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RESERVOIR HETEROGENEITY AS MEASURED BY PRODUCTION CHARACTERISTICS OF WELLS--PRELIMINARY OBSERVATIONS

by

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INTRODUCTION

In this preliminary study, we test the use of the well-production parameters of peak monthly production, peak consecutive-twelve-month production, and cumulative production in older wells as tools to quantify and understand the heterogeneity of hydrocarbon reservoirs. We define measures of variability (variation coefficients) in peak production and cumulative production and examine calculated variation coefficients with respect to internal consistency, type of production parameter, conventional versus unconventional accumulations, and reservoir depth. The bulk of the test data represent Morrowan-age clastic reservoirs of the Anadarko Basin. Well-production data from other formations of the Anadarko Basin, Williston Basin, and north-central Montana are also included in the data set to provide perspective.

BACKGROUND

Production parameters in oil and gas reservoirs vary significantly from well to well for a variety of geologic and engineering reasons. The fundamental hypothesis of this study is that well-production variability carries information about the heterogeneity of reservoirs that would be difficult or impossible to obtain using traditional geologic techniques such as petrographic study, core and well-log analysis, and outcrop observations. The flow of oil or gas to a wellbore is visualized as integrating all aspects of geology that are relevant to reservoir performance, over an area of tens to hundreds of acres.

In addition to in-situ geologic factors, completion and production practices might also influence well-production characteristics. An aspect of this preliminary study is to examine the extent to which systematic characteristics reflecting reservoir heterogeneity are masked by variability in engineering practices.

Measures of Well Production

Peak monthly production (PMP) is defined as the volume of oil or gas produced in the most productive calendar month in the history of a well. In identifying the peak month, production volumes should be adjusted to account for the fact that a calendar month can consist of 28, 29, 30, or 31 days. All else being equal, variations in PMP reflect variations in the rates at which hydrocarbons can flow to the wellbore (well deliverability). Because of the short measurement period, PMP is not commonly affected by factors relating to depletion of hydrocarbons. However, the short measurement period also means that variations in PMP in some cases might reflect human-induced engineering factors rather than in-situ natural reservoir factors.

Peak consecutive-twelve-month production, referred to for convenience in the remainder of this paper as peak yearly production (PYP), is defined as the volume of oil or gas produced in the most productive twelve month period (as differentiated from the most productive calendar year) in the history of a well. PYP is in some ways a compromise indicator of well deliverability. The longer measurement period (compared to peak monthly production) increases the probability that variations in PYP are indicative of geologic factors rather than engineering factors. However, over a one-year period, reservoir depletion could start to play a role, so that PYP might be a mixed measure of reservoir volume as well as production rate.

Cumulative production (CP) is the total volume of oil or gas recovered throughout the producing history of a well. Because most wells exhibit exponential or hyperbolic production decline as a function of time, cumulative production from older wells (that is, wells in which the curve of production versus time has flattened) asymptotically begins to approximate ultimate recovery. Although CP from older wells is not an ideal measure of ultimate recovery (being always too low unless the well is abandoned), it has the advantage of precision: cumulative production is a direct measurement, whereas ultimate recovery is an estimate based on projections into the future. In older wells, all else being equal, variations in CP reflect variations in the reservoir volume accessed by the wellbore.

Lognormal Distributions

Many geologic processes result in physical properties whose values form a lognormal distribution. A lognormal distribution is one in which the logarithms of the observations in question follow a normal distribution. Therefore, most of the observed values of a lognormal data set are relatively small, and a few are very large. Lognormal distributions in geology include such diverse properties as the grain sizes of sediments, magnitudes of earthquakes, gold-assay values from mineral deposits, frequencies of floods, and sizes of oil and gas fields (Koch and Link, 1970; Davis, 1986).

The production parameters of peak monthly production, peak yearly production, and cumulative production discussed in the previous section measure the net result of multiplicative geologic processes and so might be expected to approximate a lognormal distribution. For this reason, production data in this study are plotted on graph paper having axes arranged (as shown in Figure 1) such that a lognormal distribution plots as a straight line.

