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PRODUCTION CHARACTERISTICS AND RESOURCE ASSESSMENT OF THE BARNETT SHALE CONTINUOUS (UNCONVENTIONAL) GAS ACCUMULATION, FORT WORTH BASIN, TEXAS

by

James W. Schmoker, John C. Quinn, Robert A. Crovelli, Vito F. Nuccio, and Timothy C. Hester[1]

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[1]U.S. Geological Survey, Mail Stop 939
Denver Federal Center, Denver, CO 80225

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ABSTRACT

Organic-rich shales in the Mississippian Barnett Shale of the Fort Worth Basin are the reservoir rocks for a large unconventional gas accumulation that occupies a structurally low position straddling the basin axis. The gas can be envisioned as residing in contiguous gas-charged cells that together form a single continuous accumulation. This continuous accumulation is characterized by the occurrence of gas downdip from water-saturated rocks, no obvious lithologic or structural barriers between updip water and downdip gas, very low matrix permeability, and the absence of truly dry holes.

Production from the Barnett Shale continuous gas accumulation is established by more than 200 wells of the Newark East field in Denton and Wise counties, Texas. However, accumulation boundaries are not yet delineated by drilling, and projections of production characteristics for the accumulation as a whole rely on data from the present producing area.

Our estimate of potential additions to technically recoverable gas resources in the Barnett Shale continuous gas accumulation, calculated using a probabilistic resource-assessment method developed by the U.S. Geological Survey for continuous accumulations, ranges from 1,781 billion cubic feet of gas (bcfg) at a 95 percent probability to 5,612 bcfg at a 5 percent probability. The mean resource estimate is 3,360 bcfg, which is equivalent in energy to 560 million barrels of oil.

INTRODUCTION

Scope

As part of the U.S. Geological Survey (USGS) 1995 National Assessment of United States oil and gas resources (Gautier and others, 1995; U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995), the "Mississippian Barnett Shale Play" (play number 4503) was defined as an unconventional gas play in the Fort Worth Basin, but was not quantitatively assessed. More recent data are now sufficient to form the basis for a quantitative assessment of this accumulation.

This report examines the Barnett Shale gas reservoir from the perspective that it is a continuous (unconventional) accumulation - in effect a single very large field - underlying hundreds and perhaps thousands of square miles of the Fort Worth Basin (fig. 1). Production characteristics are discussed, boundaries of the accumulation are considered, and an estimate for potential additions to technically recoverable gas resources is developed using the method for assessing continuous accumulations devised for the USGS 1995 National Assessment (Schmoker, 1995).

The present study addresses the organic-rich shale facies of the Barnett. Barnett-age reef tracts and interreef calcareous facies that formed higher on the shelf were considered as the "Mississippian Carbonate Play" (play number 4502) for the USGS 1995 National Assessment.

Geologic Setting

The Mississippian Barnett Shale was deposited on the southwestern flank of the Southern Oklahoma aulacogen (fig. 1). Depositional patterns of the Barnett Shale reflect the generally northwest-southeast trend of the aulacogen axis, whereas burial patterns reflect the subsequent influence of the present-day Fort Worth Basin. The Barnett Shale lies unconformably on sedimentary rocks of Ordovician age (Ellenburger Group, Simpson Group, Viola Limestone) and is conformably overlain by the Pennsylvanian Marble Falls Formation (Henry, 1982).

The majority of published studies of the Barnett Shale focus on surface outcrops on the flanks of the Llano Uplift in central Texas (fig. 1). These exposures are about 150 mi south-southwest of the area of current gas production in Denton and Wise counties, in a direction roughly perpendicular to depositional strike, and therefore are of limited relevance to the petroleum geology of the Barnett Shale in the study area. Henry's comment in 1982 that the subsurface Barnett Shale "is so modestly represented in the literature" still holds true in 1996.

The Barnett Shale includes various local, informal members that differ somewhat in their physical and geochemical properties (Henry, 1982), and presumably in their gas-resource potential as well. However, for purposes of the present resource assessment, the Barnett Shale is not subdivided.

Regionally, the Barnett Shale thins to the southwest and is 30-50 ft thick where it outcrops along the flanks of the Llano Uplift; its thickness approaches 1,000 ft near the southwest fault boundary of the Southern Oklahoma aulacogen (fig. 1) (Henry, 1982). The Barnett Shale is approximately 500 ft thick near the center of the present producing area (fig. 1). Most wells are completed in the lower part of the Barnett. The separation between upper and lower perforations is typically 200-300 ft.

Barnett shales in the study area (fig. 1) have been generally described as black, organic-rich shales having resistivity values that are unusually high, gamma-ray intensities typically in the range of 150-400 API units, and a mean bulk density of about 2.50 g/cc (Henry, 1982). This description is similar to that of black shales in the United States of Devonian-Mississippian age that produce oil or gas, such as the Bakken Formation of the Williston Basin, Antrim Shale of the Michigan Basin, New Albany Shale of the Illinois Basin, Woodford Shale of the Anadarko Basin, and "Devonian" shales of the Appalachian Basin.

Based on analogies to these other black shales, the high resistivities of the Barnett shales can be attributed to the generation and retention of hydrocarbons (Schmoker and Hester, 1990). The high gamma-ray intensity and low bulk density are indicative of relatively high organic-matter content (Schmoker, 1981; Schmoker and Hester, 1983). A mean bulk density of 2.50 g/cc for the Barnett shales suggests a mean total organic carbon (TOC) content of about 4.5 wt percent (Hester and others, 1990, their figure 5), a value comparable to that for the Woodford Shale in the Anadarko Basin.

Recognition of the unconventional gas accumulation in the Barnett Shale has been relatively recent. Henry (1982) emphasized the potential for conventional fields in carbonate-dominated Barnett-age strata deposited on the shallower parts of the southwest shelf, but did not discuss the potential for gas production from more basinward Barnett shale facies. The current gas-producing area (fig. 1) was not included in a 1989 atlas of major Texas gas reservoirs (Kosters and others, 1989).

In the early 1990's, the Gas Research Institute (GRI) supported a series of engineering studies which contributed significantly to the reservoir characterization of the Barnett shales. In a series of GRI reports summarized by Lancaster and others (1993), the Barnett Shale was characterized as a layered reservoir in which well deliverability is greatest in thinner, higher permeability, naturally fractured zones, and much of the gas-in-place is held in thicker, extremely low-permeability intervals. Matrix permeabilities of the shales are measured in microdarcies.

A particularly significant finding of the GRI-sponsored studies is that natural fractures in the Barnett have a mean strike of 114 degrees, whereas induced fractures have a mean strike of about 60 degrees (Lancaster and others, 1993). Because of this shift in stress-field orientation from past to present, fractures induced from a wellbore by hydraulic fracturing tend to intersect, rather than parallel, the natural fracture system. An important question for the future development of the Barnett Shale unconventional gas accumulation is whether the present stress-field direction measured in the current producing area results from the configuration of local fault systems or represents a regional stress field with affinities to the extensional tectonics of the Gulf Coast.

