GEOLOGY AND ENGINEERING CHARACTERISTICS OF SELECTED LOW-PERMEABILITY GAS SANDS: A SURVEY

Final Report

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Title	Geology and Engineering Characteristics of Selected Low-Permeability Gas Sands: A Survey
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Principal Investigator	R. J. Finley
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Objective	To compile geologic and engineering data on blanket-geometry, low-permeability gas sands that may serve as candidates for future research.
Technical Perspective	Past and current research on tight gas sands has focused primarily on lenticular sands. Blanket-geometry sands have been deposited by different depositional systems than lenticular sands, with resulting differences in external and internal reservoir geometry and in the techniques necessary to find, develop, and produce the tight, blanket-geometry gas sand. To assure that research on selected tight gas sand reservoirs would be applicable to other reservoirs, this survey was conducted with emphasis on clastic depositional systems and the expected transferability of results between stratigraphic units. The expected transferability has been termed "extrapolation potential."
Results	Existing information was compiled for stratigraphic units in 16 sedimentary basins regarding the general attributes, economic factors, geologic parameters of the basin, geologic and engineering parameters of the unit itself, and operating conditions applicable to selected blanket-geometry tight gas sands. These sands were found to primarily be parts of the deltaic barrier-strandplain, and to a lesser extent, the shelf clastic depositional systems. The Travis Peak and Frontier Formations are areally extensive fan delta and deltaic systems, respectively, that currently enjoy high operator interest, have good extrapolation potential, and could be considered for further study. Seven formations within the Mesaverde Group in the San Juan, Piceance Creek, Uinta, and Greater Green River Basins are dominantly barrier-strandplain systems. Offshore bars and other minor facies are associated with these systems. The Cozzette and Corcoran Sandstones and the upper part of the Almond Formation have good extrapolation potential, are of interest to explorationists, and could be considered for further study. Among shelf systems the Mancos "B" and adjacent stratigraphic intervals of the Mancos could be examined in association with analysis of the Cozzette and the Corcoran Sandstones to ensure that the potential tight gas resource of shelf systems is not overlooked.

Technical Approach

Data compilation was structured using a similar tabular format for each stratigraphic unit to facilitate comparison between units. Applications by gas producers for tight formation designations under the Natural Gas Policy Act were the most important source of geologic and engineering data on specific gas reservoirs. Much data on depositional systems and reservoir parameters were acquired from publications of state and regional geological societies and from journal articles. A subcontract with the West Virginia Geological and Economic Survey and informal contact with the U.S. Geological Survey, Western Tight Gas Reservoirs Program, afforded additional insight into the Appalachian Basin and the Rocky Mountain region. The Cotton Valley Sandstone and the "J" Sandstone are tight gas sands that are already highly commercialized and therefore were included in the survey only for comparison with other stratigraphic units. A single table was prepared summarizing important characteristics of all sands considered potential candidates for future research.

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SUMMARY AND RECOMMENDATIONS

This compilation of data on blanket-geometry, low-permeability gas sands was prepared to assist CER Corporation and the Gas Research Institute (GRI) in the development of a research program on tight gas reservoirs. Stratigraphic units in 16 sedimentary basins from the Appalachian Basin to the Greater Green River Basin were included in this survey (fig. 1). Emphasis was placed on obtaining a uniform set of information on general attributes, economic factors, geologic parameters of the basin, geologic and engineering parameters of the stratigraphic unit, and operating conditions related to each formation or member. Results of this survey may be utilized to determine a smaller number of stratigraphic units, geologic basins, or depositional systems that can be investigated in a more detailed study, which will ultimately lead to the selection of primary and secondary research areas.

Each tight gas reservoir was considered within a sedimentary framework of associated lithogenetic facies that make up a depositional system. Each facies, such as the delta front within the deltaic system or the barrier island shoreface within the barrier-strandplain system, has characteristic internal and external geometry and relationships to adjacent facies. These relationships affect the distribution of any hydrocarbon within a reservoir and become particularly important in tight formations where specialized stimulation and production procedures are necessary. The depositional system and associated facies of each unit were emphasized in this survey to provide a basis of comparison between formations of different ages in different structural and sedimentary settings. Once established, the known facies within each formation became the basis for evaluating the transferability of geologic and engineering knowledge from one formation to another. Expected transferability of research results, as best as can be judged at this stage of investigation, has been termed "extrapolation potential." A synopsis of depositional systems, extrapolation potential, and selected other characteristics of tight gas sands considered to be the most likely candidates for future research is presented in table 1.

Not included in table 1 are sands reviewed in the body of this report that are not considered appropriate for a major research effort for reasons outlined herein. Also excluded are two highly commercialized unconventional gas reservoirs, the "J" Sandstone (Denver Basin) and the Cotton Valley Sandstone (East Texas Basin/North Louisiana Salt Basin), which serve as models for comparison of less developed gas resources. The extrapolation potential of the remaining stratigraphic units has been subjectively rated from poor to good (table 1). Variations in data availability influence, to some extent, the judgment made as to the extrapolation potential; adequate research potential requires that well data that can be used in a technology development program be available. For the Carter Sandstone, the Davis Sandstone, and the Blair Formation, an extrapolation potential of poor to fair was given in part because of the lack of data. For the Oriskany Sandstone, no judgment of extrapolation potential was possible because available publications do not adequately describe the depositional systems of this formation. This survey used existing information; any development of new information from basic well data may be included in future work on a more restricted group of stratigraphic units.

Three depositional systems are represented among blanket-geometry tight gas reservoirs suitable for additional study: the deltaic system, the barrier-strandplain system, and the shelf system.

Deltaic systems and barrier-strandplain systems encompass most of the siliciclastic formations suitable for additional research. Among deltaic systems the Travis Peak (Hosston) and Frontier Formations are areally extensive fan delta and delta systems, respectively, with potential for greatly increased commercialization. Operator interest in the Travis Peak is high, and depths to the formation are not excessive. The "Clinton"-Medina sands of the Appalachian Basin, which will be formally covered in an addendum to this report, are interpreted to be a fan delta system, and it appears that studies of the

Travis Peak could be utilized in the continuing development of the "Clinton"-Medina. In particular, such studies may foster closer examination of "Clinton"-Medina and equivalent sands east of the present productive areas. The Frontier Formation has a somewhat unique type of extrapolation potential in that the unit occurs in multiple basins in Wyoming and can also be compared to wave-dominated deltaic systems in other basins. The latter systems will be smaller and thinner than the Frontier, however. Operator interest in the Frontier is high and depths to the formation are not excessive around basin margins, but are in the range of 20,000 ft toward basin centers.

It is recommended that the Travis Peak and Frontier Formations be considered for more detailed study as part of the final selection of research areas. In addition, the Olmos Formation would be representative of smaller wave-dominated systems, such as the Davis and the Carter Sandstones, which may ultimately be developed. The utility of including the Olmos in a more detailed study is equivocal, however, and it may be that extrapolation of research results from the Frontier will enhance understanding of Olmos deltaic facies as well.

Barrier-strandplain depositional systems include a large number of dominantly regressive sandstones primarily within the Mesaverde Group in the San Juan, Piceance Creek, Uinta, and Greater Green River Basins (seven formations). Numerous transgressions and regressions occurred on the scale of individual formations and on even smaller scales as Late Cretaceous shorelines alternately were inundated or prograded. The progradation of shorelines by accretion of strandplain and barrier island systems, in association with offshore bar, estuarine, and other marginal marine facies, represents a style of sedimentation characteristic of much of the Upper Cretaceous stratigraphic section from the Western Interior of North America.

It is recommended that among barrier-strandplain systems the Cozzette and Corcoran Sandstones and the Almond Formation (upper part) be considered for more detailed study as part of the final selection of research areas. Published data are somewhat limited on the Cozzette and Corcoran; however, these units form a play that is currently active, and information not yet published may also become available. A study of the Cozzette and Corcoran should of necessity include the Castlegate and Sego marginal marine sandstones of the Uinta Basin, which are parts of the same major progradational package. The upper Almond may be less attractive because of greater depth, but in some trends it shows good dip continuity and excellent strike continuity and appears to be a good example of a marginal marine, blanket-geometry sandstone.

One shelf system should be included in those formations considered for more detailed study. The Mancos of the Piceance Creek Basin is recommended, and the study should examine Mancos siltstones and fine sandstones in general, and not just within the "B" interval. Such shelf clastics may have more widespread potential than currently available information and operator activity suggest. A more detailed examination of the Mancos than the present study is needed to make this determination. Study of the Mancos can be integrated with review of the Cozzette and Corcoran, which overlie the Mancos and form a continuous progradational sequence.

In summary, blanket-geometry tight gas sands were predominantly deposited by deltaic, barrier-strandplain, and, to a lesser extent, shelf systems. It is recommended that at least five formations be selected for additional study with the objective of selecting primary and secondary research areas. These units are the Travis Peak, Frontier, Cozzette/Corcoran, Almond (upper), and Mancos-Mancos "B" stratigraphic units. No ranking is implied within this group of stratigraphic units.

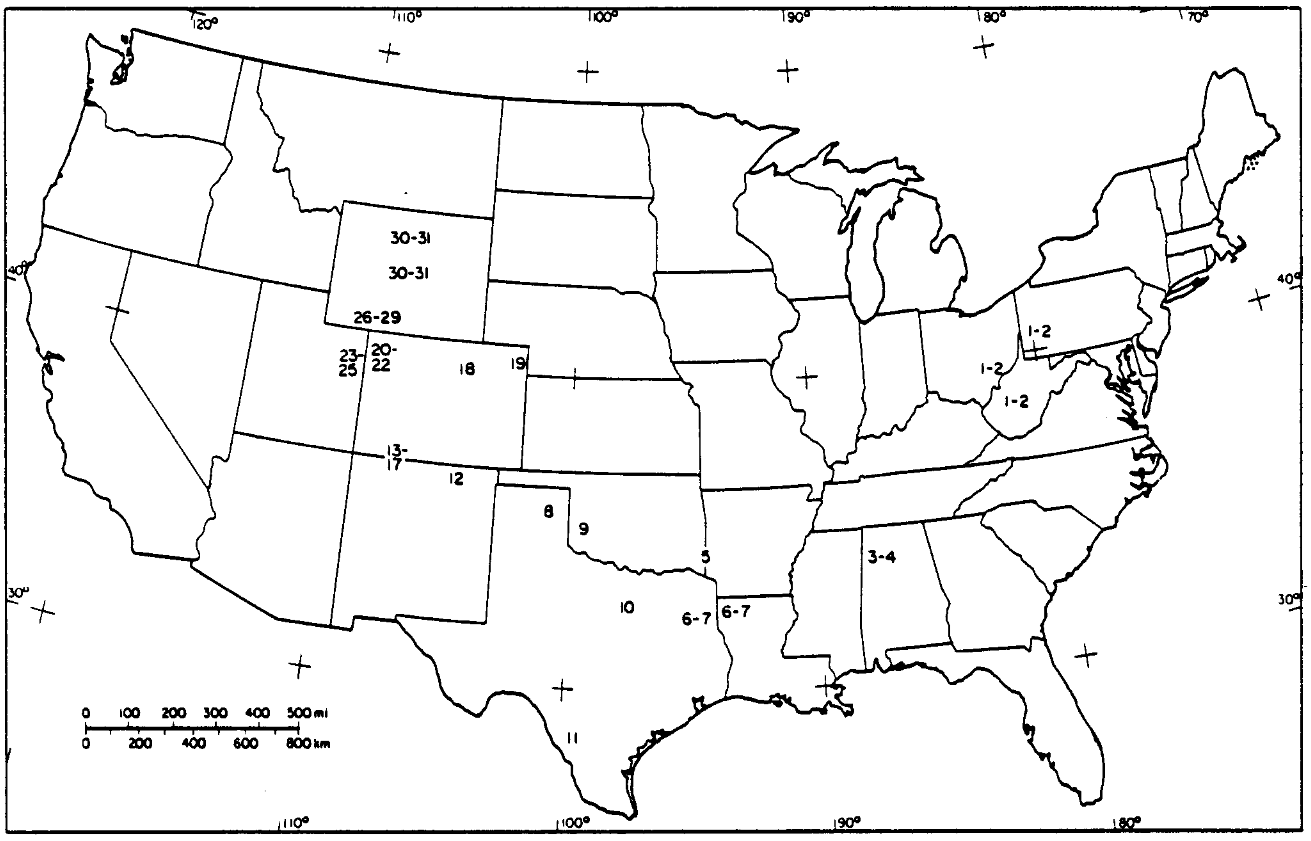

Figure 1. General location map for blanket-geometry tight gas sands included in this study. Numbers are keyed to table 2.

Table 1. Summary of major characteristics of selected blanket-geometry low-permeability gas sands.

Formation	Depositional System	Depth	Thickness
Areally Extensive Fan Delta and Deltaic Systems			
Travis Peak (Hosston) Formation, East Texas Basin (North Louisiana Salt Basin)	Fan delta, with braided alluvial surface and marine-influenced fan delta margins	Ranges from 3,100-10,900 ft. Generally 7,000-9,000 ft.	500-2,500 ft
Frontier Formation, Moxa Arch, Greater Green River Basin	Wave-dominated deltaic system with prodelta through delta plain and associated barrier-strandplain facies	Ranges from 6,700-11,900 ft. Generally 6,700-8,300 ft.	300-1,200 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	250-600 ft
Frontier Formation, Wind River Basin	(as above, for Moxa Arch area)	Ranges from outcrop to over 25,000 ft. Generally 2,000-4,200 ft.	600-1,000 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 in tight areas	No data in tight areas
Davis Sandstone, Fort Worth Basin	Deltaic and barrier-strandplain in a wave-dominated environment	4,800-5,200 ft.	20-400 ft
Olmos Formation, Maverick Basin	Deltaic and deltaic reworked by transgression, with multiple depocenters, wave-dominated	4,500-7,200 ft	400-1,200 ft
Blair Formation, Greater Green River Basin	Deltaic (prodelta to delta front?). Limited data.	Ranges from outcrop to 15,000 ft. Approx. 8,200 ft in one producing area.	1,400-1,900 ft
Barrier Strandplain Systems			
Oriskany Sandstone, Western Basin and Low Plateau Provinces of Appalachian Basin	Transgressive shallow marine or shoreline deposit	In Western Basin, ranges from 1,600-5,300 ft. In Low Plateau, ranges from 1,700-8,000 ft.	0-200 ft
Oriskany Sandstone, High Plateau and Eastern Overthrust Belt Provinces of Appalachian Basin	Transgressive shallow marine or shoreline deposit	Ranges from outcrop to greater than 12,000 ft. Generally 7,000-9,000 ft.	0-300 ft
Hartselle Sandstone, Black Warrior Basin	Barrier island with associated nearshore bars	1,000-3,400 ft.	0-150 ft
Pictured Cliffs Sandstone, San Juan Basin	Barrier-strandplain with associated nearshore bars	2,300-3,500 ft	50-400 ft

Table 1 (continued)

Net Pay	Post-Stimulation Flow	Operator Interest	Extrapolation Potential
30-86 ft	500-1,500 Mcfd	High. Five tight gas applications.	Good. Areally extensive across basins in Texas and Louisiana. Expected similarity to "Clinton"-Medina sands of the Appalachian Basin.
10-90 ft	0-2,500 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, and to barrier-strandplain elements of several units of the Mesaverde Group.
10-65 ft	0-1,500 Mcfd	High. Two tight gas applications.	Good, as above for Moxa Arch area
10-45 ft	No data from tight gas areas	Potentially moderate. No tight gas applications.	Good, as above for Moxa Arch area
No data in tight areas	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. Barrier/ bars form conventional reservoirs.
No data	No data from tight gas areas	Low. No tight gas applications.	Poor to fair. Limited data. Expected similarities to the Olmos Formation, part of the Fox Hills, and part of the Frontier.
12-85 ft	Averages 86 Mcfd	Moderate. Two tight gas applications.	Fair to good. Expected similarity to parts of the Fox Hills and Frontier Formations, the Davis Sandstone, and possibly to deltaic sediments at the base of the Cleveland.
No data	No data	Low to moderate. One tight gas application.	Poor to fair. Limited data. Possible analogies to Davis and Olmos Formations. Data inadequate to make comparisons.
10-20 ft	No data from tight gas areas	Low. No tight gas applications.	Cannot be evaluated due to inadequate available data on depositional systems.
150-265 ft	No data from tight gas areas	Low. No tight gas applications.	Cannot be evaluated due to inadequate available data on depositional systems.
No data	50-100 Mcfd	Low to moderate. One tight gas application.	Fair to good. Limited data. Expected similarity to barrier and offshore bar facies of formations within the Mesaverde Group, parts of the Fox Hills, and possibly the upper part of the Dakota Sandstone.
20-30 ft	300-1,600 Mcfd	Moderate. Two tight gas applications.	Good. Expected similarity to barrier-strandplain facies of the Mesaverde Group in the San Juan and other Rocky Mountain basins. Also, similarity expected to the upper part of the Dakota Sandstone and to part of the Fox Hills.

Table 1 (continued)

Formation	Depositional System	Depth	Thickness
Cliff House Sandstone, Mesaverde Group, San Juan Basin	Reworked barrier-strandplain, transgressive, probably preserving mostly subaqueous facies such as upper shoreface	4,000-6,300 ft	50-100 ft
Point Lookout Sandstone, Mesaverde Group, San Juan Basin	Barrier-strandplain, regressive, including minor lagoonal and estuarine channel facies	4,400-6,700 ft	100-200 ft
Dakota Sandstone, (upper part), San Juan Basin	Barrier-strandplain, dominantly transgressive, including offshore bar facies and associated lagoonal, estuarine, and washover facies	6,000-8,700 ft	200-350 ft
Cozzette Sandstone, Piceance Creek Basin	Barrier-strandplain, regressive, possibly including offshore bar facies. Limited data.	2,400-7,200 ft	Averages 175 ft
Corcoran Sandstone, Piceance Creek Basin	Barrier-strandplain, regressive, possibly including offshore bar facies. Limited data.	2,700-7,600 ft	150-200 ft
Sego and Castlegate Sandstones, Uinta Basin	Probably nearshore marine to barrier-strandplain. Regressive. Limited data.	8,000-9,500 ft (Castlegate)	
Fox Hills Formation, Washakie Basin, Greater Green River Basin	Predominantly barrier-strandplain but includes deltaic and estuarine facies	Averages 7,300 ft	150-600 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.	6,200-15,450 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.	6,000-9,400 ft. Generally less than 8,000 ft.	80-170 ft
Mancos "B" interval, Piceance Creek Basin	Marine shelf deposit	3,400-3,600 ft	400-700 ft
Mancos "B" interval, Uinta Basin	Marine shelf deposit	Averages 5,000 ft	450-1,000 ft

Table 1 (continued)

Net Pay	Post-Stimulation Flow	Operator Interest	Extrapolation Potential
10-70 ft	500-3,600 Mcfd	Moderate. Three Mesaverde tight gas applications.	Fair to good. Expected similarity to transgressive Dakota Sandstone (upper part) and to parts of the Point Lookout Sandstone. Probably also similar to other Mesaverde Group sandstones, and possibly parts of the Pictured Cliffs and Fox Hills.
10-80 ft	500-3,600 Mcfd	Moderate. Three Mesaverde tight gas applications.	Good. Expected similarity to other barrier-strandplain facies of Mesaverde Group, Hartselle, Pictured Cliffs, Fox Hills (in part), and Dakota (upper part) stratigraphic units.
10-70 ft	200-300 Mcfd	High. Six tight gas applications.	Good. Expected similarity to 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.
60-70 ft	Averages 1,229 Mcfd	High. Two tight gas applications.	Good. Expected similarity to other barrier-strandplain facies of Mesaverde Group, Hartselle, Pictured Cliffs, Fox Hills (in part), and Dakota (upper part) stratigraphic units
10-70 ft	Averages 1,251 Mcfd	High. Two tight gas applications.	Good. Expected similarity to other barrier-strandplain facies of Mesaverde Group, Hartselle, Pictured Cliffs, Fox Hills (in part) and Dakota (upper part) stratigraphic units.
25-60 ft	No data	Unknown. One tight gas application.	Fair. Limited data. Expected similarity 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, the Pictured Cliffs and possibly the Hartselle.
14-18 ft	1,500-1,700 Mcfd	Moderate. One tight gas application.	Good. Expected similarity to barrier-strandplain and possible offshore bar facies of other Mesaverde Group sandstones. In part possibly similar to the Dakota (upper part), Pictured Cliffs and Hartselle.
10-75 ft	Averages 220 Mcfd	Moderate. Two tight gas applications.	Fair. Thin deltaic deposit at base has no good analogy. Marine shelf deposit has expected similarities to the Mancos "B" in the Piceance Creek and Uinta Basins.
90-120 ft	260-350 Mcfd	High. Four tight gas applications.	Fair. Part of a trend across two basins. Also expected similarity to upper part of the Cleveland Formation.
38-98 ft	260-350 Mcfd	Moderate. One tight gas application.	Fair. Part of a trend across two basins. Also expected similarity to upper part of the Cleveland Formation.

INTRODUCTION

Project Overview

This survey of low-permeability, or tight, gas sands was undertaken for CER Corporation and the Gas Research Institute (GRI) to provide a basis for selecting a stratigraphic unit, sedimentary basin, or particular depositional system for future research and technological development. Such research and development is aimed at "the development of the technology necessary to reduce risks that are inhibiting the exploitation of these resources [tight gas reservoirs] by private industry" (Gas Research Institute, 1982).

Geologic and engineering studies of low-permeability gas sands have been categorized by overall reservoir geometry and directed toward the understanding of either lenticular or blanket sands. Kuuskraa and others (1978), in a report by Lewin and Associates, Inc., differentiated lenticular and blanket reservoirs in basins across the country. In three of these basins, the Western Gas Sands Project, funded by the U.S. Department of Energy in cooperation with the U.S. Geological Survey, various national laboratories, universities, and private industry, has included research on many aspects of gas production from tight lenticular sands. Elements of the Western Gas Sands Project have included improved determination of the gas resource, geologic characterization of local areas, research on instrumentation, modeling and tools for geologic characterization, and application of improved production technology such as hydraulic fracturing.

Some of these project elements have yielded results applicable to reservoirs of blanket geometry, but many have not. Each reservoir is a product of different modes of deposition and histories of burial, physical compaction, cementation, and possible subsequent deformation. Both the internal and external geometry of a reservoir are significant controlling factors in the development of a hydrocarbon resource and strongly affect completion techniques, well spacing, rate of resource recovery, and ultimate recovery per well and per field. Geologic variability is a complicating factor in the exploitation of any reservoir, and is probably an even greater factor in tight formations.

Because of the continued need for improved understanding of the occurrence, distribution, and recovery of gas from tight formations, the Gas Research Institute is seeking to focus research and development efforts on low-permeability blanket sand reservoirs. An objective of GRI is to promote the ultimate utilization of unconventional gas resources generally not producible with current technology; one method to accomplish this objective involves the development of tight gas sands. GRI, therefore, in accordance with their Program Plan for Tight Gas Sand Reservoirs (1982), requested the Bureau of Economic Geology to assemble geologic and engineering data necessary to enable the future selection of priority research areas. Such areas may ultimately be defined as geologic basins, sub-basins, particular formations, or products of similar depositional environments.

Technical Approach

This survey provides GRI with information on selected blanket-geometry tight gas sands within the United States and will enable GRI to define priority research areas. This survey has relied on existing information relating to the geology, engineering parameters, economic factors, and operating conditions affecting gas production in selected basins, ranging from the Appalachian Basin to the several gas-prone basins of the Rocky Mountain region. Results of this survey may be utilized to determine a smaller number of stratigraphic units, geologic basins, or depositional systems that can be investigated in a more detailed study, which will lead to the selection of primary and secondary research areas by GRI (Gas Research Institute, 1982). The information compiled in this survey is comparable to the greatest extent possible from area to area, recognizing that areal differences will exist in the availability of data.

Organization of This Survey in Support of the GRI Program Plan

A critical aspect of the GRI program plan is to ensure that the results of research and development in one tight sand area are readily transferable to another such area. This potential for technology transfer must be inherent in the program to foster increased production from tight gas sands. In reviewing blanket-geometry tight gas sands from diverse sedimentary environments, it seemed likely that the formations studied would fall into groups tied together by common genetic depositional systems. Such an approach, while allowing for an element of diversity, provides a basis for anticipating the maximum potential to extrapolate research results from one area to another. The review of each stratigraphic unit therefore places emphasis on the depositional system responsible for emplacement of the unit and on the occurrence of analagous systems in other sedimentary basins.

The assembling of data from 16 sedimentary basins from the Appalachian Basin of Pennsylvania, West Virginia, and Ohio to the Greater Green River Basin of Wyoming requires presentation in a format that facilitates comparison between areas. Use of data tables with a standard format was adopted to present data for each stratigraphic unit of major importance to this survey. Some stratigraphic units did not warrant the development of data tables, or sufficient data were not available to complete a set of tables; these units are primarily described in a textual format. A comparison of all stratigraphic units in the context of depositional systems follows presentation of the basic data.

The order of data presentation follows a geographic flow from the Appalachian region through the southern and southwestern states to the Rocky Mountain region (table 2). Stratigraphic units in the Appalachian Basin were analyzed by the West Virginia Geological and Economic Survey, Robert B. Erwin, Director, under the supervision of Douglas G. Patchen, Chief, Fossil Fuels Division. Note that two Appalachian stratigraphic units are covered in this report and two units will be covered in an addendum to this document. Assistance in identifying stratigraphic units for analysis within the Rocky Mountain region was provided by the U.S. Geological Survey, Charles W. Spencer, Program Chief, Western Tight Gas Reservoirs, and by CER Corporation, Jack S. Sanders, Senior Geologist. Actual data collection and analysis for reservoirs in the Rocky Mountain region was done by the Bureau of Economic Geology.

Table 2. Stratigraphic units and/or basin summaries included in this survey of blanket-geometry tight gas sands. Numbers are keyed to figure 1.*

Appalachian Basin
- Oriskany Sandstone (1)
- Tuscarora Sandstone (2)

Black Warrior Basin
- Carter Sandstone (3)
- Hartselle Sandstone (4)

Arkoma Basin/Ouachita Mountain Province (5)

East Texas Basin/North Louisiana Salt Basin
- Travis Peak Formation (6)
- Cotton Valley Sandstone (7)

Anadarko Basin
- Cleveland Formation (8)
- Cherokee Group (9)

Fort Worth Basin
- Davis Sandstone (10)

Maverick Basin
- Olmos Formation (11)

Raton Basin (12)

San Juan Basin
- Pictured Cliffs Sandstone (13)
- Cliff House Sandstone, Mesaverde Group (14)
- Point Lookout Sandstone, Mesaverde Group (15)
- Sanostee (Juanna Lopez) Member, Mancos Shale (16)
- Dakota Sandstone (17)

Denver Basin
- "J" Sandstone (18)
- Niobrara Formation (19)

Piceance Creek Basin
- Cozzette Sandstone, Mesaverde Group (20)
- Corcoran Sandstone, Mesaverde Group (21)
- Mancos "B" (22)

Uinta Basin
- Sego Sandstone (23)
- Castlegate Sandstone (24)
- Mancos "B" (25)

Table 2 (cont.)

Greater Green River Basin
- Fox Hills Formation (26)
- Almond Formation (upper Almond), Mesaverde Group (27)
- Blair Formation, Mesaverde Group (28)
- Frontier Formation (29)

Wind River and Big Horn Basins
- Frontier Formation (30)
- Muddy Sandstone (31)

*Additional stratigraphic units to be considered in an addendum to this report are the Berea Sandstone and the "Clinton"-Medina of the Appalachian Basin.

METHODOLOGY

Definition of Variables

The technical approach to this study involved data collection for more than 30 stratigraphic units in 16 sedimentary basins. Variables to be quantified were classified under the categories of general attributes, economic factors, geologic parameters of the basin or trend, geologic parameters of the individual stratigraphic unit, engineering parameters, and operating conditions. Variables within each category are listed in table 3.

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) constitute the most important data source for geologic and engineering data on tight gas reservoirs. Published technical papers or reports rarely include specific data on porosity, permeability, water saturation, net pay, production rates, and other key variables necessary to characterize the specific producing interval of a tight formation. The increasing amount of application materials now in the files of state regulatory agencies constitutes the most complete data base on tight gas sands in the United States. It is evident from review of these applications that over the last two years operators are increasingly doing a better job of preparing concise applications that focus on key parameters specified by NGPA regulations.

A second important data source is the guidebooks prepared by such organizations as the Wyoming Geological Association, the Rocky Mountain Association of Geologists, and numerous local and regional geological societies. These works include articles dealing with the applied sedimentology of producing reservoirs and frequently provide the geologic framework for data from operator applications. In selected western basins the open-file reports of the U.S. Geological Survey, produced as part of the Western Gas

Sands Project, provided significant data, and many published papers and news articles were also consulted.

Table 3. Variables to be defined for each low-permeability gas sand.

General Attributes

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

Economic Factors

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

Geologic Parameters - Basin or Trend

- Structural/tectonic regime
- Regional thermal gradient
- Regional pressure gradient

Geologic Parameters - Stratigraphic Unit

- Depositional system/genetic facies
- Textural maturity
- Mineralogy
- Diagenetic processes/cements
- Reservoir dimensions
- Pressure/temperature range
- Natural fractures
- Data availability

Engineering Parameters

- Porosity/permeability
- Net pay thickness
- Production/decline rates
- Typical water saturation
- Formation fluids
- Well stimulation attempts/success
- Typical logging practice/other techniques
- Development spacing

Operating Conditions

- Terrain characteristics/accessibility
- Limiting weather conditions

DEPOSITIONAL SYSTEMS

Depositional Systems as a Common Factor in Reservoir Character

A basic understanding of the sedimentary framework of a basin can be gained by using lithogenetic facies as a fundamental stratigraphic unit. Each facies is a three-dimensional body of rock whose origin in terms of environment can be inferred from a set of observable characteristics. These characteristics include petrography, external geometry, internal geometry, sedimentary structures, organic content, stratigraphic relations, and associated sedimentary facies. An assemblage of lithogenetic facies linked by depositional environment and associated processes forms 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.

As a potential hydrocarbon reservoir, each lithogenetic facies inherits a set of attributes, such as porosity, permeability, and spatial relation to other facies, that control or affect migration and distribution of hydrocarbons (Galloway and others, in press). In addition, some initial properties derived from the depositional setting of a stratigraphic unit are subsequently modified in the subsurface by compaction and diagenesis, but the overall sand-body geometry of the unit is largely unaffected. Thus delineation of depositional systems can provide the basis for characterizing blanket-geometry tight gas sands, and it will be recognized that certain depositional systems will include dominantly lenticular facies and others will include facies with good lateral continuity.

The internal and external geometry of a sand body is not only tied to locally identifiable depositional systems but will also be part of a set of contemporaneous depositional systems that may be termed a "systems tract" (Brown and Fisher, 1977). Such a tract may include, for example, fluvial, deltaic, shelf, and slope depositional systems. These systems reflect a paleoslope from source area to basin margin to deep marine environments. Thus, expected mutual relationships between depositional systems can be defined to provide a regional setting within which localized detailed studies of a tight gas sand can be extrapolated to wider areas. This process of extrapolation could be particularly important in some basins of the Rocky Mountain region where well data may be concentrated in limited basin-margin areas and deeper basin flanks are only sparsely drilled.

Major Depositional Systems

Nine principal clastic depositional systems reviewed by Fisher and Brown (1972) may be classified into three major groups established by Selley (1978) (table 4). All systems are adequately described by their major headings; but note that a fan delta will include marine-reworked margins, including a distal fan facies with a delta front and possibly marine bars. Each system may have several subclasses, as in the case of the fluvial system wherein braided streams, fine-grained meanderbelt, coarse-grained meanderbelt, and stabilized distributary channels each have distinctive sand-body geometry, texture, and distribution of internal sedimentary structures. Similarly, deltas may be divided into river-dominated types that have digitate to lobate geometries and wave-dominated types that have cuspate geometries.

The study of modern depositional systems and their ancient counterparts has led to the development of models for 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 utilized in this survey to interpret and predict the geometry of tight sand reservoirs. The Western Gas Sands Project has dealt with lenticular sands, many of which are fluvial and were deposited in continental depositional environments of the Upper Cretaceous Mesaverde Group in several Rocky Mountain basins. This survey has found that blanket-geometry tight gas sands are mostly in marginal marine environments including 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 much smaller number of blanket-geometry sands represent intracratonic shelf systems.

Table 4. A classification of clastic depositional systems.

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

Continental and intracratonic shelf systems
Continental and intracratonic slope and basinal systems

CHARACTERISTICS OF SELECTED BLANKET-GEOMETRY TIGHT GAS SANDS

Basic data on selected tight gas sands are presented in this section. Data tables were prepared for stratigraphic units of possible interest for future study when adequate information could be gathered. The general geographic order in which these individual summaries are presented is from east to west across the United States, and a summary of depositional systems has been included for each major unit. Within each basin stratigraphic units are arranged as they are encountered by the drill, from youngest to oldest.

Oriskany Sandstone, Appalachian Basin

Introduction

The Oriskany Sandstone, also termed the "Ridgeley Sandstone," was deposited during the Deerpark Stage of the Lower Devonian in the central Appalachian Basin. The regional stratigraphic relationships of the Oriskany are illustrated on a southwest to northeast correlation diagram that approximates a line through the center of the basin, parallel to strike (fig. 2), and on a west to east correlation diagram (fig. 3) that approximates a line through basin center, perpendicular to strike.

Throughout most of its extent, the Oriskany is a fossiliferous, marine quartzarenite. It is usually calcite cemented, locally quartz cemented, and is sometimes conglomeratic in its eastern facies. It has a distinctive megascopic fauna that, along with the calcite cement, tends to leach away in outcrop to produce a friable, biomoldic sandstone. This is not the case, however, in the subsurface, where it is usually tightly cemented.

No applications have been filed for designation of any part of the Oriskany as a tight gas formation, although there is operator interest in doing so (D. Patchen, personal communication, 1982). There exists significant production from the Oriskany Sandstone, approximately 40 percent of which is from tight areas and the balance from non-tight areas. Overall, more than 90 percent of the Oriskany within the Appalachian Basin is estimated to be tight, including interfield areas between conventional reservoirs. This survey of the Oriskany Sandstone was prepared by Richard J. Diecchio under the direction of Douglas G. Patchen, Chief, Fossil Fuels Division, West Virginia Geological and Economic Survey.

Structure

The structural configuration of the top of the Oriskany in the subsurface of the Appalachian plateau has been shown using a generalized 1,000-ft contour interval (fig. 4). This large a contour interval is not adequate to delineate all the major fold axes, which have been delineated in additional detail, along with the major structural provinces that will be utilized in subdividing Oriskany producing trends (fig. 5).

The Oriskany trend falls within four major structural provinces. The Eastern Overthrust Belt is located between the Blue Ridge Front and the Allegheny Front and is characterized by intensely folded and thrust-faulted strata. The High Plateau Province extends westward to the western limit of folds that are more numerous and have more structural relief than in areas further west (this is shown in a general sense in figure 4). The Low Plateau Province extends westward to the western limit of any pronounced folding. This boundary is not apparent on any of the maps in this survey but is based on reported structural complexity. The Burning Springs anticline is the primary structural feature used to delineate this boundary. The western basin province is the area west of the plateaus and is characterized by very gentle folding and very little structural relief.

Stratigraphy

In many places, the Oriskany is bounded above and/or below by an unconformity (figs. 2 and 2), and 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.

In many places (figs. 2 and 3), the Oriskany is underlain by another sandstone unit (Wildcat Valley Sandstone of Tennessee; Rocky Gap Sandstone of southwestern Virginia; Bois Blanc Sandstone of Pennsylvania and New York), which has been mistaken for Oriskany. Occasionally, where the Oriskany is absent, an adjacent sandstone (for example, Bois Blanc) was referred to as Oriskany, and may have even produced "Oriskany" gas. Figure 6 shows the limit of sandstones that are adjacent to the Oriskany horizon. Because these sandstones have often been mis-identified in the subsurface, and since it is not always possible to differentiate between the Oriskany and the other sandstones, all of these sandstones will generally be referred to as Oriskany for the purposes of this survey.

Figure 7 shows the thickness and lithologic nature of all strata of Deerpark Age. This interval is, in places, composed of units other than the Oriskany and includes the Helderberg Limestone and the Shriver Chert in Pennsylvania. In eastern New York the Oriskany changes facies into the Glenerie Limestone. Note that the zero Deerpark isopach on figure 7 does not coincide with the Oriskany pinch-out of figure 6. This is because the information on figure 7 was simplified, but without change, from a map by Oliver and others (1971). The pinch-out shown on all other maps is based on data more recent than that of Oliver and others (1971).

Distribution of Oriskany Production

All Oriskany fields are shown on figure 8, along with the pinch-out of the Oriskany and the structural province boundaries. The pinch-out is important because the fields that have well-developed intergranular porosity occur near pinch-outs and are usually stratigraphic traps at updip porosity-permeability barriers. Fracture porosity is also important in the accumulation of gas in the Oriskany. 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 comprehensive review of low-permeability areas was available in the form of an operator application, data were selected from individual field areas to characterize each of four structural provinces. These fields in the context of their corresponding provinces are described in tables 5 through 12.

The first of these fields, the Elk-Poca (Sissonville) Field (figs. 9 and 10), was chosen as typical of the western basin province because it is the best developed and largest field and because the intergranular porosity and stratigraphic trap are characteristic of fields near the western pinch-out.

The most productive fields in the low plateau province occur near the Oriskany pinch-out in Pennsylvania and New York. The best-documented field in this area is the Elk Run Pool, which may actually be in the High Plateau Province, but is considered as good an example of the fields at this pinch-out as any in the Low Plateau (fig. 11). These pinch-out fields characteristically have intergranular porosity. The other fields that do not occur at the pinch-out in the Low Plateau have characteristics that are not similar to those of the Elk Run Pool. There is only minor production from the Oriskany in this area, and of the fields that do produce, much of the production is actually from the overlying Huntersville Chert. Note that the generally less productive area in the southern portion of the Low Plateau is the only area that is overlain by strata that are predominantly chert.

The Glady Field was chosen as a good representative of High Plateau fields (fig. 12). Fields in this province are characterized by structural traps and fracture porosity. Within this province, however, some fields occur near the pinch-out in central Pennsylvania. These fields have characteristics similar to the Elk Run Pool.

The Lost River Field was chosen as a representative of the Eastern Overthrust Belt, where fields are characteristically along structural highs and have mainly fracture porosity (fig. 13).

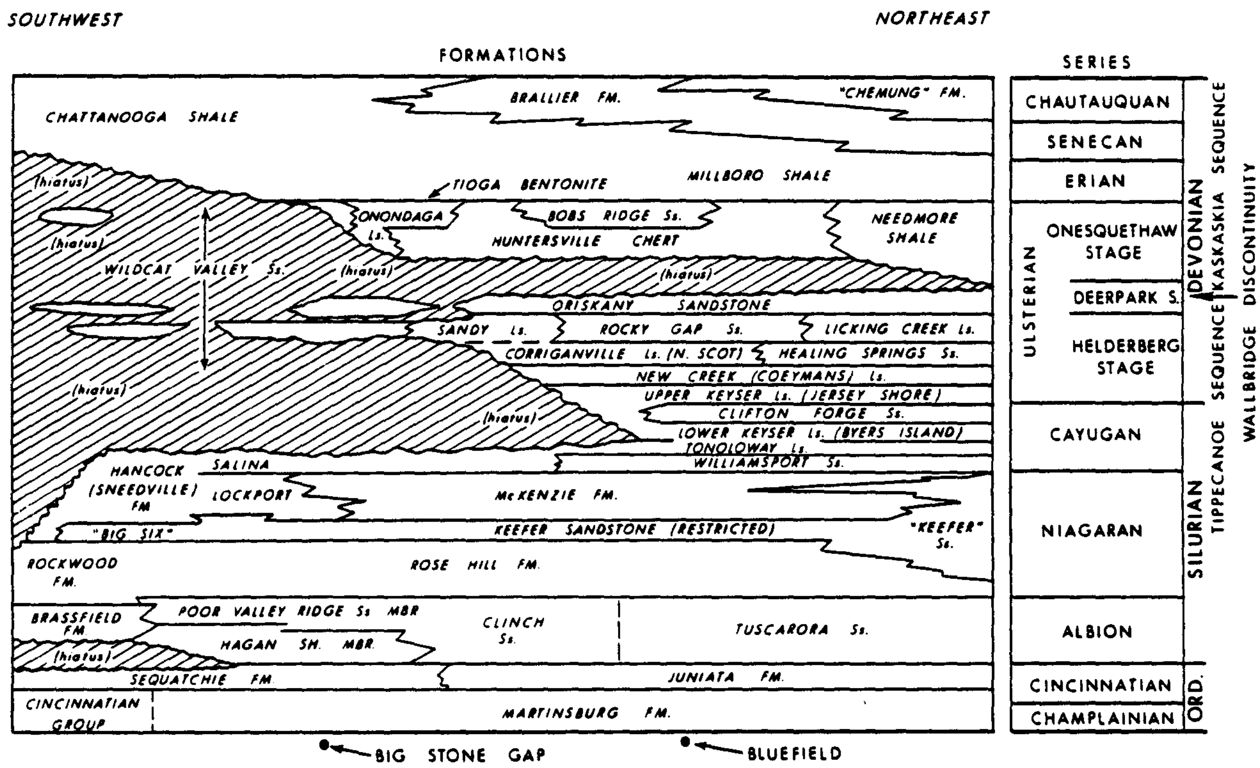

Figure 2. Southwest to northeast correlation diagram for the Appalachian Basin (from Diecchio, 1982a).

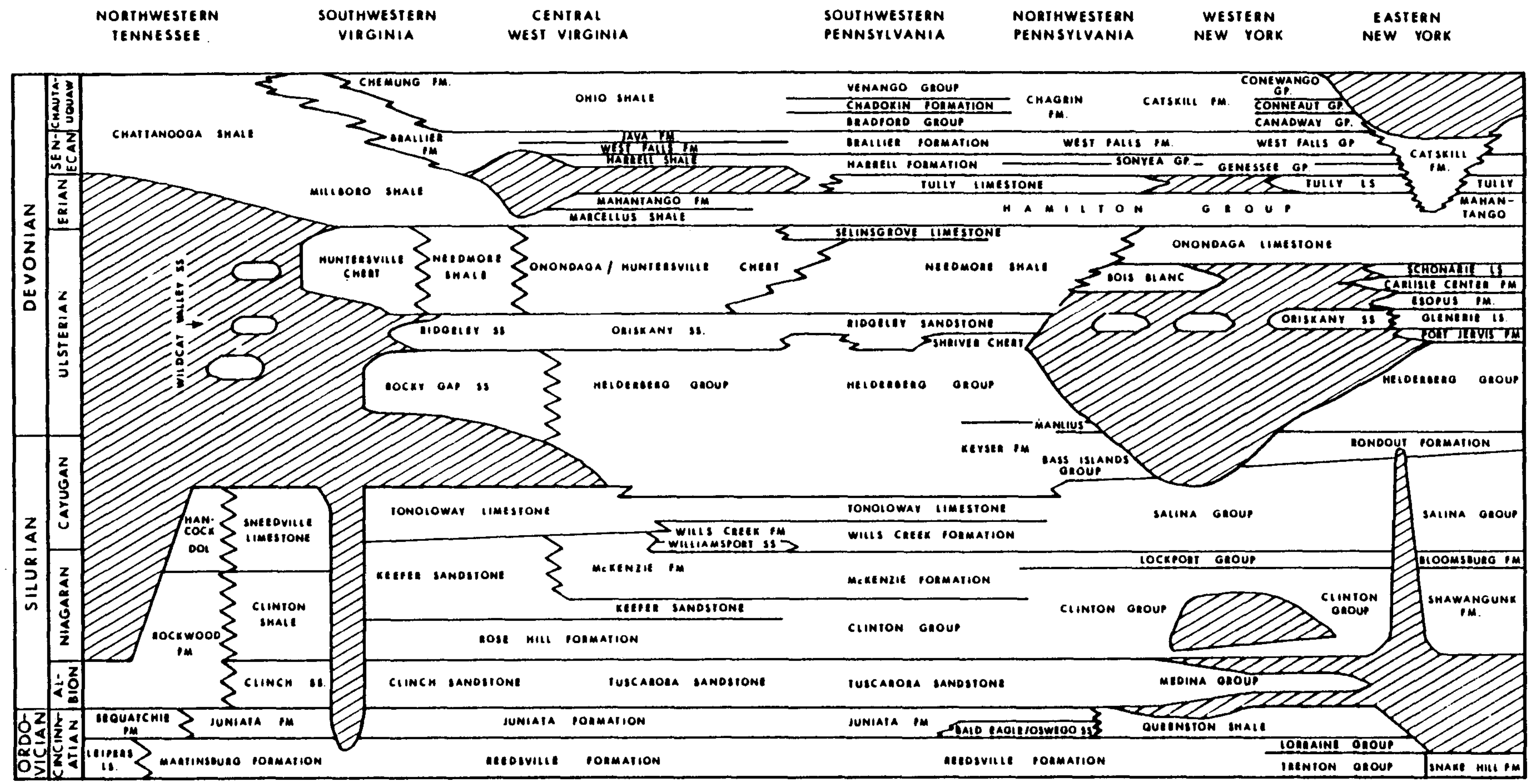

Figure 3. West to east correlation diagram for the Appalachian Basin (from Diecchio, 1982a).

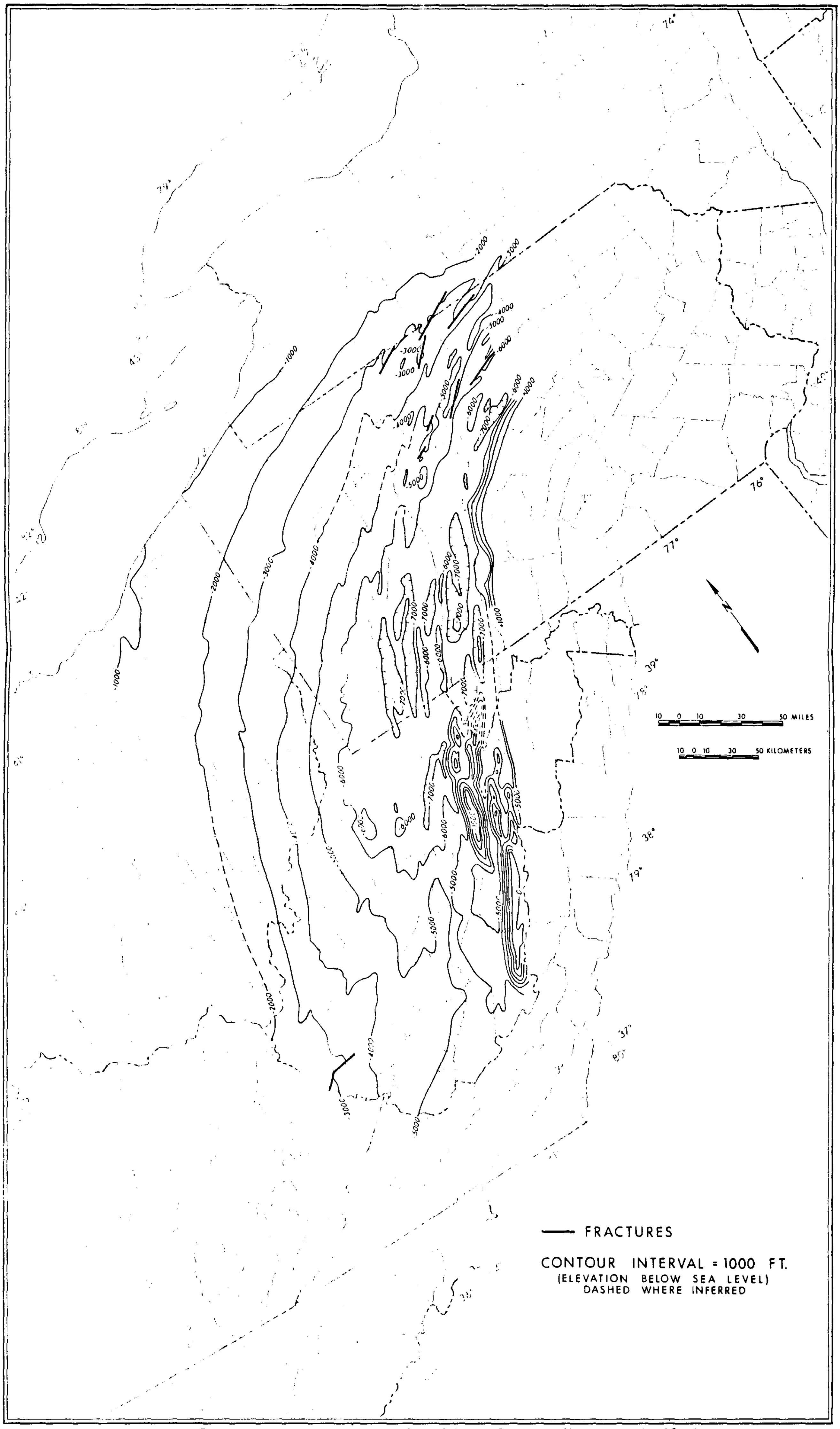

Figure 4. Structure contour map on the top of the Oriskany Sandstone (from Diecchio, 1982a).

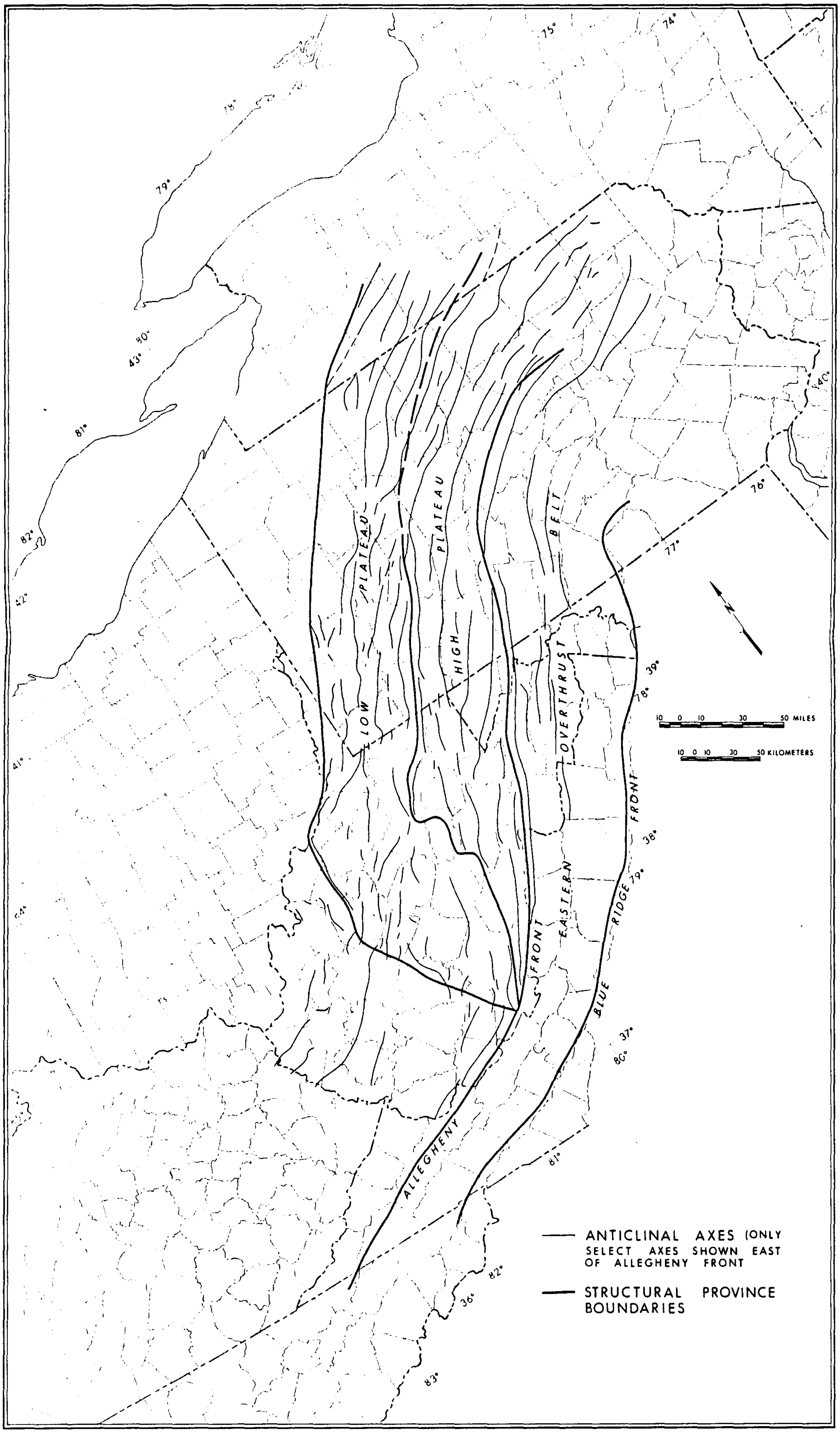

Figure 5. Structural provinces of the Appalachian Basin (from Diecchio, 1982a).

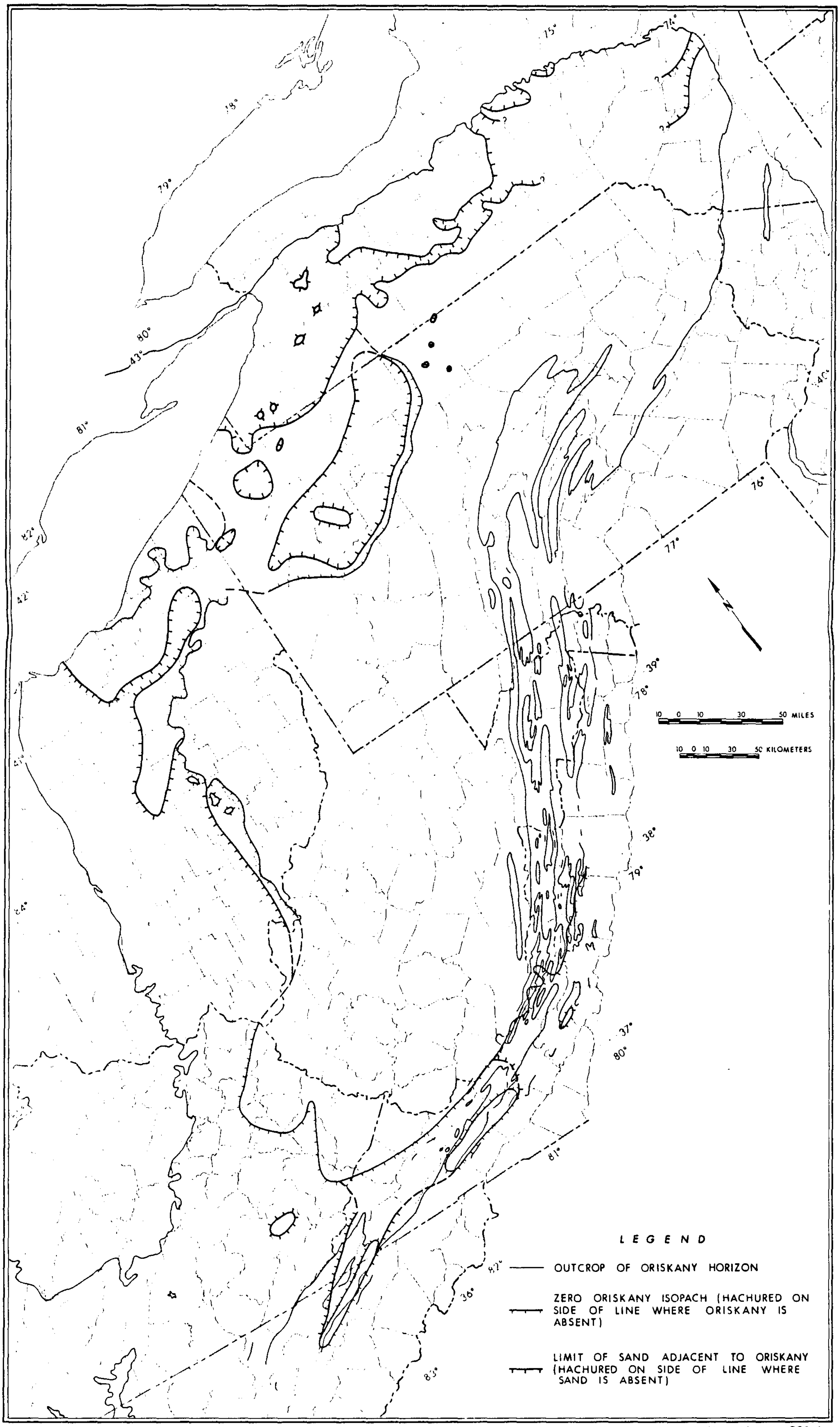

Figure 6. Areas of outcrop and extent of the Oriskany Sandstone in the subsurface of the Appalachian Basin (from Diecchio, 1982a).

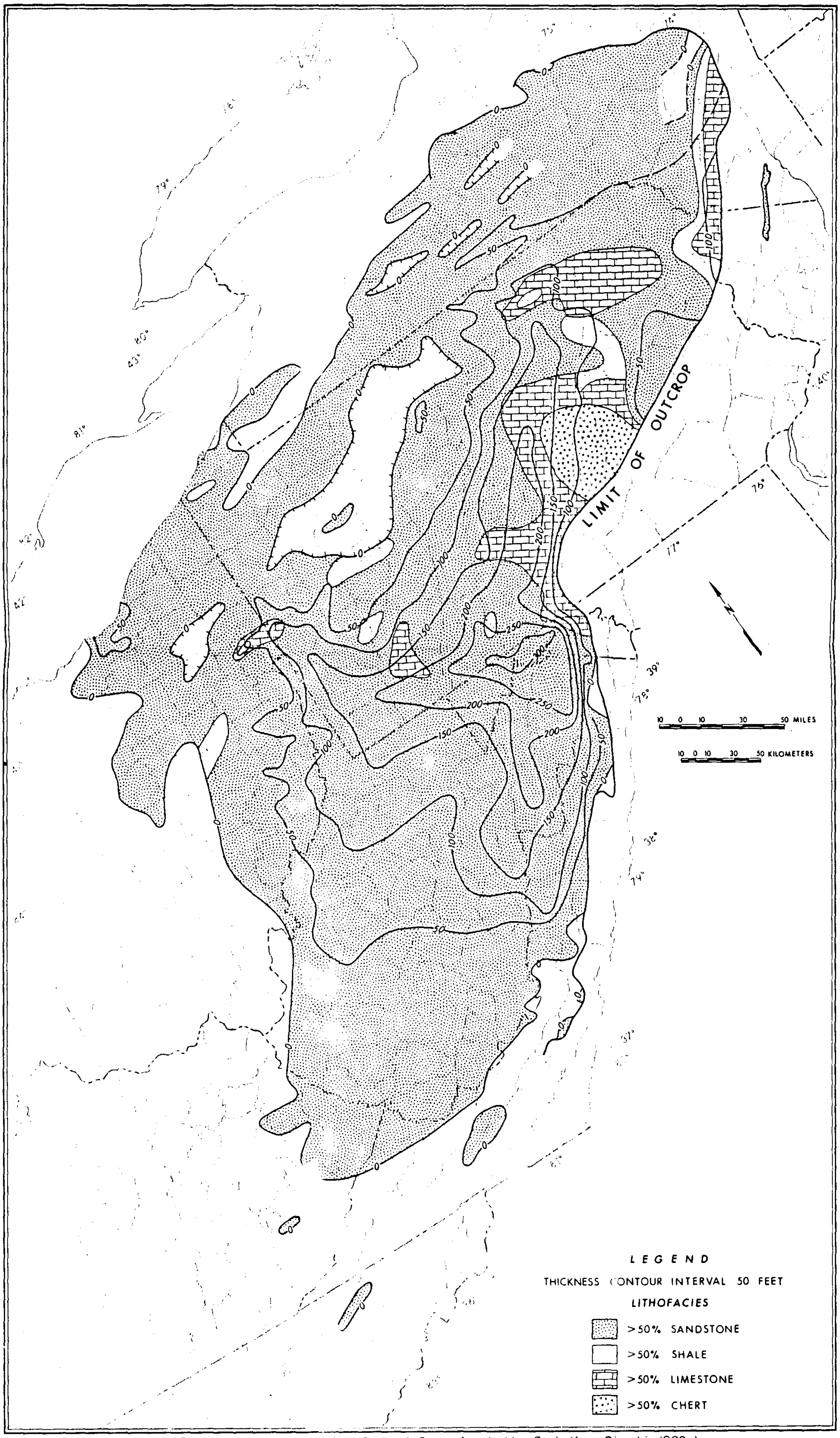

Figure 7 Isopach and lithology of the Deerpark Stage, Appalachian Basin (from Diecchio, 1982a).

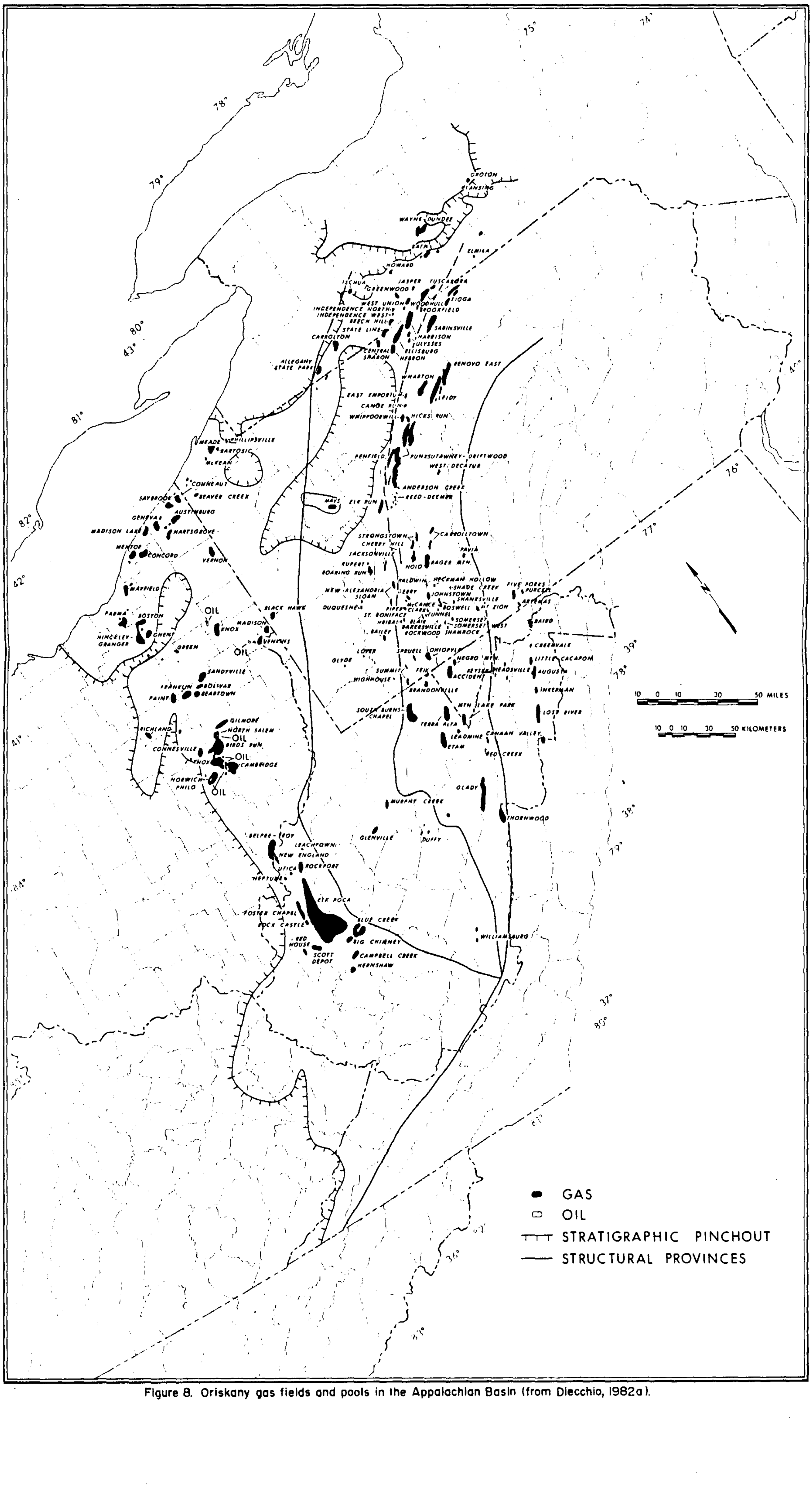

Figure 8. Oriskany gas fields and pools in the Appalachian Basin (from Diecchio, 1982a).

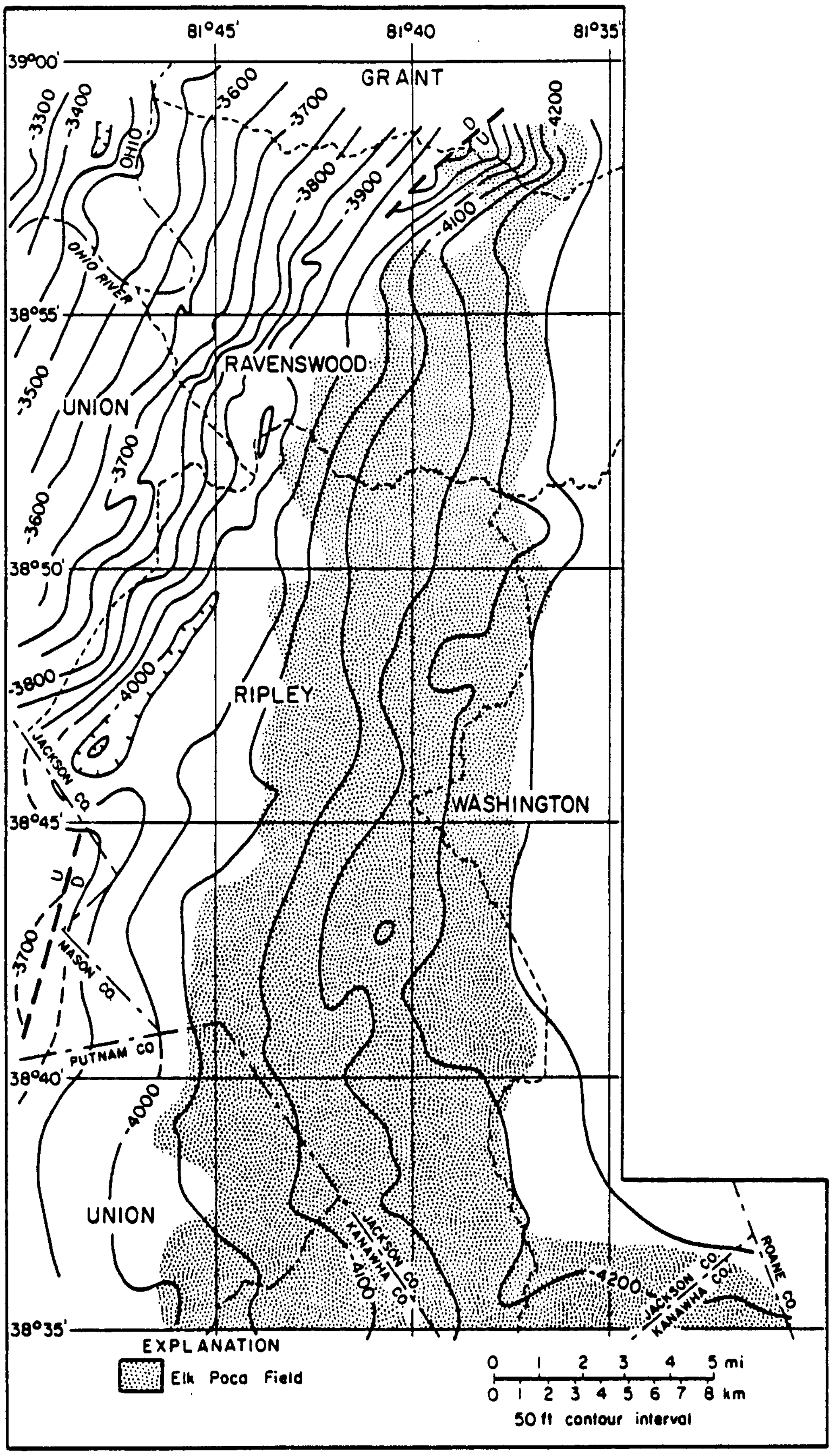

Figure 9. Elk-Poca Field, North Sissonville Area, West Virginia, contoured on the Onondaga Limestone (from Diecchio, 1982a).

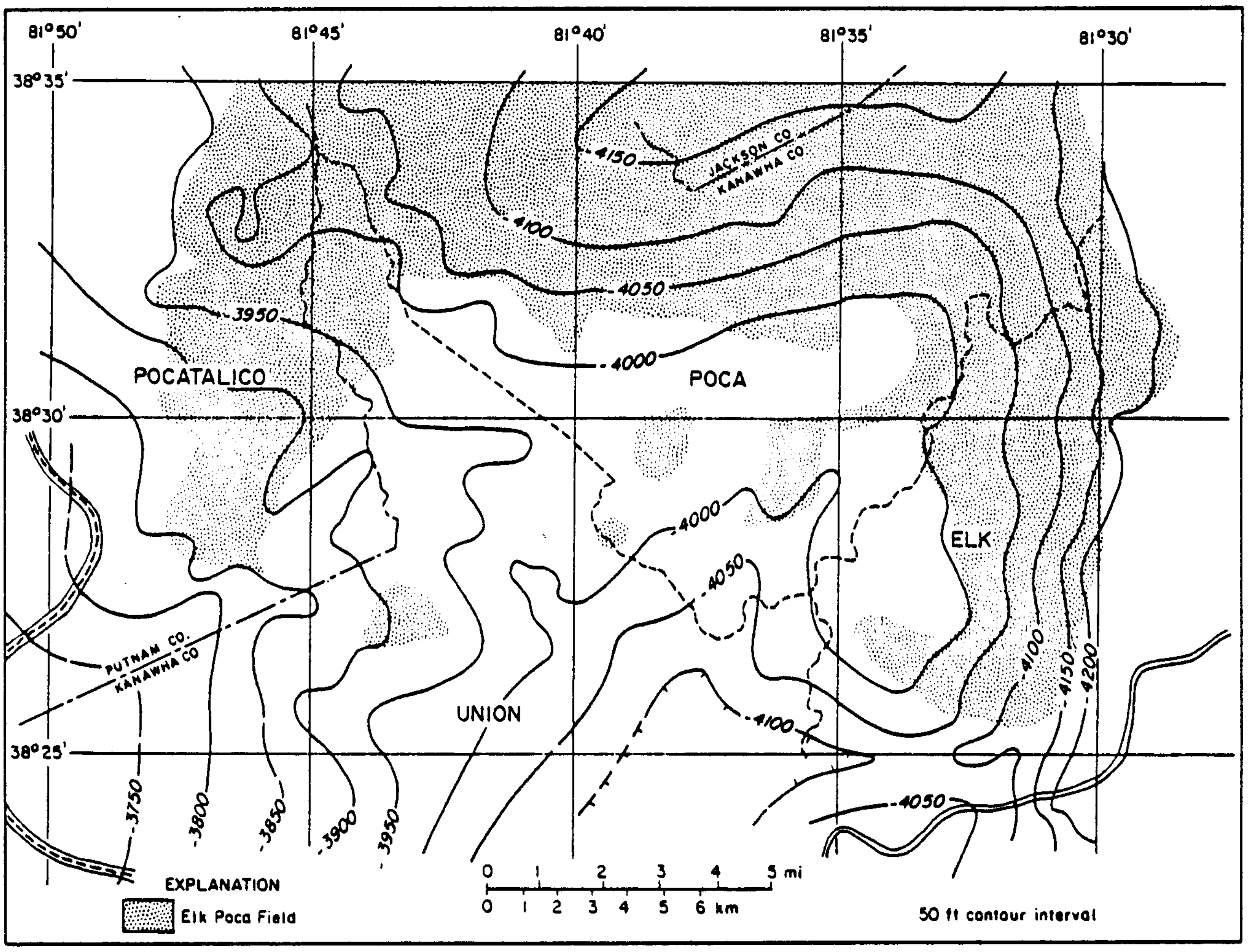

Figure 10. Elk-Poca Field, South Sissonville Area, West Virginia, contoured on the Onondaga Limestone (from Diecchio, 1982a).

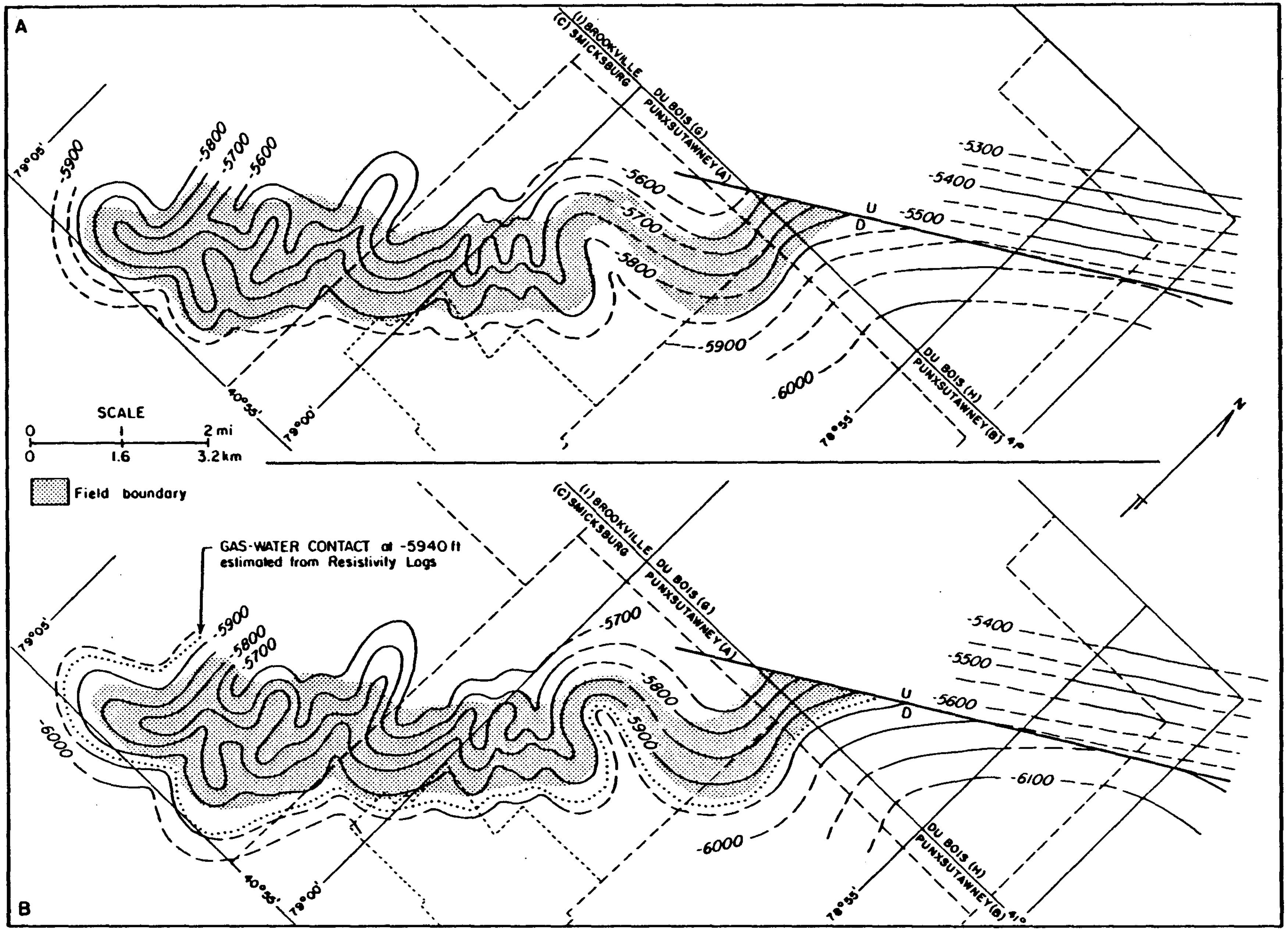

Figure 11. (A) Structure contours on top of the Onondaga Limestone, Elk Run Pool, Pennsylvania; (B) Structure contours on top of the Ridgeley Sandstone, Elk Run Pool, Pennsylvania (from Diecchio, 1982a).

