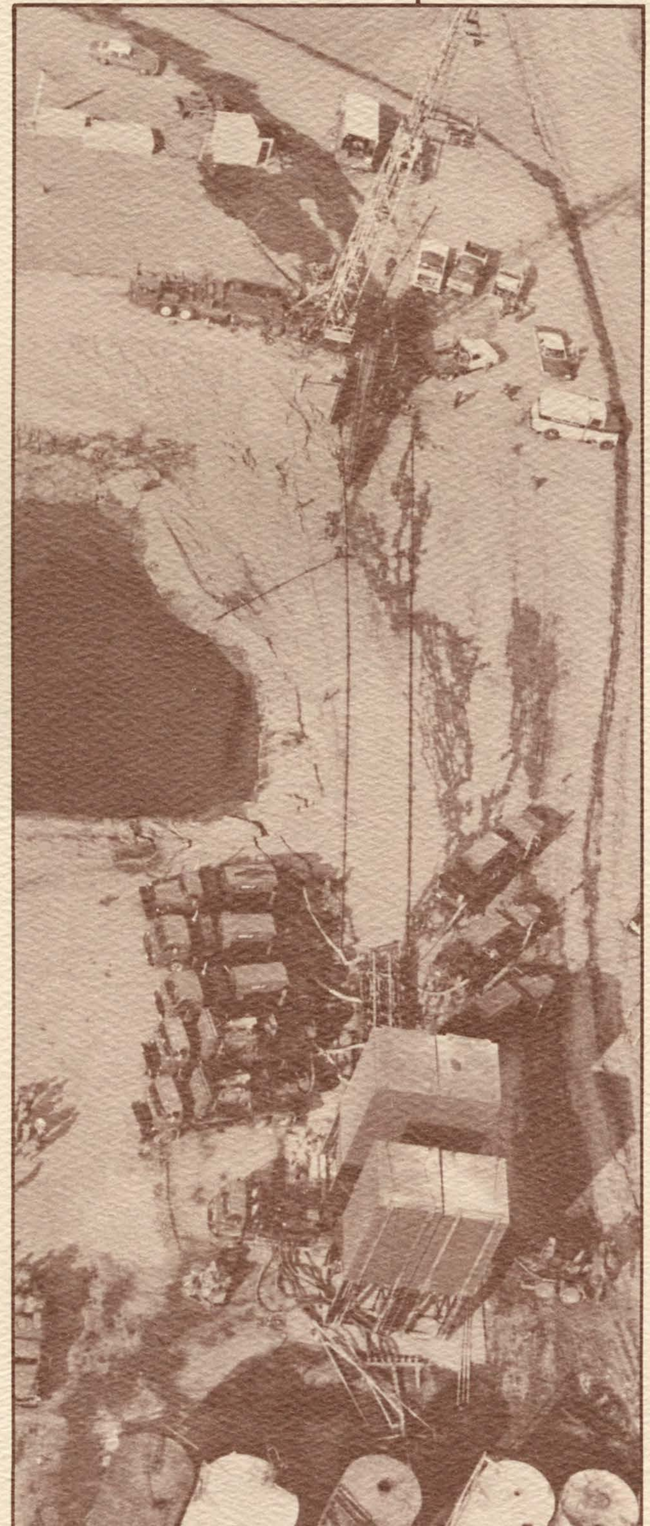
Report of Investigations No. 138

Geology and Engineering Characteristics of Selected Low-Permeability Gas Sandstones: *A National Survey*

Robert J. Finley



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Bureau of Economic Geology
W. L. Fisher, Director
The University of Texas at Austin
Austin, Texas 78712

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Geology and Engineering Characteristics of Selected Low-Permeability Gas Sandstones: *A National Survey*

by
Robert J. Finley

assisted by Stephen W. Speer
with contributions by Richard J. Diecchio of the
West Virginia Geological and Economic Survey

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ABSTRACT

Thirty-one low-permeability gas-bearing sandstones in 15 sedimentary basins were surveyed to delineate the major depositional systems and associated facies of each stratigraphic unit. The depositional system of each unit provides a basis of comparison between formations of different ages in different structural and sedimentary settings. Information was compiled on general attributes, economic factors, geologic parameters of the basin or trend, geologic and engineering parameters of the stratigraphic unit, and operating conditions at each formation or member. Results of this survey can be applied elsewhere to exploration of tight gas sandstone trends in other stratigraphic units with similar depositional systems. Tight gas sandstones reviewed here have blanket geometries and produce or could produce from strata having in situ permeabilities of 0.1 md or less, although gas may also be contained in more permeable horizons of the sandstones. Reservoirs vary from extensively developed gas plays ("Clinton"-Medina sandstone, Appalachian Basin) to active gas plays (Corcoran and Cozzette Sandstones, Piceance Creek Basin) to sparsely drilled units (Blair Formation, eastern Greater Green River Basin).

Most of the blanket-geometry tight gas sandstones surveyed were classified as one of two marginal marine depositional systems: either a deltaic system or a barrier-strandplain system. A few additional tight gas reservoirs were classified as intracratonic shelf systems. One stratigraphic unit, the Travis Peak Formation in the East Texas and North Louisiana Basins, represents an alluvial plain of braided-stream deposits having a marine-reworked distal margin. Although not specifically discussed, lagoonal, estuarine, and tidal-flat systems may be spatially related to the barrier-strandplain systems surveyed. The fluvial system was not represented in this survey because its sands are predominantly lenticular.

The Travis Peak Formation (and the equivalent Hosston Formation in the North Louisiana Basin) may provide new unconventional gas supplies from sand-rich deltaic systems. Technology resulting from development of the Travis Peak could be applied to continued development of the Lower Silurian Tuscarora Sandstone and equivalent Medina and "Clinton" sandstones in the Appalachian Basin.

The Frontier Formation is an areally extensive delta system that has potential for tight gas production in three Laramide-age basins: the Greater Green River Basin, the Wind River Basin, and the Big Horn Basin. This formation offers extrapolation potential both to other deltaic systems and to the Frontier itself within the three basins. The Olmos Formation (Maverick Basin), by analogy to an underlying stratigraphic unit and by reference to limited available data, consists of wave-dominated deltas and strandplain deposits representing several smaller delta systems.

Most of the tight gas sandstones investigated are dominantly regressive barrier-strandplain systems. Deltaic and offshore-bar sands may occur along strike within a few of these units. Prograding sands of the regressive Mesaverde Group in several basins of the Rocky Mountain region constitute most of the barrier-strandplain depositional systems.

Development of Mesaverde Group sands and the Pictured Cliffs Formation in the San Juan Basin more clearly extends existing production into adjacent tight areas than does current exploration in the Cozzette and Corcoran Sandstones of the Piceance Creek Basin. The Fox Hills Sandstone appears to have good reservoir continuity, as does the upper Almond Formation (Greater Green River Basin). The Fox Hills currently produces in only one field; because of its good continuity, it may require structural closure to form a gas trap. More gas has been produced from the nonmarine lower Almond Formation than from the blanket-geometry upper Almond.

The Oriskany Sandstone (Appalachian Basin) was tentatively classified as a barrier-strandplain system, but its component facies are poorly known and it may have been affected by marine transgression. Conventional gas production from the Oriskany has been extensive within the Appalachian Basin, but few data are available from tight areas.

Shelf deposits of the Cleveland Formation and parts of the Cherokee Group (Anadarko Basin) and the Mancos "B" interval of the Mancos Shale (Piceance Creek and Uinta Basins) are good examples of the shelf depositional system. The Cleveland is thinner than the Mancos "B" and may have a thin deltaic package at its base. The Mancos "B" interval is probably the best example of a shelf depositional system included in this survey; however, the extrapolation potential of studies of shelf systems appears limited by the small number of formations of this type.

Keywords: *Gas, low-permeability sandstone, depositional systems, Almond Formation, Berea Sandstone, Blair Formation, Cleveland Formation, Cliff House Sandstone, "Clinton"-Medina sandstone, Corcoran Sandstone, Cotton Valley Sandstone, Cozzette Sandstone, Dakota Sandstone, Davis sandstone, Fox Hills Sandstone, Frontier Formation, Hartselle Sandstone, "J" Sandstone, Mancos Shale, Muddy Sandstone, Olmos Formation, Oriskany Sandstone, Pictured Cliffs Sandstone, Point Lookout Sandstone, Travis Peak Formation, Tuscarora Sandstone*

INTRODUCTION

PROJECT OVERVIEW

Previous geologic and engineering studies have categorized low-permeability gas sandstones by external reservoir geometry. Kuuskraa and others (1978) differentiated lenticular and blanket reservoirs in basins across the country. The Western Gas Sands Project, funded by the U.S. Department of Energy in cooperation with the U.S. Geological Survey, private industry, and various universities and national laboratories, has included research on many aspects of gas production from tight lenticular sands in the Uinta, Piceance Creek, and Greater Green River Basins. Elements of the Western Gas Sands Project have included improved determination of the gas resource, geologic characterization of local areas, instrumentation research, reservoir modeling, and improvement and application of production technology such as hydraulic fracturing.

Some of the results of this project are applicable to reservoirs of blanket geometry, but many are not. Each reservoir is a product of different modes of deposition and histories of burial, physical compaction, cementation, and possible subsequent deformation. Both internal and external geometry of a reservoir control the development of a hydrocarbon resource and strongly affect completion techniques, rate of resource recovery, and ultimate recovery per well and per field. Geologic variability complicates the exploitation of any reservoir, and it is probably even more significant in the recovery of gas from tight formations.

The present study, which was supported by the Gas Research Institute, aims to improve understanding of the occurrence, distribution, and recovery of gas from tight formations by compiling data on low-permeability blanket sand reservoirs. Tight gas sands described here either produce or could produce from strata having in situ permeabilities of 0.1 md or less. Each formation surveyed may also contain gas in more permeable strata. Blanket-geometry sandstones have relatively good continuity in dip and strike directions over moderate distances. Near most wells, such sandstones do not have major sand-shale interfaces that interfere with hydraulic fracture stimulation.

TECHNICAL APPROACH

This survey is a compilation of information on the geology, engineering parameters, economic factors, and operating conditions of gas-producing areas in selected basins ranging from the Appalachian Basin to several gas-prone basins of the Rocky Mountain region. Basins that were selected are either known to produce gas or contain gas shows in tight blanket-geometry formations. The information compiled in this study includes the same parameters to the greatest extent possible from area to area, recognizing that areal differences exist in the available data.

Blanket-geometry tight gas sands were reviewed from diverse sedimentary environments; the formations studied were

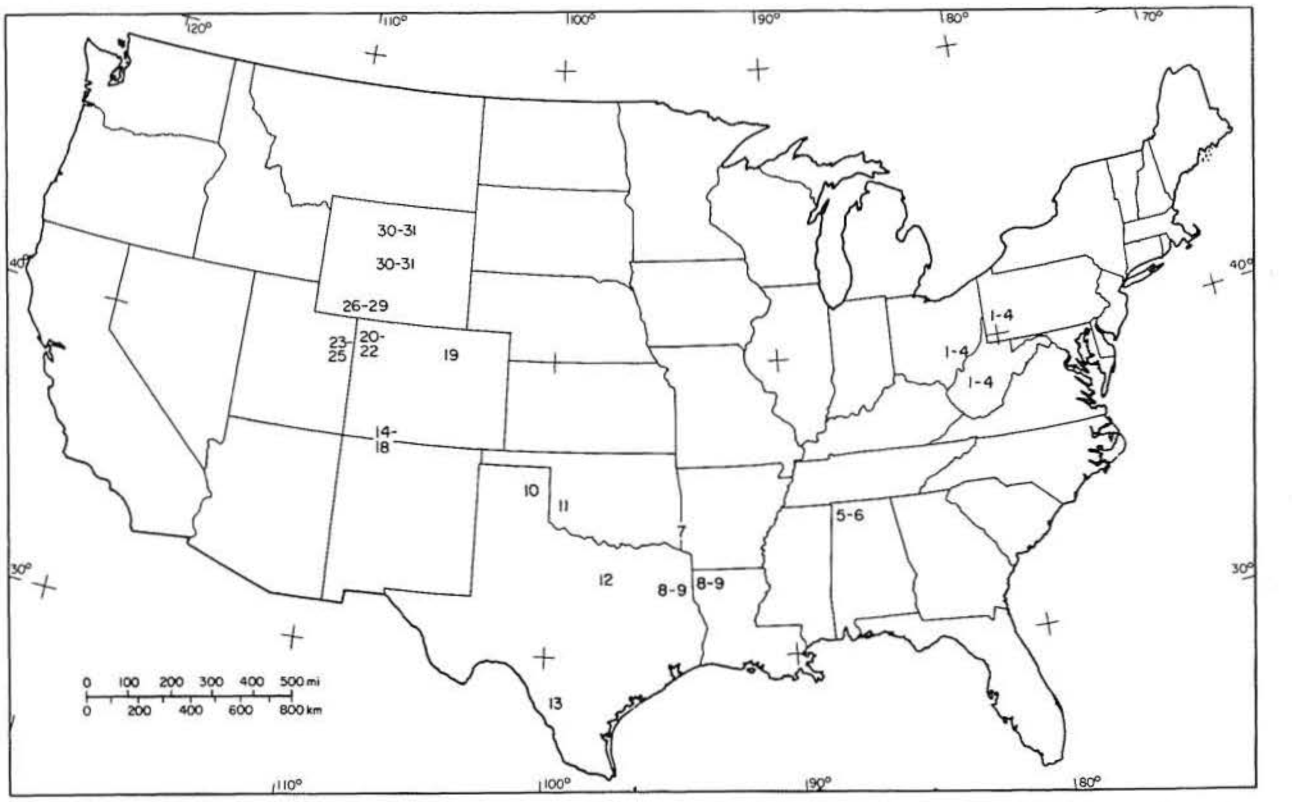


FIGURE 1. Location map of blanket-geometry tight gas sands included in this survey. Numbers are keyed to table 1.

divided into groups having common genetic depositional systems. This grouping by depositional systems allows comparison of geologic and engineering parameters from one gas-productive trend with those from another. The review of each stratigraphic unit therefore emphasizes the depositional system responsible for emplacing the unit and the occurrence of analogous systems in other sedimentary basins.

The assembly of data on 15 sedimentary basins required presentation in a format that would allow comparison between areas (fig. 1). Tables having a standard format were used to present data on each major stratigraphic unit of the basins. Some stratigraphic units did not warrant data tables; sufficient data on others to complete a set of tables were unavailable. These units are described in the text. A comparison of the depositional systems of all stratigraphic units follows presentation of the basic data. Data are presented in geographic order from the Appalachian region through the southern and southwestern states to the Rocky Mountain region (table 1).

TABLE 1. Stratigraphic units and basins included in this survey. Number following unit indicates location in figure 1.

APPALACHIAN BASIN
- Oriskany Sandstone (1)
- Tuscarora Sandstone (2)
- Berea Sandstone (3)
- "Clinton"-Medina sandstone (4)

BLACK WARRIOR BASIN
- Carter Sandstone (5)
- Hartselle Sandstone (6)

ARKOMA BASIN AND OUACHITA MOUNTAIN PROVINCE (7)

EAST TEXAS AND NORTH LOUISIANA BASINS
- Travis Peak (Hosston) Formation (8)
- Cotton Valley Sandstone (9)

ANADARKO BASIN
- Cleveland Formation (10)
- Cherokee Group (11)

FORT WORTH BASIN
- Davis sandstone (12)

MAVERICK BASIN
- Olmos Formation (13)

SAN JUAN BASIN
- Pictured Cliffs Sandstone (14)
- Cliff House Sandstone, Mesaverde Group (15)
- Point Lookout Sandstone, Mesaverde Group (16)
- Sanostee (Juana Lopez) Member, Mancos Shale (17)
- Dakota Sandstone (18)

DENVER BASIN
- "J" Sandstone (19)

PICEANCE CREEK BASIN
- Cozzette Sandstone, Mesaverde Group (20)
- Corcoran Sandstone, Mesaverde Group (21)
- Mancos "B" Shale (22)

UINTA BASIN
- Sego Sandstone (23)
- Castlegate Sandstone (24)
- Mancos "B" Shale (25)

GREATER GREEN RIVER BASIN
- Fox Hills Sandstone (26)
- Upper Almond Formation, Mesaverde Group (27)
- Blair Formation, Mesaverde Group (28)
- Frontier Formation (29)

WIND RIVER AND BIG HORN BASINS
- Frontier Formation (30)
- Muddy Sandstone (31)

METHODOLOGY

DEFINITION OF VARIABLES

Data on 31 stratigraphic units in 15 sedimentary basins were collected for this study. Variables that were quantified include general attributes, economic factors, geologic parameters of the basin or trend, geologic and engineering parameters of the stratigraphic unit, and operating conditions for each formation or member. Variables within each category are listed in table 2.

DATA SOURCES

Applications by gas producers for tight formation designations under section 107 of the Natural Gas Policy Act (NGPA) and associated rules of the Federal Energy Regulatory Commission (FERC) were the primary source of geologic and engineering data on tight gas reservoirs. Published reports rarely include specific data on porosity, permeability, water saturation, net pay thickness, production rates, and other key variables used to characterize the exact producing interval of a tight formation. Consequently, applications in the files of state regulatory agencies constitute the most complete data base on tight gas sands in the United States.

Guidebooks prepared by the Wyoming Geological Association, the Rocky Mountain Association of Geologists, and many local and regional geological societies were another data source. These guidebooks include articles on the applied sedimentology of producing reservoirs and frequently provided the geologic data needed to supplement data from operator applications. Open-file reports of the U.S. Geological Survey, produced as part of the Western Gas Sands Project, provided data on selected western basins.

TABLE 2. Variables used to define low-permeability gas sandstones.

GENERAL ATTRIBUTES
- Basin or trend
- Areal extent
- Interval thickness
- Depth range

ECONOMIC FACTORS
- FERC status
- Estimates of resource base
- Attempted completions and degree of success
- Markets and pipeline availability
- Industry interest and leasing activity

GEOLOGIC PARAMETERS - BASIN OR TREND
- Structural and tectonic regime
- Regional thermal gradient
- Regional pressure gradient

GEOLOGIC PARAMETERS - STRATIGRAPHIC UNIT
- Depositional system and genetic facies
- Textural maturity
- Mineralogy
- Diagenetic processes and cements
- Reservoir dimensions
- Pressure and temperature range
- Natural fractures
- Data availability

ENGINEERING PARAMETERS - STRATIGRAPHIC UNIT
- Porosity and permeability
- Net pay thickness
- Production and decline rates
- Typical water saturation
- Formation fluids
- Well stimulation attempts and success
- Typical logging practice and other techniques
- Development well spacing

OPERATING CONDITIONS
- Terrain characteristics and accessibility
- Limiting weather conditions

DEPOSITIONAL SYSTEMS AS A COMMON FACTOR IN RESERVOIR CHARACTER

The basic sedimentary framework of a basin can be understood by using lithogenetic facies as stratigraphic units. Each facies is a three-dimensional body of rock whose environmental origin can be inferred from a set of observable characteristics. These characteristics include external and internal geometry, sedimentary structures, lithology, organic content, stratigraphic relations, and associated sedimentary facies. A group of lithogenetic facies linked by depositional environment and associated processes is a "depositional system" (Fisher and McGowen, 1967). For example, a meandering fluvial system may include channel, point-bar, and crevasse-splay facies, each of which would tend to have similar characteristics under a given available sediment supply and set of energy conditions.

Each lithogenetic facies has certain attributes, including porosity, permeability, and spatial relations to other facies, that control or affect migration and distribution of hydrocarbons and thereby influence the potential of the facies as a hydrocarbon reservoir (Galloway and others, 1982). Although some properties derived from the depositional setting of a stratigraphic unit may have been modified in the subsurface by compaction and diagenesis, the overall sand-body geometry of the unit is largely unaffected over time. Thus, delineation of depositional systems can be used to characterize blanket-geometry tight gas sands; facies of some depositional systems will be dominantly lenticular, and facies of others will possess good lateral continuity.

A depositional system is part of a "systems tract" (Brown and Fisher, 1977), which may include, for example, fluvial, deltaic, shelf, and slope depositional systems. These coeval systems reflect a paleoslope from source-area to basin-margin to deep-marine environments. Thus, understanding relations among depositional systems within a regional setting allows extrapolation of detailed localized studies of a tight gas sand to wider areas. This extrapolation could be particularly important in the Rocky Mountain region, where well data are sometimes concentrated in limited basin-margin areas and where deeper basin flanks are only sparsely drilled.

MAJOR DEPOSITIONAL SYSTEMS

The nine principal clastic depositional systems reviewed by Fisher and Brown (1972) can be classified into three major groups established by Selley (1978): continental, shoreline (marginal marine), and marine environments (table 3). Each of the nine systems can be divided into additional categories. For example, a fan delta has marine-reworked margins, including a distal fan facies having a delta front and possibly marine bars. The fluvial system can be divided into several subclasses: braided streams, fine-grained meanderbelts, coarse-grained meanderbelts, and stabilized distributary channels. Each of these subclasses has distinctive sand-body geometry, texture, and distribution of internal sedimentary structures. Similarly, deltas can be divided into river-dominated types that have digitate to lobate geometries and into wave-dominated types that have cuspate geometries.

The study of modern depositional systems and their ancient counterparts has led to the development of models of major clastic depositional systems (Fisher and Brown, 1972; Brown and Fisher, 1977; Selley, 1978; Walker, 1979). Such models, combined with data on individual stratigraphic units, have been used in this survey to help interpret the geometry of tight sand reservoirs. The Western Gas Sands Project has included study of lenticular sands, many of which are fluvial and were deposited in continental environments of the Upper Cretaceous Mesaverde Group in several Rocky Mountain basins. This survey found that blanket-geometry tight gas sands formed mostly in marginal marine environments that include deltaic and barrier-strandplain systems. Some of these marginal marine deposits are part of regressive clastic wedges fed by the lenticular fluvial systems of the Mesaverde Group. A few blanket-geometry sands were formed in intracratonic shelf systems.

TABLE 3. Classification of clastic depositional systems by environment (after Fisher and Brown, 1972; Selley, 1978).

CONTINENTAL ENVIRONMENTS
Eolian systems
Lacustrine systems
Fluvial systems
Terrigenous fan (alluvial fan and fan-delta) systems
SHORELINE (MARGINAL MARINE) ENVIRONMENTS
Delta systems
Barrier-strandplain systems
Lagoon, bay, estuarine, and tidal-flat systems
MARINE ENVIRONMENTS
Continental and intracratonic shelf systems
Continental and intracratonic slope and basinal systems

BEREA SANDSTONE, APPALACHIAN BASIN

The Berea Sandstone of the Lower Mississippian Pocono Group is the oldest Mississippian sandstone in the Appalachian Basin. The Berea varies from a medium- to fine-grained sandstone (Fayette and Raleigh Counties, West Virginia) to siltstone and fine-grained sandstone, which may be interbedded with shale (Plateau region, western Virginia). Data base on the Berea Sandstone is fair, containing information from four applications for designation as a tight gas formation (table 4). Specific engineering data are limited; unstimulated flow rates have not been measured, and permeabilities are inferred, by comparison to a few porosity values that have corresponding permeability values, to be commonly below 0.1 md (table 5).

Depositional Systems

The Berea Sandstone is part of a Lower Mississippian progradational clastic wedge that includes major sand-filled fluvial channels, a delta plain, and a delta front. Characteristics of the depositional system suggest that it was wave dominated (Donaldson and Shumaker, 1981). Two major fluvial axes, the Gay-Fink and Cabin Creek Channels (Pepper and others, 1954), are located about 50 mi apart in north-central and south-central West Virginia, respectively. The Berea Sandstone exists in the subsurface of parts of eastern Ohio, western Pennsylvania, western West Virginia, and northeastern Kentucky and contains elements of both deltaic and barrier depositional systems. In outcrop and in quarries in Ohio, Berea sandstones are highly lenticular and are surrounded by the red Bedford Shale; these sandstones probably represent a fluvial channel facies. In other areas, barrier islands backed by lagoonal facies developed in an inferred delta-margin position. The Second Berea sandstone of southeastern Ohio is this type of barrier facies and, although entirely in the subsurface, has been extensively explored because of its gas producibility (Pepper and others, 1954).

Larese (1974) found that the Cabin Creek and Gay-Fink Channels in central West Virginia grade westward into an extensive sheet-sand facies, indicating a regressive marine environment. Barrier-island and distributary-mouth-bar facies were found to be part of the Berea deltaic complex. In the undifferentiated Pocono - Maccrady Group formations, Williamson (1974) identified shoreface and strandplain facies. Massive sandstone units having relatively sharp upper and lower contacts are interpreted to be reworked, abandoned deltaic lobes (Williamson, 1974). After deposition of the Berea Sandstone, a marine transgression resulted in the deposition of the carbonaceous Sunbury Shale. The Sunbury is an excellent subsurface marker for delineating the Berea Sandstone; neither Williamson (1974) nor Larese (1974) noted the extent to which the Berea may have been reworked during transgression.

Extrapolation Potential

The Berea Sandstone is classified with deltaic systems and reworked deltas. The Carter Sandstone, the Davis sandstone, the Olmos Formation, and the Blair Formation are also within this group (table 109). However, the Berea probably contains a greater proportion of fluvial facies than do these other stratigraphic units. In addition to the Gay-Fink and Cabin Creek fluvial axes, fluvial channels were identified in southern West Virginia (Virginia-Caroline Delta) and in northern Ohio (Berea Delta) (Pepper and others, 1954).

The extrapolation potential of the Berea Sandstone system to the deltaic systems of the other sandstones listed previously and to the Frontier deltaic system is fair to good. The proportion of preserved progradational deltaic and barrier-strandplain facies to fluvial facies determines the proportion of blanket-geometry to lenticular-geometry sandstones present in the Berea Sandstone.

TABLE 4. Tight gas sand areas of the Berea Sandstone in Virginia, West Virginia, and Ohio (Virginia Tight Sand Committee, 1981; West Virginia Tight Formation Committee, 1981a, 1981b, and 1982; Hagar and Petzet, 1982a and 1982b).

COUNTIES	TOTAL GROSS AREA (acres)	DEPTH (ft)	PERMEABILITY (md)
Virginia			
Dickenson, Lee, Scott, Wise, Russell, Buchanan, Tazewell	768,000	3,356 to 6,028	<0.1
West Virginia			
Fayette, Raleigh	1,024,000	2,766	<0.1
Mercer, McDowell, Wyoming	832,000	2,766	<0.1
Boone, Cabell, Kanawha, Lincoln, Logan, Mingo, Putnam, Wayne	no data	no data	<0.1
Ohio			
Athens, Gallia, Meigs, Morgan, Muskingum, Perry	2,580,000	1,200 to 2,000	0.012 to 0.215

TABLE 5. Selected characteristics of the Berea Sandstone in Virginia and West Virginia (Virginia Tight Sand Committee, 1981; West Virginia Tight Formation Committee, 1981a, 1981b, and 1982).

VIRGINIA
Porosity: 2% to 8%, average 4%
Permeability: <0.1 md
Water saturation: 8% to 50%, average 35%
Oil production: none in application area
Excluded areas: selected parts of four existing fields
WEST VIRGINIA
Porosity: average 7% to 8% or less
Permeability: <0.1 md
Thickness: 5 to 100 ft, mostly 55 ft or thinner
Oil production: none in application area
Excluded areas: field areas having >7.7% porosity or unstabilized flows >91 Mcfd

ORISKANY SANDSTONE, APPALACHIAN BASIN

The Oriskany Sandstone, also termed the Ridgeley Sandstone, was deposited in the central Appalachian Basin during the Deerpark Stage of the Early Devonian. The regional stratigraphic relations of the Oriskany Sandstone are illustrated on correlation diagrams of the center of the basin, parallel and perpendicular to depositional strike (figs. 2 and 3).

The Oriskany is mostly a fossiliferous marine quartzarenite. Typically calcite cemented and locally quartz cemented, it is found as a conglomerate in its eastern facies. It has a distinctive megascopic fauna, which along with the calcite cement tends to leach away in outcrop to produce a friable, biomoldic sandstone; however, in the subsurface it is usually tightly cemented. About 40 percent of Oriskany production is from tight areas. It is estimated that more than 90 percent of the Oriskany Sandstone within the Appalachian Basin is tight, including interfield areas between conventional reservoirs.

Structure

The structural configuration of the top of the Oriskany Sandstone in the subsurface of the Appalachian Plateau has been mapped using a 1,000-ft contour interval (fig. 4). This large contour interval is not adequate to delineate all the major fold axes; these are shown in detail in figure 5, along with the major structural provinces that were used to subdivide Oriskany producing trends. The Oriskany trend occurs within four major structural provinces. The Eastern Overthrust Belt, located between the Blue Ridge Front and the Allegheny Front, is characterized by intensely folded and thrust-faulted strata. The High Plateau Province extends westward to the limit of many folds, which are more numerous and have more structural relief than in areas farther west (fig. 4). The Low Plateau Province extends westward to the limit of any pronounced folding, which is about at the position of the Burning Springs anticline. The Western Basin Province, the area west of the plateaus, is characterized by very gentle folding and little structural relief.

Stratigraphy

The Oriskany Sandstone is bounded either above or below, or both, by unconformities (figs. 2 and 3); where these unconformities merge, the Oriskany pinches out (fig. 6). The Oriskany pinch-out is a critical trapping mechanism (permeability barrier) in many Oriskany fields.

The Oriskany Sandstone is underlain in many places by other sandstone units—Wildcat Valley Sandstone of Tennessee, Rocky Gap Sandstone of southwestern Virginia, Bois Blanc Sandstone of Pennsylvania and New York (figs. 2 and 3)—which have been mistaken for Oriskany. Occasionally, where the Oriskany Sandstone is absent, an adjacent sandstone (for example, Bois Blanc) has been referred to as Oriskany or credited with producing Oriskany gas. Figure 6 shows the limit of sandstones adjacent to the Oriskany horizon. Because these sandstones have often been misidentified in the subsurface and because it is not always possible to differentiate between the Oriskany and the other sandstones, all these sandstones are classified as Oriskany in this survey.

The Deerpark Stage (fig. 7) is in places composed of units other than the Oriskany Sandstone, including the Helderberg Limestone and the Shriver Chert in Pennsylvania. In eastern New York, the Oriskany changes facies and develops into the Glenerie Limestone. Note that the zero Deerpark isopach in figure 7 does not coincide with the Oriskany pinch-out in figure 6. This is because figure 7 was based on a map by Oliver and others (1971), whereas the pinch-out shown on all other maps is based on more recent data.

Distribution of Oriskany Sandstone Production

The Oriskany pinch-out (fig. 8) is important to gas production because the producing fields that have well-developed intergranular porosity exist near pinch-outs and are commonly stratigraphic traps at updip porosity-permeability barriers. Fracture porosity is also necessary for the accumulation of gas in the Oriskany Sandstone. Fields that produce from naturally fractured Oriskany reservoirs are located in the Low and High Plateau Provinces and in the Eastern Overthrust Belt.

Because no operator applications for tight gas designation in the low-permeability areas were available, data on the four structural provinces were selected from individual fields (tables 6 through 13). The first of these fields, the Elk-Poca (Sissonville area) Field (figs. 9 and 10), is the best-developed and largest field in the Western Basin Province; its intergranular porosity and stratigraphic trap are characteristic of fields near the western pinch-out.

The most productive fields in the Low Plateau Province are near the Oriskany pinch-out in Pennsylvania and New York. The best-documented field in this area is Elk Run Pool, which may actually be in the High Plateau Province but is considered a good example of the fields at this pinch-out (fig. 11). These pinch-out fields characteristically have intergranular porosity, whereas the Low Plateau fields that do not occur at the pinch-out do not. There is only minor Oriskany production in this area; most of that production is from the overlying Huntersville Chert. The less productive area in the southern part of the Low Plateau Province is the only major area that is overlain by strata containing abundant chert.

The Glady Field, having structural traps and fracture porosity, is characteristic of fields in the High Plateau Province (fig. 12). Within this province, however, some fields occur near the pinch-out in central Pennsylvania. These fields are similar to Elk Run Pool. The Lost River Field is characteristic of the Eastern Overthrust Belt, where fields typically occur along structural highs and have fracture porosity (fig. 13).

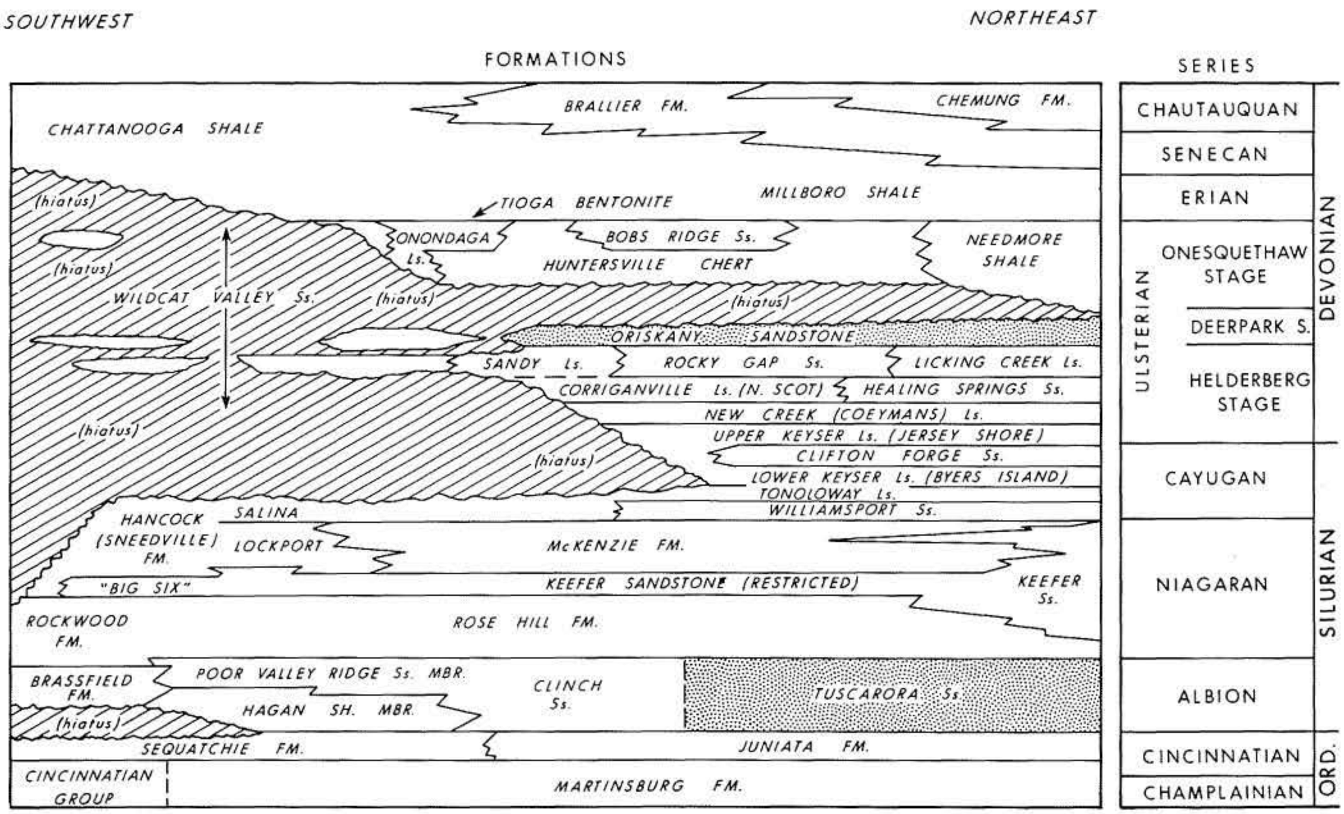


FIGURE 2. Northeast-southwest correlation diagram, Appalachian Basin (from Diecchio, 1982b).

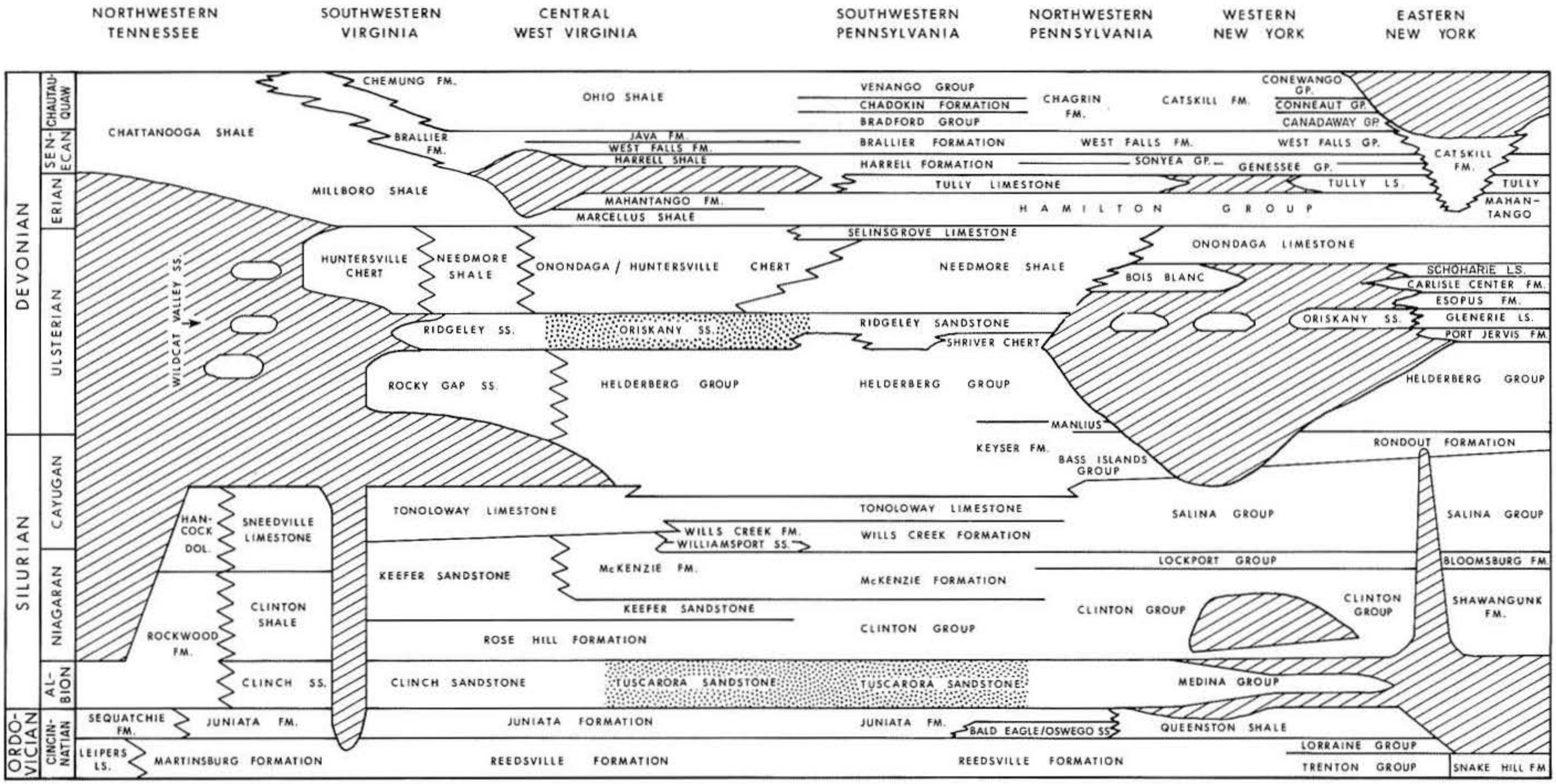


FIGURE 3. East-west correlation diagram, Appalachian Basin (from Diecchio, 1982b).

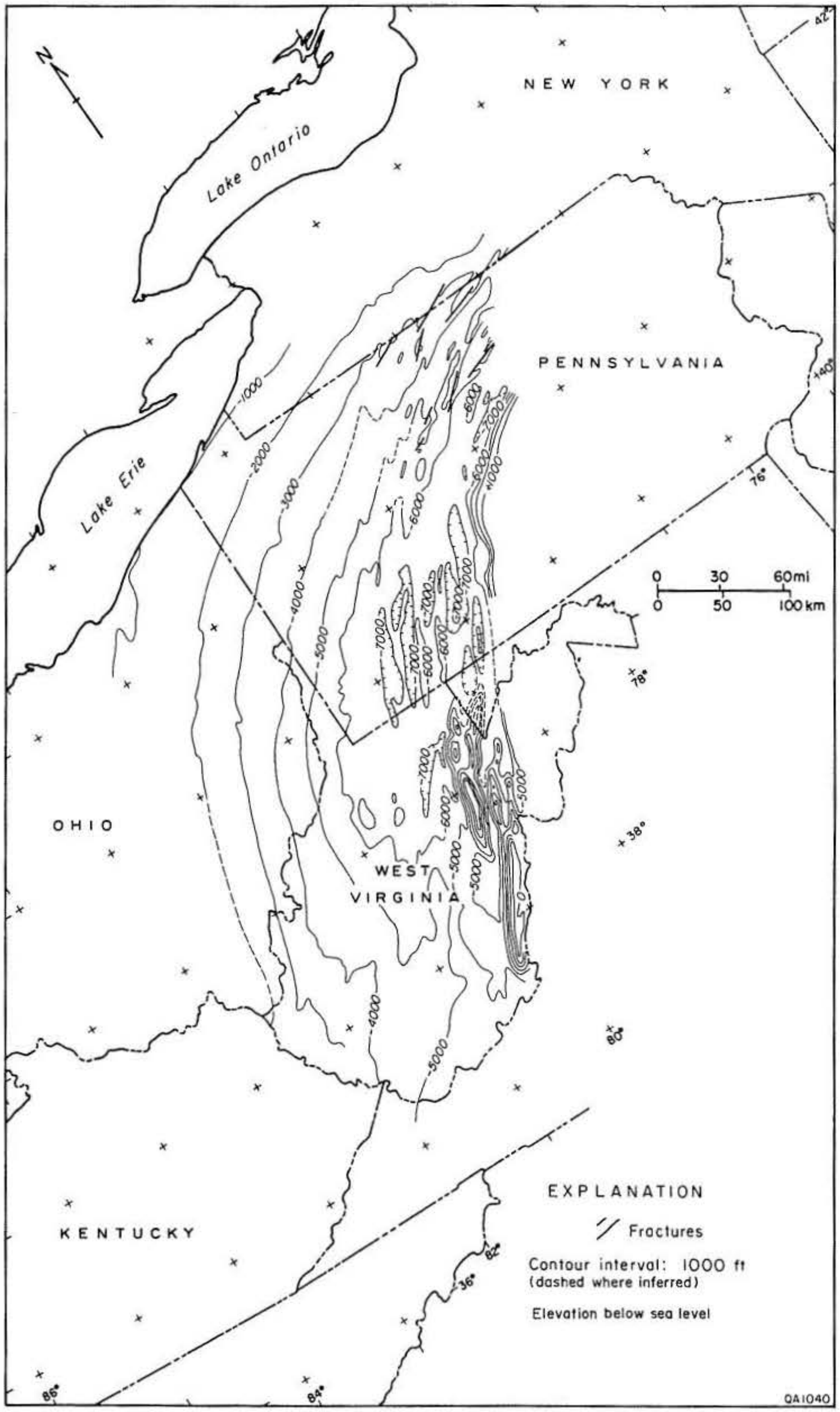


FIGURE 4. Structure contours on top of the Oriskany Sandstone, Appalachian Basin (from Diecchio, 1982b).

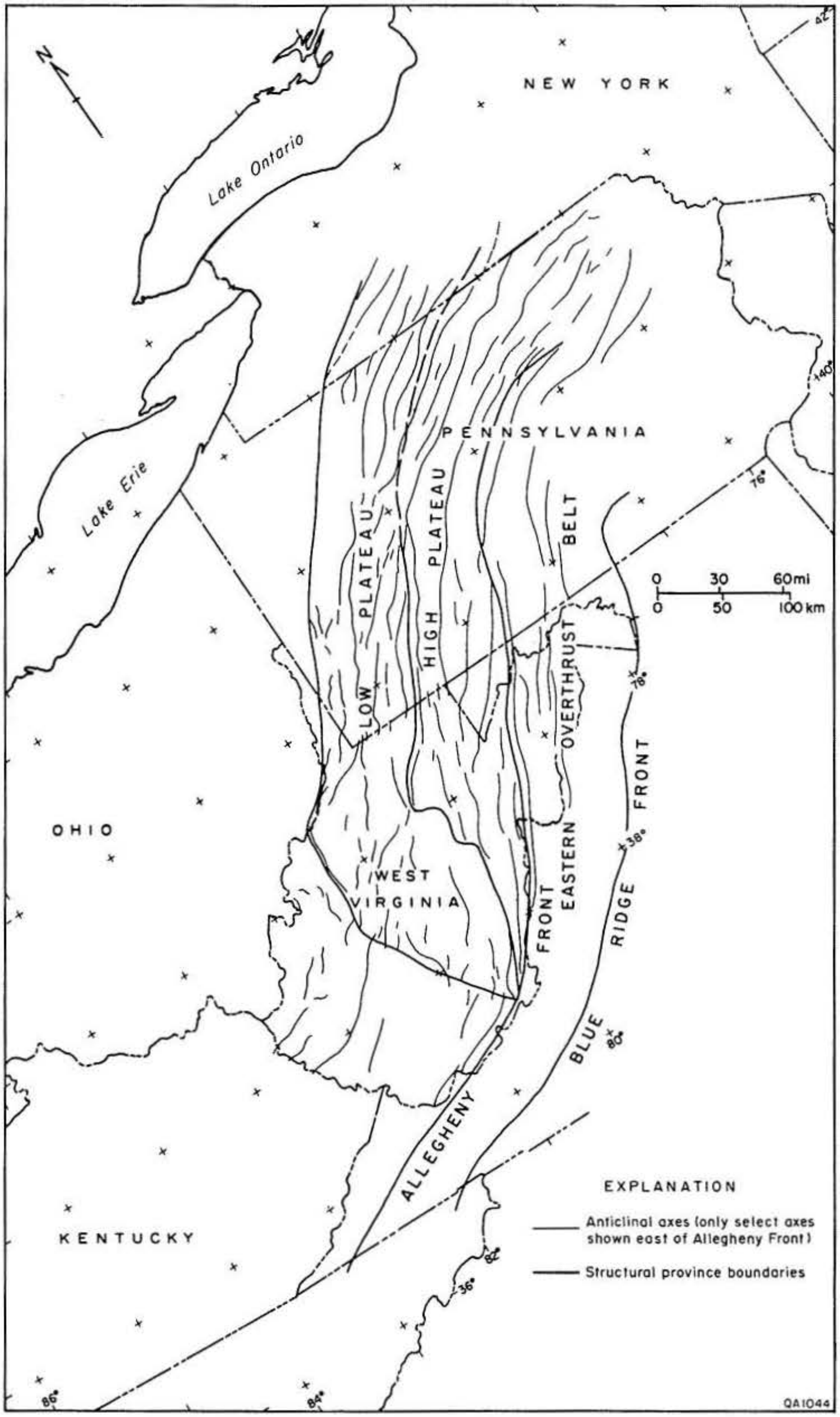


FIGURE 5. Structural provinces, Appalachian Basin (from Diecchio, 1982b).

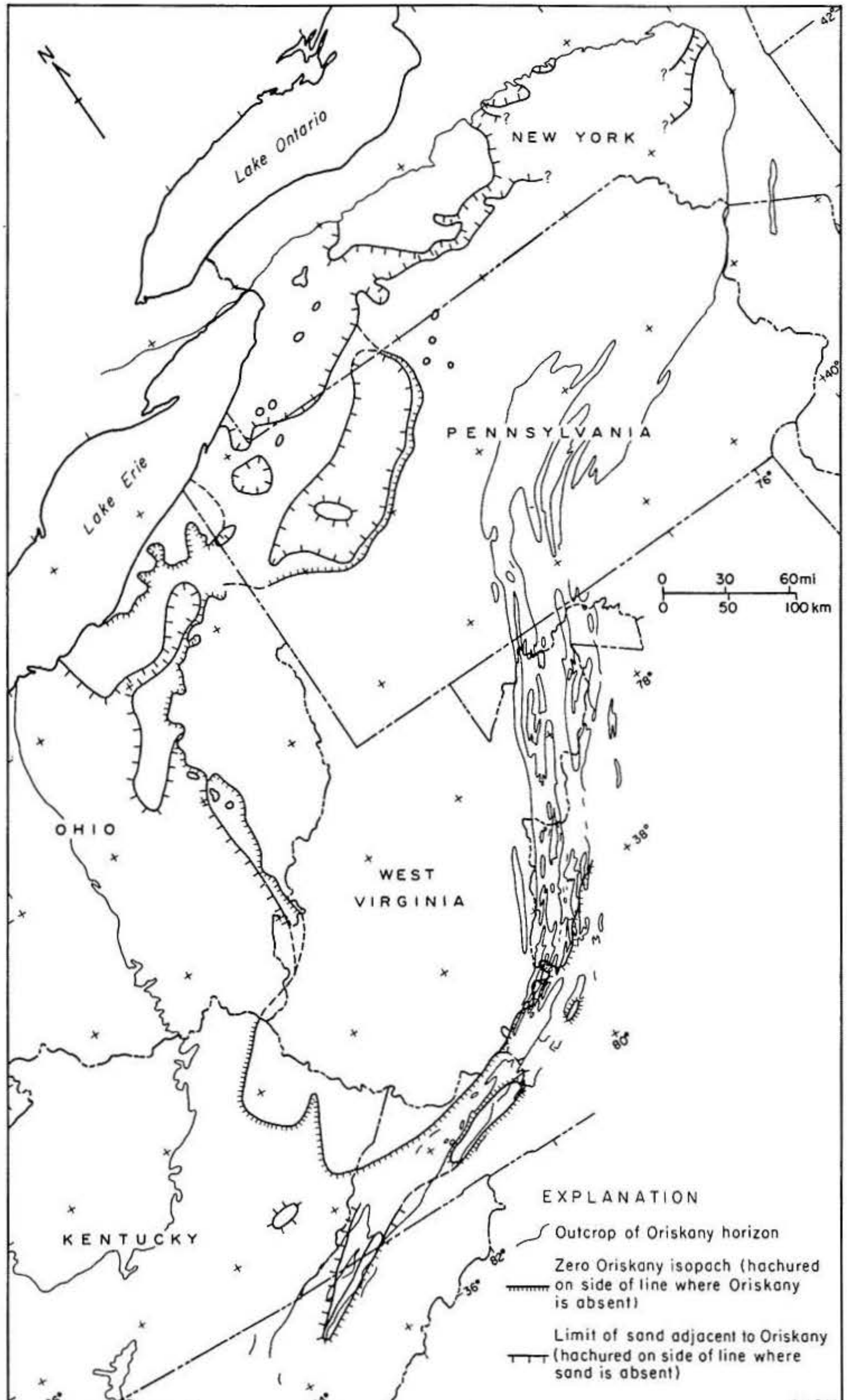


FIGURE 6. Outcrop and subsurface extent of the Oriskany Sandstone, Appalachian Basin (from Diecchio, 1982b).

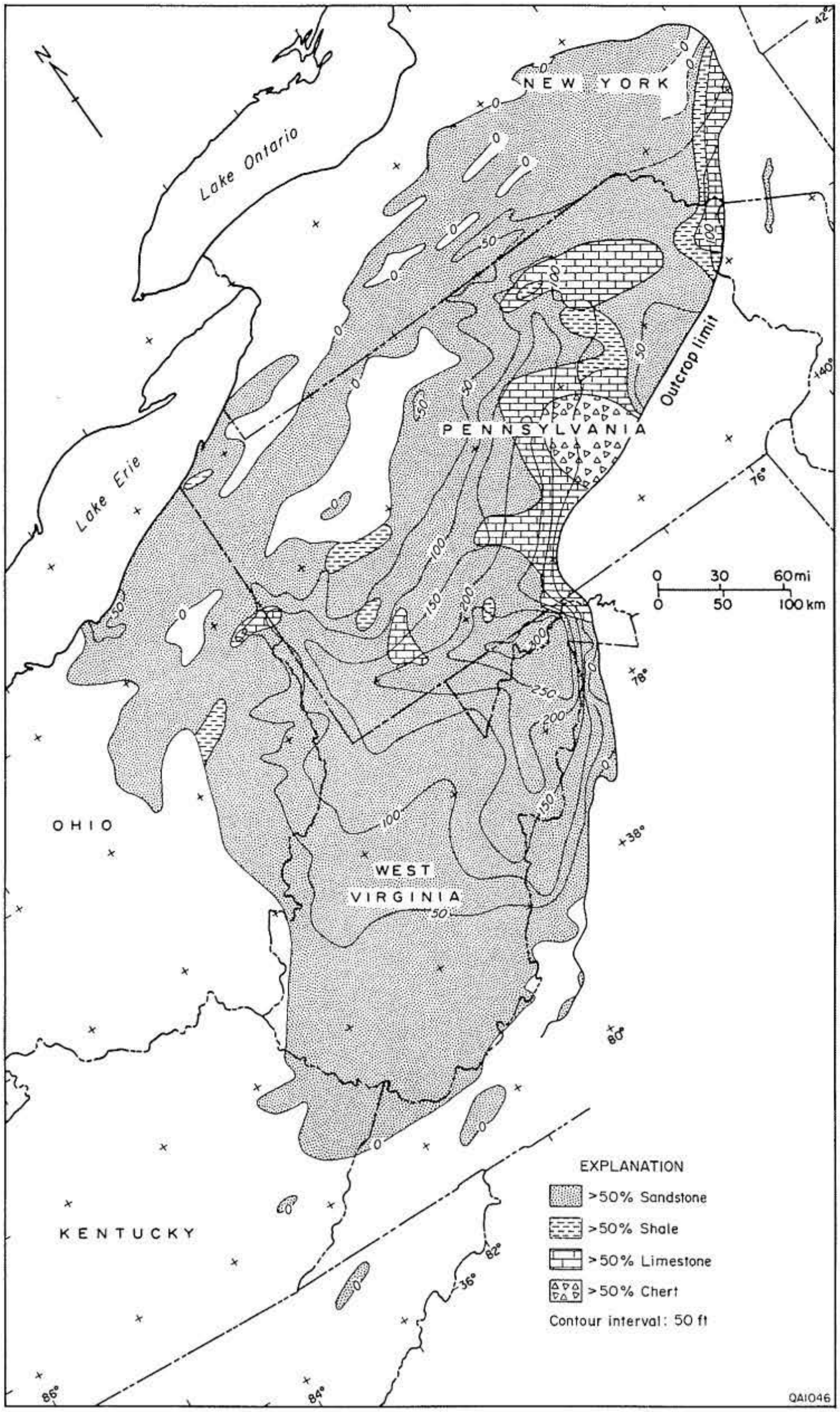
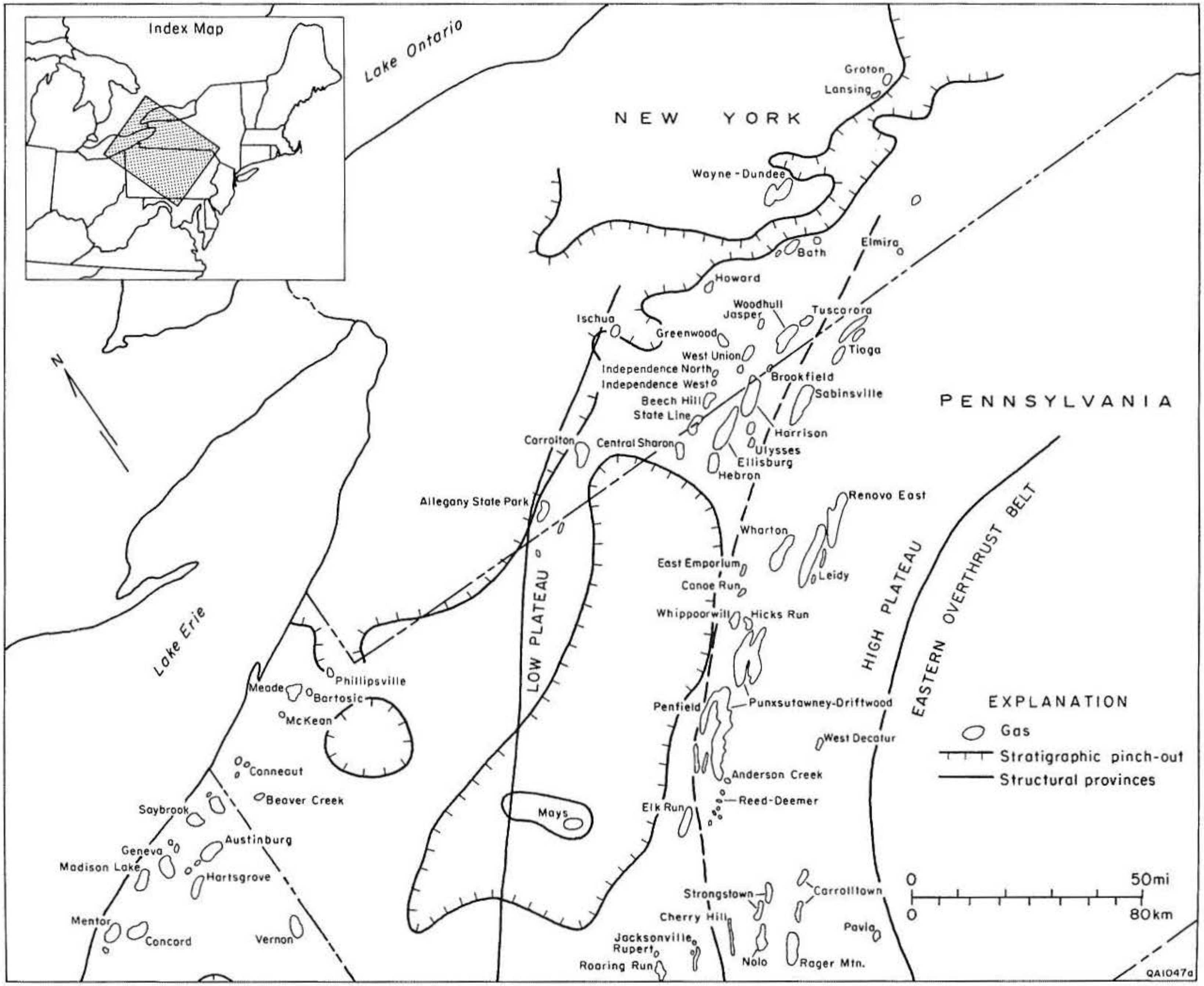


FIGURE 7. Isopach and lithofacies of the Deerpark Stage, Appalachian Basin (from Diecchio, 1982b; after Oliver and others, 1971).



Index Map
Lake Ontario
NEW YORK
PENNSYLVANIA
Lake Erie
LOW PLATEAU
HIGH PLATEAU
EASTERN OVERTHRUST BELT
N
Groton
Lansing
Wayne-Dundee
Elmira
Bath
Howard
Woodhull
Jasper
Tuscarora
Ischua
Greenwood
West Union
Tioga
Independence North
Independence West
Brookfield
Beech Hill
Sabinsville
State Line
Harrison
Carrollton
Central Sharon
Ulysses
Ellisburg
Hebron
Allegany State Park
Renovo East
Wharton
East Emporium
Leidy
Canoe Run
Whippoorwill
Hicks Run
Phillipsville
Meade
Bartosic
McKean
Penfield
Punxsutawney-Driftwood
West Decatur
Conneaut
Beaver Creek
Anderson Creek
Reed-Deemer
Saybrook
Elk Run
Mays
Austinburg
Geneva
Madison Lake
Hartsgrove
Strongstown
Carrolltown
Cherry Hill
Mentor
Concord
Vernon
Pavia
Jacksonville
Rupert
Roaring Run
Nolo
Rager Mtn.
EXPLANATION
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Stratigraphic pinch-out
Structural provinces
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50mi
0
80km
QA1047a

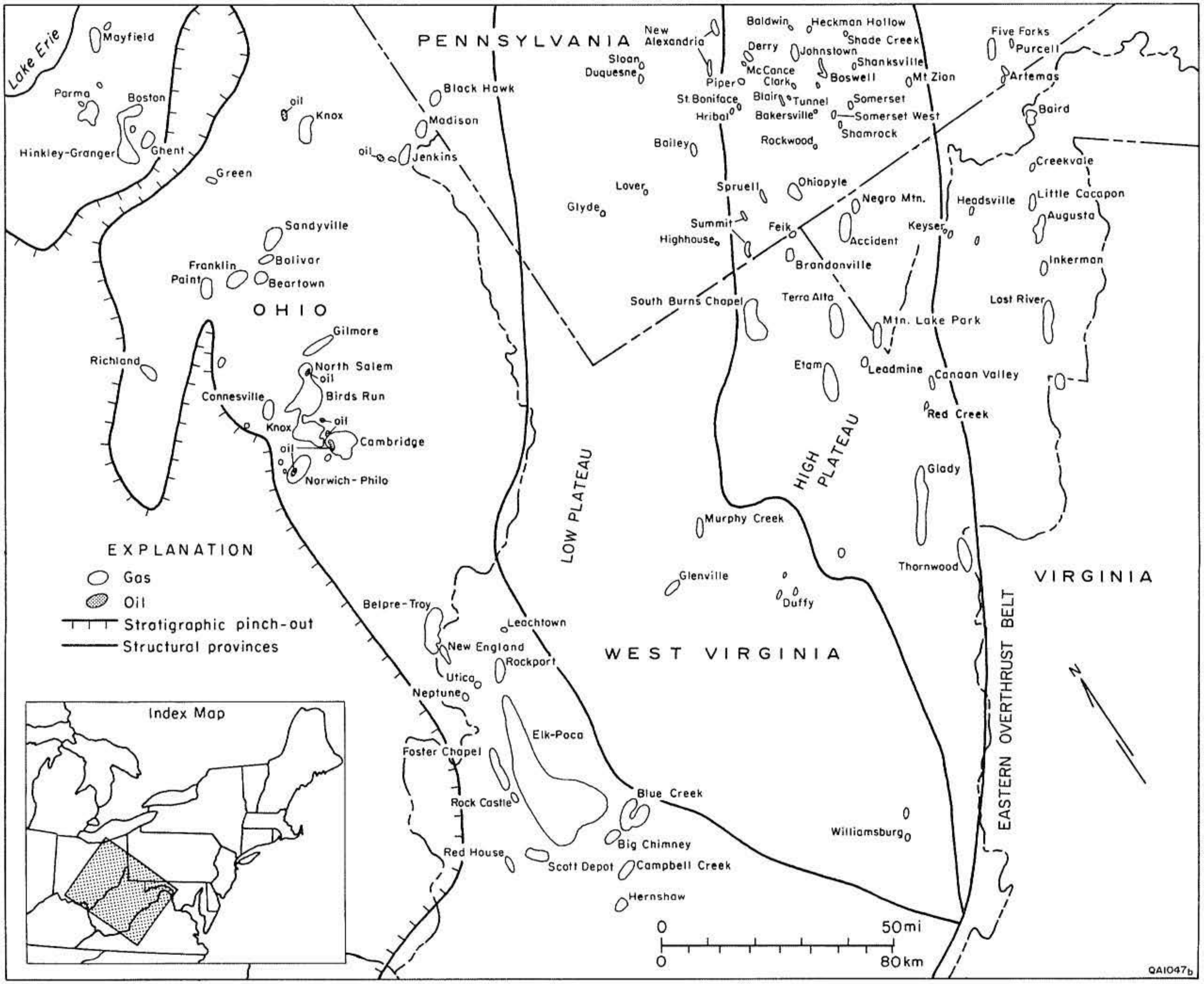


FIGURE 8. Oriskany Sandstone gas fields and pools, Appalachian Basin (from Diecchio, 1982b).

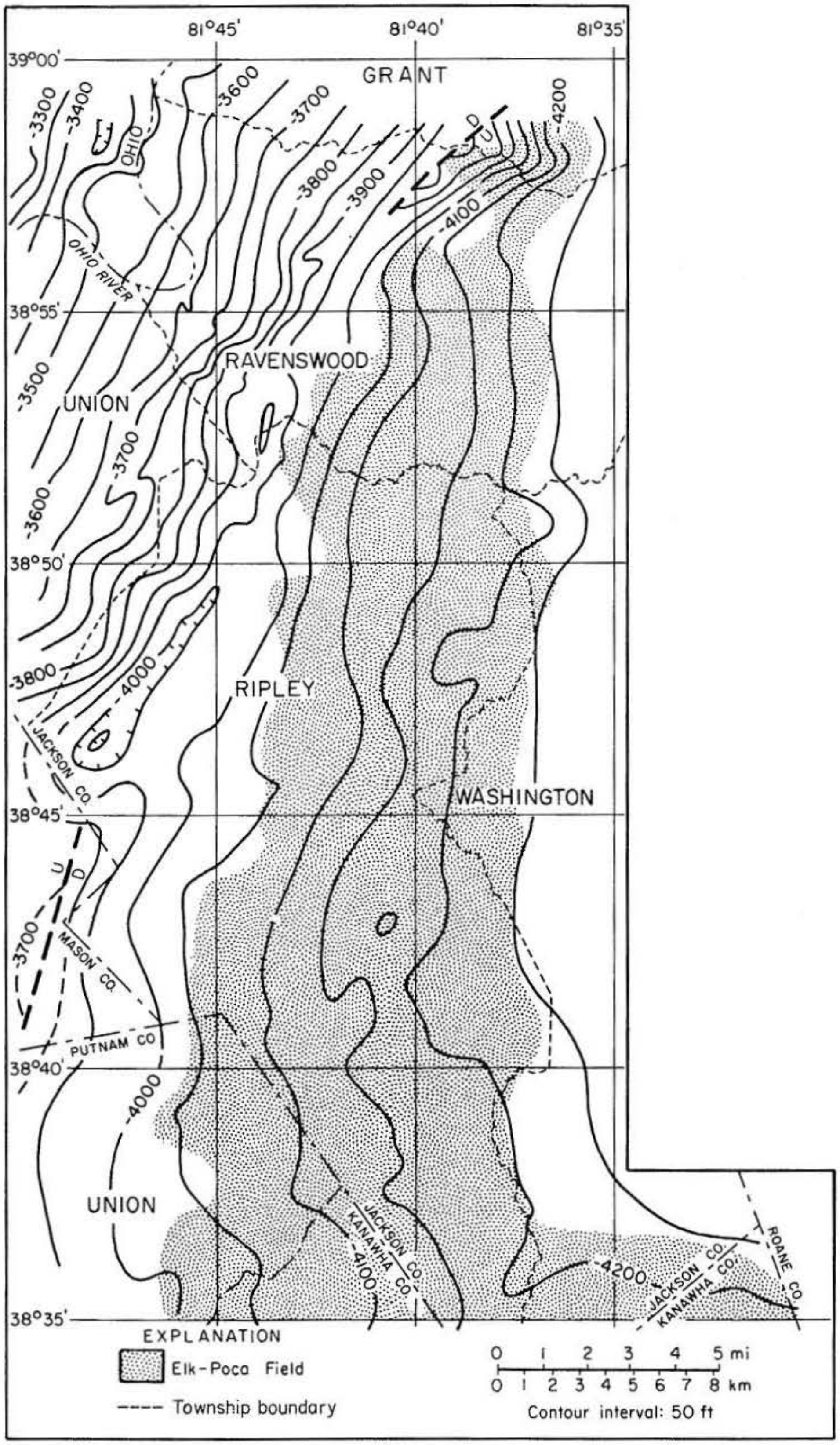


FIGURE 9. Structure contours on top of the Onondaga Limestone, Elk-Poca Field, North Sissonville area, West Virginia (from Diecchio, 1982b).

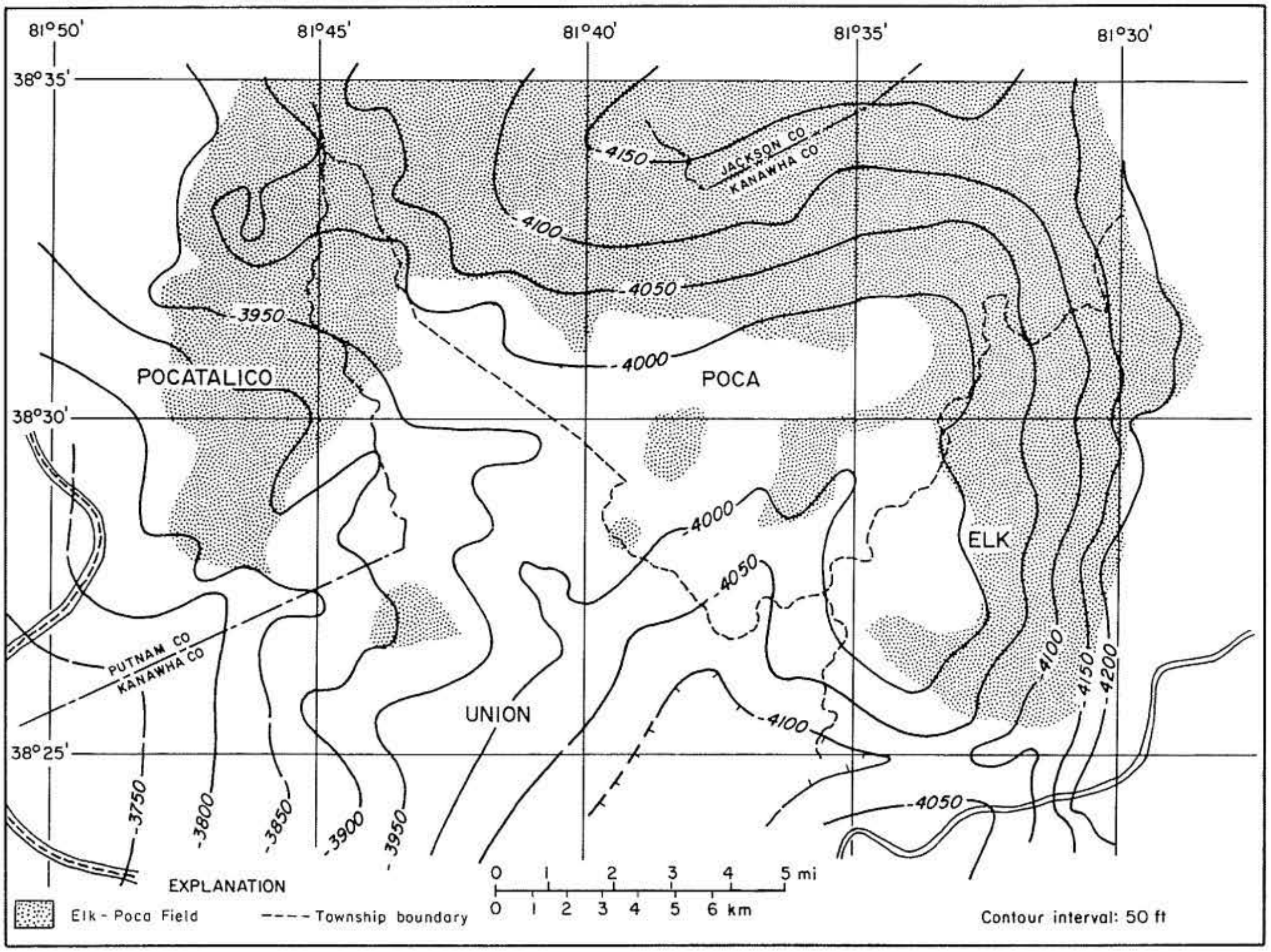


FIGURE 10. Structure contours on top of the Onondaga Limestone, Elk-Poca Field, South Sissonville area, West Virginia (from Diecchio, 1982b).

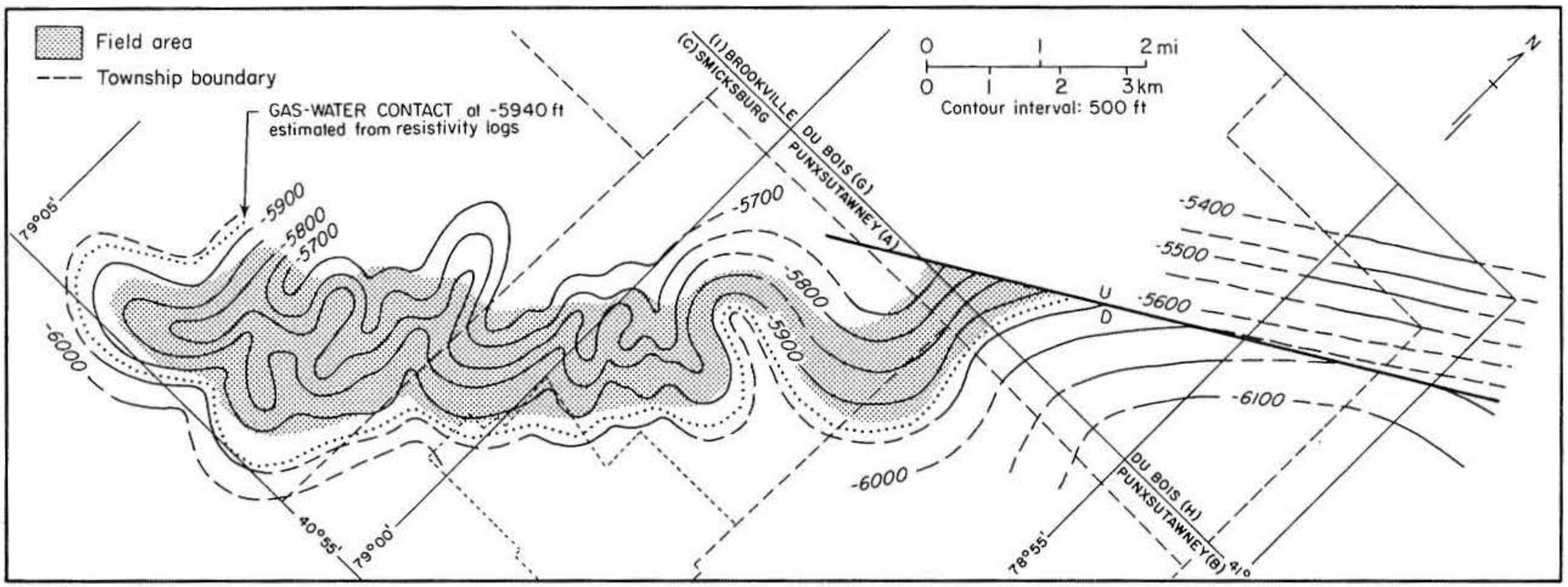


FIGURE 11. Structure contours on top of the Ridgeley Sandstone, Elk Run Pool, Pennsylvania (from Diecchio, 1982b).

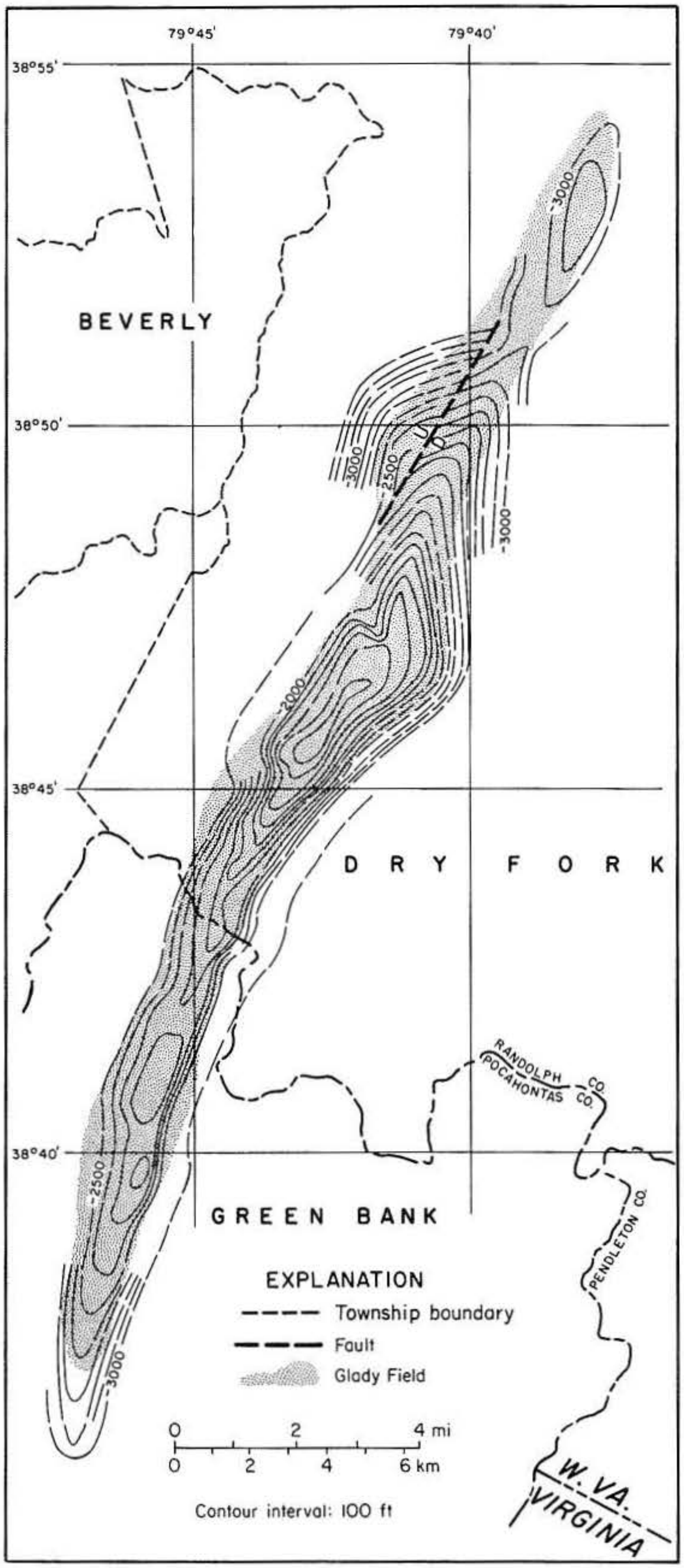


FIGURE 12. Structure contours on top of the Onondaga Limestone, Glady Field, West Virginia (from Diecchio, 1982b).

