The natural gas potential of north-central New Mexico: Colfax, Mora and Taos Counties

By
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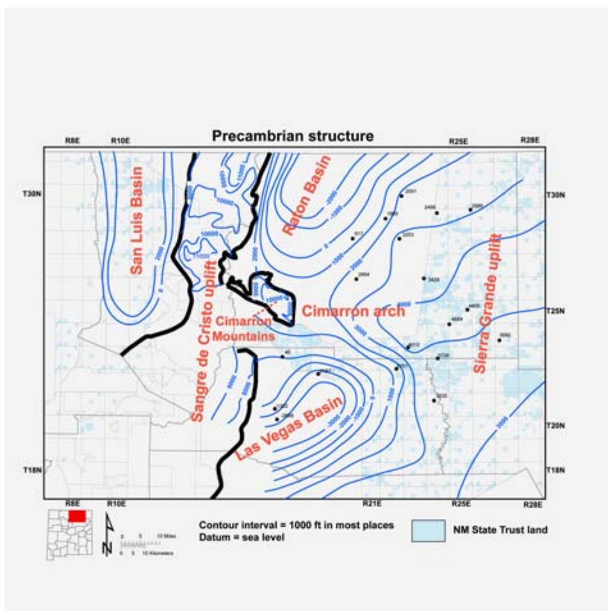
A division of New Mexico Tech



Open File Report No. 510
New Mexico Bureau of Geology and Mineral Resources
A Division of New Mexico Tech
Socorro, NM 87801
Dr. Peter A. Scholle, Director

May 2008

Work performed in cooperation with the New Mexico State Land Office
The Honorable Patrick H. Lyons, Commissioner of Public Lands

Abstract

Several major tectonic elements are present in Colfax, Mora and Taos Counties of north-central New Mexico. The Sangre de Cristo uplift trends north-south through eastern Taos and western Mora Counties and separates two basinal areas. The Raton and Las Vegas Basins are present east of the uplift. These two basins are divided by the east-west trending Cimarron arch. Precambrian basement in the Raton and Las Vegas Basins rises gradually eastward onto the Sierra Grande uplift. Both the Raton and Las Vegas Basins are Laramide in age but have Pennsylvanian ancestry. The San Luis Basin lies west of the Sangre de Cristo uplift; it is a Tertiary-age basin that is part of the Rio Grande rift.

Gas has been produced from the Raton and Las Vegas Basins. Late Cretaceous to Early Tertiary coals of the Vermejo and Raton Formations have produced 128 billion ft^3 gas. Another 173 million ft^3 gas has been produced from a single well in the Pierre and Niobrara Shales (Late Cretaceous) in the Raton Basin. On the east flank of the Las Vegas Basin, 97 million ft^3 gas have been produced from the ultra-shallow Dakota (Cretaceous) and Morrison (Jurassic) sandstones at the Wagon Mound field.

The Raton Basin has significant potential for natural gas. Additional coalbed methane is expected in undrilled parts of the Vermejo and Raton Formations. Possibilities are excellent for thermogenic shale gas in the Pierre and Niobrara Shales in the deep axial parts of the basin and for shallow biogenic gas on the east flank of the basin and adjoining parts of the Sierra Grande uplift. In addition, Dakota and Morrison sandstones are excellent reservoirs and are stratigraphically associated with source rocks. Gas may also be present in Pennsylvanian strata in a postulated Ancestral Rocky Mountain basin underneath the deeper parts of the Raton Basin.

The Las Vegas Basin holds considerable potential for natural gas in the Pennsylvanian section. This section contains up to 10,000 ft of shale and sandstone and mature organic-rich source facies are present in the shale sections. Natural gas shows have been encountered in the Pennsylvanian section by deep exploratory wells. CO_2 gas is likely to be encountered in the vicinity of Tertiary-age igneous intrusions. In addition, there is significant potential for shallow biogenic gas in Dakota and Morrison sandstones

on the east flank of the basin and on adjoining parts of the Sierra Grande uplift. Cretaceous and Jurassic sandstones hold gas potential on the shallow Cimarron arch.

Possibilities for natural gas on the Sangre de Cristo uplift are limited to the Taos trough. The Taos trough is an Ancestral Rocky Mountain basin located on the southern part of the uplift. The Taos trough is filled with Pennsylvanian sandstones and shales that have a maximum thickness of 6000 ft.

The San Luis Basin has very low potential for natural gas. In this basin, Tertiary valley-fill sandstones, clays, volcaniclastic sediments and volcanic rocks fill in the basin and rest on Precambrian basement. A Cretaceous section is not present and Paleozoic rocks appear to be absent from most or the entire basin as well. As a result, source and suitable reservoir/seal facies are absent. The only viable possibility for natural gas or oil is in a postulated northwestern extension of the Taos trough that may be present in the subsurface of the southernmost part of the San Luis Basin. However, the existence of an extension of the Taos trough is problematic and far from certain. Tertiary valley fill sediments may rest on Precambrian basement in this area as well.

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Introduction

The project area discussed in this report includes Colfax, Mora, and Taos Counties (Figure 1). Areal extent of the project area is approximately 8000 mi^2. The project area encompasses several diverse geologic elements: the Raton Basin, the Cimarron arch, the Las Vegas Basin, the western flank of the Sierra Grande uplift, the southern part of the Sangre de Cristo uplift, and the southern end of the San Luis Basin (Figure 2a). Major tectonic elements were somewhat different during the Late Paleozoic, but the present-day Raton and Las Vegas Basins both had Pennsylvanian precursors. New Mexico State Trust Lands are present chiefly along the Cimarron arch, in the northern and eastern parts of the Las Vegas Basin, on the eastern flank of the Raton Basin, on the Sierra Grande uplift, and in the San Luis Basin. There are few State Trust Lands on the Sangre de Cristo uplift, and then only on the southwestern most part of the area covered by this report. The New Mexico portion of the Sangre de Cristo uplift is covered mostly by U.S. Forest land with inliers of Native American and private land.

For purposes of this report, the description of the geology and the analysis of natural gas potential are divided into three project areas (Figure 2c):

1. ***eastern project area,*** encompassing the Raton and Las Vegas Basins, the Cimarron arch, and the west flank of the Sangre de Cristo uplift;
2. ***central project area,*** encompassing the Sangre de Cristo uplift;
3. ***western project area,*** encompassing the San Luis Basin.

The ***purpose of this report*** is to describe and analyze the geology of the investigated area and to discuss the potential for natural gas based upon the geologic description and analysis. The report consists of four parts: 1) this text, with included maps, cross sections and tabular data; 2) Appendix A that contains databases of well data (***northcentralwells.xls***) and petroleum source rock data and analyses (***northcentral source rocks.xls***); 3) Appendix B that contains five regional cross sections based on well logs as well as description of well cuttings; and 4) Appendix C that contains large-format versions of selected maps presented in the text that may be printed out at large scale and used as working maps by the reader.

The written part of this report is structured somewhat unconventionally. A synopsis of the natural gas potential of the eastern, central and western project areas is presented after this introductory section. The synopsis is presented early and takes the place of a conclusions section, traditionally presented at the end of the report. The synopsis is followed by a brief section that summarizes aspects of methodology used in this report. The methodology section is, in turn, followed by the main body of the report. First in the main body is a section on the Eastern project area, including subsections on structure, stratigraphy, petroleum source rocks, hydrocarbon occurrences (production and shows of natural gas and oil), and natural gas potential. Second in the main body is a short section that describes the geology, petroleum geology and natural gas potential of the Central project area. This section is abbreviated because of the paucity of State Trust lands in the Central project area. Third (and finally) comes a short section that describes the geology and natural gas potential of the western project area; this section is relatively short because of the very limited potential for natural gas in the area.

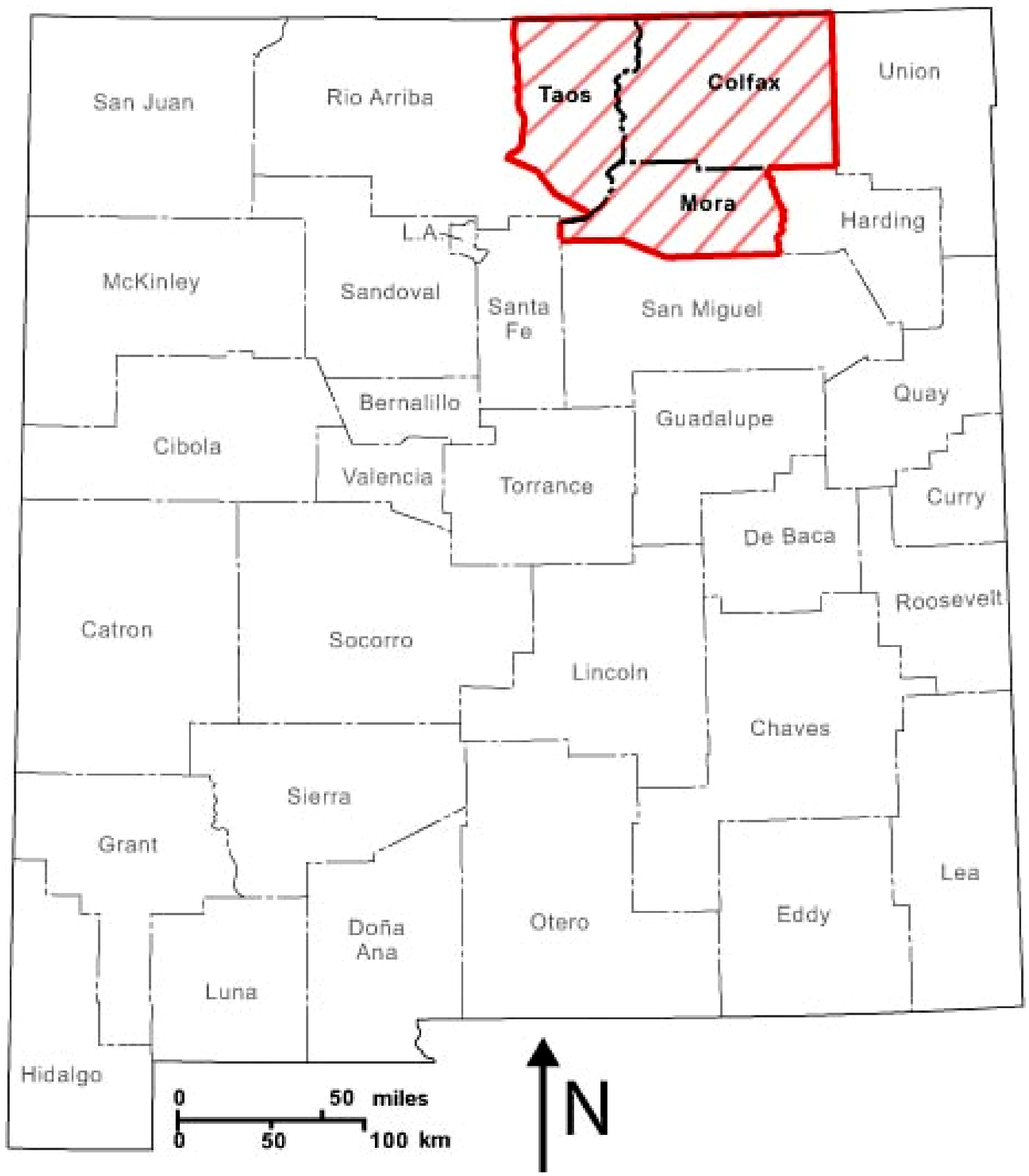

Figure 1. Location of project area within New Mexico.

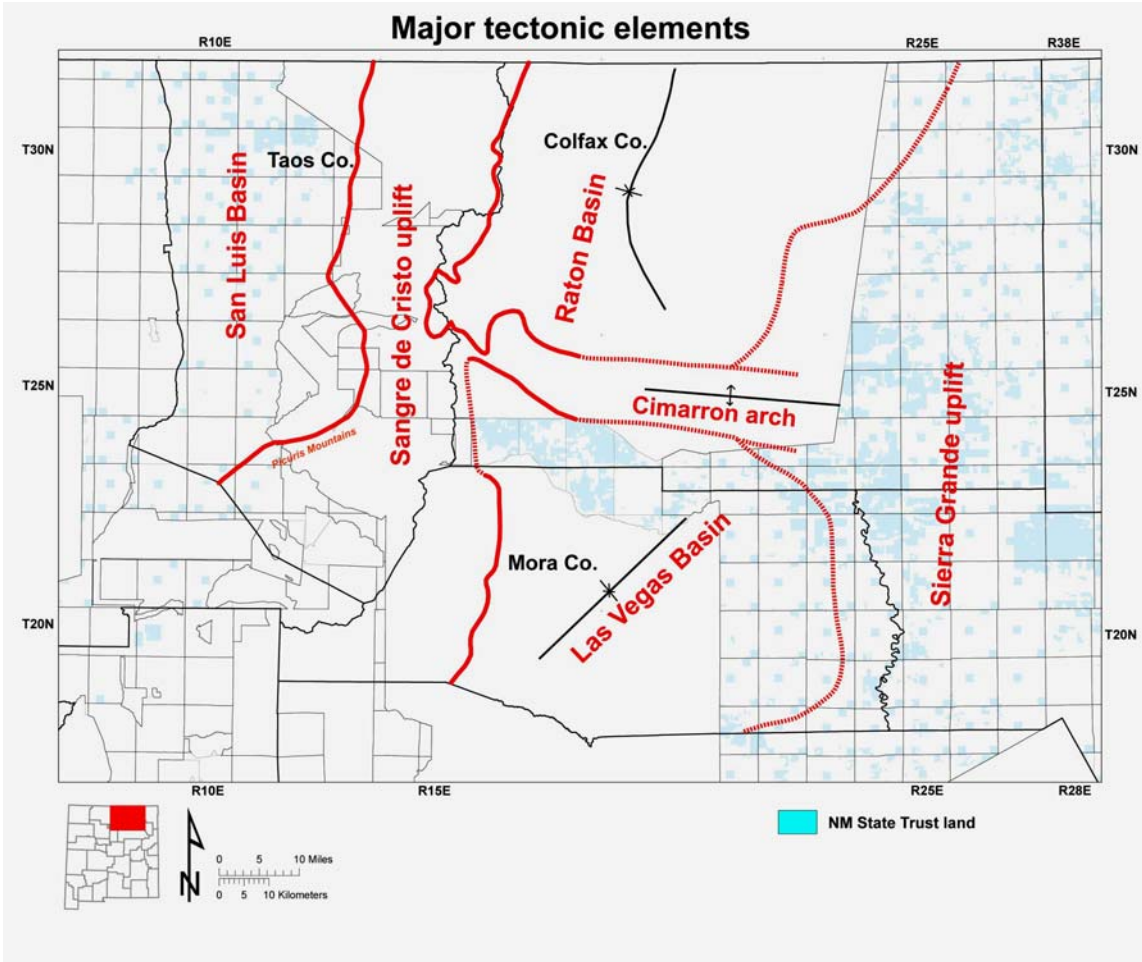

Figure 2a. Major Cenozoic tectonic elements in north-central New Mexico.

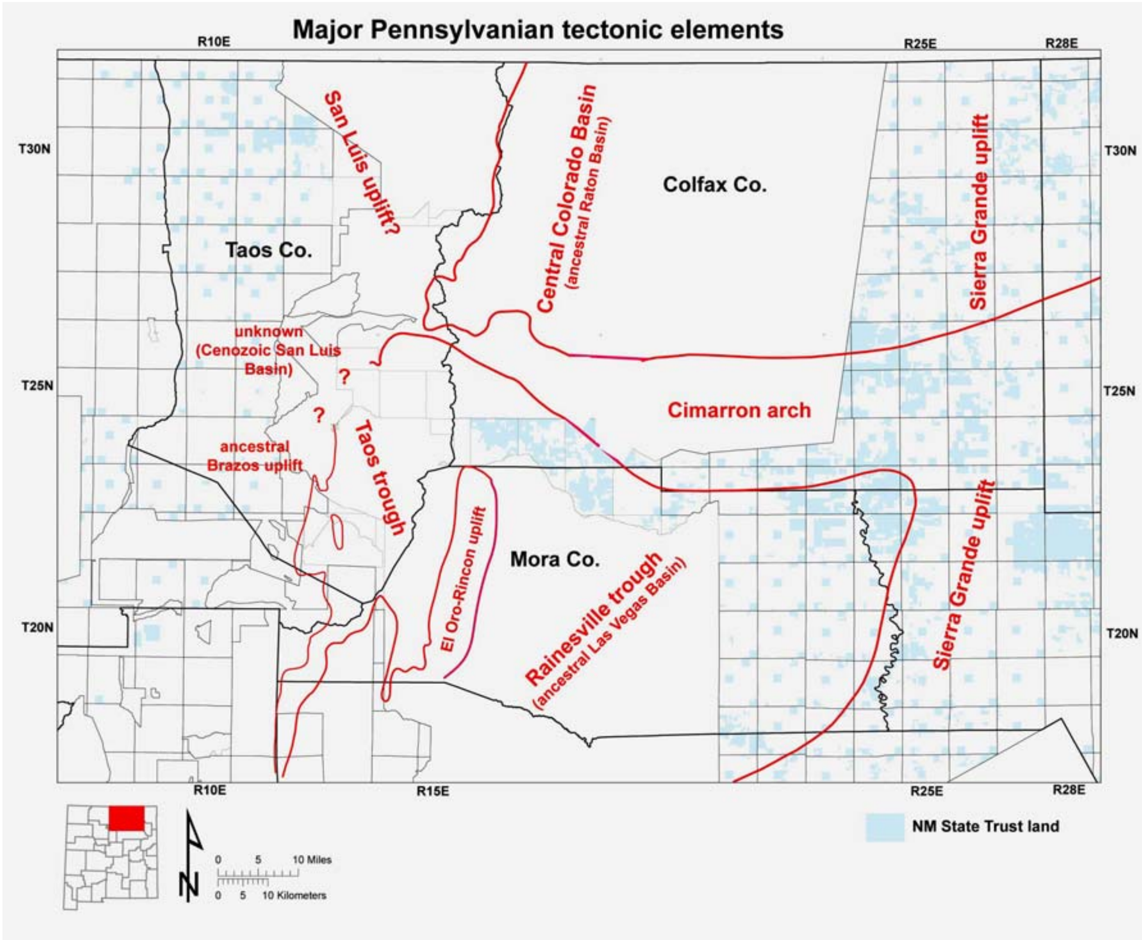

Figure 2b. Major Pennsylvanian-age tectonic elements in north-central New Mexico. Modified from Baltz and Myers (1999).

Acknowledgments

The work that resulted in this report was funded in-part by the New Mexico State Land Office (The Honorable Patrick H. Lyons, Commissioner of Public Lands) through Professional Services Contract No. 08-539-P615-6109 to the New Mexico Institute of Mining and Technology (New Mexico Tech). John Bemis, Jami Bailey and Joe Mraz of the New Mexico State Land Office were most helpful in the initiation of this project.

My appreciation extends to Mr. Dan Jarvie of Humble Geochemical Services for expediting those petroleum source rock analyses prepared specifically for this project (other, pre-existing analyses were obtained from the New Mexico Petroleum Source Rock Database; Broadhead and others, 1998). Tim Ruble of Humble Geochemical

Services provided helpful and thoughtful suggestions concerning the analyses. As always, my appreciation extends to Amy Kracke and Annabelle Lopez of the New Mexico Bureau of Geology and Mineral Resources for their meticulous efforts for maintaining the archives of well information, cuttings and cores in the New Mexico Library of Subsurface Data at the New Mexico Bureau of Geology and Mineral Resources. Peter Scholle, Director of the New Mexico Bureau of Geology and Mineral Resources, supported the production of this report. Lewis Gillard of the New Mexico Bureau of Geology and Mineral Resources digitized the maps in this report (hand-drawn) so that they could be prepared in digital, drafted format for this report.

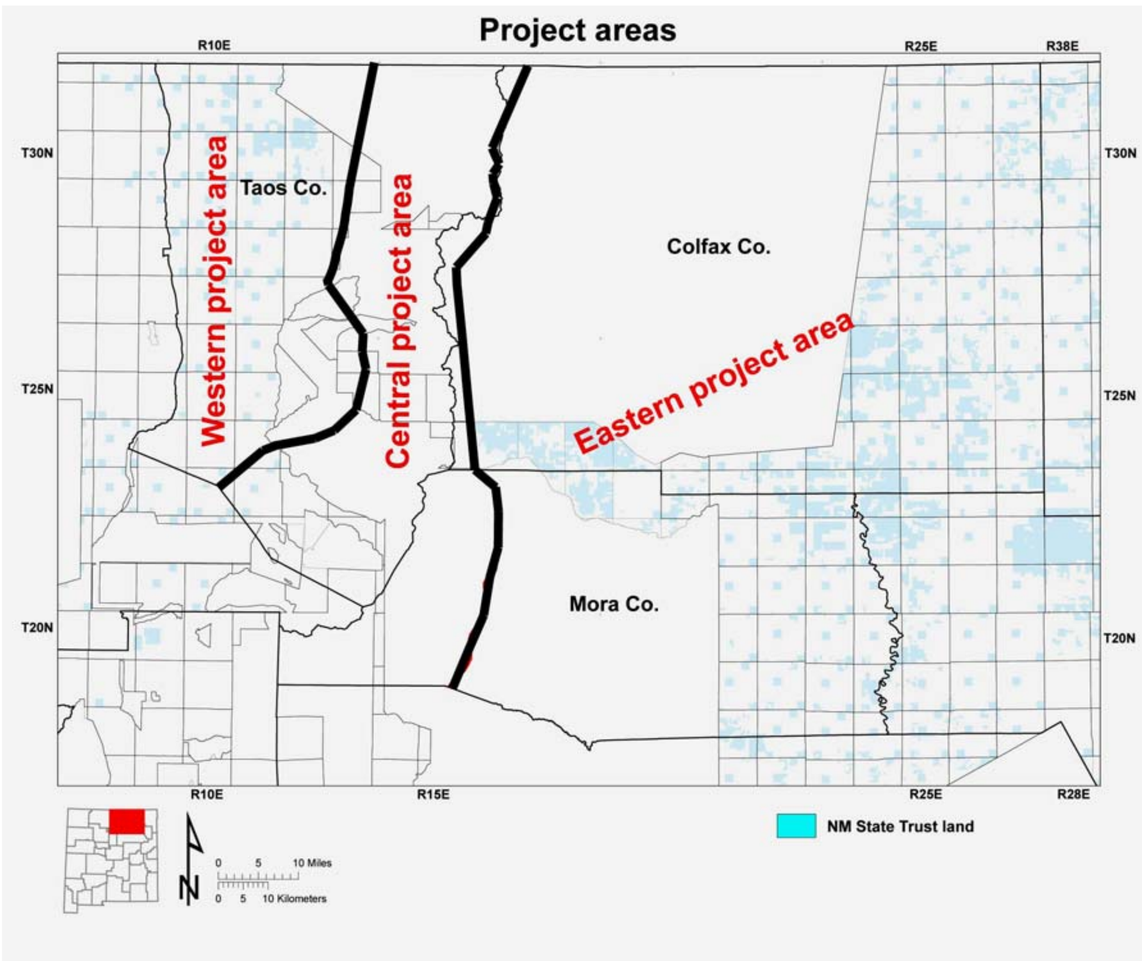

Figure 2c. Project areas within north-central New Mexico and known oil and gas accumulations.

Synopsis of Natural Gas Potential

Eastern project area: Significant volumes of natural gas have been produced from the eastern project area. In this region, modest volumes of gas (cumulative 97 MMCF) have been produced from Dakota (Cretaceous) and Morrison (Jurassic) sandstones at the Wagon Mound field on the eastern flank of the Las Vegas Basin (Figures 3, 4). Modest volumes of natural gas (cumulative 173 MMCF) have also been produced from the Pierre and Niobrara Shales in a single well located in the north-central part of the Raton Basin (Figures 3, 4). In the past decade, major volumes of coalbed methane (128 BCF cumulative) have been produced from the Vermejo (Upper Cretaceous) and Raton (Upper Cretaceous to Paleocene) in the north-central Raton Basin, along with subsidiary production of natural gas from the Trinidad Sandstone (Upper Cretaceous; Figures 3, 4).

Abundant gas source rocks are present in the Raton Basin. Obvious amongst these are the coals of the Vermejo and Raton Formations. In addition, organic-rich Upper Cretaceous shales (Pierre, Niobrara, Carlile, Graneros) are in the thermal gas window in the deeper part of the Raton Basin and are in the biogenic gas window along the shallow eastern flank of the basin. Shale gas is an exploration target in the shale units and the Graneros may be a significant gas source for a Graneros-Dakota petroleum system in which the Dakota sandstones form the reservoirs; the gas would be generated thermally in the deeper parts of the basin and biogenically on the shallow eastern flank and adjacent parts of the Sierra Grande uplift.

Shales of the Morrison Formation (Jurassic), generally devoid of significant percentages of kerogen, have an organic-rich facies in the deeper parts of the Raton Basin. The organic-rich dark-gray shale facies contains source rocks within the thermal gas window. Interbedded sandstones are exploration targets. Exploratory wells drilled on the shallow eastern flank of the Raton Basin, outside of the area encompassed by the Morrison source facies, have encountered oil and gas shows in the Morrison, indicating hydrocarbons have migrated through this area and may be trapped in structural reversals or in stratigraphic pinchouts associated with onlap onto the Sierra Grande uplift. The obvious source for the hydrocarbons encountered in the shows is the Morrison dark-gray

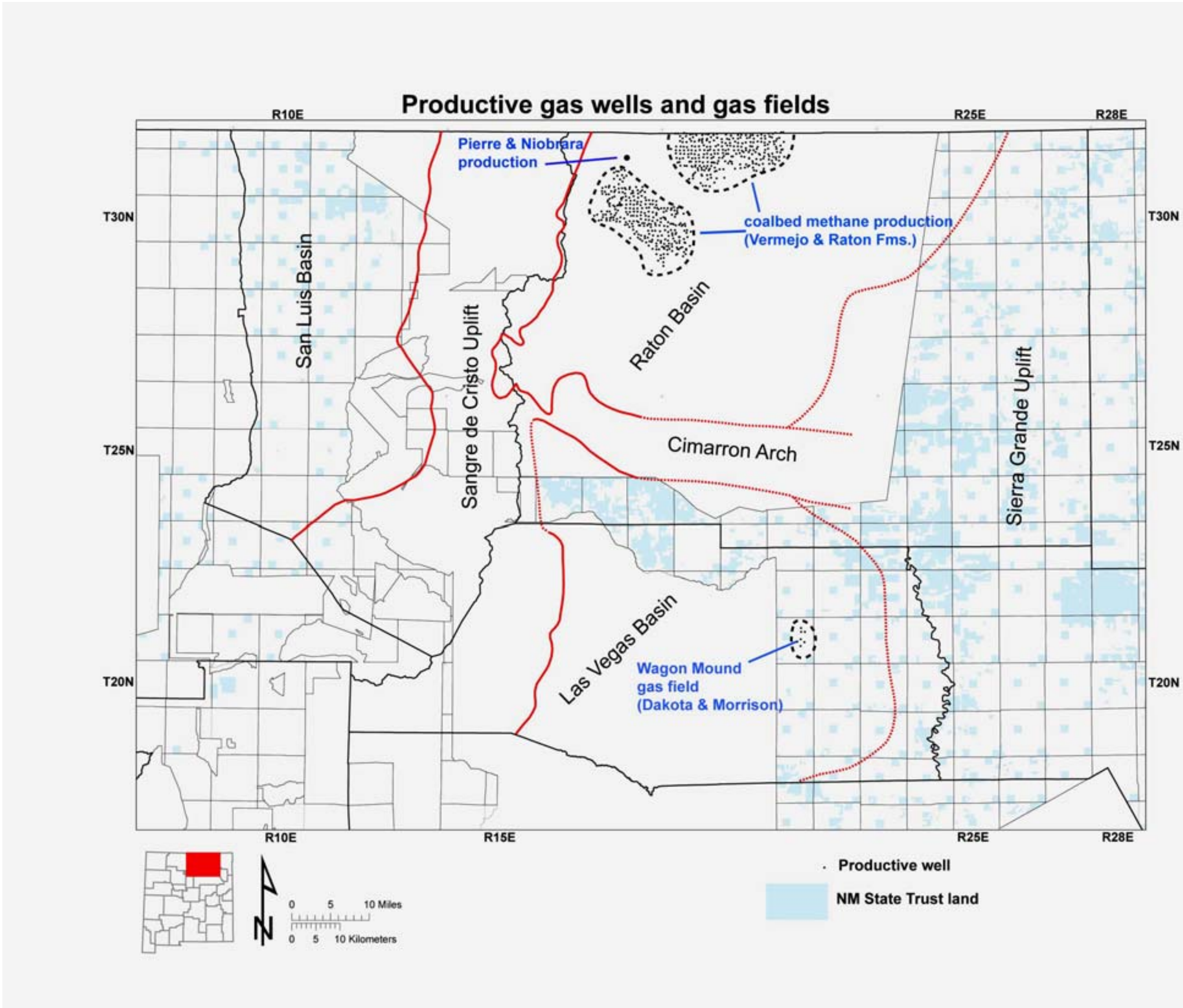

Figure 3. Productive gas wells and gas fields in north-central New Mexico.

Age		Stratigraphic units	Thickness (feet)	Description
Quaternary		Alluvial, fluvial, eolian & pediment deposits, basalt flowa		
Tertiary	Pliocene, Miocene, Oligocene, Eocene	Intrusive & extrusive rocks of various ages		laccoliths, sills, dikes, stocks
Tertiary	Paleocene	Poison Canyon Fm.	0 - 500	sandstone, conglomeratic ss, mudstones, claystones
		Raton Fm.	800 - 2000	lenticular coarse ss, shales. coals
Cretaceous	Upper	Vermejo Fm.	150-330	Gray to green, fine-coarse ss, gray carbonaceous shales, lenticular coals
		Trinidad Ss.	40-260	White-green-brown fine-coarse ss, dark-gray carbonaceous shales
		Pierre Shale	1600 - 2700	Dark-gray marine shales, minor miscritic ls, thine fine-grained ss
		Niobrara Shale	500 - 1000	Dark-gray marine shales, minor miscritic ls, thin fine-grained ss
		Fort Hays Limestone	10-100	Medium to dark-gray limemudstones & wackestones dark gray marine shale
		Carlile Shale	20-220	Very dark-gray marine shale, minor siltstone & micritic limestones
		Greenhorn Limestone	10-200	Medium to dark-gray lime mudstones and calcareous shales
		Graneros Shale	90-200	dark-gray marine shales, minor thin siltstones & micritic limestones
	Lower	Dakota Sandstone	50-250	Fine to medium quartzose ss, carbonaceous shale
Jurassic	Upper	Morrison Fm.	300 - 435	Red, brown, blue-gray, dark-gray nonmarine shales; fine to medium white to green ss
	Middle	Entrada Ss.	20 - 150	Fine to medium, white, quartzose ss
Triassic	Upper	Chinle Group	200-850	Red nonmarine shales, minor dark-gray shale, minor fine to medium nonmarine ss
		Santa Rosa Sandstone	30 - 220	Gray, fine to coarse nomarine ss and red shale
	Middle	Moenkopi Fm.	0 - 240	Red shales, fine to medium quartzose lenticular ss
Permian	Guadalupian	Bernal Fm.	30 - 160	Red-maroon shale, fine -medium lenticular quartzose ss
	Leonardian	Glorieta Ss.	40 - 400	Fine-medium white quartzose ss
		Yeso Fm.	80 - 500	Red silty shale, orange to white fine-medium ss
	Wolfcampian	Sangre de Cristo Fm.	0 - 8800	Coarse-grained conglomeratic arkosic ss. Red shales. dark-gray shales in some areas.
Pennsylvanian	Virgilian, Missourian	Madera Group		Fine to coarse ss, many arkosic dar-gray to black shale & red shale. Marine limestone.
	Des-moinesian, Atokan, Morrowan	Sandia Formation		Fine to coarse ss, many arkosic dar-gray to black shale & red shale. Marine limestone.
Mississippian		Arroyo Penasco Formation	0 - 160	Marine limestone, minor fine-coarse quartzose ss
Precambrian				quartzite, schist, gneiss, granite, granodiorite, amphibolite, gabbro, tonalite

Figure 4. Stratigraphic column of rocks present within project area. Not all strata are present in all parts of the project area. See discussions on eastern, central and western areas for more information.

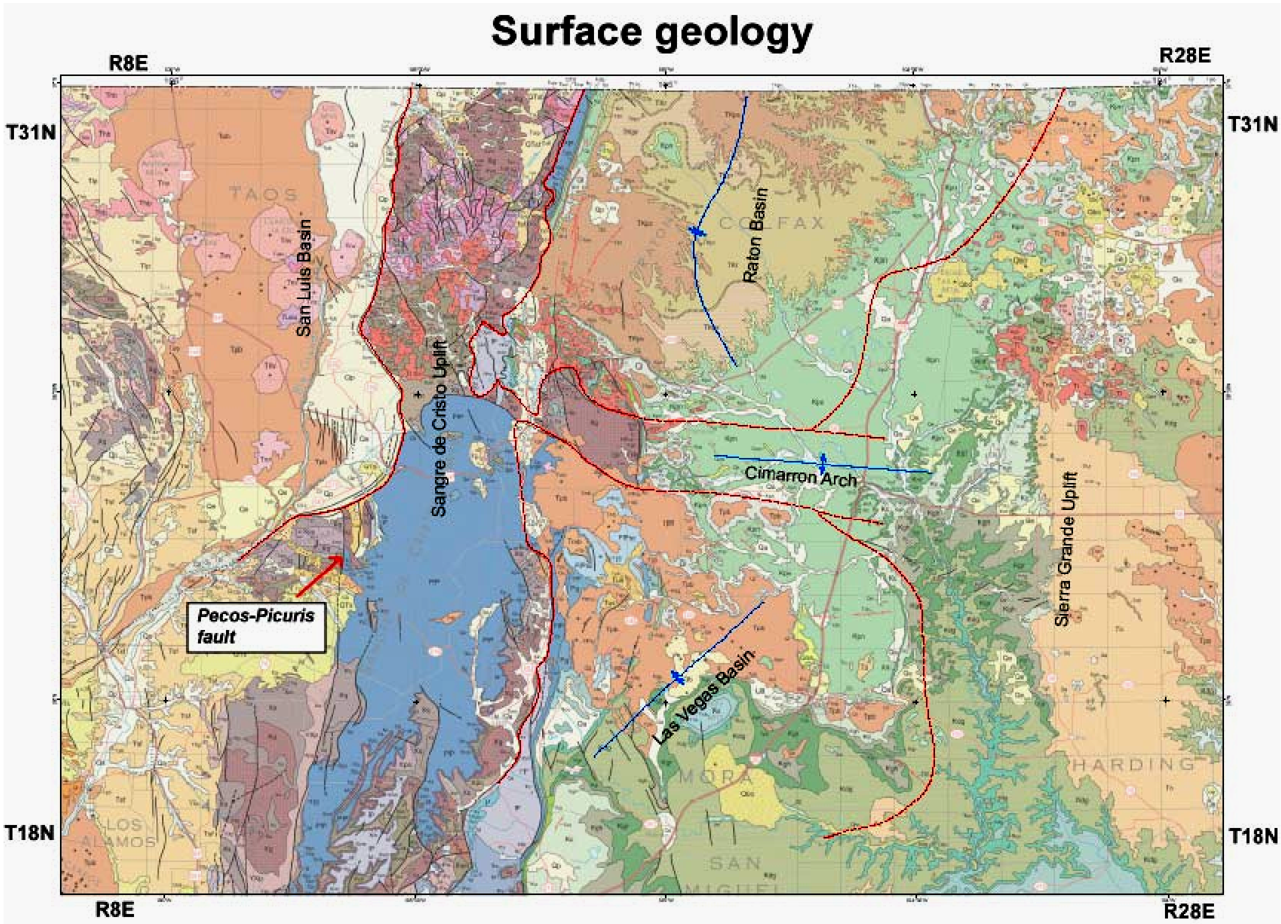

Figure 5. Surface geologic map of study area (from New Mexico Bureau of Geology and Mineral Resources, 2003) with major Cenozoic tectonic elements superimposed.

shale facies in the deep part of the basin. The Cimarron arch, penetrated by few wells and essentially untested at the Morrison level, holds potential for entrapment of basin-generated hydrocarbons in the Morrison as well as in the shallower Dakota sandstones (generated in the Graneros Shale).

Other opportunities for traps in the Raton Basin exist along the western flank of the basin. In this area, Cretaceous, Jurassic, Triassic and Paleozoic strata have been upturned and truncated by the Laramide reverse to thrust faults that form the western margin of the basin. In many places, however, the upturned strata are exposed along an outcrop belt just east of the bounding basinal faults (Figure 5).

The deep, axial part of the Raton Basin lies along the north-south trend of the Central Colorado Basin, an Ancestral Rocky Mountain basin of Pennsylvanian age that is documented in Colorado. No wells have been drilled to a sufficient depth to penetrate Upper Paleozoic strata in the deep part of the Raton Basin in New Mexico. However, analogy to other Ancestral Rocky Mountain basins in New Mexico, as well as the presence of marine Pennsylvanian strata in the mountains to the west of the Raton Basin, suggests that organic-rich shale source rocks may be present at depth. If so, they would be in the thermogenic gas window.

Triassic reservoirs and Entrada Sandstone (Middle Jurassic) in the Raton Basin are characterized by a CO_2-water system instead of a hydrocarbon-water system. Wells are characterized by CO_2 shows instead of hydrocarbon shows. There are no significant source rocks stratigraphically associated with the Entrada Sandstone or with Triassic sandstones. The CO_2 probably originated by degassing of rising magmas that formed the numerous intrusive and extrusive igneous bodies of Tertiary and Quaternary age in the basin. The Triassic sandstones and Jurassic Entrada Sandstone therefore form substantial targets for exploration for CO_2 resources. Conversely, they may also be targets for sequestration of CO_2 gas.

The Las Vegas Basin, located south of the Cimarron arch, has a significantly different petroleum setting than the Raton Basin. In the Las Vegas Basin, the lower part of the Cretaceous section and the Jurassic section have been preserved in the eastern part of the basin where they crop out at the surface (Figure 5). In these areas, the middle and upper parts of the Cretaceous section have been removed by Laramide and post-Laramide erosion. Biogenic methane has been produced from Dakota (Cretaceous) and Morrison (Jurassic) sandstones on the eastern flank of the basin at the Wagon Mound field. Significant potential for low-volume, low-pressure gas in these reservoirs, with a biogenic source in the Graneros Shale, exists on the eastern flank of the Las Vegas Basin as well as on adjacent parts of the Sierra Grande uplift.

Pennsylvanian and Lower Permian strata of the Sandia Formation, Madera Group, and Sangre de Cristo Formation crop out in the western part of the Las Vegas Basin. In the central and western parts of the basin, the Pennsylvanian section contains thick sequences of organically rich, dark-gray to black shales. In the deeper parts of the basin, these are in the thermogenic gas window. In shallower areas, they are within the oil window. Depending on structural position, potential is present either for thermogenically-generated gas or oil and associated gas. Traps may be stratigraphic or potentially associated with east-vergent thrust faults that have repeated the Pennsylvanian section. Large bodies of Tertiary-age intrusive rocks are associated with CO_2-rich gases that exsolved from the rising magmas that formed these intrusive bodies. Halos of CO_2-rich gases are expected to be present around these intrusives.

Central project area: The central project area consists of the Sangre de Cristo uplift. No natural gas or oil have been produced from this project area and no petroleum exploration wells have been drilled in this area. Some possibilities for natural gas are present in the easternmost part of the area where reverse faults have displaced Precambrian basement upward and emplaced them over Pennsylvanian strata in the Raton and Las Vegas Basins. Potential traps are in upturned strata truncated along the footwall of these reverse faults. Potential for natural gas also exists in the Taos trough in the southern part of the Sangre de Cristo uplift. Up to 6000 ft of Pennsylvanian shales and sandstones are present in this northwest-trending Pennsylvanian-age basin. Thick sections of organically-rich shales are present that appear to be thermally mature, at least at depth. Sandstones are potential reservoir targets and possibilities exist for shale gas in the thick shale sections in the deeper parts of the Taos trough.

Western project area: The western project area is coincident with the eastern part of the New Mexico portion of the San Luis Basin. The San Luis Basin is one of the northernmost basins of the Rio Grande rift and was formed during the Tertiary by extensional tectonics. It extends northward from New Mexico into Colorado. No petroleum exploration wells have been drilled in the New Mexico part of the San Luis Basin. The area it occupies was a Laramide-age high and the Cretaceous section was removed by erosion subsequent to Laramide uplift. Therefore, no Cretaceous sedimentary rocks, which produce in the Raton Basin to the east and the San Juan Basin to the west, are present in the San Luis Basin. Paleozoic rocks are absent from the Colorado part of the basin and appear to be absent from most or all of the New Mexico part of the basin as well. There is a possibility, somewhat low, that Pennsylvanian shales and sandstones of a western extension of the Taos trough have been downdropped by Tertiary-age faulting and are present in the southernmost part of the San Luis Basin. If this is the case, then shale source rocks would be present and would have generated gas or oil and associated gas. This constitutes the only possibility for natural gas within the San Luis Basin. If a western extension of the Taos trough is not present under the San Luis Basin, then the entire western project area would have a very low natural gas potential because identifiable petroleum source rocks are nil.

Methodology

Stratigraphic Data and Correlations

All stratigraphic data from wells used to construct the various maps presented in this report are presented in the well database (*northcentralwells.xls*) that is included in Appendix A of this report. Stratigraphic units were defined in the subsurface on the basis of work published by various authors (identified at appropriate points in this report) in outcrops of the Sangre de Cristo Mountains and to a lesser extent in wells drilled in the Raton and Las Vegas Basins. Outcrop studies predominate and subsurface studies generally present only sparse and generalized information. A series of cross sections (Figure 6; Plates I-V, Appendix B) were prepared based on log correlations of lithostratigraphic units identified by examining well cuttings, using previously published studies as a reference for correlations. The well cuttings used are preserved in the New Mexico Library of Subsurface Data at the New Mexico Bureau of Geology and Mineral Resources. As a result the presented cross sections are believed to reflect subsurface stratigraphic variations with a high degree of fidelity. After the cross sections were prepared, other wells used in the study were correlated and stratigraphic tops were entered into the well database.

Contour Maps

All structure and isopach contour maps were hand contoured. The hand contours were then digitized and converted to the various maps presented in this report and in Appendix C. Contours were constructed according to accepted methods of contouring. Additional information on contouring techniques is included in the section on structure for the eastern project area. Wells were plotted on the basis of latitude and longitude calculated from section-township-range locations. Latitude-longitude locations can be found in the well database in Appendix A.

