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Petroleum Exploration Plays and Resource Estimates, 1989, Onshore United States-- Region 3, Colorado Plateau and Basin and Range

By

Richard B. Powers, *Editor*[1]

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PETROLEUM EXPLORATION PLAYS AND RESOURCE ESTIMATES, 1989, ONSHORE UNITED STATES--REGION 3, COLORADO PLATEAU AND BASIN AND RANGE

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 34 individually assessed exploration plays in 12 onshore geologic provinces in assessment Region 3 within the continental United States; these 12 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.

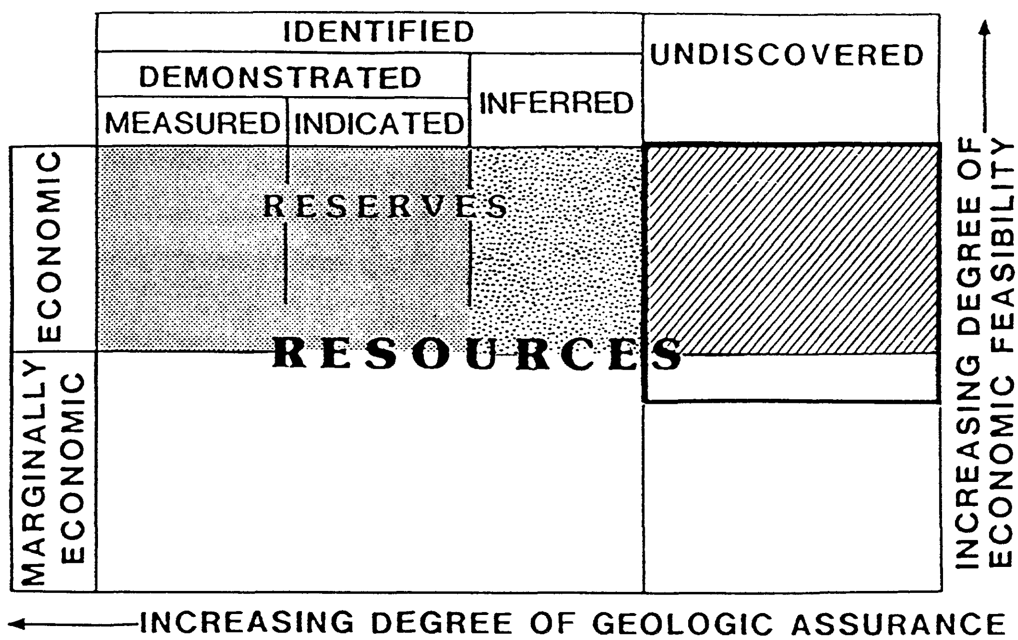

Figure 1. Diagrammatic representation of petroleum resource classification (Mast and others, 1989) representing conventional oil and gas resources. Area with heavy frame on upper right represents undiscovered recoverable resources estimated in this study.

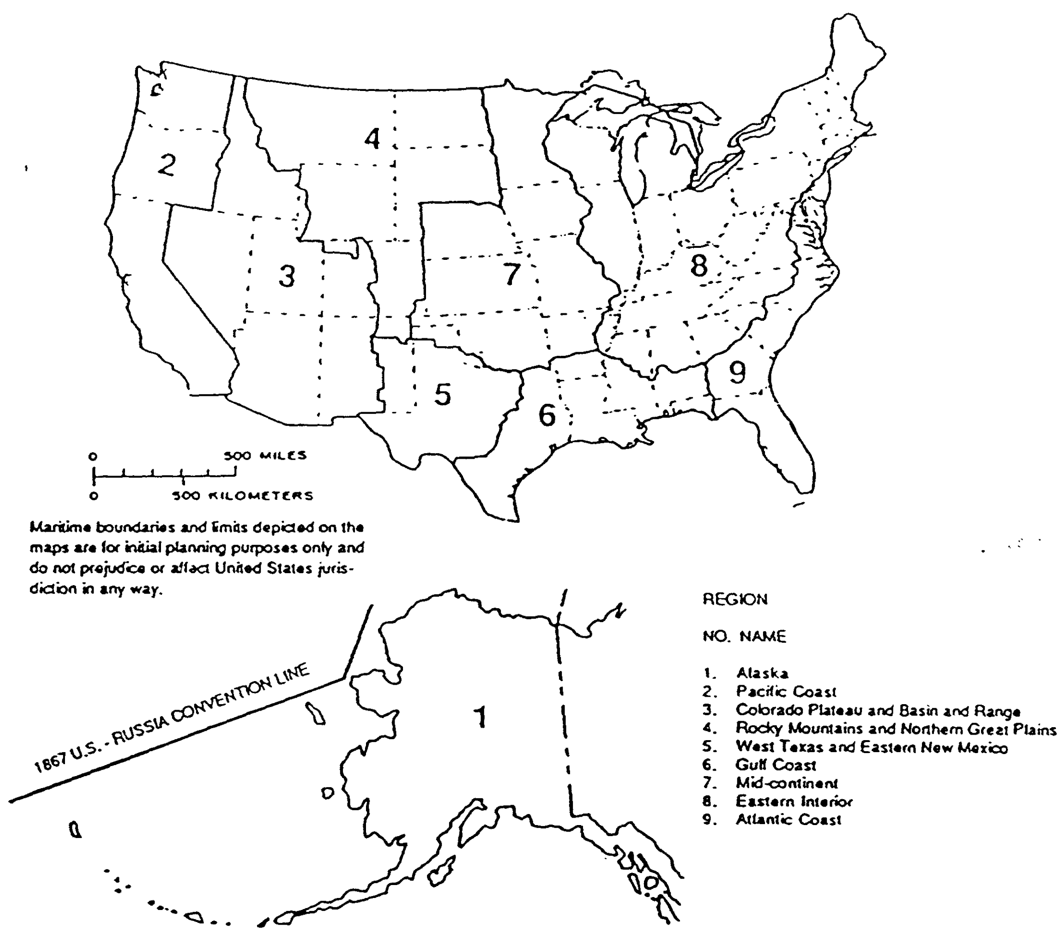

Figure 2. Map showing petroleum regions assessed in this study. Heavy lines are region boundaries, dotted lines are State boundaries.

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 3--COLORADO PLATEAU AND BASIN AND RANGE

GEOLOGIC FRAMEWORK

By Richard B. Powers

Region 3 is subdivided into 12 provinces, numbers 082-093 (fig. 3). The total number of individually assessed plays in these provinces is 34. Two of the assessed plays in province 090, Wyoming-Utah-Idaho Thrust Belt, are combined under one discussion because they cover the same play area.

The geology of Region 3 is diverse and very complex. Major structural elements reflect Laramide and post-Laramide tectonism. Many of the basins within the region are structural basins formed during this period. Also included in the Region are several basins of Paleozoic age, a major thrust belt, a portion of an extensive rift system, and areas of basin and range block and low-angle extensional faulting. Reservoir lithologies are varied, and range in age from Ordovician to Tertiary, and include both sandstones and carbonate rocks.

The intermontane basins of this region, such as the Uinta-Piceance (086) and San Juan basins (088), plus the Wyoming-Utah-Idaho (090) segment of the Cordilleran thrust belt, are particularly important in terms of oil and especially gas resources. At least four giant oil and gas fields have been found in these provinces. To date, only a few, but highly productive oil fields have been discovered in the lightly explored Eastern Basin and Range Province (082). Some basins in the Region also host thick "tight gas sands" sequences (reservoirs with *in situ* permeabilities to gas < 0.1 millidarcy), which are not covered in this report.

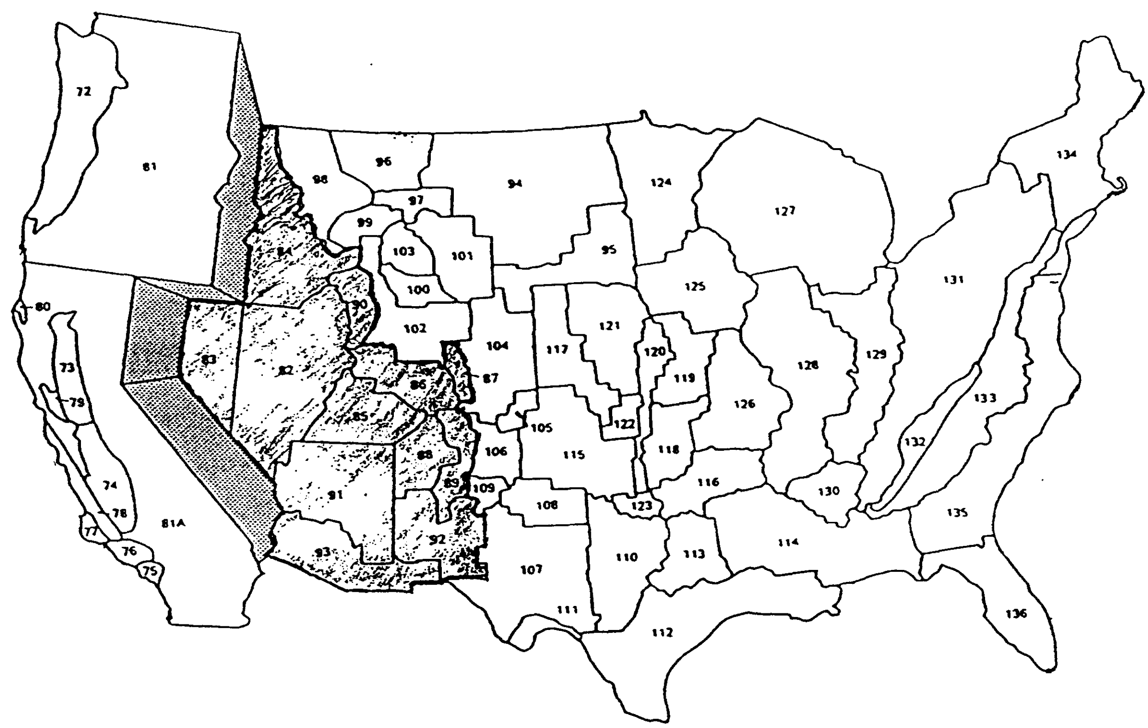


Figure 3. Index map of lower 48 states showing provinces assessed in Region 3 (shaded). Names of provinces are listed by number in the Table of estimates.

EASTERN BASIN AND RANGE PROVINCE (082)

By James A. Peterson

INTRODUCTION

The province comprises approximately 110,000 mi^2, including the eastern one-half of Nevada, western Utah west of the Wasatch Range, and a small part of southeastern Idaho. High-standing mountain ranges oriented generally north-south and broad intermontane valleys are characteristic of the province, much of which is greater than 5,000 ft in elevation except for northern Utah and southern Nevada. Several mountain ranges rise to above 8,000 ft, particularly in east-central Nevada. The geology of the province is very complex and involves a great diversity of sedimentary facies, major episodes of orogenic and igneous activity, and extensive block faulting. Complex structural features include: 1) a middle to late Paleozoic thrust belt (Antler orogenic belt) extending across south-central and northeastern Nevada into south-central Idaho; 2) low- and high-angle late Tertiary extensional faults with basin and range type block uplifts; 3) metamorphic core complexes; 4) Tertiary, Cretaceous, and Jurassic intrusives; and 5) extensive Tertiary extrusive volcanics, which are particularly widespread in central and southern Nevada and south-central Idaho. The area is one of exceptionally high heat flow, as evidenced by the many hot springs. Metallic and non-metallic ore deposits are present throughout most of the province. The original sedimentary cover of the Eastern Basin and Range is primarily late Precambrian to Permian in age, comprising as much as 50,000 ft of mostly shallow-water marine carbonate and clastic deposits (fig.4). Lacustrine and fluvial beds ranging in age from Late Cretaceous to early and middle Tertiary are present over a large area of central, northeastern, and southeastern Nevada. Late Tertiary lacustrine beds are widespread in northern Utah and part of southeastern Idaho. Paleozoic rocks are extensively exposed in the mountain ranges, and about 10,000 ft of horst-derived fill is present in some of the valleys. Most of the province is lightly explored for petroleum. As of 1987, 10 oil fields had been discovered, a few of which are marginally commercial, and all are located in Railroad Valley or Pine Valley. Two plays were individually assessed in the province, Unconformity (020) and Upper Paleozoic (030).

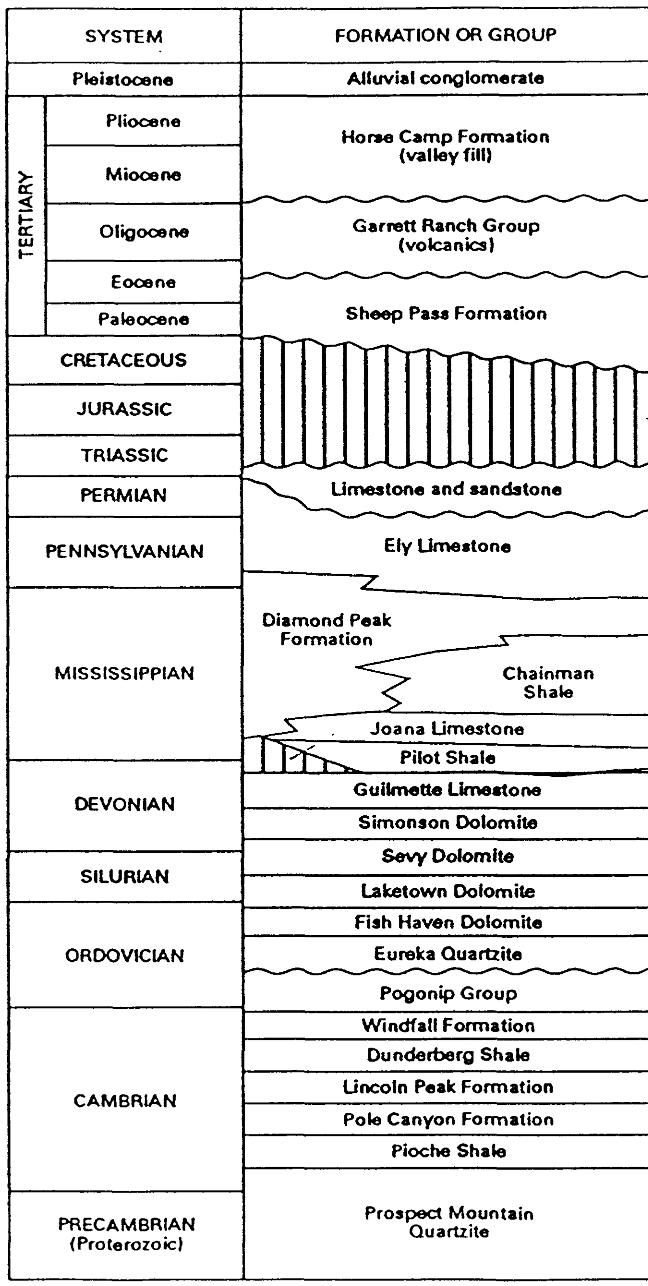


Figure 4. Generalized stratigraphic column, Eastern Basin and Range province.

UNCONFORMITY PLAY (020)

This play is based on the presence of petroleum traps beneath an unconformity seal at the base of a Miocene-Pleistocene valley fill. In most valleys, the unconformity commonly overlies volcanics, mainly ignimbrites and flows of Oligocene and Miocene age. However, depending on pre-valley fill structure, the valley fill may overlie lacustrine clastic rocks, oil shale, or carbonate rocks of early Tertiary or Cretaceous age, or Paleozoic rocks ranging in age from late Paleozoic to Cambrian. Because of late Tertiary growth of basin and range structure, much of the lacustrine and volcanic sequence, as well as the underlying Paleozoic rocks, have been removed by extensive erosion in the mountain ranges, but preserved in the valley floors, where they may be overlain by several thousand feet of valley fill. The play includes an area of approximately 32,000 mi^2 adjacent to and extending east of the Antler orogenic belt (fig. 5).

Reservoirs are in fractured Paleozoic carbonate rock and in Cretaceous and Early Tertiary lacustrine sandstone, siltstone and carbonate beds of the Paleocene Sheep Pass Formation, and in fractured Oligocene volcanics (fig. 4). Reservoirs are highly variable in thickness and are enhanced by fracturing, but matrix porosity in the carbonate and sandstone units may be high. Drilling depths have a wide range, because reservoirs may be close to the surface on valley margins and 5,000 to 15,000 ft in valley interiors.

Significant, organic-rich source beds are present in Mississippian, Devonian, Cretaceous, and Tertiary rocks, along with effective seals in the valley fill. Primary source rocks are marine, organic-rich shale in the Mississippian Chainman Shale and bituminous lacustrine shale and carbonate in Cretaceous and Tertiary beds. Some oils are mixtures of both a marine and a lacustrine source. Organic-rich shale or argillaceous carbonate rocks are present in the Ordovician Pogonip Group, Devonian-Mississippian Pilot Shale, and within the Permian and Pennsylvanian marine section. TOC (Total organic carbon) content of these units is as high as several percent over broad areas. Mississippian and Devonian source rocks probably reached the oil generation stage by Permian or Triassic time in most of the play area, and probably earlier in the main Paleozoic basins.

Stratigraphic and structural traps probably formed coincident with petroleum generation, which was related to growth of the late Paleozoic Antler orogenic belt. Traps are mainly fault block structures related to Tertiary extensional faulting and range in size from less than a square mile to several square miles. Existing fields are on high-relief structures beneath the valley fill and are complicated by basin and range type faulting. The majority of the early traps were probably destroyed or greatly altered by regional uplift and erosion during the Mesozoic. Late Tertiary extensional faulting further adversely affected remnant Paleozoic traps, but fault and fold structures formed at the same time created traps for hydrocarbons that had generated or remigrated during valley fill burial. High heat flow during late Tertiary basin and range faulting further stimulated maturation of late Paleozoic and Mesozoic-Tertiary source rocks in areas which had undergone only limited depth of burial during the late Paleozoic and Mesozoic.

The play is moderately explored in Railroad Valley, but is lightly explored or relatively unexplored elsewhere. Approximately 300 exploratory wells have been drilled in eastern Nevada, more than 75 of which are located in Railroad Valley. Existing fields are relatively small to medium, ranging from a few hundred thousand barrels, to the Trap Spring and Grant Canyon fields, each of which are approximately 15-20 MMBO in size. Future potential for both oil and gas is fair to good.

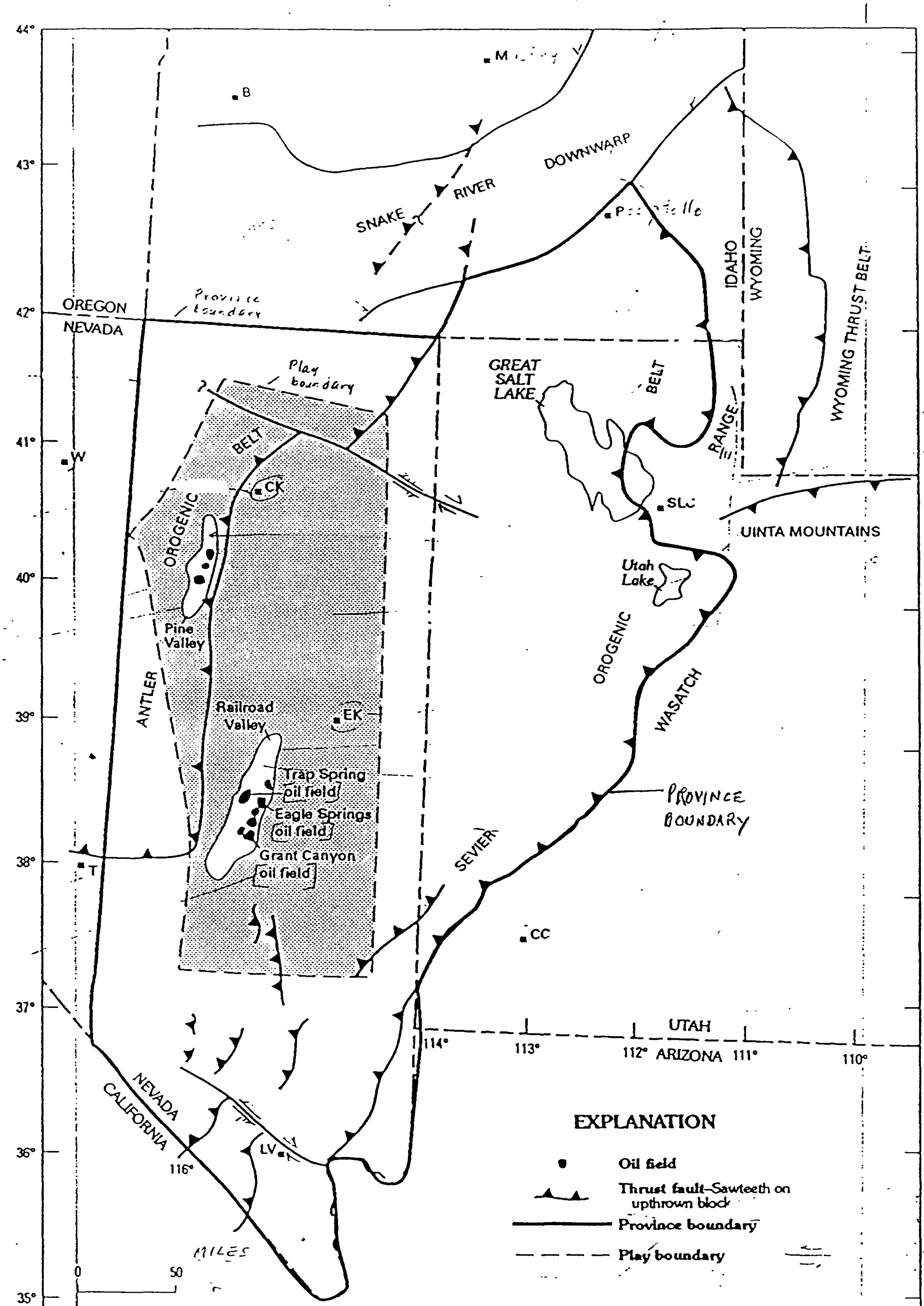


Figure 5. Map of Unconformity play.

OIL AND GAS PLAY DATA

PLAY **UNCONFORMITY**
PROVINCE **EASTERN BASIN AND RANGE** CODE **03-082-020**

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	**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**	**1.2**	**2.3**	**5**	**9**	**20**	**50**
Gas (x 10^9 CFG)	**6**	**7**	**10**	**25**	**40**	**70**	**150**
Reservoir depth (x10^3 ft)							
Oil	**5**			**8**			**15**
Gas (non-associated)	**5**			**8**			**15**
Number of accumulations	**5**	**10**	**18**	**25**	**40**	**70**	**110**

Average ratio of associated-dissolved gas to oil (GOR)	**20**	CFG/BBL
Average ratio of NGL to non-associated gas	**15**	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.

UPPER PALEOZOIC PLAY (030)

This play is defined as a stratigraphic and structural play where upper Paleozoic reservoirs may be confined by interbedded shale seals independent of the valley fill unconformity seal, or where pre-extensional faulted structures may be preserved. The play area is approximately 55,000 mi^2 in central and east-central Nevada and west-central Utah (fig. 6). In most of the play area upper Paleozoic rocks were buried to depths of less than 15,000 ft and are mostly marine carbonate and sandstone rocks.

Reservoirs are sandstone and siltstone tongues of the Mississippian Diamond Peak Formation, or similar Pennsylvanian-Permian clastic units, commonly oil stained in the subsurface, and possibly Devonian reefal carbonates.

Source rocks are mainly Mississippian organic-rich shale interbedded with sandstone or carbonate reservoirs. Organic-rich Permian shales and Pennsylvanian or Permian marine argillaceous limestone in the Antler foredeep area of east-central Nevada are also source rocks for potential accumulations in areas where structural and thermal histories have been favorable. The older source rocks probably reached the oil generation stage by Permian or Triassic time.

Potential traps are earlier-formed stratigraphic traps that were not destroyed or greatly altered by late Tertiary extensional faulting, fault traps on the flanks of basin and range structures in the valleys, and folds or fault blocks sealed by late Paleozoic shales. Traps probably formed coincident with petroleum generation with growth of the Antler orogenic belt. Because of the disruptive post-Paleozoic structural history, future undiscovered accumulations are likely to be small to medium in size. The overall future potential is low to moderate.

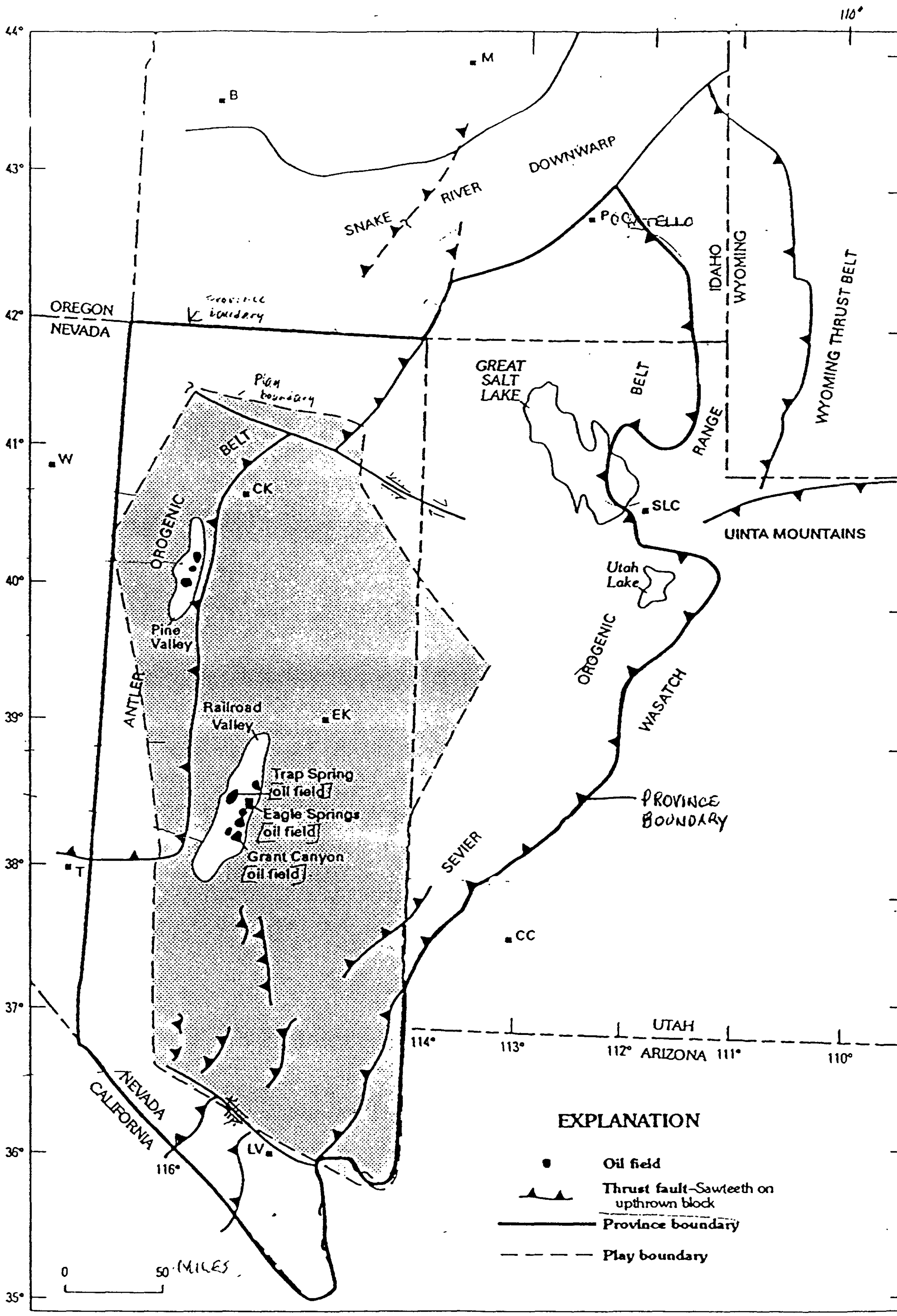


Figure 6. Map of Upper Paleozoic play.

OIL AND GAS PLAY DATA

PLAY **UPPER PALEOZOIC**
PROVINCE **EASTERN BASIN AND RANGE** CODE **03-082-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**1.00**
Timing (T)	**0.80**
Migration (M)	**0.70**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**0.56**

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	**0.8**
Gas	**0.2**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.2**	**1.7**	**3**	**5.6**	**16.5**	**50**
Gas (x 10^9 CFG)	**6**	**7**	**10**	**15**	**30**	**100**	**200**
Reservoir depth (x10^3 ft)							
Oil	**7**			**9**			**15**
Gas (non-associated)	**7**			**11**			**18**
Number of accumulations	**1**	**3**	**7**	**10**	**14**	**20**	**25**

Average ratio of associated-dissolved gas to oil (GOR)	**50**	CFG/BBL
Average ratio of NGL to non-associated gas	**15**	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.

WESTERN BASIN AND RANGE PROVINCE (083)

By Harry E. Cook

INTRODUCTION

The province encompasses the entire western half of Nevada from 117° to 120° west longitude and from 37° to 42° north latitude, an area of about 40,000 mi^2. The province is made up of a collage of diverse basin types that evolved in response to a number of geologic events, from initial rifting and development of the western margin of North America during the Late Proterozoic, to the basin and range structure in the Cenozoic. The sedimentary section consists of approximately 3,000 ft of Triassic carbonate rocks and an additional 3,000 ft of Tertiary welded ash-flow tuff (ignimbrites) beds (fig. 7). There is no commercial oil or gas production in the province; however, several minor gas shows have been reported in wells drilled in the 1920's in the Fallon area. Probable biogenic gas was produced from the shallow Fallon field, and minor asphalt or oil shows are reported in several wells associated with the gas shows. Analysis of gas from a water well immediately east of Fallon indicated a substantial amount of heavy hydrocarbons (methane, 40.21 percent, ethane +, 15.88 percent). One speculative play was individually assessed in the province, the Dixie Valley play (020).

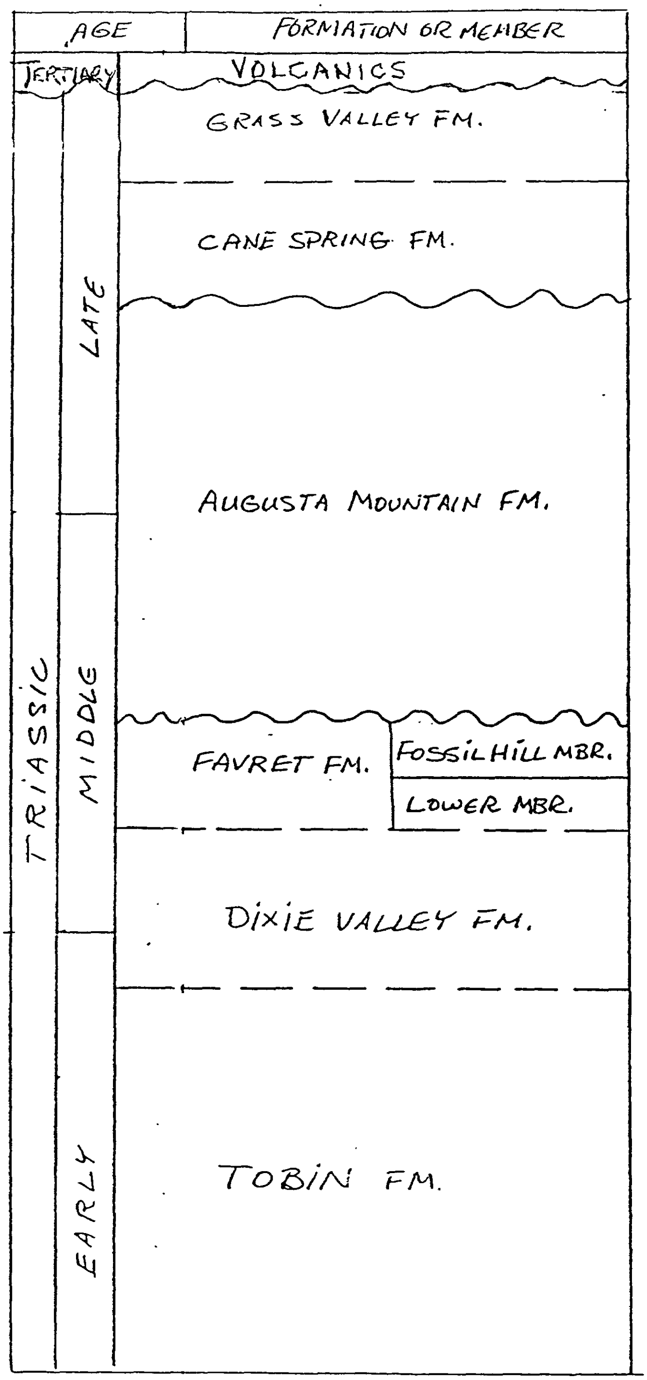


Figure 7. Generalized stratigraphic column, Western Basin and Range province.

DIXIE VALLEY PLAY (020)

This speculative play involves carbonate reservoirs of Triassic age as well as Tertiary ignimbrite reservoirs in both structural and stratigraphic traps. The play area is about 50 mi in length and 10 mi in width and is located in northwestern Nevada, about 100 mi east of Reno (fig. 8). Maximum thickness of the section involved is about 3,000 ft for Triassic carbonate rocks and at least 3,000 ft for Tertiary ignimbrites.

Potential reservoirs include Triassic marine carbonate turbidite and debris flow deposits of the Favret Formation and platform margin carbonates of the Augusta Mountain Formation (fig. 7). Devonian shoal water carbonate rocks form excellent reservoirs in several oil fields in Railroad Valley in the Eastern Basin and Range province (082). However, whether or not deep water and/or shallow water carbonate rocks have good reservoir characteristics in the Dixie Valley area is not known. Another potential reservoir type is the overlying, densely welded and intensely fractured Tertiary ignimbrites. Similar ignimbrites with fracture porosity form reservoirs in most of the oil fields of the Eastern Basin and Range province (082).

Dixie Valley contains Triassic basinal sediments that crop out in the valley's bounding Stillwater Range and Augusta Mountains and which may be probable source rocks. The Fossil Hill Member of the Favret Formation (fig. 7) is a 600-ft-thick sequence of dark gray calcareous shale and lime mudstone that contains ammonites, which, when broken open, commonly yield liquid hydrocarbons. Cenozoic lacustrine sediments may also contain probable source rocks in the play area. In Carson Sink, 10 mi west of the play, 5,000 ft of Cenozoic siltstones and clays have excellent source-rock potential, but low temperatures and insufficient depth of burial suggest that only limited amounts of oil have been generated from these rocks.

Both structural and stratigraphic traps might be present if the Dixie Valley basin has undergone Cenozoic structural modifications similar to other parts of the Basin and Range area, particularly like that exhibited in oil fields in Railroad Valley in eastern Nevada (fig. 8). Seismic data in the Carson Sink area indicates an overall structural pattern interpreted as being similar to that in the Railroad Valley area of province 082. Carbonate turbidites and debris-flow deposits could be expected to show probable reservoir transmissibility pinchouts up and down paleodip. Seals in the form of basinal shales and lime muds might encase these mass-flow deposits, adding to their trapping ability. Dolomitized platform margin carbonates may provide stratigraphic trapping in the absence of structural traps. Depths to potential reservoir targets are uncertain, but may range from 5,000 to 10,000 ft for Tertiary ignimbrites, and from 10,000 to 20,000 ft for Triassic carbonates.

There are no Paleozoic rocks in the Dixie Valley area and the oldest prospective section is limited to Triassic sedimentary rocks, volcanics, and intrusives. At least a dozen geothermal wells have been drilled in the play, ranging in depth from 3,000 to 12,500 ft, but only one oil and gas exploratory well, the Standard-Amoco S.P. Land Co wildcat, has been drilled. This well was located just west of the play area in the adjacent Carson Sink (fig.8) and penetrated 11,000 ft of Tertiary playa sediments and volcanics. Minor oil and gas shows, including free oil in vugs at the top of a basalt core at 8,168 ft, are reported from the well. Although the play is speculative, the presence of potential source rocks, carbonate reservoir rocks, and probable traps indicates that the play has a minor future oil and gas potential.

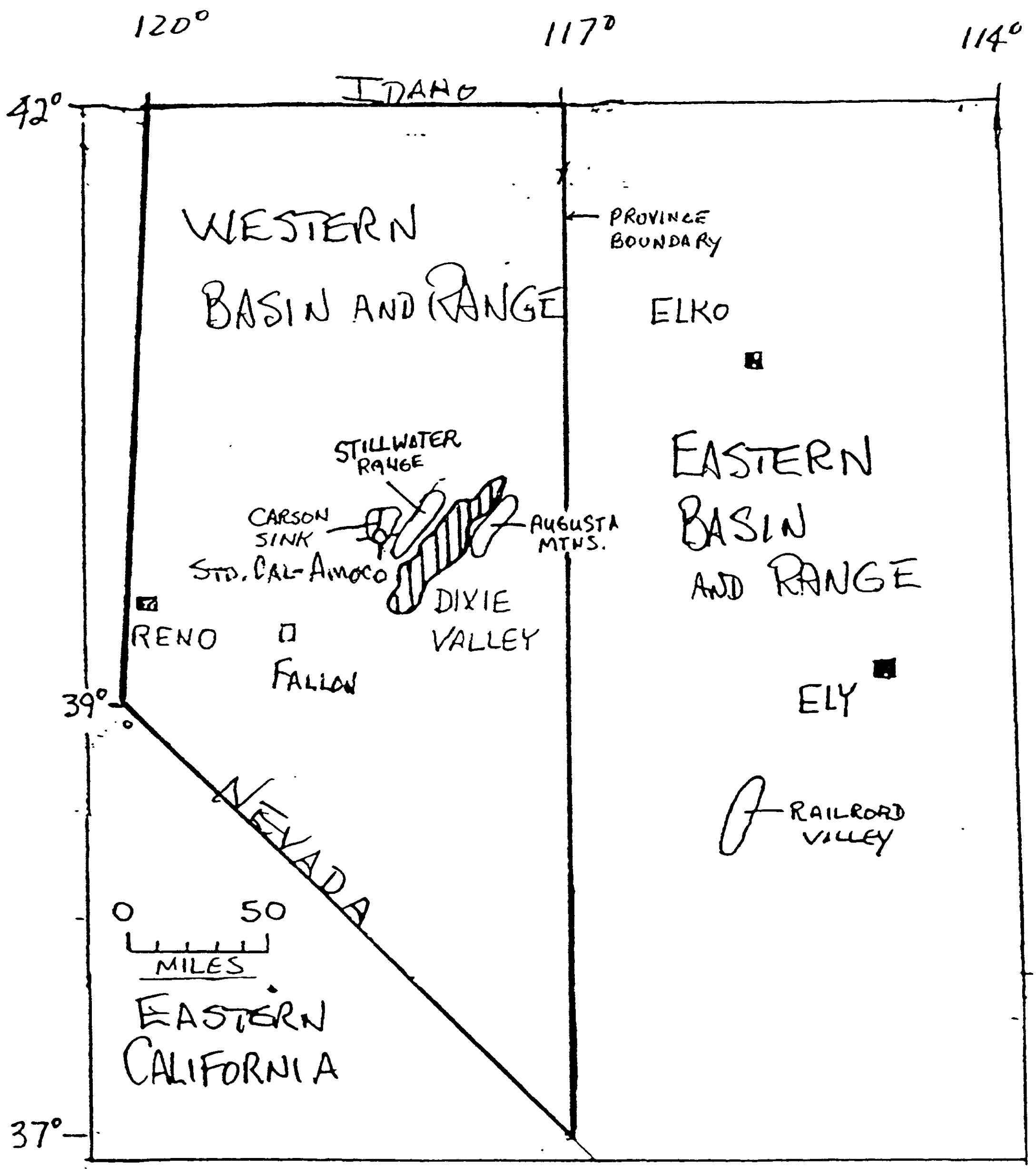


Figure 8. Map of Dixie Valley play.

