Porosity (%)	Permeability (millidarcies)	Water saturation (%)	Fluid pressure gradient (psi/ft)	Oil API gravity (degrees)	Nitrogen (%)	CO_2 (%)	Net pay (ft)
Gas-producing sandstones	min	4	0.02	30	0.40	33	0.01	0.6	10
	max	25	6	65	0.45	60	0.5	3	200
	avg	12	2	44	--	--	--	--	63
Oil-producing sandstones	min	15	2.5	40	0.23	29.7	5.11	0.14	5.5
	max	29	400	85	0.43	46	5.9	0.4	30
	avg	22	211	53	0.34	38.7	--	--	13.5

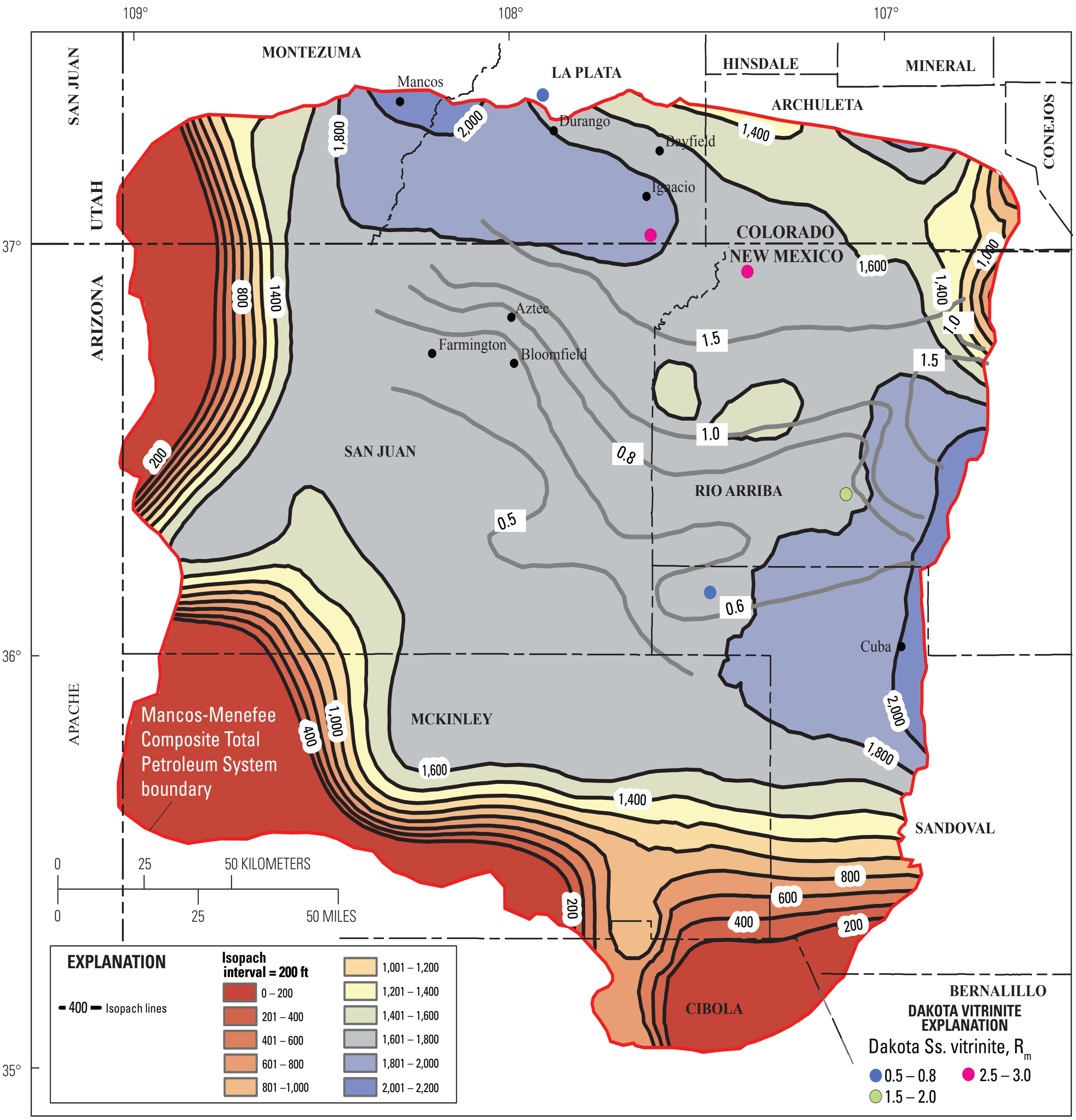


Figure 10. Isopach map of the Mancos Shale in the San Juan Basin, Colorado and New Mexico, using data from IHS Energy Group (2002). Isopach interval, 200 ft. Menefee Formation maturity contours (in gray) show vitrinite reflectance (R_m) values, in percent, using data from Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Isolated R_m vitrinite data from shale or coal in the Dakota Sandstone (colored dots) are from Fassett and Nuccio (1990) and C. Threlkeld (written commun., 2001).

(figs. 1 and 4). The Mancos Shale intertongues with thick nearshore marine sequences of the Dakota Sandstone, Gallup Sandstone, and Dalton Sandstone Member of the Crevasse Canyon Formation in the southern and southwestern areas of the San Juan Basin (fig. 3). The shale beds are of marine origin.

A generalized regional isopach map of the Mancos was constructed using the reported top of the Mancos and the top of the Greenhorn (Bridge Creek) Limestone Member of the Mancos Shale (IHS Energy Group, 2001) (fig. 10). The top of the Greenhorn was used because it is well expressed in geophysical logs, and the unit is found throughout the San Juan Basin. The isopach map does not include the Mancos that intertongues with the Dakota and may include, in some areas, sandstone intervals that belong to the Gallup or Dalton. This generalized isopach map can, however, be used to examine relative thickness of potential Mancos source rocks in the TPS. As shown in figure 10, the Mancos ranges in thickness from less than 100 ft to over 2,000 ft. Thin Mancos on the southern and southwestern margin of the TPS is related to intertonguing of the Mancos, Gallup, and Dalton units, whereas thin Mancos in the northwest and northeast parts of the TPS is due to erosion. In the latter areas, the Mancos outcrops and the thickness correspond to erosional remnants. The greater thickness of the Mancos in the northern and eastern parts of the TPS reflects the greater stratigraphic separation between the Greenhorn and the Point Lookout as a result of the stratigraphic rise of the Point Lookout Sandstone during regression. The top of the Mancos is time transgressive.

Menefee Formation Source Rock Characterization

Potential hydrocarbon source beds in the Menefee Formation part of the TPS lie above the Point Lookout Sandstone and below the Cliff House Sandstone of the Mesaverde Group (figs. 2 and 3). The source rocks consist of coal, carbonaceous shale, and humate beds. These beds may be a source of some of the oil and gas produced from reservoirs in the Menefee part of the TPS, although a study (Ross, 1980) of a few oils produced from Menefee reservoirs suggested that the oils were sourced from the Mancos Shale.

The Menefee has been divided into the Cleary Coal Member at the base of the formation and the overlying Allison Member, which also contains thin, lenticular coal beds, especially in its upper part. The Menefee is thickest in the southwest part of the basin, where it is more than 2,000 ft thick in the subsurface and thins to the northeast (fig. 3). Isopach contours, indicating the thickness of the Menefee, are oriented northwest–southeast parallel to the paleoshoreline and regional structural grain (figs. 3 and 11).

Net thickness of coal beds in the basal Cleary Coal Member is generally less than 30 ft. Beds are lenticular making correlation of individual coal beds from one area to another difficult (Hunt, 1936; Whyte and Shomaker, 1977). In the southwestern part of the basin, only remnants of the Cleary Coal Member are preserved (fig. 3), and coals beds are thinner than 6 ft (Sears, 1934). In the south-central part of the basin, the coal-bearing Cleary interval is about 1,000 ft thick, with as many as nine coal beds vertically stacked in one section; most are less than 3 ft thick. In the southeastern part of the basin, coal beds as thick as 9 ft are present at the base and near the top of the formation. However, most coal beds are 5 ft thick or thinner (Dane, 1936). The Hogback Mountain tongue, an informal unit of the Menefee located at the top of the formation (Whyte and Shomaker, 1977), interfingers with the La Ventana Tongue of the Cliff House Sandstone and contains the most abundant coal in the Menefee. It has from 3 to 18 individual coal beds, which are from 1 to 8 ft thick (Beaumont and Roybal, 1989).

In the northern part of the basin, the Menefee is also characterized by abrupt lateral changes in lithology (Zapp, 1949). As in the south, coal beds in the northern part of the basin are more abundant in the upper and lower parts of the formation, separated by a barren interval. Coal beds attain a maximum observed thickness of 9 ft in this region, but most thicknesses are between 3 and 6 ft (Zapp, 1949). Throughout the basin, Menefee coal beds are interbedded with sandstone beds, fluvial channels and crevasse splays, and overbank mudrocks.

The Menefee was estimated to contain 12 billion tons of coal in beds thicker than 2 feet at depths from 250 to 4,000 ft (Whyte and Shomaker, 1977). Nearly 11.3 billion tons are in the Hogback Mountain tongue, which is also known as the upper coal member (Beaumont and Hoffman, 1992). In a large part of the central basin, coal in the Menefee is deeper than 4,000 ft, which would increase the estimate if coals in this area were included. Coal in the area north of the 0.5-percent R_m vitrinite isoreflectance contour (fig. 11) has probably generated gas (Tissot and Welte, 1978). Heating value ranges from 9,550 to 14,940 BTU per pound, and ash content averages 12 percent (Whyte and Shomaker, 1977). The coal has a low sulfur content, from less than 1 to 3.5 percent, averaging 1.5 percent. The coal rank increases northward in the basin, ranging from subbituminous A in the Standing Rock area (approximately T. 17 N., R. 9 W.) to high-volatile C bituminous in the La Ventana area (T. 19 N., R. 1 W.) (fig. 11), and is probably higher in the deeper part of the basin. The coal along the north rim of the basin is high-volatile A bituminous. At outcrop, these coal beds display good cleat development (Siemers and Wadell, 1977).

A lithology in the Menefee, possibly important to the generation of hydrocarbons, is humate. Humate is found throughout the Menefee, both in association with coal beds and in the so called ‘barren’ parts of the formation (Shomaker and Hiss, 1974; Siemers and Wadell, 1977). Humate is dark-brown to brownish-gray mudstone that contains abundant wood and plant material and was deposited in moderately to poorly drained swamps that received an abundant influx of clay and organic matter (Siemers and Wadell, 1977). It occurs in thin beds, 1–5 ft thick, interbedded with noncarbonaceous mudstone, coal, or sandstone. Humate composes about 8–12 percent of the Menefee in sections measured on the southeast side of the basin (Siemers and Wadell, 1977). Overall, Shomaker and Hiss (1974) estimated that “many millions, probably billions” of tons of humate are in Upper Cretaceous rocks of the San Juan Basin, much of it in the Menefee Formation.

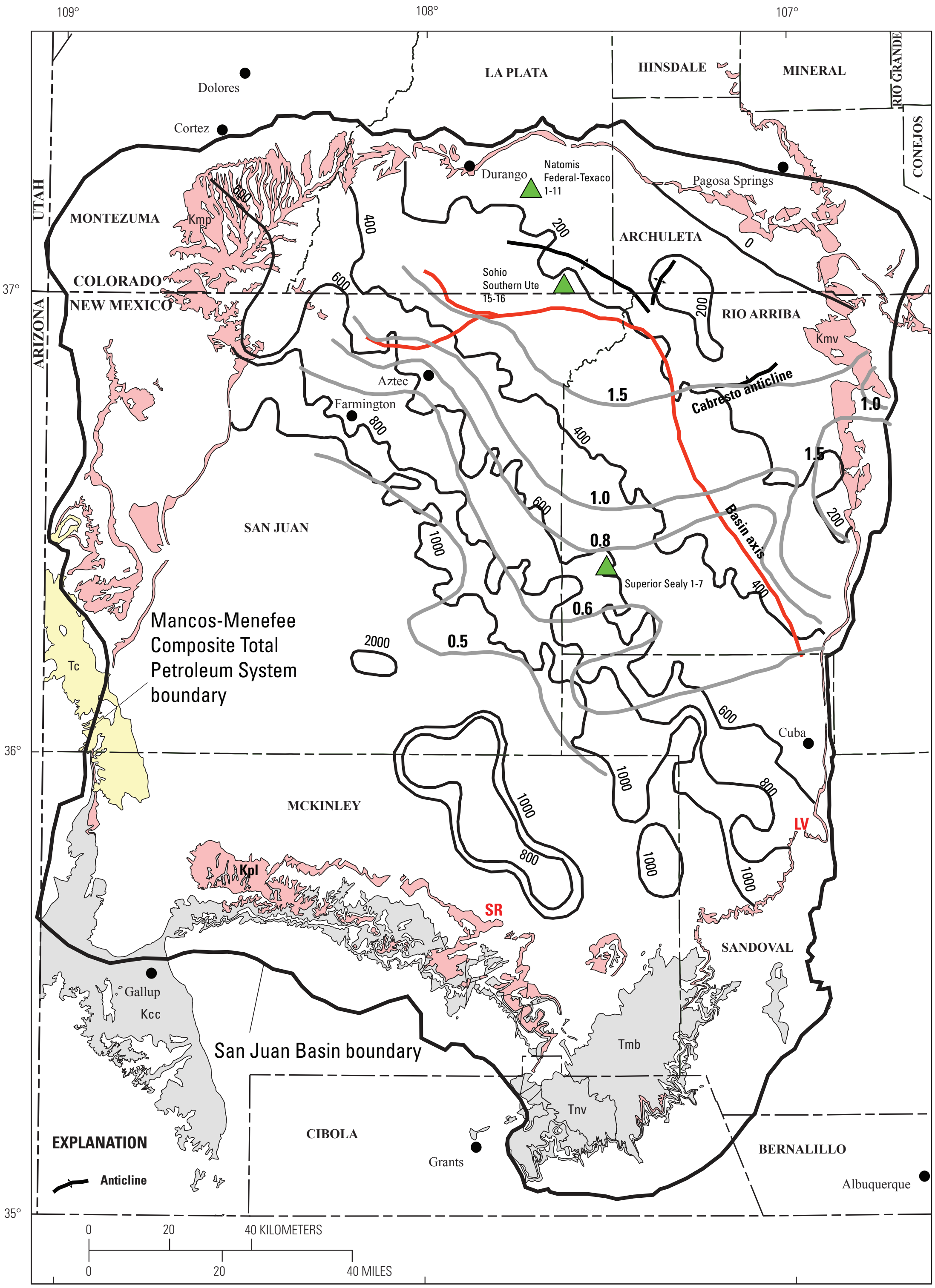


Figure 11. Isopach map of the Menefee Formation in the San Juan Basin, Colorado and New Mexico, using data from IHS Energy Group (2001). Isopach interval, 200 ft. Menefee maturity contours (in gray) show vitrinite reflectance (R_m) values, in percent, contoured using data from Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Also shown are locations of the wells (green triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*). Geologic units are from Green (1992) and Green and Jones (1997); Tc, Tertiary Chuska Sandstone; Tnv, Tertiary Neogene volcanics; Tmb, Tertiary Miocene volcanics; Kcc, Crevasse Canyon Formation; Kmp, Menefee Formation and Point Lookout Sandstone; Kmv, Mesaverde Group; Kpl, Point Lookout Sandstone. SR, Standing Rock; LV, La Ventana.

Geochemical Characteristics

The type of organic matter and its thermal maturity in the source rocks, as represented by the hydrogen indices, will determine whether oil, wet gas, or dry gas will be produced (table 3).

Mancos Shale

Geochemical data for the Mancos Shale is limited. The most definitive study of the Mancos has been in the neighboring San Juan sag, located to the northeast of the Chama platform (fig. 4) (Gries and others, 1997). Data from that study indicated that the Mancos Shale is a potential source rock for oil; it contained type-II organic matter in some intervals. Total organic carbon values (TOC) were reported to range from 0.4 to 3.1 weight percent. Similar conclusions were reached by Ridgley (2001a) based on Rock-Eval pyrolysis analysis of 13 samples from the Mancos Shale in the eastern part of the San Juan Basin. In that study, TOC values range from 0.86 to 2.68 weight percent. Both studies showed vertical variation in TOC content. Hydrogen indices for Mancos shales range from 113 to 384 in San Juan Basin samples and from 11 to 486 in San Juan sag samples. Hydrogen indices for intervals of Mancos Shale are higher than for other possible source rocks evaluated in the Menefee Formation, indicating that these intervals are source rocks for oils found primarily in Mesaverde and older Cretaceous reservoirs. Geochemical data from various sources are summarized in table 3.

Menefee Formation

Ridgley (2001b) presented Rock-Eval data from the Menefee Formation on the eastern side of the basin that has a bearing on the hydrocarbon-generating capacity of the Menefee. Analyses of carbonaceous shale from one outcrop and three core samples ranged from 4.2- to 13.0-percent TOC and one coal sample had a TOC of 73.3. These TOC values are within the range conducive to hydrocarbon generation. The hydrogen index of these samples ranged from 86 to 218, indicative of type-III organic matter, and the coal and shale would be expected to have produced mostly gas, rather than oil. Total organic carbon content of Menefee humate beds is not known, but it can be inferred that the Menefee contains a significant volume of this organic-rich, terrestrial-derived material that contributed an unknown amount of gas and possibly some oil to the Menefee part of the Mancos-Menefee TPS. Table 3 shows generalized geochemical characteristics of samples from the Menefee. Although it may be impossible to type gas in the Mesaverde back to its source, the carbonaceous shale and coal in the Menefee can be expected to produce oil or wet gas and/or dry gas depending on the thermal maturity of the organic matter.

Gas Chemistry

Both associated and nonassociated gas occurs in the Mancos-Menefee TPS. Rice (1983) reported that associated gas was chemically wetter (gas that contains greater than 1-percent ethane and higher molecular weight hydrocarbons) and isotopically lighter than nonassociated gas. These observations were based on gas samples from the Dakota Sandstone, Tocito Sandstone Lentil of the Mancos Shale, and Mesaverde Group. Natural gas compositions for the major producing reservoir intervals are summarized in table 4. Gas wetness, where wetness (percent) = $100 \times (1–[\mathrm{mol\%}C_1/\Sigma\ \mathrm{mol\%}C_1–C_5])$, CO_2 content, and methane $\delta^{13}C$ composition for the Mesaverde Group and Dakota Sandstone gases are similar. Gases from Gallup Sandstone, Graneros Shale, and Tocito Sandstone Lentil reservoirs are wetter and contain methane with more negative $\delta^{13}C$ (table 4).

For most gases from Dakota Sandstone reservoirs, relations exist between gas wetness, methane $\delta^{13}C$, and CO_2 content. As methane $\delta^{13}C$ becomes more positive, gas wetness decreases (fig. 12*A*) and CO_2 content increases (fig. 13*A*). For Dakota gases, these compositional parameters are related, in part, to present reservoir depth as shown for gas wetness in figure 14*A*. In figure 14*A*, the driest gases (wetness <2 percent)

Table 3. Means, standard deviations, ranges, and number of determinations (n) for total organic carbon contents and hydrogen indices of the Mancos Shale and Menefee Formation in the Mancos-Menefee Composite Total Petroleum System, San Juan Basin, New Mexico. Total organic carbon contents and hydrogen indices are summarized from samples with Tmax < 450°C. Data from Rice and others (1989), Pasley and others (1991), Michael and others (1993), Gries and others (1997), and C. Threlkeld (written commun., 2001).

[%, percent; mg/g, milligrams/gram; HC, hydrocarbons; μ, mean; s, standard deviation]

Interval	Total organic carbon (%)	Hydrogen index (mg/g) (Rock-Eval)	Expected types of HC
Menefee Formation coal	range = 30–73.3 (n = 3)	range = 123–290 (n = 3)	Wet and/or dry gas
Mancos Shale	μ = 1.9, s =1.0 range = 0.8–5.3 (n = 30)	μ = 300, s = 140 range = 86–620 (n = 30)	Wet and/or dry gas, oil

are mostly found at depths greater than 7,000 ft. Similarly, methane $\delta^{13}C$ and CO_2 content also show changes with present reservoir depth. Methane $\delta^{13}C$ becomes more positive and CO_2 content increases with depth, although there is some scatter. The significant scatter shown in figure 14*A* as well as the scatter in methane $\delta^{13}C$ and CO_2 content with depth is a likely result of the structural reversal of the basin axis throughout geologic time, subsequent differential erosion in the basin, and possibly some gas migration.

Gas composition relations in Mesaverde Group reservoirs are similar to those shown for Dakota Sandstone reservoirs, with gas wetness decreasing (fig. 12*B*) and CO_2 content increasing (fig. 13*B*) as methane $\delta^{13}C$ becomes more positive. These similarities suggest a common hydrocarbon source rock for the gases produced from these two intervals. Mesaverde gas compositions, in contrast to Dakota gases, do not appear to be related to present reservoir depth (fig. 14*B*). However, methane $\delta^{13}C$ and CO_2 contents show slight changes with present reservoir depth. Methane $\delta^{13}C$ becomes more positive and CO_2 content increases with depth, although there is some scatter. The lack of a relation of gas wetness to depth (fig. 14*B*) and the scatter in methane $\delta^{13}C$ and CO_2 contents with depth may also result from the structural reversal of the basin axis throughout geologic time and subsequent erosion in the basin.

Although limited to four methane $\delta^{13}C$ analyses (table 4) for gases from the Gallup Sandstone, Graneros Shale, and Tocito Sandstone Lentil reservoirs, trends in gas compositions appear similar to those shown for the Dakota Sandstone and Mesaverde Group reservoirs.

Oil Chemistry

Two studies (Ross, 1980; Gries and others, 1997) geochemically characterized the oils from the San Juan Basin and adjacent areas and attributed most of the oils to a Mancos source. Van Delinder (1986) analyzed eight Cretaceous oils in McKinley County, N. Mex. from the Dakota, Gallup, and Menefee reservoirs, but did not ascribe a source. He did, however, suggest that many of these oils had a similar source based on hydrocarbon compounds, and that differences between some of the oils could be due to degrees of biodegradation. Two different oils, "marine" and "nonmarine," are produced from Cretaceous age reservoirs and can be distinguished by their isoprenoid ratios and carbon-isotope compositions. Most of the produced oils in the San Juan Basin belong to the "marine Cretaceous" group of Ross (1980). These "marine Cretaceous" oils have been produced from reservoirs ranging from the Dakota Sandstone near the base of the Cretaceous section through reservoirs in the Farmington Sandstone Member of the Kirtland Shale above the Fruitland Formation (Ross, 1980).

The "nonmarine Cretaceous" oil of Ross (1980) is limited to the Dakota Sandstone in the extreme west side of the Mancos-Menefee TPS. Ross (1980) considered this oil to have been sourced from the Mesaverde–Lewis interval, based in part on the pristine/phytane ratios of 2.5–2.6, which are indicative of a coaly sequence. The Lewis has no coal beds, but coal beds are found in the Menefee Formation of the Mesaverde Group. Oils from the Dakota in that area (see field descriptions in Fassett, 1978a,b) have high API gravities (51°–60°), which are in the condensate range. The area where these oils are found lies outside or along the margin of the 0.5-R_m vitrinite isoreflectance contour in the Menefee (fig. 1) and where the Mancos Shale is at the surface. In order to account for the high API gravities, the oil must have migrated to this area from sources deeper in the basin to the east. Alternatively, local heating during emplacement of intrusions in the area may have thermally altered oil previously emplaced or generated locally. The Dakota in this area probably contains carbonaceous shale and thin coals that were deposited during shifts of the Dakota shoreline to the west. Geophysical logs indicate the presence of shale interbedded with sandstone. Local coals in the Dakota, rather than those in the younger Menefee Formation to the east, could have been the source of the observed pristine/phytane ratios in the oils.

Table 4. Means, standard deviations, and number of analyses (n) of gas wetness, carbon dioxide content, carbon isotope of methane $\delta^{13}C_{CH4}$) of produced natural gases from reservoirs in the Mancos-Menefee Composite Total Petroleum System, San Juan Basin. Data from Rice (1983); Moore and Sigler (1987); Rice and others (1988); Scott and others (1991); and Threlkeld, (written commun., 2001). Wetness (%) = 100 x (1–[mol%C1/∑mol%C_1–C_5]).

[%, percent; PDB, Peedee belemnite; Ss, sandstone; Mbr, member; μ, mean; s, standard deviation]

Producing interval	Wetness (%)	CO_2 (%)	$\delta^{13}C_{CH4}$ (per mil PDB)
Mesaverde Group + Point Lookout Sandstone	μ = 10.2, s = 7.3 (n = 86)	μ = 1.3, s = 1.1 (n = 87)	μ = –39.8, s = 3.8 (n = 48)
"Gallup" Ss. + Graneros Shale + Tocito Lentil of Mancos Shale	μ = 17.8, s = 10.4 (n = 30)	μ = 1.2, s = 1.5 (n = 30)	μ = –44.4, s = 6.5 (n = 4)
Dakota Sandstone + Greenhorn Limestone Mbr. of Mancos Shale	μ = 9.7, s = 10.5 (n = 89)	μ = 2.0, s = 1.8 (n = 93)	μ = –36.6, s = 4.6 (n = 47)

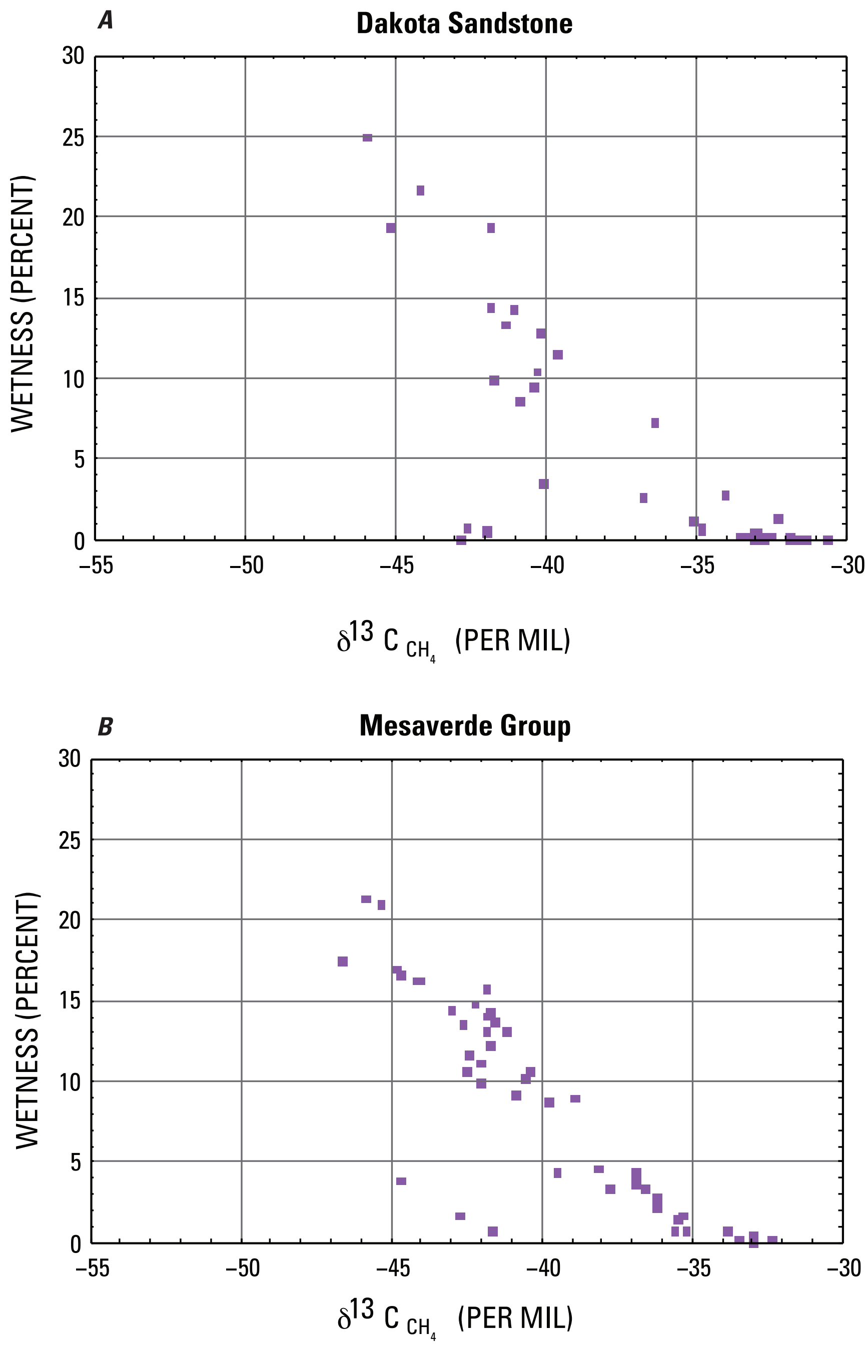


Figure 12. Cross plot showing relation between gas methane $\delta^{13}C$ and gas wetness. Data are from unpublished U.S. Geological Survey Gas Analysis Database (C. Threlkeld, written commun., 2001). (*A*) Dakota Sandstone, n = 47 samples; (*B*) Mesaverde Group, n = 48 samples.

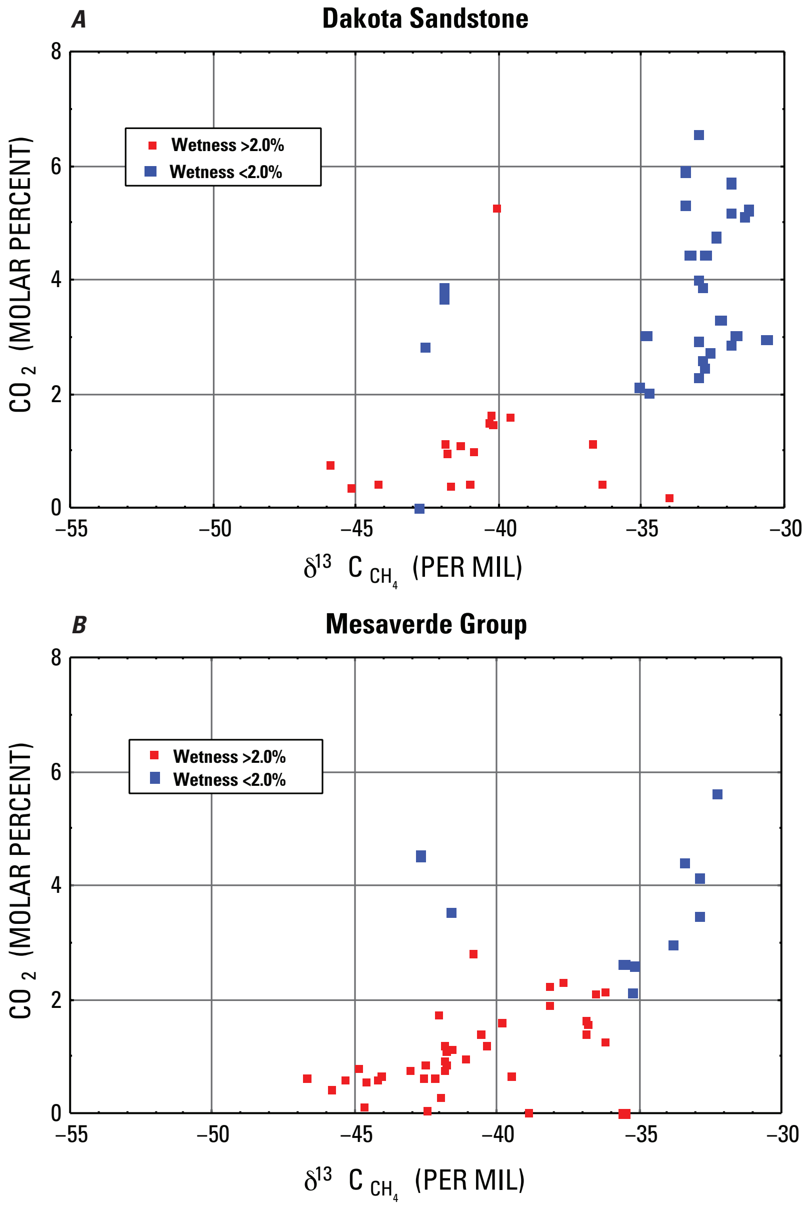


Figure 13. Cross plot showing relation between gas methane $\delta^{13}C$, CO_2 content, and gas wetness. Data are from unpublished U.S. Geological Survey Gas Analysis Database (C. Threlkeld, written commun., 2001). (*A*) Dakota Sandstone, n = 47 samples; (*B*) Mesaverde Group, n = 48 samples.

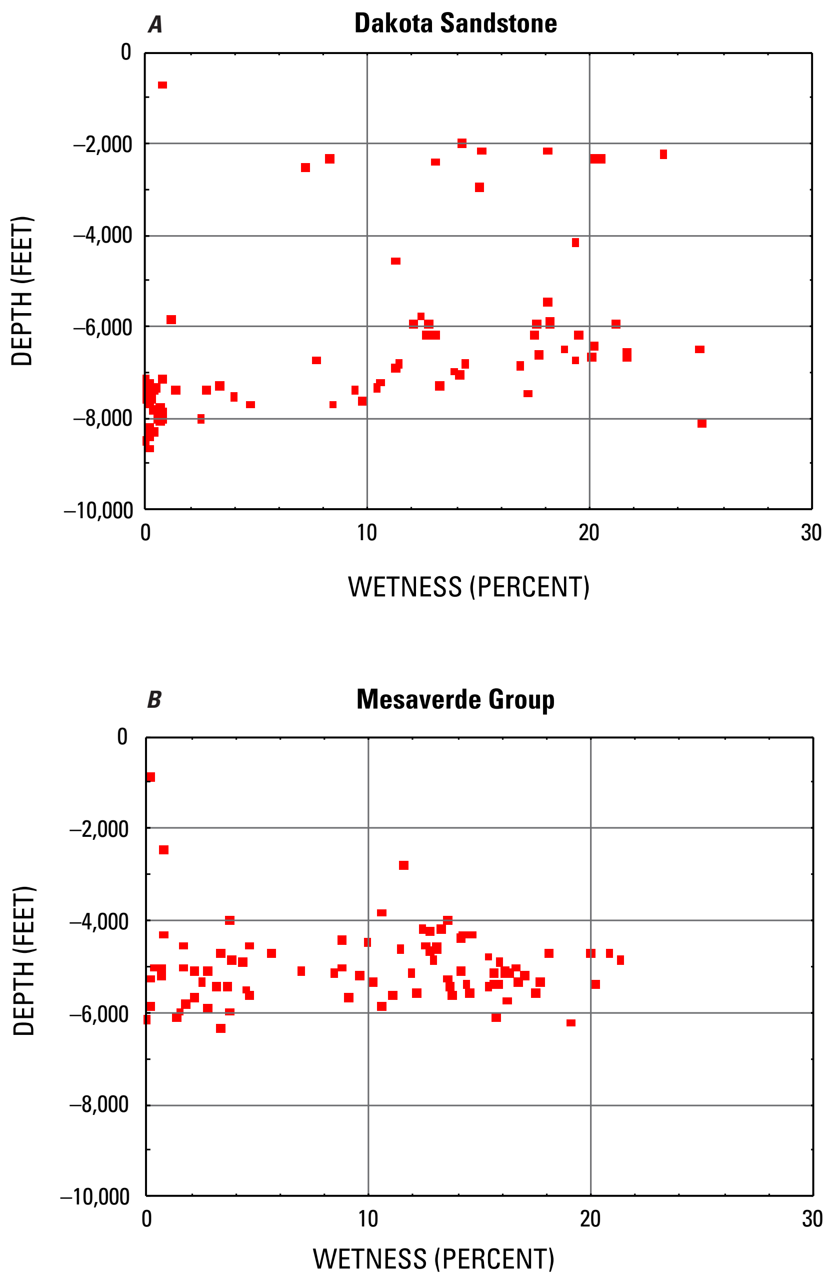


Figure 14. Cross plot showing relation between gas wetness and present reservoir depth. Data are from unpublished U.S. Geological Survey Gas Analysis Database (C. Threlkeld, written commun., 2001). (*A*) Dakota Sandstone, n = 89 samples; (*B*) Mesaverde Group, n = 86 samples.