Gas production from the Barnett accumulation is now firmly established. At the end of 1995, more than 200 Barnett wells in Denton and Wise counties were estimated to be producing roughly 60 million cubic feet of gas (mmcfg) per day (Reeves and others, 1996). Rather than collapsing, drilling activity in the Barnett Shale continuous gas accumulation has accelerated since expiration, at the end of 1992, of the Section 29 Nonconventional Fuels Tax Credit. Limits of the gas accumulation are not yet delineated by drilling. The present producing area might be constrained by proximity to existing infrastructure as well as by geologic controls upon the gas resource.

ASSESSING BARNETT SHALE RESERVOIR AS A CONTINUOUS (UNCONVENTIONAL) GAS ACCUMULATION

The approach taken here of categorizing certain types of unconventional accumulations as continuous accumulations and assessing them accordingly was developed for the USGS 1995 National Assessment (Schmoker, 1995, 1996). Continuous accumulations are essentially large single fields, having spatial dimensions of many miles, that are not localized by downdip water contacts that result from the buoyancy of hydrocarbons in water.

Hydrocarbons remain in the reservoir for a sufficient length of time to form a potentially economic accumulation in spite of their buoyancy in water. The primary trapping mechanism for such accumulations is not a lithologic or structural barrier between updip water and downdip oil or gas, Rather, the trap type has been termed "water block", which is the result of high water saturation in a rock with small pore throats reducing permeability to oil or gas to near zero (e.g., Masters, 1979). Continuous hydrocarbon accumulations can occur in low-permeability reservoirs of sandstone, siltstone, shale, chalk, or coal (coalbed gas).

The Barnett Shale reservoir meets the criteria of a continuous gas accumulation. Factors of importance to conventional gas exploration such as traps, lithologic seals, and migration pathways are largely irrelevant in the context of the Barnett Shale accumulation. The Newark East field, to which Barnett gas production is allocated, is in effect a place name rather than a geologic entity.

Analogous continuous gas accumulations in the United States include those of the Antrim Shale (USGS play numbers 6319 and 6320), New Albany Shale (6407), and Appalachian Devonian shales (6740, 6741, 6742) (Schmoker and Oscarson, 1995).

A continuous gas accumulation such as that of the Barnett Shale cannot be analyzed in terms of the number and size distribution of discrete fields, as are conventional gas plays. Rather, for purposes of quantitative resource evaluation, the gas of a continuous accumulation can be envisioned as residing in equal-area, contiguous cells. The area of each cell is equal to the median spacing, as dictated by drainage area, expected for wells of the accumulation.

A productive cell is one for which production has been reported. A nonproductive cell is one that has been evaluated by one or more wells, none of which reported production, presumably not because wells were completely dry, but because they were noncommercial. Remaining cells are untested. The success ratio of an accumulation (for purposes of resource assessment) is the fraction of untested cells expected to become productive.

Ultimate recoveries from cells are varied and difficult to predict in advance of drilling, and are therefore better represented by probability distributions than by point estimates (Stell and Brown, 1992). An estimated-ultimate-recovery (EUR) probability distribution such as illustrated by figure 2 can serve as a statistical model for recoveries from the untested cells of a play expected to become productive.

The form of an EUR probability distribution, and also of distributions for production rates, commonly approximates a lognormal function. For this reason, production data are plotted here on graph paper having axes arranged such that a lognormal distribution plots as a straight line (fig. 2). A true lognormal function has no cutoff at low percentiles, but provides an increasingly small chance for an increasingly large value. In practice, finite upper limits exist for production rates and the ultimate recovery of a cell. The low-percentile end of the probability distribution therefore flattens, as sketched in figure 2.

Given that a continuous accumulation can be regarded as a collection of contiguous hydrocarbon-charged cells, for which estimated ultimate recovery is represented by a probability distribution, the resource-assessment procedure for continuous accumulations (Schmoker, 1995) is straightforward in concept. Additions to technically recoverable resources reside in the untested cells expected to become productive. The combination (product) of success ratio, number of untested cells, and EUR probability distribution for untested cells expected to become productive yields an estimate of potential additions to technically recoverable resources (fig. 3).

A salient aspect of this assessment method is that existing technology and development practices are projected into the future. The in-place hydrocarbon volume is not used, nor is the recovery factor. Reservoir characteristics such as porosity, permeability, and water saturation are not determined. Instead, the assessment method relies on well-production histories to characterize the recovery expected from undrilled portions (cells) of the accumulation.

PRODUCTION CHARACTERISTICS OF BARNETT SHALE

General Information

Total depths of most Barnett gas wells in Denton and Wise counties (fig. 1) are between 7,200 and 8,200 ft. The Barnett Shale continuous gas accumulation is deeper than those in the Appalachian Devonian shales (2,000-5,000 ft), Antrim Shale (about 1,500 ft), and New Albany Shale (500-2,000 ft) (Reeves and others, 1996). In terms of depth-related geologic and economic factors, the Barnett Shale reservoir is more akin to that of the Bakken Formation, which produces oil from a continuous accumulation at an average depth of 10,500 ft (Schmoker, 1996).

The mean liquids to gas ratio for Barnett Shale production is about 1.5 barrels of natural gas liquids (bngl)/mmcfg. This ratio could be dependent upon the level of thermal maturity and thus vary systematically within the accumulation.

Water production is erratic but generally low. Mean cumulative water production from Barnett Shale gas wells is a little less than 3,000 barrels water per well. Many recent wells have little or no reported water production, perhaps indicating an improvement in completion methods. Like the Bakken Formation shales and unlike the Antrim Shale and most coalbed-gas reservoirs, the Barnett shales do not require dewatering to improve production rates.

Production Rates

The peak-monthly-production (PMP) probability distribution for wells of the Barnett Shale continuous gas accumulation (fig. 4) approximates a flattened lognormal function (as sketched in figure 2) between the 1st and 90th percentiles. The median of this PMP distribution is 22 mmcfg per month. Eighty percent of productive Barnett gas wells have PMP greater than 12 mmcfg per month, and 20 percent have PMP greater than 32 mmcfg per month (fig. 4). These initial production rates are higher than those for the Antrim Shale by at least a factor of two, but drilling, completion, and stimulation costs for Barnett wells are also significantly higher (Reeves and others, 1996).

The peak-yearly-production (PYP) probability distribution for wells of the Barnett Shale continuous gas accumulation (fig. 4) approximates a flattened lognormal function between the 1st and 85th percentiles. The median of this PYP distribution is 135 mmcfg per twelve-month period. Eighty percent of productive Barnett gas wells have PYP greater than 76 mmcfg per twelve-month period, and 20 percent have PYP greater than 200 mmcfg per twelve-month period (fig. 4).

Between the 1st and 85th percentiles of the two probability distributions, the ratio of peak-yearly to peak-monthly production is nearly constant (fig. 4). This ratio is about 6.2 to 1.

As shown by figure 5, the PYP probability distribution of figure 4 conceals a time dependence in the production data. PYP values for the second (more recent) half of Barnett gas wells are significantly higher than those for the first (older) half (fig. 5). The factor by which PYP values for the second half of wells exceed those for the first half is about 1.5 at lower percentiles and increases to more than 6 at high percentiles.

