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Hot deep origin of petroleum: Shelf and shallow basin evidence and application

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HOT DEEP ORIGIN OF PETROLEUM:

SHELF AND SHALLOW BASIN EVIDENCE AND APPLICATION[1/]

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ABSTRACT

Oil and gas pools in shallow basins or on the shallow, stable shelves of deeper sedimentary basins may not be exceptions to the model of a hot deep origin of petroleum. The oil in shallow basins is directly associated with faulting extending out of the deepest parts of the basin. Evidence exists that some of these shallow basins have been much hotter in the past either from igneous activity or from a higher geothermal gradient. Uplift and erosion may also have removed substantial thicknesses of sediments in some of these basins.

Oil on the stable shallow shelves of deep basins may have originated in the deeper part of the basin and undergone long lateral migration to the traps where it is now found. Conduits for such migration have been sandstones in delta-distributary systems (eastern Oklahoma and Kansas), reef trends (Alberta, Canada), or regional porosity and permeability in sheet carbonates (Anadarko basin, western Oklahoma and Kansas).

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The model applied herein allows us to (1) predict which areas of the stable shelves of deep basins should produce hydrocarbons and which areas should not, (2) predict the type of hydrocarbon (gas or oil), (3) set the limit of lateral updip migration of hydrocarbons within any one formation in a basin, and (4) predict the downdip occurrence of hydrocarbons in the formation. The model should also help us determine which shallow cratonic basins should produce oil and which should not.

INTRODUCTION

Oil and gas accumulations in shallow sedimentary basins (sediment thicknesses equal to or less than 20,000 ft (6.10 km) and accumulations on the stable shelves of deeper sedimentary basins appear to contradict the model of a hot deep origin of petroleum (Price, 1976). However, a review of oil occurrences on stable shelves and in shallow basins shows that their geology does fall within the requirements of the model. Examples are given to show how the model can be applied to shelf and shallow basin exploration.

SHELF OIL

Lateral Migration

Although only a few would now deny the possibility of lateral oil migration, a number of geologists still question the possibility of long-distance lateral oil migration. Yet at Ghawar oil field of Saudi Arabia, which is 140 mi (225 km) long (Arabian American Oil Company, 1959), oil entering the north (downdip) end of the trap must have traveled at least 140 mi (225 km) to reach the southern extremity of the trap. Gussow (1955) noted that the Kirkuk field of the Persian Gulf basin has free reservoir connection along its entire length of 60 mi (96 km). The East Texas field shows free reservoir communication along its entire length of 43 mi (69 km) (Lahee, 1934). If oil fields exist with lengths of 40 to 140 mi (64 to 225 km), it is not difficult to envision possible movement of at least an order of magnitude larger than this. In fact, Gussow (1975) believed the oil making up the Athabasca tar sand deposit could have migrated laterally as much as 2,000 mi (3,200 km). Momper (1975) believed the oil in the tar sands of Western Canada has migrated laterally hundreds of kilometers. He also stated the oil on the Central Kansas Uplift represents a documented case of at least 500-600 km (312-375 mi) of lateral oil migration from the Anadarko basin. Evans (1975) believed long distance oil migration has been demonstrated in Western Canada and the Persian Gulf. It is a crucial assumption here that as long as enough hydrocarbons are present and adequate porosity and permeability are maintained in continuous carrier beds, petroleum will migrate updip and on strike until it is all trapped, lost through seepage, or becomes so heavy and viscous that it can no longer move.

Gussow's Principle

Gussow's (1954) principle of differential entrapment of oil and gas, combined with the model of a hot, deep origin (Price, 1976), allows one to describe the hydrocarbon distribution on the shelf area of the basin. As hydrocarbons move updip into a trap (stage 1, Fig. 1), eventually the spillpoint of the trap is reached (stage 2), and any further movement of gas into the trap displaces oil out of the trap and permits the oil to move updip. The trap becomes totally filled with gas (stage 3) with continued updip movement of hydrocarbons into it. Any further movement of hydrocarbons bypasses the trap and continues updip.

Figure 2 envisions the process over time within a series of four traps. The end result is that all the traps are filled to the spillpoint, with the downdip traps containing only gas, and the updip traps only oil.

If the deepest part of a basin is indeed the source of most of the oil and gas in a basin, then, by Gussow's (1954) principle, in any one stratigraphic unit the deeper traps would be expected to contain only gas and the shallower traps only oil. Figure 3 represents such a hypothetical basin. Traps over the basin deep contain only gas (and only dry gas may be expected in some cases). Updip, a thin areal ring surrounding the deep basin contains gas pools with thin oil columns. Further updip, oil pools with small gas caps are present. This transitional stage may not be well defined in some basins. On the stable shelf only oil pools with no gas caps are found, and the API gravity and gas-oil-ratios (GOR) decrease continuously updip in any one stratigraphic unit, as the oils are subjected to the ever increasing influence of bacterial attack and water washing.

For updip lateral migration to occur, according to Gussow (1954), traps along the migration route must be filled to the spillpoint at the time of the migration. However, these same traps may not necessarily be presently filled. If fracturing or faulting exists in the trap, oil and especially gas may leak out slowly over geologic time, long after migration has been completed. Also, if the area received additional sedimentation after lateral migration was completed, the pressure on the gas pool would be increased, causing the gas pool to decrease in volume and no longer to be at spillpoint.

Salisbury (1968) noted that methane has a lower critical temperature than other hydrocarbon gases and thus always remains a gas in the pressure and temperature regime that characterizes the deeper reservoirs of the West Texas Permian basin. However, in this same pressure and temperature range, other hydrocarbon gases are more commonly condensed to liquids. Thus the distribution of the heavier ("wet") gases in a basin can also fulfill Gussow's (1954) principle. If a gas pool with a methane gas cap and a condensed phase of wet gas becomes filled to spillpoint, further entry of methane into the trap displaces the condensed wet gases out of the trap and sends them updip into shallower traps. Because of the lower pressure and temperature conditions updip, these displaced liquids return to a gaseous state. The end result is dry gas in traps of the deep basin and increasing amounts of wet gases on the stable shelf area of the basin. The gas distribution in the West Texas Permian basin (Fig. 4) is an example. Another example is the Arkoma basin of Eastern Oklahoma and Western Arkansas (Branan, 1968), which produces exclusively dry gas throughout the deep basin. However, towards the shelf of the basin, in Oklahoma, the liquid content of the gas gradually increases, and on the stable shallow shelf thin oil columns are found under the gas. Further updip, in Hughes County, Oklahoma, small oil fields with gas caps are found, and further north and west are the rich oil pools of the shallow shelf area of the Arkoma basin in eastern Oklahoma and Kansas.

The cracking of heavier hydrocarbons to methane due to increased reservoir temperatures deeper in a basin also has been invoked to explain such basinal gas distribution in the past. However, Price (1978) presented evidence that the process of in-reservoir maturation may not be occurring at the pressures and temperatures of known oil pools.

Central Kansas Arbuckle Group Production

Walters (1958) restated and provided evidence for Rich's (1931a, 1931b, 1933) earlier hypothesis that the oil in the Arbuckle Group Cambrian and Ordovician) in central Kansas ("area of interest," Fig. 5) had originated at depth in the Anadarko basin and had migrated hundreds of miles north to the shallow shelf in central Kansas. The Arbuckle dolomite in this area produces oil and some gas at depths of 3,200 to 4,400 ft (0.98 to 1.34 km) from over 15,000 wells. The dips in the area of production are only 1/10 to 1/4 degree per mile. The hydrocarbons are in the top of the Arbuckle, and either Simpson Group shales (Ordovician) or Pennsylvanian sediments (due to an unconformity) form the seal for the traps, which may be anticlines, buried hills, or stratigraphic traps. The porosity of the Arbuckle results either from dolomization or from a subaerial exposure with ground water movement that occurred in Pennsylvanian time.

Figure 6 shows the area of interest of Figure 5 in more detail. Salient features are the regional southwest dip into the Anadarko basin, and the central Kansas uplift, a regional high which isolates the shallow Salina basin of Kansas and Nebraska from the Anadarko basin. Although Rich's (1931a, 1931b, 1933) concept that the Arbuckle oil in central Kansas had originated far to the south in the Anadarko basin deep met with severe criticism, he believed that his hypothesis would stand the test of time and made two predictions: (1) the Salina basin (then the north Kansas basin) would never produce Arbuckle oil and (2) the southern side of the central Kansas uplift would hold significant undiscovered Arbuckle fields. Figure 7 shows the oil and gas distribution in the area of interest, and as Walters (1958, p. 2172) noted "Seldom have a geologist's predictions both positive and negative been as abundantly confirmed." Not only is Arbuckle oil absent in the Salina basin but the central Kansas uplift has largely prevented oil in all formations from migrating northward from the Anadarko basin into the Salina basin (Fig. 8). Landes (1970) noted that it is an enigma why the Salina basin is barren of oil even though other areas in Kansas south and west of it, which have the same structure, stratigraphy, and geologic history, produce abundant oil and gas. If the oil and gas were of local origin, Landes' (1970) point is especially valid. But if the hydrocarbons originated from the Anadarko basin, then the answer to the question could be that the regional high of the area (the central Kansas uplift) cut off the northward migration of oil, thus prevent it from ever reaching the Salina basin.

Walters (1958) provided further evidence in support of Rich's (1931a, 1931b, 1933) hypothesis, with his study of the distribution of Arbuckle oil and gas in central Kansas as related to Gussow's principle. Gas is present only in the southwesternmost and structurally lowest traps of the area (Fig. 7). Walters outlined paths of updip hydrocarbon migration where one passes from gas pools, to gas pools with thin oil columns, to large oil columns with minor gas caps, and lastly to traps with only oil. He gave examples of traps filled exactly to the spill point, including the major Kraft Prusa field of Barton County. Anticlines only a few miles north and east (updip) of these productive structures are barren, although they are otherwise identical: They contain porous Arbuckle rocks identical in lithology and stratigraphy to the producing Arbuckle rocks at similar depths; they have adequate reservoir seals and structural closure; and they formed at the same time and under the same conditions as the productive anticlines. To explain these barren structures, Walters (1958) believed that not enough oil and gas migrated from the Anadarko basin to fill downdip structures so that hydrocarbons could spill updip into the barren structures.

The known hydrocarbon distribution in central Kansas helps demonstrate how this model (Price, 1976) can be used for hydrocarbon exploration on the stable shelf area of a basin. If the hydrocarbons originate in the deep basin and migrate laterally updip for long distances, they will obey Gussow's (1954) principle. Thus we may assume that all traps downdip along the migration route must be filled to the spillpoint. In the present case, the Arbuckle downdip from the central Kansas production is a viable exploration target; any Arbuckle traps in the diagonally ruled area of Figure 7, or along the migration route the hydrocarbons followed through Oklahoma, should contain hydrocarbons. Landes (1970) noted that the Arbuckle in southwest Kansas has not been explored, as it is considered too deep (although it lies at depths shallower than 10,000 ft (3.05 km). Also, hydrocarbon production maps show that no Arbuckle production has been established in the Oklahoma portion of the migration route the Arbuckle hydrocarbons of central Kansas must have taken. However, the postulated undiscovered Arbuckle reserves will be gas only, as the gas pools on the southwest end of the central Kansas uplift (Fig. 7) show all oil has been displaced updip in accord with Gussow's (1954) principle. No Arbuckle exploration should be carried out in the Salina basin because it is too shallow to generate its own hydrocarbons, and because tests of nearby anticlines updip from producing structures have no shows, which defines the updip limit of oil migration from the Anadarko basin.

Texas Panhandle

The Texas Panhandle (lower left corner Fig. 5) provides another example of the use of this model (Price, 1976) in shelf and shallow-basin exploration. Figure 9 shows the area in greater detail. By the Price (1976) model the Palo Duro and Dalhart basins are too shallow to generate their own oil, and no evidence exists that they have been significantly deeper in the past. The Cimarron uplift, a regional high separating the shallow Dalhart basin from the deep Anadarko basin to the east, prevents updip lateral oil migration from the Anadarko basin into the Dalhart basin. The Dalhart basin should therefore be dry. Due south of the Palo Duro basin (off area of Fig. 9) is the Matador uplift, a regional high separating the shallow Palo Duro basin from the deep and productive West Texas Permian basin. The Matador uplift prevents northward migration of oil into the Palo Duro basin. The Amarillo uplift, another regional high, separates the Anadarko basin from the Palo Duro basin, and thus prevents southward migration of oil into the Palo Duro Basin from the Anadarko basin. On the other hand, the Amarillo uplift is the primary exploration target predicted by my model, because it is a fault-block high next to a deep sedimentary trough. Further, because the Anadarko basin is deep enough to generate its own hydrocarbons, the interior of this entire basin (upper right corner of Figure 9) is a viable exploration target.

The oil and gas distribution of the Texas Panhandle (Fig. 10) shows, as expected, that the Palo Duro and Dalhart basins are barren. Furthermore, one of the large hydrocarbon fields of the world, the Hugoton-Panhandle field (Pippin, 1970), lies on the Amarillo uplift. The field contains 7 billion bbls of oil-in-place and 70 Tcf of recoverable gas, most of which is in the Wolfcampian Provincial Series of the Permian System. Although it first appears that the Hugoton-Panhandle field is an exception to Gussow's (1954) principle of gas downdip and oil updip, this is not so. The Hugoton-Panhandle should be considered as a single field in a large anticline with an oil leg on the northern, downdip side of the anticline (the Amarillo uplift) and a gas cap which rides over the Amarillo uplift and extends north through Oklahoma and into Kansas (off Fig. 10). Northward migration of oil along the uplift was halted by porosity and permeability changes in the extreme northwest corner of Hutchinson County, Texas. Porosity and permeability are interconnected throughout the entire field, as the same gas-oil and oil-water contacts cut across all formational boundaries in the field. Mason (1968) notes that the gas-producing reservoirs for the field correlate through all three states in which the field lies.

Delta Systems

Regional delta systems that dip into deep basins and increase greatly in thickness downdip are perhaps the most common avenues of transport to carry hydrocarbons from the deep basins to the shallow shelves. Most geologists in the past have called upon a local (and apparently random) generation for oil found in delta sands of the stable shelf. However, according to the Price (1976) model, the oil in these pools would originate in the deep basin, travel up faults that cut the downdip portion of these delta-sand distributary systems, and then migrate off the faults into the sands. The hydrocarbons would then migrate updip to be caught by subtle stratigraphic or structural traps on the shallow shelf area of the basin.

This model offers a viable exploration approach for the stable shelf. Hydrocarbons undergo long lateral migration from the deep basin and are emplaced in a generally predictable manner in laterally continuous reservoirs, rather than being randomly emplaced by local generation and migration.

Eastern Oklahoma and Kansas.--Visher et al (1971) documented such a delta system on the stable shelf area of the Arkoma basin in northern Oklahoma. The authors studied the Lower to Middle Pennsylvanian, (Morrowan, Atokan and most of the Des Moinesian). This represents 400-500 ft (122-152 m) of sediment at the Oklahoma-Kansas border, 5,000 ft (1.52 km) of sediment 150 mi (241 km) south of this border, and over 20,000 ft (6.10 km) of equivalent sediment further south in the Arkoma basin deep. The detailed study was based on surface, paleocurrent, core and electric-log examinations of more than 5,000 wells. The authors concluded that their case was well documented for a delta system which prograded from a narrow channel only a few miles wide at the Kansas Oklahoma border into a much wider and thicker system to the south. The channel sand was deposited in a shallow shelf area restricted by marshes and bays. A complex of distributaries and channels prograded south and east into the Arkoma basin deep, where extreme thicknesses of sands and shales were deposited. The Des Moinesian sandstones of the Bluejacket delta system (Bluejacket Sandstone Member of Krebs Formation in Kansas or of Boggy Formation in Oklahoma) have produced over 1.5 billion bbls of oil (Fig. 11) mainly from stratigraphic traps. In view of the spatial and temporal delineation of this delta system (Visher et al, 1971) one can envision how hydrocarbons entered this continuous system of sand distributaries much further south in the Arkoma basin deep and migrated updip for long distances before being trapped in eastern Oklahoma and Kansas on the stable shelf of the basin.

The authors also show that the Prue, Red Fork, Booch, and Skinner deltas all developed in a similar manner. The Booch delta system was studied in detail by Busch (1959); Cole (1969) and Dogan (1969) studied the Skinner delta system; and Hudson (1970) described the Red Fork delta system (Fig. 12), which directly overlies the Bluejacket delta system. The sands he studied were 150 mi (242 km) long by 20 mi (32 km) wide and included the Red Fork sands as well as equivalents (the Burbank and Bartlesville) all of the Boggy Formation in the Cherokee Group of Des Moinesian age. Hudson concluded these were channel sands that were a part of a large delta system. He found that this delta system also thickened as it prograded south into the Arkoma basin.

It has been stated that the producing sands of eastern Oklahoma and Kansas (and other areas, such as the Denver, Powder River and Eastern Venezuela basins) are isolated, elongate, lenticular sands completely surrounded by shale (Landes, 1970), and that the hydrocarbons they contain were derived from the surrounding shales (Baker, 1962). However, work by Busch (1959), Cole (1969), Dogan (1969), Hudson (1970), Visher et al (1971), and others, shows that these sands are not isolated bodies surrounded by shale, but are continuous sand distributary systems which extend back to the deep basin environment. The possibility that the hydrocarbons in these sands have traveled laterally updip for great distances from the deep basin is compatible with the geology of these systems, and evidence exists in a number of basins that this is the case.

