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Development of an Exploration Strategy

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ABSTRACT:

Explicit screening of economic, geological and production constraints and development of exploration strategy can improve management of exploration costs and enhance exploration success rates within an overall budgetary constraint. One example of exploration planning sets corporate budget, reserve addition objectives and other constraints and asks the question, "where can we explore in the lower '48' onshore to meet these constraints and still meet financial objectives?" The question is answered by examination of economic, geologic and production factors in the various geologic provinces. Resulting quantitative and qualitative data are tabulated and ranked in a decision matrix.

Analysis of factors suggest that for a budget of five million dollars per year for ten years, objectives of twenty-five million barrels reserves additions in five years,with exposure to at least one fifty million barrel field opportunity in ten years, the Rocky Mountains province ranks number one; the Southeast and Permian Basin follow closely.

INTRODUCTION:

Exploration in the United States is at the lowest levels recorded for many years. Survival of exploration programs and companies depends on management of limited resources and greater success in the exploration program. One method that can yield better use of company resources is development of a well-defined strategy for exploration. Adherence to a well-designed strategy coupled with vigorous, effective scientific efforts can provide economic success even in today's perilous petroleum markets.

Major companies may have sufficient staff and resources to permit complete scientific evaluation of potential exploration areas, including source rock analysis and estimation of petroleum generation quantities, sophisticated statistical analysis of past plays and statistic-based forecasting, and detailed basin analysis. Smaller companies and independent explorationists do not have this advantage. This paper is focused toward providing the small company and the independent explorer with a method of strategy planning that does not require large expense or extended time for preparation. In addition, even in larger company settings, there is often need for a determination of effectiveness of existing strategy compared to alternatives without time available for a research staff to conduct a full study.

Strategy development requires consideration of several elements including: financial setting of the company, philosophy and characteristics of management, ability to risk capital and most important, a clear set of goals and communication of those goals to exploration personnel. Lack of stated goals and budgetary limitations can hamper realization of the best return on investments by permitting the diffusion of resources into uneconomic ventures. Proper assessment of corporate strategy coupled with analysis of petroleum potential of the geographic areas of interest can assist the geologist-manager in assigning exploration priorities; detailed basin analysis and play analysis can sharply focus the exploration program so that all company strategy elements can be accommodated and greater-than-average success can be achieved.

The method of strategy development presented here is based on knowledge of a corporation's financial parameters and geographic bias. The strategy developed demonstrates the process used to prepare an exploration plan that encompasses the corporate strategy and evaluates the resource potential within areas of interest. Since this paper is drawn from a specific study it necessarily is confined to the economic parameters and data base from which that study was prepared.

STRATEGY ELEMENTS

An exploration strategy or policy is a composite of corporate goals and limitations, whether stated or unstated. Factors most frequently considered in development of a strategy include financial exposure, target rate of return on investment,target size definition, risk tolerance, reserves additions goal, geographic bias and political and tax structure considerations.

Financial limitations: What are the limits for expenditures? What is the annual budget and how much is available for specific projects? It makes little sense to push strongly for a 2.5 million dollar seismic program when the entire exploration budget is only 5 million dollars. The budget level already indicates that the project scale is too large. What would be the result of a failure of the project proposed? Would the company be in serious financial condition? Examination of the company's long term debt, equity, earnings, level of commonly funded operations and other similar data will assist in determining what the financial limitations of the company are. The actual limitations may vary from stated limitations.

Rate of return on investments: Most exploration companies have a predetermined rate of return required on all new ventures. For many that rate is about 3 to 4:1 undiscounted (before federal income tax), or 30-40% discounted (BFIT) for domestic U.S. projects. Study should be able to establish that the new venture is at or above the guidelines used, or if not, that the successful venture will make industry-standard profits. Although some may view these projected returns as being unrealistically high,they are numbers in use,satisfaction with smaller returns notwithstanding.

Target size: Financial limits will in part determine what target size a company is seeking, but philosophic values are sometimes important considerations. The relative size of target seems to be a reflection of the size of the company; that is, very large companies tend to look for very large targets, smaller companies for smaller targets. However, rate of return on investment may overshadow target specifications when searching for large targets in expensive areas. For instance, searching for very large targets in foreign countries where major finds are probable may be more economic than searching for the same targets in highly taxed domestic settings.

If the company is searching for 1 MMBOE (million barrels oil equivalent) targets, it is less likely to find 25-50 MMBOE fields than if it were looking for 100 MMBOE targets. The expected size distribution of discoveries is related to the size of the target sought; generally, a field size distribution heavily skewed towards small reserve discoveries is the result of any targeted exploration program . That is, there will be relatively fewer discoveries that are larger than the target, but there will be a large number of discoveries that are smaller, ranging down to the lowest economic return acceptable to the exploration company. As a colleague in the industry once stated, "When looking for elephants, sometimes you find mice. When looking for mice, all you find are mice".

However, if a company can not finance "elephant" hunts, it can concentrate on smaller targets and still meet its rate of return.

It is possible to address target rates of daily production without setting a target size for field discoveries, but that approach limits up-side potential of a strategy. Although large-size targets are statistically limited in the "Lower 48" states, targets larger than 1-10 MMBOE do exist and can be sought if that is part of the corporate strategy.

Risk factor: The inherent risk in drilling exploratory wells is a factor in any exploration strategy. As one factor in determining where to explore, the risk of drilling dry holes must be evaluated. Drilling statistics already show that many more dry holes will be drilled than new pool discoveries. For every dry hole, some reserves are expended(that is, costs of dry holes must be paid by production of other reserves). How many dry holes can be attributed to a successful effort? If it takes a risk of three dry holes to find one producing well, can the company make its rate of return when three dry hole costs are assessed against the producer? Will the company have enough financial stamina to drill through the requisite statistical dry holes until it has commercial success? By nature exploration geologists think that their prospects will beat the odds and be successful the first time out. Unfortunately, the statistics against this are overwhelming.

Risk is a particularly onerous element of strategy, since the term has significant variability in meaning between individuals and companies. For instance, an oil company, a wholly-owned subsidiary of a chemical holding company, was requested to develop a source of natural gas for one of the company's other operations. After doing the necessary work to establish an exploration and development program and being assured that the associated chemical company understood the meaning of "risk", a series of presentations was held at various levels, including drilling success rates and reserves acquisition costs estimates. All presentations were favorably received until the presentation arrived at the holding company's corporate headquarters. The night before the final presentation, requesting a fiscal commitment of some $30,000,000, one of the corporate executives asked, over dinner, "Is there any possibility that our investment of $30,000,000 could produce an insufficient supply of gas, or even no gas?"

"Yes," was the response from the oil people, "We told you the risks."

There was stunned silence from the chemical company side of the table. Needless to say, the next day's presentation was not productive. The two companies had totally different definitions of the term "risk".

Clearly, proper definition of the all the elements of corporate fiscal policy is necessary.

Other elements: Many other elements can be considered in development of an exploration strategy. Some of these include bias for or against a particular geographic area, be it an individual basin, a state, a country or geologic province. Does the company have the budget to use the necessary exploration tools, such as extensive reflection seismic, or must it operate where these tools are not necessary? In the areas of interest, does the company have the ability to acquire land, either through leasing, concessions, or deals? What are the regulatory and tax climates of proposed exploratory areas? All of these elements and others must be considered in developing an effective exploration strategy.

THE UNDERLYING QUESTION

For this study, some exploration strategy elements were defined at the outset with other elements becoming obvious during conduct of the study. The question asked was, "Where would an oil and gas exploration program be established if the following parameters were used?"

Parameter 1: Onshore lower "48" United States location.

Parameter 2: Initial capital investment of $5MM per year for five years.

Parameter 3: Discovery of 25 MMBOE (in one or more fields) in the first five years (because of reinvestment of cash generated a $5 per barrel finding cost can not be assumed).

Parameter 4: The program should have exposure to at least one 50 MMBOE field in ten years of operations.

In addition, it was also determined from other information that the project must reflect a low risk tolerance, being engaged in a business where major expenditures occurred only after a detailed assessment of return could be made. Other factors were brought forward so that a list of desirable criteria of the selected exploration area was developed, as follows.

EXPLORATION AREA CRITERIA

Criteria for selection of areas of exploration have been summarized in three categories: Geologic Factors, Production Factors and Economic Factors.

Geologic Factors:

1. Exploration areas will be ranked in the top three regions of the forty-eight states which are believed to have the highest undiscovered petroleum potential.

2. Sedimentary rocks will be present in sufficient unexplored volume and diversity so as to permit large potential field sizes to be discovered (50 MMBOE).

3. Structural and sedimentologic style of exploration areas will be conducive to forming traps of sufficient size to permit discovery of large (50 MMBOE) accumulations of hydrocarbons.

4. There will be demonstrated source rocks and thermal maturity supported by either theoretical calculations on a real data base or actual production history.

5. There will be demonstrated potential for multiple pay targets.

6. Selected areas will contain large areas of unexplored or poorly explored land, sufficiently available for leasing to sustain a long-term exploration program.

7. Historical drilling success ratios will meet both field size and budgetary objectives.

Geological criteria are largely self-explanatory in that they provide for the geologic setting in which the 50 MMBOE ultimate discovery can be located. It is difficult to extrapolate a major-size discovery in areas of previous dense drilling or where geologic settings make such accumulations unlikely. Sufficient unexplored volume of sedimentary rock must exist to sustain such a program. No value judgment has been made as to whether the unexplored volume of rock is to be deeper targets in shallowly drilled basins or whether the area should be in a largely undrilled setting. Source-rock potential and generation must be proven before recommending an area; without this information the risk factor increases beyond tolerance.

Production Factors:

1. Historical field size distribution (reserves) will meet or exceed exploration program objectives.

2. Production decline curves of typical reservoirs will support requirements for reasonable individual well payout periods, preferably no more than two years. In other words, reservoirs must demonstrate acceptable deliverability.

3. Class A (50 MMBOE or greater) fields must be demonstrated to be possible; Class B fields (25-50 MMBOE) should be probably present. Fields of greater than 100 MMBOE should be within the realm of possibility.

4. Small scale production at relatively low risk and low finding cost should be demonstrably easy to find, so as to provide the program with a positive cash flow (to pay overhead) early in the program.

5. Reserves per well by depth must meet management requirements for both profitability and risk.

6. Regulatory climate must be supportive of exploration, development and production.

These production factors provide for an early success of the exploratory program. There is a high probability of immediate return on investment although it might be small reserves and small-scale production. This ploy tries to ensure that a company with a relatively low tolerance for risk can see early fiscal success, leading to bigger risk-taking. Also, it is important to ensure that payouts of successful efforts must begin soon enough to provide increasing cash flows to the expanding program. The requirements for field size distributions are quite specific since one of the goals of the company is to discover a 50 MMBOE field.

Economic Factors:

1. There must be a market for the produced commodities. Pipelines for gas and a transportation system for oil should already be in place within the region selected, although not at the exploration sites.

2. Exploration areas must have high accessibility. Neither overlying production nor stringent physical access rules should have significant effect on the exploration, development or production program costs.

3. Oil and gas leases must be available at reasonable cost with reference to potential reserves and risk.

4. Reservoirs should support two-year payout or better of individual well costs.

5. Potential income should meet an internal minimum 3:1 undiscounted BFIT return on investment.

6. Finding costs should meet an estimated standard of less than $10 per barrel; $7 should be the target and measurement of performance. Production costs should be less than $4 per barrel (These numbers will change with the industry economy and price of oil).

7. Oil is the major commodity sought. Gas is not to be a primary resource.

8. Experienced partners should be available; the exploration program must be able to be share risks and be part of joint ventures.