In actual practice, plots of PMP, PYP, and CP will not form exact lognormal distributions. A true lognormal distribution has no cutoff at the high end, but offers an increasingly small chance for an increasingly large value. However, PMP, PYP, and CP all have finite upper limits that are dictated by hydrocarbons in place, drainage area, permeability, etc., and the upper end of the probability distribution is therefore truncated. The lower end of the distribution might also be truncated, by economic considerations, in that some poor wells might not be completed and produced to become part of the data set.

Quantitative Measures of Production Variability

The slopes of the probability distributions for PMP, PYP, or CP (Figure 1) are direct indicators of the variability of the data set. Steeper slopes equate to greater production heterogeneity. A horizontal line on Figure 1 would represent an oil or gas field with perfectly uniform production characteristics.

A parameter that is proportional to the slopes of the four probability distributions of Figure 1 would provide a quantitative numerical representation of production heterogeneity. Such a parameter, referred to here as a variation coefficient, can be calculated 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; Schmoker, 1996). For this study, a dimensionless variation coefficient (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 PMP, PYP, or CP. These fractiles are picked directly from plots such as illustrated by Figure 1.

Note in Figure 1 that increasing VC corresponds to increasing slope of the probability distribution, and thus to increasing well-production variability. Because VC is a dimensionless variable, with the range of values normalized by the median of the values, the variation coefficient is independent of the magnitude of production. In other words, VC does not depend on whether overall production of a group of wells is "good" or "poor".

Other variation coefficients could be defined whereby the range of production values is represented by the 10th and 90th fractiles, the maximum and minimum measurements, or the standard deviation, or whereby the central tendency is represented by the mean rather than the median. Test calculations indicate that all these approaches result in similar rankings of variability.

DATA

Well-production data developed for this preliminary study represent 15 gas fields in the Pennsylvanian Morrow Sandstone of the Anadarko Basin, Oklahoma, one gas field each in the Cambrian-Ordovician Arbuckle, Ordovician Simpson, Pennsylvanian Atoka, and Devonian Hunton Groups of the Anadarko Basin, and one gas field in undifferentiated Late Cretaceous (Phillips, Greenhorn, and Bowdoin) reservoirs of north-central Montana (Table 1). The Anadarko Basin gas accumulations are conventional fields. The Bowdoin field is a localized "sweet-spot" in a shallow, regionally extensive, unconventional, biogenic-gas accumulation, of the type termed continuous by Schmoker (1995). These data are supplemented by previously developed data (Schmoker, 1996) for three areas (treated here as fields) of the Mississippian-Devonian Bakken Formation continuous (unconventional) oil accumulation in the Williston Basin, North Dakota and Montana (Table 1).

Production data for the wells of these 23 fields were obtained from the Petroleum Information Corporation (PI) National Production System (NPS) on CD-ROM. NPS contains identification, location, completion, and monthly production information by well for many basins in the United States.

Variation coefficients for each field were calculated for peak monthly production, peak yearly production, and cumulative production (from older wells in which cumulative production was approaching ultimate production) of wells and are listed in Table 1.

ANALYSIS

The variation coefficients listed in Table 1 change significantly from field to field but are generally consistent within a field. For 19 of the 22 fields for which comparisons can be made, VC derived from cumulative production is larger than VC calculated from PYP or PMP. Assuming that cumulative production of older wells is proportional to ultimate production, this relation suggests that heterogeneity associated with the reservoir volume accessed by a well is greater than heterogeneity associated with the plumbing system controlling flow rates to a well. Older wells are defined for this study as wells for which curent monthly production is less than 10 percent of initial monthly production. An alternative interpretation is that engineering practices within a field, pipeline capacity, contract constraints, seasonal demand, and other market factors are acting as filters that reduce the variability of flow rates.

In looking down the VC columns of Table 1, the variation coefficients vary widely from field to field. Among the 15 Morrow-reservoir gas fields, for example, VC_{cum} ranges from 3.19 to 33.20. Perhaps a sorting of these fields according to some causal geologic variable would reduce heterogeneity within the subgroups formed, but for the class of Morrow reservoirs as a whole, the degree of well-production heterogeneity varies significantly between fields.

Figure 2 offers a smoothed presentation of the VC data of Table 1, thereby making general relations more apparent. For each of the four reservoir groupings shown: (1) heterogeneity of cumulative production is significantly greater than the heterogeneity of peak monthly or peak yearly production; and (2) heterogeneity of PMP and PYP is approximately equal.