Powder River Basin.--Hegna (1968) discussed a trend of fields in the eastern (stable shelf) region of the Powder River Basin from South Coyote to West Moorcroft which produce from the Fall River Sandstone of the Inyan Kara Group (Lower Cretaceous) over a distance of 22 mi (35 km) (Fig. 13). Hegna (1968) noted that the fields are all interconnected, as pressure communication is maintained through the entire trend. The traps are stratigraphic and consist of clean sandstone passing updip into shale or tight siltstone. Berg (1968) studied the sands of the trend and concluded the system was a meandering channel sand. According to the Price (1976) model, the oil in these fields would have originated from the basin deep and migrated updip in the delta system of which this channel sand is a member. The trend of API gravity (Fig. 13) in these fields is consistent with this concept, because updip from the source of the oil, API gravity is expected to decrease (Fig. 3). The fact that these oils are all trapped at about the same depth (and temperature), allows us to rule out oil gravity differences due to in-reservoir maturation.

Eastern Venezuela.--The Greater Oficina area (Renz et al, 1958), near the hinge line of the Eastern Venezuela basin (Fig. 14), has at least 17 fields that re expected to produce 100 million bbls or more each. The total EUR of these 17 fields is 3.7 billion bbls (Martinez, 1970); and Oficina, the largest field in the area, has an EUR of 610 million bbls. Stratigraphic and fault traps impound the oil in sands of the Oficina Formation (Oligocene) in all these fields. Over 100 channel sands with thicknesses ranging from 2-180 ft (0.6-55 m) produce oil in the area. The sands trend north for long distances into the basin deep but grade rapidly into shale east and west.

Just downdip from the Oficina area is the Anaco thrust, which trends N 50° E, dips northwest back to the basin deep, and has 1,400-2,000 ft (427-610 m) of throw. The Tertiary along the basin axis is 30,000-40,000 ft thick, and a thick Cretaceous section is also present (Renz et al, 1958). According to my model, the Anaco thrust would have permitted transportation of hydrocarbons from these thick sediments to the Oficina area.

Renz et al (1958) noted that in the Oficina area, hydrocarbons are always found in fault blocks towards the basin, regardless of whether the fault dips north or south. This suggests that the oil migrated updip from deeper in the basin, because if the oil were of local origin it would be scattered randomly throughout all the fault blocks and not just in the blocks towards the basin. Mencher et al (1953, p. 769) had previously noted that the normal faults found on the southern stable shelf of the eastern Venezuela basin "provide the necessary traps for oil and gas migrating updip out of the central part of the basin." Renz et al (1958) noted that stratigraphic traps in the channel sands of the Oficina area have an insufficient source-bed contact for the over 3.7 billion bbls of recoverable oil found in the area. However, if the Anaco thrust transported the fluids from the deep basin, the source bed area would have been much larger. Renz et al (1958) further noted it is puzzling why the Freites Formation (Miocene) is barren while the Oficina Formation produces in the Oficina area. The Freites formation conformably overlies the Oficina Formation and represents a continuation of Oficina type of deposition into the Miocene. The lithology and environment of deposition are the same for the two formations, which also have had the same structural and geologic history. If the Oficina oil is of local origin, there should be oil in the Freites. But if, on the other hand, abnormally pressured fluids traveling up the Anaco thrust encountered the long, thin, continuous Oficina channel sands first, the fluds would enter the Oficina sands and thus never have a chance to enter the sands of the overlying Freites.

A late migration of oil into the Oficina area is called for because the faulting that forms many of the traps in the area was a late Miocene-Pliocene event. The Pliocene orogeny that caused the Anaco thrust also could have caused the late migration of oil into the fault traps.

Other examples of production on the stable shelf area in sand distributary systems of deltas are the Cretaceous sands of the eastern stable shelf of the Powder River Basin, the Cretaceous sand production of the eastern stable shelf of the Denver basin, the Pennsylvanian sand production of the Dallas-Fort Worth basin, and the Pennsylvanian and Mississippian sand production of the Illinois basin.

Fold Belts

Large areal basins that have been affected by plate collision and subduction with subsequent low-angle overthrusting can have large reserves on their stable shelves. These substantial reserves result from the large amounts of overpressured water (including dissolved oil and gas) which move out of the deep basin along thrust faults during deep basin destruction. Hubbert and Rubey (1959) and Rubey and Hubbert (1959) have shown that such water must be present for thrusting to take place. The bulk of the fluids moving up these large thrust faults out of the basin deep (Fig. 15) will first encounter a potential conduit in the underthrust blocks. The fluids will move off the faults into these conduits and migrate updip for long distances onto the stable shelf until subtle traps are encountered. Portions of the fluids, however, can enter reservoirs in the overthrust block, which can result in production in the thrust faulted and folded region of the basin (the foldbelt).

The structural style of the Western Canadian Alberta basin is characterized by thrust faulting and folding, and a large percentage of the basin's reserves are on the stable shelf in reef trends. Previous investigators believed that the shales surrounding the reefs are the source for the hydrocarbons in the reefs, and some have stated that these shales totally enclose the reefs. However, according to the present concept, these hydrocarbons have migrated from the deep basin via thrust faults, off the faults and into porous conduits, and updip for long distances to their present traps. If this is true, then fields in a reef trend should all be interconnected and we should see Gussow's distribution of gas downdip and oil updip in any one trend. The Swan Hills reef trend (Hemphill et al, 1970) of central Alberta (Fig. 16) has in-place reserves of 5.9 billion bbls and 4.5 Tcf. The producing unit is the Swan Hills Member (Upper Devonian) of the Beaverhill Lake Formation. The expected distribution of gas downdip and oil updip is present. When the initial reservoir pressure of each field is plotted against the producing depth (Fig. 17), the fields all plot on the same straight line showing they are all interconnected, in this case by the Devonian Gilwood Sandstone Member of the Watt Mountain Formation.

Gussow (1954) previously noted that the beds formed by off-flank reef debris are excellent pipelines for updip migration of oil in western Canada. Hitchon (1968) noted that the interconnected reef complexes of the Upper Devonian Woodbend Group contain the major oil and gas fields of western Canada. Figure 18 shows such a trend in southern Alberta with production in Upper Devonian reefs. Gussow's distribution is present: gas fields downdip pass into oil fields with gas caps updip, which give way to fields having only oil further updip. API gravities as well as gas-oil ratios decrease updip as one expects by this model. The fields in this area have produced 1.61 billion barrels and 2.56 Tcf to 1/1/73 from Upper Devonian sediments of the Woodbend Group.

Other examples of long distance lateral oil migration onto the stable shelves of deep basins due to intense structural deformation over the basin deep are: the Paleozoic production of Algeria; the Jurassic carbonate and Cretaceous sand production of the Arabian platform in the Persian Gulf basin; the Pennsylvanian carbonate production on the shelf of the Paradox basin of southern Colorado and Utah; and the the production on the stable shelf of the Appalachian basin.

SHALLOW BASINS

Other apparent exceptions to the model of a hot, deep origin of petroleum are cratonic basins that presently seem too shallow and too cold to have generated their own oil but that obviously have generated their own hydrocarbons. The Denver, Illinois, Williston, Michigan, North Park, and Paris basins are examples.

Illinois Basin

The Illinois basin (Bond et al, 1971) is a north-trending spoon shaped structure (Fig. 19) of gently dipping Paleozoic sediments which thicken southward. The basin contains 11.7 billion bbls of discovered in-place oil to 12/31/68 (Bond et al, 1971). Major structural features are the east-trending Rough Creek wrench fault of northern Kentucky and southern Indiana, which separates the Fairfield basin to the north from the Moorman syncline to the south, and the north-northwesttrending La Salle anticlinal belt in eastern Illinois.

The Moorman syncline differs from the Fairfield basin to the north. A thick, black, Upper Cambrian shale in the Moorman syncline is equivalent to carbonate strata in the Fairfield basin, which are the oldest sediments there. Lower and Middle Cambrian sediments are probably present in the Moorman syncline. Further, the Moorman syncline is much deeper than the Fairfield basin. Smith and Palmer (1974) report a sediment thickness in excess of 20,000 ft (6.10 km) in the Moorman syncline (not shown in Fig. 19). Bond et al. (1971) reported that the deep areas of the Moorman syncline have been extensively faulted, fractured and subjected to high-temperature hydrothermal mineralization as well as igneous intrusions. Other igneous intrusions have been encountered in the area of southern Illinois, western Kentucky and on the southwest shelf of the Moorman syncline. Landes (1970) reported peridotite dikes and hydrothermal mineralization along the Rough Creek wrench fault. Most of this high-temperature activity took place at the end of the Paleozoic when the major movement along the Rough Creek fault occurred.

Landes (1970) reported that extensive preglacial erosion has removed significant sediment thicknesses from the basin. Damberger (1971), from coal-rank studies, concluded that either extensive erosion had occurred in the Illinois basin or the basin had suffered excessive heat flows in the past due to advanced stages of coal diagenesis at shallow depths. Further, data supplied to this author demonstrate that shales at depths of 1,000-3,000 ft (305-915 m) have densities of as much as 2.65 grams per cubic centimeter, which shows that these sediments have been buried much deeper at one time.

The distribution of oil (Fig. 20) within the basin suggests that the high temperatures from the hydrothermal mineralization and igneous activity in the Moorman syncline could have caused origin and migration of oil according to the present concept. The hydrocarbons could have originated from the deep Moorman syncline, migrated up the Rough Creek wrench fault, and veered laterally off the fault into the shallower sediments of the Illinois basin. The west-southwest trending fault located in west-central Kentucky, south of the Rough Creek fault and east-southeast of the highly mineralized zone, also could have carried oil from the basin deep. The degree of control the Rough Creek fault has on the spatial occurrence of oil suggests that the oil is genetically related to the fault. Landes (1970) noted that the oil fields over the basin deep of southern Illinois and western Kentucky are all in overthrust folds. As the distance from the Rough Creek fault increases the structural style of the oil pools changes to gentle folds with normal faults. Bond et al. (1968) gave a map showing the 21 producing gas fields of the basin; all but one of these are over the basin deep. This is to be expected, as the traps over the basin deep must first be filled to the spillpoint with gas before updip migration of gas to the shallow shelf (north) area of the basin can occur.

The Illinois basin is not the exception to my model that it first appears to be, but on the contrary offers evidence supporting it. Although the basin presently is too cold to meet the temperature requirements of the concept, it was much hotter in the past due to extensive high-temperature hydrothermal mineralization and igneous activity in the deepest part of the basin. Shale densities and coal maturation show the basin was either deeper or hotter, or both, in the past. The main faulting in the basin has a profound influence on the spatial distribution of the oil, and fields over the basin deep are all associated with faults.

Williston Basin

The Williston basin (Landes, 1970; Ashmore, 1971; Hansen, 1974), with 17,000 ft (5.18 km) of sediment at the deepest point, appears to be an exception to the present hypothesis. The basin (Fig. 21) was structurally active from Middle Ordovician to Late Cretaceous time. The sediments are a thick Cambrian to upper Paleozoic sequence, a Mesozoic section of thin Triassic and thinner Jurassic-Cretaceous, and a thin Tertiary cover in the middle of the basin. Carbonates dominate the Paleozoic section, which also includes evaporites and minor shales. The Mesozoics sediments are mainly clastic. The Nesson and Cedar Creek anticlines are the main structural features of the basin. The Nesson anticline trends north for over 100 mi (161 km), plunges south, and is a large, long, low fold with many nodes and saddles along its entire length. The Cedar Creek anticline, also over 100 mi (161 km) long, is asymmetrical and has a steep southwest flank. The axis rises and falls along the entire length of the structure, again creating a series of nodes and saddles.

The main production in the basin is from the Paleozoic sediments, with the Mississippian having yielded about 75 percent and the Devonian 10 percent of the production. Most of the basin's reserves are along the Nesson and Cedar Creek anticlines in sediments of the Madison Group (Mississippian) and also on the northeast shelf of the basin (southeast Saskatchewan and southwest Manitoba), where again Madison Group sediments are the main producers. The EUR for the basin is 2.15 billion bbls (Hansen, 1974).

The production in the Williston basin is either directly associated with faults or updip from faults. Dow (1974) noted that there are documented faults along both the Nesson and Cedar Creek anticlines, McCrae and Swenson (1968) also noted that the west flank of the Cedar Creek anticline is faulted. Thomas (1974) documented extensive block-lineament faulting in the Williston basin that is closely associated with the oil production.

Dow (1974) carried out an extensive geochemical study of oil-family source-bed relationships in the Williston basin. He found three oil families (with their source rocks) in the basin. The shales of the Upper Devonian and Lower Mississippian Bakken Formation generated the oil found in the Mississippian Madison group. The shales of the Middle Ordovician Winnipeg Formation generated the oil found in the lower Paleozoic sedimentary rocks (Ordovician, Silurian and Lower Devonian), and the shales of the Lower Pennsylvanian Tyler Formation generated the oil found in the sandstones of this formation. Dow (1974) concluded that all Winnipeg generated oil found in the Paleozoic reservoirs above this source shale was emplaced by vertical migration up faults. The Weldon-Brockton fault served as such a pathway. Vertical migration of oil up faults on the Cedar Creek anticline was followed by lateral migration updip (to the southeast) along the axis of the structure.

Dow (1974) concluded that Bakken oil migrated up faults to the Madison Group on the Nesson anticline and filled the traps to spillpoint. Displaced oil migrated northward updip along the axis of the structure and off the structure onto the basin's northeast shelf. Here the oil was trapped by porosity pinchouts within the Madison or by impermeable Jurassic red shale at the Madison-Jurassic unconformity. By examining shale thermal maturity, Dow (1974) delineated the effective source areas of the basin. He found Madison oil 100 mi (161 km) beyond the limit of effective Bakken source rocks in the basin, providing evidence for the extensive lateral migration in this basin.

Paleozoic basins usually have low geothermal gradients; yet the reservoirs in the Williston basin are atypically hot. The Alexander field in North Dakota produces from the Ordovician Red River Formation at a depth of 13,600 ft (4.15 km) at 360° F (182° C). Thus the basin is still warm and could have been hotter in the past during maximum structural activity. Further, a thin sequence of Tertiary in the middle of the basin may be the remnant of a thicker section lost to erosion. In support of this theory, Weaver (1961) found the transformation of montmorillonite to illite in southern Saskatchewan (northern shelf of the Williston basin) was far advanced for the sediment depth of the shales, indicating to him significant erosion had taken place.

The Williston basin therefore is not the gross exception to the present concept that it first appears to be.

North Park Basin

The North Park basin (Oburn, 1968; and Behrendt and Popenoe, 1969) of north-central Colorado, with a sediment thickness of only 17,000 ft (5.18 km), also appears to be an exception to my model. The basin (Fig. 22) trough runs northwesterly and is cut its entire length by the Spring Creek fault, which has a maximum vertical throw of 6000 ft (1.83 km).

The oldest known sediments are Permian, and they are overlain by Triassic and Jurassic, which are in turn overlain by a thick sequence of Cretaceous and Tertiary. The upper part of the North Park Formation (late Miocene) is made up of basalts, andesites, rhyolite conglomerates and is a result of the volcanic activity which accompanied the deformation that resulted in the Independence Mountain thrust.

The main production in the basin is about 12 mi (19 km) northeast of the basin axis. Clustered within 5 mi (8 km) of each other are the Battleship, North McCallum, and Canadian River fields. All three fields are in asymmetrical anticlines and are cut by major normal or thrust faults with 200-800 ft (60-122 m) of throw. All the faults dip towards the basin deep. The Lone Pine field, a recent discovery, is in the northwestern part of the basin, over the basin deep on the Spring Creek fault.

The North Park basin is considerably deeper (8,000-10,000 ft, 2.44-3.05 km, of additional sediment thickness) than the Middle Park basin to the south, which has had the same geologic history as North Park and yet is barren of oil.

As Newton (1957) and Oburn (1968) both noted, North Park is relatively unexplored. The dotted area over the basin deep adjacent to the Spring Creek fault is a very viable target according to my model.

North Park may not be the exception to the model as it first appears to be. Although the basin is relatively shallow, the heat required by the model apparently has been supplied by late Tertiary volcanic activity. Also, faulting associated with the production in the basin is either over or dips back toward the basin deep.

Dineh-bi-Keyah

The Dineh-bi-Keyah field (McKenny and Masters, 1968) is on the uplift separating the San Juan basin of northwest New Mexico from the Paradox basin of southeast Utah. Only 8,000-10,000 ft (2.44-3.05 km) of sediment are present in the area; however, the heat necessary by the present model was probably supplied by any one of a number of igneous bodies in the area. The reservoir rock itself is an Oligocene syenite which has intruded Pennsylvanian strata. The host rock of the intrusion is a dense limestone interbedded with gray calcareous shale. A carbonaceous, black shale is 0-51 ft (0-15 m) above the sill throughout the field. Because the surrounding host rocks are tight, it is not possible that the sill "robbed" the oil from a preexisting reservoir. The oil thus had to originate during or after emplacement of the sill, and McKenny and Masters (1968) noted a good possibility exists that the oil was "distilled" from the overlying black shale during intrusion. As of 1/1/73 the field had a CP of 11.5 million bbls and 1.43 Bcf.

