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Economics and continuous-type oil and gas accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources

by

Emil D. Attanasi, James W. Schmoker, and John C. Quinn

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TABLE OF CONVERSION TO SI UNITS

multiply unit	by	to obtain metric unit
barrel	0.159	cubic meter
cubic foot	0.02832	cubic meter
foot	0.3048	meter

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ABSTRACT

The U.S. Geological Survey assessed the technically recoverable resources of continuous-type oil plays as 2.1 billion barrels of oil (Bbo) and 5.4 trillion cubic feet (Tcf) of associated gas. For the technically recoverable resources in continuous-type gas plays, it assessed 302 Tcf of nonassociated gas and 2.1 billion barrels (Bbl) of natural gas liquids. Although resources assessed in continuous-type oil plays are small by national standards, the resources in continuous-type gas plays are more than twice US proved nonassociated gas reserves as of 1993. Economic analysis of continuous-type gas plays shows, based on a 12 percent required rate of return, that at $1.50 per thousand cubic feet (Mcf), 12.8 Tcf of gas is commercially producible with 0.1 billion barrels of natural gas liquids. At $3.00 and $5.00 per Mcf, 31.6 and 85.3 Tcf of gas can be commercially produced along with 0.15 and 0.27 Bbl natural gas liquids, respectively. Cost reductions brought about by cutting capital expenditures per well, the required rate of return, or selectively drilling to avoid dry cells increase commercial quantities of gas significantly. Gas reserves in these type accumulations are attractive targets for future drilling. The economic analysis of continuous-type oil plays showed at $18.00 per barrel, 0.44 Bbo oil and 1.05 Tcf of gas is commercial while at $30 per barrel, 1.36 Bbo of oil and 3.97 Tcf of associated gas are commercially producible. Continuous-type gas plays with the lowest costs are in the San Juan Basin, Uinta-Piceance Basin, and Louisiana-Mississippi Salt Basins. Continuous-type oil plays with lowest costs are in the San Juan Basin, Denver Basin, and Western Gulf provinces.

INTRODUCTION

This report summarizes the basic results of the economic analysis of the continuous-type oil and gas accumulations of the U.S. Geological Survey's 1995 National Oil and Gas Assessment. Continuous-type accumulations are defined as those oil and gas resources that exist as geographically extensive accumulations that generally lack well-defined oil/water or gas/water contacts. A single accumulation can be pervasive throughout a large area, so that a continuous-type play is frequently identified with a single or small number of accumulations. Continuous-type plays are not amenable to an assessment methodology which relies on trends in finding rates and field size distributions. Coalbed gas accumulations are properly classified as continuous-type accumulations and the economic analysis for coalbed gas is presented elsewhere (see Attanasi and Rice, 1995).

Unconventional oil and gas resources represent a broad class of hydrocarbon accumulations that traditionally have not been produced by standard development methods. Such accumulations generally include continuous-type deposits. Standard definitions for unconventional oil and gas often hinge on gravity of oil or the permeability of the oil and gas reservoir rock. While most continuous-type accumulations are characterized by poor reservoir permeability, not all low permeable deposits are continuous-type accumulations. The primary reason for the classification of accumulations as discrete or continuous in the 1995 National Assessment is that it allows the geologist to directly couple the type of accumulation with the assessment method.

The economic component of the National Assessment is intended to place the geologic resource assessment into an economic context that is more accessible and easily understood by industry and government decision and policy makers. One goal of the economic analysis is estimation of the incremental costs of transforming undiscovered conventional resources and selected unconventional resources into additions to proved reserves. Incremental cost functions show cost-resource recovery possibilities and are not supply functions as strictly defined by economists. However, the basic data used to construct the functions could be used as input data for oil and gas supply models.

In the following section, the method and results of the geologic assessment of the continuous-type oil and gas plays are briefly reviewed. Then the method and the data used in estimating the incremental costs of finding, developing, and producing the assessed resources are discussed. Results and interpretation of the economic analysis are presented in the concluding sections.

REVIEW OF GEOLOGIC ASSESSMENT OF CONTINUOUS-TYPE ACCUMULATIONS

This section briefly summarizes the geologic assessment of the technically recoverable oil and gas resources in continuous-type plays. The appendix provides definitions of technical terms used in the discussion that follows. A more detailed description of the methodology for assessing the technically recoverable resources is found in Schmoker (1995). In general, a *play* is defined as a set of known or postulated oil or gas accumulations that share similar geologic, geographic, and temporal properties such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A single continuous-type accumulation can be identified as a single play in a province. The geologic assessment was prepared at the play level to take into account important play characteristics such as drilling risks, oil and gas production profiles, and the play's estimated ultimate recovery (EUR) distribution. These characteristics vary significantly across plays in the same province.

Detailed descriptions of the thirteen continuous-type oil and thirty-four continuous-type gas plays that were quantitatively assessed were prepared by the individual province geologists (see Gautier and others, 1995 and Schmoker and Oscarson, 1995). Complete play names for the oil and gas plays are presented in Tables A-1 and A-2 of the appendix. A play was classified as a gas play if the gas to oil ratio was at least 20,000 cubic feet to 1 barrel of oil, otherwise the play was classified as an oil play. Figures 1 and 2 show the approximate locations of the continuous-type oil and gas plays that were assessed. Outlines of the individual plays were prepared by each province geologist and each play was partitioned into a grid of *cells*. The area of the standard cell was estimated to be equivalent to the median drainage area anticipated for wells of that play. If reservoir characteristics varied systematically across the accumulation, the geologist might split the accumulation into two or more plays. Alternatively, if the geologist was uncertain about well drainage area, i.e. cell size, but could attach a probability to each size, then assessment scenarios were prepared that corresponded to each cell size assumption. The final assessment was the weighted outcome of the scenarios. The province geologist assessed the *play probability*, defined as the probability that, in total, the play's untested cells would recover at least 1 million barrels of oil or 6 billion cubic feet of gas. In the few cases where this play probability was less than one, the province geologist maintained that there was a chance that a geologic factor necessary for the existence of the accumulation was deficient.

Because not all wells that penetrate a play test the play, the province geologist was required to interpret, from the drilling record (Petroleum Information, 1993), the play's drilling and discovery history and to estimate the number of cells in the play that had been evaluated. The number of untested cells was determined as the difference between the number of cells in the play and the cells evaluated. Uncertainties associated with play boundaries and geologic interpretations were captured by characterizing the number of untested cells with a probability distribution. A cell was classified as *productive* if there was at least one well with reported production from the play, irrespective of whether the production was commercial. A *nonproductive cell* was a cell evaluated by drilling but where none of the wells reported production. Based on past drilling and geologic information about the undrilled part of the play, the geologist estimated a *success ratio* to represent the fraction of untested cells expected to be productive.

Hydrocarbon recovery from productive cells was characterized by the province geologist with a probability distribution referred to as the *estimated ultimate recovery (EUR) distribution*. An *empirical EUR distribution* was prepared for cells in the play that had reported production based on Petroleum Information's production records (Petroleum Information, 1994). The play's empirical EUR distribution is based on estimates of ultimate recoveries for a sample of wells considered to be representative of the play's range of recoveries. The EUR distribution that the geologist assessed to be representative of the recoveries of untested cells expected to be productive is, hereafter, called the *reported EUR distribution*. Based on geologic knowledge, the province geologist typically adjusted the empirical EUR distribution when assessing the reported EUR distribution. The province geologist was required to choose cell recoveries for seven fractiles (0, 5, 25, 50, 75, 95 and 100th) of the reported EUR distribution. For plays where the historical production data were insufficient to estimate an empirical EUR distribution, the geologist based the reported EUR distribution on that of an analog play.

The distribution of technically recoverable resources for the play was computed using distributions for the number of untested cells, the reported EUR distribution, play probability, and the success ratio. *Technically recoverable* resources are those resources estimated to be producible using current technology but without reference to economic profitability. Table 1 shows the technically recoverable resources of continuous-type gas and oil plays separately because the economics of gas and oil field development are substantially different. The gas plays produce nonassociated gas and natural gas liquids (ngl), and the oil-plays produce crude oil and associated gas. The mean value estimates of the technically recoverable resources were aggregated to the province level.

Data used by geologists in the assessment included the numbers of cells tested and found to be productive. If these data indicated that either more than 100 cells or at least 1 percent of the play's cells had reported production, the play was classified as proven. Otherwise the play's production was unproven. This classification was made to convey to the reader the degree to which production had been established in the play and ultimately the province.

According to Table 1, the mean technically recoverable volume of nonassociated gas assessed in continuous-type gas plays amounted to 302 trillion (Tcf) and 2.1 billion barrels (Bbl) of natural gas liquids. The three provinces having the largest quantities of gas, Southwestern Wyoming, Appalachian Basin, and North-Central Montana, together account for almost three-fourths of the 302 Tcf of gas assessed. More than 70 percent of the gas is contained in plays that were classified as having proven production. The leading provinces with proven production were Southwestern Wyoming, the Appalachian Basin, and the San Juan Basin. The gas shown in Table 1 occurs in sandstones and shales The gas assessed in shales totals 37.6 Tcf and includes all the gas in the provinces of Michigan Basin, Illinois Basin, and Cincinnati Arch, in addition to 15.3 Tcf of gas in the Appalachian Basin. The 302 Tcf assessed in continuous-type gas plays represents more than one-third of the gas assessed in the 1995 National Assessment (U.S. Geological Survey, 1995) and more than twice U.S. proved nonassociated gas reserves as of 1994 (Energy Information Administration, 1994a).

Continuous-type oil plays were estimated to contain an expected or mean value of 2.1 billion barrels of oil (Bbo) and 5.4 Tcf of gas (Table 1). More than four-fifths of the oil is contained in plays that were classified as having proven production. Two-thirds of the oil in continuous-type oil plays occurs in carbonate rocks in the Denver Basin and Western Gulf (in the Austin Chalk plays) provinces and the remaining oil occurs in shales in the other provinces. While this oil is certainly of local importance, it amounts to less than 2 percent of the oil assessed in the 1995 National Assessment (U.S. Geological Survey, 1995).

DATA, ASSUMPTIONS, AND PROCEDURE ECONOMIC ANALYSIS

The purpose of the economic analysis is to estimate the incremental costs of transforming undiscovered resources into additions to proved reserves. The cost functions include the costs of finding, developing, and producing currently undeveloped resources. The incremental cost functions are not the same as the economist's market price supply predictions for the following reasons. At any given price, the oil and gas industry will allocate funds over a number of provinces and sources of supply in order to meet market demand at lowest costs. An observed price-supply relationship represents the culmination of numerous supplier decisions over many projects and regions. The incremental cost functions represent costs that are computed independently of activities in other areas. Furthermore, the incremental cost functions are assumed to be time independent and should not be confused with the firm supply functions that relate marginal cost to production per unit time period. Because of the time-independent nature of the incremental cost functions and the absence of market demand conditions in the analysis, user costs or the opportunity costs of future resource use are not computed. However, the incremental cost functions and the data which underlie the functions can be used as basic data for market supply models.

Data

Geologic and descriptive data were provided by each province geologist and modified in the assessment meetings (see Schmoker, 1995). These data included the play probability; fractiles of the reported EUR distribution; estimated median, minimum and maximum number of undrilled cells and depth; the success ratio; and other data such as gas to oil (or liquids to gas) ratios; and well stimulation practices, if known.