A consistent hierarchy is maintained among the four groupings of Figure 2. Whether cumulative production, peak yearly production, or peak monthly production is considered, Morrow reservoirs of the Anadarko Basin are most heterogeneous, non-Morrow reservoirs of the Anadarko Basin and the Bowdoin reservoir of north-central Montana are intermediate in terms of production heterogeneity, and the Bakken Formation reservoir of the Williston Basin is least heterogeneous.

The Bakken Formation has extremely low matrix permeability. Production is controlled by fracture systems, whereas Morrow sandstone bodies commonly have conventional matrix permeability. The relatively low variation coefficients for Bakken fields (Figure 2) show that the fracture systems for this reservoir, which might be extremely heterogeneous on the scale of inches, are in fact quite homogeneous on the scale of the drainage area of wells. This circumstance was also noted by Stell and Brown (1992), who examined the Bakken Formation along with two fractured chalk reservoirs. Effects such as depositional environment, burial diagenesis, and position of wells within a trap make production from conventional Morrow fields more heterogeneous than that from fractured Bakken shales (Figure 2).

The fields in this study extend over a depth range of almost 17,000 ft (Table 1). As an example of an effort to relate reservoir heterogeneity to a causal variable, variation coefficients are plotted against depth in Figure 3. If the Arnett Southeast Morrow field is discounted as an outlier (VCcum= 33.20), shallow reservoirs (less than 10,000 feet) are only slightly more variable (mean VCcum =7.44) than deeper reservoirs (greater than 10,000 feet, mean VCcum=6.55) based on the 23 reservoirs in this study. Figure 3 shows that depth exerts little or no control on reservoir heterogeneity, at least for the fields in this limited study.

The preceding discussion is focused on the production variability of wells within a field (intrafield), but the concept of the variation coefficient can also be applied to production variability between fields (interfield), as illustrated by Figure 4. Figure 4 is a probability distribution for the highest cumulative well production in each gas field of a 20-field group (Bakken Formation oil fields are excluded). The variation coefficient of this data set is 5.66. Comparison to Figure 2 shows that, for the fields of this study, the heterogeneity of cumulative well production between fields (VC=5.66) is approximately equal to or is less than the average heterogeneity of cumulative well production within fields (VC=5.15 to 9.20).

SUMMARY

This study shows that quantitative measures of the variability of production rates and production volumes of wells, expressed as dimensionless variation coefficients, are potentially valuable tools for documenting reservoir heterogeneity. Analysis of well-production data in 23 fields (of which 20 are gas fields) indicates that trends in variation coefficients exist that are indicative of in-situ geologic factors. Masking effects relating to engineering-induced production variabilty are less likely to affect variation coefficients derived from longer-term measures of well production.

Results of this preliminary study offer sufficient encouragement to continue examination of production heterogeneities of gas reservoirs. A larger data set needs to be developed, in part because the relative effects upon production heterogeneity of geologic factors versus engineering factors are not easily separated in the present small data set. A larger data set is also needed for statistical credibility in searching for: (1) correlations between well-production variation coefficients and reservoir lithology, size, depth, depositional environment, diagenetic history, structural style, trap type, age, etc.; (2) methods to differentiate conventional and continuous (unconventional) accumulations using well-production variation coefficients; and (3) analog models based on production heterogeneity that empirically establish classes of reservoirs useful for analysis of exploration risk, exploitation methods, and field growth (reserve appreciation).

A thorough analysis of production hetrogeneities in wells and reservoirs may shed light on some important questions including: What is the range of variation in production parameters for different reservoirs? Can reservoirs be compared and categorized using measures of production? Can conventional and unconventional continuous-type reservoirs be differentiated using measures of production variability? Can production-variability models be defined which empirically capture effects of lithology, trap type, fracture development, and other geologic factors?

