U.S. DEPARTMENT OF THE INTERIOR

U.S. GEOLOGICAL SURVEY

Petroleum Exploration Plays and Resource Estimates, 1989, Onshore United States-- Region 4, Rocky Mountains and Northern Great Plains

By

Richard B. Powers, *Editor*[1]

Open-File Report 93-337

[1]Denver, Colorado

1993

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PETROLEUM EXPLORATION PLAYS AND RESOURCE ESTIMATES, 1989, ONSHORE UNITED STATES-- REGION 4, ROCKY MOUNTAINS AND NORTHERN GREAT PLAINS

Richard B. Powers, *Editor*

INTRODUCTION

By Richard B. Powers

This report, one of a series, provides brief discussions of the petroleum geology, play descriptions, and resource estimates of 48 individually assessed exploration plays in 13 onshore geologic provinces in assessment Region 4 within the continental United States; these 13 onshore provinces were among 80 provinces ,including 220 total plays,that were assessed in connection with the determination of the Nation's estimated undiscovered resources of oil and gas in 1989. The report is an outgrowth of, and is based on, studies that led to the publication of "Estimates of undiscovered conventional oil and gas resources in the United States--A part of the Nation's energy endowment" (Mast and others, 1989). That report, a cooperative effort by the USGS (U.S. Geological Survey) and MMS (Minerals Management Service), presented estimates of undiscovered conventionally recoverable oil and gas for both the onshore and offshore geologic provinces of the Nation. The data sources, assumptions, and methodologies used in the development of these estimates are summarized in Mast and others (1989) and described in more detail in a joint USGS-MMS Working Paper, U.S. Geological Survey Open-File Report 88-373 (1988). The plays discussed in this present report are those that are located exclusively within the onshore United States and where applicable, adjoining State offshore areas, as assessed by the USGS. All estimates of undiscovered oil and gas resources are as of January 1, 1987; additional data received after that date were not incorporated into the assessment.

In the 1989 National appraisal of undiscovered oil and gas resources, plays were the basic unit for quantitative estimates; this report presents not only the play estimates, but also the framework and petroleum geology for each of these basic units. Play discussions here summarize the open-file reports which were prepared by the geologists assigned to each assessment area. We are presenting the resource estimates and narrative descriptions at this basic play level because of the great interest shown by the public, State Geological Surveys, the oil and gas industry, and workers involved in oil and gas appraisal.

Sources of information for province studies included published and purchased data, data from USGS studies in progress, data from previous resource assessments, data from State Geological Surveys, and analysis of geological, geochemical, and geophysical data from various sources utilized in developing and defining plays. Computerized drilling and well completion data from oil and gas exploratory and development wells came from PI WHCS (Petroleum Information Corporation's Well History Control System). In addition, data on oil and gas fields were obtained from the "Significant oil and gas fields of the United States" file of NRG Associates, Inc.,of 1986, and from the PI PDS (Petroleum Data System) computerized file of 1986. Additional statistical information on field production and reserves was obtained from yearly publications of various State oil and gas commissions, or their equivalents.

Uncertainties are inherent in estimating undiscovered quantities of oil and gas. Play estimates presented here are judgmental and are based upon a variety of geologic data, records of exploration successes and failures, production histories, assumptions of economic and technical conditions, and appraisal methods. Methodologies were developed to aid in making decisions under conditions of uncertainty, and the results are presented as ranges of values with associated probabilities of occurrence. The estimates should be viewed as indicators, not absolutes, of the petroleum potential of the plays. The plays range from those in mature, established producing basins, to highly speculative, frontier-type plays in provinces that have experienced scant exploration or wildcat drilling.

COMMODITIES ASSESSED

Commodities assessed in this study are crude oil, natural gas, and natural gas liquids that exist in conventional reservoirs. Terms defined here are standard usage of the oil and natural gas industry and of resource estimation.

Undiscovered recoverable resources.--Resources in undiscovered accumulations analogous to those in existing fields which are producible with current recovery technology and efficiency, but without reference to economic viability. These accumulations are considered to be of sufficient size and quality to be amenable to conventional recovery technology. These resources occupy the area of the heavily framed box in figure 1.

Conventional resources.--Resources included in this category are crude oil, natural gas, and natural gas liquids that exist in reservoirs or in a fluid state amenable to extraction techniques employed in traditional development practices. They occur as discrete accumulations. They do not include oil occurring within extremely viscous and intractable heavy oil deposits, tar deposits, or oil shales, or gas from low-permeability "tight" sandstone and fractured shale reservoirs having *in situ* permeabilities to gas of less than 0.1 millidarcy, coal bed methane, gas in geopressured shales and brines, or gas hydrates.

AREAS OF STUDY

The primary organization of this report is by region (fig. 2); the nine regions described correspond to those in Mast and others (1989). Discussion of each region begins with description of its geologic framework, modified from Mast and others (1989). Discussion of provinces in the region follows; the format for each province includes an introduction covering the geologic setting, exploration history, age of sediments, and a generalized stratigraphic chart. (No stratigraphic chart is provided for a province where no individual plays were assessed; a map of the province is substituted, because no specific stratigraphy is given in that province.) Following each province introduction is systematic discussion of its individual plays. The play format includes the play name, narrative discussion and two illustrations, (1) a province map with the area of the particular play emphasized, and (2) a tabular form showing the original input data for the play appraisal.

Areas of State but not Federal waters are included in the assessment of adjacent onshore regions and provinces where applicable. The boundaries of State waters are 3 nautical miles offshore for the Pacific and Atlantic coasts and for the Alabama coast of the Gulf of Mexico. Louisiana and Mississippi have decreed State water boundaries that vary slightly from 3 nautical miles. For the Texas and Florida coasts of the Gulf of Mexico, the boundaries of State waters are 3 marine leagues (10.36 statute miles) offshore. In addition, all maritime boundaries and limits depicted on maps in the report are for initial planning purposes only, and do not prejudice or affect United States jurisdiction in any way.

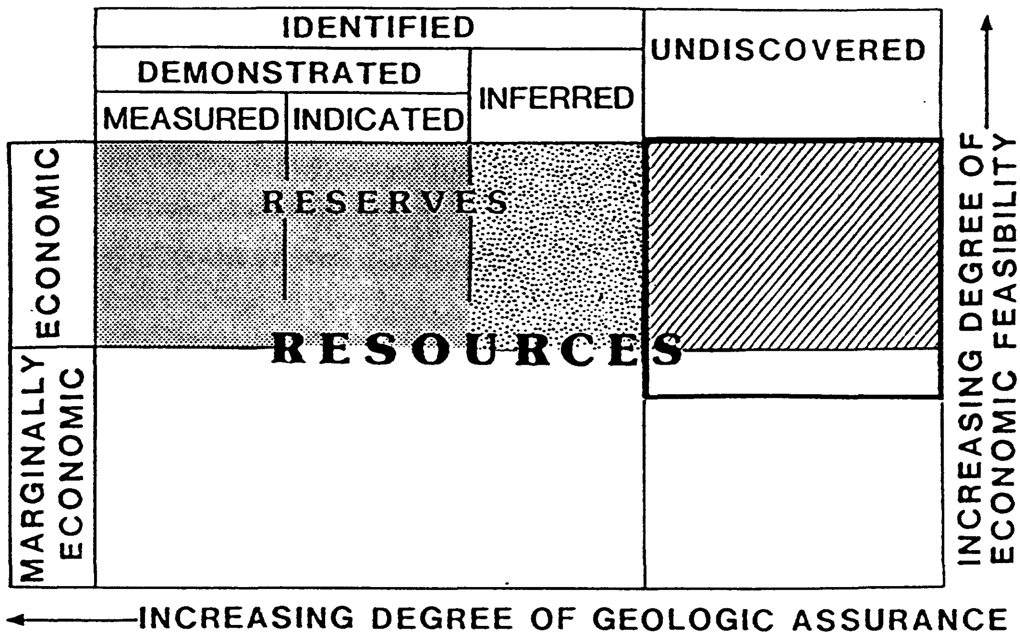

Figure 1. Diagrammatic representation of petroleum resource classification (Mast and others, 1989) representing conventional oil and gas resources. Area with heavy frame on upper right represents undiscovered recoverable resources estimated in this study.

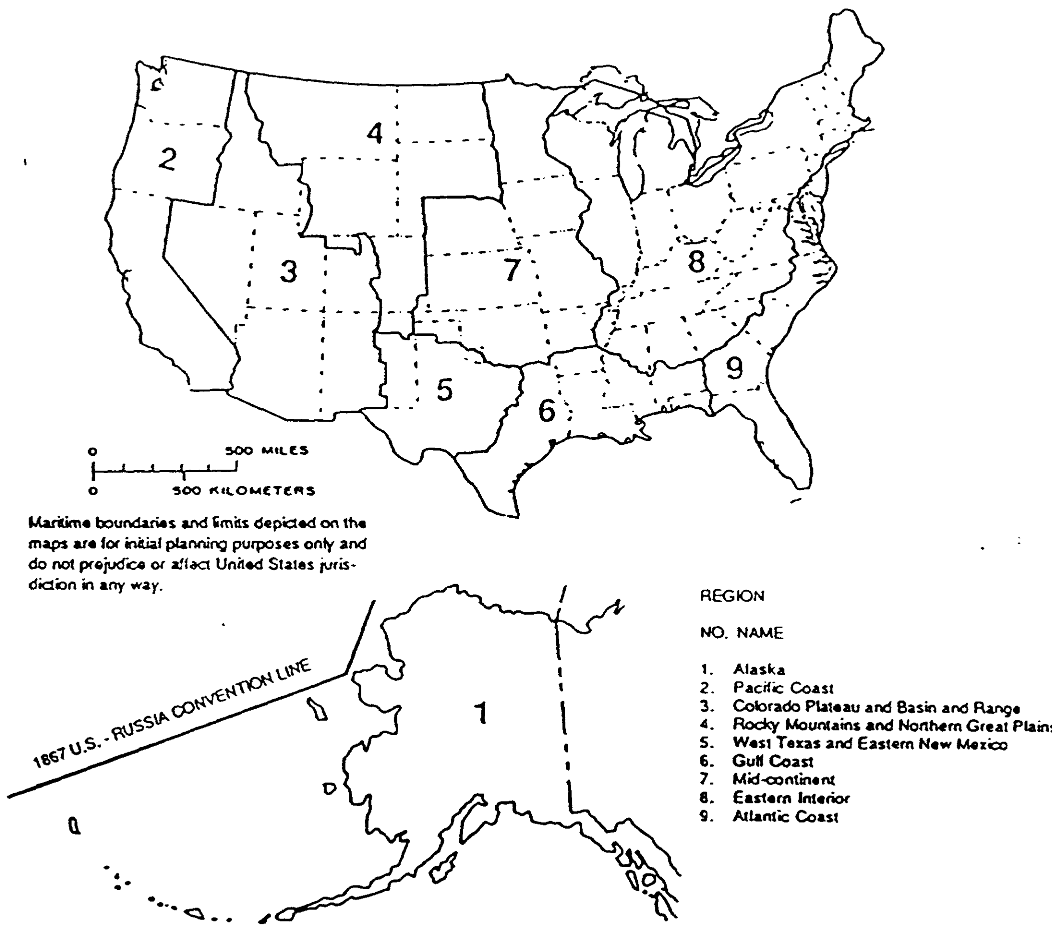

Figure 2. Map showing petroleum regions assessed in this study. Heavy lines are region boundaries, dotted lines are State boundaries.

Regions are basically geographic in character; however, their outlines reflect an attempt to group individual provinces along broad geologic lines. Provinces are constructed around natural geologic entities and may include a single dominant structural element, or a number of contiguous elements; they are named for structural or geographic features within their boundaries. These boundaries, following State and county lines wherever possible, facilitate the use of production, reserve, and other reported data. A play is named after the most dominant feature or characteristic of a structural, stratigraphic, or geographic nature that best identifies it. Its name can also apply to a concept. Many plays described herein are recognized from their titles by the petroleum industry, but play titles are in no way formal geologic or stratigraphic names.

PLAY DISCUSSION FORMAT

Individual plays described and assessed in this report include only those that were estimated to have undiscovered accumulations greater than 1 MMBO (million barrels of oil) or 6 BCFG (billion cubic feet of gas). Plays judged to have undiscovered accumulations that fell below that threshold were assessed separately for the provinces as a whole, and are not described in the report . A play is defined as a group of geologically related known, or undiscovered, accumulations and (or) prospects having similar characteristics of hydrocarbon source, reservoir, trap, and geologic history.

In order to achieve some degree of consistency in narrative discussions of a great number and variety of plays, a topical outline based on the definition of an exploration play has been used. Each play discussion notes the play characteristics, followed by descriptions of (1) reservoirs, (2) source rocks and related geochemistry, (3) timing of generation and migration of hydrocarbons, (4) traps (types, sizes, seals, and drilling depths), (5) exploration status (history, discovered volumes, field sizes, and hydrocarbon types), and (6) qualitative future hydrocarbon potential and factors limiting that potential. Although the discussions adhere to the order of the topical outline, it will be apparent that some inconsistency occurs in the amount of detail and coverage of each topic from one play to another. This is due to the relative abundance or lack of data pertinent to each play and is unavoidable in a report of this scope. Play discussions here are, of necessity, brief summaries. More detailed play information can be found in the province open-file reports, which are listed in the references at the close of each region. The number of individually assessed plays in each province ranges from 1 to as many as 13; however, most provinces contain 3-5 plays. Each play title is followed by a sequence number (for example, Topset Play (020)), and these also appear on the table of resource estimates at the close of each region.

ASSESSMENT PROCEDURES AND METHODS

Assessments of undiscovered recoverable oil and gas in the individual plays in each province, and resources in small (< 1 MMBO or < 6 BCFG) accumulations were based upon review and analysis of the petroleum geology and exploration history of each province that incorporated the most recent geologic and geophysical information available as of January 1, 1987. In the National assessment, 220 plays covering the onshore and State offshore areas were identified, and for each individually assessed play, undiscovered oil and gas resources were estimated. Plays judged to contain more than 1 MMBO or 6 BCFG were individually assessed; plays judged to contain less than those amounts were treated differently, as described following . See Mast and others (1989) and USGS/MMS (1988) for a detailed discussion of the National assessment, its assumptions, methods, and results.

In the play analysis method, geologic settings of oil and gas occurrence are modeled. The play is treated as a collection of accumulations (pools, fields) of similar geologic risk sharing common geologic characteristics that include reservoir and source rocks and known or suspected trapping conditions. A team of geoscientists made judgments as to the probability of the occurrence of those geologic factors necessary for the formation of hydrocarbon accumulations, and quantitatively assessed each factor as a geologic attribute of the play; the team then estimated the numbers and sizes of accumulations as probability distributions, conditional on favorable play attributes. All of this information was entered on the play data input form which is included in each play discussion in this report. A computer program then performed the resource calculations on the basis of the assessment information in the input form, employing an analytical method based on probability theory. Final, undiscovered oil and gas estimates for each play, based on this method, are shown on a table of estimates at the end of the discussion for each region.

Probabilistic estimates of recoverable oil and gas in accumulations smaller than the established size cut-off (1 MMBO, 6 BCFG) were made separately. These estimates of small accumulations were based primarily on log-geometric extrapolations of numbers of fields into field-size classes smaller than the cut-offs. Estimates of undiscovered resources for these small fields were made for the province as a whole, rather than for the individual plays. These are shown in the tables of estimates as: Oil < 1 MMB and Gas < 6BCF. In addition, minor plays and very mature, or nearly depleted plays not assessed individually are included in the tables of estimates as: Other Occurrences > 1 MMBO and Other Occurrences >6 BCFG. Ratios of associated-dissolved gas to oil, and NGL (natural gas liquids) to gas, were estimated from historical production data and used for calculation of these components.

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GLOSSARY

Play.--A group of geologically related known or undiscovered accumulations and (or) prospects having similar characteristics of hydrocarbon source, reservoir, trap and geologic history.

Field.--A single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.

Prospect.--A geologic feature having the potential for trapping and accumulating hydrocarbons.

Crude oil.--A mixture of hydrocarbons present in underground reservoir rocks in a liquid state that remains in a liquid state as it is produced from wells.

Associated gas.--Free natural gas, occurring as a gas cap, in contact with and above an oil accumulation within a reservoir.

Dissolved gas.--Natural gas dissolved in crude oil within a reservoir.

Nonassociated gas (NA).--Natural gas that is neither associated with nor in contact with crude oil within a reservoir.

Natural gas liquids (NGL).--Those portions of reservoir gas that are liquified at the surface in lease separators, field facilities, or gas processing plants. NGL is reported only in the tables of estimates in this report.

MMBO.--Millions (10^6) of barrels of oil (standard stock tank barrels of crude oil, 42 gallons per barrel).

BBO.--Billions (10^9) of barrels of oil.

BOPD.--Barrels of oil per day.

BCFG.--Billions (10^9) of cubic feet of gas (standard cubic feet of gas at 14.73 pounds per in^2 and 60°F). Hydrocarbon gases only.

TCFG.--Trillions (10^{12}) of cubic feet of gas.

MMBOE.--Millions of barrels of oil equivalent (conversion factor utilized is 6,000 ft^3 =1 BOE).

REGION 4--ROCKY MOUNTAINS AND NORTHERN GREAT PLAINS

GEOLOGIC FRAMEWORK

By Richard B. Powers

Region 4 is subdivided into 13 provinces, numbers 094-106 (fig. 3). The total number of individually assessed plays in these provinces is 48. The Sioux Arch province (095) is included in the Williston basin province (094) assessment, but is treated as a separate discussion. The region is characterized by some 19 Laramide intermontane sedimentary basins, such as the Powder River and Bighorn basins, which are separated by major uplifts; the intracratonic Williston basin, several Paleozoic paleostructural elements, and the western Montana salient of the Cordilleran thrust belt.

Exploration in this region during the past 125 years has resulted in the finding of major reserves of oil and gas, including the discovery of at least 18 giant fields. Most of the larger fields are structurally controlled; however, more recent exploration has led to the discovery and development of numerous stratigraphic traps. Future hydrocarbon potential varies considerably within individual provinces, but region-wide, substantial amounts of undiscovered resources remain. Region 4 also contains large volumes of gas in unconventional ("tight gas sand") reservoirs.

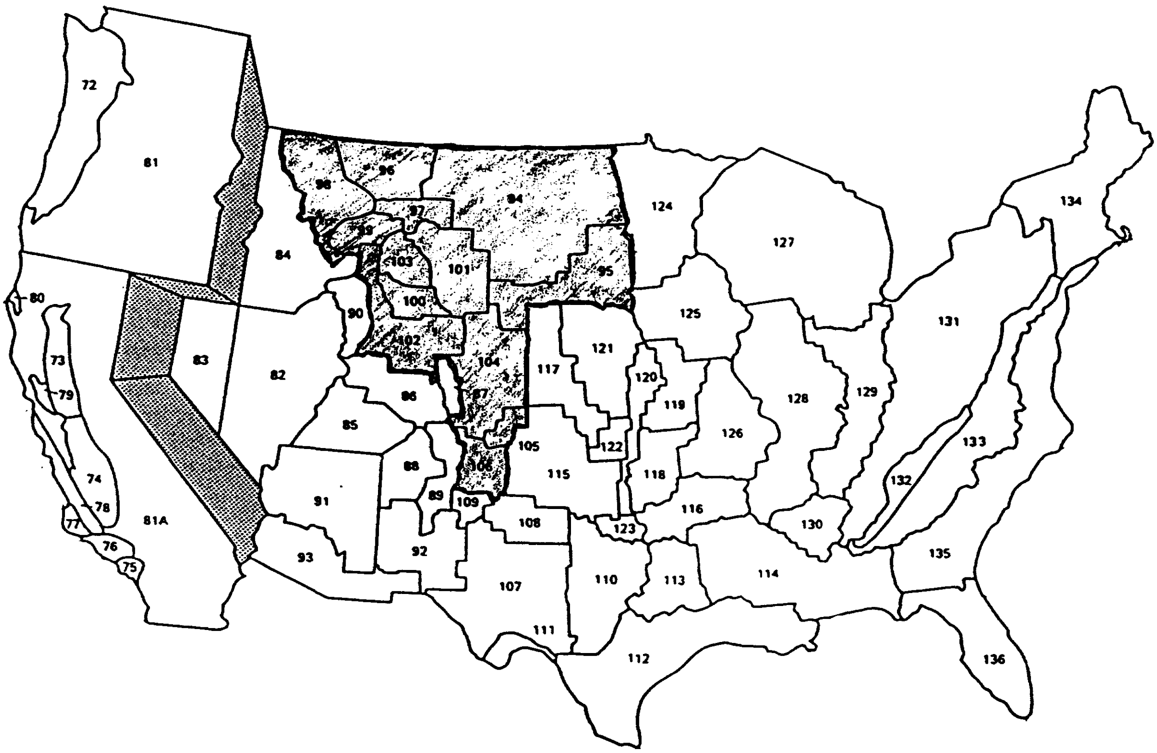

Figure 3. Index map of lower 48 states showing provinces assessed in Region 4 (shaded). Names of provinces are listed by number in the Table of Estimates.

WILLISTON BASIN PROVINCE (094)

By James A. Peterson

INTRODUCTION

The Williston basin is a structural and sedimentary intracratonic basin located on the western shelf of the Paleozoic North American craton in the United States and adjacent parts of Canada. The province area includes the present-day United States part of the basin, which occupies a large segment of the northern Great Plains physiographic province and includes most of North Dakota and parts of Montana and South Dakota. The basin is bordered on the east and southeast by the Canadian Shield and the Sioux Arch. The western and southwestern borders are defined by the Black Hills uplift, Miles City arch, Porcupine dome and Bowdoin dome. The U.S. part of the basin covers approximately 143,000 mi^2, with a total sedimentary rock volume of approximately 202,000 mi^3. Maximum sedimentary rock thickness is greater than 16,000 ft in the deepest part of the basin in northwestern North Dakota. As of 1987, more than 6,000 exploratory wells had been drilled and over 680 oil fields found in the basin. Productive and prospective petroleum intervals are mainly Paleozoic in age and include carbonate reservoirs of (in order of importance) Mississippian, Ordovician, Devonian and Silurian age and sandstone reservoirs of Ordovician, Mississippian, Pennsylvanian, and Triassic age (fig. 4).

Four plays were defined and individually assessed in the province: Northeast Basin (020); Red River (030); Post-Madison (040); and Madison-Upper Devonian (050). A deep basin gas play, now in its early stages of exploration, is also recognized. However, because of difficulties at present in isolating this play from the Red River play, which includes deeper production in the basin, it was assessed with the Red River play.

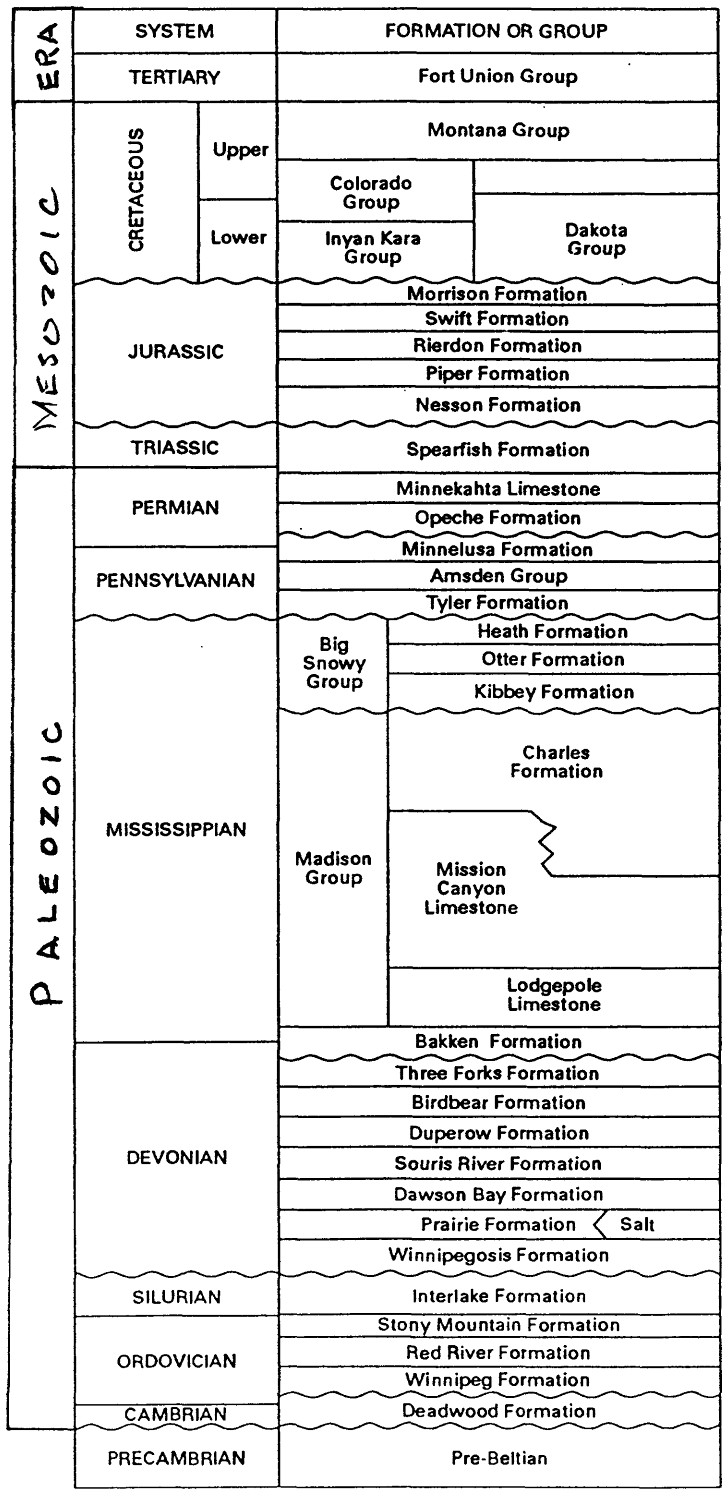

Figure 4. Generalized stratigraphic column, Williston basin province.

NORTHEAST BASIN PLAY (020)

The play is characterized by oil accumulations in updip stratigraphic changes, pinchouts, and truncation of Cambrian through Permian reservoir beds beneath a Mesozoic unconformity, and basal Triassic sandstones above the unconformity. The play area is approximately 6,400 mi^2 (fig. 5). The main part of the play includes the area where updip facies changes of dolomitized skeletal and oolitic carbonate rocks of the Mississippian Madison Group grade eastward to anhydrite, and anhydritic and denser carbonates (fig. 4). Progressively older beds are truncated by Mesozoic clastic rocks from west to east toward the eastern margin of the basin. Similar stratigraphic relationships are present along the entire eastern margin of the basin, but south of the play area in north central North Dakota, Madison and older reservoirs are hydrodynamically flushed by waters from the Black Hills uplift in South Dakota.

Reservoirs are mainly dolomitized oolitic, crinoidal or bioclastic Madison carbonate beds that range from 10 to 500 ft or more in thickness. Porosity and permeability range from 3 to 5 percent and from 1 to 2 md and occasionally higher. Updip, truncated dolomite beds of good reservoir quality are also present in the Ordovician Red River, Silurian Interlake and Devonian Duperow Formations. No production has yet been obtained from these units, probably because of vertical communication with overlying Madison carbonate reservoirs and lack of good source rocks in pre-Madison beds. Basal Triassic (Spearfish) sandstones are moderately porous, but oil accumulations in these reservoirs depend on communication with underlying Madison reservoirs.

Organic-rich shale and siltstone of the Mississippian-Devonian Bakken Formation are thermally mature downdip in the basin, below a depth of approximately 4,000 to 5,000 ft. These rocks, as well as other organically-rich black shales, cyclically interbedded with carbonate and evaporite units in the Mississippian Mission Canyon and Charles Formations downdip, are the main source of oil in the play. Downdip oil generation probably began during Middle or Late Cretaceous time coincident with updip migration and accumulation.

Traps are located mainly on gentle folds and other structural closures, some of which are related to draping of overlying beds on carbonate buildups and others to basement structure. Stratigraphic traps formed updip are common as individual oil accumulations or associated with structural traps. Seals are mainly anhydrite units interbedded with carbonate reservoirs, or impermeable shales immediately above the Mesozoic unconformity. Drilling depths range from 3,000 to 7,000 ft.

The play is moderately well explored, although down-flank and other stratigraphic traps, mostly of small accumulation size, are as yet undiscovered. As of 1987, approximately 75 oil fields had been discovered, almost all of which produce from Madison reservoirs. Most of the fields are 1-2 MMBO or less in size, six are greater than 5 MMBO and the largest is 20 MMBO. Future potential for oil and associated gas is low and probably in fields of less than 5 MMBO in size.

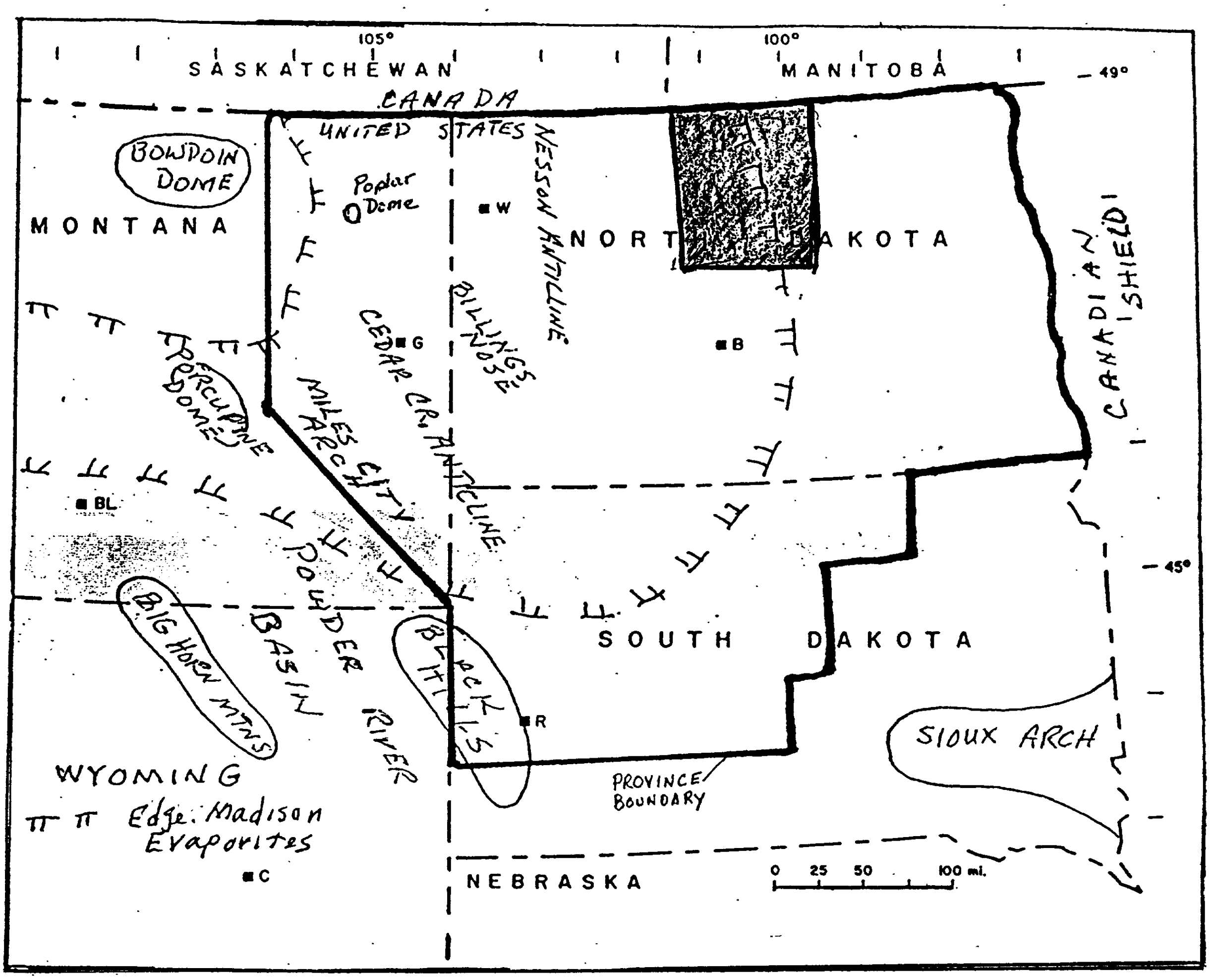

Figure 5. Map of Northeast basin play.

OIL AND GAS PLAY DATA

PLAY NORTHEAST BASIN
PROVINCE WILLISTON BASIN CODE **04-094-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.01**	**1.1**	**1.2**	**1.6**	**3.5**	**13**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**3**			**5.5**			**7**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**1**	**2**	**4**	**5**	**7**	**12**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**300**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

RED RIVER PLAY (030)

The play is characterized by oil and associated gas accumulations in reservoirs associated with carbonate mound or bank buildups in the Upper Ordovician Red River Formation. Oil accumulations also occur in Ordovician Stony Mountain carbonate reservoirs, dolomite reservoirs of the Silurian Interlake Formation, and in carbonate reservoirs of the Middle Devonian Winnipegosis and Souris River Formations, which are also included in the play. Most of the latter accumulations are probably the result of vertical migration from underlying Red River source rocks and reservoirs (fig.4). Boundaries of the play are primarily stratigraphic, and are based on two regional evaporite seals, the Middle Devonian Prairie salt and Upper Ordovician anhydrite beds that are cyclically interbedded with carbonate reservoirs and source rocks. The play area is approximately 41,000 mi^2 (fig. 6). Recently, significant gas and gas-condensate accumulations have been found in both Red River carbonate reservoirs and sandstone reservoirs in the Winnipeg Formation in the deeper part of the basin. These resources are part of the deep basin gas play that was included in the assessment of the Red River play.

Reservoirs of Ordovician age are dolomite and dolomitic limestone commonly occurring in gentle mound or bank buildups with a high bioclastic content Thicknesses of reservoirs range from 5 to 500 ft or greater and porosity and permeability range from 2 up to 30 percent and from 2 up to 50 md.. Silurian reservoirs are porous or fractured dolomite in reefoid or tidal flat facies. They vary in thickness from 20 to 400 ft. Porosity ranges from 1 up to 15 percent and permeability ranges from 1 to 20 md. Middle Devonian (Winnipegosis) reservoirs are small dolomitized reef or mound buildups capped by the Prairie salt. Reservoir thickness and quality are highly variable. A high exploratory success ratio has been achieved in identifying these carbonate buildups with the use of high-resolution seismic techniques, particularly in the upper Red River Formation.

The main source rocks are organic-rich marine shales cyclically interbedded with carbonate and anhydrite beds of the upper Red River (fig.4). Dark gray marine shale in the Souris River Formation are a probable secondary source. Dark gray to black marine shale in the Winnipeg and upper Deadwood Formations may be an important source of deep basin gas. Source rocks probably reached maturity by late Paleozoic time, and hydrocarbons migrated into early-formed stratigraphic traps, probably coincident with generation. However, the main tectonic features of the basin were in place by late Paleozoic or early Mesozoic time. Drainage into the main structures from the central basin generating area was an equally important factor.

Major traps in the Red River Formation are associated primarily with the Cedar Creek anticline, which contains more than 50 percent of the proven reserves in the play, and to a lesser extent with the Nesson anticline and Billings nose (fig. 6). Many small, productive traps are on gently draped, rootless folds associated with carbonate mound or bank buildups. Seals in the main Williston basin area are evaporite beds in the upper Red River or Middle Devonian Prairie Formation; however, these evaporites are not present on the Cedar Creek anticline. Traps in the Red River here are sealed by overlying Devonian or Mississippian argillaceous carbonate and shale beds. Drilling depths range from 7,000 to 15,000 ft. The play is well explored, but the future potential for small to medium sized accumulations is good. In addition, there is also a significant future potential for deep basin gas.

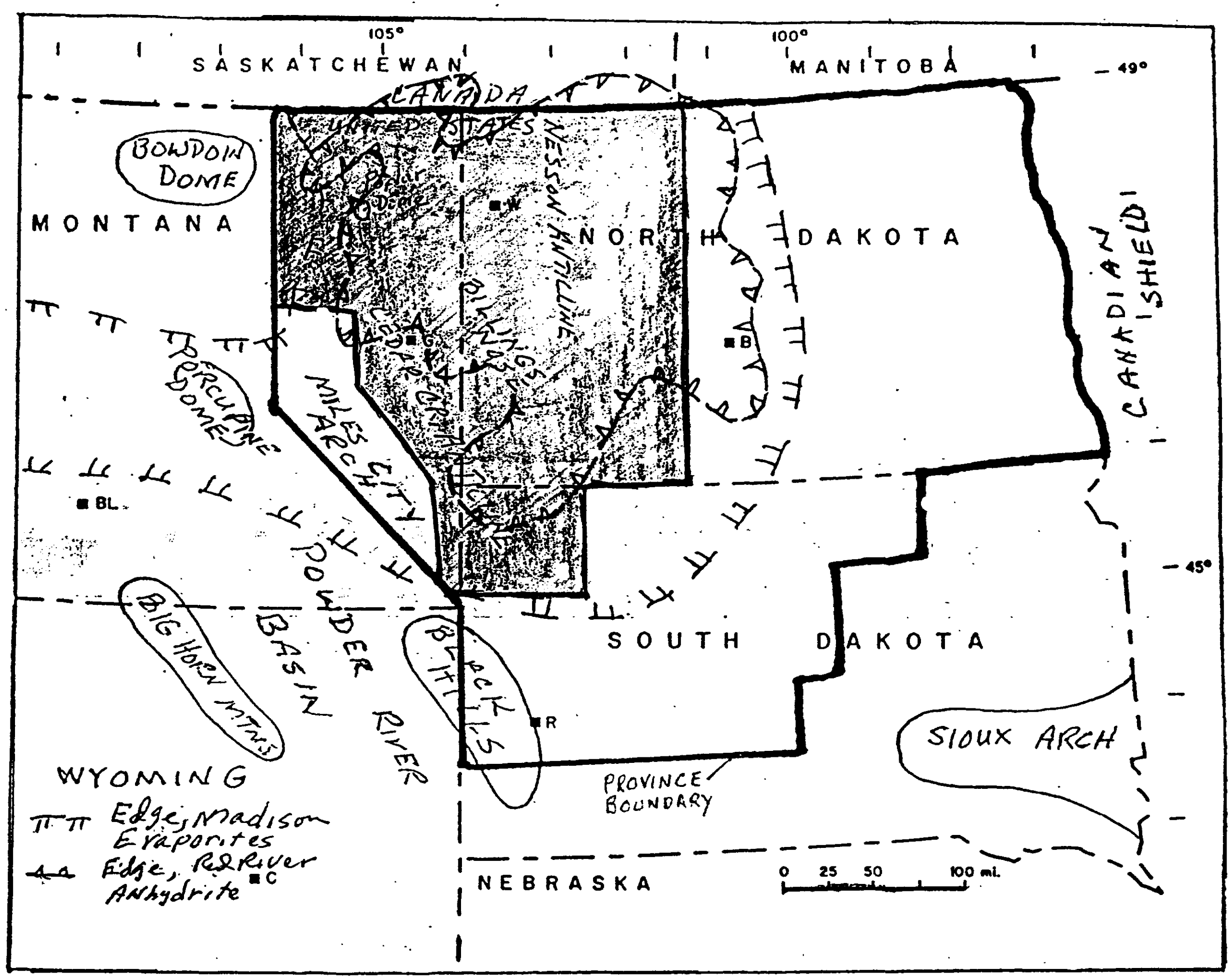

Figure 6. Map of Red River play.

OIL AND GAS PLAY DATA

PLAY **RED RIVER**
PROVINCE **WILLISTON BASIN** CODE **04-094-030**

Play attributes	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.9**
Gas	**0.1**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.03**	**1.2**	**1.5**	**2.2**	**6**	**20**
Gas (x 10^9 CFG)	**6**	**6.1**	**7**	**8**	**12**	**23**	**42**
Reservoir depth (x10^3 ft)							
Oil	**8**			**11**			**13**
Gas (non-associated)	**9**			**13**			**14**
Number of accumulations	**40**	**60**	**80**	**100**	**117**	**133**	**150**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**40**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

POST-MADISON PLAY (040)

The play is defined by oil and minor gas accumulations in stratigraphic and structural traps in mainly deltaic and alluvial sandstone, shale, and minor carbonate and minor rocks of primarily marine origin in the Upper Mississippian Big Snowy Group and the Pennsylvanian Tyler Formation. The play area covers approximately 27,000 mi^2.(fig.7). The overlying sequence of Upper Pennsylvanian, Permian, and Triassic redbeds, sandstones, and minor carbonate rocks are part of the play, although there is no hydrocarbon production in this section. The Big Snowy and Tyler, the main section of interest, is present only in the central part of the Williston basin.

Primary reservoirs are discontinuous marine or deltaic sandstone beds in the lower part of the Big Snowy Group and the basal part of the Tyler; carbonate reservoirs in the Heath Formation and in the Amsden Group are of secondary interest. Sandstone reservoirs in the Tyler are 5-10 ft in thickness and up to 25 ft thick in sandstone lenses. Porosity ranges from 5 to 10 percent and up to 20 percent in local sandstone buildups. Permeability ranges from 10 to 15 md and up to as high as 1,000 md in sandstone lenses.

Source rocks are dark gray and black, organic-rich marine shale in the Tyler Formation and black, organic-rich shale and argillaceous carbonate in the Heath Formation. These rocks reached maturity and generated hydrocarbons by late Mesozoic or early Tertiary time in the deeper central part of the Williston basin.

Stratigraphic traps were formed early, mainly by sandstone depositional processes. Anticlinal traps with stratigraphic influences were formed prior to early generation and migration with only minor late structural modification. Seals are present in both the Tyler and Heath sections. Drilling depths range from 4,000 to 8,000 ft.

The play is moderately well explored. Fifteen oil fields have been discovered in the play; of these, six are greater than 5 MMBO in size, and the largest is 25 MMBO in size. The fields are mostly on anticlines with a strong stratigraphic trapping component. Cumulative production from all fields is approximately 65 MMBO. Because the major exploration effort has concentrated on deeper prospects, almost all wells drilled have penetrated the main section of interest without substantial success. Future potential for oil resources is low and estimated to be in small stratigraphic accumulations.

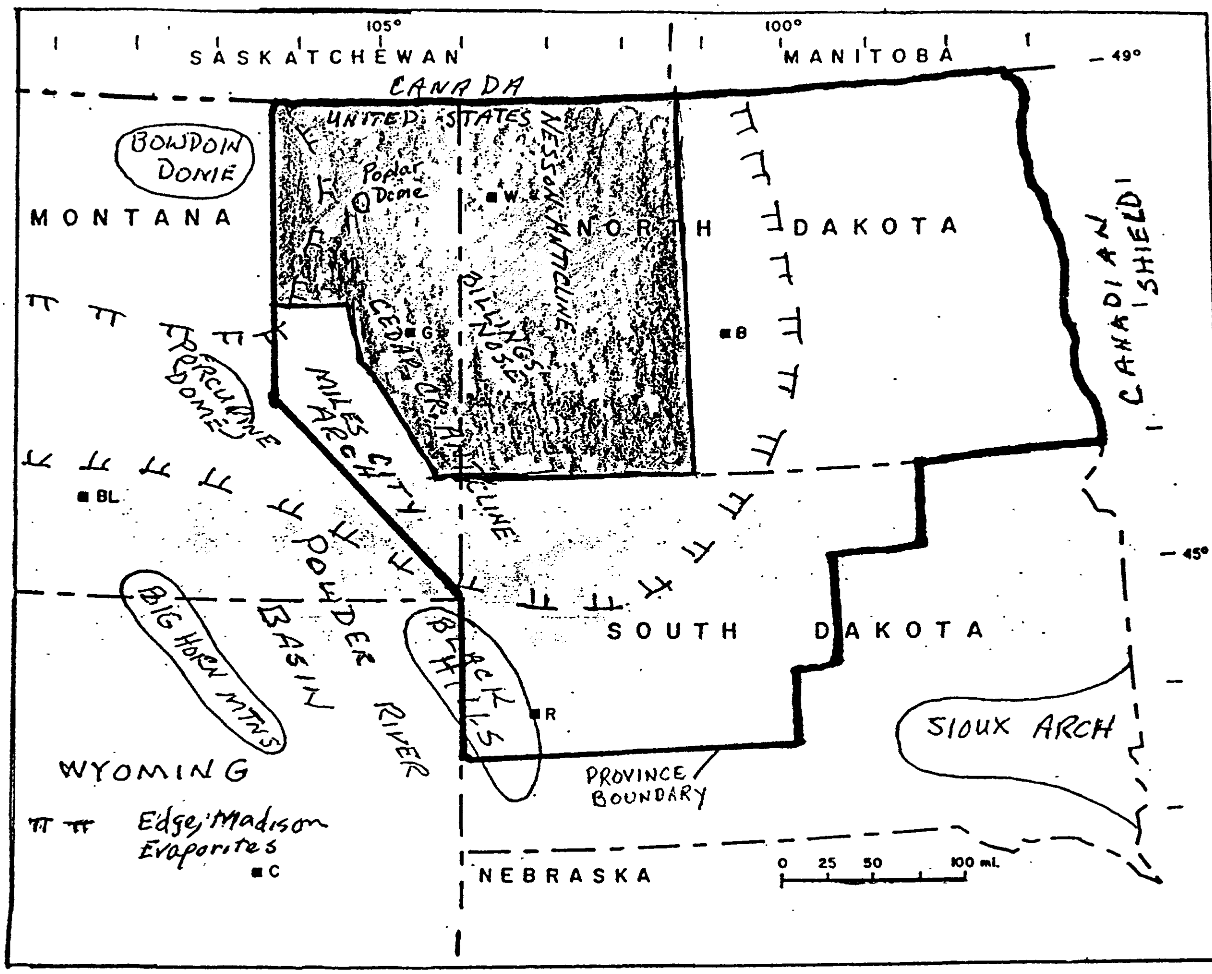

Figure 7. Map of Post-Madison play.

OIL AND GAS PLAY DATA

PLAY **POST-MADISON**
PROVINCE **WILLISTON BASIN** CODE **04-094-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.80**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.01**	**1.1**	**1.2**	**2**	**3.7**	**5**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**4**			**6**			**8**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**2**	**3**	**5**	**6**	**10**	**15**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**100**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

MADISON-UPPER DEVONIAN PLAY (050)

This major play is characterized by oil accumulations in Madison Group dolomite reservoirs related to gentle folds formed by carbonate bank buildups. In addition, oil in Upper Devonian dolomite reservoirs occurs in stratigraphic traps. The play area is approximately 41,000 mi^2 (fig. 8). Although the play is principally stratigraphic, structural closure, in part related to draping of overlying beds over carbonate buildups, is usually associated with producing oil fields.

Known productive reservoirs are primarily dolomite associated with oolitic, crinoidal, or bioclastic bank or mound buildups within carbonate-evaporite cycles, mainly in the Mission Canyon Limestone and Charles Formation of the Mississippian Madison Group. Upper Devonian reservoirs are porous dolomite beds in carbonate-evaporite cycles of the Duperow and Birdbear (Nisku) Formations. These reservoirs range from 10 to 100 ft or greater, locally. Porosity ranges from 3 up to 30 percent, and permeability ranges from 1 up to 50 md or greater. Other productive reservoirs are siltstone, sandstone, or dolomite interbedded with organic-rich shale in the middle part of the Mississippian-Devonian Bakken Formation. Reservoir quality is fair to good in most of these reservoir rocks.

Identified and probable source rocks are organic-rich shale and siltstone of the Bakken Formation, and black to dark-gray marine shale and argillaceous carbonate rocks in the Mississippian Lodgepole Limestone, Mission Canyon Limestone, Charles Formation, and the Devonian Duperow Formation (fig. 4). Shale in the Bakken averages approximately 11 percent total organic carbon, is predominantly sapropelic, and mature over a large portion of the central Williston basin. Shale in the Lodgepole contains 1 percent or more total organic carbon. Oil generation began in Madison Group rocks and the Bakken Formation by middle or latest Cretaceous time and probably is continuing at the present. In most cases, migration was probably coincident with generation, with some adjustment related to late structural growth.

Traps are formed mainly on gentle folds and other structural closures related to carbonate bank buildups, which are overlain by cyclically interbedded anhydrite beds in the Mission Canyon Limestone and Charles Formation. Seals include a number of cyclically interbedded anhydrite beds and a major seal of salt and anhydrite in the Charles Formation. Updip stratigraphic traps related to facies changes are common on the larger producing structures; the largest fields in the play are located on the Nesson anticline in the central area of the Williston basin in North Dakota and on Poplar dome in Montana (fig.8). Drilling depths range from approximately 5,000 to 13,000 ft.

As of 1986, approximately 425 Madison-Upper Devonian fields had been discovered with an average size of 3.1 MMBO and 1.2 BCFG. Approximately 35 of the fields are greater than 10 MMBO in size and five are greater than 50 MMBO. Estimated cumulative production is 750 MMBO. About 40 percent of the proved reserves in the play are in Mission Canyon reservoirs on the Nesson anticline and Poplar dome.

Although the play is moderately well explored, continued application of high resolution seismic data may result in numerous additional new field or new pool discoveries related primarily to accumulations in stratigraphic traps. Substantial reserves may also be added by the application of present and future technology advances in horizontal drilling in the Bakken Formation, and in selected Madison and Devonian carbonate reservoirs. Future potential for oil and associated gas is good; undiscovered accumulations will probably be in the small- to medium-size category.

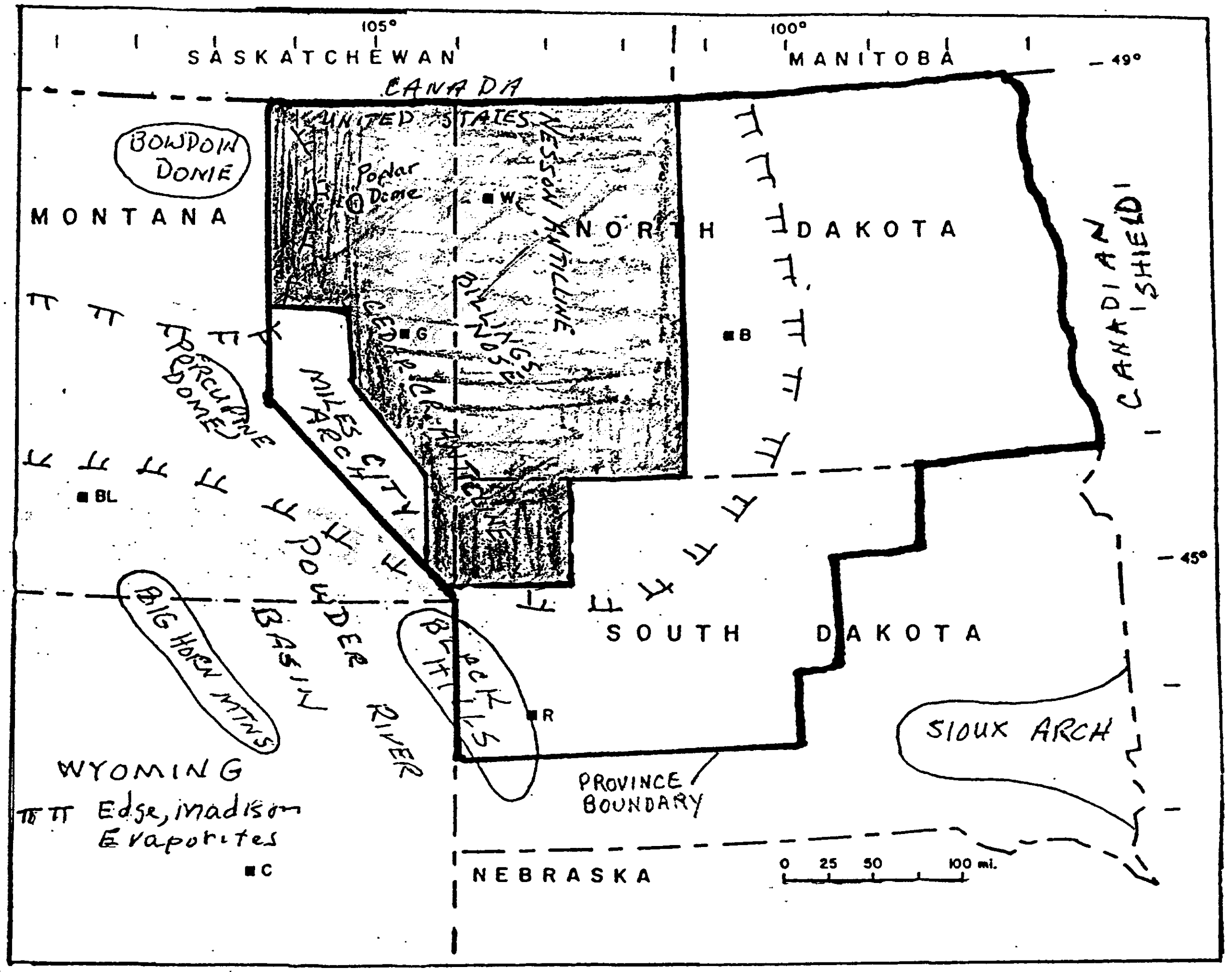

Figure 8. Map of Madison-Upper Devonian play.

