Does Bakken Horizontal Drilling Imply a Huge Oil-Resource Base in Fractured Shales?

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ABSTRACT

Previous assumptions regarding high efficiencies of primary petroleum migration from mature organic-rich source rocks appear invalid. These assumptions were based on large declines in Rock Eval hydrogen indices of source rocks with progressive burial, without equivalent increases in either Rock Eval S₁ peaks or Soxhlet-extractable hydrocarbons. Thus, it followed that the generated hydrocarbons must have escaped the source rocks by efficient primary migration. However, horizontal drilling in fractured, self-sourced shales shows that this is an erroneous hypothesis, because these shales contain high hydrocarbon concentrations. A better explanation for these missing hydrocarbons is that they were lost during recovery of rock samples from the bottom of the hole.

Basin richness for basins worldwide increases with intensity of faulting over and adjacent to basin deeps. Thus, faulting and fracturing of mature source rocks may be necessary for efficient expulsion of generated hydrocarbons from such rocks. Without such faulting, generated hydrocarbons may largely remain in cracks, fractures, parting laminae, and matrix porosity in both source rocks and in the rocks immediately adjacent to them. It follows that a huge oil-resource base may be present in and adjacent to fractured, mature, self-sourced shales.

The shales of the Upper Devonian and Lower Mississippian Bakken Formation provide insight into this proposed resource base. Both historic production data from vertical Bakken wells and Rock Eval analyses of close-spaced core and cuttings from mature basinal Bakken shales demonstrate significant movement of hydrocarbons from Bakken shales for at least 50 ft (15 m) into adjacent units. Migration probably occurred through vertical fractures created by fluid overpressuring during intense hydrocarbon generation.

It is widely believed that the Bakken shales are the source of most of the conventional oil in the Williston Basin. However, newer geochemical analyses suggest that this is not the case. The Bakken shales are calculated to have generated over 100 billion BO (15.9 x 10⁹ m³). If this oil did not charge the conventional oil reservoirs, we can only conclude that it remains in the shales and in the rocks adjacent to them.

Numerous other self-sourced, fractured shale reservoirs produce oil commercially. If the thin Bakken shales have generated 100 billion BO, then it is possible that the lower 48 states of the U.S. contain an unrecognized oil-resource base in the trillions of barrels. However, economic recovery of this possible resource base would depend on development of new exploration, drilling, completion, and production techniques appropriate to the non-classical reservoir characteristics of this oil resource base.

INTRODUCTION

There are many occurrences of oil production from fractured, self-sourced shales worldwide. However, the possible magnitude of this resource base has previously gone undefined. Here we attempt to define the size of this resource base, delineate its geological and geochemical characteristics and origins, and suggest exploration, drilling, completion, and maintenance techniques appropriate to the apparent non-classical nature of this resource base.
shales by two different laboratories failed to document increases in extractable bitumen with increasing depth (Fig. 1). These contradictions were previously explained (Price et al., 1984) as due to very efficient primary petroleum migration, with the high resistivities at depth due to a free-hydrocarbon gas phase present in the shales. However, horizontal drilling of the Bakken shales shows that this was an erroneous explanation, because large oil concentrations are clearly present in these shales.

Recently many other investigators (Cooles et al., 1986; Leythauser et al., 1987, 1988; Mackenzie et al., 1987; Talukdar et al., 1987; Ungerer et al., 1987; Espitalié et al., 1988) also concluded that primary migration is very efficient from organic-rich source rocks, such as the Bakken shales, and have provided calculations which suggest that between 75-90% of the hydrocarbons generated in organic-rich shales migrate from the shales. Furthermore, the volumes of oil which are calculated to have been generated by and moved from such source rocks are quite large and always are many times larger than the discovered oil reserves in basins. For example, Hubbard et al. (1987) calculated that the Brookian megasequence of the Alaskan Colville Basin (North Slope) alone generated 10 trillion barrels of oil. Espitalié et al. (1988) calculated that in the Paris Basin, Hettangian and Sinemurian age shales alone generated 14.7 billion BO (2.33 x 10^9 m^3), with only 10% of that as discovered, in-place oil. Calculations by other workers, including Hunt (1979), usually show that discovered oil reserves typically represent only 1-5% or less of the oil generated by all source rocks in any given basin. All such calculations are based on large decreases in Rock Eval hydrogen indices in source rocks as such rocks increase in thermal maturity. Because these decreases in hydrogen indices are not matched by numerically-equivalent increases in either Soxhlet-

extracted hydrocarbons or the Rock Eval S1 peak, most petroleum geochemists (including the senior author) have previously assumed that these generated hydrocarbons must have moved from the rock by efficient primary migration. However, recent work strongly suggests that this interpretation may be wrong.

Production data from recent Bakken shale horizontal wells show that gas:oil ratios usually range between 800 and 2,000 SCF/BO (142 to 356 m^3/m^3). Thus, significant amounts of gas are cogenerated and coexist with C15+ hydrocarbons in these source rocks. Furthermore, a large suite of aqueous-pyrolysis experiments we have carried out at the U.S. Geological Survey on six different rocks, including the Bakken shale, demonstrate that: 1) significant amounts of hydrocarbon gas are cogenerated with C15+ hydrocarbons for all organic matter types over all maturation ranks, and 2) large amounts of carbon dioxide, and lesser amounts of hydrocarbon gases, also are generated by these rocks even before mainstage hydrocarbon generation commences (Price, 1989a).

Recent work by Price and Clayton (1992) demonstrates that bitumen is not homogeneously distributed in organic-rich shales. Instead different types of voids in such rocks contain compositionally different bitumen. Price and Clayton (1992) extracted whole (unground) core of different source rocks (including six different Bakken shale cores of varying maturities) for up to ten successive extractions, by removing solvent (and the extracted solute) after each extraction, adding fresh solvent, and repeating the procedure. The resulting solutes were compositionally different from one another. The first solutes resembled crude oils, and progressive solutes became less and less like crude oil and more immature in appearance. An example from the most immature (pre-hydrocarbon generation) Bakken core extracted, for the first and sixth extractions, is given in Figure 2. Although the first and sixth extracts are from the same rock, they are quite different from, and cannot be correlated with, one another by any organic-geochemical technique, including biomarkers. Price et al. (1983) showed that methane gas preferentially entrains C15+ hydrocarbons, saturated hydrocarbons, and especially n-paraffins, over resins, asphaltenes, and high molecular weight aromatic hydrocarbons. As such, Price and Clayton (1992) hypothesized that a partitioning of bitumen in the rock they studied resulted from methane being dissolved in the bitumen and imparting its solution preferences onto the bitumen. Thus, an oil-like bitumen was fractionated from the entire bitumen in the rock and was concentrated in cracks, fractures, and parting laminae, poised and ready for expulsion from the rock. As such, this oil-like bitumen was most accessible to the first extractions of the unground (whole) rock. However, because of its position in the rock, this bitumen is most likely to be lost during the trip up the wellbore.

