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Integrating Petroleum-Occurrence Information Into a Basin-Classification System

by

Mark W. Bultman[1]

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[1]U.S. Geological Survey, University of Arizona, Tucson, Arizona 85721

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Abstract

I have used information on the distribution of oil-field sizes in American Association of Petroleum Geologists (AAPG) petroleum provinces of the contiguous United States to modify an initial, tectonically based basin-classification system modeled after a scheme developed by H.D. Klemme. The tectonic setting and oil-field-size distributions of the petroleum provinces are used to distinguish five classes of basins. Four of these classes have constrained parameterization of their oil-field-size distributions: craton-interior shallow basins, craton-interior deep basins, craton-margin Rocky Mountain basins, and convergent-margin transform basins. A fifth class, craton-margin basins, vary widely in the parameterization of their oil-field-size distributions. This class is further subdivided into type A, composite basins, and type B, downwarp basins on the basis of geologic considerations. The usefulness of such a basin classification system for use in petroleum-resource assessment is questionable, owing to the wide variation in petroleum richness (estimated ultimately producible petroleum per unit of basin area) both within and between basin classes, which discounts the use of geologic analogy as a tool in assessing frontier basins by means of an analog basin.

Introduction

The classification of sedimentary basins has interested numerous workers since the early 1950's. In general, it is hoped that a basin classification system will characterize the occurrence of hydrocarbons so as to allow the insights into petroleum occurrence gained in an explored basin to be carried over to an analogous unexplored or partly explored basin. Although methods of petroleum-resource assessment currently utilize several sophisticated concepts involving factors fundamental to the occurrence of petroleum generally aggregated at a play level, geologic analogy and analog basins have been used extensively in the past and are still the only way to appraise the approximately one-fourth of the world's basins that have not yet been tested by drilling (Klemme, 1980). The basis for classification of sedimentary basins varies among workers, but all classification systems are based on geologic knowledge or inference alone and include little or no information from the actual occurrence of hydrocarbons within a basin.

The objective of this analysis is to incorporate information on hydrocarbon occurrence directly into a sedimentary-basin-classification system. The analysis is performed by using selected American Association of Petroleum Geologists (AAPG) petroleum provinces in the conterminous United States and begins with an initial basin-classification system based only on tectonic setting. That system is then modified with the help of information on the distribution of oil-field sizes in each of the basins. Finally, the overall usefulness of the basin-classification system is examined.

Oil-Field-Size Distribution and Tectonic Setting

Within any basin, the relation between tectonic events and sedimentation determines the source rocks, reservoir rocks, and types and sizes of structures that may serve as potential traps. If the tectonic forces acting to form a basin are similar throughout it, assuming that the lithosphere responds to stress similarly in similar tectonic situations, then it is also reasonable to assume that similar types and sizes of traps would be formed in similar tectonic settings. Furthermore, the types and sizes of traps formed are directly related to the sizes of oil fields found. Therefore, the oil-field size distribution in a basin is probably related to its tectonic setting.

Klemme (1984) showed that a relation exists between the relative size distribution of the five largest oil fields in a basin and the tectonic setting and size of the basin. The tectonic setting contributes significantly to differences in the percentage of a basin's reserves that occur in its five largest fields, as shown in figure 1. Also, as basin size increases, the percentage of the basin's reserves found in its five largest fields decreases (fig. 1). Klemme concluded that more geologic constraints are placed on the size of a trap than on the size of a basin (Klemme, 1984). These findings indicate that the oil-field-size distribution of a basin should be related to tectonic setting but independent of basin size.

Petroleum-Occurrence Data

The primary source of data used in this analysis was a 1981 excerpt from the TEXS and OILY files (now combined to form the TOTL file) of the Petroleum Data System of North America (the data base). The data base contained nearly 100,000 records, each representing an individual oil field or reservoir. For each record, information was included on the location and identification of the field or reservoir, as well as some production and geologic data. Natural-gas production is ignored in this analysis for simplicity and because production data were more complete for oil than for gas.

The data base included the six-digit Department of Energy (DOE) field code and the AAPG petroleum-province designation for all records. The DOE field code allows all reservoirs with identical codes to be aggregated into a field. However, data-collection procedures and the definitions of both "reservoirs" and "fields" vary from State to State. This ambiguity is carried over into the DOE field code and is not addressed further here. The AAPG petroleum-province designations were used to aggregate oil fields into regions or "basins" on the basis of tectonic setting. Although these designations are not based purely on geologic considerations (Meyer, 1970) , almost all of them comprise entire geologic basins or some other large-scale tectonic feature.

The data base contained detailed information on annual and cumulative production for most fields and reservoirs but little information on reserve estimates. Annual and cumulative production data were generally current through 1978, 1979, or 1980. Because the results of this analysis depend on an estimation of the amount of producible petroleum in a field (field size), a simple method of approximating a field's reserves from its annual production was used. In general, a field's reserves can be approximated by multiplying its last reported annual production by 10.0 (Meyer, 1983; Woods, 1985). Field size was estimated by adding this reserve estimate to the most recent cumulative production.

The Appalachian region of the United States was excluded from this analysis. The fields in this region are old, and the data are presumed to be incomplete and inaccurate. According to Nehring (1981, p. 33), the Appalachian region holds only an estimated 3.6% of U.S. petroleum resources. Offshore regions were also excluded, owing to incomplete data and the effects of offshore exploration and production on economic truncation. Also, because of incomplete data, **approximately 7,500 records from the data base were unusable. In most cases, this data is from** small fields of less than 1 million bbl. Incomplete data are assumed to be randomly distributed in the data base and should not bias the analysis. A total of 17,506 oil fields were analyzed for this study.

Fitting a Functional Form to the Oil-Field-Size Distributions

Ideally, the underlying or parent population of oil fields in a region is used as a basis for a basin-classification system. During exploration, however, the largest oil fields are generally discovered first. This phenomena is referred to as sampling proportional to size and results in a biased sample distribution of discovered oil fields. Also, the fact that many discovered fields are too small to be profitable and so are not reported results in another form of bias, referred to as economic truncation. Both of these biases ensure that the sample population (discovered oil fields) is truncated at oil-field sizes smaller than some unspecified size. In addition, the fact that production from many pools and (or) fields is simply not reported or incorporated into the data base results in a censored sample. Censoring is assumed to occur independently of field size and thus not to affect the shape of the oil-field-size distribution in any basin.

If an adequate model of the discovery process were developed, then it might be possible to remove these biases from the sample and to actually examine the underlying population. To date, however, no adequate theoretical model has been published that correctly describes the sampling process.

It thus becomes necessary to use the distribution of sampled oil-field sizes. This information can be used in two ways. First, some form of the underlying distribution might be chosen for theoretical or other reasons and fitted only to the non truncated part of the distribution. This method requires a precise mathematical procedure for extending the truncated distribution of an assumed form to field sizes smaller than the truncation point and a method to determine the point of truncation. I have attempted to extend the truncated distributions of oil-field sizes into log-normal and log-exponential forms (Bultman, 1986), but for mathematical reasons, the extension procedures did not work in many cases. Also, although some theoretical reasoning may support either the log-normal or log-exponential form for the underlying distribution, the theoretical reasoning is inconclusive.

Second, the available information on discovered oil fields can be used to model the sample of discovered-oil-field sizes. The choice of a functional form of the distribution is not critical if the intent is to use the distribution as a representation of properties of the data, but it is critical if the intent is to make inferences on the quantity of oil which that distribution represents (Mayer et al., 1980).

Using only the sample of discovered oil fields may actually have some advantages over using the parent population. The petroleum provinces of the conterminous United States are mature regions where all of the giant and most of the large oil fields have already been found. Thus, the sampled population of oil fields in the conterminous United States represents what an explorationist can expect to find over a reasonably long period of exploration in a province.