OIL AND GAS PLAY DATA

PLAY **DIXIE VALLEY**
PROVINCE **WESTERN BASIN AND RANGE** CODE **03-083-020**

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	**0.50**

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	**0.7**
Gas	**0.3**

Fractiles * (estimated amounts)

Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.1**	**1.5**	**2.5**	**5**	**13**	**40**
Gas (x 10^9 CFG)	**6**	**6.1**	**9**	**15**	**30**	**78**	**240**
Reservoir depth (x10^3 ft)							
Oil	**5**			**12**			**20**
Gas (non-associated)	**5**			**12**			**20**
Number of accumulations	**1**	**2**	**5**	**8**	**11**	**14**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**20**	CFG/BBL
Average ratio of NGL to non-associated gas	**15**	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.

IDAHO-SNAKE RIVER DOWNWARP PROVINCE (084)

By James A. Peterson

INTRODUCTION

The province is approximately 70,000 mi^2 in size and comprises all of the state of Idaho except for the southeastern most part. It is bounded on the west by the Columbia Plateau, on the east by the western Montana disturbed belt, and on the south by the Eastern Basin and Range province (082). The central part is occupied by the Idaho Batholith. The batholith is bordered on the north and southeast by Proterozoic rocks of the Belt Supergroup and on the west by thick Tertiary basaltic volcanics of the Columbia Plateau (fig. 9). The southern part of the province comprises the late Tertiary Snake River Downwarp. The remainder of the province contains mainly intrusive, metamorphic, and volcanic rocks with little or no oil or gas potential because of high temperature gradients. There is no commercial oil or gas production in the province, and minimal subsurface information is available from the few wells that have been drilled. One speculative play was individually assessed, the Idaho Lake Basin play (030).

AGE	FORMATION OR GROUP	
PLEISTOCENE	Glenn's Ferry Formation	
PLIOCENE	Chalk Hills Formation	
	Banbury Basalt	
	Poison Creek Formation	
	Owyhee Rhyolite, or Idavada volcanics	
MIOCENE	Sucker Creek Formation	
	Jarbridge Rhyolite	
	Challis volcanics	
PRE-MIOCENE TERTIARY	Older sedimentary rocks in southwestern Idaho subsurface?	
CRETACEOUS	?	Granite of Idaho Batholith

Figure 9. Generalized stratigraphic column, Idaho-Snake River Downwarp province.

IDAHO LAKE BASIN PLAY (030)

The play involves up to 20,000 ft or more of Tertiary alluvial, volcanic and lacustrine sedimentary rocks associated with probable fault and fold structures and stratigraphic traps in the southwestern part of the Snake River Downwarp. The area of the play is approximately 25,000 mi^2 in southern Idaho, coinciding generally with the Snake River Downwarp proper (fig. 10). Prior to a rifting stage in Miocene time, the area of southwestern Idaho and southeastern Oregon may have been occupied by a basin where 5,000 ft or more of early Tertiary sediments were deposited. By early Miocene time, the basin was occupied by a large lake, where 5,000 to 7,000 ft of lacustrine sediments of the Sucker Creek Formation were deposited (fig. 9). During Paleocene time a second lake formed which occupied the approximate position of the present-day Snake River Downwarp. Up to 9,000 ft of lacustrine clay, sandstone, conglomerate, algal and oolitic limestone, ash, tuff, and basalt of the Pliocene-Pleistocene Poison Creek, Chalk Hills, and Glenn's Ferry Formations were deposited in this lake (fig. 9). Thickness of both of the lake sections is greatest in the western part of the play. The lake beds are overlain by Snake River basalts of Pleistocene and Holocene age, which are exposed at the surface over much of the Snake River Plain.

Porous sandstones, commonly mixed with volcanics, are present in several parts of the Tertiary section and in many cases probably intertongue with lacustrine beds of the Sucker Creek or Chalk Hills Formations. These sandstones, along with oolitic and algal limestone beds are potential reservoir rocks. Potential source rocks may be organic-rich shales of considerable thickness in the Sucker Creek Formation. Fault block and fold structures and stratigraphic traps may be present in the subsurface. Clay, ash, and tuff beds in the stratigraphic section should provide adequate seals. Drilling depths are estimated to range from 3,000 to 20,000 ft.

Only five or six deep exploratory wells have been drilled in the play without success, but numerous gas and some oil shows have been reported from units of mixed lithology in the Sucker Creek Formation in shallow water wells and in wells drilled for oil and gas. The play is considered to have a minor future potential for gas.

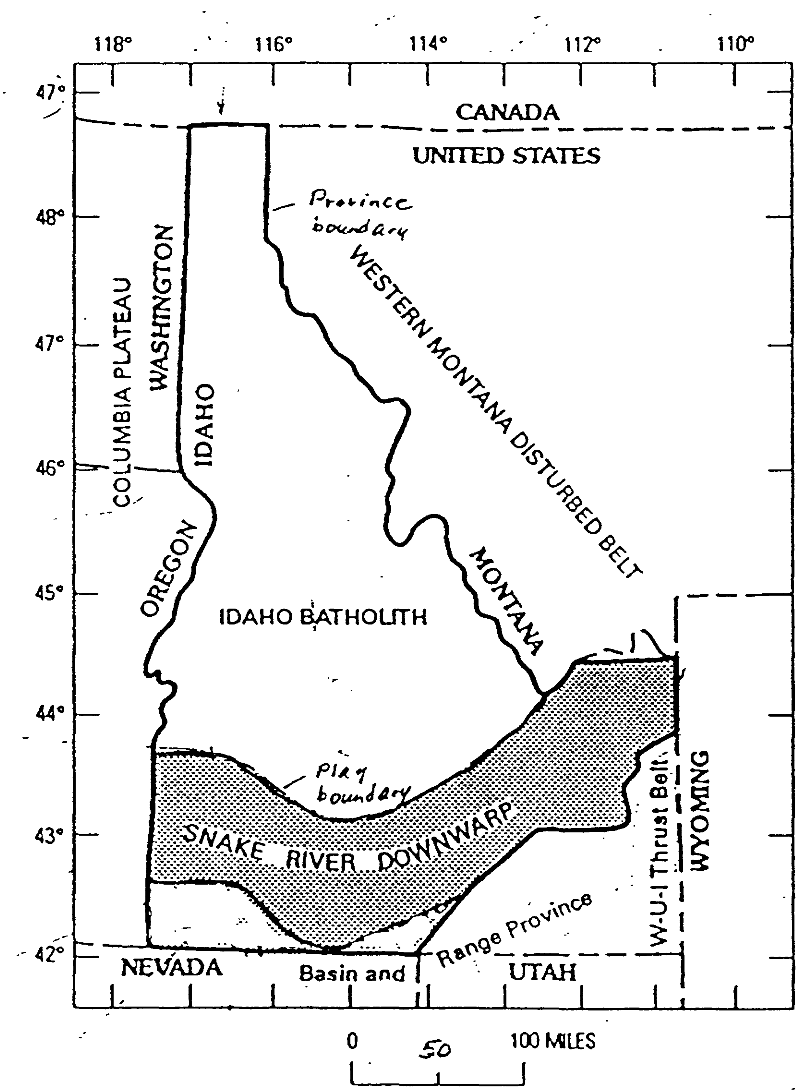


Figure 10. Map of Idaho Lake Basin play

OIL AND GAS PLAY DATA

PLAY **IDAHO LAKE BASIN**
PROVINCE **IDAHO-SNAKE RIVER DOWNWARP** CODE **03-084-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**0.80**
Timing (T)	**1.00**
Migration (M)	**0.60**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**0.48**

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	**0.20**

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**	**6.2**	**7.3**	**10**	**14**	**27**	**50**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**3**			**6**			**20**
Number of accumulations	**1**	**1**	**3**	**5**	**7**	**12**	**15**

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.

PARADOX BASIN PROVINCE (085)

By James A. Peterson

INTRODUCTION

The Paradox basin province is located in southeastern and south-central Utah and southwestern Colorado and encompasses all or parts of several major Laramide structural features; it also includes the Paradox salt basin (except for small portions extending into northwestern New Mexico and northeastern Arizona), the Uncompahgre and San Juan uplifts; San Rafael, Circle Cliffs, and Monument uplifts; the Kaiparowits and Henry Mountains basins, and the Wasatch and Paunsaugunt Plateaus. The province area is approximately 250 mi long and 200 mi wide. The maximum thickness of Phanerozoic sedimentary rocks ranges from 5,000-8,000 ft in the central part of the province to more than 15,000 ft in the Paradox salt basin, Kaiparowits basin, and Wasatch Plateau (fig. 11).

At the end of 1986, the Paradox salt basin (and carbonate shelf) contained approximately 125 oil and gas fields, producing mainly from Pennsylvanian algal mound carbonate reservoirs. Field sizes range from as small as a few hundred thousand barrels to millions of barrels of oil, with variable amounts of associated gas. Approximately two-thirds of the basin's original reserves and cumulative oil production is from Pennsylvanian carbonate reservoirs in the Aneth field (400 MMBO ultimate recovery). Additional production is from Mississippian carbonate, and Devonian and Permian sandstone reservoirs. Outside of the Paradox salt basin proper, several small to medium-sized gas fields produced from Cretaceous sandstone reservoirs in fields on the Wasatch Plateau, and one oil field produces from Permian carbonate reservoirs in the central part of the province. Four plays were individually assessed in the province: Carbonate Buildup (020); Older Paleozoic (040); Salt Interbeds (070), and Salt Anticline (080).

AGE	FORMATION OR GROUP	
CRETACEOUS		Mesaverde Group
CRETACEOUS		Mancos Shale
CRETACEOUS / JURASSIC		Dakota Sandstone Burro Canyon Formation Morrison Formation
JURASSIC		San Rafael Group
TRIASSIC		Glen Canyon Group
TRIASSIC		Chinle Formation Shinarump Member
TRIASSIC		Moenkopi Formation Sinbad Member
PERMIAN	Cutler Formation	De Chelly Sandstone
PERMIAN	Cutler Formation	Organ Rock Tongue
PERMIAN	Cutler Formation	Cedar Mesa Sandstone
PERMIAN	Cutler Formation	Halgaito Tongue
PENNSYLVANIAN	Hermosa Group	Honaker Trail Formation
PENNSYLVANIAN	Hermosa Group	Paradox Formation Ismay "Zone" Desert Creek "Zone"
PENNSYLVANIAN	Hermosa Group	Pinkerton Trail Formation
PENNSYLVANIAN		Molas Formation
MISSISSIPPIAN		Leadville Limestone
DEVONIAN		Ouray Limestone
DEVONIAN		Elbert Formation McCracken Member
DEVONIAN		Aneth Formation
SILURIAN		
ORDOVICIAN		
CAMBRIAN		Lynch Dolomite
CAMBRIAN		Muav Limestone
CAMBRIAN		Bright Angel Shale
CAMBRIAN		Ignacio Quartzite
ARCHEAN		Igneous and metamorphic rocks

Figure 11. Generalized stratigraphic column, Paradox Basin province

CARBONATE BUILDUP PLAY (020)

This play is defined by the stratigraphic and geographic occurrence of oil accumulations in Pennsylvanian carbonate mound buildups cyclically interbedded with organic-rich shale and evaporite beds. The play area is approximately 2,800 mi^2 (fig. 12). The mound-bearing shelf carbonate facies is located mainly along the southern margin of the Paradox salt basin.

Good quality reservoirs are discontinuous, porous carbonate buildups oriented generally northwest-southeast, which are composed mainly of algal, oolitic, and bioclastic fossil debris. Reservoir thickness ranges from 10-50 ft; porosity and permeability averages 9 percent and 24 millidarcies, respectively Hydrocarbons are primarily oil with moderate amounts of associated gas. Two algal mound stratigraphic intervals, the Desert Creek and Ismay "zones" of the Paradox Formation, contain most of the oil reservoirs (fig.11).

Source rocks are organic-rich black shale or shaly carbonates interbedded with the algal mounds. TOC content ranges from 1 percent to over 10 percent. Oil generation probably began in Late Cretaceous time and, in most cases, oil migration was probably coincident with oil generation with some adjustment related to late structural growth. Present-day thermal gradients in the basin are near normal.

Traps occur primarily in belts of isolated carbonate buildup that may or may not be related to structure. Areal sizes of the traps range from less than a square mile in many cases to approximately 75 mi^2 at the giant Aneth field. Structural closure is commonly influenced to varying degrees by draping of overlying sediments over mound buildups. Lateral facies changes, from porous biogenic reservoir rock to non-porous argillaceous or anhydritic carbonate and shale, aid in trapping. Seals are commonly black, organic-rich, high-carbonate shale or shaly carbonate and anhydrite beds. Drilling depths range from 5,000 to 8,000 ft.

The play is moderately to well explored; estimated ultimate recovery from all existing fields is approximately 500 MMBO, about two-thirds of which is from the Aneth field. The play has a modest future potential for a number of undiscovered small- to medium-sized fields, primarily in stratigraphic traps.

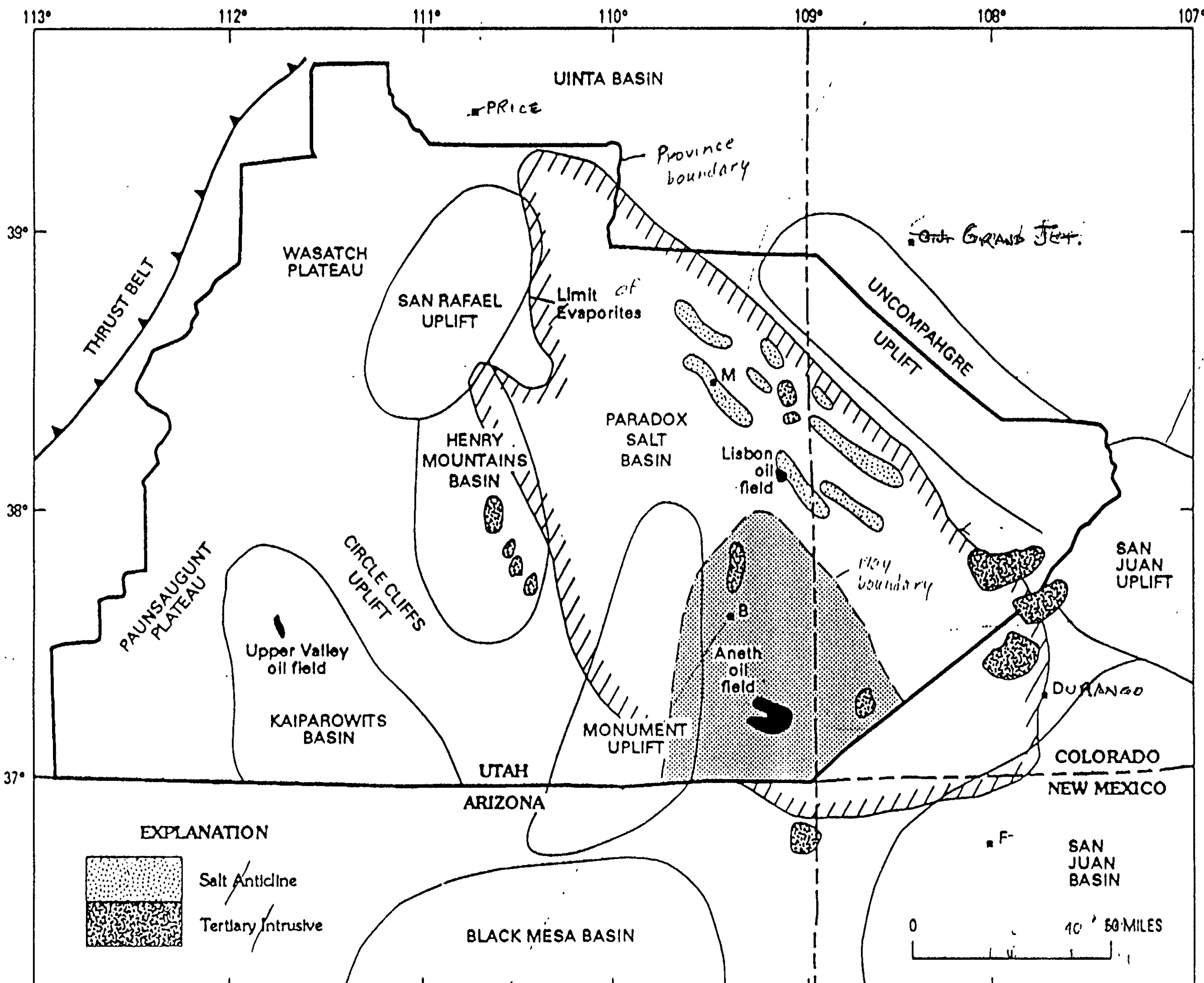


Figure 12. Map of Carbonate Buildup play.

OIL AND GAS PLAY DATA

PLAY **CARBONATE BUILDUP**
PROVINCE **PARADOX BASIN** CODE **03-085-020**

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**	**1.07**	**1.41**	**2**	**3.02**	**5.36**	**8.45**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**5**			**6**			**8**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**2**	**3**	**5**	**6**	**7**	**9**	**10**

Average ratio of associated-dissolved gas to oil (GOR)	**950**	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.

OLDER PALEOZOIC PLAY (040)

The play is based on the occurrence of oil accumulations on fault blocks involving pre-Pennsylvanian rocks, mainly in the salt anticline area of the Paradox salt basin covering an area of approximately 7,500 mi^2 (fig. 13). Reservoirs are in porous dolomite or dolomitic limestone beds of the Mississippian Leadville Limestone and the Upper Devonian McCracken Sandstone Member of the Elbert Formation (fig. 11). Reservoirs range up to 200 ft in thickness and porosity varies from 5 to as high as 25 percent in local cases. Permeability is generally low but ranges up to several hundred millidarcies in places.

Probable source rocks are the organic-rich black shales of the Paradox Formation. Migration into Leadville or McCracken reservoirs occurred where fault blocks are in structural and/or depositional contact with the black shales, which are commonly highly fractured. Hydrocarbon generation began probably as early as Permian time and has continued to the present in some cases. Migration into pre-salt reservoirs was probably contemporaneous with the deposition of Pennsylvanian age rocks and later growth of salt structures. Migration pathways were enhanced by severe fracturing of interbedded organic-rich shales during salt movement.

Known traps are on uplifted fault blocks adjacent to salt anticlines or swells. Seals are Paradox Formation evaporite beds, which overlie or are in fault contact with Mississippian or Devonian reservoirs. Drilling depths range from 7,000 to 8,000 ft at the Lisbon field to greater than 10,000 in other areas.

At the end of 1986, six oil and gas accumulations had been discovered that produce from pre-salt structural blocks; the largest of these is the Lisbon field which is approximately 43 MMBO and 250 BCFG in size. The remainder of the fields are non-commercial or marginally commercial. The play is only moderately explored with respect to smaller structures. Future potential is low to moderate and undiscovered fields are estimated to be small to medium in size with minimal oil columns, based on previous production history.

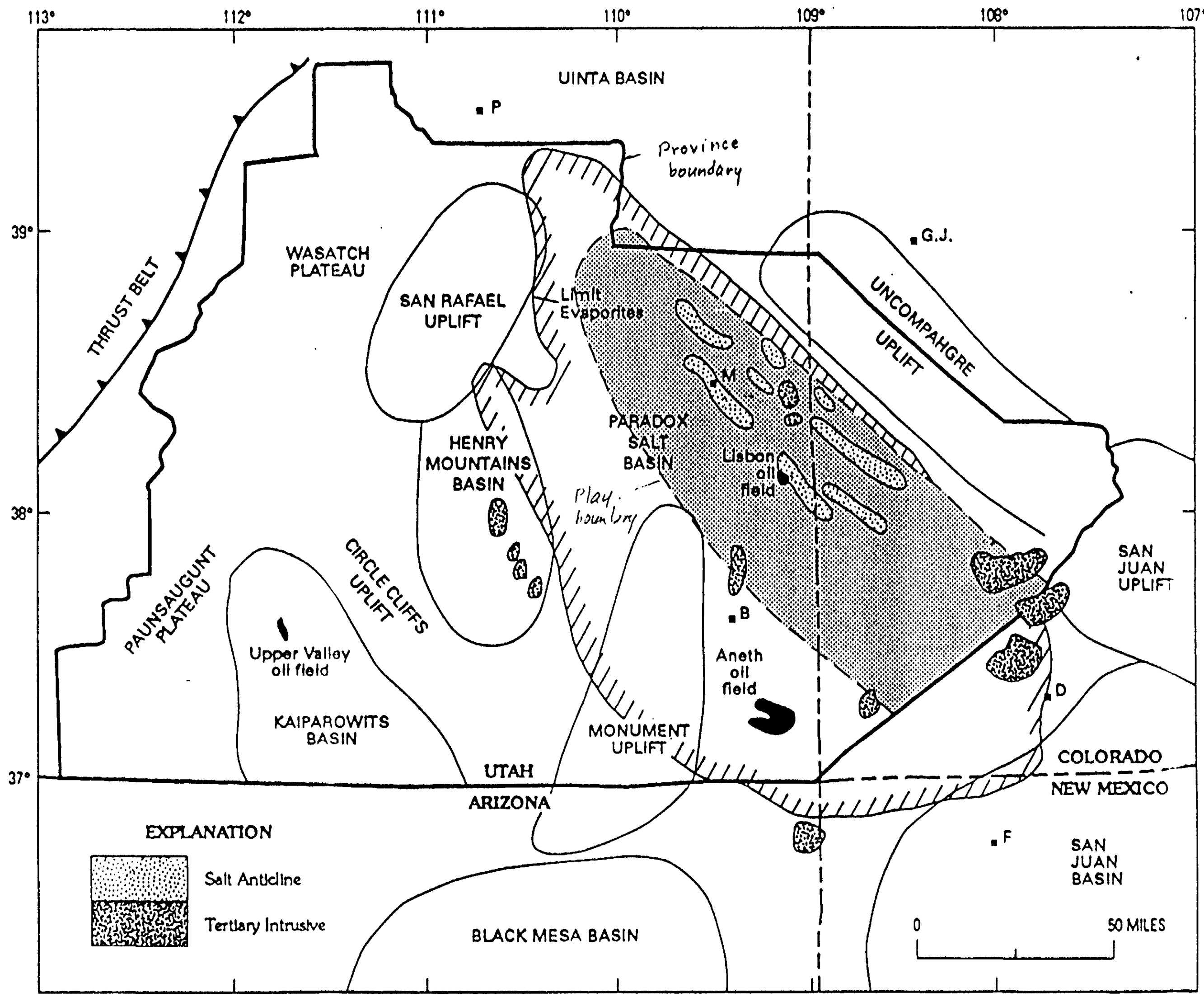


Figure 13. Map of Older Paleozoic play

OIL AND GAS PLAY DATA

PLAY **OLDER PALEOZOIC**
PROVINCE **PARADOX BASIN** CODE **03-085-040**

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	
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**	**1.07**	**1.4**	**2**	**3**	**5.8**	**10**
Gas (x 10^9 CFG)	**6**	**6.6**	**8.4**	**12**	**18**	**36**	**60**
Reservoir depth (x10^3 ft)							
Oil	**5.5**			**7**			**14**
Gas (non-associated)	**5.5**			**7**			**14**
Number of accumulations	**1**	**3**	**7**	**10**	**13**	**17**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**950**	CFG/BBL
Average ratio of NGL to non-associated gas	**80**	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.

SALT INTERBEDS PLAY (070)

The play involves oil accumulations in fractured, low-permeability Pennsylvanian-age rocks in the central, deep portion of the Paradox salt basin and includes the area of the Paradox fold and fault belt. The play area is approximately 7,500 mi^2 (fig. 14).

The central basin contains 3,000 to more than 5,000 ft of Middle Pennsylvanian evaporites cyclically interbedded with organic-rich black shale, fine-grained, dolomitic and calcareous siltstone and dolomite. These rocks are the reservoirs as well as the source rocks in the play. The reservoir section is characterized by highly variable fracture porosity, very low matrix permeability, thicknesses of up to several hundred feet, and is sealed above and below by thick beds of halite. Because of the impermeable thick salt seals, overpressuring is common, and blowouts have been encountered during drilling. Generated hydrocarbons have tended to remain in place with minimal lateral migration. As a rule, substantial oil and gas shows are almost always encountered in the interbeds, but economic accumulations depend mainly on the intensity of fracturing in these fine grained rocks. Drilling depths range from 3,000 to greater than 15,000 ft.

Exploration for fractured reservoirs is difficult and hampered because the fracturing mechanism and the patterns of fracturing are not well understood. Discoveries in the salt interbeds have been primarily accidental and made while drilling for deeper objectives. All known fields in the play are single-well fields; one well (field), for example, has a cumulative production of about 1.2 MMBO. Future potential for both oil and gas is fair to good.

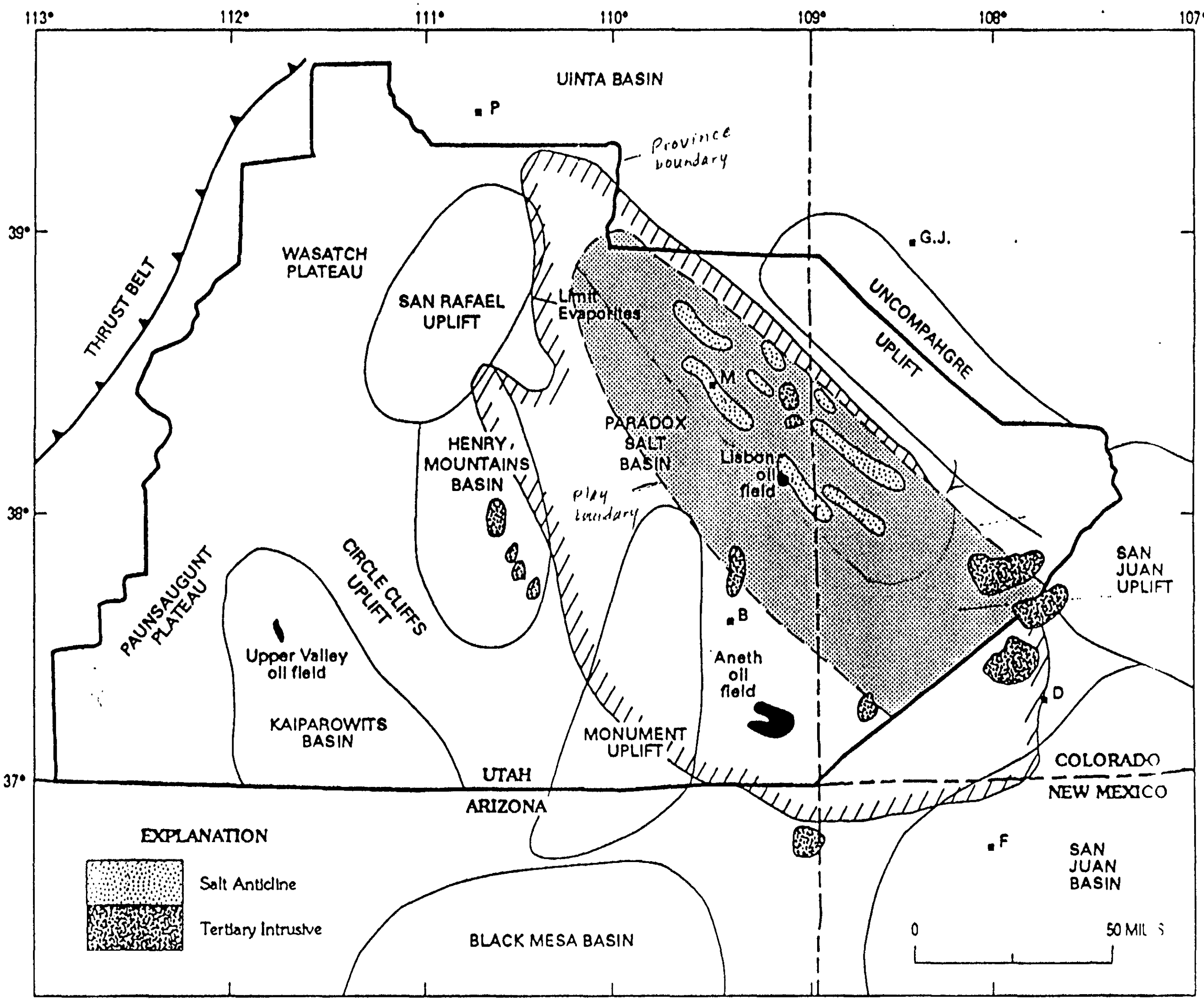


Figure 14. Map of Salt Interbeds play

OIL AND GAS PLAY DATA

PLAY **SALT INTERBEDS**
PROVINCE **PARADOX BASIN** CODE **03-085-070**

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 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	
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**	**2**	**6**	**17**	**47**	**267**	**3000**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**3**			**6**			**15**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**1**	**1**	**1**	**1**	**1**	**1**	**1**

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.

SALT ANTICLINE PLAY (080)

This play is characterized by the association of gas and oil productive Permian-Pennsylvanian reservoirs in northwest-trending salt anticlines in the axial part of the Paradox salt basin. The play area is approximately 7,500 mi^2 (fig. 15). Salt anticlines consist of long, northwest-trending welts or pillows of Paradox Formation salt over which younger rocks are arched in anticlinal form. The central, or salt-bearing cores of the anticlines range in thickness from 2,500 to more than 14,000 ft; the anticlines are flanked by deep synclines (sites of salt withdrawal) that are filled with 10,000 ft or more of chiefly arkosic clastics of the Permian Cutler Formation and a mixed sequence of clastics and carbonate rocks of the Honaker Trail Formation (fig. 11).

The main reservoirs in the play are pelletal and oolitic limestone and sandstone in the upper part of the Hermosa Group and arkosic sandstone in the Cutler Formation. Sandstone reservoirs range up to 200 ft in thickness. No data is available on reservoir quality; however, it is estimated that permeabilities may range up to 1,000 millidarcies locally. Vertical communication between these reservoirs is common because of well developed fracture systems resulting from strong subsidence in the flank synclines, and related salt movement and flowage into the adjacent salt anticlines.

Several potential sources for hydrocarbons are present in the play. Organic-rich black shales of the Paradox Formation are commonly in contact with reservoir rocks along the margins of salt structures and may also be sufficiently connected by fracture or fault systems to allow vertical migration under the synclines. Honaker Trail shales with TOC values as high as 2.5 wt. percent are also potential source rocks. Some coaly carbonaceous shales are locally present at the Cutler-Honaker Trail contract and may be the source for some of the gas accumulations. No data are available on maturity of these source rocks. Source rocks buried to depths of 4,000 to more than 10,000 ft in the synclines are mature to post-mature. Hydrocarbon generation in the deeper parts of the basin probably began by Late Pennsylvanian or Permian time. Migration was coincident with salt movement and anticlinal growth.

Stratigraphic and stratigraphic-structural traps occur in conjunction with the reservoirs as the result of both thinning and permeability pinchouts and are sealed along the steeply-dipping flanks of the salt anticlines. Some traps may be the result of updip termination against salt diapirs. Drilling depths range from less than 5,000 to greater than 15,000 ft.

The play is lightly explored; four gas fields of undetermined size have been discovered, only one of which has had any significant production (Andy's Mesa field). Cumulative production from this field to the end of 1986 was 16 MCFG and 11,000 barrels of condensate. The other three fields are small, one-well fields. Future potential for oil is low and fair to good for gas.

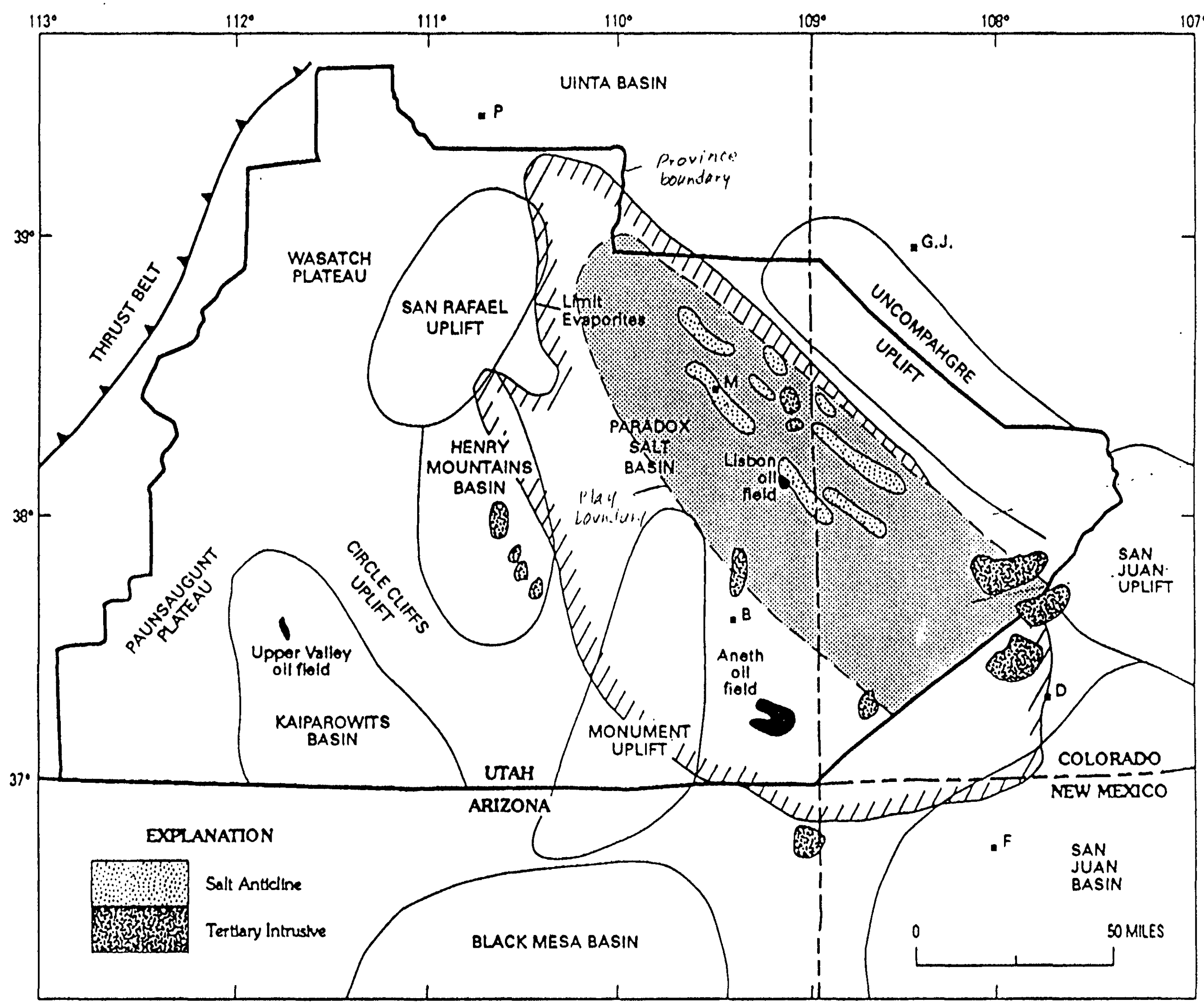


Figure 15. Map of Salt Anticline Play

OIL AND GAS PLAY DATA

PLAY **SALT ANTICLINE**
PROVINCE **PARADOX BASIN** CODE **03-085-080**

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	**0.70**

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**	**1.4**	**3.1**	**6**	**11**	**25**	**40**
Gas (x 10^9 CFG)	**6**	**7**	**13**	**25**	**45**	**100**	**200**
Reservoir depth (x10^3 ft)							
Oil	**3**			**9**			**15**
Gas (non-associated)	**3**			**9**			**15**
Number of accumulations	**1**	**2**	**4**	**5**	**7**	**10**	**15**

Average ratio of associated-dissolved gas to oil (GOR)	**950**	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.

UINTA-PICEANCE-EAGLE BASINS PROVINCE (086)

By Charles W. Spencer

INTRODUCTION

The province trends west-east, extending from the thrust belt in north-central Utah, on the west, to the southern Park Range and Sawatch uplift in northwestern Colorado on the east. The northern boundary is defined roughly by the Uinta Mountain uplift, and the southern boundary is located along a line north of the axis of the Umcompahgre uplift. The province covers an area of about 40,000 mi^2 and encompasses the Uinta, Piceance, and Eagle basins.

The Uinta and Piceance basins were formed mainly in Tertiary time. The Eagle basin is a structural feature east of the Piceance basin and coincides in part with the Pennsylvanian-age Eagle evaporite basin, although the present-day Eagle basin is much smaller than the paleodepositional basin. Numerous oil and gas fields have been discovered in the Uinta and Piceance basins; however, there have been no fields discovered in the Eagle structural basin. The lack of exploration success in the Eagle basin is attributed mainly to very high thermal maturity levels in source rocks and the generally poor quality of reservoirs. A small amount of gas might be discovered, but the expected volume is insignificant.

The Uinta basin of Utah is about 120 mi long and is bounded on the west by the thrust belt and on the east by the Douglas Creek arch. It is nearly 100 mi wide and bounded on the north by the Uinta Mountains uplift. The basin is asymmetrical with the deepest part on the north side adjacent to the Uinta Mountains uplift. Here, more than 30,000 ft of Phanerozoic sedimentary rocks may be present (fig. 16). The Piceance basin of Colorado is kidney-shaped and oriented northwest-southeast. It is about 100 mi long and 40-50 mi wide, and bounded on the south by the Uncompahagre and Gunnison uplifts, on the west by the Douglas Creek arch, on the northeast by the Axial uplift, and on the east by the White River uplift. The basin is asymmetrical and deepest along its east side near the White River uplift, where more than 20,000 ft of Phanerozoic sedimentary rocks may be present.

A total of six plays were identified. Four of the plays are conventional and two involve unconventional (tight) gas reservoirs; however, only the four conventional plays were individually assessed and all are located in the Uinta and Piceance basins: Wasatch-Green River Gas (020), Wasatch-Green River Oil(030), Upper Cretaceous (040), and Permian-Pennsylvanian.(050)

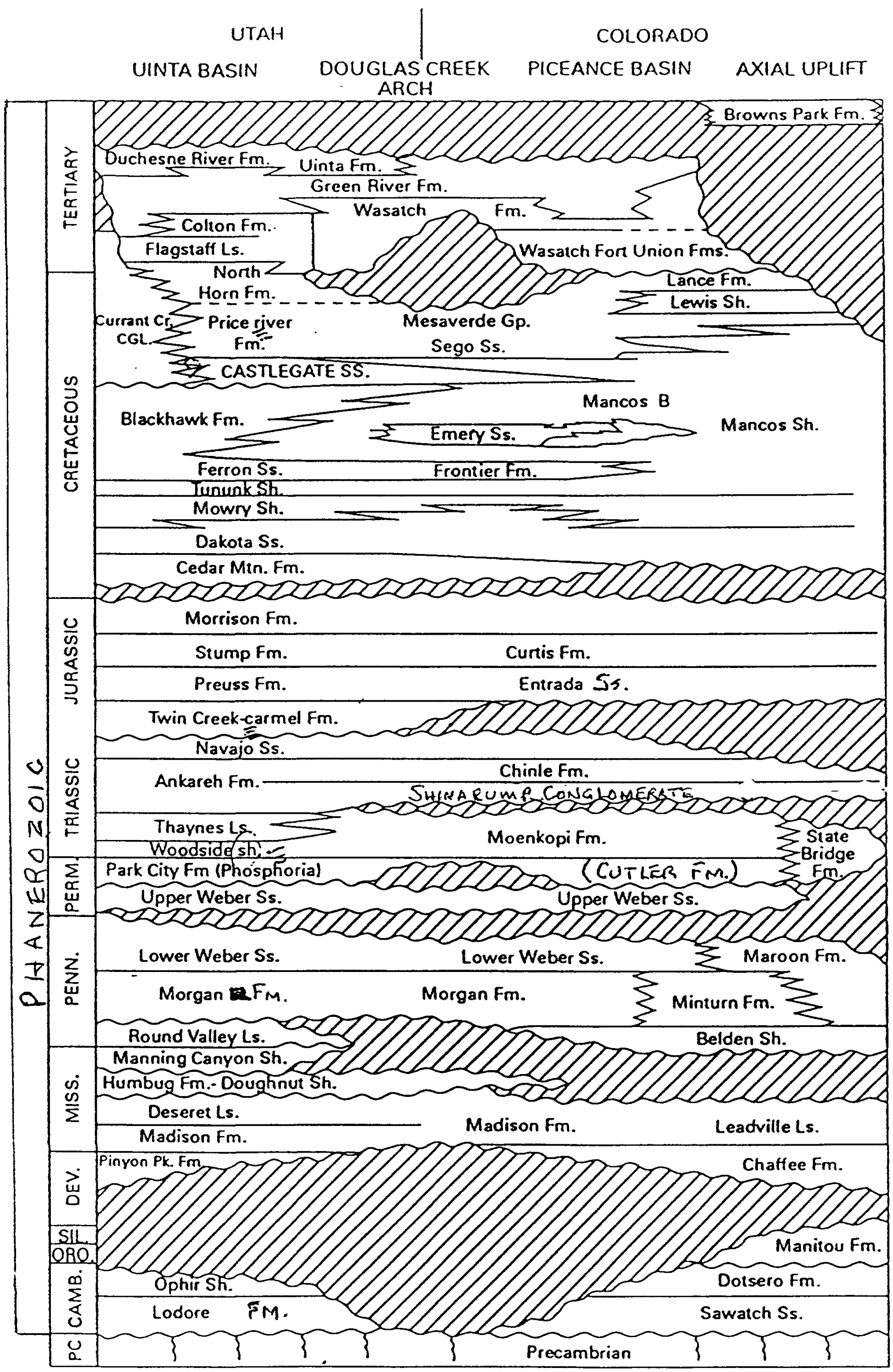


Figure 16. Generalized stratigraphic columns, Uinta-Piceance-Eagle Basins province.