As conventional core and cuttings chips ascend the...
Sokolov et al. (1971) compared the amount of gas recovered in this manner to that recovered during an open-hole rock trip up the wellbore, where only 0.11-2.13% of the gas originally in the rock was recovered.

Table 1. Hydrocarbon-gas concentration and relative loss from equivalent core samples using the “KC core lifter” and the normal “open” method. After Sokolov et al. (1971).

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Sample Depth (ft)</th>
<th>Sample Mode</th>
<th>Concentration (10^{-4}) cm³/kg ROCK</th>
<th>Relative Loss KC/OPEN</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand</td>
<td>1263</td>
<td>KC</td>
<td>106,243</td>
<td>893</td>
</tr>
<tr>
<td></td>
<td></td>
<td>OPEN</td>
<td>119</td>
<td></td>
</tr>
<tr>
<td>Shale</td>
<td>1887</td>
<td>KC</td>
<td>2,431</td>
<td>47</td>
</tr>
<tr>
<td>Shale</td>
<td>2034</td>
<td>KC</td>
<td>36,473</td>
<td>529</td>
</tr>
<tr>
<td></td>
<td></td>
<td>OPEN</td>
<td>69</td>
<td></td>
</tr>
</tbody>
</table>

Observations by well-site geologists and drilling personnel corroborate the results of Sokolov et al. (1971). Cuttings chips of organically-mature, fine-grained rocks usually violently spin and fizz at the wellhead from outgassing. This is the result of only the gas remaining in the rocks at the wellhead, which is a small fraction of the gas originally present in the rock, before the trip up the wellbore. During mud gas-logging operations, when drilling through mature organically-rich rocks, gas-logging values always dramatically increase from the outgassing of these rocks into the drilling mud. Occasionally the logging results from such shales are deleted, as the shale values can be so large as to overshadow values from gas-bearing, coarse-grained rocks. While drilling through organically-rich, mature, fine-grained rocks, mud-fluorescence values also always dramatically increase due to the effusion of oil-like bitumen from these rocks into the mud. When mature Bakken shales are penetrated with a water-based drilling mud, an oil film covers the mud pit. Source-rock cores crackle in the core barrel from gas loss at the wellhead, or bleed oil while being held at the wellhead or even in the laboratory, long after drilling.

This loss is hypothesized to be greatly enhanced by two features. First, generated hydrocarbons appear to be concentrated in fracture and parting-laminae voids (Price and Claytoni 1992), which are created or enhanced from the organic matter volume increase during hydrocarbon generation. This oil is readily mobile and easily lost to drilling muds. Second, during drilling operations, cores and especially cuttings are greatly disrupted by the drill bit. Such disruption substantially aids escape of this pre-fractionated mobile oil, poised for migration. This large loss of generated hydrocarbons during the trip up the wellbore has been well known to well-site geologists for over 40 years (C.W. Spencer, pers. comm., 1991). However, if necessary, the magnitude of this loss can be quantified.
by carefully designed and executed pressure-core barrel
tests wherein hydrocarbon concentrations of mature,
organic-rich shales brought up in sealed pressure core
barrels are directly compared to hydrocarbon concentra-
tions in shales from the same unit, but brought up-hole in
the open wellbore.

Important implications follow from this loss of gener-
ated hydrocarbons to drilling muds during drilling opera-
tions: 1.) the hypothesis of high primary migration
efficiencies would be erroneous, and instead would be
due to very high loss of generated hydrocarbons to
drilling muds, and 2.) except under conditions of intense
faulting, and accompanying fracturing, almost all gener-
ated hydrocarbons might remain in, or adjacent to, the
source rocks to extreme maturation ranks. This second
implication carries two more. First, very large in-place
oil-resource bases would exist in, and adjacent to, mature
organic-rich source rocks. Furthermore, significant parts
of these resource bases appear to be mobile and could
thus possibly be recovered. Second, although all rocks are
fractured to varying degrees, without intense structuring
these fractures do not form continuous hydraulic net-
works able to effectively transmit fluids and thus drain
source rocks. If faulting is required to effectively expel
hydrocarbons from source rocks to form commercial oil
deposits, then there should be a strong correlation of
increased basin productivity with increased faulting over
and adjacent to the hydrocarbon kitchens in basin deeps.

Bassin productivity does indeed demonstrate a strong
 correlation with increasing deep-basin structural intensity
(Table 2) for over 85% of the world’s discovered petroleum.
This correlation supports the hypothesis that intense
faulting, with accompanying fracturing, is needed to
allow significant primary migration of hydrocarbons.
Without such structural disruption, we believe that the
 generated hydrocarbons largely remain in source sys-
tems and may constitute large, previously unrecognized
oil-resource bases.

THE BAKKEN SOURCE SYSTEM

Data from the Bakken shales of the Williston Basin help
delineate this oil-resource base (Webster, 1982; Price
et al., 1984). The “Bakken source system,” as defined
here, comprises, in descending order, the lower part of
the Mississippian Lodgepole Limestone, the upper shale
member of the lower Mississippian-Upper Devonian
Bakken Formation, the middle siltstone member of the
Bakken Formation, the lower shale member of the
Bakken Formation, and the uppermost shales of the
Upper Devonian Three Forks Formation.