Source Rock Maturation and Thermal History

The thermal history of the Mancos-Menefee TPS source beds is closely linked to the structural evolution of the basin. During the Late Cretaceous (about 90 Ma—millions of years before the present), the central part of the San Juan Basin began to subside slowly. Maximum subsidence in the deepest part of the basin, north of the Colorado-New Mexico State line, occurred during the late Oligocene. During the Miocene, the basin axis shifted to the area south of the Colorado-New Mexico State line. Differential uplift, erosion, and thermal cooling followed basin subsidence. Rocks in the San Juan Basin are generally underpressured.

Burial History

Burial history curves can be used to examine the relation between structural evolution of the basin and thermal maturation of coals for different parts of the basin. Thermal maturation studies (Bond, 1984; Law, 1992) indicate changes in the geothermal gradient in the basin at different periods of geologic time and for different parts of the basin. The highest geothermal gradient was reached in the Oligocene (Bond, 1984). Burial history curves (figs. 15*A* and 15*B*) for two distinct parts of the San Juan Basin were presented by Law (1992). The southernmost burial curve is for the Superior Sealy 1-7 well located in Rio Arriba County, N. Mex. (figs. 1 and 15*A*) (Law, 1992), peripheral to the deep part of the central basin. This curve is representative of the burial history of the southern part of the central basin (fig. 4), which was not buried as deeply as other parts. Temperature profiles through this well have not been constructed; however, maximum temperature in the Dakota Sandstone–Mesaverde Group interval was probably less than temperatures for the northern burial reconstructions (figs. 15*B* and 15*C*). The well lies between the 0.7- (extrapolated) and 0.8-percent R_m vitrinite isoreflectance contours (fig. 1) in the Menefee Formation.

The curve for the Sohio Southern Ute 15-16 well (figs. 1 and 15*B*) (Law, 1992) represents burial near the present-day deepest part of the basin and indicates that this area continued to subside from about 90 Ma until the late Miocene (13 Ma). Basin deepening was interrupted by brief periods of uplift and erosion. Maximum burial in this area was in the late Miocene (~ 13 Ma), and at this time the Dakota Sandstone was buried to nearly 12,000 ft. Although temperature profiles through this well have not been constructed, maximum temperature in the Dakota Sandstone–Mesaverde Group interval was probably slightly less than those for the northern burial reconstruction. The duration of maximum temperature would have been less than for the northern well because maximum burial occurred about 12 million years later. A vitrinite reflectance value of 2.5–3.0 percent R_m was measured in the Dakota Sandstone in a nearby well, which lies north of the 1.5-percent R_m vitrinite isoreflectance contour in the Menefee Formation (fig. 1).

The northernmost burial history curve on which isotherms have been superimposed is for the Natomas 1-11 Federal well (figs. 1 and 15*C*) (Bond, 1984); it indicates that maximum subsidence of the basin in this area ceased in the late Oligocene and that uplift and erosion followed. Further, this burial history curve indicates that maximum burial occurred in the late Oligocene in this area of the basin, whereas to the south (fig. 15*B*), maximum burial was in the late Miocene. These relations indicate a shift in the basin axis from north to south concurrent with uplift of the northern margin of the basin.

The burial curve and isotherms for the Natomas 1-11 Federal well (fig. 15*C*) show the Dakota (and thus the lowermost Mancos) entering the oil generation zone in early Eocene (about 53 Ma) and the top of the Niobrara Member of the Mancos Shale entering the zone of oil generation a few million years later. The Dakota was shown to enter the wet gas zone of generation in the middle Eocene and the dry gas zone in the early Oligocene (33 Ma). The Niobrara entered these zones a few million years later. Thus the time of significant maturation of the Mancos Shale spans about 20 m.y. (million years) (Eocene to Oligocene) with the basal part of the formation maturing earlier than the top. Using the curve for the Sohio Southern Ute 15-16 well near the present-day structural axis of the basin (fig. 15*B*), the Mancos should have continued to mature and generate hydrocarbons well into the Miocene. Maximum depth of burial for the Dakota in the Natomas 1-11 Federal well was projected to exceed 14,000 ft and for the top of the Niobrara to be near 13,000 ft. The burial curve and isotherms (fig. 15*C*) for the Natomas 1-11 Federal well shows the Menefee entering the zone of oil generation in the mid-Eocene (45 Ma) at a depth of approximately 9,800 ft, entering the wet gas zone in the early Oligocene, and the dry gas zone in the late Oligocene (27 Ma) (Bond, 1984).

Vitrinite Reflectance

Vitrinite reflectance has been extensively studied in Fruitland Formation coals; however, far fewer vitrinite reflectance data exist from the Mancos-Menefee TPS. The top of the zone of oil generation is generally accepted to be at a mean vitrinite reflectance value of 0.5-percent R_m (Tissot and Welte, 1978). The onset of intense thermogenic gas generation is considered to occur between vitrinite reflectance values 0.8–1.0 percent R_m and wet gas generation between 0.5–0.8 percent R_m (Tissot and Welte, 1978). Cracking of oil (condensate) to methane is thought to occur between vitrinite reflectance values 1.0–1.35 percent R_m and maximum generation of thermogenic methane between vitrinite reflectance values 1.20–2.0 percent R_m (Tissot and Welte, 1978).

The pod of active source rock for both the Mancos Shale and Menefee Formation lies near the 0.50-percent R_m vitrinite isoreflectance contour line in the Menefee, encompassing much of the northern half of the basin (fig. 7). Most of the nonassociated gas in the Dakota, Mancos, and Mesaverde reservoirs generally is found north of the 0.8-percent R_m vitrinite isoreflectance contour (fig. 1) in the Menefee, and associated gas and oil in the Dakota, Mancos, and Mesaverde reservoirs are found south of that contour.

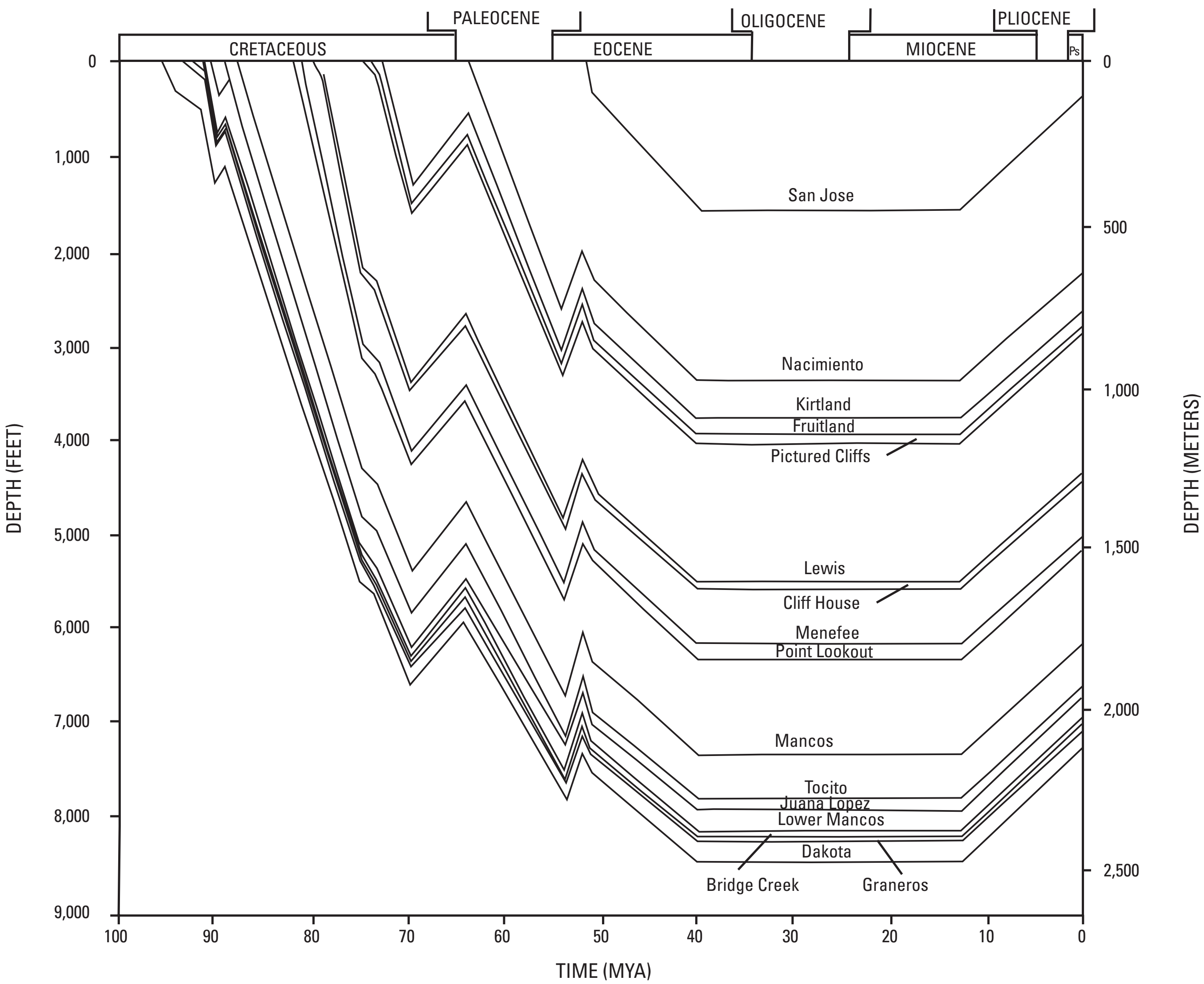


Figure 15*A*. Burial history curve for the Superior Sealy 1-7 well in the southern part of the central San Juan Basin, Colorado and New Mexico (modified from Law, 1992). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008. MYA, millions of years ago; Ps, Pleistocene.

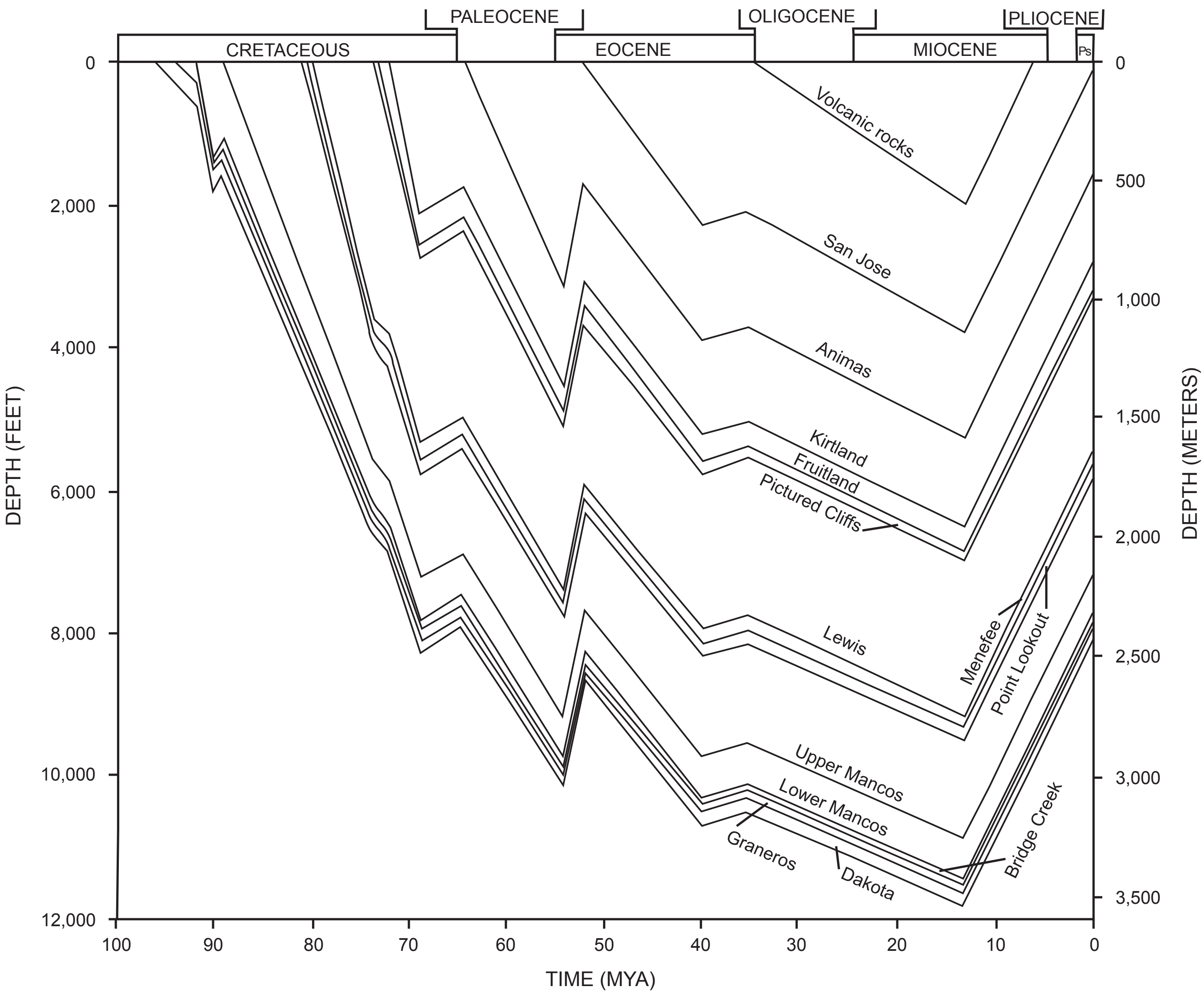


Figure 15*B*. Burial history curve for the Sohio Southern Ute 15-16 well in the northern part of the central San Juan Basin, Colorado and New Mexico (modified from Law, 1992). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008. MYA, millions of years ago; Ps, Pleistocene.

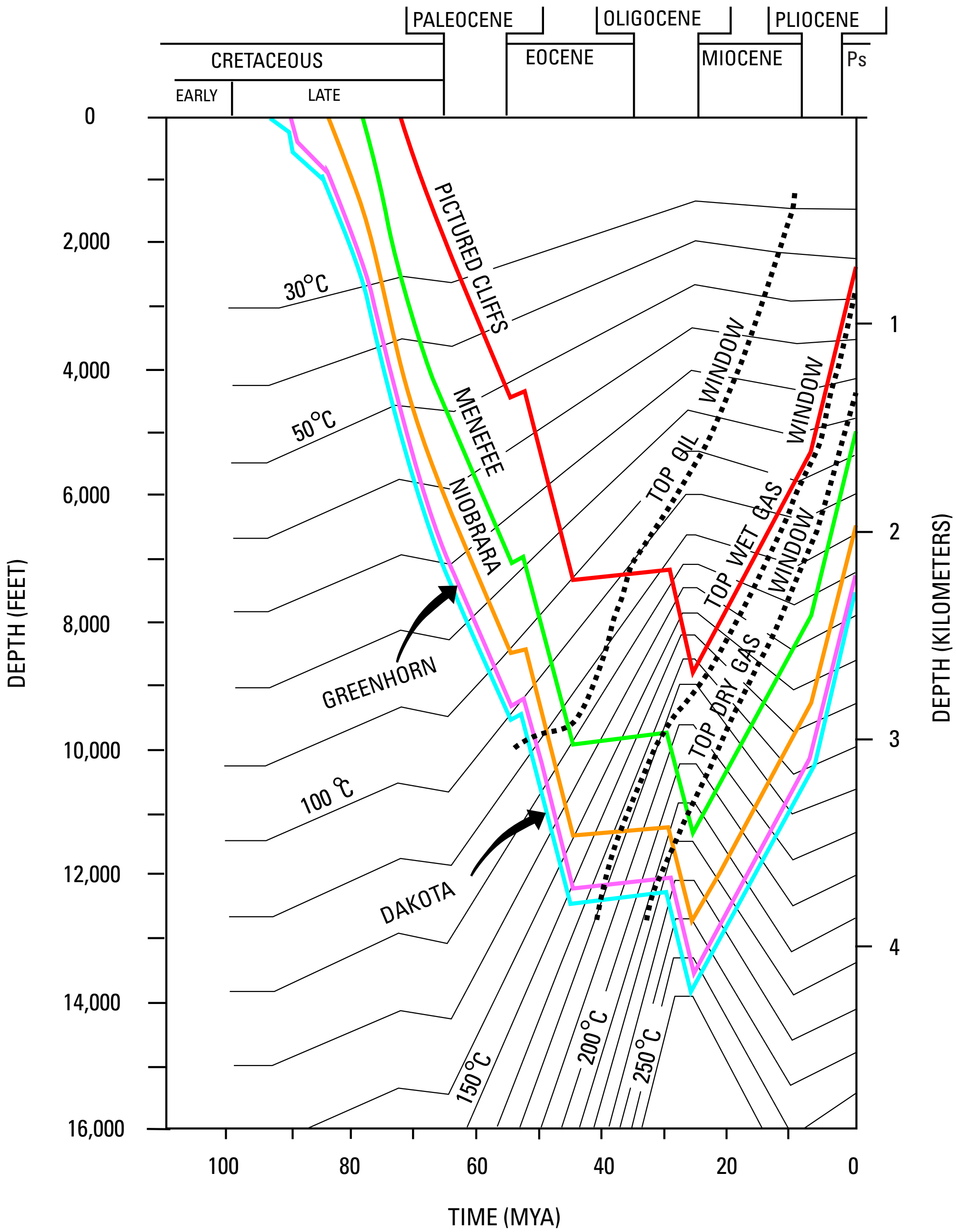


Figure 15*C*. Burial history curve and isotherms for the Natomas 1-11 Federal well in the northern part of the San Juan Basin, Colorado and New Mexico (modified from Bond, 1984). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008. MYA, millions of years ago; Ps, Pleistocene.

Dakota Sandstone

Few vitrinite reflectance values are available from coals in the Dakota Sandstone and most are from the area of the central basin (fig. 1) (Fassett and Nuccio, 1990; C. Threlkeld, U.S Geological Survey, written commun., 2001). These data indicate that the Dakota–lower Mancos and Menefee strata had a similar thermal history in the southern part of the central basin, but a higher thermal history for the Dakota–lower Mancos relative to the Menefee north of this area (Rice, 1983). Vitrinite reflectance values from coals in the northern outcrop belt of the Dakota are lower (0.5–1.0 percent R_m) than those in the northern part of the central basin (fig. 1). This decrease in the vitrinite reflectance values is similar to that observed for the Fruitland (Fassett, 2000) and reflects the effect of uplift of the northern basin margin as the basin continued to subside to the south. South of the 0.5-percent R_m vitrinite isoreflectance contour in the Menefee, no vitrinite reflectance data from the Mancos or from coals in the underlying Dakota Sandstone exists. Thus, the southern boundary within the Mancos Shale that is thermally mature enough to generate hydrocarbons is not well defined.

The Mancos Shale was probably in the zone of oil generation north of the central basin along the outcrop belt. In the central basin, Mancos sandstone reservoirs contain mainly gas north of the extrapolated 0.75-percent R_m vitrinite isoreflectance contour in the Menefee Formation, whereas oil is found mainly south of this contour. In the northern part of the San Juan Basin, vitrinite reflectance contours in the overlying Menefee Formation range from 1.0-percent to greater than 1.5-percent R_m, and two vitrinite reflectance values in the Dakota Sandstone are between 2.5- and 3.0-percent R_m (fig. 1). The combination of high thermal maturity and present (and past) overburden thickness of the Mancos in the deep part of the basin would influence the type of hydrocarbons produced in the Mancos, which would likely be gas or previously generated oil that would begin to crack to gas.

Menefee Formation

Thermal maturity data (R_m) from Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b), as well as samples analyzed for this study, were used to construct vitrinite isoreflectance contours for the Menefee Formation (fig. 1), which roughly correspond to the structure contour lines that define the shape of the basin. Isoreflectance contours indicate progressively greater thermal maturity of the coals from southwest to northeast across the TPS (fig. 1), similar to the pattern of the Fruitland Formation (Fassett, 2000). The position of the 0.5-percent R_m contour is not well constrained; however, it does indicate that Menefee source beds, which lie north of this contour, would be in the zone of oil or gas generation.

Hydrocarbon Migration Summary

Hydrocarbon migration from Mancos Shale source beds took several routes. In the southern part of the San Juan Basin (fig. 1), oil is found in Dakota Sandstone reservoirs as well as in various genetically unrelated sandstone beds in the upper Gallup Sandstone (Hospah of industry). Although no thermal maturity data have been derived from the Mancos Shale in the southern part of the basin, it is not likely that the oil was locally sourced, because the Mancos Shale is considered to be thermally immature in this area. Oils in the Dakota at Lone Pine field and producing sandstones of the Hospah field are similar; oil-source correlations indicate the Mancos is the source (Ross, 1980). Migration routes of the oil are not known, but it must have migrated from north to south out of the deeper part of the basin where the Mancos Shale is thermally more mature. Inferred migration pathways are shown on figure 16.

Migration may have been along faults. Although few faults have been mapped in the Dakota in the central part of the basin (Thaden and Zech, 1984; pl. 3), a series of interconnected basement faults have been identified (fig. 4), and some of these might extend into the Mancos Shale. Alternatively, basal fluvial Dakota sandstones, which are the most laterally continuous sandstones in the Dakota, may have served as the conduits. Oil in the Hospah field may have migrated vertically upward from the Dakota along faults that cut the sandstones of the Dakota, Gallup, and Torrivio in areas of oil production. Because of the regional orientation of the Gallup sandstones (northwest–southeast), the sandstones could not have served as direct conduits to funnel oil from the deeper part of the basin toward the south. However, oil in Gallup fields and seeps in McKinley County may have migrated through the Gallup from the area where distal Gallup facies (thin sandstone, siltstone, and shale) (fig. 8) underlies Tocito sandstones (Molenaar, 1977b). In this area, which would lie within the pod of mature source rock, there may be sufficient fractures or faults to serve as conduits for oil migration into the main Gallup or Torrivio to the south. The Coniacian unconformity may also have served as a migration path with oil migrating along the unconformity and then into sandstones of the Gallup.

Oil is found in Dakota Sandstone and Mancos Shale reservoirs west of the central basin on the Four Corners platform and east of the central basin on the Chama platform (figs. 1 and 4). In both of these areas, the fields are areally small. Some of the oil, such as that found in Dakota reservoirs at the Hogback and Table Mesa fields (fig. 1) (see field descriptions in Fassett, 1978a,b), may have been locally generated due to high temperatures from local intrusions. The remaining oil probably migrated via faults and fractures from the pod of active source rock in the Mancos Shale (fig. 7). The source rock maturity of the Mancos on the Chama platform (fig. 1) is unknown. However, because the basin was once areally larger than its current configuration, the oil could have been locally sourced, based on vitrinite reflectance in the overlying Menefee Formation and probable extent of mature source rocks in the Mancos Shale (fig. 7). Oil in Tocito and "Gallup" (drillers' term; see discussion in reservoir rock section) sandstones was locally sourced and migration pathways were short, essentially from source beds into adjacent sandstone reservoirs (fig. 16). All the oil and gas producing reservoirs in the Tocito and "Gallup" lie within the proposed extent of mature source rocks in the Mancos (fig. 7). Faults and fractures in these reservoirs, as well as in the surrounding Mancos Shale, may also have served as migration pathways.

Some reservoirs in the Dakota, "Gallup," and Mesaverde contain basin-centered gas accumulations. Here gas accumulated locally either from thermocatalytic conversion of kerogen to gas in closely associated source rocks or from thermal cracking of earlier formed oil. Migration distances are short (fig. 16) if the former is important and nonexistent if the latter is important because the gas would be generated in place.

Gas generated from the Menefee could have

1. remained in place in coal beds or other carbonaceous beds,
2. migrated to nearby fluvial sandstone reservoir rocks, or
3. migrated to the underlying Point Lookout or overlying Cliff House Sandstones, probably via fracture zones (fig. 9).

Coal in the Menefee is mainly in the upper and lower one-quarter to one-third of the formation, so migration distances to the Point Lookout or Cliff House would have been minimal.

Faults and natural fractures are the two most important pathways for vertical migration of hydrocarbons. Faults are common on the south and southeast sides of the basin (Thaden and Zech, 1984; pl. 3), including the area of oil production in the Mesaverde. Ross (1980) noted a close correlation between Mancos bitumen and marine Cretaceous oils, including oil sampled from Mesaverde reservoirs in several fields. This implies that Mancos oil moved upward along faults into Menefee and Point Lookout reservoirs.

Lorenz and Cooper (2001) summarized outcrop and core studies of fractures in Mesaverde rocks in the San Juan Basin. They noted that outcropping Mesaverde sandstones have vertical, relatively long, irregular extension fractures that are not as well-formed as fractures in the quartz-cemented Dakota Sandstone. Moreover, most fractures in both units are limited to sandstone beds and do not cross mudrock interbeds. The fractures mapped from outcrops trend generally north-northeast, with orthogonal secondary fractures related to uplift and erosion at the outcrop. Fractures described from core in the subsurface of the basin were interpreted to have the same NNE.–SSW. orientation as those observed at the outcrop (Lorenz and Cooper, 2001), but cores lacked the secondary cross fractures. Fractures in Mesaverde cores were filled to partially filled with calcite and quartz. Fault zones increased the fracture intensity. Spacing of fractures in both outcrops and core are at or less than the thickness of the beds in which they formed. Fracture intensity is greater in areas of higher productivity, including zones where fractures are closely spaced.

Hydrocarbon Traps and Seals

Mancos

Hydrocarbon traps in Mancos reservoirs vary regionally. In the southern part of the San Juan Basin, traps in the Dakota, Gallup, and Torrivio are combined structural and stratigraphic traps (see field descriptions in Fassett, 1978a,b, 1983a; Berg, 1979). Discontinuous sandstones of marginal marine origin are juxtaposed with faults that not only compartmentalize the fields, but also may have served as pathways for local vertical migration of oil. Local porosity and permeability variations in the Dakota, a result of diagenesis and bioturbation, were also considered to be important controls on trapping and retaining oil in the Dakota at the Lone Pine field (Berg, 1979). Oil in Dakota reservoirs on the Four Corners platform and Chama platform (fig. 1) is in anticlines, some of which may have associated faults. In these areas, the trapping mechanism is combined structural and stratigraphic.

Oil accumulations in the Mancos sandstone reservoirs on the Four Corners and Chama platforms (fig. 4) are in very fine grained sandy, silty, and shaly facies, associated with faults. The fine-grained heterolithic lithology and low permeability of these facies are the principal trapping mechanisms. Oil in Tocito reservoirs is stratigraphically trapped. Oil in "Gallup" reservoirs is primarily trapped by the low permeability of the facies. Some of the "Gallup" fields are associated with small folds, where faulting and fracturing may have assisted not only with local hydrocarbon migration but also with trapping (Emmendorfer, 1992; see field discussions in Fassett, 1978a,b, 1983a; Gorham and others, 1977; Ridgley, 2001a).

Nonassociated gas in Dakota, Tocito, "Gallup," and Point Lookout reservoirs occurs in basin-centered accumulations in the central basin (fig. 4). Here the principal trapping mechanisms are stratigraphic resulting from laterally discontinuous facies and high capillary pressures due to low permeability in the facies. Structures may be locally important traps.

Mesaverde

Hydrocarbon traps in the Mesaverde are stratigraphic for gas accumulations and are combination stratigraphic and structural for oil accumulations. Although gas production is normally reported as "Mesaverde" and is not identified by formation (IHS Energy Group, 2001), the trends of highest cumulative gas are associated with two linear zones of Cliff House Sandstone—one 125–300 ft thick and the other 300–500 ft thick—that are oriented northwest–southeast across the producing area. Less-productive gas wells are in areas where the Cliff House is generally less than 125 ft thick. A similar correlation between higher cumulative gas production and zones of relatively thick Point Lookout Sandstone was not observed. Gas is trapped within the marginal marine sandstones and within fluvial sandstones where those units pinch out into paludal or marine shales, or overbank mudrocks, respectively.

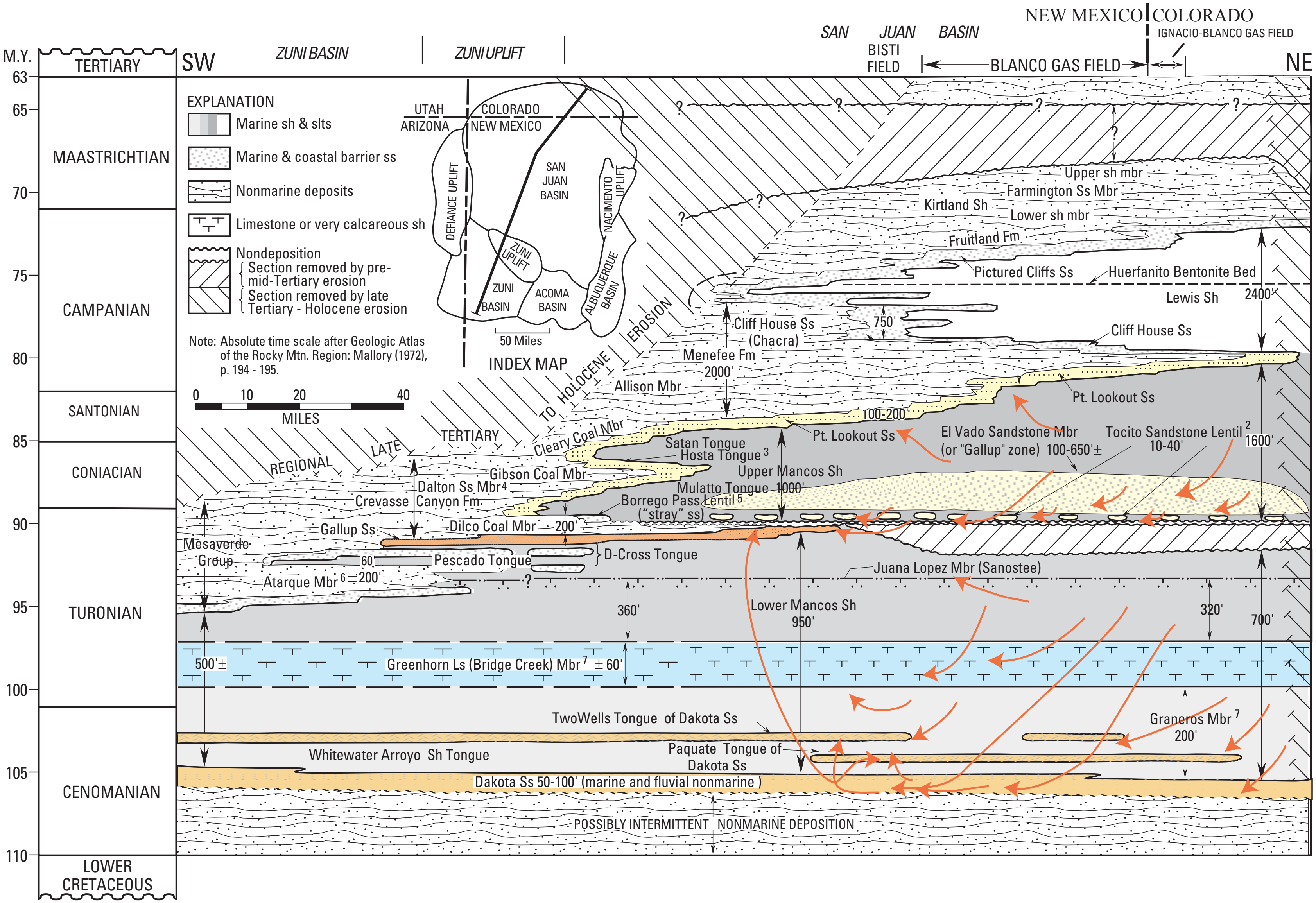


Figure 16. Time-stratigraphic cross section extending from southwest to northeast from the Zuni Basin through the central part of the San Juan Basin, Colorado and New Mexico, showing, among other things, the relation between the different source intervals in the Mancos Shale (upper, dark gray; lower, medium gray), Graneros Member (light gray), and various reservoirs: Dakota Sandstone, gold; Gallup Sandstone, orange; Tocito Sandstone Lentil of Mancos Shale and El Vado Sandstone Member ("Gallup") of Mancos Shale, pale yellow; and Mesaverde Group (modified from Molenaar, 1977b). Orange arrows show direction of oil migration from the pod of mature source rock to the various reservoirs. Members shown by footnotes: [1]of Cliff House Sandstone , [2]of Mancos Shale, [3]of Point Lookout Sandstone, [4]of Crevasse Canyon Formation, [5]of Tres Hermanos Formation, [6]of Mancos Shale, [7]of Mancos Shale. Shale, sh; siltstone, slts; sandstone, ss; member, mbr; formation, fm.

Oil accumulations in the Menefee on the southwest side of the basin are associated with fluvial channels and commonly with small anticlines or domes. Many of the accumulations also seem to be associated with faults, which could have provided migration paths from the underlying Mancos Shale.

Regional seals in the TPS consist of marine shales (Mancos Shale below and Lewis Shale above). Locally, seals in Dakota and Torrivio (Hospah) reservoirs may be a combination of shale facies into which marine and marginal marine sandstone facies pinch out and changes in permeability within the sandstone units. Seals for Tocito reservoirs are interbedded Mancos Shale, whereas for “Gallup” and other Dakota reservoirs, seals are a combination of interbedded shales and low permeability in the reservoirs. Additional seals are nearshore paludal shales and coal-bearing rocks in the Menefee and fluvial overbank mudrocks of the Menefee Formation.

Assessment Unit Definitions

Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304)

Introduction

The Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (AU) (50220304) covers nearly all but the central basin part of the TPS (fig. 17*A*). The area of this AU extends from the outcrop of the Dakota Sandstone (Green, 1992; Green and Jones, 1997) to the boundary of the Dakota-Greenhorn Continuous Gas Assessment Unit, discussed below. This AU includes wells that have a calculated gas-oil ratio (GOR) of less than 5,000 cubic feet of gas per barrel of oil (cfg/bo) (fig. 18) and are classified as oil wells (IHS Energy, 2002) (fig. 19). A GOR of 20,000 cfg/bo or greater seems to best define the low permeability gas zone of the central basin and is the cutoff used by the USGS to define a gas accumulation. Of the over 5,700 wells that produce from the Dakota Sandstone in the basin, 120 have a GOR between 5,000 and 20,000 cfg/bo. Wells in this GOR range are found mostly, but not entirely, in the Dakota-Greenhorn Continuous Gas AU (fig. 18) and tend to be surrounded by wells with a GOR greater than 20,000 cfg/bo. These wells have been included in the Dakota-Greenhorn Continuous Gas AU.