A flexible four-parameter function, the Richards growth function, is used to model the log transform of oil-field sizes in each petroleum province. The curve was developed by Richards (1959) as an empirical representation of plant-growth data. The parameterization of each distribution is used to represent properties of the oil-field-size distribution in each petroleum province; these properties are then compared between petroleum provinces.

The Richards function, when used to model oil field sizes in a petroleum province, represents the relation between the cumulative number of oil fields and oil-field size. The function is quite flexible and can precisely model almost any distribution of oil-field sizes. The Richards function consists of four parameters, A, B, C, and D, and is expressed as a function of oil-field size, x, as follows:

$$(1)\quad Q(x) = A\,[1+B\exp(-Cx)]^{-(1/D)}$$

Parameter A represents the asymptotic limit of growth, or the total number of oil fields in a province. Setting A=1, equation 1 can represent the cumulative density of oil fields as a function of oil-field size, and the first derivative of equation 1, can serve as a probability-density function (PDF) for oil-field sizes:

$$(2)\quad dQ(x)/dx = f(x) = -1/D\,(1+B\exp(-Cx))^{(-1/D+1)}\,(-CB\exp(-Cx))$$

Equation 2 can then be used to model unimodal distributions that are symmetrical or left or right skewed.

The purpose of summarizing the characteristics of a population or sample by fitting it to the Richards function is to use the various parameters of the functional form as a basis of comparison. In the Richards function, however, the role of each parameter in controlling the shape of the function is not self-evident; thus, four "modified" parameters have been created that are directly related to the geometric properties of the curve. This modification makes the comparison of oil-field-size distributions between petroleum provinces intuitively easier.

Setting A=1, the effects of the remaining parameters on the curve must be explained. Parameter D has the most obvious effect: It controls the symmetry of the first derivative of the Richards function. When $0 < D < 1$ this first derivative is right skewed. When D=1, the Richards function is equivalent to the logistic curve, and the first derivative is symmetrical. When $D > 1$, the first derivative is left skewed. By varying D from slightly more than 0 to infinity, the location of the mode of the first derivative can be controlled over almost the entire range of the data. Because parameter D has a nonlinear influence on the skewness of the distribution, it is not an easily interpretable indicator for comparing petroleum provinces. The skewness of the distribution can be expressed in terms of another parameter, S, that has a linear response to changes in D:

$$(3)\quad S = (D+1)^{-1/D}$$

Equation 3 identifies the inflection point of the cumulative-density function in terms of the range of the data used to reach that point. Parameter S ranges only from 0 to 1; it gives the proportion of the total number of fields that are smaller than the mode of the distribution, making it an excellent indicator of skewness. Parameter S is used here as a skewness indicator when comparing distributions.

For a given value of D, parameter S represents the cumulative density at the mode of the distribution. This relation can be used in equation 2 to solve for the oil-field size that represents the mode of the distribution. The mode is also used here as a modified parameter for comparing distributions.

The relation between the rate of growth of the curve and parameter C in equations 1 and 2 is quite complex. Richards (1959) plotted the rate of growth in weight of an organism versus its weight to demonstrate the significance of this parameter; the quantity C/(2D+4) represents the mean height of this plot (Richards, 1959, p. 295). The quantity (2D+4)/C gives a very good approximation to the period of time over which 90 percent of the growth of the curve takes place for constrained values of D (Richards, 1959, p. 298). The quantity (2D+4)/C is used here as a measure of the spread or variation of the first derivative of the Richards function and is referred to as the dispersion parameter. At no point were the constraints on the parameter D violated.

Simulation was used to solve for the expected value of oil-field size in a basin containing n fields. The expected value is given by:

$$(4)\ E(x) = \sum_{x=1}^{n} x\ f(x)$$

where f(x) is the first derivative of the Richards function (equation 2). The expected value is used here as a modified parameter.

Neither the method of moments nor the maximum-likelihood procedure can be used to estimate the parameters of the Richards function because both methods result in intractable equations, and so a nonlinear regression technique must be used. The particular nonlinear regression technique used in this analysis was developed by Bates and Watts (1981), it is a nonlinear least-squares procedure in which the test of convergence is based on the orthogonality of the residual vector to the tangent of the solution locus.

A two-tailed t test was performed on all results of the fitting procedure. These results show a poor fit for parameter B in 9 cases and poor fits for parameters C and D in 4 cases. However, visual inspection of the fit of the generated distribution against the actual data proved to be extremely useful by determining that a statistically significant poor fit of parameter B had little effect on the ability of the curve to match the data. A poor fit of parameters C and D, however, was significant, and so 4 of the initial 41 basins were excluded from the analysis, owing to poor parameter fits.

The results of fitting the Richards function and modifying its parameters (as described above) are listed in table 1 for each of the petroleum provinces used in the analysis. These modified parameters allow a visualization the shape of the first derivative of the function and are ideal for comparing petroleum provinces.

Figures 2 through 6 show examples of the fit of the Richards function to the data. Each of these figures includes a histogram of field-size and a cumulative-density plot of field-size overlain on the smooth curve representing the Richards function. Figure 2 shows a poor, but acceptable, fit for a province with a small number of fields (24); figure 3 shows a fit to a distribution with a large variance; figure 4 shows a fit to a skewed distribution; and figure 5 shows a fit to a symmetrical distribution.

The Tectonic-Setting/Petroleum-Occurrence Basin Classification System

Each petroleum province was initially classified on the basis of its tectonic setting. The tectonic settings used for this classification were developed for petroleum-producing basins by Klemme (1984), as outlined in table 2. This initial classification was modified by using the oil-field-size- distribution data and, where pertinent, geologic data from the data base. Table 3 summarizes the available geologic information.

Several techniques were used to reveal any structure inherent in the matrix of modified parameters. The most successful technique was classical multidimensional scaling (CMS) (Davison, 1983). The results of CMS are two scaling components, each of which is a linear combination of the four modified parameters from the Richards function. These two scaling components can be thought of as a two-dimensional representation of the four-dimensional modified-parameter space. The two scaling components together explain 98% of the variance in the scalar-product matrix (a form of the Euclidean distance matrix created from the parameter matrix and normalized over rows and columns). The results of CMS and the geologic data from the data base (table 3) suggest a new classification which is given, along with the initial classification based on tectonic setting, in table 4. The scheme is referred to as the tectonic-setting/petroleum-occurrence basin-classification system, and its basis is now discussed.

Figure 6 displays the results of CMS applied to the four modified parameters from the Richards function by graphing the first two scaling components obtained by the CMS process. In figure 6, each AAPG petroleum province is labeled by its designation and a symbol representing its classification in the new system. The two scaling components are a linear combination of the modified parameters that they summarize and can be explained in terms of these modified parameters. The first scaling component is highly dependant on both the expected-value and mode parameters, both of which increase to the right in figure 6. The second scaling component depends mostly on the dispersion parameter, which increases from top to bottom in figure 6. Skewness is weighted so that skewed distributions tend to have a high or low value of either scaling component, with more symmetrical distributions in the center of the figure.

Several tectonic settings distinguish themselves in figure 6. Group A contains 4 basins that can be distinguished on the basis of the first scaling component alone. Included in this group are all the provinces initially classified as convergent-margin transform basins, and so there is no indication here that their classification should change. Group B contains several provinces initially classified as either craton-margin composite or craton/accreted-margin-complex basins; the provinces within this group all have moderate values of the first scaling component and a second scaling component less than zero. Group B contains all the provinces, except one (AAPG province 510), in the Rocky Mountain region; these provinces all display a unique set of parameters for their oil-field-size distributions and thus justify the creation of a new class, craton-margin composite Rocky Mountain basins (after Klemme, 1984).