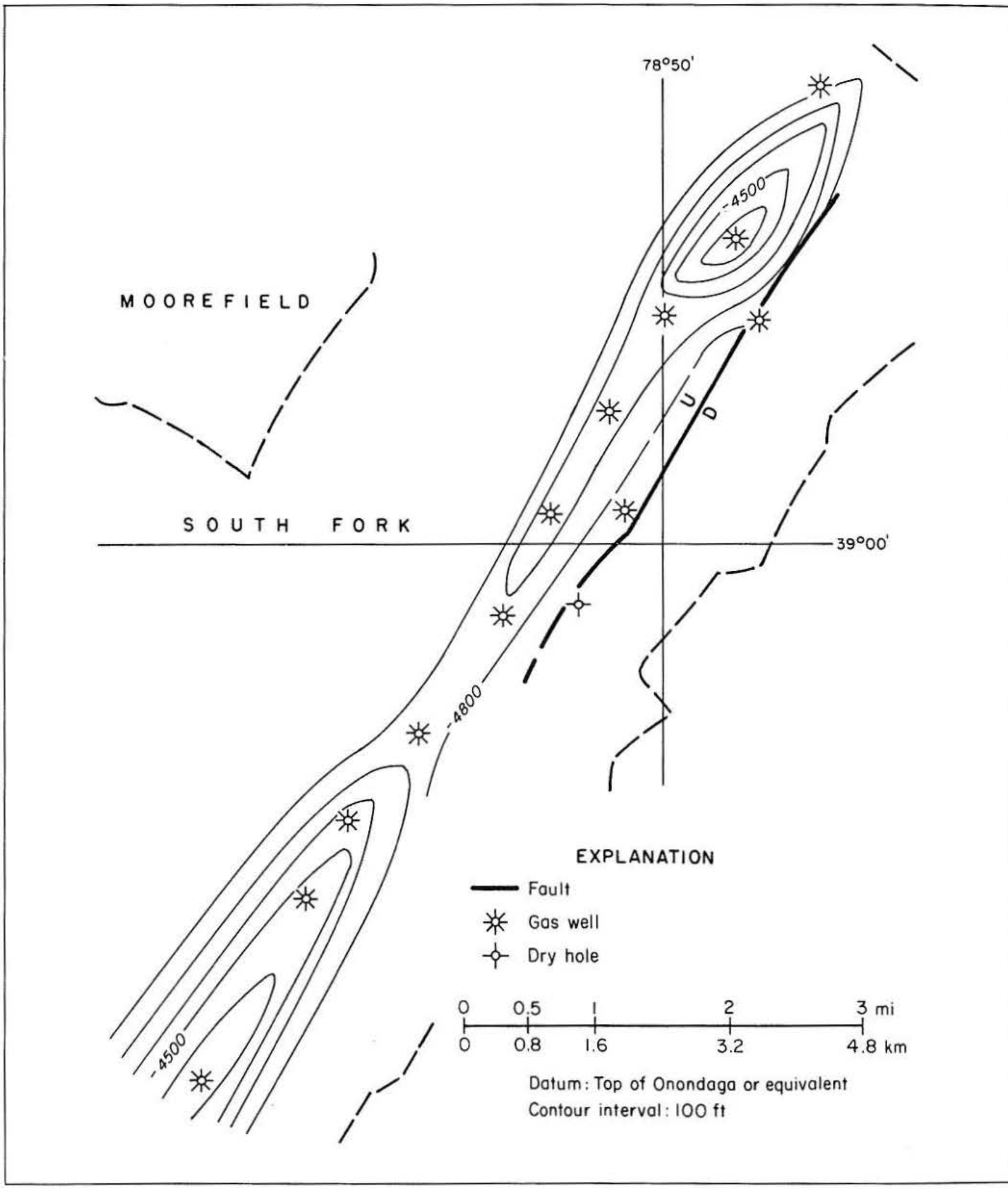


FIGURE 13. Structure contours on top of the Onondaga Limestone or equivalent, Lost River Field, Hardy County, West Virginia (from Diecchio, 1982b).

TABLE 6. Oriskany Sandstone, Western Basin and Low Plateau Provinces, Appalachian Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Oriskany (Ridgeley) Sandstone, Deerpark Stage, Lower Devonian.	Of producing areas, 40% are tight. Overall, 90% of the basin area is tight, including interfield areas between nontight fields. 1. Western Basin Province. 2. Low Plateau Province.	1. Range is 0 to 100 ft. The thickest units are found in the northern panhandle of West Virginia. 2. Range is from 0 ft in northern Pennsylvania and New York to more than 200 ft in southwestern Pennsylvania.	1. Range is from 1,600 ft in northern Ohio to more than 5,000 ft in West Virginia. In the Elk-Poca Field, range is 4,900 to 5,300 ft. 2. Range is from less than 1,700 ft in the northern parts of the province to more than 8,000 ft in southwestern Pennsylvania and adjacent West Virginia. At the southern limit of the province, depth becomes somewhat shallower (6,000 ft).	Estimate is 1.054 Tcf from Western Basin Province only.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
1. The Western Basin Province is the area west of the limit of prominent folding associated with the Low Plateau foreland foldbelt. It coincides in West Virginia with the Burning Springs anticline. Broad, open folds characterize this province. 2. The Low Plateau Province is a foreland foldbelt dominated by gentle folding. Faulting is rare. The western part of the province is bounded by the Burning Springs anticline and the Western Basin Province. The High Plateau Province bounds the eastern margin.	1. 1.1° to 1.8° F/100 ft. 2. 0.9° to 2.0° F/100 ft.	No data.	Past deformation indicates moderate to mild compression in the Low Plateau Province and weak compression in the Western Basin Province.

TABLE 7. Oriskany Sandstone, Western Basin and Low Plateau Provinces, Appalachian Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Shallow marine sandstone, possibly a transgressive, reworked marine shoreline deposit.	1. Fine- to coarse-grained, subangular to well-rounded sandstone. 2. Very fine grained to medium-grained, subrounded, poorly sorted sandstone. Sporadically coarse grained.	Sand grains are composed of quartz; however, calcareous fossils are found in the unit.	Cemented primarily by calcite, cemented locally by silica (syntaxial quartz overgrowths and pressure solution). Secondary clay mineralization is minor.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
1. Ranges from 0 to 60 ft in Elk-Poca Field, averages 40 ft. 2. Ranges from 0 to 24 ft in Elk Run Pool. Other fields within this province typically have a gross perforated interval that ranges from 0 to 12 ft. The net pay volume within Elk Run Pool is 56,700 acre-ft.	1. Average pressure is 1,940 psi. Average temperature is 125° F. 2. The shut-in pressure recorded from the discovery well of Elk Run Pool was 3,960 psi. This well was overpressured, as are many other Oriskany wells in west-central Pennsylvania.	1. Generally present but poorly developed. 2. Occasionally present but poorly developed.	Well cuttings, driller's logs, lithologic logs, and geophysical well logs are on file at the West Virginia Geological and Economic Survey in Morgantown, West Virginia, and at the Pennsylvania State Geological Survey in Harrisburg, Pennsylvania.

Abbreviations used in this report of terms related to hydrocarbon production

Bcf *- billion cubic feet (gas);* ***bopd*** *- barrels of oil per day;* ***bpd*** *- barrels per day (liquid);* ***bpm*** *- barrels per minute;* ***bwpd*** *- barrels of water per day;* ***IP*** *- initial potential or initial production;* ***IPF*** *- initial potential flow;* ***K*** *- permeability;* ***Mcf*** *- thousand cubic feet (gas);* ***Mcfd*** *- thousand cubic feet per day;* ***md*** *- millidarcys of permeability;* ***MMcf*** *- million cubic feet (gas);* ***psi*** *- pounds per square inch;* ***scf*** *- standard cubic feet (gas);* ***Tcf*** *- trillion cubic feet (gas);* ***TSTM*** *- too small to measure (gas flow during well testing).*

TABLE 8. Oriskany Sandstone, Western Basin and Low Plateau Provinces, Appalachian Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
1. Intergranular porosity ranges from 6% to 22%, average is 15%. Permeability ranges from 0.04 to 78.5 md, average is 25.5 md, indicating tight and nontight areas. 2. Maximum porosity is 20%, average is 7.75%. From two core samples, permeabilities of 6.1 and 15.7 md were measured.	1. In Elk-Poca Field, range is 10 to 20 ft. 2. In Elk Run Pool, average is 9 ft.	1. For an unknown number of wells, range was 21 to 5,955 Mcfd, average was 750 Mcfd. For naturally produced wells, range was 100 to 17,000 Mcfd, average was 5,235 Mcfd. 2. For naturally produced wells, average was 4,700 Mcfd.	1. For an unknown number of wells (drilled after 1959), range was 100 to 11,800 Mcfd, average was 1,485 Mcfd. 2. Average of fractured wells was 7,860 Mcfd.	No data.	1. Small amounts of liquid hydrocarbon were produced initially from the Elk-Poca Field discovery well; however, the well soon produced only gas. All other wells produce only gas. 2. No liquid hydrocarbons observed.	1. No data. 2. In low-porosity areas, average is 55%. Where there is higher porosity, it is typically less, ranging from 10% to 25%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Before 1959, nitroglycerine shooting was the dominant stimulation method; however, since 1959, hydraulic fracturing has been the preferred method. One operator uses 500 gal of 15% HCl and 60,000 lb of 20-40 mesh sand.	1. Flow improvement ranges from 45% to 1,350%, average is 900%. The percentage of wells that were improved by stimulation techniques is not known. 2. For 16 wells that were hydraulically fractured, the average production increase was 360%.	1. 160 acres. 2. Approximately 140 acres. There was no set spacing regulation within these provinces for development before 1973.	The depositional systems and facies of the Oriskany Sandstone are poorly documented.

TABLE 9. Oriskany Sandstone, Western Basin and Low Plateau Provinces, Appalachian Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
1. Applications are being prepared for areas in West Virginia. 2. Applications are being prepared for areas in West Virginia and possibly in Pennsylvania.	1. In Elk-Poca Field (165,000 acres), there have been 1,035 attempted completions. Approximately 80 to 100 other fields exist, but they are generally much smaller, and the total attempted completions for these fields have not been calculated. 2. In Elk Run Pool, which is representative of this province, there have been 47 attempted completions. Approximately 60 fields exist in this province, the largest of which covers 9,000 acres.	1. Success ratio for the Elk-Poca Field is 85% (889 out of 1,035). 2. Success ratio for the representative Elk Run Pool is 94% (44 out of 47).	1. On the basis of drilling costs of $60/ft, total drilling costs range from $100,000 to $300,000 per well. 2. On the basis of drilling costs of $60/ft, total drilling costs range from $100,000 to $500,000 per well.	1. Most gas is purchased by East Ohio Gas Co., Columbia Gas Transmission Corp., and Consolidated Gas Corp. Pipelines are in place. 2. Most gas is purchased by Peoples Natural Gas Co., Columbia Gas Transmission Corp., and Consolidated Gas Supply Corp. Pipelines are in place.	Moderate to low.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
In the Appalachian Highlands physiographic subdivision. Hills to the west have 300 to 500 ft of local relief, high hills to the east have 500 to 1,000 ft of local relief.	Mean annual precipitation of 40 to 48 inches, locally more than 48 inches in central West Virginia. Moderate summers and winters, colder at higher elevations. Drilling may cease during winter months.	If existing roads do not give access to an area, new roads can be easily built. Permits are necessary. Generally no terrain restrictions.	Difficult to assess because details on depositional systems are lacking. Tends to be unique as a very areally extensive sand of possible shoreline and shallow marine origin reworked by marine transgression.	Drilling and completion services available for areas of Oriskany potential in the Appalachian Basin.

TABLE 10. Oriskany Sandstone, High Plateau Province and Eastern Overthrust Belt, Appalachian Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Oriskany (Ridgeley) Sandstone, Deerpark Stage, Lower Devonian.	Of producing areas, 40% are tight. Overall, 90% of the basin area is tight, including interfield areas between nontight fields. 1. High Plateau Province. 2. Eastern Overthrust Belt.	1. Range varies from a maximum of more than 300 ft at the eastern edge of the province to 100 ft in the northern area of the province. It thins to almost 0 ft at the southern edge of the province. 2. Range is 0 to 300 ft. The thickest accumulations are in western Maryland.	1. Range is 7,000 to 9,000 ft within the province; however, at the eastern boundary, the Oriskany Sandstone abruptly shallows to 3,000 ft. 2. Range is 0 to more than 12,000 ft because of thrust faulting. Generally, depths are almost always more than 7,500 ft.	No data.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
1. The High Plateau Province is distinguished from the Low Plateau Province to the west primarily by the much greater occurrence and degree of relief and folding. It lies to the west of the Eastern Overthrust Belt and has the highest general elevation in the central Appalachians. It covers the eastern part of the foreland foldbelt. 2. The Eastern Overthrust Belt coincides with the Appalachian Valley and Ridge Province. It is distinguished from the High Plateau Province by its intensely folded strata and by the presence of east-over-west thrust faulting. The Allegheny Front forms the western edge of this province. The eastern boundary is defined by outcrops of Grenville-age basement rocks known as the Blue Ridge Front.	1. 1.1° to 1.8° F/100 ft. 2. 1.4° to 2.2° F/100 ft.	No data.	Past deformation indicates moderate compression in the High Plateau Province and strong compression in the Eastern Overthrust Belt.

TABLE 11. Oriskany Sandstone, High Plateau Province and Eastern Overthrust Belt, Appalachian Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Shallow marine sandstone, possibly a transgressive, reworked marine shoreline deposit.	Fine- to coarse-grained, subangular to rounded, poorly sorted sandstone. Locally conglomeratic. In the Eastern Overthrust Belt, shale, limestone, and siltstone interbeds occur.	Sand grains are primarily quartz; however, calcareous fossils are found in the unit.	Cemented primarily by calcite and some secondary clays.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
1. In Glady Field, average gross perforated interval is 150 ft. 2. In Lost River Field, average reservoir thickness is 265 ft.	1. Average pressure is 2,050 psi. Average temperature is 167° F. 2. Average pressure is 2,205 psi. Average temperature is 132° F.	Generally considered to be necessary for production within these provinces. It is fairly well developed in several areas.	Well cuttings, driller's logs, lithologic logs, and geophysical well logs are generally available at the West Virginia Geological and Economic Survey in Morgantown, West Virginia, and at the Pennsylvania State Geological Survey in Harrisburg, Pennsylvania.

TABLE 12. Oriskany Sandstone, High Plateau Province and Eastern Overthrust Belt, Appalachian Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
1. Not available for Glady Field. One core was taken in the field; it is on file at the West Virginia Geological and Economic Survey. Because fracture porosity is generally necessary for gas production in this province, both intergranular porosity and permeability must be quite low. 2. Same as above. One core was taken from Lost River Field; it is on file at the West Virginia Geological and Economic Survey.	1. Average is 150 ft. 2. Average is 265 ft.	1. For wells that were fractured, natural flow ranged from a show of gas to 4,225 Mcfd; average was 1,300 Mcfd. 2. For wells that were acidized, natural flow ranged from 75 to 16,200 Mcfd; average was 5,120 Mcfd.	1. Range was 94 to 25,500 Mcfd; average was 5,100 Mcfd. 2. Range was 1,500 to 44,000 Mcfd; average was 10,950 Mcfd.	No data.	1. No liquid hydrocarbon production reported. 2. No liquid hydrocarbon production reported.	No data.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
1. Most wells have been hydraulically fractured; some have been acidized. 2. Most wells have been acidized.	1. Hydraulic fracturing improved production from 55% to 3,270%; average is 830%. 2. Acidizing improved production from 53% to 2,960%; average is 704%.	1. In Glady Field, 440 acres. 2. In Lost River Field, 540 acres. There was no set spacing regulation in these provinces for development before 1973.	The depositional systems and facies of the Oriskany Sandstone are poorly documented.

TABLE 13. *Oriskany Sandstone, High Plateau Province and Eastern Overthrust Belt, Appalachian Basin: Economic factors, operating conditions, and extrapolation potential.*

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
1. Applications are being prepared for areas in West Virginia and possibly in Pennsylvania. 2. No applications.	1. A representative field in the province, Glady Field, has had 33 attempted completions in the Oriskany. Approximately 50 to 60 fields are in this province, covering from a few hundred to 15,000 acres. 2. A representative field in this province, the Lost River Field, has had 13 attempted completions in the Oriskany. Approximately 12 such fields are in the province; each field covers less than 8,000 acres.	1. For Glady Field, the success ratio is 94% (31 out of 33). Subsequent use of the field for storage has necessitated the drilling of 26 more wells. 2. For Lost River Field, the success ratio is 85% (11 out of 13).	1. On the basis of drilling costs of \$60/ft, total drilling costs range from \$420,000 to \$540,000. Increased costs are incurred along the eastern margin of the province because of terrain restrictions. 2. Because of drilling problems associated with vertical strata and rough topography, drilling costs could range from \$60/ft to \$120/ft; therefore, maximum drilling costs could approach \$1.5 million.	1. Most gas is purchased by Peoples Natural Gas Co., Columbia Gas Transmission Corp., and Consolidated Gas Supply Corp. 2. Most gas is purchased by Columbia Gas Transmission Corp.	1. Moderate to low. 2. High leasing and seismic activity but low drilling activity.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
1. In the Appalachian Highlands physiographic subdivision. Maximum relief is about 3,000 ft, and it is most prominent on the eastern edge of this mature, highly dissected plateau province. 2. A highly dissected fold and thrust belt having maximum relief of about 3,000 ft.	Mean annual precipitation of 40 to 48 inches, locally more than 48 inches in central West Virginia. Moderate summers and winters, colder at higher elevations. Drilling may cease during winter months.	Roads can be built into areas not already served by existing roads. Permits are necessary. Access may be limited in the eastern High Plateau Province by rough terrain.	Difficult to assess because detail on depositional systems is lacking. Tends to be unique as a very areally extensive sand of possible shoreline and shallow marine origin reworked by marine transgression.	Drilling and completion services available for areas of Oriskany potential in the Appalachian Basin.

TUSCARORA SANDSTONE, APPALACHIAN BASIN

The Lower Silurian Tuscarora Sandstone is a blanket deposit that correlates with the Medina Group in western New York and northwestern Pennsylvania and with the informal "Clinton" sands of eastern Ohio. The Tuscarora Sandstone is of interest to this investigation of tight gas production because of the well-established productive trends in these two areas. No applications to designate the Tuscarora as a tight formation have been filed, and data on the unit are very limited because of little development outside of the "Clinton"-Medina trend (D. G. Patchen, personal communication, 1982). The Tuscarora Sandstone was included in this survey because it is a well-defined, widespread unit having tight gas potential; however, presentation of a full set of data was not possible.

Stratigraphy

The sandy facies of the Tuscarora Sandstone, which is the prominent ridge-former throughout the Valley and Ridge Province, extends from central Pennsylvania to the New River in Virginia (fig. 14). Southwest of the New River, the sandy facies is referred to as the Clinch Sandstone; southwest of Clinch Mountain, Tennessee, the unit becomes shalier and hematitic and grades into the lower part of the Rockwood Formation (fig. 2). In the subsurface, the sandy facies is referred to as Tuscarora in West Virginia, central and southwestern Pennsylvania, and western Maryland and as Clinch in eastern Kentucky. Farther west in the subsurface of Kentucky, the Clinch Sandstone becomes more calcareous and dolomitic and is called the Brassfield Formation. To the east in the Massanutten synclinorium of northern Virginia, the Tuscarora Sandstone merges with overlying Middle Silurian sandstones, such as the Keefer, to form a single sandstone unit of Early and Middle Silurian age called the Massanutten Sandstone. A similar relation exists in eastern Pennsylvania, northern New Jersey, and southeastern New York. In those areas, the Lower Silurian strata become conglomeratic and merge with younger sandstones. This Lower and Middle Silurian conglomeratic sandstone is called the Shawangunk Formation or, along Green Pond Mountain in New Jersey, the Green Pond Conglomerate.

The Lower Silurian is divided into several formations in western New York, northwestern Pennsylvania, and eastern Ohio. In New York, the Lower Silurian Medina (Albion) Group is composed of, from base to top, the Whirlpool Sandstone, the Manitoulin Dolomite, the Cabot Head Shale, and the Grimsby Sandstone. This terminology is also used to describe these units in northwestern Pennsylvania (Piotrowski, 1981). In Ohio, these same units, with minor modification, make up the Cataract Group, which also includes the Thorold Sandstone at the top; all of these units are Lower Silurian (Knight, 1969). In Ohio, eastern Kentucky, and western West Virginia, the Tuscarora Sandstone and equivalent strata are informally called "Clinton" sand. These sands are not related to the Middle Silurian Clinton Formation or to the Clinton Group of New York, Pennsylvania, and West Virginia.

Thickness and Lithology

Lower Silurian strata generally thicken and coarsen toward the east and southeast. Throughout most of the Valley and Ridge Province, these strata are almost consistently composed of quartzarenite that is sporadically conglomeratic. They become shalier and thinner westward (fig. 15) and eventually, in Ohio and Kentucky, grade into limestone and dolomite. The Tuscarora Sandstone is mostly cemented by secondary quartz overgrowths, which produce a very durable orthoquartzite that forms resistant ridges in outcrop. The sandy facies called Tuscarora in the central Appalachian Basin is the primary focus of this review.

Depositional Systems

Because of the lack of fossils (except for the trace fossils *Arthrophycus* and *Skolithos*), there has been much controversy over the depositional environment of the Tuscarora Sandstone. Interpretations have ranged from fluvial or alluvial (Yeakel, 1962) to marginal marine (Amsden, 1955; Folk, 1960). Some researchers have suggested that the Tuscarora was deposited under varied conditions ranging from deep marine (offshore shelf) to nonmarine (Diecchio, 1973; Hayes, 1974). It is generally agreed that the Tuscarora is more marine to the west and more nonmarine to the east. The position of the shoreline is a matter of controversy; however, it is reasonable to expect that at least part of the Tuscarora Sandstone is marine in the areas where it is productive. Paleocurrent measurements indicate westward transport of sediment from an eastern source area (Yeakel, 1962; Whisonant, 1977), and recent work has suggested that part of the Tuscarora Sandstone in Pennsylvania was deposited as a fan-delta system (Cotter, 1982a).

Tuscarora Sandstone Reservoirs

The Tuscarora Sandstone typically has very low intergranular porosity, but in Clay County, West Virginia, porosity may be as high as 12.7 percent (Patchen, 1969; Piotrowski, 1981). Production depends on a well-developed system of natural fractures. Heald and Andregg (1960) attributed the low porosity to the high degree of cementation by quartz overgrowths. They found that high porosity coincided with areas in which clay coatings on quartz grains prohibited syntaxial overgrowths and with areas of high gas content (Heald and Andregg, 1960). Whole-core permeabilities ranged from less than 0.1 to 12.2 md (Patchen, 1969); presumably, in situ permeabilities would be substantially less.

Structural entrapment formed Tuscarora reservoirs, which are usually along anticlinal highs. In West Virginia, initial potential flow (IPF) values for commercial wells ranged from 2 to 26,400 Mcfd (average 3,650 Mcfd). The 10 wells that are known to have been completed naturally had initial production rates of 2 to 22,000 Mcfd (average 4,415 Mcfd). The eight fractured wells had IPF values of 47 to 4,004 Mcfd (average 1,043 Mcfd). Three wells were shot (stimulated by explosives) and had IPF values of 29 to 76 Mcfd (average 46 Mcfd) after shooting. One well (Tucker 38, West Virginia) was acidized and had an IPF value of 26,400 Mcfd, the highest initial production rate of any of the Tuscarora wells (Cardwell, 1977). However, IPF rates are commonly much higher than are stabilized flow rates.

Gas produced from the Tuscarora Sandstone typically has a low Btu rating, ranging from 352 to 990 Btu/ft^3 (average 800 Btu/ft^3) (Patchen, 1969; Cardwell, 1977; Piotrowski, 1981). Tuscarora gas typically has a high nitrogen content; nitrogen values are as high as 23 percent from the Devils Elbow Field and Heyn Pool in Pennsylvania (fig. 16) (Piotrowski, 1981), from all the wells in the productive area of north-central West Virginia, and from a well in Wayne County, West Virginia (Patchen, 1969; Cardwell, 1977). Tuscarora gas from wells in Roane, Jackson, Kanawha, and Fayette Counties, West Virginia, typically has a carbon dioxide content as high as 83 percent. Carbon dioxide stripped from the gas produced from the Tuscarora Sandstone in Kanawha County is now used in enhanced recovery operations in the Granny Creek Field (Mississippian Big Injun) of Clay County, West Virginia.

In the Devils Elbow Field and the Heyn Pool in Pennsylvania, drilling depths to Tuscarora reservoirs range from 11,100 to 11,500 ft. In northern West Virginia (Monongahela, Preston, and Tucker Counties), drilling depths are from 6,600 to 9,800 ft. Across southern West Virginia (from Cabell to Fayette Counties), drilling depths through the Tuscarora Sandstone range from 4,700 to 9,300 ft. In Indian Creek Field in Kanawha County, West Virginia, the range is from 6,300 to 6,700 ft.

The only areas in which Tuscarora development is active today are the Devils Elbow Field in Pennsylvania and areas in Kanawha County, West Virginia. The presence of noncombustible gas in some parts of the Tuscarora Sandstone may be a drawback to future production (D. G. Patchen, personal communication, 1982).

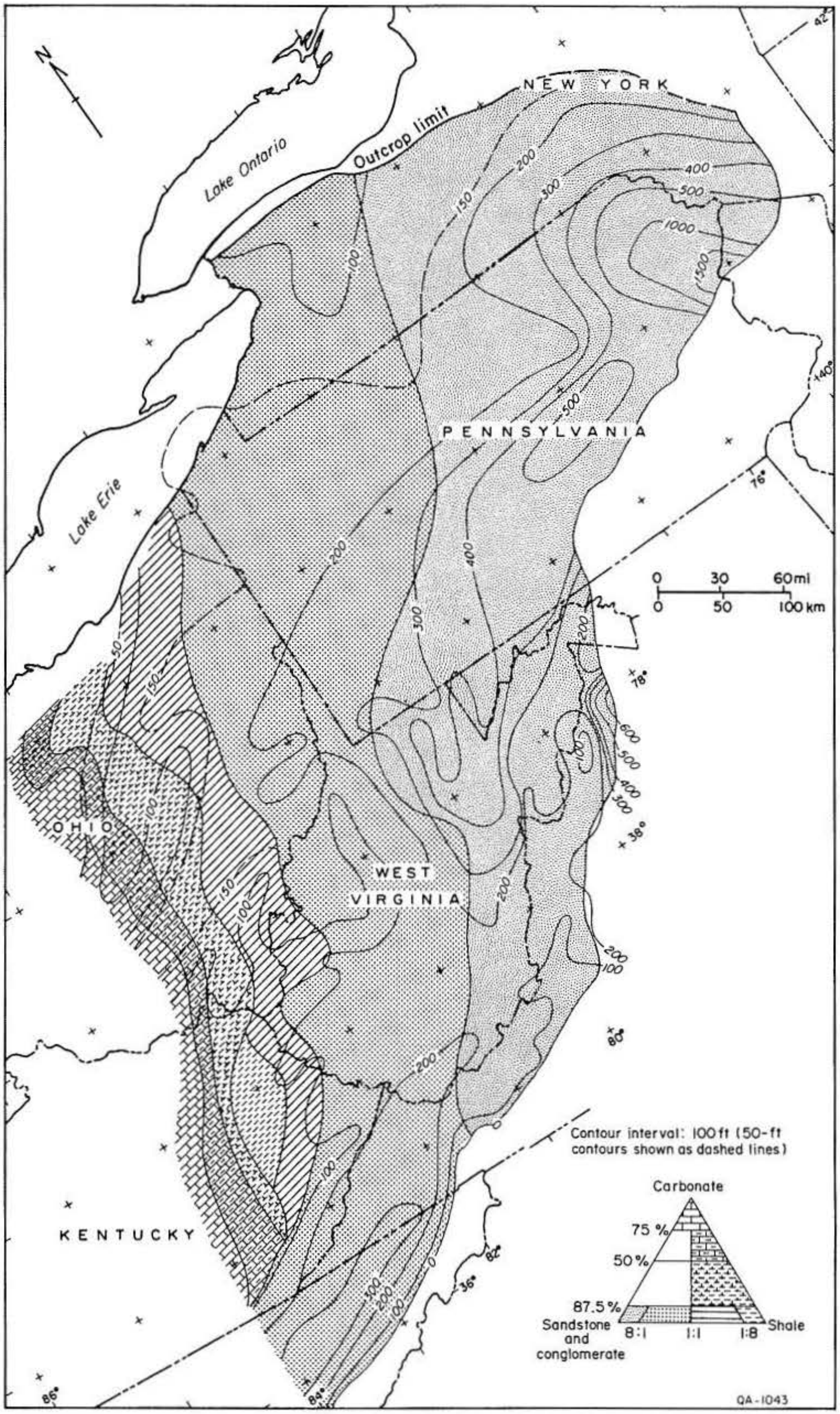


FIGURE 14. Isopach and lithofacies of the Lower Silurian Series, Appalachian Basin (from Diecchio, 1982c; after Amsden, 1955, Yeakel, 1962, Dennison and Wheeler, 1975, Chen, 1977, and Dennison, 1980).

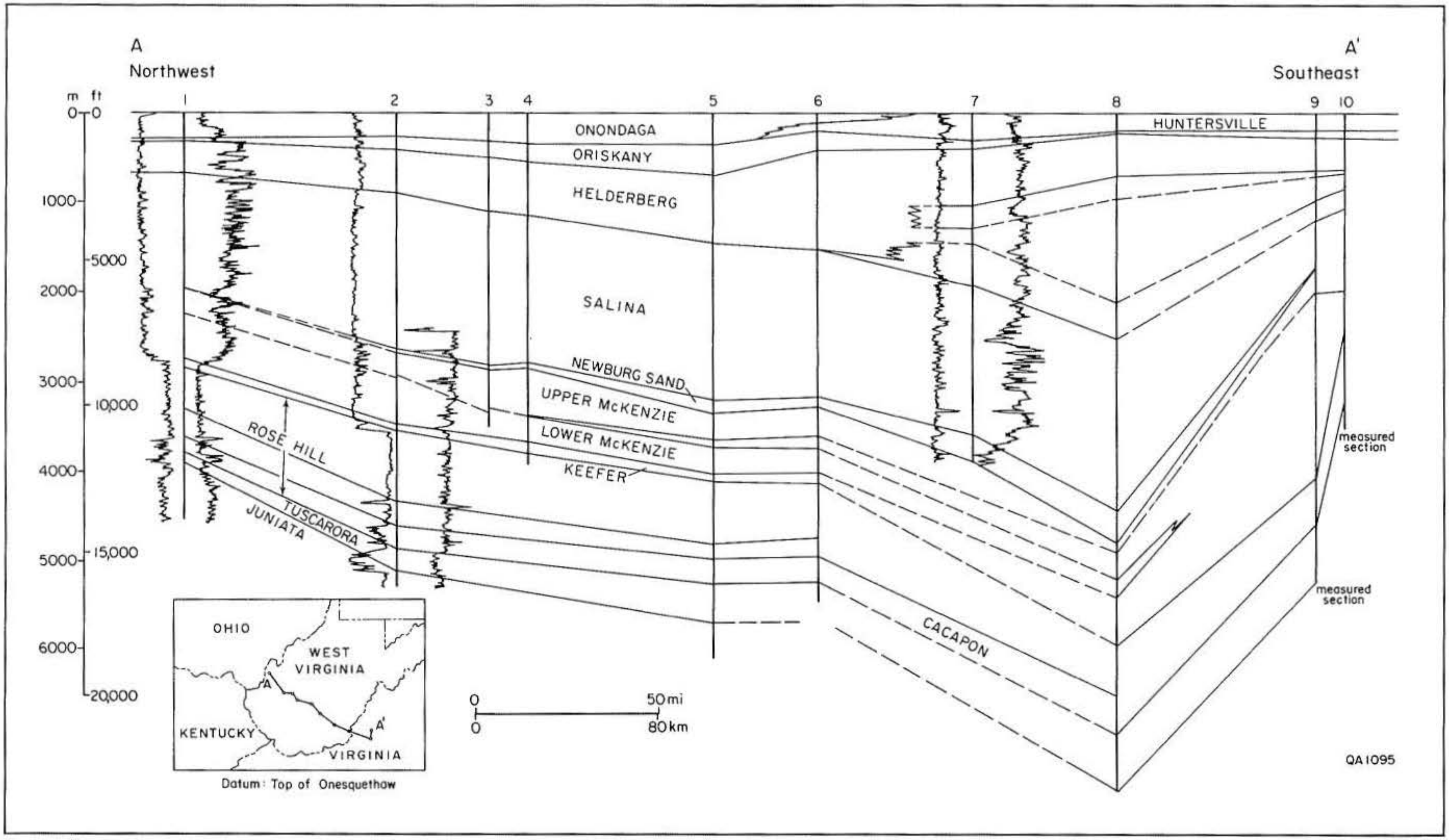


FIGURE 15. Northwest-southeast stratigraphic cross section A-A' through the Tuscarora Sandstone and overlying units showing thinning of the Tuscarora to the west (from Diecchio, 1982c; after Dennison, 1970).

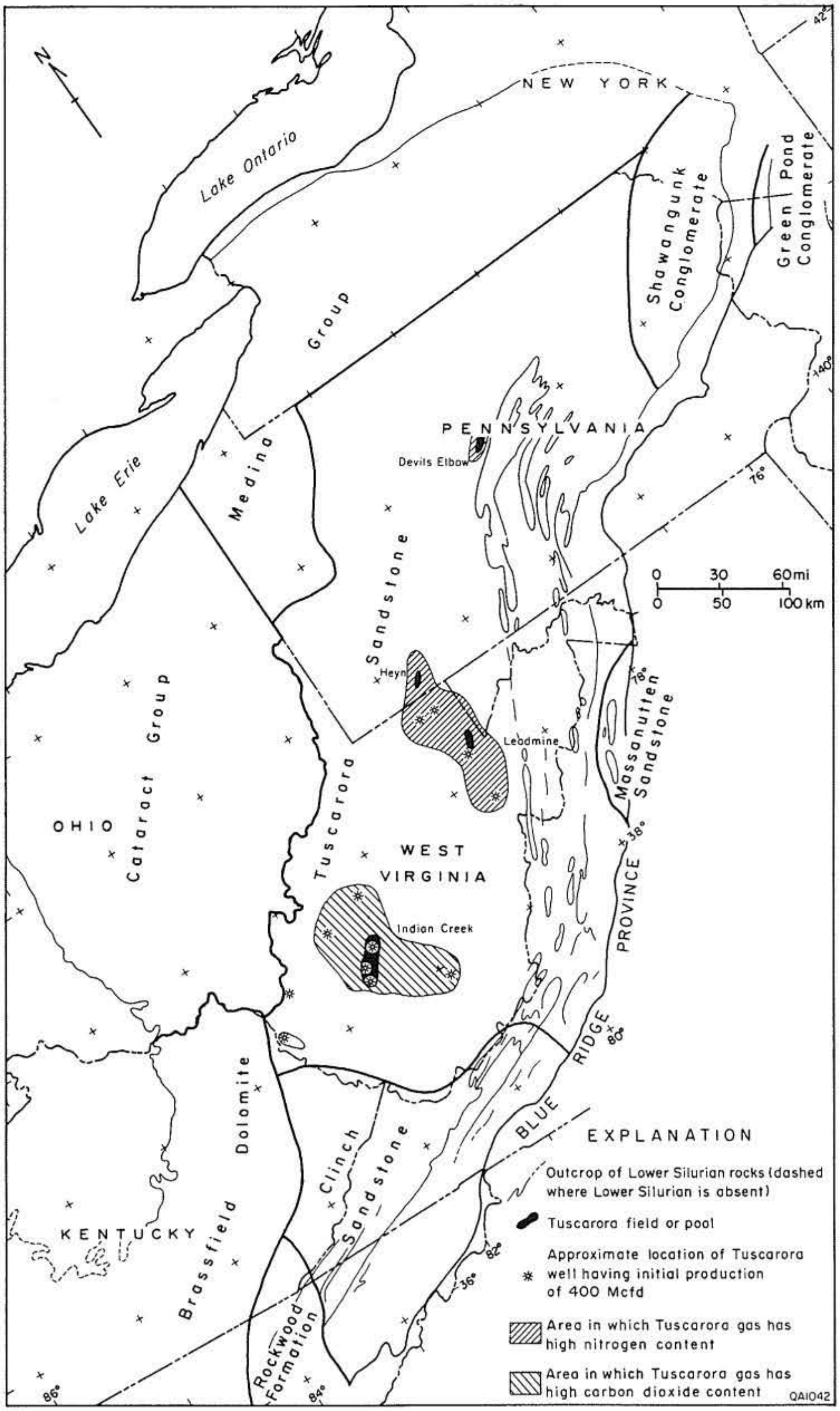


FIGURE 16. Extent and nomenclature of Lower Silurian strata, Appalachian Basin (from Diecchio, 1982c; after Dennison and Wheeler, 1975, Cardwell, 1976, and Piotrowski, 1981).

"CLINTON"-MEDINA SANDSTONE, APPALACHIAN BASIN

The "Clinton"-Medina sandstone of Early Silurian age in the Appalachian Basin is a major tight gas sand. The "Clinton"-Medina sands are generally equivalent to the Tuscarora Sandstone. Data have been compiled on three areas where "Clinton"-Medina tight gas occurs: in eastern Ohio (tables 14 through 17), in northwestern Pennsylvania (tables 18 through 21), and in western New York (tables 22 through 25).

Stratigraphy

Lower Silurian strata of the central Appalachian Basin generally become thicker and coarser toward the east and thinner, finer, and more calcareous toward the west (fig. 14). In the western part of the basin, shale is often the dominant lithology and limestone is common; sandstone typically composes a minor part of the section. These sandstones, informally referred to as the "Clinton"-Medina sandstone, are the most important hydrocarbon reservoirs in the western part of the basin. Areas of "Clinton"-Medina production are shown in figure 17.

As noted previously, Lower Silurian stratigraphic nomenclature varies from state to state (fig. 18). The use of the term "Clinton" for the sequence of Lower Silurian sandstones implies an incorrect correlation; the "Clinton" of this report has no relation to the Clinton in the eastern part of the Appalachian Basin. Another source of confusion is the term "Medina." In New York, the Medina Group is everything above the Ordovician (Queenston) and below the Thorold. In West Virginia and Ohio, the term "Medina" has been used to refer to the Upper Ordovician Queenston Shale or Juniata (Red Medina) Formation and to the Lower Silurian Tuscarora or Whirlpool (White Medina) Sandstones. Drillers tend to follow the latter designation, which is largely obsolete.

The term "Clinton"-Medina, therefore, has a double meaning. The package of middle Lower Silurian sands, which is called "Clinton" in Ohio and called Medina in New York, is over a widespread area called "Clinton"-Medina. In Ohio, where production from the Lower Silurian and Upper Ordovician comes from either the "Clinton" or the underlying Medina, the gross producing package is referred to as the "Clinton"-Medina.

As shown in figures 19 and 20, the Lower Silurian clastic sediments have blanket distribution throughout the basin. In the areas of interest to this report, these strata are deltaic and are characterized by shale containing discontinuous, broadly lenticular ("Clinton"-Medina) sand bodies. The individual "Clinton"-Medina sandstone reservoirs are multiply stacked and not laterally extensive; therefore, they should not be referred to strictly as a blanket sand.

The "Clinton"-Medina is either pending approval as or has been designated a tight formation throughout most of its productive area. In five counties in eastern Ohio (Meigs, Washington, Monroe, Belmont, and Jefferson Counties), the "Clinton" sandstone is classified as tight but has not produced. In four counties in Central Ohio (Fairfield, Licking, Knox, and Richland Counties), the "Clinton" is very productive and apparently so porous (intergranular) and permeable that it does not qualify as a tight formation. There is minor "Clinton" production in Greenup, Boyd, and Lawrence Counties, Kentucky.

Depositional Systems

The Medina Group in New York was deposited as a westward-prograding deltaic system. Similarly, the Medina Group in Pennsylvania is deltaic in origin, grading laterally into sandy shelf deposits. Diecchio (1982a) suggested, however, that the recent work of Cotter (1982a, 1982b) provides new information on the relative position of the deltaic and shelf facies. Apparently, further regional evaluation is needed to better define the paleogeography.

In Ohio, the Albion Group, also termed the Cataract Formation (fig. 18), was deposited as a deltaic system; it commonly consists of multiple, coalescing, lenticular sandstones and siltstones that were deposited as channel sands, river mouth bars, longshore bars, and reworked beach ridges (Ohio Department of Natural Resources, 1980). Although the sands are typically lenticular, cross sections by Overbey and Henniger (1971) show that these units are broadly lenticular and, having stacked and laterally juxtaposed units, can approach a blanket configuration. Diecchio (1982a), recounting Knight (1969), reported that in northeastern Ohio the Whirlpool Sandstone (fig. 18) is a strandplain deposit, the lower Cabot Head Shale is a prodelta shale, the Cabot Head ("White Clinton") and the Grimsby ("Red Clinton") Sandstones are distributary-channel sequences, and the Thorold Sandstone ("Stray Clinton") represents a transition (no specific facies described) into prodelta deposits of the upper Cabot Head Shale. Overbey and Henniger (1971) suggested that the Thorold Sandstone in eastern Ohio is a marine shelf deposit.

Most researchers concur that the "Clinton"-Medina sandstone represents a deltaic sequence forming the distal part of the Taconic clastic wedge (Diecchio, 1982a). Recent work by Cotter (1982a) on the equivalent Tuscarora Sandstone (fig. 18) implied the existence of a fan delta having proximal braided fluvial facies, marginal marine strandplain and deltaic components, and a marine shelf having sand waves and bars. The proportion of progradational strandplain or delta-front facies (blanket geometry) to channel-mouth-bar or offshore-bar facies (lenticular) will affect the overall reservoir geometry in part of the "Clinton"-Medina trend. The analogy between the "Clinton"-Medina trend and the Travis Peak deltaic system is strong; it appears that both may be, in part, fan-delta complexes.

Extrapolation Potential

The "Clinton"-Medina tight gas trend is extensively drilled in New York, Pennsylvania, and Ohio, and development continues at a relatively high rate. Most of the wells tapping a single stratigraphic unit for tight gas produce from the "Clinton"-Medina, making up the largest number of the 5,160 tight gas wells in Ohio (AAPG Explorer, 1982). Research on the Travis Peak Formation in East Texas and North Louisiana may permit more efficient exploitation of the "Clinton"-Medina sandstone and the equivalent, less developed Tuscarora Sandstone.

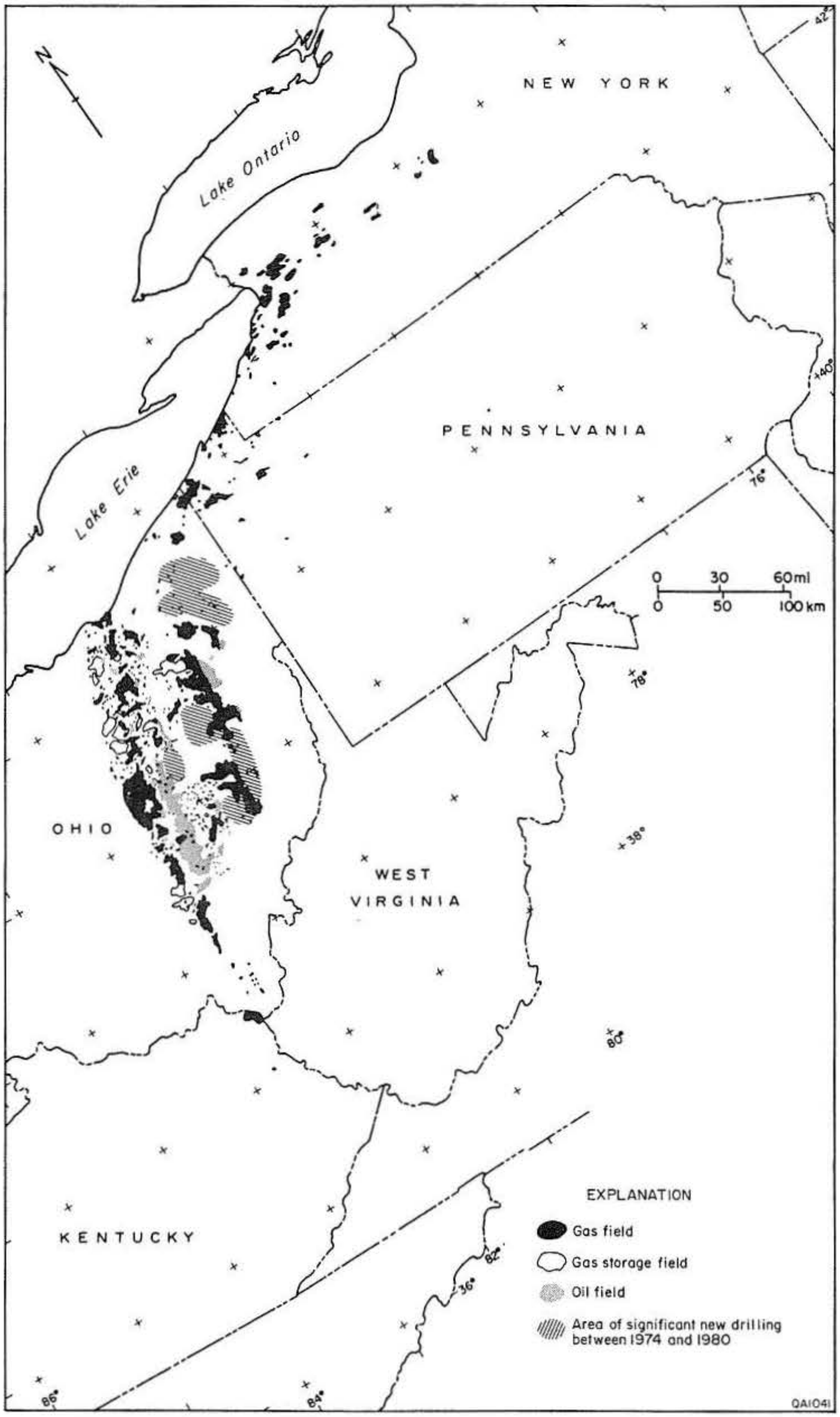


FIGURE 17. Hydrocarbon production from "Clinton"-Medina fields (after Kreidler, 1959, 1963; Kreidler and others, 1972; De Brosse and Vohwinkel, 1974; Wilson and Sutton, 1976; Piotrowski, 1981).

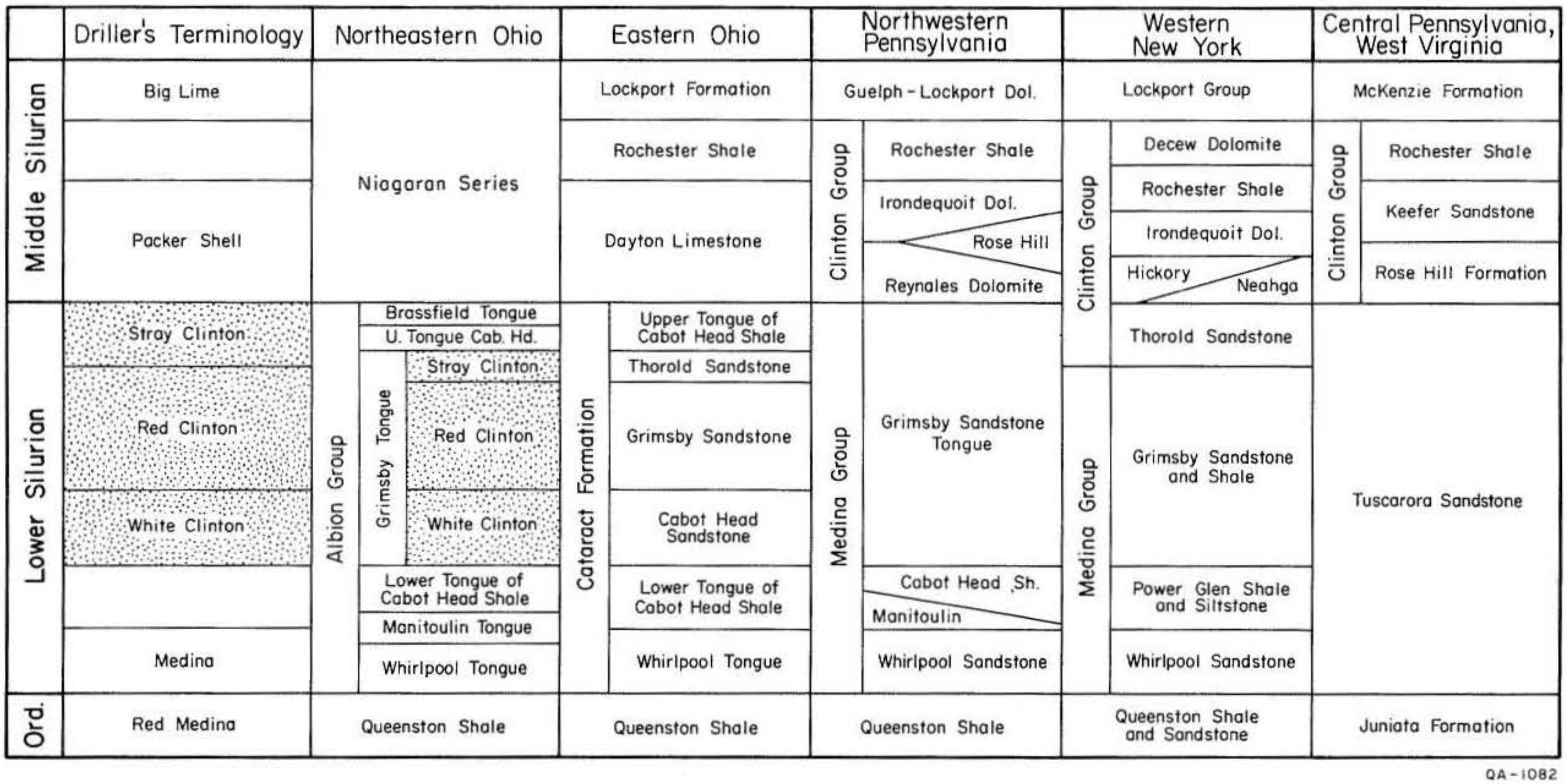


FIGURE 18. Stratigraphic terminology used to describe the Lower Silurian (after Knight, 1969; De Brosse and Vohwinkel, 1974; Richard, 1975; Ohio Department of Natural Resources, 1980; Piotrowski, 1981). Not to scale; correlations are tentative. Tight gas sandstones are stippled.

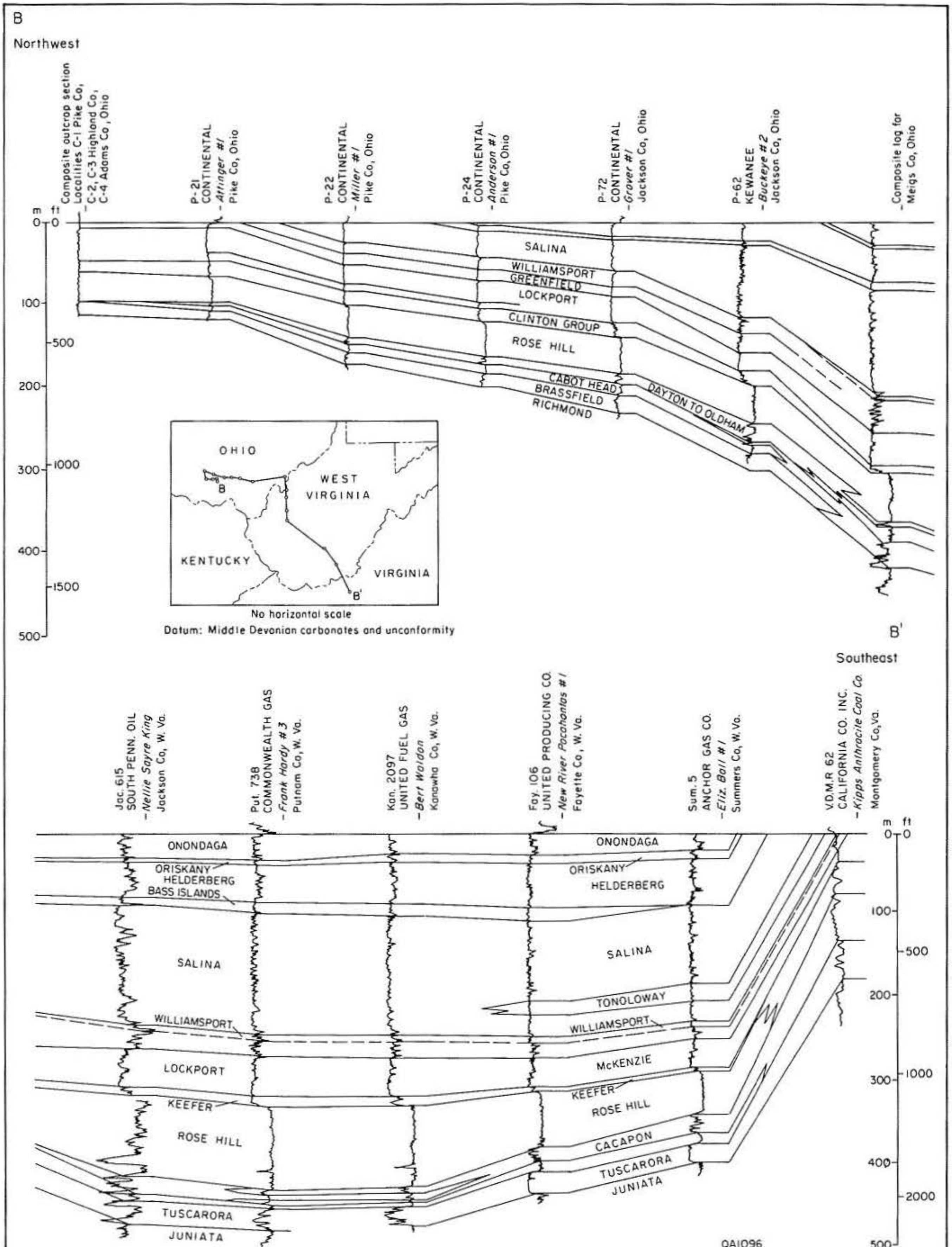


FIGURE 19. Northwest-southeast stratigraphic cross section B-B' showing strata from the Onondaga to the Upper Ordovician, Ohio to Virginia (from Horvath and others, 1970).

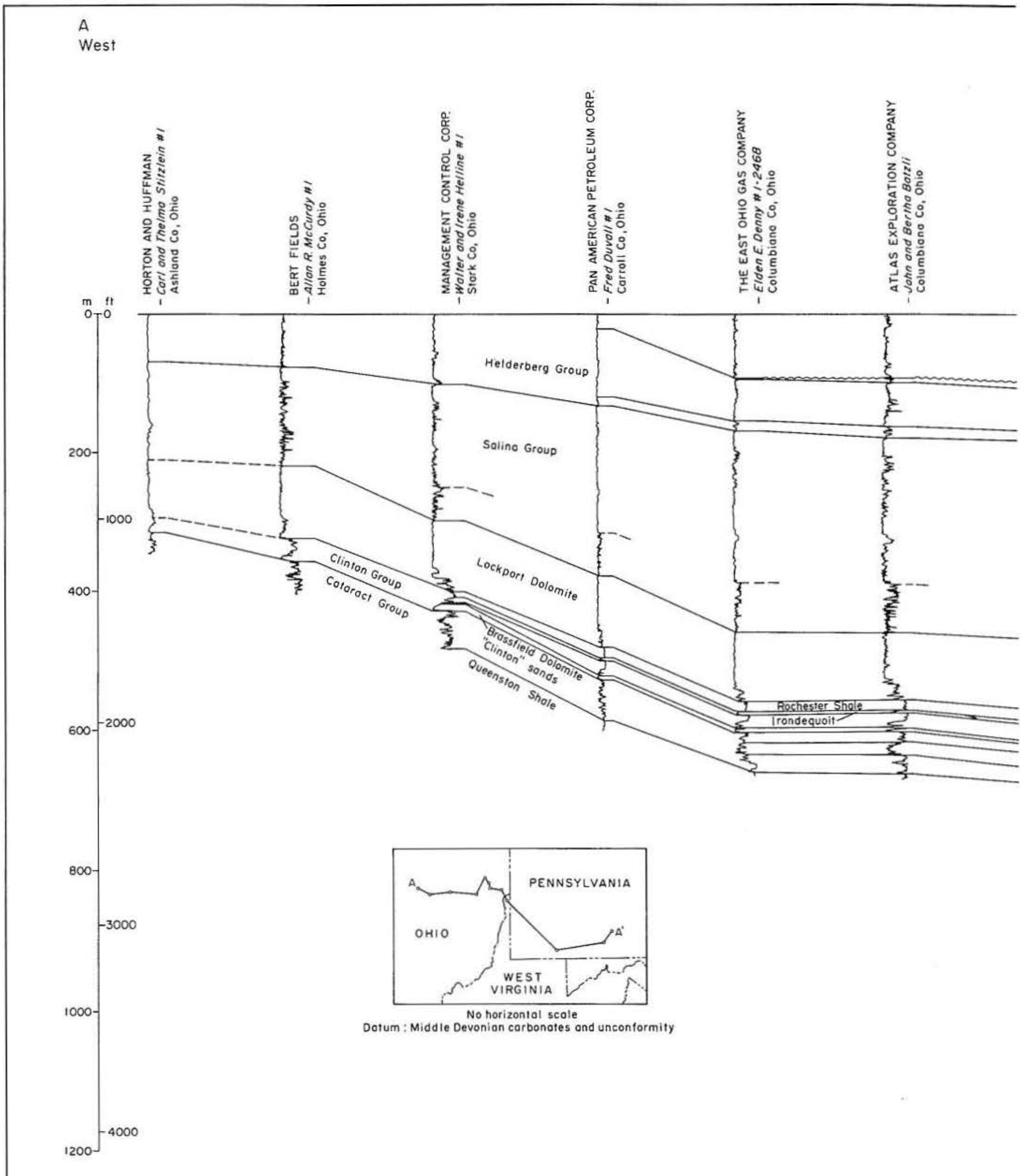
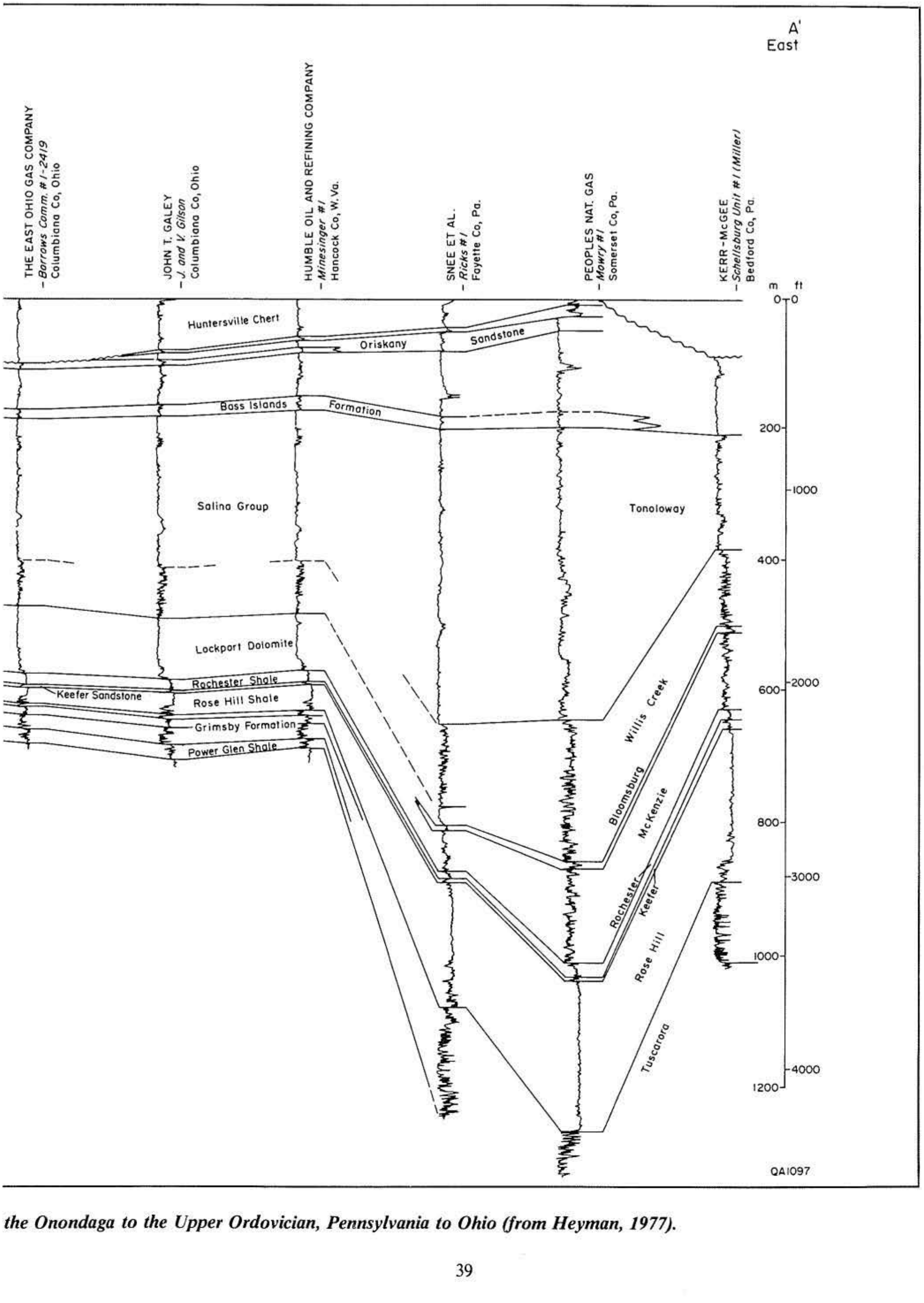


FIGURE 20. East-west stratigraphic cross section A-A' showing strata from



the Onondaga to the Upper Ordovician, Pennsylvania to Ohio (from Heyman, 1977).

TABLE 14. "Clinton"-Medina sandstone (Albion Group), eastern Ohio, Appalachian Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
"Clinton"-Medina sandstone, Albion Group, eastern Ohio, Lower Silurian.	In eastern Ohio, area is mostly east of the 83rd meridian and east of a line from Lorain County (north) to Lawrence County (south).	Albion Group is 220 ft thick in southeastern Ohio, thinning to the west and north, and about 120 ft thick at the western limit of production.	Depth to top of "Packer Shell" is more than 7,000 ft in eastern Ohio to slightly more than 1,000 ft at the western limit of production.	No data. Not included in National Petroleum Council (1980) study.	Regional dip is southeast at 50 ft/mi.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This area lies primarily in the relatively undeformed Western Basin Province of the Appalachian Basin. Stratigraphic section thins toward the Findlay Arch in west-central Ohio.	1.0° to 1.8° F/100 ft.	No data.	No specific data. May be weakly compressional in extreme eastern Ohio toward the deformed parts of the Appalachian Basin.

TABLE 15. "Clinton"-Medina sandstone (Albion Group), eastern Ohio, Appalachian Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Generally deltaic to marginal marine strandplain and shallow marine facies associated with the distal part of the clastic wedge resulting from the Taconic orogeny. Sandstones are lenticular to broadly lenticular and approach blanket geometry as a consequence of stacking and lateral juxtaposition of multistory sand bodies. Best blanket geometries may be associated with barrier and strandplain facies, whereas channel-mouth and offshore bars tend to be lenticular.	Very fine grained to fine-grained sandstone, angular to subangular, having interbeds of siltstone and shale.	The White, Red, and Stray "Clinton" sands of central Ohio are 76% to 90% detrital quartz, 1% to 4% rock fragments, 1% to 5% feldspar and other minerals, 2% to 10% clay, and 2% to 19% cement.	Quartz, calcite, hematite, and lesser amounts of clay, siderite, and ankerite have cemented the "Clinton" sandstones. Balance of quartz vs. calcite cement varies locally.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Net sandstone reaches a maximum of 90 ft in eastern Ohio but pinches out to zero to the west. Dimensions of reservoirs may be adequate only for one well or may include up to a 535-mi^2 area (East Canton Field).	Reservoir pressure varies from 1,100 to 1,390 psi in two wells in Stark and Wayne Counties, Ohio. No temperature data.	Present, but most observed natural fractures are healed.	Data on a variety of ages and qualities of driller's and wireline logs are available.

TABLE 16. "Clinton"-Medina sandstone (Albion Group), eastern Ohio, Appalachian Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Average porosity is 8%, range is 6% to 12%, rarely as low as 3%. For 25 permeability values, range is 0.011 to 1.63 md, average is 0.19 md; however, only 8 of the 25 values were larger than 0.1 md.	Average is 30 ft, range is 9 to 63 ft.	Usually TSTM.	For 10 wells, average was 60 Mcfd, range was 20 to 120 Mcfd.	No data.	Oil is produced in some areas.	20% to 35% in reservoirs having 6% porosity.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing. Nitroglycerine shooting formerly was common. No details on current techniques.	140% increase in discovery well of Canton gas pool.	Ranges from 80 to 100 acres in Perry County; 46 acres in Canton gas pool.	Traps are stratigraphic.

TABLE 17. "Clinton"-Medina sandstone (Albion Group), eastern Ohio, Appalachian Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by FERC for all or part of 35 counties in Ohio, including 5 eastern counties that have not yet produced from the "Clinton"-Medina sandstone.	Approximately 500 oil and gas pools. More than 5,000 wells produce from tight gas sands in Ohio, most of which are from the "Clinton"-Medina sandstone.	As of late 1980, the success ratio was 98% (2,405 out of 2,459).	$60,000 in central Ohio to $420,000 at the unit's deepest point in eastern Ohio (drilling costs only).	Many pipelines exist in the area, including those of Columbia Gas of Ohio, Columbia Gas Transmission Corp., Consolidated Gas Supply Corp., East Ohio Gas Co., and National Gas and Oil Corp.	High. 70% of 1981 well completions in Ohio were in the "Clinton"-Medina sandstone.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
In the Appalachian Plateaus physiographic subdivision. Local relief commonly up to 300 ft, greater in some areas.	Humid, temperate. Most drilling operations cease during winter months.	Terrain does not restrict exploration activities.	Good. Major delta having marginal marine and shallow marine facies extending into Pennsylvania, New York, and West Virginia. Similar facies expected in deeper Tuscarora equivalent to the east in the Appalachian Basin and in the Travis Peak Formation of the East Texas Basin.	All drilling and completion services readily available because of existing oil and gas production.

TABLE 18. "Clinton"-Medina sandstone (Medina Group), northwestern Pennsylvania, Appalachian Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
"Clinton"-Medina sandstone, Medina Group, northwestern Pennsylvania, Lower Silurian.	In Pennsylvania, area is in primarily five counties: Erie, Crawford, Mercer, Venango, and Warren.	Varies from 150 ft to more than 200 ft, north to south. The Grimsby Sandstone within the Medina Group varies from 80 to 180 ft across the area.	Depth to top of Medina Group is 2,500 ft along Lake Erie to more than 7,000 ft in the southeast corner of Venango County, Pennsylvania.	No data. Not included in National Petroleum Council (1980) study. Total Medina production in Pennsylvania was 45 Bcf at end of 1980.	Regional dip is southeast.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This area lies in the relatively undeformed Western Basin Province of the Appalachian Basin.	1.2° to 1.7° F/100 ft.	No data.	No specific data. May be weakly compressional.

TABLE 19. "Clinton"-Medina sandstone (Medina Group), northwestern Pennsylvania, Appalachian Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Generally deltaic to marginal marine strandplain and shallow marine facies, as indicated for "Clinton"-Medina in Ohio. Recent work implies that the Medina Group in northwestern Pennsylvania is west (seaward) of equivalent marginal marine shoreline facies, but exact stratigraphic relationships have not been determined.	Grimsby Sandstone is fine to medium grained, subrounded to subangular, moderately well sorted, interbedded with shale and silty shale. Whirlpool Sandstone is fine to medium grained, subangular, moderately well sorted.	Quartz sandstone. No detailed data.	Quartz cement in Whirlpool Sandstone. Quartz cement having some hematite and clay in the Grimsby. No detailed diagenetic studies.
Typical reservoir dimensions	***Pressure/temperature of reservoir***	***Natural fracturing***	***Data availability***
The Grimsby Sandstone is 80 to 180 ft thick; dimensions range from field areas covered by a single well to areas of approximately 375 mi².	Pressure range is mostly 700 to 1,400 psi but may vary from 50 to 1,885 psi (for 1,155 measurements in 5 counties). Average temperature is 108° F; range is 95° to 120° F.	Probably present but extent of contribution to production is not known and is thought to be minor.	Data on a variety of ages and qualities of driller's and wireline logs are available.

TABLE 20. "Clinton"-Medina sandstone (Medina Group), northwestern Pennsylvania, Appalachian Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Porosity range is 9% to 12% to the northwest, 6% to 9% to the southeast. May be as low as 3%. Average permeability is 0.050 md, range is 0.0005 to 0.159 md.	No data.	Approximately 81% of completions initially had no flow or flow TSTM.	Of 1,155 wells, 28% had flow up to 499 Mcfd, 21% had flow up to 999 Mcfd, 30% had flow up to 1,999 Mcfd, and 21% had flow of 2,000 Mcfd or more.	No data.	Some Medina wells produce water and liquid hydrocarbons; no data on relation to gas production.	No data.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing. No details on techniques.	Generally successful; see post-stimulation production rates.	No spacing requirements; ranges from 120 to 160 acres in one field.	Traps are stratigraphic, occurring where sands have greater intergranular porosity.

TABLE 21. "Clinton"-Medina sandstone (Medina Group), northwestern Pennsylvania, Appalachian Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by FERC for Erie, Crawford, Mercer, Venango, and Warren Counties, Pennsylvania.	Approximately 50 Medina gas pools in northwestern Pennsylvania.	As of late 1980, success ratio was 88% (1,186 out of 1,352).	\$150,000 to \$420,000, depending on depth (drilling costs only).	Primarily pipelines of National Fuel Gas Supply Co.; to a lesser extent, Consolidated Gas Supply, Peoples Natural Gas Co., Diversified Natural Resources, and Columbia Gas of Pennsylvania.	High. 100% increase in drilling since tight formation designation in effect. Of 53 new fields or pools discovered in Pennsylvania during 1980, 29 were in the Medina.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
In the Appalachian Plateaus physiographic subdivision. Local relief commonly up to 300 ft, greater in some areas.	Humid, temperate. Most drilling operations cease during winter months.	Terrain does not restrict exploration activities. Permits required to cut new roads.	Good. Major delta having marginal marine and shallow marine facies extending into Ohio, New York, and West Virginia. Similar facies expected in deeper Tuscarora equivalent to the south and southwest in the Appalachian Basin and in the Travis Peak Formation of the East Texas Basin.	All drilling and completion services readily available because of existing oil and gas production.

TABLE 22. "Clinton"-Medina sandstone (Medina Group), western New York, Appalachian Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
"Clinton"-Medina sandstone (Medina Group), western New York, Lower Silurian.	In western New York, area is in parts of 12 counties: Chautauqua, Cattaraugus, Allegany, Erie, Wyoming, Genesee, Livingston, Ontario, Yates, Seneca, Cayuga, and Tompkins.	Medina Group varies from 180 ft (southern Chautauqua County) to nearly complete pinch-out in northern Cayuga County. Grimsby Sandstone is thickest (150 ft) in southeastern Allegany County and thins to the west, north, and east.	Depth to top of Medina Group varies from 7,000 ft in southeastern Allegany County, New York, to outcrop just south of Lake Ontario. Production occurs as shallow as 1,000 ft.	No data. Not included in National Petroleum Council (1980) study.	Regional dip is southeast in the northern counties and south in the western part of the area near Lake Erie. Rates of dip average 40 to 60 ft/mi and may approach 125 ft/mi. Southern Cattaraugus and Allegany Counties, New York, are structurally more complex than other areas.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This area lies primarily in the relatively undeformed Western Basin Province of the Appalachian Basin. A small part of Cattaraugus County and most of Allegany County, New York, are in the Low Plateau Province, which is characterized by increased low-relief folding.	1.0° to 2.1° F/100 ft.	No data.	Mild residual compressive stress resulting from Appalachian deformation.

TABLE 23. "Clinton"-Medina sandstone (Medina Group), western New York, Appalachian Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Generally westward-prograding, deltaic to marginal marine strandplain and shallow marine facies, as indicated for "Clinton"-Medina in Ohio. The Whirlpool Sandstone may be a beach or bar sand, and the Grimsby Sandstone in western New York may include distributary-channel sands, among other facies.	Grimsby Sandstone is medium to fine grained, well rounded. Whirlpool Sandstone is fine to coarse grained.	Sandstone is predominantly quartz having some heavy minerals, especially magnetite.	Both Whirlpool and Grimsby Sandstones are usually quartz cemented and contain rare calcite cement. The Grimsby contains hematite as grain coatings and interstitial cement.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Grimsby Sandstone, the primary producing unit, is 90 to 150 ft thick. Fields contain single producing wells or range up to 120 mi^2 in area.	Average pressure is 600 psi; range is 340 to 1,020 psi in nine wells (not necessarily discovery wells so may be below initial reservoir pressure). Temperature is up to 100° F in nine wells (depth not specified).	Probably present but extent of contribution to production is not known and is thought to be minor.	Data on a variety of ages and quality of driller's and wireline logs are available.

TABLE 24. "Clinton"-Medina sandstone (Medina Group), western New York, Appalachian Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Average porosity is 7.1%; range is 2.6% to 10.1% for unknown number of wells. Permeability is 0.0455 to 0.087 md for data from 255 wells, probably revised to reflect in situ conditions. Original average (not in situ) was 0.13 md.	No data.	Limited data. Range was 58 to 6,000 Mcfd for four wells drilled in 1956-1971.	Limited data. Range was 80 to 2,700 Mcfd for 14 wells drilled in 1956-1971. No pre-stimulation rates available for these wells.	No data.	Occasional shows of oil or condensate.	No data.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing. No details on techniques.	No data.	Variable; as low as 180 acres.	Traps are stratigraphic, occurring where sands have great intergranular porosity. Low-relief structures may enhance gas production.

TABLE 25. "Clinton"-Medina sandstone (Medina Group), western New York, Appalachian Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by FERC for Chautauqua and Cattaraugus Counties, New York.	Approximately 40 Medina gas pools or fields in western New York.	63% of 51 wells for Medina Group in combination with the underlying Ordovician Queenston Formation (no separate data).	\$60,000 to \$420,000, depending on depth (drilling costs only).	Medina gas is purchased by Columbia Gas Transmission Corp. and National Fuel Gas Supply Co.	High. Even before the tight formation designation in 1979, 81% of the gas produced in New York State was from the Medina.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
In the Appalachian Plateaus and Central Lowlands physiographic subdivisions. Local relief commonly up to 300 ft, greater in some areas.	Humid, temperate. Most drilling operations cease during winter months.	Terrain does not restrict exploration activities. Permits required to cut new roads.	Good. Major delta having marginal marine and shallow marine facies extending into Pennsylvania, Ohio, and West Virginia. Similar facies expected in deeper Tuscarora equivalent to the south and southwest in the Appalachian Basin and in the Travis Peak Formation of the East Texas Basin.	All drilling and completion services readily available because of existing oil and gas production.

CARTER AND HARTSELLE SANDSTONES, BLACK WARRIOR BASIN

The Carter and Hartselle Sandstones are members of the Upper Mississippian Parkwood Formation and Floyd Shale, respectively (fig. 21). The Carter Sandstone is commonly described as a fine- to medium-grained sandstone, in part argillaceous; the Hartselle Sandstone is a very fine grained to medium-grained sandstone having siltstone and shale interbeds. The Hartselle Sandstone has been approved as a tight gas sand by the State Oil and Gas Board of Alabama (1981). No application has been filed for designation of the Carter Sandstone. The data base on both units is fair for the engineering parameters but good for the geologic setting as a result of recent publications by Mack and others (1981) and Thomas and Mack (1982). Data tables have been prepared only for the Hartselle Sandstone (tables 26 though 29).

Structure

The Black Warrior Basin of northwestern Alabama and northeastern Mississippi is bounded on the north by the Nashville and Ozark domes, on the southeast by the Appalachian Mountains, and on the southwest by the Ouachita structural trend. Mesozoic and Tertiary strata of the Mississippi Embayment and the Gulf Coastal Plain cover two-thirds of the basin. The basin was part of the stable continental interior during most of Paleozoic time, when it received a thick sequence of carbonate and clastic sediments; clastics predominated with the start of the Late Mississippian (Pike, 1968). The Hartselle Sandstone was deposited on the East Warrior platform of the basin (Thomas and Mack, 1982).

Stratigraphy

The Parkwood Formation and the Floyd Shale are part of the Upper Mississippian Chester Series. The Hartselle Sandstone Member is the uppermost sand in the Floyd, and the Carter Sandstone Member is the lowermost sand in the Parkwood Formation (fig. 21). The Carter and other sands of the Parkwood contribute about 90 percent of the total gas produced in the Black Warrior Basin (R. Peterson, personal communication, 1982). The Chester Series thickens from 800 ft in the outcrop area across northwest Alabama to about 2,100 ft toward the southwestern part of the basin.

Depositional Systems

Terrigenous clastic sediments of the Floyd Shale and Parkwood Formation accumulated mostly in the rapidly subsiding part of the basin adjacent to the Ouachita source area (Horne and others, 1976). The Hartselle Sandstone, however, is found on the much shallower east Warrior platform. Thomas and Mack (1982) interpreted the Hartselle as a northwest-trending barrier-island system that was bordered on the northeast by a shallow shelf containing a series of sand bars. Reworking and migration of the bars were controlled by storm processes. The shelf and bar facies pinches out to the east into a regional carbonate facies. Landward (southwestward), the barrier system pinches out into possibly a shallow marine bay or lagoonal mud represented by the Floyd Shale (Thomas and Mack, 1982). Provenance studies (Mack and others, 1981; Thomas and Mack, 1982) suggested that the Hartselle and Parkwood clastic sediments originated to the southwest of the Black Warrior Basin in the Appalachian-Ouachita orogenic belt; however, Cleaves and Broussard (1980) suggested that the Hartselle Sandstone had a north or northwest source.

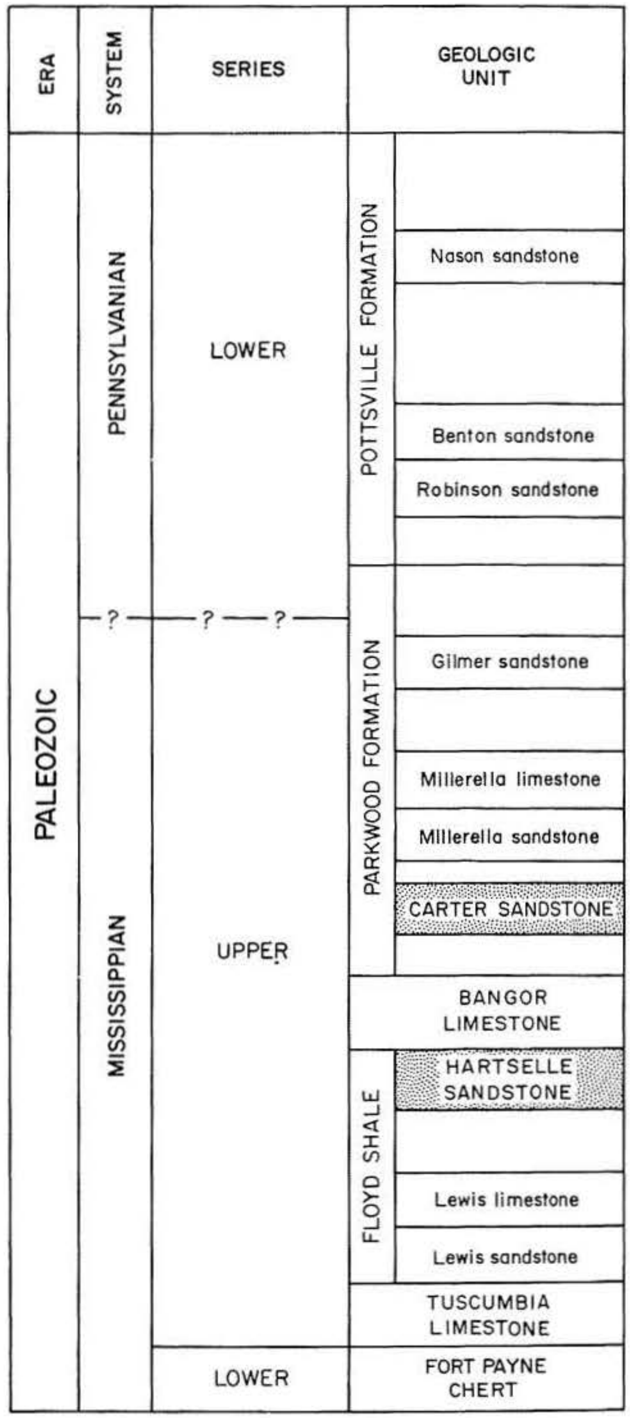


FIGURE 21. Generalized stratigraphic column of Mississippian and Pennsylvanian units in the oil- and gas-producing areas of the Black Warrior Basin, Alabama.