Denver Basin

The Denver basin (Beebe, 1968; Landes, 1970; Volk, 1974) of northeast Colorado and western Nebraska (Fig. 23) has 13,000 ft (3.96 km) of sediment at its thickest point. Ordovician, Mississippian, Pennsylvanian, and Permian sediments underlie a thick Cretaceous section, which is overlain by a sequence of thin Tertiary sediments. The basin is spoon shaped in east-west cross section and the basin axis borders the Rocky Mountain uplift on the west. The western boundary of the basin is faulted and folded from the Laramide deformation (Late Cretaceous early Eocene). The stable unstructured eastern shelf contains almost all the reserves which are trapped in the D and J sandstones of the Lower Cretaceous Dakota Sandstone. The two sands are separated by a thin shale unit, and the J has produced far more oil than the D. The hydrocarbons, as Landes (1970) notes, moved up the gently dipping shelf of the basin and were mainly caught in stratigraphic traps.

Beebe (1968) noted that several distinct deltas have been mapped in the Denver basin. The sands of these delta systems could provide avenues for long lateral oil migration from the deep basin. Landes (1970) noted that "marine bar" sand bodies in Nebraska are entirely oil filled. Considering the present hypothesis one expects this with long lateral shelf migration of petroleum in deltaic sand systems. Murray (1957) also note that sand "lenses" in the Denver basin are entirely oil filled. Harms (1966) discussed seven fields which lie on a north trend of at least 20 mi (32 km). Accumulation is in the J sand, which in the area is 1,500 ft (457 m) wide and 50 ft (15 m) thick, being a valley fill, shoestring sand in which oil moving updip was caught only where the sand crossed a southwest trending anticline.

Although the Denver basin is presently shallow, there is evidence that it was both hotter and deeper in the past. McCoy (1953) stated that the thickness of the Cretaceous alone exceeded 17,000 ft (5.18 km) in the vicinity of the Denver basin before the Laramide structural episode. Russell (1961) noted that it is generally supposed that the thickness of sediments eroded from the Denver basin increases as one approaches the Rocky Mountain front and that the sediments along the front range were once more deeply buried. Weaver (1961) in examining the montmorillinite to illite clay diagenesis in the Denver basin, found an advanced stage of diagenesis for the depth of burial of the sediments, which led him to conclude that a significant amount of sediments had been stripped from the basin. Extensive Laramide volcanic activity is now evidenced by lava-covered mesas ("table rocks") along the front range in the basin. This volcanic activity would have allowed the basin to meet the temperature requirements of my model.

Considering the present hypothesis, one expects that the fields over the deeper western part of the basin should be faulted; and this is the case. Parker (1961) showed the Berthoud field to be faulted, and Jensen et al (1954) showed the Wellington field is a faulted anticline. A structure map (Petromotion, 1973) of the Denver basin shows the Horse Creek and Borie fields to be faulted and the Boulder field to be just updip from a large fault.

A large gas field (Wattenberg) lies over the deepest part of the basin and could have spilled the oil onto the shallow shelf area of the basin. This is supported by Figure 23, which shows gas fields in the western part of the basin passing into oil fields with gas caps more to the northeast and finally to fields with oil only to the north. These changes occur along the proposed migration route of the hydrocarbons from the deeper source area.

Geochemical evidence also exists that the oils of the Denver basin originated in the deeper part of the basin and underwent extensive lateral migration away from the source area to the traps where the hydrocarbons are now found.

Swetland and Clayton (1976), in a detailed geochemical evaluation of the basin, found all the Cretaceous D and J sandstone oils to be of the same family. They also found much of the shallow shelf area of the basin had source rocks too immature to have generated the oil found there. They concluded that both of these facts implied extensive lateral migration of Cretaceous oils had taken place from a single source deeper in the basin.

Thus the Denver basin, instead of being a contradiction to the model, actually supports it. Evidence exists that the basin was both deeper and hotter in the past, and the distribution of oil and gas in the basin is what is expected by Gussow's principle of lateral migration. Geochemical evidence suggests the hydrocarbons originated in the deeper, thermally mature areas of the basin and underwent extensive updip lateral migration in deltaic sand systems.

PRODUCTIVITY

Although some shallow cratonic basins are productive, most are totally barren. Those that do produce have very small recoveries per unit area (or volume) (Halbouty et al, 1970) when compared with deeper basins (Table 1). Shallow basins such as the Black Mesa, Raton, Kennedy, Salina, Palo Duro, Dalhart, Desha, Tucumcari, Marfa, and South and Middle Park basins have no commercial hydrocarbon production.

Basins that are shown by maturation indices (coal rank, shale density, montmorillinite-to-illite clay diagenesis, or organic maturation) to have been deeper or hotter in the past are viable exploration targets. On the other hand, shallow cratonic basins that give no evidence of having been either deeper or hotter in the past, and that therefore could not have generated petroleum by this model, should not be considered for exploration.

BASIN EVOLUTION

The evolution of a petroleum basin is a complex process and the present geologic characteristics of a basin may be far different from those of the past. Generally, geothermal gradients are higher in the youthful, tectonically active stage of basin development. For example, Pusey (1973) cited geothermal gradients of between 5-6^{o}F/100 ft for the prolific central Sumatra petroleum basin and gradients as high as 14^{o}F/100 ft have been recorded on structural highs there. After the tectonic evolution of a basin has ceased, geothermal gradients usually drop off to the low values characteristic of the older basins.

Some older basins and some basins with mobile rims have been subjected to uplift, which has resulted in the loss of thick sequences of sediments. Regional or local volcanic or igneous activity could have caused temporary excessive heat flow in a basin, even though the geothermal gradients now may be quite low. In fact volcanic or igneous activity during the main stage of structural activity in shallow productive basins appears to be quite common (Illinois, Denver, Paradox, San Juan, and North Park).

Thus it may be incorrect to assume that the present geology of shallow productive basins reflects former geologic conditions, especially when maturation indices show these basins probably have been deeper and/or hotter in the past.

SUMMARY AND CONCLUSIONS

Stable shelf and shallow basin exploration can be aided greatly by using the Price (1976) model and following these points:

1. Explore primarily on the stable shelf areas of deep basins that have continuous migration paths back to the deep basin. Give lower priority to all areas on the stable shelf that are cut off from the deep basin by regional highs that were present when migration was taking place.

2. Either gas or oil in traps on the stable shelf of a basin indicate that the same formation will be productive elsewhere along the migration path the hydrocarbons have taken from the basin deep.

3. In basins where extensive lateral migration has taken place, generally expect only oil with dissolved gas on the stable shelf area of a basin, and generally expect gas only in the deep basin.

4. Traps on the stable shelf which are filled to the spill point, or may have once been filled to the spill point, indicate that production might be expected updip in the same unit.

5. Exploration on the shallow stable shelf of a basin should be carried out under the assumption that the hydrocarbons have originated from the deep basin and migrated updip onto the stable shelf. Here they were emplaced in predictable trends, rather than having been randomly emplaced by local generation.

6. Exploration in shallow cratonic basins which show by maturation indices that they have never been deeper or hotter in the past should be completely avoided.

This model, when applied to the hydrocarbon distribution in shallow cratonic basins or on the stable shallow shelf of a deep basin, allows us to:

1. Explain the distribution of gas and oil as a function of basin position.

2. Predict gas or oil downdip in a productive formation on the shelf of a basin.

3. Explain secondary lateral shelf migration and discern predictable trends.

4. Rule out some areas completely for exploration.

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Figure 8.--Oil distribution of Salina basin in sediments of all ages. The oil and gas (which are in separate reservoirs) in the Forest City basin, by the present model, would have migrated north from the Arkoma basin (to the south and off the area of the figure) into the Forest City basin, as there is no regional high separating these basins. Dashed lines signify indefinite boundaries of the Salina and Forest City Basins.

Figure 9.--Area of interest in Texas of Figure 5 (north Texas Panhandle) with main structural features. Dashed contours in Anadarko basin portion of figure are conservative. Modified from Landes (1970).

Figure 10.--Oil and gas distribution in North Texas Panhandle (Texas "area of interest" in Figure 5). Modified from Landes (1970).

Figure 11.--Oil distribution and thicknesses (in feet) of Bartlesville sands (an economic unit) of the Bluejacket delta distributary system, on the Arkoma basin shelf of eastern Kansas and Oklahoma. Modified from Visher et al (1971).

Figure 12.--Oil production in a portion of the Red Fork delta system, eastern Oklahoma. Isopach figures are sandstone thicknesses in feet. The largest pools in the trend with their CP to 1969 are Burbank (475 million bbls), Naval Reserve (51 million bbls), and Lauderdale (20 million bbls). Modified from Hudson (1970).

Figure 13.--South Coyote Creek-West Moorcroft trend, Powder River basin, Wyoming, with API gravities of produced oil in parentheses. Contours on top of Fall River Formation (Lower Cretaceous) in feet. Modified from Berg (1968), and Hegna (1968).

Figure 14.--Greater Oficina area, eastern Venezuela. Normal faults are shown by hachures; thrusts are shown by sawteeth. Contours on top of pre-Cretaceous sediments or crystalline basement. The largest fields along the Anaco thrust have a combined EUR of 535 million bbls (Martinez, 1970). Modified from Renz et al (1958).

Figure 15.--Cross section of Turner Valley field, Alberta basin, Alberta, Canada. In this part area of the basin, the Mississippian Rundle Formation is the significant hydrocarbon reservoir. Fluids moving up the Turner Valley thrust fault from the deep basin first encounter transmissive reservoirs in the underthrust block where most of them enter. This block has no traps, so the hydrocarbons migrate updip for many miles to form the rich deposits of the stable shelf of this basin. Fm. stands for Formation; Gp stands for Group. Modified from Fox (1959).

Figure 16.--Swan Hills trend central Alberta. Contour interval 500 ft on top of Beaverhill Lake Formation. Modified from Hemphill et al (1970).

Figure 17.--Plot of initial reservoir pressure versus producing depth for fields producing from the Beaverhill Lake Formation (Fig. 16). After Hemphill et al (1970).

Figure 18.--Leduc (Upper Devonian) reef trends in Leduc Formation of Woodbend Group of Alberta basin, Alberta, Canada. First number in parenthesis after the field name is API gravity of produced oil, queried where unknown, second number is the gas-oil ratio of produced hydrocarbons to 1/1/73 (Int. Oil Scouts Assoc., 1974) in bbl of oil/standard cubic feet of gas. Production in the Rimbey-Clyde trend shows free reservoir connection, as does production in the Wimborne-Bashaw trend. Note that the Pine Dale and Willingdon reefs which are not connected to the trends are barren. Modified from Ball (1972).

Figure 19.--Structure map of the Illinois basin showing major faults of the area. Structure contours are in feet on crystalline basement. Modified from Bond et al (1971).

Figure 20.--Oil and gas production in the Illinois basin. The large Lima-Indiana oil and gas field of Indiana and Ohio according to this model would have originated from the Appalachian basin to the east and migrated laterally updip to its present position. Modified from Bond et al (1971).

Figure 21.--Oil occurrence and structure map of the Williston basin modified from Hansen (1974). Contours in feet are on top of Mission Canyon Limestone (Lower and Upper Mississippian). The Weldon Brockton fault is from Dow (1974). The Cedar Creek anticline fault is from Petromotion (1974). The fault (dashed line) on Nesson anticline is approximate. Dashed arrows show proposed hydrocarbon migration route modified from Dow (1974). Stippled area shows most prospective area of basin for future exploration based on use of the present model. Any structures or stratigraphic changes along or updip from major faults in this area would be viable exploration targets.

Figure 22.-Structure map of North Park basin, Colorado, modified from Behrendt and Popenoe (1969). Contour interval is 2000 ft (610 m) on top of Precambrian crystalline rock. Dry hole markers after Oburn (1968), and Behrendt and Popenoe (1969) with updating. Lone Pine field on far western end of Spring Creek fault not labeled in figure. Thrust faults shown by sawteeth. Normal faults shown by fractured lines. Strike-slip faults shown by lines with opposing arrows. Faults of unknown nature shown by heavy lines.

Figure 23.--Oil and gas map of Denver basin. Deepest part of the basin is traced by basin axis in the western part of the basin next to the crystalline uplift of the Front Range. Dashed arrows show proposed general migration route of hydrocarbons based on present model and work of Swetland and Clayton (1976).

Table 1.--Productivity of shallow versus deep basins

[CP, cumulative production; EUR, estimated ultimate recovery]

Shallow basins				Deep basins			
Basin	Surface area	Reserves in millions of barrels	Productivity[a]	Basin	Surface area	Reserves in millions of barrels	Productivity[a]
Paris	[1]50,193 mi^2 130,000 km^2	[2]42.01 (CP) 1/1/73	837 (44)	Vienna	[1]2,703 mi^2 7,000 km^2	[3]536 (CP) 7/1/68	198,298 (10,431)
Denver	[4]60,000 mi^2 155,400 km^2	[3]734 (CP) 1/1/70	12,233 (643)	Big Horn	[15]8,500 mi^2 22,015 km^2	[14]1,560 (CP) 9/1/69	183,529 (9,653)
Williston	[5]240,000 mi^2 621,600 km^2	[25]2,152 (EUR)	8,985 (471)	Los Angeles	[16]1,200 mi^2 3,108 km^2	[7]7,650 (CP) 1/1/73	6,375,000 (333,294)
North Park	[6]1,200 mi^2 3,108 km^2	[7]18 (EUR)	15,000 (789)	Ventura	[17]2,300 mi^2 5,957 km^2	[7]1,840 (CP) 1/1/73	800,000 (42,076)
Michigan	[8]122,000 mi^2 315,980 km^2	[8]655 (CP) 1/1/68	5,369 (282)	North Sea	[20]280,000 mi^2 725,200 km^2	[20]41,800 (EUR)	149,286 (7,852)
Illinois	[9]79,246 mi^2 205,247 km^2	[9]3,400 (CP) 1/1/69	42,904 (2,256)	Cook Inlet	[18]15,000 mi^2 38,850 km^2	[18]1,890 (EUR)	126,000 (6,627)
Paradox	[7]22,500 mi^2 58,275 km^2	[10]450 (EUR)	20,000 (1,052)	Sirte	[7]265,000 mi^2 683,760 km^2	[19]30,700[d]	115,849 (6,116)
San Juan	[11]20,000 mi^2 51,800 km^2	[12]628[b] (CP) 1/1/64	31,400 (1,651)	Gippsland	[21]18,000 mi^2 46,620 km^2	[22]4,360 (EUR)	242,222 (12,740)
Black Warrior	[13]35,000 mi^2 90,650 km^2	[13].343[c] (CP) 1/1/64	9.8 (0.52)	Po Valley	[23]16,000 mi2 41,440 km^2	[24]1,870[e] (EUR)	116,875 (6,147)
Average of all			15,190 (809)	Average of all			923,006 (48,551)
Average excluding Illinois			11,726 (623)	Average excluding Los Angeles			241,507 (12,703)

[a]Bbls/mi^2, (M.T./km^2); [b]82% oil equivalent gas; [c]gas condensate; [d]EUR for only fields of 500 mm bbls EUR or greater

[e]84% oil equivalent gas.

[1]Perrodon (1963); [2]Internat. Oil Scouts Assoc. (1974); [3]Janoschek and Gotzinger (1969); [4]Volk (1972); [5]Landes (1970); [6]Oburn (1968); [7]this study; [8]Ells (1971); [9]Bond et al (1971); [10]Ohlen and McIntyre (1965); [11]Wengerd (1958); [12]Peterson et al (1965); [13]Pike (1968); [14]Weldon (1974); [15]Stauffer (1971); [16]Yerkes et al (1965); [17]Nagle and Parker (1971); [18]Crick (1971); [19]Halbouty et al (1970); [20]Watson and Swanson (1975); [21]Beddoes (1973); [22]Combined estimates of Beddoes (1973) and Halbouty et al (1970); [23]Rocco and Jaboli (1958); [24]Combined estimates of Pieri (1969) and Gardner (1975); [25]Hansen (1974).