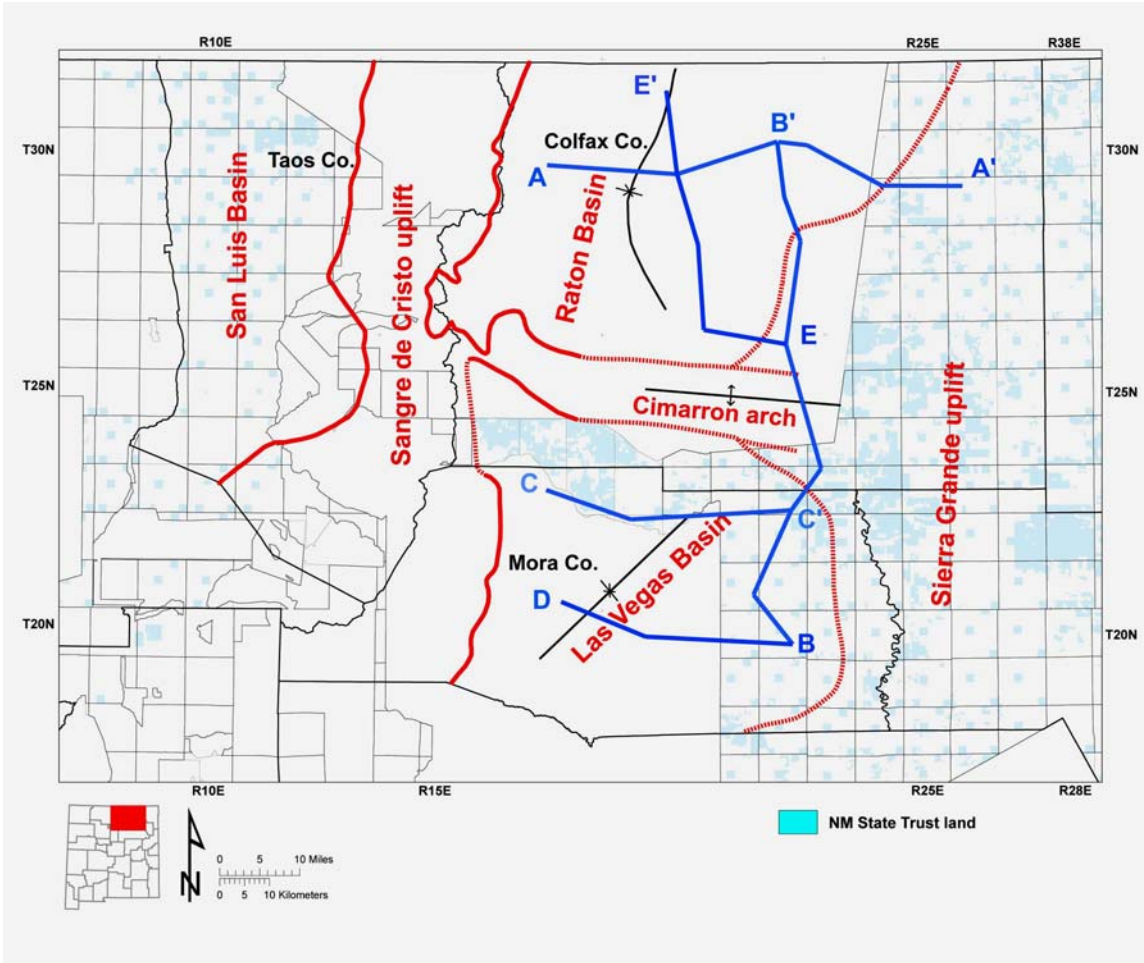

Figure 6. Locations of regional cross sections prepared for this project. Cross sections are presented as Plates I-V in Appendix B.

Petroleum Source Rock Analyses

A *petroleum source rock* can be defined as any unit of rock that has generated and expelled oil and/or gas in commercial quantities (Hunt, 1996). When assessing source-rock potential, four questions must be answered (Dow, 1978; Barker, 1980; Brooks et al., 1987; Hunt, 1996). First, does the rock have sufficient organic matter? Second, is the organic matter capable of generating petroleum and, if so, is it oil prone or gas prone? Third, is the organic matter thermally mature? Fourth, have generated hydrocarbons been expelled from the rock?

The question of whether or not the rock has sufficient organic matter to be considered a source rock can be answered on the basis of total organic carbon (TOC) measurements. Rocks that have insufficient TOC content can be rule out as possible source rocks. Jarvie (1991) has summarized TOC ratings systems for screening potential source rocks (Table 1). The TOC content needed for petroleum generation is thought to be greater in siliciclastic shales than in carbonate source rocks.

The second question asks what type of organic matter is present within the rock. The type of organic matter, if present in sufficient quantity, will determine if a source rock will produce principally oil or principally gas upon maturation (Table 2). For this project, identification of organic-matter type was based mainly on petrographic analyses of kerogen concentrate. Algal, herbaceous, and much amorphous kerogen (kerogen types I and II) will generate oil and associated gas upon maturation (Hunt, 1996; Brooks et al., 1987; Tyson, 1987). Woody kerogen (kerogen type III) and some amorphous kerogen will generate gas and possibly a minor amount of oil or condensate upon maturation. Inertinites are type IV kerogens that have extremely low hydrogen contents and are incapable of generating significant amounts of hydrocarbons. Although it is possible to differentiate kerogen types I, II, and III using Rock-Eval pyrolysis (e.g. Tissot and Welte, 1978; Peters, 1986), some type III kerogens may be confused with other types of kerogens and result in misleading characterization of kerogen types when using pyrolysis (Tyson, 1987). Oxidation of kerogen may also alter its Rock-Eval character. Also, pyrolysis cannot discern the different varieties of kerogens present in samples with mixed kerogen assemblages. For these reasons, Rock-Eval pyrolysis was used only as reinforcement for petrographically determined kerogen identification.

The level of thermal maturity can be evaluated using visual kerogen analyses. Kerogen color changes from yellow to orange to brown to black with increasing maturation (Staplin, 1969). Based on calibrated color charts, the sample is assigned a numerical value (Thermal Alteration Index or TAI), which ranges from 1.0 (immature) to 5.0 (metamorphosed; Table 3). This is a standard method of determining thermal maturity that can be used to confirm measurements made with other techniques (see Hunt, 1996; Peters, 1986). For this study, TAI determinations were available for only a few samples. As such, they were used as baseline measurements of thermal maturity that could be used to confirm thermal maturity determinations derived from less expensive Rock-Eval pyrolysis techniques.

Vitrinite reflectance (Ro) is a measure of the percentage of incident light that is reflected from the surface of vitrain, a type of woody kerogen. It can be used to assess thermal maturity of a source rock and is a standard measurement of maturity. Vitrinite reflectance increases with thermal maturity of a source rock. It is considered by many to be one of the most reliable techniques for determining thermal maturity of source rocks. Vitrinite reflectance measurements were made for one well in this study (The El Paso natural Gas No. 7 WDW, located in Sec. 1 T31N R19E) so that the top and bases of the oil window, the wet gas + dry gas window, and the dry gas window could be accurately determined for the Cretaceous section in the deep axial part of the Raton Basin. An analysis of AOM conversion (the amount of kerogen that has been converted to hydrocarbons was provided by Dr. Tim Ruble of Humble Geochemical Services as an accompaniment to the vitrinite reflectance analysis. The measurements were of whole rock vitrinite.

Table 1. Generation potential of petroleum source rocks based on TOC content. From Jarvie (1991).

Generation potential	TOC in shales (weight percent)	TOC in carbonates (weight percent)
Poor	0.0 - 0.5	0.0 - 0.2
Fair	0.5 - 1.0	0.2 - 0.5
Good	1.0 - 2.0	0.5 - 1.0
Very good	2.0 - 5.0	1.0 - 2.0
Excellent	> 5.0	> 2.0

Table 2. Kerogen types and petroleum products produced upon thermal maturation. Based on summary works of Merrill (1991) and Tyson (1987).

<table>
<tr><th>General kerogen type</th><th>Kerogen type</th><th>Petrographic form</th><th>Coal maceral group</th><th>Hydrocarbons generated</th></tr>
<tr><td rowspan="4">sapropelic
(oil prone)</td><td rowspan="2">I</td><td>algal</td><td rowspan="4">exinite
or
liptinite</td><td rowspan="4">oil, gas</td></tr>
<tr><td rowspan="2">amorphous</td></tr>
<tr><td rowspan="2">II</td></tr>
<tr><td>herbaceous</td></tr>
<tr><td rowspan="2">humic
(gas prone)</td><td>III</td><td>woody</td><td>vitrinite or
huminite</td><td>gas,
possibly
minor oil</td></tr>
<tr><td>IV</td><td>coaly
(inertinite)</td><td>inertinite</td><td>none</td></tr>
</table>

Rock-Eval pyrolysis can also be used to evaluate thermal maturity but with less certainty. The temperature at which the maximum amount of hydrocarbons is generated from the S_2 peak (TMAX, ^{o} C) has been correlated to the thermal maturity of the source rock (Peters, 1986; Table 3). This method, although quantitative, does not give as complete an evaluation of maturity as TAI and only places a sample as being within, above, or below the oil window. Also, the measured value of TMAX is partially dependent upon the type of organic matter present as well as numerous other factors and can be erroneous if the S_2 peak is bimodal or flat (see Peters, 1986; Hunt, 1996).

The Rock-Eval Productivity Index is also a measure of the thermal maturity of a source rock. The Productivity Index is a calculated value based on the S_1 and S_2 peaks of the Rock-Eval analysis and is calculated by the following equation:

$$PI = S_1/(S_1 + S_2)$$

Where: S_1 = the amount of free hydrocarbons present in the sample, as determined through pyrolysis, in mg HC/g sample,
S_2 = the amount of hydrocarbons formed by the thermal breakdown of the kerogen in the sample when the kerogen is heated during the analytical process.

The Productivity Index is essentially a measure of the amount of hydrocarbons that have been generated compared to the total amount of hydrocarbons that could be generated from a sample given maturation to the overmature stage. The Productivity Index is sensitive to a number of factors, especially the presence of hydrocarbons that contaminate the sample during the drilling process or the presence of hydrocarbons that have migrated into the sample from elsewhere by natural processes. The presence of hydrocarbon-derived contamination or migration will lead to an artificially large S_1 value that will result in an artificially high estimate of thermal maturity. Analyses with unreasonably high S_1 values should be examined carefully and not used if it is determined that the high S_1 value is a result of the presence of contaminant hydrocarbons or migrated oil. One sample analysis was rejected for this reason; on the advice of Humble Laboratories, the sample was re-analyzed after solvent extraction that removed contaminant hydrocarbons. Use of the Productivity Index as a maturation parameter should be confirmed with another standard method of estimating thermal maturity.

The fourth question concerns the expulsion of generated hydrocarbons from the source rock. This question is more difficult to answer than the other three questions. For the most part, studies of thermal maturity of a source rock are empirically correlated with the presence of oil in associated reservoirs. It is generally assumed that once a sufficient volume of hydrocarbons have been generated in a source rock, they will be expelled and migrate into reservoirs. Reservoirs that are thinly interbedded with reservoirs will expel hydrocarbons at lower levels of thermal maturity than thick source rocks that contain few or no interbedded reservoirs (Leythauser et al., 1980; Cornford et al., 1983; Lewan, 1987).

For this report, petroleum source rock parameters were not contoured on maps because of the numerous stratigraphic units involved which may contain source facies. Funding limitations precluded obtaining a sufficient number of analyses to contour all possible source units. Instead, the source rock analyses were plotted on vertical profiles of the wells that indicate stratigraphy, depth, total organic carbon measurement, a maturation parameter associated with analyses made on each well, and interpreted tops and bases of the biogenic gas window, oil window, thermogenic wet gas + dry gas window, and thermogenic gas window. These source rock profiles are presented as illustrations at appropriate points in the text. The source rock profiles were also used, in conjunction with the structure contour maps prepared for this report, to construct a series of structural cross sections that indicate the relationship of the various maturation windows to structural position of source units in the Raton and Las Vegas Basins. These source-rock cross sections are also presented as illustrations at appropriate points in the text.

Table 3. Correlation of maturation parameters with zones of hydrocarbon production. Based on Geochem Laboratories, Inc. (1980), Sentfle and Landis (1991), Peters (1986), Mukhopadhyay (1994), Peters and Cassa (1994), and Hunt (1996).

Maturation level (products generated)	Thermal Alteration Index (TAI)	Vitrinite Reflectance R_o	Rock-Eval Productivity Index (PI)	Rock-Eval TMAX (^oC)
Biogenic gas window	1.0 – 2.3	< 0.6		< 430
Oil window (upper part)	2.3 - 2.7	0.5 – 0.7	< 0.1	430 - 440
Oil window (lower Part)	2.7 - 3.3	0.7 - 1.3	0.1 – 0.4	440 - 470
Wet gas + dry gas window	3.3 – 3.7	1.3 - 2.0	> 0.4	470 - 530
Dry gas window	3. - 4.9	> 2.0		> 530
Metamorphosed	5.0			

Sampling methods

Source rock **a**nalyses for this project were obtained from samples of drill cuttings. Because of the limited volumes of samples available, cuttings were analyzed from several 10 ft intervals that were combined in order to increase the volume of sample available. Cuttings from non-source lithologies such as sandstone or cavings from shallower strata were excluded from the sample prior to analysis as was extraneous material present in the samples such as material added to the drilling fluid to prevent lost circulation. Most analyses were performed on composite cuttings over a 100 ft depth interval. Because of the sampling methodology, TOC analyses can be considered to be an average of the shales over the 100 ft composite interval; because TOC will not be distributed evenly over the entire 100 ft interval, some of the shales in the 100 ft in the interval will undoubtedly have a TOC less than what the analysis yielded and other shales within the 100 ft interval will have a TOC greater than what the analysis yielded.

Analyses on a number of samples used in this study were obtained from the New Mexico Petroleum Source Rock Project (Broadhead et al, 1998). Most of those analyses were performed by Geochem Laboratories, Inc. as part of the New Mexico Petroleum Source Rock project and include petrographic determination of kerogen type and Thermal Alteration Index in addition to Total Organic Carbon and Rock-Eval pyrolysis. For this project, Total Organic Carbon, Rock-Eval, and Whole-Rock Vitrinite Reflectance analyses were performed on additional samples by Humble Laboratories, Inc. of Humble, Texas. The sources of the analyses are identified in the Source Rock Database (*northcentralsourcerocks.xls*), which is presented in Appendix A.

Eastern area – Raton and Las Vegas Basins, Cimarron arch, Sierra Grande uplift

Structure

Four structure contour maps of the eastern area were prepared for this report (Figures 7-10): 1) top of the Trinidad Sandstone (Upper Cretaceous); 2) top of the Dakota Sandstone (Cretaceous); 3) top of the Glorieta Sandstone (Permian); and 4) top of Precambrian basement. The maps were prepared primarily with the subsea elevation of stratigraphic units obtained by making detailed correlations on approximately 200 of the 788 exploratory and development wells that have been drilled within the project area. Surface geology as portrayed on the state geologic map of New Mexico (New Mexico Bureau of Geology and Mineral Resources, 2003) as well as the surface geologic map of the Raton 30’ x 60’ quadrangle (Scott and Pillmore, 1993) proved invaluable in shaping contours and, in conjunction with topographic contour maps published by the U.S. Geological Survey, in determining structural elevations of contoured map units where they crop out at the surface. The aeromagnetic anomaly map of New Mexico (Cordell, 1983) and Bouguer gravity anomaly map of New Mexico (Keller and Cordell, 1983) were used to guide contouring and were especially useful in the shaping of contours on Precambrian basement. However, the large bodies of intrusive igneous rocks of Tertiary age and the variation in composition of Precambrian basement severely limit the application of aeromagnetic and gravity anomaly maps in structure contouring.

It is thought that basinal structure is largely fault controlled, at least in places. The region was affected by Ancestral Rocky Mountain tectonics that resulted in extensive faulting during the Pennsylvanian and Early Permian (see Baltz and Myers, 1999; Broadhead and King, 1988; Broadhead et al., 2001). These faults will not penetrate strata younger than earliest Permian except where they have been reactivated by Laramide compressional tectonism or post-Laramide Tertiary extensional tectonism.. Subsurface faults were not drawn on the contour maps constructed for this report because well spacing is not sufficiently close at the pre-Cretaceous levels to permit subsurface definition of faults. Seismic reflection lines, which would have been very useful in structure contouring and definition of faults, were not available for this project. The presence of Tertiary-age intrusive rocks on the surface and in the subsurface and the variation in composition of Precambrian basement result in aeromagnetic and gravity contours that do not correspond everywhere to basement structure and therefore do not define fault locations in the subsurface.

The structure contour maps define the general outline and structure of the Raton and Las Vegas Basins as well as the Cimarron arch, which separates the two basins. The Cimarron arch is more pronounced at the Precambrian level than at shallower levels, indicating the Ancestral Rocky Mountain genesis of this tectonic feature as well as an Ancestral Rocky Mountain ancestry for the Las Vegas and Raton Basins. Cross sections B-B' and D-D' (Appendix B) indicate that Pennsylvanian strata and the Sangre de Cristo Formation (Pennsylvanian to Lower Permian) thin onto the flanks of the Cimarron arch and are absent from its crest, supporting the concept of a late Paleozoic ancestry for the arch. To the west of the Cimarron arch is the Cimarron range, an uplifted mountain block that has exposed Precambrian basement on top of the mountain range at elevations of more than 9000 ft (Figure 10).

The eastern flank of the Raton Basin is reasonably well defined by wells and by surface outcrop patterns. This eastern flank appears to be a west-dipping ramp that gently descends into the basin. Available data are insufficient to define local structural reversals that may act to form hydrocarbons traps, especially in Paleozoic strata that were deformed by Pennsylvanian and Early Permian tectonic movements associated with Ancestral Rocky Mountain deformation.

Not mapped on the structure contour maps are the eastward-directed thrust faults that repeat the Pennsylvanian section in the Las Vegas Basin (see Baltz and Myers, 1999 as well as the discussion of Pennsylvanian stratigraphy in this report). This repeated section partially accounts for the deep basinal structure in the western part of the basin. Although eastward-directed thrust and reverse faults formed the eastern flank of the Sangre de Cristo uplift during the Laramide (Late Cretaceous to Early Tertiary; see Baltz and Myers, 1999), apparent stratigraphic limitation of some identified faults to the Pennsylvanian in the subsurface of the Las Vegas Basin as well as an absence of outcropping thrust faults on the surface throughout most of the basin suggest that the thrust faults within the Las Vegas Basin may have also formed during the Late Pennsylvanian. If so, then Pennsylvanian-age thrusting was associated with Ancestral Rocky Mountain tectonics in the region.

The western boundaries of the Raton and Las Vegas Basins are formed by reverse/thrust faults that brought the core of the Sangre de Cristo uplift up and over Paleozoic and Mesozoic strata in these basins (See New Mexico Bureau of Geology and Mineral Resources, 2003; Baltz and Myers, 1999; O'Neill and Mehnert, 1988). The structure of these western boundaries is portrayed simply in this report. In reality, numerous east-directed thrust and reverse faults define the western boundary of the basins and bring older rocks on the west in a suprapositional relationship with younger rocks to the east. Well data and the structure contour maps indicate that the eastern boundary of the Raton Basin is gentle and ramp like at the Precambrian, Glorieta and Dakota levels. The eastern boundary of the Las Vegas Basin is poorly defined at the Precambrian level, but the contour patterns at the Glorieta level suggest that the basin had been mostly filled in by the end of Glorieta time; therefore, the eastern margin of the Las Vegas Basin is mostly determined by buried Ancestral Rocky Mountain structures of Pennsylvanian to early Permian age.

More local structural features are also apparent and can be dated as being relatively late tectonic features. The Turkey Mountains uplift, located in the central deep part of the Las Vegas Basin is apparent on both the Dakota and Glorieta structure maps (Figs. 8, 9). The Vermejo Park anticline is also apparent on the Dakota structure map (Fig. 8). As discussed in the section on Tertiary intrusive rocks, both of these features have been formed by domal uplift over intrusive laccoliths of Tertiary age.

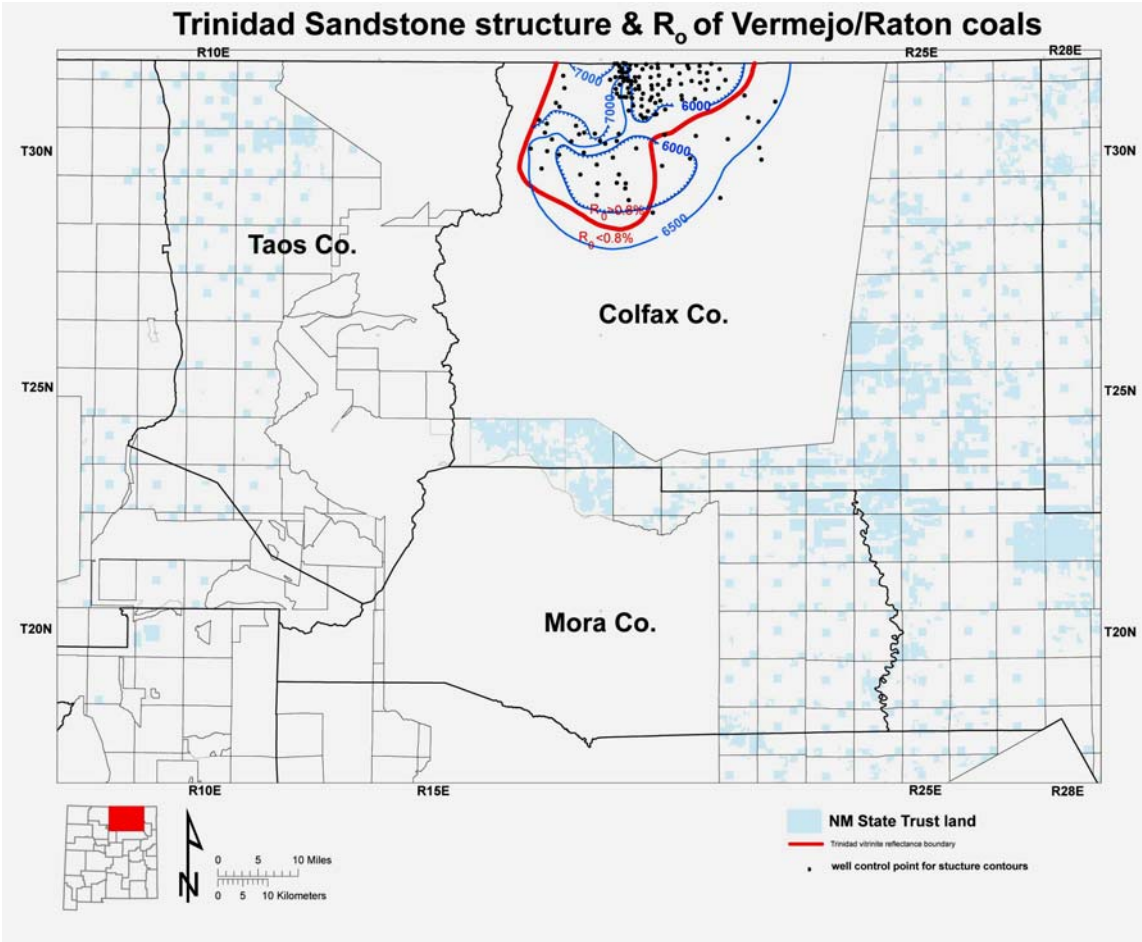

Figure 7. Structure on top of Trinidad Sandstone (Upper Cretaceous) and vitrinite reflectance boundary in Vermejo and Raton coals. Structure contours are in blue. Vitrinite reflectance boundary (in red) from Brister and others (2005). Contour interval = 500 ft.

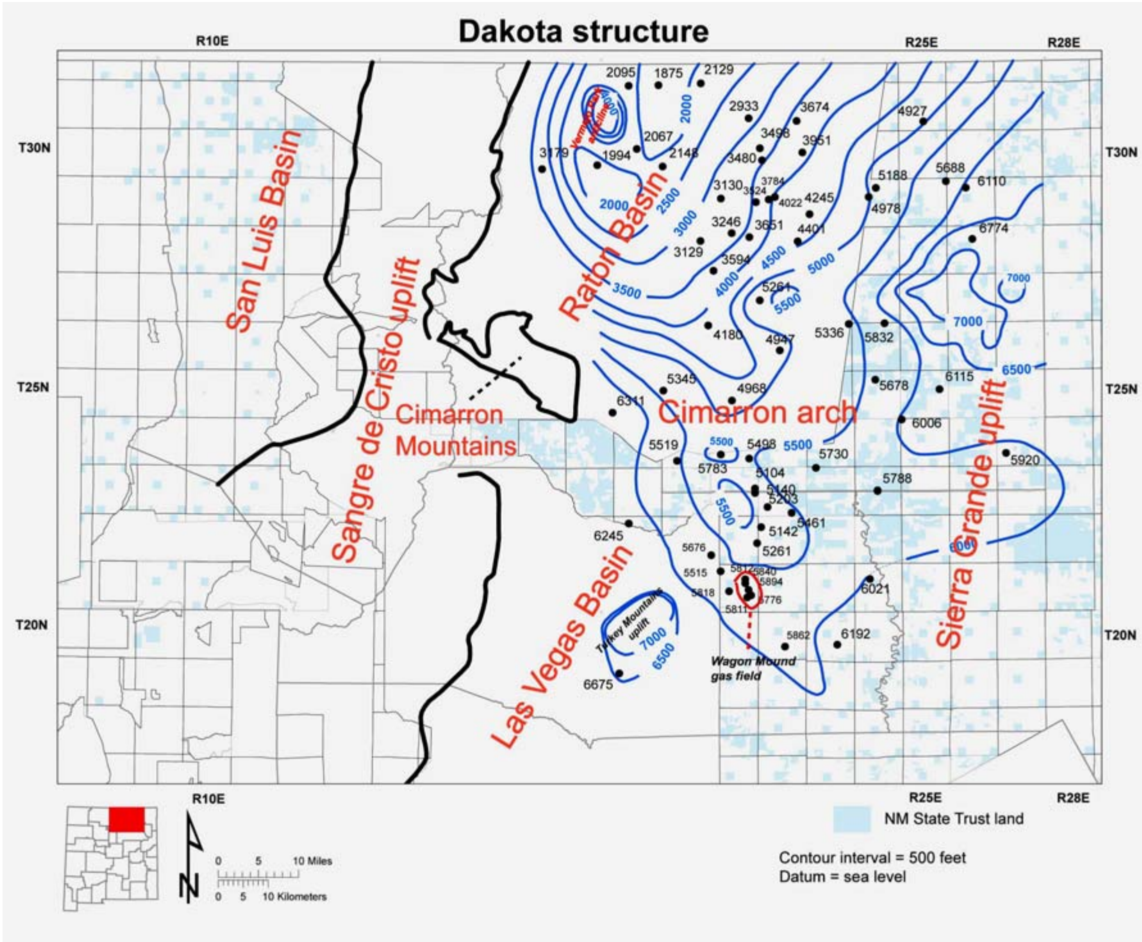

Figure 8. Structure on Dakota Group and major tectonic elements.

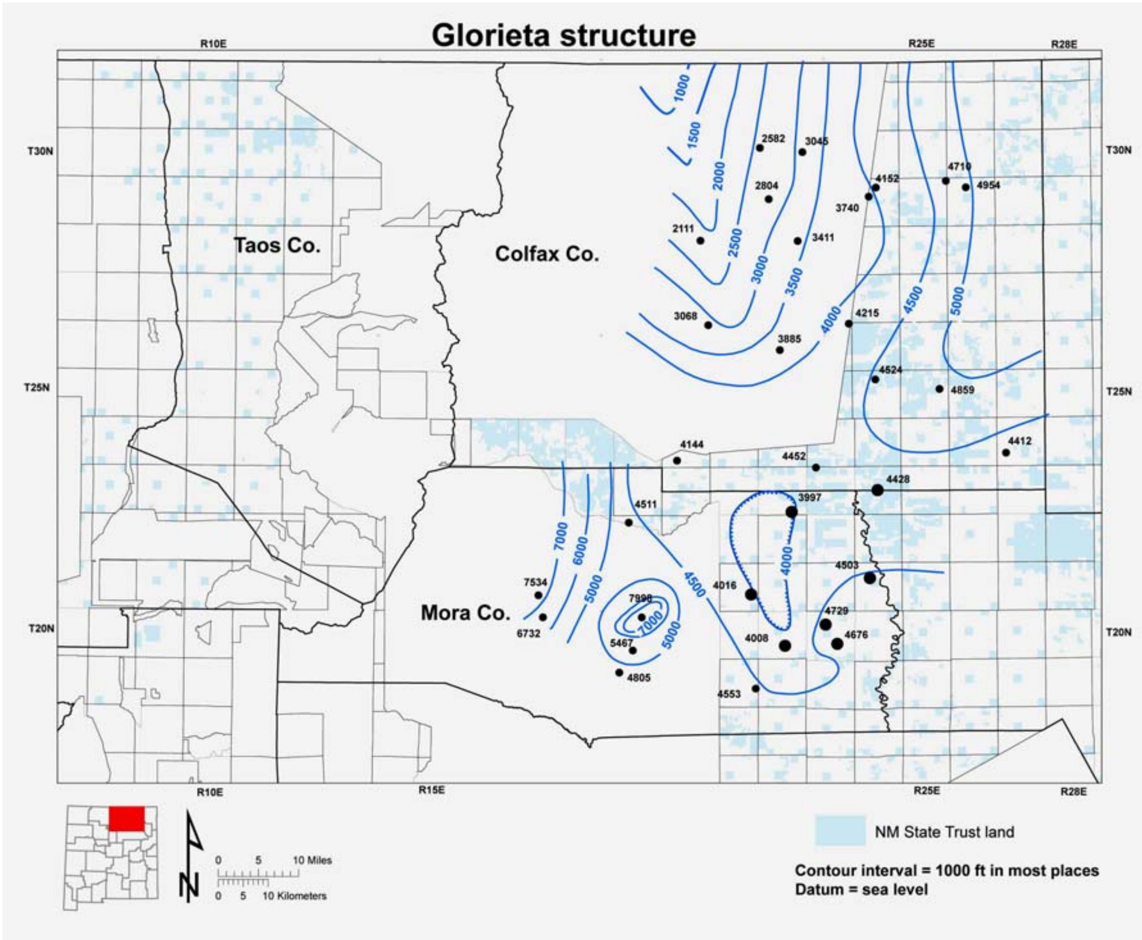

Figure 9. Structure on Glorieta Sandstone.

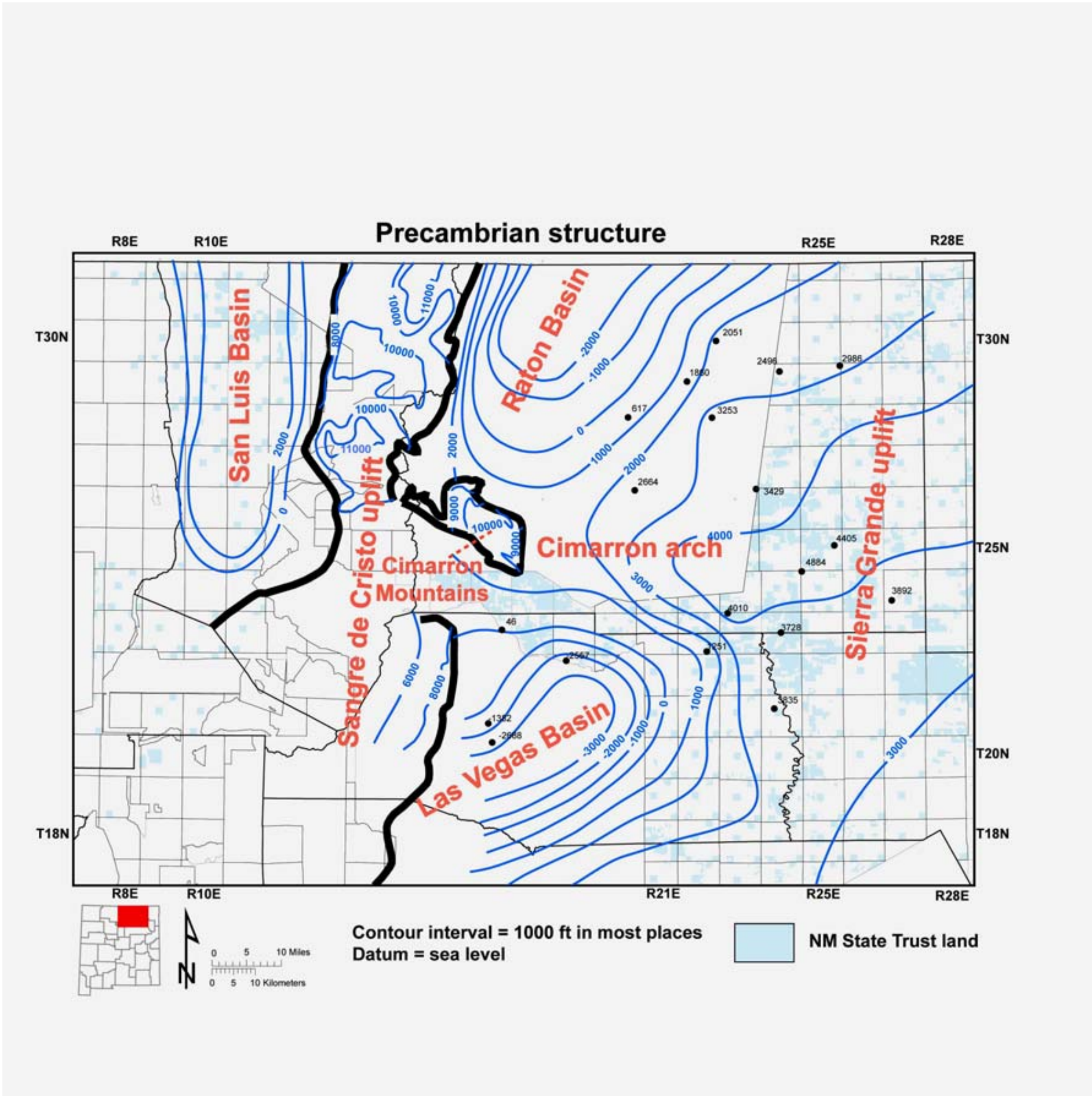

Figure 10. Structure on Precambrian basement and major tectonic elements. Structure in San Luis Basin is extrapolated south based on work in Colorado by Hemborg (1996).

Stratigraphy

Precambrian rocks

Precambrian rocks in the region consist of a complex mixture of metasediments, crystalline igneous rocks, and metavolcanics. In the Cimarron Mountains that form the western terminus of the Cimarron arch, the Precambrian crops out at the surface and consists of felsic volcanic rocks, mafic metavolcanic rocks, metapelites, granite, granodiorite, quartzite, and gneiss (Grambling and Dallmeyer, 1990). On the Sangre de Cristo uplift, quartzite, schists, phyllites, and felsic metavolcanic rocks are present (Mawer et al., 1990; Williams, 1990) as well as gabbro, metabasalt and tonalite (O'Neill, 1990) and metarhyolite (Grambling, 1990). The geology of the Precambrian basement of north-central New Mexico is beyond the scope of this report, and readers are referred to the preceding references for additional information.

Mississippian Strata

Mississippian strata are present in the subsurface of the Las Vegas Basin and on adjacent portions of the Sangre de Cristo uplift (Figure 11). The Mississippian is an erosional remnant that unconformably overlies the Precambrian basement and is unconformably overlain by Lower Pennsylvanian strata of the Sandia Formation. In outcrops of the Sangre de Cristo Mountains, the Arroyo Penasco Group constitutes the entire Mississippian section. The Arroyo Penasco consists of two formations (ascending; Baltz and Myers, 1999): the Espiritu Santo Formation and the Terrero Formation. The Espiritu Santo Formation consists of a basal unit of fine- to very coarse-grained sandstone (Del Padre Sandstone Member) that is overlain by gray limestone, dolomitic limestone, and minor sandstone and sandy limestone (Baltz and Myers, 1999). Maximum thickness of the Espiritu Santo is approximately 30 to 35 ft with the basal 10 ft belonging to the Del Padre Sandstone Member.

The Terrero Formation overlies the Espiritu Santo Formation. It consists of three members (ascending): Macho Member, Manuelitas Member, and Cowles Member. The Macho member is a detrital limestone breccia consisting of angular to rounded detrital limestone blocks in a matrix of silt and fine-sand size detrital fragments of limestone (Baltz and Myers, 1999). The Manuelitas Member is comprised of limestone conglomerate, calcarenite, sandy and silty limestone, marly shale, and finely crystalline limestone (Baltz and Myers, 1999). The Cowles Member consists of a basal sandy calcarenite and an upper unit of siltstone (Baltz and Myers, 1999). The calcarenite is crossbedded and crosslaminated and is obviously a shallow-water deposit. Baltz and Myers (1999) indicated that the Terrero Formation is 50 to 70 ft thick in the Las Vegas Basin.

For this report, Mississippian strata are mapped as the Arroyo Pensaco Group and have not been subdivided into lower-ranked stratigraphic units. The Arroyo Penasco is 0 to 160 ft thick in the subsurface of the western Las Vegas Basin and has been removed by erosion from the eastern part of the basin as well as from the Cimarron arch and the Raton Basin (Figure 11). It consists of “tight” marine limestone and a basal unit of fine- to very coarse-grained quartzose sandstone. The Arroyo Penasco appears to be characterized by low porosity and permeability in the Las Vegas Basin. Well logs indicate porosity is generally 4 percent or less.

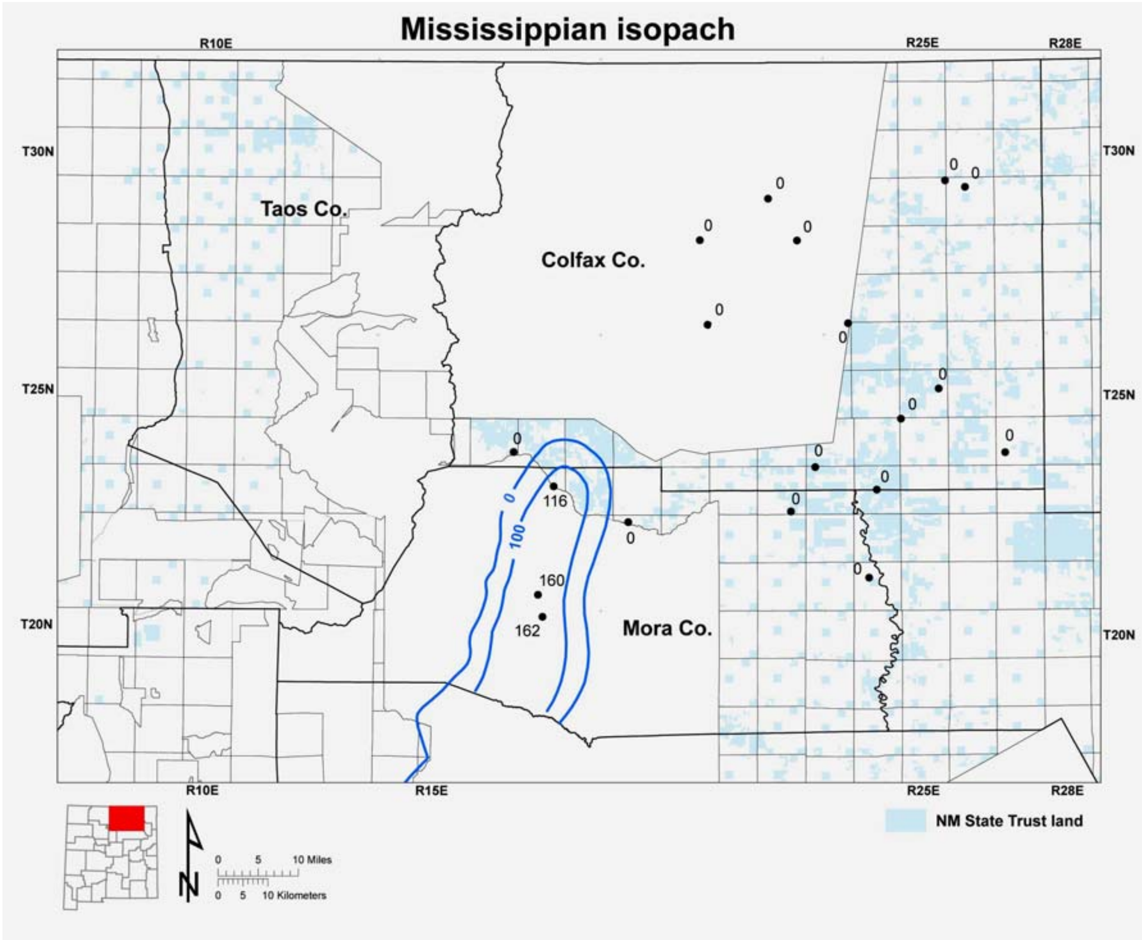

Figure 11. Isopach map of Mississippian strata.

Pennsylvanian and Lower Permian Stratigraphy

Source facies of dark-gray to black shales are present within the Sangre de Cristo Formation, the Madera Group, and the Sandia Formation in the Las Vegas and Raton Basins. Most of the source rocks occur in the Madera Group and Sandia Formation (Pennsylvanian), which also contain significant thicknesses on non-source, organic-poor, red shales. Shales in the Sangre de Cristo Formation are mostly red, organic-poor varieties, but organic-rich, dark-gray shales are locally abundant within the Sangre de Cristo and constitute source rocks where thermally mature. Pennsylvanian strata and the Sangre de Cristo Formation are better understood on the Las Vegas Basin where they have been drilled more frequently as the objects of oil and natural gas exploration.

Although Pennsylvanian strata are absent from the Cimarron arch, they are present north of the arch where they have been exposed by the faults that form the boundary between the Raton Basin on the east and the Sangre de Cristo uplift on the west. The following discussion of Lower Permian and Pennsylvanian source rocks is subdivided into section concerning the Las Vegas and Raton Basins.

Las Vegas Basin

Within the Las Vegas Basin, the Sangre de Cristo-Pennsylvanian sequence is 2000 to 9000 ft thick (Fig. 12). Baltz and Myers (1999) have used the term Rainesville trough to delineate the Pennsylvanian to Early Permian basin that occupied part of the area now occupied by the Las Vegas Basin. For this report, the term Rainesville trough has been applied to an extended area (compared to Baltz and Myers) delineated by the area east of the late Paleozoic El Oro – Rincon uplift and that is occupied by a thickened Pennsylvanian-Sangre de Cristo section. From the deepest parts of the basin where this stratigraphic sequence is thickest, these strata pinch out to the east onto the Sierra Grande uplift and to the north onto the Cimarron arch. Part of the thick section in the deepest portions of the Las Vegas Basin is caused by eastward-directed thrust faults that repeat the Pennsylvanian section. However, the non-repeated sections in wells indicate that that the depositional thickness of the Pennsylvanian-Sangre de Cristo stratigraphic section exceeds the thickness of these strata in all nearby areas, except possibly to the west in the Taos trough which has been uplifted and exposed on the Sangre de Cristo uplift.

In the True Oil Company No. 21 Medina well, located in Sec. 25 T24N R16E, the Pennsylvanian section is almost 5500 ft thick and appears to have been repeated by at least one thrust fault (Figure 29).. True thickness of the Pennsylvanian in this well is approximately 3300 ft, the same as is observed in the uplifted Taos trough to the west (Fig. 12; see Baltz and Myers, 1999).

To the southeast in the Continental Oil Company No. 1 Mares Duran well, located in Sec. 14 T23N R17E, total thickness of the Sangre de Cristo Formation, Madera Group, and Sandia Formation exceeds 7600 ft.

Further to the south in the deeper part of the basin in the Amoco No. 1 Salman Ranch A well, located in Sec. 3 T20N R17E (Fig. 12, Plate IV in Appendix B), the

Sandia Formation is 5090 ft thick (repeated by a thrust or reverse fault), the Madera Group is 1430 ft thick, and the Sangre de Cristo Formation is 2136 ft thick

In the northeastern part of the Las Vegas Basin the combined Pennsylvanian-Sangre de Cristo interval thins to 2206 ft in the Shell No. 1 Shell State well, located in Sec. 35 T23N R22E (Plates II, III in Appendix B). The Pennsylvanian section (combined Madera Group and Sandia Formation) in this well is approximately 900 ft thick.