Barnett gas wells are routinely stimulated by hydraulic fracturing. A portion of the improved performance of more recent wells (fig. 5) is due to a progressive increase in treatment sizes and number of intervals completed in a well, coupled with a better knowledge of which zones to complete (Reeves and others, 1996). Another portion of the improvement might be attributable to "closeology" -- the empirical exploitation of small-scale sweet spots by locating new wells close to existing wells having high production rates.

The efficacy of hydraulic-fracture treatments near the base of the Barnett section might depend in part on the mechanical properties of the underlying strata. In a very general sense, the northeastern half of the study area (fig. 1), which includes the present producing area, is underlain by the Viola Limestone or Simpson Group, whereas the southwestern half is underlain by the Ellenburger Group (Henry, 1982).

Ultimate Recoveries of Cells (Wells)

Gas in-place in the present producing area of the Barnett Shale continuous accumulation was estimated at 25 to 35 billion cubic feet of gas (bcfg) per sq mi by Reeves and others (1996). Reservoir properties computed in the 2 T.P. Sims GRI-supported research well (located in the present producing area) equate to a gas in-place volume of 52 bcfg per sq mi, of which about 20 percent is adsorbed gas (Lancaster and others, 1993). As shown by the two estimated-ultimate-recovery (EUR) probability distributions of figure 6, recoveries realized in actual practice are typically a small fraction of the gas in-place.

The EUR probability distribution labeled "A" (fig. 6) is based on decline-curve analysis, using the current well spacing of 320 acres and abandonment at 0.1 mmcfg/month, of the first 20 wells in the accumulation placed on production. Completion dates of these 20 oldest wells range from June, 1982, to December, 1985. The shape of distribution A approximates a flattened lognormal function as sketched in figure 2. The median EUR of distribution A is 0.35 bcfg, and the maximum EUR (the 0th percentile, which cannot be plotted) is assumed to be 3.10 bcfg. Eighty percent of productive Barnett gas wells are projected to have EUR greater than 0.12 bcfg, and 20 percent are projected to have EUR greater than 0.76 bcfg (fig. 6).

The strategy of basing distribution A on older wells emphasizes the advantages of longer production histories for decline-curve analysis. On the other hand, the peak-yearly-production data of figure 5 clearly demonstrate increased production rates for more recent wells. If ultimate recoveries also increase for more recent wells, distribution A is too conservative. The EUR probability distribution labeled "B" (fig. 6) represents an effort to deal with this problem.

Distribution B was constructed by multiplying the 0th, 5th, 25th, 50th, 75th, and 95th percentiles of distribution A by the ratio of PYP (2nd half of wells) to PYP (1st half of wells), as calculated from figure 5 at each percentile. The multiplier that converts distribution A to distribution B, which can be thought of as a technology-improvement factor, ranges from 6.2 at the 95th percentile to 1.5 at the 0th percentile. Distribution B is thus a hybrid function that relies on the longest available well-production histories for decline-curve analysis but which is adjusted upward in recognition of advancing technology.

The median EUR of distribution B is 0.60 bcfg, and the maximum EUR is 4.65 bcfg. Eighty percent of productive Barnett gas wells are projected to have EUR greater than 0.28 bcfg, and 20 percent are projected to have EUR greater than 1.18 bcfg (fig. 6).

The Barnett Shale gas play might ultimately extend far beyond the present producing area, and the relation between ultimate recoveries in the present producing area and in the continuous accumulation as a whole is unknown. Although considerable opportunity exists for error, distribution B of figure 6 is used here as a prediction, for purposes of resource assessment, of ultimate recoveries from untested cells of the Barnett Shale continuous gas accumulation expected to become productive.

BOUNDARIES OF CONTINUOUS GAS ACCUMULATION

Drilling in the present producing trend (as of September, 1994) has not yet established the limits of the Barnett Shale continuous gas accumulation, and few wells test the thick, organic-rich shale facies of the Barnett Shale outside the present producing area. To reflect the uncertainty due to sparse subsurface control in the areal extent of the continuous gas accumulation, three scenarios for areal extent are mapped here (fig. 7).

Minimum-Size Accumulation Area

The boundaries of the minimum-size continuous gas accumulation mapped in figure 7 enclose 285 sq mi and surround the existing group of producing Barnett wells. The rationale for this scenario is that existing wells define a favorable area – a sweet spot – having geologic characteristics unlikely to occur elsewhere.

The minimum-size accumulation boundaries straddle the axis of the Fort Worth Basin in Denton and Wise counties (fig. 7). The updip (southwest and northeast) limits correspond approximately to the -2,000 m (-6,560 ft) structural contour on the Ellenburger Group (Ewing, 1990). This structural contour is assumed to map a constant (but unknown) level of thermal maturity within the Barnett Shale.

No measured or published vitrinite-reflectance (R_o) values for the Barnett Shale were available for this study. R_o values calculated using a commercially available, kinetic-modeling computer program (BasinMod) are poorly constrained and not considered to be definitive. In particular, maximum burial depths (temperatures) of the Barnett Shale are uncertain because of the unknown thickness of the eroded section associated with the unconformity separating Permian and Cretaceous rocks.

Intermediate-Size Accumulation Area

The boundaries of the intermediate- or median-size continuous gas accumulation mapped in figure 7 enclose an area of 2,479 sq mi, which includes the entire minimum-size accumulation. The rationale for this scenario is that the geologic characteristics of the present producing area might continue northwest and southeast along the basin trough, beyond the existing group of producing wells.

The directions of this extension generally parallel trends of depositional environment, basin structure, erosional subcrop of underlying Ordovician age rocks, and (presumably) thermal maturity. Regional trends of the present-day stress field are poorly known. Almost no wells are present within the added area that might have adequately tested the Barnett Shale (e.g., wells that penetrate the entire Barnett section, that are not productive in underlying formations, and that were drilled after 1982 when gas production from the Barnett Shale was established in Wise County).

The boundaries of the intermediate-size accumulation straddle the axis of the Fort Worth Basin and track the -2,000 m (-6,560 ft) Ellenburger structural contour for much of the accumulation's circumference. By analogy to the present producing area, thermal-maturity levels in the Barnett Shale downdip from this structural contour are assumed to exceed the threshold for thermogenic gas generation. Maximum depth to the base of the Barnett Shale in the area of the intermediate- (and maximum-) size accumulation occurs at the intersection of the basin axis with the Ouachita structural front, where the top of the Ellenburger is approximately 3,000 m (9,840 ft) below sea level (Ewing, 1990).

Where boundaries of the intermediate-size accumulation do not follow the -2,000 m (-6,560 ft) Ellenburger structural contour, they are coincident with boundaries of the maximum-size accumulation (fig. 7). To the northeast, these coincident boundaries are dictated by erosional removal of the Barnett Shale on the Muenster Arch, which parallels the southwest fault boundary of the Southern Oklahoma aulacogen and separates the Fort Worth Basin from the Marietta Basin further to the northeast. To the northwest, the intermediate- and maximum-size accumulation boundaries both reflect an erosional Barnett Shale subcrop under the Pennsylvanian section. To the east and southeast, the coincident boundaries follow the trace of the Ouachita structural front, although the Barnett Shale and its continuous gas accumulation might continue further east under overthrust rocks. The southeast-trending straight-line boundary segment at the southern extreme of the mapped accumulation areas (fig. 7) departs from structural contours in order to exclude the depositional environment of the carbonate-prone shelf platform to the southwest.