Production profiles of representative wells associated with the fractiles of the reported EUR probability distribution were prepared, because well production streams determine the cashflow stream for the economic analysis. Historical production data for wells that produced from the formation and area of interest were sampled from Petroleum Information's well production file (Petroleum Information, 1994). Then a Fetkovich type-curve analysis (Fetkovich, 1980) was applied to determine the nature of the decline (exponential or hyperbolic) and the rate of decline.[1] With the play's EUR distribution and the corresponding decline functions for the fractiles of the reported EUR distribution, well production forecasts were computed for up to a 50-year period.

Economic and engineering cost data include certain pre-drilling costs; well drilling, completion, and stimulation costs; production equipment costs; water treatment equipment costs; annual production costs; production-related taxes; and federal income taxes. Drilling cost estimates were based on data presented in the Joint Association Surveys (JAS) of Drilling Costs for 1991 and 1992 (American Petroleum Institute, 1992, 1993). Well-stimulation cost estimates were based on data from working papers prepared by Energy and Environmental Analysis, Inc. (1992, Vidas and others, 1992) for the 1992 National Petroleum Council study entitled *The Potential for Natural Gas in the U.S.* (working papers are available from the National Petroleum Council). Cost data were supplemented by information from the literature when the information pertained to the specific play that was assessed (for example see Lingley and Walsh, 1988; Oil and Gas Journal, 1993, 1994; Hass and Lombardi, 1993; Brunsman and Saunders, 1994). Estimates of production equipment costs were based, in part, on oil and gas equipment costs published by the Energy Information Administration (1994b). The procedures for computing costs of treating produced water to meet state regulations were based on water-treatment cost functions prepared by Remediation Technologies, Inc. (1993). State taxes, including State severance and income tax, were the estimated regional tax rates used in the 1993 update of the Gas Research Institute's Hydrocarbon Supply Model (Vidas and others, 1993). The Federal corporate tax rate used in the project analysis was 35 percent. The estimated costs were assumed to represent costs that prevailed in the beginning of 1993.

Assumptions

Calculations were prepared in terms of constant 1993 dollars. The discounted cash flow (DCF) analysis was specific to individual projects and ignored minimum taxes and tax preference items that might be important from a corporate accounting stance. The DCF analysis used a 12 percent required rate of return. Using the play's success ratio, distribution of numbers of untested cells, and the reported EUR distribution, a discrete cell frequency-size distribution was computed with classes corresponding to the EUR's shown in Table 2. For each play, cells at the surface were also assigned to individual depth intervals. A DCF analysis was then prepared for representative cells based on EUR

[1] The particular software used was the MIDA Advanced Petroleum Software by Mannon Associates, Inc., Santa Barbara, California.

size classes and the expected depth of undrilled cells in each successive depth interval of 5000 feet. For calculating the incremental cost functions, it was assumed that the industry was rational and would not explore a given depth interval in a play unless the aggregate expected returns, represented by the expected aggregate after-tax net present values of all commercially developable cells, was sufficient to compensate for all costs, including exploration, development, and production, as well as a specified return to capital. The assumption that the industry must incur the costs of drilling each cell in a depth interval amounts to assuming grid drilling of that part of the play occurring in each depth interval. It was assumed that plays may be partially evaluated and developed if expected costs of exploring deeper cells in the play were not compensated by expected returns.

Even though many of the areas containing the continuous-type plays are rather mature exploration areas and the occurrence of these resources have been previously recognized, the resources may not have been assessed in previous U.S. Geological Survey national assessments. The 1995 National Assessment, which recognizes these continuous-type resources to be distinct from resources in accumulations that can be characterized by field size distributions, presents an initial attempt at the definition and assessment of these resources. Play definitions and development of play boundaries were the responsibility of the province geologist and incorporated the geologist's expert knowledge of the area and interpretation of discovery history. The economic analysis was predicated on these definitions. Additional information could lead to the refinement of plays in subsequent assessments. For example, if the results of future exploration show significantly different empirical EUR distributions for different parts of a single continuous-type play, then the original play may be partitioned into two or more plays. Partitioning of the plays by quality of the resource will improve the accuracy of the cost estimates .

The province geologist provided information describing the general practices regarding production well stimulation and in some instances the "proportion" of wells assumed to be stimulated. In every play there are cells, while classified as productive, that are noncommercial because of low EUR's. It was assumed that these cells are abandoned before production so the operator incurs no production equipment or operating costs. It was assumed that half of the noncommercial wells are stimulated before the operator decides on abandonment. Although some operators may install production equipment and try to produce the well in hopes of recovering operating costs and part of the initial investment, the additional resources from such wells are negligible at a national scale and would not significantly affect results presented here.

Most of the plays are laterally distinct. However, two plays in the Uinta-Piceance Basin and some plays in the San Juan Basin, Denver Basin, and Southwestern Wyoming provinces are stacked so that presumably some wells could be recompleted and produce from more than one play. In fact, for some continuous-type plays, much of the production has been the result of recompletions of wells that had produced from conventional reservoirs. For the base case analysis, it was assumed that a separate well would be required to evaluate each cell in each play or part of a play. For particular provinces where this assumption might not hold, the effects of the assumption were investigated and are reported in the results sections.

For plays where total depth was less than 1500 feet, it was assumed that gas would require extra compression. The production schedules were based on the production profiles of vertical wells, so that economic analysis assumed all wells would be vertical. The wells production schedules for the Antrim Shale plays of the Michigan Basin (6319, 6320) showed large amounts of water produced during the well's initial years. This produced water was assumed to be injected below the zone of production.

Procedure

The reported EUR distribution, the distribution of the number of untested cells, and success ratio were used to calculate a discrete frequency-size distribution of the productive cells at 5000 foot depth intervals of the play. Here, cell size refers to the quantity of recoverable hydrocarbons, that is, the cell EUR. Table 2 shows the cell-size classes used in the analysis. A DCF analysis was prepared for each size class at a given price (assuming a 12 percent rate of return) to determine what part of the frequency-size distribution is commercially developable. The industry will not initiate exploration of the play at a given depth interval unless the aggregate of the after-tax net present value of the developable cells would at least pay for the cost of exploration of the entire depth interval where such costs include the cost of drilling dry holes and noncommercial cells. If the aggregate after-tax net present value of the commercially developable cells was sufficient to cover such costs, the aggregate resources in the commercially developable cells would be added to the incremental cost function. The calculations were repeated assuming progressively higher prices and results were aggregated to the play level and then to the province level to arrive at province incremental cost functions.

INCREMENTAL COSTS: RESULTS AND INTERPRETATION

Geologic assessment and economic costs

Economic costs are, in part, determined by the estimated success ratio and the reported EUR distribution of productive untested cells. Tables 3 and 4 show the estimated success ratio, 50th fractile of the EUR distribution, and the mean of the reported EUR distribution by play. In terms of the economic analysis, the success ratio is used to determine the number of dry wells (cells) that must be drilled in order to obtain a productive cell and the EUR distribution shows what is likely to be recovered once a "productive" cell is found. The EUR distribution determines, in part, how many of the "productive" cells are noncommercial.

The very low success ratios shown for some plays in Tables 3 and 4 seem inconsistent with the concept of a continuous-type accumulation. Perhaps the province geologists assigned the low success ratios as a way of risking the play. A low success ratio could also reflect a low probability of intersecting a permeable pathway to the wellbore. The 50th fractile and expected value of recovery for the assessed EUR distribution is also shown in Tables 3 and 4. The province geologists anchored the 100th fractile of the reported EUR distribution at zero. The 50th fractile values shown in the tables indicate that for many plays the assessed cell recoveries were so small that half the "productive" cells associated with the EUR distributions were unlikely to be commercial, even at prices substantially higher than current levels. Success ratios and EUR distributions significantly affect the economic assessment because the returns to the commercial productive cells must be sufficient to cover the costs of dry holes and the costs of non-commercial "productive" cells.

During the last quarter-century wellhead oil prices have varied over a range from \$3.00 to \$40 per barrel and wellhead gas prices varied from less than \$1.00 to more than \$11.00 per mcf. The Energy Information Administration (1995) has projected wellhead oil prices for 2010 to be between \$23.30 and about \$25 per barrel and the wellhead gas prices between \$3.00 and \$3.75 per mcf. The following discussion focuses on reserve additions which might be expected with an oil price range of \$12 to \$30 per barrel and a gas price range of \$1.00 to \$5.00 per mcf. Even though graphs will show additions to reserves, if real oil prices rise to \$50 per barrel and gas prices rise to \$9.00 per mcf, it would be quite unrealistic to assume that constant real costs would hold at the higher wellhead price levels. The historical experience has been that oil and gas price increases lead to escalation in industry capital and operating costs.

Incremental costs of continuous-type gas plays

Figure 3 presents the incremental cost function for additions to nonassociated gas reserves from continuous-type gas plays in the conterminous 48 states. At \$1.50, \$3.00, and \$5.00 per mcf commercially recoverable additions amount to 12.8, 31.7, and 85.3 Tcf, respectively. For perspective, proved reserves of nonassociated dry gas at the beginning of 1994 were estimated to be 133 Tcf (Energy Information Administration, 1994a). Even at \$3.00 per mcf, the expected additions to reserves amount to almost one-fourth of proved nonassociated gas reserves as of 1994. For each of these three reserve-addition quantities, the required drilling amounts to 9,360, 50,273 and 199,166 wells respectively. At the 1993 gas drilling rate of about 12,000 wells per year, it would take roughly 4 years to drill the wells required for the 31.7 Tcf and 17 years to drill the wells required for 85.3 Tcf. Gas in continuous-type gas plays typically has low natural gas liquid content. and natural gas liquids account for less than 5 percent of the assessed hydrocarbons in these type of plays.

Table 3 shows entry or threshold prices at which the lowest cost part of each gas play initially becomes commercially developable. Plays with entry prices below \$1.50 per mcf include the Central Basin Mesaverde Gas play (2209, San Juan Basin), the Cotton Valley Blanket Sandstones Gas play (4923, Louisiana-Mississippi Salt Basins), and the Tight Gas Uinta Tertiary East play (2015, Uinta-Piceance Basin). The table also shows plays that are not expected to become commercial, even if gas prices were allowed to rise to \$9 per mcf. These plays are characterized by low success ratios and/or are very deep (such as the Deep Synclinal Uinta Mesaverde Play 2020 in the Uinta-Piceance Basin) or have EUR distributions where almost the entire distribution has very low noncommercial recoveries (see 50th fractiles of the Clinton-Medina Medium and Medium-Low Potential plays, 6729, 6730, Appalachian Basin).

The threshold prices shown in Table 3 and the incremental cost functions are predicated on a 12 percent after-tax rate of return and uniform drilling within depth intervals. Indeed, for some plays now under active development, Table 3 shows threshold prices that are substantially above current prices. Reasons for this are that (1) operators may be accepting returns that are substantially less than 12 percent, (2) they may have special geologic information that allows the high grading of the play, or (3) in some cases, current production is coming from recompletions of old wells. If the required after-tax return is set at 6 percent, the commercially developable gas increases by 45 percent to

18.6 Tcf at \$1.50 per mcf and by 65 percent to 52 Tcf at \$3.00 per mcf. The declines in threshold prices extend from \$0.20 to \$2.30 per mcf. For example, the threshold price for the Antrim Shale play (6319) declined from \$3.00 per mcf to \$2.50.