OIL AND GAS PLAY DATA

PLAY **MADISON-UPPER DEVONIAN**
PROVINCE **WILLISTON BASIN** CODE **04-094-050**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

Fractiles * (estimated amounts)

Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.1**	**1.3**	**2**	**4**	**10**	**30**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**5**			**10**			**12**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**20**	**25**	**33**	**40**	**50**	**72**	**100**

Average ratio of associated-dissolved gas to oil (GOR)	**400**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

SIOUX ARCH PROVINCE (095)

By James A. Peterson

The Sioux Arch province is located in eastern South Dakota immediately southeast of the Williston basin province (094) and covers an area of approximately 40,000 mi^2. No plays were individually assessed in the province. Three tectonic subdivisions are recognized in or adjacent to the province from west to east, the Siouxia uplift (or Sioux ridge), the Kennedy basin, and the northern part of the Chadron arch (fig. 9). Paleozoic and early Mesozoic rocks pinch out eastward beneath Cretaceous rocks in the western part of the province, and Precambrian rocks are exposed on the Siouxia uplift. Thickness of the total sedimentary cover is less than 5,000 ft, and Cretaceous rocks are less than 2,000 ft thick in most of the province, pinching out against exposed Precambrian rocks on the Siouxia uplift.

Unconventional gas in Cretaceous chalk and shelf sandstone reservoirs sealed by enclosing marine shale is the main potential resource in the province. Organic-rich, low-porosity, shaly Cretaceous carbonate beds are also probable reservoirs as well as probable source rocks for biogenic gas. However, these source rocks have probably not been buried deep enough throughout the province to reach the level of oil generation. Traps may be both stratigraphic and structural, and undiscovered small conventional gas accumulations may occur primarily in stratigraphic traps in thicker Cretaceous sandstones. Two extensive chalk units and shelf sandstones, which may be more localized in the eastern and western parts of the province, might contain potential reservoirs. Depth to prospective reservoirs is generally less than 2,000 ft.

The province is relatively unexplored and any hydrocarbon potential is speculative. The potential for any appreciable oil or gas resources in the province is considered remote and is based on analogy with gas production in shelf sandstones of the western Williston basin and Cretaceous chalk of the northeastern Denver basin. However, some small, isolated undiscovered accumulations of less than 1 MMBO or 6 BCFG may be present. Resources in this category were assessed in the aggregate with the Williston basin province (094) assessment.

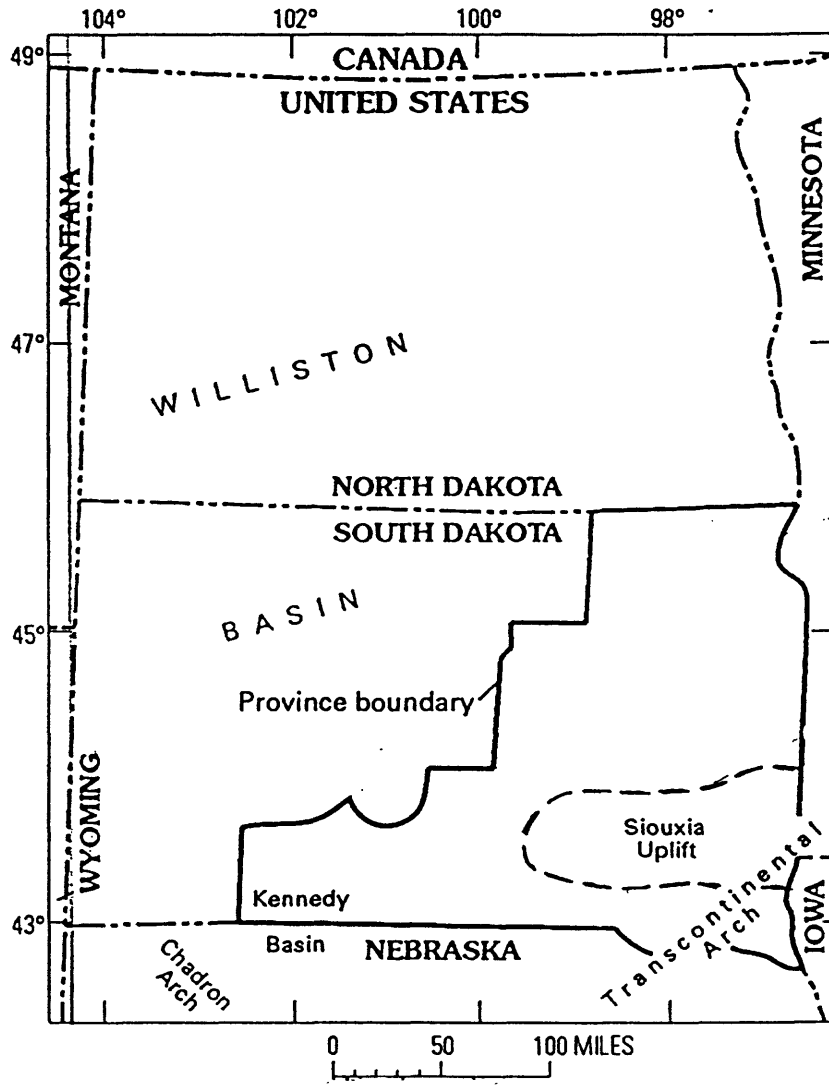

Figure 9. Map of Sioux Arch province.

SWEETGRASS ARCH PROVINCE (096)

By Thaddeus S. Dyman

INTRODUCTION

The Sweetgrass arch province lies within the state of Montana; it is approximately 250 mi. long from east to west and 150 mi. wide from north to south. It is bounded by the Montana disturbed belt to the west, the central Montana trough to the south, the Williston basin to the east, and the Alberta shelf and the United States-Canadian border to the north. Other features included in the province are the south Sweetgrass arch (South arch), Kevin-Sunburst and Bowdoin domes and Bearpaw uplift. The province has been actively explored for hydrocarbons since 1903 when oil was discovered in adjoining Alberta, Canada (Medicine Hat field). Of the 124 discovered fields in theprovince, 31 are greater than 1 MMBOE in size and are productive from an average depth of 2,150 ft. Cumulative production in the province is greater than 340 MMBO and 1,175 BCFG since the 1919 discovery of the Cat Creek field in Petroleum County, Montana. Late Precambrian through Tertiary strata occur in outcrop and in the subsurface in the province (fig. 10) and are grouped into three plays that were individually assessed: Upper Cretaceous (020), Jurassic-Cretaceous (030), and Devonian-Mississippian (030).

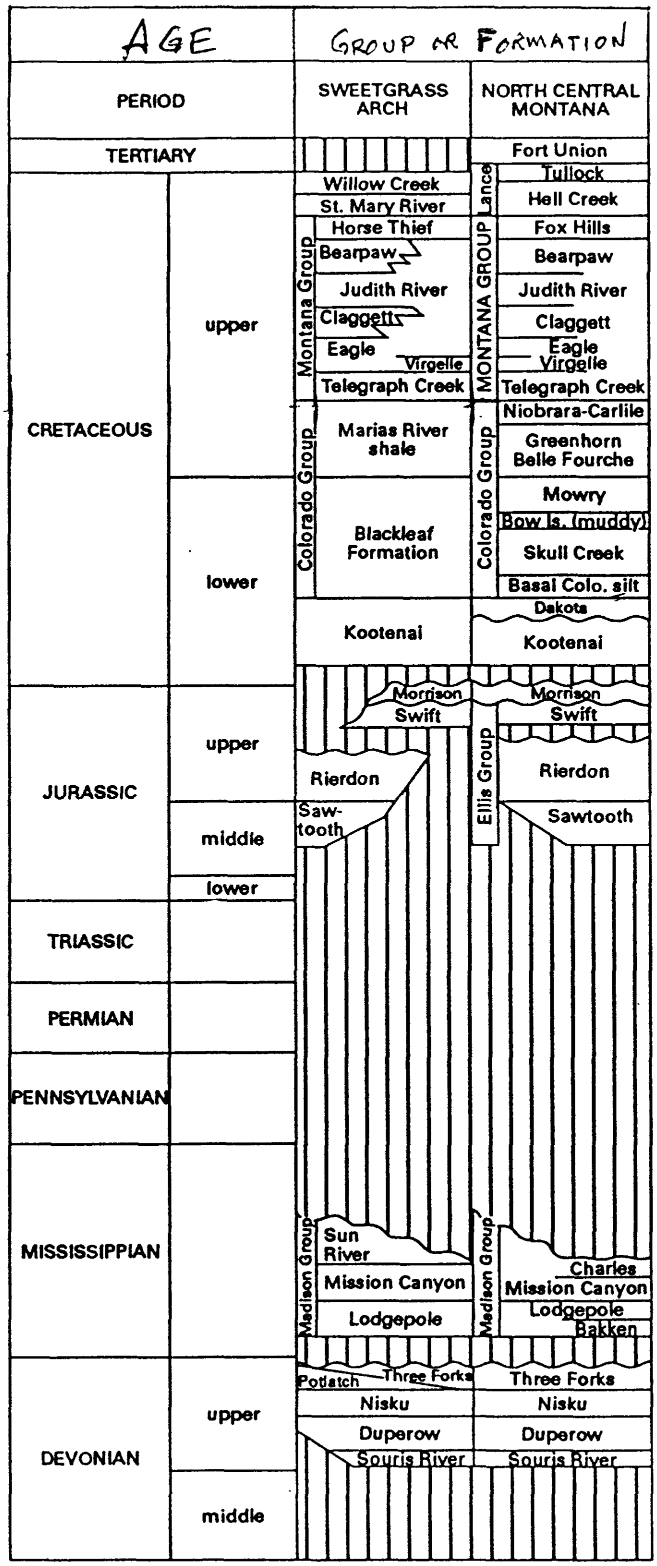

Figure 10. Generalized stratigraphic columns, Sweetgrass Arch province

UPPER CRETACEOUS PLAY (020)

The Upper Cretaceous is a biogenic gas play and is characterized by accumulations in shallow, low permeability reservoirs in predominantly clastic rocks of the Montana Group, although similar reservoirs in the lower Upper Cretaceous Blackleaf Formation and equivalent strata are included (fig. 10). Boundaries of the play are defined by the distribution of Late Cretaceous strata. Montana Group rocks are generally absent along the axis of the Sweetgrass arch in the western part of the province due to Tertiary erosion. The western boundary of the play extends along a north-south line defining the western limit of Late Cretaceous strata (fig. 11). Upper Cretaceous strata vary in thickness from less than 1,000 to more than 3,000 ft within the play area.

Sandstone reservoirs are generally less than 3,000 ft deep and were deposited in both marine and nonmarine depositional environments. The best gas accumulations are in Upper Cretaceous reservoirs in shoreface sandstones that are more permeable. Tiger Ridge field in Hill and Blaine Counties (fig. 11) produces gas from regressive shoreface sandstones reservoirs in the Eagle Sandstone. At Bowdoin dome in Phillips County (fig. 11), production is from thin bedded, low-permeability sandstone reservoirs in the Carlile Shale. Reservoirs in a low-permeability marine chalk facies of the Greenhorn Formation, which is approximately equivalent to the the Marias River Shale, produce some gas at the north end of the Bowdoin field.

Late Cretaceous source rocks were generally not buried deep enough for oil generation in northern Montana. Most Late Cretaceous gas is methane-rich and formed from the breakdown of organic matter by anaerobic bacteria at relatively low temperatures.

Stratigraphic trapping of gas within the chalks may be due to permeability barriers related to facies changes and to the distribution of fracture systems; however, many Upper Cretaceous stratigraphic traps are, in part, structurally controlled.

Tiger Ridge field is a representative example of the Upper-Cretaceous biogenic gas play. The field was discovered in 1966 as the result of an offset from a dry hole that bottomed in the Madison Group. At present, 83 wells produce methane-rich gas from the Eagle Sandstone and Judith River Formation in a field area of approximately 52,000 acres. Production occurs at an average depth of 1,600 ft in a 45-foot pay zone that has an average porosity of 26 percent. By January 1987, more than 75 BCFG was produced from the field. The play is moderately explored in the more favorable areas and the future potential for undiscovered gas is fair, but limitations exist because of economic considerations associated with low permeability reservoirs, and many potential reservoirs are considered unconventional.

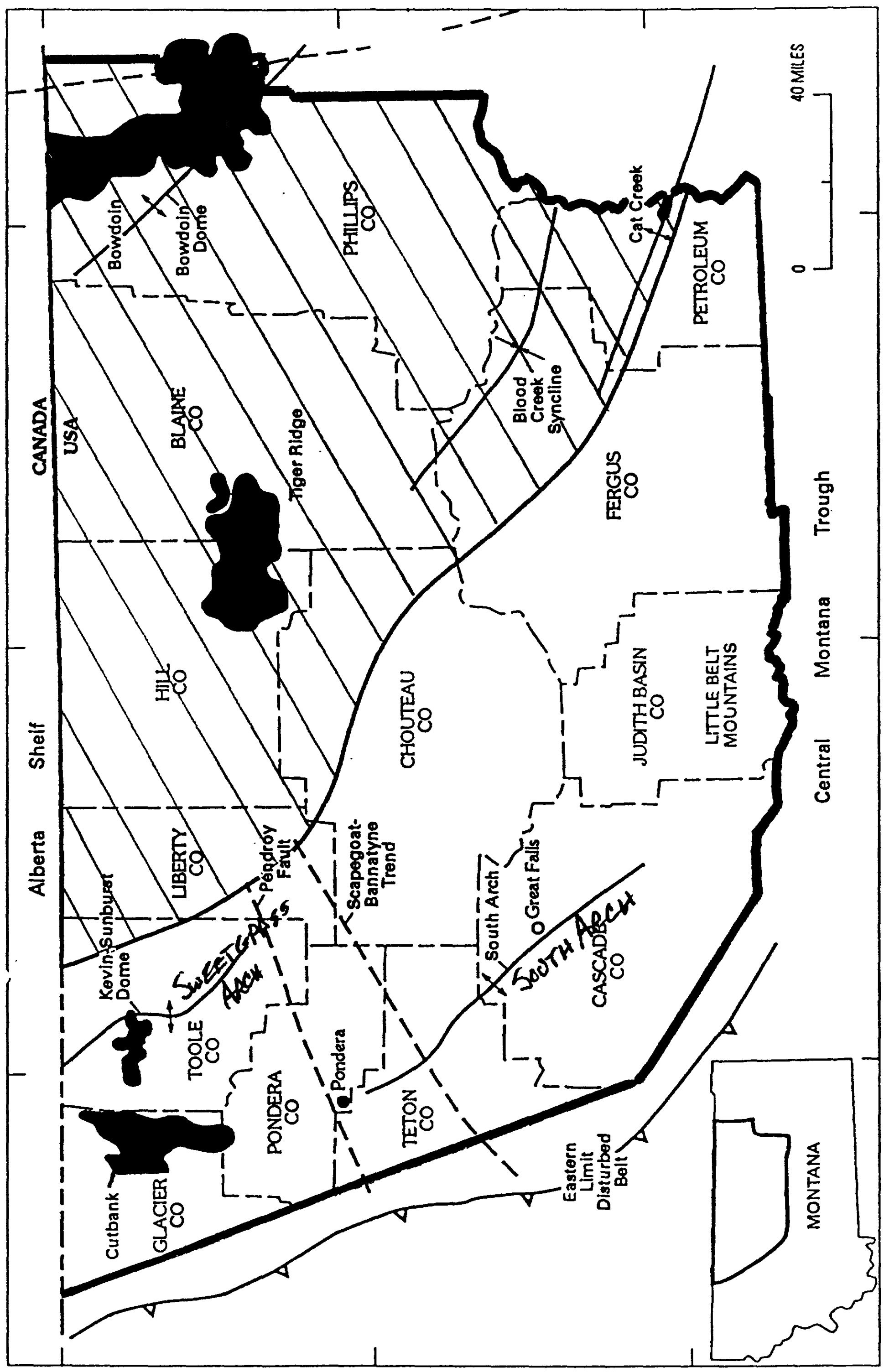

Figure 11. Map of Upper Cretaceous play

OIL AND GAS PLAY DATA

PLAY **UPPER CRETACEOUS**
PROVINCE **SWEETGRASS ARCH** CODE **04-096-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas ($\times 10^9$ CFG)	**6**	**6.5**	**9**	**14**	**25**	**40**	**70**
Reservoir depth ($\times 10^3$ ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**0.5**			**2**			**4**
Number of accumulations	**1**	**2**	**4**	**6**	**9**	**14**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

JURASSIC-CRETACEOUS PLAY (030)

The play is defined by oil and gas accumulations mainly in stratigraphic traps, locally affected by structure, in fluvial and deltaic sandstone reservoirs of Jurassic-Cretaceous age. The play covers most of the area of the province, about 250 mi east-west and 115 mi north-south, except for the Little Belt Mountains (fig. 12). It includes predominantly clastic rocks of the Jurassic Sawtooth, Swift, and Morrison Formations, the Lower Cretaceous Kootenai Formation, the Lower and Upper Cretaceous Colorado Group, and the Upper Cretaceous Montana Group (fig. 10). These strata vary in thickness from approximately 1,500 to 2,500 ft in the play, but are thin on the Sweetgrass arch. Cretaceous strata are absent in the play from the southern part of the Sweetgrass arch to the Little Belt Mountains, and their zero edge forms the southwestern boundary of the play. The base of the Jurassic section varies in depth from 1,000 to 5,000 ft. Jurassic and Cretaceous strata are combined in the play because of similarities in depositional environment and facies, trapping mechanisms, and source rocks.

The best reservoir rocks include fluvial to nearshore marine sandstones of the Swift, Sawtooth, Morrison, Kootenai, Blackleaf, and Marias River Formations and their stratigraphic equivalents (fig. 10). Jurassic reservoirs of the Sawtooth and Swift Formations occur in generally lenticular, laterally discontinuous marine sandstones. Permeability barriers associated with environments of deposition, diagenetic alteration of sandstones, and Laramide folding and faulting affect the quality of reservoirs. Kootenai sandstone reservoirs are well developed and of good quality where they are adjacent to and sealed by flood plain and interdistributary mudrocks with reduced porosity. Fluvial and deltaic sandstones of the Blackleaf Formation (Vaughn Member) in the western part of the play and to the south in southwestern Montana are rich in volcanic detritus and are of poor reservoir quality.

The most important source rocks are dark-gray phosphatic shale of Jurassic age, and dark-gray shale in the Kootenai, Blackleaf, and Marias River Formations and their stratigraphic equivalents (fig.10). Generally, the organic material in these shale beds is thermally immature except where buried to greater depths near the disturbed belt or near Tertiary intrusives and volcanic rocks. Total organic carbon values average 2.4 wt percent for the Marias River Shale (Cone Member) in the disturbed belt near Glacier National Park in Glacier County, and vitrinite reflectance values average 0.6 percent along the crest of the Sweetgrass arch.

Major traps are primarily stratigraphic and were filled with hydrocarbons migrating updip from source rocks in deeper parts of the disturbed belt. The relative importance of stratigraphic versus structural factors in trap definition for Cretaceous strata is difficult to define. Updip shale beds form effective seals in the Jurassic-Cretaceous section. Drilling depths range from 1,000 to 6,000 ft.

The play has been moderately explored, in part, because of early attention to surface oil seeps and subsequent discoveries at shallow depths (usually less than 2,500 ft). Twenty-two significant oil and gas fields have been found in the play since the 1919 discovery at the Cat Creek field. Cutbank field in Glacier and Toole Counties, Montana (fig. 12) is one of the largest fields in the play. The field was discovered in 1926 and has produced more than 40 MMBO and 500 BCFG from fluvial and deltaic sandstone reservoirs of the Kootenai Formation (Cutbank Sandstone). One hundred and eighty-seven wells produce from an average depth of 3,000 ft in the field, which covers more than 65,000 acres. The most productive gas reservoir, the Cutbank Sandstone, was deposited in a widespread fluvial system; the sandstone pinches out against Jurassic strata on the east to form a large stratigraphic trap. Sandstone reservoirs of the Blackleaf

Formation, and its equivalents, are generally less productive than sandstone reservoirs in the Kootenai Formation. Future potential is estimated to be low for oil and moderate for gas.

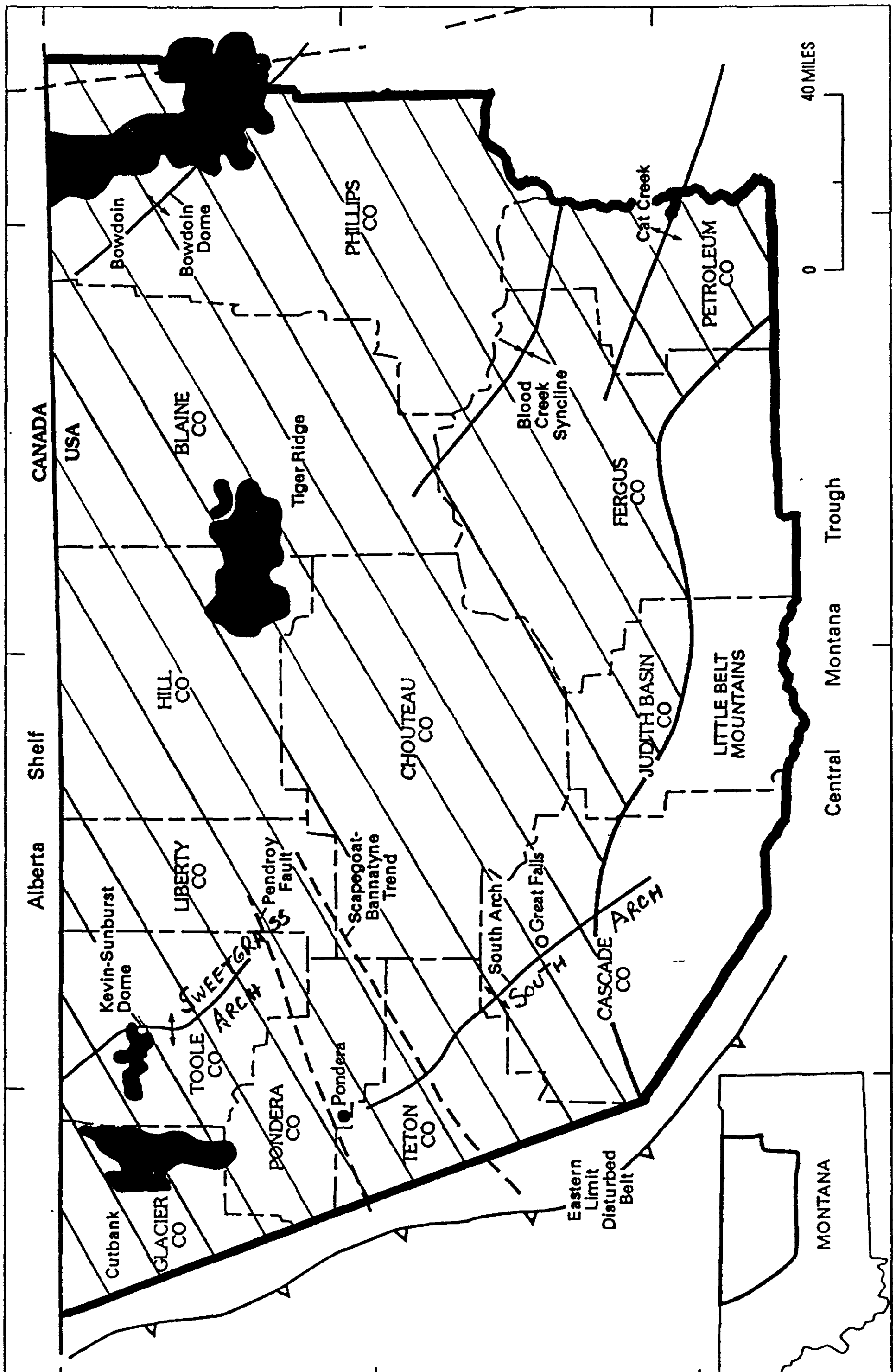

Figure 12. Map of Jurassic-Cretaceous play

OIL AND GAS PLAY DATA

PLAY **JURASSIC-CRETACEOUS**
PROVINCE **SWEETGRASS ARCH** CODE **04-096-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0.5**
Gas	**0.5**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.4**	**2**	**3.2**	**7**	**16**
Gas (x 10^9 CFG)	**6**	**6.6**	**7**	**10**	**15**	**25**	**50**
Reservoir depth (x10^3 ft)							
Oil	**1**			**3**			**6.5**
Gas (non-associated)	**1**			**3**			**6.5**
Number of accumulations	**7**	**9**	**12**	**15**	**20**	**28**	**40**

Average ratio of associated-dissolved gas to oil (GOR)	**1500**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

DEVONIAN-MISSISSIPPIAN PLAY (040)

The play is characterized by oil and gas accumulations in carbonate and clastic reservoirs of Devonian-Mississippian age in both structural and stratigraphic traps. The play includes (1) Devonian carbonate strata of the Souris River, Duperow, Nisku, Potlatch, and Three Forks Formations throughout the 250 mi x 150 mi area of the province (fig. 13); (2) shale and sandstone of the Bakken Shale, especially in the eastern part of the province; and (3) predominantly carbonate rocks of the Mississippian Madison Group (fig. 10). The play extends throughout the area of the province although rocks vary in reservoir quality and thickness. Late Devonian strata are included in the play because of similarities in reservoirs, source rocks, and trapping mechanisms. Devonian and Mississippian strata vary in total thickness from approximately 1,000 to 2,500 ft.

Known reservoir rocks include (1) dolomite facies within carbonate-evaporite cycles of the Devonian Nisku Formation; (2) thin sandstones and fractured beds in the Bakken Shale; and (3) oolitic and bioclastic carbonate banks and karst zones in the Mississippian Madison Group (fig. 10). Dolomitization probably associated with nearshore salinity variations within Devonian reservoirs is greatest along a line trending northwestward from the Little Belt Mountains. Widespread paleokarst reservoir intervals in the middle and upper part of the Madison Group are the result of post-Mississippian erosion. In addition, dolomitized subtidal carbonate banks within the Madison Group are excellent quality reservoirs where they are interbedded with supratidal anhydrite. Productive zones in reservoirs vary from 10 to 32 ft in thickness.

Source rocks include black organic-rich shale in the Bakken Shale, shale in the Three Forks Formation (Sappington Member), Lodgepole Limestone and Heath Formations (fig. 10). The Heath is the uppermost unit in the Big Snowy Group which overlies the Madison Group and occurs in the central Montana trough immediately south of this province. Vitrinite reflectance values vary from 0.49 to 0.55 percent in Heath shale in southern Fergus County, Montana, indicating that they are thermally immature and are at or immediately below the oil generation window. In the Williston basin (province 094), organic matter in the Bakken Shale is primarily sapropelic kerogen and averages 11 percent total organic carbon. These source rocks are generally thermally mature to immature in the central part of the play, but are overmature in the disturbed belt to the west. In the western part of the play Devonian and Mississippian hydrocarbons were generated and migrated eastward from source areas within the disturbed belt.

Stratigraphic traps are the result of selective dolomitization of limestones, facies barriers in carbonate- evaporite sequences, and paleosol and karst systems. Most traps have been enhanced by Laramide folding and faulting. Oil being produced from several Jurassic Sawtooth fields may have been generated in Mississippian source rocks in places where Jurassic resrvoirs unconformably overlie Sun River (Madison) dolomite reservoirs. Many Madison traps (e.g. Pondera Field, fig. 13) are strongly influenced by Laramide faulting and folding. Drilling depths to the top of the Devonian varies from approximately 2,700 to 6,700 ft but the average depth is generally less than 5,000 ft. Evaporite and shale sealing beds are present in the Devonian-Mississippian section.

Hydrocarbons have been produced in the play since 1922 when oil was discovered in the Madison at the Kevin Sunburst field (fig. 13). Eight fields greater than 1 MMBO in size have been found up to the present time that produce from Madison reservoirs. Typical of these is the Pondera field complex, discovered in 1927, that produces from a 90-ft thick pay zone in a paleokarst dolomite reservoir in the Sun River at an average depth of 1,950 ft. Reservoir porosity in the field averages 14 percent and oil gravity is 32° API. A total of 360 wells had been completed in a field area of 7,600 acres and greater than 22 MMBO had been produced to the end of 1986. The Mississippian section is moderately well explored in the northwestern corner of the play, but Devonian production, to date, has been limited to two small Nisku Formation accumulations in the Kevin Sunburst field complex that produce less than 20 BOPD. Oil shows have been reported in the Nisku from several wildcat wells in the southern part of the Sweetgrass Arch area in the 1980's. Future potential for oil is moderate and low for gas, mainly in smaller fields.

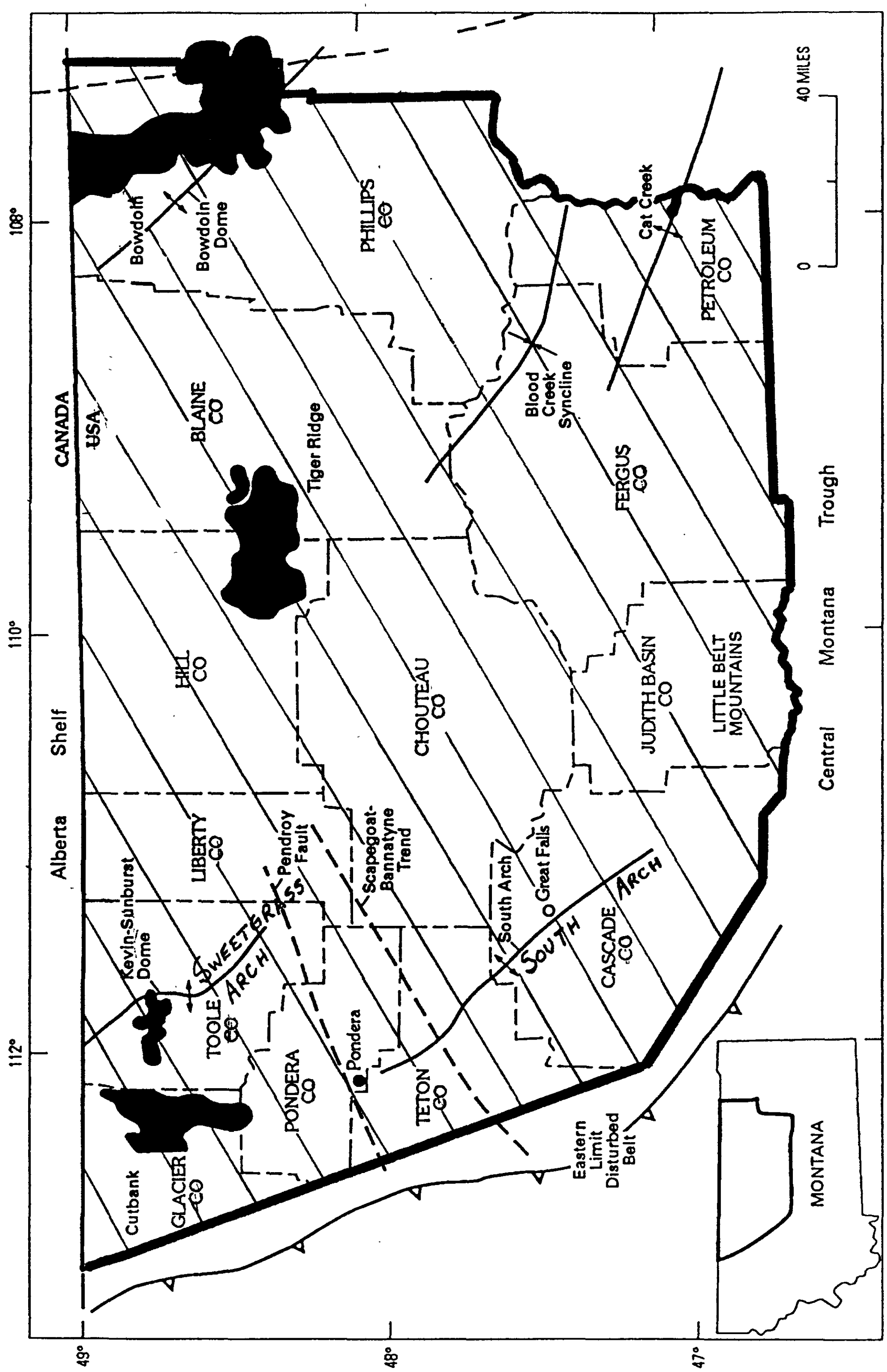

Figure 13. Map of Devonian-Mississippian play.

OIL AND GAS PLAY DATA

PLAY **DEVONIAN-MISSISSIPPIAN**
PROVINCE **SWEETGRASS ARCH** CODE **04-096-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.3**	**2**	**4**	**8**	**20**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**2**			**4**			**7.5**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**6**	**8**	**10**	**13**	**22**	**30**

Average ratio of associated-dissolved gas to oil (GOR)	**400**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

CENTRAL MONTANA PROVINCE (097)

By Edwin K. Maughan

INTRODUCTION

The Central Montana province includes all or part of seven counties in west central Montana and covers an area of 12,500 mi^2. It is bordered by six other assessment provinces: Montana Thrust belt (098), Sweetgrass Arch (096), Williston basin (094), Powder River basin (101), Bighorn basin (103), and Southwest Montana (099). Most of the province lies within the Big Snowy trough that has been the center of structural development, including subsidence or uplift during several epeirogenic episodes during the Phanerozoic. Most of the principal structures in the province may coincide with major lineaments, such as the Musselshell lineament, and are mainly basins and domes which are the result of tectonism during the Laramide orogeny. The first oil production in the province occurred in 1919 at the Devil's Basin field from the Heath Formation of the Mississippian Big Snowy Group (fig. 14). Approximately 80 percent of the total oil production in the province is from the Pennsylvanian Tyler Formation, with lesser amounts produced from other units in the Amsden Group, the Mississippian Heath Formation, and Cretaceous reservoirs. Gas is produced primarily from Cretaceous rocks at a few fields and gas production from Pennsylvanian reservoirs is negligible. A total of 48 oil and gas fields have been discovered in the province over a 70-year period of exploration. One play, the Tyler play, was individually assessed.

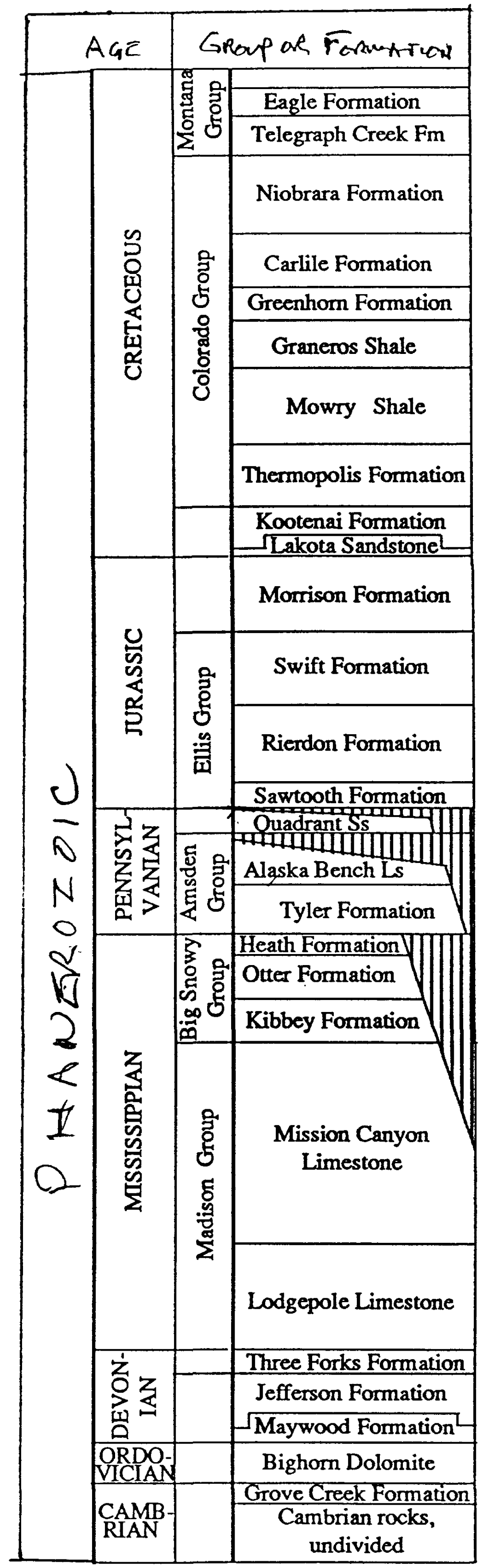

Figure 14. Generalized stratigraphic column, Central Montana province.

TYLER PLAY (020)

The play is characterized by oil fields that produce from fluvial sandstone reservoirs of the Pennsylvanian Tyler Formation in stratigraphic traps that are localized by structure. The play lies almost entirely in the northern part of the province where the Tyler is greater than 100 ft thick, and covers an irregularly bounded area of approximately 5,800 mi^2, with parts of it extending north and west into the edges of the adjacent Sweetgrass Arch (096) and Montana thrust belt (098) provinces (fig. 15). Undiscovered resources in the play were, however, assessed only in the subject province; no part of the assessment was apportioned to the two adjacent provinces. The southern boundary of the play approximates the depositional boundary of the Tyler Formation along the Musselshell lineament which marked the southern boundary of the Big Snowy trough. To the east, the play boundary is based on the thermal immaturity of source rocks and therefore, the eastern limit of the play was arbitrarily drawn where post-depositional burial does not appear to have exceeded 6,500 ft. The northern boundary is at the erosional edge of Pennsylvanian rocks. The Tyler Formation does not occur at some places within these boundaries, such as the Little Belt, Big Snowy and Little Snowy Mountains, because there has been repeated diastrophism in this structurally complex area, and the deposition and preservation of source beds, reservoirs, and trapping structures is inconsistent.

Reservoirs are lenticular fluvial stream channel, delta related, and shoreface sheet sandstones in the Pennsylvanian Tyler Formation (Stonehouse Canyon Member) (fig. 14). These reservoirs are generally less than 10 ft thick, although locally they range up to about 40 ft, and are areally limited to tectonically controlled paleo-channels within the Big Snowy trough. The reservoirs are sealed by mudstone and claystone deposited coevally with the sandstones in overbank ponds and in paralic lakes of a fluvial-deltaic system. Reservoir porosity and permeability vary from poor to good. A few reservoirs occur in fractured or porous carbonate rocks in the Quadrant Sandstone (Devil's Pocket Member).

Source rocks are organic carbon-rich mudstone and limestone of shallow lagoonal deposits in the underlying Mississippian Heath Formation that are areally restricted to the Big Snowy trough. Catagenesis of hydrocarbons has been variable owing to local differences in times and depths of burial because of tectonic complexities within the trough. Most thermal maturation probably occurred during maximum burial prior to Late Cretaceous uplift in some areas, and during Late Cretaceous and Paleocene downwarping in other areas. Migration of oil into reservoirs occurred where there is direct contact of source and reservoir, or by fracture communication. Some oil has likely been derived from carbonaceous mudstone beds that are indigenous to the Tyler, but these are low-grade source rocks in that much of the organic matter is of terrestrial plant origin and low in hydrogen. Catagenesis has varied because diastrophism has been episodically recurrent in the Big Snowy trough and Heath source rocks have been differentially buried. These strata are thermally immature adjacent to the Little Snowy Mountains in contrast to areas south and east of these mountains where oil generation occurred.

Fields occur mainly in stratigraphic traps resulting from sandstone deposition in fluvial stream channels. The sandstones are encased in finer grained overbank sediments and sealed by these deposits and further localized by structural folds and faults. Seals are mudstone and claystone within the Tyler. Drilling depths range from 2,000 to 5,500 ft; average drilling depths to production in known fields is 4,500 ft.

Discovery of oil in the Tyler Formation first occurred in 1948 at the Big Wall field (fig. 15). Twenty-nine additional fields have been discovered in the play to the present. Approximately 80 MMBO has been produced (1986) from Tyler reservoirs in the play, and the largest field is Sumatra in Rosebud County, which has a cumulative production of about 43 MMBO through 1986. Large, sparsely drilled areas of the play are not considered to have as much potential as the already productive areas because of shallow burial and thermal immaturity of organic-rich shale in the Heath. Although the western area of the play has not been adequately tested, the future potential of the play for oil and the probability of finding new resources in fluvial-deltaic reservoirs is estimated to be low.

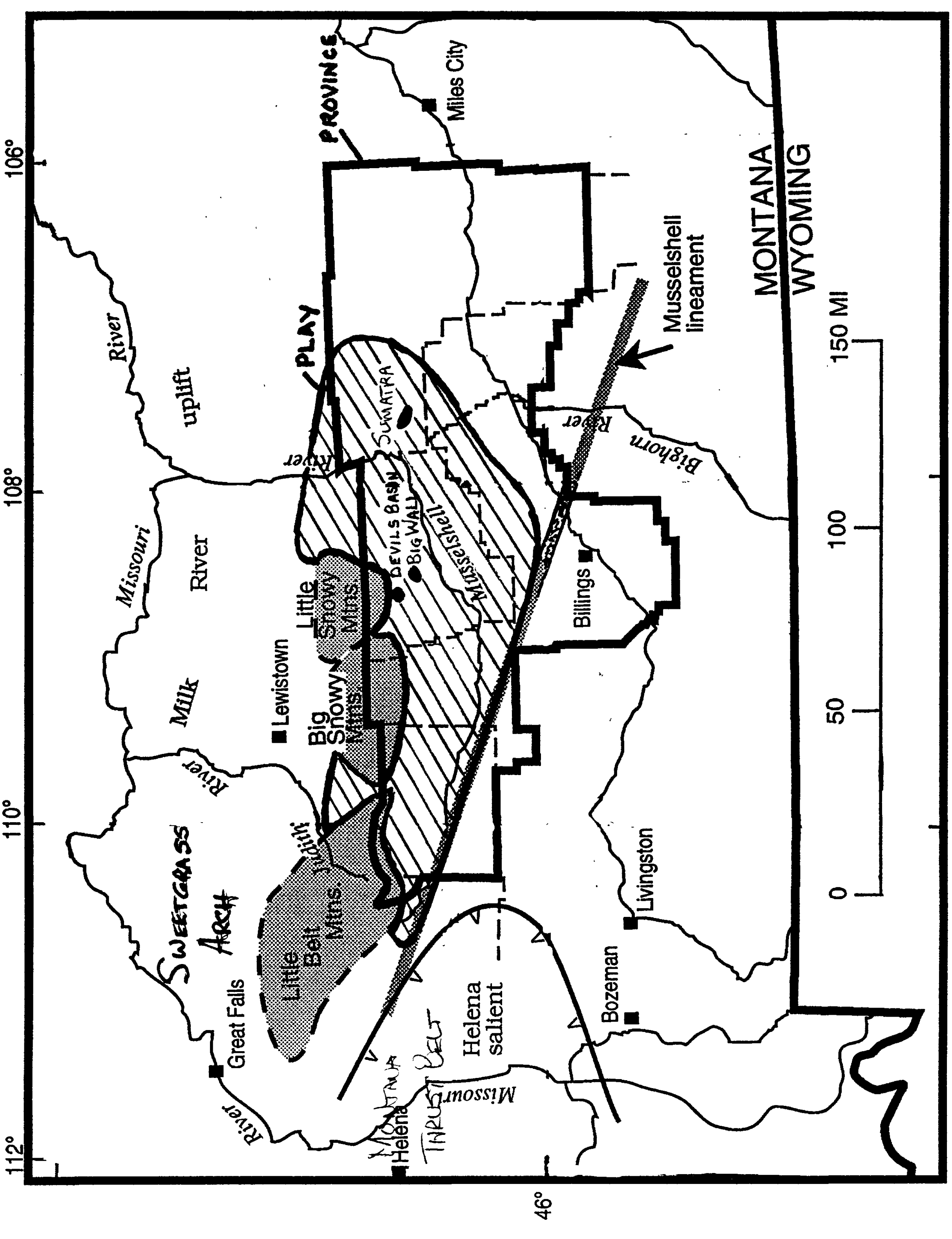

Figure 15. Map of Tyler play.

OIL AND GAS PLAY DATA

PLAY **TYLER PLAY**
PROVINCE **CENTRAL MONTANA** CODE **04-097-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.6**	**2.5**	**4.4**	**10.4**	**24**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**2**			**3.5**			**5.5**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**2**	**2**	**3**	**4**	**6**	**11**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**80**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

MONTANA THRUST BELT PROVINCE (098)

By William J. Perry, Jr.

INTRODUCTION

The province, approximately 41,400 mi^2 in area, lies in the generally mountainous terrain of western Montana, adjoining Idaho and includes that part of the Cordilleran thrust belt which occurs within the State of Montana. The northern boundary is the International Boundary between the United States and Canada. The southern boundary is the Idaho-Montana State Boundary. The basic setting of the province consists of numerous thrust sheets and intrusive bodies. Thrusting took place generally from west to east during Late Cretaceous and Paleocene time. The overall structure of much of the province is very complex, and many structural and stratigraphic relationships remain obscure or are the subject of controversy. The pre-Jurassic stratigraphic sequence varies markedly from south to north as shown in figure 16. Unlike the adjacent and contiguous Alberta foothills belt to the north, the Montana thrust belt has failed to yield appreciable hydrocarbons in spite of more than 80 years of exploration, the drilling of approximately 110 wildcat wells, favorable source rocks in the eastern part of the province, and hydrocarbon seeps in the northern part. Only one producing gas field is present in the province, the 2-well Knowlton field, which has produced about 6 BCFG and 33,000 BBLS of condensate. Three plays were individually assessed, two north of the Lewis and Clark lane, and one in the Lima area of southwestern Montana; these are the Eldorado-Lewis Subthrust (030), Frontal Imbricate (040), and Blacktail Mountains Salient (050) plays.

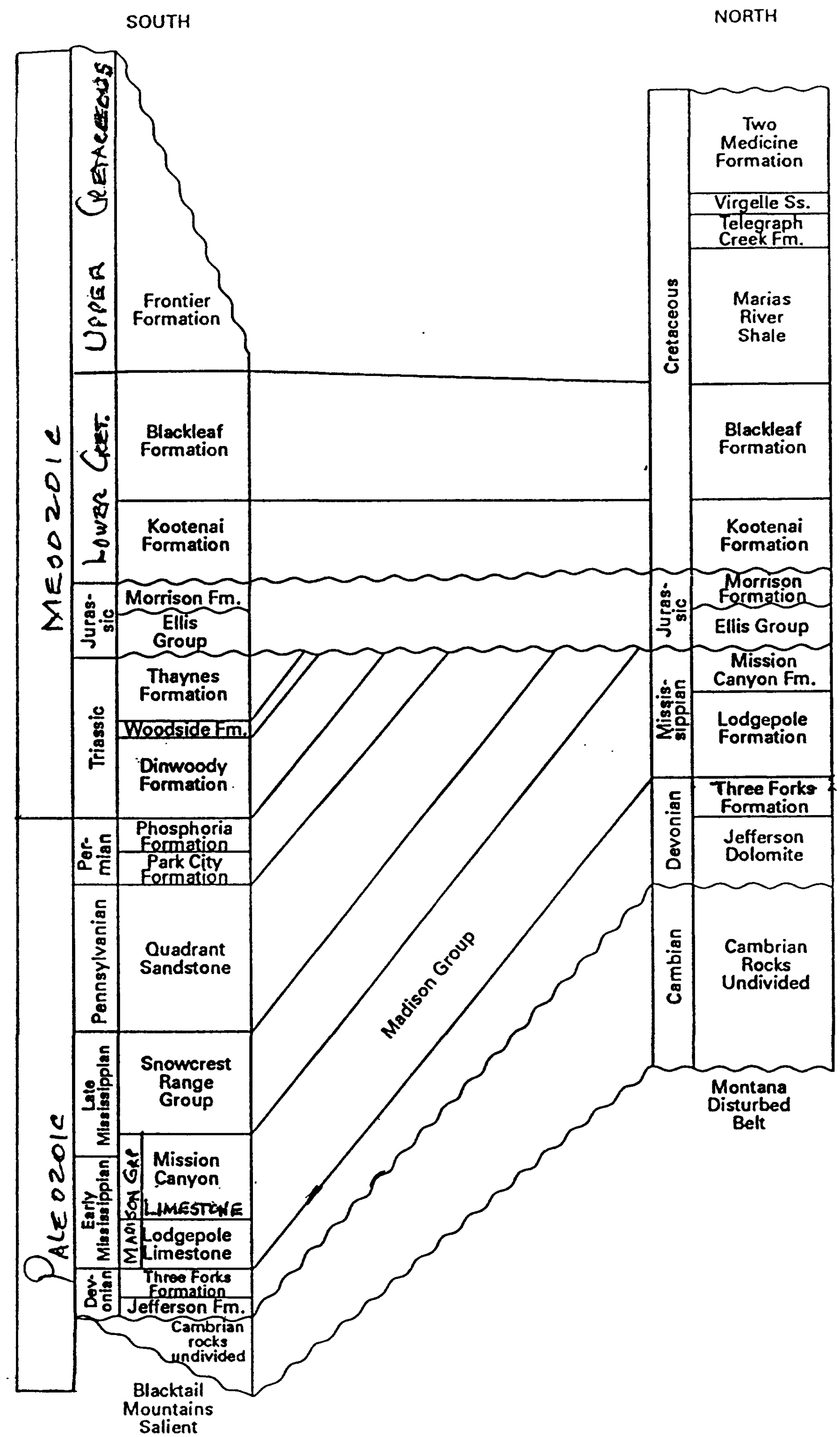

Figure 16. Generalized stratigraphic columns, Montana Thrust Belt province.

ELDORADO-LEWIS SUBTHRUST PLAY (030)

The play is structural and involves inferred anticlines and imbricate thrust slices of Paleozoic rocks in the footwall of the Eldorado-Lewis thrust system (ELTS). The play area is approximately 130 mi in length and 30 to 45 mi in width and extends southward from the United States-Canada Boundary to the Lewis and Clark lane (fig. 17). The western boundary of the play is the Rocky Mountain trench. The eastern limit is the leading edge of the Eldorado-Lewis thrust system south of Glacier Park and the front of the Lewis thrust in Glacier Park.

Potential reservoir rocks are primarily dolomitized grainstone, packstone, and wackestone in the upper part of the Mississippian Madison Group (Castle Reef Formation) (fig. 16). This reservoir section ranges from less than 200 ft to about 500 ft in thickness farther east where it is exposed in the Frontal Imbricate play (040). There, the lower member of the Castle Reef exhibits both vuggy and intercrystalline porosity (4-12 percent) but low permeability (6-12 md) as measured from surface exposures; similar values were measured from the gas productive interval in the subsurface in the Blackleaf Canyon area. A less likely but possible reservoir sequence would be in sandstones of the Jurassic Ellis Group or Lower Cretaceous Kootenai Formation and Lower and Upper Cretaceous Blackleaf Formation (fig. 16). No commercial amounts of hydrocarbons in these reservoir rocks have yet been encountered in the province.

Source rocks include the Cretaceous Marias River Shale in the Glacier Park area and Cretaceous Blackleaf Formation (Flood Member), dark shales and mudrocks of the Jurassic Ellis Group (Sawtooth and Rierdon Formations), and the Devonian-Mississippian section (Exshaw Formation), throughout the play area. Of these units, only the Flood Member of the Blackleaf Formation is well developed in the southern part of the play area. Several very shallow wells were drilled prior to World War I in what is now western Glacier National Park in an area of historic hydrocarbon seeps; however, no sustained volumes of hydrocarbons were discovered. Hydrocarbon generation in Cretaceous source rocks and migration is suspected to have occurred from these rocks beneath the Precambrian rocks in the hanging wall of the ELTS during the emplacement of this thick sequence in latest Cretaceous and Paleocene time. Underlying Paleozoic source rocks may have generated hydrocarbons at an earlier time.

The known position of certain major Tertiary normal faults provides clues to the position of ramps and hence footwall cutoffs in the ELTS. Likewise, the positions of major synclines and structural culminations in the Montana disturbed belt provide important clues to thrust stacking at depth. Limited available geophysical data support these clues. These several types of data may also provide clues as to the size and distribution of possible structural traps. Adequate seals are present in the Cretaceous shale sequence. Drilling depths are expected to range from 6,000 to more than 20,000 ft to reach potential reservoirs in both Mesozoic and Paleozoic rocks. Potential Madison reservoirs in the footwall of the ELTS should contain high amounts of CO_2, based on the results of recent wells drilled by Shell Canada, Ltd. northwest of Glacier National Park and wells drilled in the Blackleaf Canyon area to the east. Future potential for gas is fair to good; the probability exists for the presence of a few large gas fields near the size and structural style of large gas fields in southern Alberta, Canada.

