Origins and characteristics of the basin-centered continuous-reservoir unconventional oil-resource base of the Bakken Source System, Williston Basin

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1.0 ABSTRACT/EXECUTIVE SUMMARY

As discussed in section 2.0, the Williston Basin, the most structurally-simple basin in the world, is characterized by unvarying flat-lying sediments. Most (75%) of the conventional oil production of this basin is found in the Mississippian mid-Madison limestones, the principal oil reservoir of the basin. Sediment age in the basin ranges from Cambrian to early Tertiary with numerous unconformities present. The lower Mississippian-upper Devonian Bakken Formation contains two black shales, the richest source rocks in the basin, indeed, among the richest source rocks worldwide. The rocks adjacent to the two Bakken shales are organic-poor, carbonate-rich, brittle, low-porosity, impermeable rocks, which, with the two shales, form a tight, closed-fluid system which cannot transmit fluids. These rocks have been termed the "Bakken Source System" (Price and LeFever, 1992).

Due to several unrelated circumstances, the North Dakota portion of the Williston Basin has the best rock, oil, and well-history sample base worldwide. Because of this sample base, and because of the relatively simple geologic history of the basin (compared to many other basins), the Williston Basin is also one of the best-studied petroleum basins worldwide. This unique sample and data base, and the structural simplicity of the Williston Basin, has led to the recognition and delineation of an unconventional basin-centered oil-resource base there, possibly 200-400 billion barrelss in place, the point of this discussion.

In section 3.0, we discuss how early classic research by Amoco Oil Company personnel (Dow, 1974; Williams, 1974) in the Williston Basin established important petroleum-geochemical concepts, now universally applied in oil exploration. Indeed, this early research by Amoco helped

lay the foundation for then fledgling new science of petroleum geochemistry. Dow (1974) and Williams (1974) concluded that the richest source rocks in the Williston Basin, the Bakken shales, had sourced the most important conventional oil resource base in the basin, the oils in the Mississippian mid Madison reservoirs about 800 to 1,000 ft (244 to 305 m) above the Bakken shales. Subsequent research by other investigators supported the early Amoco work, and led to the synthesis of the model of oil expulsion from source rocks, and accumulation into conventional oil deposits, now universally accepted in the petroleum geosciences, to wit:

1) Petroleum basins, including petroleum-basin depocenters, are open-fluid systems where fluid movement is very easy.
2) Source rocks expel almost all of the oil that they generate.
3) Only a small fraction of this expelled oil is actually caught in commercial traps.

Thus, most oil expelled from source rocks is believed to be irrevocably lost over geologic time. Countless ROCK-EVAL analyses, the most widely-used analytical instrument in petroleum geochemistry, appear to support the above model of oil expulsion and accumulation.

Many of the concepts developed by Dow (1974) and Williams (1974) have stood the test of time and remain unmodified to this day. However, newer research conclusively demonstrates that a major conclusion of these studies, that the Bakken shales are the source rocks for the mid-Madison oils, is wrong.

Section 4.0 discusses how the analytical instruments and methods available when Amoco carried out their early (1968 to 1972) Williston Basin work are (understandably) archaic compared to today's tools. Petroleum geochemistry's most reliable analysis is oil-to-oil correlation, wherein it can be irrefutably determined if two or more oils have been sourced from the same rock, and are thus of one oil family, or not. State of the art analyses, and comparison of mid-Madison oils with oils produced directly from the Bakken Source System, demonstrate that these two oil suites are different. Thus, the Bakken shales could not have sourced the mid Madison oils. Moreover, no oil sourced from the Bakken shales has been found in a conventional oil reservoir on the U.S. side of the Williston Basin. Because of the structural simplicity of, and lack of faulting in, the Williston Basin, it is inconceivable, by any model of basin evolution, that the oil generated by the Bakken shales leaked out of the basin without charging at least one conventional oil reservoir in the basin. Thus, the inescapable conclusion follows, that all the oil generated by the Bakken shales remains in the Bakken Source System. Hard data (section 6.0) support this conclusion.