Maximum-Size Accumulation Area

The boundaries of the maximum-size continuous gas accumulation mapped in figure 7 enclose an area of 4,227 sq mi, which includes the entire intermediate-size accumulation. The rationale for this scenario is that levels of thermal maturity within the Barnett Shale sufficient for gas generation and maintenance of a continuous accumulation extend updip beyond the boundaries of the intermediate-size accumulation.

This optimistic scenario assumes also that other favorable characteristics evident in the present producing area, relating to factors such as basin structure, Paleozoic stratigraphy, stress regimes, and depositional facies, extend updip from current production. About a dozen widely scattered wells that might possibly have tested the Barnett Shale for gas production are located within the added area.

The boundaries of the maximum-size accumulation are somewhat arbitrarily drawn to track the -1,600 m (-5,250 ft) Ellenburger structural contour (Ewing, 1990), except for the segments described in the preceding section. Most of the added area extends shelfward, to the west and southwest (fig. 7). The western boundary of the maximum-size accumulation is not intended to extend shelfward beyond the thick, black, organic-rich facies of the Barnett Shale.

RESOURCE ASSESSMENT OF BARNETT SHALE

Input Parameters

The data used here to estimate the resource potential of the Barnett Shale continuous gas accumulation are given in table 1. The liquids/gas ratio of 1.5 bngl/mmcfg is used as a multiplier to calculate volumes of natural gas liquids associated with assessed gas resources. Values of the EUR distribution for gas are taken from figure 6 (distribution B). The minimum, median, and maximum accumulation areas are planimetered from figure 7. The minimum, median, and maximum numbers of untested cells are calculated from the respective accumulation areas, by assuming a cell size of 320 acres (corresponding to the present-day well spacing of two wells per square mile) and subtracting the 210 cells (180 productive and 30 nonproductive) classified as tested as of September, 1994. The success ratio of 0.86 projected for untested cells of the accumulation is based on drilling results in and near the current producing area of Denton and Wise counties.

A spacing of two wells per square mile provides opportunities for infill development (Reeves and others, 1996). Infill drilling might increase ultimate recoveries from 320-acre cells, which is an argument that the EUR distribution of table 1 is conservative. On the other hand, long fracture lengths developed by massive hydraulic-fracture treatments and well-production history matches calculated using a drainage area of 320 acres (Lancaster and others, 1993) argue in favor of an EUR distribution based on the current well spacing of 320 acres.

Assessment Results

The distribution for potential additions to technically recoverable gas resources in the Barnett Shale continuous gas accumulation, estimated using the assessment method outlined in figure 3, has a median of 3,162 bcfg and a mean of 3,360 bcfg (table 1, figure 8). A 19 in 20 chance exists for the occurrence of an undiscovered, technically recoverable gas volume of at least 1,781 bcfg (F95) and a 1 in 20 chance exists for a gas volume exceeding 5,612 bcfg (F5). The volume of natural gas liquids associated with these gas-resource estimates ranges from 2.67 (F95) to 8.42 (F5) million barrels.

The mean resource assessment of 3,360 bcfg in the Barnett Shale is a significant volume of gas, equivalent in energy to 560 million barrels of oil (equating 6,000 cubic feet of gas to 1 barrel of oil). Our resource estimate thus indicates that the Barnett Shale continuous gas accumulation is a giant field, especially by the standards of present-day exploration in the onshore lower-48 states.

DISCUSSION AND SUMMARY

The Mississippian Barnett Shale of the Fort Worth Basin holds a continuous (unconventional) gas accumulation, which occupies a structurally low position straddling the axis of the basin. Gas production from this accumulation is firmly established by more than 200 wells of the Newark East field in Denton and Wise counties. However, accumulation boundaries are not yet delineated by drilling. The area of the accumulation might be as small as 285 sq mi or as large as 4,200 sq mi. The current producing trend is not necessarily the only economically favorable area within the continuous accumulation.

The resource potential of the Barnett Shale is assessed here using a probabilistic method developed by the USGS for continuous accumulations. The Barnett Shale continuous gas accumulation is immaturely explored. As pointed out in the text of this report, much uncertainty exists in projecting characteristics of the current producing area to the study region in general. The present resource assessment is an example of wrestling with uncertainty.

Our estimate of undiscovered technically recoverable gas resources in the Barnett Shale ranges from 1,781 bcfg at a 95 percent probability to 5,612 bcfg at a 5 percent probability. The mean resource estimate is 3,360 bcfg, which is equivalent in energy to 560 million barrels of oil.

The economic risk associated with developing the Barnett Shale continuous accumulation is not so much that of finding gas but rather that of obtaining sufficient production rates. Drilling activity in the Barnett Shale has accelerated in recent years, suggesting that at least a portion of the play is economic at today's prices and technology levels. As older, conventional gas fields in the region go into decline, and as technology continues to improve, the Barnett Shale continuous gas accumulation could help sustain gas production from the Fort Worth Basin.

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Table 1. Resource-assessment input parameters and results for continuous gas accumulation in the Barnett Shale, Fort Worth Basin, Texas. See text for discussion of data. [F75, for example, represents a 3 in 4 chance of occurrence of at least the amount tabulated. mmcfg = million cubic feet of gas. bcfg = billion cubic feet of gas. bngl = barrels of natural gas liquids. mmbngl = million barrels of natural gas liquids. s.d. = standard deviation.]

Input Parameters

Cell size: 320 acres
Liquids/gas ratio: 1.5 bngl/mmcfg

Productive Cells: 180
Tested nonproductive cells: 30
Success ratio estimated for untested cells: 0.86

	minimum	median	maximum
Area of accumulation (sq mi):	285	2,479	4,227
Number of untested cells:	360	4,748	8,244

Estimated ultimate recovery (EUR) distribution of gas for untested cells expected to be productive

percentiles:	F100	F95	F75	F50	F25	F5	F0	mean
mmcfg:	0	130	320	600	1,040	1,990	4,650	837

Assessment Results -- potential additions to technically recoverable resources

Gas	percentiles:	F95	F75	F50	F25	F5	mean	s.d.
	bcfg:	1,781	2,499	3,162	4,000	5,612	3,360	1,209

Liquids	percentiles:	F95	F75	F50	F25	F5	mean	s.d.
	mmbngl:	2.67	3.75	4.74	6.00	8.42	5.04	1.81