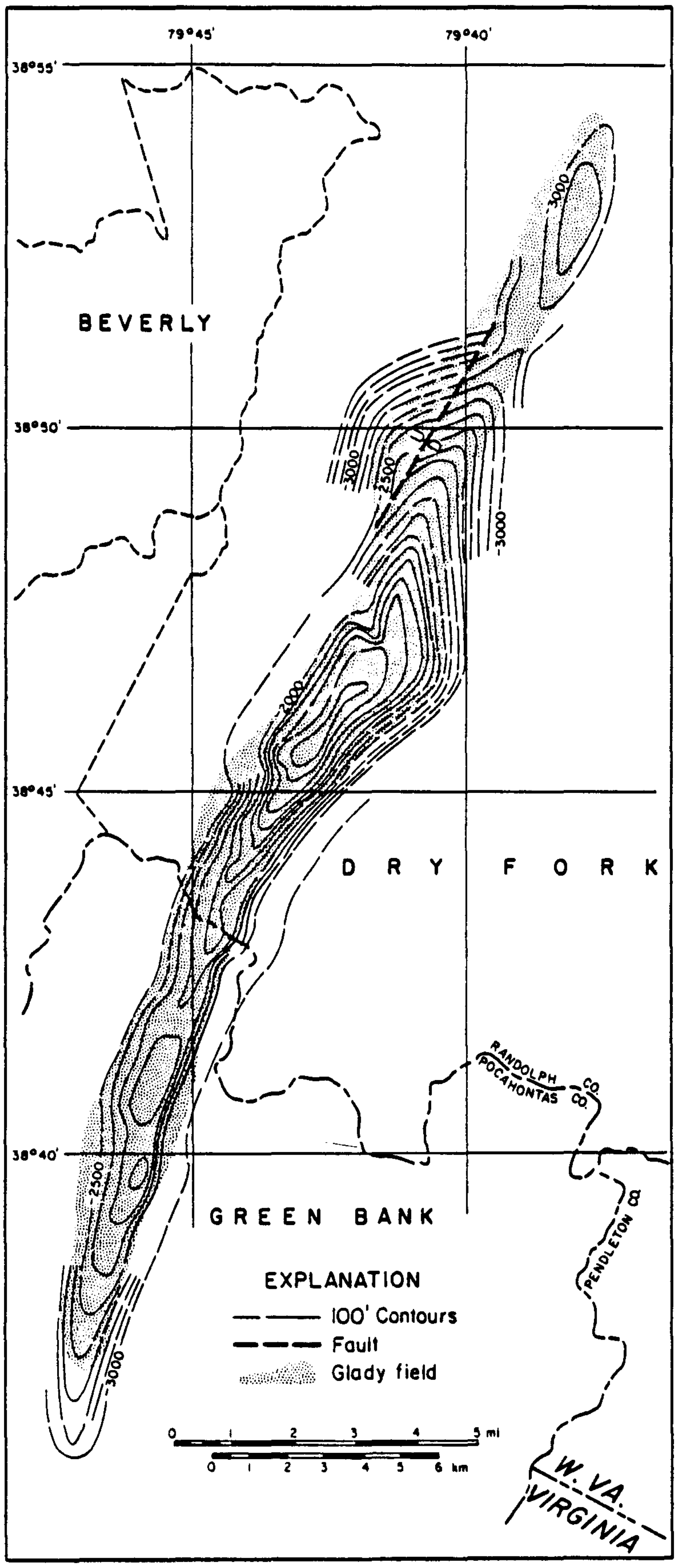

Figure 12. Structure contours on top of the Onondaga Limestone, Glady Field, West Virginia (from Diecchio, 1982a).

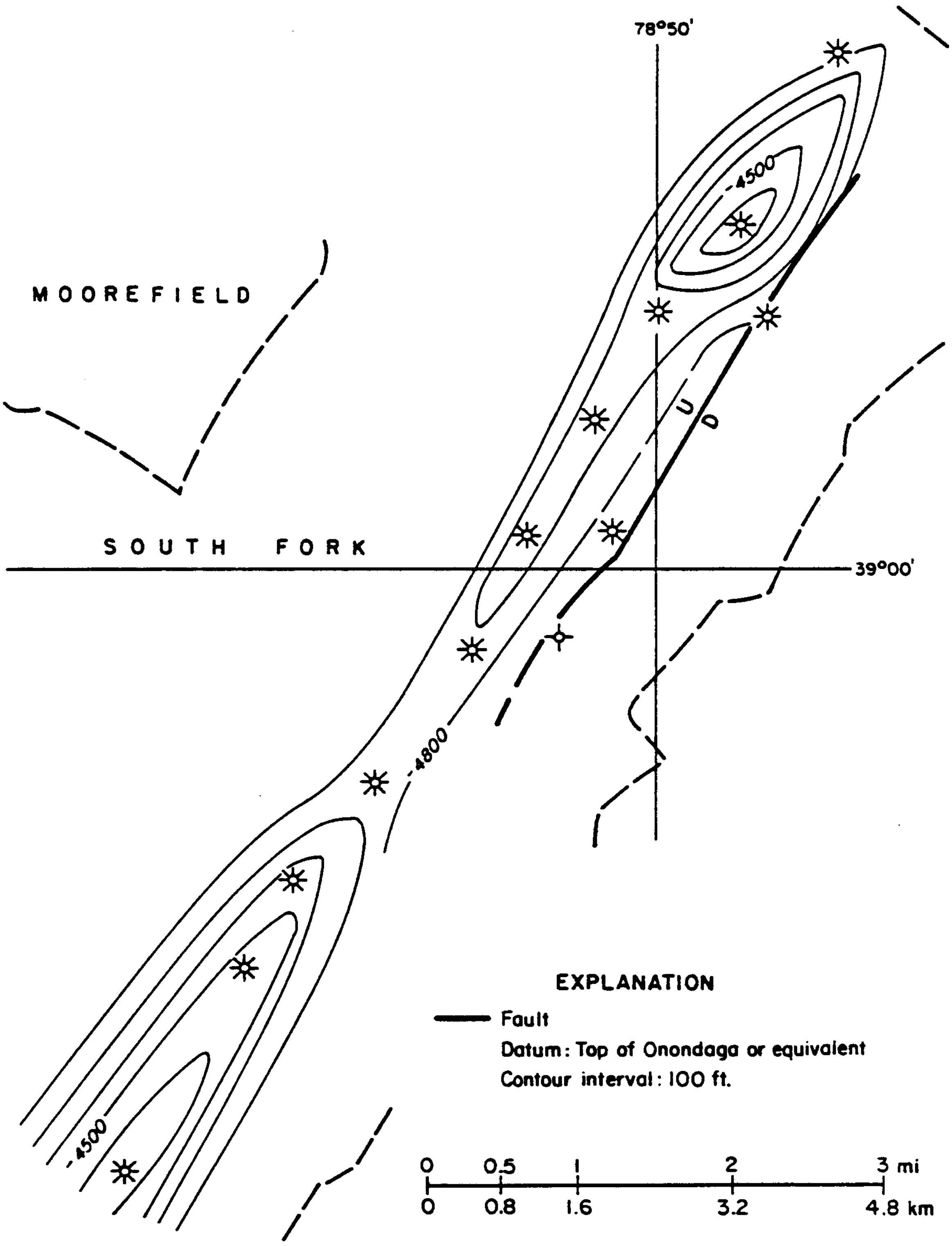

Figure 13. Structure contours on top of the Onondaga Limestone or equivalent, Lost River Field, Hardy County, West Virginia (from Diecchio, 1982a).

Table 5. 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 Sandstone, Deerpark Stage, Lower Devonian	40% of producing areas are tight. Overall, 90% of the basin area is tight including interfield areas between non-tight fields. Area 1 is the Western Basin Province. Area 2 is the Low Plateau Province.	1. Thickness ranges from 0-100 ft within this province, with the thickest units found in the northern panhandle of West Virginia. 2. Thickness ranges from 0 ft in northern Pennsylvania and New York to more than 200 ft in southwestern Pennsylvania.	1. Depth ranges from 1,600 ft in northern Ohio to over 5,000 ft in West Virginia. In the Elk-Poca Field, depth ranges from 4,900-5,300 ft. 2. Depth ranges from less than 1,700 ft in the northern portions of the province, to greater than 8,000 ft in southwestern Pennsylvania and adjacent West Virginia. At the southern limit of the province, it becomes somewhat shallower (6,000 ft).	1.054 Tcf estimated for 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 that is dominated by gentle folding. Faulting is rare. The western boundary of the province is bounded by the Burning Springs anticline and the Western Basin Province. The High Plateau Province bounds the eastern margin.	1. 1.1-1.8°F/100 ft. 2. 0.9-2.0°F/100 ft.	No data.	Past deformation indicates moderate to mild compression in the Low Plateau Province, weak compression in the Western Basin Province.

Table 6. 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, sub-angular to well rounded sandstone. 2. Very fine to medium grained sub-rounded, poorly sorted sandstone. Sporadically coarse grained.	Sand grains are composed of quartz; however, many calcareous fossils are present within the unit.	Primarily cemented by calcite, locally silica-cemented (syntaxial quartz overgrowths and pressure solution). Minor secondary clay mineralization is present.

Typical Reservoir Dimensions	Pressure/Temperature of Reservoir	Natural Fracturing	Data Availability (logs, cores, tests, etc.)
1. Ranges from 0-60 ft in Elk-Poca Field, averages 40 ft. 2. Ranges from 0-24 ft in the Elk Run Pool. Other fields within this province typically have a gross perforated interval that ranges from 0-12 ft. The net pay volume within Elk Run pool is 56,700 acre-feet.	1. Average reservoir temperature = 125^{o}F. Average reservoir pressure = 1,940 psi. 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, however is poorly developed. 2. Occasionally present, and when present, is 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; also at the Pennsylvania State Geological Survey office in Pittsburgh, Pennsylvania.

Table 7. Oriskany Sandstone, Western Basin and Low Plateau Provinces, Appalachian Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir Parameters

1. Intergranular porosity ranges from 6-22%, average = 15%. Permeability ranges from 0.04-78.5 md, average = 25.5 md.

2. Maximum porosity = 20%, average = 7.75%. Based on two core samples, permeabilities of 6.1 and 15.7 md were measured.

Net Pay Thickness

1. In Elk-Poca Field, net pay ranges from 10-20 ft.

2. In Elk Run Pool, net pay thickness averages 9 ft.

Production Rates

Pre-Stimulation

1. Based on an unknown number of wells, pre-stimulation flow rates ranged from 21-5,955 Mcfd, average = 750 Mcfd. For naturally produced wells, rates ranged from 100-17,000 Mcfd, average = 5,235 Mcfd.

2. For naturally produced wells, average = 4,700 Mcfd.

Post-Stimulation

1. Based on an unknown number of wells, post-stimulation flow rates (for wells after 1959) range from 100-11,800 Mcfd, average = 1,485 Mcfd.

2. Fractured wells produced at an average flow rate = 7,860 Mcfd.

Decline Rates

No data.

Formation Fluids

1. Small amounts of liquid hydrocarbons were produced initially from the Elk-Poca Field discovery well; however, it soon produced only gas. All other wells produce only gas.

2. No liquid hydrocarbons observed.

Water Saturation

1. No data.

2. In low porosity areas, water saturation = 55%. Where there is higher porosity, water saturation is generally less, ranging from 10-25%.

Well Stimulation Techniques

Prior to 1959 nitroglycerine shooting was the predominant stimulation method; however, since 1959, hydraulic fracturing is the preferred method. One operator uses 500 gal of 15% HCl and 60,000 lb of 20/40 mesh sand.

Success Ratio

1. Flow improvement ranges from 45-1,350% of pre-stimulation flow rates. The average improvement is 900%. The percentage of wells that were improved by stimulation techniques is not known.

2. For 16 wells which were hydraulically fractured, the average production increase was 360%.

Well Spacing

1. 160 acres.

2. Approximately 140 acres. There was no set spacing regulation within these provinces for development prior to 1973.

Comments

The depositional systems and facies represented by the Oriskany Sandstone are poorly documented.

Table 8. 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.	1. In the Elk-Poca Field (165,000 acres), there have been 1,035 attempted completions. Approximately 80-100 other fields exist, but they are generally much smaller, and the total attempted completions for these fields has not been compiled.	1. Success ratio for the Elk-Poca Field is approximately 85% (889/1035).	1. Drilling costs are currently $60/ft, therefore, total drilling costs range from $100,000-$300,000 per well.	1. Most gas is purchased by East Ohio Gas Co., Columbia Gas Transmission Co., and Consolidated Gas Corp. Pipelines are in place.	1. Moderate to low.
2. Applications are being prepared for areas in West Virginia and possibly Pennsylvania.	2. In the 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.	2. Success ratio for the representative Elk Run Pool is 94% (44/47).	2. Based on a drilling cost of $60/ft, total drilling costs range from $100,000-$500,000 per well.	2. Most gas is purchased by Peoples Natural Gas Co., Columbia Gas Transmission Co., and Consolidated Gas Supply Corp. Pipelines are in place.	2. Low to moderate.

OPERATING CONDITIONS

Physiography	Climatic Conditions	Accessibility
In the Appalachian Highlands physiographic subdivision. Hills to the west with 300-500 ft of local relief, high hills to the east with 500-1,000 ft of local relief.	Mean annual precipitation of 40-48 inches, locally over 48 inches in central West Virginia. Moderate summers and winters, colder at higher elevations. Drilling may cease during winter months.	When existing roads do not give access to an area, new roads can be easily created. Permits are necessary. Generally no terrain restrictions.

EXTRAPOLATION POTENTIAL

	Comments
Difficult to assess because detail on depositional systems is lacking. Tends to be unique as an areally very 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 9. 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	40% of producing areas are tight. Overall 90% of the basin area is tight, including interfield areas between non-tight fields. Area 1 is the High Plateau Province. Area 2 is the Eastern Overthrust Belt.	1. Thickness varies from a maximum of over 300 ft at the eastern edge of the province to 100 ft in the northern area of the province. It thins to almost 0 at the southern edge of the province. 2. Thickness ranges from 0-300 ft, with the thickest accumulations occurring in western Maryland.	1. Depths generally range from 7,000-9,000 ft within the province; however, at the eastern boundary, the Oriskany abruptly shallows to 3,000 ft. 2. Depths range from 0 to greater than 12,000 ft due to thrust faulting. Generally, depths are almost always greater than 7,500 ft in this province.	No data for these two provinces.	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
1. The High Plateau Province is delineated from the Low Plateau Province to the west primarily by the much greater occurrence and degree of relief or folding. It lies to the west of the Eastern Overthrust Belt, and generally exhibits the highest elevation in the central Appalachians. It comprises the eastern portion of the foreland fold belt. 2. The Eastern Overthrust Belt coincides with the Appalachian Valley and Ridge Province. It is differentiated from the high plateau province by its intensely folded strata and 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. 1.1-1.8°F/100 ft. 2. 1.4-2.2°F/100 ft.	No data.	Past deformation indicates moderate compression in the High Plateau Province, strong compression in the Eastern Overthrust Belt.

Table 10. 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 fossil constituents are found in the sandstone.	Calcite is the primary cement in the Oriskany; however, secondary clays are present in minor amounts.
Typical Reservoir Dimensions	**Pressure/Temperature of Reservoir**	**Natural Fracturing**	**Data Availability (logs, cores, tests, etc.)**
1. For the Glady Field, average gross perforated interval = 150 ft. 2. For the Lost River Field, average reservoir thickness = 265 ft.	1. Average reservoir temperature = 167°F. Average reservoir pressure = 2,050 psi. 2. Average reservoir temperature = 132°F. Average reservoir pressure = 2,205 psi.	Is 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 also at the Pennsylvania State Geological Survey office in Pittsburgh, Pennsylvania.

Table 11. Oriskany Sandstone, High Plateau Province and Eastern Overthrust Belt, Appalachian 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. Not available for Glady Field. One core was taken in the field, and it is on file at the West Virginia Geological Survey. Since fracture porosity is generally necessary for gas production in this province, both intergranular porosity and permeability must be quite low. 2. Same as above, including one core from Lost River Field which is on file at the West Virginia Geological Survey.	1. Average = 150 ft. 2. Average = 265 ft.	1. For wells that were fractured, natural flow ranges from a show of gas - 4,225 Mcfd, average = 1,300 Mcfd. 2. For wells that were acidized, natural flows ranged from 75-16,200 Mcfd, average = 5,120 Mcfd.	1. Ranges from 94-25,500 Mcfd, average = 5,100 Mcfd. 2. Ranges from 1,500-44,000 Mcfd, average = 10,950 Mcfd.	No data.	1. No liquid hydrocarbon production reported. 2. No liquid hydrocarbon production reported.	No data for either province.

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 55-3,270%, average = 830%. 2. Acidizing improved production from 53-2,960%, average = 704%.	1. In the Glady Field, 440 acres. 2. In the Lost River Field, 540 acres. There was no set spacing regulation in these provinces for development prior to 1973.	The depositional systems and facies represented by the Oriskany Sandstone are poorly documented.

Table 12. 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 in West Virginia and possibly in Pennsylvania. 2. Not yet applied for.	1. A representative field for the province, Glady Field, has had 33 attempted completions in the Oriskany. There are approximately 50-60 fields in this province, varying from a few hundred to as much as 15,000 acres. 2. A representative field for this province, the Lost River Field, has had 13 attempted completions in the Oriskany. There are approximately a dozen such fields in the province, with each field covering less than 8,000 acres.	1. For Glady Field, the success ratio = 94% (31/33). Subsequent use of the field for storage has necessitated the drilling of 26 more wells. 2. For Lost River Field, the success ratio = 85% (11/13).	1. Based on a current cost of $60/ft, total drilling costs range from $420,000-$540,000. Increased costs are incurred along the eastern margin of the province due to terrain restrictions. 2. Due to inherent 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 $1,500,000 in this province.	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 Co.	1. Moderate to low. 2. High leasing and seismic activity, but low drilling activity.

OPERATING CONDITIONS			EXTRAPOLATION POTENTIAL	
Physiography	Climatic Conditions	Accessibility		Comments
1. In the Appalachian Highlands physiographic subdivision. Maximum relief is on the order of 3,000 ft, and it is most prominent on the eastern edge of this mature, highly dissected plateau province. 2. This area is a highly dissected fold and thrust belt, with maximum relief on the order of 3,000 ft.	Mean annual precipitation of 40-48 inches, locally over 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 problems may exist in the eastern High Plateau Province due to rough terrain.	Difficult to assess because detail on depositional systems is lacking. Tends to be unique as an areally very extensive sand of possible shoreline and shallow marine origin reworked by shallow marine transgression.	Drilling and completion services available for areas of Oriskany potential in the Appalachian Basin.

Tuscarora Sandstone, Appalachian Basin

Introduction

The Lower Silurian Tuscarora Sandstone is a blanket sandstone that is correlative with the Medina Group in western New York and northwestern Pennsylvania and with the informal "Clinton" sands of eastern Ohio. As such, it is of interest for tight gas production because of the well-established productive trends in the latter areas. No applications to designate the Tuscarora as a tight formation have been filed, and data on the unit are very limited as a consequence of little development outside of the "Clinton"-Medina trend (D. Patchen, personal communication, 1982). It is appropriate to include the Tuscarora in this survey because it is a well-defined, widespread unit with tight gas potential; however, development of a full set of data tables is not possible. Alternatively, this narrative summary was prepared by Richard J. Diecchio under the direction of Douglas G. Patchen, Chief, Fossil Fuels Division, West Virginia Geological and Economic Survey.

Stratigraphy

The more sandy facies of the Tuscarora, which is the prominent ridge-former throughout the Valley and Ridge Province, is referred to in outcrop as the Tuscarora Sandstone 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 portion 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 becomes more calcareous and dolomitic and is called the Brassfield Formation. To the east, in the Massanutten synclinorium of northern Virginia, the Tuscarora merges with the overlying Middle Silurian sandstones, such as the Keefer, to form a single sandstone unit of Lower and Middle Silurian age called the Massanutten Sandstone. A similar relationship exists in eastern Pennsylvania, northern New Jersey, and southeastern New York. In these areas, the Lower Silurian strata become conglomeratic and merge with younger sandstones, and this Lower and Middle Silurian conglomeratic sandstone is referred to as the Shawangunk Formation, or, along Green Pond Mountain in New Jersey, the Green Pond Conglomerate.

The Lower Silurian is divided into numerous 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, Manitoulin Dolomite, Cabot Head Shale, and Grimsby Sandstone. This terminology can be extended into northwestern Pennsylvania (Piotrowski, 1981). In Ohio, these same units (with minor modification) comprise the Cataract Group, which also includes the Thorold Sandstone at the top, all of which is Lower Silurian (Knight, 1969). In Ohio, eastern Kentucky, and western West Virginia, the Tuscarora and equivalent strata are informally called "Clinton sand" by the drillers. This name bears no relationship whatsoever to the Middle Silurian Clinton Formation or Clinton Group of New York, Pennsylvania, and West Virginia.

Thickness and Lithology

In general, Lower Silurian strata thicken and coarsen toward the east and southeast. Throughout most of the Valley and Ridge Province these strata are almost consistently composed of quartz arenite that is usually quartz cemented and sporadically conglomeratic. This facies coincides with the Tuscarora Sandstone (or Clinch Sandstone in southwestern Virginia and northeastern Tennessee). These strata become shalier and thinner westward (fig. 15), and eventually, in Ohio and Kentucky, grade into limestone and dolomite. The sandy facies termed "Tuscarora" in the central Appalachian Basin is the primary focus of this review.

The Tuscarora is typically a white to light-gray, fine- to coarse-grained quartz sandstone that is often conglomeratic (Patchen, 1969; Piotrowski, 1981). The Tuscarora is usually cemented by secondary quartz overgrowths, producing a very durable orthoquartzite that forms resistant ridges in outcrop. Shale interbeds occur in the Tuscarora and become much more common to the west.

Depositional Systems

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

Tuscarora Reservoirs

The Tuscarora 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 is dependent on a well-developed system of natural fractures. Heald and Andregg (1960) attribute the low porosity to the high degree of cementation by quartz overgrowths. High porosity was found to coincide with areas in which clay coatings on quartz grains prohibited syntaxial overgrowths, or areas of high gas content (Heald and Andregg, 1960). Permeability ranges from less than 0.1 to 12.2 millidarcy (md) (Patchen, 1969) and presumably would be substantially less under in situ conditions.

Structural entrapment is responsible for Tuscarora reservoirs, which are usually along anticlinal highs. In West Virginia, initial potential flow (IPF) values for commercial wells range from 2 to 26,400 Mcfd (average 3,650 Mcfd). Wells that are known to have been completed naturally (10 wells) had initial production rates of 2 to 22,000 Mcfd (average 4,415 Mcfd). Fractured wells (8 wells) had IPF's of 47 to 4,004 Mcfd (average 1,043 Mcfd). Three wells were shot, and had IPF's of 29 to 76 Mcfd (average 46 Mcfd) after shooting. One well (Tucker 38, West Virginia) was acidized, and had an IPF of 26,400 Mcfd, the highest initial production rate of any of the Tuscarora wells (Cardwell, 1977). It should be recognized that initial potential flows are frequently much higher than stabilized flow rates.

Gas produced from the Tuscarora Sandstone typically has a low Btu rating, ranging from 352 to 990 Btu per cubic foot (average 800 Btu/cu ft) (Patchen, 1969; Cardwell, 1977; Piotrowski, 1981). Tuscarora gas is typically high in nitrogen content, with nitrogen values 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 high CO_2 content, with CO_2 values as high as 83 percent. CO_2 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 (Monongalia, 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 Kanawha County, West Virginia, the range is from 6,300 to 6,700 ft in Indian Creek Field.

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

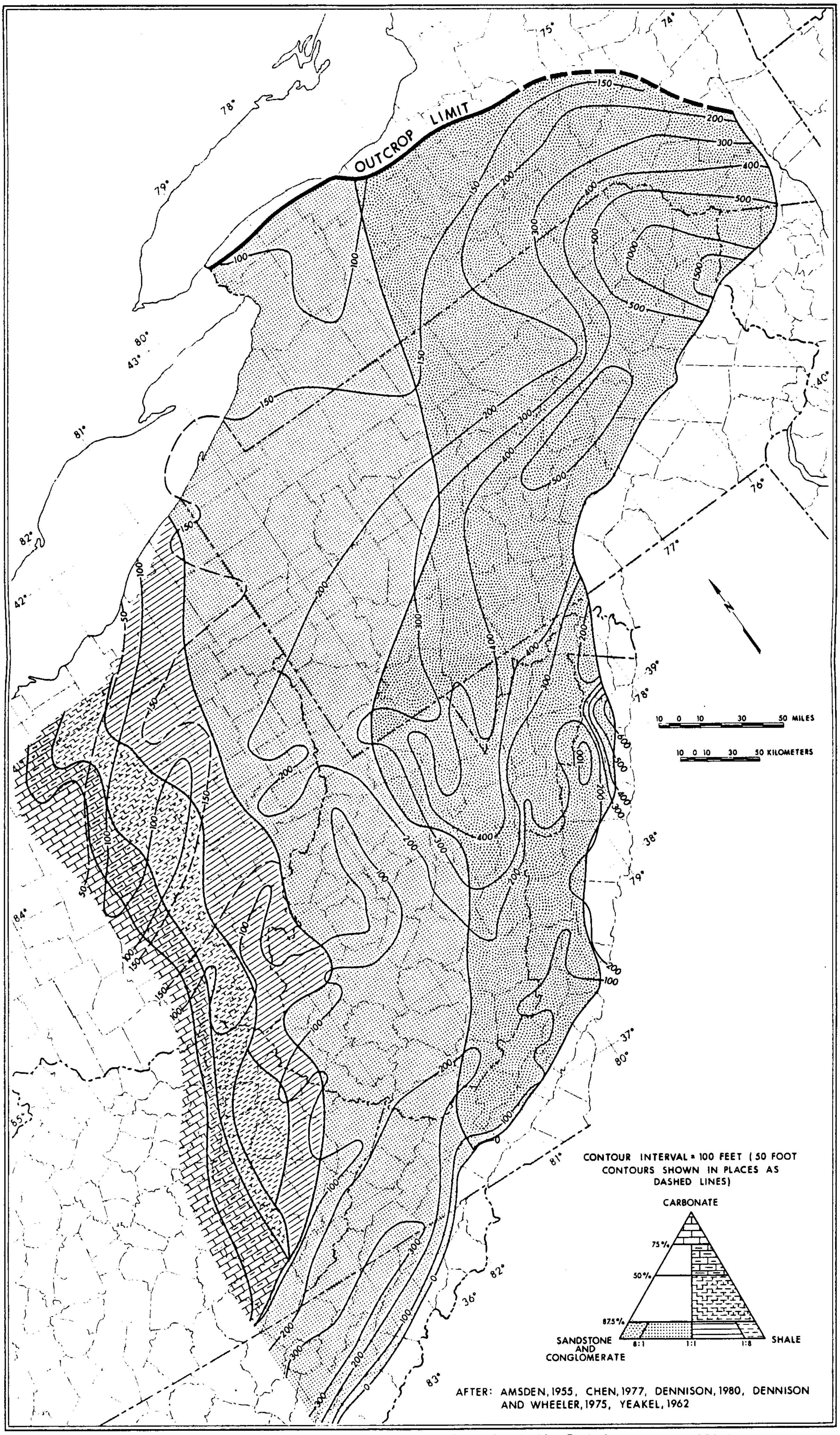

Figure 14. Isopach and lithofacies of the Lower Silurian in the Appalachian Basin (from Diecchio, 1982b).

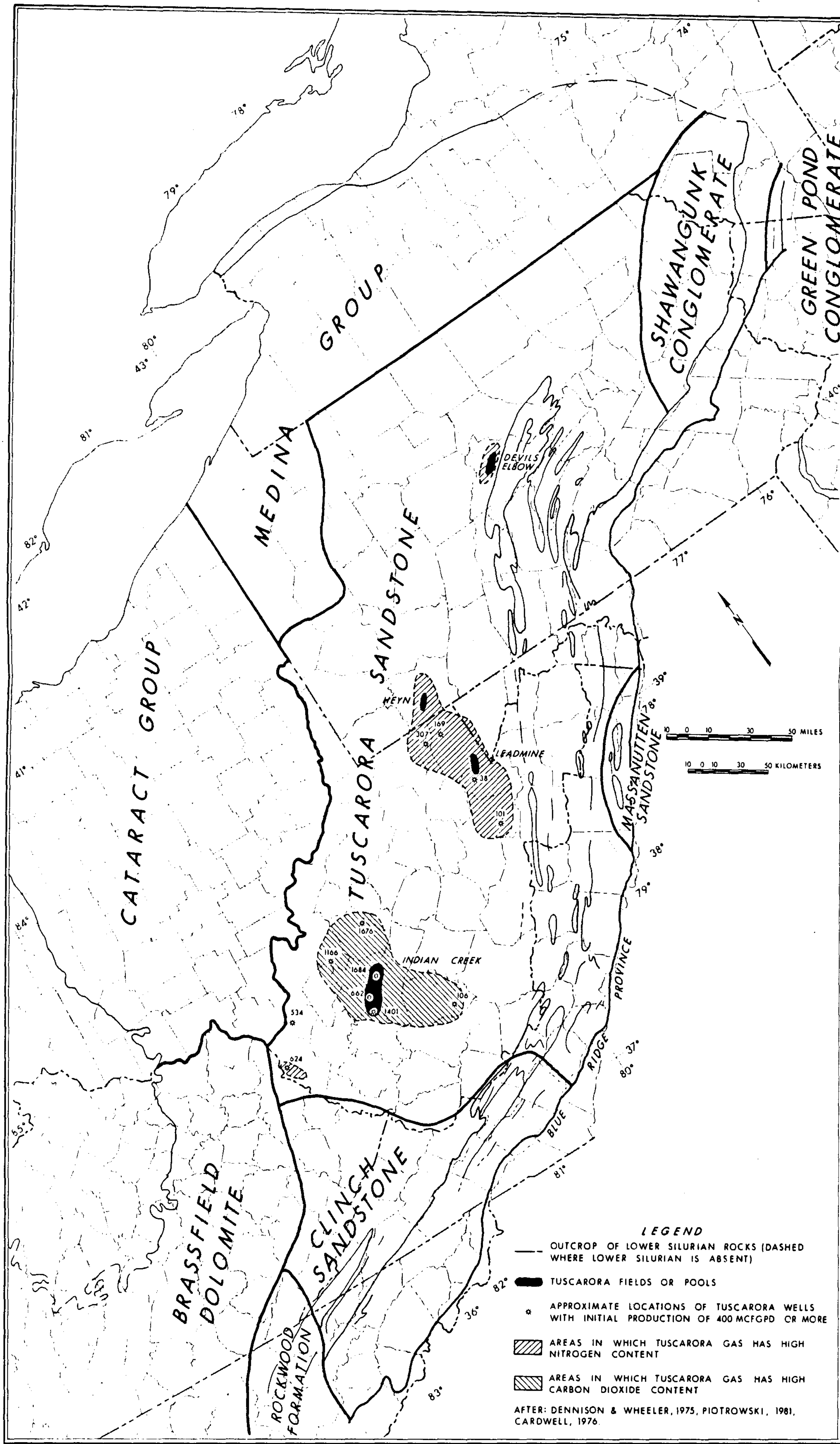

Figure 16. Extent and nomenclature of Lower Silurian strata in the Appalachian Basin (from Diecchio, 1982b).

Carter and Hartselle Sandstones, Black Warrior Basin

Introduction

The Carter and Hartselle Sandstones are members of the Upper Mississippian Parkwood Formation and Floyd Shale, respectively (fig. 17). The Carter is generally described as a fine- to medium-grained sandstone, in part argillaceous, and the Hartselle is a very fine to medium-grained sandstone with siltstone and shale interbeds. The Hartselle has been approved as a tight gas sand by the State Oil and Gas Board of Alabama (Docket 10-9-817-A, 1981), and FERC approval is pending. No application has been filed for the Carter Sandstone. The available data base for both units is only fair for the engineering parameters, but good for the geologic setting as a result of recent publications by Thomas and Mack (1982) and Mack and others (1981). Data tables have been prepared only for the Hartselle (tables 13-16).

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 and received a thick sequence of carbonate and clastic sediments, with clastics predominating with the start of the Upper Mississippian (Pike, 1968). The Hartselle 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 (fig. 17). The Carter and other sands of the Parkwood contribute approximately 90 percent of the total cumulative gas production in the basin (R. Peterson, personal communication, 1982). The Chester Series thickens from 800 ft in the outcrop area across northwest Alabama to approximately 2,100 ft toward the southwestern Black Warrior Basin.

Depositional Systems

Terrigenous clastic sediments of the Floyd and Parkwood Formations accumulated mostly in the rapidly subsiding part of the basin adjacent to the Ouachita source area (Horne and others, 1976). The Hartselle, however, is found on the much shallower East Warrior Platform. Thomas and Mack (1982) interpret 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. To the east the shelf and bar facies pinches out into a regional carbonate facies. Landward (southwestward) the barrier system pinches out into 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) suggest that the origin of the Hartselle and Parkwood clastics is to the southwest of the Black Warrior Basin in the Appalachian-Ouachita orogenic belt; however, Cleaves and Broussard (1980) suggest an alternative north or northwest source for the Hartselle.

Evidence for the origin of the Hartselle based on extensive outcrop studies is reasonably complete, but no subsurface data are presented by Thomas and Mack (1982) from which to judge the lateral continuity of the Hartselle on a regional basis. A generalized isopach of the Hartselle is available, showing a thick in the tight sand application area (fig. 18). The log character of a thin, upward-coarsening sequence overlain by a blocky sand unit shown on logs from Walker and Winston Counties is consistent with a barrier origin (figs. 19 and 20). Minor transgressions and decreases in the sand supply could account for the thin breaks within the thick sand package shown on the SP logs (fig. 20).

Sandstones of the Parkwood Formation were deposited by northeastward-prograding deltas and also reflect a sediment supply from the southwest (Thomas and Mack, 1982). The Parkwood, which is more immature than the Hartselle, is composed of litharenites to sublitharenites (Mack and others, 1981). The Carter Sandstone may represent barrier and bar sands within the Parkwood deltaic system (R. Peterson, personal communication, 1982). Other Parkwood sandstones are delta front or distributary sands, reflecting individual cycles of deltaic progradation in the Parkwood (Thomas, 1979).

The Carter as an Unconventional Gas Sand

Much of the conventional gas production in the Black Warrior Basin is derived from the Carter Sandstone. Gas production from the Carter is from the better developed sands, such as the offshore bar facies. Thinner sheet sands between the bars are likely to have more lateral continuity than the bar sands and, with an increase in content of fine clastics, would tend to form a blanket-geometry, low-permeability reservoir. Unfortunately, reservoir characteristics for interfield areas are unknown (R. Peterson, personal communication, 1982), but these areas may represent an important untested resource.

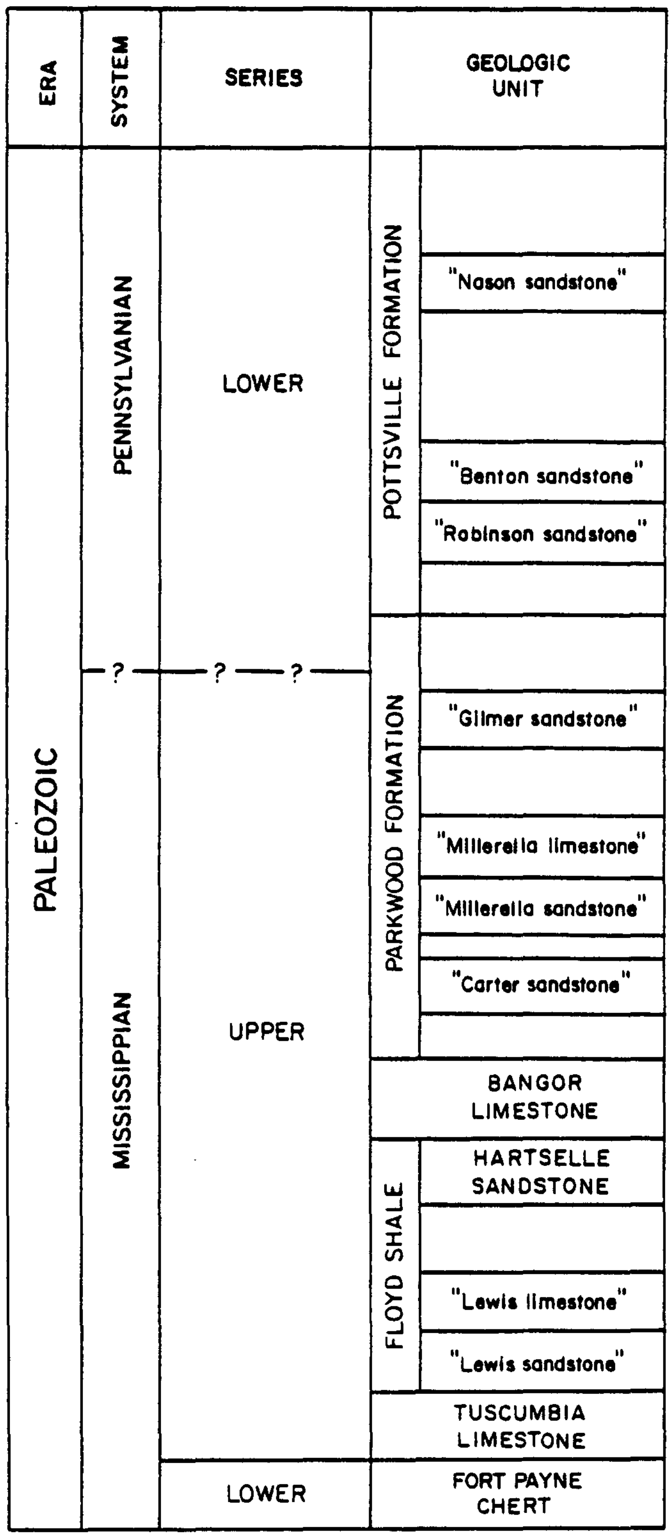

Figure 17. Generalized stratigraphic column of Mississippian and Pennsylvanian units in the oil and gas producing areas of the Black Warrior Basin, Alabama.

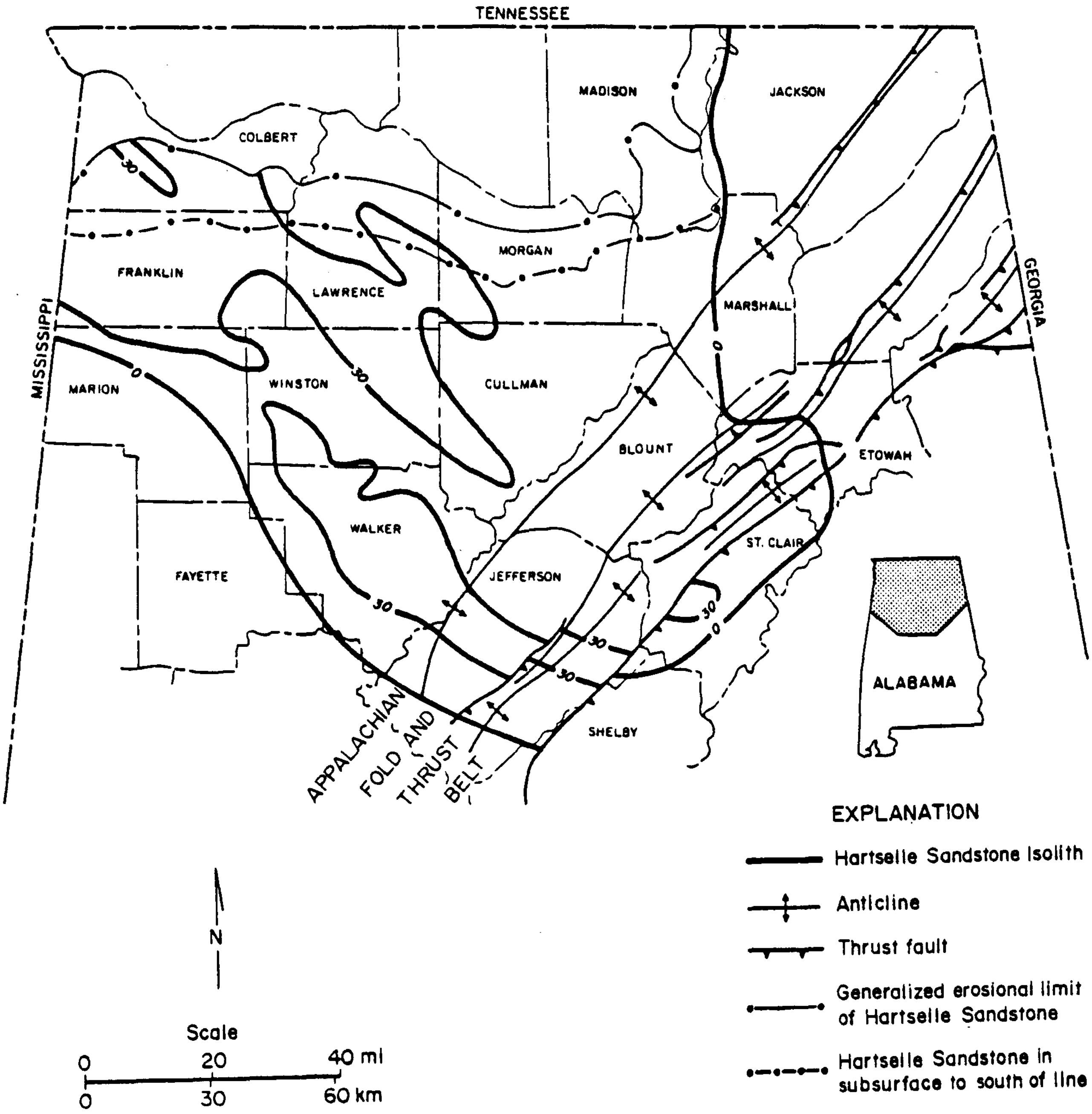

Figure 18. Generalized Hartselle Sandstone isolith in the Black Warrior Basin, Alabama (after Thomas and Mack, 1982).

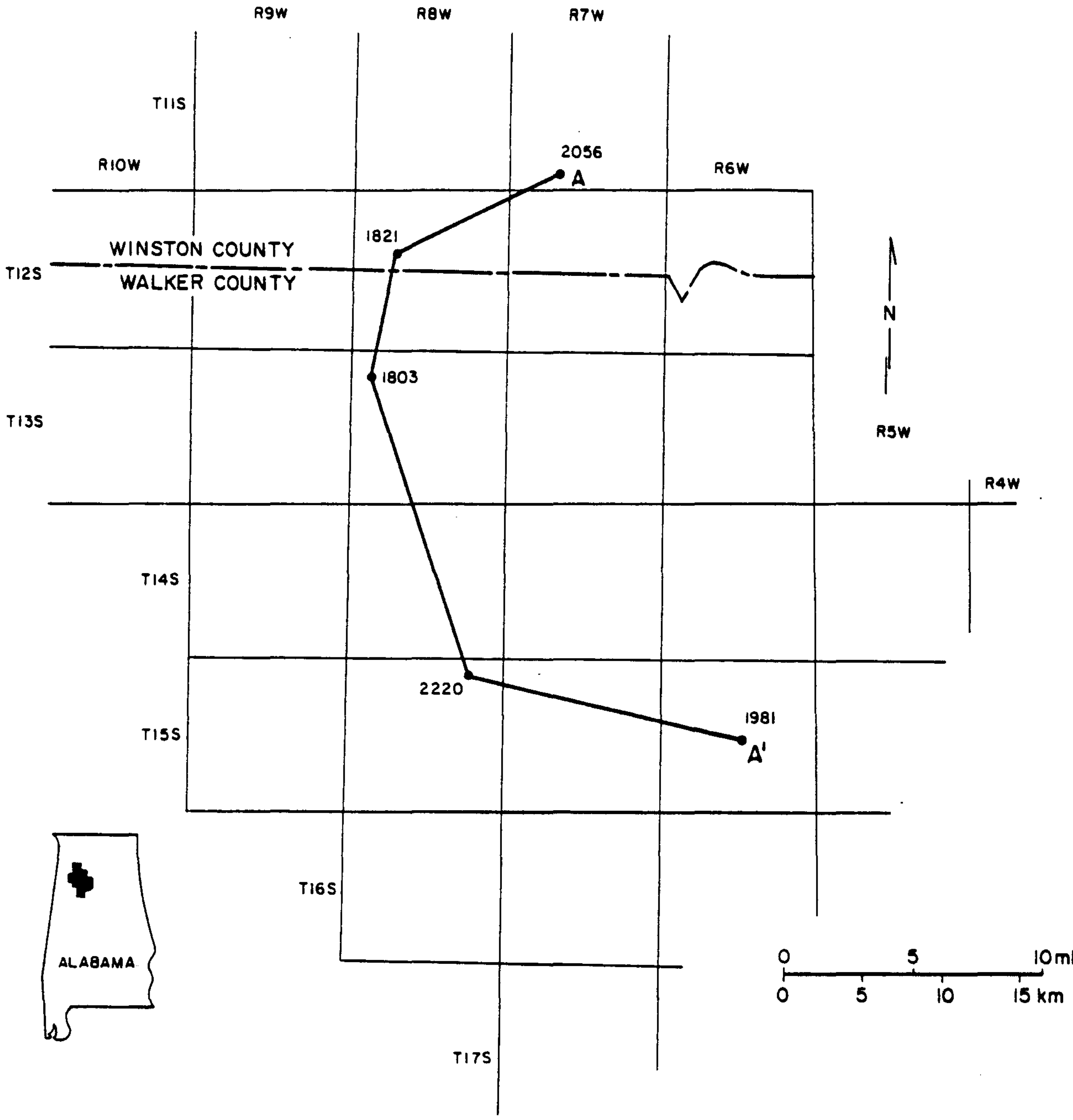

Figure 19. Index map for cross section A-A' through the Hartselle Sandstone, Black Warrior Basin, Alabama (after Alabama State Oil and Gas Board, 1981).

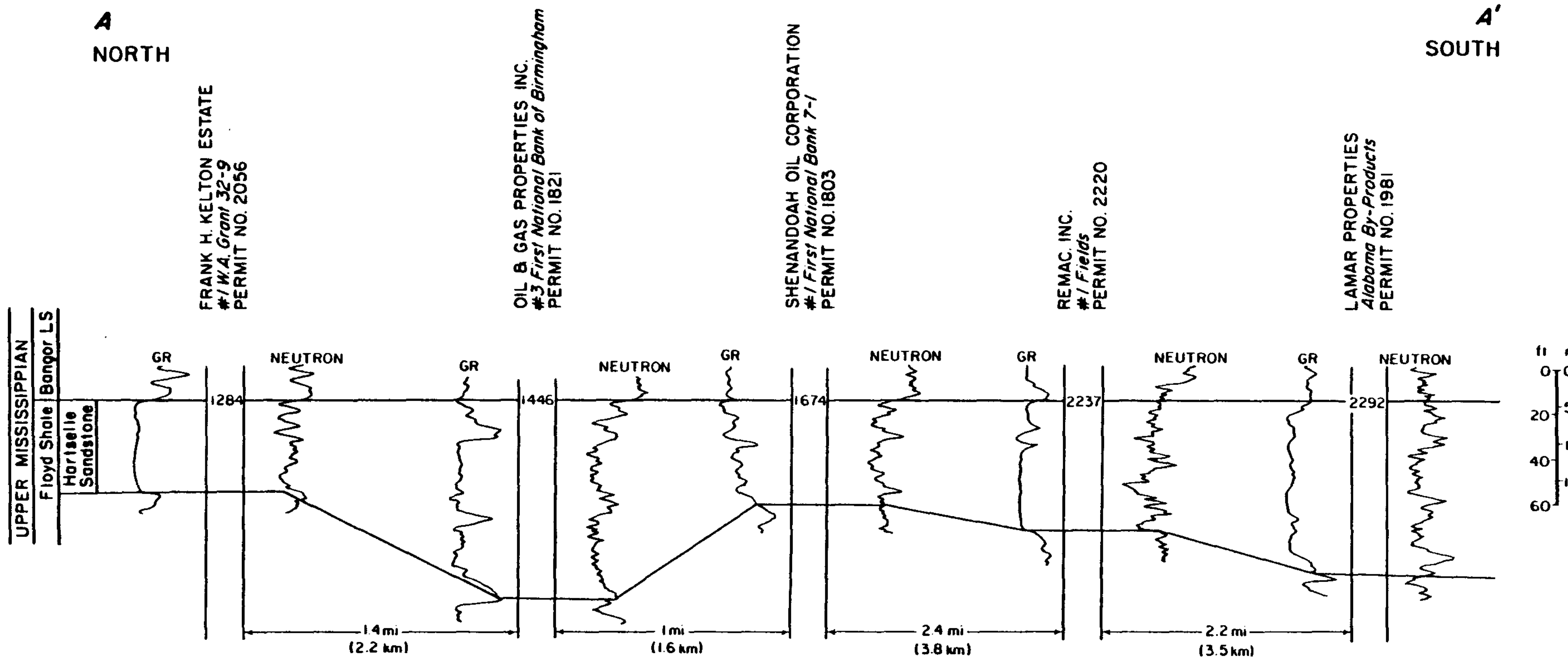

Figure 20. Stratigraphic cross section A-A' through the Hartselle Sandstone, Black Warrior Basin, Alabama (after Alabama State Oil and Gas Board, 1981).

Table 13. 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 T 11-17 S, R 4-10 W in Winston and Walker Counties, Alabama, equals approximately 996 mi^2.	Ranges from 0-150 ft from the southwest part to the center of the application area.	Ranges from 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). 0.1 to 0.5 Tcf estimated by R. Peterson (personal communication, 1982), primarily for blanket sands in the basin other than the Hartselle.	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.	1.0-1.8°F/100 ft.	No data.	Compressional stresses related to Appalachian and Ouachita folding and thrust faulting.

Table 14. Hartselle Sandstone, Black Warrior Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies	Texture	Mineralogy	Diagenesis
The Hartselle Sandstone was 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 to coarse-grained, but generally fine-grained, sandstones which are well sorted, well rounded, and occasionally interbedded with mudstones.	Primarily quartz (average over 90%) with traces of potassium feldspar, plagioclase, chert, and various types of rock fragments which include metamorphic, pelitic, sandstone, granitic, and volcanic types. Approximately 2% clay (montmorillonite) is present in sandstones in the designated area.	Cemented primarily by calcite and/or silica.
Typical Reservoir Dimensions	**Pressure/Temperature of Reservoir**	**Natural Fracturing**	**Data Availability (logs, cores, tests, etc.)**
No data.	No data.	Locally present in Jasper Field, located within the designated area. This field is excluded from the designated area application.	Limited core. SP-resistivity and GR-density or GR-neutron comprise the typical log suite.

Table 15. Hartselle Sandstone, Black Warrior 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
Based on one core analysis, permeability to air is 0.099 md, and based on calculated values from 6 wells, average permeability = 0.0515 md, range = 0.0020-0.0938 md. Based on calculations from 6 wells, and core analysis of one well, average porosity = 5%, range = 0-15%.	No data.	Based on data from 40-45 wells, pre-stimulation flow was not present or too small to measure.	Rates obtained from pre-1970 stimulation techniques ranged from 50-100 Mcfd.	No data.	No recorded liquid hydrocarbon production within the area.	Average = 87% and range = 0-100%, based on data from 6 wells.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
Stimulation techniques prior to 1970 utilized explosives detonated in the borehole. Current techniques utilize hydraulic fracture treatment involving a 70% nitrogen foam with KCl, methanol, and water mix, and various quantities of sand proppant. Average design specifications were unavailable.	No data on specific success or failure of fracture treatments.	320 acres.	Tight sand application is less complete than applications in other states. Data generally is limited.

Table 16. 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 Alabama and pending with FERC.	Approximately 45, excluding Jasper Field.	55% basinwide in 1979.	Average stimulation costs = \$20,000, range = \$18,000-\$50,000 (date unknown for these cost estimates).	Limited. Short spur of a Southern Natural Gas Co. pipeline extends only into southeastern Walker County. As of early 1980, 55 wells were awaiting pipeline connection in Alabama.	Low to moderate, based on 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 with less than half of the area gently sloping and local relief of 300-500 ft.	Humid with 48-56 inches mean annual precipitation. 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 for 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 primarily drilled by independents and small companies.

Arkoma Basin and Ouachita Mountains, Oklahoma and Arkansas

Arkoma Basin

The Arkoma Basin of eastern Oklahoma and western Arkansas is a Paleozoic basin trending approximately east-west, lying along the Ouachita structural front and overlapped by Coastal Plain sediments to the east (Branan, 1968). No applications for tight gas sand designations had been filed in the Arkoma Basin as of February 1982. Although announcing a new wildcat success, McCaslin (1982) noted that exploration activity has been at a relatively low rate in past years within the Arkoma Basin. Others, however, expect that exploration activity will be increasing, fostered in part by a new 285-mi-long, 20-inch pipeline through the basin, known as the Ozark Gas Transmission System. Ozark Gas Pipeline, which built the system, hopes to tap 1.5-2.0 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 with additional reservoirs in the Mississippian Chester Series (fig. 21). Some older Paleozoic strata have also yielded gas, and the entire basin is a dry gas province with little or no associated oil production (McCaslin, 1982). A geologic overview of the basin and a review of selected producing fields has been prepared by Gromer (1981), therefore a similar review will not be undertaken here, except to comment on the blanket-geometry tight gas sand potential.

The blanket-geometry gas reservoirs of the Arkoma Basin include the Spiro Sand within the Atokan Group and the Cromwell Sand of the Morrowan Group. The Spiro appears to be the unit of greater interest, and it represents marginal marine environments with subsequent redistribution of sand by a northward marine transgression across the basin (Gromer, 1981). No detailed description of the depositional systems of the Spiro Sand was found. Other Atokan sands above the Spiro are lenticular. Gromer (1981) and Branan (1968) both describe 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 over 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 ranges from a conventional to an unconventional reservoir. Operator interest is difficult to judge because the recent increase in well completions cited by Gromer (1981) in part reflects a nation-wide trend of increased drilling in the last several years. No applications for tight sand designations have been filed in Arkansas as of May 24, 1982, and as of the same date the Oklahoma Corporation Commission has only received an inquiry, not an application, regarding a stratigraphic section including the Cromwell Sand in Hughes and Coal Counties, Oklahoma. This lack of application activity indicates relatively low operator interest in tight gas sands in the Arkoma Basin at this time. Low operator interest and blanket-geometry sands within only two intervals probably limit GRI research opportunities in this basin.

Ouachita Mountains

Kuuskraa and others (1978) estimated 5 Tcf of gas in place in the Stanley Group of the Ouachita Mountains. The Stanley is part of the "Ouachita facies" consisting of shales, cherts, novaculites and thin sandstones (Gromer, 1981). As part of the Ouachita front the Ouachita Mountains are complexly folded and thrust faulted with steeply dipping and overturned strata, making this province unlike others included in this survey. Because of this structural complexity, lack of operator interest indicated by lack of FERC applications, and irregular surface topography that affects exploration activity, it appears that the Ouachita Mountains do not offer GRI the desired opportunity to foster new gas supplies in the near term.

Era	System	Series		Arkoma Basin		Ouachita Mountains
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.	Atoka Fm.
					(Gilcrease) Middle Atoka - Red Oak	
					Lower Atoka Spiro Sand Foster SS.	
		Morrow		Wapanucka Fm. (Okl.) Union Valley Hale Fm. (subsurface Cromwell)	Bloyd Sh. (Ark.) Kessler Ls. Mb. Brentwood Ls. Mb.	Johns Valley Fm.
					Prairie Grove Mb. Cane Hill (Springer)	Jackfork Group
	Mississippian	Chester		Caney Shale	Pitkin Ls. Fayetteville Sh. Batesville SS.	Stanley Group
		Meramec			Moorefield Fm.	
		Osage		Woodford Fm. (Okl.)	Boone Fm. (Ark.)	Arkansas Novaculite
	Devonian					

Figure 21. Column showing part of the stratigraphic sequence in the Arkoma Basin and Ouachita Mountains, Oklahoma and Arkansas (from Gromer, 1981).

Travis Peak Formation, East Texas Basin and North Louisiana Salt Basin

Introduction

The Travis Peak Formation consists of Lower Cretaceous very fine to fine-grained sandstones within the East Texas Basin and the North Louisiana Salt Basin. The Travis Peak directly overlies the Cotton Valley Sandstone and has also been termed the "Hosston Formation," especially in Louisiana (fig. 22). In Texas, applications for three Travis Peak fields have been filed (two have been approved by FERC), and an application is pending with FERC for approval of a 47-county area (Texas Railroad Commission, 1981b, Docket No. 5-76, 659). In Louisiana, an application has been state-approved for the Hosston Formation in all of Winn Parish and parts of three other parishes (Louisiana Office of Conservation, 1981b, Docket No. NGPA 81-TF-7).

The data base for the Travis Peak Formation is generally good as a consequence of the tight sand applications and a limited number of publications (tables 17-20), but some parameters cannot be determined without additional operator input. A comprehensive analysis of the Travis Peak using modern concepts of depositional systems was not encountered in the published literature for either East Texas or Louisiana, except for a study in parts of seven counties by McGowen and Harris (in press).

Exploration for the Travis Peak, or Hosston, Formation extends into the Mississippi Salt Basin of northeast Louisiana and Mississippi (Weaver and Smitherman, 1978). The Hosston reservoirs in the latter area are relatively deep (14,000 ft and greater), and some offer conventional permeabilities. In Mississippi, an FERC-approved tight sand designation for the Hosston exists for only one well in Jefferson Davis County where 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 basins in East Texas and North Louisiana is summarized as part of the review of the Cotton Valley Sandstone in this survey. As in the case of the

Cotton Valley, deposition of the Travis Peak is thought to result from tilting of rift margin blocks toward the incipient Gulf of Mexico and concurrent erosion of these blocks. A structure contour map on the top of the Travis Peak shows depths of 6,000 to over 10,000 ft in the East Texas area (fig. 23).

Stratigraphy

The Travis Peak Formation is Early Cretaceous in age and directly 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, but this unit does not extend through all of the East Texas Basin (M. McGowen, personal communication, 1982). The top of the Travis Peak Formation is transitional, with 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. No informal stratigraphic terminology for parts of the Travis Peak Formation was noted in the literature or in the tight sand applications. The base of the Travis Peak contains a chert pebble conglomerate in some areas, and the 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 clastics into these areas occurred during the Late Jurassic (Cotton Valley) and the Early Cretaceous (Travis Peak). In East Texas the terrigenous clastics were supplied by numerous small rivers rather than one or two major rivers as in Louisiana and Mississippi. A major source for the Travis Peak, as well as 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 quartz arenites and subarkoses (McGowen and Harris, in press).

The Travis Peak Formation has been examined in detail in the northwestern East Texas Basin by McGowen and Harris (in press) and over the entire basin in a general manner by Bushaw (1968). The interpretation of the larger area is consistent with the detailed work wherein the Travis Peak is interpreted as a system of coalescing fan deltas that prograded from the west, northwest, and north. A fan delta is defined as an alluvial fan that progrades into a body of water from an adjacent highland (McGowen, 1970). The subaerial, proximal part of the fan is characterized by bed-load braided streams with flashy discharge and a relatively high ratio of coarse-grained to fine-grained sediment. The distal part of the fan includes a transition zone between subaerial and subaqueous depositional environments wherein delta front sediments may be reworked into bars, spits, and shoals, especially as 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 fan deltas varies with width of the marine shelf and wave energy (Galloway, 1976; Wescott and Ethridge, 1980).

Regional analysis of the Travis Peak Formation of the East Texas Basin by Bushaw (1968) is remarkably consistent with more recent process studies on fan deltas and with the areally limited subsurface study of McGowen and Harris (in press). The progression of environments is shown by Bushaw (1968) (fig. 24) for three informal intervals of the Travis Peak that culminated in the deposition of the Pettet (Sligo) Limestone (fig. 24c).

A highly generalized regional cross section of the Travis Peak shows a thick, sand-dominated wedge of sediment probably composed predominantly of braided stream deposits (fig. 25). Braided streams form a continuous, laterally extensive sand sheet wherein shales will be patchy and discontinuous (Walker and Cant, 1979). On a local scale, sands from the braided stream facies will show lateral continuity consistent with their deposition as longitudinal and transverse bars within the braided stream system. This implies thickening and thinning of individual beds within sand packages from well to well (fig. 26). Where the braided stream facies has been reworked by marine transgression, or where the fan delta enters the marine environment, it is likely that lateral continuity of beds will be greater, but not necessarily similar in both dip and strike directions.

Travis Peak Well Data Profile

The Travis Peak Formation is an areally extensive fan delta system with the potential to meet GRI criteria for future studies; therefore, additional data were sought from the Well History Control System (WHCS) file of Petroleum Information Corporation. Consistent with the nation-wide increase in drilling of the last several years the number of Travis Peak gas completions increased from 1978 to 1980 and then leveled off in 1981 (fig. 27). The depths to the top of perforated intervals in the Travis Peak show a broad peak in the 7,000- to 9,000-ft-depth range, with few wells having their upper perforations as deep as 11,000 ft (fig. 28). The mean perforated interval is 312 ft thick for 191 wells, and the interval thickness ranges from 2 to 2,265 ft. The initial potential flow from 183 gas wells was 5,249 Mcfd, with a range of 67 to 31,000 Mcfd. It should be noted that initial potential flows are often significantly higher than stabilized or partially stabilized gas flow. Gas-oil ratio has been noted in table 19, and where condensate is produced, its API gravity is predominantly between 50^{o} and 60^{o}. High API gravity and light color are frequently cited in tight gas applications as evidence that liquids produced with gas are actually in a gaseous state under reservoir conditions.

Approximately one-third of the fracture treatments used on 398 Travis Peak producing gas wells involved sand and gelled fluid, and one-third involved sand and water-base fluids. Acidization was noted in the WHCS file for 11 percent of the treatments, but this figure seems low and may be the result of incomplete reporting. Only 1.5 percent of the treatments were reported as using foam, a figure which may increase with increasing use of foam to avoid formation damage due to swelling of water-sensitive clays.

SYSTEM	SERIES	GROUP	FORMATION
CRETACEOUS	COAHUILAN	NUEVO LEON	SLIGO / PETTET
			TRAVIS PEAK / HOSSTON
JURASSIC	UPPER JURASSIC	COTTON VALLEY	COTTON VALLEY SANDSTONE (UPPER COTTON VALLEY/SCHULER)
			BOSSIER SHALE
			COTTON VALLEY LIME (GILMER / HAYNESVILLE)
		LOUARK	BUCKNER
			SMACKOVER

Figure 22. Stratigraphic column showing parts of the Jurassic and Cretaceous systems in the East Texas Basin and North Louisiana Salt Basin.

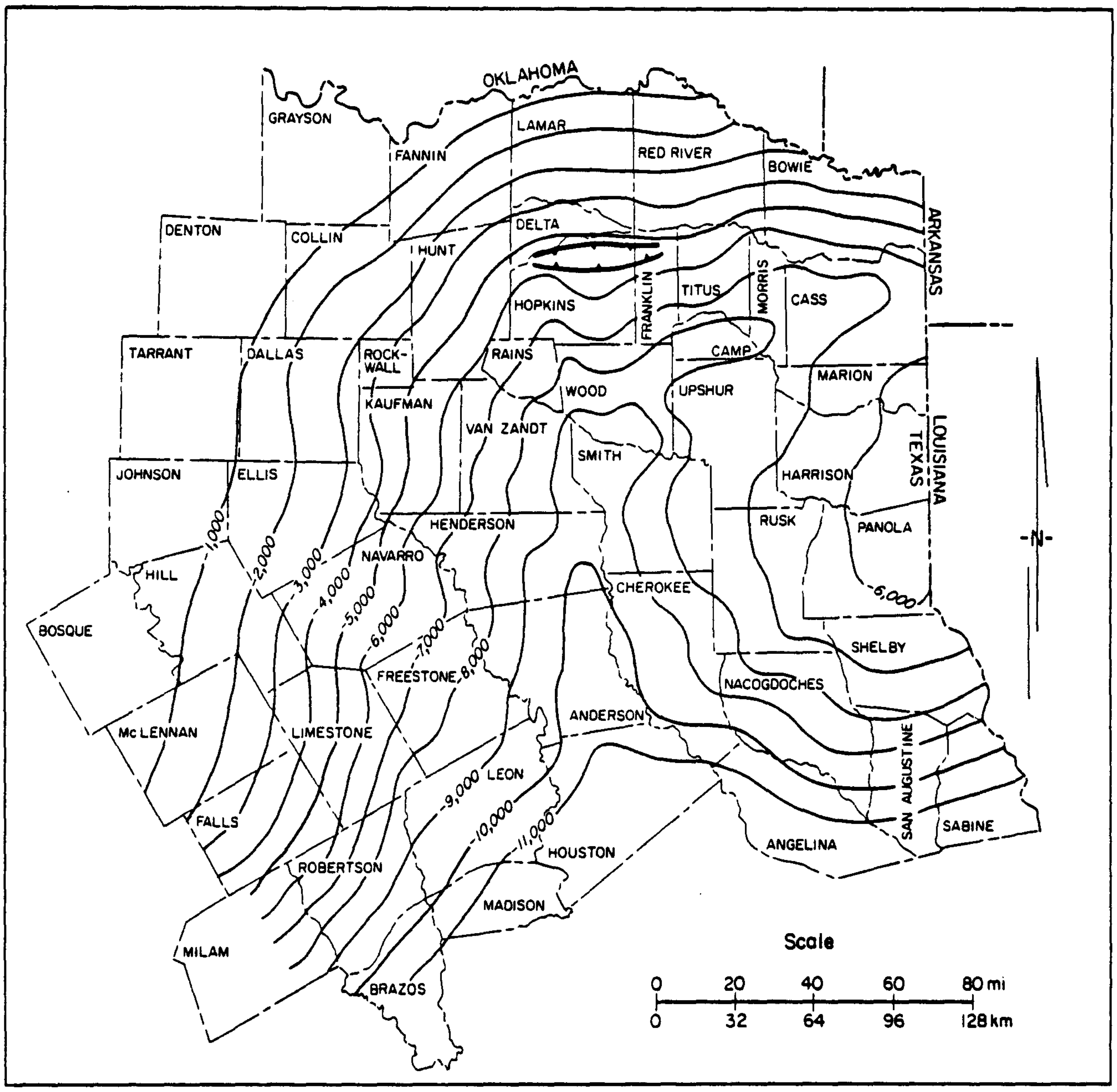

Figure 23. Structure contours on top of the Travis Peak Formation, East Texas Basin (from Texas Railroad Commission, 1981b).

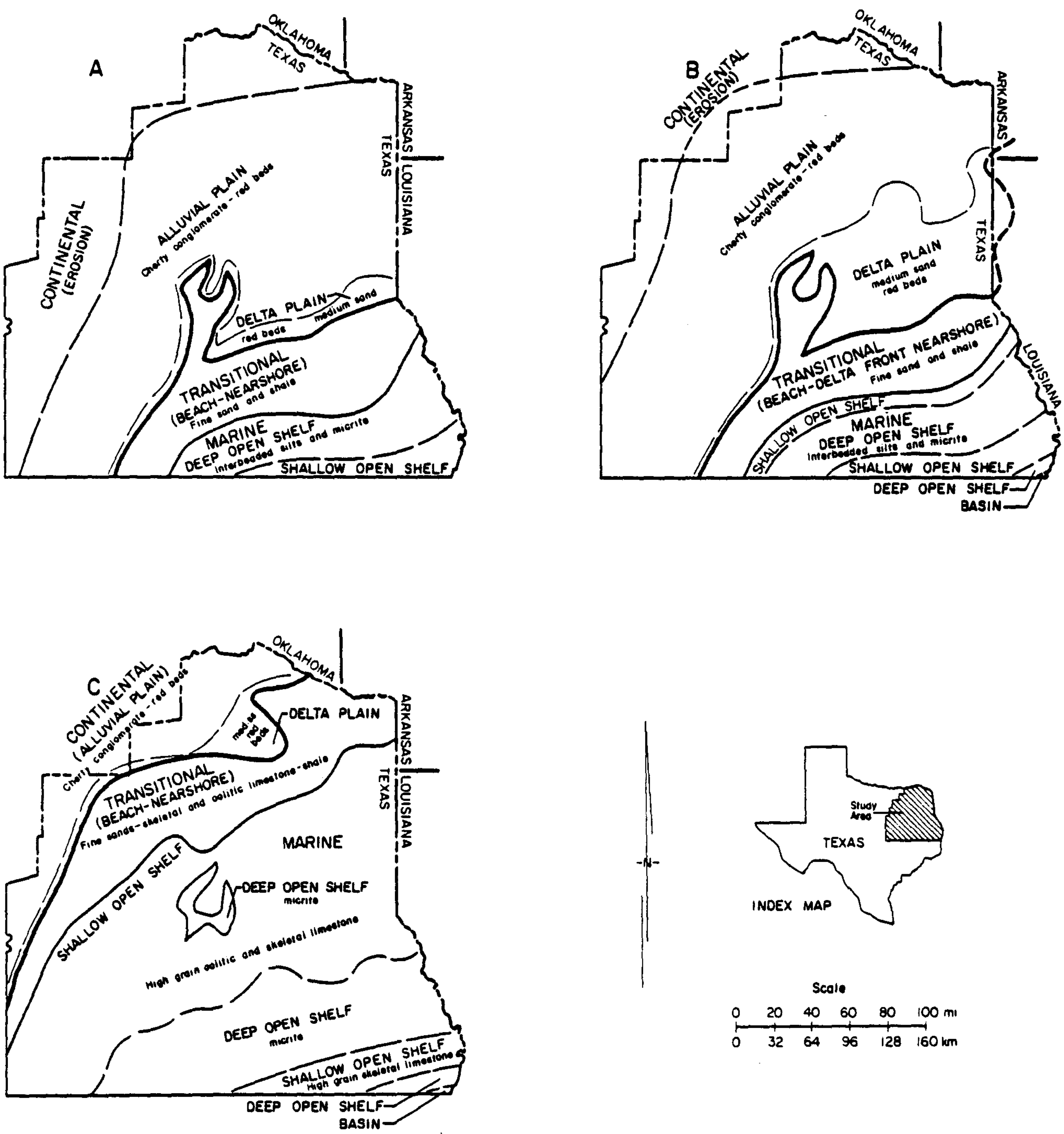

Figure 24. Facies tracts in the (A) lower Travis Peak, (B) middle Travis Peak, and (C) upper Travis Peak-Pettet Formations (after Bushaw, 1968).

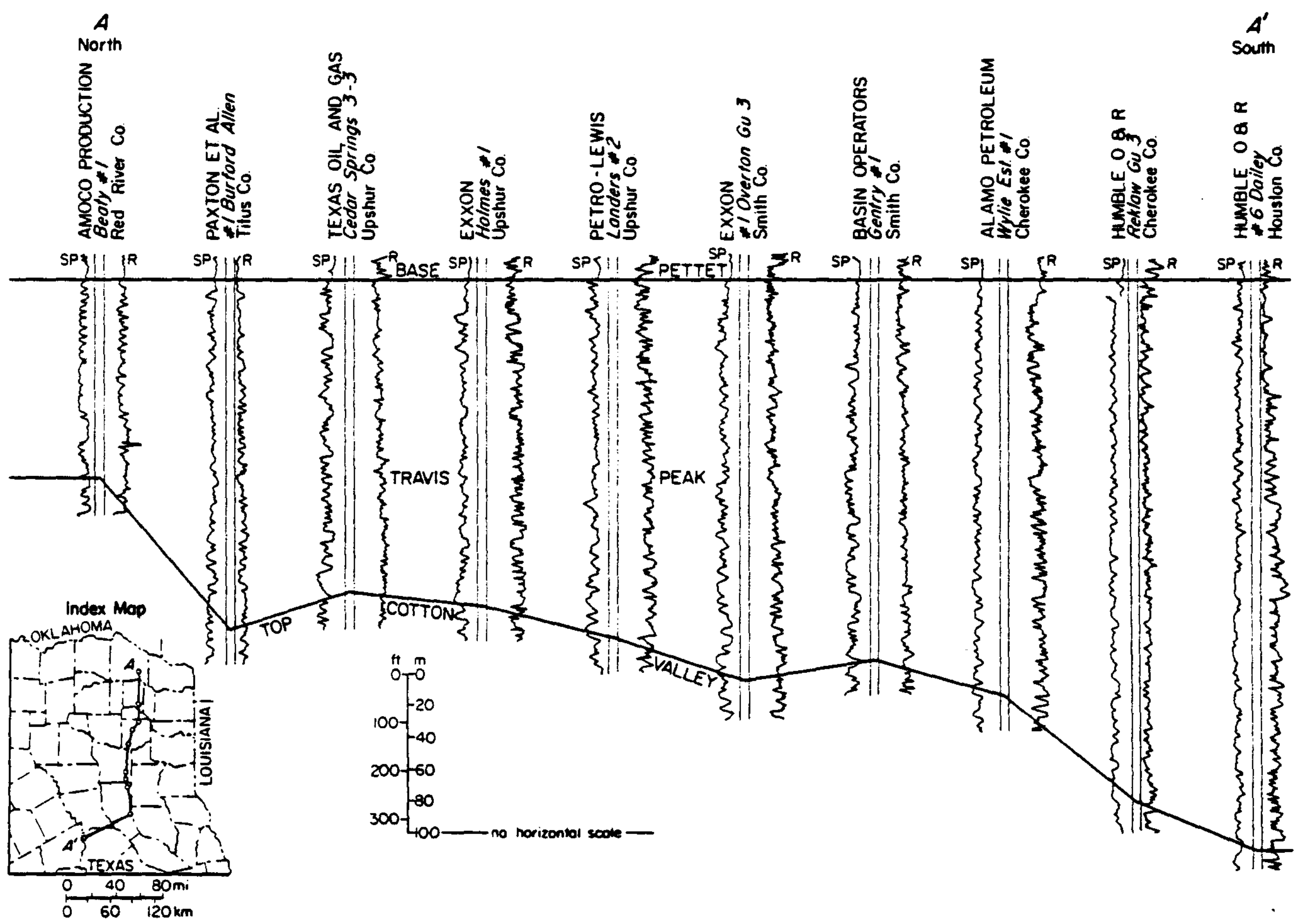

Figure 25. Generalized regional stratigraphic cross section through the Travis Peak Formation (from Texas Railroad Commission, 1981b).