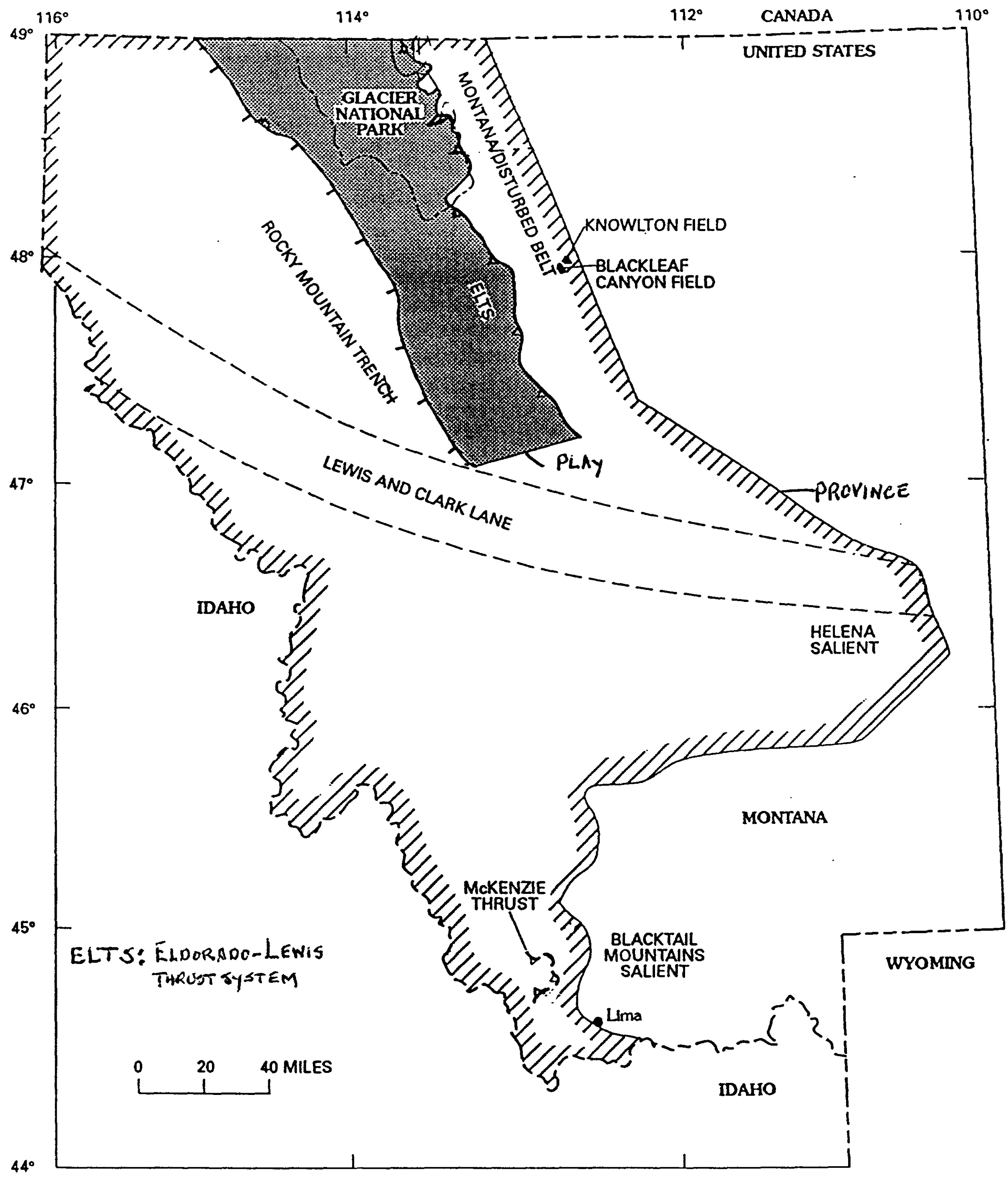

Figure 17. Map of Eldorado-Lewis Subthrust play.

OIL AND GAS PLAY DATA

PLAY **ELDORADO-LEWIS SUBTHRUST**
PROVINCE **MONTANA THRUST BELT** CODE **04-098-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**0.40**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**0.40**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**6**	**8.4**	**21**	**50**	**125**	**560**	**2800**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**6**			**14**			**20**
Number of accumulations	**1**	**2**	**4**	**5**	**6**	**8**	**10**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**5**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

FRONTAL IMBRICATE PLAY (040)

The play is primarily structural and involves small imbricate or "pop-up" structures warped into anticlines involving Mississippian rocks east of the ELTS in the eastern part of the Montana disturbed belt, east and south of Glacier National Park. The play area is approximately 130 mi long and 16 to 25 mi wide and extends southward from the International Boundary with Canada to the Lewis and Clark lane (fig 18). The disturbed belt sector has undergone a structural and stratigraphic history similar to the Alberta foothills thrust belt in Canada, which contains giant reserves of gas in Mississippian carbonate rocks. The Frontal Imbricate play is subdivided into two parts based on geologic characteristics: (1) the eastern part of the Montana disturbed belt which is characterized by numerous, closely spaced thrust faults involving chiefly Upper Cretaceous rocks; and (2) the western part of the disturbed belt, east of the ELTS, in which Devonian and Mississippian rocks are imbricately thrusted and secondarily folded.

Demonstrated and anticipated reservoir rocks in the play are primarily dolomitized grainstone, packstone, and wackestone in the upper part of the Mississippian Madison Group (Castle Reef Formation) (fig. 16). This reservoir section ranges in thickness from less than 200 ft to about 500 ft. Here, the lower member of the Castle Reef exhibits good both vuggy and intercrystalline porosity (4-12 percent) but low permeability (6-12 md) as measured from surface exposures; similar values were measured from the gas productive interval in wells in the subsurface in the Blackleaf Canyon area. A less likely but possible reservoir sequence would be in sandstone of the Jurassic Ellis Group or Lower Cretaceous Kootenai and Blackleaf Formations which have not yet produced commercial hydrocarbons in the province. Reservoirs discovered to date in the eastern Montana disturbed belt are contained in small fields (<20 BCFG).

Marine shale of Jurassic and Cretaceous age contains abundant organic material, much of which is demonstrated oil-prone source rock. The Upper Cretaceous Marias River Shale (Cone Member) contains the greatest amount of hydrogen-rich kerogen (greatest oil-generating capacity) with an average TOC of 2.4 wt. percent organic carbon. This rock has probably generated the minor quantities of oil discovered in Upper Cretaceous rocks in the eastern part of the play. However, gas and gas condensate are the principal hydrocarbon resources expected in the play; more than 11 percent CO_2 is anticipated in undiscovered gas in Paleozoic reservoirs based on analyses of natural gases recovered to date. Generation and migration of hydrocarbons probably took place in Paleocene time.

Traps are structural or combination (structural and stratigraphic). They are located near the faulted leading edges of reservoir rocks in the upper plates of imbricate thrusts and associated pop-up structures and are expected to be small to medium in size. Adequate seals in the form of Cretaceous shale are present to seal reservoirs in Mesozoic and late Paleozoic rocks. Drilling depths are expected to range from 3,000 to 12,000 ft.

No oil has been discovered in Mississippian rocks in the extreme southern part of the southern Alberta foothills thrust belt near the United States, nor in the Montana thrust belt. Oil and gas exploration has been conducted for nearly 80 years in the eastern part of the Montana disturbed belt, chiefly on private lands east of the mountain front, resulting in the discovery of the small (<20 BCFG) 2-well Knowlton gas field (fig. 18). However, the presence of large-size gas fields in the southern Alberta foothills belt of Canada, near the International Boundary, continues to draw exploration interest to the Frontal Imbricate play. Future potential for gas is estimated to be good to very good, even though more than 60 exploration dry holes have been drilled to date.

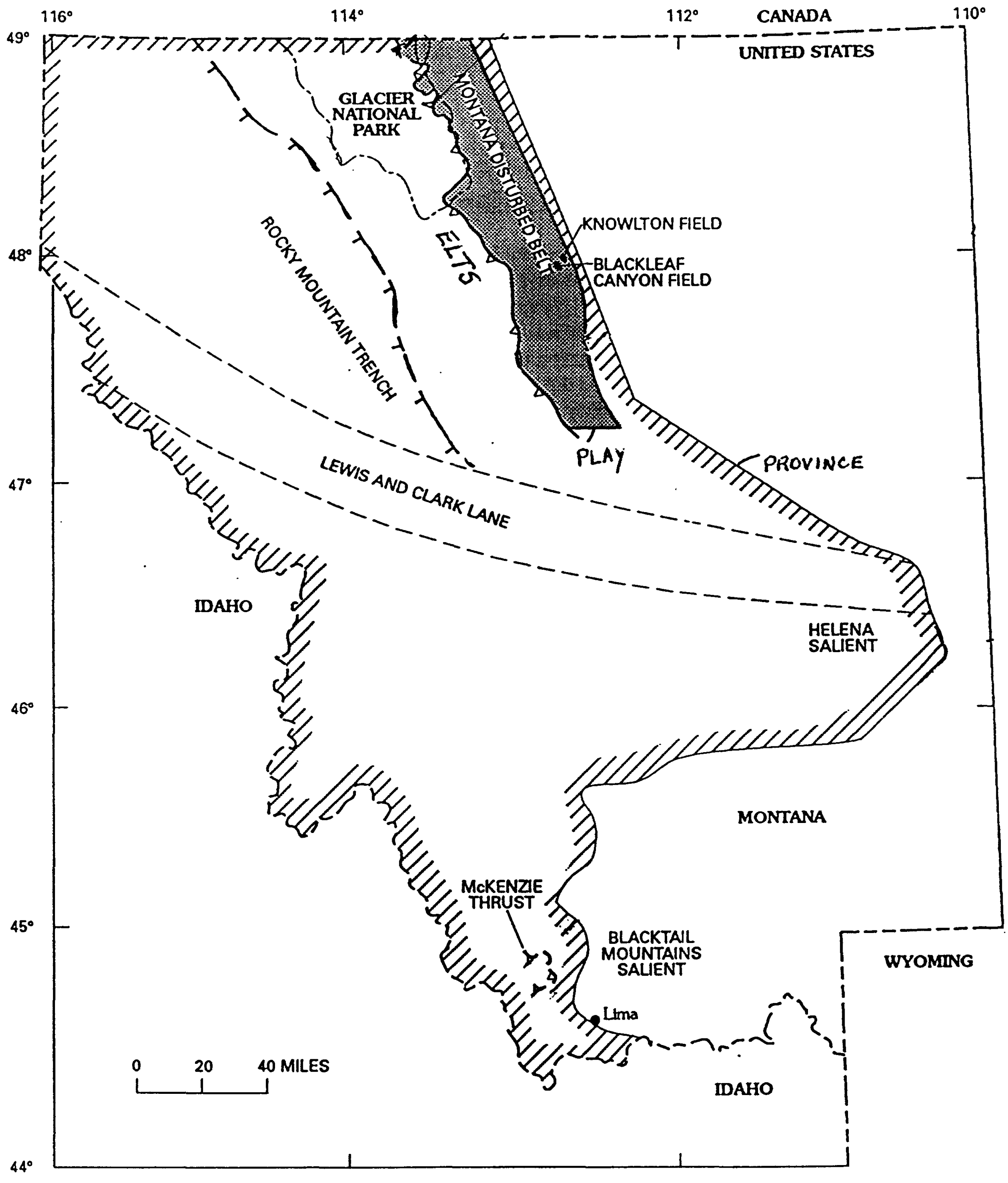

Figure 18. Map of Frontal Imbricate play.

OIL AND GAS PLAY DATA

PLAY **FRONTAL IMBRICATE**
PROVINCE **MONTANA THRUST BELT** CODE **04-098-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.75**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**6**	**11**	**35**	**100**	**240**	**1100**	**5600**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**3**			**7**			**12**
Number of accumulations	**5**	**6**	**8**	**9**	**11**	**14**	**18**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**25**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BLACKTAIL MOUNTAINS SALIENT PLAY (050)

The play involves inferred anticlines and imbricate thrust slices of Paleozoic rocks in the footwall of and east of the McKenzie thrust system. The play area is ovate, covering approximately 21 mi north-south and 19 mi east-west (fig.19). The play extends westward from the front of the Blacktail Mountains Salient to a major down-to-west normal fault system suspected to mark the position of a footwall ramp, the estimated western limit of significant source-rock and reservoir section, beneath the McKenzie thrust.

Potential reservoir rocks include (1) the Pennsylvanian Quadrant Sandstone, which thickens southward, (2) underlying sandstones and carbonate rocks equivalent to the Tyler Formation in the Central Montana province (097), and (3) limestones of the lower Mississippian Madison Group with possible karstic porosity and secondary dolomitization near the top of the Mission Canyon Limestone (fig. 16).

Probable oil-prone source rocks in the play include the Permian Phosphoria Formation (Retort Shale Member) and the Devonian Three Forks Formation (Sappington Member--Bakken equivalents). The presence of clinker beds within the Sappington, exposed in the McKenzie thrust system, suggests a high original TOC content, in excess of the 7 percent TOC reported in previous studies. The type area of the Retort Shale lies within the Blacktail Mountains Salient, where it is a demonstrated oil shale. Gas-prone source rocks may be present in the Mississippian to Pennsylvanian Snowcrest Range Group (formerly Amsden and Big Snowy Groups); recent analyses show mainly woody to herbaceous kerogen in the Big Snowy where it was sampled farther south, in the Lima, Montana, area. Generation and migration of hydrocarbons from beneath the McKenzie thrust system probably occurred during emplacement of this system. Rocks at the surface in the northeastern part of the play are submature with respect to oil generation. Those of the McKenzie thrust system are late mature to supermature.

Possible structural traps in anticlines and imbricate thrusts in rocks of favorable thermal maturity are anticipated to underlie the frontal part of the McKenzie thrust system, beneath Cretaceous through Quaternary cover. Drilling depths should range from 2,000 to 10,000 ft.

Only one well has been drilled within the play, a 4,351-ft Devonian test (A, fig. 19) drilled in 1977 by American Quasar in the northeastern part of the area, from which shows of gas were reported in Madison rocks. However, recent examination of drill cuttings from the well revealed that the shows actually occurred in Pennsylvanian rocks of the upper Snowcrest Range Group, and the test bottomed in Upper Mississippian Lombard (formerly Big Snowy) limestones. Numerous black shale stringers were encountered in both the upper Snowcrest Range Group and underlying Lombard Limestone of the lower Snowcrest Range Group as well as slight oil cuts in samples in the deeper section. The apparent dip of the section drilled is very steep, and the well appears to be located near the leading edge of a thrust that does not reach the surface. The Amoco McKnight Canyon 16,000 ft Quadrant test (Tensleep Sandstone equivalent), drilled just south of the play area (B, fig. 19), encountered complexly faulted Cretaceous and older rocks. The test was drilled, in part, on the basis of oil saturation in Upper Cretaceous rocks at the surface, oil that was generated from Cretaceous or older rocks beneath the Salient. This well suggests that undiscovered hydrocarbons may be trapped farther north, within the play area. Future potential for small-size gas fields is low.

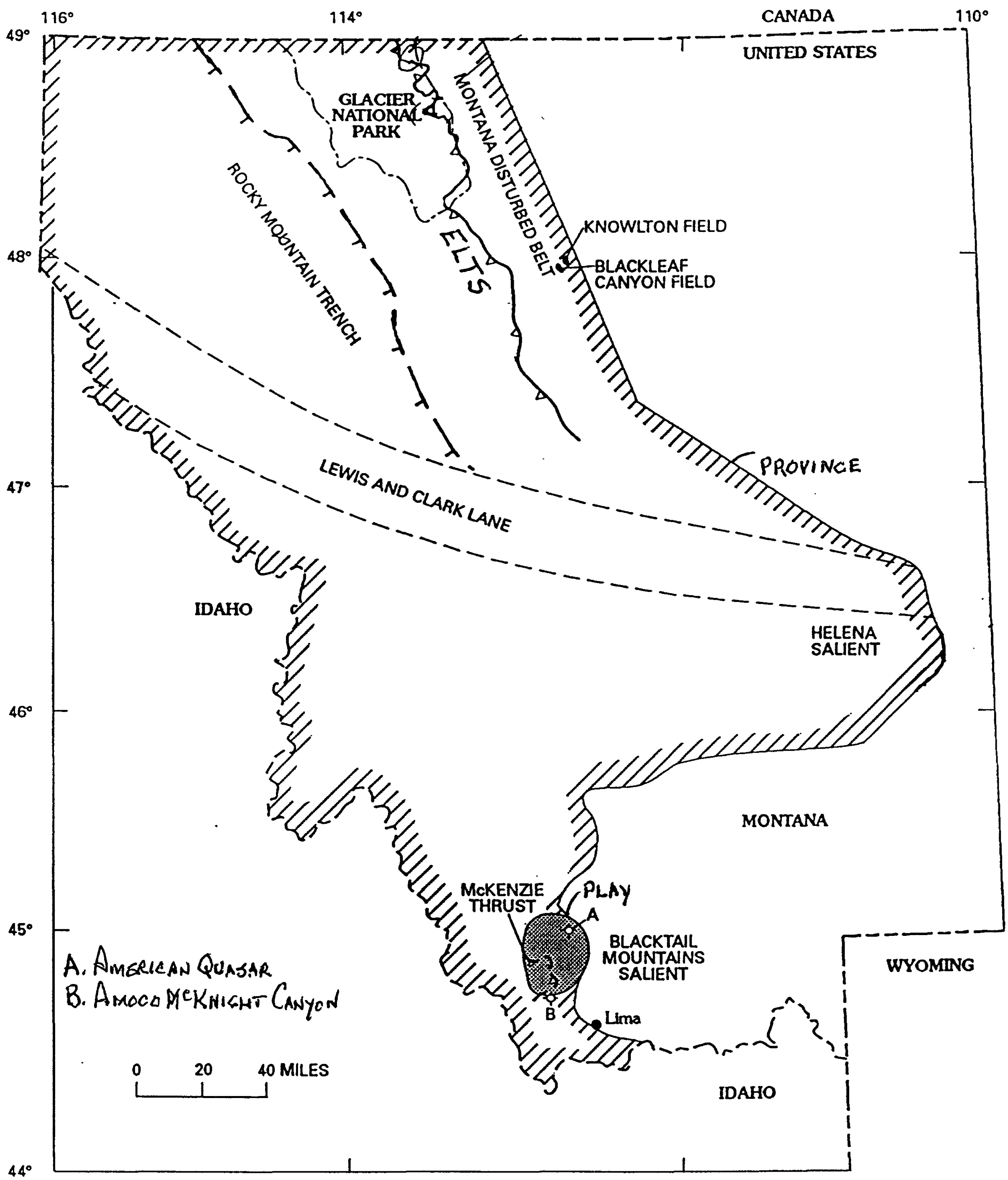

Figure 19. Map of Blacktail Mountains Salient play.

OIL AND GAS PLAY DATA

PLAY **BLACKTAIL MOUNTAIN SALIENT**
PROVINCE **MONTANA THRUST BELT** CODE **04-098-050**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**0.50**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**0.50**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.50**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.6**	**4.5**	**10**	**21**	**57**	**135**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**2**			**6**			**10**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**1**	**1**	**2**	**2**	**3**	**4**	**4**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

SOUTHWEST MONTANA PROVINCE (099)

By William J. Perry, Jr.

INTRODUCTION

The province is approximately 12,960 mi^2 in area, lies north and northwest of Yellowstone National Park and east and southeast of the Cordilleran thrust belt in the southwestern part of the State of Montana. It includes that part of the Rocky Mountain foreland in southwest Montana. Three major Laramide uplifts exist in the province, the Blacktail-Snowcrest, Madison-Gravelly, and Beartooth uplifts. The entire Phanerozoic stratigraphic sequence varies widely across the province (fig. 20); in the western part, the Laramide Blacktail-Snowcrest uplift (column A, fig. 20) has a profoundly different stratigraphy from areas to the east and south (column B, fig. 20), as this uplift represents the prior upper Paleozoic Snowcrest trough bounded by thinner upper Paleozoic sequences of the Wyoming shelf to the east and south. The Devonian Three Forks Formation includes the Bakken equivalent Sappington Member at the top, and the Permian Phosphoria Formation includes the Shedhorn Sandstone. The northeastern part of the province (East, fig. 20) contains very different Jurassic and Cretaceous rocks from those of the western part of the province. Much of the southern part of the province is floored by Archean igneous and high grade metamorphic rocks with a thin veneer of Cretaceous to Tertiary igneous rocks. No significant amounts of hydrocarbons have been found in the province; only four small Cretaceous gas fields have been discovered in the easternmost corner where two surface heavy oil accumulations containing 10° API black oil have produced small quantities of the unconventional oil by steam injection. Three plays were individually assessed in the province, Subthrust (030), Basement Structure (040), and Wrench Fault (050).

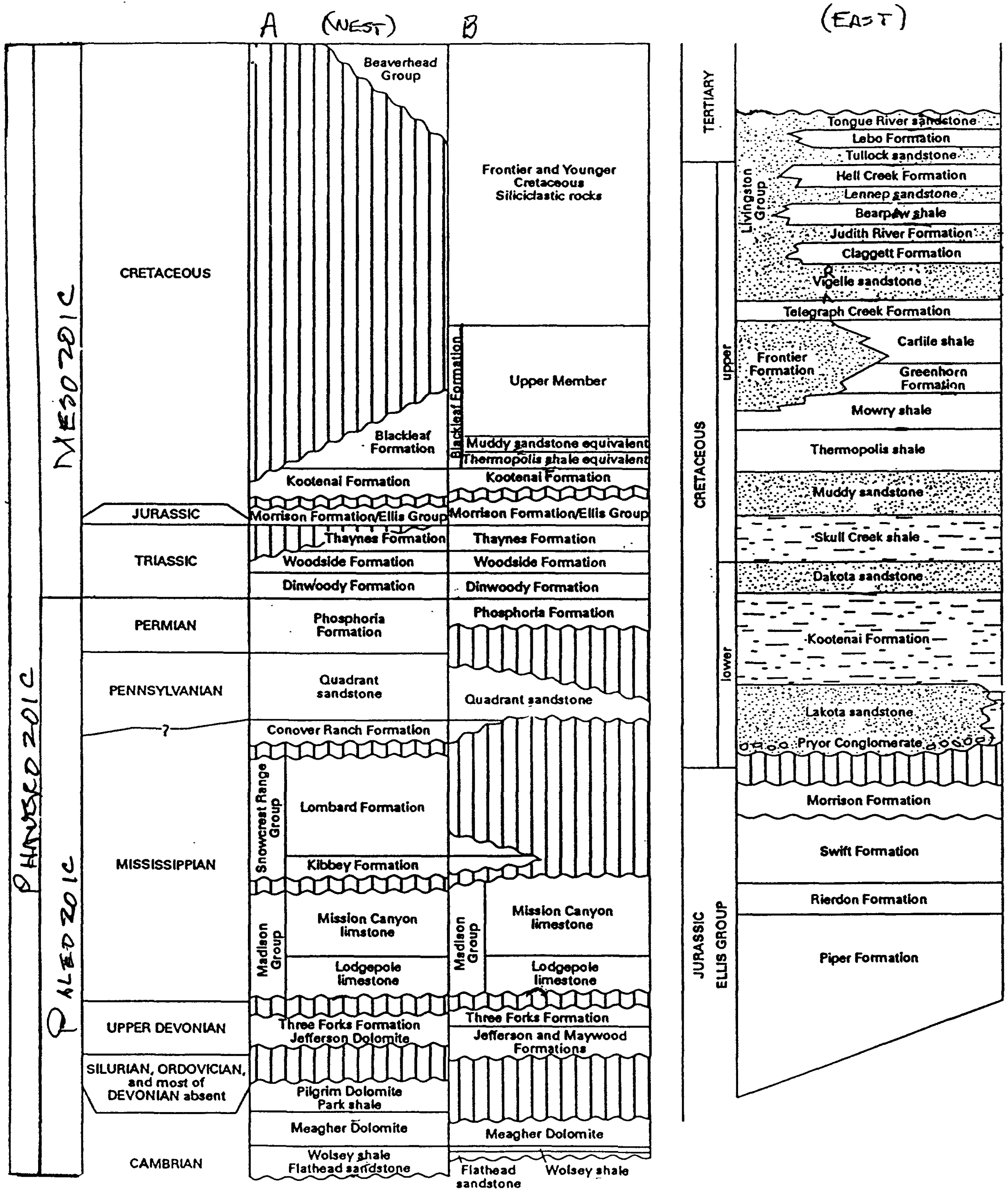

Figure 20. Generalized stratigraphic columns, Southwestern Montana province.

SUBTHRUST PLAY (030)

The play is structural and based on the premise that hydrocarbons may be trapped in subthrust (footwall) Paleozoic and Mesozoic sedimentary rocks to thrust "overhangs" (basement-involved hanging walls) along the thrust-faulted margins of three Laramide uplifts. The play consists of three related subthrust segments, those beneath major thrust overhangs along the northeastern, eastern and southeastern margins of, respectively, the Beartooth, Madison-Gravelly, and Blacktail-Snowcrest uplifts (fig. 21). The Beartooth segment extends 39 mi northwest-southeast along the northeastern and eastern margin of the Beartooth uplift. Its boundary extends into province 103, but its resources were assessed within this (099) province. Width of the Beartooth segment is up to 4 mi in the southeastern edge of the province; this overhang increases in width farther east, along the eastern margin of the Beartooth uplift. Older structures appear to have been locally overridden by the thrust-bounded Beartooth uplift. The Madison-Gravelly subthrust segment extends 47 mi northwest-southeast along the southwestern side of the Big Sky basin and is up to 6 mi wide. It extends from the lip of a major west-dipping basement-involved thrust on the east, to the Tertiary Madison Range normal fault system on the west. The Snowcrest subthrust segment extends about 47 mi northeast along the northwestern margin of the Ruby basin and is up to 5 mi wide. It extends from the buried lip of the sub-Snowcrest thrust northwest to a Tertiary normal fault system along its northwestern margin.

Primary reservoir rocks include sandstone of the Pennsylvanian Quadrant Formation and Permian Shedhorn Sandstone, as well as carbonate rocks of the Madison Group. Secondary, shallow reservoirs may be present in Cretaceous sandstone where deeper primary reservoirs have been breached by faulting.

Pre-Cretaceous source rocks are thin to absent in the Beartooth segment of the play, and Cretaceous source rocks are organically lean in the Madison and Snowcrest Subthrust segments. The Cretaceous Thermopolis and Mowry Shales are the principal source rocks in the area of the Beartooth segment; Cretaceous source rocks in the overall province are gas-prone. Oil-prone Upper Devonian (Bakken equivalent) and Permian Phosphoria source rocks are present on the flanks of the Laramide Blacktail-Snowcrest uplift, inverted from the upper Paleozoic Snowcrest trough. Pre-thrust migration of hydrocarbons from these Paleozoic source rocks to early formed traps in the Madison and Beartooth segments may have occurred. Long distance migration (50 to 100 mi) prior to development of the Beartooth uplift is required to account for the presence of oil derived from these Paleozoic rocks to be present in the southeastern part of the province north and east of the Beartooth uplift.

The Beartooth part of the play has been extensively drilled (more than 100 wells), but only one deep test well has penetrated the Beartooth subthrust segment, the Amoco 1-A USA, which reached a total measured depth of 15,800 ft in Devonian rocks (fig. 21). In this test, oil and gas shows are rumored to have been encountered in the Cretaceous footwall sequence beneath the Precambrian rocks of the hanging wall of the Beartooth thrust. Dean Dome and Mackay Dome heavy-oil deposits lie just north of the Beartooth segment (fig. 21). The future oil and gas potential of the Beartooth Subthrust segment is moderate.

Drilling to date in the Madison and Snowcrest segments consist of one well. The Marathon 1 Cornell Camp-Federal, drilled into the Snowcrest subthrust segment, whereas the Madison subthrust segment has not been tested. The Marathon 7,711 ft test encountered low-porosity Paleozoic rocks and found evidence of elevated paleotemperatures in the potential reservoir section of the subthrust. The future potential of these segments is low.

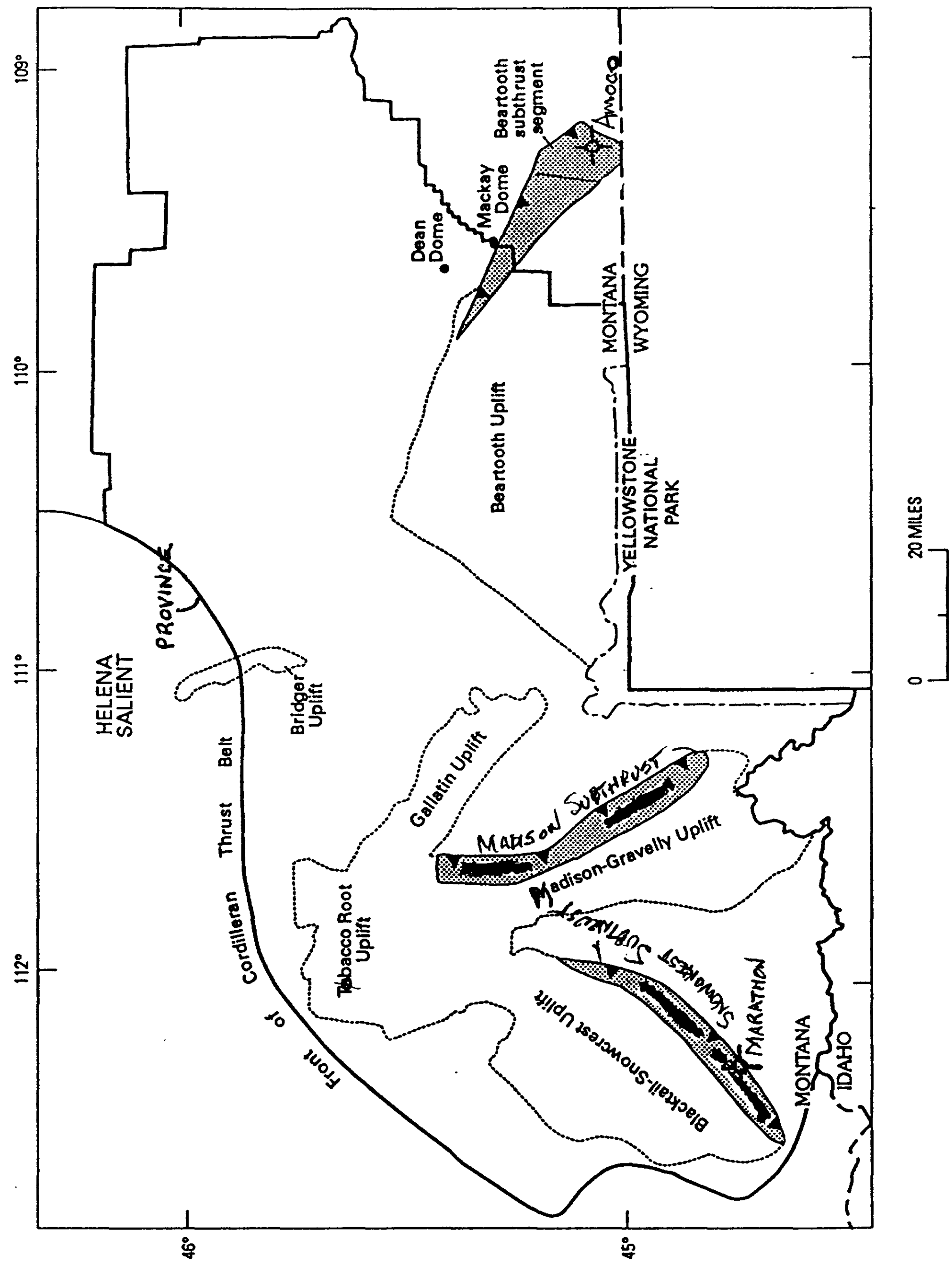

Figure 21. Map of Subthrust play.

OIL AND GAS PLAY DATA

PLAY SUBTHRUST
PROVINCE SOUTHWESTERN MONTANA CODE **04-099-030**

Play attributes	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**0.50**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**0.50**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.50**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.2**
Gas	**0.8**

Fractiles * (estimated amounts)

Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.4**	**3.3**	**7**	**15**	**40**	**100**
Gas (x 10^9 CFG)	**6**	**8**	**13**	**25**	**60**	**200**	**500**
Reservoir depth (x10^3 ft)							
Oil	**6**			**8**			**15**
Gas (non-associated)	**6**			**10**			**18**
Number of accumulations	**1**	**1**	**2**	**3**	**4**	**5**	**5**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**20**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BASEMENT STRUCTURE PLAY (040)

This play is speculative and is based on the anticipated occurrence of hydrocarbons trapped in early formed basement involved structures. Most of these features may not be reflected in the surface structural attitudes of unconformably overlying younger rocks. The play includes three separate basinal areas; the southwestern Crazy Mountains basin, Big Sky basin, and Ruby basin (fig. 22). The Crazy Mountains area extends nearly 60 mi in a northwest-southeast direction along its southern margin, and about 40 mi north-south along the eastern edge of the Helena salient of the thrust belt. The central part of the area is about 28 mi wide east-west. The Big Sky basin extends about 51 mi northwest-southeast from the northwest corner of Yellowstone National Park and has a maximum width of approximately 17 mi. The Ruby basin in the southwestern part of the play is subtriangular in shape, nearly 44 mi wide (east-west) along the base at its southern margin, with a maximum north-south extent of 41 mi.

During Late Cretaceous time, the southwestern part of the Crazy Mountains basin received approximately 8,900 ft of volcanoclastic sediments. These rocks thin rapidly to the north, east, and south. Igneous dikes and plugs associated with the Eocene Crazy Mountains intrusive complex occur throughout the western part of the Crazy Mountains basin. Geophysical modelling indicates that the Crazy Mountains intrusive complex probably merges into a single large laccolithic body at depth, thus limiting the areal size of the Crazy Mountains segment of the Basement Structure play to that shown in figure 22. A large laccolithic body also occurs in the northern part of the Big Sky basin segment, and igneous dikes are common in both areas.

The Big Sky basin segment is a small Cretaceous basin containing several northwest-trending structures. At least one of these structures predates the major Late Cretaceous basement-involved thrust system along the western margin of the basin. Small, north-northwest-trending anticlines are present in the northern part of the Ruby basin segment. Other such structures appear to be present farther southwest in the basin, as indicated by geophysical data. Intrabasin structures are also present in the Crazy Mountains basin segment. Time of development of many of these structures is uncertain.

The Big Sky and Crazy Mountains basins contain a thin sequence of upper Paleozoic rocks comparable to those in the Ruby basin (column B, fig. 20). Potential reservoir rocks are primarily dolomitized Mississippian limestones, with anticipated karstic porosity, and overlying Pennsylvanian sandstone of variable thickness and generally low porosity, where encountered in wells. Cretaceous sandstone of potential reservoir quality is present in the Crazy Mountains basin and is possibly present in the Big Sky basin.

Devonian and Permian source rocks are thin to absent, particularly in the Crazy Mountains basin segment. Permian rocks are low in organic matter where they occur in areas immediately west of the Crazy Mountains basin. Lower Cretaceous source rocks are also low in organic matter and gas-prone; Paleozoic source rocks within the Ruby basin are postmature with respect to oil generation. It is probable that hydrocarbons migrated updip into early Laramide basement-involved structural closures within the play area prior to the development of major Laramide foreland uplifts. However, a number of test wells drilled within the play did not confirm the presence of commercial quantities of hydrocarbons. The Ruby basin alone lacks the numerous igneous dikes and stocks that plague the remainder of the play. However, such igneous activity could have provided local heat sources to generate thermogenic gas if source rocks were present.

Potential intrabasin structural traps, with estimated structural closures of less than 1,000 ft, are believed to be present in the play segments at depths of 3,000 to nearly 20,000 ft. The presence of fresh to brackish waters at depth suggest that many seals may have been breached, and the near absence of adequate organic-rich source rocks are negative factors. The future potential of this speculative play is low for oil and moderate for gas.

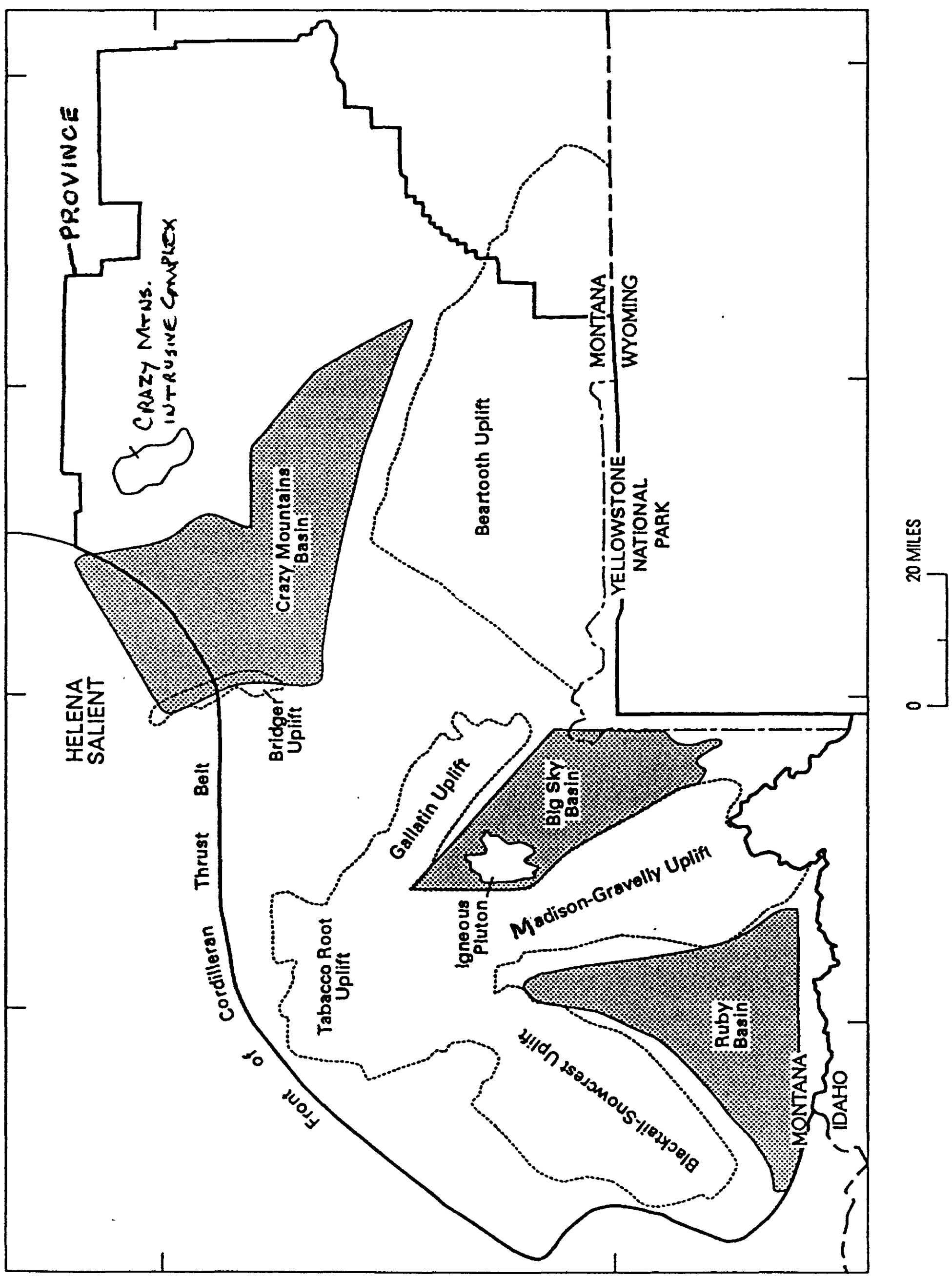

Figure 22. Map of Basement Structure play.

OIL AND GAS PLAY DATA

PLAY **BASEMENT STRUCTURE**
PROVINCE **SOUTHWESTERN MONTANA** CODE **04-099-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**0.80**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**0.80**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.2**
Gas	**0.8**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.4**	**3.3**	**7**	**15**	**40**	**100**
Gas (x 10^9 CFG)	**6**	**7**	**10**	**20**	**60**	**200**	**500**
Reservoir depth (x10^3 ft)							
Oil	**3**			**8**			**15**
Gas (non-associated)	**5**			**9**			**18**
Number of accumulations	**2**	**3**	**4**	**5**	**7**	**11**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**20**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

WRENCH FAULT PLAY (050)

The play is based on the premise of additional hydrocarbons being structurally trapped in Cretaceous reservoirs within two zones of strike-slip faulting, the Lake Basin fault zone and the Nye-Bowler zone segments (fig. 23). These two fault zones have long been interpreted to exhibit Late Cretaceous to Tertiary left-lateral shear within the basement. En echelon folds and faults, which contain known hydrocarbon traps, occur in the sedimentary cover along both fault zones. Both of these zones are considered as segments of the Wrench Fault play.

The Lake basin segment extends more than 80 mi in an east-southeast direction along the northeastern boundary of the province from the edge of the Helena salient of the Cordilleran thrust belt. It is 12 to 18 mi wide and consists of a nearly east-west zone of relatively short, north– northeast-trending, en echelon right-separation faults and associated anticlines which extend into the Central Montana province (097). Undiscovered resources were assessed, however, in the subject province (099).

The Nye-Bowler segment is nearly 100 mi long and generally less than 5 mi wide, extending from the southern margin of the Crazy Mountains basin to east of the northeastern margin of the Beartooth uplift in the northern Bighorn Basin province (103). The Nye-Bowler segment is a west-northwest-trending zone of faults and folds north, northwest, and east of the Beartooth uplift, which includes the oil-productive Dean and Mackay domes. The Nye-Bowler segment extends west of Dean dome and includes a zone of en echelon anticlines. Mesozoic strike-slip movements in this segment commenced in Cretaceous time, based on known abrupt changes in thicknesses and lithology of stratigraphic units.

Sandstone from the the Lower Cretaceous Dakota up through the Upper Cretaceous Judith River Formation is the primary reservoir rock in this play (fig. 20). To a limited extent, Mississippian carbonate rocks may also be reservoirs, although they generally have low porosity and permeability in the play area.

Source rocks for gas are believed to be the marine black shales in the Cretaceous Mowry and Skull Creek Shales. These shales are gas-prone and contain up to 1 percent total organic carbon. The origin of the minor amounts of oil discovered to date in both segments of the play is problematic. Source rocks for this oil may include the Permian Phosphoria Formation of the present Laramide Blacktail-Snowcrest uplift and (or) Helena salient (fig. 23). Oil-prone source rocks may also be present in the Helena salient outside of the province (Middle Proterozoic Belt Supergroup), although, where exposed (and reported), organic-rich beds in this section have been metamorphosed because of proximity to Mesozoic batholiths. Probable traps are anticipated to be en echelon anticlines, some of which may be fault-bounded. Drilling depths should range from 1,000 to 5,000 ft.

More than 146 wells have been drilled within or near the eastern part of the Lake Basin segment of the play, resulting in the discovery of several small gas fields (fig. 23) that are nearly depleted. These fields produce from a number of sandstones of Cretaceous age, as well as in one case (Big Coulee field) from the Jurassic Morrison Formation, at depths of generally less than 3,000 ft. They contain an estimated 115 BCF of total gas in place. The future oil potential of this segment is very low, and the gas potential is low.

The eastern end of the Nye-Bowler segment includes unconventional heavy oil accumulations at the Dean and Mackay domes. Viscous black oil of 10° API gravity has been produced only in small quantities by steam injection and diesel soak at Dean Dome (75,945 bbl of oil, cumulative), and Mackay Dome (63,472 bbl of oil, cumulative). Both fields are currently shut in. At Dean Dome, the Cretaceous Lakota Sandstone (Greybull Sandstone locally) produces oil at depths ranging from 2,100-2,700 ft. At Mackay Dome, the Cretaceous Greybull Sandstone is productive at depths ranging from 3,700-3,900 ft. The western part of the Nye-Bowler segment of the play has also been explored and drilled, but has yielded no commercial quantities of hydrocarbons. The estimated future potential for conventionally recoverable hydrocarbons in the Nye-Bowler segment of the play is low.

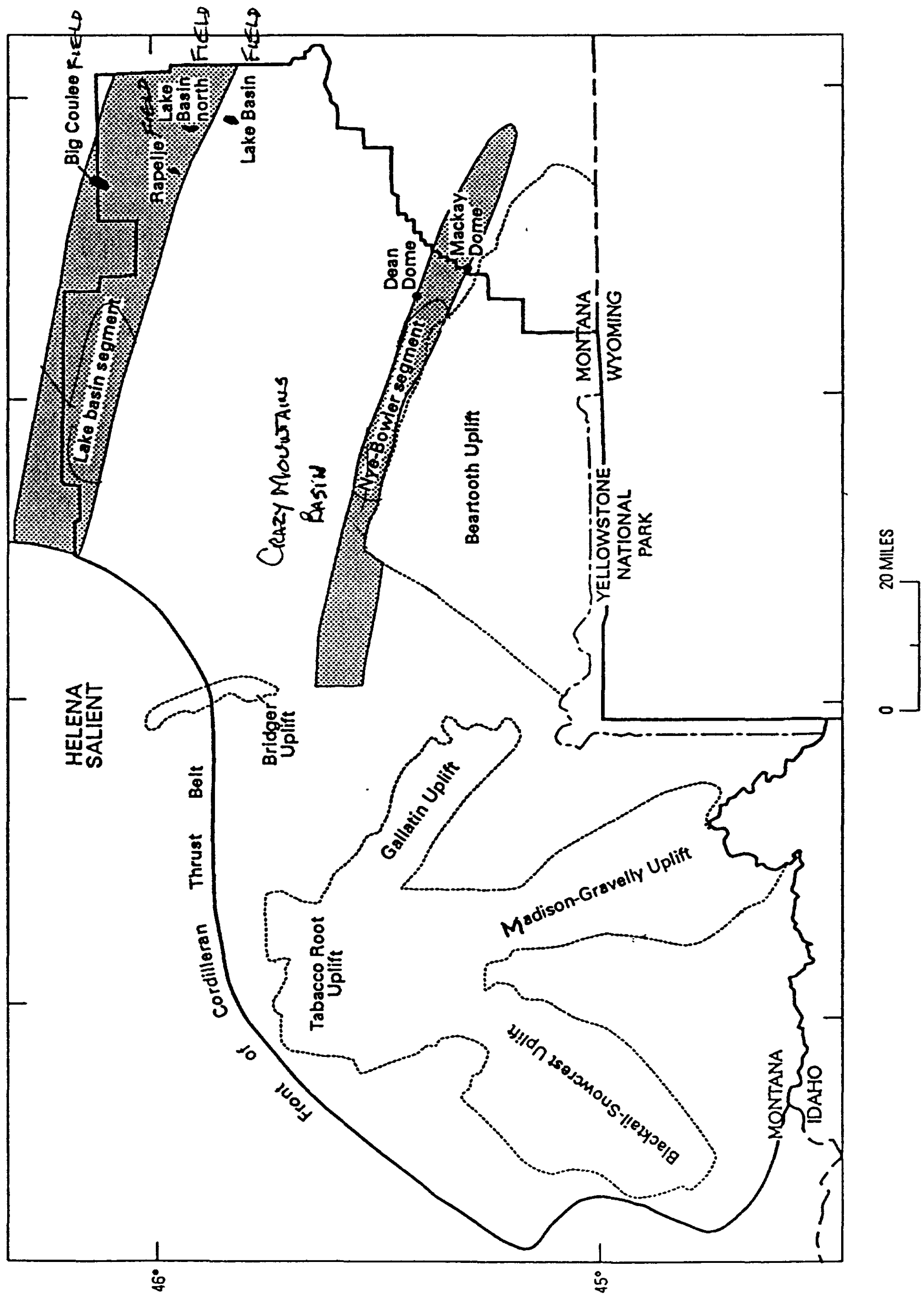

Figure 23. Map of Wrench Fault play.

OIL AND GAS PLAY DATA

PLAY **WRENCH FAULT**
PROVINCE **SOUTHWESTERN MONTANA** CODE **04-099-050**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**6**	**7.2**	**12**	**20**	**35**	**70**	**100**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**1**			**4**			**8**
Number of accumulations	**1**	**1**	**2**	**3**	**4**	**5**	**5**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**10**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

WIND RIVER BASIN PROVINCE (100)

By James E. Fox and Gordon L. Dolton

INTRODUCTION

The Wind River basin is one of several large, asymmetrical, intermontane basins of Laramide origin in the northern Rocky Mountains foreland and occupies the central portion of Wyoming. It is surrounded by major basement highs including the Wind River Mountains uplift to the southwest, the Owl Creek and Big Horn Mountains uplifts to the north, the Casper arch to the east, and the Granite Mountains uplift (Sweetwater arch) to the south which formed during the Laramide orogeny. Bounded by thrust, high-angle reverse, and normal faults as well as anticlinal flexures, this markedly asymmetrical basin has its axis along the north side near the Owl Creek mountains and Casper arch. Here, the basin is filled with a relatively complete sequence of Phanerozoic strata, and where Permian strata are at a depth in excess of 25,000 ft (-20,000 ft subsea) adjacent to the uplift. Phanerozoic strata consist of a relatively thin sequence of Paleozoic shelf carbonate, sandstone, and shale overlain by a thick sequence of Mesozoic and early Tertiary terrigenous rocks. The Wind River basin province has been productive of oil and gas since the discovery of Wyoming's first oil field in 1884 at Dallas Dome in rocks ranging from Mississippian to Eocene in age (fig. 24). Approximately 0.5 BBO and 2.1 TCFG have been discovered to the end of 1986 from approximately 41 fields. Structural and stratigraphic plays were identified in the province, four of which were individually assessed: Deep Basin Structure (020), Basin Margin Anticlinal (030), Muddy Sandstone (060), and Basin Margin Subthrust (080).

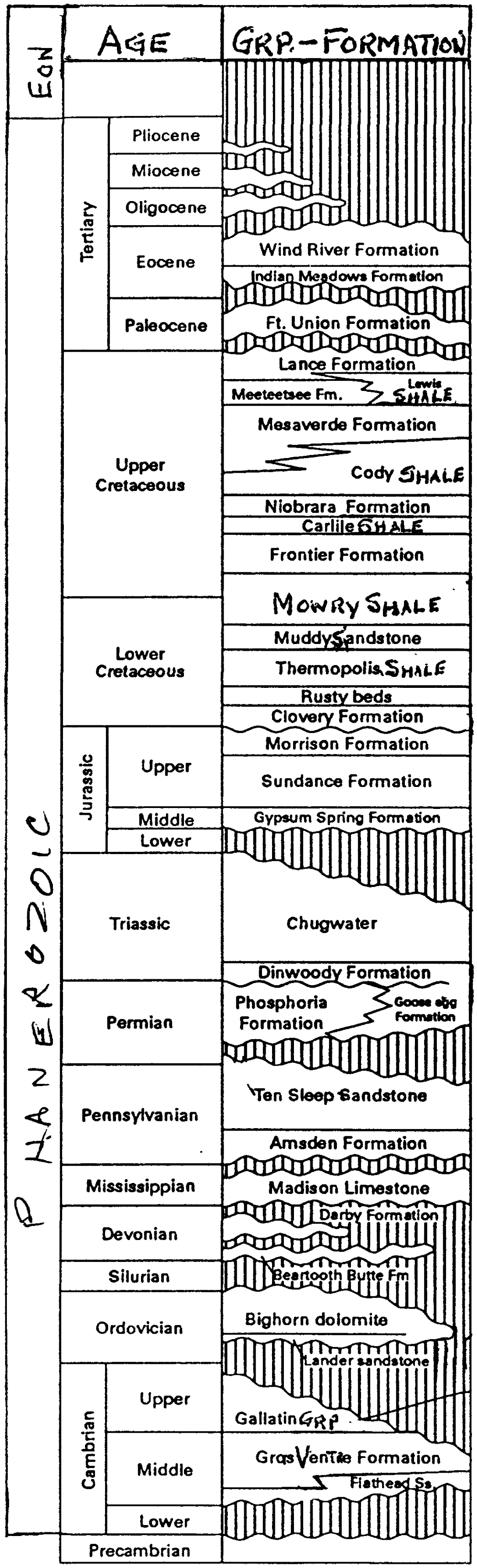

Figure 24. Generalized stratigraphic column, Wind River basin province.

DEEP BASIN STRUCTURE PLAY (020)

The play is characterized by gas accumulations in Tertiary and Cretaceous sandstone reservoirs in structural traps within the deep axial portion of the Wind River basin, where interbedded reservoir and source rocks occur at depths in excess of 23,000 ft (fig. 25). Significant amounts of gas resources have also been found in the Mississippian Madison Limestone in this part of the play at a depth of 23,700 ft; depth to the Precambrian here has been reported to be greater than 24,800 ft.

Reservoir rocks of good quality are primarily Cretaceous and Tertiary sandstone, deposited in a variety of environments including deltaic, marginal marine, and fluvial. The great depth of burial has resulted in reduced reservoir porosity and permeability through diagenesis. Although reservoir thicknesses exceed 200 ft at the Madden field, it is estimated that reservoirs in undiscovered accumulations would range from 20 to 150 ft in thickness. In cases where oil had migrated into sandstone reservoirs early in the burial history, some of the original porosity and permeability may have been preserved. Fracturing may also be important in enhancing reservoir quality. Deeply buried Mississippian carbonate reservoirs in the Madden field are also important as indicated by gas discoveries in these rocks below 20,000 ft.