9. Regional tax structure must be stable and fair.

Economic constraints clearly reflect the reluctance to plunge full-scale into risky operations and also recognition that many exploration ideas may be too expensive for the financial limitations imposed upon the program. A $5 MM annual budget does not permit 100% participation in deep wells or technically difficult wells, such as some of the Tuscaloosa trend and Overthrust wells. Certainly, this budget will not permit major participation in remote area deep wells nor where litigation from disinterested parties delays drilling. Environmental restrictions unfairly applied or being extremely stringent may rule out areas of otherwise good potential simply because of the increased costs and time involved. Similarly, a history of fair taxation and a supportive regulatory climate are favorable. At this writing, it is clearly a favorable criterion to have access to fee leases rather than federal leases because of the uncertain federal regulatory position, land accessibility questions, evaluations on Known Geologic Structures and similar factors. On the other hand, if the fee leases are split into minute tracts, the requisite detailed leasing and title work necessary for them may outweigh even the federal paperwork and delays.

The company set the minimum rate of return it expects, targeted some tough cost-of-finding criteria and specified that it is looking for an "oily" province rather than gas. The need for a transportation system is important since it removes many remote areas of high potential, but the costs of building the transportation infrastructure can be exorbitant for a small company with a limited budget. At best, the large-size of reserves necessary to consider a discovery to be profitable increases.

This listing of factors is not exhaustive but does cover the essential pieces of information necessary for a company to formulate its decision about an exploration program. A next step is to examine the lower forty-eight United States to determine what areas, if any, best fit the defined elements of exploration strategy that now confine our search for petroleum.

DATA BASE

Estimates of petroleum potential, exploration probabilities and future economic success are based upon integration of broad geologic studies and experience and a relatively small body of literature. Many of the interpretations and analyses cannot be attributed to any single or even several references.

Among the most important data sources are Nehring (1981) whose compilation of information about the 2300 largest fields in the United States has been used extensively. Dolton et al (1981) provided significant information in their estimates of undiscovered petroleum resources. The papers by Haun (1981), Bois and Pelet (1982) and Bishop et al (1983) were very useful in developing the rationale for interpretations. Klemme (1975), and Kingston et al (1983) have done pioneering work in the synthesis of global potential petroleum resource occurrence in a geologic framework.

The publications of the Potential Gas Agency, American Petroleum Institute, American Association of Petroleum Geologists, Department of Energy, Petroleum Information, Independent Petroleum Association of America, Arthur Anderson, Inc. and Degolyer-Macnaughton have all provided essential data which have been interwoven into the illustrations and text of this paper. They are cited at the end of the text; individual papers or publications are cited where they form the major basis for interpretations or can be specifically identified with statements or illustrations.

ECONOMIC AND SCIENTIFIC CLIMATE

Economic rationale for entering or increasing hydrocarbon exploration activity must be based upon a balance of costs, risks and price. From 1975 to 1982 the price of oil continued to increase, but began to drop in 1983. The price collapsed early in 1986, but now seems to have stabilized or slightly increased at this writing. We regard the price to be unstable, and an original forecast of stable and rising price has not occurred (fig.2). However, drilling costs which had steeply climbed from 1978 through 1981 have also declined, even more sharply than the price of oil and now approximate pre-1978 prices, whereas the price of oil in 1986 through the present is approximately its value in 1978. Cost per barrel of additions to reserves (Anderson, 1985) is a difficult number to evaluate, since the variations are large. The five year (1980-1984) weighted average cost per net barrel of domestic additions reported is $12.57; the lowest cost reported by a major was Shell Oil at $8.47, the lowest by an independent was $1.32 (Chaparral Resources). Shell had over 2.25 billion barrels proved reserves, Chaparral had only

896,000 barrels. It is intuitively obvious from the base data of increasing costs that the smaller company had a good discovery in 1984 ($0.12 per barrel) but had costs of $13.98 in 1982, with no significant discoveries. Shell's cost was erratic, but reflected market cost ($5.39 - 1980, $11.93 - 1981, $8.69 - 1982, $9.88 - 1983, $8.67 - 1984).

Conversely, Texaco was the high major at $18.99, reflecting a $33.49 cost in 1984 and $37.73 in 1983 (after revisions, Texaco's 1984 cost was $81.73 per barrel!). There were fifteen independents with more than a $30 per barrel weighted average, with the high being United Canso Oil and Gas at $88.62 (Canadian dollars). Overall, majors had a $12.57 average and independents averaged $11.08 (utilities and diversified companies not included)(data from Anderson, 1985). Clearly, a small company's reserves addition costs can be dramatically impacted by a single discovery or development whereas a major's costs are evened out by the large numbers of opportunities which are drilled.

Within the time period selected, 1980-1984, the cost of finding a net barrel of oil averaged $12.47. The cost increased during that time from $10.40 (1980) to $15.89 (1982), and declined to $9.56 (1984). Many companies found that starting in 1982 finding costs declined from previous years; we can extrapolate from these figures that finding costs will continue to decrease.

With these figures, the economics of domestic investment become somewhat clearer. Drilling costs (fig. 1) rose from about $57 per foot, domestic onshore, 1978, to $87 per foot in 1981 but then started a decline to about $83 in 1983 and are about $60 per foot for 1984, the latest data available for this study (data from I.P.A.A.). The costs-of-additions curve compared to the drilling costs and price demonstrates decreased financial risk in the industry. Therefore, if the risks are acceptable, the extrapolated opportunity to find oil at a profit would have been better in 1987 than in the preceding five years. The gap between price received and costs of finding, using drilling costs as curve-prediction control, presented a window of financial opportunity in 1987.

Much of the potential success of a company in using the window of economic opportunity suggested above is the ability to sustain finding costs below industry averages. Several approaches may be useful in accomplishing that goal.

In historical perspective, the vast majority of significant domestic United States onshore fields have been discovered in structural traps and in detrital (clastic) reservoir rocks (fig. 2). Combination and stratigraphic traps and production from carbonate rocks appear to be less important to the exploration effort than the preceding duality of lithology and trap style. This is an artifact of statistics which illustrates the quandary of the modern explorationist: the easiest petroleum to discover is located in large anticlines, with concurrent surface expression, in sandstones which have regional "blanket" permeability. Consequently, these pools are discovered early and bias the statistics of occurrence. The statistics really indicate the importance of carbonate reservoirs and combination/stratigraphic trapping to the modern explorationist who must find the more difficult to locate pools. As Moody and Emmerich (1972) stated, carbonate reservoirs only account for about 33% of the world's large fields, but account for nearly 50% of total world reserves (biased by Middle East traps).

Similarly, a comparison of reservoir rock age and cumulative production by geologic province (figs. 3,4) indicates the relative importance of Paleozoic rocks in the United States. The tectonic history of each province determines the age of the rocks that are present, although a relationship between younger age and greater cumulative production is apparent. cumulative production figures indicate the relative development maturity of the geologic province and help lead to a decision as to whether the province has the potential for undiscovered large fields.

In summary, use of historical occurrences of petroleum in decision-making for future exploration must be made with care; lithology, trap style and reservoir age of the past are not good indicators of the future in non-frontier areas; rather, they may suggest exactly opposite conclusions. Nonetheless, detrital reservoirs continue to be significant to world exploration. Explorationists of today have technology to discover petroleum in carbonate rocks in combination traps that was not available to past generations of explorationists. Simple structural traps have already been exploited and stratigraphic traps are still difficult to predict with today's geological and geophysical technology.

Business plan constraints on exploration strategy in this case include geographic restriction to the lower "48" contiguous United States, onshore. Within this geographic area several tectonic styles of petroleum accumulation are present, breaking the United States into relatively simple "petroleum provinces" (fig. 3). Province boundaries are in part based upon geologic structure and tectonic style, but also upon statistical reporting areas, such as the various railroad districts of Texas. It was necessary to include non-producing but potential areas in the study; therefore some are attached to otherwise cohesive regions, i. e., Iowa and Minnesota are included in the Midcontinent region.

Finally, consideration of the targets and the data base of Nehring (1981) require that fields be categorized by size (table 1). Various data are portrayed on the basis of "large" or "significant" oil fields, greater than 10 million barrels oil equivalent, and

"Class A" or larger fields, greater than 50 million barrels. Our targets include exposure to Class A fields and the discovery of reserves equal to one significant field in five years.

UNITED STATES PETROLEUM STATUS

Klemme (1975) outlined a classification of petroleum provinces based upon tectonic or sedimentologic styles which the writers have adopted. Although this scheme is neither unique nor perfect, it permits the characterization of the geographic area of interest and comparison with other producing areas (fig.5). The relationships of tectonic setting, percentage of total U.S. reserves and percentage of the petroleum that occurs in large fields (greater than 10 million barrels) clearly indicates that craton-margin basins have great significance (39% of reserves) to the national oil supply, whereas craton-interior basins appear less significant (2.5% of reserves). Downwarps, deltas and subduction-related "basins" are intermediate in importance, in descending order. The occurrence of large fields in subduction zones (92.6% of all petroleum in this tectonic setting) is also noteworthy (Klemme, 1975).

Within the United States there is disparity between production levels of regions. Reporting of production is largely by state rather than by geologic basin and that convention is followed here (table 2). Texas production has historically led the nation and continues to lead at over 2.5 million barrels of oil equivalent per day; the rapid falloff in daily production below Texas (Alaska , 1.6 million; California, 1.05 million; Gulf of Mexico, 789 thousand; and Louisiana, 458 thousand barrels per day) illustrates the tenuous position of the United States as a petroleum consumer of over sixteen million barrels per day. The number one producing state, Texas, produces at the rate of about twelve barrels of oil per day (12 BOPD per well). A high percentage of the approximately 209,000 wells in Texas are reaching economic limits, are already stripper wells and will be candidates for plugging in this poor oil economy. Of the top-ten oil-producing states, five produce less than 25 barrels per well per day. Together these five (Texas, California, Oklahoma, New Mexico and Kansas) account for about 4.3 million barrels a day, which is over 25% of the United States daily consumption. Replacement of that production would entail a 50% increase in imported crude (data from I.P.A.A., 1986).

Examination of the same statistics shows the lack of importance to the national oil supply of production from the bottom ten producing states of the top twenty-five: together they produce an average of 335,000 BOPD, enough to run one large refinery. All but two of those ten states produce at average stripper rates (10 or less BOPD) (table 3).

This compilation illustrates the status of United States oil production and its vulnerability to fluctuations in both price and availability of risk capital. Increases in production have only come with increases in drilling; increases in drilling come with price incentives and the availability of risk capital.

Finally, an analysis of the volume of drilling necessary to discover oil in the United States further defines the problems and challenges facing today's explorationist. From 1969 to 1979 the number of exploratory wells drilled to make an economic discovery actually declined (probably due as much to economic factors as to technological success). The United States needs discovery of 1.5 significant fields every day (defined as having reserves of at least 10 mmboe) just to replace consumption. These fields are not discovered easily. Current data suggest that only one well of each thousand exploratory wells drilled results in the discovery of a significant field, a rise from 1:190 in 1965 (fig. 6). Further, the finding rate for large fields (>50 mmboe) has dropped from 1:750 to a disturbing 1:10,000. As pointed out by Haun (1981), the United States is no longer in control of its energy supplies and probably will never be able to significantly reduce its present dependence upon foreign petroleum. The explorationist's job is to maintain current levels of production, if possible, and to discover enough petroleum on foreign lands so as to maintain sufficient petroleum import supplies. Developing an exploration strategy to increase the odds of success in domestic drilling and to locate targets of the appropriate size can assist those goals.

LOWER "FORTY-EIGHT" CHARACTERISTICS

Subdivision of the contiguous forty-eight United States into petroleum provinces (fig. 3) permits the generalization of regional characteristics and evaluation of future petroleum potential. Numerous parameters can be examined to compare these provinces and then rank them in terms of favorable conditions for meeting corporate objectives. Not all parameters are useful in terms of projecting petroleum potential, but are included as part of the evaluation process and for completeness of characterization.