Raton Basin

The combined Pennsylvanian and Sangre de Cristo sections thicken westward in the Raton Basin from 18 to 1000 ft on the northern part of the Sierra Grande uplift to a projected thickness of more than 3000 ft along the axis of the Central Colorado Basin

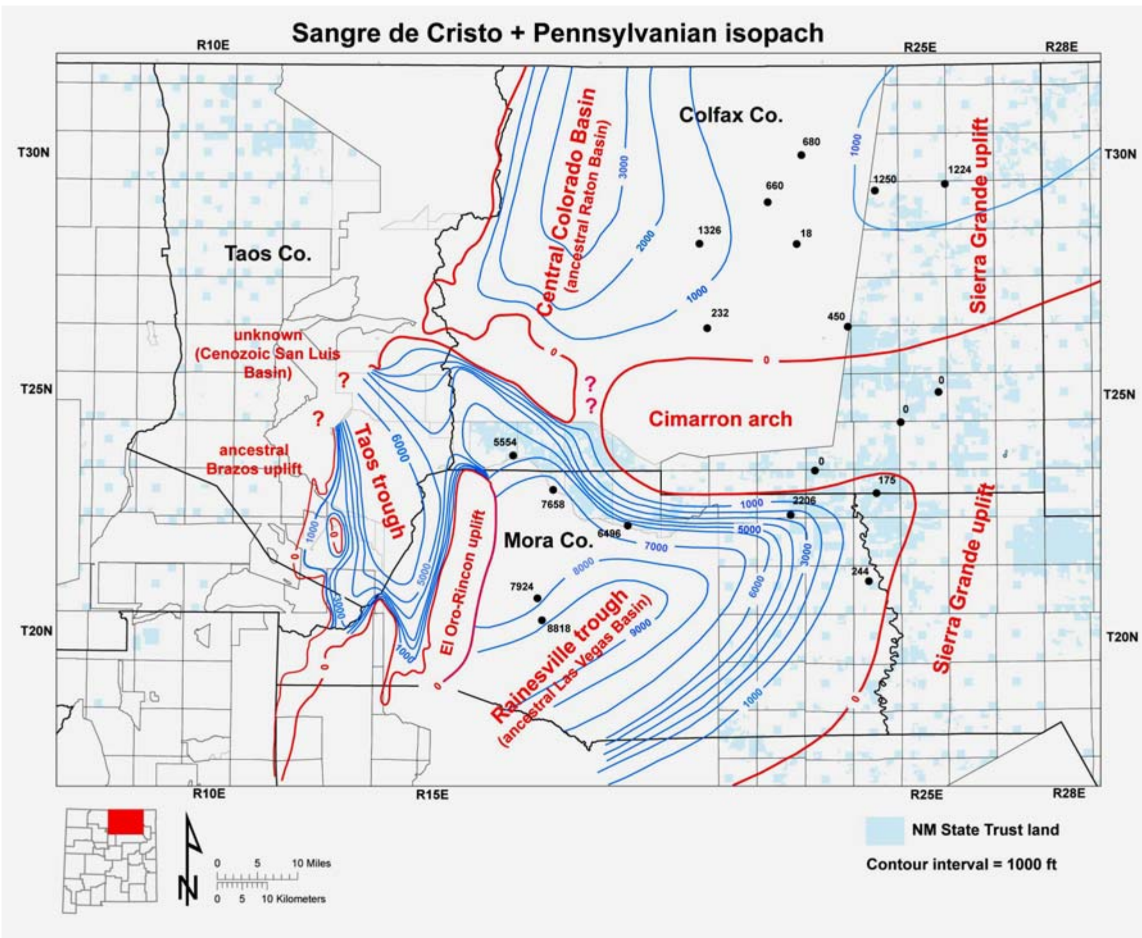

Figure 12. Isopach map of combined thickness of Sangre de Cristo Formation, Madera Group and Sandia Formation. Contours in Taos trough area, ancestral Brazos uplift, and El-Oro Rincon uplift from Baltz and Myers (1999).

(the late Paleozoic forerunner of the Raton Basin). The geology of this sequence of strata has not been established in the deeper parts of the Raton Basin because no wells have been drilled sufficiently deep to penetrate the sub-Mesozoic section. The thickest known, penetrated section of the Sangre de Cristo-Pennsylvanian interval is 1326 ft in the Pan American No. 1 Phelps Dodge well, located in Sec. 11 T28N R20E (Palte V in Appendix B). The top of the Sangre de Cristo/base of Yeso occurs at a depth of 4834 ft. Precambrian granite was encountered at a depth of 5710 ft. The section between the top of the Sangre de Cristo and 5000 ft consists of red shales and fine- to very fine-grained, red to orange, silty sandstones. Between 5000 ft and the top of the Precambrian, the section consists of interbedded dark-red shales, very dark-gray shales, and fine- to very coarse-grained, conglomeratic arkosic sandstones and minor blue-green shales. The dark-red shales dominate the section as a whole, but the dark-gray shales are dominant in places. The top of the Madera is provisionally placed at 4986 ft at a depth that corresponds to a change in log character associated with the presence of the very dark-gray shales and coarser-grained sandstones below this depth. This boundary can be correlated eastward within the Raton Basin with well logs. However, on the eastern flank of the Raton Basin sparse dark-gray shales occur in the Sangre de Cristo Formation above this boundary. In the absence of biostratigraphic data, the Sangre de Cristo-Pennsylvanian boundary is placed at this log marker (indicated on cross sections, Plates I, II, V in Appendix B). The gamma-ray and resistivity log characteristics of strata above and below this provisional boundary are similar to the log characteristics of the strata above and below the Sangre de Cristo-Madera boundary in the Las Vegas Basin, where it is better defined. Therefore, the top of the Madera in the Raton Basin, as correlated in this report, is based upon lithologic changes above and below this boundary as well as similarity of well log characteristics to the boundary as defined in the Las Vegas Basin.

In any event, it is evident that lateral facies belts defined by the presence or absence of dark-gray shales exist in both the Madera-Sandia section and in the Sangre de Cristo section in the Raton Basin. These facies belts are at present poorly defined but delineate areas of possible source rocks in these stratigraphic units. Areas without the more organic-rich dark-gray shales contain few of no potential source rocks; areas with dark-gray shales have possible source rocks whose assessment will be dependent upon maturation parameters as well as organic content.

In the CO_2-in-Action No. 1 Moore well, located in Sec 10 T29N R24E (Plate I in Appendix B) in the transitional area between the Raton Basin on the west and the Sierra Grande uplift on the east, the top of the Sangre de Cristo Formation occurs at a depth of 2804 ft, the provisional Madera top at a depth of 3274 ft, and the top of the Precambrian at a depth of 4056 ft. Relatively thin packages of organic-rich, dark-gray shales are present in the lower 250 ft of the Sangre de Cristo Formation, which is otherwise dominated by red shales and fine- to very fine-grained sandstones. The Madera-Sandia interval is dominated by dark-gray shales and fine- to very coarse-grained conglomeratic sandstones.

The Sangre de Cristo and Madera-Sandia intervals have not been penetrated further to the west in the deepest parts of the Raton Basin.

Permian Strata

Yeso Formation (Permian: Wolfcampian? To Leonardian)

The Yeso Formation overlies the Sangre de Cristo Formation. In the Sangre de Cristo Mountains, the Yeso intertongues laterally with the upper part of the Sangre de Cristo Formation and is replaced in a northward direction by the Sangre de Cristo Formation at the approximate latitude of the Cimarron arch (Bachman, 1953).

The Yeso Formation, as correlated in the subsurface for this report, is 80 to 500 ft thick. It attains maximum thickness of 300 to 500 ft in the Las Vegas Basin and thins to the north and east. In outcrops to the west and in the subsurface of the westernmost part of the Las Vegas Basin, the Yeso pinches out over the Cimarron arch. However in the subsurface it covers the eastern two-thirds of the arch and is 120 to 160 ft thick in this area (Plates II, V in Appendix B). North of the Cimarron arch, the Yeso thins to less than 100 ft in the central and western parts of the Raton Basin but thickens to 260 to 300 ft in the northeastern portion of the New Mexico part of the Raton Basin and onto that part of the Sierra Grande uplift that lies north of the Cimarron arch. Thickness variations of the

Yeso Formation do not appear to be related to the location of the Cimarron arch, indicating that this positive tectonic element did not exhibit sufficient topographic relief to be a major influence on deposition during Yeso time.

In the subsurface of the Las Vegas and Raton Basins, the Yeso can be subdivided into a lower unit and an upper unit on the basis of lithologic-related log properties. The lower unit consists of dark-red silty shales, subordinate pale-red to orange-red fine- to very fine-grained silty sandstones and minor blue-green to medium-gray shales. The lower unit of the Yeso Formation bears a striking resemblance to the Abo Formation of the Tucumcari Basin and central New Mexico and may be its lithostratigraphic and temporal equivalent.

The upper unit of the Yeso Formation consists of interbedded sandstones and shales. The sandstone and shale beds, as defined on well logs, are typically less than 10 ft thick. The sandstones are white to light pink in color, very fine to medium grained, moderately to well sorted, and subangular to subrounded. The shales are silty and either dark-red or blue-green to medium-gray in color; blue-green shales tend to be prevalent in the upper part of the upper Yeso unit and dark-red shales tend to be prevalent in the lower part of the upper Yeso unit. In this upper unit of the Yeso Formation, shales tend to be more abundant than sandstones in the northern part of the project area; sandstones and shales are generally present in approximately equal percentages in the southern part of the project area.

Glorieta Sandstone (Permian: Leonardian?)

The Glorieta Sandstone is 40 to 400 ft thick in the Las Vegas and Raton Basins and on that part of the Sierra Grande uplift covered by this report. Maximum thickness of 300 to 400 ft is attained in the southern part of the Las Vegas Basin. From there, the Glorieta thins to the north and west. To the north, the Glorieta thins gradually to less than 100 ft in the Raton Basin; thickness variations, similar to the underlying Yeso Formation, appear to be independent of the Cimarron arch. Eastward from the Raton Basin, the Glorieta thickens to more than 200 ft on the Sierra Grande uplift, but local thickness variations of more than 100 ft may be related to relict topography inherited from Pennsylvanian to earliest Wolfcampian structures.

The Glorieta Sandstone consists of white, fine- to medium-grained, moderately to well-sorted, subrounded to rounded quartz sandstones. Most of the sandstones appear to be porous and permeable under the binocular microscope. The lower contact with the Yeso Formation appears sharp and distinct on well logs and is drawn at the top of the highest shale within the Yeso. Where the Glorieta is more than 200 ft thick, the lowermost 100 ft is somewhat more radioactive than the overlying parts of the Glorieta. The character of the gamma-ray and resistivity logs indicates that the Glorieta is generally more radioactive and less resistive in the northern parts of the project area. This northward increase in radioactivity appears to coincide with a northward transition from white sandstones in the south to pink and orange sandstones in the north.

Bernal Formation (Permian: Guadalupian)

Strata correlated as the Bernal Formation are 30 to 160 ft thick where they are present in the subsurface of the Las Vegas and Raton Basins. The Bernal rests unconformably on the Glorieta Sandstone (Permian: Leonardian). The Bernal is unconformably overlain by the Moenkopi Formation (Middle Triassic); where the Moenkopi is not present, the Bernal is unconformably overlain by the Santa Rosa Sandstone (Upper Triassic). The Bernal is thickest in the Las Vegas Basin where it is 120 to 160 ft thick throughout most of the basin. To the west, the Bernal thins to 80 to 150 ft in outcrops in the Sangre de Cristo Mountains (Baltz and Myers, 1999) and is apparently absent from the Sangre de Cristo Mountains in the area of the Cimarron arch (Baltz, 1965). Sparse subsurface data suggest that the Bernal thins northward within the Las Vegas Basin and pinches out before it reaches the crest of the Cimarron arch. The Bernal is absent from the Raton Basin north of the Cimarron arch and is also absent from that part of the Sierra Grande uplift that is north of the Cimarron arch except for local erosional outliers that attain a maximum known thickness of approximately 40 ft. These erosional remnants are present in areas where the overlying Moenkopi Formation has been removed by pre-Santa Rosa erosion. Maximum thickness of the Bernal in areas where the Moenkopi is absent is 60 ft.

The Bernal Formation is named for exposures of fine- to medium-grained brownish-red sandstone, siltstone and red to purple shale that crop out in the southern

Sangre de Cristo Mountains near the village of Bernal (Bachman, 1953; Baltz, 1965). It is correlative with the Artesia Group of southeastern New Mexico (Tait et al., 1962). In the subsurface of the Las Vegas Basin, the Bernal consists of fine- to medium-grained, moderately sorted, light- to medium-gray sandstone and interbedded dark-red to maroon silty shales. Anhydrites and light-brown to medium-gray microcrystalline dolostones are present in the lower part of the formation; in this lower portion, sandstones are subordinate to shale. Some of the shales in the lowermost part of the Bernal are blue-gray in color, sandy, silty and pyritic.

Triassic Strata

Triassic strata are present throughout the Raton Basin, the Las Vegas Basin, over the Cimarron arch and on the Sierra Grande uplift. In the southeast part of the project area they have been exposed by erosion on the Canadian River valley along the Mora-Harding county line. They have also been exposed by erosion within the central uplifted core of the Turkey Mountains. To the west, Triassic strata crop out in a narrow outcrop belt along the west flanks of the Raton and Las Vegas Basins. Triassic strata consist primarily of nonmarine fluvial to lacustrine sandstones and shales. Stratigraphic subdivisions of the Triassic, as correlated in this report, include (ascending): Moenkopi Formation, Santa Rosa Sandstone, Chinle Formation.

Moenkopi Formation (Middle? Triassic)

The fluvial Moenkopi Formation of Middle (?) Triassic age rests unconformably on Permian strata. The Moenkopi crops out in the southern Sangre de Cristo Mountains where it consists of 90 to 160 ft of grayish-red, trough-crossbedded lithic sandstones and subordinate shale (Lucas et al., 1990). The Moenkopi, as correlated into the subsurface of the Raton and Las Vegas Basins for this report, attains a maximum thickness of 240 ft. It is 180 to 240 ft in the central part of the Las Vegas Basin and thins eastward to approximately 100 ft thick on the Sierra Grande uplift. It thins northward to less than 100 ft on the south flank of the Cimarron arch and is absent from the crest of the arch as well as from the Raton Basin and that part of the Sierra Grande uplift that lies north of the

Cimarron arch. In the subsurface, the Moenkopi Formation is comprised primarily of fine- to medium-grained quartzose sandstones with minor lithic fragments. The sandstones appear to be lenticular and are interbedded with maroon shales. The sandstones are absent to the north as the Moenkopi onlaps the south flank of the Cimarron arch. On the south flank of the arch, the Moenkopi consists primarily of maroon shales with minor thin beds of light- to medium-gray microcrystalline dolostones.

Santa Rosa Sandstone (Upper Triassic)

The fluvial Santa Rosa Sandstone (or Formation) unconformably overlies the Moenkopi Formation where the Moenkopi is present. Where the Moenkopi is not present, the Santa Rosa unconformably overlies Permian strata. In the Sangre de Cristo Mountains, the Santa Rosa Sandstone consists of 10 to 120 ft of quartzose sandstone and yellow-green to purple shale. In the subsurface of the Raton and Las Vegas Basins, the Santa Rosa sandstone is 30 to 220 ft thick. Maximum thickness occurs in the southern part of the Las Vegas Basin where the Santa Rosa is 100 to 200 ft thick. It thins gradually to the north and is less than 50 ft thick throughout much of the Raton Basin. From the Raton Basin, the Santa Rosa thickens eastward to approximately 100 ft on the Sierra Grande uplift. In the subsurface, the Santa Rosa consists of light- to medium-gray, fine- to coarse-grained sandstones and conglomeratic sandstones interbedded with shales. Most of the Santa Rosa shales are red, but some are green to dark gray.

Chinle Group (Upper Triassic)

The fluvial to lacustrine Chinle Group conformably overlies the Santa Rosa Sandstone. In outcrops of the Sangre de Cristo Mountains, four constituent formations have been recognized (ascending; Lucas et al., 1990): Garita Creek Formation, Trujillo Formation, Bull Canyon Formation, and Redonda Formation. The Garita Creek Formation consists of grayish-red, purple, and reddish-brown shales and is 25 to 85 ft thick (Lucas et al., 1990). The Trujillo Formation consists of olive, yellow and gray crossbedded to planar-laminated quartzose sandstones and is 40 to 190 ft thick (Lucas et al., 1990). The Bull Canyon Formation consists of reddish-brown and grayish-red shales and is 50 to 100 ft thick (Lucas et al., 1990). The Redonda Formation is 200 ft thick in the Sangre de Cristo Mountains and is comprised of reddish-brown and grayish-red siltstone (Lucas et al., 1990); it unconformably overlies the Bull Canyon Formation.

In the northern part of the Sangre de Cristo Mountains, the Johnson Gap Formation represents the Triassic section (Johnson and Baltz, 1960; Baltz, 1965). The Johnson Gap Formation consists of siliceous limestone conglomerate, gray and red finely crystalline limestone, siltstone, shale and gray and red sandstone (Johnson and Baltz, 1960; Baltz, 1965). Exact correlation with post-Moenkopi Triassic strata (Santa Rosa Sandstone, Chinle Group) further south is uncertain (see Baltz, 1965; Lucas et al., 1990), but it appears that the Johnson Gap Formation is correlative with at least part of the Chinle Group and perhaps to the upper part of the Santa Rosa Sandstone as well. The Johnson Gap Formation as correlated by Johnson and Baltz (1960) is approximately 100 ft thick in the northernmost part of the Sangre de Cristo Mountains in New Mexico. Inasmuch as the Santa Rosa Sandstone was correlated northward to the Colorado state line in the subsurface for this report, the Johnson Gap Formation is included as part of the Chinle Group for correlation purposes in this report.

The Chinle Group is 200 to 850 ft thick in the subsurface of the Las Vegas and Raton Basins. Maximum thickness is 700 to 800 ft thick in the Las Vegas Basin. It thins gradually northward to approximately 200 ft at the Colorado state line. East-west variation is minimal although there is some eastward thinning of the Chinle Group as it rises out of the Las Vegas Basin onto the Sierra Grande uplift to the east. The same east-west variation in thickness is not present on or north of the Cimarron arch. These thickness relationships suggest that the Cimarron arch and the Central Colorado Basin (the Paleozoic predecessor of the Raton Basin) were not topographically defined during the Late Triassic but that the east flank of the Las Vegas Basin may have exerted some topographic control on sedimentation. It is currently undetermined if the northward thinning of the Chinle represents northward depositional thinning or a northward-directed post-depositional erosional truncation under the Entrada Sandstone (Jurassic).

In the subsurface of the area covered by this report, the Chinle group is comprised of interbedded shales and sandstone. Shales are dominant and are mostly maroon to red in color; a minor amount of shales are a dark-gray color and may contain appreciable organic content. The distribution of dark-gray shales in the Chinle Group was not mapped for this project. Sandstones are white to light gray, fine to medium grained, well to moderately sorted and quartzose, although some sandstones appear to have appreciable contents of lithic fragments and micas.

Jurassic Strata

Jurassic strata are present throughout the Raton Basin, the Las Vegas Basin, on the Cimarron arch, and on the Sierra Grande uplift. In the southeast, they have been exposed by Cenozoic erosion in the Canadian River valley along the Mora-Harding county line. To the west, Jurassic strata crop out along a narrow outcrop belt along the west flanks of the Las Vegas and Raton Basins. Jurassic strata consist primarily of nonmarine sandstones and shales. Stratigraphic subdivisions of the Jurassic, as correlated in this report, are (ascending): Entrada Sandstone, Morrison Formation.

Entrada Sandstone (Middle Jurassic)

The Entrada Sandstone is 60 to 150 ft thick in the subsurface of the Las Vegas Basin and 20 to 115 ft thick in the subsurface of the Raton Basin. It is 25 to 60 ft thick on the Cimarron arch. The Entrada is a blanket sandstone of eolian origin that rests unconformably on the Chinle Formation (Triassic). The unconformity at the base of the Entrada represents a considerable time period ranging from the beginning of the Early Jurassic to the later part of the Middle Jurassic.

The Entrada Sandstone is composed of white, fine- to medium-grained, well-sorted, rounded, quartzose sandstone. The sand grains are typically frosted. In outcrops along the west flanks of the Raton and Las Vegas Basins, the Entrada is a crossbedded, fine- to very fine-grained quartzose sandstone (Scott and Pillmore, 1993).

Morrison Formation (Upper Jurassic)

The Morrison Formation overlies the Entrada Sandstone in the Raton and Las Vegas Basins, on the Cimarron arch, and on the Sierra Grande uplift. The Morrison Formation is 300 to 435 ft thick in the subsurface of these areas (Figure 13). Although subsurface data are sparse, thickness variations in the Morrison do not appear to be related to major tectonic elements.

The Morrison Formation consists of interbedded nonmarine shales and fluvial sandstones (Speer, 1976). The shales are red to maroon, light to medium gray, light green, blue-gray, and dark gray to very dark-gray, and are typically silty. The sandstones are fine to medium grained, angular to subangular, moderately sorted, and white to light gray to green. Some sandstones are coarse grained and conglomeratic. Both sandstones and shales are present throughout the lateral extent of the Morrison. Sandstone beds appear to generally be lenticular, although more widespread sandstones appear to be present. Thin beds of micritic limestones are locally present.

The Morrison can be subdivided into facies belts on the basis of shale color. Morrison Shales in the Raton Basin are dark gray to very dark gray to black. Morrison shales on the Sierra Grande uplift, the Cimarron arch and in the Las Vegas Basin are red, light to medium gray, and green to blue-gray. Tongues of this black shale facies extend eastward onto the Sierra Grande uplift and southward onto the Cimarron arch where they pinchout. As discussed later in this report, the black shale facies in the Raton Basin constitutes a petroleum source facies that is not present elsewhere within the Morrison east of the Sangre de Cristo uplift.

The lowermost 20 to 50 ft of the Morrison locally contains anhydritic shales and possibly thin anhydrites. This interval may the lateral equivalent of the Todilto Formation of the San Juan Basin.

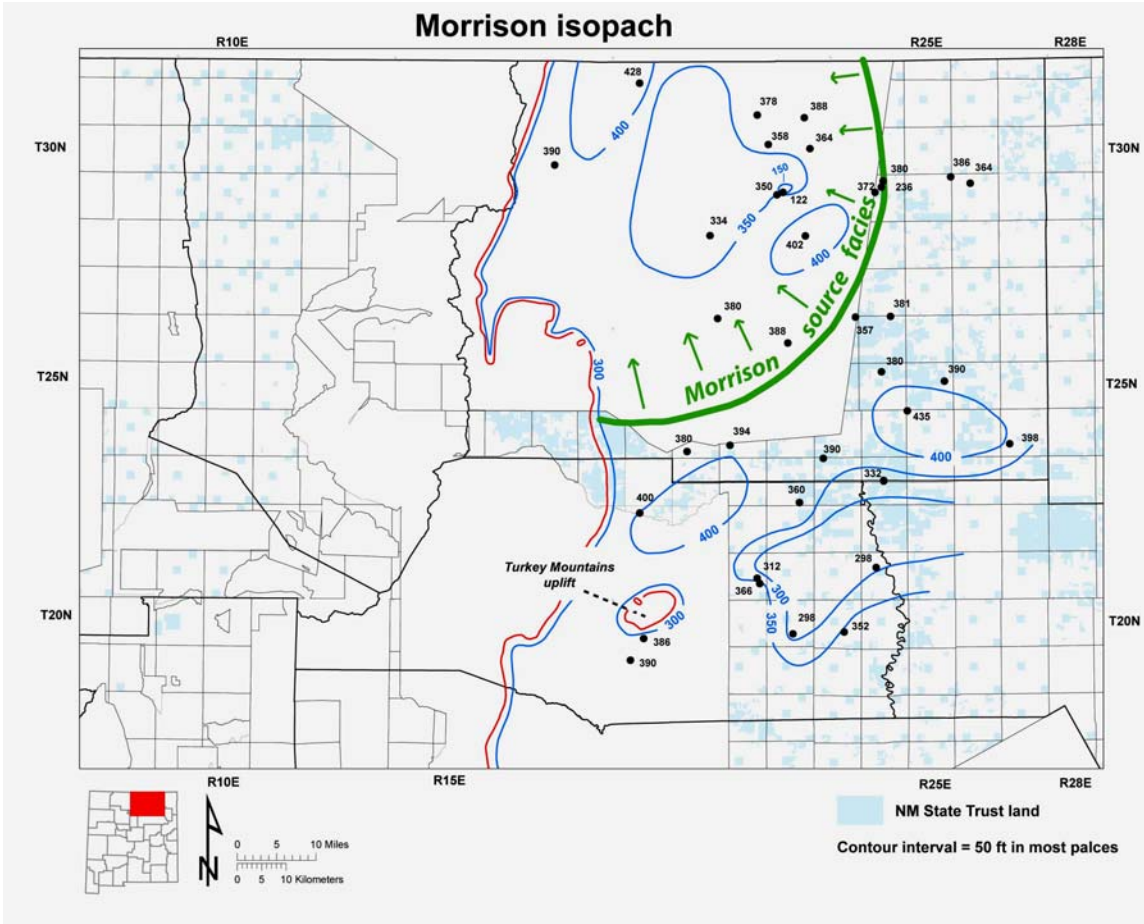

Figure 13. Isopach map of Morrison Formation (blue contours) and boundary of Morrison source facies (green line).

Cretaceous Strata

Dakota Group and Purgatoire Formation (Lower to Upper Cretaceous)

The Dakota Group of north-central New Mexico (Gilbert and Asquith, 1976; Lucas, 1990; Lucas et al, 2001) consists of three formations (ascending): Mesa Rica Sandstone, Pajarito Formation, and Romeroville Sandstone. The age of the Dakota Group has been assigned by various workers (Gilbert and Asquith, 1976; Baldwin and Muehlberger, 1959; Reeside, 1957; Scott, 1957) to either the Early Cretaceous or Late Cretaceous. More recently, Lucas and others (2001) concluded that the Mesa Rica Sandstone and Pajarito Formation are Early Cretaceous and the Romeroville Sandstone is Late Cretaceous.

The Dakota Group is 50 to 250 ft thick where it is present in north-central New Mexico (Figure 14). Throughout most of the project area it is 100 to 200 ft thick. The Dakota Group has been removed by post-Cretaceous erosion from the Turkey Mountains uplift as well as from the Sangre de Cristo uplift; outcrops of the Dakota are present along the flanks of these tectonic features (see New Mexico Bureau of Geology and Mineral Resources, 2003). Although data are sparse, the Dakota appears to be thinner over the Cimarron arch than in the Raton Basin to the north and the Las Vegas Basin to the south, indicating that the Cimarron arch was a positive tectonic element during Dakota deposition.

The Dakota Group has not been subdivided into its component formations for this project, although a lower sandstone-rich unit (Mesa Rica Sandstone), a middle shale-rich unit with interbedded sandstones (Pajarito Formation), and an upper sandstone unit (Romeroville Sandstone) are evident on well logs. Lucas (1990) published a well log for a designated subsurface reference section at the W.J. Gourley (later Odessa Natural Corp.)
No. 2 Vermejo well in sec. 16 T30N R19E, Colfax County; in Lucas' reference well, the Dakota Group is 204 ft thick.

The Mesa Rica Sandstone, the lowest unit of the Dakota, consists of white to light-gray, fine- to medium-grained, moderately to well-sorted, quartzose sandstone. Gilbert and Asquith (1976) indicated that lenses of chert conglomerate are common. This part of the Dakota was deposited as a sheet of sand and gravel on a piedmont plain (Jacka and Brand, 1973). Examination of well logs indicates that the lower part of the Mesa Rica is more radioactive than the upper part and contains light- to dark-gray shales in addition to sandstones and conglomerates. This lower, more shaly part may be the Purgatoire Formation (Lower Cretaceous; see Speer, 1976). Distinction between the Purgatoire and the Mesa Rica Sandstone in the subsurface of the Raton Basin is unclear at this point. Overall, gamma-ray logs indicate that the Mesa Rica forms an upward-coarsening sequence in many but not all wells. Thicknesses of 100 ft appear to be common, but as discussed above, this may include the Purgatoire Formation. The lower contact with the Morrison Formation (Jurassic) is disconformable.

The Pajarito Formation consists of carbonaceous (i.e. dark-gray and organic-rich) shales, siltstones, and bioturbated sandstones (Lucas, 1990). The sandstones are lenticular

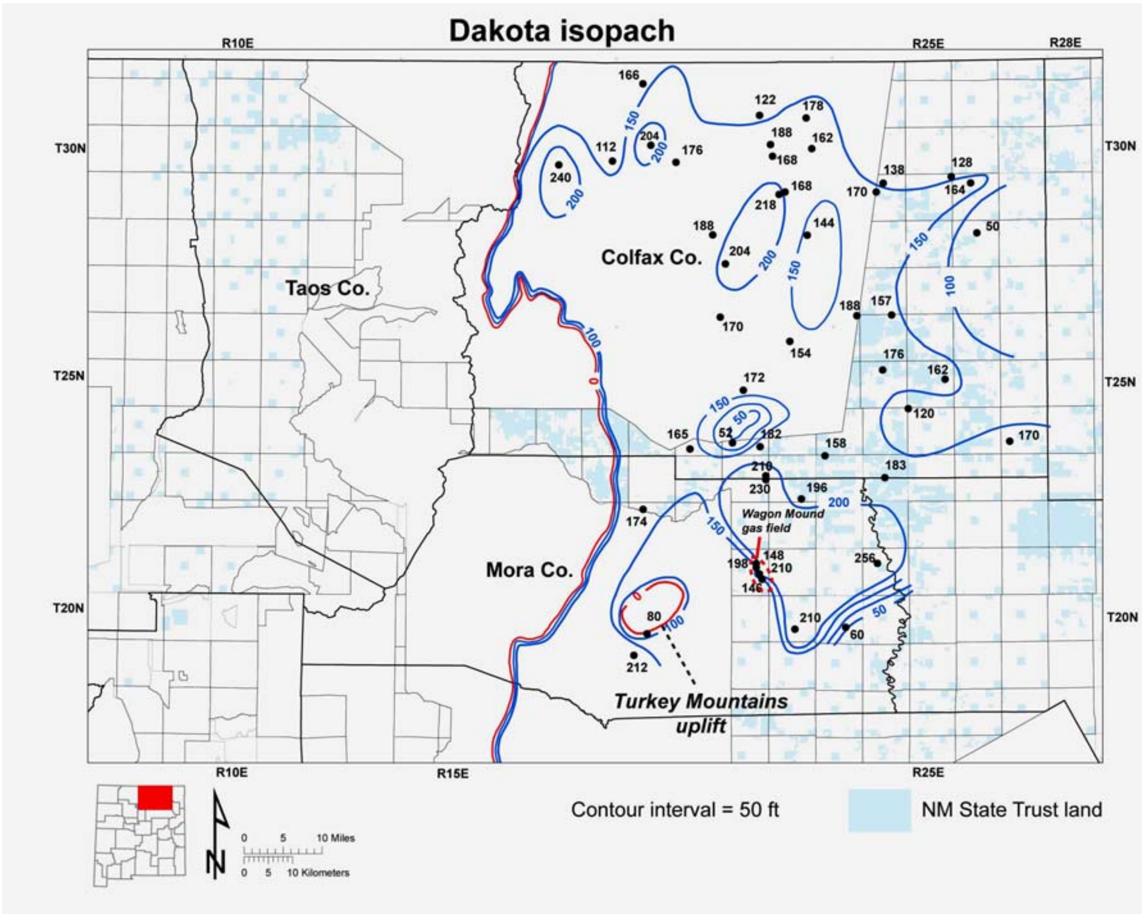

Figure 14. Isopach map of Dakota Group.

and contain abundant plant debris (Gilbert and Asquith, 1976). Deposition was in coastal marsh dominated by meandering streams (Jacka and Brand, 1973). The Pajarito Formation is typically of 50 to 70 ft thick in the subsurface of the Raton Basin.

The Romeroville Sandstone is a transgressive unit that disconformably overlies the Pajarito Formation (Lucas, 1990). It appears to consist of fine- to medium-grained, white quartzose sandstone. According to Gilbert and Asquith (1976) and Lucas (1990), *Ophiomorpha* burrows are common, indicating a marine origin for portions of it. Trough-shaped and planar crossbeds and planar horizontal stratification are present. Deposition was in intertidal and nearshore subtidal environments parallel to the shoreline

(Jacka and Brand, 1973). The Romeroville Sandstone is typically 20 to 60 ft thick in the subsurface of the Raton Basin.

Graneros Shale (Upper Cretaceous)

The Graneros Shale conformably overlies the Dakota Group in the Raton Basin and on the Cimarron arch. It has been removed by post-Cretaceous erosion from most of the Las Vegas Basin and from the Sierra Grande uplift. It has also been removed by post-Cretaceous erosion from the Turkey Mountains uplift as well as from the Sangre de Cristo uplift. The Graneros Shale is 90 to 200 ft thick where it is present in north-central New Mexico and is more than 150 ft thick in most places. The Graneros consists of very dark-gray marine shales and minor thin siltstones and micritic limestones.

Greenhorn Limestone (Upper Cretaceous)

The Greenhorn Limestone conformably overlies the Graneros Shale in the Raton Basin and on the Cimarron arch. It has been removed by post-Cretaceous erosion from most of the Las Vegas Basin and the Sierra Grande uplift as well as the Sangre de Cristo uplift. The Greenhorn Limestone is 10 to 200 ft thick where it is present in the subsurface of north-central New Mexico; the Greenhorn is 30 to 80 ft thick in most places. It has been removed by post-Cretaceous erosion from most of the Las Vegas Basin and from the Sierra Grande uplift. It has also been removed by post-Cretaceous erosion from the Turkey Mountains uplift as well as from the Sangre de Cristo uplift.

Well logs indicate the lower contact of the Greenhorn Limestone is sharp in most places. The upper contact with the Carlile Shale varies from sharp to gradational. The Greenhorn consists of medium- to dark-gray lime mudstones and bioclastic wackestones and medium- to dark-gray calcareous shales. It generally exhibits an upward gradation from predominantly limestones in its lower part to predominantly shales in the upper part. On well logs, the Greenhorn has a sharp contact with the underlying Graneros Shale. It has distinct shale interbeds that are a few feet thick. The gamma-ray logs indicate that the overall character of the limestones becomes more radioactive, and presumably more argillaceous (“shaly”) upward. Despite the upward increase in clay content, the

Greenhorn has a sharp contact with the overlying Carlile Shale in most places; in other places the contact is gradational.

Carlile Shale (Upper Cretaceous)

The Carlile Shale conformably overlies the Greenhorn Limestone in the Raton Basin and on the Cimarron arch. It has been removed by post-Cretaceous erosion from the Las Vegas Basin and the Sierra Grande uplift. It has also been removed by post-Cretaceous erosion from the Turkey Mountains uplift as well as from the Sangre de Cristo uplift. The Carlile Shale is 20 to 600 ft thick where it is present in the subsurface of north-central New Mexico and is 140 to 220 ft thick in most places. Thicknesses greater than 220 ft are in wells with normal thickness of the underlying Greenhorn Limestone and the overlying Fort Hays Limestone. In those wells with anomalously thick sections of Carlile (greater than 220 ft), the Carlile therefore exhibits either true stratal thickness (and not apparent thickness caused by stratal dip on the flank of a structure), the excessive thickness of the Carlile in these wells is either caused by intraformational folding or reverse faulting that has repeated the Carlile section. The Carlile consists of very dark gray marine shales and minor thin-bedded siltstones and micritic limestones.

Fort Hays Limestone (Upper Cretaceous)

The Fort Hays Limestone conformably overlies the Carlile Shale in the Raton Basin and on the Cimarron arch. It has been removed by post-Cretaceous erosion in the Las Vegas Basin and on the Sierra Grande uplift. It has also been removed by post-Cretaceous erosion from the Turkey Mountains uplift as well as from the Sangre de Cristo uplift. Scott and others (1986) consider the Fort Hays to be the basal member of the Niobrara Formation.

The Fort Hays Limestone is 10 to 100 ft thick where it is present in the subsurface of north-central New Mexico and is 20 to 40 ft thick in most places. The Fort Hays Limestone consists of medium- to dark-gray lime mudstones and bioclastic wackestones and interbedded dark-gray calcareous marine shale. Laferriere (1987) described the limestones as intensely bioturbated biomicrosparites consisting of bivalve remains and pelagic foraminifers in a recrystallized matrix of coccoliths. The interbedded shales are laminated and exhibit relatively little bioturbation.

On well logs, the Fort Hays has a sharp contact with the underlying Carlile Shale. It has distinct shale interbeds that are a few feet thick. The gamma-ray logs indicate that the overall character of the limestones becomes more radioactive, and presumably more argillaceous ("shaly") upward. Despite the upward increase in clay content, the Fort hays has a sharp contact with the overlying Niobrara Shale in most places; in other places the contact is gradational.

Niobrara Shale (Upper Cretaceous)

The Niobrara Shale conformably overlies the Fort Hays Limestone. The Niobrara consists predominantly of dark-gray marine shales and contains minor thin interbeds of micritic limestones and fine-grained sandstones. The Niobrara Shale is 200 to 1000 ft thick where it is present in the subsurface of north-central New Mexico. In most places it is more than 500 ft thick. Where it is exposed at the outcrop, it thins to a feather edge at the outcrop contact between the Niobrara and the underlying Fort Hays Limestone.

Separate isopach maps of the Niobrara and Pierre Shales were not prepared for this report. Instead, an isopach map of the combined thickness of the Pierre and Niobrara was prepared (Fig. 15). This map indicates these two formation have a maximum combined thickness of more than 3000 ft in the deep part of the Raton Basin. Thickness of the combined units decreases to the east and south.

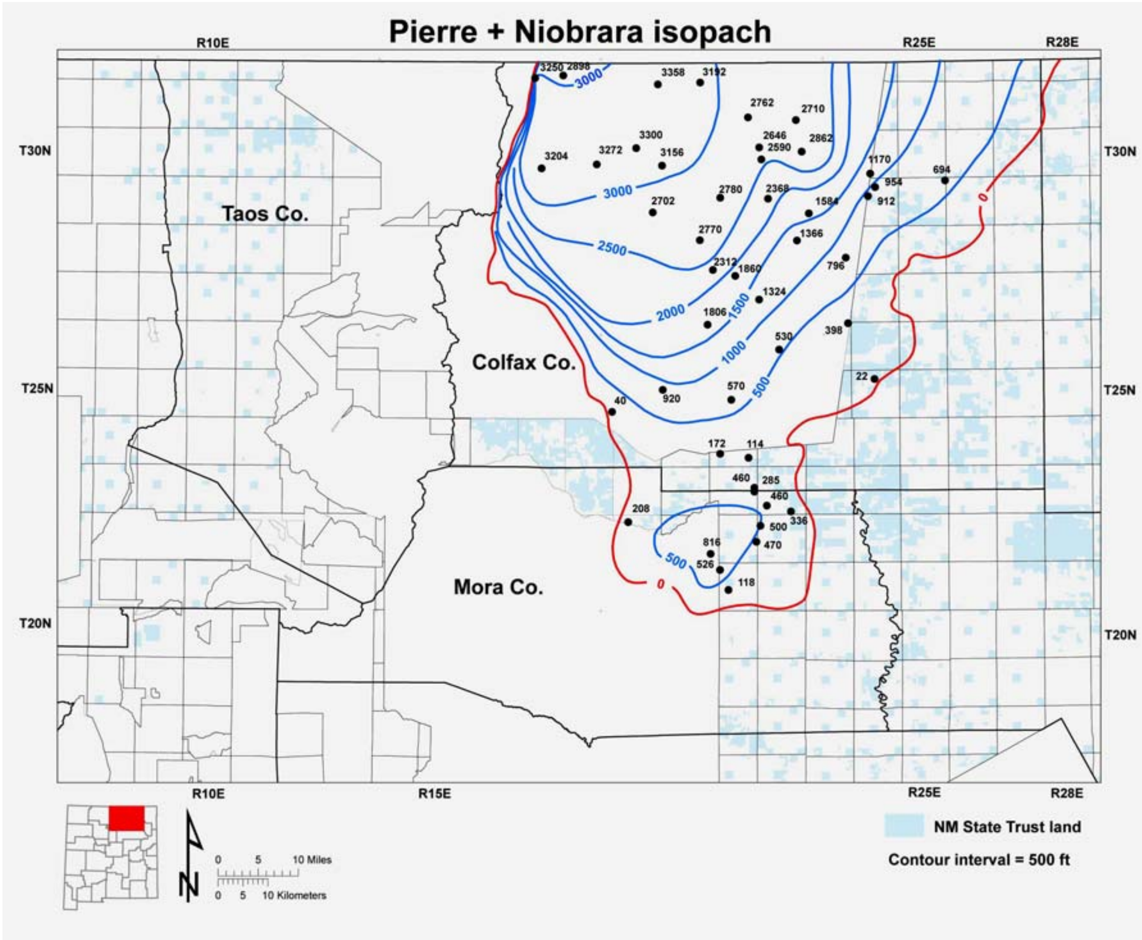

Figure 15. Isopach map of combined thickness of Pierre and Niobrara Shales.

Pierre Shale (Upper Cretaceous)

The Pierre Shale conformably overlies the Niobrara Shale. The Pierre consists predominantly of dark-gray marine shales and contains minor thin interbeds of micritic limestones and fine-grained sandstones. The Pierre Shale is 1600 to 2700 ft where it is present in north-central New Mexico. From its outcrop contact with the overlying Trinidad Sandstone (Upper Cretaceous), it thins by Cenozoic erosion to a feather edge at its outcrop contact with the underlying Niobrara Shale.

The contact of the Pierre with the underlying Niobrara Shale is distinct, sharp and easily correlatable on well logs (Plates I, II, V in Appendix B). The contact is delineated by a distinct decrease in resistivity from the Niobrara (more resistive) to the Pierre (less resistive). A minor thin (< 10 ft thick) limestone appears at the top of the Niobrara in places. Presumably the more resistive nature of the Niobrara shales indicates that they have a higher carbonate content than the Pierre shales, given that both units have a similar organic content (see section on petroleum source rocks). There does not appear to be any significant difference in radioactivity of the two units. Gamma-ray logs indicate that the upper 200 to 300 ft of the Pierre is characterized by an upward increase in sand content, and therefore an upward decrease in clay content of the shales as well as an increase in sandstone beds. The upper contact of the Pierre with the Trinidad Sandstone is sharp in some places, but in most places is gradational.

Trinidad Sandstone (Upper Cretaceous)

The Trinidad Sandstone overlies the Niobrara Shale in the Raton Basin. It is 40 to 260 ft thick. Its outcrop belt forms a narrow band that defines the structurally deeper parts of the basin on the east, south and northwest. On the southwest, the Trinidad is truncated in the subsurface by the faults that form the western margin of the basin. In the New Mexico part of the basin, thicker areas where the Trinidad is more than 140 ft thick trend northeast-southwest (Wu, 1987; Figure 16). To the north in the Colorado part of the basin, the axes of thick trends in the Trinidad are aligned northwest-southeast (Dolly and Meissner, 1977), parallel to the direction of the paleoshoreline in that part of the basin (Billingsley, 1977).

The Trinidad sandstone consists mostly of sandstone with minor shale. It was deposited in regressive beach and nearshore environments (Speer, 1976; Pillmore and Maberry, 1976). The sandstones are white to light gray to green to brown, subangular to subrounded, well sorted, and very fine to coarse grained (Wu, 1987). Shales occur in thin beds and are medium to very dark gray, silty, sandy and carbonaceous (Wu, 1987). On the outcrop, the Trinidad can be subdivided into a lower sandstone unit and an upper sandstone unit (Manzolillo, 1967; Billingsly, 1977; Tur, 1979; Leighton, 1980) that can be recognized and correlated on well logs (Wu, 1987). Each unit coarsens upward and is characterized by ripple cross lamination in the lower part and planar- to trough-shaped crossbeds in the upper part. In the New Mexico part of the Raton Basin, axial trends of thick sandstone accumulations trend northeast-southwest (Figure 16; Wu, 1987). Net thickness of sandstone attains a maximum of 100 ft along these axial trends.