WASATCH-GREEN RIVER GAS PLAY (020)

The play involves oil and gas accumulations in stratigraphic traps in fluvial and lacustrine sandstones in the Wasatch and Green River Formations; most of the undiscovered gas resources are in the Wasatch. In the deeper portions of the Uinta basin, the reservoirs (mainly tight Green River Formation sandstones) are oil productive. The play area is limited updip by the presence of brackish and fresh water in shallower sandstone reservoirs, and is located in the central and updip flanks of both the Uinta and Piceance basins (fig. 17). In the Uinta basin the play area is about 85 mi in length and in the Piceance basin the potential area extends for about 60 mi.

Reservoir sandstones are mostly litharenites to feldspathic litharenites with porosities of about 11 percent to more than 15 percent, and vary in thickness from about 10 ft to more than 50 ft. Locally, reservoirs may be more than 100 ft thick.

Potential source rocks associated with the reservoirs are thermally immature. Isotopic studies indicate that gases in some of the larger fields have migrated vertically from deeper, more thermally mature source rocks. In many cases, these source rocks appear to be Upper Cretaceous carbonaceous shales and coals. Gas probably migrated vertically into reservoirs in late Tertiary time in response to overpressuring in the more deeply buried rocks caused by hydrocarbon (gas) generation. Gas migrated up along joints, faults, and fractures by pressure differential, and then laterally updip by buoyancy into porous Wasatch-Green River reservoir sandstones where the gas is trapped by updip porosity pinchouts.

Seals are tight siltstone, mudstone, and shale that overlie and underlie reservoirs. Updip seals are facies changes and, in some instances, involve a diagenetic loss of porosity and permeability. The downdip flow of fresh, meteroic water helps to enhance the trapping capability of many updip edges of reservoirs. This condition is typical of shallow stratigraphic traps in other Rocky Mountain basins. Drill depths range from less than 3,000 ft to more than 7,000 ft. At depths greater than 8,000 ft, reservoir sandstones are mostly tight (low porosity). These tight rocks form the downdip limit of the conventional gas play. Unconventional resources of gas are found in these deeper, low-porosity sandstones.

Fields in the play range in size from less than 1 BCFG to more than 180 BCFG, but most fields are less than 20 BCFG. The play is moderately well explored. Substantial amounts (> 100 BCF) of associated-dissolved gas have been produced from the Greater Altamont and Greater Redwash oil fields in the Uinta basin. However, these two fields are anomalous in size, and no large, shallow, oil fields containing significant associated-dissolved gas resources are expected to be found in this play. The potential for the discovery of moderate size nonassociated gas accumulations is fair to good.

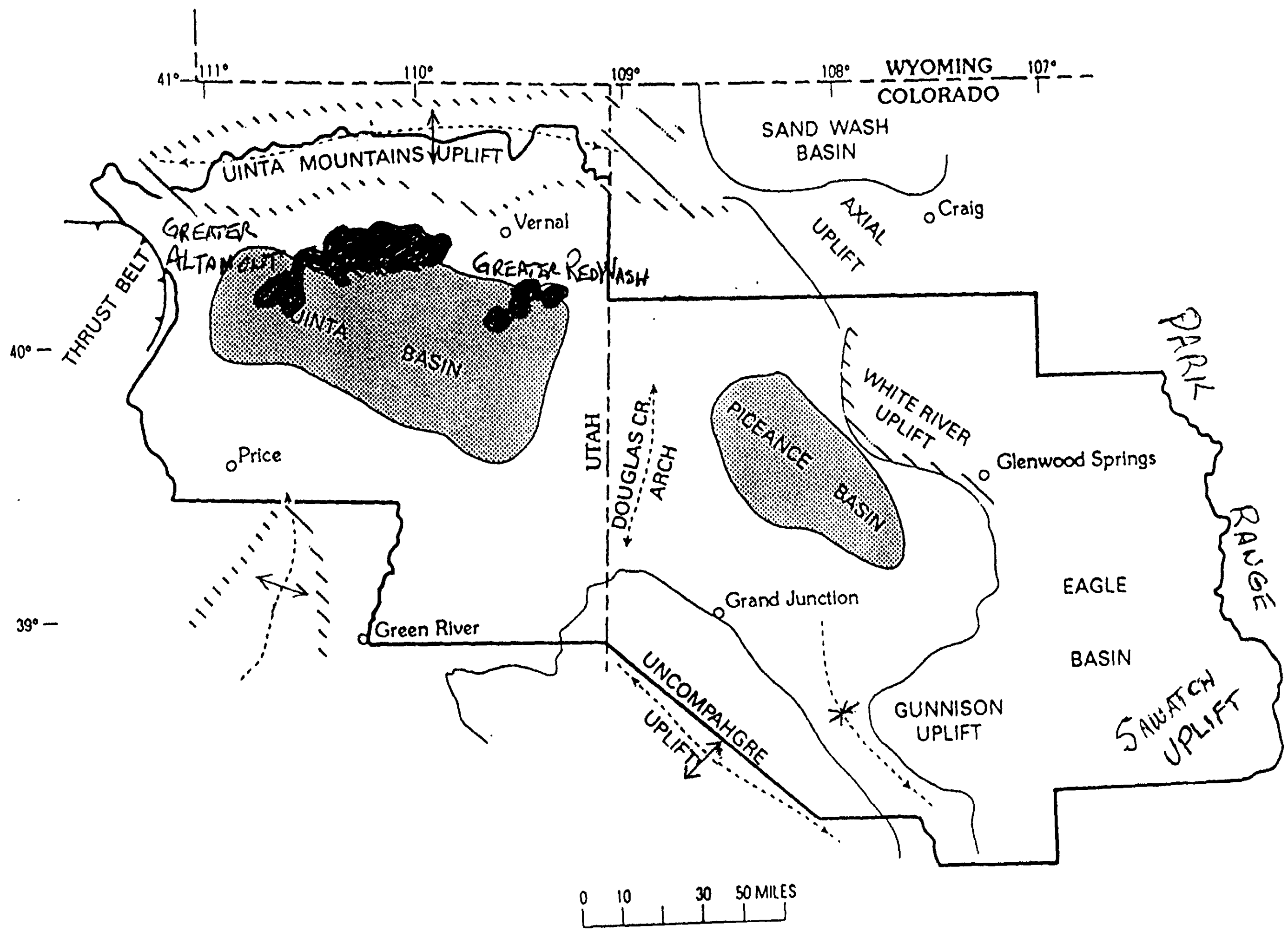


Figure 17. Map of Wasatch-Green River Gas play.

OIL AND GAS PLAY DATA

PLAY **WASATCH-GREEN RIVER GAS**
PROVINCE **UINTA-PICEANCE-EAGLE BASINS** CODE **03-086-020**

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 (x 10^6 BBL)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Gas (x 10^9 CFG)	**6**	**6.6**	**8.4**	**12.6**	**23**	**62**	**180**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**2**			**4**			**8**
Number of accumulations	**8**	**9**	**12**	**15**	**20**	**35**	**40**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**7**	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.

WASATCH-GREEN RIVER OIL PLAY (030)

The shallower oil play in the Wasatch and Green River Formations involves sandstone and minor lacustrine carbonate reservoirs in stratigraphic traps, with interbedded marlstones (oil shale) as source rocks. Both formations have produced major amounts of oil and associated gas in the north and northeast parts of the Uinta Basin. The play is limited to the Uinta Basin; there is no equivalent play in the Piceance Basin due to the immature to marginally mature nature of Green River source beds. The area of the play is about 40 mi wide and 100 mi long (fig. 18). It is limited on the west by a transition zone east of the thrust belt, and on the east, south, and north by a zone of invasion of fresh water into reservoirs, and cooler rock temperatures due to shallow depths.

Known reservoirs are fluvial and lacustrine sandstones and minor lacustrine carbonates. Sub-litharenite and feldspathic litharenite reservoirs vary in thickness from about 10 ft to more than 50 ft, and reservoir porosity ranges from about 11 percent to more than 15 percent. The objective reservoir rocks are conventional reservoirs and consequently are shallower than the more thermally mature, overpressured, tight, unconventional reservoirs present in the Greater Altamont producing trend located in the northern part of the Uinta basin (fig. 18). This trend produces from rocks mostly at depths greater than 10,000 ft. Oil in these reservoirs, contained within thermally immature rocks, is derived from deeper source beds and moved updip laterally and vertically along faults and fractures.

Source rocks are oil-prone marlstone (oil shale) both interbedded with, and deeper than the reservoir rocks. Oil and gas generation and expulsion from oil shale source rocks began in late Tertiary time and is probably ongoing based on the widespread occurrence of deep (> 10,000 ft) overpressuring caused by active hydrocarbon generation in the deeper part of the Uinta basin. The oils have characteristically high pour points (60°-105°F).

Oil fields occur in stratigraphic and structural-stratigraphic traps. Undiscovered fields will be found primarily in small stratigraphic (including diagenetic) traps, involving facies changes from porous channel and marginal lacustrine sandstone, to impermeable mudstone, marlstone, and shale. Drilling depths in the unexplored parts of the play range from about 3,000 ft to 9,000 ft. Reservoirs are considered to be unconventional (tight) at depths greater than 10,000 ft.

The play is moderately well explored. All oil fields discovered are relatively small (< 5 MMBO); large fields in the Greater Redwash complex are exceptions. Only four oil fields have produced more than 1 MMBO, exclusive of Greater Redwash. The largest of these, Monument Butte, has produced less than 5 MMBO through 1986. The future potential for the discovery of moderate-size fields is fair, but undiscovered fields the size of Redwash are unlikely.

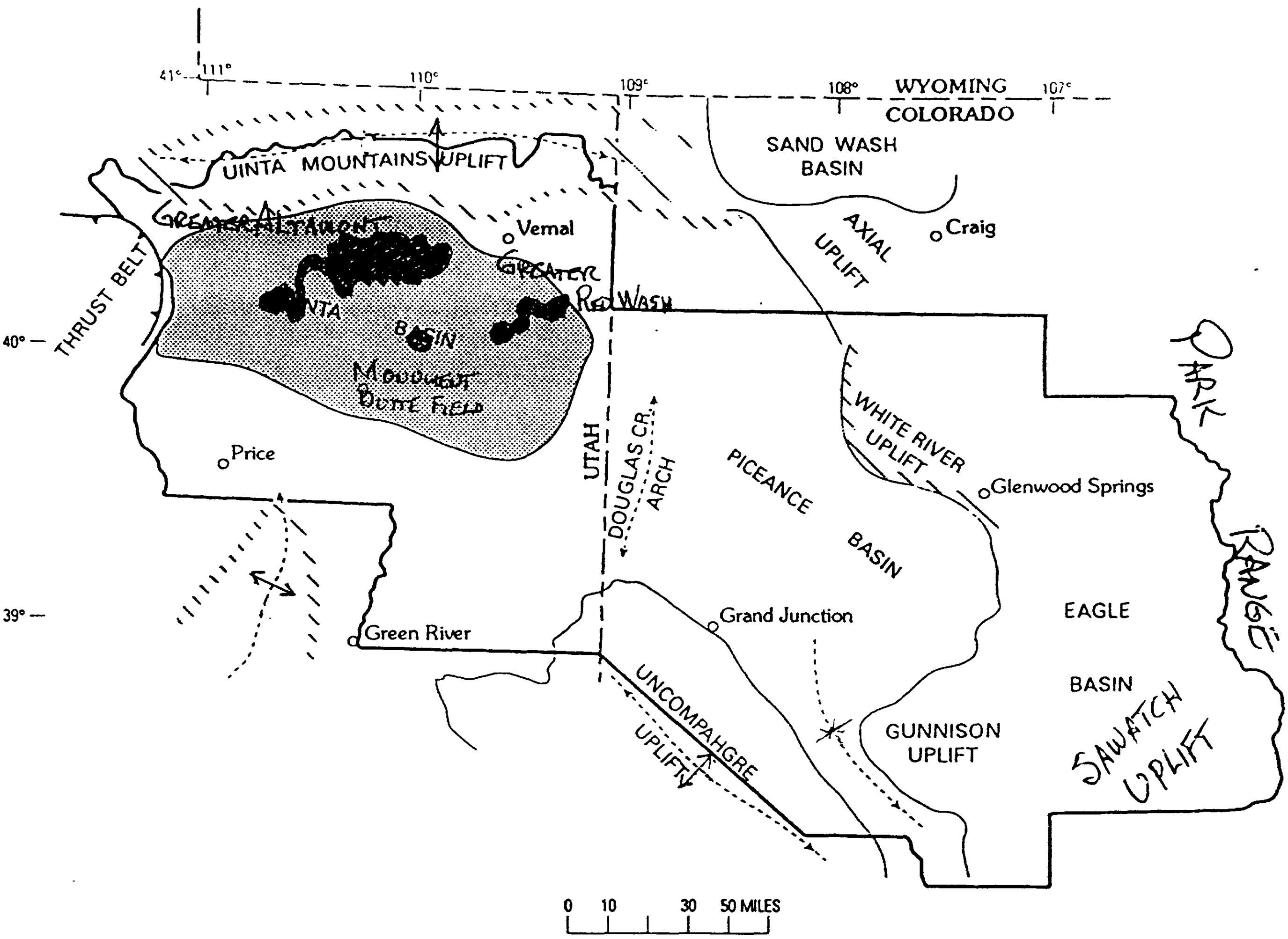


Figure 18. Map of Wasatch-Green River Oil play.

OIL AND GAS PLAY DATA

PLAY **WASATCH-GREEN RIVER OIL**
PROVINCE **UINTA-PICEANCE-EAGLE BASINS** CODE **03-086-030**

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

	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**	**1.2**	**1.6**	**2.5**	**8**	**35**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**3**			**7**			**9**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**4**	**6**	**7**	**8**	**10**	**14**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**2000**	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.

UPPER CRETACEOUS PLAY (040)

The play is characterized by gas fields in structural and stratigraphic traps that produce from Upper Cretaceous Mesaverde Group sandstone reservoirs. The play area involves both the Uinta and Piceance basins. In the Uinta basin the play extends from the thrust belt on the west to the west flank of the Douglas Creek arch on the east, an area about 120 mi long and 30 mi wide (fig. 19). The northern limit is where sandstone reservoirs become dominantly tight (unconventional), and the southern limit is where the sandstones are shallow (< 2,000 ft) and water bearing. The eastern boundary is drawn where reservoirs have been designated as conventional by the (FERC) Federal Energy Regulatory Commission.

The play area in the Piceance basin is kidney shaped and about 100 mi long and 40 mi wide. It is limited on the east by the White River uplift, on the south and east by the Gunnison uplift, on the south and southwest by shallow, water-bearing Mesaverde Group sandstones, and on the west by the area of gas development on the Douglas Creek arch. Within the basin center the lower depth limit of the play is about 8,000 ft.

Reservoirs in both basins are fluvial and marine sandstones that range in thickness from 10 ft to more than 50 ft. Porosities range from about 12 percent to more than 20 percent. Source rocks are gas-prone carbonaceous shale, mudstone, and coal interbedded with sandstone. Rocks in the Upper Cretaceous sequence are thermally mature except at shallow depth. Gas generation began about mid-Tertiary time in the deeper parts of both basins and is continuing to the present in deep, tight, overpressured Upper Cretaceous rocks.

Traps in producing fields are both structural and stratigraphic, and most of the pure structurally-controlled accumulations have been discovered. New gas resources will probably be found in stratigraphic and structural-stratigraphic traps. Traps are the result of facies changes from porous litharenites to tight mudstones and shales. Drill depths range from 2,000 ft to 8,000 ft.

The play is moderately well explored in the Piceance basin and less explored in the Uinta basin. Nineteen fields greater than 6 BCFG in size have been discovered, most of these in the Piceance basin portion of the play. Divide Creek gas field, discovered in 1956, is a major structural accumulation in Mesaverde reservoir rocks. It has produced approximately 47.6 BCFG to the end of 1986. Future potential for undiscovered gas resources in stratigraphic traps is considered to be very good.

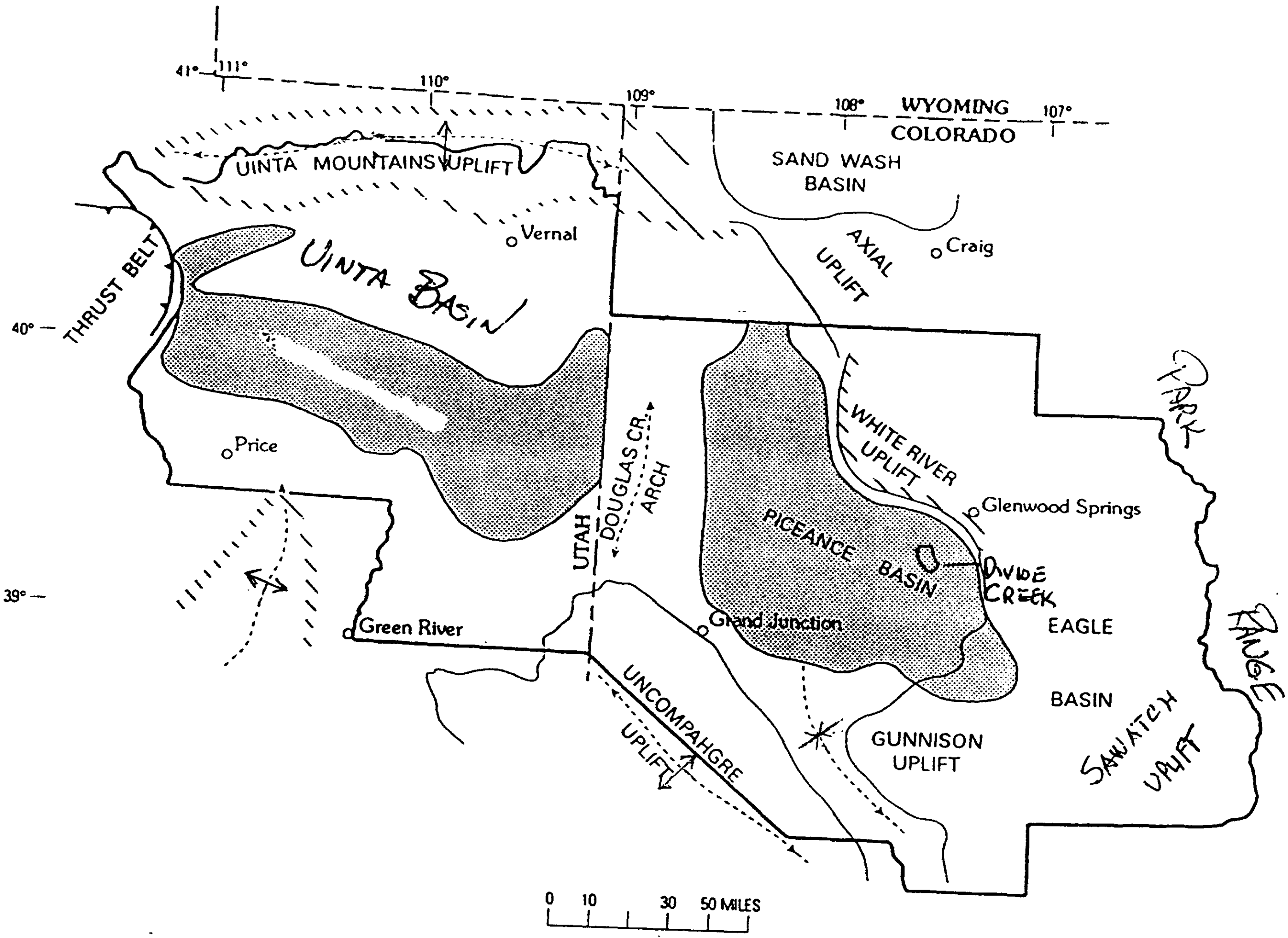


Figure 19. Map of Upper Cretaceous play

OIL AND GAS PLAY DATA

PLAY **UPPER CRETACEOUS**
PROVINCE **UINTA-PICEANCE-EAGLE BASINS** CODE **03-086-040**

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	
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**	**7.1**	**12.2**	**21.4**	**38.3**	**81.4**	**148.4**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**2**			**6**			**8**
Number of accumulations	**20**	**25**	**33**	**40**	**47**	**55**	**60**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**1**	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.

PERMIAN-PENNSYLVANIAN PLAY (050)

This oil and associated gas play is characterized by regional pinchouts of Permian-Pennsylvanian age eolian and marine sandstone into impermeable redbed claystones, siltstones, and shales. The updip limits of the play extend from south of the province boundary in Utah, north and east to the Axial uplift (fig. 20). The overall eastern (updip) limit of the play extends for more than 200 mi, and the downdip limit is at depths of about 12,000 ft where sandstones become impermeable.

Reservoir sandstones are eolian and marginal marine orthoquartzites varying in thickness from 10 ft to several hundred ft. Porosity ranges from about 11 percent to more than 15 percent. The source rocks are not specifically identified, but long-range migration of hydrocarbons into these blanket reservoirs is suggested. Likely source rocks are in the overlying marine Triassic Moenkopi Formation (central and south), Permian Phosphoria Formation (east and north), and possibly the Pennsylvanian Belden Shale (east) (fig. 16). Generation and migration of hydrocarbons probably occurred in Late Cretaceous time with some remigration in response to Laramide structure. The few known traps are both structural and stratigraphic, and undiscovered traps are expected to be similar in geometry. Seals are claystones, shales, siltstones, and (or) tight arkosic sandstones ranging in age from Triassic to Pennsylvanian. Drill depths range from about 8,000 ft to 12,000 ft.

The play is sparsely explored. One giant accumulation, the Rangely field, was discovered in 1933. The Permian-Pennsylvanian Weber Sandstone pool in the Rangely field (fig. 20) produces from a Laramide age thrust-faulted anticlinal trap that intersected a prior stratigraphic accumulation, and has an estimated ultimate recovery of about 850 MMBO. The Tar Sand Triangle of Utah is on the regional pinchout trend, just south of the province boundary (fig. 20). Here, 6 to 16 billion barrels of tar occur in a partially exposed, regional stratigraphic trap in the Cutler Formation (Permian White Rim Sandstone Member). Sandstones at both giant accumulations pinch out updip into tight red claystones, siltstones, and shales. Only three fields have been discovered in the play (within the province), Rangely, which has produced more than 730 MMBO and 700 BCFG (some gas is recycled), Ashley Valley field in northeast Utah (anticlinal-hydrodynamic trap) which has produced nearly 9 MMBO with minor gas from the Weber, and Wilson Creek field (anticline) which has produced noncommercial amounts of oil and gas from the Weber to date. The potential for the discovery of additional accumulations is fair to good; however, they will probably be of intermediate size.

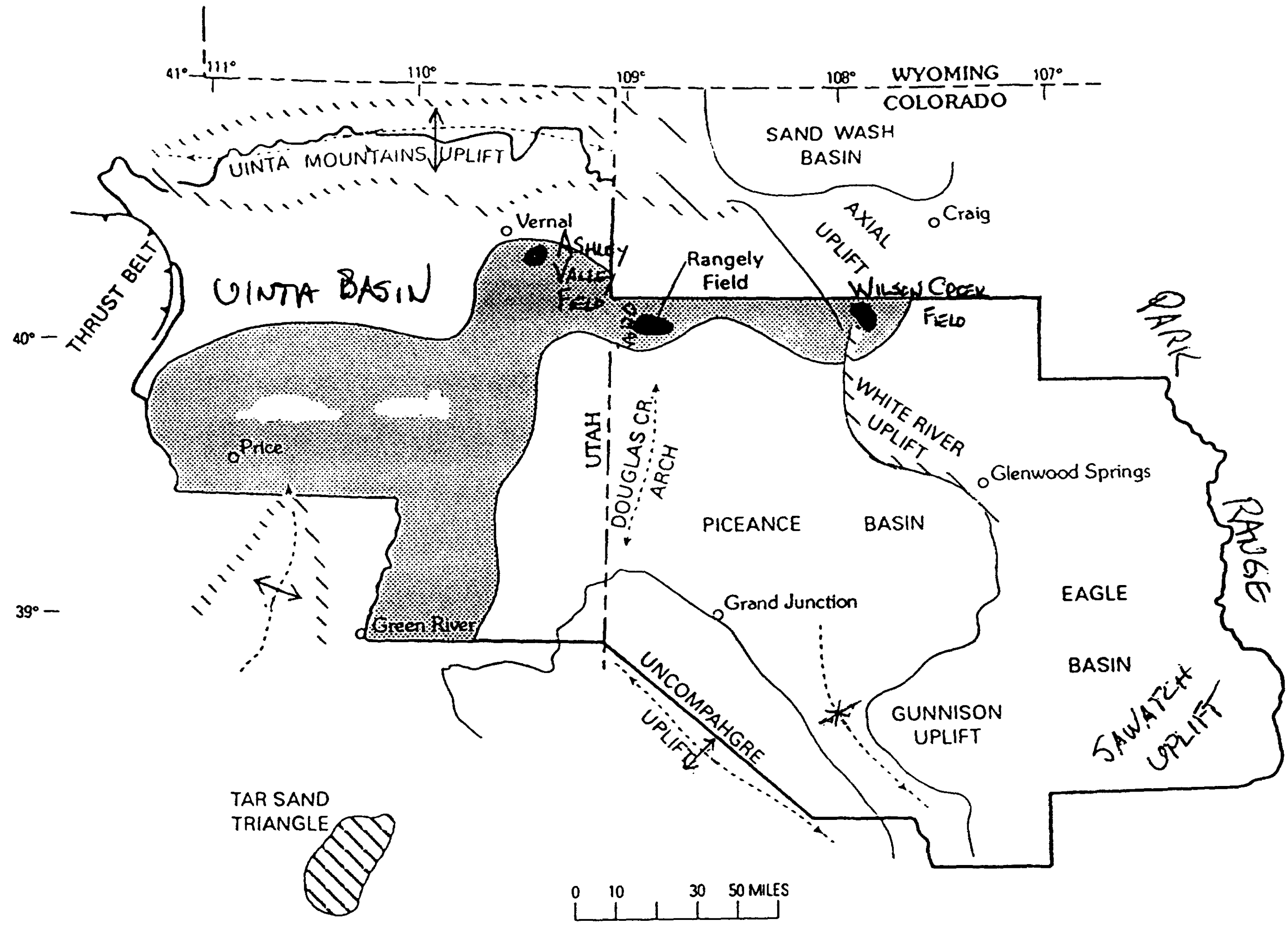


Figure 20. Map of Permian-Pennsylvanian play

OIL AND GAS PLAY DATA

PLAY **PERMIAN-PENNSYLVANIAN**
PROVINCE **UINTA-PICEANCE-EAGLE BASINS** CODE **03-086-050**

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) ($S \times T \times M \times R = MP$)	**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	
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**	**4**	**9**	**23**	**103**	**500**
Gas ($\times 10^{9}$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^{3}$ ft)							
Oil	**8**			**10**			**12**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**2**	**2**	**3**	**4**	**6**	**10**	**15**

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.

PARK BASINS PROVINCE (087)

By Edwin K. Maughan

INTRODUCTION

The province includes North, Middle, and South Parks, as well as the Blue River Valley, in north-central Colorado and covers an area of approximately 6,800 mi^2. These structurally complex parks comprise the Colorado Parks syncline, which is essentially a north-south elongated asymmetrical basin composed of mostly Cretaceous and lower Tertiary sedimentary rocks that lie above Precambrian crystalline rocks (fig. 21). Sedimentary units in the syncline are flanked by elevated and overthrust terrains of older Phanerozoic and the Precambrian rocks. North Park and Middle Park comprise a northern basin, but are separated geomorphically by the Neogene volcanic complex of the Rabbit Ears Range. South Park, which is genetically related, is a distinct basin within the southern part of the syncline that has been isolated on the north by Neogene uplift of Precambrian rocks, and is limited on the south by the Thirty-nine Mile Mountain volcanic complex. Exploration in the province has occurred over a period of about 75 years, resulting in the discovery of some 30 oil and gas fields of small size. Most of the produced gas has a high CO_2 content. One play was individually assessed in the province, the Mesozoic Structure play (020).

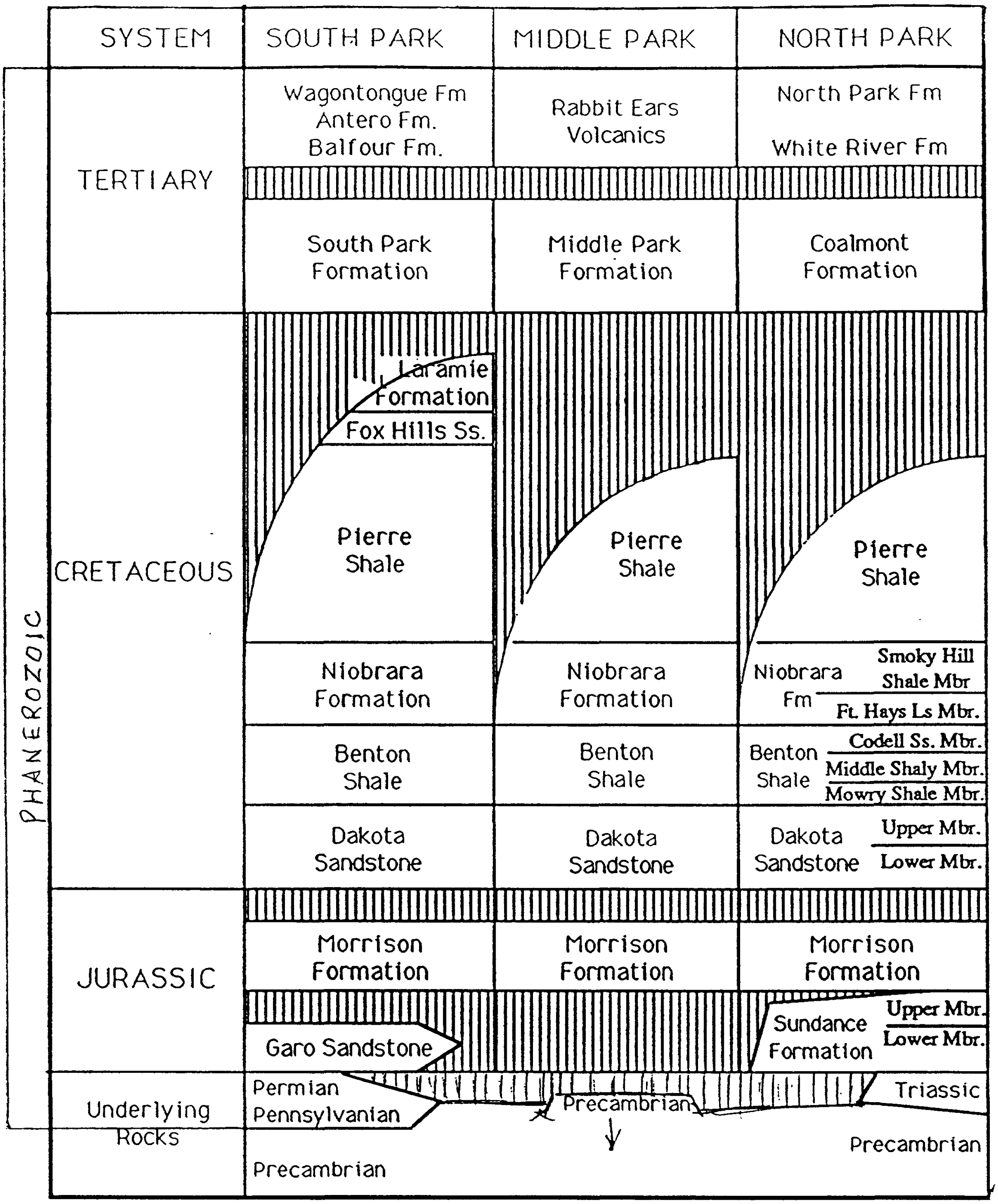


Figure 21. Generalized stratigraphic column, Park Basins province

MESOZOIC STRUCTURE PLAY (020)

The play is characterized by oil and gas accumulations in complex structural traps involving mainly Lower Cretaceous sandstone reservoirs in the North Park portion of the province. Minor production occurs in the Jurassic Sundance (Entrada Sandstone) Formation and shows are recorded in the Jurrasic Morrison Formation. The play area is approximately 3,350 mi^2 and boundaries include the Front Range on the east, Independence Mountain to the north, The Park Range on the west, and the Thirty-Nine Mile Mountains on the south (fig. 22). Maximum thickness of sedimentary rocks is about 9,000 ft, which range in age from Jurassic to Paleocene.

Known reservoir rocks include sandstones in the Dakota Sandstone, Codell Sandstone Member of the Benton Shale and the "B Sandstone" of the Pierre Shale. Highly fractured rocks in the Fort Hays Limestone Member of the Niobrara Formation produce oil at one field in the North Park area (fig. 21). Average reservoir thicknesses of major reservoirs range from 10 to 50 ft, and porosity and permeability values are fair to good.

Probable source rocks are organic-rich shales in the Cretaceous sequence. Sufficient depth of burial to achieve thermal maturation and generation of oil is estimated to have been reached at the end of the Cretaceous in those areas where overlying sediments had accumulated to a thickness of about 6,500 ft. Traps were formed at about the same time as catagenesis in the North Park area, but vitrinite reflectance values indicate that source rock maturation and oil migration occurred prior to the development of trapping structures in the South Park portion of the play.

Traps are developed in high-angle reverse faults and in associated anticlinal folds. Similar structures may be present beneath overthrust blocks marginal to and within the Parks syncline. Oil accumulations are limited at present to north-trending structures developed during the early stages of the Laramide orogeny. Seals are present throughout the Cretaceous shale section. Late Laramide structures were probably formed after major generation and migration of hydrocarbons. Drilling depths range from 1,500 to more than 10,000 ft.

Exploration began in 1912 in the North Park area, and the initial discovery of oil was in 1926 on the North McCallum anticline. The discovery was completed in the Dakota Sandstone for an unusual combination of 30 MCF of CO_2 and 500 barrels of condensate per day. High, late Tertiary heat flow, evidenced by thermal springs and intrusives at many localities, may have locally contributed to the high CO_2 mixture at the McCallum field (fig. 22). Through 1986 a total of 548 wildcat and development wells have been drilled, mostly in the 30 discovered fields and in areas immediately adjacent to these fields in the North Park portion of the play. Cumulative production from 23 fields in the play is 14.8 MMBO and cumulative gas production from 7 fields is 9.4 BCF. Cumulative CO_2 gas production from 6 fields is 1.33 BCF. Future potential for both oil and gas is minimal and future discoveries will probably be in small fields.

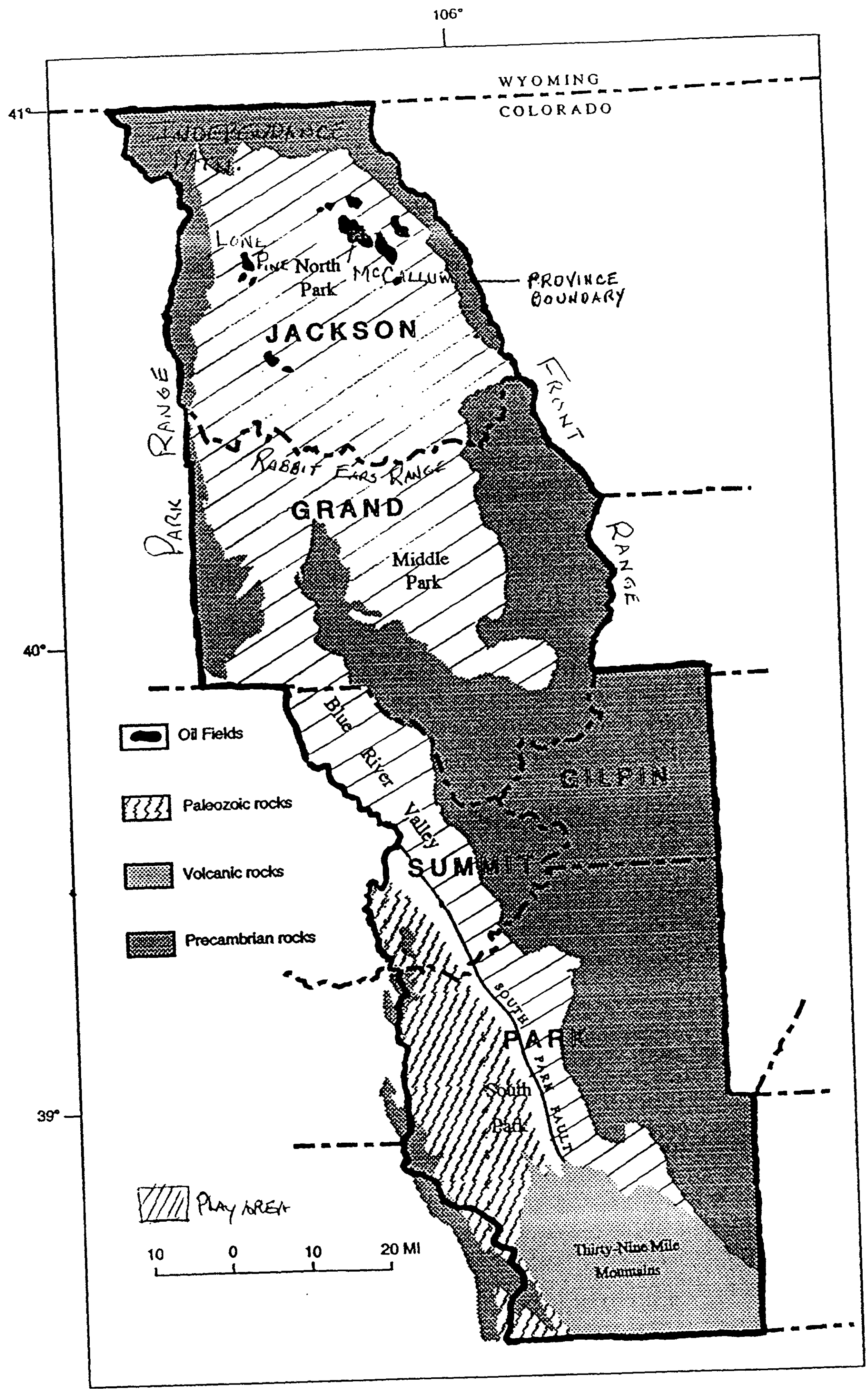


Figure 22. Map of Mesozoic Structure play

OIL AND GAS PLAY DATA

PLAY **MESOZOIC STRUCTURE**
PROVINCE **PARK BASINS** CODE **03-087-020**

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**	**1.03**	**1.4**	**2**	**3.4**	**9.2**	**26**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**1.5**			**7**			**15**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**1**	**1**	**2**	**2**	**3**	**5**	**6**

Average ratio of associated-dissolved gas to oil (GOR)	**1700**	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.