The geologists typically defined continuous-type plays over broad areas so the assessed play characteristics represented the entire area, often obscuring smaller highly productive areas located within the play boundary. If play boundaries delineated the resource by quality, the accuracy of the economic cost estimates would improve. To illustrate this, a special geologic assessment of the highly productive Frontier-Moxa Arch area within the Greater Green River - Cloverly-Frontier Play (3740) was prepared (personal communication from Ben E. Law, 1995). The Frontier-Moxa Arch area is located along the Moxa Arch and represents the shallowest part of the play. The Cloverly-Frontier Play (3740) encompasses about 13,600 square miles while the Frontier-Moxa Arch area covered 917 square miles. A success ratio of 0.8 was assigned to the Frontier-Moxa Arch area instead of 0.6 and its EUR distribution was shifted to higher values than the reported EUR distribution for the Cloverly-Frontier Play (3740). These changes reduced the threshold price shown for Play 3740 by 28 percent to \$3.00 per mcf. Further refinement of the play, strategic drilling, and reduction in the assumed 12 percent after-tax rate of return cut costs to below current market prices.

Figures 4a through 4i present province level incremental cost functions. The province incremental cost functions are drawn with the same horizontal scale axis to show clearly the few provinces where most of the resource is found. Table 6 shows the incremental costs and expected additions to nonassociated gas and natural gas liquid reserves for each of the provinces having continuous-type gas plays. Reserve additions that come with incremental costs of \$1.50 per mcf or less are in the Uinta-Piceance Basin (6 percent), the San Juan Basin (64 percent), and Louisiana-Mississippi Salt Basins (30 percent). Similarly, at \$3.00 per mcf, the provinces contributing the largest quantities of reserve additions are the San Juan Basin (37 percent), North-Central Montana (16 percent), Louisiana-Mississippi Salt Basins (17 percent), and Michigan Basin (13 percent). As incremental costs increase beyond \$5.00 per mcf, large quantities of higher cost reserves are added from North-Central Montana, Southwestern Wyoming, and the Appalachian Basin.

Sensitivity of the estimated costs to the assumption that the entire play must be drilled was investigated by assuming that half the dry cells could be avoided by "selective drilling". The plays most affected by adoption of a selective drilling assumption are those plays having the lowest success ratios. For plays having lower success ratios, i.e. below 0.7, the effect was to reduce the threshold entry price from 10 to 15 percent below the base case value. Overall, the reserves added were unchanged at \$1.50 per mcf, increased by 10 percent at \$3.00 per mcf, and increased by 30 percent at \$5.00 per mcf. Almost two-thirds of the large increase in the reserve additions at \$5.00 per mcf came from the plays in the Southwestern Wyoming province.

The continuous-type gas plays in the Southwestern Wyoming province are stacked. However, the play boundaries are not geometrically congruent so that it is difficult to consider all the possibilities of multiple pay wells. To illustrate one possibility, suppose the Greater Green River-Lewis play (3742) was evaluated as a secondary target and was produced only through well recompletions. Assuming investment costs incurred are one-third the drilling costs of an original well and the cost of well stimulation. The entry or threshold price for the play would decline from $6.60 per mcf to $2.70 per mcf.

Incremental costs of continuous-type oil plays

The aggregate incremental cost function for the continuous-type oil plays for the conterminous 48 states is presented in Figure 5. The oil resources in continuous-type oil plays represent a very small part of the resources assessed in the National Assessment. At $18 per barrel 0.44 Bbo oil and 1.05 Tcf of associated gas can be commercially found and produced. Similarly, at $30 per barrel about 1.36 Bbo and 3.97 Tcf of associated gas is commercial. The drilling required to find and produce the reserves at $18.00 and $30.00 per barrel is 12,305 and 40,519 wells, respectively. Incremental costs and expected additions to crude oil and associated natural gas reserves are presented in Table 6. The table also shows that in the aggregate about 30 percent of the hydrocarbon additions to reserves from continuous-type oil plays are in the form of associated gas. The Austin Chalk plays (4747, 4748, and 4749) of the Western Gulf province and the Greater Wattenberg Codell/Niobrara Oil and Gas play (3904) of the Denver Basin account for most of the associated gas.

Table 4 shows the entry or threshold prices at which the lowest cost part of each play becomes commercial to develop. The continuous-type oil plays showing the lowest costs are the Mancos Fractured Shale (2208, San Juan Basin), Codell/Niobrara (3904, Denver Basin), and the Austin Chalk-Giddings (4748, Western Gulf). In the $18 to $30 per barrel range, the Austin Chalk plays account for almost three-fifths of the oil with most of the remainder coming from the Mancos Fractured Shale (2208) and the Codell/Niobrara (3904) plays. Data supplied by the province geologists indicated that only continuous-type oil plays in the Denver Basin were routinely stimulated.

Table 4 shows the Cretaceous Self-Sourced Fractured Shales Play (2009) of the Uinta-Piceance Basin province with a success ratio of 0.01. The mean of the technically recoverable oil contained in this play is 0.093 Bbo. Productive cells in this play have been confined to anticlinal structures. The province geologist estimated that only 436 cells or 1 percent of the total number of cells in the contiguous area within the play boundary would be productive. If the target structures were identified, eliminating most of the dry cells and increasing the success ratio to, say 0.8, the play's threshold price is $11 per barrel and an additional 94 million barrels would be added to reserves.

The effect of reducing the after-tax required return to 6 percent (from 12 percent) increases commercially developable oil at $18.00 per barrel to 1.01 Bbo. At $30.00 per barrel, however, the reserve increase is negligible. Threshold price declines range from $2.00 (Greater Wattenberg Codell/Niobrara, 3904 and Austin Chalk-Giddings, 4748) to $9.00 per barrel (Fractured Niobrara Greater Silo/Dale Salt Edge Oil, 3920).

Incremental costs were recalculated assuming that by selectively drilling, the industry could avoid drilling half of the dry holes. The effect of such a change in assumptions on the overall economic assessment was limited. At $18 per barrel commercially producible oil increased to 0.67 Bbo, while at $30 per barrel the increase in producible reserves over the base case is negligible. For individual plays, the degree of decline in threshold price level was inversely proportional to the play's success ratio. With the assumption of selectivity, the Fractured Interbed (play 2103) threshold price declined from $22 to $15 per barrel, the Mancos Fractured Shale (2208) from $15 to $11 per barrel, and the Austin Chalk-Outlying (4749) from $30 to $21 per barrel.

Some continuous-type accumulations have been drilled only as secondary targets and a significant proportion of the play's production has resulted from recompletions of wells originally targeted for conventional reservoirs. However, for the base case analysis presented here, it was assumed that a separate well would be required to evaluate each cell in each play or part of a play. Suppose the cost incurred in recompleting wells in a shallower formation is one-third the cost of an original well, but excludes pre-drilling costs and production equipment costs. Under such a scenario, for example, the Denver Basin oil plays' threshold price, based on wells drilled to the underlying J sandstone, would be below $6 per barrel for the Codell/Niobrara oil play (3904), $9 per barrel for the Fractured Niobrara-Greater Silo/Dale Salt-Edge Oil play (3920), and $13 per barrel for the Fractured Niobrara-Greater Northern Denver Basin Oil play (3921). Similarly, under such a scenario, the threshold price of the Bakken Fairway play (3110), based on wells drilled to the underlying Ordovician, would decline to $11 per barrel.

Figure 6 a, b, and c shows the incremental cost functions for the San Juan Basin, Denver Basin, and the Western Gulf provinces. To convey the relative magnitudes of the quantities of potential reserve additions, the vertical and horizontal scales of each graph are the same. In a range of up to $50 per barrel, these three provinces account for 80 to 90 percent of the additions to reserves from continuous-type oil plays.

Summary and implications

The magnitude of the technically recoverable resources of gas estimated in continuous-type gas accumulations is large - more than twice 1993 nonassociated gas proved reserves - and represents a significant target for exploration, production, and advancement in recovery technologies. About 10 percent of the technically recoverable gas resource of 302 Tcf can be commercially produced at $3 per mcf or less. The analysis showed that if the explorationists selectively drill within plays or if development costs per well are spread over more than one producing formation, assessed commercial quantities of gas increase significantly. Continued drilling and development of these continuous-type gas plays, even during periods of low wellhead prices and after the expiration of tax incentives, suggests that these resources are profitable to produce. The technically and commercially recoverable oil in continuous-type oil accumulations for some areas may represent an important local resource, but by national standards the resource accounts for a small percentage of potential additions to proved oil reserves.

In the future, additional drilling and production data may lead to redefinition of play boundaries to reflect the resource quality allowing the cost estimates to fully reflect the high-grading of the resource by the industry. Both the geologic assessment and the economic analysis were tied to historical recoveries and current technology. If well spacing, for example, could be reduced in half because actual well drainage area is half of the area assumed, the total recovery from the play could double. Alternatively, if new technology were developed that could be used to evaluate a cell without drilling, the incremental costs of exploring and producing a play would decline substantially. Finally, improvements in well stimulation technologies reduce risks, but also alter the EUR distribution in such a way as to improve the chances of commercial production.

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APPENDIX A. NOMENCLATURE AND PLAY NAMES

Unconventional oil and gas accumulations.- a broad class of hydrocarbon deposits of a type that traditionally have not been produced using standard development practices Such unconventional deposits generally include continuous-type accumulations. Standard definitions of unconventional oil and gas accumulations often hinge on gravity of oil or the permeability of the oil and gas reservoir rock. While most continuous-type accumulations are characterized by poor reservoir permeability not all low-permeability deposits are continuous-type accumulations.

Continuous-type accumulation.- a hydrocarbon accumulation that is pervasive throughout a large area, that is not significantly affected by hydrodynamic influences, and for which the standard methodology for assessment of sizes and numbers of discrete accumulations is not appropriate.

Play.- a set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.

Cell.- a subdivision of a of a continuous-type oil or gas play the size or area of which is equivalent to the median drainage area of wells producing from the play. A productive cell has at least one well with reported production. A nonproductive cell is a cell that was evaluated with drilling but where none of the wells have reported production. An untested cell is one that has not been evaluated by a well. The number of cells in a play is equal to the area of the play divided by the cell size.

Success ratio.- the fraction of cells in a play expected to become productive.

Play probability.- An estimate, expressed as a decimal fraction, of the chance that oil or natural gas exist within the particular play being assessed.

Estimated Ultimate Recovery (EUR) probability distribution.- a probability distribution of ultimate recoveries of oil or gas, that characterizes the distribution of gas recoveries in productive cells within a play. An empirical EUR distribution is based on the estimated ultimate recoveries of wells thought to be representative of the play's range of recoveries. The reported EUR distribution for untested cells is judged by the assessor to represent the distribution of recoveries from potentially productive, but as of yet untested cells within the play.

Technically recoverable resources.- those resources estimated to be producible using current technology but without reference to economic profitability.

Table A-1. Province, play number and play names for continuous-type oil plays.