Examination of the distribution of the remaining, unclassified provinces reveals that almost all of the craton-interior basins and some of the craton-margin composite basins are constrained to the center of figure 6. The provinces in this central area (group C) display low values of the first scaling component and moderate values of the second scaling component. Two provinces that were classified as craton-interior basins by Klemme (1984) lie outside of this central area, namely, the Williston Basin (AAPG province 395) and the Denver Basin (AAPG province 540). Geologic data in table 6 reveal that both of these basins have average reservoir depths of greater than 1 mi., whereas all other craton-interior basins have average reservoir depths of less than 1 mi. Although other workers generally classify them as Rocky Mountain-type basins, the evidence in this analysis shows that they are not related to the Rocky Mountain basins on the basis of their oil-field-size distributions. Therefore, on the basis of both oil-field-size distribution and average reservoir depth, two provinces are classified as craton-interior deep basins, and the other craton-interior basins (in group C) as craton-interior shallow basins.

Several provinces (AAPG provinces 355, 365, 370, 375, 380, 390, and 450) initially classified as craton-margin composite basins also fall within group C. These provinces are almost entirely shallow basins or arches in Oklahoma and Kansas; they are asymmetric and generally represent a miogeosynclinal foreland setting. On the basis of their constrained parameterization and owing to a tectonic setting that does not conflict with such a classification, these provinces are classified as craton-interior shallow basins. Some interesting observations can be made about this group of provinces when some of their geologic parameters are compared with those of craton-margin composite basins (table 3). All of these provinces have an average reservoir depth of less than 5,000 ft and an average reservoir thickness of less than 22 ft (table 3). Almost all of the craton-margin composite basins have reservoir depths and thicknesses greater than those of these basins.

Although group C delineates the constraints placed on craton-interior shallow basins, these constraints do not preclude any craton margin composite basins from lying within those constraints. In fact, AAPG provinces 360, 350, and 435 lie within the constraints, but on the basis of their geology they can not be classified as craton-interior shallow basins.

Many other provinces in figure 6 do not fall into any of the defined basin classes. These provinces all have an extensive range of the second scaling component and a somewhat more limited, but still fairly large, range of the first scaling component. They demonstrate no natural groupings and, collectively, are not closely related to any of the previously mentioned groups. They also belong to several of the tectonic-setting classifications, but all are found on craton margins, and so they are here classified as craton margin basins. They are subdivided into two types on the basis of tectonic setting and the geologic data listed in table 3. Type A, composite basins (after Klemme, 1984), are subduction-related foredeep basins with a complex multi stage history. Type B, downwarp basins, are formed by downwarping of a craton margin into a small ocean basin (after Klemme, 1980). Table 3 indicates that the downwarp basins contain much deeper reservoirs, a much higher reservoir permeability, and a higher reservoir porosity than the composite basins.

In summary, the incorporation of oil-field-size distributions into a basin-classification system has created differences in the initial classification based on tectonic setting. First, a group of basins with a constrained parameterization of oil-field-size distribution contains the "traditional" craton-interior basins, as well as some basins formerly classified as craton-margin basins. Second, two basins formerly grouped with the craton-interior or craton-margin basins can be reclassified as craton-interior deep basins. Third, the craton-margin basins of the Rocky Mountains all display a similar size distribution and so are classified as craton-margin Rocky Mountain basins. Fourth, the other craton-margin composite and crustal-collision-zone open basins can not be distinguished from each other and so are classified as craton-margin basins, further subdivided into types on the basis of tectonic setting. Finally, the convergent-margin transform basins display a unique set of oil-field-size distributions, and so their initial classification will not be changed.

A Comparison of Parameters Across Basin Types

The parameterization of petroleum provinces within the tectonic-setting/petroleum-occurrence basin-classification system is summarized in table 5, which lists the averages and the ranked values of modified parameters for each basin class. Table 5 also lists the results of a Kruskal-Wallis non parametric test to see whether the basins belonging to each class were taken from populations with similar means. The Kruskal-Wallis test fails for all the parameters except the skewness parameter. That is, for the expected-value, dispersion, and mode parameters, there is some indication that all the populations do not have similar means. Some conclusions based on parameter averages, listed in table 5, and geologic information, listed in table 3, will be briefly discussed here.

I. Craton-Interior Shallow Basins

The craton-interior shallow basins display the smallest expected values and small dispersions. The low level of subsidence and absence of sediment sources with large topographic relief have resulted in thin, neritic, homogeneous sedimentation and in homogeneous, continuous reservoir facies. In this environment of gentle extension, trap types are nearly uniform, and traps of a given type are generally similar in size (small) and style.

II. Craton-Interior Deep Basins

With only two craton-interior deep basins, it is difficult to infer anything about the parameters that describe these basins. These basins are thought to represent larger and deeper versions of craton-interior shallow basins. The geologic data in table 3 indicate that reservoir thicknesses are similar to those of the craton-margin shallow basins but that reservoir depths are much greater. The large expected values and small dispersions displayed by these basins may simply reflect economic truncation due to the deeper locations of the producing horizons in these basins than in the shallow basins. Only large oil fields would be reported, which would reduce the dispersion of field-sizes and increase their expected value.

III. Craton-Margin Rocky Mountain Basins

The craton-margin Rocky Mountain basins display large dispersions and expected values. The large expected values may partly be due to economic truncation because the average reservoir depth of these basins is more than 7,000 feet. The dispersions show that trap-forming mechanisms differ from those of either of the craton-interior basins and that various trap sizes are available in this highly tectonized environment. Reservoirs are much thicker in this class than in all the others except the convergent margin-transform basins. Thicker reservoirs and wider variations in reservoir thickness are evident in the parameterization as larger expected-value and dispersion parameters, respectively, than for the craton-margin composite basins and may be the main reasons why they have been differentiated.

IV. Craton-Margin Basins

The craton-margin basins display an average expected value and an average dispersion similar to those of the craton-interior shallow basins (table 5), but the variations in both of these parameters are much wider than for the craton-interior shallow basins. This difference is emphasized both in the parameter data (table 1) and in figure 6, where the craton margin basins display very wide variations in both first and second scaling components. Thus, whereas the average oil-field-size distribution is similar to that of the craton-interior shallow basins, each craton-margin basin tends to have a unique distribution in terms of its location parameters (expected value and mode) and dispersion parameter. This uniqueness may indicate that these basins are situated in areas of the crust that have responded differently to stress, possibly owing to differences in crustal thickness or composition, or, alternately, that the quantity and (or) quality of the stress that formed these basins was not comparable among all the basins in this class.

The craton-margin basins belong to more than one tectonic setting. They are classified together because their parameterizations are unrelated to that of existing groups and to each other. This basin class is further subdivided on the basis of tectonic setting and the geologic difference in these settings, as shown in table 3.

V. Convergent-Margin Transform Basins

The convergent-margin transform basins display the largest dispersions and expected values. The high expected-value parameter is due to several features found in these basins that favor large deposits; these features are formed from the large wrench motion associated with this tectonic setting. The wrench tectonics ensures that there will be many upthrown and downthrown blocks which act as both sources and sinks of sediment. Rates of uplift are generally high and create thick sedimentary units. Table 3 shows that the reservoir rocks in this tectonic setting, which are predominantly sandstone, are much thicker and much more porous and permeable than in the other tectonic settings. Traps are formed by sediment draping over faulted blocks and by both wrench and compressional anticlines. The geologic characteristics of this basin class, as outlined above, are ideally suited to generating both large traps and a large variation in trap size, as shown by their large expected-values and dispersions.