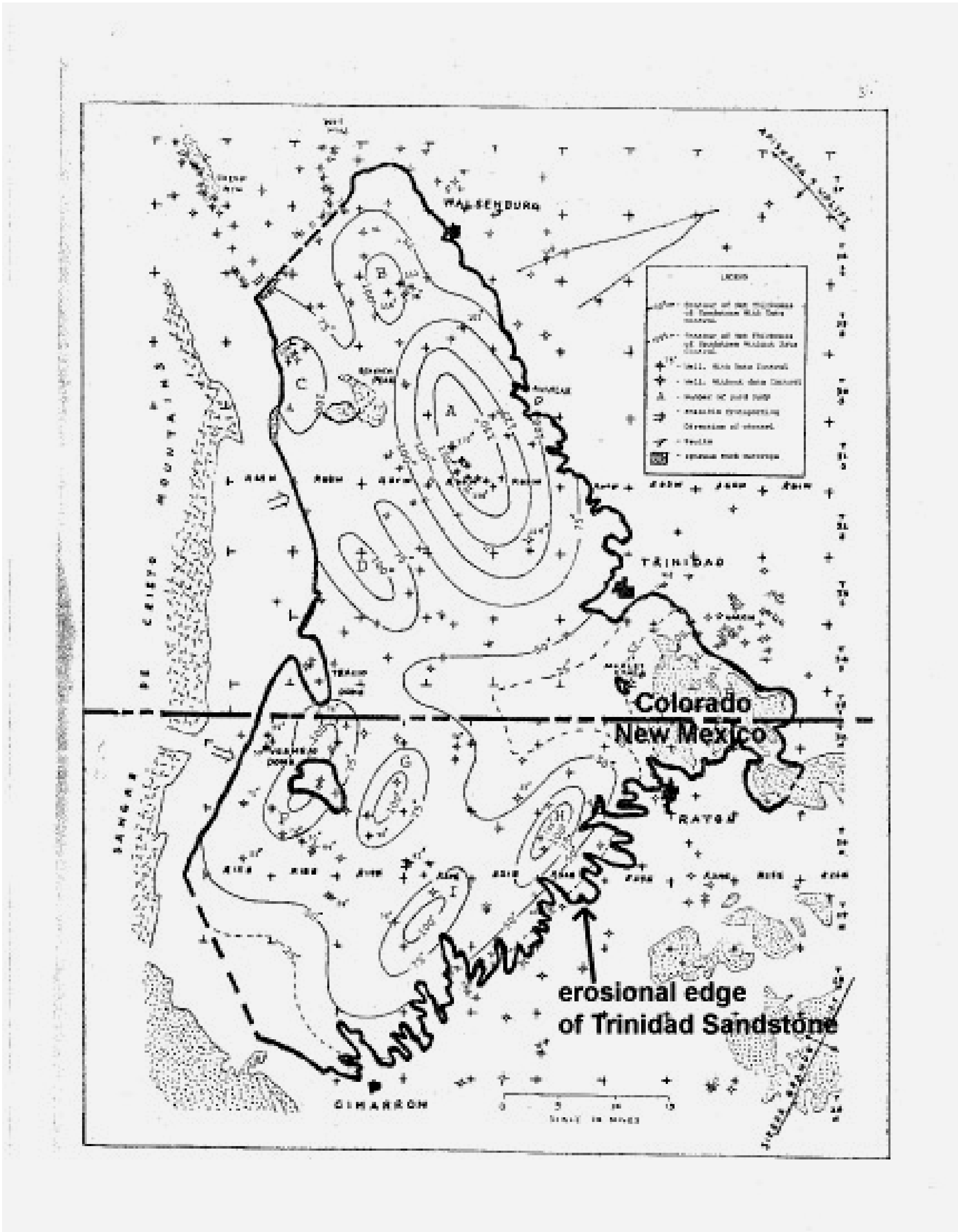

Figure 16. Sandstone isolith map of Trinidad Sandstone in Raton Basin. Contour interval equals 25 ft. From Wu (1987).

Vermejo Formation (Upper Cretaceous)

The Vermejo Formation (Upper Cretaceous) conformably overlies and intertongues with the Trinidad Sandstone in the Raton Basin (Lee, 1924; Johnson and Wood, 1956; Speer, 1976; Flores, 1987). Its distribution is limited to the Raton Basin. The Vermejo Formation is 150 to 330 ft thick (Wu, 1987). It is erosionally truncated at its outcrop belt around the margins of the basin.

The Vermejo Formation consists of interbedded sandstones, shales, and coal (Speer, 1976; Wu, 1987; Flores, 1987). It was deposited in lagoon, coastal swamp and floodplain environments backshore of the Trinidad Sandstone (Speer, 1976). The sandstones are light to medium gray to green, poorly to well sorted, very fine to coarse grained, and composed predominantly of quartz with weathered feldspars, mica, heavy minerals, clay matrix, and calcite cement (Wu, 1987; Speer, 1976). The shales are medium to very dark gray, carbonaceous, silty, and sandy. The coals are thin to thick bedded and lenticular (Speer, 1976) with partings of carbonaceous shale, siltstone, and sandstone (Wu, 1987).

Raton Formation (Upper Cretaceous to Lower Tertiary)

The Raton Formation unconformably overlies the Vermejo Formation. It is Late Cretaceous to Paleocene (Early Tertiary) in age. Distribution of the Raton Formation is limited to the Raton Basin. It is a synorogenic deposit associated with tectonic uplift of the Sangre de Cristo mountain range/uplift and a milder uplift of the Sierra Grande uplift during the latest Cretaceous and Early Tertiary (Speer, 1976). This tectonic activity resulted in the outline of the Raton Basin in its present form. The basal conglomerate and sandstone sequence within the Raton Formation overlies an erosionally beveled surface on top of the Vermejo Formation (Speer, 1976).

Maximum thickness of the Raton Formation is 2000 ft (Speer, 1976). Variations in thickness between 800 and 2000 ft are common and are in part a result of an intertonguing relationship with the overlying Poison Canyon Formation (Tertiary: Paleocene). The formation consists of laterally discontinuous and lenticular coarse-grained sandstones, shales and coals deposited in fluvial and flood plain environments (Speer, 1976). The coals occur in two stratigraphically confined coal-shale sequences

(Pillmore, 1976; Speer, 1976; Hoffman, 1990). Coals are typically 2 to 10 ft thick (Hoffman, 1990; Close and Dutcher, 1990). A fine- to medium-grained basal sandstone and conglomerate approximately 100 ft thick marks the lowermost part of the Raton Formation and rests on the unconformity at the base of the formation.

Tertiary (post- Raton Formation) and Quaternary Strata and Igneous Rocks

Poison Canyon Formation (Lower Tertiary)

The Poison Canyon Formation (Tertiary: Paleocene) conformably overlies and intertongues with the Raton Formation (Speer, 1976; Flores, 1987). The Raton Formation grades laterally northward into the lower part of the Poison Canyon Formation in the Colorado part of the Raton Basin (Johnson et al., 1956). The Poison Canyon Formation is a synorogenic stratal unit that was deposited as a piedmont facies in response to uplift and erosion of the Sangre de Cristo mountain range/uplift (Speer, 1976). Maximum thickness of the Poison Canyon is 500 ft (Scott and Pillmore, 1993). The formation is composed of sandstone and conglomeratic sandstone with interbedded mudstone and claystone (Johnson et al., 1966; Scott and Pillmore, 1993). The claystones and mudstones are medium gray to tallow (Scott and Pillmore, 1993) and apparently contain little, if any, organic matter. The sandstones are laterally discontinuous and intertongue with the claystones and mudstones. Unlike the underlying Raton Formation, the Poison Canyon Formation contains little or no coal or carbonaceous shale (Speer, 1976; Scott and Pillmore, 1993).

Post-Poison Canyon stratal units of Tertiary age

Several sedimentary units overlie the Poison Canyon Formation in the Colorado part of the Raton Basin (Speer, 1976). These are the Cuchara and Huerfano Formations (Eocene), the Farasita Conglomerate (Oligocene), and the Devil's Hole Formation (Miocene). As these stratal units are not present in the New Mexico part of the basin, they are not further discussed in this report.

Intrusive and extrusive volcanic rocks

Intrusive and extrusive igneous rocks of Tertiary age are widespread in northeastern New Mexico. In the eastern part of the project area, the intrusive rocks have been described and mapped by Scott and Pillmore (1993), O'Neill and Mehnert (1988), and Scott et al. (1990). A wide variety of intrusive rock types is present including phonolites, phono-tephrite, quartz syenite, quartz monzonite, trachyte, trachyandesite, ankarartrites, phonolites, syenite, rhyodacites and basanites that variously form laccoliths, sills, dikes, and volcanic plugs and stocks. Many of these intrusive rocks have been exposed by Cenozoic erosion of the Cretaceous and Tertiary sections. Several oil and gas exploratory wells in the Raton and Las Vegas Basins have penetrated igneous sills, dikes, stocks and laccoliths that lurk in the subsurface and have not been exposed by erosion.

Large domal and anticlinal structures have been created by intrusion of laccoliths. These include the Turkey Mountains of Mora County and the Vermejo Park anticline (Figure 17). The Turkey Mountains, located in the Las Vegas Basin, are formed by a northeast-southwest trending elongated dome whose uplift has exposed Triassic strata in the center of the dome; Jurassic strata and Cretaceous strata of the Dakota Group and Graneros Shale form the surface exposures on the flanks of the uplift. The Union Oil Company No. 1 Fort Union well, located in Sec. 2 T20N R19E, was drilled in the interior of the Turkeys and was spud in Triassic strata at the surface. The well penetrated a series of intrusive rocks (described on the scout card as intrusive porphyries) between a depth of approximately 2800 ft and total depth of 4070 ft. The intrusive bodies are apparently a part of a laccolith or laccoliths, the intrusion of which created the domal structure that is the Turkey Mountains. Northerly intrusive mafic dikes are exposed in the interior of the Turkey Mountains (Boyd, 1983). The dikes are alkalic lamprophyres with a date of 15.0 +- 0.7 million years. Hayes (1957) had postulated that the Turkey Mountain dome was formed by uplift over an intrusive Tertiary laccolith and that the dikes exposed at the surface were connected to the laccolith. Subsequent drilling of the Union Oil No. 1 Fort Union well in 1961-1962 proved Hayes' hypothesis correct.

The Vermejo Park anticline, located in the northwestern part of the Raton Basin (Figure 17), is also formed by uplift over an intrusive laccolith of Tertiary age. Structural relief on this anticline, at the top of the Trinidad Sandstone, is approximately 2500 ft (see Scott and Pillmore, 1993). Union Oil Company drilled two wells (the No. 1 Bartlett and the No. 2 Bartlett) on the anticline between 1924 and 1926. Both wells penetrated igneous rocks at depth – 3740 ft in the No. 1 Bartlett and 3218 ft in the No. 2 Bartlett. Upper Cretaceous sedimentary rocks are present just above the igneous rocks. Although the igneous rocks were described as Precambrian granite in the 1926 scout reports, the lack of an orogenic coarse-grained clastic facies in the Cretaceous section in nearby wells indicates that the igneous rocks at total depth are part of a Tertiary-age laccolith, similar to what formed the Turkey Mountains.

Other major intrusive bodies include the rhyodacite domes that form Laughlin Peak, Raspberry Mountain, and Palo Blanco Mountain (see Scott and Pillmore, 1993). At Laughlin Peak, the volcanic dome is associated with lahars that contain extrusive pumice and vitrophyre. Large bodies of Tertiary-age (Cimarron pluton) are also exposed on the north side of the Cimarron Range west of the town of Cimarron; these rocks are trachydacites and rhyolites that form large, stacked laccoliths (Kish et al., 1990).

Extrusive igneous rocks are plentiful in the eastern part of the area covered by this report. They mostly consist of Tertiary and Quaternary basalt flows and volcanic cones of mafic composition (Scott and Pillmore, 1993; O'Neill and Mehnert, 1988; Scott et al., 1990). These are concentrated on the Sierra Grande uplift east of the Raton Basin, over the Cimarron arch, and in the northern part of the Las Vegas Basin. Most of the basalt flows can be assigned to either the Ocate volcanic field of northwestern Mora County and the Clayton-Raton volcanic field of northeastern Colfax County. The basalts in each of these volcanic fields are associated with numerous dikes and vents.

The geology of the Tertiary igneous rocks of north-central New Mexico is beyond the scope of this report. Readers are referred to the preceding references for additional information.

Quaternary sediments

Various lenses and sheets of Quaternary alluvium, eolian sands, and lake sediments are scattered over the Raton and Las Vegas Basins (Scott and Pillmore, 1993;

New Mexico Bureau of Geology and Mineral Resources, 2003). Most of these unconsolidated sediments are less than 20 ft thick.

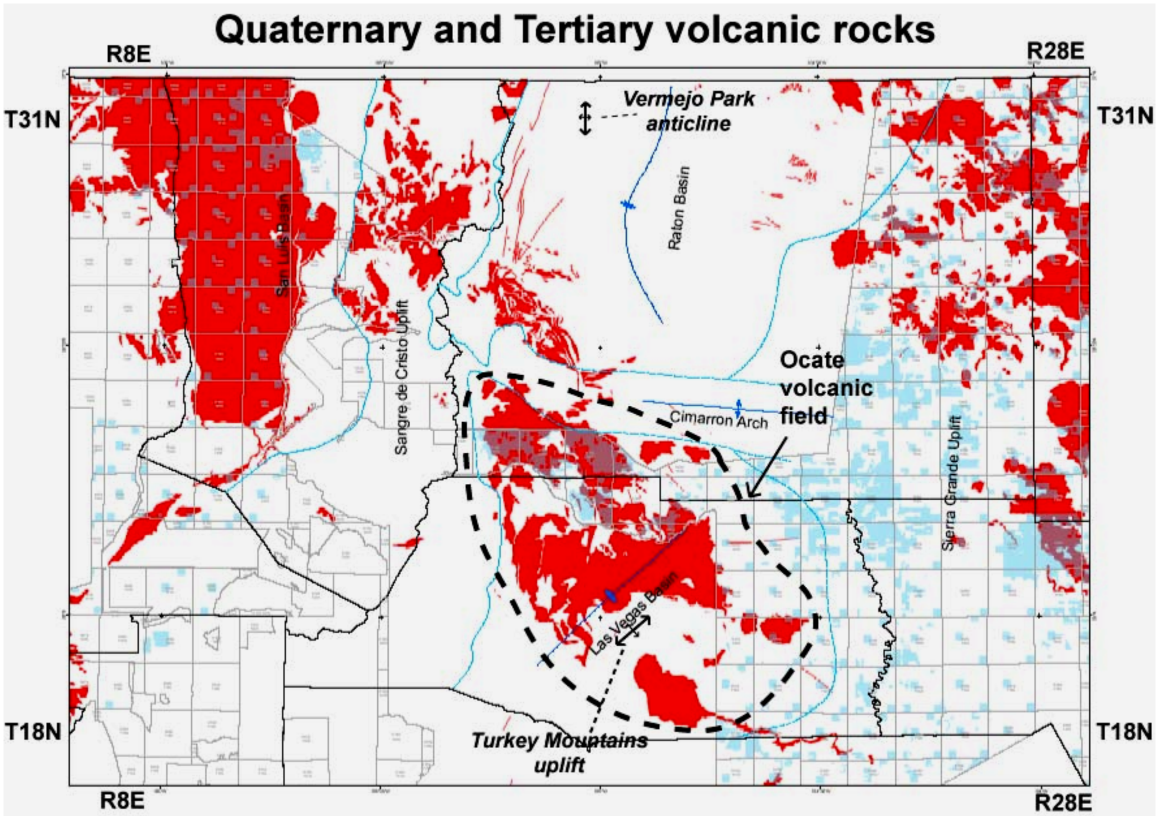

Figure 17. Tertiary and Quaternary age igneous rocks that crop out at the surface in the study area. Both intrusive and extrusive rocks are shown, as is the outline of the Ocate volcanic field (dominantly Tertiary basalt flows). The Turkey Mountains uplift and the Vermejo park anticline are cored by intrusive laccoliths of Tertiary age. New Mexico State Trust lands are shown in light blue. Outcrop patterns of igneous rocks are from New Mexico Bureau of Geology and Mineral Resources (2003). See Figure 5 and New Mexico Bureau of Geology and Mineral Resources (2003) for distinction between intrusive and extrusive rocks and different types of volcanic rocks.

Petroleum Source Rocks

Several stratigraphic units contain dark-gray to black shales with sufficient organic matter to be considered possible source rocks of oil and gas in that part of the project area east of the Sangre de Cristo uplift (Figure 18). These stratigraphic units include several Upper Cretaceous shales (Pierre Shale, Niobrara Shale, Carlile Shale, Graneros Shale) as well as basinal facies in the Sangre de Cristo Formation (Lower Permian) and the Madera Group and Sandia Formation (Pennsylvanian). In addition, a fetid facies of the Morrison Formation (Jurassic) contains sufficient organic matter to be considered a source rock. Thermal maturity of these organic rich units is highly variable, ranging from immature (possible biogenic gas only) to overmature (dry gas window). Furthermore, the Vermejo and Raton Formations contain gas-productive lenticular coal beds in the north-axial portion of the Raton Basin and are mature source rocks in that area. Source rocks are discussed in order from youngest to oldest strata, the order in which they will be encountered by the drill bit and, in general, in order of increasing thermal maturity. Figure 19 indicates the locations of wells and outcrops with source rock analyses used for this report and also indicates the locations of structural cross sections with thermal maturity windows superimposed. Source rock data for wells are presented in spreadsheet format in database ***northcentral source rocks.xls*** in Appendix A.

Cretaceous Source Rocks

Raton and Vermejo Formations (Upper Cretaceous to Paleocene)

The Raton Formation (Upper Cretaceous to Paleocene) and the Vermejo Formation (Upper Cretaceous) contain lenticular coal beds. In the Raton Formation, coal beds are typically 2 to 10 ft thick (Hoffman, 1990; Close and Dutcher, 1990). Net thickness of coal in the Raton varies from 10 ft to more than 60 ft, but is less than 30 ft in most places (Brister et al., 2005). In the Vermejo Formation, net coal thickness is typically 16 ft and varies from 4 to 33 ft; it is less than 25 ft in most places (Brister et al., 2005). Vitrinite reflectance (R_o) values are more than 0.6 percent throughout most of the extent of the Raton and Vermejo Formations in the Raton Basin and are more than 0.8 percent in the area where coalbed methane has thus far been developed (Brister et al., 2005; Figure 7). Therefore, the Raton and Vermejo coals are within the generative

Age		Stratigraphic units	TOC (percent)	Thermal maturity: Raton Basin	Thermal maturity: Las Vegas Basin
Quaternary			no source facies		
Tertiary	Pliocene	Intrusive & extrusive rocks of various ages			
	Miocene				
	Oligocene				
	Eocene				
	Paleocene	Poison Canyon Fm.	no source facies		
		Raton Fm.	coal beds	biogenic gas window, upper oil window	absent
Cretaceous	Upper	Vermejo Fm.	coal beds		absent
		Trinidad Ss.	reservoir facies		
		Pierre Shale	0.5 - 1.67	wet gas + dry gas window (in deep basin)	absent
		Niobrara Shale	0.95 - 2.03		oil window
		Fort Hays Limestone			
		Carlile Shale	0.85 - 1.61		oil window
		Greenhorn Limestone	1.63		
		Graneros Shale	1.14 - 2.45		oil window
	Lower	Dakota Sandstone	reservoir facies		
Jurassic	Upper	Morrison Fm.	0.16 - 1.49	oil window (basin margin); gas window (deep basin)	oil window?
	Middle	Entrada Ss.		reservoir facies	
Triassic	Upper	Chinle Group	no major source facies		
		Santa Rosa Sandstone	reservoir facies		
	Middle	Moenkopi Fm.	no source facies		
Permian	Guadalupian	Bernal Fm.	no source facies		
	Leonardian	Glorieta Ss.	reservoir facies		
	Wolfcampian	Yeso Fm.	no source facies reservoir facies		
		Sangre de Cristo Fm.	0.08 - 1.35	oil window (east) dry gas window (deep basin)	biogenic gas window to oil window
Pennsylvanian	Virgilian Missourian Des-moinesian	Madera Group	0.16 - 9.55	dry gas window (deep basin)	oil window to dry gas window
	Atokan Morrowan	Sandia Formation			
Mississippian		Arroyo Penasco Formation	no source facies		
Precambrian			no source facies		

Figure 18. Stratigraphic column of petroleum source rock characteristics for Paleozoic and Mesozoic strata in Raton and Las Vegas Basins.

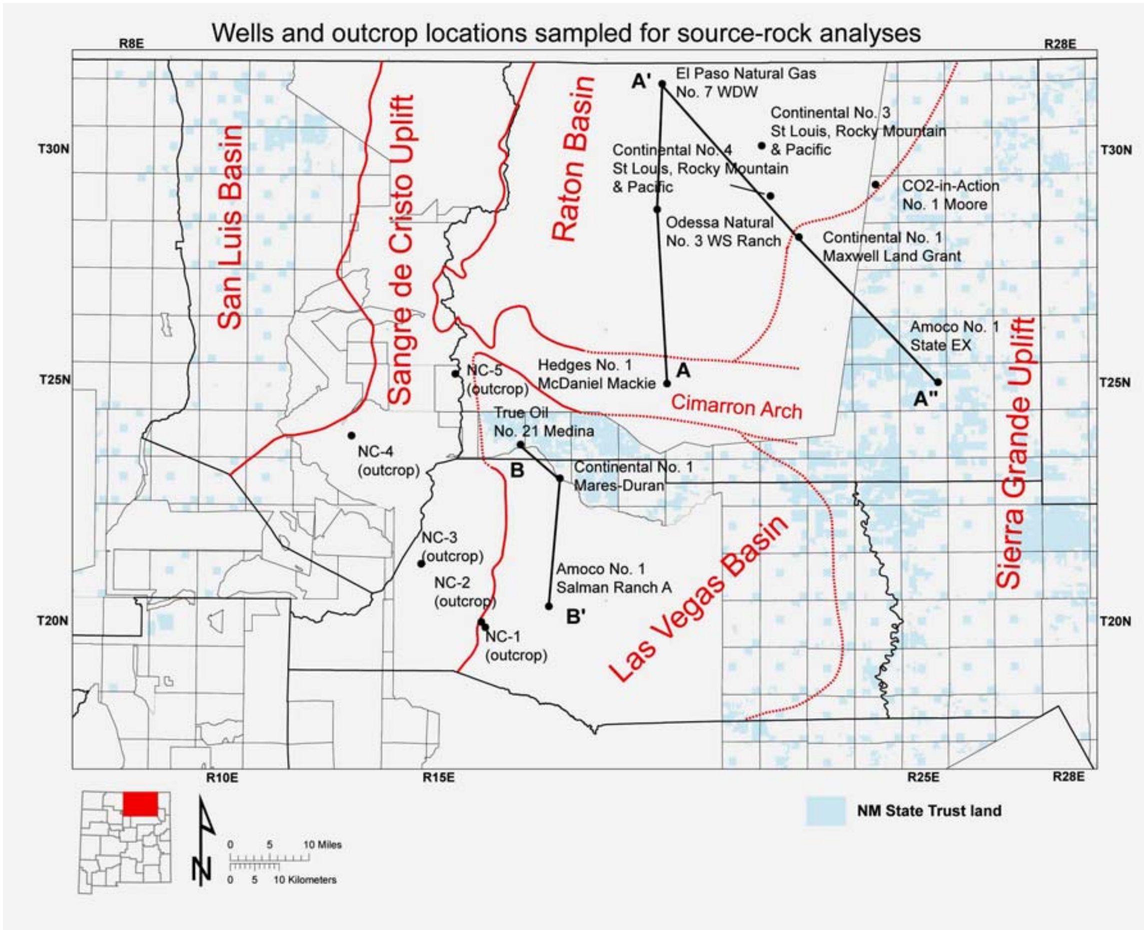

Figure 19. Wells and outcrop locations sampled for petroleum source rock analysis. See database ***northcentral source rocks.xls*** in Appendix A for source rock data. Lines of cross section refer to Figures 20, 21 and 32.

window in the core area of development and have at least reached the stage of early thermal gas generation throughout most of the rest of their extent in the Raton Basin.

The Vermejo Formation also contains beds of dark-gray carbonaceous coals. Although these have not been analyzed for their source-rock capabilities, they should be thermally mature because the Vermejo coals are thermally mature. In a terrestrial setting such as the Vermejo was deposited in, they should contain predominantly gas-generative kerogens. Therefore, the Vermejo shales may have generated gas.

Pierre and Niobrara Shales (Upper Cretaceous)

The Pierre and Niobrara Shales attain a maximum thickness of more than 3300 ft in the Raton Basin; the stratal units thin to the east over the Sierra Grande uplift and to the south over the Cimarron arch (Figure 15). South of the Cimarron arch, they thicken southward to a maximum of almost 1000 ft in the northeastern part of the Las Vegas Basin, but have been removed by post-Cretaceous erosion from most of the Las Vegas Basin as well as from the Sierra Grande uplift. This package of organic-rich marine shales is of interest not only for its source-rock capabilities, but as both a source rock and a reservoir (shale gas).

The Pierre Shale has total organic carbon (TOC) contents that range from 0.5 to 1.67 percent, and in most places has a TOC content of more than 1 percent. This is more than adequate for petroleum generation. The Pierre is immature and in the biogenic gas window where it is near its outcrop belt at shallow depths. In the deeper axial parts of the basin, the Pierre is within the wet gas/dry gas window and is within the oil window in transitional areas (Figs. 20-27). Although TOC within the deep axial parts of the basin is less than 1 percent, the kerogen in this area can be regarded as residual organic material as the kerogen in this area has generated most of its hydrocarbons; original TOC contents were higher than the present ones. There is more than 80 percent AOM conversion in the deeper pats of the basin. Optical petrographic analyses indicate that Type II organic matter is dominant, but that woody and amorphous types are also present and may be locally dominant. The kerogens would have generated oil and associated gas upon maturation. However, maturation of generated hydrocarbons into the wet gas/dry gas and

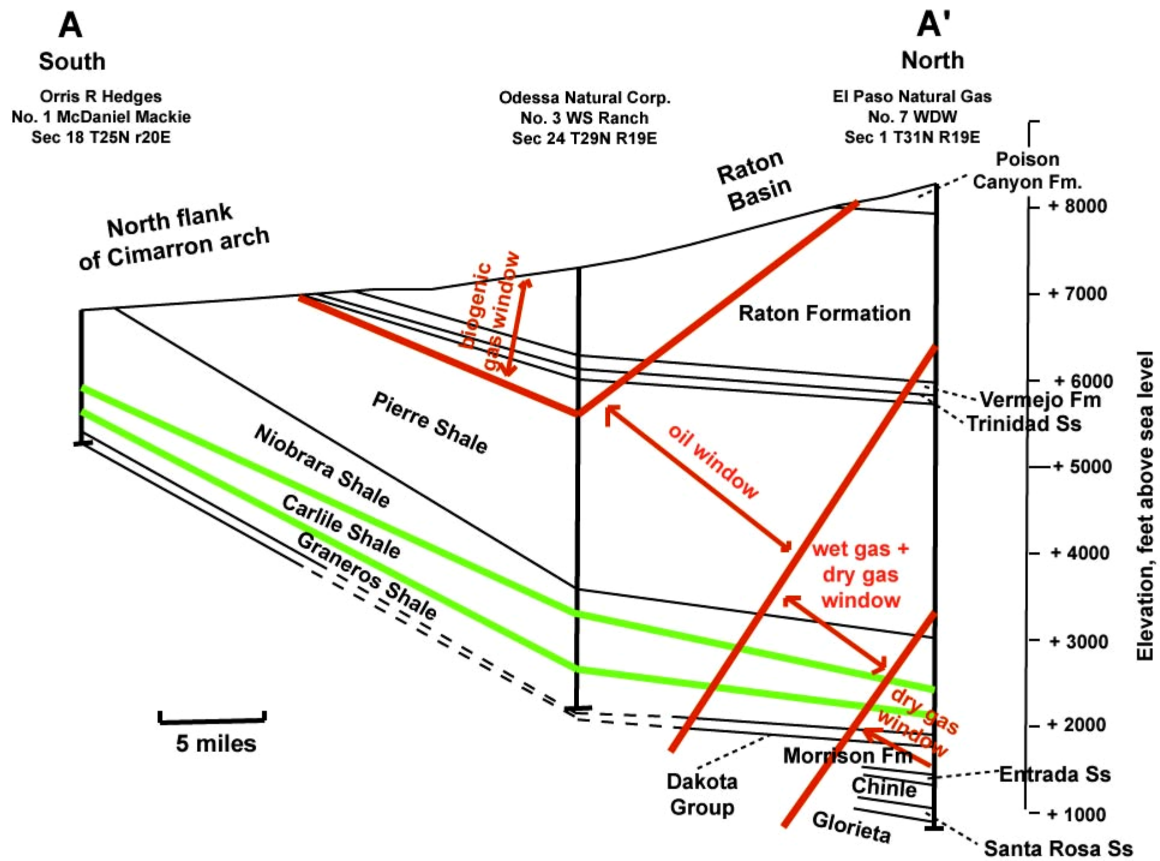

Figure 20. Structural cross section A-A', indicating tops and bases of oil and gas maturity windows. See Figure 19 for location.

dry gas windows has resulted in conversion of oil to gases, so that only gases are now present in the deeper parts of the basin.

The Niobrara Shale has TOC contents of 0.95 to 2.03 percent. This is more than adequate for petroleum generation. Although the Niobrara is immature and capable of generating only biogenic gas where it crops out along the east flank of the Raton Basin, it is mature throughout most of its extent where it is either in the oil window or, in the deeper parts of the basin, within the wet gas/dry gas window. In the deepest parts of the basin along the basin axis, the Niobrara Shale is within the dry gas window. TOC is more than 1 percent in the deepest parts of the basin, but much of the kerogen in this area can be regarded as residual and post-generative and has generated most of the hydrocarbons it

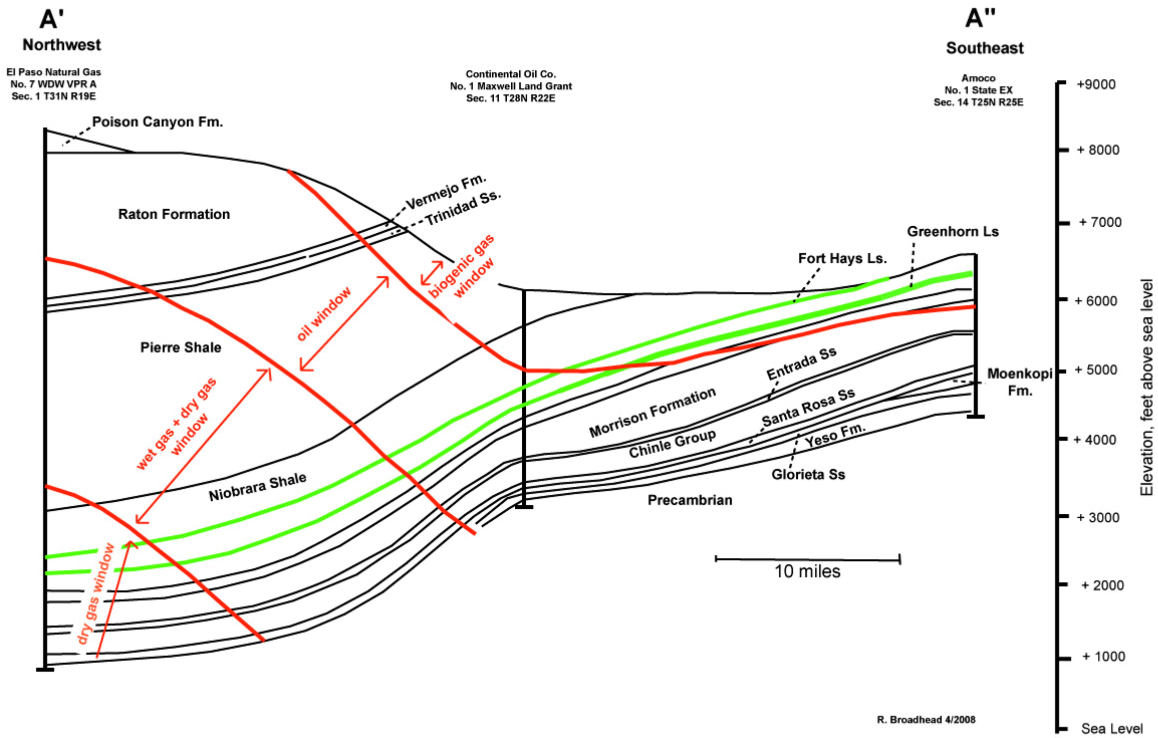

Figure 21. Structural cross section A'-A", indicating tops and bases of oil and gas maturity windows. See Figure 19 for location.

is capable of producing. There is more than 90 percent AOM conversion in the deeper more mature parts of the basin. As with the Pierre Shale, original TOC values were higher than present ones. Optical petrographic analyses indicate the kerogens are mostly Type II amorphous and herbaceous types that would have generated oil and associated gas upon maturation. However, maturation of generated hydrocarbons into the wet gas/dry gas and dry gas windows has resulted in conversion of oil to gases, so that only gases are now present in the deeper parts of the basin. A significant amount of generative kerogen has probably been converted to inertinite in the deeper, more mature parts of the basin. In the northeastern part of the Las Vegas Basin, the Niobrara contains 0.95 percent TOC in the Shell No. 1 Shell State well, located in Sec. 35 T23N R22E (Fig. 28). The Niobrara in this well crops out at the surface and is present to a depth of 336 ft. It is mature and within the oil window and has a Rock-Eval S2/S3 ratio of 3.7, suggesting that kerogens are a mixture of oil-prone and gas-prone types with perhaps gas-prone type predominating.

Carlile Shale (Upper Cretaceous)

The Carlile Shale has TOC contents of 0.85 to 1.61 percent. In most places, Carlile TOC is more than 1 percent, adequate for petroleum generation. Along the periphery of the Raton Basin where the Carlile has been exposed by post-Cretaceous erosion, the Carlile is either immature and capable of generating only biogenic gas or is mature and within the oil window (Figs. 20-27). Throughout most of the basin however, the Carlile Shale is thermally mature. In the deeper, axial parts of the Raton Basin, the Carlile is either within the wet gas/dry gas window or the dry gas window. As with the Pierre and Niobrara Shales, much of the organic carbon in the Carlile can be considered as residual and post-generative within the deeper parts of the Raton Basin. Original TOC contents were higher than present TOC contents. There is more than 90 percent AOM conversion in the more mature parts of the basin. Optical petrography indicates kerogens are a mixture of amorphous, herbaceous and woody types that would have generated oil and associated gas upon maturation. However, maturation of generated hydrocarbons into the wet gas/dry gas and dry gas windows has resulted in conversion of oil to gases, so that only gases should now be present in the deeper parts of the basin. A significant amount of generative kerogen has probably been converted to inertinite in the deeper, more mature parts of the basin.

South of the Cimarron arch in the northeastern part of the Las Vegas Basin, the Carlile Shale is presently buried to depths of less than 1000 ft but is mature and within the oil window (Fig. 28). The Rock-Eval S2/S3 ratio is 5.0, suggestive of the presence of mixed gas-prone and oil-prone kerogens with perhaps oil-prone types predominating. TOC is in excess of 1 percent and it is likely that oil as well as gas has been generated by Carlile shales in this area.

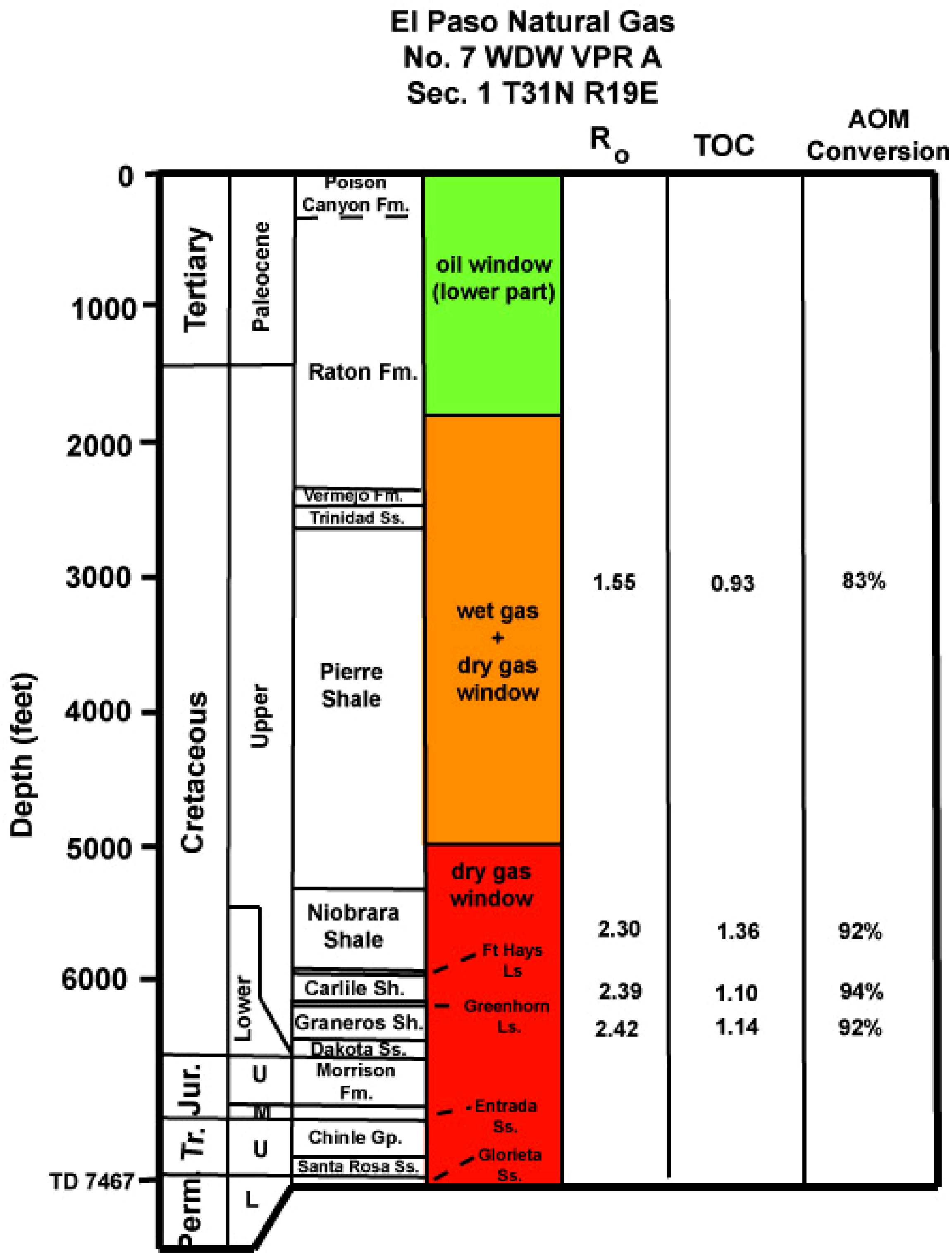

Figure 22. Petroleum source rock profile for El Paso Natural Gas No. 7 WDW VPR A well, located in Sec. 1 T31N R19E. See Figure 19 for location of well.

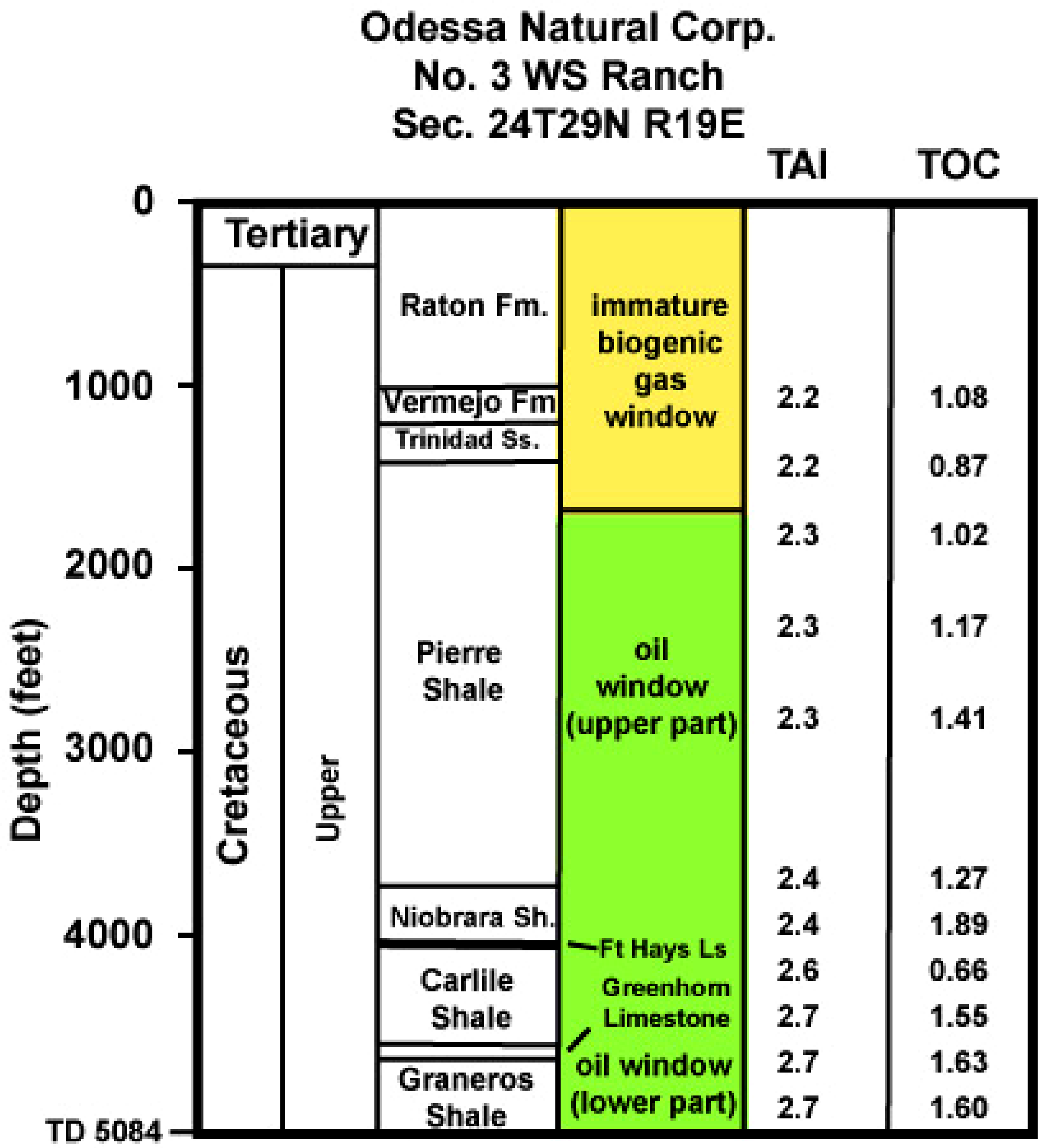

Figure 23. Petroleum source rock profile for Odessa Natural Corp. No. 3 WS Ranch well, located in Sec. 24 T29N R19E. See Figure 19 for location of well.

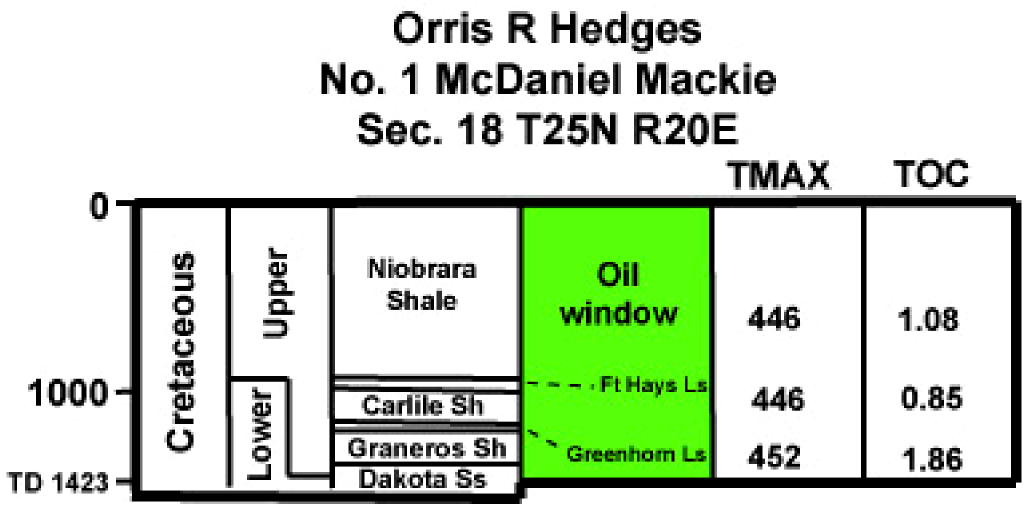

Figure 24. Petroleum source rock profile for Orris R. Hedges No. 1 McDaniel Mackie well, located in Sec. 18 T25N R20E. See Figure 19 for location of well.