Thomas and Mack (1982) presented reasonably complete evidence, based on extensive outcrop studies, for the origin of the Hartselle Sandstone; however, they gave no subsurface data from which to judge the regional lateral continuity of the Hartselle. A generalized isolith of the Hartselle shows a thick in Walker County, Alabama (fig. 22). The thin, upward-coarsening sequence overlain by a blocky sand unit shown on logs from Walker and Winston Counties, Alabama, is consistent with a barrier or deltaic origin (figs. 23 and 24). Minor transgressions and decreases in sand supply could account for the thin breaks within the thick sand package indicated by gamma-ray - neutron logs (fig. 24).

Sandstones of the Parkwood Formation were deposited by northeast-prograding deltas, indicating a sediment supply from the southwest (Thomas and Mack, 1982). The Parkwood, which is less mature than the Hartselle Sandstone, is composed of litharenites to sublitharenties (Mack and other, 1981). The Carter Sandstone may be made up of barrier and bar sands within the Parkwood deltaic system (R. Peterson, personal communication, 1982). Other Parkwood sandstones are delta-front or distributary sands that were formed during individual cycles of deltaic progradation (Thomas, 1979).

The Carter Sandstone as an Unconventional Gas Sand

Much of the conventional gas produced in the Black Warrior Basin is from the better developed sands, such as the offshore-bar facies, of the Carter Sandstone. Thinner sheet sands between the bars are likely to have more lateral continuity than the bar sands; accompanied by an increase in fine-grained clastic sediments, the sheet sands would tend to form a blanket-geometry, low-permeability reservoir. Reservoir characteristics of interfield areas are unknown (R. Peterson, personal communication, 1982), but these areas may represent an important untested resource.

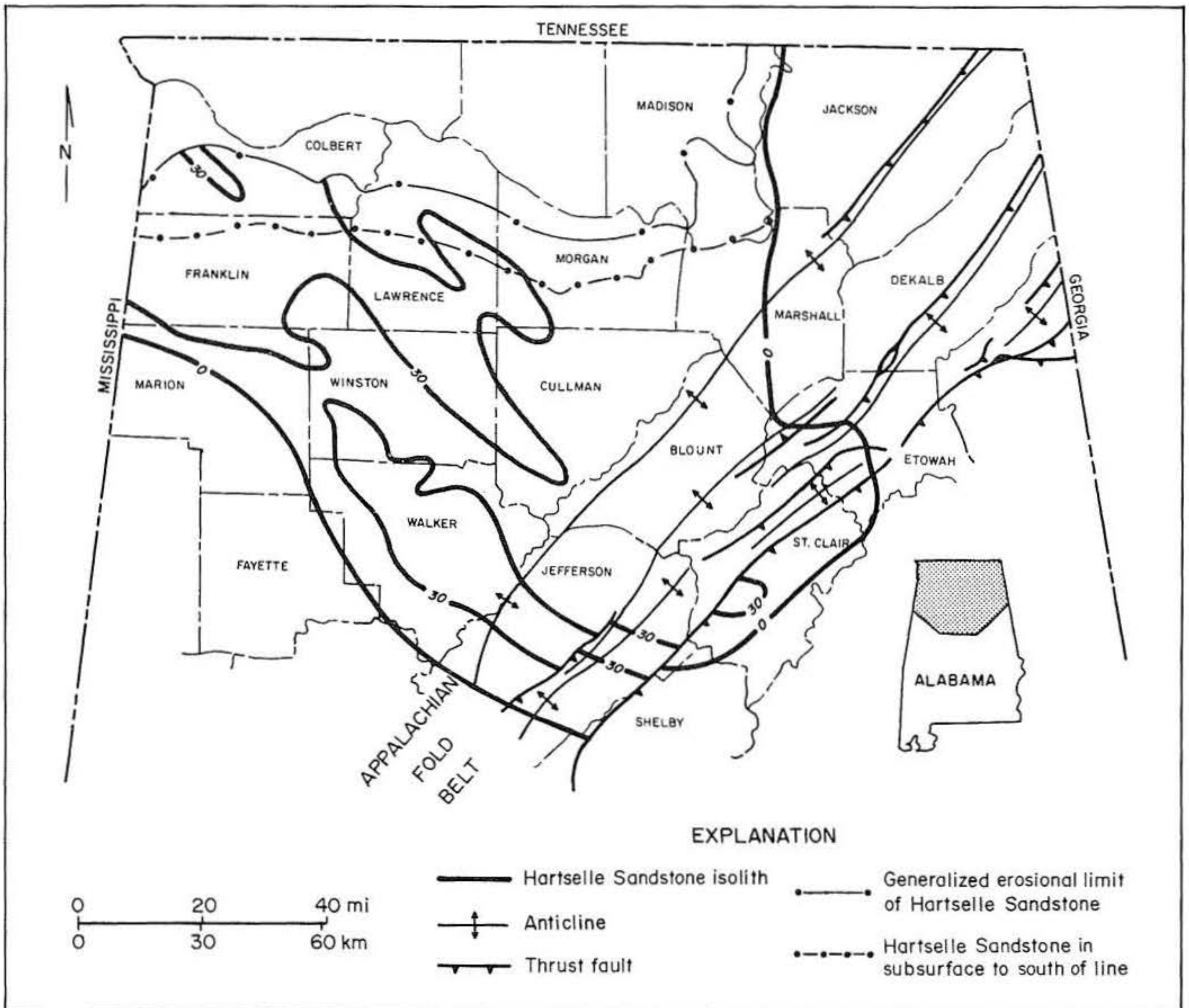


FIGURE 22. Generalized isolith map of the Hartselle Sandstone, Black Warrior Basin, Alabama (after Thomas and Mack, 1982).

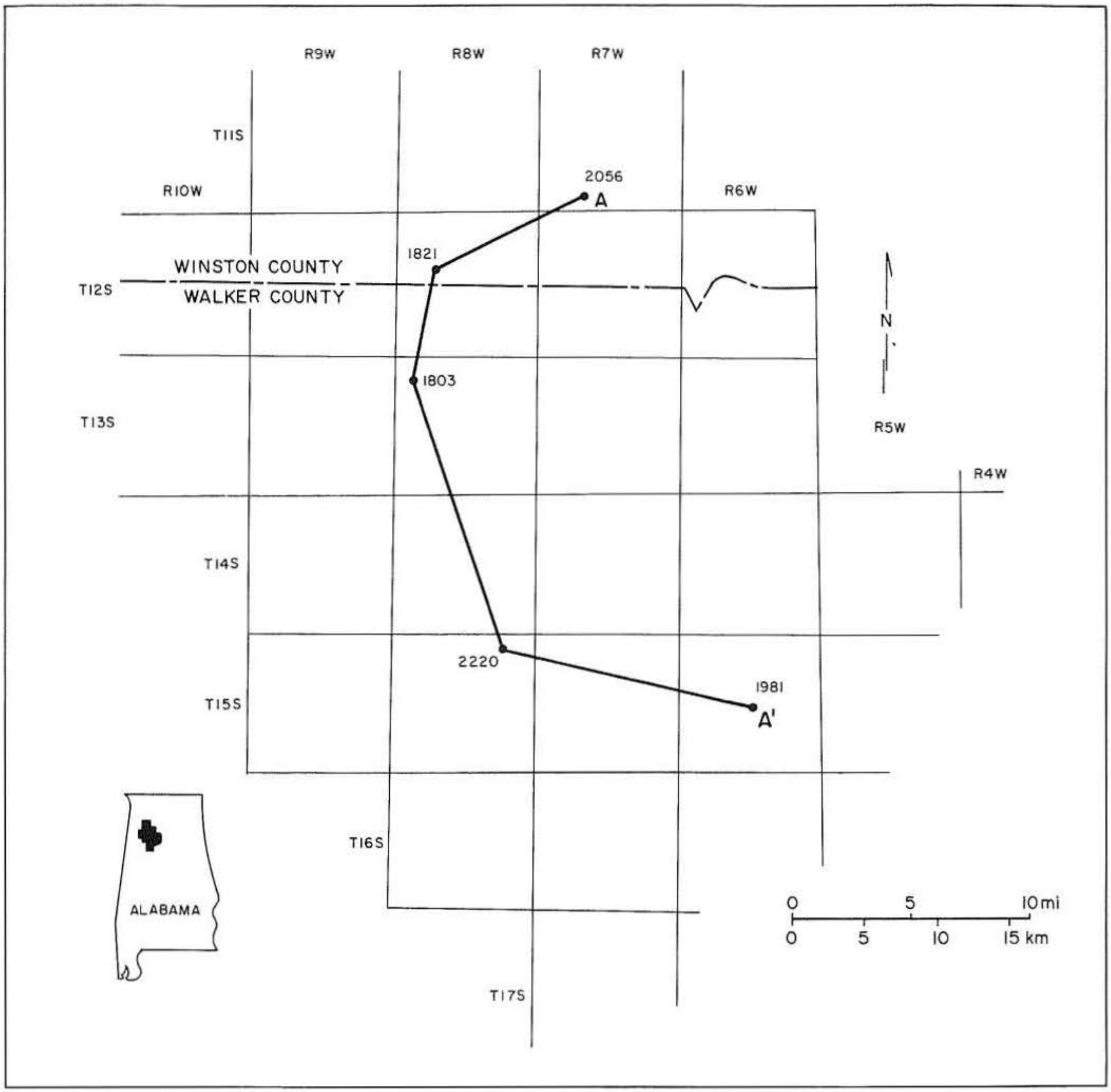


FIGURE 23. Index map of cross section A-A' (fig. 24) through the Hartselle Sandstone, Black Warrior Basin, Alabama (after State Oil and Gas Board of Alabama, 1981).

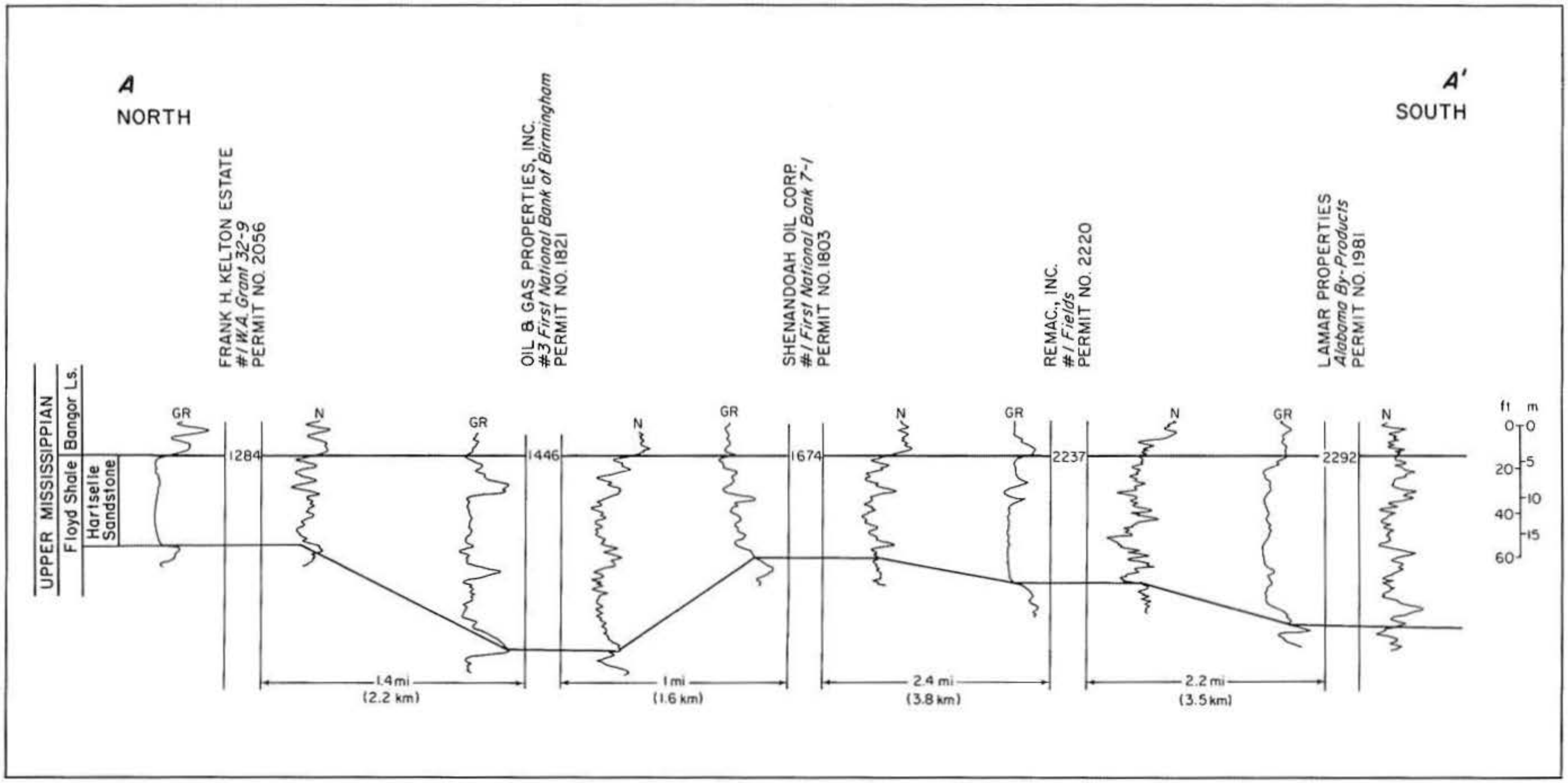


FIGURE 24. North-south stratigraphic cross section A-A' through the Hartselle Sandstone, Black Warrior Basin, Alabama (after State Oil and Gas Board of Alabama, 1981). Line of section shown in figure 23. Depths shown are drilling depths.

TABLE 26. Hartselle Sandstone, Black Warrior Basin:
General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Hartselle Sandstone Member of the Floyd Shale, Upper Mississippian.	A designated area in parts of T11-17S, R4-10W in Winston and Walker Counties, Alabama, is approximately 996 mi^2.	Range is 0 to 150 ft from the southwest part to the center of the application area.	Range is 3,400 to 1,000 ft from south to north in the designated area.	No data. Not included in National Petroleum Council (1980) or Kuuskraa and others (1981). R. Peterson (personal communication, 1982) estimated 0.1 to 0.5 Tcf, primarily for blanket sands in the basin other than in the Hartselle Sandstone.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
The designated area lies in the northeastern part of the Black Warrior foreland basin on the Warrior Platform. The basin is bounded to the north by the Ozark and Nashville domes, to the south and east by the Appalachian Fold Belt, and to the south and west by the Ouachita salient.	1.0° to 1.8° F/100 ft.	No data.	Compressional stresses resulting from Appalachian and Ouachita folding and thrust faulting.

TABLE 27. Hartselle Sandstone, Black Warrior Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Deposited by a northwest-trending, linear barrier-island complex and an associated offshore-bar system. The barrier-island facies includes shoreface and foreshore sandstones, as well as occasional tidal channels. The offshore-bar system represents reworking of the upper barrier-island facies during a regional net transgression.	Ranges from very fine grained to coarse-grained but generally fine-grained sandstone, which is well sorted, well rounded, and occasionally interbedded with mudstone.	Primarily quartz (average more than 90%) having traces of potassium feldspar, plagioclase, chert, and various types of rock fragments that include metamorphic, shale, sandstone, granitic, and volcanic types. Sandstone in the designated area is approximately 2% clay (montmorillonite).	Cemented primarily by calcite or silica, or both.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
No data.	No data.	Locally present in Jasper Field within the designated area. This field is excluded from the designated application area.	Limited core. SP-resistivity and GR-density or GR-neutron make up the typical log suite.

TABLE 28. Hartselle Sandstone, Black Warrior Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Calculated from one core analysis, permeability to air is 0.099 md; calculated from six wells, average permeability is 0.0515 md, range is 0.0020 to 0.0938 md. Calculated from six wells and core analysis of one well, average porosity is 5%, range is 0% to 15%.	No data.	For 40 to 45 wells, pre-stimulation flow was not present or TSTM.	Rates obtained from pre-1970 stimulation techniques ranged from 50 to 100 Mcfd.	No data.	No recorded liquid hydrocarbon production.	Average is 87%, range is 0% to 100% for six wells.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Stimulation techniques before 1970 used explosives detonated in the borehole. Current techniques use hydraulic fracture treatment involving a mix of 70% nitrogen foam and KCl, methanol, and water and various quantities of sand proppant. Average design specifications unavailable.	No data.	320 acres.	Fewer tight sand applications submitted than in other states. Data generally limited.

TABLE 29. Hartselle Sandstone, Black Warrior Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
One application approved by State.	Approximately 45, excluding Jasper Field.	55% basinwide in 1979.	Average stimulation costs are $20,000; range is $18,000 to $50,000 (date unknown for these cost estimates).	Limited. Short spur of a Southern Natural Gas Co. pipeline extends only into southeastern Walker County, Alabama. As of early 1980, 55 wells were awaiting pipeline connection in Alabama.	Low to moderate. One FERC application and generally increased interest in the Black Warrior Basin.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
Open hills of the Eastern Interior Uplands and Basins physiographic subdivision. Less than half of the area is gently sloping. Local relief of 300 to 500 ft.	Humid having mean annual precipitation of 48 to 56 inches. Moderately hot summers, mild winters. No climatic restrictions on exploration activity.	No access problems described in application; probably no major limitations.	Fair to good. Expected to be similar to barrier and bar facies of regressive marginal marine units of the Mesaverde Group. Rates of sediment input probably lower than those of Late Cretaceous deposition in Rocky Mountain basins. Intracratonic depositional setting somewhat similar between Cretaceous seaway and parts of Paleozoic basin and platform.	The Black Warrior Basin has been drilled primarily by independents and small companies.

ARKOMA BASIN, OKLAHOMA AND ARKANSAS

The Arkoma Basin of eastern Oklahoma and western Arkansas is a Paleozoic basin trending approximately east to west; it lies along the Ouachita structural front and is overlapped by Coastal Plain sediments to the east (Branan, 1968). Although new wildcat successes have been announced, exploration activity within the Arkoma Basin has been relatively low in past years (McCaslin, 1982). However, exploration may increase, fostered in part by a new 285-mi-long, 20-inch pipeline, known as the Ozark Gas Transmission System, through the basin. Ozark Gas Pipeline, which built the system, hopes to tap 1.5 to 2.0 Tcf of gas reserves and potential resources within the basin (Oil and Gas Journal, 1982).

The main gas reservoirs in the Arkoma Basin are Lower Pennsylvanian sandstones; additional reservoirs are in the Mississippian Chester Series (fig. 25). Some older Paleozoic strata have also yielded gas. The entire basin is a dry gas province, having little or no associated oil production (McCaslin, 1982). Gromer (1981) prepared a geologic overview of the basin and a review of selected producing fields.

The blanket-geometry gas reservoirs of the Arkoma Basin include the Spiro Sandstone within the Atokan Group and the Cromwell Sandstone of the Morrowan Group. The Spiro is the unit of greater interest; it represents marginal marine environments that underwent redistribution of sand by a northward marine transgression across the basin (Gromer, 1981). No detailed description of the depositional systems of the Spiro Sandstone was found. Other Atokan sands above the Spiro are lenticular. Branan (1968) and Gromer (1981) described these two blanket sands, noting that the Spiro is already an important producer throughout the basin from depths of 3,000 to 12,000 ft. Permeability of the Spiro varies widely even within a single field, from near zero to greater than 100 md, and porosity may vary from 5.4 to 23.3 percent in the same area (Six, 1968). Thus, it appears that the Spiro Sandstone ranges from a conventional to an unconventional reservoir.

Era	System	Series		Arkoma Basin	
Paleozoic	Pennsylvanian	Des Moines		Marmaton Group	Calvin Fm.
			Cherokee Group	Cabaniss Group	Senora Fm. Stuart Fm. Thurman Fm.
				Krebs Group	Boggy Fm. (Base Bartlesville) Savanna Fm. McAlester (Booch) Fm. Hartshorne Fm.
		Atoka		Atoka Fm.	Upper Atoka Fanshawe Ss.
					(Gilcrease) Middle Atoka - Red Oak
					Lower Atoka Spiro Ss. Foster Ss.
		Morrow		Wapanucka Fm. (Okla.) Union Valley	Bloyd Sh. (Ark.) Kessler Ls. Mbr. Brentwood Ls. Mbr.
				Hale Fm. Cromwell Ss. (subsurface)	Prairie Grove Mbr. Cane Hill (Springer)
	Mississippian	Chester		Coney Sh.	Pitkin Ls Fayetteville Sh. Batesville Ss.
		Meramec			Moorefield Fm.
		Osage		Woodford Fm. (Okla.)	Boone Fm. (Ark.)

FIGURE 25. Partial stratigraphic column of the Arkoma Basin, Oklahoma and Arkansas (from Gromer, 1981).

TRAVIS PEAK FORMATION, EAST TEXAS AND NORTH LOUISIANA BASINS

The Lower Cretaceous Travis Peak Formation within the East Texas and North Louisiana Basins consists of very fine grained to fine-grained sandstones. The Travis Peak Formation directly overlies the Cotton Valley Sandstone (fig. 26). The Travis Peak has been termed the Hosston Formation, primarily in Louisiana. The data base on the Travis Peak Formation is good; information was obtained from tight sand applications and several publications (tables 30 through 33). A comprehensive analysis of the Travis Peak Formation in parts of seven counties in East Texas and Louisiana, using modern concepts of depositional systems, was done by McGowen and Harris (in press).

Exploration of the Travis Peak, or Hosston, Formation extends into the Mississippi salt basin of northeastern Louisiana and Mississippi (Weaver and Smitherman, 1978). The Hosston reservoirs in that basin are relatively deep (14,000 ft and deeper); some have permeabilities greater than 0.1 md. In Mississippi, an FERC-approved tight sand designation for the Hosston has been given for only one well. The well is in Jefferson Davis County; permeability is 0.075 md and depth to the top of the formation is 14,460 ft (Hagar and Petzet, 1982a).

Structure

The structural setting of the East Texas and North Louisiana Basins is summarized in the section that follows on the Cotton Valley Sandstone (p. 69). Deposition of the Travis Peak Formation, like that of the Cotton Valley, is thought to have resulted from tilting of rift-margin blocks toward the incipient Gulf of Mexico and concurrent erosion of these blocks. A structure-contour map on top of the Travis Peak indicates depths of 1,000 to more than 10,000 ft in the East Texas area (fig. 27).

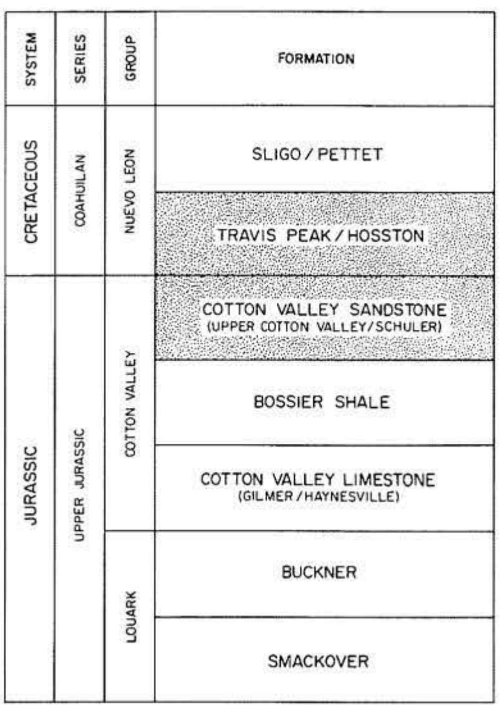


FIGURE 26. Partial stratigraphic column of the Jurassic and Cretaceous Systems in the East Texas and North Louisiana Basins.

Stratigraphy

The Travis Peak Formation is Early Cretaceous in age and overlies the Cotton Valley Sandstone. In Louisiana a thin limestone, the Knowles Limestone, marks the boundary between the Cotton Valley Sandstone and the overlying Travis Peak Formation; however, the Knowles Limestone does not extend through all of the East Texas Basin (M. K. McGowen, personal communication, 1982). The top of the Travis Peak Formation is transitional, having marine-reworked clastic sediments overlain by carbonates of the Pettet (Sligo) Member of the lower Glen Rose Formation, which was deposited as part of a major marine transgression. Subunits of the Travis Peak Formation were not delineated either in previous studies or in the tight sand applications. The base of the Travis Peak contains a chert-pebble conglomerate in some areas; contact between the Travis Peak and the Cotton Valley sandstones varies from conformable to unconformable (Nichols and others, 1968).

Depositional Systems

The Early Jurassic in East Texas and North Louisiana was dominated by deposition of carbonates, evaporites, and mudstones. The first major influx of terrigenous clastic sediments into these areas occurred during the Late Jurassic (Cotton Valley) and the Early Cretaceous (Travis Peak). In East Texas, the terrigenous clastic sediments were supplied by many small rivers rather than by one or two major rivers, as in Louisiana and Mississippi. A major source of the Travis Peak Formation and the Cotton Valley Sandstone appears to have been older sedimentary rocks surrounding the East Texas and North Louisiana Basins. Sandstones in the Travis Peak are texturally mature quartzarenites and subarkoses (McGowen and Harris, in press).

The Travis Peak Formation has been examined in detail in the northwestern part of the East Texas Basin by McGowen and Harris (in press) and over the entire basin in a general manner by Bushaw (1968). Bushaw showed the progression of environments of three informal intervals of the Travis Peak Formation that resulted in the deposition of the Pettet (Sligo) Limestone (fig. 28). The interpretation of the larger area is consistent with the interpretation by McGowen and Harris (in press) of the Travis Peak as a system of coalescing deltas that prograded from the west, northwest, and north. The distal part of these deltas included a transition zone between subaerial and subaqueous depositional environments wherein delta-front sediments may be reworked into bars, spits, and shoals, most commonly when individual deltaic lobes are abandoned. Basinward of the transition zone, a subaqueous delta front develops; the configuration of the transition and subaqueous zones in Modern deltas varies with wave energy and with the width of the marine shelf (Galloway, 1976; Wescott and Ethridge, 1980).

A generalized regional cross section through the Travis Peak shows a thick, sand-dominated wedge of sediment probably composed mainly of braided-stream deposits (fig. 29). Braided streams form a continuous, laterally extensive sand sheet wherein shales are patchy and discontinuous (Walker and Cant, 1979). On a local scale, sands from the braided-stream facies show lateral continuity consistent with their deposition as longitudinal and transverse bars. This implies thickening and thinning of individual beds within sand packages from well to well (fig. 30). Where the braided-stream facies has been reworked by marine transgression or where the delta enters the marine environment, lateral continuity of beds probably is greater, but it is not necessarily similar in both dip and strike directions.

Travis Peak Formation Well Data Profile

Consistent with nationwide variations in drilling activity during the past several years, the number of gas completions in the Travis Peak Formation increased from 1978 through 1980 and then leveled off in 1981 (fig. 31). The depths to the top of perforated intervals of wells in the Travis Peak show a broad peak between 7,000 and 9,000 ft; few wells have upper perforations as deep as 11,000 ft (fig. 32). The mean perforated interval of 191 wells is 312 ft; interval thickness ranges from 2 to 2,265 ft. The mean IPF of 183 gas wells was 5,249 Mcfd; range was 67 to 31,000 Mcfd. It should be noted that IPF rates are often higher than stabilized or partly stabilized gas flow rates. Gas-oil ratio is noted in table 32; where condensate is produced, its API gravity is predominantly between 50° and 60°. High API gravity and light color values were frequently cited in tight gas applications as evidence that liquids produced with gas are actually in a gaseous state under reservoir conditions.

About one-third of the fracture treatments used on 398 producing gas wells in the Travis Peak Formation involved sand and gelled fluid, and one-third involved sand and water-based fluid. Acidization was noted in the WHCS file on 11 percent of the treatments, but this figure may be low because of incomplete reporting. Only 1.5 percent of the treatments used foam. In the future, the number of foam treatments may increase to avoid formation damage caused by swelling of water-sensitive clays.

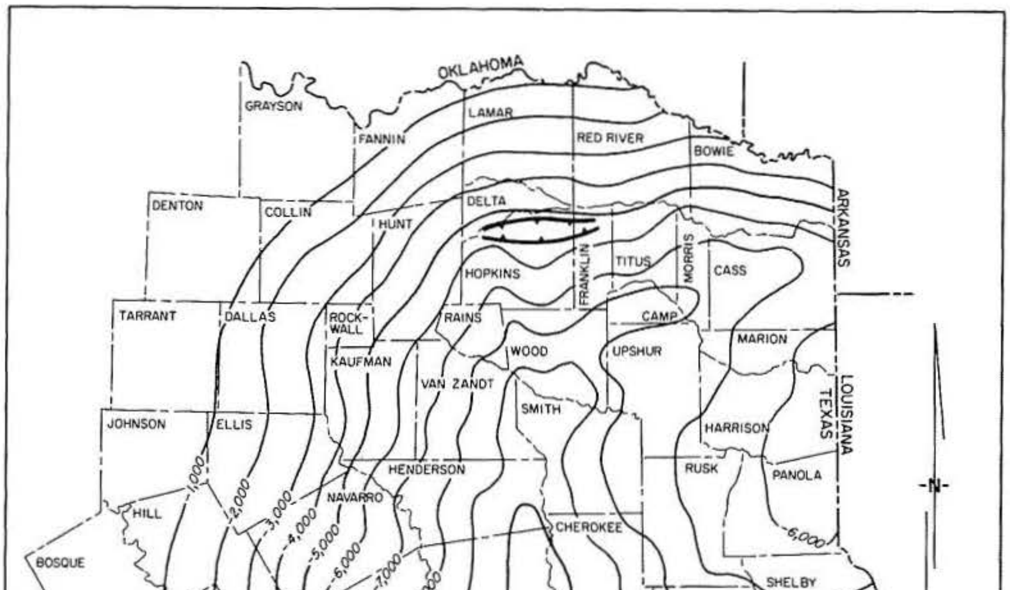


FIGURE 27. Generalized structure contours on top of the Travis Peak Formation, East Texas Basin (from Railroad Commission of Texas, 1981b).

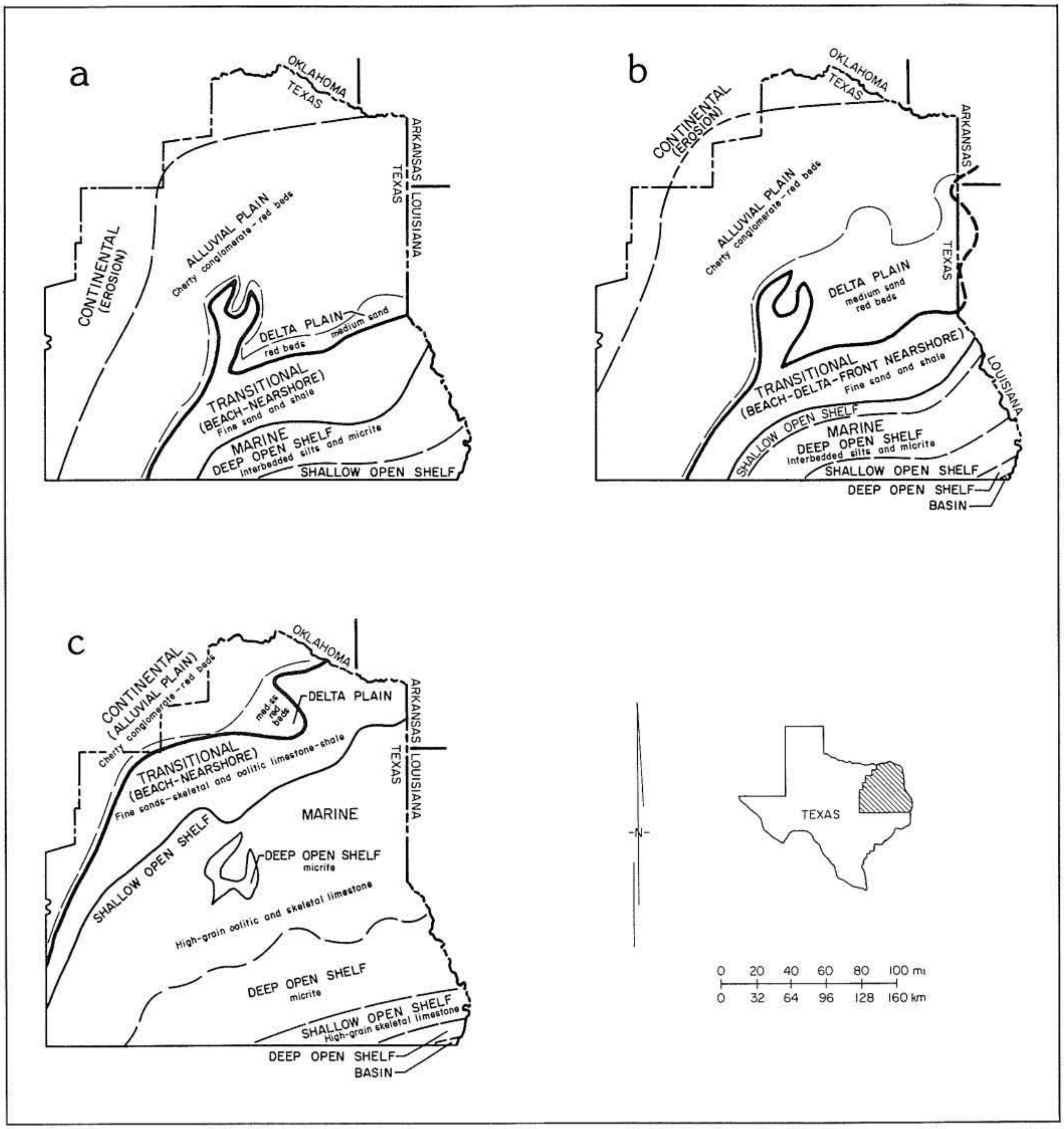


FIGURE 28. Facies tracts of the (a) lower, (b) middle, and (c) upper Travis Peak - Pettet (Sligo) Formations (after Bushaw, 1968).

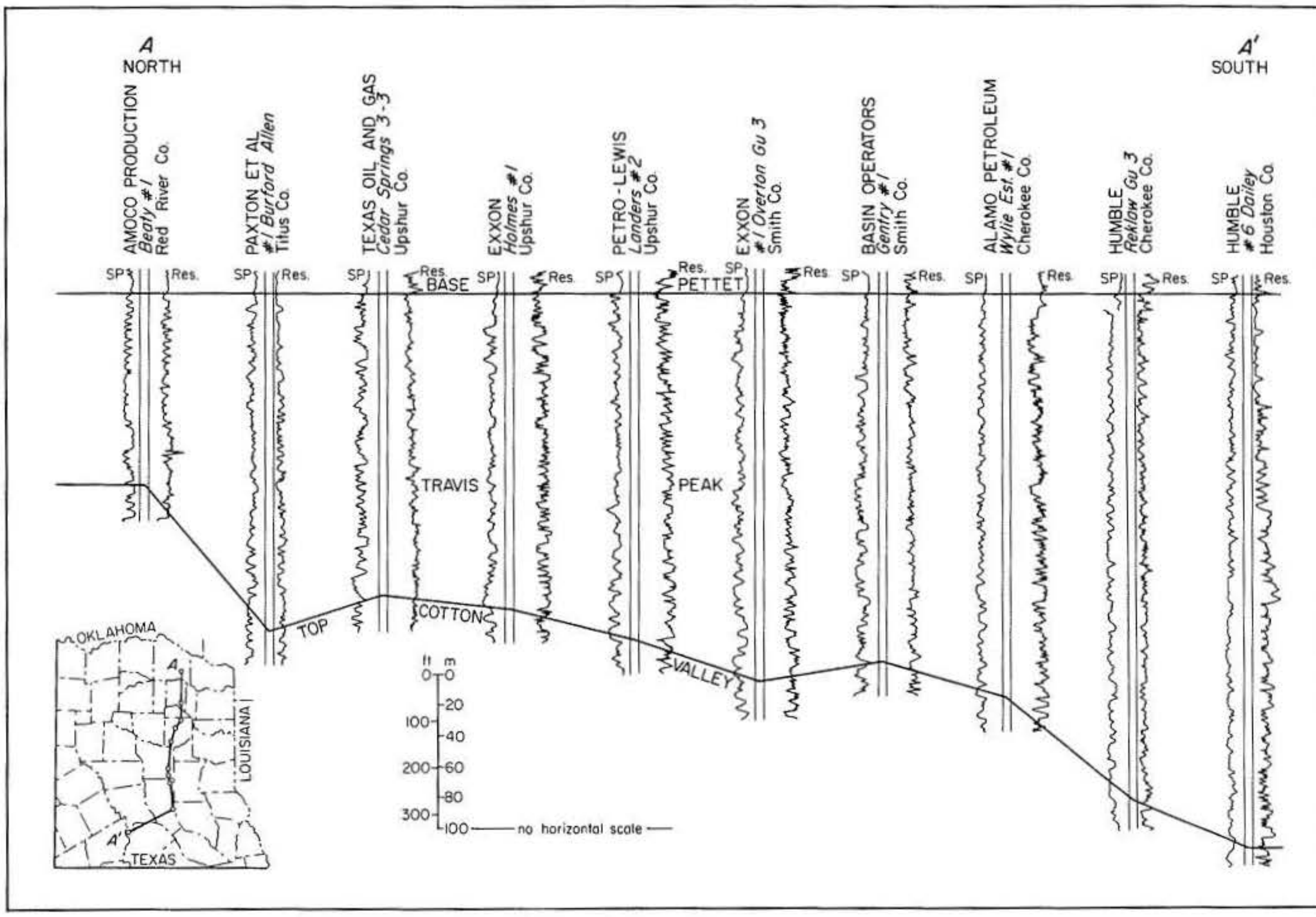


FIGURE 29. North-south regional stratigraphic cross section A-A' through the Travis Peak Formation (from Railroad Commission of Texas, 1981b).

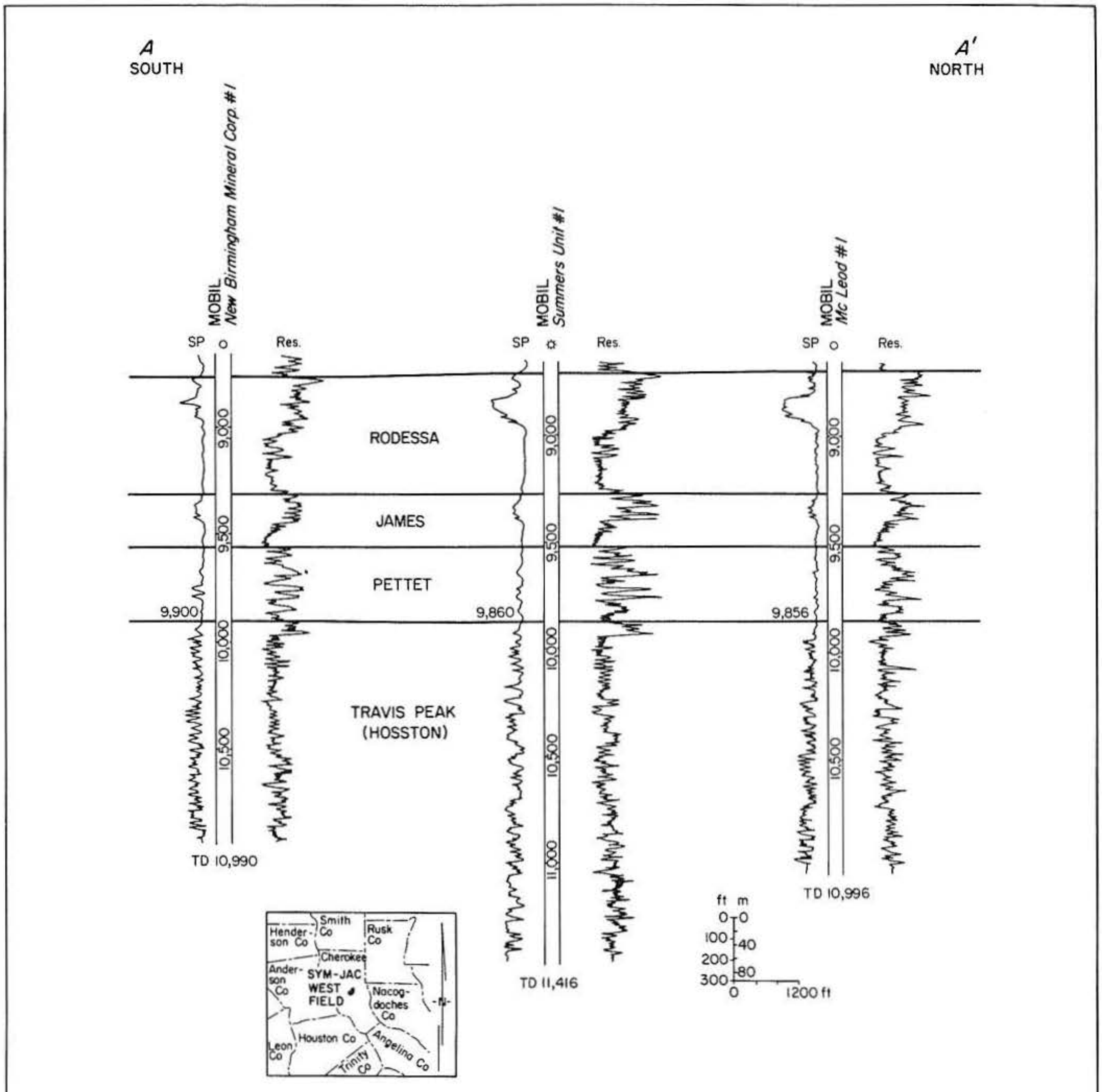


FIGURE 30. North-south stratigraphic cross section A-A′ through the upper Travis Peak Formation and overlying units in Sym-Jac West Field, Cherokee County, Texas (from Railroad Commission of Texas, 1981c).

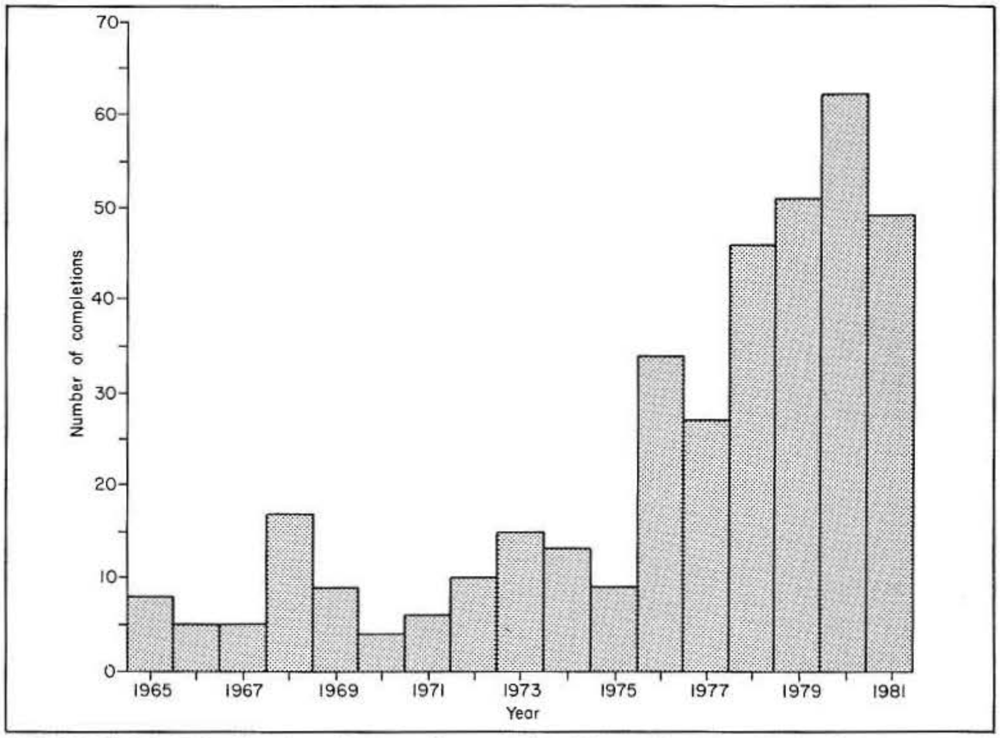


FIGURE 31. Distribution of gas wells completed from 1965 to 1981 in the Travis Peak Formation.

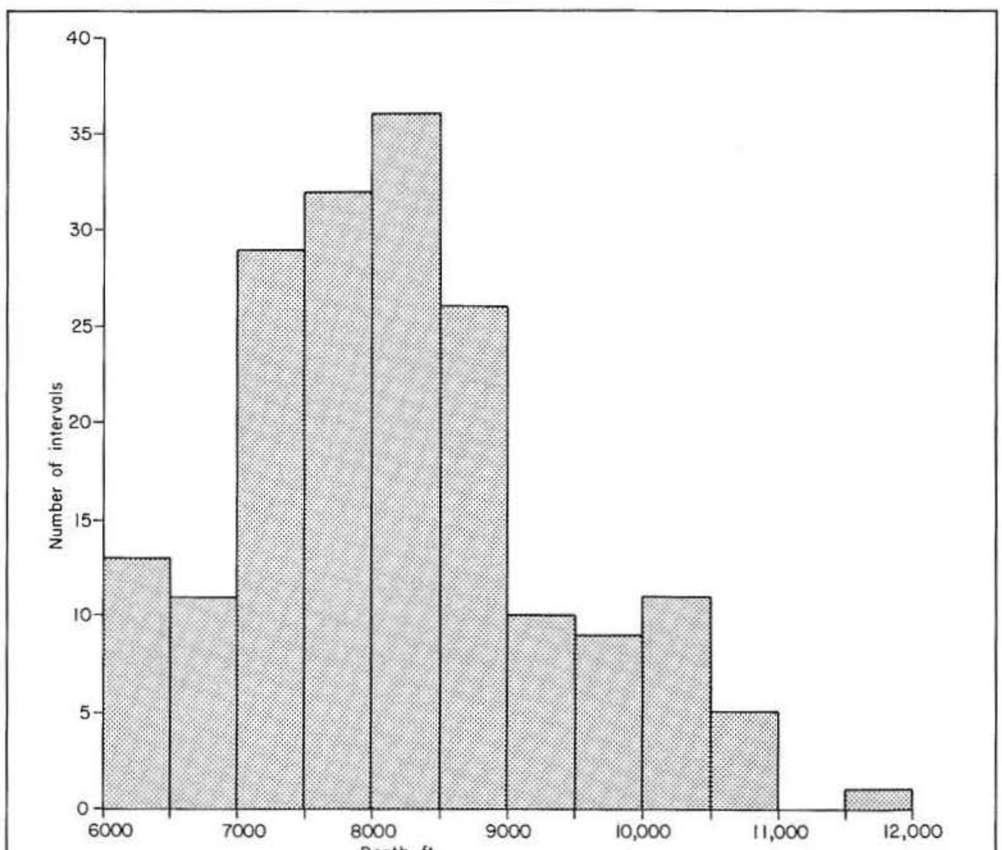


FIGURE 32. Depth to top of perforated interval of 191 gas wells completed in the Travis Peak Formation.

TABLE 30. Travis Peak Formation, East Texas and North Louisiana Basins: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Travis Peak (Hosston) Formation, Lower Cretaceous.	By analogy to the Cotton Valley Sandstone, possible productive and speculative areas of 6,000 mi^2 and 7,000 mi^2 in Texas and Louisiana, respectively. Texas approval for tight formation designation applies to 47 counties covering 35,830 mi^2 in Railroad Commission Districts 5 and 6.	Upper 200 ft of the formation, which is 500 to 2,500 ft thick, is the most likely source of blanket-geometry sands in updip East Texas Basin.	Ranges from 3,100 ft in Lamar County, Texas, to 10,900 ft in southern Cherokee County, Texas, to the top of the formation. Depth to top of Travis Peak ranges from -1,000 ft subsea on the northern and western basin margins to -6,000 ft over the Sabine Uplift to -11,000 ft on the southern basin margin and the deep central part of the basin.	Maximum recoverable gas in place is 13.8 to 17.3 Tcf if 12% to 15% of the basin is ultimately productive.	Local variations in thickness and attitude owing to salt structure(s).

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
In graben or structural sag formed along the margin of the Gulf of Mexico by continental rifting. East Texas Basin now bounded by major fault systems and the Sabine Uplift.	1.4° to 1.8° F/100 ft, mostly 1.6° to 1.8° F/100 ft.	0.43 to 0.59 psi/ft (mean is 0.50 psi/ft) for eight zones in five Amoco wells in Cherokee and Nacogdoches Counties, Texas.	Tensional; local stress variations caused by salt tectonics.

TABLE 31. *Travis Peak Formation, East Texas and North Louisiana Basins: Geologic parameters.*

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Lower Travis Peak: Alluvial plain and marine-influenced delta margins on the southern edge of the basin. Middle Travis Peak: Alluvial plain and delta environments receded toward the north and northwest source areas. Fluvial to marginal marine environments represented. Upper Travis Peak: As transgression continued, marine-influenced delta margins retreated to the northern parts of the basin and an open marine shelf occupied the central basin, receiving both terrigenous clastics and some skeletal and oolitic carbonate sediments. This upper facies of the Travis Peak, dominated by shallow marine transgression, is of most interest to tight gas sand development. Marine reworking has created strike-elongate sand thicks as well as sheetlike sands, thereby stacking both lenticular and blanket-geometry sand bodies.	Interbedded very fine grained to fine-grained sandstone, shale, and some sandy, fossiliferous, oolitic limestone. Well sorted in some areas.	Quartz sandstone, possibly having some chert. Clay clasts present. In one well in Freestone County, Texas, a Travis Peak core consisted of 44% quartz, with remaining grains consisting of chert, claystone, and silty shale. Colors vary from gray to tan to brownish red.	Quartz overgrowths and calcite cement reduce primary porosity. Clay matrix is reported as minor, but sampling is limited. Data from one field suggest leaching of carbonate cements to form secondary porosity.

Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Mean gross perforated interval of 191 wells is 312 ft; range of interval thickness is 2 to 2,265 ft.	Pressure range is 3,920 to 6,000 psi (mean is 4,866 psi) for eight zones in five Amoco wells in Cherokee and Nacogdoches Counties, Texas. Temperature range is 190° to 272° F (mean is 243° F) for eight zones in five Amoco wells in Cherokee and Nacogdoches Counties, Texas. Pressure range is 3,200 to 3,300 psi at 9,000 to 9,300 ft for two wells in Red River Parish, Louisiana.	Contribution of natural fractures is unknown but is generally considered minimal.	Limited core. Exxon has Travis Peak core from 18 wells, representing 5 field wells and 4 wildcats, and possibly has core from 10 other wells. At least one core in application area is in Louisiana. The primary log is SP-resistivity; a sonic log and a neutron-density log are often run for porosity identification.

TABLE 32. Travis Peak Formation, East Texas and North Louisiana Basins: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir parameters	*Net pay thickness*	*Production rates*		*Decline rates*	*Formation fluids*	*Water saturation*
		Pre-stimulation	*Post-stimulation*			
Mean calculated in situ permeability is 0.026 md for a group of 125 wells in Texas that have not been stimulated. Porosity ranges from 2% to 9% for a group of wells from seven counties in Texas.	Range is 30 to 86 ft (mean is 48 ft) for eight zones in five Amoco wells in Cherokee and Nacogdoches Counties, Texas. Net pay of 31 and 33 ft for two Mobil wells in Cherokee County, Texas.	Stabilized mean flow rate was 765 Mcfd for a group of 125 wells in Texas; as low as 43 Mcfd for two Mobil wells in Cherokee County, Texas.	Range was 500 to 1,500 Mcfd.	Decline from 940 to 330 Mcfd in 56 days for one stimulated well in Cherokee County, Texas, reported as typical. Rapid decline in first 12 to 24 mo expected for most wells.	High API gravity condensate is produced by some wells at rates less than 5 bpd in some areas but at rates of 10 to 20 bpd in other areas. Mean gas-oil ratio of 287 wells is 175,645:1.	Range is 29% to 60%, average is 43% for eight zones in five Amoco wells in Cherokee and Nacogdoches Counties, Texas.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Massive hydraulic fracturing, often as multistage treatments, to effectively treat all zones of interest. Techniques vary widely among operators; typical may be 500,000 lb sand in 200,000 to 300,000 gal fluid.	An average 418% increase after fracture treatment for four wells reported in tight sand applications.	640-acre spacing in eight fields described in FERC applications; two of these have optional 320-acre spacing.	Amoco has reported the following specific data on production rates before and after massive hydraulic fracturing for four wells in Nacogdoches and Cherokee Counties, Texas:

Depth (ft)	Pre-stimulation (Mcfd)	Post-stimulation (Mcfd)	Permeability (calculated)
8,560-8,652	475	900	0.032
9,730-9,954	40	230	0.002
9,130-9,164	373	900	0.027
10,526-10,710	225	1,500	0.033

TABLE 33. Travis Peak Formation, East Texas and North Louisiana Basins: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Two fields approved by Texas and FERC. A 47-county area of East Texas approved by State on October 26, 1981. All of Winn Parish and parts of three other parishes approved by Louisiana on November 24, 1981.	Approximately 1,239 completions in Railroad Commission of Texas Districts 5 and 6; 676 were active as of May 1981. In Louisiana, 53 Hosston penetrations are in the application area.	See table 37 for basinwide data on gas wells.	By analogy to costs for Cotton Valley tests, probable costs are $1.0 million to complete a deep (9,000-ft) well.	Well-established regional pipeline and gathering system, including Arkansas Louisiana Gas Co., Lone Star Gas Co., and Delhi Gas Pipeline Co.	High. A number of FERC applications. Potential tight sand designation by FERC for 47-county area in Texas and parts of four parishes in Louisiana would spur interest. Travis Peak gas potential probably overlooked in many deeper Cotton Valley tests. Independents, small companies, and large companies are active in East Texas and North Louisiana.

OPERATING CONDITIONS

Physiography	*Climatic conditions*	*Accessibility*
Gently sloping Gulf Coastal Plain having 100 to 300 ft of local relief and absolute elevations less than 1,000 ft above sea level.	Subhumid to humid having 44 to 56 inches mean annual precipitation. Hot summers, mild winters. Possible heavy rain from remnant tropical storms.	No major terrain barriers. Heavy vegetation in some uncleared areas. Adequate drainage must be provided for some sites.

EXTRAPOLATION POTENTIAL

	Comments
Good. An areally extensive fan-delta system having marine-influenced fan-delta margins and overlying transgressive marine deposits. Good analogy to the Silurian "Clinton"-Medina sands of New York, Pennsylvania, and Ohio.	All drilling and completion services readily available in East Texas and North Louisiana.

COTTON VALLEY SANDSTONE, EAST TEXAS AND NORTH LOUISIANA BASINS

The Cotton Valley Sandstone, deposited in the East Texas and North Louisiana Basins, forms the upper part of the Cotton Valley Group of Late Jurassic age. Stratigraphic terminology varies across the area; for example, the term "Schuler Formation" is frequently used for the Cotton Valley Sandstone, primarily in Louisiana (fig. 26). A major area of gas production in the Cotton Valley Sandstone trends generally east to west across northern Louisiana into northeastern Texas. Gas was initially found during the 1940's in Louisiana in updip pinch-outs parallel to structural strike. Today, a productive area of 5,805 mi^2 exists across these two states (National Petroleum Council, 1980). Initial production was from very porous blanket sandstones, which were probably part of wave-dominated deltas (Collins, 1980; Coleman and Coleman, 1981). This suggests that strandplain, barrier-island, and tidal-bar sands may be among the specific facies making up reservoirs within the deltaic depositional system. These facies probably include the more readily correlated blanket coastal sandstones, referred to by Collins (1980), that yield gas in drill-stem tests and are already highly commercialized. Aided by massive hydraulic fracturing and by incentive pricing in Texas, a second trend of low-permeability sandstones has been developed into a major gas play.

This second potential area of interest for tight gas in Cotton Valley sandstones is generally downdip of the more permeable sandstone trend and extends well into Texas. It covers an area of about 14,800 mi^2, which includes a speculative, unevaluated region in the central and western parts of the East Texas Basin (fig. 33) (National Petroleum Council, 1980). The flanks of the Sabine Uplift in Texas and Louisiana (fig. 34) are considered prime targets of tight gas exploration in the Cotton Valley Sandstone, but the deeper part of the East Texas Basin is largely untested (Collins, 1980). The widespread low-permeability reservoirs in the Cotton Valley Sandstone show less continuity than do the updip facies and are probably distal to proximal delta-front deposits, possibly reworked during alternating regression and transgression of shifting delta margins. This has been established as the depositional system in the northwestern corner of the East Texas Basin by McGowen and Harris (in press); it might also be proposed as a first approximation of the depositional system in other areas that have not been studied in detail.

The data base on the Cotton Valley Sandstone is good (tables 34 through 37); information was obtained from applications for tight gas designation in Texas (Railroad Commission of Texas, 1980) and in Louisiana (Louisiana Office of Conservation, 1981). More data have been published recently about the subsurface Cotton Valley Sandstone than about most tight gas sands because of the extent of its commercialization, the development of fracture-treatment technology, and the additional operator interest generated by incentive pricing. Geologic studies (Sonnenberg, 1976; Frank, 1978; Collins, 1980; Coleman and Coleman, 1981; McGowen and Harris, in press) and engineering studies (Jennings and Sprawls, 1977; Bostic and Graham, 1979; Tindell and others, 1981; Meehan and Pennington, 1982) have been done recently, but a detailed basinwide study using modern concepts of defining hydrocarbon reservoirs as genetic stratigraphic units has not been published.

Structure

Kehle (1971) and Wood and Walper (1974) suggested that the interior salt basins of East Texas and North Louisiana were part of a series of marginal grabens formed by continental rifting and the opening of the Gulf of Mexico. These basins are bounded by major systems of down-to-the-basin faulting: the Mexia-Talco fault zone (fig. 34) and the South Arkansas fault zone (northeast of area shown in fig. 34). Much of the Cotton Valley gas exploration in the East Texas Basin has been near the Sabine Uplift, where the top of the Cotton Valley Group is encountered at 9,500 ft or deeper (fig. 35). Another relatively positive feature, the Monroe Uplift, is located in northeastern Louisiana (northeast of area shown in fig. 34) and forms part of the eastern boundary of the North Louisiana Basin in Morehouse, West Carroll, and East Carroll Parishes (fig. 35). Jurassic evaporites in East Texas and North Louisiana (Werner Anhydrite and Louann Salt) indicate early deposition in a restricted basin; limestone deposition (Smackover and Gilmer Limestones, fig. 26) indicates that more open marine conditions later occurred. The major influx of terrigenous clastic sediments, which formed the Cotton Valley Sandstone and the Travis Peak Formation, resulted from tilting of the rift margin toward the basin; before that influx, crustal blocks may have been tilted away from the incipient rift (several authors summarized by McGowen and Harris, in press).

A major area of influx of the Cotton Valley clastic sediments is inferred to be a deltaic depocenter in northeastern Louisiana; subsequent shore-parallel sediment transport was to the west (Thomas and Mann, 1966). Some researchers have suggested that this transport system resulted in deposition of the Terryville massive sandstone complex (equivalent to part of the Cotton Valley Sandstone) (Thomas and Mann, 1966); others have inferred additional points of deltaic input (Coleman and Coleman, 1981). Dip-oriented trends of high sand percent indicate that sediment sources existed in the northwestern part of the East Texas Basin during Cotton Valley time (McGowen and Harris, in press).

Salt tectonics played an important role in the structural history of the East Texas and North Louisiana Basins because salt structures grew actively from Jurassic to Tertiary time (Coleman and Coleman, 1981). Salt was mobilized in response to sediment loading, and in turn, salt structures influenced subsequent sedimentation. Complex fault patterns are often found surrounding salt structures, especially piercement domes.

Stratigraphy

In the terminology typically applied to East Texas, the name "Cotton Valley" describes a group as well as a limestone and a sandstone within that group (fig. 26). The terms "Haynesville" and "Schuler" are more frequently applied to northern Louisiana. The Schuler Formation, considered to be the updip equivalent of the entire Cotton Valley Group in Louisiana, includes red sandstone and shale and is locally conglomeratic (Thomas and Mann, 1966). In Louisiana, the Knowles Limestone, an argillaceous limestone alternating with thin shales, forms the uppermost unit of the Cotton Valley Group (Thomas and Mann, 1966); this unit is present in parts of Texas. The Terryville Sandstone in Louisiana is equivalent, in part, to the Cotton Valley Sandstone in Texas. The Terryville and Cotton Valley Sandstones in Louisiana are frequently referred to by an informal nomenclature that varies locally.

Depositional Systems

The Terryville Sandstone was deposited in northern Louisiana as a complex of wave-dominated deltas having interdeltaic barrier-island and offshore-bar sequences (Thomas and Mann, 1966; Sonnenberg, 1976; Coleman and Coleman, 1981). Thin wedges of transgressive blanket sands were deposited landward of the barrier facies contemporaneous with deltaic subsidence and were interspersed with lagoonal shale. Coleman and Coleman (1981) placed major deltaic depocenters in northeastern Louisiana and in the area of the Texas-Louisiana border. Detailed study would no doubt reveal additional sources of sediment, possibly small deltas such as are now found on the Texas coast, prograding into lagoons and bays.

Detailed studies of individual fields have been conducted and specific genetic facies have been identified, such as lower to upper barrier-island shoreface of the Davis and "B" sandstones (informal terminology) in Frierson Field, Louisiana. These units have an average permeability of 0.2 md, which would be even less under in situ conditions. Cementation by quartz and calcite in the Davis and incorporation of lime-mud matrix in the "B" sandstone contribute to the low permeability (Sonnenberg, 1976). In general, barrier-island shoreface, offshore bar, and possibly delta front are the major depositional environments of the updip Cotton Valley Sandstone in northern Louisiana.

In the East Texas and the North Louisiana Basins, these same genetic facies probably also form major reservoirs and potential reservoirs. Highly generalized regional cross sections indicate extensive basinwide accumulation of sand in the Cotton Valley Sandstone (figs. 36 through 39). Many individual sands show blocky log character, some having a thin, upward-coarsening base, in the downdip part of the north-south section and the eastern part of the east-west section. Such log character is expected of offshore-bar and barrier-island shoreface to foreshore sequences, although it is not unique to these facies. Massive sands at the western end of the section shown in figure 37 and the northern end of the section shown in figure 38 may be a braided fluvial facies, which is characteristic of a system supplying deltaic and barrier systems.

Prodelta, delta-front, and braided-stream facies have been identified in the Cotton Valley Group in the northwestern part of the East Texas Basin (McGowen and Harris, in press). The prodelta facies contains minor amounts of very fine grained sandstone and siltstone. The delta-front deposits typically consist of interbedded sandstone and mudstone having a few thin beds of sandy limestone. In the updip part of the study area of McGowen and Harris (in press), delta-front deposits are overlain by a thick wedge of braided-stream sediments; these sediments form part of the fan-delta system that deposited most of the terrigenous clastic sediments of the Cotton Valley Group.

A percent-sand map of the Cotton Valley Sandstone along the northwestern margin of the basin shows dip-oriented trends of high sand content, indicating fluvial axes (fig. 40). A net-sand map of this same area illustrates downdip, strike-parallel net-sand thicks that are coincident with an older carbonate shelf edge (fig. 41) (McGowen and Harris, in press). This strike-parallel pattern, when compared to the distribution of marginal marine barrier and bar facies of northern Louisiana, suggests that the depositional environments of the East Texas and North Louisiana Basins may be similar. Individual sand bodies of good lateral continuity are more likely to form in these marginal marine environments.

Hydraulic Fracturing and Other Technology

Many of the technological innovations in hydraulic fracturing now being used were developed or improved since 1972 during the completion of Cotton Valley tight gas reservoirs (Jennings and Sprawls, 1977). Techniques to avoid killing wells with brine, to treat individual pay zones, to improve cleanup by using carbon dioxide, and to help recover the fracturing fluid are among the methods now used in Cotton Valley and many other tight gas well completions. Treatments vary in volume, fluid type, and injection rate. Comparison of fracture treatments used before 1975 (Jennings and Sprawls, 1977) with those used as recently as 1980 (Tindell and others, 1981) shows that the volume of fluids used in well treatments has increased from generally less than 120,000 gal to 300,000 to 400,000 gal. Similarly, proppant quantities have increased from generally less than 75,000 lb to as much as 600,000 to 800,000 lb. More data on well treatments are probably available for the Cotton Valley Group than for any other unit; therefore, the Cotton Valley forms an excellent basis of comparison for the aggressive fracture treatment techniques being tried in other areas.

Specialized studies of log interpretation (Frank, 1978), pressure testing (Bostic and Graham, 1979), and numerical simulation of reservoirs (Meehan and Pennington, 1982) have been published. However, all geologic and engineering problems encountered in Cotton Valley tight gas production have not been solved. Consequently, studies of the Cotton Valley Sandstone will probably be a continuing source of information on technological innovations applicable to other low-permeability gas sands.

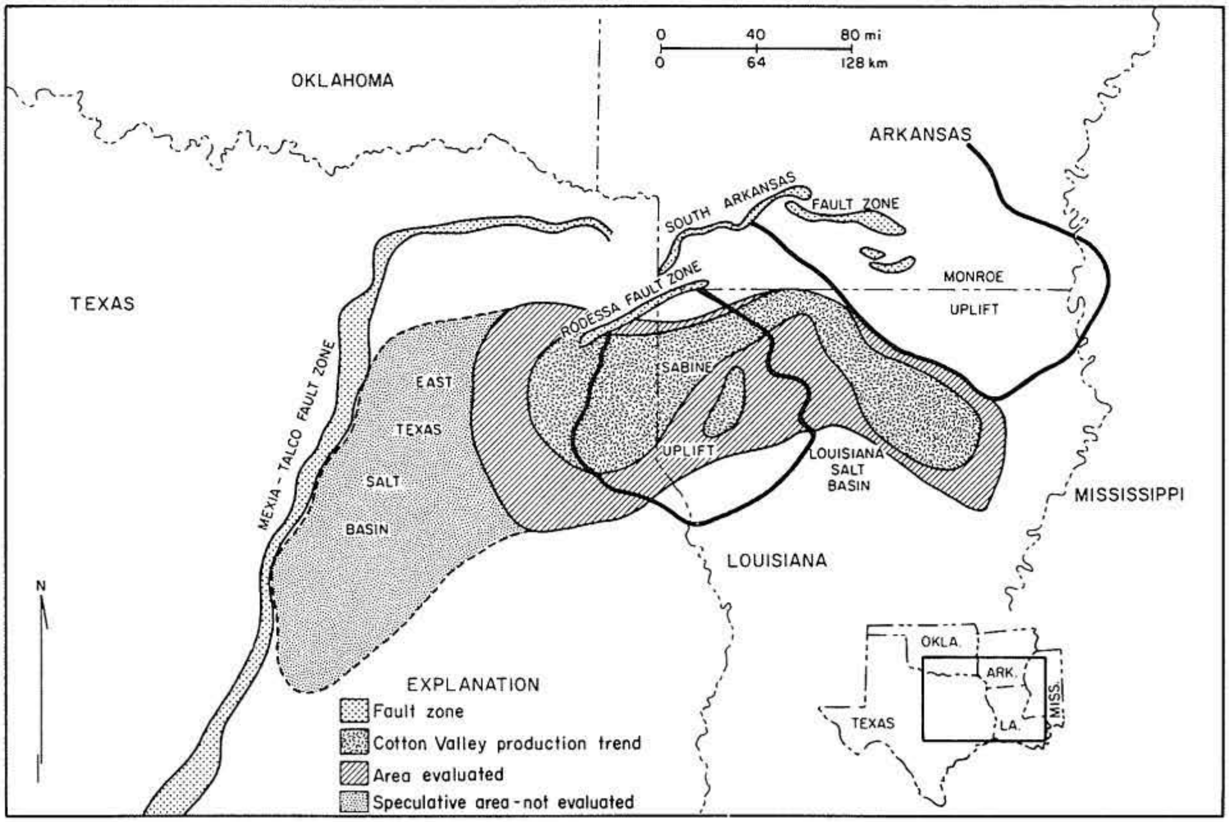


FIGURE 33. Production trends of the Cotton Valley Sandstone evaluated by the National Petroleum Council (1980).

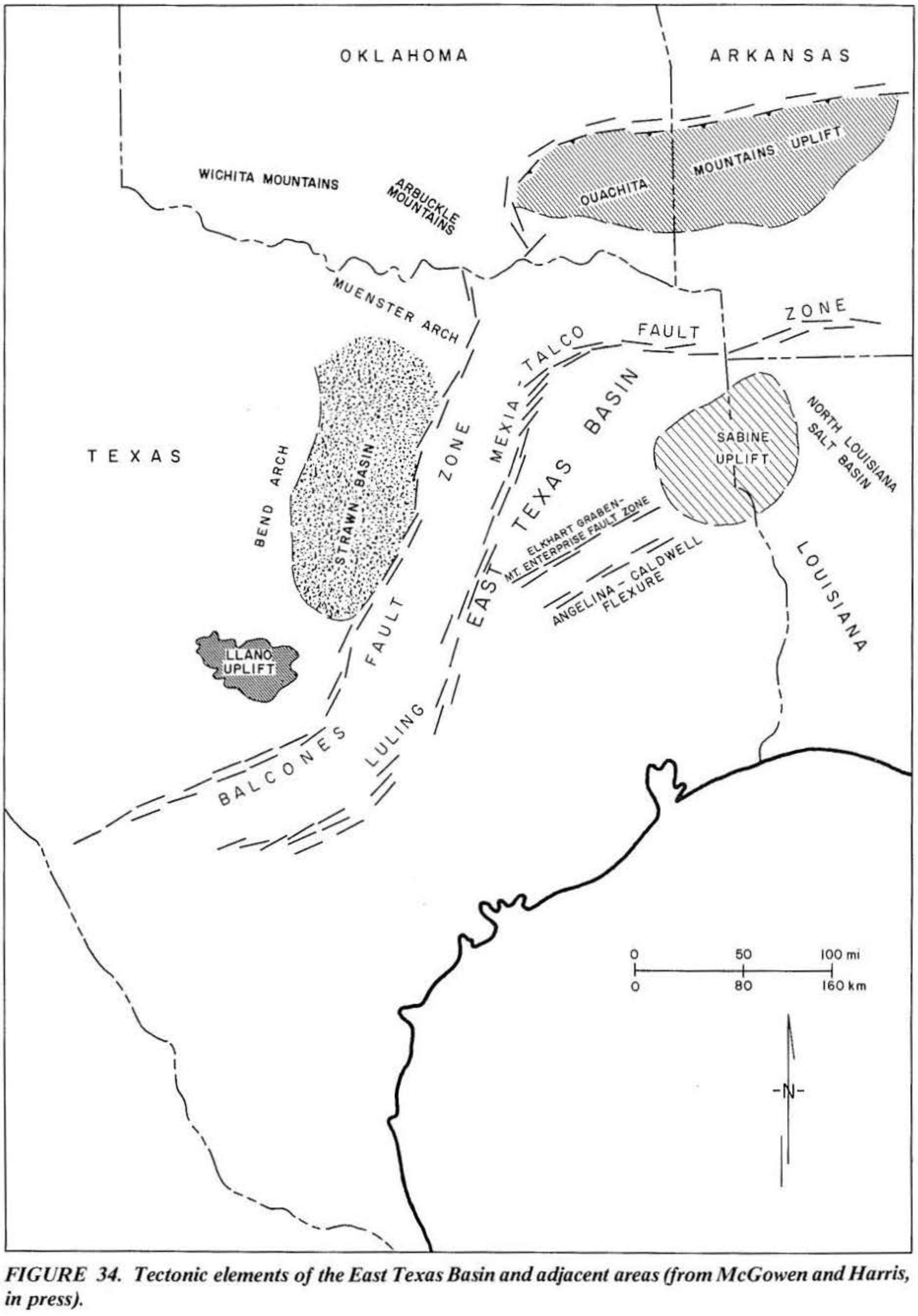


FIGURE 34. Tectonic elements of the East Texas Basin and adjacent areas (from McGowen and Harris, in press).

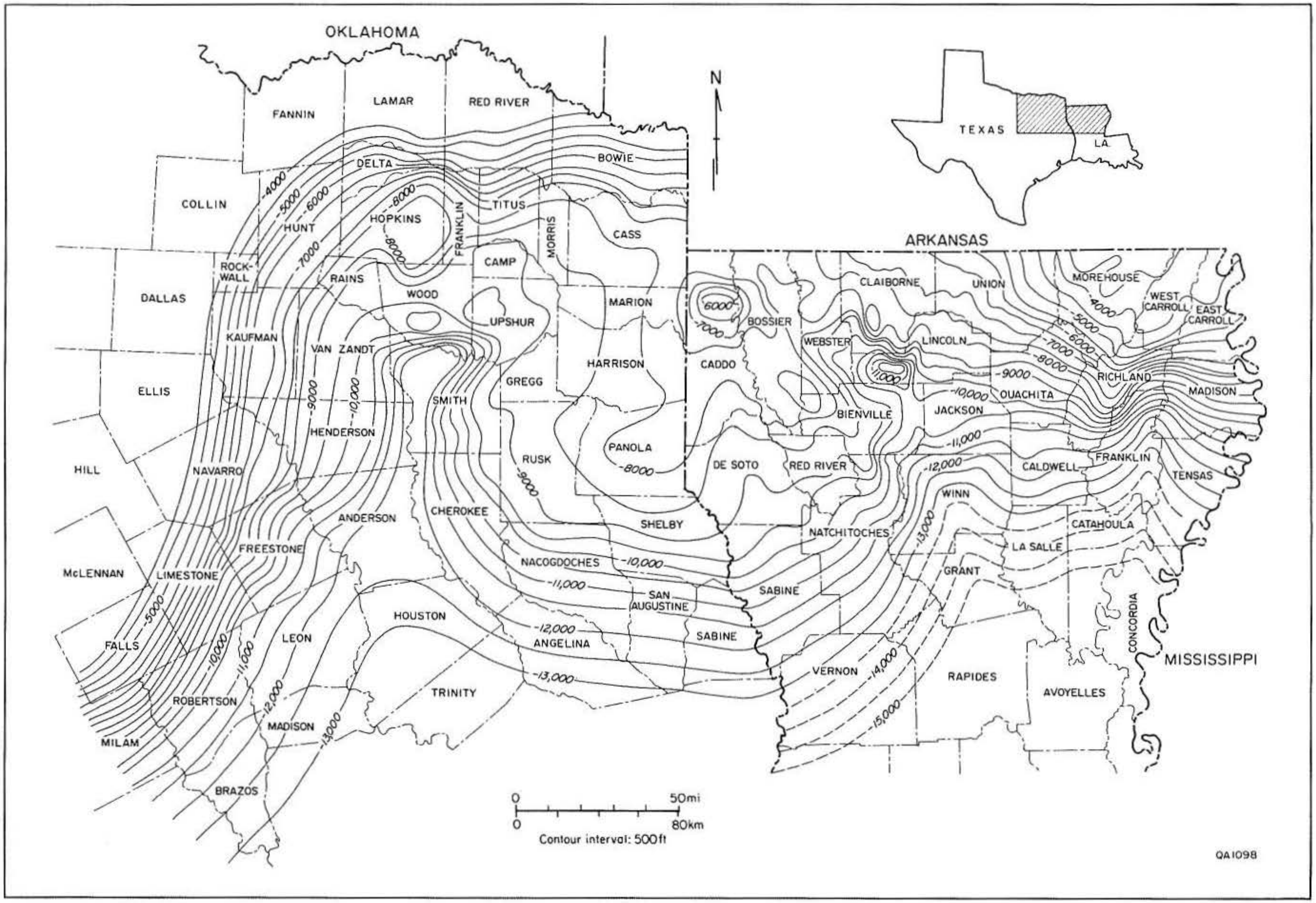


FIGURE 35. Generalized structure contours on top of the Cotton Valley Sandstone in the East Texas Basin (after Railroad Commission of Texas, 1980) and the North Louisiana Basin (after Louisiana Office of Conservation, 1981).