Province	Play Number	Play Name
Uinta-Piceance Basin	2009	Cretaceous Self-Sourced Fractured Shales
Paradox Basin	2103	Fractured Interbed
San Juan Basin	2208	Mancos Fractured Shale
North-Central Montana	2804	Bakken Shale Fracture Systems
Williston Basin	3110	Bakken Fairway
Williston Basin	3111	Bakken Intermediate
Williston Basin	3112	Bakken Outlying
Denver Basin	3904	Greater Wattenberg Codell/Niobrara Oil and Gas
Denver Basin	3920	Fractured Niobrara-Greater Silo/Dale Salt-Edge Oil
Denver Basin	3921	Fractured Niobrara-Greater Northern Denver Basin Oil
Western Gulf	4747	Austin Chalk-Pearsall
Western Gulf	4748	Austin Chalk-Giddings
Western Gulf	4749	Austin Chalk-Outlying

Table A-2. Province, play number and play names for continuous-type gas plays assessed.

Province	Play Number	Play Name
Eastern Oregon-Washington	503	Columbia Basin- Basin-Centered gas
Uinta-Piceance Basin	2007	Tight Gas Piceance Mesaverde Williams Fork
Uinta-Piceance Basin	2010	Tight Gas Piceance Mesaverde Iles
Uinta-Piceance Basin	2015	Tight Gas Uinta Tertiary East
Uinta-Piceance Basin	2016	Tight Gas Uinta Tertiary West
Uinta-Piceance Basin	2018	Basin Flank Uinta Mesaverde
Unita-Piceance Basin	2020	Deep Synclinal Uinta Mesaverde
San Juan Basin	2205	Dakota Central Basin Gas
San Juan Basin	2209	Central Basin Mesaverde Gas
San Juan Basin	2211	Pictured Cliffs Gas
North-Central Montana	2810	Northern Great Plains Biogenic Gas, High Potential
North-Central Montana	2811	Northern Great Plains Biogenic Gas, Moderate Potential (Suffield Block Analog)
North-Central Montana	2812	Northern Great Plains Biogenic Gas, Low Potential
Williston Basin	3113	Southern Williston Basin Margin -Niobrara Shallow Biogenic
Southwestern Wyoming	3740	Greater Green River Basin-Cloverly-Frontier
Southwestern Wyoming	3741	Greater Green River Basin-Mesaverde
Southwestern Wyoming	3742	Greater Green River Basin-Lewis
Southwestern Wyoming	3743	Greater Green River Basin-Fox Hills-Lance
Southwestern Wyoming	3744	Greater Green River Basin-Fort Union
Denver Basin	3906	J Sandstone Deep Gas (Wattenberg)
Louisiana-Mississippi Salt Basins	4923	Cotton Valley Blanket Sandstones Gas
Michigan Basin	6319	Antrim Shale Gas, Developed Area
Michigan Basin	6320	Antrim Shale Gas, Undeveloped Area
Illinois Basin	6407	Illinois Basin- New Albany Shale Gas
Cincinnatti Arch	6604	Devonian Black Shale Gas
Appalachian Basin	6728	Clinton/Medina Sandstone Gas High Potential
Appalachian Basin	6729	Clinton/Medina Sandstone Gas Medium Potential
Appalachian Basin	6730	Clinton/Medina Sandstone Gas Medium-Low Potential
Appalachian Basin	6733	Upper Devonian Sandstone Gas High Potential
Appalachian Basin	6734	Upper Devonian Sandstone Gas Medium Potential
Appalachian Basin	6735	Upper Devonian Sandstone Gas Medium-Low Potential
Appalachian Basin	6740	Devonian Black Shale-Greater Big Sandy
Appalachian Basin	6741	Devonian Black Shale-Greater Siltstone Content
Appalachian Basin	6742	Devonian Black Shale-Lower Thermal Maturity

Table 1. Estimates by province of mean values of technically recoverable oil and gas in continuous-type accumulations onshore conterminous United States as of January 1, 1994. [Bbl, billion barrels of liquids;Tcf, trillion of cubic feet; Bbo, billion barrels of oil]

CONTINUOUS-TYPE GAS PLAYS	TOTAL		*PROVEN PRODUCTION		UNPROVEN PRODUCTION	
Province	Nonassoc. Gas (Tcf)	Na. Gas Liquids (Bbl)	Nonassoc. Gas (Tcf)	Gas Liquids (Bbl)	Nonassoc. Gas (Tcf)	Gas Liquids (Bbl)
E. Oregon-Wasington	12.20	0.12	0.00	0.00	12.20	0.12
Uinta-Piceance Basin	16.71	0.10	11.84	0.06	4.87	0.04
San Juan Basin	21.06	0.00	21.06	0.00	0.00	0.00
North-Central Montana	41.27	0.00	5.44	0.00	35.83	0.00
Williston Basin	1.89	0.00	0.00	0.00	1.89	0.00
Southwestern Wyoming	119.17	1.73	107.96	1.62	11.21	0.11
Denver Basin	0.83	0.00	0.83	0.00	0.00	0.00
Louisiana-Mississippi Salt Basins	6.03	0.15	6.03	0.15	0.00	0.00
Michigan Basin	18.87	0.00	4.93	0.00	13.94	0.00
Illinois Basin	1.89	0.00	1.89	0.00	0.00	0.00
Cincinnati Arch	1.39	0.00	1.39	0.00	0.00	0.00
Appalachian Basin	61.21	0.01	55.60	0.01	5.61	0.00
Conterminous United States	302.53	2.12	216.97	1.85	85.56	0.27

CONTINUOUS-TYPE OIL PLAYS	TOTAL		*PROVEN PRODUCTION		UNPROVEN PRODUCTION	
Province	Oil (Bbo)	Associated Gas (Tcf)	Oil (Bbo)	Associated Gas (Tcf)	Oil (Bbo)	Associated Gas (Tcf)
Uinta-Piceance Basin	0.094	0.028	0.094	0.028	0.000	0.000
Paradox Basin	0.242	0.194	0.000	0.000	0.242	0.194
San Juan Basin	0.189	0.094	0.189	0.094	0.000	0.000
North-Central Montana	0.016	0.013	0.000	0.000	0.016	0.013
Williston Basin	0.151	0.128	0.073	0.065	0.078	0.063
Denver Basin	0.285	2.325	0.258	2.272	0.027	0.053
Western Gulf	1.089	2.633	1.089	2.633	0.000	0.000
Conterminous United States	2.066	5.416	1.703	5.093	0.364	0.323

*Plays with proven production have 100 cells productive or at least 1% of total cells productive.
Source: Data on mean values presented in Gautier and others (1995).

Table 2.--Cell size class, based on EUR, used in this report

	Cell Size	
Class	Oil Plays (Thousands barrels)	Gas Play (Billions cubic feet)
1	3.9125 - 7.825	.0234375 -.046875
2	7.825 - 15.625	.046875 - .09375
3	15.625 - 31.25	.09375 - .1875
4	31.25 - 62.50	.1875 - .375
5	62.5 - 125.0	.375 - .750
6	125. - 250.	.75 - 1.5
7	250 - 500	1.5 - 3.
8	500 - 1000	3 - 6.
9	1000 - 2000	6 - 12
10	2000 - 4000	12 - 24
11	4000 - 8000	24 - 48
12	8000 - 12000	48 - 96
13	12000 - 24000	96 - 192

Table 3. Continuous-type gas plays - province, play, play characteristics, threshold price, in dollars per thousand cubic feet, at which play is initally commercially developable with associated reserves and required drilling.*

Province	Play No.	Play Name	Success Ratio	Recovery per productive cell 50th frac (Bcf)	Recovery per productive cell Mean (Bcf)	Average Depth (Ft)	Threshold Price ($/Mcf)	Initial Reserves (Bcf)	Cells Tested
E. Oregon-Wash.	503	Basin-Centered Gas	0.70	0.90	1.42	13100			
Uinta-Pic. Bas.	2007	Mesaverde Williams Fork	0.55	0.90	0.92	7600	3.70	3870	9638
Uinta-Pic. Bas.	2010	Mesaverde Iles	0.55	0.85	0.90	7800	4.10	3750	9792
Uinta-Pic. Bas.	2015	Uinta Tertiary East	0.88	1.10	1.40	5400	1.30	737	707
Uinta-Pic. Bas.	2016	Uinta Tertiary West	0.30	1.08	1.35	6000	2.30	133	375
Uinta-Pic. Bas.	2018	Basin Flank Mesaverde	0.60	0.90	1.06	11900	6.80	588	1082
Uinta-Pic. Bas.	2020	Deep Synclinal Mesaverde**	0.20	0.90	1.06	18400			
San Juan Basin	2205	Dakota Central Basin	0.60	0.60	1.48	6900	3.90	7500	9266
San Juan Basin	2209	Central Basin Mesaverde	0.55	0.80	2.36	2600	1.10	8137	7396
San Juan Basin	2211	Pictured Cliffs	0.50	0.27	0.90	2100	2.50	2669	7294
N. Central Mon.	2810	Biogenic High	0.80	0.80	0.90	1600	1.80	4380	7520
N. Central Mon.	2811	Biogenic Moderate	0.70	0.32	0.43	1900	3.90	18588	67354
N. Central Mon.	2812	Biogenic Low	0.50	0.18	0.26	2100	8.30	14764	119832
Williston Basin	3113	Niobrara Shallow Biogenic**	0.33	0.08	0.11	1000			
Southwestern Wy.	3740	GGR*** -Cloverly-Frontier	0.60	0.70	1.43	15900	4.10	1348	1824
Southwestern Wy.	3741	GGR*** -Mesaverde	0.70	0.90	1.80	14900	3.10	3270	2920
Southwestern Wy.	3742	GGR*** -Lewis	0.70	0.60	1.31	12900	6.60	12975	16014
Southwestern Wy.	3743	GGR*** -Fox Hills-Lance	0.70	0.80	0.90	11300	6.00	1497	3028
Southwestern Wy.	3744	GGR*** -Fort Union	0.70	0.65	0.80	11200	8.00	308	614
Denver Basin	3906	J Sandstone Deep	0.60	0.52	0.60	7700	2.80	613	2315
La-Ms. Salt Bas.	4923	Cotton Valley Blanket	1.00	0.83	3.47	9100	1.20	3477	1257
Michigan Basin	6319	Antrim Shale-Developed	0.99	0.22	0.32	1400	3.00	3985	15703
Michigan Basin	6320	Antrim Shale-Undeveloped	0.80	0.22	0.32	1400	3.40	9620	46730
Illinois Basin	6407	New Albany**	0.50	0.08	0.12	3000			
Cincinatti Arch	6604	Devonian Black Shale	0.50	0.09	0.12	1800			
Appalachian Bas.	6728	Clinton-Medina High	0.90	0.07	0.12	5900	6.10	4313	53829
Appalachian Bas.	6729	Clinton-Medina Medium**	0.70	0.05	0.08	4500			
Appalachian Bas.	6730	Clinton-Medina Med.-Low**	0.30	0.03	0.05	6000			
Appalachian Bas.	6733	U. Devonian Sandstone-High	0.80	0.05	0.08	4600	8.60	5279	99275
Appalachian Bas.	6734	U. Devonian Sandstone-Medium**	0.50	0.05	0.08	5400			
Appalachian Bas.	6735	U. Dev. Sanstone-Med.-Low**	0.30	0.03	0.05	5400			
Appalachian Bas.	6740	Devonian Shale-Big Sandy	0.90	0.33	0.60	3600	2.60	2735	6180
Appalachian Bas.	6741	Devonian Shale-Siltstone**	0.85	0.04	0.09	5400			
Appalachian Bas.	6742	Devonian Shale-Lower Matur.**	0.70	0.10	0.12	3000			