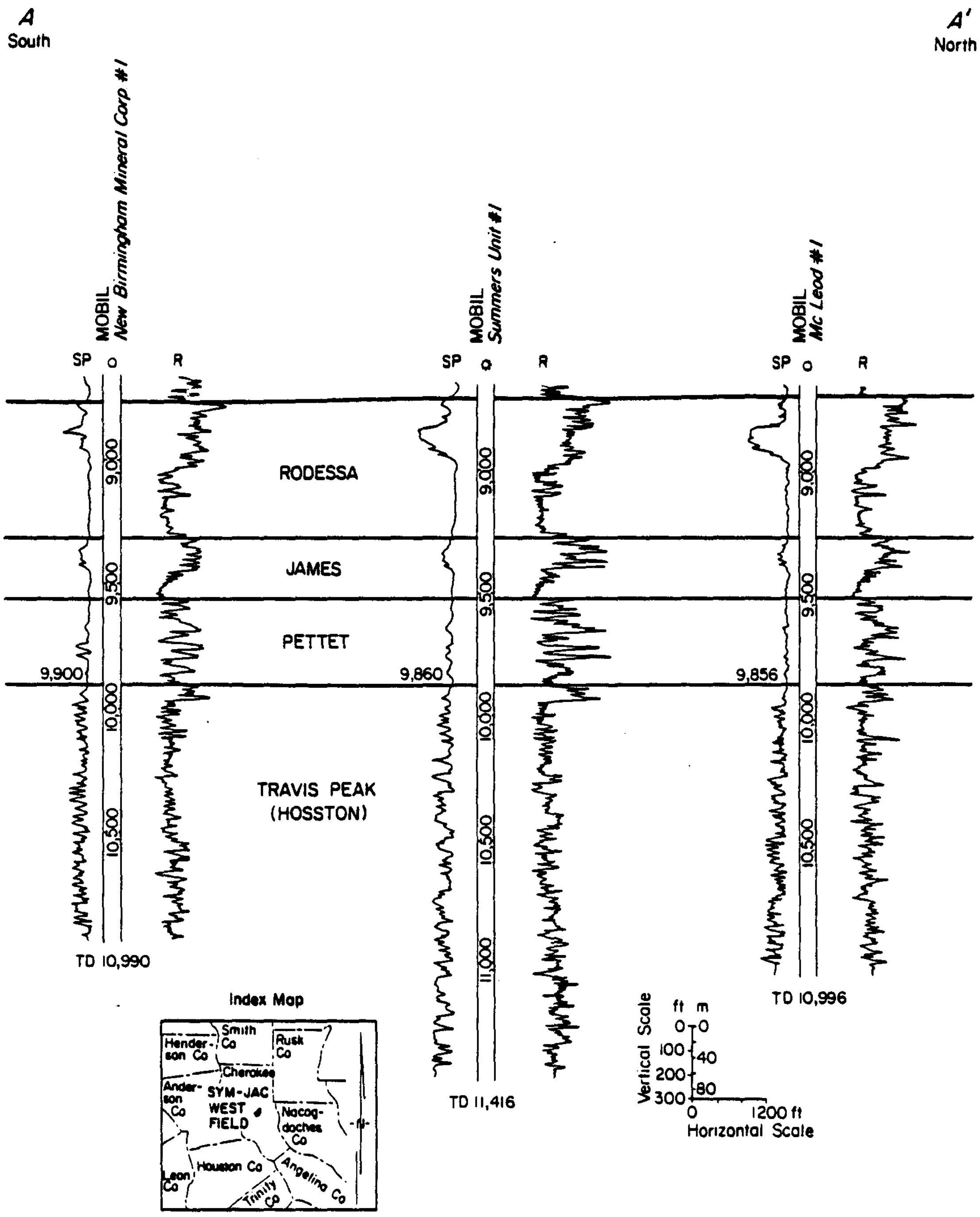

Figure 26. Stratigraphic cross section through the upper Travis Peak Formation and overlying units in Sym-Jac Field, Cherokee County, Texas (Texas Railroad Commission, 1981d).

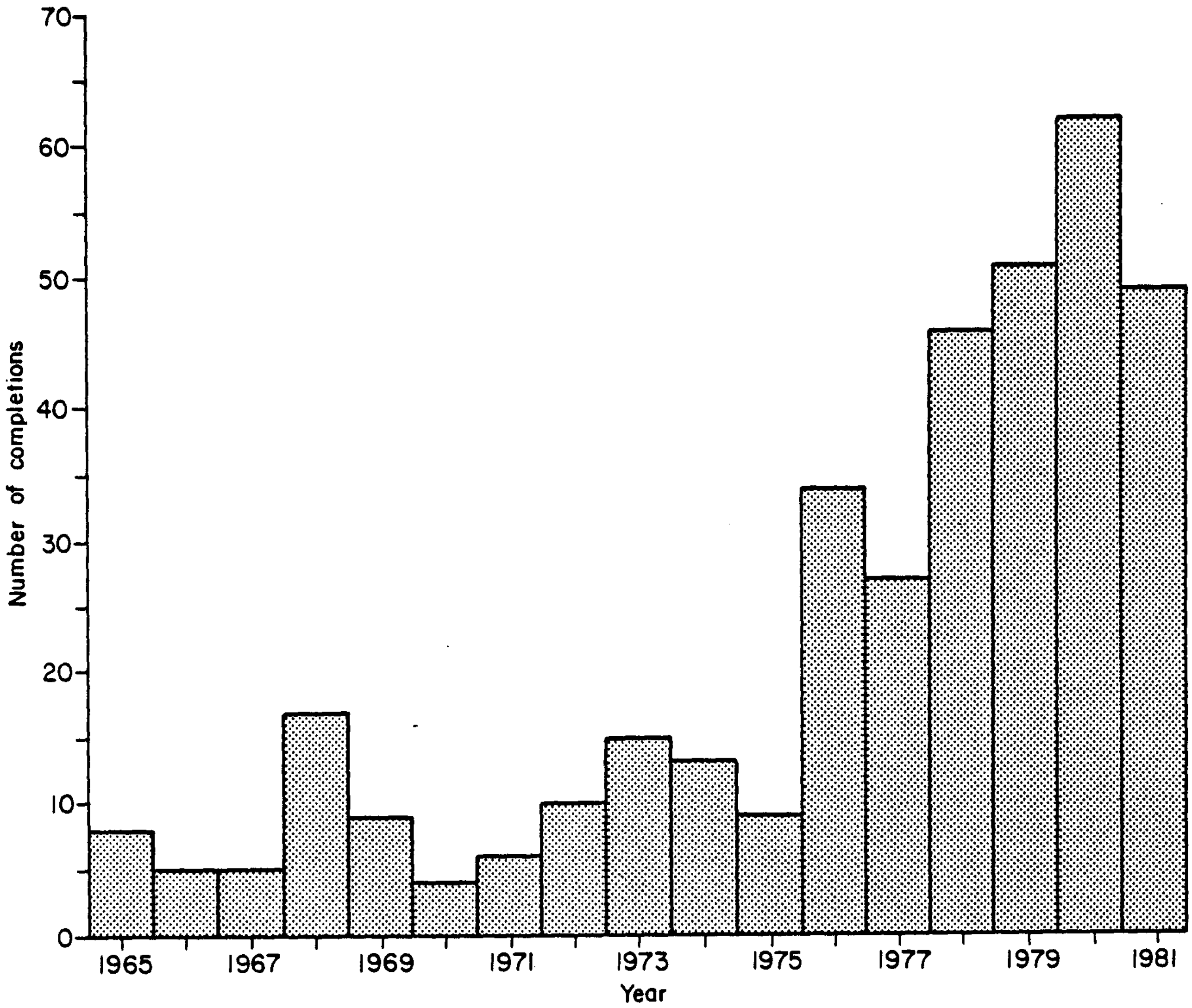

Figure 27. Distribution of Travis Peak gas well completions by year, 1965-1981.

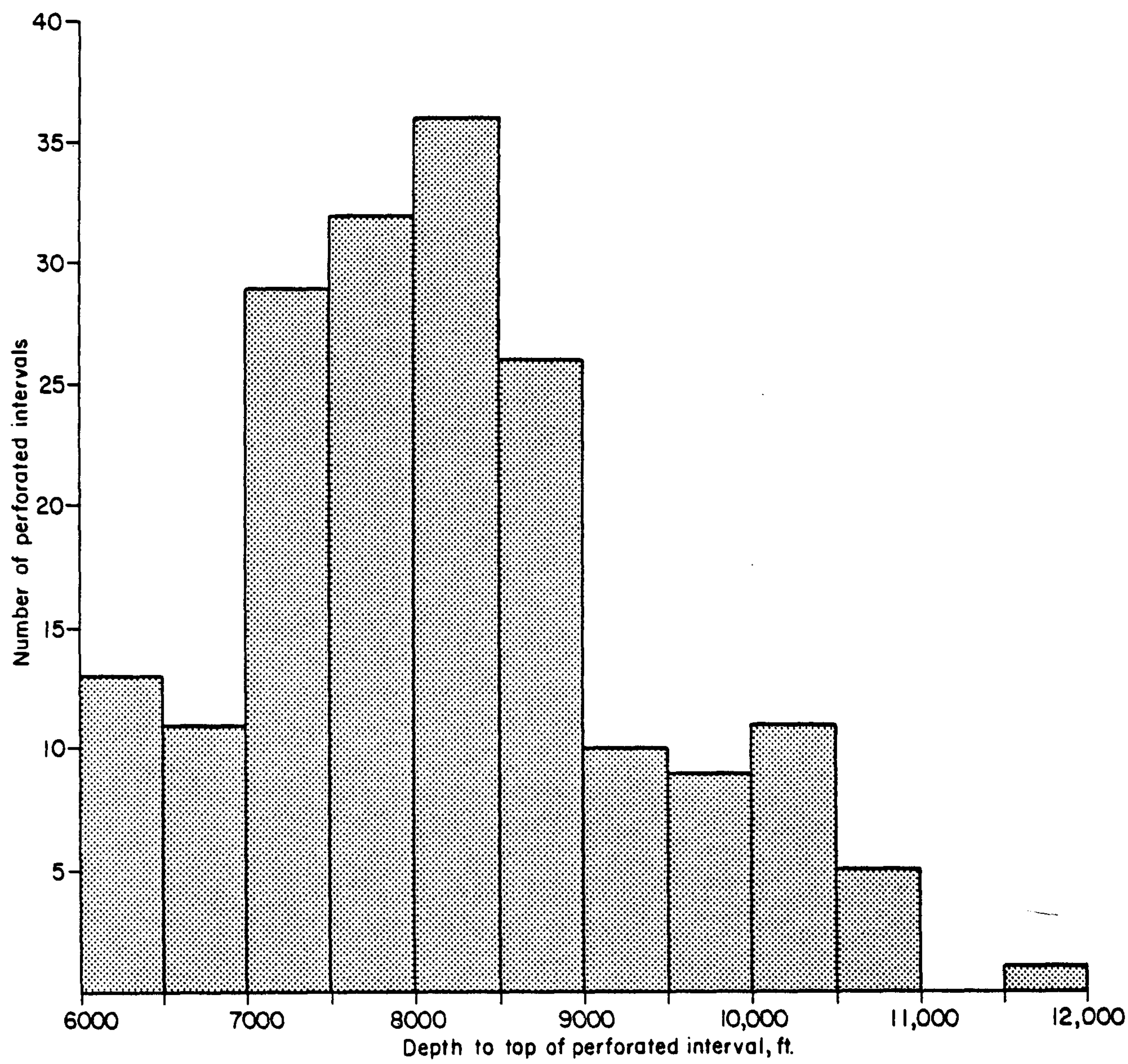

Figure 28. Depth to top of perforations for 191 gas wells completed in the Travis Peak Formation .

Table 17. Travis Peak Formation, East Texas Basin and North Louisiana Salt Basin: 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, respectively, in Texas and Louisiana. Texas approval for tight formation designation applies to 47 counties equal to 35,830 mi^2 in Railroad Commission Districts 5 and 6.	Upper 200 ft of the 500-2,500-ft-thick formation is of most interest for blanket-geometry sands in updip East Texas Basin.	Drilling depth of 3,100 ft in Lamar County to 10,900 ft in southern Cherokee County to the top of the formation. Top 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.	Not included in National Petroleum Council (1980).	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Graben formed along the margin of the Gulf of Mexico associated with continental rifting. Basin presently bounded by major fault systems and the Sabine Uplift.	1.4-1.8°F/100 ft. Mostly 1.6-1.8°F/100 ft.	From 0.43 to 0.59 psi/ft (mean = 0.50 psi/ft) for 8 zones in 5 Amoco wells in Cherokee and Nacogdoches Counties.	Tensional. Local stress variations due to salt tectonics.

Table 18. Travis Peak Formation, East Texas Basin and North Louisiana Salt Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies	Texture	Mineralogy	Diagenesis
Lower Travis Peak: alluvial fan and marine-influenced fan-delta margins in the extreme southern edge of the basin. Middle Travis Peak: alluvial fan and fan-delta environments receded toward the north and northwest source areas. Fluvial to marginal marine environments represented. Upper Travis Peak: as transgression continued, marine-influenced fan-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 for tight gas sand development. Marine reworking has created strike-elongate sand thicks as well as sheet-like sands, thereby stacking both lenticular and blanket-geometry sand bodies.	Interbedded very fine to fine sandstone, shale, and some sandy, fossiliferous, oolitic limestone. Well sorted in some areas.	Quartz sandstones, possibly with some chert. Clay clasts present. In one well in Freestone County a Travis Peak core consisted of 44% quartz with the 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 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 (logs, cores, tests, etc.)**
Mean gross perforated interval is 312 ft thick for 191 wells, and the range of interval thickness is 2 to 2,265 ft.	From 3,920 to 6,000 psi (mean = 4,866 psi) for 8 zones in 5 Amoco wells in Cherokee and Nacogdoches Counties. From 190°F to 272°F (mean = 243°F) for 8 zones in 5 Amoco wells in Cherokee and Nacogdoches Counties. From 3,200 to 3,300 psi at 9,000-9,300 ft for two wells in Red River Parish, Louisiana.	Contribution of natural fractures is unknown.	Limited number of cores taken. 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 in Louisiana. SP-resistivity is the primary log, often with sonic log in addition.

Table 19. Travis Peak Formation, East Texas Basin and North Louisiana Salt Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir Parameters	Net Pay Thickness	Production Rates: Pre-Stimulation	Production Rates: Post-Stimulation	Decline Rates	Formation Fluids	Water Saturation
Mean calculated in situ permeability = 0.026 md for a group of 125 wells which have not been stimulated (in Texas). Porosity ranges from 2-9% for a group of wells from 7 counties in Texas.	From 30 to 86 ft (mean = 48 ft) for 8 zones in 5 Amoco wells in Cherokee and Nacogdoches Counties, Texas. Net pay of 31 and 33 ft for 2 Mobil wells in Cherokee County, Texas.	Stabilized mean flow rate = 765 Mcfd for a group of 125 wells in Texas. As low as 43 Mcfd for 2 Mobil wells in Cherokee County.	500-1,500 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 12-24 months expected for most wells.	High API gravity condensate is produced by some wells at rates less than 5 bbls/day in some areas, but at rates of 10-20 bbls/day in other areas. Mean gas-oil ratio for 287 wells = 175,645:1.	From 29-60% (mean = 43%) for 8 zones in 5 Amoco wells in Cherokee and Nacogdoches Counties.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
Massive hydraulic fracturing, often as multi-stage treatments to effectively treat all zones of interest. Technique varies widely among operators; typical may be 500,000 lb sand in 200,000-300,000 gal fluid.	An average 418% increase after fracture treatment for 4 wells reported in tight sand applications.	640-acre spacing in 8 fields described in FERC applications; two of these have optional 320-acre spacing.	Amoco has reported some specific data for 5 wells on production rates before and after massive hydraulic fracturing in Nacogdoches and Cherokee Counties:

Depth (ft)	Pre-stimulation (Mcfd)	Post-stimulation (Mcfd)	K, 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
10,937-11,045	30	work in progress, 5/29/81	--

Table 20. Travis Peak Formation, East Texas Basin and North Louisiana Salt Basin: Economic factors, operating conditions and extrapolation potential.

ECONOMIC FACTORS

FERC Status	Attempted Completions	Success Ratio	Drilling/ Completion Costs	Market Outlets	Industry Interest
Two fields Texas-approved and FERC-approved. A 47-county area of East Texas state-approved on 10/26/81. FERC action pending. One field pending Texas state approval. All of Winn Parish and parts of 3 other parishes approved by Louisiana on 11/24/81. FERC action pending.	Approximately 1,239 completions in Railroad Commission Districts 5 and 6 of which 676 were active as of 5/81. In Louisiana, 53 Hosston penetrations are located in the application area.	See Cotton Valley Sandstone, this survey, for basin-wide data on gas wells.	By analogy to cost for Cotton Valley tests, probable cost of \$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, based on number of FERC applications. Potential tight sand designation by FERC for 47-county area in Texas and parts of 4 parishes in Louisiana would further 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 / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
Gently sloping Gulf Coastal Plain with 100-300 ft of local relief and absolute elevations less than 1,000 ft above sea level.	Sub-humid to humid with 44-56 inches mean annual precipitation. Hot summers, mild winters. Possible heavy rain from remnant tropical storms.	No major terrain barriers to exploration activity. Heavy vegetation in some previously uncleared areas. Adequate drainage must be provided for some sites.	Good. The Travis Peak is an areally extensive fan-delta system with 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 Basin, and North Louisiana Salt Basin

Introduction

The Cotton Valley Sandstone forms the upper part of the Cotton Valley Group of Late Jurassic age, and was deposited in the East Texas Basin and the North Louisiana Salt Basin. Stratigraphic terminology varies across the area with the term "Schuler Formation" frequently used for the Cotton Valley Sandstone, especially in Louisiana (fig. 22). A major area of gas production in the Cotton Valley Sandstone exists across northern Louisiana into northeast Texas with a generally east-west trend. Gas was initially found in the 1940's in Louisiana in updip pinch-outs parallel to structural strike, and 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, probably as part of wave-dominated delta complexes (Collins, 1980; Coleman and Coleman, 1981). This further suggests that strandplain, barrier island, and tidal bar sands may represent some of the specific facies present as reservoirs within the deltaic depositional system. These facies probably include the more readily correlated blanket coastal sandstones referred to by Collins (1980) which yield gas to drill-stem tests and are already highly commercialized. A second trend of low-permeability massive sandstones is now, with massive hydraulic fracturing technology and with incentive pricing in Texas, a major gas play.

The additional 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 has an area of approximately 14,800 mi^2, which includes a speculative region in the east and central parts of the East Texas Basin (fig. 29) (National Petroleum Council, 1980). The flanks of the Sabine Uplift in Texas and Louisiana (fig. 30) are considered prime candidates for tight gas in the Cotton Valley, but the deeper basin potential in the East Texas Basin is largely untested at this time (Collins, 1980). The widespread, low-permeability reservoirs in the Cotton Valley Sandstone show less continuity than the updip facies and are probably distal to proximal delta front deposits, possibly reworked during alternating regression and transgression of shifting fan delta margins. This concept has been established in the northwest corner of the East Texas Basin by McGowen and Harris (in press), and possibly can be extended as a first approximation of the depositional system in other areas where detailed studies are not available.

The data base for the Cotton Valley Sandstone is good (tables 21-24). Information has been gathered from applications for tight gas formation designations in Texas (Texas Railroad Commission, 1980, Docket No. 20-75, 144) and in Louisiana (Louisiana Office of Conservation, 1981a, Docket No. NGPA 81-TF-1, 2). Tight formation status has been approved by the Federal Energy Regulatory Commission (FERC) in Texas, and is pending, following state approval, in Louisiana. More recently published subsurface information is available for the Cotton Valley Sandstone than for most tight gas sands as a consequence of the extent of commercialization, development of fracture treatment technology, and additional operator interest due to incentive pricing. Recent geological 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) are available, but a detailed basin-wide study using modern concepts of hydrocarbon reservoirs as genetic stratigraphic units has not been published. The Cotton Valley Sandstone is fairly well commercialized and is included here primarily for comparison with other units rather than as a potential research candidate for consideration by GRI.

Structure

Kehle (1971) and Wood and Walper (1974) suggest that the interior salt basins of East Texas and North Louisiana were part of a series of marginal grabens associated with 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 and the South Arkansas Fault Zone (fig. 30). Much of the Cotton Valley gas exploration in the East Texas Basin has been in the vicinity of the Sabine Uplift where the top of the Cotton Valley Group is encountered at -9,500 ft or less (fig. 31). Another relatively positive feature, the Monroe Uplift, is located in northeast Louisiana (fig. 30), and forms part of the eastern boundary of the North Louisiana Salt Basin in Morehouse, West Carroll, and East Carroll Parishes (fig. 32). Jurassic evaporites in East Texas and North Louisiana (Werner Anhydrite and Louann Salt) indicate early deposition in a restricted basin; later, more open marine conditions are indicated by limestone deposition (Smackover and Gilmer Limestones) (fig. 22). The major influx of terrigenous clastics, which includes the Cotton Valley Sandstone and the Travis Peak Formation, reflects tilting of the rift margin toward the basin, whereas previously crustal blocks may have been tilted away from the incipient rift (various authors summarized in McGowen and Harris, in press).

A major source area for the Cotton Valley clastics is inferred to be a deltaic depocenter in northeast Louisiana with subsequent shore-parallel sediment transport to the west (Thomas and Mann, 1966). While some workers have suggested that this transport system resulted in deposition of the Terryville massive sandstone complex (equivalent to 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 document sediment sources to the northwestern East Texas Basin in Cotton Valley time (McGowen and Harris, in press).

Salt tectonics play an important role in the structural history of the East Texas and North Louisiana Salt Basins in that salt structures have been actively growing from Jurassic to Tertiary time (Coleman and Coleman, 1981). Salt has been mobilized in response to sediment loading, and, in turn, salt structures have affected subsequent sedimentation. Complex fault patterns are found in association with salt structures, especially piercement domes.

Stratigraphy

As part of the terminology typically used in East Texas the name "Cotton Valley" applies both to a group and to a limestone and a sandstone within that group (fig. 22). The terms "Haynesville" and "Schuler" are more frequently applied in northern Louisiana. The Schuler Formation is considered to be the updip equivalent of the entire Cotton Valley Group in Louisiana and includes red sandstone and shale, and is locally conglomeratic (Thomas and Mann, 1966). Other usage, probably informal, may refer to the Schuler as the sandstone unit above the Bossier Shale (fig. 22). In Louisiana an argillaceous limestone alternating with thin shales, known as the "Knowles Limestone," forms the uppermost unit of the Cotton Valley Group (Thomas and Mann, 1966); however, this unit is largely absent in Texas.

The Terryville Sandstone in Louisiana is the equivalent of the Cotton Valley Sandstone in Texas. The Terryville-Cotton Valley Sandstone in Louisiana is frequently referred to by an informal nomenclature with some local variation.

Depositional Systems

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

Where detailed studies of individual fields have been conducted, specific genetic facies have been identified, such as lower to upper barrier island shoreface for the Davis and "B" sandstones (informal terminology) in the Frierson Field, Louisiana. The latter 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, it appears that barrier island shoreface, offshore bar and possibly delta front are major environments of deposition for updip Cotton Valley Sandstone in northern Louisiana.

In the East Texas Basin and the North Louisiana Salt Basin these same genetic facies probably also form major reservoirs and potential reservoirs. Highly generalized regional cross sections show the extensive basin-wide accumulation of sand in the Cotton Valley Sandstone (figs. 33-37). Many individual sands show blocky log character, sometimes with a thin, upward-coarsening base, in the downdip part of the north-south section and the eastern part of the west-east section. Such log character might be expected in offshore bar and barrier island shoreface to foreshore sequences. Massive sands shown at the western end of the section in figure 34 and the north end of the section in figure 35 may represent a braided stream fluvial facies characteristic of the system supplying the deltaic and barrier systems.

Prodelta, delta front, and braided stream facies have been recognized as part of the Cotton Valley Group in the northwestern part of the East Texas Basin, for which a detailed depositional systems study has been prepared (McGowen and Harris, in press). The prodelta facies contains minor amounts of very fine sandstone and siltstone. The delta front deposits typically consist of interbedded sandstone and mudstone with a few thin beds of sandy limestone. In the updip position of the study area of McGowen and Harris (in press) the delta front deposits are overlain by a thick wedge of braided stream sediments forming part of the fan delta system that deposited much of the terrigenous clastics of the Cotton Valley Group.

A percent sand map of the Cotton Valley Group along the northwestern basin margin shows dip-oriented trends of high sand content indicative of fluvial axes (fig. 38). 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. 39) (McGowen and Harris, in press). This strike-parallel pattern, when compared to the marginal marine barrier and bar facies of northern Louisiana, suggests that similar depositional environments may be present in the East Texas Basin. The opportunity for individual sand bodies of good lateral continuity would increase in these marginal marine environments.

Hydraulic Fracturing and Other Technology

Special mention of hydraulic fracturing must be made in connection with the Cotton Valley Group because many of the current technological innovations were developed or improved since 1972 during the completion of Cotton Valley tight gas reservoirs (Jennings and Sprawls, 1977). Avoidance of killing wells with brine, treatment of pay zones individually, and better clean-up using CO_2 to help produce back the fracturing fluid are among the techniques tested, and now utilized, in Cotton Valley and many other tight gas sand completions. Treatments vary in size, fluid type, and injection rate. Comparison of frac treatments up to 1975 (Jennings and Sprawls, 1977), with those used as recently as 1980 (Tindell and others, 1981) shows well treatments increasing from generally less than 120,000 gal of fluid to 300,000 to 400,000 gal of fluid. Similarly, proppant quantities have increased from generally less than 75,000 lb to as much as 600,000 to 800,000 lb. The available literature on such treatments is perhaps greater for the Cotton Valley Group than for any other unit; therefore the Cotton Valley forms an excellent basis of comparison as more aggressive fracture treatment techniques are tried in other areas.

Specialized studies in log interpretation (Frank, 1978), pressure testing (Bostic and Graham, 1979), and numerical simulation of reservoirs (Meehan and Pennington, 1982) are now appearing in the published literature as a result of research on Cotton Valley reservoirs. Studies on the Cotton Valley will probably be a continuing source of technological innovations applicable to other low-permeability gas sands in that a solution to all geologic and engineering problems associated with Cotton Valley tight gas production is not yet at hand.

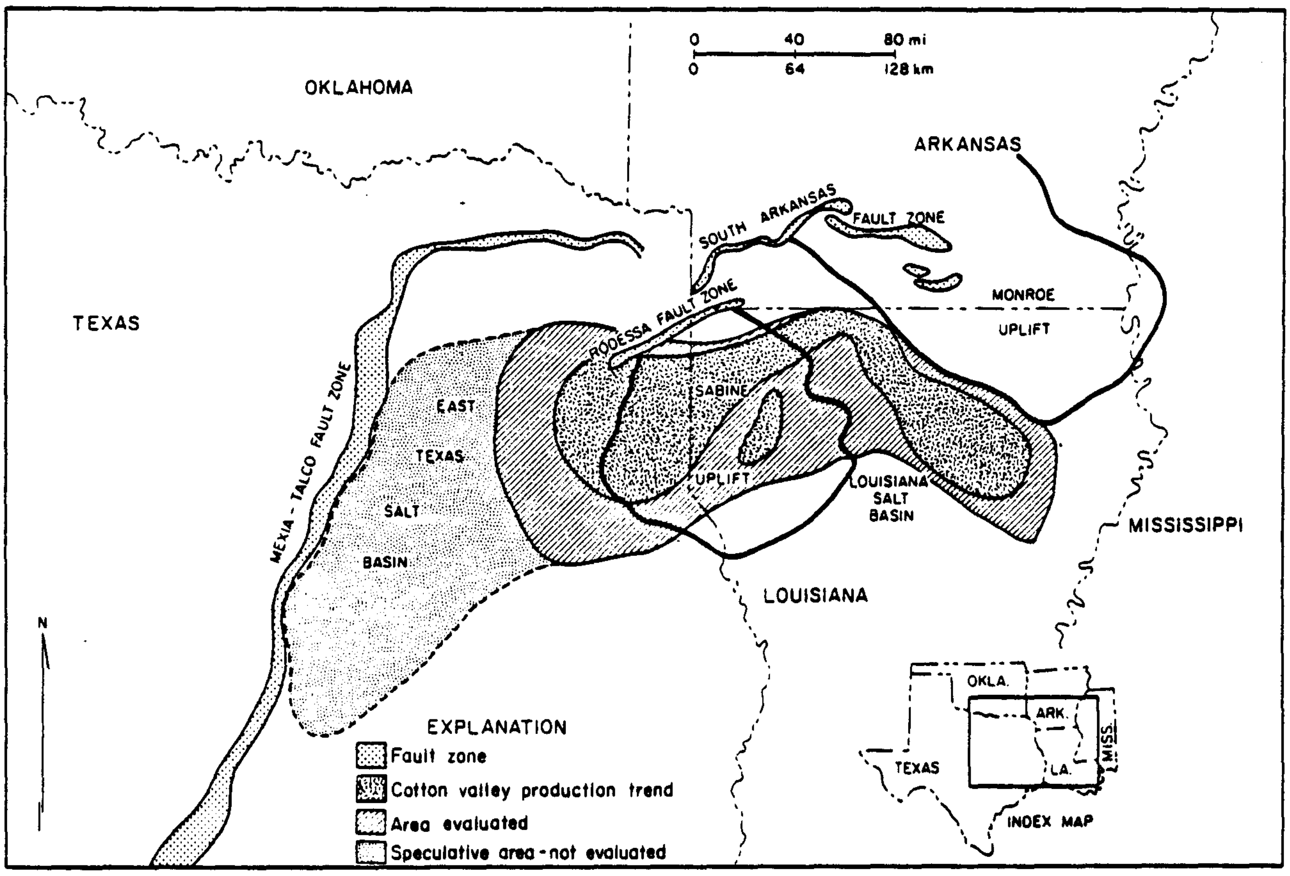

Figure 29. Production trends of the Cotton Valley Sandstone evaluated by the National Petroleum Council (1980).

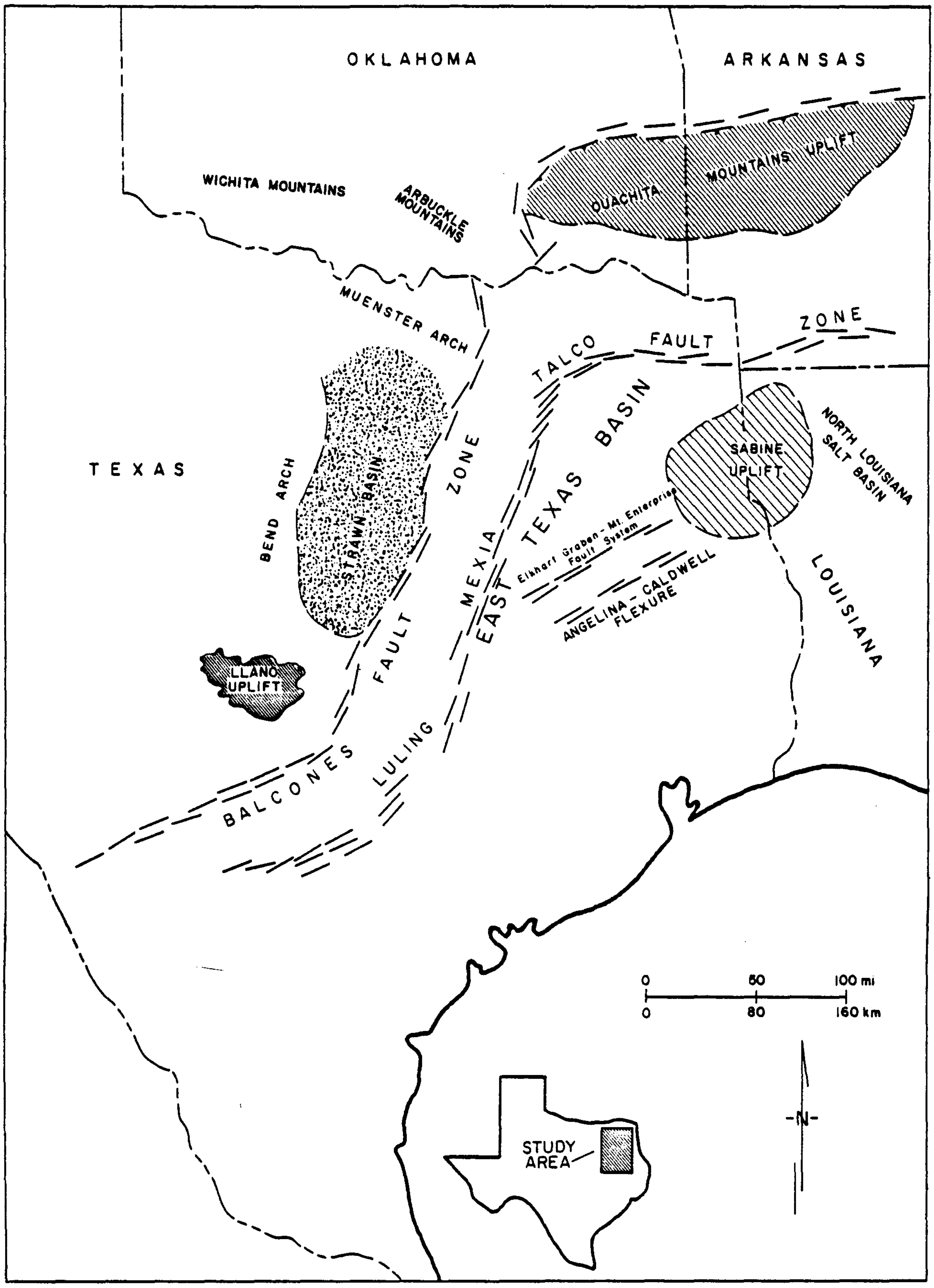

Figure 30. Tectonic elements of the East Texas Basin and adjacent areas (from McGowen and Harris, in press).

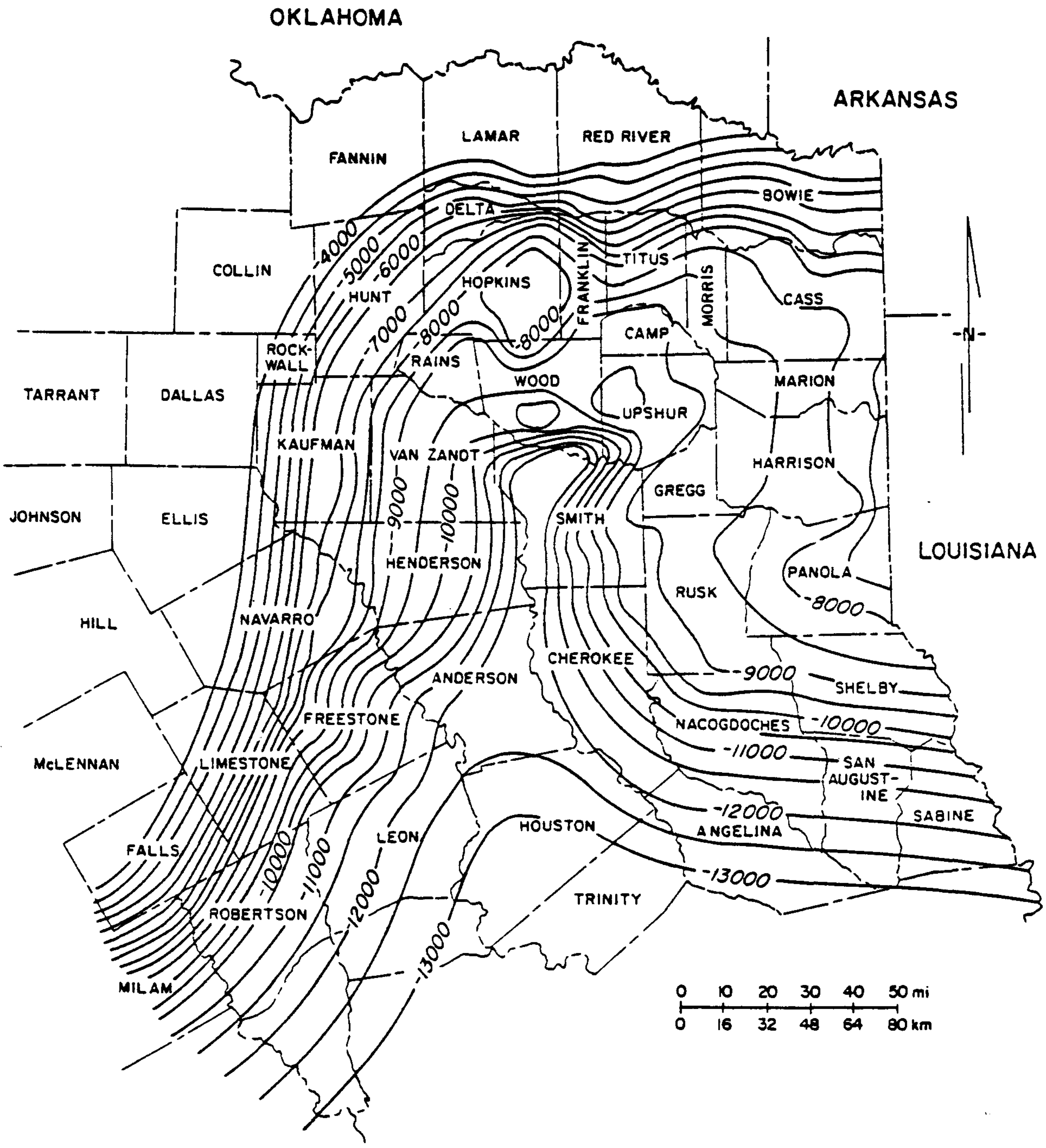

Figure 31. Structure contours on top of the Cotton Valley Sandstone, East Texas Basin (from Texas Railroad Commission, 1980).

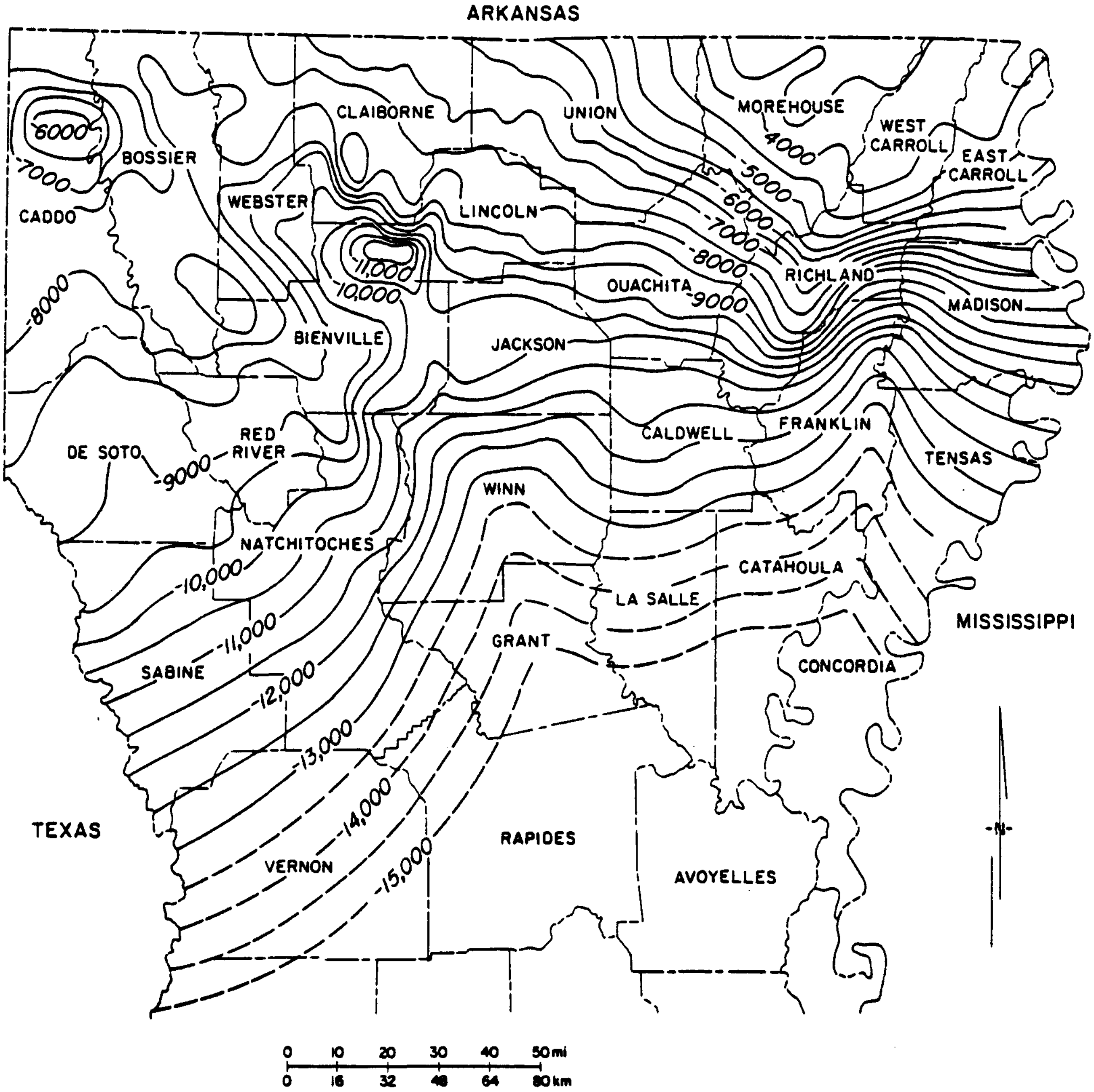

Figure 32. Structure contours on top of the Cotton Valley Sandstone, North Louisiana Salt Basin (from Louisiana Office of Conservation, 1981a).

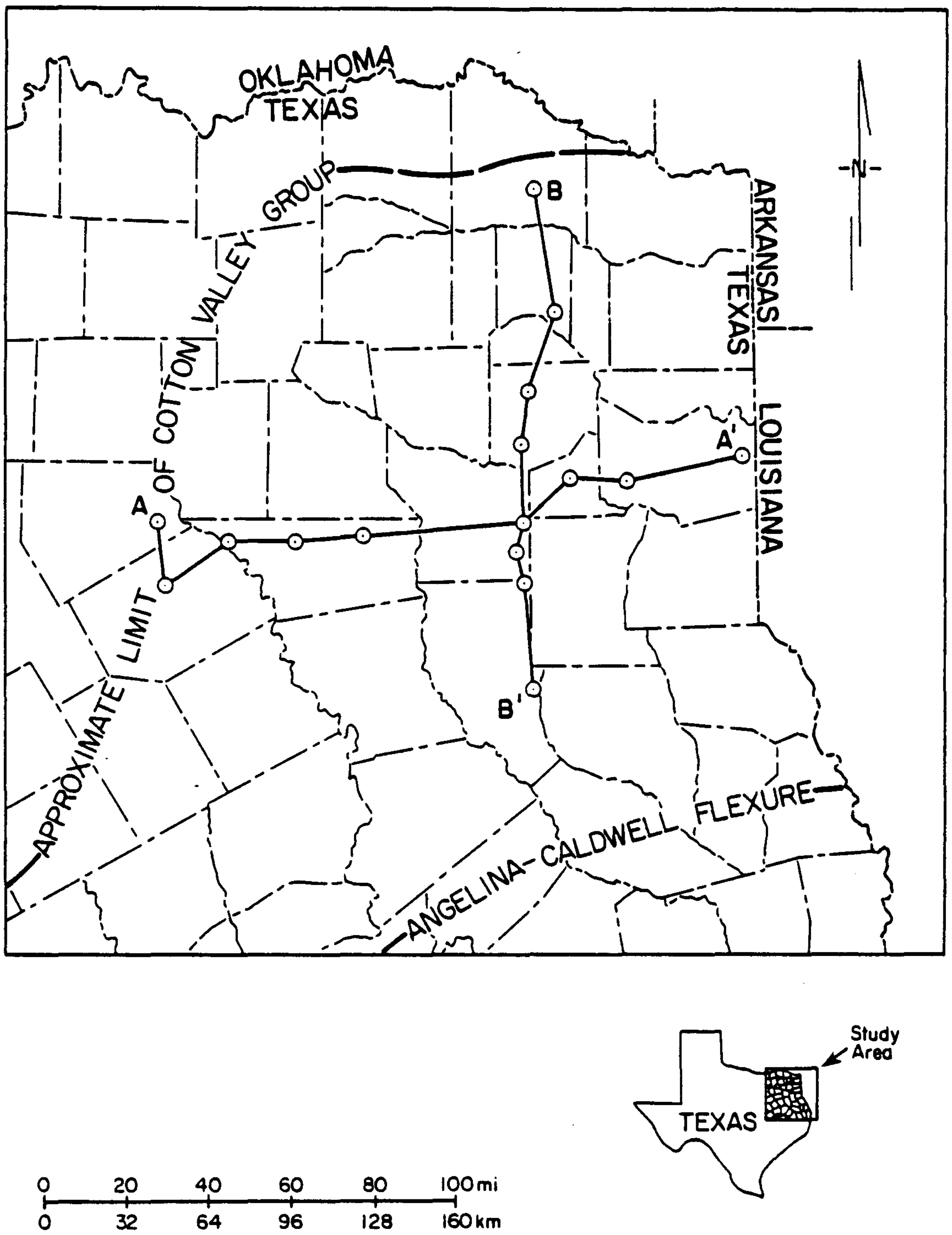

Figure 33. Index map for cross sections through the Cotton Valley Group, East Texas Basin (after Texas Railroad Commission, 1980).

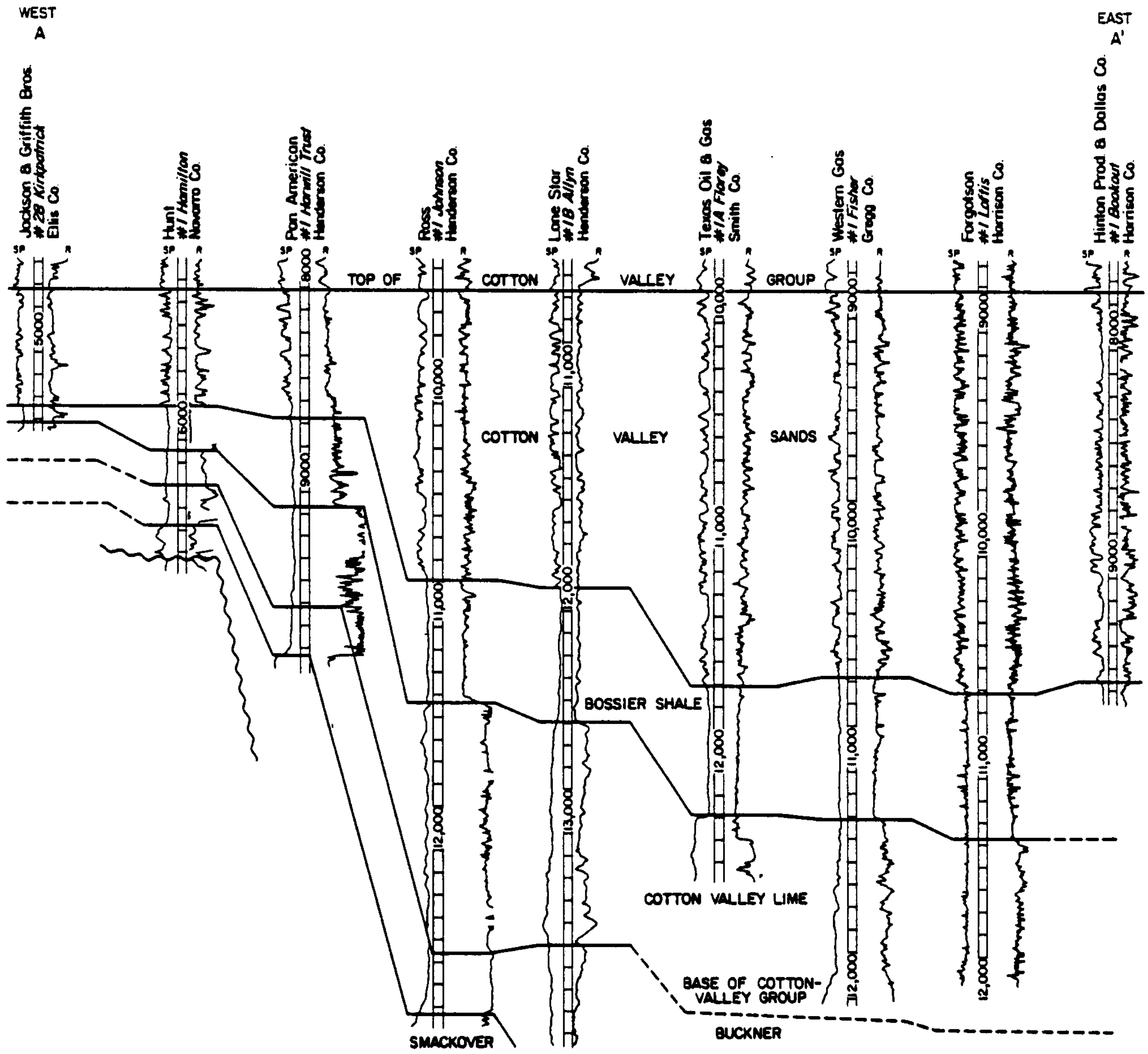

Figure 34. West-east stratigraphic cross section A-A' through the Cotton Valley Sandstone and underlying units in the East Texas Basin (from Texas Railroad Commission, 1980).

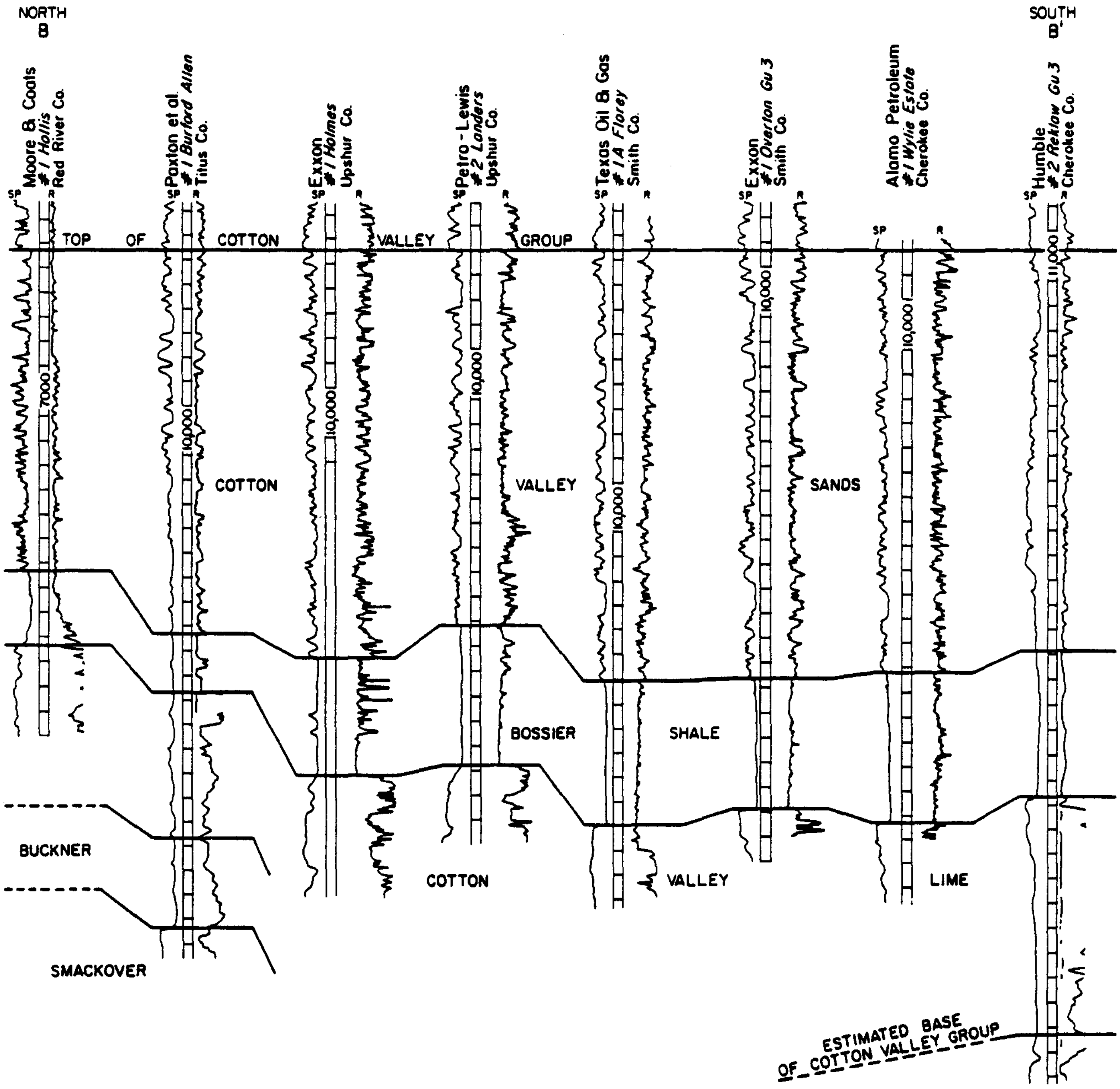

Figure 35. North-south stratigraphic cross section B-B' through the Cotton Valley Sandstone and underlying units in the East Texas Basin (from Texas Railroad Commission, 1980).

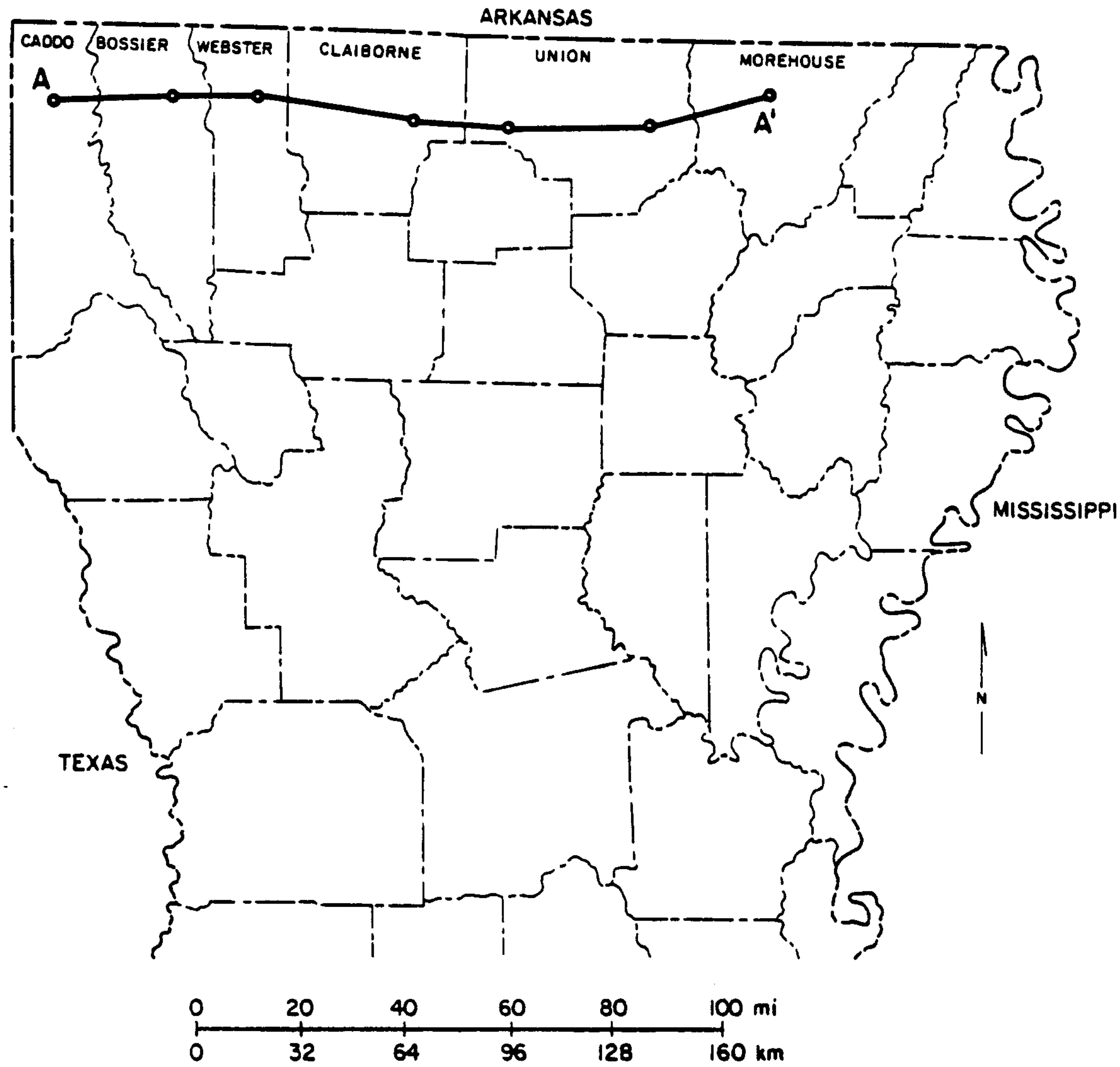

Figure 36. Index map for cross section A-A' through part of the Cotton Valley Group, North Louisiana Salt Basin (after Louisiana Office of Conservation, 1981a).

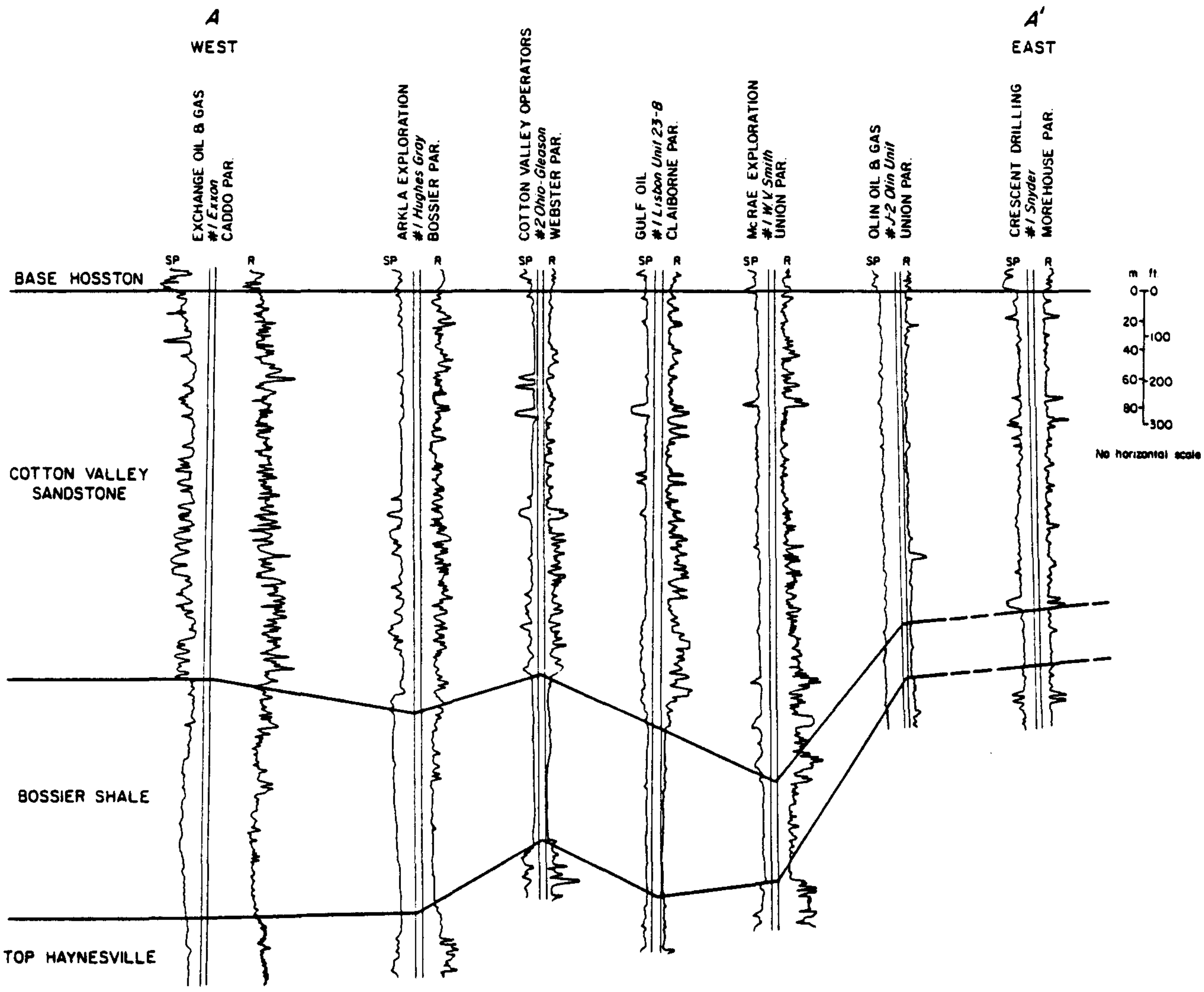

Figure 37. West-east stratigraphic cross section A-A' through the Cotton Valley Sandstone and underlying units in the North Louisiana Salt Basin (from Louisiana Office of Conservation, 1981a).

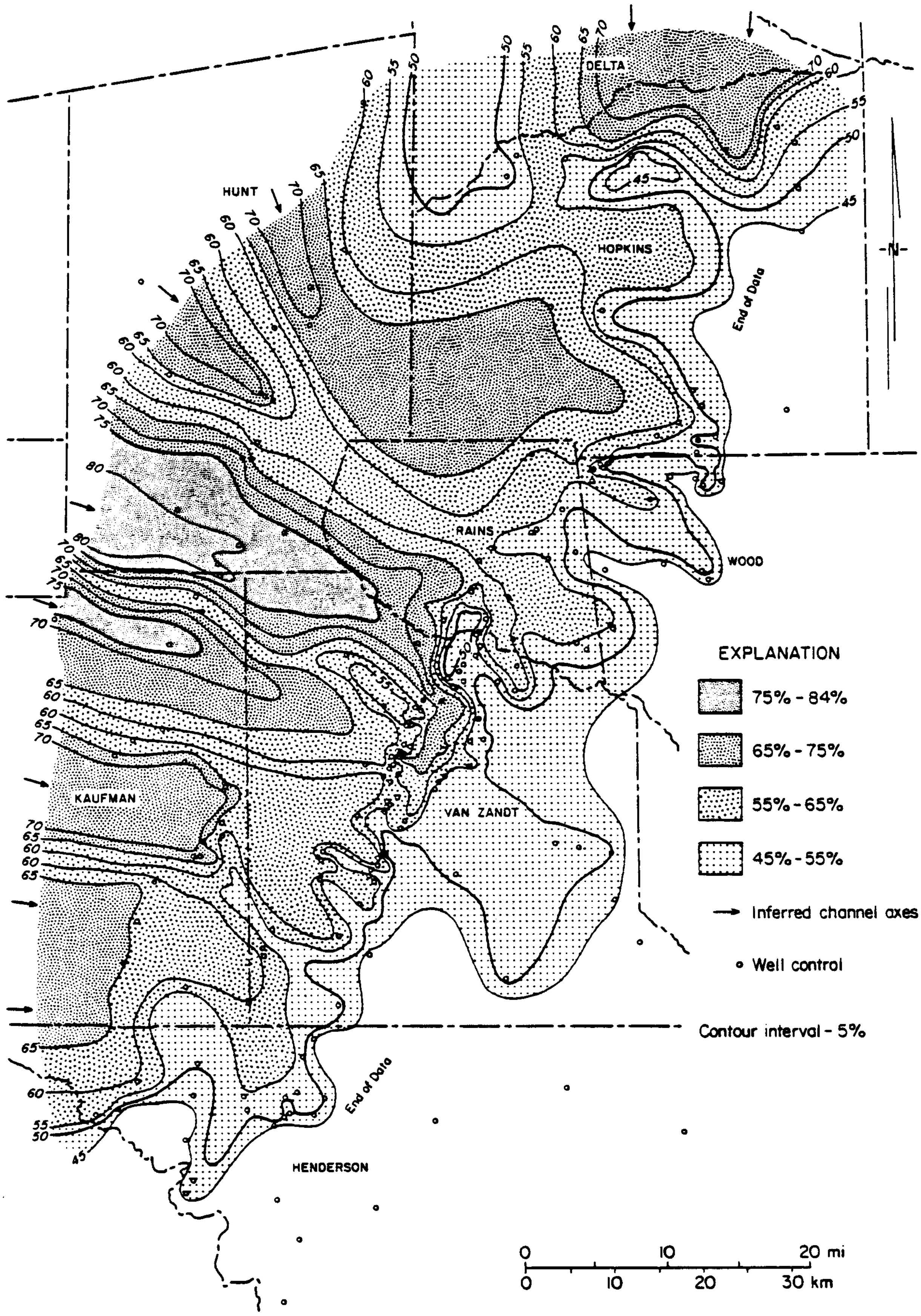

Figure 38. Percent sand map for the Cotton Valley Sandstone in the northwestern East Texas Basin (from McGowen and Harris, in press).

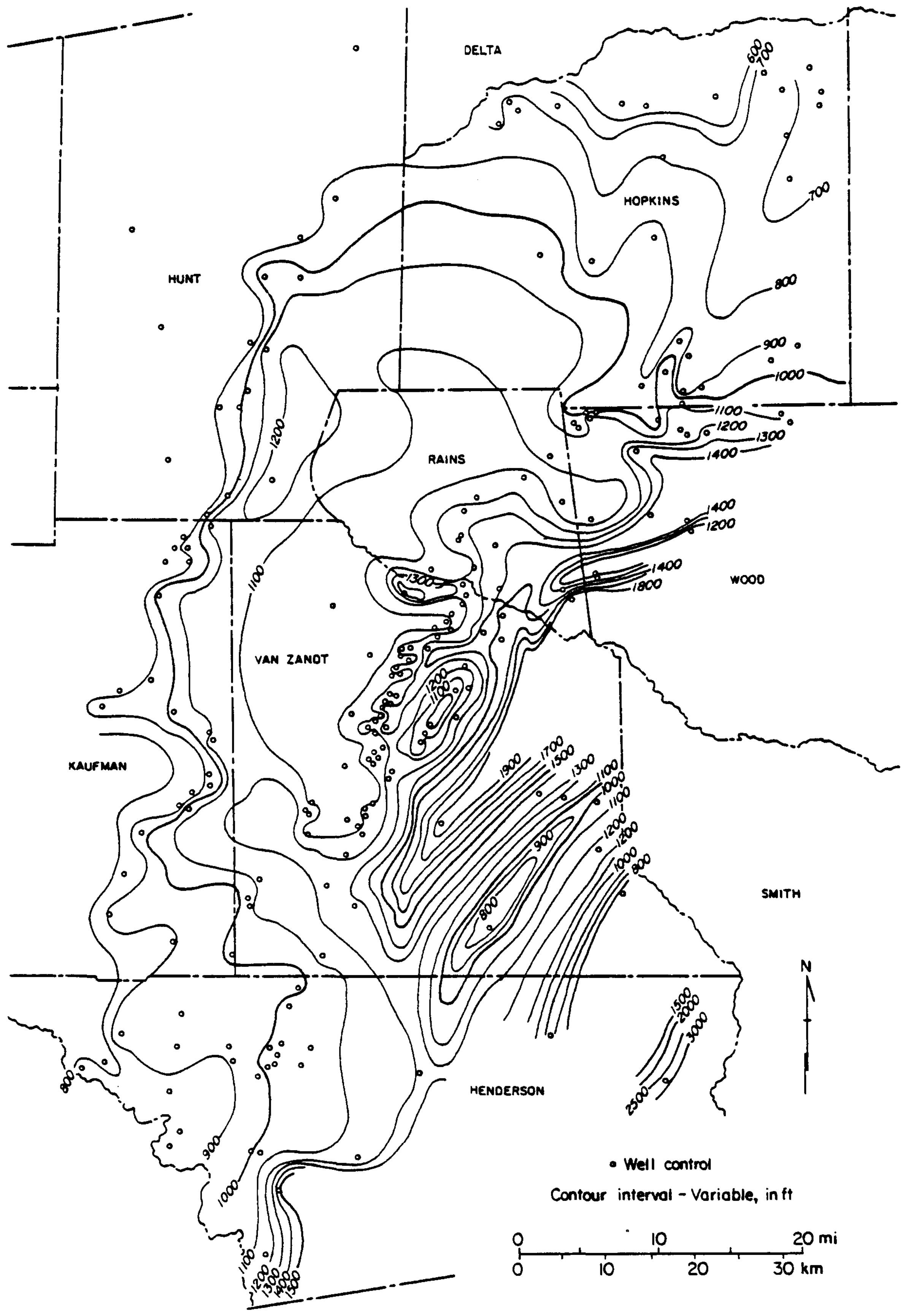

Figure 39. Net sand map for the Cotton Valley Sandstone in the northwestern East Texas Basin (from McGowen and Harris, in press).

Table 21. Cotton Valley Sandstone, East Texas Basin and North Louisiana Salt Basin: 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 mi^2 and speculative area of 7,460 mi^2 in Texas and Louisiana (National Petroleum Council, 1980).	Sands in the low-permeability trend occur within an interval 1,000-1,400 ft thick.	Drilling depths to top Cotton Valley Sand are 7,000 ft in the north, 8,000 ft in the east, 10,000-11,000 ft in the south and 5,000 ft in the west parts of the East Texas Basin. Top Cotton Valley Sand 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.	12.816 Tcf maximum recoverable gas in net productive area of 1,026 mi^2 (Texas and Louisiana) (National Petroleum Council, 1980).	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Graben formed along the margin of the Gulf of Mexico and associated with continental rifting. Basin presently bounded by major fault systems and the Sabine Uplift. Cotton Valley sandstone thins over the ancestral Sabine Uplift in Harrison and Panola Counties, Texas.	1.4-1.8°F/100 ft. Mostly 1.6-1.8°F/100 ft. National Petroleum Council (1980) indicates 250°F at 9,000 ft.	No specific regional data. National Petroleum Council (1980) indicates 5,500 psi at 9,000 ft.	Tensional. Local stress variations due to salt tectonics.

Table 22. Cotton Valley Sandstone, East Texas Basin and North Louisiana Salt Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies

Cotton Valley Sandstone was derived from prograding fan deltas with associated braided stream, delta-front and prodelta environments with source areas to the western, northwestern, and northern margins of the East Texas Basin. Dip-oriented percent sand patterns exist in Hopkins, Hunt, and eastern Kaufman Counties, changing to strike-aligned patterns (reworked marginal marine facies) in western Wood, Rains, Van Zandt, and north-central Henderson Counties. Cotton Valley Sandstone in the adjacent North Louisiana Salt 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 DeSoto and Caddo Parishes, Louisiana, and into Harrison, Rusk, and Panola Counties, Texas.

Texture

Fine to very fine sandstone with minor mud matrix; one sample reported as tightly packed and moderately well sorted.

Mineralogy

One core analysis reports: 71% quartz, 12% clay, 5% chert, 5% dolomite (euhedral cement), 4% feldspar (mostly plagioclase), and limonite and opaques. In general, the sandstones are quartz arenites to subarkoses.

Diagenesis

Cements reported in one core analysis are (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 as well. Pressure solution of quartz sand.

Typical Reservoir Dimensions

Gross productive intervals range as high as 600-800 ft.

Pressure/Temperature of Reservoir

Amoco: 5,500 psi at 270°F. Kuuskraa and others (1981): 6,000 psi at 250°F.

Natural Fracturing

Contribution of natural fractures unknown; some zones are reported to be naturally fractured. Fluid-loss treatment materials are required in some wells.

Data Availability (logs, cores, tests, etc.)

Exxon has core from Cotton Valley and Bossier sands from 10 wells in Panola and Rusk Counties. In Louisiana approximately 10% of wells penetrating Cotton Valley Group core some portion of the Group, and 72 core analyses have been identified.

Table 23. Cotton Valley Sandstone, East Texas Basin and North Louisiana Salt Basin: Engineering parameters.

ENGINEERING PARAMETERS

		Production Rates				
Reservoir Parameters	**Net Pay Thickness**	**Pre-Stimulation**	**Post-Stimulation**	**Decline Rates**	**Formation Fluids**	**Water Saturation**
Mean permeability = 0.042 md for 126 wells primarily in Harrison, Rusk and Panola Counties. Overall, in situ permeabilities of 0.0053-0.042 are expected, depending upon method of calculation. Average permeability for 302 wells in Louisiana is 0.015 md. Porosity is typically 6-10%, locally up to 18%.	35 to 88 ft (Kuuskraa and others, 1981), ranging down to 20 ft at the margins of the trend. Another estimate: 100 ft in Carthage and East Bethany Fields.	Average of 289 Mcfd for 126 wells (primarily in Harrison, Panola and Rusk Counties) at an average depth of 10,187 ft. Too small to measure in some wells both in Texas and Louisiana.	500 to 1,500 Mcfd, some up to 2,500 Mcfd.	Rapid decline in first 12-24 months; no specific data obtainable for the trend as a whole. In Oak Hill Field, Rusk County, Texas, production decline averaged 46% for 27 wells from 1 month to 6 months after fracturing.	Typically no oil is produced from tight Cotton Valley sands. Some condensate produced, initially 20-40 b/d. Initial water production possible up to 200 bbl/day, declining to 50 bbl/day after 1-2 years. Some formation waters contain 500-1,000 ppm iron, requiring special fracture fluids, to avoid formation damage by iron oxide precipitates.	Generally from less than 45 to 65%; may be difficult to determine with conventional log analysis.

Well Stimulation Techniques	**Success Ratio**	**Well Spacing**	**Comments**
Massive hydraulic fracturing, often as multi-stage treatments to effectively treat all zones of interest. Technique varies widely among operators; typical may be 500,000 lbs sand in 200,000-300,000 gals fluid injected in 3 to 4 stages. Some jobs much larger, using 2.0-2.6 million lbs of sand.	Generally 2 to 10 times improvement in production; dependent upon original permeability and formation damage.	640 acres per well. Some operators believe spacing as low as 80 acres will be required for ultimate drainage.	Fracture treatments intersecting zones of salt water have led to production problems. Gas-water contacts are very difficult to determine. Predicted ultimate well yields of 2-4 Bcf are possible.

Table 24. Cotton Valley Sandstone, East Texas Basin and North Louisiana Salt Basin: Economic factors, operating conditions and extrapolation potential.

ECONOMIC FACTORS

FERC Status	Attempted Completions	Success Ratio	Drilling/ Completion Costs	Market Outlets	Industry Interest
A 48-county area of East Texas was approved by FERC on 10/24/80. All or part of 28 parishes in Louisiana was state approved (less certain existing fields) on 9/3/81, but has not been FERC approved as of 2/26/82.	Over 930 gas wells completed in the Cotton Valley Group in Texas. Over 886 gas wells completed in the Cotton Valley Group in Northern Louisiana.	9.8% new field wildcats and 48.4% of new pool and deeper production wells, 1960-1977 in Texas (National Petroleum Council, 1980). 8.3% new field wildcats and 31.7% of new pool and deeper production wells, 1960-1977 in Louisiana (National Petroleum Council, 1980).	Typical Cotton Valley well of approximately 10,000 ft depth will cost $1.2 million to drill and complete depending upon number of pay zones and fracture treatment used (1981 dollars).	Well established regional pipeline and gathering system including Arkansas Louisiana Gas Co., Lone Star Gas Co., and Delhi Gas Pipeline Co.	High, with incentive pricing approved in Texas and pending in Louisiana, and with developing fracture treatment technology.