Source rocks are abundant in Upper Cretaceous and lower Tertiary formations throughout the play. Seals include shale facies interbedded with the reservoirs, some of which may also be source beds. Probable source rocks include organic-rich shale in the Permian Phosphoria and the Cretaceous Mowry Shale and the Frontier, Niobrara, Mesaverde, Lance, and Tertiary Fort Union Formations (fig. 24), and range from thermally mature to supermature. Source rocks may have generated only gas. Some source beds may have been buried deeply enough to have generated hydrocarbons before the advent of the Laramide orogeny, when most of these hydrocarbon-bearing structures formed; however continued hydrocarbon generation during the Laramide orogeny is evident. Major reservoir rocks are interbedded with source rocks, facilitating easy migration from source to reservoir.

Traps are mainly structural and include several large anticlines, domes and folded structural noses. These trap types produce primarily gas from Cretaceous (Frontier, Cody, Mesaverde, Lance) and Tertiary (Fort Union, Wind River) age rocks. Drilling depths range from 4,000 to greater than 24,000 ft.

The play is productive, and a moderate level of exploration has been maintained. About 10 fields greater than 1 MMBOE in size are currently producing. The largest of these is the deep Madden field which contains in excess of 500 BCF of ultimately recoverable gas and has produced 232 BCFG to the end of 1986 from Upper Cretaceous reservoirs. Other major fields in the play include West Poison Spider, Waltman, and Pavillion (fig. 25). West Poison Spider field also produces oil from the Jurassic Morrison Formation and the Madden field, when put on line, is capable of producing a high volume of gas from the Madison Limestone. Future gas potential is very good.

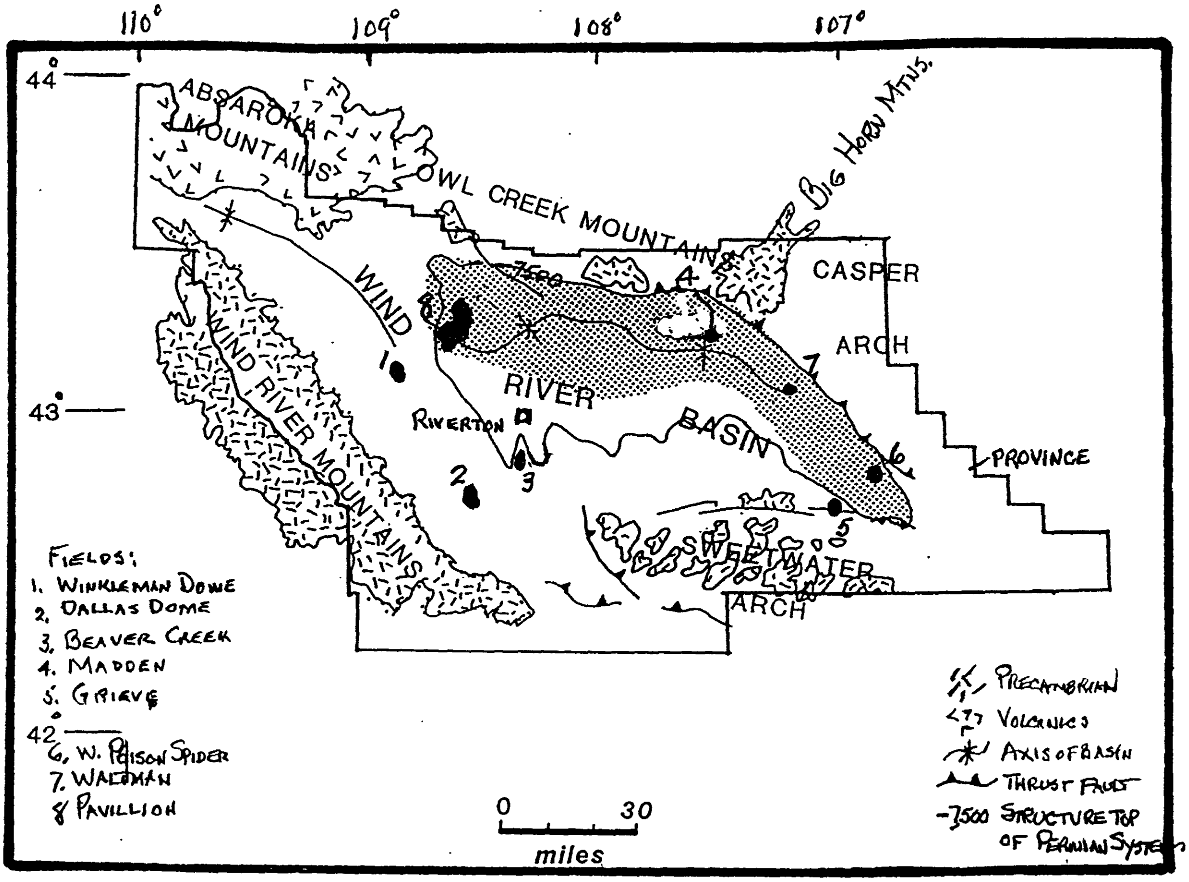

Figure 25. Map of Deep Basin Structure play.

OIL AND GAS PLAY DATA

PLAY **DEEP BASIN STRUCTURE**
PROVINCE **WIND RIVER BASIN** CODE **04-100-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**6**	**10**	**30**	**60**	**120**	**250**	**450**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**4**			**12**			**25**
Number of accumulations	**5**	**6**	**8**	**10**	**13**	**17**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**10**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BASIN MARGIN ANTICLINAL PLAY (030)

The play is characterized by oil and gas accumulations in multiple-age reservoirs, ranging from Cambrian to Eocene, in faulted anticlinal traps. The play is composed of three segments located along the shallow margins of the Wind River basin (fig. 26).

Productive reservoirs are in various formations and include the Madison, Tensleep, Phosphoria, Lakota, Muddy, Frontier, Cody, Mesaverde, Fort Union, and Wind River (fig. 24). Although sandstone is the dominant reservoir lithology, hydrocarbons have also been produced from carbonate reservoirs in the Madison Limestone, and Phosphoria Formation. Thickness of reservoirs in the larger producing fields exceed 300 ft; however, it is anticipated that combined reservoir thicknesses in undiscovered fields will range from 10 to 150 ft.

Numerous organic-rich shales are within the thick sequence of hydrocarbon-bearing strata. Oil and gas in Cretaceous and younger age reservoirs was probably sourced from associated organic-rich Cretaceous shale, while oil and gas in Paleozoic reservoirs was likely to have been derived primarily from a separate source in the Permian Phosphoria Formation. Thermal maturation is advanced in certain areas of the play, especially where source beds are very deeply buried, and in these areas the predominant resource is gas. Permian source rocks may have been generating hydrocarbons to the west long before the advent of the Laramide orogeny, when most of the shallow, hydrocarbon-bearing basin margin structures of the play formed, approximately at the same time as the basin was deepening. Deepening of the basin center occurred during the Laramide orogeny. This may have resulted in remigration of previously generated hydrocarbons, and the more recently generated hydrocarbons, into developing structures. Structural traps are anticlines, many of which are faulted, allowing migrating hydrocarbons to move into multiple levels of porous and permeable reservoirs in the various formations. Seals are present throughout the productive section; reservior depths range from less than 1,000 ft to 12,000 ft.

This is a mature play that has been extensively explored and developed. The first commerical oil well in the play, and in the State of Wyoming, was drilled in 1884 at Dallas Dome, a basin margin anticlinal structure located along the western margin of the Wind River basin (fig. 26). Field sizes range from about 90 MMBO in Winkleman Dome field, and 810 BCFG in Beaver Creek field, to numerous fields in the category of less than 1 MMBOE. Historically, most of the oil and gas in the province has been produced from this play. Approximately 500 MMBO and 1,250 BCF of both nonassociated and associated gas had been discovered to the end of 1986. Future potential is low for both oil and gas, mainly in small-size fields.

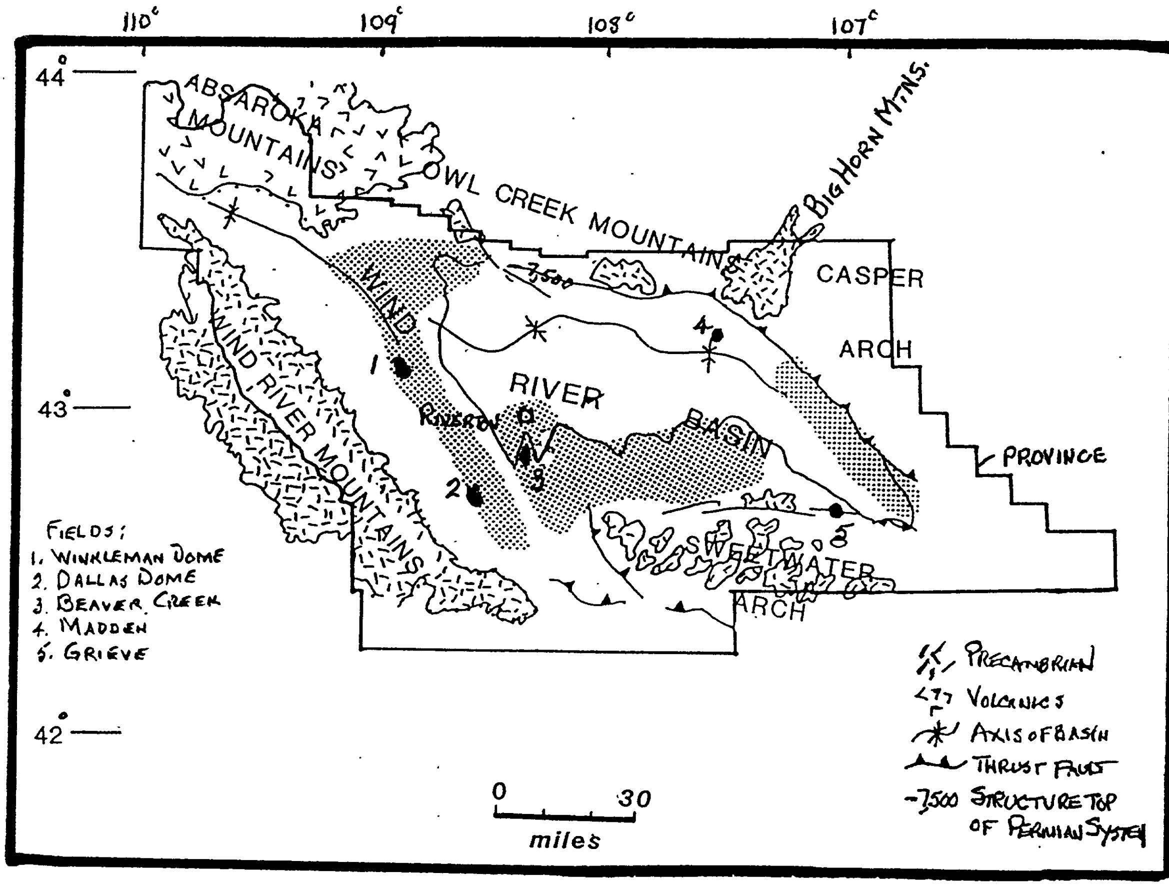

Figure 26. Map of Basin Margin Anticlinal play.

OIL AND GAS PLAY DATA

PLAY **BASIN MARGIN ANTICLINAL**
PROVINCE **WIND RIVER BASIN** CODE **04-100-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.8**
Gas	**0.2**

Fractiles * (estimated amounts)

Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.4**	**2**	**3**	**7**	**16**
Gas (x 10^9 CFG)	**6**	**6.1**	**6.7**	**7.8**	**10**	**17.6**	**30**
Reservoir depth (x10^3 ft)							
Oil	**1**			**7**			**12**
Gas (non-associated)	**1**			**7**			**12**
Number of accumulations	**2**	**2**	**3**	**4**	**5**	**6**	**6**

Average ratio of associated-dissolved gas to oil (GOR)	**550**	CFG/BBL
Average ratio of NGL to non-associated gas	**21**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

MUDDY SANDSTONE PLAY (060)

The play is characterized by oil and associated gas accumulations stratigraphically trapped in pinchouts of the Lower Cretaceous Muddy Sandstone into shale facies. Although the Muddy Sandstone may extend beyond the limits shown on the map (fig. 27), the area of the play (10-30 mi wide and 120 mi long) is restricted to the outline shown due to, (1) anticipated reservoir degradation of sandstone in the deeper, axial part of the basin, and (2) the generally poor development and quality of the Muddy Sandstone to the north.

Reservoir beds in the Muddy were deposited as a complex series of sand bodies, in fluvial, deltaic, estuarine, beach, and offshore bar environments. The distribution of these facies may have been controlled by paleotopography and structural growth during Muddy deposition. The reservoirs are closely associated with thick source rocks, making conditions for primary stratigraphic entrapment of hydrocarbons ideal. Total thickness of the Muddy is as great as 150 ft in places along the western margin of the basin, thinning locally and grading almost completely into shale and siltstone. Although effective pay zones in the Muddy are thin and average only about 15-20 ft in thickness, the high porosity and permeability of reservoirs and favorable commercial quality of the oil make it a prime exploration objective.

Source beds are organic-rich black shale of the Mowry Shale which overlies, and the Thermopolis Shale that underlies Muddy Sandstone reservoir rocks (fig. 24). As overburden accumulated through burial, oil was squeezed out of both the thick overlying and underlying source rocks into the intervening porous sandstone reservoir rocks. Depth of burial of the Muddy is in excess of 5,000 ft throughout the play, which is a sufficient depth for the generation of hydrocarbons.

The basic trapping mechanism throughout the play is updip pinchout of discontinuous sandstone reservoirs, such as that found at the Grieve field, the largest field in the play (about 28 MMBO in size), where production is from an unusually thick section (60 ft) of estuarine sandstone which thins abruptly updip to the west forming a stratigraphic trap. Good seals are present in the Mowry and Thermopolis Shales; drilling depths range from 2,000 to 12,000 ft.

The level of exploration of the play ranges from maturely explored along the southern margin of the basin, to lightly explored in the central part. Only a few fields are greater in size than 1 MMBOE. Cumulative production is approximately 40 MMBO and 80 BCF of associated gas to the end of 1986. Future potential for both oil and gas in the play is estimated to be very good.

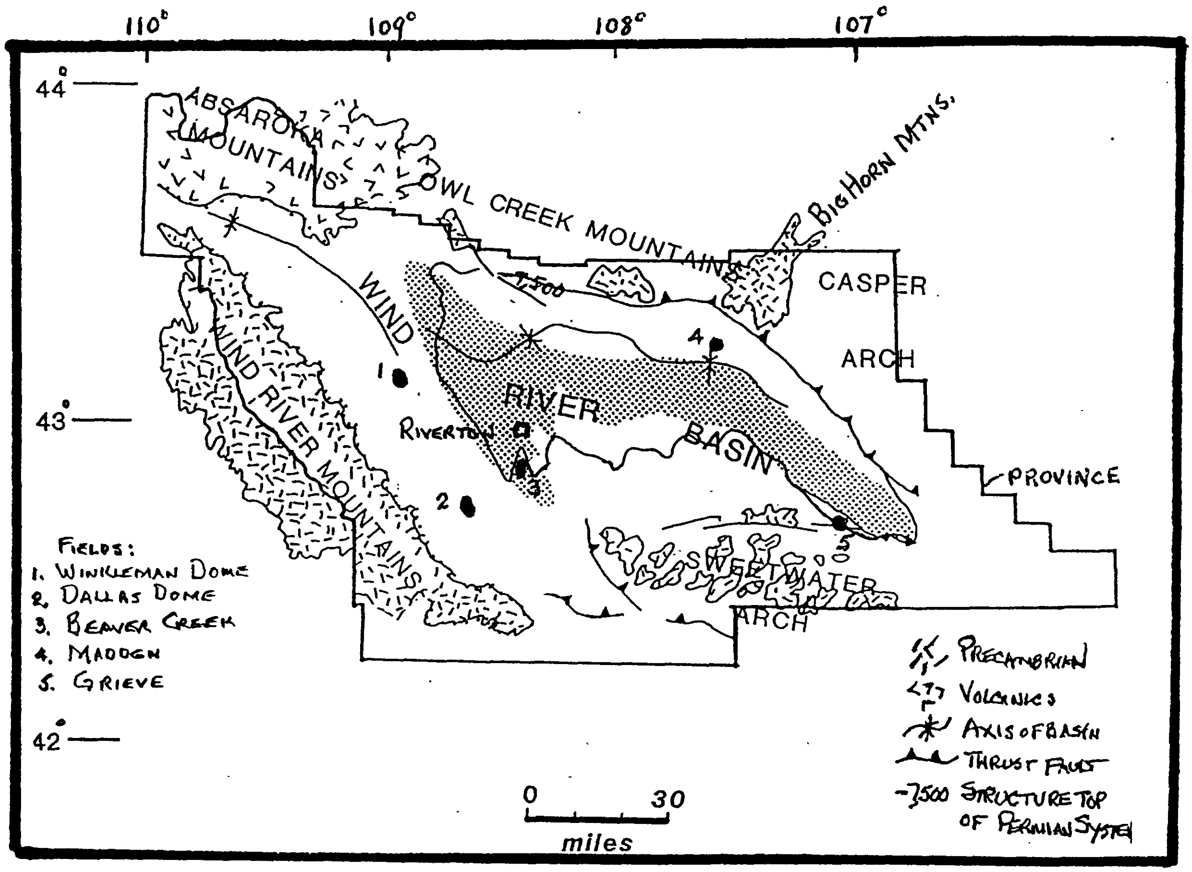

Figure 27. Map of Muddy Sandstone play.

OIL AND GAS PLAY DATA

PLAY **MUDDY SANDSTONE**
PROVINCE **WIND RIVER BASIN** CODE **04-100-060**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.6**	**2.5**	**4.7**	**14**	**50**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**2**			**7**			**12**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**10**	**13**	**17**	**20**	**23**	**27**	**30**

Average ratio of associated-dissolved gas to oil (GOR)	**2500**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BASIN MARGIN SUBTHRUST PLAY (080)

The play is characterized by probable oil and gas accumulations in Phanerozoic strata in footwall structural traps beneath the hanging wall of thrusted or reverse faulted Precambrian crystalline rocks. The area of the play is made up of three narrow segments along the thrusted flanks of the Wind River basin (fig. 28). Depths to target zones will be highly variable and dependent on the thickness of the Precambrian wedge (dip angle of the thrust plane) and orientation and thickness of underlying Phanerozoic strata.

Reservoir rocks would be similar in quality and type to known Paleozoic and Mesozoic reservoirs in other plays in this province. Some of the less conventional reservoir lithotypes (e.g. shales) may also have good reservoir characteristics due to probable extensive fracture systems associated with the thrusting.

Source rocks in the footwall section are numerous, including organic-rich shale of the Phosphoria Formation, Mowry Shale and Frontier, Niobrara, Mesaverde, and Fort Union Formations (fig. 24). Because Laramide faulting has thrust Precambrian over Phanerozoic rocks, the burial depth of source rocks is usually great enough for them to have generated hydrocarbons locally, or hydrocarbons could have migrated from shales in thermally mature areas in other, deeper parts of the basin. Generation in this case occurred during and after the Laramide orogeny when structures formed. Some early, or pre-Laramide, migration may have taken place, moving hydrocarbons into porous sandstone reservoirs before tectonic development of basin margin folds and faults. If these reservoirs had been sealed due to the presence of impermeable facies, stratigraphic traps may have developed prior to basin-margin thrusting. Faulting could have then superimposed some degree of structural control on such stratigraphic traps. It is probable that structural settings below the Precambrian thrust plate are very complex.

Drilling and seismic exploration in subthrust rocks in the play is quite recent and at a low level of activity. Two fields have been discovered , Bullfrog in 1979 and Tepee Flats in 1981. Bullfrog is located below the leading of a thrust on a faulted structural closure and has produced 3.7 BCFG to the end of 1986 from combined reservoirs in the Cretaceous Frontier Formation, Muddy Sandstone, Lakota Sandstone (Cloverly Formation) and Jurassic Morrison and Sundance Formations. Tepee Flats field is located 3 mi north of Bullfrog on a closed structure and under the Precambrian overhang wedge. The discovery well drilled through more than 8,800 ft of Precambrian granite to a total depth of 19,733 ft in the Morrison Formation, and was completed in a 165-ft-thick zone in the Frontier Formation for an initial potential of 11 MMCF of gas per day. Cumulative production from the field to the end of 1986 is 3.3 BCFG. Future potential for both gas and oil is fair; it is probable that the majority of undiscovered fields will be gas in deep segments of the play and oil fields in shallower segments.

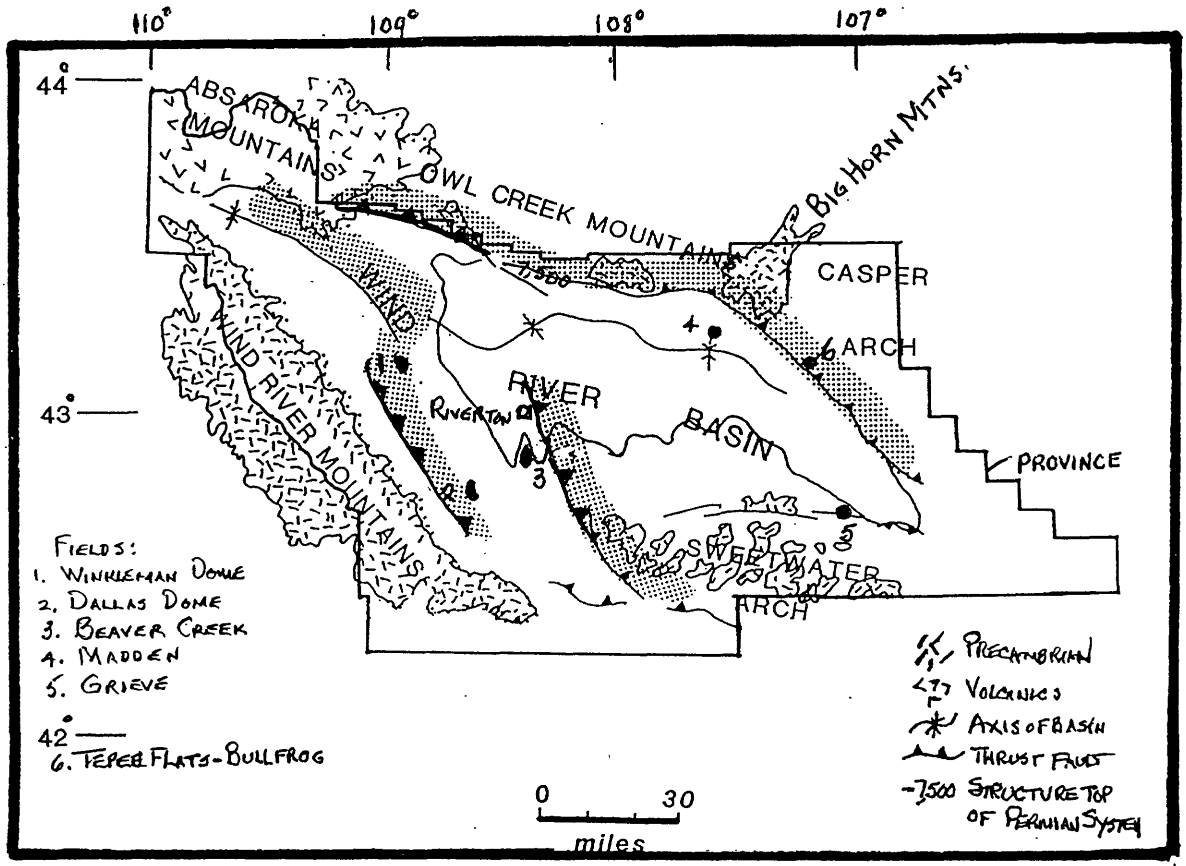

Figure 28. Map of Basin Margin Subthrust play.

OIL AND GAS PLAY DATA

PLAY **BASIN MARGIN SUBTHRUST**
PROVINCE **WIND RIVER BASIN** CODE **04-100-080**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.3**
Gas	**0.7**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**2.2**	**4**	**7.5**	**16**	**30**
Gas (x 10^9 CFG)	**6**	**6.6**	**10**	**18**	**33**	**75**	**180**
Reservoir depth (x10^3 ft)							
Oil	**6**			**10**			**15**
Gas (non-associated)	**8**			**12**			**25**
Number of accumulations	**1**	**1**	**2**	**3**	**5**	**11**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**550**	CFG/BBL
Average ratio of NGL to non-associated gas	**10**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

POWDER RIVER BASIN PROVINCE (101)

By Gordon L. Dolton and James E. Fox

INTRODUCTION

The Powder River basin is a major intermontane basin of Laramide origin in the northern Rocky Mountains and occupies northeastern Wyoming and a small part of southeastern Montana. Together with portions of adjoining uplifts, it comprises the Powder River basin province and covers an area of more than 40,000 mi^2. The basin is a deep, northerly trending, asymmetric, mildly deformed trough, approximately 250 mi long and 100 mi wide. Its structural axis is close to its western margin, which is defined by reverse and thrust faults and by hogbacks of steeply dipping and overturned strata along the Bighorn uplift and by the Casper arch. It is bounded on the south by reverse or thrust faults along the Laramie and Hartville uplifts, and on the east by the Black Hills, where strata are mildly folded and locally faulted along monoclines associated with the Black Hills uplift. The northern margin is defined by the structurally subtle, northwest-trending Miles City arch.

The Powder River basin is filled with a thick sequence of Phanerozoic strata that exceed 18,000 ft in thickness along the basin axis (fig. 29). This sequence is comprised of a relatively thin blanket of Paleozoic shelf carbonate, sandstone, and shale, that rarely exceeds 2,200 ft, followed by a very thick succession of Mesozoic and early Tertiary terrigenous rocks that record the evolution, fill, and destruction of the Western Interior seaway, uplift of the western Cordillera, and development of local uplifts and the present basin.

The basin is one of the richest petroleum provinces in the Rocky Mountains. Greater than 2.5 BBO have been discovered in approximately 225 fields since the discovery of the giant Salt Creek field in 1908. Hydrocarbons occur in reservoirs ranging in age from late Paleozoic to late Mesozoic in both structural and stratigraphic traps. Ten plays were individually assessed in the province: Basin Margin Anticline (020), Sussex-Shannon (030), Leo Sandstone (040), Dakota Sandstone (050), Mesaverde-Lewis (060), Deep Frontier Sandstone (070), Deep Muddy Sandstone (080), Shallow Muddy Explored (090), Minnelusa Explored (100), and Minnelusa Unexplored (110).

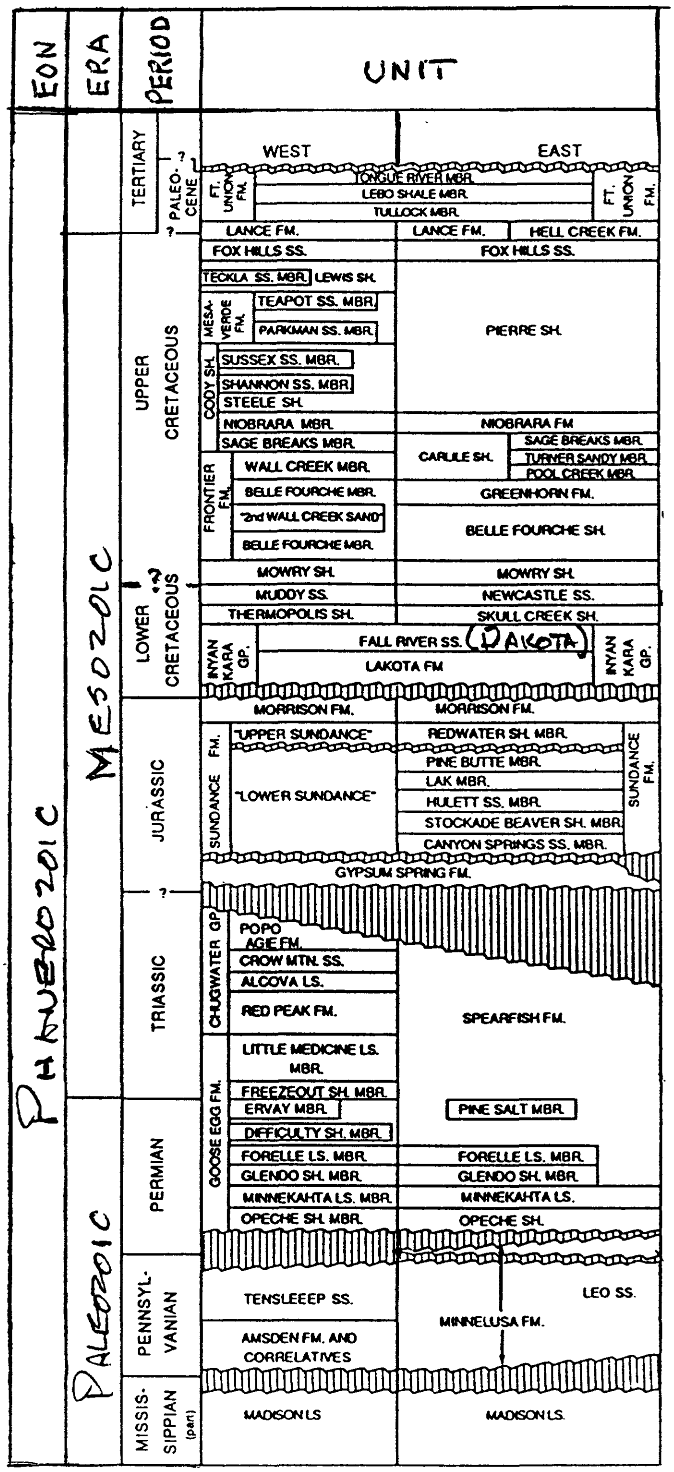

Figure 29. Generalized stratigraphic columns, Powder River basin province.

BASIN MARGIN ANTICLINE PLAY (020)

The play is characterized by oil and gas accumulations in sandstone and carbonate reservoirs trapped in large anticlines along the southern and western margins of the basin (fig. 30). Major reservoir rocks are sandstone, carbonate; minor reservoirs occur in fractured shale. The most important of these are sandstone reservoirs in the Cretaceous Frontier Formation, Muddy and Dakota Sandstones, and the Pennsylvanian-Permian Tensleep Sandstone and Minnelusa Formation (fig. 29). Multiple pay zones are common; however, Mississippian rocks are rarely productive and pre-Mississippian reservoirs are not productive. The Permian-Triassic redbed sequence is a regional seal, and separates Paleozoic and Mesozoic reservoirs in most of the fields.

Principal source rocks for Paleozoic reservoirs include Pennsylvanian black shales and probably organic-rich rocks of the Permian Phosphoria (Goose Egg equivalent) Formation to the west of the province. Cretaceous rocks, especially in the Mowry and Niobrara, are the principal source of oil and gas in Cretaceous reservoirs and may have contributed to older reservoirs where migration paths were available, particularly where source and reservoir rocks have been juxtaposed by faults. However, Cretaceous producing reservoirs are almost always segregated from underlying Paleozoic reservoirs; each typically has a distinct oil type which is related to different source rocks. Black shale beds in the middle member of the Minnelusa Formation are excellent source rocks and appear to have reached thermal maturity during the Laramide orogeny. Permian black shales in western Wyoming and eastern Idaho would have been buried deep enough to generate hydrocarbons by Jurassic time. If petroleum was derived from both distant and local sources, some of it could have migrated into the area of the present basin during the Jurassic and been trapped until redistributed and augmented by locally generated hydrocarbons during the Laramide orogeny. Cretaceous age source rocks probably began expelling oil in Eocene time into structures which were developing around the basin margins. Principal among these source rocks is the Mowry Shale, which expelled large quantities of oil, and the less prolific Skull Creek Shale. The Niobrara Formation and Carlile Shale are also significant sources of oil for Upper Cretaceous reservoirs, however, the areal extent of effective source rocks in these formations is less extensive than in the underlying Mowry Shale. Lower Cretaceous shale and shale of the Upper Cretaceous Frontier and Steele Shale have generated lesser amounts of oil.

The majority of the anticlinal traps are relatively simple folds which are reverse or thrust faulted at depth but with extensional faults on their crests, such as Salt Creek field (fig. 30). Fault closures, particularly on plunging antclinal noses also are productive as are several combination traps. Impermeable, fine-grained rocks interbedded with reservoir rocks provide seals. Drilling depths range from 4,000 to 10,000 ft.

Exploration in the play spans approximately 100 years with the discovery of a series of major and giant fields, including main Salt Creek (1908), Teapot Dome(1922), Big Muddy (1916), and Lance Creek (1918) fields. Most of these were found early in the exploration history of the basin. Total discovered recoverable oil exceeds 1 BBO, along with substantial amounts of dissolved-associated gas. Salt Creek alone has produced almost three-quarters of a BBO. The play is very mature, and future undiscovered resources will probably be in small, subtle traps.

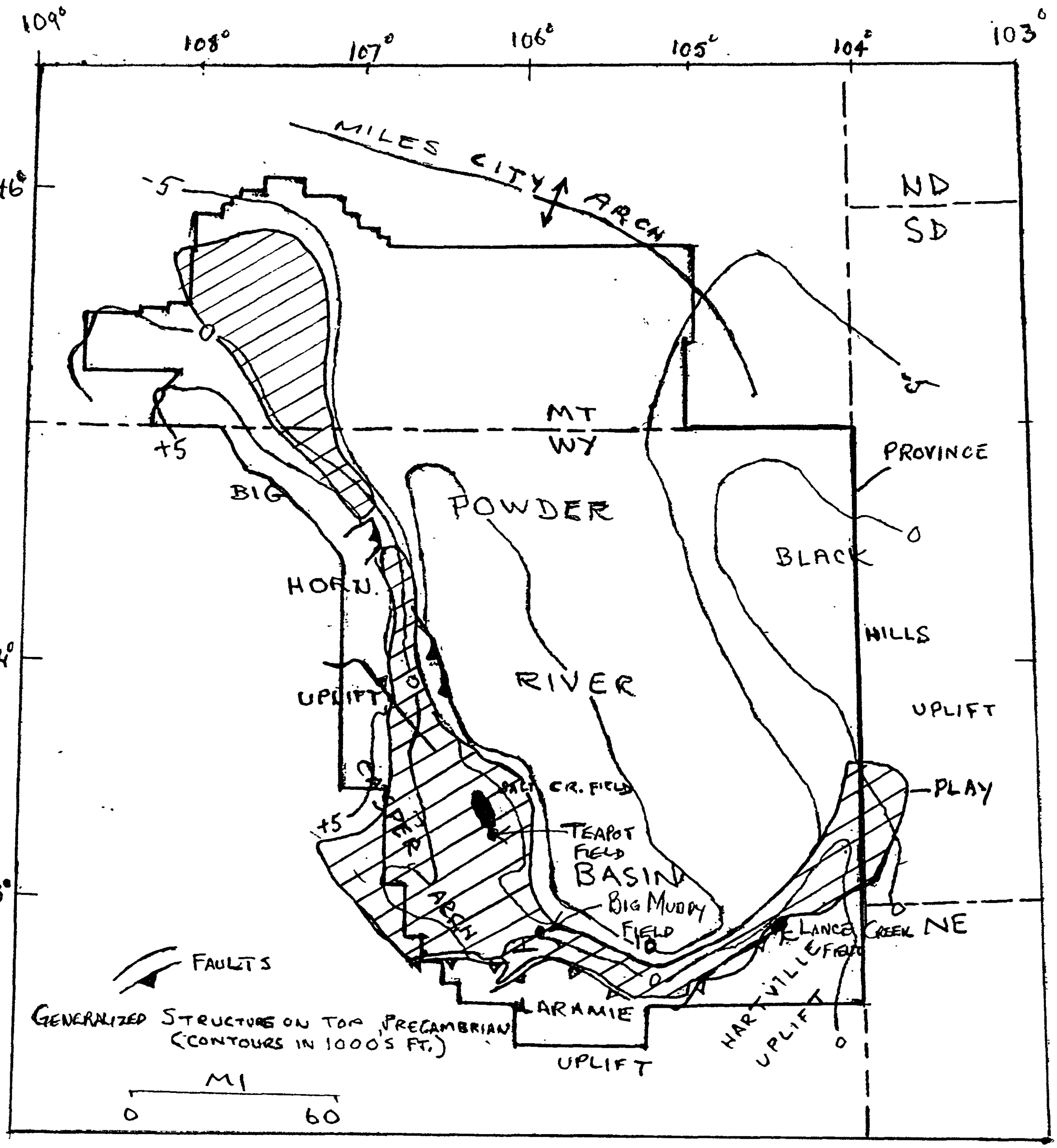

Figure 30. Map of Basin Margin Anticline play.

OIL AND GAS PLAY DATA

PLAY **BASIN MARGIN ANTICLINE**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.8**	**3**	**6**	**12**	**20**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**4**			**8**			**10**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**2**	**3**	**4**	**5**	**7**	**10**	**12**

Average ratio of associated-dissolved gas to oil (GOR)	**860**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

SUSSEX-SHANNON SANDSTONE PLAY (030)

The play is characterized by oil and gas fields in stratigraphic traps in the Sussex and Shannon Members of the Upper Cretaceous Cody Shale. These two units were deposited as parts of offshore bar complexes. They are the result of residual sand sheets on the shelf being transported and formed into broad, elongate sandstone bodies or offshore bars by marine currents. The play covers an area of approximately 15,300 mi^2 in the deeper part of the basin (fig. 31).

Mapped limits of known oil fields suggest that reservoirs have a relatively narrow and sinuous distribution; however, the overall sandstone bodies are much broader, with relief on the order of tens of feet over an area of several miles. Local mapping identified at least 12 well-sorted imbricated sandstone bodies in the Sussex that trend generally N. 30°-40° W. and are separated by zones of siltstone and mudstone. Areal extent of these units is about 0.5 to 2 mi wide, 5 to 30 mi long, and up to 33 ft thick. Sandstones of good reservoir quality are up to 30 ft thick and may extend 20 or more miles along strike and about 3 mi downdip. Average porosity and permeability range from 10 to 14 percent and 1 to 20 md, respectively.

Shale beds in the Niobrara and Carlile are major sources of oil in Upper Cretaceous reservoirs; however, the areal extent of effective source rocks in these formations is less extensive than the deeper Mowry Shale. Shale in the Frontier Formation and Steele Shale have also generated and expelled oil, but in amounts secondary to the major Cretaceous source rocks (fig. 29). In most of the play vertical migration of oil and gas allowed reservoirs of both the Sussex and Shannon to be charged from deeper source rocks. Traps are formed by classic updip pinchout of porous and permeable shelf sandstone bars into impermeable shale; the shale also forms both top and bottom seals. Drilling depths to prospective traps range from 7,000 to 12,000 ft.

Exploration in the play has resulted in the discovery of about 170 MMBO and 80 BCFG to the end of 1986. Of the discovered fields, 10 are larger than 10 MMBO in size and 10 are smaller. The largest producing Sussex field is House Creek, approximately 20 MMBO, and the largest producing Shannon field, Hartzog Draw, is about 60 MMBO and 28 BCFG in size. The southern part of the play is well explored, but the northern part is in an immature stage of exploration. Future potential for undiscovered resources is moderate, and future fields are estimated to be in the same size range as those discovered.

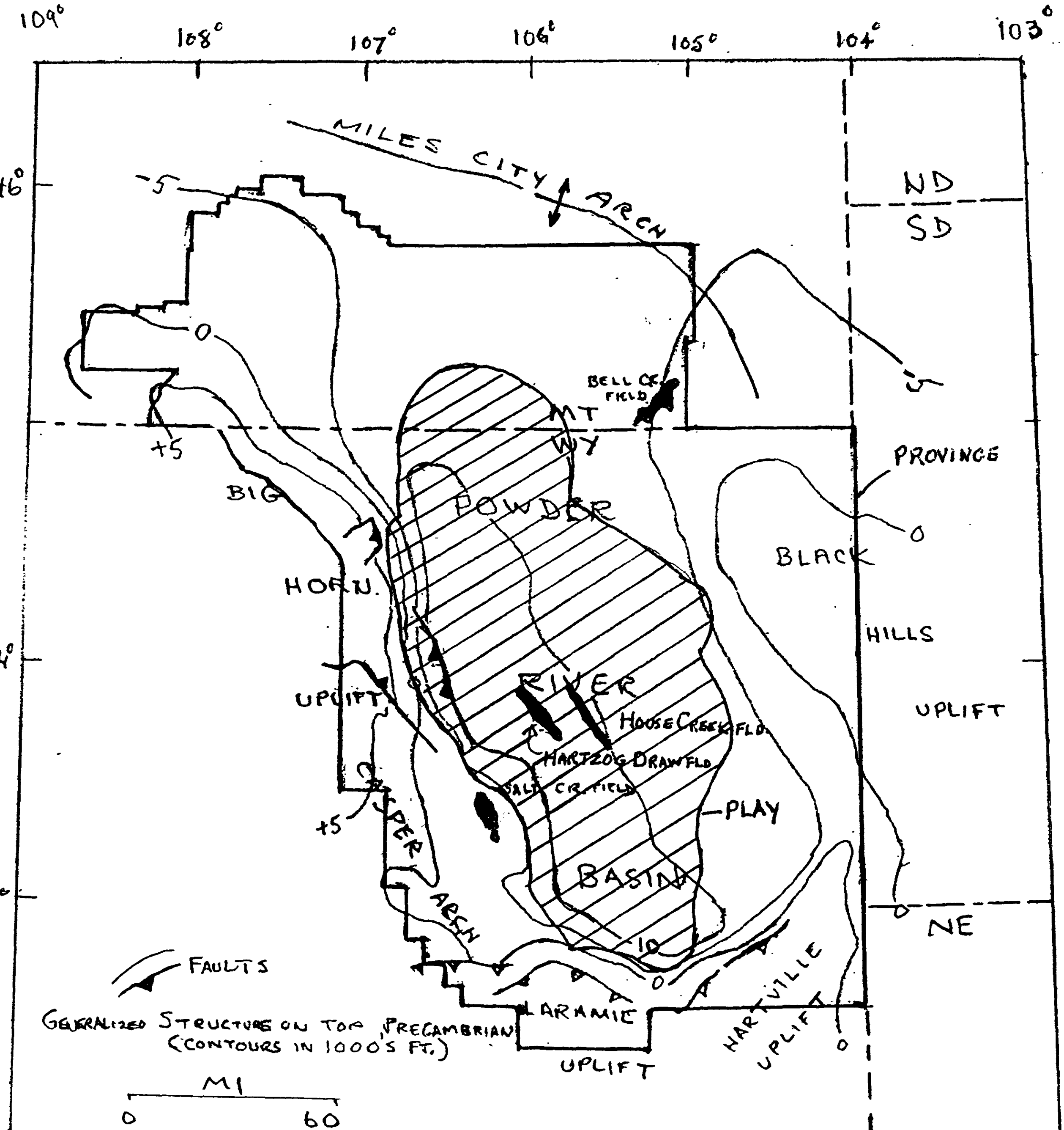

Figure 31. Map of Sussex-Shannon play.

OIL AND GAS PLAY DATA

PLAY **SUSSEX-SHANNON**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.8**	**3**	**6**	**18**	**52**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**7**			**9.5**			**12**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**10**	**12**	**16**	**20**	**24**	**28**	**30**

Average ratio of associated-dissolved gas to oil (GOR)	**850**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

LEO SANDSTONE PLAY (040)

The play is characterized by the occurrence of oil in stratigraphic traps in quartzose sandstone reservoirs of the Leo Sandstone member of the Minnelusa Formation, in the southern part of the basin (fig. 32). The Leo consists of sandstone, carbonate, shale and evaporite beds, which were deposited in a suite of environments associated with offshore-prograding eolian sand dunes. Reservoirs in the Leo range from a few feet to more than 50 ft in thickness, and are variable in quality.

Pennsylvanian age black shale beds associated with the reservoir sequence are believed to be the principal source for oil in the Leo. Organic carbon content of the shale ranges from less than 1 to 26 wt percent and averages 5.4 percent. These shales reached a sufficient level of thermal maturity to have generated substantial quantities of liquid hydrocarbons. Speculative migration models also propose long distance pre-Laramide migration through Tensleep-Minnelusa reservoirs from Phosphoria (Goose Egg) source beds, far to the west, prior to the formation of the present basin. Gravity of the oil ranges generally from 20° to 35° API., and increases with depth. Oils are typically undersaturated relative to gas. Traps are subtle and include primarily sandstone pinchouts or gradations into impermeable and sealing facies. Drilling depths range from 6,000 to as deep as 17,000 ft.

Although a few fields have been found in the Leo in structural traps, the Leo stratigraphic play is only lightly explored. The future potential is good; however, accumulation sizes are anticipated to be small.

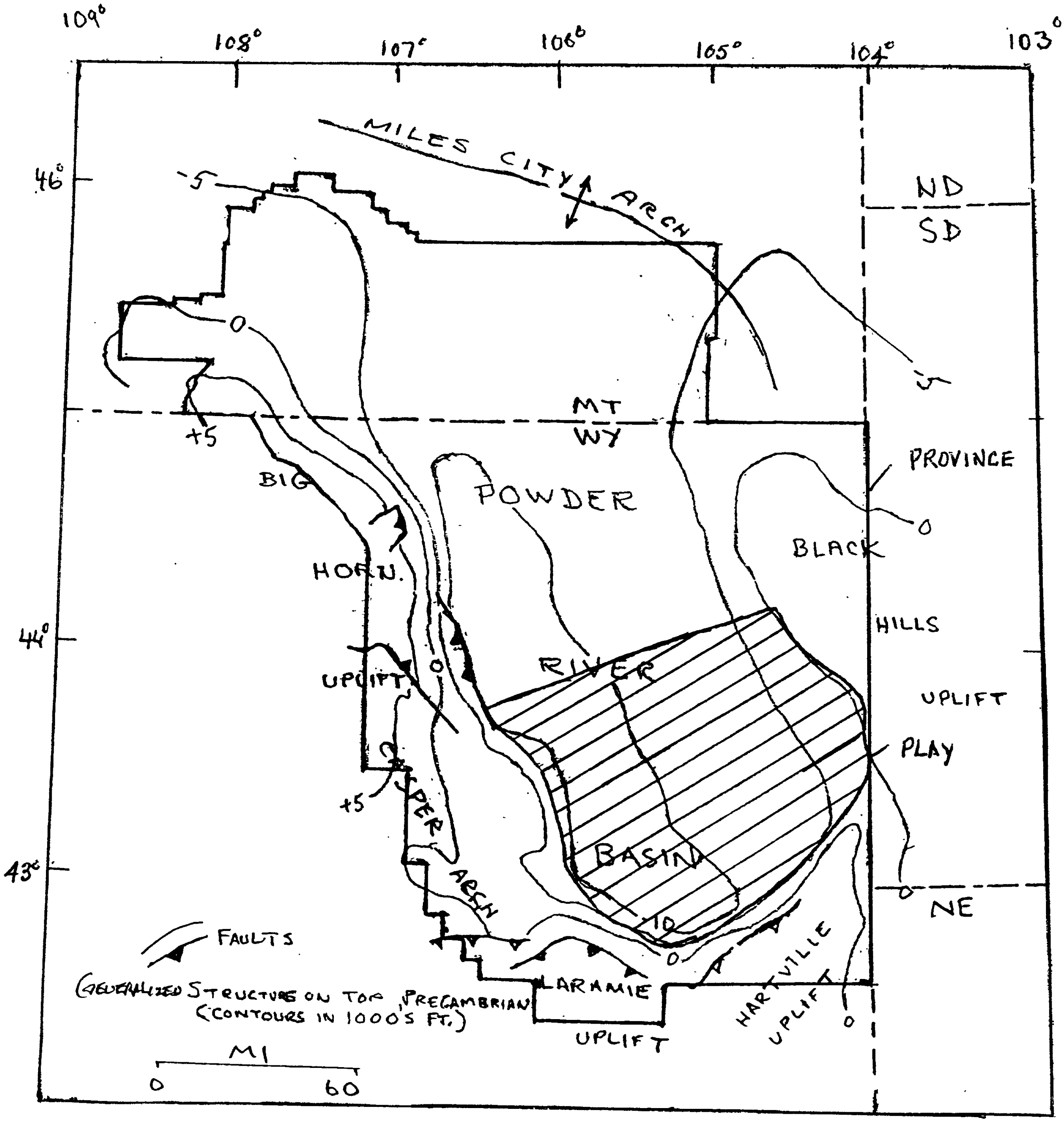

Figure 32. Map of Leo Sandstone play.

OIL AND GAS PLAY DATA

PLAY **LEO SANDSTONE**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.04**	**1.2**	**1.5**	**2.1**	**3.4**	**5.6**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**6**			**10**			**17**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**20**	**30**	**40**	**50**	**70**	**110**	**200**

Average ratio of associated-dissolved gas to oil (GOR)	**275**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL/10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL/10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

DAKOTA SANDSTONE PLAY (050)

The play is characterized by oil and gas accumulations in stratigraphic traps that produce from reservoirs in the regressive clastic wedge of the Dakota Sandstone (Fall River Sandstone) of the Lower Cretaceous Inyan Kara Group (fig. 29). The play covers an area of about 21,600 mi^2 in the east-central part of the basin (fig. 33). This widespread clastic wedge prograded into the Western Interior Seaway from the south and east. It is composed of a marine, deltaic, and alluvial complex which becomes progressively more marine to the west, where it consists entirely of marine shale and siltstone of the Thermopolis Shale on the west side of the basin.

Reservoir rocks are generally fine-grained, mature quartzose sandstones. Average reservoir porosity ranges from 12 to 23 percent and averages 13 to 18 percent. The Dakota Sandstone is sealed at both top and bottom by enclosing shales of the Skull Creek Shale. Lateral and vertical seals for individual traps within the unit are provided by finer grained rocks, such as those found in abandoned channel oxbow fills and low energy marine sequences.

Oil is probably derived from the organic-rich, overlying Mowry Shale, which is separated by several hundred feet from the reservoir sequence. Other possible source rocks include associated marine shale in the Skull Creek and Fall River. Shale in the Mowry and Skull Creek contains a mixture of types II and III organic matter. Because it has a generally higher proportion of type II matter, the Mowry is a richer petroleum source rock than the others. All of these source rocks are thermally mature in the deeper parts of the basin.

Most of the oil and gas accumulations in the play occur on the structurally uncomplicated east flank of the basin. Traps are principally those associated with distributary and estuarine channel sandstone within the Dakota depositional complex. Individual point-bar deposits or point-bar complexes have cut into older marine, deltaic, and strandline sediments and are typically sealed updip by fine-grained abandoned channel deposits. Marine bar sandstone traps resulting from pinchouts are also considered prospective, although not well documented. In a few instances, structure plays a role in providing additional closure. For example, near the western edge of the Dakota regressive wedge, several stratigraphic accumulations have been discovered in combination with large structural closures or plunging anticlinal noses. Drilling depths range from 4,000 to 13,500 ft.

Exploration in the play has been continuous for approximately 30 years resulting in the discovery of more than 30 individual accumulations, aggregating between 60 and 100 MMBO. The largest field, Coyote Creek, is approximately 22 MMBO in size. Exploration is currently expanding into deeper parts of the basin. Future potential is good and undiscovered fields will probably be similar in size (< 10 MMBO) to those found.