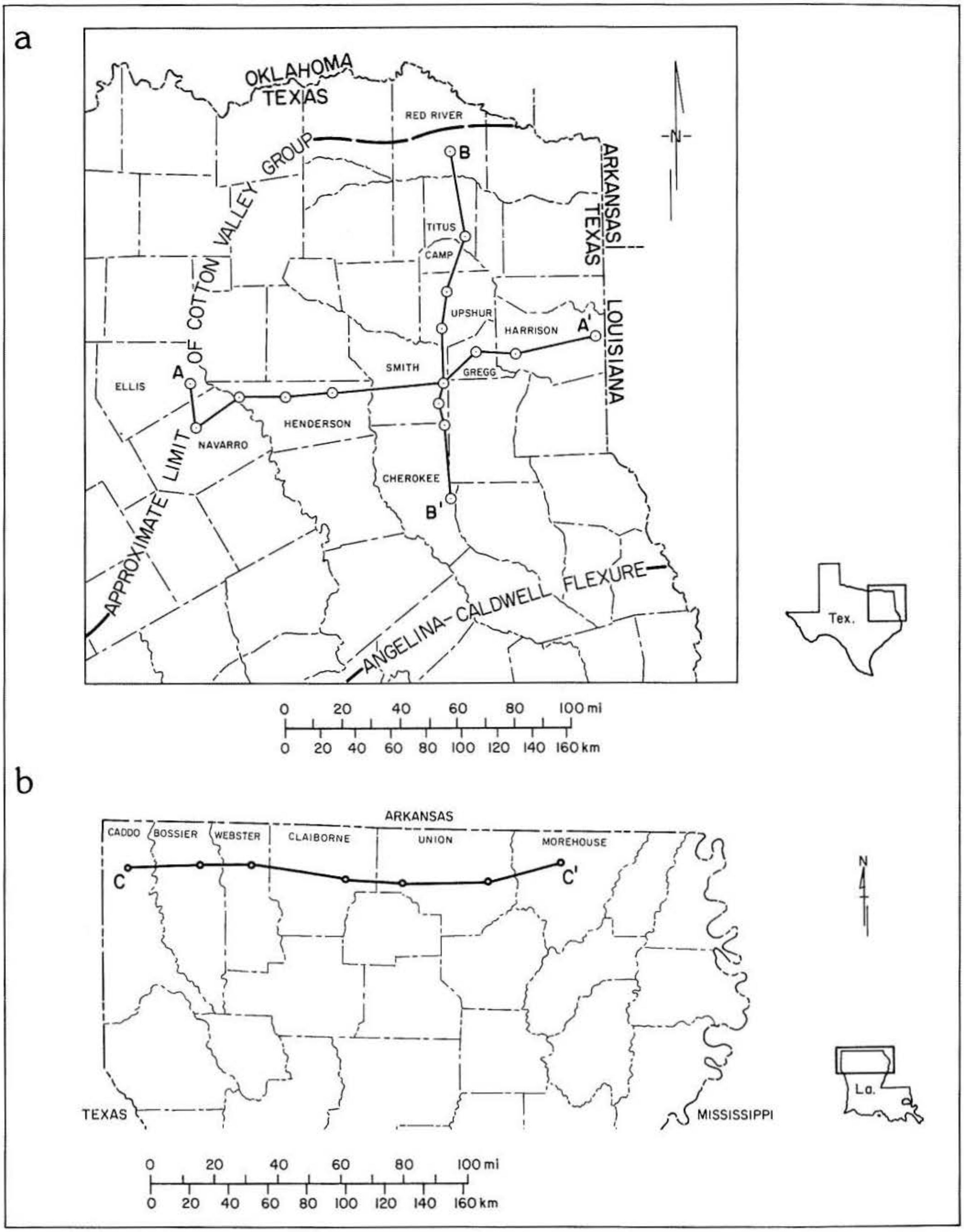


FIGURE 36. Index maps of cross sections through the Cotton Valley Sandstone in (a) the East Texas Basin and (b) the North Louisiana Basin. Cross section A-A' shown in figure 37, B-B' in figure 38, and C-C' in figure 39.

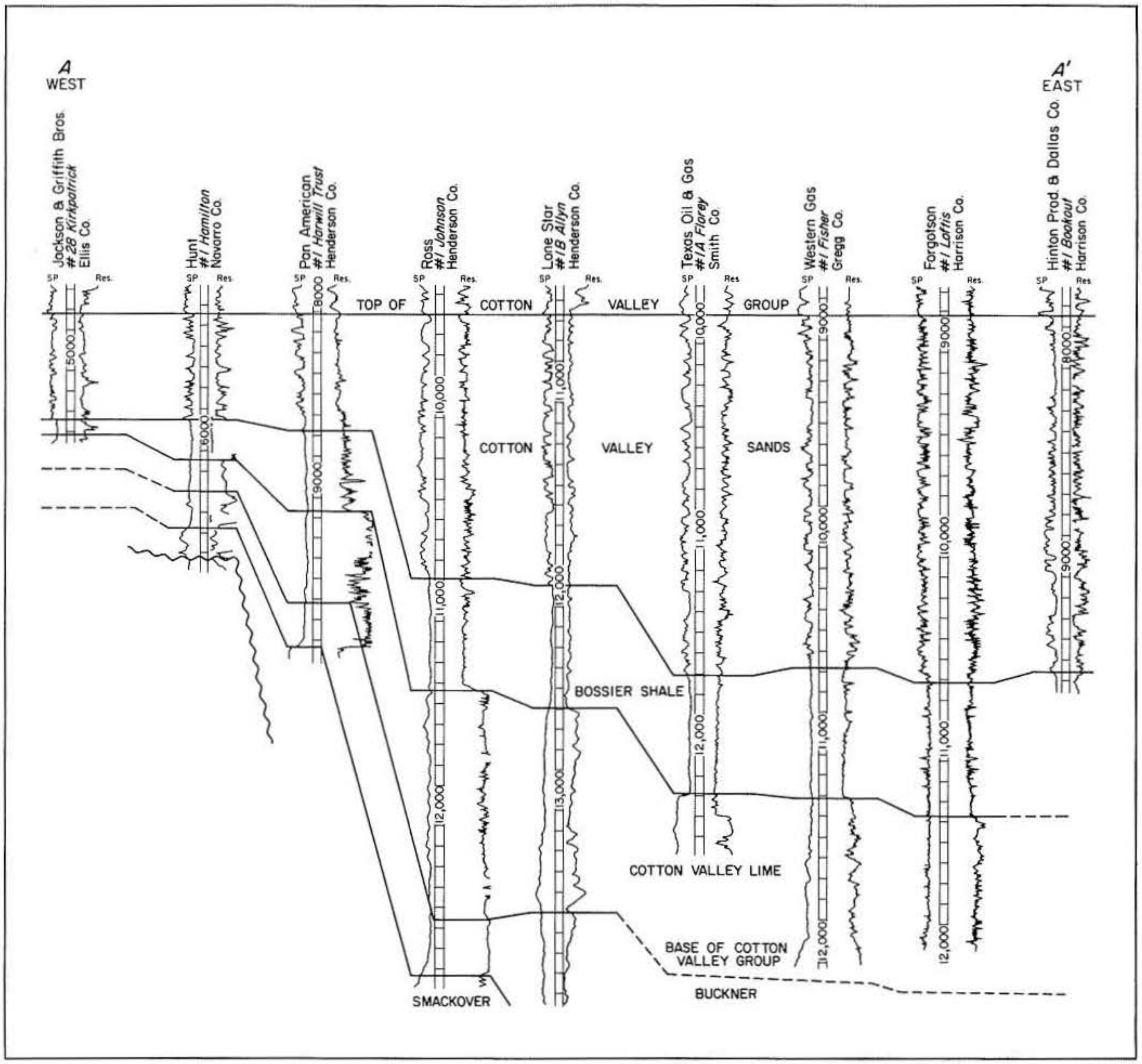


FIGURE 37. East-west stratigraphic cross section A-A' through the Cotton Valley Sandstone and underlying units, East Texas Basin (from Railroad Commission of Texas, 1980). Line of section shown in figure 36.

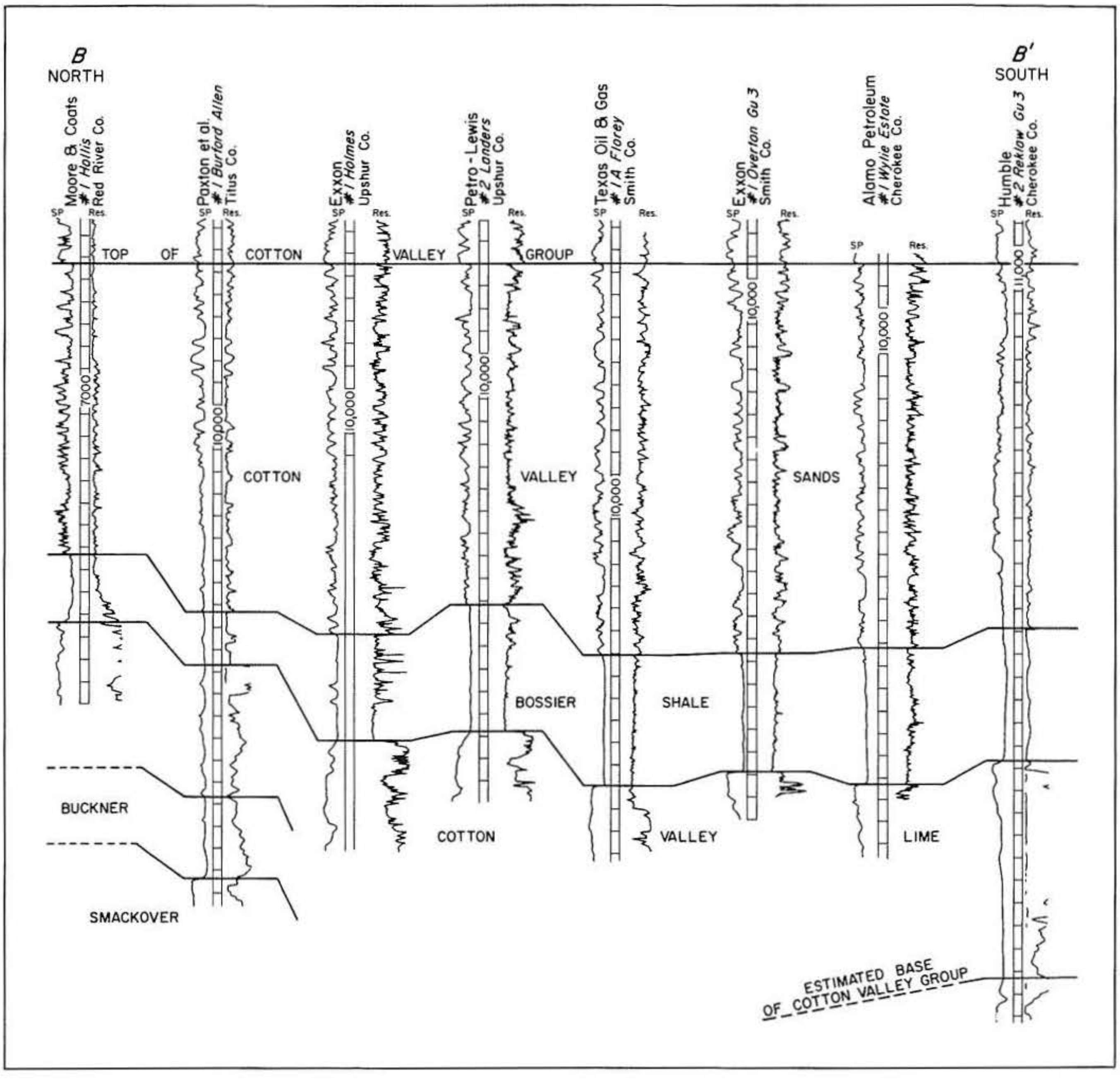


FIGURE 38. North-south stratigraphic cross section B-B' through the Cotton Valley Sandstone and underlying units, East Texas Basin (from Railroad Commission of Texas, 1980). Line of section shown in figure 36.

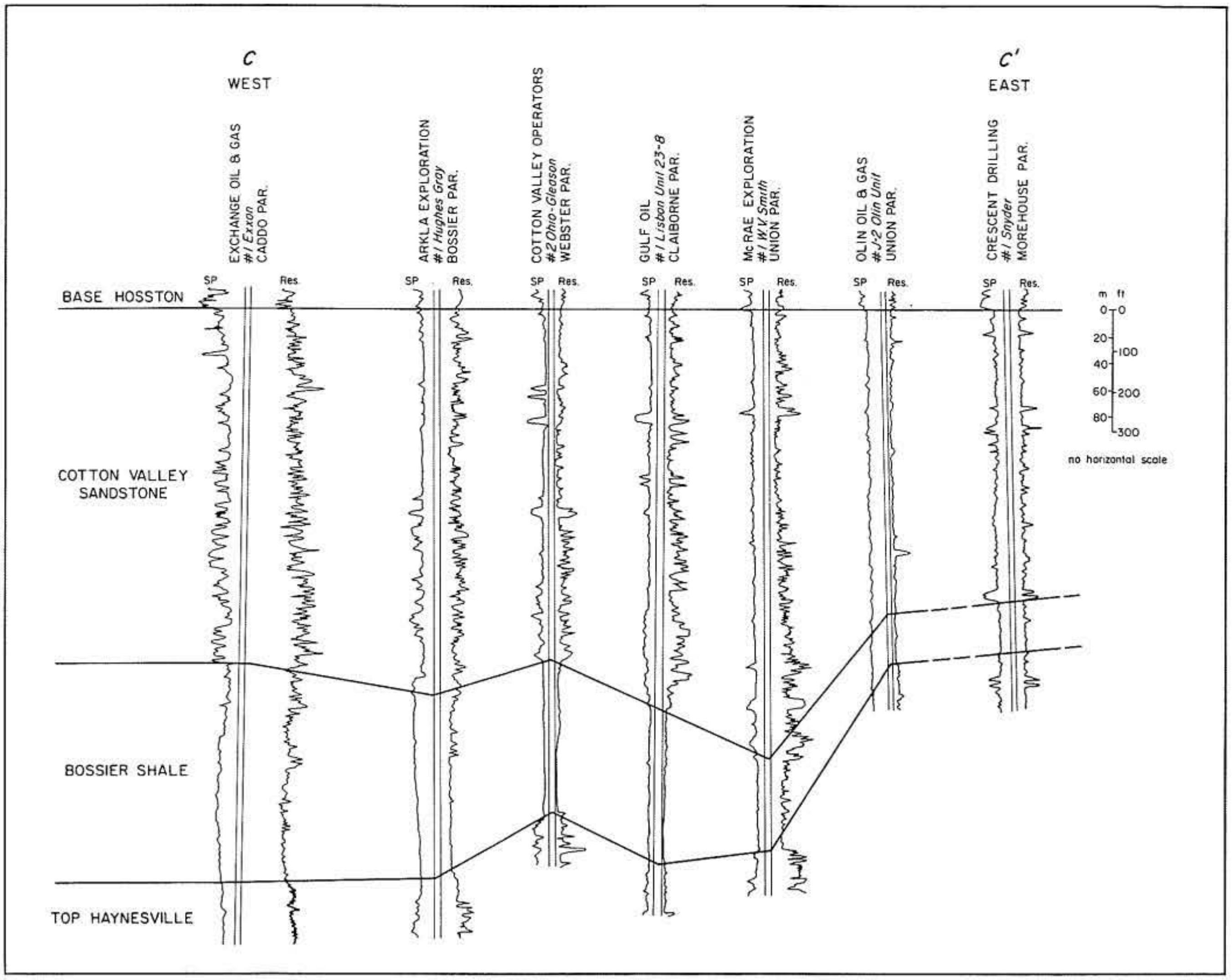


FIGURE 39. East-west stratigraphic cross section C-C' through the Cotton Valley Sandstone and underlying units, North Louisiana Basin (from Louisiana Office of Conservation, 1981). Line of section shown in figure 36.

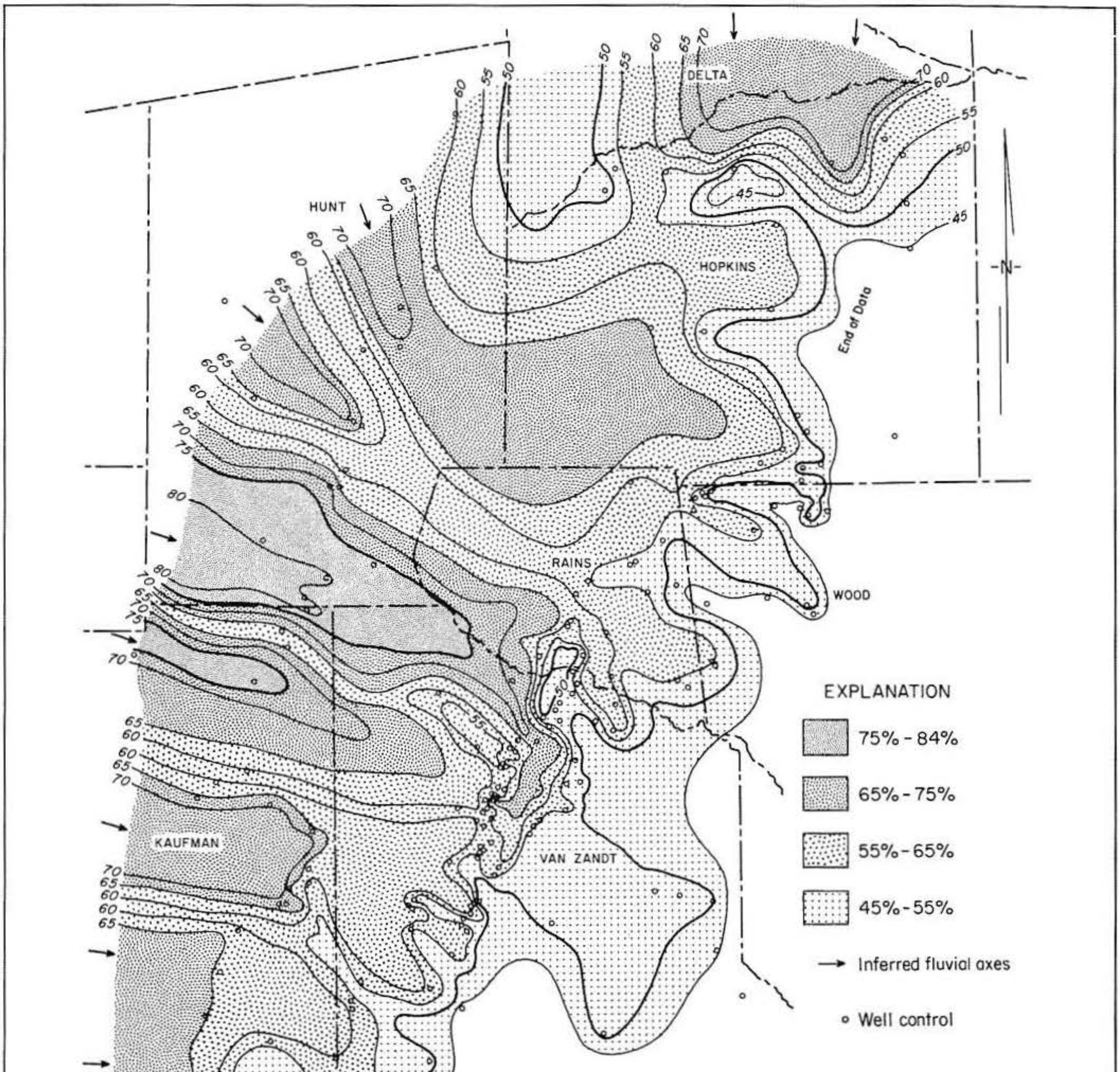


FIGURE 40. Percent-sand map of the Cotton Valley Sandstone, northwestern part of the East Texas Basin (from McGowen and Harris, in press).

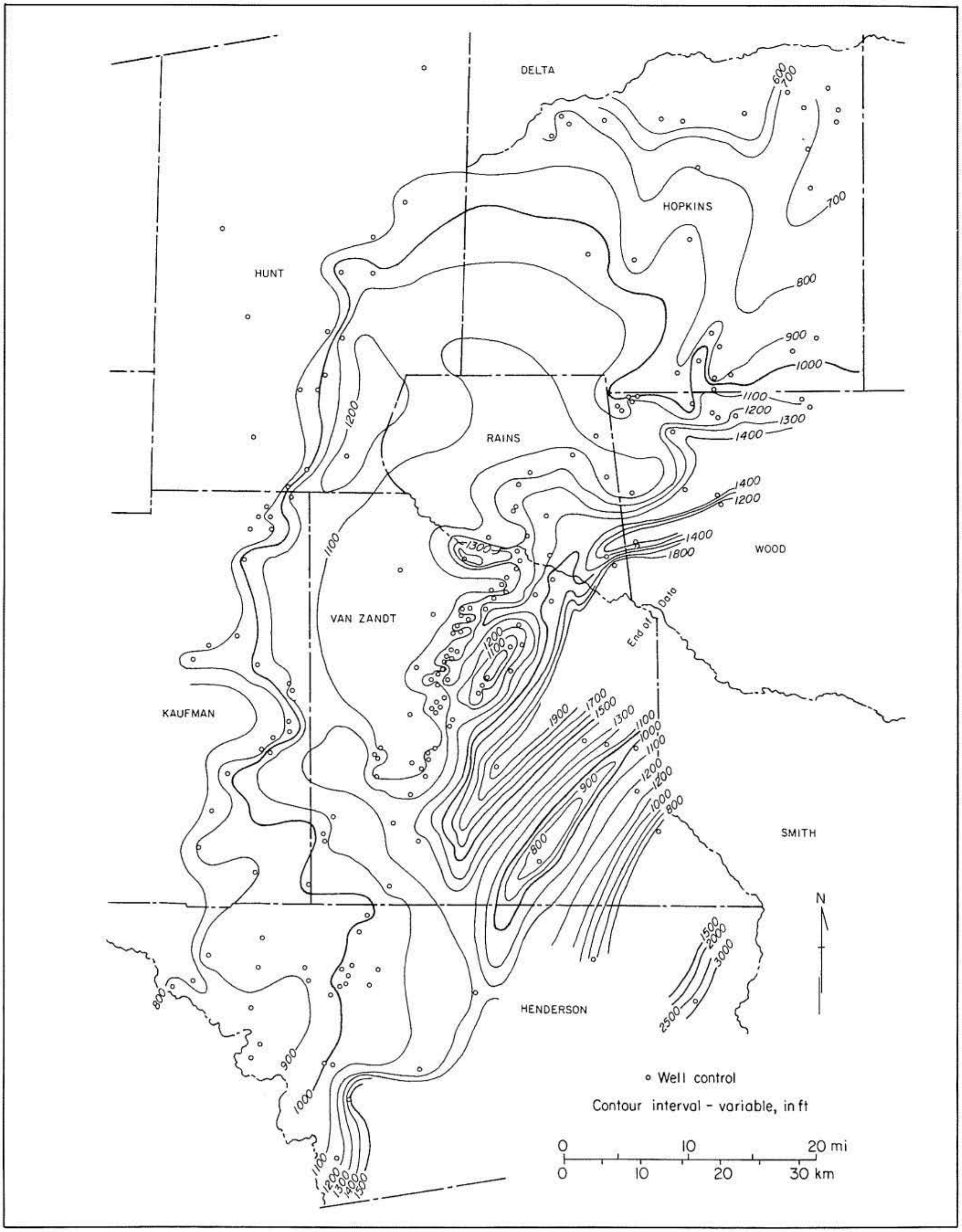


FIGURE 41. Net-sand map of the Cotton Valley Sandstone, northwestern part of the East Texas Basin (from McGowen and Harris, in press).

TABLE 34. Cotton Valley Sandstone, East Texas and North Louisiana Basins: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Cotton Valley Sandstone, Cotton Valley Group, Upper Jurassic.	Productive area of 5,805 mi² and speculative area of 7,460 mi² are in Texas and Louisiana (National Petroleum Council, 1980).	Sands in the low-permeability trend are within an interval 1,000 to 1,400 ft thick.	Average drilling depths to the top of the Cotton Valley Sandstone are 7,000 ft in the north, 8,000 ft in the east, 10,000 to 11,000 ft in the south, and 5,000 ft in the western parts of the East Texas Basin. Top of Cotton Valley Sandstone ranges from -4,000 ft subsea on the northern and western margins of the basin to -7,500 ft over the Sabine Uplift to -13,000 ft on the southern basin margin.	Maximum recoverable gas is 12.816 Tcf in net productive area of 1,026 mi² in Texas and Louisiana (National Petroleum Council, 1980).	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
In graben or structural sag formed along the margin of the Gulf of Mexico by continental rifting. East Texas Basin now bounded by major fault systems and the Sabine Uplift. The Cotton Valley Sandstone thins over the ancestral Sabine Uplift in Harrison and Panola Counties, Texas.	1.4° to 1.8° F/100 ft, mostly 1.6° to 1.8° F/100 ft. National Petroleum Council (1980) indicated 250° F at 9,000 ft.	No specific regional data. National Petroleum Council (1980) indicated 5,500 psi at 9,000 ft.	Tensional; local stress variations caused by salt tectonics.

TABLE 35. Cotton Valley Sandstone, East Texas and North Louisiana Basins: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Derived from prograding fan deltas having associated braided-stream, delta-front, and prodelta environments. Source areas are toward the western, northwestern, and northern margins of the East Texas Basin. Dip-oriented percent-sand patterns exist in Hopkins, Hunt, and eastern Kaufman Counties, Texas, changing to strike-aligned patterns (reworked marginal marine facies) in western Wood, Rains, Van Zandt, and north-central Henderson Counties, Texas. Cotton Valley Sandstone in the adjacent North Louisiana Basin includes coastal barrier sands and marine bar sands likely derived from sources to the east. The latter form conventional Cotton Valley gas reservoirs; however, a broad tongue of low-permeability sandstone extends from north-central Louisiana into De Soto and Caddo Parishes, Louisiana, and into Harrison, Rusk, and Panola Counties, Texas.	Fine-grained to very fine grained sandstone having minor mud matrix. One sample reported as tightly packed and moderately well sorted.	One core analysis reported 71% quartz, 12% clay, 5% chert, 5% dolomite (euhedral cement), 4% feldspar (mostly plagioclase), and limonite and opaques. In general, the sandstone is quartzarenite to subarkose.	One core analysis reported, in order of formation, quartz overgrowths, dolomite, and clay (mostly chlorite). In Louisiana, calcite cements also reported, and calcite also likely in most Texas areas. Pressure solution in quartz sand.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Gross production intervals range as high as 600 to 800 ft.	Amoco: Pressure is 5,500 psi at 270° F. Kuuskraa and others (1981): Pressure is 6,000 psi at 250° F.	Contribution of natural fractures is unknown; some zones are reported to be naturally fractured. Fluid-loss treatment materials are required in some wells.	Exxon has core from Cotton Valley and Bossier sands from 10 wells in Panola and Rusk Counties, Texas. In Louisiana, approximately 10% of wells penetrating the Cotton Valley Group core some part of the group, and 72 core analyses have been identified.

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TABLE 36. Cotton Valley Sandstone, East Texas and North Louisiana Basins: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir parameters	*Net pay thickness*	*Production rates* — *Pre-stimulation*	*Production rates* — *Post-stimulation*	*Production rates* — *Decline rates*	*Formation fluids*	*Water saturation*
Mean permeability is 0.042 md for 126 wells primarily in Harrison, Rusk, and Panola Counties, Texas. Overall, in situ permeabilities of 0.0053 to 0.042 are expected, depending on method of calculation. Average permeability for 302 wells in Louisiana is 0.015 md. Porosity is typically 6% to 10%, locally up to 18%.	Kuuskraa and others (1981) reported 35 to 88 ft, ranging down to 20 ft at the margins of the trend. Another estimate is 100 ft in Carthage and East Bethany Fields.	Average was 289 Mcfd for 126 wells (primarily in Harrison, Panola, and Rusk Counties, Texas) at an average depth of 10,187 ft. In some wells in Texas and Louisiana, TSTM.	500 to 1,500 Mcfd, some up to 2,500 Mcfd.	Rapid decline in first 12 to 24 mo; no specific data obtained on the trend as a whole. In Oak Hill Field, Rusk County, Texas, production decline averaged 46% for 27 wells from 1 to 6 mo after fracturing.	Typically, no oil is produced from tight Cotton Valley sands. Some condensate produced initially at 20 to 40 bpd. Initial water production possible up to 200 bpd, declining to 50 bpd after 1 to 2 yr. Some formation waters contain 500 to 1,000 ppm iron, requiring special fracture fluids to avoid formation damage by iron oxide precipitates.	Typically from less than 45% to 65%; may be difficult to determine using conventional log analysis.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Massive hydraulic fracturing, often as multistage treatments, to effectively treat all zones of interest. Techniques vary widely among operators; typical may be 500,000 lb sand in 200,000 to 300,000 gal fluid injected in three to four stages. Some jobs are much larger, using 2.0 to 2.6 million lb sand.	Typically 2 to 10 times improvement in production, depending on original permeability and formation damage.	640 acres. Some operators believe spacing as low as 80 acres ultimately will be required for drainage.	Fracture treatments intersecting zones of salt water have led to production problems. Gas-water contacts are difficult to determine. Ultimate well yields of 2 to 4 Bcf are possible.

TABLE 37. *Cotton Valley Sandstone, East Texas and North Louisiana Basins: Economic factors, operating conditions, and extrapolation potential.*

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by FERC for a 48-county area of East Texas on October 24, 1980. All or part of 28 parishes in Louisiana were approved by State (less certain existing fields) on September 3, 1981.	More than 930 gas wells completed in the Cotton Valley Group in Texas. More than 886 gas wells completed in the Cotton Valley Group in Louisiana.	9.8% new field wildcats and 48.4% new pool and deeper production wells, 1960-1977 in Texas (National Petroleum Council, 1980). 8.3% new field wildcats and 31.7% new pool and deeper production wells, 1960-1977 in Louisiana (National Petroleum Council, 1980).	Typical Cotton Valley well approximately 10,000 ft deep will cost $1.2 million (1981 dollars) to drill and complete, depending on number of pay zones and fracture treatment used.	Well-established regional pipeline and gathering system including Arkansas Louisiana Gas Co., Lone Star Gas Co., and Delhi Gas Pipeline Co.	High, having incentive pricing approved in Texas and pending in Louisiana and having developing fracture treatment technology.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
Gently sloping Gulf Coastal Plain having 100 to 300 ft of local relief and absolute elevations less than 1,000 ft above sea level.	Subhumid to humid having 44 to 56 inches mean annual precipitation. Hot summers, mild winters. Possible heavy rain from remnant tropical storms.	No major terrain barriers. Heavy vegetation in some uncleared areas. Adequate drainage must be provided for some sites.	Good. A thick and widespread formation having fluvial, deltaic, interdeltaic, and shallow marine components, individually analogous to other vertically and areally more restricted formations. As a major progradational sediment package, the Travis Peak, Frontier Formation, and "Clinton"-Medina sandstone have selected comparable attributes.	All drilling and completion services readily available in East Texas and North Louisiana.

CLEVELAND FORMATION, ANADARKO BASIN

The Cleveland Formation is a fine-grained sandstone of Pennsylvanian age that was deposited on the northern shelf of the Anadarko Basin (fig. 42). It is found in the subsurface of the northeast Texas Panhandle and extends into northwestern Oklahoma and the Oklahoma Panhandle. No published studies specifically concerned with the Cleveland Formation were located. The area in which the formation is found is a mixed gas and oil to somewhat gas-prone province having many conventional reservoirs in Pennsylvanian and older Paleozoic rocks. The Cleveland Formation produces oil in some areas but rates of production are low, probably reflecting poor reservoir quality. The data base on the Cleveland Formation is fair to good (tables 38 through 41).

Structure

As early as Middle Devonian time, the Amarillo-Wichita Uplift was a relatively positive feature; significant uplift occurred during the Late Mississippian through Early Pennsylvanian (Eddleman, 1961). After the late Morrowan Wichita orogeny, large quantities of arkosic sediment (granite wash) were deposited along the rapidly subsiding axis of the Anadarko Basin adjacent to the Amarillo-Wichita Uplift. A broad, stable platform north and northwest of the basin axis received carbonates, thin shales, and fine sands (Eddleman, 1961), including the Cleveland Formation. It is thought that the clastic sources of the Cleveland Formation were to the west, north, and east of this platform (Railroad Commission of Texas, 1981d).

Eastward tilting during Late Cretaceous time was the most recent major event affecting the Anadarko Basin (Eddleman, 1961). The present structure of the Cleveland Formation north of the Amarillo Uplift dips to the east and southeast; the top of the formation is less than 10,000 ft below the surface everywhere in the northeast Texas Panhandle (fig. 43).

Stratigraphy

The Cleveland Formation is most often classified as basal Missourian and has variously been considered part of either the Pleasanton Group (Nicholson and others, 1955; Cunningham, 1961) or the Kansas City Group (Railroad Commission of Texas, 1981d). A recent publication (Taylor and others, 1977) seems to have dispensed with the group terminology and used "Kansas City" as a formation name. Sediments of the Kansas City and Marmaton Groups above and below the Cleveland are considered undifferentiated.

The Cleveland Formation thickens across the northeast Texas Panhandle as it extends into the deeper central part of the Anadarko Basin. Interval thickness ranges from 78 to 170 ft. In the same area, the Cleveland Formation becomes more shaly as it grades into granite wash off the north flank of the Amarillo-Wichita Uplift (figs. 44 through 46). The maximum formation thickness is 160 ft in the Shenandoah Oil Corp. No. 1 Grubbs well (fig. 45); however, net pay in the Cleveland Formation generally varies from 10 to 40 ft, having an estimated maximum of 75 ft (M. K. Moshell, personal communication, 1982).

The most recent studies of the northeast Texas Panhandle (S. P. Dutton, personal communication, 1982) have suggested that the Cleveland Formation is uppermost Desmoinesian. Sample logs, paleontologic data, and geophysical well logs support this classification; the exact group designation is not significant to this study but helps to clarify the discussion of depositional systems that follows.

Depositional Systems

One study has suggested that the Cleveland Formation was deposited in a shelf environment (Railroad Commission of Texas, 1981d). This conclusion appears to be based primarily on the position of the Cleveland Formation in the Anadarko Basin. Detailed study of the unit itself, however, indicates that the Cleveland is bounded by shales or limestones and was deposited north and northeast of the fan-delta and alluvial fan systems on the margins of the Amarillo-Wichita Uplift (figs. 47 and 48). Consequently, it appears that although sediments were deposited on a structural shelf, they were not necessarily distributed only by shelf processes. Being a distal tongue of terrigenous clastic sediments surrounded by carbonates and thin shales, the Cleveland Formation may be part of a thin distal to proximal delta-front sedimentary package.

Generally, the character of spontaneous potential (SP) logs in the Cleveland Formation is poorly developed, possibly owing to the unit's high level of cementation and low permeability. The SP logs that are of good character frequently show an upward-coarsening sequence followed by an upward-fining sequence. This cycle may consist of prodelta to delta-front environments followed by transgression and reworking by waves and currents. Thin distributary-channel or distributary-mouth-bar deposits may be present (S. P. Dutton, personal communication, 1982). The Cleveland Formation is therefore thought to be a thin deltaic unit overlain by a thicker package of prodelta sediment that was distributed by shelf processes.

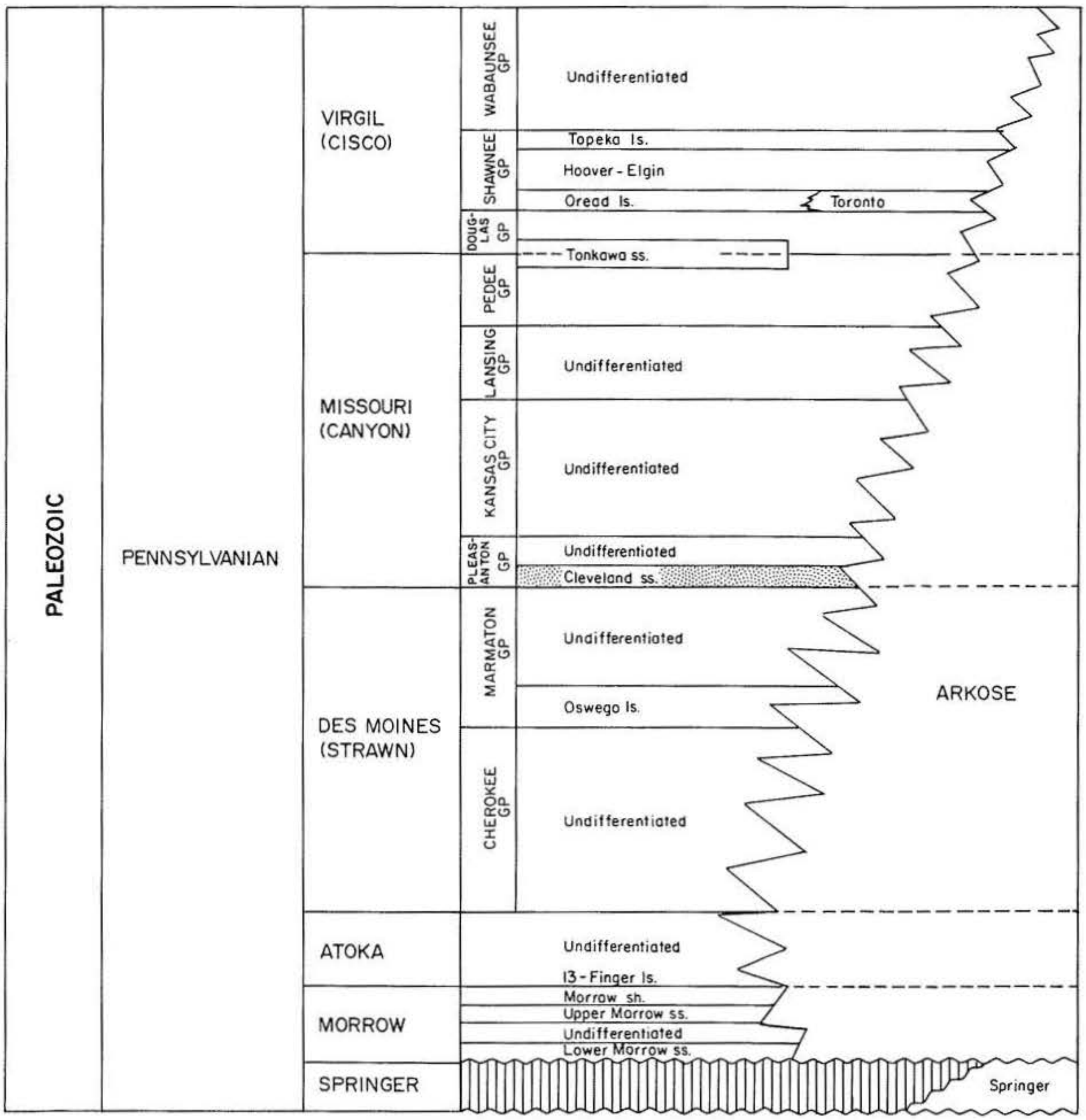

FIGURE 42. Stratigraphic column of the Pennsylvanian System in the Anadarko Basin, Texas (from Nicholson and others, 1955).

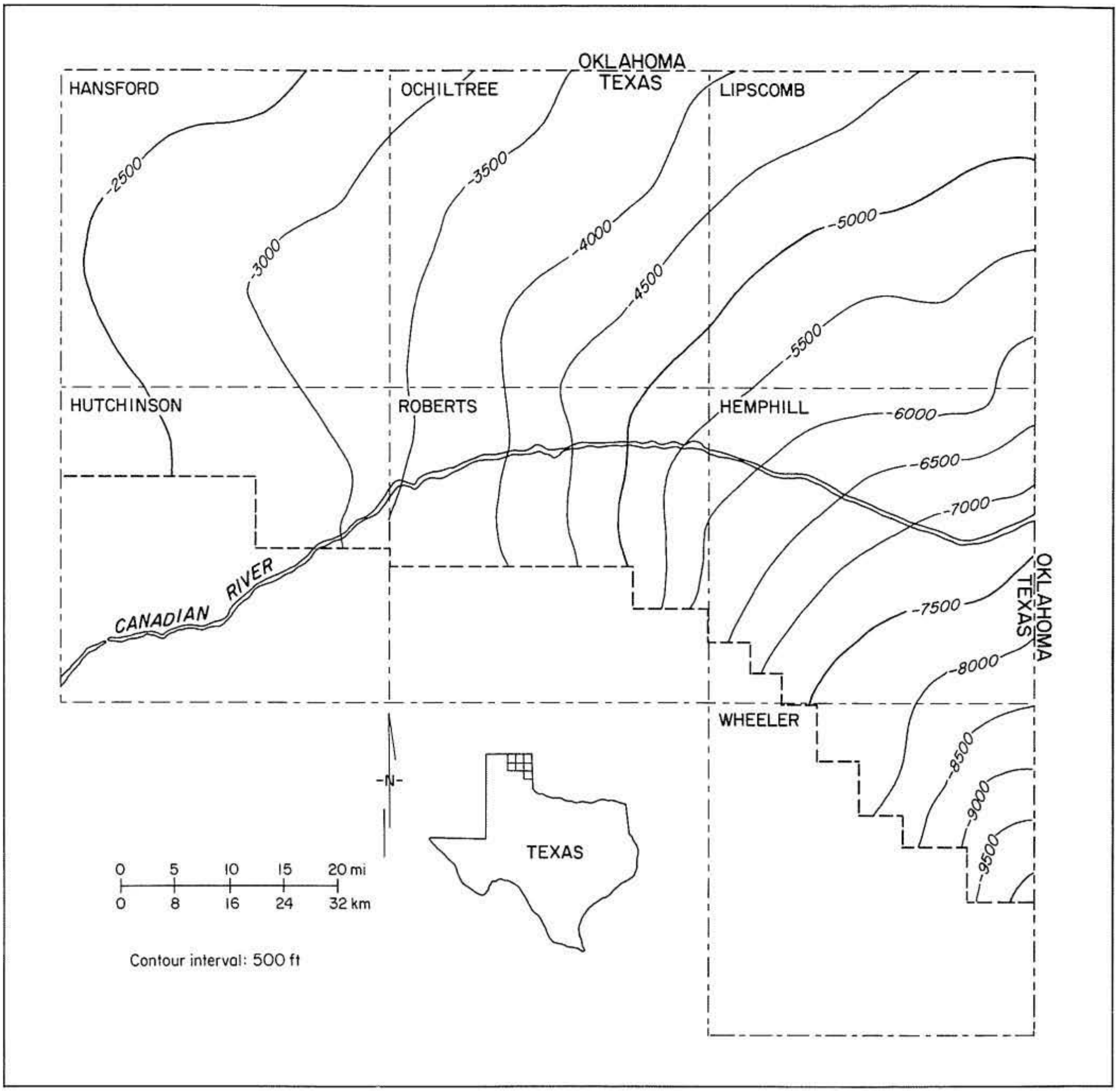

FIGURE 43. Structure contours on top of the Cleveland Formation, northeast Texas Panhandle (from Railroad Commission of Texas, 1981d).

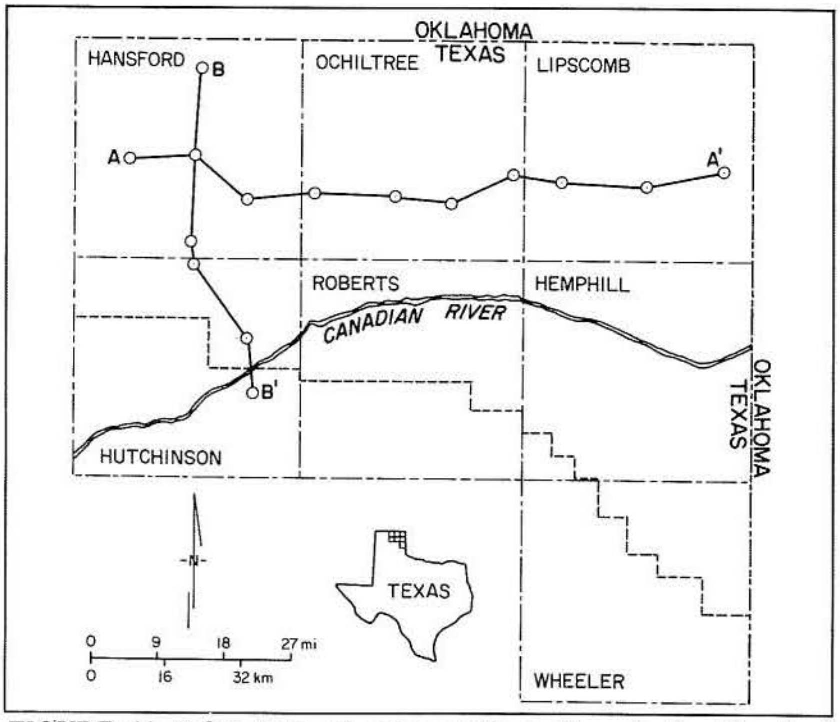

FIGURE 44. Index map of cross sections through the Cleveland Formation, Anadarko Basin. Cross section A-A' shown in figure 46 and B-B' in figure 45.

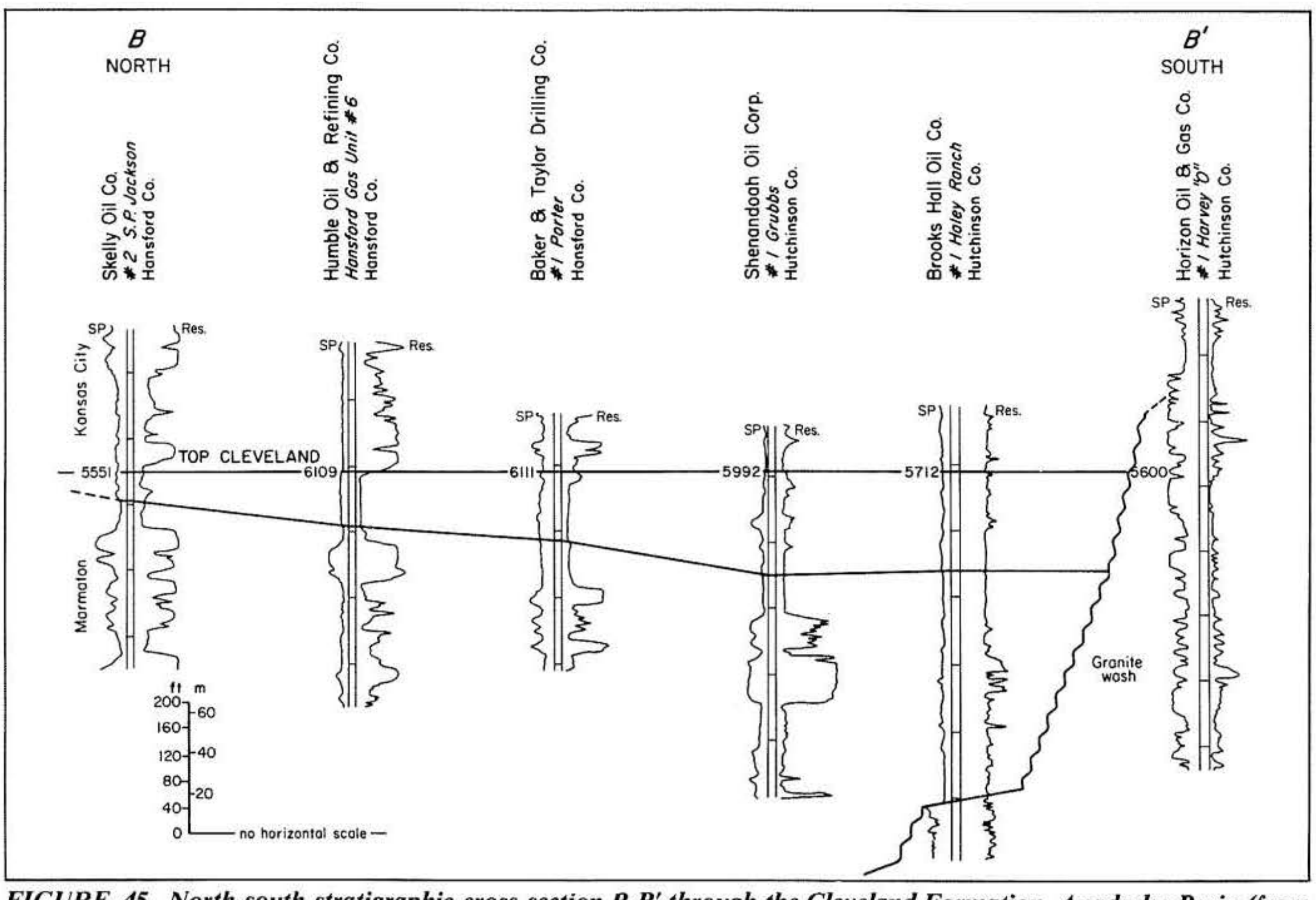

FIGURE 45. North-south stratigraphic cross section B-B' through the Cleveland Formation, Anadarko Basin (from Railroad Commission of Texas, 1981d). Line of section shown in figure 44.

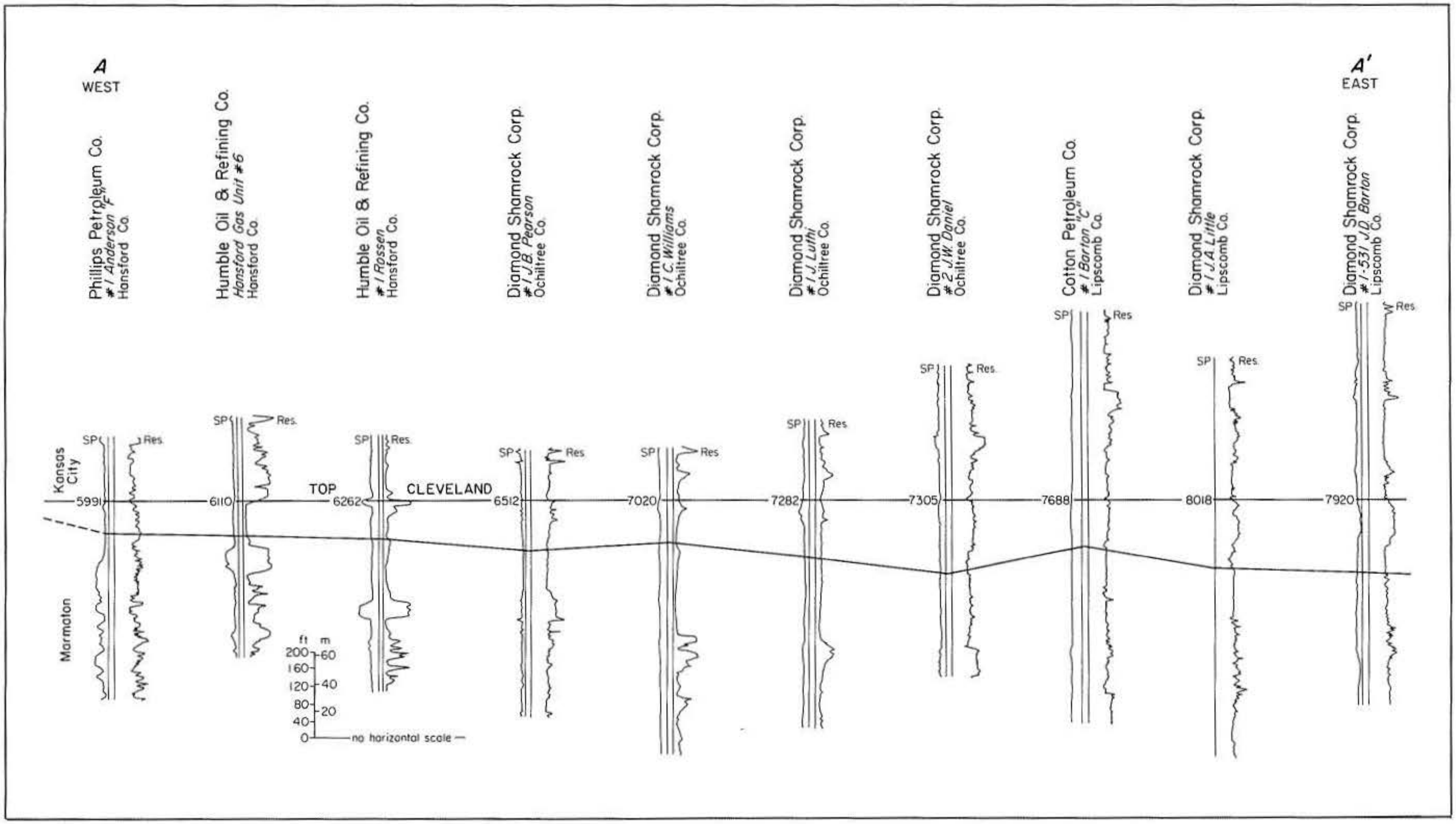

FIGURE 46. East-west stratigraphic cross section A-A' through the Cleveland Formation, Anadarko Basin (from Railroad Commission of Texas, 1981d). Line of section shown in figure 44. Depths shown are drilling depths.

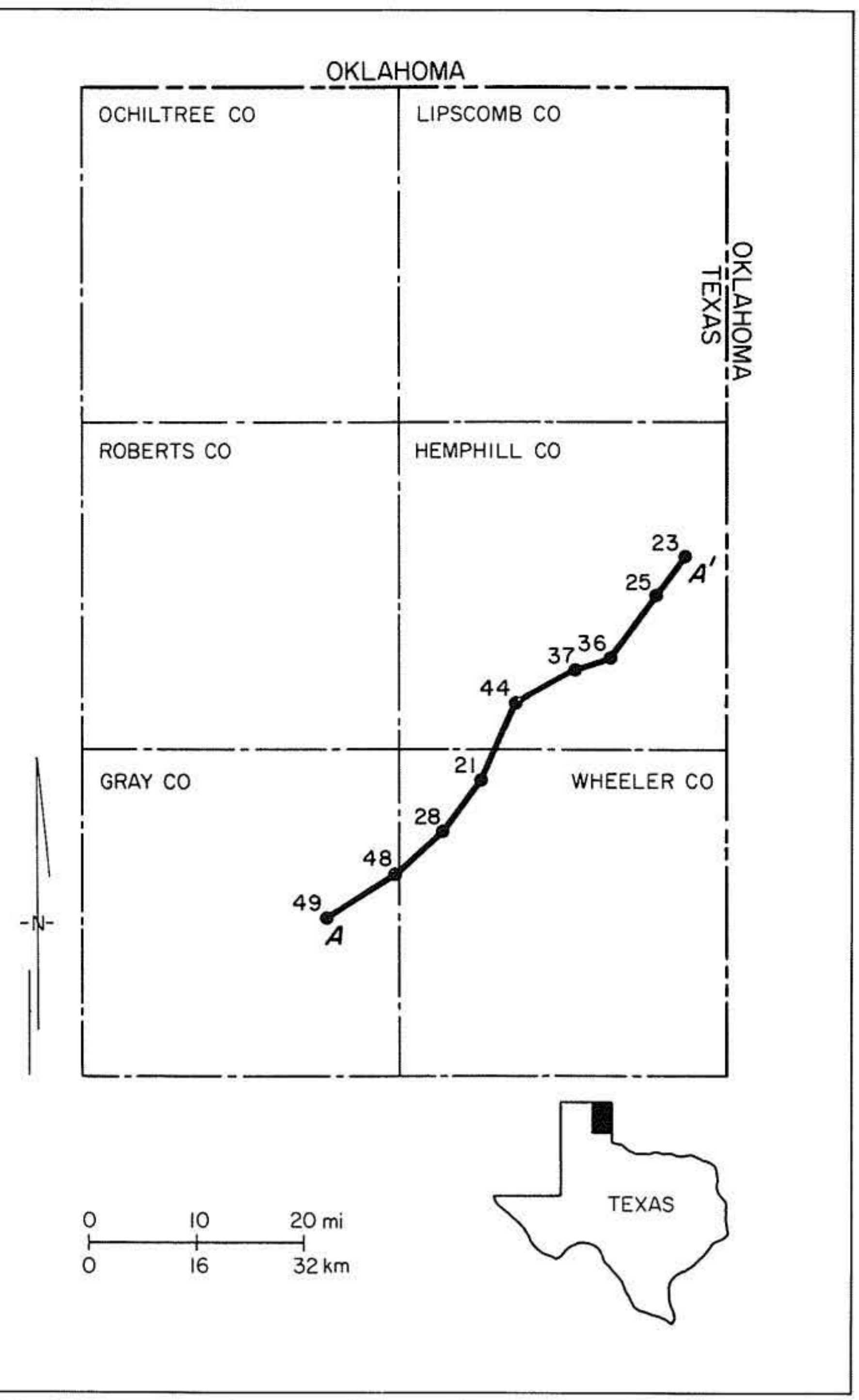

FIGURE 47. Index map of cross section A-A' (fig. 48) through Gray, Wheeler, and Hemphill Counties, Texas (after Dutton, 1982).

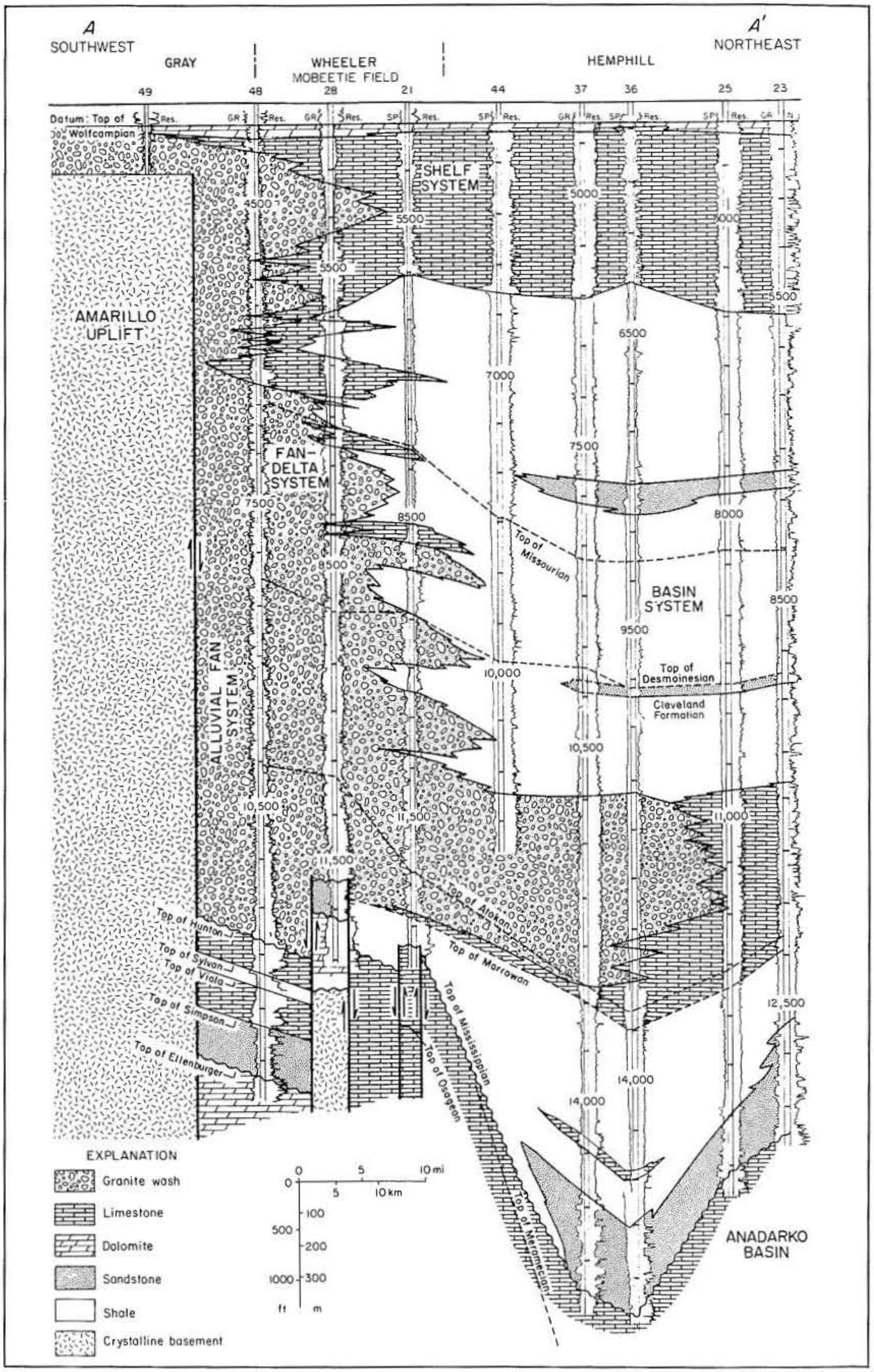

FIGURE 48. Northeast-southwest stratigraphic cross section A-A' showing facies of the Cleveland Formation, Anadarko Basin, Texas (after Dutton, 1982). Line of section shown in figure 47.

TABLE 38. Cleveland Formation, Anadarko Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Cleveland Formation, Kansas City Group, Missourian and Pennsylvanian.	Approximately 4,500 mi^2 gross area in all or part of seven counties in the Texas Panhandle. Probable additional area is in adjacent Oklahoma.	Across Hansford, Ochiltree, and Lipscomb Counties, Texas, range is 80 to 170 ft, average is 120 ft.	Depth to top of Cleveland ranges from -2,500 ft subsea (western Hansford County, Texas) to -9,700 ft subsea (Wheeler County, Texas). Depth to top of perforations ranges from 6,258 to 9,439 ft; most perforations are shallower than 8,000 ft.	No data.	Strike is north to northeast. Across northeast Texas Panhandle, average dip is approximately 1° east-southeast.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
Deposited along the northwest and northeast margins of the Anadarko Basin. Bounded to the south by the Amarillo-Wichita Uplift.	Less than 1.2° to 2.2° F/100 ft, mostly 1.4° to 2.0° F/100 ft.	No data. Mud weights suggest normal hydrostatic gradients.	Compressional; bounded on the south by high-angle reverse fault of the Amarillo Uplift.

TABLE 39. Cleveland Formation, Anadarko Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Marine shelf environment having sources to the west, north, and east other than the Amarillo Uplift. Thin (20- to 40-ft) deltaic unit possible at the base of the formation in some areas, represented by upward-coarsening (possibly delta-front) to blocky (possibly distributary-bar) log characters. Rest of unit may be shelf-dispersed sands near or at storm-wave base.	Fine-grained to very fine grained, well-sorted sand, tending to be tightly packed in diagenetic and detrital clay matrix.	One core of 60 ft reported 65% quartz, 10% feldspar (mostly plagioclase), 3% mica, plus heavy minerals and traces of chert and glauconite. Rest of sample consists of matrix and cements.	Reduction of porosity and permeability owing to, in order of abundance, quartz overgrowths, diagenetic clay matrix, and calcite cement (on the basis of one 60-ft core). Quartz apparently was the initial cement. Feldspars have been altered to clay, and biotite has been altered to chlorite.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Areal extent is usually 25 to 75 mi²; however, operators have developed smaller reservoirs. Average thickness is 120 ft.	Typically, original pressure range is 2,200 to 2,700 psi, and temperature range is 145° to 160° F.	No definite evidence of natural fracturing.	Whole core seldom obtained. It is estimated that less than 1% of the Cleveland wells in the Texas Panhandle have been cored. Logs typically include dual induction resistivity and neutron density for porosity.

TABLE 40. Cleveland Formation, Anadarko Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Median calculated in situ permeability for 391 wells is 0.028 md, representing an unknown mixture of pre-stimulation and post-stimulation well tests.	Average is 10 to 40 ft, maximum is estimated to be 75 ft.	Often TSTM	Average of 396 wells now producing (may include data from a few non-stimulated wells) was 218 Mcfd, stabilized flow rate.	Approximately 56% the first year followed by 11%/yr for the life of the well.	Minor amount of condensate produced at less than 5 bpd/well.	30% to 40% for the usual pay zone. Calculated values typically range from 30% to 50% and up to 100%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing. Typical procedure includes acidizing with 3,000 gal of 7.5% HCl and fracturing with 80,000 to 90,000 gal of 2% KCl water with cross-linked polymer and 250,000 lb of 20-40 mesh sand. Pressures of 4,500 to 5,000 psi are used.	Stimulation is commonly successful.	640 acres, 320 acres optional. Operators are interested in lowering this to 320 acres, 160 acres optional.	Pre-stimulation flow tests of adequate duration are rare. An unknown number of wells have been plugged (owing to low permeability) before development and more widespread use of hydraulic fracturing.

TABLE 41. Cleveland Formation, Anadarko Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by State for northeast Texas Panhandle on November 30, 1981.	At least 507 total completions in 6 counties; 439 were active as of August 1981.	Wildcat: no data. Infill: 80% to 90%, dropping toward the edges of a field.	Typical productive costs for an 8,000-ft Cleveland gas well are $600,000 to $650,000 (1981 dollars). In addition, a $50,000 fracture treatment is required (1981 dollars).	Many pipelines in place and healthy competition exists for the available gas. Gas is purchased for interstate sale, agricultural irrigation, fertilizer plants, power generation, and residential use.	Moderate to high. One FERC application prepared by Diamond Shamrock and supported by 22 other companies.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
Low-relief High Plains to escarpments and broken terrain along rivers and streams.	Semiarid to subhumid having 18 to 24 inches mean annual precipitation. Rainfall primarily during spring and summer as thunderstorms. Occasional rapid temperature drops in late fall and winter caused by frontal passages. Hot summers, moderately cold winters.	Excellent access on High Plains, good in other areas. Roads typically at 1-mi spacing on High Plains. No major terrain barriers.	Fair. Very thin deltaic package has no good analogy. Shelf sand having abundant clay matrix has analogy in the Mancos "B" (Piceance Basin), Mancos "B" (Uinta Basin), and Sanostee Member (San Juan Basin), although the Mancos "B" is much thicker, and the Sanostee is a calcarenite- and calcite-cemented sandstone.	All drilling and completion services readily available in the Oklahoma and Texas Panhandle areas.

ATOKAN AND DESMOINESIAN (PENNSYLVANIAN) SANDSTONES, ANADARKO BASIN, OKLAHOMA

In the Anadarko Basin of western Oklahoma, Pennsylvanian sands of the Atokan and Desmoinesian (Strawn) Series include several units for which tight gas applications have been filed. Among these units are undifferentiated Atokan sands, the Cherokee Group (undifferentiated), and the Red Fork Sandstone (fig. 49). Applicable areas are primarily in counties bordering Texas, including Washita, Beckham, Custer, Roger Mills, and Caddo Counties, Oklahoma. Updip to the north and west of these counties, the Cherokee Group is a well-known productive unit consisting of lenticular sands deposited in fluvial channels, distributary bars, and offshore bars (Lyon, 1971; Albano, 1975; Shipley, 1977). No published stratigraphic studies were found that deal directly with the area of tight gas sand applications. The Atokan and Desmoinesian sands of the Cherokee Group in the application areas are probably distal delta-front to shelf deposits, possibly overlapping a shelf break into the deeper Anadarko Basin adjacent to the Amarillo-Wichita Uplift (J. H. Nicholson, personal communication, 1982). The source of these sands is to the northwest and northeast rather than from the uplift (Evans, 1979).

The application for the Red Fork Sandstone requested tight gas status for the largest area (1,080 mi^2) of the several applications in western Oklahoma. The zone of interest has permeability of 0.008 to 0.014 md, porosity of 6 to 10 percent, and thickness of 10 to 20 ft; it occurs at a depth of 11,100 to 12,700 ft. Stimulation (fracture treatment) typically costs $150,000 (1981 dollars) per well, and 71 wells produce from the formation within the application area. Other Pennsylvanian tight sands in western Oklahoma are thin and generally occur below 11,000 ft. Shallower Pennsylvanian sands exist in southwestern Oklahoma (fig. 49), but the Tonkawa Sandstone is oil prone and the Douglas Group, particularly the lower part, tends to be lenticular, having 10- to 20-ft-thick sand bodies lacking lateral continuity (J. H. Nicholson, personal communication, 1982).

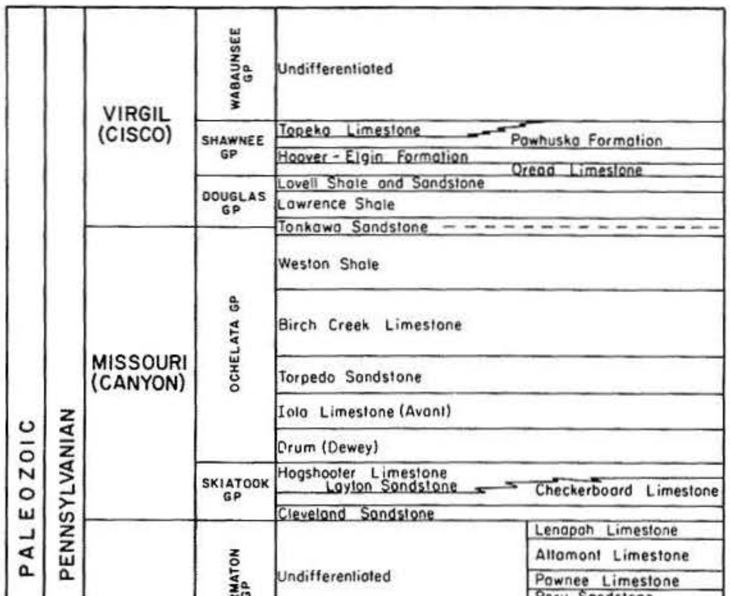

FIGURE 49. Stratigraphic column of the Pennsylvanian System in the Anadarko Basin, western Oklahoma (from Nicholson and others, 1955).

DAVIS SANDSTONE, FORT WORTH BASIN

The Davis sandstone of the Atoka Group is Early-Middle Pennsylvanian in age and was deposited in the northern Fort Worth Basin of North-Central Texas (figs. 50 and 51). An informal lithogenetic unit within the upper part of the Atoka Group (fig. 51), it has been interpreted as a system of coalesced wave-dominated deltas. The Davis unit has not been a prime exploration target; it is tight and has been tested infrequently. Most Atokan production from tight, predominantly gas-bearing sandstones and conglomerates in the northern Fort Worth Basin has been from the lower Atoka Group (Thompson, 1982). Cumulative production from the Atoka Group as a whole through 1977 was more than 408 Bcf of gas and 94 million bbl of oil.

The data base on the Davis is poor (tables 42 through 45). Only two fields in northern Parker County produce from the Davis, suggesting that a potential gas province most likely would be confined to an area of about 300 mi².

SYSTEM		SERIES	GROUP OR FORMATION
CRETACEOUS		UNDIVIDED	
PERMIAN		WOLFCAMP	CISCO Group
PENNSYLVANIAN	UPPER	VIRGIL	
		MISSOURI	CANYON Group
	MIDDLE	DES MOINES	STRAWN Group
		ATOKA	ATOKA Group
	LOWER	MORROW	MARBLE FALLS & COMYN Formations
MISSISSIPPIAN		CHESTER	CHESTER Formation
		MERAMEC	BARNETT & CHAPPEL Formations
		OSAGE	
		KINDERHOOK	
CAMBRO-ORDOVICIAN		CANADIAN	VIOLA & SIMPSON Formations
			ELLENBURGER Group
			WILBERNS & RILEY Formations
PRECAMBRIAN		UNDIVIDED	

FIGURE 50. Stratigraphic column in the Fort Worth Basin (from Thompson, 1982).

Structure

The Fort Worth Basin, a Paleozoic foreland basin, is about 20,000 mi² in area. The east-northeast part of the basin adjacent to the Ouachita thrust belt is deepest; the basin shallows to the west and south. It is bounded on the east by the Ouachita thrust belt, on the north by the Red River - Electra and Muenster Arches, on the west by the Bend Arch, and on the south by the Llano Uplift (fig. 52) (Thompson, 1982).

Within the basin, normal faults developed in response to extension as the basin subsided. In the north-central part of the basin, faults are subparallel to the Ouachita thrust belt; however, near the northern basin margin, faults become subparallel to the Red River - Electra and Muenster Arches. These faults are downthrown toward the center of the basin (Thompson, 1982).

Stratigraphy

The uplifts surrounding the Fort Worth Basin were the sources of the Pennsylvanian clastic sediments that filled the basin; a progressive westward shift of depocenters occurred in Middle to Late Pennsylvanian time. The Ouachita Uplift was the predominant source (Ng, 1979; Thompson, 1982); additional sediment was shed from the Muenster Arch (Lovick and others, 1982).

The Davis lithogenetic unit overlies a major fluvially dominated fan-delta system in the lower Atoka Group. The unit itself consists primarily of sands and shales and a few thin limestones. These limestones are interpreted to be lacustrine in origin and have a thick, strike-oriented geometry. Electric log patterns suggest concurrent progradation and aggradation (Thompson, 1982). The Davis sandstone of Thompson (1982) is equivalent to the Pregnant Shale of Ng (1979).

Depositional Systems

The Davis sandstone has been interpreted to be a wave-dominated system of coalesced chevron to arcuate deltas primarily composed of coastal barrier facies (Thompson, 1982). These facies may consist of barrier-island beach ridges or sand ridges on a strandplain that accreted parallel to the shoreline to form a sand-rich facies having excellent strike continuity and moderately good dip continuity. The Davis facies in the northern Fort Worth Basin include many coastal barriers in western Parker and southern Wise Counties that resulted from wave redistribution of substantial amounts of sand along the delta margins (fig. 53) (Thompson, 1982). This deltaic geometry suggests a period of tectonic quiescence and low sediment input, which resulted in the dominance of marine over fluvial processes. The post-Davis depositional system shows a return to a fluvially dominated, highly digitate sandstone geometry.

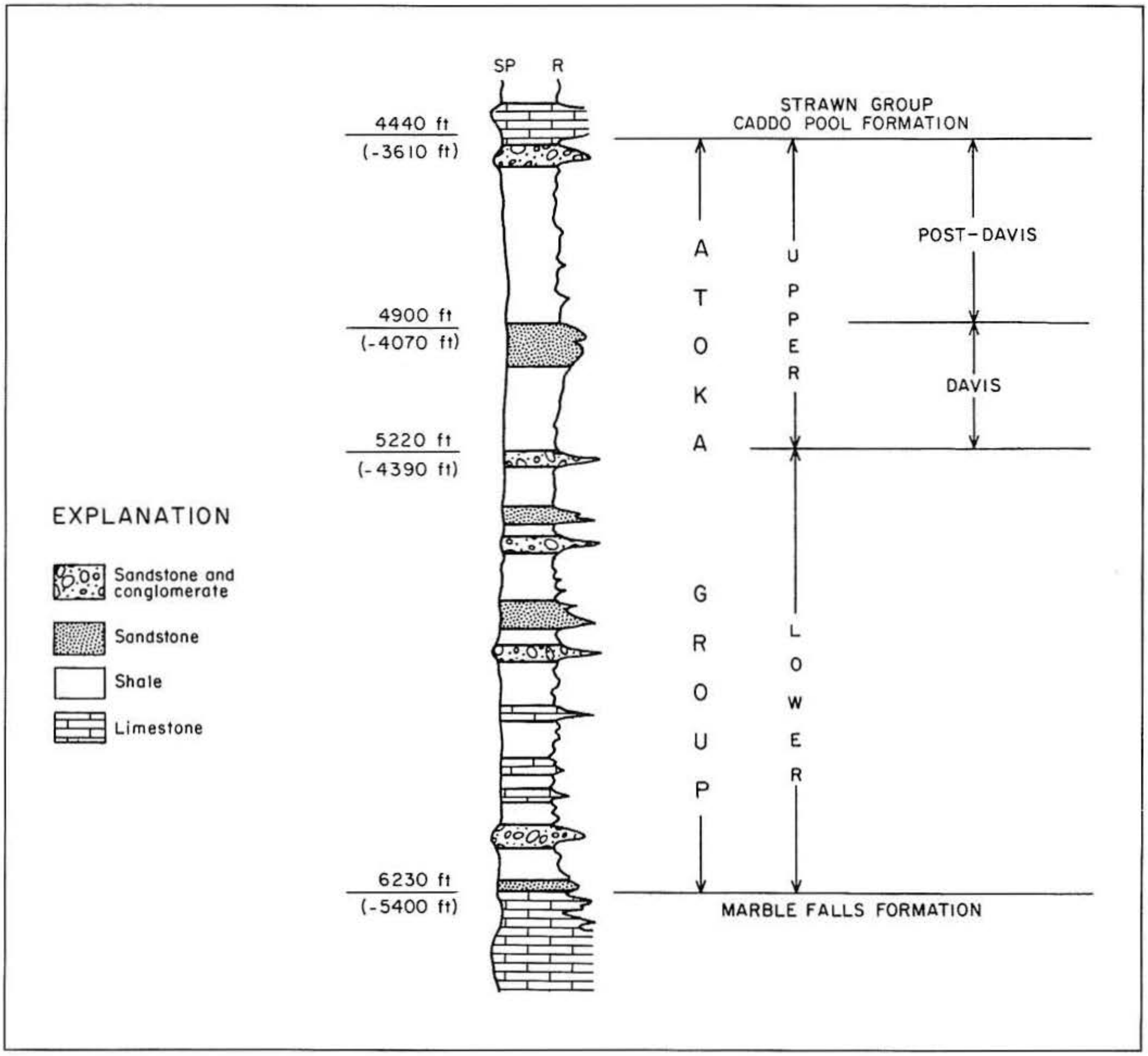

FIGURE 51. Typical log response and lithologies of the Atoka Group in the Fort Worth Basin (after Thompson, 1982).

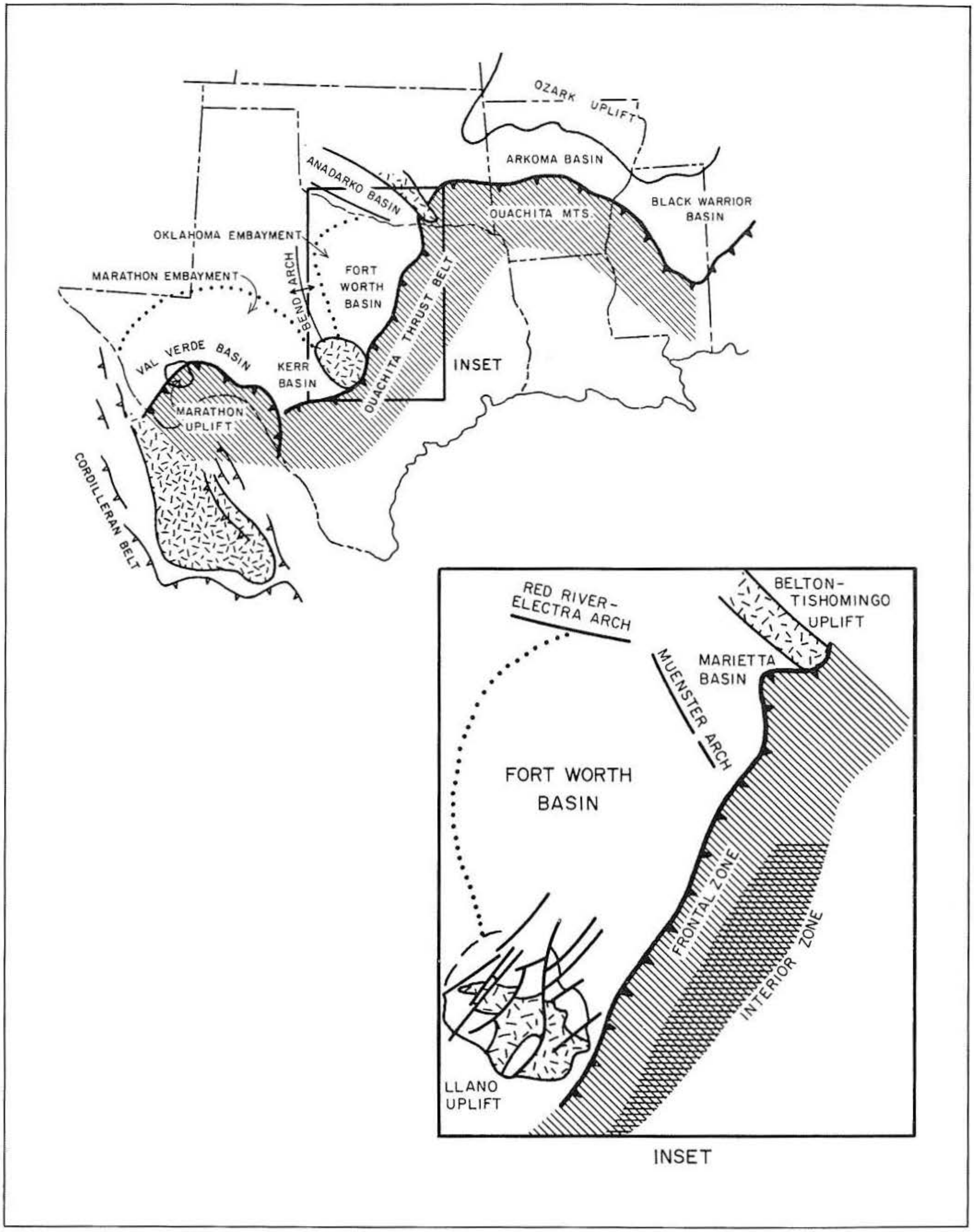

FIGURE 52. Regional and local structural setting of the Fort Worth Basin (after Thompson, 1982).