Reserve Target Factors

One measure of the petroleum potential of any region is the extent of previous exploration and the length of time during which the region has undergone exploration. Generally speaking, the less exploration in a region, the greater potential for further significant discoveries. Since the target specified is exposure to 50 mmboe fields, the rankings use that figure as a base of comparison. Exploration maturity can be expressed as a function of discovery dates of major fields by province (fig. 7). The percentage of large fields discovered is grouped into three quarter-century categories: pre-1926 (pre-seismic); 1926-1950 (the middle years of increasing geological expertise and development of geophysics); and 1951-1975 (the modern era of exploration). Based against the national norms (which show that 20% of the nation's large fields were discovered before 1926, 57% between 1926 and 1950 and 23% since 1950), several provinces stand out as either youthful or elderly. The Pacific Coast, Midcontinent/North Central Texas, Eastern Interior and Arkla/East Texas all stand out as elderly provinces, in that many of their large fields were discovered early, with additional development of large fields in the next twenty-five years, but only a few large fields discovered in the last twenty-five years. This can be contrasted with the Rocky Mountains and Southeastern provinces, where a major number of large fields were discovered in the last twenty-five years and few in the earliest of the three time periods; none were discovered in the Southeast province in that earliest period. This does not mean that all the large fields in those elderly provinces have been found, only that the likelihood of finding large fields is less than in youthful provinces or that new methods or concepts are needed to find additional significant reserves. Point Arguello field, California, is an example of the recent discovery of a significant field in an elderly province (although offshore and thus younger in development). Exploration- maturity assessment can be useful in other ways. For instance, if a company wishes to work towards lower risk (with consequent lower rewards) drilling, then the additional drilling experience and data available in a mature or elderly area may well be of major assistance.

Similarly, provinces can be characterized by dominant lithology of major reservoirs and by tectonic setting (fig. 8). Lithology is a function of tectonic setting and tectonic setting is important to petroleum potential. But as Klemme (1975) pointed out, combinations of lithologies coupled to structural styles control the distribution of giant oil fields, not just tectonic setting and lithologic dominance. Trapping mechanisms have also been evaluated, largely from Nehring (1981), but modified by the writers' bias towards viewing more traps as combination than simple structural or stratigraphic (fig. 9). This information is, of course, historical, and mostly serves to illustrate the need to evaluate combination traps more fully and to look towards the increasing significance of purely or mostly stratigraphic traps.

Some exploration guidance comes from this information. Those provinces in which large numbers of combination and stratigraphic traps have been discovered are less likely to contain additional accumulations of petroleum than those which have not yet exploited those trap types; traditionally, structural traps are the easiest to locate and the first exploited, therefore relegating the combination and stratigraphic traps to later cycles of exploration.

Economic Factors

Depth of drilling of exploratory wells is one major factor in exploration costs. Since successful efforts are related to number of wells attempted, the more wells drilled, the better the chances of large field discovery; therefore, this factor has to be considered in evaluating exploration provinces (fig. 10). Clearly, it takes much more capital to drill in the Louisiana Coast or Southeastern provinces than others since the average drilling depth is 2000-3000 feet deeper than other provinces(about 30% deeper), and drilling costs thus are about doubled or more. Eastern Interior drilling costs are the lowest of the provinces because of the thin sedimentary cover in known-producing areas.

Average-initial-potential (I.P.) production figures give another yardstick for economic analysis of exploration potential, although this does not assist in defining reserve targets (fig. 11). Deep drilling can be justified when the production from a well can be expected to pay the extra cost in a short time; I.P.s are useful for prediction of payout period although they are normally calculated at a rate above expected sustained production rates. Low average drilling depths as compared to high initial potentials is a favorable factor for exploration success.

Another economic factor that bears upon the exploration selection decision is the likelihood that large fields may be encountered in a province. One way of examining this factor is to examine provinces for production from large fields; the higher the percentage, the more likely the province has future large fields (fig. 12), although this must be balanced somewhat against the exploration maturity of the province. West Coast fields tend to be very large; approximately 60% of that province's production is from very large fields, greater than 400 mmboe, and an additional 30% is from large fields; only 10% of the production is from smaller than 50 mmboe accumulations. At the other extreme, less than 50% of the production from the Eastern Interior province comes from large fields (data from Nehring, 1981). Thus, the Eastern Interior province is not a good place to look for large targets. It has a high exploration maturity with a history of small accumulations.

Successful completion rates are also important for economic evaluation of the various geographic provinces. The number of wells drilled can be plotted against the number of successful wells for each province, which can then be read as a percentage of success (fig. 13). Nationally, the success rate for development wells has held constant at about 79% since 1972. During this time the wildcat success rate has gained from about 10% to 19% and all wells have gained from 60% to 70% success (fig. 14). Improved economics, brought about by higher wellhead prices since 1972, have had favorable impact upon the statistics.

Geologic Factors

Two factors based upon regional geological conditions also have an impact on the exploration decisions (figs. 15, 16). First, the amount of oil to be found is in part a function of the amount of sedimentary rock in the province. Evaluation of this factor has been accomplished by plotting the volume of sedimentary rock against the surface area of the province, giving a numerical ratio of volume-to-surface area. The greater the ratio value, the greater the stratigraphic section thickness averaged over the region and the more opportunity to encounter petroleum accumulations. The estimated average recovery of petroleum in barrels per acre-foot has been tested against the area already developed. These numbers are too highly generalized to be singly evaluated so they have been cross-plotted.

Projections

Various strategems for forecasting reserves, future discoveries and resources have been developed over the years in an effort to quantify the probabilities of petroleum being discovered and produced for national planning purposes. While most of these calculations are not really valid for individual basins or reservoirs, they can be very useful in context when viewed as provincial probabilities and considered to be "order of magnitude" figures. Several of these extrapolations are of use to this study.

First, total recoverable reserves show which provinces have been successful to date (table 4, reserves calculated to 1975), and which are heaviest in gas and in oil. The significance of small but prolific areas, such as the Permian Basin and South Texas, is clear. The Rocky Mountains province is remarkable for its size and lack of reserves. Reserves position is one measure of exploration maturity; these figures must be compared to estimates of future potential in order to be meaningful as an exploration strategy factor (table 4). These recent estimates of undiscovered petroleum in the United States indicate that the Rocky Mountains has the greatest potential of any province for both oil and gas; it is however, also the largest in size. Subdivided into eastern and western Rockies subprovinces, the total province is thought to contain over 23 BBO future oil and 159 TCF future gas, with the eastern Rockies containing the majority of those undiscovered resources. Second to the Rockies is offshore West Coast, then Texas Gulf Coast and the Permian Basin. Midcontinent/North Central Texas future discoveries are rated fourth and onshore West Coast is fifth.

A summary of the production factors, including remaining reserves (as contrasted to total reserves), cumulative production and reservoir data (table 5) completes the data tabulations from which the exploration strategy decision can be made.

SELECTION CRITERIA

Basic exploration parameters specified at the beginning of this exercise included financial factors ($5MM per year for 5 years), geographic bias (lower "48" United States onshore), reserves target (25 mmboe in the first five years) and ultimate target exposure (50 mmboe targets probably present in the geographic area selected and exposure to at least one such prospect possible within ten years). It is necessary to interpret the data already presented to arrive at a recommendation for selection of a specific province for petroleum exploration. The interpretations are necessarily biased by selection of evaluated criteria, relative weighting of criteria and by the parameters by which the strategy will be developed.

First, those geologic factors are summarized that have been examined and which may be useful for making a geographic exploration decision (table 6). This summary includes some factors that may not be useful in making the decision, but which are dropped from consideration near the end of the decision-making process (such as the age of reservoir rocks). Next, the factors are ranked by province, using a straight numerical ranking (9 = best). Duplicate values are assigned to equal rankings. Summation of the ranking scores (table 7) then shows relative rank of each province. In this study the Rocky Mountain province is first, followed by the Southeastern province and the Permian Basin. The Midcontinent province ranks last, on geologic factors only.

A similar rating and ranking system is developed for production factors (tables 8, 9). For these data and factors, the Louisiana Coast ranks first, followed by the Permian Basin and the Rocky Mountains.

In order to make the exploration decision, the last step is selection of final criteria or factors which are judged to be most significant. This selection is the subjective culmination of data assimilation from all preceding parts of the study; these factors are both geologic and production, influenced by economic assumptions. The evaluation of factors described in the preceding text and figures now controls the final selection. Twelve criteria that we judge to be the most important in making the exploration decision for our project have been selected. Not all will agree that these criteria are as important as used herein, but the purpose of this exercise is the process of establishing a exploration decision, not the absolute decision itself.

Our evaluation of the data and concepts studied ranks the nine provinces for exploration potential according to the parameters specified (table 10). The Rocky Mountains meet the parameters best, followed by the Southeastern province and the Permian Basin, with the Eastern Interior being the least likely to meet the parameters. A similar study done by the writers in 1982 also ranked the Rocky Mountains first, but the Texas Gulf Coast was second and the Permian Basin third, using all the same criteria. Changes in various parameters through time also change the area of greatest potential for the exploration criteria.

Although the Rocky Mountains have been picked as the appropriate region to expend the dollars allotted to the exploration program, much work remains to define the priority of basins and intrabasinal plays that will compose the actual exploration program. Priority setting will come about much as the definition of the primary province of exploration: by comparison of basin and play characteristics to the exploration parameters imposed by the program operator. Additional characteristics may be used which were not considered to be significant on a regional basis, such as land costs and environmental costs. Certainly these factors will affect decisions about plays and basins in the Rockies, since federal acreage is so abundant and thus federal regulations are important financial considerations. Levels of state taxation, regulatory philosophy, transportation systems, water disposal and other engineering considerations all will have a bearing upon the final priority of individual basins and plays.

SUMMARY

The preferred geographic area for exploration under the constraints issued for this exercise is the Rocky Mountain province. The factors that have been evaluated included exploration maturity, tectonic setting, volume of sedimentary rock, petroleum-bearing section thickness, reservoir thickness, lithology, trap types, depth of wildcat drilling, volumes of undiscovered petroleum, reserves, historical production and production rates, historical size distribution of fields and success rates.

Although the present petroleum market is depressed and exploration dollars are difficult to find, planned exploration can still be profitable. Operators must make careful decisions about where exploration is conducted so that the greatest possibility of meeting corporate objectives is compatible with the exploration area selected. Exploration-strategy planning can reduce risks and focus expenditures, both necessary to success in a poor petroleum market.

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Figure captions:

Fig. 1 Plot of cost of additions to reserves, drilling costs and price. Gap between price and drilling costs has expanded from 1978, although the gap is closed somewhat by 1984. Data from Petroleum Information (1986) and I. P. A. A. (1986).

Fig. 2 Trap types and reservoir lithologies, 2300 U. S. onshore significant fields. Data from Nehring (1981).

Fig. 3 Oil and gas regions as used in this report.

Fig. 4a Age of reservoir rock and cumulative production by regions. Data from Dolton et al (1981) and A. A. P. G. (1986). Abbreviations are used in succeeding figures.

Fig. 4b Discovery methods by region, percentage. Data from Nehring (1981).

Fig. 5. Geologic styles of some U. S. "lower 48" onshore oil and gas producing regions, as examples of tectonic-geologic setting. Classification and data adapted from Klemme (1975), although other classifications (such as Kingston et al, 1983) may also be used.

Fig. 6 Exploratory wells necessary to discover various field sizes. Note that the number of wells to discover large fields is increasing steadily; the number of wells necessary to discover any size field has decreased from 1966 to 1980, the latest data available. The difference at least in part due to increased crude oil prices which permit the completion of wells previously considered to be uneconomic.

Fig. 7 Exploration maturity of regions, based upon percentages of significant fields discovered during three time periods. Data from Nehring (1981). The Pacific coast and Midcontinent regions are the most mature, with major numbers of significant fields discovered early, whereas the Southeast region is the least mature.

Fig. 8 Reservoir lithologies of large fields by region and tectonic setting, percentage. Data from Nehring (1981).

Fig. 9 Plot of trap types by region, percentage. Data from Nehring (1981).

