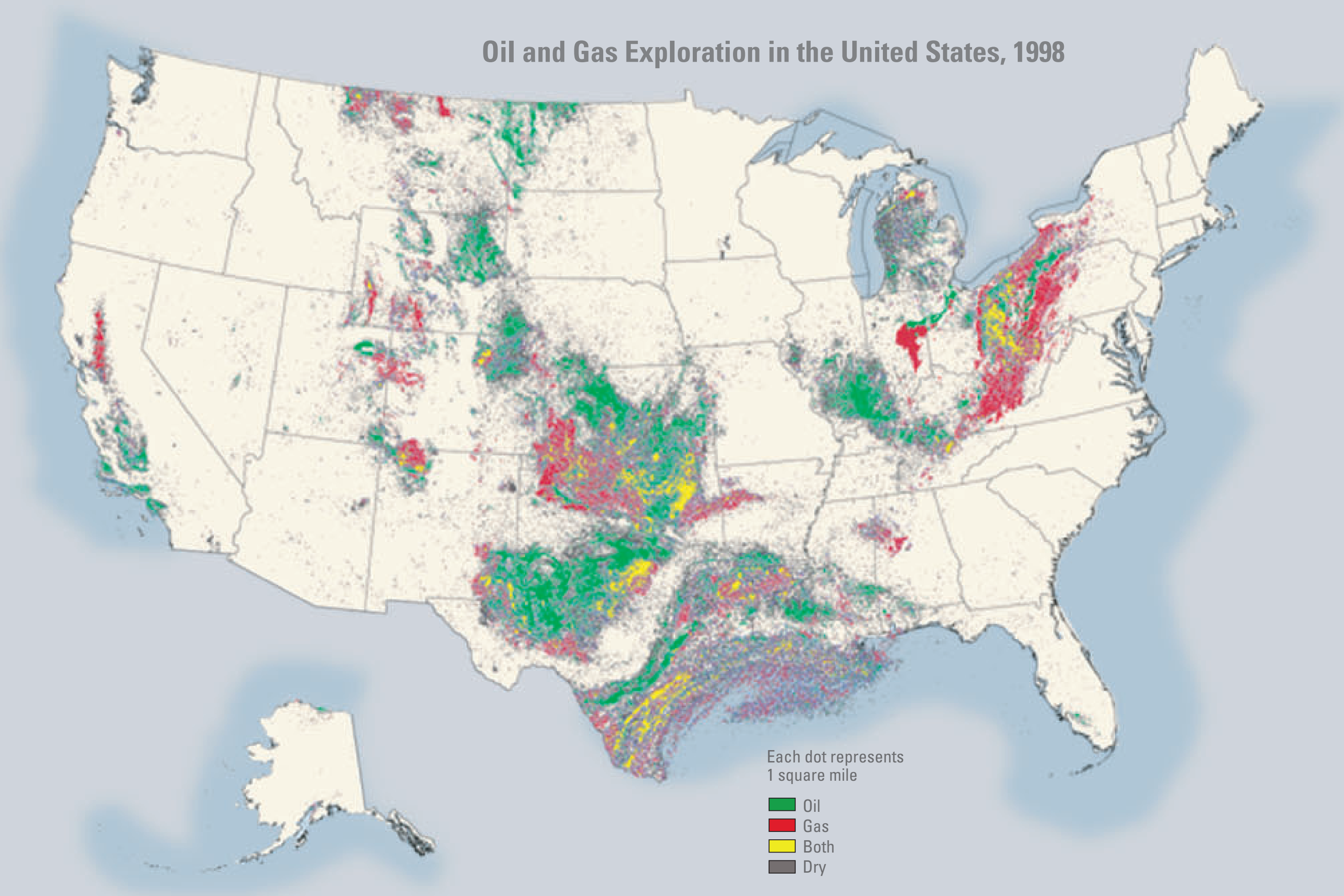
Geologic Controls on the Growth of Petroleum Reserves

Chapter I of
Geologic, Engineering, and Assessment Studies of Reserve Growth

U.S. Geological Survey Bulletin 2172-I



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Cover. This map represents historical oil and gas exploration and production data for the conterminous United States and Alaska. It was derived from data used in U.S. Geological Survey Geologic Investigations Series I-2582.* The map was compiled using Petroleum Information Corporation's (currently IHS Corporation) database of more than 2.2 million wells drilled in the United States as of June 1993. The area of the United States was subdivided into 1 mi^2 grid cells for which oil and gas well completion data were available. Each colored symbol represents a 1 mi^2 cell (to scale) for which exploration has occurred. Each cell is identified by color as follows: red, a gas-producing cell; green, an oil-producing cell; yellow, an oil- and gas-producing cell; gray, a cell that has been explored through drilling, but no production has been reported. Mast and others (1998) gives details on map construction.

*Mast, R.F., Root, D.H., Williams, L.P., Beeman, W.R., and Barnett, D.L., 1998, Areas of historical oil and gas exploration and production in the conterminous United States: U.S. Geological Survey Geologic Investigations Series I-2582, one sheet.

Geologic Controls on the Growth of Petroleum Reserves

By Neil S. Fishman, Christine E. Turner, Fred Peterson, Thaddeus S. Dyman, and Troy Cook

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Edited by T.S. Dyman, J.W. Schmoker, and Mahendra Verma

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Abbreviations Used in This Report

ft	foot, feet
mD	millidarcies
mi	mile, miles
CCRC	central class rate of change
UCRC	upper class rate of change

Geologic Controls on the Growth of Petroleum Reserves

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Abstract

The geologic characteristics of selected siliciclastic (largely sandstone) and carbonate (limestone and dolomite) reservoirs in North America (largely the continental United States) were investigated to improve our understanding of the role of geology in the growth of petroleum reserves. Reservoirs studied were deposited in (1) eolian environments (Jurassic Norphlet Formation of the Gulf Coast and Pennsylvanian-Permian Minnelusa Formation of the Powder River Basin), (2) interconnected fluvial, deltaic, and shallow marine environments (Oligocene Frio Formation of the Gulf Coast and the Pennsylvanian Morrow Formation of the Anadarko and Denver Basins), (3) deeper marine environments (Mississippian Barnett Shale of the Fort Worth Basin and Devonian-Mississippian Bakken Formation of the Williston Basin), (4) marine carbonate environments (Ordovician Ellenburger Group of the Permian Basin and Jurassic Smackover Formation of the Gulf of Mexico Basin), (5) a submarine fan environment (Permian Spraberry Formation of the Midland Basin), and (6) a fluvial environment (Paleocene-Eocene Wasatch Formation of the Uinta-Piceance Basin).

Reservoirs in each formation were further subdivided into categories, as appropriate, where the reservoirs had sufficiently different geological attributes to warrant separate treatment. Variables viewed as important when we considered the designation of a reservoir category included depositional setting, source rock for contained petroleum, postdepositional alteration of the reservoirs, and type of trap or seal.

The connection between an oil reservoir's production history and geology was also evaluated by studying production histories of wells in disparate reservoir categories and wells in a single formation containing two reservoir categories. This effort was undertaken to determine, in general, if different reservoir production heterogeneities could be quantified on the basis of gross geologic differences. Of the formations studied, wells in oil fields producing from the Frio Formation (fluvial category) demonstrated the least production heterogeneity; heterogeneity increased successively in the Morrow Formation (incised valley-fill category), Ellenburger Group (platform category), Wasatch Formation (Green River–source category), Minnelusa Formation (Minnelusa category), and Ellenburger Group (karst category). The differences in intraformational geologic variability and production heterogeneity between the Ellenburger Group karst and platform reservoir categories are especially large. The greatest production heterogeneity was observed in fields of the Ellenburger karst category, where production is enhanced by porous, fractured, cave-roof and by clast-supported, brecciated, cave-floor materials. In contrast, the Ellenburger platform category produces from rocks that have low porosity and permeability.

It appears that reserve growth in existing fields is most predictable for those in which reservoir heterogeneity is low and thus production differs little between wells, probably owing to relatively homogeneous fluid flow. In fields in which reservoirs are highly heterogeneous, prediction of future growth from infill drilling is notably more difficult. In any case, success at linking heterogeneity to reserve growth depends on factors in addition to geology, such as engineering and technological advances and political or cultural or economic influences.

Introduction

The majority of additions to domestic oil and gas reserves (reserves are defined as the identified accumulations that can be extracted at a profit by use of existing technology (after McKelvey, 1972)) are attributed to growth of existing fields and reservoirs. In fact, from 1978 to 1990, growth of known fields in the United States accounted for more than 85 percent of known additions to proven reserves (Root and Attanasi, 1993; McCabe, 1998). Thus, field growth and reserve growth are essentially synonymous for discussions of domestic resources. Evaluating the nature of growth in fields requires understanding of both geologic and nongeologic factors that affect growth estimations. Ultimately, however, geology is the underlying control on accumulations of oil and gas, so knowledge of the effects of geologic characteristics of reservoirs and associated strata on growth in reserves is critical not only from the perspective of exploration and production of energy resources in known fields but also for the purpose of assessing the undiscovered resources of oil and gas in a region. How geology affects growth in reserves is particularly important in the United States, which is considered to be a mature petroleum province where new accumulations of oil and gas are becoming more difficult to find.

Fields may grow when (1) additional geologic data on existing reservoirs becomes available and are used to identify new reservoirs or to guide infill drilling, (2) there are annual updates of reserves data, (3) field boundaries are extended, (4) recovery technology is improved, or (5) nongeologic factors such as economics, reporting policies, or politics favor expanded production and development. In this study, we specifically focus on the growth of fields by infill drilling of existing reservoirs.

To date, reserve growth investigations have largely emphasized mathematical approaches; in fact, as stated by Attanasi and others (1999), "…the modeling approach used by the USGS (U.S. Geological Survey) to characterize this phenomenon is statistical rather than geologic in nature." Volumetric estimates of reserve growth are calculated by using these mathematical approaches and large data bases that record field reserves through time. Crovelli and Schmoker (2001), Verma (2003), and Klett (2003) present details of various methods used to estimate reserve growth.

Our goal is not to assess the growth of fields through time but to try to evaluate some of the geologic controls that may bear on the growth of reserves. Although growth is also affected by nongeologic factors, geology controls the location and characteristics of all oil and gas accumulations as well as the fluid flow dynamics that affect production, and thus it is of fundamental importance in evaluating reserve growth.

Geologists tend to think in terms of entire reservoirs, in some cases down to facies level, whereas reservoir engineers deal with measurements at the well bore. To fully understand the geologic factors that affect growth in reserves, this gap in investigative approaches must be bridged. It has become increasingly important to integrate different scales and different observational techniques as secondary and tertiary recovery methods are applied more frequently in mature petroleum provinces such as the United States.

Fluid-flow pathways, governed predominantly by rock porosity and permeability, are a reflection of heterogeneities of varying scales within a reservoir. Because these reservoir hetereogeneities are fundamentally geologic in nature (Hamilton and others, 1998; Dyman and others, 2000), an adequate understanding of the reservoir architecture, obtained through evaluation of geologic, engineering, or production data, or a combination of these data sets, can provide the basis for "…geologically targeting potential infill and stepout drilling locations, recompletions, and field management," as stated by Hamilton and others (1998).

In spite of the different scales of observation, several attempts have been made to integrate geologic, engineering (Hamilton and others, 1998; Pulham, 1999), and well production data (Dyman and Schmoker, 2000). These approaches lead toward a more precise understanding of reserve growth because the engineering and production data are ultimately a function of geologic parameters. For engineering data, the link between direct measurement of rock properties and a determination of the processes involved that contribute to those rock properties can be established through systematic study. Currently, petrophysical analysis of a given reservoir is used to establish its storage capacity and its hydrocarbon pore volume at the well bore, which serve as the basis for determining areal variation in reservoir quality (Hamilton and others, 1998). These characteristics, which are a function of porosity and permeability, are then used to measure the capacity of the reservoirs to yield fluids such as hydrocarbons. Production data such as peak-monthly or 12-month production figures, as well as cumulative production volumes, are potentially valuable for documenting reservoir heterogeneity (Dyman and Schmoker, 1998; Dyman and others, 2000, Dyman and Schmoker, 2003).

Reservoir Categories

To evaluate the geologic factors that affect reserve growth in both siliciclastic (largely sandstone) and carbonate (limestone and dolomite) reservoirs, we selected 10 formations in the United States (one of which extends into southern Canada) that represent various depositional environments in both siliciclastic and carbonate settings (table 1). We then categorized reservoirs within formations in cases where geological criteria warrant separate treatment; these criteria were principally depositional setting, source rock for contained petroleum, and postdepositional alteration of the reservoirs. Details of the geology of all reservoirs in each category can be found in the appendix.

Formations studied were deposited in (1) eolian environments—Norphlet Formation of the Gulf of Mexico Basin (fig. 1) and Minnelusa Formation of the Powder River Basin (fig. 2); (2) interconnected fluvial, deltaic, and shallow marine environments—Frio Formation of the Gulf of Mexico Basin (fig. 3) and Morrow Formation of the Anadarko and Denver Basins (fig. 2); (3) deeper marine environments—Barnett Shale of the Fort Worth Basin (fig. 3) and Bakken Formation of the Williston Basin (fig. 2); (4) marine carbonate environments—Ellenburger Group of the Permian Basin (fig. 3) and Smackover Formation of the Gulf of Mexico Basin (fig. 1); (5) submarine fan environment—Spraberry Formation of the Midland Basin (fig. 3); and (6) fluvial environment—Wasatch Formation of the Uinta-Piceance Basin (fig. 2).

Reservoir categories are briefly discussed below; detailed descriptions of each of the formations evaluated, the criteria used to establish reservoir categories within them, and stratigraphic and structural data are given in the Appendix to this report. A table for each formation summarizes the criteria that were evaluated for all reservoir categories. Each table, therefore, attempts to be inclusive but may be modified in the future when additional reservoir categories are evaluated or when additional geological information is available.

Table 1. Depositional environments and rock units selected for study of reserve growth, and geologic age and general location of units.

Depositional environment and formation studied	Age	General location
Eolian sandstone		
Norphlet Formation	Upper Jurassic	Gulf of Mexico Basin
Minnelusa Formation	Pennsylvanian-Permian	Powder River Basin
Fluvial or deltaic–shallow marine		
Frio Formation	Tertiary (Oligocene)	Gulf of Mexico Basin
Morrow Formation	Pennsylvanian (Morrowan)	Anadarko and Denver Basins
Marine shale		
Barnett Shale	Mississippian (Chesterian)	Fort Worth Basin
Bakken Formation	Devonian-Mississippian	Williston Basin
Marine carbonates		
Ellenburger Group	Ordovician (Early Ordovician)	Permian Basin
Smackover Formation	Upper Jurassic (late Oxfordian)	Gulf of Mexico Basin
Submarine sands		
Spraberry Formation	Permian (Leonardian)	Permian Basin
Nonmarine fluvial–deltaic		
Wasatch Formation	Tertiary (Paleocene-Eocene)	Uinta-Piceance Basin

Eolian Reservoirs

Norphlet Formation

The Middle(?) to Upper Jurassic Norphlet Formation of the Gulf of Mexico Basin consists largely of eolian sandstones, with minor black shale, conglomerate, and red beds; thicknesses are as much as 100 ft. The Norphlet produces oil and gas largely in Alabama, offshore in Mobile Bay, and in Mississippi (fig. 1). Principal reservoirs in the Norphlet are eolian sandstones (table 2), which are known to have excellent porosity (as much as 20 percent) and permeability (as much as 500 mD).

Broad similarities in reservoir characteristics throughout the area of production suggest that only a single reservoir category is warranted (table 2). Although characteristics such as the geographic distribution of wells and the type of petroleum (oil or gas) produced were considered when we attempted to categorize Norphlet reservoirs, the available literature pointed out more similarities than differences between reservoirs in the formation. For this reason we designated only a single reservoir category for the Norphlet.

Minnelusa Formation

The Pennsylvanian to Early Permian Minnelusa Formation of the Powder River Basin, northeastern Wyoming, consists largely of eolian sandstones, with minor shale and carbonate; thicknesses are as much as 1,200 ft. Most production is in the north-central and northeastern parts of the basin; lesser production is in the southerly and southeastern parts (fig. 2). Principal reservoirs are the eolian sandstones (table 3), which can have excellent porosity (as much as 47 percent) and permeability (as much as 830 mD).

Reservoirs in the Minnelusa Formation are placed into two categories, Minnelusa and Leo (table 3). This twofold division seemed warranted because of differences in stratigraphic position, depositional environment, and geographic distribution of producing wells; in addition, reservoirs in the two categories may have different source rocks. Reservoir rocks of the Leo category have been variously referred to by previous workers as the “Leo sandstone” (Hunt, 1938), “Leo section” (Desmond and others, 1984), “Leo Formation” (Morel and others, 1986), or the “Leo sandstone of the Minnelusa Formation” (Dolton and Fox, 1995).

Figure 1. Gulf of Mexico Basin region, the petroleum-producing region of the Norphlet and Smackover Formations. Both formations produce in both onshore and offshore locations; the Norphlet produces from Mobile Bay.