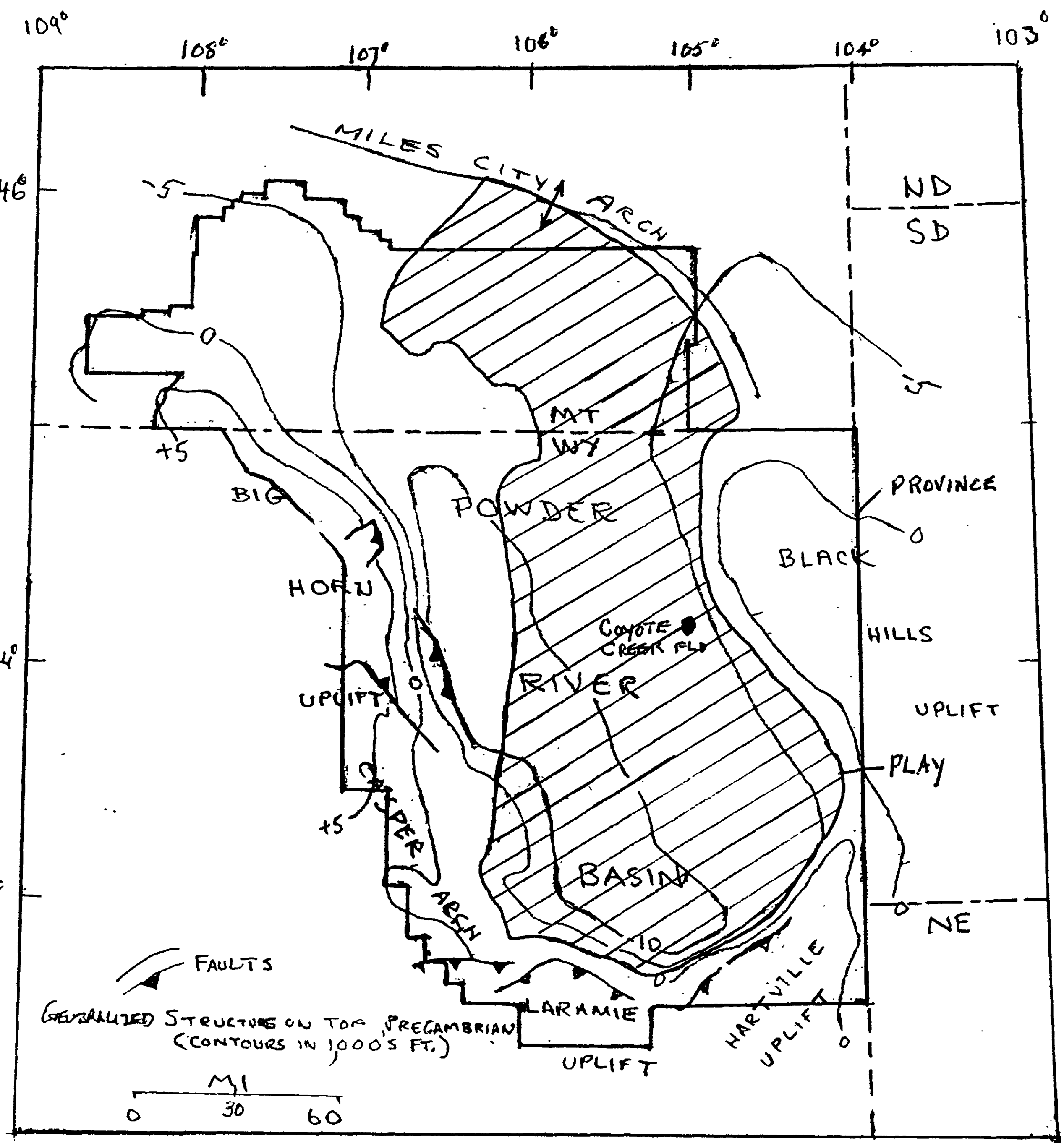

Figure 33. Map of Dakota Sandstone play.

OIL AND GAS PLAY DATA

PLAY **DAKOTA SANDSTONE**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-050**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.6**	**2.7**	**5**	**9.5**	**20**	**30**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**4**			**8.5**			**13.5**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**10**	**12**	**16**	**20**	**26**	**34**	**50**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

MESAVERDE-LEWIS PLAY (060)

The play involves oil and gas fields that produce from stratigraphic traps in sandstone reservoirs of the Upper Cretaceous Mesaverde Formation and Lewis Shale. The play area is an elongate, northwesterly trend in the deeper, western part of the basin and covers about 9,250 mi^2 (fig. 34). Strata involved in the play are part of a large western-derived regressive clastic sequence and include deltaic and marine shelf sandstones that grade into siltstone or shale.

Deltaic sands were deposited in a wave-dominated high-destructive shoreline environment and were locally modified into offshore bars. These bars make up the porous reservoir sandstone that pinch out eastward and are the primary reservoirs in the Teapot and Parkman Members of the Mesaverde Formation and the Teckla Sandstone Member of the Lewis Shale (fig. 29). Average reservoir thicknesses typically range from 10 to 50 ft, and average porosity and permeability range from 13 to 18 percent and less than 2 to 34 md, respectively.

The Niobrara Formation and Carlile Shale are probably the primary sources of oil for Mesaverde and Lewis reservoirs, although the areal extent of effective source rocks in these formations is less extensive than the deeper Mowry Shale. Shale in the Frontier and Steele Shale have also generated and expelled oil in amounts secondary to the major Cretaceous source rocks. Expelled oil probably migrated vertically into reservoirs in the play

Traps are created by updip, eastward pinchout of shallow marine sandstone reservoirs into finer-grained prodelta facies which also act as seals. In the largest oil field that produces from the Teckla Sandstone, Poison Draw, the reservoirs are a complex of strandline sandstones in which oil is trapped by updip loss of porosity due to increasing siltstone and shale content. The complexity of reservoir sandstones is attested to by the presence of multiple oil-water contacts. One of the largest Teapot Sandstone producing fields, Well Draw, is a large northwest-trending stratigraphic trap formed by an updip facies change from porous, shallow-water marine sandstone into tight, offshore siltstone and shale. Parkman Sandstone reservoirs also contain oil trapped stratigraphically in marine bar sandstones. Depth to objective traps ranges from 5,000 ft down to about 10,000 ft in the axial part of the basin.

Over a period of 30 years starting in 1957, approximately 100 MMBO and 165 BCFG have been discovered in the play. About 13 of the fields are greater than 1 MMBOE in size, and 45 fields are less than 1 MMBOE in size. The largest field, Well Draw, is about 45 MMBO and 85 BCFG in size. A very large area in the northern part of the play is minimally explored. Overall undiscovered resources are estimated to be moderate, and new fields will probably be similar in size to those already found.

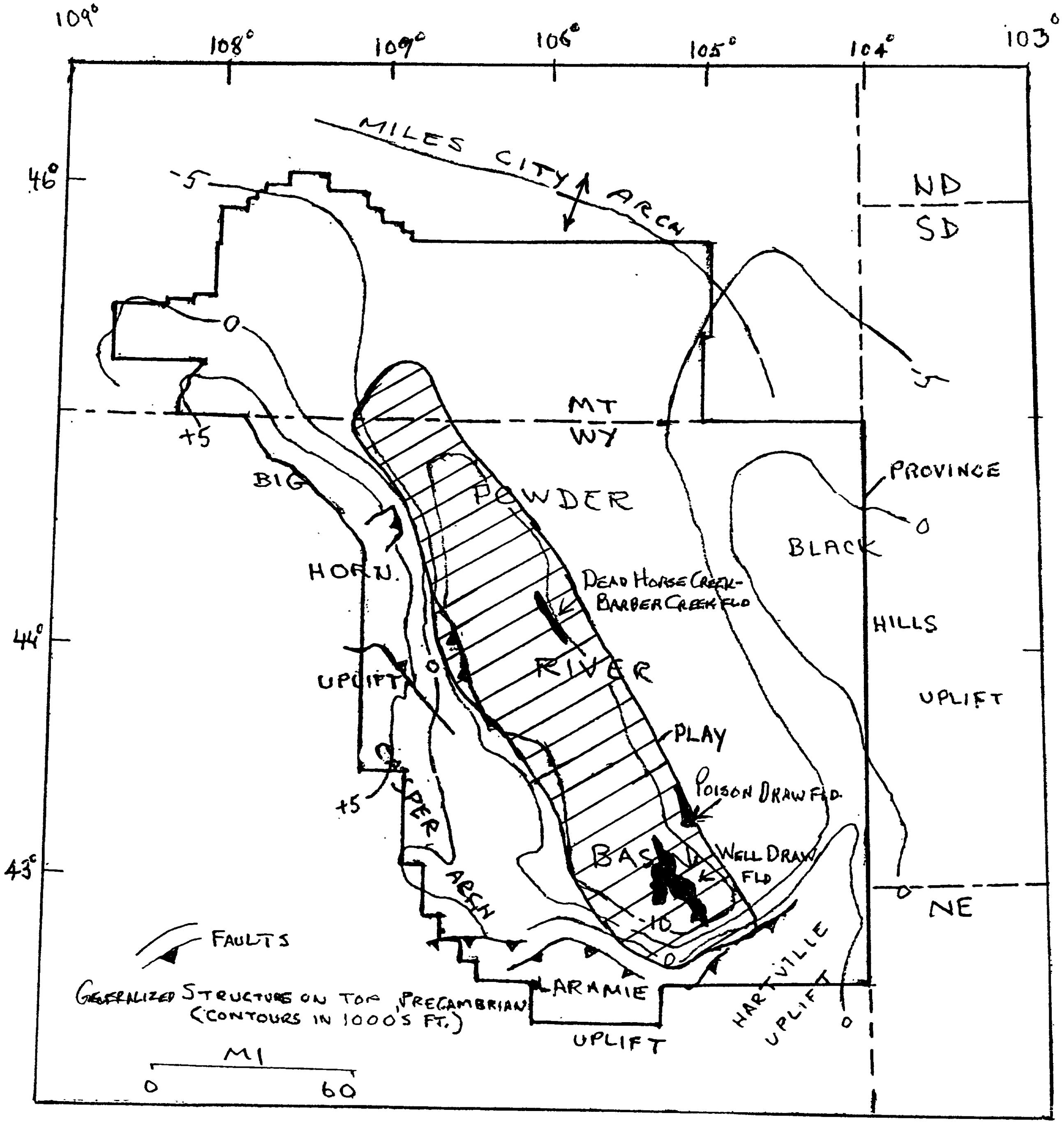

Figure 34. Map of Mesaverde-Lewis play.

OIL AND GAS PLAY DATA

PLAY **MESAVERDE-LEWIS**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-060**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.5**	**2**	**6**	**20**	**40**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**5**			**7**			**10**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**6**	**8**	**10**	**12**	**15**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**1600**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

DEEP FRONTIER SANDSTONE PLAY (070)

The play involves the occurrence of oil and gas in stratigraphic traps in offshore marine shelf sandstones of the Upper Cretaceous Frontier Formation in large, high-energy bar complexes, located in the deeper parts of the present basin. The play covers an area of about 5,800 mi^2 in the southwestern quarter of the Powder River basin (fig. 35).

Sandstone units known as "First Wall Creek," "First Frontier," and the Turner Sandy Member of the Carlile Shale are the principal reservoir objectives in this play (fig. 29). Similar sandstone reservoirs lower in the Frontier in the western part of the basin are also prospective and are included within the play. The Frontier is part of a prograding clastic sequence derived from the west. Deltaic facies of equivalent age have been identified to the west. To the east, the marine sandstones thin and grade into offshore sandstone of the Turner. Reservoirs contain abundant quartz, chert, lithic fragments, and appreciable interstitial clay. Average reservoir porosities range from 10 to 16 percent, and some of the reservoirs are fracture-enhanced; reservoir thicknesses range between 4 and 30 ft.

Source rocks include organic-rich shales of the Mowry and Carlile Shales and Niobrara and Frontier Formations. All achieve thermal maturity in the deeper parts of the basin. The Mowry Shale contains a mixture of types II and III organic matter and is estimated to have generated a great amount of oil. The Niobrara Formation and Carlile Shale together are a primary source of oil found in Upper Cretaceous reservoirs, however, the areal extent of effective source rocks in these formations is less extensive than the deeper Mowry Shale. Shale in the Frontier Formation has also generated and expelled oil, but in amounts secondary to the major Cretaceous source rocks. Oils in the play tend to have a high API gravity and are rich in dissolved gas.

Accumulations are in traps resulting from pinchouts at the margins of individual bars or bar complexes, and from porosity loss within sandstone bodies. The giant oil pool in the "Second Frontier sandstone" at the Salt Creek field (over 300 MMBO in size) has been attributed to remigration of oil from a pre-existent stratigraphic trap. Most of these sandstone bodies trend northwest-southeast although they coalesce locally into less regular configurations. Shale and siltstone of the Frontier and overlying Carlile Shale and Niobrara Formation form seals. Drilling depths to prospective future traps will range from 8,000 to 13,000 ft.

Exploration in the play began in the early 1970's. Sizes of discovered fields are not well documented as yet but the largest field found to date, Powell-Ross, is estimated to be about 25 MMBO in size (fig. 35). Approximately 45 MMBO have been discovered by 1987. Several of the approximately 20 individual pools in the play may eventually coalesce. Future undiscovered fields will probably be medium in size.

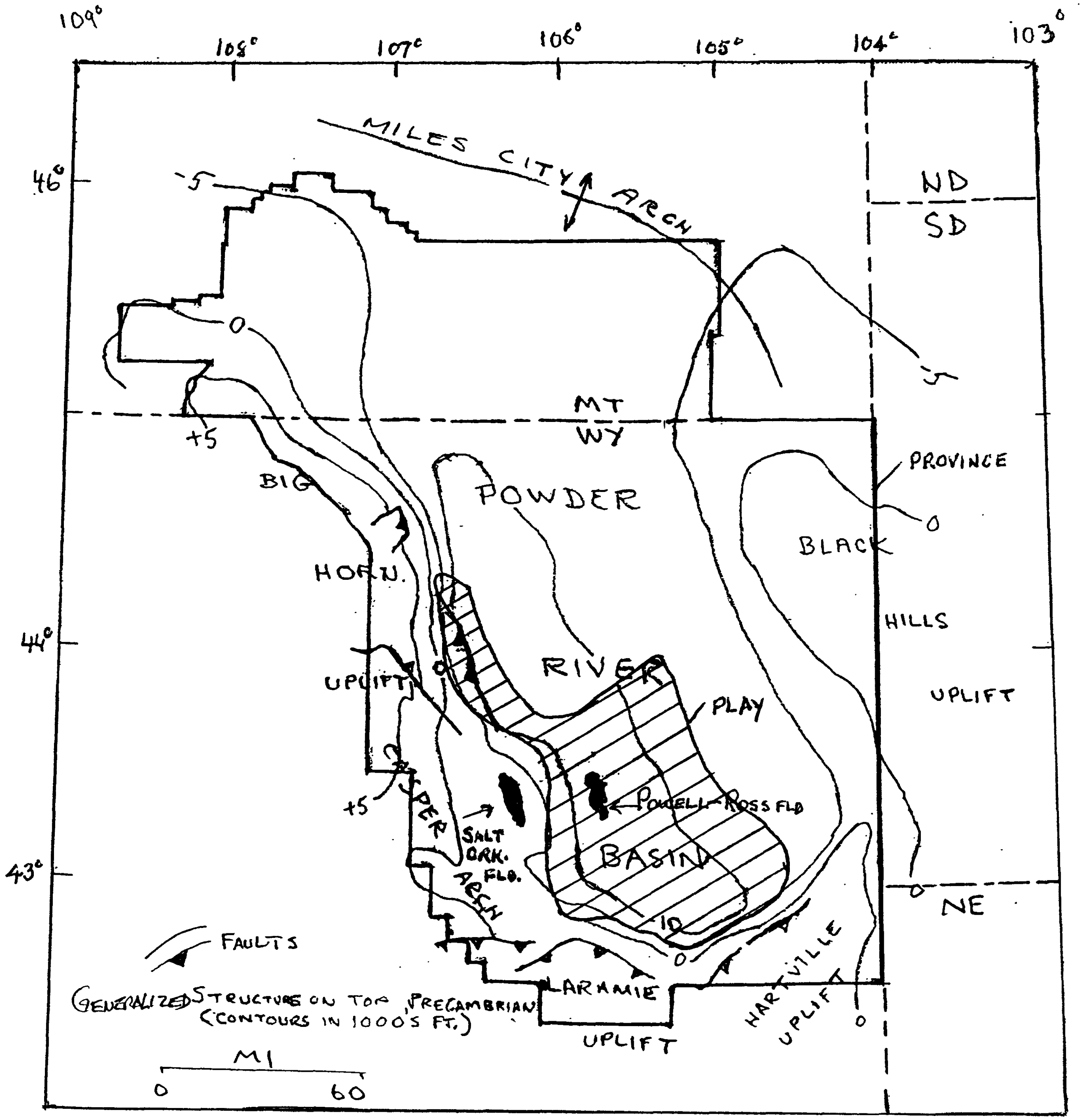

Figure 35. Map of Deep Frontier Sandstone play.

OIL AND GAS PLAY DATA

PLAY **DEEP FRONTIER SANDSTONE**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-070**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.6**	**2.6**	**5**	**12**	**30**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**8**			**11**			**13**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**3**	**4**	**5**	**6**	**8**	**11**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**3500**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

DEEP MUDDY SANDSTONE PLAY (080)

The play is characterized by potential oil and gas accumulations in deep stratigraphic traps in the Lower Cretaceous Muddy (Newcastle) Sandstone complex. The play area is approximately 6,150 mi^2 and covers the deeper portion of the Powder River basin (fig. 36). For assessment purposes this less well explored play was treated separately from the shallow well explored updip part of the Muddy Play (090).

The Lower Cretaceous Muddy Sandstone is composed of sediment transported into the Cretaceous seaway from the east, accompanying or following regional subareal erosion of the underlying Skull Creek Shale. Much of the Muddy was deposited during a gradual transgressive phase, interrupted by periodic regressive pulses in which appreciable sand was supplied, accompanied by some local erosion, although the interval also contains abundant shale. Thicker Muddy Sandstone reservoirs often accumulated within the more deeply dissected troughs cut into the Skull Creek Shale. Reservoirs updip to the east are fine- to very fine grained sandstones, with abundant scattered lithic fragments, chert, and interstitial clay. Average reservoir porosities vary, but usually range between 10 to 25 percent, average about 15 percent and decrease in quality with depth; average permeabilities range from 1 to over 1,000 md. Reservoir thicknesses vary from 10 to 25 ft.

The probable source of hydrocarbons is the organic-rich overlying Mowry Shale. Secondary sources are black shale of the underlying Skull Creek Shale, whose source rock quality is adequate to have provided some petroleum. Probable geographic distribution of fields would be limited to an area which overlies or is peripheral to mature source rocks in these formations. Oil in shallower, known fields has a generally high gravity, ranging typically from 35° to 45° API, and the accumulations are rich in dissolved gas.

Stratigraphic traps are in dominantly marine, bar-facies sandstone; they are estimated to be primarily north-trending, representing still-stands during transgression when high-energy, marine bar or barrier sandstone accumulated. Quite often a known, individual field is a composite of overlapping separate traps. Seals are provided by enclosing shale of the Skull Creek, Muddy, and overlying Mowry. Drilling depths to prospective traps are estimated to range from 8,000 to 13,000 ft, with the greatest potential in the deeper zones.

The play is in an immature exploration stage; however, the updip, well explored shallow area of the overall Muddy Sandstone play is considered to be an appropriate analog. Sizes of undiscovered fields are expected to be somewhat similar to known fields in the explored area, i.e., an abundance of small accumulations and a few of very substantial size. Future undiscovered oil and gas resources, overall, are estimated to be large in this deeper part of the basin.

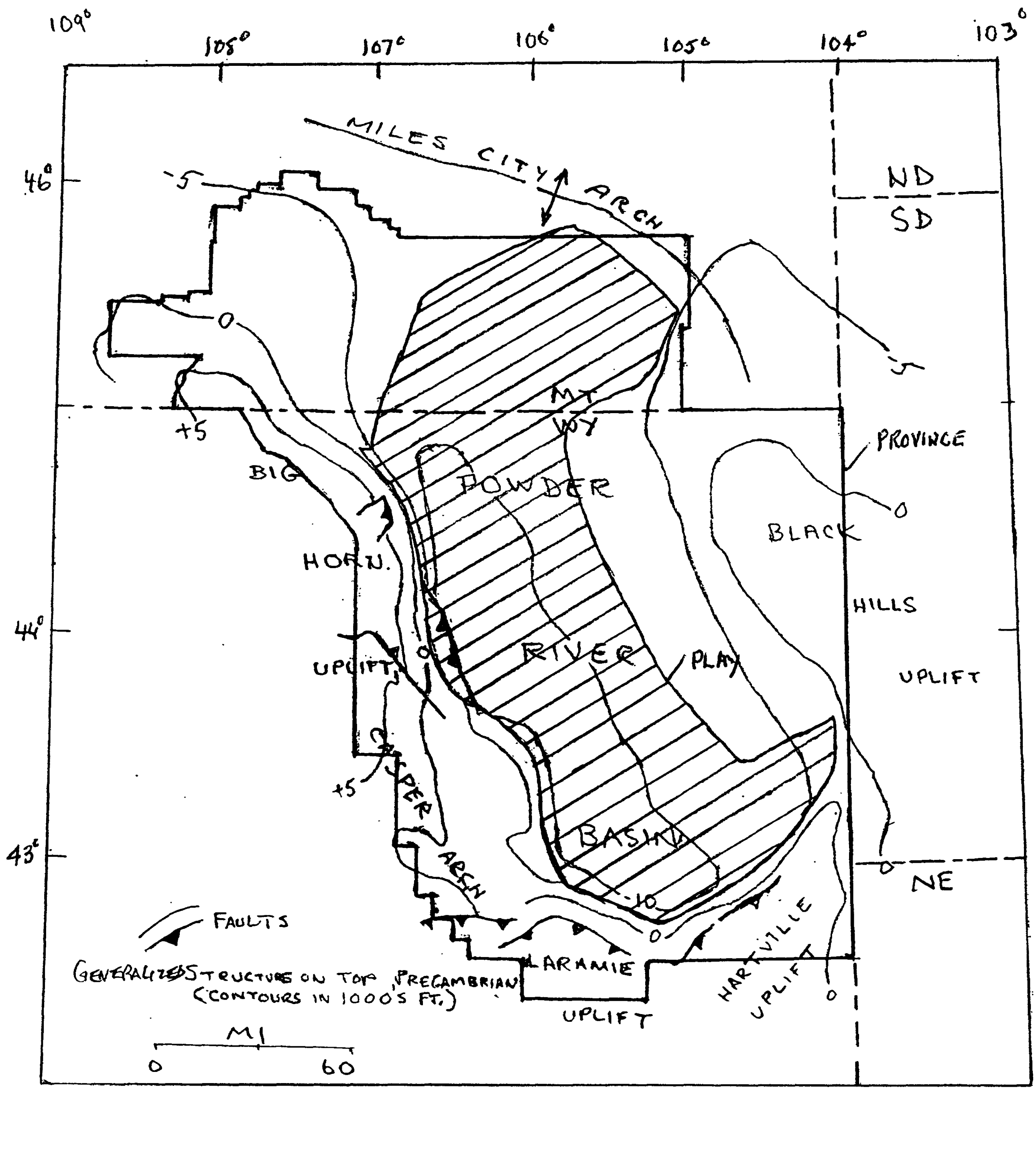

Figure 36. Map of Deep Muddy Sandstone play.

OIL AND GAS PLAY DATA

PLAY **DEEP MUDDY SANDSTONE**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-080**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.2**	**2**	**4**	**9**	**35**	**150**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**8**			**10**			**13**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**10**	**18**	**25**	**30**	**35**	**42**	**50**

Average ratio of associated-dissolved gas to oil (GOR)	**3500**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

SHALLOW MUDDY EXPLORED PLAY (090)

This play is defined by oil and gas fields in variety of stratigraphic traps that produce from Lower Cretaceous Muddy Sandstone reservoirs on the shallow eastern flank of the Powder River basin The play covers about 4,200 mi^2 in area (fig. 37). The play is similar in many respects to the previously described Deep Muddy Sandstone Unexplored Play (080) except that it was treated separately because of its well explored character, in contrast to the less explored area of the preceding play.

General conditions of reservoirs, source rocks, trap types, and seals in this play are similar to those described in the Deep Muddy Play. Drilling depths to known traps ranges from 500 to 8,000 ft. This play is well established, with a history of more than 40 years of exploration. Over 170 individual fields, including the Clareton and Fiddler Creek trends, have been discovered through 1986, accounting for about 580 MMBO; 39 of the fields exceed 1 MMBO in size. The largest field, Bell Creek, in the southeastern Montana portion of the play, is greater than 140 MMBO in size.

Future overall potential for undiscovered oil and gas resources is estimated to be modest and sizes of undiscovered fields are expected to be smaller, on average, than those found to date. This play is representative of a population of fields containing an abundance of small accumulations and a few of substantial size.

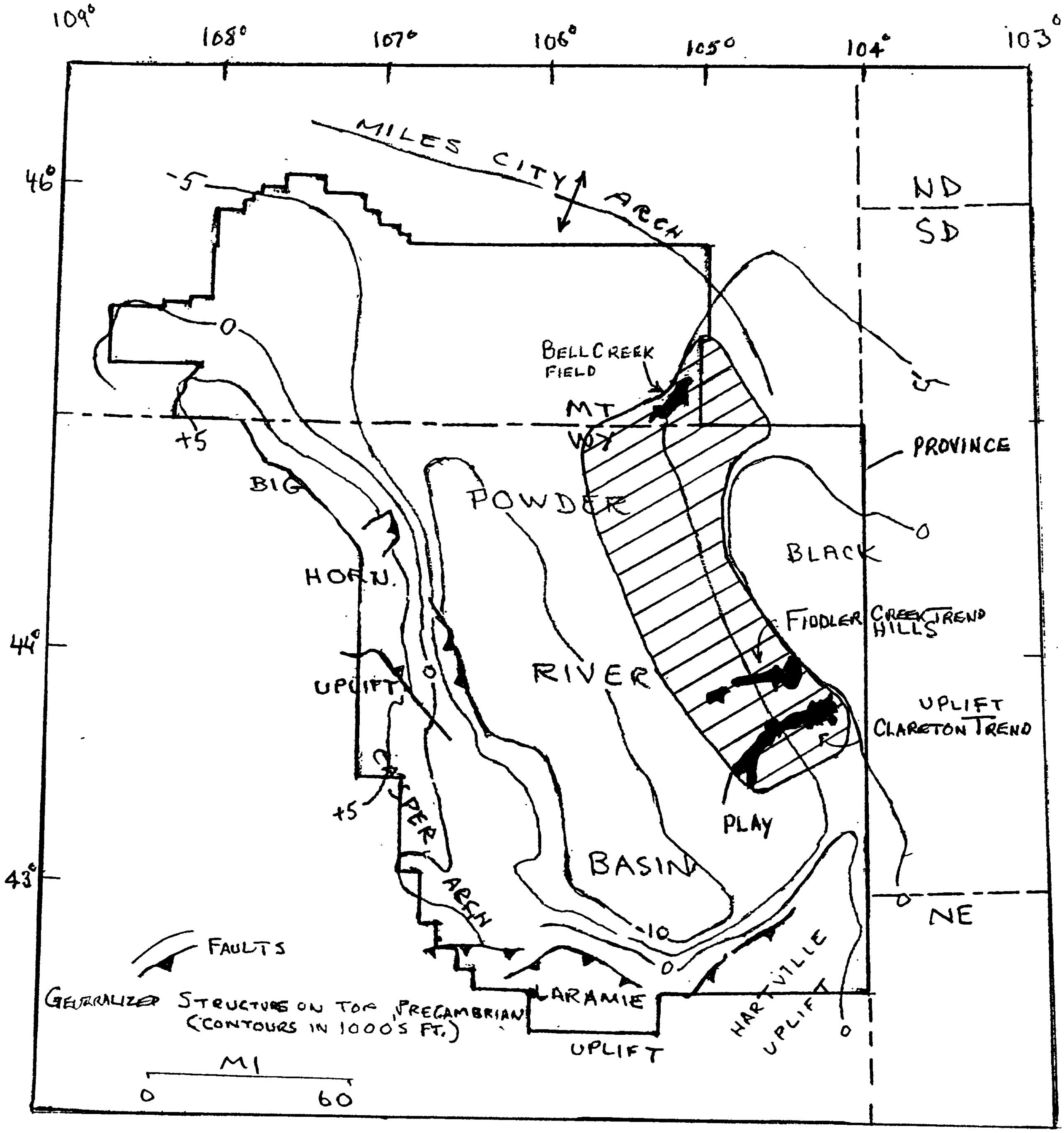

Figure 37. Map of Shallow Muddy Explored play.

OIL AND GAS PLAY DATA

PLAY **SHALLOW MUDDY EXPLORED**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-090**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) ($S \times T \times M \times R = MP$)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.1**	**1.6**	**2.6**	**5.6**	**20**	**50**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**0.5**			**6.5**			**8**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**6**	**8**	**10**	**12**	**14**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**1400**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

MINNELUSA EXPLORED PLAY (100)

The play involves oil and gas fields in stratigraphic traps largely related to observed paleotopography and reservoir truncation at the top of the Permian-Pennsylvanian Minnelusa Formation. The play is restricted to an approximate 1,500 mi^2 area on the gently sloping eastern flank of the Powder River basin where eolian sandstones are well developed in the upper part of the Minnelusa Formation (fig. 38). Depth to traps ranges from 5,000 to 12,000 ft. The play is similar to the Minnelusa-Unexplored play (110) that follows, although for assessment purposes, it was assessed separately as a well explored, mature play. For a fuller discussion of the general geology of this play, the reader is referred to the discussion of the Minnelusa Unexplored play (110) following.

This play is well-established, with an active exploration history exceeding 30 years, and covers a restricted area on the shallow eastern flank of the basin. Approximately 160 fields, which contain more than 380 MMBO, have been discovered in the play through 1986. The largest field, Raven Creek, is approximately 47 MMBO in size. The mean size of all accumulations is approximately 2.5 MMBO. Undiscovered resources would be primarily oil with minor dissolved gas; future discoveries are expected to be fewer in number and generally smaller in size than those already found.

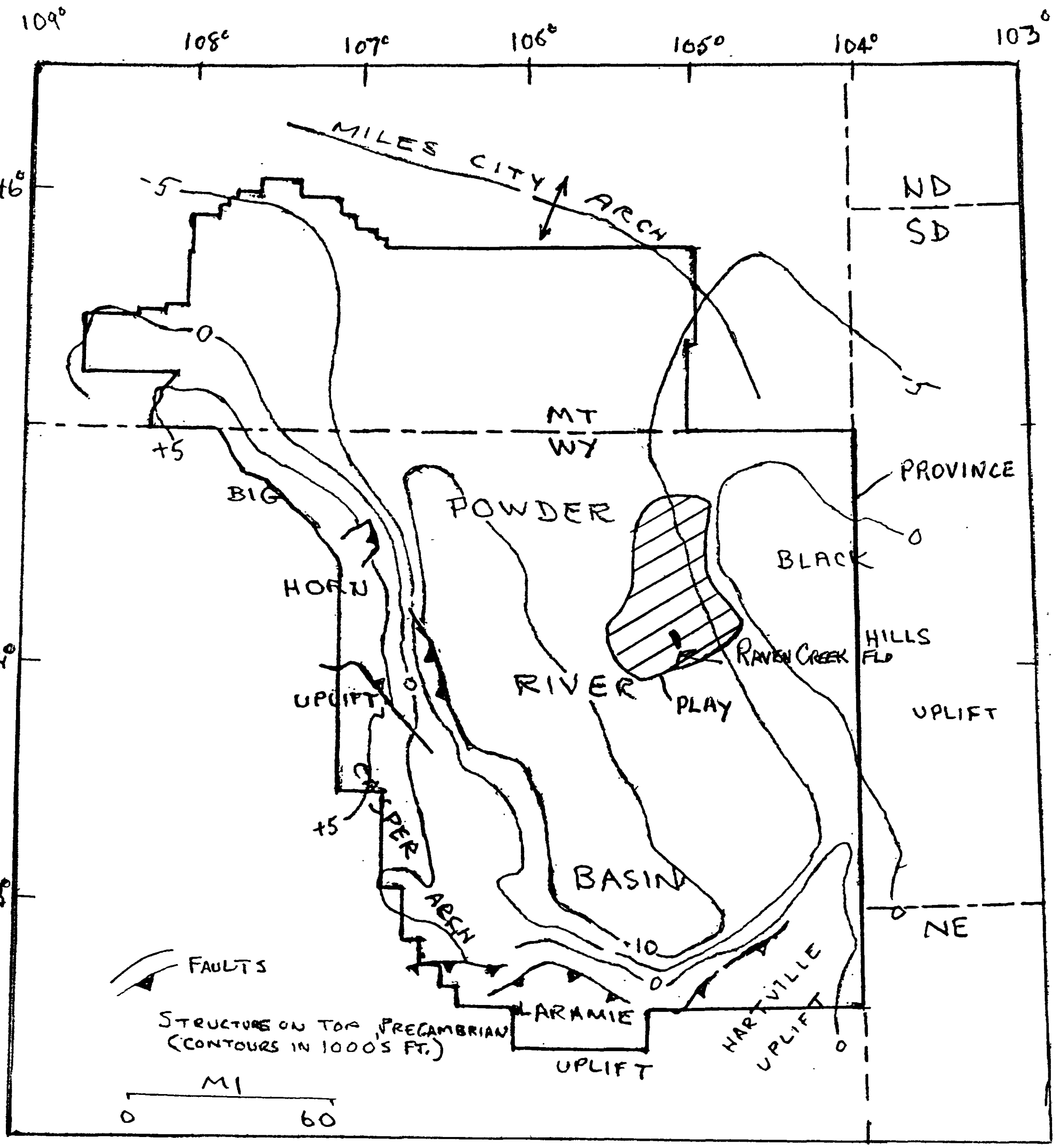

Figure 38. Map of Minnelusa Explored play.

OIL AND GAS PLAY DATA

PLAY **MINNELUSA EXPLORED**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-100**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditioned on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	probability of oc
One or more undiscovered accumulations of at least minimum size assessed	**1.00**

Estimates of character of undiscovered accumulations, conditioned on at least one undiscovered accumulation present

Reservoir lithology

Sandstone	**X**
Carbonate rocks	
Other	

Hydrocarbon type	Probability of occurrence
Oil	**1**
NA Gas	**0**

*Fractiles**	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.04**	**1.2**	**1.5**	**2.1**	**3.4**	**5.6**
NA Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**5**			**8**			**12**
NA Gas	**0**			**0**			**0**
Total Number of accumulations	**15**	**17**	**21**	**25**	**30**	**40**	**50**

Average ratio of associated-dissolved gas to oil (GOR)	**200**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile .95 represents a 19 in 20 chance of the occurrence of at least the quantity assessed.
NA Gas = Non-associated gas.

MINNELUSA UNEXPLORED PLAY (110)

This play is based on the probable occurrence of oil in stratigraphic traps which may be largely related to paleotopography and reservoir truncation at the top of the Permian-Pennsylvanian Minnelusa Formation. The play covers approximately 14,500 mi^2 and is located on the eastern flank and central portion of the Powder River basin (fig. 39). It is anticipated that eolian sandstone reservoirs would be well developed in the upper part of the Minnelusa Formation. The play is limited to the south essentially by the widespread occurrence of evaporites which adversely effect both hydrocarbon migration and reservoir quality. The significance of subtle paleotectonic features on potential hydrocarbon accumulations is problematic. The play was treated as an entirely separate play from the areally restricted Minnelusa Explored play (100) for resource assessment purposes. Nevertheless, the maturely explored Minnelusa play on the shallow eastern flank of the basin is considered to be an appropriate analog.

Probable reservoirs would be principally eolian dune sandstone of Permian age within a complex cyclic sequence of carbonate and sandstone of marine and non-marine origin dominated by erg and sabkha environments. Porous, vuggy dolomite zones contribute to production in several fields in the Minnelusa Explored play (100) but are rarely a primary reservoir. Sandstones may be generally very mature, fine- to medium-grained with a varying carbonate component. Typical reservoir porosities may range from 15 to 24 percent.

Source rocks are probably dark-colored marine shale of Pennsylvanian age, which lie below upper Minnelusa sandstones beds. Organic carbon content of these shales ranges from less than 1 to 26 wt percent and averages 5.4 wt percent. Speculative migration models propose long distance migration through Tensleep-Minnelusa reservoirs from Phosphoria source beds, far to the west (outside this province), prior to formation of the present basin. Probable gravity of oils range generally from 20° to 35° API, increasing with depth; oils are typically undersaturated. Permian black shales in the area of western Wyoming and eastern Idaho would probably have been buried deeply enough by Jurassic time to have generated hydrocarbons. If petroleum was derived from both distant and local sources, some of it could have moved into the area of the play during the Jurassic; however, during the Laramide orogeny this oil may have been partially redistributed into available stratigraphic traps.

Anticipated traps would be in paleotopographic highs or in erosional remnants at the top of the Minnelusa, overlain by the Permian Opeche Shale Member of the Goose Egg Formation (fig. 29). Other significant traps would include preserved dune forms, permeability pinchouts of both depositional and diagenetic origin within a cyclothem sequence, and low relief structural closures. Seals would be provided by overlying impermeable rocks and by internal lithologic variation and cementation. Drilling depths to prospective traps generally range from 6,000 to 15,000 ft.

Future undiscovered oil resources are estimated to be substantial. Size and number of undiscovered accumulations in the play are expected to be greater than those in the analog play (100).

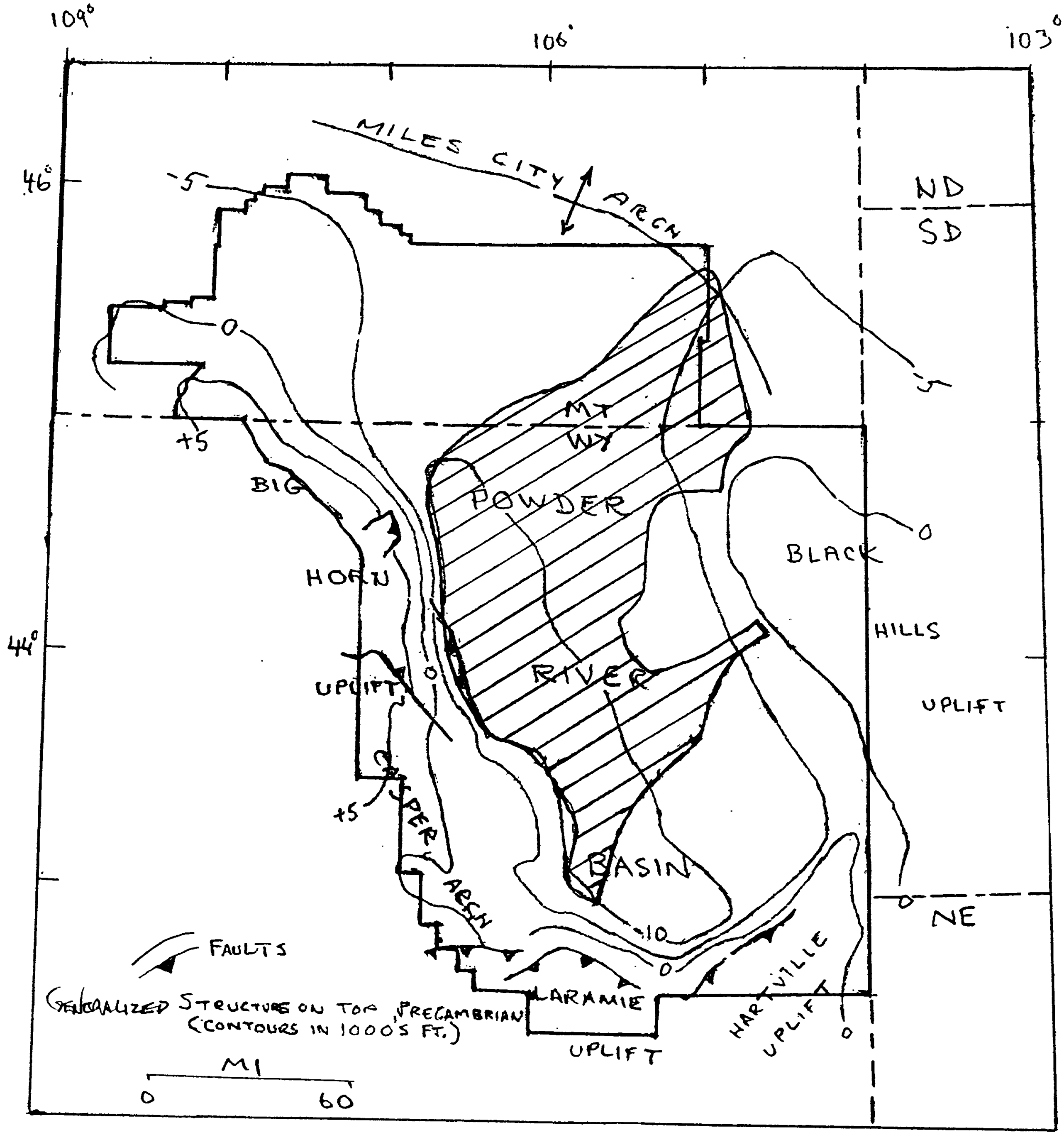

Figure 39. Map of Minnelusa Unexplored play.

OIL AND GAS PLAY DATA

PLAY **MINNELUSA UNEXPLORED**
PROVINCE **POWDER RIVER BASIN** CODE **04-101-110**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.1**	**1.6**	**2.75**	**5.5**	**15**	**50**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**6**			**9**			**16**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**50**	**70**	**100**	**130**	**170**	**230**	**300**

Average ratio of associated-dissolved gas to oil (GOR)	**250**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

SOUTHWESTERN WYOMING BASINS PROVINCE (102)

By Ben E. Law

INTRODUCTION

The Southwestern Wyoming Basins province is located in the Rocky Mountain foreland. It is an irregularly-shaped area encompassing about 40,500 mi^2 and is actually a composite of several basins and adjacent basement involved uplifts: the Laramie, Shirley, Hanna, Carbon, Great Divide, Washakie, Sand Wash, and Green River basins in Wyoming, Colorado, and Utah. The province is bounded on the north and northeast by the Beartooth, Absaroka, and Wind River Uplifts, and the Sweetwater Arch. The eastern boundary is the Laramie Range and the southern boundary passes through the northern part of the Medicine Bow and Park Range Uplifts along the Wyoming-Colorado State line, the Axial arch, and the Uinta Uplift. The Wyoming-Utah-Idaho thrust belt forms the western boundary of the province. Total sedimentary rock thicknesses in the individual basins in the province vary greatly. In the Hanna basin, one of the deepest in the Rocky Mountain region, the total thickness of sedimentary rocks is over 42,000 ft; in the northern part of the Green River and Washakie basins the sections are about 32,000 ft. In contrast, the rock thickness in the Shirley and Laramie basins is 7,000 and 13,000 ft, respectively. Stratigraphic nomenclature is also variable over the extensive province area as shown in figure 40.

Oil and associated gas production, since the 1916 discovery of the giant Lost Soldier field, is mainly from fields located in and adjacent to the Laramie basin, Rawlins uplift, Axial Arch uplift and the La Barge platform. Productive reservoirs range from Cambrian through Tertiary in age and are dominantly sandstone. Carbonate reservoirs are minor. More than 100 fields greater than 1 MMBOE in size have been discovered in the province. Cumulative production from these fields to the end of 1986 is 748 MMBO and 4.9 TCFG.

Eight plays were individually assessed in the province: Cherokee Ridge (020), Jackson Hole (030), Moxa-LaBarge (040), Platform (050), Axial Arch (060), Basin Margin Anticline (070), Subthrust (080), and Rock Springs (090).

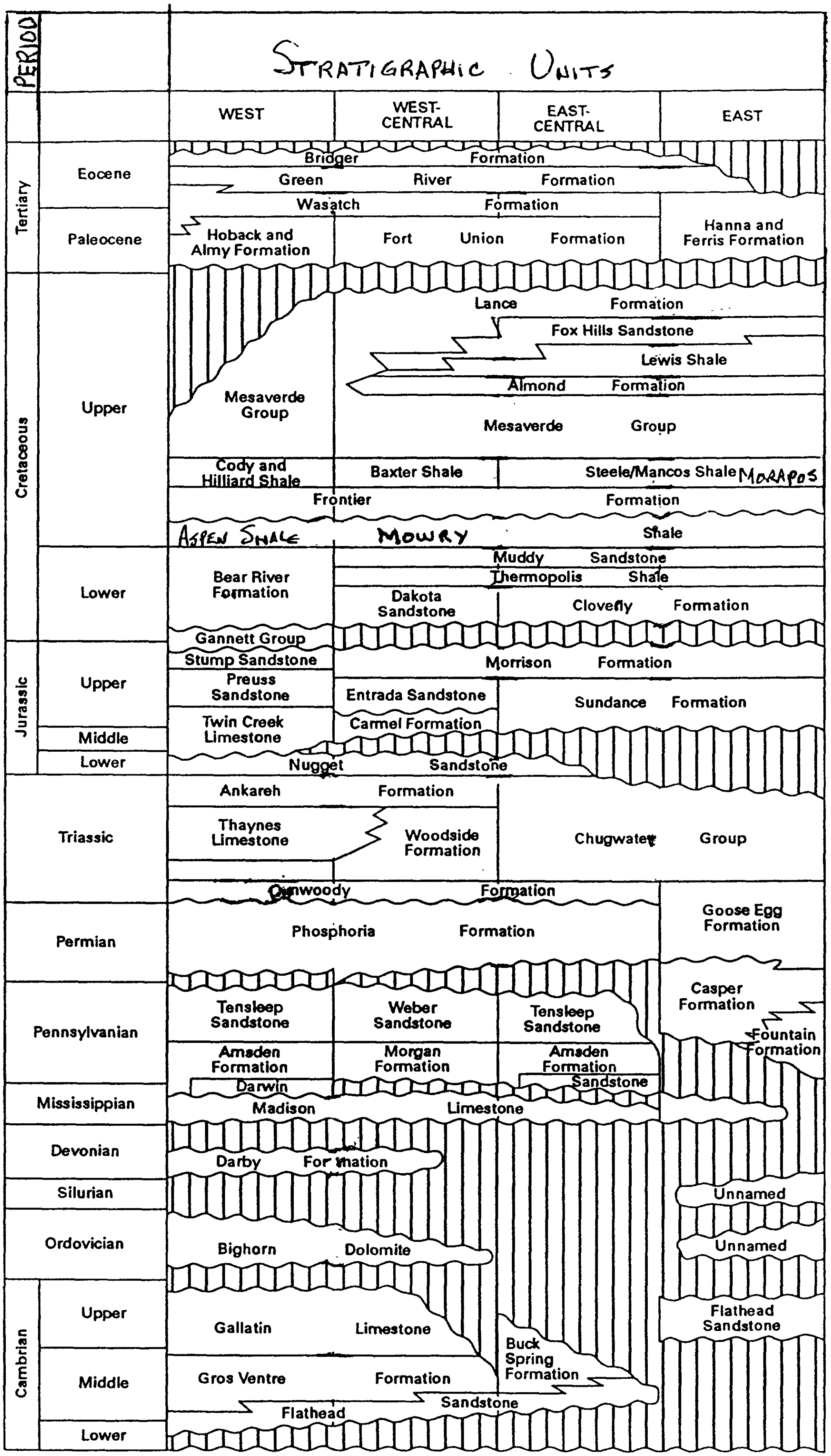

Figure 40. Generalized stratigraphic columns, Southwestern Wyoming Basins province.

CHEROKEE RIDGE PLAY (020)

The play is mainly structural and involves gas and oil accumulations in Jurassic, Cretaceous, and Tertiary age sandstone reservoirs in faulted anticlines. It is located on the Cherokee Ridge, an arch that straddles the Wyoming-Colorado State line (fig. 41). The arch separates the Washakie basin in Wyoming from the Sand Wash basin in Colorado and is characterized by an east-west-trending zone of en échelon faults and folds that are believed to be due to wrench faulting. Structural deformation occurred during the Laramide orogeny. The play area is rectangular-shaped with dimensions of about 12 by 75 mi. The east and west boundaries abut against the Platform (050) and Basin Margin Anticline (070) plays, respectively.

Reservoirs include the Jurassic Nugget Sandstone, Lower Cretaceous Dakota Sandstone, Upper Cretaceous Williams Fork Formation, Almond Formation, Lewis Shale sandstones, Lance Formation, Paleocene Fort Union Formation, and Eocene Wasatch Formation (fig. 40). Porosity ranges from 10 to 30 percent and permeability from 0.1 to 500 md. Reservoir thicknesses are highly variable, ranging from less than 10 to 150 ft.

Although no oil or gas analyses are available, it is likely that oil is sourced by Cretaceous rocks and gas is sourced by Cretaceous and older rocks. Based on thermal maturity mapping, the Cretaceous and older source rocks are thermally mature to over mature; it is not known when Cretaceous and older rocks entered the oil window, but it is likely that structural traps were in existence when Cretaceous source rocks entered the oil window. Older source rocks such as shale in the Permian Phosphoria Formation may have passed through the oil window prior to the formation of structural traps. Traps are mainly structural, and existing fields are located on anticlinal folds that are commonly faulted. Impermeable shales and (or) faults provide seals. Drilling depths range from 2,000 to 18,000 ft.

The play is maturely explored; the first discovery was the Hiawatha field in 1926. Cumulative production to the end of 1986 in 3.9 MMBO and 132 BCFG. The largest oil and gas field in the play is Powder Wash (fig. 41) with a cumulative production of 7.0 MMBO and 215 BCFG. Future remaining potential is low and probably in stratigraphic traps with less potential for structural accumulations. Results of deep drilling (23,000 ft) to Paleozoic reservoirs (Mississippian Madison Limestone) to date have not been encouraging for older, deeper reservoirs.

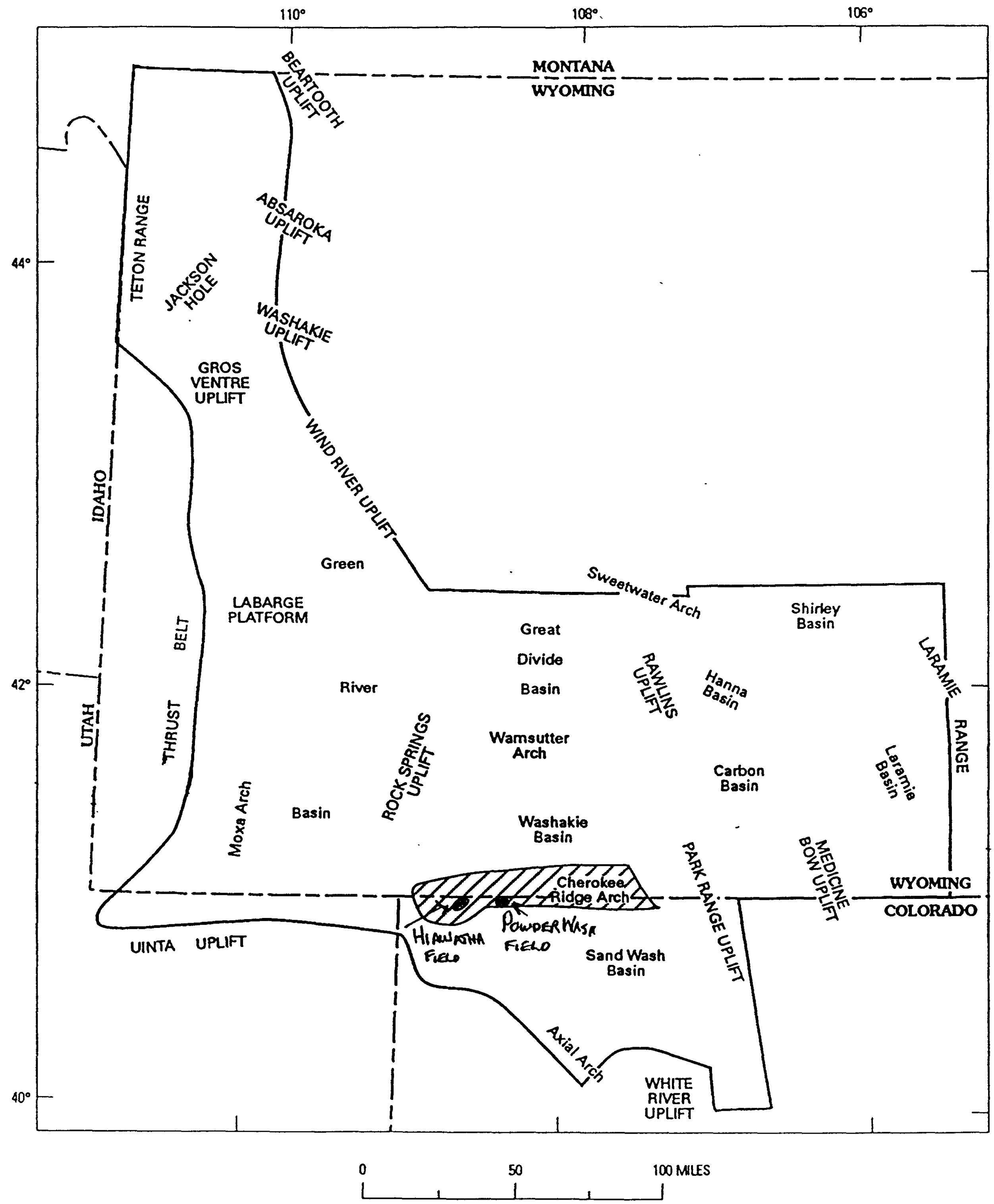

Figure 41. Map of Cherokee Ridge play.