SAN JUAN BASIN PROVINCE (088)

By A. Curtis Huffman, Jr.

INTRODUCTION

The San Juan Basin province incorporates much of the area from 35° to 38° north latitude and from 106° to 109° west longitude and comprises all or parts of four counties in northwest New Mexico, and six counties in southwestern Colorado. It covers an area of about 22,000 mi^2.

Nearly all hydrocarbon production and available subsurface data are restricted to the topographic San Juan Basin. Also included in the province, but separated from the structural and topographic basin by the Hogback monocline and Archuleta arch are, respectively, the San Juan dome and Chama basin that contain sedimentary sequences similar to those of the San Juan Basin. Within much of the San Juan dome area the sedimentary section is covered by variable thicknesses of volcanic rocks surrounding numerous caldera structures. The stratigraphic section in the San Juan Basin (fig. 23) attains a maximum thickness of approximately 15,000 ft in the northeast part of the structural basin where the Upper Devonian Elbert Formation lies on Precambrian basement. Elsewhere in the province Cambrian, Mississippian, Pennsylvanian or Permian rocks may overlie the Precambrian.

Plays have been defined primarily on the basis of stratigraphy because of the strong stratigraphic controls on the occurrence of hydrocarbons throughout the province. In general, the plays correspond to lithostratigraphic units containing good quality reservoir rocks and with access to source beds. Several of the plays are combined into basinal and basin flank components based on both location and dominant trap type. In the central part of the basin, stratigraphy and hydrodynamic forces control nearly all production, while around the flanks both structure and stratigraphy are the key trapping factors. Although most Pennsylvanian age oil and gas is found on structures around the northwestern margin, it commonly accumulates only in highly porous biohermal limestone buildups. Jurassic oil on the southern margin of the basin is stratigraphically trapped in eolian dunes at the top of the Entrada Sandstone. Nearly all oil and gas in Upper Cretaceous sandstone plays (Dakota, Gallup, Mesaverde, Pictured Cliffs, and Fruitland-Kirtland plays) of the central basin is produced from stratigraphic traps. Around the flanks of the basin, some of the same Cretaceous units produce oil on many of the structures. Seven plays were defined and individually assessed in the province; Mesaverde (020), Fruitland-Kirtland (030), Pictured Cliffs (040), Tocito-Gallup (050), Dakota (060), Pennsylvanian (080) and Entrada (110).

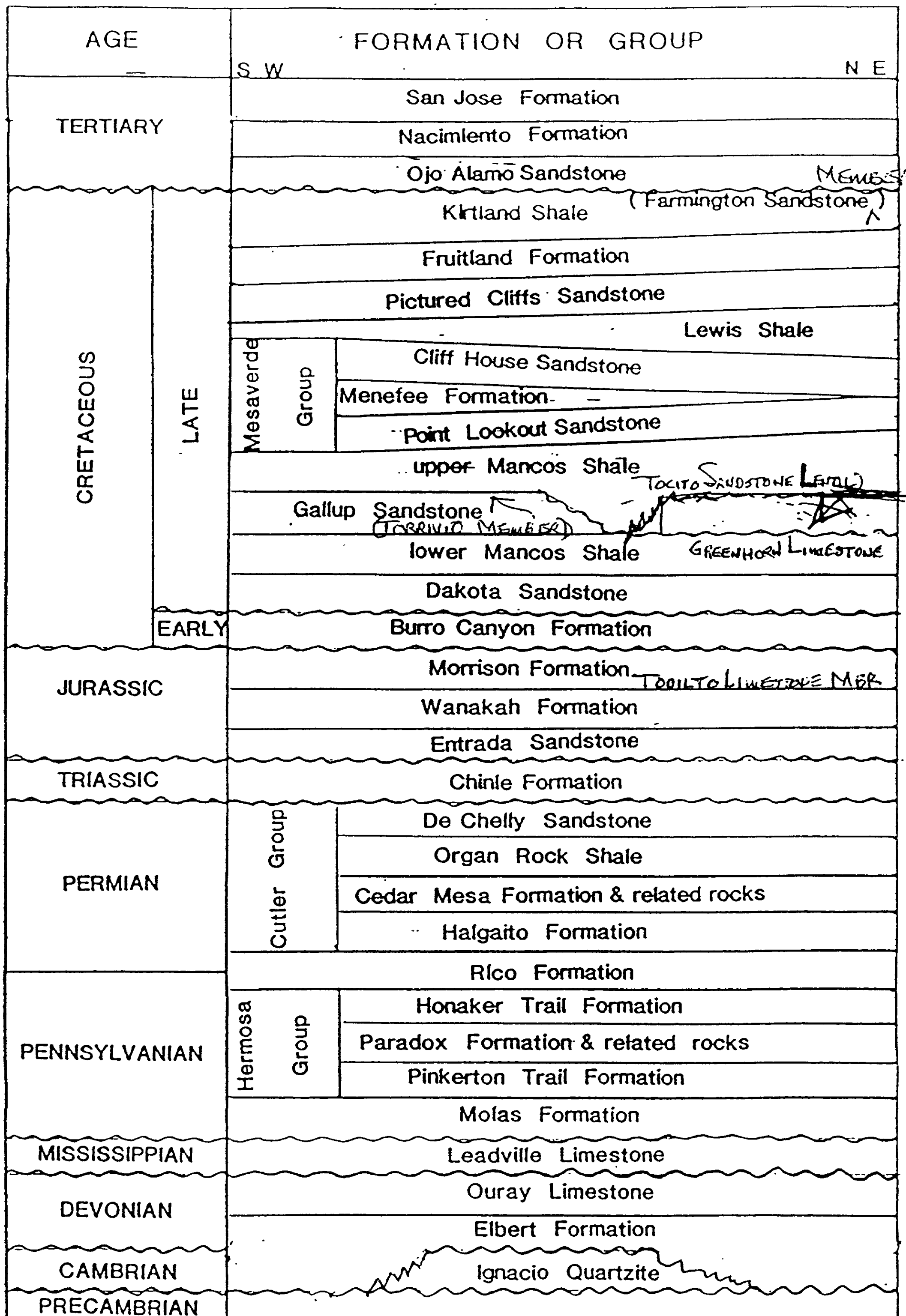


Figure 23. Generalized stratigraphic column, San Juan Basin province

MESAVERDE PLAY (020)

This is a gas and oil play in sandstone buildups associated with stratigraphic rises in the Upper Cretaceous Point Lookout and Cliff House Sandstones. It is a combined basinal gas play that is dominantly stratigraphic, and a basin flank oil and gas play that is both stratigraphic and structural (fig. 24). The major gas producing interval in the San Juan Basin, the Upper Cretaceous Mesaverde Group, comprises the regressive marine Point Lookout Sandstone, the nonmarine Menefee Formation, and the transgressive marine Cliff House Sandstone (fig. 23). Total thickness of the interval ranges from about 500 to 2,500 ft, of which 20 to 50 percent is sandstone. The Mesaverde interval is enclosed by marine shale, with the Mancos Shale lying beneath and the Lewis Shale lying above.

Principal gas reservoirs that are productive in the Mesaverde interval are the Point Lookout and Cliff House marine sandstones in addition to smaller amounts of dry, nonassociated gas from thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. Reservoir quality depends largely on the degree of fracturing. Together, the Blanco Mesaverde and Ignacio Blanco fields account for nearly half of the total nonassociated gas and condensate production from the San Juan Basin (fig. 24). Within these two fields, porosity averages about 10 percent and permeability about 2 millidarcies, with a total pay thickness range of 20 to 200 ft. Smaller Mesaverde fields have porosities ranging from 14 to 28 percent and permeabilities from 2 to 400 millidarcies, with 6 to 25 ft of pay thickness.

The chemical composition (C_1/C_{1-5}) of 0.99-0.79 and isotopic ($d^{13}C_1$) range of -33.4 to -46.7 per mil of the nonassociated gas suggest a mix of source rocks, including coal and carbonaceous shale in the Menefee Formation. Mesaverde oil is correlated with bitumen from the marine Mancos Shale and the API gravity of Mesaverde oil ranges from 37°to 50°. In the central part of the basin the Mancos Shale entered the oil generation window in the Eocene and the gas window in the Oligocene. The Menefee Formation also entered the gas generation window in the Oligocene. Because basin configuration was similar to that of today, updip migration would have been toward the south. Migration was impeded by hydrodynamic pressures directed toward the central basin, as well as by the deposition of authigenic swelling clays due to dewatering of Menefee coals.

Trapping mechanisms for the largest fields in the central part of the San Juan Basin are not well understood. Both of these fields, the Blanco Mesaverde and Ignacio Blanco, are thought to employ hydrodynamic forces to contain gas in structurally lower parts of the basin, but other factors such as cementation and swelling clays may also play a role. Production depths are most commonly from 4,000-5,300 ft. Updip pinchouts of marine sandstone into finer grained paludal or marine sediments account for nearly all of the stratigraphic traps with a shale or coal seal. Structural or combination structural-stratigraphic traps with similar seals have accounted for most of the small amount of oil production from the Mesaverde on the basin flanks.

The Blanco Mesaverde field discovery well was completed in 1927 and the Ignacio Blanco Mesaverde field discovery well was completed in 1952. Areally, these two closely adjacent fields cover more than 1,000,000 acres, encompass much of the central part of the San Juan Basin, and have produced nearly 7,000 BCFG and more than 30 MMB of condensate, which is approximately half of their estimated total recovery. Most of the recent gas discoveries range in areal size from 2,000 to 10,000 acres and have estimated total recoveries from 10 to 35 BCF. Mesaverde oil fields are generally small, covering less than 1,000 acres, and range in size from 300,000 to 400,000 BO. Future potential for both oil and gas is considered to be low.

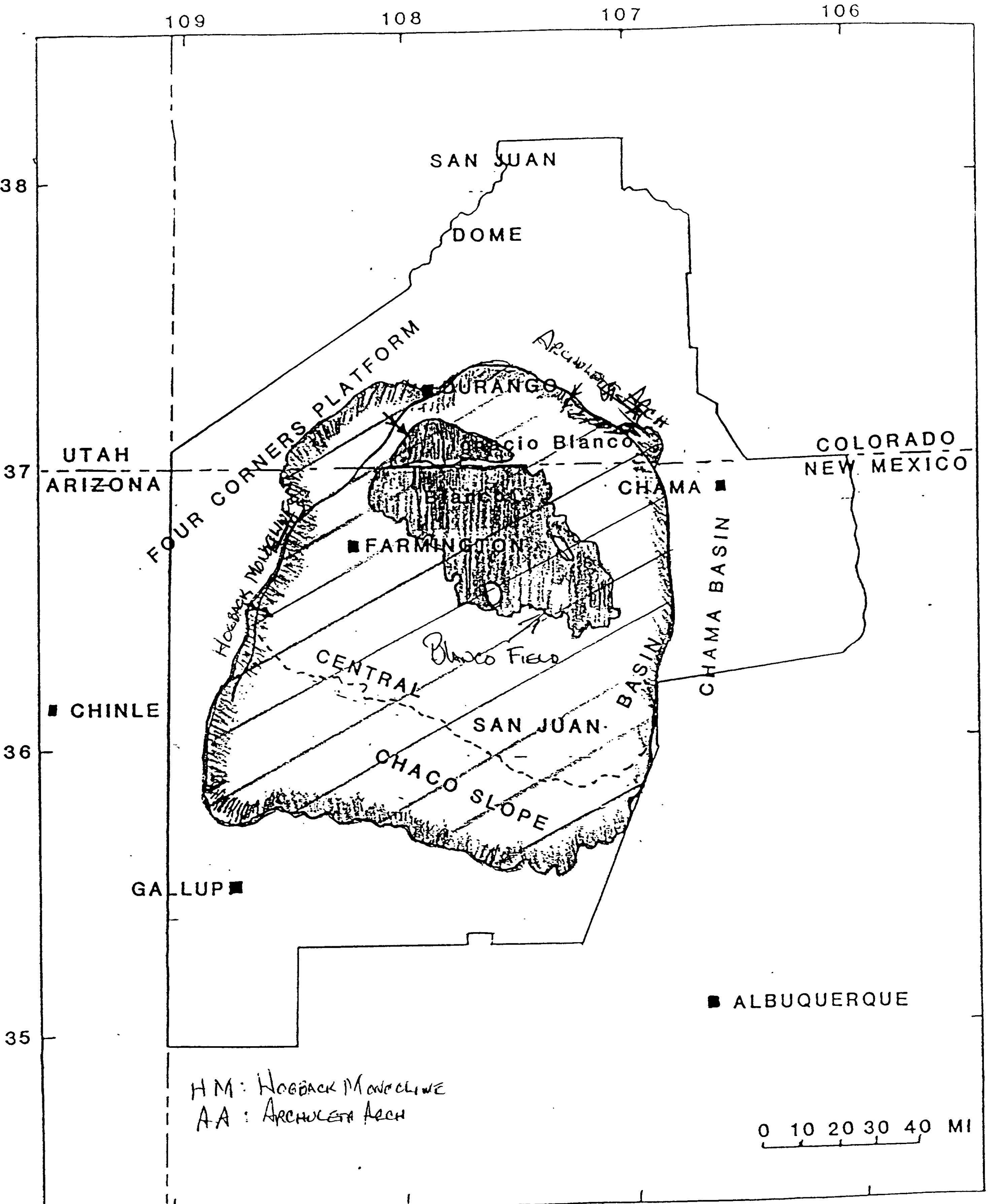


Figure 24. Map of Mesaverde play

OIL AND GAS PLAY DATA

PLAY **MESAVERDE**
PROVINCE **SAN JUAN BASIN** CODE **03-088-020**

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

Reservoir lithology	Probability of occurrence
Sandstone	**X**
Carbonate rocks	
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**	**1.03**	**1.2**	**1.5**	**2.5**	**10**	**30**
Gas (x 10^9 CFG)	**6**	**6.2**	**7.3**	**10**	**18**	**50**	**100**
Reservoir depth (x10^3 ft)							
Oil	**0.3**			**2**			**4**
Gas (non-associated)	**0.3**			**2**			**4**
Number of accumulations	**1**	**2**	**4**	**5**	**6**	**8**	**10**

Average ratio of associated-dissolved gas to oil (GOR)	**500**	CFG/BBL
Average ratio of NGL to non-associated gas	**4**	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.

FRUITLAND-KIRTLAND PLAY (030)

The play covers the central part of the basin (fig.25) and is characterized by gas production from stratigraphic traps in lenticular fluvial sandstone bodies enclosed in shale source rocks and/or coal. Production of coalbed methane from the lower part of the Fruitland has been known since the 1950's. The Fruitland and Kirtland are continental deposits with a maximum combined thickness of more than 2,000 ft. The Fruitland is composed of interbedded sandstone, siltstone, shale, carbonaceous shale, and coal. Sandstone occurs primarily in northerly trending channel deposits in the lower part of the unit. The lower part of the overlying Kirtland Shale is dominantly siltstone and shale, differing from the upper Fruitland mainly in the absence of carbonaceous shale and coal. The upper two-thirds or more of the Farmington Sandstone Member of the Kirtland Shale is composed of interbedded sandstone lenses and shale (fig. 23).

Reservoirs within the Fruitland-Kirtland are predominantly lenticular fluvial channel sandstone bodies, most of which are considered tight gas sands. They are commonly cemented with calcite and have an average porosity of 10-18 percent and low permeability (0.1 to 1.0 millidarcy). Pay thicknesses range from 15 to 50 ft. The Farmington Sandstone Member is typically fine grained with porosity ranges from 3 to 20 percent and permeability from 0.6 to 9 millidarcies. Pay thicknesses are generally in the 10 to 20 ft range.

The Fruitland-Kirtland interval produces nonassociated gas with very little condensate. It has a chemical composition (C_1/C_{1-5}) that ranges from 0.99 to 0.87 and isotopic ($d^{13}C_1$) compositions ranging from -43.5 to -38.5 per mil. Source rocks are thought to be primarily organic-rich nonmarine shales encasing sandstone bodies. In the northern part of the basin the Fruitland-Kirtland entered the oil window during the latest Eocene, and the wet gas window probably during the Oligocene. Migration of hydrocarbons updip through fluvial channel sandstones is suggested by the occurrence of gas production from immature reservoirs, and by the areal distribution of production from the Fruitland.

The discontinuous lenticular channel sandstone bodies that form the reservoirs in both the Fruitland and Kirtland intertongue with overbank mudstone and shale and with paludal coals and carbonaceous shale in the lower part of the Fruitland. Although some producing fields are located on structures, the actual traps are predominantly stratigraphic, occurring at updip pinchouts of sandstone into the fine-grained sediments that form the seals. Most production is from depths of 1,500 to 2,700 ft. Production from the Farmington Sandstone Member occurs between 1,100 to 2,300 ft.

The first commercially produced gas in New Mexico was discovered in 1921 in the Farmington Sandstone Member at a depth of 900 ft in what later became part of the Aztec field (fig. 25). Areal field sizes range from 160 to 32,000 acres, with nearly 50 percent of the fields in the 1,000 to 3,000 acre size. The near linear northeasterly alignment of fields along the western side of the basin suggests a paleo-fluvial channel system of northeasterly flowing streams. Similar channel systems may be present in other parts of the basin and are likely to contain similar amounts of hydrocarbons. Future potential for gas is good and undiscovered fields will probably be in the 2 to 5 mi^2 size range at depths between 1,000 and 3,000 ft. Because most of the large structures have probably been tested, future gas resources will probably occur in updip stratigraphic pinchout traps of channel sandstone into coal or shale in traps of moderate size.

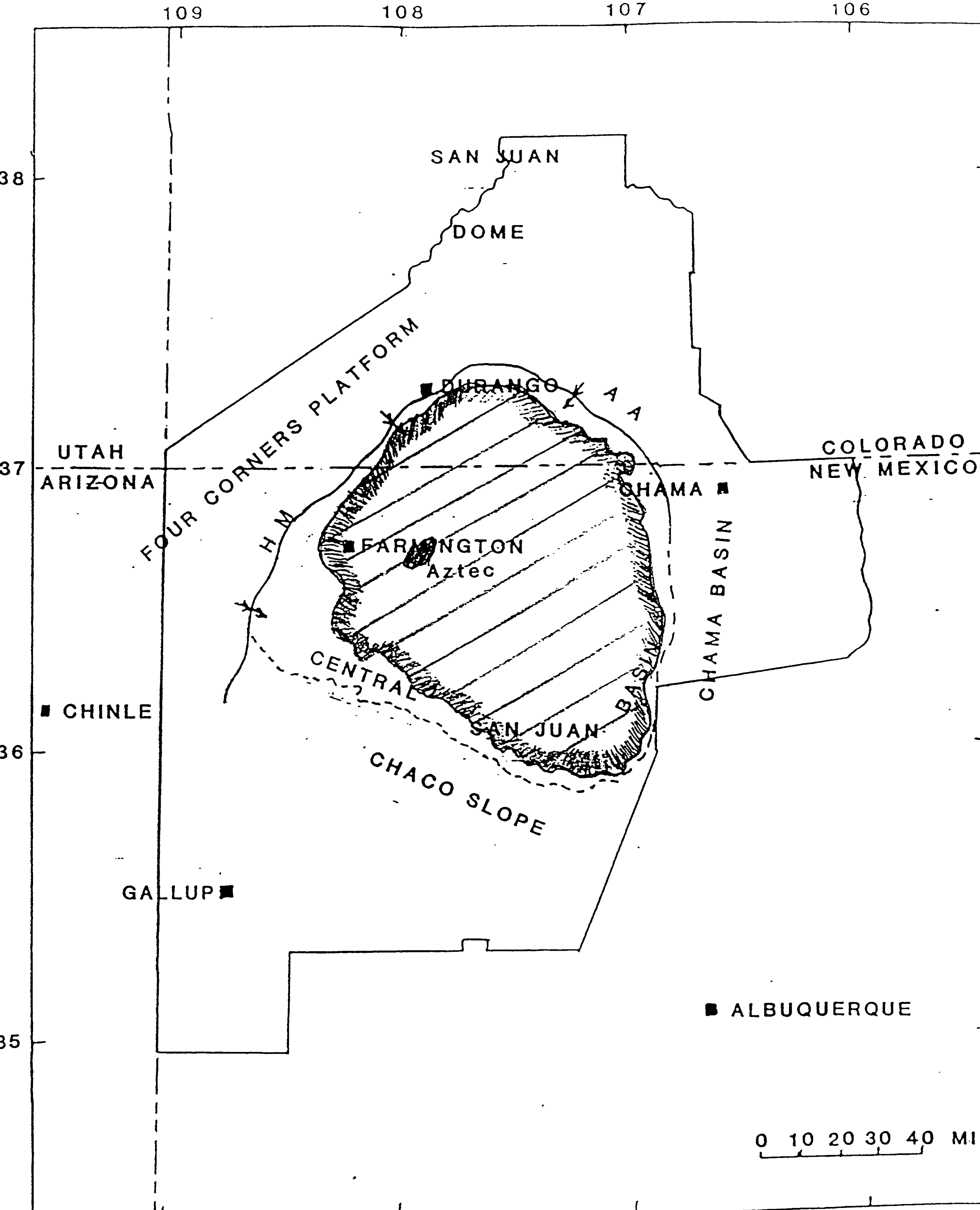


Figure 25. Map of Fruitland-Kirtland play

OIL AND GAS PLAY DATA

PLAY **FRUITLAND-KIRTLAND**
PROVINCE **SAN JUAN BASIN** CODE **03-088-030**

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**
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**	**6.8**	**10.5**	**18**	**33**	**76**	**120**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**6**	**8**	**9**	**10**	**12**	**15**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**0.2**	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.

PICTURED CLIFFS PLAY (040)

The play is defined primarily by gas production from stratigraphic traps in sandstone reservoirs enclosed in shale or coal at the top of the Pictured Cliffs unit, and is confined to the central part of the basin (fig. 26). Still stands, or brief reversals in the regression of the Cretaceous sea to the northeast, produced thicker shoreline sandstones which have been the most productive. The Pictured Cliffs is the uppermost regressive marine sandstone in the San Juan Basin (fig. 23). It ranges in thickness from 0-400 ft and is conformable with both the marine Lewis Shale beneath and the overlying nonmarine Fruitland Formation.

Reservoir quality is determined to a large extent by the abundance of authigenic clay. Cementing material averages 60 percent calcite, 30 percent clay, and 10 percent silica. Average porosity is about 15 percent and permeability averages 5.5 millidarcies, although many field reservoirs are less than 1 millidarcy. Pay thicknesses range from 5-150 ft but are typically less than 40 ft. Reservoir quality improves southward from the deepest parts of the basin due to secondary diagenetic effects.

The source of gas was probably marine shales of the underlying Lewis Shale and nonmarine shales of the Fruitland Formation. The gas is nonassociated with very little condensate (0.006 gal/mcf). It has a chemical composition (C1/C1-5) of 0.85-0.95 and an isotopic ($d^{13}C1$) range of -43.5 to -38.5 per mil. Gas generation was probably at a maximum during the late Oligocene and the Miocene. Updip gas migration would have been predominantly toward the southwest because the basin configuration was similar to that of today.

Stratigraphic traps resulting from landward pinchout of nearshore and foreshore marine sandstone bodies into finer grained silty, shaly, and coaly facies of the Fruitland Formation (especially in the areas of stratigraphic rises) contain most of the hydrocarbons. Seals are formed by finer grained back-beach and paludal sediments into which marine sandstone intertongues throughout most of the central part of the basin. The Pictured Cliffs is sealed off from any connection with other underlying Upper Cretaceous reservoirs by the Lewis Shale. The Pictured Cliffs unit crops out around the perimeter of the central part of the San Juan Basin and reaches depths of about 4,300 ft. Most production has been from depths of 1,000 to 3,000 ft.

Gas was discovered in the play in 1927 at the Blanco and Fulcher Kutz fields (fig. 26) of northwest New Mexico. Most Pictured Cliffs fields were discovered before 1954, with only 9 relatively small fields coming into production since then. Discoveries since 1954 have averaged about 11 BCFG, estimated ultimate recovery. A large quantity of gas is held in tight sandstone reservoirs north of the currently producing areas. Stratigraphic traps and excellent source rocks exist in the deeper parts of the basin, but low permeabilities due to authigenic illite-smectite clay have so far limited production. Future conventional gas potential is very good.

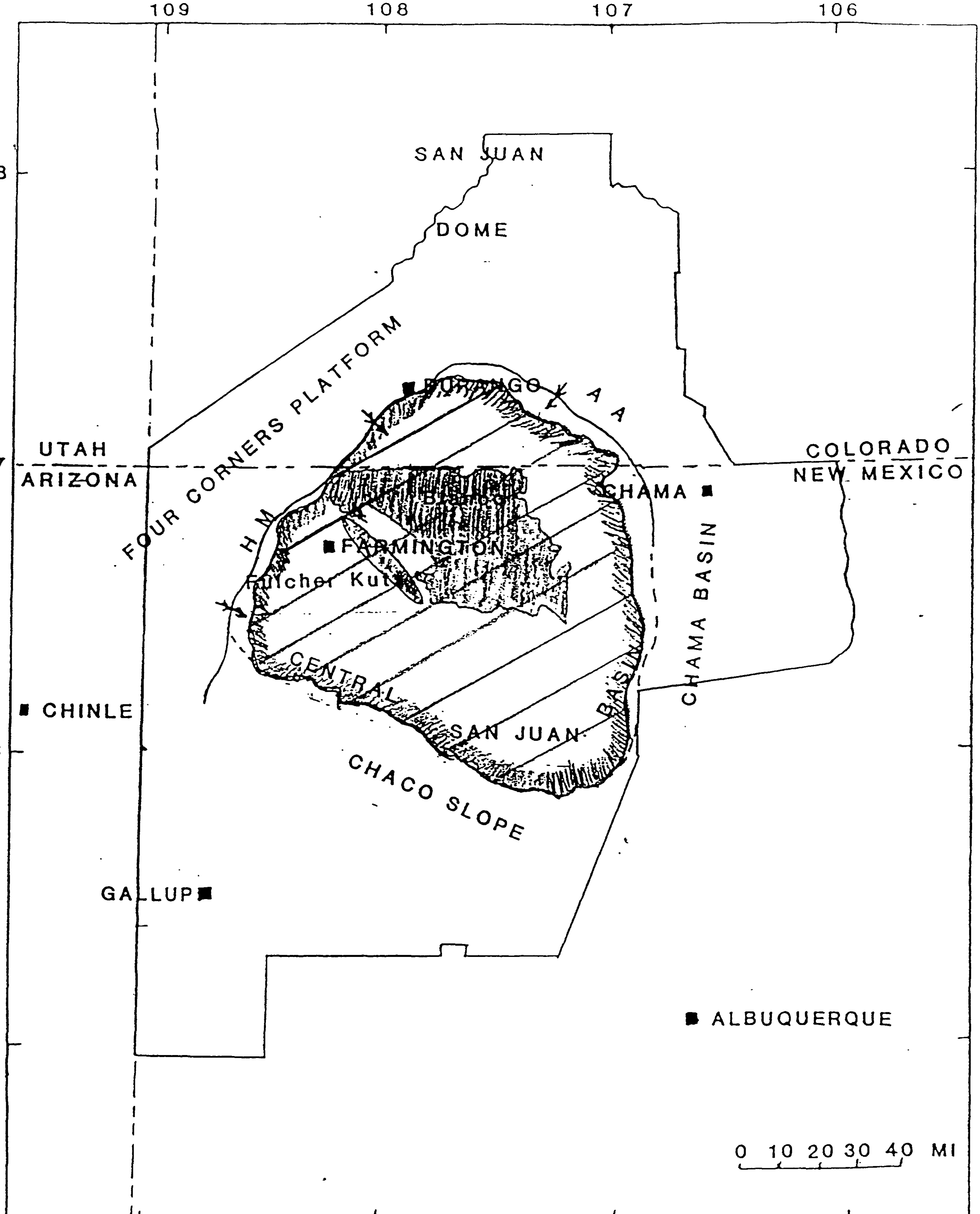


Figure 26. Map of Pictured Cliffs play

OIL AND GAS PLAY DATA

PLAY **PICTURED CLIFFS**
PROVINCE **SAN JUAN BASIN** CODE **03-088-040**

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	
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)	**1000**	**1100**	**1200**	**1300**	**1400**	**1600**	**2000**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**1**			**3**			**4.5**
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	**0.2**	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.

TOCITO-GALLUP PLAY (050)

This is an oil and associated gas play in bar-like sandstone bodies of Upper Cretaceous Tocito sandstones associated with Mancos Shale source rocks lying immediately above an unconformity. The play covers the entire area of the province (fig. 27). Most of the producing fields are stratigraphic traps along a NW-SE trending belt near the southern margin of the central San Juan Basin. As used here, the Gallup interval extends essentially from the top of the Bridge Creek Limestone Member (formerly Greenhorn limestone Member), to the base of the Mesaverde Group (fig. 23). Overall thickness of the Gallup interval is about 1,500 to 2,000 ft and the lithology is dominantly dark gray marine shale. With the exception of several fields producing from fractured Mancos Shale, nearly all production from this thick and rather nebulous interval has been more specifically from the Tocito Sandstone Lentil of the Mancos Shale and the Torrivio Member of the Gallup Sandstone.

The Tocito Sandstone Lentil of the Mancos Shale is the major oil producing reservoir in the San Juan Basin. The name is applied to a number of lenticular sandstone bodies, commonly less than 50 ft thick, that lie on or just above an unconformity, and are of undetermined origin. Reservoir porosities in producing fields range from 4 to 20 percent and average about 15 percent. Permeabilities range from 0.5 to 150 millidarcies with 50 to 100 millidarcies being most typical.

The only significant production from the regressive Gallup Sandstone is from the Torrivio Member, a lenticular fluvial channel sandstone lying above and in some places scouring into the top of the main marine Gallup Sandstone. Hospah and Hospah South (fig. 27), the largest fields developed in the regressive Gallup, are combination stratigraphic and structural traps. Nearly all Gallup production is from stratigraphic traps at depths between 1,500 and 5,500 ft. The Tocito bar-like sandstone bodies are sealed, encased in and intertongue with the marine Mancos Shale. Similarly, the fluvial channel Torrivio Member of the Gallup is encased in and intertongues with finer grained, organic-rich coastal plain shales.

Source beds for Gallup oil have been identified as the marine Upper Cretaceous Mancos Shale. The Mancos contains 1-3 weight percent organic carbon and produces a sweet, low-sulfur, paraffin-base oil that ranges from 38° to 43° API gravity in the Tocito fields, and from 24° to 32°API gravity farther south in the Hospah and Hospah South fields. The upper Mancos Shale of the central part of the San Juan Basin entered the oil generation window in the late Eocene and the gas window in the Oligocene. Migration updip to reservoirs in the Tocito Sandstone Lentil and regressive Gallup followed pathways similar to those determined by present structure since basin configuration has changed little over time.

Initial Gallup field discoveries were made in the mid 1920's. The major discoveries, however, were not made until the late 1950's and early 1960's in the deeper Tocito fields, the largest of which, Bisti (fig. 27), covers 37,500 acres and has estimated total ultimate recovery of 51 MMBO. Gallup producing fields are typically 1,000 to 10,000 acres in area with 15 to 30 ft of pay. About one-third of these fields have an estimated cummulative production exceeding one MMBO and one BCF of associated gas. All of the larger fields produce from the Tocito Sandstone Lentil of the Mancos Shale and are stratigraphically controlled. South of the zone of bar-like sandstone buildups of the Tocito, the regressive Gallup Sandstone produces primarily from the fluvial channel sandstone of the Torrivio Member. The only large field producing from the Torrivio is the Hospah field, which is primarily a structural trap. Similar, undiscovered traps of small size may exist in the southern half of the basin. The future potential for oil and gas is low to moderate.

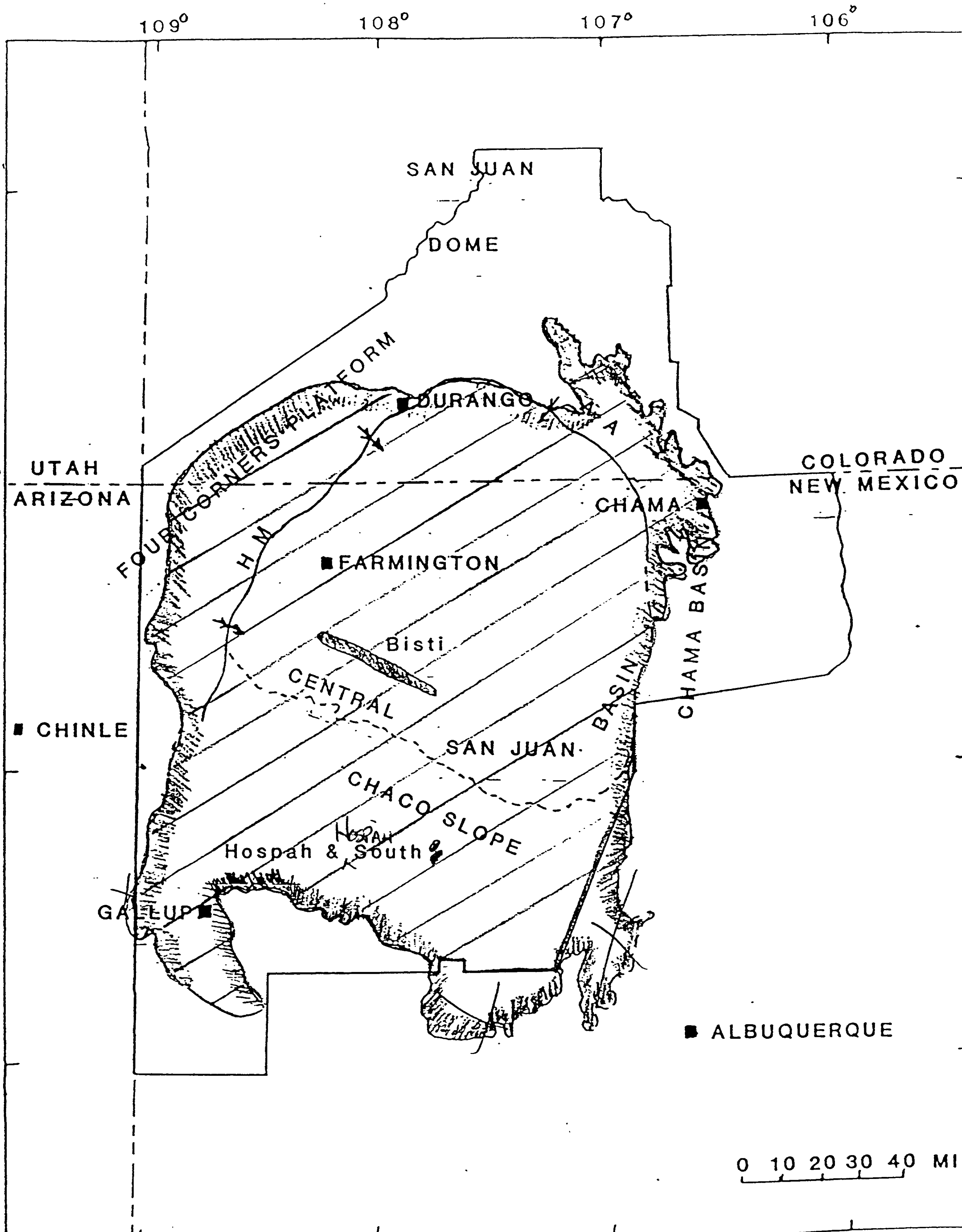


Figure 27. Map of Tocito-Gallup play

OIL AND GAS PLAY DATA

PLAY TOCITO-GALLUP
PROVINCE SAN JUAN BASIN CODE **03-088-050**

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	
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**	**1.3**	**2**	**4.5**	**10**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**0.1**			**3**			**6**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**2**	**3**	**4**	**5**	**6**	**8**	**10**

Average ratio of associated-dissolved gas to oil (GOR)	**5000**	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 PLAY (060)

The play is contained in coastal marine barrier-bar sandstone and continental fluvial sandstone units, primarily within the transgressive Dakota Sandstone, and is a combined basinal stratigraphic and basin flank play, the latter being both stratigraphic and structural. The Dakota producing interval in the play is not confined to only the Dakota Sandstone. The top of the interval is at the base of the Greenhorn Limestone, extending downward a vertical length of about 400 ft and includes, in many places, uppermost sandstones and shales of the underlying lower Cretaceous Burro Canyon Formation, or upper Jurassic Morrison Formation. The play area covers nearly two-thirds of the province (fig. 28).

Reservoir quality within the Dakota producing interval is highly variable. Most of the marine sandstone reservoirs within the Basin field (fig. 28) are considered "tight", with porosities ranging from 5 to 15 percent and permeabilities from 0.1 to 0.25 millidarcies. Fracturing, both natural and induced, is essential for effective field development. In contrast, the Lone Pine field (fig. 28) at the southern basin flank has an average porosity of 20 percent and a permeability range from about 80 to 150 millidarices. Permeabilities elsewhere may be as high as 400 millidarcies.

Source beds for oil and gas are also variable. Nonassociated gas in the Dakota pool of the Basin field was generated during late mature and post-mature stages, and probably had a marine Mancos Shale source. Oil produced from the Dakota on the southern basin flank has a marine Mancos Shale source. Oil produced from the Dakota on the Four Corners Platform originated from nonmarine Cretaceous source rocks of the Lewis-Mesaverde interval. Although these latter source beds are nearly 4,000 ft stratigraphically above the Dakota, they are brought into nearly the same structural position across the Hogback monocline (HM) (fig. 28).

In the northern part of the central San Juan Basin the Dakota Sandstone and Mancos Shale entered the oil generation window in the Eocene and were elevated to temperatures appropriate for the generation of dry gas by the late Oligocene. Along the southern margin of the central basin the Dakota and lower Mancos entered the oil generation window during the Late Miocene. It is not known at what point hydrodynamic forces reached sufficient strength to act as a trapping mechanism, but early Miocene time would seem a reasonable estimate for the establishment of the present-day uplift and erosion pattern throughout most of the basin. Migration of oil in the Dakota was still taking place in the late Miocene, or even more recently, in the southern part of the San Juan Basin.

The Dakota gas accumulation in the Basin field occurs on the flanks and bottom of a large depression and is not localized by structural trapping. The fluid transmissibility characteristics of Dakota sandstones is generally consistent from the central basin to the outcrop. Hydrodynamic forces, acting in a basinward direction, have been suggested as the trapping mechanism, but these forces are still poorly understood. Most oil production from Dakota fields is in structural or combination traps on the basin flanks; some fields are located on faulted anticlinal structures. The seal is commonly provided by either marine shale or paludal carbonaceous shale and coal. Production is found at depths ranging from 6,500-7,500 ft.

The Dakota discovery well in the central basin was drilled in 1947 southeast of Farmington, New Mexico (fig. 28) and the Basin field, containing the Dakota gas pool, was formed February 1, 1961 by combining several existing fields. By the end of 1986 it had produced over 4.0 TCFG of gas and 38 MMB of condensate. Approximately 30 percent of the basin flank oil fields have an estimated total production exceeding 1 MMBO with the largest, Price Gramps, (fig. 28) estimated to have produced just over 7 MMBO. About 15 BCF of associated gas has been produced through 1986. Field depths in this part of the play commonly range from 1,000 to 3,000 ft. Nearly all of the Dakota interval in the central part of the basin is saturated with gas, and additional, future gas discoveries within the Basin field and around its margins appear probable. The future potential for undiscovered oil in combination traps around the margins of the central basin is moderate.