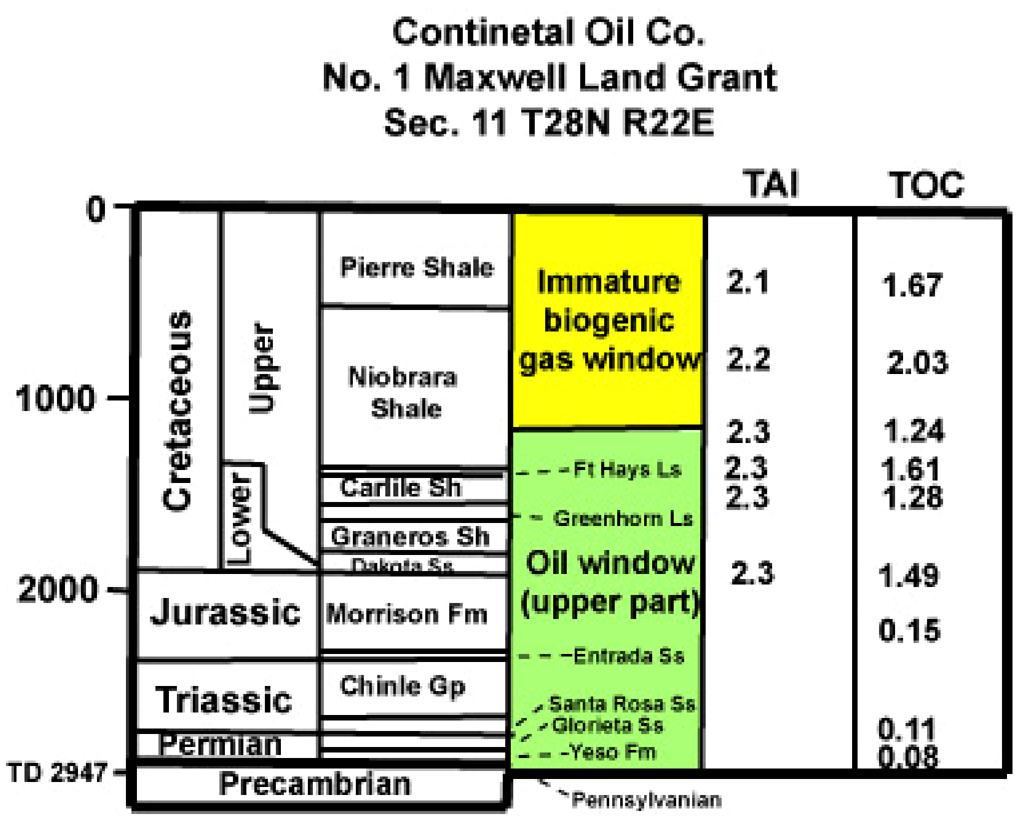

Figure 25. Petroleum source rock profile for Continental Oil No. 1 Maxwell Land Grant well, located in Sec. 18 T28N R22E. See Figure 19 for location of well.

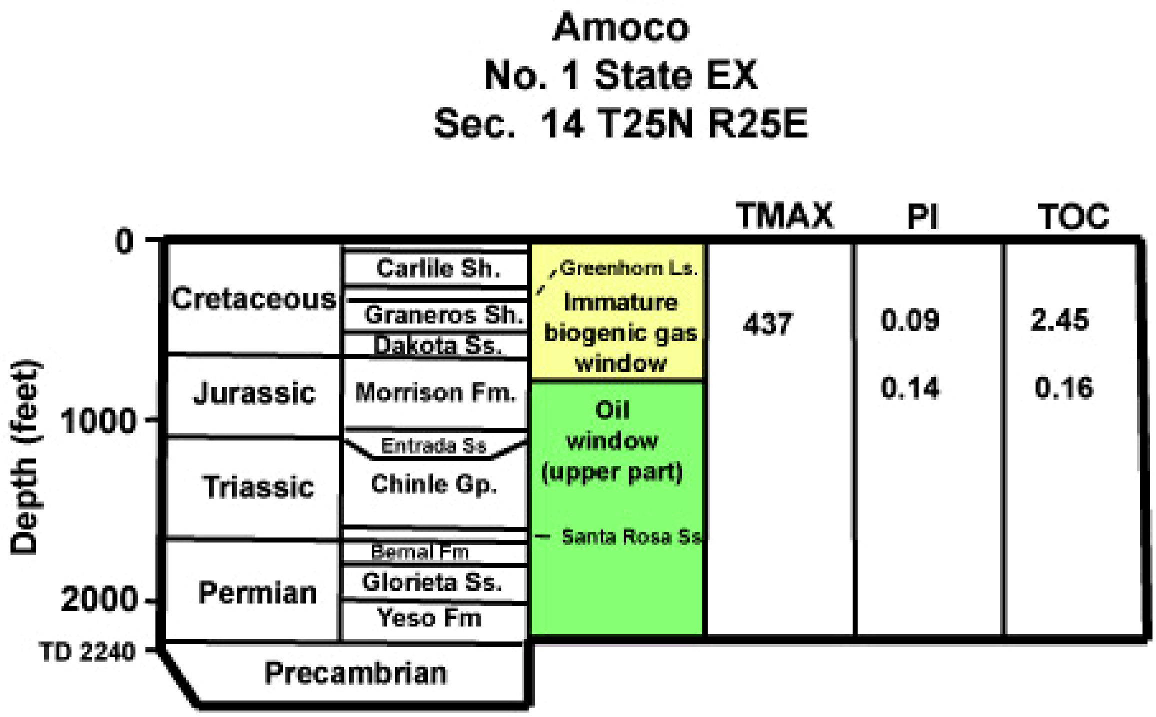

Figure 26. Petroleum source rock profile for Amoco No. 1 State EX well, located in Sec. 14 T25N R25E. See Figure 19 for location of well.

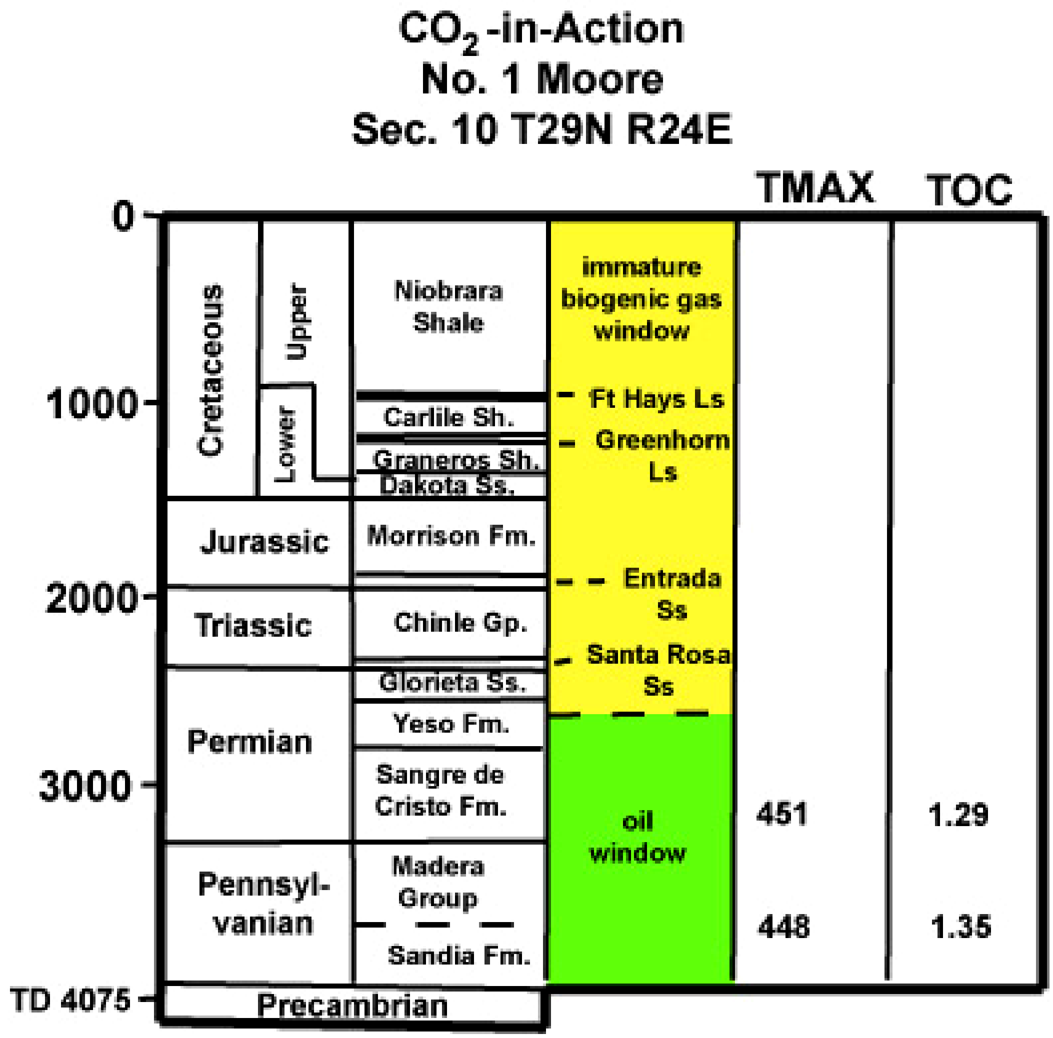

Figure 27. Petroleum source rock profile for CO_2-in-Action No. 1 Moore well, located in Sec. 10 T29N R24E. See Figure 19 for location of well.

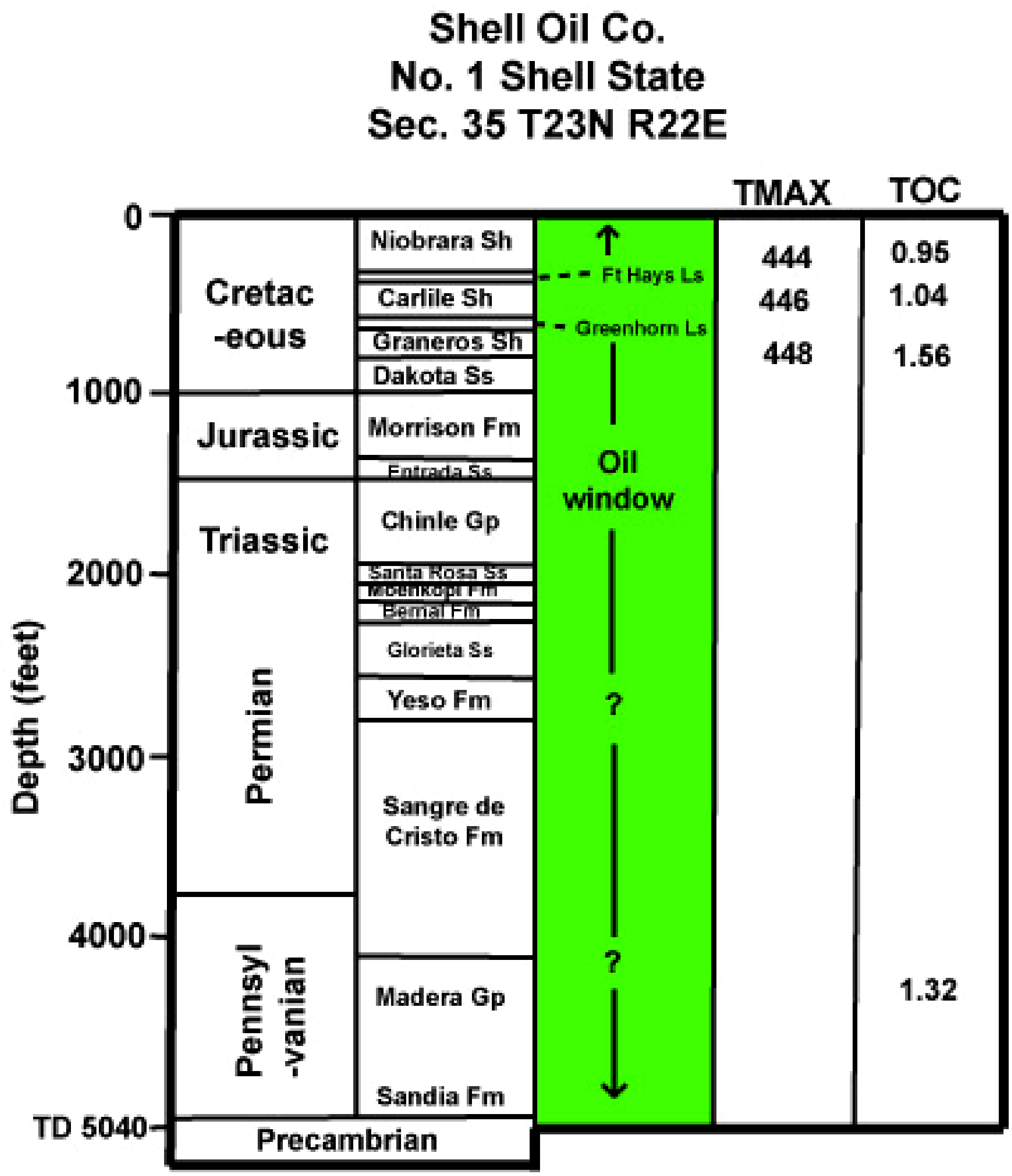

Figure 28. Petroleum source rock profile for Shell Oil Co. No. 1 Shell State well, located in Sec. 35 T23N R22E. See Figure 19 for location of well.

Graneros Shale (Upper Cretaceous)

The Graneros Shale has TOC contents of 1.14 to 2.45 percent, rendering it the most organic rich of the Upper Cretaceous shale units. The Graneros is immature and within the biogenic gas window where it occurs at shallow depths near its outcrop belt on the eastern flank of the Raton Basin. Within the deeper portions of the basin, the Graneros is mature and within the wet gas/dry gas window or within the dry gas window (Figs. 20-27). As with the Pierre, Niobrara and Carlile Shales, much of the organic carbon in the deeper parts of the basin can be regarded as residual and post generative with original TOC contents higher than the present TOC contents. AOM conversion in the deeper parts of the basin exceeds 90 percent. Optical petrography indicates the kerogens are a mixture of amorphous, herbaceous and woody types that would have generated oil and associated gas upon maturation. However, maturation of generated hydrocarbons into the wet gas/dry gas and dry gas windows has resulted in conversion of oil to gases, so that only gases are now present in the deeper parts of the basin. A significant amount of generative kerogen has probably been converted to inertinite in the deeper, more mature parts of the basin.

South of the Cimarron arch in the northeastern part of the Las Vegas Basin, the Graneros Shale is presently buried to depths of less than 1000 ft but is mature and within the oil window (Fig. 28). The Rock-Eval S2/S3 ratio is 4.3, suggestive of the presence of mixed gas-prone and oil-prone kerogens. TOC is in excess of 1 percent and it is likely that oil as well as gas has been generated by the Graneros Shale in this area.

Jurassic Source Rocks

Morrison Formation (Upper Jurassic)

As previously discussed in the section on stratigraphy, the Morrison Formation contains a facies belt of dark-gray to black shales in the Raton Basin (Fig. 13). The dark-colored shales are organic rich and have TOC contents between 1.15 and 1.49 percent, adequate for petroleum generation. Within the shallower parts of the Raton Basin, the Morrison appears to be mostly within the oil window. Although source rock analyses are not available from the deeper parts of the basin where the Morrison has yet to be penetrated by the drill bit, it is almost certain that the Morrison is within the wet gas/dry gas and dry gas windows because the overlying Cretaceous section has been matured to these levels. Limited data indicate that Morrison kerogens are a mixture of oil-prone and gas-prone types, so that oil and associated gas would have been generated upon maturation. However, maturation of generated hydrocarbons into the wet gas/dry gas and dry gas windows has resulted in conversion of oil to gases, so that only gases are now present in the deeper parts of the basin.

Outside of the dark-shale facies belt, Morrison shales are red to maroon, light to medium gray, and blue gray. TOC contents of these lighter colored shales are low, 0.15 to 0.16 percent, insufficient for hydrocarbon generation.

Lower Permian and Pennsylvanian Source Rocks

Source facies of dark-gray to black shales are present within the Sangre de Cristo Formation, the Madera Group, and the Sandia Formation in the Las Vegas and Raton Basins. Most of the source rocks occur in the Madera Group and Sandia Formation (Pennsylvanian) which also contain significant thicknesses on non-source, organic-poor, red shales. Shales in the Sangre de Cristo Formation are mostly red, organic-poor varieties, but organic-rich, dark-gray shales are locally abundant within the Sangre de Cristo and constitute source rocks where thermally mature. Pennsylvanian strata and the Sangre de Cristo Formation are better understood in the Las Vegas Basin where they have been drilled more frequently as the objects of oil and natural gas exploration. Although Pennsylvanian strata are absent from the Cimarron arch, they are present north of the arch where they have been exposed by the faults that form the boundary between the Raton Basin on the east and the Sangre de Cristo uplift on the west. The following discussion of Lower Permian and Pennsylvanian source rocks is subdivided into section concerning the Las Vegas and Raton Basins.

Las Vegas Basin

Within the Las Vegas Basin, the Sangre de Cristo-Pennsylvanian sequence is 2000 to 9000 ft thick (Fig. 12). From the deepest parts of the basin where this stratigraphic sequence is thickest, these strata pinch out to the east onto the Sierra Grande uplift and to the north onto the Cimarron arch. As discussed previously, a portion of the thickening in the Las Vegas Basin is caused by eastward-directed thrust faults that repeat the Pennsylvanian section. However, the non-repeated sections in wells indicate that that the depositional thickness of the Pennsylvanian-Sangre de Cristo stratigraphic section exceeds the thickness of these strata in all nearby areas, except possibly to the west in the Taos trough which has been uplifted and exposed on the Sangre de Cristo uplift.

In the True Oil Company No. 21 Medina well, located in Sec. 25 T24N R16E (Figure 29), the Pennsylvanian section is almost 5500 ft thick and appears to have been repeated by at least one thrust fault. True thickness of the Pennsylvanian in this well is approximately 3300 ft, the same as is observed in the uplifted Taos trough to the west (Fig. 12; see Baltz and Myers, 1999). TOC content varies from approximately 0.5 percent to more than 9 percent and is more than 1 percent in most samples (Figure 29). Rock-Eval Tmax and Productivity Index (PI) values indicate that the Pennsylvanian section in this well is thermally mature with the upper part of the section in the oil window and the lower part in the wet gas/dry gas window. Maturity windows are not repeated by the thrust fault, indicating that maturation may have post-dated faulting, which may be Pennsylvanian in age. Kerogens are dominantly woody types with a secondary population of inertinite and a tertiary population of herbaceous types. Therefore, generated hydrocarbons were predominantly gas.

To the southeast in the Continental Oil Company No. 1 Mares Duran well, located in Sec. 14 T23N R17E (Figure 30), total thickness of the Sangre de Cristo Formation, Madera Group, and Sandia Formation exceeds 7600 ft. TOC content of the dark-gray to black shales in the Pennsylvanian section ranges from 0.88 to 3.95 percent and is more than 1 percent throughout most of the section (Fig. 30). TOC in the reddish shales of the Sangre de Cristo Formation is low, less than 0.2 percent, and is inadequate for petroleum generation.

Sangre de Cristo strata in the Mares Duran well are thermally immature and in the biogenic gas window. This lack of maturity, in conjunction with the low TOC content, indicates these strata have a negligible source-rock capacity. Pennsylvanian strata, however, are thermally mature in the Mares Duran well and are in the upper part of the oil window. Kerogens are predominantly herbaceous and woody types, indicating that generated hydrocarbons are gas with some associated oil.

Further to the south in the deeper part of the basin in the Amoco No. 1 Salman Ranch A well, located in Sec. 3 T20N R17E (Figs. 31, 32), TOC contents of the dark-gray Pennsylvanian shales range from 1.1 to 2.4 percent, more than adequate for petroleum generation. The upper part of the Madera Group is within the oil window and peak oil generation has been attained in the middle part of the Madera. The lower part of the Madera Group and the upper part of the Sandia Formation are within the wet gas/dry gas window and the lower part of the Sandia Formation is within the dry gas window. Kerogens are predominantly herbaceous and woody types, plus inertinite; therefore, hydrocarbons may have been a mixture of gas and associated oils, but the oils were turned into gas in the lower Madera and within the Sandia. It is probable that significant amounts of gaseous hydrocarbons are associated with the dark-gray shales that occur throughout the Pennsylvanian section in this well.

In the northeastern part of the Las Vegas Basin the combined Pennsylvanian-Sangre de Cristo interval thins to 2206 ft in the Shell No. 1 Shell State well, located in Sec. 35 T23N R22E (Figure 28). The Pennsylvanian section (combined Madera Group and Sandia Formation) in this well is approximately 900 ft thick and the single analysis available indicates an average TOC content of 1.32 percent from shales over a 60 ft depth interval (Fig. 28). The Pennsylvanian is shallow in this well and present at depths of 3000 to 5000 ft and appears to be entirely within the oil window and therefore mature. The Rock-Eval S_2/S_3 ration of 3 indicates gas-prone or mixed kerogen. The low Hydrogen Index of 7 indicates the presence of gas-prone and/or inertinitic kerogens. Therefore, it appears that the Pennsylvanian section in the shallow northeastern and eastern parts of the basin has generated gas but may not have attained a peak level of generation.

Brister and others (2005), without the benefit of the source rock analyses used in this report, concluded that the recovery of CO_2 from exploration wells in the Las Vegas was related largely to the thermal destruction of methane at high temperatures in the basin, therefore rendering large portions of the basin overmature and without possibility for gas or oil preservation. This hypothesis can be discounted for two reasons. First, the source rock analyses presented in this report put Pennsylvanian source rocks either in the wet gas-dry gas windows or within the immediately underlying dry gas window. The thermal maturity within the basin is not all that high when compared to maximum thermal maturity in other documented petroleum systems (see Demaison and Murris, 1984). Furthermore, methane can survive temperature of up to 550^{o} C (Hunt, 1979) and can be present in rocks at thermal and pressure conditions up to the onset of metamorphism associated with the greenschist facies (Horsfeld and Rullkotter, 1994), which is certainly a more stressful condition than is present in the Las Vegas Basin where indications of metamorphic conditions are not present anywhere in the Paleozoic section.

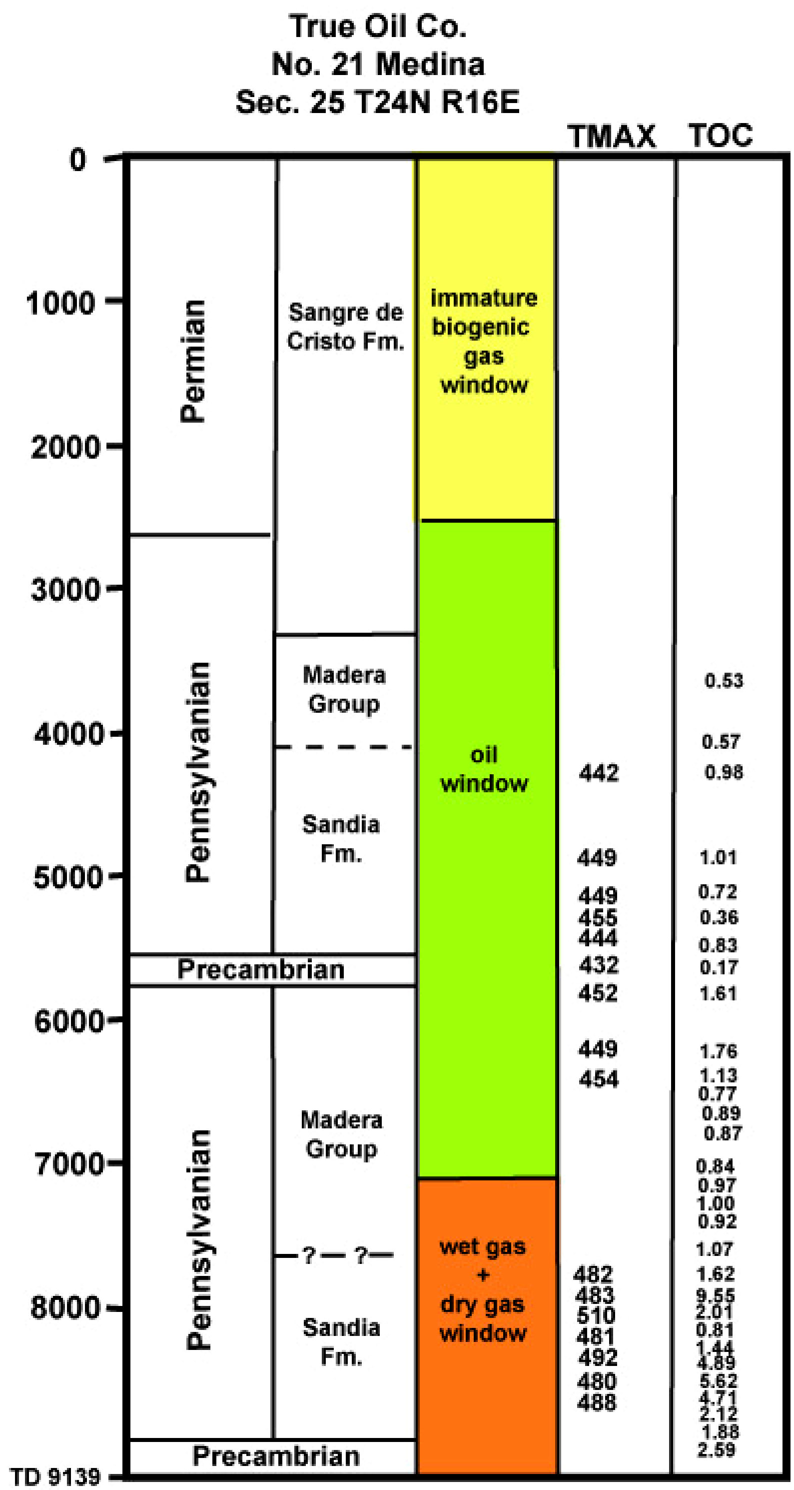

Figure 29. Petroleum source rock profile for True Oil Co. No. 21 Medina well, located in Sec. 25 T24N R16E. See Figure 19 for location of well.

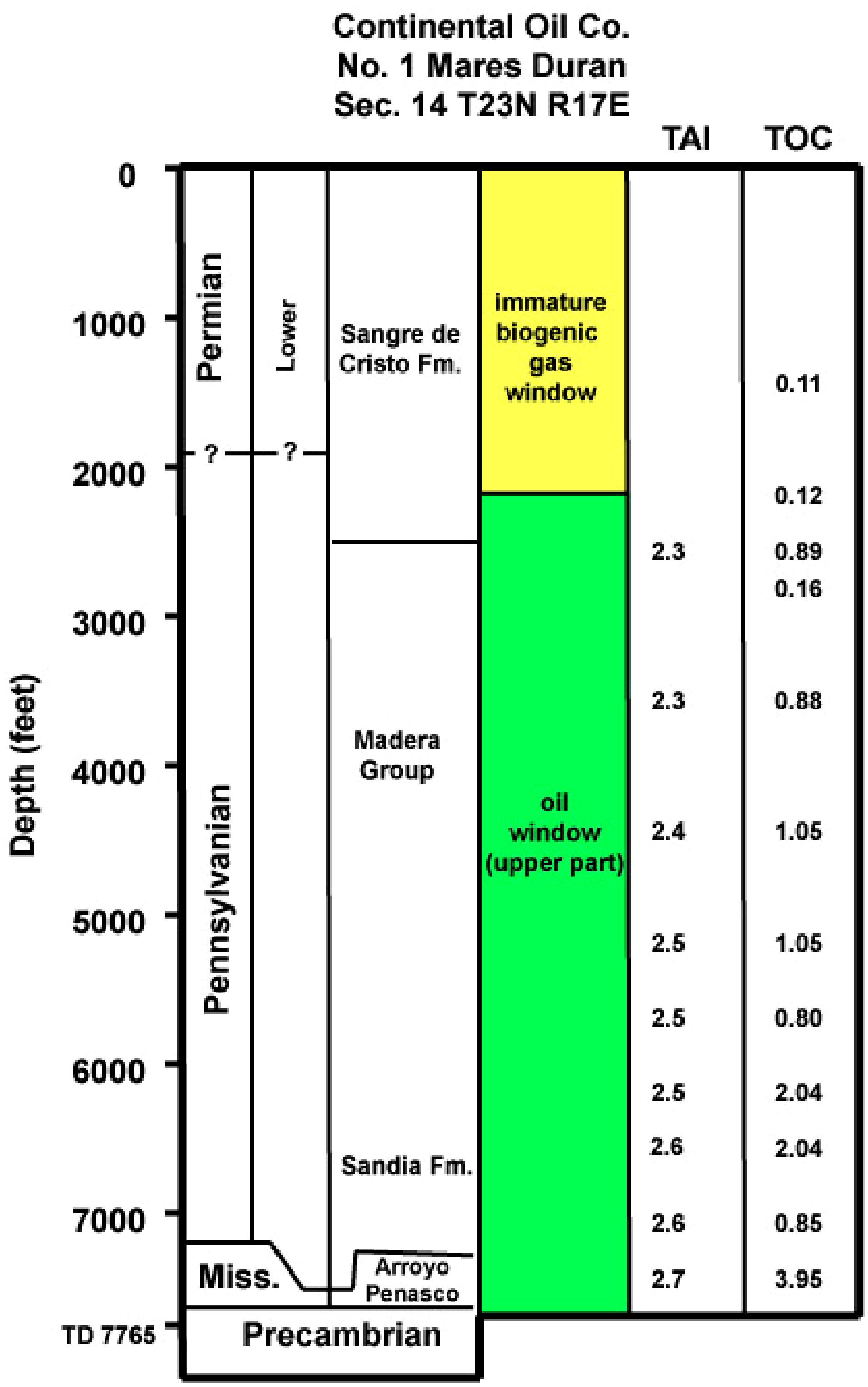

Figure 30. Petroleum source rock profile for Continental Oil Co. No. 1 mares Duran well, located in Sec. 14 T23N R17E. See Figure 19 for location of well.

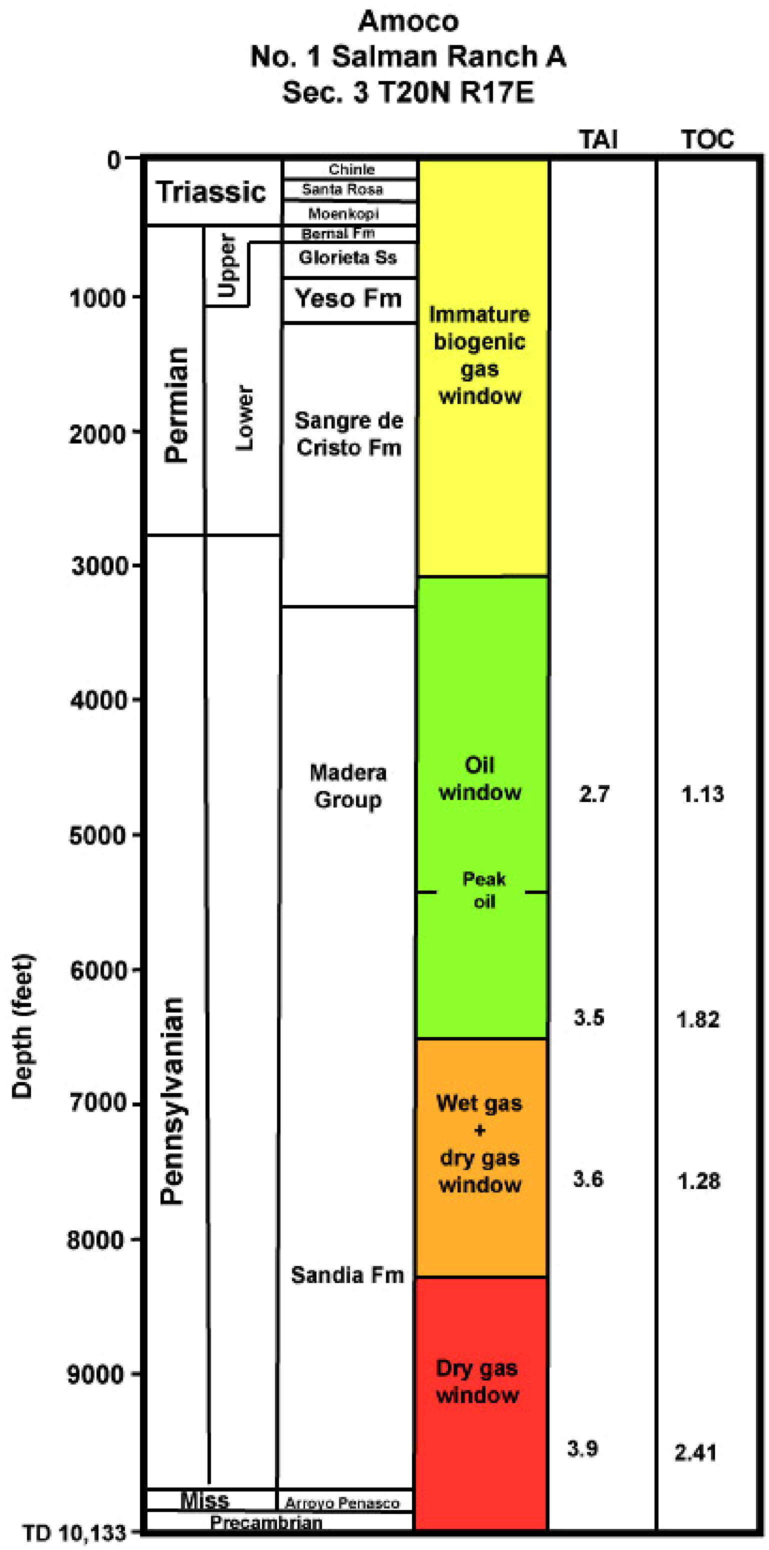

Figure 31. Petroleum source rock profile for Amoco No. 1 Salman Ranch A well, located in Sec. 3 T20N R17E. See Figure 19 for location of well.

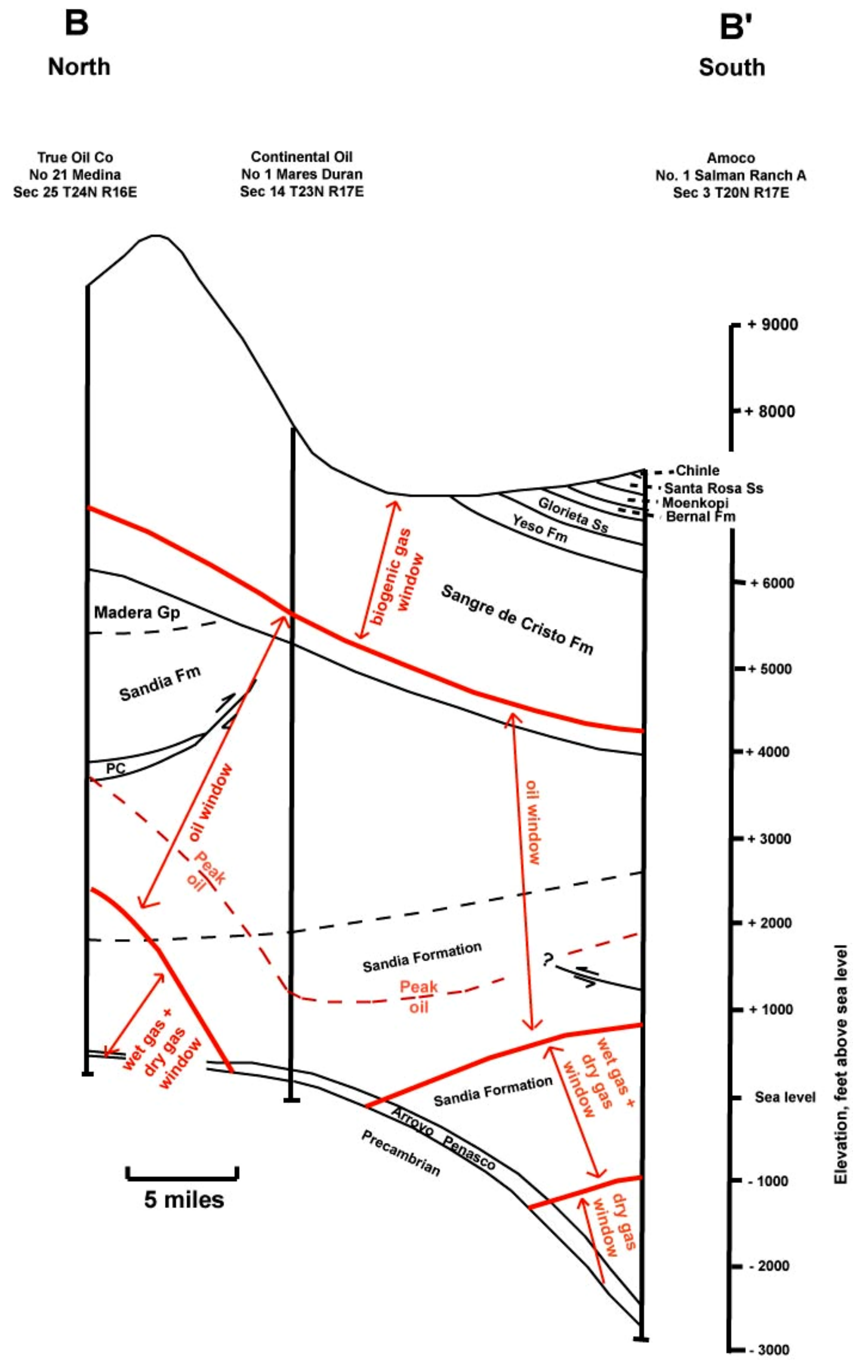

Figure 32. Structural cross section B-B’, indicating tops and bases of oil and gas maturity windows. See Figure 19 for location.

Raton Basin

The combined Pennsylvanian and Sangre de Cristo sections thicken westward in the Raton Basin from 18 to 1000 ft on the northern part of the Sierra Grande uplift to a projected thickness of more than 3000 ft along the axis of the Central Colorado Basin (the late Paleozoic forerunner of the Raton Basin). The geology of this sequence of strata has not been established in the deeper parts of the Raton Basin because no wells have been drilled sufficiently deep to penetrate the sub-Mesozoic section. The thickest known, penetrated section of the Sangre de Cristo-Pennsylvanian interval is 1326 ft in the Pan American No. 1 Phelps Dodge well, located in Sec. 11 T28N R20E (Plate V in Appendix B). The top of the Sangre de Cristo/base of Yeso occurs at a depth of 4834 ft. Precambrian granite was encountered at a depth of 5710 ft. The section between the top of the Sangre de Cristo and 5000 ft consists of red shales and fine- to very fine-grained, red to orange, silty sandstones. Between 5000 ft and the top of the Precambrian, the section consists of interbedded dark-red shales, very dark-gray shales, and fine- to very coarse-grained, conglomeratic arkosic sandstones and minor blue-green shales. The dark-red shales dominate the section as a whole, but the dark-gray shales are dominant in places. The top of the Madera is provisionally placed at 4986 ft at a depth that corresponds to a change in log character associated with the presence of the very dark-gray shales and coarser-grained sandstones below this depth. This boundary can be correlated eastward within the Raton Basin with well logs. However, on the eastern flank of the Raton Basin sparse dark-gray shales occur in the Sangre de Cristo Formation above this boundary. In the absence of biostratigraphic data, the Sangre de Cristo-Pennsylvanian boundary is placed at this log marker (indicated on cross sections, Plates I, II, V in Appendix B). The gamma-ray and resistivity log characteristics of strata above and below this provisional boundary are similar to the log characteristics of the strata above and below the Sangre de Cristo-Madera boundary in the Las Vegas Basin, where it is better defined. Therefore, the top of the Madera in the Raton Basin, as correlated in this report, is based upon lithologic changes above and below this boundary as well as similarity of well log characteristics to the boundary as defined in the Las Vegas Basin.

In any event, it is evident that lateral facies belts defined by the presence or absence of dark-gray shales exist in both the Madera-Sandia section and in the Sangre de

Cristo section in the Raton Basin. These facies belts are at present poorly defined but delineate areas of possible source rocks in these stratigraphic units. Areas without the more organic-rich dark-gray shales contain few of no potential source rocks; areas with dark-gray shales have possible source rocks whose assessment will be dependent upon maturation parameters as well as organic content.

In the CO_2-in-Action No. 1 Moore well, located in Sec 10 T29N R24E in the transitional area between the Raton Basin on the west and the Sierra Grande uplift on the east (Plate I in Appendix A), the top of the Sangre de Cristo Formation occurs at a depth of 2804 ft, the provisional Madera top at a depth of 3274 ft, and the top of the Precambrian at a depth of 4056 ft. Relatively thin packages of organic-rich, dark-gray shales are present in the lower 250 ft of the Sangre de Cristo Formation, which is otherwise dominated by red shales and fine- to very fine-grained sandstones. The dark-gray shales have an average TOC content of 1.29 percent (Fig. 27), more than adequate for petroleum generation. Rock-Eval Tmax is 451 ^{O}C and the Productivity Index is 0.2, indicating that these rocks are thermally mature and within the oil window. The Madera-Sandia interval is dominated by dark-gray shales and fine- to very coarse-grained conglomeratic sandstones. The shales have an average TOC content of 1.35 percent, more than adequate for petroleum generation. They are thermally mature and within the oil window with a Rock-Eval Tmax of 448 ^{o}C and a Productivity Index of 0.2.

Although the Sangre de Cristo and Madera-Sandia intervals have not been penetrated further to the west in the deepest parts of the Raton Basin, the shallower Cretaceous section is in the dry gas window, as previously discussed. Therefore, the Sangre de Cristo and Pennsylvanian sections are almost certainly in the dry gas window in the deepest parts of the basin because they are buried more than 1000 ft deeper than the base of the Cretaceous in this area.

Hydrocarbon Occurrences – Production and Shows

Commercial production of natural gas has been obtained from the Dakota Sandstone (Cretaceous) and the Morrison Formation (Jurassic) at the Wagon Mound field in Mora County and from coals in the Raton and Vermejo Formations (Upper Cretaceous to Tertiary: Paleocene) in northern Colfax County (Figure 3). In addition, gas has been produced noncommercially from the Pierre and Niobrara Shales (Upper Cretaceous) in a single well in the northern part of the Raton Basin in northern Colfax County. Gas shows have been encountered in the Pierre and Niobrara Shales in the Raton Basin, from the Greenhorn Limestone on the Cimarron arch, from the Morrison Formation on the eastern flank of the Raton Basin, and from Pennsylvanian strata in the Las Vegas Basin. Oil shows have been encountered in the Pierre and Niobrara Shales on the eastern flank of the Raton Basin, in the Dakota Sandstone on the eastern flank of the Raton Basin, and from the Morrison Formation on the eastern flank of the Raton Basin. Shows of carbon dioxide (CO_2) gas have been encountered in Triassic strata on the eastern flank of the Raton basin and the eastern flank of the Las Vegas Basin, in the Glorieta Sandstone (Permian) on the eastern flank of the Raton Basin and the eastern flank of the Las Vegas Basin, and from the Sangre de Cristo Formation (Upper Pennsylvanian to Lower Permian) in the central part of the Las Vegas Basin. Oil and gas production and shows are described in the well database (*northcentralwells.xls*) in Appendix A. Production and shows are described and discussed in the following section in descending stratigraphic order, the order that they will be encountered by the drill bit.

Cretaceous strata

Vermejo and Raton Formations (Upper Cretaceous to Tertiary: Paleocene)

Natural gas is produced from coal beds in the Vermejo Formation (Upper Cretaceous) and the Raton Formation (Upper Cretaceous to Tertiary: Paleocene) in the northern axial part of the Raton Basin (Figure 3). Geology and occurrence of coalbed methane in the Raton Basin has been discussed by Jurich and Adams (1984), Close and Dutcher (1990), and Brister and others (2005). At the time this project was undertaken, there were 583 well productive from coals in the Vermejo and Raton Formations, with production in at least 354 wells commingled from Vermejo coals and from Raton coals.

In eight wells (Table 4), gas produced from the Vermejo Formation is commingled with gas produced from the underlying Trinidad Sandstone (Upper Cretaceous). As of the end of 2003, the 583 productive wells had yielded a cumulative 128 billion ft^3 (BCF) gas. Annual field production in 2007 was approximately 26 BCF. Wells continue to be drilled and the field continues to be developed through the present.

The coalbed methane resources of the Raton Basin were initially evaluated through a series of 15 wells drilled from 1989 through 1991 by Pennzoil. No well were drilled and completed for coalbed methane production until 1999 when Sonat Raton began to explore and develop the field. Operations in the field were assumed by El Paso Energy Raton in late 1999 and its successor, El Paso E&P Company, which continues to operate and develop the coalbed methane resource in the basin. For regulatory purposes, this coalbed methane accumulation has been divided into the Stubblefield Canyon, Van Bremmer Canyon, and Castle Rock Park pools. Production depths range from 700 ft for the stratigraphically highest coals in the Raton Formation to 2700 ft for the stratigraphically lowest coals in the Vermejo Formation.