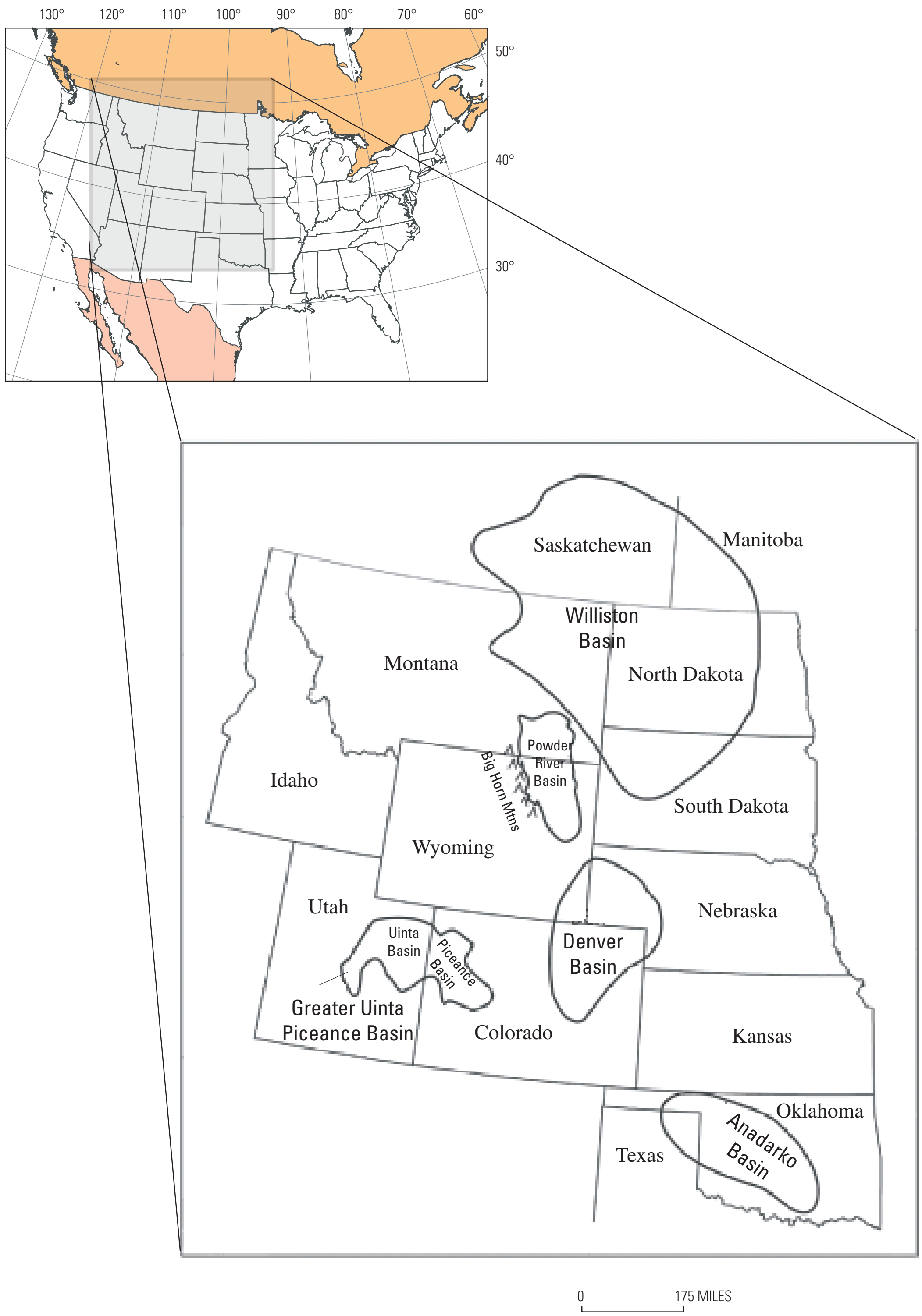

Figure 2. General region from which petroleum is produced from formations discussed in this paper, including the Minnelusa (Powder River Basin), Morrow (Anadarko and Denver Basins), Bakken (Williston Basin), and Wasatch (Uinta and Piceance Basins) Formations.

Figure 3. Area from which petroleum is produced from the Frio Formation, Barnett Shale, Ellenburger Group, and Spraberry Formation. Extent of depositional environments in the Frio (such as the Norias delta complex or the Buna barrier–strandplain) from Galloway and others (1982). For the Barnett, the locations of the Llano uplift and Ouachita thrust belt mark the southern and eastern limits of the Fort Worth Basin, respectively. Horseshoe Atoll is a Pennsylvanian structure that effectively separates productive rocks of the Spraberry Formation (to the south) from nonproductive rocks (to the north).

Interconnected Fluvial, Deltaic, and Shallow Marine Reservoirs

Frio Formation

The Oligocene Frio Formation of the Gulf of Mexico Basin consists largely of sandstone and shale deposited in various environments; it is as much as 15,000 ft thick. The Frio produces largely from onshore and offshore locations in Texas. Principal reservoirs in the Frio are sandstones (table 4), which are known to have good to excellent porosity (as much as 35 percent) and variable permeability (as much as 3,500 mD).

Reservoir categories defined in the Frio Formation are fluvial, deltaic, strandplain-barrier, and shelf sandstones (table 4). These four categories were selected principally because reservoirs within them differ in terms of their broad depositional and geographic settings, structural setting, proximity to structures and potential source rocks, and reservoir characteristics.

Morrow Formation

The Lower Pennsylvanian Morrow Formation of the Anadarko and Denver Basins consists largely of sandstone and shale; it is as much as 1,500 ft thick. The Morrow produces oil and gas in Oklahoma, Texas, Kansas, and Colorado (fig. 2). Principal reservoirs in the Morrow are sandstones (table 5), which are known to have good porosity (as much as 22 percent) and permeability (as much as several darcies).

Petroleum reservoirs in the Morrow Formation were placed into three categories—incised valley-fill, deltaic, and shallow marine (table 5). These categories were selected because reservoirs within them differ in terms of their broad geographic and depositional setting. The differing depositional settings of the reservoir categories have led to differing reservoir-rock characteristics, such as porosity and permeability, which bear directly on the reservoir properties and contained resources.

Deeper Marine Shales

Barnett Shale

The Middle to Late Mississippian Barnett Shale of the Fort Worth Basin, Texas, consists largely of black marine shales with some limestone; it is as much as 650 ft thick. Most production is of nonassociated gas, principally in the northeastern part of the basin (fig. 3). Reservoirs of this self-sourced unit are marine shales in the Barnett (table 6), which have very low porosity (less than 6 percent) and extremely low permeability (a few nanodarcies).

Reservoirs in the Barnett Shale are grouped in a single category termed the shale (unconventional) category (table 6). Until recently, the lower shale member has been the more productive, although considerable production is now being realized from the upper shale member as well (Bowker, 2002). Both members characteristically have a high content of organic material, which is largely Type–II (Jarvie and others, 2001; Hill and others, 2007). In general, the current average content of organic material in both members is 4 to 5 percent (Jarvie and others, 2007), although in places the Barnett is thought to have contained as much as 20 percent total organic carbon when it was deposited (Bowker, 2002). The organic material serves as the source of the gas, thereby defining these reservoirs as self sourced and unconventional.

Bakken Formation

The Late Devonian to Early Mississippian Bakken Formation (of the Williston Basin of North Dakota, Montana, and the Canadian provinces of Saskatchewan and Manitoba (fig. 2)) consists largely of marine shale with minor sandstone; it is as much as 140 ft thick. The Bakken produces mostly oil, principally in North Dakota and Montana and lesser amounts in Saskatchewan and Manitoba. Reservoirs in the Bakken are principally marine shales, although smaller reservoirs are found in interbedded near-shore to shoreface sandstones (table 7). Porosity of the shales is very low (typically less than 5 percent) as is their permeability (<0.01–60 mD). Porosity of sandstone reservoirs is higher (as much as 10 percent) as is permeability (<0.01–109 mD).

Two categories of reservoirs were defined in the Bakken Formation—shale (unconventional) and siltstone-sandstone (unconventional) (table 7). These two categories were selected because they have different characteristics, stratigraphic positions, and geographic distributions. In each, however, the petroleum is thought to be generated within the Bakken, so both categories are considered to be unconventional, similar to those in the Barnett Shale.

Marine Carbonate Reservoirs

Ellenburger Group

The Early Ordovician Ellenburger Group of the Permian Basin (fig. 3) consists largely of marine carbonate rocks; the group is as much as 1,500 ft thick. Units in the Ellenburger produce oil and gas chiefly in Texas. Principal reservoirs in the Ellenburger are in karstified parts of a carbonate platform and in dolomitized carbonate muds (table 8). Reservoirs in karstified rocks have low but variable porosity (2–7 percent) and moderate but variable permeability (2–750 mD). Reservoirs in dolomitized muds have higher porosity (2–14 percent) but lower permeability (1–44 mD) than karstified reservoirs.

Reservoirs in the Ellenburger Group are placed into three categories (table 8)—karstified, platform, and tectonically fractured—based primarily on differences in the nature and volume of porosity and permeability, geographic distribution, produced petroleum, and the degree to which structure influenced reservoir development. This threefold division is similar to that presented by others (Kerans and others, 1989; Kosters and others, 1989c; Holtz and Kerans, 1992) and is also consistent with that presented by Ball (1995).

Table 2. Norphlet Formation, Gulf of Mexico Basin—Summary of geological characteristics and reserve growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
	Environ-ment	Reservoir facies	Nonreservoir facies	Lithology	Porosity (bulk rock)			
					Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Norphlet	Sand sea	Eolian sands	Overlying and interbedded marine shale and interdune sediments	Sandstone	Primary intergranular and secondary intergranular and moldic	Dissolution of early authigenic cements and authigenic chlorite	Local quartz, anhydrite, halite, illite. Intense quartz cementation may seal some accumulations	As much as 20% in onshore reservoirs and 12% in deeper offshore reservoirs

Smackover Formation

The Upper Jurassic Smackover Formation in onshore parts of Texas, Arkansas, Louisiana, Mississippi, Alabama, and Florida, as well as offshore in the Gulf of Mexico Basin, consists largely of carbonate rocks with minor black shale and siltstones; it is as much as 1,000 ft thick. Most oil and gas is produced from onshore locations in the above-listed states (fig. 1). Principal reservoirs in the Smackover are in carbonate rocks deposited in a ramp setting (table 9) that have good to excellent porosity (as much as 35 percent) and variable permeability (<1–4,100 mD).

Reservoir categories in the Smackover Formation are salt structure, basement structure, graben, stratigraphic, and updip fault (table 9). These categories, which were defined or later refined through regional studies by other workers (for example, Bishop, 1973; Collins, 1980; Moore, 1984; Mancini and others, 1990; Kopaska-Merkel and Mann, 1993; Tew and others, 1993) were selected because of differences in their geographic extent and in the role that structures played in both source-rock deposition and petroleum trapping.

Submarine Fan Reservoir

Spraberry Formation

The Early Permian Spraberry Formation of the Midland Basin consists largely of turbiditic sandstones, with minor black shales, silty dolostones, and argillaceous siltstones; it is as much as 1,000 ft thick. Most production of oil is in west-central Texas, in the Midland Basin (fig. 3). Principal reservoirs in the Spraberry are the tubiditic sandstones (table 10), which have good porosity (as much as 18 percent) but relatively low permeability (maximum, 10 mD). A single reservoir category, submarine sand, was defined for the Spraberry Formation.

Fluvial Reservoir

Wasatch Formation

The Paleocene-Eocene Wasatch Formation of the Uinta-Piceance Basin of Utah and Colorado consists largely of overbank and lacustrine mudstones with some fluvial and fluvial-dominated deltaic sandstones; it is as much as 5,000 ft thick. The Wasatch produces oil and associated gas mostly in the Uinta Basin of northeastern Utah, although minor gas is also produced in the Piceance Basin of Colorado (fig. 2). Principal reservoirs in the Wasatch are the fluvial sandstones (table 11), which are known to have good porosity (maximum, 15 percent) but low permeability (maximum, 40 mD).

Reservoirs in the Wasatch Formation are categorized as Green River source and Mesaverde source (table 11). The two categories are distinguished by (1) the source of the petroleum produced from each, (2) the nature of the petroleum produced from each, and (3) the geographic distribution of production. This division is important because it recognizes that petroleum produced from the Wasatch comes from two different source rocks; hence, two petroleum systems generated economic amounts of petroleum within the greater Uinta-Piceance Basin.

Table 2. Norphlet Formation, Gulf of Mexico Basin—Summary of geological characteristics and reserve growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
Generally high; as much as 500 mD	May be complexly faulted	Overlying marine shale of Smackover Formation; interbedded or interfingering organic-rich shale in Norphlet Formation	Updip pinchout against basement complex	Overlying shale and interbedded interdune, sabkha, or playa units	Reservoir rocks thicken in basement-controlled grabens and are absent or thin over basement-controlled highs	Anticlines, faulted anticlines, faults associated with basement structures and halokinesis of Louann Salt	Dominantly nonassociated gas (cracked) and minor oil

Quantitative Measures of Well Production Variability

Our preliminary reservoir analysis (based largely on the examination of pertinent literature and the field and laboratory experience of the authors) was supplemented by an analysis of well production data to determine if production heterogeneities could be quantified based on gross geologic differences between reservoirs in five of the formations we have discussed (see also the Appendix to this report) and also internally within an individual formation. Such quantification could be a valuable tool in evaluating the potential for identifying more reserves in a formation.

We compared historical well production data of the five formations by use of proprietary information. In addition, we considered data from two specific reservoir categories in the Ellenburger Group (karst and platform, table 8), which are based on gross geologic differences, to evaluate the possible intraformational variability in production within that formation. This analysis was an attempt to determine whether the production variabilities seen in each reservoir type could be identified and related to the growth of field reserves. Production data for the formations studied were obtained from IHS Energy Group (petroRom production data on CD-ROM (petroRom is a trademark of Petroleum Information/Dwights, d.b.a. IHS Energy Group)).

Our analysis of the production histories of the five formations was modified from that discussed in Dyman and Schmoker (2003). In their study, they (1) tested the use of certain well-production parameters—peak monthly production, peak consecutive 12-month production, and cumulative production—in older wells as a means to quantify and understand the heterogeneity in a population of reservoirs; (2) defined measures of variability (variation coefficients) in peak monthly production, peak consecutive 12-month production, and cumulative production; and calculated variation coefficients with respect to internal consistency, type of production parameter, conventional and unconventional accumulations, and reservoir depth; and (3) discussed the application of well-production parameters to field growth. Because in most wells production declines exponentially or hyperbolically as a function of time, cumulative production from older wells (those for which current monthly production is less than 10 percent of initial monthly production) asymptotically begins to approximate ultimate recovery. In such wells, variations in cumulative production reflect variations in the volume of reservoir rocks accessed by the well bore. The slopes of the probability distributions for cumulative production (fig. 4) are direct indicators of the variability as shown by the data set. For example, steeper slopes reflect greater production heterogeneity (fig. 4), whereas a horizontal line represents uniform production characteristics. A dimensionless parameter that is proportional to the slopes of the four probability distributions of figure 4 would provide a quantitative numerical representation of production heterogeneity. Such a parameter, referred to here as a variation coefficient (*VC*), can be calculated by using a measure of the dispersion (range) of the data set divided by a measure of central tendency such as the mean or the median (Stell and Brown, 1992; Dyman and others, 1996; Schmoker, 1966; Dyman and Schmoker, chapter E, this volume).

A dimensionless *VC* is calculated as

$$VC = (F_5 – F_{95})/F_{50} ,$$

where F_5, F_{95}, and F_{50} are the 5th, 95th, and 50th (median) fractiles of the probability distribution for peak monthly production, peak cumulative 12-month production, or cumulative production. These fractiles are picked directly from diagrams such as that in figure 4. Note that in figure 4 increasing variation coefficient corresponds with increasing slope of the probability distribution and thus to increasing variability in well production.

Cumulative production measures the net result of multiplicative geologic processes and so might be expected to approximate a log-normal distribution. For this reason, production was plotted on graph paper having axes arranged such that a log normal distribution plots as a straight line (see fig. 4).

In this study, we modified the uncertainty coefficient of Dyman and Schmoker (chapter E, this volume) by not considering wells in the upper 5 percent and lower 20 percent, as described further below, because we realized that the log-normal distribution defining the productive behavior of wells can be broken into component parts. The different parts of the distribution behave differently—that is, a single straight-line fit does not adequately describe the behavior of the entire distribution of production data. We are interested in the central part of the distribution because it represents production from the vast majority of wells. Extreme production behavior, categorized by wells in the upper 5 percent and lower 20 percent of the production distribution, were not examined; the former generally includes old wells with production combined from more than one formation, and the latter are typically unproductive. Wells were sorted by production from lowest to highest and subdivided into two size classes: a central class representing a productive range of 20–60 percent along the distribution and an upper class representing a productive range of 80–95 percent (fig. 5).

We measured rates of change in productivity for both size classes by calculating the variation coefficient (slope) of each line segment for each well distribution and compared each new variation coefficient with the original variation coefficients of Dyman and Schmoker (2003). We then compared the central and upper well classes for each distribution as well as

Table 3. Minnelusa Formation, Powder River Basin—Summary of geological characteristics and reserve growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Minnelusa	Coastal sand sea	Eolian dunes	Overlying shallow marine shales, anhydrite, and carbonate rocks	Sandstone, quartz arenite, sublitharenite	Primary and secondary intergranular; moldic	Dissolution of early authigenic cements and of some unstable detrital grains	Quartz, carbonates minerals, and anhydrite/gypsum where not dissolved. Cemented zones may act as seals	Averages 12–24% but may be as high as 47%
Leo	Coastal dunes	Eolian dunes	Overlying shallow marine shales, anhydrite, and carbonate rocks	Sandstone, quartz arenite, sublitharenite	Primary and secondary intergranular; moldic	Dissolution of early authigenic cements and of some unstable detrital grains	Quartz, carbonates minerals, and anhydrite/gypsum where not dissolved. Cemented zones may act as seals	Averages 12–24%

both central and upper classes for different well distributions as slope ratios. The slope ratio (*SR*) is defined as follows:

$$SR = UCRC/CCRC$$

where *UCRC* is the upper class rate of change and *CCRC* the central class rate of change. The higher the slope ratio, the greater the difference in rate of change between the two classes, which indicates that the most productive wells are more productive than would be expected if the slope ratio were smaller. Our focus was on wells in fields producing oil from the reservoirs representing the (1) fluvial category of the Frio Formation, (2) incised valley-fill category of the Morrow Formation, (3) Green River–source category of the Wasatch Formation, (4) Minnelusa category of the Minnelusa Formation, and both the (5) platform and karst categories of the Ellenburger Group.