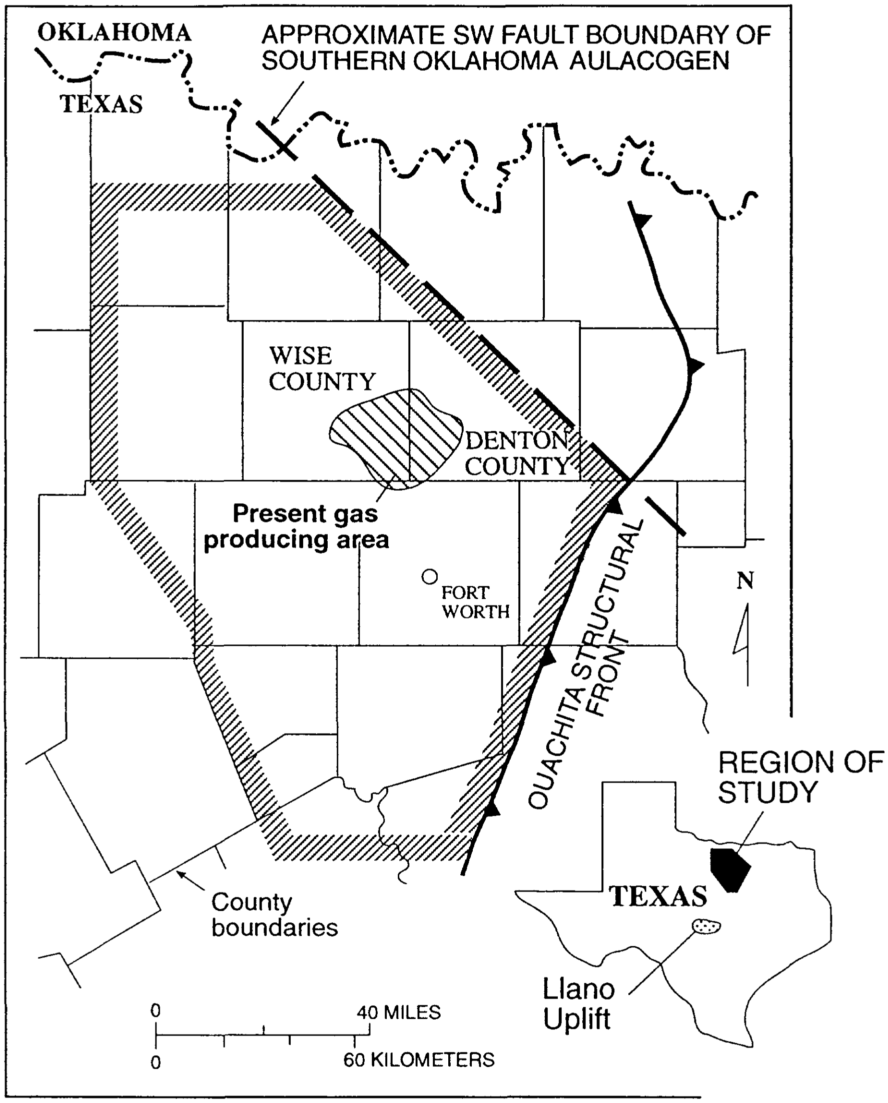


Figure 1. Index map showing study area (outlined by hachure pattern) in the Fort Worth Basin, area of current production (as of September, 1994) from the Barnett Shale continuous gas accumulation (Newark East field), and selected structural features.

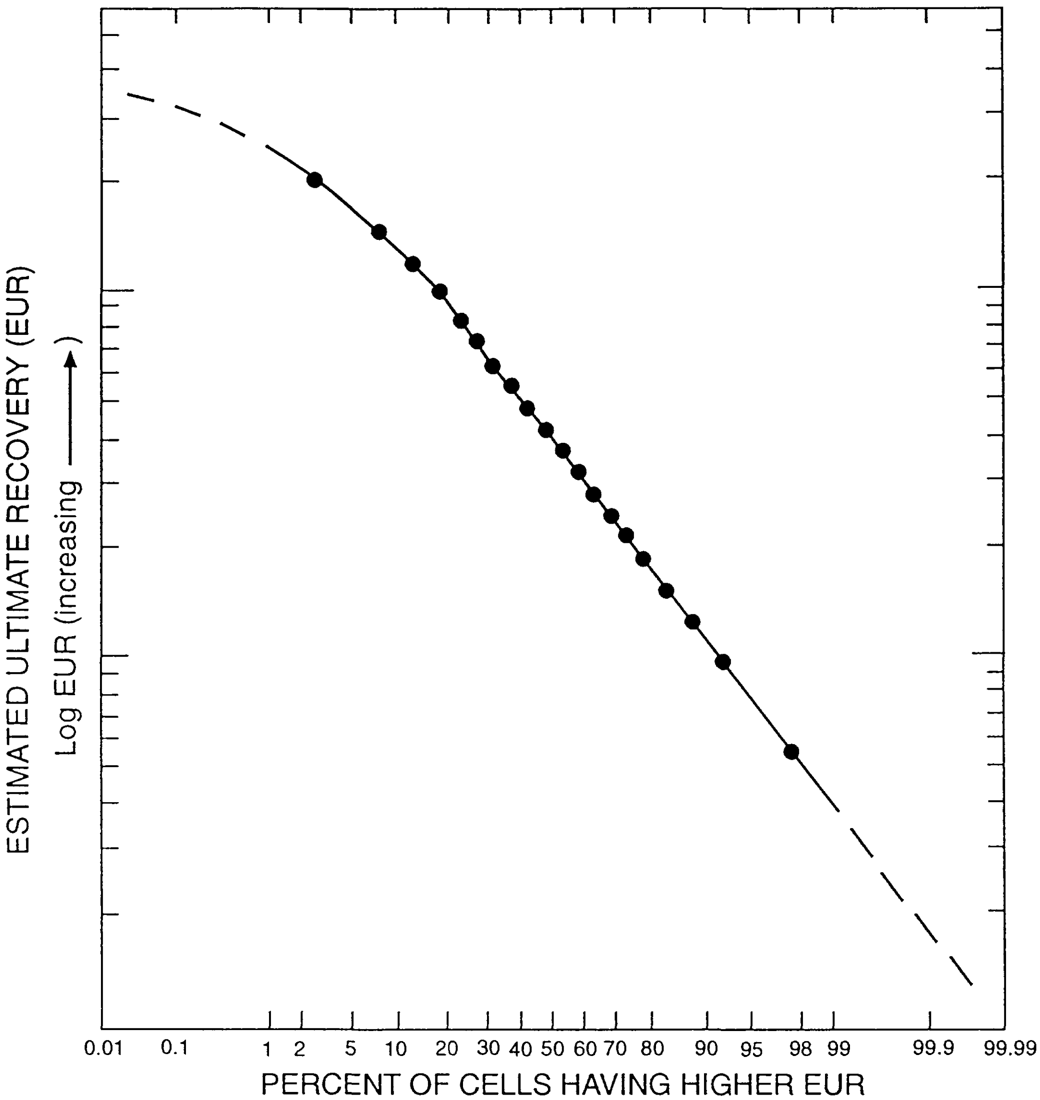


Figure 2. Illustration, using hypothetical data, of an estimated-ultimate-recovery (EUR) probability distribution for untested cells of a continuous accumulation expected to become productive (Schmoker, 1995). Curve shape is that of a lognormal function flattened at low percentiles because of a finite maximum-EUR value.