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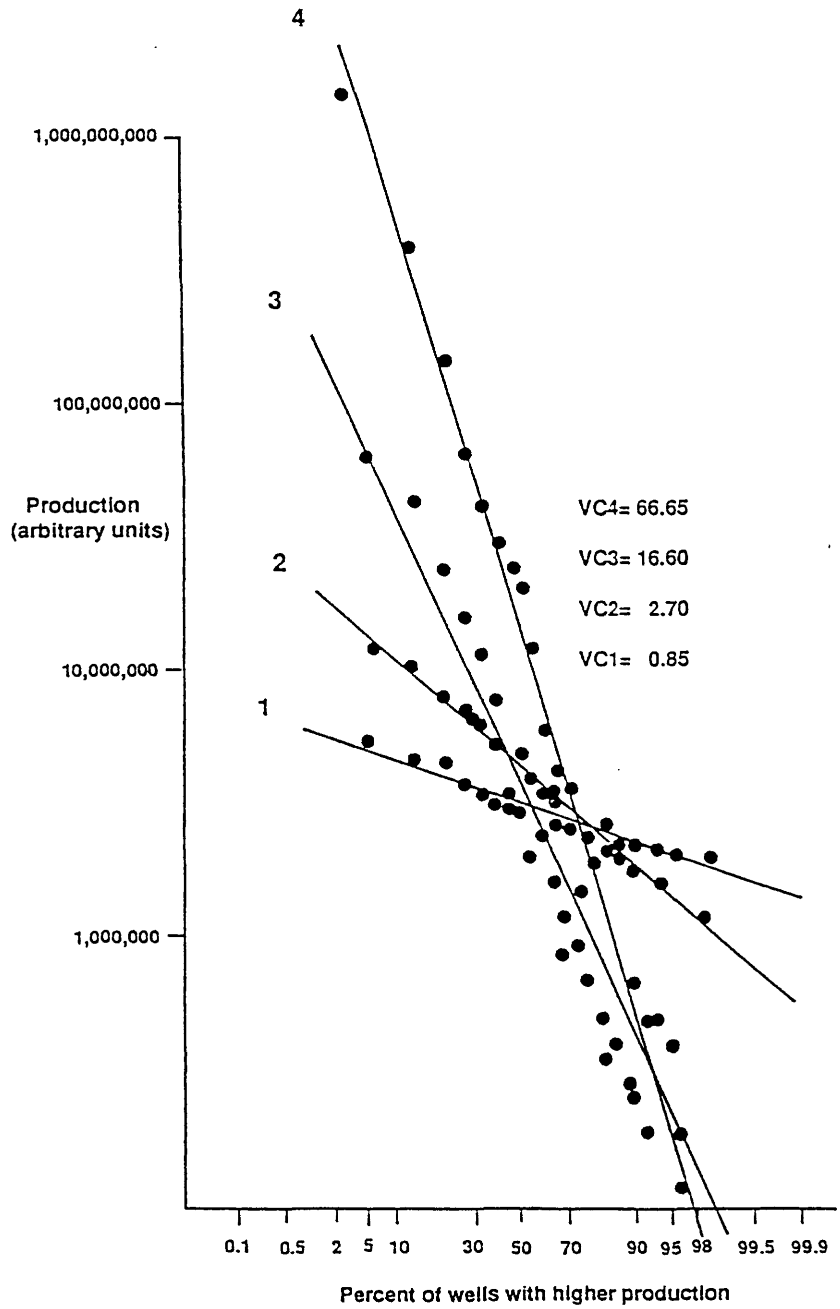

Fig. 1. Probability distributions based on hypothetical data for production from wells of an oil or gas field (peak monthly production, peak twelve-month production, or cumulative production). Each point represents a well; four different fields are depicted. Figure illustrates a type of plot in which: (1) lognormal distributions plot as straight lines; and (2) steeper slopes of lines correspond to a greater range of production and thus 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 increases as slope increases.