Gas was first discovered in the Dakota Sandstone in 1921 on Ute Dome and oil was discovered the following year on the Hogback dome (fig. 17*B*) (Matheny and Ulrich, 1983); both are on the Four Corners platform (fig. 17*A*). In 1924, oil was discovered in the Dakota on Rattlesnake dome and gas in the Red Mesa field (fig. 17*B*). Gas was discovered in the Dakota on Barker dome and oil was discovered in the Dakota on Table Mesa anticline in 1925 (fig. 17*B*). In the approximately twenty years that followed, additional oil and gas fields were discovered; all were in structural traps, mostly anticlines, marginal to the central basin (figs. 4 and 17*A*). Here gas is associated with oil accumulations. The prevailing philosophy of that era was to locate surface structures and drill them.

There were 27 fields producing oil and associated gas in 1983; production was also reported from five additional wells not assigned to any field (Fassett, 1983b). Only three new fields, Hay Gulch, Sierra, and Rio Arriba (figs. 17*A* and 17*B*) have been discovered since 1983; each of these is small and only produced for a few years. The easily identified targets for conventional oil and gas in the Dakota have been drilled. New targets will require a thorough understanding of the depositional patterns in the Dakota, the identification of buried structures through seismic analysis, and identification with more certainty the migration pathways into the Dakota from the area of sufficiently mature Mancos Shale (fig. 7). Key parameters of the AU and their timing are listed below and summarized in the events chart (fig. 20).

Source

The primary petroleum source rock for this assessment unit is interpreted to be the Mancos Shale.

Maturation

Thermal maturation for oil and associated gas is interpreted to range from early to late Eocene.

Migration

Oil from the mature pod of the Mancos Shale, located north of the Chaco slope (figs. 4 and 7), migrated into Dakota Sandstone reservoirs in the western, southern, and eastern parts of the AU (figs. 17*A* and 17*B*). Migration may have been along faults or through basal channel sandstones that filled valleys incised into the underlying Morrison Formation. In this AU, oil occurs in the updip or flank parts of anticlines or domes in most fields on the Four Corners or Chama platforms (fig. 17*A*) that formed during the Laramide orogeny, and migration of oil was probably coincident with formation of the structural traps. Within any specific field, migration may have been upward through permeable beds draped on structures or along faults into the upper laterally discontinuous marine and shelf sandstones.

Reservoirs

Reservoirs in the Dakota Sandstone are mostly marginal marine and marine shelf sandstones that are lenticular in shape and are interbedded with shale (see field descriptions and geophysical logs in Fassett, 1978a,b, 1983a). These sandstones tend to be finer grained than the basal fluvial sandstones. In many of the oil fields, the basal fluvial sandstones are water wet. Some oil has been produced from fluvial sandstones deposited on the lower delta plain as well as those that occupy incised valleys. The basal sandstones that are part of the lower incised valley fill tend to be coarser grained and water wet.

Oil and associated gas have also been produced from fractured limestone in the Greenhorn (Bridge Creek) Limestone Member, from sandstone in the Semilla Sandstone Member of the Mancos Shale, and from calcarenites from the Jauna Lopez Member of the Mancos Shale in a few isolated wells.

Traps/Seals

Traps are either stratigraphic, structural, diagenetic, or a combination of these. Stratigraphic traps occur where laterally discontinuous marine sandstone lenses pinch out in marine shales of the Mancos. Structural traps consist of folds, many of which are faulted. Draping of lenticular marine sandstone bodies over folds provides combined stratigraphic-structural traps commonly with an associated gas cap. In such traps, natural fracturing associated with fold development has aided production. Seals are primarily shale beds within the Dakota, regional shale tongues in the Mancos Shale, and local faults.

Geologic Model

Oil fields in the Dakota, except for those that occur in the southern part of the AU, form a rim around the central basin, basin-centered gas accumulation (Dakota-Greenhorn Continuous Gas AU) (fig. 17*A*). Oil in this conventional AU was generated from marine carbonaceous shale in the Mancos from early to late Eocene (figs. 15*C* and 20). Along the western, northwestern, and northeastern margins of the AU where the Dakota oil fields are closer to the mature pod of source beds (fig. 7), oil was expelled from the source beds and migrated relatively short distances into marginal marine sandstones of the Dakota (such as in the Hogback, Price Gramps, Rattlesnake, Red Mesa, and Shiprock fields; figs. 17*A* and 17*B*). Traps in these areas are structural, stratigraphic, or a combination of both; fractures are important for production (Lauth, 1983). Gas fields in this AU, such as Alkali Gulch, Ute Dome, Barker Creek, and Straight Canyon (fig. 17*B*) (Fassett, 1983b, 1991), may consist of migrated associated gas because the gas tends to be wet, and gas-water contacts have been identified for most of the fields. Oil in the Price Gramps and Red Mesa fields (figs. 17*A* and 17*B*) have low API gravities (31°–33°) (see discussion in Fassett, 1978a, 1983a) and may be biodegraded because the accumulations occur at depths generally less than 1,000 ft. These API gravities are much less when compared to API gravities (>50°) of oil in the Hogback, Rattlesnake, and Shiprock fields (fig. 17*B*). In the latter fields, oil may have been generated locally in the vicinity of intrusions. Oil production on the Four Corners and Chama platforms has been small, probably due to the shallow depths of the reservoirs, which are within a few hundred feet of the surface, and to water encroachment.

Oil in the southern part of the AU must have migrated to the reservoirs from the pod of mature source rock to the north because the fields lie well beyond mature Mancos source beds, as defined in this report. Inferred migration pathways are shown in figure 16. The oil is hypothesized to have migrated updip into the reservoirs either along regional faults or through the basal fluvial channel sandstones in the Dakota (fig. 16) into overlying marginal marine sandstones, which form stratigraphic traps. The marine sandstones have a lenticular geometry and pinch out laterally into shales of the Dakota and Mancos.

API gravities of oils from Chacon, Gallo, Lindrith South, Lindrith West, Lybrook, Ojito, and Rio Arriba fields (fig. 17*A*) (Fassett, 1991) range from 38°–43°, higher than those on the Four Corners and Chama platforms and lower than those from Dakota reservoirs in the southern part of the AU. The oil probably migrated short distances into these reservoirs during the latter part of the Laramide orogeny (Eocene). Most of the oil is stratigraphically trapped, although small structures may have aided in early trapping. Reservoirs have been described as tight, with low permeability (around 0.05 millidarcy) and porosity (<9 percent); natural and induced fractures are needed for economic production (see field discussions in Fassett, 1978b, 1983a). These reservoir properties are similar to those observed in the Dakota basin-centered gas accumulation and point out the need to better understand the time of hydrocarbon generation (oil and gas) relative to the time of loss of effective permeability. Although the fields have some characteristics of continuous accumulations, it is possible that there was initially sufficient permeability in the reservoirs to trap the oil early, but over time, loss of effective permeability (diagenesis) prevented updip migration of the oil. This would then result in an updip permeability barrier to hydrocarbons moving out of the central basin (and water moving in) as downwarping of the central basin continued into the Miocene. Rice (1983) also noted the low permeability barrier between the oil and basin-centered gas accumulation, but did not address the timing loss of effective permeability.

Assessment Results

The Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304) covers 5,811,310.79 acres. The AU was estimated at the mean to have potential additions to reserves of 2.45 million barrels of oil (MMBO), 21.69 billion cubic feet of gas (BCFG), and 0.61 million barrels of natural gas liquids (MMBNGL). The volumes of undiscovered oil, gas, and natural gas liquids estimated in 2002 for the Dakota-Greenhorn Conventional Oil and Gas AU are shown in appendix A. A summary of the assessment input data of the AU is presented on the data form in appendix B, which for this AU estimates the numbers and sizes of undiscovered accumulations. There is adequate charge, reservoir, traps, seals, access, and timing of generation and migration of hydrocarbons, indicating a geologic probability of 1.0 for finding at least one additional field with a total recovery greater than the stated minimum of 0.5 MMBO (grown) for oil or 3 BCF gas (grown).

This assessment unit produces both oil and associated gas (IHS Energy Group, 2002). In estimating the number and sizes of undiscovered oil and gas accumulations, historical data from NRG (2001) database were used. Seven Dakota oil fields meet

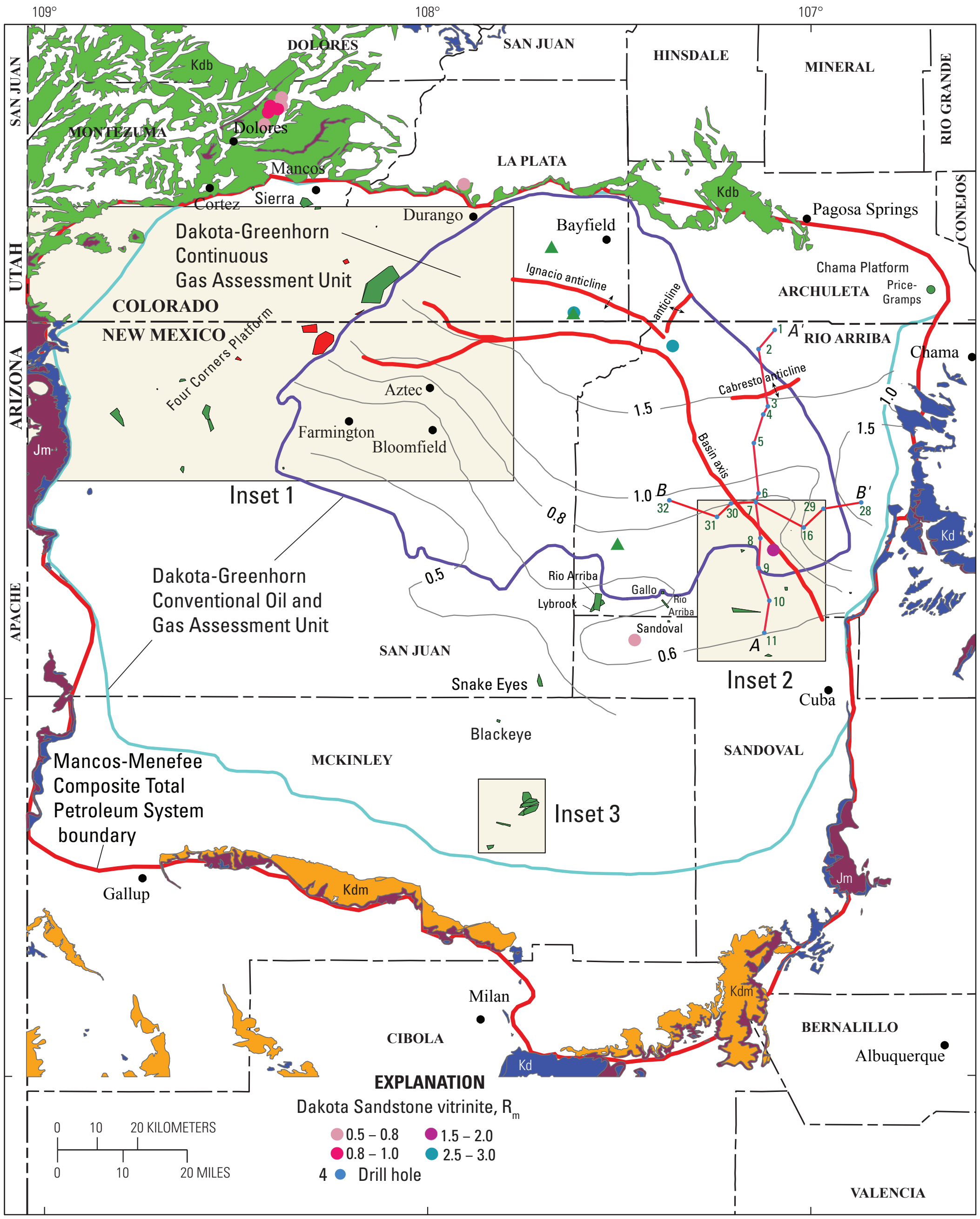


Figure 17*A*. Map showing the Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (AU) (50220304) boundary (purple), oil (green polygons) and gas (red polygons) fields in the AU, and locations of the wells (green triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*). Also shown are locations of cross sections *A*–*A′* and *B*–*B′* (pls. 1 and 2). Thermal maturity contours (gray) are in the Menefee Formation (Fassett and Nuccio, 1990; Law, 1992; and Ridgley, 2001b); vitrinite data for the Dakota Sandstone (colored dots) are from Fassett and Nuccio (1990) and C. Threlkeld (written commun., 2001). Enlargement of areas of insets 1–3 are shown in figure 17*B*. Field boundaries are extrapolated from data in IHS Energy Group (2002). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation (Green, 1992; Green and Jones, 1997).

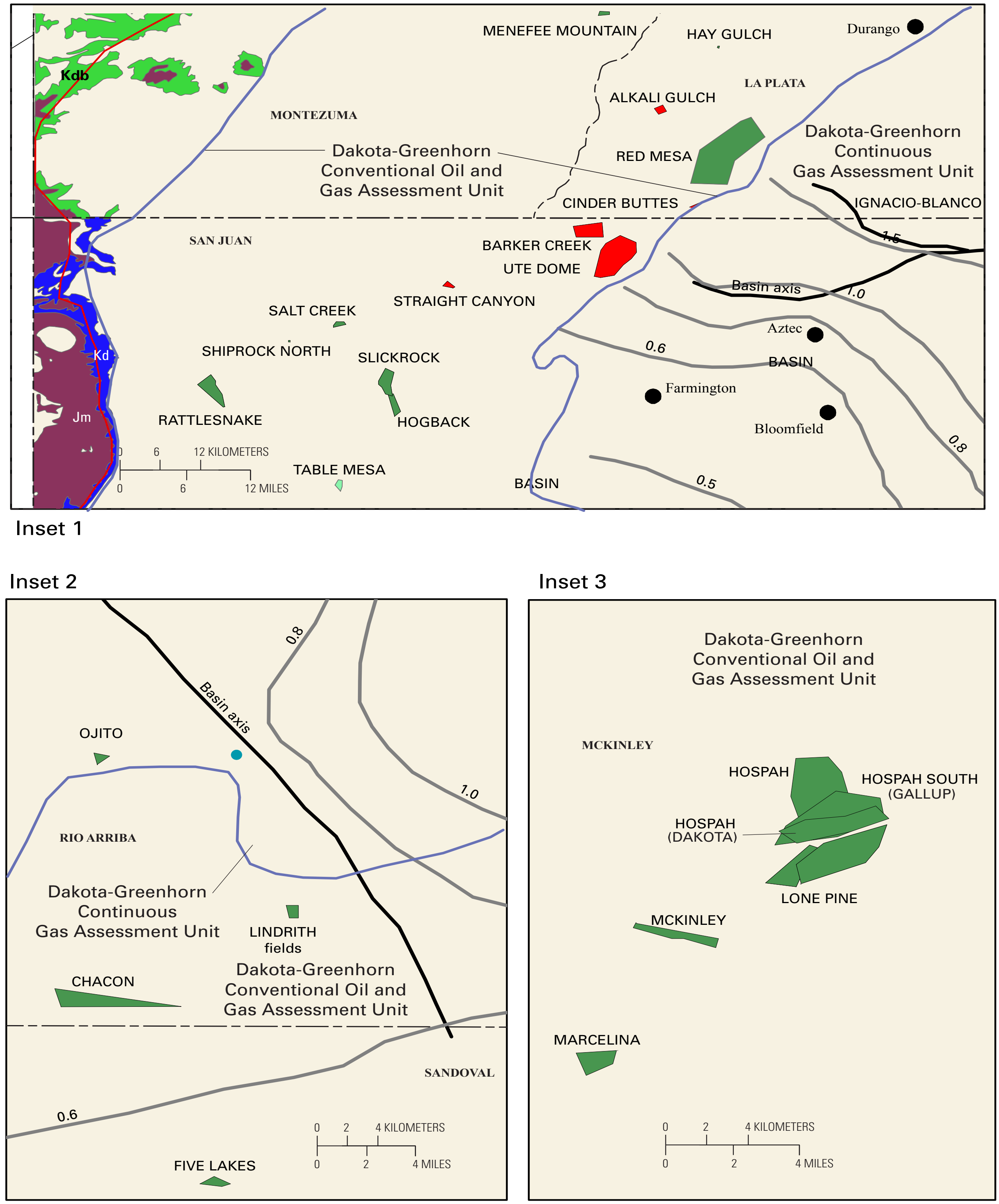


Figure 17*B*. Selected oil (green) and gas (red) fields in the Dakota Sandstone-Juana Lopez Member of the Mancos Shale interval in insets 1–3 from figure 17*A*.

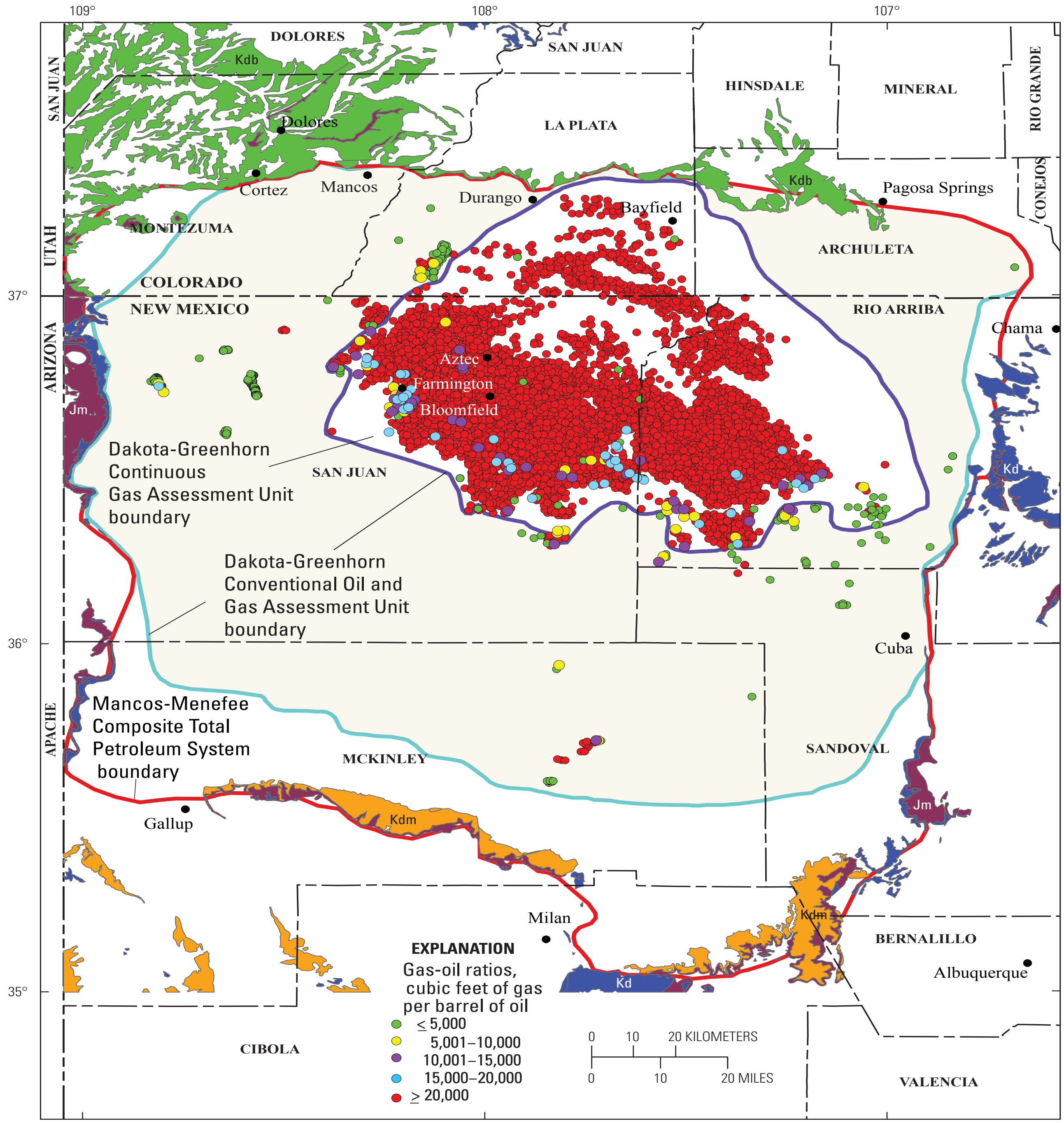


Figure 18. Map showing distribution of gas-oil ratios from producing reservoirs in the Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (tan) and Dakota-Greenhorn Continuous Gas Assessment Unit (white with purple boundary). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation from Green (1992) and Green and Jones (1997).

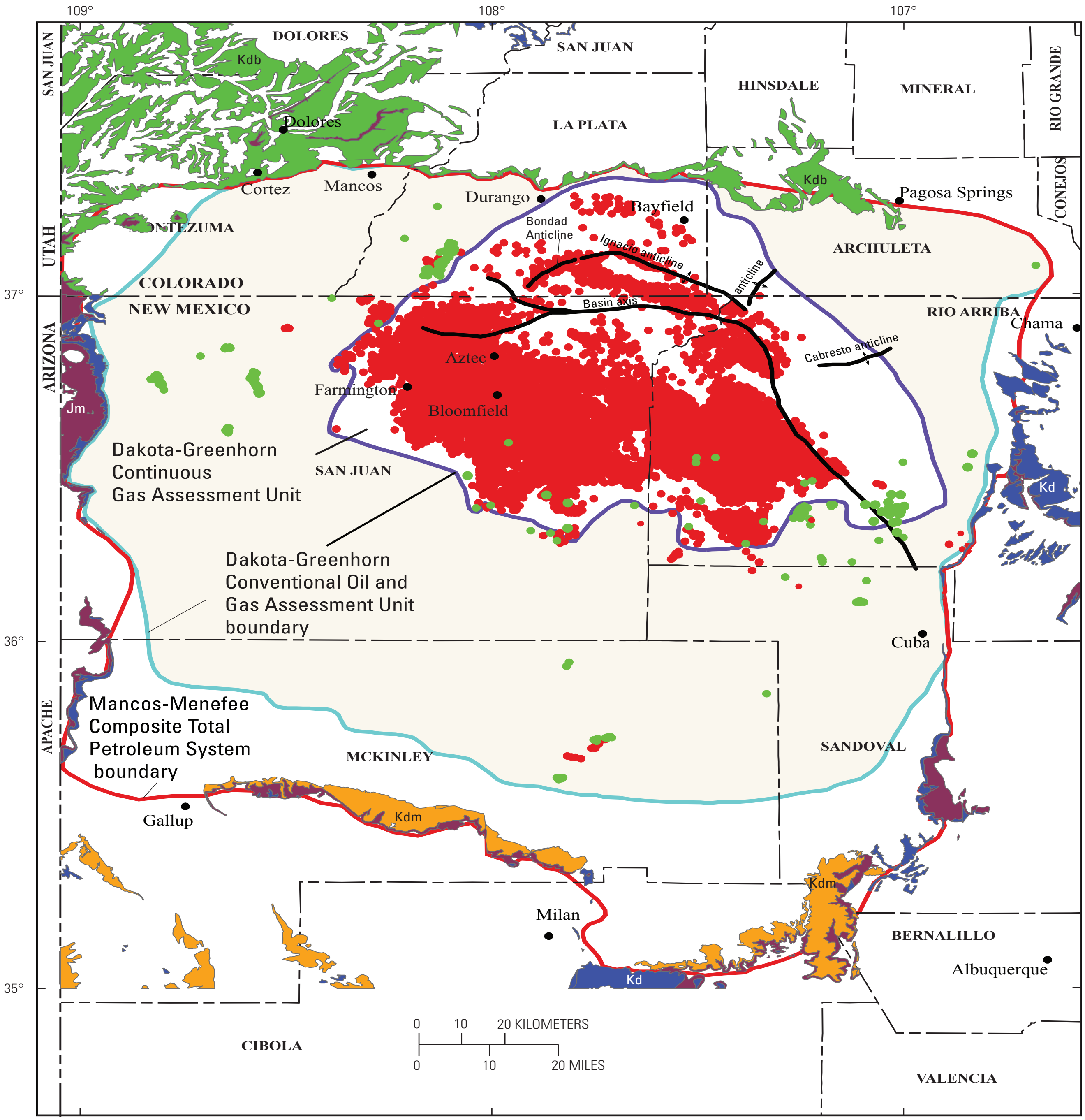
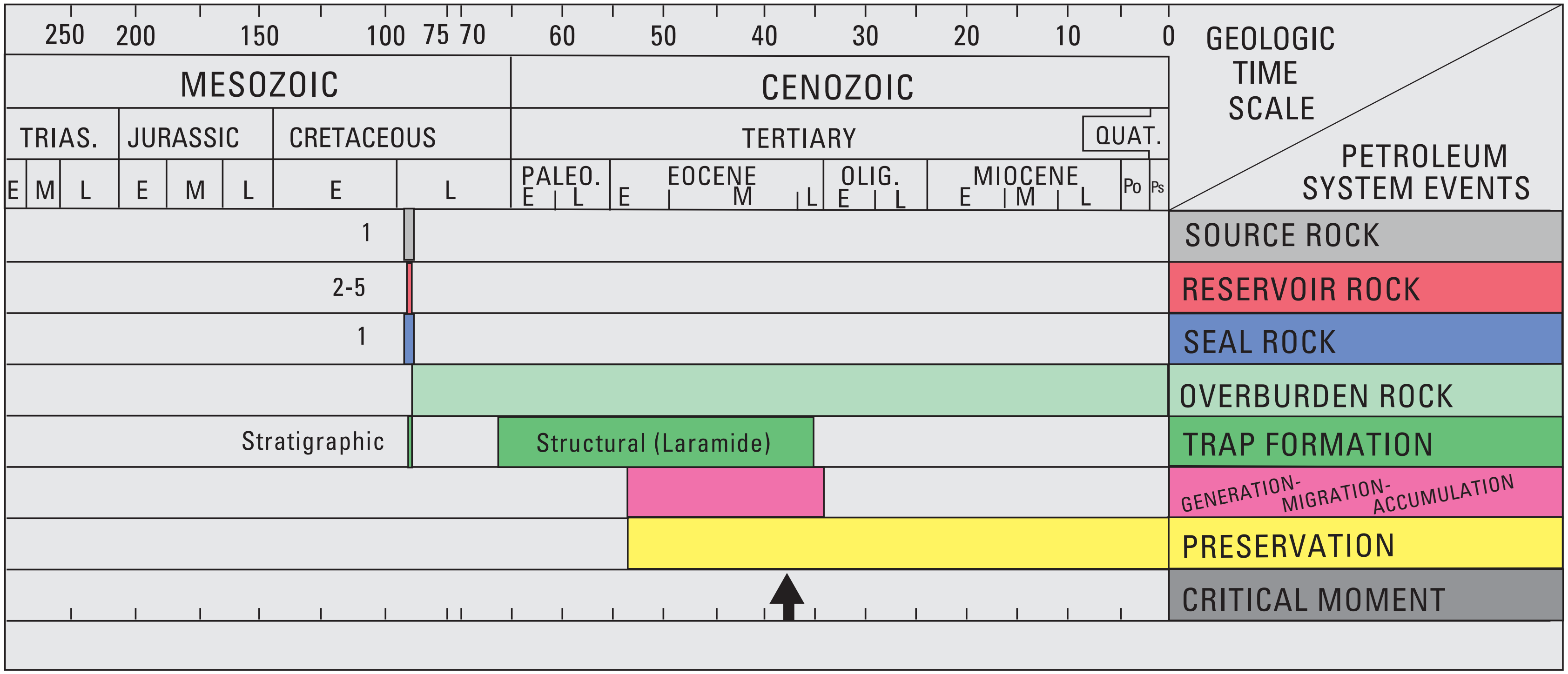


Figure 19. Map showing distribution of oil (green dots) and gas wells (red dots) from producing reservoirs in the Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (tan) and Dakota-Greenhorn Continuous Gas Assessment Unit (white with purple boundary). Some wells also produce from the Morrison or Burro Canyon Formations. Data from IHS Energy Group (2002). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation from Green (1992) and Green and Jones (1997).



Rock Units:

1. Mancos Shale
2. Dakota Sandstone
3. Greenhorn (Bridge Creek) Limestone Member of Mancos Shale
4. Semilla Sandstone Member of Mancos Shale
5. Juana Lopez Member of Mancos Shale

Figure 20. Events chart showing timing of key geologic events for the Dakota-Greenhorn Conventional Oil and Gas Assessment Unit. Black arrow, critical moment for oil and gas generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

the 0.5 MMBO cutoff: Hogback, Lone Pine, Price Gramps, Rattlesnake, Red Mesa Dakota, Slick Rock, and Table Mesa (figs. 17*A* and 17*B*). There have been no new oil fields that have met the minimum field-size cutoff since the discovery of the Lone Pine oil field in 1970.

Although the detailed geology of Dakota reservoirs is unknown for large portions of this AU, the general geology and location of major sandstone bodies is known and allows for an abundance of sedimentary traps. Small structures are probably present but remain unmapped. However, our understanding of migration pathways—from the area where the Mancos is sufficiently mature to produce oil, to the southern part of the AU—is poor. Most of the oil fields are found in close proximity to, and border, the mature source area of the central basin, suggesting that either the charge to the reservoirs was local or the traps efficiently captured most migrating oil. The Lone Pine field, however, is some distance from the central basin. Taking these factors into consideration, it was estimated that a maximum of four undiscovered oil accumulations meeting the minimum cutoff still exist. At the median, this value is estimated at two, and at the minimum, one undiscovered oil accumulation.

Using the discovery information for known fields that meet the minimum cutoff, the median grown size of discovered accumulations is 5.98 MMBO for the first half of the discovery period and 1.69 MMBO for the second half (fig. 21). Four fields meet the minimum cutoff in the first half of the discovery period and three in the second half. Figure 21 also shows the ranking of these fields, by size, for the two discovery periods, and that the three fields in the first half are larger than those in the second half. The size of the undiscovered fields was estimated from the distribution of the discovered field sizes versus the discovery year (fig. 22), where the grown size of an accumulation is determined by adjusting upward the known petroleum volume to account for future reserve growth. The sizes of discovered fields have decreased over the years. The largest grown oil field is about 8 MMBO. Using these data, the maximum estimated size of undiscovered accumulations is 6 MMBO, the median size is 1 MMBO, and the minimum size is 0.5 MMBO. The number and sizes of undiscovered oil accumulations in the 2002 assessment are lower than those estimated in 1995 (table 5) (Huffman, 1996), even though a smaller minimum size was used in this assessment. This lower estimate reflects the lack of discovery of new fields since 1970.

Three gas fields in this AU, Barker Creek Dome, Ute Dome, and Lindrith (fig. 17*B*), meet the minimum field-size cutoff of 3 BCF gas; no new gas fields that have met the minimum field-size cutoff have been found since the discovery of the Lindrith field in 1973. A maximum of three undiscovered gas accumulations meeting the minimum cutoff is estimated to exist. At the median, this value would be two and at the minimum, one undiscovered gas accumulation.

Using the discovery information for fields that meet the minimum cutoff, the median grown size of discovered gas accumulations is 31.02 BCFG for the first half of the discovery period and 11.4 BCFG for the second half (fig. 23). Two fields meet the minimum cutoff in the first half of the discovery period and one in the second half. Figure 23 also shows the ranking of these fields, by size, for the two discovery periods. The size of the undiscovered fields was estimated from the distribution of the discovered field sizes versus the discovery year (fig. 24), where the grown size of an accumulation is determined by adjusting upward the known petroleum volume to account for future reserve growth. The sizes of discovered fields have decreased over the years. The largest grown gas accumulation is about 36.5 BCFG. Using these data, the maximum estimated size of undiscovered accumulations is 25 BCFG, the median size is 6 BCFG, and the minimum size is 3 BCFG. The number and sizes of undiscovered gas accumulations in the 2002 assessment are somewhat lower than those estimated in 1995 (table 6) (Huffman, 1996), even though a smaller minimum size was used in this assessment. This lower estimate reflects the lack of discovery of new fields since 1973.

Dakota-Greenhorn Continuous Gas Assessment Unit (50220363)

Introduction

The Dakota-Greenhorn Continuous Gas Assessment Unit (50220363) covers the central part of the TPS (fig. 25). The boundary of this AU was drawn to include

1. the Dakota Sandstone that is surrounded by the Dakota-Greenhorn Conventional Oil and Gas AU, discussed above (fig. 1*A*); and
2. wells that have a calculated gas-oil ratio (GOR) of greater than 20,000 cubic feet of gas per barrel of oil (cfg/bo) (fig. 18) and are classified as gas wells (IHS Energy, 2002) (fig. 19).

A GOR of 20,000 or greater seems to best define the low permeability gas zone of the basin and is the cutoff used here to define a gas accumulation. However, this AU includes some wells with a GOR between 5,000 and 20,000 because they are totally surrounded by wells with a GOR >20,000 (fig. 18). This gas assessment unit is typical of basin-centered accumulation, in that the gas occupies the central part of a basin and water is found updip from the gas (Schmoker, 1996), although the updip water is not a control on the location of the gas accumulation.

The Dakota-Greenhorn Continuous Gas AU consists of two principal gas fields, Ignacio Blanco (Dakota) in Colorado and Basin in New Mexico (fig. 25). Both the Ignacio Blanco (Dakota) and Basin fields are composites of a number of small fields, the first of which were found in the 1940s (Matheny and Ulrich, 1983). When the Basin pool was established in 1961, many individual field names were abandoned. Most of the wells in this AU have now been drilled on 160-acre spacing in New Mexico; the original spacing was 320 acres. The original approved spacing of wells in the Ignacio Blanco (Dakota) was 640 acres (Bowman, 1978), but over the years as infill drilling has been approved, this spacing has decreased to 160 acres (Matheny and Ulrich, 1983).

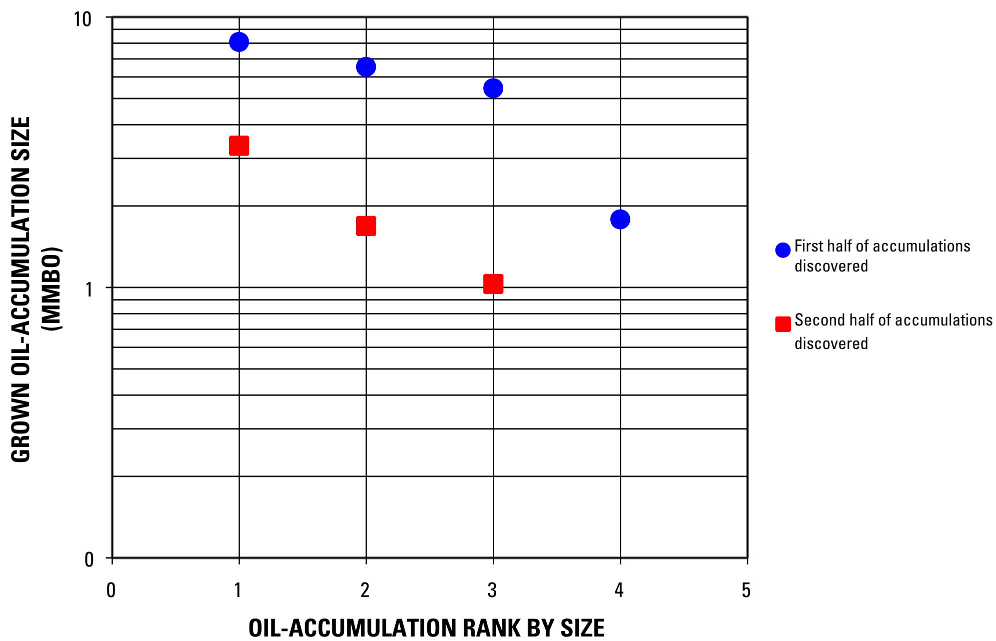


Figure 21. Distribution by halves of grown oil-accumulation size versus rank by size for the Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304). Data from NRG (2001). Only fields exceeding the minimum size of 0.5 MMBO (million barrels oil) are shown.