Short Distance Migration of Bakken Oil

Producing vertical “Bakken” wells in the Williston
Basin are completed in the middle Bakken siltstone, either

<table>
<thead>
<tr>
<th>Class</th>
<th>Basin Type</th>
<th>EUR B Bbls</th>
<th>Productivity $10^6$Bbls/1000 mi$^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>Shallow cratonic (Williston, Paris)</td>
<td>12.48</td>
<td>17.4</td>
</tr>
<tr>
<td>II</td>
<td>Moderately deep to deep cratonic basins with slight to moderate mobile rims (Uapna, Fort Worth)</td>
<td>22.67</td>
<td>88.4</td>
</tr>
<tr>
<td>III</td>
<td>Pull aparts (Gabon, NW Shelf Australia)</td>
<td>7.58</td>
<td>74.9</td>
</tr>
<tr>
<td>IV</td>
<td>Block fault - Aborted rift (North Sea, West Texas Permian)</td>
<td>317.6</td>
<td>265</td>
</tr>
<tr>
<td>V</td>
<td>Mobile Foredeeps (Anadarko, Persian Gulf)</td>
<td>930.5</td>
<td>299</td>
</tr>
<tr>
<td>VI</td>
<td>Downwarps (Greater Gulf Coast, Tampico-Reforma)</td>
<td>269</td>
<td>472.5</td>
</tr>
<tr>
<td>VII</td>
<td>Deltas (Niger, Mississippi Fan)</td>
<td>85</td>
<td>555</td>
</tr>
<tr>
<td>VIII</td>
<td>Wrench (Los Angeles, Eastern Venezuela)</td>
<td>132.6</td>
<td>969.3</td>
</tr>
</tbody>
</table>

of the Bakken shales, the uppermost Three Forks, the low-
ermost Lodgepole, or in combinations thereof (Table 3), a
fact also noted by Cramer (1991). Such production data
strongly suggest migration of Bakken-generated oil into

Table 3. Perforated intervals and cumulative water and oil
production (with last cumulative date) for some of the more
productive vertical Bakken wells in the Williston Basin.

<table>
<thead>
<tr>
<th>Well</th>
<th>Field</th>
<th>Perforations</th>
<th>Cum. Oil Bbls</th>
<th>Production Water Bbls</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shell USA 42-24A</td>
<td>Bicentennial</td>
<td>LP, US, SS</td>
<td>190,190</td>
<td>2,092</td>
</tr>
<tr>
<td>Apache Federal 2-4</td>
<td>Buckhorn</td>
<td>LP, US, SS</td>
<td>303,905</td>
<td>11,902</td>
</tr>
<tr>
<td>Federal 11-1</td>
<td>Buckhorn</td>
<td>LP, US, SS, LS</td>
<td>298,054</td>
<td>13,897</td>
</tr>
<tr>
<td>Supron Federal 10-1</td>
<td>Buckhorn</td>
<td>LP, US, SS</td>
<td>301,102</td>
<td>3,497</td>
</tr>
<tr>
<td>Tenneco Graham</td>
<td>Buckhorn</td>
<td>LP, US, SS</td>
<td>131,277</td>
<td>1,662</td>
</tr>
<tr>
<td>USA 1-15</td>
<td>Larkhorn Ranch</td>
<td>LP, US, SS</td>
<td>243,759</td>
<td>2,592</td>
</tr>
<tr>
<td>Asem Graham 1-12</td>
<td>Devils Pass</td>
<td>LP, US, SS</td>
<td>136,051</td>
<td>3,256</td>
</tr>
<tr>
<td>Supron Federal 6-4</td>
<td>Devils Pass</td>
<td>LP, US, SS</td>
<td>108,152</td>
<td>1,467</td>
</tr>
<tr>
<td>Chambers Blacktail</td>
<td>Larkhorn Ranch</td>
<td>LP, US, SS</td>
<td>243,759</td>
<td>2,592</td>
</tr>
<tr>
<td>Federal 1-20</td>
<td>Larkhorn Ranch</td>
<td>LP, US, SS</td>
<td>204,481</td>
<td>1,973</td>
</tr>
<tr>
<td>Chambers Blacktail</td>
<td>Larkhorn Ranch</td>
<td>LP, US, SS</td>
<td>204,481</td>
<td>1,973</td>
</tr>
<tr>
<td>Federal 19-1</td>
<td>Larkhorn Ranch</td>
<td>LP, US</td>
<td>306,109</td>
<td>1,647</td>
</tr>
<tr>
<td>Cities Service</td>
<td>Rough Rider</td>
<td>LP, US, SS</td>
<td>243,494</td>
<td>3,203</td>
</tr>
<tr>
<td>Shell USA 43-27A</td>
<td>Squaw Gap</td>
<td>LP, US, SS</td>
<td>347,479</td>
<td>2,165</td>
</tr>
</tbody>
</table>
adjacent rock units, a movement supported by Rock Eval analyses of both close-spaced (3-12 in., or 7.6 to 30.5 cm) core samples from the units adjacent to the two Bakken shales and from cleaned and microscopically-picked cuttings chips from the adjacent units (Table 4). These analyses demonstrate that organically immature samples from the three organic-poor units adjacent to the Bakken shales (Group I) have only minute capacities for hydrocarbon generation. Thus, the $S_1$ peak (by rock weight) ranges between 0 and 120 ppm, and averages 23 ppm, and when normalized to total organic carbon (TOC), the hydrocarbon index ranges between 0 and 53, and averages 10. The $S_2$ peak for these samples ranges between 0 and 270 ppm, and averages 97 ppm, with carbon-normalized values (hydrogen indices) ranging between 0 and 80 and averaging 28. In contrast, Rock Eval values of these same units from organically-mature areas of the Williston Basin (Groups II and III) yield ranges and averages 10 to 50 times the values of immature samples. Thus, the three units adjacent to the Bakken shales in mature basal areas contain 10 to 50 times more hydrocarbons than they possibly could have generated.

Two explanations are possible: 1.) the hydrocarbons in mature samples of these rocks are nonindigenous and have migrated into the rocks, or 2.) facies changes occur within the three units adjacent to the Bakken shales, such that these units become organically richer towards the deeper basin. The second possibility is improbable because microscopic examination reveals no lithologic change laterally in these units and TOC values do not measurably change laterally. Furthermore, Rock Eval data for the North Dakota Geological Survey (NDGS)-607 wellbore (Fig. 3) testify that the hydrocarbons are non-indigenous. In NDGS 607, the Bakken shales are well into hydrocarbon generation and the $S_1$ and $S_2$ pyrolysis peak values in the three units adjacent to the Bakken shales are much higher than values from immature examples of these units (Table 4). The Rock Eval transformation ratio exhibits high values in the three units adjacent to the two Bakken shales, compared to the transformation ratio values in the Bakken shales themselves (Fig. 3). Such elevated transformation ratio values are usually attributed to migrated, non-indigenous hydrocarbons. Also, $T_{max}$ declines from values of 435 to 441 °C in the two Bakken shales to values of 350 to 420 °C in the three adjacent units (not shown in Fig. 3), which is a strong indication of migrated, non-indigenous hydrocarbons.