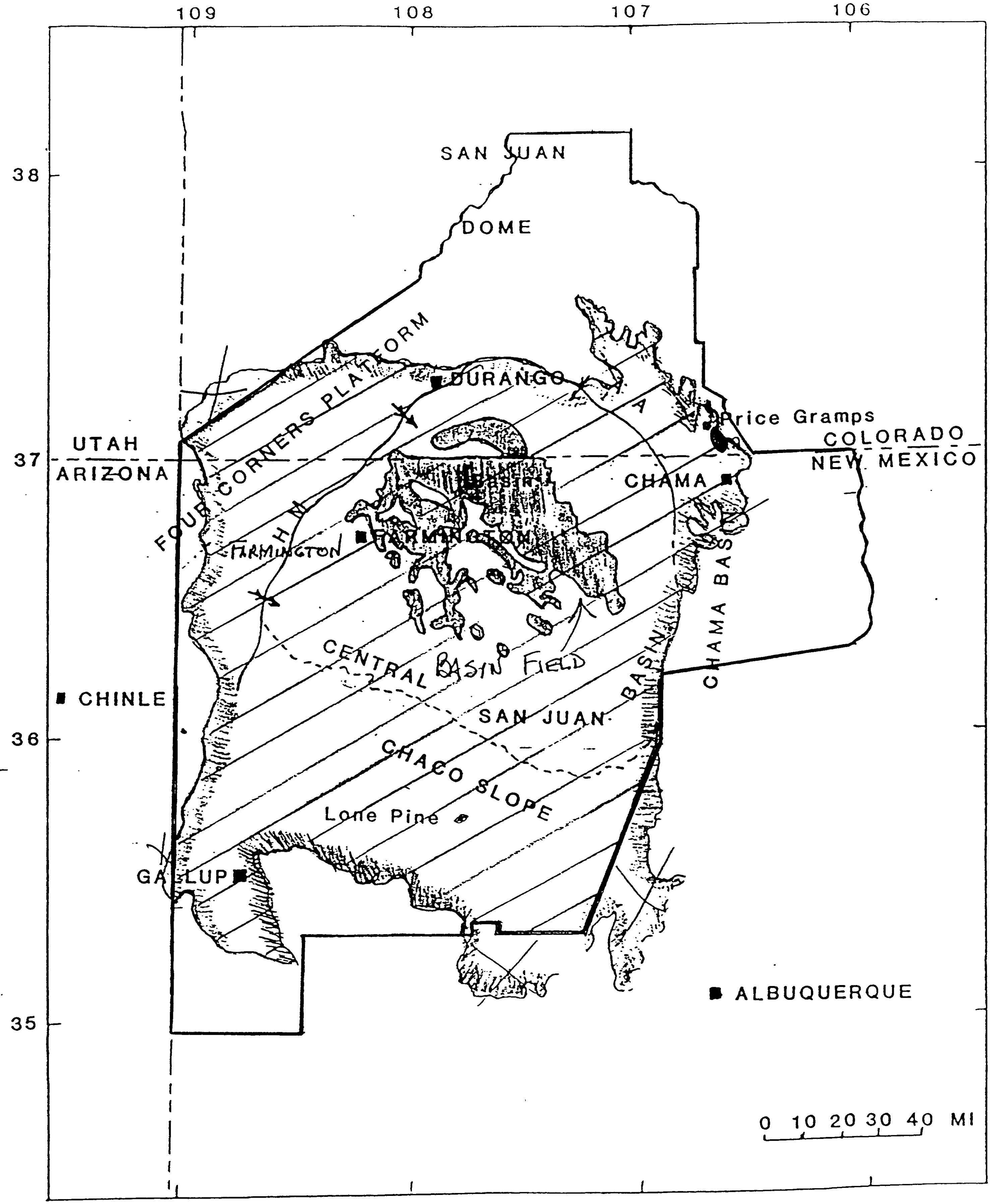


Figure 28. Map of Dakota Play

OIL AND GAS PLAY DATA

PLAY **DAKOTA**
PROVINCE **SAN JUAN BASIN** CODE **03-088-060**

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 ($\times 10^6$ BBL)	**1**	**1.03**	**1.17**	**1.5**	**2.5**	**8**	**20**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**2**			**4.5**			**7.5**
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)	**1000**	CFG/BBL
Average ratio of NGL to non-associated gas	**30**	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.

PENNSYLVANIAN PLAY (080)

This is primarily a gas play and is characterized by oil and gas accumulations in mounds of algal (Ivanovia) limestone associated with organic-rich black shale rimming the evaporite sequences of the Paradox Formation of the Hermosa Group (fig. 23). Most of the developed fields within the play produce from combination traps on the Four Corners platform (fig. 29), but for this analysis, the play has been extended southeast to the limit of the black shale facies, roughly corresponding to the limit of the central basin.

Nearly all hydrocarbon production has been from vuggy limestone and dolomite reservoirs in 5 zones of the Paradox Formation. In ascending order, these informal zones (related rocks) are the Alkali Gulch, Barker Creek, Akah, Desert Creek, and Ismay (fig. 23). The zones gradually become less distinct toward the central part of the San Juan Basin. Net pay thicknesses generally vary from 10-50 feet with porosities of 5-20 percent.

Source beds for Pennsylvanian oil and gas are believed to be organic-rich shales and laterally equivalent carbonates within the Paradox Formation. The presence of hydrogen sulfide (H_2S) and appreciable amounts of CO_2 at Barker Creek and Ute Dome fields (fig. 29) probably indicates high temperature decomposition of carbonates. Correlation of black shale units of the Paradox Formation with prodelta facies in clastic cycles which are present in a proposed fan delta complex on the northeastern edge of the Paradox evaporite basin helps to account for the high percentage of kerogen from terrestrial plant material in the black shale source rocks. In the central part of the San Juan Basin, Pennsylvanian sediments entered the oil generation window during the Late Cretaceous to Paleocene, and the dry gas window during the Eocene to Oligocene. It also seems probable that Pennsylvanian source rocks would have entered the oil window during the Oligocene throughout most of the Four Corners Platform. Updip migration and local migration from laterally equivalent carbonates and shale beds in areas of favorable reservoir beds predominate, with possible remigration occurring in areas of faulting and fracturing.

Combination stratigraphic and structural trapping mechanisms are dominant among Pennsylvanian fields of the San Juan Basin and Four Corners platform. Most fields are located on structures, although not all of these demonstrate closure. The structures themselves may have been a critical factor in the deposition of bioclastic limestone reservoir rocks. Seals are provided by a variety of mechanisms including porosity differences in the reservoir rock, overlying evaporites, and interbedded shale. Most production on the Four Corners platform ranges in depth from 5,100 to 8,500 ft, but minor production and shows in the central part of the San Juan Basin occur as deep as 11,000 ft.

Field sizes in the play vary considerably, with most oil discoveries in the 100 to 1 MMBO size range and include associated gas production. The largest, Tocito Dome and Tocito Dome North (fig. 29), have produced a total of about 13 MMBO and 26 BCFG. Eight significant nonassociated and associated gas fields have been developed in the play, the largest of which, Barker Creek, has produced 205 BCFG. The Pennsylvanian is basically a gas play with a moderate future potential for medium-size fields.

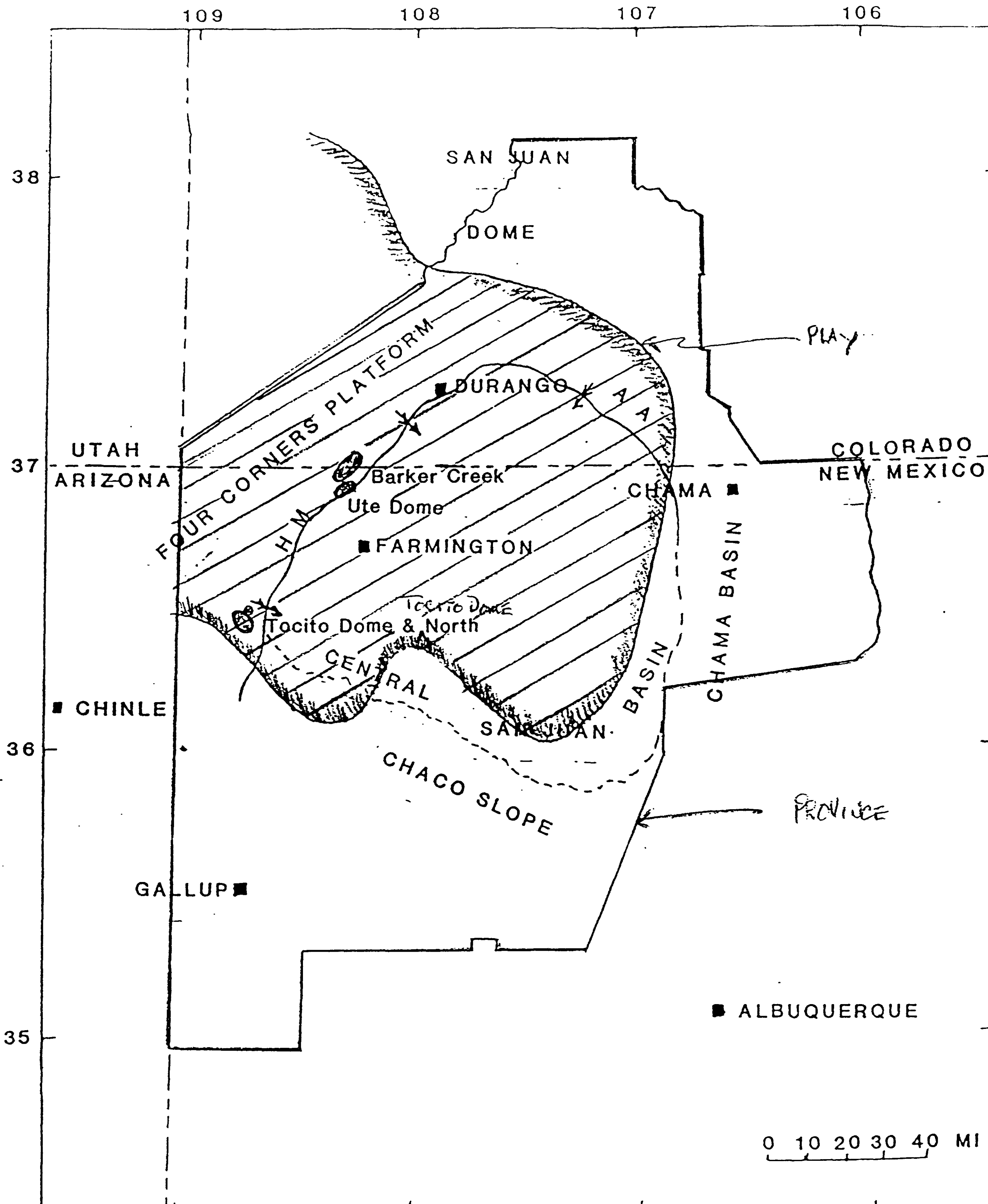


Figure 29. Map of Pennsylvanian play

OIL AND GAS PLAY DATA

PLAY **PENNSYLVANIAN**
PROVINCE **SAN JUAN BASIN** CODE **03-088-080**

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

	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)	**6**	**6.2**	**7.5**	**10**	**16**	**30**	**50**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**9**			**11.5**			**14**
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	**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.

ENTRADA PLAY (110)

The Entrada play is associated with relict dune topography on top of the eolian Middle Jurassic Entrada Sandstone in the southeastern part of the San Juan Basin (fig. 30), and is based on the presence of organic-rich limestone source rocks and anhydrite of the overlying Todilto Limestone Member of the Wanakah Formation. North of the present producing area, in the deeper, northeastern part of the San Juan Basin, porosity in the Entrada diminishes rapidly. Compaction and silica cement make the Entrada very tight below a depth of 9,000 ft. No eolian sandstone buildups have been found south and west of the producing area.

Some of the relict dunes are as thick as 100 ft but have flanks that dip at only 2 degrees. Dune reservoirs are composed of fine-grained, well-sorted sandstone, massive or horizontally bedded in the upper part, and thinly laminated, with steeply dipping crossbedding in the lower part. Porosity (23 percent average) and permeability (370 millidarcies average) are very good throughout. Average net pay in developed fields is 23 ft.

Limestone in the Todilto Limestone Member (fig. 23) has been identified as the source of Entrada oil. There is a reported correlation between the presence of organic material in the Todilto Limestone and the presence of the overlying Todilto anhydrite. This association limits the source rock potential of the Todilto to the deeper parts of the depositional basin in the eastern San Juan Basin. Elsewhere, the limestone was oxygenated during deposition and much of the organic material destroyed. Maximum depth of burial throughout most of the San Juan Basin occurred during the Oligocene. In the eastern part of the basin the Todilto entered the oil generation window during the Oligocene. Migration into Entrada reservoirs either locally or updip to the south probably occurred almost immediately. However, in some fields, remigration of the original accumulations has occurred subsequent to original emplacement.

All traps so far discovered in the Entrada are stratigraphic and are sealed by the Todilto limestone and anhydrite. Local faulting and drape over deep-seated faults has enhanced, modified, or destroyed the potential closures of the Entrada sand ridges. Hydrodynamic tilting of oil/water contacts and/or "base of movable oil" interfaces has had a destructive influence on the oil accumulations because the direction of tilt typically has an updip component. All fields developed to date have been at depths of 5,000 to 6,000 ft. Because of increasing cementation, the maximum depth at which suitable reservoir quality can be found is estimated to be at approximately 9,000 ft.

The initial Entrada discovery, the Media field (fig. 30), was made in 1953. Development was inhibited by problems of high water cut and high pour point of the oil, problems common to all subsequent Entrada field development. Between 1972 and 1977, seven fields similar to Media were discovered, primarily though seismic techniques. Areal sizes of fields range from 100 to 400 acres, with total estimated production varying from between 150,000 BBLS and 2 MMBO each. A number of areas of anomalously thick Entrada in the southeastern part of the San Juan Basin have yet to be tested. There is a good probability that at least a few of these areas of thick Entrada might have adequate trapping conditions for undiscovered oil accumulations, but with similar development problems as the present fields. Limiting factors to the moderate future oil potential of the play include the presence of sufficient paleo-topographic relief on top of the Entrada, local structural conditions, hydrodynamics, source-rock and oil migration history, and local porosity and permeability variations.

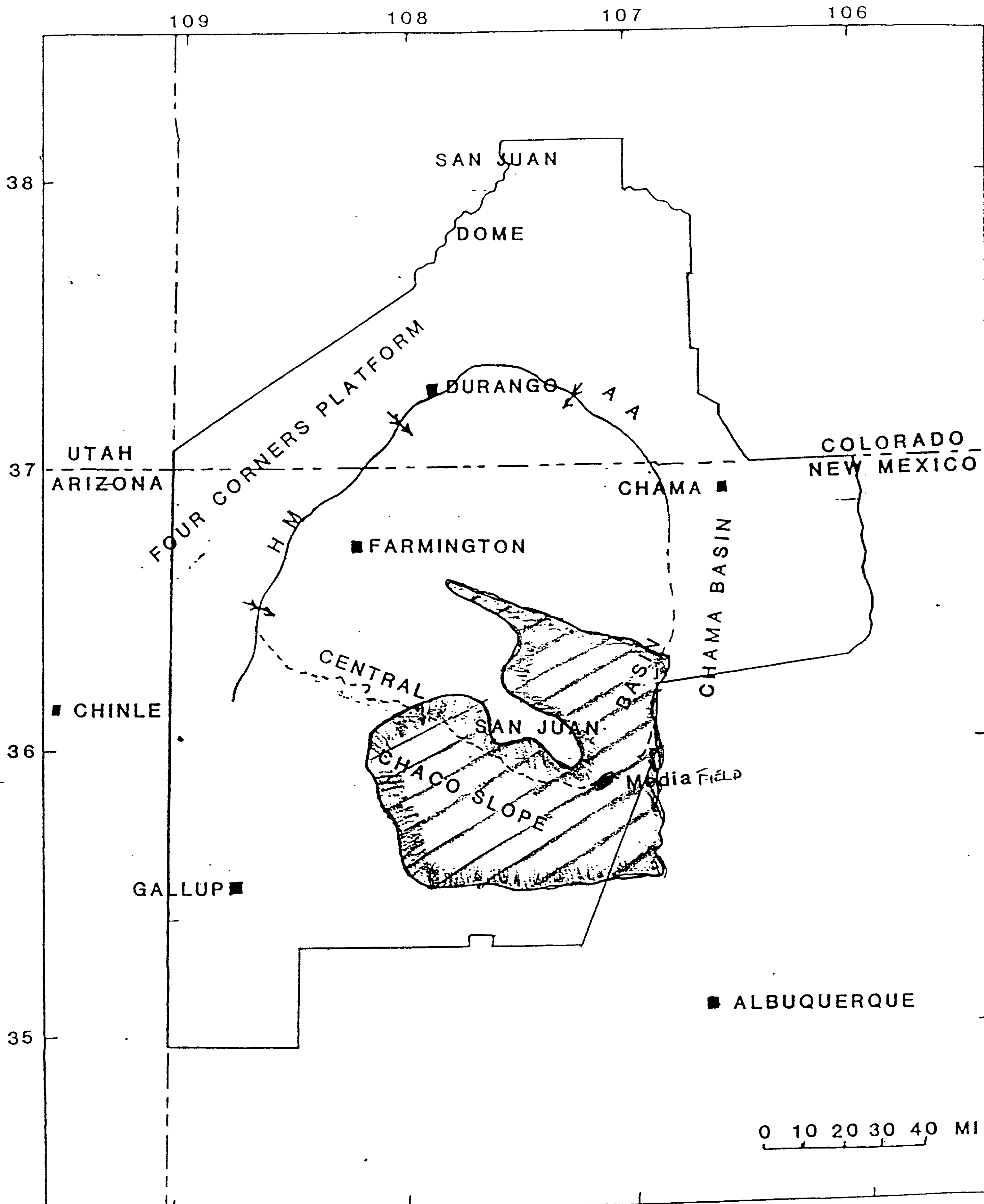


Figure 30. Map of Entrada play

OIL AND GAS PLAY DATA

PLAY **ENTRADA**
PROVINCE **SAN JUAN BASIN** CODE **03-088-110**

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

	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**	**1.01**	**1.03**	**1.1**	**1.3**	**2**	**3**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**3**			**5.5**			**8**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**6**	**8**	**10**	**13**	**17**	**25**

Average ratio of associated-dissolved gas to oil (GOR)	**10**	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.

ALBUQUERQUE-SANTA FE-SAN LUIS RIFT BASINS PROVINCE (089)

By Cornelius M. Molenaar

INTRODUCTION

This province, part of the general Rio Grande rift system, is an elongate area of segmented or offset rift basins extending from Socorro, New Mexico on the south to the northern end of the San Luis Valley in Colorado, a distance of about 280 miles. The east-west width of the province ranges from 15 to 65 miles; the eastern and western boundaries are mostly uplifted mountain blocks exposing Precambrian to Mesozoic rocks (fig. 31) generally dipping away from the rifted basins. The province can be divided into sub-basins, some of which contain similar rocks to those that produce oil and gas in the San Juan Basin and adjacent areas to the west or northwest. Oil and gas has been found in the province since initial drilling in the 1920's but in amounts that were noncommercial. A total of five plays were recognized; three of the plays, the Albuquerque Basin (020), Hagan-Santa Fe embayment (030) and San Juan Sag (040), were individually assessed.

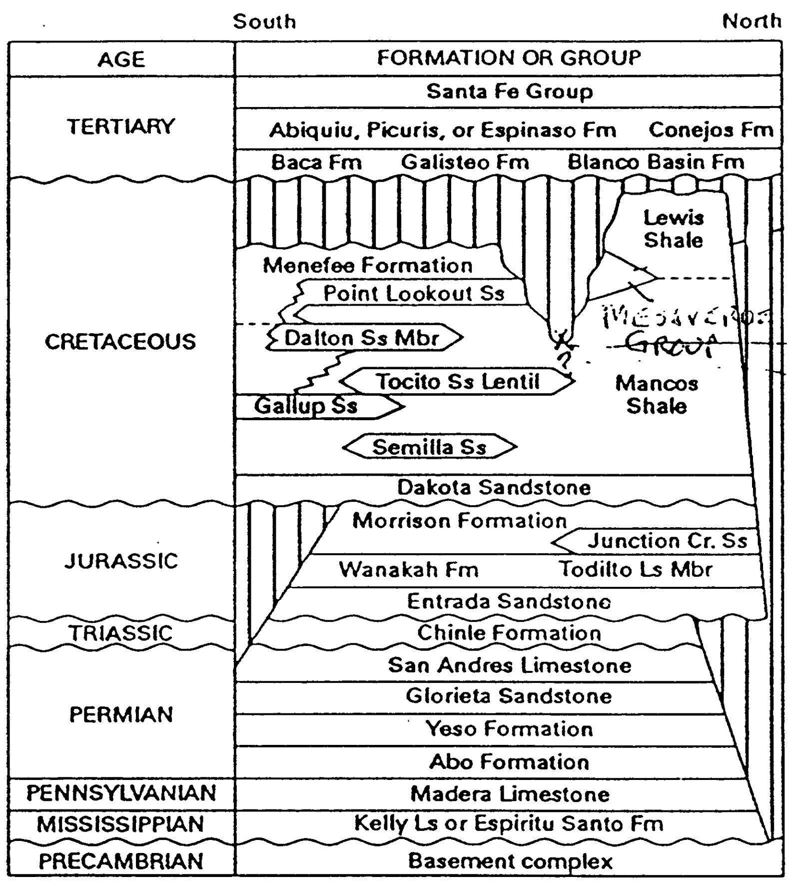


Figure 31. Generalized stratigraphic column, Albuquerque-Sante Fe-San Luis Rift Basins province

ALBUQUERQUE BASIN PLAY (020)

The play is primarily structural and is related to down-dropped blocks of Mesozoic and Paleozoic rocks that have been buried sufficiently for the source rocks (primarily Cretaceous) to generate hydrocarbons, or structures that are along migration paths of downdip-generated hydrocarbons. The play area is approximately 110 mi long and 23 to 35 mi wide and essentially covers the entire Albuquerque basin (fig. 32), and is bounded on the east and west by uplifted blocks of Precambrian to Mesozoic rocks. In the basin, these rocks are buried by 1,000 to 20,000+ ft of mostly middle to late Tertiary nonmarine basin-fill.

Primary reservoir objectives are Cretaceous sandstones and the Jurassic Entrada Sandstone (fig. 31) that range from 30 to 200 ft in thickness. Secondary objectives are Pennsylvanian carbonate rocks which may have porosity development, although this has not been documented. The play area lies along depositional strike with prolific gas- and oil-producing Cretaceous rocks in the San Juan Basin (088) to the northwest (fig. 32). Small oil accumulations also occur in the Entrada Sandstone in the southeastern part of the San Juan Basin.

Cretaceous, Jurassic (Todilto), and possibly Pennsylvanian source rocks are all expected to be present in the Albuquerque basin; however, the lower part of the Mancos Shale is the primary source rock in the play (fig. 31). Maturation levels of Cretaceous rocks, the most prospective objective, range from marginally mature (R_o <0.6 percent) to post mature (R_o >2 percent). Maturation probably occurred in late Tertiary time. Hydrocarbon shows in nonmarine Tertiary basin-fill rocks probably originated in underlying Cretaceous source rocks.

Traps are anticipated to be structural closures within different fault blocks; many would probably be fault traps. The subsurface structure is poorly known from publicly available data. Drilling depths to the Dakota Sandstone would be 6,000-20,000+ ft, but the sizes of possible traps are unknown. Stratigraphic traps involving lenticular Cretaceous sandstones may also be a factor in the play as more subsurface data become available. Seals would be the marine Mancos Shale overlying most of the Cretaceous reservoirs, and anhydrite of the Todilto Limestone Member that overlies the Entrada Sandstone. Shale within the cyclic Pennsylvanian System would be the seal for carbonate reservoirs.

Although no production has been established in the play, numerous gas and some oil shows were reported from the 46 wells drilled in the Albuquerque basin dating back to the 1920s. Most of these tests were less than 6,000 ft deep and penetrated only Tertiary rocks. Nine deep tests, 10,000-19,375 ft, penetrated Cretaceous and older rocks and indicated that the area is broken by large normal faults.

The play has a good potential for undiscovered gas and minor potential for oil. Limiting factors in finding new hydrocarbons include a general lack of knowledge about subsurface structure and the expense involved in required detailed seismic work to delinate structure.

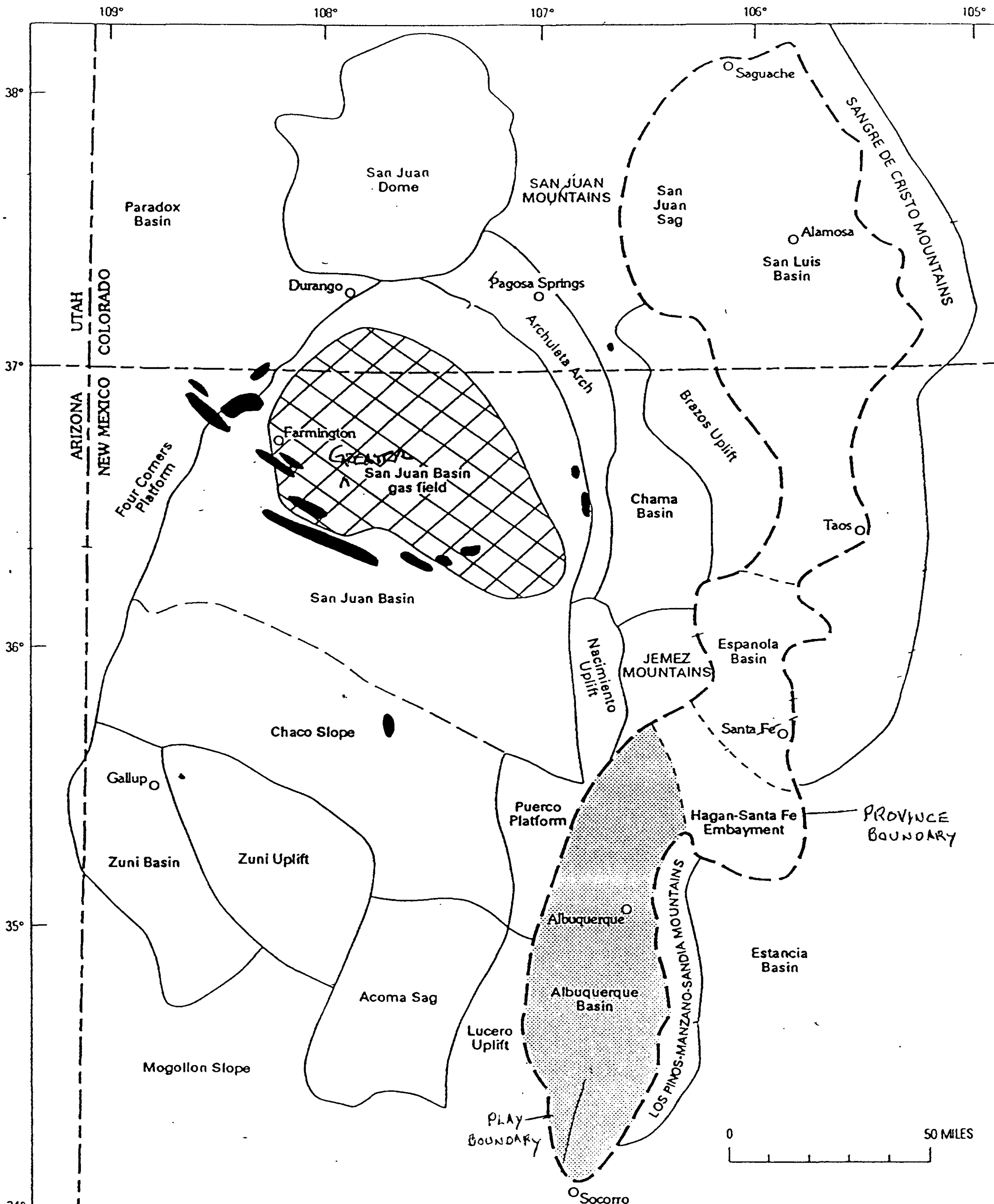


Figure 32. Map of Albuquerque Basin play

OIL AND GAS PLAY DATA

PLAY **ALBUQUERQUE BASIN**
PROVINCE **ALBUQ.-SANTA FE-SAN LUIS RIFT BASINS** CODE **03-089-020**

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	**0.90**

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 ($\times 10^6$ BBL)	**1**	**1.3**	**2.5**	**5**	**10**	**26**	**60**
Gas ($\times 10^9$ CFG)	**6**	**7.5**	**13**	**25**	**50**	**100**	**240**
Reservoir depth ($\times 10^3$ ft)							
Oil	**6**			**9**			**12**
Gas (non-associated)	**6**			**12**			**25**
Number of accumulations	**1**	**2**	**3**	**5**	**8**	**15**	**20**

Average ratio of associated-dissolved gas to oil (GOR)	**2000**	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.

HAGAN-SANTA FE EMBAYMENT PLAY (030)

The play located at the south end of the Española basin, is a structural-stratigraphic play for oil in relatively shallow (<7,000 ft) Cretaceous rocks. The play area is roughly ovoid-shaped and covers about 1,250 m^2 (fig. 33); the northern boundary is at the projected northeast truncation edge of Cretaceous rocks in the Española basin, as determined by well and regional geologic data. The western boundary is the projection of the fault marking the east side of the Albuquerque basin, and the southern and eastern boundaries are within the Cretaceous outcrop belt.

Primary reservoirs are sandstones in the lower part of the Cretaceous; the Dakota Sandstone, and the Semilla and Tocito Sandstone Members of the Mancos Shale (fig. 31). These sandstones range in thickness from 30 to 200 ft and could be fair to good reservoirs. Secondary objectives are Jurassic sandstones and Pennsylvanian carbonate rocks in which net reservoir thicknesses could be as much as 200 ft.

Source rocks of moderate quality in the lower part of the Mancos Shale, Jurassic Todilto Limestone Member, and possibly Pennsylvanian shales, are all expected to be present in the Hagan-Santa Fe embayment. Maturation levels range widely because of the many intrusive dikes and sills in the area, but many of the source rocks are in the oil-generation window as indicated by the numerous oil shows reported from wells and by analyses of a limited number of well samples. Geochemical analysis of Cretaceous rock samples generally range from 0.5 to 1.5 percent R_o, with one sample at 2.7 percent R_o. The proximity of intrusive rocks is probably responsible for this wide range in maturation level. Maturation probably occurred in late Tertiary time.

Traps, of probable small to moderate size, are both structural and stratigraphic, the latter is typified by the lenticular Semilla and Tocito Sandstone Members. Seals would be the overlying Mancos Shale for Cretaceous reservoirs, Todilto anhydrite for the Entrada Sandstone, and interbedded shales for Pennsylvanian carbonate reservoirs.

As of December 1986, approximately 34 wells had been drilled in the play. All but two of the wells were drilled since 1974 and only two or three wells were drilled into or through the Cretaceous objective section; several wells were drilled to the Entrada Sandstone. Most of the wells reported oil or gas shows, mainly in Cretaceous rocks. One well had subcommercial oil production and two or three wells might have been completed as gas wells if gas pipeline facilities had been available. The play is limited in area, and the future potential for oil and gas is low. Undiscovered fields will probably be small in size. Although adequate amounts of gas have been encountered, the main potential is oil. Favorable factors include relatively shallow drilling depths and good outcrop and well control which makes delineation of structure considerably easier here than in the Albuquerque Basin play (020).

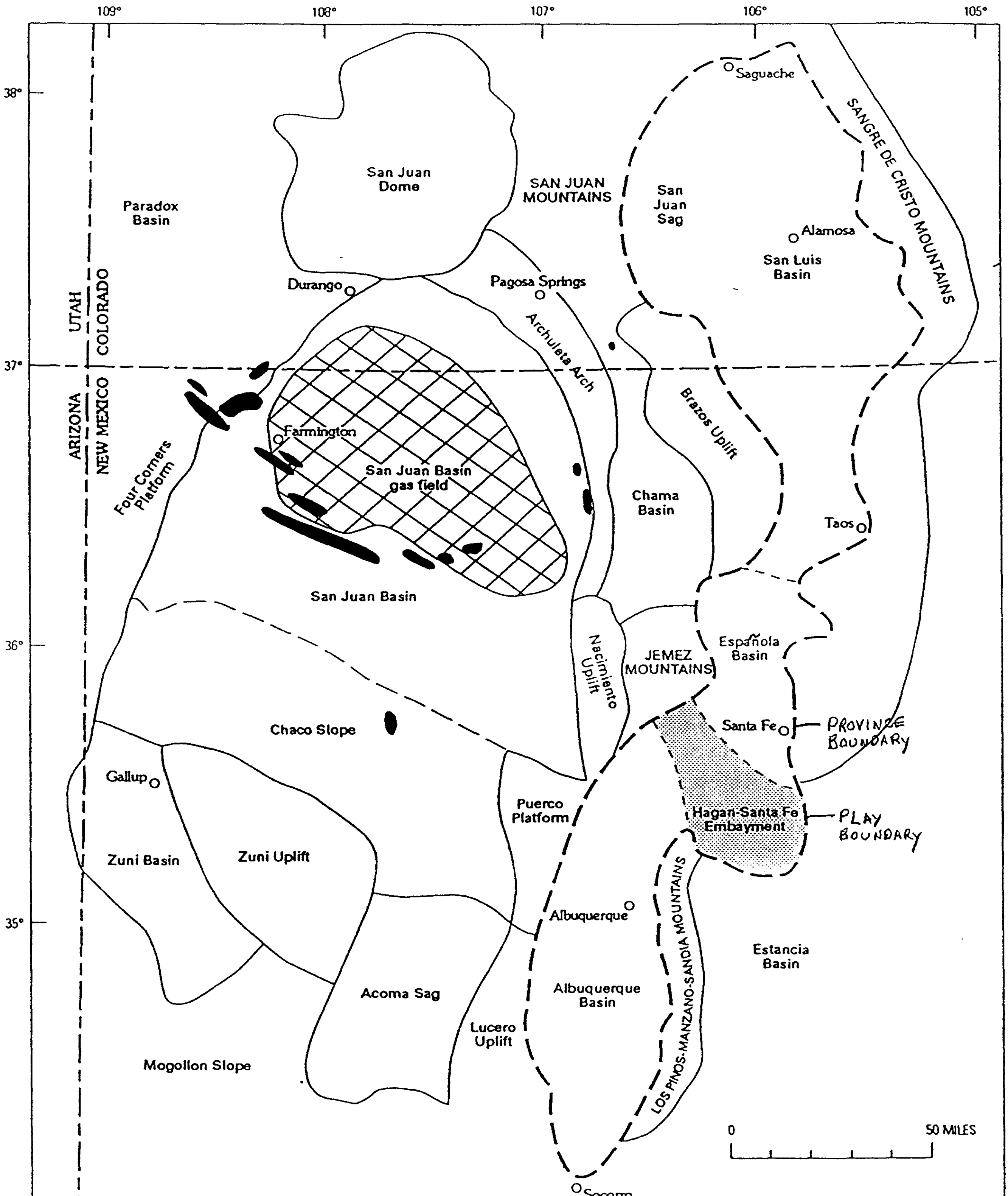


Figure 33. Map of Hagan-Sante Fe Embayment Play

OIL AND GAS PLAY DATA

PLAY **HAGAN-SANTA FE EMBAYMENT**
PROVINCE **ALBUQ.-SANTA FE-SAN LUIS RIFT BASINS** CODE **03-089-030**

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	**0.70**

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	**0.8**
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**	**1.2**	**1.6**	**2.3**	**4.5**	**10**
Gas (x 10^9 CFG)	**6**	**6.5**	**6.7**	**7.2**	**9**	**13**	**30**
Reservoir depth (x10^3 ft)							
Oil	**2**			**4.5**			**7**
Gas (non-associated)	**2**			**4.5**			**7**
Number of accumulations	**1**	**1**	**2**	**3**	**4**	**5**	**6**

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.

SAN JUAN SAG PLAY (040)

This is primarily an oil play involving Cretaceous and Jurassic sandstone and Oligocene fractured igneous reservoirs in structural or stratigraphic traps underlying a thick Oligocene volcanic cover. The play area underlies volcanic rocks along the foothills of the San Juan Mountains west of the San Luis Valley (Basin) (fig. 34), and is about 60 mi long and 15-20 mi wide. The play area is actually not part of the San Luis rift system, although the boundary is poorly defined. The eastern boundary is the eastern extent of Cretaceous rocks preserved under an Eocene unconformity as identified from seismic data and limited well control. The western boundary is arbitrarily placed where the terrain becomes more mountainous and the volcanic cover thicker. The play area could actually be extended farther west if the pre-Tertiary structure could be delineated under the area of greater topographic relief and thicker volcanic cover.

Potential reservoir rocks are the Entrada Sandstone, Junction Creek Sandstone, and sandstones in the Morrison Formation, all of Jurassic age, and the Cretaceous Dakota Sandstone (fig. 31). These sandstone range from 30 to 200 ft in thickness and are reported to have good to excellent porosities. Other sandstones of the Cretaceous sequence that are present in the San Juan Basin have pinched out within the Mancos Shale to the southwest, and the Pictured Cliffs Sandstone has been removed by erosion under the Eocene unconformity. Fractured intermediate to acidic igneous sills of Oligocene age may also be good reservoirs.

The Mancos and Lewis Shales are the primary source rocks for either oil or gas. The lower and middle parts of the Mancos probably contain the best oil-prone source rocks. The favorable organic-rich facies of the Todilto would also be a potential source rock if it extends this far north. Source rocks are apparently in the oil-generation window of maturation. It also seems likely that the oil was locally generated, because the probable time of oil generation coincided with high heat flow and maximum burial associated with Oligocene volcanic activity.

Traps would be structural, probably both anticlinal as well as fault traps. Delineation of such traps would have to be done by seismic methods and drilling. Drilling depths range from 6,000 to over 9,000 ft. Fractured igneous sills that may occur anywhere in the play could be a special type of trap where the limits of fracturing or updip and overlying impermeable rocks, such as the Mancos Shale, form seals.

The San Juan Sag play is a quite recent and ongoing play by the oil industry with the first exploratory well drilled in 1982. Through 1986, about five tests have been drilled, one of which produced 4,000 barrels of oil over a four-months period. Oil or gas shows commonly reported are an encouraging aspect for continued exploration in the play. The many igneous intrusive rocks encountered in the play, usually considered to be a negative aspect, could serve as fracture reservoirs. However, delineating structure under the thick volcanic cover with seismic surveys is difficult, but not impossible. The future potential is fair for small-size fields. The main limiting factor in exploration will be delineating structure under the volcanic cover either by seismic methods or drilling.