Table 12 contains the basic data used in calculating production variability for each reservoir category. We selected a minimum of 35 producing wells as necessary to adequately describe the production behavior for each category and to calculate upper class and central class rates of recovery and slope ratios for each. We also identified a well productive life of at least 10 years on the basis of data in the IHS Energy Group production file. For example, 6,301 wells were selected from IHS data as Frio Formation producers in all or parts of Starr, Hidalgo, Brooks, Jim Hills, and Kleburg Counties, Texas (table 12). Our computer program then calculated upper and central class rates of recovery and slope ratios on the basis of a subset of these wells that met our selection criteria. The six reservoirs analyzed in this study have produced more than 2 billion barrels of oil and 12 trillion cubic feet of gas from nearly 13,000 producing wells. The results are plotted in figure 5.

The geologic implications of the slope ratio are the primary focus of this study. One of the questions we attempted to address was, Do gross geologic variables such as depositional environment, diagenesis, and lithology affect reservoir productivity as can be determined by production parameters? Comparing the slope ratios and variation coefficients of reservoirs with different geologic characteristics may provide insight into productivity analysis and ultimately into estimating field growth through time.

Table 3. Minnelusa Formation, Powder River Basin—Summary of geological characteristics and reserve growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
Generally high, 10–830 mD, and as high as 3,200 mD	Negligible	Phosphoria Formation, but requires long-distance migration before uplift of Big Horn Mountains	Uncertain	Reservoir rocks overlain by marine shale and carbonate rocks; lateral pinchouts; bounding surfaces	Low-relief closures associated with minor anticlines	Largely stratigraphic structures play a minor role	Oil
Uncertain	Negligible	Interbedded organic-rich shale, short-distance migration	Uncertain	Reservoir rocks overlain by marine shale and carbonate rocks; lateral pinchouts; bounding surfaces	Low-relief closures associated with minor anticlines	Largely stratigraphic structures play minor role	Oil

Table 4. Frio Formation, Gulf of Mexico Basin—Summary of geological characteristics and reserve growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Fluvial, chiefly the Gueydan and Chita/Corrigan fluvial systems	Chiefly fluvial with associated channel fill, point bar, crevasse splay, and floodplain sediments	Channel sands, point bars, and crevasse splay sands	Floodplain and lacustrine muds	Feldspathic litharenite, litharenite, and sublitharenite sandstone	Intergranular and moldic	Dissolution of unstable detrital grains and earlier formed cements, resulting in secondary pore space	Quartz, calcite, and clay cements; mechanical compaction	15–35%
Deltaic; chiefly the Norias and Houston delta complexes	Delta-plain, delta-front, and delta-flank environments of a prograding continental margin in the Gulf Basin. Norias contains more sediment and more sand, and was less influenced by marine processes than Houston	Distributary channel, delta-front and delta-flank, and channel-mouth bar sands	Prodelta and shelf shales	Feldspathic litharenite, litharenite, and sublitharenite sandstone	Intergranular and moldic	Dissolution of unstable detrital grains and earlier formed cements, resulting in secondary pore space	Quartz, calcite, and clay cements; mechanical compaction	10–35%
Strandplain-barrier; chiefly the Buna and Greta/Carancahua barrier strandplains	Shoreface, beach, barrier, and lagoonal deposits adjacent to deltaic depocenters	Shoreface, beach, and barrier sands	Marsh and lagoonal muds	Feldspathic litharenite, litharenite, and sublitharenite sandstones	Intergranular and moldic	Dissolution of unstable detrital grains and earlier formed cements, resulting in secondary pore space	Quartz, calcite, and clay cements; mechanical compaction	20–35%
Shelf; offshore Gulf Coast Basin	Shelf, slope, and perhaps submarine fan environments in deeper parts of the Gulf Coast Basin	Shelf, slope, and possibly fan sandstones	Marine shales and siltstones	Feldspathic litharenite, litharenite, and sublitharenite sandstones	Intergranular and moldic	Dissolution of unstable detrital grains and earlier formed cements, resulting in secondary pore space	Quartz, calcite, and clay cements; mechanical compaction	As much as 30%

Table 4. Frio Formation, Gulf of Mexico Basin—Summary of geological characteristics and reserve growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
20–1,500 mD	Important in hydrocarbon migration from source to reservoir	Shales that underlie reservoirs	Gueydan system largely a single drainage; leads to stacked channels and lateral amalgamation of channels. Chita Corrigan largely multiple channels with somewhat less stacking of sands	Stratigraphic component of trap is the interval where facies change to mud-rich floodplain rocks; mud-rich rocks are seals	Production best where fluvial and splay sands cross anticlines, faulted anticlines, or growth-fault trends, and faults served as conduits for upward petroleum migration	Rollover anticlines, particularly on downdip side of Vicksburg growth fault	Oil and gas
10–2,400 mD	Important in hydrocarbon migration from source to reservoir; also juxtapose reservoirs and seals	Shales that underlie or are basinward facies of reservoirs	Abundant sediment supply and single fluvial system input lead to vertically stacked sandy deltaic lobes (Norias), whereas Houston delta fed by several smaller fluvial systems that led to numerous small dispersed lobes with less continuous sands	Stratigraphic component of trap is at abrupt facies changes from reservoir to fine-grained rocks; mud-rich rocks are seals	Syndepositional movement on growth faults and salt diapirs but no thickening of deltaic sediments, including reservoir rocks	Anticlines and faulted anticlines, some of which are associated with growth faults (Noria and Houston) or salt diapirism (Houston); also growth faults juxtapose reservoirs with seals or compartmentalize reservoirs	Associated gas and oil from more proximal parts, and nonassociated gas from more distal parts
8–3,500 mD	Important in hydrocarbon migration from source to reservoir; also juxtaposes reservoirs and seals	Shales that underlie or are basinward facies of reservoirs	Greater marine influence on Houston delta led to greater redistribution of sands into strandplain systems than on sands that originated in Norias delta	Stratigraphic component of trap is the interval where facies change to mud-rich floodplain rocks; mud-rich rocks are seals	Vertical stacking of sands and strike-parallel orientation of sands greatly influenced by orientation and movement of growth faults	Anticlines, rollover anticlines, and faulted anticlines	Associated gas and oil
As much as 1,500 mD	Important in hydrocarbon migration from source to reservoir; also juxtaposes reservoirs and seals	Shales that interbed with or underlie reservoir rocks	Stratigraphic controls on reservoir location unclear	Stratigraphic component of trap is at abrupt change from reservoir to fine-grained rocks; fine-grained rocks serve as seals	Sediment accumulation in submarine canyons or intraslope basins that formed from active faulting or salt diapirs (or both)	Faulted anticlines and salt-related structures. Seals formed by fault-related juxtaposition of reservoirs with impermeable rocks	Largely gas

Table 5. Morrow Formation, Anadarko and Denver Basins—Summary of geological characteristics and reserve growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Incised valley fill	Braided streams that grade upward into meandering and estuarine environments	Dominantly in coarser grained fluvial sands that fill incised valleys	Floodplain, estuarine, and marine mudstone	Sandstone; varies from quartz arenite to litharenite or arkosic	Intergranular; variable volume of moldic porosity due to dissolution of detrital grains	Secondary pore space from dissolution of early formed authigenic cements and some unstable detrital grains	Extensive cement in lower parts of channel sands with calcite or iron carbonate minerals, or both	12–21%
Deltaic	Lower delta plain	Point bar, meander channel, stream-mouth bar, and distributary channel sands	Overbank, backswamp marsh, prodelta, and marine mudstone	Sandstone; varies from quartz arenite to litharenite or arkosic		Secondary pore space from dissolution of early formed authigenic cements and some unstable detrital grains	Late-stage calcite or iron carbonate minerals, or both	12–22%
Shallow marine	Near-shore and marginal marine	Beach, barrier island, and shoreline parallel sand bar sands	Marine shale and siltstone	Sandstone; varies from quartz arenite to litharenite or arkosic; locally fossiliferous		Secondary pore space from dissolution of early formed authigenic cements and some unstable detrital grains	Late-stage calcite or iron carbonate minerals, or both; mechanical compaction	4–20%

Table 5. Morrow Formation, Anadarko and Denver Basins—Summary of geological characteristics and reserve growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seal	Reservoir location	Traps or seals	
As much as several darcies	Could have helped hydrocarbons to migrate from any overlying or underlying sources	Possibly marine muds of the Morrow Formation, where mature in Anadarko Basin; other organic-bearing formations outside the Morrow	Downcutting and formation of paleovalleys localized fluvial channel–reservoirs, dominantly in upper part of Morrow	Underlying marine limestone or shale and overlying floodplain muds	Paleostructures and perhaps subsidence from dissolution of underlying evaporates may have localized areas of downcutting and incision	Anticlines may influence but are secondary to stratigraphic controls	Associated gas and oil
1–100 mD	Could have helped hydrocarbons to migrate from any overlying or underlying sources	Possibly marine muds of the Morrow Formation, where mature in Anadarko Basin; other organic-bearing formations outside the Morrow	Unclear	Lateral pinch out of sands into fine-grained marine muds	Unclear	Anticlines may influence but are secondary to stratigraphic controls	Dominantly gas
<1–200 mD	Could have helped hydrocarbons to migrate from any overlying or underlying sources	Possibly marine muds of the Morrow Formation, where mature in Anadarko Basin; other organic-bearing formations outside the Morrow	Location of sands in part a function of longshore currents, dominantly in lower part of Morrow	Lateral pinch out of sands into fine-grained marine muds	Unclear	Anticlines may influence but are secondary to stratigraphic controls	Dominantly nonassociated gas

Table 6. Barnett Shale, Fort Worth Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Shale (unconventional)	Offshore marine	Marine shale	Dense limestone	Organic-rich shale	Matrix, but very low	Uncertain	Calcite along fractures	Very low, typically <6%

Table 7. Bakken Formation, Williston Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Shale (unconventional)	Deep marine, below wave base	Black, organic-rich mudstone	Overlying shallow marine carbonates and shales	Black mudstone	Fracture	Little or none	Little or none	Very low, typically <5%
Siltstone-sandstone (unconventional)	Near-shore and shoreface	Siltstone and very fine to medium-grained sandstone	Enclosing black mudstone	Dolomitic siltstone and sandstone	Fracture	Dissolution of carbonate cement	Carbonate cement	Can be >10% but typically 3–10%

Table 6. Barnett Shale, Fort Worth Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
Very low, typically in the range of nanodarcies	Naturally fractured in deeper parts of basin and over structures; fractures reduce productivity	Organic-rich shale in the Barnett that also serves as reservoir rock	Uncertain	Gas trapped by fine-grained nature of shale reservoir	Best production away from fractured areas	Open faults tended to leak gas out of formation, whereas calcite-filled faults prevented gas migration	Non-associated gas

Table 7. Bakken Formation, Williston Basin—Summary of geological characteristics and reserve-growth potential of reservoirs..—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
<0.01–60 mD	Critical for production	Black, organic-rich mudstone; is also the reservoir rock	Apparently not important	Apparently not important	Fracture zones overlying anticlinal or monoclinal folds and solution fronts in underlying salts	Minimal; reservoirs unconventional	Oil
<0.01–109 mD	Critical for production	Organic-rich mud in Bakken, interbedded with or perhaps downdip from reservoirs	Local thickening owing to subsidence associated with dissolution of underlying salts	Overlying shales of the Bakken	Fracture zones overlying anticlinal or monoclinal folds and solution fronts in underlying salts	Updip against enclosing mudstone strata	Oil

Table 8. Ellenburger Group, Permian Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Karstified, principally in Central Basin platform and Midland Basin	Shallow aggrading marine carbonate platform	Inner platform	Reef, forereef, supratidal	Dolomitized mudstone	Interbreccia fragment and within fractures	Dissolution of lime mud leading to karstification and brecciation; intercrystalline owing to dolomitization of muds	Late-stage saddle dolomite	Average, 3% Range, 2–7%
Platform, dominantly in southern and eastern parts of Midland Basin	Shallow aggrading marine carbonate platform	Middle to outer platform	Reef, forereef, supratidal	Dolomitized packstone and mudstone	Intercrystalline	Intercrystalline porosity owing to dolomitization	Late-stage saddle dolomite	Average, 14% Range, 2–14%
Tectonically fractured, dominantly in the eastern Delaware Basin	Shallow aggrading marine carbonate platform	Inner platform	Reef, forereef, supratidal	Dolomitized mudstone	Fracture (tectonic)	Dissolution of lime mud leading to karstification and brecciation; intercrystalline owing to dolomitization of muds	Late-stage saddle dolomite	Average, 4% Range, 1–8%

Table 8. Ellenburger Group, Permian Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
Mean, 32 mD Range, 2–750 mD	Channeled pore fluids that allowed vertical infiltration of dissolving waters into various stratigraphic horizons to promote karstification	Overlying Ordovician Simpson Group	Lime muds remaining after early dolomitization, which became horizons subject to dissolution leading to karstification	Traps and seals include overlying Simpson Group and unkarsted Ellenburger dolomite. Seals also include impermeable cave-fill sediments and collapse zone adjacent to reservoirs	Anticlines, faulted anticlines, and fault-bounded anticlines	Uncertain	Principally oil with some associated gas and gas condensate
Average, 12 mD Range, <1–44 mD	Focused early dolomitizing fluids, which resulted in intercrystalline porosity and permeability	Overlying Devonian Woodford Shale?	Lime muds that were dolomitized	Traps and seals include overlying Simpson Group	Anticlines, faulted anticlines	Uncertain	Largely oil
Average, 4 mD Range, 1–100 mD	Early fracturing promoted karstification, whereas later fracturing improved porosity and permeability of the reservoir	Overlying Ordovician Simpson Group	Lime muds that were dolomitized	Traps and seals include overlying Simpson Group	Fractured anticlines and faults critical	Uncertain	Nonassociated gas

Table 9. Smackover Formation, Gulf Coast region—Summary of geological characteristics and reserve-growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Salt structure, dominantly in southern and eastern Texas, southern Arkansas, southern and central Mississippi, southwestern Alabama, and northern Louisiana	Slow regressive to stillstand marine carbonate ramp	Ramp, higher energy shoaling facies	Subtidal mudstone, wackestone, supratidal units, and outer ramp dolostones	Largely dolomitic oolitic grainstones and packstones	Dominantly intercrystalline where dolomitized, oomoldic in updip regions, intergranular in basinal regions	Intercrystalline owing to dolomitization; ooid dissolution; late calcite dissolution; diagenesis most pronounced on structural highs	Late-stage saddle dolomite, anhydrite, and calcite	2–35%
Basement structure, primarily in eastern Texas, central Mississippi, southern Arkansas, and southwestern Alabama	Slow regressive to stillstand marine carbonate ramp	Ramp, higher energy shoaling facies	Subtidal mudstone, wackestone, supratidal units, and outer ramp dolostones	Largely dolomitic oolitic grainstones and packstones	Principally oomoldic; minor primary interparticle and intercrystalline where dolomitized	Principally oomoldic; minor intercrystalline owing to minor dolomitization; diagenesis pronounced on structural highs	Late-stage calcite and dolomite	As much as 20%
Graben, principally along Arkansas-Louisiana border	Slow regressive to stillstand marine carbonate ramp	Ramp, higher energy shoaling facies	Subtidal mudstone, wackestone, supratidal units, and outer ramp dolostones	Oolitic limestone, locally dolomitic	Considerable interparticle pore space preserved; also oomoldic	Some interparticle and intercrystalline owing to dolomitization; some oomoldic	Partial cementation by calcite	4–19%
Stratigraphic, principally in southern Arkansas	Slow regressive to stillstand marine carbonate ramp	Ramp, higher energy shoaling facies	Subtidal mudstone, pelloid packstone, wackestone, supratidal units, and outer ramp dolostones	Oolitic, oncolitic, or skeletal grainstone limestone minimally dolomitized	Considerable interparticle; some oomoldic and intercrystalline where dolomitized	Some interparticle and intercrystalline owing to dolomitization; considerable early- and late-stage dissolution of particles and late-stage cement	Cements such as early and late stage calcite and anhydrite; some compaction	3–30%
Updip fault, principally in eastern Texas, southern Arkansas, central Mississippi, southwestern Alabama, and Florida Panhandle	Slow regressive to stillstand marine carbonate ramp	Ramp, higher energy shoaling facies	Subtidal mudstone, wackestone, supratidal units, and outer ramp dolostones	Oolitic limestone, locally dolomitic	Principally oomoldic	Ooid dissolution common; some dolomitization	Early calcite cement	10–20%

Table 9. Smackover Formation, Gulf Coast region—Summary of geological characteristics and reserve-growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
<1–4,100 mD	Large-scale open fractures not now widespread; however, fractures probably served as conduits for hydrocarbon migration	Organic-rich units in lower part of Smackover Formation	Shoaling sequences best developed on positive features formed by salt diapirism during deposition	Fine-grained beds in overlying Buckner Formation acted as seals	Salt anticlines, faulted salt anticlines, faulted salt-pierced anticlines	Faults seal some reservoirs	Dominantly oil and associated gas with minor condensate
60–350 mD	Faults now act as seals owing to impermeability of fault zones but earlier probably served as conduits for hydrocarbon migration	Organic-rich units in lower part of Smackover Formation	Facies changes up on basement highs; shoaling on positive basement highs during deposition. Little evidence of halokinesis	Stratigraphic and structural trap with overlying Buckner Formation; pinchouts on basement highs serve as seals	Regional fault zones, anticlines, faulted anticlines	Downdip fault zone served as reservoir seal	Dominantly oil in updip areas; associated gas or gas condensate in basinal areas
<1–1,000 mD	Faults now act as seals owing to impermeability of fault zones but earlier probably served as conduits for hydrocarbon migration	Organic-rich units in lower part of Smackover Formation	Shoaling sequences best developed on horst blocks adjacent to grabens	Structural and stratigraphic trap; overlying Buckner Formation serves as seal	Fault zones and faulted anticlines	Faults seal some reservoirs	Dominantly oil
1–250 mD	Faults probably served as conduits for hydrocarbon migration	Organic-rich units in lower part of Smackover Formation	Facies changes and regressive units overlying reservoirs	Structural and stratigraphic trap; overlying Buckner Formation serves as seal	Likely; structures limited deposition of reservoir rocks or facilitated pinchouts	Faults seal some reservoirs	Dominantly oil; some associated gas
3–280 mD	Faults now act as seals owing to impermeability of fault zones but earlier probably served as conduits for hydrocarbon migration	Organic-rich units in lower part of Smackover Formation	Near updip limit of Smackover deposition	Dominantly structural trap; fault systems serve as seals	Uplift on faults juxtaposed reservoirs and impermeable beds	Fault zones	Dominantly oil; some gas or gas condensate

Table 10. Spraberry Formation, Midland Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Submarine sand	Deep-water submarine basin and fan	Submarine fan and turbidite sandstones	Silty dolostone, organic-rich shale, and argillaceous sandstone	Sandstone	Largely intergranular but some minor moldic	Dissolution of preexisting authigenic cements and unstable detrital grains	Mechanical compaction and authigenic cements such as illite, chlorite, quartz, and dolomite	Matrix porosity usually 5–15% but may be as high as 18%

Table 11. Wasatch Formation, greater Uinta-Piceance Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.