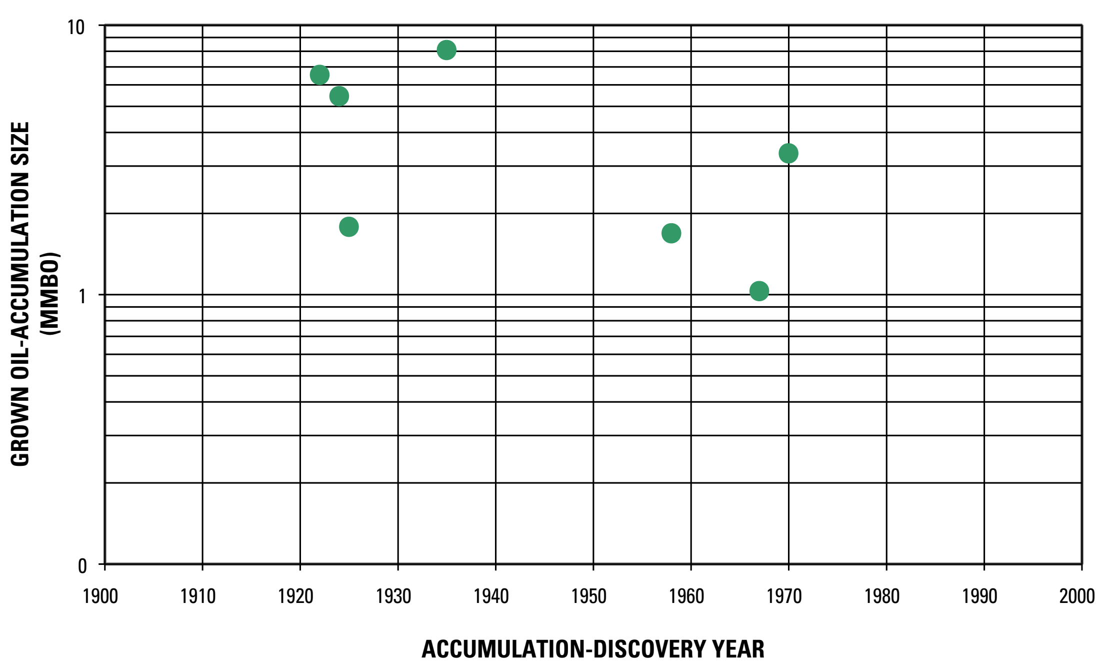


Figure 22. Distribution of grown oil-accumulation size versus accumulation-discovery year for Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304). Data from NRG (2001). Only fields expected to exceed the minimum size of 0.5 MMBO (million barrels oil) are shown.

Table 5. Comparison of 2002 and 1995 estimates of number and sizes of undiscovered oil accumulations in the 2002 Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304) and the 1995 Basin Margin Dakota Oil Play 2205. Sizes and minimum size are in million barrels of oil. Minimum size, minimum size of assessed field. 1995 data from Huffman (1996).

Assessment year	Minimum	Median	Maximum	Minimum size
Number of undiscovered oil accumulations				
2002	1	2	4	0.5
1995	5	10	20	1
Sizes of undiscovered oil accumulations				
2002	0.5	1	6	0.5
1995	1	2	10	1

Gas production in this AU is from a variety of sandstone facies in the Dakota Sandstone that reflect deposition in fluvial, crevasse splay, coastal marine, and shelf environments. These sandstones are now characterized by low porosity and very low permeability (table 1), and the stratigraphic interval from the Dakota Sandstone to the Coniacian unconformity (fig. 2) is underpressured, as is most of the basin. Generally, the fluvial facies that occupy the lowermost part of the incised-valley fill are not gas productive and tend to be water wet (Hoppe, 1978). Although it has been suggested that the gas is being held in place by the updip water (Berry, 1959; Cumella, 1981), Fassett (1991) suggested that the presence of updip water was irrelevant, and that the principal trapping mechanism for holding the gas in place was some type of permeability barrier. It is suggested that high capillary pressure along with low permeability (less than a few millidarcies) barriers due to diagenesis and lateral facies changes are the principal trapping mechanisms. Thus, basin-wide connectivity of permeable beds is absent. Natural fractures are needed to enhance production.

Most of the production comes from the western and southern two-thirds of the AU; the arcuate band of gas production in the northern part of the AU is on the Ignacio-Blanco anticline (fig. 19). South of this anticline is an area where there is little or no production from the Dakota. Part of this latter area coincides with the present-day axis of the basin. The Dakota is reported to be very tight here. In the eastern third of the AU, the uppermost shelf sandstone facies equivalent to the Twowells Tongue (fig. 3, pl. 2) is not well developed and may be absent over large areas. The absence of this unit may have precluded a higher density of exploratory or infill drilling in this part of the AU. New production in the Dakota from this AU may come from

1. additional wells in the eastern third of the AU,
2. infill drilling at less than 160-acre spacing, and
3. recompletion in bypassed sandstone beds in wells that already produced from some Dakota Sandstone beds.

Key parameters of the AU are listed below and are summarized on figure 26.

Source

The primary petroleum source rock for this assessment unit is interpreted to be the Mancos Shale.

Maturation

Thermal maturation for oil and gas is interpreted to range from early Eocene to late Miocene.

Migration

Gas produced in the Mancos Shale or interbedded carbonaceous shale beds in the Dakota migrated short distances into interbedded Dakota Sandstone reservoirs. If the Dakota was originally oil-bearing in this AU and the oil cracked to gas as a result of prolonged heating of the stratigraphic section during the Oligocene and Miocene, migration was nonexistent and the gas was generated in place.

Reservoirs

Reservoirs in the Dakota Sandstone are marginal marine and marine shelf sandstones that are lenticular in shape and interbedded with shale (Bowman, 1978; Hoppe, 1978; Ridgley, 1990; Fassett, 1991) and tend to be finer grained than the basal fluvial sandstones. In the AU, the basal fluvial sandstones are commonly water wet. Reservoirs in the Greenhorn are fractured limestone and in the Juana Lopez, calcarenites.

Traps/Seals

The principal trapping mechanisms are controlled by low permeability of the sandstone and capillary pressure. These factors are augmented by the laterally discontinuous geometry of the sandstone beds, which pinch out into marine shales and paludal mudstones. Local faulting may also be important in compartmentalization of production (Ridgley, 1995). Many of these faults formed syndepositionally, and thus were instrumental in controlling the spatial geometry of sandstone-shale

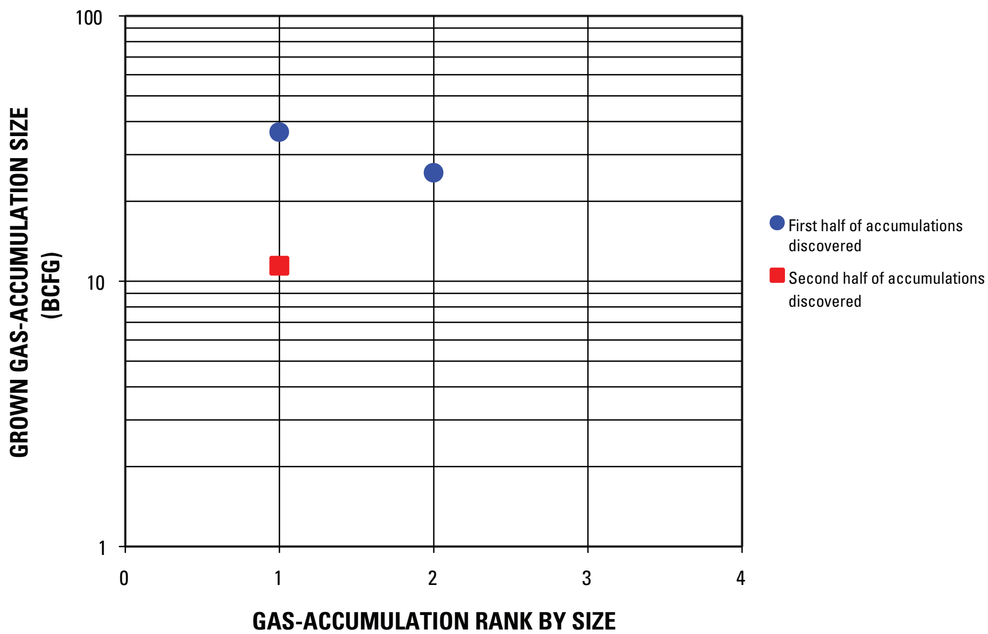


Figure 23. Distribution by halves of grown gas-accumulation size versus rank by size for the Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304). Data from NRG (2001). Only fields exceeding the minimum size of 3 BCFG (billion cubic feet gas) are shown.

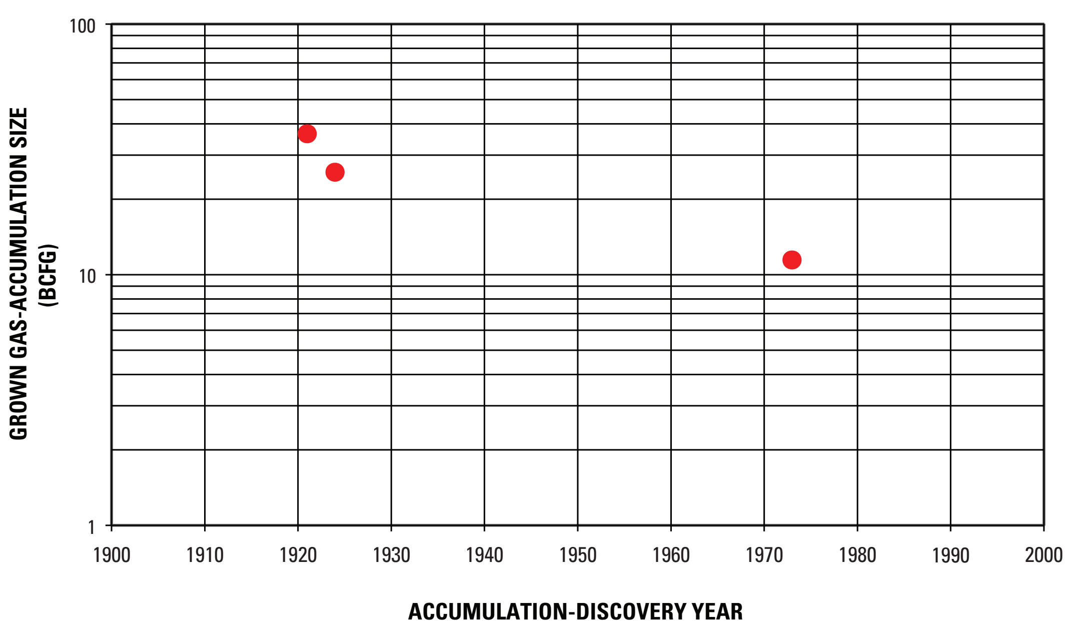


Figure 24. Distribution of grown gas-accumulation size versus accumulation-discovery year for Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304). Data from NRG (2001). Only fields expected to exceed the minimum size of 3 BCFG (billion cubic feet gas) are shown.

Table 6. Comparison of 2002 and 1995 estimates of number and sizes of undiscovered gas accumulations in the 2002 Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304) and the 1995 Basin Margin Dakota Oil Play 2205. Sizes and minimum size gas accumulation are in billion cubic feet of gas. Minimum size, minimum size of assessed field. 1995 data from Huffman (1996).

Assessment year	Minimum	Median	Maximum	Minimum size
Number of undiscovered gas accumulations				
2002	1	2	3	3
1995	1	2	5	6
Size of undiscovered gas accumulations				
2002	3	6	25	3
1995	6	10	25	6

units (Ridgley, 1989). Structures, such as the Ignacio Blanco anticline (fig. 25) and Bondad anticline (fig. 19), are gas bearing. These structures may be important early traps for gas or oil that subsequently cracked to gas. Seals are the various shale beds.

Geologic Model

Gas in this AU occurs within the central part of the San Juan Basin and was generated locally. Gas generated in shale beds in the Mancos Shale or interbedded carbonaceous shale beds of the Dakota as a result of thermocatalytic conversion of kerogen migrated short distances into interbedded sandstone reservoirs of the Dakota. If the Dakota originally contained oil in this AU as suggested by Rice (1983) and the oil cracked to gas as a result of prolonged heating during the Oligocene and Miocene, migration was nonexistent. Facies that host both conventional oil and gas and the continuous basin-centered gas accumulations in the Dakota are the same, stratigraphically, but differ in effective permeability and porosity (table 1). Trapping of the gas in this AU is due to the combination of facies changes, low permeability of the reservoirs, and capillary pressure. The low permeability must have developed in part as well as concurrent with oil and gas generation, thus creating a self-sealing system that did not permit effective updip migration of the late-generated oil and gas. Subtle structures and fractures in addition to lateral pinchout of sandstone reservoirs into enclosing shale may enhance trapping and production, and thus can be used to help define the "sweet" spots within the overall gas-charged AU.

Assessment Results

The Dakota-Greenhorn Continuous Gas Assessment Unit (50220363) was assessed to have potential additions to reserves of 3.93 trillion cubic feet of gas (TCFG) and 15.72 MMBNGL at the mean. The volumes of undiscovered oil, gas, and natural gas liquids estimated in 2002 for the Dakota-Greenhorn Continuous Gas AU are shown in appendix A. These values (table 7) are lower for gas and higher for natural gas liquids compared to the 1995 USGS assessment (Huffman, 1996). The Ignacio-Blanco and Basin fields have produced over 6 TCFG (IHS Energy Group, 2003). Of this total, slightly more than 211 BCFG (IHS Energy Group, 2002) has been produced from new wells since the last USGS assessment in 1995. A summary of the results, characteristics, and evaluation of the AU is presented on the data form in appendix C.

This AU encompasses an area of 2,513,000 acres at the median, 2,412,000 acres at the minimum, and 2,563,000 acres at the maximum extent of the AU. It contains 5,823 tested cells; for this assessment tested cells are wells that have produced or had some other production test, such as initial production test, drill stem test, or core analysis. A 0.02 BCFG minimum recovery was used for each cell. Applying this cutoff, 5,262 tested cells equaled or exceeded this cutoff. Adequate charge, favorable reservoirs, traps, seals, and favorable timing for charging the reservoirs with greater than the minimum recovery of 0.02 BCFG are present. If the production history of the Dakota-Greenhorn Continuous Gas AU is divided into nearly three equal discovery time periods, plots of the estimated ultimate recoveries (EUR) indicate that the early time period has the best EUR distribution, overall, and the best median total recovery (1.4 BCFG) per cell (fig. 27). Production has generally declined for the remaining two time periods. Part of this apparent decline is due to the fact that wells drilled during the first time block were located in the southern part of the AU, where thicker (stacked) reservoirs are found. Dividing the total production into three nearly equal time periods provides some indication of the maturity of the assessment unit and aids in the estimation of future resources. The EUR distribution for all producing wells in the Dakota-Greenhorn Continuous Gas AU (fig. 28) shows a median total recovery per cell of 0.85 BCFG.

Despite the density of drilling, over 50 percent of the AU remains untested. The subsurface geology is still poorly understood in the eastern part of the AU. Unlike the western half of the AU, the eastern half has much thicker Mancos Shale that overlies overall thinner Dakota Sandstone. Thickness of sandstones of the Dakota, and hence, reservoir facies, is directly related to the various positions of the Dakota shorelines. Positions of these shorelines shifted throughout Dakota deposition, were arcuate in geometry, and thus lacked the strong northwest–southeast geometry of subsequent Cretaceous

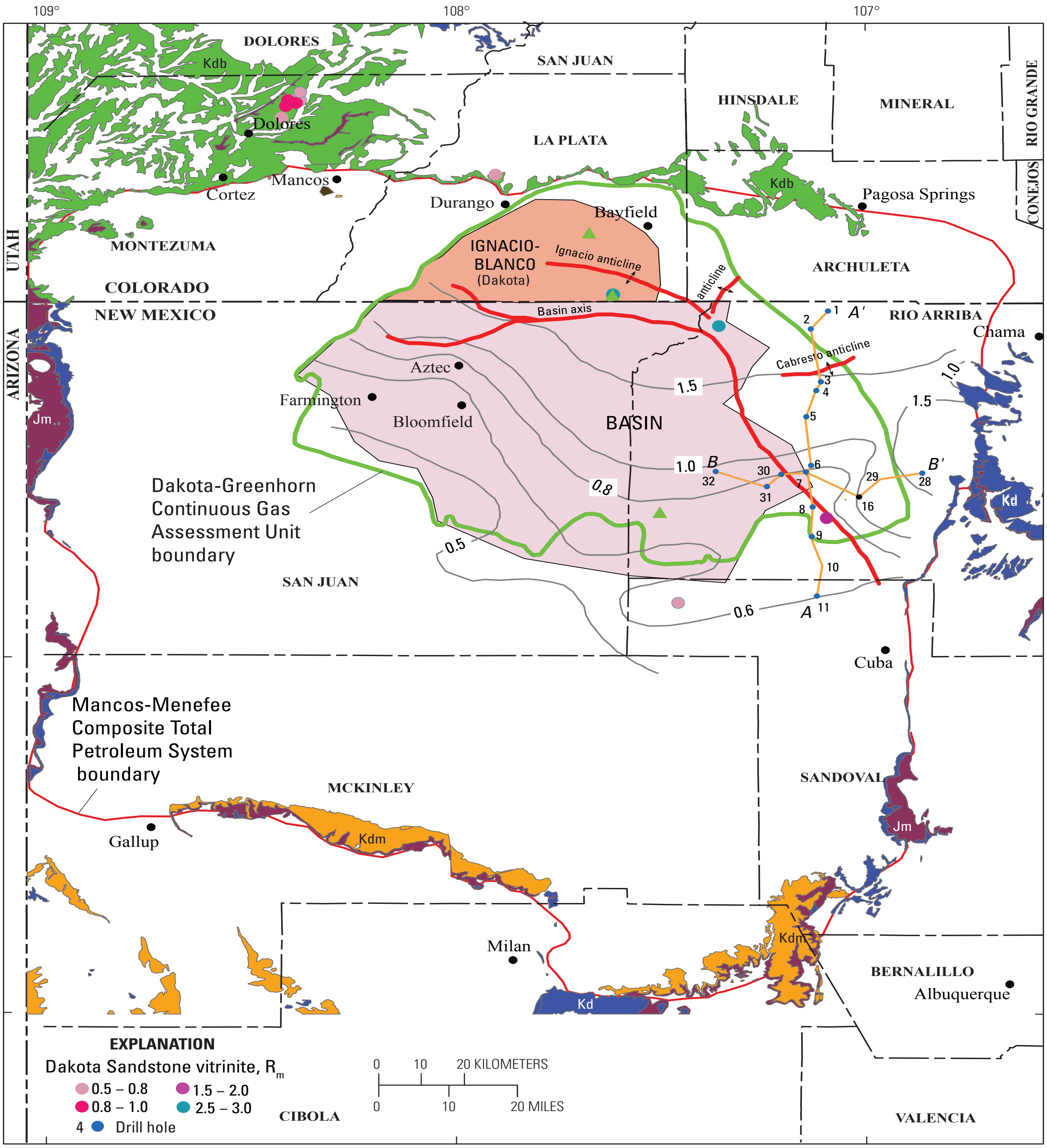
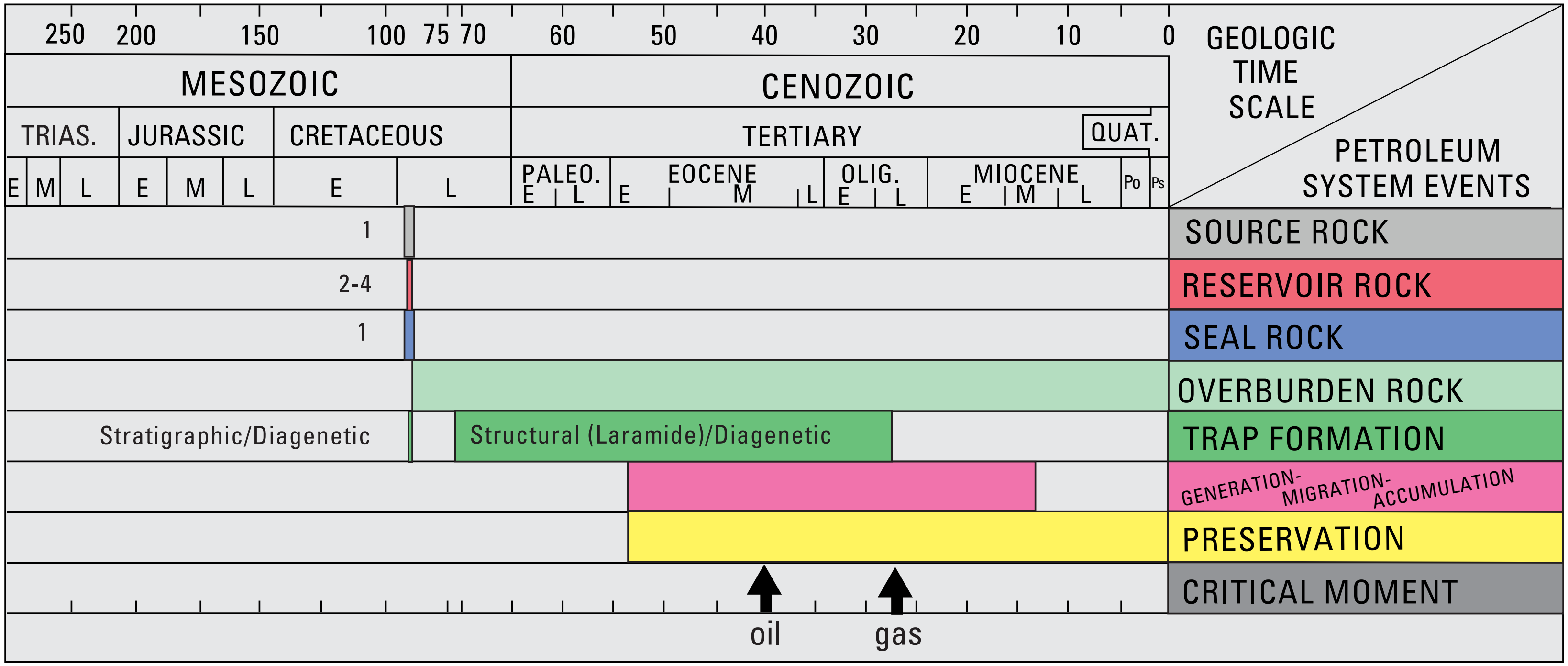


Figure 25. Map showing the Dakota-Greenhorn Continuous Gas Assessment Unit (50220363) boundary (green) in the lower part of the Mancos-Menefee Composite Total Petroleum System, and locations of burial history curves (green triangles) (figs. 15*A*–*C*). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation (Green, 1992; Green and Jones, 1997). Also shown are locations of cross sections *A*–*A′* and *B*–*B′* (pls. 1 and 2). Thermal maturity contours (gray) are in the Menefee Formation (Fassett and Nuccio, 1990; Law, 1992; Ridgley, 2001b), and vitrinite data for the Dakota Sandstone (colored dots) are from Fassett and Nuccio (1990) and C. Threlkeld (written commun., 2001). Basin gas field (pink polygon) and Ignacio-Blanco gas field (orange polygon) areas are generalized from data in IHS Energy Group (2002).



Rock Units:
1. Mancos Shale
2. Dakota Sandstone
3. Greenhorn (Bridge Creek) Limestone Member of Mancos Shale
4. Juana Lopez Member of Mancos Shale

Figure 26. Events chart that shows timing of key geologic events for the Dakota-Greenhorn Continuous Gas Assessment Unit. Black arrows, critical moments for oil and gas generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

shorelines (fig. 5). Drilling for Dakota reservoirs should take into account this different depositional style.

Taking our current knowledge of these constraints into consideration, the entire untested area was not considered to be favorable for having potential additions to reserves in the next 30 years. At the minimum, we estimate 46 percent of the untested area to have potential additions to reserve; at the median, this value is 55 percent of the untested area, and at the maximum, this value is 76 percent. These values were obtained by multiplying the various percentages of untested area deemed favorable by different success ratios. New discoveries will come from infill drilling on closer spacing, step-out drilling from existing fields, and new field discoveries. Total gas recovery per cell for these untested cells is estimated at 0.02 BCFG at the minimum (the cutoff used), 0.4 BCFG at the median, and 8 BCFG at the maximum. The maximum value of 8 BCFG was based on isolated occurrences of high-producing wells (fig. 27).

Gallup Sandstone Conventional Oil and Gas Assessment Unit (50220302)

Introduction

The Gallup Sandstone Conventional Oil and Gas Assessment Unit (50220302) is located in the western and southern part of the TPS (fig. 29). The boundary of this AU was drawn to

1. include the area that lies basinward of the outcrop of the Gallup Sandstone (Green, 1992; Green and Jones, 1997) and roughly the most seaward position of the Gallup A sandstone (fig. 8) (Molenaar, 1983; Nummedal and Molenaar, 1995),
2. include the area of wells that have penetrated the Gallup, and
3. exclude other sandstone reservoirs in the Mancos that occur above the regional unconformity of Coniacian age and thus are genetically unrelated to the Gallup.

Oil with small quantities of associated gas is produced from the Gallup Sandstone.

Almost all of the oil produced from Gallup reservoirs has been from Hospah and Hospah South fields (fig. 8) on the Hospah dome, a north–south trending structure located on the southern flank of the San Juan Basin in the southern part of the AU (fig. 29). Two northeast-trending parallel faults bisect the dome. Production is from two distinct Gallup reservoirs informally called the “upper Hospah” sand (Torrivio Sandstone Member of Molenaar, 1977b) and “lower Hospah” sand (main Gallup Sandstone). Production from the upper sandstone occurs both within the fault-bounded block as well as north of the faulted zone. Production from the “lower Hospah” sand occurs only within the fault-bounded block that defines the Hospah South field. The Hospah structure was identified in 1924, and oil was first produced in 1927 (Bircher, 1978) from the upper Hospah sand. The upper and lower Hospah sand in the Hospah South field (within the fault block) were brought online in the mid-1960s. Oil produced from the Hospah fields is heavy; API gravities range from 24° to 30° and may be biodegraded (Van Delinder, 1986).

Additional oil production has come from the Nose Rock field (figs. 8 and 29), reportedly in a fluvial channel of the Torrivio (Fassett, 1991), although no detailed description is available on this field. The field was discovered in 1986 and produced for less than 12 years (IHS Energy, 2001). A small quantity of oil (243 barrels of oil) was reportedly produced from Gallup reservoirs in one well in the Marcelina field (Edmister, 1983; Fassett, 1991). The Marcelina field (fig. 29) occurs at the north end of a faulted anticline, which has only subtle surface expression. This field was discovered in 1977 and only produced oil from 1980 to 1981 before being abandoned (Edmister, 1983). The oil was reported to have API gravity around 40°. Oil has also been produced from “upper Hospah” or Torrivio in the Miguel Creek and Miguel Creek North fields (fig. 29) in sandstones above the main Gallup. This oil has a reported API gravity of 31°. The small Rattlesnake field (Matheny, 1983) is located outside the AU boundary (fig. 29), and production from the Gallup appears to be localized. Like oil in the underlying Dakota at the Rattlesnake field, oil in Gallup reservoirs is light, between 58° and 60° API

Table 7. Comparison of 2002 and 1995 estimated undiscovered resources for the 2002 Dakota-Greenhorn Continuous Gas Assessment Unit (50220363) and 1995 Dakota Central Basin Play 2205, and the 2002 Mesaverde Central-Basin Continuous Gas Assessment Unit (50220361) and the 1995 Central Basin Mesaverde Gas Play 2209. Gas values are in trillion cubic feet and natural gas liquids in millions of barrels. 1995 data from Huffman (1996)

Commodity	1995 assessment results	2002 assessment results
Dakota-Greenhorn Continuous Gas Assessment Unit		
Gas	8.211	3.929
Natural gas liquids	0.33	15.72
Mesaverde Central-Basin Continuous Gas Assessment Unit		
Gas	9.584	1.317
Natural gas liquids	0.48	5.27

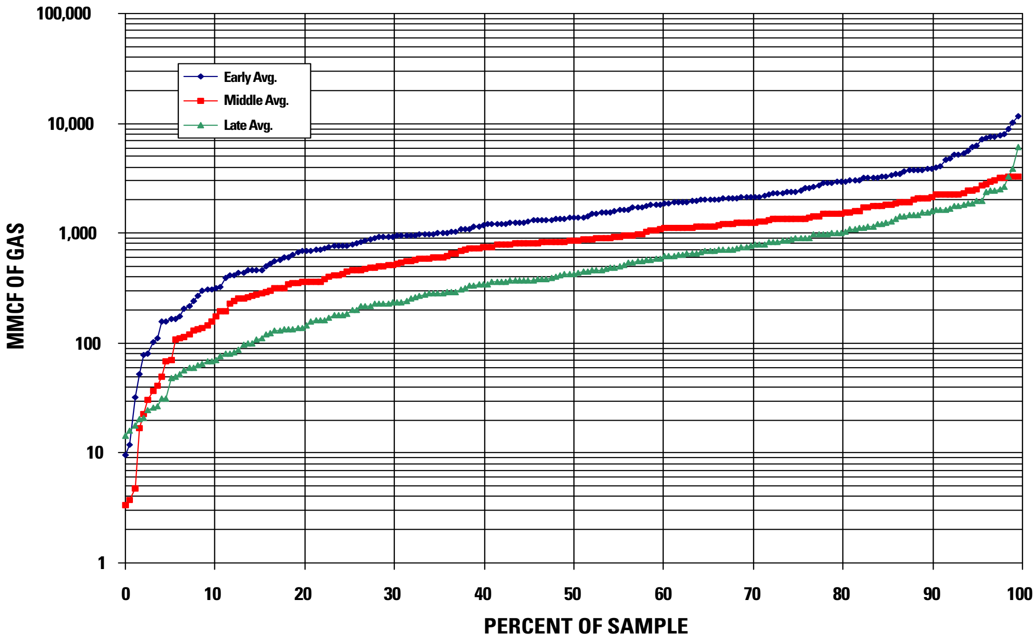


Figure 27. Graph showing estimated ultimate recoveries (EUR) of Dakota-Greenhorn Continuous Gas Assessment Unit gas wells divided into three nearly equal periods of production time. EURs calculated using data from IHS Energy Group (2002). MMCF, million cubic feet. Data provided by T. Cook (2002). MMCF, million cubic feet.

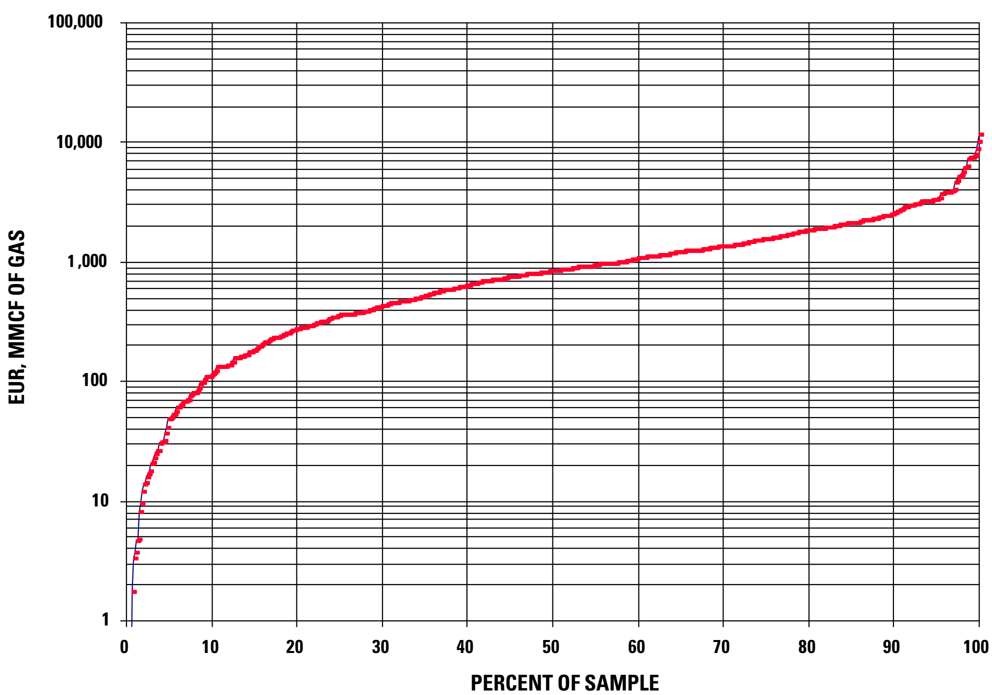


Figure 28. Graph showing combined distribution of estimated ultimate recoveries (EUR) of Dakota-Greenhorn Continuous Gas Assessment Unit gas wells. EURs calculated using data from IHS Energy Group (2002). Data provided by T. Cook (written commun., 2002). MMCF, million cubic feet.

gravity. It was felt that no additional productive areas in the Gallup Sandstone would be found between the Rattlesnake field and the AU, and thus the AU boundary was not extended to include the field.

Oil staining and seeps have been found in the Torrivio Sandstone Member of the Gallup in the outcrop area near Pinedale, N. Mex. (fig. 29) (Molenaar, 1977c; Nummedal and Molenaar, 1995, their figs. 11 and 11*G*). The stains and seeps occur in several stratigraphic traps in a braided channel system and have been interpreted to be a remnant of a previously formed oil accumulation. The location of oil seeps in the Pinedale area (fig. 29), which is southwest of the Hospah and Marcelina fields, indicates that oil may have moved through a much broader area of the Gallup system. Key parameters of the AU are listed below and are summarized on figure 30.

Source

The primary petroleum source rock for this assessment unit is interpreted to be the Mancos Shale.

Maturation

Thermal maturation is interpreted to range from early to late Eocene.

Migration

Migration distances were longest in the reservoirs in the southern part of the AU (Hospah, Marcelina, Miguel Creek and Miguel Creek North, and Nose Rock fields and Pinedale outcrop). These fields and outcrop lie outside the area of the mature pod of source rock in the Mancos (fig. 7) as previously defined. In the area of the Hospah, Nose Rock, and Marcelina fields, the Gallup shorelines have a northwest–southeast orientation and sandstones in the fluvial Torrivio Sandstone Member are oriented perpendicular or oblique to this. With these orientations, the Gallup sandstones may not be conducive to serving as direct conduits for long distance migration from the pod of mature Mancos Shale to the northeast because the last major sandstone (Gallup A) shoreline lies south of the main oil producing sandstones in the Tocito. However, Molenaar (1977b) suggests that oil in Gallup fields and seeps in McKinley County migrated through the Gallup from the area where distal Gallup facies (thin sandstone, siltstone, and shale) (fig. 8) underlies Tocito sandstones. It is possible that in this area, which would lie within the pod of mature source rock, there are sufficient fractures or faults to serve as conduits for oil migration into the main Gallup or Torrivio to the south. The Coniacian unconformity may also have served as a migration path with oil migrating along the unconformity and then into sandstones of the Gallup. Oil originally from the mature pod of the Mancos Shale, located north of the Chaco slope (figs. 4 and 7), may also have migrated into the underlying Dakota Sandstone at the Hospah and Marcelina fields (fig. 29) and from there updip along faults into reservoirs of the Gallup Sandstone. Expulsion and migration of oil was probably enhanced by tectonic activity during the Laramide orogeny.