That the richest source rock in the Williston Basin has contributed nothing to the conventional oil reservoirs there is a staggering conclusion as related to petroleum geochemistry. Moreover, independent research demonstrates that the same situation exists in the Western Canadian Alberta Basin. The Williston and Alberta Basins are at the opposite ends of the spectrum regarding structural style and degree of structural intensity. Two such disparate basin styles having the same source rock-reservoir problem strongly suggests that the accepted model of oil expulsion and accumulation may be widely inoperable. In this light, an alternate model of oil expulsion and accumulation was proposed (Price, 1994a), to wit:

1) The deep parts of petroleum basins, where the sediments are thickest (the depocenters), are closed-fluid systems, where fluid movement is difficult or impossible.
2) Oil expulsion from source rock systems is uncommon.
3) Unless source rocks are physically disrupted by intense structural activity, such

as faulting or salt diapirism, or are directly adjacent to good fluid conduits, such as sandstones, oil expulsion does not occur at all.

4) Therefore, in many cases, most generated oil remains in or adjacent to its source rock.

This hypothesized alternate model of oil expulsion and accumulation is easily tested. If the model is valid, a strong correlation should exist between increasing structural intensity in the depocenters of petroleum basins with increasing amounts of recoverable conventional hydrocarbons (HCS) for well-explored, petroleum-bearing basins worldwide. A pronounced correlation between increasing basin richness and increasing deep-basin structural intensity does exist (Price, 1994a). This observation in turn suggests that the alternate model of oil expulsion and accumulation may be correct and that the accepted expulsion-accumulation model could be invalid, or at least widely inapplicable. This last conclusion has profound implications for petroleum geology, one of which concerns us here: huge unconventional oil-resource bases should then theoretically exist over large basinal areas, as continuous oil reservoirs, in and around source rocks in the deep unstructured parts of some sedimentary basins.

In section 5.0 we discuss the general characteristics of unconventional-resource bases, all of which have a number of attributes in common, two of which immediately concern us here. First, economic exploitation of unconventional resources is almost completely governed by technology. Second, unconventional resources, which can be economically produced due to technological advances, can be very large. Many examples exist of different unconventional resources where these characteristics apply, just one being the bulk-tonnage, low-grade gold deposits of northern Nevada, which were once "unconventional", but are now considered eminently conventional. However, we are concerned here principally with unconventional-energy deposits.

Examples of unconventional, or once unconventional, energy deposits are: basin-centered gas deposits, tight-sand gas deposits, tar-sand deposits, shale-gas deposits, and coal-gas deposits. One unconventional shale-gas resource at one time involved the most intense gas-drilling play in the U.S., the Antrim shale-gas play of northern Michigan, where, as of 1996, over 4,300 wells were producing 425 million cubic feet of gas per day. Antrim shale-gas production began because of the Section 29 Federal Tax Credit, but quickly became a technological play, based on research carried out, and applied by, the preeminent research group, the Gas Research Institute. The Antrim shale-gas resource base, and the play itself, have numerous parallels to the Bakken oil-resource base, which we discuss.

Coal gas has become a major source of natural gas, especially in the San Juan Basin (New Mexico and Colorado). Coal-gas production, like Antrim shale-gas production and production of oil from the Bakken Source System, requires specific drilling, completion, and stimulation procedures, to economically produce the resource base. In all three of the aforementioned cases, geology is constant, or nearly so, in the respective basins, and economic HC retrievals are almost entirely-dependent on appropriate recovery procedures specifically designed for the resource base in question. If inappropriate recovery procedures are applied, the wells are economic failures and the resource base is incorrectly viewed as non-recoverable. San Juan Basin coal-gas production has other pointed parallels with production of Bakken oil, which we also discuss.

Section 6.0 discusses the origin and characteristics of the huge continuous oil deposit in the Bakken Source System. Because of the oil shows encountered whenever the drill penetrated even marginally-mature Bakken Source System rocks, these rocks have been cored in at least 107 wells in the North Dakota portion of the Williston Basin alone. Moreover, at least 41 of these cored wells have had traditional core analyses performed on them: porosity, permeability, residual-oil and water saturations, and visual examinations, analyses which exist in the public domain. Detailed ROCK-EVAL analyses on Bakken Source System reservoir rocks, with spacings of 6" to 24" (0.15-0.61m) between samples, for 26 geographically-separated wells in the Williston Basin, have also measured the amount of oil in Bakken Source System rocks (much like residual-oil saturation analyses) and the general organic richness of these rocks.