[mD, millidarcies]

Reservoir category	Depositional characteristics			Reservoir characteristics				
					Porosity (bulk rock)			
	Environment	Reservoir facies	Nonreservoir facies	Lithology	Principal pore space	Diagenetic enhancement	Diagenetic occlusion	Porosity
Green River source	Fluvial, deltaic, and lacustrine	Fluvial, channel sandstone, and sands deposited in lacustrine deltas	Overlying and interbedded overbank, floodplain, delta plain, and lacustrine mudstone and claystone	Sandstones, lithic arkoses, or feldspathic litharenites	Intergranular, principally secondary; some minor moldic	Dissolution of early authigenic cements and unstable detrital grains	Some quartz and carbonate cements and authigenic clays	Ranges up to 15% at shallow (<4,000 ft) depths but <10% at greater depths (>8,500 ft)
Mesaverde source	Fluvial, deltaic, and lacustrine	Fluvial, channel sandstone, and sands deposited in lacustrine deltas	Overlying and interbedded overbank, floodplain, delta plain, and lacustrine mudstone and claystone	Sandstones, lithic arkoses, or feldspathic litharenites	Intergranular, principally secondary; some minor moldic	Dissolution of early authigenic cements and unstable detrital grains	Some quartz and carbonate cements and authigenic clays	Ranges up to 15% at shallow (<4,000 ft) depths but <10% at greater depths (>8,500 ft)

Table 10. Spraberry Formation, Midland Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seals	
Average matrix permeability low, <1 mD, but may be as high as 10 mD	Very common; multiple orientations observed; fractures cemented to various degrees	Interbedded organic-rich shales	Most reservoirs downdip from the ancient Horseshoe Atoll at mouth of submarine canyons or where facies change from channel to interchannel deposits	Pinchouts of reservoir rocks updip and downdip into fine-grained rocks serve as traps. Shales seal reservoirs	Uncertain	Mostly stratigraphic traps; one small field on an anticline	Largely oil

Table 11. Wasatch Formation, greater Uinta-Piceance Basin—Summary of geological characteristics and reserve-growth potential of reservoirs.—Continued

[mD, millidarcies]

Reservoir characteristics—Continued		Source rock	Stratigraphic controls		Structural controls		Oil or gas
Permeability	Fractures		Reservoir location	Traps or seals	Reservoir location	Traps or seal	
Generally low; as much as 40 mD but commonly <0.1 mD	Reservoirs may be complexly faulted; faults allow production	Organic-rich lacustrine mudstones of Green River Formation, which largely interfingers with the Wasatch	Reservoir rocks deposited adjacent to and in deltas within ancient Lake Uinta	Overlying and interbedded shales, mudstones, and claystones trap and seal reservoirs	Uncertain	Secondary to stratigraphic traps or seals	Dominantly oil; some associated gas
Generally low; as much as 40 mD but commonly <0.1 mD	Reservoirs may be complexly faulted; faults allow production; migration along fractures	Coals and organic-rich shale of the Mesaverde Group, which underlies the Wasatch	Reservoir rocks deposited adjacent to and in deltas within ancient Lake Uinta	Overlying and interbedded shales, mudstones, and claystones trap and seal reservoirs	In areas where gas could migrate up fractures that cut from source to reservoir rocks	Secondary to stratigraphic traps or seals	Nonassociated gas

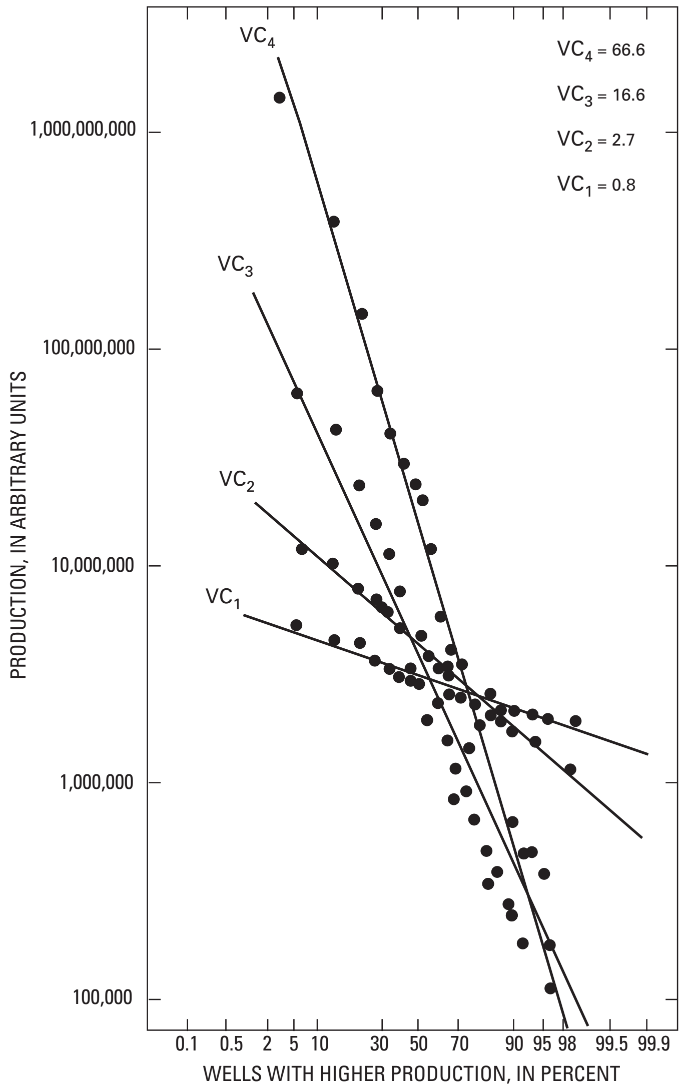

Figure 4. Probability distributions for production from wells of an oil or gas field (distributions based on hypothetical data—peak monthly production, peak yearly production, or cumulative production). Each point represents a well, and four fields (VC_1–VC_4) are depicted. In this type of plot log normal distributions plot as straight lines, and steeper slopes of lines correspond with a greater range of production and thereby greater production variability. The variation coefficient $VC = (F_5 - F_{95})/F_{50}$ provides a dimensionless numerical value for the variability of each data set, and its value increases as slope increases.

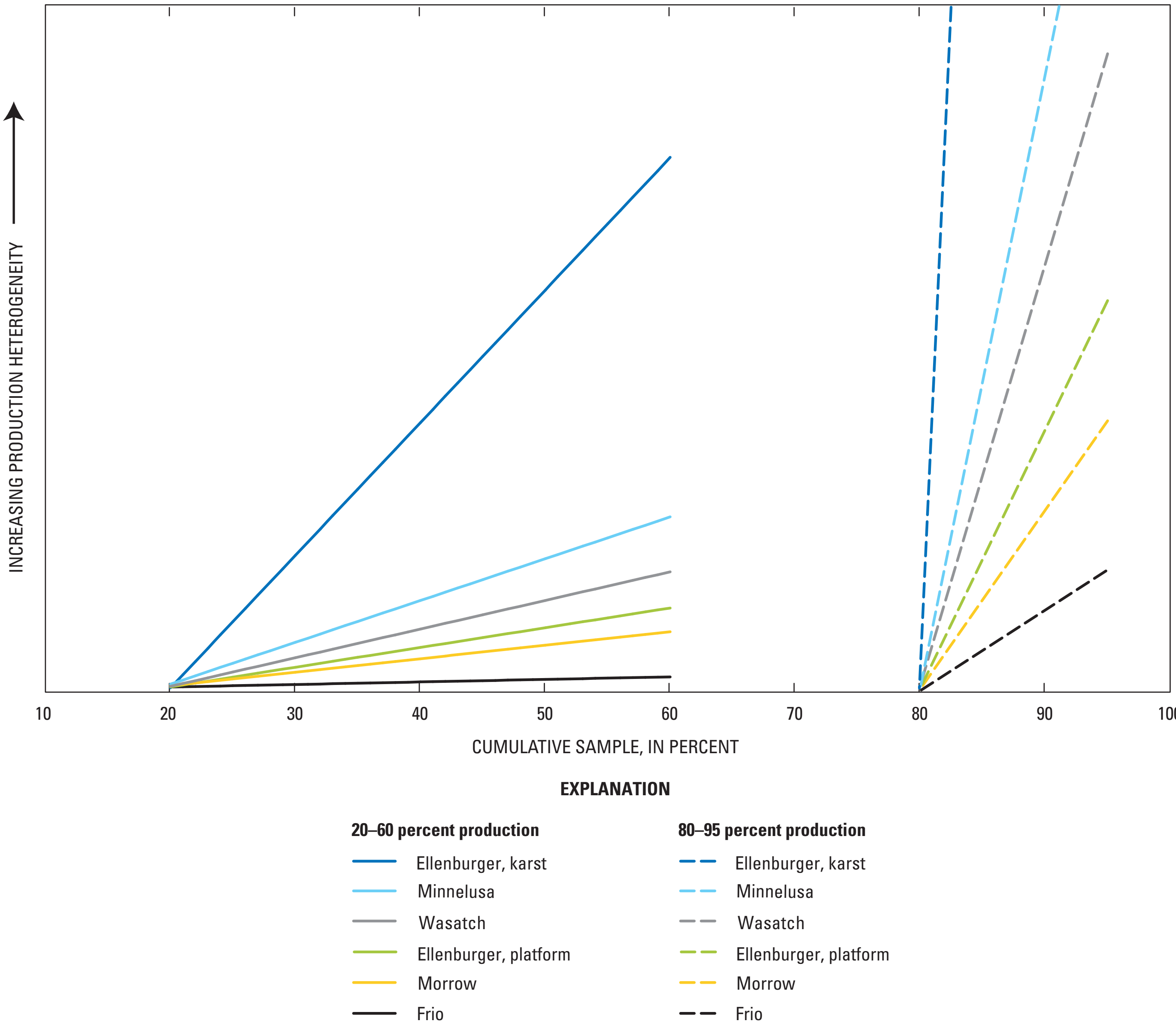

Figure 5. Production data of gas wells in fields in the Ellenburger Group karst and platform categories, Frio Formation fluvial category, Morrow Formation incised-valley category, Minnelusa Formation Minnelusa category, and Wasatch Formation Green River–source category.

Table 12. Location of, number of fields and wells in, cumulative production of, and largest fields in each reservoir category analyzed in this study.

[BCF, billion cubic feet; MMBO, million barrels oil; No., number of; cum., cumulative]

Reservoir category	Location	No. fields	No. wells	Cum. oil (MMBO)	Cum. gas (BCF)	Largest oil fields	Cum. oil (MMBO)	Cum. gas (BCF)
Frio	Texas[1]	272	6,301	534.4	11,193.0	Seeligson	238.1	2,306.0
						Tijerina-Canales-Blucher	87.0	753.8
						Stratton	41.8	1,841.5
Morrow	Colorado[2]	38	386	74.7	116.8	Arapahoe	23.2	35.7
						Mt. Pearl	13.6	41.2
						Sorrento	12.6	8.5
Wasatch	Utah[3]	24	436	89.9	139.2	Altamont	48.6	74.5
						Bluebell	34.9	48.6
						Cedar Rim	4.4	6.6
Ellenburger (karst)	Texas[4]	141	2,784	1,155.8	1,042.5	Andector	178.4	70.2
						TXL	129.3	29.8
						Pegasus	96.3	361.2
Ellenburger (ramp)	Texas[5]	134	928	65.0	29.0	Barnhart	16.7	11.9
						Swenson-Barron	5.8	1.2
						Swenson-Garza	4.2	0.7
Minnelusa	Wyoming[6]	315	1,936	586.8	14.9	Raven Creek	44.2	0.03
						Timber Creek	16.2	1.2
						Dillinger Ranch	16.2	1.6

[1]All or parts of Starr, Hidalgo, Brooks, Jim Hills, and Kleburg Counties, Texas.

[2]Morrow Formation producing wells in Colorado.

[3]Wasatch Formation producing wells in Utah.

[4]All or parts of Andrews, Winkler, Ector, Midland, Upton, and Crane Counties, Texas.

[5]All or parts of Borden, Garza, Scurry, Coke, Mitchell, Irion, Reagan, and Crockett Counties, Texas.

[6]All of Campbell, Crook, and Johnson Counties, Wyoming.

Results and Discussion

Of the formations studied, oil wells in fields from the Frio Formation (fluvial category) demonstrated the least production variability as shown by the relatively low slope of the central (20–60 percent) size class (fig. 5). After the Frio, successively increasing production heterogeneity (based on the slope of the central size class) was observed for the Morrow Formation (incised valley-fill category), Ellenburger Group (platform category), Wasatch Formation (Green River–source category), Minnelusa Formation (Minnelusa category), and finally Ellenburger Group (karst category) (fig. 5). Although the slopes for the formations of the upper (80–95 percent) size class are, overall, steeper than slopes for the central class, the lowest degree of production heterogeneity is again the Frio, and production heterogeneity increases following the same order as discussed above for the central size class.

Low variation coefficients suggest that Frio fluvial reservoirs, particularly those deposited in the Gueydan fluvial system (the fluvial reservoirs analyzed in this study; see Appendix for detailed geologic information), are lithologically homogeneous at the field scale. Gueydan channel sands tend to be thick and coarse grained, stack vertically, and amalgamate laterally; the sands probably were deposited in a single river complex (Galloway, 1977; Galloway and others, 1982). These characteristics are probably the reason that the Frio fluvial reservoirs are relatively homogeneous and why there is little difference in reservoir characteristics from field to field.

The intraformational production heterogeneity between the Ellenburger Group karst and platform categories is large (fig. 5). The same is true for geologic variability; in fact, the striking geologic differences between fields producing from the platform and karst categories prompted a closer look at their respective production characteristics. The greatest production heterogeneity noted in this study is in the Ellenburger karst category, where production is largely from pore spaces within fractured cave roof and clast-supported, brecciated, cave-floor materials (see the Appendix). In contrast, Ellenburger platform-category units produce primarily from intercrystalline porosity and permeability, different from the type of porosity and permeability in reservoirs of the karst category.

Although it is tempting to extrapolate production heterogeneities to a reservoir's potential for reserve growth on the basis of geologic characteristics, other factors (such as engineering and technological advances in production and political or cultural or economic influences on drilling) must also be fully considered. Furthermore, much additional study is needed before reliable extrapolations of the production characteristics of one reservoir category to the production characteristics of another reservoir that possesses similar geologic features can be made—for example, determining whether the production heterogeneities of the Ellenburger Group karst-category reservoirs share anything in common with the production heterogeneities of karst reservoirs found elsewhere in the world.

It was not our purpose to calculate the growth rate of fields for the six reservoir categories described here but rather to calculate the production variabilities for the reservoirs. By using the variation coefficient concept as modified from Dyman and Schmoker (2003) those variabilities were calculated. Results show that for fields with low variation coefficients, such as the Frio (fluvial category), wells also show low variation coefficients (fig. 5), and hence successive field size estimates are predictable. For fields with high variation coefficients, such as the Ellenburger (karst category), wells show high production variability (fig. 5) to the extent that field size estimates are likewise subject to greater variability. Consequently, we feel that future growth of existing fields through infill drilling is more predictable for fields with low production variability in part because fluid flow is homogeneous in these fields and, thus, there is less internal production variability (that is, less reservoir heterogeneity) in these reservoirs. In contrast, high variability in well productivity makes prediction of future field growth from infill drilling of that reservoir more difficult because fluid flow is heterogeneous and, thus, there is more internal production variability, resulting in a greater degree of reservoir heterogeneity. Although our analysis was based on a relatively limited data set, use of larger data sets will help to refine the methodology for estimating reserve growth through study of reservoir characteristics.