FIGURE 1

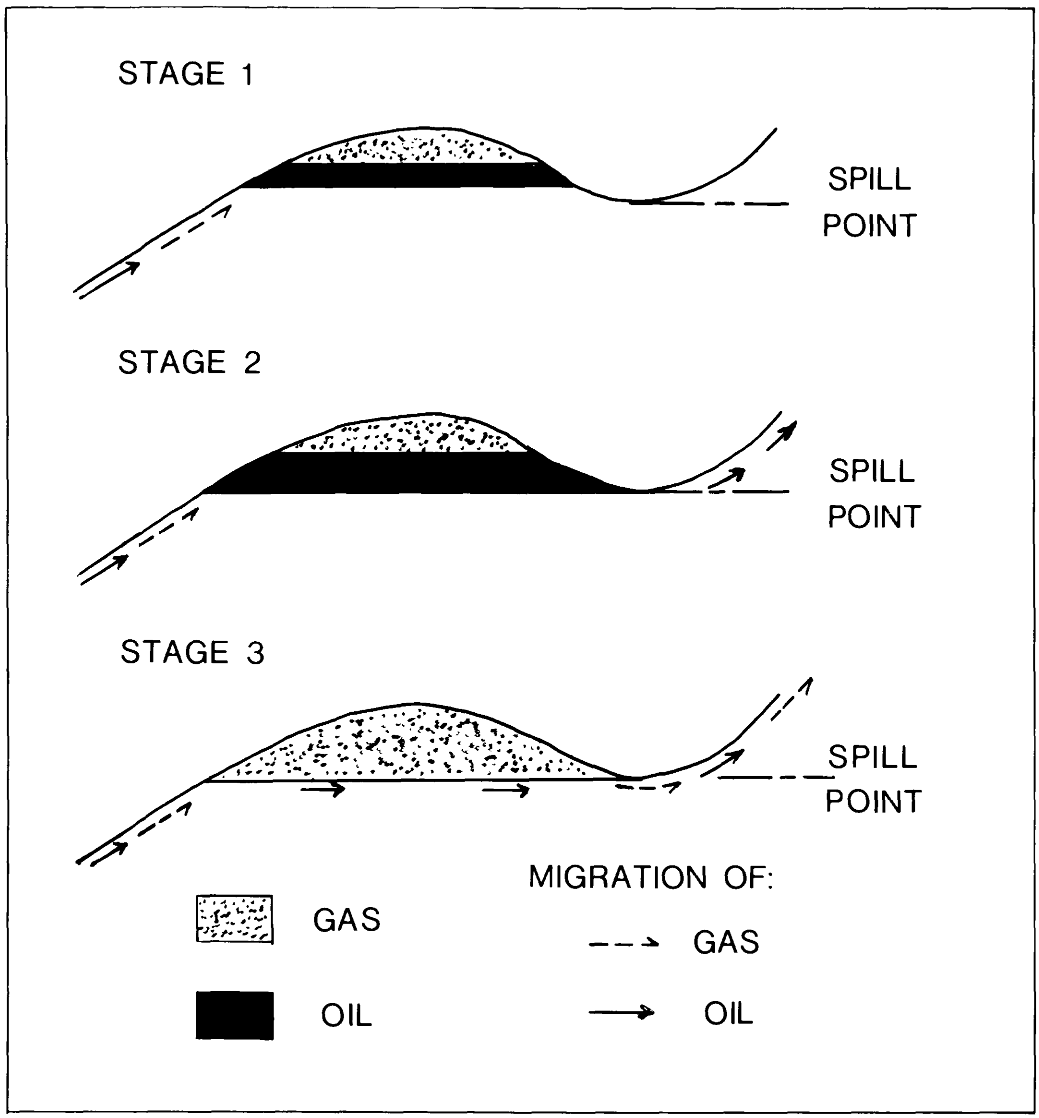
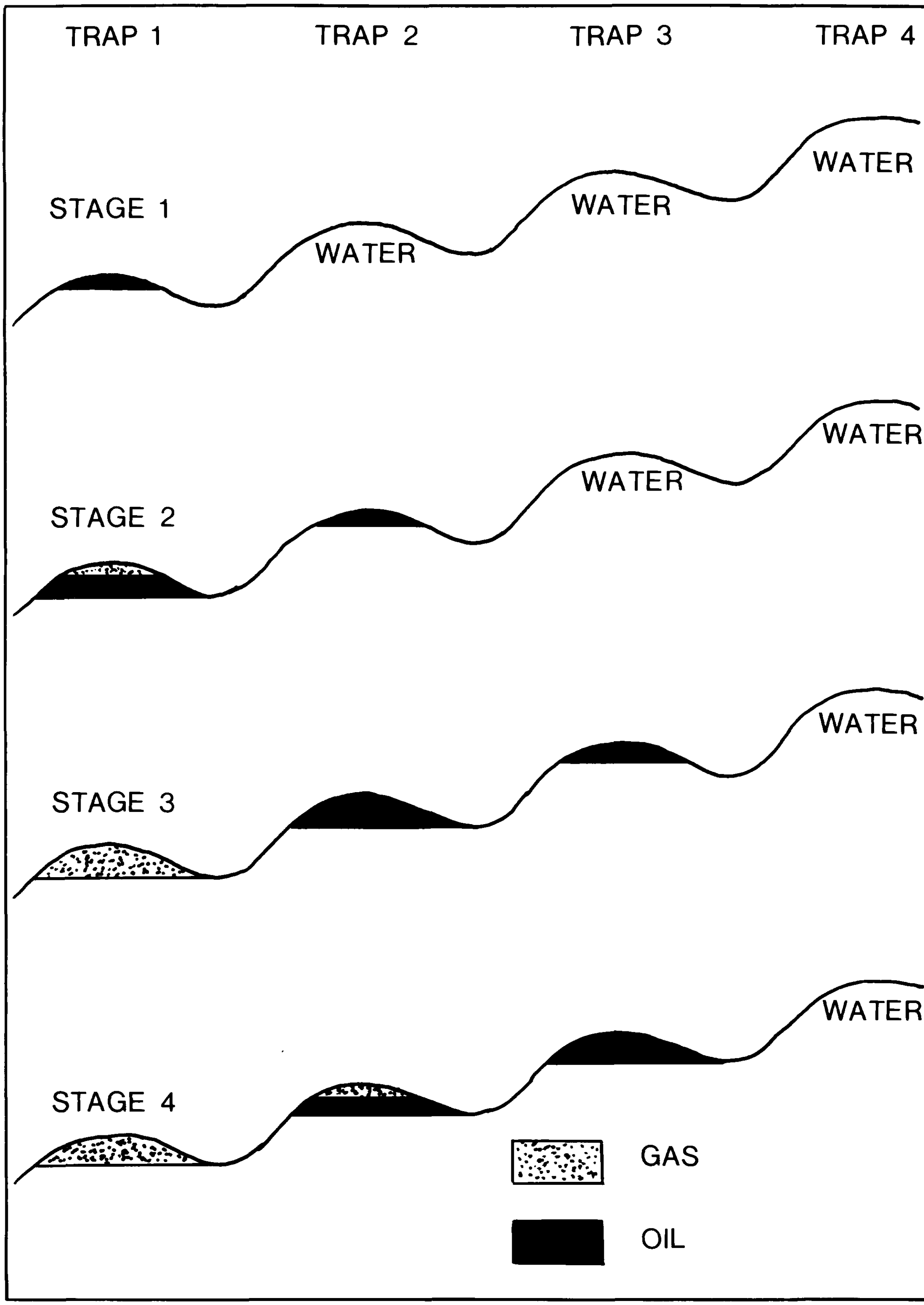

STAGE 1
SPILL
POINT
STAGE 2
SPILL
POINT
STAGE 3
SPILL
POINT
GAS
OIL
MIGRATION OF:
GAS
OIL

FIGURE 2



TRAP 1
TRAP 2
TRAP 3
TRAP 4
STAGE 1
WATER
WATER
WATER
STAGE 2
WATER
WATER
STAGE 3
WATER
STAGE 4
WATER
GAS
OIL

FIGURE 3

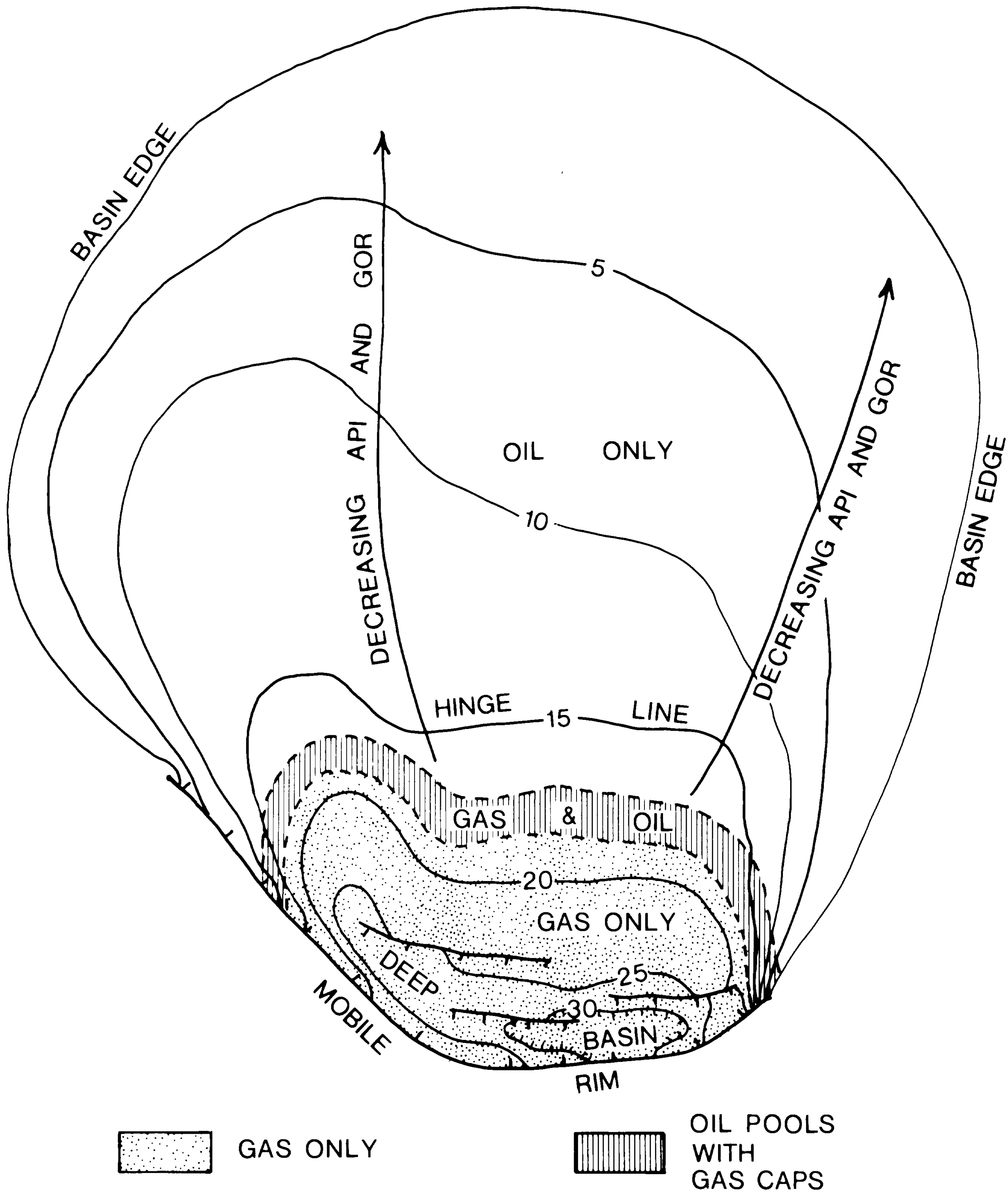
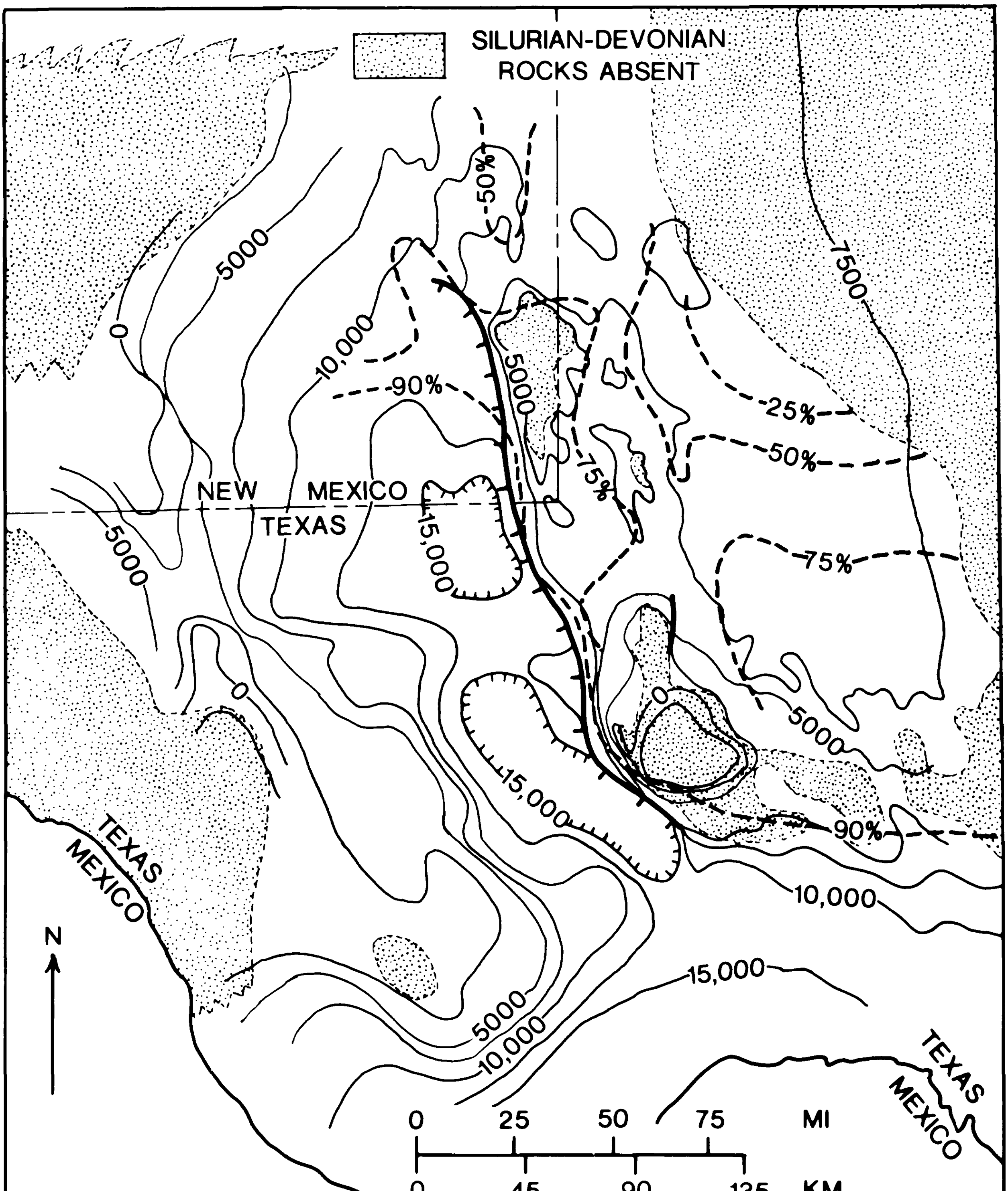
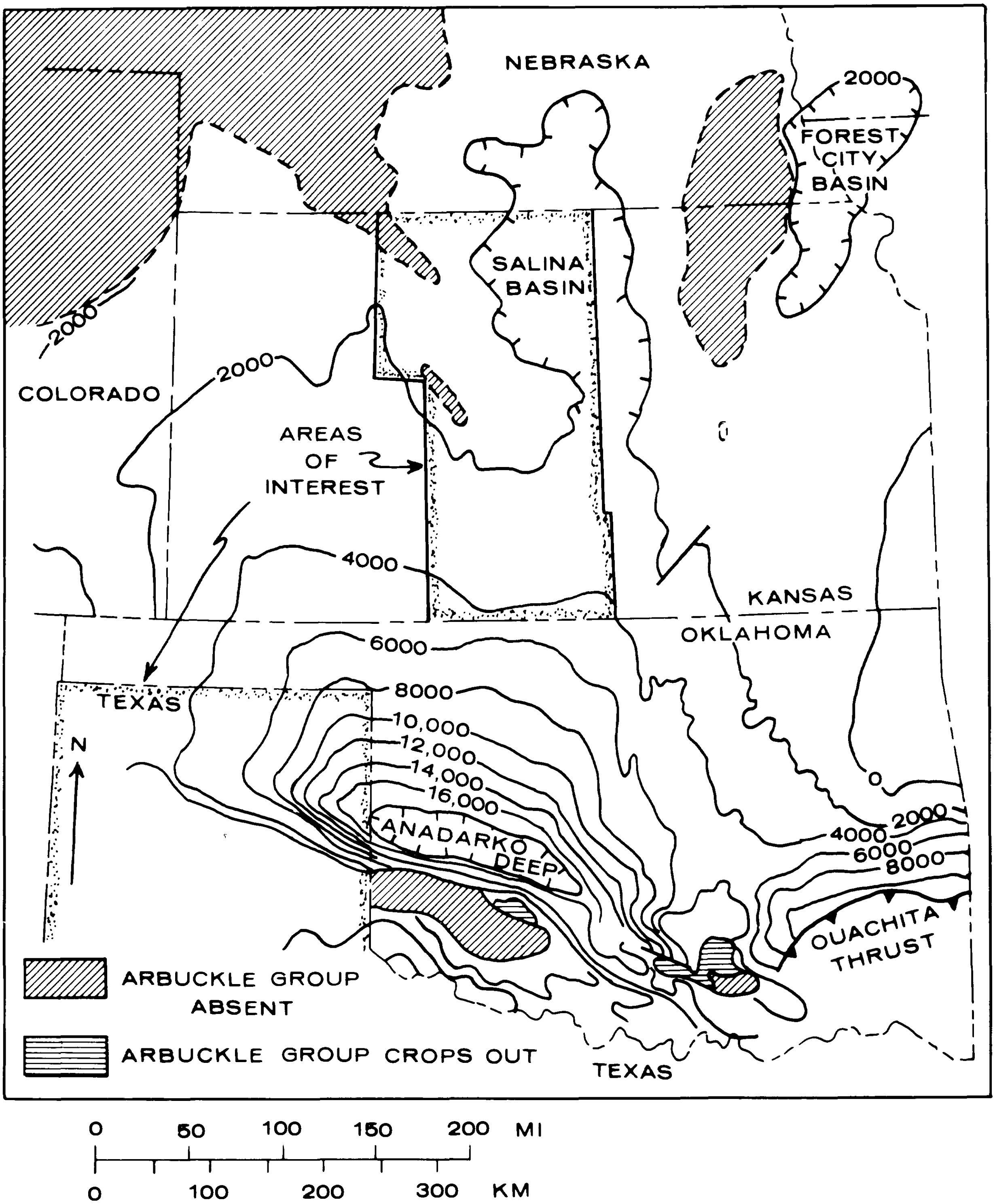