Reservoirs

Reservoirs in the Gallup Sandstone are mostly fluvial sandstones of the Torrivio Sandstone Member in the Hospah or Nose Rock fields; lenticular marine sandstones of the main Gallup at Hospah South field and Torrivio Sandstone Member at Marcelina, Miguel Creek, and Miguel Creek North fields; and possibly marginal marine sandstones of the Gallup in the Rattlesnake field. The reservoir sandstones are interbedded with shale.

Traps/Seals

Traps in the Gallup Sandstone are combination stratigraphic and structural. Stratigraphic traps occur where laterally discontinuous fluvial and marginal marine sandstone lenses pinch out into continental carbonaceous shales of the Gallup or marine shales of the Mancos. Structural traps consist of folds, many of which are faulted. Draping of lenticular fluvial or marine sandstone bodies over folds provide combined stratigraphic-structural traps. Seals are primarily shale beds within the Gallup, regional shale tongues in the Mancos Shale, and local faults.

Geologic Model

In this AU, all the reported oil accumulations lie outside the pod of mature source beds in the Mancos Shale (fig. 7). The oil was generated from marine carbonaceous shale in the Mancos from early to late Eocene. A model to explain the presence of oil in Gallup reservoirs in the southern part of the AU is speculative because of the lack of data to clearly define the migration pathways. In this area, oil API gravities in Hospah fields are very low (24°–32°). However, these oils could be biodegraded (Van Delinder, 1986) because oil from the nearby Marcelina field was reported to have API gravity near 40°. This value (table 1) is close to that reported for most Mancos-sourced oils in fields near the pod of mature source rock. The presence of oil in the Hospah, Marcelina, Miguel Creek, Miguel Creek North, and Nose Rock fields and in outcrops near Pinedale (fig. 29) to the southwest suggests that oil once occurred throughout a large area but has either been removed by erosion or through later meteoric water encroachment (Molenaar, 1977c; Struna and Poettmann, 1988). Traps in this area are structural, stratigraphic, or a combination of both. In the Hospah and Marcelina fields, faults that extend into the underlying Dakota may have served as conduits for upward migration of oil from the Dakota to the Gallup reservoirs. The traps at Nose Rock and Pinedale are both stratigraphic and occur where fluvial sandstone of the Torrivio pinches out laterally into enclosing mudstones.

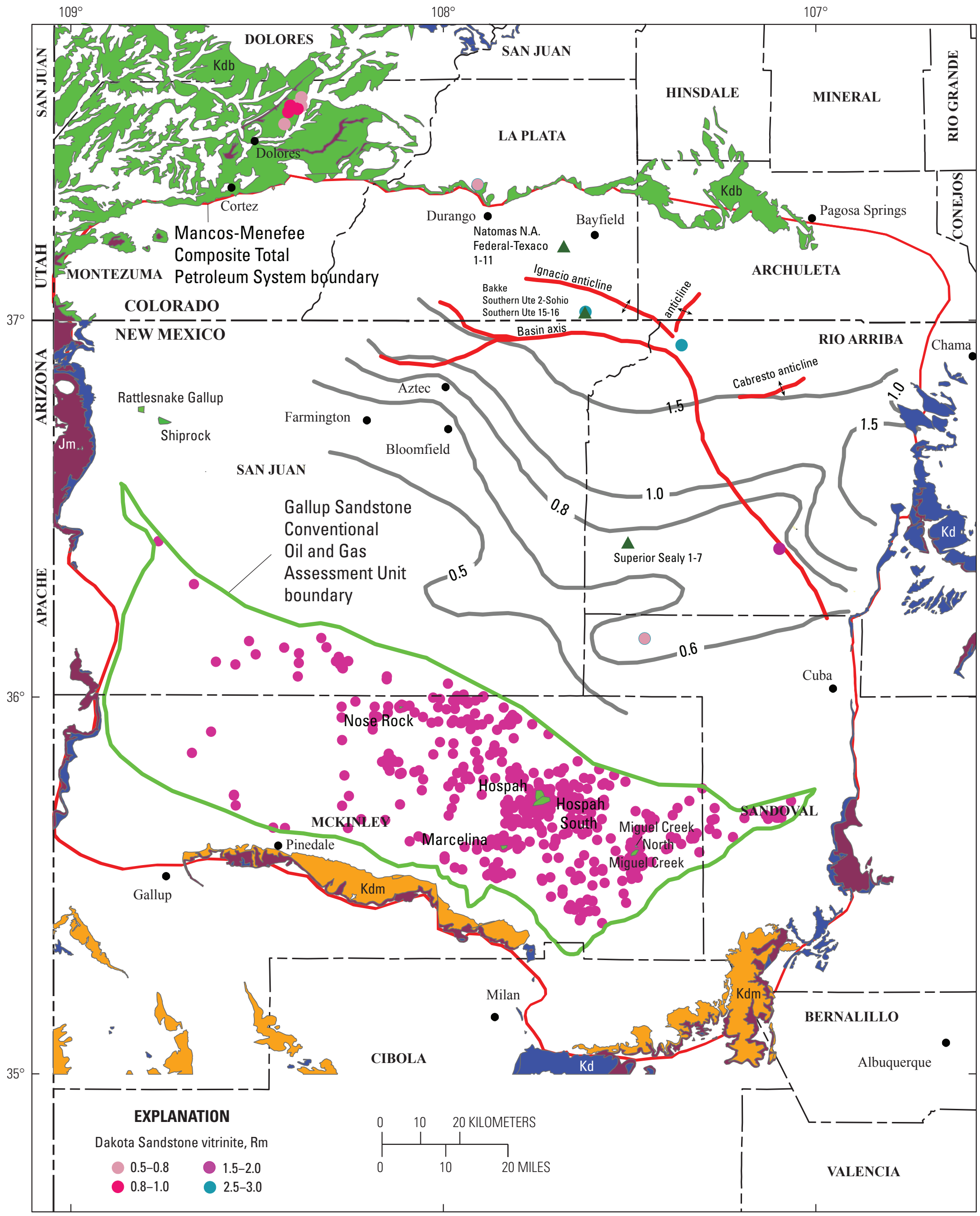
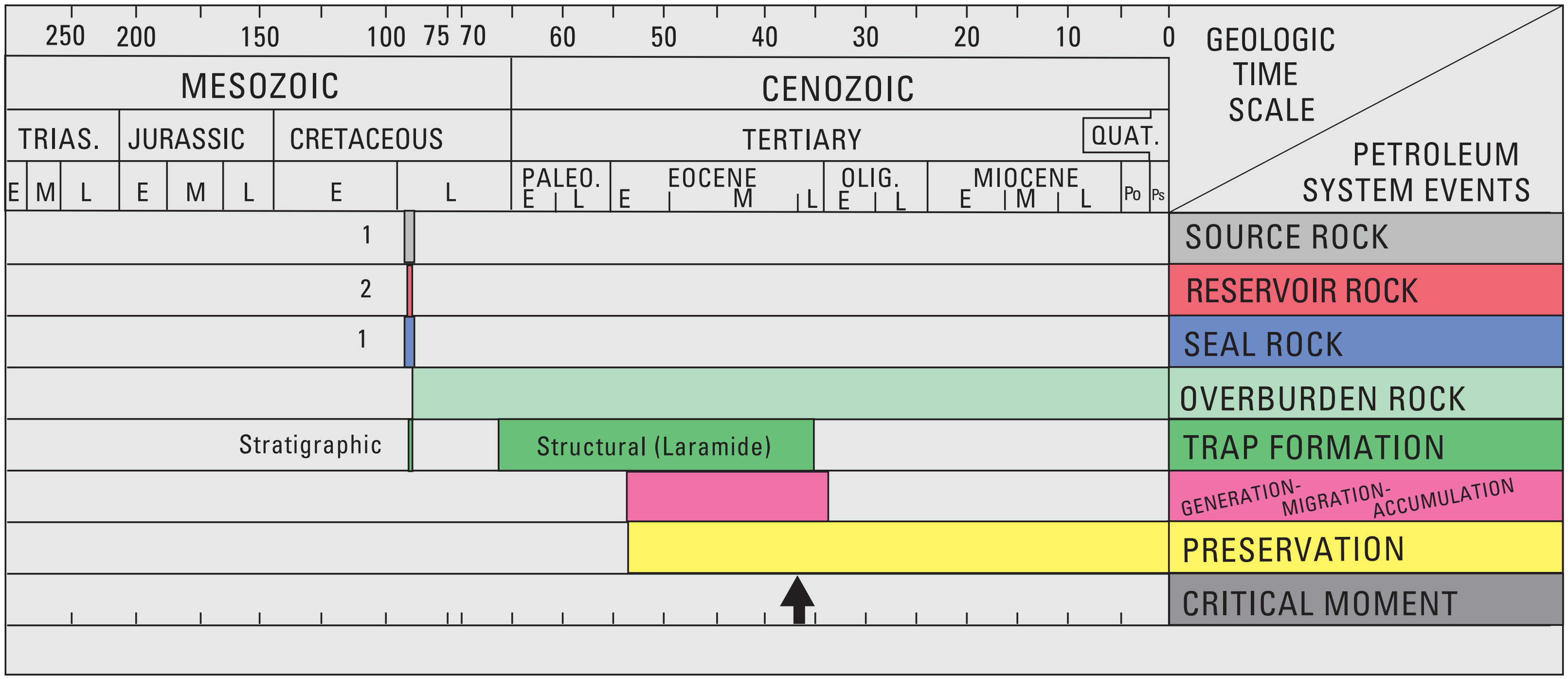


Figure 29. Map showing the Gallup Sandstone Conventional Oil and Gas Assessment Unit (AU) (50220302) boundary (green) in the lower part of the Mancos-Menefee Composite Total Petroleum System, oil and gas fields, distribution of wells that penetrate the Gallup (pink dots) (data from IHS Energy Group, 2002), and locations of burial history curve (green triangles) (figs. 15*A*–*C*). Oil field (green) and gas field (red) boundaries are extrapolated from IHS Energy Group (2002). Thermal maturity contours (gray) are in the Menefee Formation (Fassett and Nuccio, 1990; Law, 1992; and Ridgley, 2001b), and vitrinite data for the Dakota Sandstone (colored dots) are from Fassett and Nuccio (1990) and C. Threlkeld (written commun., 2001). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation from Green (1992) and Green and Jones (1997).



Rock Units:
1. Mancos Shale
2. Gallup Sandstone, Torrivio Sandstone Member

Figure 30. Events chart showing key geologic events for the Gallup Sandstone Conventional Oil and Gas Assessment Unit. Black arrow shows the critical moment for oil generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others, (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

Assessment Results

The Gallup Conventional Oil and Gas Assessment Unit (50220302) covers about 2,079,044 acres and was estimated at the mean to have potential additions to reserves of 2.34 MMBO, 0.35 BCFG, and 0 barrels of natural gas liquids. The volumes of undiscovered oil, gas, and natural gas liquids estimated in 2002 for the Gallup Conventional Oil and Gas AU are shown in appendix A. A summary of the results, characteristics, and evaluation of the AU is presented on the data form in appendix D, which in this case evaluates the size and distribution of producing fields in the area. This AU was included in the Tocito-Gallup Play 2207 in the 1995 USGS assessment (Huffman, 1996). There is less than adequate charge (probability 0.8) but adequate reservoirs, traps, seals, access, and timing of generation and migration of hydrocarbons (probabilities of 1.0 each) for finding at least one additional field with a total recovery greater than the stated minimum of 0.5 MMBO (grown). The lower charge probability reflects our inadequate knowledge of charge of these reservoirs.

This assessment unit produces mainly oil with minor associated gas (IHS Energy Group, 2002). No non-associated gas accumulations were estimated. Historical data from the NRG (2001) database were used to estimate the number and sizes of undiscovered oil accumulations. Currently only two oil fields producing from the Gallup Sandstone, Hospah and Hospah South, meet the minimum cutoff. There have been no new oil fields that have met the minimum field-size cutoff of 0.5 MMBO since the discovery of the Hospah South field in 1965. Although many outcrop studies of the Gallup Sandstone describe the relation of the Gallup to the Torrivio (a principal reservoir at the Hospah fields) (Molenaar, 1977b,c, 1983; Nummedal and Molenaar, 1995), the subsurface expression of these relations is poorly known, and no regional studies have been published. Most of the wells drilled through the Gallup are in the eastern half of the AU (fig. 29), and thus the western half of the AU is geologically less well known. Migration pathways from the area where the Mancos is thermally mature enough to produce oil to reservoirs in the AU are poorly understood. These migration pathways are further complicated by the unconformity that progressively cuts into and eventually removes the Gallup to the northeast. We estimated that a maximum of four oil, a median of two, and a minimum of one accumulation, meeting the minimum cutoff, could still be discovered.

Hospah field was discovered in 1926 and Hospah South field in 1965. About 8.3 MMBO have been produced from the Gallup at Hospah and 14.3 MMBO from the Gallup at Hospah South (IHS Energy Group, 2002). Using these data the maximum estimated size of undiscovered accumulations is 15 MMBO, the median size 1 MMBO, and the minimum size 0.5 MMBO.

Mancos Sandstones Conventional Oil Assessment Unit (50220303)

Introduction

The Mancos Sandstones Conventional Oil Assessment Unit (50220303) covers all but the central part of the TPS (fig. 31). The boundary of this AU was drawn to include

1. the area within the TPS boundary of the Mancos Shale that lies basinward of the Mancos outcrop (Green, 1992; Green and Jones, 1997) in the north and lies north of the Gallup Sandstone Conventional Oil and Gas AU,
2. the area outside the boundary of the Mancos Sandstones Continuous Gas Assessment Unit,
3. that part of the Mancos Shale that lies above the Coniacian unconformity and below the Point Lookout Sandstone of the Mesaverde Group, and
4. most wells in these strata that have a calculated gas-oil ratio (GOR) of less than 20,000 cubic feet of gas per barrel of oil (cfg/bo) (fig. 32).

Over 3,800 wells produce from the Mancos Shale Tocito Sandstone Lentil, and “Gallup” (see prior discussion) sandstone reservoirs. Wells with a GOR ≥20,000 are found in the Mancos Sandstones Conventional Oil AU as well as in the Mancos Sandstones Continuous Gas AU described in the following pages. Where they occur in the conventional AU, the wells with a GOR >20,000 are located mostly in gas caps (fig. 32), especially in “Gallup” sandstone reservoirs in the eastern part of the AU. Most wells with a GOR ≤20,000 have been included in the conventional AU. This approach differs from that used in differentiating the Dakota-Greenhorn Conventional Oil and Gas AU from the Dakota-Greenhorn Continuous AU where wells with a GOR between 5,000 and 20,000 were placed in the Dakota-Greenhorn Continuous Gas AU because they were surrounded by wells with a GOR ≥20,000. A different approach was needed because here the GOR changes gradually both between fields and in a basinward direction, especially in the “Gallup” fields in the southeast part of the AU near the boundary with the Mancos Sandstones Continuous Gas AU (fig. 32).

Oil in this AU is primarily produced from two intervals, the Tocito Sandstone Lentil and “Gallup” sandstone; however, production from Tocito reservoirs is reported as “Gallup” in both Colorado and New Mexico (IHS Energy, 2002), making it difficult to differentiate the volume of oil produced from Tocito reservoirs from that produced from the overlying “Gallup.” Volumetric analysis must be completed on a field-by-field basis and in some fields production from the Tocito and overlying “Gallup” is commingled. This requires the examination of well logs to determine the producing interval in each field. In 1991, the last time such a breakout of production was reported, Fassett (1991) reported 30 fields completed in the Tocito and 39 in the overlying “Gallup.” At that time, Tocito production was nearly two and one-half times that of the “Gallup.” The difference in production can be attributed to the better reservoir properties of the Tocito sandstones (table 1). Also, Tocito reservoirs produce little if any water, unlike most conventional accumulations, and this has led to more produced oil because of the lack of regional water encroachment. Production in the "Gallup" interval is enhanced by the presence of natural fractures, especially in the area of small structures (Gorham and others, 1977; Emmendorfer, 1992). The fractures were reported to be tectonically induced, and thus probably formed during the Laramide orogeny in the Late Cretaceous through Eocene. The best production is reported to come from wells containing open fractures that appear to be filled with oil (see various field descriptions in Fassett, 1978a, b, 1983a).

Earliest oil production from Mancos sandy shale reservoirs was in 1924 at the Red Mesa field (fig. 31), on the west side of the Hogback monocline (fig. 4). Production is reported to be in shale reservoirs of the Mancos and mostly from fractures (Lauth, 1983). In 1927 oil was discovered in the Mancos Shale (below the Juana Lopez and above the Greenhorn Members) in the Mancos River field (fig. 31) on an anticlinal structure on the Mancos Creek monocline; production has been small, less than the 0.5 MMBO cutoff used in this assessment (Emmendorfer, 1983). The oil has an API gravity of 33°. The first Tocito fields were discovered in 1951 and are now combined to form the Blanco Tocito South field (see fig. 37 for location under Mancos Sandstones Continuous Gas Assessment Unit). The next Mancos oil fields were discovered in 1955; production was from Tocito sands in the Bisti field and the silty, sandy zones in the overlying "Gallup" section in the Verde field (fig. 31). Additional fields were discovered in the Tocito and overlying "Gallup" interval in the late 1950s, early 1960s, late 1960s, and sporadically throughout the 1970s (Matheny and Ulrich, 1983). Ten of the 30 fields with oil production from the Tocito (Fassett, 1991) were discovered in 1981 (Matheny and Ulrich, 1983). No major oil field discoveries in the Tocito or "Gallup" have been found since 1984.

Oil in Tocito fields (Fassett, 1991) is from a series of elongate northwest- to southeast-trending reservoirs that are found principally in San Juan County, N. Mex. (figs. 31 and 33). Most of the oil production from the "Gallup" is in Rio Arriba County, although a few oil fields do produce from the "Gallup" in San Juan County (fig. 33) (Fassett, 1991, his fig. 5). The lack of oil production from Tocito reservoirs in Rio Arriba County is due to the fact that most of the Tocito-like sandstones, except for Blanco Tocito South field (see fig. 37 under Mancos Sandstones Continuous Gas Assessment Unit) that are found north of the main oil-producing area, should be gas bearing (Ridgley, 2001a) and thus are found in the Mancos Continuous Gas AU. Key parameters of the AU are listed below and are summarized on figure 34.

Source

The primary petroleum source rock for this assessment unit is interpreted to be the Mancos Shale.

Maturation

Thermal maturation is interpreted to range from early Eocene to early Oligocene.

Migration

Oil in the Tocito reservoirs bordering the western and southern margin of the basin-centered gas accumulation (Mancos Sandstones Continuous Gas AU described below) migrated short distances from the mature Mancos source beds into the sandstone reservoirs where it was stratigraphically trapped. Oil produced from the other "Gallup" reservoirs also migrated short distances from the Mancos source beds and was also stratigraphically trapped in the fine-grained, heterolithic facies.

Reservoirs

Reservoirs included in this AU are

1. lenticular Tocito sandstones, which overlie the Coniacian unconformity, and
2. the "Gallup" sandstones of industry, which includes the transgressive El Vado Sandstone Member of the Mancos Shale, and the regressive wedge of rocks that overlie the Tocito (pls. 1 and 2) (Ridgley, 2001a).

Traps/Seals

The principal traps in the Tocito are stratigraphic; the lenticular sandstones pinch out in all directions into the surrounding marine shales of the Mancos. The principal traps in the overlying "Gallup" sequence are also stratigraphic and enhanced by the low permeability of the sandstone as well as by capillary pressure. These factors are augmented by the laterally discontinuous geometry of the marine sandstone beds, which pinch out into marine shales and neritic mudstones. Structures are locally important in trapping early generated oil. Seals are interbeds of shale.

Geologic Model

Oil in this AU was generated from the mature pod (fig. 7) of marine carbonaceous shale in the Mancos. Initial oil expulsion occurred during the Eocene in the latter part of the Laramide orogeny and may have continued into early Oligocene. During this period, the oil migrated into Tocito and "Gallup" reservoirs in the western, southern, and eastern parts of the AU. Migration distances were short to these reservoirs, essentially from shale source beds to enclosed sandstone reservoirs. All the producing fields lie within the mature part of the Mancos Shale. The Tocito reservoirs are stratigraphic

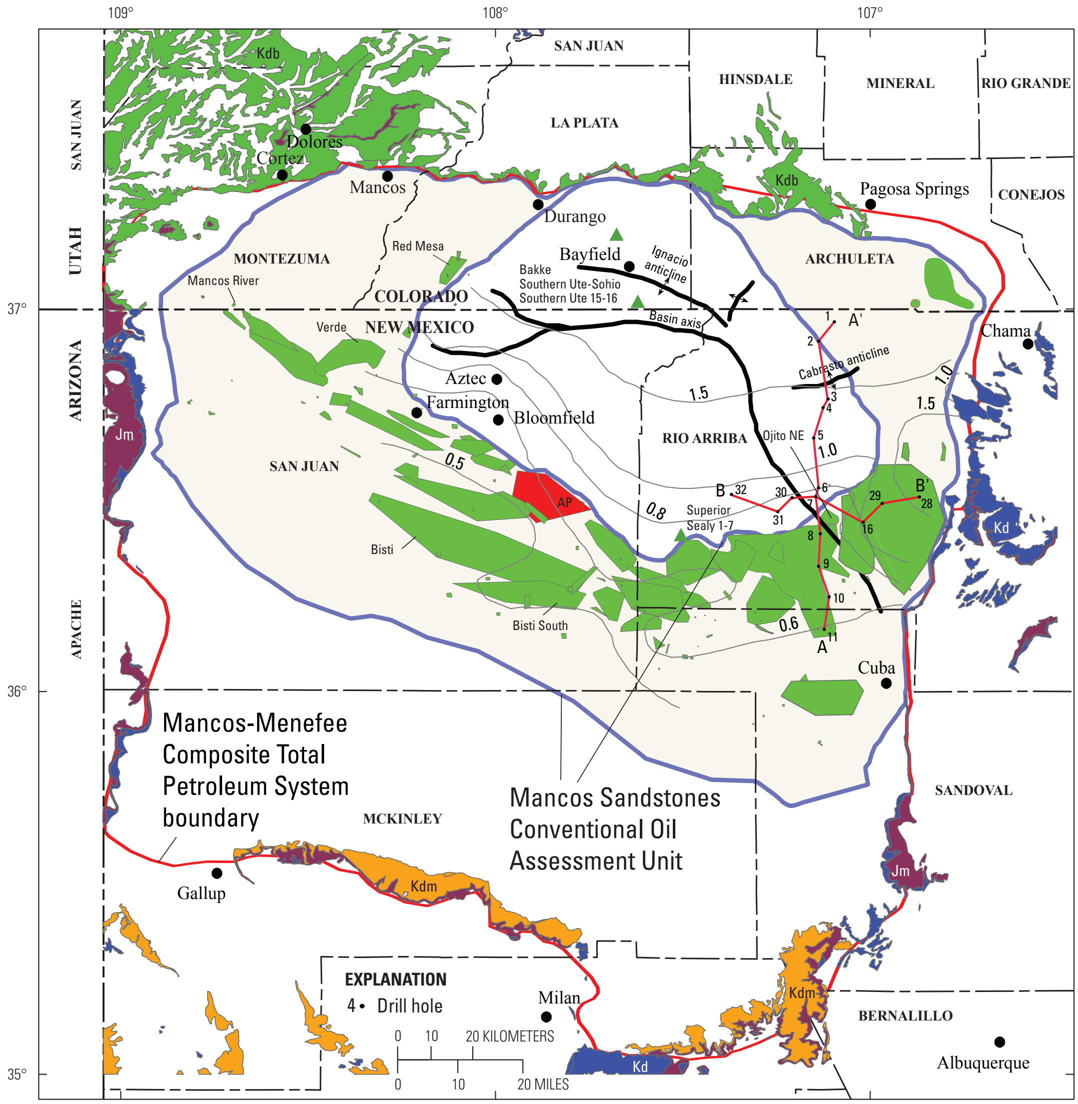


Figure 31. Map showing the Mancos Sandstones Conventional Oil Assessment Unit (50220303) (light tan) in the upper part of the Mancos-Menefee Composite Total Petroleum System, oil (green) and gas (red) fields, and locations of the wells (green triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*). Also shown are locations of cross sections *A*–*A'* and *B*–*B'* (pls. 1 and 2). Thermal maturity contours are in the Menefee Formation (Fassett and Nuccio, 1990; Law, 1992; and Ridgley, 2001b) and vitrinite data for the Dakota Sandstone (colored dots) are from Fassett and Nuccio (1990) and Threlkeld (written commun., 2001). Field boundaries are extrapolated from data in IHS Energy Group (2002). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation from Green (1992) and Green and Jones (1997). AP, Angel's Peak field.

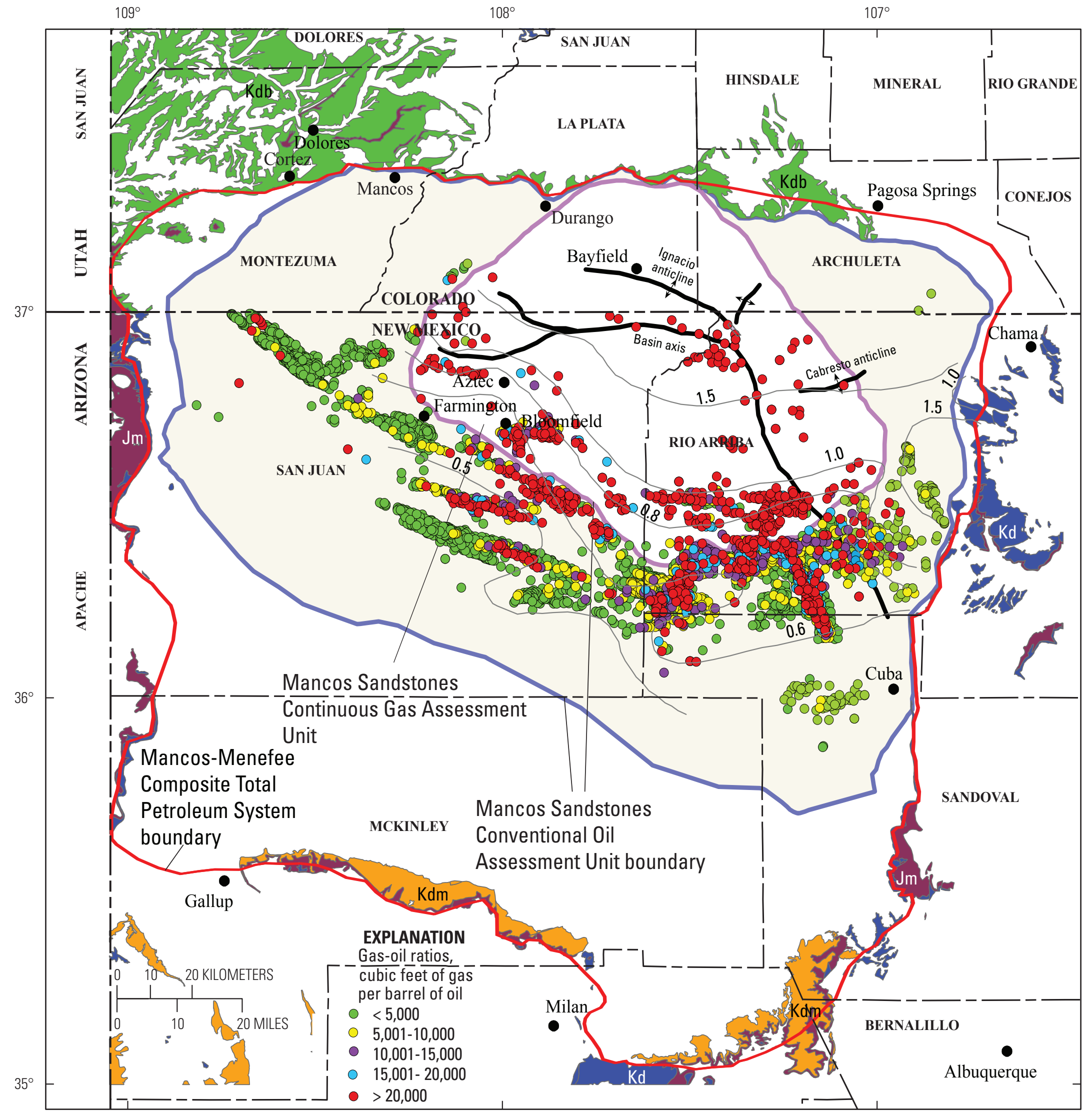


Figure 32. Map showing distribution of gas-oil ratios (in cubic ft of gas per barrel of oil) in wells producing from upper Mancos Shale, Tocito Sandstone Lentil, and "Gallup" sandstones in the Mancos Sandstones Conventional Oil Assessment Unit (shaded light tan with purple boundary) and Mancos Sandstones Continuous Gas Assessment Unit (white with mauve boundary). Data from IHS Energy Group (2002). Thermal maturity contours are in the Menefee Formation (Fassett and Nuccio, 1990; Law, 1992; and Ridgley, 2001b). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation from Green (1992) and Green and Jones (1997).

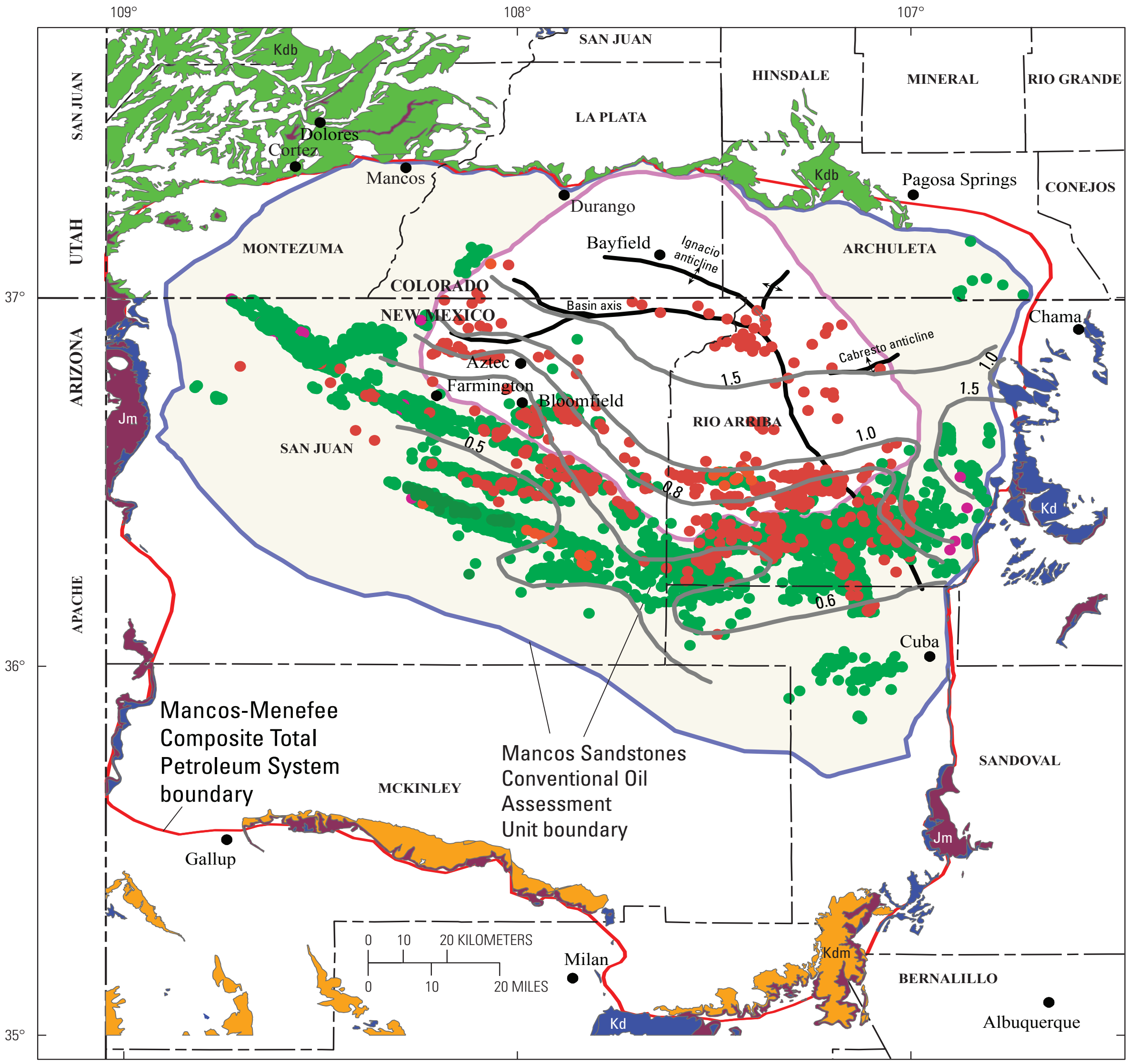
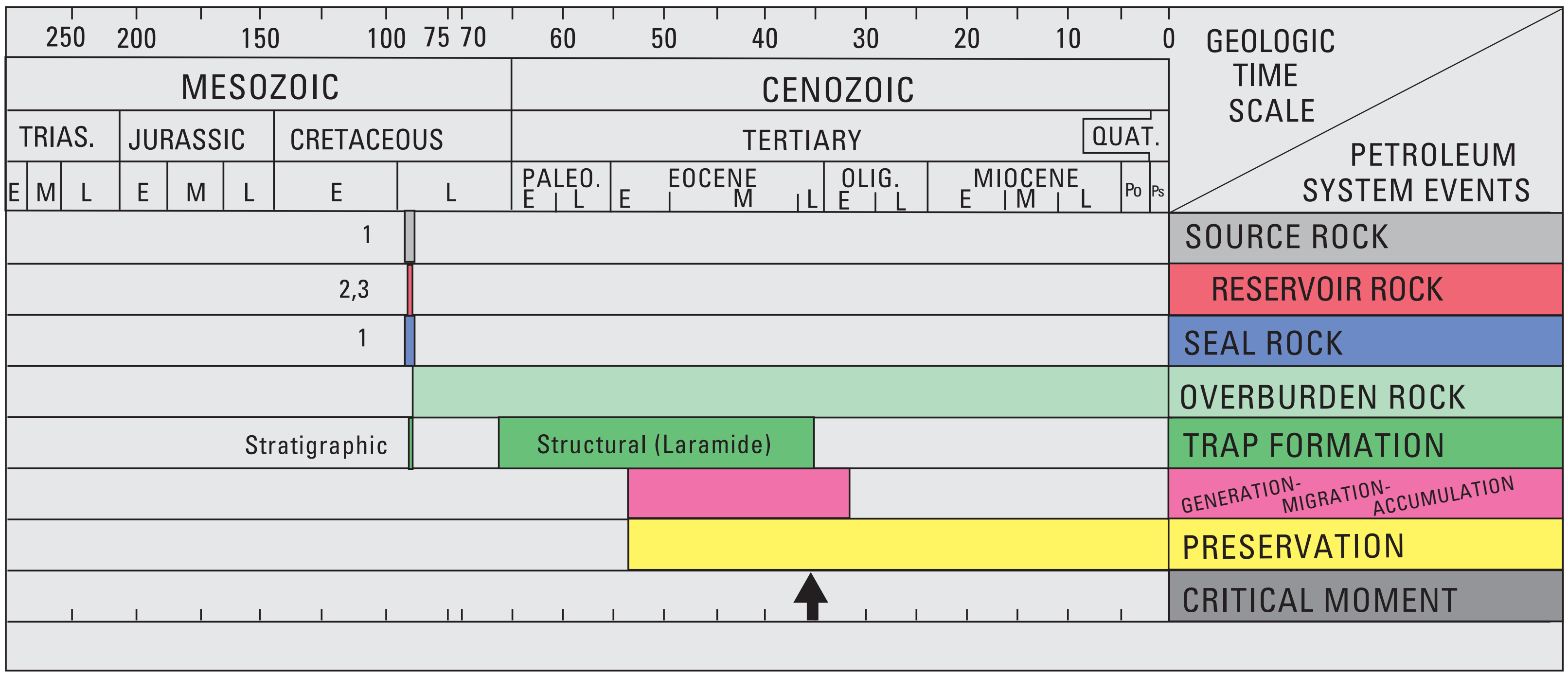


Figure 33. Map showing distribution of producing oil (green dots) and gas wells (red dots) in upper Mancos Shale, Tocito Sandstone Lentil, and "Gallup" sandstone reservoirs in the Mancos Sandstones Conventional Oil Assessment Unit (light tan) and Mancos Sandstones Continuous Gas Assessment Unit (white with mauve boundary). Data from IHS Energy Group (2002). Thermal maturity contours are in the Menefee Formation (Fassett and Nuccio, 1990; Law, 1992; and Ridgley, 2001b). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation from Green (1992) and Green and Jones (1997).