OPERATING CONDITIONS

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

EXTRAPOLATION POTENTIAL

	Comments
Included in this survey as a basis for comparison with other tight gas sands. A thick and widespread formation with 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 have selected comparable attributes.	All drilling and completion services readily available in East Texas and North Louisiana.

Cleveland Formation, Anadarko Basin

Introduction

The Cleveland Formation is a fine-grained sandstone of Pennsylvanian age that was deposited on the northern shelf of the Anadarko Basin (fig. 40). It is found in the subsurface of the northeastern Texas Panhandle, extending into northwestern Oklahoma and the Oklahoma Panhandle. A tight gas formation designation has been approved by the State of Texas but has not been approved by the FERC as of January 1, 1982. The present data base for the Cleveland Formation is fair to good (tables 25-28), based largely on the tight sand application (Texas Railroad Commission, 1981d, Docket No. 10-77, 222) and contact with Diamond Shamrock Corp. (M. K. Moshell, personal communication, 1982). No published studies specifically concerned with the Cleveland Formation have been located. The area in which the Cleveland is found is a mixed gas and oil, to somewhat gas-prone, province with numerous conventional reservoirs in Pennsylvanian and older Paleozoic rocks. The Cleveland Formation is oil productive in some areas, but rates of production are low, probably reflecting poor reservoir quality.

Structure

As early as middle Devonian time the Amarillo-Wichita Uplift was a relatively positive feature with significant uplift occurring in the Late Mississippian through Early Pennsylvanian (Eddleman, 1961). After the late Morrowan Wichita Orogeny, the rapidly subsiding axis of the Anadarko Basin received large quantities of arkosic sediment (granite wash) adjacent to the Amarillo-Wichita Uplift. A broad, stable platform area north and northwest of the basin axis received carbonates, thin shales, and fine sands (Eddleman, 1961), including the Cleveland. Presumably the clastic sources for the Cleveland Formation were to the west, north, and east of this platform (Texas Railroad Commission, 1981d).

Eastward tilting in Late Cretaceous time was the last major event affecting the Anadarko Basin (Eddleman, 1961). The present structure of the Cleveland Formation north of the Amarillo Uplift shows dip to the east and southeast, with the top of the formation everywhere less than 10,000 ft below the surface in the northeast Texas Panhandle (fig. 41).

Stratigraphy

The Cleveland Formation is most often classified as basal Missourian and has variously been considered part of the Pleasanton Group (Nicholson and others, 1955; Cunningham, 1961) or the Kansas City Group (Texas Railroad Commission, 1981d). A recent publication (Taylor and others, 1977) appears to have dispensed with the group terminology and used "Kansas City" as a formation name. Usage by oil and gas operators is shown in figure 42. Sediments of the Kansas City and Marmaton Groups above and below the Cleveland have not been defined on a formation basis and are therefore considered undifferentiated (fig. 42).

A regional stratigraphic cross section oriented west-east across the northeast Texas Panhandle shows thickening of the Cleveland Formation as it extends into the deeper central part of the Anadarko Basin (fig. 44). The interval thickness shown ranges from 78 to 170 ft. A regional north-south stratigraphic cross section in the same area shows the Cleveland Formation becoming more shaly just before passing into granite wash off the north flank of the Amarillo-Wichita Uplift (figs. 43 and 45). The maximum formation thickness on the latter cross section is 160 ft in the Shenandoah Oil Corp. #1 Grubbs well; however, net pay in the Cleveland Formation generally varies from 10 to 40 ft with an estimated maximum of 75 ft (M. K. Moshell, personal communication, 1982).

The most recent studies of the northeast Texas Panhandle ((S. Dutton, personal communication, 1982) suggest that the Cleveland is uppermost Des Moinesian. A comparison of sample logs, paleontologic data, and geophysical well logs supports this classification; the exact group designation is not significant to this study, but is noted for clarification of the northeast-southwest cross sections presented below.

Depositional Systems

Deposition of the Cleveland Formation in a shelf environment has been suggested by the applicants for the tight gas sand designation (Texas Railroad Commission, 1981d). This conclusion seems to be drawn more from the relative position of the Cleveland in the Anadarko Basin than from a detailed study of the unit itself. 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. 46 and 47). Although sediments are deposited on a structural shelf, the distribution of sediments may not necessarily be the product of shelf processes. As a distal tongue of terrigenous clastics surrounded by carbonates and thin shales, the Cleveland Formation may be part of a thin distal delta-front sedimentary package. However, such distal deltaic sediments may be indistinguishable from prodelta shelf muds.

Generally the character of the spontaneous potential (SP) log is poorly developed in the Cleveland Formation, possibly due to this unit's high level of cementation and low permeability. Where the character of the SP log is good, an upward-coarsening sequence followed by an upward-fining sequence is frequently seen. This cycle may consist of prodelta to delta front environments followed by transgression and reworking by wave and current action. Possible thin distributary channel or distributary mouth bar deposits may be present (S. Dutton, personal communication, 1982). The Cleveland Formation may therefore be a composite of a thin, basal deltaic unit overlain by a thicker package of prodelta sediment actually being distributed by shelf processes.

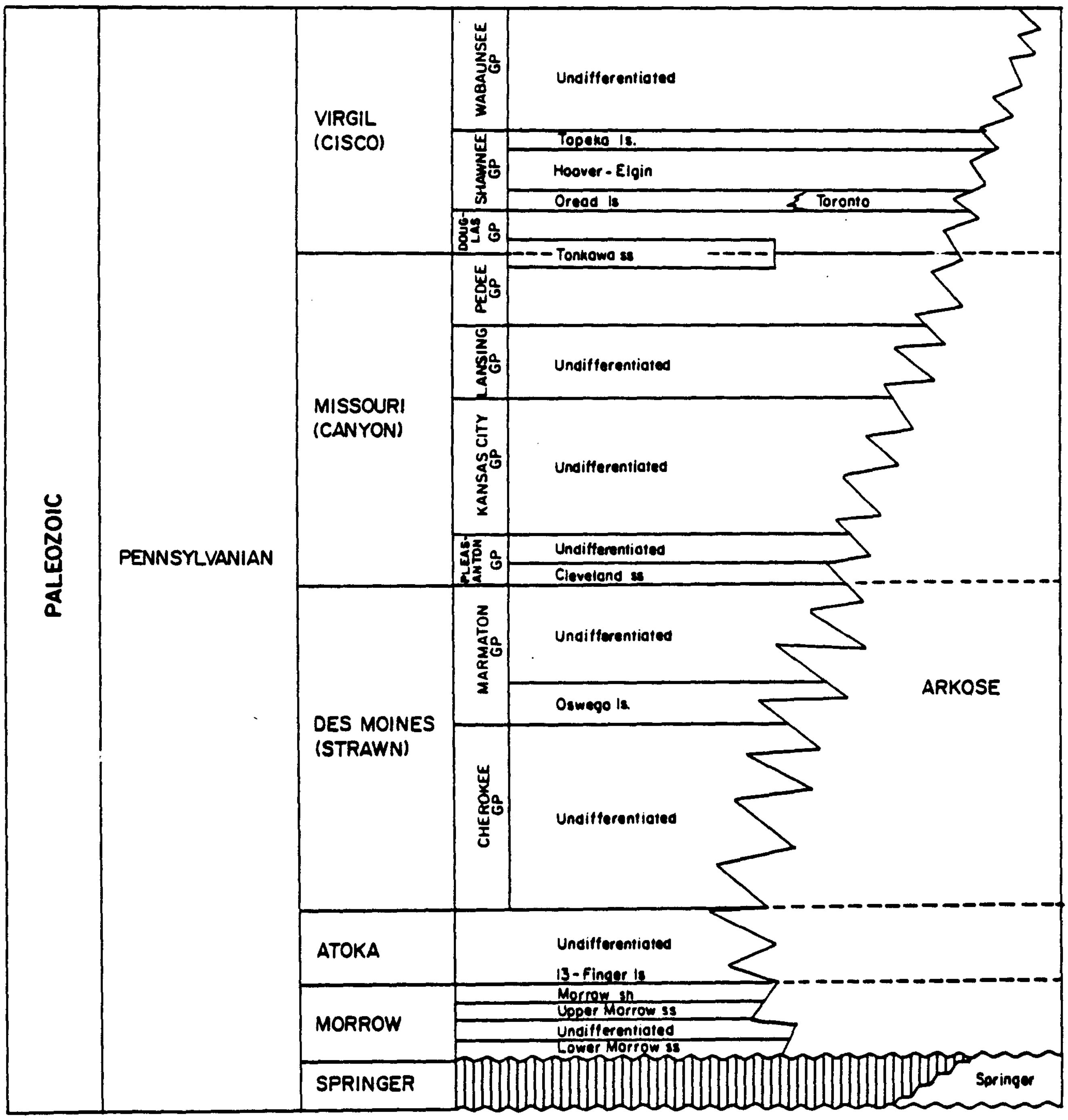

Figure 40. Stratigraphic column of the Pennsylvanian System in the Texas portion of the Anadarko Basin (Nicholson and others, 1955).

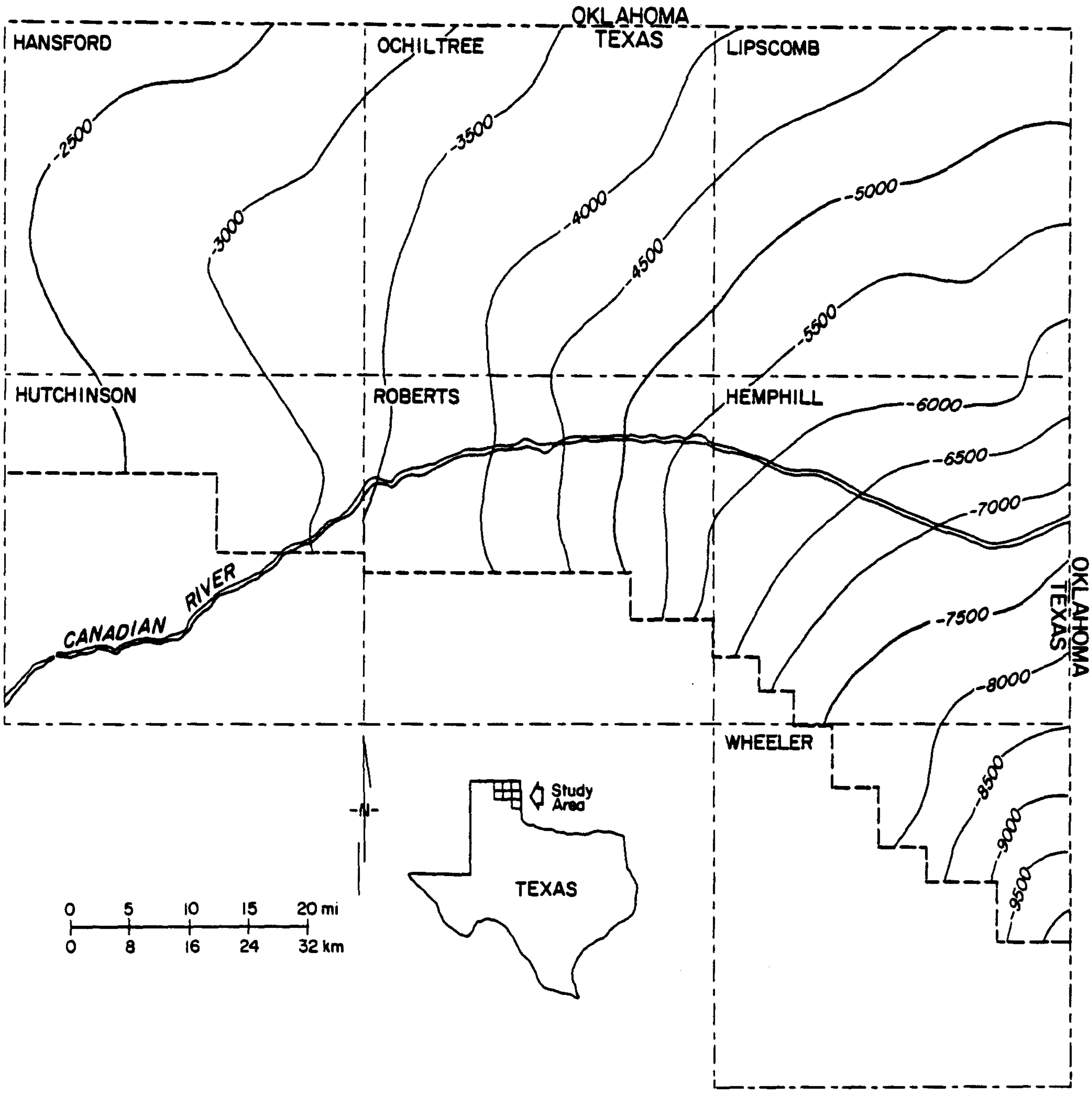

Figure 41. Structure contours on top of the Cleveland Formation, northeastern Texas Panhandle (from Texas Railroad Commission, 1981c).

SYSTEM	SERIES	GROUP	FORMATION
PENNSYLVANIAN	MISSOURIAN	KANSAS CITY	KANSAS CITY (UNDIFFERENTIATED)
			CLEVELAND
	DES MOINESIAN	MARMATON	MARMATON (UNDIFFERENTIATED)
			OSWEGO

Figure 42. Stratigraphic terminology used by applicants for tight gas sand designation for the Cleveland Formation (from Texas Railroad Commission, 1981c).

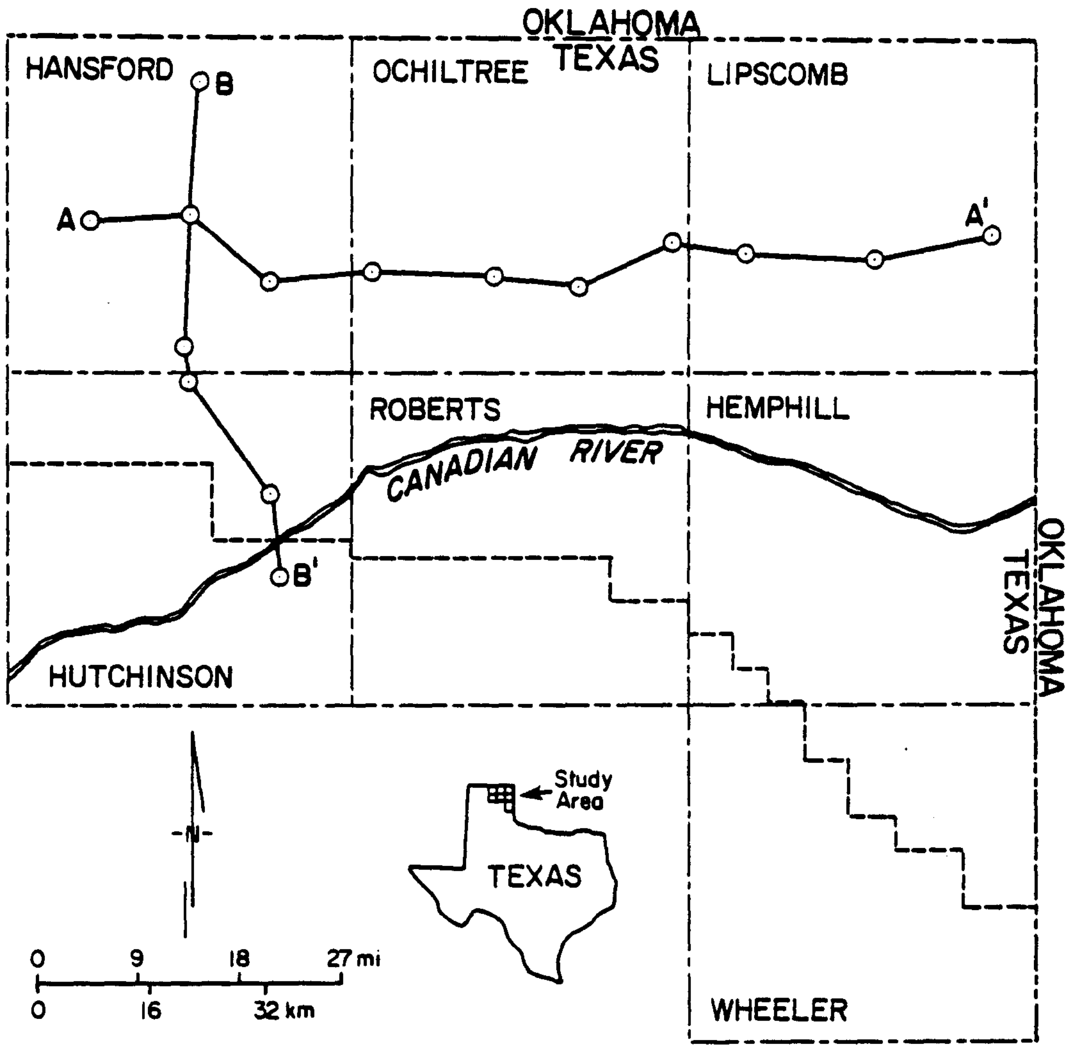

Figure 43. Index map for cross sections through the Cleveland Formation, Anadarko Basin.

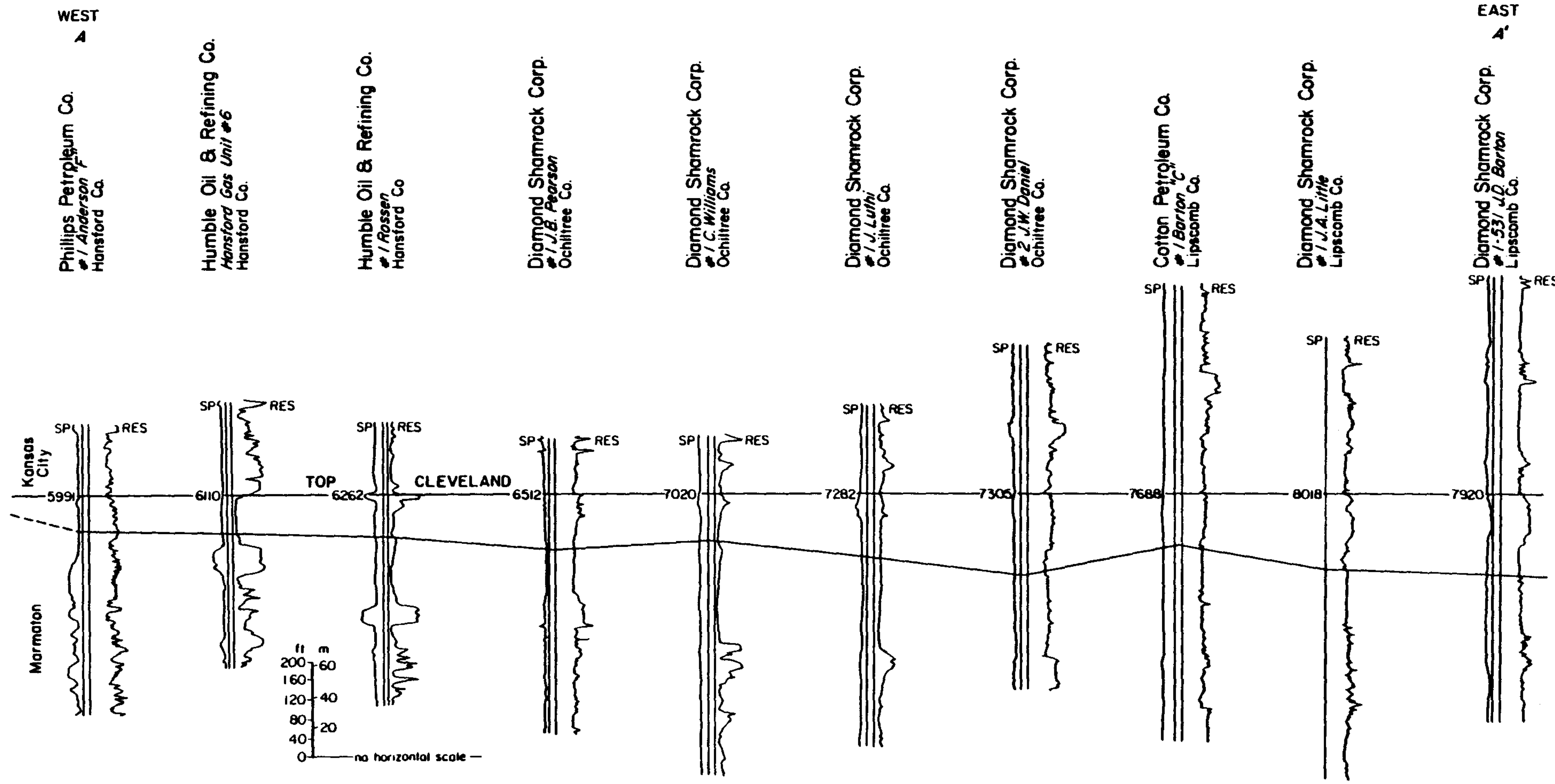

Figure 44. West-east stratigraphic cross section A-A' through the Cleveland Formation, Anadarko Basin (from Texas Railroad Commission, 1981c).

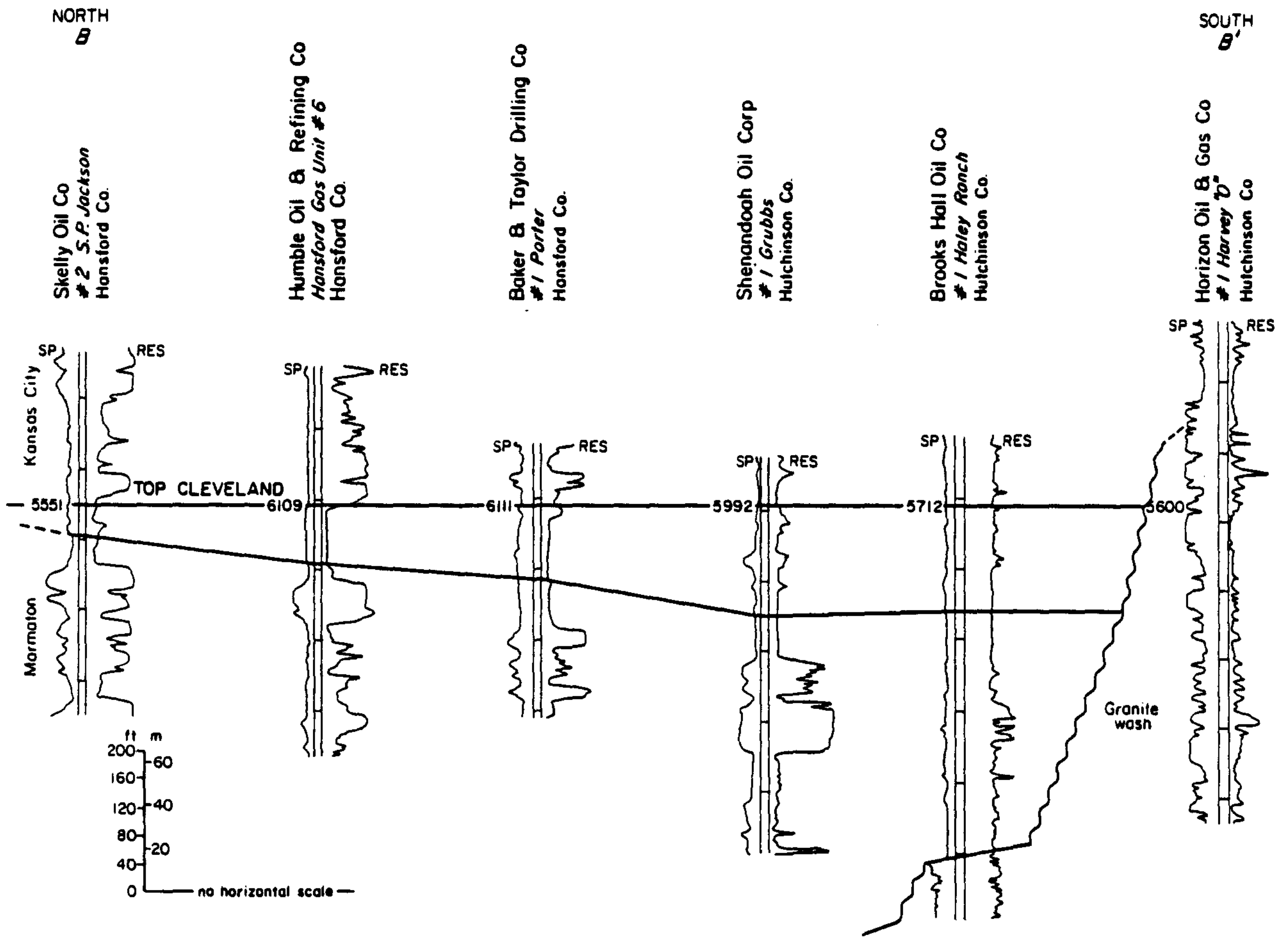

Figure 45. North-south stratigraphic cross section B-B' through the Cleveland Formation, Anadarko Basin (from Texas Railroad Commission, 1981c).

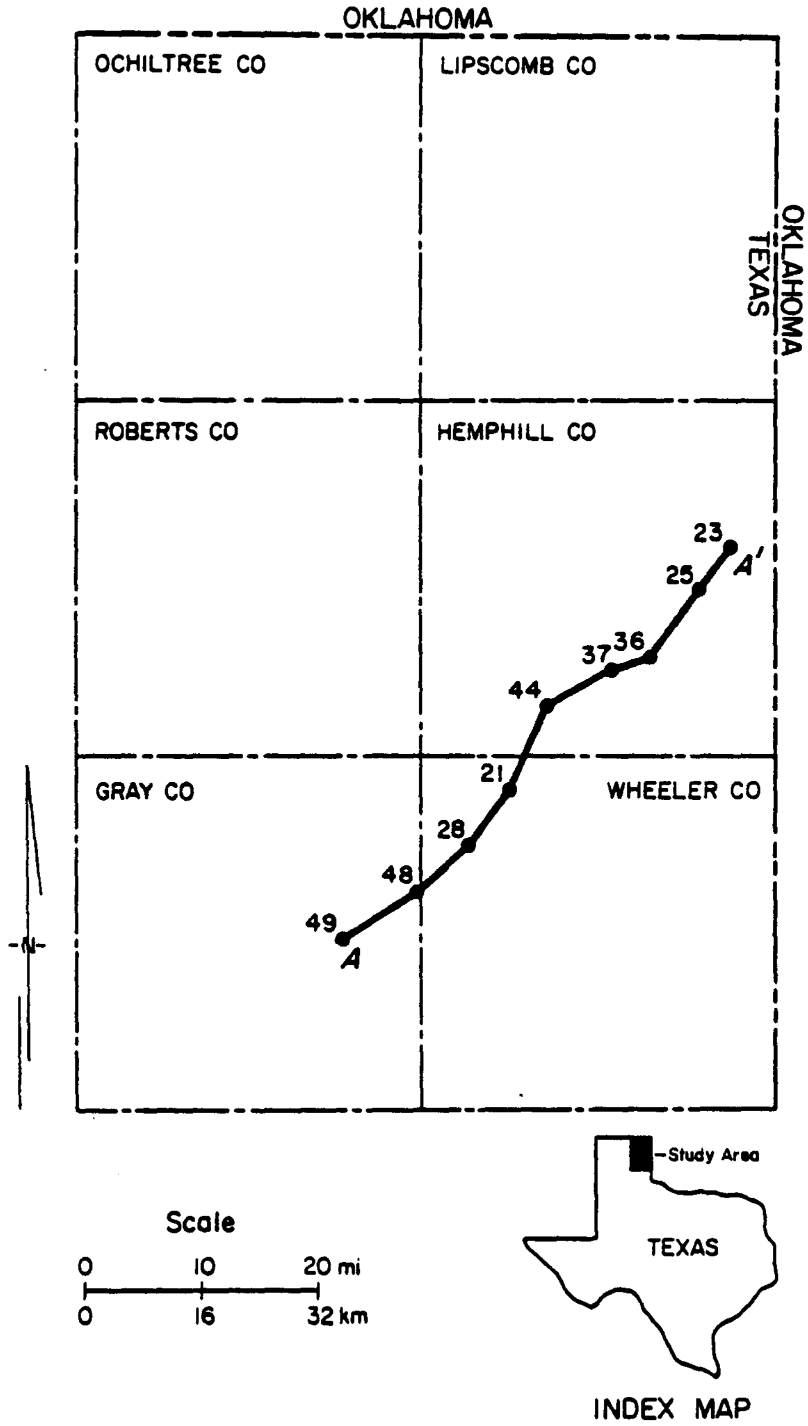

Figure 46. Index map for local cross section A-A', Gray, Wheeler, and Hemphill Counties, Texas (after Dutton, 1982).

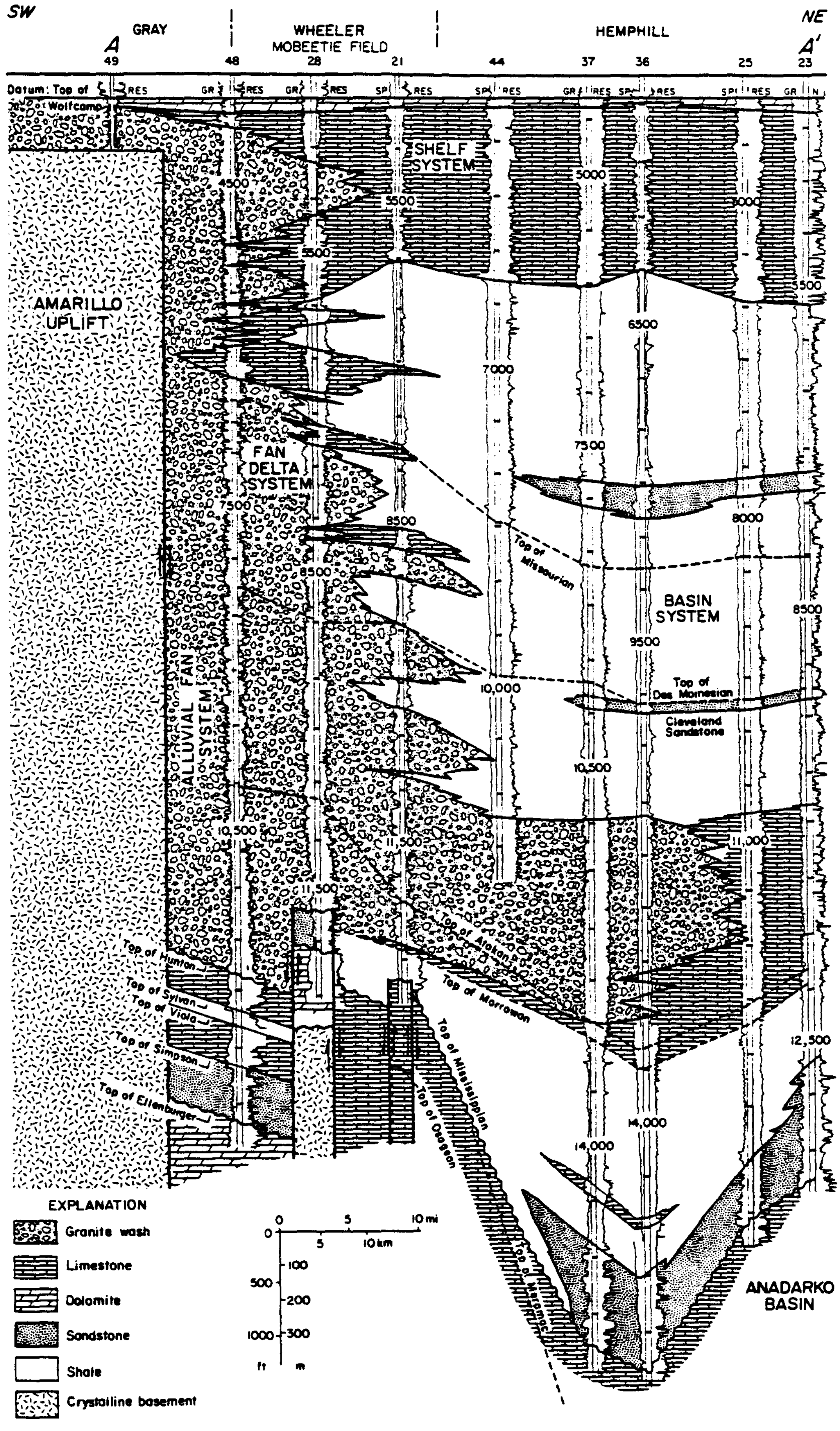

Figure 47. Local cross section A-A' through Gray, Wheeler, and Hemphill Counties showing the Cleveland Formation in the Anadarko Basin (after Dutton, 1982).

Table 25. 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, Pennsylvanian	Approximately 4,500 mi^2 gross area in all or part of 7 counties in the Texas Panhandle. Probable additional area in adjacent Oklahoma.	Across Hansford, Ochiltree, and Lipscomb Counties the Cleveland is 80-170 ft thick and averages 120 ft thick.	Top Cleveland ranges from -2,500 ft subsea (western Hansford Co.) to -9,700 ft subsea (Wheeler Co.). Top of perforations ranges from 6,258-9,439 ft, with most perforations shallower than 8,000 ft.	No specific data.	Strike: north to northeast. Across northeast Texas Panhandle: average dip approximately 1° east to southeast.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Northwest and northeast margin of the Anadarko Basin bounded to the south by the Amarillo-Wichita Uplift.	<1.2-2.2°F/100 ft. Mostly 1.4- 2.0°F/100 ft.	No specific data. Mud weights suggest normal hydrostatic gradients.	Compressional. Bounded on the south by high angle reverse fault of the Amarillo Uplift.

Table 26. Cleveland Formation, Anadarko Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies	Texture	Mineralogy	Diagenesis
Marine shelf environment with sources to the west, north and east rather than the Amarillo Uplift. Thin (20-40 ft) deltaic unit possible at the base of the formation in some areas; represented by coarsening upward (possible delta front) to blocky (possible distributary bar) log characters. Balance of unit may be shelf dispersed sands near or at storm wave base.	Fine to very fine, well-sorted sand, tending to be tightly packed in diagenetic and detrital clay matrix.	Based on one core of 60 ft length: 65% quartz, 10% feldspar (mostly plagioclase), 3% mica, plus heavy minerals and traces of chert and glauconite. Balance of sample consists of matrix and cements.	Reduction of porosity and permeability due to (in order of greatest abundance): quartz overgrowths, diagenetic clay matrix, and calcite cement (based on one core of 60 ft length). Quartz appears to be 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 (logs, cores, tests, etc.)**
Areal extent is usually 25 to 75 mi^2. Operators have developed smaller reservoirs, however. Average thickness = 120 ft.	Typically original reservoir pressures range from 2,200 to 2,700 psi and temperatures range from 145°F 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 usually include dual induction-SFL resistivity and density-neutron for porosity.

Table 27. 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 = 0.028 md, representing an unknown mixture of pre- and post-stimulation well tests.	10-40 ft with a maximum estimated to be 75 ft.	Often too low to effectively measure.	Mean of 396 wells now producing (may include data from a few non-stimulated wells) = 218 Mcfd, stabilized flow rate.	Approximately 56% the first year followed by 11% per year for the life of the well.	Minor amounts of condensate produced, less than 5 bbls/day per well.	30-40% 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 gals 7.5% HCl, and fracturing with 80,000-90,000 gals 2% KCl water with cross-linked polymer and 250,000 lbs of 20/40 mesh sand. Pressures of 4,500 to 5,000 psi are utilized.	Stimulation is usually successful.	640 acres, 320 acres optional. Operator interest exists in reducing this to 320 acres with 160 acres optional.	Pre-stimulation flow tests of adequate duration are rare. An unknown number of wells have been plugged (due to low permeability) prior to development and more widespread use of hydraulic fracturing.

Table 28. 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
State approved for northeast Texas Panhandle on 11/30/81. No FERC approval as of 1/1/82.	At least 507 total completions in 6 counties of which 439 were active as of 8/81.	Wildcat: no data. Infill: 80-90%, dropping toward the edges of a field.	Typical productive cost for an 8,000 ft Cleveland gas well is \$600,000-\$650,000 (1981 dollars). In addition, a \$50,000 frac job is required (1981 dollars).	Numerous pipelines in-place and healthy competition exists for the available gas. Gas is purchased for interstate sale, agricultural irrigation use, 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 (18-24 inches mean annual precipitation). Rainfall dominantly during spring and summer as thunderstorms. Occasional rapid temperature drops in late fall and winter due to frontal passages. Hot summers, moderately cold winters.	Excellent on High Plains, good other areas. Roads at 1-mile spacing on High Plains surface (typically). No major terrain barriers.	Fair. Very thin deltaic package has no good analogy. Shelf sand with 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 Des Moinesian (Pennsylvanian) Sandstones, Anadarko Basin, Oklahoma

In the Anadarko Basin of western Oklahoma, Pennsylvanian sands of the Atokan and Des Moinesian (Strawn) Series include several units that have been applied for as tight gas reservoirs. These units include undifferentiated Atokan sands, the Cherokee Group, and the Red Fork Sandstone (fig. 48). Applicable areas are primarily in counties bordering Texas (table 29). 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. J. Nicholson (personal communication, 1982) believes that the Atokan sands and the Des Moinesian sands of the Cherokee Group in the application areas are probably distal delta front to shelf deposits, possibly lapping over a shelf break into the deeper Anadarko Basin adjacent to the Amarillo-Wichita Uplift. The source for these sands is to the northwest and northeast rather than from the uplift (Evans, 1979).

The application for the Red Fork covers the largest area (1,080 mi^2) of the several applications in western Oklahoma. The zone of interest has permeability of 0.0082 to 0.014 md, porosity of 6 to 10 percent, thickness of 10 to 20 ft, and occurs at a depth of 11,100 to 12,700 ft. Stimulation (fracture treatment) typically costs $150,000 per well (1981 dollars), and there are 71 wells producing from the formation within the application area. Other Pennsylvanian tight sands in western Oklahoma also occur at depths of 11,000 ft or more (table 29).

Because these Pennsylvanian sands are relatively thin and are predominantly at depths exceeding 11,000 ft, they are not considered prime candidates for further research by GRI. Other, shallower Pennsylvanian sands occur in southwestern Oklahoma (fig. 48), but the Tonkawa is oil-prone and the Douglas Group tends to be lenticular with 10- to 20-ft-thick sand bodies without lateral continuity, especially in the lower Douglas (J. Nicholson, personal communication, 1982).

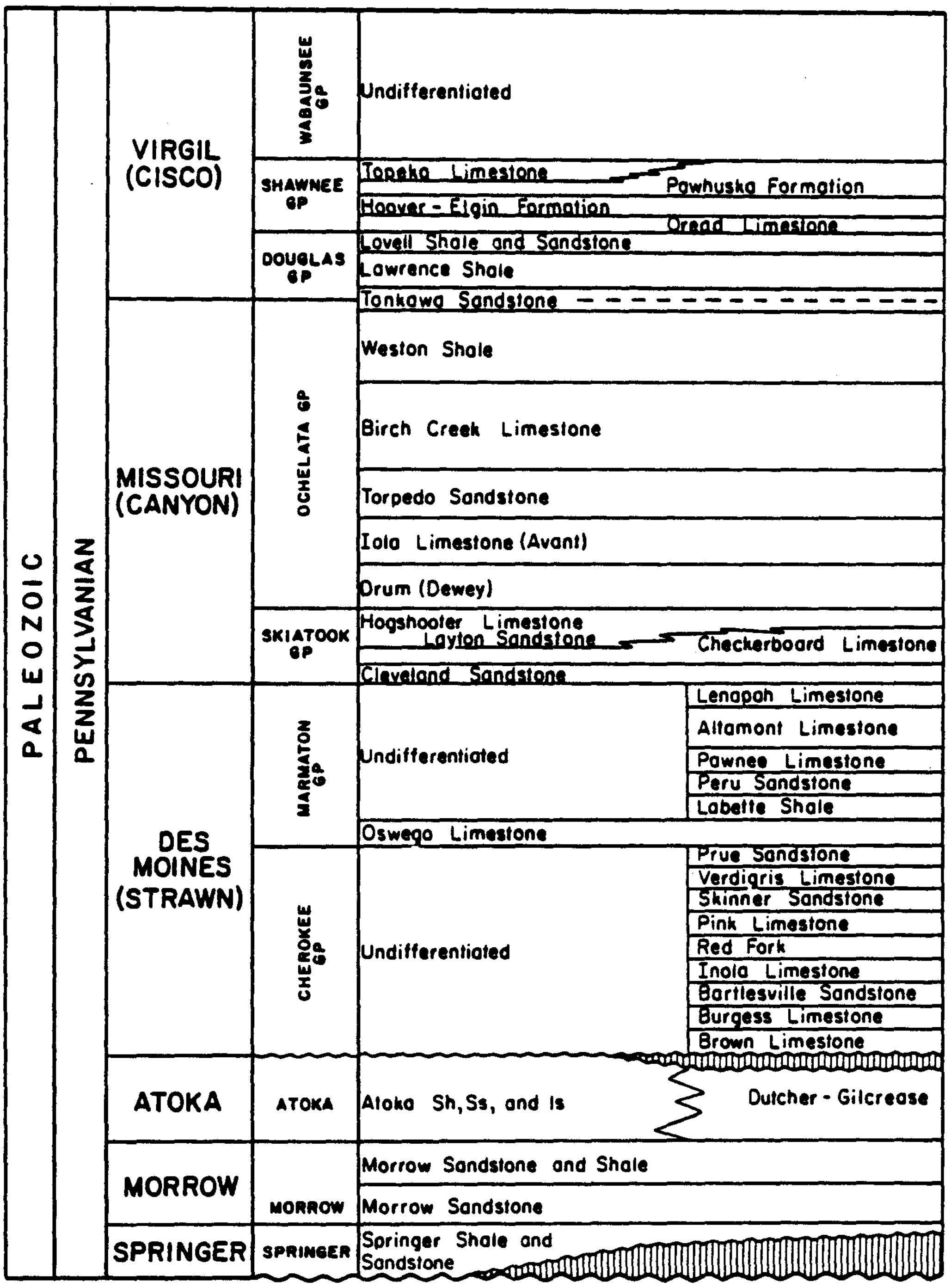

Figure 48. Stratigraphic column of the Pennsylvanian System in the western Oklahoma portion of the Anadarko Basin (after Nicholson and others, 1955).

Table 29. Tight gas sand applications in the Anadarko Basin, southwestern Oklahoma (C. Bowlin, personal communication, 1982; Hagar and Petzet, 1982a and b)

Group or Formation	Approval Status	Total Area (acres)	Counties	Depth (ft)
Atokan Group	FERC approved	55,680	Washita	12,500-13,500
upper and lower Cherokee Group	State approved (exceptions filed)	690,000	Beckham, Custer, Washita, Roger Mills	11,100-12,700
Atokan Group	State pending	5,120	Washita	10,950
Red Fork Sandstone	State pending	32,640	Washita, Caddo	11,500

Davis Sandstone, Fort Worth Basin

Introduction

The Davis Sandstone of the Atokan Group is Lower-Middle Pennsylvanian in age and was deposited in the northern Fort Worth Basin of North-Central Texas (fig. 49). The Davis Sandstone is an informal lithogenetic unit which is within the upper part of the Atokan Group (fig. 50), and 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 infrequently been tested. Most Atokan production from tight, predominantly gas-bearing sandstones and conglomerates in the northern Fort Worth Basin has been from the lower Atokan (Morton-Thompson, 1982). Cumulative production from the Atokan Group as a whole through 1977 was over 408 Bcf of gas and 94 million bbl of oil.

The data base for the Davis is poor (tables 30-33). Only two fields in northern Parker County produce from the Davis, suggesting that a potential gas province is most likely to be confined to an area of approximately 300 mi^2. An application for tight formation status regarding the Davis has not been filed.

Structure

The Fort Worth Basin is a Paleozoic foreland basin and is approximately 20,000 mi^2 in area. It is deepest toward the east-northeast part of the basin adjacent to the Ouachita Thrust Belt and shallows to the west and south. The 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 Concho Platform-Bend Flexure, and on the south by the Llano Uplift (fig. 51) (Morton-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, but 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 (Morton-Thompson, 1982).

Stratigraphy

The uplifts surrounding the Fort Worth Basin provided the source areas for the Pennsylvanian clastics filling the basin, with a progressive westward shift of depocenters in Middle to Late Pennsylvanian time. The Ouachita Uplift was the predominant source (Morton-Thompson, 1982; Ng, 1979) with additional sediment shed from the Muenster Arch (Lovick and others, 1982).

The Davis lithogenetic unit overlies a major fluvially dominated fan delta system in the lower Atokan. The unit itself consists dominantly of sands and shales with a few thi limestone units, interpreted to be lacustrine in origin, and has a thick strike-orientea geometry. Electric log patterns suggest concurrent progradation and aggradation (Morton-Thompson, 1982). No stratigraphic terminology has been encountered for any subdivision of the Davis interval. The Davis Sandstone of Morton-Thompson (1982) is equivalent to the Pregnant Shale of Ng (1979), wherein the coarser lithology occurs at the top of the unit. The post-Davis, upper Atokan clastics represent a return to the highly digitate sandstone geometry of a fluvially dominated fan delta system (Morton-Thompson, 1982).

Depositional Systems

The Davis Sandstone has been interpreted as a wave-dominated system of coalesced chevron to arcuate deltas primarily composed of coastal barrier facies (Morton-Thompson, 1982). The latter 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 with excellent strike continuity and moderately good dip continuity. Although core from the Davis is unavailable, and other data are limited, a suggested reconstruction of the Davis facies tracts has been made (fig. 52). This model is based on analogous modern delta systems. The Davis facies distribution for the northern Fort Worth Basin shows the predominance of coastal barrier facies in western Parker and southern Wise Counties that resulted from wave redistribution of substantial amounts of sand along the delta margins (fig. 53) (Morton-Thompson, 1982). This deltaic geometry suggests a period of tectonic quiescence and less sediment input, hence the dominance of marine over fluvial processes. The post-Davis depositional system shows a return to a fluvially dominated, highly digitate sandstone geometry.

SYSTEM		SERIES	GROUP OR FORMATION
CRETACEOUS		UNDIVIDED	
PERMIAN		WOLFCAMP	CISCO Group
PENNSYVANIAN	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 49. Stratigraphic column in the Fort Worth Basin (from Morton-Thompson, 1982).

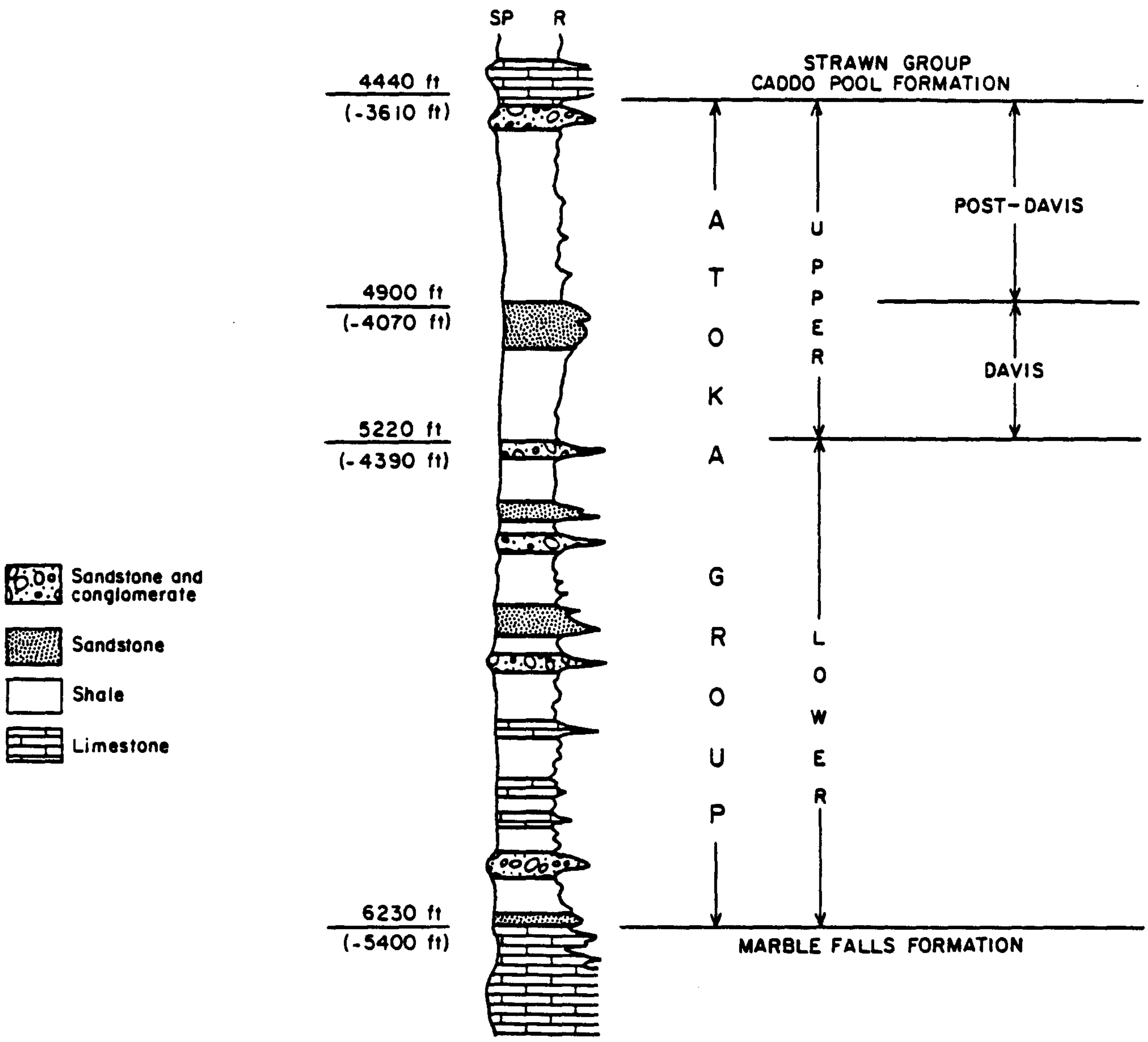

Figure 50. Typical log response and lithologies of the Atokan Group in the Fort Worth Basin (after Morton-Thompson, 1982).

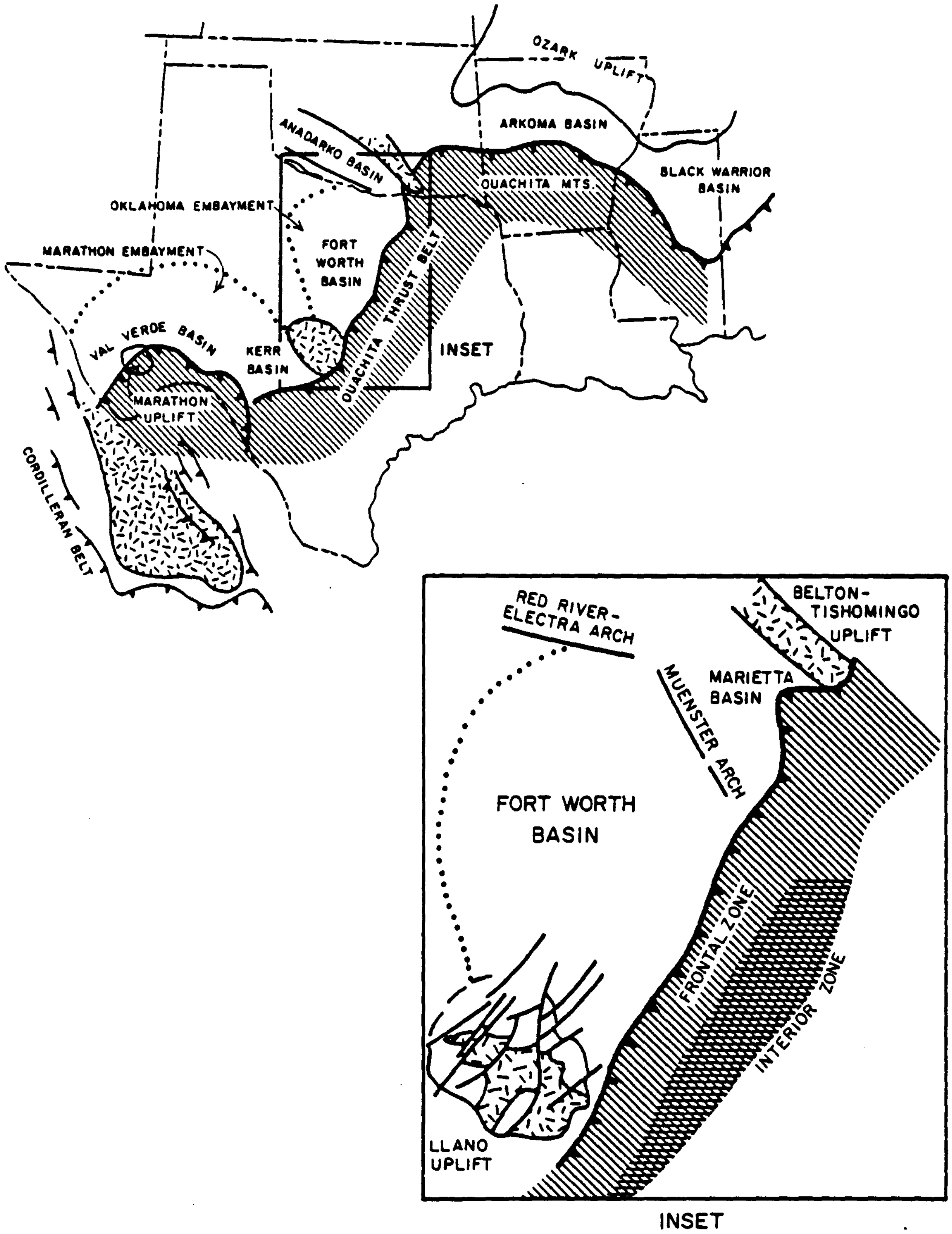

Figure 51. Regional and local structural setting of the Fort Worth Basin (after Morton-Thompson, 1982).

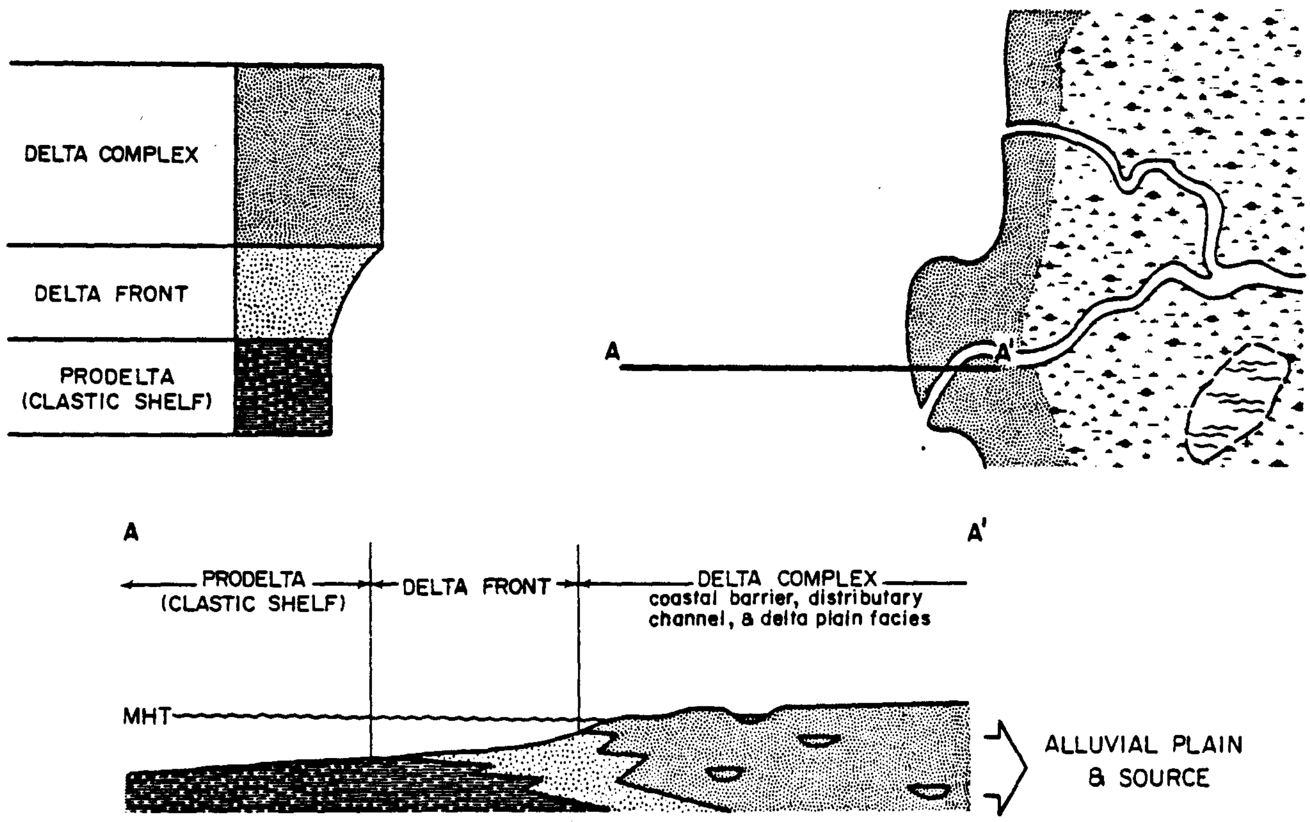

Figure 52. Idealized facies tract of the Davis Sandstone based on an analogy to the Rhône Delta (after Morton-Thompson, 1982).

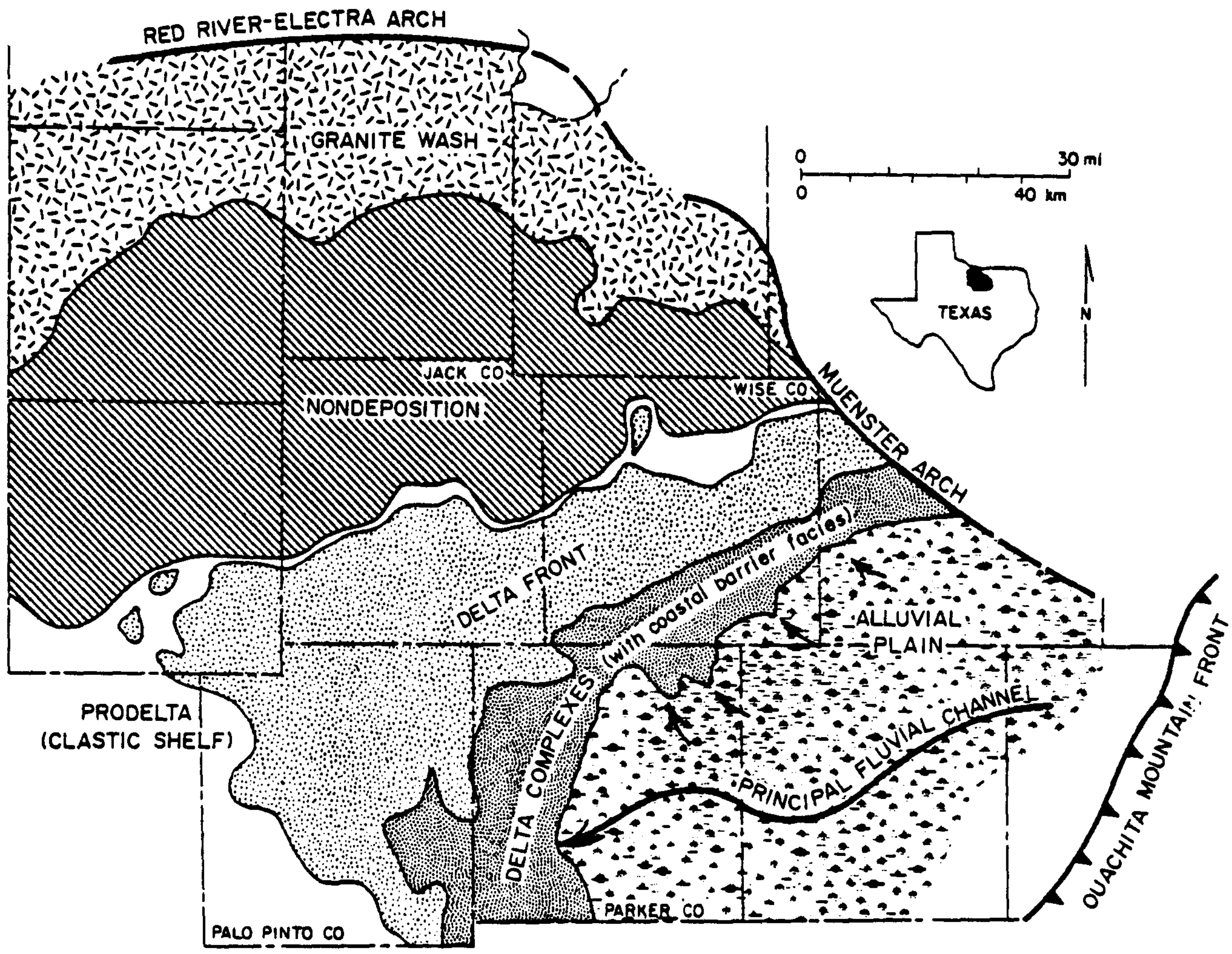

Figure 53. Distribution of deltaic facies of the Davis Sandstone in part of the Fort Worth Basin (from Morton-Thompson, 1982).

Table 30. 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 consisting generally of the northern one-third of Parker County, or approximately 300 mi^2.	Averages 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 multiple 30 ft-thick units in the northeastern to eastern parts of the basin. Major depocenter in Parker County.	Approximately 4,800-5,200 ft.	Unknown.	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Paleozoic foreland basin, 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 Concho Platform, and on the south by the Llano Uplift.	1.2-1.6°F/100 ft.	No data.	Compressional thrust belt margin on the east. Inferred normal faults within the basin related to extension during basin subsidence.

Table 31. Davis Sandstone, Fort Worth Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies	Texture	Mineralogy	Diagenesis
A 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 with a strike-oriented facies framework.	Shale to medium to very fine sand with minor, thin limestone stringers (derived from a lacustrine delta-plain environment).	Generally the Atokan Group consists of a quartz-rich, feldspathic litharenite. No core from the Davis Sand available. Generally more feldspathic sediments derived from the Muenster Arch. More quartz-rich sediments derived from the Ouachita Thrust Belt.	Compaction resulting 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 (logs, cores, tests, etc.)**
Generally unknown in northern half of Fort Worth Basin.	No data.	Extent unknown.	Core not available.

Table 32. Davis Sandstone, Fort Worth Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir Parameters	Net Pay Thickness	Production Rates: Pre-Stimulation	Production Rates: Post-Stimulation	Decline Rates	Formation Fluids	Water Saturation
Generally expected permeability of less than 1.0 md and 8-12% porosity. Porosity ranges from 3-6% in alluvial plain - coastal barrier facies, and up to 15% in some deltaic sandstones. Better porosity in upper one-fourth of Davis Sand.	No data.	No data.	No data.	No data.	Gas prone; only very minor oil production.	No data.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
Hydraulic fracturing. Example: one job in underlying Bend Conglomerate in Wise County involved 506,000 lbs of sand, 139,000 gals foam and 198,000 gals emulsion.	No data.	No data.	No additional information.

Table 33. 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 operator applications.	Primarily in two fields in Parker County.	No data.	No specific data.	Pipelines in place as a result of existing gas production include Southwestern Gas Pipeline Co. and Lone Star Gas Co.	Probably low to moderate; no FERC applications; overall data appears to be limited. Some infill and step-out well drilling for objectives below the Davis flourished in the mid-1970's.

OPERATING CONDITIONS

Physiography	Climatic Conditions	Accessibility
In the North-Central Prairies, with up to 300-500 ft of local relief. Most of area is gently sloping.	Continental climate with 28-34 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.

EXTRAPOLATION POTENTIAL

	Comments
Fair to poor. Evaluation limited by incomplete data on this unit. Wave-dominated deltaic system has analogies in the Olmos Formation of the Maverick Basin, and deltaic parts of the Fox Hills Formation of the eastern Greater Green River Basin. The Fox Hills, however, probably includes more extensive interdeltaic barrier facies.	Drilling and completion services available as result of previous exploration and current production associated with deeper horizons.

Olmos Formation, Maverick Basin

Introduction

The Olmos Formation is Late Cretaceous in age and was deposited in the Maverick Basin of the Rio Grande Embayment (fig. 54). The subsurface extent of the Olmos is primarily within seven counties of South Texas and part of adjacent Mexico (figs. 55 and 56). The Olmos Formation consists of fine to very fine silty sand interbedded with massive shales; some horizons contain disseminated grains of lignite and glauconite (Texas Railroad Commission, 1981a, Docket No. 4-77, 136; Glover, 1955). Two applications for tight gas formation designations regarding the Olmos Formation have been received by the Railroad Commission of Texas. As of January 1, 1982, one application has been approved by the Commission, but no applications have been acted upon by FERC. The present data base for the Olmos Formation is fair (tables 34-37), with data for limited areas found in the tight formation applications. Published data specifically on the Olmos deals primarily with oil and associated gas production, and does not include recent information (Dunham, 1954; Glover, 1955; Glover, 1956). A publication on the underlying San Miguel Formation (Weise, 1980), and limited data on diagenesis of the Olmos (Guven and Jacka, 1981) do contain data valuable to this survey of gas in the Olmos Formation.

Structure

The Maverick Basin is bounded in Texas by the Balcones Fault Zone and the San Marcos Arch (fig. 55). This arch acted as a mildly positive structure that subsided at a slower rate than adjacent basins during Cretaceous sedimentation. Other boundaries are the Devil's 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 occur in the Maverick Basin. The Upper Cretaceous clastics of the Maverick Basin do not include the thick shale units characteristic of the Gulf Coast Tertiary section; therefore, large growth faults do not cut the Upper Cretaceous units (Weise, 1980).

Numerous basaltic volcanic plugs occur in the northern Maverick Basin, especially in Zavala County. Differential compaction and small tensional structures over these plugs can be demonstrated. Their significance to tight gas production is not known; none are mentioned in the operator applications for tight formation designations.

Stratigraphy

The Olmos Formation is part of the Upper Cretaceous Taylor Group (fig. 54). Prior to deposition of the Taylor Group, carbonate sedimentation had been dominant in the Maverick Basin. The San Miguel, Olmos, and Escondido Formations are dominantly terrigenous clastics, 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 shifted to the southeast within the Gulf Coast Basin (Pisasale, 1980).

Within the Olmos there is no widely recognized designation for the individual sand units. An apparently informal designation of sands as N-2 through N-5, with some upper and lower subdivisions, was used by Petro-Lewis and others in their application for tight formation status (Texas Railroad Commission, 1981a) (figs. 57-59). In the latter 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 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 occur (Texas Railroad Commission, 1981a). Generally, the N-3 and older sands are interpreted to be regressive, and progradational patterns on spontaneous potential (SP) logs support this contention within areas probably representing deltaic lobes. The N-4 and N-5 sands in the Trans Delta, No. 3-18 Petty and No. 6-7 Petty wells (fig. 58) show representative upward-coarsening sequences. The N-2 sands are considered transgressive (Texas Railroad Commission, 1981a); however, for the area covered by 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 has been reworked by transgression resulting in a very sharp upper contact (fig. 59).

In the Segundo Field, Webb County, Texas, geologists of Union Oil Company of California (no docket number assigned) suggest that Olmos sands represent strandline deposits in the form of sand ridges. This description suggests the occurrence of a barrier island facies, as might be expected to develop marginal to a delta lobe.

No basin-wide depositional systems analysis is available for the Olmos Formation, but a study has been completed by Weise (1980) for the underlying San Miguel Formation. The San Miguel consists of wave-dominated deltas "reworked to varying degrees by contemporaneous marine processes and by physical and biological processes during subsequent transgression" (Weise, 1980). Available data suggest a similar depositional setting for the Olmos with multiple deltaic sandstone bodies and incomplete strandplain-barrier sequences. Such an interpretation would be consistent with a study of the Olmos in adjacent Mexico where coals up to 6 ft thick occur in a more proximal delta plain environment with associated fluvial and lacustrine facies (Caffey, 1978).

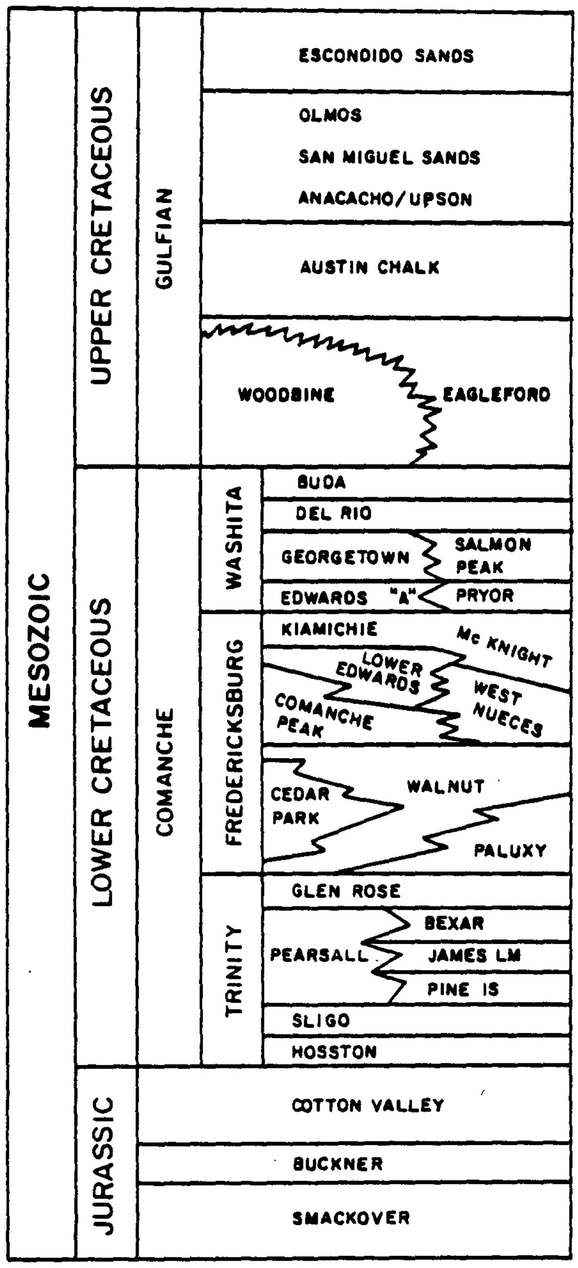

Figure 54. Stratigraphic column for part of the Jurassic and the Cretaceous Systems in the Maverick Basin.

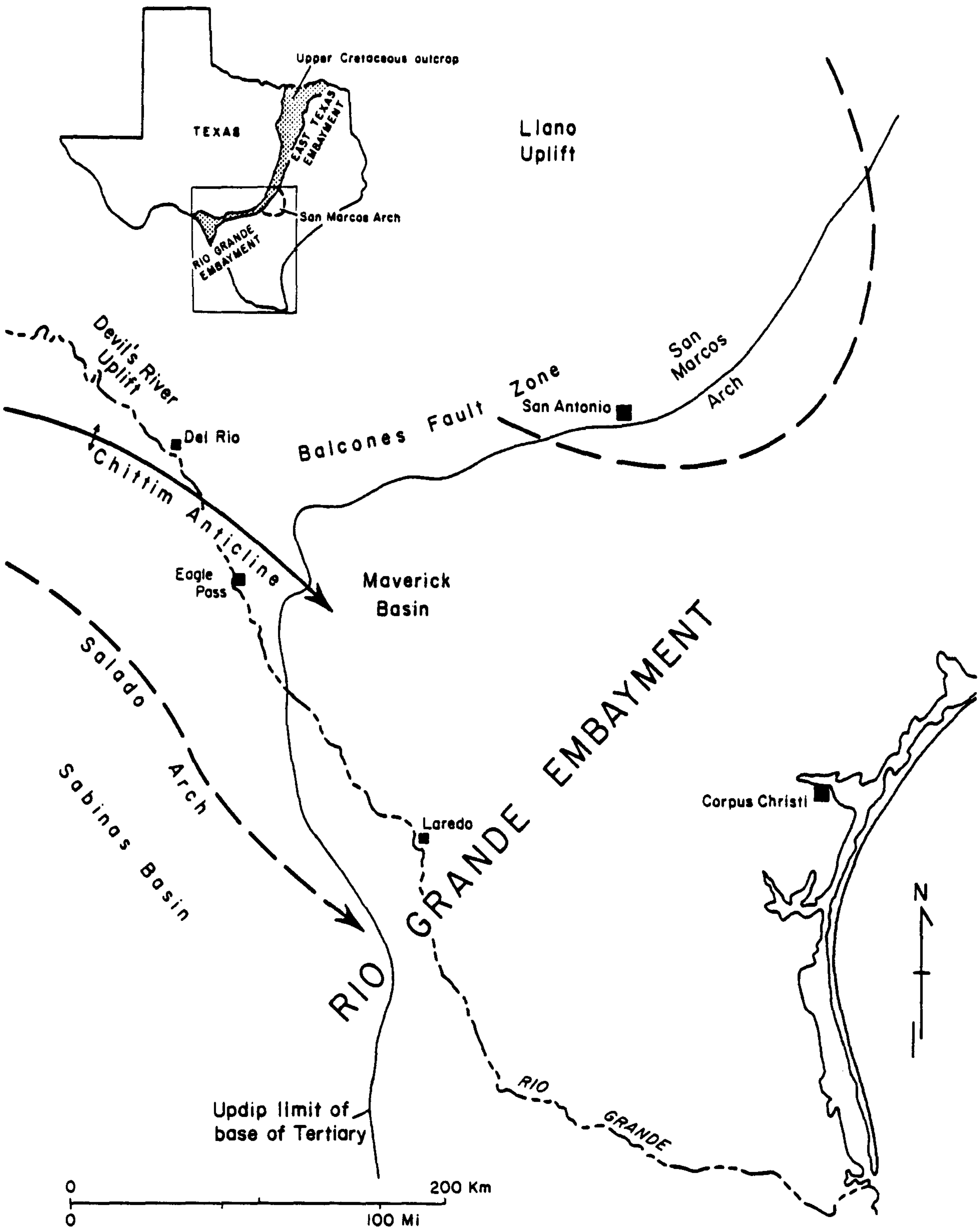

Figure 55. Structural framework of the Maverick Basin (from Weise, 1980).