Conclusions

Numerous factors contribute to the growth in reserves but, ultimately, geology is the underlying control on production variability in oil and gas accumulations. In this study we identified 10 formations that possess gross geologic differences as determined by environments of deposition, and we defined various categories of reservoirs within many of the formations on the basis of such parameters as (1) environments in which the reservoirs were deposited, (2) reservoir characteristic such as porosity and permeability, (3) source rocks, (4) traps and seals, (5) structural evolution of the reservoir rocks, and (6) postdepositional alteration history of the reservoirs.

The connection between well production and geology was evaluated by studying the oil production histories of six disparate reservoir categories, two of which were found within one formation. Of the formations studied, oil wells in fields from the Frio Formation (fluvial category) demonstrated the least production heterogeneity, whereas successively increasing oil-production heterogeneity was observed for fields in the Morrow Formation (incised valley-fill category), the Ellenburger Group (platform category), Wasatch Formation (Green River–source category), Minnelusa Formation (Minnelusa category), and Ellenburger Group (karst category). The intraformational geologic variability between the Ellenburger karst and platform reservoir categories is large, as is the production heterogeneity between these two reservoir categories.

Fields with low production variability have the potential for more predictable growth than fields with high production variability, on the basis of evaluation of historic production information from various reservoirs including reservoirs from within the same formation. The variability in production history is likely due to reservoir heterogeneity. Nevertheless, linking such heterogeneity with field growth requires consideration of factors in addition to geology, including engineering and technological advances in production and the political or cultural or economic influences on drilling. Additional investigations utilizing large data sets are required before the production heterogeneity of one reservoir category can be reliably extrapolated to another reservoir that demonstrates similar geologic features.

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Appendix

Appendix. Stratigraphy and Depositional History of Formations Studied

The geology of the 10 formations evaluated for this study is described below. Although much of this information is summarized by formation in tables 2–11, we felt that inclusion of detailed geologic descriptions would benefit those readers who wanted to further explore the differing nature of the formations studied as well as the criteria used to establish reservoir categories. Formations evaluated were deposited in (1) eolian environments (the Norphlet and Minnelusa Formations) (2) interconnected fluvial, deltaic, and shallow marine environments (Frio and Morrow Formations) (3) deeper marine environments (Barnett Shale and the Bakken Formation) (4) marine carbonate environments (Ellenburger Group and the Smackover Formation) (5) submarine fan environment (Spraberry Formation), and (6) fluvial environment (Wasatch Formation).

Norphlet Formation

The Norphlet Formation, which reaches thicknesses of as much as 1,000 ft (Dixon and others, 1989), is present in the Gulf Coast from Texas eastward to at least the northwestern part of Florida (fig. 1) and has produced both oil and gas since 1967 (Marzano and others, 1988). The formation is considered to be Late Jurassic (Oxfordian) in age by most workers (for example, Andrews, 1960; Murray, 1961; Imlay, 1980), although some consider it to be late Middle Jurassic (late Callovian) (Wade and Moore, 1993). It consists largely of eolian sandstone beds that were deposited in an extensive sand sea formed by northwesterly winds (Peterson, 1988); interdune, fluvial, and marine rocks, such as black shale, conglomerate, and red beds are also present (Schenk, 1990). The eolian sandstones are bordered to the north by fluvial strata washed off the ancestral Appalachian and Ouachita Mountain belts and to the south by either open marine or hypersaline marine strata deposited in the ancestral Gulf of Mexico, when South America was beginning to separate from North America.

Although the Norphlet Formation is regionally extensive, most of its production comes from a relatively narrow band in central and southern Alabama and Mississippi and in the shallow offshore in Mobile Bay, Alabama (fig. 1; Schenk, 1995a). South of the producing area, the Norphlet is deeply buried (>25,000 ft), so the production potential there is uncertain; however, the formation is known to have excellent porosity and permeability even at depths greater than 20,000 ft (Marzano and others, 1988; Dixon and others, 1989; Mancini and others, 1990). Oil is produced largely from reservoirs in south-central Mississippi (Schenk, 1995a), whereas gas is produced in more southwesterly areas as well as offshore in Mobile Bay.

Broad similarities in reservoir characteristics of Norphlet Formation reservoirs throughout the area of production suggest that only a single reservoir category is warranted (table 2). Although characteristics such as the geographic distribution of wells and the type of petroleum produced were considered when we attempted to categorize Norphlet reservoirs, the available data indicate that more similarities than differences exist between reservoirs, and thus we designated only a single reservoir category.

Porosity and permeability of reservoirs in the formation are relatively high, even for offshore fields in deeper parts of the Gulf of Mexico Basin. Porosity is as much as 20 percent in fields producing from locations onshore, and it may be as high as 12 percent in deep fields producing from offshore locations in Mobile Bay (Schenk, 1995a). Permeabilities are as much as 500 mD (Schenk, 1995a), even in some of the deep fields.

Diagenesis has played an important role in either trapping or sealing petroleum accumulations or influencing porosity and permeability in the Norphlet Formation reservoirs. A zone pervasively cemented by authigenic quartz has been observed at the top of the formation in many places (Dixon and others, 1989; Lock and Broussard, 1989; Kugler, 1993), making these low-porosity or -permeability cemented zones an effective intraformational seal. Elsewhere, authigenic cements act as barriers or baffles to fluid flow (Kugler, 1993; Schenk and Schmoker, 1993), which also contributes to trapping or sealing petroleum. In contrast, chlorite (a common authigenic clay in the Norphlet) is thought to inhibit pressure solution and cementation (Schenk, 1990). In fact, chlorite has been considered responsible for preserving at least some of the excellent porosity and permeability observed in the Norphlet even at great depths (Dixon and others, 1989). In contrast, authigenic illite possibly promoted pressure solution of some detrital grains, thereby degrading reservoir properties by reducing porosity and permeability (MacGowen and others, 1993). Secondary porosity, resulting from dissolution of unstable detrital grains as well as some cements (for example, calcite, anhydrite, and halite), has also been thought to contribute significantly to production, even where the Norphlet is deeply buried (McBride and others, 1987; Lock and Broussard, 1989; Kugler, 1993).

Structural features served to not only influence sand depositional patterns but also to later trap hydrocarbons in some of the Norphlet Formation fields. The syndepositional downdropping of basement-controlled grabens led to local thickening of sandstones in these paleolows, whereas sandstones thinned or are absent on paleohighs, the uplift of which was also structurally controlled (Wilson, 1975; Sigsby, 1976; Mancini and Benson, 1980; Mancini and others, 1985). Structurally controlled traps may be anticlines, faulted anticlines, and extensional faults that formed after movement of either or both basement structures and salts in the underlying Louann Salt (Mancini and others, 1985). Norphlet fields are complexly faulted in several places in southern Alabama, where the position of the water table beneath the hydrocarbons is a guide to compartmentalization once the faults have been located by seismic surveys (Mancini and others, 1985; Mudford and others, 1995; Story, 1998).

Although mudstones of the overlying Upper Jurassic Smackover Formation are considered one of the dominant units that seal Norphlet Formation reservoirs (Schenk, 1995a), other stratigraphic features also serve to trap and seal petroleum. Stratigraphic traps occur where reservoir sands pinch out against the flanks of large structures (Mancini and others, 1985; Schenk, 1995a) or basement knobs and ridges and possibly by updip onlap against the metamorphic rocks at the edge of the depositional basin (Rhodes and Maxwell, 1993; Mink and Mancini, 1995; Dean, 1998). Thin interdunal, sabkha, or playa lake deposits (strata originally deposited horizontally and ranging from a few inches to several tens of feet thick) also serve as stratigraphic traps and seals owing to their low porosity and permeability, which results from the considerable quantities of silt, clay, and alteration products in them (Krystinik, 1990a). Lateral intraformational fluid flow barriers also exist in Norphlet reservoirs insofar as permeability trends tend to be closely related to the orientation of cross-bedding in eolianites, and that orientation is in turn a function of paleowind flow. As an example, permeability tends to have maximum values horizontally and perpendicular to paleowind flow and lower values horizontally but parallel to paleowind flow (Krystinik, 1990a). Lateral barriers within a reservoir have been documented in Mobile Bay, where the boundaries of northwest-southeast–trending linear paleodunes in the Norphlet compartmentalize the reservoir (Story, 1998).

Minnelusa Formation

The Minnelusa Formation of Pennsylvanian to Early Permian (Morrowan to Wolfcampian) age, which achieves thicknesses as much as 1,200 ft (Martinsen, 1997), has been a major producer of oil for some 40 years in the Powder River Basin in northeastern Wyoming (fig. 2) (Krystinik, 1990a; De Bruin, 1993; Dolton and Fox, 1995; Martinsen, 1997). The formation, which was deposited in a cratonal basin on the edge of a large, shallow inland seaway, the Midcontinent Sea (Trotter, 1984), consists of sandstone, dolomite, anhydrite, and sparse shale beds deposited in cyclic sequences in eolian, sabkha, shoreface, hypersaline marine, and shallow marine environments (Krystinik, 1990b; Schenk, 1990). Almost all of the reservoir rocks are eolian sandstones, although some petroleum may extend into laterally adjacent shoreface sandstone beds where they interfinger with eolianites (Tromp and others, 1981; Desmond and others, 1984; Trotter, 1984; Jorgensen and James, 1988). The eolianites formed in a coastal dune field deposited by generally southward-blowing winds (oriented in terms of present geographic coordinates) along the west edge of the sea (Peterson, 1988). Nonreservoir strata consist of marginal marine limestone, dolomite, and shale.

Reservoirs were placed into two categories, referred to as Minnelusa and Leo. This division seemed warranted because of differences in the stratigraphic positions of reservoirs in the two categories and the geographic distribution of producing wells; moreover, the two categories may have different source rocks. Note that previous workers have variously referred to the reservoir rocks of the Leo category as the “Leo sandstone”(Hunt, 1938), “Leo section” (Desmond and others, 1984), “Leo Formation” (Morel and others, 1986), and the “Leo sandstone of the Minnelusa Formation” (Dolton and Fox, 1995).

Reservoirs in the Minnelusa category are stratigraphically in the uppermost part of the formation, whereas those in the Leo category are in the middle part. Minnelusa-category reservoirs are principally in the north-central and northeastern parts of the Powder River Basin. In contrast, Leo reservoirs produce largely in the more southern and southeastern parts of the basin as well as outside the basin near the conjunction of the Wyoming–South Dakota–Nebraska state lines. Although reservoirs in both categories are eolianites, those of the Minnelusa category were deposited as extensive sand sheets whereas those of the Leo category were more isolated dune sands (Martinsen, 1997).

Sandstones in both reservoir categories were originally well-sorted and largely clay-free quartz arenites and subfeldspathic arenites (James, 1989). Average porosity of reservoirs in both categories is 12–24 percent (Dolton and Fox, 1995), although maximum porosity can be about 47 percent. Permeabilities in the Minnelusa-category reservoirs are typically 10–830 mD (Wyoming Geological Association, 1981); however, some have been reported as high as 3,200 mD (Helmold and Loucks, 1985). Little information has been reported on permeabilities for Leo-category reservoirs.

In general, early cementation helped to prevent permanent loss of porosity and permeability from mechanical compaction, and later dissolution of some of these cements created secondary porosity that allowed for accumulation of oil. Gypsum or anhydrite cementation is most common in dune sands, whereas widespread quartz cementation appears preferentially in sands deposited in other environments (Schenk and others, 1986). Much of the anhydrite was removed at or near maximum burial depth to produce a large amount of secondary porosity (Markert and Al-Shaieb, 1984; Schenk and Richardson, 1985). Subsequent quartz and dolomite cements are present in increasing amounts in more deeply buried rocks, reducing porosity to <4 percent. Clay content is low (about 2–5 percent), and illite makes up 80 percent of those clays; minor amounts of mixed-layer illite-smectite, corrensite, and kaolinite have also been reported (Markert and Al-Shaieb, 1984; James, 1989; Pollastro and Schenk, 1991).

Oil in reservoirs of both categories is principally in stratigraphic traps. The primary trapping mechanism consists of an overlying, relatively impermeable barrier of marine shale and dolomite, such as the Permian Opeche Shale for reservoirs in the Minnelusa category (Bean and others, 1984; James, 1989). Lateral pinchouts are common where an eolian dune ridge thins and pinches out against impermeable marine carbonate rocks and shales (Jorgensen and James, 1988; James, 1989). In addition, various bounding surfaces within eolian beds mark local or widespread interruptions in deposition within a sand sea (Kocurek, 1981, 1988; Fryberger, 1990; Shebl, 1995). The bounding surfaces, which are most common in reservoirs of the Minnelusa category, may be characterized by greater cementation or diagenesis in underlying rocks, or they may be associated with strata of markedly different lithologies above them; either of these conditions can create permeability barriers. The surfaces are not necessarily planar and, where they possess some relief, lateral compartmentalization of the reservoir may be substantial. Overlying shales and carbonate rocks seal Leo-category reservoirs; bounding surfaces and lateral pinchouts do so as well.

Structural features may also serve to control reservoir location, although these features seem to be less important than stratigraphic or diagenetic controls. Low-relief closures of anticlines, which are present in areas of production from reservoirs in both categories, place some controls on reservoir location (Dolton and Fox, 1995). Reduced porosity and permeability across lithologic and diagenetic zones commonly serve to seal reservoirs.

Source rocks have been considered to be either distant from or interbedded with reservoirs of the two categories in the Minnelusa Formation. Volumetrically, however, oil produced from the reservoirs of the Minnelusa category far exceeds that produced from reservoirs of the Leo category (Dolton and Fox, 1995; Martinsen, 1997), making the source for Minnelusa-category reservoirs of much greater importance. The Lower Permian Phosphoria Formation has been considered the source of oil in Minnelusa-category reservoirs, even though likely source beds in western Wyoming are far removed from reservoirs in eastern Wyoming (Barbat, 1967; Sheldon, 1967; Stone, 1967; Fryberger, 1984; MacGowan and others, 1993). Because the sands in the upper part of the Minnelusa are areally widespread, long-distance migration of oil into reservoirs of the Minnelusa category is possible. However, the early Tertiary (Laramide) timing of uplift of what are now the Big Horn Mountains (fig. 2), which lie between areas of possible source rocks in the Phosphoria and reservoirs in the Minnelusa category, indicates that oil had been generated and had migrated before uplift (Barbat, 1967). Later Laramide deformation served to disrupt fault migration pathways, making the flow of oil through the area of the Big Horn Mountains highly unlikely. In contrast, reservoir sands of the Leo category are areally more restricted than those of the Minnelusa category, so it is much less likely that they were in hydrologic communication with regional fluid flow, such as the flow of petroleum that might have also migrated from distant Phosphoria source rocks. Instead, organic-rich shales within the Minnelusa may have served as the source of oil for at least some reservoirs (Momper and Williams, 1979; Tromp and others, 1981; Clayton and Ryder, 1984; James, 1989). The limited lateral extent of reservoirs of the Leo category, the relative stratigraphic isolation of the reservoir sandstones, and the fact that in places the sandstones interfinger with organic-rich shale suggest that oil in Leo-category reservoirs probably migrated relatively short distances from intraformational source beds.

Frio Formation

The Oligocene Frio Formation, which reaches a thickness of more than 15,000 ft, is present both onshore and offshore throughout much of the Texas Gulf Coast region (fig. 3) and has produced oil and gas since the 1920s. The formation represents a large progradational wedge of siliciclastic sediments that were shed from the continent into the Gulf of Mexico Basin periodically during the Tertiary. Deposition of the Frio resulted in considerable basinward advancement of the North American continental margin: the coastal plain aggraded hundreds of feet and the continental margin prograded as much as 50 mi (Galloway and others, 1982; Galloway, 1989). Although much of Frio deposition occurred during continental margin outbuilding, several transgressional units reflect marine flooding of the platform and concomitant deposition of tongues of marine shale (Galloway and others, 1982).

Reservoirs in the Frio Formation are placed into four categories (table 4)—fluvial, deltaic, barrier-strandplain, and shelf—because reservoirs within them differ in terms of their broad depositional, geographic, and structural settings; proximity to structures and potential source rocks; and reservoir characteristics.

Two major fluvial complexes in the Frio Formation, the Gueydan and the Chita-Corrigan fluvial systems (fig. 3; Galloway, 1977; Galloway and others, 1982; Kosters and others, 1989a), transported much of the detritus in the formation (Galloway and others, 1982). The Gueydan system delivered sediment to the Norias delta complex, whereas the Chita-Corrigan fluvial system delivered sediment to the Houston delta complex (fig. 4; Galloway and others, 1982). The two deltaic complexes were separated by the intervening San Marcos arch (Galloway and others, 1982; Galloway, 1986). Longshore currents reworked some sediment from the deltas, resulting in the lateral intertonguing of barrier and strandplain sandstones with deltaic strata. Between the two delta complexes was the Greta-Carancahua barrier-strandplain system (Boyd and Dyer, 1964), whereas sediments of the Buna barrier-strandplain system were deposited east of the Houston delta complex, from south Texas into Louisiana (fig. 3; Galloway and others, 1982). The delta and strandplain systems, in turn, grade basinward into Frio shelf rocks.