We present examples of conventional core analyses from six different wells wherein Bakken Source System rocks were cored. The conclusions drawn from these six examples are representative of the analyses from all 41 cored wells. The three reservoir rocks adjacent to the two Bakken shales always have low matrix permeabilities (0.01 to 0.03 millidarcies, or less) and zero residual-oil-saturation percentages in basin areas where the Bakken shales are at shallow depths of burial and are thus very immature and have not begun HC generation. Moreover, these three adjacent rocks also have no, or only few, fractures in basin areas where the Bakken shales are immature. As maturity increases in the Bakken shales, so do the residual-oil concentrations and the incidence of fractures in the rocks adjacent to the shales. Where the Bakken shales are both thick and mature (e.g., the shales have extensively generated HCS), the three rocks adjacent to the two Bakken shales always have both high residual-oil saturations and also a high incidence of fractures. These fractures dramatically increase the permeability of the rocks in which they occur. Both the fracturing and the high residual-oil saturations are a result of oil and gas generation in the extremely organic-rich Bakken shales.

Our close-spaced ROCK-EVAL analyses of Bakken Source System reservoir rocks corroborate the observations from the traditional core analyses: For example, the three rocks adjacent to the two Bakken shales, where the Bakken shales are immature, are extremely organic-poor and, throughout the area of investigation have no capability to generate indigenous HCS. Second, progressive movement of Bakken-shale-generated oil into these three rocks occurs with increasing maturity of the Bakken shales. Third, samples of these three rocks adjacent to the two Bakken shales from basinal areas where the Bakken shales are both thick and mature, always have very large increases in organic richness compared to background levels, due to massive injection of Bakken-shale-generated oil into them.

We present calculations demonstrating that the conversion of solid organic matter (OM; kerogen) in source rocks to oil and gas during HC generation with sediment burial is a volume-expansive reaction. That is, the products of the reaction (oil and gas) occupy a greater volume than the reactants (kerogen). Because all the rocks of the Bakken Source System are "tight", with essentially no permeability, they cannot transmit fluids. Thus, during HC generation, the newly-generated oil and gas from the Bakken shales could not be transported from the shales, resulting in a volume expansion of material within a fixed volume. This expansion in turn created very high fluid pressures which compressed the solid OM (the kerogen) in the Bakken shales, resulting in stored potential energy of compression. The abnormally high pressure from HC generation eventually became so high that the rocks were fractured, thereby relieving the accumulated stress in the system. However, the energy of compression stored within the Bakken shales actually created super-lithostatic pressures, pressures greater than the weight of the overlying column of rocks. The resulting expulsion of oil from the Bakken shales under these super-lithostatic pressure events in turn created super-lithostatic fracturing events, resulting in extremely well-interconnected reservoirs in the three rocks adjacent to the two Bakken shales with a dominantly-horizontal fracture system.

Section 7.0 concerns Williston Basin heat flow and sediment-burial temperatures. Increasing burial temperatures principally cause HC generation in source rocks. High heat flows cause abnormally high geothermal gradients, which either in the geologic past, paleo geothermal gradients, or occurring today, result in relatively high sediment-burial temperatures at relatively shallow depths. High geothermal gradients thus result in HC generation occurring in source rocks at shallower than normal burial depths.

Paleo-geothermal gradients may be estimated by measuring different petroleum-geochemical parameters versus depth ("maturity indices"). Vitrinite reflectance (R_o), and to a lesser extent, ROCK-EVAL T_{max}, are the two very best maturity indices in petroleum geochemistry, especially when these two analyses can be executed on coal samples. Previously published R_o profiles versus depth suggested extreme paleo temperatures existed in the Williston Basin in the geologic past. We have augmented the previously published database with further vitrinite reflectance analyses, versus depth including coal samples in the shallowest samples. Our data corroborate the previous findings: Extreme paleo-geothermal gradients existed in the Williston Basin in the geologic past. Moreover, the heat flow causing these gradients occurred recently in the geologic past, in Eocene or younger time. In point of fact, the Williston Basin has had the highest heat flow we have observed in any sedimentary basin worldwide.