OIL AND GAS PLAY DATA

PLAY **CHEROKEE RIDGE**
PROVINCE **SOUTHWESTERN WYOMING BASINS** CODE **04-102-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.50**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.1**
Gas	**0.9**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.1**	**1.2**	**1.5**	**2**	**3**	**5**
Gas ($\times 10^9$ CFG)	**6**	**10**	**18**	**30**	**50**	**80**	**125**
Reservoir depth ($\times 10^3$ ft)							
Oil	**2**			**6**			**18**
Gas (non-associated)	**2**			**6**			**23**
Number of accumulations	**1**	**1**	**2**	**2**	**3**	**4**	**5**

Average ratio of associated-dissolved gas to oil (GOR)	**800**	CFG/BBL
Average ratio of NGL to non-associated gas	**5**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

JACKSON HOLE PLAY (030)

The play involves Paleozoic and Mesozoic reservoirs in probable anticlinal traps and is based on its location within a structurally complex area containing several large faulted surface anticlines. The play area covers the northwest corner of Wyoming (fig. 42), and is bounded on the north by the Montana State line, on the east by the Beartooth, Absaroka, and Washakie uplifts, on the south by the Gros Ventre uplift, and on the west by the Idaho-Montana State line. It is about 100 mi long by 55 mi wide. Large areas of the play are covered by volcanic flows that obscure sub-volcanic delineation of structure.

Potential reservoirs include the Madison Limestone, Darwin Sandstone Member of the Amsden Formation, Tensleep Sandstone, Phosphoria Formation, Cloverly Formation, Muddy Sandstone, Frontier Formation, and Mesaverde Group (fig. 40). The thickness of each of these reservoirs is highly variable, ranging from less than 20 ft to a few hundred feet. No data are available concerning porosity and permeability, however, fractured reservoirs may be present. Reservoirs are estimated to occur at depths ranging from 1,000 to 18,000 ft and possibly as deep as 25,000 ft.

The most likely hydrocarbon source rocks are black shales in the Amsden, Phosphoria, Thermopolis, Mowry, and Cody. Oil seeps in volcanic rocks of the Absaroka uplift and Yellowstone Plateau and numerous gas seeps have been reported from several areas. There is no hydrocarbon production in the play, although numerous shows of oil and gas have been reported in some wildcat wells. No information is available concerning the temporal relationships between structural trap formation and the generation and migration of hydrocarbons from the various source rocks. Traps are mainly anticlinal and seals are probably shale beds and faults. Several large northwest-trending anticlines in the play remain untested.

Exploration has been minimal, largely because of limited access to most of the acreage in the play, in addition to the large volcanic-covered areas that would require extensive geophysical exploration. The play has some minor future potential, however, because of its relatively unexplored status and the favorable presence of complex structures.

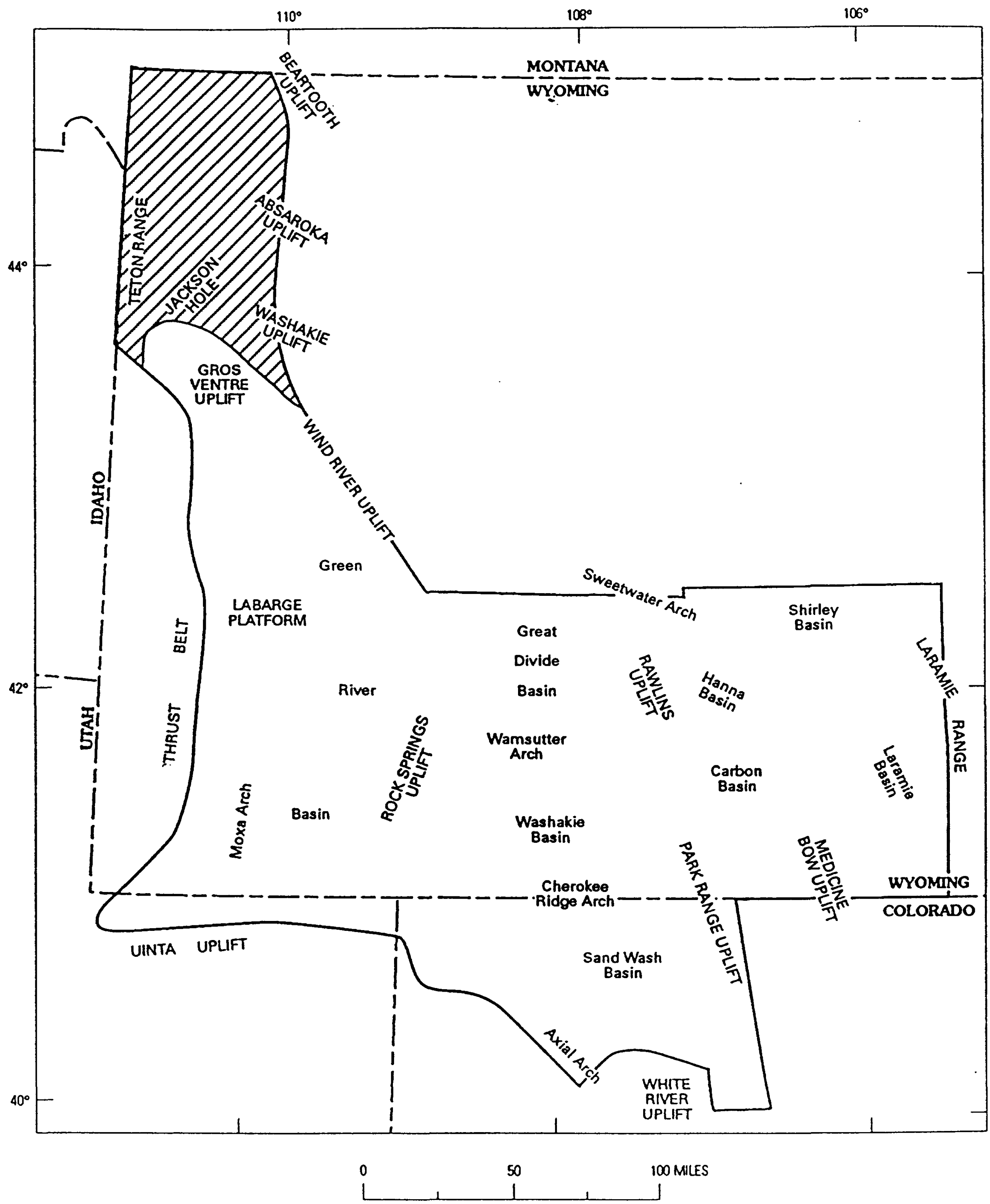

Figure 42. Map of Jackson Hole play.

OIL AND GAS PLAY DATA

PLAY **JACKSON HOLE**
PROVINCE **SOUTHWESTERN WYOMING BASINS** CODE **04-102-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.75**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.5**
Gas	**0.5**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.5**	**3**	**5**	**8**	**12**	**20**
Gas (x 10^9 CFG)	**6**	**7**	**15**	**30**	**50**	**100**	**200**
Reservoir depth (x10^3 ft)							
Oil	**3**			**10**			**18**
Gas (non-associated)	**3**			**10**			**25**
Number of accumulations	**1**	**1**	**2**	**3**	**4**	**5**	**6**

Average ratio of associated-dissolved gas to oil (GOR)	**300**	CFG/BBL
Average ratio of NGL to non-associated gas	**10**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

MOXA-LA BARGE PLAY (040)

The play is characterized by both structural and stratigraphic gas and oil accumulations in Paleozoic, Mesozoic, and Tertiary reservoir rocks, and is located in the western part of the Green River basin (fig. 43), a few miles east of and parallel to the Wyoming-Utah-Idaho thrust belt. The play area is basically a large north-south-trending regional structural arch (Moxa arch) about 110 mi long and 7 to 20 mi wide with individual areas of structural closure along the crest.

Known reservoirs include the Madison Limestone, Morgan Formation, Nugget Sandstone, Bear River Formation, Dakota Sandstone, Frontier Formation, Mesaverde Group, and Almy Formation (fig. 40). However, south of the La Barge platform, the principal reservoirs are the Dakota Sandstone and Frontier Formation in which reservoirs range in thickness from 10 to 200 ft. Porosity and permeability of these reservoirs are highly variable, and reservoir quality appears to be slightly more enhanced along the crest of the arch than on the flanks.

The most likely source rocks are the Phosphoria Formation and Mowry (Aspen) Shale. Based on preliminary oil-to-source rock correlations at the south end of the Moxa arch, oil, gas, and condensate in the Dakota Sandstone is derived from the Mowry Shale. Gas in Pennsylvanian and Mississippian reservoirs is sourced from the Phosphoria, and is commonly non-flammable and sour (H_2S content) with high proportions of CO_2. The average CO_2 content in Paleozoic reservoirs is about 65 percent and H_2S ranges from 1 to 3 percent. The Moxa arch has experienced pre-Laramide deformation, possibly as old as late Paleozoic. Therefore, source rocks that may have generated hydrocarbons during or subsequent to that deformation could have migrated to favorable structural and(or) stratigraphic traps along the crest of the structure. At the south end of the arch there is some evidence that oil migrated into Dakota reservoirs prior to or near the start of the Laramide orogeny.

Traps are both structural and stratigraphic. Most fields in the vicinity of the La Barge platform are primarily structurally trapped, while fields south of the La Barge platform along the Moxa arch, have significant stratigraphic aspects. Numerous shale beds act as seals. Drilling depth ranges from 7,000 to more than 22,000 ft.

The play is maturely explored with greater than 50 fields found. The first discovery was the La Barge field in 1928 (fig. 43). The largest oil and gas fields are La Barge, at 23.5 MMBO and Church Buttes, 343.4 BCFG in size. There is a considerable amount of current drilling activity, and it appears likely that deeper productive reservoirs will be found. Within the play, the Frontier Formation is locally designated as a "tight gas sand" (unconventional) reservoir, however, in assessing resources, the Frontier was treated as a conventional gas reservoir. The overall future potential for oil is fair to good and a very significant potential exists for gas.

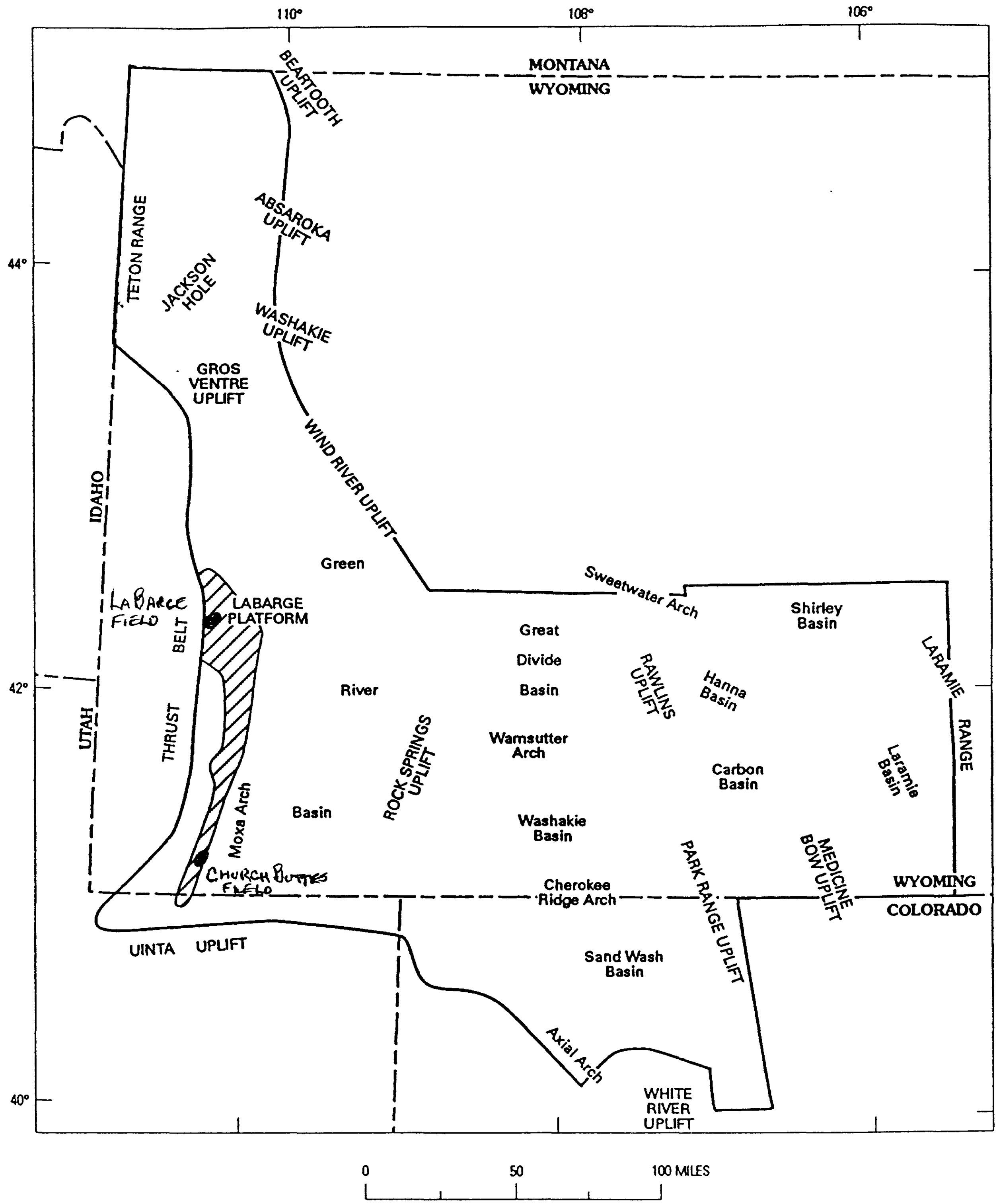

Figure 43. Map of Moxa-LaBarge play.

OIL AND GAS PLAY DATA

PLAY MOXA-LA BARGE
PROVINCE SOUTHWESTERN WYOMING BASINS CODE 04-102-040

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	1.00
Timing (T)	1.00
Migration (M)	1.00
Potential reservoir-rock facies (R)	1.00
Marginal play probability (MP) (S x T x M x R = MP)	1.00

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	1.00

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	X
Carbonate rocks	X
Other	
Hydrocarbon type	
Oil	0.25
Gas	0.75

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	1	1.5	3.8	7.8	14	26	35
Gas (x 10^9 CFG)	6	9	15	35	75	180	300
Reservoir depth (x10^3 ft)							
Oil	7			11			22
Gas (non-associated)	7			11			25
Number of accumulations	8	10	15	20	25	28	30

Average ratio of associated-dissolved gas to oil (GOR)	2000	CFG/BBL
Average ratio of NGL to non-associated gas	10	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	0	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

PLATFORM PLAY (050)

The play is characterized by hydrocarbon accumulations in structural and stratigraphic traps involving sandstone and carbonate reservoirs ranging from Cambrian to Tertiary in age. The play covers nearly all of the eastern half of the province including the Laramie, Shirley, and Carbon basins (fig. 44), an area of about 8,000 mi^2. It extends from the eastern edge of the Great Divide and Washakie basins east to the Laramie Range. The Medicine Bow and Park Range uplifts form the southern boundary and the Sweetwater arch and north end of the Shirley basin form the northern boundary.

Reservoirs include Cambrian through Tertiary sandstone and carbonate rocks that range in thickness from 8 to 260 ft. Porosities range from 6 to 22 percent and permeabilities range from 1.0 to 288 millidarcies.

Unpublished oil analyses from nine fields in the play indicate that oil in Cretaceous and Jurassic reservoirs is sourced from Cretaceous rocks, and oil in the Casper Formation (Tensleep) is sourced from Paleozoic rocks, perhaps Pennsylvanian shale. It is not known when generation and migration of oil from the various source rocks occurred, but it is likely that structural traps were available for the accumulation of hydrocarbons from Cambrian through Tertiary time.

Traps are both structural and stratigraphic, although existing accumulations are all structural traps, mainly in anticlines. Seals are provided by low permeability shales. The potential for stratigraphic traps exists in several of the reservoirs such as the Pennsylvanian Casper Formation, Jurassic Sundance Formation, and the Cretaceous Dakota Formation, and Muddy Sandstone, where they may undergo facies changes into finer grained, relatively impermeable lithologies. Depth of reservoirs ranges from 1,500 to 15,000 ft and most commonly from 3,000 to 6,000 ft.

The play is maturely explored with 76 fields discovered. Dates of discovery of the oldest fields are Lost Soldier (1916), Rock River (1918), Mahoney Dome (1919), and Wertz (1921). The largest size fields are Lost Soldier (231 MMBO), Wertz (114.0 MMBO), and Rock River (39.8 MMBO). Only a few smaller-size fields have been discovered since 1960, and it appears that future discoveries will be in small-size fields for both oil and gas.

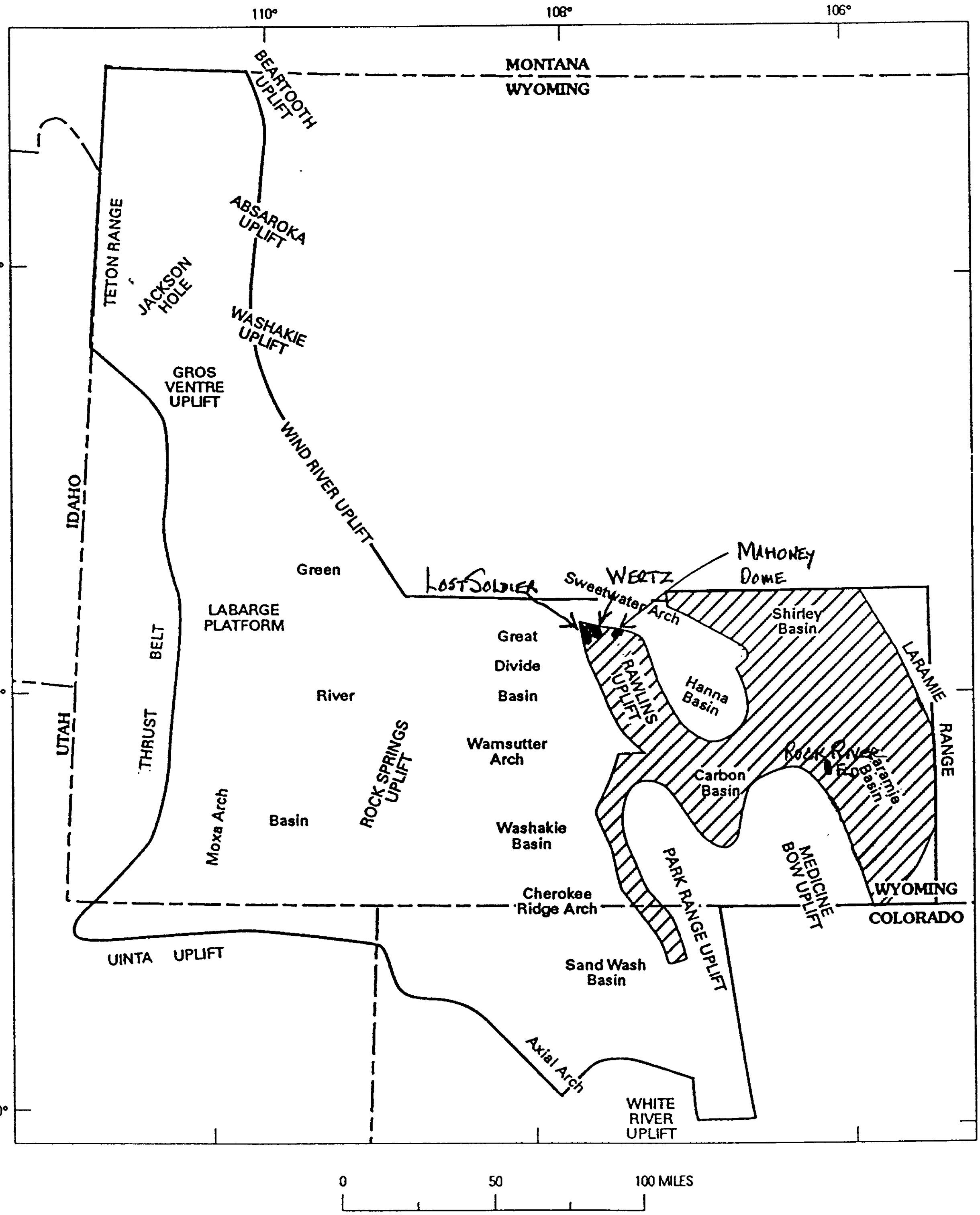

Figure 44. Map of Platform play.

OIL AND GAS PLAY DATA

PLAY **PLATFORM**
PROVINCE **SOUTHWESTERN WYOMING BASINS** CODE **04-102-050**

Play attributes	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.6**
Gas	**0.4**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.1**	**2.1**	**4**	**6.5**	**11**	**20**
Gas ($\times 10^9$ CFG)	**6**	**6.2**	**7**	**9**	**14**	**44**	**100**
Reservoir depth ($\times 10^3$ ft)							
Oil	**1.5**			**6.5**			**15**
Gas (non-associated)	**1.5**			**6.5**			**15**
Number of accumulations	**5**	**6**	**8**	**10**	**15**	**18**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**300**	CFG/BBL
Average ratio of NGL to non-associated gas	**10**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

AXIAL ARCH PLAY (060)

The play is defined by oil and gas accumulations in faulted anticlines in clastic and carbonate reservoirs ranging from Pennsylvanian to Upper Cretaceous in age. It is located south of the Sand Wash basin in northwestern Colorado. It is an irregular-shaped area encompassing about 1,200 mi^2 and forms a southeast extension at the eastern end of the Uinta Mountain uplift (fig. 45). Northwest-trending, faulted anticlinal folds are common structural features. During much of Paleozoic time, the Axial arch was a structurally depressed area referred to as the Colorado trough.

Principal reservoirs are clastic and carbonate rocks in the Pennsylvanian Morgan Formation equivalent (Minturn Formation), Weber Sandstone, Triassic Woodside equivalents (Shinarump Sandstone, Moenkopi Formation), Jurassic Entrada Sandstone and Morrison Formation, Lower Cretaceous Dakota Sandstone, and Upper Cretaceous Frontier Formation, Niobrara Formation, and Marapos Sandstone Member of the Mancos Shale (fig. 40). Reservoir porosities range from 12 to 20 percent, permeabilities range from 0.1 to 300 millidarcies and reservoir thicknesses range from 8 to 65 ft.

Possible source rocks include Pennsylvanian shale (Belden Shale), Permian Phosphoria Formation, and shale in several Cretaceous units. Recent work south of the Axial arch has identified Pennsylvanian age shale (Belden) as a potential source rock. This shale and the Phosphoria Formation may have both been the source of oil in the Weber Sandstone. There is no data available concerning the burial and thermal history of rocks, however, because the area has experienced recurrent structural deformation; structural traps were most likely formed as early as Pennsylvanian time. Therefore, hydrocarbons that may have been generated in Late Cretaceous and Tertiary times could have migrated into these early-formed structural traps.

Most hydrocarbon accumulations are in anticlinal traps, although traps in reservoirs such as the Weber, Entrada, Shinarump, Dakota and Frontier have stratigraphic aspects. Fractured reservoirs in the Upper Cretaceous Mancos Shale are also important in the tightly folded crests of some anticlines. Drilling depths range from 2,000 to 13,000 ft. Adequate seals are present throughout the productive section.

The play is maturely explored with 35 oil and gas fields discovered. The first discoveries were in 1924 (Iles, Moffat, and Tow Creek). The largest fields are Wilson Creek with cumulative production of 86.0 MMBO and 64.0 BCFG, and Maudlin Gulch with cumulative production of 17.0 MMBO to the end of 1986. Because the area is structurally complex and has experienced a long history of structural deformation dating back to Precambrian time, with recurrent movement occurring on some of these old structures during Late Pennsylvanian and Late Cretaceous to middle Tertiary time, there is a possibility that some of the older structures have been overlooked as being prospective. Future potential is fair for smaller size fields.

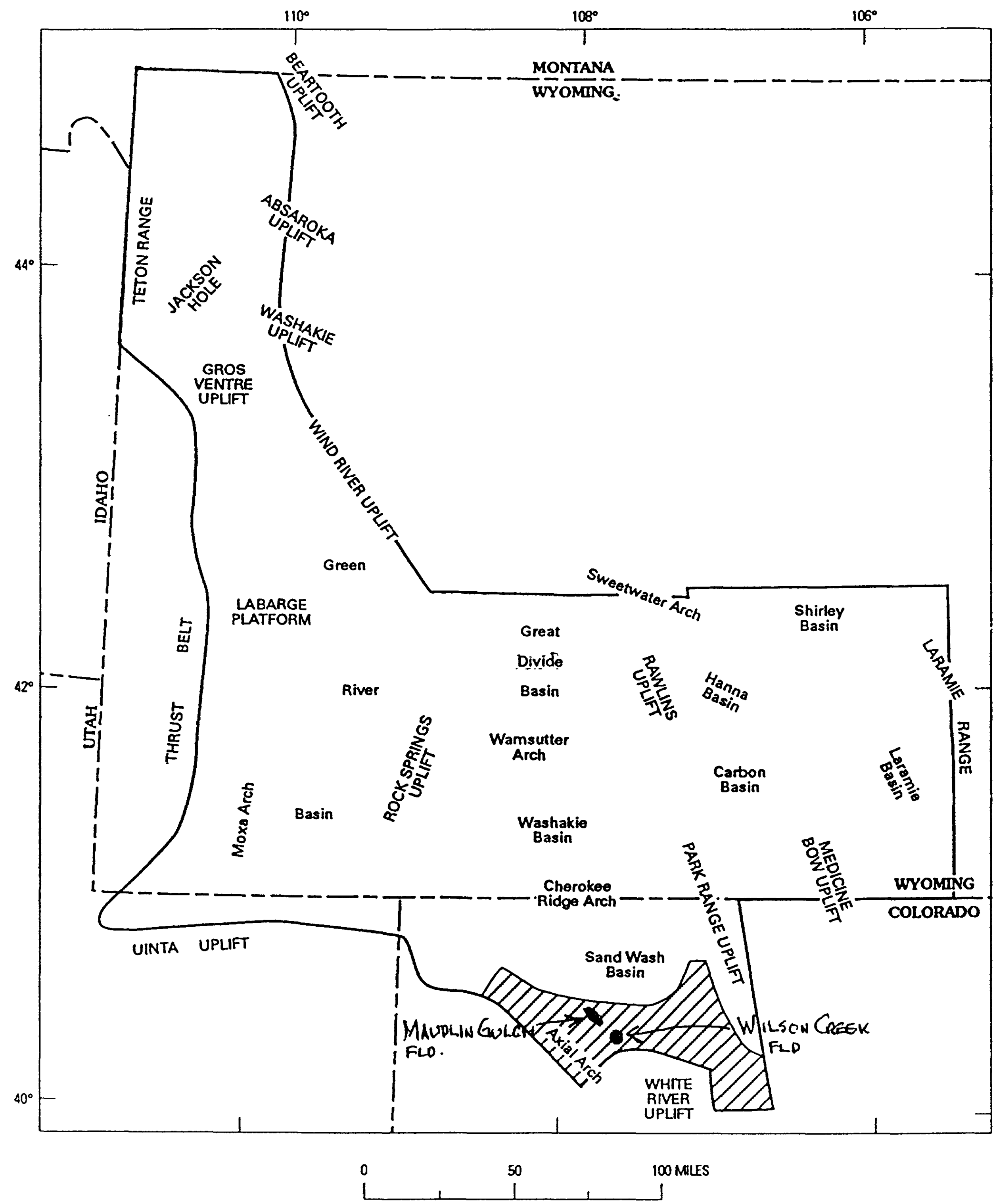

Figure 45. Map of Axial Arch play.

OIL AND GAS PLAY DATA

PLAY **AXIAL ARCH**
PROVINCE **SOUTHWESTERN WYOMING BASINS** CODE **04-102-060**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.75**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0.65**
Gas	**0.35**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.3**	**2.6**	**5**	**9**	**18**	**30**
Gas (x 10^9 CFG)	**6**	**7.8**	**10**	**15**	**25**	**50**	**100**
Reservoir depth (x10^3 ft)							
Oil	**3**			**9**			**13**
Gas (non-associated)	**3**			**9**			**17**
Number of accumulations	**1**	**2**	**3**	**5**	**7**	**9**	**10**

Average ratio of associated-dissolved gas to oil (GOR)	**1300**	CFG/BBL
Average ratio of NGL to non-associated gas	**5**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BASIN MARGIN ANTICLINE PLAY (070)

The play is primarily structural and involves anticlinal traps in reservoirs ranging in age from Cambrian to Tertiary, and consists of four narrow tracts, 5 to 20 mi wide, paralleling the thrusted margins of uplifts in the Greater Green River basin (fig. 46). Potential reservoirs include all known oil and gas producing reservoirs in the stratigraphic column, especially clastic reservoirs in the Weber, Nugget, Dakota, and Frontier. Thicknesses of reservoirs range from less than 10 to 150 ft.

Source rocks include shale beds previously discussed in prior plays and particularly shale in the Phosphoria and Mowry. An unusually low level of thermal maturity occurs along the north flank of the Uinta uplift, which effectively lowers the level of the top of the oil window to depths greater than 15,000 ft. Within this area, hydrocarbons that were generated and had migrated during and after Late Cretaceous time could have been trapped in Laramide structural features.

Anticipated traps in the play are anticlinal. Analogues are anticlines of the types associated with the Clay Basin, Pinedale, and Mickelson Creek fields (fig. 46). These anticlines appear to be genetically related to structural deformation associated with Laramide thrusting along the north flank of the Uinta uplift, southwest flank of the Wind River uplift, and the Wyoming-Utah-Idaho thrust belt, respectively. Relatively impermeable lithologies in the Upper Cretaceous Baxter or Hilliard Shales provide good seals. Drilling depths may range from 5,000 down to 25,000 ft.

This is an immature to moderately mature explored play. Only three fields have been found; the largest of these is Clay Basin field with a cumulative production of 148 BCFG at the end of 1986. Extensive areas along the north flank of the Uinta uplift and along the southwest flanks of the Wind River and Gros Ventre uplifts are virtually unexplored. These areas may have a fair to good future potential for probable moderate-size accumulations.

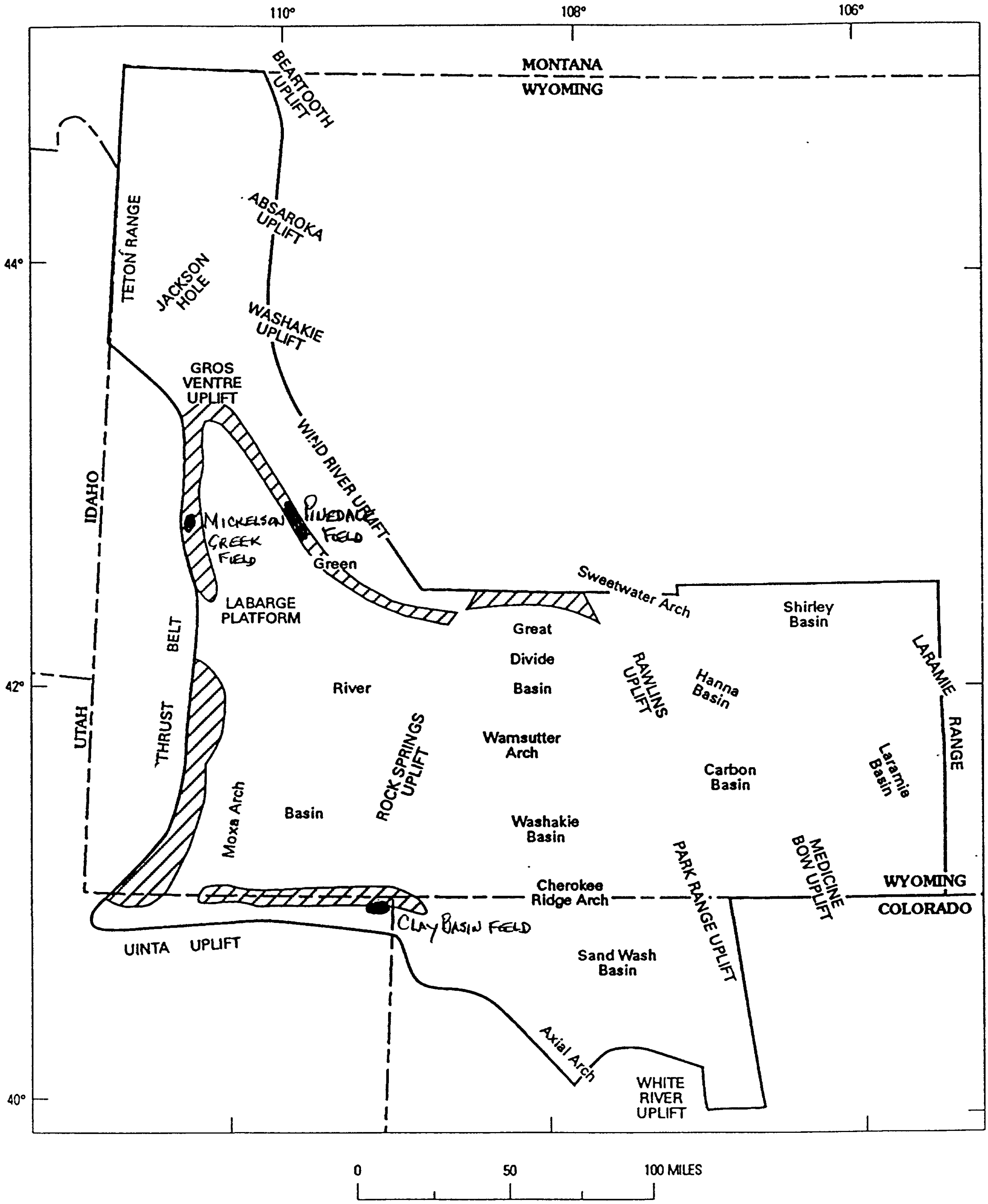

Figure 46. Map of Basin Margin Anticline play.

OIL AND GAS PLAY DATA

PLAY **BASIN MARGIN ANTICLINE**
PROVINCE **SOUTHWESTERN WYOMING BASINS** CODE **04-102-070**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.2**
Gas	**0.8**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.2**	**5**	**10**	**20**	**35**	**50**
Gas (x 10^9 CFG)	**6**	**8**	**20**	**40**	**80**	**180**	**300**
Reservoir depth (x10^3 ft)							
Oil	**5**			**10**			**22**
Gas (non-associated)	**5**			**10**			**25**
Number of accumulations	**2**	**2**	**3**	**4**	**5**	**6**	**6**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**5**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

SUBTHRUST PLAY (080)

The play is highly speculative due to the paucity of well data and overall exploration. It is based on probable hydrocarbon accumulations beneath the overriden thrusted margins of basins, primarily in structural traps, but possibly in stratigraphic traps. The play area consists of five narrow segments that parallel the individual basin margins (fig. 47).

Possible reservoirs include most of the reservoirs previously discussed in other plays in the overall province, especially carbonate and clastic reservoirs in the Madison, Weber, Nugget, Dakota, and Frontier. Thicknesses of reservoirs range from 10 to 200 ft and porosities and permeabilities are anticipated to range from poor to very good.

Probable source rocks include shale in the Phosphoria and Mowry. Although there is no definitive evidence for timing of hydrocarbon generation and migration, maximum burial and sufficient temperatures probably occurred primarily during mid to late Tertiary time. In general, thrusting in the play was a Laramide event, therefore, thrust-related structural traps and pre-thrust traps would have been in place for hydrocarbon entrapment.

Types of traps which may occur in the play are: (1) conventional anticline, (2) stratigraphic, (3) fault truncation of upturned strata, and (4) fracture. Anticlinal traps may be of two types, those formed as a result of thrusting and those anticlines formed prior to thrusting that were overridden at the time of thrusting. Relatively impermeable shales and (or) faults may provide seals, and the anticipated drilling depths to objectives may be as deep as 25,000 ft.

Although less than ten wells have been drilled in the play, these wells represent the greatest number of penetrations to have actually tested the subthrust play concept than in any other individual province in the Rocky Mountain region. The play is still immaturely explored, however, with large areas remaining to be evaluated. Although no fields have been discovered, the large unexplored areas and positive attributes of the play are significant; the future potential is estimated to be fair to good for both oil and gas.

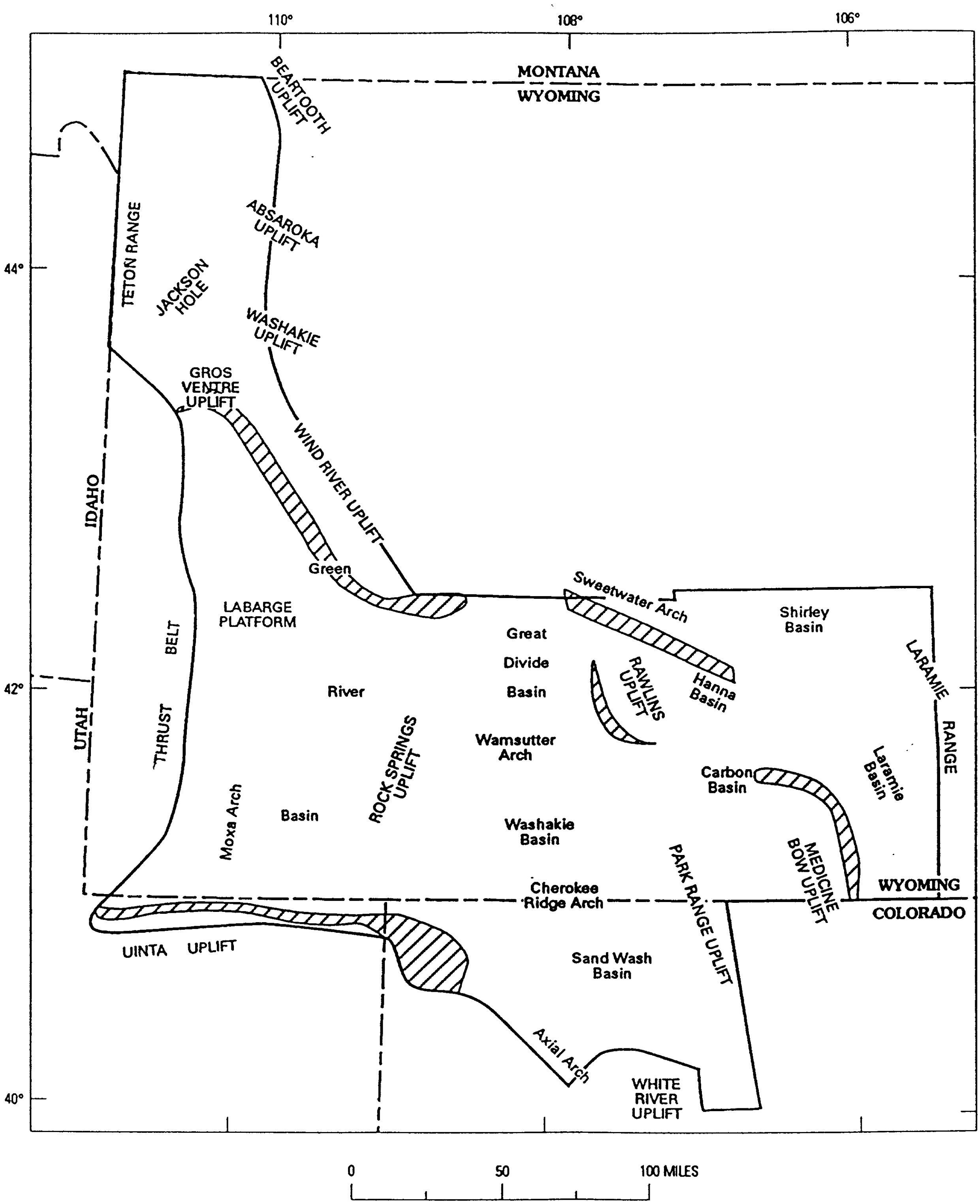

Figure 47. Map of Subthrust play.

OIL AND GAS PLAY DATA

PLAY SUBTHRUST
PROVINCE SOUTHWESTERN WYOMING BASINS CODE **04-102-080**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.90**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.3**
Gas	**0.7**

Fractiles * (estimated amounts)

Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.2**	**5**	**10**	**20**	**35**	**50**
Gas (x 10^9 CFG)	**6**	**8**	**20**	**40**	**80**	**180**	**300**
Reservoir depth (x10^3 ft)							
Oil	**6**			**12**			**22**
Gas (non-associated)	**6**			**12**			**25**
Number of accumulations	**1**	**1**	**2**	**3**	**6**	**12**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**5**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

ROCK SPRINGS PLAY (090)

The play is defined by mainly gas accumulations primarily in structural traps in sandstone and carbonate reservoirs ranging from Mississippian to Upper Cretaceous in age. The play includes the north-south plunging Rock Springs uplift and the western part of the Wamsutter arch and covers an area about 80 mi long and 12 to 40 mi wide (fig. 48). The western boundary is coincident with the surface trace of a buried high-angle thrust fault, and the eastern boundary is the structurally highest part of the east-west trending Wamsutter arch. Numerous northeast- and east-northeast-trending normal faults occur in the play area.

Principal reservoirs include the Mississippian Madison Limestone, Pennsylvanian Weber Sandstone, Permian Phosphoria Formation, Jurassic Nugget and Entrada Sandstones, Lower Cretaceous Dakota Sandstone, Upper Cretaceous Frontier Formation, Almond Formation, and sandstone in the Lewis Shale (fig. 40). Productive reservoirs range in thickness from 10 to 80 ft and occur at depths ranging from 1,700 to 18,300 ft. In general, reservoir porosity exceeds 10 percent and permeability exceeds 40 md.

The most likely source rocks for oil and gas include the Phosphoria Formation and Mowry Shale. Analyses of oil from the Almond Formation in the Patrick Draw field indicate a Cretaceous source. Nonassociated gas in other Cretaceous reservoirs may have been derived from any of the numerous shale and coal beds in the Cretaceous sequence. Pre-Cretaceous as well as most of the Cretaceous rocks are within the oil generation window, and reached their present levels of thermal maturity by late Eocene or Oligocene time. Thus, temporal relationships between Laramide trap formation and hydrocarbon generation and migration from Cretaceous and older source rocks were favorable for hydrocarbon accumulation.

Nearly all productive traps are in several small, faulted anticlines along the crest and east flank of the Rock Springs uplift. On the east flank of the uplift are two significant anticlinal folds (Table Rock and Brady structures) bounded on their west flanks by high-angle reverse or thrust faults. The Rock Springs uplift is believed to be due primarily to Laramide deformation. A notable exception to the predominance of anticlinal traps is the Patrick Draw field; it is located on the western crest of the Wamsutter arch, on the east flank of the Rock Springs uplift. In this field, oil is stratigraphically trapped in westward, updip pinchouts of sandstone in the Almond Formation. Cretaceous shales and (or) juxtaposition of relatively impermeable lithologies along faults provide good seals. Projected drilling depths range from 5,000 to 22,000 ft.

Exploration in the play is relatively mature, although the west flank of the Rock Springs uplift remains essentially unexplored. There are 46 oil and gas fields in the play; the first discovery was the South Baxter Basin field on the Rock Springs uplift in 1922. The largest oil fields are Brady (Nugget, Phosphoria, and Weber production) and Patrick Draw (Almond and Lewis production) fields with calculated ultimate recoveries of 80 and 63 MMBO respectively. The largest gas fields are the Table Rock (Almond, Nugget, Weber, and Madison production) and Brady fields with ultimate gas recoveries of 750 and 390 BCFG, respectively. Along the west flank of the Rock Springs uplift there is a probability that structural traps, in association with a buried high-angle reverse or thrust faults are present. Overall, however, it is unlikely that the majority of undiscovered fields will exceed 1 MMBOE in size, but there is a good possibility of finding small fields of less than 1 MMBOE. Most future discoveries will probably be in small- to medium--size gas fields.

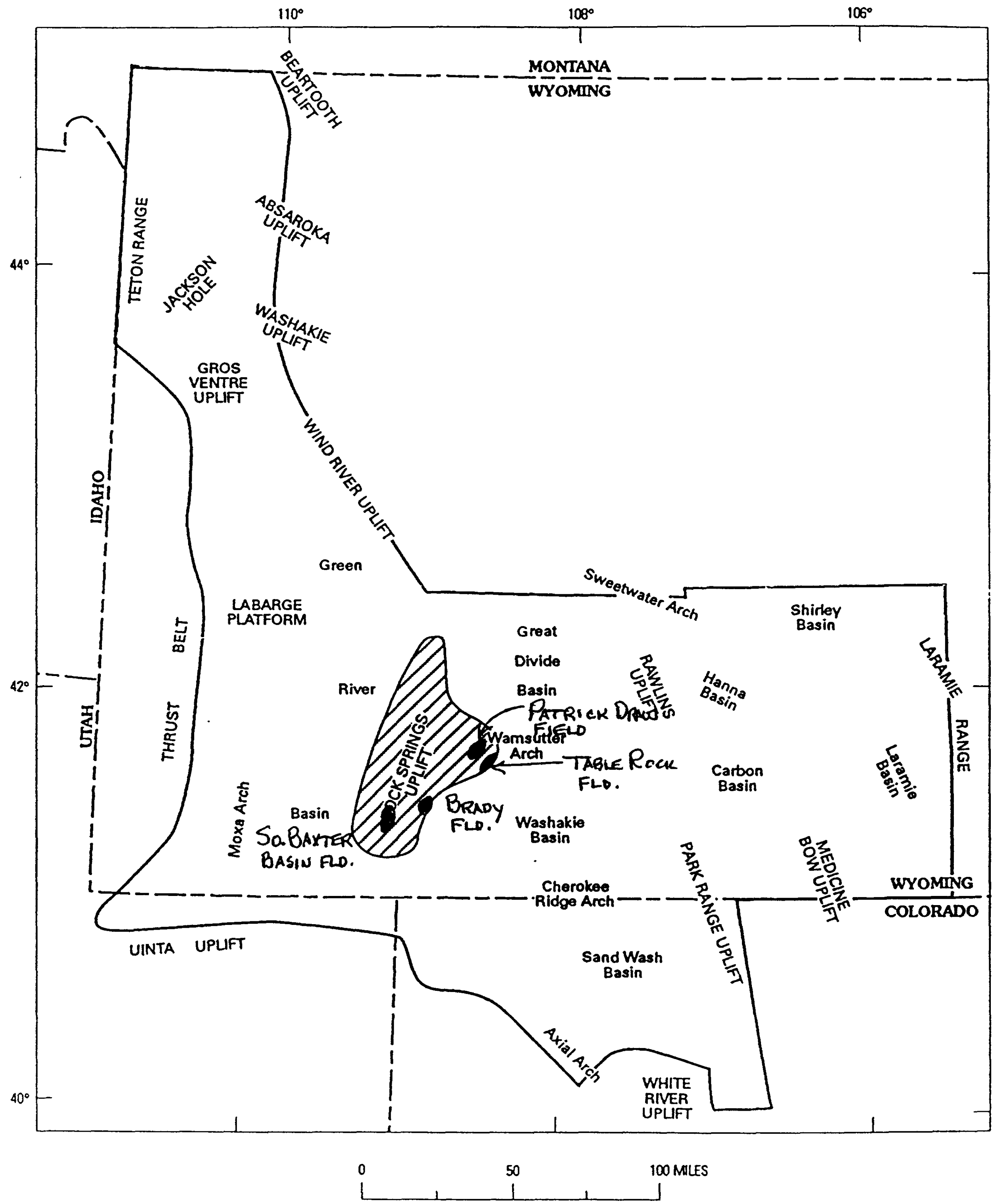

Figure 48. Map of Rock Springs play.

OIL AND GAS PLAY DATA

PLAY **ROCK SPRINGS**
PROVINCE **SOUTHWESTERN WYOMING BASINS** CODE **04-102-090**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0.1**
Gas	**0.9**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.2**	**2**	**3**	**5**	**12**	**25**
Gas (x 10^9 CFG)	**6**	**8**	**10**	**15**	**25**	**70**	**150**
Reservoir depth (x10^3 ft)							
Oil	**5**			**11**			**16**
Gas (non-associated)	**5**			**11**			**22**
Number of accumulations	**4**	**4**	**5**	**7**	**9**	**12**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**2000**	CFG/BBL
Average ratio of NGL to non-associated gas	**40**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BIGHORN BASIN PROVINCE (103)

By James E. Fox and Gordon L. Dolton

INTRODUCTION

The Bighorn Basin Province is comprised of one of several large, asymmetrical, intermontane basins of Laramide origin in the northern Rocky Mountain foreland and is located in north-central Wyoming and south-central Montana. The basin is surrounded by major basement highs, including the Beartooth Mountains uplift to the northwest, the Bighorn and Pryor Mountains uplifts to the east, and the Owl Creek Mountains uplift to the south. The basin is asymmetrical, with the axis lying along the west-central side. Elevations of the Precambrian surface range from about 11,000 ft in the Bighorn mountains to -30,000 ft (relative to sea level) in the deepest part of the basin. A high volcanic upland, the Absaroka (Mountains) Volcanic Plateau, lies on the west side of the basin, overlapping folded sedimentary rocks. Strata along the uplifts generally range in structural dip from 10-20 degrees or they may be overturned.

The basin is bounded by overthrust, high-angle reverse, and normal faults as well as anticlinal flexures, many of which are faulted, and are the result of Laramide deformation. Broad outcrop belts of folded and faulted Paleozoic and Mesozoic rocks surround the resulting crustal depressions. The basin is filled with a relatively complete stratigraphic sequence. Included is a thin section of Paleozoic shelf carbonate, sandstone, and shale beds overlain by a thick sequence of Mesozoic and early Tertiary terrigenous rocks (fig. 49). The province has been productive of oil and gas from rocks ranging in age from Cambrian to Eocene; about 2.5 BBO and 1.6 TCFG had been discovered by the end of 1986. Two of the largest fields in the Rocky Mountain region (Elk Basin and Oregon Basin) occur in structural traps along the margin of the basin and have produced a combined 1 BBO. Both structural and stratigraphic plays were defined in the province, five of which were individually assessed: Phosphoria (020), Deep Basin

Anticlinal (040), Basin Margin Subthrust (050), Sub-Absaroka (060), and Basin Margin Anticlinal (070).

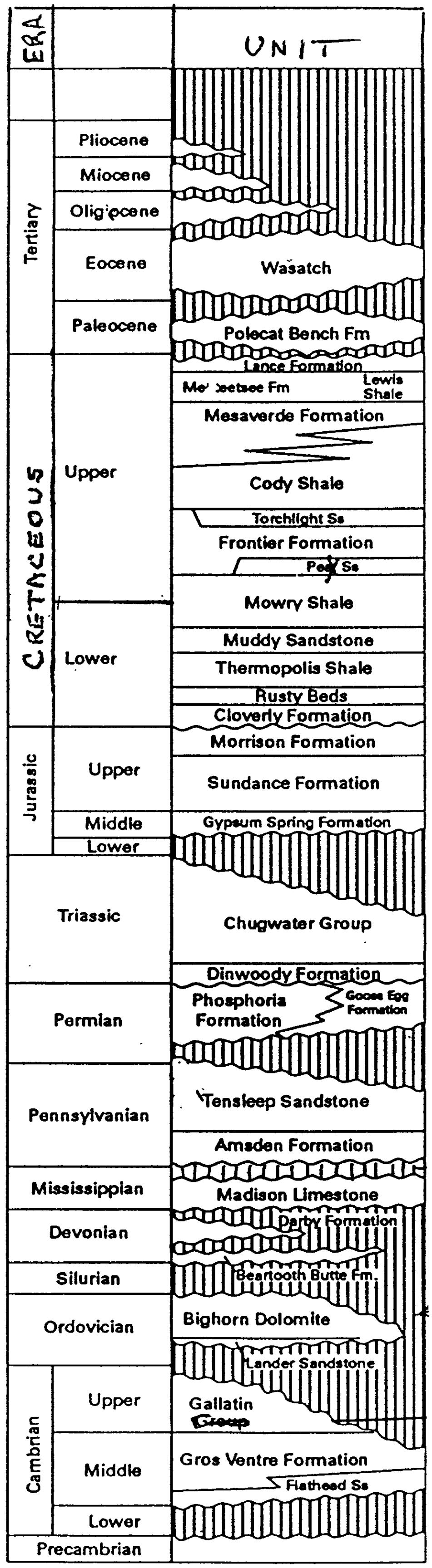

Figure 49. Generalized stratigraphic column, Bighorn basin province.

PHOSPHORIA PLAY (020)

This play is characterized by oil accumulations in stratigraphic traps along the eastern side of the Bighorn basin where carbonate members of the Phosphoria Formation intertongue with, and grade eastward into red shales and evaporites of the Goose Egg Formation (figs. 49,50).

Reservoirs are typically dolomitized grainstones and packstones, although local fenestrate algal rocks contain good porosity. Reservoir matrix porosities average about 10 percent, and are often fracture-enhanced, and productive zones range from 10 to 20 ft. Source rocks are organic-rich Phosphoria shales to the west, which are at a depth considered to be sufficient to have generated oil. Most of the oils are high in sulfur with gravities that range from 19° to 29° API.

Phosphoria carbonate tongues (Ervay Member) grade into red shale and evaporite of the Goose Egg Formation, and occupy a transitional zone between sabkha and supratidal redbeds bordering the seaway to the east, and marine carbonates and dark shales to the west. Oil accumulations occur in stratigraphic traps in porous, detrital carbonate reservoirs near the eastward pinchout of the Ervay Member. These carbonate rocks were deposited in high energy regimes of tidal channels on a coastal flat, and sealed updip by tight, fine-grained carbonates of intertidal and supratidal origin. Lateral seals for the traps are the mud-supported carbonate rocks of the Ervay Member, although the regional trap can be viewed as the overall facies change from carbonate into redbeds. Vertical seals are the fine-grained rocks of the overlying Triassic Dinwoody Formation and Chugwater Group (fig. 49). Internal footseals are provided by fine-grained redbeds or carbonates. Depth to objectives in the play ranges from 4,000 to more than 12,000 ft.