The Rock Eval results from NDGS-607 with regard to the three units adjacent to the Bakken shales are repeated in the nine organically-mature wells which we have thus far examined. Both these Rock Eval results and historic oil-production data lead to the conclusion that an effusion of hydrocarbons has occurred from the two Bakken shales to the three adjacent units. Furthermore, from the Rock Eval data thus far in hand, this effusion of hydrocarbons appears to extend continuously through the middle siltstone member and at least 50 ft (15 m) into the lowermost Lodgepole Limestone and uppermost Three Forks shale in mature basal areas. This hydrocarbon emplacement no doubt occurred along vertical fractures extending from the Bakken shales into these units; fractures caused by fluid overpressuring from organic matter volume expansion during mainstage hydrocarbon generation.

Table 4. Rock-Eval analyses for cuttings chips and core samples from the Lodgepole Limestone, Bakken siltstone, and Three Forks shale where values from the three stratigraphic units are averaged together for nine wells from organically-mature areas of the Williston Basin; for one well (NDGS 607) from a moderately-mature area (“Group II”) of the basin; and for four wells (NDGS 1405, 527, 12162, and 4340) from organically-mature areas (“Group III”) of the basin. For each entry, the upper line is the range of values and the lower line is the average value. NDGS NUM. is the North Dakota Geological Survey well number. The Rock-Eval $S_1$ and $S_2$ pyrolysis peak values are normalized to rock-weight (ppm); and to organic carbon (mg/g OC); HCl (hydrocarbon index) for the $S_1$ pyrolysis peak, and HI (hydrogen index) for the $S_2$ pyrolysis peak.

<table>
<thead>
<tr>
<th>NDGS NUM.</th>
<th>Unit</th>
<th>$S_1$ ppm</th>
<th>$S_2$ ppm</th>
<th>$S_1$ ma/g OC</th>
<th>$S_2$ ma/g OC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Immature</td>
<td>Lodgepole Siltstone</td>
<td>0-120</td>
<td>97</td>
<td>0-80</td>
<td>0-80</td>
</tr>
<tr>
<td>Moderate Maturity</td>
<td>Lodgepole</td>
<td>1,003</td>
<td>28</td>
<td>143</td>
<td>143</td>
</tr>
<tr>
<td>Very Mature</td>
<td>Lodgepole</td>
<td>1,003</td>
<td>28</td>
<td>143</td>
<td>143</td>
</tr>
</tbody>
</table>

Bakken Shales as the Madison Oil Source

Dow (1974), using then extant petroleum-geochemical correlation tools concluded that the oil in mid-Madison reservoirs in the Williston Basin had been sourced from Bakken shales. However, Osadetz et al. (1990, 1992a, 1992b), using more sophisticated present-day correlation tools, concluded that most mid-Madison oils were not sourced from the Bakken shales but were sourced from Mississippian Madison Group rocks. Osadetz and Snowdon (1992) also...
provided a large body of geochemical data that delineates possible Paleozoic source rocks in the Williston Basin. Separate studies carried out by two major oil company research centers have also concluded that the Bakken shales did not source the mid-Madison oils, either in Canada or in the U.S. (pers. comm. from personnel at those research centers, 1990).

Gas chromatograms of C\textsubscript{15}, saturated hydrocarbons from mid-Madison oils are quite different from those of bitumen from Bakken shales (Fig. 4). Bakken samples are depleted in n-paraffins, have generally larger naphthene envelopes, and have n-paraffin profiles different from the mid-Madison oils. Sidney B. Anderson, the past North Dakota State Geologist, has long maintained that the Bakken shales are not the source of the mid-Madison oils on the basis of geology, variations in oil composition, and petroleum geochemistry (various personal communications, 1980-1991). Price et al. (1984) could not correlate Bakken shale bitumen to mid-Madison oils using isoprenoid hydrocarbon profiles, although this technique has been successfully used to relate other oil families (Price, 1990). Also, Price et al. (1984) noted that saturated and aromatic hydrocarbon gas chromatograms from the mid-Madison oils were identical to each other but always significantly different from those from Bakken shale extracts.

There are no avenues of vertical transport to move Bakken-sourced oils upward through the 1,000 to 1,500 ft (305 to 457 m) of low permeability Mississippian limestone separating the Bakken shales from the mid-Madison oil reservoirs. The near absence of faulting in the Williston Basin compelled Meissner (1978) to call on hydrocarbon generation in the Bakken shales to induce hydraulically continuous fractures from the Bakken shales through the Mississippian carbonates to the mid-Madison oil reservoirs. This is an untenable hypothesis. Although non-indigenous hydrocarbons have migrated into adjacent units from mature Bakken shales (Fig. 3), Rock Eval analyses show that the vertical extent of this migration is limited.

Leenher (1984) claimed correlation of Bakken shale bitumen to mid-Madison oils in the Williston Basin. However, her correlation examples were for shallow Bakken shales (about 6,500 ft, or 1,980 m). Price et al. (1984) found that shallow Bakken shales near the depositional edge of the Bakken Formation could undergo a facies change from type II organic matter to type III organic matter. Although TOC contents remained high, hydrogen indices strongly decreased, and the C\textsubscript{15}, saturated hydrocarbon gas chromatograms became more mature in appearance with strong increases in n-paraffins (from the influence of the terrestrial type III organic matter). Leenher’s (1984) C\textsubscript{15}, saturated hydrocarbon gas chromatograms from Bakken shales are overlays of those presented by Price et al. (1984) from samples at depositional-edge sites, and are not representative of the type II organic matter present in the Bakken shales in the deep Williston Basin.