Reservoirs in the fluvial category were deposited in either the Gueydan or the Chita-Corrigan fluvial systems, and all reservoirs in this category are combined because of their fluvial origin. These reservoirs are widespread, occur principally in south Texas (Galloway and others, 1982; Schenk, 1995b), and account for approximately 30 percent of all the gas produced from the Frio (Kosters and others, 1989a) although oil is also produced from them. Most gas produced from fluvial rocks in the Frio appears to be from sandstones deposited in the Gueydan system (Kosters and others, 1989a).

Characteristics of reservoirs in the fluvial category differ depending on the fluvial system and spatial position within that system. Gueydan channel sandstones tend to be coarse grained and stack vertically or amalgamate laterally, features that probably reflect deposition from a single river complex (Galloway, 1977; Galloway and others, 1982). In contrast, the Chita-Corrigan fluvial system contains many rivers, which led to many channel sandstones that are more isolated, laterally discontinuous, and finer grained than those of the Gueydan system (Galloway, 1977; Galloway and others, 1982). In both systems, mud-rich floodplain strata serve as stratigraphic traps and seals. The thickness and extent of sandstones in the Gueydan system, as well as their generally coarse grain size, make them more favorable for exploration and production than those of the Chita-Corrigan. Within the Gueydan fluvial system, production is generally best where reservoirs lie on the downthrown (basinward) side of the Vicksburg fault zone, one of the major growth faults in the region. Although reservoir characteristics are somewhat similar throughout the system (for instance, porosity is 15–35 percent and permeability is 20–1,500 mD) (Loucks and others, 1984; Kosters and others, 1989a; Schenk, 1995b), traps such as rollover anticlines on the downthrown side of the Vicksburg fault zone were more effective in localizing economic accumulations of petroleum (Kosters and others, 1989a). The fault zone was also the likely conduit for upward migration of petroleum from deeper units (Schenk, 1995b), insofar as potential intraformational source rocks (for example, interbedded floodplain mudstones) are largely immature (Galloway and others, 1982).

Frio Formation reservoirs of the deltaic category were deposited in delta-plain, delta flank, delta-front, and distributary channel environments in either the Norias or Houston delta complexes. Although different in overall size, volume of sediment input, degree of influence of underlying salt, and rates of progradation (Galloway and others, 1982), in this report the two delta systems are grouped in a single reservoir category because both were deposited in active delta-building areas. Reservoirs in this category are widespread, principally in southern and southeastern Texas and southern Louisiana (Galloway and others, 1982; Kosters and others, 1989a; Schenk, 1995b). Roughly equivalent volumes of gas have been produced from reservoirs in each delta system, and together they account for about 34 percent of the total volume of gas removed from the Frio (Kosters and others, 1989a). Oil is also produced from reservoirs in this category.

Characteristics of the reservoirs in the deltaic category differ depending on the delta system. In general, greater volumes of coarse sediment were deposited in the Norias delta system, which prograded farther basinward than did the Houston delta system farther east (Galloway, 1977; Galloway and others, 1982). Additionally, growth of the Norias delta was strongly influenced by growth faults that were active during deposition of the Frio (Galloway and others, 1982), whereas strata in the Houston delta system were complexly influenced by both salt tectonics and growth fault movement (Galloway and others, 1982). These differing structural histories resulted in differing sandstone thicknesses and geometries, which has led to differing reservoir configurations in the two delta systems. Anticlines, rollover anticlines, and faulted anticlines appear in both systems; however, salt tectonics was responsible for at least some structures that controlled hydrocarbon accumulations in the Houston delta system. Porosity of reservoir rocks from both systems is about 10–35 percent and permeability is about 10–2,400 mD (Kosters and others, 1989a). Oil and gas are produced from both delta systems (Kosters and others, 1989a; Schenk, 1995b), and nonassociated gas is more common in distal parts of each.

Reservoir sandstones of the barrier-strandplain category were deposited in shoreface, beach, and barrier environments in either of the Greta-Carancahua or Buna barrier-strandplain systems. Sediments in both systems were reworked from delta complexes by longshore drift (Galloway and others, 1982); the reservoirs are some of the most productive along the Gulf Coast and have produced about 35 percent of the gas in the Frio (mostly sandstones in the Greta-Carancahua system; Kosters and others, 1989a).

Barrier-strandplain sandstones are unique among all the Frio Formation reservoirs, in part because the sandstone bodies are typically the thickest, averaging about 55 ft (Galloway and others, 1982). These units are typically elongate parallel to the strike of growth faults, and the faults likely influenced stacking of the sandstones (Galloway and others, 1982). Seals within the thickest sandstones are rare, however, so reservoirs of this category are more common where individual sandstones are thinner and are interbedded with marine (basinward) or lagoonal (shoreward) shales (Galloway and others, 1982). Anticlines, rollover anticlines, and faulted anticlines play a key role in structural trapping styles in both systems, and seals are principally fine-grained interbeds and fault-juxtaposed fine-grained units (Galloway and others, 1982; Kosters and others, 1989a). Porosity of reservoir rocks in the barrier-strandplain category is about 20–35 percent and permeability is about 8 to >3,500 mD (Kosters and others, 1989a).

Reservoirs sandstones of the shelf category were deposited in shelf, slope, and possibly submarine fan environments throughout the Gulf of Mexico Basin. Although these units tend to be mud rich, redistribution of some coarser sediments by gravity- and storm-driven events caused sand to accumulate in delta-front, shelf, and slope settings (Galloway and others, 1982). The reservoirs produce largely gas, although collectively they contribute <2 percent of all gas produced from the Frio Formation (Kosters and others, 1989a).

Shelf reservoirs are typically the most distal of all Frio Formation reservoirs. Sandstones deposited in this environment are highly variable in thickness but average about 33 ft (Galloway and others, 1982). Active faulting or salt diapirism created depressions in some places on the slope, and these depressions trapped submarine sediments (Galloway and others, 1982). Structures such as anticlines, faulted anticlines, and salt-related features also served as traps for these reservoirs, and in places faults act as seals by juxtaposing reservoirs with more impermeable units (Galloway and others, 1982). Maximum porosity of reservoir rocks in shelf systems is as much as 30 percent and permeability is as much as 1,500 mD (Kosters and others, 1989a), although porosity and permeability decrease with increasing depth.

Diagenesis was important in forming economic accumulations of hydrocarbons in all reservoir categories of the Frio Formation. The deeply buried sandstones were subjected to intense mechanical compaction, and stress continues from overburden and multiple events of cementation (that emplaced quartz, feldspar, carbonate minerals, and clay) and dissolution (Milliken and others, 1981; Loucks and others, 1984; Milliken and others, 1994). These compactional events occurred both before and after hydrocarbon generation and migration. Sandstones not deeply buried may also demonstrate a complex diagenetic history depending on the relative abundance of contained unstable detrital mineral grains and the nature of pore fluids that passed through the rocks. In spite of ongoing mechanical and chemical compaction, some deeply buried sandstone reservoirs, particularly those of the delta, barrier-strandplain, and shelf categories, currently have sufficient porosity and permeability to produce hydrocarbons owing largely to formation of secondary porosity from dissolution of earlier formed cements and detrital grains (Loucks and others, 1984; Milliken and others, 1994; Lynch, 1996). However, secondary porosity had to form before hydrocarbon generation and migration for this process to facilitate petroleum accumulation. The absence of secondary porosity, or its formation well after hydrocarbon generation and migration, severely limits the likelihood that any given sandstone in any reservoir category could produce economic quantities of petroleum.

Morrow Formation

The Morrow Formation (Lower Pennsylvanian), principally located in the Anadarko Basin of Oklahoma and Texas; adjacent areas in southern and western Kansas; southeastern Colorado; and the Denver Basin in eastern Colorado (fig. 2) is typically 250–750 ft thick, but it thickens in a southeasterly direction to >1,500 ft in the deepest part of the Anadarko Basin in Oklahoma (Rascoe and Adler, 1983). It has been an important gas-producing and, to a lesser degree, oil-producing unit since the early 1930s (Kosters and others, 1989b; Bingham and Woodward, 1993). The formation represents a wedge of siliciclastic sediment that was shed into an asymmetric depositional basin that includes the present-day region of the Anadarko Basin and surrounding areas (Rascoe and Adler, 1983). In eastern Colorado and western Kansas, the upper part is dominantly of fluvial and deltaic origin (Krystinik and Blakeney, 1990; Wheeler and others, 1990; Bowen and Weimer, 2003), whereas much of the formation to the southeast in the Anadarko Basin is largely of marine origin (Rascoe and Adler, 1983).

Several transgressive-regressive sequences are recorded in Morrow Formation strata. Global climate change, which resulted in several episodes of glaciation followed by deglaciation, is considered the likely cause for the alternating transgression-regression sequences that characterize the Morrow (Sonnenberg, 1985; Sonnenberg and others, 1990; Krystinik and Blakeney, 1990). The episodic change in sea level resulted in multiple sequences of genetically related fluvial, deltaic, and nearshore marine rocks.

In Early Pennsylvanian time, a broad, shallow shelf with relatively low relief lay adjacent to and northward of deep-water environments that existed in central Oklahoma. During periods of low sea level, which roughly corresponded with times of maximum glaciation, the shallow shelf was subaerially exposed and became a site of erosion and accompanying incision into underlying sediments. Although in places valleys formed largely through incision, subsidence related to dissolution of underlying marine evaporites may have also caused valleys to form (Bartberger and others, 2001). Basinward from the valleys, deltaic and slope sedimentation continued near the shelf-slope break area in western Oklahoma (Sonnenberg and others, 1990). The incised drainages that formed became sites of infilling with clastic sediment upon the subsequent rise in sea level (Sonnenberg, 1985; Krystinik and Blakeney, 1990; Wheeler and others, 1990; Bowen and Weimer, 2003). Subsequently, the sands of the incised valleys became reservoirs throughout the region as did the more distal sands deposited in delta and marine environments (Rascoe and Adler, 1983; Sonnenberg and others, 1990; Wheeler and others, 1990). Foreshore sands and shore-parallel bars, which also locally became reservoir rocks, accumulated concurrently in the marine environment.

On the basis of depositional setting and reservoir characteristics, hydrocarbon reservoirs in the Morrow Formation have been placed into three categories—incised valley fill, deltaic, and shallow marine (table 5). These categories were selected because of differences in their broad geographic and depositional settings, which led to differing reservoir rock characteristics (such as porosity and permeability) that bear directly on the reservoirs' physical properties and contained resources.

Reservoirs in the incised-valley-fill category, located principally in eastern Colorado and western Kansas, record multiple episodes of incision and valley filling during which fluvial sands overlain by overbank deposits and possibly estuarine sands and muds were deposited (Krystinik and Blakeney, 1990; Wheeler and others, 1990; Bowen and Weimer, 2003). Both fluvial and estuarine sandstones serve as reservoirs, but fluvial sandstones commonly are the more productive. Finer grained units such as floodplain mudstone and estuarine mudstone are nonreservoir rocks and may serve to compartmentalize Morrow reservoirs in this category (Bowen and Weimer, 2003).

Reservoir characteristics of the incised-valley-fill category are generally favorable for production of petroleum. Sandstones deposited in braided fluvial environments are commonly medium to coarse grained and are compositionally quartz arenites, litharenites, or arkoses; they can have excellent porosity of 12–21 percent (Brown and others, 1993) and permeability of several darcies (Krystinik and Blakeney, 1990; Brown and others, 1993), although diagenetic cements may locally occlude pore space (Krystinik and Blakeney, 1990). In contrast, sandstones deposited in estuarine environments, although relatively porous (locally 20–23 percent; Kasino and Davies, 1979), are finer grained than fluvial sandstones and also have lower permeabilities of <1–200 mD (Kasino and Davies, 1979; Krystinik and Blakeney, 1990).

Reservoirs of the deltaic category are widespread throughout southwestern Kansas, western Oklahoma, and the Oklahoma-Texas panhandle, where a broad delta plain existed during much of the depositional period of the upper part of the Morrow Formation (Swanson, 1979). Sandstones, deposited as sand sheets by streams that meandered across the delta plain as well in point bars, distributary channels, and in stream-mouth bars, are the most important deltaic reservoirs in the Morrow (Swanson, 1979). They are commonly interbedded with or enclosed within nonreservoir rocks such as finer grained units (overbank, backswamp marsh, prodelta, and marine muds), which compartmentalize the sandstones (Swanson, 1979).

Sandstone reservoirs within the deltaic category in the Morrow Formation possess variable characteristics. Those deposited in the lower part of point bars, where interstitial clays and clay laminations are rare or absent, are commonly good reservoirs and are compositionally quartz arenites, lithic arenites, or arkoses with porosities of 15–22 percent (Swanson, 1979). In contrast, the upper parts of stream mouth bars contain the least amount of interstitial and laminated clays and have porosities of 12–18 percent (Swanson, 1979). Permeabilities vary from 1 to 100 mD in deltaic-category reservoirs (Kosters and others, 1989b).

Reservoirs of the shallow-marine category are largely in the lower part of the Morrow Formation in southwestern Kansas, western Oklahoma, and the Oklahoma-Texas panhandle; some are also in the upper part of the Morrow in south-central Kansas (Brown and others, 1993). Sandstone reservoirs in the marine category were deposited largely in beach, barrier-island, and offshore-bar environments. Most of these sands are thought to have been redistributed by longshore currents, following their original deposition in fluvial systems (McManus, 1959; Rascoe and Adler, 1983; Brown and others, 1993).

As with sandstones of other reservoir categories, those in the shallow-marine category possess variable compositions (quartz arenites, litharenties, or arkoses), porosities (4–20 percent), and permeabilities (<1 to about 200 mD) (Kasino and Davies, 1979; Kosters and other, 1989b; Brown and others, 1993). Although some of the bar sandstones coarsen upward at the base and fine upward at the top, sandstone of highest porosity tends to be within the central portions of these intervals (Kosters and others, 1989b).

Diagenesis was important in the formation of economic accumulations of hydrocarbons in all reservoir categories of the Morrow Formation. Although most sandstones in the formation underwent a complex history of diagenetic cementation (Adams, 1964; Kasino and Davies, 1979; Krystinik and Blakeney, 1990; Rader, 1990), sandstones of the incised valley-fill category have a relatively simple history. In those reservoirs, dissolution of early-formed cements and some unstable detrital grains produced secondary porosity, which is the most important alteration as it pertains to petroleum accumulations in incised valley-fill reservoirs (Krystinik and Blakeney, 1990). In contrast, in marine sandstones in the deeper parts of the Anadarko Basin, pore space is occluded and permeability is reduced by authigenic cements and excessive mechanical compaction, both of which diminish the potential for favorable reservoir conditions (Rascoe and Adler, 1983). Although cementation may have occluded primary pore space in marine sandstones deposited in shallower parts of the Anadarko Basin, variable secondary porosity in these sandstones promoted their development as reservoirs (Kasino and Davies, 1979).

Traps and seals associated with most Morrow Formation reservoirs are almost entirely stratigraphic (Henry and Hester, 1995). Although the formation contains fluvial, deltaic, and marine depositional environments, most porous and permeable reservoir sandstones are encased within finer grained rocks—the dominant rock type of Morrow strata as a whole (Swanson, 1979). Thus, lithofacies relations are responsible for trapping and sealing most of the hydrocarbons that are produced from the formation (Swanson, 1979; Rascoe and Adler, 1983; Kosters and others, 1989b; Brown and others, 1993; Henry and Hester, 1995). Although subsidence and structural conditions may have played a role in forming valleys and influencing sedimentation in them (Bartberger and others, 2001; Bowen and Weimer, 2003), their role in trapping and sealing reservoirs seems to be subsidiary to stratigraphic factors.

Barnett Shale

The Barnett Shale of Middle to Late Mississippian age (Lancaster and others, 1993) is an unconventional (or continuous) gas reservoir in the Fort Worth Basin of north Texas (Pollastro and others, 2004; Pollastro and others, 2007; fig. 3). The formation crops out on the north flank of the Llano uplift of central Texas (Fig. 4) and extends into the subsurface north and northeast from there into the basin (Henry, 1982; Lancaster and others, 1993). Gas has been produced from the formation since 1981, largely from rocks positioned down the hydrologic gradient from water-saturated rocks (Kuuskraa and others, 1998), and although oil has been discovered in some areas, its low flow rate makes oil extraction largely uneconomic (Bowker, 2002). Since about the year 2000, however, gas production has increased dramatically (Pollastro and others, 2004), largely owing to the recognition and refinement of appropriate reservoir stimulation technologies (Bowker, 2007). Because of its relatively recent production history, publicly available information is limited; nevertheless, the Barnett recently became the largest gas-producing formation in Texas (Bowker, 2007).

The Barnett Shale, which has been divided into three informal members in the Fort Worth Basin, reaches a maximum thickness of about 650 ft (Pollastro and others, 2007). Principal producing intervals are marine shale units, informally termed the lower shale (average thickness 300 ft in producing region) and upper shale (average thickness 150 ft in producing region). In much of the area of current production, the two shale members are separated by a limestone of variable thickness. Constituents of the shales include quartz (possibly altered radiolarian tests), clay (dominantly smectite), carbonate, feldspar, and organic matter.

Reservoirs in the Barnett Shale are grouped in a single shale category (table 6). Until recently, most production has been from the lower shale member, although appreciable production is now being realized from the upper shale member (Bowker, 2002). Both members characteristically have a high content of organic material, which is largely Type–II (Jarvie and others, 2001; Hill and others, 2007). In general, the average total organic carbon in both members is about 4 to 5 percent (Jarvie and others, 2007), although in places the Barnett is thought to have contained as much as 20 percent total organic carbon when it was deposited (Bowker, 2002). The organic material in these shales is the source of the gas produced from them, thereby defining these reservoirs as self sourced.