BASIN EDGE
DECREASING API AND GOR
5
OIL ONLY
10
DECREASING API AND GOR
BASIN EDGE
HINGE
15
LINE
GAS & OIL
20
GAS ONLY
DEEP
25
30
BASIN
MOBILE
RIM
GAS ONLY
OIL POOLS WITH GAS CAPS

FIGURE 4



SILURIAN-DEVONIAN ROCKS ABSENT
NEW MEXICO
TEXAS
TEXAS
MEXICO
TEXAS
MEXICO
N
0
5000
10,000
15,000
7500
25%
50%
75%
90%
0 25 50 75 MI
0 45 90 135 KM

FIGURE 5



NEBRASKA
2000
FOREST CITY BASIN
SALINA BASIN
2000
2000
COLORADO
AREAS OF INTEREST
4000
KANSAS
OKLAHOMA
6000
TEXAS
8000
10,000
12,000
14,000
16,000
N
0
ANADARKO DEEP
4000
2000
6000
8000
OUACHITA THRUST
ARBUCKLE GROUP ABSENT
ARBUCKLE GROUP CROPS OUT
TEXAS
0 50 100 150 200 MI
0 100 200 300 KM

FIGURE 6

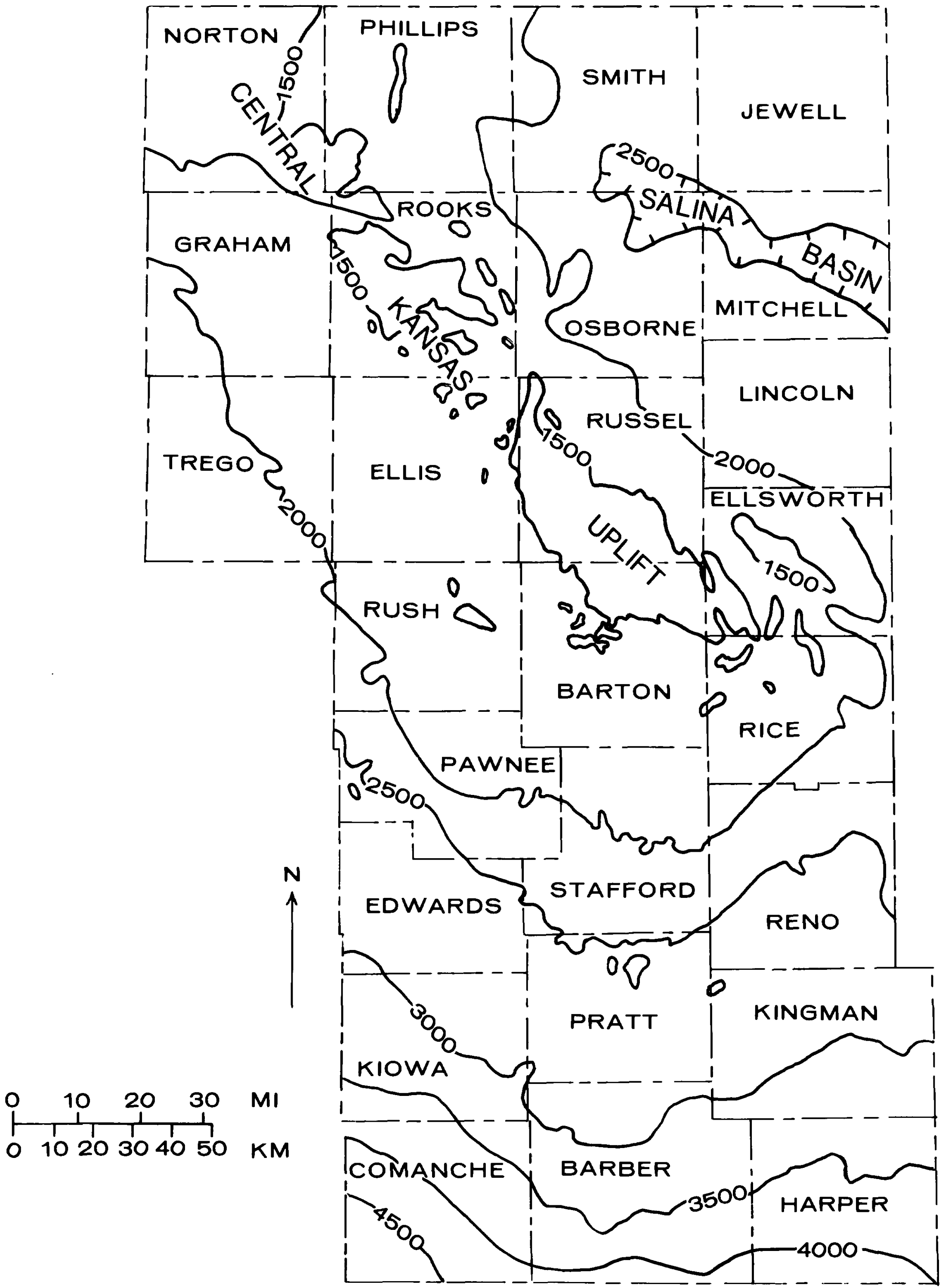
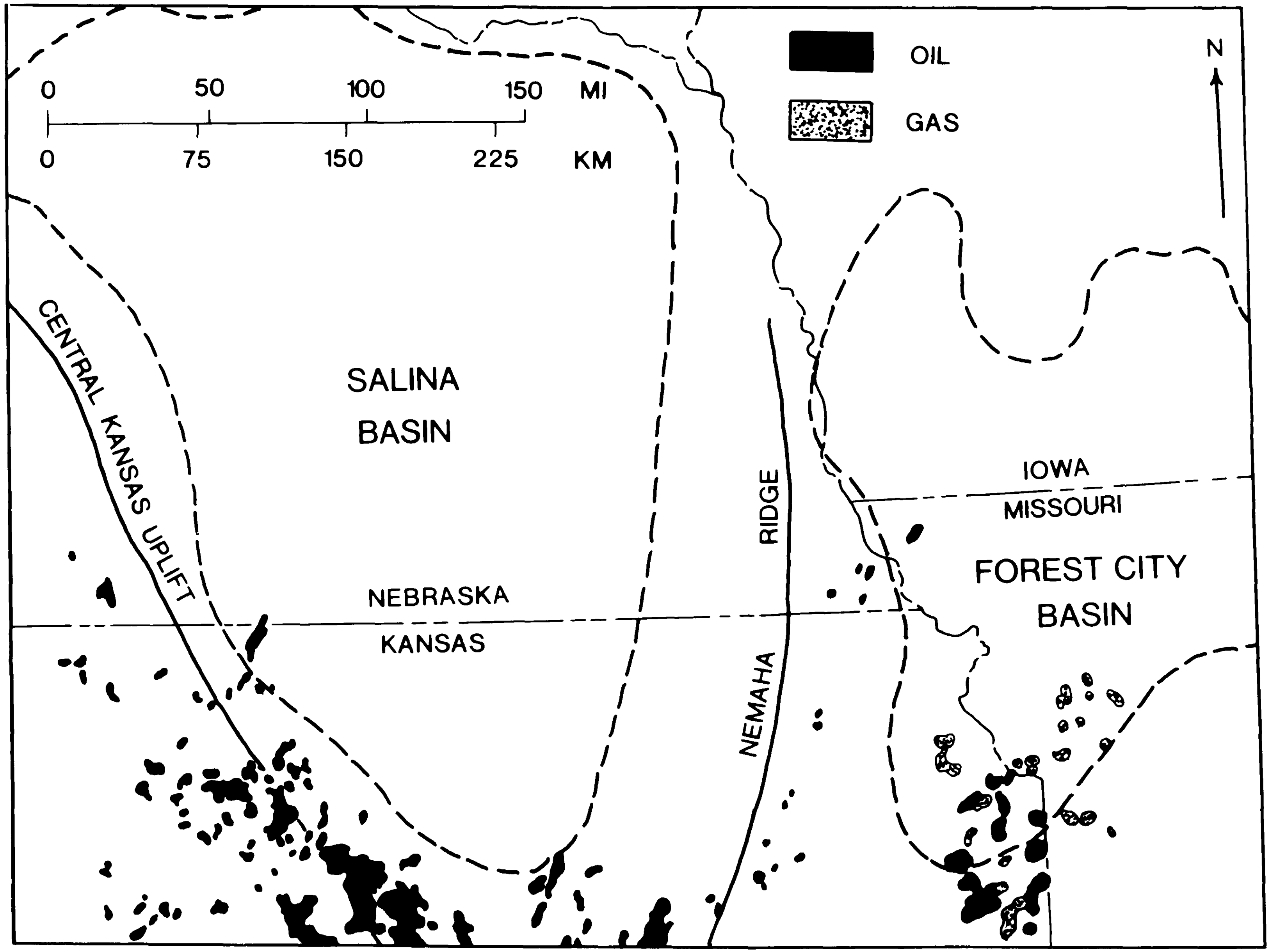

NORTON
PHILLIPS
SMITH
JEWELL
GRAHAM
ROOKS
OSBORNE
MITCHELL
LINCOLN
TREGO
ELLIS
RUSSEL
ELLSWORTH
RUSH
BARTON
RICE
PAWNEE
EDWARDS
STAFFORD
RENO
PRATT
KINGMAN
KIOWA
COMANCHE
BARBER
HARPER
CENTRAL
KANSAS
UPLIFT
SALINA
BASIN
1500
2000
2500
3000
3500
4000
4500
N
0 10 20 30 MI
0 10 20 30 40 50 KM

FIGURE 8



0
50
100
150
MI
0
75
150
225
KM
OIL
GAS
N
SALINA
BASIN
CENTRAL KANSAS UPLIFT
NEBRASKA
KANSAS
RIDGE
NEMAHA
IOWA
MISSOURI
FOREST CITY
BASIN

FIGURE 9

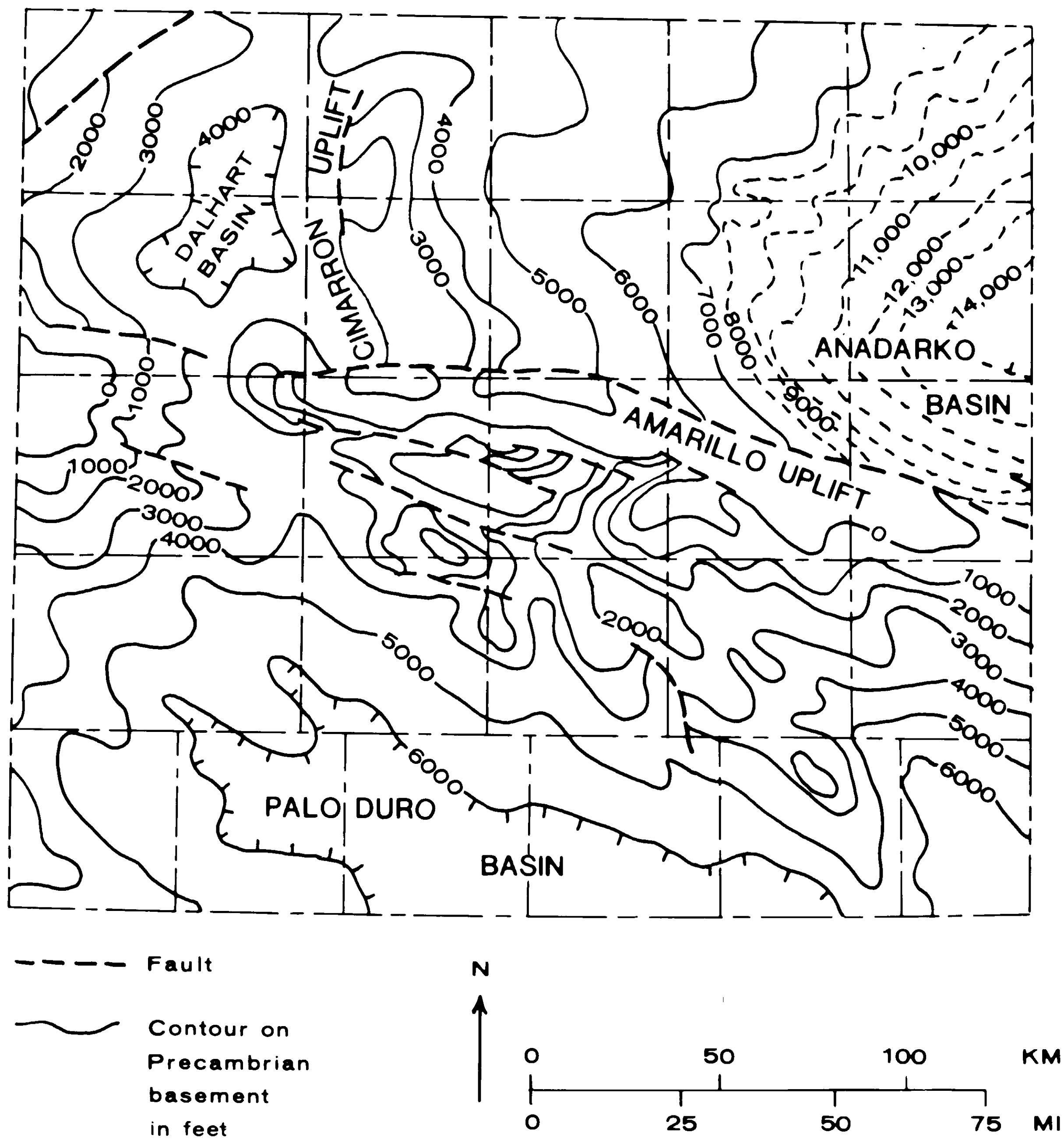
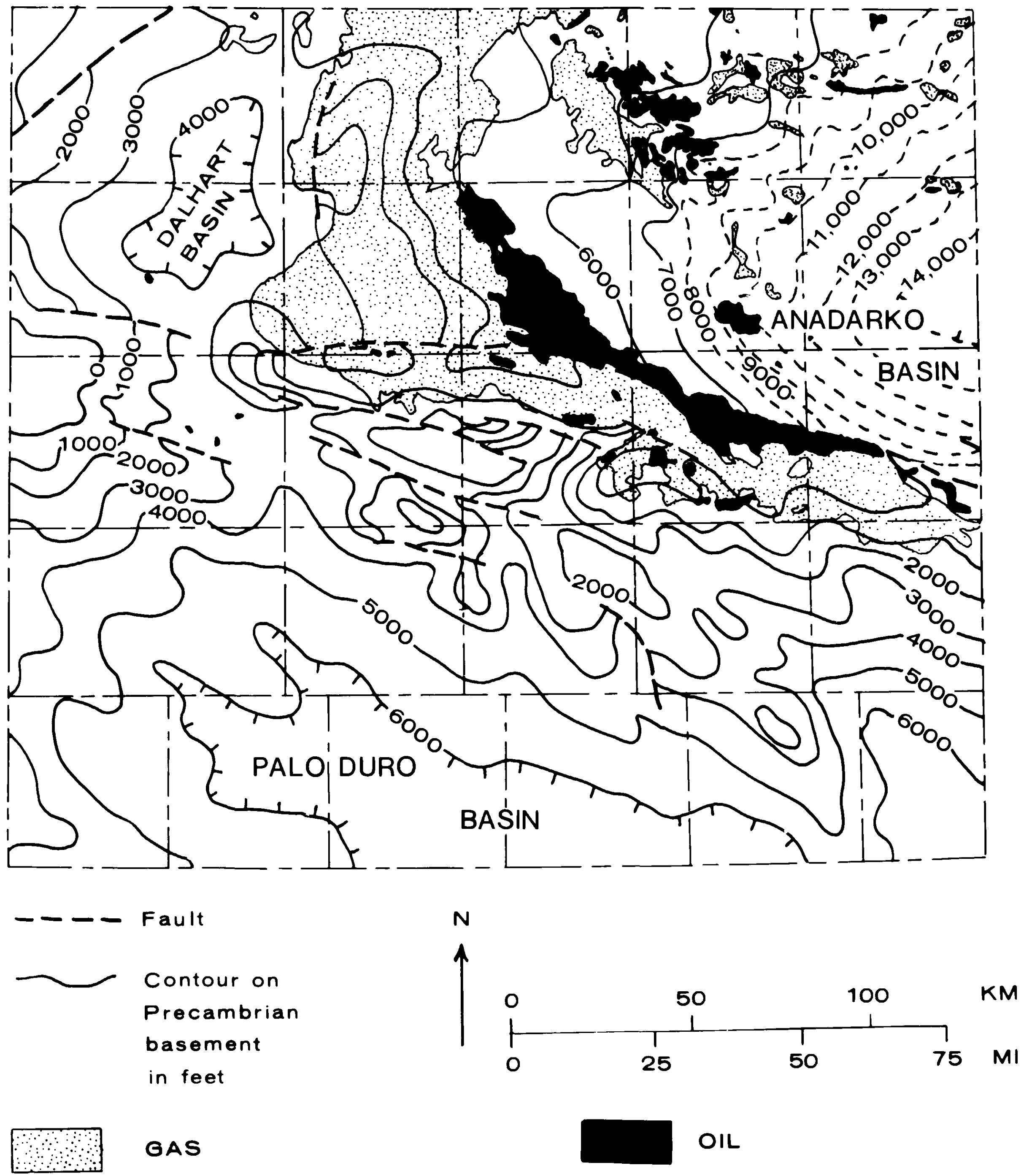