Conclusions: The Usefulness of the Tectonic-Setting/Petroleum-Occurrence Basin-Classification System as a Petroleum-Resource-Assessment Tool

On the basis of both their tectonic setting and oil-field-size distribution, the five classes of petroleum-producing provinces in the contiguous United States are: (1) craton-interior shallow basins, (2) craton-interior deep basins, (3) craton-margin composite Rocky Mountain basins, (4) craton-margin basins (two types), and (5) convergent-margin transform basins. All of these basin classes display a unique and constrained parameterization of the oil-field-size distribution except for the craton-margin basins, whose parameterization is so unconstrained that they may lie within the range of all the other basin classes except the convergent-margin transform basins.

Although the relation between the parameterization of the oil-field-size distribution and the tectonic-setting petroleum-occurrence basin-classification system is interesting geologically, it is of little use, by itself, when trying to use geologic analogy as a resource-assessment tool in a frontier basin. The oil-field-size distribution benefits an explorationist in that it outlines explicit probability rules for the size of the next field that will be found, but it does not indicate the chances of discovering a new field. If statements about the ultimate petroleum recovery of a basin are required, then something must be known about the richness of that basin, where "richness" is defined as the amount of ultimately producible petroleum per unit of surface area.

The relation between richness and tectonic setting is difficult to explain. Although the sizes of traps in a basin influence richness, other factors also play a role in determining richness. The quantity and quality of source material, primary and secondary migration processes, the quantity and quality of reservoir rocks, a basin's thermal setting and hydrodynamic characteristics all strongly influence the richness parameter. It is difficult to specify exactly how tectonic setting affects these factors in any generalized manner.

Table 6 indicates that both the richness and the density of fields vary extremely both within and between the basin classes presented in this analysis. Only in the convergent-margin transform basins are the differences in richness less than an order of magnitude. Even if the parameterization of the oil-field-size distribution is similar within a given basin class, both the total recovery from the basin and the number of expected fields per unit of area varies extremely. Nor does there seem to be any optimal way of classifying basins on the basis of richness.

These findings indicate that any petroleum resource assessment model incorporating geologic analogy and based on analog basins may yield extremely inaccurate results. If the richness of a basin is truly independent of the basin's geology and tectonic setting, then a petroleum-resource assessment of an unexplored or under explored basin can be successful only after a moderate amount of exploration has occurred.

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Table 1: Modified Richards Parameters for American Association of Petroleum Geologists Petroleum Provinces

AAPG Petroleum Province Name	AAPG Pet. Province Designation	expected value	dispersion	mode	skewness
Mid-Gulf Coast Basin	210	13.67	6.88	13.36	0.457
Gulf Coast Basin	220	12.99	9.32	12.71	0.470
Arkla Basin	230	13.53	8.07	14.08	0.565
East Texas Basin	260	12.91	9.26	12.73	0.481
Michigan Basin	305	12.99	8.47	13.29	0.534
Illinois Basin	315	12.46	8.34	12.72	0.532
Forest City Basin	335	11.96	8.39	12.66	0.588
Arkhoma Basin	345	11.52	8.97	11.29	0.479
S. Oklahoma fold belt	350	12.91	8.53	12.55	0.459
Chautauqua platform	355	12.83	7.84	12.84	0.501
Anadarko Basin	360	11.94	7.90	11.89	0.496
Cherokee Basin	365	12.25	8.34	12.51	0.533
Nemaha anticline	370	12.67	7.42	12.30	0.453
Sedgwick Basin	375	12.19	7.67	12.38	0.525
Salina Basin	380	12.38	7.42	12.63	0.533
Central Kansas uplift	385	12.25	6.24	12.11	0.479
Chadron arch	390	11.83	7.64	11.17	0.419
Williston Basin	395	14.01	6.38	13.89	0.482
Ouachita tectonic belt	400	11.65	10.48	11.57	0.500
Llano uplift	410	10.59	7.69	11.22	0.593
Fort Worth syncline	420	12.31	6.85	12.58	0.536
Bend arch	425	11.81	6.41	11.83	0.504
Permian Basin	430	13.00	9.00	12.71	0.467
Palo Duro Basin	435	12.62	7.46	12.83	0.527
Los Aminas arch	450	11.56	8.15	11.34	0.477
Central Montana uplift	510	13.66	6.40	14.39	0.605
Powder River Basin	515	13.37	8.82	13.87	0.555
Big Horn Basin	520	13.97	9.06	13.91	0.490
Wind River Basin	530	13.29	10.64	13.43	0.512
Green River Basin	535	12.58	10.69	12.78	0.525
Denver Basin	540	12.53	6.30	12.77	0.535
San Juan Basin	580	12.88	9.33	13.32	0.550
Paradox Basin	585	12.06	9.77	12.27	0.530
San Joaquin Basin	745	15.48	11.30	16.63	0.591
Santa Maria Basin	750	15.66	10.54	17.03	0.622
Ventura Basin	755	14.74	9.09	14.27	0.439
Los Angeles Basin	760	16.19	9.15	17.34	0.612

Table 2: Klemme's (1984) Basin-Classification System

PETROLEUM BASIN TYPE	REGIONAL STRESS	RATIO OF VOLUME TO AREA
I. CRATON-INTERIOR BASINS	1. EXTENSIONAL	95%
II. CONTINENTAL MULTICYCLE BASINS		
A. CRATON MARGIN COMPOSITE	1. EXTENSION 2. COMPRESSION	195%
B. CRATON/ACCRETED MARGIN COMPLEX	1. EXTENSION 2. SAG	160%
C. CRUSTAL COLLISION ZONE a. Closed b. Trough c. Open	1. EXTENSION 2. COMPRESSION	a) 250% b) high c) 250%
III. CONTINENTAL RIFTED BASINS		
A. CRATON AND ACCRETED ZONE RIFT	1. EXTENSION (LOCAL WRENCH COMPRESSION)	235%
B. RIFTED CONVERGENT MARGIN OCEANIC CONSUMPTION a. Back Arc b. Transform c. Median	1. EXTENSION 2. WRENCH COMPRESSION	180%
C. RIFTED PASSIVE MARGIN-DIVERGENCE a. Parallel b. Transform	1. EXTENSION	200%
IV. DELTA BASINS - Tertiary to Recent	1. EXTENSIONAL SAG	350%
A. Synsedimentary	??	
B. Structural	??	
V. FOREARC BASINS	1. COMPRESSION AND EXTENSION	?