Fig. 10 Average drilling depths for 1982 and 1985. Data from Petroleum Information (1983, 1986) and A. A. P. G. (1983, 1986). Note that although national depth average slightly increased, the major increase is in three regions, with decreases in the remainder.

Fig. 11 Average initial potential by region, in barrels (1982). Data from Petroleum Information.

Fig. 12 Production from large fields by region, showing percentage of total production by very large fields (> 400 mmboe) and large fields (>50, <400 mmboe). Remaining production is from smaller fields. Data from Nehring (1981).

Fig. 13 Exploratory wells drilled, successful completions and percentage completions by region (1985). Data from A. A. P. G. (1986).

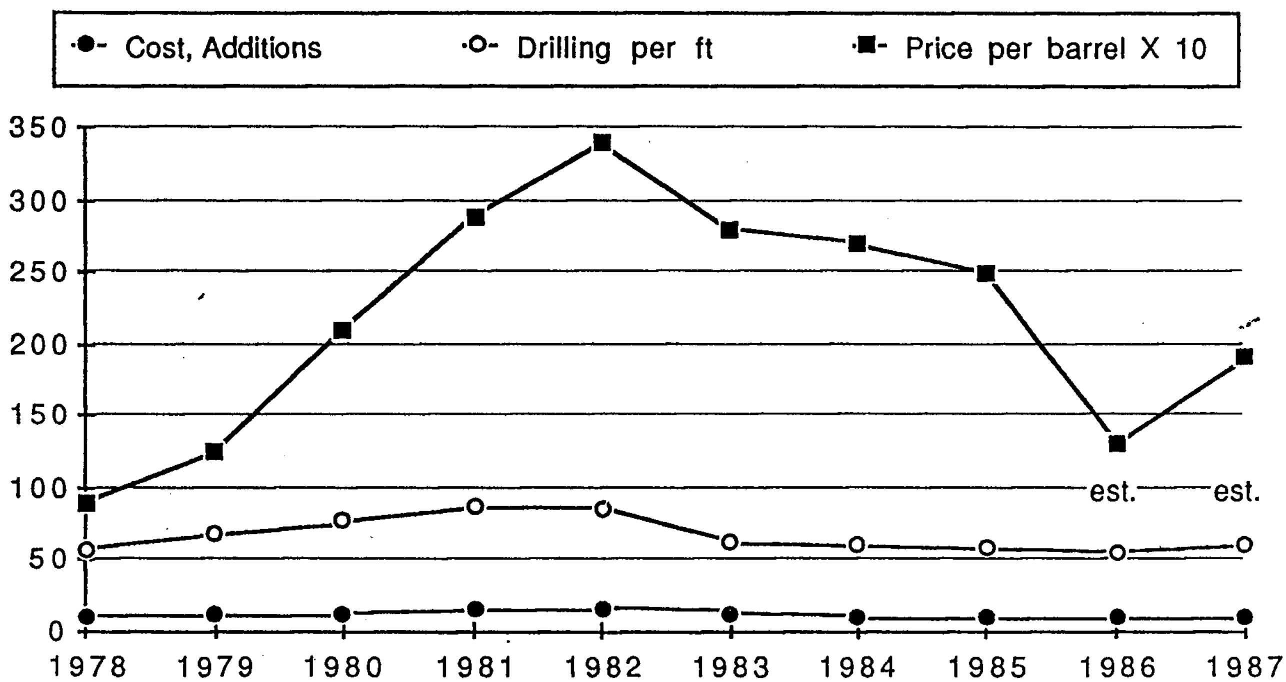
Fig. 14 Percent success for various well categories. Data from A. A. P. G. Data starts at initiation of current exploration cycle.

Fig. 15. Volume of sedimentary rocks by region vs. surface area. Ratio expresses the relative thickness of the sedimentary section. These data must be used with care since producing basins are not individually broken out.

Fig. 16 Average reservoir yield in barrels per acre foot and developed area in millions of acres, by region. Data from I. P. A. A. (1986) and Nehring (1981).

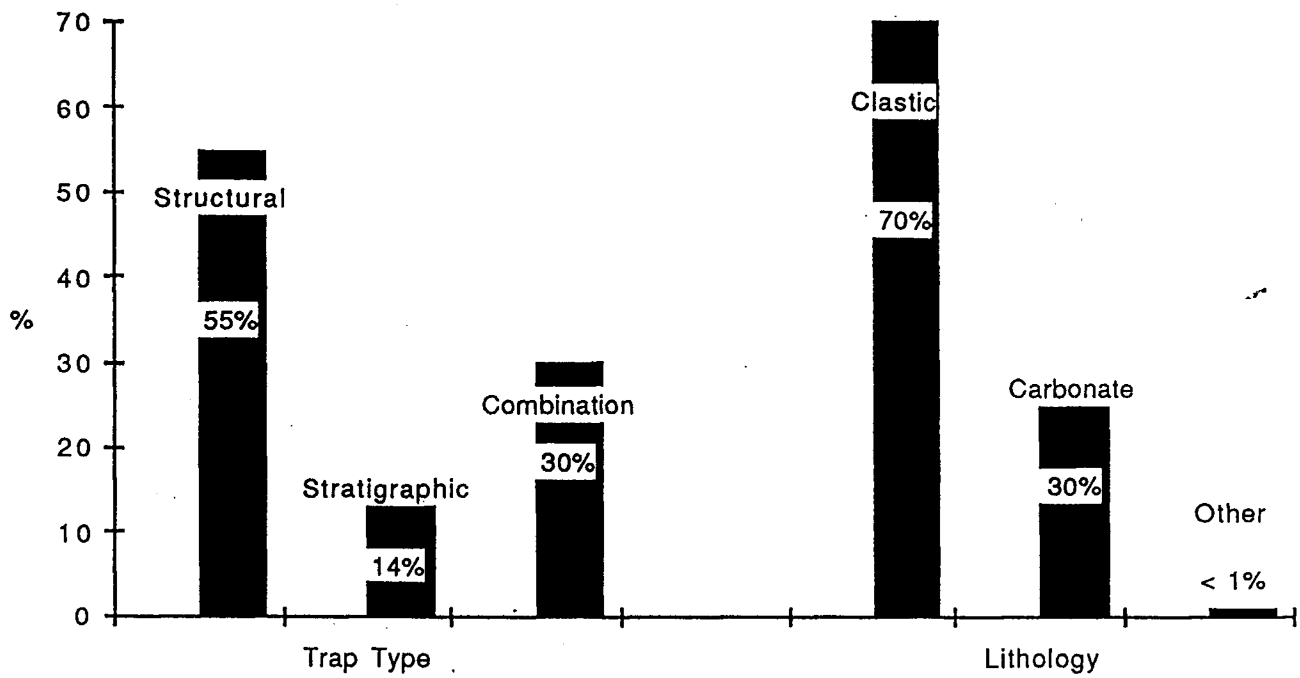
Table 10 Composite scores and regional rankings on some significant exploration decision criteria.

Fig. 1, Revision 1/88



Costs versus price.

Fig. 2 Trap types and reservoir lithologies.



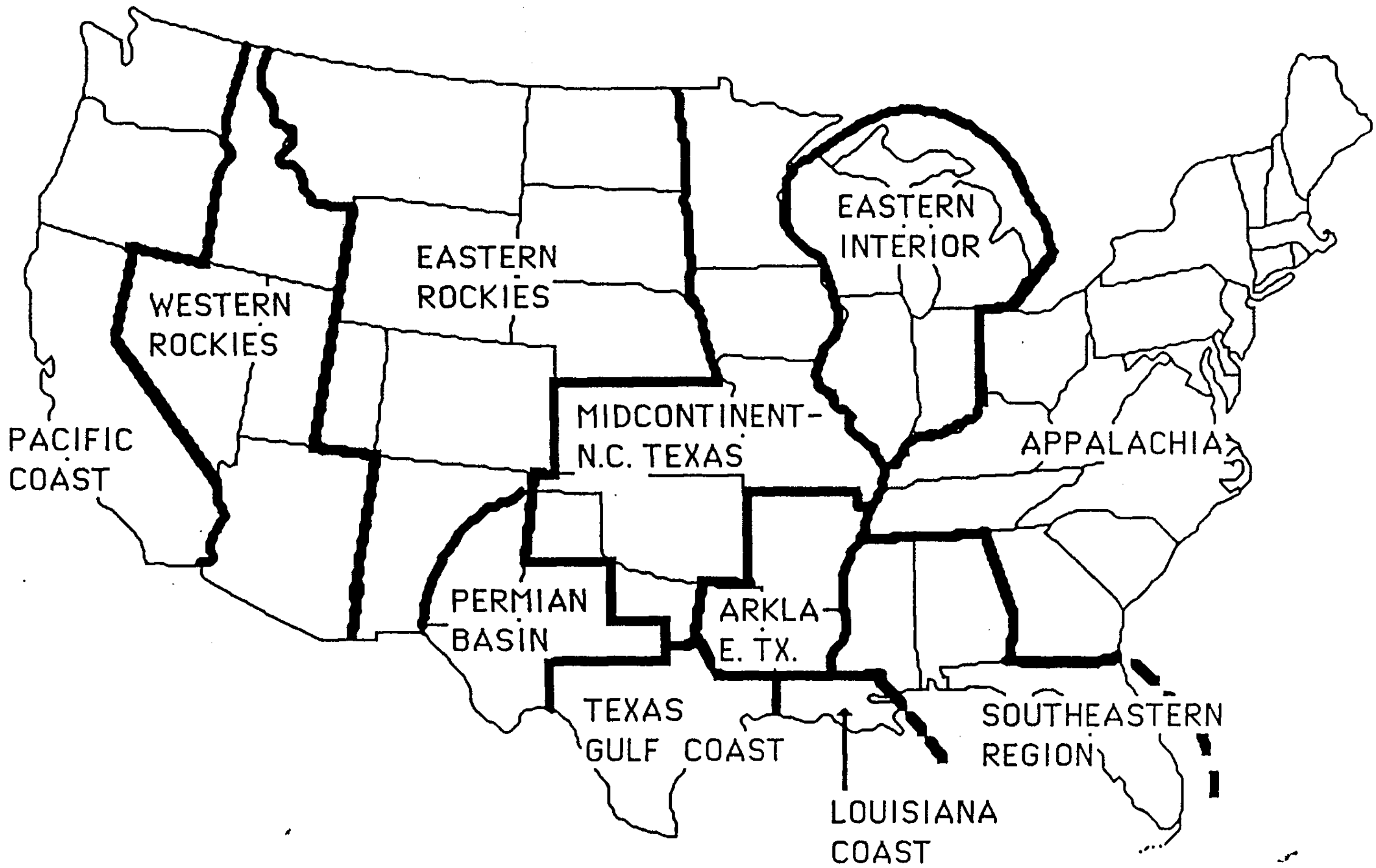


Fig. 3 Oil and gas regions as used in this report.

Fig. 4a Age and production by region (revised)

Fig. 4a Age of reservoir rock and cummulative production by regions. Data from Dolton et al (1981) and A.A.P.G. (1986). Abbreviations are used in succeeding figures.

	Abbr.	Reservoir Age	Cum. Prod., BBOE, to 1/1/85
Pacific Coast	PC	Cenozoic	26.9
Rocky Mtns.	RM	Phanerozoic	20.5
Permian Bas.	PB	Paleozoic	56.8
Midcontinent	MC	Paleozoic	46.4
Eastern Inter.	EI	Paleozoic	5.6
E. Tx/Arkla	ET	Paleozoic-Mes.	33.9
Southeast	SE	Mesozoic	4.5
Gulf Coast*		Mes.-Cenozoic	78.4

*In other figs. this separately includes:
Tx. Gulf Coast: TG
Louisiana Coast LC

Fig. 4b Discovery methods by province, percentage. Data from Nehring (1981).