Recent studies have been undertaken to better understand the variability and degree of thermal maturity of the organic matter in the Barnett Shale in the Fort Worth Basin. Within the area of gas production, there is an eastwardly increase in vitrinite reflectance (R_o) from about 1.1 to >1.9 percent (Pollastro and others, 2007). Interestingly, portions of the Barnett closest to the Ouachita thrust belt, which marks the east margin of the Fort Worth Basin (fig. 3), tend to possess the highest degree of thermal maturity, whereas the Barnett is less thermally mature in the deepest part of the basin; this difference suggests a relation between maturation and the Ouachita thrust belt (Bowker, 2002). Outside the area of gas production, in areas where R_o<1.1 percent, oil is the common hydrocarbon but it is uneconomic to produce owing to low porosity and permeability of the rocks (Bowker, 2002). Nevertheless, the presence of oil in areas of lower thermal maturity and gas in the more thermally mature rock, along with the nature (Type–II) of the organic matter, suggests that the gas was generated either by primary cracking of kerogen or by cracking of gas from oil, or both (Jarvie and others, 2001; Hill and others, 2007; Jarvie and others, 2007).

Effective matrix porosity and permeability in Barnett Shale reservoirs are low. The productive portions have an average porosity of <6 percent and permeabilities are exceedingly low, typically in the nanodarcy range (Bowker, 2002). Although fractures, both induced and natural, play a critical role in the producibility of gas from Barnett reservoirs, more than a decade of experimentation and research (largely by Mitchell Energy and Development Corporation) has demonstrated that the best production is in areas lacking large natural faults and fractures. Apparently, where open, such features facilitated slow but possibly continuous migration of gas out of the Barnett into other formations or to the surface. Furthermore, where mineralized with authigenic calcite, the fractures are largely impermeable (Bowker, 2002). In contrast to the commonly detrimental affects of natural fractures on production, induced fractures are critical for production. Results of experiments and research have indicated that massive induced fracturing through well stimulation was necessary to achieve economic levels of gas production from the formation (Lancaster and others, 1993; Bowker, 2002). Induced fracturing disrupts the apparent pressure equilibrium in the reservoirs, allowing gas, whether in matrix porosity or possibly sorbed onto organic material, to diffuse into the borehole through the porosity and permeability created by the induced fractures (Bowker, 2002). Although natural fractures may contribute to gas flow, the permeability of most natural fractures is low relative to that produced by induced fractures; thus, natural fractures contribute only in a subordinate way to gas production.

Bakken Formation

The Bakken Formation of Late Devonian and Early Mississippian age is an entirely subsurface marine stratigraphic unit that is present in the Williston Basin in North Dakota and Montana and the Canadian provinces of Saskatchewan and Manitoba (fig. 2). Production from the formation dates back to at least 1953 (LeFever, 1991). The Bakken was deposited in the ancestral Williston Basin, an intracratonic basin just north of the paleoequator that, during Late Devonian and Early Mississippian time, was near the west edge of the North American continent (Smith and Bustin, 1998). Shales in the formation were deposited in a partially isolated marine basin in which underflow from the ancestral Pacific Ocean moved through a channel in the old Montana aulacogen into the ancestral Williston Basin (Smith and Bustin, 1998). The eastward-flowing nutrient-rich underflow from the ancestral Pacific mixed with surface waters that were driven westward by prevailing winds, all of which promoted high production of organic matter of algal origin. Some thought that the water in the Williston Basin was stratified; the bottom waters were anoxic and therefore preserved organic matter that fell through the water column (Carlisle, 1991; Meissner, 1991; Smith and Bustin, 1998). This view is questioned by other workers who postulate that the organic matter was preserved because of high organic productivity rather than anoxia at depth (Parrish and Curtis, 1982; Pedersen and Calvert, 1990). Siltstone and sandstone were deposited in shoreface and nearshore environments (Carlisle, 1991; Smith and Bustin, 2000).

The Bakken Formation is a thin unit whose average thickness is only about 52 ft (16 m) and whose maximum thickness is about 140 ft (43 m). It is divided into three members that are recognized throughout much of the Williston Basin: lower and upper organic-rich black mudstone members and an intervening organic-poor siltstone-sandstone member. Average and maximum thicknesses, respectively, for the upper member are 6.5 ft (2 m) and 23 ft (7 m), for the middle member 33 ft (10 m) and 98 ft (30 m), and for the lower member 13 ft (4 m) and 66 ft (20 m) (Martiniuk, 1991; Meissner, 1991; Smith and Bustin, 1998). Subsidence owing to dissolution of salts in the underlying Devonian "Prairie Evaporite" of Martiniuk (1991) allowed for local thickening of all members (Martiniuk, 1991).

The lower and upper members are finely laminated, organic-rich, hemipelagic black mudstones deposited below wave base (Carlisle, 1991; Smith and Bustin, 2000), whereas the middle member was deposited in shoreface or nearshore environments. Detrital constituents in the black mudstones are principally organic material and differing amounts of quartz, feldspar, dolomite, pyrite, clay (dominantly illite), and calcite (Druyff, 1991; Smith and Bustin, 2000). In contrast, the middle member contains a variety of rock types that coarsen northward, from siltstone in the United States' part of the Williston Basin into sandstone in the Canadian part, reflecting proximity to a sediment source from the Canadian Shield (Carlisle, 1991). Commonly the middle member is dolomitic and variably bioturbated (Smith and Buston, 2000).

Reservoirs in the Bakken Formation are placed into two categories—shale and siltstone-sandstone (table 7)—selected on the basis of differences in character, stratigraphic position, and geographic distribution.

Reservoirs in the shale category occur in either or both of the upper and lower members of the Bakken Formation (Smith and Bustin, 2000), and they account for considerable production from the formation in North Dakota and Montana (Smith and Bustin, 2000). Both members are black owing to a high content of organic material derived from marine algae (Smith and Bustin, 2000). In general, the average total organic carbon in both members is similar (~11–13 percent; Schmoker and Hester, 1983), although the upper member locally contains intervals with high total organic carbon (>35 percent), whereas such high values are not observed in the lower member (Smith and Bustin, 2000). The organic material in these shales is the source of the oil produced from them, thereby defining these reservoirs as self sourced (Schmoker, 1995). It is likely, however, that some oil migrated out and charged reservoirs in other units (Price, 2000). Thus, the Bakken can be viewed as both an internally sourced reservoir and as the source rock for oil in other formations.

Although high in oil-prone organic material, this formation generated oil in only part of the area throughout which it was deposited because of variable thermal conditions. Studies of the organic material reveal that it is mature enough for oil generation largely in western North Dakota and northeastern Montana (Hansen and Long, 1991a; Meissner, 1991), and that maturity increases in a southwesterly direction (Meissner, 1978; Schmoker and Hester, 1983; LeFever, 1991; Meissner, 1991).

Effective porosity and permeability in the shale reservoirs are low (Meissner, 1991); porosity is typically <5 percent and permeability is <0.01 to ~60 mD (Cramer, 1991; LeFever, 1991; Meissner, 1991). The reservoirs are self sourced.

Reservoirs in the siltstone-sandstone category are in the middle member of the Bakken Formation. They produce most of the oil from the formation in Saskatchewan and Manitoba as well as a large proportion of that produced in the United States (Hansen and Long, 1991a; Martiniuk, 1991; Smith and Bustin, 2000). The reservoir rocks are typically organic poor. Porosity generally is 3–10 percent but locally may exceed 10 percent (Deans and others, 1991; Hansen and Long, 1991a; LeFever, 1991). Some or most of this porosity is secondary, resulting from dissolution of carbonate cements that formed prior to oil migration (Kasper and others, 1992; Ferdous and Renaut, 1997). Pemeability is <0.01–109 mD (LeFever, 1991). Although the porosity and permeability of the reservoir rocks are low, the lack of an internal source of oil in the middle member indicates that the oil must have migrated into it, presumably from the surrounding, organic-rich shales. Areas of thickening in the middle member, owing to salt-induced subsidence, may also coincide with areas of better sand development and improved reservoir quality (such as coarser grain size, good grain sorting, possibly higher porosity and permeability). The overlying shales serve to stratigraphically trap and seal oil in the middle member (Martiniuk, 1991).

Fractures, both natural and induced, are critical to production of oil from all Bakken Formation reservoirs because they provide the porosity and permeability necessary to increase the flow of oil to the well bore. Most production is related to natural fractures created by tectonic stresses (Murray, 1968; Meissner, 1978; Hansen and Long, 1991b) and possibly through overpressuring that may have developed in association with oil generation (Meissner, 1991; Burrus and others, 1996). Tensional fractures over anticlinal folds, drapes over monoclinal folds, or drapes over strata that are flexed over solution fronts several hundred feet (or meters) deeper in the older Devonian "Prairie Evaporite" of Martiniuk (1991) salt deposits (Carlisle, 1991; Druyff, 1991; Meissner, 1991; Sperr, 1991) are also important for oil production (Martiniuk, 1991).

Ellenburger Group

The Ellenburger Group, which locally exceeds a total thickness of 1,500 ft, is present in the Permian Basin throughout west Texas and southeastern New Mexico (fig. 3) and has produced both oil and gas since at least the early 1930s. Much of the formation is Early Ordovician in age although the onset of deposition may have been as early as Late Cambrian (Paige, 1912). Deposition occurred on a shallow, mud-dominated, marine carbonate platform that covered most of present-day Texas (Barnes and others, 1959; Loucks and Anderson, 1982; Kerans, 1988; Kerans and others, 1989; Kosters and others, 1989c). Reservoirs are in rocks deposited from the inner to outer parts of the platform, whereas reef, forereef, and supratidal deposits are largely nonreservoir rocks. Relatively open-marine conditions persisted throughout most of the time the Ellenburger was deposited, resulting in accumulation of carbonate mud; only subtle facies changes are preserved, which points to the likelihood that deposition occurred during a regional aggradational phase with limited progradation (Kerans, 1988).

Reservoirs in the Ellenburger Group are placed into karstified, platform, and tectonically fractured categories (table 8), selected principally because the reservoirs, although demonstrating certain similarities, differ in the nature and volume of porosity and permeability, geographic distribution, and produced hydrocarbons as well as in the extent to which structure influenced reservoir development. This threefold division is similar to that presented by Kerans and others (1989), Kosters and others (1989c), Holtz and Kerans (1992), and Ball (1995).

The karstified category refers to reservoirs that were deposited in the inner parts of the platform and in which postdepositional dissolution and karstification played a critical role in their development. These reservoirs are principally in the Central Basin platform and Midland Basin of west Texas (fig. 3), and collectively they have produced much of the oil extracted from the Ellenburger (Holtz and Kerans, 1992). Furthermore, some wells completed in reservoirs of the karstified category have the highest recovery efficiency of reservoirs in the Ellenburger (Holtz and Kerans, 1992).

Karstification of the Ellenburger Group carbonate rocks commenced shortly after deposition and upon subaerial exposure, which was caused by a pronounced and prolonged drop in sea level that began at the end of the Early Ordovician (Barnes and others, 1959; Lucia, 1995). Waters responsible for karstification were probably introduced into the unit along pathways created by faults, fractures, and joints. The vertical and lateral dissolution of limestone beds led to formation of an extensive network of caves, sinks, and collapse features at several stratigraphic levels (Lucia, 1969; Kerans, 1988; Loucks and Handford, 1992; Lucia, 1995; Hammes and others, 1996). Most caves in the Ellenburger contain a fractured cave roof, a clast-supported cave-floor collapse breccia, and an intervening clay-rich cave fill. Of these three "facies," the cave roof and cave floor maintained sufficient porosity to ultimately form reservoirs; porosity is 2–7 percent (average 3 percent) and permeability of 2–750 mD (average 32 mD) (Kerans, 1988; Holtz and Kerans, 1992). The cave-fill deposits commonly are impermeable and thus inhibited fluid communication between the cave floor and roof, resulting in reservoir compartmentalization. Structural traps may be anticlines, faulted anticlines, or fault-bounded anticlines. Fine-grained cave-fill sediments, impermeable collapse zones adjacent to reservoirs, and shale in the overlying Simpson Group form reservoir seals. Oil is the principal hydrocarbon produced from these reservoirs in the karstified category, although gas and condensate are also produced (Ball, 1995).

Dolomitization and some karstification were critical in formation of reservoirs of the platform category. These reservoirs are largely in the southern and eastern marginal areas of the Midland Basin and the Eastern shelf in west-central Texas (Kerans and others, 1989; Holtz and Kerans, 1992), where they largely produce oil (Ball, 1995) as well as minor gas. Overall, these reservoirs contribute about 4 percent of all hydrocarbon produced from the Ellenburger (Holtz and Kerans, 1992).

An important feature of reservoirs in the platform category is their diagenetic history, which greatly enhanced reservoir quality. Dolomitized packstone and mudstone deposited toward the middle and outer portions of the platform of the Ellenburger Group depositional system (southern and eastern parts of the Midland Basin) are typical reservoirs formed by dolomitization of the lime mud that led to intercrystalline pore space and permeability (Holtz and Kerans, 1992). The process was probably facilitated by early-formed fractures that allowed freer infiltration of dolomitizing fluids. Anticlines and faulted anticlines serve as structural controls on reservoir development, and overlying and laterally adjacent limestones form seals.

Platform-category reservoir porosity is 2–14 percent (average 14 percent) and permeability is 1–44 mD (average 12 mD) (Holtz and Kerans, 1992), values that favor the production of economic quantities of petroleum.

The third reservoir category, the tectonically fractured category, is defined largely by reservoir porosity and permeability that resulted from tectonic fracturing, which developed after deposition of the Ellenburger Group. These reservoirs are in the Delaware Basin of west Texas (fig. 3) and contain most of the hydrocarbons that originally accumulated in the Ellenburger (Holtz and Kerans, 1992). The fracture porosity, along with relatively low permeability values for tectonically fractured reservoirs, results in a high mobility of gas relative to oil, which is the reason that these reservoirs typically produce dominantly nonassociated gas (Holtz and Kerans, 1992; Ball, 1995).

Although the Ellenburger Formation in the Delaware Basin was subjected to both early dolomitization and karstification, the reservoirs in this area produce largely because of porosity (1–8 percent, average 4 percent) and permeability (1–100 mD, average 4 mD) that had been increased by fracturing (Holtz and Kerans, 1992). Regional tectonic processes associated with the Marathon-Ouachita orogeny were responsible for the fracturing.

Smackover Formation

The Upper Jurassic Smackover Formation lies entirely in the subsurface, principally in onshore parts of Texas, Arkansas, Louisiana, Mississippi, Alabama, and Florida (fig. 1), as well as offshore in the Gulf of Mexico; it has produced oil and natural gas since the 1930s (Bingham, 1938; Collins, 1980). The formation thickens to more than 1,000 ft in the Gulf of Mexico from its depositional margin in the central part of the Gulf Coast states (Bishop, 1968; Budd and Loucks, 1981; Moore, 1984). The Smackover was deposited on a broad carbonate ramp that existed throughout much of the Gulf Coast region during the Late Jurassic (Ahr, 1973; Collins, 1980; Mancini and Benson, 1980; Budd and Loucks, 1981; Moore, 1984; Kosters and others, 1989d). A rapid transgression, marking the beginning of Smackover deposition, resulted in the accumulation of fine-grained organic-rich carbonate mudstone and siliciclastic siltstone basinal sediments (Dickinson, 1968), whereas the upper parts were deposited during a slow regression (Mancini and Benson, 1980; Budd and Loucks, 1981) or under stillstand conditions (Moore, 1984). Shoaling on top of and adjacent to paleotopographic highs resulted in formation of thick sequences of ooid-rich grainstones and packstones, the dominant reservoir lithologies in the Smackover (Mancini and Benson, 1980; Moore, 1984; Benson and others, 1997). Sabkha units, including bedded anhydrite in the Buckner Formation, overlie the Smackover and reflect a marine regression in response to a drop in sea level (Mancini and Benson, 1980; Budd and Loucks, 1981; Moore, 1984; Wade and Moore, 1993).

Reservoirs in the Smackover Formation are placed into five reservoir categories—salt structure, basement structure, graben, stratigraphic, and updip (table 9)—that were defined and later refined through regional studies by other workers (for example, Bishop, 1968; Collins, 1980; Moore, 1984; Mancini and others, 1990; Kopaska-Merkel and Mann, 1993; Tew and others, 1993). Selection was based on differences in geographic extent and the role that structures played in both source rock deposition and hydrocarbon trapping.

The salt structure category refers to those reservoirs in which structures related to salt movement in the underlying Louann Salt (Jurassic) influence both the areal distribution of reservoirs and formation of traps. They are associated with salt basins in three geographic areas: (1) southern and east Texas, (2) southern Arkansas and northern Louisiana, and (3) south-central Mississippi and southwestern Alabama (Collins, 1980; Moore, 1984; Tew and others, 1993; Schenk, 1995a,b). Paleotopographic highs related to halokinesis of the Louann Salt served to develop shoals, which in turn led to formation of ooids; thick accumulations of ooids subsequently evolved into the oolitic grainstones and packstones typical of the reservoirs (Moore, 1984; Kopaska-Merkel and Mann, 1993; Tew and others, 1993). Porosity is largely intercrystalline (2–35 percent) owing to dolomitization and permeablilities are 1–4,100 mD); there is some oomoldic porosity in updip regions. The salt-cored structures (salt anticlines, faulted salt anticlines, and faulted salt-pierced anticlines) also served to control fluid flow after Smackover deposition, and associated faults probably served as migration conduits for hydrocarbons (Moore, 1984; Mancini and others, 1986; Tew and others, 1993). Fine-grained units and beds of anhydrite in the overlying Buckner Formation serve as reservoir seals.