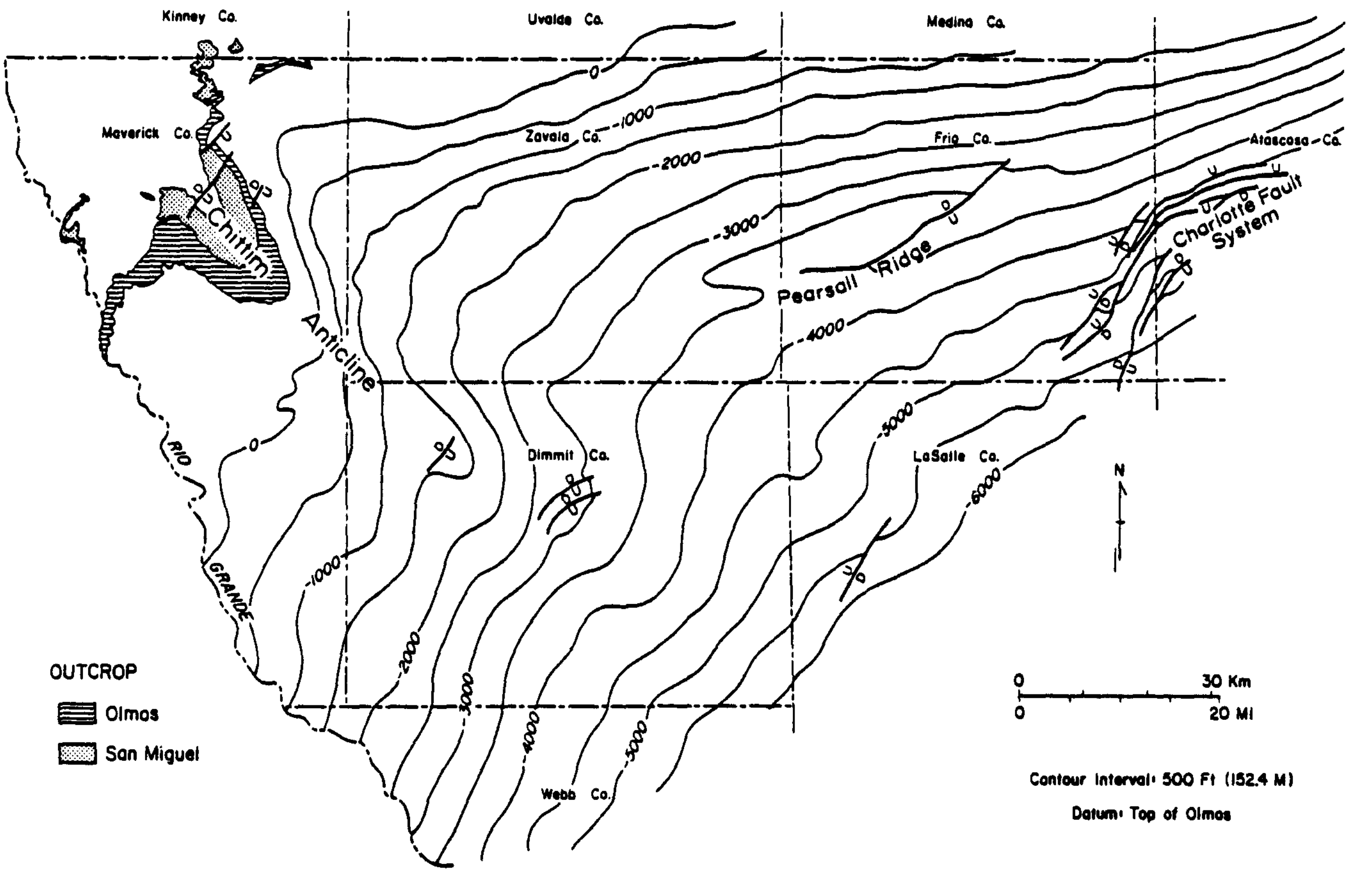

Figure 56. Structure contours on the top of the Olmos Formation, Maverick Basin (from Weise, 1980).

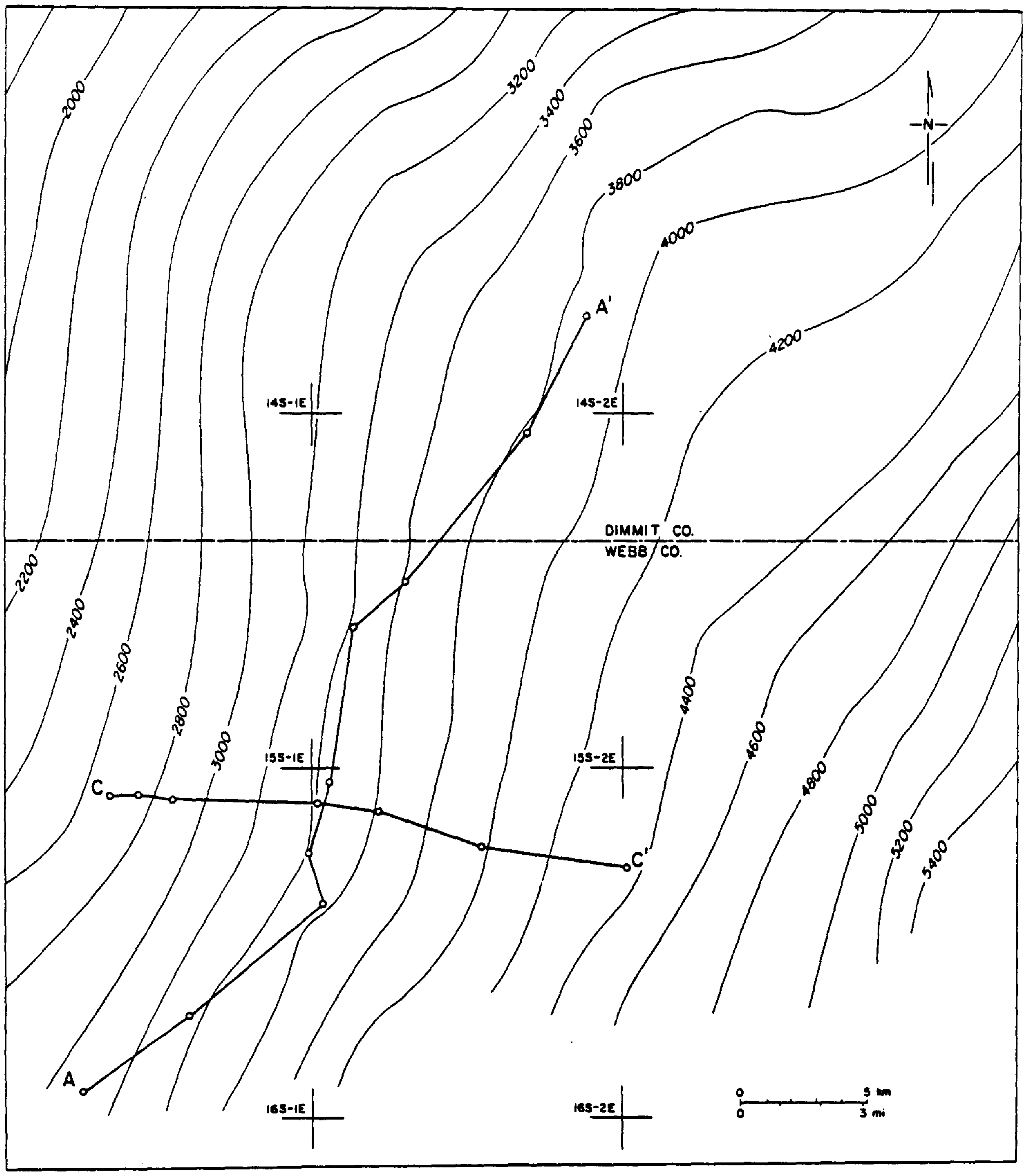

Figure 57. Index map for cross sections through the Olmos Formation and structure contours on top of the Olmos in parts of Dimmitt and Webb Counties. Structure contours show subsea depths (after Texas Railroad Commission, 1981a).

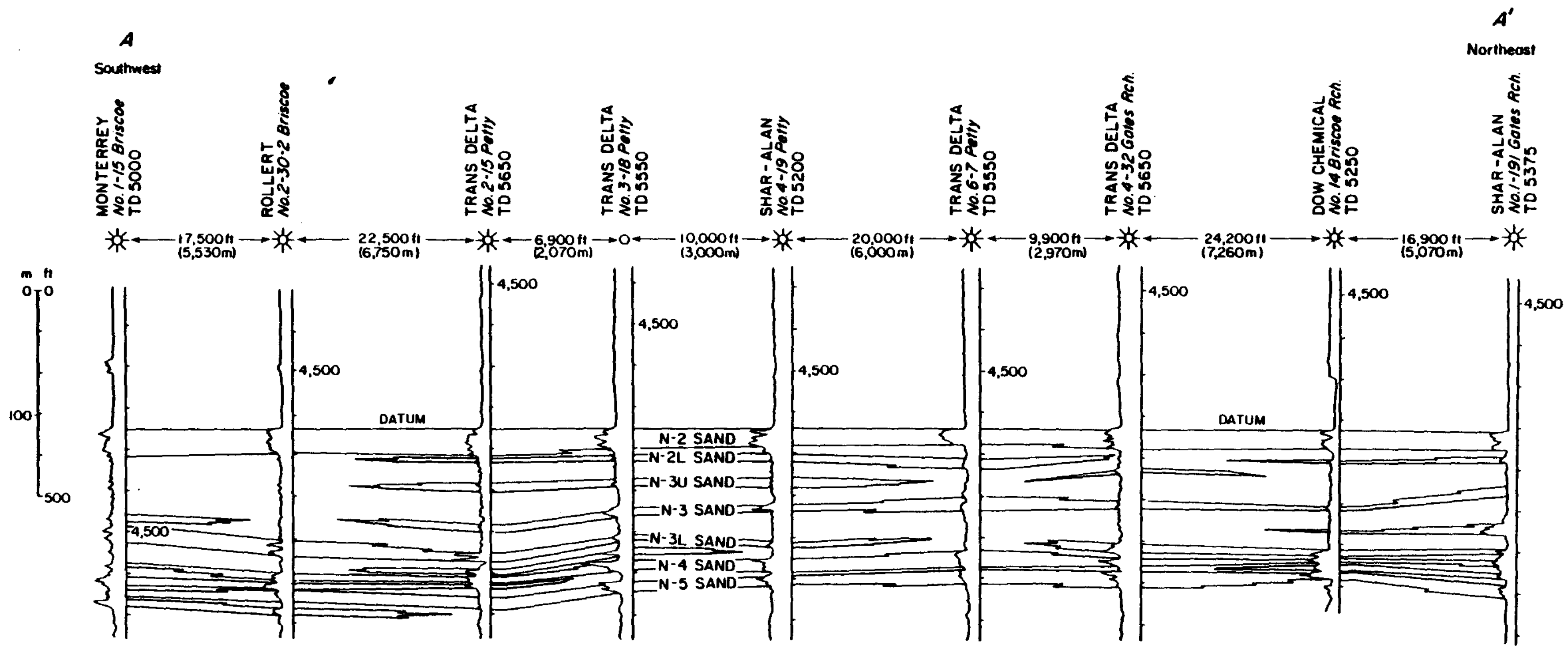

Figure 58. Stratigraphic cross section A-A' through the upper Olmos Formation showing lateral sand continuity (after Texas Railroad Commission, 1981a).

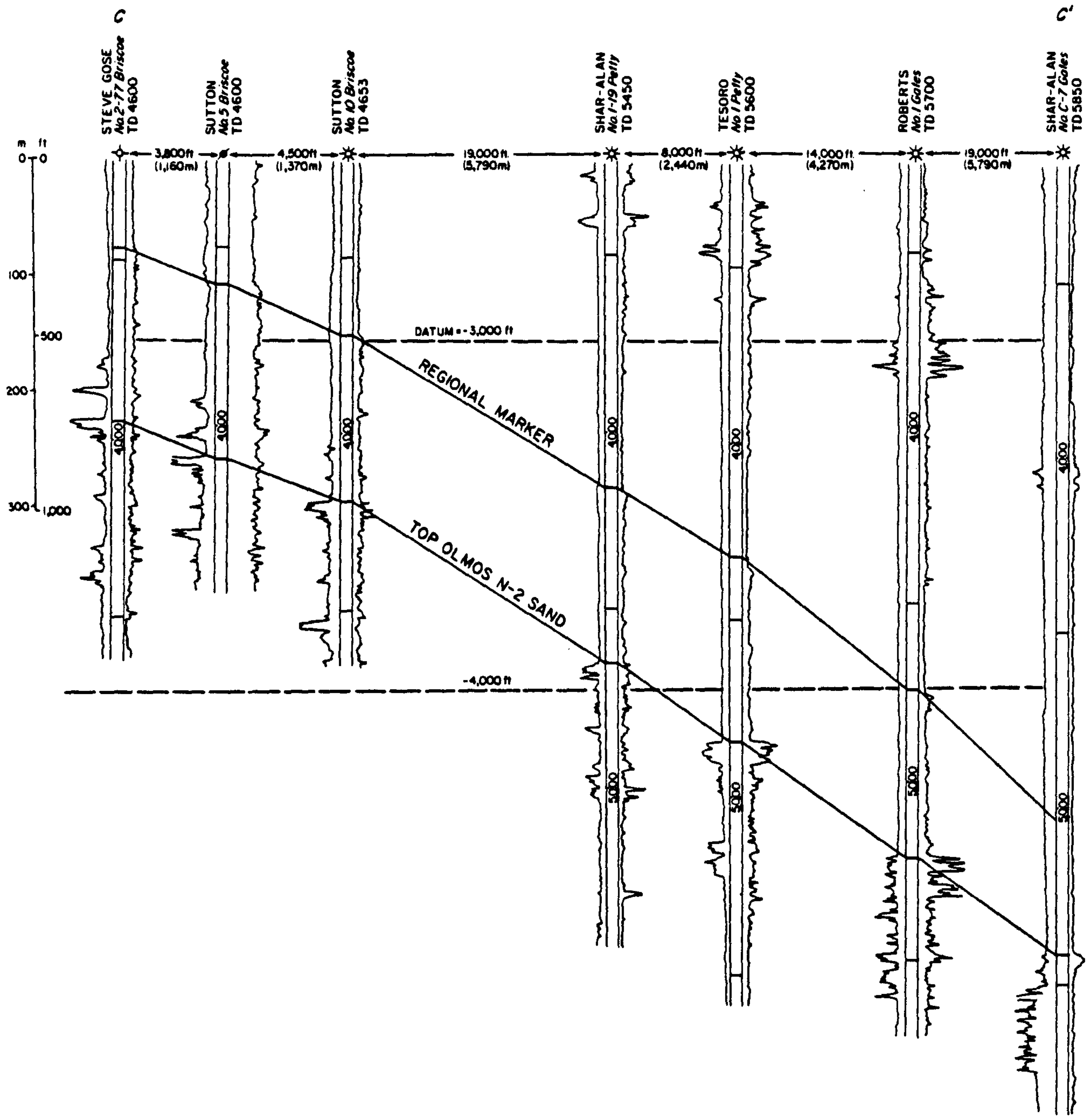

Figure 59. Structural cross section C-C' through the upper Olmos Formation showing continuity of the N-2 sand (after Texas Railroad Commission, 1981a).

Table 34. 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	Approximately 2,700 mi^2 gross basin area.	400-500 ft at outcrop. 1,000-1,200 ft southeastward in subsurface. 400-500 ft thick sand-bearing interval (S. Dimmit/N. Webb Counties).	Top Olmos ranges from sea level (eastern Maverick Co.) to -6,000 ft subsea (southeastern Dimmit Co.). Drilling depth of 4,500-5,400 ft in N.W. Webb and S. Dimmit Counties. Production occurs as deep as 7,200 ft.	Unknown.	Strike: north-south to northeast-southwest; N.W. Webb and S. Dimmit Counties; dip: 1° east-southeast; no major structural closures, minor faulting.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Easternmost Rio Grande Embayment of the Gulf Coast Basin. Distinct structural negative since Late Jurassic Maverick Basin bounded by the San Marcos Arch (NE), the Balcones Fault Zone (N), the Devil's River Uplift (NW), and Salado Arch (W) (in Mexico).	1.0-1.8°F/100 ft, predominantly 1.4-1.8°F/100 ft.	No data.	Mildly tensional; Upper Cretaceous clastics generally lack growth faulting.

Table 35. 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 (Segundo Field, Webb County) strandline and shallow marine sand ridge. Lower Olmos (N-3 and older) deposited in regressive, probably deltaic environment in contrast to upper Olmos sands (younger than N-3), which were reworked by marine transgression and have a more blanket-like geometry. Laterally, the Olmos is deltaic in Maverick and parts of Zavala and Dimmit Counties and 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 Olmos equivalent represents delta-plain with fluvial, overbank, and possible lacustrine environments. Carbonaceous shales and coal beds are present in a more proximal setting than the Texas deltaic deposits.	Fine to very fine silty to shaly sand with alternating shale. Lignitic shale and coal beds in updip delta-plain environments. Poorly sorted, limy sands and calcareous shales in Segundo Field, Webb County.	Based on reported similarity to underlying San Miguel Formation in adjacent Mexico: 35-40% quartz, 25-30% feldspar, and 30-35% volcanic rock fragments with varied 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 has, in places, reduced porosity. Similar diagenesis may be expected in the Maverick Basin.

Typical Reservoir Dimensions	Pressure/Temperature of Reservoir	Natural Fracturing	Data Availability (logs, cores, tests, etc.)
Top to base of perforated interval varies from less than 10 ft to 280 ft and is more commonly less than 10 ft to 100 ft among 514 wells.	No data.	Extent unknown.	Lewis Energy Corp., Denver, CO, and Union Oil, Houston, TX, have obtained core, but quantity unknown. Log suite includes SP-resistivity, GR-resistivity, and compensated neutron-formation density logs.

Table 36. 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**
N.W. Webb and S. Dimmit Counties: calculated in situ K for 42 wells (pre-stimulation) = 0.0335 md at median depth of 5,488 ft. For a sample of 107 wells, median pre-stimulation permeability = 0.072 md and median post-stimulation permeability = 0.14 md.	For 42 wells in Owen and Dos Hermanos Fields (N.W. Webb and S. Dimmit Counties) mean net pay = 35 ft with a range of 12-81 ft.	Zero for many wells, average of 25 Mcfd for 11 selected wells from at least three fields.	Mean flow rate = 86 Mcfd for 488 wells in 67 fields (37 of which are one-well fields).	No data.	Expected production of hydrocarbon liquids is less than 1 bbl/day.	Generally high in part of Segundo Field, Webb County, where Union 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.	Union Oil uses 12% density-log porosity as a practical minimum lower limit to productive capability in Segundo Field, Webb County. Traps are generally updip sand pinch-outs without structural closure.

Table 37. 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
State approved for N.W. Webb and S. Dimmit Counties (10/26/81). State action pending for Segundo Field, Webb County. No FERC approvals as of 1/01/82.	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

Physiography	Climatic Conditions	Accessibility
Mostly gently rolling Nueces Plains (inner Coastal Plain) with 100-300 ft of local relief, greater in some areas along the Nueces River.	Semiarid (20-25 inches mean annual precipitation) with infrequent heavy rain due to remnant tropical storms. Hot summers and mild winters. No climatic constraints on drilling operations.	Good. No terrain barriers. Most areas only sparsely vegetated with brush.

EXTRAPOLATION POTENTIAL

	Comments
Fair. A small deltaic system, probably with multiple 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 Formation (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.

Dakota and Trinidad Sandstones, Raton Basin

Introduction

The Raton Basin of northeast New Mexico and southeast Colorado (fig. 60) does not currently have commercial gas production despite a variety of gas shows that have been encountered (J. Gromer, personal communication, 1982; Speer, 1976). Drilling activity within the basin has been cyclical, but never at a high level; therefore, the well data base is poor. There have been approximately 80 wells drilled within a basin area of some 2,000 mi^2 (J. Gromer, personal communication, 1982). For the purposes of this study the Raton Basin offers the least potential for near-term commerciality of tight gas sands because operator interest is relatively low, no tight formation designations are under consideration, and opportunities seem limited to integrate GRI research efforts with ongoing exploration activity.

It is therefore appropriate to include only a brief review of the structure and stratigraphy of the Raton Basin. Potential exists in this basin for unconventional gas production from two Cretaceous units, the Trinidad and Dakota Sandstones (fig. 61).

Structure

The Raton Basin may be defined by the boundary of the Trinidad Sandstone outcrop, thereby excluding other minor structural features to the north and south (fig. 60). The western boundary of the basin is formed by the Sangre de Cristo Mountains, and the eastern boundary is formed by two subsurface positive features, the Apishapa Arch and the Sierra Grande Uplift (Speer, 1976). The Raton Basin is the southernmost basin formed along the eastern side of the Rocky Mountains as a result of Laramide and younger tectonic activity (Dolly and Meissner, 1977). The western margin of the basin dips steeply to the east, the beds of the central basin are essentially horizontal, and along the eastern margin of the basin beds dip gently to the west. Tertiary igneous intrusives occur in parts of the basin and are sometimes unexpectedly encountered in wells as sills of varying thickness (Speer, 1976).

Stratigraphy

The stratigraphic units of interest as tight gas reservoirs in the Raton Basin are of Cretaceous and Paleocene age. Those units with predominantly blanket geometries include the Dakota Sandstone and the Trinidad Sandstone (fig. 61).

The Dakota Sandstone includes beach and nearshore sands spread during the transgression of the Cretaceous epicontinental seaway over the area of the central United States (Speer, 1976). The Dakota is 140 to 200 ft thick. The lower part of the Dakota consists of floodplain and fluvial channel deposits that are likely to have a lenticular sandstone geometry. The upper part of the Dakota includes barrier, delta front, and offshore bar sands (J. Gromer, personal communication, 1982), which would form more laterally extensive reservoirs.

The Trinidad Sandstone was deposited during northeastward shoreline regression as seas withdrew in the Late Cretaceous. The Trinidad has transitional relationships with the underlying, marine Pierre Shale and the overlying sands, shales, and coals of the Vermejo Formation (Speer, 1976). The Trinidad is slightly younger than its stratigraphic equivalent in the San Juan Basin, New Mexico, the Pictured Cliffs Sandstone (Billingsley, 1977). The Trinidad Sandstone and the Vermejo Formation may in part be time-stratigraphic equivalents of the Pierre Shale (J. Gromer, personal communication, 1982), representing the transition from marine to deltaic to delta plain environments. Where outcrops of the Trinidad have been studied in detail, the unit consists of lower delta front sheet sands grading upward into an upper delta front that includes distributary bar sands (Billingsley, 1977).

Future Potential

Speer (1976) suggests that sub-commercial indications of hydrocarbons and a favorable stratigraphic and structural geologic setting indicate the potential for future hydrocarbon discoveries in the Raton Basin. The basin is, however, very much at a frontier stage of development.

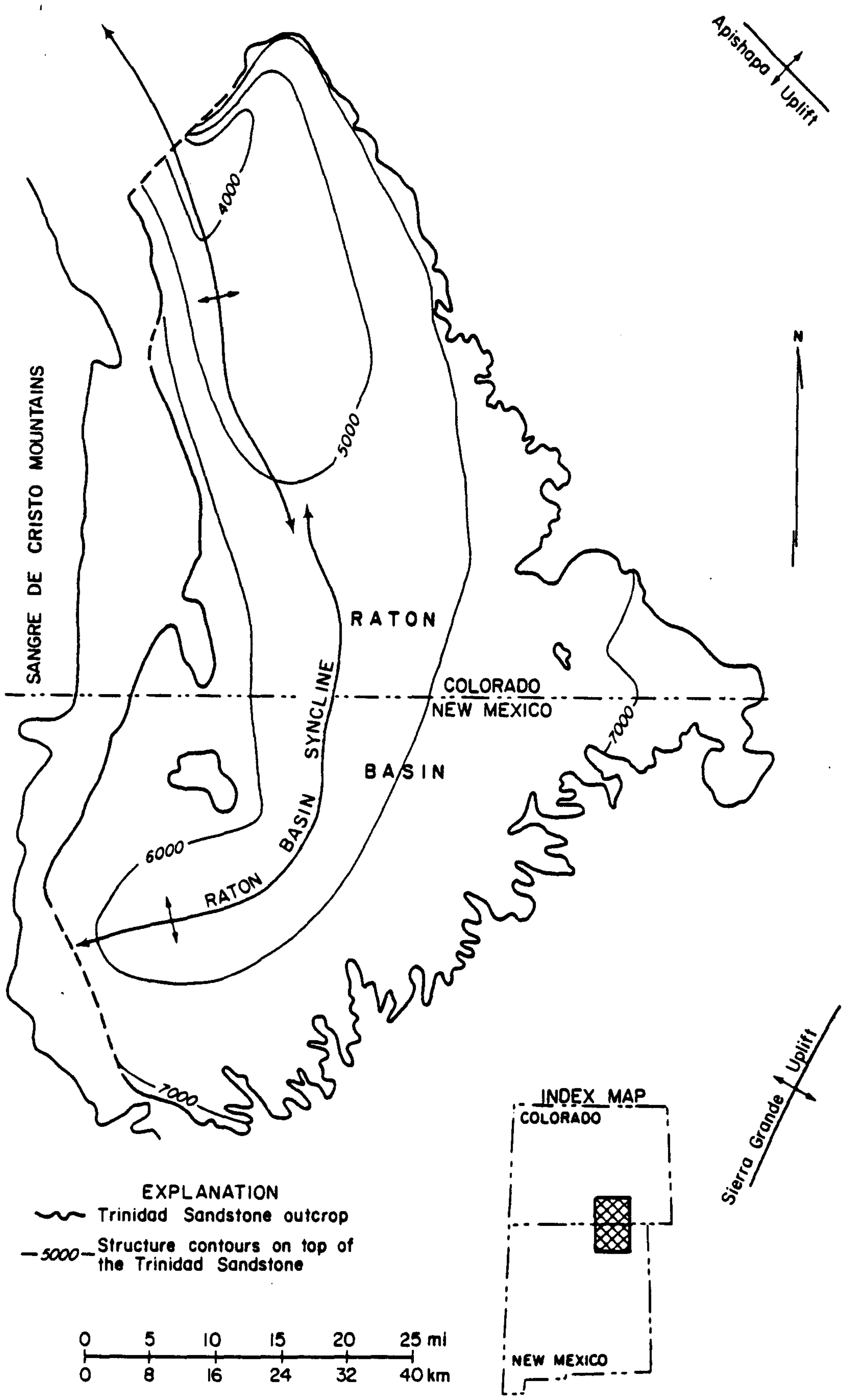

Figure 60. Location and generalized structure map of the Raton Basin (after Speer, 1976).

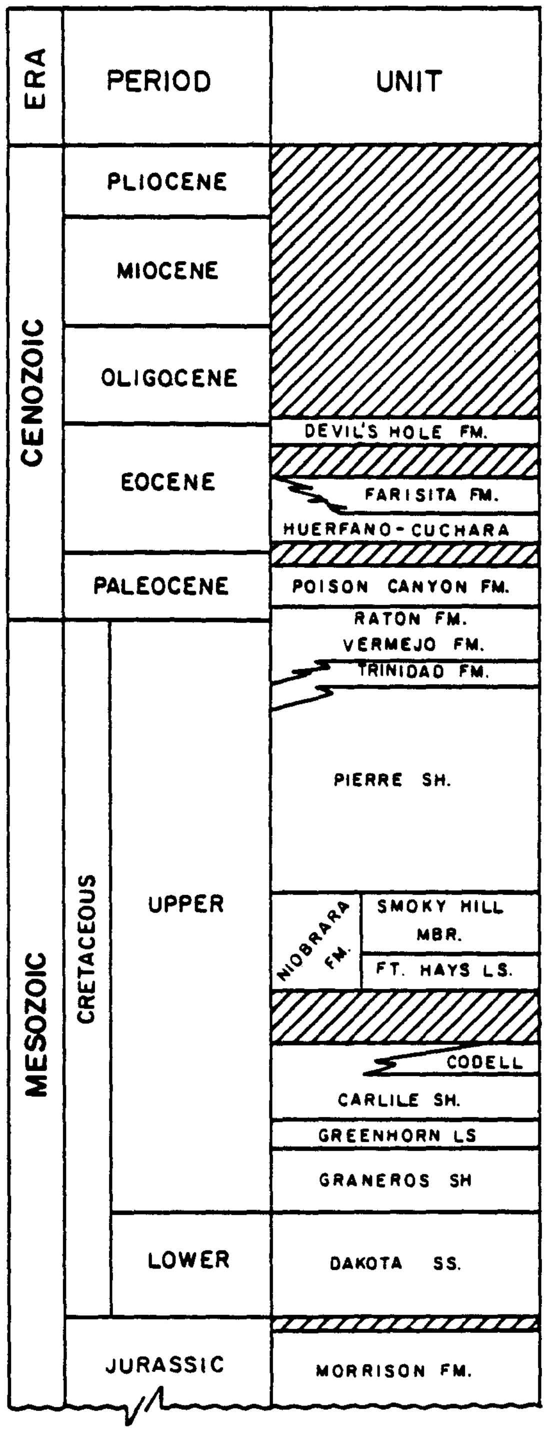

Figure 61. Stratigraphic column from the Jurassic Morrison Formation through the Pliocene Epoch in the Raton Basin (after Rocky Mountain Association of Geologists, 1977).

Pictured Cliffs Sandstone, San Juan Basin

Introduction

The Pictured Cliffs Sandstone consists of siltstone and very fine to medium-grained sandstone of Late Cretaceous age (fig. 62). The data base for the Pictured Cliffs is good, based on two applications for tight gas sand designations (New Mexico Oil Conservation Division, 1981a, Case No. 7086 and 1982, Case No. 7395), published articles, and a report by consulting geologist William R. Speer (tables 38-41). Both tight gas sand designations have been approved by FERC.

Structure

The San Juan Basin is a roughly circular, asymmetrical structural basin with a northwest-southeast trending axial trace forming a gentle arc along the northern edge of the basin (fig. 63). The southwest flank of the basin is gently dipping while the north and northwest margins are steeply dipping. 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 surrounding the San Juan Basin are listed in table 38. Epeirogenic uplift of the Colorado Plateau, including the San Juan Basin, took place in post-Laramide Tertiary time (Woodward and Callender, 1977).

Stratigraphy

The marine Lewis Shale underlying the Pictured Cliffs separates it from the older Mesaverde Group, although in several respects the regressive marginal marine deposits of the Pictured Cliffs resemble regressive sandstones of the Mesaverde. The final regression of the Cretaceous is represented by the Pictured Cliffs; 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 prograded across the San Juan Basin area (Cumella, 1981; Fassett, 1977). Specific facies present in the Pictured Cliffs include shoreface, represented by thickly bedded, Ophiomorpha-burrowed sandstone, channeled estuarine and lagoonal deposits, represented by medium-bedded, cross-stratified sandstone and adjacent inner shelf deposits of interbedded very fine sandstone and siltstone. Foreshore deposits were probably destroyed during minor transgression, and an indication of barrier islands is noted in the presence of lagoonal deposits beneath reworked barrier sands (Cumella, 1981).

The sandstones of the Pictured Cliffs 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 Sandstone beds is relatively good as a consequence of its origin as a progradational sandy strandplain (figs. 64 and 65). The formation rises stratigraphically and becomes younger from southwest to northeast across the basin (Fassett, 1977). Successive shoreline positions did not move uniformly across the basin, leading to step-like character of the regressive sandstone deposits. Where the relative rates of subsidence and sediment supply remained in balance for 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 Sandstone (Hollenshead and Pritchard, 1961); the same terminology applies to the Pictured Cliffs, and the thicker sections of the Pictured Cliffs probably have the same origin.

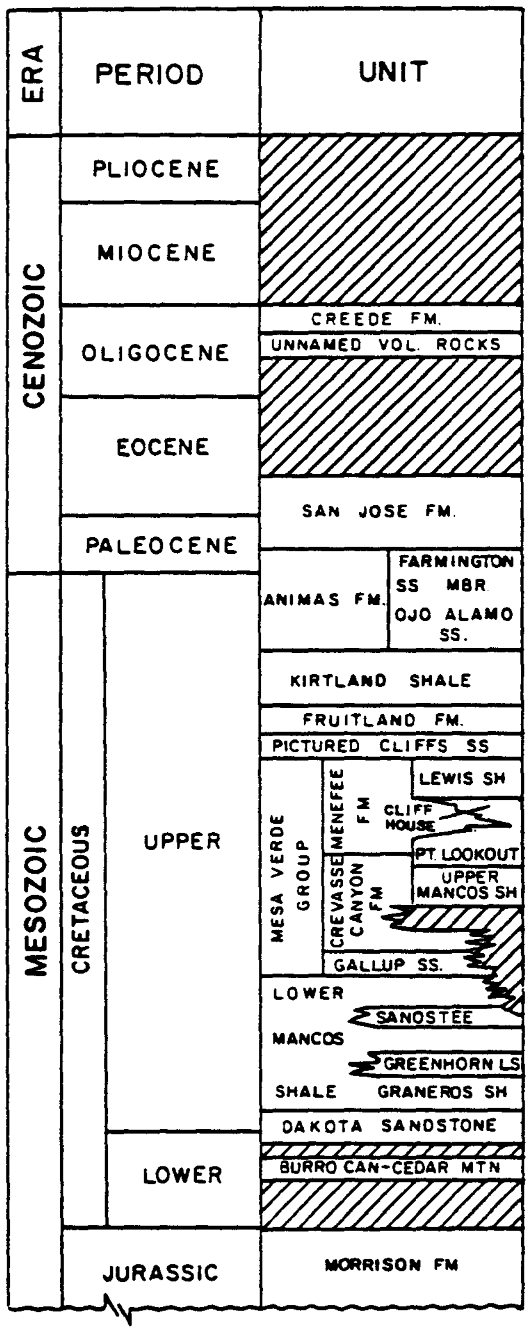

Figure 62. Stratigraphic column from the Jurassic Morrison Formation through the Pliocene Epoch in the San Juan Basin (after Rocky Mountain Association of Geologists, 1977).

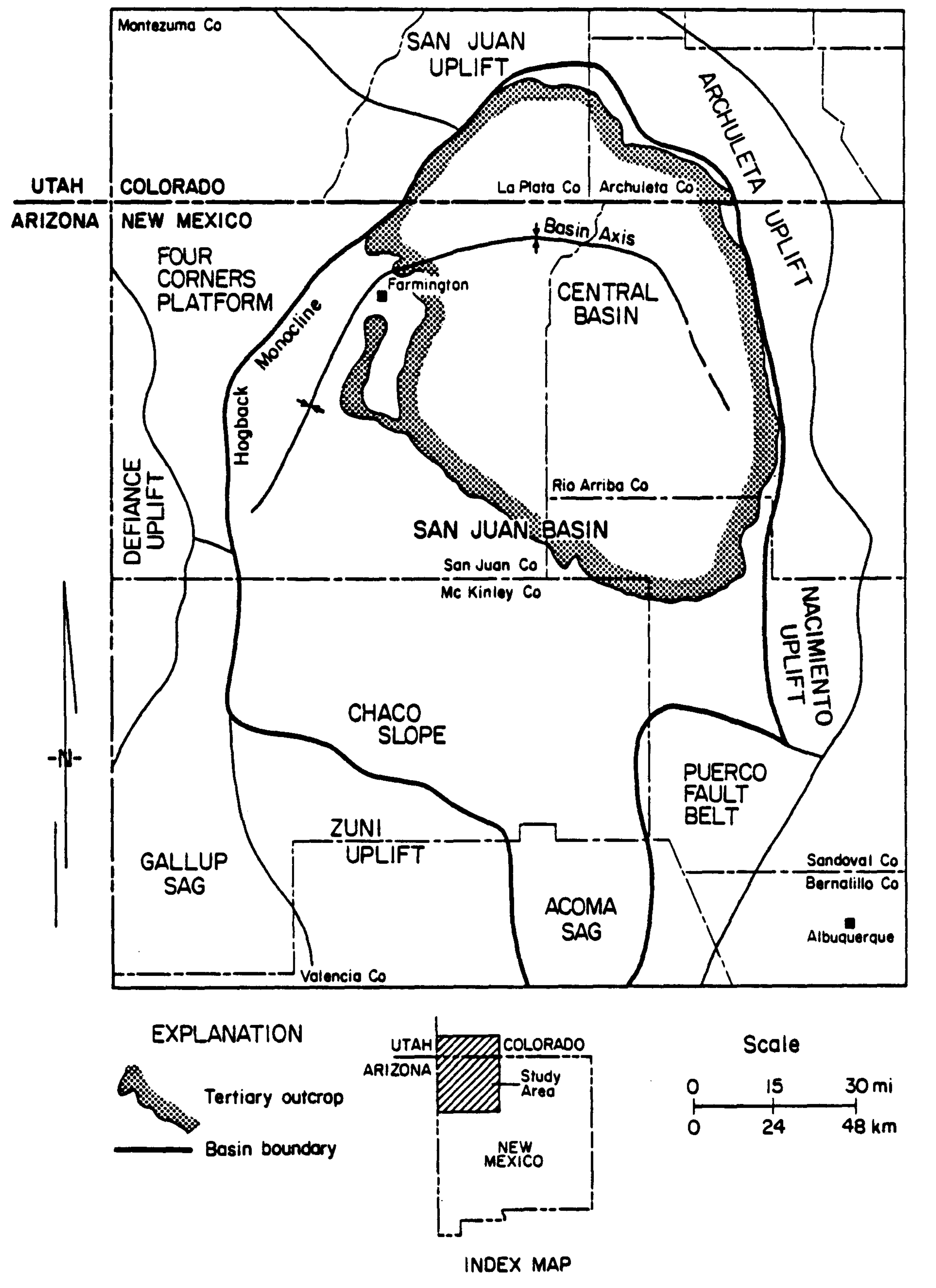

Figure 63. Location and generalized structure map of the San Juan Basin (after Peterson and others, 1965).

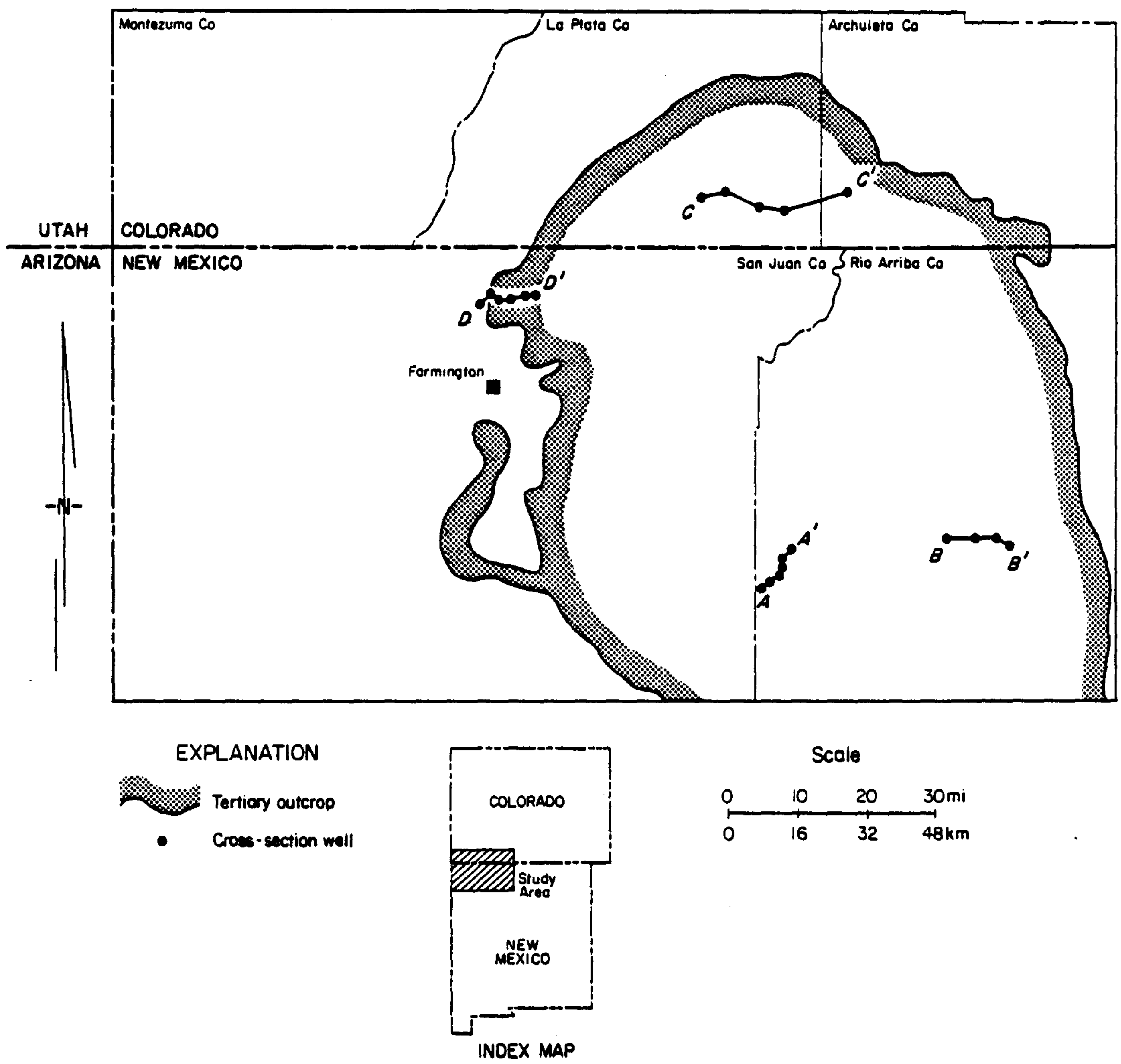

Figure 64. Index map for cross sections through Cretaceous strata in the central and northern San Juan Basin.

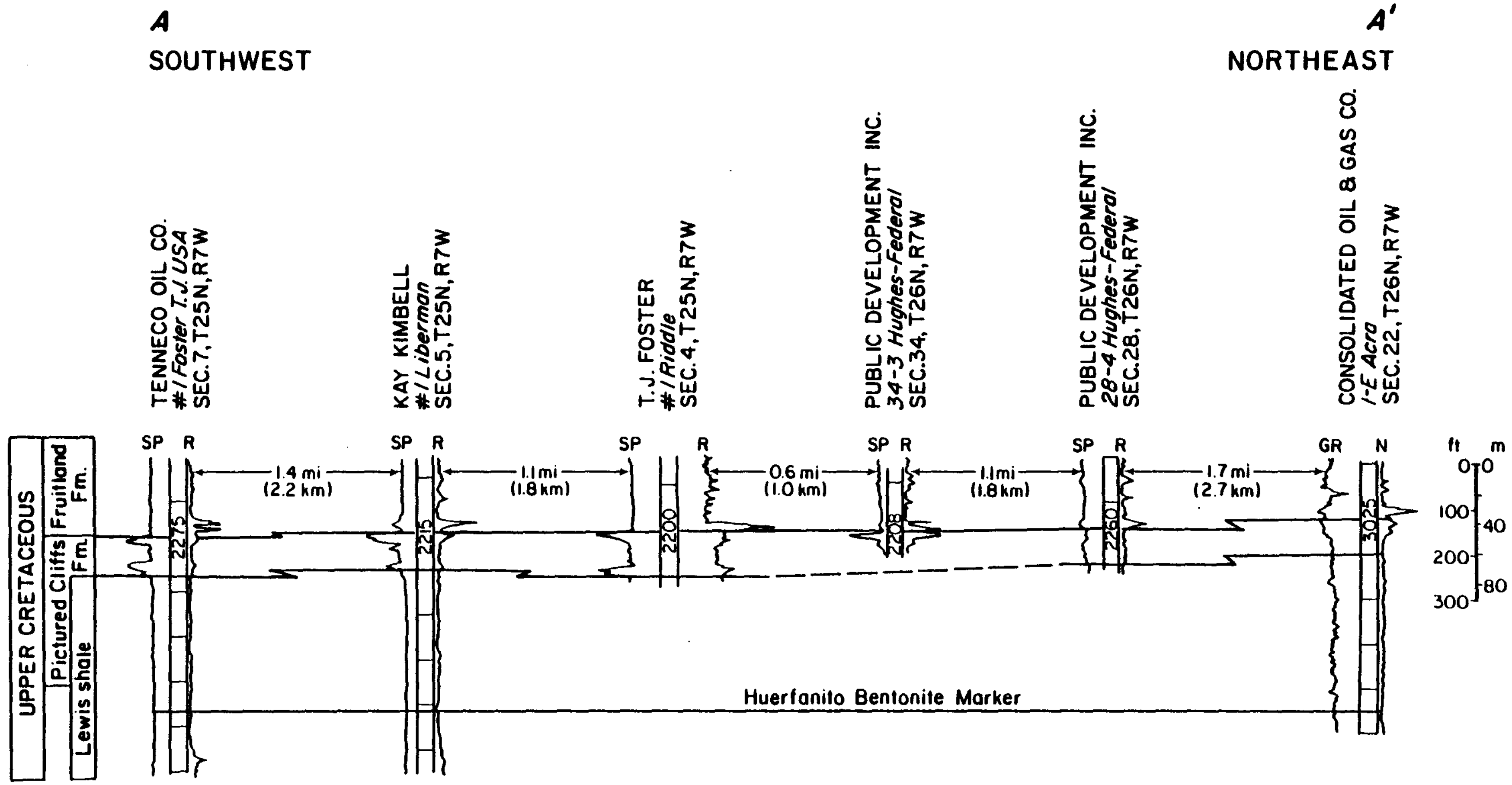

Figure 65. Stratigraphic cross section A-A' through the Pictured Cliffs Sandstone and adjacent strata, San Juan Basin (after New Mexico Oil Conservation Division, 1982).

Table 38. 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 -33,500 acres (52.3 mi^2) in T30-31N, R6-8W in San Juan and Rio Arriba Counties, New Mexico. 2. Largo Canyon Tight Gas area - 14,400 acres (22.5 mi^2) in T25-26N, R6-7W in Rio Arriba County, New Mexico.	Basinwide, thickness range = 50-400 ft. 1. Range = 75-140 ft. 2. Range = 65-115 ft, average = 91 ft.	1. Range = 2,750-3,500 ft. 2. Range = 2,200-2,800 ft.	1. 0.25-0.65 Bcf per well. 2. 0.23-0.40 Bcf per 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 with a NW-SE trending axial trace forming an arc along the northern edge of the basin. Tectonic events which formed the basin occurred principally during Late Cretaceous - Early Tertiary (Laramide) time. Principal structures which bound the basin include the Hogback monocline (W, NW), San Juan-Archuleta Uplift (N), Nacimiento Uplift (E, SE), Puerco fault zone (SE), Chaco Slope and Zuni Uplift (S, SW).	1.6-2.5°F/100 ft.	No data.	Compressional in Late Cretaceous - Early Tertiary, followed by extensional on eastern side of basin in Late Tertiary.

Table 39. 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, with progressively younger strata being 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 to medium grained sandstone, well sorted, angular to subrounded. 2. Fine grained sandstone and siltstone.	Quartz: Ranges from 18.5-55%, averages 30%. Feldspar: Ranges from 4-22%, averages 12%. Average plagioclase = 6.5% Average K-feldspar = 5.5% Rock fragments: Ranges from 21-50%, averages 38% with volcanic rock fragments 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, patchy calcite. Minor development of secondary porosity. During and after basin formation - Calcite extensive locally, as is kaolinite at basin margin.
Typical Reservoir Dimensions	**Pressure/Temperature of Reservoir**	**Natural Fracturing**	**Data Availability (logs, cores, tests, etc.)**
1. Gross pay range = 75-140 ft. 2. Gross pay range = 75-80 ft.	Reservoir temperature average = 120°F. Reservoir pressure typical range = 1,375-1,500 psi.	Occasionally present, no specific data.	Core is infrequently taken at present stage of development. Typical log suite includes GR-resistivity and GR-density logs.

Table 40. Pictured Cliffs Sandstone, San Juan 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. Permeability, based on calculations from testing of two wells, ranges from 0.0116-0.0030 md/ft. 2. Based on core analysis of 6 wells, permeability to air = 0.37 md, which calculates to an in situ permeability of 0.007 md at 2,387 ft. Also, calculations from six unstimulated flow tests (average flow = 13.7 Mcfd), shows permeability = .02 md.	1. Range = 40-50 ft. 2. Range = 30-50 ft.	1. For seven producing wells, average production is 27 Mcfd. 2. 3 hr. unstimulated flow test on 7 wells, average flow = 13.7 Mcfd. These tests were run after an acid stimulation to clean up the hole.	1. 300-1,600 Mcfd. 2. 335-1,300 Mcfd.	1. 8-9%/yr after stabilization. 2. 7-14%/yr.	1. Liquid hydrocarbons, when present, are produced at less than 5 bpd. 2. Liquid hydrocarbons present approximately 10% of the time with the highest production value being 1.9 bd of condensate.	1. No specific data available, but is fairly high, generally greater than 50%. 2. Average water saturation = 78%.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
Typical stimulations utilize sand-water (gel) hydraulic fracturing techniques using approximately 50,000 gal of fluid with 50,000-75,000 lb of sand. However, fracture sizes and techniques vary greatly with operators, with some using over 100,000 gal of fluid and approximately 200,000 lb of sand.	Very successful, however no specific data is available regarding percent improvement or percent success.	160 acres.	The distribution of authigenic grain-coating clay is probably a major control of gas production by its effect on permeability.

Table 41. 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 New Mexico; FERC approval pending.	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 cost range = \$100,000-\$155,000. 2. Average total cost range = \$60,000-\$100,000. One reported fracture treatment cost \$55,250; however, average stimulation cost range = \$10,000-\$25,000.	1. Northwest Pipeline Corp., El Paso Natural Gas Co., Southern Union Natural Gas Co. 2. El Paso Natural Gas Co.	Moderate. Two tight gas sand applications.

OPERATING CONDITIONS

Physiography	Climatic Conditions	Accessibility
Highly dissected terrain of Colorado Plateau with numerous mesas and canyons. Local relief of 500-1,000 ft, and greater than 1,000 ft in some areas.	Arid to semi-arid with 8-16 inches mean annual precipitation. Moderately hot summers, cold winters. Generally late afternoon thundershowers in the summer, moderate snowfall in the winter, and irregular precipitation patterns in the fall and spring.	Fair in areas which have already been developed, poor in other areas. Access road development requires large earth-moving machinery to reach remote areas.

EXTRAPOLATION POTENTIAL

	Comments
Good. Expected to have similarities 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. Less similarity expected 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

Introduction

The Cliff House and Point Lookout Sandstones are part of the Upper Cretaceous Mesaverde Group within the San Juan Basin (fig. 62). These units are quartzose fine to very fine sandstones, and production is primarily from the north-central part of the basin east and northeast of Farmington, New Mexico. The Point Lookout was deposited as a basal regressive marine sandstone of the Mesaverde Group, and the Cliff House was deposited during a subsequent transgression. The Menefee Formation is continental in origin, including fluvial sands and coal (fig. 62).

The data base for the Cliff House and Point Lookout Sandstones is good (tables 42-45) based on published articles, on an unpublished thesis, and three tight gas sand applications (New Mexico Oil and Gas Conservation Commission, 1981c, Case No. 7154 and 1981d, Case No. 7209; Colorado Oil and Gas Conservation Commission, 1981c, Cause NG-24-1).

Structure

The San Juan Basin is a roughly circular, asymmetrical, Laramide-age basin of northwest New Mexico (fig. 63). Further details on the structure of the basin are included in the previous section on the Pictured Cliffs Sandstone.

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 southwest part of the San Juan Basin the continental Menefee Formation, or an equivalent unit, forms the entire Mesaverde Group. This unit thins from 860 ft along the southwest edge of the basin to 160 ft along the northeast edge as the regressive and transgressive Mesaverde sandstones converge. The stratigraphic rise in the Point Lookout Sandstone is on the order of 350 ft over this same geographic area (Hollenshead and Pritchard, 1961). The Point Lookout, as the regressive sandstone, is generally thicker than the transgressive Cliff House Sandstone that underlies the Lewis Shale.

Depositional Systems

The Point Lookout was deposited during northeastward regression, and the Cliff House was deposited during southwestward transgression of the Upper Cretaceous epicontinental sea. In the Point Lookout Sandstone a series of strike-oriented, cuspate-to-linear sand thicks indicate deltaic strandplain progradation in a wave-dominated environment. Beach ridges prograded seaward to successive shoreline positions, and shallow channels passing through the accretionary ridges were points of input for sediment subsequently moved alongshore and incorporated into the ridges (Devine, 1980). The progradation of the shoreline was step-wise, depending upon the relative rate of subsidence, the rate of sediment input, and the occurrence of any eustatic change in sea level. Where the shoreline stabilized due to a balance of sediment supply and relative rate of subsidence, thick sandstone "benches" were deposited (Hollenshead and Pritchard, 1961).

Periodic minor transgressions reworked strandplain deposits as avulsion of distributaries occurred and depocenters shifted along the shoreline. Detailed outcrop studies provide evidence for this process in the form of reworked barrier island and lagoonal deposits. These lagoons were subsequently partially filled, transformed to a channeled estuarine system, and ultimately completely filled as sediment again reached the nearshore zone and a new cycle of progradation was initiated (Devine, 1980).

The Cliff House Sandstone is thinner than the Point Lookout (figs. 64 and 66) and consists of a few thick sandstone lenses irregularly dispersed along a surface that rises gently to the southwest (Fassett, 1977). These sands may represent the preserved portions (upper shoreface?) of transgressive barrier island systems, but the exact facies composition of the Cliff House has not been detailed in the literature.

The sandstone continuity of the regressive Point Lookout Sandstone appears to be better than that of the Cliff House Sandstone, and it would tend to form gas reservoirs of more widespread blanket geometry (figs. 64 and 66). 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.

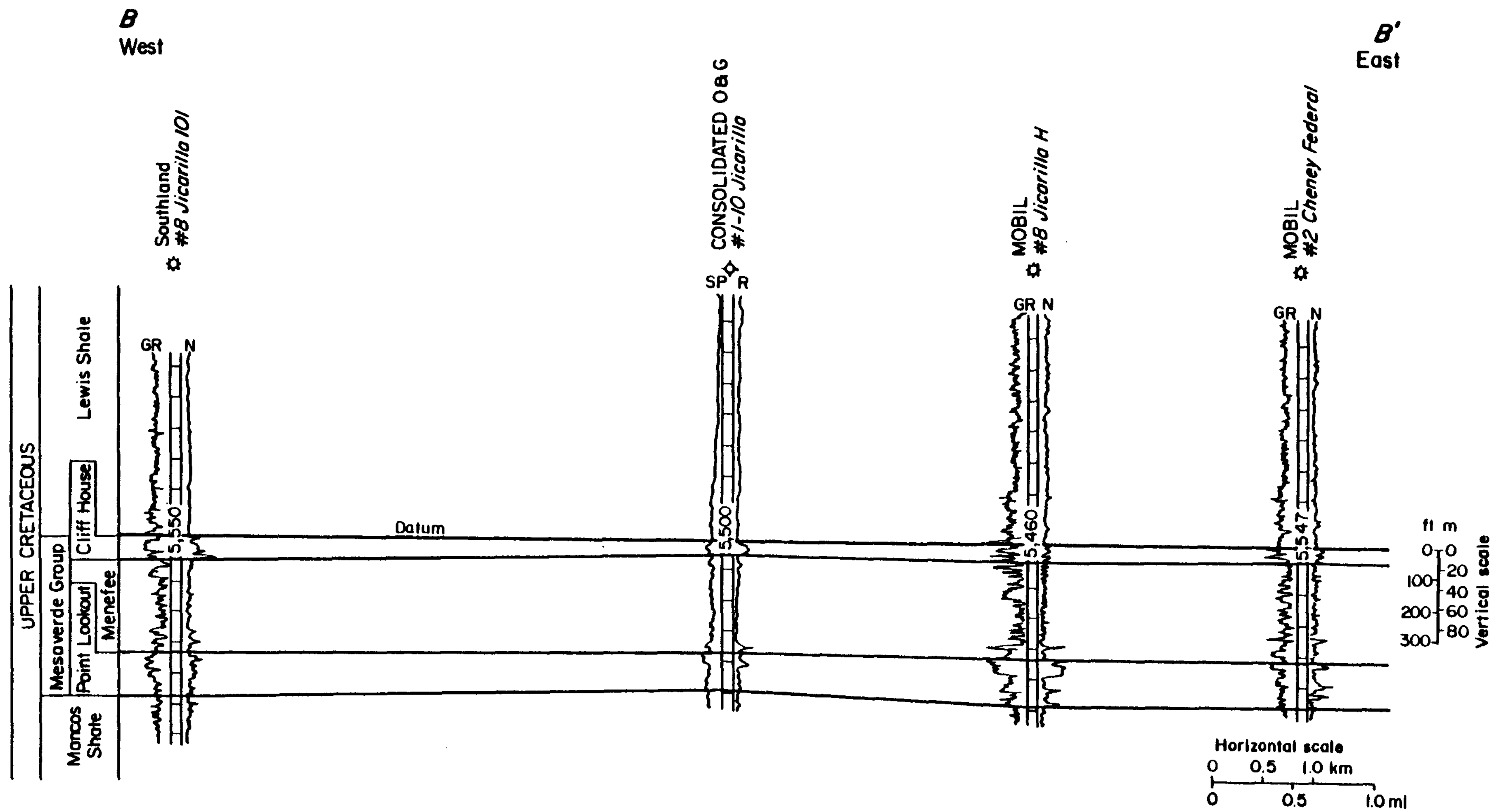

Figure 66. Stratigraphic cross section B-B' through the Mesaverde Group, San Juan Basin (after New Mexico Oil Conservation Division, 1981c).

Table 42. 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 12,160 acres (19 mi^2) in parts of T32N, R8-9W in San Juan County, New Mexico. 2. Blanco Mesaverde area. Includes 13,920 acres (21.75 mi^2) in parts of T26-27N, R2-3W, in Rio Arriba County, New Mexico. 3. Ignacio Blanco Field. Includes 576 mi^2 in parts of T32-34N, R6-11 W in LaPlata and Archuleta Counties, Colorado.	1. Cliff House average = 50 ft. Point Lookout range = 150-200 ft. 2. Average thickness for Cliff House and Point Lookout separately = 100 ft in western part of area; average = less than 50 ft in eastern part of area. 3. Total Mesaverde range = 500-800 ft.	1. Average depth to top of Cliff House = 4,200 ft. 2. Average depth to top of Cliff House = 5,560 ft. 3. Depth to top of Cliff House, range = 4,500-6,300 ft, average = 5,380 ft.	1. 1.25-2.0 Bcf per well. 2. 1.0-1.75 Bcf per well. 3. 0.5-4.0 Bcf per well, total estimated recovery = 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 with a NW-SE trending axial trace forming an arc along the northern edge of the basin. Tectonic events which formed the basin occurred principally during Late Cretaceous - Early Tertiary (Laramide) time. Principal structures which bound the basin include the Hogback Monocline (W, NW), San Juan-Archuleta Uplift (N), Nacimiento Uplift (E, SE), Puerco fault zone (SE), Chaco Slope and Zuni Uplift (S, SW).	1.6-2.5°F/100 ft.	No data.	Compressional in Late Cretaceous - Early Tertiary, followed by extensional on eastern side of basin in Late Tertiary.

Table 42. 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 12,160 acres (19 mi^2) in parts of T32N, R8-9W in San Juan County, New Mexico. 2. Blanco Mesaverde area. Includes 13,920 acres (21.75 mi^2) in parts of T26-27N, R2-3W, in Rio Arriba County, New Mexico. 3. Ignacio Blanco Field. Includes 576 mi^2 in parts of T32-34N, R6-11 W in LaPlata and Archuleta Counties, Colorado.	1. Cliff House average = 50 ft. Point Lookout range = 150-200 ft. 2. Average thickness for Cliff House and Point Lookout separately = 100 ft in western part of area; average = less than 50 ft in eastern part of area. 3. Total Mesaverde range = 500-800 ft.	1. Average depth to top of Cliff House = 4,200 ft. 2. Average depth to top of Cliff House = 5,560 ft. 3. Depth to top of Cliff House, range = 4,500-6,300 ft, average = 5,380 ft.	1. 1.25-2.0 Bcf per well. 2. 1.0-1.75 Bcf per well. 3. 0.5-4.0 Bcf per well, total estimated recovery = 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 with a NW-SE trending axial trace forming an arc along the northern edge of the basin. Tectonic events which formed the basin occurred principally during Late Cretaceous - Early Tertiary (Laramide) time. Principal structures which bound the basin include the Hogback Monocline (N, NE, NW), San Juan Uplift (N), Nacimiento Uplift (E, SE), Puerco fault zone (SE), Chaco Slope and Zuni Uplift (S, SW), and the Defiance Uplift and monocline to the SW and W.	1.6-2.5°F/100 ft.	No data.	Compressional in Late Cretaceous - Early Tertiary, followed by extensional on eastern side of basin in Late Tertiary.

Table 43. Cliff House and Point Lookout Sandstones, San Juan Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies

The Mesaverde 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 which prograded northeastward. Associated non-marine (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. Due to 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 comprise the uppermost Mesaverde formation, the Cliff House Sandstone.

Texture

Cliff House: Very fine grained, angular-subangular, poorly-moderately sorted sandstones.

Point Lookout: Fine-very fine grained, angular-subangular, poorly-moderately sorted sandstones.

Mineralogy

Cliff House: Dominantly quartz, with chert, feldspars, and clays present in varying amounts. Rock fragments are present in minor amounts.

Point Lookout: Dominantly quartz, with feldspar and clays present in varying amounts. Rock fragments and chert are present in minor amounts.

Diagenesis

Cliff House: Authigenic clays and calcareous cements present.

Point Lookout: Authigenic clays and calcareous cements, as well as siliceous cements, are present.

Typical Reservoir Dimensions

1. Cliff House average gross perforated interval = 50 ft. Point Lookout gross perforated interval = 150-200 ft.

2. For Cliff House and Point Lookout, gross perforated interval = 50-100 ft for each unit.

3. For Cliff House and Point Lookout, gross perforated interval = 50-120 ft for each unit.

Pressure/Temperature of Reservoir

1. Temperature average = 150°F. Pressure average = 1,177 psi.

2. Temperature average = 142°F. Pressure average = 1,250 psi.

3. Temperature average = 160°F Pressure average = 1,300 psi.

Natural Fracturing

Occasionally developed, but no specific data available on the distribution of fractures in relation to gas production.

Data Availability (logs, cores, tests, etc.)

Core is infrequently taken at present stage of development. Typical log suite includes GR-resistivity and GR-density logs.

Table 44. 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 as calculated from flow tests is less than 0.02 md. Average porosity = 11.3%.	1. Total net pay average = 156 ft.	1. Based on one test, flow = 47 Mcfd.	1. Range = 145-3,483 Mcfd.	1. 7-8%/yr.	1. No liquid hydrocarbons are produced in this area.	1. Average = 55%
2. Average in situ permeability as calculated from flow tests ranges from ~ .06-.07 md. Average porosity = 14%.	2. Total net pay average = 146 ft.	2. Based on eleven tests, flow = 150 Mcfd.	2. Range = 1,800-3,300 Mcfd.	2. 4-5%/yr.	2. Liquid hydrocarbons are produced after stimulation, with an average production of 3.2 bpd of condensate per well.	2. No data.
3. Average in situ permeability = 0.061 md based on flow tests and core data of 13 wells. Average porosity = 9.1%.	3. Total net pay range = 20-150 ft.	3. Based on 5 tests, average = 100 Mcfd, range = 30- 289 Mcfd.	3. Range = 500-3,600 Mcfd.	3. 6%/yr.	3. Liquid hydrocarbons generally not present.	3. Range = 35-65%.

Well Stimulation Techniques	**Success Ratio**	**Well Spacing**	**Comments**
Hydraulic fracturing techniques using a sand-water (gel) mixture are presently in use. The typical size of treatments includes 100,000-200,000 gal of fluid combined with 75,000-200,000 lb of sand. However, treatments using well over 400,000 lb of sand and a correspondingly large volume of fluid have been reported.	Very successful, however no actual data is available regarding percentage improvement or success.	160 acres.	The Point Lookout Sandstone is the better gas producer of the two Mesaverde Group sandstones that were examined.

Table 45. 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 of New Mexico and FERC action pending. One application pending state action.	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 cost range = \$275,000-\$375,000, average = \$336,000. Average stimulation treatment = \$65,000 (1981). 2. Total cost range = \$250,000-\$375,000. Average stimulation treatment = \$40,000 (1981). 3. Total cost range = \$280,000-\$400,000. Average stimulation treatment = \$50,000 (1981).	1. El Paso Natural Gas Co., Northwest Pipeline Corp. 2. Northwest Pipeline Corp. 3. El Paso Natural Gas Co., Northwest Pipeline Corp.	Moderate. Three tight gas sand applications cover these units within the Mesaverde Group.

OPERATING CONDITIONS

Physiography	Climatic Conditions	Accessibility
Highly dissected terrain of Colorado Plateau with numerous mesas and canyons. Local relief of 500-1,000 ft, and greater than 1,000 ft in some areas.	Arid to semi-arid with 8-16 inches mean annual precipitation. Moderately hot summers, cold winters. Generally late afternoon thundershowers in the summer, moderate snowfall in the winter, and irregular precipitation patterns in the fall or spring.	Fair in areas which have already been developed, poor in other areas. Access road development requires large earth-moving machinery to reach remote areas.

EXTRAPOLATION POTENTIAL

	Comments
Good. Expected to have similarities to barrier-strandplain facies of the Pictured Cliffs Sandstone and the upper Dakota Sandstone in the San Juan Basin, and of the Fox Hills Formation. 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, shale and argillaceous, very fine grained calcareous sandstone. The terrigenous clastics occur mostly toward the base of the unit. The calcarenite beds, which are fractions of an inch to over a foot in thickness, occur 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 FERC as a tight gas sand in the Ignacio area of LaPlata and Archuleta Counties, Colorado on the northern margin of the San Juan Basin (Colorado Oil and Gas Conservation Commission, 1980f, Cause NG-11). In the application area the Sanostee Member is described as a "very fine grained, extremely silty, heavily clay filled calcareous sandstone." It seems likely that the very abundant calcareous cement was derived from the calcarenite beds included in the unit. Such a lithology would make the Sanostee somewhat unique relative to other units included in this survey; the tight gas sand most similar to the Sanostee is the Mancos "B" interval. Both these units are shelf deposits within the Mancos Shale, but the "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 is considered low. It appears not to be a major exploration target and only limited data are available on its characteristics (table 46). The Sanostee is not considered a major candidate for future research by GRI; therefore, additional detail on its geologic and engineering parameters has not been sought.

Table 46. Characteristics of the Sanostee Member of the Mancos Shale, Ignacio area, San Juan Basin (from Colorado Oil and Gas Conservation Commission, 1980f, Cause NG-11).

Permeability: 0.04 md

Pressure: 3,100 psi

Temperature: 240°F

Porosity: 6.7-9.5%, average 8.3%

Net pay: 14-20 ft, average 17 ft

Depth: 7,550-7,700 ft, average 7,600 ft

Water saturation: 56-60%

Pre-stimulation flow rate: 20-42 Mcfd, average 31 Mcfd

Dakota Sandstone, San Juan Basin

Introduction

The Dakota Sandtone consists of fine-grained quartz sandstone that stratigraphically overlaps the Lower to Upper Cretaceous boundary in the San Juan Basin (fig. 62). That part of the Dakota that contains gas reservoirs of blanket geometry is within the upper part of the formation and is therefore most probably of Late Cretaceous age. The Dakota 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 (Hoppe, 1978; Bowman, 1978). Early production was dependent on natural fracturing and stimulation by shooting with nitroglycerin. Subsequently sand-water fracture treatments were developed and used routinely. Both these fields have low permeability, ranging from 0.1 to 0.25 md in the Basin Dakota Field, for example, and present interest for tight gas designations is in even tighter field-margin areas where development has not yet occurred.

The data base for the Dakota Sandstone is very good, based on numerous publications, a report by consulting geologist William R. Speer, and five applications for tight gas sand designations in Colorado and New Mexico (Colorado Oil and Gas Conservation Commission, 1980e, Cause No. NG-10, 1980f, Cause No. NG-11 and 1981b, Cause No. NG-23; New Mexico Oil Conservation Division, 1981e, Case No. 7252, 1981f, Case No. 7515, 1981b, Case No. 7116). Tables 47-50 cover the New Mexico portion of the basin, and tables 51-54 cover application areas in Colorado.

Structure

The San Juan Basin is a roughly circular, asymmetrical, Laramide-age basin of northwest New Mexico (fig. 63). Further details on the structure of the basin are included in a previous section on the Pictured Cliffs Sandstone.

Stratigraphy

The Dakota Sandstone was the basal sequence of the southwesterly transgressing Cretaceous sea as it entered the western interior of North America. Beneath the Dakota are fluvial and lacustrine rocks of the Upper Jurassic Morrison Formation, and above the Dakota is the marine Mancos Shale (Hoppe, 1978) (fig. 62). A major unconformity exists between the Morrison and the Dakota; the unconformity can be recognized in outcrop but is difficult to pick in the subsurface. In the northern part of the basin the Burro Canyon Formation occurs between the unconformity and the Morrison, but a review of stratigraphic nomenclature suggests that some authors would include this unit with the Dakota Sandstone (Owen and Siemers, 1977). Some authors have established formal members within the Dakota, but these 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 in the southeastern part it is nearly all marine sandstones and shales (Fassett and others, 1978). Between these end members intertonguing of facies is prevalent 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 through the central basin area and much of the productive tight sand area along the north to northeastern margin of the basin (Owen, 1973).

A vertical sequence through the Dakota in the latter areas begins with fluvial sandstones deposited by meandering streams and with associated floodplain deposits. The floodplain deposits consist of carbonaceous shales, a few thin coal beds and minor siltstones. Non-marine facies are succeeded by transitional estuarine and lagoonal facies of mudstone, siltstone, and minor 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 associated with the barrier-strandplain system are interpreted as offshore bars. Multiple minor episodes of regression and transgression occur within the upper part of the Dakota, leading to repetition of barrier-strandplain facies over distances of several tens of miles perpendicular to shoreline trends (Hoppe, 1978; Owen, 1973).

The lateral continuity of sands in the barrier-strandplain facies is moderately good. Widely spaced wells (figs. 64 and 67) show expected variation in sand continuity, except for the uppermost sand underlying the transgression of the Graneros Shale. On a more local basis, sands show good lateral continuity at well spacing of 0.5 to 1.5 mi (figs. 64 and 68).

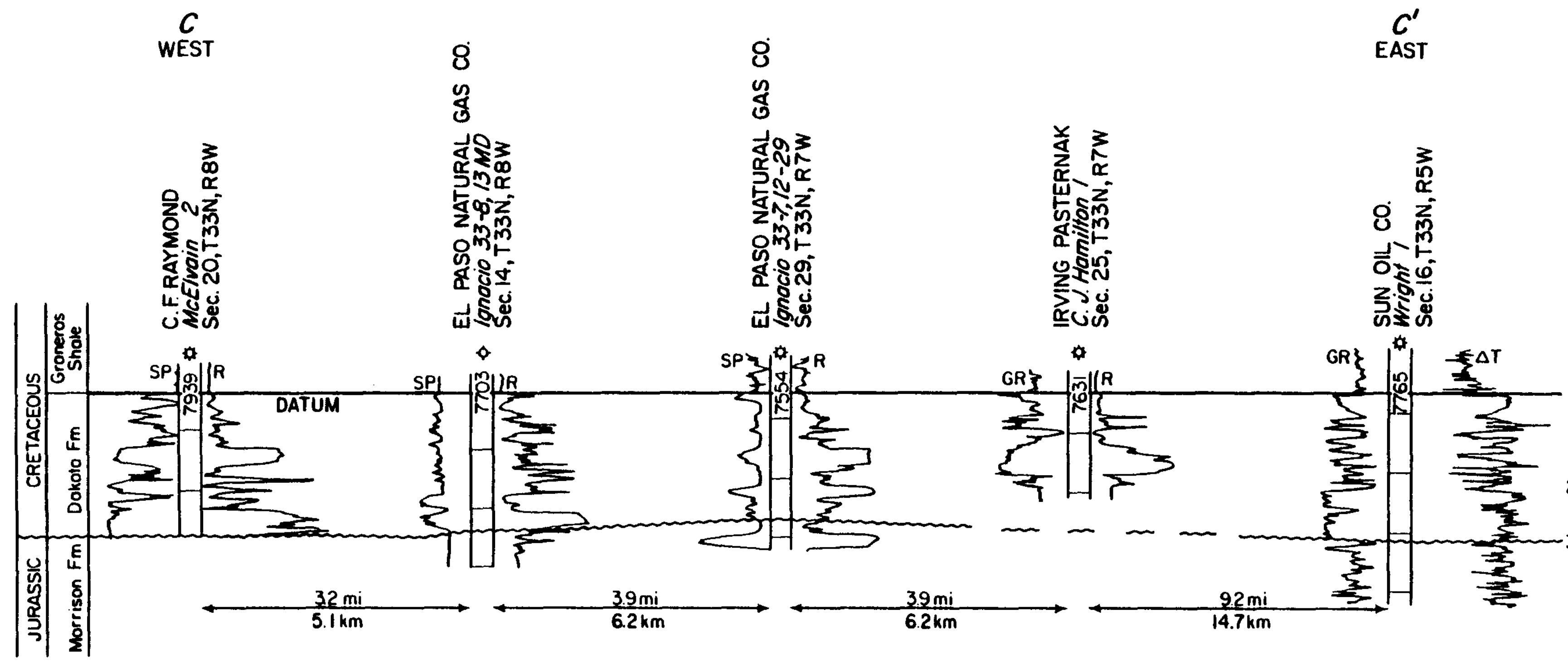

Figure 67. Stratigraphic cross section C-C' through the Dakota Sandstone, San Juan Basin (after Colorado Oil and Gas Conservation Commission, 1981b).

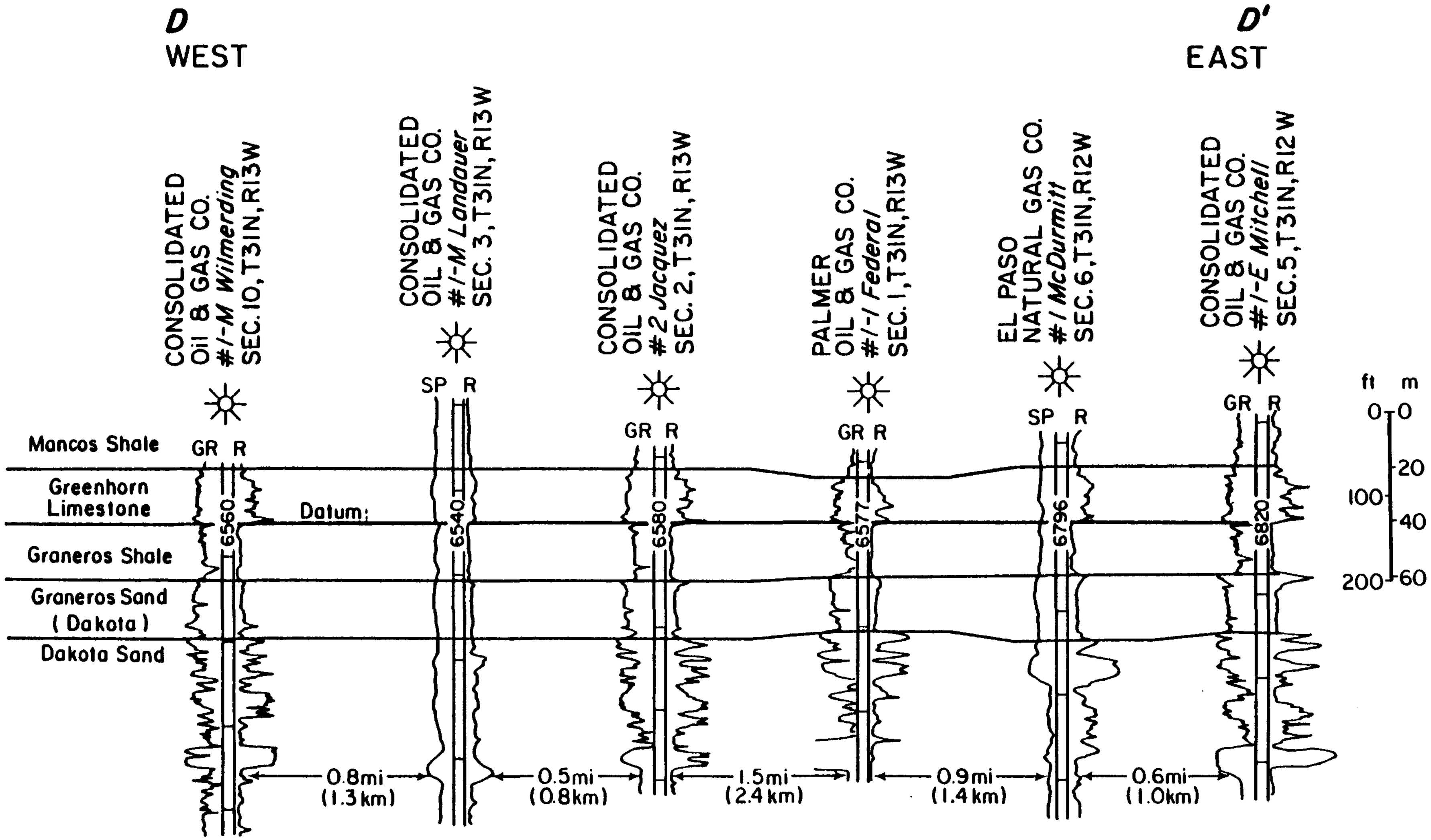

Figure 68. Stratigraphic cross section D-D' through the Dakota Sandstone and overlying strata, San Juan Basin (after New Mexico Oil Conservation Division, 1981b).