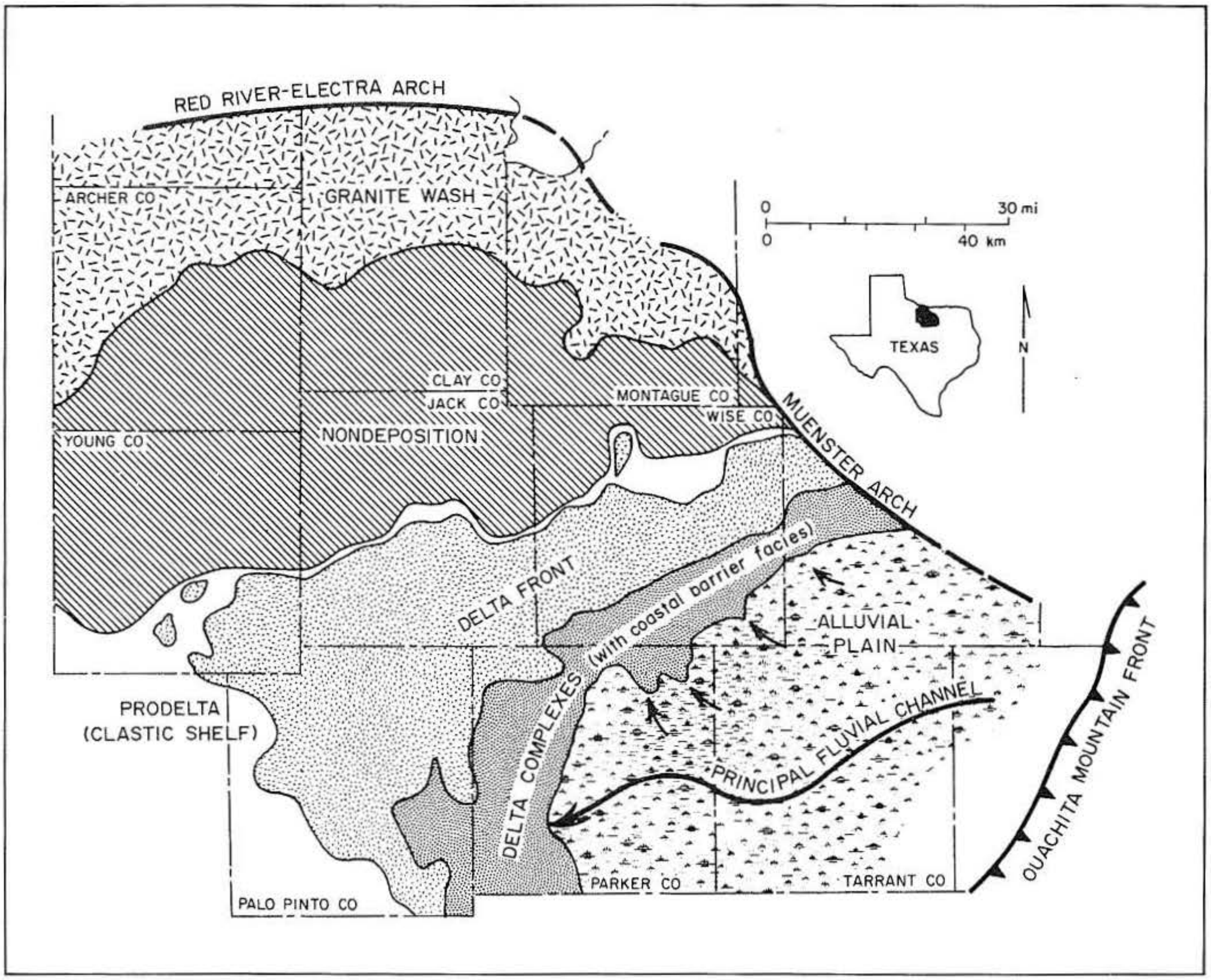

FIGURE 53. Distribution of deltaic facies in the Davis sandstone, northern part of the Fort Worth Basin (from Thompson, 1982).

TABLE 42. Davis sandstone, Fort Worth Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Davis sandstone, Atoka Group, Lower-Middle Pennsylvanian.	Gas-prone province consists generally of the northern one-third of Parker County, Texas, or approximately 300 mi^2.	Average is 400 ft in the north-central part of the basin. Thins to 20 ft in the northwestern and northern parts of the basin; thins to many 30-ft-thick units in the northeastern to eastern parts of the basin. Major depocenter in Parker County.	Range is approximately 4,800 to 5,200 ft.	No data.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This Paleozoic foreland basin is bounded on the east by the Ouachita thrust belt, on the north by the Red River - Electra and Muenster Arches, on the west by the Bend Arch, and on the south by the Llano Uplift.	1.2° to 1.6° F/100 ft.	No data.	Compressional thrust belt margin on the east. Inferred normal faults within the basin caused by extension during basin subsidence.

TABLE 43. Davis sandstone, Fort Worth Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Moderately progradational system of wave-dominated chevron- to arcuate-shaped deltas. Coastal barriers or sand-rich strandplains are the principal facies components. A period of tectonic quiescence and reduced sediment input marked the upper Atokan Davis interval, resulting in the dominance of marine processes over the fluvial processes of the lower Atoka. Net-sandstone geometry is generally tabular, having a strike-oriented facies framework.	Shale to medium-grained to very fine grained sand having minor thin limestone stringers derived from a lacustrine delta-plain environment.	Generally the Atoka Group consists of a quartz-rich, feldspathic litharenite. No core from the Davis sandstone available. More feldspathic sediments derived from the Muenster Arch, more quartz-rich sediments derived from the Ouachita thrust belt.	Compaction resulted in stylolitization and development of pseudomatrix, development of quartz overgrowths, dissolution of chert, feldspar, and rock fragments, and filling of pore space by carbonate cements. Minor amounts of authigenic kaolinite are present.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Generally unknown in northern half of Fort Worth Basin.	No data.	Extent unknown.	Core unavailable.

TABLE 44. Davis sandstone, Fort Worth Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Generally expected permeability of less than 1.0 md and 8% to 12% porosity. Porosity ranges from 3% to 6% in alluvial plain - coastal barrier facies and up to 15% in some deltaic sandstones. Better porosity in upper one-fourth of Davis sandstone.	No data.	No data.	No data.	No data.	Gas prone; only minor oil production.	No data.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing. One job in underlying Bend Conglomerate in Wise County, Texas, used 506,000 lb sand, 139,000 gal foam, and 198,000 gal emulsion.	No data.	No data.	No additional information.

TABLE 45. *Davis sandstone, Fort Worth Basin: Economic factors, operating conditions, and extrapolation potential.*

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
No applications as of July 1983.	Primarily in two fields in Parker County, Texas.	No data.	No data.	Pipelines in place as a result of existing gas production include those of Southwestern Gas Pipeline Co. and Lone Star Gas Co.	Probably low to moderate. No FERC applications; overall data appear to be limited. Some infill and step-out well drilling for objectives below the Davis flourished during the mid-1970's.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
In the North-Central Prairies having up to 300 to 500 ft of local relief. Most of area is gently sloping.	Continental climate having 28 to 34 inches mean annual precipitation. Hot summers, mild to moderately cold winters. Frequent spring thunderstorms.	Good. Some locally steep scarps may result in minor terrain restrictions.	Fair to poor. Evaluation limited by incomplete data. Wave-dominated deltaic system has analogies in the Olmos Formation of the Maverick Basin and deltaic parts of the Fox Hills Sandstone of the eastern Greater Green River Basin. The Fox Hills, however, probably includes more extensive interdeltaic barrier facies.	Drilling and completion services available because of previous exploration and current production from deeper horizons.

OLMOS FORMATION, MAVERICK BASIN

The Olmos Formation, which is Late Cretaceous in age, was deposited in the Maverick Basin of the Rio Grande Embayment (fig. 54). The subsurface of the Olmos Formation is primarily within seven counties of South Texas and part of adjacent Mexico (figs. 55 and 56). The Olmos Formation consists of fine-grained to very fine grained silty sand interbedded with massive shales; some horizons contain disseminated grains of lignite and glauconite (Glover, 1955; Railroad Commission of Texas, 1981a). The data base on the Olmos Formation is fair (tables 46 through 49); information on limited areas was obtained from tight formation applications. Published data specifically on the Olmos deal primarily with oil and associated gas production (Dunham, 1954; Glover, 1955; Glover, 1956); no regional studies specifically on the Olmos Formation have been published recently. A report on the underlying San Miguel Formation (Weise, 1980) and limited data on diagenesis of the Olmos Formation (Guven and Jacka, 1981) do contain information valuable to this survey of gas in the Olmos.

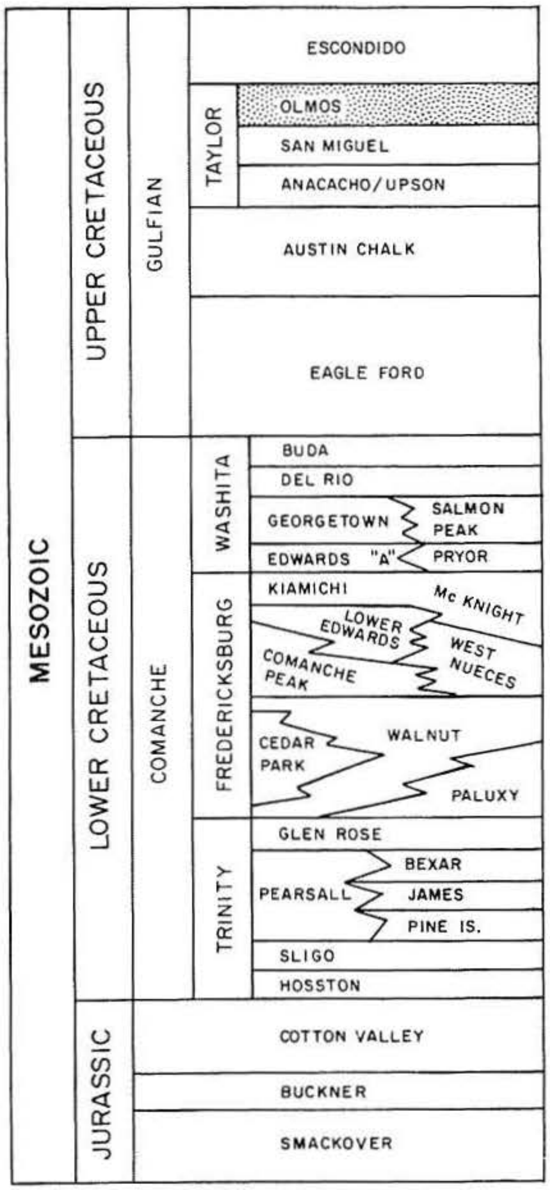

FIGURE 54. Partial stratigraphic column of the Jurassic and Cretaceous Systems in the Maverick Basin.

Structure

The Maverick Basin in Texas is bounded by the Balcones Fault Zone and the San Marcos Arch (fig. 55). This arch was a mildly positive structure that subsided at a slower rate than did adjacent basins during Cretaceous sedimentation. Other boundaries are the Devils River Uplift and the Salado Arch. The most prominent structural feature within the basin is the southeastward-plunging Chittim Anticline, which is well defined by the outcrop of the Olmos Formation (fig. 56). Other than the Charlotte fault system, which is part of the hinge line of the Gulf Coast Basin, few large faults exist in the Maverick Basin. The Upper Cretaceous clastic sediments of the Maverick Basin do not include the thick shale units characteristic of the Gulf Coast Tertiary section and are not cut by large growth faults (Weise, 1980).

Stratigraphy

The Olmos Formation is part of the Upper Cretaceous Taylor Group (fig. 54). Before deposition of the Taylor Group, carbonate sedimentation had been dominant in the Maverick Basin. The San Miguel, Olmos, and Escondido Formations are primarily terrigenous clastic units, however, and were derived from Late Cretaceous tectonic uplifts to the west and northwest (Weise, 1980). By Eocene time, the Maverick Basin was largely filled and depocenters had shifted to the southeast within the Gulf Coast Basin (Pisasale, 1980).

There is no widely recognized nomenclature to describe the individual sand units within the Olmos Formation. An informal designation of sands as N-2 through N-5, having some upper and lower subdivisions, was used by Petro-Lewis Corp. and others in their applications for tight formation status (Railroad Commission of Texas, 1981a) (figs. 57 through 59). In that application area, the N-2 sand is relatively continuous and is apparently useful as a stratigraphic datum.

Depositional Systems

The alternating sands and shales of the Olmos Formation are considered to be deltaic in origin, representing delta-plain to distal deltaic environments. Associated shoreline deposits (no specific facies have been described) and shallow marine bar sands are also thought to exist (Railroad Commission of Texas, 1981a). Generally, the N-3 and older sands are interpreted to be regressive; progradational patterns on SP logs of areas probably representing deltaic lobes support this contention. Logs of the N-4 and N-5 sands in the Trans Delta No. 3-18 and No. 6-7 Petty wells (fig. 58) exhibit upward-coarsening sequences. The N-2 sands are considered transgressive (Railroad Commission of Texas, 1981a); however, in the area shown on figure 58, the N-2 sand may consist of a progradational deltaic lobe and associated delta-margin facies capped by a transgressive marine shale. It seems likely that only the uppermost part of the N-2 sand has been reworked by transgression, which resulted in a very sharp upper contact (fig. 59).

No basinwide analysis of depositional systems of the Olmos Formation has been done, but a study of the underlying San Miguel Formation was completed by Weise (1980). The San Miguel consists of wave-dominated deltas reworked by marine processes and by physical and biological processes that occurred during subsequent transgression (Weise, 1980). Available data suggest a similar depositional setting for the Olmos of many deltaic sandstone bodies and incomplete barrier-strandplain sequences. This interpretation would be consistent with a study of the adjacent Olmos Formation in Mexico, where coals up to 6 ft thick exist in a more proximal delta-plain environment with associated fluvial and lacustrine facies (Caffey, 1978).

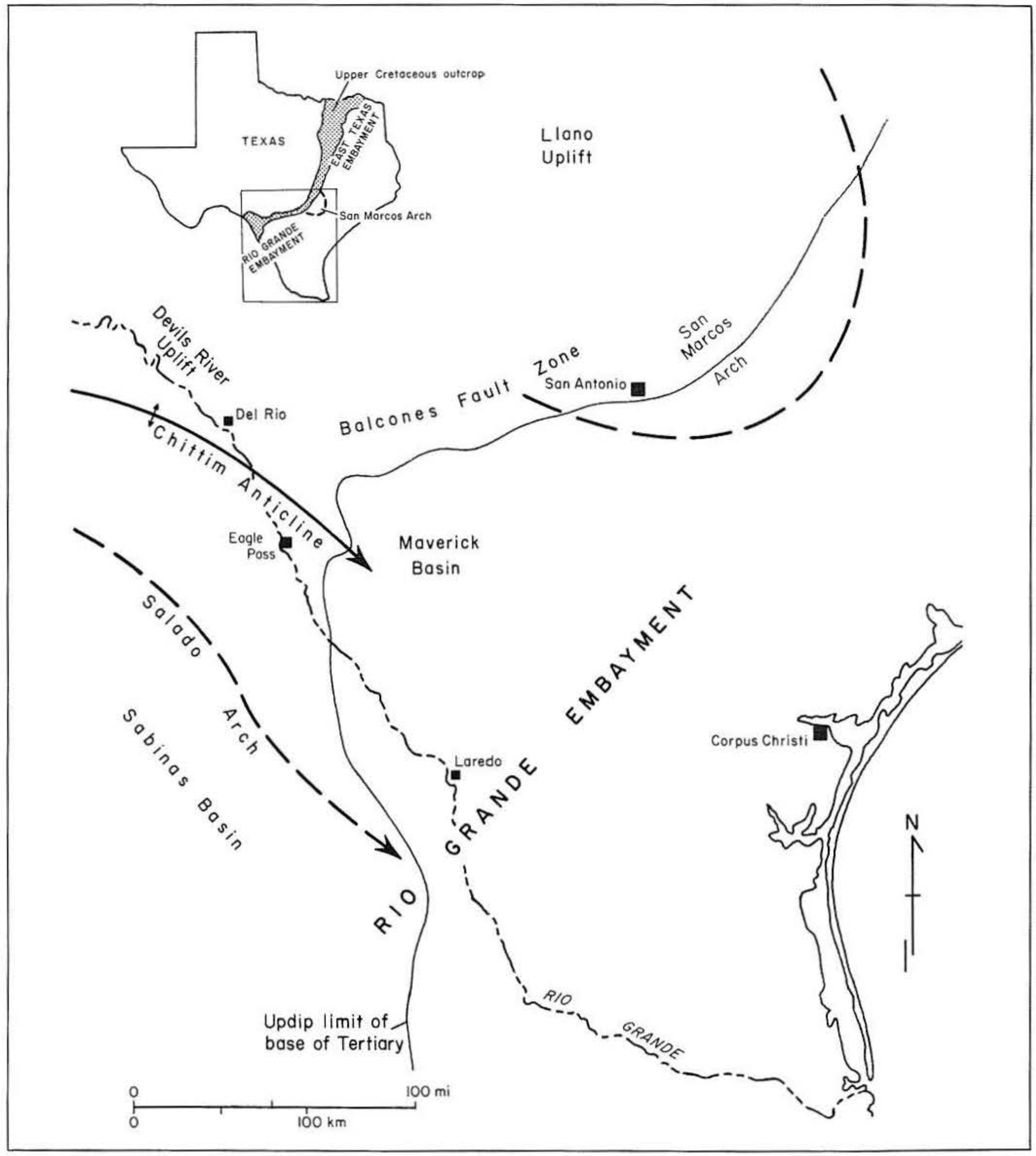

FIGURE 55. Local structural setting of the Maverick Basin (from Weise, 1980).

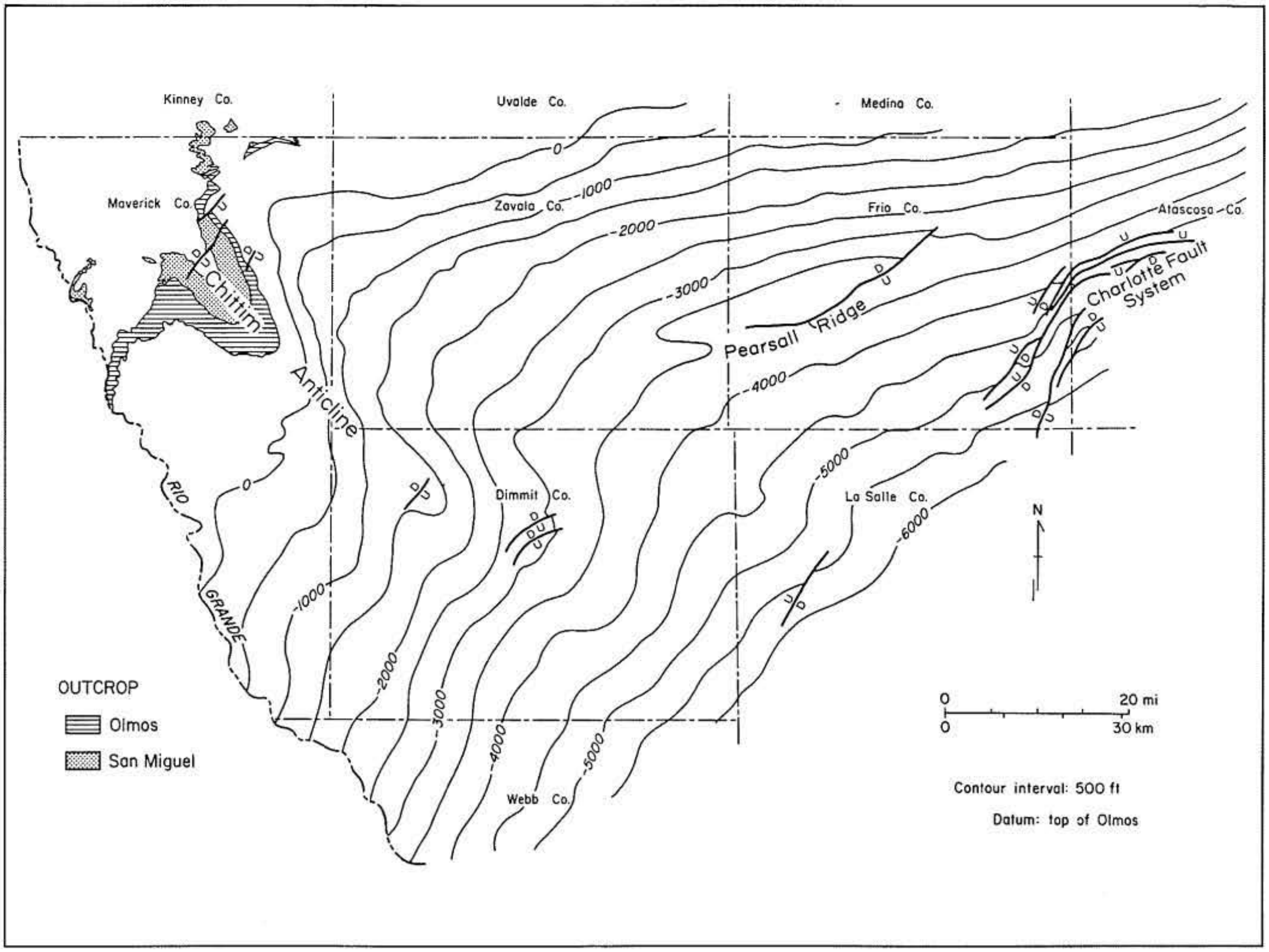

FIGURE 56. Structure contours on top of the Olmos Formation, Maverick Basin (from Weise, 1980).

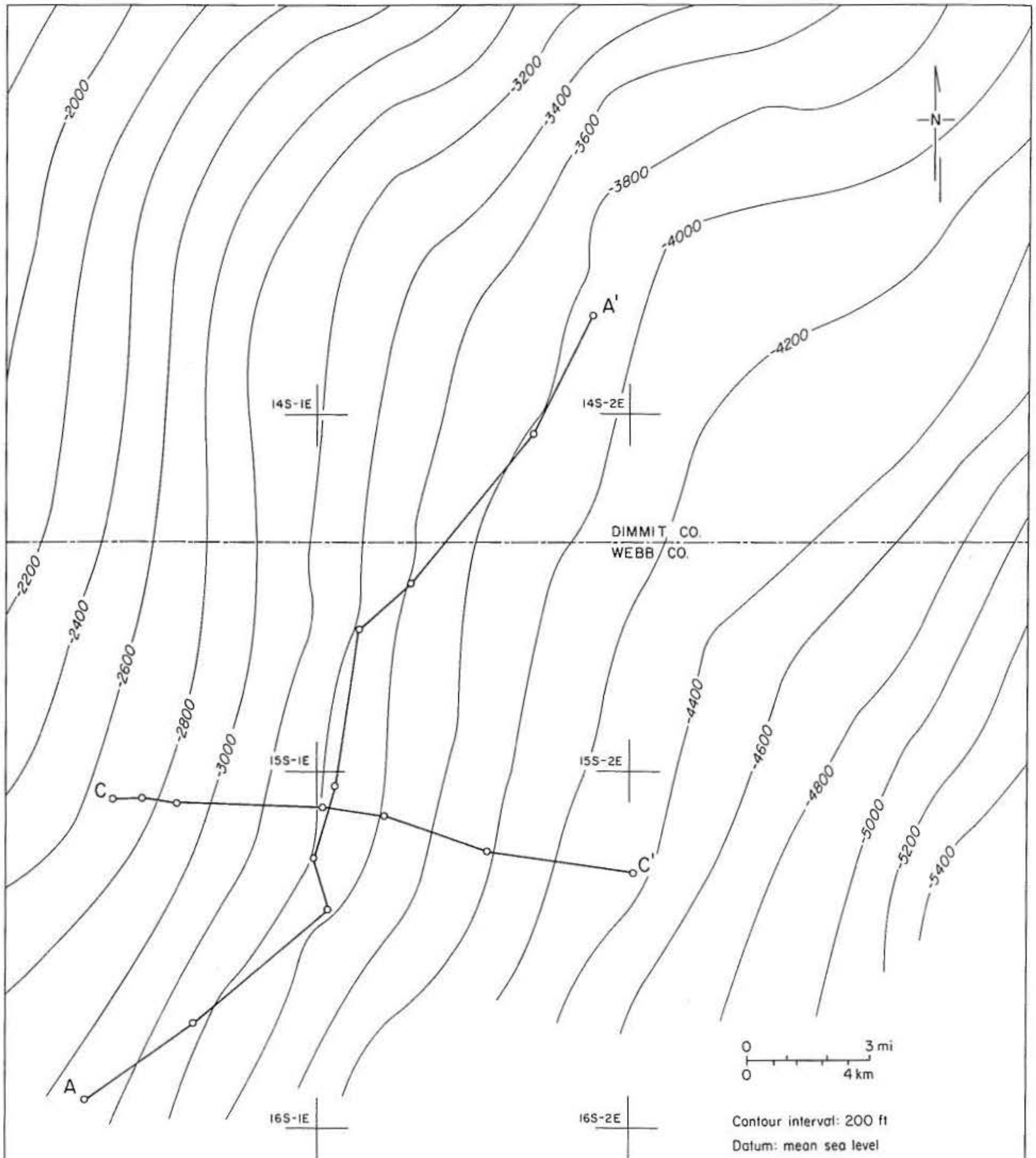

FIGURE 57. Index map of cross sections through the Olmos Formation and structure contours on top of the Olmos in parts of Dimmit and Webb Counties, Texas (after Railroad Commission of Texas, 1981a). Cross section A-A' shown in figure 58 and C-C' in figure 59.

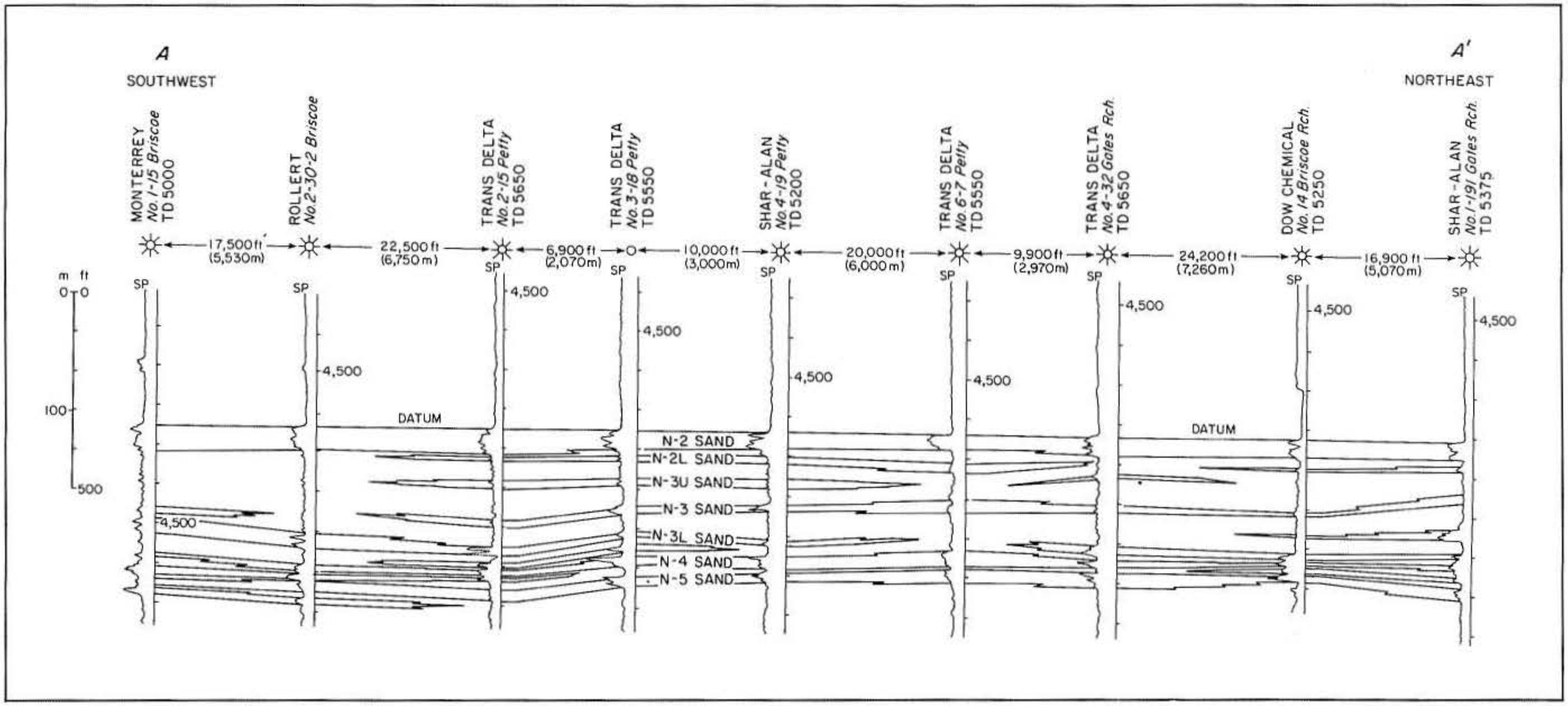

FIGURE 58. Northeast-southwest stratigraphic cross section A-A' through the upper Olmos Formation, Maverick Basin, showing lateral sand continuity (after Railroad Commission of Texas, 1981a). Line of section shown in figure 57.

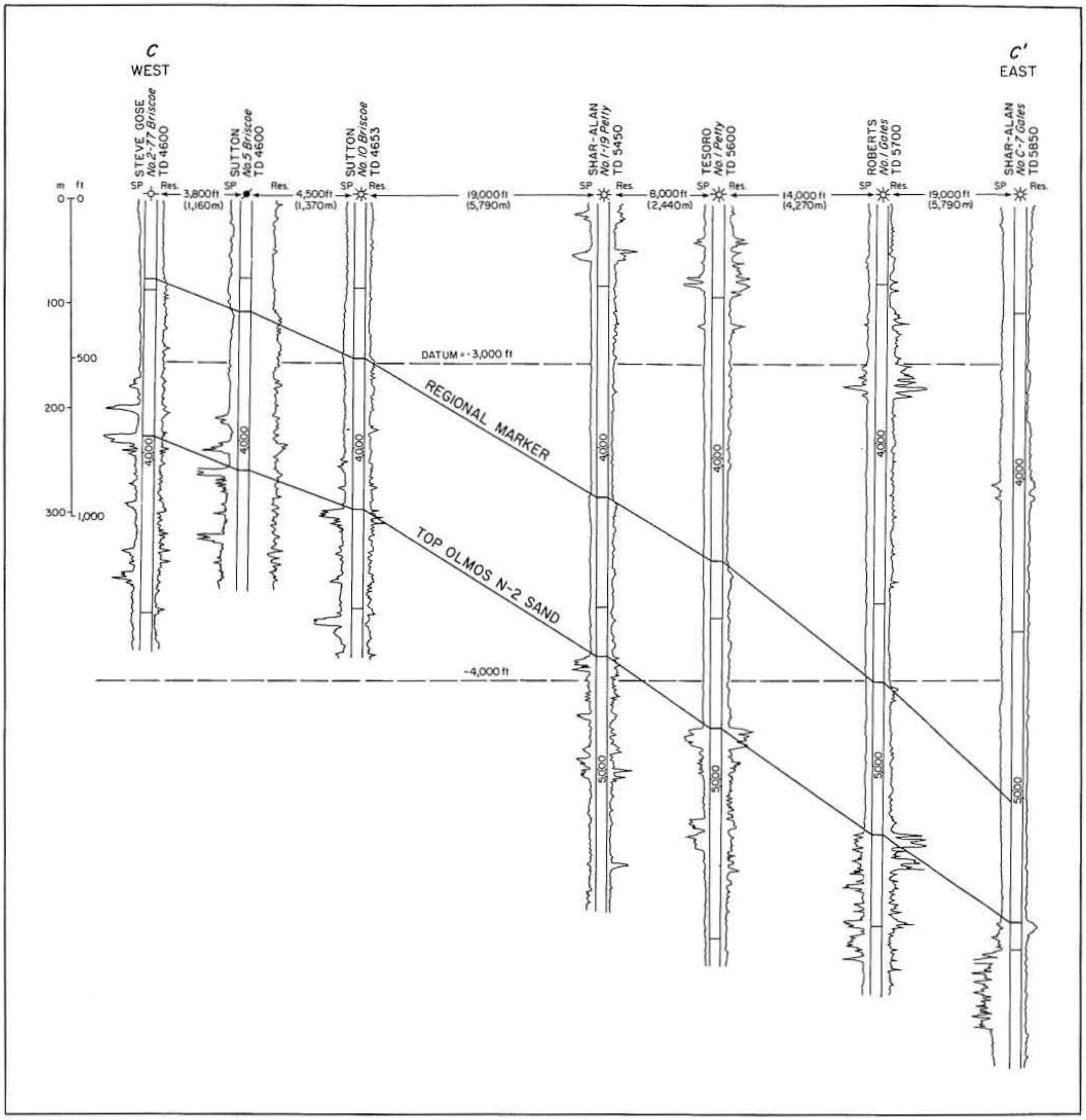

FIGURE 59. East-west stratigraphic cross section C-C' through the upper Olmos Formation, Maverick Basin, showing continuity of the N-2 sand (after Railroad Commission of Texas, 1981a). Line of section shown in figure 57.

TABLE 46. Olmos Formation, Maverick Basin:
General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Olmos Formation, Taylor Group, Upper Cretaceous.	Gross basin area is approximately 2,700 mi^2.	Range is 400 to 500 ft at outcrop, 1,000 to 1,200 ft southeastward in subsurface. Sand-bearing interval is 400 to 500 ft thick (southern Dimmit and northern Webb Counties, Texas).	Depth to top of Olmos Formation ranges from sea level (eastern Maverick County, Texas) to -6,000 ft subsea (southeastern Dimmit County, Texas). Range is 4,500 to 5,400 ft in northwestern Webb and southern Dimmit Counties, Texas. Production occurs as deep as 7,200 ft.	No data.	Strike is north-south to northeast-southwest in northwestern Webb and southern Dimmit Counties, Texas. Dip is 1° east-southeast. No major structural closures, minor faulting.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This basin is located in the Rio Grande Embayment of the Gulf Coast Basin. Distinct structural negative of the basin is bounded by the San Marcos Arch (northeast), the Balcones Fault Zone (north), the Devils River Uplift (northwest), and the Salado Arch (west) (in Mexico).	1.0° to 1.8° F/100 ft, mostly 1.4° to 1.8° F/100 ft.	No data.	Mildly tensional; Upper Cretaceous clastics generally lack growth faults.

TABLE 47. Olmos Formation, Maverick Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
In Texas: Delta-plain to distal deltaic and shallow marine, including strandline and shallow marine sand ridge in Segundo Field, Webb County. Lower Olmos (N-3 and older) was deposited in regressive, probably deltaic environment; upper Olmos sands (younger than N-3) were reworked by marine transgression and have a more blanketlike geometry. Laterally, the Olmos is deltaic in Maverick and parts of Zavala and Dimmit Counties; it shows greater reworking and more strike-aligned geometry toward Atascosa County and the San Marcos Arch. In Mexico: In adjacent parts of Rio Escondido Basin, the Olmos equivalent is delta plain having fluvial, overbank, and possible lacustrine environments. Carbonaceous shales and coal beds are present in a setting more proximal than that of the Texas deltaic deposits.	Fine-grained to very fine grained, silty to shaly sand and alternating shale. Lignitic shale and coal beds in updip delta-plain environments. Poorly sorted, limy sand and calcareous shale in Segundo Field, Webb County, Texas.	On the basis of reported similarity to underlying San Miguel Formation in adjacent Mexico: 35% to 40% quartz, 25% to 30% feldspar, and 30% to 35% volcanic rock fragments, having varying amounts of coal clasts and plant debris in delta-plain environments updip.	In adjacent Mexico, leaching of calcite cement and feldspars has created some secondary porosity. Authigenic kaolinite and chlorite have, in places, reduced porosity. Similar diagenesis may be expected in the Maverick Basin.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Top to base of perforated interval varies from less than 10 to 280 ft and is more commonly less than 10 to 100 ft in 514 wells.	No data.	Extent unknown.	Lewis Energy Corp., Denver, Colorado, and Union Oil, Houston, Texas, have obtained core, but quantity is unknown. Log suite includes SP-resistivity, GR-resistivity, and compensated neutron-formation density logs.

TABLE 48. Olmos Formation, Maverick Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
In northwestern Webb and southern Dimmit Counties, Texas, calculated in situ permeability for 42 wells (pre-stimulation) is 0.0335 md at median depth of 5,488 ft. For a sample of 107 wells, median pre-stimulation permeability is 0.072 md and median post-stimulation permeability is 0.14 md.	For 42 wells in Owen and Dos Hermanos Fields (northwestern Webb and southern Dimmit Counties, Texas), average is 35 ft, range is 12 to 81 ft.	TSTM for many wells, average was 25 Mcfd for 11 selected wells from at least 3 fields.	Average was 86 Mcfd for 488 wells in 67 fields (37 of which are 1-well fields).	No data.	Expected production of hydrocarbon liquids is less than 1 bpd.	Generally high in part of Segundo Field, Webb County, Texas, where Union Oil uses 65% as a practical upper limit.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing and acidizing.	Expected 2.5 times improvement as a result of fracture treatment.	160 acres in several fields in Dimmit and Webb Counties, Texas.	Union Oil uses 12% density-log porosity as a practical minimum limit of productive capability in Segundo Field, Webb County, Texas. Traps are generally updip sand pinch-outs lacking structural closure.

TABLE 49. Olmos Formation, Maverick Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by State for northwestern Webb and southern Dimmit Counties, Texas, on October 26, 1981.	At least 514 producing wells in trend.	No data.	No data.	Houston Pipeline Co., Valero Transmission Co., Delhi Gas Pipeline Corp., and Esperanza Transmission Co. have pipeline networks within the Maverick Basin.	Moderate. Two FERC applications.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
Mostly gently rolling Nueces Plains (inner Coastal Plain) having 100 to 300 ft of local relief, greater in some areas along the Nueces River.	Semiarid having 20 to 25 inches mean annual precipitation. Infrequent heavy rain from remnant tropical storms. Hot summers, mild winters. No climatic constraints on drilling operations.	Good. No terrain barriers. Most areas only sparsely vegetated by brush.	Fair. A small deltaic system probably having many individual deltaic lobes subsequently subject to marine transgression. Analogous to possible thin deltaic system at the base of the Cleveland Sandstone (Anadarko Basin), to the Davis sandstone, and to deltaic components of the Fox Hills Sandstone (eastern Greater Green River Basin). Possible analogy to parts of the Frontier Formation.	Most drilling and production services readily available in South Texas. Basaltic plugs in the northern part of the Maverick Basin have caused differential compaction and some thinning of Upper Cretaceous sediments.

PICTURED CLIFFS SANDSTONE, SAN JUAN BASIN

The Pictured Cliffs Sandstone consists of siltstone and very fine grained to medium-grained sandstone of Late Cretaceous age (fig. 60). The data base on the Pictured Cliffs Sandstone is good (tables 50 through 53); information was obtained from two applications for tight gas sand designation (New Mexico Oil Conservation Division, 1981a and 1982), from published articles, and from a report by consulting geologist W. R. Speer (1982).

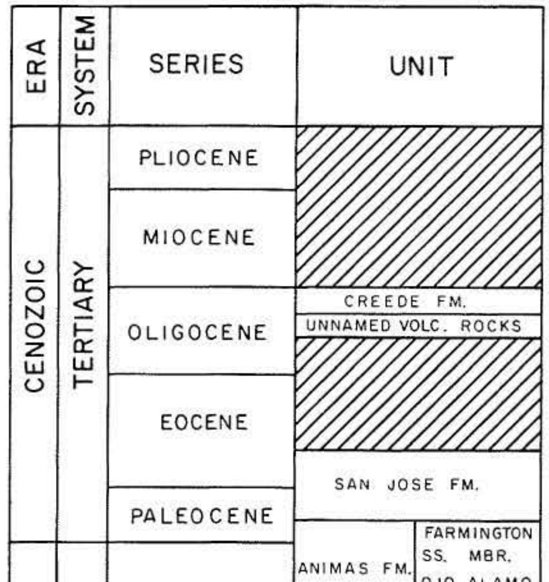

FIGURE 60. Stratigraphic column from the Upper Jurassic through the Pliocene, San Juan Basin (from Rocky Mountain Association of Geologists, 1977).

Structure

The San Juan Basin is a roughly circular, asymmetrical structural basin having a northwest-southeast-trending axial trace forming a gentle arc along the northern edge of the basin (fig. 61). The southwest flank of the basin dips gently, whereas the north and northwest margins dip steeply. The basin developed during the Late Cretaceous - early Tertiary Laramide orogeny. Volcanic activity in Arizona during Campanian time apparently marked the beginning of the Laramide orogeny and supplied some of the sediments forming the Pictured Cliffs Sandstone (Cumella, 1981). The structural boundaries of the San Juan Basin are listed in table 50. Epeirogenic uplift of the Colorado Plateau, including the San Juan Basin, took place in post-Laramide Tertiary time (Woodward and Callender, 1977).

Stratigraphy

Although the underlying marine Lewis Shale separates the Pictured Cliffs Sandstone from the older Mesaverde Group, the regressive marginal marine deposits of the Pictured Cliffs Sandstone resemble regressive sandstones of the Mesaverde. The final regression during the Cretaceous formed the Pictured Cliffs Sandstone; the overlying Fruitland Formation consists of fluvial and delta-plain sediments and contains abundant coal deposits (Fassett and Hinds, 1971). A prominent basal coal interval of the Fruitland directly overlies the Pictured Cliffs Sandstone (Peterson and others, 1965).

Depositional Systems

The Pictured Cliffs Sandstone was deposited during the last regression of the Cretaceous epicontinental seaway as a sandy strandplain that prograded across the San Juan Basin area (Fassett, 1977; Cumella, 1981). Specific facies of the Pictured Cliffs include shoreface (thickly bedded, *Ophiomorpha*-burrowed sandstone), channeled estuarine and lagoonal deposits (medium-bedded, cross-stratified sandstone), and adjacent inner shelf deposits (interbedded very fine grained sandstone and siltstone). Foreshore deposits were probably destroyed during minor transgression, and lagoonal deposits beneath reworked barrier sands indicate barrier islands had formed (Cumella, 1981).

The Pictured Cliffs sandstones are litharenites to feldspathic litharenites containing abundant volcanic rock fragments. The source for much of this sediment is postulated to be a highland in southeastern Arizona raised during a Campanian tectonic event (Cumella, 1981). The lateral continuity of the Pictured Cliffs beds is relatively good because of the sandstone's origin as a progradational sandy strandplain (figs. 62 and 63). The formation rises stratigraphically and becomes younger from southwest to northeast across the basin (Fassett, 1977). Successive shoreline positions moved sporadically across the basin, resulting in steplike regressive sandstone deposits. In areas where the relative rates of subsidence and sediment supply remained in balance over a period of time, a thicker package of sand was deposited. This unusually thick sand body has been termed a "bench" where it occurs in the Point Lookout and Cliff House Sandstones (Hollenshead and Pritchard, 1961); the same terminology is used to describe the thicker sections of the Pictured Cliffs Sandstone.

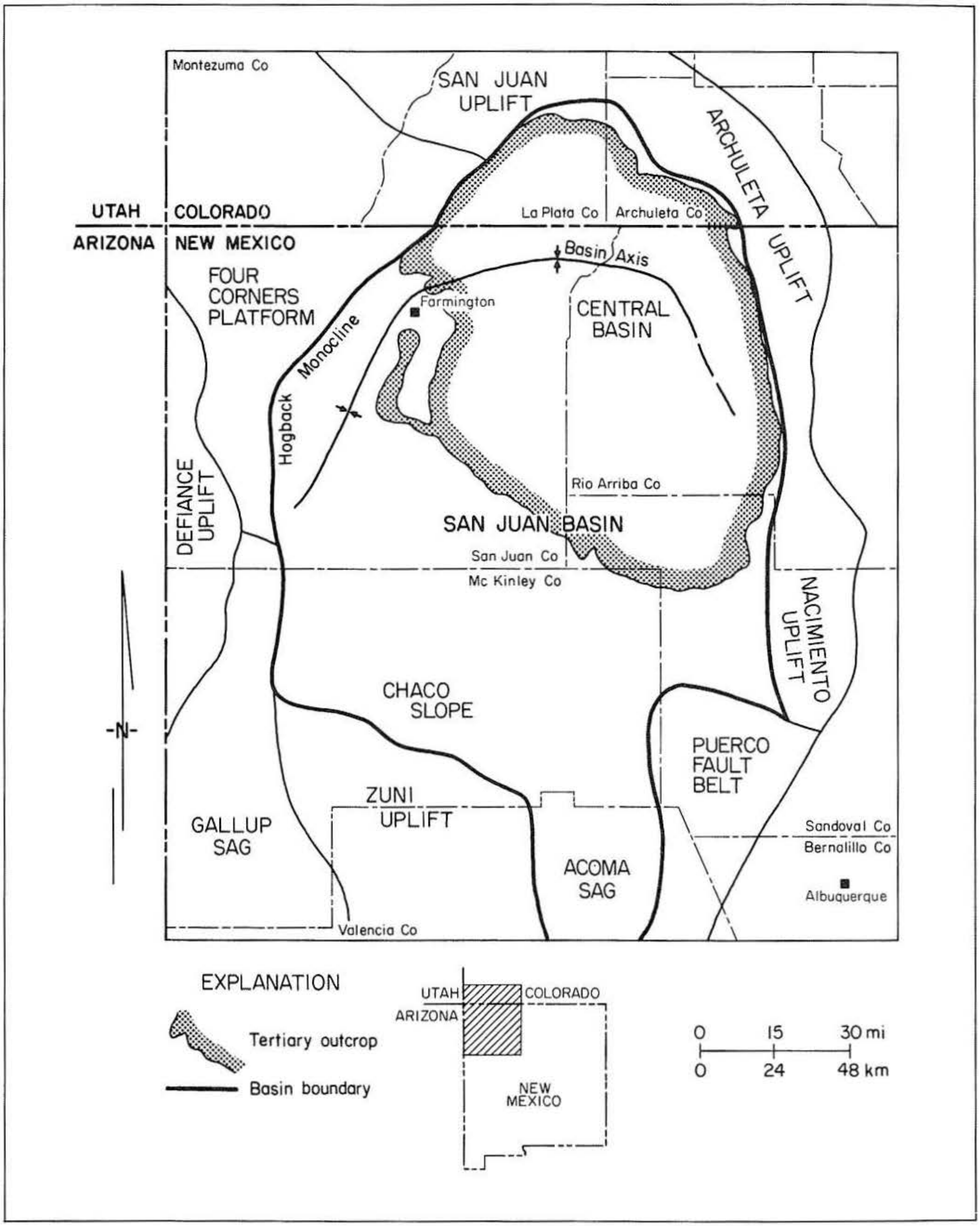

FIGURE 61. Location and generalized structure map, San Juan Basin (after Peterson and others, 1965).

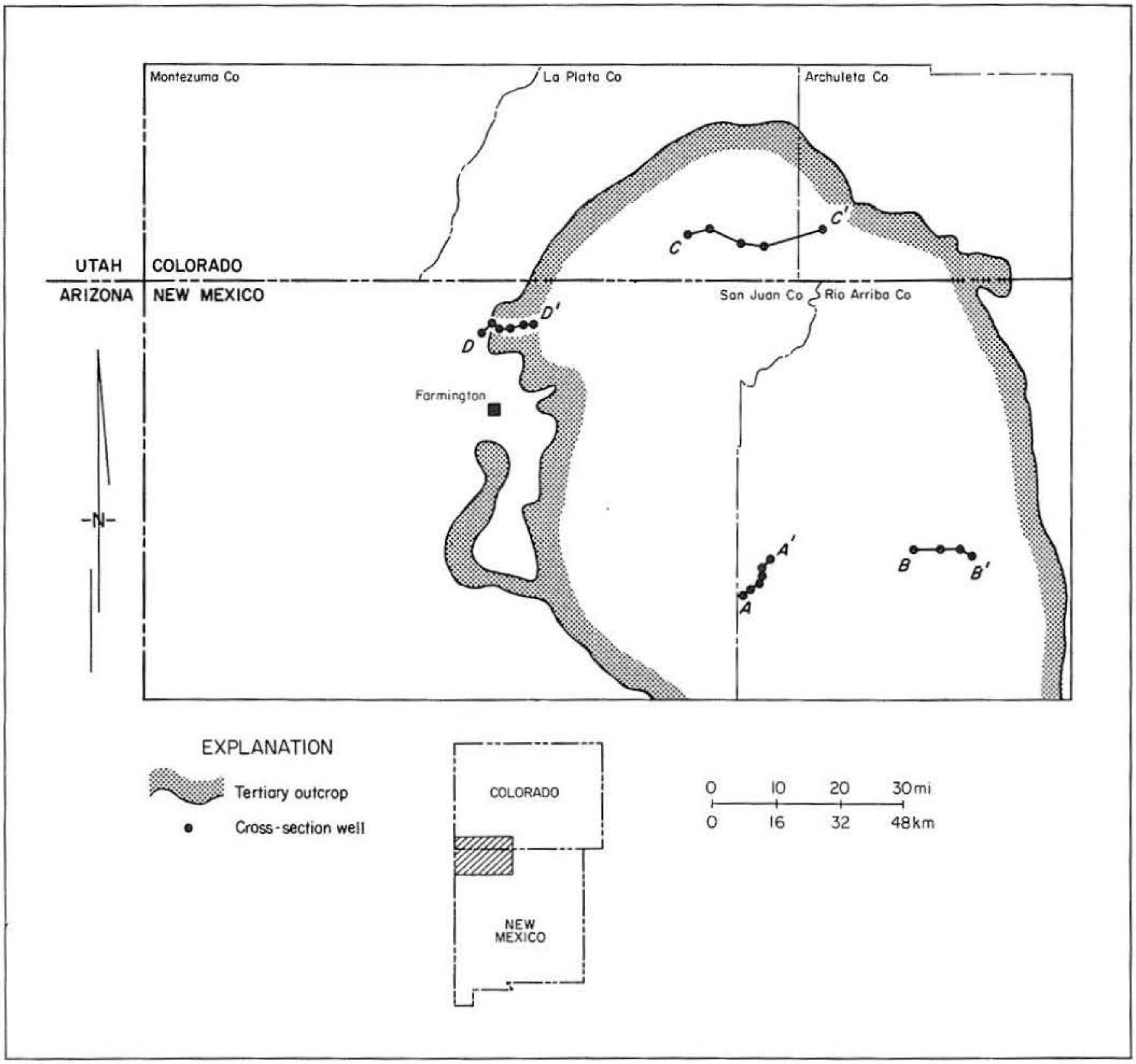

FIGURE 62. Index map of cross sections through Cretaceous strata, central and northern San Juan Basin. Cross section A-A' shown in figure 63, B-B' in figure 64, C-C' in figure 65, and D-D' in figure 66.

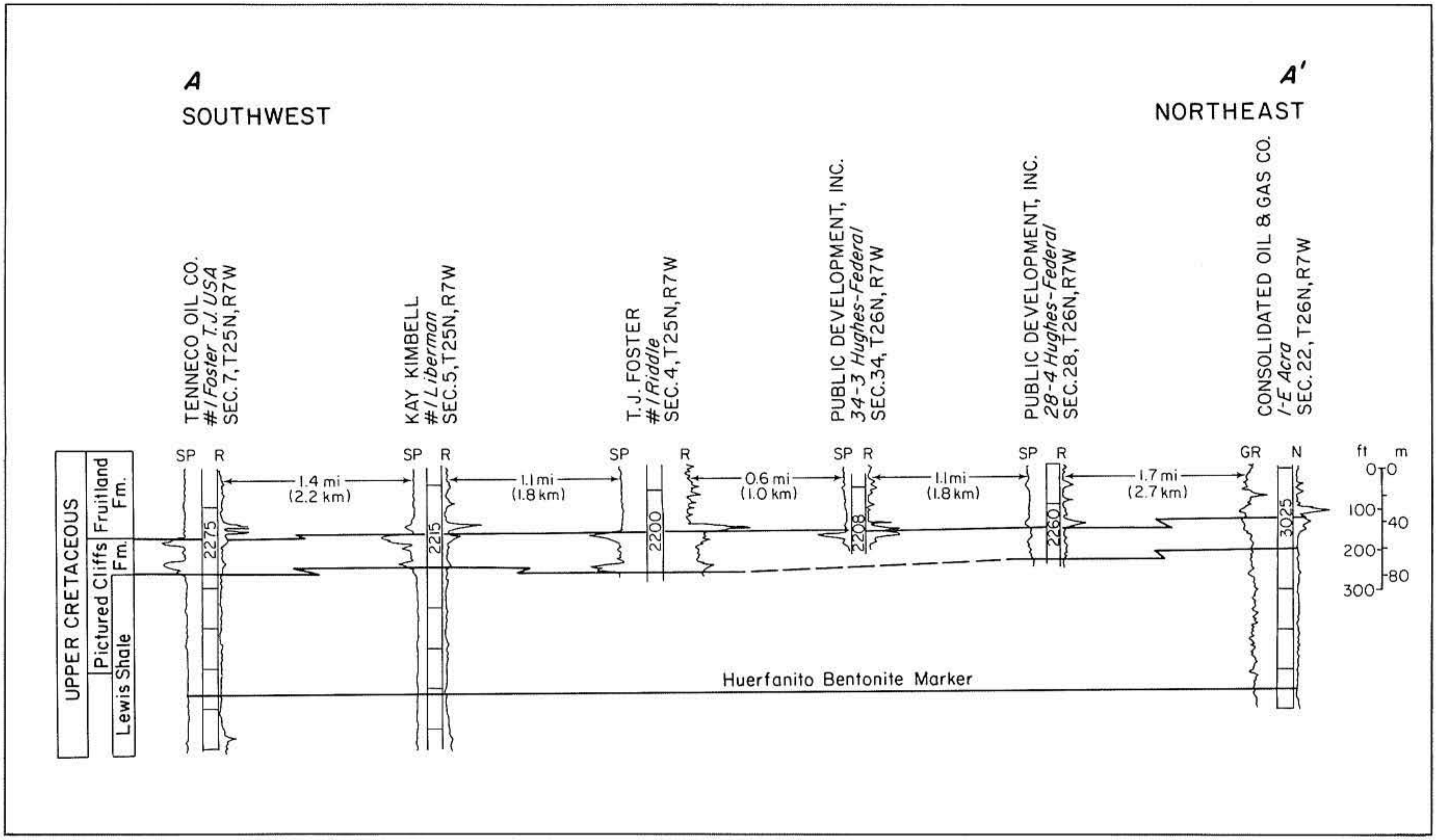

FIGURE 63. Northeast-southwest stratigraphic cross section A-A' through the Pictured Cliffs Sandstone and adjacent strata, San Juan Basin (after New Mexico Oil Conservation Division, 1982). Line of section shown in figure 62.

TABLE 50. Pictured Cliffs Sandstone, San Juan Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Pictured Cliffs Sandstone, Upper Cretaceous.	1. Northeast Blanco unit is 52.3 mi^2 in T30-31N, R6-8W in San Juan and Rio Arriba Counties, New Mexico. 2. Largo Canyon tight gas area is 22.5 mi^2 in T25-26N, R6-7W in Rio Arriba County, New Mexico.	Basinwide thickness range is 50 to 400 ft. 1. Range is 75 to 140 ft. 2. Range is 65 to 115 ft, average is 91 ft.	1. Range is 2,750 to 3,500 ft. 2. Range is 2,200 to 2,800 ft.	1. 0.25 to 0.65 Bcf/well. 2. 0.23 to 0.40 Bcf/well. No resource estimate for the entire trend.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
The San Juan Basin is a roughly circular, asymmetrical structural basin having a northwest-southeast-trending axial trace forming an arc along the northern edge of the basin. Tectonic events that formed the basin occurred principally during Late Cretaceous - early Tertiary (Laramide) time. Principal structures that bound the basin include the Hogback Monocline (west, northwest), the San Juan - Archuleta Uplifts (north), the Nacimiento Uplift (east, southeast), the Puerco fault zone (southeast), and the Chaco Slope and Zuni Uplift (south, southwest).	1.6° to 2.5° F/100 ft.	No data.	Compressional in Late Cretaceous - early Tertiary. Extensional on eastern side of basin in late Tertiary.

TABLE 51. Pictured Cliffs Sandstone, San Juan Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Deposition occurred during a net regression of the Upper Cretaceous epeiric seaway as strandplain, beach, and nearshore bar deposits. This formation is time transgressive; progressively younger strata were deposited to the northeast as the seaway receded. When the shoreline stabilized for brief periods during net regression, additional winnowing of fines occurred, resulting in trends of better reservoir quality.	1. Very fine grained to medium-grained sandstone, well sorted, angular to subrounded. 2. Fine-grained sandstone and siltstone.	Quartz ranges from 18.5% to 55%, averages 30%. Feldspar ranges from 4% to 22%, averages 12%. Average plagioclase is 6.5%. Average K-feldspar is 5.5%. Rock fragments range from 21% to 50%, average 38%. Volcanic rock fragments are most abundant, followed by metamorphic and then sedimentary rock fragments. Minor amounts of mica (biotite, muscovite, and chlorite), plus minor glauconite. Dolomite grains are common. Calcite cement.	Early: Dolomite grains precipitated along with some siderite. Burial (pre-Laramide): Abundant illite-smectite, relatively abundant quartz overgrowths, and patchy calcite. Minor development of secondary porosity. During and after basin formation: Calcite extensive locally; kaolinite extensive at basin margin.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
1. Gross pay range is 75 to 140 ft. 2. Gross pay range is 75 to 80 ft.	Pressure range is 1,375 to 1,500 psi. Average temperature is 120° F.	Occasionally encountered, no specific data.	Limited core at current stage of development. GR-resistivity and GR-density are typical logs.

TABLE 52. Pictured Cliffs Sandstone, San Juan Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
1. Permeability calculated from two wells ranges from 0.0116 to 0.0030 md/ft. 2. Calculated from core analysis of six wells, permeability to air is 0.37 md, which corresponds to an in situ permeability of 0.007 md at 2,387 ft. Also, calculated from six unstimulated flow tests (average flow is 13.7 Mcfd), permeability is 0.02 md.	1. Range is 40 to 50 ft. 2. Range is 30 to 50 ft.	1. For seven producing wells, average production was 27 Mcfd. 2. On the basis of 3-hour unstimulated flow test on seven wells, average flow was 13.7 Mcfd. These tests were run after an acid stimulation to clean the hole.	1. Range was 300 to 1,600 Mcfd. 2. Range was 335 to 1,300 Mcfd.	1. 8% to 9%/yr after stabilization. 2. 7% to 14%/yr.	1. When liquid hydrocarbons are produced, rates are less than 5 bpd. 2. Liquid hydrocarbons are produced approximately 10% of the time. The highest rate is 1.9 bpd of condensate.	1. No specific data available, but it is generally higher than 50%. 2. Average is 78%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Typical stimulations are sand and water (gel) hydraulic fracturing techniques using approximately 50,000 gal fluid and 50,000 to 75,000 lb sand. However, fracture sizes and techniques vary greatly among operators; some use more than 100,000 gal fluid and approximately 200,000 lb sand.	Very successful; however, no data are available regarding percent improvement.	160 acres.	The distribution of authigenic grain-coating clay is probably a major control on gas production by its effect on permeability.

TABLE 53. Pictured Cliffs Sandstone, San Juan Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
1. Approved by FERC. 2. Approved by State.	Total of 38 data wells referenced in both application areas combined. As of January 1974, a total of 1,666 wells produced gas from the Pictured Cliffs in Rio Arriba County, New Mexico.	1. 40%. 2. 64%.	1. Average total costs range from $100,000 to $155,000. 2. Average total costs range from $60,000 to $100,000. One reported fracture treatment cost $55,250; however, average stimulation costs range from $10,000 to $25,000.	1. Northwest Pipeline Corp., El Paso Natural Gas Co., and Southern Union Natural Gas Co. 2. El Paso Natural Gas Co.	Moderate. Two tight gas sand applications.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
Highly dissected terrain of Colorado Plateau having many mesas and canyons. Local relief of 500 to 1,000 ft and greater than 1,000 ft in some areas.	Arid to semiarid having 8 to 16 inches mean annual precipitation. Moderately hot summers, cold winters. Typically late afternoon thundershowers in the summer, moderate snowfall in the winter, and irregular precipitation patterns in the fall and spring.	Fair in areas that have been developed, poor in other areas. Road building requires large earth-moving machinery to reach remote areas.	Good. Expected to be similar to the barrier-strandplain facies of the Point Lookout Sandstone and the upper Dakota Sandstone of the San Juan Basin. Probably also similar to barrier-strandplain facies of the Mesaverde Group of the Uinta and Piceance Creek Basins and of the Hartselle Sandstone. Expected to be less similar to the transgressive Cliff House Sandstone.	All exploration and drilling services readily available in the San Juan Basin area. Farmington, New Mexico, is a major regional service center.

CLIFF HOUSE AND POINT LOOKOUT SANDSTONES, MESAVERDE GROUP, SAN JUAN BASIN

The Cliff House and Point Lookout Sandstones are part of the Upper Cretaceous Mesaverde Group within the San Juan Basin (fig. 60). These units are quartzose, fine-grained to very fine grained sandstones. Production is primarily from the north-central part of the basin east and northeast of Farmington, New Mexico. The Point Lookout Sandstone was deposited as a basal regressive marine sandstone of the Mesaverde Group, and the Cliff House Sandstone was deposited during a subsequent transgression. The Menefee Formation is continental in origin and contains fluvial sands and coal (fig. 60).

The data base on the Cliff House and Point Lookout Sandstones is good (tables 54 through 57); information was obtained from published articles, an unpublished thesis (Devine, 1980), and three tight gas sand applications (Colorado Oil and Gas Conservation Commission, 1981c; New Mexico Oil Conservation Division, 1981c and 1981d).

Structure

The San Juan Basin is a roughly circular, asymmetrical basin of Laramide age in northwest New Mexico and southern Colorado (fig. 61). Details on the structure of the basin are included in the previous section on the Pictured Cliffs Sandstone (p. 113).

Stratigraphy

The Mesaverde Group of the San Juan Basin forms a regressive wedge between the marine Mancos Shale and the marine Lewis Shale. In the southwestern part of the San Juan Basin, either the continental Menefee Formation or an equivalent unit forms the entire Mesaverde Group. This unit thins from 860 ft along the southwestern edge of the basin to 160 ft along the northeastern edge, where the regressive and transgressive Mesaverde sandstones converge. The stratigraphic rise in the Point Lookout Sandstone is about 350 ft over this same geographic area (Hollenshead and Pritchard, 1961). The regressive Point Lookout Sandstone is generally thicker than the transgressive Cliff House Sandstone, which underlies the Lewis Shale.

Depositional Systems

The Point Lookout was deposited during the northeastward regression and the Cliff House was deposited during the southwestward transgression of the Upper Cretaceous epicontinental sea. A series of strike-oriented, cuspate to linear sand thicks in the Point Lookout Sandstone indicates deltaic strandplain progradation in a wave-dominated environment. Beach ridges prograded seaward to successive shoreline positions; shallow channels through the accretionary ridges were points of input for sediment subsequently moved alongshore and incorporated into the ridges (Devine, 1980). Progradation of the shoreline was in steps, depending on the relative rate of subsidence, the rate of sediment input, and the occurrence of eustatic changes in sea level. In areas where a balance of sediment supply and the relative rate of subsidence caused the shoreline to stabilize, thick sandstone benches were deposited (Hollenshead and Pritchard, 1961).

As periodic minor transgressions reworked strandplain deposits, distributaries avulsed and depocenters shifted alongshore. Detailed outcrop studies revealing reworked barrier-island and lagoonal deposits provide evidence of this process. These lagoons were partly filled, transformed to a channeled estuarine system, and later completely filled when sediment again reached the nearshore zone and a new cycle of progradation began (Devine, 1980).

The Cliff House Sandstone is thinner than the Point Lookout Sandstone (figs. 62 and 64) and consists of a few thick sandstone lenses irregularly dispersed along a surface that rises gently to the southwest (Fassett, 1977). These sands may be the preserved parts, possibly upper shoreface, of transgressive barrier-island systems, but the exact facies composition of the Cliff House has not been described in published studies.

The continuity of the regressive Point Lookout Sandstone appears to be better than that of the Cliff House Sandstone; therefore, the former would tend to form gas reservoirs of more widespread blanket geometry (figs. 62 and 64). The depositional systems of the Mesaverde Group in the San Juan Basin are relatively well understood and form a good model for Mesaverde deposition throughout the Rocky Mountain region.

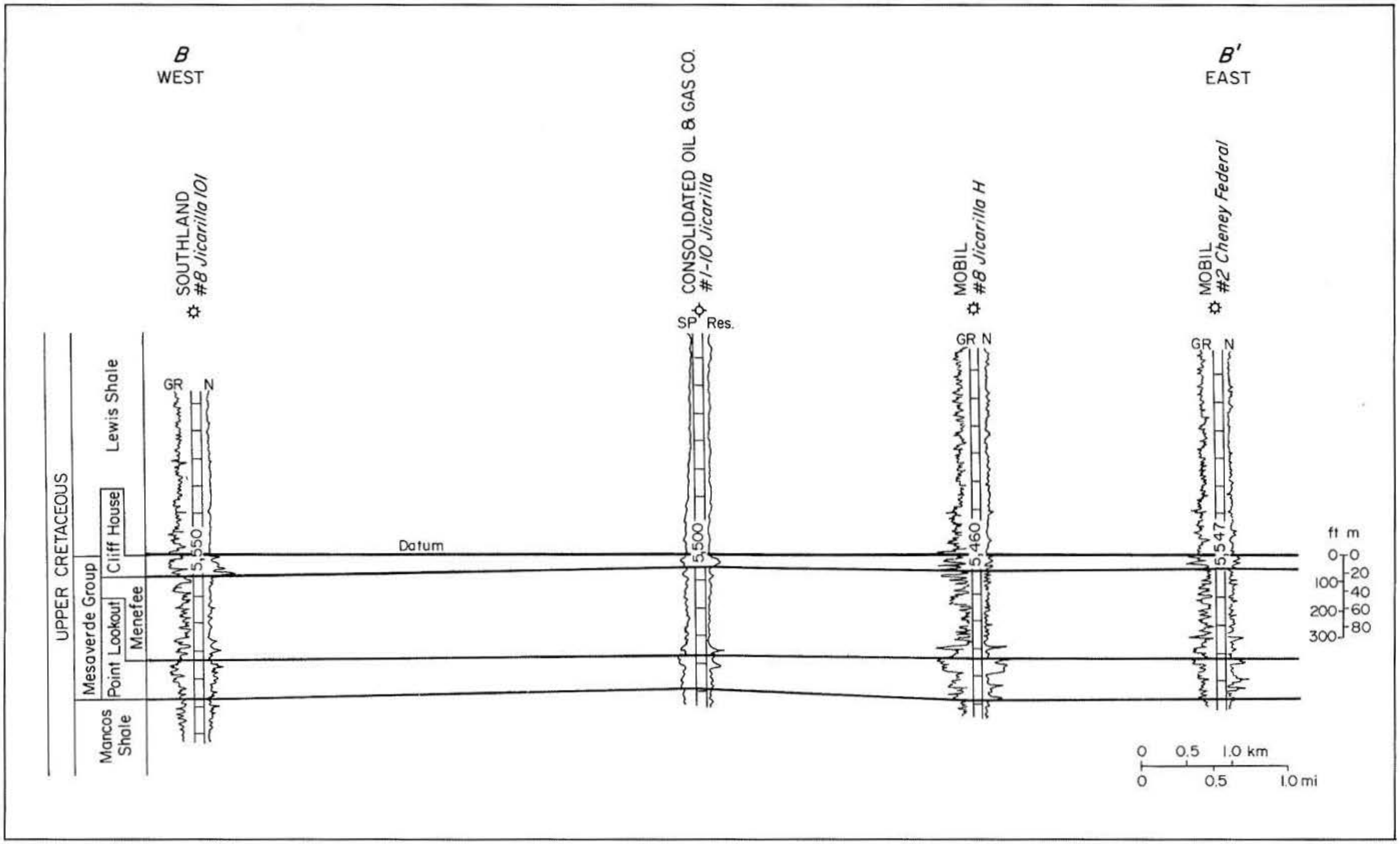

FIGURE 64. East-west stratigraphic cross section B-B′ through the Mesaverde Group, San Juan Basin (after New Mexico Oil Conservation Division, 1981c). Line of section shown in figure 62.

TABLE 54. Cliff House and Point Lookout Sandstones, San Juan Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Cliff House and Point Lookout Sandstones, Mesaverde Group, Upper Cretaceous.	1. Rattlesnake Canyon area includes 19 mi^2 in parts of T32N, R8-9W in San Juan County, New Mexico. 2. Blanco Mesaverde area includes 21.75 mi^2 in parts of T26-27N, R2-3W in Rio Arriba County, New Mexico. 3. Ignacio Blanco Field area includes 576 mi^2 in parts of T32-34N, R6-11W in La Plata and Archuleta Counties, Colorado.	1. Cliff House average is 50 ft. Point Lookout range is 150 to 200 ft. 2. Average thickness of Cliff House and Point Lookout separately is 100 ft in western part of area; average is less than 50 ft in eastern part of area. 3. Total Mesaverde range is 500 to 800 ft.	1. Average to top of Cliff House is 4,200 ft. 2. Average to top of Cliff House is 5,560 ft. 3. Depth to top of Cliff House ranges from 4,500 to 6,300 ft, average is 5,380 ft.	1. 1.25 to 2.0 Bcf/well. 2. 1.0 to 1.75 Bcf/well. 3. 0.5 to 4.0 Bcf/well. Total estimated recovery is 550 Bcf. No resource estimate for the entire trend.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
The San Juan Basin is a roughly circular, asymmetrical structural basin having a northwest-southeast-trending axial trace forming an arc along the northern edge of the basin. Tectonic events that formed the basin occurred principally during Late Cretaceous - early Tertiary (Laramide) time. Principal structures that bound the basin include the Hogback Monocline (west, northwest), the San Juan Archuleta Uplift (north), the Nacimiento Uplift (east, southeast), the Puerco fault zone (southeast), and the Chaco Slope and Zuni Uplift (south, southwest).	1.6° to 2.5° F/100 ft.	No data.	Compressional in Late Cretaceous - early Tertiary. Extensional on eastern side of basin in late Tertiary.

TABLE 55. Cliff House and Point Lookout Sandstones, San Juan Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
The Mesaverde Group consists of three stacked, time-transgressive formations. The lowermost formation, the Point Lookout, was deposited as strandplain and nearshore sands during a net northeastward regression of the Late Cretaceous epeiric seaway. Sediment dispersal was from small, wave-dominated deltas that prograded northeastward. Associated nonmarine (fluvial, coastal plain, paludal) units were deposited to the southwest of the Point Lookout. These units are found in the Menefee Formation, which overlies the Point Lookout. Because of changes in sediment supply, rates of subsidence, or eustatic conditions, the Point Lookout regression halted and the Late Cretaceous seaway once again transgressed the area. Transgressive shoreline sands were deposited over the Menefee, and they compose the uppermost formation of the Mesaverde Group, the Cliff House Sandstone.	Cliff House is very fine grained, angular to subangular, poorly to moderately sorted sandstone. Point Lookout is fine-grained to very fine grained, angular to subangular, poorly to moderately sorted sandstone.	Cliff House is dominantly quartz, having chert, feldspar, and clay in varying amounts and rock fragments in minor amounts. Point Lookout is dominantly quartz, having feldspar and clay in varying amounts and rock fragments and chert in minor amounts.	Cliff House has authigenic clays and calcareous cements. Point Lookout has authigenic clays, calcareous cements, and siliceous cements.

Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
1. Cliff House average gross perforated interval is 50 ft. Point Lookout gross perforated interval is 150 to 200 ft. 2. In Cliff House and Point Lookout, gross perforated interval is 50 to 100 ft for each unit. 3. In Cliff House and Point Lookout, gross perforated interval is 50 to 120 ft for each unit.	1. Average pressure is 1,177 psi. Average temperature is 150° F. 2. Average pressure is 1,250 psi. Average temperature is 142° F. 3. Average pressure is 1,300 psi. Average temperature is 160° F.	Occasionally encountered, but no data available on the distribution of fractures in relation to gas production.	Limited core at current stage of development. GR-resistivity and GR-neutron density are typical logs.

TABLE 56. Cliff House and Point Lookout Sandstones, San Juan Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
1. Average in situ permeability calculated from flow tests is less than 0.02 md. Average porosity is 11.3%.	1. Average is 156 ft.	1. On the basis of one test, flow was 47 Mcfd.	1. Range was 145 to 3,483 Mcfd.	1. 7% to 8%/yr.	1. No liquid hydrocarbons are produced.	1. Average is 55%.
2. Average in situ permeability calculated from flow tests ranges from approximately 0.06 to 0.07 md. Average porosity is 14%.	2. Average is 146 ft.	2. On the basis of 11 tests, flow was 150 Mcfd.	2. Range was 1,800 to 3,300 Mcfd.	2. 4% to 5%/yr.	2. Liquid hydrocarbons are produced after stimulation; average rate is 3.2 bpd of condensate/well.	2. No data.
3. Average in situ permeability is 0.061 md calculated from flow tests and core data of 13 wells. Average porosity is 9.1%.	3. Range is 20 to 150 ft.	3. On the basis of five tests, average was 100 Mcfd, range was 30 to 289 Mcfd.	3. Range was 500 to 3,600 Mcfd.	3. 6%/yr.	3. Liquid hydrocarbons generally not produced.	3. Range is 35% to 65%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing techniques using a sand and water (gel) mixture are currently used. Typical treatment includes 100,000 to 200,000 gal fluid and 75,000 to 200,000 lb sand. However, treatments using more than 400,000 lb sand and a correspondingly large volume of fluid have been reported.	Very successful; however, no data are available regarding percent improvement.	160 acres.	The Point Lookout Sandstone is the better gas producer of the two Mesaverde Group sandstones that were examined.

TABLE 57. *Cliff House and Point Lookout Sandstones, San Juan Basin: Economic factors, operating conditions, and extrapolation potential.*

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Two applications approved by State.	As of December 1973, a total of 2,095 wells were producing from the Blanco Mesaverde Pool in Rio Arriba County, New Mexico.	No data.	1. Total costs range from $275,000 to $375,000, average costs are $336,000. Average stimulation treatment costs are $65,000 (1981 dollars). 2. Total costs range from $250,000 to $375,000. Average stimulation treatment costs are $40,000 (1981 dollars). 3. Total costs range from $280,000 to $400,000. Average stimulation treatment costs are $50,000 (1981 dollars).	1. El Paso Natural Gas Co. and Northwest Pipeline Corp. 2. Northwest Pipeline Corp. 3. El Paso Natural Gas Co. and Northwest Pipeline Corp.	Moderate. Three tight gas sand applications cover these units within the Mesaverde Group.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
Highly dissected terrain of Colorado Plateau having many mesas and canyons. Local relief of 500 to 1,000 ft and greater than 1,000 ft in some areas.	Arid to semiarid having 8 to 16 inches mean annual precipitation. Moderately hot summers, cold winters. Typically, late afternoon thundershowers in the summer, moderate snowfall in the winter, and irregular precipitation patterns in the fall and spring.	Fair access in areas that have been developed, poor in other areas. Road building requires large earth-moving machinery to reach remote areas.	Good. Expected to be similar to barrier-strandplain facies of the Pictured Cliffs Sandstone and the upper Dakota Sandstone in the San Juan Basin and of the Fox Hills Sandstone. Probably also similar to barrier-strandplain facies of the Mesaverde Group in the Uinta and Piceance Creek Basins and of the Hartselle Sandstone.	All exploration and drilling services readily available in the San Juan Basin area. Farmington, New Mexico, is a major regional service center. Extrapolation potential probably somewhat less for the transgressive Cliff House Sandstone than for the Point Lookout Sandstone.

SANOSTEE MEMBER OF THE MANCOS SHALE, SAN JUAN BASIN

The Sanostee Member of the Mancos Shale, also known as the Juana Lopez Member, consists of fine- to coarse-grained calcarenites and shale and argillaceous, very fine grained, calcareous sandstone. The terrigenous clastic sediments are mostly toward the base of the unit. The calcarenite beds, which are fractions of an inch to more than a foot thick, are near the top of the unit and contain an ammonite-pelecypod fauna. Most beds are predominantly *Inoceramus* sp. Some beds in the lower part of the unit contain fish bone, teeth, and scales. It has been suggested that a decrease in the amount of clastic material coming into the basin permitted the accumulation of the calcarenite beds undiluted by mud (Dane and others, 1966; Lamb, 1968).

The Sanostee Member of the Mancos Shale has been approved by the FERC as a tight gas sand in the Ignacio area in La Plata and Archuleta Counties, Colorado, on the northern margin of the San Juan Basin (Colorado Oil and Gas Conservation Commission, 1980g). The Sanostee Member in the application area is described as a very fine grained, very silty, clay-rich, calcareous sandstone. It seems likely that the abundant calcareous cement was derived from the calcarenite beds in the unit. Such a lithology would make the Sanostee Member somewhat different from other units included in this survey; the tight gas sand most similar to the Sanostee Member is the Mancos "B" interval. Both of these units are shelf deposits within the Mancos Shale, but the Mancos "B" interval does not have the extensive calcareous cement and the interspersed calcarenite beds of the Sanostee. Because of its lithologic characteristics, the extrapolation potential of the Sanostee Member is considered low. It apparently is not a major exploration target, and only limited data on its characteristics are available (table 58).

TABLE 58. Selected characteristics of the Sanostee Member of the Mancos Shale, Ignacio area, San Juan Basin (Colorado Oil and Gas Conservation Commission, 1980g).

Permeability: 0.04 md
Pressure: 3,100 psi
Temperature: 240° F
Porosity: 6.7% to 9.5%, average 8.3%
Net pay: 14 to 20 ft, average 17 ft
Depth: 7,550 to 7,700 ft, average 7,600 ft
Water saturation: 56% to 60%
Pre-stimulation flow rate: 20 to 42 Mcfd, average 31 Mcfd

DAKOTA SANDSTONE, SAN JUAN BASIN

The Dakota Sandstone consists of fine-grained quartz sandstone that stratigraphically overlaps the Lower to Upper Cretaceous boundary in the San Juan Basin (fig. 60). The part of the Dakota Sandstone that contains blanket-geometry gas reservoirs is within the upper part of the formation and is therefore most probably of Late Cretaceous age. The Dakota Sandstone has been a long-term gas producer in the San Juan Basin. The Basin Dakota Field (5.0 Tcf estimated recovery) was discovered in 1947, and the Ignacio Blanco Dakota Field (0.3 Tcf estimated recovery) was discovered in 1950 (Bowman, 1978; Hoppe, 1978). Early production depended on natural fracturing and stimulation by shooting with nitroglycerin. Sand-water fracture treatments were later developed and used routinely. Both these fields have low permeabilities, ranging from 0.1 to 0.25 md in the Basin Dakota Field, for example; tight gas designations are currently of interest for even tighter field-margin areas than those areas already developed.