Table 3: Summary of Data Base

AAPG Province Designation	Number of fields	Number of reservoirs	Mean reservoir thickness (# reservoirs -form) *	Mean reservoir porosity (# reservoirs -form) *	Mean reservoir permeability (# reservoirs -form) *	Mean reservoir API gravity (# reservoirs -form) *	Mean reservoir depth (# reservoirs -form) *	Estimated ultimate reserves	% of ult. reserves in 5 largest fields
Craton Interior Shallow Provinces									
305	339	1151	39.6 (1123-ln)	11.8 (32-n)	57 (13-ln)	45.7 (634-n)	4714 (1129-n)	1.072E+09	21.5
315	972	1495	12.2 (1267-ln)	17.1 (36-n)	266 (30-ln)	35.4 (651-n)	2442 (1358-ln)	4.564E+09	42.3
335	62	108	12.2 (55-ln)	NA	NA	27.1 (24-n)	2225 (23-ln)	9.350E+07	68.7
355	1129	4784	21.7 (222-ln)	16.6 (222-n)	75 (162-ln)	38.9 (1926-n)	4980 (2874-n)	6.471E+09	36.3
365	175	226	21.0 (86-ln)	NA	NA	32.4 (37-n)	2017 (18-n)	2.612E+08	40.3
370	240	276	14.0 (225-ln)	NA	NA	36.9 (136-n)	2942 (154-ln)	7.176E+08	55.6
375	376	586	17.8 (512-ln)	NA	NA	37.2 (250-n)	4053 (391-n)	7.197E+08	40.2
380	23	40	9.6 (39-ln)	NA	NA	34.2 (29-n)	3047 (31-n)	4.585E+07	87.5
390	52	75	9.4 (54-ln)	13.7 (14-n)	NA	28.5 (46-n)	4039 (58-n)	9.091E+07	81.0
450	56	87	16.2 (56-ln)	NA	NA	35.0 (28-n)	5067 (46-ln)	4.369E+07	66.1
		AVERAGE:	*17.3*	*14.8*	-	*35.1*	*3553*		
Craton Interior Deep Provinces									
395	247	445	24.7 (334-ln)	12.0 (261-n)	20 (59-ln)	40.0 (349-n)	9524 (160-n)	1.542E+09	37.6
540	791	1416	9.3 (1052-ln)	18.0 (446-n)	307 (152-ln)	38.0 (699-n)	5878 (1076-ln)	9.081E+08	19.9
Craton Margin-Rocky Mountain Provinces									
515	360	753	20.3 (404-ln)	15.2 (310-n)	203 (132-ln)	34.4 (360-n)	7667 (434-n)	1.999E+09	29.7
520	114	339	47.0 (219-ln)	13.9 (141-n)	121 (74-ln)	30.3 (183-n)	6800 (268-n)	3.173E+09	64.7
530	84	351	44.5 (209-ln)	15.0 (123-n)	156 (56-ln)	33.1 (137-n)	7283 (223-ln)	1.892E+09	82.6
535	138	754	39.3 (450-ln)	15.4 (345-n)	196 (185-ln)	40.2 (200-n)	9192 (506-ln)	8.450E+08	59.4
580	82	246	114.6 (141-ln)	12.6 (74-n)	27 (70-ln)	45.0 (106-n)	6543 (154-ln)	2.786E+08	56.2
585	49	30	84.3 (21-ln)	NA	NA	45.0 (14-n)	5849 (26-n)	4.933E+08	94.6
		AVERAGE:	*58.3*	*14.4*	*141*	*38*	*7222*		
Craton Margin-Composite Provinces									
345	55	223	27.0 (190-ln)	12.7 (113-ln)	NA	NA	6666 (114-n)	4.305E+08	93.8
350	371	529	26.2 (75-ln)	16.7 (267-n)	256 (76-ln)	35.4 (485-n)	7935 (517-ln)	3.863E+09	65.2
360	1346	1428	16.9 (677-ln)	12.8 (309-n)	52 (82-ln)	35.4 (810-n)	9344 (1182-ln)	2.602E+09	29.6
385	1295	1576	12.0 (1439-ln)	NA	NA	35.8 (895-n)	3751 (1076-ln)	2.774E+09	36.6
400	47	78	16.7 (29-ln)	26.6 (11-n)	NA	31.3 (69-n)	3304 (72-ln)	5.269E+07	65.0
410	49	167	12.2 (67-ln)	15.2 (20-n)	282 (15-ln)	35.6 (115-ln)	3964 (164-ln)	1.099E+07	67.9
420	483	1527	18.4 (254-ln)	14.7 (360-n)	128 (158-ln)	41.7 (1234-n)	6519 (1503-ln)	6.503E+08	31.9
425	1479	4049	12.3 (1627-ln)	15.4 (817-n)	264 (442-ln)	41.3 (3341-n)	4683 (3921-ln)	2.054E+09	43.3
430	2526	7145	37.2 (4379-ln)	11.6 (1844-n)	79 (1224-ln)	39.7 (6045-n)	10960 (6659-ln)	2.805E+10	22.8
435	182	313	22.7 (77-ln)	14.7 (85-n)	185 (58-ln)	41.1 (287-n)	6270 (301-ln)	1.361E+09	86.4
510	24	59	24.6 (37-ln)	14.0 (37-n)	NA	31.1 (43-n)	5462 (32-n)	5.973E+07	55.7
		AVERAGE:	*20.6*	*15.4*	*178*	*36.8*	*5987*		
Craton Margin-Downwarp Provinces									
210	423	1327	16.7 (1255-ln)	23.7 (1047-n)	446 (453-ln)	39.0 (1019-n)	11293 (1017-n)	3.125E+09	43.5
220	2858	26803	15.9 1452-ln)	26.2 (1418-n)	926 (1160-ln)	42.2 (15406-n)	10604 (26485-ln)	2.338E+10 **	12.5
230	455	700	12.4 (491-ln)	24.1 (392-n)	810 (172-ln)	33.0 (511-ln)	6395 (333-n)	3.494E+09	29.2
260	389	1814	19.6 (20-ln)	19.75 (271-n)	435 (128-ln)	42.9 (1464-n)	10392 (1794-ln)	8.712E+09	64.2
		AVERAGE:	*16.2*	*23.5*	*654*	*39.3*	*9671*		
Convergent Margin-Transform Provinces									
745	98	297	132.9 (214-ln)	26.4 (81-n)	1260 (64-ln)	27.9 (278-n)	8628 (67-n)	9.321E+09	52.1
750	28	67	381.0 (35-ln)	25.8 (24-n)	NA	23.6 (53-n)	8433 (29-ln)	1.620E+09	65.2
755	42	109	437.5 (73-ln)	24.1 (63-n)	229 (18-ln)	27.2 (101-n)	8532 (38-ln)	1.935E+09	86.9
760	67	282	260.9 (113-ln)	28.1 (181-n)	725 (77-ln)	24.6 (272-n)	7909 (73-n)	9.815E+09	69.2
		AVERAGE:	*303.1*	*26.1*	*738*	*25.8*	*8376*		

* : (# of reservoirs, form) refers to the number of reservoirs or fields (if only field data given) that contain data for this variable. The form refers to the shape of the distribution of the available data, ln for log normal, n for normal. If a distribution is log normal, a lognormal mean was used for the parameter.

** after Houghton, 1986

Table 4: Classification Based on Tectonic Setting and Hydrocarbon-Occurrence Data

Province Name	AAPG Designation	Initial Tectonic Setting (after Klemme, 1984)
TYPE I BASINS : CRATON INTERIOR SHALLOW		
Michigan Basin	305	craton interior
Illinois Basin	315	craton interior
Forest City Basin	335	craton interior
Chautauqua platform	355	craton margin composite
Cherokee Basin	365	craton margin composite
Nemaha anticline	370	craton margin composite
Sedgwick Basin	375	craton margin composite
Salina Basin	380	craton interior
Chadron arch	390	craton margin composite
Los Aminas arch	450	craton margin composite
TYPE II BASINS: CRATON INTERIOR DEEP		
Williston Basin	395	craton interior
Denver Basin	540	craton interior
TYPE III BASINS: CRATON MARGIN ROCKY MOUNTAIN		
Powder River Basin	515	craton margin composite
Big Horn Basin	520	craton margin composite
Wind River Basin	530	craton margin composite
Green River Basin	535	craton margin composite
San Juan Basin	580	craton margin composite
Paradox Basin	585	craton margin composite
TYPE IV BASINS: CRATON MARGIN, TYPES A and B		
TYPE IV-A: COMPOSITE		
Arkhoma Basin	345	craton margin composite
S. Oklahoma fold belt	350	craton margin composite
Anadarko Basin	360	craton margin composite
Central Kansas uplift	385	craton margin composite
Ouachita tectonic belt	400	craton margin composite
Llano uplift	410	craton margin composite
Fort Worth syncline	420	craton margin composite
Bend arch	425	craton margin composite
Permian Basin	430	craton margin composite
Palo Duro Basin	435	craton margin composite
Central Montana uplift	510	craton margin composite
TYPE IV-B: DOWNWARP		
Mid Gulf Coast Basin	210	continental collision open
Gulf Coast Basin	220	continental collision open
Arkla Basin	230	continental collision open
East Texas Basin	260	continental collision open
TYPE V BAISNS: CONVERGENT MARGIN TRANSFORM		
San Joaquin Basin	745	convergent margin transform
Santa Maria Basin	750	convergent margin transform
Ventura Basin	755	convergent margin transform
Los Angeles Basin	760	convergent margin transform