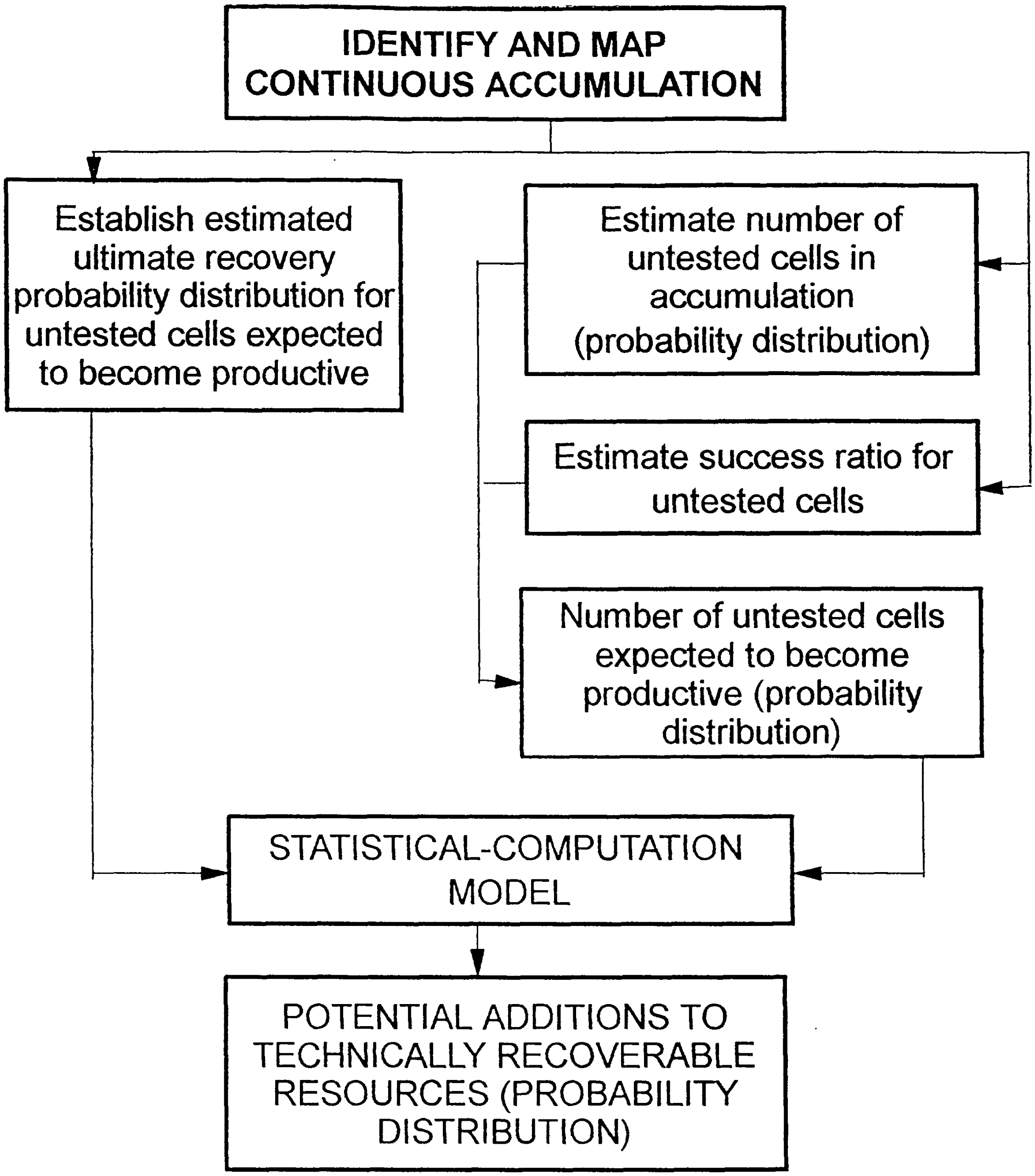


Figure 3. Flow diagram for resource assessment of continuous gas or oil accumulations (after Schmoker, 1995). Statistical-computation model is described by Crovelli and Balay (1995).

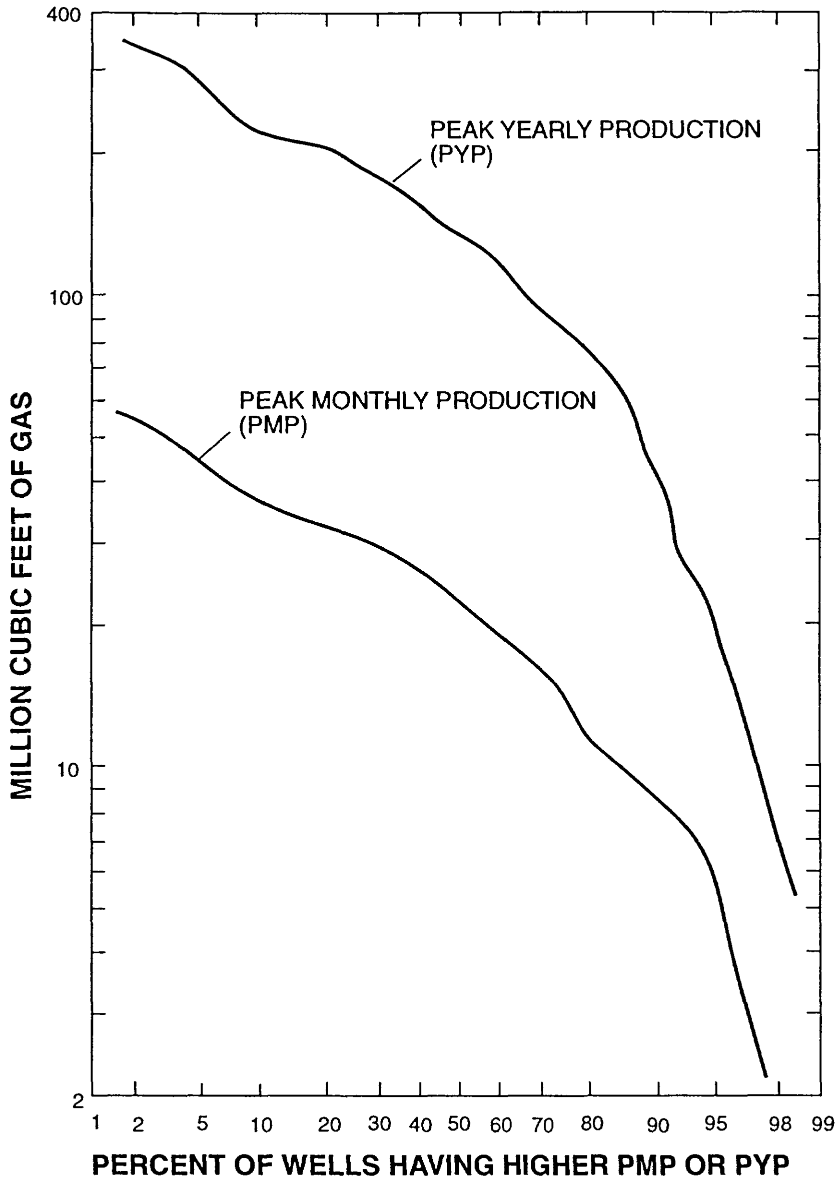


Figure 4. Peak-yearly-production (PYP) and peak-monthly-production (PMP) probability distributions for 173 wells producing from the Barnett Shale continuous gas accumulation in Denton and Wise counties, Texas. Distributions are developed from commercially available well-production data on CD-ROM (Petroleum Information Corporation National Production System), current through September, 1994. PYP is the volume of gas produced in the most productive twelve-month period (as differentiated from the most productive calendar year) in the history of a well. PMP is the volume of gas produced in the most productive calendar month in the history of a well.