Characteristics of reservoirs in the salt structure category differ regionally—porosity is largely intercrystalline where the Smackover Formation has been dolomitized, oomoldic in some updip regions, and intergranular in basinal areas; porosities are 2–35 percent and permeabilities are 1–4,100 mD. The reservoirs produce either oil or gas as the dominant hydrocarbon, with minor condensate, but gas is dominant in deeper, more basinward (southerly) locations (Moore, 1984; Mancini and others, 1986; Petta and Rapp, 1990; Tew and others, 1993; Schenk, 1995a).

The basement structure category defines reservoirs that are a combination of structural and stratigraphic traps, and they are associated with structures extending from the basement in areas containing little or no salt and removed from regional fault zones. They are located in east Texas, southern Arkansas, central and southern Mississippi, and southwestern Alabama (Collins, 1980; Moore, 1984; Tew and others, 1993; Schenk, 1995a). Horst blocks that formed as positive elements during deposition of the Smackover Formation served to localize shoals. In general, areas adjacent to paleohighs became sites of ooid formation and thick accumulation that formed the principal reservoirs (Moore, 1984; Kosters and others, 1989d; Petta and Rapp, 1990; Prather, 1992; Schenk, 1995b), whereas the oolitic rocks are thin or absent on the crests of the structures (Schenk, 1995b). The horst blocks also contributed to formation of small anticlines and faulted anticlinal features that subsequently focused fluid flow, and the faults served as hydrocarbon migration conduits (Collins, 1980; Moore, 1984; Tew and others, 1993). Downdip regional fault zones and fine-grained evaporitic units in the overlying Buckner Formation served as seals for these reservoirs (Moore, 1984; Schenk, 1995b).

Reservoirs in the basement structure category differ regionally. Gas and condensate are the dominant hydrocarbons in the more basinal areas, whereas oil is produced in more updip areas (Collins, 1980; Moore, 1984; Schenk, 1995a). Porosity is principally oomoldic but also is formed by minor intercrystalline pores in dolomitized areas; maximum porosity is as much as 20 percent; permeabilities are 60–350 mD.

The graben trap category represents a complex mixture of stratigraphic and structural traps that are most common in a region along the present-day Louisiana-Arkansas border (Collins, 1980; Moore, 1984; DeMis and Milliken, 1993). Movement along graben-edge faults, probably related to salt tectonics of the underlying Louann Salt near the north edge of the north Louisiana salt basin, served to raise adjacent horst blocks to become positive features during Smackover deposition. Fine-grained sediment accumulated in the grabens, whereas the horst blocks promoted shoaling and the accumulation of oolites on and near them (Moore, 1984). Continued movement along these faults after Smackover deposition not only led to fragmentation of the potential reservoirs but also facilitated trap formation owing to a juxtaposition of porous (porosity 4–19 percent) and permeable (permeability 1–1,000 mD) oolites with impermeable shale and anhydrite of the overlying Buckner in adjacent grabens. The impermeable units acted as reservoir seals. Because the traps in this reservoir category owe their origin in part to complex faulting associated with salt tectonics, the reservoirs differ in origin from those of the salt anticline category described above, where syndepositional faulting and horst or graben structural relations are less complex. Oil is the dominant hydrocarbon produced from reservoirs in this category.

Although most traps in the Smackover Formation have a stratigraphic component to them, some can be considered to be dominantly stratigraphic, so reservoirs demonstrating these features were defined as the stratigraphic category; they are identified principally in southern Arkansas (Collins, 1980). The rocks, which are thick oolites, pinch out laterally into less permeable basinal or lagoonal-sabkha units such as mudstone or pelloid packstones. As a result, hydrocarbon reservoirs are trapped and sealed through facies changes that are concomitant with porosity pinchouts. Although deposition of some of these reservoirs may have been influenced by subtle salt structures most were, instead, deposited independent of structure (Moore, 1984). Thus, the relative absence of structural controls on the formation or trapping of reservoirs in this category distinguishes them from reservoirs in other categories.

Characteristics of reservoirs in the stratigraphic category are quite variable even though their geographic extent is limited. Porosity, which is interparticle or intercrystalline where rocks are dolomitized, is 3–30 percent, and permeability is 1–250 mD. Oil is the dominant hydrocarbon although some gas is also produced.

The updip fault category defines reservoirs that are in a combination of structural and stratigraphic traps; they formed near the updip limit of Smackover Formation deposition in east Texas, southern Arkansas, central Mississippi, southwestern Alabama, and in the Florida panhandle (Collins, 1980; Moore, 1984; Tew and others, 1993; Schenk, 1995a). Faulting subsequent to Smackover deposition juxtaposed upthrown reservoir rocks and downthrown blocks containing impermeable seals such as shale or thick beds of anhydrite of the overlying Buckner Formation. This reservoir subtype is only a minor producer of petroleum because each of the graben blocks moved independently and has only a small areal extent.

Characteristics of reservoirs in the updip fault category are also quite variable despite their limited distribution. Porosity is principally oomoldic (10–20 percent), and permeability is 3–280 mD. Oil is the dominant hydrocarbon, although some associated gas and gas condensate are also produced.

The role of diagenesis in opening or occluding pore space differed in grainstones and packstones in the Smackover Formation, the typical lithologies of reservoirs. In general, secondary (oomoldic) porosity, which is common in stratigraphic, updip fault, and graben reservoirs, is best developed in updip regions of the depositional basin but is less important basinward (Moore and Druckman, 1981; Moore, 1984). In contrast, primary porosity is best preserved in basinal parts of the Smackover depositional system (Moore and Druckman, 1981; Moore, 1984), but compaction increases toward the basin center (Feazel, 1985). Dolomitization of salt- and basin-structure reservoir rocks, resulting from infiltration of brines from the overlying Buckner Formation, is extensive where oolite dissolution occurred (Feazel, 1985; Barrett, 1986; Saller and Moore, 1986; Benson and others, 1996). Where dolomitization is pervasive, reservoir porosity is largely interparticle and intercrystalline (Feazel, 1985; Mancini and others, 1986; Benson and others, 1996). Late-stage carbonate minerals, anhydrite, and compaction locally occlude pore space in the Smackover (Lloyd and others, 1986).

Spraberry Formation

The Spraberry Formation of Early Permian (late Leonardian) age is a submarine unit deposited in the deeper part of the Midland Basin of west-central Texas (fig. 3, Tyler and others, 1997). The formation, as much as 1,000 ft thick (Montgomery and others, 2000), is one of the most widespread petroleum plays in the world: it produces throughout an area of 25,000 mi^2 (Lorenz and others, 2002). Furthermore, the formation contains the largest oil accumulation in Texas (>10 billion barrels). Although the formation has produced since about 1949 (Montgomery and others, 2000; Lorenz and others, 2002), recovery from most wells is typically low, rarely exceeding about 15 percent of the original oil in place (Lorenz and others, 2002). However, despite its low recovery, it appears to have good potential for reserve growth from enhanced oil-recovery methods and from a greater understanding of geologic conditions (Montgomery and others, 2000).

The Spraberry Formation was deposited in a large, basin-floor, submarine fan (Handford, 1981; Guevara, 1988; Tyler and Gholston, 1988; and Tyler and others, 1997); sediment probably was derived from eolian sand blown into the margins of the ancestral Midland Basin (Handford, 1981). Influx of sand to the heads of major submarine channels is thought to have occurred when sea levels were dropping to low levels (Tyler and others, 1997). Density currents carried the sand basinward to form southward-thinning submarine fans and turbidites. Units deposited by suspension settling, such as silty dolostones, organic-rich shale, and argillaceous siltstones, constitute either poor reservoir or nonreservoir rocks (Montgomery and others, 2000).

An important structure that governed petroleum accumulations in the Spraberry Formation is the Horseshoe Atoll, an arcuate, concave-northward structure in underlying strata of Pennsylvanian (Desmoinesian-Virgillian) age that is present beneath the northern part of the Midland Basin. The topographic relief above the ancient atoll, increased by differential compaction, divided the ancestral basin into two subbasins. The northern subbasin contains only minor quantities of hydrocarbons, whereas the southern one contains by far the largest hydrocarbon resource in the Spraberry (Tyler and others, 1997) and is of most interest with respect to the present study.

A single reservoir category, the submarine sand category, was defined for the Spraberry Formation (table 10). Porosity and permeability of the sandstones are characteristically low. Porosity, mostly intergranular or minor moldic, is about 5–15 percent (Guevara and Mukhopadhyay, 1987; Ball, 1995; Lorenz and others, 2002), although in the lower and upper parts of the formation it can be as high as about 18 percent (Warn and Sidwell, 1953; Guevara and Mukhopadhyay, 1987). The matrix permeability averages <1 mD (Guevara and Mukhopadhyay, 1987; Guevara and Tyler, 1991; Ball, 1995; Montgomery and others, 2000), although it can locally be as high as 10 mD (Montgomery and others, 2000; Lorenz and others, 2002).

Diagenesis in the Spraberry Formation includes both reservoir degradation owing to mechanical compaction and precipitation of authigenic cements and porosity enhancement resulting from dissolution. Mechanical compaction, particularly where reservoirs contain little authigenic cement, permanently reduced porosity and permeability. Cements contributing to low porosity and permeability include illite, chlorite, quartz, and dolomite (Warn and Sidwell, 1953; Montgomery and others, 2000). Clays, particularly illite, not only fill pores but bridge pore throats and thus diminish permeability (Montgomery and others, 2000). Porosity was increased by dissolution of some previously precipitated cement and some unstable detrital grains (Montgomery and others, 2000).

A key to successful extraction of oil from the Spraberry Formation is intersection of the well bore with natural fractures. At least two systems of vertical fractures, which differ in fracture orientation and volume of fracture cement, have been identified, and both are probably related to Laramide tectonic events (Lorenz and others, 2002). The two systems owe their origin, at least in part, to the volume of authigenic cement in the reservoir rocks at the time of fracturing. Reservoirs that were more competent owing to greater volumes of quartz cement were broken by subparallel extension fracturing, whereas those of lesser competence owing to higher volumes of authigenic clay were broken by conjugate shears or by hybrid fracturing (Lorenz and others, 2002). Notwithstanding work by Lorenz and others (2002) and by Montgomery and others (2000), who cautioned against extrapolating fracture information outside of study areas, the influence of fractures and fluid movement in the Spraberry remains unclear.

Traps and seals associated with reservoirs of the Spraberry Formation are largely stratigraphic, although minor structural trapping is known. In the updip direction, reservoirs pinch out into finer grained slope sediments, and in the downdip direction into mudstones at the base of the slope (Guevara and Tyler, 1991; Ball, 1995; Tyler and others, 1997). In addition, facies changes from submarine-channel to interchannel deposits also result in stratigraphic trapping (Guevara and Tyler, 1991). Interbedded shales not only trap but seal the reservoir rocks (Guevara and Tyler, 1991; Ball, 1995). A few minor anticlinal traps exist, contributing to some production (Ball, 1995).

Wasatch Formation

The Tertiary Wasatch Formation is part of the lower Green River–Wasatch interval that produces oil and gas (both associated and nonassociated) in the greater Uinta-Piceance Basin of Utah and Colorado (fig. 2). The formation, which can exceed 5,000 ft in thickness (Donnell, 1961), is continental in origin and was deposited in fluvial, deltaic, and lacustrine environments (Ryder and others, 1976; Pitman and others, 1986). Production began in 1890 and continues to the present (Spencer, 1995). Most current production is in the Uinta Basin in northeastern Utah, although relatively minor amounts of gas are produced in the Piceance Basin of northwestern Colorado (Fouch and others, 1994; Spencer, 1995; Dubiel, 2003; Johnson and Roberts, 2003). Oil and gas is produced from both conventional and unconventional accumulations (Fouch and others, 1994; Spencer, 1995; Dubiel, 2003; Johnson and Roberts, 2003).

Sandstones of the Wasatch Formation were deposited in fluvial settings as well as in fluvial-dominated deltas and lacustrine shoreline areas (Fouch and others, 1994; Allison, 1995; Morgan, 1997; Montgomery and Morgan, 1998), along the margins of and in deltas prograding into ancient Lake Uinta (Ryder and others, 1976; Pitman and others, 1986), a large lacustrine system that existed in the early Tertiary in much of the central area of the present Uinta Basin (fig. 2). Ancient Lake Uinta occupied an internally drained, closed basin where tectonically driven long-term depositional cycles and climatically driven short-term cycles controlled the distribution of large-scale fluvial-lacustrine sequences, such as those in the Wasatch, that were similar to those in the Green River Basin (Fouch and others, 1994; Matthews and Perlmutter, 1994).

The Wasatch Formation consists predominantly of variegated overbank floodplain and shallow lacustrine or wetland mudstone and also contains light brown fluvial and fluvial-dominated deltaic sandstones or other sandstones deposited along lacustrine shorelines (Montgomery and Morgan, 1998; Groeger and Bruhn, 2001). Reservoir rocks are the coarser fluvial or fluvial-dominated deltaic sandstones, whereas nonreservoir rocks are finer grained units such as overbank, floodplain, delta plain, and lacustrine mudstones and claystones. The formation grades laterally into the lacustrine Colton and Green River Formations in many places, and its fluvial-deltaic beds intertongue with lacustrine strata, some of which are organic rich.

Reservoirs of the Wasatch Formation are placed into two categories—Green River source and Mesaverde source (table 11)—distinguished by (1) the source of the hydrocarbon produced from each, (2) the nature of the hydrocarbons produced, and (3) the geographic distribution of production. This twofold division is important because it recognizes that hydrocarbons produced from the Wasatch derive from two different source rocks and thus reflect two petroleum systems, both of which generated economic amounts of petroleum within the greater Uinta-Piceance Basin.

Reservoir rocks in of the Wasatch Formation, in both categories, are typically fine- to medium-grained lithic arkoses or feldspathic litharenites (Pitman and others, 1986; Fouch and others, 1994; Spencer, 1995). Porosities differ largely as a function of depth: at depths less than 4,000 ft, porosity can reach 15 percent (Pitman and others, 1986; Spencer, 1995), whereas at depths greater than 8,500 ft it is commonly <10 percent (Spencer, 1995). Permeability is also variable but is typically <0.1 mD (Osmond, 1992; Spencer, 1995); however, locally, permeabilities can be as high as 40 mD in reservoirs where clay content is low (Morgan, 1997).

The dominant hydrocarbon produced from reservoirs of the Green River–source category is oil along with some associated gas (Fouch and others, 1994; Spencer, 1995; Dubiel, 2003). In contrast, reservoirs of the Mesaverde source category produce nonassociated gas (Spencer, 1995; Johnson and Roberts, 2003). Reservoirs of the Green River category occur largely in the Uinta Basin, whereas those of the Mesaverde category occur in both the Uinta and Piceance Basins (Dubiel, 2003; Johnson and Roberts, 2003).

Diagenesis has played an important role in the development potential of Wasatch reservoirs. Although early cementation of reservoir sands by quartz and carbonate minerals served to occlude intergranular pore space (Pitman and others, 1986), the cements did preserve some of the intergranular volume by preventing early mechanical compaction. Subsequent dissolution of some of the early-formed carbonate minerals and some unstable detrital grains promoted formation of both secondary and moldic porosity; secondary porosity is the dominant type of intergranular porosity (Pitman and others, 1986). Subsequent precipitation of clays, such as illite, illite-smectite, chlorite, kaolinite, and corrensite, occluded some of the secondary pores that formed from carbonate dissolution (Pitman and others, 1986). The clays are important in that they form complex micropores that are generally disconnected and thereby limit permeability, which in turn markedly lowers the transmissivity of the formation and its ability to store or release hydrocarbons for production (Pitman and others, 1986).

Hydrocarbons in both reservoir categories are largely in stratigraphic traps that formed during initial deposition of the Wasatch Formation and related stratigraphic units in the Colton and Green River Formations. The fine-grained units that serve as traps also seal reservoirs (Fouch and others, 1994; Dubiel, 2003; Johnson and Roberts, 2003).

Although structures play a minor role in trapping hydrocarbons in reservoirs in both reservoir categories, fractures are important as they relate to production. Fracturing is thought to be, at least in part, related to high fluid pressures associated with hydrocarbon generation (Pitman and others, 1986; Johnson and Roberts, 2003), although some is probably also associated with late Tertiary uplift in the region (Pitman and Sprunt, 1986). The fractures, some of which are open or only partly mineralized, are thought to provide conduits through which hydrocarbons are delivered to well bores in otherwise tight Wasatch Formation sandstones (Pitman and Sprunt, 1986). Furthermore, larger fractures appear to cut across stratigraphic intervals, which suggests that they served as the likely conduits for hydrocarbon migration from sources in the underlying Cretaceous Mesaverde Group for reservoirs of the Mesaverde source category (Pitman and others, 1986; Fouch and others, 1994; Johnson and Roberts, 2003).

As indicated above, two different source rocks generated the hydrocarbons produced from the Wasatch Formation. For reservoirs of the Green River–source category, organic-rich lacustrine beds within the Green River Formation were the source of the oil and associated gas produced from the Wasatch (Fouch and others, 1994; Ruble and others, 2001). Lateral migration of the hydrocarbons from the Green River into the Wasatch was facilitated by the interfingering of the source (Green River) and reservoir (Wasatch) rocks. In contrast, reservoirs in the Mesaverde source category received nonassociated gas generated from coals and organic-rich shales in rocks of the Mesaverde Group, which underlies the Wasatch (Fouch and others, 1994; Johnson and Roberts, 2003). Migration of the gas occurred along vertical fractures which hydrologically connected the two stratigraphic intervals.

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