Geochemical comparison of 15 oils produced from the Bakken shales with 19 oils produced from mid-Madison Group reservoirs is being carried out at the U.S. Geological Survey. Even by superficial examination, the two groups of oils are quite different. The mid-Madison oils for the most part are black oils, opaque to transmitted light in an 8-dram vial, solid or slightly liquid at 6°C (43°F), with API gravities of 28-41°. The Bakken-produced oils are shades of reddish-brown to orange-brown, moderately translucent to transparent to transmitted light, very liquid at 6°C, with API gravities of 40-46°. Distinct differences are present in whole-oil gas chro-


degrees of 28-41°. The Bakken-produced oils are shades of reddish-brown to orange-brown, moderately translucent to transparent to transmitted light, very liquid at 6°C, with API gravities of 40-46°. Distinct differences are present in whole-oil gas chro-

![Image of graph showing total organic carbon, hydrogen index, and transformation ratio](image)

**Figure 3.** Total organic carbon (in weight percent); and Rock Eval S\textsubscript{1} pyrolysis peak normalized to organic carbon (mg/g OC), hydrogen index, and transformation ratio (S\textsubscript{1}/S\textsubscript{1}+S\textsubscript{2}) for cores from the Socony-Vacuum Angus Kennedy F32-24-D (NDGS-607), Sec. 24, T149N, R93W, Williston Basin, North Dakota. The sample density for NDGS-607 is typical of the different wells of Table 4.
matograms (Fig. 5): 1.) the pristane to phytane ratios are different, 2.) the Madison oils are distinctly more paraffinic, having higher n-paraffin peaks in the n-C20 to n-C30 elution range, and having smaller peaks between the n-C10 to n-C17 n-paraffins than the Bakken oils, and 3.) the Bakken-produced oils have larger naphtheno-aromatic (unresolved) envelopes.

Whole-oil gas chromatograms for the same six oils for the n-C9 to n-C20 elution range (to show that elution range in expanded detail) are given in Figure 6, and some of the principal peaks are labeled in Figure 7, which serves as a guide for the other chromatograms in Figure 6. The peaks labeled 00 through 10 and A through M were used to construct “generic-hydrocarbon” ratio plots (Fig. 8, discussed below). Again, differences exist between the two groups of chromatograms: 1.) the naphtheno-aromatic (unresolved) envelope is higher in the Bakken oils, 2.) the compounds between the n-paraffins have greater peak heights in the Bakken oils, and 3.) the mid-Madison oils are distinctly more paraffinic. Furthermore, clusters

Figure 4. Gas chromatograms of C_15+ saturated hydrocarbons from two mid-Madison crude oils and from six Bakken shale core composites (identified by NDGS numbers) from Price et al. (1984). The NDGS well number, sample depth (ft), and Rock Eval T_max values (C) for the samples are given above each chromatogram. Crude oil and well information are in Price et al. (1984).
Figure 5. Whole-oil (resins and asphaltenes removed) gas chromatograms for three oils produced from mid-Madison reservoirs (North Westhope, unknown well Bottineau County, North Dakota, 37.0° API; Scoria, #1 Scoria Unit, Sec. 10, T139N, R101W, Billings County, North Dakota, 41.7° API; Fryburg, #1-23 State, Sec. 23, T141N, R101W, Billings County, North Dakota) and three Bakken-produced oils (Antelope, Brenna-Lacey-1, Sec. 1, T152N, R95W, McKenzie County, North Dakota, 45.4° API; Elkhorn Ranch, MOI 44-25H Sec. 25, T143N, R102W, Billings County, North Dakota, 40.0° API; Bicentennial, MOI 33-19 Sec. 19, T145N, R103W, McKenzie County, North Dakota. The Rock Eval hydrogen indices of the Bakken shales at the Antelope well are 130, at the Elkhorn Ranch well are 150, and at the Bicentennial well are 490. Every fifth n-paraffin is numbered (n-C followed by the respective carbon number), PR is pristane, PY is phytane.
Figure 6. Whole-oil gas chromatograms of the six oils in Figure 5 over the n-C₉ to n-C₂₁ elution interval. Compound labeling and oil origins as in Figure 5 caption. See Figure 7 for detailed index of compounds.
of peaks are similar within each oil group but different between the two oil groups. Thus, the two small clusters of peaks between the n-C17 and n-C18 and the n-C18 and n-C19 n-paraffins are similar for the Bakken oils but different for the mid-Madison oils, which are similar to each other. The trimethylnaphthalenes have been proposed as useful indices for both maturity and source-facies, much like biomarkers. The trimethylnaphthalene distributions between the two oil groups are distinctly different; the middle group of peaks containing peak "D" (Fig. 7) is much higher than the other two groups of peaks in the Bakken oils, compared to the mid-Madison oils.

Biomarkers are widely used to type oils into oil families. However, in moderately-mature to mature oils, these compounds rarely make up more than several hundred ppm (and often much less) of the whole oil by weight, and are found in only a restricted boiling range of the oil.

A superior method of oil correlation was presented by Kaufman et al. (1990) and Price (1990), using ratios or percentages of "generic" hydrocarbons found over all boiling ranges and in much higher concentrations in oils than biomarkers. Kaufman et al. (1990) were even able to demonstrate whether oils from the same family were in the same hydraulically connected reservoir. This technique was applied to the different oils of Figure 5. A number of ratios were calculated (based on the peaks labeled 00 to 10, A through M, and on some n-paraffins) and the ratios plotted in three different figures, one of which is Figure 8. The three Bakken oils plot in a tight cluster far from data for three mid-Madison oils. The three Bakken oils are clearly a different oil family than the three mid-Madison oils.

The tight distribution of the plots for the three Bakken oils in Figure 8 is unexpected and surprising considering the wide maturity range (Rock Eval hydrogen indices = 130 to 490) and geographic separation (23 to 69 mi or 37 to 111 km) of the oils examined. The variance in the plots of the three mid-Madison oils is also unexpected considering that the mid-Madison oils are thought to be a single oil family. The other two compound ratio plots constructed for the six oils of Figure 5 lead to the same conclusions as Figure 8.

These preliminary results corroborate the findings of Osadetz and his coworkers and support the conclusion that the Bakken shales have not sourced much of the mid-Madison oil in the Williston Basin.

The Bakken Source System Resource Base

Webster (1982), Artindale (1990), and Schmoker and Hester (1983) estimated that the Bakken has generated 92 to 150 billion BO (14.6 to 23.8 x 10^9 m^3). However, a large Rock Eval data base for the Bakken shales we have compiled suggests these calculations may be conservative. Both the original TOC and hydrogen index values for basin-center shales, before commencement of hydrocarbon generation, appear to have been higher than the values used by the above investigators. The large amount of oil generated by the Bakken shales could not have been expelled from the shales and leaked out of the basin over geologic time without charging the conventional mid-Madison reservoirs. Thus it appears that an in-place resource base of 100 to 150 billion BO (15.9 to 23.8 x 10^9 m^3), a portion of which is mobile and possibly could be recovered, exists over a large part of the Williston Basin in fractures, cracks, parting laminae, and matrix porosity within the Bakken source system.