Pierre Shale (Upper Cretaceous)

The Pierre Shale has been productive from one well in the Raton Basin. Well records indicate gas shows were encountered in two additional wells (Table 5; Fig. 33). The productive well, the Pennzoil No. 2 Vermejo Ranch, located in Sec. 1 T31N R17E, was completed in 1981 through an open-hole interval between depths of 3383 and 3737 ft, a depth interval that included both the Pierre and the Niobrara Shales. Until abandonment in 1991, the well produced a cumulative 173 MMCF gas and 20 thousand bbls water (MBW). The well supplied natural gas for local use on the Vermejo Park Ranch. The completion forms indicate production was obtained from below 3383 ft as production casing with a packer was set at this depth. The top of the Niobrara is at a depth of 3592 ft, so the productive open-hole interval straddles the Pierre-Niobrara

Table 4. Wells with reported production, shows and tests in the Trinidad Sandstone.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Comp	TD	Status	Trinidad depth	ProdForm1	ProdInterval1	ProdForm2	ProdInterval2	Remarks	Trinidad production or show
El Paso Energy Raton	35	VPR B	30	N	18	E	27	Jun-01	2793	Gas		Vermejo-Trinidad	2468-2580				gas production
El Paso Energy Raton	34	VPR B	30	N	18	E	34	Jul-01	2855	Gas		Vermejo-Trinidad	2392-2607				gas production
El Paso Energy Raton	37	VPR A	32	N	20	E	28	May-00	2270	Gas		Vermejo-Trinidad	1985-2206				gas production
El Paso Energy Raton	32	VPR B	29	N	18	E	1	Jun-01	2735	Gas		Vermejo	2239-2460	Trinidad	2462-2464		gas production
El Paso Energy Raton	31	VPR B	29	N	18	E	2	Jun-01	2890	Gas		Vermejo	2381-2593	Trinidad	2630-2632		gas production
El Paso Energy Raton	34	VPR A	32	N	20	E	30	May-00	2500	Gas		Vermejo	2377-2399	Trinidad	2405-2409		gas production
El Paso Energy Raton	11	VPR E	31	N	19	E	5	Aug-01	2735	Gas		Raton-Vermejo	1172-2431	Trinidad	2489-2496		gas production
El Paso Energy Raton	17	VPR E	32	N	19	E	32	Jul-01	2643	Gas	2486	Raton-Vermejo	1025-2411	Trinidad	2422-2427		gas production
Odessa Natural Corp	5	ODESSA NATURAL W S RANCH	30	N	18	E	22	Nov-72	6390	D&A	2108					Perf Trinidad (2140-2220), frac	

Table 5. Wells with production, shows and tests in the Pierre Shale.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Comp	TD	Status	Pierre depth	Pierre thickness	ProdForm1	ProdInterval1	Remarks	Pierre production or show
Bennett Petroleum	3Y	Phelps Dodge	28	N	21	E	9	Apr-80	3135	D&A					Perf Pierre (500-510) 40 MCFD natural	gas show 40 MCFD
Continental Oil Company	4	St. Louis, Rocky Mountain and Pacific RR	29	N	22	E	17	Nov-54	4709	D&A	0	1618			DST 1919-2001 (Pierre) rec 20 mud, very slight blow.	
Odessa Natural Corp	4	W S Ranch	29	N	18	E	12	Aug-72	6196	D&A					Persistent weak gas shows in middle Pierre (Speer, 1976).	Gas shows in middle Pierre.
Odessa Natural Corp	3	ODESSA NATURAL WS RANCH	29	N	19	E	24	Oct-72	5084	D&A	1330	2412			Persistent weak gas shows in middle Pierre (Speer, 1976). Perf Pierre (2275-2317), frac.	Gas shows in middle Pierre.
Odessa Natural Corp	4X	W S Ranch	29	N	19	E	12	Sep-72	6394	D&A					Persistent weak gas shows in middle Pierre (Speer, 1976).	Gas shows in middle Pierre.
Odessa Natural Corp	5	ODESSA NATURAL W S RANCH	30	N	18	E	22	Nov-72	6390	D&A	2232	2668			Persistent weak gas shows in middle Pierre (Speer, 1976).	Gas shows in middle Pierre.
Odessa Natural Corp	2	VERMEJO PARK	30	N	19	E	16	Sep-72	5426	D&A	1390	2682			Persistent weak gas shows in middle Pierre (Speer, 1976).	Gas shows in middle Pierre.
Odessa Natural Corp	2	ODESSA NATURAL & MAGUIRE OIL	30	N	20	E	30	Feb-73	5160	D&A	1338	2564			Persistent weak gas shows in middle Pierre (Speer, 1976).	Gas shows in middle Pierre.
Odessa Natural Corp	1	W S Ranch	30	N	20	E	30	Mar-72	4962	J&A					Persistent weak gas shows in middle Pierre (Speer, 1976).	Gas shows in middle Pierre.
Odessa Natural Corp	1X	W S Ranch	30	N	20	E	30	Sep-72	5063	D&A					Persistent weak gas shows in middle Pierre (Speer, 1976).	Gas shows in middle Pierre.
Pennzoil	2	Vermejo Ranch	31	N	17	E	1	Jul-81	3737	Gas	970	2622	Pierre-Niobrara	3383-3737	Open hole completion (Pierre-Niobrara); OWPA 9/9/1991; cum 173 MMCF + 20 MBW	gas production (commingled with Niobrara)

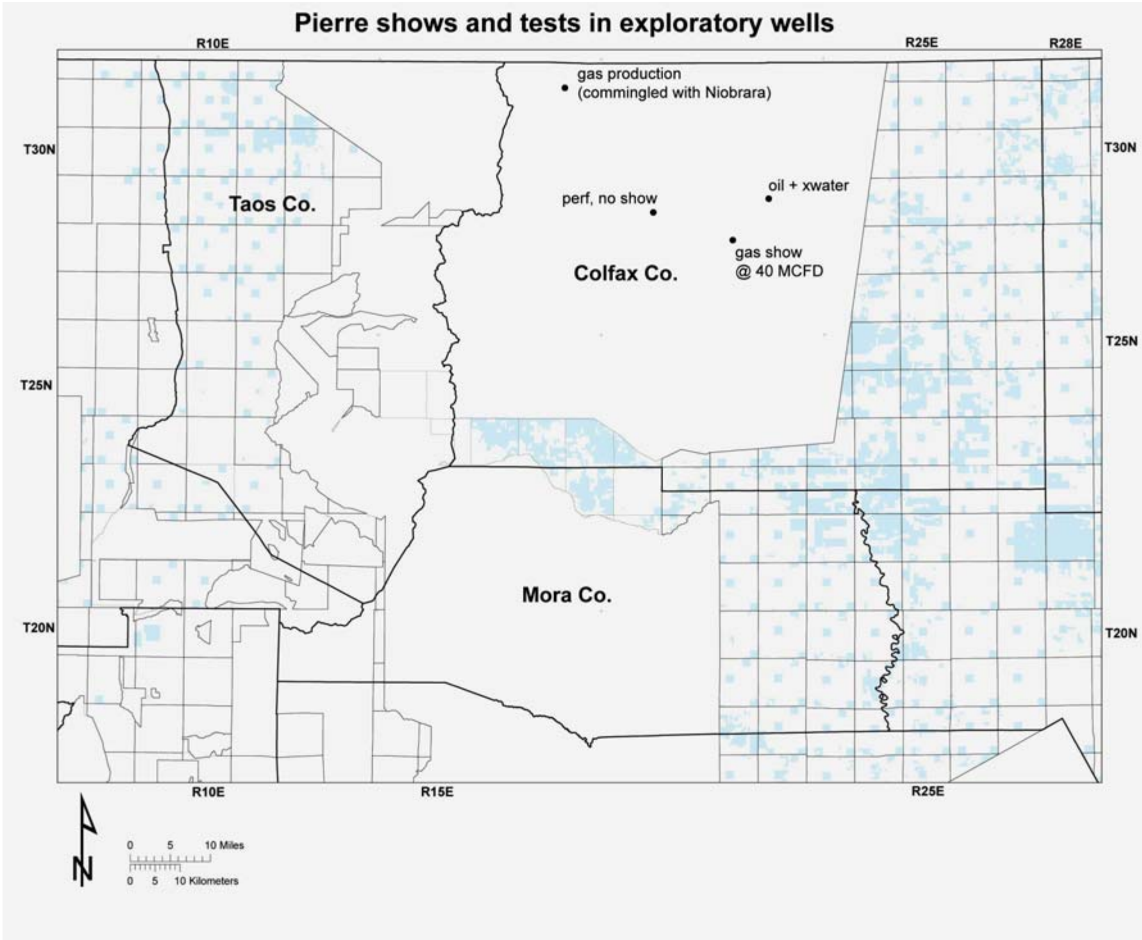

Figure 33. Wells with production, shows and tests in the Pierre Shale. See Table 5 for descriptions.

contact. The well was not reported to be artificially fractured or otherwise stimulated. Therefore, the flow rates were natural. Initial flow was reported at 691 thousand ft^3 gas per day (MCFD). Presumably production rates may have been increased if the productive shales had been artificially fractured. The Pierre is thermally mature and within the wet gas/dry gas window in this well.

Other Pierre shows include a natural flow of 40 MCFD from casing perforations at 500 to 510 ft in the Bennett Petroleum No. 3Y Phelps Dodge well, located on the southwest flank of the Raton Basin in Sec. 9 T28N R21E. In this well, the Pierre appears to be thermally immature and in the biogenic gas window. The Continental Oil. No. 4 St. Louis, Rocky Mountain and Pacific well, located in Sec 17 T29N R22E, had a very slight blow on a drill-stem test of the Pierre; this well is located on the southeast flank of the basin where the Pierre is thermally mature and in the biogenic gas window. Speer (1976) indicated that several wells drilled in the Raton Basin by Odessa Natural Corp. (Table 5) encountered what he described as "persistent weak gas shows" throughout a 630 ft interval in the middle part of the Pierre; an unsuccessful attempt was made to complete one of the shows in the Odessa Natural Corp. No. 3 W S Ranch well, located in Sec. 24 T29N R19E.

Niobrara Shale (Upper Cretaceous)

The Niobrara Shale has been productive from one well and well records indicate shows were encountered in four additional wells (Table 6; Fig. 34). The productive well, the Pennzoil No. 2 Vermejo Ranch located in Sec. 1 T31N R17E, was productive from an open-hole zone that straddles the Pierre-Niobrara boundary, as previously discussed. Three other wells have reported shows from the Niobrara on the eastern flank of the basin where the Niobrara is either immature and in the biogenic gas window or is mature and in the uppermost part of the oil window. The Willard C Franks No. 1 Lowe well, located in Sec. 19, T27N R22E encountered a gas show in the middle part of the Niobrara Shale. The CO_2-in-Action No. 2 Moore well, located in Sec. 10 T29N R24E, encountered gas with a reported flow rate of 500 ft^3/day from the upper part of the Niobrara. The CO_2-in-Action No. 1 Moore well, also located in Sec 10 T29N R24E, encountered water in three sandy zones in the upper, middle, and lower parts of the Niobrara. A short distance away, the Inflow Oil Co. No. 1 Brown well, located in Sec. 3 T29N R24E, had a reported show of oil in the upper part of the Niobrara. In addition, the HNG Fossil Fuels No. 1 Maxwell, located in Sec. 1 T26N R23E, was perforated and acidized over a 20 ft interval in the lower Niobrara, presumably to test a show or other indication of hydrocarbons. In the Brooks Yetter No. 1 Fernandez Brothers well, located in Sec. 34 T23N R21 E on the south flank of the Cimarron arch, a show of gas was reported at a depth of 140 ft in the Niobrara Shale.

Table 6. Wells with production, shows and tests in the Niobrara Shale.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Comp	TD	Status	Niobrara depth	Niobrara thickness	ProdForm1	ProdInterval1	Remarks	Niobrara production or show
HNG Fossil Fuels	1	Maxwell	26	N	23	E	1	Nov-82	3100	D&A	0	398			Perf 367-387, acidized. (Niobrara)	perf, no show
Franks, Willard C.	1	Laroe	27	N	22	E	19	Nov-65	1825	D&A					slight show gas @ 1200 ft (Niobrara)	gas show
Inflow Oil Company	1	Brown	29	N	24	E	3	192?	260	D&A					show oil 240-260 ft (Niobrara)	oil show
CO2 in Action	2	Moore	29	N	24	E	10	Jul-78	4083	D&A					Water @ 30 (Niobrara). Show gas 180 (Niobrara), 270-290 (Niobrara; 1/2 MCF), 980 (Niobrara).	gas show 1/2 MCF
CO2 in Action	1	Moore	29	N	24	E	10	Jun-78	4075	D&A	0	954			Water sands @ 240-264 (Niobrara), 650-670 (Niobrara), 970-990 (Niobrara-Fort Hays).	water (in Niobrara sands)
Pennzoil	2	Vermejo Ranch	31	N	17	E	1	Jul-81	3737	Gas	3592		Pierre-Niobrara	3383-3737	Open hole completion (Pierre-Niobrara); OWPA 9/9/1991; cum 173 MMCF + 20 MBW	gas production (commingled with Pierre)

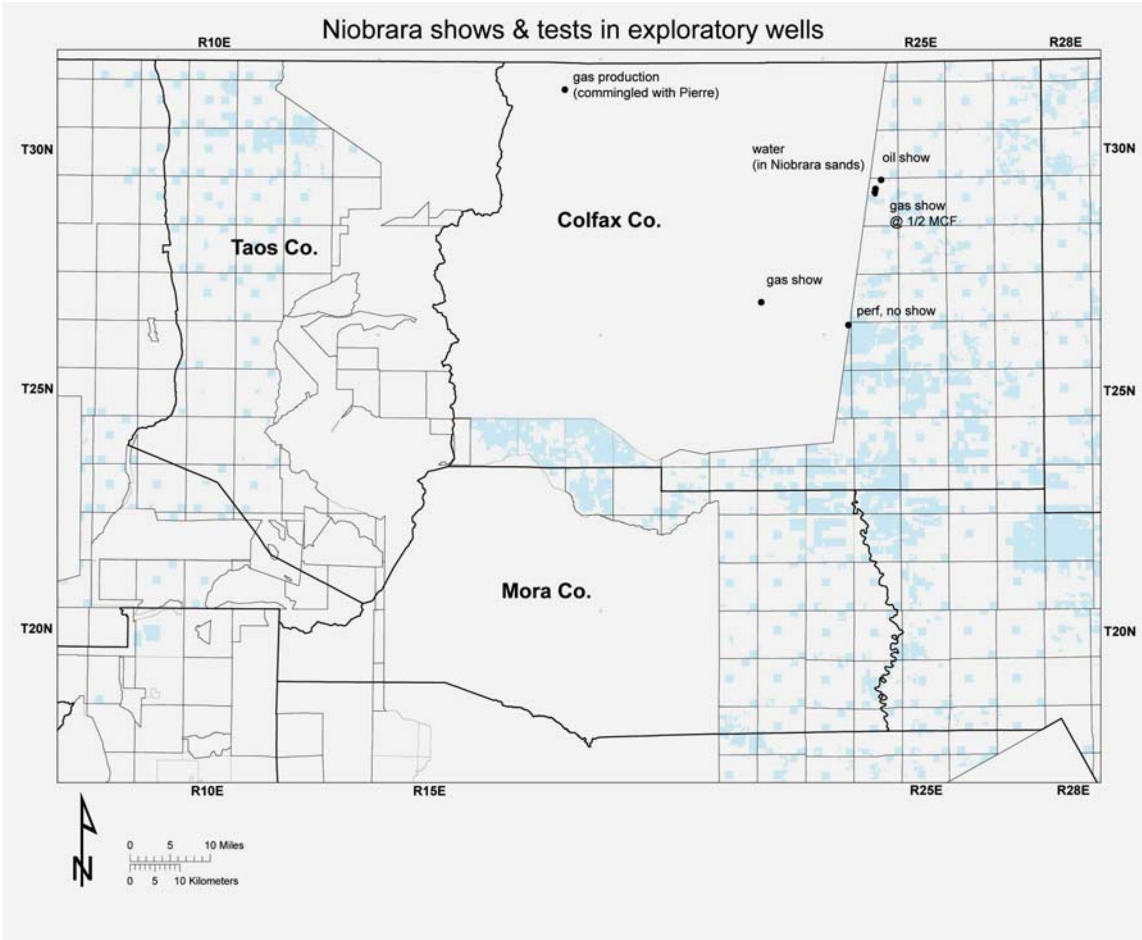

Figure 34. Wells with production, shows and tests in the Pierre Shale. See Table 6 for descriptions.

Carlile Shale, Graneros Shale, and Greenhorn Limestone (Upper Cretaceous)

The Carlile and Graneros Shales and the intervening Greenhorn Limestone have been sparsely tested. One drill-stem test and two sets of casing perforations in three different wells in the northern part of the Las Vegas Basin yielded no reported shows (Figure 35; Table 7). Along the northernmost fringe of the Las Vegas Basin (south flank of Cimarron arch), gas flowed at a reported rate of 500 MCFD from the Greenhorn Limestone in the Brooks Yetter Drilling No. 1 Fernandez Brothers well, located in Sec. 34 T23N R21E.

In the Raton Basin, the Graneros interval was perforated and fractured in the Odessa Natural Corp. No. 3 Odessa Natural well, but no shows were reported. In the

Table 7. Wells with shows and tests in theFort hays Limestone, Carlile Shale, Greenhorn Limestone and Graneros Shale.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	TD	Status	PoolName	Carlile depth	Greenhorn depth	Graneros depth	Remarks	Carlile-Graneros production or show
Cibola Energy	4	Mora Ranch	21	N	21	E	5	801	D&A	Wagon Mound				Perf 550-775 (Carlile); water @ 801 ft (Greenhorn)	water
Cibola Energy	3	Mora Ranch	21	N	21	E	5	1062	D&A	Wagon Mound	570	796	852	Perf 600-790 (Carlile), perf 798-806 (Greenhorn), acidized	perf, no show
Shell Oil	1	Mora Ranch	22	N	19	E	5	9690	D&A		266	484	548	DST 525-580 (Greenhorn-Graneros) rec 15 mud.	DST, no show
Brooks Yetter Drilling	1	Fernandez Brothers	23	N	21	E	34	1485	D&A		385	760	810	Gas @ 500 MCF @ 780-782 ft (Greenhorn).	gas @ 500 MCFD in Greenhorn
Odessa Natural Corp	3	ODESSA NATURAL WS RANCH	29	N	19	E	24	5084	D&A		4046	4620	4672	Perf Graneros (4928-4998), frac.	perf Graneros, no show
Continental Oil Company	1	St. Louis, Rocky Mountain and Pacific RR	30	N	22	E	13	5185	D&A		2884	3040	3112	DST 2875-2920 (Fort Hays-Carlile) rec 26 mud; DST 3090-3128 (Greenhorn-Graneros) rec 27 mud.	DST Ft Hays-Greenhorn-Carlile-Graneros, no show

Continental No. 1 St. Louis, Rocky Mountain and Pacific RR well, located in Sec. 13 T30N R22E, only drilling mud was recovered from drill-stem tests in the Fort Hays, Carlile, Greenhorn and Graneros intervals. Presumably, all of these tests of the Fort Hays, Carlile, Greenhorn and Graneros were run to evaluate shows or other indications of hydrocarbons.

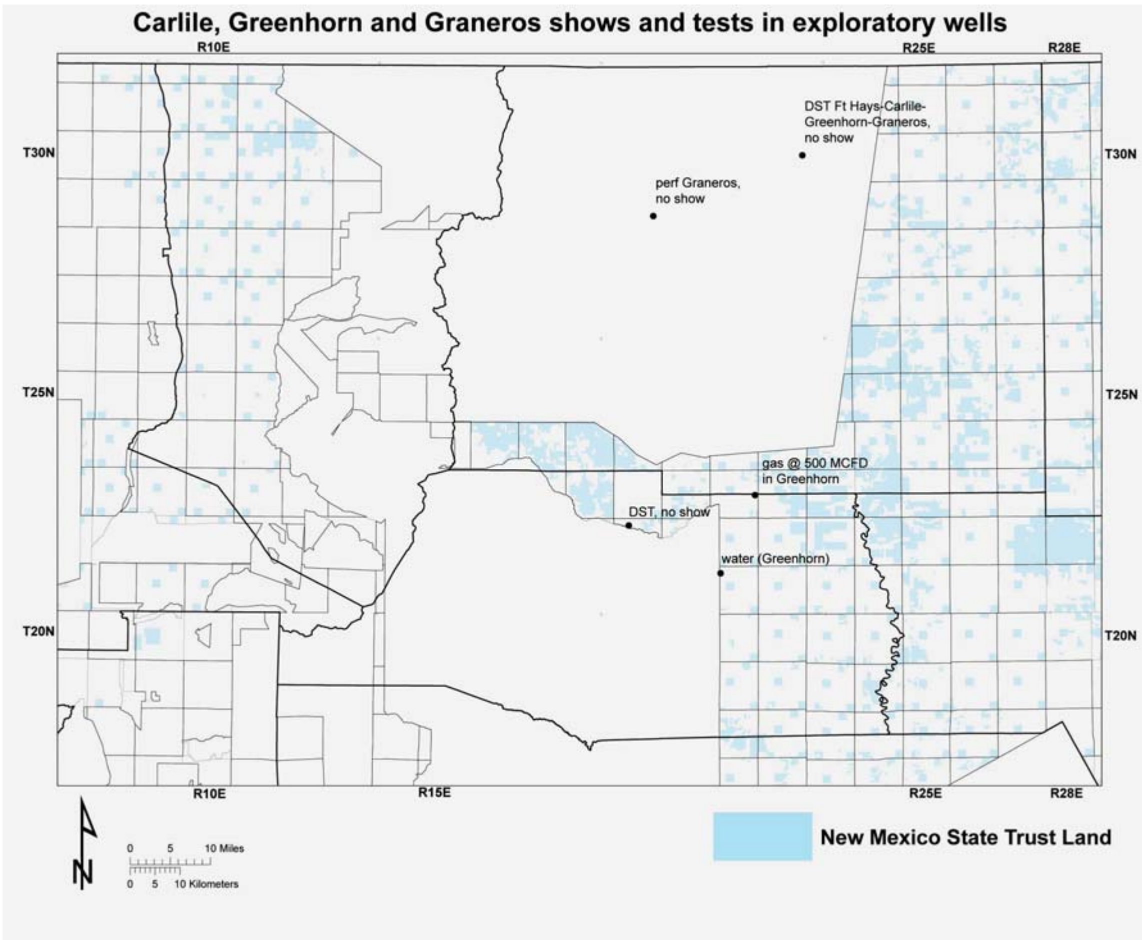

Figure 35. Wells with shows and tests in the Fort Hays Limestone, Carlile Shale, Greenhorn Limestone and Graneros Shale. See Table 7 for descriptions.

Dakota Sandstone (Lower to Upper Cretaceous)

Natural gas has been produced from the Dakota Sandstone (Cretaceous) and Morrison Formation (Jurassic) at the Wagon Mound field. This gas field is situated on the eastern flank of the Las Vegas Basin in central Mora County (Figure 36; Table 8). Elsewhere in Mora County, numerous wells have tested the Dakota Sandstone and have encountered either fresh water or gas shows or gas shows accompanied by recovery of fresh water. Further to the north in the Raton Basin, several wells have drilled and tested

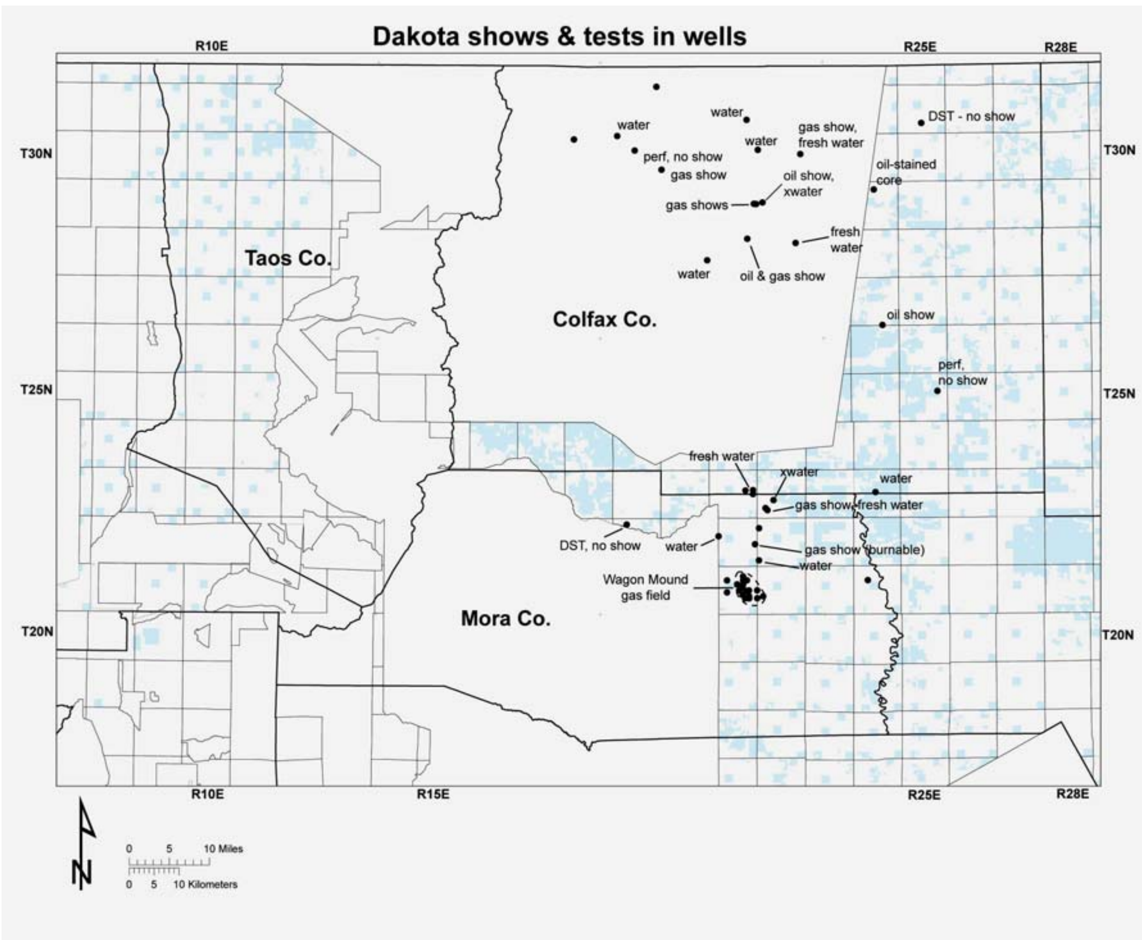

Figure 36. Wells with production, shows and tests in the Dakota Group. See Table 8 for descriptions.

Table 8. Wells with production, shows and tests in the Dakota Group.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Comp	TD	Status	PoolName	Dakota depth	Dakota thickness	ProdForm1	ProdInterval 1	Remarks	Dakota production or show
Wood Oil	1	Simms	21	N	21	E	9	Nov-74	632	Shut in?	Wagon Mound			Dakota	586-632	IP 387 MCFD	gas flow
W E Bakke Jr	2	Darwin Daniels	21	N	21	E	11	Feb-77	502	Gas	Wagon Mound			Dakota	455-502	IPCAOF 895 MCFD; flowed 149 MCFD/55 min	gas production
W E Bakke Jr	4	Darwin Daniels	21	N	21	E	11	Nov-77	673	Gas	Wagon Mound	408	198	Dakota	571-608	flowed SSG TSTM; SIGW	gas production
W E Bakke Jr	3	Darwin Daniels	21	N	21	E	11	May-77	549	Gas	Wagon Mound			Dakota	500-549	IPCAOF 600 MCFD	gas production
Brooks Exploration	1	Clyde Berlier A	21	N	21	E	14	Oct-75	434	Gas	Wagon Mound			Dakota	292-434	IPF 456 MCFD (81% methane, 17% N2, 2% CO2, 0.01% O2)	gas production
W E Bakke Jr	1	FLB Daniels	21	N	21	E	14	Sep-77	756	Gas	Wagon Mound	366	148	Morrison	558-718	IPF 385 MCFD	gas production
Brooks Exploration	1	E R Julian	21	N	21	E	15	Sep-73	480	Shut in?	Wagon Mound			Dakota	379-480	IPCAOF 490 MCFD	gas flow
Cibola Energy	2	Clyde Berlier	21	N	21	E	21	Nov-79	900	D&A	Wagon Mound	602				IP 75 MCFD; gas 62% N2; 38% methane; OH 646-TD	gas show
Brooks Exploration	3	Clyde Berlier	21	N	21	E	22	Oct-75	440	Gas	Wagon Mound			Dakota	364-440	IP 396 MCFD; gas 21% N2, 0.5% CO2, 78% methane, 0.01% O2, H2S 1.74 grains/100ft3.	gas production
Brooks Exploration	4	Clyde Berlier	21	N	21	E	23	Oct-75	416	Gas	Wagon Mound			Dakota	324-416	IP 493 MCFD; gas 15% N2, 1.5% CO2, 83% methane, 0.02% O2, H2S 2.13 grains/100 ft3	gas production
Brooks Exploration	2	Clyde Berlier	21	N	21	E	23	Nov-82	844	Gas	Wagon Mound	306	210	Dakota	358-390	IP 237 MCFD; gas 19% N2, 0.37% CO2, 81% methane, 0.01% O2	gas production
William Gruenerwald	WS1	Gonzales Pittman	21	N	21	E	24	Dec-77	2916	water		414	146	Dakota	410-490	Drilled as petroleum exploration well, converted to water supply well from Dakota. Perf 496-529 (Dakota). PB 490.	water
William Gruenerwald	1Y	Gonzales Pittman	21	N	21	E	24	Nov-77	2916	D&A	Wagon Mound					Perf 496-526 (Dakota).	
William Gruenerwald	2	Gonzales Pittman	21	N	21	E	24	Apr-78	895	Shut in?	Wagon Mound			Dakota-Morrison	481-895	IPF 850 MCFD	gas flow
William Gruenerwald	5	Gonzales Pittman	21	N	21	E	25	Aug-77	905	Shut in?	Wagon Mound			Dakota-Morrison	425-905	IPF 94 MCFD	gas flow
Brooks Exploration	5	Clyde Berlier	21	N	21	E	26	Oct-75	461	Shut in?	Wagon Mound	374		Dakota	379-461	IPF 17 MCFD; gas 58% N2, 2.1% CO2, 39% methane, 0.01% ethane, 0.03% O2	gas flow
William Gruenerwald	4	Gonzales Pittman	21	N	22	E	19		1500	D&A							
William Gruenerwald	WS3	Gonzales Pittman	21	N	22	E	19	May-77	1050	water						Drilled as petroleum exploration well; completed as water supply well.	
William Gruenerwald	6	Gonzales Pittman	21	N	22	E	30		1500	D&A							
Mobil Oil Corp.	1	Joliff & Eubank	21	N	24	E	8	Nov-77	2414	D&A		0	256				
Shell Oil	1	Mora Ranch	22	N	19	E	5	Feb-69	9690	D&A		750	174			DST 746-776 (Dakota) rec 15 mud.	DST no show
Brooks Exploration	1	Fernandez-Maes	22	N	21	E	17	Nov-74	1272	water						water @ 1252 ft (Dakota) @ 8 gallons per minute; lost circulation @ 1272 ft; Drilled as petroleum exploration well, converted to water well	water
W E Bakke Jr	1	Harold Daniels	22	N	21	E	24	Oct-77	1034	D&A		944				3-4 ft gas flare at 989 ft (Dakota); PB to 985 ft (Dakota), swbd water with show gas.	gas show(burnable)
W E Bakke Jr	1	J Lee Daniels	22	N	22	E	7	Oct-77	1512	D&A		978				Perf 988-1004 (Dakota).	Dakota perf
W E Bakke Jr	1	Earl Daniels	22	N	22	E	31	Feb-77	1025	water						Water @ TD. Drilled as petroleum exploration well, converted to water well.	water
Columbine Oil Co.	1	George	23	N	21	E	13	Sep-58	1607	water		910	210			Drilled as petroleum exploration well. Converted to water v	fresh water
Kelly Bell	1	Fernandez-Montoya	23	N	21	E	14	Nov-73	1171	water						Drilled as petroleum exploration well. Converted to water well. Perf 992-1075 (Dakota), acidized, flowed 968 BW.	fresh water
Brooks Yetter Drillin	1	Fernandez Brothers	23	N	21	E	34	Jan-26	1485	D&A		990	230			HFW (fresh) @ 1025 ft (Dakota)	fresh water
R W Filkey	1	Jeoffrey	23	N	22	E	21	Aug-59	1080	D&A						Salt water @ 1053 ft (Dakota)	xwater
Trio Oil	1	Rinehart	23	N	22	E	29	Jul-59	1090	water		922				Drilled as petroleum exploration well; converted to water well.	water
Franks & Hesser	1	Jeoffrey	23	N	22	E	32	Oct-61	1048	water						Water @ 215 ft; show gas @ 955-965 ft (Dakota); Drilled as petroleum exploration well, converted to water well.	gas show; fresh water
California Company	1	Floersheim State	23	N	24	E	15	Jan-25	2556	D&A		35	183				water
Amoco	1	State EX	25	N	25	E	14	Sep-74	2240	water		494	162			Drilled as petroleum exploration well. Converted to water well. Perf 586-652 (Dakota), 1771-1810, 1850-1868, 1870-1888, 1902-1920, 1958-1986 (Glorieta)	water
York and Denton et a	1	Tex Mex	26	N	24	E	2	Oct-39	1525	D&A		432	157			Show oil 432, 478, 499 ft (Dakota). Show gas 488 ft (Dakota).	oil show, gas show
Bennett Petroleum	5	Phelps Dodge	28	N	20	E	24	Apr-85	3057	D&A		2872				DST 2869-2920 (Dakota) rec 45 mud-cut water + 2013 water.	water
Continental Oil Com	1	Springer	28	N	21	E	11	Apr-55	2900	D&A		2872				Cored 2873-2874 ft (Dakota) rec 0.5 ft sand with oil stain & gas odor	oil & gas show
Continental Oil Com	1	Maxwell Land Grant	28	N	22	E	11	Jun-54	2947	D&A		1780	144			DST 1782-1823 (Dakota) rec 120 fresh water; DST 2775-2	fresh water
Howard & O'Hern	1	Moore	28	N	24	E	8	Jan-58	1478	D&A						Oil show 1421-1453 (Dakota - with enough gas to kick mud); bailed 25 gal water/min + 4-5 gal oil	oi & gas show
Perma Energy	1	Kaiser-Edson	29	N	21	E	13	Dec-84	3510	Gas		3216		Dakota	3230-3276	IPS 50 MCFD + 37 BWPD; shut-in gas well	gas show
Perma Energy	1Y	CHALFONT-KAISER	29	N	21	E	13	Jun-84	3448	Gas		3274		Dakota	3293-3338	IPF 550 MCFD + 540 BWPD; shut-in gas well	gas show
Continental Oil Com	4	St. Louis, Rocky Mountair	29	N	22	E	17	Nov-54	4709	D&A		2758	218			Perf 2792-2806 (Dakota), frac, swbd 4 BO + 8 BWPD. Frac'd again, swbd 8 BXWPH. DST 2771-2793 (Dakota) rec 20 water-cut mud; DST 2793-2843 (Dakota) rec 195 oil-cut mud, light blow for 1 hour 30 minutes.	oil show; xwater
Perma Energy	1	Rushton	29	N	22	E	18	Jan-85	3374	Gas		2952		Dakota	3056-3101	IPS from perfs 2984-3012 (Dakota) - 100 MCFD + 60 BW	gas show
CO2 in Action	1	Moore	29	N	24	E	10	Jun-78	4075	D&A		1362	138			Water sands @ 1460-1500 ft (Dakota).	oil show - oil stained core
El Paso Energy Ratc	25	VPR D	30	N	18	E	5	Sep-00	7247	Inj						Inject produced water into Dakota (6420-6450), Entrada (7050-7138)	
American Fuels Corp	1	W-S RANCH NM-B	30	N	19	E	6	Jun-73	4330	D&A						DST Dakota? (4171-4261) rec 760 WCM	water
Odessa Natural Corp	2	VERMEJO PARK	30	N	19	E	16	Sep-72	5426	D&A		5146	204			Perf Dakota (5210-5266), frac	perf, no show
Odessa Natural Corp	1X	W S Ranch	30	N	20	E	30	Sep-72	5063	D&A						Perf & frac Dakota (4910-5026), acid, frac, swbd gas-cut load water.	gas show
Continental Oil Com	1	St. Louis, Rocky Mountair	30	N	22	E	13	Aug-54	5185	D&A		3264	162			DST 3274-3315 (Dakota) rec slight gas-cut fresh water.	gas show; fresh wat
Continental Oil Com	3	St. Louis, Rocky Mountair	30	N	22	E	18	Sep-54	5500	D&A		4474	188			DST 4539-4591 (Dakota) rec 840 muddy water.	water
El Paso Energy Ratc	7 WDW	VPR A	31	N	19	E	1	Feb-02	7467	Inj		6400				Inject produced water into Dakota 6400-6564 ft	
Continental Oil Com	2	St. Louis, Rocky Mountair	31	N	21	E	26	Oct-54	7268	D&A		4818	122			DST 4889-4938 (Dakota) rec 780 fresh water.	water
Brooks Exploration (	1	Towndrow	31	N	25	E	27	Dec-72	3513	D&A		3340				DST 3331-3405 (Dakota) rec 70 mud	DST - no show

the Dakota Sandstone; most have encountered water but a few have encountered shows of oil and/or gas. The Dakota throughout most of this area is thermally mature and within the oil window.

The Wagon Mound gas field is located in T21N R21E in central Mora County (Figure 36). Production from this field has mostly been obtained from the Dakota Sandstone. The Morrison Formation has contributed to production in eight wells (Figure 36; Table 8). The geology of the Wagon Mound field has been summarized by Brooks and Clark (1978) and most of the following section has been extracted from their work. The main pay zone is formed by lenticular sandstones in the upper part of the Dakota that were apparently deposited in shallow-marine conditions. Secondary pays are present within a conglomeratic sandstone in the lower part of the Dakota, but in most places this part of the section is below the gas-water contact and is therefore water bearing. Relatively minor pay zones are present in the lenticular, fluvial sandstones of the Morrison Formation. Depth to production ranges from 300 to 700 ft. Initial reservoir pressures were low, only 5.5 psi. Porosities of productive zones range from 15 to 25 percent. The trapping mechanism is a low-relief anticline with a structural relief of approximately 150 ft. Presumably, the lenticular nature of the primary reservoirs lends a stratigraphic component to trapping. The Dakota and Morrison have different gas-water contacts and therefore are hydraulically isolated from each other. Produced gas is 81 to 83 percent methane, 15 to 18 percent nitrogen, and contains only a trace amount of carbon dioxide.

The Wagon Mound field was discovered in 1973. Production began in 1976 and continued until field abandonment in 1979. Cumulative production was 97,281 MCF gas from eight wells. The reservoir produced via a water-drive mechanism. Produced waters were described as fresh.

Jurassic strata

Morrison Formation (Upper Jurassic)

As discussed above, the Morrison Formation was productive from the Wagon Mound field in central Mora County. Several wells have encountered gas shows or oil shows in the Morrison on the eastern flank of the Raton Basin (Figure 37; Table 9). Shows include the recovery of gas on drill-stem tests and through casing perforations. Associated reservoir waters are reported as fresh, indicating that the shallow Morrison strata on the east flank of the basin have been flushed by influent fresh waters. In the deep part of the Raton Basin, the Morrison is used as an injection zone for the disposal of produced coalbed methane water, an indication of its satisfactory porosity and permeability.

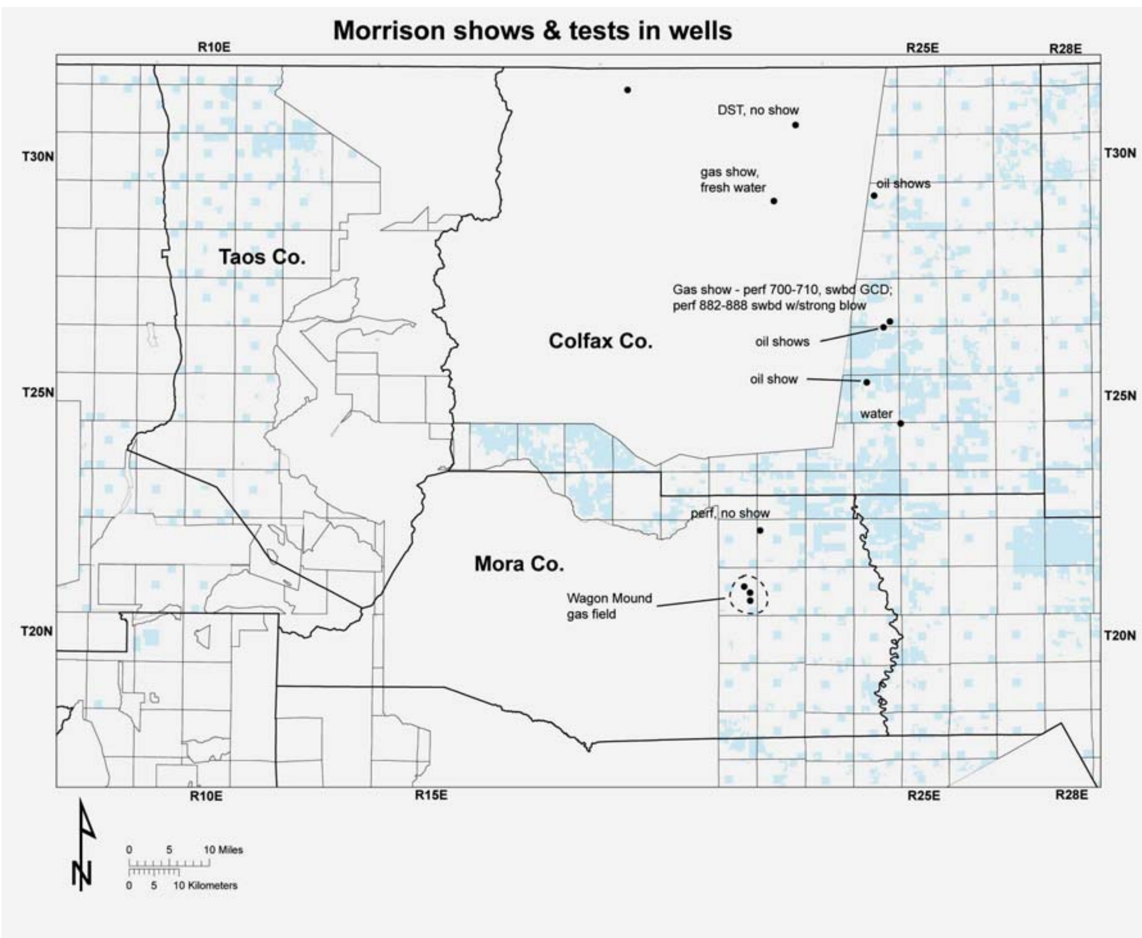

Figure 37. Wells with production, shows and tests in the Morrison Formation. See Table 9 for descriptions.