The data base on the Dakota Sandstone is very good; information was obtained from numerous publications, a report by consulting geologist W. R. Speer (1982), and six applications for tight gas sand designations in Colorado and New Mexico (Colorado Oil and Gas Conservation Commission, 1980f, 1980g, and 1981b; New Mexico Oil Conservation Division, 1981b, 1981e, and 1981f). Tables 59 through 62 are on the New Mexico part of the basin, and tables 63 through 66 are on application areas in Colorado.

Structure

The San Juan Basin is a roughly circular, asymmetrical basin of Laramide age in northwest New Mexico (fig. 61). Details on the structure of the basin are included in the previous section on the Pictured Cliffs Sandstone (p. 113).

Stratigraphy

The Dakota Sandstone was the basal sequence formed by the southwesterly transgression of the Cretaceous sea as it entered the western interior of North America. Beneath the Dakota Sandstone are fluvial and lacustrine rocks of the Upper Jurassic Morrison Formation, and above the Dakota is the marine Mancos Shale (Hoppe, 1978) (fig. 60). A major unconformity between the Morrison Formation and the Dakota can be recognized in outcrop but is difficult to pick in the subsurface. In the northern part of the basin, the Burro Canyon Formation lies between the unconformity and the Morrison Formation; some authors consider this unit to be part of the Dakota Sandstone (Owen and Siemers, 1977). Although formal members within the Dakota have been delineated, these units are not of particular concern to this study.

Depositional Systems

In the northwestern part of the San Juan Basin, the Dakota Sandstone is composed entirely of fluvial sandstones, whereas nearly all marine sandstones and shales are in the southeastern part (Fassett and others, 1978). Intertonguing is common between these facies as transgressive marine shales wedge out to the west and north and regressive marginal marine sandstones wedge out to the south and east. The Dakota includes fluvial through marine facies in the central basin area and in much of the productive tight sand areas along the northern to northeastern margin of the basin (Owen, 1973).

In the basin-margin areas, fluvial sandstones deposited by meandering streams and associated floodplain deposits begin a vertical sequence through the Dakota Sandstone. The floodplain deposits consist of carbonaceous shales, a few thin coal beds, and minor siltstones. Nonmarine facies are followed by transitional estuarine and lagoonal facies of mudstone, siltstone, and small amounts of sandstone representing tidal inlets, tidal channels, and washover fans. The uppermost Dakota consists of an upward-coarsening sequence of barrier-strandplain deposits including lower and upper shoreface facies. Less well sorted and less porous sands in the barrier-strandplain system are interpreted to be offshore bars. Many minor episodes of regression and transgression occurred within the upper part of the Dakota Sandstone, leading to deposition of barrier-strandplain facies over distances of several tens of miles perpendicular to shoreline trends (Owen, 1973; Hoppe, 1978).

The lateral continuity of sands in the barrier-strandplain facies is moderate. Widely spaced wells (figs. 62 and 65) show variation in sand continuity, except in the uppermost sand underlying the transgression of the Graneros Shale; by its use as a stratigraphic boundary, this sand appears to have good continuity. Locally, sands show good lateral continuity at well spacings of 0.5 to 1.5 mi (figs. 62 and 66).

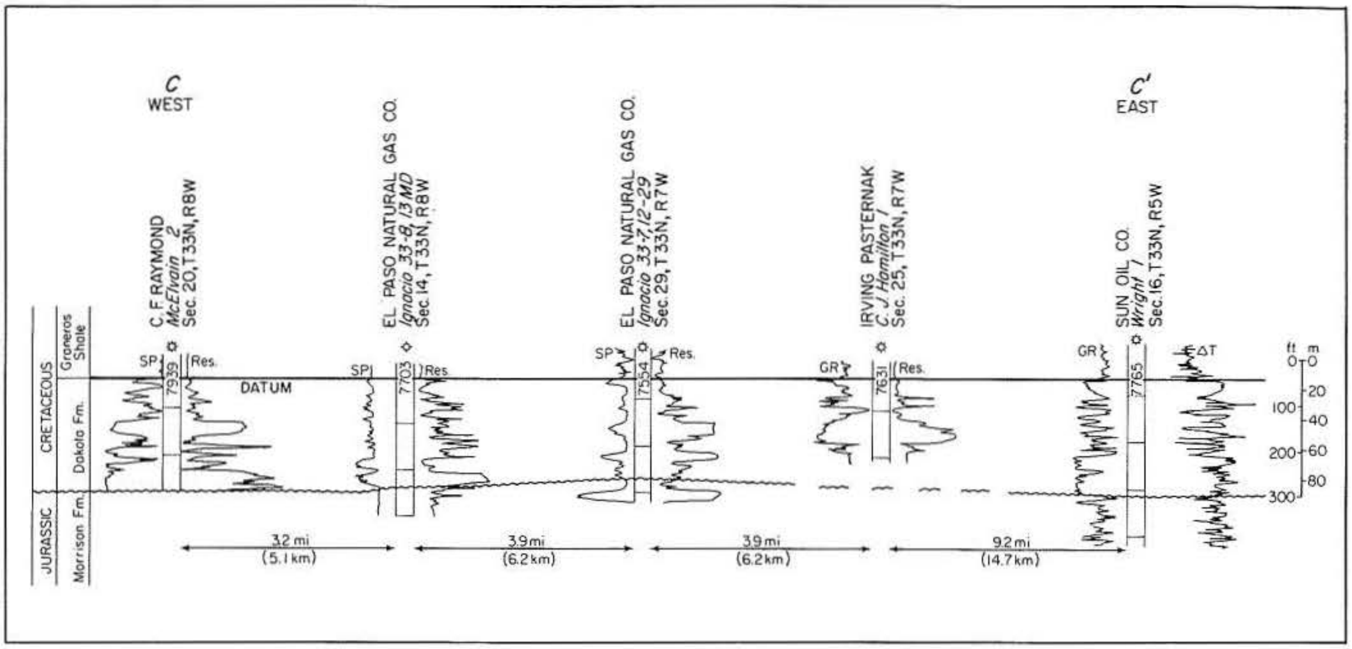

FIGURE 65. East-west stratigraphic cross section C-C' through the Dakota Sandstone, San Juan Basin (after Colorado Oil and Gas Conservation Commission, 1981b). Line of section shown in figure 62.

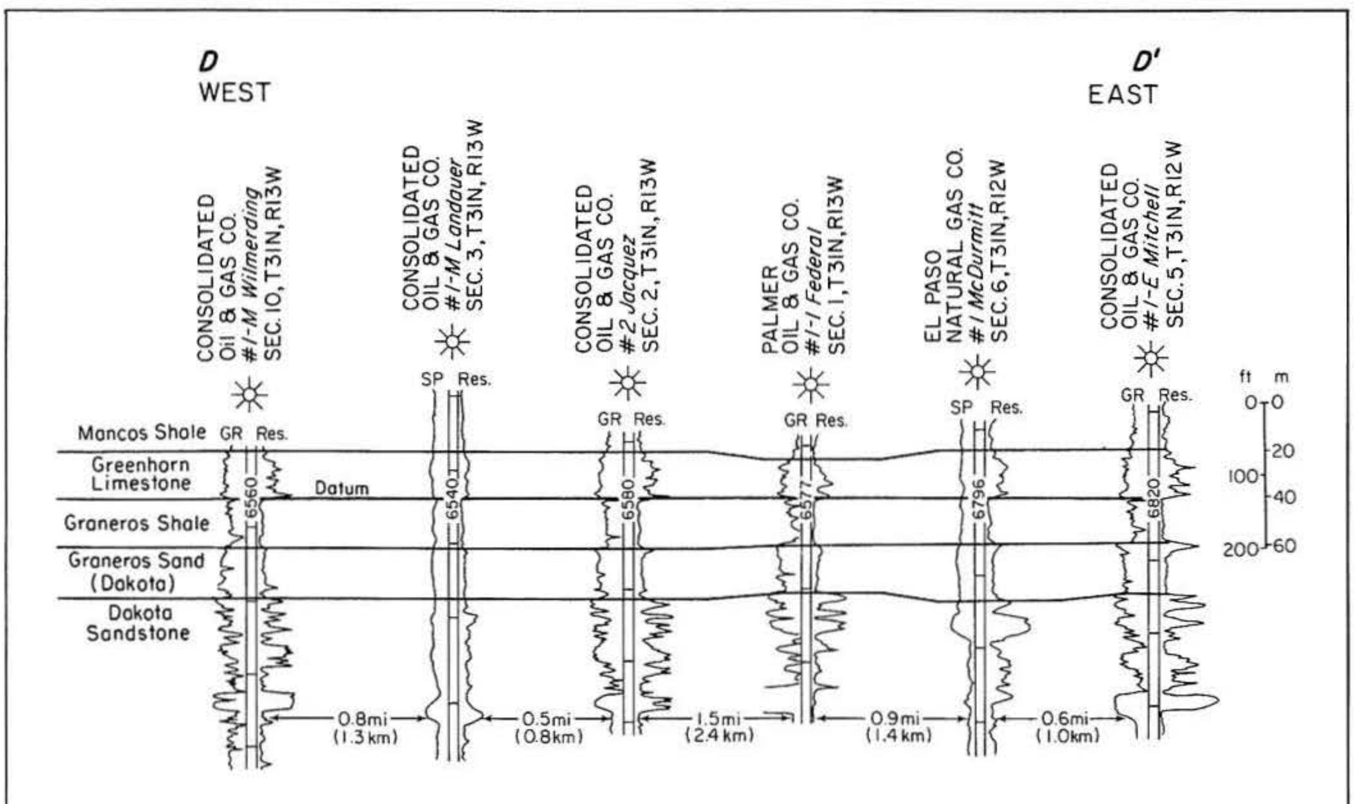

FIGURE 66. East-west stratigraphic cross section D-D' through the Dakota Sandstone and overlying strata, San Juan Basin (after New Mexico Oil Conservation Division, 1981b). Line of section shown in figure 62.

TABLE 59. Dakota Sandstone, San Juan Basin (New Mexico): General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Dakota Sandstone, Upper Cretaceous.	1. In Huerfano area of Basin Dakota Field, total area applied for is 211 mi² in T24-25N, R7-10W in parts of San Juan and Rio Arriba Counties, New Mexico. 2. In northwest Blanco area, total area applied for is 23.7 mi² in parts of T31N, R13W in San Juan County, New Mexico. 3. In Westside tight gas area, total area applied for is 258 mi² in parts of T26-30N, R12-15W in San Juan County, New Mexico.	1. Range is 200 to 350 ft. 2. Range is 200 to 300 ft. 3. Range is 250 to 300 ft.	1. Average is 6,350 ft, range is 6,000 to 6,500 ft. 2. Average is 6,544 ft, range is 6,100 to 6,820 ft. 3. Average is 5,942 ft, range is 5,900 to 6,800 ft.	1. 0.3 to 2.0 Bcf/well. 2. 0.8 to 2.5 Bcf/well. 3. 0.5 to 2.0 Bcf/well. Additional 2.2 Tcf maximum recoverable gas is outside present field limits (National Petroleum Council, 1980).	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
The San Juan Basin is a roughly circular, asymmetrical structural basin having a northwest-southeast-trending axial trace forming an arc along the northern edge of the basin. Tectonic events that formed the basin occurred principally during Late Cretaceous - early Tertiary (Laramide) time. Principal structures that bound the basin include the Hogback Monocline (west, northwest), the San Juan - Archuleta Uplift (north), the Nacimiento Uplift (east, southeast), the Puerco fault zone (southeast), and the Chaco Slope and Zuni Uplift (south, southwest).	1.6° to 2.5° F/100 ft.	1. No data. 2 and 3. 0.38 to 0.42 psi/ft.	Compressional in Late Cretaceous - early Tertiary. Extensional on eastern side of basin in late Tertiary.

TABLE 60. Dakota Sandstone, San Juan Basin (New Mexico): Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY			
Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Deposited as the basal sequence of the southwest-transgressing Late Cretaceous sea. The basal Dakota was deposited in nonmarine conditions as a braided-stream system. This was followed by a meandering-stream system, which included paludal and overbank deposits. Transitional nonmarine and marine sedimentation followed. Lagoonal, estuarine, and storm-washover deposits constitute this facies tract. The upper Dakota Sandstone includes barrier- and offshore-bar facies. These are laterally persistent, about 40 to 60 ft thick, and consist of an upward-coarsening sandstone sequence.	Fine-grained, quartzose sandstone and carbonaceous shale having occasional conglomerates and coal in the basal section. The upper coastal sandstones are typically very fine grained to fine grained. Upward, they coarsen, and sorting improves.	Sandstone is quartzose. Coastal units are locally glauconitic and are characteristically micaceous (muscovite and biotite), whereas fluvial units have shale lenses composed dominantly of illite and minor amounts of kaolinite.	Calcareous and argillaceous cements present.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Typically, only the upper Dakota sands are gas prone; therefore, gross pay range is 75 to 200 ft.	1. Pressure range is 2,500 to 3,500 psi. Average temperature is 150° F. 2. Pressure range is 2,590 to 2,660 psi. Average temperature is 150° F. 3. Average pressure is 2,320 psi. Average temperature is 150° F.	Occasionally encountered.	Limited core at current stage of development. GR-resistivity and GR-neutron density are typical logs.

TABLE 61. Dakota Sandstone, San Juan Basin (New Mexico): Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
1. In Huerfano area, porosity range is 5% to 15%, average is 5%. Average in situ permeability is 0.024 md (calculated from seven core analyses). 2. Calculated in situ permeability of five wells ranges from 0.0877 to 0.00068 md, average is 0.0218 md. 3. Permeability calculated from cores of seven wells is 0.07 md to air, which corresponds to 0.003 md in situ. In pay zone, porosity range is 2% to 16%, average is 9.5%.	1. Average is 60 ft, range is 25 to 75 ft. 2. Average is 66 ft, range is 50 to 100 ft. 3. Average is 40 ft, range is 35 to 50 ft.	1. On the basis of one natural unstimulated flow test, natural flow was 152 Mcfd. 2. On the basis of five unstimulated flow tests, natural flow range was TSTM to 224 Mcfd. 3. On the basis of one unstimulated flow test after acidizing, natural flow was 6.7 Mcfd.	1. Range was 100 to 350 Mcfd. 2. Range was 50 to 380 Mcfd. 3. Range was 100 to 350 Mcfd.	1. 9%/yr. 2. 5% to 7%/yr. 3. 5% to 9%/yr.	1. Average unstimulated oil (plus condensate) production is 1.3 bpd (average of all producing Dakota wells in the area). 2. When liquid hydrocarbons are produced, rates are less than 5 bpd. 3. Ratio of oil and condensate to gas after stimulation is 0.026 bbl/Mcf. Water is generally produced from the lower Dakota interval in most areas.	Range is 30% to 50%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Two methods of hydraulic fracturing in stages are used: (1) isolating potential pays by using bridge plugs and selectively perforating and fracturing them; (2) perforating all potential pays, then using a ball-sealer staging fracture method. Typical sand and water (gel) hydraulic fracture treatments use 60,000 to 125,000 gal fluid and 60,000 to 110,000 lb sand. Maximum injection pressure is about 4,000 psi, and average injection rate is 30 bpm.	Very successful; however, no data are available regarding percent improvement.	160 acres.	Originally drilled at 320-acre spacing, but infill drilling extensively conducted since mid-1970's at 160-acre spacing. Development wells in all formations in the San Juan Basin had a 96% success ratio in 1980. Many of the 826 wells drilled were infill wells.

TABLE 62. Dakota Sandstone, San Juan Basin (New Mexico): Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
1. Approved by FERC. 2. Approved by State.	1. Area contains 35 Dakota gas wells, 22 of which were abandoned as of May 6, 1981. 2. No data. 3. 7% of the application area contains 36 producing wells and 69 abandoned wells. As of January 1, 1974, a total of 2,299 producing Dakota wells in the basin.	1. 37% of Dakota wells in area have gas production. 2. No data. 3. 34% of Dakota wells in area have gas production. 40% success for exploratory wells in 1980 for all formations in the San Juan Basin.	Total drilling and completion costs, including stimulation, range from \$300,000 to \$500,000. Average stimulation costs are \$75,000 (1980-1981 period).	El Paso Natural Gas Co., Northwest Pipeline Corp., and Southern Union Gathering Co. Other outlets are the Gas Company of New Mexico, Amoco Production Co., Inland Corp., Permian Corp., Plateau, Inc., Giant Refinery, Caribou Four Corners Oil, Inc., and Thriftway Co. Pipelines are adequate in all areas.	High. Six FERC applications.

OPERATING CONDITIONS

Physiography	*Climatic conditions*	*Accessibility*
Highly dissected terrain of Colorado Plateau having many mesas and canyons. Local relief of 500 to 1,000 ft and greater than 1,000 ft in some areas.	Arid to semiarid having 8 to 16 inches mean annual precipitation. Moderately hot summers, cold winters. Typically late afternoon thundershowers in the summer, moderate snowfall in the winter, and irregular precipitation patterns in the fall and spring.	Fair access in areas that have been developed, poor in other areas. Road building requires large earth-moving machinery to reach remote areas.

EXTRAPOLATION POTENTIAL

	Comments
Good. Expected to be similar to barrier-strandplain facies of the Cliff House Sandstone, which is also transgressive, and possibly to parts of the Pictured Cliffs and Point Lookout Sandstones. Probably also similar to transgressive and regressive sandstones of the Mesaverde Group, such as the upper Almond Formation, in other Rocky Mountain basins.	All exploration and drilling services readily available. Farmington, New Mexico, is a major regional service center.

TABLE 63. Dakota Sandstone, San Juan Basin (Colorado): General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Dakota Sandstone, Upper Cretaceous.	1. In Ignacio area, La Plata County, Colorado, total area applied for is 283 mi^2. 2. In Ignacio Blanco Field area, La Plata and Archuleta Counties, Colorado, total area applied for is 428.5 mi^2.	1. Range is 210 to 230 ft. 2. Range is 225 to 250 ft.	1. Range is 7,300 to 8,000 ft, average is 7,600 ft. 2. Range is 7,180 to 8,720 ft, average is 7,930 ft.	Estimated gas recovery is 250 to 300 Bcf from the Ignacio Blanco Dakota Field. Additional 2.2 Tcf maximum recoverable gas is outside present field limits (National Petroleum Council, 1980).	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
The San Juan Basin is a roughly circular, asymmetrical structural basin having a northwest-southeast-trending axial trace forming an arc along the northern edge of the basin. Tectonic events that formed the basin occurred principally during Late Cretaceous - early Tertiary (Laramide) time. Principal structures that bound the basin include the Hogback Monocline (west, northwest), the San Juan - Archuleta Uplift (north), the Nacimiento Uplift (east, southeast), the Puerco fault zone (southeast), and the Chaco Slope and Zuni Uplift (south, southwest).	1.6° to 2.5° F/100 ft.	No data.	Compressional in Late Cretaceous - early Tertiary. Extensional on eastern side of basin in late Tertiary.

TABLE 64. Dakota Sandstone, San Juan Basin (Colorado): Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
See Dakota Sandstone, San Juan Basin (New Mexico), table 60.	See Dakota Sandstone, San Juan Basin (New Mexico), table 60.	See Dakota Sandstone, San Juan Basin (New Mexico), table 60.	See Dakota Sandstone, San Juan Basin (New Mexico), table 60.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Typically, only the upper Dakota sands are gas prone; therefore, gross pay range is 60 to 100 ft.	1. Average pressure is 2,800 psi. Average temperature is 240° F. 2. Average pressure is 3,400 psi. Average temperature is 210° F.	Occasionally encountered.	Limited core at current stage of development. GR-resistivity and GR-density are typical logs.

TABLE 65. Dakota Sandstone, San Juan Basin (Colorado): Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
1. Porosity range is 7% to 10%, average is 8.8%. Permeability range is 0.05 to 0.07 md, average is 0.06 md. 2. Average porosity is 7.5%. Average permeability is 0.0765 md.	1. Range is 6 to 25 ft, average is 15 ft. 2. Range is 10 to 60 ft.	1. Range was 22 to 272 Mcfd, average was 117 Mcfd. 2. Range was 27 to 480 Mcfd, average was 253 Mcfd.	2. Approximately 200 Mcfd average for 90 wells (long term).	Typically 5% to 9%/yr.	Liquid hydrocarbons generally are not produced. Water is produced from the lower Dakota in most areas.	Range is 41% to 60%, average is 49%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
See Dakota Sandstone, San Juan Basin (New Mexico), table 61.	See Dakota Sandstone, San Juan Basin (New Mexico), table 61.	640 acres.	Infill drilling has been proposed.

TABLE 66. Dakota Sandstone, San Juan Basin (Colorado): Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
1. Approved by FERC. 2. Approved by State.	As of January 1, 1974, a total of 2,099 producing Dakota wells in the basin.	No specific data. 40% success for exploratory wells in 1980 for all formations in the San Juan Basin.	Total drilling and completion costs, including stimulation, range from \$400,000 to \$600,000. Stimulation costs range from \$75,000 to \$100,000 (1980-1981 period).	El Paso Natural Gas Co., Southern Union Gathering Co., and Northwest Pipeline Corp. Pipelines are adequate in all areas.	High. Six FERC applications.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
See Dakota Sandstone, San Juan Basin (New Mexico), table 62.	See Dakota Sandstone, San Juan Basin (New Mexico), table 62.	See Dakota Sandstone, San Juan Basin (New Mexico), table 62.	See Dakota Sandstone, San Juan Basin (New Mexico), table 62.	See Dakota Sandstone, San Juan Basin (New Mexico), table 62.

"J" SANDSTONE, DENVER BASIN

The "J" Sandstone is a coarse silt to fine-grained sandstone within the Lower Cretaceous Dakota Group of the Denver Basin (fig. 67), also more formally known as the Denver-Julesburg Basin. The "J" Sandstone is part of a major deltaic system that prograded from east and southeast to northwest over the northeast Denver Basin area in Early Cretaceous time (Matuszczak, 1973). Tight formation designation has been approved by the FERC for the gas-producing Wattenberg Field and vicinity in Adams, Weld, Larimer, and Boulder Counties, Colorado (Colorado Oil and Gas Conservation Commission, 1980a). The "J" Sandstone also produces oil from deltaic reservoir sands in parts of the Denver Basin, such as in Peoria Field in Arapahoe County, Colorado.

Gas production from the blanket-geometry "J" Sandstone is well established at Wattenberg Field. Amoco Production Co. has used massive hydraulic fracture treatments on 563 Wattenberg wells, including 68 wells drilled and treated in 1980 and 25 wells drilled in 1981 (Hagar and Petzet, 1982a). Polymer emulsion fracture treatments have been developed using a combination of condensate and 1.5-percent potassium chloride water, which stimulates well productivity (Fast and others, 1977).

The "J" Sandstone is a blanket-geometry tight gas sandstone having relatively well known geologic and engineering characteristics; hence, it serves as a good model for comparison with other sandstones in this survey. The following discussion and the assembled data (tables 67 through 70) refer almost exclusively to Wattenberg Field; one exception is the estimated resource base (table 67), which refers to a larger area from north of Greeley to near Denver, Colorado (fig. 68). The National Petroleum Council (1980) found that formations in the Denver Basin other than the "J" Sandstone and the Niobrara Formation had only limited potential as tight gas reservoirs.

Structure

The Denver Basin is a Laramide-age structural basin having an axis along the western margin subparallel to the Front Range of the central Rocky Mountains. The basin is bounded by positive subsurface and surface structural features (table 67). The Denver Basin is asymmetric, with a gently dipping eastern flank and a steep western flank. More than 13,000 ft of sediment has accumulated at the deepest point in the basin near Denver, Colorado. The present form of the basin developed during the Laramide orogeny, which extended from near the end of Cretaceous to Eocene time (Martin, 1965).

Within the Denver Basin, recurrent movement on Precambrian fault zones controls facies thickness and variations in Paleozoic and Mesozoic strata. Northeast-trending paleostructures are thought to have influenced the depositional patterns of the Dakota Group, wherein deltaic depocenters developed in structural and topographic lows (Sonnenberg and Weimer, 1981; Weimer and Sonnenberg, 1982). Also, recurrent movement on basement fault blocks is thought to have caused the present structurally low position of Wattenberg Field. Paleostructural analysis suggests that the field formerly had a structurally high position, indicating that the trapping mechanism of Wattenberg gas is possibly both structural and stratigraphic (Weimer and Sonnenberg, 1982).

Stratigraphy

The "J" Sandstone of the Dakota Group is sometimes referred to as the Muddy Sandstone, to which it is approximately equivalent; the latter name is primarily used in

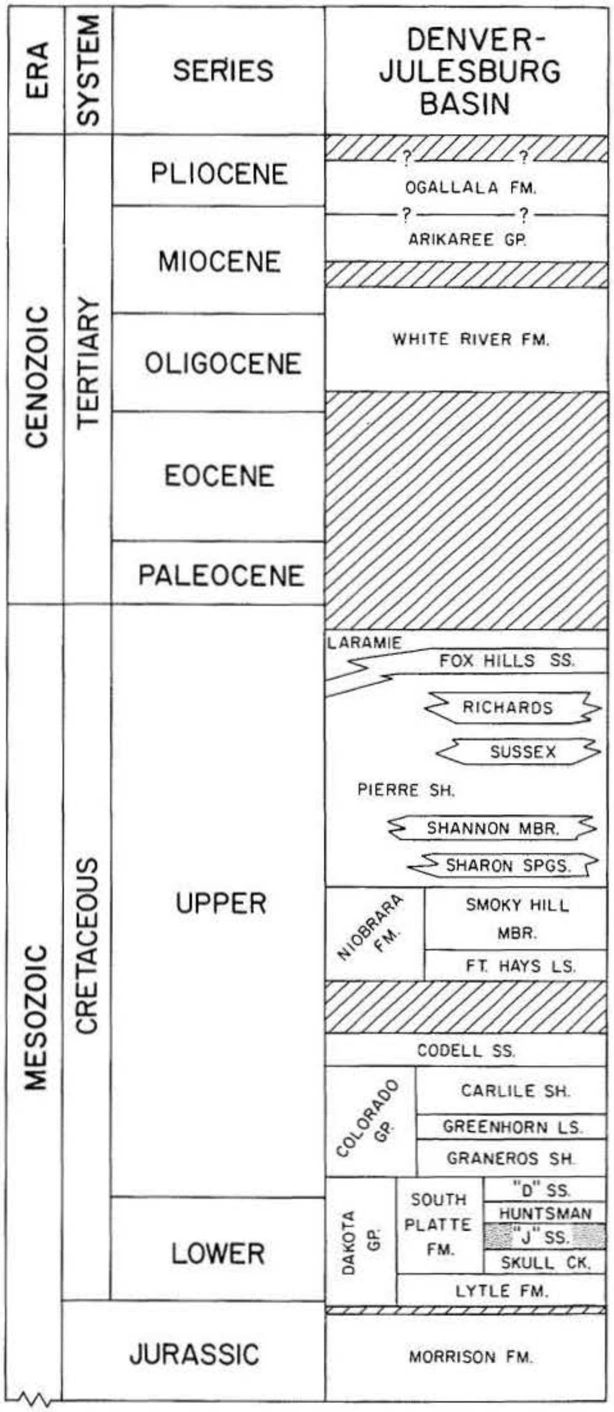

FIGURE 67. Stratigraphic column from the Upper Jurassic through the Pliocene, Denver Basin (from Rocky Mountain Association of Geologists, 1977).

Wyoming (Matuszczak, 1973; C. M. Garrett, personal communication, 1982). The "J" Sandstone represents a major regression of the Early Cretaceous sea that had previously entered the area of the Denver Basin from the northwest. The "J" interval sandstones were derived from a Kansas-Nebraska provenance, and the distributary pattern of this unit indicates progradation from east to west (Martin, 1965; Matuszczak, 1973).

Depositional Systems

The producing interval of the "J" Sandstone in Wattenberg Field forms a delta front, coarsening upward into a distributary-mouth bar; both facies are laterally extensive over a moderately large deltaic lobe. This lobe is apparently a subsidiary depocenter on the southwest margin of the larger, northwestward-prograding Greeley Lobe, which is located between Greeley, Colorado, and the Colorado-Wyoming border (Peterson and Janes, 1978). The log character of the delta front shows a consistent upward-coarsening pattern across the field (figs. 69 and 70). A distributary-bar facies is probably indicated by the uppermost, slightly more blocky part of the upward-coarsening sequence (fig. 69) but is difficult to discriminate without conventional core. In core, the distributary bar shows (1) less bioturbation than the underlying delta front, (2) horizontal laminations, and (3) robust *Ophiomorpha* commonly in a vertical position (Peterson and Janes, 1978). Neither published vertical profiles of permeability nor detailed petrographic studies were available for this review. However, it is likely that cleaner, slightly more permeable reservoir rock will correlate with the occurrence of the distributary-bar facies.

Directly overlying the delta-front facies is a delta plain that consists of carbonaceous shale to fine-grained sand; the delta plain is burrowed and contains root traces. Individual facies, such as channel, natural levee, crevasse-splay, and interdistributary-bay deposits, are limited and highly variable in areal extent. The final interval of the "J" Sandstone consists of a parallel laminated silt and shale sequence that is continuous across the field. It has been interpreted as a transgressive marine sequence (Peterson and Janes, 1978).

"J" Sandstone Model

The "J" Sandstone has been included in this survey primarily for comparison with other formations. It is an ideal model of a unit having both blanket geometry and the excellent lateral continuity characteristic of delta-front sandstones (figs. 70 and 71). Although not described by Peterson and Janes (1978), core of the delta front of the "J" Sandstone would be expected to have trough cross-stratification in the upper part, ripple cross-lamination, and some deformational structures. These features have been described in outcrop of the Fox Hills Sandstone in the Denver Basin, which also is interpreted to be a delta-front sandstone (Weimer, 1973). The same delta-front facies also probably exist in parts of the Fox Hills Sandstone and Frontier Formation of the Greater Green River Basin, which are included in this survey, and other formations in which deltaic deposits were not completely reworked by subsequent marine transgression.

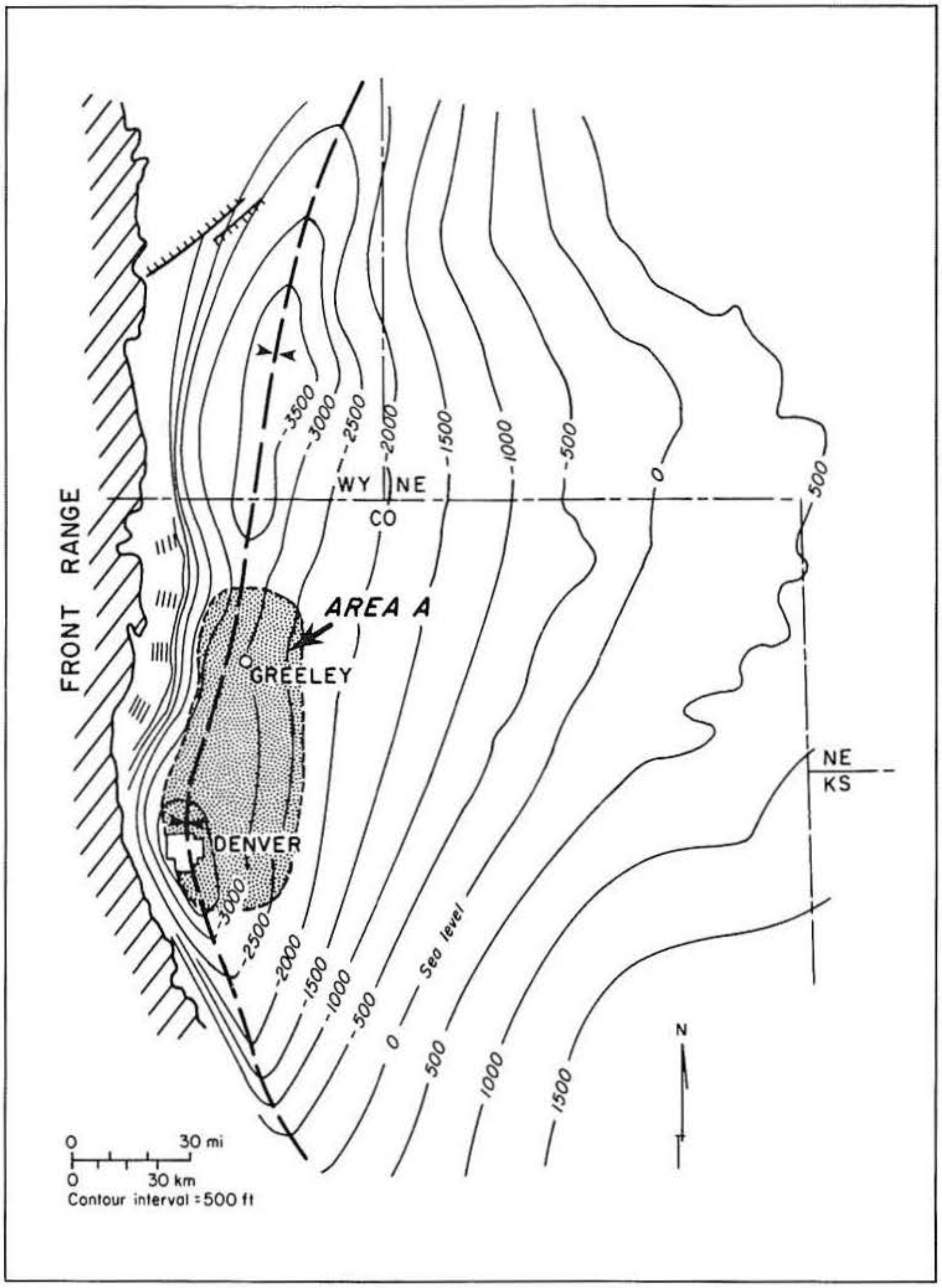

FIGURE 68. Generalized structural configuration and area of tight gas sand potential (area A), Denver Basin (after National Petroleum Council, 1980). Structure contours on top of the Lower Cretaceous sequence.

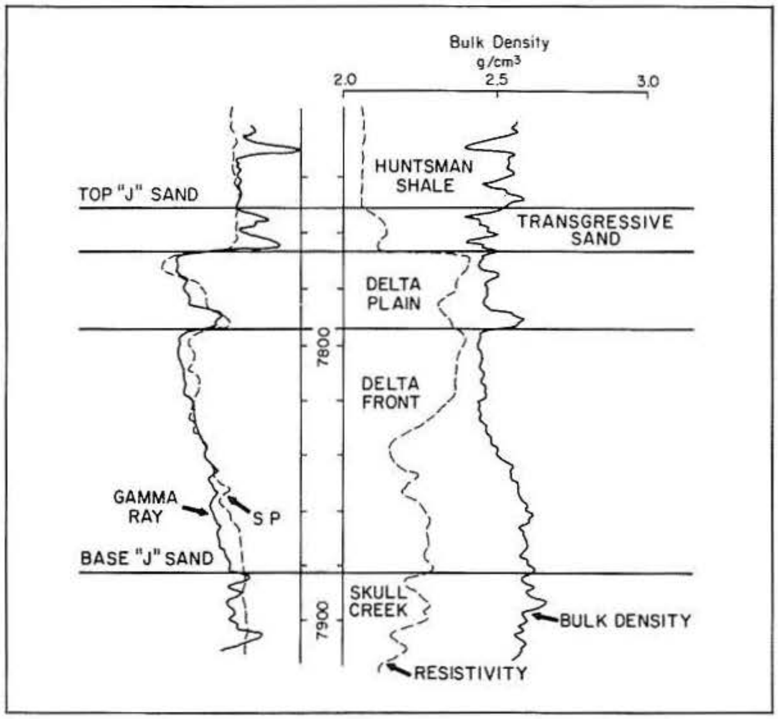

FIGURE 69. Typical log response of the "J" Sandstone, Denver Basin (after Peterson and Janes, 1978).

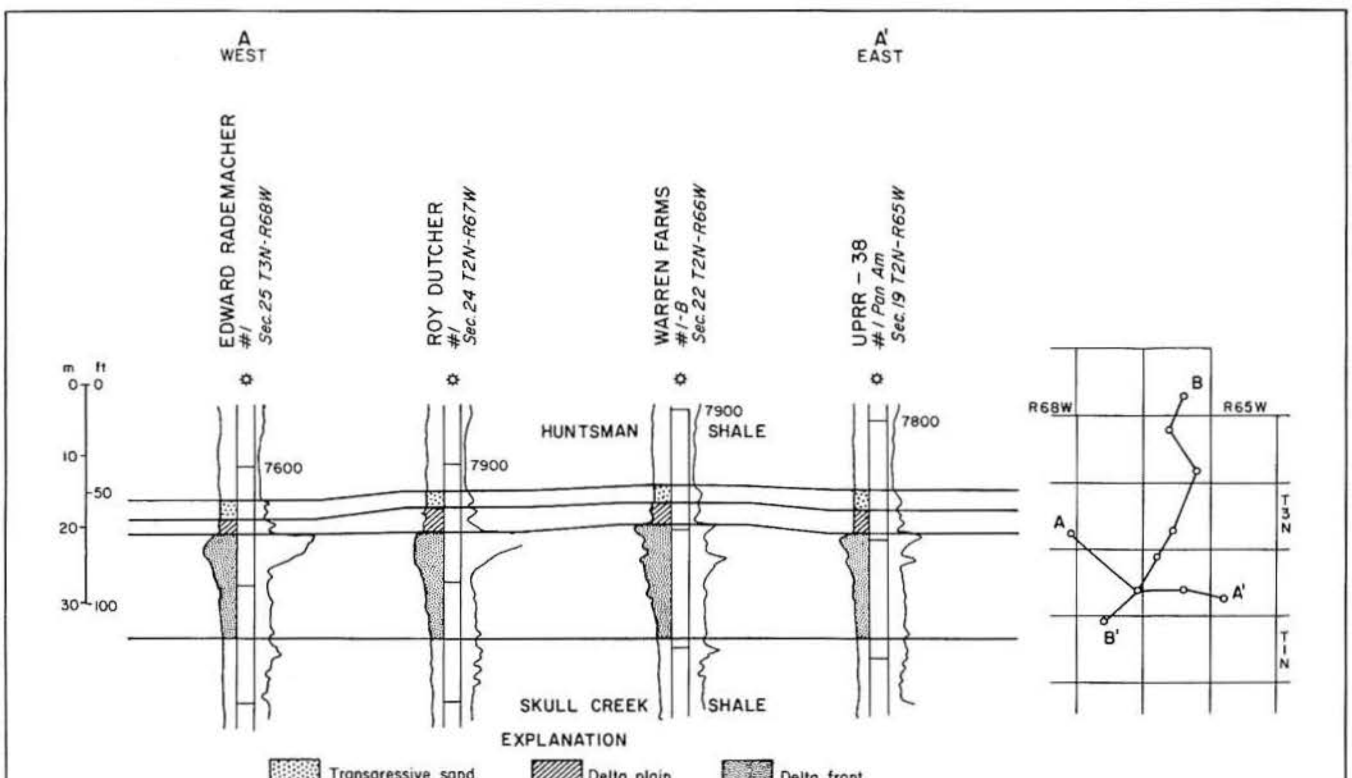

FIGURE 70. East-west stratigraphic cross section A-A' showing facies of the "J" Sandstone, Denver Basin (after Peterson and Janes, 1978).

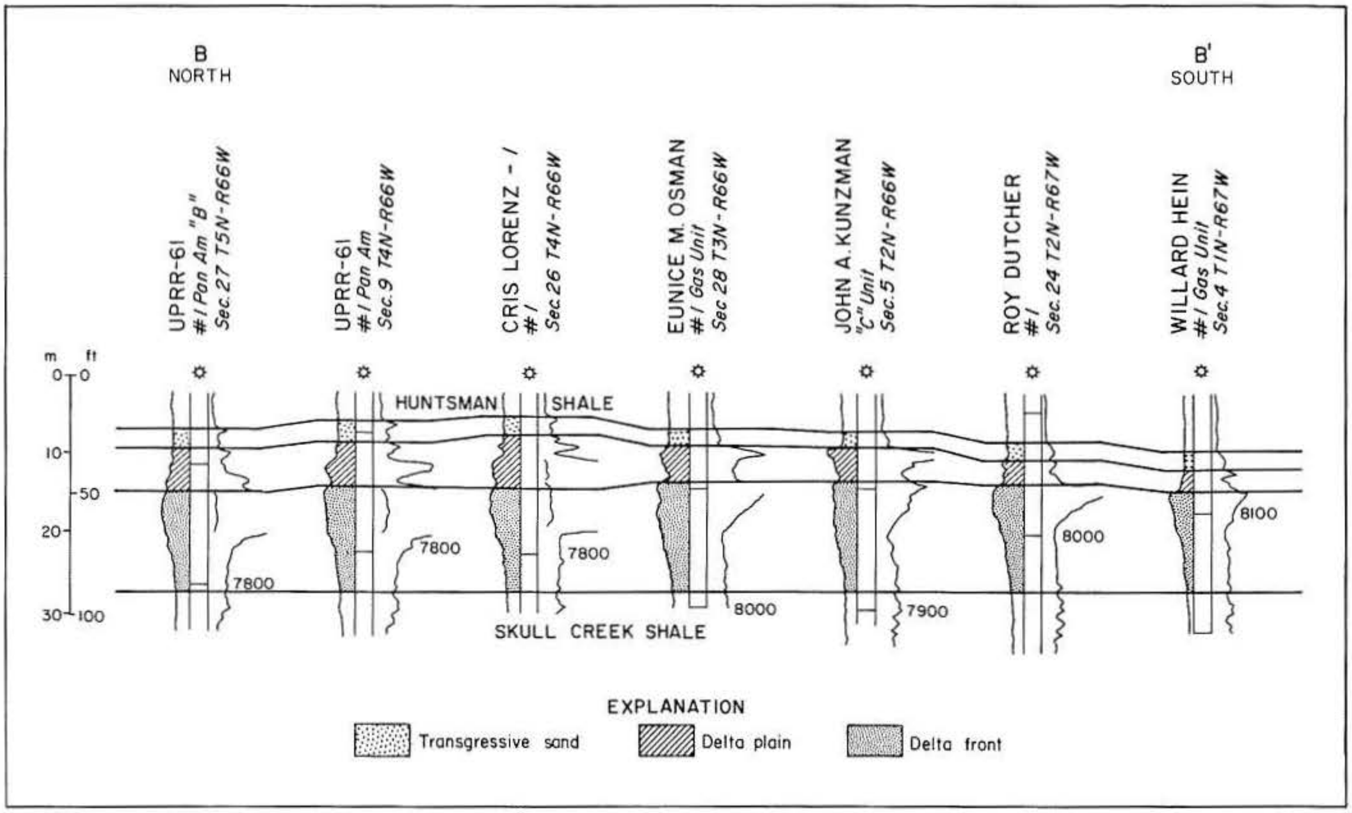

FIGURE 71. North-south stratigraphic cross section B-B' showing facies of the "J" Sandstone, Denver Basin (after Peterson and Janes, 1978). Line of section shown in figure 70.

TABLE 67. "J" Sandstone, Denver Basin:
General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
"J" Sandstone, Dakota Group, Lower Cretaceous.	Probable and possible area is 1,100 mi². Speculative area is 500 mi² (National Petroleum Council, 1980). Productive Wattenberg Field area is 978 mi².	Range is 40 to 140 ft in Wattenberg Field area; upper "J" contributes to variation because of its lenticularity relative to lower "J."	Range is 7,350 to 8,500 ft, average is 8,000 ft in Wattenberg Field.	Maximum recoverable gas is 5.539 Tcf of 9.175 Tcf gas in place in area generally from Denver to Greeley, Colorado. Additional 1.1 to 1.3 Tcf ultimately recoverable from Wattenberg Field excluded from above estimates (National Petroleum Council, 1980).	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This asymmetrical, Laramide-age structural basin has an axis along the western margin of and is subparallel to the Front Range of the central Rocky Mountains. Other major bounding features include the Hartville Uplift (northwest), the Chadron Arch (northeast), Las Animas Arch (southeast), and the Wet Mountains and Apishapa Uplift (southwest).	2.6° F/100 ft (high gradient).	0.36 psi/ft (underpressured).	Compressional Laramide deformation followed by post-Laramide vertical uplift and subsequent subsidence.

TABLE 68. "J" Sandstone, Denver Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Delta front, distributary bar, and delta plain, capped by a transgressive marine unit and related to a deltaic lobe on the margin of the more areally extensive Greeley Lobe of the "J" Sandstone. The producing interval is the laterally continuous delta front, coarsening upward into a distributary-mouth-bar facies that can be distinguished in core but is less readily distinguished from logs. Progradation of the Greeley Lobe was toward the northwest, and progradation of the lobe containing the Wattenberg reservoir was toward the southwest on the south margin of the main deltaic depocenter.	Coarse silt to fine-grained sandstone, partly bioturbated in the delta-front facies. Poorly sorted and well indurated in outcrop.	Presumably a quartz sandstone and sandy siltstone, but no detailed petrography has been published. Generally described as dark gray having abundant clay matrix.	Trap is bounded by area of silica cementation; some silica cementation probable in reservoir area, and diagenetic clay may occur as a product of feldspar and rock-fragment diagenesis.
Typical reservoir dimensions	***Pressure/temperature of reservoir***	***Natural fracturing***	***Data availability***
40 to 140 ft thick over the 900 mi^2 area including Wattenberg Field.	3,000 psi pressure, 260° F temperature are average Wattenberg Field values.	Extent unknown.	Typical log program includes SP-Dual Induction Laterolog and GR-Density-Caliper log. Conventional whole core data include 26 cores taken by Amoco early in development of Wattenberg Field.

TABLE 69. "J" Sandstone, Denver Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Porosity range is 7.7% to 13.9%, average is 10.8%. Permeability range is 0.0003 to 0.0306 md, average in situ is 0.0059 in Wattenberg Field. Some permeability to 0.5 md (conventional reservoir) for unknown areal extent.	Range is 4 to 58 ft, average is 27 ft for Wattenberg Field.	Range was 1 to 167 Mcfd, average was 19.9 Mcfd.	100 to 3,575 Mcfd.	Rapid in first 6 mo.	Typically, 64 bbl/1,000 Mcf condensate of 64° API gravity for Wattenberg Field.	Range is 27% to 99%, average is 42% for conventional and 55% for unconventional.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Massive hydraulic fracture treatments. Size of treatments has varied from 183,000 gal fluid and 277,000 lb sand to 517,000 gal fluid and more than 1,000,000 lb sand. A typical program used by Amoco has involved 310,800 gal KCl water with gelling agent and emulsifier, and 598,600 lb 20-40 mesh and 10-20 mesh sand in a multistage treatment injected at 20 bbl/min at a pressure of 4,000 to 4,500 psi.	Considered effective in appropriate areas; larger treatments have been superior to the smaller treatments in improving production rate and cumulative production.	320 acres.	The Wattenberg reservoir is stratigraphically controlled by sand pinch-out to the west and south and by loss of permeability to the northeast.

TABLE 70. "J" Sandstone, Denver Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by FERC on January 23, 1981, for 38 townships; exceptions mostly in Wattenberg Field.	After discovery in 1970, 480 wells drilled in 1974-1975. In 1975-1977, 826 wells were producing from tight gas reservoirs.	8.3% of 877 wildcats in 1970-1977 for Denver Basin as a whole.	Drilling costs are $430,000. Fracture treatment costs are $93,000 to $304,000 (1979 dollars) (National Petroleum Council, 1980). Completion: no data.	8-inch to 20-inch pipelines plus gathering system in Wattenberg Field area.	Moderate, although designated tight formation area is primarily within Wattenberg Field in Adams and Weld Counties, Colorado.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
In the Rocky Mountain Piedmont physiographic subdivision, consisting of irregular plains having 100 to 300 ft of local relief. Most of area is gently sloping.	Semiarid having 10 to 16 inches mean annual precipitation. Mild summers, cold winters.	No terrain barriers. Many State and County highways; unpaved section roads at 1-mi spacing in many areas.	Excellent example of laterally continuous delta-front facies. Included in this survey for comparison with other tight gas sands. Similar facies may be expected in parts of the Frontier Formation and Muddy and Fox Hills Sandstones (Greater Green River Basin).	Drilling and completion services readily available because of established oil and gas production in northeast Colorado.

COZZETTE AND CORCORAN SANDSTONES, PICEANCE CREEK BASIN

The Cozzette and Corcoran Sandstones are part of the Upper Cretaceous Mesaverde Group in the subsurface of southern Piceance Creek Basin (fig. 72). The Piceance Creek Basin lies in northwestern Colorado; Grand Junction, Colorado, is southwest of the basin margin (figs. 73 and 74). Two applications for tight formation designation have been approved by the FERC for parts of Mesa and Garfield Counties, Colorado (Colorado Oil and Gas Conservation Commission, 1980h and 1980k). An application for part of the southern Piceance Creek Basin has been approved for the entire Mesaverde Group in part of Garfield County (fig. 74) (Colorado Oil and Gas Conservation Commission, 1981a).

The data bases on the Cozzette Sandstone (tables 71 through 74) and the Corcoran Sandstone (tables 75 through 78) are good, although there are notable exceptions. Specifics on the genetic stratigraphy of the producing intervals are lacking; however, core taken as part of the Multi-Well Experiment (MWX) and studies of outcrop near the MWX site should soon yield this information. Outcrop studies reported so far have been fairly generalized (U.S. Department of Energy, 1982), and published data on the texture, mineralogy, and diagenesis of the Cozzette and Corcoran reservoirs are sparse (tables 72 and 76). Outcrop studies of mineralogy and diagenesis should be interpreted cautiously because mineral transformations and redistribution of cementing agents may have occurred in the near-surface environment. Gas in these formations can be produced from relatively shallow depths (fig. 75).

Structure

The Piceance Creek Basin is a Late Cretaceous to early Tertiary sedimentary basin defined by a series of Laramide-age uplifts. The basin is bounded on the southeast by the Sawatch Range, on the east by the White River Uplift, on the southwest by the Uncompahgre Uplift, on the north by the Uinta Mountain Uplift, and on the west by the Douglas Creek Arch (figs. 73 and 74). The Douglas Creek Arch is a mildly positive feature that separates the Piceance Creek Basin from the Uinta Basin in Utah. During Mesaverde Group deposition, there was little or no uplift of the Douglas Creek Arch and the Uncompahgre Uplift; Laramide structural elements generally had little influence on Cretaceous depositional patterns (Murray and Haun, 1974; Johnson and Keighin, 1981).

Stratigraphy

In eastern Garfield County, Colorado, the sedimentary sequence between the top of the Dakota Sandstone and the Precambrian surface is about 8,000 ft thick. The Dakota Sandstone and younger Cretaceous sediments (fig. 72) constitute the thickest sedimentary sequence in northwestern Colorado; the sequence includes thick marine shales and dominantly regressive deposits (Murray and Haun, 1974). The Mesaverde Group is among these regressive strata, having a source area to the west of the present basin. Much of the Mesaverde Group is nonmarine, and fluctuations between nonmarine and marine conditions occurred frequently during its deposition.

Depositional Systems

Specific genetic stratigraphic interpretations of the Cozzette and Corcoran Sandstones are limited. Analysis of core acquired as part of the Western Gas Sands Project should soon provide

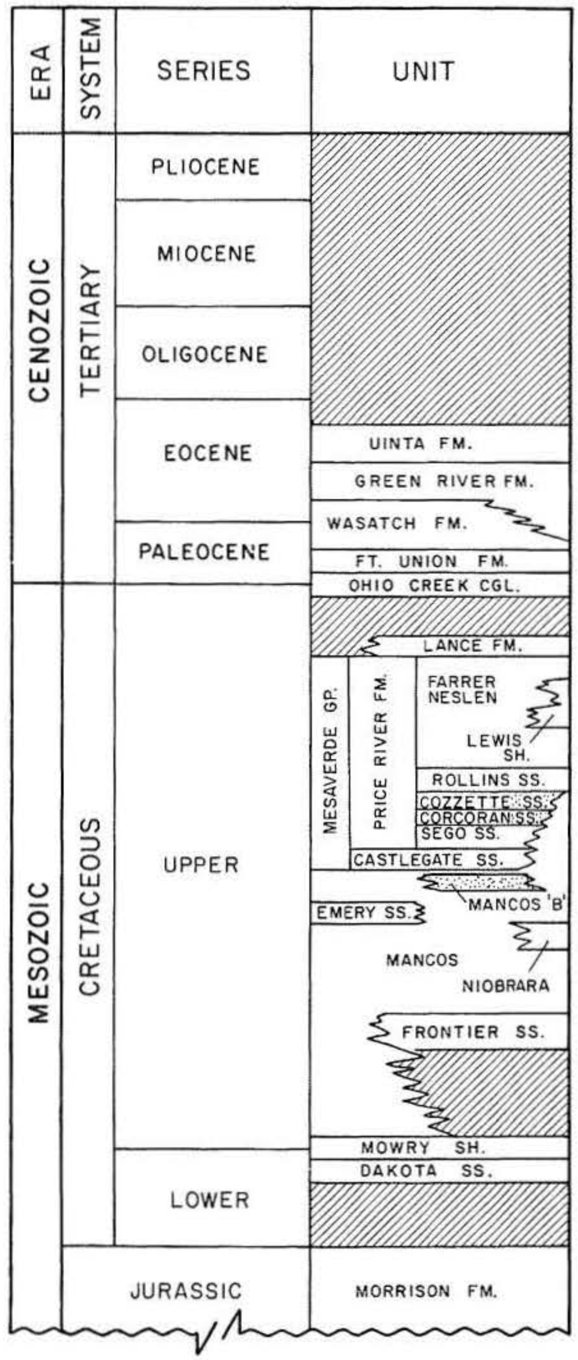

FIGURE 72. Stratigraphic column from the Upper Jurassic through the Pliocene, Piceance Creek Basin (after Rocky Mountain Association of Geologists, 1977).

some of this information (U.S. Department of Energy, 1982). These units in part of the Mesaverde Group are classified as marginal marine (Dunn, 1974), but some progradational deposits, such as delta front, may be present. Reworking during transgressive phases, however, may have altered the original regressive deposits.

Interpretation of published studies on parts of the Mesaverde Group is complicated by inconsistent differentiation of the group into separate sandstone bodies. Some studies term the Mesaverde Group a formation and treat it as a single thick unit (Knutson and others, 1971). Another classification divides the Mesaverde Group into the Williams Fork and Iles Formations; these terms are used to describe measured outcrop sections in parts of the basin (Hansley and Johnson, 1980).

A limited number of logs in T8S, R99W through T9S, R97W in Mesa County, Colorado, show few upward-coarsening progradational sequences and more numerous blocky aggradational sequences. Blocky SP log patterns having slightly transitional tops and bases, such as in Andrews et al. No. 1 Government and Marathon No. 2 Government wells (fig. 76), may represent barrier-island or strandplain sands. Lateral continuity between these two wells is good; the remaining wells on the cross section, except the Koch No. 2 Horseshoe Canyon well, show poorer sandstone development and may indicate nearshore marine environments having relatively thin bar sands. This interpretation agrees with what is known of the Cozzette and Corcoran Sandstones and the Mesaverde Group but can only be verified by a localized study.

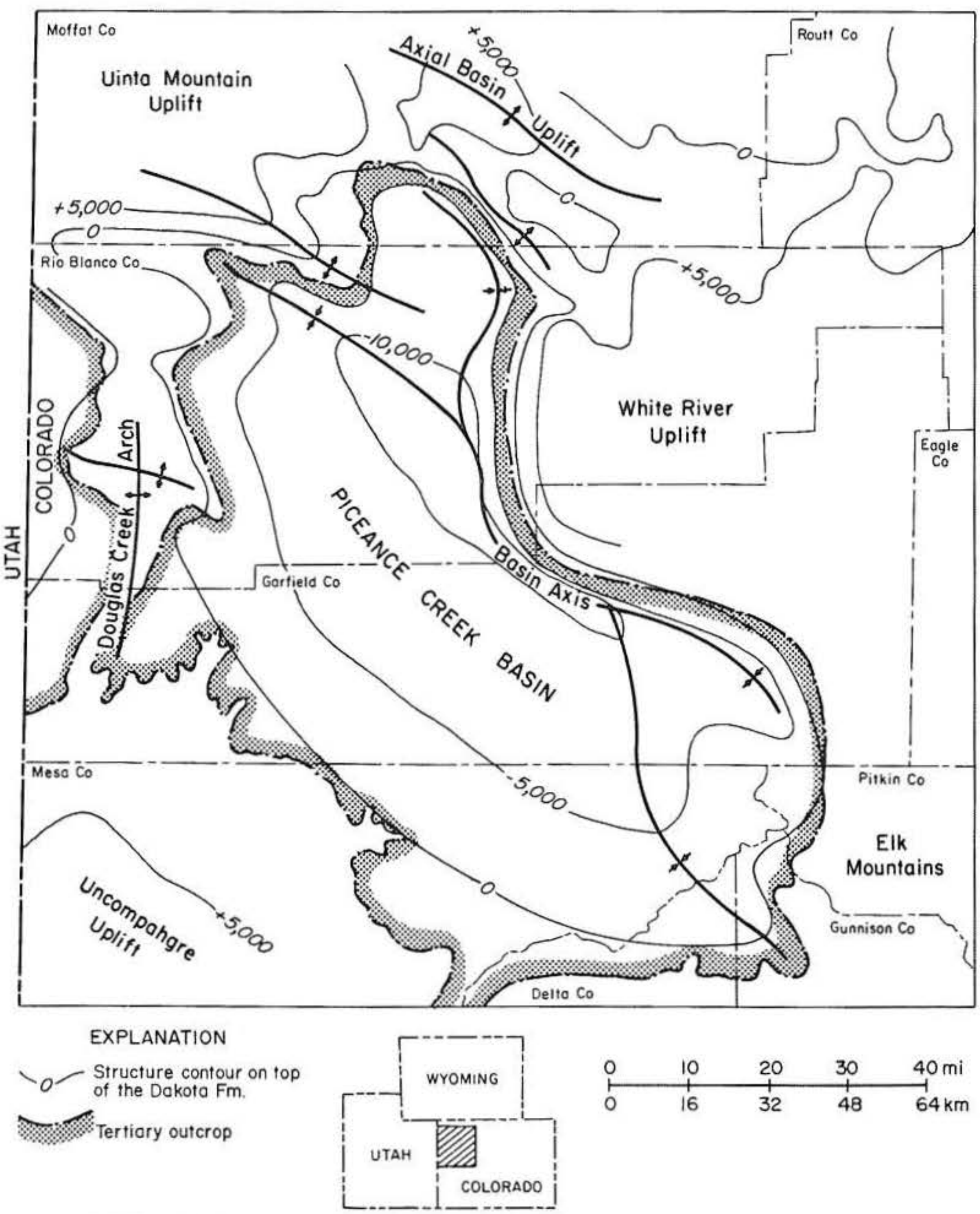

FIGURE 73. Location and generalized structure map, Piceance Creek Basin (after Dunn, 1974).

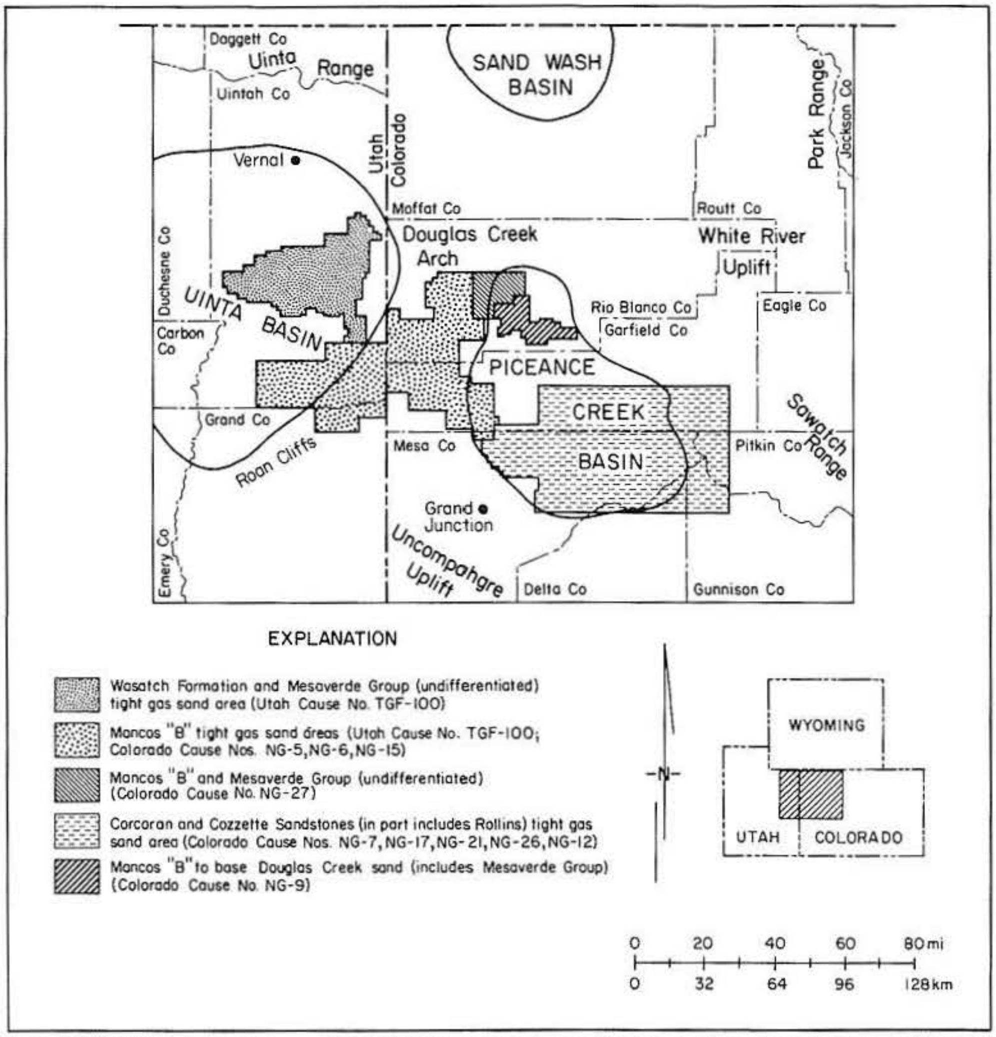

FIGURE 74. Areas covered by tight gas sand applications, Piceance Creek and Uinta Basins (Colorado Oil and Gas Conservation Commission, 1980b, 1980c, 1980e, 1980j, 1980k, 1981a, 1982a; Utah Board of Oil, Gas, and Mining, 1981a).

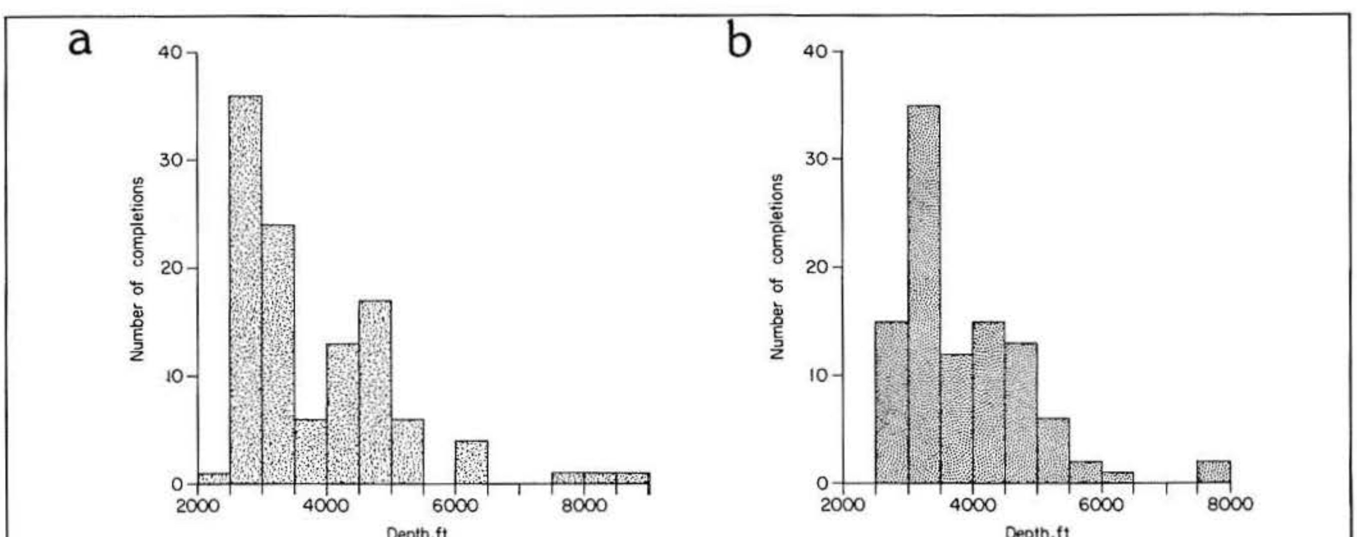

FIGURE 75. Number of producing wells with depth to the top of (a) the Cozzette Sandstone (110 wells) and (b) the Corcoran Sandstone (101 wells), Piceance Creek Basin.

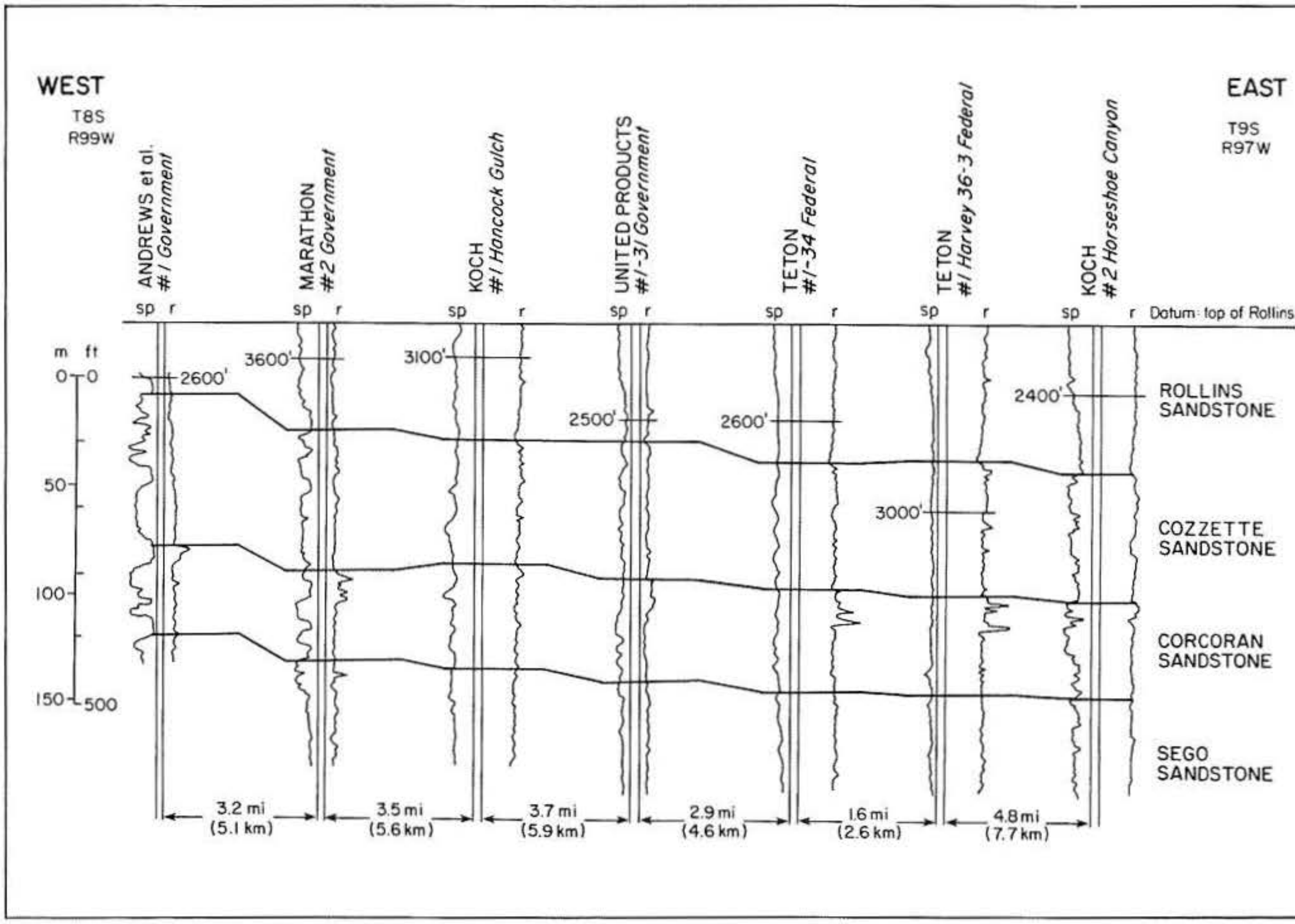

FIGURE 76. East-west stratigraphic cross section from T8S, R99W to T9S, R97W through the Cozzette and Corcoran Sandstones and adjacent strata, Piceance Creek Basin (after Colorado Oil and Gas Conservation Commission, 1980h).

TABLE 71. Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Cozzette Sandstone, Mesaverde Group, Upper Cretaceous.	Total designated area is 319 mi^2 in Mesa and Garfield Counties, Colorado. Total additional potential area of approximately 1,990 mi^2 in Mesa, Garfield, Delta, Gunnison, and Pitkin Counties, Colorado.	Average is 175 ft in T8-10S, R97-100W.	Average is 7,250 ft in R7S, T91W. Average is 2,480 ft in T8-10S, R97-100W.	National Petroleum Council (1980) reported maximum recoverable gas of 2.294 Tcf from Cozzette-Corcoran uniquely. Additional amounts of Cozzette-Corcoran gas are classified with both the Fort Union Formation and other parts of the Mesaverde Group and cannot be uniquely identified.	Area in T8-10S, R97-100W is on the southwest flank of the basin and has structural dips of 2° to 3° northeast.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This Late Cretaceous - early Tertiary Laramide-age basin is bounded on the southeast by the Sawatch Uplift, on the east by the White River Uplift, on the north by the Uinta Uplift, on the southwest by the Uncompahgre Uplift, and on the west by the Douglas Creek Arch. Areas of interest overlap the Douglas Creek Arch.	Mostly 2.6° to 2.9° F/100 ft.	0.42 psi/ft on the basis of eight values generally in T7-10S, R95-97W.	Compressional Laramide deformation followed by post-Laramide vertical uplift.

TABLE 72. Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
A regressive, marginal marine sandstone, possibly shoreface or offshore-bar facies grading upward into barrier or strandplain facies. Genetic facies data are limited.	Very fine grained sandstone having detrital silt and clay. Typically poorly sorted.	Undifferentiated Mesaverde Group in southern Garfield County is 35% to 67% detrital quartz, 2% to 20% detrital feldspar, and 30% to 52% lithic fragments, having varying amounts of authigenic calcite, dolomite, and clay. No specific data on Corcoran or Cozzette.	Authigenic clays and carbonate cements common. Feldspars usually highly altered in Mesaverde Group.

Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
In two or more sandstones typically within the Cozzette interval, average is a total of 90 ft.	In T7-8S, R90-91W, 3,200 psi at 250° F at approximately 7,500 ft. In T8-10S, R97-100W, 1,019 psi at 107° F at approximately 2,550 ft. These are average parameters for undifferentiated lower Mesaverde.	In T7-8S, R90-91W, fracturing is probably present along north-plunging nose.	Limited amount of core available. Drill-stem tests often not run because of little or no natural flows. SP-resistivity or GR-resistivity and GR-neutron density are typical logs. New core from Multi-Well Experiment site.

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TABLE 73. Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Permeabilities are 0.0187 and 0.0109 md and porosities are 12.25% and 13.78% for two wells in T9-10S, R97W. In T7-8S, R90-91W, average permeability is 0.05 md, average porosity is 7% (composite data for nine Rollins, Corcoran, and Cozzette wells).	Average is 70 ft from four or more wells in T9S, R97W, undifferentiated lower Mesaverde. Gross completion interval is 61 ft for 89 wells in T6-11S, R89-97W (Cozzette only). Net pay typically 30 ft or less (Cozzette only).	For most wells, TSTM.	Average was 964 Mcfd for approximately 121 wells from Rollins, Cozzette, and Corcoran (undifferentiated). Average was 942 Mcfd for four Cozzette completions in the area T10S, R93-97W. Average was 1,229 Mcfd for 41 Cozzette completions.	Once placed on sustained production, selected decline curves show drop to one-half of IP in 6 to 9 mo.	No oil is produced from the lower Mesaverde (including Cozzette). See Corcoran Sandstone (table 77) for water and condensate data on undifferentiated lower Mesaverde.	Probably similar to Corcoran in the range of 40% to 60%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Massive hydraulic fracturing. One of the largest Corcoran fracture jobs, expected to be similar to treatment of the Cozzette, used 3,000 gal acid, 104,000 gal fluid, and 255,000 lb sand. More typical job involves zero to several hundred gallons acid, 25,000 to 60,000 gal fluid, and up to 100,000 lb sand.	No data.	160 to 320 acres.	Some Mesaverde or lower Mesaverde completions do not distinguish Corcoran, Cozzette, or Rollins. Some parameters of these three members are derived collectively from FERC applications. Trapping is basically stratigraphic because of lateral and vertical changes in permeability even though reservoir is of blanket geometry. In Shire Gulch and Plateau Fields, Mesa County, Colorado, 37% to 71% of the wells in Petroleum Information Corp. WHCS file produce water.

TABLE 74. Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Two applications approved in May 1981.	91 producing or shut-in wells in Mesa, Garfield, and Pitkin (1 well) Counties, Colorado, as of December 31, 1980, from Mesaverde (undifferentiated) or some combination of Corcoran, Cozzette, and Rollins. 26 producing or shut-in wells are specifically identified as being from either Corcoran or Cozzette, or both.	42.4% in the Piceance Creek Basin as a whole for all wildcat gas wells, 1970-1977.	For wells to 3,300 ft in T9S, R97W, well costs were $300,000 to $350,000, as reported in August 1980. Costs for a small fracture job (15,000 gal fluid, 65,000 lb sand) were $44,000, as reported in August 1980 (cost for each perforated interval).	14-inch and 10-inch pipelines (and several 8 inches or less) serve the area of T6-11S (inclusive), R89-97W (inclusive). These pipelines are operated by Northern Natural, Northwest Pipeline Corp., Panhandle Eastern Pipeline Co., Western Slope Gas Co., and Rocky Mountain Natural Gas, among others.	High. Two FERC applications approved. Recent State applications approved for upper Mancos and Mesaverde probably include the Cozzette.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
In the middle Rocky Mountains physiographic subdivision. Area includes Battement Mesa and a small part of Grand Mesa having elevations above 10,000 ft. Valleys of the Colorado River and Plateau Creek are below 7,500 ft. Local relief is generally 1,000 to 3,000 ft, and only 20% to 50% of the area is gently sloping.	Semiarid having 8 to 16 inches mean annual precipitation. Mild summers, cold winters. Winter conditions may cause suspension of exploration activities.	Very poor access to tops of mesas and bordering steep slopes. Drilling and development is concentrated in river valleys, primarily of the Colorado River and Plateau Creek; access is difficult away from the rivers.	Good. Expected to have similarities to barrier and bar facies of the Mesaverde Group in the San Juan, Uinta, and eastern Greater Green River Basins. Also similar to regressive barrier-strandplain facies of the Hartselle, Pictured Cliffs, and Fox Hills Sandstones and the upper part of the Dakota Sandstone (San Juan Basin).	Overall geology and engineering parameters expected to be similar for both Corcoran and Cozzette.

TABLE 75. *Corcoran Sandstone (Mesaverde Group), Piceance Creek Basin: General attributes and geologic parameters of the trend.*

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Corcoran Sandstone, Mesaverde Group, Upper Cretaceous.	Total designated area is 319 mi² in Mesa and Garfield Counties, Colorado. Total additional potential area of approximately 1,990 mi² in Mesa, Garfield, Delta, Gunnison, and Pitkin Counties, Colorado.	Range is estimated at 150 to 200 ft in T7-8S, R90-91W. Average is 150 ft in T8-10S, R97-100W.	Average is 7,680 ft in T7-8S, R90-91W. Average is 2,670 ft in T8-10S, R97-100W.	National Petroleum Council (1980) reported maximum recoverable gas of 2.294 Tcf from Cozzette-Corcoran uniquely. Additional amounts of Cozzette-Corcoran gas are classified with both the Fort Union Formation and other parts of the Mesaverde Group and cannot be uniquely identified.	Area in T8-10S, R97-100W is on the southwestern flank of the basin and has structural dips of 2° to 3° northeast.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 71.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 71.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 71.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 71.

TABLE 76. Corcoran Sandstone (Mesaverde Group), Piceance Creek Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
A regressive, marginal marine sandstone, possibly shoreface or offshore-bar facies grading upward into barrier or strandplain facies. Genetic facies data are limited.	Very fine grained sandstone having detrital silt and clay. Typically poorly sorted.	Undifferentiated Mesaverde Group in southern Garfield County is 35% to 67% detrital quartz, 2% to 20% detrital feldspar, and 30% to 52% lithic fragments, having varying amounts of authigenic calcite, dolomite, and clay. No specific data on Corcoran or Cozzette.	Authigenic clays and carbonate cements common. Feldspars usually highly altered.in Mesaverde Group.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
In T8-10S, R97-100W, total of 70 to 80 ft of sand in one to three units within the total thickness of the Corcoran.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 72.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 72.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 72.

TABLE 77. Corcoran Sandstone (Mesaverde Group) Piceance Creek Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
In T7-8S, R90-91W, average permeability is 0.05 md, average porosity is 7% (composite data for nine Rollins, Corcoran, and Cozzette wells). Core permeabilities corrected to in situ conditions averaged 0.0267 md for eight samples from another five wells (Corcoran only). Average porosity for these samples is 8.1%.	Average is 70 ft from four or more wells in T9S, R97W, undifferentiated lower Mesaverde. Gross completion interval is 63 ft for 119 wells in T6-11S, R89-97W (Corcoran only). National Petroleum Council (1980) reported 16 to 70 ft as a range. Net pay typically 30 ft or less (Corcoran only).	In T7-8S, R90-91W, 0, 7, and 765 Mcfd for three wells. For most wells, TSTM.	Average was 1,251 Mcfd for 33 Corcoran completions. Average was 964 Mcfd for approximately 121 wells from Rollins, Cozzette, and Corcoran (undifferentiated). Average was 756 Mcfd for 21 wells in T6-11S, R89-97W (Corcoran only).	In T7-8S, R90-91W, a well having 765 Mcfd IP was plugged and abandoned after 42 mo. Once placed on sustained production, selected decline curves show drop to one-half of IP in 6 to 9 mo.	No oil is produced from the lower Mesaverde (including Corcoran). Those wells producing water average 5 bpd (Rollins, Cozzette, and Corcoran undifferentiated). Those wells producing condensate average 2.5 bpd (Rollins, Cozzette, and Corcoran undifferentiated).	Average for eight core samples from five wells is 49%, range is 40% to 63%. Other operators report 50% as a typical value.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Massive hydraulic fracturing. One of the largest Corcoran fracture jobs used 3,000 gal acid, 104,000 gal fluid, and 255,000 lb sand. More typical job involves zero to several hundred gallons acid, 25,000 to 60,000 gal fluid, and up to 100,000 lb sand.	No data.	160 to 320 acres.	Some Mesaverde or lower Mesaverde completions do not distinguish Corcoran, Cozzette, or Rollins. Some parameters of these three members are derived collectively from FERC applications. Trapping is basically stratigraphic because of lateral and vertical changes in permeability even though reservoir is of blanket geometry. In Shire Gulch and Plateau Fields, Mesa County, Colorado, 14% to 23% of wells in Petroleum Information Corp. WHCS file produce water.