Such a large oil-resource base is reasonable from both...
rock-storage capacity and geologic standpoints. To estimate rock storage capacity, the following assumptions were made: 150 billion BO (8.42 x 10^{11} \text{ ft}^3) are stored in the rocks; the upper Bakken shale is mature over an area of 22,345 mi^2 (57,873 km^2) (J.W. Schmoker, pers. comm., 1991); the average thickness of the Bakken Formation (both shales and the middle siltstone) over the mature area is 75 ft (22.9 m); the oil has penetrated 150 ft (45.7 m) into the lowermost Lodgepole and uppermost Three Forks; the total thickness of rock where the oil is stored is thus 375 ft (114 m). Therefore, the volume of rock where the oil is stored is 1.472 x 10^{11} \text{ ft}^3/\text{mi}^2 x 22,345 \text{ mi}^2 x 0.071 \text{ mi} (= 375 \text{ ft}/5,280 \text{ ft/} \text{ mi}) = 2.336 x 10^{14} \text{ ft}^3 (2.174 x 10^{13} \text{ m}^3). The volume of stored oil is 150 x 10^9 \text{ BO} x 5.615 \text{ ft}^3/\text{BO} = 8.422 x 10^{11} \text{ ft}^3, and the stored oil thus equals 0.361\% (8.42 x 10^{11}/2.34 x 10^{14}) of the volume of the rock in which it resides.

From a geologic standpoint, the Williston Basin is a "pancake" cratonic basin (Table 2), which, as a class, is the least oil-rich of petroleum-basin types. The Williston Basin is also characterized by flat-lying sediments with almost no faulting. This lack of structuring makes reasonable the hypothesis that most hydrocarbons generated in the sealed and undeformed source rocks have remained in place over geologic time.

**MIXED RESULTS OF HORIZONTAL BAKKEN DRILLING**

In spite of the huge volume of in-place oil proposed above, horizontal drilling and production results in the Bakken shales thus far have been mixed, and do not support the existence of such large in-place reserves. These mixed results have largely been attributed to lack of fractures. However, a key hypothesis of this paper is that the lack of success may be due in part to use of drilling, completion, maintenance, and production practices which may be inappropriate to the non-classical Bakken source system.

Organically-mature Bakken shales are oil-wet (Meissner, 1978; Webster, 1982; Cramer, 1991). Marginally to moderately mature Bakken shales may contain small amounts of immobile and discontinuous water (Fig. 9). However, mature shales apparently contain no water in the small remaining rock porosity (Schmoker and Hester, 1990). The three organic-poor units adjacent to the two Bakken shales have had substantial amounts of oil emplaced into their porosity (Fig. 9). However, these units, because they cannot generate meaningful amounts of hydrocarbons, probably still retain significant water saturations, even at very mature ranks. The fracture porosity in the two Bakken shales, and the three adjacent units should also be oil-wet, as this fracture porosity was created by abnormal pressuring due to organic matter volume expansion during hydrocarbon generation and charged by an oil-only phase. However, fractures that existed in the three units adjacent to the two Bakken shales before mainstage hydrocarbon generation would have been water wet, and thus would still retain mobile water. Production records of vertical "Bakken" wells testify to the largely oil-wet nature of the Bakken source system (Table 3); because production of such small percentages of water is unusual, given the volumes of produced oil. The water that has been produced likely originated from the partially water-saturated indigenous fracture and matrix porosity in the three units adjacent to the Bakken shales.

Fully oil-wet systems are very rare compared to conventional water-and-oil-wet oil reservoirs. Consequently, the industry is unaccustomed to dealing with oil-wet systems, which cannot be treated like conventional reservoirs. During drilling, completion, or maintenance operations, if water is introduced into these systems, the principles of two-phase fluid flow (Fig. 10) and the Jamin effect (Hedberg, 1980) come into effect.

The principles of two-phase fluid flow state that where two immiscible fluid phases (here water and oil) coexist in matrix porosity, both fluids have critical fluid saturation levels that must be exceeded before either fluid can flow. If the concentrations of both fluids under consideration exceed their respective critical fluid saturation levels, then both fluids can move through the solid. However, their relative permeabilities will be greatly reduced with
Geological or no carbonate minerals, and thus there is no reason to assume that water occurs from drilling with a salt-water-based mud, as there are no carbonate minerals present. However, the low water production from “Bakken” wells (Table 3) strongly suggests that scaling should be minor. Furthermore, NDGS records reveal that acidization of previously oil-productive vertical “Bakken” wells often greatly diminishes, or ruins, the oil-productive capability of the well.

Cramer (1991) noted that low-productivity vertical “Bakken” wells can have productivity increases after a fracture treatment. Examination of NDGS production histories reveals that many such previously nonproductive wells had water introduced into them. The subsequent fracture treatments penetrated water-induced skin damage surrounding the wellbore. NDGS records also suggest that fracture treatments using lease oil are much more effective than water-based or gelled-water fracture treatments. Cramer (1991) also noted that gelled-oil fracture treatments on low productivity “Bakken” wells are more effective than gelled-water treatments, because in the latter case, the wells have trouble unloading their water after treatment. Cramer (1991) further noted that post-fracture treatment of the wellbore with a liquid gel breaker, after fracturing with a gelled-oil system, greatly improves a well’s productivity, as incompletely degraded gelled oil can impair the productivity of “Bakken” wells. Skin damage around vertical “Bakken” wellbores from inappropriate drilling, completion, or maintenance operations can almost always be rectified by a lease-oil fracture treatment. Apparently this is not always possible with horizontal wells drilled within the Bakken shales, because much of the fracture treatment appears to be directed into a limited number of pre-existing fractures.

The introduction of water to the largely oil-wet Bakken source system is not the only possible detriment to “Bakken” productivity. With horizontal Bakken wells, two other possible controlling parameters are: 1) the time the drill bit and string spend in the horizontal portion of the hole, and 2) overbalanced drilling muds. With horizontal drilling, the drill bit and string spend a large amount of time in the beginning and middle portions of the horizontal segment of Bakken wells, ample time to inflict significant damage to the relatively plastic Bakken shales. Evidence of such damage arises from visual examination of Bakken shale cuttings chips. A significant percentage of these chips has been highly deformed and smeared out by the drill bit.