Table 5: Comparison of Parameter Means and Rank Means Between Basin Types

PARAMETER (K-W statistic)**	BASIN TYPE *	PARAMETER MEAN	MEAN OF RANKED VALUE
EXPECTED VALUE (K-W=14.18)	C.I.S.	12.3	13.1
	C.I.D.	13.3	24.5
	C.M. R.M.	13.0	22.3
	C.M.	12.5	16.5
	T.	15.5	35.5
DISPERSION (K-W=19.34)	C.I.S.	8.0	14.9
	C.I.D.	6.3	2.5
	C.M. R.M.	9.7	30.5
	C.M.	8.0	16.0
	T.	10.0	31.5
MODE (K-W=15.29)	C.I.S.	12.4	13.7
	C.I.D.	13.3	25.5
	C.M. R.M.	13.3	24.2
	C.M.	12.5	15.3
	T.	16.3	35.2
SKEWNESS (K-W=3.58)	C.I.S.	0.509	17.8
	C.I.D.	0.509	19.5
	C.M. R.M.	0.527	21.9
	C.M.	0.508	16.5
	T.	0.566	27.0

* **Basin classes:** C.I.S. = craton interior shallow, C.I.D.=craton interior deep, C.M. R.M.=craton margin rocky mountain, C.M.=craton margin, T.=convergent margin transform

** **Kruskal-Wallis test:** H_0 = all samples are taken from populations with similar means. Rejected if Kruskal-Wallis statistic is greater than a chi-squared distribution with N-1 degrees of freedom.
Chi-squared distribution with 4 degrees of freedom: 9.488

Table 6: Richness of Petroleum Provinces

AAPG Petroleum Province Name	AAPG Petroleum Prov. Desig.	Richness (Thous. of Barrels of Oil per sq. mi)	Oil Field Density (Oil Fields per 1000 sq. mi)
TYPE I BASINS : CRATON INTERIOR SHALLOW			
Michigan Basin	305	21.49	6.79
Illinois Basin	315	67.23	14.32
Forest City Basin	335	2.77	1.84
Chautauqua platform	355	300.77	52.48
Cherokee Basin	365	25.86	17.33
Nemaha anticline	370	85.84	28.71
Sedgwick Basin	375	90.44	47.25
Salina Basin	380	1.00	0.50
Chadron arch	390	2.65	1.52
Los Aminas arch	450	4.09	5.24
TYPE II BASINS: CRATON INTERIOR DEEP			
Williston Basin	395	9.65	1.55
Denver Basin	540	17.23	15.00
TYPE III BASINS: CRATON MARGIN ROCKY MOUNTAIN			
Powder River Basin	515	53.40	9.62
Big Horn Basin	520	206.56	7.42
Wind River Basin	530	129.96	5.77
Green River Basin	535	20.40	3.33
San Juan Basin	580	9.46	2.79
Paradox Basin	585	16.01	1.59
TYPE IV BASINS: CRATON MARGIN, TYPES A and B			
TYPE IV-A: COMPOSITE			
Arkhoma Basin	345	19.40	2.48
S. Oklahoma fold belt	350	379.65	36.46
Anadarko Basin	360	45.31	23.44
Central Kansas uplift	385	201.04	93.86
Ouachita tectonic belt	400	1.64	1.46
Llano uplift	410	0.99	4.42
Fort Worth syncline	420	120.14	89.23
Bend arch	425	128.85	92.79
Permian Basin	430	295.48	26.61
Palo Duro Basin	435	31.70	4.24
Central Montana uplift	510	3.42	1.38
TYPE IV-B: DOWNWARP			
Mid Gulf Coast Basin	210	51.09	6.92
Gulf Coast Basin	220	246.13	30.09
Arkla Basin	230	132.00	17.19
East Texas Basin	260	0.33	14.91
TYPE V BAISNS: CONVERGENT MARGIN TRANSFORM			
San Joaquin Basin	745	324.69	3.41
Santa Maria Basin	750	642.29	11.10
Ventura Basin	755	951.52	20.65
Los Angeles Basin	760	2101.18	14.34

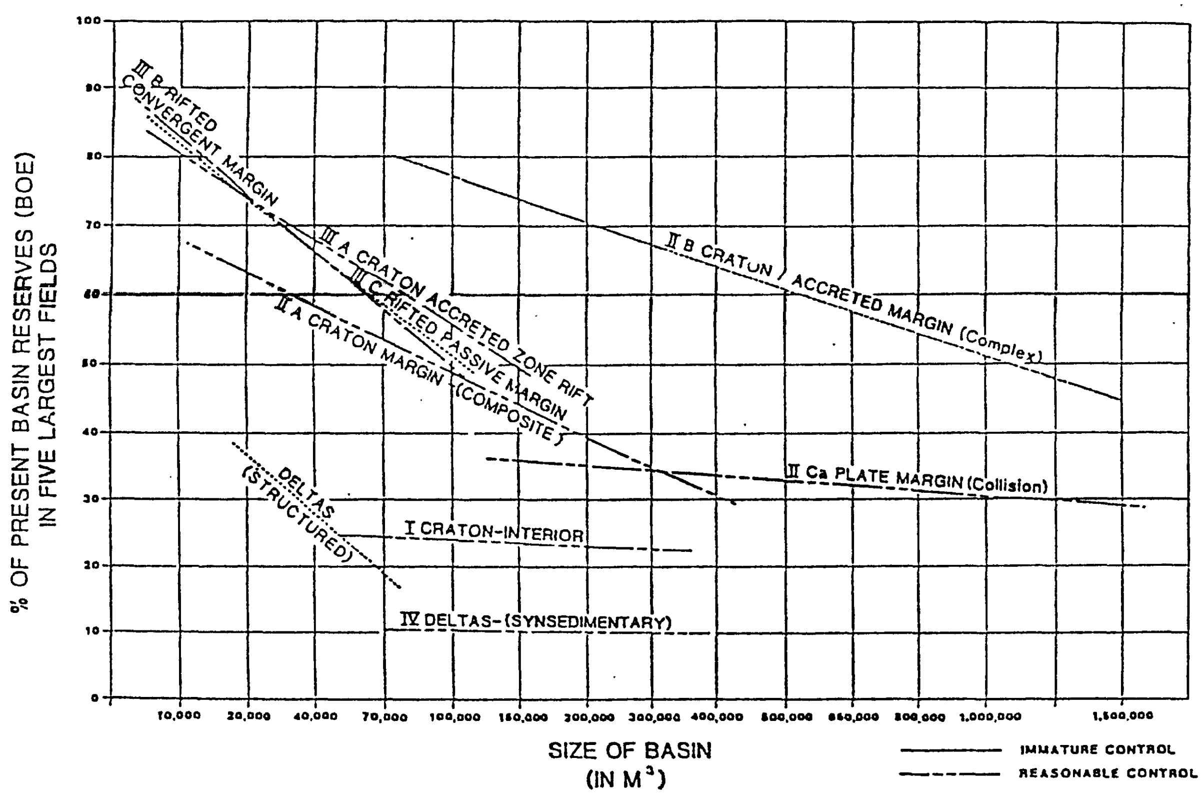


Figure 1 : Percentage of a basin's reserves in the five largest oil fields, by basin size and tectonic setting (Klemme, 1984).