Other evidence also exists that extreme heat flows occurred in the Williston Basin. Moreover, other investigators have also hypothesized high paleo-heat flows from completely separate lines of research. However, still other investigators, dealing with petroleum-geochemical computer modeling have simply assumed, with no supporting data, that heat flows in the Williston Basin have been constant through geologic time at the moderate present-day levels. We contend that these assumptions were made simply to facilitate construction of the aforementioned models, and thus have no basis in reality.

In recent geologic time, the Williston Basin has been significantly cooled by strong cross-basinal meteoric-water recharge, via five Tertiary to Cambrian aquifers very transmissible to fluids. This rapid (in a geologic sense) basin cooling explains today's moderate burial temperatures in the Williston Basin.

Marine-derived, hydrogen-rich kerogen, the OM type which has sourced most of the world's oil, requires far higher burial temperatures than generally recognized to initiate and sustain HC generation. This situation has largely gone undetected because all aspects of organic metamorphism, and hence all organic maturation indices, are strongly suppressed in hydrogen-rich OM compared to hydrogen-poor type III OM buried at the same rank. Examples, and causes, of this suppression are presented, and discussed. Because of this strong suppression of organic metamorphism in hydrogen-rich kerogen, the extreme paleo-heat flows in the Williston Basin, and the resulting extreme paleo-burial temperatures thereof, have created a highly unusual situation. Specifically, world-class source rocks, the Bakken shales, have generated hundreds of billions of barrels of oil and created superlative oil reservoirs in the rocks adjacent to the two shales, all at shallow burial depths (9,000-11,500 ft; 2,743-3,505 m). Similar oil-resource bases in other basins worldwide will occur only at depths of 20,000 to 30,000 ft (6,095-9,144 m) because of the significantly lower present-day or paleo-geothermal gradients in these basins. Thus, extraction of oil from these as yet unrecognized resource bases will be much more difficult than from the Bakken Source System, because of the much greater depths, and therefore higher temperatures and pressures, involved.

Four different investigations (Burrus et al., 1996; Schmoker, 1996; Carlisle et al., 1992; and LeFever et al., 1991) have reached conclusions divergent from those herein regarding the origin, fate, and recoverability of the oil generated by the Bakken shales. Each of these studies are discussed in some detail in section 8.0.

Burrus et al. (1996), in a computerized model of the Williston Basin, *assumed* that the heat flow, and therefore the geothermal gradients, of the Williston Basin had been constant through geologic time at today's moderate values. They further assumed that abnormal fluid pressures never occurred from HC generation in the Bakken shales, and therefore, that no hydraulic fracturing of any Bakken Source System rocks had occurred. On the basis of these assumptions, Burrus et al. (1996) thus concluded that all the oil generated by the Bakken shales had been dispersed throughout the Williston Basin at irreducible oil saturations in porous and permeable Lodgepole limestones. In fact, because of this hypothesized dispersion, Bakken oil saturations in the Lodgepole were predicted to be too low to be analytically detectable.

Burrus et al. (1996) made very unrealistic inputs for their model, those inputs thus yielding unrealistic results in their calculations. In one such example, Burrus et al. (1996) assumed an average lateral permeability of 40 millidarcies in the Lodgepole limestone. This assumed value is 4,000 times greater than measured average lateral matrix permeabilities from hundreds of core analyses from numerous wells throughout the Williston Basin. Moreover, predictions from the model of Burrus et al. (1996) strongly contradict actual observations from Bakken Source System rocks. These contradictions reveal that key computer predictions of Burrus et al. (1996) are wrong. We examine how this came to be.