Exploration in the play was stimulated by the discovery of Cottonwood Creek field in 1953. The size of this field, the largest in the play, is in excess of 50 MMBO. Additional discoveries since 1953 have been infrequent, approximately 10 in number, and smaller in size. Manderson field (4 MMBO and 40 BCFG ultimate recovery), a combination trap, contains substantial amounts of sour gas, as does Cottonwood Creek. Future potential for discoveries of large fields is low; most undiscovered fields are estimated to be in small accumulations.

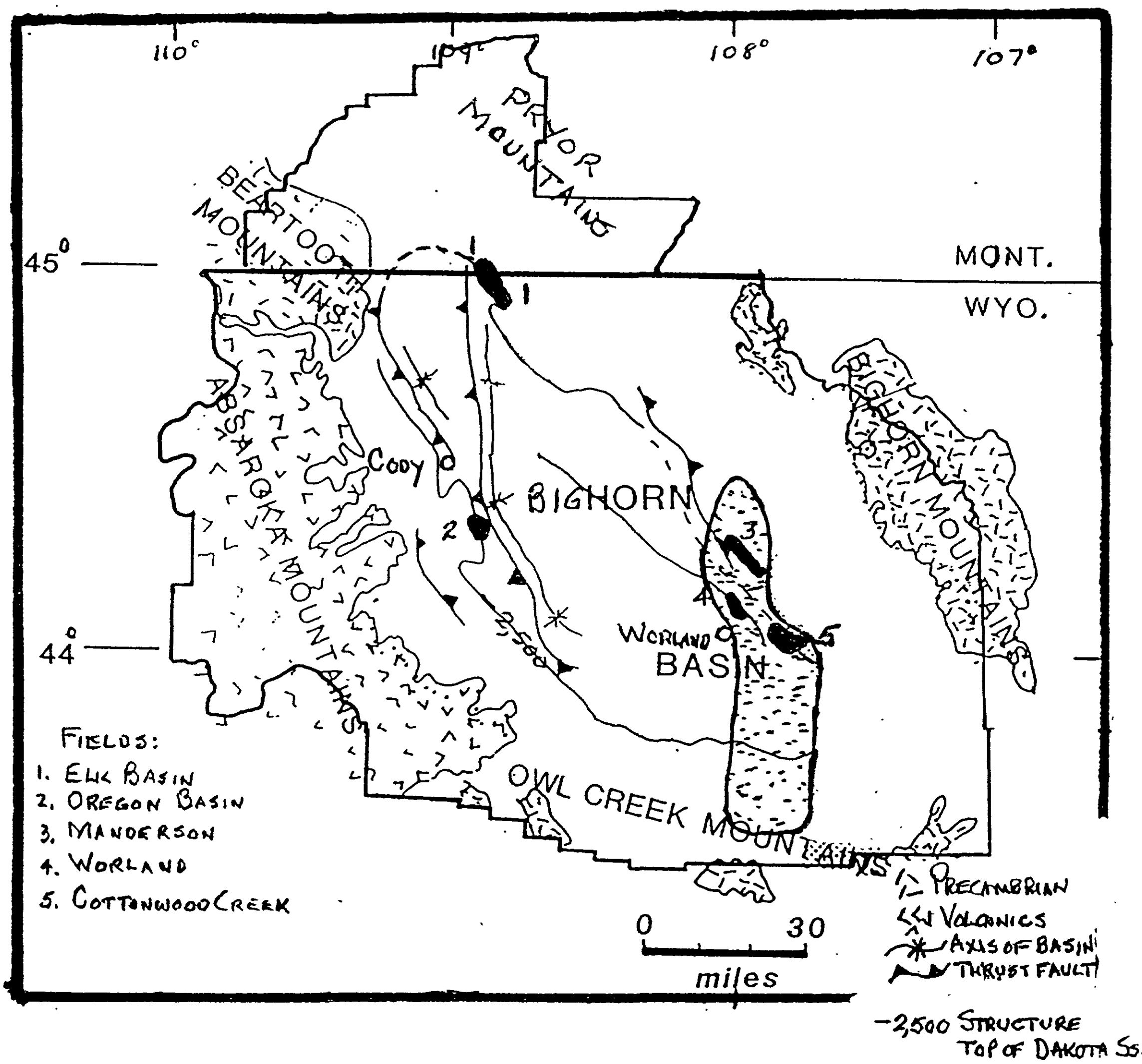

Figure 50. Map of Phosphoria play.

OIL AND GAS PLAY DATA

PLAY **PHOSPHORIA**
PROVINCE **BIGHORN BASIN** CODE **04-103-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.1**	**1.2**	**1.5**	**2.2**	**5**	**15**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**4**			**8**			**12**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**1**	**2**	**3**	**4**	**5**	**7**	**10**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

DEEP BASIN ANTICLINAL PLAY (040)

The play is characterized by probable gas accumulations in anticlinal, domal, and faulted anticlinal structures that formed within the deep part of the basin and involves Tertiary and Cretaceous rocks (fig. 51); it is primarily a gas play because of the great depth of burial. Depth to anticipated productive units ranges from about 11,000 ft at the southeast end of the play to greater than 20,000 ft at the northwest end.

Reservoir rocks are primarily sandstones from a variety of environments, including deltaic channel and bar, marginal marine, and fluvial channel. Because of the uncertain quality of reservoirs at these great depths, older reservoirs, such as the Tensleep and Phosphoria, were not included in the play, although they may have potential. Reservoir sandstones in the Frontier and Mesaverde Formations are interbedded with marine shale; reservoir sandstones in the Lance and Fort Union Formations are interbedded with source rocks of nonmarine origin. These interbedded relationships favored easy migration from source to reservoir rock; however, the depth of burial has very likely reduced the quality of reservoirs. If hydrocarbons were being generated and structures began forming prior to excessive burial, oil and gas could have been trapped within the reservoirs, helping to preserve some of the original porosity and permeability. Carbonate rocks are considered to be secondary in importance as reservoirs. It is anticipated that reservoir thicknesses will generally range from 10 to 70 ft.

Thick sections of marine shale may serve as potential source rocks in the Permian Phosphoria Formation and Cretaceous Thermopolis Shale, Mowry Shale, Frontier Formation, and Cody Shale. Paludal shale within the Mesaverde, Meeteetse, Lance, and Fort Union Formations (fig. 49) are also organic-rich and may be good sources for natural gas. Most of these formations are deeply buried and may be beyond the thermal maturity range of the oil generation zone and into the gas zone. Some of the stratigraphically lowest Cretaceous shales and the Phosphoria Formation may have been buried deeply enough in the area west of the play for hydrocarbon migration to begin, even before the onset of the Laramide orogeny. Hydrocarbons subsequently migrated into reservoirs in the play. On the shallower southeast end of the play gas is produced, in part, from the Phosphoria at Five Mile field from a depth of 11,650 ft.

The primary trapping mechanism is an intrabasin anticlinal feature, fault bounded on the north side and locally referred to as the "Five Mile Trend" (fig. 51). It trends northwest, diagonally across the center of the basin, and is the only known major productive structure in the play. The anticline plunges in a northwesterly direction where the depth to the top of the Tensleep exceeds 25,000 ft at the northwest end. At the southeast end of the play, close to the Cottonwood Creek and Worland fields, depth to the Tensleep is about 11,000 ft. Seals may be fine-grained beds that are interbedded with reservoirs and which may also be source rocks.

Although the play is productive, the level of exploration is minimal and the potential for future discoveries of gas is fair. Only the Five Mile field is greater than 1 MMBOE ultimately recoverable in size; two other fields are less than 1 MMBOE in size. Approximately 3 BCFG has been discovered in the play to the end of 1986.

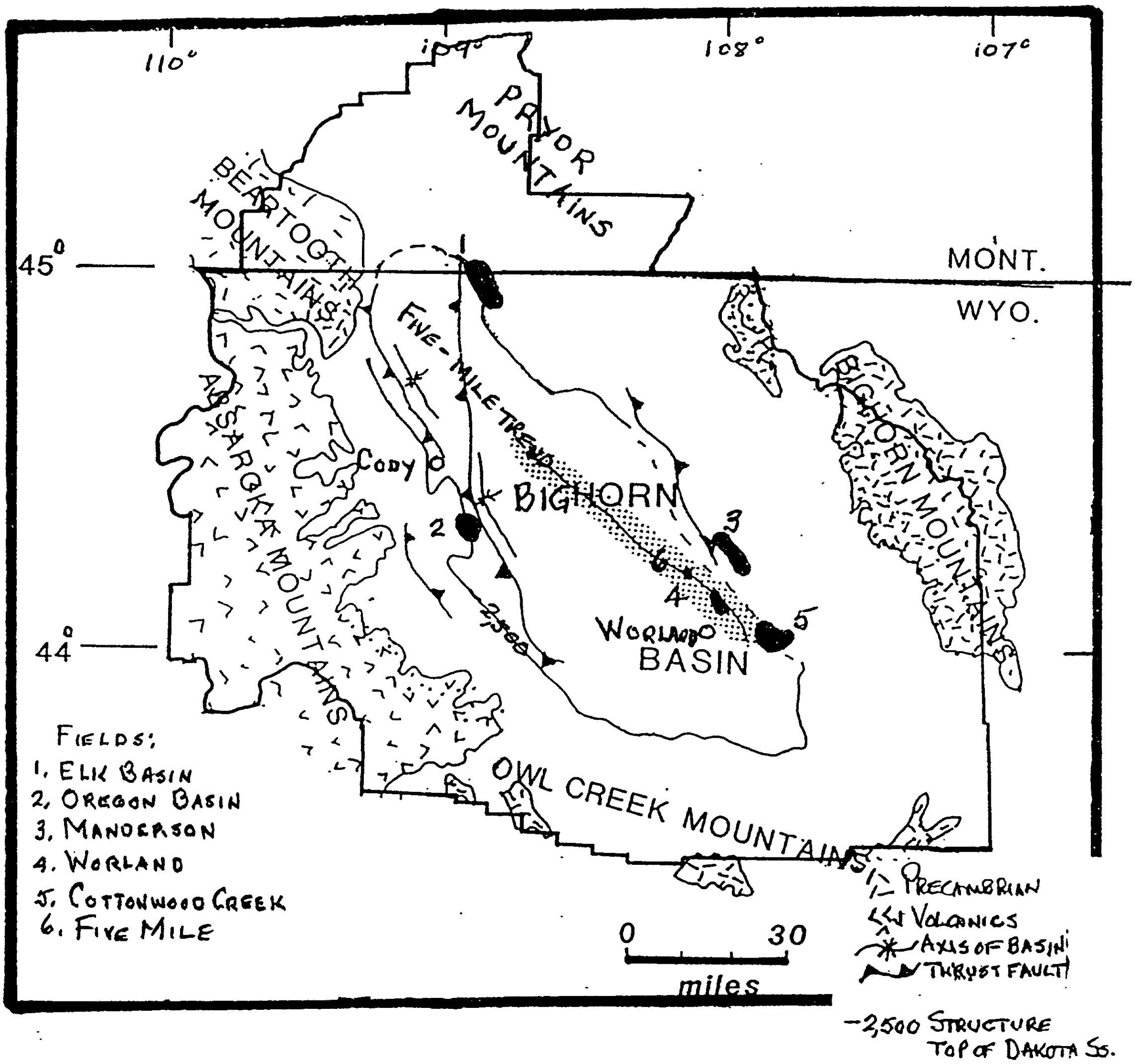

Figure 51. Map of Deep Basin Anticlinal play.

OIL AND GAS PLAY DATA

PLAY **DEEP BASIN ANTICLINAL**
PROVINCE **BIGHORN BASIN** CODE **04-103-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**6**	**6.6**	**8**	**12**	**24**	**72**	**350**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**8**			**13**			**18**
Number of accumulations	**1**	**2**	**3**	**4**	**5**	**7**	**10**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**25**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BASIN MARGIN SUBTHRUST PLAY (050)

The play is characterized by potential hydrocarbon accumulations in footwall structural traps beneath, and concealed by, the hanging wall of thrust faulted Precambrian crystalline rocks. The play area is composed of three narrow segments located along the flanks of the Bighorn basin (fig. 52).

Reservoir rock types include porous and permeable sandstones and carbonates, and shale units may also have good reservoir quality due to potentially extensive fracturing associated with thrusting. Source rocks are numerous, and include organic-rich rocks of the Phosphoria, Mowry, Frontier, and Niobrara (fig. 49). The depth of burial of source shales is usually great enough for them to have generated hydrocarbons locally, or hydrocarbons may have migrated from mature areas in deeper parts of the basin. Generation in this case occurred during and after the Laramide orogeny when the structures formed.

Traps would be mainly structural, however, early, or pre-Laramide, migration may have taken place, moving hydrocarbons into sandstone reservoirs before tectonic development of basin margin folds and faults. If these sandstones were sealed by facies changes, stratigraphic traps may have developed prior to basin margin thrusting. Faulting could then have superimposed structural control on the stratigraphic traps. Depth of hydrocarbon occurrence is highly variable, and depends on the thickness of the Precambrian overhang wedge (dip angle of the thrust plane) and orientation and thickness of the underlying strata. Depths may exceed 10,000 ft where thrusting takes place over the structurally deep northwestern side of the basin, and less than 10,000 ft in other segments of the play. The level of exploration is unexplored to very lightly explored, and the future potential for both oil and gas is fair.

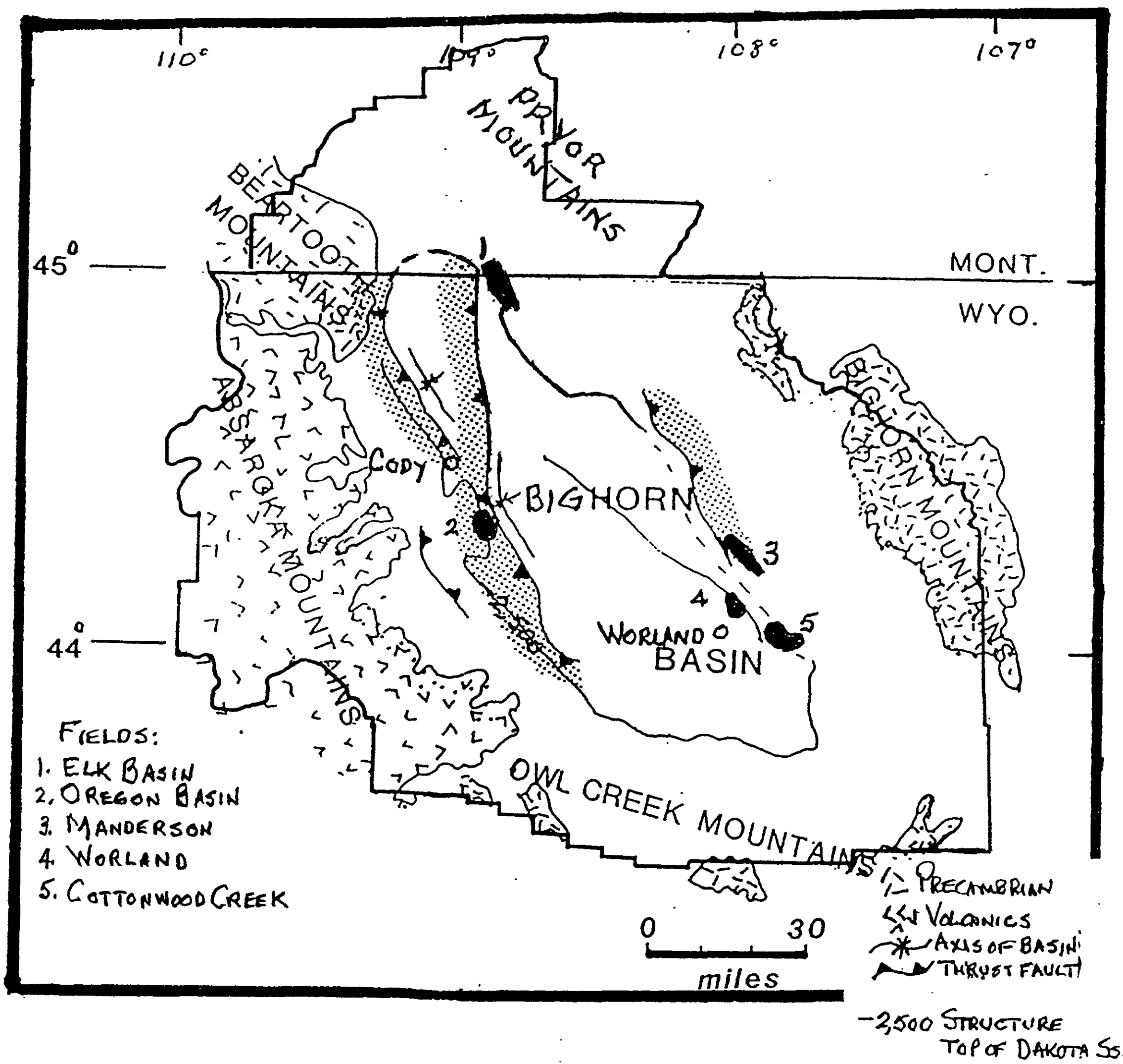

Figure 52. Map of Basin Margin Subthrust play.

OIL AND GAS PLAY DATA

PLAY **BASIN MARGIN SUBTHRUST**
PROVINCE **BIGHORN BASIN** CODE **04-103-050**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0.75**
Gas	**0.25**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.3**	**2.5**	**5**	**10**	**25**	**60**
Gas (x 10^9 CFG)	**6**	**7**	**10**	**14**	**22**	**75**	**200**
Reservoir depth (x10^3 ft)							
Oil	**8**			**12**			**16**
Gas (non-associated)	**8**			**12**			**20**
Number of accumulations	**1**	**2**	**4**	**6**	**8**	**13**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**10**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

SUB-ABSAROKA PLAY (060)

The play is speculative and is based on probable hydrocarbon accumulations in anticlines and fault traps in Paleozoic and Mesozoic reservoirs that are concealed by a thick surface cover of Eocene volcanic and volcaniclastic rocks of the Absaroka Volcanic Plateau. Structures beneath the Absaroka Volcanic Plateau in the far western area of the play are on trend with northwest-trending productive structures slightly to the east of the volcanic cover (fig. 53) These productive structures can be used as analogs to estimate relative size and geometry for sub-Absaroka structures. The eastern and southern boundaries of the play are defined by the farthest extent of the overlying volcanics, the northern boundary by the approximate Precambrian contact with the volcanic cover, and the western limit by the approximate position of truncated, subcropping strata beneath the volcanics. The depth range of objective intervals would be highly variable because of the rugged topographic relief of the Absaroka Mountains.

Based on production from fields on trend with the area of play, the Tensleep Sandstone has the best reservoir potential. The Tensleep ranges up to 100 ft in thickness, consists of quartzose sandstone deposited in both a marginal marine to eolian environment, and has very good primary porosity; the degree of destruction of primary porosity by secondary cementation is quite variable. Phosphoria and Madison carbonate rocks are also potential reservoirs, as well as sandstone of Lower Cretaceous age (fig. 49).

Abundant, organic-rich source rocks are present in Paleozoic and Mesozoic formations within the Bighorn basin, many of which were buried deeply enough to have generated hydrocarbons even before the Laramide orogeny. Numerous oil seeps occur along surface fractures at the basal contact of the Absaroka volcanics, strong evidence that oil has been generated in the play. The play is near the basin axis where hydrocarbons were most likely generated early. The Willow Draw and Fourbear fields (fig. 53) produce oil from five different Mesozoic and Paleozoic formations, and are believed to be field analogs on structural trend with the play. A considerable amount of Laramide faulting occurred on this far western side of the basin; these faults may have acted as conduits for hydrocarbons migrating upward, until reaching porous and permeable reservoir beds in traps. Most traps were formed during the Laramide orogeny; oil may have been redistributed after earlier (pre-Laramide) migration, in addition to oil that was generated during the Laramide.

Concealed domes and plunging anticlines may be probable trapping mechanisms for hydrocarbons, and in some cases may be combined with faults and possibly smaller individual fault traps within these larger structures. Impermeable interbeds of shale could act as seals; drilling depths may range from 1,000 to over 4,000 ft. Since the play area was covered by Eocene basaltic volcanic flows subsequent to the formation of most of the anticlinal structures, structural traps may lie under the volcanic cover that are on trend with producing fields immediately east of the play area.

The play has not been extensively explored because of difficulties in identifying probable structural traps that are concealed beneath the volcanic cover. Although these restraints make the play somewhat speculative, it is felt that the future undiscovered potential is fair.

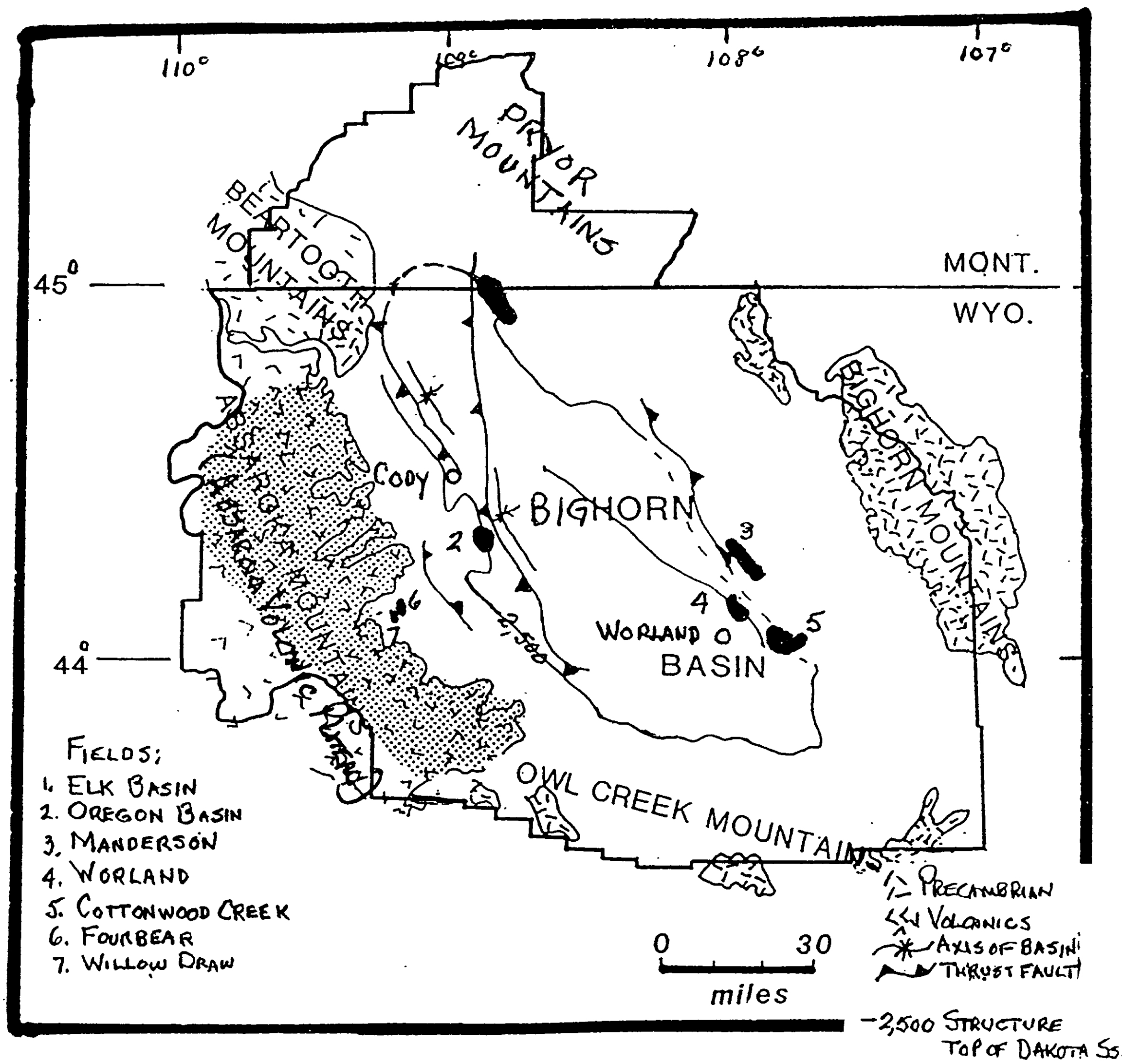

Figure 53. Map of Sub-Absaroka play.

OIL AND GAS PLAY DATA

PLAY **SUB-ABSAROKA**
PROVINCE **BIGHORN BASIN** CODE **04-103-060**

Play attributes	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.2**	**2.4**	**4.6**	**9.3**	**25**	**50**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**1**			**2.5**			**4**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**3**	**5**	**8**	**10**	**12**	**14**	**15**

(Fractiles * (estimated amounts))

Average ratio of associated-dissolved gas to oil (GOR)	**50**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

BASIN MARGIN ANTICLINAL PLAY (070)

The play is characterized by the occurrence of oil and gas fields on anticlines and associated structural closures which are developed mainly along the shallow margins of the basin as a result of compression during the Laramide orogeny (fig. 54).

As many as 13 formations ranging in age from Cambrian to Paleocene contain good quality reservoirs that are productive in the play. Principal reservoirs are the Madison, Tensleep, Phosphoria and Frontier (fig. 49).

A number of organic-rich shale beds lie within the thick sequence of hydrocarbon-bearing strata. Oil and gas in Cretaceous and younger reservoirs was probably sourced from associated Cretaceous organic-rich shale, while Paleozoic oil and gas was more likely to have been derived primarily from a distinct Phosphoria source. Thermal regimes are high-temperature in many localized areas of the basin, especially where source beds are deeply buried; gas is the dominant resource in these areas. Although Phosphoria source beds may have been generating hydrocarbons to the west and migrating into the area before the Laramide orogeny when the hydrocarbon-bearing structures in the play formed, basin margin structures formed at the time the basin was deepening; these structures trapped major volumes of hydrocarbons which were actively being generated at that time. Deepening of the basin center during Laramide time may have resulted in the remigration of previously generated hydrocarbons, as well as migration of newly generated hydrocarbons into developing structures.

Traps are mainly anticlines and domes, many of which are faulted, allowing migrating hydrocarbons to move vertically into multiple levels of porous and permeable reservoirs. Producing fields commonly have multiple pay zones in rocks of Paleozoic, Mesozoic, and Cenozoic age. Impermeable interbeds act as seals, although common oil-water contacts are sometimes observed between the Paleozoic reservoirs. Tilted oil-water contacts are also known. Depth of production ranges from a few hundred ft to more than 12,000 ft.

The play has been extensively explored and developed and the future potential for both oil and gas is low; new production may occur in extensions to existing fields. Significantly, most of the oil and gas produced in the Bighorn basin comes from this play, which includes 8 giant (>100 MMBO) fields. An estimated 2.4 MMBO and 1.4 TCFG have been discovered to the end of 1986. Field sizes range from over 500 MMBO at Elk Basin and 387 BCFG at Worland, to fields of less than 1 MMBO in size.

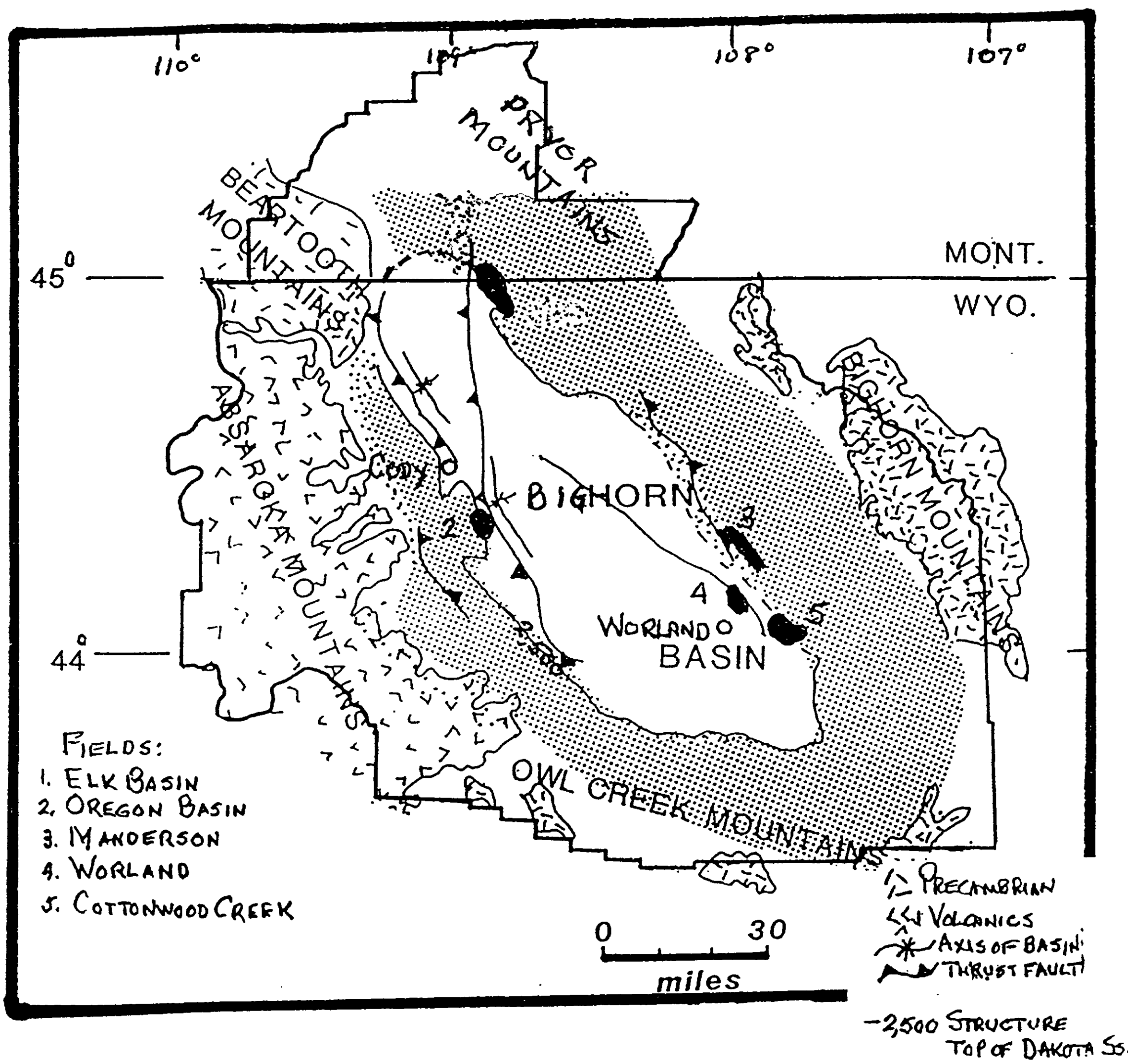

Figure 54. Map of Basin Margin Anticlinal play.

OIL AND GAS PLAY DATA

PLAY **BASIN MARGIN ANTICLINAL**
PROVINCE **BIGHORN BASIN** CODE **04-103-070**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) ($S \times T \times M \times R = MP$)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^{6} BBL; gas, 6×10^{9} CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

Fractile percentages *	Fractiles * (estimated amounts) *100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^{6} BBL)	**1**	**1.05**	**1.3**	**1.7**	**2.8**	**7.1**	**20**
Gas (x 10^{9} CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^{3} ft)							
Oil	**2**			**8**			**12**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**6**	**8**	**10**	**13**	**17**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**500**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^{6} CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^{6} CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

DENVER BASIN PROVINCE (104)

By Donald L. Gautier

INTRODUCTION

The Denver Basin province contains one of the largest Laramide (Late Cretaceous-early Tertiary) structural basins in the Rocky Mountains covering more than 60,000 mi^2 in northeastern Colorado, southeastern Wyoming, western Nebraska, and northwestern Kansas. The Denver structural basin is a composite, asymmetrical feature. Its axis parallels the Front and Laramie Ranges (Colorado and Wyoming, respectively), which together form the western boundary of the basin. The east flank of the basin dips gently westward at less than 1/2 degree, but the western flank is steep, with dips ranging from 10 degrees to overturned. The west flank is faulted and overthrust from the latitude of Denver southward. Two deeps occur along the basin axis, one near Cheyenne, Wyoming, and the other near Denver, Colorado. Near Denver, sedimentary rocks are greater than 13,000 ft thick, more than 8,000 ft which are of Late Cretaceous age (fig. 55). The Denver basin is bounded on the southwest by the Apishapa uplift and the Cañon City Embayment, on the southeast by the Las Animas arch, on the northwest by the Hartville uplift, and on the northeast by the Chadron and Cambridge arches. The basin thus extends approximately 300 mi. from north to south and more than 200 mi. from east to west. Structural relief along the western margin from near the basin axis onto the Front Range exceeds 16,000 ft.

The Denver basin is the second oldest producing area in the United States; oil was first discovered in 1862 in the Cañon City Embayment area and later, in 1876, the Florence field was discovered in the same vicinity. Cumulative production in the province to the end of 1986 is approximately 800 MMBO and 1.2 TCFG, mostly from stratigraphic traps in Cretaceous rocks. Four plays were individually assessed in the province: Shallow Niobrara Gas (030), Paleozoic (040), D-J Sandstone (050), and Pierre Shale Sandstone (060).

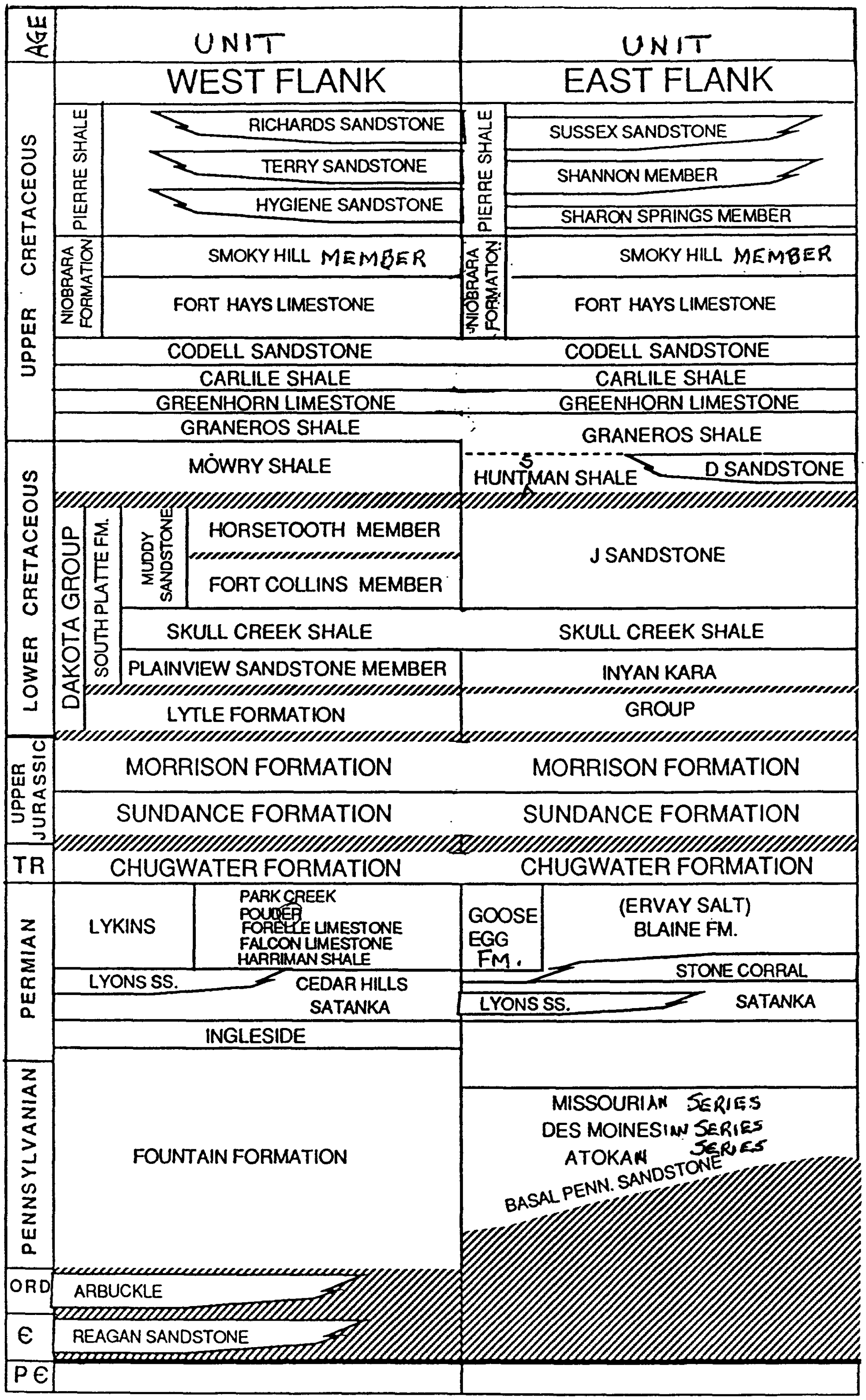

Figure 55. Generalized stratigraphic columns, Denver basin province.

SHALLOW NIOBRARA GAS PLAY (030)

The play consists of widespread accumulations of mainly biogenic methane gas at low reservoir pressures in low-permeability, fine-grained carbonate rocks covering an area of about 50 by 250 mi. The play is bounded by the facies, depth, and outcrop of chalks of the Niobrara Formation in eastern Colorado and western Kansas (fig. 56).

Reservoirs are in the upper 20 to 50 ft of chalk at the top of the Smoky Hill Member of the Niobrara Formation (fig. 55). The Smoky Hill consists of pelagic carbonate and hemipelagic shale deposited during Late Cretaceous time. Reservoirs consist of chalk of high porosity and low permeability (0.1 to 20 md). Permeability may be locally enhanced by natural or induced fracturing. The quality of the reservoirs is strongly dependent upon burial diagenesis. Porosity declines systematically with increasing burial, such that production is generally not considered economic in eastern Colorado or western Kansas where depths exceed 3,000 to 4,000 ft.

Source rocks are believed to be in the Smoky Hill. Producible hydrocarbons consist mainly of natural gas considered to be biogenic by virtue of its molecular (99% methane) and isotopic (-60 to -70 o/oo,PDB) composition. The shallow depth and low-permeability of reservoirs, gas composition, and distance from other oil and gas accumulations in the Denver basin suggest that migration distances have been short, with gas being generated in-situ during shallow diagenesis, early in the burial history of the rocks.

Most, but not all, economic accumulations in eastern Colorado and western Kansas are associated with small structural closures. Niobrara gas fields on the eastern flank of the Denver basin occur where regional, structural dip is generally less than one half degree. In consequence, structures are low-relief features with structural closures of 50 to 200 ft. Entrapment results from overlying shales of extremely low permeability, which serve as moderately effective seals. Most production has been from 800 to 2,800 ft deep.

The existence of shallow gas reservoirs in Cretaceous rocks in the Western Interior has been known for a long time. Niobrara gas production began in 1919 at Beecher Island field, with commercial production in eastern Colorado since 1972. Since the early 1970's, development has been largely dependent upon gas prices. In 1972, increased gas prices and improved technology encouraged drilling, and more than 60 fields were discovered in the subsequent four or five years. Market conditions in recent years have caused a marked downturn in exploration and development activity in the Niobrara shallow gas fields. Individual wells are generally of low yield and many fields are small. Typical initial gas potentials through the middle 1970's for wells in western Kansas were one to three MCFGPD, with field cumulative production of between 1.4 and 4.8 MMCFG. However, the widespread occurrence of gas indicates that total resources could be very large. Reserves of one to two TCFG are estimated for the eastern Denver basin. Based upon existing data, it seems likely that additional areas of gas accumulation, beyond present production, will be developed in the future. The widespread occurrence of potential shallow gas reservoirs in the Niobrara suggests possibly that a large number of small size fields may be found which could untimately merge into a single, areally large accumulation in the play area with resources in excess of one TCFG.

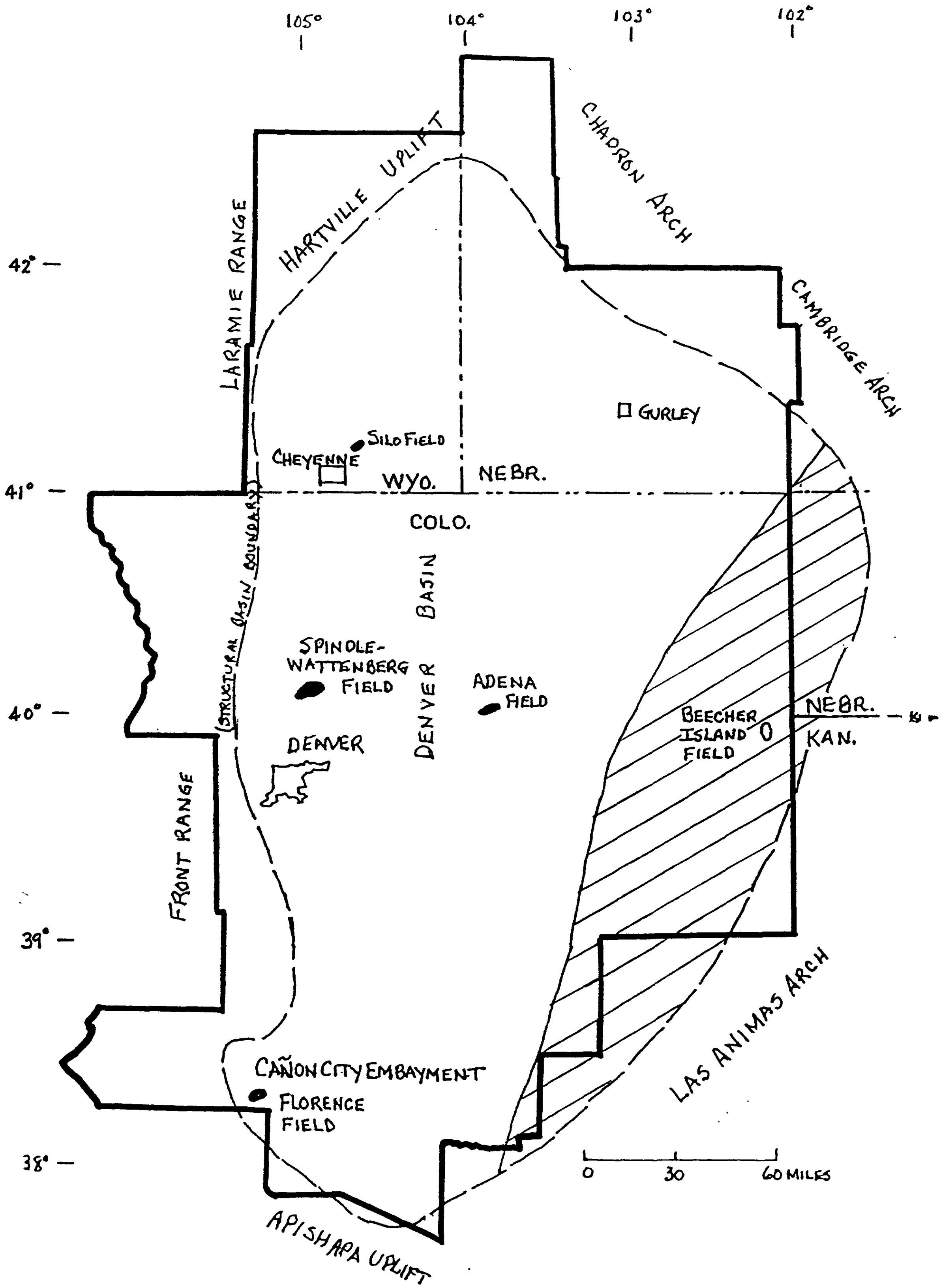

Figure 56. Map of Shallow Niobrara Gas play.

OIL AND GAS PLAY DATA

PLAY **SHALLOW NIOBRARA GAS**
PROVINCE **DENVER BASIN** CODE **04-104-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) ($S \times T \times M \times R = MP$)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

	Fractiles * (estimated amounts)						
Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**200**	**300**	**400**	**500**	**750**	**1250**	**2000**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**0.8**			**1.5**			**3**
Number of accumulations	**1**	**1**	**1**	**1**	**1**	**1**	**1**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

PALEOZOIC PLAY (040)

The play consists mainly of oil accumulations in stratigraphic traps, in some cases affected by local structure or by diagenetic alterations of reservoirs or seals, in Pennsylvanian and Permian age rocks in northeastern Colorado, western Kansas, and western Nebraska. The play area extends over most of the northeastern quarter of the Denver basin covering most of an area of about 130 mi on a side (fig. 57). Known and potential reservoirs in the eastern basin area include dolomite, limestone, and sandstone of mainly Pennsylvanian and Permian age, but also includes the Cambrian Reagan Sandstone (fig. 55). Pay thicknesses may range up to a few tens of ft in reservoir rocks of uncertain quality.

Studies of oil produced from Paleozoic rocks in the eastern basin area indicate that they have been derived from several source beds, all of which are geochemically distinct from oils of older production in the Permian Lyons Sandstone in structural traps in the western part of the basin. Source rocks appear to be various Paleozoic black shales, possibly in the vicinity of the Wyoming border, western Nebraska, and eastern Colorado. Timing and migration of oils into traps in the eastern part of the basin is mainly speculative. The occurrence of multiple distinct oil types suggests several small, local sources, and various generation and migration histories. Fields discovered so far consist mainly of stratigraphic accumulations with possible trap enhancement by local structures and by significant lateral variations in diagenetic alteration. Paleozoic rocks in the eastern Denver basin are considered to be prospective over depths ranging from 3,000 to 10,000 ft.

Oil production has been known from Paleozoic rocks in the Denver basin since at least 1953, when Black Hollow field was discovered in the Lyons Sandstone. Numerous discoveries have followed in the Lyons in the western portion of the basin, however, exploration in Paleozoic rocks of the eastern basin was regarded as purely speculative until the discovery of oil in Upper Pennsylvanian age reservoirs in the Amazon field in 1980. Since then, several additional small and single well fields have produced oil from Paleozoic rocks. The results of exploration to 1987 and the occurrence of multiple oil types suggests that future undiscovered accumulations may be relatively small.

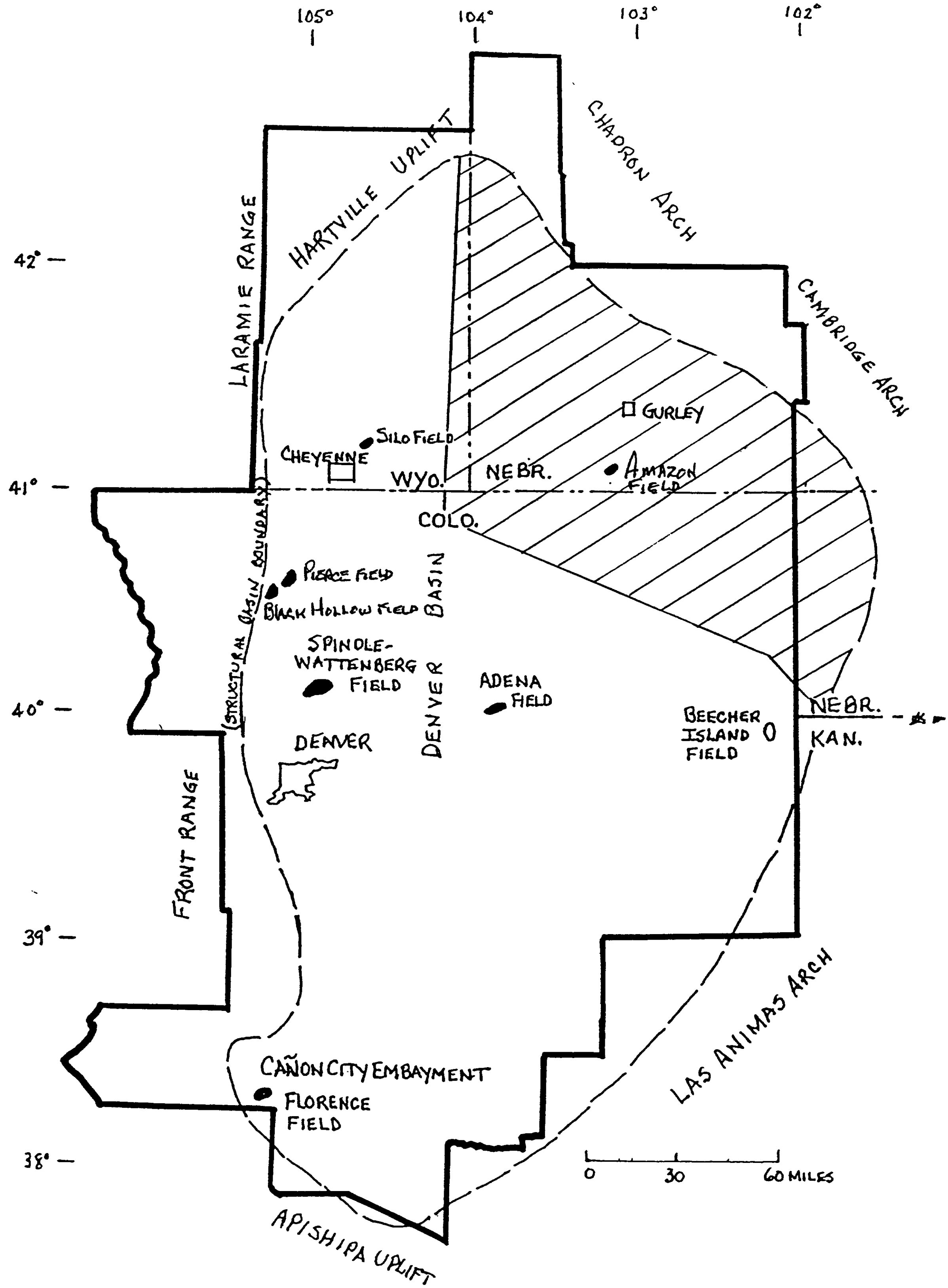

Figure 57. Map of Paleozoic play.

OIL AND GAS PLAY DATA

PLAY **PALEOZOIC**
PROVINCE **DENVER BASIN** CODE **04-104-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.03**	**1.2**	**1.5**	**2.4**	**7**	**32**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**3**			**6**			**10**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**6**	**8**	**10**	**15**	**24**	**50**

Average ratio of associated-dissolved gas to oil (GOR)	**900**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

D-J SANDSTONE PLAY (050)

The play is characterized by oil accumulations in combined stratigraphic-structural traps in the Lower Cretaceous D and J Sandstones of the Denver basin. The principal oil fields in the play are distributed widely in a productive fairway through east-central, northern and northeastern Colorado, westernmost Nebraska, and southeastern Wyoming (fig. 58). The play covers an arcuate area about 200 mi by 120 mi in the north-central part of the basin.

Reservoirs of the J Sandstone consist of very fine to coarse-grained quartzitic sandstones deposited in coastal plain and nearshore marine environments in late Lower Cretaceous time. The D Sandstone has been interpreted variously as having been deposited in coastal plain and shallow marine environments. Reservoirs are highly discontinuous, and one of the most significant exploration obstacles involving these reservoirs is in the prediction of reservoir quality. This prediction is commonly reduced to a search for significant thicknesses of sandstones within finer-grained rocks. Reservoirs of the J may be more than 150 ft thick, whereas reservoirs of the D may be up to 50 ft thick.

Oils produced from the D and J Sandstones are derived from Cretaceous shale source rocks, presumably in the Mowry-Huntsman, Greenhorn, Graneros, and possibly Skull Creek intervals (fig. 55). These source beds are thermally mature with respect to conventional concepts of oil generation only in the deeper parts of the basin, particularly in the vicinity of the Wattenberg gas field. This suggests either generation from comparatively low maturity source rocks or that long distances of migration have been involved in the D and J oil accumulations.

Most hydrocarbon accumulations in the D and J Sandstones are due mainly to stratigraphic entrapment, but with significant enhancement by local structures. Upper seals for the D and J are in the Cretaceous shales such as the Huntsman, Mowry, or Graneros (fig. 55). In places, especially in the deeper parts of the basin, diagenetic alterations have been so severe that diagenetic entrapment, especially due to quartz cementation, has played a significant role in hydrocarbon entrapment. Oil accumulations occur in a large area of Colorado, Nebraska, and Wyoming, at depths ranging from 3,000 to 8,000 ft.

Oil was first discovered in the J Sandstone near Gurley, Nebraska in 1949 and J oil production now accounts for more than 75 percent of the total hydrocarbon production in the overall Denver Basin province. The largest field in the play is Adena, with a cumulative production at the end of 1986 of more than 62 MMBO and 90 BCFG from the D and J Sandstones. Although exploration has been intense in the Denver basin and production is now severely declining, the possibility remains for significant discoveries in some areas. This is especially true because of the subtle stratigraphic traps which form many of the D and J oil accumulations. The Wyoming portion of the Denver basin is a particularly noteworthy area owing to its relatively low level of exploratory drilling. It appears likely that no fields larger than 60 MMBO in size remain, and that whereas 177 fields greater than 1 MMBO have been found, it is estimated that only a small number of such fields of this size remain undiscovered. In addition to these remaining fields larger than 1 MMBO, numerous smaller accumulations might be discovered in the play.