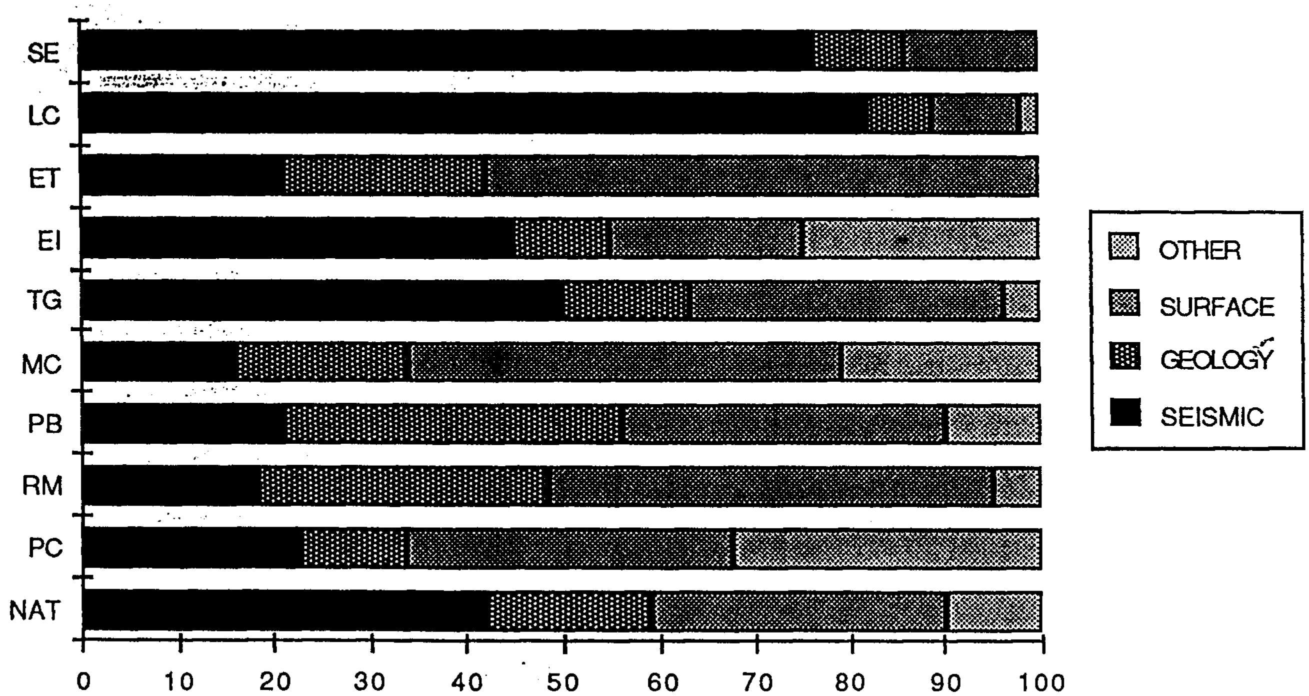


Fig. 5 Geologic styles of U. S. "Lower 48" onshore oil and gas production regions. Classification and data from Klemme (1975).

Geologic style	% U.S. total reserves	% Petrol. in large fields	Ave. max. depth	Reservoir age
Craton Interior	2.5			
Illinois Basin		50-60	5500	Paleozoic
Michigan Basin		<25	10,500	Paleozoic
Williston Basin		50-60	12,500	Paleozoic
Craton Margin	39			
Shallow:				
Powder River Basin		50	6-13000	Paleozoic & Mesozoic
Deep:				
Anadarko, Permian		82.5	20,000	Paleozoic
Intermediate:				
San Juan, Big Horn		82.1	16,000	Paleozoic & Mesozoic
Craton Rifts	0.01			
See Anadarko basin.				
Downwarps	27.3			
Gulf Coast		79	15,000	Mesozoic & Cenozoic
Subduction	10.9			
California		92.6	11,000	Cenozoic
Delta	16.7			
Mississippi Delta, Louisiana		60	18,000	Mesozoic &Cenozoic

WELLS NECESSARY TO DISCOVER VARIOUS FIELD SIZES. SEMILOG VERTICAL SCALE.