Because of the sloughing characteristics of horizontal Bakken holes during drilling, mud weights must be kept relatively high to prevent hole collapse. The intrusion of mud into, and caking of mud onto, Bakken shale fracture walls during drilling operations would greatly reduce Bakken oil productivity.

**Figure 10.** Plot of relative oil ($k_r$-OIL) and water ($k_r$-WATER) permeabilities versus oil and water concentrations. The shaded field represents reduced or zero permeability with respect to oil from the Jamin effect at water saturations below the critical water saturation level. Water saturation value of 1.0 represents 100% water saturation.

Respect to what their permeabilities would be if one fluid were in the solid alone.

The Jamin effect states that where two separate and immiscible fluid phases coexist in a rock, and one phase (water) is below its critical fluid saturation level, a portion of that water may be in the form of immobile spherical globules that cannot be distorted, and that occupy a percentage of connecting pore throats. These globules decrease, or reduce to zero, the permeability of the rock with respect to the other fluid phase. In natural systems, water below its critical fluid saturation is largely in the form of discontinuous or discontinuous films. However, in drilling, completion, and maintenance operations, significant percentages of the water introduced into the Bakken source system from the wellbore will have the form of discontinuous, pore-throat-plugging, spherical globules.

We hypothesize that introduction of water into the largely oil-wet Bakken source system creates a skin effect around the wellbore. This results in reduced, or zero, permeability with respect to oil, which greatly reduces or takes to zero the potential oil-productivity of the well. Introduction of such water occurs from drilling with a salt-water-based mud, acidizing the wellbore, or fracturing with water. Drilling with an oil-based mud reduces such damage, but does not eliminate it, as an oil-based drilling mud is an emulsion (small globules) of water in a greater volume of oil.

As Cramer (1991) noted, the Bakken shales have little or no carbonate minerals, and thus there is no reason to acidize these shales. Some productive Bakken source-system wells have been treated with acid during maintenance operations on the premise that scaling around the perforations had impaired fluid flow to the wellbore. Scaling occurs by precipitation of minerals from a water phase during production. However, the low water production from “Bakken” wells (Table 3) strongly suggests that scaling should be minor. Furthermore, NDGS records reveal that acidization of previously oil-productive vertical “Bakken” wells often greatly diminishes, or ruins, the oil-productive capability of the well.

Cramer (1991) noted that low-productivity vertical “Bakken” wells can have productivity increases after a fracture treatment. Examination of NDGS production histories reveals that many such previously nonproductive wells had water introduced into them. The subsequent fracture treatments penetrated water-induced skin damage surrounding the wellbore. NDGS records also suggest that fracture treatments using lease oil are much more effective than water-based or gelled-water fracture treatments. Cramer (1991) also noted that gelled-oil fracture treatments on low productivity “Bakken” wells are more effective than gelled-water treatments, because in the latter case, the wells have trouble unloading their water after treatment. Cramer (1991) further noted that post-fracture treatment of the wellbore with a liquid gel breaker, after fracturing with a gelled-oil system, greatly improves a well’s productivity, as incompletely degraded gelled oil can impair the productivity of “Bakken” wells. Skin damage around vertical “Bakken” wellbores from inappropriate drilling, completion, or maintenance operations can almost always be rectified by a lease-oil fracture treatment. Apparently this is not always possible with horizontal wells drilled within the Bakken shales, because much of the fracture treatment appears to be directed into a limited number of pre-existing fractures.

The introduction of water to the largely oil-wet Bakken source system is not the only possible detriment to “Bakken” productivity. With horizontal Bakken wells, two other possible controlling parameters are: 1) the time the drill bit and string spend in the horizontal portion of the hole, and 2) overbalanced drilling muds. With horizontal drilling, the drill bit and string spend a large amount of time in the beginning and middle portions of the horizontal segment of Bakken wells, ample time to inflict significant damage to the relatively plastic Bakken shales. Evidence of such damage arises from visual examination of Bakken shale cuttings chips. A significant percentage of these chips has been highly deformed and smeared out by the drill bit.

Because of the sloughing characteristics of horizontal Bakken holes during drilling, mud weights must be kept relatively high to prevent hole collapse. The intrusion of mud into, and caking of mud onto, Bakken shale fracture walls during drilling operations would greatly reduce Bakken oil productivity.
Because of the greater competence of the middle Bakken siltstone member and the Lodgepole Limestone and Three Forks Formation, horizontal drilling in these rocks would be possible with reduced mud weights. Attempting to produce oil from these rocks while drilling might also help to reduce formation skin damage.

Lastly, productivities of individual Bakken horizontal wells have significantly decreased due to apparent regional decline in Bakken source-system reservoir pressures in the “fairway” area of the Bakken play. Schmoker (1992) hypothesized, and we agree, that this regional pressure decline was enhanced by an interconnected fracture network in the Bakken source system. This regional decline in “reservoir” pressure is a consequence of overproduction of individual Bakken wells in attempts to drain as much oil as possible from adjacent sections. The pressure decline also results from the nature of the organic matter in the Bakken shales; the type II and II/I organic matter of the Bakken shales is a poor generator of hydrocarbon gases (per unit of oil) compared to type III and III/II organic matter (Price, 1989b). Because the principal drive mechanism of the Bakken source system is gas expansion, this limited capability for gas generation will greatly detract from ultimate production of this resource base. It is likely that only a small fraction of the in-place resource base in the Bakken source system will be recovered unless reservoir pressure maintenance by gas injection is instituted.

Given the excellent sweep capabilities demonstrated by carbon dioxide in tertiary oil-recovery programs, carbon dioxide would be a natural candidate for such a gas injection program. If the Bakken source system is well interconnected by a regional fracture system, given the diffusive capabilities of carbon dioxide, a gas-injection program could be expected to be effective.