Rock Units:
1. Mancos Shale
2. Tocito Sandstone Lentil of Mancos Shale
3. "Gallup" sandstone (El Vado Sandstone Member of Mancos Shale)

Figure 34. Events chart that shows key geologic events for the Mancos Sandstones Conventional Oil Assessment Unit. Black arrow shows critical moment for oil and gas generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others, (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

traps; the sandstone reservoirs are encased in mudstone. The “Gallup” reservoirs are very fine grained and extremely heterolithic; both these properties would inhibit long distance migration, and any oil generated may have developed relatively in place (Ridgley, 2001a). Production from the “Gallup” reservoirs is enhanced by fractures, especially those associated with the development of small structures (Gorham and others, 1977; Emmendorfer, 1992).

Assessment Results

The Mancos Sandstones Conventional Oil Assessment Unit (50220303) covers about 4,412,500 acres. This AU incorporates part of the Tocito-Gallup Play 2207 and the Mancos Fractured Shale Play 2208 from the 1995 USGS assessment (Huffman, 1996). The AU was estimated at the mean to have potential additions to reserves of 11.99 MMBO, 57.57 BCFG, and 2.3 MMBNGL. The volumes of undiscovered oil, gas, and natural gas liquids estimated in 2002 for the Mancos Sandstones Conventional Oil AU are shown in appendix A. A summary of the assessment input data for the AU is presented on the data form in appendix E, which for this AU estimates the numbers and sizes of undiscovered accumulations. This approach differs from that used in the 1995 National Oil and Gas Assessment of these rocks (Huffman, 1996). In the 1995 assessment, most of the area in this AU and in the Mancos Sandstones Continuous Gas AU were assessed as containing continuous oil and gas accumulations and used a cell-based methodology to assess undiscovered resources (Schmoker, 1996). There is adequate charge, reservoir, traps, seals, access, and timing of generation and migration of hydrocarbons, indicating a geologic probability of 1.0 for the presence of at least one additional field with a total recovery greater than the stated minimum of 0.5 MMBO (grown) or 3 BCFG (grown).

Although the oil was probably generated locally and thus may constitute a continuous oil system (Ridgley, 2001a), most of the oil production is in somewhat defined areas, characterized by sandstone distribution or structure. Areas between the fields do not appear to host oil accumulations. It was therefore decided in this 2002 assessment to assess the oil and associated gas in this AU in terms of conventional accumulations. Most of the gas in Tocito or “Gallup” reservoirs occurs as continuous accumulations, and these accumulations were assigned to the Mancos Sandstones Continuous Gas AU, described below. The change in resource methodology affected the assessment results, and in this case the numbers for oil were reduced and the numbers for gas increased compared to those presented in the 1995 assessment.

This assessment unit produces oil and small quantities of associated gas. There are 29 oil fields in this AU that meet the 0.5 MMBO minimum cutoff and one gas field that meets the minimum 3 BCFG cutoff. Production comes from the Tocito and overlying “Gallup” reservoirs. There have been no new oil fields that have met the minimum field-size cutoff since the discovery of the Ojito Northeast and Bisti South oil fields in 1984 (fig. 31). Most of the oil fields are found in the southern part of the central basin. The trend of Tocito sandstones is defined by the elongate northwest–southeast areas of oil production, mostly in San Juan County, New Mexico (fig. 33). Within the general exploration area of the AU, the Tocito sandstones are probably well delineated, and any new oil-bearing Tocito sandstones are likely to be found to the southeast in the direction of extension of the Tocito sandstone trend. We estimate that a maximum of 10 undiscovered oil accumulations, a median of 5, and a minimum of 2 meeting the minimum cutoff, could still be discovered.

Using the discovery information for fields that meet the minimum cutoff, the median grown size of discovered oil accumulations is 5.84 MMBO for the first third of the discovery period, 1.84 MMBO for the second third, and 2.9 MMBO for the last third (fig. 35). Figure 35 also shows the ranking of these fields, by size, for the three discovery periods. Grown sizes of oil accumulations are, except for two fields, larger in the first third reflecting discovery of the major Tocito fields. Later production is commingled from the Tocito and “Gallup” interval, or from the “Gallup.” The size of the undiscovered fields is estimated from the distribution of the discovered field sizes versus the discovery year (fig. 36), where the grown size of an accumulation is determined by adjusting upward the known petroleum volume to account for future reserve growth. Later grown accumulations generally show decline from the first third. The largest grown oil field is about 50.9 MMBO. Using these data, the maximum estimated size of undiscovered accumulations is 10 MMBO, the median size is 2 MMBO, and the minimum size is 0.5 MMBO.

There is only one gas field in this AU (NRG, 2001), the Angel’s Peak field (fig. 31), which was discovered in 1958. This field produces both associated gas and oil, although gas exceeds oil production (IHS Energy Group, 2002). There may be small gas accumulations in this AU, but if they exist, they would be less than the minimum 3 BCFG cutoff used in this assessment. No non-associated gas fields exceeding the minimum cutoff are estimated to exist.

Mancos Sandstones Continuous Gas Assessment Unit (50220362)

Introduction

The Mancos Sandstones Continuous Gas Assessment Unit (50220362) covers the central part of the TPS (figs. 4 and 37). The boundary includes

1. the area basinward of the outcrop of the Mancos Shale (Green, 1992; Green and Jones, 1997) that is central to and excluded from the Mancos Sandstones Conventional Oil AU, previously discussed (fig. 31);
2. that part of the Mancos Shale that lies above the Coniacian unconformity and below the Point Lookout Sandstone of the Mesaverde Group; and

3. most wells that have a calculated gas-oil ratio (GOR) of greater than 20,000 cubic feet of gas per barrel of oil (cfg/bo) (fig. 32) and thus are primarily reported as gas wells (IHS Energy, 2002) (fig. 33).

A GOR of greater than 20,000 seems to best define the low permeability gas zone of the central part of the basin. Outside that zone, there are wells that have a GOR between 5,000 and 20,000. Most wells in this GOR range have been included in the conventional category. This gas assessment unit is typical of those called basin-centered, in that the gas occupies the central part of a basin (Schmoker, 1996).

Gas is primarily produced from two intervals, the Tocito Sandstone Lentil and "Gallup" in this AU. Production from Tocito reservoirs is reported as "Gallup" in both Colorado and New Mexico. The only production reported as Tocito is from the Blanco Tocito South field, which is an oil field (Fassett and Jentgen, 1978; IHS Energy, 2002) (fig. 37). This makes it difficult to differentiate the volume of gas produced from Tocito sandstones from that produced from the fine-grained facies of the overlying "Gallup." However, based on the regional distribution of fields producing from the Tocito and "Gallup" (fig. 37), most gas produced to date has come from the "Gallup" interval and nearly all has been from wells in New Mexico. More than 7 MMBO and 174 BCFG have been produced from reservoirs in this AU (IHS Energy Group, 2003).

Currently 31 fields produce gas from the Tocito and "Gallup" in this AU; many of these are small and only the large fields are labeled (fig. 37). In addition there are a number of undesignated fields and wildcat wells that produce from these reservoirs. Based on field descriptions (Fassett, 1978a,b, 1983a), gas is produced from Tocito sandstones in the Blanco Tocito South, BS Mesa, Flora Vista, Largo, and Wild Horse fields (fig. 37), all discovered between 1951 and 1964. The gas is stratigraphically trapped in the lenticular sandstones that lie on or not far above the Coniacian regional unconformity (pls. 1 and 2). These sandstones have good porosity and permeability, although the permeability is less than that found in the oil-producing Tocito sandstones (table 1). Gas is produced from silty and sandy beds at various stratigraphic intervals in the "Gallup" in many fields. Many of the fields consist of one or two wells. Natural fractures are important for production and may have developed in the brittle, tightly cemented rocks concurrent with folding during the Laramide orogeny. A number of the fields are associated with small structures.

Several of the fields included in this AU produce both oil and gas and have wells with a GOR between 5,000 and 20,000. The principal fields that fit these criteria are Armenta, Blanco Tocito South, Baca, Lindrith West, and Tapacito (fig. 37). All are located in the southern part of the AU and point to the difficulty of drawing the boundary between a continuous-type accumulation and conventional accumulations, especially if the reservoirs were once charged with oil and some of that oil has cracked to gas. The Blanco Tocito South field (fig. 37) has produced over 4 MMBO and 12 BCFG (IHS Energy Group, 2002), yet the neighboring Largo and BS Mesa fields produce only gas. All these fields underlie the 0.8- and 1.0-percent R_m vitrinite isoreflectance contours in the Menefee Formation (fig. 37). These fields, with the exception of part of the Armenta field, lie stratigraphically below wells that produce only gas in the overlying Mesaverde Central-Basin Continuous Gas AU and stratigraphically above gas-bearing sandstones in the underlying Dakota-Greenhorn Continuous Gas AU (fig. 19).

Most of the Tocito and "Gallup" reservoirs in this AU have not been adequately tested for gas, and fracture stimulation may be required in order to test for the presence of gas. Because of the low permeability of the reservoirs, gas zones go undetected on conventional log suites. Our uncertainty in evaluating the presence or absence of reservoir facies in this AU lies in the poor understanding of the depositional system and the identification of subtle structures where fractures may have formed. Additionally, it is important to have a better understanding of the origin of the gas. If the gas cracked from oil, most of the reservoirs should be charged with gas, although they may not all be economic. If the gas formed after loss of effective permeability in the "Gallup" reservoirs, production may well be found only in association with fractures.

Potential sandstone and siltstone reservoirs in the Mancos that are transitional with the overlying Point Lookout Sandstone of the Mesaverde Group constitute a hypothetical target to host gas in this AU. These units are the distal marine facies of the prograding Point Lookout shoreface. There is no reported production from these reservoirs, yet the overlying Point Lookout does produce gas in places where it overlies this AU. Key parameters of the AU are listed below and are summarized on figure 38.

Source

The primary petroleum source rock for this assessment unit is interpreted to be the Mancos Shale.

Maturation

Thermal maturation is interpreted to range from early Eocene to late Miocene.

Migration

Migration distances from Mancos source beds into the adjacent sandy reservoirs were short for both early generated oil and late generated gas from the thermocatalytic conversion of kerogen in the marine shales. It is hypothesized that much of the gas now found in the various sandy reservoirs of the Mancos Shale cracked from oil within the reservoirs as a result of prolonged heating induced by greater depths of burial in this AU. As such, this gas was generated in place.

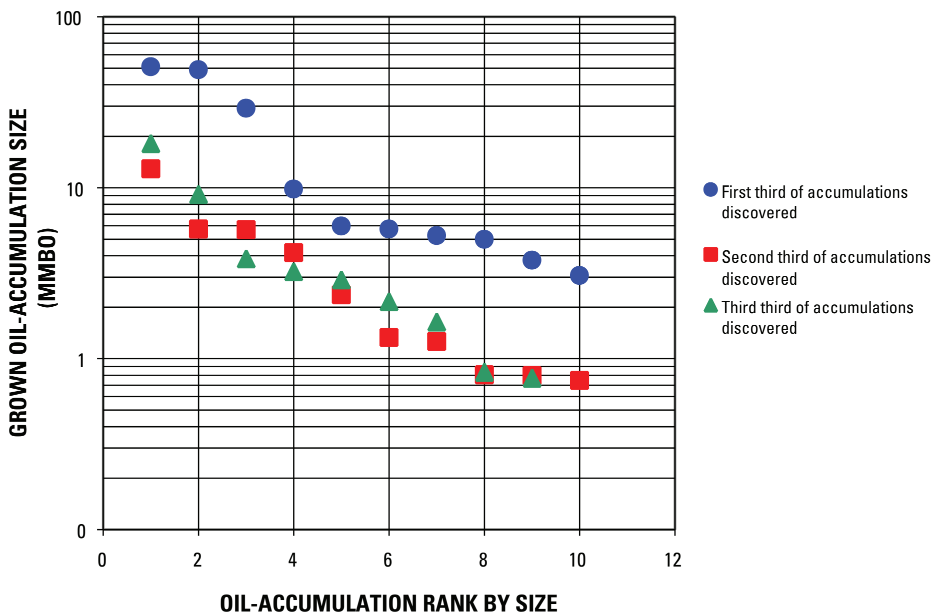


Figure 35. Distribution by thirds of grown oil-accumulation size versus rank by size for producing fields greater than 0.5 MMBO (million barrels oil) in the Mancos Sandstones Conventional Oil Assessment Unit (50220303). Data is from NRG (2001).

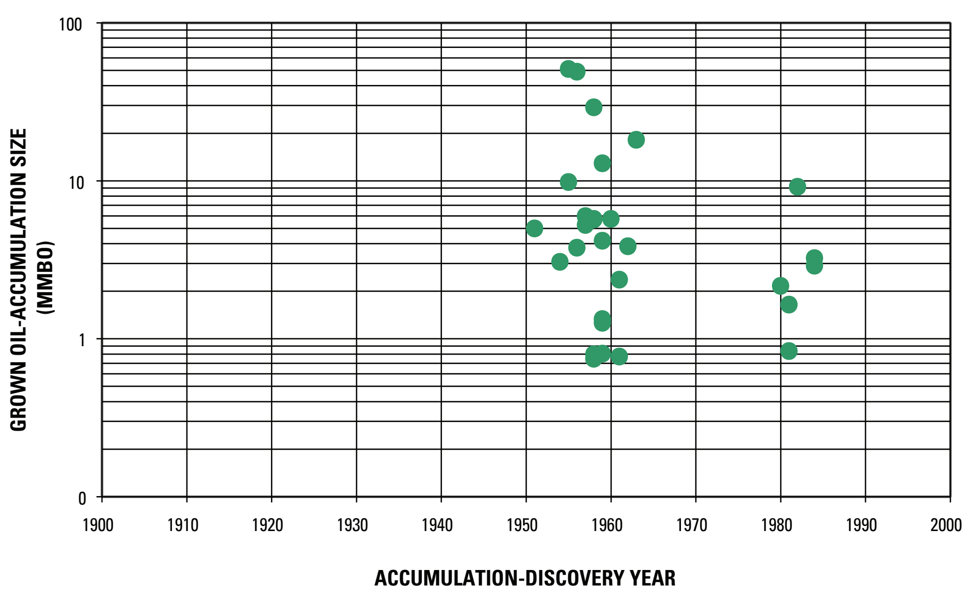


Figure 36. Distribution of grown oil-accumulation size versus accumulation-discovery year for producing fields greater than 0.5 MMBO (million barrels oil) in the Mancos Sandstones Conventional Oil Assessment Unit (50220303). Data is from NRG (2001).

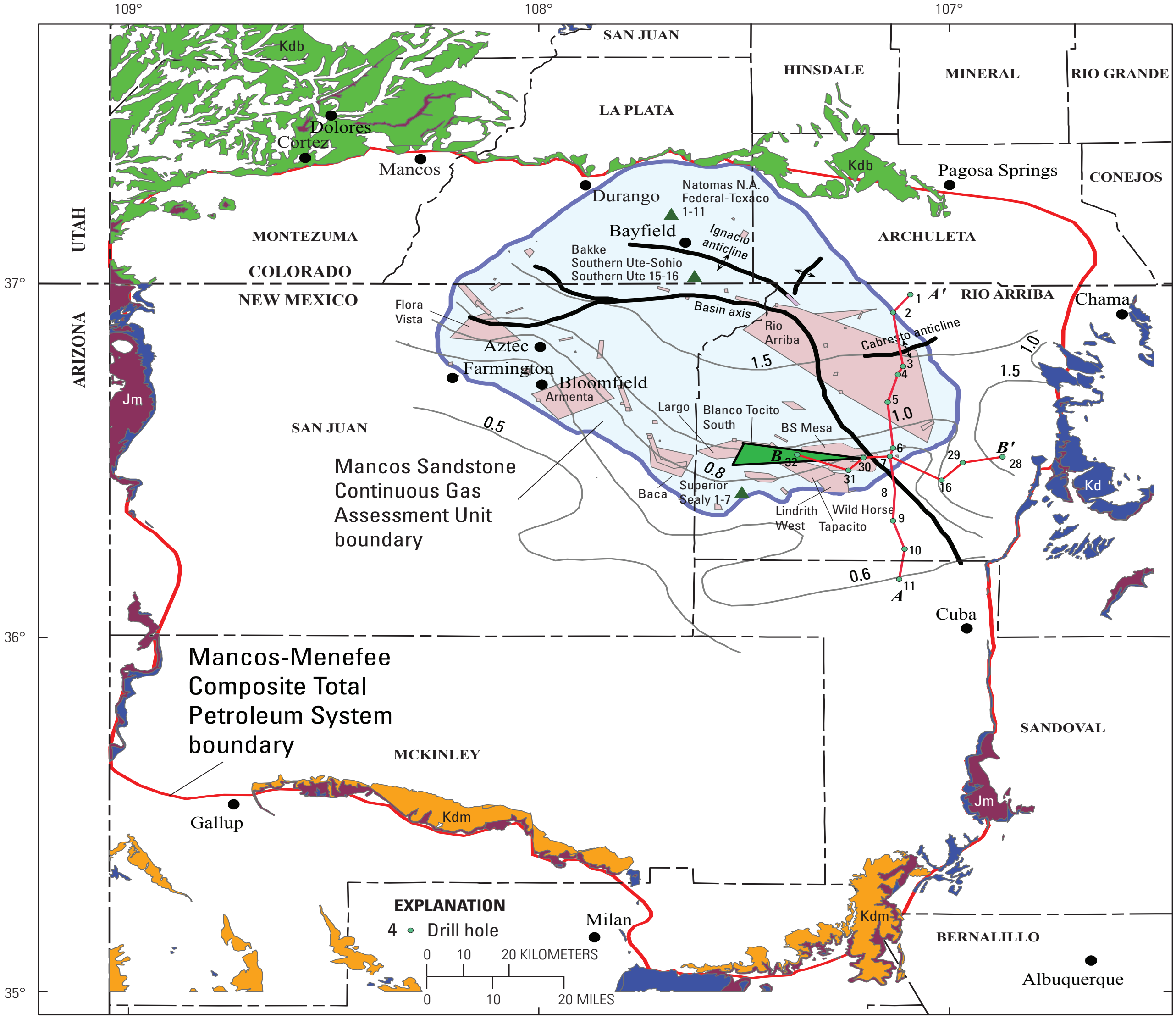


Figure 37. Map showing the location of the Mancos Sandstones Continuous Gas Assessment Unit (50220362) area (light blue) and boundary (light purple) in the middle and upper part of the Mancos-Menefee Composite Total Petroleum System. Also shown are the locations of the wells (green triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*), oil fields (green), and gas fields (pink) in the assessment unit. All gas fields are in the "Gallup" interval, except for the Blanco Tocito South field, which is in the Tocito Sandstone Lentil. Only fields discussed in the text are labeled. Thermal maturity contours (gray) are in the Menefee Formation (Fassett and Nuccio, 1990; Law, 1992; and Ridgley, 2001b). Field boundaries are extrapolated from data in IHS Energy Group (2002). Also shown are the locations of cross sections *A*–*A*′ and *B*–*B*′ (pls. 1 and 2). Symbols for geologic map units: Kdm, Dakota Sandstone-Mancos Shale; Kdb, Dakota Sandstone-Burro Canyon Formation; Kd, Dakota Sandstone; Jm, Morrison Formation from Green (1992) and Green and Jones (1997).

Reservoirs

The reservoirs in this AU, as in the Mancos Shale Conventional Oil AU, are the sandstone, siltstone, and sandy mudstone units variously called Tocito, "Gallup" (by industry), and basal Niobrara sands by Molenaar (1977b). Included in this group are

1. lenticular Tocito sandstones or basal Niobrara sands of Molenaar (1977b), which overlie the Coniacian unconformity;
2. the "Gallup," which includes the transgressive El Vado Sandstone Member of the Mancos Shale and regressive wedges of rocks that overlie the Tocito; and
3. sandstone and siltstone reservoirs in the Mancos that are transitional into the overlying Point Lookout Sandstone of the Mesaverde Group (pls. 1 and 2).

Traps/Seals

The principal traps are local structures, low permeability sandstone, and capillary pressure. These factors are augmented by the laterally discontinuous geometry of the marine sandstone beds, which pinch out into marine shales and neritic mudstones. Seals are the various shale beds. Local faulting and fracturing may also be important in compartmentalization of production, as well as in enhancing production (Gorham and others, 1977; Emmendorfer, 1992).

Geologic Model

Gas in this AU occurs in the central part of the San Juan Basin and was generated locally. Gas produced in shale beds of the Mancos Shale as a result of thermocatalytic conversion of kerogen migrated short distances into interbedded sandstone reservoirs of the Tocito and Mancos. Any early generated oil in Tocito or Mancos reservoirs in this AU cracked to gas as a result of prolonged heating during Oligocene and Miocene time, and migration of the gas was nonexistent. Facies that host conventional oil and gas accumulations and continuous basin-centered gas in the Tocito and Mancos are the same. The principal differences between the two types of accumulations are lower permeability and a reduction in porosity in this AU (table 1). Trapping of the gas in this AU is due to the combination of small structures, low permeability of the reservoirs, and capillary pressure, coupled with underpressuring of the reservoirs. The low permeability must have developed, in part, prior to oil generation as well as concurrent with oil and gas generation, thus creating a self-sealing system that did not permit effective updip migration of late generated oil and gas. Subtle structures and fractures in addition to lateral pinchout of sandstone reservoirs into enclosing shale may enhance production, and thus can be used to define the "sweet" spots within the overall gas-charged AU.

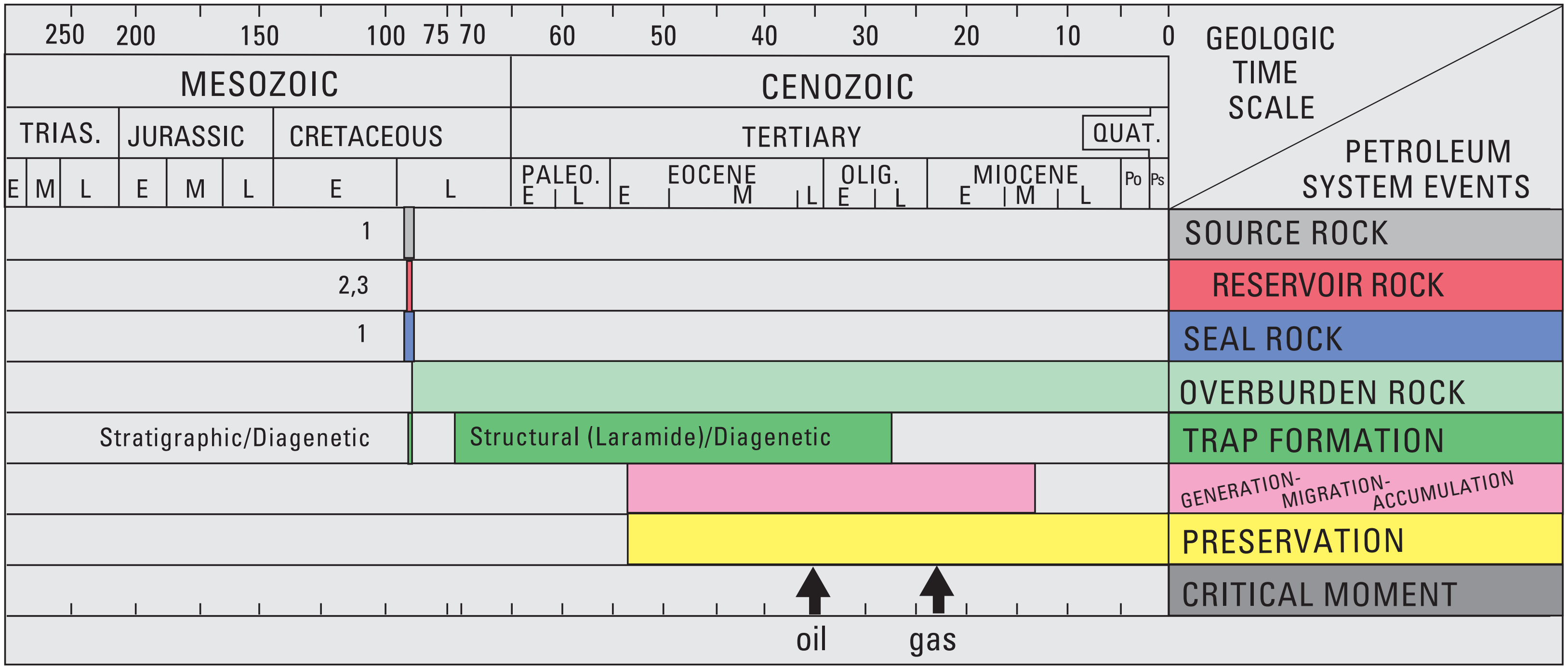
Assessment Results

The Mancos Sandstones Continuous Gas AU (50220362) was assessed to have potential additions to reserves of 5,116.37 BCFG and 75.96 MMBNGL at the mean. The volumes of undiscovered oil, gas, and natural gas liquids estimated in 2002 for the Mancos Sandstones Continuous Gas AU are shown in appendix A. This AU encompasses an area of 1,884,000 acres at the median, 1,845,000 acres at the minimum, and 1,942,000 acres at the maximum. A summary of the assessment input data are presented in the data form in appendix F.

There were 513 tested cells; tested cells include wells that have produced or had some other production test, such as initial production test, drill stem test, or core analysis. A 0.02 BCFG minimum recovery was used for each cell. Applying this cutoff, 460 tested cells equaled or exceeded this cutoff. There is adequate charge, reservoir, traps, seals, access, and timing of generation and migration of hydrocarbons, indicating a geologic probability of 1.0 for finding at least one additional field with a total recovery greater than the stated minimum recovery of 0.02 BCFG per cell. If the production history of the Mancos Sandstones Continuous Gas AU is divided into nearly three equal time periods by discovery date, plots of the estimated ultimate recoveries (EUR) indicate that the earliest time period has resulted in the best EUR distribution overall, and the best median total recovery of 0.53 BCFG per cell (fig. 39). Production has shown a general decline for the remaining two time periods. Part of this apparent decline is due to the fact that wells in this AU drilled during the first time period were located closer to the oil fields in the Mancos Sandstone Conventional Oil AU and were drilled based on step-out drilling from areas of known production. The EUR distribution for the Mancos Sandstones Continuous Gas AU (fig. 40) shows a median total recovery per cell of 0.25 BCFG.

The bulk of the AU remains untested (median is 97.1 percent), and the subsurface geology is poorly defined especially in the northern and western parts. The geologic depositional model predicts that Tocito-like sandstones, where they occur, lie on the unconformity near the base of the Mancos Shale, just above the Juana Lopez Member. Because these sandstones have a linear geometry, elongated northwest–southeast, they should trend throughout most of the AU. They have been identified in the subsurface on the east side of the AU (Ridgley, 2001a) where some of these sandstones are gas bearing (pls. 1 and 2). These sandstones are not present everywhere and, even if gas-bearing, would probably not provide the bulk of the potential resources in this AU, because the sandstones are typically less than 20 ft thick and are laterally discontinuous in all directions.

The transgressive-regressive wedge of sediments of the "Gallup" that overlies the Tocito-like sandstones does produce gas in this AU (wells 2 and 5, pl. 1; wells 16, 28, and 30, pl. 2) and may be several hundred feet thick. However, the distribution of local sandstone buildups, some of which are associated with various shoreline positions, is poorly defined.



Rock Units:
1. Mancos Shale
2. Tocito Sandstone Lentil of Mancos Shale
3. "Gallup" sandstone (El Vado Sandstone Member of Mancos Shale)

Figure 38. Events chart that shows key geologic events for the Mancos Sandstones Continuous Gas Assessment Unit. Black arrows show critical moments for oil and gas generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others, (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

These slightly sandier intervals might provide better reservoirs and stratigraphic traps in overall low permeability rocks. There are also poorly defined small-scale structures that might define areas of either initial traps or sites of later fractures. Intervals consisting entirely or mostly of shale, although not now productive, should be examined for their shale-gas potential, especially considering whether early oil, produced in the source beds, was retained and subsequently cracked to gas. Silty and thinly bedded sandstones might be productive (similar to the Lewis Continuous Gas AU, in Dubiel, chap. 5, this CD-ROM), but probably would require fracture stimulation for testing and production.

Taking our current knowledge and the level of uncertainty into consideration, the entire untested area is not considered to be favorable for having potential additions to reserves. We estimate 35 percent of the untested area to have potential additions to reserves at the minimum, 60 percent at the median, and 75 percent at the maximum. These values were obtained by multiplying the various percentages of untested area deemed favorable by different success ratios. New drilling will essentially be infill drilling on closer spacing, step-out drilling from existing fields, and new field discoveries from wildcat drilling. Total gas recovery per cell for untested cells is estimated at 0.02 BCFG at the minimum, 0.35 BCFG at the median, and 5 BCFG at the maximum, which was based on isolated occurrences of high-producing wells (fig. 39).

Mesaverde Updip Conventional Oil Assessment Unit (50220301)

Introduction

The unassessed Mesaverde Updip Conventional Oil AU boundary (fig. 41) includes

1. the area within the outcrop of the Mesaverde Group that lies outside the boundary of the Mesaverde Central-Basin Continuous Gas AU (fig. 41), discussed below; and
2. wells that primarily have a calculated gas-oil ratio (GOR) of less than or equal to 5,000 cubic feet of gas per barrel of oil (cfg/bo).

The main exception to this second parameter is the Red Mesa field on the northwestern side of the basin (fig. 41), which produces only gas in the Mesaverde. The Mesaverde Updip Conventional Oil AU includes areas of potential oil production that are in the structurally shallower and less thermally mature parts of the basin, including the Four Corners platform on the west, the Archuleta arch on the east, and the Chaco slope on the south (fig. 4). The outer boundary of the AU was drawn at the top of the outcropping Point Lookout Sandstone, or where the Point Lookout is not differentiated from the Mesaverde, at about midpoint of the Mesaverde Group.

Oil production from the Menefee Formation in this AU includes the Seven Lakes field in McKinley County, N. Mex. (fig. 41), which produced the first oil in New Mexico in 1911. Nearly all of the other fields were discovered between 1950 and 1975. Only one oil field (Franciscan Lake) (fig. 41) has had production above the minimum cutoff size of 0.5 MMBO used in the present assessment, and thus this AU was not quantitatively assessed. Production from this assessment unit, as of January 2003, was approximately 6.8 MMBO and 33.5 BCFG (IHS Energy Group, 2003). The possibility of future oil or gas discoveries above the minimum size is estimated to be very low. Any future discoveries will probably be near places where oil has already been found in the southern part of the basin. Key parameters of the AU are listed below and are summarized on figure 42.

Source

The primary petroleum source rock for this assessment unit is interpreted to be the Mancos Shale.

Maturation

Thermal maturation is interpreted to have begun in early Eocene time.

Migration

Oil has migrated upward from the Mancos Shale into Point Lookout Sandstone and sandstones of the Menefee Formation. Many of the small oil fields are associated with faults, which are likely migration routes into reservoir sandstone beds.

Reservoirs

Most production has been from fluvial channels in the Menefee Formation. Two fields, Cuervo and Devils Fork (fig. 41), produce oil from the marginal marine Point Lookout Sandstone.

Traps/Seals

Traps in the Menefee are a combination of stratigraphic and structural. Many fields produce from fluvial channel sandstones that pinch out laterally into overbank mudrocks. Additionally, many of the fields are draped over small anticlines or domes, some of which are faulted. Seals are paludal and overbank mudrocks in the Menefee Formation. Traps in the Point Lookout are stratigraphic pinchouts of marginal marine sandstone into paludal shales in the lower part of the Menefee. Shales in the lower part of the Menefee and in the Mancos are seals for these traps.

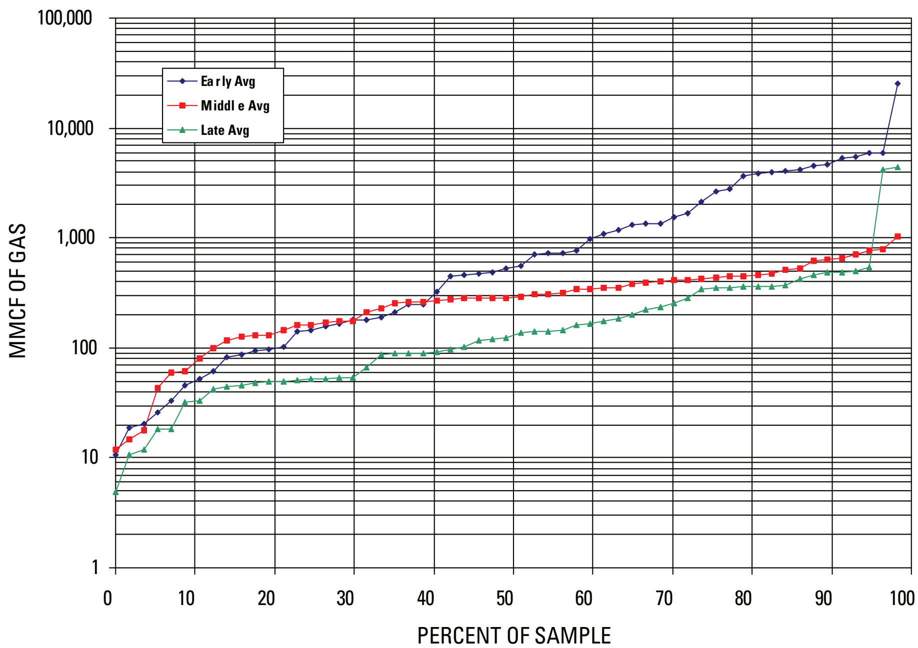


Figure 39. Graph showing estimated ultimate recoveries (EUR) of Mancos Sandstones Continuous Gas Assessment Unit gas wells divided into three equal numbers of wells based on start of production. EURs were calculated using data from IHS Energy Group (2002). Data provided by T. Cook (written commun., 2002). MMCF, million cubic feet.