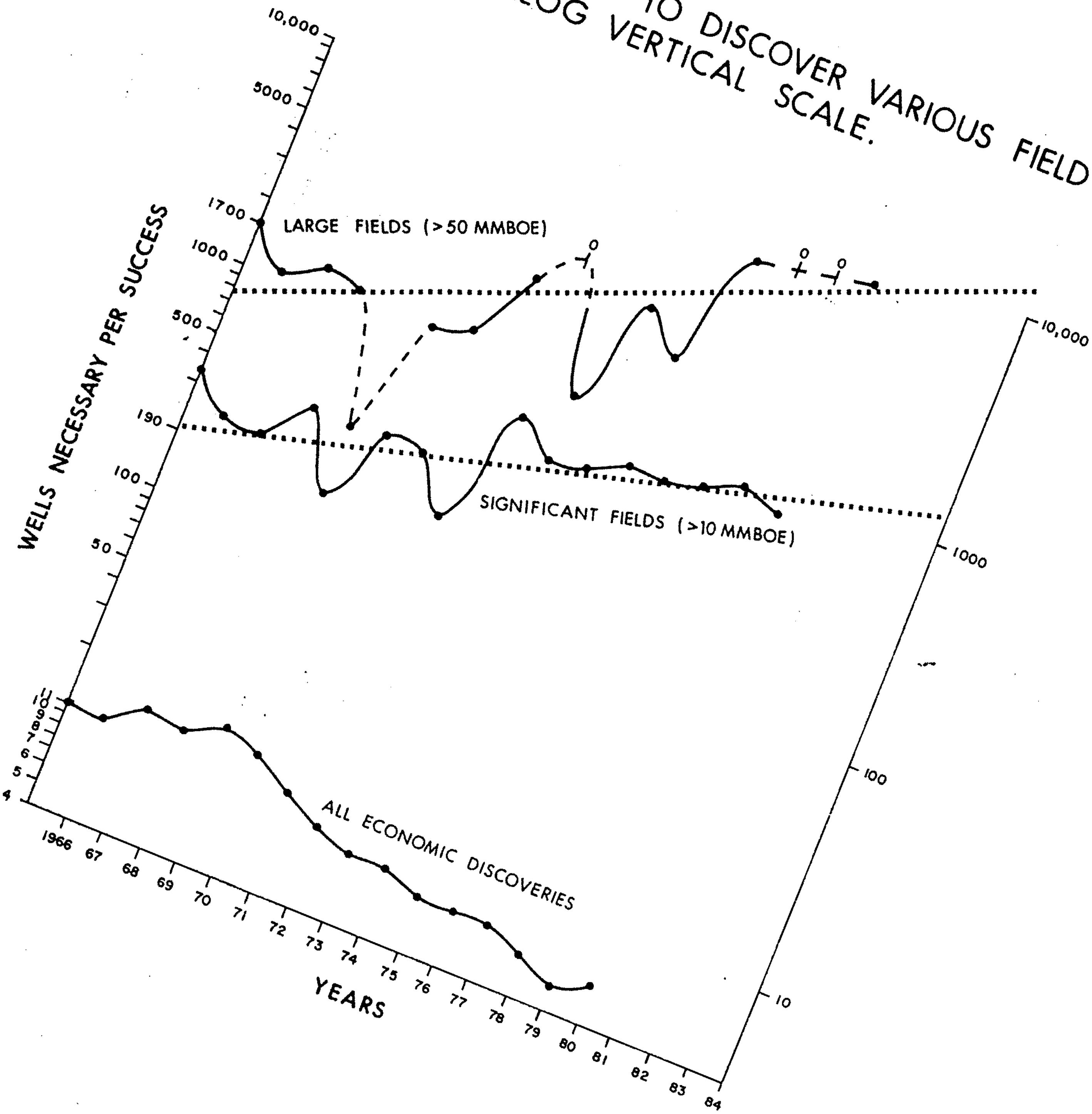


Fig. 7 Maturity of provinces,

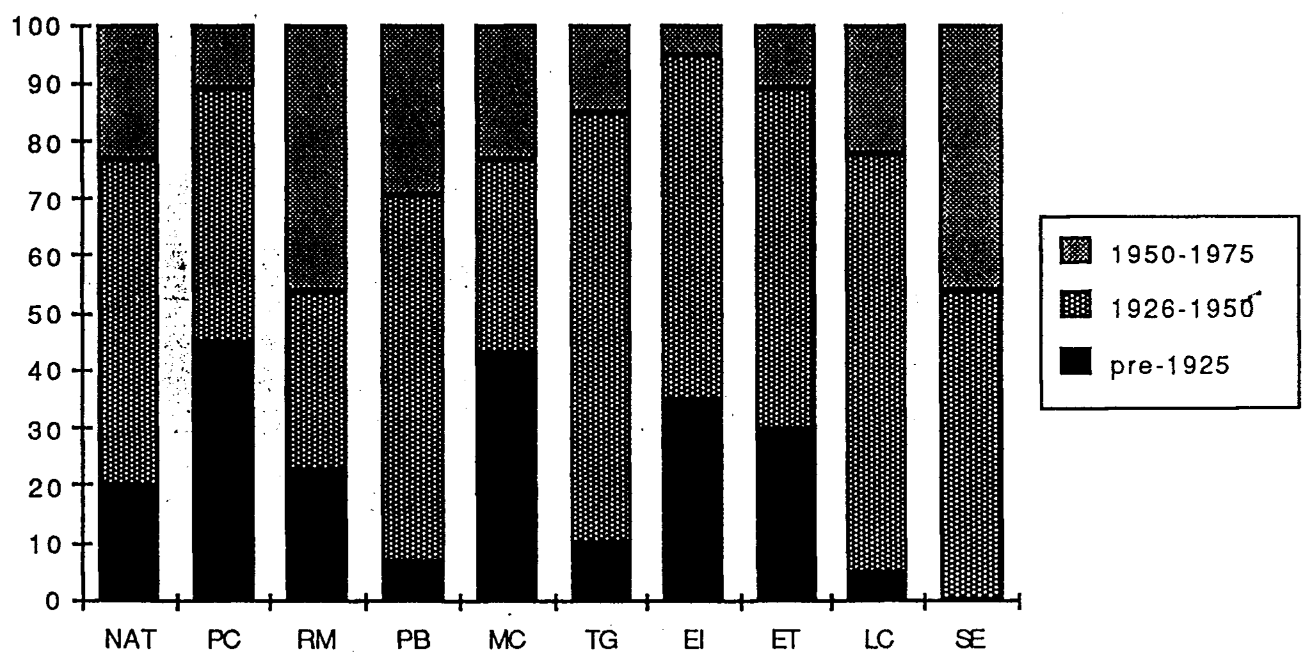


Fig. 8 Lithologies of large fields

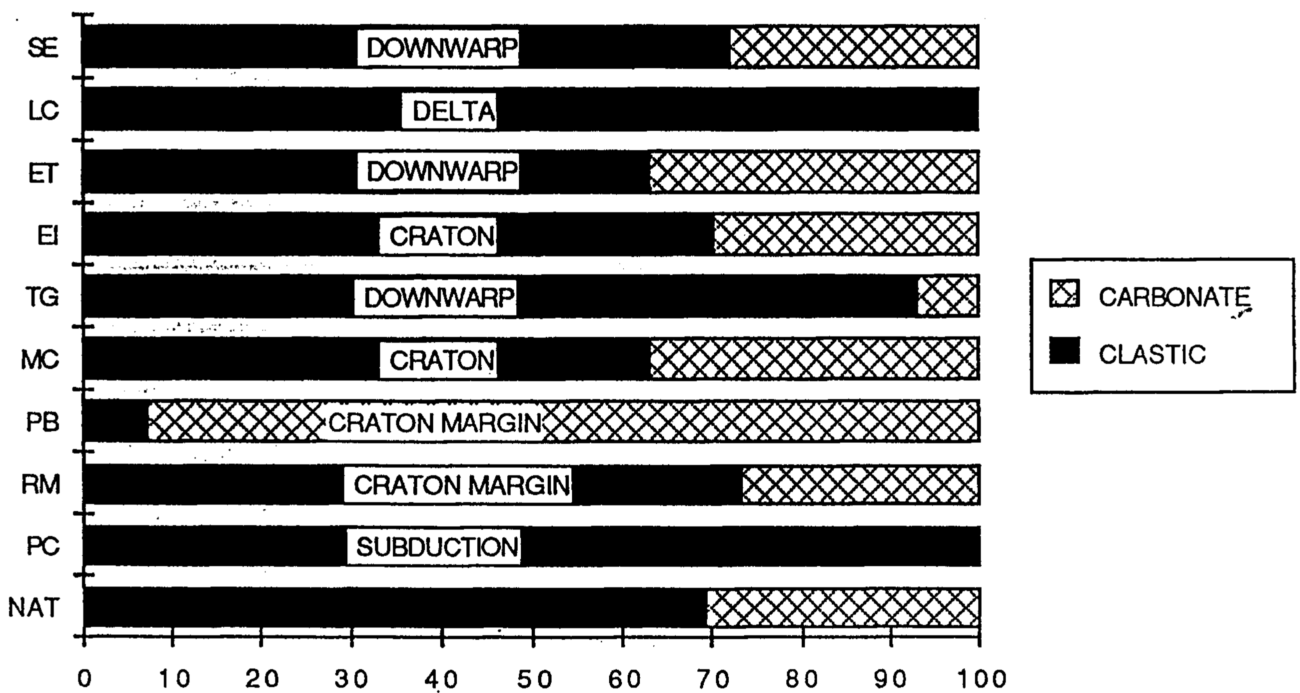


Fig. 9 Plot of trap types by province, percentage. Data from Nehring (1981).

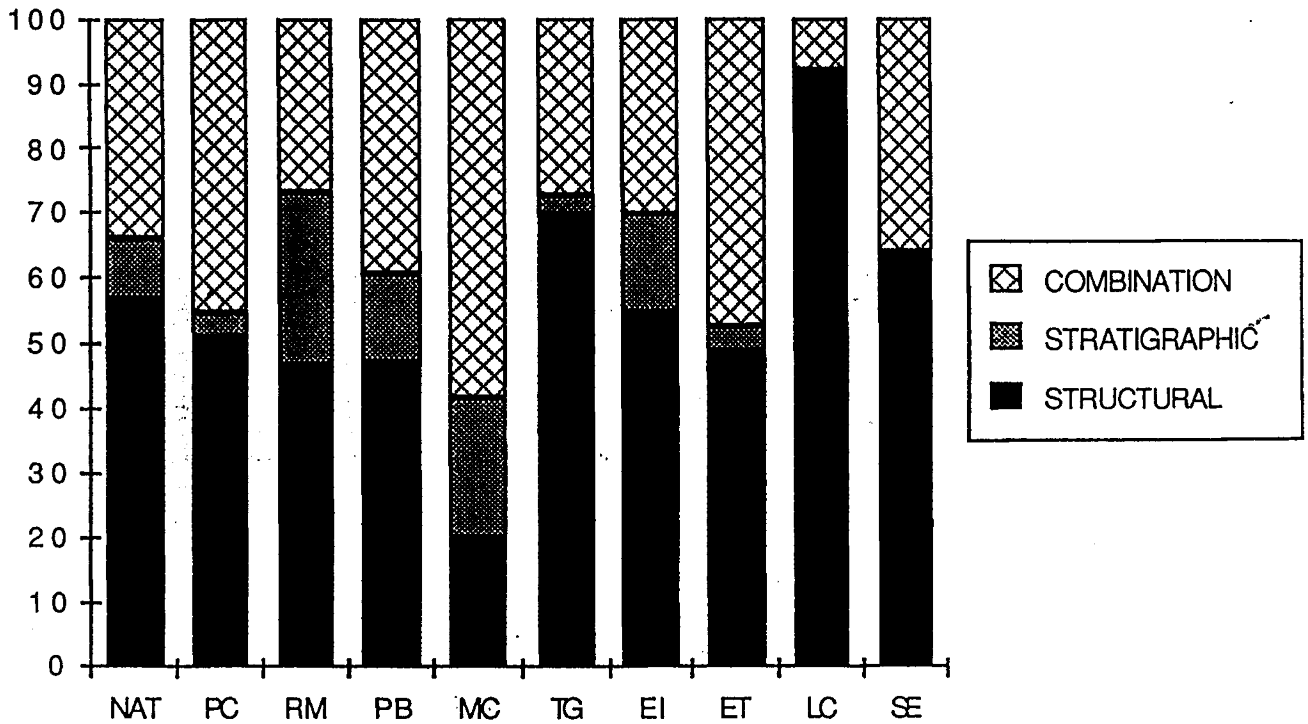


Fig. 10 Average drilling depths for 1982 and 1985.

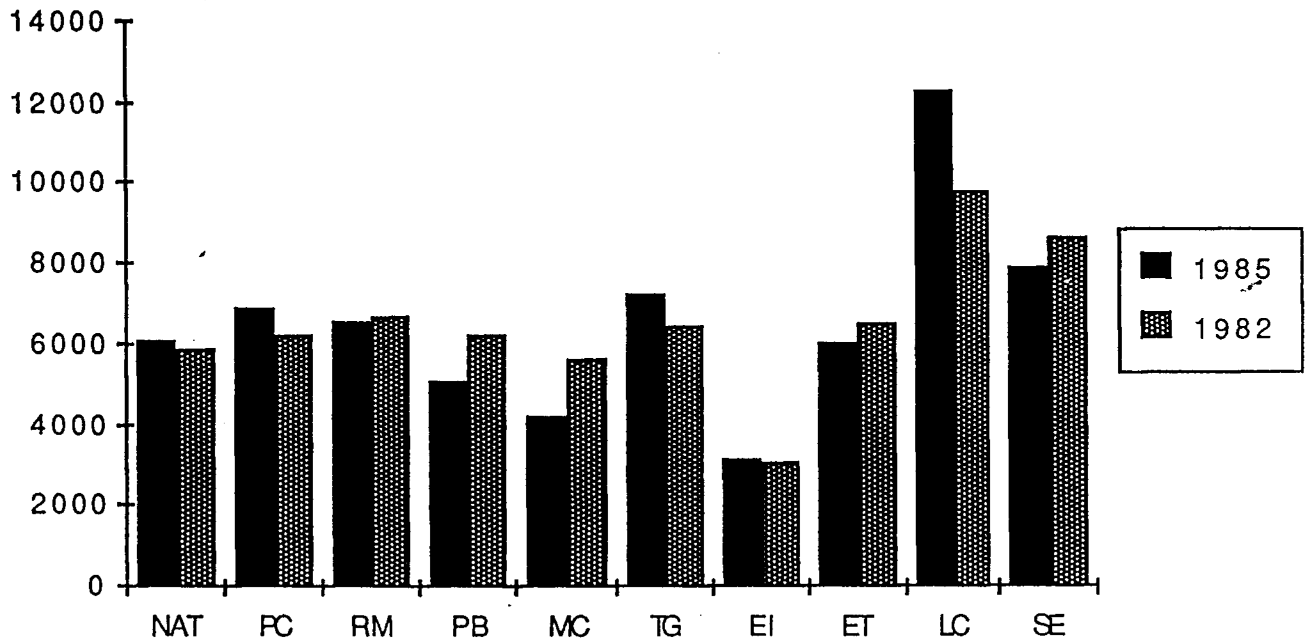


Fig. 11 Initial potential by region, 1982, (barrels).