Table 9. Wells with production, shows and tests in the Morrison Formation.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Comp	TD	Status	PoolName	Morrison depth	Morrison thickness	ProdForm1	ProdInterval1	Remarks	Morrison production or show
W E Bakke Jr	1	FLB Daniels	21	N	21	E	14	Sep-77	756	Gas	Wagon Mound	514		Morrison	558-718	IPF 385 MCFD	gas production
William Gruenerwald	2	Gonzales Pittman	21	N	21	E	24	Apr-78	895	shut in?	Wagon Mound			Dakota-Morrison	481-895	IPF 850 MCFD	gas flow
William Gruenerwald	5	Gonzales Pittman	21	N	21	E	25	Aug-77	905	shut in?	Wagon Mound			Dakota-Morrison	425-905	IPF 94 MCFD	gas flow
W E Bakke Jr	1	J Lee Daniels	22	N	22	E	7	Oct-77	1512	D&A		1200				Perf 1236-1395 (Morrison), acidized.	Morrison perf, no show
Frontier Oil Co	1	Chico	24	N	25	E	6	Oct-27	1326	D&A		300	435			Water @ 560 (Morrison). Drilled on Chico dome (80 ft closure at surface)	water
Winston Marks	1	Sierracita State	25	N	24	E	5	Mar-39	1650	D&A						Show oil 660-665 (Morrison), 905-910 (Morrison?).	oil show
York and Denton et a	1	Tex Mex	26	N	24	E	2	Oct-39	1525	D&A		589	381			Show oil @ 603, 688, 725, 784, 793 ft.	oil shows
HNG Fossil Fuels	1	Sauble	27	N	24	E	35	Apr-80	2568	D&A		650				Perf 882-888 (Morrison) swbd with no show; Perf 882-888 (Morrison) swabbed with string blow; Perf 700-710 (Morrison) swabbed gas-cut water with trace of mud.	Gas show -Perf 700-710, swbd GCW; perf 882-888, swbd w/ strong blow
Continental Oil Com	5	St. Louis, Rocky Mountain and Pacific RR	29	N	22	E	16	Mar-55	2890	D&A		2610	122			DST 2668-2709 (Morrison) rec 120 mud + 120 gas-cut fresh water; DST 2700-2720 (Dakota) rec 240 water-cut mud; DST 2615-2640 (Morrison) rec 2000 water-cut mud, packer failed	gas show; fresh water
CO2 in Action	2	Moore	29	N	24	E	10	Jul-78	4083	D&A		1656				Show oil 1745 (Morrison), 1840 (Morrison).	oil shows
El Paso Energy Ratc	99	VPR E	31	N	19	E	5	Sep-02	7723	Inj		6628	478			Disposal Openhole Morrison-Entrada-Chinle (6824-7690 ft)	
Continental Oil Com	6	St. Louis, Rocky Mountain and Pacific RR	31	N	22	E	26	Apr-55	3675	D&A		3276	388			DST 3358-3390 (Morrison) rec 35 mud; DST 3665-3675 (Entrada) rec 90 mud	DST, no show

Entrada Sandstone (Middle Jurassic)

The Entrada Sandstone has been penetrated by relatively few wells. Nevertheless, there have been some intriguing fluid recoveries and shows from the Entrada in the Raton Basin (Figure 38; Table 10). The easternmost well with a record of fluid recovery, the Frontier Oil No. 1 Chico well located in Sec. 6 T24N R25E, recovered salt water from the Entrada at a depth of 735 ft; that well was drilled on a defined and mapped surface structure that has 80 ft of closure with the Greenhorn Limestone forming the surface outcrops. Only slightly further to the west in the Winston Marks No. 1 Sierracita State, located in Sec. 5 T25N R24E, an oil show was reported in the Entrada from depths of 990 to 1025 ft. To the north in the CO_2-in-Action No. 2 Moore, located in Sec. 10 T29N R24E, an oil show was reported in the Entrada at a depth of 1950 ft. Further to the west in the Continental No. 6 St. Louis, Rocky Mountain and Pacific RR well, located in Sec. 26 T31N R22E, a drill-stem test of the Entrada from 3665 to 3675 ft recovered drilling mud, and presumably tested some show or other indication of hydrocarbons. Yet further to the west, the Entrada was perforated from depths of 6886 to 6970 ft along the basin axis in the El Paso Energy No. 27 VPRB well. In the deep basinal area, the Entrada is used as an injection zone for the disposal of produced coalbed methane water, an indication of its satisfactory porosity and permeability.

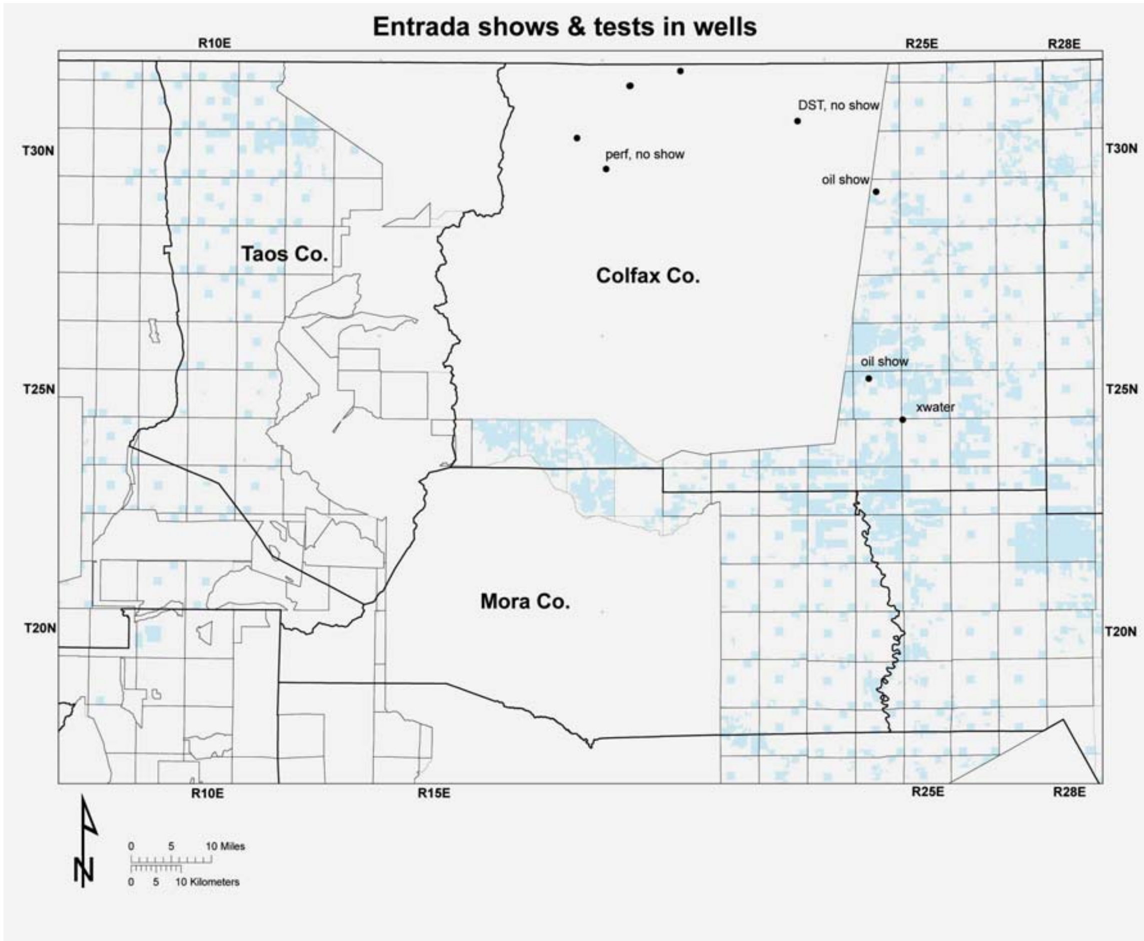

Figure 38. Wells with shows and tests in the Entrada Sandstone. See Table 10 for descriptions.

Table 10. Wells with shows and tests in the Entrada Sandstone.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Comp	TD	Status	Entrada depth	Entrada thickness	Remarks	Entrada production or show
Frontier Oil Co	1	Chico	24	N	25	E	6	Oct-27	1326	D&A	735	25	Xwater @ 735 (Entrada); drilled on Chico dome (80 ft closure at surface)	xwater
Winston Marks	1	Sierracita State	25	N	24	E	5	Mar-39	1650	D&A			Show oil 990-1025 (Entrada).	oil show
CO2 in Action	2	Moore	29	N	24	E	10	Jul-78	4083	D&A	1892		Show oil @ 1950 (Entrada).	oil show
El Paso Energy Raton	25	VPR D	30	N	18	E	5	Sep-00	7247	Inj			Inject produced water into Dakota (6420-6450), Entrada (7050-7138)	
El Paso Energy Raton	27	VPR B	30	N	18	E	36	Aug-00	7428	Inj			Perf Entrada (6886-6970).	perf, no show
El Paso Energy Raton	99	VPR E	31	N	19	E	5	Sep-02	7723	Inj	7106	102	Disposal Openhole Morrison-Entrada-Chinle (6824-7690 ft)	
El Paso Energy Raton	34	VPR E	31	N	19	E	5	Apr-02	7654	Inj			Disposal Openhole Entrada-Chinle (7133-7614 ft)	
Continental Oil Company	6	St. Louis, Rocky Mountain and Pacific RR	31	N	22	E	26	Apr-55	3675	D&A	3664		DST 3358-3390 (Morrison) rec 35 mud; DST 3665-3675 (Entrada) rec 90 mud	DST, no show
El Paso Energy Raton	182WDW	VPR A	32	N	20	E	28	Sep-05	7168	Inj			Inject into Entrada (6044-6694)	

Triassic strata

There have been a number of shows of gas and recoveries of fresh water from Triassic strata in the Raton and Las Vegas Basins (Figure 39; Table 11). Gas in Triassic strata is noncombustible with high CO_2 content. Water recovered on drill-stem tests and through casing perforations is generally described as fresh water; some exploratory wells that recovered fresh water from Triassic strata have been converted into water-supply wells. The distribution of water recoveries indicates that Triassic strata on the eastern flanks of the Raton and Las Vegas Basins has been flushed by influent fresh water.

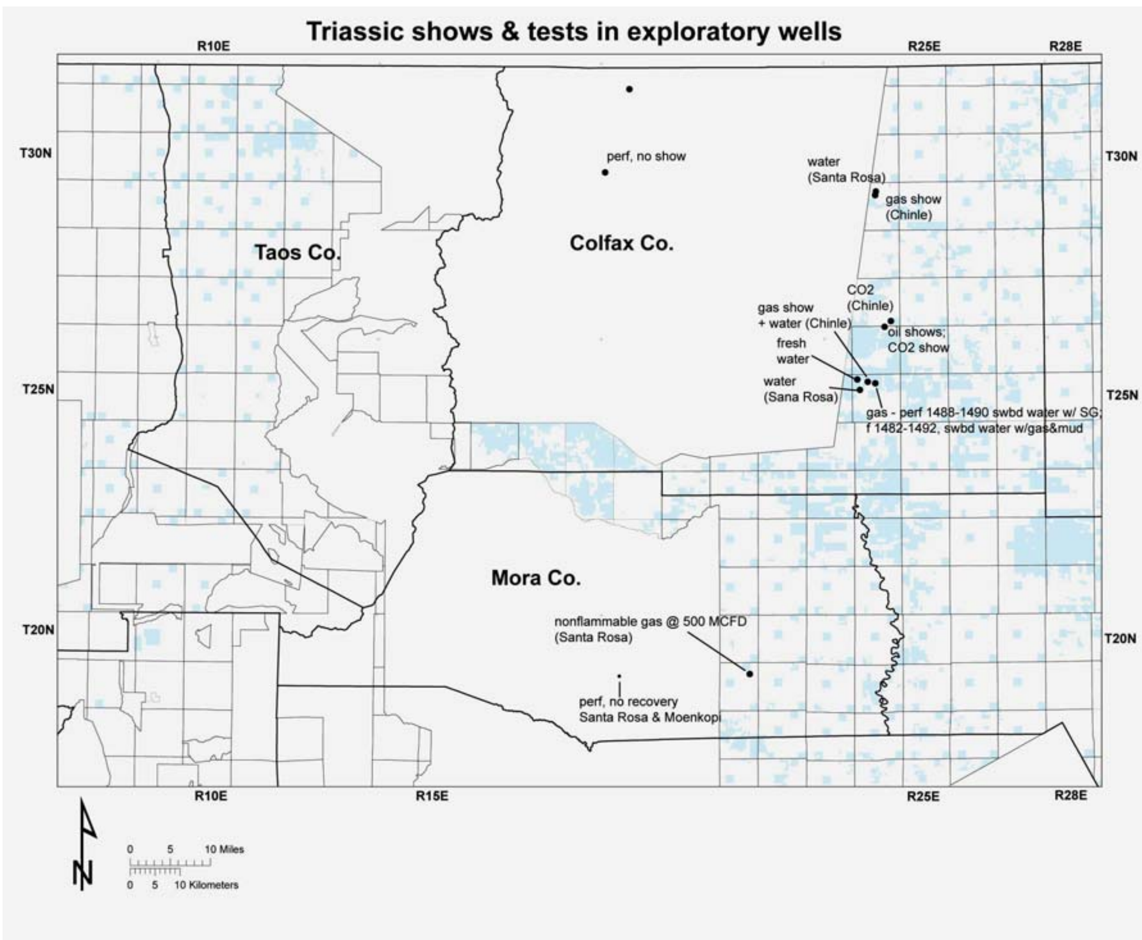

Figure 39. Wells with shows and tests in Triassic strata. See Table 11 for descriptions.

Table 11. Wells with shows and tests in Triassic strata.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	TD	Status	Chinle depth	Santa Rosa depth	Moenkopi depth	Triassic thickness	Remarks	Triassic production or show
Cities Service	2	Fort Union	19	N	19	E	18	2725	water	662	1508	1604	1140	Perf 2056-2068 (Glorieta), swbd 300 BW; Perf 1511-1703 (Santa Rosa-Moenkopi), swbd 100 BFW in 9 hours; Drilled as petroleum exploration well, converted to water well.	perf, no recovery (Santa Rosa-Moenkopi)
Arkansas Fuel Oil	1	Kruse	19	N	21	E	11	2613	D&A					Nonflammable gas @ 12 MMCFD @ 1420-1425 ft (Glorieta?); Nonflammable gas @ 2 MMCFD @ 1670 ft (Glorieta?); Nonflammable gas @ 2 MMCFD @ 1795 ft (Permian); Nonflammable gas @ 10 MMCFD @ 2220-2225 ft (Permian?); 4-6 bbls fresh water per hour @ 2361 ft (Permian?).	nonflammable gas @ 500 MCFD (Santa Rosa)
Winston Marks	1	Sierracita State	25	N	24	E	5	1650	D&A					Water @ 1056 (Chinle) Show gas 1535-1543 (Chinle?)	gas show + water (Chinle)
Kelly Bell	1	State	25	N	24	E	6	1565	water					Drilled as petroleum exploration well. Converted to water well. Pumped 720 BW from open hole 150-1565 (Cretaceous-Triassic).	fresh water
W D Weathers	1		25	N	24	E	7	1097	D&A					water @ 1012 &1078 FT (Santa Rosa)	water (Santa Rosa)
HNG Fossil Fuels	1	State	25	N	24	E	9	2664	D&A	1060	1484	absent	538	Perf 1542-1625 (Santa Rosa-Glorieta) no recovery; Perf 1482-1492 (Santa Rosa) swbd water, gas & mud; Perf 1488-1490 (Santa Rosa) swbd water with show gas.	Gas - perf 1488-1490 swbd water w/ SG; f 1482-1492 swbd water w/ gas & mud
York and Denton et al (Amoco/Colfax Carbide)	1	Tex Mex	26	N	24	E	2	1525	D&A	1021	1298	absent	351	IP 250 MCFD, decreased to 153 MCFD; 99.85% CO2; CO2 show @ 1147 ft. Show oil @ 1025, 1046, 1092, 1108, 1140, 1245-1286, 1328, 1365 ft.	oil shows; CO2 show
HNG Fossil Fuels	1	Sauble	27	N	24	E	35	2568	D&A	1070	absent?	absent?		Perf 1634-1646 (Chinle); perf 1538-1558 (Chinle), frac, rec CO2 + water; perf 1538-1572 (Chinle) no recovery; Perf 1280-1307 (Chinle) acidized, rec acid + drilling mud; Perf 1311-1318 (Chinle) swbd dry.	CO2 (Chinle)
CO2 in Action	2	Moore	29	N	24	E	10	4083	D&A	2010	2450	absent		Salt water @ 2345 (Chinle). Show oil @ 2095, 2345 (Chinle).	gas show (Chinle)
CO2 in Action	1	Moore	29	N	24	E	10	4075	D&A	1946	2310	absent	452	DST 2350-2430 (Santa Rosa-Glorieta) rec 50 water-cut mud + 420 muddy water.	water (Santa Rosa)
El Paso Energy Raton	27	VPR B	30	N	18	E	36	7428	Inj					Perf Chinle (7016-7074).	perf, no show
El Paso Energy Raton	99	VPR E	31	N	19	E	5	7723	Inj	7208	DNP			Disposal Openhole Morrison-Entrada-Chinle (6824-7690 ft)	
El Paso Energy Raton	34	VPR E	31	N	19	E	5	7654	Inj					Disposal Openhole Entrada-Chinle (7133-7614 ft)	

Post-Sangre de Cristo Permian strata

There have been several well that have yielded shows of gas from post-Sangre de Cristo Permian strata. Most of the tests that have yielded gas shows have been in the Glorieta Sandstone (Figure 40; Table 12). Most of the tests and shows have been located on the eastern flanks of the Raton and Las Vegas Basins and on the eastern part of the Cimarron arch. Gases are nonflammable and contain large percentages of CO_2. In general, waters recovered from exploratory wells have been described as fresh, indicating that much of the Glorieta in these areas has been flushed by fresh groundwater.

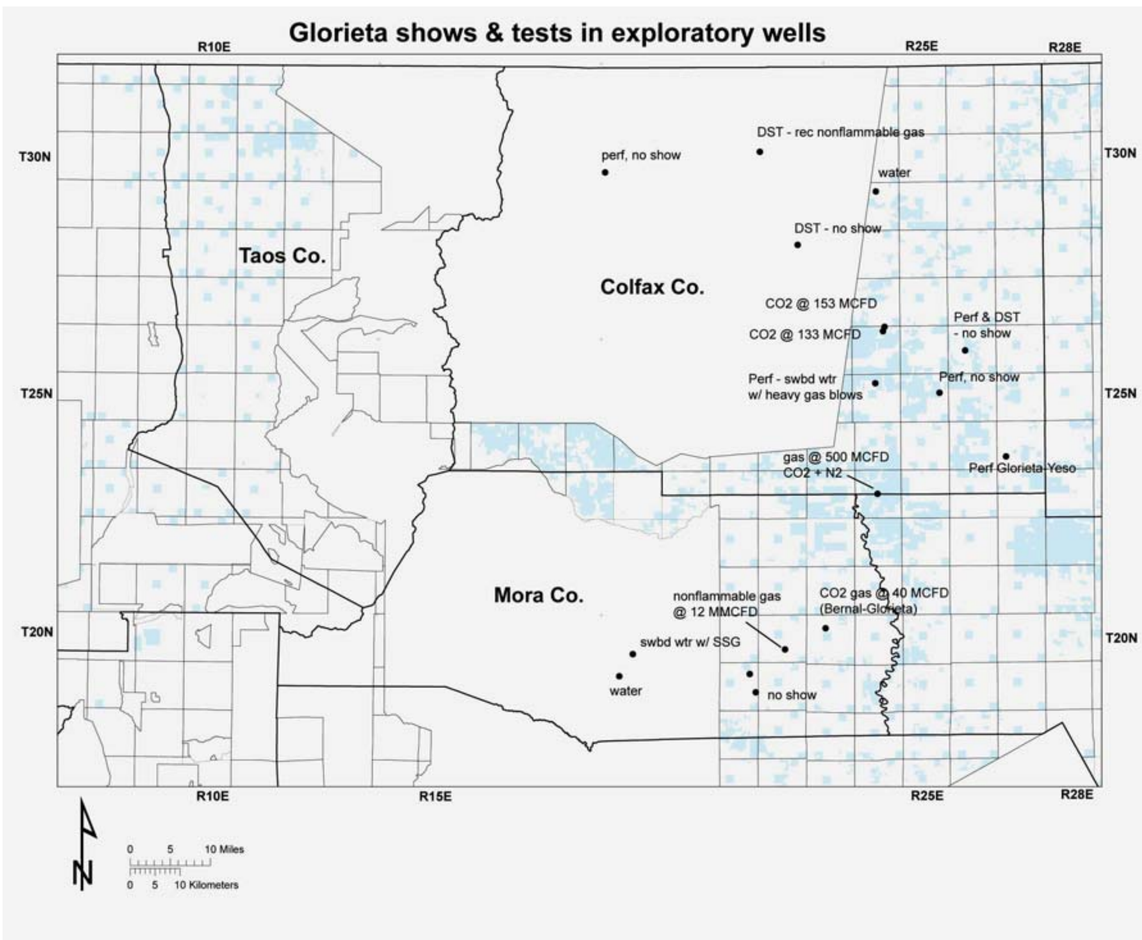

Figure 40. Wells with shows and tests in the Glorieta Sandstone. See Table 12 for descriptions.

Table 12. Wells with shows and tests in the Glorieta Sandstone.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Elev	Comp	TD	Status	Glorieta depth	Glorieta thickness	Remarks	Glorieta production or show
Cities Service	2	Fort Union	19	N	19	E	18	6675	Jul-78	2725	water	1870	248	Perf 2056-2068 (Glorieta), swbd 300 BW; Perf 1511-1703 (Santa Rosa-Moenkopi), swbd 100 BFW in 9 hours; Drilled as petroleum exploration well, converted to water well.	water
Arkansas Fuel Oil	1	Kruse	19	N	21	E	11	6500	Feb-26	2613	D&A			Nonflammable gas @ 12 MMCFD @ 1420-1425 ft (Glorieta?); Nonflammable gas @ 2 MMCFD @ 1670 ft (Glorieta?); Nonflammable gas @ 2 MMCFD @ 1795 ft (Permian); Nonflammable gas @ 10 MMCFD @ 2220-2225 ft (Permian?); 4-6 bbls fresh water per hour @ 2361 ft (Permian?).	nonflammable gas @ 12 MMCFD
Mobil Producing Texas	1	E C Wiggins	19	N	21	E	24	6265	Oct-77	2697	Gas	1712	374	IP 30 MCFGD; Tested Yeso and Glorieta with no shows.	no show
Cities Service	1	Fort Union	20	N	19	E	33	7321	Feb-78	5836	D&A	1854	316	CO_2 encountered above 2000 ft (Permian?)	swbd water w/ SSG (perfs)
Mobil Oil Corp.	1	Wooton & Reardon	20	N	23	E	9	5975	Dec-77	2127	D&A	1246	338	Flowed 175 MCFD @ 1243 ft (Bernal); Perf 1181-1286 ft (Bernal-Glorieta), frac, flowed 40 MCFD (CO_2).	CO_2 gas @ 40 MCFD (Bernal-Glorieta)
California Company	1	Floersheim State	23	N	24	E	15	5823	Jan-25	2556	D&A	1395	325	Gas at 500 MCFD 1510-1560 (Glorieta) - 67% CO_2, 28.7% N_2, 4.1% O_2, 0.2% He.	gas @ 500 MCFD CO_2 + N_2
Amoco	1	State FA	24	N	27	E	29	6172	Sep-74	2325	D&A	1760	198	Perf 1766-2039, acidized (Glorieta-Yeso)	Perf Glorieta-Yes
HNG Fossil Fuels	1	State	25	N	24	E	9	6122	May-80	2664	D&A	1598		Perf 1600-1680 (Glorieta) no recovery; perf 1630-1680 (Glorieta) no recovery; Perf 1542-1625 (Santa Rosa-Glorieta) no recovery; Perf 1600-1650 (Glorieta) swbd 70 BW with heavy gas blows.	Gas - Perf, swbd water w/ heavy gas blows
Amoco	1	State EX	25	N	25	E	14	6609	Sep-74	2240	water	1750	236	Drilled as petroleum exploration well. Converted to water well. Perf 586-652 (Dakota), 1771-1810, 1850-1868, 1870-1888, 1902-1920, 1958-1986 (Glorieta)	Perf, no show
York and Denton et al (Amoco/Colfax Carbide)	1	Tex Mex	26	N	24	E	2	6264	Oct-39	1525	D&A			1515-1525 ft (Glorieta?), IP 250 MCFD, decreased to 153 MCFD; 99.85% CO_2.	CO_2 @ 153 MCFD?
Neill & Steffan	3	Sauble	26	N	24	E	3	6203	Dec-47	1560	water			IP 133 MCFD of CO_2; converted to water well	Gas CO_2 @ 133 MCFD
Brooks Exploration	1-21	State of New Mexico	26	N	26	E	21	6693	Sep-79	2075	D&A			DST 1322-1384 (Glorieta + supra-Glorieta Permian) no rec; DST 1455-1497 (Glorieta) rec 5 ft mud	Perf & DST, no show
Continental Oil Company	1	Maxwell Land Grant	28	N	22	E	11	6181	Jun-54	2947	D&A	2770	64	DST 2775-2820 (Glorieta) rec 90 mud	DST, no show
CO2 in Action	1	Moore	29	N	24	E	10	6550	Jun-78	4075	D&A	2398	106	DST 2350-2430 (Santa Rosa-Glorieta) rec 50 water-cut mud + 420 muddy water.	water
El Paso Energy Raton	27	VPR B	30	N	18	E	36	8070	Aug-00	7428	Inj			Perf Glorieta (6886-7356)	perf, no show
Continental Oil Company	3	St. Louis, Rocky Mountair	30	N	22	E	18	7972	Sep-54	5500	D&A	5390	58	DST 5327-5477 (Glorieta?) rec 1030 mud, hard blow dies in 50 minutes; DST 5321-5477 (Glorieta?) rec 390 mud + 300 non-inflammable gas-cut mud.	DST rec nonflammable gas

Sangre de Cristo Formation (Pennsylvanian to Lower Permian), Madera Group (Pennsylvanian), and Sandia Formation (Pennsylvanian)

Few wells have been drilled sufficiently deep to penetrate and test the Sangre de Cristo Formation and Pennsylvanian strata in the Las Vegas and Raton Basins. Nevertheless, several shows have been reported (Figure 41; Table 13). In the Union Land and Grazing No. 1 Fort Union well, located in Sec. 2 T20N R19E in the central deep part of the Las Vegas Basin, gas composed of 97 percent CO_2 was recovered from a depth of 2343 ft and flowed at a rate of 923 MCFD; this well was drilled on the Turkey Mountains uplift and it is probable that the Tertiary-age igneous intrusives that from the core of the mountain range were the source of the CO_2. To the northwest, gas-cut water was recovered on a drill-stem test of the Pennsylvanian section in the Continental No. 1 Mares Duran well, located in Sec. 14 T23N R17E; the composition of the gas is unknown. Numerous, substantial gas shows were recorded on the mudlog for the Mares Duran well. Elsewhere, gas was recovered from Pennsylvanian sandstones on a drill stem test in the Shell No. 1 Mora Ranch well, located in Sec. 5 T22N R19E; logs indicate prospective sands in this well have porosities ranging from 8 to 12 percent. In the True Oil No. 34 Arguello well, located in Sec. 24 T23N R 17E, and in the True Oil No. 21 medina well, located in Sec. 25 T24N R16E, there was crossover of neutron and density porosity logs (“gas effect”) in sandstones within the Pennsylvanian section, indicating that gas is present within those sandstone beds. The sandstones with the gas effect are 6 to 16 ft thick and have porosities that vary from 5 to 10 percent. Donegan (1985) has pointed out that porosities in sandstones of the Sandia Formation contain silica overgrowths that have reduced porosity in wells drilled in the vicinity of igneous intrusions and that the overgrowths may have a hydrothermal origin. Sandia sandstones that crop out in the Taos trough on the Sangre de Cristo uplift have reduced porosities due to compaction and cementation by authigenic clay and chlorite. It is expected that wells drilled distant from major igneous intrusions will not encounter as much porosity reduction by quartz overgrowths and that areas of distal, more mature (and therefore less feldspathic) sandstones will have suffered less compaction and less cementation by authigenic phyllosilicates (Donegan, 1985).

In the Las Vegas Basin nine miles south of the southern boundary of the project area, gas was recovered from Pennsylvanian strata in the James D. Hancock No. 1 Sedberry well, located in Sec. 25 T17N R16E and drilled in 1957. In that well, the lowermost Pennsylvanian section (Atokan or possibly Morrowan; see fusulinid determinations for this well in Broadhead and King, 1988) was perforated from 4662 to 4668 ft. The well was shut in until 1960 when it was opened and flow tested. During the flow test, the well unloaded salt water along with traces of fracture oil, and also flowed gas; gas volume decreased to zero after 15 minutes. The gas was composed of 98.69 percent CH_4, 0.12% CO_2, 0.94% N_2, 0.24% C_2H_6. and 0.01% C_3H_8 and had a heating

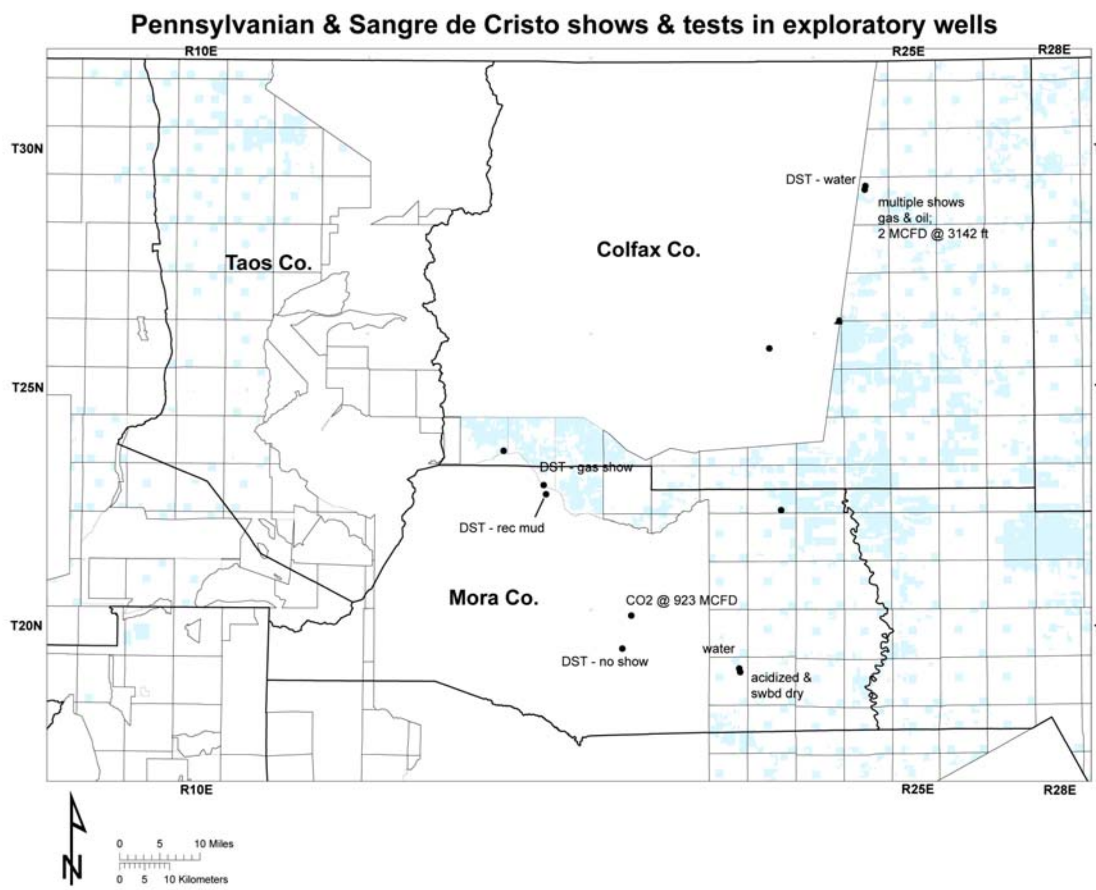

Figure 41. Wells with shows and tests in the Sangre de Cristo Formation, Madera Group, and Sandia Formation. See Table 13 for descriptions.

Table 13. Wells with shows and tests in the Sangre de Cristo Formation, Madera Group, and Sandia Formation.

Operator	Well#	Lease name	Twp	N/S	Rng	E/W	Sec	Comp	TD	Status	Sangre de Cristo depth	Madera depth	Sandia depth	Sangre de Cristo + Pennsylvanian thickness	Remarks	Sangre de Cristo - Pennsylvanian production or show
Arkansas Fuel Oil	1	Kruse	19	N	21	E	11	Feb-26	2613	D&A					HFW @ 2515 ft (Sangre de Cristo?)	water
Mobil Oil Corp.	1	Clyde Berlier	19	N	21	E	12	Jan-78	3221	D&A	2188				Acidized 1985-2225 ft (Permian & Sangre de Cristo), swabbed dry	acidized & swbd dry
Union Land & Grazing	1	Fort Union	20	N	19	E	2	Mar-62	4070	D&A	896				Gauged 401.9 MCFD @ 2343 ft (Sangre de Cristo). Gas was 97% CO2. Gauged 923 MCFD of gas that is 97% CO2.	923 MCFD CO2
Cities Service	1	Fort Union	20	N	19	E	33	Feb-78	5836	D&A	2432	4350			DST 2994-3159 (Sangre de Cristo), rec 35 ft drilling fluid. CO2 encountered above 2000 ft (Permian?)	DST, no show
Shell Oil	1	Mora Ranch	22	N	19	E	5	Feb-69	9690	D&A	3056	6246		6496	DST 6483-6660 (Pennsylvanian) rec 185 mud DST 8029-8135 ft (Pennsylvanian) rec 732 gas-cut salt water	show gas (DST)
Continental Oil Company	1	Mares Duran	23	N	17	E	14	Jul-58	7765	D&A	0	2540		7658	DST 4009-4050 (Pennsylvanian) slight blow, rec 40 mud-cut water DST 6729-6754 (Pennsylvanian) weak to fair blow, rec 100 mud + 270 gas & mud-cut water	gas shows (DST)
True Oil	34	Arguello	23	N	17	E	24	Feb-82	8669	D&A					Crossover of neutron and density porosity logs (gas effect)	gas effect on logs
Shell Oil	1	Shell State	23	N	22	E	35	Apr-69	5040	D&A	2808	4160		2206		
True Oil Company	21	Medina	24	N	16	E	25	Apr-82	9139	D&A	0		4054/5724	5554	DST 6087-6147 (Sandia), rec 10 ft mud. Crossover of neutron and density porosity logs (gas effect)	gas effect on logs
CO2 in Action	2	Moore	29	N	24	E	10	Jul-78	4083	D&A	2922				Water @ 2955 (Sangre de Cristo). Salt water @ 2345 (Chinle). Show gas @ 2938 (Sangre de Cristo), 3142 (Sangre de Cristo; 2 MCF). Show oil @ 2938 (Sangre de Cristo), 3022 (Sangre de Cristo), 3260 (Sangre de Cristo; 52 gravity), 3876 (Sangre de Cristo).	multiple shows gas, oil; 2 MCFD @ 3142 ft
CO2 in Action	1	Moore	29	N	24	E	10	Jun-78	4075	D&A	2804			1250	DST 3050-4074 (Sangre de Cristo-Precambrian) rec 355 muddy water.	water (DST)

value of 1003 BTU/ft^3. Although the well was subsequently plugged and abandoned, it offers definitive proof that at least some reservoir gases in the Pennsylvanian of the Las Vegas Basin are comprised dominantly of hydrocarbons and that volcanically emitted CO_2 has not pervasively migrated through the entire Pennsylvanian section in all parts of the basin.

On the eastern flank of the Raton Basin, gas and oil shows were reported from the Sangre de Cristo Formation at multiple depths in the CO_2-in-Action No. 2 Moore well, located in Sec. 10 T29N R24E; a gas flow from a depth of 3142 was reported to have a flow rate of 2 MCFD.

Natural Gas Potential

Several stratigraphic units contain substantial natural gas potential as well as more limited oil potential in the Raton and Las Vegas Basins. The most obvious stratal units with natural gas potential are the Vermejo and Raton Formations (Upper Cretaceous to Tertiary: Paleocene) along the axial part of the Raton Basin where they currently are productive of coalbed methane and the Dakota Group (Cretaceous) and Morrison Formation (Jurassic) which have in the past produced natural gas from the Wagon Mound field in central Mora County. The Pierre and Niobrara Formations (Upper Cretaceous) which produced gas from a single well in the Raton Basin have considerable shale-gas potential. Other strata with potential are the Upper Cretaceous Carlile and Graneros Shales (shale gas), the Greenhorn Limestone (Upper Cretaceous; shale gas and oil); the Morrison Formation in the Raton Basin, on the Cimarron arch, and on the eastern flank of the Las Vegas Basin, the Dakota Group in the Raton Basin, on the Cimarron arch, and on the eastern flank of the Las Vegas Basin, and Pennsylvanian-age strata, particularly those in the Las Vegas Basin. In addition, there is significant potential for CO_2 gas in the Entrada Sandstone (Jurassic), Triassic strata including the Santa Rosa Sandstone, and in Pennsylvanian strata in localized areas of the Raton and :Las Vegas Basins. Oil and gas potential of stratigraphic units is discussed below in descending stratigraphic order, which is the order they will be penetrated by the drill bit.

Higley and others (2007) assessed the potential for oil and natural gas resources in the Raton and Las Vegas Basins as part of a regional reconnaissance effort to quantify petroleum resources. They provided assessments for the shallow coalbed methane in the Raton and Vermejo Formations, the Graneros and Niobrara Shales, the Dakota Group, the Morrison Formation, and the Entrada Sandstone. Their conclusions are cited where appropriate. However, they utilized no source rock data and analyses from New Mexico, extrapolating from data in the Colorado part of the Raton Basin. In addition, they provided little information on shows and had little source rock information outside of the Pierre and Niobrara Shales and the coals of the Raton and Vermejo Formations. For these reasons, the following data-explicit work on natural gas potential was completed that integrates source-rock character with structure, detailed analyses of shows and production, and work on regional stratigraphy.

Cretaceous strata

Vermejo and Raton Formations (Upper Cretaceous to Tertiary: Paleocene)

The Vermejo and Raton Formations are productive of substantial volumes of coalbed methane in the Raton Basin. As of the time this report was being prepared, most development has been in the central deeper part of the basin where vitrinite reflectance (R_o) is greater than 0.8 percent (see Figure 7) and therefore where the coals are most mature. Presumably, areas with R_o less than 0.8 percent will also contain coalbed methane; coals in these less mature areas will have generated less gas per unit volume of cola than the coals in the mature areas because of their lower thermal maturity.

Another factor that bears on resource potential is that coals in the less mature areas are shallower than the coals in the more mature areas. Therefore, the hydrostatic head exerted by the water within the aquifer formed by the cleat system will be less for the shallower colas than for the deeper coals and reservoir pressures exerted by the water column will be less. The maximum amount of gas that can be adsorbed onto coal is proportional to the pressure exerted by the water column in the cleat system (see Ayers, 2002). Therefore coals in the shallower, less mature parts of the basin will have less gas per unit volume of coal because they will have generated less gas and will have less adsorptive capacity. Still, considerable potential for additional coalbed methane is present where the Vermejo and Raton Formations are present outside of currently developed areas. Potential becomes lower nearer to the outcrop edge of these formations. Some gas generated in the coals may also have migrated out of the coals and into adjacent sandstones.

Higley and others (2007) provided a quantitative estimate of undiscovered coalbed methane resources in the Vermejo and Raton Formations. Their assessment indicated 611 BCF gas in the Raton Formation and 979 BCF gas in the Vermejo Formation. At least two-thirds of this gas is in the Colorado side of the basin. They also estimated that only 0.41 percent of the gas, or 6.5 BCF, is under New Mexico State Trust Lands. Most of the gas in the New Mexico part of the basin lies under private lands of the Maxwell Land Grant.

Trinidad Sandstone (Upper Cretaceous)

Gas is produced from the Trinidad Sandstone from eight wells (Table 4). In these wells, the gas is commingled with gas produced from the overlying Vermejo Formation. Because the Trinidad contains no significant source facies, the gas may have migrated either from source beds in the overlying Vermejo coals or Vermejo shales or from the underlying Pierre Shale. Speer (1976) regarded the Trinidad as having favorable potential for oil and gas accumulations because it is thick bedded, well sorted and porous, and because it bears a number of similarities to the gas-productive Point Lookout Sandstone of the San Juan Basin of northwestern New Mexico. The blanket nature of the Trinidad Sandstone suggests that structural closures are among the places to localize exploration efforts. Dolly and Meissner (1977) postulated that a basin-centered hydrodynamic trap might be present within the Trinidad Sandstone in the deeper parts of the Raton Basin. Production of gas from the Trinidad in eight wells in the deep part of the basin and a lack of shows and tests where the Trinidad is shallower on the basin flanks suggests that the deeper areas may offer better potential for Trinidad gas. Rose and others (1986) mapped a sandstone-dominated deltaic lobe in the Trinidad in the Colorado part of the basin; in this area the Trinidad has higher porosity and lower clay content and was postulated as a target for a basin-centered gas accumulation. Similar thick areas in the New Mexico part of the basin trend northeast-southwest and are also interpreted to be deltaic deposits (Figure 16; Wu, 1987; Flores and Tur, 1982); these thick areas of the Trinidad in New Mexico may also be exploration targets for gas.

Higley and others (2007) estimated a mean value of 59 BCF gas from the Trinidad Sandstone and sandstones in the Vermejo, Raton and Poison Canyon Formations in both the Colorado and New Mexico parts of the Raton Basin. Because approximately 1/3 of the basin lies within New Mexico, that indicates approximately 20 BCF gas within these sandstones in the New Mexico part of the basin with perhaps a significant portion of the gas in Raton and Vermejo sandstones that are lenticularly interbedded with coals and nonmarine shales.

Pierre, Niobrara, Carlile and Graneros Shales

Gas has been produced from one interval that straddles the Pierre-Niobrara boundary in the Pennzoil No. 2 Vermejo Ranch well, located in Sec. 1 T31N R17E along the deep, axial portion of the Raton Basin. In addition, several wells have reported gas shows from these shale units both within the deep part of the basin and on the shallow eastern and southern flanks of the basin. Many of the shows occur within the deeper portions of the Raton Basin where the Pierre, Niobrara, Carlile and Graneros Shales are within the thermogenic wet gas/dry gas and the dry gas windows. Given that one well has already produced a substantial volume of gas (173 BCF) without having had the benefit of artificial fracturing, there is high potential for a sizeable accumulation of thermogenic shale gas within the deeper portion of the basin.

In addition, the Pierre and Niobrara intervals have produced gas from the Colorado part of the Raton Basin. The Garcia field in the southeastern Colorado portion of the Raton Basin, located approximately 10 miles north of the New Mexico-Colorado border, produced 1.56 BCF gas from the Niobrara and Pierre Shales (Lawson and Hemborg, 1999; Higley and others, 2007).

Higley and others (2007) estimated a mean value of 89 BCF undiscovered gas and 3.5 million bbls natural gas liquids in the fractured Pierre, Niobrara and Carlile Shale. Based on the portion of the basin present in New Mexico, one might postulate that one-third of this resource, or 30 BCF gas, are present in the New Mexico part of the basin. Given that one well, in an unstimulated state, has produced a cumulative 173 MMCF from an open-hole interval that straddles the Pierre-Niobrara contact, one could calculate that 173 similar wells would produce the 30 BCF gas. Given the low permeability of the shales and the current spacing for presumably more permeable Upper Cretaceous reservoirs in the San Juan Basin, 160-acre spacing could be assumed. This calculates to wells covering 43 sections, or 1.2 townships. If one assumes that stimulated wells might produce 50 percent more gas than unstimulated wells, then only 115 wells would produce 30 BCF – at 160-acre spacing that calculates to 29 sections (0.8 townships). Given that the deep part of the basin, which is within the thermogenic gas window, covers approximately 20 townships (and perhaps more), the Pierre and Niobrara would only need to be productive over 4 percent of the deep basin to produce the 30 BCF. Given these calculations, it appears that these shale units may contain substantial resources of producible gas, and that a 30 BCF resource base is a minimal estimate. If one assumed that all 20 townships could be productive at the rate of the one well that has thus far produced, then a resource base of 750 BCF can be calculated, which may be perhaps a bit optimistic. This discussion does not include any shallow biogenic gas that may be present in shallower areas on the basin flanks, discussed below.

On the shallow flanks of the basin, the Upper Cretaceous shales are immature and within the biogenic gas window. Gas shows have been encountered within these shallow areas and measured flows have been less than what has been reported from the deeper parts of the basin. The gas in these shallow areas is probably biogenically-derived shale gas. Alternatively, it may be thermogenically derived gas generated in the deeper parts of the basin, but this is considered to be a less likely possibility because of the limitations associated with long-distance migration of gases through low-permeability shales. In general, it may be expected that biogenic shale gas will have lower rates of production than thermal shales gas but the shallower occurrence may compensate for lower productivity where drilling economics are concerned.