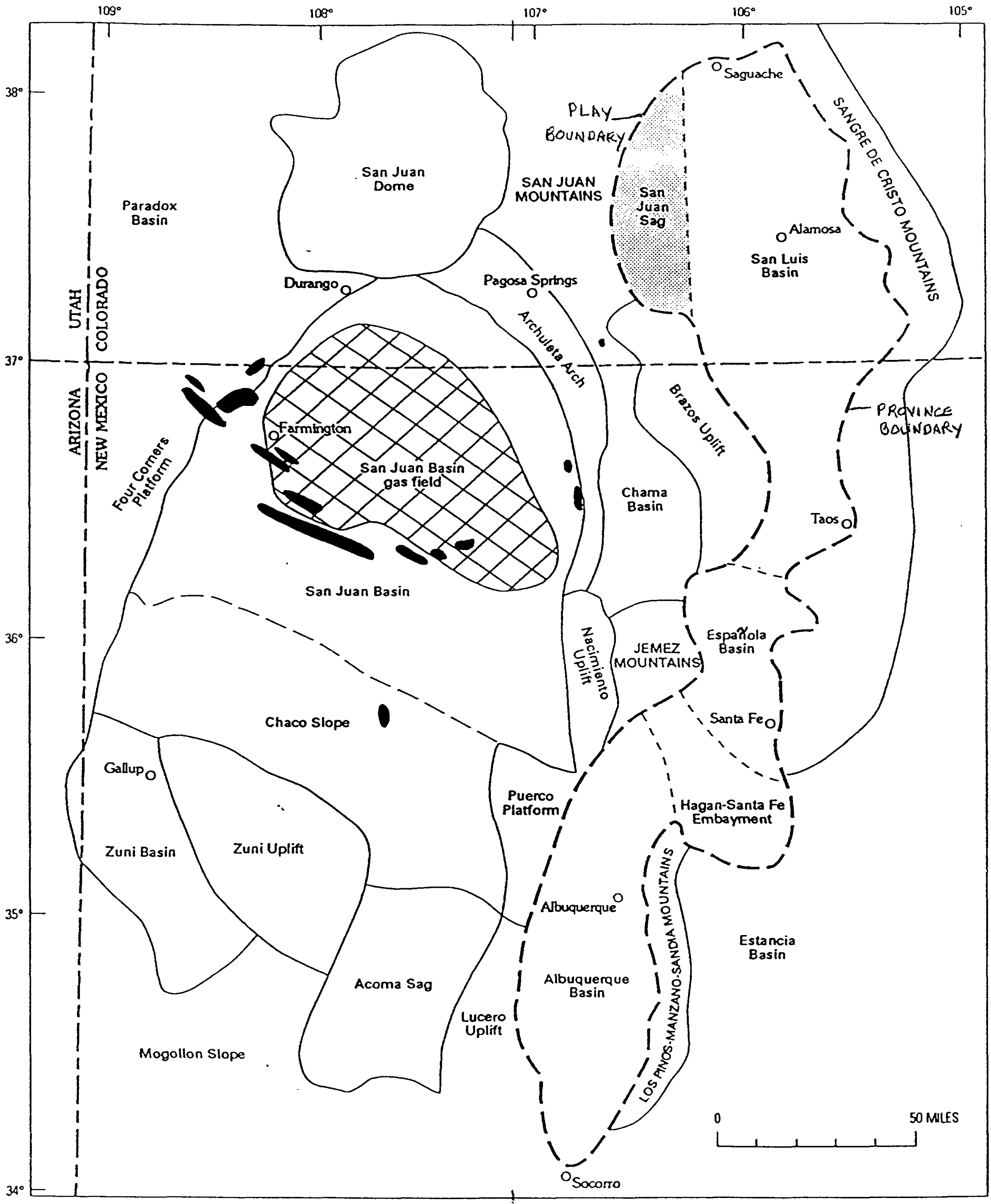


Figure 34. Map of San Juan Sag play

OIL AND GAS PLAY DATA

PLAY **SAN JUAN SAG**
PROVINCE **ALBUQ.-SANTA FE-SAN LUIS RIFT BASINS** CODE **03-089-040**

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) ($S \times T \times M \times R = MP$)	**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	**0.90**

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	**0.8**
Gas	**0.2**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^{6}$ BBL)	**1**	**1.1**	**1.4**	**2**	**3.4**	**9.2**	**26**
Gas ($\times 10^{9}$ CFG)	**6**	**6.5**	**7.2**	**9**	**14**	**30**	**80**
Reservoir depth ($\times 10^{3}$ ft)							
Oil	**3**			**7**			**9**
Gas (non-associated)	**3**			**7**			**9**
Number of accumulations	**1**	**1**	**2**	**3**	**4**	**5**	**6**

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.

WYOMING-UTAH-IDAHO THRUST BELT PROVINCE (090)

By Richard B. Powers

INTRODUCTION

The province is an arcuate, north-south trending structural feature covering approximately 15,000 mi^2 that extends from the Uinta Mountains on the south to the Teton Range and Snake River Plain on the north, encompassing parts of Wyoming, Utah, and Idaho. It is an easterly bulge, or salient, of the greater Cordilleran thrust belt of western North America that stretches over 5,000 mi from Alaska to Mexico. The wide axis of the thrust belt is roughly coincident with the eastern hingeline of a Paleozoic and Mesozoic miogeocline whose depocenter was located in southeastern Idaho where more than 60,000 ft of predominantly marine sediments were deposited (fig. 35). This sequence was strongly folded and thrust eastward starting in latest Jurassic time in the west and ending possibly as late as Eocene time in the east, followed later by extensional faulting from Eocene to the present. The resulting transition from a thick marine section on the west to a thinner shelf section to the east provides an optimum setting for migration of hydrocarbons from source rocks to updip reservoir rocks in structural traps formed by the thrusting.

Four major thrust systems make up the present structural setting of the province, two of which form its western and eastern boundaries. From west to east these thrust systems are the Willard-Paris, Crawford-Meade, Absaroka and Prospect-Darby-Hogsback. Thrust faults are low-angle, moderately to highly imbricated and do not involve crystalline basement, except in the area of the Moxa Arch extension. Productive traps found on three of the major thrust systems are in complexly faulted, upright to nearly recumbent folds. Twenty-nine oil and gas fields, 22 of which are currently productive, have been discovered in the province in traps of this type since the initial discovery at Pineview field in 1975, although exploration dates as far back as the 1890's. Cumulative production from these fields, 5 of which are giant fields, to the end of 1986 was 148 MMBO and 1.4 TCFG.

Seismic exploration, drilling and new field discoveries have been heavily concentrated in the southernmost one-fourth of the province area ("Fossil basin" area); this is due mainly to the availablity of access on land-grant (Union Pacific Railroad) and other private lands in this area. The northern three-fourths of the province has undergone minimal exploration and drilling, most of which is in small, scattered clusters of activity.

The areal patterns of the seven plays individually assessed in the province are constrained mainly by the linear configuration of the major thrust systems; the plays are discussed in the following sequence: Moxa Arch Extension (020), Crawford-Meade Thrusts (030), Northern Thrusts (040), Absaroka Thrust Gas (050), Absaroka Thrust Oil (060), Hogsback Thrust (070), and Cretaceous Stratigraphic (080).

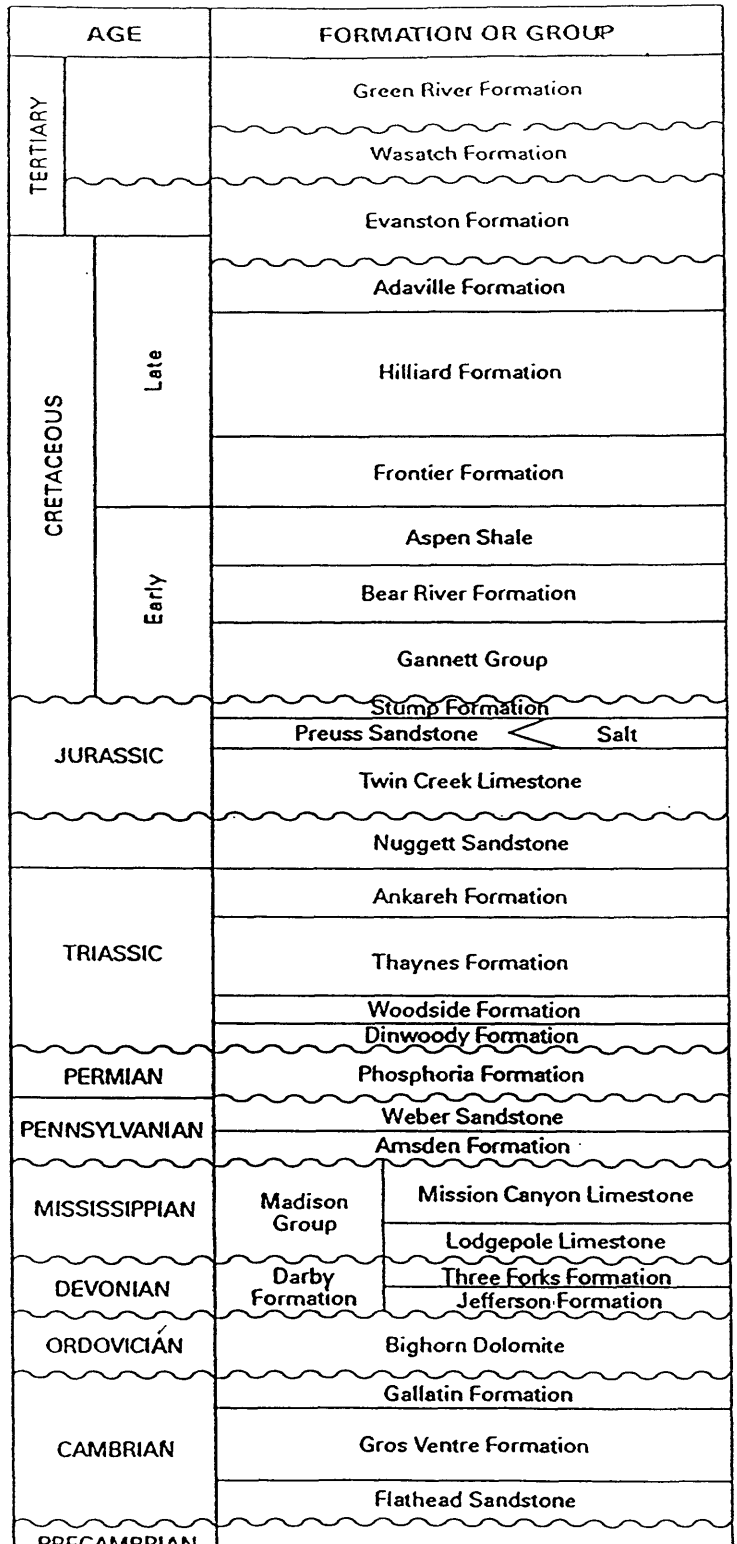


Figure 35. Generalized stratigraphic column, Wyoming-Utah-Idaho Thrust Belt province

MOXA ARCH EXTENSION PLAY (020)

The play is characterized by probable CO_2 (carbon dioxide)-rich gas accumulations in Paleozoic carbonate reservoirs in footwall anticlinal traps on the extensional axis of the Moxa Arch. The Arch is a north-south trending regional basement uplift in the western Green River basin that extends north from the Utah boundary for about 100 miles before swinging northwest at LaBarge (fig. 36) where it intersects and passes beneath the leading edge of the Hogsback thrust. At this point, within the thrust belt, the axial portion of the Arch is part of a large, thrust faulted northwest-southeast-trending productive structural feature, about 40 mi long and 18 mi wide, locally termed the LaBarge anticline. From here, the axis of the Arch bends again and trends in a northerly direction for about 100 mi, its crestal portion lying below the surface trace of the Darby thrust. The area of the play follows this extension, its width varying from 6-10 mi, from the southeast part of the LaBarge area to an estimated termination south of Jackson, Wyoming.

Recognized and potential reservoirs in the play are in the Mississippian Madison Group, Ordovician Bighorn Dolomite, Devonian Darby and Permian Phosphoria Formations, and possibly the Pennsylvanian Weber (Tensleep) Sandstone (fig. 35). Major CO_2-rich gas reservoirs occur mainly in porous dolomite and limestone units of the 850 ft thick Madison, a substantial portion of which is of very good reservoir quality, with porosities greater that 6 percent and as much as 30 percent. The 450 ft thick Bighorn has tested high volumes of CO_2-rich gas in 5 wells, and core analysis in one of the wells showed an average porosity in one dolomite zone of 11 percent and an average permeability of 77 millidarcies. Reservoirs in the 360 ft thick Darby and 320 ft thick Phosphoria have also yielded significant quantities of gas from generally low porosity, fractured dolomite units. Reservoir development in the Weber is minimal, although substantial initial amounts of gas have been recovered in a few wells. All productive reservoirs contain CO_2, CH_4 (methane), N (nitrogen), H_2S (hydrogen sulfide), and He (helium).

Dark gray to black, phosphatic shale of the Phosphoria Formation is the apparent primary source rock for hydrocarbons in the play. Various studies indicate that hydrocarbon generation in the Phosphoria began in Late Jurassic time in the far western part of the thrust belt. Hydrocarbons were expelled, over time, and migrated eastward into the thrust belt area and beyond. Cores from Paleozoic reservoir rocks include fractures filled with dead oil in wells in the LaBarge area. It is postulated that these hydrocarbons were from a Phosphoria source that later accumulated in the Madison and Weber (Tensleep). Subsequent thermal degradation altered the original liquid hydrocarbons into solid bitumen, methane, CO_2 and H_2S. Gas analyses from these Paleozoic reservoirs indicate that density stratification of CO_2-rich gas has taken place to some extent on the LaBarge anticline. In addition to the CO_2-rich productive wells on the LaBarge anticline, 3 wells, located 12 , 25, and 55 mi north of the LaBarge area, have drilled into the subthrust Paleozoic rocks that constitute the Moxa Arch extensional play. Two of the wells tested large volumes of CO_2-rich gas in Madison carbonate rocks, similar to the gas mix at LaBarge.

Traps are speculated to be mostly anticlinal, similar in style to the thrust-faulted footwall trap on the LaBarge anticline. Seals include anhydrite beds in the upper part of the Madison and in overlying shales of Pennsylvanian age. Drilling depths are estimated to range from 10,000 to 18,000 ft to Madison and Bighorn targets in the footwall section of the Arch extension.

The first well to penetrate the Paleozoic section and establish the presence of CO_2-rich gas in the area of the play was completed in 1961, and was located on the crestal part of the LaBarge anticline. More than 50 additional wells have been drilled to Paleozoic targets, clustered mainly on this feature, since the initial test well was drilled. Flow rates in these wells are substantial, ranging from 8 to 18 MMCFPD, with the CO_2 content of total gas increasing with the age or depth of the containing formation. CH_4 content of total gas varies, but an estimated average CH_4 content in the Madison is about 20 percent. Gas from a typical well completed in the Madison analyzed 19 percent CH_4, 70 percent CO_2, 7 percent N , 3 percent H_2S, and 1 percent He.

Production reports list 3 individual fields within the southern area of the play, Fogarty Creek, Graphite, and Lake Ridge (No. 10, 11, 14, fig. 36), that were discovered in 1976, 1986, and 1981, respectively; however, the wells in these fields are included in the overall LaBarge anticline complex. Cumulative production from 27 wells to the end of 1986 was 53.4 BCFG and 50,000 bbls of condensate Future potential for undiscovered methane resources is excellent; however limiting factors affecting exploration include extremely rugged topography and possible restrictions to access on public lands.

STATUS OF FIELDS

1. AAGARD RANCH
2. ANSCHUTZ RANCH
3. ANSCHUTZ RANCH EAST
4. BESSIE BOTTOM
5. CAVE CREEK
6. CLEAR CREEK
7. CHICKEN CREEK
8. ELKHORN RIDGE
9. ELKOL (SI)
10. FOGARTY CREEK
11. GRAPHITE
12. HOGBACK RIDGE (ABD)
13. HORSETRAP (ABD)
14. LAKE RIDGE
15. LAZEART (SI)
16. LODGEPOLE
17. LODGEPOLE SOUTH (ABD)
18. MILL CREEK (ABD)
19. NORTH PINEVIEW
20. PAINTER RESERVOIR
21. PAINTER RESERVOIR EAST
22. PINEVIEW
23. RED CANYON
24. ROAD HOLLOW
25. RYCKMAN CREEK
26. SESSION MOUNTAIN
27. SHURTLEFF CREEK (SI)
28. WHITNEY CANYON-CARTER CREEK
29. YELLOW CREEK

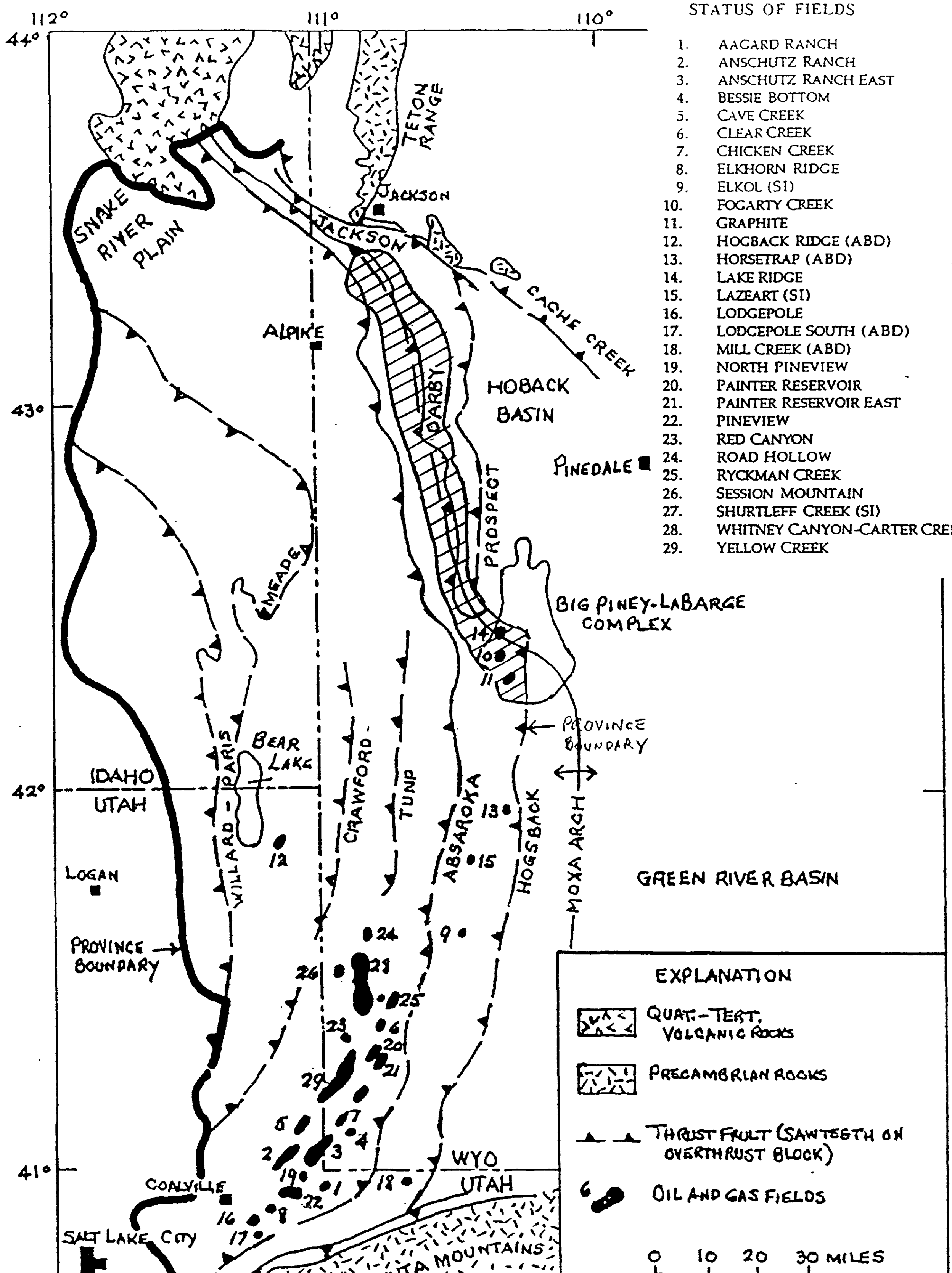


Figure 36. Map of Moxa Arch Extension play

OIL AND GAS PLAY DATA

PLAY **MOXA ARCH EXTENSION**
PROVINCE **WYOMING-UTAH-IDAHO THRUST BELT** CODE **03-090-020**

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	**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)	**1000**	**1200**	**1600**	**2000**	**2500**	**3400**	**5000**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**10**			**14**			**18**
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.

CRAWFORD-MEADE THRUSTS PLAY (030)

The play is characterized by (1) probable hydrocarbon accumulations in footwall structural or truncation traps in reservoir rocks interbedded with source rocks, both of Cretaceous age, and (2) gas accumulations sourced by Paleozoic shale in tightly folded anticlines in hanging wall traps involving Paleozoic and Mesozoic reservoirs within the Crawford thrust plate. The play area lies mainly in Utah and Idaho and is bounded on the west by the Willard-Paris thrust and on the east by the Crawford-Meade thrusts. The northwestern boundary is at the edge of the Snake River Plain and the southern boundary is at a point where the thrust systems swing abruptly westward. The play is approximately 180 mi long and from 8-30 mi wide (fig. 37).

Limited well and seismic data indicate that a moderately thick Cretaceous section is preserved under the leading edge of the Crawford thrust plate, where clastic reservoirs of marginal quality and thickness may be present. These include sandstone units of the Frontier and Bear River Formations (fig. 35) in which probable reservoir facies are fluvial, deltaic and barrier bar sandstones. Analagous, known low productive reservoir facies east of the toe area of the Absaroka thrust are 10-50 ft thick, have porosities that range from 7-12 percent, but are low in permeability. Fractured carbonates in the Triassic Dinwoody and Permian Phosphoria Formations are the productive reservoirs in the abandoned Hogback Ridge field (fig. 37). Other potential reservoirs may exist in younger Triassic and Jurassic units and in older Paleozoic rocks.

Possible source rocks in the hanging wall of the Crawford thrust include shale of Triassic, Permian and Mississippian age. Triassic shales are of limited areal extent and appear to be low in organic carbon, and the Permian Phosphoria is very mature to post-mature, based on thermal-maturity data. It is probable, however, that scattered dry gas shows in the play area and the dry gas produced at Hogback Ridge field are late-stage products of Phosphoria hydrocarbon generation, but Mississippian shales may also have been a very localized source of dry gas in this field. Data from the few wells that penetrated the Crawford plate in the southern half of the play delineate a narrow corridor of Cretaceous age potential source rocks beneath the leading edge of the Crawford plate. Thermal maturation studies of this section indicate that it contains a mixture of kerogen types; however, it does include oil-prone Type II kerogen, and it is tentatively estimated that these oil-prone source rocks are presently at an oil-generative level of thermal maturation. Gas chromatography studies of oil stained samples in the Jurassic Twin Creek Limestone and Triassic Ankareh and Thaynes Formations from two wells in the hanging wall indicate that the hydrocarbons migrated into the hanging wall in Late Cretaceous time from these footwall Cretaceous source rocks.

Structural traps normally present along the leading edge of an anticlinal fold trend, typical of the toe area of most thrust sheets, are absent from the Crawford Plate due to uplift and beveling of the leading edge of the thrust, resulting in the breaching and erosion of possible hanging wall traps. Potential hanging wall traps may exist, however, in the form of low relief folds above associated splay faults, or in tightly folded anticlines sealed by shale and anhydrite within intraplate imbricate thrusts. Other footwall traps may be present that are related to folding within trailing edge imbricates off the Absaroka thrust, or splays off the Crawford thrust into the footwall. Truncation traps, with asphaltic seals, at the updip edge of footwall beds may also be present. Drilling depths are estimated to range from 10,000 to 17,500 ft to Mesozoic and Paleozoic targets.

The play is considered to be speculative, overall, and in a young stage of exploration with only about 50 wildcat wells drilled. The majority of shows reported are limited to dry gas, except for the few wells that had oil staining in Triassic rocks. The only production found in the play was from the one-well Hogback Ridge field, located midway between the edges of the Crawford and Willard-Paris thrusts (No. 12, fig. 37). The field was discovered in 1977 and abandoned in 1981 after producing 5.8 BCF of dry gas from fractured carbonates of Permian and Triassic age. A few wells drilled in the northwestern one-third of the play had recorded elevated bottom-hole temperatures, indicating that higher geothermal gradients exist here in proximity to volcanics of the Snake River Plain of Idaho. This type of setting would be a probable deterrent to future exploration. Any significant future potential in the play, particularly for gas, would remain in the footwall Cretaceous section of the Crawford thrust plate in the southern half of the play.

STATUS OF FIELDS

1. AAGARD RANCH
2. ANSCHUTZ RANCH
3. ANSCHUTZ RANCH EAST
4. BESSIE BOTTOM
5. CAVE CREEK
6. CLEAR CREEK
7. CHICKEN CREEK
8. ELKHORN RIDGE
9. ELKOL (SI)
10. FOGARTY CREEK
11. GRAPHITE
12. HOGBACK RIDGE (ABD)
13. HORSETRAP (ABD)
14. LAKE RIDGE
15. LAZEART (SI)
16. LODGEPOLE
17. LODGEPOLE SOUTH (ABD)
18. MILL CREEK (ABD)
19. NORTH PINEVIEW
20. PAINTER RESERVOIR
21. PAINTER RESERVOIR EAST
22. PINEVIEW
23. RED CANYON
24. ROAD HOLLOW
25. RYCKMAN CREEK
26. SESSION MOUNTAIN
27. SHURTLEFF CREEK (SI)
28. WHITNEY CANYON-CARTER CREEK
29. YELLOW CREEK

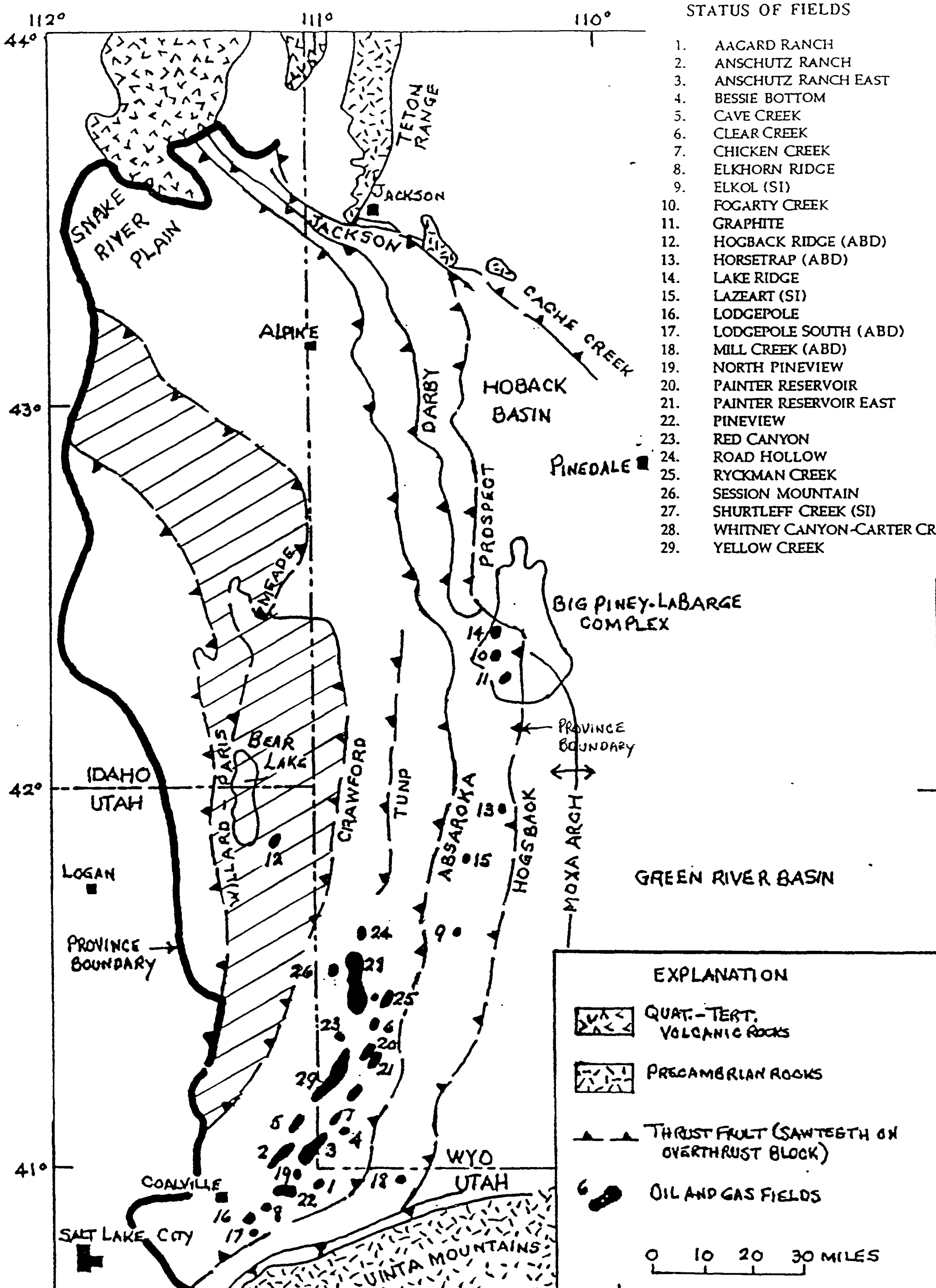


Figure 37. Map of Crawford-Meade Thrusts play

OIL AND GAS PLAY DATA

PLAY **CRAWFORD-MEADE THRUSTS**
PROVINCE **WYOMING-UTAH-IDAHO THRUST BELT** CODE **03-090-030**

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	**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**	**7**	**12**	**20**	**50**	**225**	**1000**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**4.5**			**11**			**17**
Number of accumulations	**2**	**3**	**5**	**7**	**9**	**13**	**18**

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.

NORTHERN THRUSTS PLAY (040)

The play area includes the northern extensions of 3 of the major thrust systems, Crawford-Meade, Absaroka, and Prospect-Darby. It is characterized by a range of possible trapping conditions but involves mainly Paleozoic reservoir rocks in hanging wall anticlines juxtaposed against Cretaceous source rocks in the footwall of the thrust systems. The play trends mainly northwest-southeast for a distance of about 105 mi and varies in width from 35-55 mi. It is bounded on the west by the Meade thrust, on the east by the Prospect thrust, on the northwest by the Snake River Plain and on the south by an east-west projection of the easterly change in strike of the Darby thrust (fig. 38).

Potential reservoir rocks are of primarily Pennsylvanian (Weber Sandstone), Mississippian (Madison Group) and Ordovician (Bighorn Dolomite) age (fig. 35). The best porosity development occurs in the Madison, based on data from the scattered wells that have penetrated and tested dolomitized zones in this 1,400 ft thick unit. The 1,000 ft thick Weber is characterized by erratic porosity development, and is relatively tight overall, although fairly strong hydrocarbon shows have been identified in some wells. The Bighorn is 400-500 ft thick and contains zones of intercrystalline and vuggy porosity.

The only source rocks of significance are organic-rich shales in Cretaceous and Permian age rocks. Shale beds in the Bear River Formation and Aspen Shale are the richest and marine shale in the Frontier and Hilliard Formations also contain sufficient organic carbon to be considered potential source rocks. The organic-rich shale in the Phosphoria Formation is believed to be in an advanced stage of thermal maturity throughout the play and well into the dry gas stage. Minimal well data available indicate that humic material is common in the organic matter of Cretaceous shale, so that these rocks are slightly more gas prone. Shows of dry gas have been reported in wells in the northwestern area of the play, near the Idaho-Wyoming border, in subthrust Cretaceous rocks. In this same general locality bleeding oil was reported in fractured Cambrian (Gallatin equivalent) dolomite beds in one wildcat well. A well that drilled under a blind thrust into Cretaceous shale beneath the Prospect thrust in the northeastern part of the play flowed sub-commercial oil and gas from a thick, porous dolomite zones in the Madison. Probable source of these trapped hydrocarbons is thought to be shale in the Cretaceous Frontier and Hilliard Formations in the footwall of the blind thrust.

Traps may occur as tightly folded anticlines associated with duplex fault zones, or as "pop-up" block structures (triangle zone) formed in areas of backthrusting and as broad, faulted anticlinal structures in hanging walls where reservoir beds toe down to blind thrust zones in contact with Cretaceous source rocks in the footwall. Paleozoic rocks contain adequate seals, especially shale in the Devonian Darby Formation and anhydrite beds in the upper part of the Madison. Drilling depths are estimated to range from 4,500 to 15,000 ft.

The play is speculative because of the extremely low density of drilling (about 60 total wildcats) within the broad area of the play. Although there are no field discoveries and no hydrocarbon production, the Chevron Cabin Creek wildcat well (fig. 38) tested up to 100 BOPD and about 800 MCFGPD from a 200 ft porous dolomite zone in the Madison beneath the Prospect thrust, and was completed as a non-commercial oil and gas discovery in 1986. No additional confirmation wells were drilled within this prospective area. Future potential for undiscovered oil is fair to good and is excellent for gas. Additional exploration in the play may be hampered by limited access to some public lands and extremes of topography.

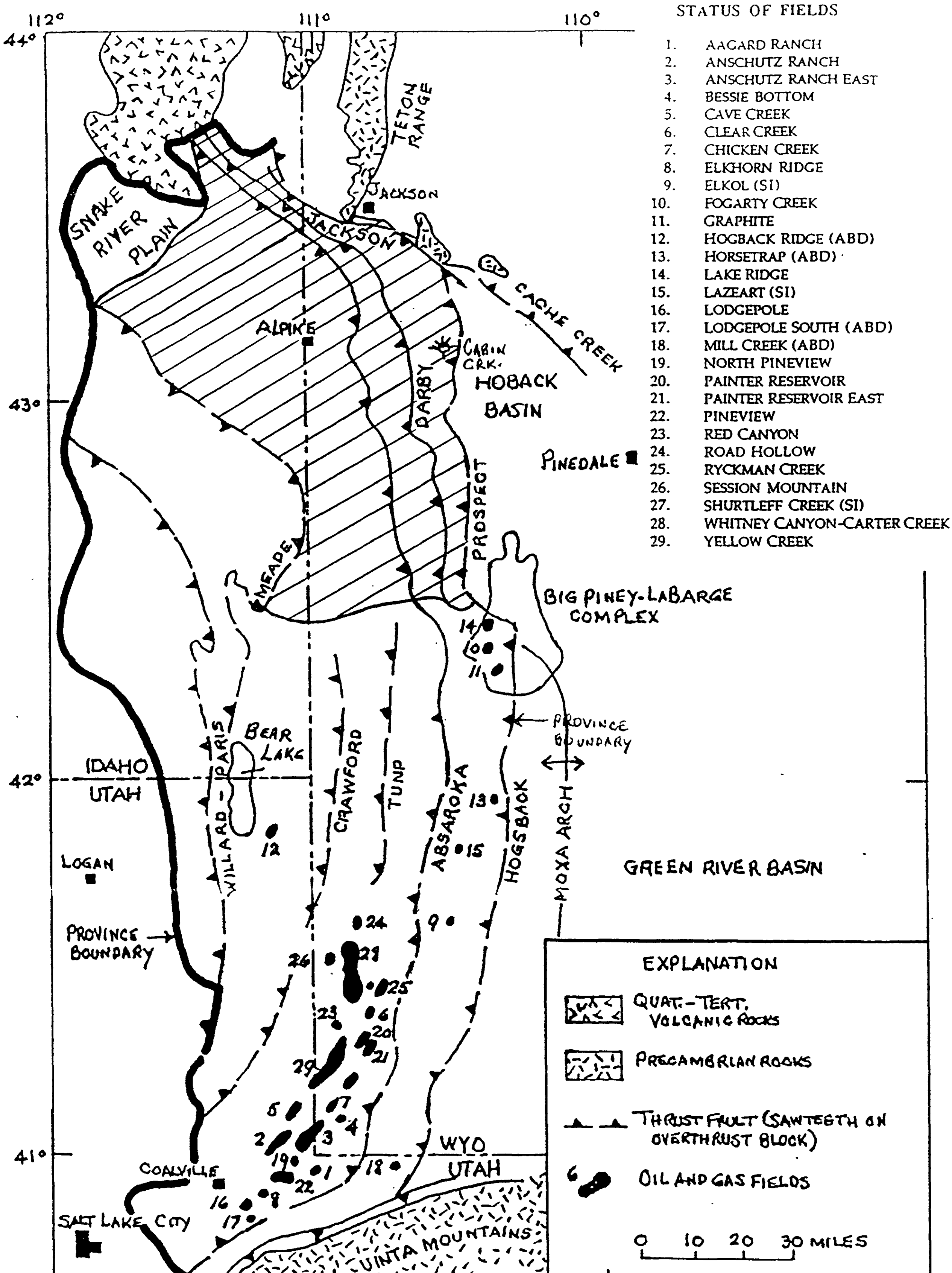


Figure 38. Map of Northern Thrusts play

OIL AND GAS PLAY DATA

PLAY **NORTHERN THRUSTS**
PROVINCE **WYOMING-UTAH-IDAHO THRUST BELT** CODE **03-090-040**

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	**0.3**
Gas	**0.7**

Fractiles * (estimated amounts)

Fractile percentages * ----	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.6**	**4.5**	**10**	**21**	**57**	**135**
Gas (x 10^9 CFG)	**6**	**9**	**27**	**60**	**180**	**900**	**3500**
Reservoir depth (x10^3 ft)							
Oil	**4.5**			**10**			**15**
Gas (non-associated)	**4.5**			**10**			**15**
Number of accumulations	**5**	**16**	**24**	**30**	**36**	**44**	**50**

Average ratio of associated-dissolved gas to oil (GOR)	**8000**	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.

ABSAROKA THRUST GAS PLAY (050)

ABSAROKA THRUST OIL PLAY (060)

The two plays are combined and treated under one discussion because they share a common play area, although they were assessed as individual plays differentiated only by the hydrocarbon commodities assessed. The area of these two plays contains nearly all of the discovered fields in the province. The plays are characterized by gas and oil accumulations in dolomite and sandstone reservoirs in hanging-wall anticlines sourced by footwall Cretaceous shale along three subparallel lines of folding within the Absaroka thrust plate. Fields on the eastern line of folds produce mainly oil with associated gas from Mesozoic rocks (mainly Nugget Sandstone), fields on the central line of folds produce primarily sour, wet gas and condensate from Paleozoic rocks (mainly Mission Canyon Limestone), and the low-relief western line of anticlinal folds produces minor wet gas and condensate, also from Paleozoic rocks. The play area trends north-south for approximately 140 mi and ranges from 18-35 mi in width in northern Utah and southwestern Wyoming. Play boundaries and fields are shown on figure 39.

High-quality reservoir rocks of demonstrated productive capacity range from Upper Cretaceous to Ordovician in age and include 12 different formations (fig. 35). The major producing reservoir on the eastern line of folds is the 1,000 ft thick eolian Jurassic Nugget Sandstone which has recorded core porosity that ranges from 2 to 23 percent and permeability ranging from 0.1 to 2,000 millidarcies. Net pay thicknesses range as high as 850 ft. The Nugget produces 44° A.P.I. sweet oil with associated gas from 14 fields. Other productive oil and gas reservoirs are found in the Triassic Ankareh and Thaynes Formations and Jurassic Twin Creek Limestone. The primary reservoir on the central line of folding is the 750 ft thick Mission Canyon Limestone Member of the Mississippian Madison Group. Data from core analysis in this unit shows porosity ranging from 6 to 8 percent and permeability ranging from 0.7 to 1.5 millidarcies. Production of sour gas (15 percent H_2S) and condensate is from an average net pay zone (at Whitney Canyon-Carter Creek) about 260 ft thick in the Mission Canyon. Other sour gas pay zones are in the Lodgepole Limestone, Darby and Phosphoria Formations, Weber Sandstone and Bighorn Dolomite; minor sweet gas and condensate production occurs in Triassic and Jurassic reservoirs. Sour gas production also occurs in 2 fields on the western line of folds from Mission Canyon and Bighorn reservoirs.

Organic-rich shale of Cretaceous age preserved in the footwall of the Absaroka thrust has been well documented by geochemical analysis as the main source of all hydrocarbons trapped in hanging wall structures in the play area. The Absaroka thrust rode on shale in the Cretaceous Bear River Formation, Aspen Shale and Frontier Formation for about 15 mi in an east-west direction in the play. Hanging-wall reservoir rocks are in direct contact with these subthrust source rocks across much of this distance. Hydrocarbons were generated in these shales and migrated along fault pathways into reservoirs in the hanging wall in latest Cretaceous-Tertiary time. Maximum total organic carbon (TOC) recorded from geochemical analysis of the Bear River, Aspen and Frontier is 9.3, 2.7 and 2.0 percent, respectively. Kerogen in these units is mainly mixed Type II and Type III. Preserved organic material is moderately oil-prone and becomes more gas-prone to the west as the percent of humic material increases, and as the maturation level of organic matter advances. This has resulted in hydrocarbons being in the wet gas-condensate stage in fields along the central and west fold trends and in the oil stage in fields on the eastern trend. Excellent shows and recoveries of both oil and gas from down-hole testing are reported in footwall Cretaceous rocks in a few wells, but no wells have been successfully completed in this section as yet.