Table 47. 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. Huerfano area of Basin Dakota Field. Total area applied for is 135,040 acres (211 mi^2) in T24-25N, R7-10W in portions of San Juan and Rio Arriba Counties, New Mexico. 2. Northwest Blanco area. Total area of 15,163 acres (23.7 mi^2) in part of T31N, R13W in San Juan County, New Mexico. 3. Westside Tight Gas area. Total area of 165,120 acres (258 mi^2) in parts of T26-30N, R12-15W in San Juan County, New Mexico.	1. Range = 200-350 ft. 2. Range = 200-300 ft. 3. Range = 250-300 ft.	1. Average = 6,350 ft, range = 6,000-6,500 ft. 2. Average = 6,544 ft, range = 6,100-6,820 ft. 3. Average = 5,942 ft, range = 5,900-6,800 ft.	1. 0.3-2.0 Bcf per well. 2. 0.8-2.5 Bcf per well. 3. 0.5-2.0 Bcf per well. 2.2 Tcf maximum recoverable gas 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 with a NW-SE trending axial trace forming an arc along the northern edge of the basin. Tectonic events which formed the basin occurred principally during Late Cretaceous - Early Tertiary (Laramide) time. Principal structures which bound the basin include the Hogback monocline (W, NW), San Juan-Archuleta Uplift (N), Nacimiento Uplift (E, SE), Puerco fault zone (SE), Chaco Slope and Zuni Uplift (S, SW).	1.6-2.5°F/100 ft.	1. No data. 2&3. Calculated pressure gradient ranges from 0.38-0.42 psi/ft.	Compressional in Late Cretaceous - Early Tertiary, followed by extensional on eastern side of basin in Late Tertiary.

Table 48. Dakota Sandstone, San Juan Basin (New Mexico): Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies

Deposited as the basal sequence of the southwesterly transgressing Late Cretaceous sea. The basal Dakota was deposited in non-marine conditions as a braided stream system. This was followed by a meandering stream system which includes paludal and overbank deposits. Transitional non-marine - marine sedimentation followed. Lagoonal, estuarine, and storm washover deposits constitute this facies tract. Finally, the upper Dakota Sandstone includes barrier- and offshore-bar facies. These are laterally persistent, about 40-60 ft thick, and consist of a coarsening-upward sandstone sequence.

Texture

Fine grained, quartzose sandstones and carbonaceous shales with occasional conglomerates and coals in the basal section. The upper coastal sandstones are typically very fine to fine grained. They coarsen upward and sorting also improves upward.

Mineralogy

The sandstones are quartzose. The coastal sandstones, however, have a suite of metamorphic heavy minerals present that is not present in the fluvial units. The coastal units are locally glauconitic and are characteristically micaceous (muscovite and biotite), whereas the fluvial units have shale lenses composed dominantly of illite with minor amounts of kaolinite.

Diagenesis

Calcareous and argillaceous cements present.

Typical Reservoir Dimensions

Typically only the upper Dakota sands are gas prone, therefore the gross pay range = 75-200 ft.

Pressure/Temperature of Reservoir

1. Pressure range = 2,500-3,500 psi.
   Temperature average = 150°F.

2. Pressure range = 2,590-2,660 psi.
   Temperature average = 150°F.

3. Pressure average = 2,320 psi.
   Temperature average = 150°F.

Natural Fracturing

Occasionally encountered.

Data Availability (logs, cores, tests, etc.)

Limited coring at present stage of development. Typical log suite includes GR-resistivity and GR-density.

Table 49. 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 = 5-15%, average = 5%. Average calculated in situ permeability = 0.024 md (based on 7 core analyses). 2. Calculated in situ permeability of 5 wells ranges from .0877-.00068 md, with an average = .0218 md. 3. Permeability determined from cores of 7 wells is 0.07 md to air, which calculates to 0.003 md in situ. Porosity range = 2-16%, average = 9.5% in pay zone.	1. Average = 60 ft, range = 25-75 ft. 2. Average = 66 ft, range = 50-100 ft. 3. Average = 40 ft, range = 35-50 ft.	1. Based on one natural unstimulated flow test, natural flow = 152 Mcfd. 2. Based on 5 unstimulated flow tests, natural flow range = TSTM-224 Mcfd. 3. Based on one unstimulated flow test after acidizing, natural flow = 6.7 Mcfd.	1. 100-350 Mcfd. 2. 50-380 Mcfd. 3. 100-350 Mcfd.	1. 9%/yr. 2. 5-7%/yr. 3. 5-9%/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 present, they are produced at rates less than 5 bpd. 3. Oil and condensate/gas ratio after stimulation = 0.026 barrel/Mcf. Water is generally produced from the lower Dakota interval in most areas.	Range = 30-50%.

Well Stimulation Techniques	**Success Ratio**	**Well Spacing**	**Comments**
Two methods of hydraulic fracturing in stages are used: A. Isolating potential pays with bridge plugs and selectively perforating and fracturing them. B. Perforating all potential pays, then using a ball sealer staging fracture method. Typical sand-water (gel) hydraulic fracture treatments utilize 60,000-125,000 gal of fluid and 60,000-110,000 lb of sand. Maximum injection pressure is about 4,000 psi, and average injection rate = 30 bpm.	Very successful, however no actual data is available regarding percent improvement in gas flow.	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 experienced a 96% success ratio in 1980. Many of the 826 wells drilled were infill wells.

Table 50. 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 New Mexico, FERC action pending. 3. State approval pending.	1. Area contains 35 Dakota gas wells, 22 of which are abandoned as of 5/6/81. 2. No data. 3. 7% of the application area contains 36 producing wells and 69 abandoned wells. As of 1/1/74, 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 currently. 40% success for exploratory wells in 1980 for all formations in the San Juan Basin.	Total drilling and completion cost, including stimulation, range = \$300,000-\$500,000. Average stimulation cost = \$75,000.	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. Total of 6 FERC applications.

OPERATING CONDITIONS / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
Highly dissected terrain of Colorado Plateau with numerous mesas and canyons. Local relief of 500-1,000 ft, and greater than 1,000 ft in some areas.	Arid to semi-arid with 8-16 inches mean annual precipitation. Moderately hot summers, cold winters. Generally late afternoon thundershowers in the summer, moderate snowfall in the winter, and irregular precipitation patterns in the fall and spring.	Fair in areas which have already been developed, poor in other areas. Access road development requires large earth-moving machinery to reach remote areas.	Good. Expected to have similarities 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 51. 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 Formation, Upper Cretaceous	1. Ignacio area, La Plata County, Colorado. Total area applied for includes 181,105 acres (283 mi^2). 2. Ignacio Blanco Field, La Plata and Archuleta Counties, Colorado. Total area applied for includes 274,270 acres (428.5 mi^2).	1. Range = 210-230 ft. 2. Range = 225-250 ft.	1. Range = 7,300-8,000 ft, average = 7,600 ft. 2. Range = 7,180-8,720 ft, average = 7,930 ft.	Estimated gas recovery for the Ignacio Blanco Dakota Field is 250-300 Bcf. 2.2 Tcf maximum recoverable gas 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 with a NW-SE trending axial trace forming an arc along the northern edge of the basin. Tectonic events which formed the basin occurred principally during Late Cretaceous - Early Tertiary (Laramide) time. Principal structures which bound the basin include the Hogback Monocline (N, NE, NW), San Juan Uplift (N), Nacimiento Uplift (E, SE), Puerco fault zone (SE), Chaco Slope and Zuni Uplift (S, SW), and the Defiance Uplift and monocline to the SW and W.	1.6-2.5°F/100 ft.	No data.	Compressional in Late Cretaceous - Early Tertiary, followed by extensional on eastern side of basin in Late Tertiary.

Table 52. Dakota Sandstone, San Juan Basin (Colorado): Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies	**Texture**	**Mineralogy**	**Diagenesis**
See Dakota Formation (New Mexico).	See Dakota Formation (New Mexico).	See Dakota Formation (New Mexico).	See Dakota Formation (New Mexico).
Typical Reservoir Dimensions	**Pressure/Temperature of Reservoir**	**Natural Fracturing**	**Data Availability (logs, cores, tests, etc.)**
Typically only the upper sands are gas-prone, therefore the gross pay range = 60-100 ft.	1. Average reservoir pressure = 2,800 psig. Reservoir temperature = 240°F. 2. Average reservoir temperature = 210°F. Average reservoir pressure = 3,400 psi.	Occasionally encountered.	Limited core at present stage of development. Typical log suite includes GR-resistivity and GR-density.

Table 53. 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 = 7-10%, average = 8.8%. Permeability range = 0.05-0.07 md, average = 0.06 md. 2. Average porosity = 7.5%. Average permeability = .0765 md.	1. Range = 6-25 ft, average = 15 ft. 2. Range = 10-60 ft.	1. Range = 22-272 Mcfd, average = 117 Mcfd. 2. Range = 27-480 Mcfd, average = 253 Mcfd.	2. Approximately 200 Mcfd average for 90 wells (long term).	Typically 5-9%/yr.	Liquid hydrocarbons generally are not produced. Water is produced from the lower Dakota in most areas.	Range = 41-60%, average = 49%.

Well Stimulation Techniques	**Success Ratio**	**Well Spacing**	**Comments**
See Dakota Formation (New Mexico).	See Dakota Formation (New Mexico).	640 acres.	Infill drilling has been proposed.

Table 54. 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. FERC approved. 2. Approved by Colorado. FERC action pending.	As of 1/1/74, 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 cost, including stimulation, range = \$400,000-\$600,000. Stimulation cost range = \$75,000-\$100,000.	El Paso Natural Gas Co., Southern Union Gathering Co., and Northwest Pipeline Corp. Pipelines are adequate in all areas.	High. Total of 6 FERC applications.

OPERATING CONDITIONS / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
Highly dissected terrain of Colorado Plateau with numerous mesas and canyons. Local relief of 500-1,000 ft, and greater than 1,000 ft in some areas.	Arid to semi-arid with 8-16 inches mean annual precipitation. Moderately hot summers, cold winters. Generally late afternoon thundershowers in the summer, moderate snowfall in the winter, and irregular precipitation patterns in the fall and spring.	Fair in areas which have already been developed, poor in other areas. Access road development requires large earth-moving machinery to reach remote areas.	Good. Expected to have similarities 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.

"J" Sandstone, Denver Basin

Introduction

The "J" Sandstone is a coarse silt to fine-grained sandstone within the Lower Cretaceous Dakota Group of the Denver Basin (fig. 69). 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). A tight formation designation has been approved by FERC for the gas-productive Wattenberg Field and vicinity in Adams, Weld, Larimer and Boulder Counties, Colorado (Colorado Oil and Gas Conservation Commission, 1980a, Cause NG-3). The "J" Sandstone is also oil productive from deltaic reservoir sands in parts of the Denver Basin, such as in Peoria Field, Arapahoe County, Colorado.

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

Because of its high level of development, the "J" Sandstone in the Wattenberg vicinity is not considered a likely candidate for further research by GRI. The "J" Sandstone is therefore included in this survey primarily as a model for a blanket-geometry, tight gas sandstone whose geologic and engineering characteristics are relatively well known. This discussion and assembled data (tables 55-58) refer almost exclusively to Wattenberg Field, except for the estimated resource base (table 55) that refers to a larger area from north of Greeley to the vicinity of Denver, Colorado (fig. 70). The National Petroleum Council (1980) found that formations in the Denver Basin other than the "J" Sandstone and the Niobrara had only minor to very limited potential for additional tight gas reserves.

Structure

The Denver Basin is an asymmetrical Laramide structural basin with an axis along the western margin subparallel to the Front Range of the Central Rocky Mountains. The basin is bounded by subsurface and surface positive structural features listed in table 56. The Denver Basin is asymmetric with a gently dipping eastern flank and a steep western flank. More than 13,000 ft of sediments have accumulated near Denver at the deepest point in the basin. 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 relationships exist between recurrent movement on Precambrian fault zones, and thickness and facies variations in Paleozoic and Mesozoic strata. Northeast-trending paleostructures are considered 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 be responsible for the present structurally low position of the Wattenberg field. Paleostructural analysis suggests a former structurally high position for the field, 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, although the latter formation name is primarily used in Wyoming (Matuszczak, 1973; C. 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 reflect a Kansas-Nebraska provenance, and the distributary pattern of this unit reflects progradation from east to west (Martin, 1965; Matuszczak, 1973).

Depositional Systems

The producing interval of the "J" Sandstone in Wattenberg Field is 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 generally located between Greeley, Colorado, and the Colorado-Wyoming boundary (Peterson and Janes, 1978). The log character of the delta front shows a consistent upward-coarsening pattern across the field (fig. 71). The distributary bar facies is probably represented by the uppermost, slightly more blocky part of the upward-coarsening sequence (fig. 71) but is difficult to discriminate without the availability of conventional core. In core, the distributary bar shows (1) less bioturbation than the underlying delta front, (2) horizontal laminations, and (3) robust Ophiomorpha generally in a vertical position (Peterson and Janes, 1978). Published vertical profiles of permeability or of detailed petrography were not available for this review. However, it is likely that the development of cleaner, slightly more permeable reservoir rock will correlate with the occurrence of the distributary bar facies.

Immediately overlying the delta front facies is a delta plain that consists of carbonaceous shale to fine sand, is burrowed, and contains root traces. Individual facies, such as channel, natural levee, crevasse splay, and interdistributary bay deposits are both limited and highly variable in areal extent. The final interval of the "J" Sandstone consists of a parallel-laminated silt and shale that is continuous across the field. It has been interpreted as a transgressive marine sequence and represents the end of deltaic deposition (fig. 71) (Peterson and Janes, 1978).

"J" Sandstone Model

The "J" Sandstone has only been included in this survey as a model for other formations, not as a potential research target for GRI. As a model it is an ideal example of a unit with blanket geometry and with excellent lateral continuity characteristic of delta front sandstones (fig. 72 and 73). Although not described by Peterson and Janes (1978), core of the delta front sandstone of the "J" would be expected to have ripple cross-lamination, some deformational structures, and in the upper part, some trough cross-stratification. These features are described from outcrop for the Fox Hills Formation in the Denver Basin, also interpreted to be a delta front sandstone (Weimer, 1973). The same delta front facies may be expected in parts of the Fox Hills and Frontier Formations of the Greater Green River Basin, which are included in this survey, and other formations where deltaic deposits were not completely reworked by subsequent marine transgression.

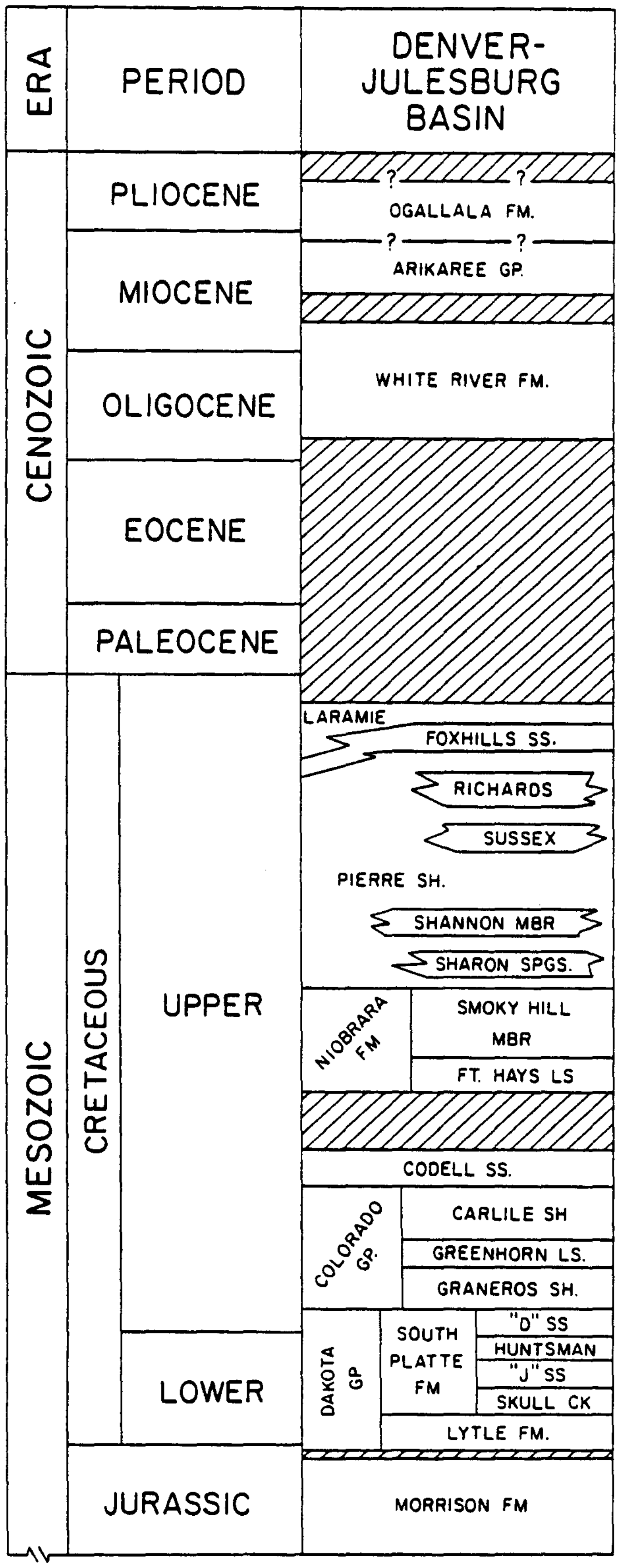

Figure 69. Stratigraphic column from the Jurassic Morrison Formation through the Pliocene Epoch in the Denver-Julesberg Basin (after Rocky Mountain Association of Geologists, 1977).

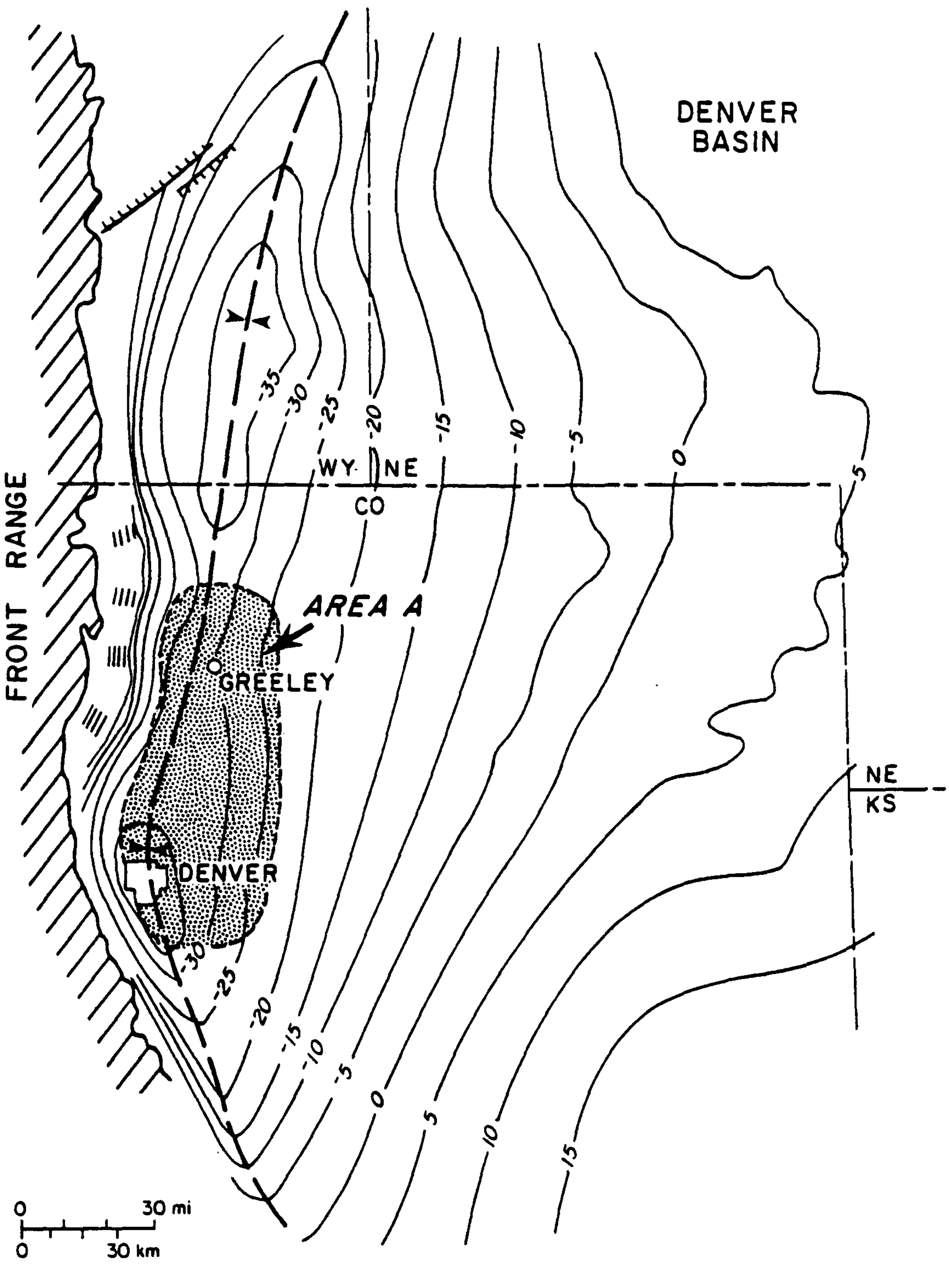

Figure 70. Generalized structural configuration of the Denver Basin (contour interval x 100 ft) and area of tight gas sand potential (A) (after National Petroleum Council, 1980).

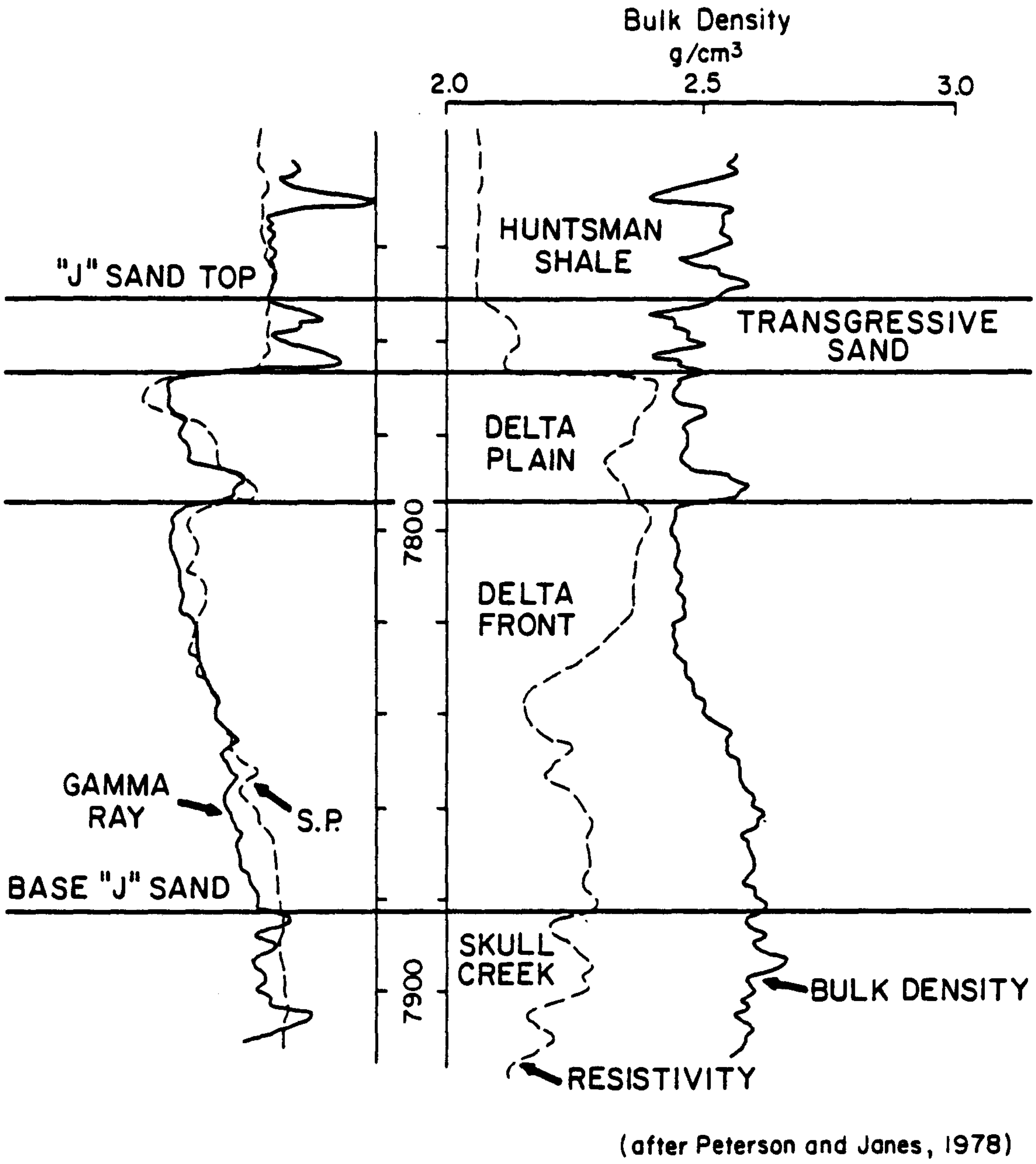

Figure 71. Type log for the "J" Sandstone, Denver Basin.

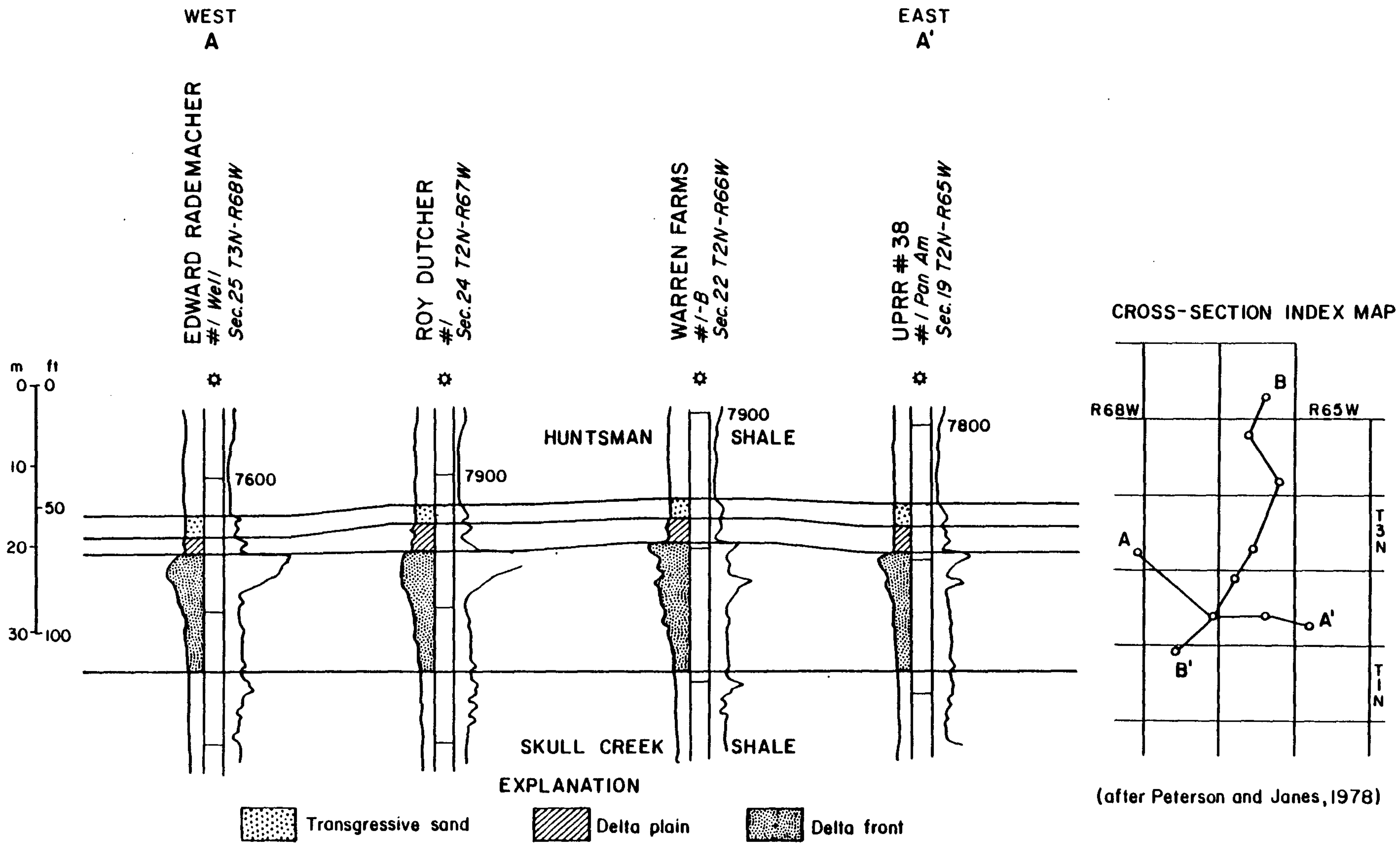

Figure 72. West-east stratigraphic cross section A-A' and cross section index map showing facies of the "J" Sandstone, Denver Basin.

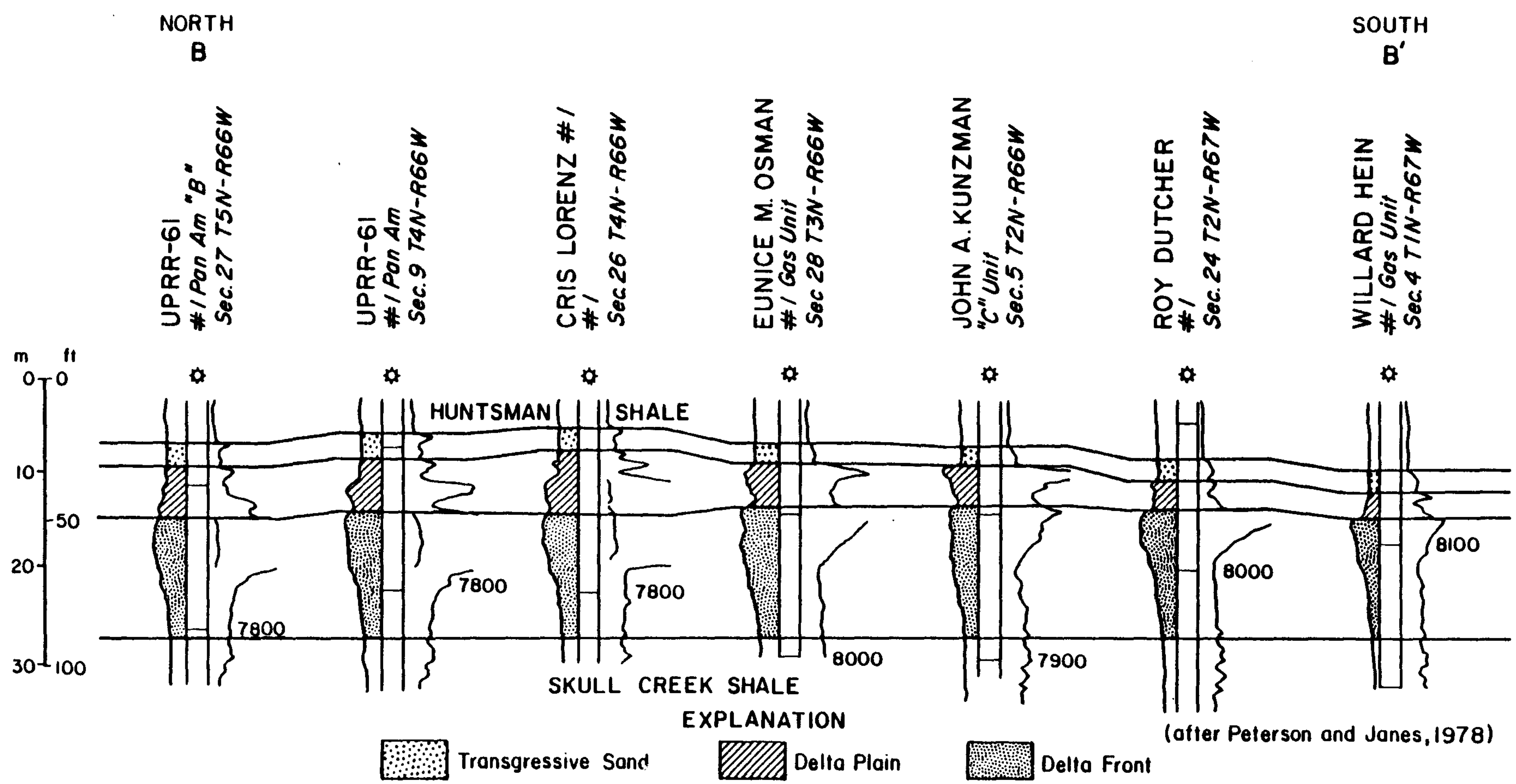

Figure 73. North-south stratigraphic cross section B-B' showing facies of the "J" Sandstone, Denver Basin.

Table 55. "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 = 1,100 mi^2. Speculative area = 500 mi^2(National Petroleum Council, 1980). Productive Wattenberg Field area = 978 mi^2.	40-140 ft in Wattenberg with upper "J" contributing to variation due to its lenticularity relative to lower "J".	7,350-8,500 ft, average = 8,000 ft in Wattenberg Field.	9,175 Tcf estimated gas in place. 5,539 Tcf maximum recoverable gas in area generally from Denver to Greeley, Colorado. 1.1-1.3 Tcf ultimately recoverable from Wattenberg excluded from above estimates (National Petroleum Council,1980).	No additional formation.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
An asymmetrical Laramide structural basin with an axis along the western margin and 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 Wet Mountains/Apishapa Uplift (southwest).	2.6°F/100 ft (high gradient).	0.36 psi/ft (underpressured).	Compressional Laramide deformation followed by vertical post-Laramide uplift and subsequent subsidence.

Table 56. "J" Sandstone, Denver Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies

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 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.

Texture

Coarse silt to fine sand, bioturbated in part, within the delta-front facies. Poorly sorted and well indurated where studied in outcrop.

Mineralogy

Presumably a quartz sandstone and sandy siltstone but no detailed petrography published. Generally described as dark gray, with abundant clay matrix.

Diagenesis

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

40-140 ft thick, over the 900 mi^2 in area including Wattenberg Field.

Pressure/Temperature of Reservoir

3,000 psi pressure, 260°F temperature are average Wattenberg Field values.

Natural Fracturing

Extent unknown.

Data Availability (logs, cores, tests, etc.)

Typical log program includes SP-Dual Induction Laterlog and GR-Density-Caliper log. Extent of conventional whole core data includes 26 cores taken by Amoco early in development of Wattenberg Field.

Table 57. "J" Sandstone, Denver Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir Parameters	Net Pay Thickness	Production Rates: Pre-Stimulation	Production Rates: Post-Stimulation	Decline Rates	Formation Fluids	Water Saturation
Porosity: 7.7% - 13.9%, range, 10.8% average. Permeability: 0.0003-0.0306 md, range, 0.0059 average in situ for Wattenberg Field. Some permeability to 0.5 md (conventional reservoir) for unknown areal extent.	4-58 ft range, 27 ft average for Wattenberg Field.	1-167 Mcfd range, 19.9 Mcfd average.	100 - 3,575 Mcfd.	Rapid in first 6 months.	Typically, 64 bbl/1,000 Mcf condensate of 64^{o}API gravity for Wattenberg Field.	27% - 99% range, 42% average for conventional, 55% average for unconventional.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
Massive hydraulic fracture treatment. Size of treatments has varied from 183,000 gal fluid and 277,000 lb of sand to 517,000 gal fluid and over 1,000,000 lb of 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 with a pressure of 4,000 - 4,500 psi.	Considered effective in appropriate areas; larger treatments have been superior in production rate and cumulative production to the smaller treatments.	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 58. "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, 1/23/81 for 38 townships, less certain exceptions, mostly in Wattenberg Field.	After discovery in 1970, 480 wells drilled in 1974-1975 period. In the period 1975-1977, 826 wells were producing from tight gas reservoirs.	8.3% based on 877 wildcats in the period 1970-1977 for Denver Basin as a whole.	Drilling: $430,000; Fracture treatment: $93,000-$304,000; Completion: no data; (1979 dollars) (National Petroleum Council, 1980).	8 in to 20 in 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

Physiography	Climatic Conditions	Accessibility
Rocky Mountain Piedmont physiographic subdivision, consisting of irregular plains with 100-300 ft of local relief. Most of area is gently sloping.	Semiarid with 10-16 inches mean annual precipitation. Mild summers, cold winters.	No terrain barriers. Numerous state and county highways; unpaved section roads at 1 mi spacing in many areas.

EXTRAPOLATION POTENTIAL

	Comments
Excellent example of laterally continuous delta-front facies included in this survey as a basis for comparison with other tight gas sands. Similar facies may be expected in parts of the Frontier, Muddy, and Fox Hills Formations (Greater Green River Basin).	Drilling and completion services readily available as a consequence of established oil and gas production in northeast Colorado.

Niobrara Formation, Denver Basin

Introduction

The Upper Cretaceous Niobrara Formation in the Denver Basin produces gas at low pressures from a low-permeability chalk that is found at depths of 1,000 to 3,000 ft in Colorado, Kansas and Nebraska (Hanley and Van Horn, 1982). Gas production in the Niobrara comes from the upper part of the formation, the Smoky Hill chalk member (fig. 69). This member was deposited during a major marine transgression, and can be recognized and correlated over a very wide area, thereby qualifying as a blanket formation. The lithology of this unit is unique in that it consists of fine-grained carbonate debris, primarily coccospheres, coccolith plates, and rabdolith plates (Hanley and Van Horn, 1982). The source of the gas in the Niobrara is also unique because it is believed to be biogenic in origin, having formed at temperatures less than 150°F, and derived from the organic matter in the Niobrara itself (D. Reese, personal communication, 1982).

Because of its blanket geometry the Niobrara has been included in this survey; the extrapolation potential of any studies on the Niobrara is limited, however, by the unique lithology of the formation. The only other carbonate unit included in this survey is the Sanostee Member of the Mancos Shale (San Juan Basin, New Mexico), which is a highly calcite cemented sandstone and calcarenite consisting of shell fragments and phosphatic debris, also dissimilar to other tight gas sands and to the Niobrara. This discussion has been included primarily for comparative purposes, and to cover a play that has involved the drilling of 919 wells since 1974, 454 of which are gas producers (D. Reese, personal communication, 1982). The pertinent characteristics of the Niobrara reservoir and its productive capabilities are listed in table 59.

The Niobrara was approved by FERC as a tight formation in Cheyenne, Kit Carson, Lincoln, Logan, Phillips, Sedgwick, Washington, and Yuma Counties, Colorado, on March 30, 1981 (Colorado Oil and Gas Conservation Commission, 1980b, Cause NG-4).

The State of Kansas approved the Niobrara as a tight gas formation in Cheyenne, Rawlins, Sherman, and Thomas Counties on March 1, 1982 (Kansas State Corporation Commission, 1982, Docket No. 130, 751-C). In Nebraska, a portion of the Niobrara Formation has also been classified as a tight formation. There are no pipelines in the area in Nebraska where the Niobrara is productive, however, and sale of gas is awaiting completion of the Trailblazer system from western Wyoming to Beatrice, Nebraska (P. H. Roberts, personal communication, 1982).

Structure

The Niobrara gas production occurs on the eastern and southeastern flanks of the Denver Basin where regional dips are less than 1°. Additional information on the structure of the Denver Basin is included in this survey under the description of the "J" Sandstone. Structural traps are formed by low relief domal and oval features, with 50 to 200 ft of closure, which are frequently modified by normal faulting. The brittle nature of the chalk makes it readily susceptible to faulting, which has probably developed as a result of tension over deeper horst-and-graben structures. Frequently the Niobrara has been prospected by analysis of well logs from previous tests of deeper horizons and by reinterpretation of older seismic records (Lockridge and Scholle, 1978; D. Reese, personal communication, 1982).

Stratigraphy

The Niobrara Formation lies between the Carlile and Pierre Shales and consists of the lower Ft. Hays Member and the upper Smoky Hill Member (fig. 69). The productive interval consists of relatively clean chalk at the top of the Smoky Hill Member, which is informally referred to as the Beecher Island zone after Beecher Island Field in Yuma County, Colorado (fig. 74). The bulk of the Smoky Hill Member consists of chalky shale with locally developed massive chalk beds. Studies using the scanning electron microscope readily show the calcareous nannofossils that make up the Beecher Island zone

(Lockridge and Scholle, 1978). Deposition of the cleaner chalks occurred when terrigenous muds failed to reach all parts of the Late Cretaceous epicontinental sea.

Significance of the Niobrara to this Survey

The calcareous nannofossils making up the productive interval of the Niobrara, and the occurrence of biogenic gas as a result of anaerobic action on organic matter make the Niobrara unique among blanket tight gas sands. This survey has revealed no other similar gas occurrences; therefore, the extrapolation potential of any future detailed studies is considered low. In fact, because of its unique lithology, the productive interval of the Niobrara Formation has already received fairly extensive study, and the genesis of the rock unit appears well understood.

Table 59. Selected geologic and engineering characteristics of the Niobrara Formation based on data primarily from Washington and Yuma Counties, Colorado (from Lockridge, 1977; Smagala, 1981; Hanley and Van Horn, 1982; D. Reese, personal communication, 1982).

Composition: carbonate nannofossils.

Lithology: 85% calcite, 5% quartz, 10% clay.

Porosity: 45% at 1,000 ft; 30% at 2,500 ft.

Permeability: 0.5 to 0.1 md or less.

Depth of producing interval: 1,000 to 3,200 ft.

Gross interval thickness: 35 to 50 ft.

Reservoir pressure: 60 psi at 900 ft; 800 psi at 3,000 ft.

Reservoir temperature: 130°F at 3,000 ft.

Water saturation: 50%.

Trap: Low-relief domal to oval structures with 50 to 200 ft of closure.

Production rate: 25 to 400 Mcfd.

Decline rate: Sharp decline first 6-12 months, 3 to 5% annually thereafter.

Stimulation: Sand/nitrogen foam fracture treatment; acidization avoided because of release of fines.

Cozzette and Corcoran Sandstones, Piceance Creek Basin

Introduction

The Cozzette and Corcoran Sandstones are part of the Upper Cretaceous Mesaverde Group in the subsurface of the southern Piceance Creek Basin (fig. 75). The Piceance Creek Basin is located in northwestern Colorado, with Grand Junction, Colorado, located on the southwestern margin of the basin (figs. 76 and 77). Two applications for tight formation designation have been approved by FERC for parts of Mesa and Garfield Counties, Colorado (Colorado Oil and Gas Conservation Commission, 1980g, Cause NG-12, and 1980j, Cause NG-17). An additional application for part of the southern Piceance Basin (Colorado Oil and Gas Conservation Commission, 1981a, Cause NG-21) has been approved for the entire Mesaverde Group in part of Garfield County (fig. 77).

The present data base for the Cozzette and Corcoran Sandstones is good (tables 60-67) with some notable exceptions. Specifics on the genetic stratigraphy of the producing intervals are lacking at this time, although core taken as part of the Multi-Well Experiment (MWX) and outcrop studies near the MWX site should yield such information in the near future. Outcrop studies reported thus far have been fairly generalized (U.S. Department of Energy, 1982), and data on the texture, mineralogy and diagenesis of the Cozzette and Corcoran reservoirs are lacking (tables 61 and 65). Outcrop studies of mineralogy and diagenesis must be interpreted with extreme caution because mineral transformations and redistribution of cementing agents may occur in the near-surface environment.

Present operator interest in the Cozzette and Corcoran Sandstones is quite high (C. Spencer, personal communication, 1982). This is in part related to the relatively shallow depths at which gas can be produced (fig. 78).

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 Uplift, on the east by the White River Uplift, on the southwest by the Uncompahgre Uplift and on the west by the Douglas Creek Arch. The Douglas Creek Arch is a mildly positive feature that separates the Piceance Creek Basin from the Uinta Basin in Utah. At the time of Mesaverde Group deposition there is evidence of little or no uplift on both the Douglas Creek Arch and the Uncompahgre Uplift, and Laramide structural elements in general had little influence on Cretaceous depositional patterns (Johnson and Keighin, 1981; Murray and Haun, 1974).

Stratigraphy

In eastern Garfield County the sedimentary sequence between the top of the Dakota Sandstone and the Precambrian surface is approximately 8,000 ft thick. The Dakota and younger Cretaceous sediments (fig. 75) constitute the thickest sequence in northwestern Colorado, including thick marine shales and dominantly regressive sequences (Murray and Haun, 1974). The Mesaverde Group is such a regressive sequence with a source area to the west of the present basin. Much of the Mesaverde Group is non-marine, and fluctuations between non-marine and marine conditions occurred frequently during its deposition.

Depositional Systems

Specific genetic stratigraphic interpretations of the Cozzette and Corcoran Sandstones are lacking. Analysis of core acquired as part of the Western Gas Sands Project may provide some of this information in the near term (U.S. Department of Energy, 1982). Generally these units are in part of the Mesaverde Group classified as marginal marine of "beach and bar origin" (Dunn, 1974), but it can also be inferred that some progradational deposits, such as delta front, may be present. Reworking during transgressive phases, however, may have obliterated all traces of the original regressive deposits.

Complicating the interpretation of published studies on parts of the Mesaverde Group is the lack of differentiation into separate sandstone bodies. Some studies term the Mesaverde a formation and treat it as a single, thick unit (Knutson and others, 1971). By one classification the Mesaverde Group is divided into the Williams Fork and the Iles Formation, which are terms used in describing measured outcrop sections in various parts of the basin (Hanley and Johnson, 1980).

Examination of a limited number of logs in T8S, R99W through T9S, R97W in Mesa County shows few upward-coarsening progradational sequences and more numerous blocky, aggradational sand sequences. Blocky SP log patterns with slightly transitional tops and bases may represent barrier island or strandplain sands as in the Andrews et al. Gov't #1 and the Marathon Gov't #2 well (fig. 79). Lateral continuity between these two wells is good; the remaining wells on the cross section, except the Koch #2 Horseshoe Canyon well, show poorer sandstone development and may represent nearshore marine environments with relatively thin bar sands. This interpretation seems reasonable based on what is generally known of the Cozzette and Corcoran sandstones and the Mesaverde Group as a whole, but could only be verified by a future localized study.

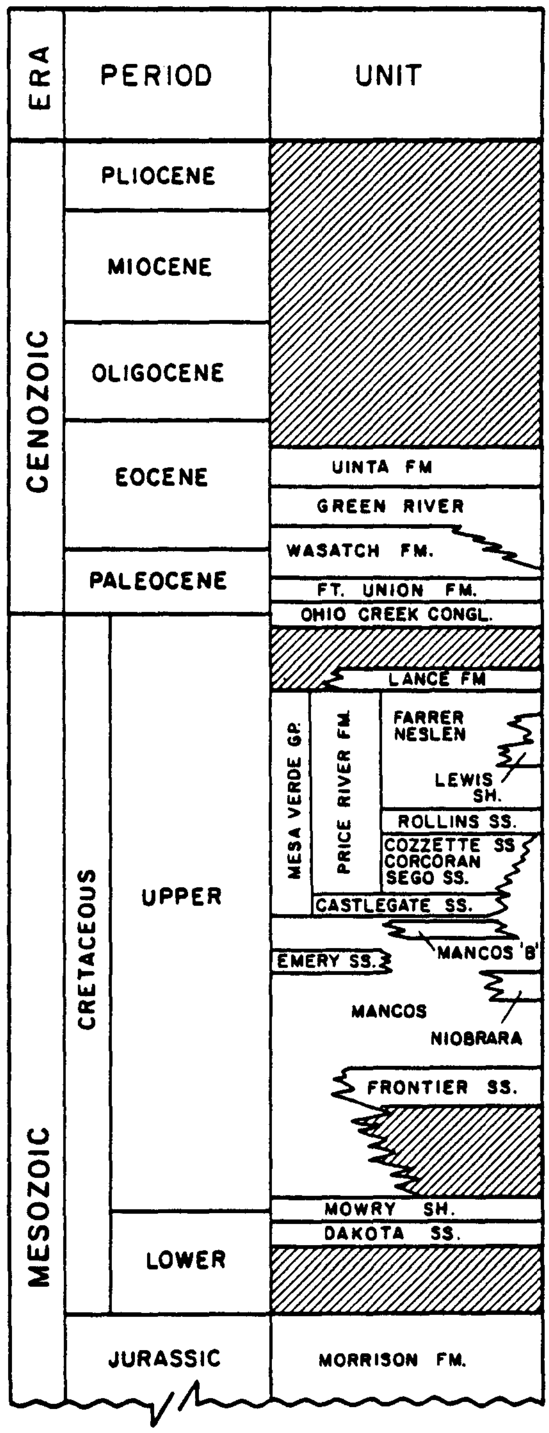

Figure 75. Stratigraphic column from the Jurassic Morrison Formation through the Pliocene Series, Piceance Creek Basin (after Rocky Mountain Association of Geologists, 1977).

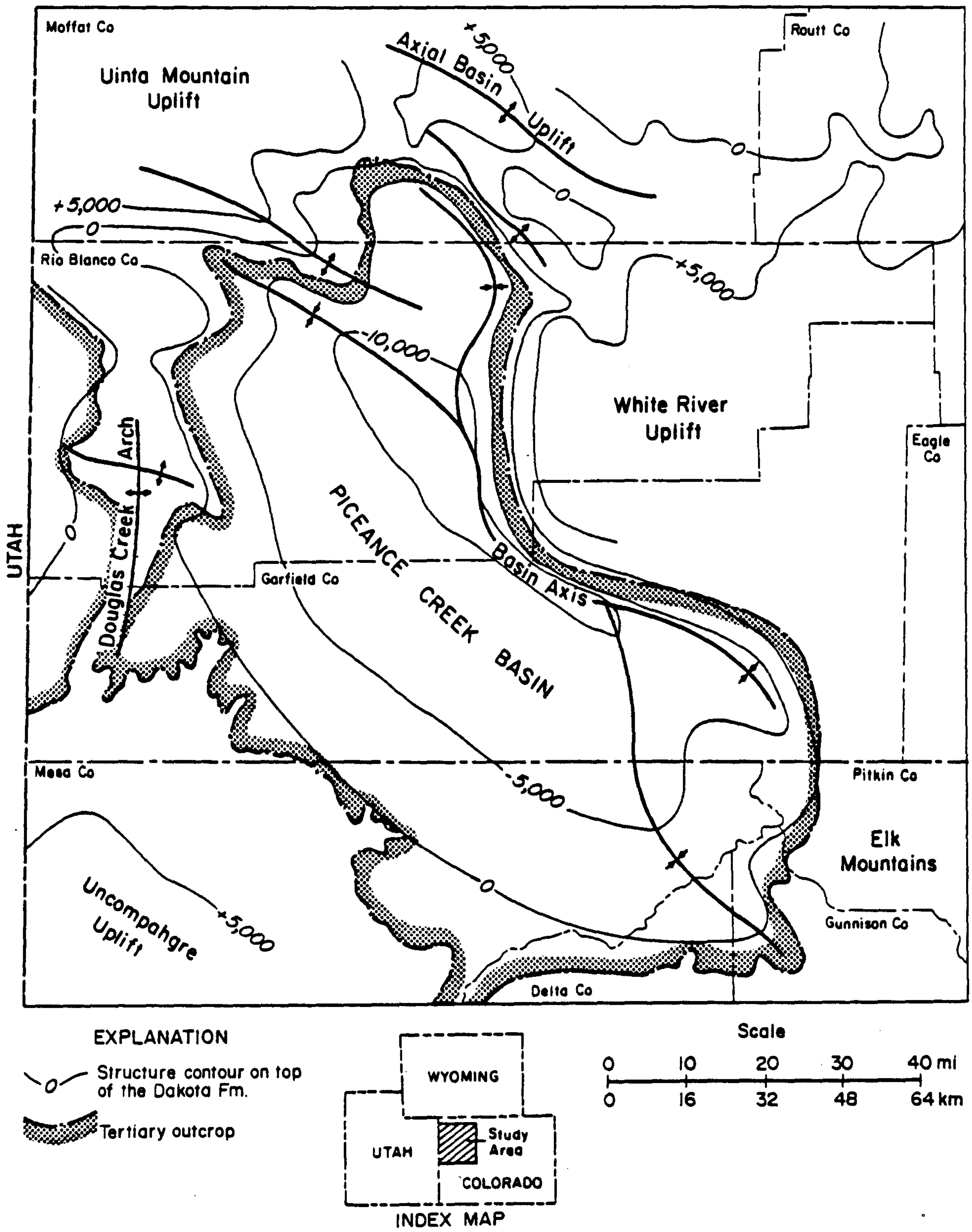

Figure 76. Location and generalized structure map for the Piceance Creek Basin (after Dunn, 1974).

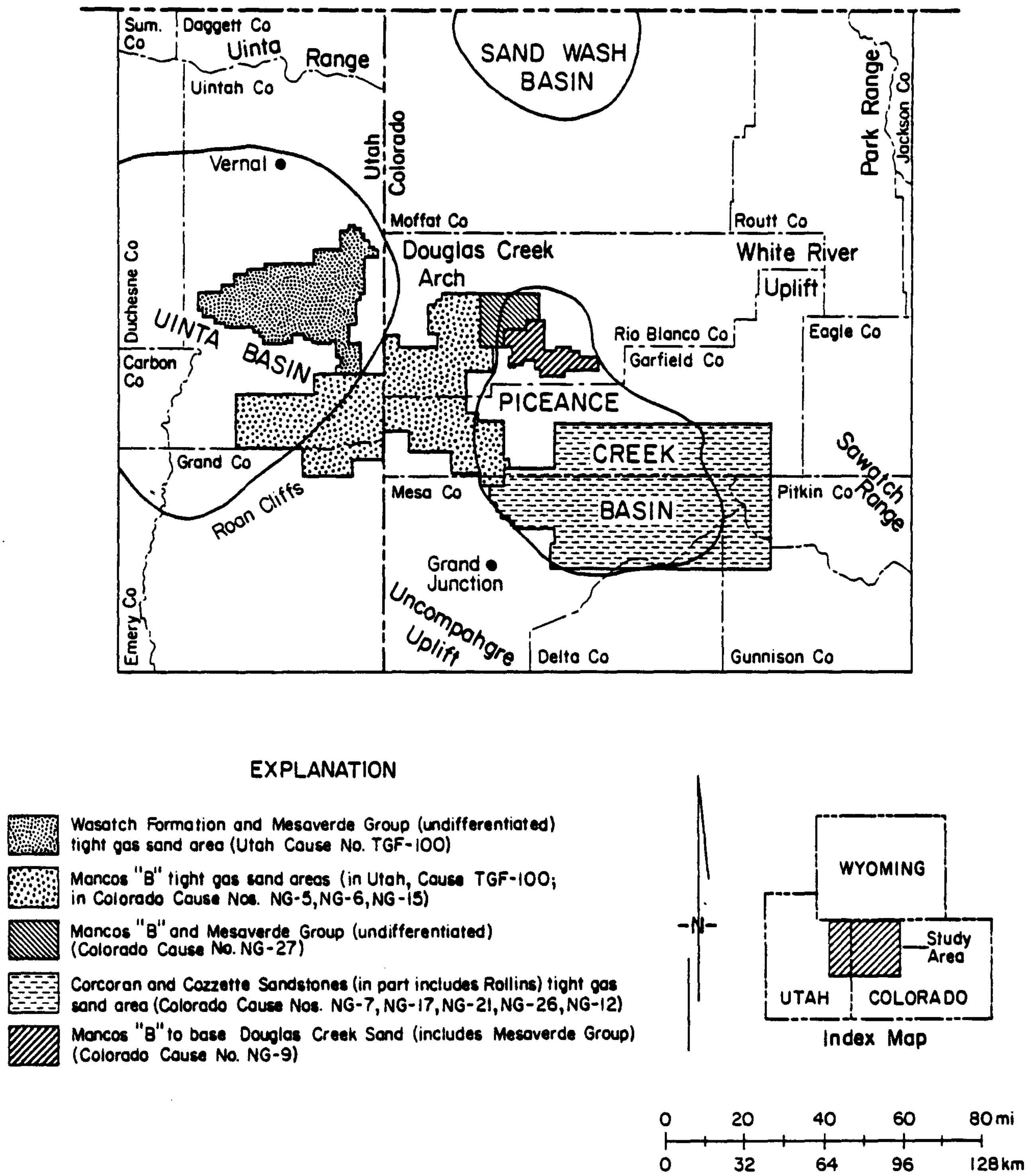

Figure 77. Areas covered by tight gas sand applications, Piceance Creek and Uinta Basins.

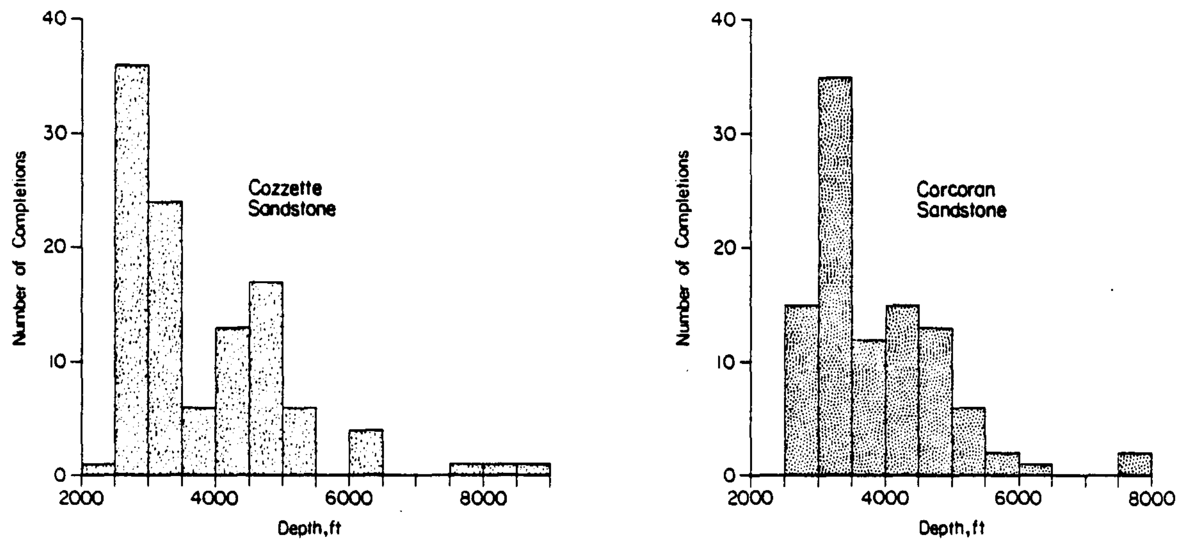

Figure 78. Depth to the top of the Cozzette Sandstone (110 wells) and the Corcoran Sandstone (101 wells) in producing gas wells, Piceance Creek Basin.

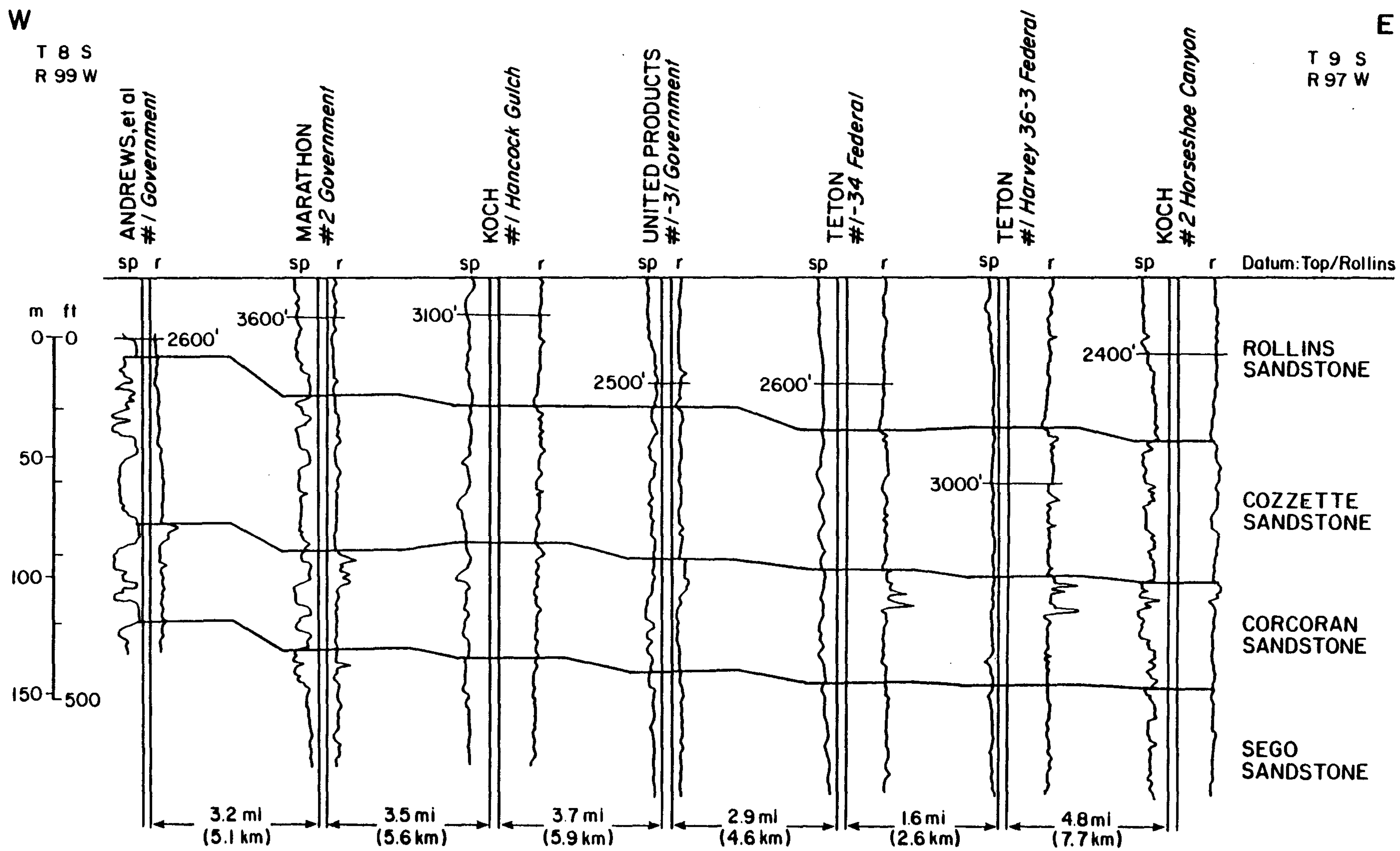

Figure 79. West-east stratigraphic cross section from T8S, R99W to T9S, R97W showing the Cozzette and Corcoran Sandstones, Piceance Creek Basin (after Colorado Oil and Gas Conservation Commission, 1980g).

Table 60. 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 as tight formation = 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 of 175 ft in T8-10S, R97-100W.	Average drilling depth of 7,250 ft in R7S, T91W. Average drilling depth of 2,480 ft in T8-10S, R97-100W.	National Petroleum Council (1980) reports maximum recoverable gas of 2.294 Tcf for Corcoran-Cozzette uniquely. Additional amounts of Corcoran-Cozzette gas are lumped 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 with structural dips of 2-3^{o} northeast.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Late Cretaceous - Early Tertiary, Laramide basin 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.	Generally 2.6-2.9^{o}F/100 ft.	0.42 psi/ft based on 8 readings generally in T7-10S, R95-97W.	Compressional Laramide deformation followed by vertical post-Laramide uplift.

Table 61. 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 sandstone with detrital silt and clay. Typically poorly sorted.	For undifferentiated Mesaverde Group in southern Garfield County: 35-67% detrital quartz, 2-20% detrital feldspar, 30-52% lithic fragments, and 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 in general.
Typical Reservoir Dimensions	**Pressure/Temperature of Reservoir**	**Natural Fracturing**	**Data Availability (logs, cores, tests, etc.)**
Two or more sandstones typically within the Cozzette interval, averaging a total of 90 ft in thickness.	T7-8S, R90-91W: 3,200 psi/250^{o}F at approximately 7,500 ft. T8-10S, R97-100W: 1,019 psi/107^{o}F at approximately 2,550 ft. Above are average parameters for undifferentiated lower Mesaverde.	T7-8S, R90-91W: probably present along north plunging nose.	Limited to moderate amount of core available. Few drill stem tests but often not run because of low to nil natural flows. SP-resistivity or GR-resistivity and neutron-density are typical log suite. New core from Multi-Well Experiment site.

Table 62. Cozzette Sandstone, Mesaverde Group, Piceance Creek Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir Parameters	Net Pay Thickness	Production Rates: Pre-Stimulation	Production Rates: Post-Stimulation	Decline Rates	Formation Fluids	Water Saturation
Permeability = 0.0187 and 0.0109 md and porosity = 12.25% and 13.78% for two wells in T9-10S, R97W. T7-8S, R90-91W: average permeability = 0.05 md, average porosity = 7% (composite data for 9 Rollins/Corcoran/Cozzette).	70 ft average from 4 or more wells in T9S,R97W, undifferentiated lower Mesaverde. Gross completion interval = 61 ft for 89 wells in T6-11S, R89-97W (Cozzette only).	For most wells, too low to measure.	Average initial potential of 964 Mcfd for approximately 121 wells from Rollins/Cozzette/Corcoran (undifferentiated). Average initial potential of 942 Mcfd for 4 Cozzette completions in the area T10S,R93-97W. Average initial potential of 1,229 Mcfd for 41 Cozzette completions.	Once placed on sustained production, selected decline curves show drop to one-half of initial potential in 6-9 months.	No oil is produced from the lower Mesaverde (including Cozzette). See Corcoran listing for water and condensate data for undifferentiated lower Mesaverde.	Probably similar to Corcoran in the range of 40-60%.
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, involved 3,000 gal acid, 104,000 gal fluid and 255,000 lb sand. More typical job involves zero to several hundred gal acid, 25,000-60,000 gal fluid and up to 100,000 lb sand.		No specific data.		160 to 320 acres.	Some Mesaverde or "lower Mesaverde" completions do not distinguish Corcoran, Cozzette, or Rollins. Some parameters for these three members are derived collectively for 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 Co.) 37 to 71% of the wells in Petroleum Information's Well History Control System file produce water.	

Table 63. 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 5/81; applications pending with the State of Colorado may include the Cozzette.	91 producing or shut-in wells in Mesa, Garfield, and Pitkin (1 well) Counties, as of 12/31/80, from Mesaverde (undifferentiated) or some combination of Corcoran, Cozzette and Rollins. 26 producing or shut-in wells are specifically identified as from Corcoran and/or Cozzette.	42.4 percent in the Piceance Creek Basin as a whole for all wildcat gas wells.	For wells to 3,300 ft in T9S, R97W well cost was \$300,000-\$350,000, as reported in 8/80. Cost for a small fracture job (15,000 gal fluid, 65,000 lb sand) was \$44,000 as reported in 8/80 (cost per perforated interval).	14 and 10 inch-diameter pipelines (and several of 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; more recent applications pending before the State of Colorado for Upper Mancos/Mesaverde probably include the Cozzette.

OPERATING CONDITIONS / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
Within the middle Rocky Mountains physiographic subdivision. Area includes Battement Mesa and a small part of Grand Mesa with elevations above 10,000 ft. Valleys of the Colorado River and Plateau Creek are below 7,500 ft. Local relief is generally 1,000-3,000 ft and only 20-50% of the area is gently sloping.	Semiarid with 8-16 inches mean annual precipitation. Mild summers and cold winters. Winter conditions may cause suspension of exploration activities.	Very poor to tops of mesas and bordering steep slopes. Drilling and development is concentrated in river valleys, primarily of the Colorado River and Plateau Creek, with difficult access 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 and Pictured Cliffs Sandstones, the Fox Hills Formation, 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 64. 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 as tight formation = 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.	Estimated at 150-200 ft in T7-8S, R90-91W. Average of 150 ft in T8-10S, R97-100W.	Average drilling depth of 7,680 ft in T7-8S, R90-91W. Average drilling depth of 2,670 ft in T8-10S, R97-100W.	National Petroleum Council (1980) reports maximum recoverable gas of 2.294 Tcf for Cozzette-Corcoran uniquely. Additional amounts of Cozzette-Corcoran gas are lumped 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 with structural dips of 2-3^{o} northeast.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Late Cretaceous - Early Tertiary, Laramide basin 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.	Generally 2.6-2.9^{o}F/100 ft.	0.42 psi/ft based on 8 values generally in T7-10S, R95-97W.	Compressional Laramide deformation followed by vertical post-Laramide uplift.

Table 65. 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 sandstone with detrital silt and clay. Typically poorly sorted.	For undifferentiated Mesaverde Group in southern Garfield County: 35-67% detrital quartz, 2-20% detrital feldspar, 30-52% lithic fragments, and 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 in general.
Typical Reservoir Dimensions	**Pressure/Temperature of Reservoir**	**Natural Fracturing**	**Data Availability (logs, cores, tests, etc.)**
T8-10S, R97-100W: total of 70-80 of sand thickness in 1 to 3 units within the total thickness of the Corcoran.	T7-8S, R90-91W: 3,200 psi/250°F at approximately 7,500 ft. T8-10S, R97-100W: 1,019 psi/107°F at approximately 2,550 ft. Above are average parameters for undifferentiated lower Mesaverde.	T7-8S, R90-91W: probably present along northern plunging nose.	Limited to moderate amount of core available. Few drill-stem tests but often not run because of low to nil natural flows. SP-resistivity or GR-resistivity and neutron-density logs are typical log suite. New core from Multi-Well Experiment site.

Table 66. 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**
T7-8S, R90-91W: average permeability = 0.05 md, average porosity = 7% (composite data for 9 Rollins/Corcoran/Cozzette wells). Core permeabilities corrected to in situ conditions averaged 0.0267 md for 8 samples from another 5 wells (Corcoran only). Average porosity for these samples = 8.1%.	70 ft average from 4 or more wells in T9S, R97W, undifferentiated lower Mesaverde. Gross completion interval = 63 ft for 119 wells in T6-11S, R89-97W (Corcoran only). National Petroleum Council (1980) gives 16-70 ft as a range.	T7-8S, R90-91W: 0, 7 and 765 Mcfd for 3 wells. For most wells flow is too low to measure.	Average initial potential of 1,251 Mcfd for 33 Corcoran completions. Average initial potential of 964 Mcfd for approximately 121 wells from Rollins/Cozzette/Corcoran (undifferentiated). Average initial potential of 756 Mcfd from 21 wells in T6-11S, R89-97W (Corcoran only).	T7-8S, R90-91W: 765 Mcfd IP well plugged and abandoned after 42 months. Once placed on sustained production, selected decline curves show drop to one-half of initial potential in 6-9 months.	No oil is produced from the lower Mesaverde (including Corcoran). Those wells making water produce an average of 5 bbl/d (Rollins/Cozzette/Corcoran undifferentiated). Those wells making condensate produce an average of 2.5 bbl/d (Rollins/Cozzette/Corcoran undifferentiated).	Average for 8 core samples from 5 wells = 49% with a range of 40-63%. 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 involved 3,000 gal acid, 104,000 gal fluid, and 255,000 lb sand. More typical job involves zero to several hundred gal acid, 25,000-60,000 gal fluid, and up to 100,000 lb sand.	No specific data.	160 to 320 acres.	Some Mesaverde or "lower Mesaverde" completions do not distinguish Corcoran, Cozzette, or Rollins. Some parameters for these three members are derived collectively for 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) 14-23% of wells in Petroleum Information's Well History Control System file produce water.

Table 67. 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 5/81; other applications pending with the State of Colorado 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, as of 12/31/80, from Mesaverde (undifferentiated) or some combination of Corcoran, Cozzette and Rollins. 26 producing or shut-in wells are specifically identified as from Corcoran and/or Cozzette.	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 cost was \$300,000-\$350,000, as reported in 8/80. Cost for a small fracture job (15,000 gal fluid, 65,000 lb sand) was \$44,000 as reported in 8/80 (cost for each perforated interval).	14 and 10 inch-diameter pipelines (and several of 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; more recent applications pending before the State of Colorado for upper Mancos/Mesaverde probably include the Corcoran.

OPERATING CONDITIONS

Physiography	Climatic Conditions	Accessibility
Within the Middle Rocky Mountains physiographic subdivision. Area includes Battement Mesa and a small part of Grand Mesa with elevations above 10,000 ft. Valleys of the Colorado River and Plateau Creek are below 7,500 ft. Local relief is generally 1,000-3,000 ft and only 20-50% of the area is gently sloping.	Semiarid with 8-16 inches mean annual precipitation. Mild summers and cold winters. Winter conditions may cause suspension of exploration activities.	Very poor to tops of mesas and bordering steep slopes. Drilling and development is concentrated in river valleys, primarily of the Colorado River and Plateau Creek, with difficult access away from the rivers.

EXTRAPOLATION POTENTIAL

	Comments
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 and Pictured Cliffs Sandstones, the Fox Hills Formation, 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.

Mancos "B," Piceance Creek Basin

Introduction

The Mancos "B" zone is a part of the Upper Cretaceous Mancos Shale, which is characterized by finely interbedded claystone, siltstone, and very fine sandstone (fig. 75). Applications for tight formation designations have been approved by FERC for four areas, one in Rio Blanco and Garfield Counties and three in Rio Blanco County (fig. 77) (Colorado Oil and Gas Conservation Commission, 1980c, Cause NG-5 and 1980d, NG-6; 1980h, Cause NG-14 and 1980i, NG-15-1). The data base for the Mancos "B" is good (tables 68-71) based on operator applications and a complete summary by Kellogg (1977). All areas designated as a tight formation 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 except for 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 for the Mancos "B" within the Piceance Creek Basin is similar to that of the Cozzette and Corcoran Sandstones described in this survey; however, more detail on the Douglas Creek Arch must 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 smaller, 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 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 where rocks younger the Mancos are present (Kellogg, 1977).