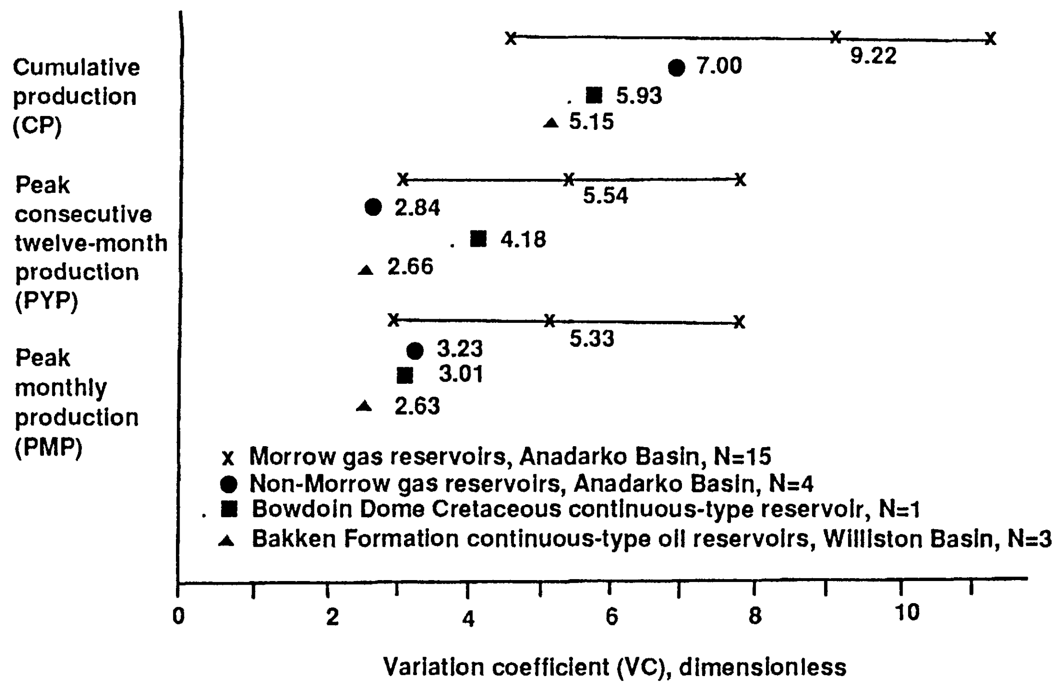

Fig. 2. Average variation coefficients for cumulative production, peak twelve-month production, and peak monthly production for the 23 fields of this study. For Morrow reservoirs, the two outer X's represent the standard deviation about the mean. Data taken from Table 1.