Traps in productive structures on the fold trends are basically truncation anticlines complicated by faulting (Mesozoic or Paleozoic hanging-wall rocks truncate against the subjacent Absaroka thrust). Structural geometry of traps varies from asymmetric, overturned folds (Ryckman Creek), leading-edge fold pair (Anschutz Ranch East west and east lobes), and upright fold (Whitney Canyon-Carter Creek) (fig. 39). Trap size ranges from one-square mi, low-relief anticlines (Bessie Bottom), to giant accumulations such as Whitney Canyon-Carter Creek which has 1,470 to 2,500 ft of structural closure, a hydrocarbon column of 2,400 ft (Mission Canyon) and an areal extent of 13 mi by 2 mi, and Anschutz Ranch East which has 2,000 ft of structural closure in the west lobe and 1,000 ft in the east lobe. Maximum hydrocarbon column in the Anschutz Ranch East fold pair trap is 2,100 ft. Areal extent of the west lobe is 7 mi by 1.5 mi, and 4 mi by 3/4 mi in the east lobe. Major seals include anhydrite in the Twin Creek Limestone and salt in the Preuss Sandstone, where present, overlying Nugget oil reservoirs in the eastern fold trend, and anhydrite at the top of the Madison Group, along with thick shale in the Triassic section capping wet gas Paleozoic reservoirs in the two western lines of folds. Drilling depths range from about 5,000 to over 17,000 ft to footwall Cretaceous rocks beneath the Absaroka thrust.

Between 1975, when Pineview field was discovered, and 1986 a total of 22 new fields had been found in both plays, 14 on the oil and associated gas productive eastern trend of folds and 8 on the wet gas and condensate productive central and western lines of folds. Cumulative production to the end of 1986 in the oil play is approximately 141 MMBO and 942 BCFG; 4 giant fields, Anschutz Ranch East, Painter Reservoir, Painter Reservoir East and Pineview, have produced the bulk of the oil and gas in this play (fig. 39). Cumulative production for the same period in the gas play from 4 fields reported is 6.6 MMBO (condensate) and 411 BCFG; the giant Whitney Canyon-Carter Creek field accounted for over 90 percent of this total. The largest field in the oil play is Anschutz Ranch East with an estimated 1 BBOE ultimate recovery. Whitney Canyon-Carter Creek is the largest field in the gas play with an estimated ultimate recovery of 500 MMBOE (includes gas, condensate, sulfur and NGL).

Seismic coverage in the northern half of the play is less than 10 percent of the dense coverage in the southern, productive half, with only about 25 total wildcat wells drilled in the northern portion (north of Bighorn production at Road Hollow field). Although the richly productive easterly trend of folds involving the Nugget Sandstone is essentially cut off by overriding of Paleozoic rocks some 10 mi north of Ryckman Creek field, the productive central and western fold trends persist into the sparsely explored northern half of the play. Encouraging oil and gas shows have been reported here in the Bighorn Dolomite in the few wells drilled on these two trends where porous Bighorn in the hanging wall is in direct contact with Cretaceous source beds in the footwall. Frontier and Bear River sandstone reservoirs in the Absaroka footwall have had good to excellent flows of sweet gas and some liquids from tested intervals in the few wells that have penetrated this section throughout the play area. Future potential for the gas play is good to excellent and fair to very good for the oil/associated gas play.

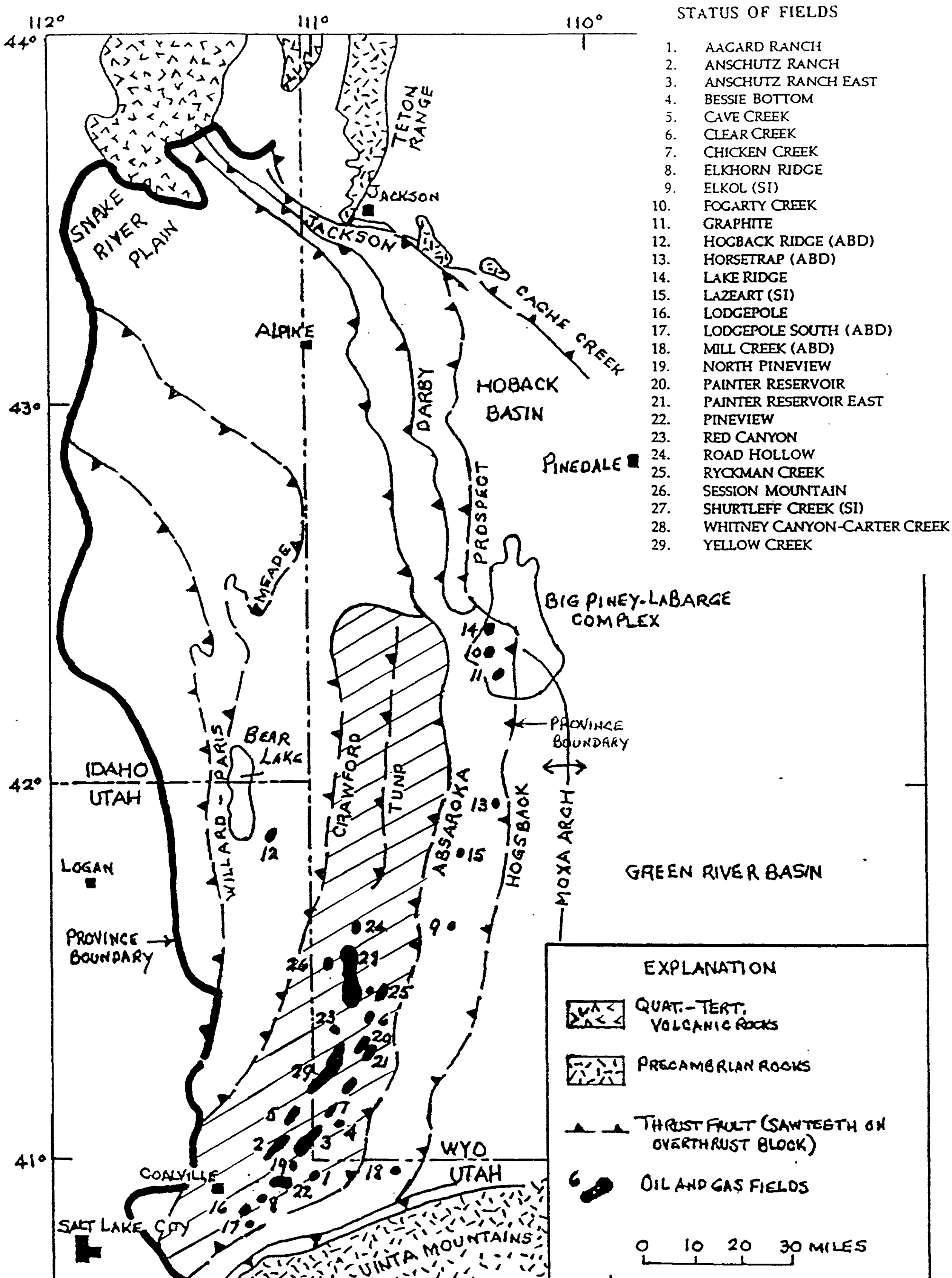


Figure 39. Map of Absaroka Thrust Gas play, Absaroka Thrust Oil play

OIL AND GAS PLAY DATA

PLAY **ABSAROKA THRUST GAS**
PROVINCE **WYOMING-UTAH-IDAHO THRUST BELT** CODE **03-090-050**

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**
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**	**9.6**	**30**	**75**	**200**	**880**	**4300**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**5**			**9**			**16**
Number of accumulations	**6**	**8**	**11**	**13**	**17**	**21**	**25**

Average ratio of associated-dissolved gas to oil (GOR)	**0**	CFG/BBL
Average ratio of NGL to non-associated gas	**116**	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.

OIL AND GAS PLAY DATA

PLAY **ABSAROKA THRUST OIL**
PROVINCE **WYOMING-UTAH-IDAHO THRUST BELT** CODE **03-090-060**

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	**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**	**1.7**	**4.9**	**11**	**23.6**	**63.6**	**150**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**5**			**10**			**17**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**6**	**8**	**10**	**12**	**15**	**20**	**22**

Average ratio of associated-dissolved gas to oil (GOR)	**6500**	CFG/BBL
Average ratio of NGL to non-associated gas	**35**	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.

HOGSBACK THRUST PLAY (070)

The play is structural and defined by probable hydrocarbon accumulations in highly imbricated fault traps related to the hanging wall of the Hogsback thrust in both carbonate and clastic reservoirs. The play extends for 120 mi from the north flank of the Uinta Mountains northward to the west-east strike line of the Darby thrust west of LaBarge, Wyo. The width ranges from 12-15 mi from the toe of the Absaroka thrust on the west, to the toe of the Hogsback thrust, the eastern boundary of the province (fig. 40).

Data from the few discovered fields in the play indicate that reservoirs are mainly carbonate and sandstone rocks in the Triassic Thaynes, Permian Phosphoria and Pennsylvanian Amsden Formations, the Mississippian Madison Group and Devonian Darby Formation (fig. 35). Gross thicknesses of reservoir units vary widely from about 30 ft in the Thaynes, 90 ft in the Phosphoria, 70 ft in the Amsden, 8-10 ft zones in the Madison and 130 ft in the Darby. Reservoir quality is fair but overall on the low side. Cretaceous reservoirs (Frontier and Bear River Formations in the footwall) are mainly thinner sandstones interbedded with shale and are of fair quality.

Limited geochemical analyses suggest that hydrocarbon source rocks may be shale in the Amsden and Phosphoria in the hanging-wall of the Hogsback thrust in the central and northern area of the play, and footwall Cretaceous shale, especially in the southern portion of the play. Analysis of samples in footwall Cretaceous shale, mainly in the Frontier, in the few deep wells in the play indicate that catagenesis has advanced at least to the peak oil-generation stage in these rocks and has reached the dry gas phase in a number of places. Analysis of footwall Frontier shale in the deepest and most southerly well in the play, at 18,400 ft, showed the kerogen in these rocks to be in the oil stage of catagenesis. Description of drill samples about 700 ft uphole in this well indicated brown oil staining with bright yellow cut and fluorescence in thin sandstone zones in the Frontier. Based on the presence of non-commercial oil accumulations in two abandoned fields, Mill Creek and Christmas Creek (fig. 40), hydrocarbons were generated in these footwall Cretaceous shales and migrated along faults into Thaynes, Phosphoria and Darby reservoirs in the hanging wall in Late Cretaceous-early Tertiary time. Fair shows of gas and moderate gas recoveries on DST are reported in the Triassic Thaynes and Phosphoria Formations, Weber Sandstone and Madison Group (where oil was also swabbed) in wells drilled in the central and northern areas of the play.

Traps are in highly faulted, narrow anticlines and within sharply bounded splay faults in the hanging-wall near the eastern edge of the Hogsback thrust. Scant information is available on trap geometry or amount of closure in discovered fields. Seismic and well information indicate that the leading edge of the thrust is characterized by numerous imbricate faults that appear to limit traps to distinct zones within the imbricate faults. This is typified by holes drilled in the vicinity of the one-well Horse Trap field (Amsden gas) (fig. 40), where one of the drill holes cut 12 separate faults within a 4,800 ft interval in Paleozoic rocks. Shale and anhydrite seals are present in both Paleozoic and Mesozoic rocks, although the effectiveness of the seals may be adversely affected in places by excessive faulting. Drilling depths will range from less than 6,000 to about 17,000 ft.

Exploration is minimal and consists of about 30 scattered wells in the overall play since the middle 1960's and only a very limited amount of seismic exploration in the northern half, although seismic coverage in the southern half of the play is nearly as dense as in the area of the Absaroka thrust plays (050, 060). Exploration to date has resulted in the discovery in the early 1980's of 3 one-well fields (all abandoned as sub-commercial) in 4 different age reservoirs: Mill Creek (Devonian Darby Formation, cumulative production of 2,205 barrels of 46° A.P.I. green oil), Horse Trap (Pennsylvanian Amsden Formation, cumulative production of 1.3 BCF of wet gas and 6,000 barrels of 50° A.P.I. condensate), and Christmas Creek (Triassic Thaynes and Phosphoria Formations, cumulative production of 14,448 barrels of 36° A.P.I. oil (fig. 40)). Projected sizes of undiscovered accumulations are estimated to be in the small to medium size range; future potential for oil is moderate and fair to good for gas.

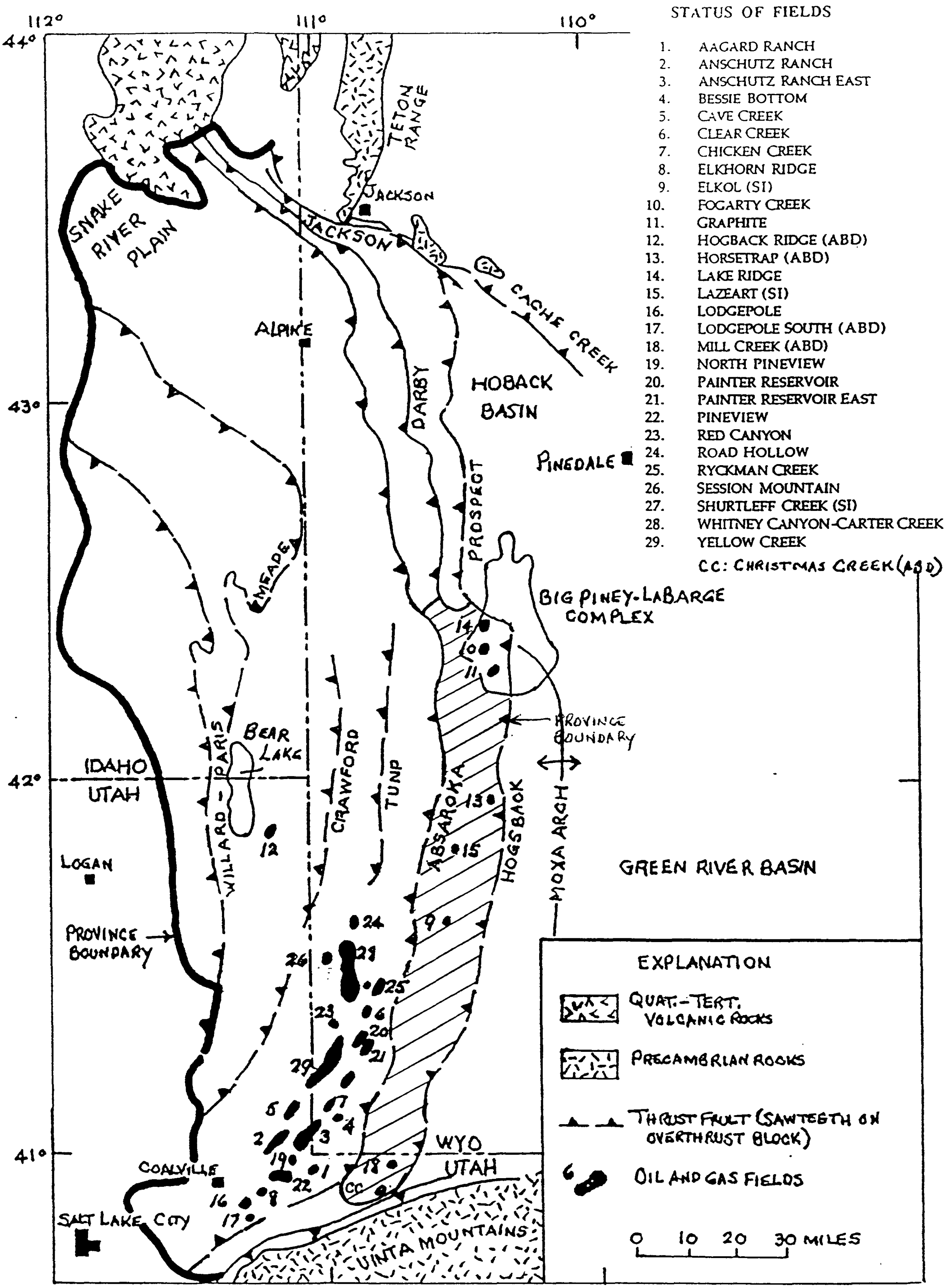


Figure 40. Map of Hogsback Thrust play

OIL AND GAS PLAY DATA

PLAY **HOGSBACK THRUST**
PROVINCE **WYOMING-UTAH-IDAHO THRUST BELT** CODE **03-090-070**

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	**0.4**
Gas	**0.6**

Fractiles * (estimated amounts)

Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil ($\times 10^6$ BBL)	**1**	**1.4**	**3.3**	**7**	**14.5**	**38**	**90**
Gas ($\times 10^9$ CFG)	**6**	**7**	**15**	**25**	**58**	**180**	**500**
Reservoir depth ($\times 10^3$ ft)							
Oil	**6.5**			**10**			**17**
Gas (non-associated)	**6.5**			**10**			**17**
Number of accumulations	**3**	**5**	**10**	**15**	**20**	**26**	**28**

Average ratio of associated-dissolved gas to oil (GOR)	**500**	CFG/BBL
Average ratio of NGL to non-associated gas	**30**	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.

CRETACEOUS STRATIGRAPHIC PLAY (080)

The play is characterized by probable oil accumulations resulting from pinchout of reservoir sandstone facies updip and eastward into shale source-rock facies of Cretaceous age on the west-dipping trailing edge of the Hogsback thrust. The play extends from the Wyo.-Utah line northward for 115 mi to a point west of the LaBarge complex (fig. 41). The western boundary of the play is at the toe of the Absaroka thrust and the play extends 3-8 mi to the east on the western part of the hanging-wall of the Hogsback thrust. Within this trend lies the axial trace of the narrow, sharply folded Lazeart syncline whose gently inclined eastern limb forms the trailing edge (hanging-wall) of the Hogsback thrust. The western limb of the syncline is vertical, overturned in places as much as 35° past vertical, and truncated by the Absaroka thrust.

Nearly the entire 15,000 ft Cretaceous section is present in the play, including the Adaville, Hilliard and Frontier Formations, Aspen Shale and Bear River Formation (fig. 35). Potential reservoirs are limited, however, to sandstone beds of fluvial, deltaic, barrier bar and offshore bar origin within the 3,000 ft-thick Frontier and 800 ft thick Bear River. Reservoir sandstones interbedded with coals in the lower Frontier range from 10-40 ft thick, have porosities of from 7-12 percent, but generally have low permeabilities, averaging 0.1 millidarcies or less. Thin, fossiliferous brown sandstones of the Bear River are interbedded with black shale and thin stringers of impure coal. Reservoir quality of the sandstones is fair to good, with porosity ranging up to 16 percent and permeability commonly exceeding 0.1 millidarcies. Reservoirs in both formations, or equivalent units, are productive in a number of fields on the Moxa Arch in the Green River Basin (fig. 41).

Within the total Cretaceous section deposited in the province, the thickness of dark shales containing organic carbon alone exceeds 5,000 ft. TOC of shale in the Adaville and Hilliard is about 1 wt. percent, but the most organic-rich shale in the play, and the main oil source rock, is interbedded with sandstone in the Frontier and Bear River and intervening Aspen Shale. Maximum TOC measured in these units is 2 wt. percent, 9.3 wt. percent, and 2.7 wt. percent, respectively. These interbedded shale beds contain mixed Type II and Type III kerogen which is at the stage of peak oil generation mainly in the vicinity of the trailing edge of the Hogsback thrust hanging-wall. Produced oil from two recent Frontier discoveries is 40° A.P.I. gravity, waxy and has a pour-point of 70° F. Active oil seeps are present in outcrops of the Cretaceous section along and in front of the toe of the Absaroka thrust in the southern part of the play, where a sizeable number of older, shallow wells have produced small amounts of oil. Generation and migration of oil occurred in Late Cretaceous to early Tertiary time from indigenous source to reservoirs in the Frontier and Bear River. It has been suggested that the Cretaceous shale section is still generating hydrocarbons.

Stratigraphic trap potential exists where porous and permeable sandstone beds grade updip (east) and pinchout into tighter, non-permeable sandstone or shale on the trailing edge of the Hogsback thrust. Top and bottom seals are source shale encompassing the reservoir sandstone. Several fields on the Moxa Arch, productive from both Frontier and Bear River, are at least partly controlled by this same type of stratigraphic pinchout. Two recent new field wildcat discoveries in the play are productive at depths of less than 7,000 ft; however, the projected depth range for future drilling is estimated to be from 4,000-17,000 ft. Seismic data in the vicinity of the two discoveries shows that they are located on uniform westward-dipping (±30°) beds on the Hogsback hanging-wall with no indication of structural reversal or faults to account for hydrocarbon accumulations in the two discoveries, except by stratigraphic control.

The earliest exploration and drilling in the play was concentrated near oil seeps in the vicinity of the present-day Aspen field in 1884. The first wells completed, however, were in the nearby Spring Valley field in 1900, followed by the discovery of the Sulphur Creek field in 1942 (fig. 41). Depth to production in the Aspen, Frontier, and Bear River in these field ranges from 100-2,000 ft and oil gravity ranges from 22° to 48° A.P.I. Two recent discoveries in 1984 and 1985, the Lazeart (87 BOPD) and Elkol (6 BOPD) fields (currently shut-in), were drilled to test the validity of a Frontier-Bear River stratigraphic play and were based on the presence of known, productive shallow reservoir sandstones in the older fields, modern geochemical modeling and seismic-stratigraphic interpretation. Without additional offset drilling the size of these accumulations cannot be determined, however, some 20 separate sandstone zones with oil saturation were logged between 6,300 and 7,000 ft in the lower Frontier in the Lazeart discovery.

Cumulative production from all fields in the play to the end of 1986 was 276,909 BO and 30,525 MCFG. Future potential for oil and associated gas is low to moderate and field sizes are anticipated to be in the small to medium category. The amount of oil-in-place in Cretaceous rocks in the play, based on present well data, appears to be quite significant, but improvement in extraction practices will be necessary in order to realize commercially recoverable amounts of oil in undiscovered accumulations. Advances in the technology of reservoir stimulation, possibly the use of inclined drilling techniques, and different completion methods may be required to accomplish this.

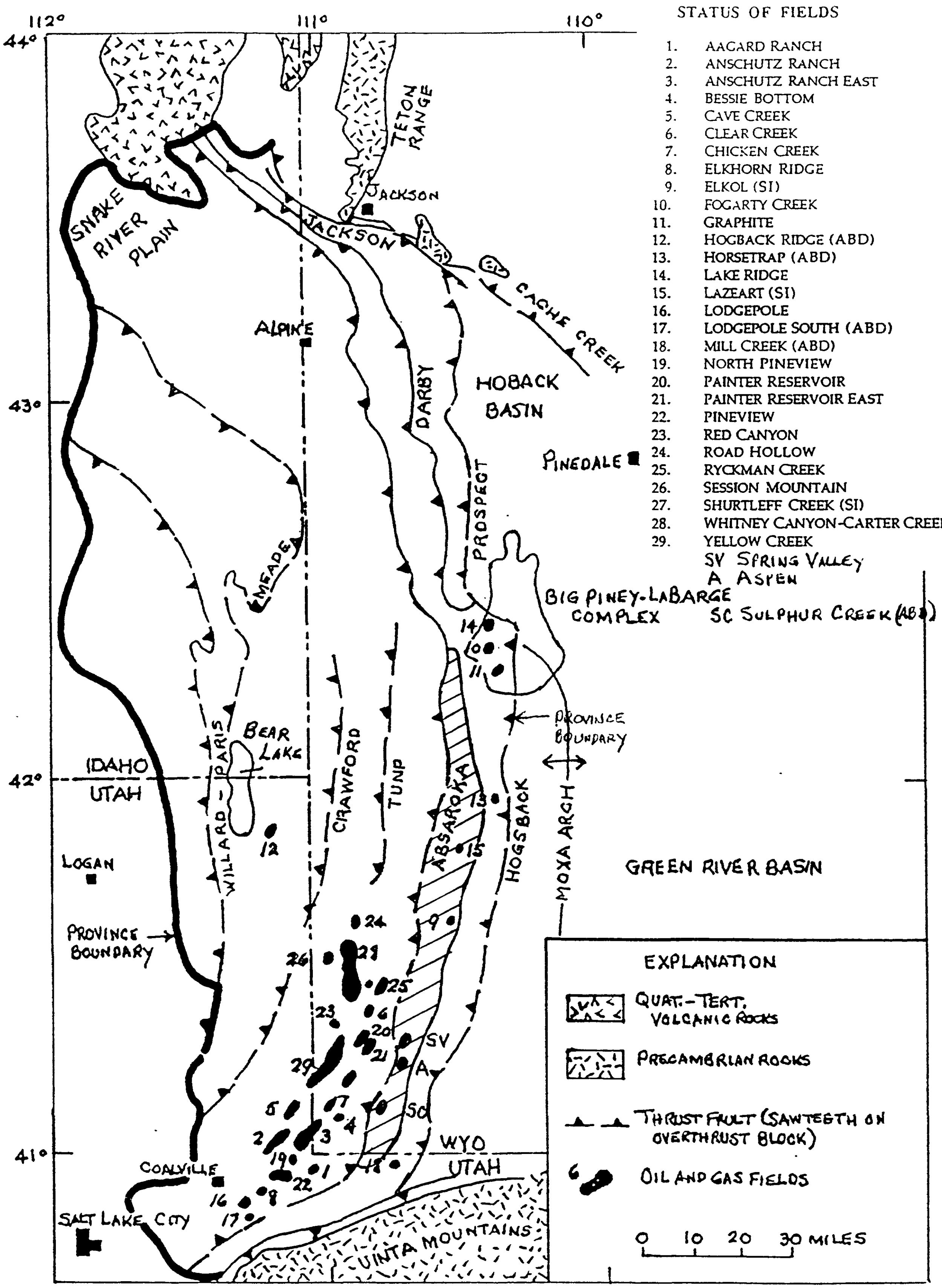


Figure 41. Map of Cretaceous stratigraphic play

OIL AND GAS PLAY DATA

PLAY **CRETACEOUS STRATIGRAPHIC**
PROVINCE **WYOMING-UTAH-IDAHO THRUST BELT** CODE **03-090-080**

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**	**1.1**	**1.5**	**2.5**	**5.1**	**20**	**100**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**4**			**10**			**17**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**5**	**5**	**6**	**7**	**9**	**13**	**25**

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.

NORTHERN ARIZONA PROVINCE (091)

By William C. Butler

INTRODUCTION

The province covers an area of roughly 69,000 mi^2 mostly in the southwestern portion of the Colorado Plateau, an area characterized by Laramide age monoclines and gentle crustal warping. Major structural features include the Grand Canyon, Mogollan Highlands transition zone, Black Mesa basin and Defiance uplift. The northwestern part of the province includes the Cordilleran hingeline that involves platform and miogeosynclinal rocks of Paleozoic age, plus continental to coastal sediments of Mesozoic age. These rocks are considered as the southern extension of the Sevier Thrust Belt of Utah, and were affected by thrusting in Late Cretaceous time followed by regional extension in the Cenozoic. Approximately 25,000 ft of sedimentary rocks (based on seismic data) may fill resultant basins here (fig. 42). Further east (to approximately 112° 30' W.) high-angle, north-south trending normal faults occur, which have displacements of up to several thousands of feet. The southwestern part of the province is characterized by structural horsts and half-grabens (basin and range). The extreme southern part of the province involves a wider transition from relatively simple Plateau structure and stratigraphy, to complex basin and range style detachment faults. Uplifted and dissected rocks of Proterozoic age crop out in this transition zone (Mesozoic Mogollon Highlands) and exhibit very little evidence of hydrocarbon potential. Only one oil field of significant size has been discovered in the province, Dineh-bi-Keyah, in the northeastern corner of Arizona. Two plays were individually assessed in the province: Defiance Uplift (020), and Oraibi Trough (030)

ERA	PERIOD		STRATIGRAPHIC UNITS — NORTH		STRATIGRAPHIC UNITS — SOUTH
CENOZOIC	QUAT.	HOLOCENE		UNDIFF. ALLUVIUM & DUNES	ALLUVIUM WITH OLDER BASALT AND TUFF
		PLEISTOCENE		UNDIFF. OLDER VALLEY FILL	
	TERTIARY			CHUSKA SS (EAST)	BIDAHOCHI FM
MESOZOIC	CRETACEOUS	LATE	MESA-VERDE GRP	YALE POINT SS	UNDIFF. ROCKS (MOSTLY OF MANCOS SH AND DAKOTA SS)
				WEPO FM	
				TOREVA SS	
				MANCOS SH UNDIFF.	
				DAKOTA SS	
		EARLY		(? BURRO CANYON FM)	MISSING
	JURASSIC	LATE	MORRISON FM	BRUSHY BASIN MB	UNDIFF.
				WESTWATER CANYON MB	
				RECAPTURE CREEK	
				SALT WASH MB	
				BLUFF MB	
			SAN RAFAEL GRP	COW SPRINGS SS-BLUFF-SUMMERVILLE	MISSING
				(? TODILTO LS)	
		—?—		ENTRADA SS	
		MIDDLE		CARMEL FM	
		EARLY ?	GLEN CANYON GRP	NAVAJO SS	
	EARLY JURASSIC AND/OR LATE TRIASSIC			KAYENTA FM	UNDIFF.
				? MOENAVE FM	
	—?—			WINGATE SS	
	TRIASSIC	LATE	CHINLE FM	CHURCH ROCK MB	UNDIFF.
				OWL ROCK MB	
				PETRIFIED FOREST MB	
				SONSELA SS MB	
				MONITOR BUTTE MB	
				SHINARUMP CONGLOMERATE MB	SHINARUMP CONGLOMERATE MB
		EARLY		MOENKOPI FM	MOENKOPI FM
PALEOZOIC	PERMIAN	MIDDLE		? KAIBAB LS	KAIBAB LS - SAN ANDRES LS EQUIV. — ?
		EARLY		? TOROWEAP FM - DE CHELLY SS	GLORIETA SS - DE CHELLY SS - COCONINO SS EQUIVALENTS
				COCONINO SS - DE CHELLY SS	
				(? HERMIT SH)	
			SUPAI CUTLER GRPS	ORGAN ROCK SH	"UPPER UNIT" ABO-YESO-CORDUROY EQUIV. / EVAPORITES FT. APACHE LS
				CEDAR MESA SS	
				HALGAITO SH	
	PENNSYLVANIAN		HERMOSA GRP	SUPAI—HONAKER TRAIL FM	"LOWER UNIT" EARP FM EQUIV. / BIG A BUTTE-AMOS WASH-CIBECUE-GAMMA "B"
				PARADOX FM: ISMAY MB	NACO GRP UNDIFF. (HORQUILLA - HERMOSA FMS EQUIV.)
				PARADOX FM: DESERT CREEK MB	
				PARADOX FM: AKAH MB	
				PARADOX FM: BARKER CREEK MB	
				PARADOX FM: ALKALI GULCH MB	
				PINKERTON TRAIL FM	
				MOLAS SH	MOLAS SH
	EARLY MISSISSIPPIAN			REDWALL LS	LEADVILLE LS
	LATE DEVONIAN			OURAY LS	MARTIN FM
				TEMPLE BUTTE — UPPER ELBERT FMS	
				MC CRACKEN SS	
				ANETH FM	
	CAMBRIAN	MIDDLE TO LATE		LYNCH DOLOMITE	MISSING
			TONTO GRP	? MUAV LS	
				BRIGHT ANGEL SH	
		EARLY-MIDDLE		TAPEATS SS - ? IGNACIO QRTZITE	
PRE-CAMBRIAN	LATE PROTEROZOIC			CHUAR GRP	METASEDIMENTS
				UNKAR GRP	
	EARLY PROTEROZOIC			VISHNU SCHIST	METAMORPHICS & GRANITE

Figure 42. Generalized stratigraphic columns, Northern Arizona province

DEFIANCE UPLIFT PLAY (020)

The main basis of the play is the combination of thermally mature, organic-rich black shale source rocks of Pennsylvanian age brought to thermal maturation by heat generated from intrusive igneous rocks of Cenozoic age, with the fractured intrusives acting as reservoirs. The Dineh-Bi-Keyah field is the primary analog, however, the play is expanded, conceptually, to include all strata of the Pennsylvanian Hermosa Group (Horquilla Formation) as both source rock and reservoir. These rocks were deposited on the perimeter of the Defiance Uplift, which was reactivated in late Paleozoic time. The play covers an area of 1,800 mi^2 on the northern, western, and southern flanks of this uplift in northeastern Arizona (fig.. 43).

Total rock thicknesses include 1,500-3,750 ft of Paleozoic and 1,500-2,000 ft of Mesozoic strata. Pennsylvanian strata range from 100 to 1,000 ft thick and thicken generally northward into the Paradox basin. Hermosa equivalent (in part) strata of the Paradox Formation (fig. 42) are the major source and reservoir rocks productive of oil and gas at the giant Aneth field in the Blanding Basin of southeastern Utah. Here, depositional cycles of organic-rich, black pelletal shale and dolomite encase northwest-trending fairways of discontinuous, porous carbonate mound reservoirs (algal bioherms and oolite banks) on the southern shelf of the Blanding basin. In addition, oil and gas is produced from similar biohermal carbonate reservoirs in the Paradox Formation, east of the Dineh-Bi-Keyah field, in northwestern New Mexico (fig. 43). Similar source and reservoir relationships are believed to be present in the play area. Depths to Pennsylvanian reservoirs range from 1,500 to more than 3,500 ft.

Outcrops exhibit thermal maturity levels ranging from 0.48 to 0.60 percent R_o. However, existing anomalous heat sources and igneous intrusives, such as diorite laccoliths in the Carrizo Mountains, can raise maturation levels of potential source rocks into the oil-generating window. Positive gravity and magnetic anomalies suggest intrusive igneous rocks at shallow depths within the play. Long-distance migration of hydrocarbons from more deeply buried and more mature Pennsylvanian source rocks in the Black Mesa Basin may have filled potential stratigraphic-structural traps on the west and northwestern flanks of the Defiance Uplift. Structural relief on the Precambrian surface of 2,000 to 3,000 ft, plus a number of undrilled Laramide age folds, offer the additional possibility for late, updip migration of oil into stratigraphic, structural and combination traps.

The major field in the play, Dineh-Bi-Keyah, is a unique hydrocarbon accumulation discovered in 1967, which is estimated to be 20 MMBO (ultimately recoverable) in size. It produces from fractured syenite sills of Cenzoic age intruding Pennsylvanian source rocks and is structurally controlled, locally, by a northwest-trending anticline. Exclusive of this field, drilling density in the play is about one well per 45 mi^2. No wells south of Canyon DeChelly have been drilled deeper than 2,500 ft. Limiting factors to the minor future potential are the decreasing quality and thickness of source rocks in the southern part of the play. However, the potential exists for additional fields of small size.

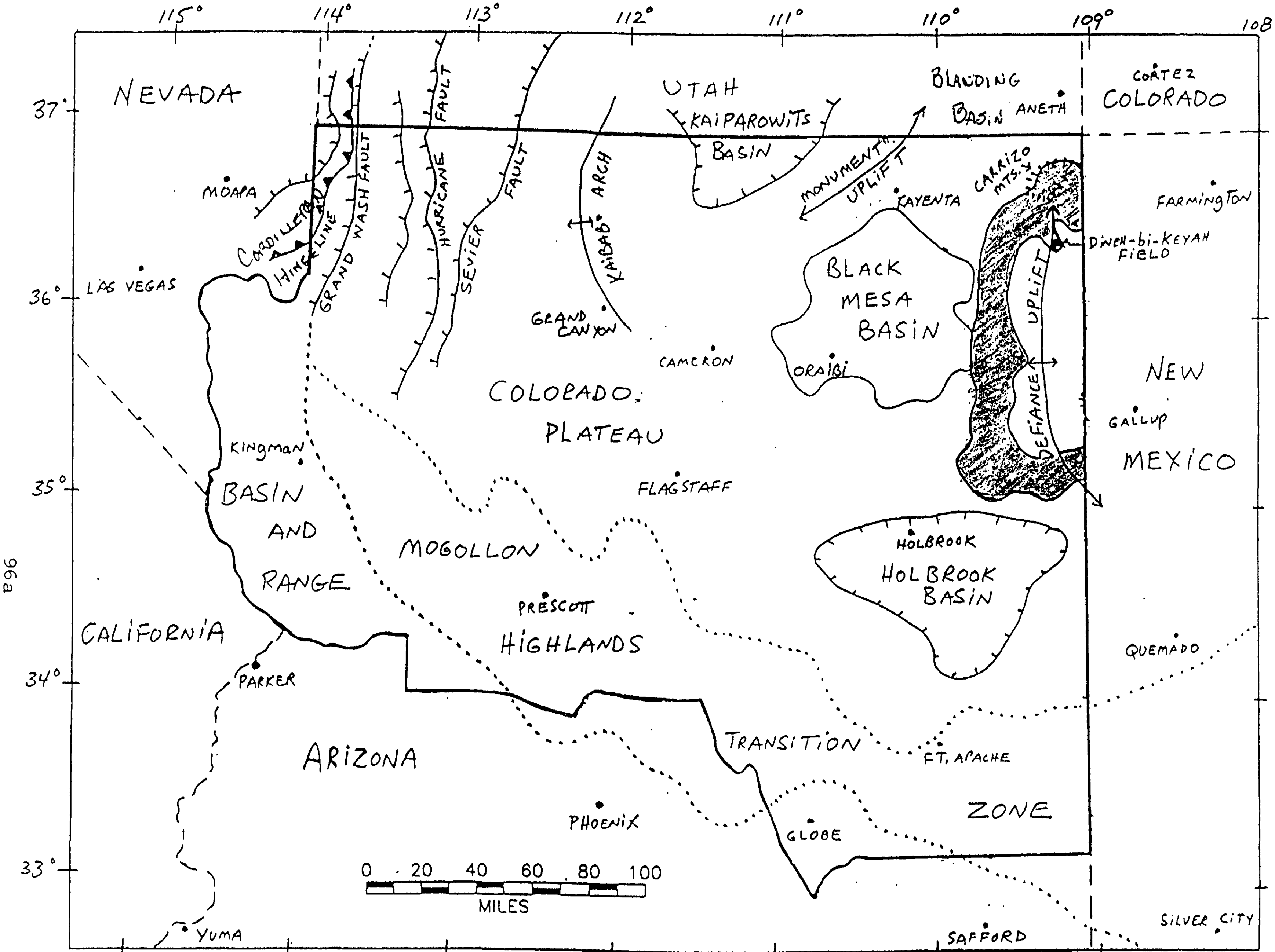


Figure 43. Map of Defiance Uplift play

OIL AND GAS PLAY DATA

PLAY **DEFIANCE UPLIFT**
PROVINCE **NORTHERN ARIZONA** CODE **03-091-020**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**0.50**
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)	**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	**0.90**

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**	**1.06**	**1.4**	**2**	**3**	**10**	**50**
Gas (x 10^9 CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth (x10^3 ft)							
Oil	**1.5**			**2.5**			**3.5**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**1**	**1**	**2**	**2**	**2**	**4**	**5**

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.

ORAIBI TROUGH PLAY (030)

The play is based on the potential relationship of Late Devonian age source and reservoir strata involved in anticlinal and stratigraphic traps in the Devonian Oraibi sedimentary trough. The trough coincides nearly geographically with the Greater Black Mesa basin of younger, Laramide origin. The play covers 18,750 mi^2 and is located southeast of the Monument uplift, west of the Defiance uplift and north of the Holbrook basin (fig. 44). Roughly one-half of the 4,000-9,000 ft of sedimentary rocks in the play, which thin generally southward, consist of foreland shelf deposits of Paleozoic age; the remainder consist of mixed continental-marine deposits of Mesozoic age.