Stratigraphy

The Mancos "B" was deposited on a nearly horizontal marine shelf east of a time-equivalent shoreline deposit, the Emery Sandstone of the Uinta Basin (Kellogg, 1977). Its thickness varies from 400 to 700 ft in most of the Douglas Creek Arch area (Colorado Oil and Gas Conservation Commission, 1980h, Cause NG-14; 1980i, Cause NG-15-1). The top of the unit is denoted by an informal driller's datum that may be the same as the silt marker utilized by Kellogg (1977). The base of the unit is marked by a return of the gamma ray log count to higher values characteristic of the remainder of the Mancos Shale.

Because of the finely laminated nature of the claystone, siltstone, and sandstone of the Mancos "B," geophysical well logs do not define beds that have recognizable character from log to log (Kellogg, 1977). Thus it is the entire Mancos "B" unit that is of blanket geometry, and within that unit those intervals with greater quantities of sandstone, or sandstone and siltstone, form potential gas reservoirs. Conspicuous individual sandstone beds are not present (fig. 80), but Kellogg (1977) has defined generalized shaly, silty and sandy facies.

Depositional Systems

Kellogg's (1977) study area, centered over the Douglas Creek Arch, covers all the approved tight gas areas for Mancos "B" production in Colorado, and also extends into Grand and Uintah Counties in Utah. He divides the Mancos "B" into five subunits (table 72). Kellogg (1977) suggests that deposition took place on a submarine terrace or slope with tendency toward decrease in slope angle as deposition continued through unit B and younger sediments. The tendency toward increased sand content over the Douglas Creek Arch may be a winnowing effect or simply a tendency to stack strata of greater original sand content (Kellogg, 1977).

The upward-coarsening cycles represented by units A and B of the Mancos "B" (table 72) certainly suggest that the Mancos "B" may be related to 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, the Mancos "B" sandy intervals may have been deposited on a shallow cratonic shelf well within storm wave base, thereby allowing for dispersal by shelf processes.

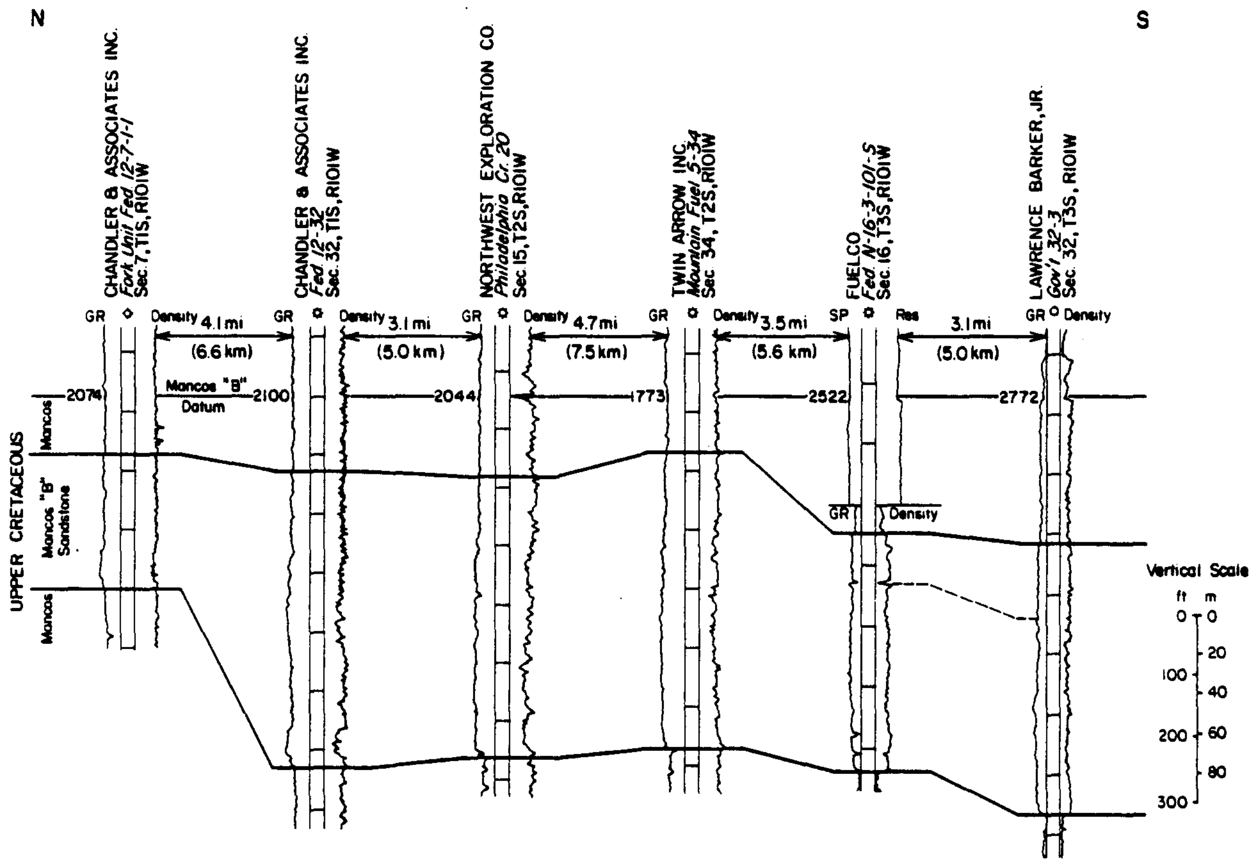

Figure 80. North-south stratigraphic cross section through the Mancos "B" interval of the Mancos Shale, Piceance Creek Basin (after Colorado Oil and Gas Conservation Commission, 1980d).

Table 68. Mancos "B" Interval, 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
Mancos "B" interval, Mancos Formation, Upper Cretaceous.	Total area designated as tight formation = 1,029 mi^2 in Rio Blanco and Garfield Counties, Colorado.	400 to 700 ft in designated areas.	Average drilling depth of 3,475-3,603 ft in all but 38 mi^2 of designated tight formation areas. Sea level datum elevations of top Mancos "B" are +3,400 to +4,000 ft.	Unknown. National Petroleum Council's (1980) analysis of the Piceance Creek Basin does not include the Mancos "B."	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Late Cretaceous - Early Tertiary, Laramide Basin 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.	Generally 2.6°F/100 ft.	No data.	Compressional Laramide deformation followed by regional, vertical post-Laramide uplift.

Table 69. Mancos "B" Interval, Piceance Creek Basin: 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 "B" interval is encased in Mancos marine shales. Decrease in sand content off the Douglas Creek Arch to the southeast. Sands also pinch out northward on the Arch.	Thinly bedded and interlaminated very fine sandstone, siltstone, and shale. May be up to 80% sandstone in beds up to 0.5 inches thick with 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 (logs, cores, tests, etc.)**
30 to 250 ft thick in Douglas Creek Arch area in a gross interval of 400 ft.	450 psi/90°F typical in the Fork Unit, Rio Blanco County (T1-2S, R101-102W) at average producing depth of 2,470 ft.	Silty and shaly facies may contribute to production through fractures. Infrequently faulted zones produce without stimulation.	Cores available. Density log is the standard open-hole logging tool, although neutron-density or induction log may also be utilized.

Table 70. Mancos "B" Interval, Piceance Creek Basin: Engineering parameters.

ENGINEERING PARAMETERS

Reservoir Parameters	Net Pay Thickness	Production Rates: Pre-Stimulation	Production Rates: Post-Stimulation	Decline Rates	Formation Fluids	Water Saturation
Estimated average in situ permeability = 0.01 md for a group of 56 wells. Average in situ permeability = 0.087 md for another group of 63 wells. Porosity averages 10-11% and ranges from 6-14%. Conventional core analysis averages 0.7 md over Douglas Creek Arch, which is at least 10 times greater than in situ values.	Average of 120 ft for a group of 10 wells in the Douglas Creek Arch area. Average of 90 ft for a group of 5 wells in an adjacent area.	Sustained flows, if present, are at a rate too small to measure. Zero for a group of 56 wells.	Average of 263 Mcfd for a group of 56 wells. Average of 350 Mcfd for a group of 22 wells.	Generally stabilizes at half of initial potential.	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 utilizes 2,500-4,000 psi injection pressures, an average injection rate of 30-40 bbl/min and 500-900 SCF/bbl CO_2. Total materials typically include 65,000-70,000 gal 2% KCl water, 30,000 lb 100 mesh sand, 80,000-100,000 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 the Dragon Trail Unit, Douglas Creek Arch, a 9-fold increase in production was usually achieved after fracturing.	No data.	Mancos "B" is highly susceptible to water damage. Wells are best drilled with 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 71. Mancos "B" Interval, 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
Four applications approved, 2 in 1980 and 2 in 1981.	276 producing or shut-in wells as of 12/31/80 in Rio Blanco and Garfield Counties.	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-$150,000 in February 1981; other data indicate costs of $50,000-$190,000, depending upon 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 N-S through the area. A smaller pipeline of the Western Slope Gas Co. follows the same route.	High. Total of 4 FERC applications approved; additional applications pending that specify Mancos Formation, therefore probably including Mancos "B".

OPERATING CONDITIONS

Physiography	Climatic Conditions	Accessibility
Generally rough terrain with surface elevations of 6,500-9,500 ft in the middle Rocky Mountain physiographic subdivision. Local relief of 1,000-3,000 ft outside of Colorado River Valley.	Winter weather limits exploratory work and drilling to a 7-8 month period per year, usually mid-May to mid-December. The climate is semiarid with 10-16 inches mean annual precipitation.	Limited in part to use of secondary and ranch roads from one state highway (No. 139). Easiest access along stream valleys. Difficult access to high mesas, such as Grand Mesa.

EXTRAPOLATION POTENTIAL

	Comments
Fair. Much thicker than, but similar to, upper part of Cleveland Formation (Anadarko Basin). Mancos "B" in the Uinta Basin is a continuation of the same depositional system. Sanostee Member of the Mancos (San Juan Basin) is also a shelf deposit but is dominantly a calcarenite.	Grand Junction, Colorado, is an expanding base for exploration and production services in the Piceance Creek Basin. Some service work may incur significant mileage charges in this region.

Table 72. Subunits of the Mancos "B" in the Douglas Creek Arch area, Colorado. (from Kellogg, 1977).

Unit	Description
A	Basal siltstone and shale coarsening upward into 50-100 ft of more sand-rich strata. Thins to the northern part of the arch, where it is mostly sand-rich.
B	Basal siltstone and shale coarsening upward with increasing sand content toward the top of the unit.
C	Mostly siltstone and shale with some increase in sand over the north end of the Douglas Creek Arch. Units A-C generally indicate transport eastward from the source area and then to the north.
D	Siltstone grading upward into sandstone with 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-C. This interval is very sandy in adjacent Utah.
E	Most uniform in thickness of all units; between 100 and 200 ft thick in most areas, but is thinnest (40 ft) and has the most sand toward the southern Douglas Creek Arch area.

Sego and Castlegate Sandstones, Uinta Basin

The Sego and Castlegate Sandstones have a blanket geometry and are part of the Upper Cretaceous Mesaverde Group of the eastern Uinta Basin (fig. 81) (T. Fouch, personal communication, 1982). Only the Castlegate was included in the National Petroleum Council (1980) study, and applications for tight formation status have not been filed for either of these units specifically. Instead, the Sego and Castlegate are included in an FERC-approved designation for a 4,000- to 6,200-ft-thick interval including the Wasatch Formation and Mesaverde Group in Uintah County, Utah (fig. 77) (Utah Board of Oil, Gas, and Mining, 1981a, Cause No. TGF-100). Within this application area the average gross productive interval is 1,150 ft thick, but the distribution of production relative to the specific units of interest is not readily determinable. Because of limited data availability, a complete set of data tables for each of these sandstones cannot be prepared. Selected characteristics of the Castlegate Sandstone are known (table 73). Several published studies have focused on other parts of the Mesaverde Group in the Uinta Basin, notably the overlying Neslen, Farrar, and Tuscher Formations (Keighin, 1979, 1981; Keighin and Sampath, 1982). The latter formations have been interpreted as fluvial channel deposits (Keighin and Fouch, 1981); therefore, individual sand bodies are likely to have a lenticular geometry.

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

Hale and Van de Graaff (1964) note that the Sego includes an upper and lower sandstone separated by a transgressive marine shale termed the "Anchor Tongue" of the Mancos. The upper Sego represents a fairly rapid regression and the final retreat of the sea from northeastern Utah to be followed by a major period of continental deposition represented by the remainder of the Mesaverde Group.

Where gas production occurs from the Castlegate and the Sego, primarily in the southeast corner of the Uinta Basin, it is from depths of 8,000 ft or more. The gas is trapped on-structure, and the formations are wet off-structure. Core plug permeabilities are 0.5 to 0.9 md and greater, meaning that these units may exceed 0.1 md in situ permeability in some areas. Very little core data are available. There have been approximately 50 penetrations of the Castlegate, primarily on the south and east sides of the basin, and long distances exist without subsurface control (T. Fouch, personal communication, 1982). The Castlegate, upper Sego, and lower Sego are each approximately 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 appears to be of lesser interest for tight gas than the Cozzette and Corcoran in the southern Piceance Creek Basin (R. Johnson, personal communication, 1982).

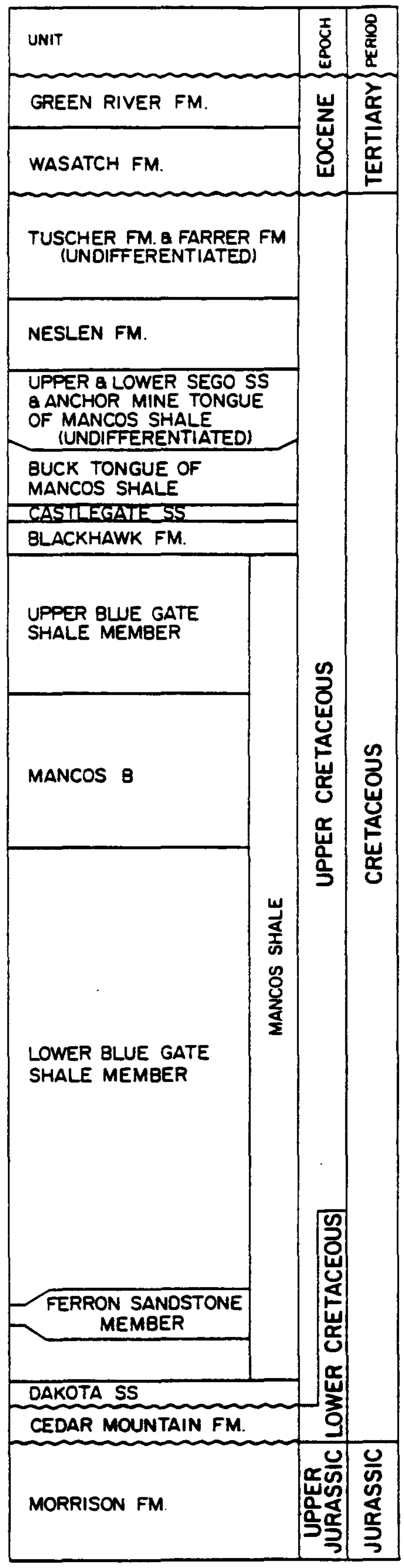

Figure 81. Stratigraphic column from the Jurassic Morrison Formation through the Eocene Green River Formation, Uinta Basin (after Fouch and Cashion, 1979).

Table 73. Reservoir parameters and reserves of the Upper Cretaceous Castlegate Formation, Mesaverde Group, eastern Uinta Basin, Utah (from National Petroleum Council, 1980).

Permeability range: 0.1 - 0.003 md

Pressure: 4,275 psi

Temperature: 233°F

Gas-filled porosity: 4.2 - 2.3%

Net pay: 25-60 ft

Depth: 9,500 ft

Maximum recoverable gas: 1.131 Tcf plus additional gas in area of combined Coaly and Castlegate resource.

Mancos "B," Uinta Basin

Introduction

The Mancos "B" tight gas trend 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" zone is a part of the Upper Cretaceous Mancos Shale which is characterized by finely interbedded shale, siltstone, and very fine sandstone (fig. 81). One application to designate the Mancos "B" as a tight formation has been approved by FERC for the southeast Uinta Basin and the southern Douglas Creek Arch (fig. 77) (Utah Board of Oil, Gas, and Mining, 1981b, Cause No. TGF-101).

The data base for the Mancos "B" in Utah is fair (tables 74-77). Some data were not found for the Uinta Basin, and an analogy must be made with nearby parts of the Mancos "B" trend on the Douglas Creek Arch and in the Piceance Creek Basin of Colorado.

Structure

The Uinta Basin is a strongly asymmetric structural as well as topographic basin with a generally east-west structural axis located close to the northern basin margin. The Uinta Mountains and the Wasatch Plateau bound the basin on the north and west, respectively. The San Rafael swell bounds the basin on the southwest, the Uncompahgre Uplift on the southeast, and the Douglas Creek Arch on the east (fig. 77). The development of the Uinta Basin began with the Late Cretaceous-Early Tertiary Laramide orogeny and the uplift of the Uinta Mountain block, accompanied by simultaneous basin subsidence (National Petroleum Council, 1980).

Stratigraphy

Upper Cretaceous and Tertiary rocks comprise the major part of the sedimentary fill within the Uinta Basin (fig. 81). 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 marine Mancos shale, and the stratigraphy described by Kellogg (1977) is applicable in Utah as it is in adjacent Colorado (see Mancos "B," Piceance Creek Basin, this survey).

Depositional Systems

The study area of Kellogg (1977) included parts of the Uinta and Piceance Creek Basins and the Douglas Creek Arch; therefore, the reader is referred to the section of this survey dealing with the Mancos "B" in the Piceance Creek Basin for a summary of depositional systems.

Table 74. Mancos "B" Interval, Uinta Basin: 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 Formation, Upper Cretaceous	Application area lies in Grand and Uintah Counties, Utah, covering an area of 670 mi^2.	Thickness ranges from 450-1,000 ft.	Average depth to the top of the Mancos "B" is 5,049 ft in the application area.	Possible recoverable reserves are estimated to be as high as 10-12 Bcf per mi^2. National Petroleum Council (1980) did not include the Mancos "B" in its analysis.	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
The present Uinta Basin is a topographic basin that has developed on a lower Tertiary structural and depositional basin. The basin axis forms an arc that trends east-west along the northern edge of the basin, creating a steep northern flank and a broad, gentle southern flank. The basin is bounded on the north by exposed Precambrian rocks in the Uinta Mountains; on the east by the Douglas Creek Arch; on the south by the Roan and Book Cliffs of the Uncompaghre Uplift; and on the west by the fault-block Wasatch Mountains.	1.4^{o}-$1.8^{o}F/100$ ft.	No data.	Compressional Laramide deformation and uplift of the Uinta Mountains, followed by differential downwarping of the basin as surrounding areas rose.

Table 75. Mancos "B" Interval, Uinta Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies

Deposited in a marine shelf environment approximately 100 mi east of an Upper Cretaceous shoreline in a position stratigraphically equivalent to sands of the Emery Formation. The Mancos "B" sand is encased in Mancos marine shales. A decrease in sand content occurs off the Douglas Creek Arch to the southeast, and sands also pinch out northward on the Arch.

Texture

Thinly bedded, very fine grained sandstone, interlaminated with layers of siltstone and shale. May be up to 80% sandstone in beds up to 0.5 inches thick with shale laminae 0.0625 inches thick or less. The sandstone is poorly sorted and may have carbonaceous laminae.

Mineralogy

Sandstones are predominantly quartz, and shales are bentonitic.

Diagenesis

Diagenetic calcite and clay have reduced porosity and effective permeability.

Typical Reservoir Dimensions

Typically 50-150 ft gross reservoir rock determined by porosity and permeability characteristics.

Pressure/Temperature of Reservoir

Pressure averages 1,160 psi.

Natural Fracturing

The rocks are extensively fractured in some areas with cores showing a predominant horizontal fracture orientation. Nonstimulated production infrequently occurs in the fractured and faulted areas.

Data Availability (logs, cores, tests, etc.)

Cores available. GR-density log is the standard open-hole logging tool, although neutron-density or induction logs are also utilized if the operator loads the hole with fluid.

Table 76. Mancos "B" Interval, Uinta 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
Porosity averages 8.2%, and ranges from 6 to 14%. Permeability averages 0.032 md from core analysis (as reported by applicant for tight sand designation) and would be expected to be less under in situ conditions. Generally permeability is lower than Colorado portion of Douglas Creek Arch.	Average = 71 ft, range = 38-98 ft.	Of 9 tests by Coseka Resources, only one well was observed to have any stabilized pre-stimulation flow rate. That well flowed 39 Mcfd before stimulation.	No specific data for Uinta Basin. Probably similar to 263-350 Mcfd average for Piceance Creek Basin.	Analogous Mancos "B" producing wells in Colorado typically show a decline of 36% of initial production rates in a 13-month period.	Typically no liquid hydrocarbons produced.	Conventional log analyses yield saturations ranging from 75-100%. These figures are probably too high due to the effects of clay in the formation.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
Massive hydraulic fracturing techniques used. Wells are treated with 1,000-2,000 gal 7½% HCl. Average fracture treatments call for 54,000 gal gelled water and 193,000 lb sand injected with either CO_2 or N_2. Currently, these figures have been increased to approximately 80,000 gal gelled water and 350,000 lb sand.	Most treatments result in increased population.	No data.	The Mancos "B" is highly susceptible to formation damage by drilling and stimulation fluids. Therefore the wells are air drilled when possible. CO_2 or N_2 is used during stimulation, and fluids are reversed out as soon as possible.

Table 77. Mancos "B" Interval, Uinta 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 for part of the southeastern Uinta Basin and the southern Douglas Creek Arch.	Coseka Resources (USA) Ltd. has drilled and stimulated 9 Mancos "B" tests in the designated tight formation area.	The nine test wells are presently shut in. Pre-stimulation stabilized flow was only observed on one of the test wells (39 Mcfd).	Stimulation costs range from $90,000 to $120,000.	Limited network of 6- and 8-inch pipelines in the application area. Pipelines are operated by Mountain Fuel Supply Co. and Mesa Gas Pipeline Co.	Moderate, based on one application compared to 4 in the adjacent Piceance Creek Basin of Colorado.

OPERATING CONDITIONS / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
Rugged terrain with mountains, upland mesas and locally deep valleys. Surface elevations range from 5,000-8,000 ft, and local relief ranges from 500-1,000 ft.	Severe winter weather limits drilling and exploration activity to 7-8 months per year. Arid to semiarid climate with less than 8 inches to approximately 14 inches mean annual precipitation. Moderate summers, cold to very cold winters.	Area can be reached by traveling unpaved roads north from Mack, CO. Off-road travel is extremely difficult. Limited major highway access.	Fair. Much thicker, but similar to upper part of Cleveland Formation (Anadarko Basin). Mancos "B" in the Piceance Creek Basin is a continuation of the same depositional system.	Service work may incur significant mileage charges in this region. Vernal, UT, and Grand Junction, CO, are regional centers for exploration and drilling services.

Fox Hills Formation, Greater Green River Basin

Introduction

The Upper Cretaceous Fox Hills Formation 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. 82). The Fox Hills 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 vicinity but offered no other littoral to shallow marine facies as an alternative. Both the upper and lower contact of the Fox Hills are difficult to establish consistently over longer distances (Newman, 1981).

The data base for the Fox Hills sandstone is fair (tables 78-81) and is based on one FERC application (Wyoming Oil and Gas Conservation Commission, 1981b, Docket 69-80) and several published articles. Additional data on this formation are desirable, but 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). The National Petroleum Council (1980) did not include the Fox Hills in its assessment of the Greater Green River Basin, nor did Kuuskraa and others (1978) include it in the "Lewin report."

Structure

The Greater Green River Basin of southwestern Wyoming and northwestern Colorado has a surface area of approximately 23,000 mi^2, and 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 (National Petroleum Council, 1980). The basin is bounded by the Overthrust Belt on the west and on other margins by a series of surrounding positive features (fig. 83). 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 Special Note on the Lewis Shale

Underlying the Fox Hills Formation and overlying the dominantly regressive Mesaverde Group is the Lewis Shale, which represents 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 and may present opportunities for blanket tight gas sand exploration. Otherwise, siltstones and thin sandstones within the Lewis are lenticular and are potential tight gas reservoirs (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 itself, although regressive, is interrupted by local marine transgressions (Newman, 1981). The Fox Hills is notably time transgressive, and outcrop studies on the northeast flank of the Rock Springs Uplift have shown the Fox Hills to become progressively younger to the southeast and east (Weimer, 1961). This time-transgressive relationship would be expected to continue to the limit of deposition to the east in the Red Desert and Washakie Basins.

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

Depositional Systems

The Fox Hills Formation represents a regressive sand body with an overall blanket geometry. Outcrop studies indicate, however, that individual sandstone units show varying dip and strike continuity, with a tendency toward better strike continuity

(Weimer, 1961; Land, 1972). In the Rock Springs Uplift-Wamsutter Arch area Land (1972) concluded that the Fox Hills was deposited along an embayed barrier island coastline. The individual facies represented include shales and siltstones of shallow-water origin grading upward into very fine 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 an estuarine deposit. In outcrop along the western edge of the Denver Basin the Fox Hills is a delta front deposit (Weimer, 1973); thus it is possible that deltaic depocenters are to be found within the Fox Hills of the eastern Greater Green River Basin as well.

The electric log characteristics of the Fox Hills Sandstone show both aggradational, blocky character, and progradational upward-coarsening sequences (fig. 84). The latter may coarsen upward over as much as a 50-ft interval from shale baseline to maximum SP deflection, whereas the sands with blocky character attain maximum deflection over 10 to 20 ft (Tyler, 1978, 1980a, 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 non-marine Tertiary deposits.

Although the Fox Hills was deposited over an extensive area in the central Rocky Mountain region, hydrocarbon production is limited. Gas production from this formation occurs in the Washakie Basin, primarily from Bitter Creek Field. The only Fox Hills FERC application area (Wyoming Oil and Gas Conservation Commission, 1981b, Docket 69-80) is also located in the Washakie Basin (fig. 85), encompassing the areas peripheral to Bitter Creek Field.

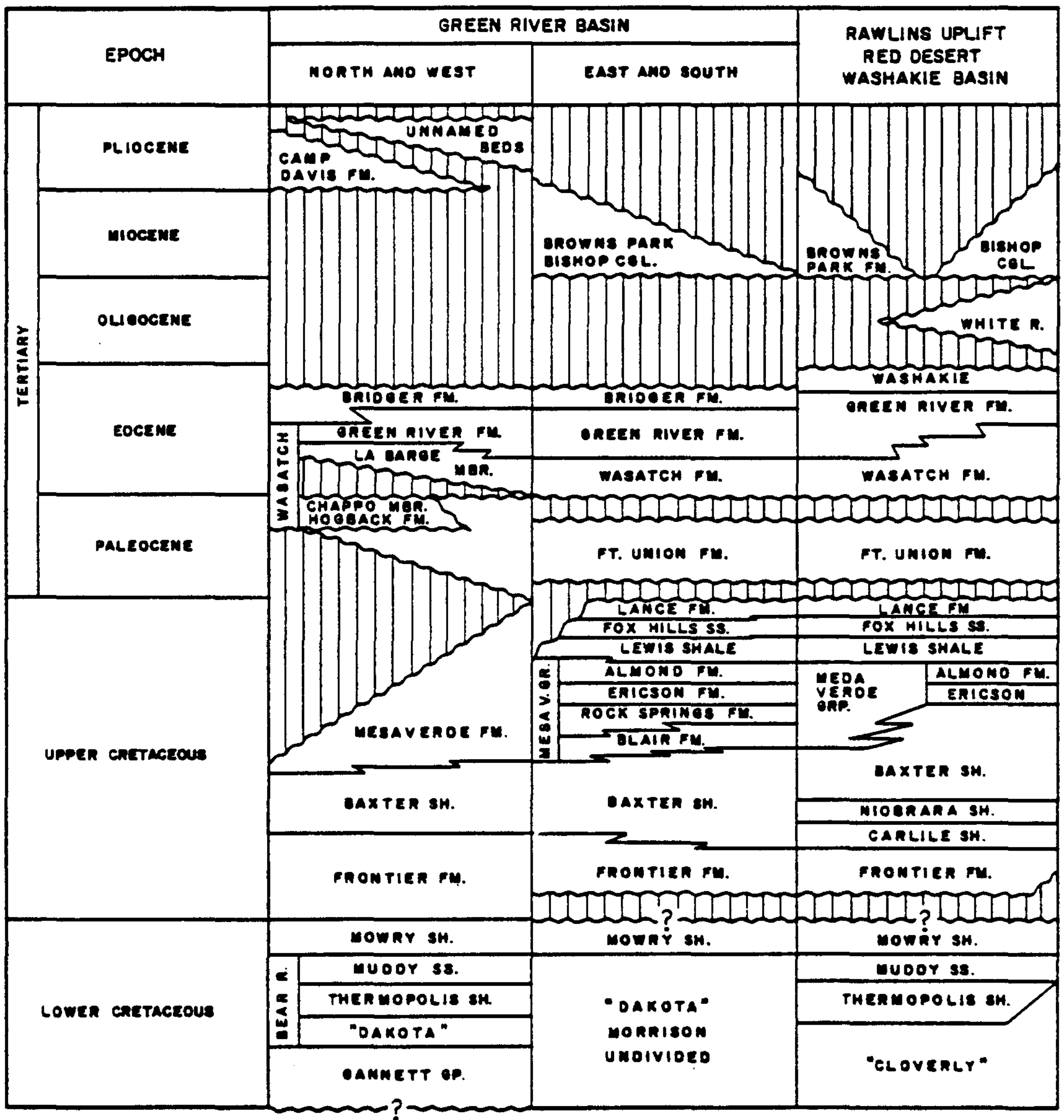

Figure 82. Stratigraphic column from the Lower Cretaceous Dakota-Morrison (undivided) through the Pliocene Epoch in the Greater Green River Basin (after Newman, 1981).

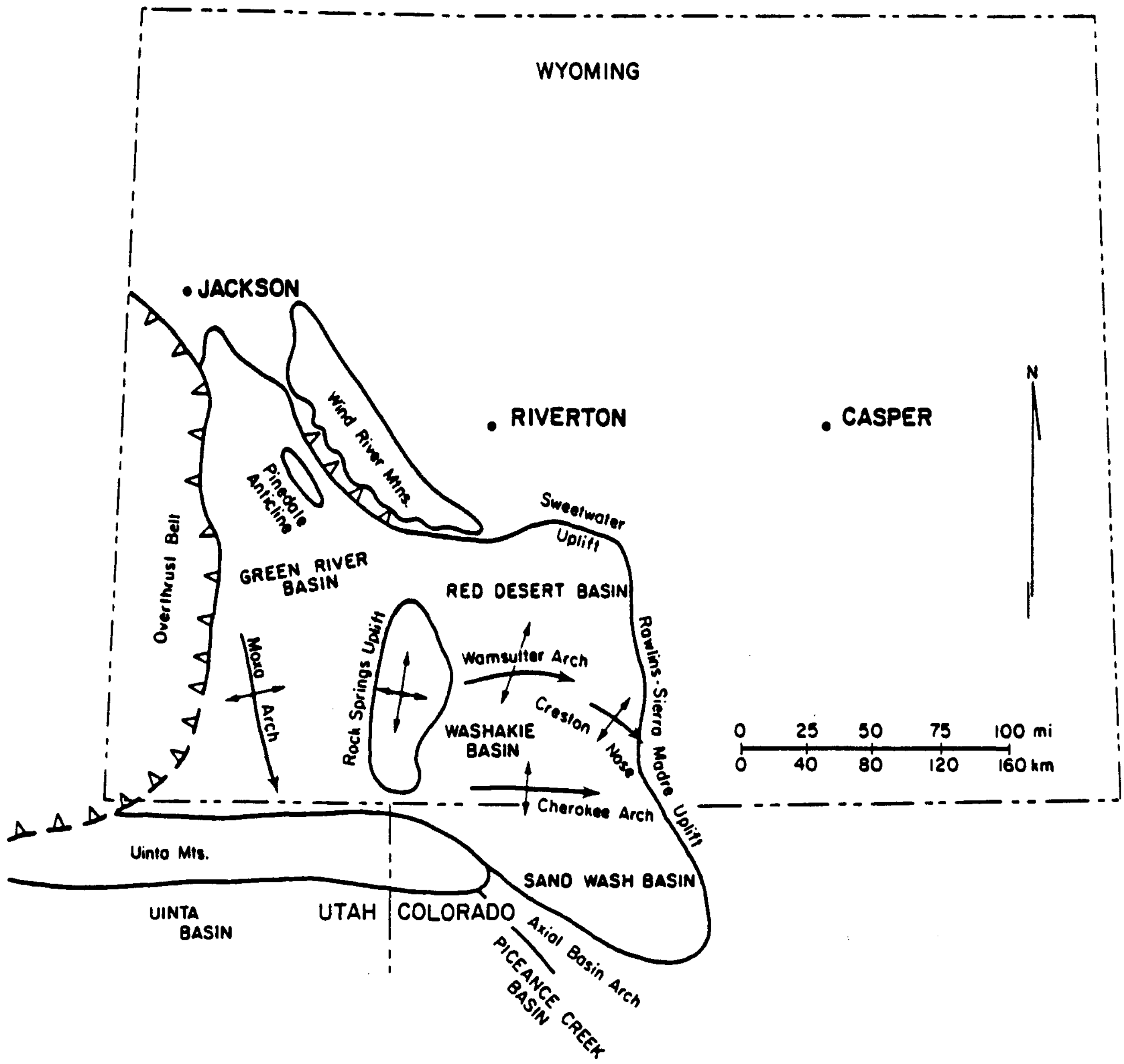

Figure 83. Tectonic elements of the Greater Green River Basin and adjacent areas (after Newman, 1981).

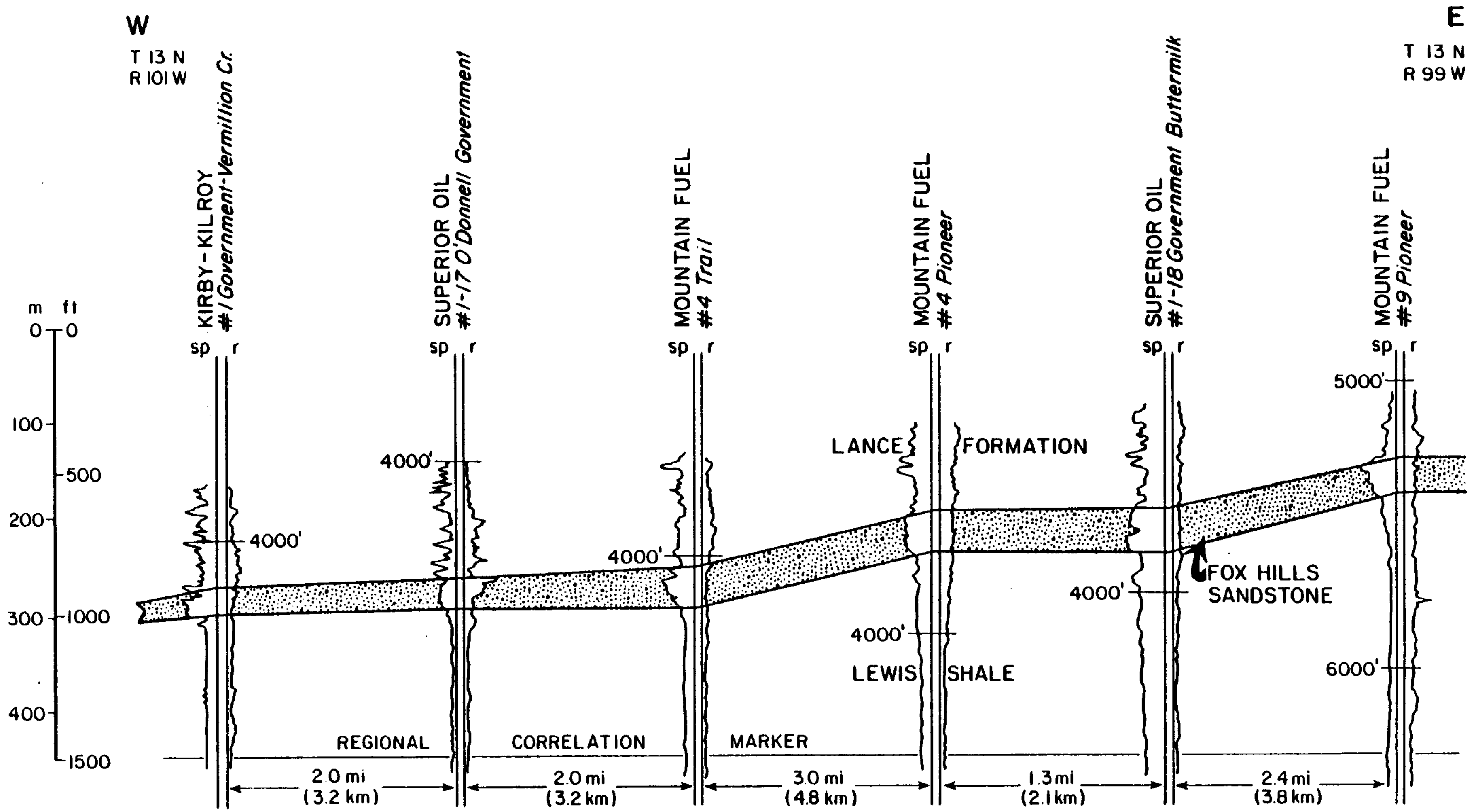

Figure 84. West-east stratigraphic cross section from T13N, R101W to T13N, R99W through the Fox Hills and adjacent strata, Greater Green River Basin (after Tyler, 1980b).

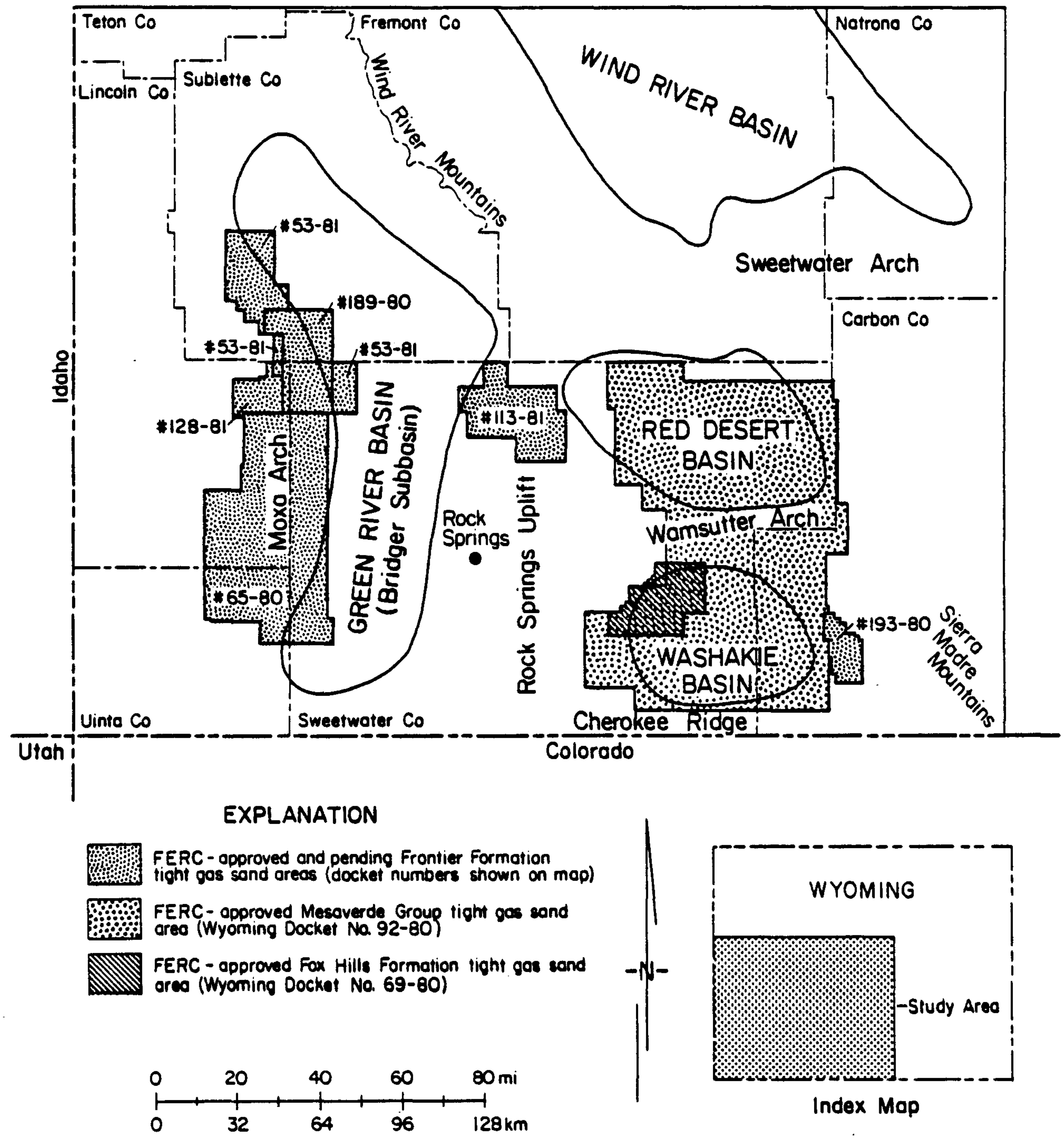

Figure 85. Areas covered by tight gas sand applications, Greater Green River Basin.

Table 78. Fox Hills 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
Fox Hills Formation, Upper Cretaceous.	303 mi^2 area in parts of T16-18N, R96-99W, Sweetwater County, Wyoming.	Generally 300 ft to a maximum of 600 ft in application area. Ranges from 150-250 ft to the north in the Wamsutter Arch area near Patrick Draw Field.	Average depth = 7,360 ft.	Not included in National Petroleum Council (1980) study of the Greater Green River Basin.	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 to the west by the Rock Springs Uplift and to 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.	1.2-1.6°F/100 ft.	No specific data.	Compressional and vertical stresses related to Late Cretaceous - Early Tertiary Laramide tectonism.

Table 79. Fox Hills Formation, Greater Green River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies	Texture	Mineralogy	Diagenesis
Deposition of the Fox Hills Formation 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 it 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 as lower to upper delta-front and distributary bar.	Siltstones and very fine to medium-grained sandstones.	55-90% quartz, 3-15% chert, 3-30% rock fragments, predominantly pelitic clay-aggregate (sericite-illite) clasts, with some siltstone and volcanic rock fragments; 2-15% feldspar, (plagioclase and K-feldspar); trace of muscovite, biotite, and heavy minerals.	Cemented primarily by calcite, but some authigenic clays present.

Typical Reservoir Dimensions	Pressure/Temperature of Reservoir	Natural Fracturing	Data Availability (logs, cores, tests, etc.)
Gross perforation interval average = 254 ft, with range = 83-447 ft based on 4 wells.	Average temperature = 150°F.	No specific data.	SP-resistivity logs available. No information on core availability. More outcrop studies available than typical for other formations. GR-neutron density logs may also be run.

Table 80. Fox Hills Formation, 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
Permeability = .004 md, based on calculations from the flow test from one well. Porosity average range = 12-14%.	From one well, net pay = 25 ft.	Average = 175 Mcfd based on unknown number of wells.	Average = 775 Mcfd based on unknown number of wells.	No specific data.	When present, liquid hydrocarbons are produced at rates less than 5 bpd.	Generally less than 70%.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
Hydraulic fracture techniques currently average 100,000 gal gel-KCl fluid with 300 scf CO_2 per bbl of fluid and 138,000 lb of 20-40 mesh sand proppant.	No data on specific success or failure of fracture treatments.	160-acre spacing except for sec. 35, 36, T17N, R99W, sec. 31, T17N, R98W, sec. 1, 2, 3, T16N, R99W, where 320-acre spacing in effect.	Good continuity of SP log character over distances of 1-4 miles is evident on regional cross sections prepared by the U.S. Geological Survey.

Table 81. Fox Hills 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
Approved by FERC.	450 penetrations in an area of 2,500 mi^2.	No specific data.	Average drilling and completion cost = $445,000. Average stimulation cost = $70,000 (1980 dollars).	Pipelines are available to 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, based on one FERC application.

OPERATING CONDITIONS / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
The Greater Green River Basin is within the Wyoming - Big Horn Basin physiographic subdivision with 300-500 ft of local relief in most areas but 1,000-3,000 ft of local relief over the Rock Springs Uplift and around the margins of the basin.	Semiarid to arid with most areas receiving 8-16 inches mean annual precipitation, but 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 a problem locally in areas of low mountains with 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.	Service to remote areas may incur significant mileage charges in parts of the eastern Greater Green River Basin.

Upper Almond Formation (Almond "A") and Blair Formation, Greater Green River Basin

Introduction

The Almond (upper part, or Almond "A") and Blair Formations are part of the Upper Cretaceous Mesaverde Group within the eastern Greater Green River Basin (fig. 82). These units consist of fine to very fine grained sandstone with some detrital silt and clay (upper Almond) to fine to very fine grained sandstone, siltstone, and shale (Blair). One application for designation of the Mesaverde Group as a tight formation has been approved by FERC and covers most of the Red Desert and Washakie Basins and the Wamsutter Arch (Wyoming Oil and Gas Conservation Commission, 1981b, Docket 69-80) (fig. 85). Most of the gas production from the Mesaverde Group is from either the upper or the lower Almond, 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 for the upper Almond is good, based to a large extent on McPeek (1981) (tables 82-85), but the availability of data for the Blair is poor (tables 86-89). This distribution is a function of greater operator interest in the shallower upper and lower Almond. The upper Almond is the better known blanket reservoir of the Mesaverde Group, but the Blair Formation is marine influenced and should have some lateral continuity. The lower Almond contains lenticular sandstones.

Structure

The structural setting of the Greater Green River Basin has been described in the discussion of the Fox Hills Formation in this survey. 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. 83). It is noted that the National Petroleum Council (1980) expects that the Green River Basin proper (also known as the Bridger Basin) and the Moxa Arch will yield little gas from lenticular sandstones. They make no 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 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) uses the terms "upper" and "lower," the National Petroleum Council (1980) uses "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 includes fluvial and paludal deposits with coal beds. West of the Rock Springs Uplift the upper Almond 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 reach much past the western edge of the uplift; hence shale is not present between the Almond and the Lance. The upper Almond is a marginal marine deposit of the Lewis transgression, and there occurred stillstands and localized regressions of the Lewis sea during which barrier and shoreface sandstones were deposited. These facies form the upper Almond Formation (Newman, 1981; Jacka, 1965).

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 a marine sandstone ranging in thickness from 150 to 500 ft, and it is this sandstone that is typically chosen as the contact with the underlying Baxter Shale. The sandstone is well developed around the Rock Springs Uplift, but east of the uplift the Blair consists mostly of shallow marine siltstones and shales that become difficult to distinguish from underlying Baxter and overlying Rock Springs Formations (Newman, 1981).

Depositional Systems

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

Generally the Almond shoreline rises stratigraphically to the east across the eastern Greater Green River Basin and becomes younger. Approximately the upper 100 ft of the Almond Formation constitutes the upper Almond that is associated with the shoreline deposits (Miller, 1977). Regional cross sections generally do not distinguish upper and lower Almond. These sections do show excellent lateral continuity of the uppermost Almond sandstones across the Wamsutter Arch and the Patrick Draw Field (fig. 86), and fair to good lateral continuity across the southern end of the Rock Springs Uplift (fig. 87) (Tyler, 1978 and 1980b). The generally blocky SP log character of the uppermost Almond sandstone is typical of a barrier sandstone, perhaps very similar to the idealized 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 known. The sandstones and siltstones of the Blair are generally considered to be shallow marine, in part on the basis 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 Rock Springs Uplift in the area of the Green River Basin proper (Miller, 1977). Parts of the Blair may therefore represent a deltaic system.

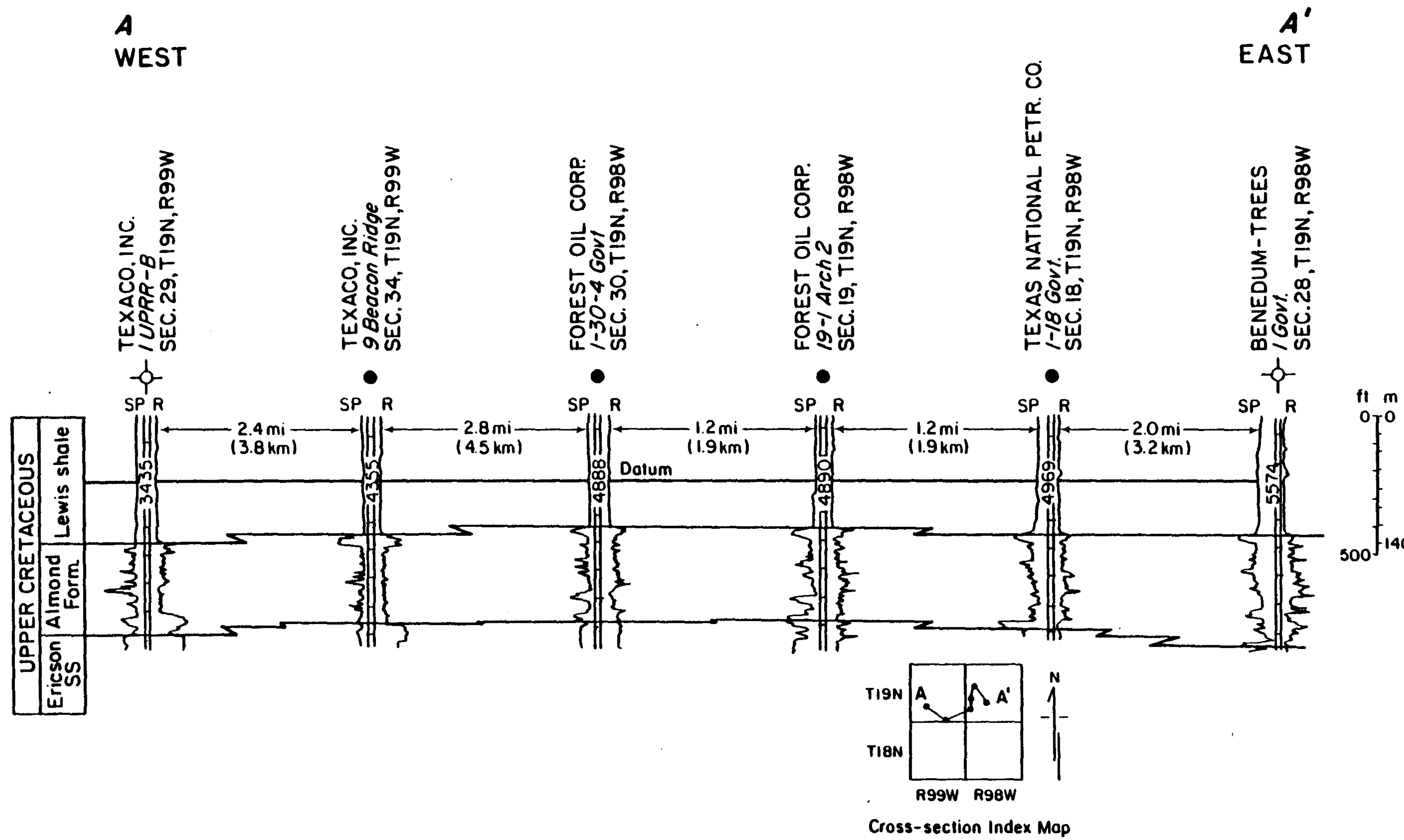

Figure 86. West-east stratigraphic cross section A-A' through the Almond Formation (undivided), Greater Green River Basin (after Tyler, 1978).

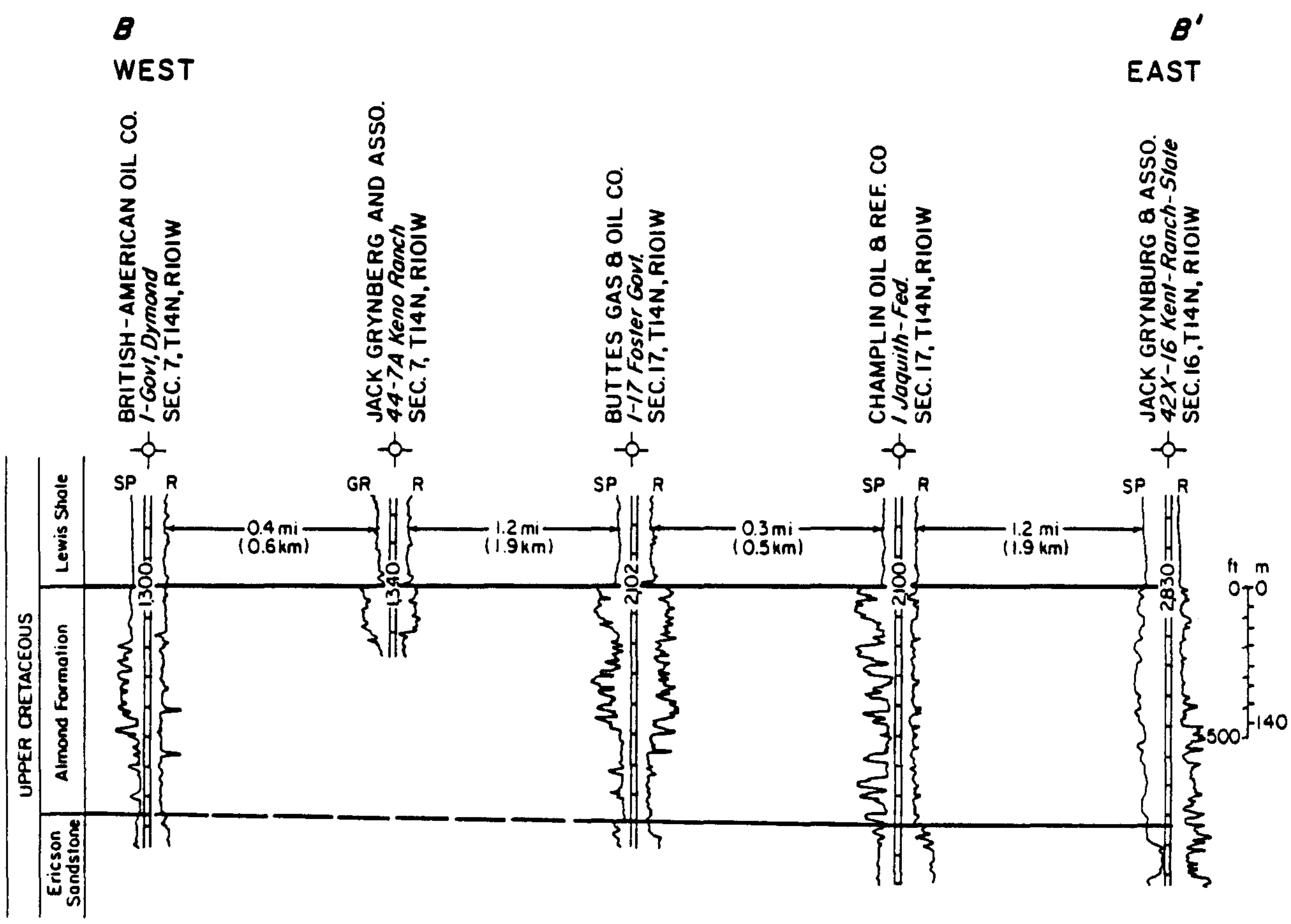

Figure 87. West-east local stratigraphic cross section B-B' through the Almond Formation (undivided), Greater Green River Basin (after Tyler, 1980a).

Table 82. 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
Almond Formation (upper), Mesaverde Group, Upper Cretaceous	Marginal marine upper Almond is only found east of the Rock Springs Uplift. Total designated area for the Mesaverde Group = 4,117 mi^2 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 100-150 ft of the total thickness. Only the upper 100 ft or less of the Almond Formation is associated with marginal marine processes.	Drilling depth ranges from approximately 6,200 ft on the Wamsutter Arch (T19N, R98W) to 15,450 ft (T14N, R96W) in the deep Washakie Basin. Average = 10,170 for 43 Amoco-operated wells in tight formation area.	Maximum recoverable gas of 0.307 Tcf in 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 upper Almond, stacked in association with other reservoirs (National Petroleum Council, 1980). Estimated recoverable gas of 2.6 Bcf per average section (McPeek, 1981).	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Occurs 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. (See text figure in survey of Fox Hills Formation.)	1.2-1.6°F/100 ft, mostly 1.4-1.6°F/100 ft.	Overpressured in much of the Greater Green River Basin with gradients of 0.5 to 0.64 psi/ft.	Compressional Laramide deformation followed by vertical post-Laramide uplift.

Table 83. 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 to very fine sandstone with varying amounts of detrital silt and clay; also sandy and silty shales. In outcrop on the eastern side of the Rock Springs Uplift, sandstones are moderately to well-sorted and subangular to subrounded.	In outcrop on the eastern side of the Rock Springs Uplift, sandstones consist of quartz, rock fragments, feldspar (altered), mica, minor amounts of dark chert, and rare glauconite. Some reworked carbonaceous debris. One outcrop study reports 31-50% quartz, 14-19% rock fragments, 7-14% feldspar, 10-13% matrix and 19-27% cement.	Probably similar to other Mesaverde Group formations with quartz and calcite cement and diagenetic clay, including chlorite.
Typical Reservoir Dimensions	**Pressure/Temperature of Reservoir**	**Natural Fracturing**	**Data Availability (logs, cores, tests, etc.)**
Reservoir sandstone up to 40 ft thick over an area 2 to 4 miles wide and 5 to 40 miles long in the overpressured area.	Average pressure of 5,854 psi for 43 wells in tight formation area from undifferentiated Mesaverde Group.	No specific data for existing production, but 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 = 3,110 Mcfd).	SP-resistivity and compensated neutron-formation density is a typical log suite. Cores are available and have been described by the U.S. Geological Survey.

Table 84. Upper Almond Formation, 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
Average in situ permeability in designated tight formation area for Mesaverde Group is 0.041 md. Average porosity = 18% in overpressured area.	14-18 ft in the overpressured areas.	214 Mcfd from undifferentiated Mesaverde in tight formation area. No specific data for upper Almond.	First year average daily production of 1,500-1,700 Mcfd.	No data.	Little water production; no specific details. No oil produced from Mesavede Group in designated tight formation area.	Average = 59%, range = 45-88% 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 (MHF). MHF's in the undifferentiated Mesaverde Group have used 275,000 to 290,000 gal fluid and 482,000 to 800,000 lb of sand at pressures as high as 6,500 to 8,000 psi. Average fracture treatment for 43 Amoco wells in tight formation area utilized 162,000 gal fluid and 321,000 lb of proppant (for undifferentiated Mesaverde Group).	An average 451% increase in post-stimulation over pre-stimulation gas flow for 43 Amoco-operated wells in designated tight formation area (undifferentiated Mesaverde).	640 acres.	Average gas recoverable per well estimated at 8-9 Bcf. Some pre-stimulation flow tests are taken after treatment with acid, but all are prior to fracturing. Mesaverde production is generally from the upper or lower Almond Formation.

Table 85. 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 drilling, testing, or 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 overpressured zone costs approximately $1,200,000 completed (1980 dollars). An 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 and recent publication pointed out extent of undrilled areas, especially at greater depths than present production.

OPERATING CONDITIONS

Physiography	Climatic Conditions	Accessibility
Within the Wyoming - Big Horn Basins physiographic subdivision with 300-500 ft of local relief east and west of the Rock Springs Uplift, 1,000 ft or more of local relief in the vicinity of the Rock Springs Uplift.	Arid to semiarid with less than 8 inches to approximately 12 inches mean annual precipitation, increasing at surrounding higher elevations. Mild summers and very cold winters. Winter conditions can adversely affect exploration activities.	Limited major highway access to parts of the Greater Green River Basin area.

EXTRAPOLATION POTENTIAL

	Comments
Good. Barrier island, shoreface, and offshore bar facies similar to other marginal marine sandstones of the Mesaverde Group including Corcoran, Cozzette, and possibly the Sego and Castlegate Sandstones. Hartselle Sandstone and Fox Hills Formation also contain barrier, shoreface, and shallow marine deposits.	McPeek (1980) reviewed Mesaverde potential in the Red Desert Basin, Wamsutter Arch and the Washakie Basin.

Table 86. 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.	Approximately 1,400 ft in the deep basin area of T27N, R103W. Approximately 1,900 ft in T18-19N, R97-98W, Table Rock Field area, east flank of Rock Springs Uplift.	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.	At least 1.2 Tcf maximum recoverable gas as a general guideline (National Petroleum Council, 1980). Blair resource not sufficiently differentiated from other formations of the Mesaverde Group in National Petroleum Council (1980) study in order to give more precise estimate.	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
Same as upper Almond Formation, this survey.	1.2-1.6°F/100 ft, mostly 1.4-1.6°F/100 ft.	Overpressured in much of the Greater Green River Basin with gradients of 0.5-0.64 psi/ft.	Compressional Laramide deformation followed by vertical post-Laramide uplift.

Table 87. 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. 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. 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 to very fine sandstone, siltstone and shale, massive to thin bedded in various 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 with quartz, sedimentary rock fragments and detrital clay.	Probably similar to other Mesaverde Group formations, with quartz and calcite cements, and diagenetic clays, including chlorite.

Typical Reservoir Dimensions	Pressure/Temperature of Reservoir	Natural Fracturing	Data Availability (logs, cores, tests, etc.)
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.	Non-existent in deeper parts of the basin, limited elsewhere.

Table 88. Blair Formation, Mesaverde Group, 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
No data.	No data.	214 Mcfd from undifferentiated Mesaverde Group in tight formation area. No specific data for Blair.	No data.	No data.	No oil 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 data, this survey.	See Upper Almond data, this survey.	No data.	Gas shows with no further details given in Table Rock Field area, T18-19N, R97-98W. For all engineering parameters, no data specific to the Blair only, as distinguished from the Mesaverde Group as a whole.

Table 89. 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 only, rather than Mesaverde Group. See upper Almond data, this survey, and allow costs for a minimum of 25% greater depth.	Similar to other Mesaverde Group production in the eastern Greater Green River Basin, but pipelines lacking in the northwestern part of the Green River Basin proper where marine Blair sands best developed.	Relatively low to moderate industry interest. Apparently little incentive to drill to the base of the Mesaverde Group in preference to shallower formations in the Group.

OPERATING CONDITIONS / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
Same as upper Almond, this survey.	Same as upper Almond, this survey.	Same as upper Almond, this survey.	Fair. Data limited. Distal to proximal deltaic facies suggest analogy to Davis and Olmos Formations. May have similarities to barrier-strandplain-offshore bar facies of other parts of the Mesaverde Group, but data are inadequate to make a full comparison.	In 1973 only 5 wells produced predominantly from the Blair, or Blair-equivalent Adaville Formation.

Frontier Formation, Greater Green River Basin

Introduction

The Frontier Formation is the lowermost Upper Cretaceous unit in the Greater Green River Basin and is a major regressive deposit of alternating sands and shale. The Frontier is encased between the marine Mowry and Baxter Shales (fig. 82). Six applications for designation of the Frontier Formation as a tight gas sand have been filed for parts of the Greater Green River Basin (fig. 85) (Wyoming Oil and Gas Conservation Commission, 1980a, Docket 65-80; 1981e, Docket 189-80(A); 1981f, Docket 193-80; 1981a, Docket 53-81(A); 1981c, Docket 113-81; 1981d, Docket 128-81). These six areas have been separated into two groups: those areas forming a contiguous block over the Moxa Arch, and 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. 85).

The data base for the Frontier Formation is good to very good for both the Moxa Arch (tables 90-93) and the eastern Greater Green River Basin (tables 94-97). Note that each area has been further subdivided into the northern and southern Moxa Arch, and the Rock Springs Uplift and Washakie Basin, respectively, for the purposes of tabular data presentation.

Structure

The present form of the Greater Green River Basin resulted from the Late Cretaceous - Early Tertiary Laramide orogeny. The basin is bounded on the west by the Overthrust Belt and on other margins by a series of surrounding positive features (fig. 83) (National Petroleum Council, 1980). Subbasins and intervening uplifts further divide the basin; some of these features are only present in the subsurface.

Both the Rock Springs Uplift and the Moxa Arch have similar structural styles and are the result of basement movement predominantly in the vertical sense. Uplift on the Moxa Arch appears to have been active during the deposition of the Baxter Shale (equivalent to the Hilliard Shale) and the lower Mesaverde Group as suggested by thickening of these units away from the axis of the arch. The Rock Springs Uplift may be a slightly younger feature than the Moxa Arch in that the steep dip of Paleocene strata indicates a post-Paleocene age for much of the development 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 is related to minor regressive and transgressive episodes within the major regressive sequence represented by the Frontier delta. This alternation has led to a terminology of First through Fifth Frontier for the sand-bearing intervals within the Frontier, as further described in this survey for the Frontier in the Wind River and Big Horn Basins. The terminology of numbered Frontier sandstones is informal, and these do not everywhere represent precisely the same stratigraphic unit.

In general, the lower third of the Frontier is fluvial, grading upward into alternating fluvial and shallow marine deposits. This transition ends with the Second Frontier, which is dominantly marine except near the Frontier paleoshoreline between the Moxa Arch and the Overthrust Belt (De Chadenedes, 1975). The lithologic zonation of the First and Second Frontier is present throughout most of Wyoming, extending even into the Powder River Basin of northeast Wyoming. The Third through Fifth Frontier have a much lower degree of continuity (De Chadenedes, 1975), as might be expected for dominantly fluvial sandstones.

Depositional Systems

The Frontier Formation is an areally extensive Late Cretaceous deltaic sequence that prograded from the west into a Cretaceous seaway approximately 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), and shows all the genetic facies, from fluvial to offshore marine, inherent in a deltaic system. The marine-influenced facies of the Second Frontier, which may be expected to have the best lateral continuity, include upper and lower delta front, coalescing offshore bars, and deltaic strandplain. Winn and Smithwick (1980) suggest that the Frontier delta was wave dominated. Myers (1977) notes that the individual sands within the Second Frontier may represent individual pulses of deltaic progradation, consisting of delta front sheet sandstones capped by tidal channel fill and rarely by marsh deposits. Hawkins (1980) considers the capping units to be mixed tidal flat and lagoonal deposits where the second bench of the Second Frontier is interpreted as a lower shoreface to backshore deposit of a barrier island sequence (fig. 89).

Although most of the published studies have focused on the Frontier producing areas in the western Greater Green River Basin, other information suggests that lateral continuity of Frontier sandstones is also favorable in parts of the eastern Greater Green River Basin. On the flank of the Moxa Arch, continuity of 20- to 28-ft-thick sands is evident (fig. 90), as it is (to a lesser extent) in the eastern Washakie Basin, where Frontier sands of similar thickness are interpreted as the delta front facies of southeast-prograding deltas (fig. 91). Shales between the individual sands of the Second Frontier represent transgressive marine deposits in the Washakie Basin area.

Frontier Well Data Profile

Because the Frontier Formation is an areally extensive deltaic system with the potential to meet GRI criteria for future studies, additional data were sought from the Well History Control System (WHCS) file of Petroleum Information Corporation. Where tables 90-97 include parameters on a basin-wide basis, these data have been derived from the latter file. Wells were selected from WHCS on the basis of gas wells that had received fracture treatments and were perforated within the Frontier Formation.

A minimum of 555 gas wells have been completed in the Frontier Formation in the period 1954-1981 (fig. 92). The bimodal distribution with time reflects the development of the Frontier on the Moxa Arch in the period 1958-1963 and the national increase in well completions over the last 5 years. The distribution of completions only in the Second Frontier shows a similar pattern (fig. 93). Note that for many wells the part of the Frontier Formation in which the well was completed was not specified; therefore, data reported for the First and Second Frontier were from a more limited sample. The depth to the top of perforations in the Second Frontier shows a peak at 6,500 to 8,000 ft, probably reflecting completions on the northern end of the Moxa Arch (fig. 94). Off-structure wells in the latter area would encounter the unconventional reservoirs of the Second Frontier at depths of 10,000 to 11,500 ft, as would wells on the southern part of the Arch. Thicknesses of the gross perforated interval for wells completed in the Second Frontier show a predominance of perforated intervals of 20 ft or less in thickness (fig. 95), probably reflecting the productivity of the second bench, or second sandstone, within the Second Frontier. Gross perforated intervals up to 80 ft thick probably reflect production from the second bench plus other sandstones within a narrow interval of the Second Frontier. Fewer perforated intervals are 80 to 200 ft thick, and only a limited number exceed 200 ft in thickness.

Where the type of fracture treatment fluid used in the Second Frontier was reported, oil-based fluid and emulsion predominated over water base fluid. Certainly this is an effort to avoid formation damage that might result from the contact of water-base fluids and unstable clays. Gas-oil ratios were noted for six wells from the Second Frontier, averaging 42,712:1 and ranging from 11,100:1 to 80,000:1. The API gravity of hydrocarbon liquids was noted for eight wells, averaging 51.5° and ranging from 38.4° to 62.3°, also in the Second Frontier.

Far fewer wells perforated in the First Frontier were specifically identified in the WHCS printout. The depth to the top of perforations in the First Frontier is predominantly

6,000 to 6,500 ft (fig. 96), and the thickness of the gross perforated interval is mostly 100 ft or less (fig. 97). 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. The predominant fracture treatment for the First Frontier used oil-based fluid; no gas-oil ratio or gravity data were reported. Other basin-wide data on the First Frontier have been added to the Comments section of table 96.

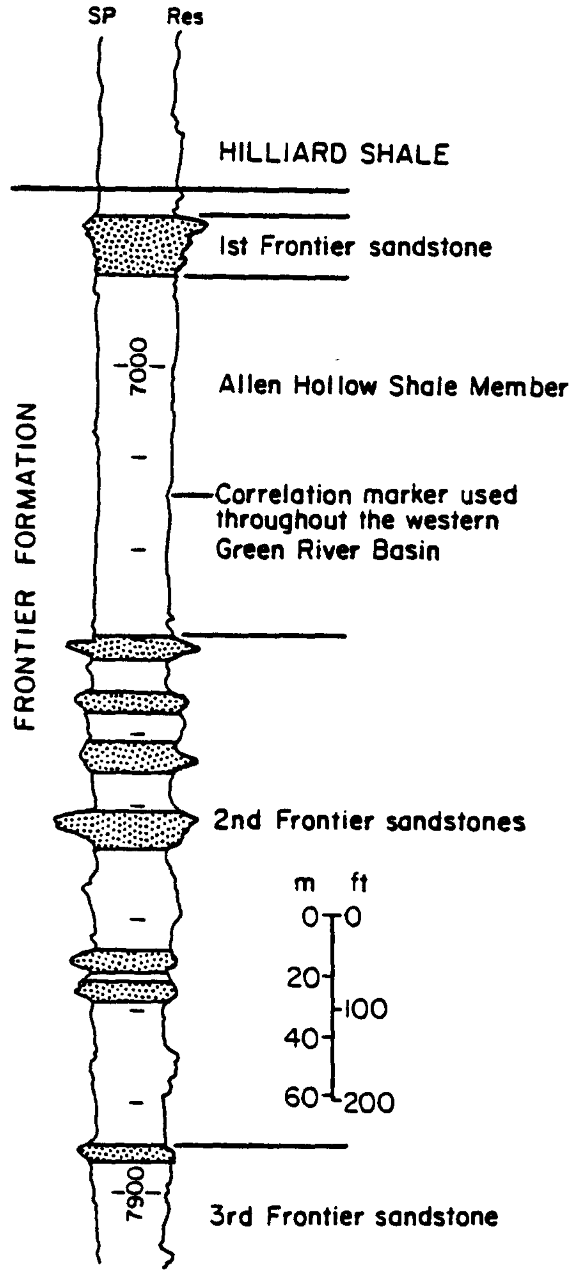

Figure 88. Type log through the upper Frontier Formation, Big Piney-LaBarge Field, Greater Green River Basin (after Myers, 1977).

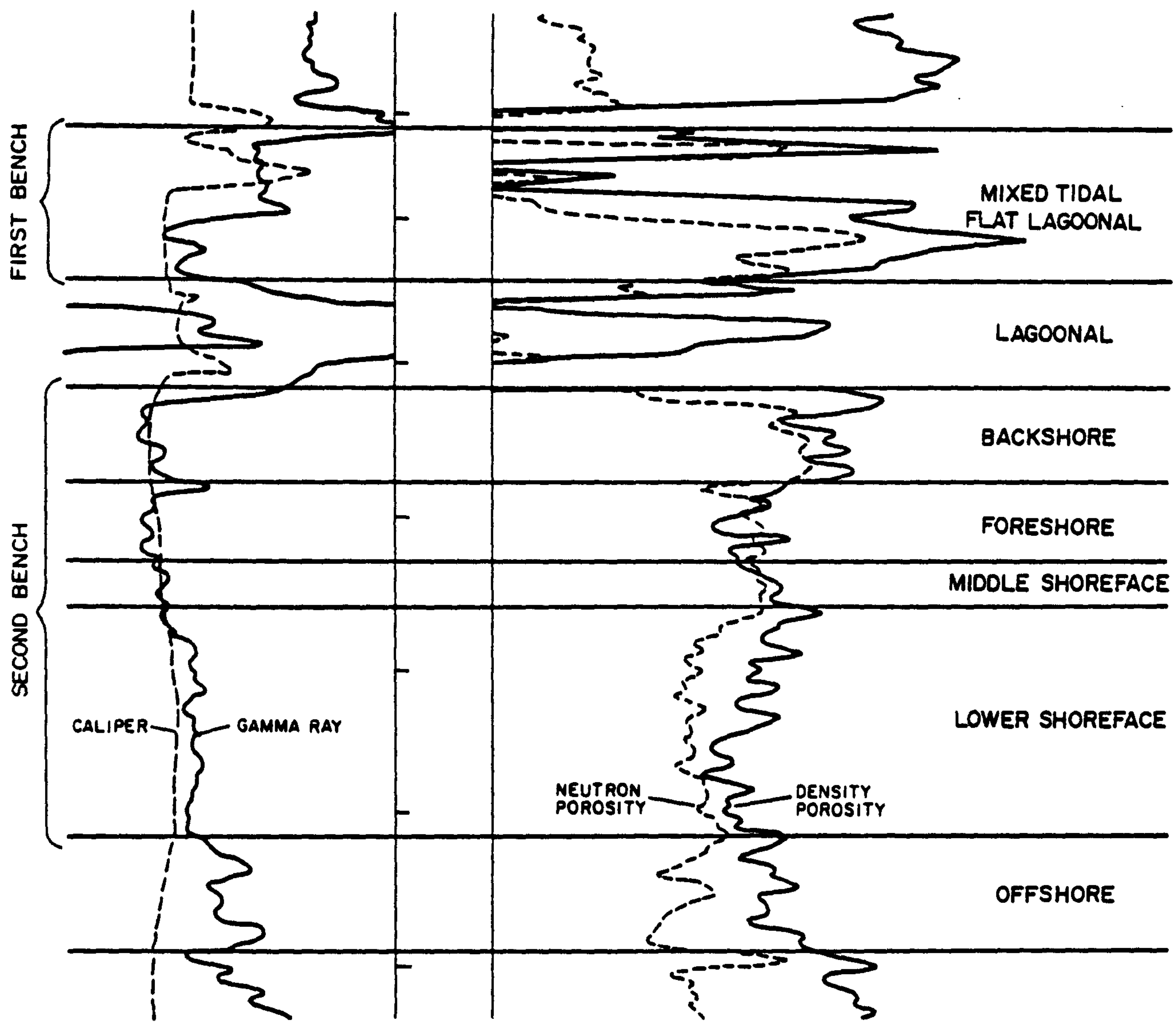

Figure 89. Interpretation of environments of deposition of the first and second sandstone benches in the Second Frontier, Frontier Formation, Greater Green River Basin (after Hawkins, 1980).