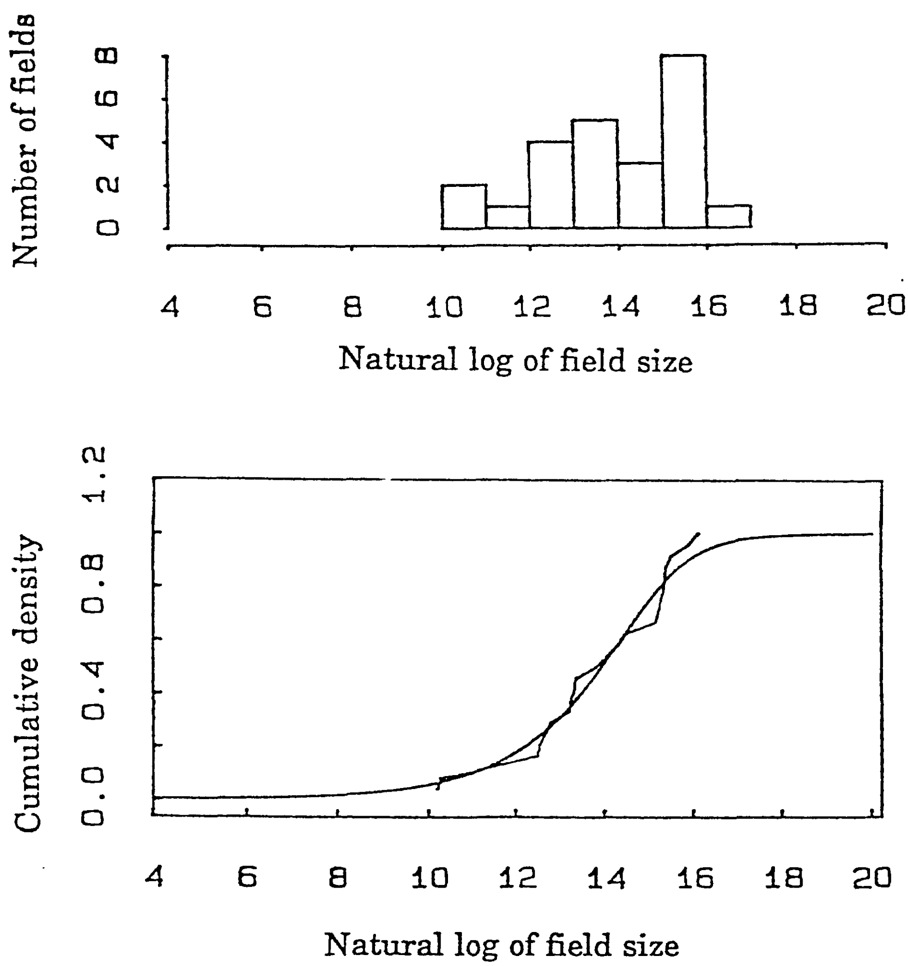


Figure 2: Richards function as a model of oil-field-size distribution in the central Montana uplift. Top: histogram of field sizes; bottom: actual cumulative field-size density versus Richards function. Here, there are only 24 fields in the basin, yet the Richards function describes the distribution fairly well.

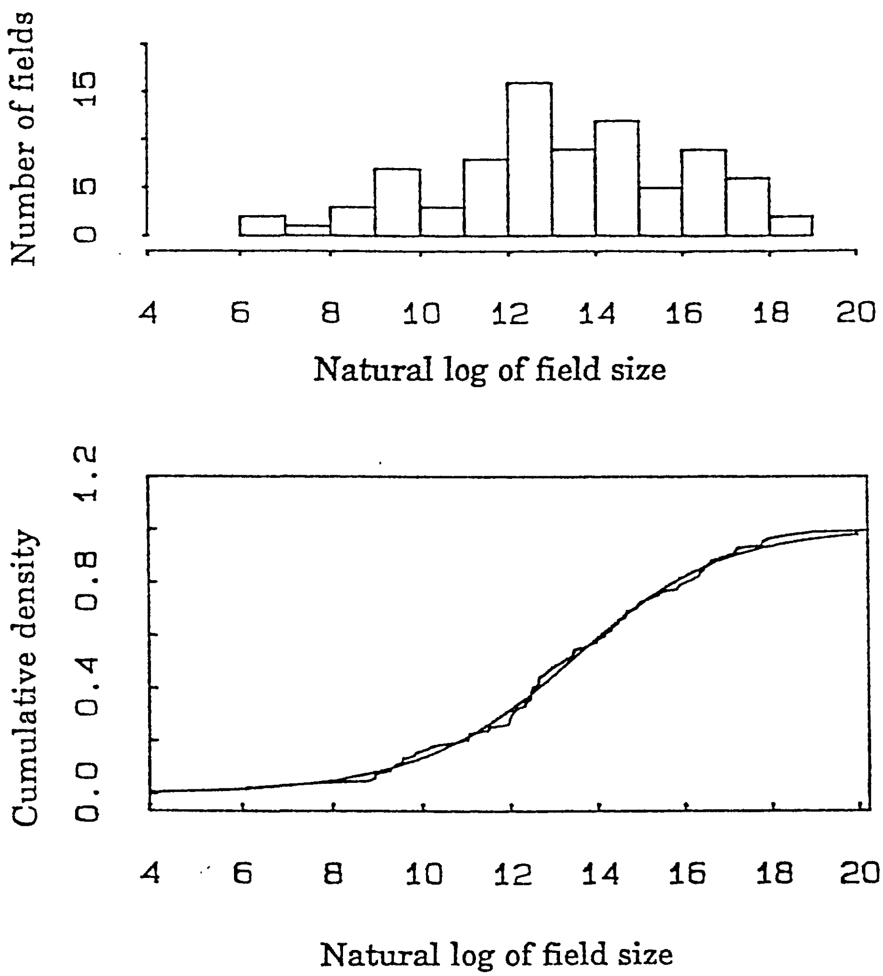


Figure 3: Richards function as a model of oil-field-size distribution in the Wind River Basin. Top: histogram of field sizes; bottom: actual cumulative field-size density versus Richards function. Here, the Richards function is used to model a distribution with a large variance.