* Initial reserves that are available at the threshold price are generally associated with resources in the shallowest 5000 foot depth interval.
**Indicates threshold price greater than $9 per mcf.
***GGR: abbreviation for Greater Green River

Table 4. Continuous-type oil plays - province, play, play characteristics, threshold price in dollars per barrel, at which play is initially commercially developable with associated reserves and required drilling.*

Province	Play No.	Play Name	Success Ratio	Recovery per productive cell: 50th frac (MMbo)	Recovery per productive cell: Mean (MMbo)	Average depth (Ft)	Threshold Price ($/Bbl)	Initial Reserves (MMbo)	Cells Tested
Uinta-Pic. Bas.	2009	Self-Sourced Shales**	0.01	0.07	0.21	2900			
Paradox Basin	2103	Fractured Interbed	0.20	0.30	0.42	9000	22.00	208	2903
San Juan Basin	2208	Mancos Fractured Shale	0.20	0.03	0.16	3000	15.00	133	5079
N.-Central Mon.	2804	Bakken Shale Fracture Sys.**	0.20	0.02	0.05	7500			
Williston Basin	3110	Bakken Fairway	0.70	0.09	0.14	10500	34.00	55	753
Williston Basin	3111	Bakken Intermediate**	0.20	0.02	0.05	10100			
Williston Basin	3112	Bakken Outlying**	0.10	0.01	0.01	8800			
Denver Basin	3904	Codell/Niobrara	0.50	0.02	0.02	6400	17.00	33	4734
Denver Basin	3920	Niobrara-Silo/Dale	0.90	0.02	0.06	8000	30.00	25	577
Denver Basin	3921	Niobrara-N. Denver Basin	0.50	0.01	0.02	7000	40.00	2	339
Western Gulf	4747	Austin Chalk-Pearsall	0.80	0.06	0.14	7300	20.00	369	4348
Western Gulf	4748	Austin Chalk-Giddings	0.90	0.07	0.14	8300	18.00	259	2492
Western Gulf	4749	Austin Chalk-Outlying	0.25	0.05	0.09	7300	30.00	20	974

* Initial reserves that are available at the threshold price are generally associated with resources in the shallowest 5000 foot depth interval.

** Indicates threshold price greater than $50 per barrel.

Table 5. Continuous-type gas accumulations: incremental costs of additions to reserves for provinces* and for the conterminous United States. [Mcf, thousand cubic feet; Tcf, trillion cubic feet; Bbl, billion barrels]

Province Name	Cost ($/Mcf)	Nonassociated Gas (Tcf)	Natural Gas Liquids (Bbl)	Required Wells
Uinta-Piceance Basin	1.00	0.00	0.000	0
	1.50	0.74	0.005	707
	2.00	1.84	0.014	1740
	2.50	2.04	0.015	2115
	3.00	2.06	0.015	2115
	3.50	2.15	0.016	2115
	4.00	6.05	0.035	11753
	4.50	10.16	0.053	22389
	5.00	11.47	0.059	22389
San Juan Basin	1.00	0.00	0.000	0
	1.50	8.21	0.000	7396
	2.00	8.74	0.000	7396
	2.50	11.44	0.001	14690
	3.00	11.66	0.001	14690
	3.50	11.69	0.001	14690
	4.00	19.51	0.001	23956
	4.50	19.55	0.001	23956
	5.00	19.57	0.001	23956
North-Central Montana	1.00	0.00	0.000	0
	1.50	0.00	0.000	0
	2.00	5.00	0.000	7520
	2.50	5.02	0.000	7520
	3.00	5.05	0.000	7520
	3.50	5.24	0.000	7520
	4.00	23.99	0.000	74874
	4.50	24.29	0.000	74874
	5.00	24.38	0.000	74874
Southwestern Wyoming	1.00	0.00	0.000	0
	1.50	0.00	0.000	0
	2.00	0.00	0.000	0
	2.50	0.00	0.000	0
	3.00	0.00	0.000	0
	3.50	3.28	0.049	2920
	4.00	3.29	0.049	2920
	4.50	4.64	0.070	4744
	5.00	4.65	0.070	4744

table 5 continued

Denver Basin	1.00	0.00	0.000	0
	1.50	0.00	0.000	0
	2.00	0.00	0.000	0
	2.50	0.00	0.000	0
	3.00	0.61	0.000	2315
	3.50	0.63	0.000	2315
	4.00	0.64	0.000	2315
	4.50	0.65	0.000	2315
	5.00	0.72	0.000	2315
Louisiana-Miss. Salt Basins	1.00	0.00	0.000	0
	1.50	3.86	0.097	1257
	2.00	5.36	0.134	1740
	2.50	5.37	0.134	1740
	3.00	5.51	0.138	1740
	3.50	5.52	0.138	1740
	4.00	5.57	0.139	1740
	4.50	5.58	0.139	1740
	5.00	5.67	0.142	1740
Michigan Basin	1.00	0.00	0.000	0
	1.50	0.00	0.000	0
	2.00	0.00	0.000	0
	2.50	0.00	0.000	0
	3.00	3.99	0.000	15703
	3.50	13.67	0.000	62433
	4.00	13.78	0.000	62433
	4.50	14.33	0.000	62433
	5.00	15.47	0.000	62433
Appalachian Basin	1.00	0.00	0.000	0
	1.50	0.00	0.000	0
	2.00	0.00	0.000	0
	2.50	0.00	0.000	0
	3.00	2.78	0.000	6190
	3.50	3.07	0.000	6714
	4.00	3.12	0.000	6714
	4.50	3.14	0.000	6714
	5.00	3.39	0.000	6714

table 5 continued

Conterminous United States	1.00	0.00	0.000	0
	1.50	12.82	0.103	9360
	2.00	20.96	0.148	18396
	2.50	23.88	0.150	26065
	3.00	31.65	0.154	50273
	3.50	45.24	0.204	100447
	4.00	75.94	0.225	186705
	4.50	82.35	0.263	199165
	5.00	85.31	0.271	199165

* Expected incremental costs of continuous-type gas plays in the Eastern Oregon-Washington province, Williston Basin, Illinois Basin, and Cincinnati Arch exceeded $5.00 per Mcf and are therefore not included in this table.

Table 6. Continuous-type oil accumulations:incremental costs of additions to reserves for provinces* and for the conterminous United States. [bbl, barrel; Bbo, billion of barrels of oil; Tcf, trillion cubic feet]

Province Name	Cost ($/bbl)	Crude Oil (Bbo)	Associated Gas (Tcf)	Required Wells
Paradox Basin	12	0.000	0.000	0
	15	0.000	0.000	0
	18	0.000	0.000	0
	21	0.000	0.000	0
	24	0.208	0.166	2903
	27	0.208	0.166	2903
	30	0.225	0.180	2903
San Juan Basin	12	0.000	0.000	0
	15	0.132	0.066	5079
	18	0.145	0.072	5079
	21	0.145	0.072	5079
	24	0.145	0.073	5079
	27	0.145	0.073	5079
	30	0.149	0.074	5079
Denver Basin	12	0.000	0.000	0
	15	0.000	0.000	0
	18	0.035	0.344	4734
	21	0.035	0.349	4734
	24	0.040	0.398	4734
	27	0.040	0.401	4734
	30	0.207	1.829	24148
Western Gulf	12	0.000	0.000	0
	15	0.000	0.000	0
	18	0.258	0.631	2492
	21	0.629	1.523	6840
	24	0.676	1.635	6840
	27	0.678	1.640	6840
	30	0.777	1.881	8389
Conterminous United States	12	0.000	0.000	0
	15	0.132	0.066	5079
	18	0.437	1.048	12305
	21	0.809	1.945	16653
	24	1.069	2.272	19556
	27	1.071	2.280	19556
	30	1.358	3.965	40519

* Expected incremental costs for plays in the North-Central Montana and Williston Basin provinces exceed $30 per barrel, and are therefore not included in the table..

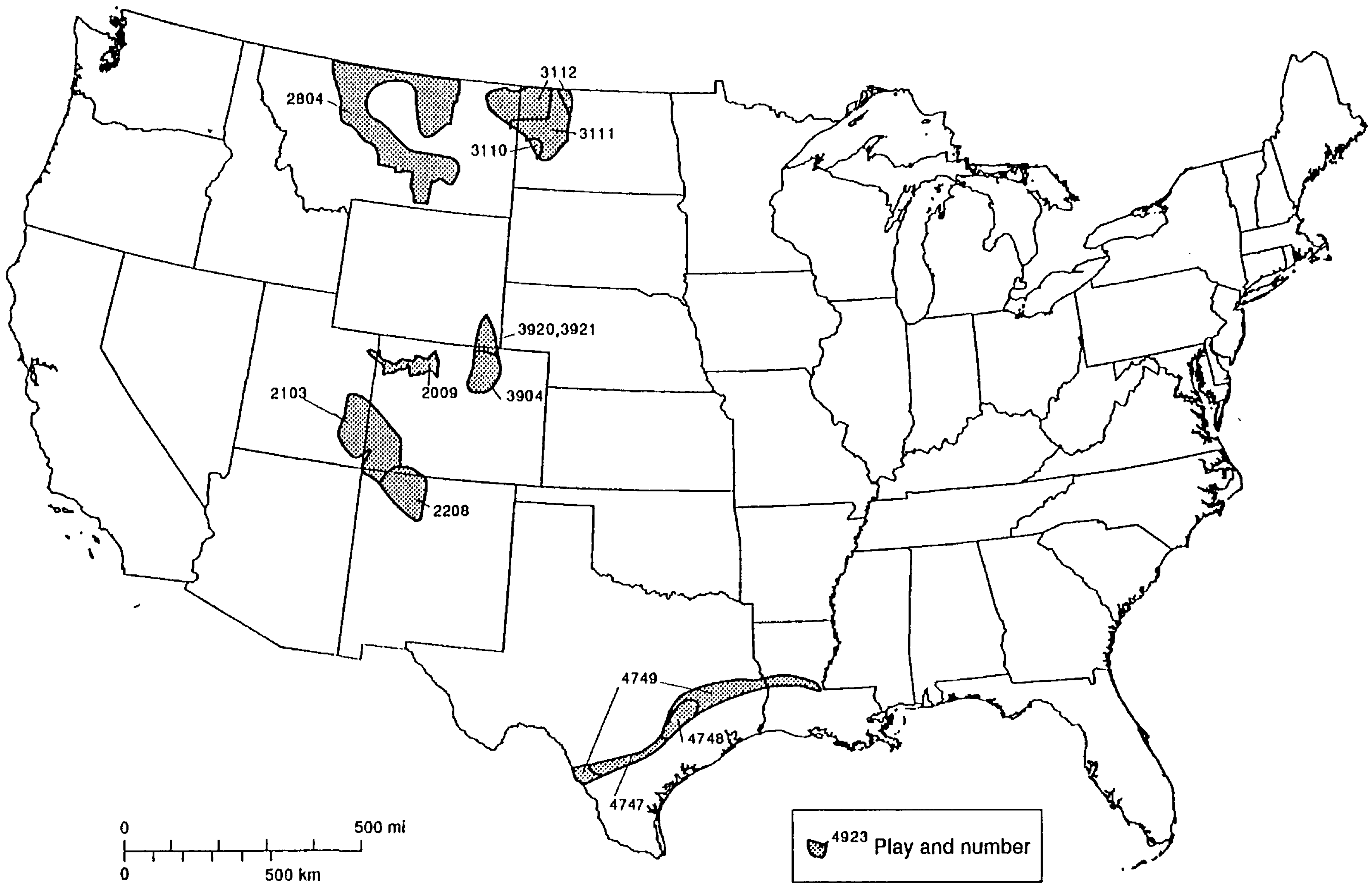

FIGURE 1. Locations of assessed continuous-type oil plays. Table A-1 shows play names and play codes. See Gautier and others (1995) or Schmoker and Oscarson (1995) for descriptions of individual plays.