DALHART BASIN
CIMARRON UPLIFT
AMARILLO UPLIFT
ANADARKO BASIN
PALO DURO BASIN
1000
2000
3000
4000
5000
6000
7000
8000
9000
10,000
11,000
12,000
13,000
14,000
Fault
Contour on Precambrian basement in feet
N
0
50
100
KM
0
25
50
75
MI

FIGURE 10



DALHART BASIN
ANADARKO BASIN
PALO DURO BASIN
2000
3000
4000
1000
0
5000
6000
7000
8000
9000
10,000
11,000
12,000
13,000
14,000
Fault
Contour on Precambrian basement in feet
GAS
OIL
N
0 50 100 KM
0 25 50 75 MI

FIGURE 11

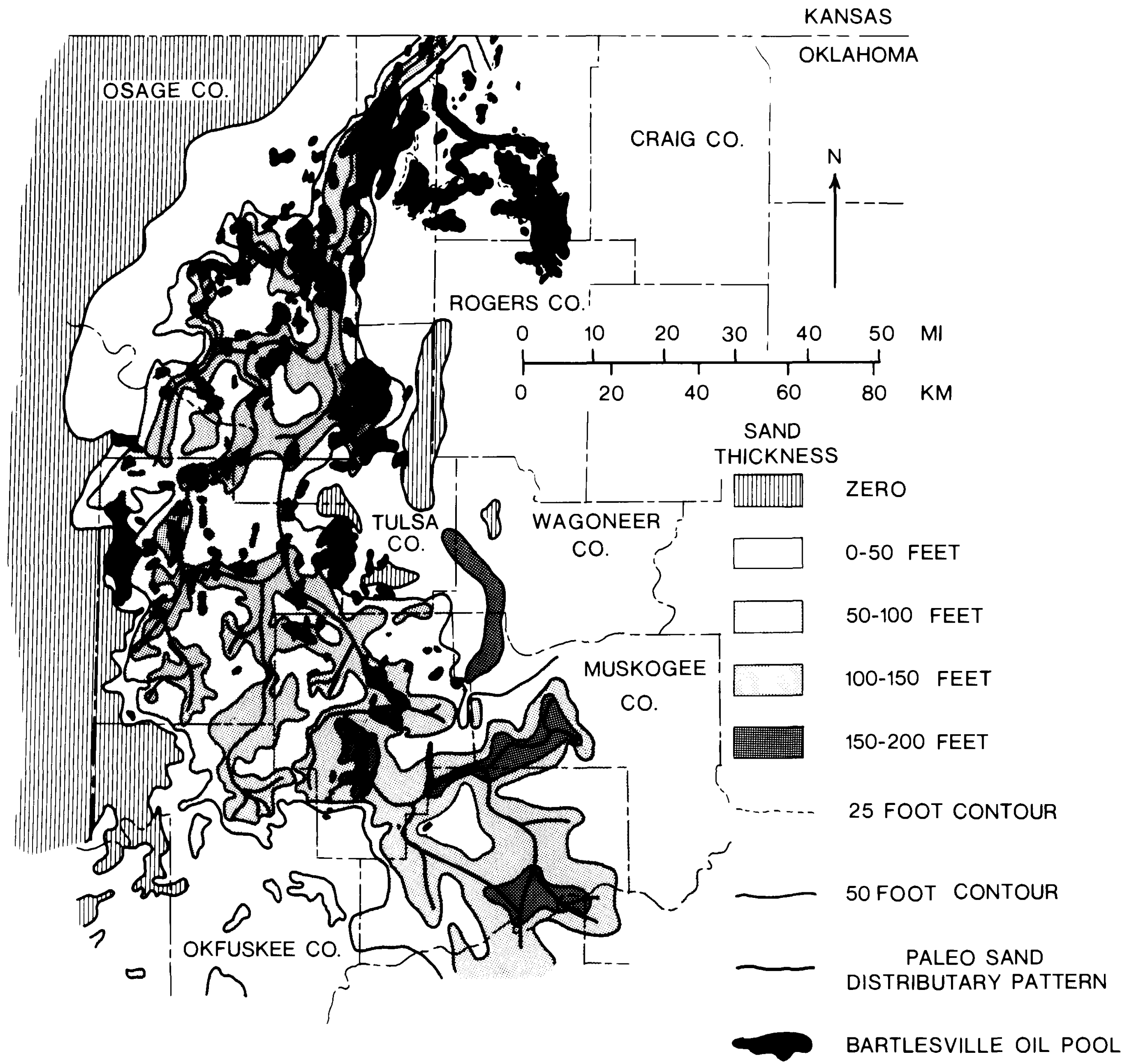
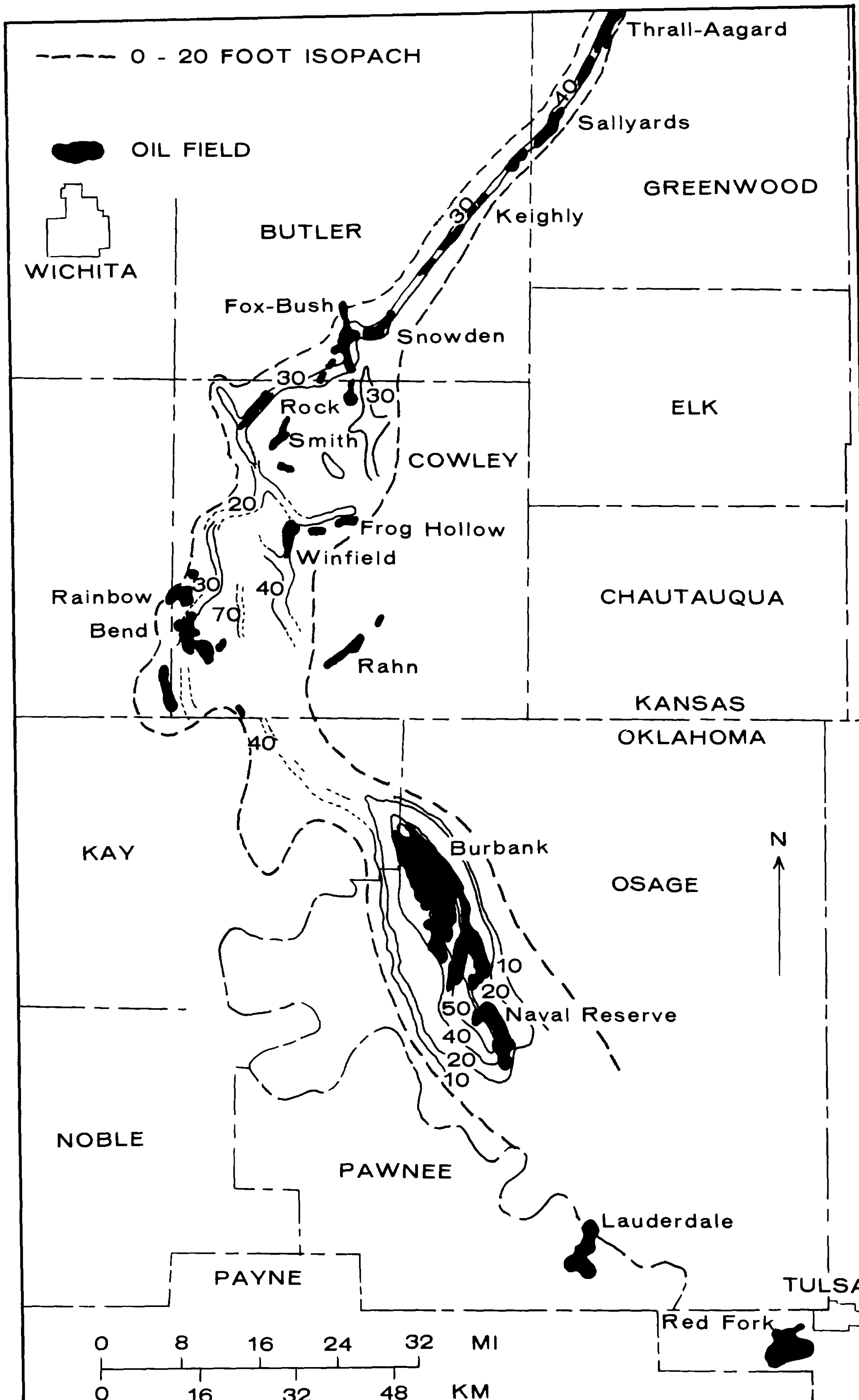

KANSAS
OKLAHOMA
OSAGE CO.
CRAIG CO.
N
ROGERS CO.
0 10 20 30 40 50 MI
0 20 40 60 80 KM
TULSA CO.
WAGONEER CO.
MUSKOGEE CO.
OKFUSKEE CO.
SAND THICKNESS
ZERO
0-50 FEET
50-100 FEET
100-150 FEET
150-200 FEET
25 FOOT CONTOUR
50 FOOT CONTOUR
PALEO SAND DISTRIBUTARY PATTERN
BARTLESVILLE OIL POOL

FIGURE 12



0 - 20 FOOT ISOPACH
OIL FIELD
WICHITA
BUTLER
GREENWOOD
ELK
CHAUTAUQUA
COWLEY
KANSAS
OKLAHOMA
KAY
OSAGE
NOBLE
PAWNEE
PAYNE
TULSA
Thrall-Aagard
Sallyards
Keighly
Fox-Bush
Snowden
Rock
Smith
Frog Hollow
Winfield
Rainbow
Bend
Rahn
Burbank
Naval Reserve
Lauderdale
Red Fork
N
0 8 16 24 32 MI
0 16 32 48 KM

FIGURE 13

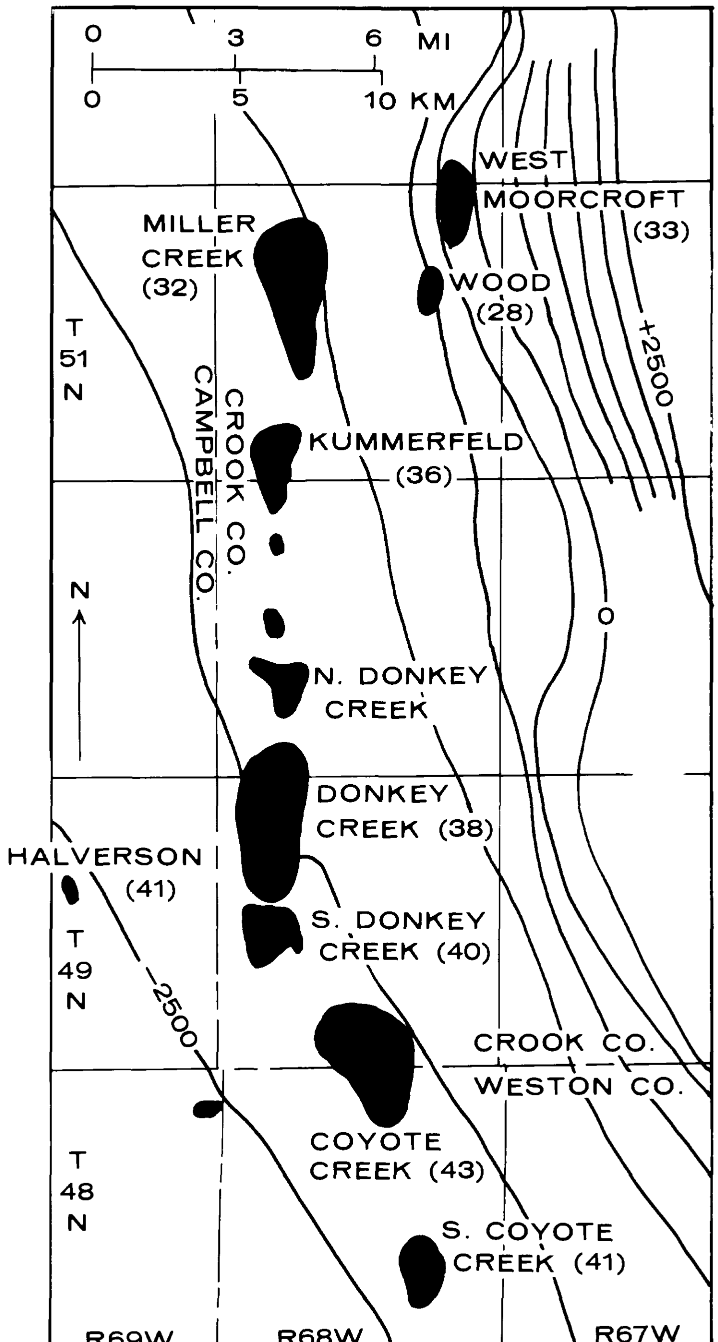
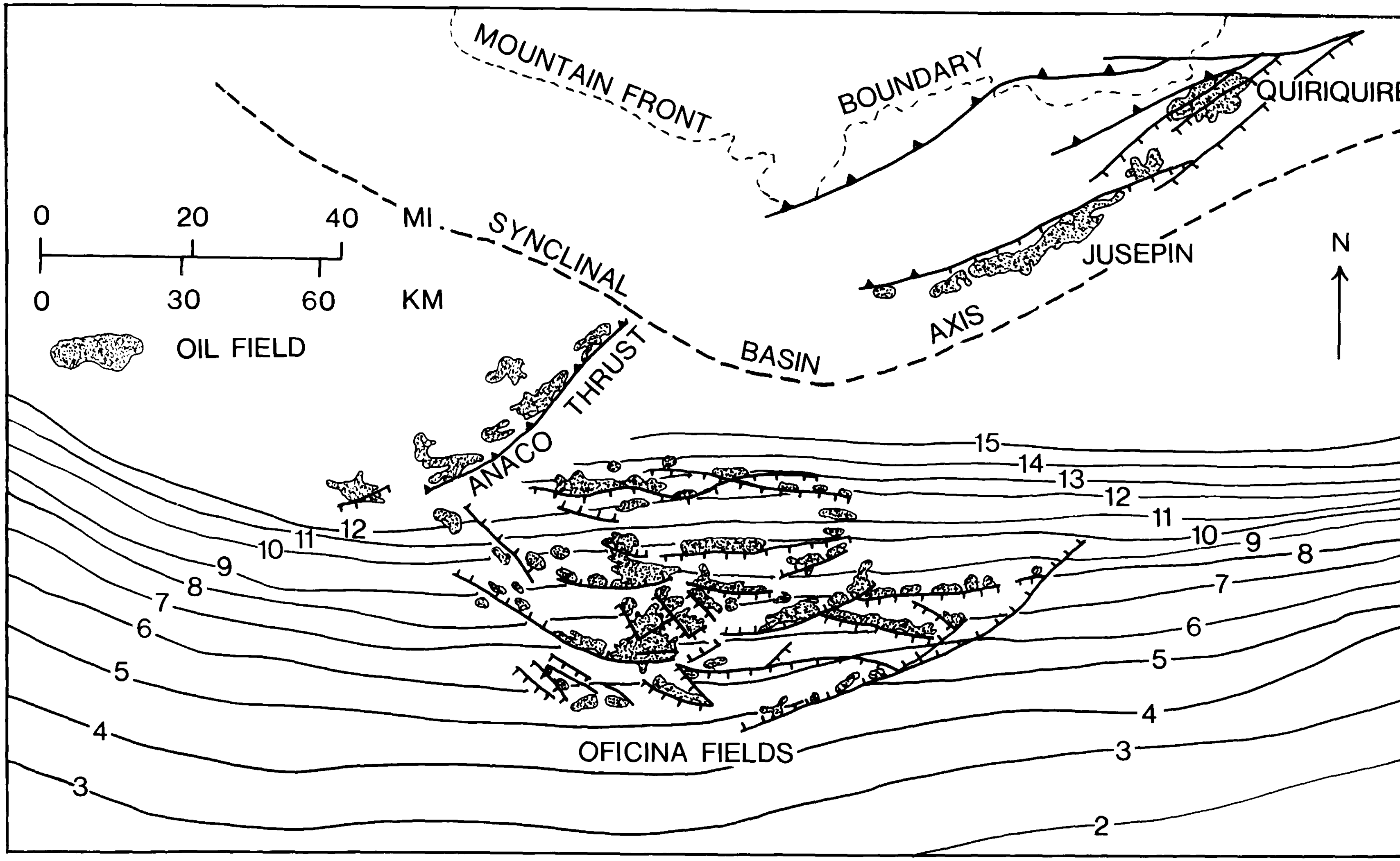
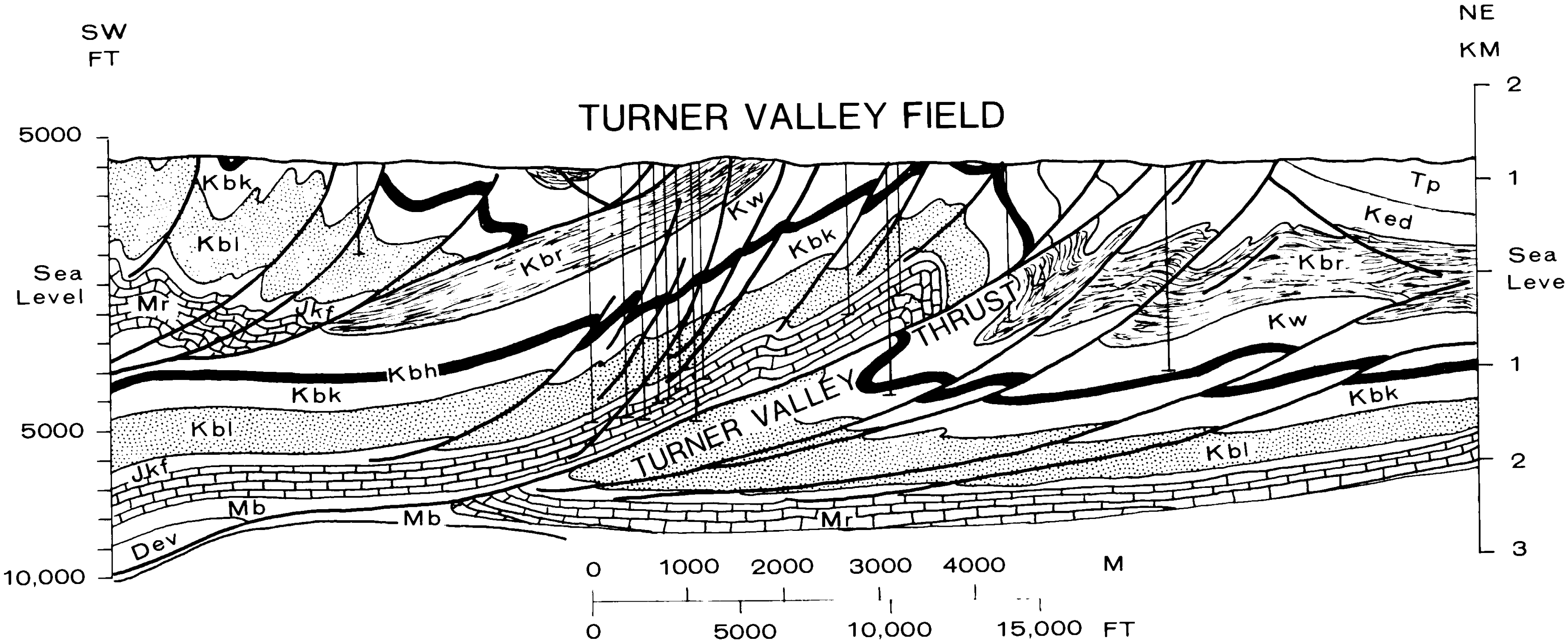