A zone of oil generation and production (the oil window) lies between the shallow flanks of the basin with biogenic gas and the deeper basin with thermogenic gas. Possibilities for oil accumulations within this oil-prone area include fractured shale reservoirs, fracture systems in the Fort Hays Limestone and the Greenhorn Limestone which will be more brittle (and therefore more prone to fracturing) than the overlying and underlying shale units, and reservoirs formed by cooling fractures in Tertiary-age igneous sills and dikes that have intruded the shales. The Dineh-Bi-Keyah field of northeastern Arizona is formed by a fractured Tertiary-age igneous sill that has intruded low-permeability Pennsylvanian source rocks (Danie, 1978) and is an exploration model for sill and dike reservoirs in the Upper Cretaceous section of the Raton Basin.

In the Las Vegas Basin, the Pierre Shale was been removed by erosion subsequent to Laramide uplift. The Niobrara Shale is present only at shallow, near-surface depths in the northeastern part of the basin and has been removed by erosion elsewhere within the basin. Where the Niobrara is present, the Greenhorn Limestone, Carlile Shale, and Graneros Shale are also present. In the northeastern part of the basin, a gas flow of 500

MCFD was reported from the Brooks Yetter No. 1 Fernandez Brothers well, located in Sec. 34 T23N R21E, indicating the presence of hydrocarbons in this area. The general properties of the Greenhorn indicate that fractures within the Greenhorn probably form the reservoir. The source rock characteristics of the Carlile Shale in the northeastern part of the Las Vegas Basin indicate that oil and associated gas have been generated. Shale gas is a possibility in this area and is a possibility in the more brittle Greenhorn Limestone and Fort Hays Limestone.

Dakota Group (Lower to Upper Cretaceous)

Sandstones of the Dakota Group are excellent reservoir rocks (Speer, 1976) that have produced 97 MMCF low-pressure gas from the Wagon Mound field in central Mora County (Figure 36; Table 8). The overlying Graneros Shale is the most obvious source rock for a petroleum system involving Dakota reservoirs. The high content of nitrogen (15-18% with methane 81-83%) and the presence of only trace amounts of carbon dioxide and the near absence of gas liquids plus the thermal immaturity of the Niobrara in the Wagon Mound area indicate that the gas at Wagon Mound is biogenically derived (see Hunt, 1996). Because the Graneros covers the Dakota over much of the eastern two-thirds of the Las Vegas Basin, and these two units are also present at shallow depths on the Sierra Grande uplift northward of the latitude of the Cimarron arch, the possibility for additional, shallow, low-pressure accumulations of biogenic gas in Dakota sandstones is high. Traps may be structural, such as at Wagon Mound. Internal facies changes associated with thinning of the Dakota as it onlaps the Cimarron arch and the Sierra Grande uplift should be considered as possible Dakota gas plays.

On the eastern limb of the Raton Basin where the Dakota is present at depths between 2000 and 4000 ft, several wells several wells have encountered gas shows and oil shows, as previously discussed (Figure 36; Table 8). The Dakota has been invaded by influent surface waters over a large area on the eastern limb of the basin, indicating that Dakota reservoirs are sufficiently interconnected to allow for migration of fresh water long distances into the subsurface. Nevertheless, the presence of several shows over a large area indicates that oil and gas have been generated and have migrated through the Dakota. Potential targets include structural reversals on the eastern limb of the basin where deeper, higher pressure analogs of the Wagon Mound may be located that would be filled with natural gas.

Structures in deeper parts of the basin are also attractive. In this area, the Dakota is sufficiently permeable in places and produced waters from the shallow coalbed methane wells are injected.

The southern flank of the Raton Basin offers some intriguing exploration possibilities. The Dakota thins as it rises out of the basin and onto the Cimarron arch. Consideration should be given to the possibility of entrapment associated with updip permeability pinchouts associated with this thinning or with traps formed on top of the Cimarron arch and sourced by the Graneros Shale within the deeper, mature parts of the Raton Basin.

The western boundary of the Raton Basin offers some intriguing possibilities for hydrocarbon entrapment in Dakota sandstones. The Dakota is terminated on the west side of the basin along the boundary faults that form the western margin of the basin. These faults have a reverse aspect, are upturned by the boundary faults and are in places truncated against the faults in an upturned, trap-forming geometry. Hydrocarbons would be thermally generated gases formed in the deep axial portion of the Raton Basin and have migrated upward through the Dakota until trapped against the faults.

Higley and others (2007) calculated a mean value of undiscovered gas 615 BCF in both the Colorado and New Mexico portions of the Raton Basin in a play involving reservoirs in the Dakota, the Morrison Formation (Jurassic), and the Entrada sandstone (Jurassic). Based on an approximate one-third/two-thirds portioning of the basin between New Mexico (1/3) and Colorado (2/3), one can estimate that 205 BCF are present in the New Mexico portion of the basin. Given that the Wagon Mound field produced only 97 MMCF gas from the Dakota and Morrison, it would require that more than 2000 Wagon Mound fields be present to produce this volume of resource. This seems perhaps, a bit optimistic. On the other hand, gas in the deeper parts of the basin would be higher pressured and would be expected to have more per-well resource than present at Wagon Mound. Also, the numerical estimate cited above did not consider the dark-gray shale source facies present within the Morrison Formation in the deeper parts of the Raton Basin, which may have generated substantial volumes of gas and oil.

Jurassic strata

Morrison Formation (Upper Jurassic)

As previously discussed, the Morrison Formation forms the secondary reservoir at the Wagon Mound gas field. As with the Dakota gases at Wagon Mound, the high nitrogen contents and the paucity of CO_2 and gas liquids as well as the shallow occurrence and thermal immaturity of source rocks in the area suggest that the gas is biogenic. As with the Dakota, potential exists for similar, structurally-associated shallow gas accumulations throughout the eastern limbs of the Las Vegas and Raton Basins, the Cimarron arch, and the western flank of the Sierra Grande uplift.

More intriguing possibilities for Morrison oil and gas occur in the deeper parts of the Raton Basin associated with the dark-gray shale source facies (Figure 13). Morrison source facies are mature and within the oil window where present in the shallower parts of the basin and are within the dry gas window within the deepest parts of the basin (Figures 20, 21). As previously discussed, limited data indicate that the dark-gray shale facies contains more than sufficient TOC for hydrocarbon generation and that kerogens are a mixture of oil-prone and gas-prone types. The shows of oil and gas encountered in Morrison sandstones along the eastern flank of the Raton Basin (Figure 37; Table 9) indicate hydrocarbons have migrated through the shallow (< 1000 ft) Morrison sandstones on the eastern flank of the basin. Although it is possible that the oil and gas migrated into the Morrison from the Graneros Shale, this is considered unlikely because shale seals are present at most places in the upper Morrison. It is also possible that oil and gas were generated in the Morrison dark-gray shale source facies and migrated laterally updip through Morrison sandstones. In either case, the presence of a mature source facies in the basin center makes the basin center as well as the basin flanks prospective for oil and gas. Lateral updip terminations of fluvial Morrison sandstones as well as structural reversals coming out of the basin are trap possibilities.

The Morrison is present over the Cimarron arch. The arch is located updip of the gray-shale source facies. Therefore, the Cimarron arch constitutes an excellent and sparsely drilled target for oil and gas accumulations in the Morrison.

The Morrison is laterally truncated by the major reverse faults that form the western boundary of the Raton Basin. Similar too the overlying Dakota Group, strata are upturned by drag along the basin ward side of the fault, forming opportunities for traps for thermal gas generated in the deep axial portion of the basin.

Entrada Sandstone (Middle Jurassic)

The Entrada Sandstone is a blanket sand that forms a widespread permeable and porous reservoir across the Raton Basin, the Cimarron arch, the eastern two-thirds of the Las Vegas Basin, and the Sierra Grande uplift. Although the Entrada can be regarded as a favorable reservoir rock, Speer (1976) pointed out that it is not stratigraphically associated with source facies. Therefore the Entrada has limited potential for oil and natural hydrocarbon gases. CO_2 emitted from volcanic rocks in the deeper parts of the Raton Basin may have entered the Entrada and migrated updip until it was either trapped, dissipated as dissolved CO_2 in Entrada formation water, or leaked to the surface at the outcrop. Domal areas uplifted by Tertiary-age volcanic intrusions might be considered among the possible places for entrapment of CO_2 gas in the Entrada.

Triassic strata

Gas shows have been reported from Triassic strata on the eastern flanks of the Raton and Las Vegas Basins (Figure 39; Table 11). Where gauged, flow rates have been substantial ranging from 153 MCFD to 500 MCFD. The shows are downdip from surface occurrences of Tertiary intrusive and extrusive igneous rocks but are updip from Tertiary intrusive bodies located within the deeper parts of the Las Vegas and Raton Basins. Although isotopic data from the CO_2 and associated gases are not available, the most plausible sources of CO_2 are gases that were exsolved from the magmas that formed the intrusives as the magmas rose through the crust. The exsolved CO_2 then entered reservoir strata and migrated updip through water-saturated Triassic reservoirs. It is unlikely that the CO_2 was formed by magmas that came into contact with limestone beds and caused thermal decomposition of the limestones (see Hunt, 1996 for a description of this process) because of the almost complete absence of limestone in the Triassic section.

With an absence of hydrocarbon shows and an absence of petroleum source facies, potential in the Triassic section is for CO_2 accumulations.

Permian strata

Glorieta Sandstone (Permian)

The Glorieta Sandstone makes an excellent reservoir rock across the Las Vegas and Raton Basins. Several wells have yielded substantial flows of CO_2 and nonflammable gas from the Glorieta (Figure 40; Table 12). Reported flow rates range from 40 MCFD to 12 MMCFD. As Speer (1976) has pointed out, there is no petroleum source rock associated with the Glorieta. Therefore, potential in the Glorieta is for CO_2 accumulations. As with CO_2 in the Entrada Sandstone (Jurassic), the Glorieta CO_2 is most plausibly derived from exsolution of gas from rising magmas that form the igneous intrusions in the deeper parts of the Raton and Las Vegas Basins.

Pennsylvanian and Lower Permian strata

Sangre de Cristo Formation (Upper Pennsylvanian to Lower Permian), Madera Group (Pennsylvanian), and Sandia Formation (Pennsylvanian)
Raton Basin

Pennsylvanian strata hold considerable potential for accumulations of hydrocarbon gases and CO_2. Shows of light oil as well as natural gas have been encountered by wells drilled through the Sangre de Cristo Formation on the eastern flank of the Raton Basin where the Sangre de Cristo rests directly on Precambrian basement. In this area, there are some dark-gray shales in the Sangre de Cristo that may be source rocks for oil and gas. Alternatively, the hydrocarbons may have migrated onto the basin flank from source rocks to the west, deeper in the basin. In the latter case, the entire area between the deep axial part of the basin and the shallow eastern flank would be located along the migration path and would therefore be prospective. In the former case the shallow strata on the eastern flank have significant potential.

Raton Basin

The Pennsylvanian section is absent from the Sierra Grande uplift and the eastern flank of the Raton Basin. In both of these areas, the Sangre de Cristo Formation rests unconformably on basement, although thin erosional remnants of Lower Pennsylvanian strata may be present locally. The Madera Group and Sandia Formation are exposed immediately west of the Raton Basin in the Sangre de Cristo Mountains where they have been uplifted along the Laramide-age reverse faults that form the western boundary of the basin. Along the outcrop in the mountains, the Pennsylvanian section is primarily arenaceous with subordinate marine limestones and shales (Brill, 1952; Bolyard, 1959). Although dark-gray shales that may contain sufficient organic matter to be considered source rocks are present, they are a minor component of the Pennsylvanian section north of the Cimarron arch and are therefore of only marginal interest as a source facies.

No wells have been drilled sufficiently deep to penetrate the Pennsylvanian section in the deeper, axial portion of the Raton Basin. This area was occupied by the southern part of the Central Colorado basin during the Pennsylvanian and Early Permian (see Baltz, 1965). Baltz (1965) postulated that sub-basins (his term was synclines) might underlie synclines that are mappable at the surface where Cretaceous strata crop out. The surficial synclines would have resulted from subsidence and differential compaction associated with the underlying sub-basins of late Paleozoic age. Because basement in the region forms primarily though faulting of the brittle Precambrian crystalline rocks, the sub-basins would have been formed by faults of Pennsylvanian to Early Permian age, similar to what occurred in the Tucumcari Basin to the southeast (Broadhead and King, 1988; Broadhead et al., 2001). Furthermore, the axis of the late Paleozoic Central Colorado Basin is approximately geographically coincident with the axis of the modern Raton Basin (formed during the Laramide). Many late Paleozoic basins in New Mexico have deep grabens or elevator sub-basins that lie just off the flanks of the uplifts that bound the basins (Broadhead, 2001a, 2001b, 2001c). These grabens are the loci of deposition of thick sections of petroleum source rocks whose TOC contents are enhanced relative to neighboring areas outside of the grabens (Broadhead, 2001a, 2001b, 2001c). The position of the Central Colorado Basin east of an area predominated by arenaceous sediments during the Pennsylvanian suggests, but certainly does not prove the presence of a Pennsylvanian graben in the area. Although the presence of a Pennsylvanian-age graben is speculative and must await either deep drilling of the acquisition of reflection seismic lines, the postulation of such a hidden graben is reasonable given the relationship of source rock-rich grabens to adjoining uplifts in other parts of New Mexico. A seismic reflection line that is located in the general Raton Basin area but was not available to the author is reported to show a deep section of reflectors that may be a buried elevator basin (Roy Johnson, personal communication, 2007). If a source rock-rich Pennsylvanian elevator basin is present under the Raton Basin, its source facies would be in the dry gas window because shallower strata are in the dry gas window; any hydrocarbons will be dry gases. Trap opportunities may be associated with intragraben structures, updip structural and stratigraphic truncation of sandstone reservoirs at graben margins, truncation of upturned reservoir strata along the Laramide reverse faults on the western flank of the Raton Basin, and stratigraphic pinchouts of sandstones associated with marine or fluvial-deltaic sedimentary packages that infill the graben.

Las Vegas Basin

Several wells have penetrated the Pennsylvanian section and Precambrian basement within the Las Vegas Basin. As previously discussed, mature organic-rich source rocks within the oil window are present within the Pennsylvanian throughout most of the subsurface of the Las Vegas Basin. Some rocks are within the wet gas/dry gas and condensate windows in deeper areas or perhaps in areas proximal to major Tertiary-age intrusive bodies. Shows in the basin have ranged from hydrocarbon gases to gases that are comprised mostly of CO_2. The CO_2-rich gases recovered from the Sangre de Cristo Formation in the Union Land and Grazing No. 1 Fort Union well, located in Sec. 2 T20N R19E within the Turkey Mountains are associated with the laccolith that forms the core of the Turkey Mountains uplift. As discussed under the section on source rocks, the origin of the CO_2 within the Las Vegas Basin is best explained by exsolution of juvenile gases from rising magmas during Tertiary-age intrusion. As the magmas rise through the crust, confining pressure is continually decreased and gases, principally water vapor and CO_2 are devolved and migrate into surrounding permeable reservoir beds. Although the CO_2 may have originated by thermal decomposition of limestones subjected to heat emitted by the intrusions, this origin is problematic because there is little carbonate present within the Sangre de Cristo. The concept of CO_2 originating from the thermal destruction of methane at depth is unsupported by modern concepts regarding the thermal stability of methane.

CO_2 gas is the trapped in the domal structures associated with the igneous intrusives. Thus the Turkey Mountain dome may function as a trap for CO_2 released by the magmas that formed the laccolith at the core of this mountain range. Where intrusives do not form a domal uplift with quaquaversal closure, then CO_2 will migrate outward from cooling magmas into adjacent reservoir strata and then will move updip until it is either trapped, dispersed in a dissolved state in reservoir waters, or vented to the surface at the outcrop.

In areas distant from igneous intrusive bodies, the dark-gray to black organic-rich shales in the Pennsylvanian section are mature source rocks that have generated oil and gas. Reservoirs are interbedded sandstones and the source shales function as seals as well as source rocks. Donegan (1985) has pointed out that porosities in sandstones of the Sandia Formation contain silica overgrowths that have reduced porosity in wells drilled in the vicinity of igneous intrusions and that the overgrowths may have a hydrothermal origin. Sandia sandstones that crop out in the Taos trough on the Sangre de Cristo uplift have reduced porosities due to compaction and cementation by authigenic clay and chlorite. It is expected that wells drilled distant from major igneous intrusions will not encounter as much porosity reduction by quartz overgrowths and that areas of more distal, mineralogically mature (and therefore less feldspathic) sandstones will have suffered less compaction and less cementation by authigenic phyllosilicates (Donegan, 1985). Significant gas shows or other indications of gas (such as crossover of neutron-porosity and density-porosity logs) have been encountered in wells drilled in the deep basin and sandstone porosities associated with gas indications indicate that at least selected sandstones in the Pennsylvanian section have favorable reservoir properties. Opportunities for traps are associated with truncated and onlapping strata along basin margins as well as intrabasin structures and stratigraphic traps associated with clastic sedimentary packages that infilled the basin. Of special interest are the Pennsylvanian-age thrust faults penetrated in the True Oil Medina well and in the Amoco Salmon Ranch wells. These faults have repeated the Pennsylvanian section and have no doubt resulted in trap-forming geometries both above and below the faults, including possible, but as yet undocumented, hanging-wall anticlines.

Central area – Sangre de Cristo uplift

Geologic overview

The ***central project area*** is defined by the Sangre de Cristo uplift (Figures 2a, 3). Geologically, the area is characterized by outcrops of Precambrian basement in its northern part and outcrops of Pennsylvanian and Lower Permian sedimentary rocks of the Sandia Formation, Madera Group, and Sangre de Cristo Formation in its southern part (see Figures 5, 12). As previously mentioned, the central project area contains very little State Trust Land and its geology and petroleum potential are therefore only summarized here. Most of the land within the area is U.S. Forest land with lesser amounts of private and Native American lands. This part of the study area is discussed partially for completeness of coverage and partially because aspects of its natural gas potential have a bearing on the natural gas potential of the San Luis Basin to the west (***western project area***).

The Taos trough (Figures 2b, 12) is a northwest-southeast trending basin on the Sangre de Cristo uplift that is filled with sedimentary rocks of the Sandia Formation, Madera Group and Sangre de Cristo Formation. The Taos trough formed during the Pennsylvanian. Although some workers (e.g. Casey, 1980; Soegaard, 1990) include the Las Vegas Basin in the Taos trough, others (Baltz and Myers, 1999) have applied the term Rainesville trough to that portion of the Pennsylvanian-age basin that is located east of the Sangre de Cristo uplift and underlies the present-day Las Vegas Basin. Baltz and Myers (1999) separate the Taos trough from the Rainesville trough with the El Oro – Rincon uplift, a Late Paleozoic tectonic highland from which Pennsylvanian strata are absent. The eastern boundary of the El Oro – Rincon uplift coincides with a portion of the western boundary of the Las Vegas Basin, indicating that this tectonic boundary, active during the Pennsylvanian, was reactivated during the Laramide. This restricted definition of the Taos trough, limiting it to the Sangre de Cristo uplift, is utilized in this report.

The total thickness of Pennsylvanian and lowermost Permian strata exceeds 6000 ft along its northwesterly trending axis (Figure 12; Baltz and Myers, 1999). There is a marked facies change within the Pennsylvanian section that reflects the presence of highlands that supplied coarse-grained clastic sediments (sandstones and conglomerates) from the north and west, the deep basinal Taos trough, and a shallow marine shelf to the south. The lower part of the Pennsylvanian is characterized by a facies change from conglomerates and sandstones in the Sandia Formation in the north and west to dark-gray or black basinal shales to the east and south; the basinal facies, in turn, grades southward into carbonates of the Madera Group on the Pecos shelf located south of the area covered by this report (Figure 42; Sutherland, 1963; Casey, 1980; Soegaard, 1990). This facies pattern represents tectonic segmentation of the area into an uplift to the north that was a source of coarse clastic sediments, a deep basin along the Taos trough axis (dark-shale facies), and the shallow-marine Pecos shelf to the south. The ancestral Brazos uplift to the west (Figures 2b, 12) was also a source of coarse clastic sediment. There is some uncertainty as to the exact areas of provenance for sandstones and conglomerates in the Sandia Formation (see Baltz and Myers, 1999).

Toward the end of the Pennsylvanian there was a period of tectonic quiescence. During this period, the flood of clastics from the tectonic uplifts was diminished as these paleotopographically high areas were worn down by erosion. The carbonate-dominated sediments of the Pecos shelf (Madera Group) migrated northward over the clastics of the Sandia Formation (Figure 42; Sutherland, 1963; Casey, 1980; Soegaard, 1990).

Another phase of tectonic activity during the latest Pennsylvanian and earliest Permian resulted in rejuvenation of tectonically high elements and deposition of coarse clastics (Sangre de Cristo Formation) in a dominantly braided alluvial system that covered the entire region (see Soegaard and Caldwell, 1990; Baltz and Myers, 1999). The primary source of clastic sediments appears to have been the western part of the Cimarron arch, just as the eastern part of this feature similarly supplied the clastic sediments of the Sangre de Cristo Formation in the northern part of the Rainesville trough. Shales in the Sangre de Cristo Formation are primarily red in color and are organic poor.

The present-day erosional surface on the top of outcropping Sandia, Madera, and Sangre de Cristo rocks ends our definitive evidence for what transpired on top of the Sangre de Cristo uplift after the Early Permian. However, the Upper Cretaceous of the Raton Basin provides evidence that the uplift was submerged, and stayed submerged, at least through most of the Cretaceous. As previously discussed, Cretaceous (as well as

Triassic and Jurassic) strata in the Raton Basin are laterally terminated by the reverse faults that form the boundary between the Raton Basin and the Sangre de Cristo uplift. There is no indication in Cretaceous strata older than the Trinidad Sandstone of a shoreline or shallow water facies associated with the present-day Sangre de Cristo uplift. Rather, it is evident that deeper-water facies such as the Pierre and Niobrara Shales once covered the Sangre de Cristo uplift and were removed by erosion associated with Laramide uplift of this tectonic feature. Although this has no bearing on the petroleum potential of the Sangre de Cristo uplift, it does have implications for the petroleum potential of the San Luis Basin, as will be discussed later.

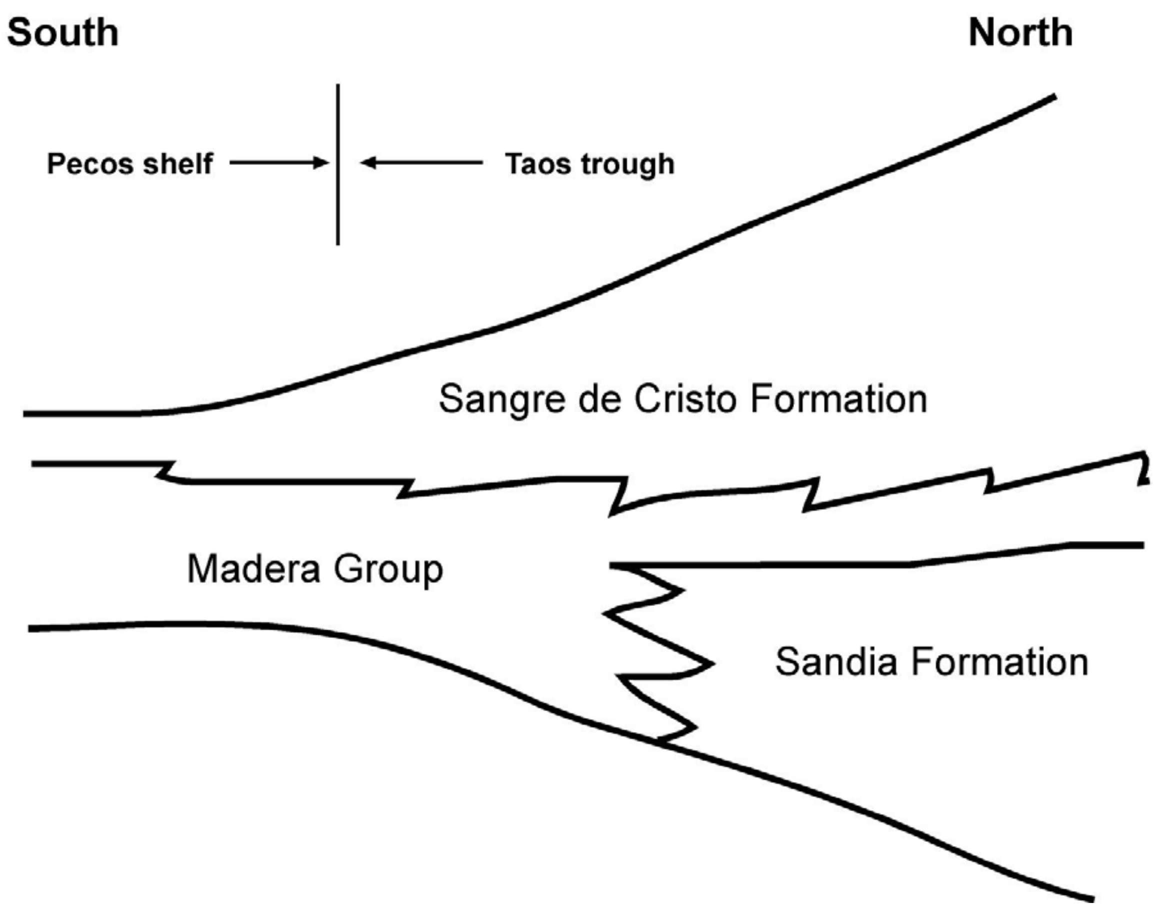

Figure 42. Stratigraphic relations of Pennsylvanian and Lower Permian rocks in the Taos trough. Simplified from Soegaard (1990).

Petroleum geology and natural gas potential

Ben Donegan (Donegan, 1985) summarized the geology and petroleum potential of Pennsylvanian strata in the Taos trough as part of his application to form a federal exploration unit in the Taos trough and Las Vegas Basin (Rainesville trough) areas. Donegan concluded that the distal facies in the progradational alluvial fan, braided stream and fan-delta systems of the Sandia Formation provide the best reservoirs. Seals are shales in the Sandia Formation that intertongue with the reservoirs and also shales in the overlying Madera Group. Traps may be both structural and stratigraphic according to Donegan, but the possibility of stratigraphic traps in the transition from the sandstone-rich alluvial and fluvial facies in the north and west to the shale-rich facies in the south is most intriguing. The possibility of shale gas in the deeper part of the Taos trough should not be overlooked.

Source rocks are shales in the Sandia Formation and also possibly shales and micritic limestones in the overlying Madera Group. Analyses of five outcrop samples of shales from the Lower (Morrowan to Atokan) and Middle (Desmoinesian) Pennsylvanian on the Sangre de Cristo uplift (Figure 43) indicate TOC contents of 0.50 to 1.51 weight percent. Although these TOC contents are less than the TOC contents of Pennsylvanian source facies in the Las Vegas Basin (Rainesville trough), they are still more than sufficient for hydrocarbon generation (> 1.0 percent) in 3 of the five samples analyzed for this project. Given the widespread, thick distribution of dark-gray shales within the Taos trough, it is evident that kerogen-rich rocks are voluminous in nature.

The Pennsylvanian shales of the Taos trough are mature and either within the oil window or the gas window. Rock-Eval TMAX ranges from 358^{o} C to 544^{o} C and is more than 444^{o} C in four of the five outcrop samples that were analyzed. Although flat S2 peaks in some of the samples render interpretation of the TMAX values problematic, the values generally suggest oil or gas maturity. The one sample with an absolutely normal S2 peak (NC-1) has a TMAX of 445^{o} C, indicating thermal maturity within the oil window. Other TMAX values of 445, 509, and 544 indicate increasing thermal maturity into the wet gas – dry gas windows (445 and 509) and the dry gas window (544), but as mentioned these may not be valid indications of maturity.

These TMAX measurements were made on samples collected from outcrops. Given that the Pennsylvanian sediments in the Taos trough attain a maximum thickness of approximately 6000 ft, it is reasonable to hypothesize that the deepest part of the section within the Taos trough will be more mature than at the surface and that maturation into the wet gas – dry gas and the dry gas windows may occur at depth.

The Rock-Eval S2/S3 ratios (see database ***northcentral source rocks.xls*** in Appendix A) vary from 0.3 to 26.0 indicating that the kerogen populations vary from oil prone to gas prone. With four of the samples having S2/S3 values equal to or less than 3.8, it appears that most of the source rocks in the Taos trough are gas prone. Given the high levels of thermal maturity and the consequent generation of hydrocarbons, original TOC values were undoubtedly higher than present-day TOC values.

In summary, significant volumes of hydrocarbons, almost certainly including natural gas, have been generated by the thick sections of organically rich source rock within the Pennsylvanian of the Taos trough. At shallow depths some associated oils may be present but in the deeper parts of the subsurface dry gas and perhaps mixtures of dry gas and wet gases will be present. Adequate reservoirs will be present in Sandia sandstones, but porosity and permeability may be best in the more distal part of the coarse-clastic facies. Porosity and permeability may be somewhat diminished by quartz cementation in the vicinity of igneous intrusions.

The optimum exploration fairway is located along the transition from the northern and western coarse clastic facies and the basinal facies in the south and east. Additional gas resources may be present as low-volume shale gas in the deeper parts of the Taos trough.

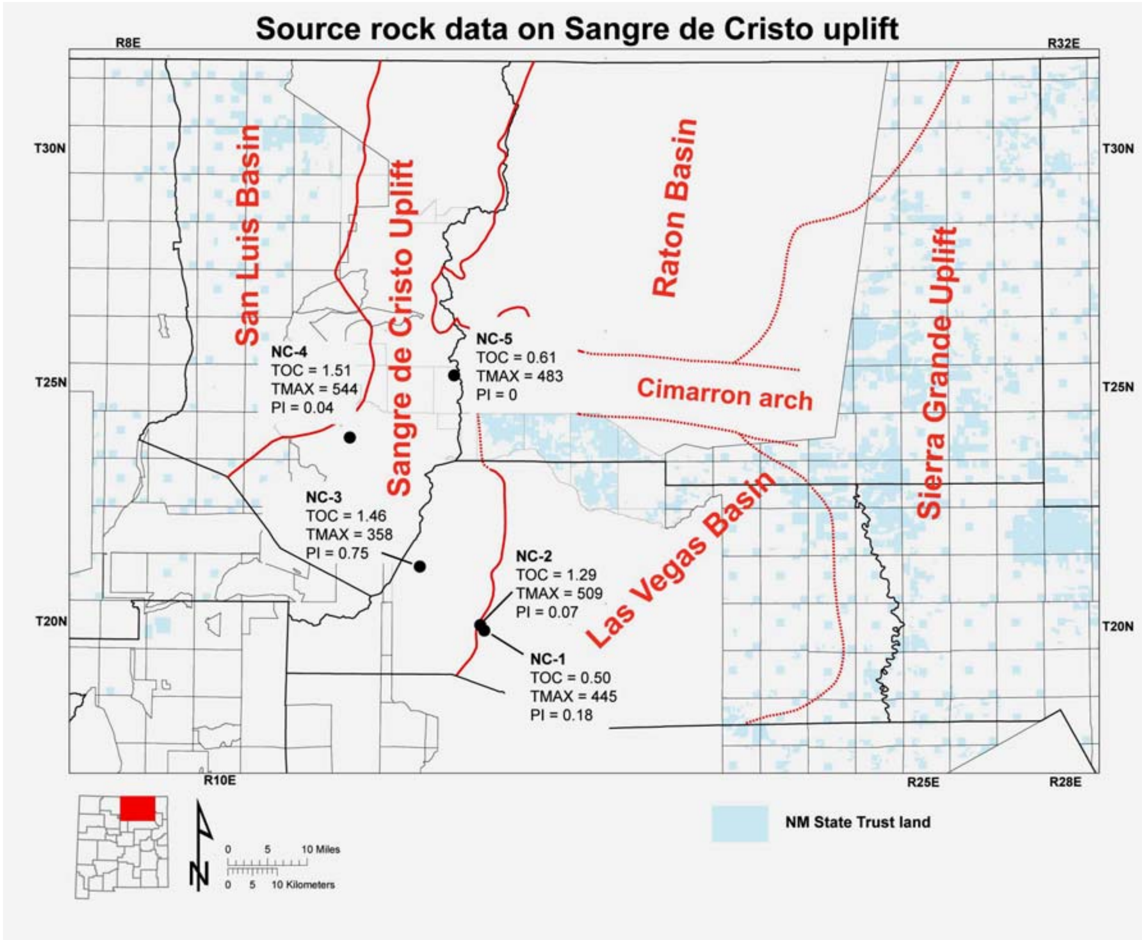

Figure 43. Locations of outcrop samples of Pennsylvanian shales analyzed for TOC and Rock-Eval pyrolysis and values of some key analytical parameters for each sample. See database *northcentral sourcerocks.xls* in Appendix A for additional analytical parameters and information on each sample.

Western area – San Luis Basin

The San Luis Basin lies west of the Sangre de Cristo uplift. It is a Tertiary-age extensional basin that is one of the northernmost basins of the Rio Grande rift (Hawley, 1978; Burroughs, 1981). The San Luis Basin is an east-tilted graben that extends northward into Colorado (Burroughs, 1981). The San Luis Basin is bordered on its east side by the Sangre de Cristo uplift. A system of north-trending high-angle extensional faults separates the Sangre de Cristo uplift from the San Luis Basin. On its west side, it is bordered by the north-trending Brazos uplift (consisting in New Mexico of the Tusas and Ortega Mountains) where Precambrian rocks are exposed at high elevations west of the basin. The western boundary of the basin is located in Rio Arriba County, west of the study area covered by this report.

Basin fill consists of Tertiary-age nonmarine sedimentary rocks, volcanic rocks, and volcaniclastic sedimentary rocks. The surface of the New Mexico part of the basin is dominated by Pliocene basaltic lava flows that are dotted by shield volcanoes and vents (Figure 5; Hawley, 1978). Quaternary alluvial sediments and pediment deposits are present on the surface in the eastern part of the basin. No exploration wells have been drilled in the New Mexico part of the basin, so that the subsurface stratigraphy and structure are highly conjectural. Nevertheless, several wells have been drilled in the Colorado part of the basin and studies made utilizing these wells, in addition to the surface geology of the Sangre de Cristo and Brazos uplifts, can be used to infer the subsurface geology of the New Mexico part of the basin. A synopsis is discussed below along with implications for natural gas potential.

Several deep exploratory wells have been drilled in the Colorado part of the San Luis Basin that reveal its subsurface stratigraphy and structure (Burroughs, 1981; Brister and Gries, 1994). In the Colorado part of the basin, Paleozoic and Mesozoic sedimentary rocks are absent; Tertiary valley-fill sediments rest directly on Precambrian basement rocks. Total thickness of valley fill ranges from 5000 to 10,000 ft (see Burroughs, 1981). The deepest part of the basin is filled by alluvial sandstones and reddish-brown shales of the Blanco Basin Formation (Eocene) that is in turn overlain by the Conejos Formation (Oligocene). The Conejos Formation consists of 1300 to 7500 ft of andesitic to latitic lava flows, volcaniclastic sedimentary rocks, and minor ash-flow tuffs as well as lacustrine claystones (Lipman, 1975, 1989; Brister and Gries, 1994). The Conejos Formation is, in turn, overlain by a series of ash-flow tuffs and associated sedimentary rocks that range in thickness from approximately 300 to 2000 ft. These are overlain by sediments of the Santa Fe Group (Miocene to Pliocene).

The Santa Fe Group consists of buff to orange clays and interbedded silty sands (Burroughs, 1981). The sands have a mixed provenance of plutonic igneous rocks, metamorphic rocks, and volcanic rocks. To the west, sediments of the Santa Fe Group intertongue with alluvial-fan sediments of the Los Pinos Formation, which were deposited as a clastic wedge shed off of the San Juan Mountains (located west of the Colorado part of the San Luis Basin).

The Santa Fe Group is overlain by the Alamosa Formation (Pleistocene; Burroughs, 1981). The Alamosa Formation forms the surface exposures over most of the Colorado part of the basin. The Alamosa consists of up to 2000 ft of green and blue to blue-gray beds of clays and fine- to very coarse-grained sands. The clay beds are, at least in part, lacustrine (Burroughs, 1981).

Cretaceous strata do not appear to be present in the subsurface of the New Mexico part of the San Luis Basin. As discussed above, no exploratory wells have been drilled in the New Mexico part of the San Luis Basin, so evidence of the subsurface geology is indirect. Cretaceous strata are not present in the Colorado part of the basin. As previously discussed, the Cretaceous section has been removed from the Sangre de Cristo uplift by erosion that ensued as a result of Laramide uplift. Although Cretaceous strata are present in the Chama Basin in Rio Arriba County, the Chama basin is separated from the San Luis Basin by the Brazos uplift. On the Brazos uplift, Precambrian rocks are exposed in the Tusas and Ortega Mountains and the Upper Paleozoic, Triassic, Jurassic, and Cretaceous sections have been removed by erosion. The San Luis Basin, as well as the uplifts that form its eastern and western flanks, appear to have been a Laramide high from which the sedimentary cover was removed pursuant to Laramide uplift. The San Luis Basin was formed subsequently during Tertiary extension associated with formation of the Rio Grande rift.

It is possible, but by no means certain, that Pennsylvanian sedimentary rocks are present in the southernmost part of the San Luis Basin. The Pecos-Picuris fault (see Figure 5), which separates the Taos trough from the Precambrian outcrops in the Picuris Mountains to the west. This fault was apparently active during the Pennsylvanian when it separated the Taos trough from the emergent highlands of the ancestral Brazos uplift (Figure 2b; Sutherland, 1963; Baltz and Myers, 1999). Most workers (e.g. Casey, 1980; Soegaard, 1990) have assumed that the Pecos-Picuris fault extended northward into Colorado during the Pennsylvanian and that along its length in Taos County separated the Uncompaghre uplift on the west from the Taos trough and associated tectonic elements (e.g. Cimarron arch) on the east. The Uncompaghre uplift is a well-documented emergent highland of Pennsylvanian age in Colorado, where it trends north-south (Mallory, 1972). Casey (1980) and Soegaard (1990) concluded that the Uncompaghre uplift was emergent along its entire length and shed coarse clastic debris eastward into the Taos trough. If so, then Pennsylvanian sediments are not present in the subsurface of the San Luis Basin.

Baltz and Myers (1999) cast doubt on the presence of a Late Paleozoic uplift (Uncompaghre) that was continuous from Colorado southward into the area now occupied by the Picuris Mountains. Instead, they place the ancestral Brazos uplift in the area from the present-day Picuris Mountains south to the Taos-Santa Fe county line based on outcrop work of Sutherland (1963) and Just (1937) as well as their own field work. North of the Picuris Mountains, Precambrian basement has been downdropped into the San Luis basin by the Embudo fault that defines the north side of the Picuris Mountains uplift. Baltz and Myers (1999) have used a negative gravity anomaly in the area north of the Embudo fault to conclude that a northern continuation of the ancestral Brazos uplift is not present in the San Luis Basin north of the Picuris Mountains and recognized an ancestral Brazos uplift that is distinct and separate from the Uncompaghre uplift. Therefore they conclude that it is possible, but certainly problematic, that the Taos trough extends northwest beyond its present limits and has been downdropped by Tertiary-age faulting into the San Luis Basin. If so, then Pennsylvanian strata are present in the subsurface of the San Luis Basin along the purple line shown in Figure 44. This possible, but far from certain extension, marks the only viable possibility for hydrocarbons, whether oil or gas, in the New Mexico part of the San Luis Basin.

Marginal amounts of oil have been produced from the San Juan sag in southern Colorado. The San Juan sag is located west of the San Luis Basin and is an area where Cretaceous sedimentary rocks are preserved underneath the volcanic pile that forms the San Juan Mountains. In the San Juan sag, minor noncommercial volumes of oil have been produced from a volcanic sill of Oligocene age that has intruded the Mancos Shale (Upper Cretaceous; Gries et al., 1997). The Mancos functions as both the source rock and the seal. The sill is presumably fractured and is the reservoir. Given the absence of Cretaceous strata from the New Mexico part of the San Luis Basin, analogous oil accumulations cannot be present in the New Mexico part of the basin. In looking at the New Mexico part of the basin as a whole, the only possibility of oil and gas accumulations is highly uncertain and is associated with the very uncertain presence of a downdropped part of the Taos trough in the southernmost part of the basin. This is the only place where petroleum source rocks might be present, and without source rocks no hydrocarbons, oil or gas, could have been generated.

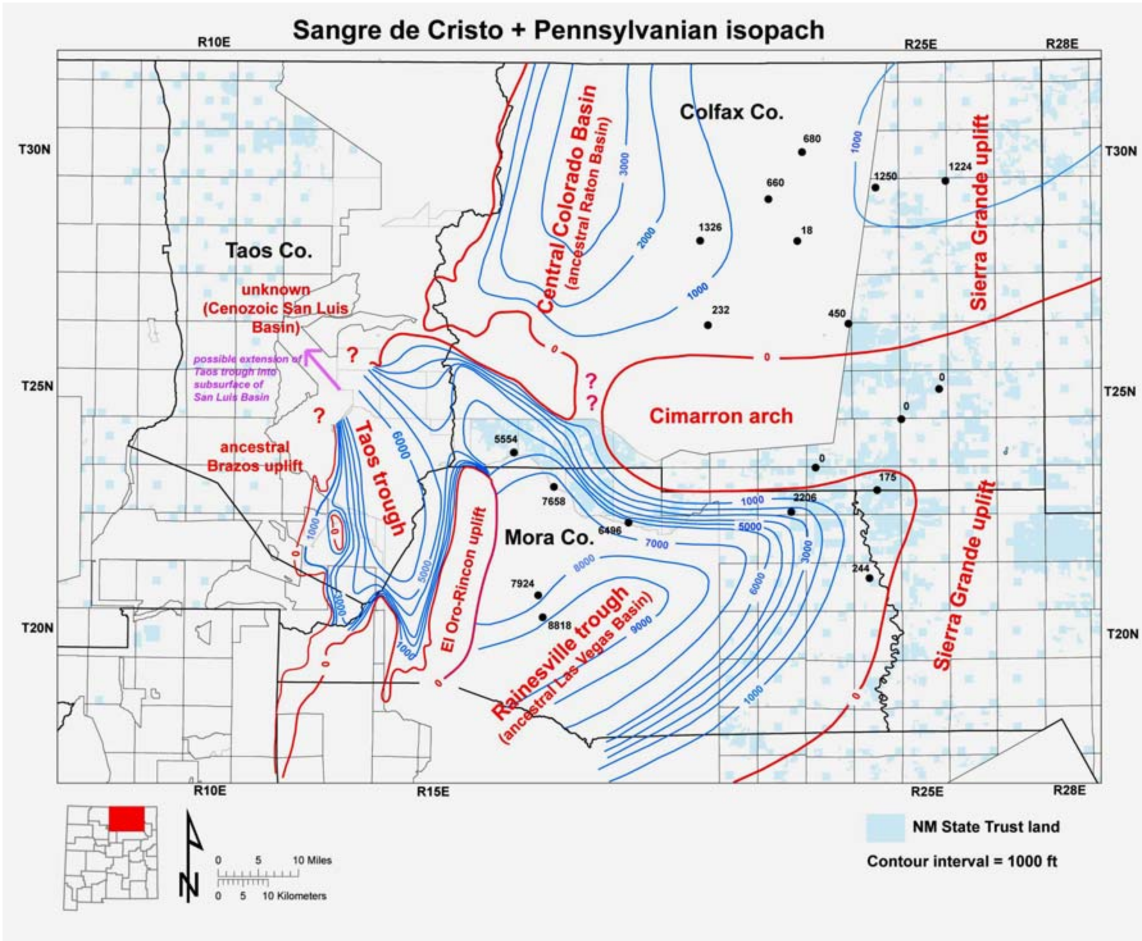

Figure 44. Isopach map of Sangre de Cristo Formation, Madera Group and Sandia Formation, late Paleozoic tectonic elements, and possible extension of Taos trough into subsurface of San Luis Basin (purple arrow).

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