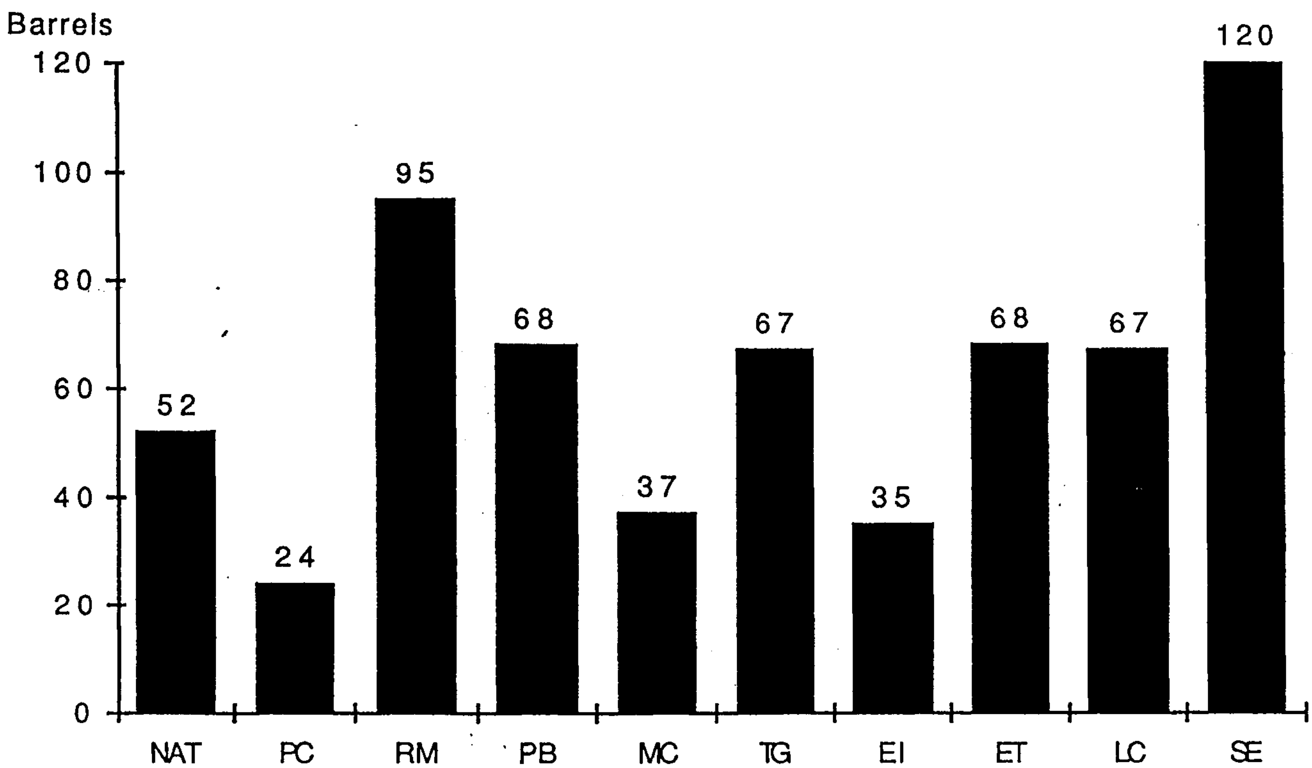
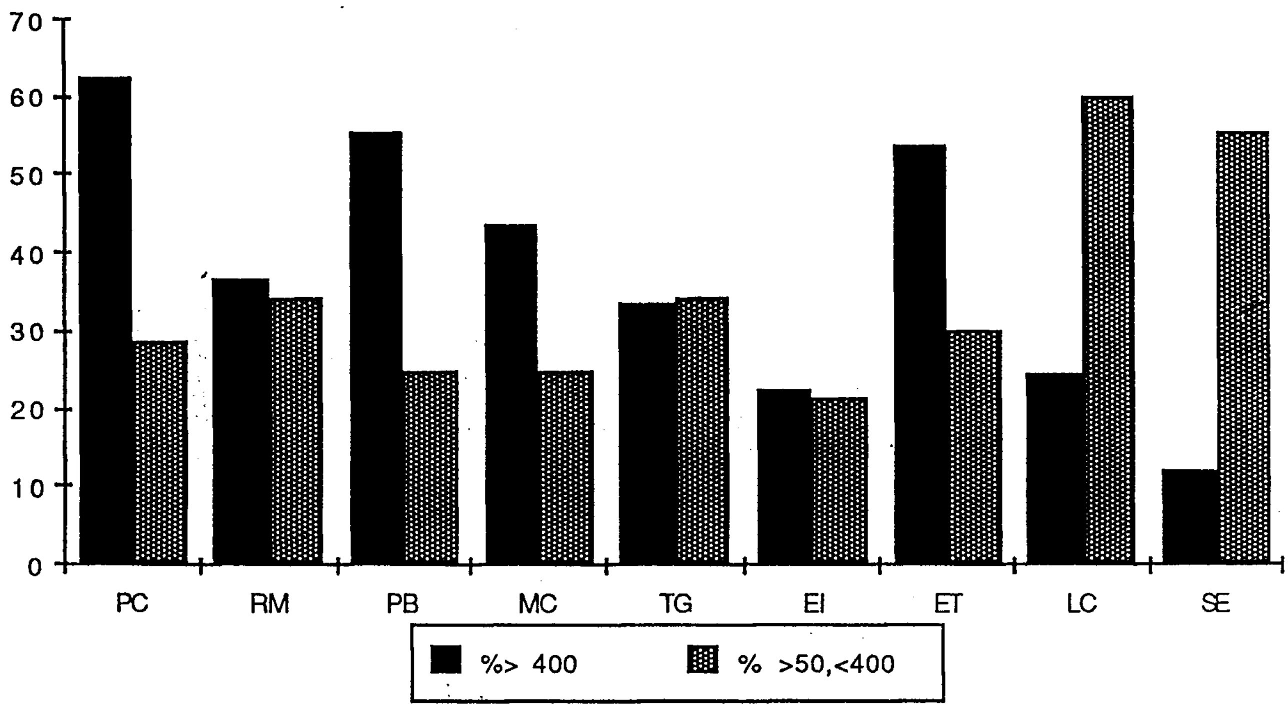
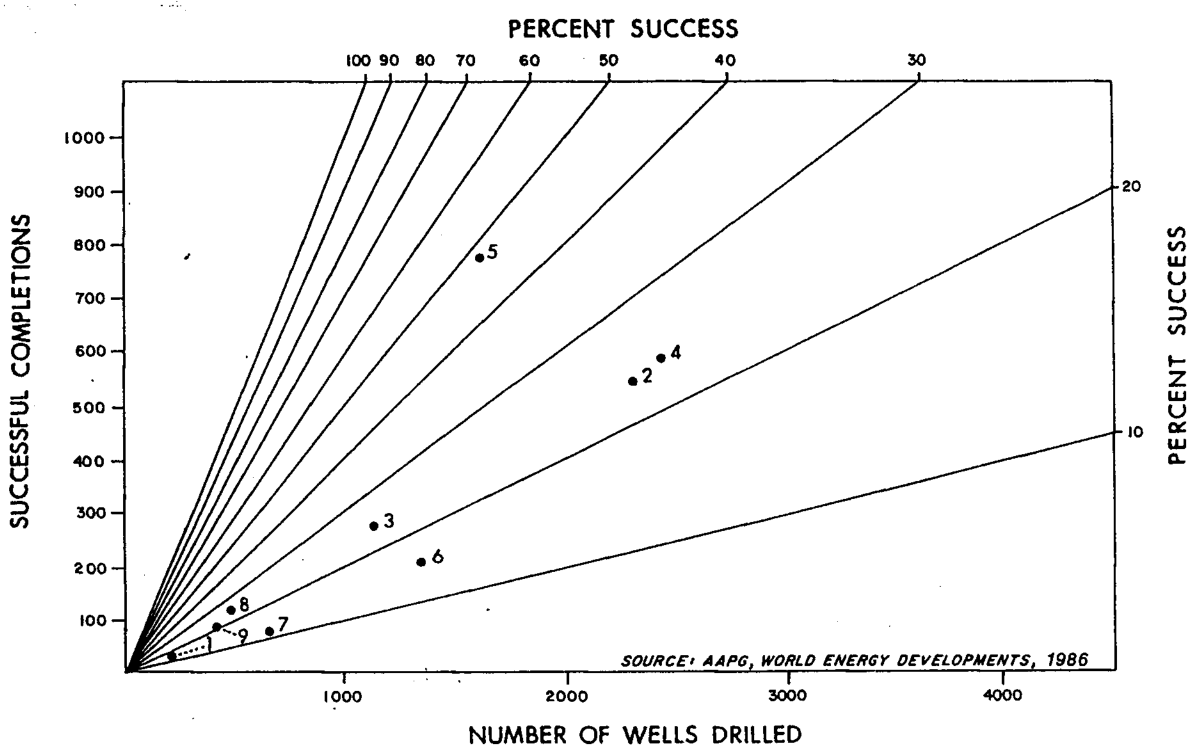


Fig. 12 Production from large fields by region,

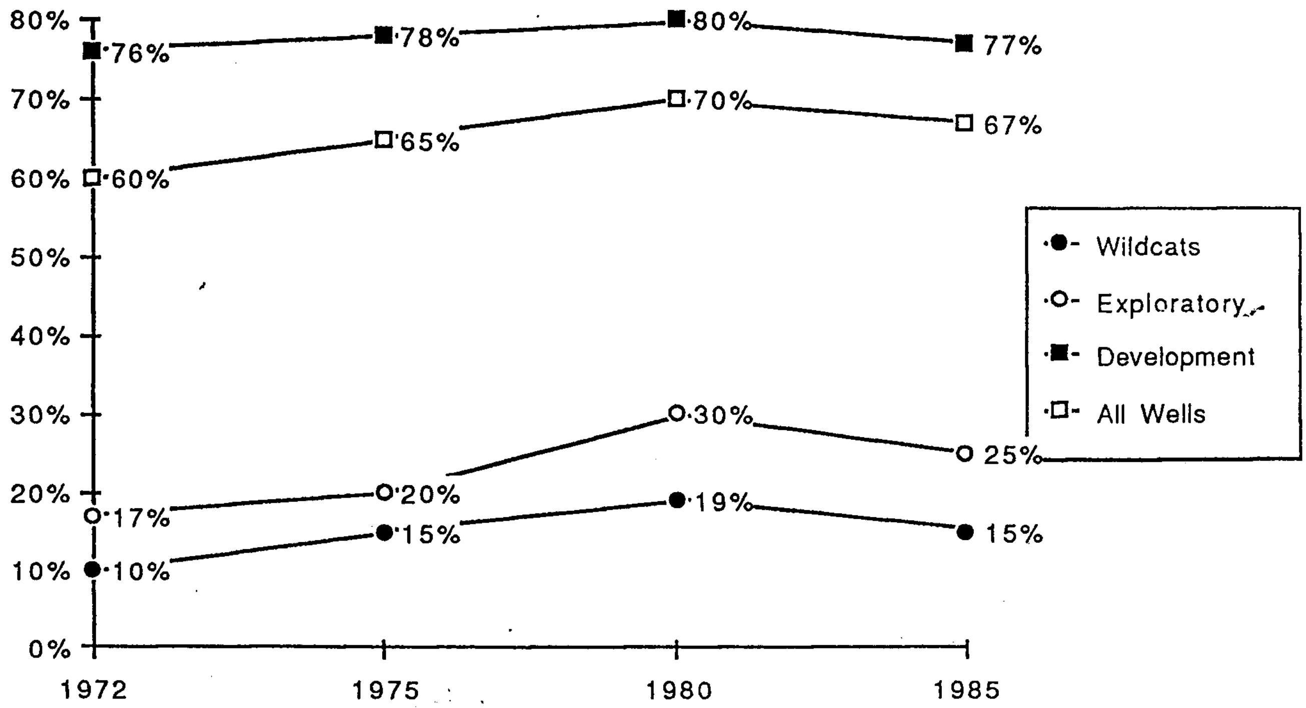


1985 TOTAL EXPLORATORY WELLS DRILLED
VS
SUCCESSFUL COMPLETIONS WITH SUCCESS RATIOS BY REGION



1. PACIFIC COAST
2. ROCKY MOUNTAINS
3. PERMIAN BASIN-W. TEXAS
4. MID-CONTINENT-N.C. TEXAS
5. TEXAS GULF COAST
6. EASTERN INTERIOR
7. ARK-LA-E. TEXAS
8. LOUISIANA COAST
9. SOUTHEAST REGION

Fig. 14 Drilling success



VOLUME OF SEDIMENTARY ROCKS VS. SURFACE AREA BY REGION

NUMBERS ARE VOLUME DIVIDED BY AREA

DATA FROM U.S.G.S. 1981

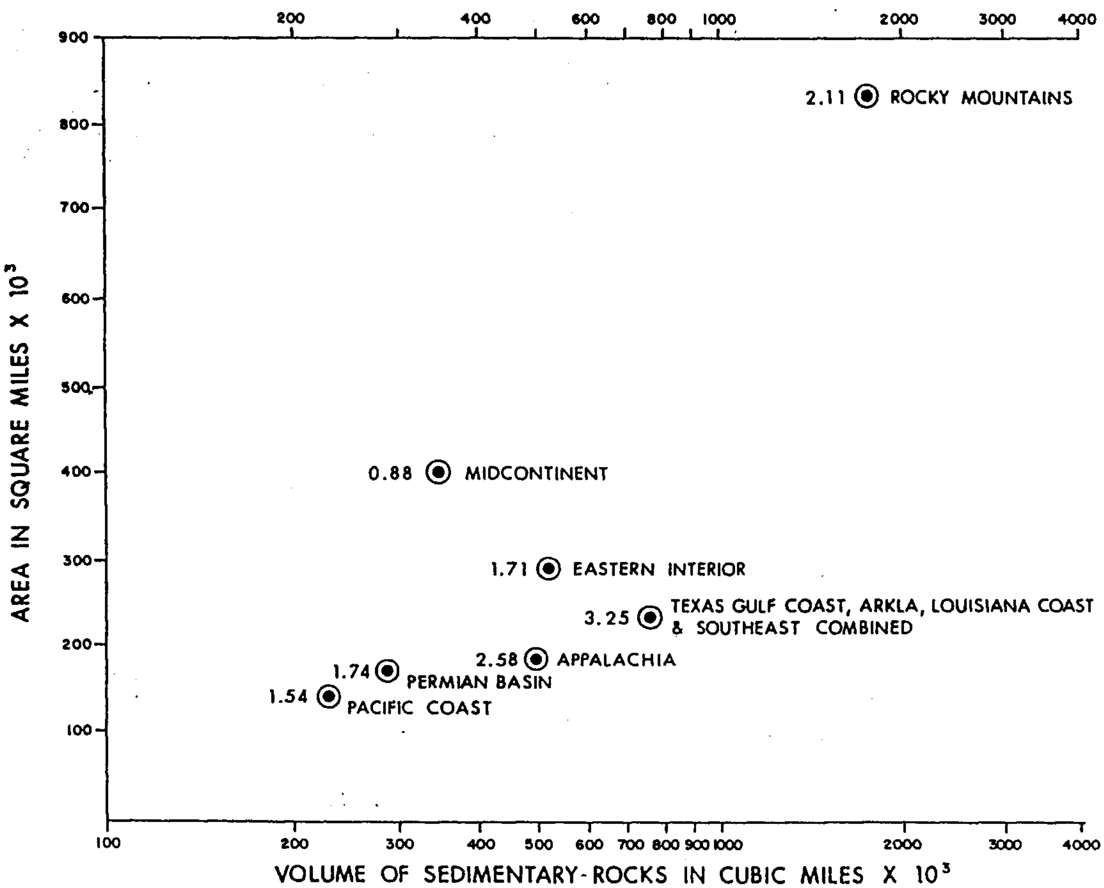


Fig. 16 Yield in barrels per acre foot etc.