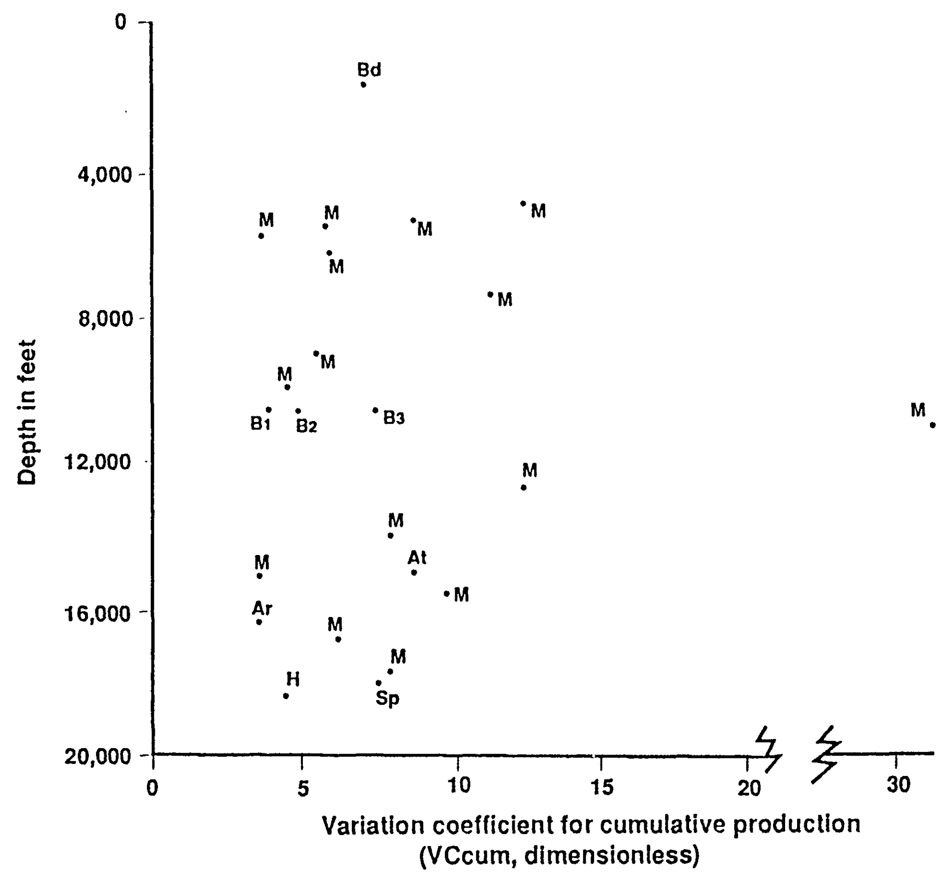

Fig. 3. Plot of variation coefficients of cumulative production for 23 fields used in this study versus depth in feet (Table 1). M, Morrow Sandstone fields, Anadarko Basin; Bd, Bowdoin field, north-central Montana; At, Atoka Group field, Anadarko Basin; Ar, Arbuckle Group field, Anadarko Basin; H, Hunton Group field, Anadarko Basin; B_1, Bakken Formation Fairway Area, Williston Basin; B_2, Bakken Formation Intermediate Area, Williston Basin; B_3, Bakken Formation, Antelope field, Williston Basin.