0 3 6 MI
0 5 10 KM
WEST MOORCROFT (33)
MILLER CREEK (32)
WOOD (28)
+2500
T 51 N
CROOK CO.
CAMPBELL CO.
KUMMERFELD (36)
N
0
N. DONKEY CREEK
DONKEY CREEK (38)
HALVERSON (41)
S. DONKEY CREEK (40)
T 49 N
2500
CROOK CO.
WESTON CO.
COYOTE CREEK (43)
T 48 N
S. COYOTE CREEK (41)
R69W
R68W
R67W

FIGURE 14



MOUNTAIN FRONT
BOUNDARY
QUIRIQUIRE
MI.
SYNCLINAL
BASIN
AXIS
JUSEPIN
N
0
20
40
0
30
60
KM
OIL FIELD
ANACO THRUST
OFICINA FIELDS
15
14
13
12
11
10
9
8
7
6
5
4
3
2

FIGURE 15



Tp -Paskapoo	Tertiary	Kbl-Blairmore	Lower Cretaceous
Ked-Edmonton-Bearpaw	Upper Cretaceous	Jkf-Kootenay Fernie	Jurassic
Kbr-Belly River		Mb -Banff	Mississippian
Kw -Wapiabi		Mr -Rundle	
Kbh-Bighorn		Dev- Devonian	
Kbk-Blackstone			

FIGURE 16

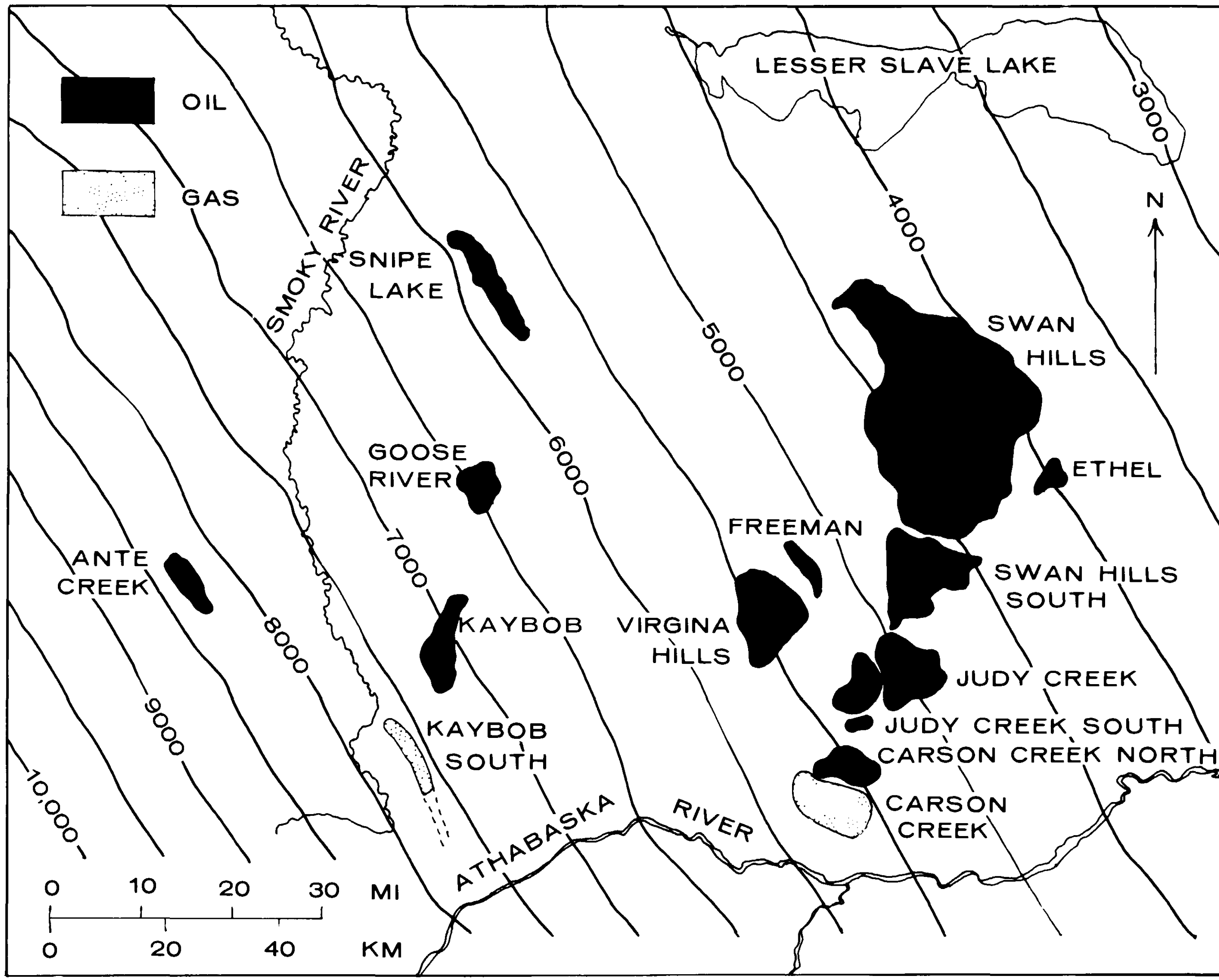
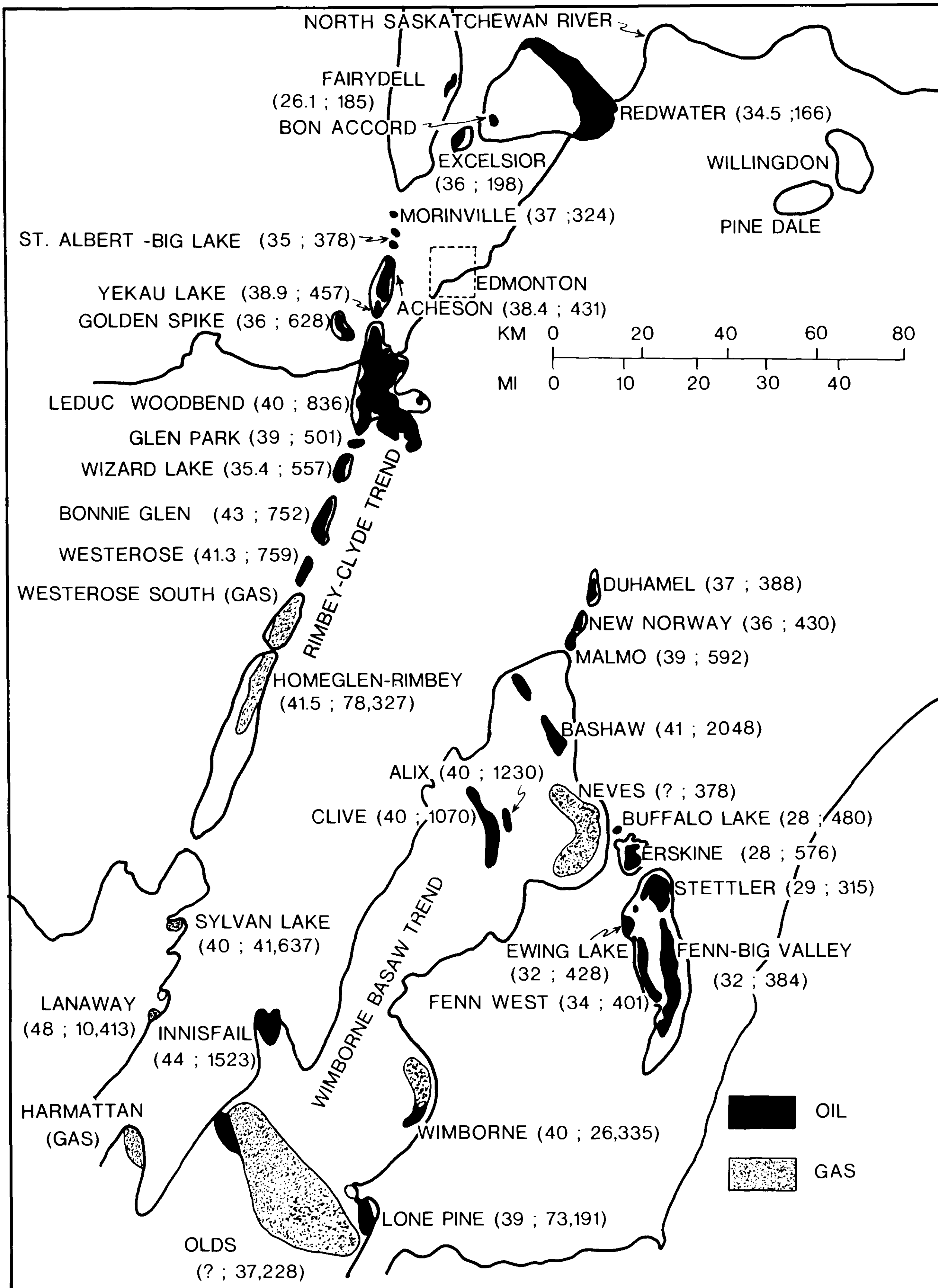

OIL
GAS
LESSER SLAVE LAKE
3000
4000
5000
6000
7000
8000
9000
10,000
N
SMOKY RIVER
SNIPE LAKE
SWAN HILLS
ETHEL
GOOSE RIVER
FREEMAN
SWAN HILLS SOUTH
ANTE CREEK
KAYBOB
VIRGINA HILLS
JUDY CREEK
JUDY CREEK SOUTH
CARSON CREEK NORTH
KAYBOB SOUTH
CARSON CREEK
ATHABASKA
RIVER
0 10 20 30 MI
0 20 40 KM

FIGURE 18



NORTH SASKATCHEWAN RIVER
FAIRYDELL
(26.1 ; 185)
BON ACCORD
REDWATER (34.5 ;166)
EXCELSIOR
(36 ; 198)
WILLINGDON
PINE DALE
MORINVILLE (37 ;324)
ST. ALBERT -BIG LAKE (35 ; 378)
EDMONTON
YEKAU LAKE (38.9 ; 457)
ACHESON (38.4 ; 431)
GOLDEN SPIKE (36 ; 628)
KM 0 20 40 60 80
MI 0 10 20 30 40
LEDUC WOODBEND (40 ; 836)
GLEN PARK (39 ; 501)
WIZARD LAKE (35.4 ; 557)
BONNIE GLEN (43 ; 752)
WESTEROSE (41.3 ; 759)
WESTEROSE SOUTH (GAS)
RIMBEY-CLYDE TREND
DUHAMEL (37 ; 388)
NEW NORWAY (36 ; 430)
MALMO (39 ; 592)
HOMEGLEN-RIMBEY
(41.5 ; 78,327)
BASHAW (41 ; 2048)
ALIX (40 ; 1230)
NEVES (? ; 378)
CLIVE (40 ; 1070)
BUFFALO LAKE (28 ; 480)
ERSKINE (28 ; 576)
STETTLER (29 ; 315)
SYLVAN LAKE
(40 ; 41,637)
WIMBORNE BASAW TREND
EWING LAKE
(32 ; 428)
FENN-BIG VALLEY
(32 ; 384)
FENN WEST (34 ; 401)
LANAWAY
(48 ; 10,413)
INNISFAIL
(44 ; 1523)
OIL
GAS
HARMATTAN
(GAS)
WIMBORNE (40 ; 26,335)
LONE PINE (39 ; 73,191)
OLDS
(? ; 37,228)

FIGURE 19

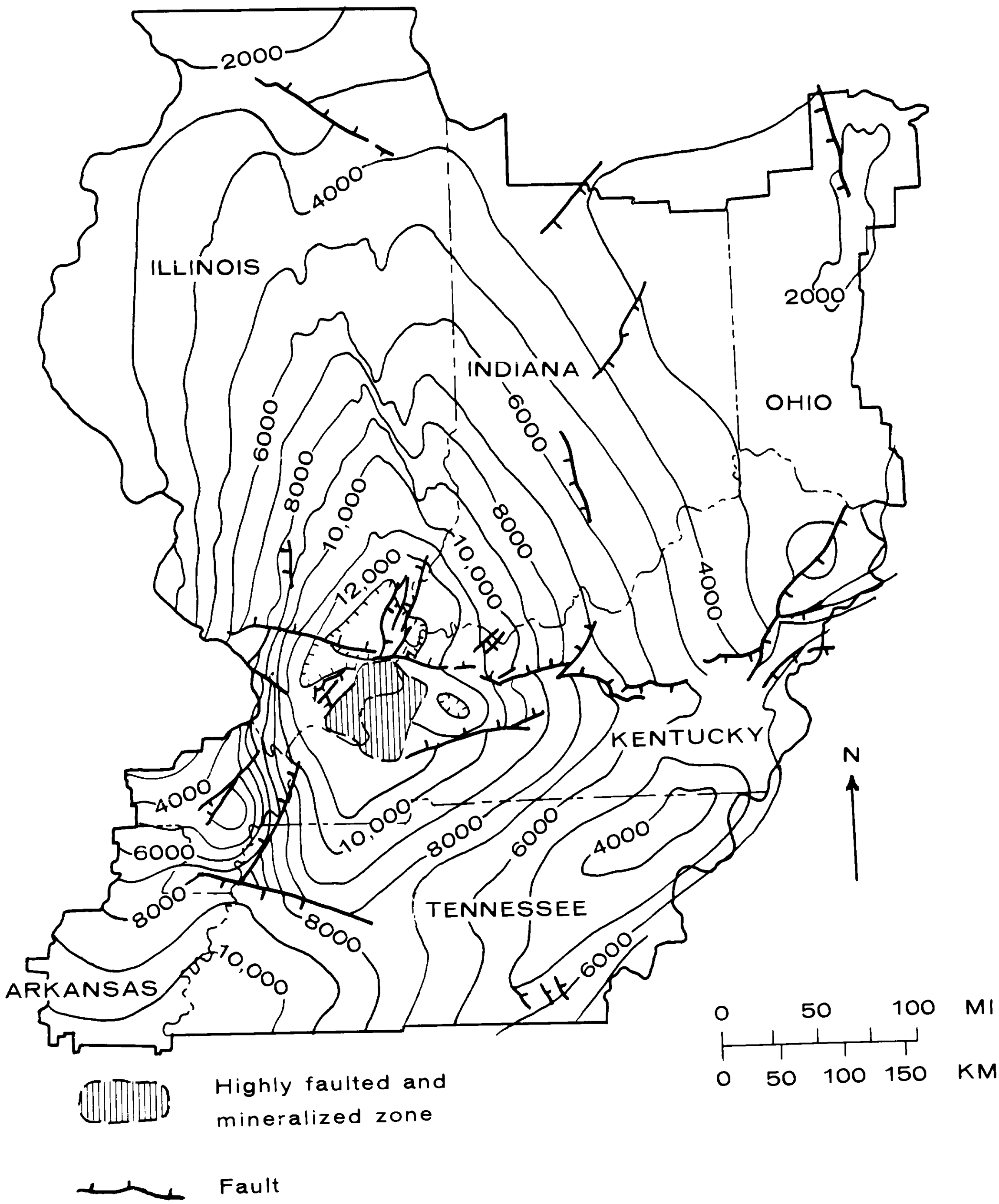

ILLINOIS
INDIANA
OHIO
KENTUCKY
TENNESSEE
ARKANSAS
2000
4000
6000
8000
10,000
12,000
N
0 50 100 MI
0 50 100 150 KM
Highly faulted and mineralized zone
Fault