**OTHER SOURCE SYSTEMS**

The Bakken source system is not unique. Other examples of self-sourced, fractured-shale oil deposits include the prolific Upper Cretaceous Austin Chalk in South Texas and the Upper Cretaceous Niobrara Formation in the Silo Field, Laramie County, Wyoming (Johnson and Bartsh, 1991a, b). Lucas and Drexler (1976) discussed the Altamont-Bluebell trend of the Uinta Basin, Utah, where intense structuring allows many of the generated hydrocarbons to escape the source system entirely, perhaps to form conventional oil deposits. Truex (1972) discussed oil production from fractured, organic-rich, black shales in the East Wilmington Field, Long Beach, California. These shales, possibly equivalent to the mid-Miocene Altamira Shale Member of the Monterey Formation, are highly organic-rich (Price, 1983, his Figs. 3 and 4) and are at burial temperatures of 105 C or higher. Yet by conventional maturity indices, these shales appear not to have begun hydrocarbon generation. Rock Eval transformation ratios range between 0.016-0.046 and R0 ranges between 0.23 and 0.40%. Rock Eval T max values of 431-444 C reflect the elevated burial temperatures of these rocks. Given the established oil production from these shales and their elevated burial temperatures, it appears that hydrocarbons generated in these shales were lost to the drilling mud during the trip up the wellbore, and thus were not measured by Rock Eval or Soxhlet extraction.

Production from the shales in the East Wilmington Field is from vertical tensional fractures in organic-rich black shales, silts, cherty shales, marls, and phosphatic shales on the crest of the Wilmington anticline. As of November, 1971, five productive wells (of ten attempts) in the fractured shale had produced 2,100,000 BO (334,000 m3). Truex (1972) noted that the five nonproduc-
tive wells had good oil and gas shows, produced only hydrocarbons and no water during completion attempts, but were abandoned due to restricted fluid entry into the wells. The oil-bearing zones appeared to have been damaged during drilling. All ten wells were drilled with water-based mud. Truex (1972) noted that the fracture systems are highly sensitive to damage from emulsion blockage by drilling and kill fluids.

As of 1971, fractured, self-sourced, shale reservoirs had produced over 100,000,000 BO (15.9 x 10^6 m^3) from fields in California (Truex, 1972). Organic-rich, fractured shales have been penetrated many times in California basins, and always have had abundant oil and gas shows. Yet few formation tests of completions have been attempted away from established production (Truex, 1972). Truex (1972, p. 1938), discussing self-sourced, fractured shales noted, and we concur, “It is time for all petroleum geologists to enlarge their thinking to include this neglected reservoir.”

DISCUSSION

Assume that most of the 100-150 billion barrels (15.9 to 23.8 x 10^9 m^3) of oil generated by Bakken shales has remained in place. Then it is not difficult to estimate an in-place oil resource base in the lower 48 United States in the tens to hundreds of trillions of barrels, given the facts that the Bakken shales are thin and that thick sections of mature, organic-rich shales of many different geologic ages exist in many other onshore U.S. basins. Examples include the up to 9,000 ft (2,700 m) thick Eocene and Paleocene shales in the deep Uinta Basin; the different units in the several thousand foot thick Upper and Lower Cretaceous black shale section present in Rocky Mountain basins; the rich Permian Phosphoria and Minnelusa shales and equivalents in Rocky Mountain basins; the Pennsylvanian black shales of the Paradox, Anadarko, and other basins; the organic-rich Tertiary shales of the California basins; the organic-rich organic matter; and the required ranks increase as size of the reservoir increases (Price, 1991). Recent dry holes in the Denver Basin in drilling attempts of the Niobrara Chalk away from the Silo Field serve as examples of this point.

If the in-place oil resource base that we hypothesize does exist in the lower 48 U.S., it would fulfill the most important requirements for frontier exploration: the possible reserves are huge and are in a politically and economically stable country. Furthermore, established markets are near possible production, and an infrastructure already exists which includes pipelines, refineries, and distribution centers.

CONCLUSIONS AND SUMMARY

1.) In all petroleum basins examined, strong decreases in source-rock hydrogen indices toward the organically-mature basin deeps are not matched by numerically-equivalent increases in either Soxhlet-extractable hydrocarbons or the Rock Eval S_o pyrolysis peak. Furthermore, the amount of oil in conventional deposits in basins is typically much smaller (1-5%, or less) than the hydrocarbons calculated to have been generated by the mature source rocks in the basin. Thus, based on recent petroleum-geochemical literature, primary migration was thought to be very efficient, whereas secondary migration and accumulation were very inefficient. Petroleum basins were thus inferred to be very leaky systems, and most generated hydrocarbons were thought to be lost through leakage over geologic time.

2.) Increasing basin richness (as measured by recoverable oil normalized to basin area) strongly correlates with increase in faulting over and adjacent to basin deeps. We hypothesize that faulting and fracturing are necessary to disrupt mature source rock systems and to free generated hydrocarbons for migration. Without such faulting, generated hydrocarbons would remain in the source rocks, or in the rocks adjacent to the source rocks, to extreme maturation ranks.

3.) In the Bakken source system of the Williston Basin, evidence suggests an exodus of oil from mature Bakken

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shales to adjacent rocks for vertical distances of at least 50 ft (15 m) in mature basinal locations.

5.) Bakken-shale bitumen and Bakken-produced oils do not resemble or correlate to Williston Basin mid-Madison oils. Furthermore, lack of viable migration paths would seem to preclude possible vertical migration of Bakken-generated oil to the mid-Madison reservoirs. The 100 to 150 billion barrels (15.9 to 23.8 x 10^9 m^3) of Bakken-generated oil certainly did not leak out of the basin without charging the conventional basinal reservoirs. We thus conclude that almost all of this generated oil remains in the Bakken source system in cracks, fractures, parting laminae, and matrix porosity.

6.) The mixed economic success of the Bakken play is probably due less to geologic reasons than to drilling, completion, and maintenance procedures inappropriate to the largely oil-wet Bakken source system.

7.) There are other examples of self-sourced, fractured-shale oil deposits that have been commercially produced and that have characteristics in common with the Bakken source system. Given the huge amount of oil generated from relatively thin Bakken source shales, the very thick and areally extensive source rocks in many different basins in the lower 48 United States may hold in-place oil resources on the order of tens of hundreds of trillions of barrels, a portion of which is clearly mobile and thus possibly recoverable.

8.) If such a large in-place oil resource base indeed exists, we believe that its recovery will depend on the development of new, non-classical exploration, drilling, completion, production, and maintenance techniques. Furthermore, a much closer working relationship, than has previously been the case, between research scientists and engineers of these varied disciplines will be necessary.

ACKNOWLEDGMENTS

We thank Jim Schmoker, Kathy Varnes, Gordon Dolton, and Sid Anderson for reviews of the manuscript.

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