TABLE 78. Corcoran Sandstone (Mesaverde Group), Piceance Creek Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Two applications approved in May 1981; State applications approved may include the Corcoran and Cozzette as parts of the Mesaverde Group.	91 producing or shut-in wells in Mesa, Garfield, and Pitkin (1 well) Counties, Colorado, as of December 31, 1980, from Mesaverde (undifferentiated) or some combination of Corcoran, Cozzette, and Rollins. 26 producing or shut-in wells are specifically identified as being from either Corcoran or Cozzette, or both.	42.4% in the Piceance Creek Basin as a whole for all wildcat gas wells, 1970-1977.	For wells to 3,300 ft in T9S-R97W, well costs were $300,000 to $350,000, as reported in August 1980. Costs for a small fracture job (15,000 gal fluid, 65,000 lb sand) were $44,000, as reported in August 1980 (cost for each perforated interval).	14-inch and 10-inch pipelines (and several 8 inches or less) serve the area of T6-11S (inclusive), R89-97W (inclusive). These pipelines are operated by Northern Natural, Northwest Pipeline Corp., Panhandle Eastern Pipeline Co., Western Slope Gas Co., and Rocky Mountain Natural Gas, among others.	High. Two FERC applications approved. State applications approved for upper Mancos and Mesaverde probably include the Corcoran.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 74.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 74.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 74.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 74.	See Cozzette Sandstone (Mesaverde Group), Piceance Creek Basin, table 74.

MANCOS "B" SHALE, PICEANCE CREEK BASIN

The Mancos "B" interval is part of the Upper Cretaceous Mancos Shale (fig. 72), which is characterized by finely interbedded claystone, siltstone, and very fine grained sandstone (table 79). The FERC has approved applications for tight formation designations in four areas in Colorado: one primarily in Rio Blanco and Garfield Counties, Colorado, and three entirely in Rio Blanco County (fig. 74) (Colorado Oil and Gas Conservation Commission, 1980c, 1980d, 1980i, and 1980j). The data base on the Mancos "B" interval in Colorado is good (tables 80 through 83); it is based on operator applications and a summary by Kellogg (1977). All areas now designated as tight formations are on the Douglas Creek Arch or its eastern flank, where the depth to the top of the Mancos "B" varies from 3,475 to 3,603 ft; one exception is a 38-mi^2 area where the Mancos "B" is as shallow as 2,500 ft (Kellogg, 1977; Hagar and Petzet, 1982a).

Structure

The structural setting of the Mancos "B" Shale within the Piceance Creek Basin is similar to that of the Cozzette and Corcoran Sandstones (see p. 146); however, detail on the Douglas Creek Arch should be added. The Douglas Creek Arch extends northward from the Uncompahgre Uplift to the eastern end of the Uinta Uplift and separates the Piceance Creek Basin from the Uinta Basin. The arch is broken into small separate anticlinal features by northwest-trending asymmetrical folds and northeast-trending normal faults. These faults have an average dip of 75° to 80° and generally have less than 500 ft of displacement. The faults tend to die out downward in the Mancos Shale; therefore, they are most common in the northern part of the arch, which contains rocks younger than the Mancos (Kellogg, 1977).

Stratigraphy

The Mancos "B" interval was deposited on a nearly horizontal marine shelf east of the Emery Sandstone of the Uinta Basin, a time-equivalent shoreline deposit (Kellogg, 1977). Its thickness varies from 400 to 700 ft in most of the Douglas Creek Arch area (Colorado Oil and Gas Conservation Commission, 1980i and 1980j). The top of the unit is denoted by an informal driller's datum that may be the same as the silt marker used by Kellogg (1977). At the base of the unit, the gamma-ray log count returns to higher values characteristic of the rest of the Mancos Shale.

Because of the finely laminated claystone, siltstone, and sandstone of the Mancos "B," geophysical well logs do not delineate beds that have recognizable character from log to log (Kellogg, 1977). Thus, the entire Mancos "B" interval is considered to be of blanket geometry, rather than individual sandstone beds, and within that unit those intervals having greater quantities of either sandstone or sandstone and siltstone are considered potential gas reservoirs. Individual sandstone beds are not readily defined in the Mancos "B" (fig. 77), but Kellogg (1977) has isolated generalized shaly, silty, and sandy facies.

Depositional Systems

Kellogg's (1977) study area, centered over the Douglas Creek Arch, covered all the approved tight gas areas of Mancos "B" production in Colorado; the study area also extended into Grand and Uintah Counties, Utah. He divided the Mancos "B" interval into five units (table 79). Kellogg (1977) suggested that deposition took place on a submarine terrace or slope and that slope angle tended to decrease as deposition continued through unit B and younger sediments. Increased sand content over the Douglas Creek Arch may have resulted from a winnowing effect or may simply reflect a tendency to stack strata of progressively greater original sand content (Kellogg, 1977).

The upward-coarsening cycles of units A and B (table 79) suggest that the Mancos "B" interval may be the source of progradational pulses to the west in the present Uinta Basin. Whether the Douglas Creek Arch area could have been receiving distal delta-front to prodelta deposits is unclear from published studies. Alternatively, sandy sequences of the Mancos "B" interval may have been deposited on a shallow cratonic shelf well within storm-wave base, thereby allowing dispersal by shelf processes.

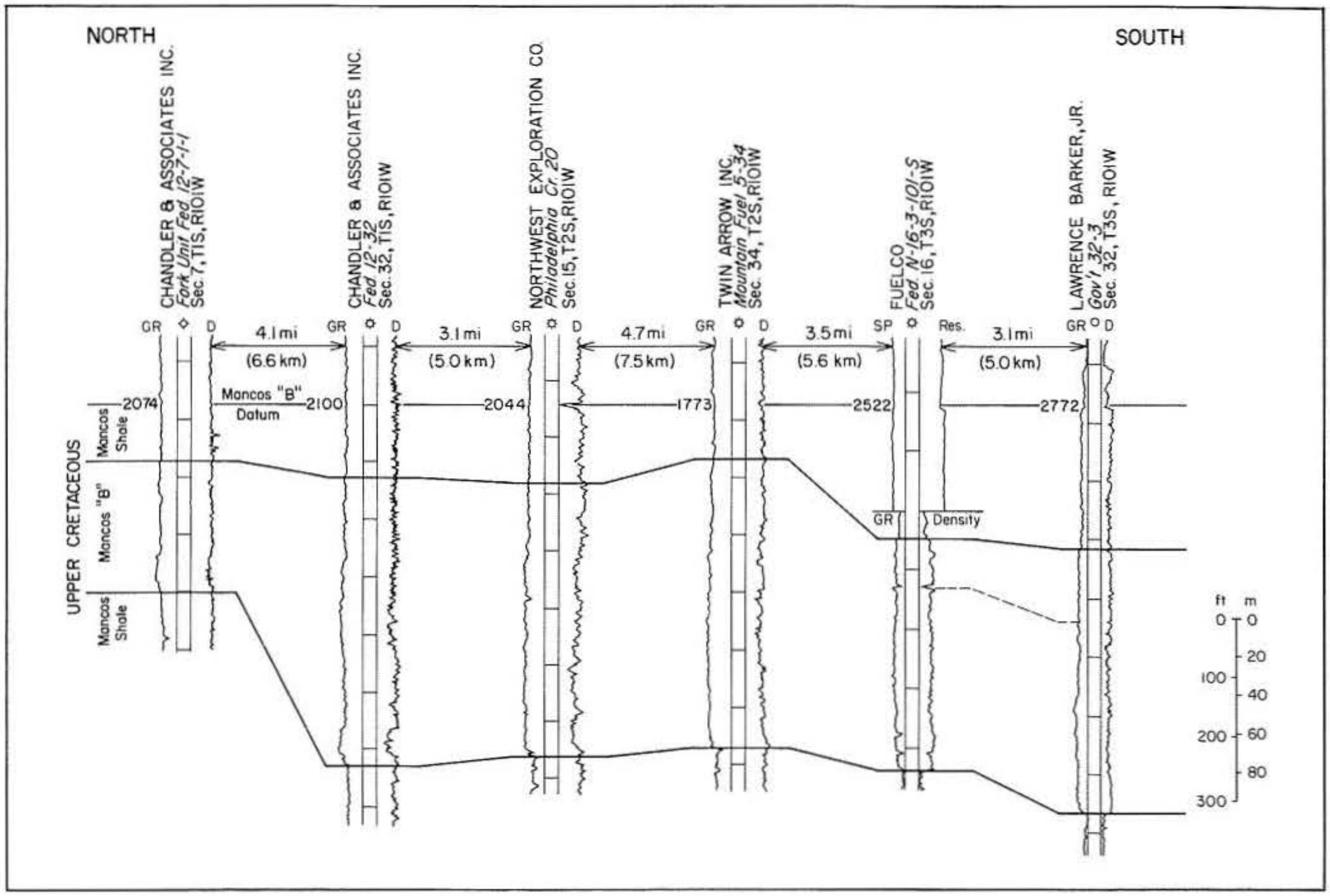


FIGURE 77. North-south stratigraphic cross section through the Mancos "B" interval of the Mancos Shale, Piceance Creek Basin (after Colorado Oil and Gas Conservation Commission, 1980c).

TABLE 79. Units of the Mancos "B" Shale in the Douglas Creek Arch area, Colorado (from Kellogg, 1977).

UNIT	DESCRIPTION
E	Most uniform in thickness of all units. Between 100 and 200 ft thick in most areas, it is thinnest (40 ft) and has the most sand toward the southern Douglas Creek Arch area.
D	Siltstone grading upward into sandstone having apparent fill of erosional topography developed on top of unit C. Transport eastward from the source area and then to the south, in contrast to units A, B, and C. This unit is very sandy in adjacent Utah.
C	Mostly siltstone and shale having some increase in sand over the north end of the Douglas Creek Arch. Units A, B, and C generally indicate transport eastward from the source area and then to the north.
B	Basal siltstone and shale coarsening upward; sand content increases toward the top of the unit.
A	Basal siltstone and shale coarsening upward into 50 to 100 ft of increasingly sand-rich strata. Thins to the northern part of the arch, where it is mostly sand rich.

TABLE 80. Mancos "B" Shale, Piceance Creek and Uinta Basins: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Mancos "B" interval, Mancos Shale, Upper Cretaceous.	1. Total designated area is 1,029 mi² in Rio Blanco and Garfield Counties, Colorado. 2. Application areas in Grand and Uintah Counties, Utah, are 670 mi².	1. Range is 400 to 700 ft in designated areas. 2. Range is 450 to 1,000 ft.	1. Range is 3,475 to 3,603 ft in all but 38 mi² of designated tight formation areas. Sea-level datum elevations of top Mancos "B" are +3,400 to +4,000 ft. 2. Average is 5,049 ft in application area.	1. No data. Not included in National Petroleum Council (1980) study. 2. Possible reserves up to 10 to 12 Bcf/mi².	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
1. This Late Cretaceous - early Tertiary Laramide-age basin is bounded on the southeast by the Sawatch Uplift, on the east by the White River Uplift, on the north by the Uinta Uplift, on the southwest by the Uncompahgre Uplift, and on the west by the Douglas Creek Arch. Areas of interest overlap the Douglas Creek Arch. 2. Uinta Basin is bounded on the north by the Uinta Mountains, on the east by the Douglas Creek Arch, on the south by the Uncompahgre Uplift, and on the west by the Wasatch Mountains fault block.	1. Mostly 2.6° F/100 ft. 2. 1.4° to 1.8° F/100 ft.	No data.	1. Compressional Laramide deformation followed by regional post-Laramide vertical uplift. 2. Differential downwarping of the basin as surrounding areas rose in post-Laramide time.

TABLE 81. *Mancos "B" Shale, Piceance Creek and Uinta Basins: Geologic parameters.*

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Deposited in a marine shelf environment approximately 100 mi east of an Upper Cretaceous shoreline represented by sands of the Emery Formation. The Mancos "B" interval is encased in Mancos marine shales. Sand content decreases off the Douglas Creek Arch to the southeast, and sands also pinch out northward on the arch.	Thinly bedded and interlaminated very fine grained sandstone, siltstone, and shale. May be up to 80% sandstone in beds up to 0.5 inches thick having shale laminae 0.0625 inches thick or less. The sandstone is poorly sorted and may have carbonaceous microlaminae.	Sandstone is predominantly quartz. Shale is bentonitic.	Diagenetic calcite and clay have reduced porosity and effective permeability.

Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
1. 30 to 250 ft thick in Douglas Creek Arch area in a gross interval of 400 ft. 2. 50 to 150 ft gross reservoir rock.	1. 450 psi at 90° F typical in the Fork Unit, Rio Blanco County, Colorado (T1-2S, R101-102W) at average producing depth of 2,470 ft. 2. Average pressure is 1,160 psi.	Silty and shaly facies may contribute to production through fractures. Infrequently, faulted zones produce without stimulation.	Core available. Density log is the standard open-hole logging tool, although neutron-density or induction log may also be used.

TABLE 82. Mancos "B" Shale, Piceance Creek and Uinta Basins: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Estimated average in situ permeability is 0.01 md for a group of 56 wells. Average in situ permeability is 0.087 md for another group of 63 wells. Porosity averages 10% to 11% and ranges from 6% to 14%. Conventional core analysis averages 0.7 md over Douglas Creek Arch; this is at least 10 times greater than in situ values. Generally lower permeability on Utah side of Douglas Creek Arch.	Average is 120 ft for a group of 10 wells in the Douglas Creek Arch area. Average is 90 ft for a group of five wells in an adjacent area. In Uinta Basin, average is 71 ft, range is 38 to 98 ft.	Sustained flows, if present, are TSTM. Zero for a group of 56 wells. For one Uinta Basin well, 39 Mcfd.	Average was 263 Mcfd for 56 wells. Average was 350 Mcfd for 22 wells.	Generally stabilizes at half of IP.	Typically no oil or condensate is produced.	Typically 50% in the sandy facies of the Douglas Creek Arch, increases in the lower half of the formation.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing. A typical fracture treatment uses 2,500 to 4,000 psi injection pressures, an average injection rate of 30 to 40 bbl/min and 500 to 900 scf/bbl CO_2. Total materials typically include 65,000 to 70,000 gal 2% KCl water, 30,000 lb 100 mesh sand, 80,000 to 100,000 lb 10-20 mesh sand, 90 tons CO_2, plus acid, surfactant, and gelling agent. Acid treatment varies from 250 to 3,000 gal of 5.0% to 15.0% HCl. In Uinta Basin, treatments range up to 350,000 lb sand.	In the Dragon Trail unit, Douglas Creek Arch, a ninefold increase in production was usually achieved after fracturing.	No data.	Mancos "B" interval is highly susceptible to water damage. Wells are best drilled using air to avoid formation damage, and fracture fluids must be reversed out rapidly. Nitrogen is also used in place of CO_2 during fracture treatment. Larger than normal compressor engines are needed during air drilling operations because of the altitude (up to 9,000 ft) of producing areas.

TABLE 83. Mancos "B" Shale, Piceance Creek and Uinta Basins: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Four applications approved, two in 1980 and two in 1981, for Colorado. One application approved for Utah.	276 producing or shut-in wells as of December 31, 1980, in Rio Blanco and Garfield Counties, Colorado.	42.4% in the Piceance Creek Basin as a whole for all wildcat gas wells, 1970-1977.	On the Douglas Creek Arch, well cost exclusive of fracturing quoted as approximately $275,000 (1981 dollars). Fracture job quoted at $75,000 to $150,000 in February 1981; other data indicate costs of $50,000 to $190,000, depending on complexity of treatment.	Gathering systems with 6-inch to 16-inch pipelines are in place in the Douglas Creek Arch area. A 26-inch pipeline of Northwest Pipeline Corp. generally parallels State Highway 139, running north-south through the area. A smaller pipeline of the Western Slope Gas Co. follows the same route.	High in Colorado. Four FERC applications approved. Additional applications pending that specify Mancos Formation; therefore, they probably include Mancos "B." Moderate in Utah. One FERC application.

OPERATING CONDITIONS | **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
Generally rough terrain having surface elevations of 6,500 to 9,500 ft in the middle Rocky Mountain physiographic subdivision. Local relief of 1,000 to 3,000 ft outside of Colorado River valley.	Winter weather limits exploratory work and drilling to 7 to 8 mo/yr, usually mid-May to mid-December. The climate is semiarid, having 8 to 16 inches mean annual precipitation. Moderate summers, cold to very cold winters.	Limited in part to use of secondary and ranch roads from State Highway 139. Easiest access along stream valleys. Difficult access to high mesas, such as Grand Mesa. Difficult access in parts of Uinta Basin.	Fair. Much thicker than, but similar to, upper part of Cleveland Formation (Anadarko Basin). Sanostee Member of the Mancos (San Juan Basin) is also a shelf deposit but is dominantly a calcarenite. Similar to other shelf deposits not included in this study.	Grand Junction, Colorado, is an expanding base of exploration and production services in the Piceance Creek Basin. Mileage charges in this region may be high for some service work. Vernal, Utah, is a base of services in the Uinta Basin.

SEGO AND CASTLEGATE SANDSTONES, UINTA BASIN

The Sego and Castlegate Sandstones have blanket geometries and are part of the Upper Cretaceous Mesaverde Group of the eastern Uinta Basin (fig. 78) (T. D. Fouch, personal communication, 1982). Of the two, only the Castlegate Sandstone was included in the National Petroleum Council (1980) study. Both sandstones were included in an FERC-approved designation for an interval 4,000 to 6,200 ft thick that also includes the Wasatch Formation and Mesaverde Group in Uintah County, Utah (fig. 74) (Utah Board of Oil, Gas, and Mining, 1981a). Within this application area, the average gross productive interval is 1,150 ft thick, but the distribution of production among specific units of interest cannot be readily determined. Limited data are available on the Castlegate Sandstone (table 84). Several published studies have focused on other parts of the Mesaverde Group in the Uinta Basin, such as the overlying Neslen, Farrer, and Tuscher Formations (Keighin, 1979 and 1981; Keighin and Sampath, 1982). These formations have been interpreted as fluvial channel deposits (Keighin and Fouch, 1981); therefore, individual sand bodies are likely to have a lenticular geometry.

In an area south and east of Vernal, Utah, the blanket-geometry Castlegate Sandstone probably represents upper and lower shoreface to shallow marine deposition. To the west, the Castlegate Sandstone probably represents coastal plain and braided-stream environments (T. D. Fouch, personal communication, 1982). Between Price and Green River, Utah, the Castlegate is a poorly sorted, partly conglomeratic fluvial deposit (Hale and Van de Graaff, 1964). The marginal marine Castlegate is generally a very fine grained to medium-grained sandstone and siltstone having some carbonaceous sandy and silty shale (Fouch and Cashion, 1979). The Sego Sandstone has the same lithology and also represents nearshore marine deposition; more specific data on depositional systems are unavailable (T. D. Fouch, personal communication, 1982). Both formations tend to be more quartzose than the feldspathic litharenites to sublitharenites of the Neslen, Farrer, and Tuscher Formations (Keighin and Fouch, 1981).

Hale and Van de Graaff (1964) noted that the Sego Sandstone is separated into upper and lower parts by a transgressive marine shale termed the Anchor Mine Tongue of the Mancos Shale. The upper Sego Sandstone was formed during a fairly rapid regression and the final retreat of the sea from northeastern Utah; this was followed by a major period of continental deposition during which the remainder of the Mesaverde Group was laid down.

Gas from the Castlegate and Sego Sandstones is produced primarily in the southeast corner of the Uinta Basin from depths of 8,000 ft or deeper. The gas is trapped on-structure, and the formations produce water off-structure. Core plug permeabilities are 0.5 to 0.9 md and greater; these units may exceed 0.1 md in situ permeability in some areas. Very limited core data are available. There have been about 50 penetrations of the Castlegate Sandstone, primarily on the south and east sides of the basin, and large areas exist without subsurface control (T. D. Fouch, personal communication, 1982). The Castlegate, upper Sego, and lower Sego are each about 50 to 70 ft thick in the southeastern Uinta Basin (Fouch and Cashion, 1979). The Sego extends into the northwest corner of the Piceance Creek Basin of Colorado, but it appears to have less potential for tight gas than do the Cozzette and Corcoran Sandstones in the southern Piceance Creek Basin (R. C. Johnson, personal communication, 1982).

TABLE 84. *Reservoir parameters and reserves of the Upper Cretaceous Castlegate Sandstone (Mesaverde Group), eastern Uinta Basin, Utah (from National Petroleum Council, 1980).*

Permeability: 0.1 to 0.003 md
Pressure: 4,275 psi
Temperature: 233° F
Gas-filled porosity: 4.2% to 2.3%
Net pay: 25 to 60 ft
Depth: 9,500 ft
Maximum recoverable gas: 1.131 Tcf plus additional gas in area of combined Coaly and Castlegate resource

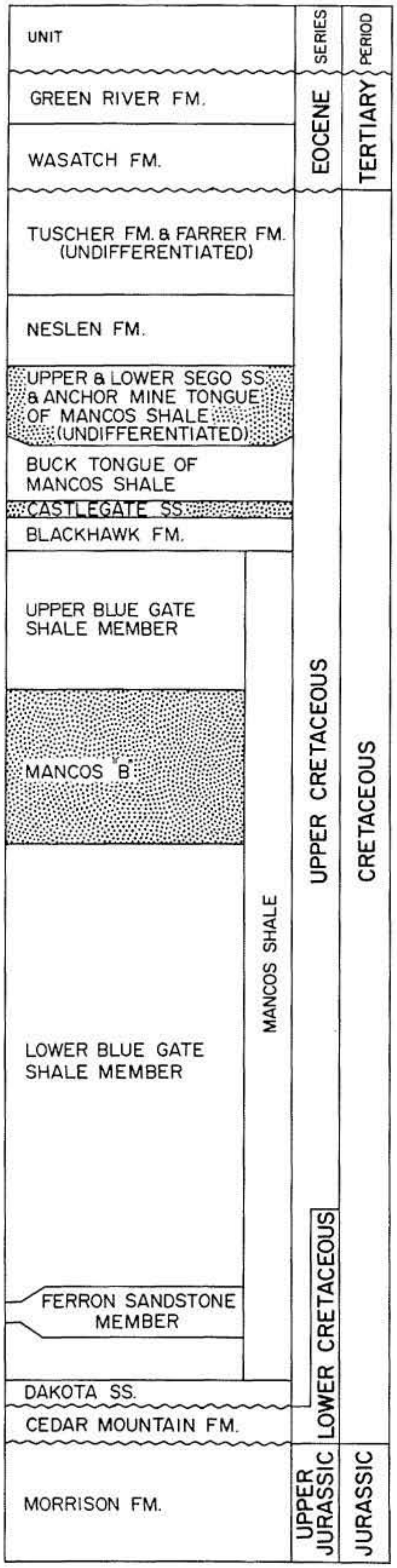


FIGURE 78. Stratigraphic column from the Upper Jurassic through the Eocene, Uinta Basin (from Fouch and Cashion, 1979).

MANCOS "B" SHALE, UINTA BASIN

The tight gas trend of the Mancos "B" Shale extends from the Piceance Creek Basin and Douglas Creek Arch of Colorado into the southeastern Uinta Basin of Uintah and Grand Counties, Utah. As in Colorado, the Mancos "B" interval is part of the Upper Cretaceous Mancos Shale (fig. 78), which is characterized by finely interbedded shale, siltstone, and very fine grained sandstone. An application to designate the Mancos "B" as a tight formation in the southeastern Uinta Basin and on the southern Douglas Creek Arch has been approved by the FERC (fig. 74) (Utah Board of Oil, Gas, and Mining, 1981b). The data base on the Mancos "B" in Utah is fair (tables 80 through 83). Some data on the Uinta Basin were not available, but data on nearby parts of the Mancos "B" interval on the Douglas Creek Arch and in the Piceance Creek Basin of Colorado are analogous.

Structure

The Uinta Basin is a strongly asymmetric, structural and topographic basin having a generally east-to-west axis located close to the northern basin margin. The Uinta Range and the Wasatch Plateau bound the basin on the north and west, respectively. The Uncompahgre Uplift bounds the basin on the southeast, the Douglas Creek Arch on the east (fig. 74), and the San Rafael swell on the southwest (west of area shown in fig. 74). The development of the Uinta Basin began during the Late Cretaceous - early Tertiary Laramide orogeny and the uplift of the Uinta Mountain block, which was accompanied by simultaneous subsidence of the basin (National Petroleum Council, 1980).

Stratigraphy

Upper Cretaceous and Tertiary rocks compose the major part of the sedimentary fill within the Uinta Basin (fig. 78). During Cretaceous time, clastic sediments were shed from the Sevier Arch in western Utah, including the eastward-thickening Mancos Shale, which is 2,000 to 5,000 ft thick within the basin (Osmond, 1965). The Mancos "B" interval is encased in the marine Mancos Shale, and the stratigraphy described by Kellogg (1977) for adjacent Colorado is also applicable in Utah (see previous section on the Mancos "B" Shale, Piceance Creek Basin, p. 158).

Depositional Systems

The study area of Kellogg (1977) included parts of the Uinta and Piceance Creek Basins and the Douglas Creek Arch. For a summary of depositional systems, see previous section on the Mancos "B" Shale, Piceance Creek Basin, p. 158.

FOX HILLS SANDSTONE, GREATER GREEN RIVER BASIN

The Upper Cretaceous Fox Hills Sandstone is a regressive sequence of marginal marine siltstones and sandstones deposited along the western edge of the Cretaceous epicontinental seaway. It is underlain by the marine Lewis Shale and overlain by paludal and fluvial deposits of the Lance Formation (fig. 79). The Fox Hills Sandstone has been studied in outcrop from the western margin of the Denver Basin near Golden, Colorado (Weimer, 1973) to the eastern edge of the Rock Springs Uplift near Rock Springs, Wyoming (Harms and others, 1965). The latter authors questioned the interpretation of the Fox Hills as a barrier-island sequence in that area but proposed no other littoral to shallow marine facies as an alternative. Both the upper and lower contacts of the Fox Hills Sandstone are difficult to establish consistently over longer distances (Newman, 1981).

The data base on the Fox Hills Sandstone is fair (tables 85 through 88); it is based on several published articles and one FERC application (Wyoming Oil and Gas Conservation Commission, 1981b). Although additional data on this formation are needed, it appears that tight gas production in the Fox Hills is hampered in many areas by excessive production of water (D. Reese, personal communication, 1982). Neither the National Petroleum Council (1980) nor Kuuskraa and others (1978) included the Fox Hills in their assessments of the Greater Green River Basin.

Structure

The Greater Green River Basin of southwestern Wyoming and northwestern Colorado has a surface area of about 23,000 mi^2; Cretaceous and Tertiary rocks within the basin have an average thickness of 15,000 ft. The present form of the basin resulted from the Late Cretaceous - early Tertiary Laramide orogeny. The basin is bounded by the Overthrust Belt on the west and by a series of surrounding positive features on other margins (fig. 80). The basin is further divided into subbasins and intervening uplifts, some of which, such as the Wamsutter Arch and the Cherokee Ridge, are only subsurface features (National Petroleum Council, 1980).

Stratigraphy, with a Note on the Lewis Shale

Underlying the Fox Hills Sandstone and overlying the dominantly regressive Mesaverde Group is the Lewis Shale, which was deposited during the last major marine invasion of the eastern Greater Green River Basin. The Lewis sea did not advance very far west of the western edge of the Rock Springs Uplift, where a Lewis strandplain developed. The strandplain facies may contain blanket tight gas sandstones; otherwise, siltstones and thin sandstones within the Lewis Shale are expected to be lenticular (Newman, 1981). An application for a tight formation designation has been approved by the State of Wyoming for the Lewis in parts of Sweetwater and Carbon Counties (Hagar and Petzet, 1982b).

The Lewis - Fox Hills contact is transitional, and the Fox Hills Sandstone itself, although regressive, is interrupted by local marine transgressions (Newman, 1981). The Fox Hills is notably time-transgressive, and outcrop studies of the northeast flank of the Rock Springs Uplift have shown that the Fox Hills becomes progressively younger to the southeast and east (Weimer, 1961). This time-transgressive relationship would be expected to continue to the eastern limit of deposition in the Red Desert and Washakie Basins.

The overlying Lance Formation is a nonmarine sequence of carbonaceous shales, siltstones, sandstones, and coal beds that is up to 2,000 ft thick in the Red Desert and Washakie Basins. It is primarily fluvial, lacustrine, and paludal in origin (Newman, 1981).

Depositional Systems

The Fox Hills Sandstone is a composite regressive sand body having an overall blanket geometry. Outcrop studies, however, indicate that individual sandstone units show varying dip and strike continuity, with a tendency toward better strike continuity (Weimer, 1961; Land, 1972). Land (1972) concluded that the Fox Hills Sandstone in the area of the Rock Springs Uplift and Wamsutter Arch was deposited along an embayed barrier-island coastline. Individual facies include shales and siltstones of shallow-water origin grading upward into very fine grained and fine-grained sandstone of the lower and upper shoreface and foreshore of a barrier island. These facies are generally overlain by a fine- to medium-grained sandstone with a scoured base interpreted to be estuarine. In outcrop along the western edge of the Denver Basin, the Fox Hills Sandstone is a delta-front deposit (Weimer, 1973); thus, deltaic depocenters may also be found within the Fox Hills of the eastern Greater Green River Basin.

Electric logs of the Fox Hills Sandstone show both aggradational, blocky character and progradational, upward-coarsening sequences (fig. 81). The sequences may coarsen upward over as much as 50 ft from shale baseline to maximum SP deflection, whereas the sandstones having blocky character attain maximum deflection over 10 to 20 ft (Tyler, 1978, 1980a, and 1980b). Thus, the Fox Hills may be a combination of shoreline and shallow marine deposits, including both aggradational coastal barrier sands and progradational deltaic sands deposited on the leading edge of a major regression culminating in thick, nonmarine Tertiary deposits.

Although the Fox Hills Sandstone was deposited over an extensive area in the central Rocky Mountain region, hydrocarbon production is limited. Gas is produced from this formation in the Washakie Basin, primarily from Bitter Creek Field. An FERC-approved tight gas sand area in the Fox Hills Formation is also located in the Washakie Basin (fig. 82), encompassing the areas peripheral to Bitter Creek Field (Wyoming Oil and Gas Conservation Commission, 1981b).

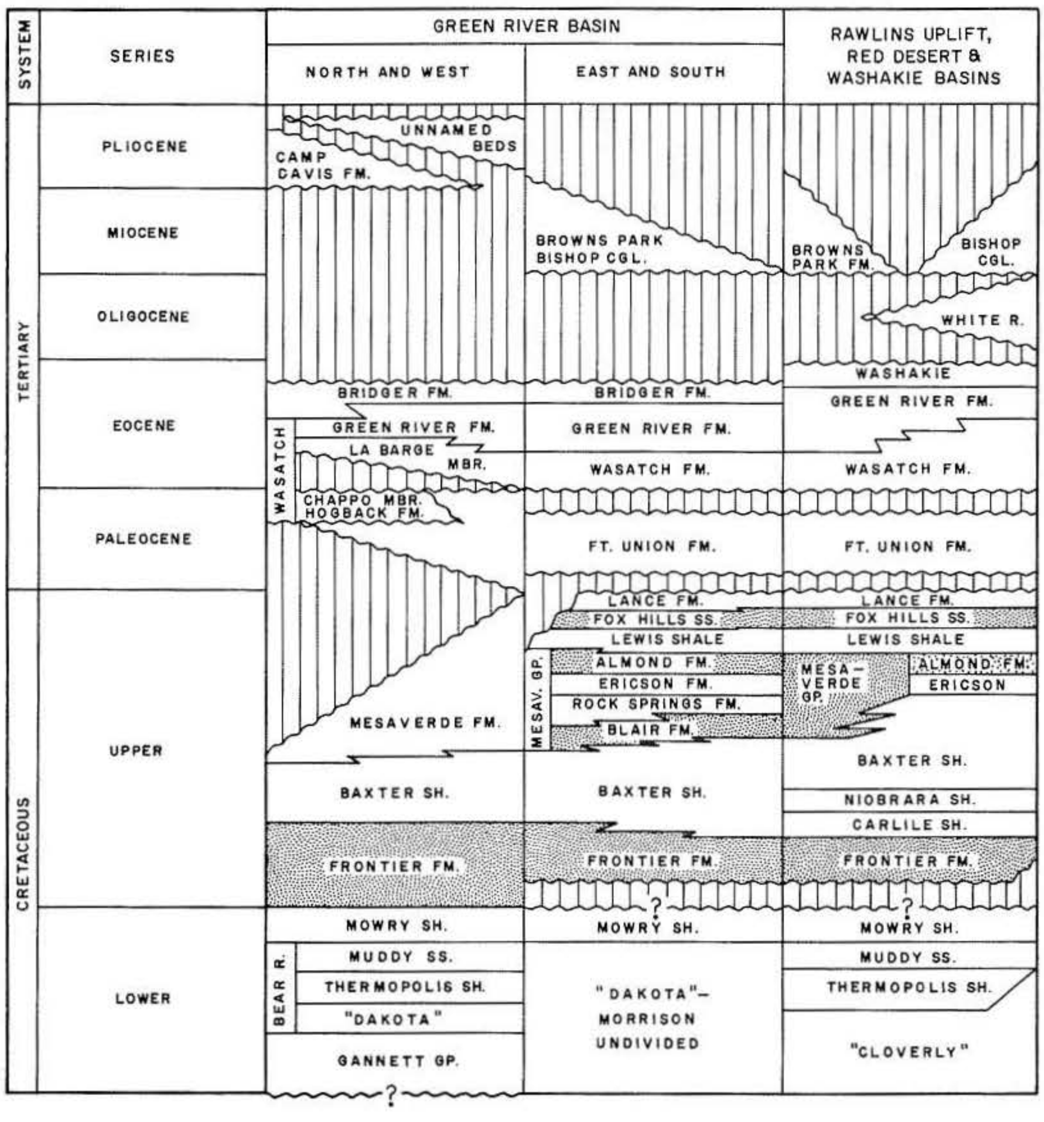


FIGURE 79. Stratigraphic column from the Lower Cretaceous through the Pliocene, Greater Green River Basin (after Newman, 1981).

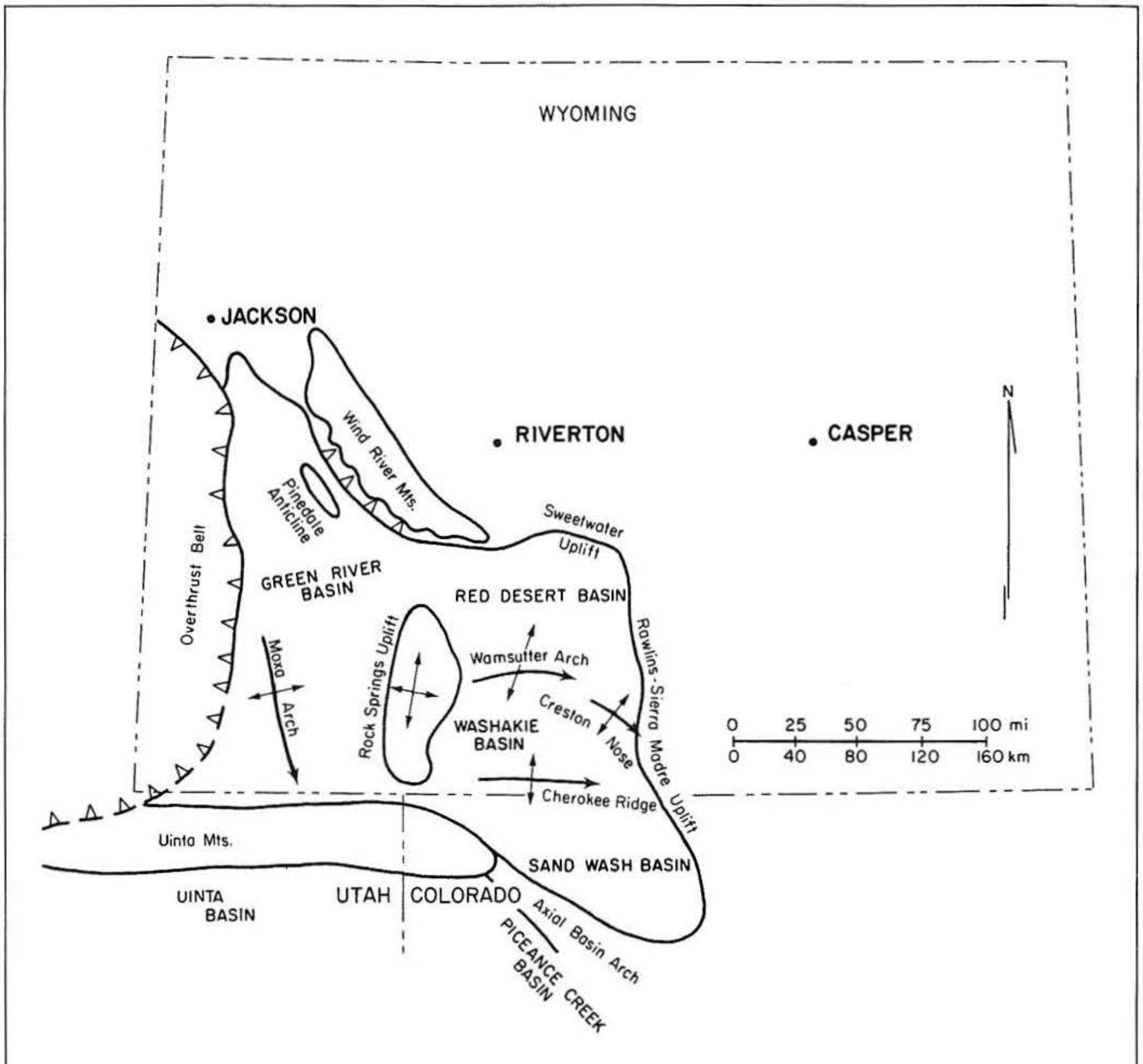


FIGURE 80. Tectonic elements of the Greater Green River Basin and adjacent areas (after Newman, 1981).

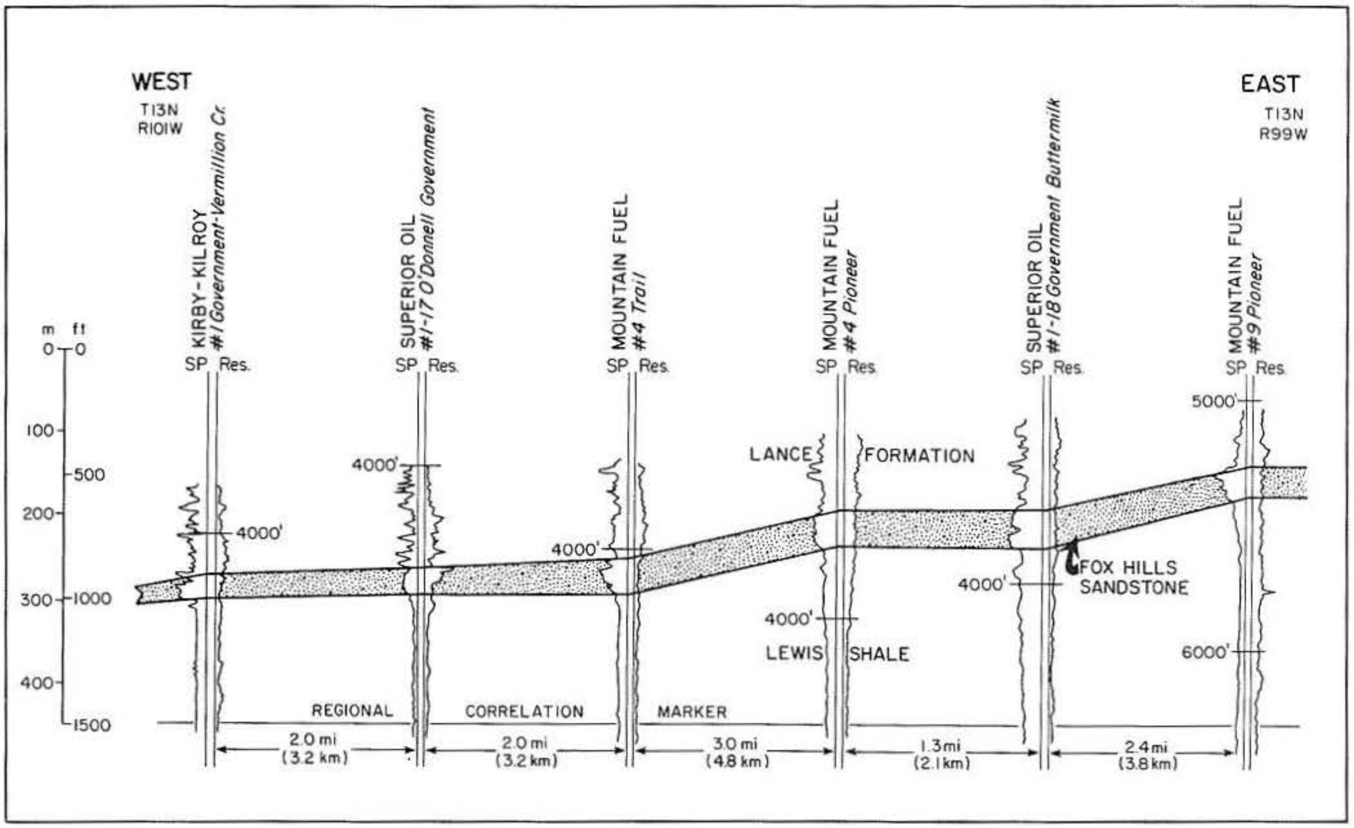


FIGURE 81. East-west stratigraphic cross section from T13N, R101W to T13N, R99W through the Fox Hills Sandstone and adjacent strata, Greater Green River Basin (after Tyler, 1980b).

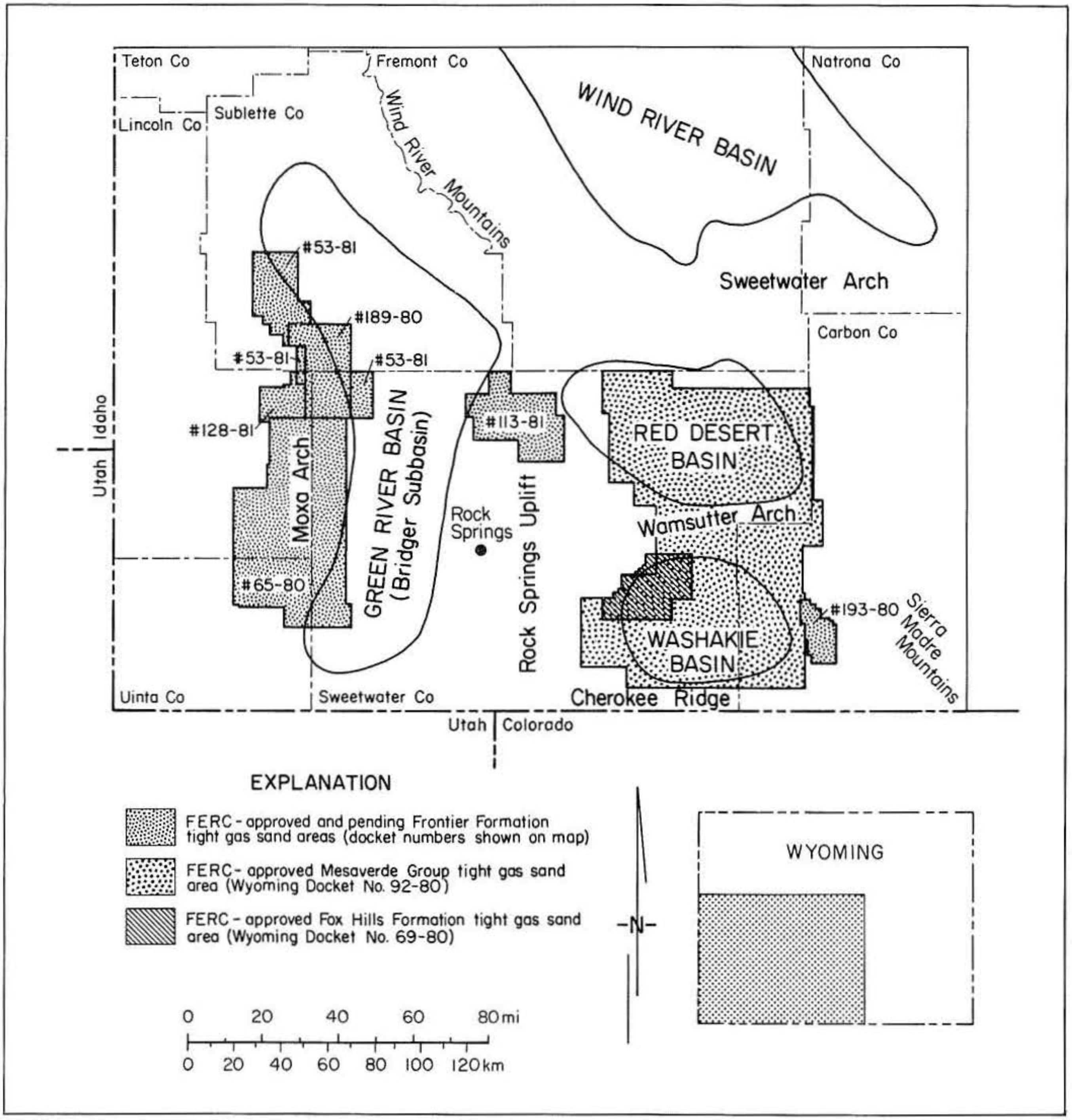


FIGURE 82. Areas covered by tight gas sand applications, Greater Green River Basin (Wyoming Oil and Gas Conservation Commission, 1980a, 1980b, 1981a, 1981b, 1981c, 1981d, 1981e, 1981f).

TABLE 85. Fox Hills Sandstone, Greater Green River Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Fox Hills Sandstone, Upper Cretaceous.	Area in parts of T16-18N, R96-99W, Sweetwater County, Wyoming, is 303 mi^2.	Generally 300 ft to a maximum of 600 ft in application area. Range is 150 to 250 ft to the north in the Wamsutter Arch area near Patrick Draw Field.	Average is 7,360 ft.	No data. Not included in National Petroleum Council (1980) study.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
The designated area lies within the Washakie Basin, which is a subbasin of the Greater Green River Basin. The area is bounded on the west by the Rock Springs Uplift and on the north by the Wamsutter Arch. Parts of the area lie on the flanks of these structures. The Sierra Madre Uplift borders the eastern edge of the Washakie Basin, and the Cherokee Ridge separates the Washakie from the Sand Wash Basin to the south.	1.2° to 1.6° F/100 ft.	No data.	Compressional and vertical stresses related to Late Cretaceous - early Tertiary Laramide tectonism.

TABLE 86. Fox Hills Sandstone, Greater Green River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Deposition occurred during a net regression of the Late Cretaceous epeiric seaway. The Fox Hills intertongues with the marine Lewis Shale, which it overlies, and with the nonmarine Lance Formation, which is underlies. Depositional systems include deltaic and wave-dominated barrier-island coastline. Individual facies represent deposition in upper and lower shoreface and foreshore environments on the open sides of the barrier islands and estuarine environments between and behind the barrier islands. To the south, near Golden, Colorado, outcrops of the Fox Hills are interpreted to be lower to upper delta front and distributary bar.	Siltstone and very fine grained to medium-grained sandstone.	55% to 90% quartz, 3% to 15% chert, 3% to 30% rock fragments, predominantly pelitic clay-aggregate (sericite-illite) clasts, having some siltstone and volcanic rock fragments; 2% to 15% feldspar (plagioclase and K-feldspar); trace of muscovite, biotite, and heavy minerals.	Cemented primarily by calcite and some authigenic clays.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Gross perforation interval average is 254 ft; range is 83 to 447 ft in four wells.	Average temperature is 150° F.	No data.	SP-resistivity logs available. No information on core availability. More outcrop studies available than typical for other formations. GR-neutron density logs may have been run.

TABLE 87. Fox Hills Sandstone, Greater Green River Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
Permeability is 0.004 md calculated from the flow test of one well. Porosity range is 12% to 14%.	From one well, net pay is 25 ft.	Average was 175 Mcfd for unknown number of wells.	Average was 775 Mcfd for unknown number of wells.	No data.	When liquid hydrocarbons are produced, rates are less than 5 bpd.	Typically less than 70%.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracture techniques currently average 100,000 gal gel-KCl fluid and 300 scf CO_2/bbl of fluid and 138,000 lb of 20-40 mesh sand proppant.	No data.	160-acre spacing except for sec. 35, 36, T17N, R99W; sec. 31, T17N, R98W; and sec. 1, 2, and 3, T16N, R99W, where 320-acre spacing is in effect.	Good continuity of SP log character over distances of 1 to 4 mi is evident on regional cross sections prepared by the U.S. Geological Survey.

TABLE 88. Fox Hills Sandstone, Greater Green River Basin:
Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by FERC.	450 penetrations in an area of 2,500 mi^2.	No data.	Average drilling and completion costs are $445,000. Average stimulation costs are $70,000 (1980 dollars).	Pipelines are available for production along the margins of the Washakie Basin and on the Wamsutter Arch, but the basinward townships of the designated tight formation area were not served by pipelines as of April 1980. Cities Service Gas Co., Northwest Pipeline Co., and Western Transmission Corp. have pipelines in the area.	Low to moderate. One FERC application.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
In the Wyoming - Big Horn Basins physiographic subdivision. Local relief of 300 to 500 ft in most areas, 1,000 to 3,000 ft over the Rock Springs Uplift and around the margins of the basin.	Semiarid to arid. Most areas receive 8 to 16 inches mean annual precipitation; however, low-relief areas east and west of the Rock Springs Uplift receive less than 8 inches mean annual precipitation. Mild summers, cold to very cold winters.	Access may be limited in areas of low mountains by significant local relief.	Good. The deltaic facies have analogies in parts of the Frontier, Olmos, Davis, and Carter Formations. The Olmos is overlain and possibly reworked by marine transgression, but the Fox Hills is overlain by regressive paludal deposits. Barrier-island marine bar sandstones of the Fox Hills have analogies in the upper Dakota, upper Almond, and marginal marine deltaic to interdeltaic sands of the Mesaverde Group, probably including Cozzette and Corcoran Sandstones.	Mileage charges in parts of the eastern Greater Green River Basin may be high for service to remote areas.

UPPER ALMOND AND BLAIR FORMATIONS, GREATER GREEN RIVER BASIN

The upper Almond and Blair Formations are part of the Upper Cretaceous Mesaverde Group within the eastern Greater Green River Basin (fig. 79). These units consist of fine-grained to very fine grained sandstone having some detrital silt and clay (upper Almond) to fine-grained to very fine grained sandstone, siltstone, and shale (Blair). An application for designation of the Mesaverde Group as a tight formation has been approved by the FERC for an area that covers most of the Red Desert and Washakie Basins and the Wamsutter Arch (fig. 82) (Wyoming Oil and Gas Conservation Commission, 1981b). Most of the gas produced from the Mesaverde Group is from either the upper or the lower Almond Formation, but operators may drill to the Blair Formation at the base of the Mesaverde Group to test all parts of the group (R. Marvel, personal communication, 1982).

The data base on the upper Almond Formation is good (tables 89 through 92); it is based to a large extent on McPeek (1981). The data base on the Blair Formation is poor (tables 93 through 96). More data are available on the Almond Formation because of high operator interest in its shallow upper and lower parts. The upper Almond is better known as a blanket reservoir, but the Blair Formation is marine influenced and should have some lateral continuity. The lower Almond Formation contains lenticular sandstones.

Structure

The structural setting of the Greater Green River Basin is described in the previous section on the Fox Hills Sandstone (p. 167). The areas of interest for tight gas production in the upper Almond and Blair Formations are the Red Desert Basin, the Wamsutter Arch, and the Washakie Basin (fig. 80). The National Petroleum Council (1980) concluded that the Green River Basin proper (also known as the Bridger Basin) and the Moxa Arch will yield little gas from lenticular sandstones; the Council did not comment on expected yield of blanket units younger than the Frontier Formation.

Stratigraphy

The Almond Formation conformably overlies the Ericson Formation within the Mesaverde Group (fig. 79) and ranges from 200 to 800 ft thick (Newman, 1981). The Almond is divided into the upper Almond, or Almond "A," and the lower Almond, or Almond "B." Terminology for these units varies; McPeek (1981) used the terms "upper" and "lower," the National Petroleum Council (1980) used "A" and "B," and some authors do not distinguish the two on regional cross sections (Miller and VerPloeg, 1980). McPeek's (1981) usage will be followed here.

The lower Almond Formation contains fluvial and paludal deposits, including coal beds. West of the Rock Springs Uplift, the upper Almond Formation is not developed and the lower Almond merges with similar deposits of the overlying Lance Formation. The marine transgression represented by the Lewis Shale did not extend past the western edge of the uplift; hence, shale is absent between the Almond and Lance Formations. The upper Almond Formation is a marginal marine deposit of the Lewis transgression. When sea-level stillstands and localized regressions of the Lewis sea occurred, the barrier and shoreface sandstones that were deposited formed the upper Almond (Jacka, 1965; Newman, 1981).

The Blair Formation, at the base of the Mesaverde Group, consists of shallow marine sandstones, siltstones, and shales. The basal part of the Blair contains marine sandstone ranging in thickness from 150 to 500 ft; this sandstone is thought to be the contact with the underlying Baxter Shale. The sandstone is well developed around the Rock Springs Uplift; however, east of the uplift, the Blair consists mostly of shallow marine siltstones and shales that become difficult to distinguish from the underlying Baxter and overlying Rock Springs Formations (Newman, 1981).

Depositional Systems

The primary depositional control on the upper Almond Formation was exerted by the transgression (dominant) and regression (subordinate) of the Lewis seaway shoreline. This resulted in intertonguing of marine shales and barrier and shallow marine sandstones and led to vertical repetition of facies (Weimer, 1965). Outcrop studies of the eastern margin of the Rock Springs Uplift have suggested that upper Almond depositional cycles resulted in barrier-island, marsh or mudflat, and lagoonal-bay deposits (Jacka, 1965). Marginal marine environments shifted laterally and vertically over time. Lateral migration of the barrier island formed a blanket sandstone consisting of shoreface, foreshore, tidal-delta, tidal-channel, and possibly dune facies (Flores, 1978).

Generally, the Almond Formation shoreline rises stratigraphically to the west across the eastern Greater Green River Basin and becomes younger. Approximately the upper 100 ft of the Almond Formation constitutes the part of the upper Almond that is made up of shoreline deposits (Miller, 1977). The uppermost Almond sandstone has excellent lateral continuity across the Wamsutter Arch and Patrick Draw Field (fig. 83) (Tyler, 1978) and fair to good lateral continuity across the southern end of the Rock Springs Uplift (fig. 84) (Tyler, 1980b). The generally blocky SP log character of the uppermost Almond sandstone is typical of a barrier sandstone; the sequence may be similar to the barrier-island sequence of shoreface and foreshore deposits described from outcrop by Jacka (1965, fig. 6).

The genetic facies of the Blair Formation are not well documented. The sandstones and siltstones of the Blair are commonly considered to be shallow marine, in part because of a shallow-water fauna. The Blair may have been deposited adjacent to or offshore of the mouth of a major northwest-southeast-trending distributary entering the Baxter sea northwest of the Rock Springs Uplift in the area of the Green River Basin proper (Miller, 1977). Parts of the Blair Formation therefore may represent a deltaic system.

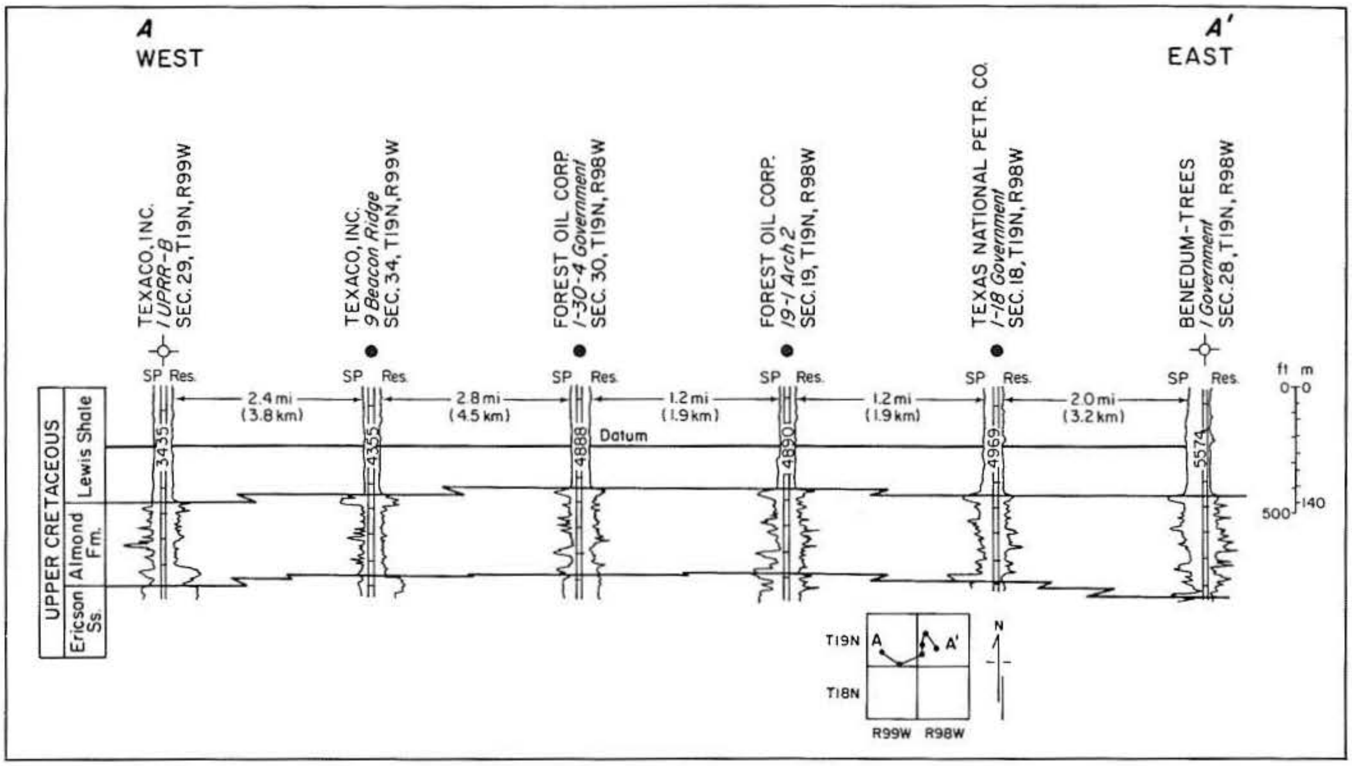


FIGURE 83. East-west stratigraphic cross section A-A' through the Almond Formation (undivided), Greater Green River Basin (after Tyler, 1978).

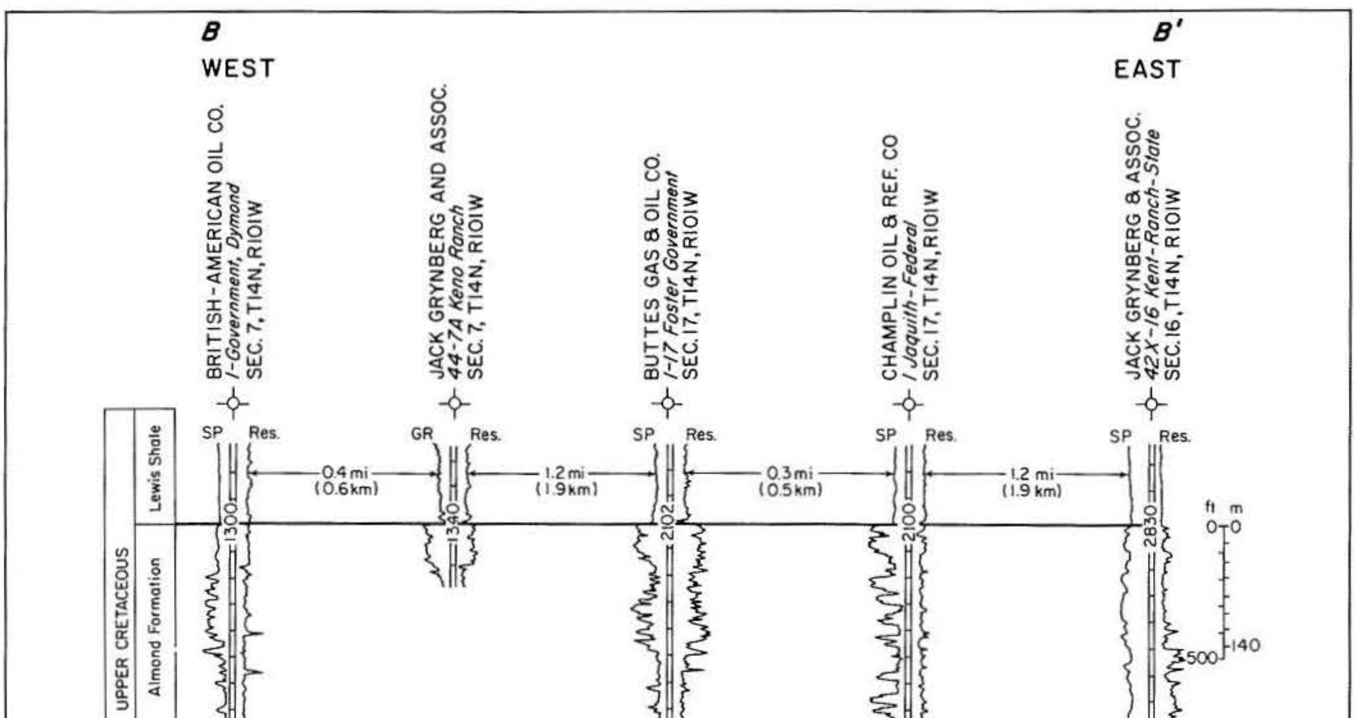


FIGURE 84. East-west stratigraphic cross section B-B' through the Almond Formation (undivided), Greater Green River Basin (after Tyler, 1980b).

TABLE 89. *Upper Almond Formation, Greater Green River Basin: General attributes and geologic parameters of the trend.*

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Upper Almond Formation, Mesaverde Group, Upper Cretaceous.	Marginal marine upper Almond Formation is found east of the Rock Springs Uplift. Total designated area for the Mesaverde Group is 4,117 mi² in the Red Desert Basin, Wamsutter Arch, and Washakie Basin.	Almond Formation (lower and upper) averages 490 ft thick in 31 wells. The upper Almond is estimated to represent no more than 100 to 150 ft of the total thickness. Only the upper 100 ft or less of the Almond Formation is associated with marginal marine processes.	Range is from approximately 6,200 ft on the Wamsutter Arch (T19N, R98W) to 15,450 ft in the deep Washakie Basin (T14N, R96W). Average is 10,170 ft for 43 Amoco-operated wells in tight formation area.	Maximum recoverable gas is 0.307 Tcf in the Red Desert Basin and 1.465 Tcf on the Wamsutter Arch and the eastern flank of the Washakie Basin (uniquely identified with the upper Almond). Considerable additional reserves are present in the upper Almond, stacked in association with other reservoirs (National Petroleum Council, 1980). Estimated recoverable gas is 2.6 Bcf per average section (McPeek, 1981).	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This area lies within the Red Desert and Washakie subbasins and on the Wamsutter Arch of the eastern Greater Green River Basin. Positive and negative structural features are a product of the Laramide orogeny.	1.2° to 1.6° F/100 ft, mostly 1.4° to 1.6° F/100 ft.	Overpressured in much of the Greater Green River Basin. Gradients are 0.5 to 0.64 psi/ft.	Compressional Laramide deformation followed by post-Laramide vertical uplift.

TABLE 90. Upper Almond Formation, Greater Green River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Shallow marine embayment and offshore bar, shoreface, barrier island, and mixed tidal flats of interlaminated mud to sand. Minor regressive and transgressive episodes led to reworking and stacking of sandy facies. Overlain by major Lewis transgression, generally to the western edge of the Rock Springs Uplift. Upper Almond sandstones interfinger with basal Lewis shales. Tidal-inlet and tidal-delta lithofacies are also represented. Shoreline facies rise stratigraphically and become younger from east to west.	Fine-grained to very fine grained sandstone having varying amounts of detrital silt and clay and sandy and silty shales. In outcrop on the eastern side of the Rock Springs Uplift, sandstone is moderately to well sorted and subangular to subrounded.	In outcrop on the eastern side of the Rock Springs Uplift, sandstone consists of quartz, rock fragments, feldspar (altered), mica, minor amounts of dark chert, rare glauconite, and some reworked carbonaceous debris. One outcrop study reported 31% to 50% quartz, 14% to 19% rock fragments, 7% to 14% feldspar, 10% to 13% matrix, and 19% to 27% cement.	Probably similar to other Mesaverde Group formations having quartz and calcite cement and diagenetic clay, including chlorite.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Reservoir sandstone up to 40 ft thick over an area 2 to 4 mi wide and 5 to 40 mi long in the overpressured area.	Average pressure is 5,854 psi in 43 wells in tight formation area from undifferentiated Mesaverde Group.	No data on existing production, but fracturing is expected to enhance production in highly overpressured areas. Three wells in designated tight formation area were excluded from the application because they are thought to produce from a natural fracture (average prestimulation flow was 3,110 Mcfd).	SP-resistivity and compensated neutron-formation density are typical logs. Core is available from and has been described by the U.S. Geological Survey.

TABLE 91. Upper Almond Formation, Greater Green River Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir parameters	Net pay thickness	Production rates: Pre-stimulation	Production rates: Post-stimulation	Production rates: Decline rates	Formation fluids	Water saturation
Average in situ permeability in designated tight formation area of Mesaverde Group is 0.041 md. Average porosity is 18% in overpressured area.	Range is 14 to 18 ft in the overpressured areas.	214 Mcfd for undifferentiated Mesaverde in tight formation area. No specific data on upper Almond.	First year average daily production was 1,500 to 1,700 Mcfd.	No data.	Little water is produced, no specific details. No oil is produced from Mesaverde Group in designated tight formation area.	Average is 59%, range is 45% to 88% for core through one producing interval sampled at 1-ft intervals.

Well stimulation techniques	Success ratio	Well spacing	Comments
Hydraulic fracturing and massive hydraulic fracturing. Massive hydraulic fracturing in the undifferentiated Mesaverde Group has used 275,000 to 290,000 gal fluid and 482,000 to 800,000 lb sand proppant at pressures as high as 6,500 to 8,000 psi. Average fracture treatment for 43 Amoco wells in tight formation area used 162,000 gal fluid and 321,000 lb sand proppant (for undifferentiated Mesaverde Group).	An average 451% increase in gas flow after stimulation for 43 Amoco-operated wells in designated tight formation area (undifferentiated Mesaverde).	640 acres.	Average gas recoverable per well estimated at 8 to 9 Bcf. Some pre-stimulation flow tests were taken after treatment with acid, but all were taken before fracturing. Mesaverde production is generally from the upper or lower Almond Formation.

TABLE 92. *Upper Almond Formation, Greater Green River Basin: Economic factors, operating conditions, and extrapolation potential.*

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
One FERC application approved for the undifferentiated Mesaverde Group.	319 penetrations, not all of which were solely targeted for the upper Almond (overpressured area). An additional 143 wells, as of March 1980, were being drilled or tested, or had been announced as locations; some of these may test the upper Almond.	39% of penetrations in the overpressured areas.	A typical 10,000-ft well to upper Almond in the over-pressured zone costs approximately $1.2 million (1980 dollars). Average cost for a Mesaverde fracture treatment of 205,000 gal fluid and 396,000 lb proppant is $232,600 (1980 dollars).	Panhandle Eastern Pipeline Co., Colorado Interstate Gas Co., and Cities Service Gas Co. have pipelines in the Red Desert and Washakie Basins. Mapco has completed a pipeline to accept natural gas liquids not used locally.	Moderate to high. Tight gas designation in effect; recent publication pointed out extent of undrilled areas, especially at greater depths than current production.

OPERATING CONDITIONS			**EXTRAPOLATION POTENTIAL**	
Physiography	*Climatic conditions*	*Accessibility*		*Comments*
In the Wyoming - Big Horn Basins physiographic subdivision. Local relief of 300 to 500 ft east and west of the Rock Springs Uplift, 1,000 ft or more near the Rock Springs Uplift.	Arid to semiarid having less than 8 inches to approximately 12 inches mean annual precipitation, increasing at surrounding higher elevations. Mild summers, very cold winters. Winter conditions can adversely affect exploration activities.	Limited major highway access to parts of the area.	Good. Barrier-island, shoreface, and offshore-bar facies similar to other marginal marine sandstones of the Mesaverde Group, including Corcoran, Cozzette, and possibly Sego and Castlegate Sandstones. Hartselle and Fox Hills Sandstones also contain barrier, shoreface, and shallow marine deposits.	McPeek (1981) reviewed Mesaverde potential in the Red Desert Basin, Wamsutter Arch, and Washakie Basin.

*TABLE 93. **Blair Formation (Mesaverde Group), Greater Green River Basin: General attributes and geologic parameters of the trend.***

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Blair Formation, Mesaverde Group, Upper Cretaceous.	Northern Rock Springs Uplift and north-central Greater Green River Basin.	Average is 1,400 ft in the deep-basin area of T27N, R103W. Average is 1,900 ft in T18-19N, R97-98W, Table Rock Field area, eastern flank of Rock Springs Uplift.	Range is from outcrop on the northern end of the Rock Springs Uplift to 15,000 ft in T27N, R103W on the northern basin margin. Drilling depth of 8,200 ft in Table Rock Field area (T18-19N, R97-98W), eastern flank of Rock Springs Uplift.	Maximum recoverable gas is at least 1.2 Tcf (National Petroleum Council, 1980). Blair Formation not sufficiently differentiated from other formations of the Mesaverde Group in National Petroleum Council (1980) study to give more precise estimate.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
See upper Almond Formation, Greater Green River Basin, table 89.	See upper Almond Formation, Greater Green River Basin, table 89.	See upper Almond Formation, Greater Green River Basin, table 89.	See upper Almond Formation, Greater Green River Basin, table 89.

TABLE 94. Blair Formation (Mesaverde Group), Greater Green River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
A marine regressive sandstone forming the basal unit in the Mesaverde Group. Contains marine shale toward its upper contact with the Rock Springs Formation in the northern Rock Springs Uplift area. The Blair becomes indistinguishable from the Baxter Shale to the northeast, southwest, and southeast of the Rock Springs Uplift in the north-central part of the Greater Green River Basin. May be distal delta front rather than purely prodelta, as suggested by subaqueous slumps and contorted bedding seen in outcrop. Facies may grade landward into proximal delta front and possibly distributary bar where thick sandstones occur in the lower Blair. Boundaries of the Blair are transitional and difficult to pick.	Fine-grained to very fine grained sandstone, siltstone, and shale, massively to thinly bedded in outcrops along the Rock Springs Uplift. Most sandy facies found around the northern Rock Springs Uplift and the northern basin margin; more silty and shaly between the Moxa Arch and the Rock Springs Uplift.	Probably similar to other Mesaverde Group formations having quartz, sedimentary rock fragments, and detrital clay.	Probably similar to other Mesaverde Group formations having quartz and calcite cements and diagenetic clays, including chlorite.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
Basal marine sandstone or a younger middle Blair sandstone ranges from 150 to 500 ft thick in the subsurface east of the Rock Springs Uplift.	No data.	No data.	Nonexistent in deeper parts of the basin, limited elsewhere.

TABLE 95. Blair Formation (Mesaverde Group), Greater Green River Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
No data.	No data.	214 Mcfd for undifferentiated Mesaverde Group in tight formation area. No specific data on Blair.	No data.	No data.	No oil is produced from Mesaverde Group in designated tight formation area.	No data.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing and massive hydraulic fracturing. See upper Almond Formation, Greater Green River Basin, table 91.	See upper Almond Formation, Greater Green River Basin, table 91.	No data.	Gas shows, having no further details given, are in Table Rock Field area, T18-19N, R97-98W. For all engineering parameters, no data specific to the Blair as distinguished from the Mesaverde Group as a whole.

TABLE 96. Blair Formation (Mesaverde Group), Greater Green River Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
One FERC application approved for the undifferentiated Mesaverde Group.	No data.	No data.	No data specific to Blair. See upper Almond Formation, Greater Green River Basin, table 92; allow costs for a minimum of 25% greater depth.	Similar to other Mesaverde Group production in the eastern Greater Green River Basin, but pipelines are lacking in the northwestern part of the Green River Basin proper where marine Blair sands are best developed.	Low to moderate. Apparently little incentive to drill to the base of the Mesaverde Group because of shallower formations in the group.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
See upper Almond Formation, Greater Green River Basin, table 92.	See upper Almond Formation, Greater Green River Basin, table 92.	See upper Almond Formation, Greater Green River Basin, table 92.	Fair. Data limited. Distal to proximal deltaic facies suggest analogy to Davis and Olmos Formations. May have similarities to barrier-strandplain and offshore-bar facies of other parts of the Mesaverde Group, but data are inadequate to make a full comparison.	In 1973, only five wells produced predominantly from the Blair or the Blair-equivalent Adaville Formation.

FRONTIER FORMATION, GREATER GREEN RIVER BASIN

The Frontier Formation, the lowermost Upper Cretaceous unit in the Greater Green River Basin, is a major regressive deposit of alternating sand and shale. The Frontier is encased between the marine Mowry and Baxter Shales (fig. 79). Applications have been filed for designation of the Frontier Formation as a tight gas sand in parts of the Greater Green River Basin (fig. 82) (Wyoming Oil and Gas Conservation Commission, 1980a, 1981a, 1981c, 1981d, 1981e, and 1981f). For presentation of data, the Frontier has been separated into two groups: (1) the northern and southern areas forming a contiguous block flanking the Moxa Arch and (2) the two remaining areas, one at the north end of the Rock Springs Uplift and one on the eastern margin of the Washakie Basin (fig. 82). The data base on the Frontier Formation is good to very good for both the Moxa Arch (tables 97 through 100) and the eastern Greater Green River Basin (tables 101 through 104).

Structure

The Late Cretaceous - early Tertiary Laramide orogeny shaped the Greater Green River Basin. The basin is bounded on the west by the Overthrust Belt and on other margins by a series of surrounding positive features (fig. 80) (National Petroleum Council, 1980). Subbasins and intervening uplifts further divide the basin; some of these features are present only in the subsurface.

Both the Rock Springs Uplift and the Moxa Arch have similar structural styles, and both resulted primarily from vertical basement movement. Uplift on the Moxa Arch appears to have been active during deposition of the Baxter Shale (equivalent to the Hilliard Shale) and the lower Mesaverde Group; this is suggested by thickening of these units away from the axis of the arch. The Rock Springs Uplift may be slightly younger than the Moxa Arch; the steep dip of Paleocene strata indicates a post-Paleocene age for much of the Rock Springs Uplift (Stearns and others, 1975).

Stratigraphy

The entire Frontier Formation varies from 240 to 1,200 ft thick but in most areas is 400 to 600 ft thick. Alternation of sands and shales was caused by minor regressive and transgressive episodes and possibly also by alternating development and abandonment of individual deltaic lobes within the major regressive sequence that formed the Frontier delta. This alternation has led to designation of the First through Fifth Frontier sands within the Frontier Formation; these intervals are further described in the section that follows on the Frontier in the Wind River and Big Horn Basins (p. 201). The numbered Frontier sandstones are informal, and these do not everywhere represent precisely the same stratigraphic unit.

The lower third of the Frontier Formation is primarily fluvial, grading upward into alternating fluvial and shallow marine deposits. This transition ends at the Second Frontier sand, which is dominantly marine except near the Frontier paleoshoreline between the Moxa Arch and the Overthrust Belt (De Chadenedes, 1975). The stratigraphic sequence of the First and Second Frontier sands is present throughout most of Wyoming, extending northeast into the Powder River Basin. The Third through Fifth Frontier sands have a much lower degree of continuity than the first two (De Chadenedes, 1975), which would be expected of dominantly fluvial sandstones.

Depositional Systems

The Frontier Formation, an areally extensive Late Cretaceous fluvial and deltaic sequence, prograded from the west into a Cretaceous seaway about 1,000 to 1,500 mi wide (Weimer, 1960). The Frontier has been studied in outcrop (Cobban and Reeside, 1952; Siemers, 1975; Myers, 1977) and in the subsurface (De Chadenedes, 1975; Hawkins, 1980; Winn and Smithwick, 1980, among others); it shows all the genetic facies, from fluvial to offshore marine, characteristic of a deltaic system. The marine-influenced facies of the Second Frontier sand, which may be expected to be among the most laterally continuous of the formation, include upper and lower delta front, coalescing offshore bar, and deltaic strandplain. Winn and Smithwick (1980) suggested that the Frontier delta was wave dominated. Myers (1977) noted that the individual sands within the Second Frontier sand may have been formed during individual pulses of deltaic progradation, consisting of delta-front sheet sandstones capped by tidal channel fill and rarely by marsh deposits. Hawkins (1980) considered the capping units to be mixed tidal-flat and lagoonal deposits at the second bench of the Second Frontier; the bench is interpreted to be a lower shoreface to backshore deposit of a barrier-island sequence (fig. 85).

Although most published studies of the Frontier Formation have focused on producing areas in the western Greater Green River Basin, lateral continuity of Frontier sandstones also appears favorable in parts of the eastern Greater Green River Basin. On the flank of the Moxa Arch, continuity of sands 20 to 28 ft thick is evident (fig. 86); continuity also is evident, to a lesser extent, in the eastern Washakie Basin, where Frontier sands of similar thickness are interpreted as delta-front facies of southeast-prograding deltas (fig. 87). In the Washakie Basin area, shales between the individual sands of the Second Frontier sand are transgressive marine deposits.