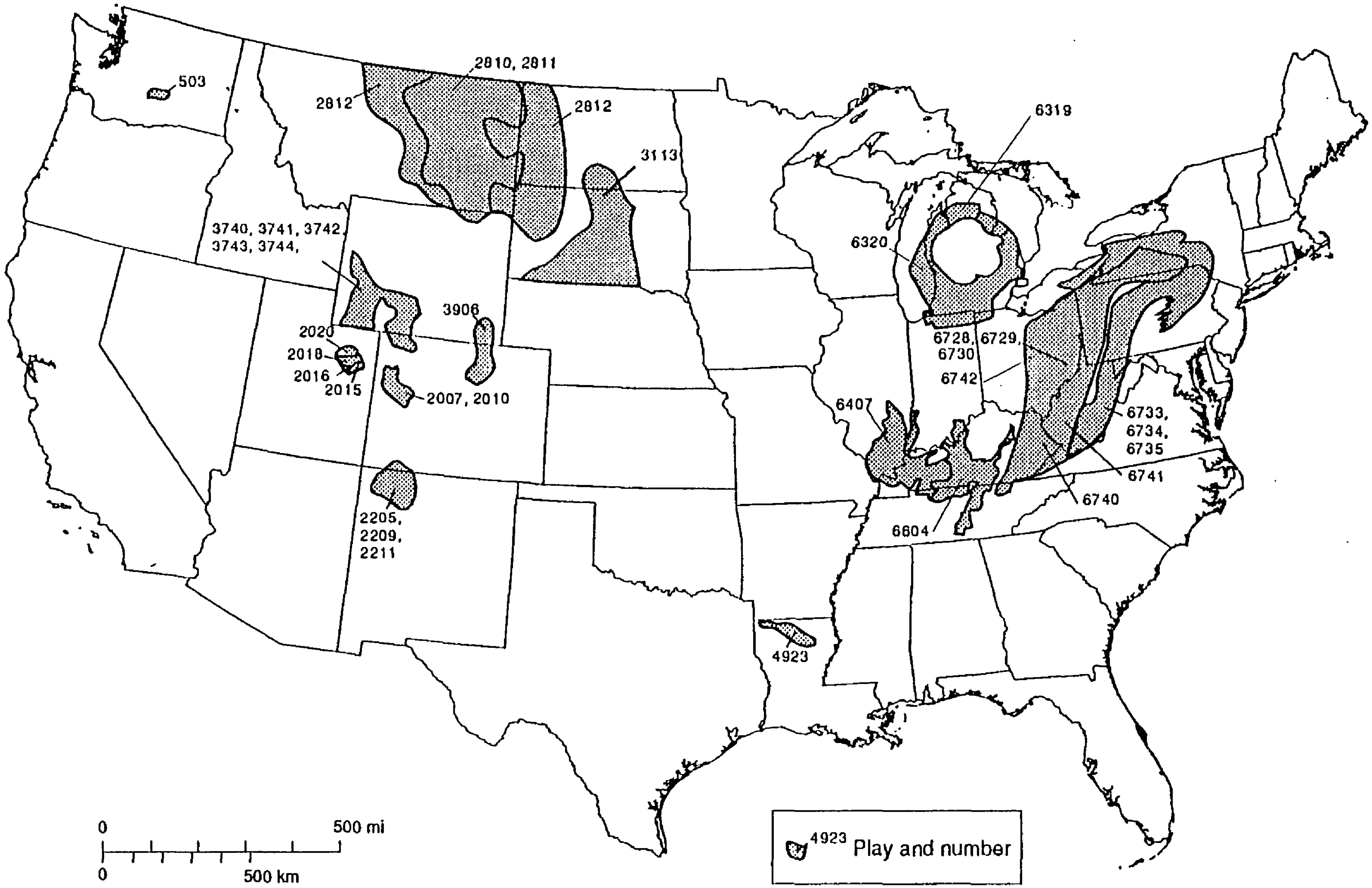

FIGURE 2. Locations of assessed continuous-type gas plays. Table A-2 shows play names and play codes. Plays 6728, 6729, and 6730 along with plays 6733, 6734, and 6735 are all laterally distinct, however, the scale of the location map could not capture this detail. See Gautier and others (1995) and Schmoker and Oscarson (1995) for detailed descriptions of individual plays.

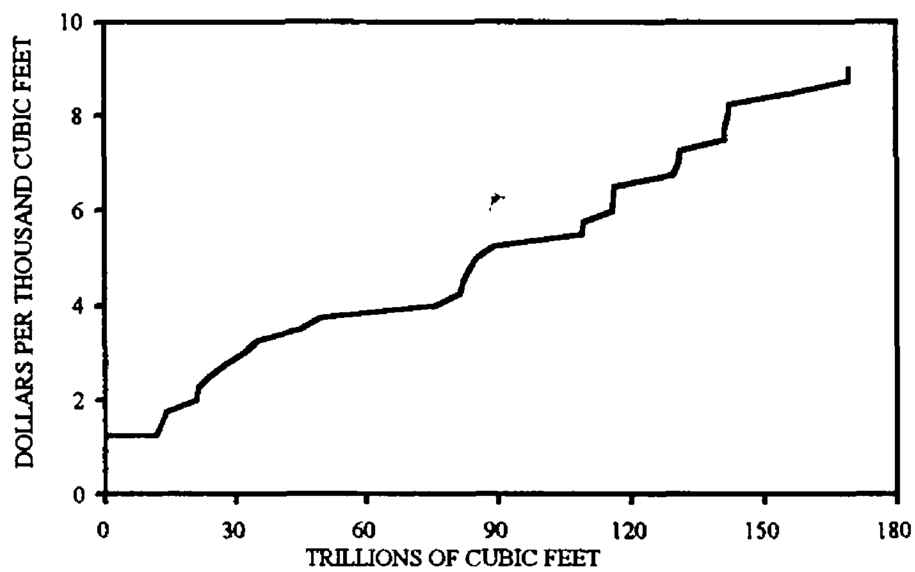

FIGURE 3A. Incremental costs, in dollars per thousand cubic feet, of finding and producing technically recoverable nonassociated gas in continuous-type gas accumulations in the conterminous United States.

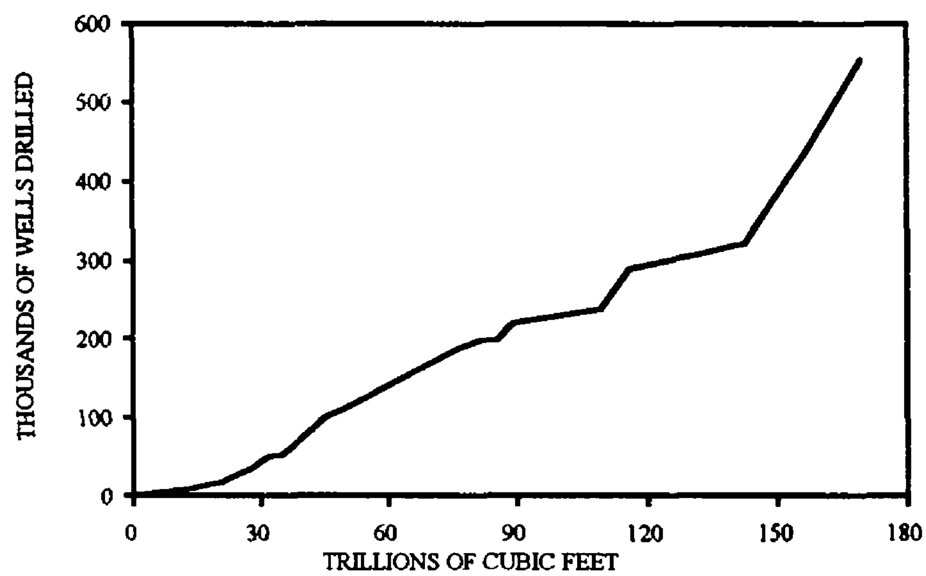

FIGURE 3B. Drilling required, in thousands of wells, to find and produce corresponding additions to nonassociated gas reserves that are shown in Figure 3A from continuous-type gas accumulations in the conterminous United States.

FIGURE 4A. PROVINCE 20 - UINTA-PICEANCE BASIN

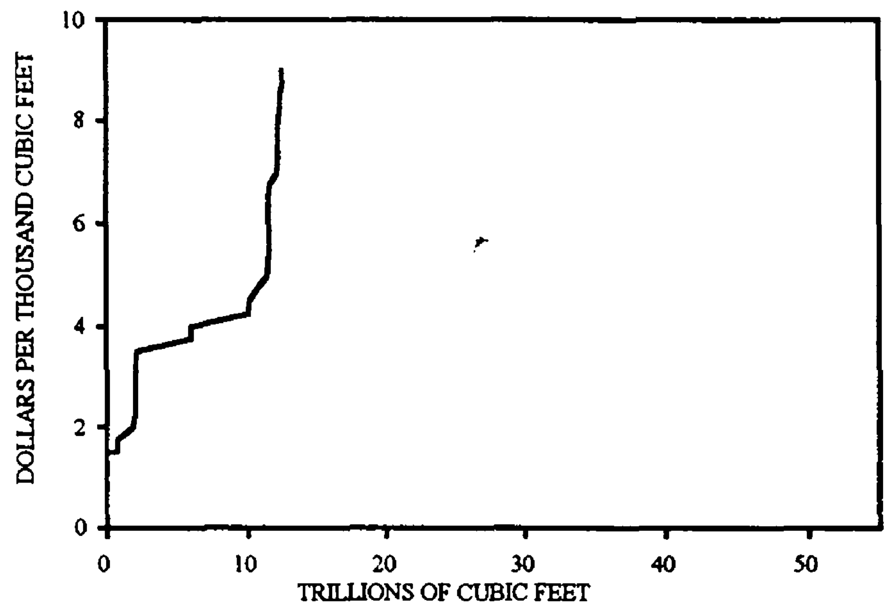

FIGURE 4B. PROVINCE 22 - SAN JUAN BASIN

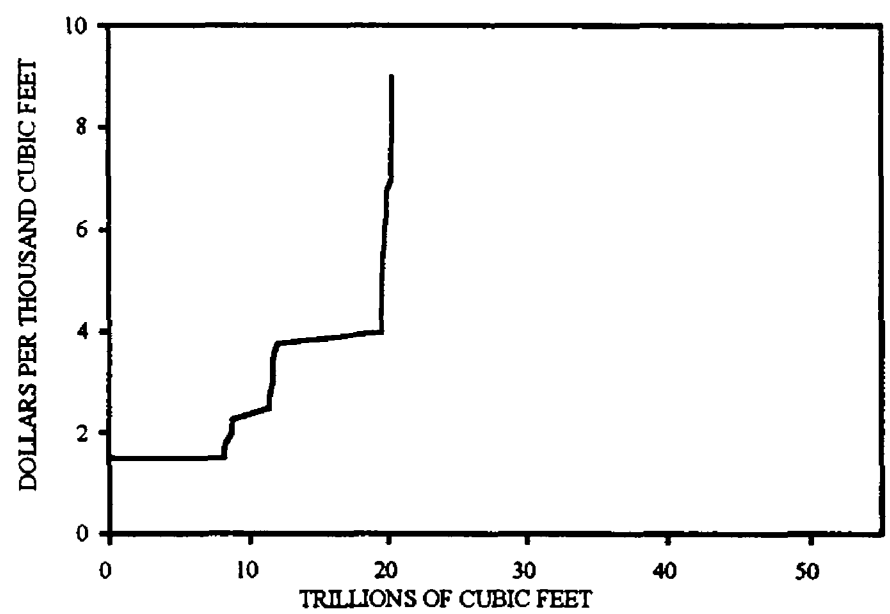

Figure 4. Incremental costs, in dollars per thousand cubic feet, of finding and producing technically recoverable nonassociated gas from continuous-type gas accumulations in individual provinces. A. Uinta-Piceance Basin; B. San Juan Basin; C. North-Central Montana; D. Southwestern Wyoming; E. Denver Basin; F. Louisiana-Mississippi Salt Basins; G. Michigan Basin, H. Appalachian Basin.