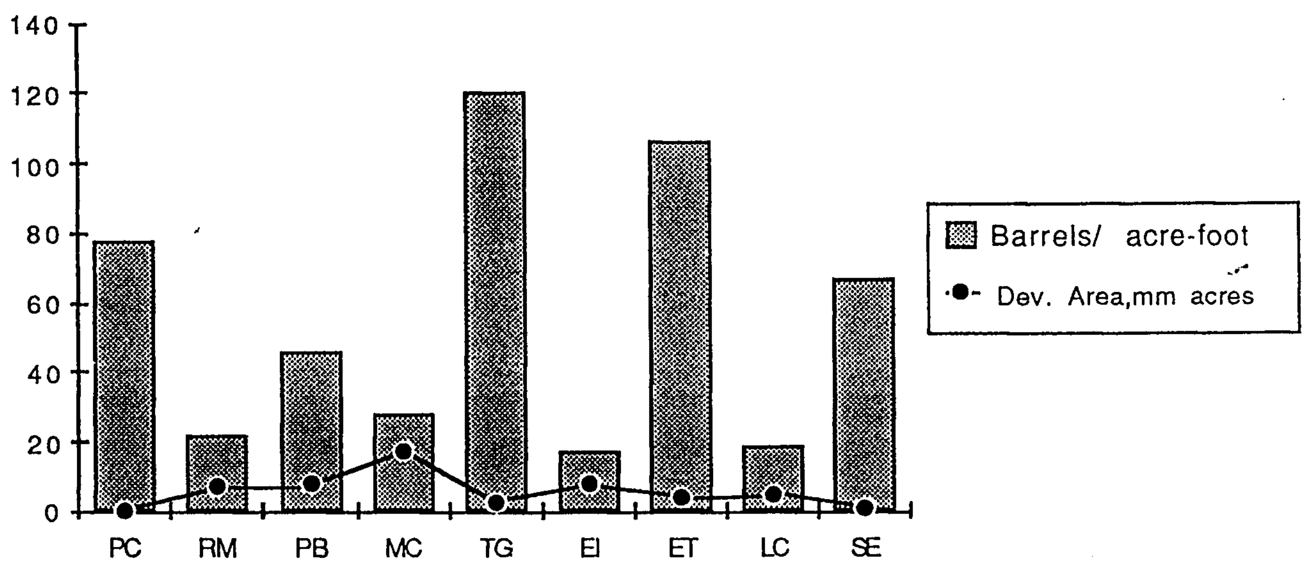


Table 1

Table 1. Field size classification used in this paper. Modified from Nehring (1981)

World-class "giant" field:	Greater than 500 million barrels of oil equivalent.
National-class "giant field:	100-500 million barrels of oil equivalent.
Large field (significant field):	At least 10 million barrels of oil equivalent.

Note: oil equivalency for gas is calculated at 6000 cubic feet of gas equals one barrel of oil

Table 2. Top ten oil producing states of the United States, 1984. Data from I.P.A.A.

Rank	State	Daily prod. (MBOPD)	Prod. per well per day, bbls.	Number of wells prod.	Prod. per well per day, 1981
1	Texas	2435	11.6	209040	14
2	Alaska	1825	1868	977	2299
3	Louisiana	1392	54	25823	49
4	California	1161	23.2	49874	22
5	Oklahoma	446	4.3	103000	5
6	Wyoming	352	29.2	12038	31
7	New Mexico	215	11.5	18697	12
8	Kansas	207	4	51888	4
9	North Dakota	139	37.6	3697	48
10	Utah	112	57.6	1944	46

Table 3. Lower level oil producing states of the United States, 1984. Data from I.P.A.A.

11	Mississippi	84	24.2	3468	30
12	Colorado	83	15.2	5457	29
	Illinois	83	2.7	31100	2
14	Montana	82	19.5	4196	21
15	Michigan	75	14.6	5125	20
16	Alabama	59	72	810	57.6
17	Arkansas	52	5.4	9700	6
18	Ohio	41	1.5	27975	1.6
19	Florida	31	208	149	814
20	Kentucky	21	1	21844	18
21	Nebraska	19	9	2091	18.2
22	Indiana	14	2	7164	2
23	Pennsylvania	13	0.5	24000	0.4
24	West Virginia	10	0.6	15895	0.6

Table 4 Reserves and undiscovered petroleum, by province, onshore.

Total recoverable petroleum reserves by region, 1975.

	Oil(BBO)	Gas (TCF)	Total (BBOE)
Pacific Coast	23.7	33.2	29.197
Rocky Mountains	10.1	44	17.385
Permian Basin	31.5	84.2	43.535
Midcontinent	19.7	151.9	44.992
Texas Gulf Coast	14.3	130.4	35.991
Eastern Interior	4.7	3.5	5.264
Arkla-East Texas	12.9	53.4	21.853
Louisiana Coast	17.2	169.3	45.373
Southeast Region	2.6	7.8	3.859

(Data from Nehring, 1981)

Estimated undiscovered recoverable petroleum by region.

	Oil (BBO)	Gas (TCF)	Total (BBOE)
Pacific Coast	4.4	34	10.4
Rocky Mountains	23.6	159	51.9
Permian Basin	5.4	34	11.1
Midcontinent	4.9	99	22.5
Texas Gulf Coast	5.6	35	11.4
Eastern Interior	1.4	3	1.9
Arkla-East Texas	0.5	39	7.4
Louisiana Coast	0.5	51	9
Southeast Region	0.3	43	7.5

(U.S.G.S., 1981: Oil; Potential Gas Agency, 1984: Gas)

Table 5. Summary of cumulative production, average reservoir thickness and yield in barrels per acre-foot. Data from I.P.A.A. (1986) and Nehring (1981)

	CUMULATIVE PRODUCTION	RESERVOIR THICKNESS	YIELD, BAF
	BBOE	FEET	BARRELS PER ACRE FOOT
Pacific Coast	26.9	776	101
Rocky Mountains	20.5	87	46
Permian Basin	56.8	118	101
Midcontinent	46.4	62	50
Texas Gulf Coast	31.7	64	206
Eastern Interior	4.9	40	99
Arkla-East Texas	33.8	50	200
Louisiana Coast	46.6	233	46
Southeast Region	4.5	50	99
Average Value		164	105

Table 6 GEOLOGICAL FACTORS OF SIGNIFICANCE TO REGIONAL EXPLORATION DECISION.
This table presents data only.

	SE	LC	ET	EI	TG	MC	PB	RM	PC
Exploration maturity	Y	M	M	M	M	O	M	Y	O
Sed. rock vol. (cu. mi.)	415	185	400	520	395	360	285	1780	230
BAF in gross pay (BOE)	99	46	199	19	206	50	105	46	101
Ave. Reservoir thickness	50	233	50	40	64	62	118	87	776
Ave. Drilling depth (1985)	7888	12246	6015	3140	7271	4236	5082	6593	6910
Reservoir rock age	M	C	M	P	C	P	P	P/M	C
Trap style	STRCT	STRCT	MIX	STRCT	STRCT	COMB	MIX	MIX	MIX
Res. Lithology	MIX	CLSTC	MIX	MIX	CLSTC	MIX	CARB	MIX	CLSTC
Geologic Style	DNWP	DELTA	CrMrgn	CrIntr	DNWP	CrIntr	CrMrgn	CrMrgn	Sbduct
Drilling density (1 = most dense)	8	5	6	7	2	1	4	9	3

Table 7 GEOLOGICAL FACTORS OF SIGNIFICANCE TO REGIONAL EXPLORATION DECISION.
This table presents evaluation of factors and rankings.

	SE	LC	ET	EI	TG	MC	PB	RM	PC
Exploration maturity	9	8	8	8	8	7	8	9	7
Sed. rock vol. (cu. mi.)	7	1	6	8	5	4	3	9	2
BAF in gross pay (BOE)	5	3	8	1	9	4	7	3	6
Ave. Reservoir thickness	3	8	3	1	5	4	7	6	9
Ave. Drilling depth (1985)	2	1	6	9	3	8	7	5	4
Reservoir rock age	Not applicable to rankings								
Trap style	9	9	8	9	9	7	8	8	8
Res. Lithology	9	8	9	9	8	9	7	9	8
Geologic Style	8	7	9	5	8	8	9	9	6
Drilling density (1 = most dense)	8	5	6	7	2	1	4	9	3
Point total: (high=favorable	60	50	63	57	57	52	60	67	53
RANKING OF PROVINCE	3	9	2	5	5	7	3	1	7

Table 8 PRODUCTION FACTORS OF SIGNIFICANCE TO REGIONAL EXPLORATION DECISION. This table presents data.

	SE	LC	ET	EI	TG	MC	PB	RM	PC
Undiscovered Oil (BBO)	0.3	0.5	0.5	1.4	5.6	4.9	5.4	23.6	4.4
Undiscovered Gas (TCF)	43	51	39	3	35	99	34	159	34
Remaining Reserves (BBOE)	1	9.3	6.3	1	5.6	9	40.6	8.4	6.9
Cum. Production (BBOE)	4.5	46.6	33.8	4.9	31.7	46.4	56.8	20.5	26.9
% Total known reserves prod.	81	83	84	83	85	84	58	71	80
No. >400MMBOE fields known (offshore incl.)	10	21	9	6	18	1	24	8	15
No. >50 MMBOE fields known (offshore incl.)	80	257	59	15	140	119	111	68	78
Success rate, all wells %	46	54	69	49	74	61	80	60	89
Wildcat Success rate, 1985	20	25	12	15	48	25	23	23	13
Ave. Daily Prod per well, bbls.	53	45	18	5	13	5	13	26	23
Ave. IP, per well	120	67	68	35	67	37	68	95	24

Table 9 PRODUCTION FACTORS OF SIGNIFICANCE TO REGIONAL EXPLORATION DECISION.
This table presents evaluation and rankings.

	SE	LC	ET	EI	TG	MC	PB	RM	PC
Undiscovered Oil (BBO)	1	3	3	4	8	6	7	9	5
Undiscovered Gas (TCF)	6	7	5	1	4	8	3	9	3
Remaining Reserves (BBOE)	2	8	4	2	3	7	9	6	5
Cum. Production (BBOE)	1	8	6	2	5	7	9	3	4
% Total known reserves prod.	6	5	3	5	1	3	9	8	7
No. >400MMBOE fields known (offshore incl.)	4	8	3	1	7	5	9	2	6
No. >50 MMBOE fields known (offshore incl.)	5	9	2	1	8	7	6	3	4
Success rate, all wells %	1	3	6	2	7	5	8	4	9
Wildcat Success rate, 1985	4	8	1	3	9	8	6	6	2
Ave. Daily Prod per well, bbls.	9	8	5	2	4	2	4	7	6
Ave. IP, per well	9	5	7	2	5	3	7	8	1
Point total: (high=favorable)	48	72	45	25	61	61	77	65	52
RANKING OF PROVINCE	7	2	8	9	5	5	1	3	6

Table 10 Composite scores and province ranking on some significant exploration decision criteria.

	SE	LC	ET	EI	TG	MC	PB	RM	PC
Exploration maturity	9	8	8	8	8	7	8	9	7
Sedimentary Rock Volume	7	1	6	8	5	4	3	9	2
Geologic Style	8	7	9	5	8	5	9	9	6
No. >50 MMBOE Fields	5	9	2	1	8	7	6	3	4
Drilling Density	8	5	6	7	2	1	4	9	3
Drilling Depth	2	1	6	9	3	8	7	5	4
Wildcat Success	4	8	1	3	9	8	6	6	2
Oil Prod. per well per day	9	8	5	2	4	2	4	7	6
Initial Production	9	5	7	2	5	3	7	8	1
Undiscovered Gas	6	7	5	1	4	8	3	9	3
Undiscovered Oil	1	3	3	4	8	6	7	9	5
% Tot. Reserves Produced	6	5	3	5	1	3	9	8	7
TOTAL POINTS	74	67	61	55	65	62	73	91	50
FINAL RANKING	2	4	7	8	5	6	3	1	9