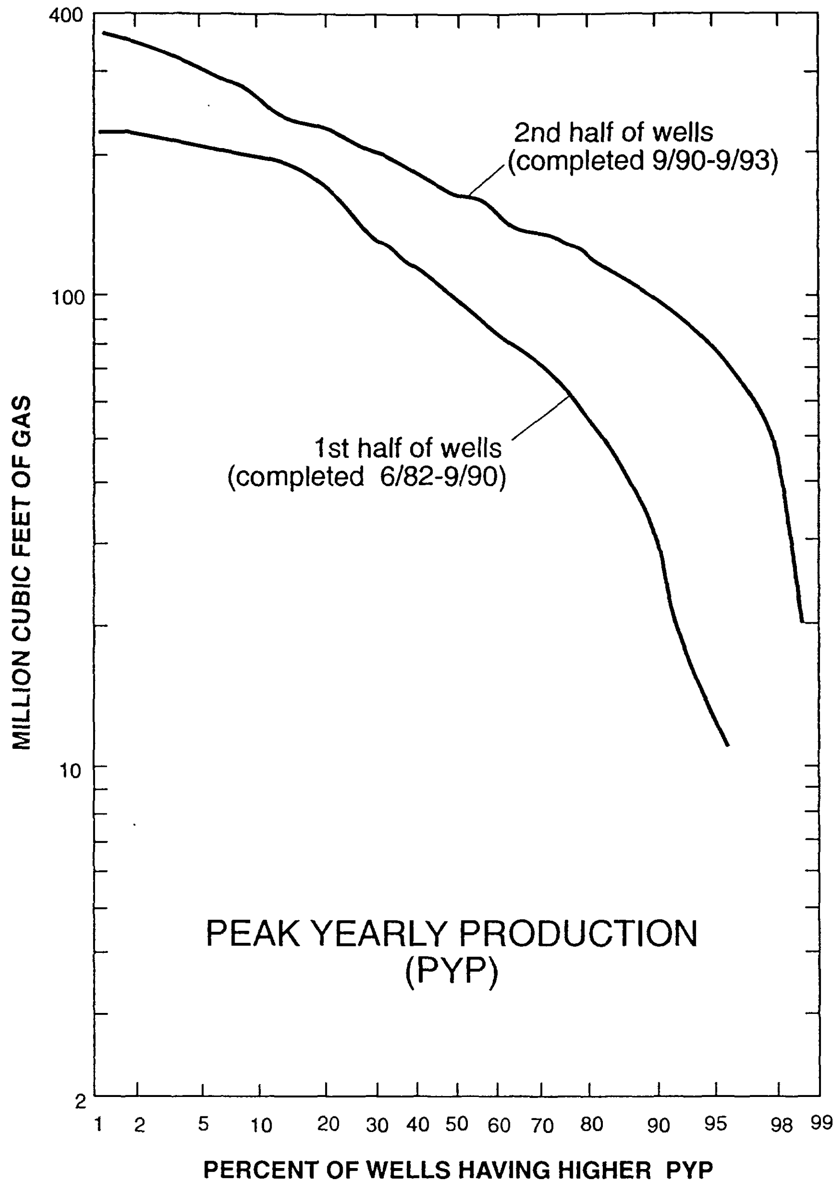


Figure 5. Peak-yearly-production (PYP) data of figure 4 grouped into two probability distributions according to the time period in which wells were completed.

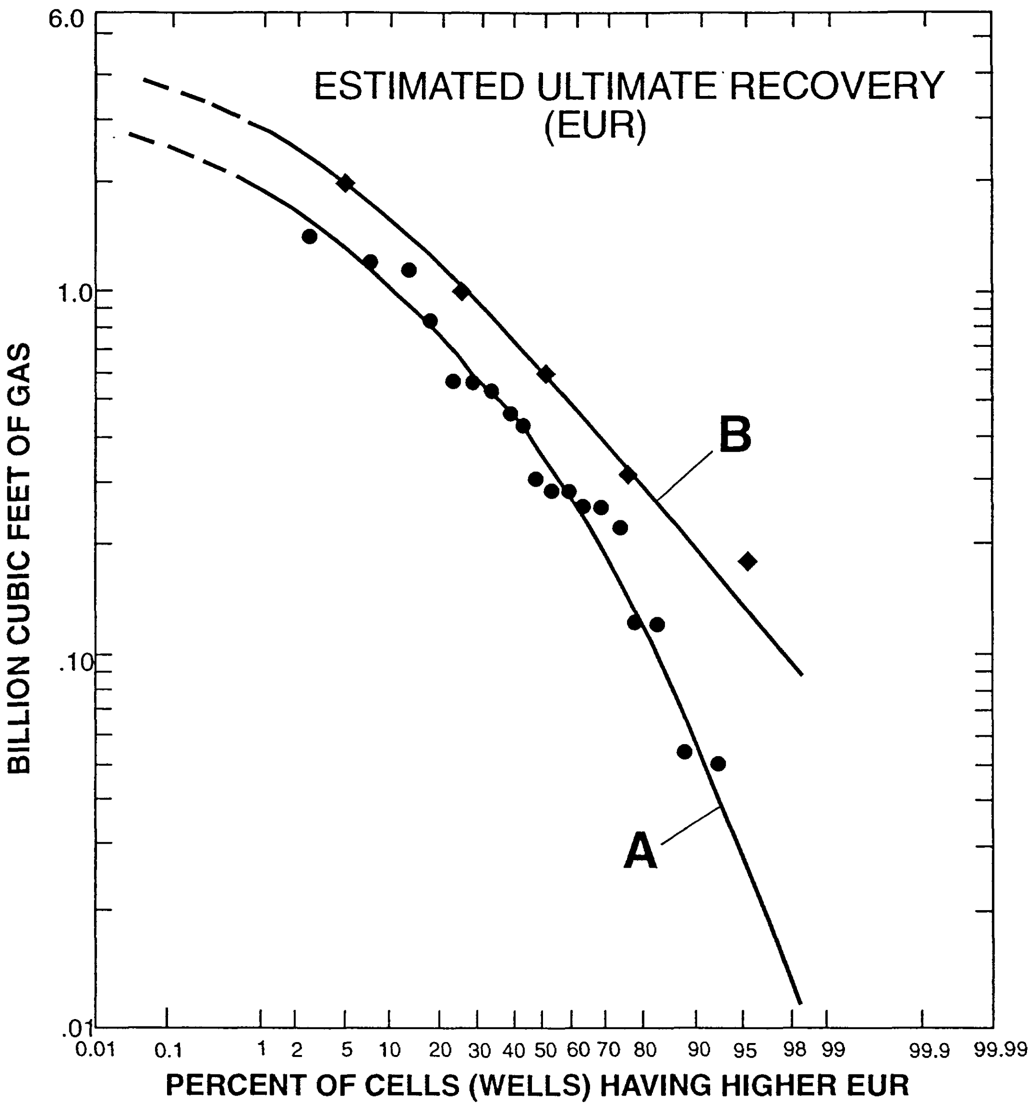


Figure 6. Estimated-ultimate-recovery (EUR) probability distributions for cells (wells) of the Barnett Shale continuous gas accumulation, based on 320 acre spacing. Distribution A is developed from decline-curve analyses of the first 20 wells in the accumulation placed on production (6/82-12/85). Distribution B is constructed by multiplying distribution A by a technology-improvement factor defined as the ratio of PYP (2nd half of wells) to PYP (1st half of wells), as calculated from figure 5.