Probable reservoirs are in deltaic clastics of the Late Devonian McCracken Sandstone (productive in the Paradox basin) and dolomite to sandy dolomite strata of the Elbert Formation. Waxy shale and anhydrite of the Elbert would provide good seals. A secondary potential for both reservoir and source rocks may exist in Cambrian, Mississippian, and Pennsylvanian strata.

Probable source rocks for oil and gas are the dark, glauconitic, argillaceous dolomite, and interbedded dark carbonaceous shale and siltstone with minor limestone and evaporites of the Aneth Formation, also of Late Devonian age (fig. 42). These strata in the play area, and particularly in outcrops to the south (Mogollon area), are known for their fetid odor, seeps, shows and hydrocarbon impregnation. Based on the thermal maturation level of outcrops (percent R_o = 0.41-0.60) and thermal gradients, the floor of the oil window in Devonian rocks may range from +3,000 ft to -500 ft in elevation.

Potential structural traps include localized zones on anticlines and monoclines of Laramide origin. Certain upfolds have a composite axial length of over 350 mi, and some of the anticlines have axes that are 50-70 mi in length. Structural closure on these anticlines ranges from 500-1,000 ft. In addition, reservoir pinchouts eastward, toward the Defiance uplift, and updip wedge-out of reservoirs southward toward the Mogollon zone, are potential stratigraphic traps. Depth to probable traps would range from 3,300 to 7,500 ft.

Exploration in the play is minimal overall averaging only one wildcat well drilled per 75 mi^2, with the exception of more concentrated exploratory drilling (one well per 7 mi^2) in the Arizona portion of the Blanding basin. The average total depth per well in the play is 5,750 ft, and less than 2 percent of the wells have penetrated even the Early Permian Coconino Sandstone. More significantly, less than 1 percent of all wells have penetrated Devonian age rocks, the primary objective of the play. The future potential for undiscovered resources is estimated to be moderate to good; however, factors of possibly low total organic carbon in source rocks and low quality of reservoir rocks may further limit the potential in some areas of the play.

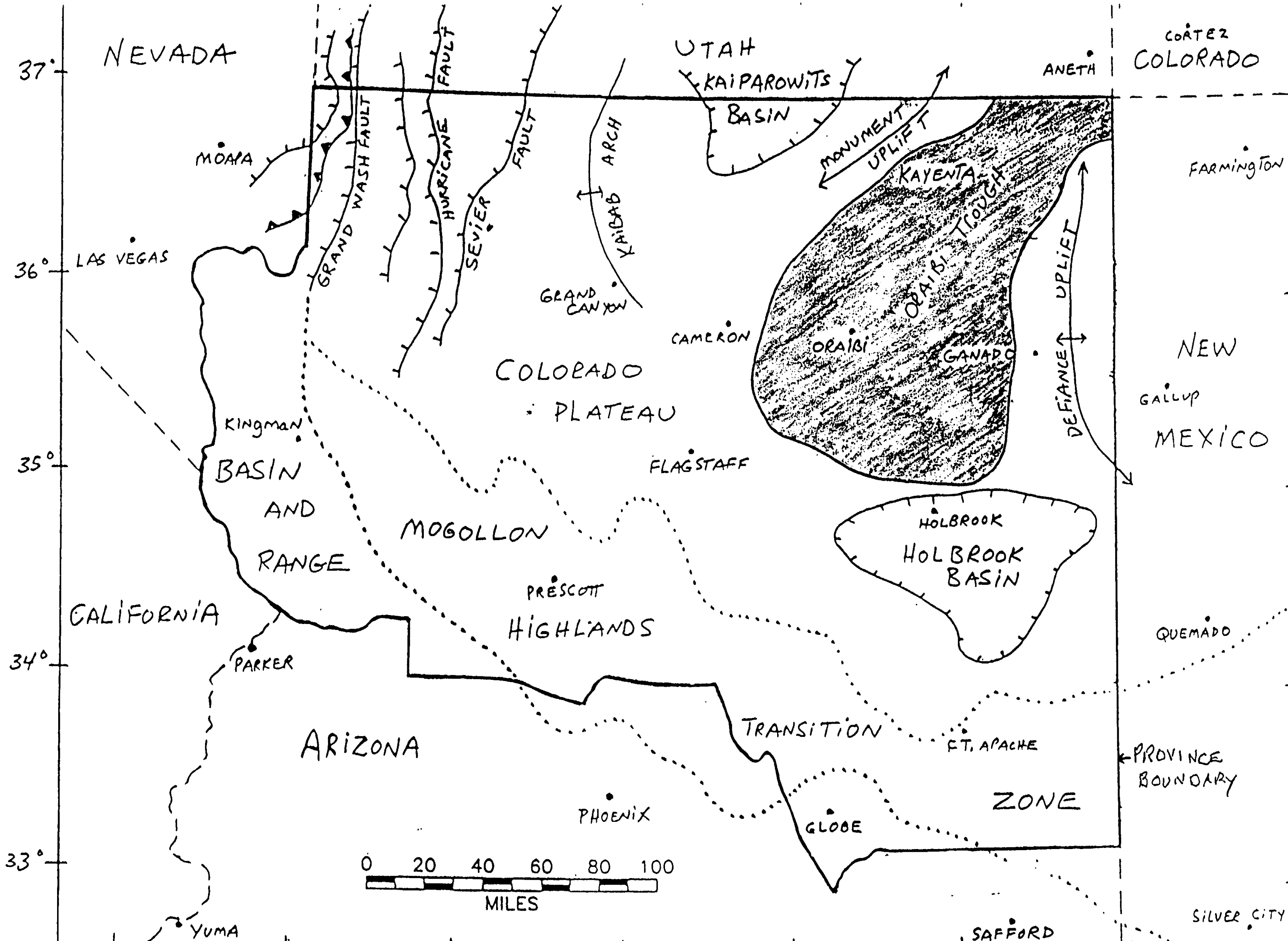


Figure 44. Map of Oraibi Trough play

OIL AND GAS PLAY DATA

PLAY **ORAIBI TROUGH**
PROVINCE **NORTHERN ARIZONA** CODE **03-091-030**

Play attributes

	Probability of attribute being favorable or present
Hydrocarbon source (S)	**0.90**
Timing (T)	**1.00**
Migration (M)	**0.90**
Potential reservoir-rock facies (R)	**1.00**
Marginal play probability (MP) (S x T x M x R = MP)	**0.81**

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 ($\times 10^6$ BBL)	**1**	**1.5**	**4**	**10**	**20**	**65**	**200**
Gas ($\times 10^9$ CFG)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Reservoir depth ($\times 10^3$ ft)							
Oil	**4**			**6**			**7.5**
Gas (non-associated)	**0**			**0**			**0**
Number of accumulations	**2**	**3**	**4**	**5**	**6**	**7**	**8**

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.

SOUTH-CENTRAL NEW MEXICO PROVINCE (092)

By William C. Butler

INTRODUCTION

The province is roughly 43,000 mi^2 in area, characterized by diverse and complex geology, and located principally in the easternmost part of the Basin and Range physiographic province. However, the northwest quadrant lies within the southeastern part of the Colorado Plateau, and the southwest quadrant is located in a zone of transition between the less complicated structure of the plateau and the more complex structure of the Basin and Range area. Major features include a series of Paleogene-Neogene basins (Mesilla, Jornada Del Muerto, Tularosa, which comprise the Orogrande and Estancia basins) filled with up to 10,000 ft of alluvium and volcanics which obscure a thick section of deeply buried Paleozoic strata (fig. 45). The most prominent uplift in the province is the Organ-San Andres-Oscura uplift.

This part of New Mexico was near the terminus of the northeast-trending Transcontinental Arch during the late Proterozoic and Paleozoic. Within this time period, sediments were deposited in platform, shallow shelf, basinal and alluvial plain environments. Paleozoic land masses surrounding the province include the Pedernal arch, Burro uplift, and Zuni uplift. In late Paleozoic time, convergence of the North and South American plates resulted in intraplate deformation, which included development of the late Paleozoic Orogrande basin. During the Laramide orogeny, older structures and zones of weakness were rejuvenated and northeast directed thrusts developed in the southwestern part of the province. Laramide plutons and other intrusions, with attendant mineralization, are present in the basin and range transition zone. The southerly flowing Rio Grande River bisects the province and follows numerous, 20-30-mi wide faults and grabens that formed in Oligocene to Holocene time. The province is not productive of oil or gas. One play was individually assessed, the Orogrande Basin play (020).

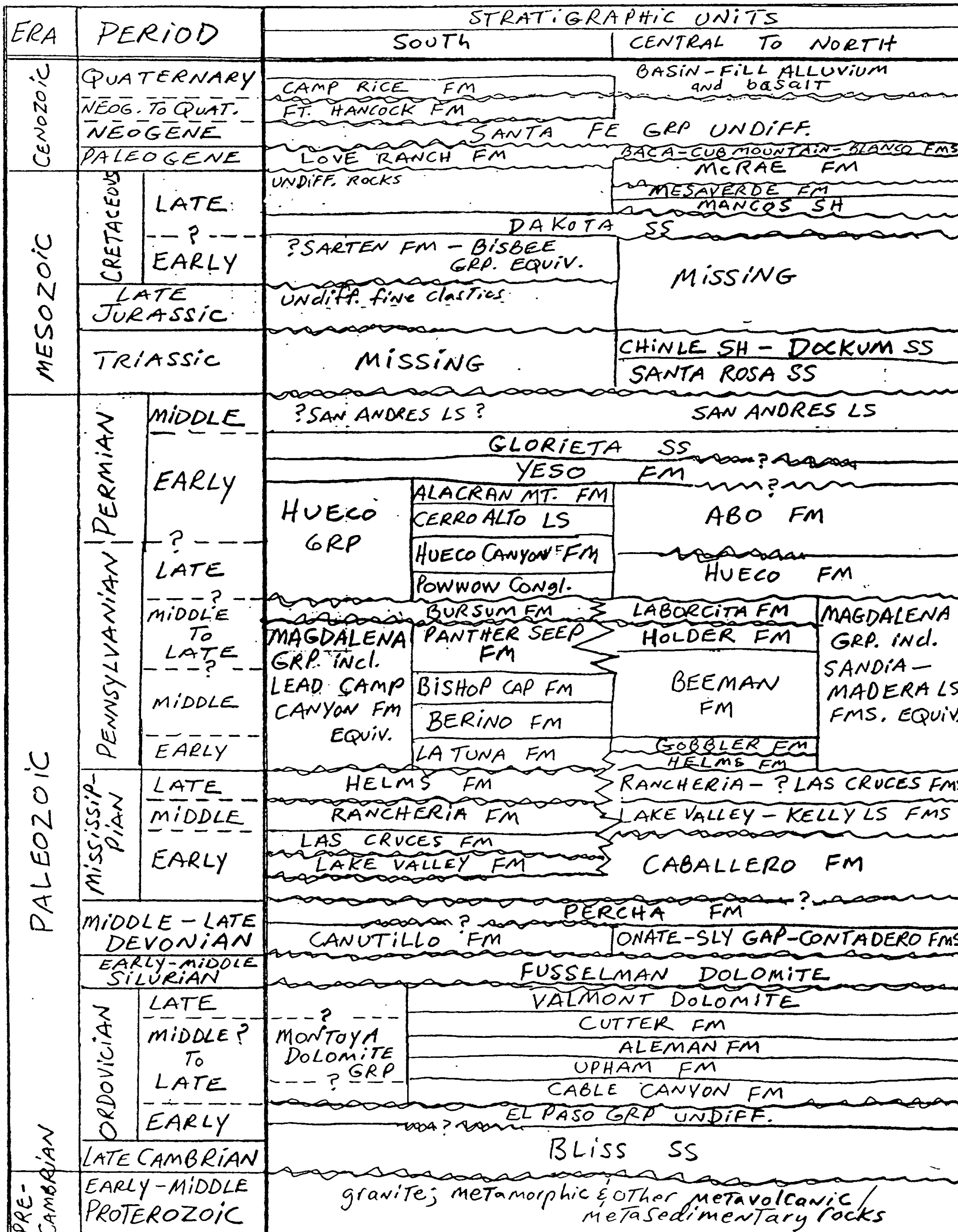
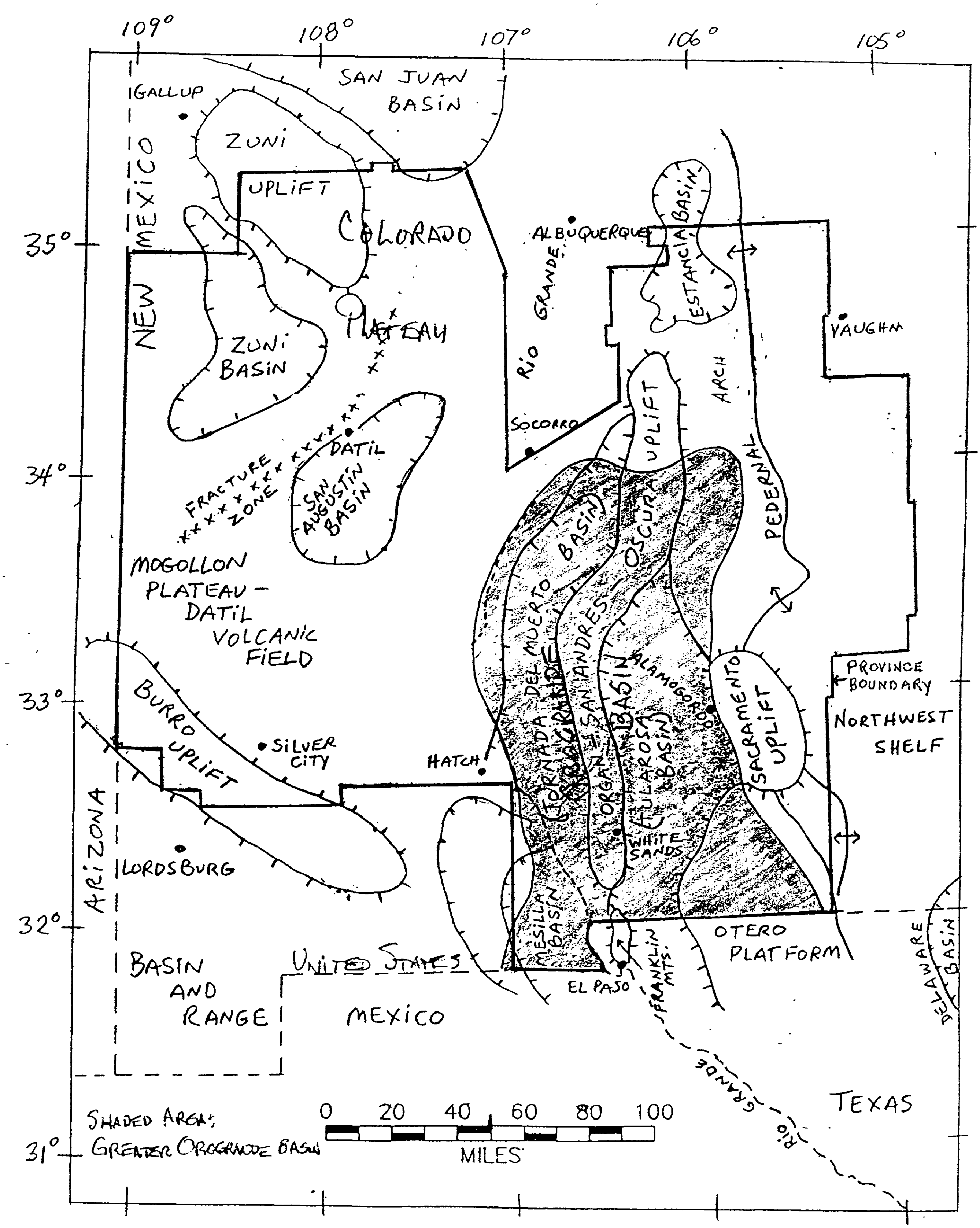


Figure 45. Generalized stratigraphic column, South-Central New Mexico province



Figuure 46. Map of Orogrande Basin play

OIL AND GAS PLAY DATA

PLAY **OROGRANDE BASIN**
PROVINCE **SOUTH-CENTRAL NEW MEXICO** CODE **03-092-020**

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	**0.70**

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	**0.25**
Gas	**0.75**

	Fractiles * (estimated amounts)						
Fractile percentages *	*100*	*95*	*75*	*50*	*25*	*5*	*0*
Accumulation size							
Oil (x 10^6 BBL)	**1**	**1.2**	**2.2**	**4**	**7.7**	**20**	**50**
Gas (x 10^9 CFG)	**6**	**7.2**	**12**	**22**	**40**	**100**	**250**
Reservoir depth (x10^3 ft)							
Oil	**2**			**7.5**			**10**
Gas (non-associated)	**2**			**9**			**22**
Number of accumulations	**1**	**3**	**7**	**10**	**15**	**23**	**30**

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.

OROGRANDE BASIN PLAY (020)

The play is speculative and based on the relationship of thermally mature source rocks and phylloid algal carbonate reservoirs of the Pennsylvanian Magdalena Group in anticipated structural and stratigraphic traps in Tertiary basins within the Orogrande basin (fig. 46). The Magdalena Group is a thick, widespread section that is virtually unexplored. The section includes reefoid units that bear some resemblance to rocks that are productive in the possibly analogous Delaware basin of West Texas, east of the province. Total thickness of strata ranges up to 25,000 ft. The Paleozoic part of the section ranges from 4,000 to 8,500 ft in thickness, and wedges out generally northward, but also eastward (basin to shelf) where the number and magnitude of disconformities increase. Important lateral and stratigraphic variations are present in the many isolated, disconnected outcrops that expose the total stratigraphic section along the north-south backbone in the play (Organ-SanAndres-Oscura uplift and Franklin Mountains).

Potential reservoirs are in phylloid algal mounds, banks and bioherms of the Magdalena Group that range from 75-100 ft in thickness. Other potential reservoirs in the Pennsylvanian section include rocks occurring in a close association of alternating porous and permeable algal reefs, calcarenites, coquinas and quartz sandstones, with other beds of carbonaceous shale and dark, fetid petroliferous limestones. In addition, there are probable reservoirs of lesser quality in Mississippian and Permian bioherms that range up to 350 ft in thickness, and in other, Permian petroliferous carbonates (fig. 45).

The most promising source rocks are organic-rich, brown to black shales of the Panther Seep Formation of the Magdalena Group. Overall, Pennsylvanian strata in the Orogrande basin range from 1,000 to 3,300 ft in thickness, and are thickest in the central Tularosa basin. Other probable source rocks are Ordovician and Silurian dolomites and dark, basinal Devonian shales, as well as carbonate rocks and shales in the Permian Hueco Formation. Vitrinite reflection data from outcrops of these rocks ranges from about 1.2 R_o to 4.0 percent R_o in the central San Andres uplift. This data indicates that thermal maturation increases from basins on the east and west toward the north-south axis of the play.

Anticipated traps include stratigraphic, in the form of pinchouts around basin margins, unconformity and biohermal buildups, as well as thrust fold and anticlinal traps of Laramide age. Because of the great relief of the Precambrian surface, drill depths in the play may range from 2,000 to more than 20,000 ft.

In spite of the thick alluvial cover, the eolian dunes and pyroclastic rocks that cover 75 percent of the play, plus the low level of drilling activity, the number and quality of hydrocarbon shows in Permian-Pennsylvanian rocks may indicate the probable existence of commercial hydrocarbons. Drilling density in favorable areas of the play is only one well per 145 mi^2. These wells were drilled to an average depth of 4,250 ft, and most hydrocarbon shows occur between 2,430 and 8,600 ft. The deepest wildcat well was drilled in the Mesilla basin and reached Ordovician rocks at a total depth of 21,759 ft. The future potential in the play for oil is low and is fair for gas.

SOUTHERN ARIZONA-SOUTHWESTERN NEW MEXICO PROVINCE (093)

By William C. Butler

INTRODUCTION

The province is located almost entirely within the Basin and Range physiographic province and covers an area of roughly 53,000 mi^2, 80 percent of which is in Arizona and the remainder in New Mexico. Most sediment deposition during Paleozoic time in southern Arizona was in shallow marine platform and shelf environments, but was interrupted by times of general emergence in the Ordovician, Silurian and Permian (fig. 47). In the Pedregosa basin of late Paleozoic age, somewhat deeper marine basin sediments and supratidal evaporites were deposited. The northwest-southeast trending Mogollon Highlands transition zone, nearly paralleling the northern edge of the province, was a prominent Mesozoic uplift, and is characterized by outcropping Proterozoic and Cenozoic rocks. A magmatic arc was present in southwestern Arizona in earliest Cretaceous time, while in the eastern one-half of the province the coeval tectonic setting was a back arc rift into which thick, poorly sorted clastics were deposited, with local patch reef deposition near its edge. Late Cretaceous depositional settings in the eastern half included alluvial fans adjacent to a coastal plain and a fluvial-marine deltaic complex. Tectonic events during the early to late Cenozoic included continuation of Laramide folding, faulting, intrusive and extrusive activity, widespread volcanism, detachment and block faulting, and finally, uplift, erosion and alluvial basin filling.

The most prominent tectonic feature in the province is the 100 mi wide Texas lineament, a major zone of crustal weakness which trends northwest-southeast through the province, and beyond. Parts of the lineament are associated with strike-slip faults involving both left- and right-lateral movement. Some of these faults have been intermittently active since Precambrian time. Transpressional and transtensional structures associated with slight bends in these strike-slip planes include local thrust blocks, tilt blocks and pull-apart basins. Possible traps for hydrocarbons are associated with en echelon anticlinal welts, drag folds, and normal faults in this fundamental fault zone.

The province is non-productive of hydrocarbons. The deeper water facies of the late Paleozoic Pedregosa basin are present in southwestern New Mexico in a local basin where one speculative play, the Alamo-Hueco Basin (030), was individually assessed.

ERA	PERIOD			STRATIGRAPHIC UNITS
CENOZOIC	QUATERNARY			basin-fill alluvium
CENOZOIC	MIDDLE-LATE TERTIARY			undiff. fanglomerates and volcanics, including GILA and PANTANO FMS. equiv.
CENOZOIC / MESOZOIC	LATE CRETACEOUS-PALEOGENE			HIDALGO FM
MESOZOIC	CRETACEOUS	LATE		RINGBONE FM
MESOZOIC	CRETACEOUS	EARLY	BISBEE GRP	MOJADA FM
MESOZOIC	CRETACEOUS	EARLY	BISBEE GRP	U-BAR FM
MESOZOIC	CRETACEOUS	EARLY	BISBEE GRP	HELL-TO-FINISH FM
PALEOZOIC	PERMIAN	MIDDLE	NACO GRP	? RAINVALLEY FM
PALEOZOIC	PERMIAN	MIDDLE	NACO GRP	CONCHA LS
PALEOZOIC	PERMIAN	EARLY	NACO GRP	SCHERRER QUARTZITE
PALEOZOIC	PERMIAN	EARLY	NACO GRP	EPITAPH DOLOMITE
PALEOZOIC	PERMIAN	EARLY	NACO GRP	COLINA LS
PALEOZOIC	?		NACO GRP	EARP FM (ABO-HUECO equiv.)
PALEOZOIC	PENNSYLVANIAN		NACO GRP	HORQUILLA LS (OSWALDO LS-MAGDALENA LS)
PALEOZOIC	MISSISSIPPIAN	LATE		PARADISE FM
PALEOZOIC	MISSISSIPPIAN	EARLY		ESCABROSA FM (LAKE VALLEY equiv.) / HACHITA FM, KEATING FM
PALEOZOIC	LATE DEVONIAN			? PERCHA SH
PALEOZOIC	EARLY SILURIAN			? FUSSELMAN DOLOMITE
PALEOZOIC	ORDOVICIAN	LATE		MONTOYA DOLOMITE
PALEOZOIC	ORDOVICIAN	EARLY		EL PASO LS
PALEOZOIC	LATE CAMBRIAN			BLISS SS
PRE-CAMBRIAN	LATE PROTEROZOIC			? TROY QUARTZITE (APACHE GRP. equiv.)
PRE-CAMBRIAN	EARLY-MIDDLE PROTEROZOIC			PINAL SCHIST; granite

Figure 47. Generalized stratigraphic column, Southern Arizona-Southwestern New Mexico province

ALAMO-HUECO BASIN PLAY (030)

The play, which covers less than 875 mi^2 (fig. 48), is speculative, and is based on a postulated updip migration of hydrocarbons, mainly gas, from deep basinal mudstones and dark limestone source rocks, into shelf-slope and shelf-margin reservoirs of the Pennsylvanian Horquilla Limestone (fig. 47). Phylloid algal mounds are also present in this unit in the northern portion of the play. The overall Paleozoic section thins from 14,000 ft on the south to 3,000 ft at the north within the play area.

Excluding Devonian rocks, nearly all Paleozoic strata are believed to have generally favorable reservoir quality. In addition, good reservoirs should also be present in rudistid reefs of the Early Cretaceous U-Bar Formation. The most promising source rocks are black shales, mudstones and reef carbonates of the Horquilla Formation that range from 2,500-3,500 ft in thickness. Other possible source rocks may include Ordovician carbonates, Devonian and Mississippian shales, and younger sources in black, algal limestone associated with the Early Cretaceous reefs (fig. 47). Available vitrinite reflectance data from outcropping Paleozoic strata ranges from about 0.6 to 1.8 percent R_o, indicating that the thermal maturity of these rocks increases southeastwardly.

Various styles and types of local structure are exposed in the mountains in the play, including horst and graben, uplifts, northeast directed Laramide overthrusts, reverse and normal faults, right lateral strike slip wrench faults and major northwest-trending folds. In many of the half-grabens in the play between 15,000 and 25,000 ft of rocks, including Cenozoic, Cretaceous and Permian strata, overlie the target Horquilla limestone. Paleozoic rocks may have several thrust repeated sections in the southern part of the play, and both the Paleozoic and Cretaceous sections may be involved in numerous thrust sheets in the northern play area. This complex structural setting involving faulting and folding could provide any number and variety of potential traps. However, few of the suspected traps have been drilled.

Density of exploratory drilling in the Alamo-Hueco basin is about 1 well per 40 mi^2 and in the entire Pedregosa basin the density of wells that have penetrated Paleozoic and (or) Precambrian rocks is only 1 well per 1,340 mi^2. Twelve wells drilled in the play had documented oil and gas shows of some significance, and one well had good shows of gas in the Permian Epitaph Dolomite. Limiting factors to future resource potential include possible flushing of reservoirs by meteoric water, and rupturing of traps by repeated episodes of post-migration block-faulting, especially during the Late Tertiary (Miocene). In addition, thermal destruction of hydrocarbons may have occurred in this highly mineralized terrain which has been affected by Laramide regional plutonism. The undiscovered potential of the play is estimated to be low for non-associated gas.

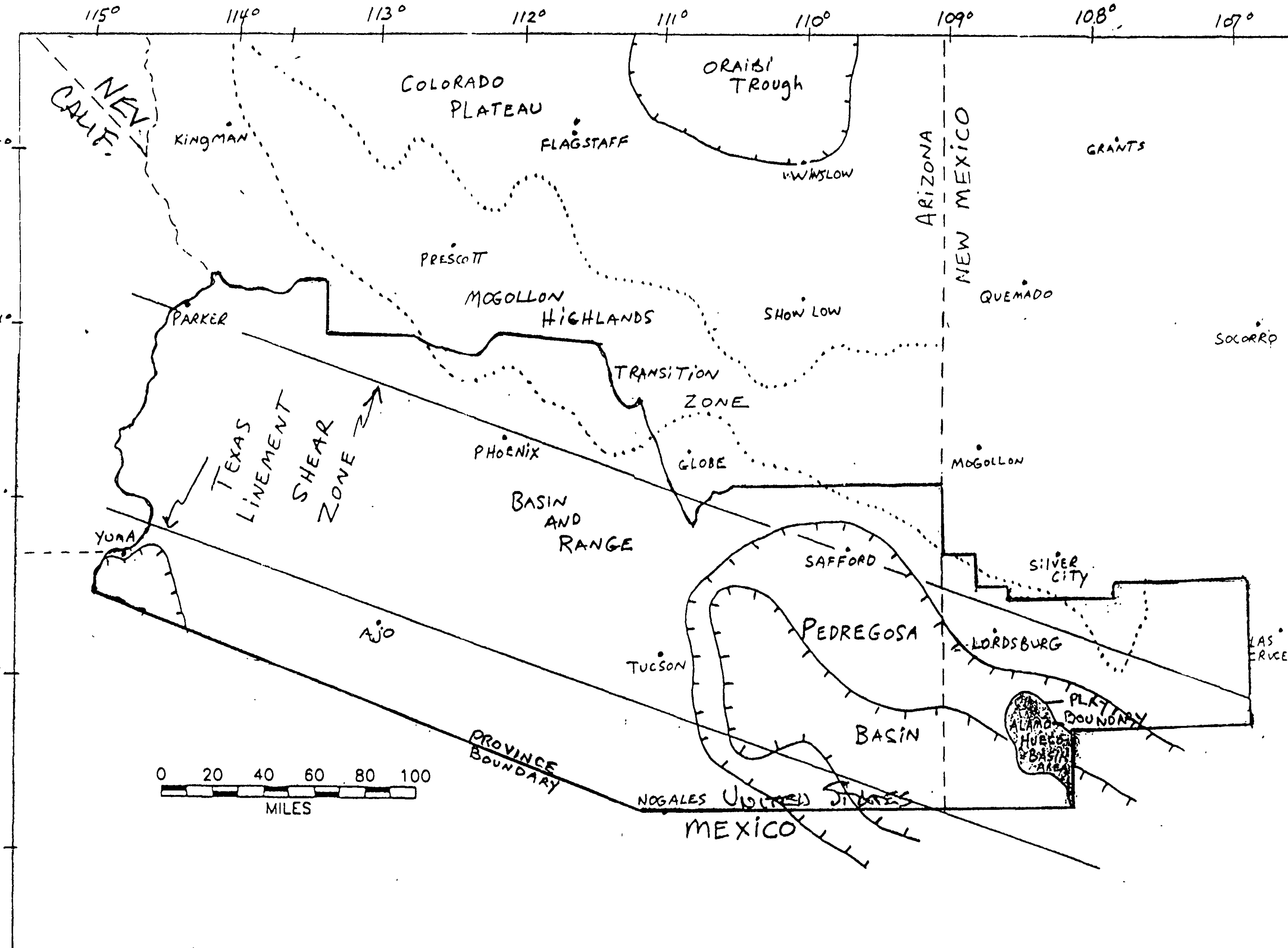


Figure 48. Map of Alamo-Hueco Basin play

OIL AND GAS PLAY DATA

PLAY **ALAMO-HUECO BASIN**
PROVINCE **SOUTHERN ARIZONA-SW NEW MEXICO** CODE **03-093-030**

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	**0.50**

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**
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**	**10**	**15**	**25**	**50**	**100**
Reservoir depth (x10^3 ft)							
Oil	**0**			**0**			**0**
Gas (non-associated)	**4**			**8**			**25**
Number of accumulations	**1**	**1**	**2**	**3**	**4**	**5**	**6**

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.

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TABLE 1.--Region 3, Colorado Plateau and Basin and Range, 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 (F95, F5) 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)		
			F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
082	E. Basin and Range										
	020	Unconformity	65.6	503.5	220.0	20.3	276.6	102.7	0.0	4.1	1.5
	030	Upper Paleozoic	0.0	89.4	24.3	0.0	141.1	33.5	0.0	2.2	0.5
	320	Oil <1 MMB	31.0	53.9	41.5	0.8	1.3	1.0	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	21.3	44.1	31.5	0.0	0.0	0.0
		Province Total	87.2	646.3	285.8	31.2	464.8	168.7	0.3	5.9	2.0
083	W. Basin and Range										
	020	Dixie Valley	0.0	49.0	12.8	0.0	139.9	33.1	0.0	2.2	0.5
	320	Oil <1 MMB	2.3	7.2	4.3	0.0	0.1	0.1	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	5.6	12.3	8.5	0.1	0.2	0.1
		Province Total	2.3	51.8	17.1	3.8	138.9	41.7	0.1	2.1	0.6
084	Idaho-Snake River Downwarp										
	030	Idaho Lake Basin	0.0	0.0	0.0	0.0	51.2	6.2	0.0	0.0	0.0
	310	Other Occurrences >6 BCFG	0.0	0.0	0.0	0.0	49.0	9.1	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	19.6	34.1	26.2	0.0	0.0	0.0
		Province Total	0.0	0.0	0.0	6.2	122.3	41.5	0.0	0.0	0.0
085	Paradox Basin										
	020	Carbonate Buildup	6.8	24.6	14.0	6.5	23.4	13.3	0.5	1.9	1.1
	040	Older Paleozoic	0.0	31.8	9.4	0.0	99.2	27.9	0.0	6.1	1.5
	070	Salt Interbeds	3.0	480.6	124.8	3.0	480.6	124.8	0.0	0.0	0.0

TABLE 1.--Region 3, Colorado Plateau and Basin and Range, 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)		
			F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
	080	Salt Anticline	0.0	36.4	9.7	0.0	311.5	104.2	0.0	0.0	0.0
	320	Oil <1 MMB	23.6	53.5	36.7	23.6	53.5	36.7	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	55.3	100.1	75.6	1.1	2.0	1.5
		Province Total	8.8	718.1	194.5	35.8	1,264.1	382.5	1.1	9.8	4.1
086	Uinta-Piceance-Eagle Basins										
	020	Wasatch-Green River Gas	0.0	0.0	0.0	153.8	813.2	402.0	1.1	5.7	2.8
	030	Wasatch-Green River Oil	9.2	59.2	27.4	18.5	118.5	54.9	0.0	0.0	0.0
	040	Upper Cretaceous	0.0	0.0	0.0	771.2	1,881.3	1,249.6	0.8	1.9	1.2
	050	Permian-Pennsylvanian	21.8	451.4	151.5	21.8	451.4	151.5	0.7	13.5	4.5
	320	Oil <1 MMB	15.1	28.2	21.0	18.1	33.8	25.2	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	214.9	421.9	307.5	5.4	10.5	7.7
		Province Total	37.0	551.0	199.9	1,112.5	3,761.2	2,190.7	6.3	32.8	16.3
087	Park Basins										
	020	Mesozoic Structure	1.6	20.5	7.8	2.8	34.9	13.2	0.0	0.0	0.0
	320	Oil <1 MMB	3.1	7.9	5.2	5.2	13.5	8.8	0.0	0.0	0.0
		Province Total	4.0	29.0	12.9	6.9	49.3	22.0	0.0	0.0	0.0
088	San Juan Basin										
	020	Mesaverde	2.5	31.3	12.2	3.6	63.7	22.3	0.0	0.2	0.1
	030	Fruitland-Kirtland	0.0	0.0	0.0	149.9	477.9	284.8	Negl.	0.1	0.1
	040	Pictured Cliffs	0.0	0.0	0.0	1,054.8	1,629.4	1,322.5	0.2	0.3	0.3
	050	Tocito-Gallup	3.9	17.9	9.3	19.3	89.7	46.4	0.0	0.0	0.0
	060	Dakota	12.1	52.5	27.8	12.1	52.5	27.8	0.0	0.0	0.0

Table 1. Region 3, Colorado Plateau and Basin and Range--Estimates of undiscovered recoverable conventional oil, gas, and natural gas liquids (NGL) in onshore provinces by play--Continued.

			Crude Oil (Millions of Barrels)			Total Gas (Billions of Cubic Feet)			NGL (Millions of Barrels)		
			F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
	080	Pennsylvanian	0.0	0.0	0.0	18.9	104.2	50.7	0.0	0.0	0.0
	110	Entrada	6.7	22.6	13.2	0.1	0.2	0.1	0.0	0.0	0.0
	320	Oil <1 MMB	19.8	33.6	26.1	25.7	43.7	33.9	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	154.9	269.6	207.3	0.2	0.3	0.2
		Province Total	42.0	158.6	88.6	1,402.2	2,727.1	1,995.9	0.3	0.9	0.6
089	Albuquerque-Santa Fe-San Luis Rift Basins										
	020	Albuquerque Basin	0.0	37.1	9.5	0.0	515.5	188.3	0.0	0.0	0.0
	030	Hagan-Santa Fe Embayment	0.0	9.4	3.1	0.0	12.8	3.4	0.0	0.0	0.0
	040	San Juan Sag	0.0	19.1	6.5	0.0	24.7	7.0	0.0	0.0	0.0
	320	Oil <1 MMB	2.9	6.1	4.3	5.8	12.1	8.6	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	30.9	53.4	41.2	0.0	0.0	0.0
		Province Total	3.4	69.5	23.4	58.2	628.9	248.5	0.0	0.0	0.0
090	Wyoming-Utah-Idaho Thrust Belt										
	020	Subthrust Moxa Arch	0.0	0.0	0.0	1,152.6	3,558.1	2,147.5	0.0	0.0	0.0
	030	Crawford-Meade Thrusts	0.0	0.0	0.0	108.5	1,318.2	504.4	0.5	6.6	2.5
	040	Northern Thrusts	58.7	352.3	167.1	2,893.5	12,804.0	6,741.7	50.9	276.0	135.1
	050	Absaroka Thrust Gas	0.0	0.0	0.0	1,219.8	8,694.2	3,891.8	141.5	1,008.5	451.4
	060	Absaroka Thrust Oil	114.7	486.2	260.1	745.8	3,160.0	1,690.4	0.0	0.0	0.0
	070	Hogsback Thrust	19.4	180.2	75.9	176.9	1,226.6	553.9	4.6	35.2	15.5
	080	Cretaceous Stratigraphic	13.3	139.6	55.6	13.3	139.6	55.6	0.0	0.0	0.0
	320	Oil <1 MMB	10.2	23.8	16.1	61.1	142.9	96.6	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	86.0	178.2	126.9	4.3	8.9	6.3
		Province Total	211.8	1,186.0	574.8	6,290.8	31,314.0	15,808.8	200.4	1,335.7	610.9

TABLE 1.--Region 3, Colorado Plateau and Basin and Range, 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)		
			F95	F5	Mean	F95	F5	Mean	F95	F5	Mean
091		Northern Arizona									
	020	Defiance Uplift	0.0	16.5	3.6	0.0	4.1	0.9	0.0	0.0	0.0
	030	Orabai Trough	0.0	214.1	77.4	0.0	21.4	7.7	0.0	0.0	0.0
	300	Other Occurrences >1 MMBO	4.8	37.8	16.4	1.0	7.6	3.3	0.0	0.0	0.0
	320	Oil <1 MMBO	2.1	4.8	3.3	0.2	0.5	0.3	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	8.3	34.4	18.6	0.0	0.0	0.0
		Province Total	19.8	271.5	100.7	9.6	68.9	30.8	0.0	0.0	0.0
092		South-Central New Mexico									
	020	Orogrande Basin	0.0	49.0	13.7	0.0	651.6	220.1	0.0	0.0	0.0
	320	Oil <1 MMB	2.2	4.3	3.1	Negl	Negl.	Negl.	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	29.8	57.4	42.2	0.0	0.0.	0.0
		Province Total	2.3	50.7	16.9	52.8	702.0	262.3	0.0	0.0	0.0
093		Southern Arizona-SW New Mexico									
	030	Alamo-Hueco Basin	0.0	0.0	0.0	0.0	99.5	27.2	0.0	0.0	0.0
	300	Other Occurrences >1 MMBO	2.7	12.3	6.4	4.0	18.4	9.5	0.0	0.0	0.0
	310	Other Occurrences >6 BCFG	0.0	0.0	0.0	11.8	80.1	36.4	0.0	0.0	0.0
	320	Oil <1 MMB	1.3	2.9	2.0	2.0	4.3	3.0	0.0	0.0	0.0
	330	Gas <6 BCF	0.0	0.0	0.0	7.7	30.9	16.9	0.0	0.0	0.0
		Province Total	3.9	15.1	8.4	23.1	230.2	93.0	0.0	0.0	0.0
		REGION TOTAL	482.7	3,384.9	1,523.0	9,596.7	39,278.0	21,280.1	212.2	1,374.2	634.5