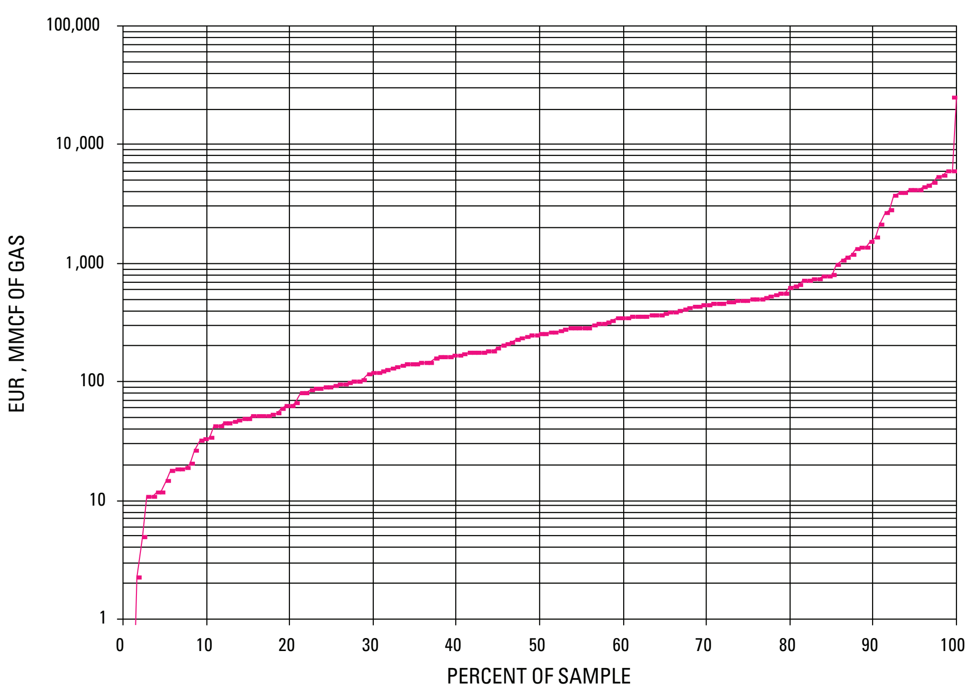


Figure 40. Graph showing combined distribution of estimated ultimate recoveries (EUR) of Mancos Sandstones Continuous Gas Assessment Unit gas wells. EURs were calculated using data from IHS Energy Group (2002). Data provided by T. Cook (written commun., 2002). MMCF, million cubic feet.

Geologic Model

Based on geochemical studies, Ross (1980) indicated that the source of the oil in the Mesaverde is the Mancos Shale. Coal or other carbonaceous beds within the Menefee Formation are not thought to have contributed to the Menefee reservoirs. The Mancos (as defined by the top of the Dakota in fig. 15*C*) entered the zone of oil generation in the early Eocene and the zone of wet gas in the middle Eocene (fig. 15*C*). Mancos-generated oil likely migrated upward along faults to reservoirs in the Point Lookout and Menefee. Fluvial channel reservoirs are isolated, sinuous, and scattered through the Menefee, presenting limited targets for exploration. In addition, many of the known producing areas are in association with faults and/or small structures, thus limiting the potential of the AU for further drilling success.

Assessment Results

This AU was not quantitatively assessed as there was significant risk on the existence of a field of minimum size.

Mesaverde Central-Basin Continuous Gas Assessment Unit (50220361)

Introduction

The Mesaverde Central-Basin Continuous Gas Assessment Unit boundary was drawn to include gas accumulations in the deeper part of the central San Juan Basin (fig. 43). The structure contour map drawn on the base of the Dakota Sandstone (Thaden and Zech, 1984; pl. 1) was used as a general guide for locating the boundary on the western and eastern sides of the AU where it is placed along the upper limb of the monocline that borders the basin. The boundary along the northern side of the AU is at the top of the steeply dipping Mesaverde Group contact on the digital geologic map of Colorado (Green, 1992).

The boundary along the southwestern side of the AU includes most wells that produce gas and excludes most wells that produce oil from the Mesaverde, which are included in the Mesaverde Updip Conventional Oil AU. Gas-oil ratios (GOR) were calculated for all producing wells for which data were available. Wells with GOR >20,000 cfg/bo are included in the Mesaverde Central-Basin Continuous Gas AU. Wells with GOR values of <5,000 cfg/bo are excluded from the AU in most cases. Most wells with the GOR range between 5,000 and 20,000 are included in this AU because these wells are surrounded by wells with GOR ratios >20,000.

There have been few divisions of Mesaverde production into separate fields in the AU (fig. 43). The largest Mesaverde field is the Blanco field in New Mexico, whose discovery well was completed in 1927. The Ignacio-Blanco field in Colorado was discovered in 1952. Two small Mesaverde fields just west of the Blanco field, Crouch Mesa and Flora Vista (fig. 43), were discovered in 1961. Development of the Mesaverde gas fields has been somewhat cyclic. The first big surge of development was from about 1952 to 1962, with peak drilling in 1957 (IHS Energy Group, 2001). Prichard (1973) and Fassett (1991) noted that major development of the Mesaverde (and other units) followed completion of a gas pipeline from the San Juan Basin to California in 1951. Prior to that time much of the produced gas was used locally. A second round of development peaked between 1978 and 1982, and a third cycle of active drilling was between 1987 and 1992. Drilling again increased from 1997 through 2000. Production from this assessment unit as of January 2003 was about 13 TCFG and 54.9 MMBO (IHS Energy Group, 2003).

Drilling is currently permitted on 160-acre spacing. Produced water increases somewhat at the margins of the area of production, and the water to gas ratio (barrels of water to thousand cubic feet of gas) shows marked increases along the entire southern boundary of the AU and in the center of the northeast margin. Future development may be focused more on infill than on discoveries in new areas. Key parameters of the Mesaverde Central-Basin Continuous Gas AU are listed below and are summarized on figure 44.

Source

Mancos Shale and Menefee Formation provide the source. Carbon isotope data suggests a mixed marine and continental source. The Menefee contains abundant volumes of coal, carbonaceous shale, and humate of terrestrial origin, which are all gas prone. Some contribution to Cliff House Sandstone gas may have come from the overlying Lewis Shale.

Maturation

Thermal maturation for oil and associated gas is interpreted to range from middle Eocene to late Oligocene time.

Migration

Migration consists of upward migration of gas from the Mancos Shale into permeable sandstones of the Point Lookout Sandstone; internal lateral migration from coal, carbonaceous shale, and humate beds in the Menefee Formation to sandstone beds in the Menefee; and downward or lateral migration from the Lewis Shale into the Cliff House Sandstone.

Reservoirs

Reservoirs include shoreface and foreshore marginal-marine sandstones of the Point Lookout and Cliff House Sandstones and fluvial channels in the Menefee Formation. In an oblong area that straddles the State line in the northern part of the basin, reservoir rocks in the Mesaverde are poorly developed. The highest gas production is near the center of Blanco

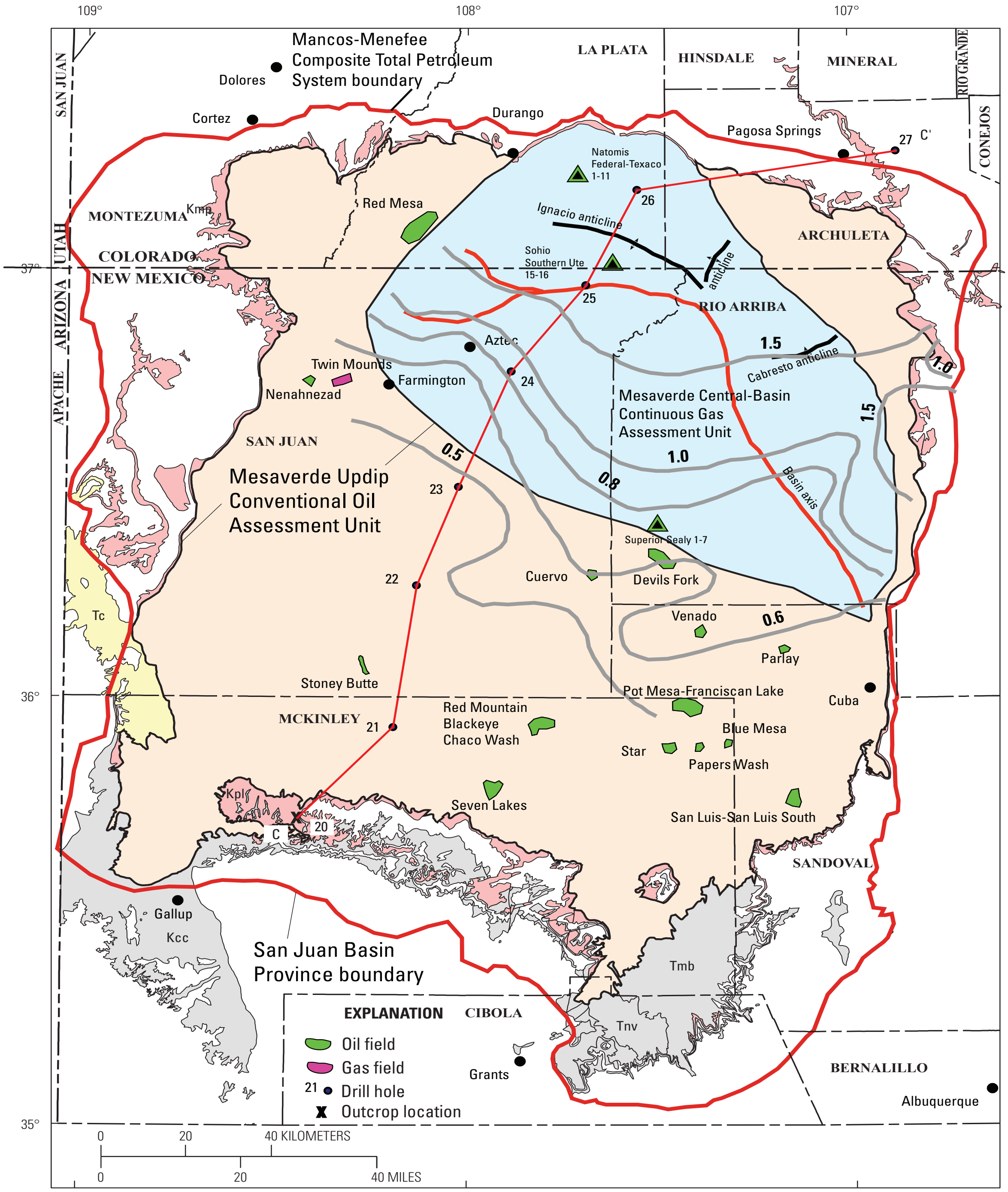
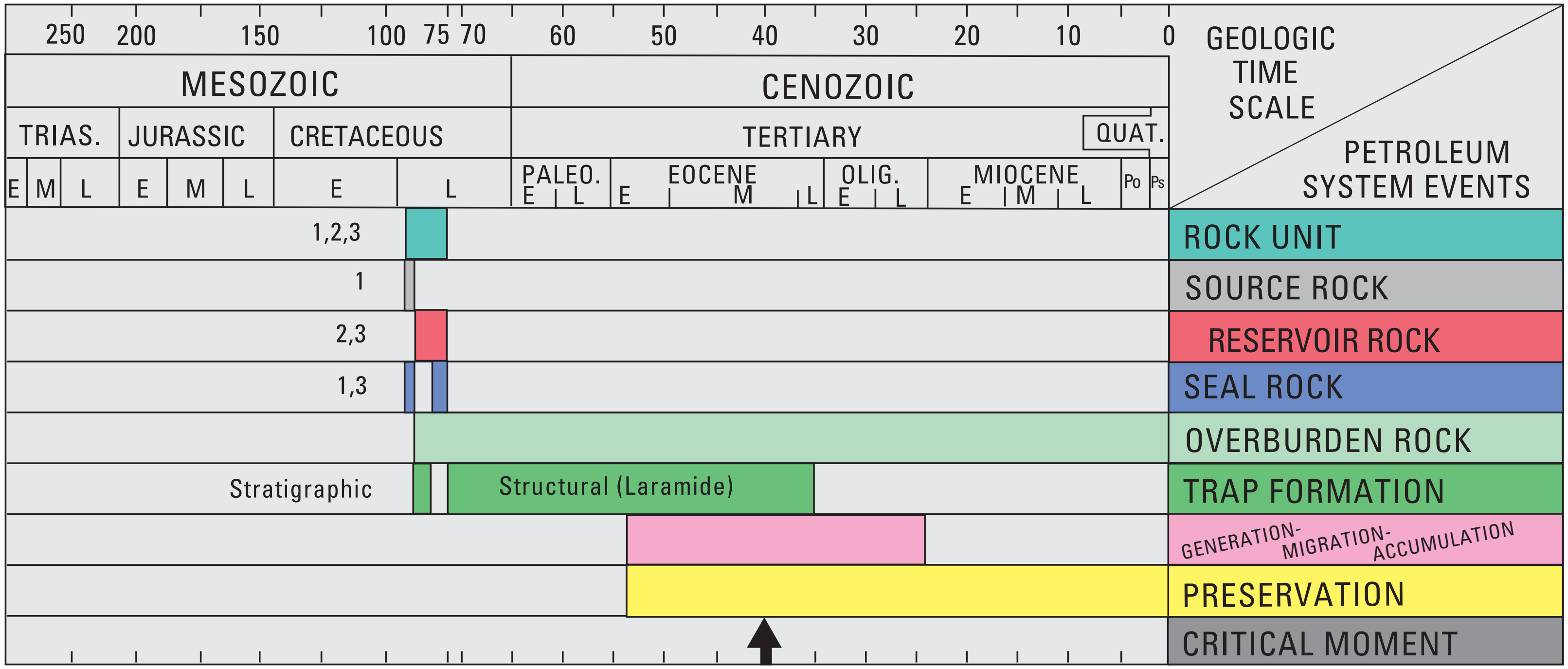


Figure 41. Map showing the location of the Mesaverde Updip Conventional Oil (light tan) and Mesaverde Central-Basin Continuous Gas (light blue) Assessment Units in the upper part of the Mancos-Menefee Composite Total Petroleum System. Menefee maturity contours (in gray) show vitrinite reflectance (R_m) values in percent, contoured from data in Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Also shown are the locations of the wells (green and black triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*) and the regional cross section *C*–*C′* (fig. 9). Geologic units are from Green (1992) and Green and Jones (1997): Tc, Tertiary Chuska Sandstone; Tnv, Tertiary Neogene volcanics; Tmb, Tertiary Miocene volcanics; Kcc, Crevasse Canyon Formation; Kmp, Menefee Formation and Point Lookout Sandstone; Kmv, Mesaverde Group; Kpl, Point Lookout Sandstone.



Rock Units:
1. Mancos Shale
2. Point Lookout Sandstone
3. Menefee Formation

Figure 42. Events chart that shows the timing of key geologic events for the Mesaverde Updip Conventional Oil Assessment Unit. Black arrow shows critical moment for oil generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others, (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

field, and decreases outward toward the margins of the field. Higher gas production is probably associated with a greater degree of fracturing (Teufel and Herrin, 2003).

Traps/Seals

Pinchouts of marine sandstone (Point Lookout and Cliff House Sandstones) into marine or paludal shales, and pinchouts of fluvial sandstones of the Menefee into overbank mudrocks form traps/seals.

Geologic Model

In this AU, gas was generated from the overlying and underlying Lewis and Mancos Shales, and from coal beds and other carbonaceous beds within the Menefee Formation from the middle Eocene to the late Oligocene. Gas was expelled from the source beds and migrated into Point Lookout and Cliff House marginal marine sandstones and into fluvial Menefee sandstones. Gas was trapped stratigraphically where marginal marine rocks pinch out into marine or paludal shales, and also where fluvial channels in the Menefee pinch out laterally into overbank mudrocks. Water saturation is also an important control, preventing gas from migrating updip to the south or north (Masters, 1979). The development of tightly cemented zones within the reservoirs probably also plays an important role in preventing the gas from migrating out of the reservoirs. Natural fracturing enhances production, and induced fracturing is an integral part of well completions.

Assessment Results

The Mesaverde Central-Basin Continuous Gas Assessment Unit (50220361) was assessed to have potential additions to reserves of 1,316.79 (BCFG) and 5.27 (MMBNGL) at the mean. The volumes of undiscovered oil, gas, and natural gas liquids estimated in 2002 for the Mesaverde Central-Basin Continuous Gas AU are shown in appendix A. These values are lower for gas and higher for natural gas liquids compared to the 1995 USGS assessment (Huffman, 1996) (table 7). A summary of the input data for the AU is presented on the data form in appendix G.

This AU encompasses an area of 2,348,000 acres at the median, 2,231,000 acres at the minimum, and 2,583,000 acres at the maximum. There were 6,667 tested cells; tested cells include wells that have produced or had some other production test, such as initial production test, drill stem test, or core analysis. A 0.02 BCFG minimum recovery cutoff was used per cell. Applying this cutoff, 6,478 tested cells equaled or exceeded this cutoff. There was deemed to be adequate charge, favorable reservoirs, traps, and seals over most of the area and favorable timing for charging the reservoirs with greater than the minimum recovery. If the production history of the Mesaverde Central-Basin Continuous Gas AU is divided into three nearly equal time periods, plots of the estimated ultimate recoveries (EUR) indicate that the first third of production history had the highest median recovery per cell, 2.1 BCFG (fig. 45). The second period of time had lower recovery, at 1.6 BCFG per cell, and the last period of time recovery dropped to 0.5 BCFG per cell. The EUR distribution for the Mesaverde Central-Basin Continuous Gas AU (fig. 46) shows a median total recovery per cell of 1.4 BCFG.

Even with a large part assigned to established fields, the median untested area is 57 percent of the total median AU area. The untested areas are mainly

1. south of the producing area to the Mesaverde outcrops, where the Mesaverde has increasing water/gas ratios;
2. northeast of established producing areas, where the Mesaverde is tightly cemented and also has higher than average water/gas ratios; and
3. areas within producing fields that remain undrilled, either because of State minimum spacing requirements or because of diminishing production trends in areas of established drilling due to lack of reservoir facies, poor fracture development, or water saturation.

With these considerations, the entire untested area was not considered to be favorable. Geologically unfavorable areas were considered to have higher water saturation mainly to the northeast and southeast of the producing fields. Additionally, an oblong area extending northwest to southeast from Colorado to New Mexico was found to have poorly developed sandy reservoirs in the Mesaverde. This area and areas of high water saturation were subtracted from the untested area because they were not considered to be areas favorable for potential additions to reserves. At the minimum, we estimate 15 percent of the untested area to have potential additions to reserves in the next 30 years; at the median, this value is 22 percent of the untested area; and at the maximum, the value is 26 percent. New drilling will consist of infill drilling on closer spacing, step-out drilling from existing fields, and new field discoveries from wildcat drilling. The minimum cutoff of 0.02 BCFG would apply to the percentage of untested cells considered to have potential additions to reserves. Total gas recovery per cell of untested cells considered to have potential additions to reserves is estimated at 0.02 BCFG at the minimum, 0.5 BCFG at the median, and 6.0 BCFG at the maximum. The maximum of 6.0 BCFG is based on the isolated occurrences of high-producing wells (fig. 46).

Menefee Coalbed Gas Assessment Unit (50220381)

Introduction

The Menefee Coalbed Gas AU boundary (fig. 47) coincides with the boundary of the Mesaverde Updip Conventional Oil AU (fig. 41), except in the far northeast part of the basin where the Menefee Formation pinches out between the

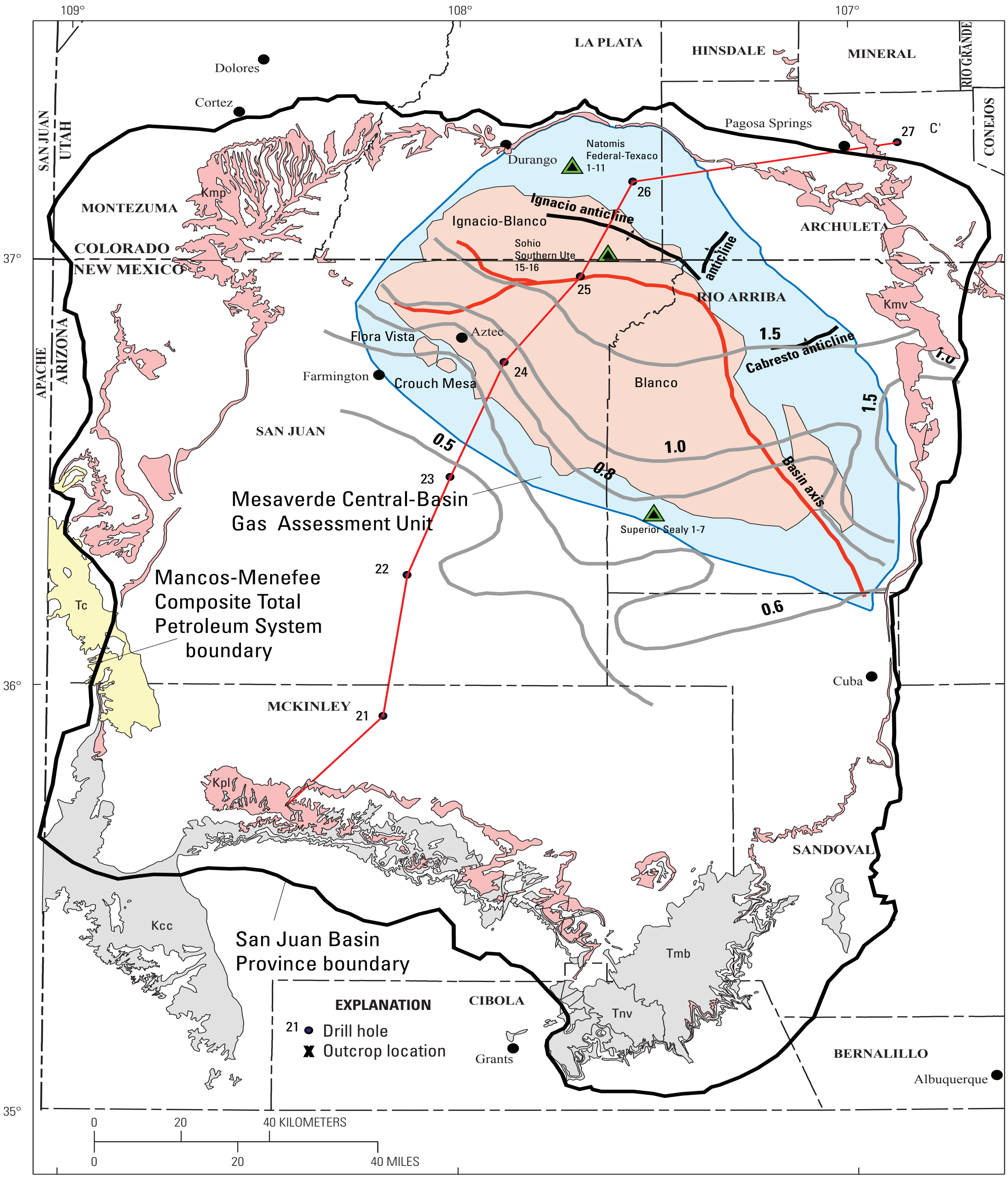
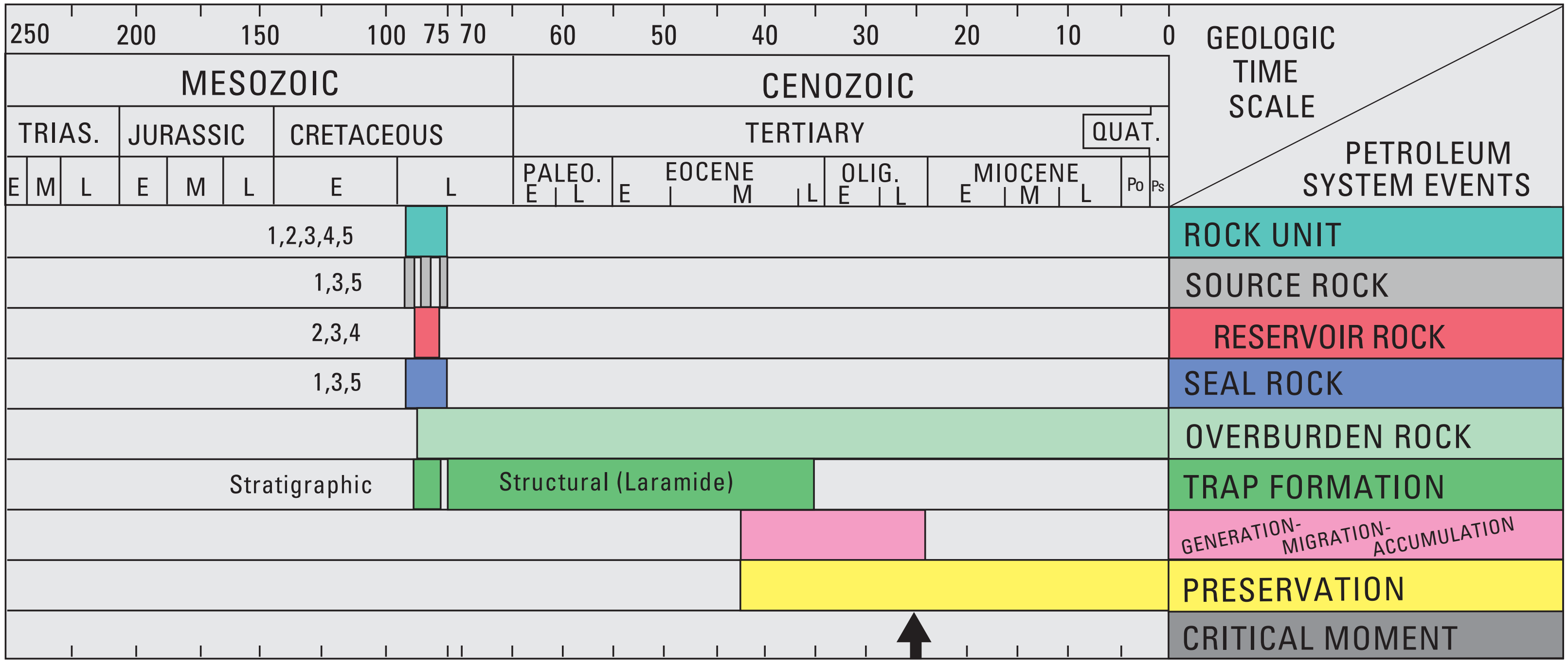


Figure 43. Map showing the extent of the Mesaverde Central-Basin Continuous Gas Assessment Unit (blue) and its included gas fields (light tan) in the upper part of the Mancos-Menefee Composite Total Petroleum System. Menefee maturity contours (in gray) show vitrinite reflectance (R_m) values in percent, contoured from data in Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Also shown are the locations of the wells (green and black triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*) and the regional cross section *C*–*C′* (fig. 9). Geologic units are from Green (1992) and Green and Jones (1997): Tc, Tertiary Chuska Sandstone; Tnv, Tertiary Neogene volcanics; Tmb, Tertiary Miocene volcanics; Kcc, Crevasse Canyon Formation; Kmp, Menefee Formation and Point Lookout Sandstone; Kmv, Mesaverde Group; Kpl, Point Lookout Sandstone.



Rock Units:
1. Mancos Shale
2. Point Lookout Sandstone
3. Menefee Formation
4. Cliff House Sandstone
5. Lewis Shale

Figure 44. Events chart that shows the timing of key geologic events for the Mesaverde Central-Basin Continuous Gas Assessment Unit. Black arrow shows the critical moment for gas generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others, (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

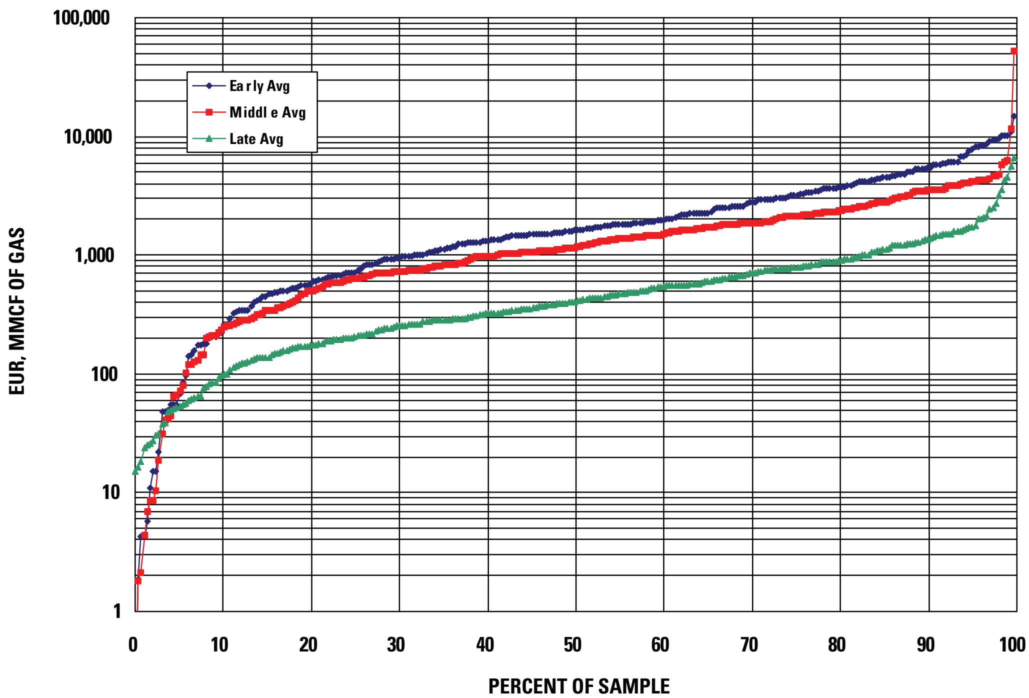


Figure 45. Graph showing the estimated ultimate recoveries (EUR) of the Mesaverde Central-Basin Continuous Gas Assessment Unit gas wells divided into three nearly equal numbers of wells based on start of production. EURs were calculated using data from IHS Energy Group (2002). Data provided by T. Cook (written commun., 2002). MMCF, million cubic feet.

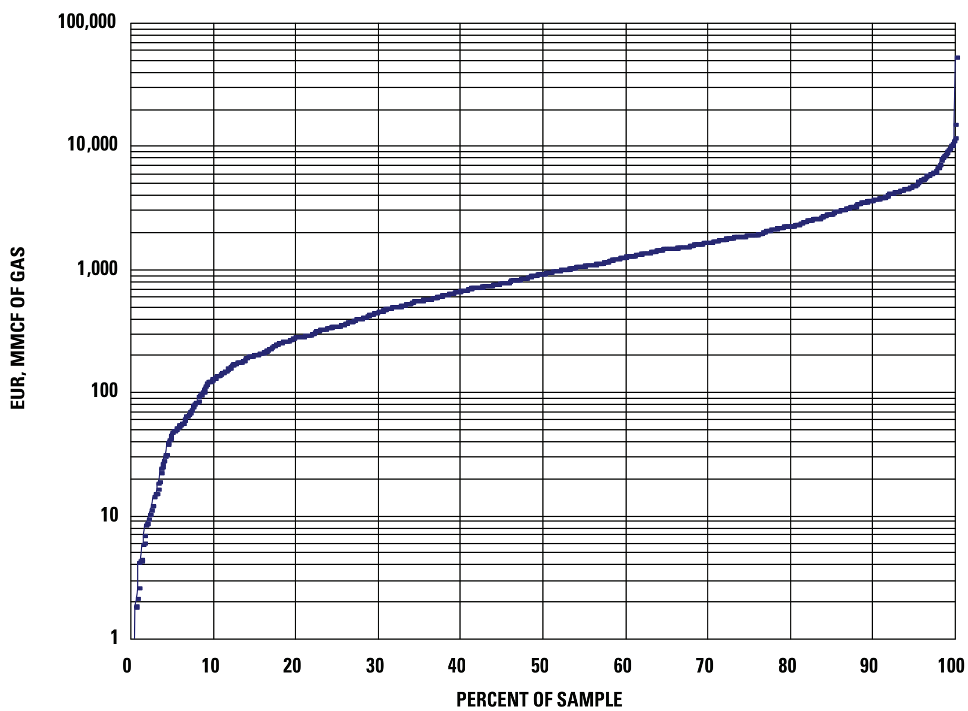


Figure 46. Graph showing the combined distribution of estimated ultimate recoveries (EUR) of the Mesaverde Central-Basin Continuous Gas Assessment Unit gas wells. EURs were calculated using data from IHS Energy Group (2002). Data provided by T. Cook (written commun., 2002). MMCF, million cubic feet.

Cliff House Sandstone and the Point Lookout Sandstone. The Mesaverde Coalbed Gas AU occupies the structurally shallower parts of the basin where the Menefee has been recognized. The AU adjoins the Mesaverde Central-Basin Continuous Gas AU in the deeper parts of the basin, and the top of the Point Lookout Sandstone delimits the AU boundary in the southern part of the basin (Green and Jones, 1997).

To date there has been no gas production from targeted Menefee coals. Three coal-bed wells have been drilled in the southeastern part of the basin, but these have not been productive. Mesaverde coal beds have certainly produced gas in some parts of the basin, but Menefee production is not commonly reported separately from Mesaverde production, making the relative contribution of gas from Menefee coal beds unknown. Bowman (1978) thought that the Menefee contributed only about 10 percent of the total Mesaverde gas production in the Ignacio-Blanco field (fig. 43) in southern Colorado. Possibilities for future discoveries of coal-bed gas may be best in the southern part of the basin where the most coal occurs in the upper part of the Menefee (Siemers and Wadell, 1977), although the coal in this area is of low maturity. Although microbial gas has been produced from low thermal maturity coals in the Powder River Basin (Hobbs, 1978; Law and others, 1991), microbial generation of either early or late coal-bed gas in the Menefee has not been documented. Key parameters of the Menefee Coalbed Gas AU are listed below and are summarized on figure 48.

Source

The primary petroleum source rocks for this assessment unit are interpreted to be coals, carbonaceous shales, and humate beds in the Menfee Formation.

Maturation

Thermal maturation is interpreted to range from early to late Oligocene for thermogenic gas. A contribution from microbial gas is possible.

Migration

Gas is generated and retained in coal beds or shales with little migration.

Reservoirs

Reservoirs are Menefee coal beds, which are thin and discontinuous in most places. Net coal thickness in the Hogback Mountain tongue (an informal unit), in the upper part of the Menefee, is 30 ft; in the basal Cleary Coal Member, it is also about 30 ft. Coal beds, which are thinner and discontinuous in the north part of the basin, are more thermally mature than those in the south part.

Traps/Seals

Deltaic and fluvial overbank mudrocks within the Menefee Formation

Geologic Model

The Hogback Mountain tongue (or upper coal member) of the Menefee is estimated to contain 94 percent of the total amount of coal in the Menefee Formation in beds greater than 2 ft thick and at depths of from 250 to 4,000 ft (Siemers and Wadell, 1977). Coals in this tongue are present in a zone 92 mi long and 12 mi wide, trending northwest–southeast, approximately parallel to and just north of the upper Menefee outcrop contact. Coals occur in an interval of about 450 ft in the upper Menefee and at the base of the Menefee in the Cleary Coal Member. The main coal-bearing belt is south of the 0.60-percent R_m maturity contour of coals in the Menefee, and much of it is outside the 0.50-percent R_m vitrinite isoreflectance contour, suggesting that the coal beds were not buried deeply enough to have generated much thermal gas. In one area where the Hogback Mountain tongue occurs, the overlying Fruitland Formation produces coal-bed gas, suggesting that either the Fruitland, and by inference, the Menefee has a high enough thermal maturity to produce gas, or that the Fruitland, and possibly the Menefee, may contain gas generated through microbial processes. Gas samples from the Fruitland in this area have isotopes indicative of biogenic or mixed biogenic-thermogenic gas (Rice and others, 1989; Ridgley and others, chap. 6, this CD-ROM).