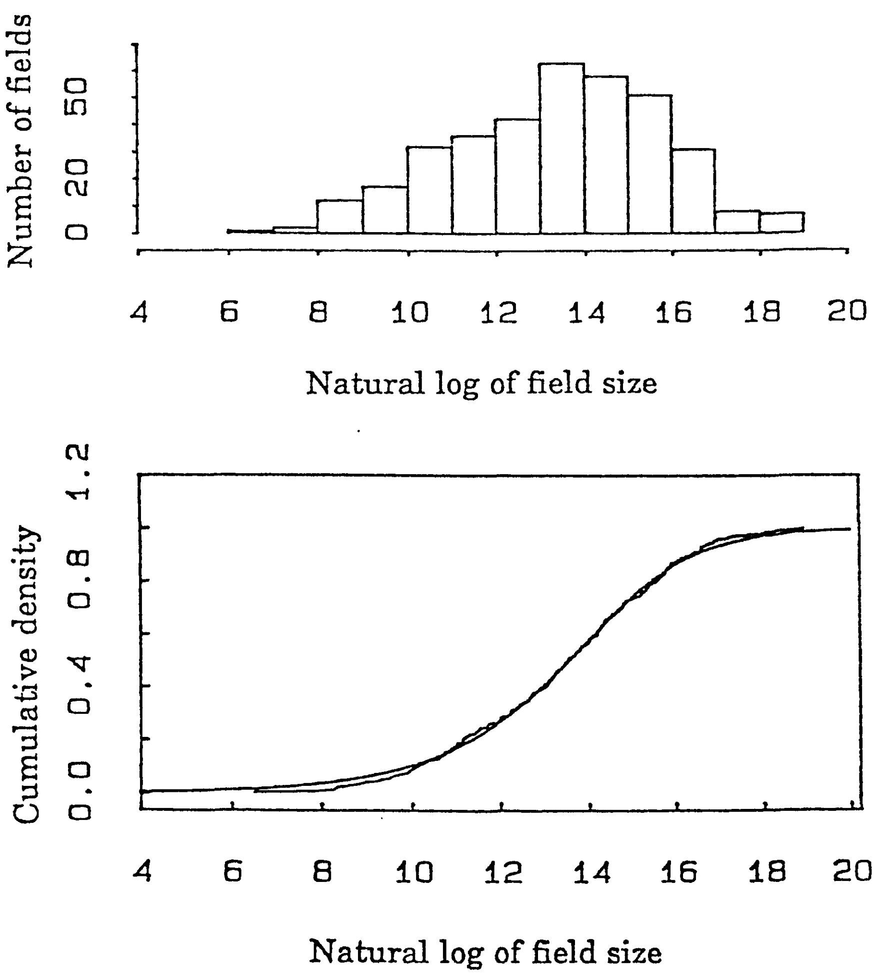


Figure 4: Richards Function as a model of oil-field-size distribution in the Powder River Basin. Top: histogram of field sizes; bottom: actual cumulative field-size density versus Richards function. Here, the Richards function is used to model a skewed distribution.

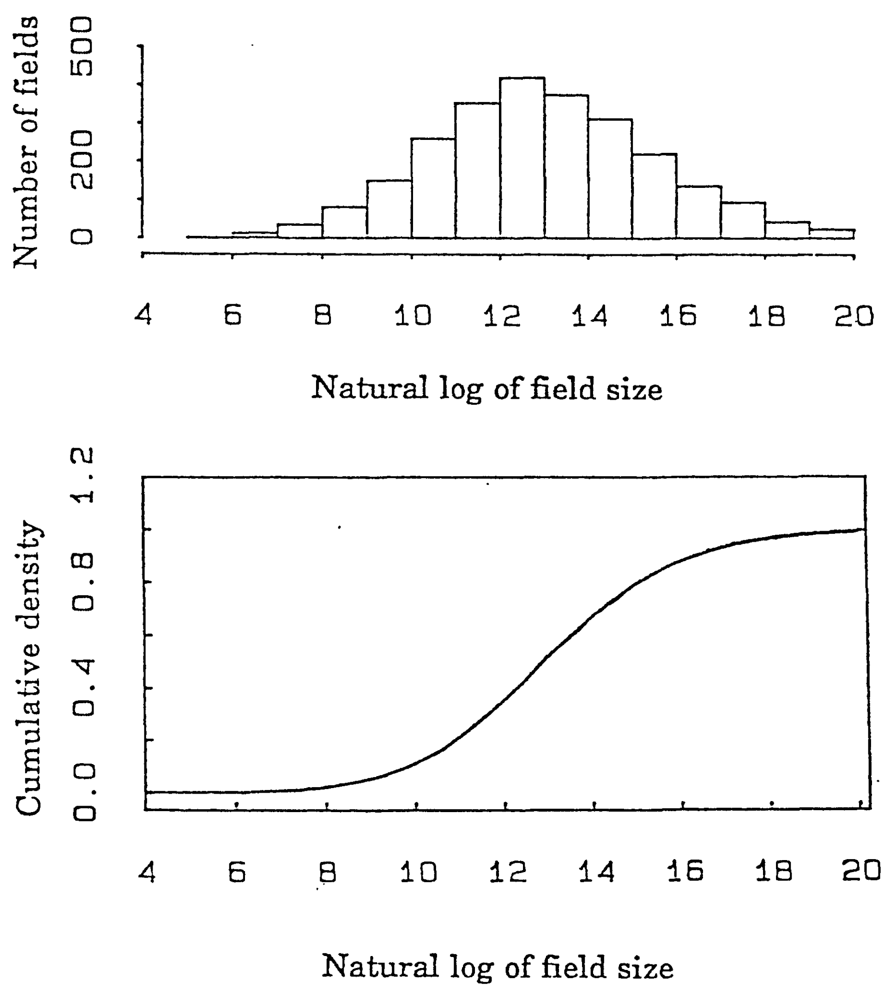
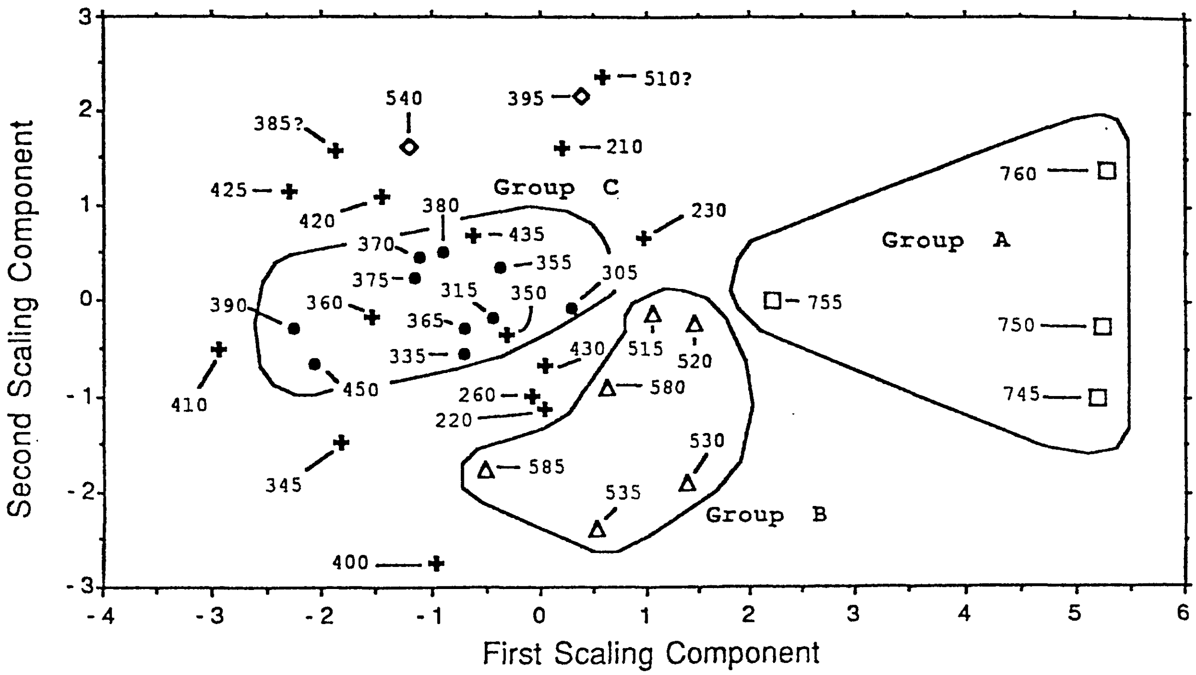


Figure 5: Richards function as a model of oil-field-size distribution in the Permian Basin. Top: histogram of field sizes; bottom: actual cumulative field size density versus Richards function. Here the Richards function is used to model a symmetrical distribution.



Note: Each number refers to an AAPG Petroleum Province designation - see table 1.

EXPLANATION

●	1. Craton-interior shallow basins (GROUP C)
◇	2. Craton-interior deep basins
Δ	3. Craton-margin Rocky Mountain basins (GROUP B)
+	4. Craton-margin basins a. Composite b. Downwarp
□	5. Convergent-margin transform basins (GROUP A)

Figure 6: Classical multidimensional scaling applied to the parameterization of oil-field sizes in American Association of Petroleum Geologists petroleum provinces.