FIGURE 20

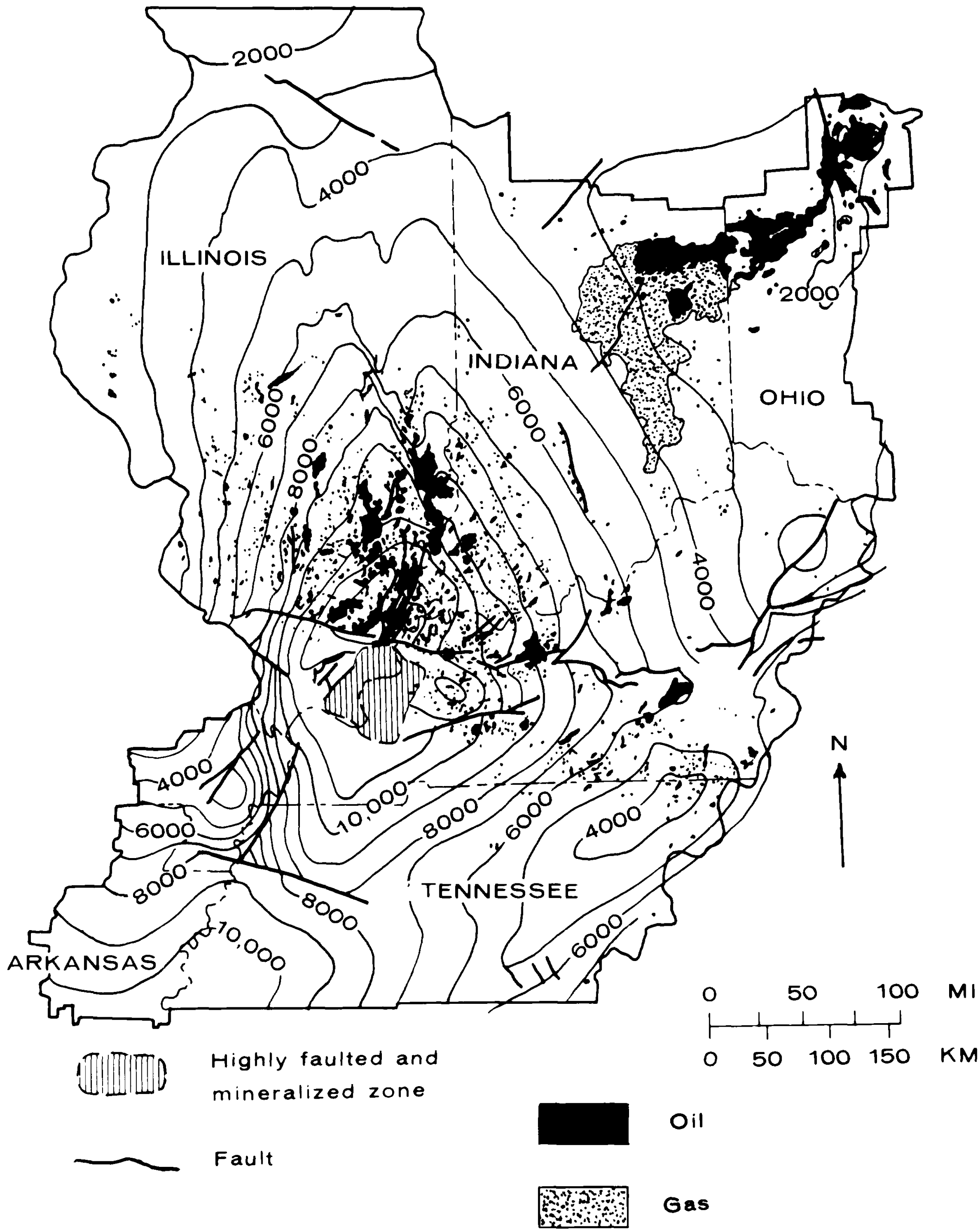

ILLINOIS
INDIANA
OHIO
TENNESSEE
ARKANSAS
2000
4000
6000
8000
10,000
N
0 50 100 MI
0 50 100 150 KM
Highly faulted and mineralized zone
Fault
Oil
Gas

FIGURE 21

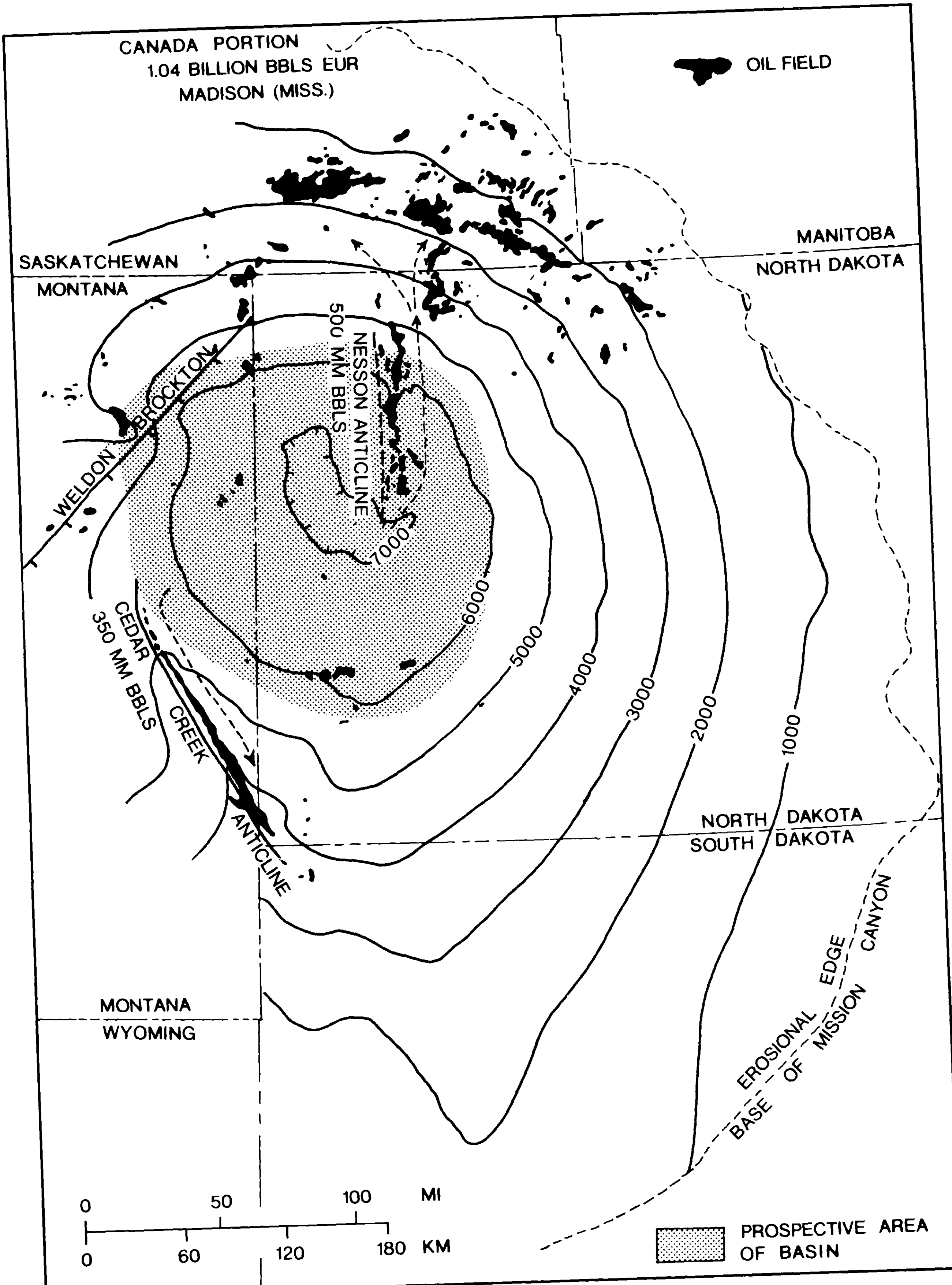
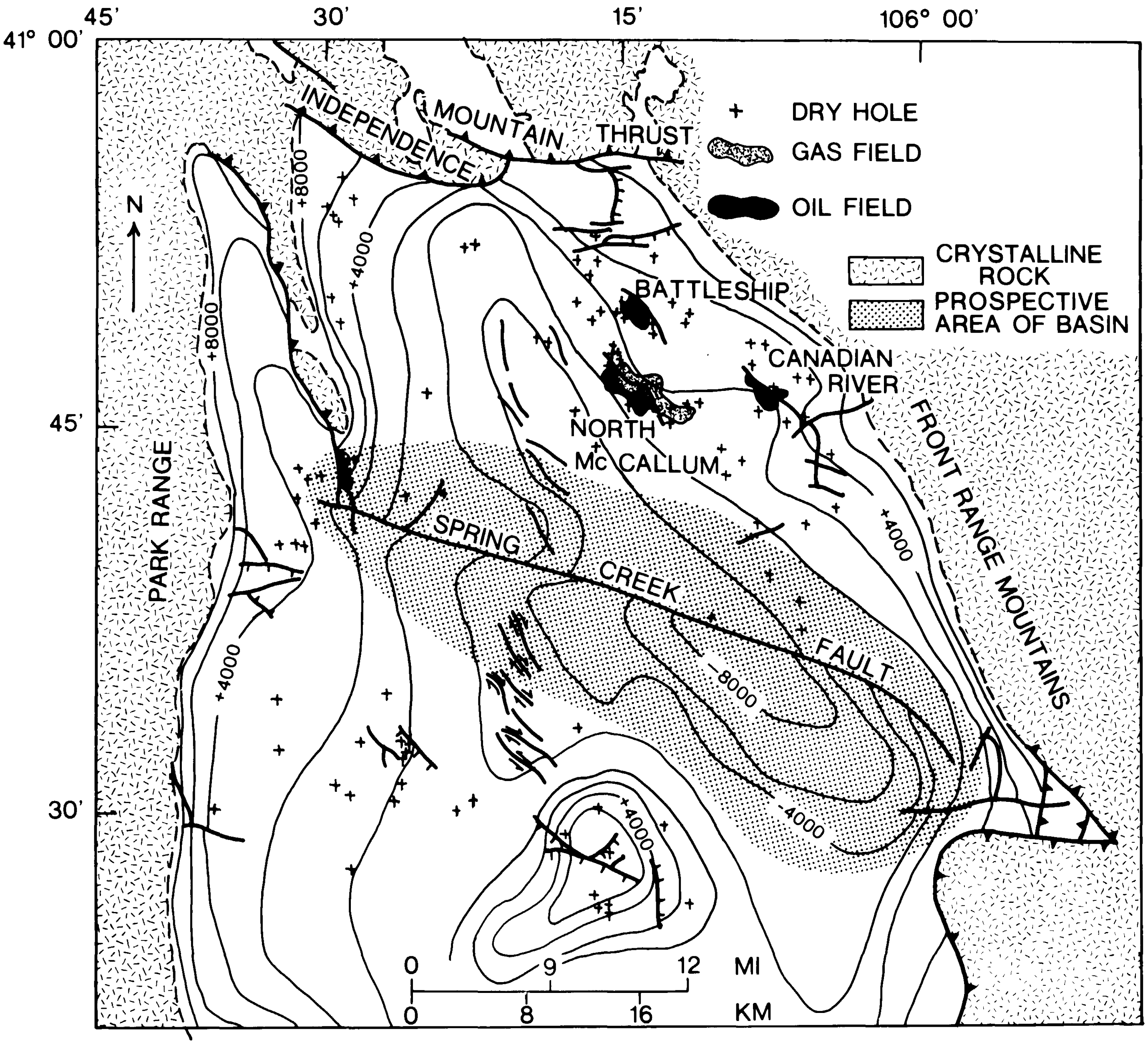
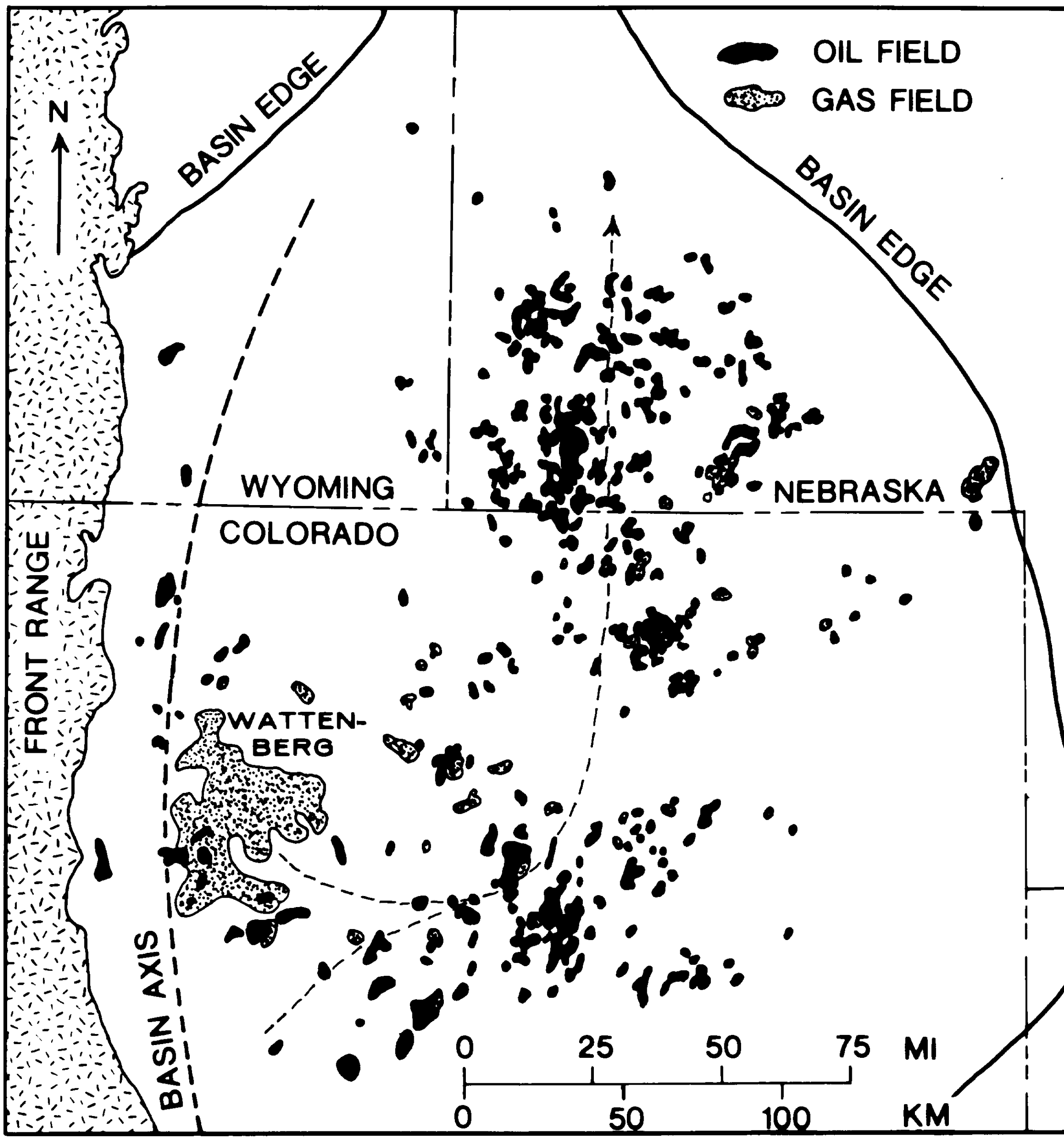

CANADA PORTION
1.04 BILLION BBLS EUR
MADISON (MISS.)
OIL FIELD
SASKATCHEWAN
MONTANA
MANITOBA
NORTH DAKOTA
NESSON ANTICLINE
500 MM BBLS
BROCKTON
WELDON
CEDAR
350 MM BBLS
CREEK
ANTICLINE
7000
6000
5000
4000
3000
2000
1000
NORTH DAKOTA
SOUTH DAKOTA
MONTANA
WYOMING
EROSIONAL EDGE
BASE OF MISSION CANYON
0 50 100 MI
0 60 120 180 KM
PROSPECTIVE AREA OF BASIN

FIGURE 22



45'
30'
15'
106° 00'
41° 00'
45'
30'
DRY HOLE
GAS FIELD
OIL FIELD
CRYSTALLINE ROCK
PROSPECTIVE AREA OF BASIN
INDEPENDENCE MOUNTAIN THRUST
BATTLESHIP
CANADIAN RIVER
NORTH Mc CALLUM
SPRING CREEK FAULT
FRONT RANGE MOUNTAINS
PARK RANGE
N
+8000
+4000
-8000
-4000
0 9 12 MI
0 8 16 KM

FIGURE 23


OIL FIELD
GAS FIELD
BASIN EDGE
BASIN EDGE
N
WYOMING
COLORADO
NEBRASKA
FRONT RANGE
WATTEN-
BERG
BASIN AXIS
0 25 50 75 MI
0 50 100 KM