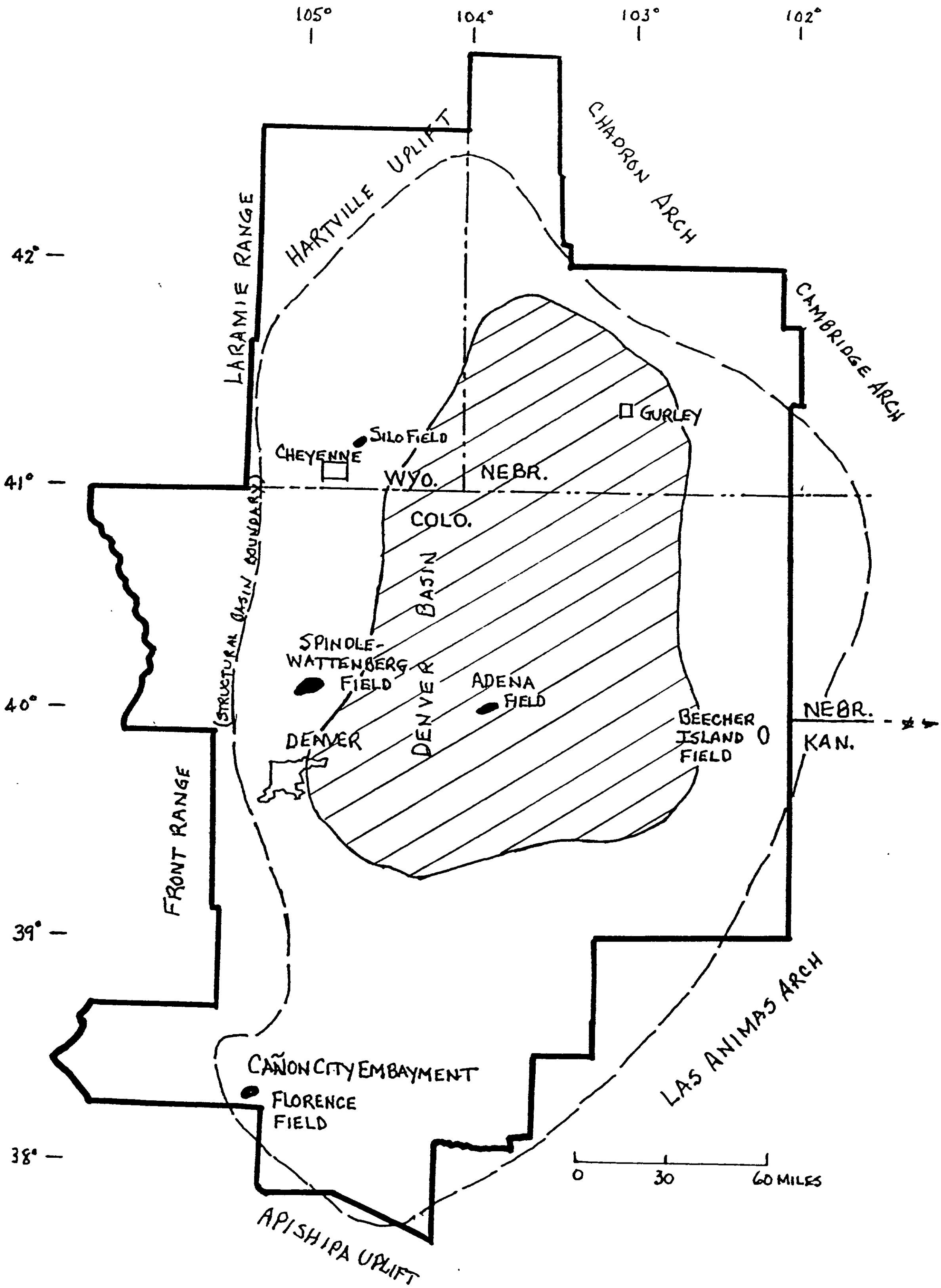

Figure 58. Map of D-J Sandstone play.

OIL AND GAS PLAY DATA

PLAY **D-J SANDSTONE**
PROVINCE **DENVER BASIN** CODE **04-104-050**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.03**	**1.2**	**1.5**	**2.5**	**5**	**20**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**3**			**5.5**			**8**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**20**	**23**	**27**	**30**	**35**	**44**	**60**

Average ratio of associated-dissolved gas to oil (GOR)	**1400**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

PIERRE SHALE SANDSTONE PLAY (060)

The play consists of relatively small oil accumulations trapped stratigraphically in discontinuous and heterogeneous reservoir sandstonès enclosed by mudstones of much lower permeability in the Pierre Shale. The play area is ultimately limited by the distribution of sandstones within the Pierre Shale, and is located along a generally north-south trend, parallel to the Colorado Front Range. It extends from just north of Denver, north into Wyoming and eastward 50 to 100 mi from the mountain front, covering an area about 160 mi long and 70 mi wide (fig. 59).

Reservoirs consist generally of upward coarsening glauconitic litharenites with reasonably good, but local and discontinuous porosity, ranging from 8 to 16 percent and permeabilities of 5 to 50 md. Because they are mineralogically immature, the sandstones have been significantly altered by diagenesis. These sandstones are in many ways typical of shale-enclosed sandstones of the upper shelf setting in the Western Interior basin, such as the Shannon or Sussex of the Powder River basin, with which the nomenclature of Pierre Shale sandstones (Terry, Hygiene, etc.) is commonly confused. Reservoirs are commonly linearly elongate, with sand bodies extending in zones roughly parallel to the ancient shoreline.

Oils being produced from known sandstone reservoirs in the Pierre Shale in the play are almost certainly derived from Cretaceous marine rocks such as shale in the Greenhorn, Mowry, and Carlile. Most of the Pierre section, with the exception of the lowermost part, is thermally immature with respect to oil generation. Most of these sandstone reservoirs overlie thermally mature source rocks, but are separated from them by a thick section of thermally immature marine shale. This evidence leads to the conclusion that significant vertical migration has occurred, with oil and gas migrating generally upward along fractures into the sandstone reservoirs. Time and temperature data and thermal maturity mapping in the Denver basin suggest that source rocks began to generate oil near the end of Cretaceous time and may still be generating oil in some areas today.

Trapping is provided by permeability differences between the sandstones and the surrounding marine mudstones. Locally, paleostructures may have affected the thickness and distribution of sandstones and local structures may play a role in enhancing closure and reservoir properties Drilling depths range from 4,000 to 8,000 ft. Depth to production in the Spindle field, for example, is at less than 5,000 ft, and this may be considered a typical depth for most production from sandstone in the Pierre Shale.

The exploration status of the Terry, Hygiene, and other other Pierre sandstones has changed in the last decade. Prior to 1972, exploration for these targets was not considered to be of commercial significance. The 1972 discovery of Spindle field, (fig. 59) which has an estimated ultimate recovery of about 50 MMBO, stimulated widespread interest in exploration. No discoveries of similar field size have been forthcoming, and although extensively explored, a possibity of other discoveries in the play exists in similar sandstones in the northwestern part of the basin. However, the occurrence of Spindle field, the only really large accumulation in Pierre sandstones, directly over the Wattenberg gas field, and over an area of elevated thermal maturity is probably not coincidental. In light of the generic relationship between Wattenberg and Spindle, and judging from the degree of exploration in the area of Pierre sandstone occurrence, it seems unlikely that any additional large size fields will be found. More likely, a number of smaller field discoveries will maintain the Pierre sandstones as an exploration target.

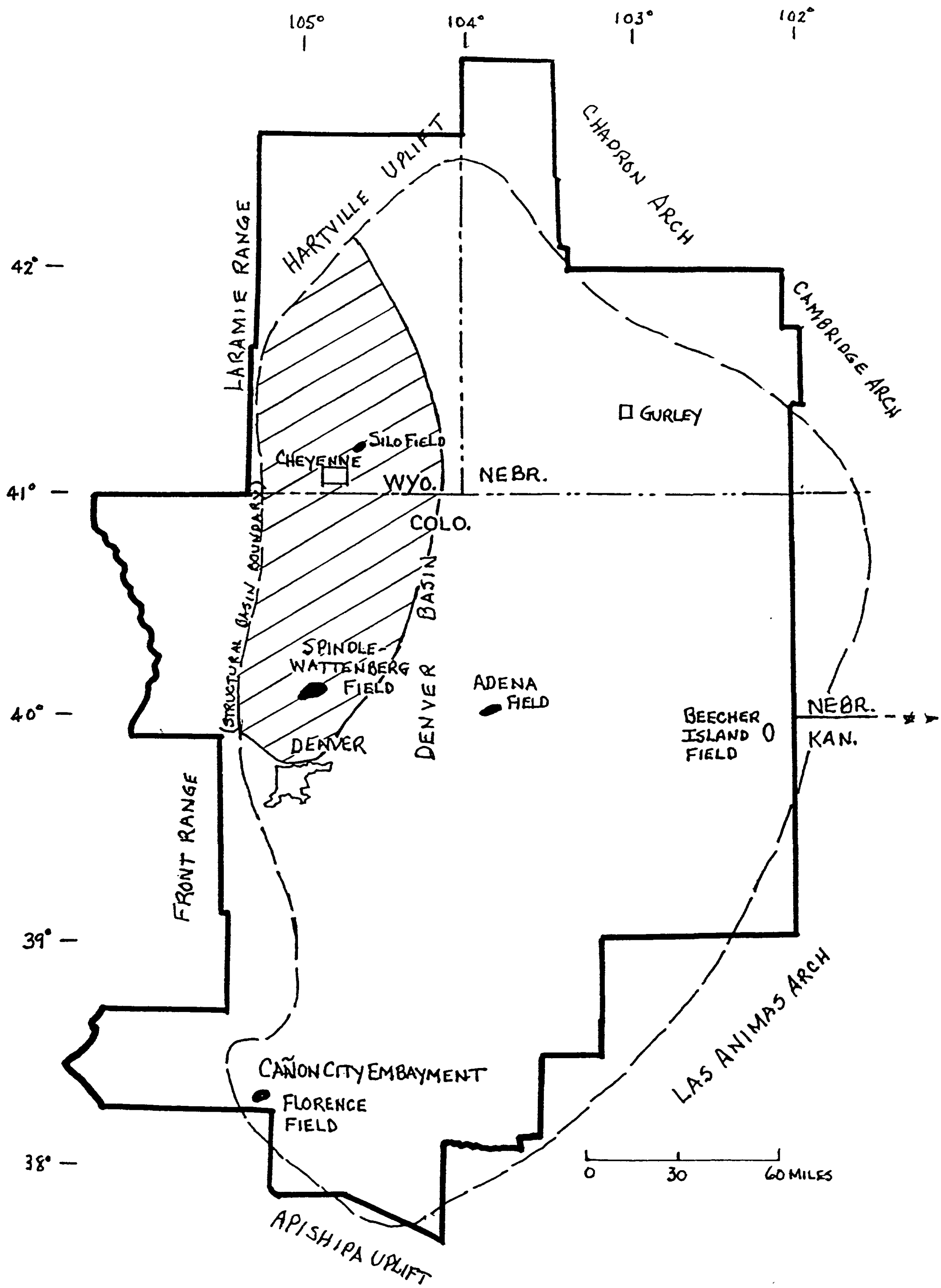

Figure 59. Map of Pierre Shale Sandstone play.

OIL AND GAS PLAY DATA

PLAY **PIERRE SHALE SANDSTONE**
PROVINCE **DENVER BASIN** CODE **04-104-060**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.25**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.02**	**1.14**	**1.4**	**2**	**4**	**7**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**4**			**4.5**			**8**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**1**	**1**	**2**	**2**	**3**	**6**	**8**

Average ratio of associated-dissolved gas to oil (GOR)	**4000**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

LAS ANIMAS ARCH PROVINCE (105)

By E. Allen Merewether

INTRODUCTION

The province is located in southeastern Colorado and is composed of Cheyenne, Kiowa, Otero, and Bent Counties, which comprise an area of about 6,300 sq mi. The Las Animas Arch is a broad, gently dipping, northeast-trending uplift that separates the Denver Basin of northeastern Colorado from the Hugoton Embayment (Anadarko Basin) of southeastern Colorado and southwestern Kansas. Deformation during Late Mississippian-Pennsylvanian time formed the ancestral Las Animas uplift, which was reactivated and arose again in Late Cretaceous-early Tertiary time. Sedimentary rocks in the province are of Paleozoic and Mesozoic ages and consist of siliciclastic and carbonate beds of marine and continental origin; their thickness ranges from about 2,000 ft to as much as 8,000 ft. (fig. 60)

Exploration in the province for oil and gas began in about 1920 and continued intermittently during the following thirty years. The first commercial discovery, the McClave field, was in 1951 in Kiowa County where gas was found in sandstone of the Pennsylvanian Morrowan series. Production from pre-Pennsylvanian beds was established in 1964 at the Comanche field, several miles southeast of the province, and in 1965 at the Brandon field within the province. Two plays were individually assessed in the province, the Morrowan (020) and the Mississippian (050).

ERA	SYSTEM	SERIES	UNITS
CENOZOIC	QUATERNARY	Holocene	
		Pleistocene	
	TERTIARY	Miocene	Ogallala Formation
MESOZOIC	CRETACEOUS	Upper	Pierre Shale Niobrara Fm. Carlile Shale Greenhorn Ls. Graneros Shale
		Lower	Dakota Sandstone
	JURASSIC	Upper	Morrison Fm. Ralston Creek Fm. (part)
		Middle	Ralston Creek Fm. (part) Entrada Ss.
	TRIASSIC	Upper	Dockum Group
PALEOZOIC	PERMIAN	Guadalupian	Taloga Formation Day Creek Dol. Whitehorse Ss.
		Leonardian	Hippewalla Group Sumner Group
		Wolfcampian	Chase Group Council Grove Group Admire Group
	PENNSYLVANIAN	Virgilian	Wabaunsee Group Shawnee Group Douglas Group
		Missourian	Lansing Group Kansas City Group
		Desmoinesian	Marmaton Group Cherokee Group
		Atokan	
		Morrowan	McCLAVE SAND KEYES SAND
	MISSISSIPPIAN	Meramecian	Ste. Genevieve Ls. St. Louis Fm. Salem Fm. Warsaw Fm.
		Osagean	Harrison Shale St. Joseph Fm.
		Kinder-Hookian	Gilmore City Ls. equivalent Misener sand
	ORDOVICIAN	Lower	Arbuckle Group
	CAMBRIAN	Upper	Reagan Sandstone
PRECAMBRIAN			

Figure 60. Generalized stratigraphic column, Las Animas Arch province.

MORROWAN PLAY (020)

The play is characterized by accumulations of gas and minor oil in stratigraphic traps within fluvial sandstone reservoirs of the Pennsylvanian Morrowan Series. The area of the play is the same as the area of the province (about 6,300 sq mi) which is underlain by Morrowan rocks (fig. 61).

In the play area, the Morrowan Series unconformably overlies the Mississippian and is conformably overlain by the Pennsylvanian Atokan Series (fig. 60). Morrowan strata are 100-500 ft thick and enclose discontinuous reservoirs of fluvial sandstone. These reservoirs range in thickness from 6 to 50 ft and commonly have porosities of 11-19 percent and permeabilities of 0.5-2.0 md.

Source rocks in the Morrowan consist mainly of fluvial mudrocks and marine shale. Data from pyrolytic and vitrinite-reflectance analyses of samples of cores from these rocks indicate poor to good quality source rocks that grade from thermally mature to questionably mature. Studies of the thermal history of strata in southeastern Colorado indicate that hydrocarbons were generated in Paleozoic source rocks and that migration of hydrocarbons probably began in early Paleocene time.

Oil and gas in Morrowan strata were trapped in lenticular bodies of porous sandstone which are sealed mainly by mudrocks and impervious sandstone. Oil and gas in these reservoirs generally are not associated with the crests of anticlines or with faults. Drilling depths to objectives range from about 4,600 to 5,600 ft.

The current level of exploratory activities is considered to be mature. Strata of Pennsylvanian age on the Las Animas Arch have been explored for oil and gas since the 1920's; hydrocarbons were first discovered in the Morrowan in 1951 in Kiowa County where the McClave field was later developed (fig. 61). As of December 1986, 30 total fields in the play have yielded a cumulative production of 8.7 MMBO and 66.9 BCFG. The largest field in the play is McClave, which covers greater than 50 mi^2 (33,000 acres) and has a cumulative production of 33.2 BCFG. The play probably has a low to intermediate future potential for gas, which would be limited by the number and small areal size of potential reservoirs.

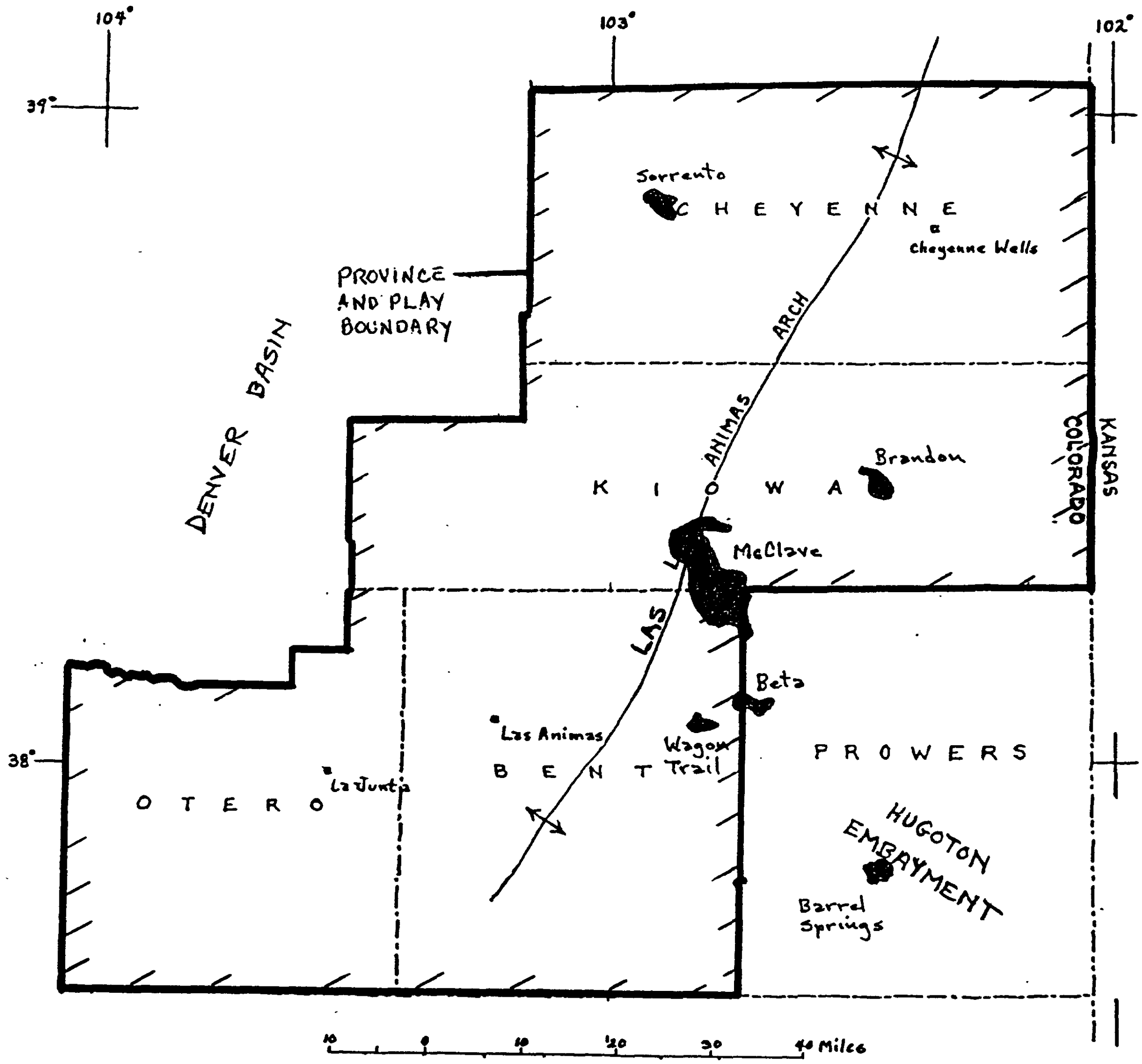

Figure 61. Map of Morrowan play.

OIL AND GAS PLAY DATA

PLAY **MORROWAN**
PROVINCE **LAS ANIMAS ARCH** CODE **04-105-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1 x 10^6 BBL; gas, 6 x 10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0**
Gas	**1**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**6**	**6.3**	**7.6**	**10**	**16**	**35**	**65**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**4**			**5**			**6**
Number of accumulations	**2**	**2**	**3**	**4**	**5**	**6**	**6**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**0.03**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

MISSISSIPPIAN PLAY (050)

The play is defined by accumulations of oil and minor gas in structural traps partly controlled by stratigraphy, some of which are affected by lithologies associated with underpressured carbonate reservoirs of Mississippian age. Mississippian rocks in the subsurface extend throughout the play, excepting southwestern Otero County. The area of the play, about 4,800 sq mi, a small part of which lies outside the province, was determined from the distribution of Mississippian oil and gas fields and from structure contours that define the Las Animas Arch (fig. 62).

In the play, Mississippian strata enclose a disconformity, unconformably overlie Lower Ordovician beds, and are unconformably overlain by Pennsylvanian rocks (fig. 60). The Mississippian System is as much as 600 ft thick. Productive formations include the St. Joseph Formation in the Osagean Series and the Warsaw, Salem, and St. Louis formations in the Meramecian Series. Reservoirs within these formations have average thicknesses of 3 to 50 ft, and consist of carbonate rocks, which commonly have porosities of 5-15 percent and permeabilities as great as 300 md. Porosity is either inter-crystalline, vugular, or caused by fracturing.

Source rocks occur in the Mississippian and Pennsylvanian and consist of carbonate strata, calcareous shale, and shale. Data from pyrolytic and vitrinite-reflectance analyses of cores from Mississippian strata indicate poor quality source rocks that grade from thermally mature to questionably mature. Analyses or samples of Pennsylvanian shale indicate poor to excellent source rocks that grade from mature to marginally mature. Investigations of the thermal history of strata in southeastern Colorado concluded that hydrocarbons were generated in Paleozoic source rocks and that migration probably began in early Paleocene time.

Oil and gas were trapped in porous carbonate reservoirs of Mississippian age, which are overlain and sealed generally by dense dolomite and limestone. These accumulations are found along the crestal parts of anticlines. Nevertheless, the lateral extent of some individual pools is limited by a reduction in reservoir porosity as well as by the amplitude of the trapping structures. Drilling depths to objectives commonly range from 4,700 to 5,700 ft.

In the vicinity of the arch, the first production from Mississippian reservoirs was in 1964 at the Comanche field in Prowers County, Colorado; however, initial production from the Mississippian within the play was at the Brandon field in Kiowa County, Colorado. Since 1964, at least 25 fields of various sizes have been found in Mississippian rocks. Cumulative production to the end of 1986 was 20 MMBO and 1.4 BCFG. The largest field, Brandon, produced approximately one-half of the total oil cumulative, and the combined Smoky Creek and Cheyenne Wells fields, which cover about 3,000 acres (5 mi^2) produced 3.7 MMBO. The future potential for oil and gas is low to intermediate; it is constrained mainly by estimates of the number of potential stratigraphic traps.

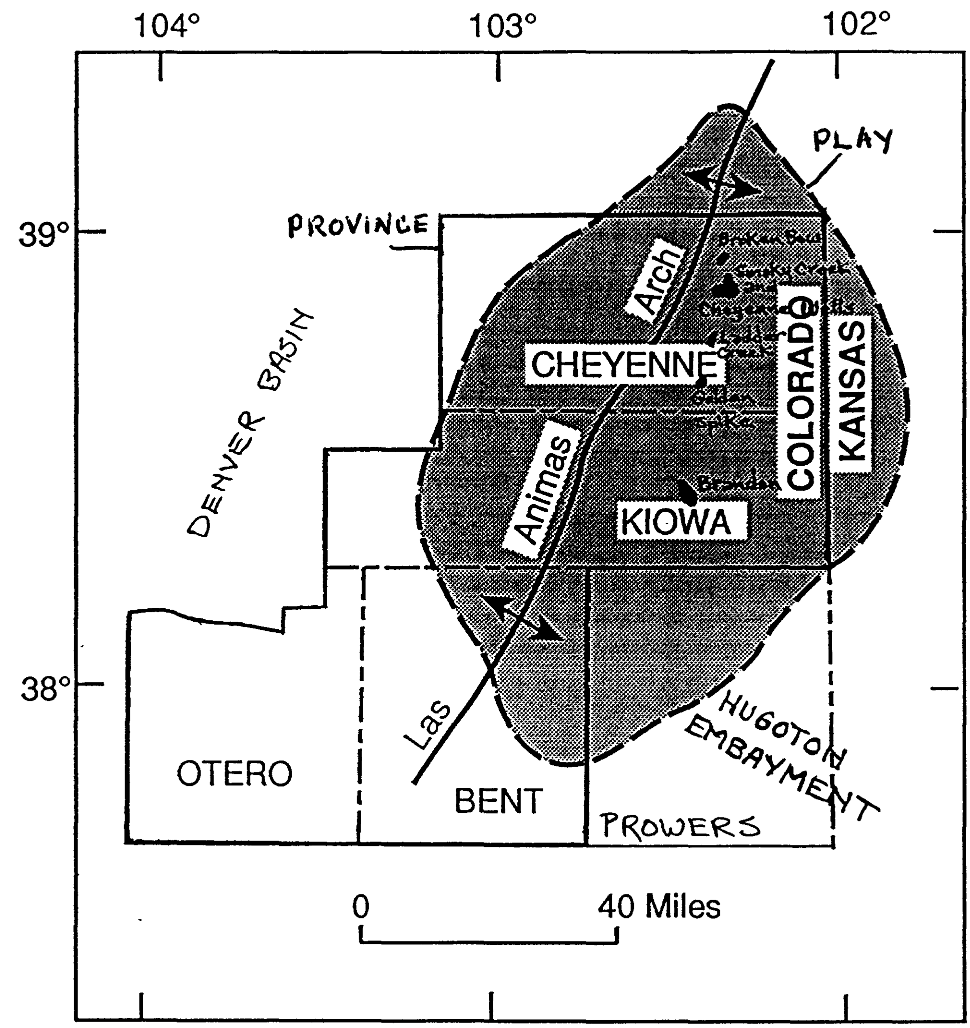

Figure 62. Map of Mississippian play.

OIL AND GAS PLAY DATA

PLAY **MISSISSIPPIAN**
PROVINCE **LAS ANIMAS ARCH** CODE **04-105-050**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**1.00**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

Reservoir lithology	Probability of occurrence
Sandstone	
Carbonate rocks	**X**
Other	
Hydrocarbon type	
Oil	**1**
Gas	**0**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.04**	**1.25**	**1.5**	**2.5**	**5.5**	**10**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**4.5**			**5.5**			**6**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**6**	**8**	**10**	**13**	**17**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**100**	CFG/BBL
Average ratio of NGL to non-associated gas	**0**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

RATON BASIN-SIERRA GRANDE UPLIFT PROVINCE (106)

By E. Allen Merewether

INTRODUCTION

The province is located in southeastern Colorado and northwestern New Mexico and includes Custer, Huerfano, and Las Animas Counties, Colorado, and Colfax, Union, Mora, and Harding Counties, New Mexico. These seven counties comprise an area of about 18,770 mi^2. The Raton basin is an elongate, asymmetric synclinorium that extends irregularly southward from Huerfano County, Colorado, to Mora County, New Mexico and is separated in New Mexico into northern and southern parts by the east-southeast-trending Cimarron arch. The basin is bounded to the west by the Sangre de Cristo uplift, to the northeast by the Wet Mountains and Apishapa uplifts, and to the southeast by the Sierra Grande arch.

Sedimentary rocks in the province consist of siliciclastic and carbonate beds, which were deposited in marine and nonmarine environments during Paleozoic, Mesozoic, and Cenozoic time; their aggregate thickness could be as much as 20,000 ft. Some of these rocks reflect orogenic events in the vicinity of the Raton basin during late Paleozoic time and again in the Late Cretaceous and early Tertiary. The Cretaceous rocks contain hydrocarbons; minor quantities of oil and gas have been produced from Upper Cretaceous reservoirs in the northwestern part of the province. Marginally commercial amounts of methane have also been found in the Dakota Sandstone and in several other fractured Cretaceous formations in scattered structural and stratigraphic traps. At the Gardner field in western Huerfano County, an Upper Cretaceous sandstone produced (as of December 1986) about 4,200 BO and about 3.2 MCFG. For the abandoned Garcia field in southern Las Animas County, where fractures in Upper Cretaceous beds have yielded gas, cumulative production (as of December 1986) was about 1.6 BCFG. One play was individually assessed in the province, the Purgatoire-Dakota(040).

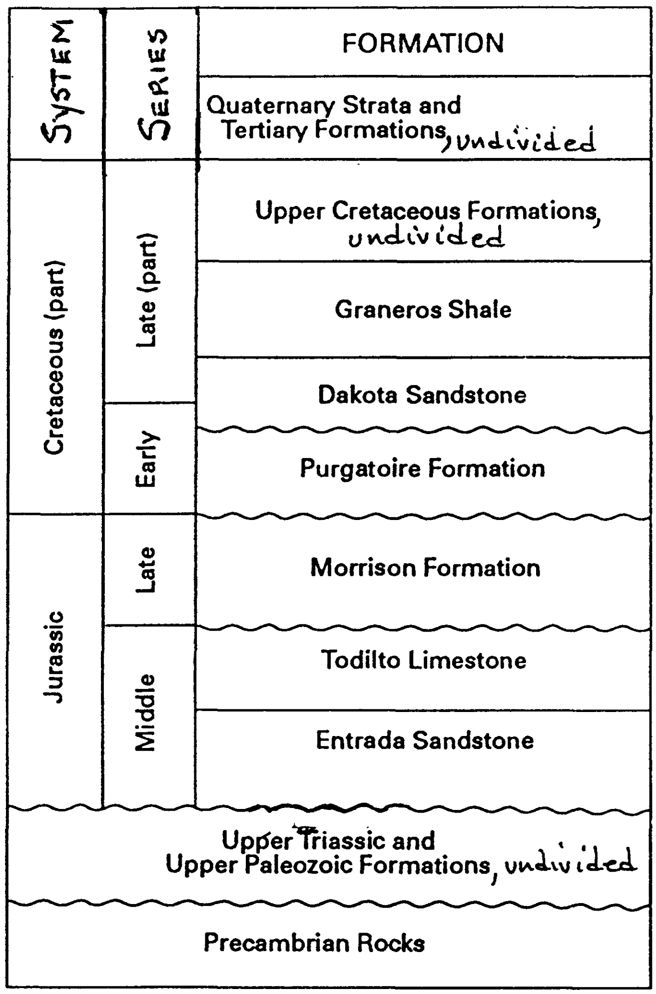

Figure 63. Generalized stratigraphic column, Raton Basin-Sierra Grande Uplift province.

PURGATOIRE-DAKOTA PLAY (040)

The play is characterized by potential accumulations of oil and gas that might be located in structural or stratigraphic traps in sandstone reservoirs of these two formations; the sandstone may be enclosed by shale source rocks. The Purgatoire and Dakota extend in the subsurface throughout most of the western half of the province. The area of the play is about 5,400 mi^2 and lies within a north-trending synclinorium that is composed of two asymmetric sub-basins (Raton and Las Vegas) en echelon and the intervening Cimarron arch. The play area (fig. 64) is outlined by outcropping beds of the Purgatoire-Dakota, which dip steeply eastward along the western edge of the synclinorium and gently westward on the eastern flank of this structural depression.

In the Raton basin and on the east-west trending Sierra Grande uplift, the Lower Cretaceous Purgatoire Formation is 70-180 ft thick and is disconformably overlain by the Lower and Upper Cretaceous Dakota Sandstone, which is 30-200 ft thick (fig. 63). Potential reservoirs in these formations are lenticular units of porous and permeable sandstone, which are about 30 ft thick, and commonly yield moderate amounts of water and minor amounts of gas. In two cores from wells drilled in the northwestern part of the Raton basin, reservoir sandstone in the Dakota has porosities of 8-15 percent and permeabilities of 7-8 millidarcies.

Source-rocks include shale and coal in the Purgatoire-Dakota and shale in overlying Cretaceous formations. Data from pyrolytic analyses of four samples from outcrops of the Purgatoire-Dakota in the eastern part of the province indicate that the formations contain moderate to fair quality source-rocks, which probably include both humic and sapropelic organic matter. These data and other information also indicate that the organic matter in the Purgatoire-Dakota is thermally immature to questionably mature at the eastern outcrops and thermally mature at the western outcrops and in the subsurface. Sub-commercial amounts of methane gas were found in the Purgatoire-Dakota at several wells in Mora and Colfax Counties, New Mexico, and in Las Animas County, Colorado. Large amounts of carbon dioxide gas have also been produced from these formations in Huerfano County, Colorado. In the northern part of the Raton basin, generation of hydrocarbons might have begun during the Permian. Furthermore, outcropping strata of latest Cretaceous and Paleocene ages in the western part of the play are thermally mature to marginally mature. Presumably, generation and migration of oil began near the end of the Paleozoic and were also active during the Eocene.

Hydrocarbons apparently were trapped in the Purgatoire-Dakota in sandstone reservoirs, which were overlain and sealed by shale. Producible methane gas was found in these formations on the crest of the Wagon Mound anticline in the south-central part of the play (fig. 64). However, hydrocarbons might also occur in stratigraphic and hydrodynamic traps or in fracture-reservoirs, which could be at depths as great as 10,000 ft.

During the past century, the play has been explored intermittently but only modest amounts of gas and oil have been found. Although a moderate number of wildcats have been drilled, the Purgatoire-Dakota has not been penetrated in large areas of the play. Producible amounts of methane were found at the small, now abandoned,Wagon Mound field in east-central Mora County, New Mexico, and in one well (1.5 MMCFG per day) of several drilled in central Colfax County, New Mexico. The future potential of the play is moderate for gas and low for oil. However, Cretaceous reservoirs formed by closely spaced fractures associated with folds have not been carefully investigated and could contain significant hydrocarbon resources.

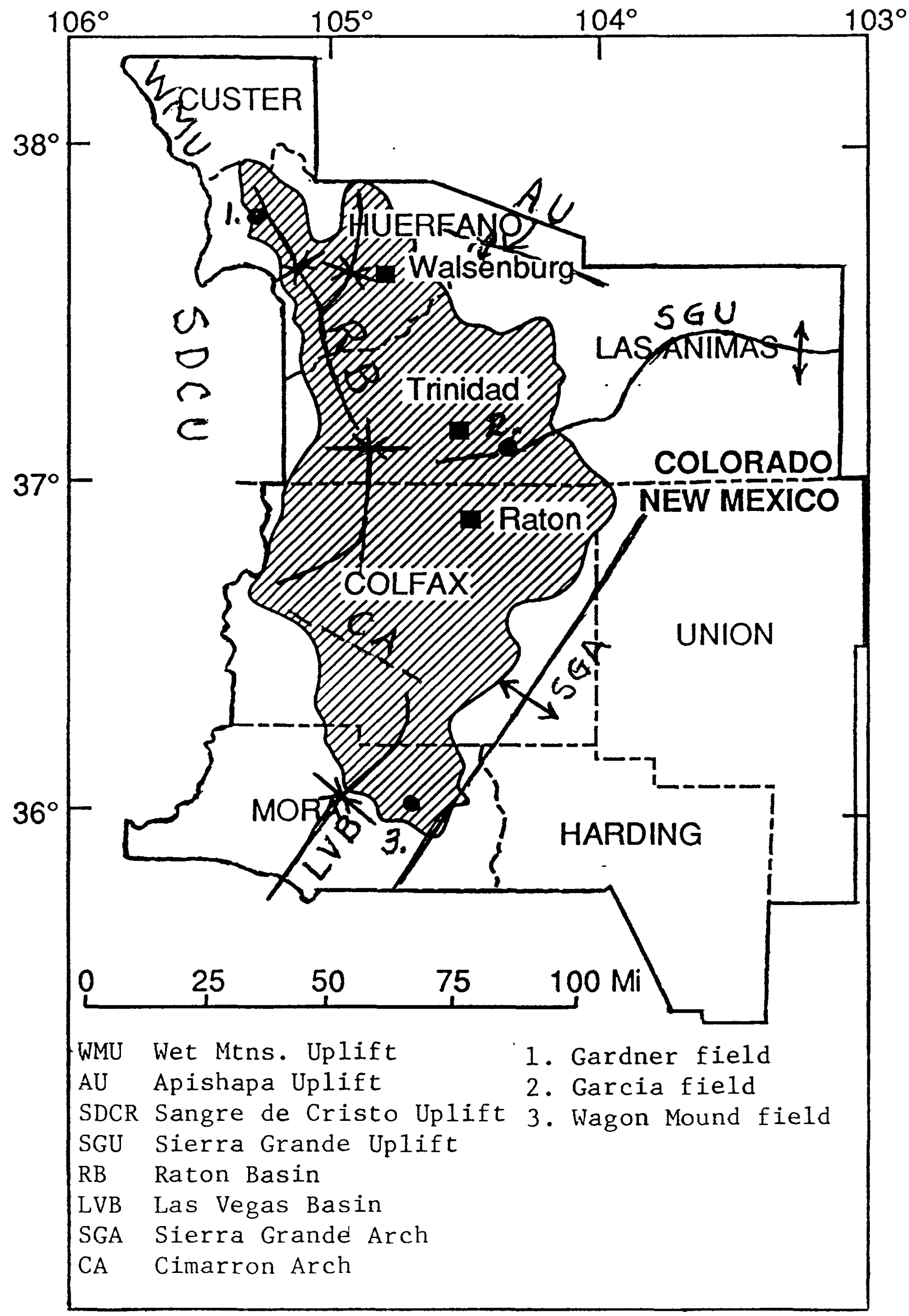

Figure 64. Map of Purgatoire-Dakota play.

OIL AND GAS PLAY DATA

PLAY **PURGATOIRE-DAKOTA**
PROVINCE **RATON BASIN-SIERRA GRANDE UPLIFT** CODE **04-106-040**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**1.00**
Migration (M)	**1.00**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**1.00**

Accumulation attribute, conditional on favorable play attributes

Minimum size assessed: oil, 1×10^6 BBL; gas, 6×10^9 CFG

	Probability of occurrence
At least one undiscovered accumulation of at least minimum size assessed	**0.50**

Character of undiscovered accumulations, conditional on at least one undiscovered accumulation present

	Probability of occurrence
Reservoir lithology	
Sandstone	**X**
Carbonate rocks	
Other	
Hydrocarbon type	
Oil	**0.2**
Gas	**0.8**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.03**	**1.2**	**1.5**	**2.4**	**7.3**	**30**
Gas ($\times 10^9$ CFG)	**6**	**6.2**	**7**	**7.5**	**12**	**30**	**120**
Reservoir depth ($\times 10^3$ ft)							
Oil	**3**			**5**			**10**
Gas (non-associated)	**3**			**5**			**10**
Number of accumulations	**2**	**4**	**7**	**10**	**16**	**32**	**50**

Average ratio of associated-dissolved gas to oil (GOR)	**500**	CFG/BBL
Average ratio of NGL to non-associated gas	**5**	BBL /10^6 CFG
Average ratio of NGL to associated-dissolved gas	**0**	BBL /10^6 CFG

* For example, fractile percentage 95 represents a 19 in 20 chance of the occurrence of at least the fractile tabulated.

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TABLE 1.--Region 4, Rocky Mountains and Northern Great Plains; estimates of undiscovered recoverable conventional oil, gas, and natural gas liquids (NGL)in onshore provinces by play. Province and region totals are given

[Mean value totals may not be equal to the sums of the component means because numbers have been independently rounded. Fractile values (F_{95} F_5) are not additive and represent estimates with a 19 in 20 chance and a 1 in 20 chance, respectively, of at least these tabulated estimates. Gas includes both nonassociated and associated-dissolved gas. Negl., negligible quantity; -, no estimate.]

			Crude Oil (Millions of Barrels)			Total Gas (Billions of Cubic Feet)			NGL (Millions of Barrels)		
			F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
094	Williston Basin										
	020	Northeast Basin	2.9	22.6	9.8	0.9	6.8	2.9	0.0	0.0	0.0
	030	Red River	138.0	336.9	223.7	204.3	501.5	332.2	11.1	26.6	17.8
	040	Post-Madison	0.0	24.8	10.0	0.0	2.5	1.0	0.0	0.0	0.0
	050	Madison-Upper Devonian	81.9	292.9	166.9	32.7	117.2	66.8	2.0	7.0	4.0
	320	Oil <1 MMB	274.4	475.4	366.3	192.1	332.8	256.4	11.5	20.0	15.4
	330	Gas <6 BCF	0.0	0.0	0.0	64.1	105.9	83.4	2.6	4.2	3.3
		Province Total	489.2	1,152.0	776.6	489.6	1,065.5	742.7	26.9	57.8	40.5
095	Sioux Arch (Incl. in 094)										
096	Sweetgrass Arch										
	020	Upper Cretaceous	0.0	0.0	0.0	37.3	274.7	121.7	0.0	0.0	0.0
	030	Jurassic-Cretaceous	9.0	49.7	24.2	62.8	260.0	140.2	Negl.	0.1	0.1
	040	Devonian-Mississippian	14.1	75.8	37.2	5.6	30.3	14.9	0.0	0.0	0.0
	320	Oil <1 MMB	31.1	52.9	41.1	26.4	45.0	34.9	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	197.7	335.8	261.0	0.4	0.7	0.5
		Province Total	50.9	178.4	102.5	308.6	946.4	572.7	0.4	0.8	0.6

TABLE 1.--Region 4, Rocky Mountains and Northern Great Plains; estimates of undiscovered recoverable conventional oil, gas, and natural gas liquids (NGL)in onshore provinces by play. Province and Region totals are given--continued.

		Crude Oil (Millions of Barrels)			Total Gas (Billions of Cubic Feet)			NGL (Millions of Barrels)		
		F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
097	Central Montana									
	020 Tyler	4.8	45.3	18.6	0.4	3.6	1.5	0.0	0.0	0.0
	320 Oil <1 MMB	5.6	12.3	8.5	0.4	1.0	0.7	0.0	0.0	0.0
	330 Gas <6 BCF	0.0	0.0	0.0	6.1	16.5	10.5	0.0	0.0	0.0
	Province Total	9.2	58.2	27.1	6.7	21.2	12.7	0.0	0.0	0.0
098	Montana Thrust Belt									
	030 Eldorado-Lewis Subthrust	0.0	0.0	0.0	0.0	1,578.9	337.7	0.0	7.9	1.7
	040 Frontal Imbricate	0.0	0.0	0.0	0.0	7,340.8	2,497.3	0.0	183.5	62.4
	050 Blacktail Mountains Salient	0.0	55.4	9.7	0.0	55.4	9.7	0.0	0.0	0.0
	330 Gas <6 BCF	0.0	0.0	0.0	49.7	108.4	75.5	1.0	2.2	1.5
	Province Total	0.3	36.7	9.7	416.4	8,714.5	2,920.2	10.7	188.3	65.6
099	Southwestern Montana									
	030 Subthrust	0.0	11.3	1.7	0.0	188.5	33.0	0.0	3.7	0.6
	040 Basement Structure	0.0	49.4	12.0	0.0	661.1	221.6	0.0	12.7	4.2
	050 Wrench Fault	0.0	0.0	0.0	21.8	160.4	71.1	0.2	1.6	0.7
	320 Oil <1 MMB	1.2	3.3	2.1	1.2	3.3	2.1	0.0	0.0	0.0
	330 Gas <6 BCF	0.0	0.0	0.0	34.2	73.3	51.5	0.5	1.1	0.8
	Province Total	0.9	56.5	15.8	65.0	1,071.4	379.2	0.9	18.6	6.3
100	Wind River Basin									
	020 Deep Basin Structure	0.0	0.0	0.0	425.5	1,752.7	947.3	4.3	17.5	9.5
	030 Basin Margin Anticlinal	2.4	18.8	8.3	3.1	27.0	11.4	0.0	0.5	0.1
	060 Muddy Sandstone	51.0	175.4	101.5	127.5	438.6	253.7	0.0	0.0	0.0

TABLE 1.--Region 4, Rocky Mountains and Northern Great Plains; estimates of undiscovered recoverable conventional oil, gas, and natural gas liquids (NGL)in onshore provinces by play. Province and region totals are given--continued.

			Crude Oil (Millions of Barrels)			Total Gas (Billions of Cubic Feet)			NGL (Millions of Barrels)		
			F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
	080	Basin Margin Subthrust	0.0	25.8	7.1	12.3	243.4	82.6	0.0	2.4	0.8
	300	Other Occurrences >1 MMBO	24.3	118.5	60.3	48.6	236.9	120.5	0.5	2.4	1.2
	310	Other Occurrences >6 BCFG	0.0	0.0	0.0	137.9	645.7	333.1	0.0	0.0	0.0
	320	Oil <1 MMB	14.5	30.0	21.4	31.8	66.0	47.0	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	56.1	120.9	84.6	0.6	1.2	0.8
		Province Total	87.9	370.2	198.5	815.0	3,551.2	1,880.3	5.2	24.1	12.5
101	Powder River Basin										
	020	Basin Margin Anticline	8.9	50.3	24.3	7.6	43.3	20.9	0.0	0.0	0.0
	030	Sussex-Shannon	60.5	210.6	121.2	51.4	179.0	103.1	3.6	12.5	7.2
	040	Leo Sandstone	43.7	217.5	109.8	12.0	59.8	30.2	0.0	0.0	0.0
	050	Dakota Sandstone	77.1	279.2	158.4	77.1	279.2	158.4	0.0	0.0	0.0
	060	Mesaverde-Lewis	23.1	111.9	57.0	37.0	179.1	91.3	3.7	17.9	9.1
	070	Deep Frontier Sandstone	10.3	59.1	28.4	36.1	206.9	99.5	3.1	17.6	8.5
	080	Deep Muddy Sandstone	162.4	627.5	347.4	568.5	2,196.2	1,215.8	15.9	61.5	34.0
	090	Shallow Muddy Explored	23.7	115.4	58.7	33.2	161.6	82.2	0.3	1.6	0.8
	100	Minnelusa Explored	28.2	74.1	47.7	5.6	14.8	9.5	0.0	0.0	0.0
	110	Minnelusa Unexplored	385.6	1,346.7	774.6	96.4	336.7	193.6	0.0	0.0	0.0
	300	Other Occurrences >1 MMBO	53.2	177.0	103.8	63.9	212.4	124.5	1.3	4.2	2.5
	310	Other Occurrences >6 BCFG	0.0	0.0	0.0	48.1	230.6	118.0	0.5	2.3	1.2
	320	Oil <1 MMB	301.6	554.5	416.0	361.9	665.4	499.2	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	7.5	14.9	10.8	Negl.	Negl.	Negl.
		Province Total	1,157.9	3,823.0	2,247.3	1,378.8	4,779.3	2,757.0	28.2	117.8	63.3
102	Southwestern Wyoming Basins										
	020	Cherokee Ridge	0.0	1.7	0.2	0.0	124.8	34.6	0.0	0.6	0.2
	030	Jackson Hole	0.0	19.0	5.7	0.0	135.9	40.6	0.0	1.5	0.5

TABLE 1.--Region 4, Rocky Mountains and Northern Great Plains; estimates of undiscovered recoverable conventional oil, gas, and natural gas liquids (NGL)in onshore provinces by play. Province and region totals are given--continued.

			Crude Oil (Millions of Barrels)			Total Gas (Billions of Cubic Feet)			NGL (Millions of Barrels)		
			F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
	040	Moxa-La Barge	16.0	106.5	49.4	478.3	1,687.2	966.8	6.5	21.5	12.6
	050	Platform	12.5	64.7	32.2	25.1	173.4	78.4	0.4	2.1	1.1
	060	Axial Arch	0.0	47.2	16.0	0.0	129.9	47.0	0.0	2.7	1.0
	070	Basin Margin Anticline	0.0	37.1	9.9	58.8	429.2	190.7	0.4	2.8	1.3
	080	Subthrust	0.0	57.0	15.4	0.0	537.5	179.8	0.0	4.2	1.4
	090	Rock Springs	0.0	12.8	3.2	61.9	332.2	163.3	2.5	13.3	6.5
	300	Other Occurrences >1 MMBO	20.7	80.6	44.5	41.5	161.1	89.0	1.7	6.4	3.6
	310	Other Occurrences >6 BCFG	0.0	0.0	0.0	328.1	2,300.0	1,035.0	3.3	23.0	10.4
	320	Oil <1 MMB	21.4	43.2	31.1	30.0	60.4	43.5	1.2	2.4	1.7
	330	Gas <6 BCF	0.0	0.0	0.0	408.8	628.0	511.0	4.1	6.3	5.1
		Province Total	62.7	471.7	207.6	1,321.5	6,758.1	3,379.6	19.0	87.3	45.3
103	Bighorn Basin										
	020	Phosphoria	2.7	19.0	8.5	2.7	19.0	8.5	0.0	0.0	0.0
	040	Deep Basin Anticlinal	0.0	0.0	0.0	19.9	294.3	107.0	0.5	7.4	2.7
	050	Basin Margin Subthrust	8.7	99.2	39.8	18.8	197.9	78.8	0.0	1.3	0.4
	060	Sub-Absaroka	33.9	146.2	77.7	1.7	7.3	3.9	0.0	0.0	0.0
	070	Basin Margin Anticlinal	12.8	55.8	29.6	6.4	27.9	14.8	0.0	0.0	0.0
	300	Other Occurrences >1 MMBO	22.3	105.3	54.1	33.4	157.9	81.2	0.5	2.4	1.2
	310	Other Occurrences >6 BCFG	0.0	0.0	0.0	75.9	777.1	311.9	0.8	7.8	3.1
	320	Oil <1 MMB	19.7	51.2	33.2	13.8	35.9	23.2	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	19.7	51.2	33.2	0.3	0.8	0.5
		Province Total	97.1	489.4	246.0	179.0	1,588.8	664.6	1.9	19.7	7.9
104	Denver Basin										
	030	Shallow Niobrara Gas	0.0	0.0	0.0	242.7	1,277.5	632.5	0.0	0.0	0.0
	040	Paleozoic	10.1	88.1	37.1	9.1	79.3	33.4	0.0	0.0	0.0

TABLE 1.--Region 4, Rocky Mountains and Northern Great Plains; estimates of undiscovered recoverable conventional oil, gas, and natural gas liquids (NGL)in onshore provinces by play. Province and region totals are given--continued.

		Crude Oil (Millions of Barrels)			Total Gas (Billions of Cubic Feet)			NGL (Millions of Barrels)		
		F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
050	D-J Sandstone	45.8	121.3	77.9	64.1	169.8	109.0	6.4	17.0	10.9
060	Pierre Shale Sandstone	0.0	6.3	1.1	0.0	25.1	4.5	0.0	Negl.	Negl.
300	Other Occurrences >1 MMBO	21.6	121.1	58.7	21.6	121.1	58.7	0.0	0.0	0.0
320	Oil <1 MMB	310.8	529.4	411.0	373.0	635.3	493.2	37.3	63.5	49.3
330	Gas <6 BCF	0.0	0.0	0.0	313.9	459.3	382.3	0.0	0.0	0.0
	Province Total	371.1	865.3	585.7	958.3	2,762.5	1,713.5	43.5	80.4	60.2
105	Las Animas Arch									
020	Morrowan	0.0	0.0	0.0	20.7	104.0	52.4	Negl.	Negl.	Negl.
050	Mississippian	11.4	42.0	23.6	1.1	4.2	2.4	0.0	0.0	0.0
320	Oil <1 MMB	10.2	23.8	16.1	1.0	2.4	1.6	0.0	0.0	0.0
330	Gas <6 BCF	0.0	0.0	0.0	21.4	43.2	31.1	0.0	0.0	0.0
	Province Total	21.4	65.8	39.7	42.7	153.8	87.4	Negl.	Negl.	Negl.
106	Raton Basin-Sierra Grande Uplift									
040	Purgatoire-Dakota	0.0	17.8	3.9	0.0	286.7	73.7	0.0	1.4	0.4
320	Oil <1 MMB	1.4	7.4	3.7	0.7	3.7	1.8	0.0	0.0	0.0
330	Gas <6 BCF	0.0	0.0	0.0	32.3	78.5	52.2	0.2	0.4	0.3
	Province Total	0.9	23.8	7.6	22.7	356.6	127.7	0.1	1.7	0.6
	REGION TOTAL	2,676.4	6,852.4	4,460.9	7,017.6	27,771.0	15,235.5	148.7	531.2	302.9