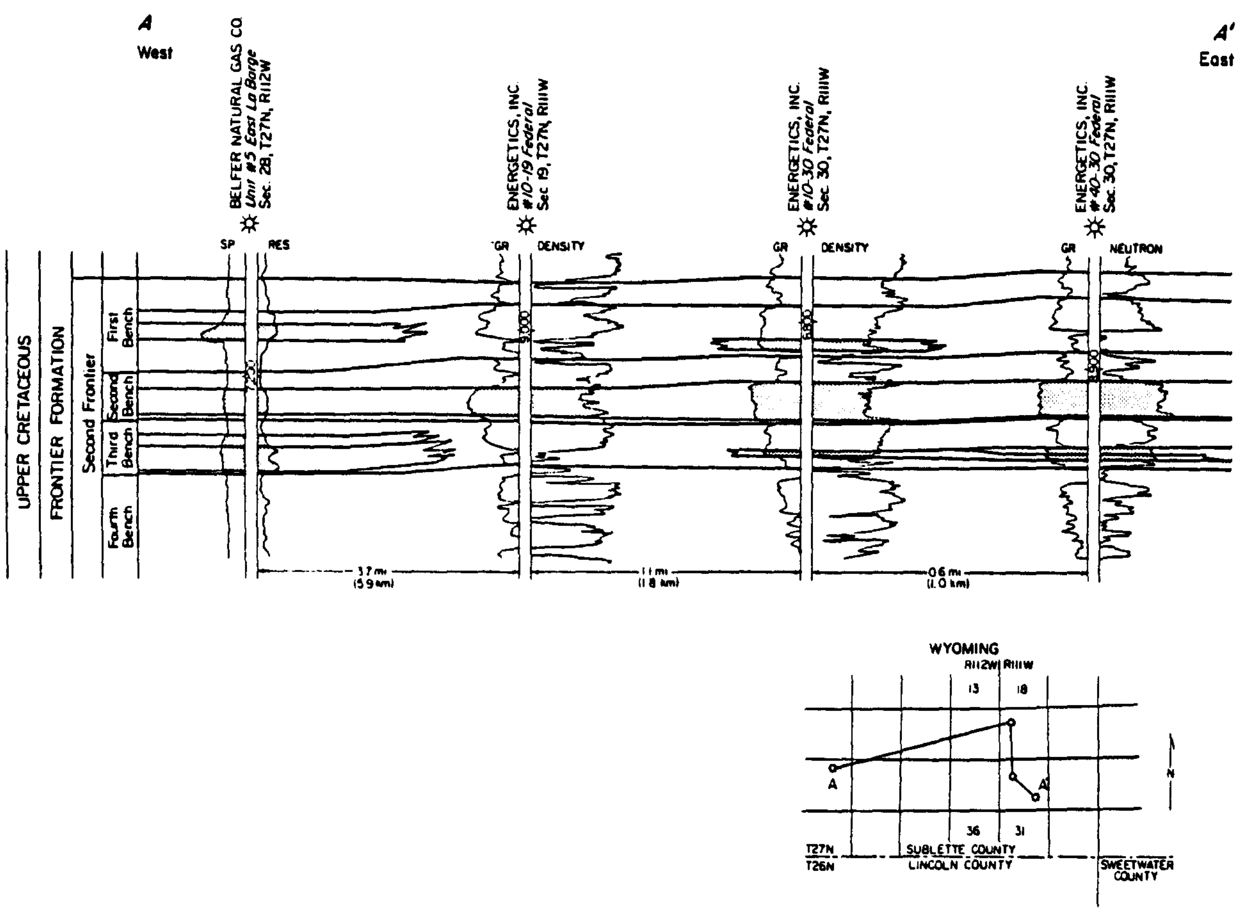

Figure 90. West-east stratigraphic cross section A-A' showing continuity of the second sandstone bench, Second Frontier, Frontier Formation, Greater Green River Basin (after Wyoming Oil and Gas Conservation Commission, 1981e).

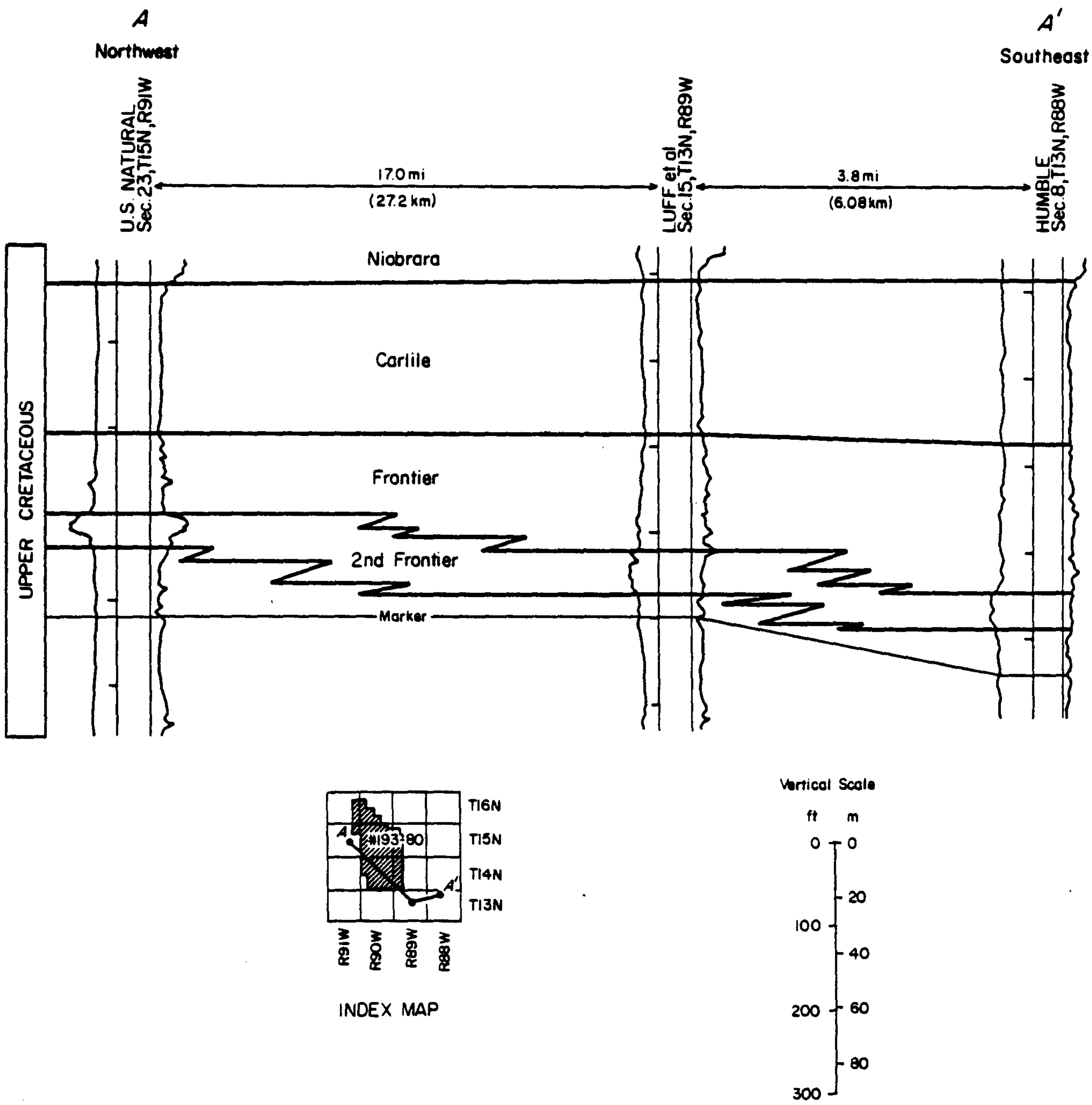

Figure 91. Northwest-southeast stratigraphic cross section A-A' showing correlation of the Second Frontier, Frontier Formation in the Washakie Basin of the Greater Green River Basin (from Wyoming Oil and Gas Conservation Commission, 1981f).

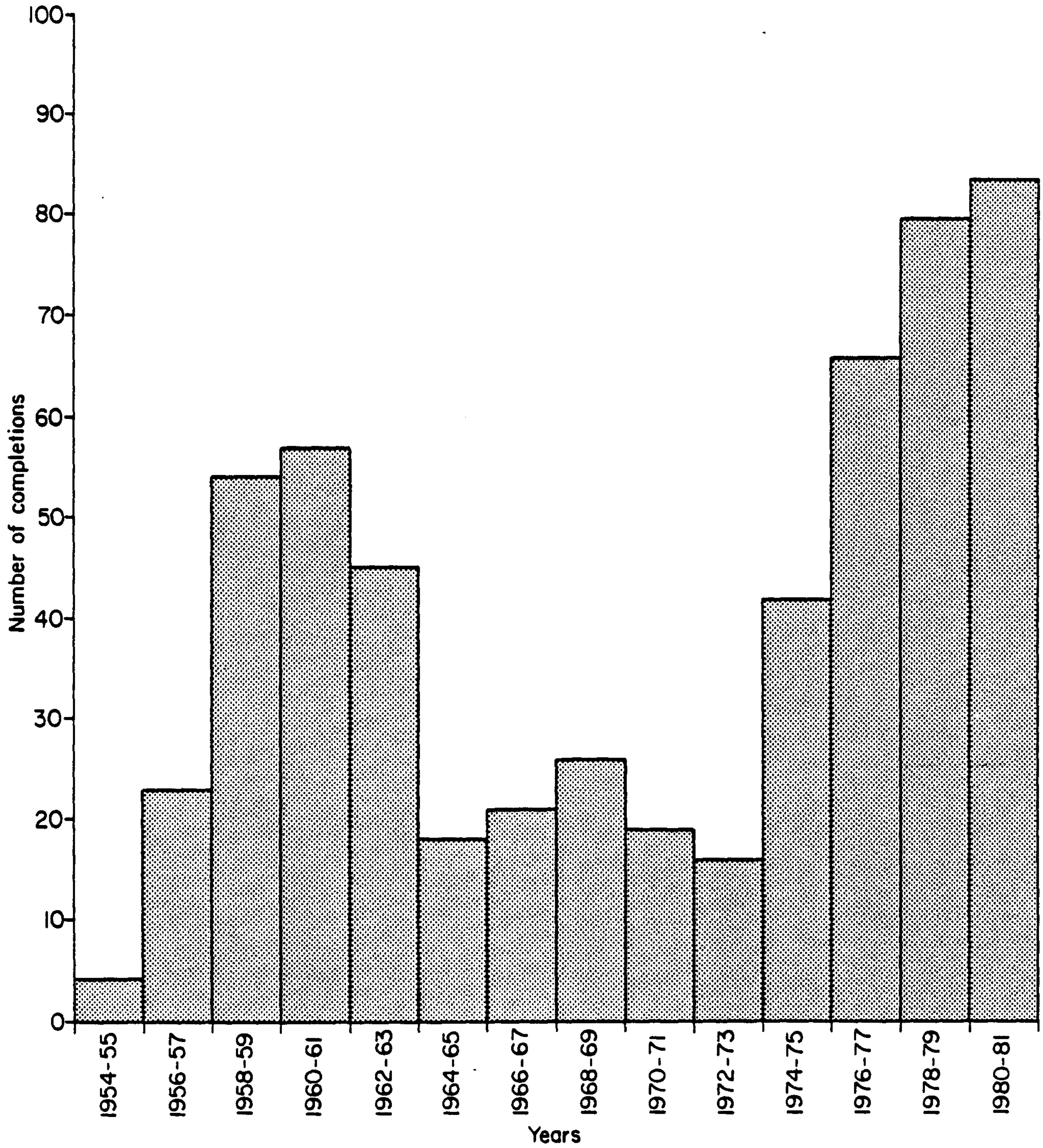

Figure 92. Distribution by two-year intervals of 555 gas well completions in the Frontier Formation, Greater Green River Basin.

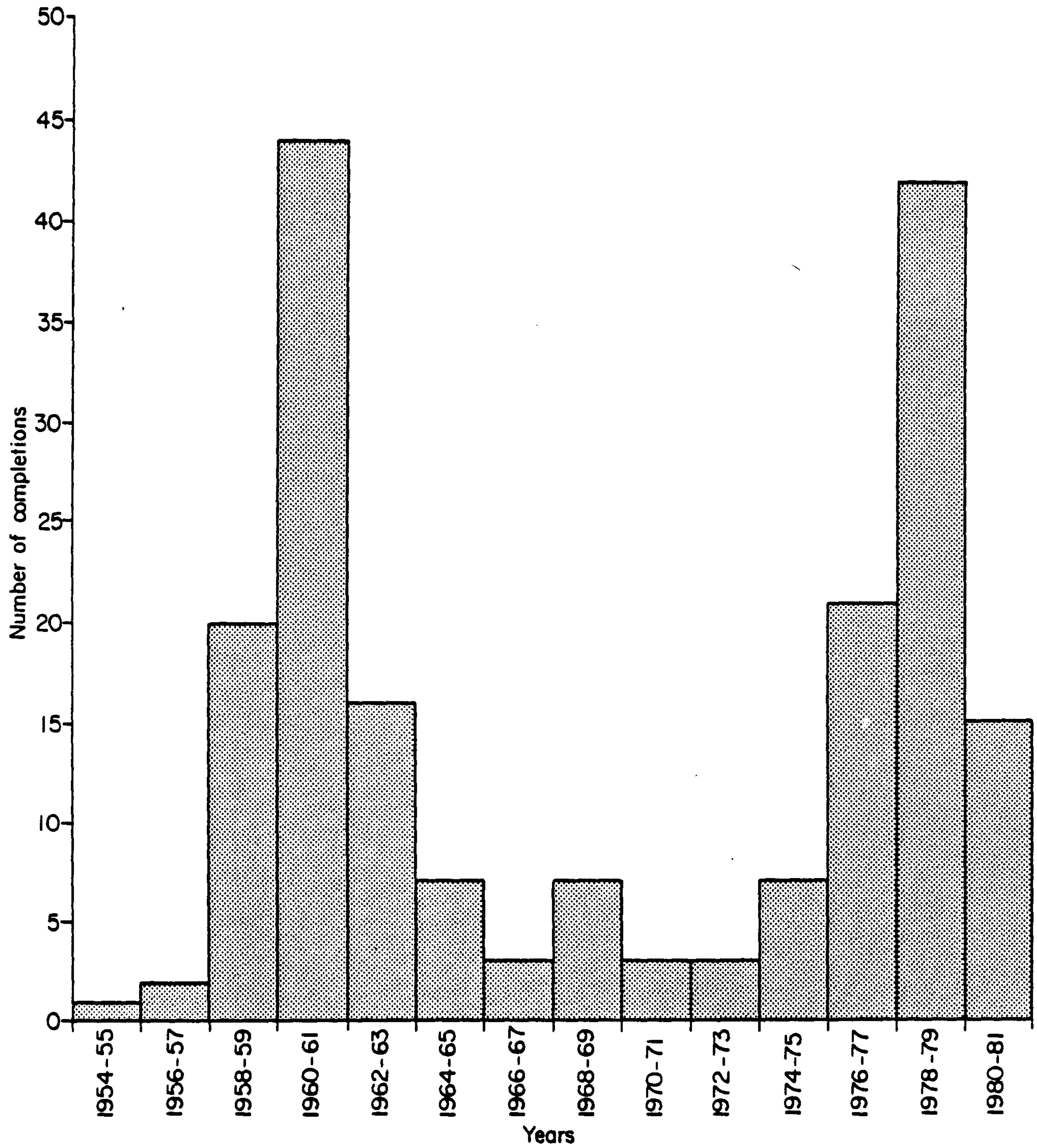

Figure 93. Distribution by two-year intervals of 191 gas well completions in the Second Frontier of the Frontier Formation, Greater Green River Basin.

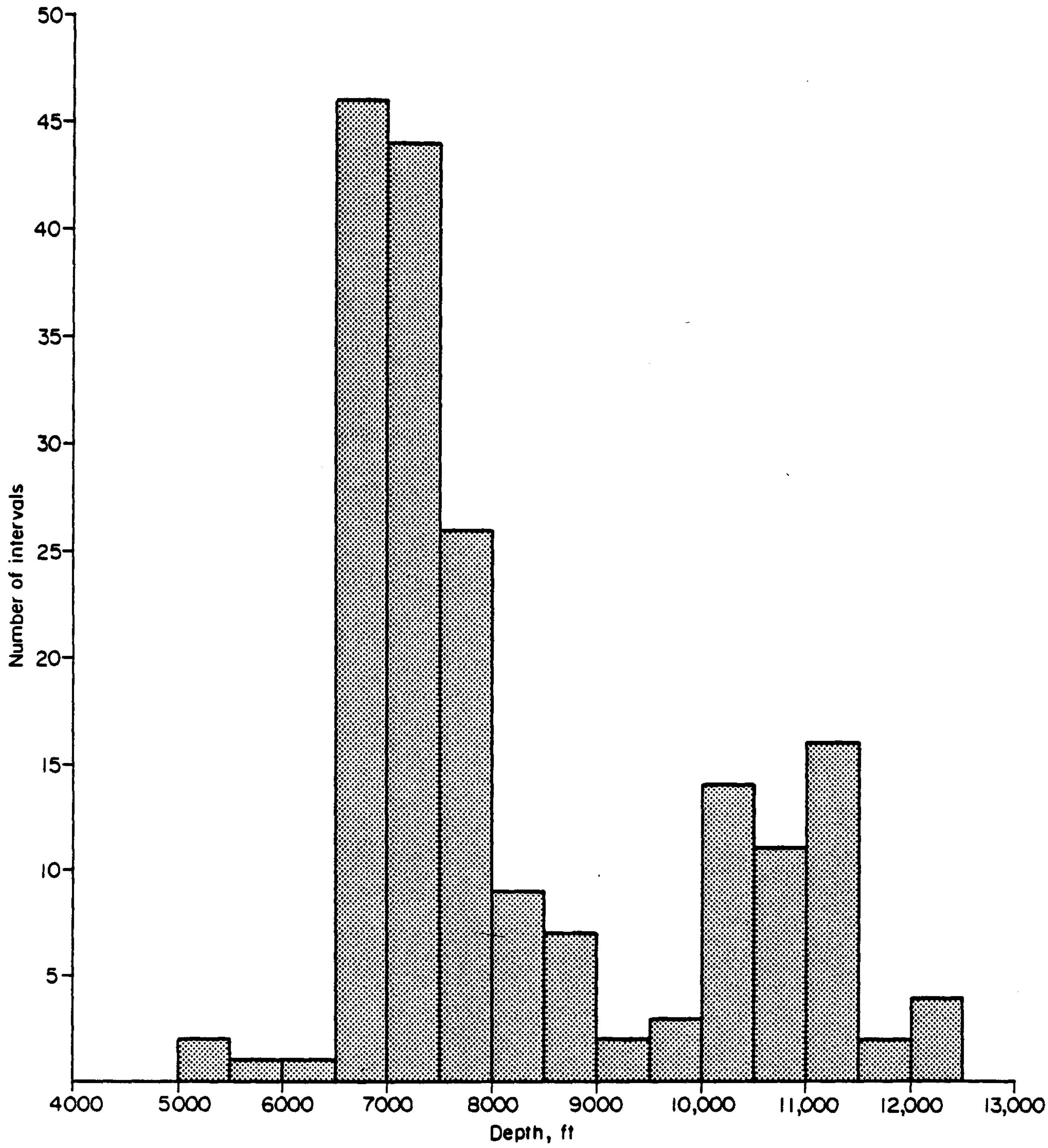

Figure 94. Depth to top of perforated interval for 186 gas well completions in the Second Frontier of the Frontier Formation, Greater Green River Basin.

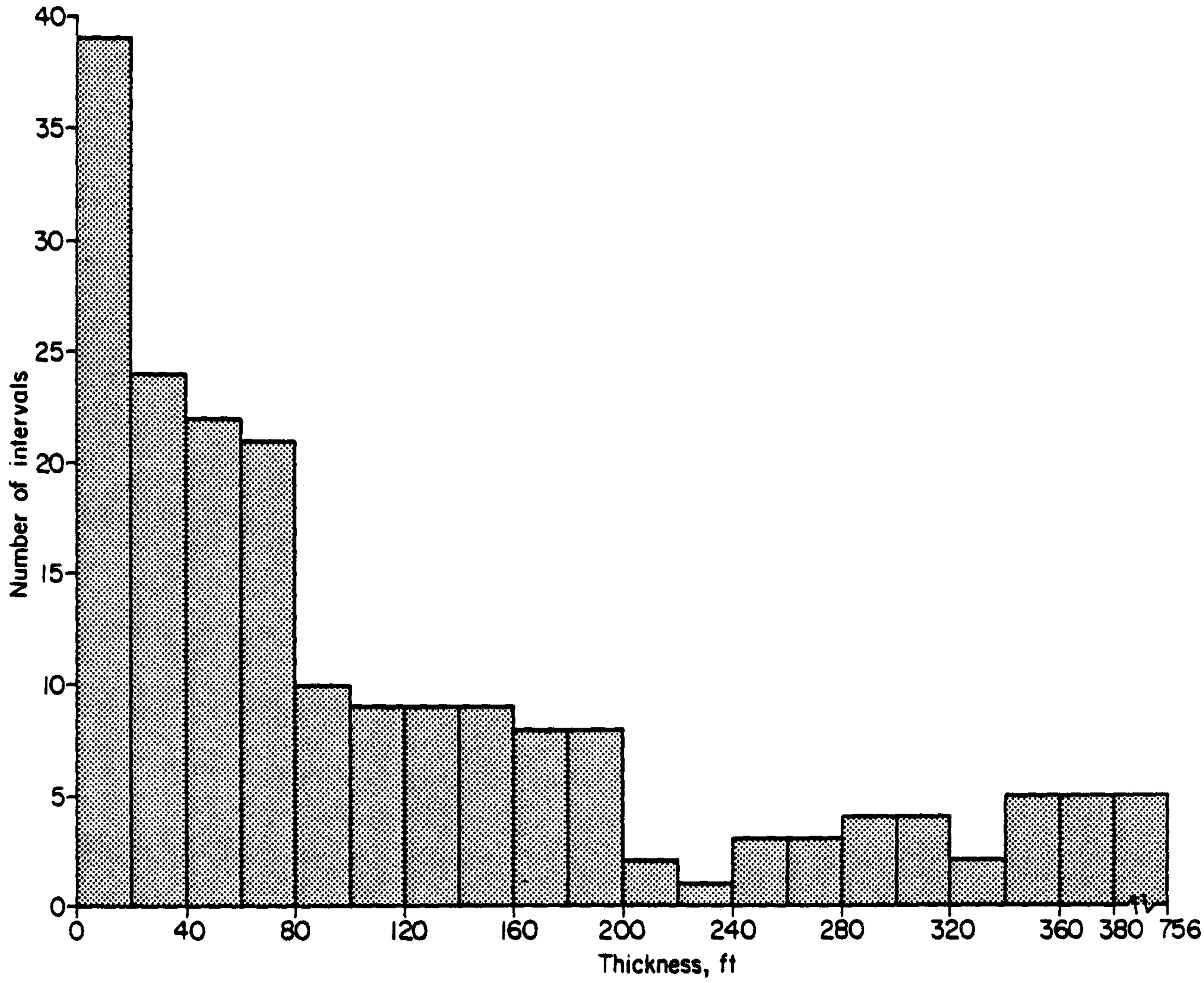

Figure 95. Thickness of gross perforated interval for 189 gas well completions in the Second Frontier of the Frontier Formation, Greater Green River Basin.

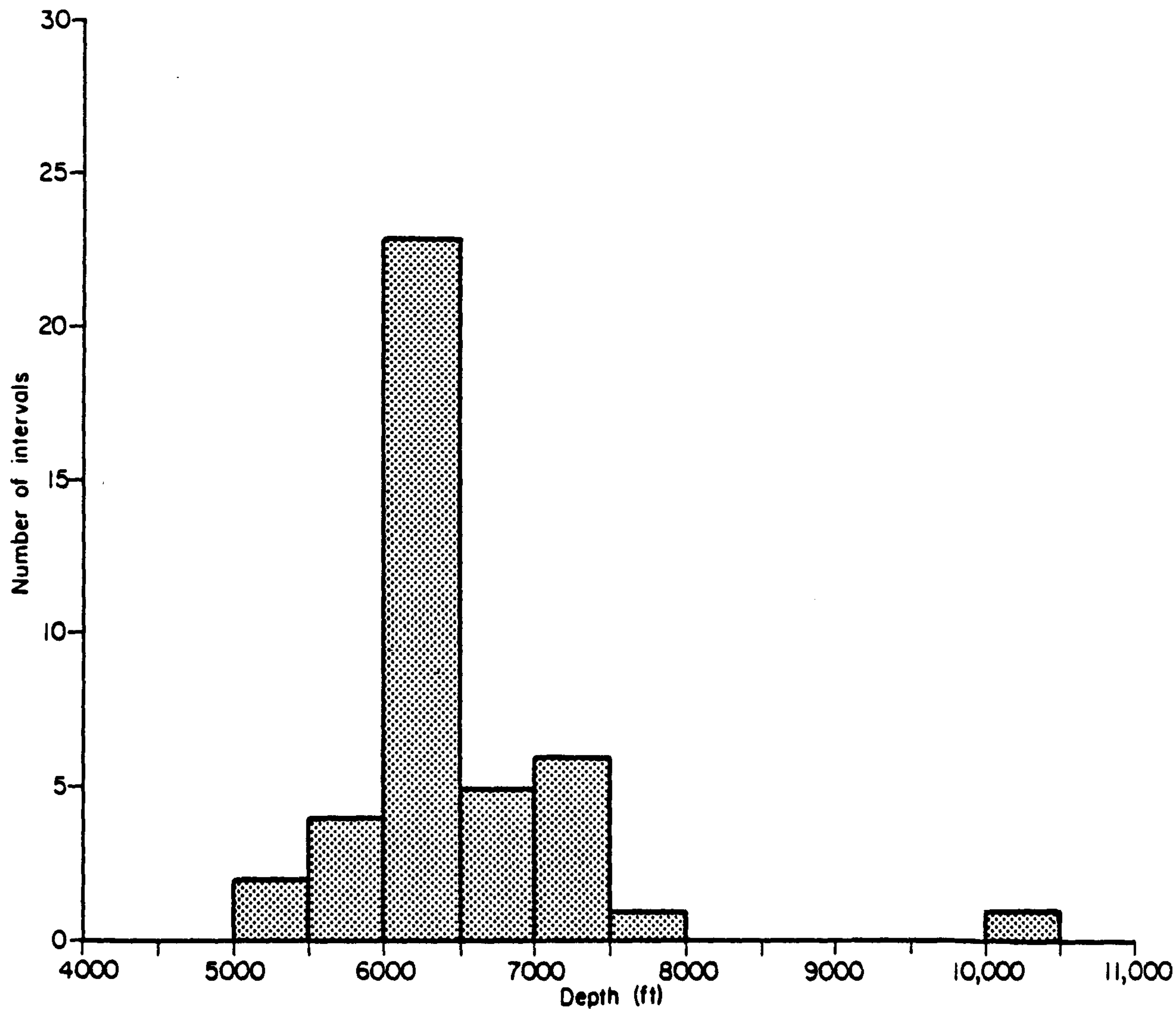

Figure 96. Depth to top of perforated interval for 43 gas well completions in the First Frontier, Frontier Formation, Greater Green River Basin.

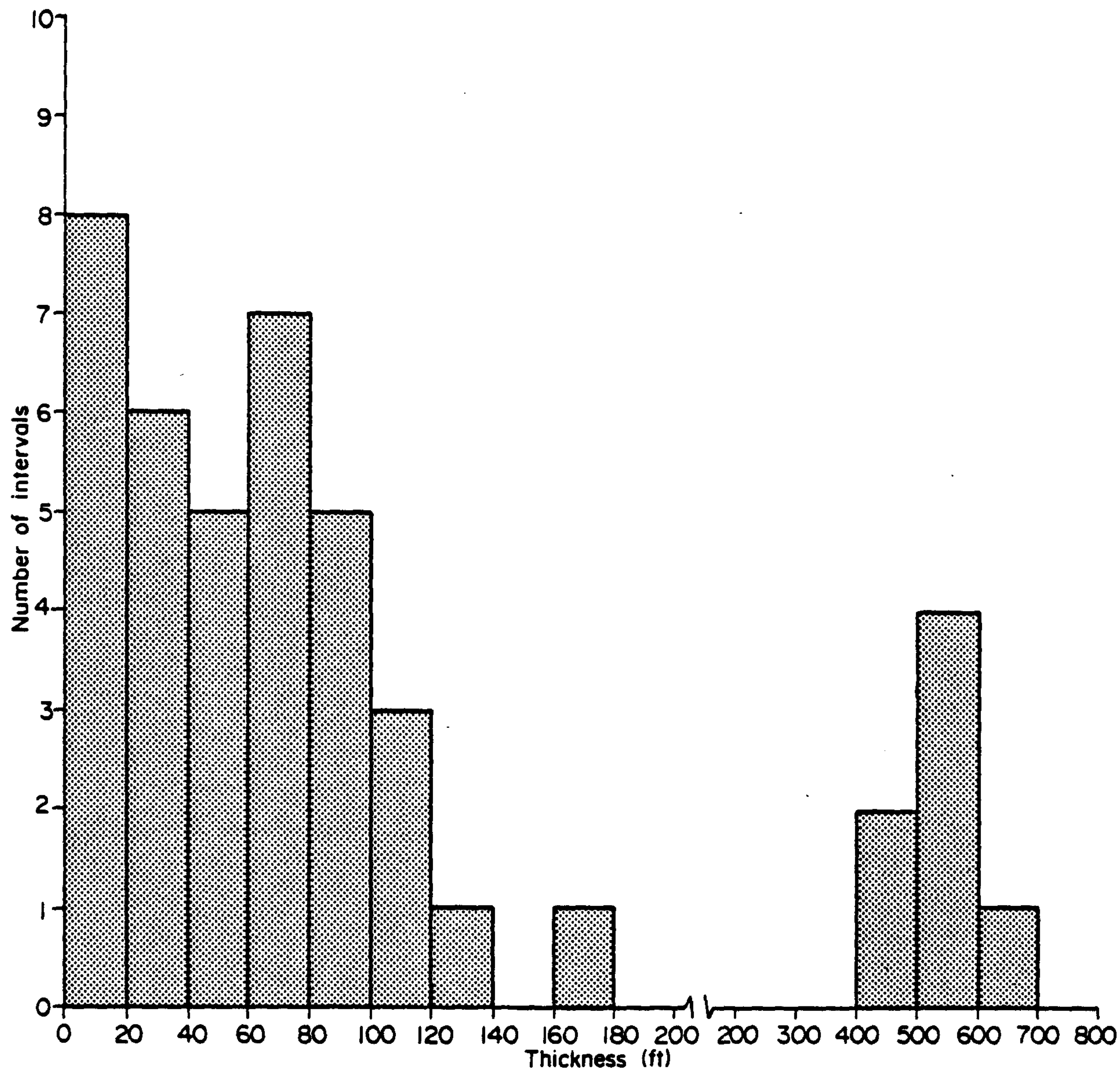

Figure 97. Thickness of gross perforated interval for 43 gas well completions in the First Frontier, Greater Green River Basin.

Table 90. Frontier Formation, Greater Green River Basin (Moxa Arch): 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 in the vicinity of the northern Moxa Arch (T24-31N, R109-114W) = 765.5 mi^2. 2. Designated areas on and in the vicinity of the southern Moxa Arch (T16-24N, R110-115W) = 1,398 mi^2.	1. Ranges from 1,200 ft (NW) to 300 ft (S). 2. Average thickness = 450 ft.	1. Average drilling depth to the top of the First Frontier ranges from 6,700 ft (NW) to 8,300 ft (S), when present. The First Frontier is not present in the SE portion of the area. Drilling depths to the top of the Second Frontier range from 7,250 ft (NW) to greater than 15,000 ft (SE). 2. Average drilling depth to the top of Second Frontier = 11,870 ft. First Frontier not developed; Third and Fourth Frontier sands are too deep.	4.921 Tcf for 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 portion of the Greater Green River Basin. It is bounded to the north by the Wind River Range, to the east by the Rock Springs Uplift, to the south by the Uinta Mountains, and to the west by the Wyoming Overthrust Belt. The present structural setting formed primarily as a result of Late Cretaceous - Early Tertiary Laramide tectonism.	1.2-1.6°F/100 ft.	Overpressured in the Second Frontier of the Moxa Arch with a gradient of approximately 0.54 psi/ft in area of Docket No. 189-80 application.	Compressional Laramide deformation formed uplifts and adjacent basins, followed by post-Laramide vertical uplift.

Table 91. Frontier Formation, Greater Green River Basin (Moxa Arch): Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies

The Frontier Formation was deposited as several distinctive, 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, with the Second Frontier being the most laterally consistent and productive unit. The Frontier was deposited as an eastward-prograding deltaic complex which includes pro-delta 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.

Texture

Very fine to medium and coarse-grained sandstones with some silty and shaly intervals. Poorly to moderately sorted, subangular to subrounded sands.

Mineralogy

Variable, with continental sands being more compositionally immature and containing abundant quartz, feldspar, chert, micas, and rock fragments, while marine sands, being much more quartzitic, contain some chert and glauconite. Terrigenous clays are present in varying degrees in all sands, depending upon the amount of winnowing within the depositional environment.

Diagenesis

Cements include authigenic clays, calcite and quartz overgrowths. Authigenic chlorite and mixed-layer illite-smectite may be expected.

Typical Reservoir Dimensions

1. When present (in the northwestern part of the area), the First Frontier average = 62 ft, range = 40-71 ft. The Second Frontier average = 280 ft, range = 31-617 ft to the north, while to the south, average = 40 ft, range = 12-70 ft.

2. Second Frontier average = 47 ft, range = 9-64 ft. First Frontier not developed.

Pressure/Temperature of Reservoir

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 depth), pressure = 7,700 psi, temperature = 242°F. DST data from 66 Second Frontier wells basin-wide show an average initial shut-in pressure of 3,211 psi and a range of 6,789 to 224 psi.

Natural Fracturing

No specific data.

Data Availability (logs, cores, tests, etc.)

SP-resistivity or GR-resistivity and GR-neutron density are typical logs. Core has been taken in 15% of Frontier gas wells in the Greater Green River Basin (86 of 555 completions). Thirty-nine of these cores were taken in the Second Frontier.

Table 92. Frontier Formation, Greater Green River Basin (Moxa Arch): 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 = 13.4%, range = 5.7-20.7%; average permeability = 0.007 md, range = less than .0001-1.3 md. Permeabilities were calculated from core analysis, DST analysis, and flow tests. First Frontier, based on 4 wells, average in situ permeability = less than 0.0001 md; Second Frontier, based on 58 wells, average in situ permeability = approx. 0.016 md, range = less than .00001-0.306 md. Average porosity = 13.8%, range = 11-20%, based on 25 wells. 2. Based on flow tests of 37 wells, average in situ permeability = 0.0308 md, range = less than 0.0001-0.171md. Average porosity = 12%, range up to 18%.	1. Based on 35 wells, average = 36 ft, range = 10-90 ft for the Second Frontier only. 2. Based on 63 wells, average = 21 ft, range = 9-66 ft for the Second Frontier only.	1. First Frontier, for 3 wells, all had flow TSTM. Second Frontier, for 20 wells, average = 314 Mcfd, range = TSTM-2,630 Mcfd. 2. Second Frontier, for 43 wells, average = 224 Mcfd, range = 10-1,365 Mcfd.	1. First and Second Frontier commingled, average = 360 Mcfd, range = TSTM-2,506 Mcfd for 36 wells. 2. Second Frontier, average = 1,824 Mcfd, range = 0-5,700 Mcfd for 35 wells.	No data.	Liquid hydrocarbons, when present, occur only as condensate at surface conditions, and in quantities less than 5 bpd. Basin-wide in the Second Frontier, 27 of 191 wells produce an average of 17 bpd of condensate; condensate production ranges from 1 to 76 bpd. Thirty of 191 wells produce an average of 25 bpd of water; water production ranges from 1 to 130 bpd.	Average = 51%, range = 36-68%.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
1. Based on 27 enhanced recovery completions, hydraulic fracture techniques using diesel (older completions) or KCl water or cross-linked water/methanol gel (recent completions) fluids averaged 65,000 gal, ranging from 8,000-311,300 gal and sand proppants averaging 90,250 lb, ranging from 11,000-628,000 lb. 2. Of 35 recent hydraulic fracture completions, the average amount of fluid was 273,840 gal, with a range of 87,300-510,000 gal and the average amount of sand proppant was 605,320 lb, with a range of 80,000-1,161,890 lb.	1. No data. 2. 34/35 = 97% successful fracture treatments (where treatment resulted in improved flow).	640 acres.	Approved and pending tight gas applications exclude existing Frontier gas production from conventional reservoirs in the vicinity of LaBarge, Wyoming, on the northern end of the Moxa Arch. Initial potential flow (IPF) (mostly post-stimulation) for 186 Second Frontier gas completions (basin-wide) averages 3,479 Mcfd and ranges from 51 to 57,128 Mcfd. IPF will always be higher than stabilized, or nearly stabilized, production rates.

Table 93. Frontier Formation, Greater Green River Basin (Moxa Arch): 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 portions of these areas have FERC approval, while the rest are under review.	Total of 555 Frontier gas completions in the Greater Green River Basin, of which at least 104 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 the period 1970-1977 (National Petroleum Council, 1980). No data specific to the Frontier.	1. Total well costs for 7 Frontier and Bear River dual completions (excluding Bear River fracture) averaged $932,000. This includes Frontier fractures which averaged $91,400 (1979 dollars). 2. Based on 3 wells that were completed from 10/78-3/80, stimulation costs by hydraulic fracturing methods averaged $220,000. For another operator the typical cost for fracture treatment was $280,000 (1980 dollars, based on 4 wells).	Pipelines in place to serve established production on the Moxa Arch, especially on the northern end of the Arch in the vicinity of Big Piney, Dry Piney, and LaBarge, 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 for 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
The Greater Green River Basin is within the Wyoming - Big Horn Basin physiographic subdivision with 300-500 ft of local relief in most areas, but 500-1,000 ft of local relief toward the western margin of the basin before encountering greater relief along the overthrust belt.	Semiarid to arid with most areas receiving 8-16 inches mean annual precipitation; generally more precipitation at higher elevation. Mild summers, cold winters. Exploration and development drilling are conducted all year in this area.	Access to this area is by unimproved roads and may be a problem locally where significant relief occurs.	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 member which would be analogous to other delta front, barrier, and strandplain facies in other, less areally extensive, deltaic and interdeltaic deposits.	Some locations may be remote from exploration services and may incur significant mileage charges. Selected services based at Rock Springs, Wyoming.

Table 94. Frontier Formation, Greater Green River Basin (Rock Springs Uplift and Washakie 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) equal to 396 mi^2. 2. Designated area at the eastern margin of the Washakie Basin (T14-16N, R89-91W) equal to 98 mi^2.	1. Total Frontier average = 400 (East) - 600 ft (West), with Second Frontier average = 180 ft and Third Frontier average = 150 ft. 2. Total Frontier average = 240-270 ft, with Second Frontier average = 20 ft.	1. Average to top of First Frontier = 11,530 ft, range = 8,585-17,495 ft; average to top of Second Frontier = 11,681 ft, range = 8,814-17,672 ft; average to top of Third Frontier = 11,860 ft, range = 8,958-17,894. 2. Average range to top of First Frontier = 6,930-7,360 ft; average range to top of Second Frontier = 7,035-7,470 ft.	No resource estimate for the Frontier in the eastern Greater Green River Basin.	No additional information.

GEOLOGIC PARAMETERS - Basin/Trend

Structural/Tectonic Setting	Thermal Gradient	Pressure Gradient	Stress Regime
1. This area lies along the northern flanks of the Rock Springs Uplift. This structure, as were all other associated structures, formed primarily as a result of Laramide tectonism. The area is bounded to the north by the Wind River Range, to the west by the Green River Basin, and to 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 to the north by the Wamsutter Arch and the Rawlins Uplift, to the east by the Sierra Madre Uplift, and to the south by Cherokee Ridge.	1.2-1.6°F/100 ft.	No data.	Compressional Laramide deformation formed uplifts and adjacent basins followed by post-Laramide vertical uplift.

Table 95. Frontier Formation, Greater Green River Basin (Rock Springs Uplift and Washakie Basin): Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies

See Frontier Formation, Greater Green River Basin (Moxa Arch), this survey.

Texture

Second Frontier: moderately to very well sorted, angular to well-rounded, very fine to fine-grained sandstones with silt and shale interbeds.

Third Frontier: moderately to very well sorted, subangular to subrounded, very fine to fine-grained sandstones with silt and shale interbeds.

Mineralogy

Second Frontier: quartz, rock fragments, some feldspar and terrigenous clays.

Third Frontier: quartz, feldspar, rock fragments, some glauconite.

Diagenesis

Second Frontier: cements include quartz overgrowths, calcite, dolomite, siderite, and authigenic chlorite and illite-smectite.

Third Frontier: cements include quartz overgrowths, authigenic chlorite and illite-smectite, and some calcite.

Typical Reservoir Dimensions

1. Second Frontier average = 55 ft, range = 11-70 ft.

   Third Frontier average = 139 ft, range = 23-234 ft.

2. Second Frontier average = 20 ft.

Pressure/Temperature of Reservoir

1. Pressure = 3,400 psi at Nitchie Gulch Field (at approx. 7,800 ft) in Third Frontier near designated area.

2. Average reservoir temperature = 152°F. Pressure = 3,900 psi at Deep Gulch Field (at approx. 8,000 ft) in Frontier near application area.

Natural Fracturing

No specific data.

Data Availability (logs, cores, tests, etc.)

See Frontier Formation, Greater Green River Basin (Moxa Arch), this survey.

Table 96. Frontier Formation, Greater Green River Basin (Rock Springs Uplift and Washakie 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. A. First Frontier: permeability as calculated from 1 flow test = 0.011 md. B. Second Frontier: permeability calculated from 7 flow tests, average = 0.006 md; from 1 core analysis, permeability = 0.154 (to air). Porosity averaged from 4 wells = 10.1%, range = 2-16%. 2. Second Frontier: permeability as calculated from 1 flow test = 0.07 md. Porosity as calculated from 2 wells ranged from 7-12%.	1. Second Frontier average = 39 ft, range = 11-64 ft. 2. Second Frontier average = 20 ft.	1. First Frontier = 12.7 Mcfd from 1 well. Second Frontier, based on 7 wells, average = 57 Mcfd, range = 5-178 Mcfd. 2. Second Frontier, based on two wells = 65-110 Mcfd.	1. Second Frontier, based on 5 wells, average = 640 Mcfd, range = 7-1,546 Mcfd. 2. Second Frontier, based on two wells = 100-745 Mcfd.	No data.	Liquid hydrocarbons rarely present, but when produced, it is as gas condensate. Condensate production is on the order of 1 bpd when present. A few wells subject to high water production (100 Mcfd gas, 55 bwpd).	1. Second Frontier, based on 4 wells, average = 65%. 2. Second Frontier typical S_w = 60-100%. Generally produces water in rates of 20-55 bpd.

Well Stimulation Techniques	Success Ratio	Well Spacing	Comments
1. Hydraulic fracture techniques utilize an average of 86,500 gal fluid and 110,300 lb sand proppant in the Second Frontier, based on 5 fracture jobs. 2. Of the two attempted completions, one was acidized with 2,000 gal acid only and it produced, while the other was hydraulically fractured using 26,000 lb of sand proppant. It was abandoned due to water production.	1. No data. 2. ½ = 50%.	640 acres.	Initial potential flows (IPF) (mostly post-stimulation) for 42 First Frontier completions (basin-wide) averages 7,043 Mcfd and ranges from 116 to 20,089 Mcfd. IPF will always be higher than stabilized, or nearly stabilized, production rates. DST data from 45 First Frontier wells (basin-wide) show an average initial shut-in pressure of 2,177 psi and a range of 4,432 to 241 psi.

Table 97. Frontier Formation, Greater Green River Basin (Rock Springs Uplift and Washakie Basin): Economic factors, operating conditions and extrapolation potential.

ECONOMIC FACTORS

FERC Status	Attempted Completions	Success Ratio	Drilling/ Completion Costs	Market Outlets	Industry Interest
1. Under review by FERC. 2. Approved by FERC.	1. Second Frontier = 6, and Third Frontier = 2, in application area. 2. Second Frontier = 2, in application area. Also, total of 555 Frontier gas completions in the Greater Green River Basin.	1. Second Frontier = 5/6 = 83%. Third Frontier = 0/2 = 0%. 2. ½ = 50%.	1. For a 10,700 ft well (1980), drilling cost was \$800,000. Fracture treatment cost was \$65,000 (1980) (now estimated at over \$100,000) with total completion costs over \$500,000. 2. For a 7,600 ft well (1976), drilling cost was \$754,000, which included acidization. Fracture treatment was not performed but was estimated to cost \$100,000-\$150,000. Surface equipment needed for water disposal cost \$150,000-\$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	Extrapolation Potential	Comments
The eastern Greater Green River Basin is within the Wyoming - Big Horn Basin physiographic subdivision, with 300-500 ft of local relief in the basin and 1,000-3,000 ft of local relief along the eastern and northeastern basin margins.	Semiarid to arid with most areas receiving 8-16 inches mean annual precipitation; generally more precipitation at higher elevation. Mild summers, cold winters. Exploration and development drilling are conducted all year in this area.	Access to this area is by unimproved roads and may be a problem locally where significant relief occurs.	Good to very good. See Frontier Formation, Greater Green River Basin (Moxa Arch), this survey.	Some locations may be remote from exploration services and may incur significant mileage charges. Selected services based at Rock Springs and at Rawlins, Wyoming.

Frontier Formation, Wind River and Big Horn Basins

Introduction

The Upper Cretaceous Frontier Formation consists of sandstone alternating with shale and represents a major regressive unit encased between the marine Mowry and Cody shales (fig. 98). Applications for tight gas formation status have not been filed for the Frontier in either the Wind River or the Big Horn Basins. Miller and VerPloeg (1980) suggest, however, that much of the Frontier in both these basins would likely be eligible for a tight sand designation and that lack of reservoir quality has been a factor in retarding exploration activity.

The data base for the Frontier Formation is fair to good for the Wind River Basin but only fair to poor for the Big Horn Basin. Summary tables were prepared for the Wind River Basin (tables 98-101), 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 figure for the Frontier and the Muddy Sandstone, a formation which underlies the Mowry shale (fig. 99) (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 formation-by-formation resource estimates.

Structure

The Wind River Basin is a geological and topographic basin in central Wyoming that contains an average thickness of 13,000 ft of Cretaceous and Tertiary sediments. 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^{o} to 20^{o} northeastward, whereas the 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 northern boundary of the basin is formed by the Nye-Bowler left-lateral wrench-fault zone; the southern boundary is formed by the Owl Creek Uplift; the western boundary is formed by the Yellowstone-Absaroka volcanic plateau and the Beartooth Mountains; and the eastern boundary is formed by the Pryor and Big Horn Mountains. The Big Horn Basin has many peripheral anticlinal folds oriented parallel to its northeastern and southwestern flanks, accounting for much on-structure oil production (Thomas, 1965).

Stratigraphy

The Frontier Formation in the Wind River Basin ranges from 650 to 1,000 ft thick and in the Big Horn Basin ranges from 400 to 800 ft thick. In both basins the Frontier consists of shale, siltstone, and sandstone of marine and continental origin associated with a major regressive sequence with sources to the west (Keefer, 1969; Merewether and others, 1975). Alternation of sand and shale units is related to more minor regressive and transgressive episodes. This alternation has led to a terminology of First Frontier sand through Fifth Frontier sand, from youngest to oldest, for the five major sandstone bearing intervals of the Frontier. An older terminology included the First Wall Creek sand (equivalent to the Second and Third Frontier), the Second Wall Creek sand (equivalent to the Fourth Frontier), and the Third Wall Creek sand (equivalent to the Fifth Frontier) (Keefer, 1969). The Second Frontier is the most significant of the several sandstone units, both as an existing oil producer at some localities and as a potential tight gas sand at others.

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 present within the Frontier. The grain size of most sandstone beds 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 represent episodes of deltaic sedimentation separated by transgressive marine deposits as sedimentation shifted in space and time. Lateral continuity of the numbered sandstone intervals within the Frontier would be expected to be good in the most marine units within the formation. Where studied in outcrop on the western margin of the Big Horn Basin the middle part of the Frontier includes paludal and fluvial deposits with expected greater lenticularity of beds (Siemers, 1975). The major facies and subfacies recognized by Siemers (1975) in studies along a 30-mi-long outcrop belt near Cody, Wyoming, are listed in table 102.

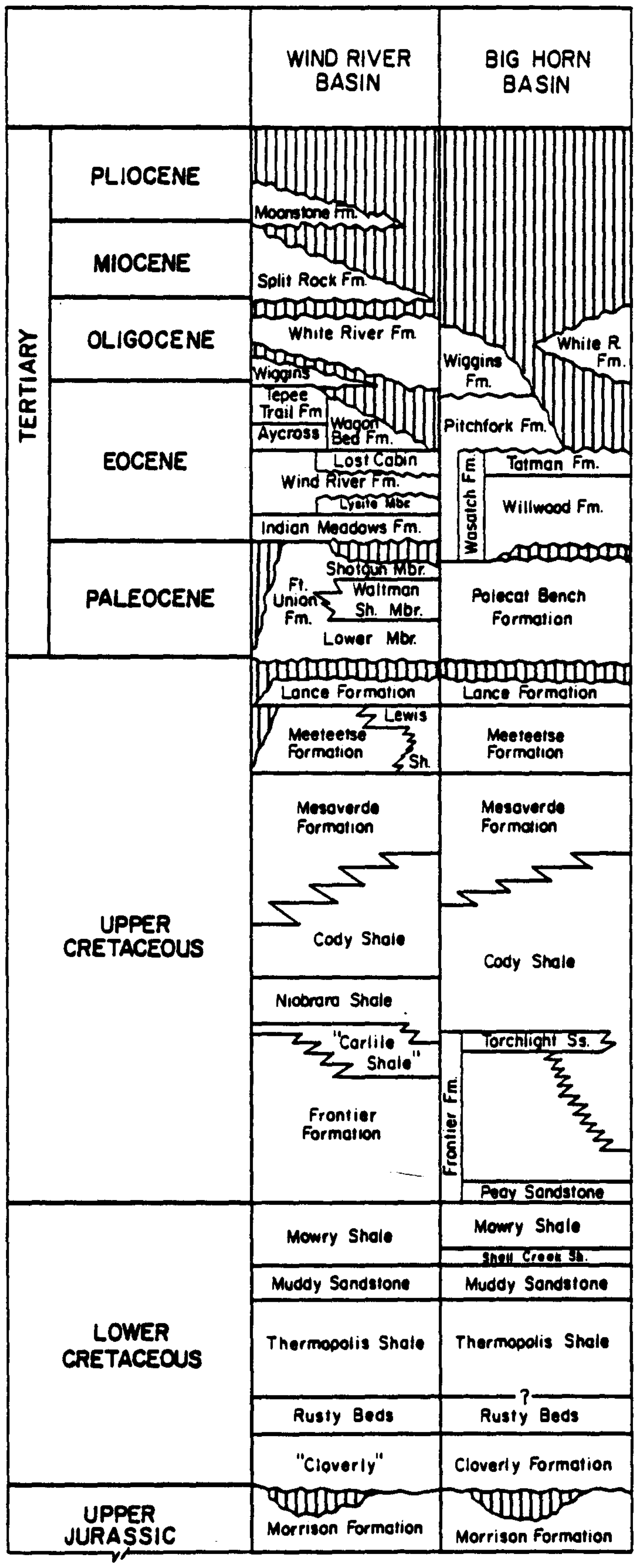

Figure 98. Stratigraphic column from the Jurassic Morrison Formation through the Pliocene Epoch in the Wind River and Big Horn Basins (after Hollis, 1980).

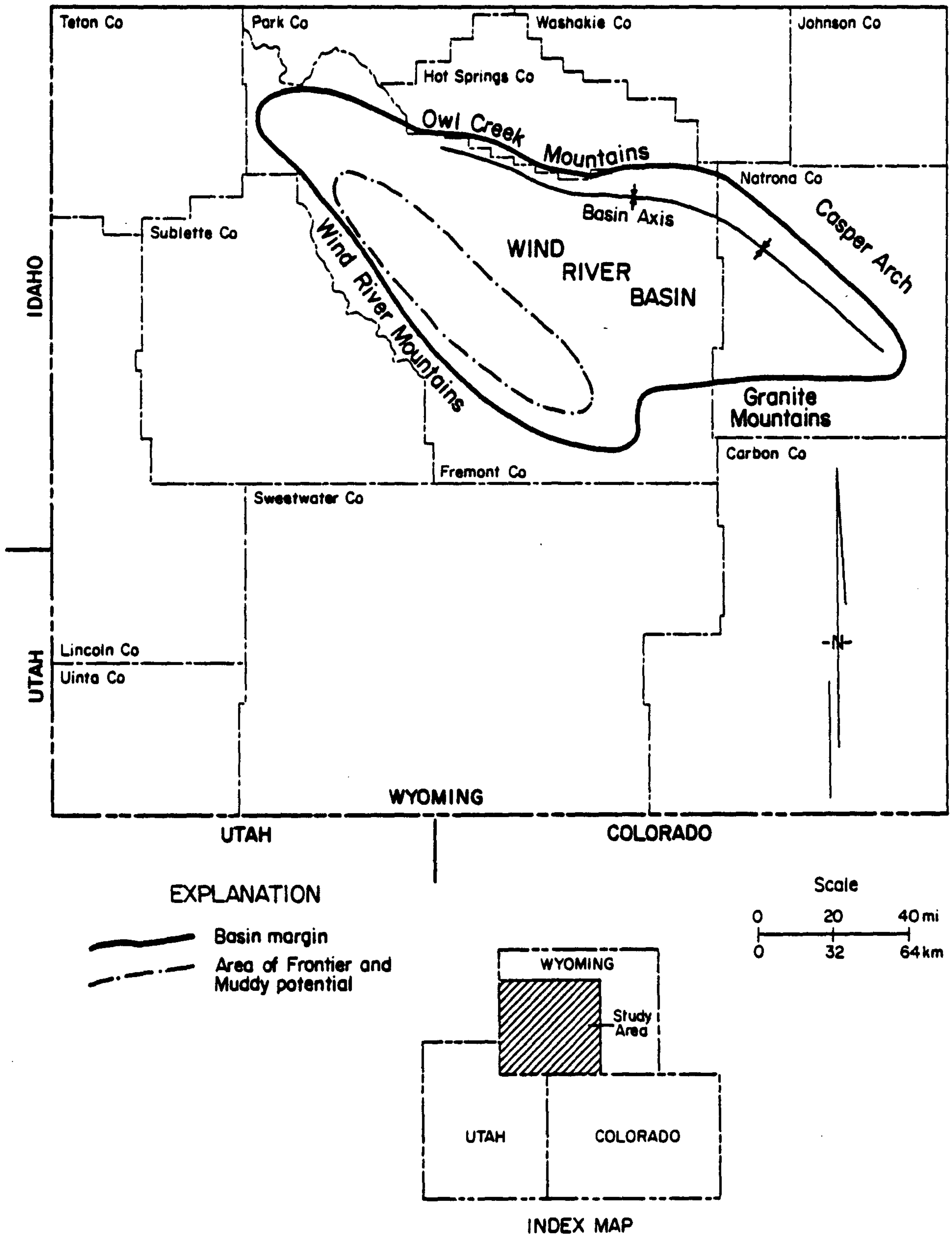

Figure 99. Area of potential tight gas sand resource in the Frontier and Muddy Formations, Wind River Basin (from National Petroleum Council, 1980).

Table 98. 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 = 480 mi^2 (National Petroleum Council, 1980).	Ranges from 580 to more than 1,000 ft.	Ranges from outcrop to 25,000 ft in depth. The average depth to the Frontier in 18 fields which 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 = 1.547 Tcf of 2.035 Tcf gas in place for Frontier and Muddy (National Petroleum Council, 1980) in an area of potential development along the southwest margin of the basin. Kuuskraa and others (1981) estimates 3 Tcf gas in place for the formation with no specific area 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 10-20° northeastward, whereas the strata on the northeastern flank are commonly vertical or overturned.	1.2-2.2°F/100 ft.	0.39 psi/ft based on one value reported as typical, probably in area of shallow production.	Compressional Laramide deformation followed by vertical post-Laramide uplift. Extensive thrusting on all basin flanks.

Table 99. Frontier Formation, Wind River Basin: Geologic parameters.

GEOLOGIC PARAMETERS - Unit/Play

Depositional Systems/Facies	Texture	Mineralogy	Diagenesis
Frontier depositional systems are associated with an eastward, prograding, wave-dominated delta system. Recognizable facies include deltaic 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 thin bedded to massive sandstone beds with shale partings and thin shale streaks. Sandstone grains are mostly subrounded to subangular.	Dominantly quartz with 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 can be expected.

Typical Reservoir Dimensions	Pressure/Temperature of Reservoir	Natural Fracturing	Data Availability (logs, cores, tests, etc.)
For production in 1,400-1,500 ft depth range 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 = 104°F and pressure = 775 psi. However, pressures and temperatures will vary according to depth and some of the deeper Frontier may be overpressured.	No data.	SP-resistivity or GR-resistivity and GR-neutron density are typical logs.

Table 100. 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 ranges from 0.3-0.0033 md, and porosity ranges from 7.0-10.5% for all sands. In the West Poison Spider Field, southeast Wind River Basin, there are four sandstones which are developed. The 1st sandstone is best developed and produces oil with permeability averaging 0.3 md, porosity averaging 7.3%. The other 3 sandstones do not produce and their parameters are: 2nd and 3rd permeability less than 0.01 md, with porosity 3.5-4.3%. There is no analysis for the 4th sandstone.	Net pay thickness in the area of minimum development potential ranges from 10-45 ft. In the West Poison Spider Field, net pay averages 40 ft.	No data.	No data.	No data.	No data.	By analogy to the Frontier Formation in other areas, 40-70% can be 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 this to greater depths.

Table 101. 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, costs are: Drilling: $123,000 per well (1980 dollars). Fracture and Completion: $84,000-$275,000 per well dependent upon size of fracture treatment (1980 dollars).	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 at present.

OPERATING CONDITIONS / EXTRAPOLATION POTENTIAL

Physiography	Climatic Conditions	Accessibility	Extrapolation Potential	Comments
In the Wyoming – Big Horn Basin physiographic subdivision with local relief of 500-1,000 ft in the central area, 1,000-3,000 ft on the southern margin, and over 3,000 ft on the southwestern margin in the Wind River Mountains.	Arid to semiarid with less than 8 inches to approximately 14 inches mean annual precipitation. Mild summers and 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 member.	Worland and Casper, WY, are centers for exploration services for the Wind River Basin. Service to remote areas may incur significant mileage charges.

Table 102. Facies, lithology and geometry of a part of the Frontier Formation, northwestern Big Horn Basin, Wyoming (after Siemers, 1975).

Major Facies	Subfacies	Lithology and Geometry
1) Marine bar and interbar	1) Subaqueous bar	Sandstone, laterally continuous in outcrop but discontinuous regionally
	2) Interbar	Shale, laterally continuous in outcrop but discontinuous regionally
2) Prodelta	(no subfacies)	Sandy shale and v.f. sandstone, locally with good lateral continuity
3) Delta plain	1) Channel	Sand and gravel, laterally discontinuous lenses
	2) Well-drained swamp	Claystone, laterally discontinuous
	3) Poorly-drained swamp	Carbonaceous silty claystone, laterally discontinuous
	4) Splay	Sandstone, laterally discontinuous
4) Delta margin	1) Bioturbated sand and shale	(inadequate data; only one exposure)
	2) Tidal-flat	Sandstone, laterally discontinuous
	3) Marine-influenced channels	Sandstone and rip-up clasts, laterally discontinuous
5) Nearshore marine	1) Transgressive marine	Sandstone, laterally continuous
	2) Transitional marine	Silty and sandy shale and shaly sandstone, laterally continuous in outcrop, but discontinuous regionally

Muddy Sandstone, Wind River Basin

In addition to the Frontier Formation, the National Petroleum Council (1980) lists the Muddy Sandstone as a tight gas sand of blanket geometry within the Wind River Basin. The Muddy is Lower Cretaceous in age and is separated from the Frontier Formation by the marine Mowry Shale (fig. 98). The area of interest for tight gas in the Muddy is coincident with the area of interest in the Frontier (fig. 99).

The Muddy is analogous to the Frontier in that it represents progradational deltaic and interdeltaic shoreline environments, with source areas generally to the west, encased in marine shales (Gopinath, 1978). It is thinner than the Frontier, approximately 120 ft thick in outcrop along the west margin of the Wind River Basin, and consists of fine- to medium-grained sandstone with variable amounts of black shale and siltstone. The facies represented include distal and proximal delta front, shoreface and foreshore of barrier spits and mainland shoreline, lagoonal deposits, tidal flats, and tidal channels (Gopinath, 1978; Dresser, 1974). Delta front facies and the coalescing of barrier beach or barrier spit facies during shoreline progradation would be expected to produce a blanket sand, or a reservoir with moderate to good lateral continuity. The Muddy presents an opportunity to explore a second deltaic depositional system in the same area as the Frontier, but the exact relationships of overlying depositional facies remains to be worked out.

DISCUSSION: GENERIC BLANKET-GEOMETRY SANDS AND EXTRAPOLATION POTENTIAL

Relating selected tight gas sands to their depositional systems and component facies establishes a framework for comparison between stratigraphic units of different ages in different sedimentary basins. Local details of the depositional fill will vary between basins and within basins, but it is the common aspects of genetic facies that have been emphasized in this study. Table 103 lists four categories of clastic depositional systems within which selected formations included in this survey have been distributed. Not included in this list are formations reviewed only for comparative purposes and not as a potential research candidate for GRI. These excluded units are the Cotton Valley Sandstone of the East Texas Basin and the North Louisiana Salt Basin (areally extensive fan delta with marginal marine barrier and bar systems) and the "J" Sandstone of the Denver Basin (deltaic system). Also excluded are a blanket-geometry carbonate sand (Sanostee Member, Mancos Shale, San Juan Basin) and a chalk (Niobrara Formation, Denver Basin), which are fundamentally different in lithology from the other siliciclastic units included in this survey.

Extrapolation Potential

The expected transferability of geologic and engineering knowledge gained in the study of one formation, depositional environment or geographic area may be termed "extrapolation potential." The ability to transfer technology developed as part of the GRI research program will ensure a wider impact of research results on development of the tight gas resource than if genetic similarities between tight gas reservoirs were not considered in advance.

A comment on the extrapolation potential of each major unit has been included in the data tables, and depositional systems have been described in the text. From this

Table 103. Blanket-geometry tight gas sands categorized by major depositional system.

Areally extensive fan-delta and deltaic systems

Tuscarora--Medina--"Clinton" Sandstones, Appalachian Basin
Travis Peak Formation--East Texas Basin and North Louisiana Salt Basin
Frontier Formation (second Frontier)--Greater Green River, Big Horn and Wind River Basins

Deltaic systems and deltas reworked by transgression

Carter Sandstone--Black Warrior Basin
Cleveland Formation (minor part)--Anadarko Basin
Davis Sandstone--Ft. Worth Basin
Olmos Formation--Maverick Basin
Blair Formation--eastern Greater Green River Basin
Berea Sandstone--Appalachian Basin

Barrier-strandplain (dominantly regressive, parts may be deltaic, parts may include offshore bars)

Oriskany Sandstone (transgressive, reworked?)--Appalachian Basin
Hartselle Sandstone--Black Warrior Basin
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 Formation--eastern Greater Green River Basin
Almond Formation (upper part)--eastern Greater Green River Basin

Shelf systems

Cleveland Formation (major part)--Anadarko Basin
Atokan and Des Moinesian Sandstones (including Cherokee Group), Anadarko Basin
Mancos "B"--Piceance Creek Basin
Mancos "B"--Uinta Basin

information it is evident that the marginal marine and marine depositional systems that account for nearly all blanket-geometry reservoirs are deltaic, barrier-strandplain, and shelf systems. The fan delta, an exception to this generalization, is a largely continental environment with a proximal part dominated by braided streams and a distal part wherein a subaqueous delta front develops and sediment may be reworked laterally into barrier and bar sands. Progradation of the fan-delta margin with concurrent marine reworking would tend to improve lateral continuity of the distal part of the fan delta. Within the braided stream facies clastics are relatively coarse, mostly sand to occasional conglomerates, and a lack of mud leads to a higher degree of reservoir continuity than in other fluvial systems. Thus the proximal part of the fan delta is not to be excluded from this survey of blanket-geometry sand bodies.

Areally Extensive Fan-Delta and Deltaic Systems

The Travis Peak Formation of the East Texas Basin and North Louisiana Salt Basin represents an extensive fan delta deposit that is similar to the Tuscarora Sandstone, Medina Group sandstones, and informal "Clinton" sandstones of the Appalachian Basin. Both the Travis Peak and the Tuscarora-"Clinton"-Medina are clastic wedges resulting from major tectonic events. The Travis Peak was derived from tilted rift margin blocks associated with the Jurassic opening of the Gulf of Mexico, and the Tuscarora-"Clinton"-Medina was eroded from source areas tectonically uplifted during the Late Ordovician Taconic Orogeny, a possible consequence of plate collision along eastern North America (King, 1977). Both units show large-scale similarities in facies tracts, grading from proximal, braided alluvial fans with conglomerates and red beds, to distal, deltaic marine margins with possible strandplains and shallow marine deposition of sand (Cotter, 1982; McGowen and Harris, in press). In the Appalachian Basin the developed reservoirs of this clastic wedge are the marginal marine "Clinton" sandstones of Ohio, while the equivalent Tuscarora Sandstone has thus far produced only limited quantities of gas. Gas completions in the Travis Peak are more evenly distributed throughout the trend of the formation, but the full potential of the Travis Peak has, to an extent, been overlooked in favor of other reservoirs, especially 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 which prograded across much of Wyoming. It now is found in the Greater Green River Basin, the Wind River Basin and the Big Horn Basin. The extrapolation potential of the Frontier is both within itself across different Laramide-age basins, and to similar deltaic facies in less extensive deltaic systems. Examples of the latter might be parts of the Carter, Olmos, and Fox Hills Formations and to deltaic components of the Mesaverde Group that are otherwise predominantly barrier, strandplain, and offshore bar sands. Subsurface data from the Frontier are concentrated on structural highs and basin margins, but the unit is also present across extensive, mostly undrilled, deeper basin areas. The potential exists to encourage the development of these deeper areas and to apply research results from the Frontier to other deltaic systems.

Deltaic Systems and Deltas Reworked by Transgression

Among the smaller deltaic systems (table 103) the Davis Sandstone and the Olmos Formation 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 present in the Blair and the Carter deltas are incompletely known, but probably distal to proximal delta front and possibly distributary bars are preserved. The Cleveland Sandstone may have a thin deltaic package at the base of the unit, but grades upward into a shelf deposit. Thus, among the smaller deltaic systems some important variations exist, but 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 upon the degree of marine reworking. Because these deltaic systems are inferred 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 will likely have both deltaic depocenters and deposits reworked along strike within the same formation. Thus the distinction made in this survey between deltaic and barrier-strandplain depositional systems is based on the preponderance of information available for each stratigraphic unit. The Fox Hills Formation is a good example of a stratigraphic unit described as a delta front deposit in one area and a barrier/estuarine deposit in another (Weimer, 1973; Land, 1972). Such differences are expected variations within a regional depositional framework, and may, in fact, be better understood by active explorationists than publicly available information would indicate.

Barrier-Strandplain Systems

Barrier-strandplain systems are frequently cited as the depositional systems for many of the regressive marine sandstones of the Mesaverde Group. The Mesaverde Group is a major regressive wedge of terrigenous clastics deposited in the Late Cretaceous epicontinental seaway. Numerous minor transgressions and regressions during Mesaverde time resulted in intertonguing relationships between sands from a western source and thick marine shales, such as the Mancos. Stratigraphic units within this category include (table 103) the Pictured Cliffs, Point Lookout and Dakota (upper part) Sandstones, the Cozzette and Corcoran Sandstones, probably the Sego and the Castlegate Sandstones, and probably parts of the Fox Hills and Almond (upper part) Formations. The Pictured Cliffs and Dakota Sandstones and the Fox Hills Formation are within the Rocky Mountain region but are not parts of the Mesaverde Group. The barrier sands of the Hartselle occur on a structural platform in the northeast part of the Black Warrior Basin.

Although stratigraphic units in this group are dominantly regressive, two transgressive sands are included among these barrier-strandplain deposits. The Oriskany Sandstone is considered to be of shoreline or shallow marine origin, but its specific facies composition is unknown. Its widespread occurrence supports the concept that it may have been spread laterally by marine transgression. The Cliff House Formation of the Mesaverde Group is definitely associated with marine transgression. The periodic transgressive and regressive cycles of the Mesaverde Group in the San Juan Basin are well defined by cyclically interstratified non-marine, barrier-strandplain and shallow marine clastic sediments (Sabins, 1964; Hollinshead and Pritchard, 1961, among others). Little potential to extrapolate between the Oriskany and the Cliff House is evident, however, primarily due to lack of data on the Oriskany, even though both may be related to marine transgression.

Regressive barrier-strandplain depositional systems in a wave-dominated environment are associated with volumetrically minor deltaic facies as well. Where fluvial channels enter the marine environment a delta front will develop that will merge laterally with the shoreface of barrier-strandplain deposits. Bars may occur 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 becomes important to consider any one study in the regional framework of deposition.

Aside from the Oriskany, the Cliff House, and possible influence of the transgressing Lewis sea on the upper Almond Formation, the remaining 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 transferability of geologic and engineering characteristics of similar facies between these units should be good.

Shelf Systems

The shelf systems included in this survey include two stratigraphic intervals from the Anadarko Basin and the Mancos "B" zone of the Mancos Shale in the Piceance Creek and Uinta Basins (table 103). The Mancos "B" prospective area is substantially the same trend overprinted by the development of two Laramide-age structural basins and the intervening Douglas Creek Arch. Only the Mancos "B" seems to be solely the product of shelf depositional processes wherein silt and very fine to fine sand were dispersed well beyond a marine shoreline. Examination of logs through the Cleveland Formation during this survey suggests that the basal part of the Cleveland may consist of a thin deltaic package including prodelta and delta front facies. The thicker, upper part of the formation represents the shelf deposit. Atokan sands and Des Moinesian sands of the Cherokee Group may also include distal deltaic deposits grading into sediments in equilibrium with shelf processes. Brown and others (1973) point out that probably only a small percentage of cratonic basin sediments are truly of shelf origin and that many deposits on a physiographic shelf may be distal deltaic or derived from strike-fed nearshore systems. This is quite possibly the case for parts of the Cleveland Formation and for the Cherokee Group found on the northern shelf of the Anadarko Basin.

Two shelf units noted in this survey have unique lithologies. The Niobrara is a chalk, and the Sanostee Member of the Mancos Shale consists of highly calcite cemented sandstone and calcarenite, the latter consisting of shell fragments. Because all other tight gas sands examined are siliciclastics, the extrapolation potential of highly carbonate cemented and carbonate sediments is considered poor where mineralogy and diagenetic history have a major influence on reservoir producibility.

Regarding the siliciclastic shelf and (possibly) distal deltaic deposits, the group is relatively small in that only the Mancos "B" and the Cleveland can be considered prospective candidates for further GRI research. The Atokan and Des Moinesian sands are thin (10 to 20 ft in the Red Fork of the Cherokee Group) and occur at depths of 11,000 to 13,000 ft. They are judged to be secondary objectives for most operators in a sequence of multiple Pennsylvanian sand reservoirs.

CONCLUSIONS

Two marginal marine depositional systems, the deltaic system and the barrier-strandplain system, include most of the blanket-geometry tight gas sands considered candidates for future research by GRI. The intracratonic shelf system offers few additional candidates. One stratigraphic unit represents a fan delta with an alluvial plain of braided stream deposits and a marine-reworked distal margin. Lagoonal, estuarine, and tidal flat systems are included in this survey to a minor extent in association with the barrier-strandplain system.

The fluvial system is not represented in this survey because the sands of this system are predominantly lenticular and would tend to form limited multistory or multilateral sand bodies. An exception is the braided, proximal part of the fan delta system that contains sand bodies that tend to be less isolated from each other than in other fluvial systems. This better contact between sand bodies is due to the lack of mud in the braided stream system.

The Lower Cretaceous Travis Peak Formation of the East Texas Basin (and the equivalent Hosston Formation of the North Louisiana Salt Basin) offer opportunities to foster new unconventional gas supplies from a major fan delta. Resulting technology could be transferred to continued development of the Lower Silurian Tuscarora Sandstone and equivalent Medina and "Clinton" sandstones in the Appalachian Basin. The Travis Peak (Hosston) Formation should be considered in more detail.

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 in multiple basinal settings. The Olmos Formation, by analogy to an underlying stratigraphic unit and reference to limited available data, consists of wave-dominated deltas and strandplain deposits representative of several smaller delta systems. The Frontier and possibly the Olmos should be considered in more detail.

The greatest number of stratigraphic units investigated as tight gas sands are dominantly regressive, barrier-strandplain systems. Deltaic and offshore bar sands may be associated with few of these units. Prograding sands of the regressive Mesaverde Group in several basins of the Rocky Mountain region constitute most of this category of depositional systems.

Development of Mesaverde Group sands and of the Pictured Cliffs Formation in the San Juan Basin more represents extension of existing production into adjacent tight areas than does current exploration in the Cozzette and Corcoran Sandstones of the Piceance Creek Basin. The Fox Hills appears to have good reservoir continuity, as does the upper part of the Almond Formation. The Fox Hills is currently productive in only one field, and, because of its good continuity, may require structural closure to form a gas trap. Almond gas production has been more from the non-marine lower Almond than from the blanket-geometry upper Almond. The upper Almond should be examined in more detail along with the Cozzette and Corcoran Sandstones.

The Oriskany Sandstone is tentatively placed with barrier-strandplain systems, but its component facies are poorly known, and it may have been affected by marine transgression. Extensive conventional gas production from the Oriskany is developed within the Appalachian Basin, and virtually no data are available from tight areas.

Shelf deposits of the Cleveland Formation, parts of the Cherokee Group, and Mancos "B" interval of the Mancos Shale are potential research candidates within the shelf depositional system. The Cleveland is thinner than the Mancos "B" and may have a thin deltaic package at its base. The extrapolation potential of studies of shelf systems appears limited because of the limited number of formations in this category; however, the Mancos "B" is probably the best representative of the shelf depositional system.

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