FIGURE 4C. PROVINCE 28 - NORTH-CENTRAL MONTANA

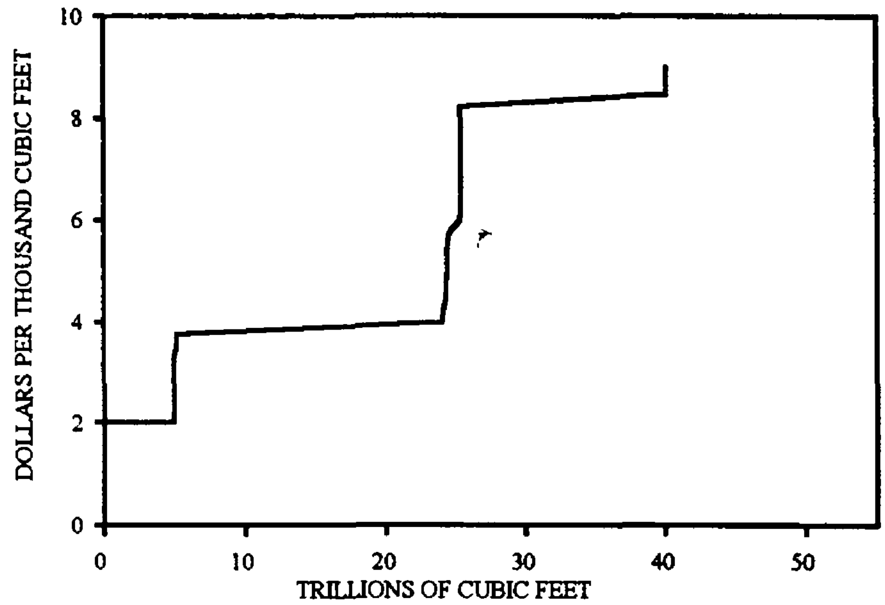

FIGURE 4D. PROVINCE 37 - SOUTHWESTERN WYOMING

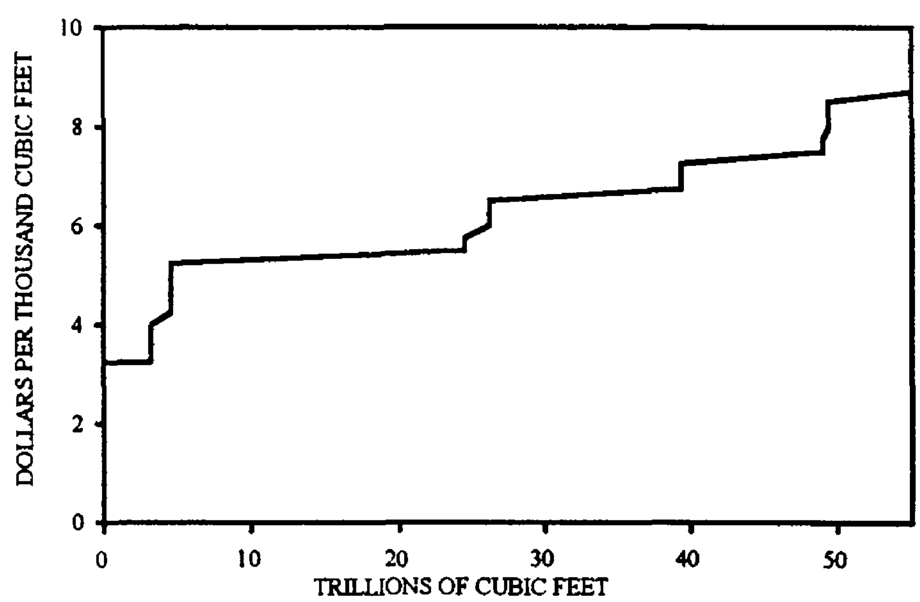

Figure 4. (cont.) Incremental costs, in dollars per thousand cubic feet, of finding and producing technically recoverable nonassociated gas from continuous-type gas accumulations in individual provinces. A. Uinta-Piceance Basin; B. San Juan Basin; C. North-Central Montana; D. Southwestern Wyoming; E. Denver Basin; F. Louisiana-Mississippi Salt Basins; G. Michigan Basin, H. Appalachian Basin.

FIGURE 4E. PROVINCE 39 - DENVER BASIN

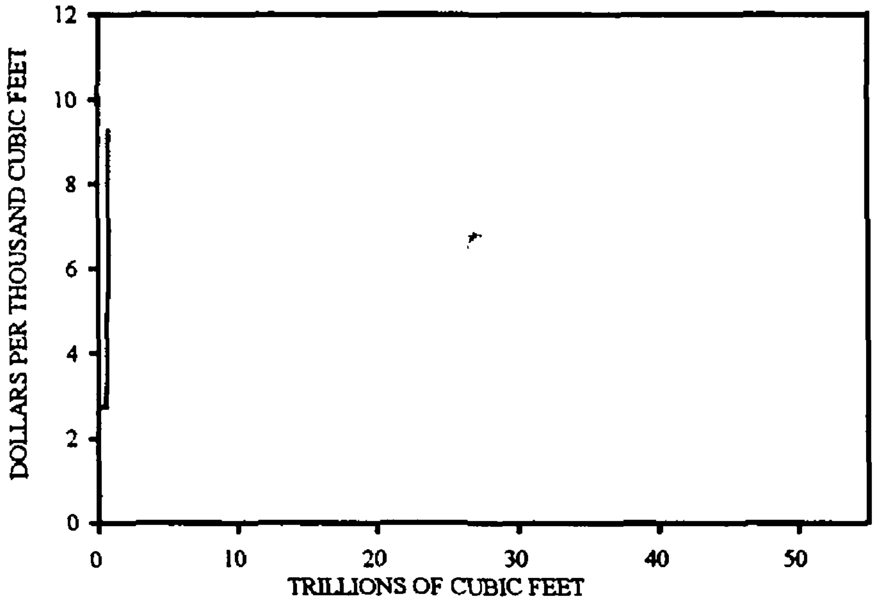

FIGURE 4F. PROVINCE 49 - LOUISIANA-MISSISSIPPI SALT BASINS

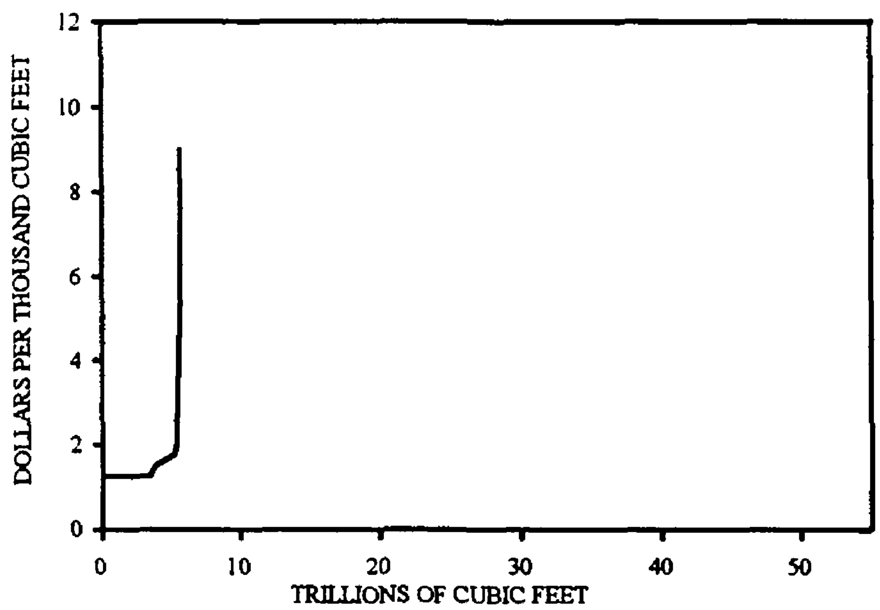

Figure 4. (cont.) Incremental costs, in dollars per thousand cubic feet, of finding and producing technically recoverable nonassociated gas from continuous-type gas accumulations in individual provinces. A. Uinta-Piceance Basin; B. San Juan Basin; C. North-Central Montana; D. Southwestern Wyoming; E. Denver Basin; F. Louisiana-Mississippi Salt Basins; G. Michigan Basin, H. Appalachian Basin.