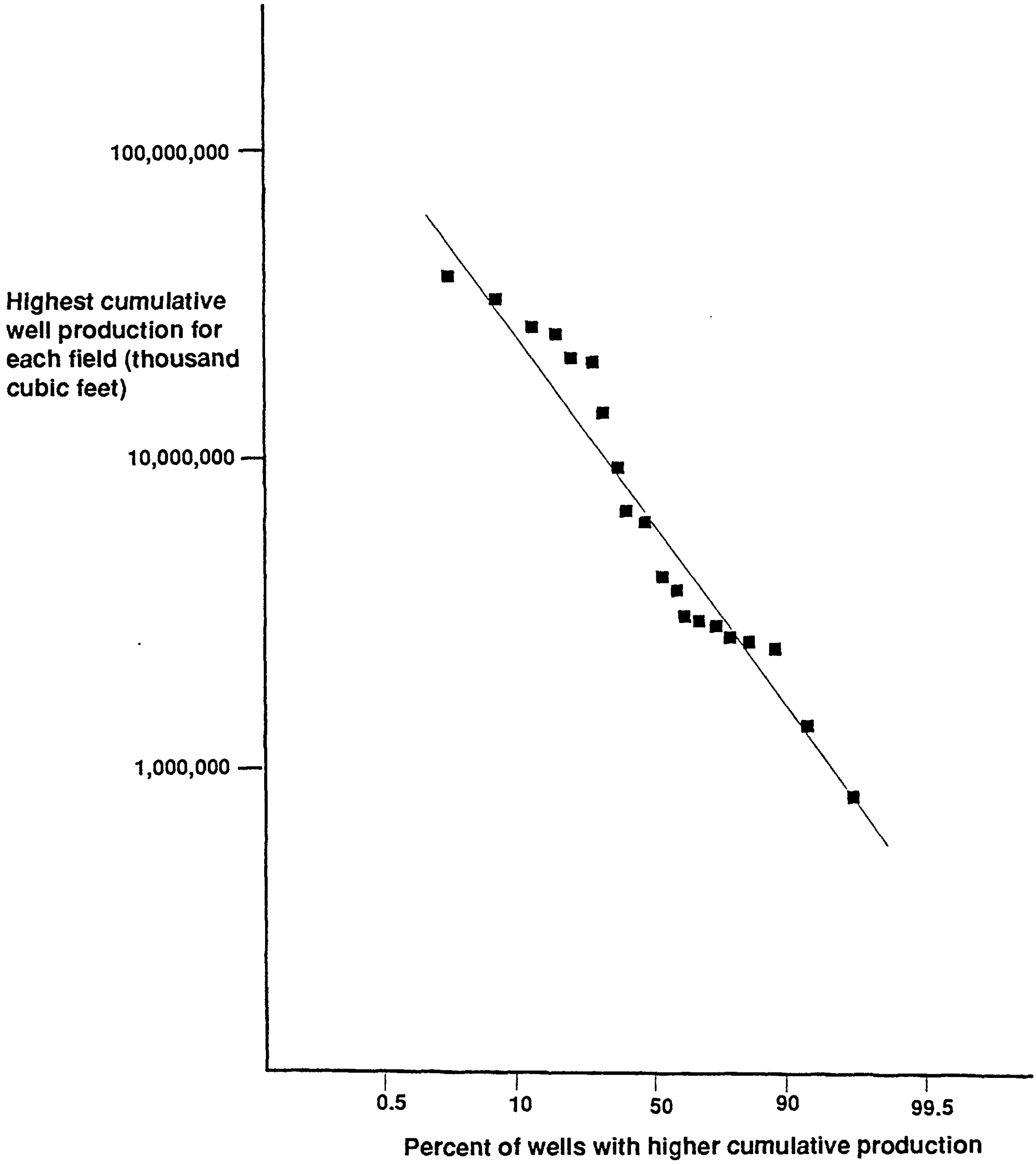

Fig. 4. Probability distribution for highest cumulative well production in each of the 20 gas fields of this preliminary study. Data are from "Peak well cum" column of Table 1. Variation coefficient of this data set is 5.66.

Table 1. Data generated in preliminary study of reservoir heterogeneity as measured by production characteristics of vertical wells. Columns give field or area name (Field), lithology of reservoir (Lith.), depositional environment of reservoir (Env.), name of reservoir formation (Reservoir), number of wells used to calculate variation coefficients (No.), average field depth, ft (Depth), dimensionless variation coefficient calculated for cumulative production (VC cum), peak yearly production (VC pyp), and peak monthly production (VC pmp) of wells, and the highest cumulative well production in each field or area, thousand cubic feet of gas for Anadarko Basin and north-central Montana and barrels of oil for Williston Basin (Peak well cum). See text for description of variation coefficient. ss, sandstone; cg, conglomerate; sh, shale; c, carbonate; f, fluvial; m, marine; fd, fluvial deltaic; e, estuarine.

Field	Lith.	Env.	Reservoir	No.	Depth	VCcum	VCpyp	VCpmp	Peak well cum
				ANADARKO BASIN					
Reydon	cg		Morrow	25	15,000	3.52	2.29	3.01	33,000,000
Elm Grove	ss	m	Morrow	13	12,500	12.40	10.13	6.97	9,980,000
Eagle City S.	ss	m	Morrow	19	10,000	4.57	3.95	2.80	3,622,000
Milder	ss	m	Morrow	24	9,000	5.11	5.35	12.46	2,944,146
Balko South	ss	m	Morrow	19	7,500	11.10	2.29	3.10	2,161,000
Angell	ss	m	Morrow	28	5,800	3.19	2.67	1.94	2,212,360
Rice SW	ss		Morrow	6	4,700	12.40	5.20	5.10	1,981,600
Carthage	ss	fd	Morrow	18	5,600	5.71	3.46	2.59	2,983,094
Carpenter	ss		Morrow	26	17,800	8.08	5.67	4.23	21,838,967
Breathwaite	ss		Morrow	11	16,600	6.00	7.66	8.60	4,222,442
Arapaho	ss	m	Morrow	22	14,000	8.06	3.89	4.38	6,389,617
Arnett SE	ss	m	Morrow	22	11,400	33.20	11.92	6.50	14,420,367
Elk City	ss		Morrow	31	15,500	9.98	5.96	5.71	39,965,748
Harper Rn.	ss	e	Morrow	17	5,300	9.21	6.58	5.00	1,360,761
Hooker SW	ss	fd	Morrow	15	6,200	5.80	6.10	7.56	2,776,212
Mayfield W.	c		Arbuckle	8	16,500	3.56	3.34	1.94	25,134,000
Mayfield W.	c		Hunton	20	18,200	4.27	4.19	1.85	27,193,000
Carpenter	cg	f	Atoka	30	15,000	8.46	5.42	5.16	22,000,000
Verden	ss		Springer	37	18,000	7.41	3.78	3.08	6,981,000
				NORTH-CENTRAL MONTANA					
Bowdoin	ss/c	m	Cretaceous (undifferentiated)	29	1,700	7.00	2.84	3.23	777,438

Table .1 continued.

Field	Lith.	Env.	Reservoir	No.	Depth	VCcum	VCpyp	VCpmp	Peak well cum
				WILLISTON BASIN					
Antelope (Sanish pool)	sh	m	Bakken	39	10,500	3.63	–	–	1,119,000
Fairway area play	sh	m	Bakken	75	10,500	4.35	–	2.85	515,000
Intermediate play	sh	m	Bakken	67	10,500	7.48	2.66	2.40	299,000