Frontier Formation Well Data Profile

A minimum of 555 gas wells were completed in the Frontier Formation from 1954 through 1981 (fig. 88a). The bimodal distribution over time reflects the development of the Frontier Formation on the Moxa Arch from 1958 through 1963 and the national increase in well completions from 1977 to 1982. The distribution of completions in the Second Frontier sand alone shows a similar pattern (fig. 88b). Note that the part of the Frontier Formation in which many wells were completed was not specified; therefore, data reported on the First and Second Frontier sands were from a smaller sample. The depth to the top of perforations in the Second Frontier sand shows a peak at 6,500 to 8,000 ft, probably reflecting completions on the northern end of the Moxa Arch (fig. 89a). Off-structure wells in this area would encounter the unconventional reservoirs of the Second Frontier sand at depths of 10,000 to 11,500 ft, as would wells on the southern part of the arch. Most of the wells completed in the Second Frontier sand have gross perforated intervals that are 20 ft thick or less (fig. 89b), probably reflecting the productivity of the second bench, or second sandstone, within the Second Frontier sand. Gross perforated intervals up to 80 ft thick probably reflect production from the second bench and from other sandstones within a narrow interval of the Second Frontier sand. A few perforated intervals are 80 to 200 ft thick, and rarely are they more than 200 ft thick.

Among the wells in the Second Frontier sand for which the type of fracture-treatment fluid used was reported, oil-based fluid and emulsion predominated over water-based fluid. This probably reflects efforts to avoid formation damage that might result from the contact of water-based fluids and unstable clays. Gas-oil ratios were noted for six wells in the Second Frontier sand; average was 42,712:1 and range was 11,100:1 to 80,000:1. The API gravity of hydrocarbon liquids was noted for eight other wells in the Second Frontier sand; average was 51.5° and range was 38.4° to 62.3°.

Few wells perforating the First Frontier sand were specifically identified in the WHCS file. The depth to the top of perforations in the First Frontier sand is typically 6,000 to 6,500 ft (fig. 90a), and the thickness of the gross perforated interval is commonly 100 ft or less (fig. 90b). Much of the First Frontier production at depths less than 7,000 ft is on the northern Moxa Arch in fields such as La Barge, Dry Piney, and Hogsback. Most fracture treatments in the First Frontier sand used oil-based fluid; no gas-oil ratios or gravity data were reported. Other basinwide data on the First Frontier sand are given in table 103.

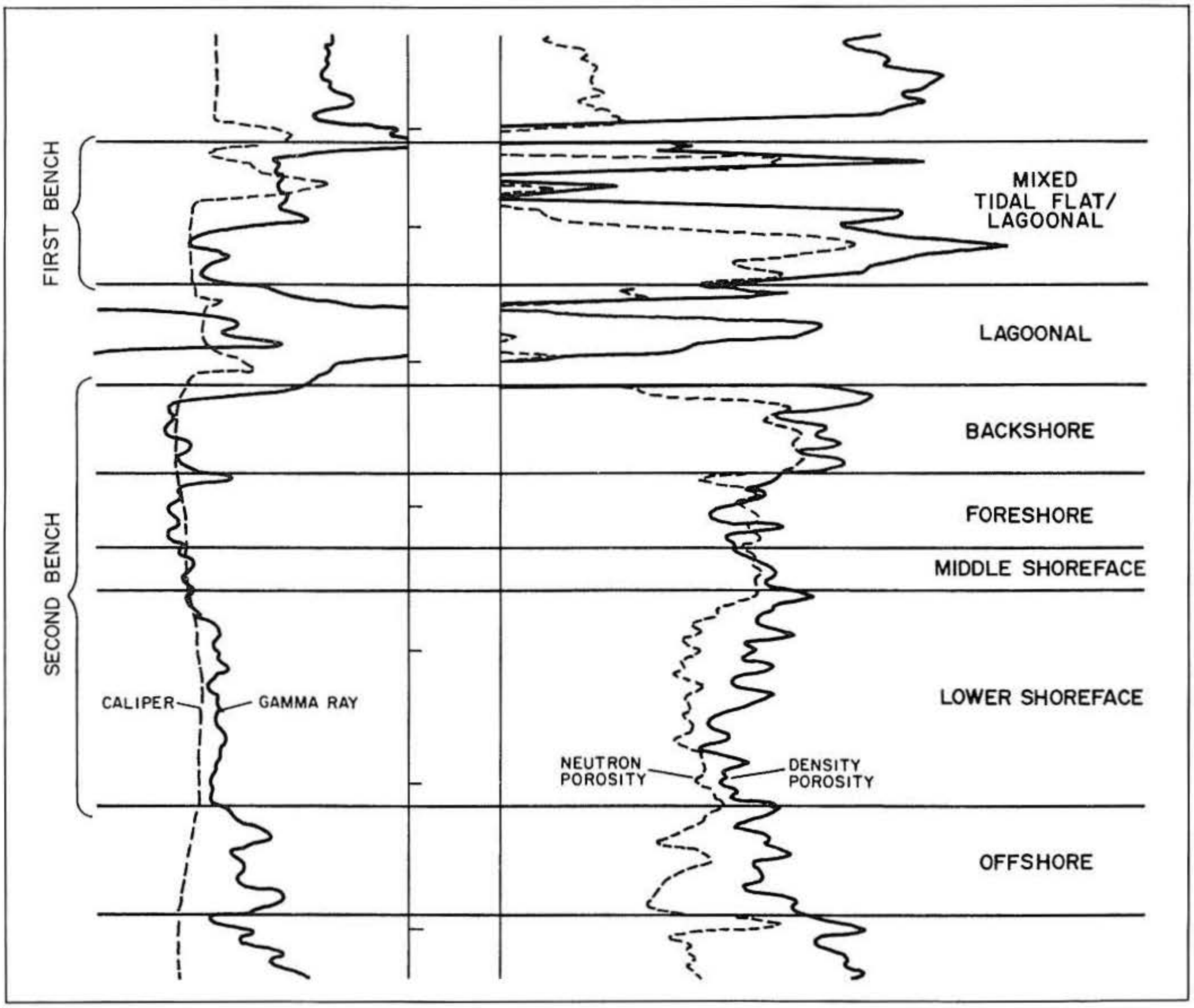


FIGURE 85. Interpretation of depositional environments of the first and second sandstone benches in the Second Frontier sand of the Frontier Formation, Greater Green River Basin (after Hawkins, 1980). Scale marks are at a spacing of 20 ft.

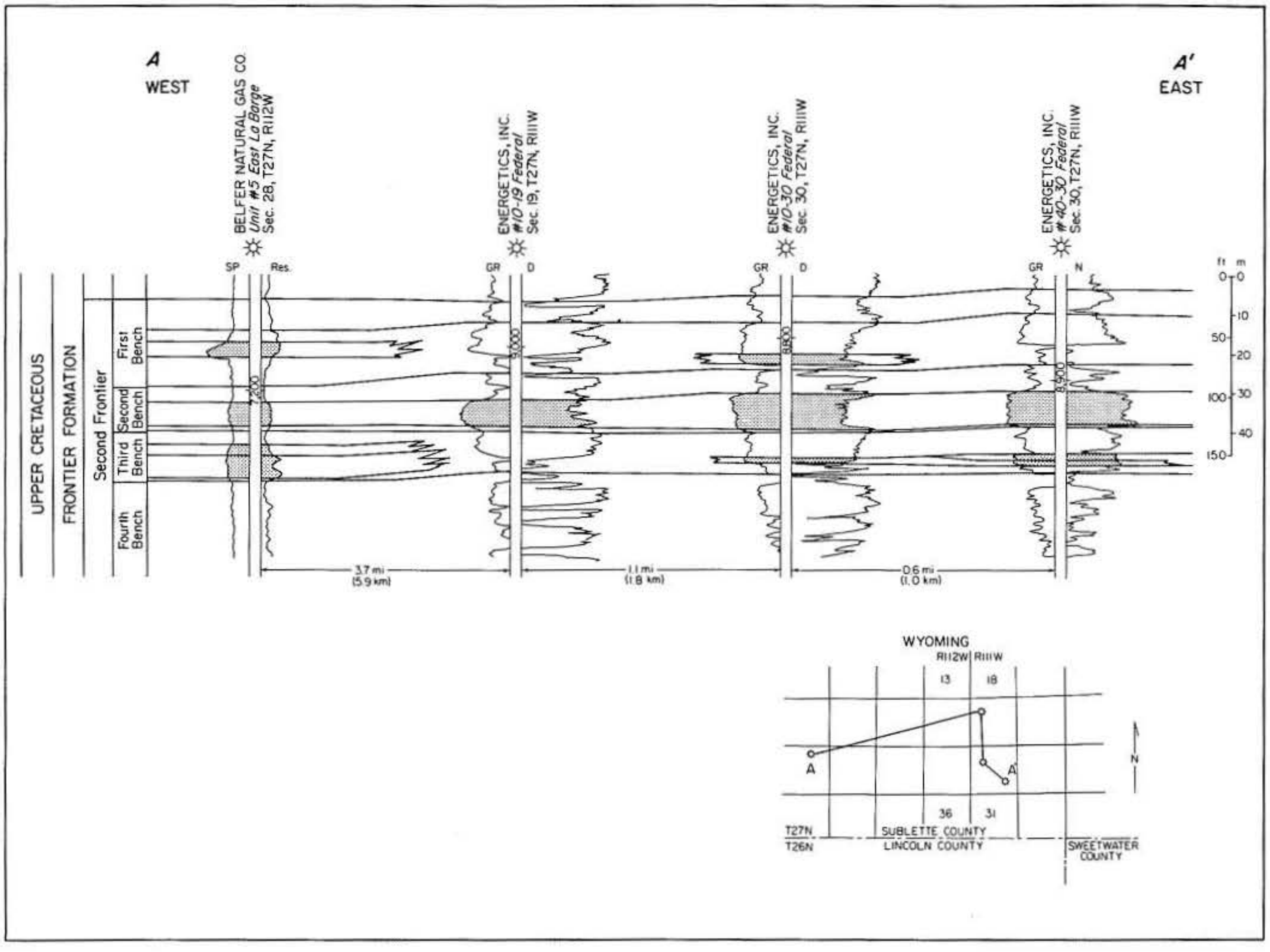


FIGURE 86. East-west stratigraphic cross section A-A' showing continuity of the second sandstone bench, Second Frontier sand of the Frontier Formation, Moxa Arch area of the Greater Green River Basin (after Wyoming Oil and Gas Conservation Commission, 1981e).

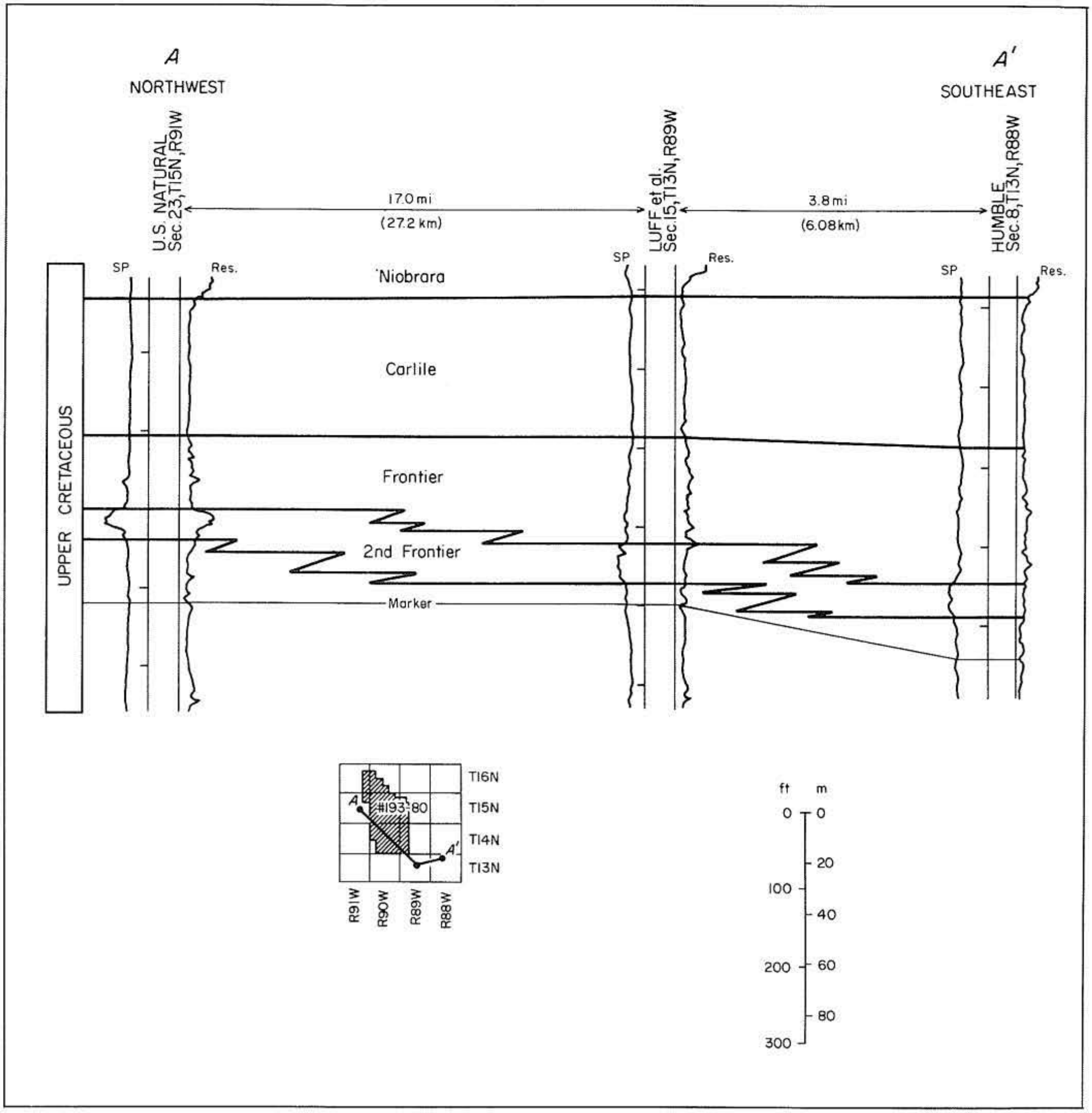


FIGURE 87. Northwest-southeast stratigraphic cross section A-A' showing correlation of the Second Frontier sand of the Frontier Formation, Washakie Basin area of the Greater Green River Basin (after Wyoming Oil and Gas Conservation Commission, 1981f).

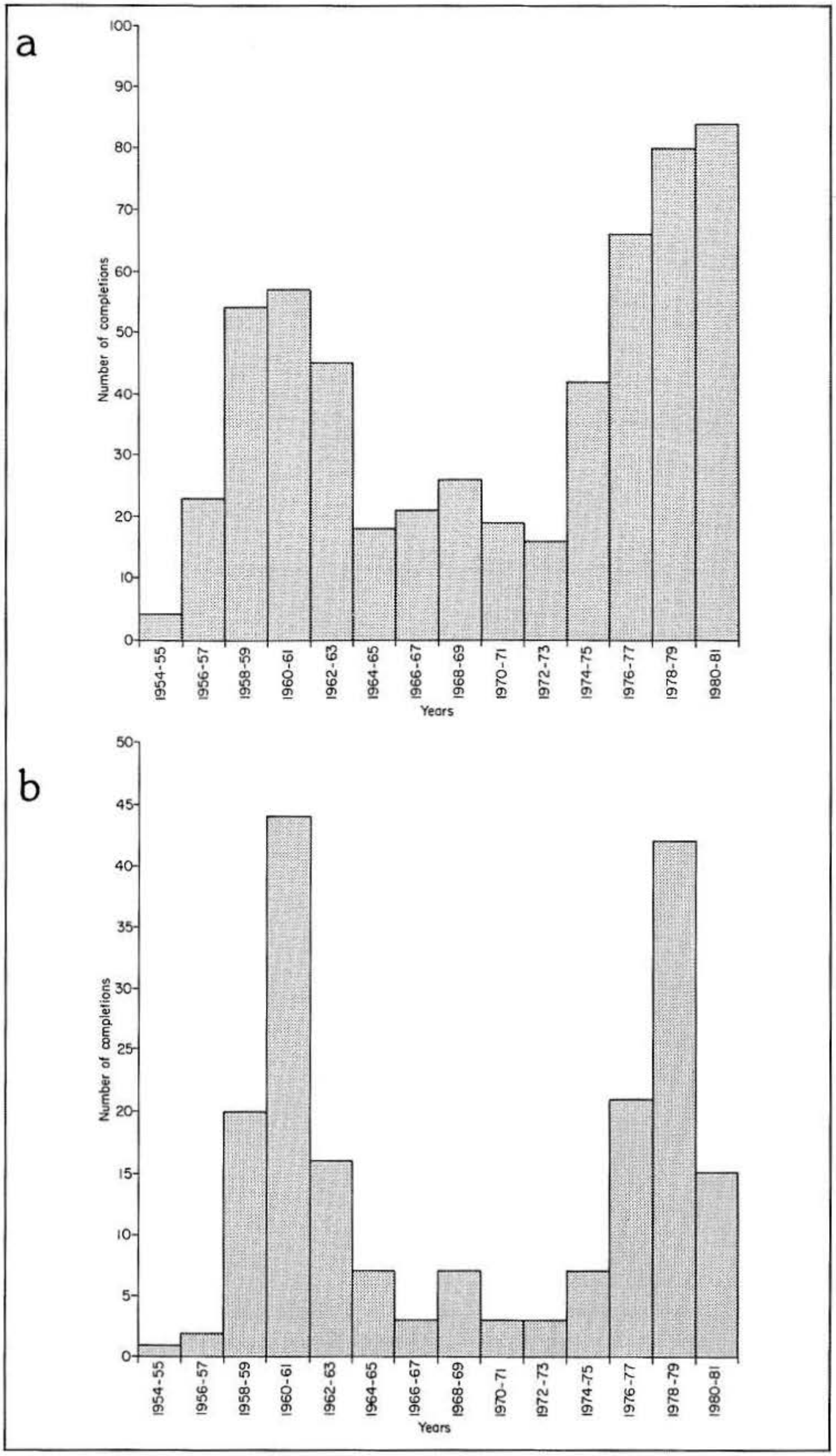
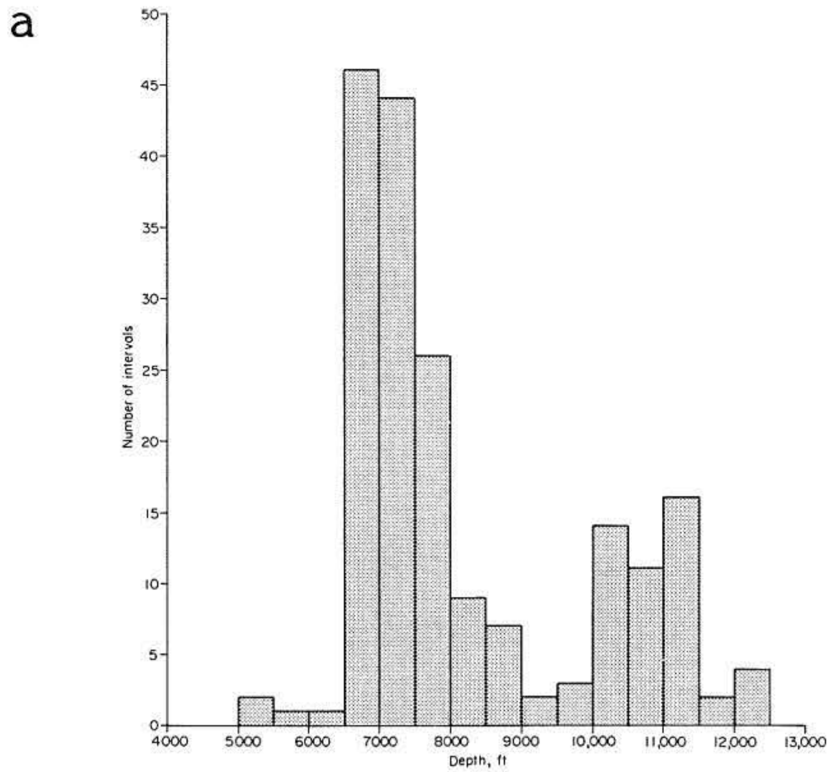


FIGURE 88. Distribution by 2-year intervals of (a) 555 gas well completions in the Frontier Formation, Greater Green River Basin, and (b) 191 gas well completions in the Second Frontier sand of the Frontier Formation, Greater Green River Basin.



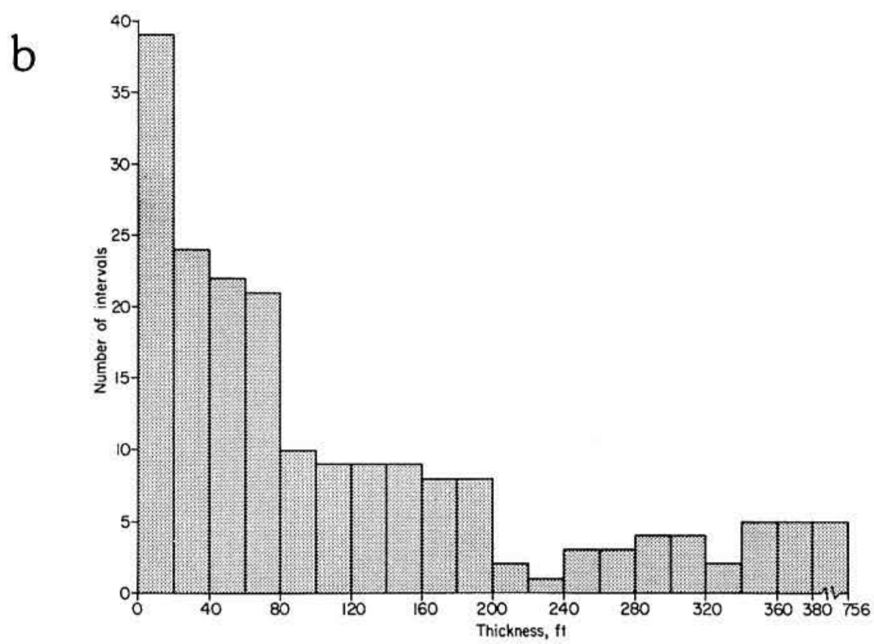


FIGURE 89. (a) Depth to top of perforated interval of 186 gas wells and (b) thickness of gross perforated interval of 189 gas wells completed in the Second Frontier sand of the Frontier Formation, Greater Green River Basin.

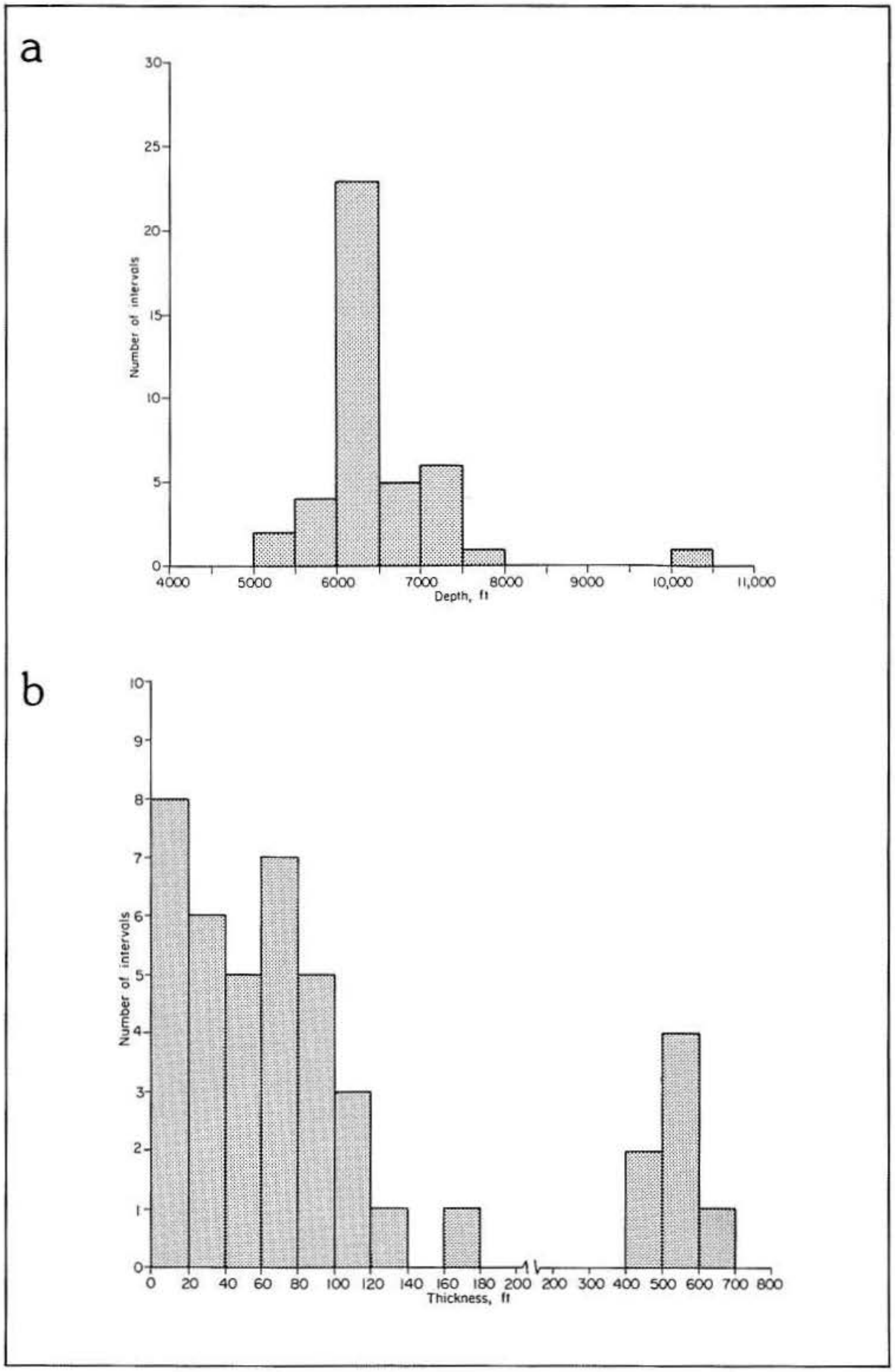


FIGURE 90. (a) Depth to top of perforated interval and (b) thickness of gross perforated interval of 43 gas wells completed in the First Frontier sand of the Frontier Formation, Greater Green River Basin.

TABLE 97. Frontier Formation, Moxa Arch area, Greater Green River Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Frontier Formation, Upper Cretaceous.	1. Designated areas on and surrounding the northern Moxa Arch (T24-31N, R109-114W) are 765.5 mi^2. 2. Designated areas on and surrounding the southern Moxa Arch (T16-24N, R110-115W) are 1,398 mi^2.	1. Range is 1,200 ft (northwest) to 300 ft (south). 2. Average is 450 ft.	1. Range to top of First Frontier is from 6,700 ft (northwest) to 8,300 ft (south), when present. The First Frontier is not present in the southeast part of the area. Range to top of Second Frontier is from 7,250 ft (northwest) to more than 15,000 ft (southeast). 2. Average to top of Second Frontier is 11,870 ft. First Frontier not developed; Third and Fourth Frontier sands are deeper.	Maximum recoverable gas is 4.921 Tcf from deep-basin area generally between Moxa Arch and Rock Springs Uplift (National Petroleum Council, 1980).	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
This area lies along the Moxa Arch in the western part of the Greater Green River Basin. It is bounded on the north by the Wind River Range, on the east by the Rock Springs Uplift, on the south by the Uinta Mountains, and on the west by the Wyoming Overthrust Belt. The present-day structural setting formed primarily as a result of Late Cretaceous - early Tertiary Laramide tectonism.	1.2° to 1.6° F/100 ft.	Overpressured in the Second Frontier of the Moxa Arch. Gradient is approximately 0.54 psi/ft in area of Docket no. 189-80 application.	Compressional Laramide deformation, which formed uplifts and adjacent basins, followed by post-Laramide vertical uplift.

TABLE 98. Frontier Formation, Moxa Arch area, Greater Green River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Deposited as several distinct progradational units of a large, wave-dominated deltaic system. These units are commonly referred to as the First, Second, Third, and Fourth Frontier sandstones. Of these, the First, Second, and Third Frontier are of primary economic interest within the area; the Second Frontier is the most laterally consistent and productive unit. The Frontier was deposited as an eastward-prograding deltaic complex that includes prodelta muds, delta-front sands, interdeltaic shoreline sands, and delta-plain sands, muds, and coals. The most laterally continuous sandstone within the Second Frontier, known as the second bench, represents regressive strandplain and barrier-bar deposition.	Very fine grained to medium-grained and coarse-grained sandstone having some silty and shaly intervals. Poorly to moderately sorted, subangular to subrounded sandstone.	Variable. Continental sands are more compositionally immature and contain abundant quartz, feldspar, chert, mica, and rock fragments; marine sands, being much more quartzitic, contain some chert and glauconite. Terrigenous clays are present in varying degrees in all sands, depending on the amount of winnowing within the depositional environment.	Cements include authigenic clays, calcite, and quartz overgrowths. Authigenic chlorite and mixed-layer illite-smectite are expected.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
1. When present (in the northwestern part of the area), the First Frontier average is 62 ft, range is 40 to 71 ft. Second Frontier average is 280 ft, range is 31 to 617 ft to the north; to the south, average is 40 ft, range is 12 to 70 ft. 2. Second Frontier average is 47 ft, range is 9 to 64 ft. First Frontier not developed.	Pressure is approximately 6,400 psi on southern Moxa Arch. Between the Moxa Arch and the Rock Springs Uplift (in a deeper basin area, 14,000 ft), pressure is 7,700 psi, temperature is 242° F. Drill-stem-test data from 66 Second Frontier wells basinwide show an average initial shut-in pressure of 3,211 psi and a range of 6,789 to 224 psi.	No data.	SP-resistivity or GR-resistivity and GR-neutron density are typical logs. Core has been taken from 15% of Frontier gas wells in the Greater Green River Basin (86 of 555 completions). Of these cores, 39 were taken from the Second Frontier.

TABLE 99. Frontier Formation, Moxa Arch area, Greater Green River Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir parameters	Net pay thickness	Production rates: Pre-stimulation	Production rates: Post-stimulation	Decline rates	Formation fluids	Water saturation
1. Frontier Formation (overall): Average porosity is 13.4%, range is 5.7% to 20.7%; average permeability is 0.007 md, range is less than 0.0001 to 1.3 md. Permeabilities were calculated from core analysis, drill-stem-test analysis, and flow tests. First Frontier: Calculated from four wells, average in situ permeability is less than 0.0001 md. Second Frontier: Calculated from 58 wells, average in situ permeability is approximately 0.016 md, range is less than 0.00001 to 0.306 md. Average porosity is 13.8%, range is 11% to 20%, calculated from 25 wells. 2. Calculated from flow tests of 37 wells, average in situ permeability is 0.0308 md, range is less than 0.0001 to 0.171 md. Average porosity is 12%, range is up to 18%.	1. Calculated from 35 wells, average is 36 ft, range is 10 to 90 ft for the Second Frontier only. 2. Calculated from 63 wells, average is 21 ft, range is 9 to 66 ft for the Second Frontier only.	1. Three wells in First Frontier all had flow TSTM. For 20 wells in Second Frontier, average was 314 Mcfd, range was TSTM to 2,630 Mcfd. 2. For 43 wells in Second Frontier, average was 224 Mcfd, range was 10 to 1,365 Mcfd.	1. In First and Second Frontier together, average was 360 Mcfd, range was TSTM to 2,506 Mcfd for 36 wells. 2. In Second Frontier, average was 1,824 Mcfd, range was 0 to 5,700 Mcfd for 35 wells.	No data.	Liquid hydrocarbons are produced only as condensate at surface conditions and at rates less than 5 bpd. Basinwide in the Second Frontier, 27 of 191 wells produce an average of 17 bpd of condensate, range is 1 to 76 bpd. Of 191 wells, 30 produce an average of 25 bpd of water, range is 1 to 130 bpd.	Average is 51%, range is 36% to 68%.

Well stimulation techniques	Success ratio	Well spacing	Comments
1. In 27 enhanced recovery completions, hydraulic fracture techniques used diesel (older completions) or KCl water or cross-linked water/methanol gel (recent completions). Fluids averaged 65,000 gal, ranging from 8,000 to 311,300 gal; sand proppants averaged 90,250 lb, ranging from 11,000 to 628,000 lb. 2. In 35 recent hydraulic fracture completions, the average amount of fluid was 273,840 gal, range was 87,300 to 510,000 gal; the average amount of sand proppant was 605,320 lb, range was 80,000 to 1,161,890 lb.	1. No data. 2. 34 out of 35, or 97% of fracture treatments, resulted in improved flow.	640 acres.	Approved and pending tight gas applications exclude existing Frontier gas production from conventional reservoirs near La Barge, Wyoming, on the northern end of the Moxa Arch. IPF (mostly post-stimulation) for 186 Second Frontier gas completions (basinwide) averaged 3,479 Mcfd, ranged from 51 to 57,128 Mcfd. IPF will always be higher than stabilized, or nearly stabilized, production rates.

TABLE 100. *Frontier Formation, Moxa Arch area, Greater Green River Basin: Economic factors, operating conditions, and extrapolation potential.*

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
Approved by Wyoming Oil and Gas Conservation Commission. Certain parts of these areas have FERC approval.	Total of 555 Frontier gas completions in the Greater Green River Basin; at least 104 of these are within the application areas on the Moxa Arch.	In the Greater Green River Basin as a whole, 22.7% of all wildcat gas wells were successful in 1970-1977 (National Petroleum Council, 1980). No data specific to the Frontier.	1. Total well costs of seven Frontier and Bear River dual completions (excluding Bear River fracture) averaged $932,000. This includes Frontier fractures, which averaged $91,400 (1979 dollars). 2. On the basis of three wells that were completed from October 1978 through March 1980, stimulation costs by hydraulic fracturing methods averaged $220,000. For another operator, the typical costs of fracture treatment were $280,000 (1980 dollars) on the basis of four wells.	Pipelines in place to serve established production on the Moxa Arch, especially on the northern end of the arch near Big Piney, Dry Piney, and La Barge East Fields. Northwest Pipeline Corp. and FMC Corp. operate pipelines in this area. Several gas fields on the eastern flank of the Moxa Arch were shut in as of April 1980, apparently by lack of pipeline connection.	High. Six applications have been filed for designation of the Frontier as a tight gas sand in different parts of the Greater Green River Basin.

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	**EXTRAPOLATION POTENTIAL**	*Comments*
In the Wyoming - Big Horn Basins physiographic subdivision. Local relief of 300 to 500 ft in most areas, 500 to 1,000 ft toward the western margin of the basin; greater relief is encountered along the Overthrust Belt.	Semiarid to arid. Most areas receive 8 to 16 inches mean annual precipitation; generally more precipitation at higher elevations. Mild summers, cold winters. Exploration and development drilling are conducted all year.	Access is by unimproved roads and may be locally limited by significant relief.	Good to very good. The Frontier is a widespread deltaic system present in several subbasins of the Greater Green River Basin and in the Wind River and Big Horn Basins. Best blanket geometry is in the Second Frontier, which would be analogous to other delta-front, barrier, and strandplain facies in other less areally extensive deltaic and interdeltaic deposits.	Mileage charges may be high for service to remote areas. Selected services based at Rock Springs, Wyoming.

TABLE 101. Frontier Formation, Rock Springs Uplift and Washakie Basin area, Greater Green River Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Frontier Formation, Upper Cretaceous.	1. Designated area at the northern end of the Rock Springs Uplift (T23-26N, R101-104W) is 396 mi^2. 2. Designated area at the eastern margin of the Washakie Basin (T14-16N, R89-91W) is 98 mi^2.	1. Total Frontier average is 400 ft (east) to 600 ft (west). Second Frontier average is 180 ft, and Third Frontier average is 150 ft. 2. Total Frontier average is 240 to 270 ft. Second Frontier average is 20 ft.	1. Average to top of First Frontier is 11,530 ft, range is 8,585 to 17,495 ft; average to top of Second Frontier is 11,681 ft, range is 8,814 to 17,672 ft; average to top of Third Frontier is 11,860 ft, range is 8,958 to 17,894 ft. 2. Range to top of First Frontier is 6,930 to 7,360 ft; range to top of Second Frontier is 7,035 to 7,470 ft.	No data.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
1. This area lies along the northern flank of the Rock Springs Uplift. This structure and all other associated structures were formed primarily as a result of Laramide tectonism. The area is bounded on the north by the Wind River Range, on the west by the Green River Basin, and on the east by the Great Divide or Red Desert Basin. 2. This area lies on the eastern margin of the Washakie Basin. It is bounded on the north by the Wamsutter Arch and the Rawlins Uplift, on the east by the Sierra Madre Uplift, and on the south by Cherokee Ridge.	1.2° to 1.6° F/100 ft.	No data.	Compressional Laramide deformation, which formed uplifts and adjacent basins, followed by post-Laramide vertical uplift.

TABLE 102. Frontier Formation, Rock Springs Uplift and Washakie Basin area, Greater Green River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
See Frontier Formation, Moxa Arch area, Greater Green River Basin, table 98.	Second Frontier is moderately to very well sorted, angular to well-rounded, very fine grained to fine-grained sandstone having silt and shale interbeds. Third Frontier is moderately to very well sorted, subangular to subrounded, very fine grained to fine-grained sandstone having silt and shale interbeds.	Second Frontier contains quartz, rock fragments, and some feldspar and terrigenous clays. Third Frontier contains quartz, feldspar, rock fragments, and some glauconite.	Second Frontier cements include quartz overgrowths, calcite, dolomite, siderite, and authigenic chlorite and illite-smectite. Third Frontier cements include quartz overgrowths, authigenic chlorite, illite-smectite, and some calcite.
Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
1. Second Frontier average is 55 ft, range is 11 to 70 ft. Third Frontier average is 139 ft, range is 23 to 234 ft. 2. Second Frontier average is 20 ft.	1. Pressure is 3,400 psi at Nitchie Gulch Field (at approximately 7,800 ft) in Third Frontier near designated area. 2. Pressure is 3,900 psi at Deep Gulch Field (at approximately 8,000 ft) in Frontier near application area. Average temperature is 152° F.	No data.	See Frontier Formation, Moxa Arch area, Greater Green River Basin, table 98.

TABLE 103. Frontier Formation, Rock Springs Uplift and Washakie Basin area, Greater Green River Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir parameters	Net pay thickness	Production rates: Pre-stimulation	Production rates: Post-stimulation	Production rates: Decline rates	Formation fluids	Water saturation
1. First Frontier permeability calculated from one flow test is 0.011 md. Second Frontier permeability calculated from seven flow tests averages 0.006 md; from one core analysis, permeability is 0.154 md. Porosity averaged from four wells is 10.1%, range is 2% to 16%. 2. Second Frontier permeability calculated from one flow test is 0.07 md. Porosity calculated from two wells ranges from 7% to 12%.	1. Second Frontier average is 39 ft, range is 11 to 64 ft. 2. Second Frontier average is 20 ft.	1. First Frontier was 12.7 Mcfd for one well. For seven wells in Second Frontier, average was 57 Mcfd, range was 5 to 178 Mcfd. 2. For two wells in Second Frontier, range was 65 to 110 Mcfd.	1. For five wells in Second Frontier, average was 640 Mcfd, range was 7 to 1,546 Mcfd. 2. For two wells in Second Frontier, 100 to 745 Mcfd.	No data.	Liquid hydrocarbons rarely produced. When produced, they are as gas condensate at the rate of approximately 1 bpd. A few wells have high water production (100 Mcfd gas, 55 bwpd).	1. In Second Frontier for four wells, average is 65%. 2. In Second Frontier, average is 60% to 100%. Generally produces water at rates of 20 to 55 bpd.

Well stimulation techniques	Success ratio	Well spacing	Comments
1. Hydraulic fracture techniques used an average of 86,500 gal fluid and 110,300 lb sand proppant in the Second Frontier in five fracture jobs. 2. Of two attempted completions, one was acidized using 2,000 gal acid only, and it produced; the other was hydraulically fractured using 26,000 lb sand proppant, and it was abandoned because of water production.	1. No data. 2. 50%.	640 acres.	IPF (mostly post-stimulation) of 42 First Frontier completions (basinwide) averages 7,043 Mcfd, ranges from 116 to 20,089 Mcfd. IPF will always be higher than stabilized, or nearly stabilized, production rates. Drill-stem-test data on 45 First Frontier wells (basinwide) show an average initial shut-in pressure of 2,177 psi, range of 4,432 to 241 psi.

TABLE 104. Frontier Formation, Rock Springs Uplift and Washakie Basin area, Greater Green River Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
2. Approved by FERC.	1. Six in the Second Frontier and two in the Third Frontier in application area. 2. Two in the Second Frontier in application area. Total of 555 Frontier gas completions in the Greater Green River Basin.	1. Second Frontier is 5 out of 6, or 83%. Third Frontier is 0 out of 2, or 0%. 2. 50%.	1. For a 10,700-ft well (1980), drilling costs were \$800,000. Fracture treatment costs were \$65,000 (now estimated at over \$100,000); total completion costs were over \$500,000. 2. For a 7,600-ft well (1976), drilling costs were \$754,000, which included acidization. Fracture treatment was not performed but was estimated to cost \$100,000 to \$150,000. Surface equipment needed for water disposal cost \$150,000 to \$200,000.	Mountain Fuel Supply Co. pipeline extends only to Nitchie Gulch Field, leaving pending area on north end of Rock Springs Uplift without pipeline connection. Savery - Cherokee Creek Gas Pipeline operates in the designated area of the eastern Washakie Basin.	High. Six applications have been filed for designation of the Frontier as a tight gas sand in different parts of the Greater Green River Basin.

OPERATING CONDITIONS | **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*		*Comments*
In the Wyoming - Big Horn Basins physiographic subdivision. Local relief of 300 to 500 ft in the basin and 1,000 to 3,000 ft along the eastern and northeastern basin margins.	Semiarid to arid. Most areas receive 8 to 16 inches mean annual precipitation; generally more precipitation at higher elevations. Mild summers, cold winters. Exploration and development drilling are conducted all year.	Access is by unimproved roads and may be locally limited by significant relief.	Good to very good. See Frontier Formation, Moxa Arch area, Greater Green River Basin, table 100.	Mileage charges may be high for service to remote areas. Selected services based at Rock Springs and Rawlins, Wyoming.

FRONTIER FORMATION, WIND RIVER AND BIG HORN BASINS

The Upper Cretaceous Frontier Formation, composed of sandstones alternating with shales, is a major regressive unit encased between the marine Mowry and Cody Shales (fig. 91). Miller and VerPloeg (1980) suggested that although much of the Frontier Formation in these basins would likely be eligible for tight sand designation, lack of reservoir quality has slowed exploration activity.

The data base on the Frontier Formation is fair to good in the Wind River Basin but fair to poor in the Big Horn Basin. Summary tables were prepared for the Frontier Formation in the Wind River Basin (tables 105 through 108), which was included in the National Petroleum Council (1980) study, but not for the Frontier in the Big Horn Basin. Resource estimates for the Frontier in the Wind River Basin are available as a combined estimate of resources in both the Frontier Formation and the Muddy Sandstone, which underlies the Mowry Shale (National Petroleum Council, 1980). This combined resource estimate was made on the assumption that wells in an area could produce from several stacked formations if similar pressures were encountered. This approach, however, does not permit individual resource estimates for each formation.

Structure

The Wind River Basin, a geologic and topographic basin in central Wyoming, contains Cretaceous and Tertiary sediments that average 13,000 ft thick. The basin is bounded on the south and west by the Sweetwater and Wind River Uplifts, on the north by the Owl Creek Uplift, and on the northeast by the subsurface Casper Arch (National Petroleum Council, 1980). The Wind River Basin is completely surrounded by broad belts of folded and faulted Paleozoic and Mesozoic rocks (Keefer, 1965). Strata along the southwest flank of the Wind River Basin dip 10° to 20° northeastward, whereas strata on the northeast flank are commonly vertical or overturned.

The Big Horn Basin of northwestern Wyoming and south-central Montana is a northwest-trending topographic and structural basin. The basin is bounded on the north by the Nye-Bowler left-lateral wrench-fault zone, on the south by the Owl Creek Uplift, on the west by the Yellowstone-Absaroka volcanic plateau and the Beartooth Mountains, and on the east by the Pryor and Big Horn Mountains. The Big Horn Basin has many peripheral anticlinal folds oriented parallel to its northeast and southwest flanks; these folds form major oil-producing structural traps (Thomas, 1965).

Stratigraphy

The Frontier Formation ranges from 650 to 1,000 ft thick in the Wind River Basin and ranges from 400 to 800 ft thick in the Big Horn Basin. In both basins, the Frontier consists of shale, siltstone, and sandstone of marine and continental origin deposited as part of a major regressive sequence having sources to the west (Keefer, 1969; Merewether and others, 1975). Alternation of sand and shale units was caused by additional minor regressive and transgressive episodes. As previously noted, this alternation has led to delineation of the five major sandstone-bearing intervals of the Frontier Formation as First Frontier sand through Fifth Frontier sand, from youngest to oldest. An older terminology delineated the First Wall Creek sand (equivalent to the Second and Third Frontier sands), the Second Wall Creek sand (equivalent to the Fourth Frontier sand), and the Third Wall Creek sand (equivalent to the Fifth Frontier sand) (Keefer, 1969). The Second Frontier sand is the most significant of the five units, both as a current oil producer at some locations and as a potential tight gas sand at others. It is evident that the Second Frontier sand is not everywhere the same specific stratum.

Depositional Systems

The Frontier Formation represents a major wave-dominated delta system that prograded across central and western Wyoming in early Late Cretaceous time (Barlow and Haun, 1966). Prodelta through delta front and distributary bar, overlain by delta plain, are major facies of the Frontier. The grain size of most sandstones increases upward from silty shale and siltstone to fine- and medium-grained sandstone followed by a sharp contact with overlying shale. This upward-coarsening sequence, illustrated on log cross sections by Barlow and Haun (1966, fig. 7), suggests that individual Frontier sandstones were formed during episodes of deltaic sedimentation separated by transgressive marine deposition as depocenters shifted over time. Lateral continuity of the numbered sandstone intervals within the Frontier would be expected to be good in the predominantly marine units within the formation. Outcrop studies of the western margin of the Big Horn Basin have shown that the middle part of the Frontier Formation includes paludal and fluvial deposits expected to have lenticular sandstones (Siemers, 1975).

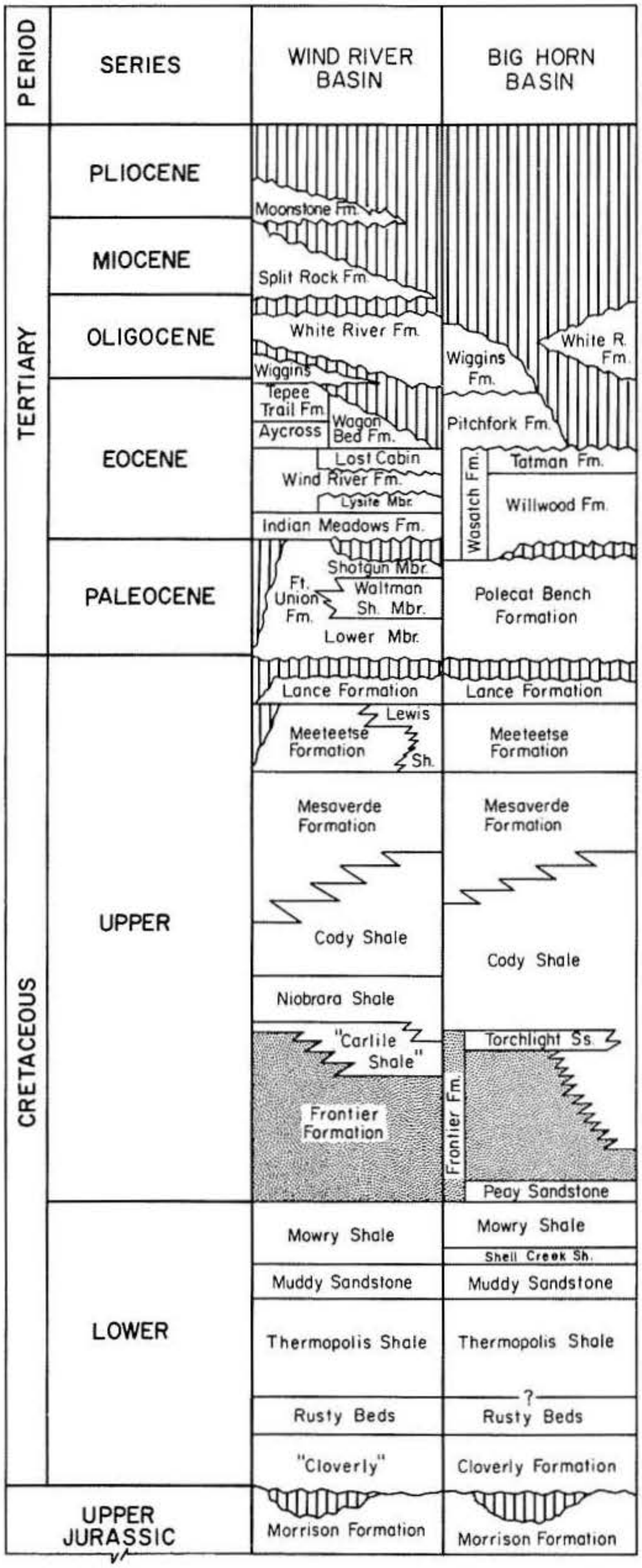


FIGURE 91. Stratigraphic column from the Upper Jurassic through the Pliocene, Wind River and Big Horn Basins (from Hollis, 1980).

TABLE 105. Frontier Formation, Wind River Basin: General attributes and geologic parameters of the trend.

GENERAL ATTRIBUTES

Stratigraphic unit/play	*Area*	*Thickness*	*Depth*	*Estimated resource base*	*Formation attitude, other data*
Frontier Formation, Upper Cretaceous.	Minimum area of development potential is 480 mi^2 (National Petroleum Council, 1980).	Range is 580 to more than 1,000 ft.	Range is from outcrop to 25,000 ft. Average depth to the Frontier in 18 fields that produce from the Frontier is approximately 4,200 ft. In the minimum area of development potential, depth is approximately 2,000 ft.	Maximum recoverable gas is 1.547 Tcf of 2.035 Tcf gas in place from Frontier and Muddy Formations in an area of potential development along the southwest margin of the basin (National Petroleum Council, 1980). Kuuskraa and others (1981) estimated 3 Tcf gas in place from the formation; no specific area was given.	No additional information.

GEOLOGIC PARAMETERS - BASIN/TREND

Structural/tectonic setting	*Thermal gradient*	*Pressure gradient*	*Stress regime*
The Wind River Basin is a large, asymmetric, northwest-southeast-trending sedimentary and structural basin that formed during Laramide deformation in latest Cretaceous and early Tertiary time. The basin is bounded on the north by the Owl Creek Uplift, on the northeast by the Casper Arch, on the south by the Sweetwater Uplift, and on the west by the Wind River Uplift. Strata along the southwestern flank dip 10° to 20° northeastward, whereas strata on the northeastern flank are commonly vertical or overturned.	1.2° to 2.2° F/100 ft.	0.39 psi/ft on the basis of one value reported as typical, probably in area of shallow production.	Compressional Laramide deformation followed by post-Laramide vertical uplift. Extensive thrusting on basin flanks.

TABLE 106. Frontier Formation, Wind River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - UNIT/PLAY

Depositional systems/facies	*Texture*	*Mineralogy*	*Diagenesis*
Depositional systems associated with an eastward-prograding, wave-dominated delta system. Recognizable facies include delta plain, distributary channel, distributary-channel-mouth bar, delta front, and prodelta. Southward-directed longshore and tidal currents redistributed sand into nearshore- and offshore-shelf bars, many of which coalesced. These bars are encased in marine prodelta muds.	Fine- to coarse-grained sandstone interbedded with shale. Extremely variable bedding, from thinly to massively bedded sandstone having shale partings and thin shale streaks. Sandstone grains are mostly subrounded to subangular.	Dominantly quartz having some chert and minor amounts of feldspar, mica, chlorite, glauconite, magnetite, clay, rock fragments, and carbonaceous material.	By analogy to the Frontier Formation in other areas, quartz overgrowths, calcite cement, and authigenic clays are expected.

Typical reservoir dimensions	*Pressure/temperature of reservoir*	*Natural fracturing*	*Data availability*
In production range of 1,400 to 1,500 ft, gross reservoir thickness is 150 ft (Kuuskraa and others, 1981).	In area of minimum potential development where average depth is approximately 2,000 ft, temperature is 104° F and pressure is 775 psi. However, pressures and temperatures vary according to depth, and some of the deep Frontier may be overpressured.	No data.	SP-resistivity or GR-resistivity and GR-neutron density are typical logs.

TABLE 107. Frontier Formation, Wind River Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production rates				
Reservoir parameters	*Net pay thickness*	*Pre-stimulation*	*Post-stimulation*	*Decline rates*	*Formation fluids*	*Water saturation*
In the minimum area of development potential, permeability range is 0.3 to 0.0033 md, porosity range is from 7.0% to 10.5% for all sands. In the West Poison Spider Field, southeast Wind River Basin, four sandstones are developed. The first sandstone is best developed and produces oil having permeability averaging 0.3 md, porosity averaging 7.3%. The other three sandstones do not produce. Parameters of the second and third are permeability less than 0.01 md, porosity 3.5% to 4.3%. The fourth sandstone has not been analyzed.	In the area of minimum development potential, range is 10 to 45 ft. In the West Poison Spider Field, average is 40 ft.	No data.	No data.	No data.	No data.	By analogy to the Frontier Formation in other areas, 40% to 70% is expected.

Well stimulation techniques	*Success ratio*	*Well spacing*	*Comments*
Hydraulic fracturing.	No data.	No data.	Existing production is primarily around the shallow margins of the basin, but potential exists to extend production to greater depths.

TABLE 108. Frontier Formation, Wind River Basin: Economic factors, operating conditions, and extrapolation potential.

ECONOMIC FACTORS

FERC status	*Attempted completions*	*Success ratio*	*Drilling/ completion costs*	*Market outlets*	*Industry interest*
No applications pending.	No data.	No data.	In area of minimum development potential, drilling costs are \$123,000 per well (1980 dollars). Fracture and completion costs are \$84,000 to \$275,000 per well (1980 dollars), depending on size of fracture treatment.	Montana-Dakota Utilities, Northern Gas, and Northern Mountain Gas have pipelines mostly in the central and eastern parts of the basin.	Unknown. No tight formation applications pending (1982).

OPERATING CONDITIONS / **EXTRAPOLATION POTENTIAL**

Physiography	*Climatic conditions*	*Accessibility*	Extrapolation potential	*Comments*
In the Wyoming - Big Horn Basins physiographic subdivision. Local relief of 500 to 1,000 ft in the central area, 1,000 to 3,000 ft on the southern margin, and more than 3,000 ft on the southwestern margin in the Wind River Mountains.	Arid to semiarid having less than 8 inches to approximately 14 inches mean annual precipitation. Mild summers, cold winters. Winter conditions can adversely affect exploration activity.	Limited major highway access. Central and north-central parts of the basin are within the Wind River Indian Reservation.	Good to very good. The Frontier is a widespread deltaic system present in several subbasins of the Greater Green River Basin and in the Big Horn Basin. The best blanket geometry is in the Second Frontier.	Worland and Casper, Wyoming, are centers of exploration services in the Wind River Basin. Mileage charges may be high for service to remote areas.

MUDDY SANDSTONE, WIND RIVER BASIN

In addition to the Frontier Formation, the Muddy Sandstone also was identified as a tight gas sand of blanket geometry within the Wind River Basin by the National Petroleum Council (1980). The Muddy Sandstone is Early Cretaceous in age and is separated from the Frontier Formation by the marine Mowry Shale (fig. 91). The area of interest for tight gas in the Muddy Sandstone coincides with the area of interest in the Frontier.

The Muddy Sandstone and the Frontier Formation both represent progradational deltaic and interdeltaic shoreline environments; both have source areas generally to the west, and both are encased in marine shales (Gopinath, 1978). The Muddy is thinner than the Frontier, being about 120 ft thick in outcrop along the west margin of the Wind River Basin. It consists of fine- to medium-grained sandstone having varying amounts of black shale and siltstone. Facies of the Muddy Sandstone include distal and proximal delta front, shoreface and foreshore of barrier spits and mainland shoreline, lagoonal, tidal flat, and tidal channel (Dresser, 1974; Gopinath, 1978). Delta-front progradation and coalescing of barrier-beach or barrier-spit facies during regression would be expected to produce a blanket sandstone reservoir having moderate to good lateral continuity. The Muddy Sandstone presents an opportunity to explore a second deltaic depositional system in the same area as the Frontier, but the specific facies in the two formations that overlie each other are not described in the literature.

DISCUSSION AND SUMMARY: GENERIC BLANKET-GEOMETRY SANDS AND EXTRAPOLATION POTENTIAL

Classifying selected tight gas sandstones by their depositional systems and component facies establishes a framework for comparison between stratigraphic units of different ages in different sedimentary basins. Unlike details of a stratigraphic sequence, which may vary between basins and within basins, characteristics of genetic facies tend to remain constant. Table 109 classifies selected formations examined in this survey into four categories of clastic depositional systems. This classification helps provide a basis for determining the extent to which geologic and engineering knowledge gained in the study of one formation can be applied to study of another; that is, the extrapolation potential of the unit. The ability to transfer technology developed as part of exploration and production programs between tight gas reservoirs having genetic similarities will ensure a wider impact of future research on the development of tight gas resources.

The marginal marine and marine sandstones, which account for nearly all blanket-geometry reservoirs examined in this study, can be classified as deltaic, barrier-strandplain, or shelf systems (table 110). The fan delta, an exception, is a largely continental environment having a proximal part dominated by braided streams and a distal part containing a subaqueous delta front. Along the delta front, sediment may be reworked laterally into barrier and bar sands. Progradation of the fan-delta margin and concurrent marine reworking would tend to improve lateral continuity of the distal part of the fan delta. Sediments within the braided-stream facies are relatively coarse, being mostly sand and occasional conglomerates; lack of mud leads to a higher degree of reservoir continuity than is commonly found in fluvial systems. Therefore, the proximal part of the fan delta was included in this survey of blanket-geometry sandstone bodies.

TABLE 109. Blanket-geometry tight gas sands categorized by major depositional system.

AREALLY EXTENSIVE FAN DELTAS AND DELTAIC SYSTEMS

- Tuscarora-Medina-"Clinton" trend—Appalachian Basin
- Travis Peak Formation—East Texas and North Louisiana Basins
- Frontier Formation—Greater Green River, Big Horn, and Wind River Basins

DELTAIC SYSTEMS AND DELTAS REWORKED BY TRANSGRESSION

- Berea Sandstone—Appalachian Basin
- Carter Sandstone—Black Warrior Basin
- Cleveland Formation (minor part)—Anadarko Basin
- Davis sandstone—Fort Worth Basin
- Olmos Formation—Maverick Basin
- "J" Sandstone—Denver Basin
- Blair Formation—eastern Greater Green River Basin

BARRIER-STRANDPLAIN SYSTEMS (dominantly regressive, parts may be deltaic or may include offshore bars)

- Oriskany Sandstone (transgressive, reworked?)—Appalachian Basin
- Hartselle Sandstone—Black Warrior Basin
- Cotton Valley Sandstone—East Texas and North Louisiana Basins
- Pictured Cliffs Sandstone—San Juan Basin
- Cliff House Sandstone (transgressive)—San Juan Basin
- Point Lookout Sandstone—San Juan Basin
- Dakota Sandstone (upper part)—San Juan Basin
- Cozzette and Corcoran Sandstones—Piceance Creek Basin
- Sego and Castlegate Sandstones—Uinta Basin
- Fox Hills Sandstone—eastern Greater Green River Basin
- Almond Formation (upper part)—eastern Greater Green River Basin

SHELF SYSTEMS

- Cleveland Formation (major part)—Anadarko Basin
- Atokan and Desmoinesian sandstones (including Cherokee Group)—Anadarko Basin
- Sanostee Member (Mancos Shale)—San Juan Basin
- Mancos "B" interval (Mancos Shale)—Piceance Creek Basin
- Mancos "B" interval (Mancos Shale)—Uinta Basin

TABLE 110. Summary of major characteristics of

FORMATION	DEPOSITIONAL SYSTEM	DEPTH	THICKNESS
Areally extensive fan deltas and deltaic systems			
Travis Peak (Hosston) Formation, East Texas and North Louisiana Basins.	Delta having braided alluvial plain and marine-influenced deltaic margins.	Ranges from 3,100 to 10,900 ft, averages 7,000 to 9,000 ft.	500 to 2,500 ft.
Frontier Formation, Moxa Arch, Greater Green River Basin.	Wave-dominated deltaic system having prodelta through delta-plain and associated barrier-strandplain facies.	Ranges from 6,700 to 11,900 ft, averages 6,700 to 8,300 ft.	300 to 1,200 ft.
Frontier Formation, Rock Springs Uplift and Washakie - Red Desert Basins, Greater Green River Basin.	As above for Moxa Arch area.	Averages 11,700 ft along Rock Springs Uplift; averages 7,100 ft in Washakie - Red Desert Basins.	250 to 600 ft.
Frontier Formation, Wind River Basin.	As above for Moxa Arch area.	Ranges from outcrop to more than 25,000 ft, averages 2,000 to 4,200 ft.	600 to 1,000 ft.
Deltaic systems and deltas reworked by transgression			
Carter Sandstone, Black Warrior Basin.	Deltaic or barrier- and offshore-bar facies in association with deltaic Parkwood Formation. Limited data.	No data from tight areas.	No data from tight areas.
Davis sandstone, Fort Worth Basin.	Deltaic and barrier strandplain in a wave-dominated environment.	Ranges from 4,800 to 5,200 ft.	20 to 400 ft.
Olmos Formation, Maverick Basin.	Deltaic facies and deltas reworked by transgression having multiple depocenters, wave-dominated.	Ranges from 4,500 to 7,200 ft.	400 to 1,200 ft.
Blair Formation, Greater Green River Basin.	Deltaic (prodelta to delta front?). Limited data.	Ranges from outcrop to 15,000 ft, approximately 8,200 ft in one producing area.	1,400 to 1,900 ft.
Barrier-strandplain systems			
Oriskany Sandstone, Western Basin and Low Plateau Provinces, Appalachian Basin.	Transgressive shallow marine or shoreline.	In Western Basin, ranges from 1,600 to 5,300 ft; in Low Plateau, ranges from 1,700 to 8,000 ft.	0 to 200 ft.
Oriskany Sandstone, High Plateau and Eastern Overthrust Belt Provinces, Appalachian Basin.	Transgressive shallow marine or shoreline.	Ranges from outcrop to more than 12,000 ft, averages 7,000 to 9,000 ft.	0 to 300 ft.
Hartselle Sandstone, Black Warrior Basin.	Barrier island and associated nearshore bars.	Ranges from 1,000 to 3,400 ft.	0 to 150 ft.
Pictured Cliffs Sandstone, San Juan Basin.	Barrier strandplain and associated near-shore bars.	Ranges from 2,300 to 3,500 ft.	50 to 400 ft.

selected blanket-geometry low-permeability gas sands.

NET PAY	POST-STIMULATION FLOW	OPERATOR INTEREST (1982)	EXTRAPOLATION POTENTIAL
30 to 86 ft.	500 to 1,500 Mcfd.	High. Five tight gas applications.	Good. Areally extensive across basins in Texas and Louisiana. Expected to be similar to "Clinton"-Medina sands of the Appalachian Basin.
10 to 90 ft.	0 to 2,500 Mcfd.	High. Four tight gas applications.	Good. Areally extensive across several basins in Wyoming and a good example of a wave-dominated deltaic system. Probably, in part, similar to deltaic elements of the Davis, Olmos, and Fox Hills stratigraphic units and to barrier-strandplain elements of several units of the Mesaverde Group.
10 to 65 ft.	0 to 1,500 Mcfd.	High. Two tight gas applications.	Good, as above for Moxa Arch area.
10 to 45 ft.	No data from tight areas.	Potentially moderate. No tight gas applications.	Good, as above for Moxa Arch area.
No data.	No data from tight areas.	Unknown. No tight gas applications.	Poor to fair. Limited data. Deltaic facies may be similar to parts of Fox Hills Sandstone. Barrier bars form conventional reservoirs.
No data.	No data from tight areas.	Low. No tight gas applications.	Poor to fair. Limited data. Expected to be similar to the Olmos Formation and parts of the Fox Hills Sandstone and Frontier Formation.
12 to 85 ft.	Averages 86 Mcfd.	Moderate. Two tight gas applications.	Fair to good. Expected to be similar to parts of the Fox Hills Sandstone and Frontier Formation, the Davis sandstone, and possibly to deltaic sediments at the base of the Cleveland Formation.
No data.	No data.	Low to moderate. One tight gas application.	Poor to fair. Limited data. Possible analogies to Davis and Olmos stratigraphic units. Data inadequate to make comparisons.
10 to 20 ft.	No data from tight areas.	Low. No tight gas applications.	Cannot be evaluated owing to inadequate available data on depositional systems.
150 to 265 ft.	No data from tight areas.	Low. No tight gas applications.	Cannot be evaluated owing to inadequate available data on depositional systems.
No data.	50 to 100 Mcfd.	Low to moderate. One tight gas application.	Fair to good. Limited data. Expected to be similar to barrier- and offshore-bar facies of formations within the Mesaverde Group, parts of the Fox Hills Sandstone, and possibly the upper part of the Dakota Sandstone.
20 to 30 ft.	300 to 1,600 Mcfd.	Moderate. Two tight gas applications.	Good. Expected to be similar to barrier-strandplain facies of the Mesaverde Group in the San Juan Basin and other Rocky Mountain basins. Also, expected to be similar to the upper part of the Dakota Sandstone and to part of the Fox Hills Sandstone.

TABLE 110 (cont.)

FORMATION	DEPOSITIONAL SYSTEM	DEPTH	THICKNESS
Barrier-strandplain systems (cont.)			
Cliff House Sandstone, Mesaverde Group, San Juan Basin.	Reworked barrier strandplain, transgressive, probably preserving mostly subaqueous facies such as upper shoreface.	Ranges from 4,000 to 6,300 ft.	50 to 100 ft.
Point Lookout Sandstone, Mesaverde Group, San Juan Basin.	Barrier strandplain, regressive, including minor lagoonal and estuarine channel facies.	Ranges from 4,400 to 6,700 ft.	100 to 200 ft.
Dakota Sandstone (upper part), San Juan Basin.	Barrier strandplain, dominantly transgressive, including offshore-bar facies and associated lagoonal, estuarine, and washover facies.	Ranges from 6,000 to 8,700 ft.	200 to 350 ft.
Cozzette Sandstone, Piceance Creek Basin.	Barrier strandplain, regressive, possibly including offshore-bar facies. Limited data.	Ranges from 2,400 to 7,200 ft.	Averages 175 ft.
Corcoran Sandstone, Piceance Creek Basin.	Barrier strandplain, regressive, possibly including offshore-bar facies. Limited data.	Ranges from 2,700 to 7,600 ft.	150 to 200 ft.
Sego and Castlegate Sandstones, Uinta Basin.	Probably nearshore marine to barrier strandplain. Regressive. Limited data.	Ranges from 8,000 to 9,500 ft (Castlegate only).	No data from tight areas.
Fox Hills Sandstone, Washakie Basin, Greater Green River Basin.	Predominantly barrier strandplain but includes deltaic and estuarine facies.	Averages 7,300 ft.	150 to 600 ft.
Almond Formation (upper part), eastern Greater Green River Basin.	Shallow marine and offshore bar to barrier strandplain, possibly including tidal-flat, tidal-inlet-channel, and tidal-delta facies.	Ranges from 6,200 to 15,450 ft. Averages 10,200 ft.	100 ft (upper Almond only).
Shelf systems			
Cleveland Formation, Anadarko Basin.	Possible thin deltaic deposit at base of the unit. Major part is a marine shelf deposit.	Ranges from 6,000 to 9,400 ft. Averages less than 8,000 ft.	80 to 170 ft.
Mancos "B" interval, Piceance Creek Basin.	Marine shelf deposit.	Ranges from 3,400 to 3,600 ft.	400 to 700 ft.
Mancos "B" interval, Uinta Basin.	Marine shelf deposit.	Averages 5,000 ft.	450 to 1,000 ft.

TABLE 110 (cont.)

NET PAY	POST-STIMULATION FLOW	OPERATOR INTEREST (1982)	EXTRAPOLATION POTENTIAL
10 to 70 ft.	500 to 3,600 Mcfd.	Moderate. Three tight gas applications.	Fair to good. Expected to be similar to transgressive Dakota Sandstone (upper part) and to parts of the Point Lookout Sandstone. Probably also similar to other Mesaverde Group sandstones and possibly to parts of the Pictured Cliffs and Fox Hills stratigraphic units.
10 to 80 ft.	500 to 3,600 Mcfd.	Moderate. Three tight gas applications.	Good. Expected to be similar to other barrier-strandplain facies of the Mesaverde Group and the Hartselle, Pictured Cliffs, Fox Hills (in part), and Dakota (upper part) stratigraphic units.
10 to 70 ft.	200 to 300 Mcfd.	High. Six tight gas applications.	Good. Expected to be similar to the transgressive Cliff House Sandstone, to parts of the Mesaverde Group in the San Juan Basin and other Rocky Mountain basins, and to parts of the Fox Hills and Pictured Cliffs stratigraphic units.
10 to 70 ft.	Averages 1,229 Mcfd.	High. Two tight gas applications.	Good. Expected to be similar to other barrier-strandplain facies of the Mesaverde Group and the Hartselle, Pictured Cliffs, Fox Hills (in part), and Dakota (upper part) stratigraphic units.
10 to 70 ft.	Averages 1,251 Mcfd.	High. Two tight gas applications.	Good. Expected to be similar to other barrier-strandplain facies of the Mesaverde Group and the Hartselle, Pictured Cliffs, Fox Hills (in part), and Dakota (upper part) stratigraphic units.
25 to 60 ft.	No data.	Unknown. One tight gas application.	Fair. Limited data. Expected to be similar to Cozzette and Corcoran Sandstones and other Mesaverde Group sandstones in Rocky Mountain basins.
25 ft.	Averages 775 Mcfd.	Low to moderate. One tight gas application.	Good. The deltaic facies is expected to be similar to parts of the Frontier and Olmos Formations. Barrier-strandplain facies have analogies in the Dakota Sandstone (upper part), the Mesaverde Group, and the Pictured Cliffs and possibly the Hartselle stratigraphic units.
14 to 18 ft.	1,500 to 1,700 Mcfd.	Moderate. One tight gas application.	Good. Expected to be similar to barrier-strandplain and possibly offshore-bar facies of other Mesaverde Group sandstones. In part possibly similar to the Dakota (upper part) and the Pictured Cliffs and Hartselle stratigraphic units.
10 to 75 ft.	Averages 220 Mcfd.	Moderate. Two tight gas applications.	Fair. Thin deltaic deposit at base has no good analogy. Marine shelf deposit expected to be similar to the Mancos "B" interval in the Piceance Creek and Uinta Basins.
90 to 120 ft.	260 to 350 Mcfd.	High. Four tight gas. applications.	Fair. Part of a trend across two basins. Also expected to be similar to upper part of the Cleveland Formation.
38 to 98 ft.	260 to 350 Mcfd.	Moderate. One tight gas application.	Fair. Part of a trend across two basins. Also expected to be similar to upper part of the Cleveland Formation.

AREALLY EXTENSIVE FAN-DELTA AND DELTAIC SYSTEMS

The Travis Peak Formation of the East Texas and North Louisiana Basins represents an extensive braided alluvial plain and deltaic deposit that is similar to the Tuscarora Sandstone, Medina Group sandstones, and the informally named "Clinton" sandstones of the Appalachian Basin. Both the Travis Peak Formation and the Tuscarora-"Clinton"-Medina trend are clastic wedges that resulted from major tectonic events. The Travis Peak was derived from tilted rift margin blocks formed during the Jurassic opening of the Gulf of Mexico. The Tuscarora-"Clinton"-Medina trend was eroded from source areas tectonically uplifted during the Late Ordovician Taconic orogeny; this orogenic event was a consequence of plate collision along eastern North America (King, 1977). The two units show large-scale similarities in facies tracts; both grade from proximal braided alluvial fans having conglomerates and red beds to distal deltaic marine margins having possible strandplains and shallow marine sand deposits (Cotter, 1982a; McGowen and Harris, in press). In the Appalachian Basin, the marginal marine "Clinton" sandstones of Ohio are developed reservoirs; the equivalent Tuscarora Sandstone has produced only limited quantities of gas. Gas completions in the Travis Peak Formation are more evenly distributed, but the full potential of the Travis Peak has, to an extent, been overlooked in favor of other reservoirs, especially those in the Cotton Valley Group. New knowledge of tight gas reservoirs in the Travis Peak will have high potential transferability to the Tuscarora-"Clinton"-Medina trend.

The Frontier Formation is an areally extensive, wave-dominated deltaic system that prograded across much of Wyoming. It exists in the Greater Green River Basin, the Wind River Basin, and the Big Horn Basin. The extrapolation potential of the Frontier is good both within itself between different Laramide-age basins and to similar deltaic facies in less extensive deltaic systems. Examples of the latter might include parts of the Carter and Fox Hills Sandstones, the Olmos Formation, and deltaic components of Mesaverde Group sands that are otherwise predominantly barrier, strandplain, and offshore bar. Subsurface data from the Frontier Formation are mostly concerning structural highs and basin margins, but the unit is also present across extensive, mostly undrilled, deeper basin areas. The potential exists for the development of these deeper areas.

DELTAIC SYSTEMS AND DELTAS REWORKED BY TRANSGRESSION

Among the smaller deltaic systems of this study are the Davis sandstone and the Olmos Formation (table 109). Both are wave-dominated delta systems, but the Olmos was affected by subsequent transgression and the Davis was succeeded by a fluvially dominated fan delta. The specific facies of the Blair and Carter deltas have not been clearly identified but probably include distal to proximal delta front and possibly distributary bar. The Cleveland Formation may have a thin deltaic package at its base, but the unit grades upward into a shelf deposit. Thus, although variations exist among the smaller deltaic systems, all are prograding into intracratonic basins and can be expected to show a moderate degree of lateral continuity in sheetlike delta-front facies. The extent of delta-front development depends on the degree of marine reworking. Because these deltaic systems are thought to have been wave dominated, much of the sediments discharged at the depocenter will be reworked laterally to form barrier-island systems or strandplains.

A wave-dominated, prograding coastline likely has both deltaic depocenters and deposits reworked along strike within the same formation. The distinction made in this survey between deltaic and barrier-strandplain depositional systems is based on the amount of information available on each stratigraphic unit. For example, one area of the Fox Hills Sandstone has been described as a delta-front deposit and another area as a barrier-estuarine deposit (Land, 1972; Weimer, 1973). Such differences are expected within a regional depositional framework.

BARRIER-STRANDPLAIN SYSTEMS

Many of the regressive marine sandstones of the Mesaverde Group are considered to be barrier-strandplain depositional systems. The Mesaverde Group is a major regressive wedge of terrigenous clastic sediments deposited in the Late Cretaceous epicontinental seaway. Many minor transgressions and regressions during Mesaverde time resulted in intertonguing of sands from a western source and thick marine shales, such as the Mancos Shale. Stratigraphic units within this category include the Pictured Cliffs, Point Lookout, upper Dakota, Cozzette, and Corcoran Sandstones, probably the Sego and the Castlegate Sandstones, and probably parts of the Fox Hills Sandstone and upper Almond Formation (table 109). The Pictured Cliffs, Dakota, and Fox Hills Sandstones are within the Rocky Mountain region but are not part of the Mesaverde Group. The barrier sands of the Hartselle Sandstone are on a structural platform in the northeastern part of the Black Warrior Basin.

Although most stratigraphic units in this barrier-strandplain group are regressive, two of the sandstones are transgressive. The Oriskany Sandstone is thought to have a shoreline or shallow marine origin, but its specific facies composition is unknown. Its occurrence over a major part of the Appalachian Basin supports the concept that it was spread laterally by marine transgression. The Cliff House Sandstone of the Mesaverde Group was definitely formed during marine transgression. The periodic transgressive and regressive cycles of the Mesaverde Group in the San Juan Basin are well defined by cyclically interstratified nonmarine, barrier-strandplain, and shallow marine clastic sediments (Hollenshead and Pritchard, 1961; Sabins, 1964, among others). Even though both may be related to marine transgression, potential to extrapolate between the Oriskany Sandstone and the Cliff House Sandstone appears limited, primarily owing to lack of data on the Oriskany.

Regressive barrier-strandplain depositional systems in a wave-dominated environment may be associated with deltaic facies as well. Where fluvial channels enter the marine environment, a delta front could have developed and merged laterally with the shoreface of barrier-strandplain deposits. Bars may exist at the channel mouths. Delta-front and channel-mouth-bar facies are expected to be less extensive than in more fluvially dominated systems but will be associated with barrier and strandplain deposits. Lagoonal, estuarine, and tidal-inlet facies and shelf-bar sands may also be present. In an outcrop or subsurface study of limited areal extent, any one of these facies may predominate; therefore, it is important to consider any one study in the regional depositional framework.

Aside from the Oriskany and Cliff House Sandstones, and possibly the upper Almond Formation owing to the influence of the transgressing Lewis sea, the formations listed as barrier-strandplain systems are expected to have major similarities. All are dominantly regressive, and most were deposited in the same Cretaceous intracratonic basin. The extrapolation potential among these units should be good.

SHELF SYSTEMS

The shelf systems identified in this survey include two stratigraphic units from the Anadarko Basin and the Mancos "B" interval of the Mancos Shale in the Piceance Creek and Uinta Basins (table 109). The Mancos "B" prospective area is basically one trend overprinted by the development of two Laramide-age structural basins and the intervening Douglas Creek Arch. Of all the shelf systems surveyed, only the Mancos "B" seems to be solely the product of shelf depositional processes wherein silt and very fine grained to fine-grained sand were dispersed well beyond a marine shoreline. Logs from the Cleveland Formation suggest that the basal part of the Cleveland may consist of a thin deltaic package including prodelta and delta-front facies. The thick upper part of the formation is the shelf deposit. Atokan and Desmoinesian sands of the Cherokee Group may include distal deltaic deposits grading into sediments in equilibrium with shelf processes.

Brown and others (1973) pointed out that probably only a small percentage of cratonic basin sediments are of shelf origin and that many deposits on a physiographic shelf may be either distal deltaic or derived from strike-fed nearshore systems. This is quite possibly the case for parts of the Cleveland Formation and for the sands of the Cherokee Group on the northern shelf of the Anadarko Basin. The Atokan and Desmoinesian sands are thin (10 to 20 ft in the Red Fork Formation of the Cherokee Group) and occur at depths of 11,000 to 13,000 ft. In a sequence of several Pennsylvanian sand reservoirs, they are considered secondary objectives by most operators.

The Sanostee Member of the Mancos Shale consists of sandstone highly cemented with calcite and calcarenite. Its extrapolation potential is considered poor because its unique mineralogy and diagenetic history have a major influence on reservoir producibility.

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