FIGURE 4G. PROVINCE 63 - MICHIGAN BASIN

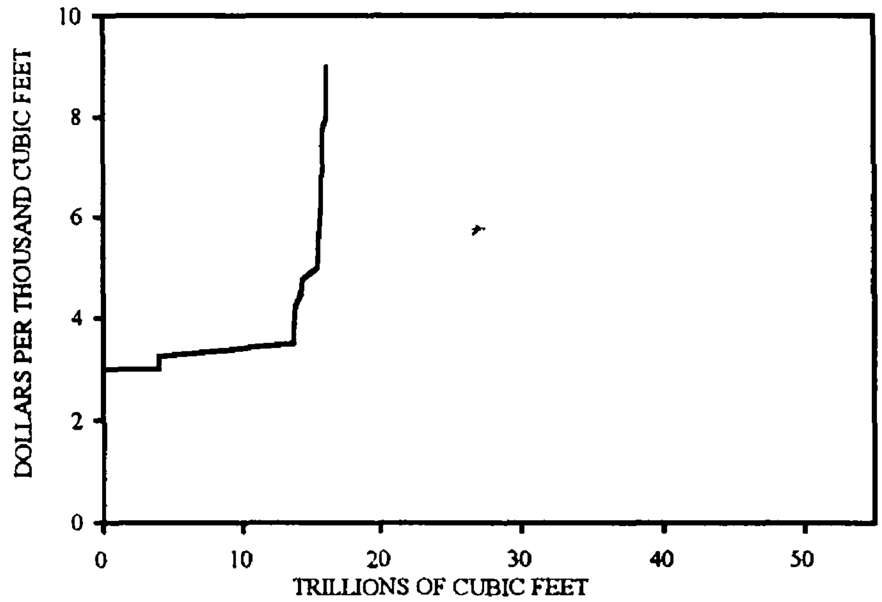

FIGURE 4H. PROVINCE 67 - APPALACHIAN BASIN

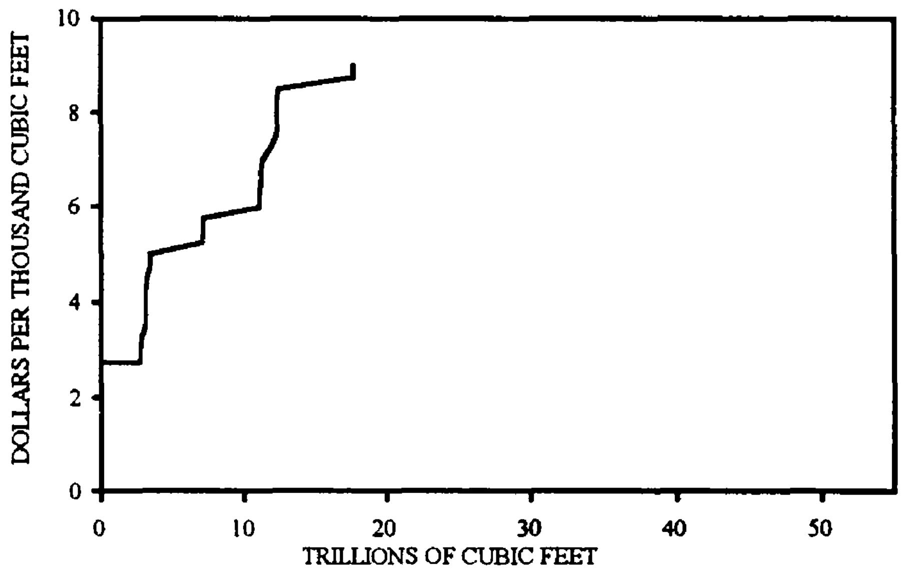

Figure 4. (cont.) Incremental costs, in dollars per thousand cubic feet, of finding and producing technically recoverable nonassociated gas from continuous-type gas accumulations in individual provinces. A. Uinta-Piceance Basin; B. San Juan Basin; C. North-Central Montana; D. Southwestern Wyoming; E. Denver Basin; F. Louisiana-Mississippi Salt Basins; G. Michigan Basin, H. Appalachian Basin.

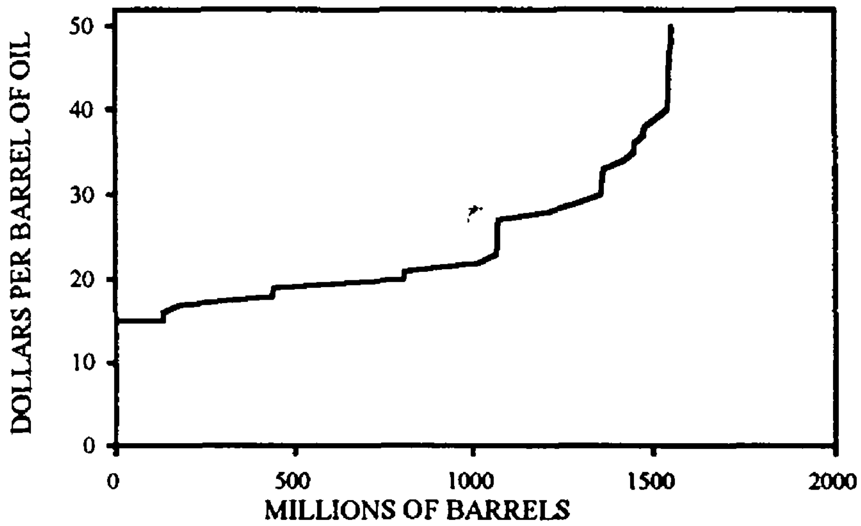

FIGURE 5A. Incremental costs, in dollars per barrel, of finding and producing technically recoverable crude oil from continuous-type oil accumulations in the conterminous United States.

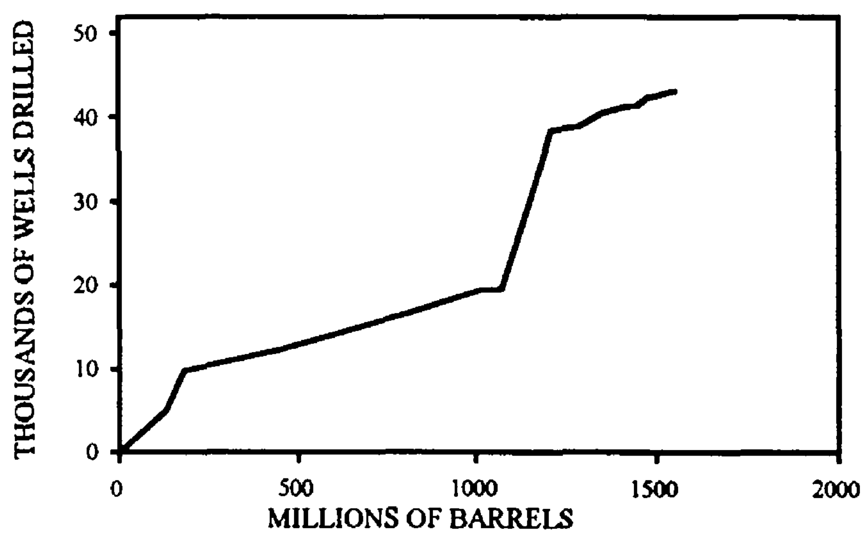

FIGURE 5B. Drilling required, in thousands of wells, to find and produce corresponding additions to crude oil reserves that are shown in Figure 5A from continuous-type oil accumulations in the conterminous United States.

FIGURE 6A. PROVINCE 22 - SAN JUAN BASIN

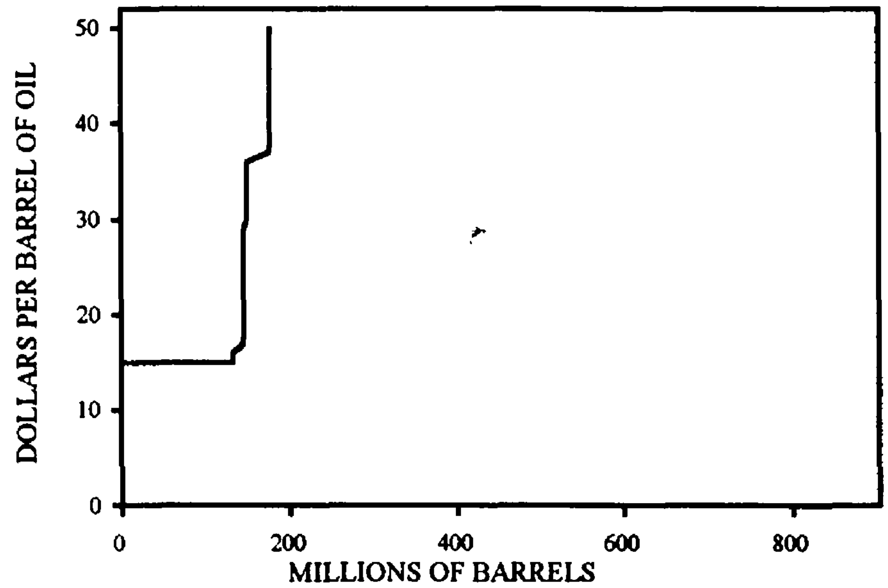

FIGURE 6B. PROVINCE 39 - DENVER BASIN

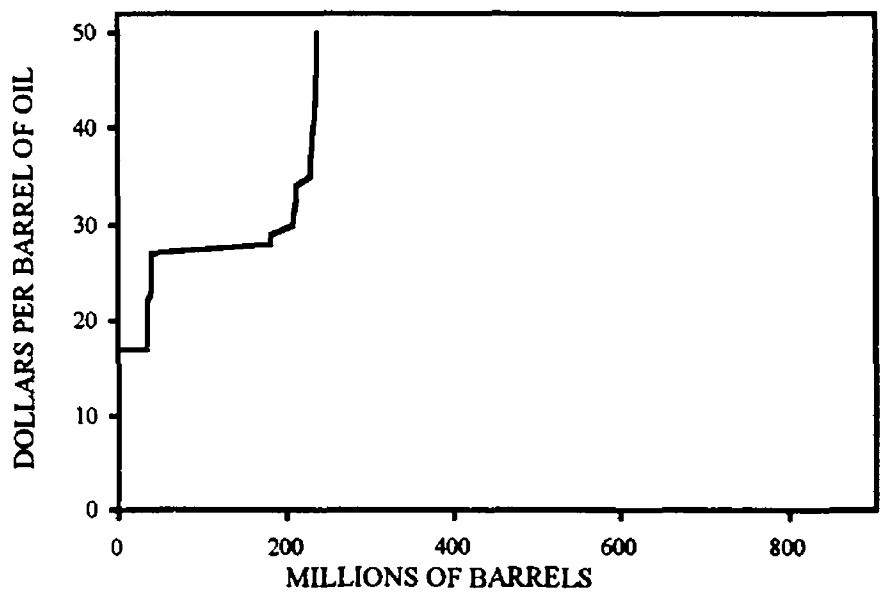

FIGURE 6. Incremental costs, in dollars per barrel, of finding and producing technically recoverable crude oil from continuous-type oil accumulations in individual provinces. A. San Juan Basin; B. Denver Basin; C. Western Gulf

FIGURE 6C. PROVINCE 47 - WESTERN GULF

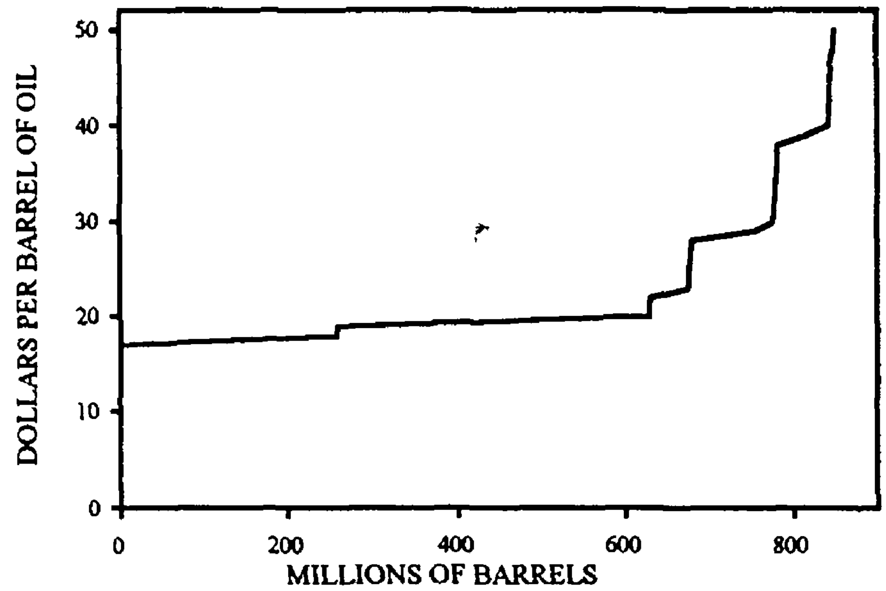

FIGURE 6. (cont.) Incremental costs, in dollars per barrel, of finding and producing technically recoverable crude oil from continuous-type oil accumulations in individual provinces. A. San Juan Basin; B. Denver Basin; C. Western Gulf