Assessment Results

Because there has been no reported coal-bed gas production from the Menefee, an analog was used for EUR distributions. Similarities in the geology of coal beds, and some established coal-bed gas production, led to using the Mesaverde Group of the Uinta-Piceance Province (Johnson and Roberts, 2003) as an analog for the Menefee in the San Juan Basin. The mean assessed undiscovered resources in this AU are 663.94 BCFG at the mean (appendix A). A summary of the input data are presented in the data form in appendix H. The total AU area is 4,797,000 acres, of which 9 percent, or 431,730 acres is considered to have potential for additions to reserves at the median. This area was calculated by adding the area underlain by the Hogback Mountain tongue in New Mexico with an area surrounding the Red Mesa field in Colorado (Lauth, 1983) (where production from coal has been noted in the literature), and multiplying the sum by a success ratio of 70 percent.

The minimum untested area with potential for additions to reserves of thermogenic or microbial coal-bed gas was determined to be only 1 percent of the total AU area, or 47,970 acres. This minimum area takes into account the low thermal maturity of most of the coal in the Hogback Mountain tongue. Only a small area, where there is currently production

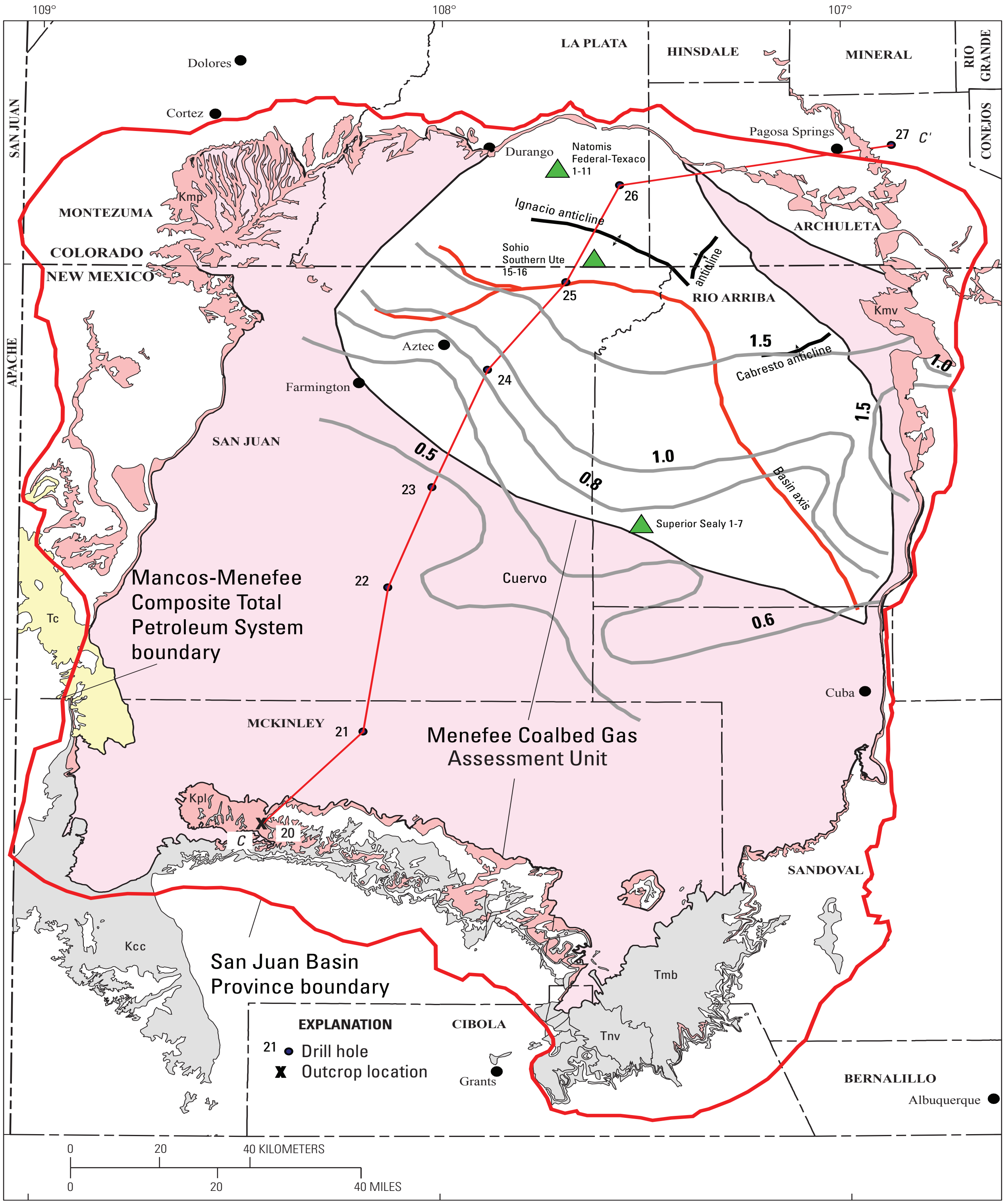


Figure 47. Map showing the Menefee Coalbed Gas Assessment Unit (pink) in the upper part of the Mancos-Menefee Composite Total Petroleum System. Menefee maturity contours (in gray) show vitrinite reflectance (R_m) values in percent, contoured from data in Fassett and Nuccio (1990), Law (1992), and Ridgley (2001b). Also shown are the locations of the wells (green triangles) used to construct the burial history curves found in this report (figs. 15*A*–*C*) and the regional cross section *C*–*C′* (fig. 9). Geologic units are from Green (1992) and Green and Jones (1997): Tc, Tertiary Chuska Sandstone; Tnv, Tertiary Neogene volcanics; Tmb, Tertiary Miocene volcanics; Kcc, Crevasse Canyon Formation; Kmp, Menefee Formation and Point Lookout Sandstone; Kmv, Mesaverde Group; Kpl, Point Lookout Sandstone.

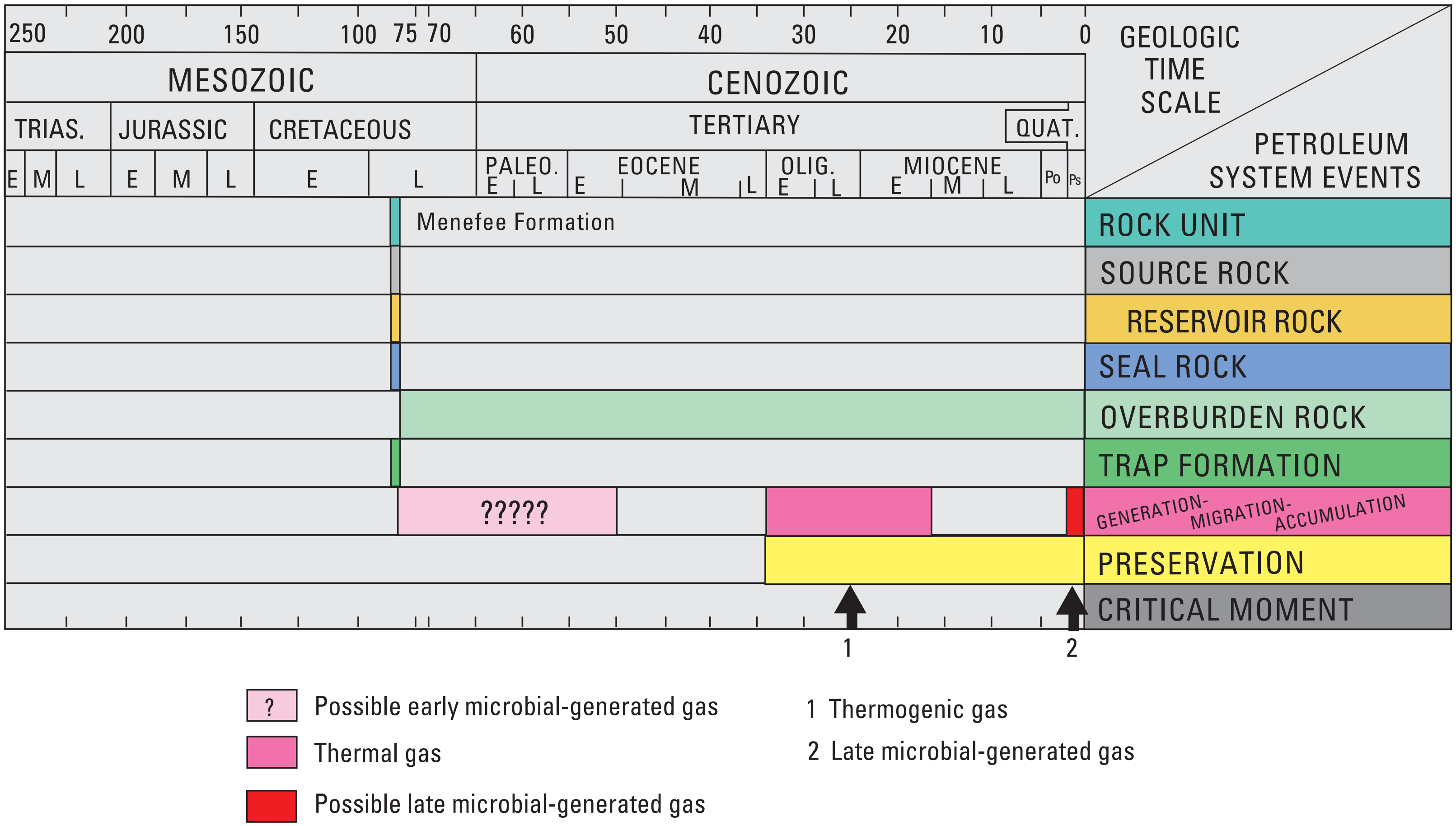


Figure 48. Events chart that shows the timing of key geologic events for the Menefee Coalbed Gas Assessment Unit. Black arrow shows the critical moment for gas generation. Events chart format is modified from Magoon and Dow (1994). Geologic time scale is from the Geological Society of America web page *http://www.geosociety.org/science/timescale/timescl.htm*, last accessed 2/1/2008, and from Berggren and others, (1995). Trias., Triassic; Quat., Quaternary; Po, Pliocene; Ps, Pleistocene; E, early; M, middle; L, late.

from coal in the Fruitland Formation, was considered to be a potential sweet spot in the Hogback Mountain tongue. The area of the Red Mesa field was added to this, and a success ratio of 90 percent was factored in. The maximum untested area with potential for additions to reserves of thermogenic or microbial coal-bed gas was calculated at 27 percent of the AU, or 1,295,190 acres. This area was calculated by first eliminating areas where the Menefee Formation crops out and then reducing the area further by factoring in a 50 percent success ratio.

Summary

The Mancos-Menefee Composite TPS includes all genetically related hydrocarbons generated from organic-rich shales in the Cretaceous Mancos Shale and from carbonaceous shale, coal beds, and humate in the Cretaceous Menefee Formation of the Mesaverde Group. Eight AUs were defined in the Mancos-Menefee Composite TPS. Of the eight AUs, four were assessed as conventional oil or gas accumulations and four as continuous-type accumulations. The conventional AUs are Dakota-Greenhorn Conventional Oil and Gas AU, Gallup Sandstone Conventional Oil and Gas AU, Mancos Sandstones Conventional Oil AU, and the Mesaverde Updip Conventional Oil AU. Continuous-type AUs are Dakota-Greenhorn Continuous Gas AU, Mancos Sandstones Continuous Gas AU, Mesaverde Central-Basin Continuous Gas AU, and Menefee Coalbed Gas AU. Total oil resources that have the potential for additions to reserves are estimated at a mean of 16.78 MMBO and gas resources that are estimated at a mean of 11.11 TCFG for this petroleum system.

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Appendix A.. Assessment results summary for the Mancos-Menefee Composite Total Petroleum System, San Juan Basin Province, New Mexico and Colorado.

[MMBO, million barrels of oil; BCFG, billion cubic feet of gas; MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 denotes a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive only under the assumption of perfect positive correlation. CBG, coalbed gas. Gray cells indicate not assessed or applicable.]

Assessment Units (AU)	Field Type	Total Undiscovered Resources											
		Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Conventional Oil and Gas Resources													
Gallup Sandstone Conventional Oil and Gas AU	Oil	0.00	1.98	6.29	2.34	0.00	0.29	0.98	0.35	0.00	0.00	0.01	0.00
Mancos Sandstones Conventional Oil AU	Oil	5.41	11.33	20.72	11.99	23.34	53.28	106.75	57.57	0.84	2.07	4.52	2.3
Dakota-Greenhorn Conventional Oil and Gas AU	Oil	0.78	2.26	4.73	2.45	2.53	7.49	17.1	8.34	0.02	0.07	0.16	0.08
	Gas					5.59	12.63	22.4	13.35	0.22	0.50	0.96	0.53
Total		6.19	15.57	31.74	16.78	31.46	73.69	147.23	79.61	1.08	2.64	5.65	2.91
Continuous Gas Resources													
Menefee Coalbed Gas AU	CBG					228.3	569.08	1,418.55	663.94	0.00	0.00	0.00	0.00
Mesaverde Central-Basin Continuous Gas AU	Gas					1,053.32	1,305.62	1,618.35	1,316.79	3.44	5.12	7.6	5.27
Mancos Sandstones Continuous Gas AU	Gas					3,980.80	5,062.07	6,437.03	5,116.37	50.64	73.97	108.04	75.96
Dakota-Greenhorn Continuous Gas AU	Gas					3,148.66	3,896.17	4,821.14	3,928.98	10.29	15.27	22.66	15.72
Total						8,411.08	10,832.94	14,295.07	11,026.08	64.37	94.36	138.3	96.95

Appendix B. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304), San Juan Basin Province.

Appendix B. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Dakota-Greenhorn Conventional Oil and Gas Assessment Unit (50220304), San Juan Basin Province.

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (NOGA, Version 5, 6-30-01)

IDENTIFICATION INFORMATION

Assessment Geologist:……..	J.L. Ridgley	Date:	9/25/2002
Region:………………………..	North America	Number:	5
Province:………………………	San Juan Basin	Number:	5022
Total Petroleum System:……	Mancos-Menefee Composite	Number:	502203
Assessment Unit:……………	Dakota-Greenhorn Conventional Oil and Gas	Number:	50220304
Based on Data as of:……….	PI/Dwights 2001, NRG 2001 (data current through 1999)		
Notes from Assessor……….			

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall):… Oil

What is the minimum accumulation size?………. 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves in the next 30 years)

No. of discovered accumulations exceeding minimum size:…….. Oil: 7 Gas: 3
Established (>13 accums.) ____ Frontier (1-13 accums.) X Hypothetical (no accums.) ____

Median size (grown) of discovered oil accumulation (mmbo):
1st 3rd 5.98 2nd 3rd 1.69 3rd 3rd ____
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size……………	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size……	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum siz	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……..……....…. 1.0

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered accumulation ≥ minimum size……………………………………………..………………..……..………… 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:…………………min. no. (>0)	1	median no.	2	max no.	4
Gas Accumulations:………………min. no. (>0)	1	median no.	2	max no.	3

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):…..….min. size	0.5	median siz	1	max. size	6
Gas in Gas Accumulations (bcfg):….…..min. size	3	median siz	6	max. size	25

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………...………	1700	3400	5100
NGL/gas ratio (bngl/mmcfg)……………………...….	4	9	14

Gas Accumulations:	minimum	median	maximum
Liquids/gas ratio (bliq/mmcfg)….…………..……..	20	40	60
Oil/gas ratio (bo/mmcfg)………………………….…			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	median	maximum
API gravity (degrees)…………………….………….	30	50	55
Sulfur content of oil (%)………………………...…..	0.01	0.1	0.2
Drilling Depth (m) ……………...…………….……..	300	1100	2400
Depth (m) of water (if applicable)……………..…..			

Gas Accumulations:	minimum	median	maximum
Inert gas content (%)……………………….....……	0.1	0.5	1
CO_2 content (%)……………………………….....…	0.1	0.2	0.5
Hydrogen-sulfide content (%)………………...…….	0	0	0
Drilling Depth (m)……………………………………	560	1250	2200
Depth (m) of water (if applicable)………………….			

Appendix C. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Dakota-Greenhorn Continuous Gas Assessment Unit (50220363), San Juan Basin Province.

Appendix C. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Dakota-Greenhorn Continuous Gas Assessment Unit (50220363), San Juan Basin Province.

FORSPAN ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATIONS--BASIC INPUT DATA FORM (NOGA, Version 8, 8-16-02)

IDENTIFICATION INFORMATION

Assessment Geologist:…	J.L. Ridgley	Date:	9/25/2002
Region:……………………	North America	Number:	5
Province:…………………	San Juan Basin	Number:	5022
Total Petroleum System:.	Mancos-Menefee Composite	Number:	502203
Assessment Unit:……….	Dakota-Greenhorn Continuous Gas	Number:	50220363
Based on Data as of:……	PI/Dwights 2001		
Notes from Assessor…..			

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-Unit type: **Oil** (<20,000 cfg/bo) **or** **Gas** (≥20,000 cfg/bo) Gas
What is the minimum total recovery per cell?… 0.02 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 5823
Number of tested cells with total recovery per cell ≥ minimum: ……... 5262
Established (>24 cells ≥ min.) X Frontier (1-24 cells) ____ Hypothetical (no cells) ____
Median total recovery per cell (for cells ≥ min.): (mmbo for oil A.U.; bcfg for gas A.U.)
1st 3rd discovered 1.4 2nd 3rd 0.9 3rd 3rd 0.45

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an untested cell with total recovery ≥ minimum ……	1.0
2. **ROCKS:** Adequate reservoirs, traps, seals for an untested cell with total recovery ≥ minimum.	1.0
3. **TIMING:** Favorable geologic timing for an untested cell with total recovery ≥ minimum………..	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……….......……. 1.0

4. **ACCESS:** Adequate location for necessary petroleum-related activities for an untested cell with total recovery ≥ minimum ………………………………………………………………… 1.0

NO. OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES IN THE NEXT 30 YEARS

1. Total assessment-unit area (acres): (uncertainty of a fixed value)
minimum 2,412,000 median 2,513,000 maximum 2,563,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres): (values are inherently variable)
calculated mean 148 minimum 40 median 135 maximum 360

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
minimum 60 median 66 maximum 70

4. Percentage of untested assessment-unit area that has potential for additions to reserves in next 30 years (%): (a necessary criterion is that total recovery per cell ≥ minimum)
(uncertainty of a fixed value) minimum 46 median 55 maximum 76

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves in next 30 years:
(values are inherently variable)
(mmbo for oil A.U.; bcfg for gas A.U.) minimum 0.02 median 0.4 maximum 8

AVERAGE COPRODUCT RATIOS FOR UNTESTED CELLS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil assessment unit:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………..……			
NGL/gas ratio (bngl/mmcfg)…………………..…..			
Gas assessment unit:			
Liquids/gas ratio (bliq/mmcfg)….……………..……	2	4	6

SELECTED ANCILLARY DATA FOR UNTESTED CELLS
(values are inherently variable)

Oil assessment unit:	minimum	median	maximum
API gravity of oil (degrees)………….………….			
Sulfur content of oil (%)………………………...…			
Drilling depth (m) ……………...…………….……			
Depth (m) of water (if applicable)……………….			
Gas assessment unit:			
Inert-gas content (%)………………………....…..	0.00	1.20	2.80
CO_2 content (%)……………………………..…..	0.00	1.10	6.60
Hydrogen-sulfide content (%)……………...…….	0.00	0.00	0.00
Drilling depth (m)…………………………………	2000	2200	3000
Depth (m) of water (if applicable)……………….			

Success ratios:	calculated mean	minimum	median	maximum
Future success ratio (%).....	85	80	85	90

Historic success ratio, tested cells (%). 90

Appendix D. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Gallup Sandstone Conventional Oil and Gas Assessment Unit (50220302), San Juan Basin Province.

Appendix D. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Gallup Sandstone Conventional Oil and Gas Assessment Unit (50220302), San Juan Basin Province.

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (NOGA, Version 5, 6-30-01)

IDENTIFICATION INFORMATION

Assessment Geologist:……..	J.L. Ridgley	Date:	9/25/2002
Region:………………………..	North America	Number:	5
Province:………………………	San Juan Basin	Number:	5022
Total Petroleum System:……	Mancos-Menefee Composite	Number:	502203
Assessment Unit:……………	Gallup Sandstone Conventional Oil and Gas	Number:	50220302
Based on Data as of:……….	PI/Dwights 2001, NRG 2001 (data current through 1999)		
Notes from Assessor……….			

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall):… Oil

What is the minimum accumulation size?………. 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves in the next 30 years)

No. of discovered accumulations exceeding minimum size:…….. Oil: 2 Gas: 0
Established (>13 accums.) ______ Frontier (1-13 accums.) X Hypothetical (no accums.) ______

Median size (grown) of discovered oil accumulation (mmbo):
1st 3rd ______ 2nd 3rd ______ 3rd 3rd ______
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ______ 2nd 3rd ______ 3rd 3rd ______

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size……………	0.8
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size……	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum siz	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……...……....…. 0.8

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered accumulation ≥ minimum size…………………………………………………..………………..……..………… 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

	min. no. (>0)	median no.	max no.
Oil Accumulations:…………………	1	2	4
Gas Accumulations:………………	0	0	0

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

	min. size	median size	max. size
Oil in Oil Accumulations (mmbo):…...….	0.5	1	15
Gas in Gas Accumulations (bcfg):…..….			

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………………	75	150	225
NGL/gas ratio (bngl/mmcfg)……………………………	5	10	15

Gas Accumulations:	minimum	median	maximum
Liquids/gas ratio (bliq/mmcfg)…………………………			
Oil/gas ratio (bo/mmcfg)……………………………………			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	median	maximum
API gravity (degrees)……………………………………	20	28	32
Sulfur content of oil (%)……………………………………	0.2	0.25	0.5
Drilling Depth (m) ………………………………………	121	487	945
Depth (m) of water (if applicable)………………………			

Gas Accumulations:	minimum	median	maximum
Inert gas content (%)……………………………………			
CO_2 content (%)………………………………………………			
Hydrogen-sulfide content (%)……………………………			
Drilling Depth (m)……………………………………………			
Depth (m) of water (if applicable)………………………			

Appendix E. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Mancos Sandstones Conventional Oil Assessment Unit (50220303), San Juan Basin Province.

Appendix E. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Mancos Sandstones Conventional Oil Assessment Unit (503220303), San Juan Basin Province.

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (NOGA, Version 5, 6-30-01)

IDENTIFICATION INFORMATION

Assessment Geologist:……..	J.L. Ridgley	Date:	9/25/2002
Region:………………………..	North America	Number:	5
Province:………………………	San Juan Basin	Number:	5022
Total Petroleum System:……	Mancos-Menefee Composite	Number:	502203
Assessment Unit:……………	Mancos Sandstones Conventional Oil	Number:	50220303
Based on Data as of:……….	PI/Dwights 2001, NRG 2001 (data current through 1999)		
Notes from Assessor……….			

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall):… Oil

What is the minimum accumulation size?………. 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves in the next 30 years)

No. of discovered accumulations exceeding minimum size:…….. Oil: 29 Gas: 2
Established (>13 accums.) X Frontier (1-13 accums.) ____ Hypothetical (no accums.) ____

Median size (grown) of discovered oil accumulation (mmbo):
1st 3rd 5.84 2nd 3rd 1.84 3rd 3rd 2.9
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size……………	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size……	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum siz	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……..……...…. 1.0

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered accumulation ≥ minimum size……………………………………………………..………………..……..………… 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

	min. no. (>0)	median no.	max no.
Oil Accumulations:…………………	2	5	10
Gas Accumulations:………………	0	0	0

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

	min. size	median size	max. size
Oil in Oil Accumulations (mmbo):…..….	0.5	2	10
Gas in Gas Accumulations (bcfg):….….			

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	median	maximum
Gas/oil ratio (cfg/bo)……………………..………	2400	4800	7200
NGL/gas ratio (bngl/mmcfg)……………………...….	20	40	60

Gas Accumulations:	minimum	median	maximum
Liquids/gas ratio (bliq/mmcfg)….…………..……..			
Oil/gas ratio (bo/mmcfg)………………………….….			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	median	maximum
API gravity (degrees)…………………….………….	33	40	45
Sulfur content of oil (%)………………………...…..	0	0.1	0.3
Drilling Depth (m) ……………...…………….……..	60	1760	2300
Depth (m) of water (if applicable)……………...…..			

Gas Accumulations:	minimum	median	maximum
Inert gas content (%)…………………………....……			
CO_2 content (%)……………………………….....…			
Hydrogen-sulfide content (%)………………...…….			
Drilling Depth (m)……………………………………			
Depth (m) of water (if applicable)………………….			

Appendix F. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Mancos Sandstones Continuous Gas Assessment Unit (50220362), San Juan Basin Province.

FORSPAN ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATIONS--BASIC INPUT DATA FORM (NOGA, Version 8, 8-16-02)

IDENTIFICATION INFORMATION

Assessment Geologist:…	J.L. Ridgley	Date:	9/25/2002
Region:……………………	North America	Number:	5
Province:…………………	San Juan Basin	Number:	5022
Total Petroleum System:.	Mancos-Menefee Composite	Number:	502203
Assessment Unit:……….	Mancos Sandstones Continuous Gas	Number:	50220362
Based on Data as of:……	PI/Dwights 2001		
Notes from Assessor…..			

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-Unit type: **Oil** (<20,000 cfg/bo) **or** **Gas** (≥20,000 cfg/bo) Gas
What is the minimum total recovery per cell?… 0.02 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 513
Number of tested cells with total recovery per cell ≥ minimum: ……... 460
Established (>24 cells ≥ min.) X Frontier (1-24 cells) Hypothetical (no cells)
Median total recovery per cell (for cells ≥ min.): (mmbo for oil A.U.; bcfg for gas A.U.)
1st 3rd discovered 0.53 2nd 3rd 0.31 3rd 3rd 0.14

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an untested cell with total recovery ≥ minimum ……	1.0
2. **ROCKS:** Adequate reservoirs, traps, seals for an untested cell with total recovery ≥ minimum.	1.0
3. **TIMING:** Favorable geologic timing for an untested cell with total recovery ≥ minimum………..	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……….........……. 1.0

4. **ACCESS:** Adequate location for necessary petroleum-related activities for an untested cell with total recovery ≥ minimum ……………………………………………………………… 1.0

NO. OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES IN THE NEXT 30 YEARS

1. Total assessment-unit area (acres): (uncertainty of a fixed value)
   minimum 1,845,000 median 1,884,000 maximum 1,942,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres): (values are inherently variable)
   calculated mean 105 minimum 40 median 100 maximum 200

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
   minimum 96 median 97.1 maximum 98

4. Percentage of untested assessment-unit area that has potential for additions to reserves in next 30 years (%): (a necessary criterion is that total recovery per cell ≥ minimum)
   (uncertainty of a fixed value) minimum 35 median 60 maximum 75

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves in next 30 years:
(values are inherently variable)

	minimum	median	maximum
(mmbo for oil A.U.; bcfg for gas A.U.)	0.02	0.35	5

AVERAGE COPRODUCT RATIOS FOR UNTESTED CELLS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil assessment unit:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………...…….			
NGL/gas ratio (bngl/mmcfg)……………………..….			
Gas assessment unit:			
Liquids/gas ratio (bliq/mmcfg)….……………..……	8	15	21

SELECTED ANCILLARY DATA FOR UNTESTED CELLS
(values are inherently variable)

Oil assessment unit:	minimum	median	maximum
API gravity of oil (degrees)………….………….			
Sulfur content of oil (%)………………………...…			
Drilling depth (m) ……………...…………….……			
Depth (m) of water (if applicable)……………….			
Gas assessment unit:			
Inert-gas content (%)………………………....…..	0.10	0.20	0.40
CO_2 content (%)…………………………………..…..	0.50	1.40	1.80
Hydrogen-sulfide content (%)……………...…….	0.00	0.00	0.00
Drilling depth (m)………………………………….	1280	2195	2439
Depth (m) of water (if applicable)……………….			

Success ratios:	calculated mean	minimum	median	maximum
Future success ratio (%).....	83	75	83	90

Historic success ratio, tested cells (%). 90

Appendix G. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Mesa Verde Central-Basin Continuous Gas Assessment Unit (50220361), San Juan Basin Province.

FORSPAN **ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATIONS--BASIC INPUT DATA FORM (NOGA, Version 8, 8-16-02)**

IDENTIFICATION INFORMATION

Assessment Geologist:…	S.M. Condon	Date:	9/24/2002
Region:……………………	North America	Number:	5
Province:…………………	San Juan Basin	Number:	5022
Total Petroleum System:.	Mancos-Menefee Composite	Number:	502203
Assessment Unit:……….	Mesaverde Central-Basin Continuous Gas	Number:	50220361
Based on Data as of:……	PI/Dwights 2001		
Notes from Assessor…..			

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-Unit type: **Oil** (<20,000 cfg/bo) **or Gas** (>20,000 cfg/bo) Gas
What is the minimum total recovery per cell?… 0.02 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 6667
Number of tested cells with total recovery per cell > minimum: …….. 6478
Established (>24 cells > min.) X Frontier (1-24 cells) ____ Hypothetical (no cells) ____
Median total recovery per cell (for cells > min.): (mmbo for oil A.U.; bcfg for gas A.U.)
1st 3rd discovered 2.1 2nd 3rd 1.6 3rd 3rd 0.5

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an untested cell with total recovery > minimum ……	1.0
2. **ROCKS:** Adequate reservoirs, traps, seals for an untested cell with total recovery > minimum.	1.0
3. **TIMING:** Favorable geologic timing for an untested cell with total recovery > minimum………..	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……….......……. 1.0

4. **ACCESS:** Adequate location for necessary petroleum-related activities for an untested cell with total recovery > minimum ……………………………………………………………… 1.0

NO. OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES IN THE NEXT 30 YEARS

1. Total assessment-unit area (acres): (uncertainty of a fixed value)
   minimum 2,231,000 median 2,348,000 maximum 2,583,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres): (values are inherently variable)
   calculated mean 150 minimum 40 median 140 maximum 320

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
   minimum 47 median 57 maximum 62

4. Percentage of untested assessment-unit area that has potential for additions to reserves in next 30 years (%): (a necessary criterion is that total recovery per cell > minimum)
   (uncertainty of a fixed value) minimum 15 median 22 maximum 26

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves in next 30 years:
(values are inherently variable)
(mmbo for oil A.U.; bcfg for gas A.U.) minimum 0.02 median 0.5 maximum 6

AVERAGE COPRODUCT RATIOS FOR UNTESTED CELLS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil assessment unit:	minimum	median	maximum
Gas/oil ratio (cfg/bo)…………………………...…….			
NGL/gas ratio (bngl/mmcfg)……………………..….			
Gas assessment unit:			
Liquids/gas ratio (bliq/mmcfg)….……………..…….	2	4	6

SELECTED ANCILLARY DATA FOR UNTESTED CELLS
(values are inherently variable)

Oil assessment unit:	minimum	median	maximum
API gravity of oil (degrees)…………….…………			
Sulfur content of oil (%)…………………………...…			
Drilling depth (m) ……………...………………..……			
Depth (m) of water (if applicable)………………			
Gas assessment unit:			
Inert-gas content (%)……………………………....…..	0.01	0.25	0.50
CO_2 content (%)………………………………..…..	0.50	1.00	3.00
Hydrogen-sulfide content (%)……………...…….	0.00	0.00	0.00
Drilling depth (m)……………………………………	500	1485	2275
Depth (m) of water (if applicable)………………			

Success ratios:	calculated mean	minimum	median	maximum
Future success ratio (%).....	94	90	94	97

Historic success ratio, tested cells (%). 97

Appendix H. Input data form used in evaluating the Mancos-Menefee Composite Total Petroleum System, Menefee Coalbed Gas Assessment Unit (50220381), San Juan Basin Province.

FORSPAN ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATIONS--BASIC INPUT DATA FORM (NOGA, Version 8, 8-16-02)

IDENTIFICATION INFORMATION

Assessment Geologist:…	S.M. Condon	Date:	9/24/2002
Region:……………………	North America	Number:	5
Province:…………………	San Juan Basin	Number:	5022
Total Petroleum System:.	Mancos-Menefee Composite	Number:	502203
Assessment Unit:……….	Menefee Coalbed Gas	Number:	50220381
Based on Data as of:……	PI/Dwights 2001		
Notes from Assessor…..	Analog: Uinta-Piceance Mesaverde Coalbed Gas Assessment Unit (50200282)		

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-Unit type: **Oil** (<20,000 cfg/bo) **or** **Gas** (>20,000 cfg/bo) Gas
What is the minimum total recovery per cell?… 0.02 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 3
Number of tested cells with total recovery per cell > minimum: …….. 0
Established (>24 cells > min.) ______ Frontier (1-24 cells) ______ Hypothetical (no cells) X
Median total recovery per cell (for cells > min.): (mmbo for oil A.U.; bcfg for gas A.U.)
1st 3rd discovered ______ 2nd 3rd ______ 3rd 3rd ______

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an untested cell with total recovery > minimum ……	1.0
2. **ROCKS:** Adequate reservoirs, traps, seals for an untested cell with total recovery > minimum.	1.0
3. **TIMING:** Favorable geologic timing for an untested cell with total recovery > minimum………..	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……………….. 1.0

4. **ACCESS:** Adequate location for necessary petroleum-related activities for an untested cell with total recovery > minimum ……………………………………………………………… 1.0

NO. OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES IN THE NEXT 30 YEARS

1. Total assessment-unit area (acres): (uncertainty of a fixed value)
   minimum 4,317,000 median 4,797,000 maximum 5,037,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres):
   (values are inherently variable)
   calculated mean 129 minimum 40 median 120 maximum 280

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
   minimum 100 median 100 maximum 100

4. Percentage of untested assessment-unit area that has potential for additions to reserves in next 30 years (%): (a necessary criterion is that total recovery per cell > minimum)
   (uncertainty of a fixed value) minimum 1 median 9 maximum 27

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves in next 30 years:
(values are inherently variable)

	minimum	median	maximum
(mmbo for oil A.U.; bcfg for gas A.U.)	0.02	0.08	5

AVERAGE COPRODUCT RATIOS FOR UNTESTED CELLS, TO ASSESS COPRODUCTS

(uncertainty of fixed but unknown values)

Oil assessment unit:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………..…….			
NGL/gas ratio (bngl/mmcfg)…………………….….			

Gas assessment unit:	minimum	median	maximum
Liquids/gas ratio (bliq/mmcfg)…………………..….	0	0	0

SELECTED ANCILLARY DATA FOR UNTESTED CELLS

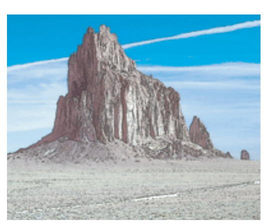
(values are inherently variable)

Oil assessment unit:	minimum	median	maximum
API gravity of oil (degrees)…………….………….			
Sulfur content of oil (%)………………………...…..			
Drilling depth (m) ……………...………………….….			
Depth (m) of water (if applicable)……………….			

Gas assessment unit:	minimum	median	maximum
Inert-gas content (%)…………………………....…..	0.10	0.30	1.00
CO_2 content (%)……………………………….....…..	0.20	4.00	15.00
Hydrogen-sulfide content (%)………………...…….	0.00	0.00	0.00
Drilling depth (m)……………………………………	90	900	1400
Depth (m) of water (if applicable)……………….			

Success ratios:	calculated mean	minimum	median	maximum
Future success ratio (%).....	70	50	70	90

Historic success ratio, tested cells (%)..___________



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