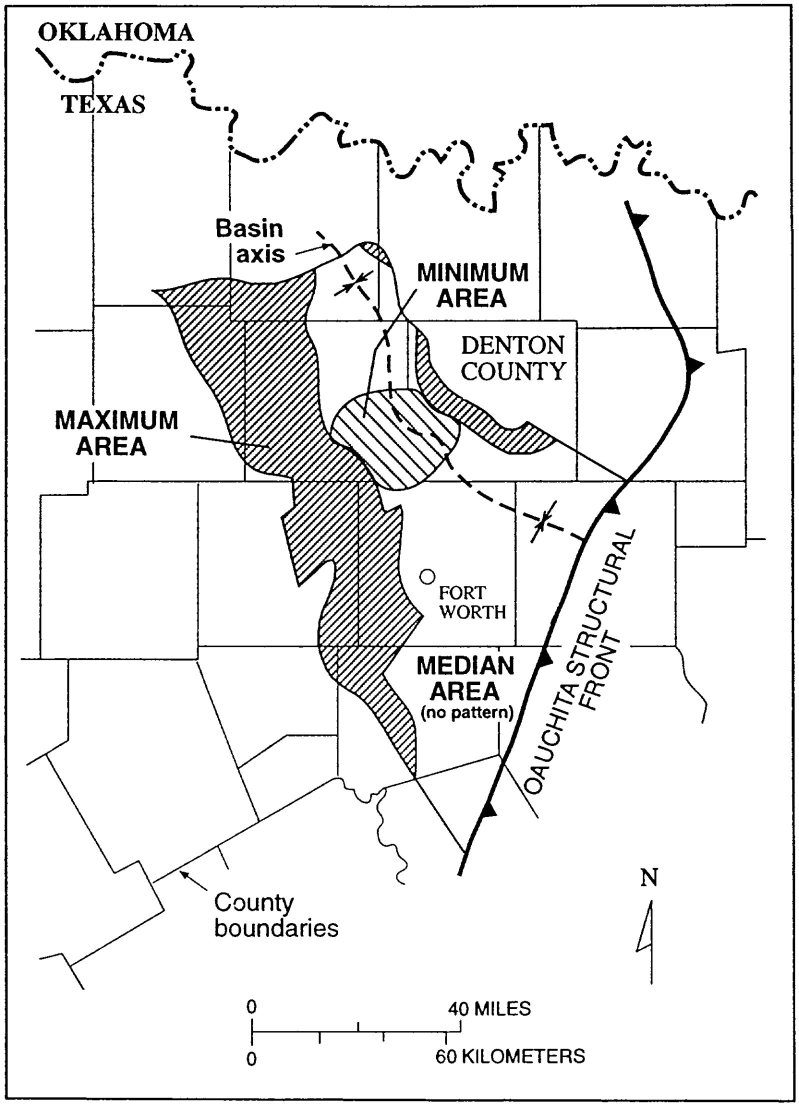
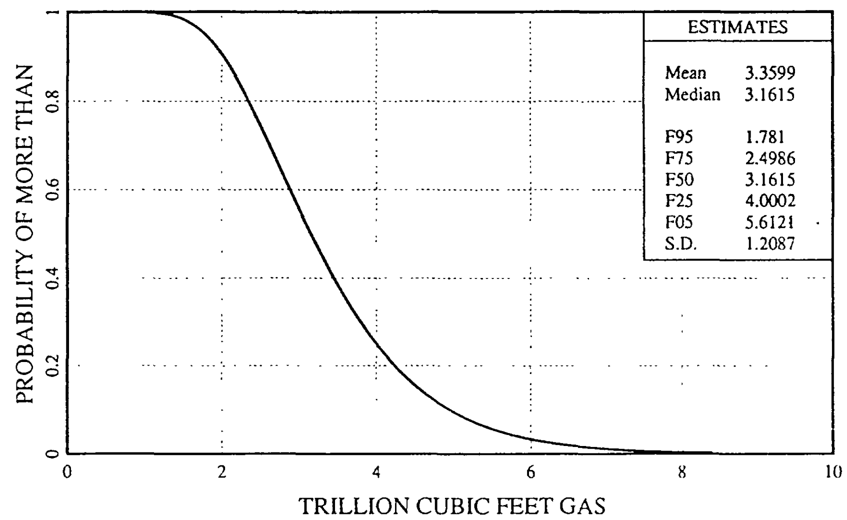


Figure 7. Map showing three scenarios for the areal extent of the Barnett Shale continuous gas accumulation: 1) a minimum-size area (labeled MIN, horizontal line pattern) that closely surrounds the existing group (as of September, 1994) of producing wells; 2) an intermediate- or median-size area (labeled MED, no line pattern) that encloses the minimum-size area and extends along the basin trough northwest and southeast of existing production; and 3) a maximum-size area (labeled MAX, vertical line pattern) that encloses the intermediate-size area and extends further updip, primarily to the west and southwest. To the east and southeast, the intermediate- and maximum-size accumulation boundaries follow the trace of the Ouachita structural front. A dashed line shows the axis of the Fort Worth Basin as indicated by structural contours on the Ordovician Ellenburger Group (Ewing, 1990).



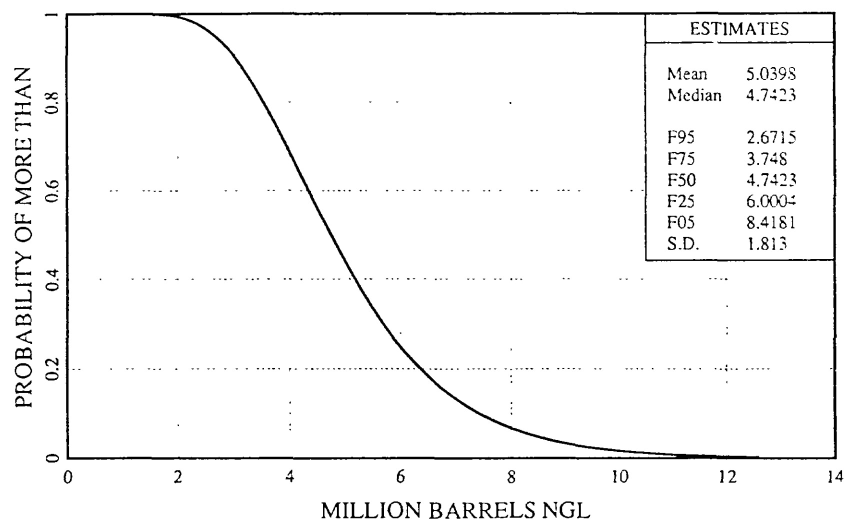


Figure 8. Potential additions to technically recoverable resources for the Barnett Shale continuous gas accumulation, Fort Worth Basin. The upper chart represents gas; the lower chart represents natural gas liquids. The inset on each chart lists parameters of the graphed probability distribution: mean, median, 95th, 75th, 50th, 25th, and 5th percentiles, and standard deviation. Units of the inset parameters are those of the graph's horizontal axis. Data are from Table 1.