Schmoker (1996) observed marked heterogeneities in the oil productivities of Williston Basin Bakken wells at both local and regional levels. Local production heterogeneities (e.g., where two spatially-close wells produced vastly different amounts of oil) *were assumed* to be due to heterogeneities in reservoir geology between the two wells over short lateral distances. However, no proof was offered to support this assumption. In contrast, we demonstrate that reservoir geology is constant over the entire area of discussion in the Williston Basin. Schmoker's (1996) assumption on this point is incorrect. Schmoker (1996) also attributed the cause of the highest Bakken well productivities to date in the "Fairway area" was due to a regional geologic change in the Fairway area, compared to the rest of the Williston Basin. By way of information, the "Fairway area" is an area of the Williston Basin in Billlings and McKenzie Counties (North Dakota) near the depositional edge of the Bakken Formation where the Bakken shales are thin compared to other basinal areas. The "Fairway" was so named because apart from the Antelope Field, this area had the most productive vertical and horizontal Bakken wells, and was thus perceived as a Fairway (favorable) area of Bakken oil production. Schmoker's (1996) regional geologic variation was hypothesized to have significantly improved reservoir properties, thus explaining the elevated productivities of Bakken Fairway wells, compared to Bakken wells in other basin areas. We demonstrate that there is no detectable regional geologic change in the Fairway, compared to other areas of the Williston Basin, and that Schmoker's (1996) assumption on this point is unfounded.

We concur with Schmoker (1996) that pronounced local and regional production heterogeneities are present between Bakken wells throughout the Bakken HC kitchen. However, these production heterogeneities appear to be completely due to variable drilling, completion, stimulation, and maintenance procedures applied to different Bakken wells. Inappropriate procedures result in bad wells. Application of procedures appropriate to the unique characteristics of the Bakken Source System results in productive wells. Our studies suggest that very rarely does variation in local geology have any measurable effect on the productivities of Bakken Source System wells.

American Hunter, a Canadian Hunter subsidiary, put a substantial, but failed, effort into the Bakken horizontal play. Only one publication (Carlisle et al., 1992) came out of this effort. The principal conclusion of this publication, which concerns this discussion, is that the Fairway area of the Williston Basin in North Dakota has the most productive wells, because this is where the Bakken shales are most mature, and therefore have the best reservoir qualities. This conclusion was based on analyses of 5 Bakken-produced oils to determine oil maturity. However, their oil-sample base was biased and too small. In point of fact, the Fairway area does not have the most mature Bakken shales in the Williston Basin, and the conclusion of Carlisle et al. (1992) in this regard is incorrect. Moreover, Carlisle et al. (1992) assumed that the Bakken shales are the principal (only?) reservoir for the Bakken oils. We believe that this is an erroneous assumption.

Four small conventional oil fields are present in the middle Bakken siltstone in Canada, which takes on sandier characteristics in Canada compared to Bakken siltstones on the American side of the Williston Basin. These facts led LeFever et al. (1991) to propose long-distance lateral secondary migration of oil generated by Bakken shales from far south on the American side of the

Williston Basin, in the Bakken HC kitchen, northward into Canada. The siltstone itself was proposed to have served as the conduit for this migration. We demonstrate that this proposed lateral migration of Bakken shale generated oil is unlikely given observed data. The Bakken siltstone does take on sandier characteristics in a northward direction into Canada. However, siltstone core analyses available from eight wells on the American side of the basin near the Canadian border demonstrate that even at these northern locations, the middle Bakken siltstone is still a tight rock with very low permeabilities. As such, these more northern siltstones are still incapable of transmitting fluids. Also, oil distribution patterns in siltstones on the American side of the basin could not possibly result from secondary migration of oils. Thus we conclude that the hypothesis of LeFever et al. (1991) concerning long lateral migration of Bakken oil through the Bakken siltstone although logical, is improbable.

The Canadian Bakken siltstone oil pools most likely originated by a fractionation of indigenous bitumen to an oil-like phase within the Bakken shales. Previous research has demonstrated that this fractionation occurs in Bakken shales even at very immature ranks. When even moderately-poor fluid conduits are directly adjacent to rich source rocks, then expulsion of this fractionated oil phase may occur to the more porous rock. This is most likely the situation in Canada, where immature Bakken shales are directly adjacent to a moderately-transmissible fluid conduit, the Bakken siltstone, which actually has become a poor quality sandstone in Canada. Thus, the Bakken siltstone oil pools in Canada appear to have had a local origin. Moreover, this model of a local origin is supported by significant differences, both at the whole-oil, and at the molecular level, between American Bakken produced oils and Canadian Bakken siltstone oils.

The lower Lodgepole Waulsortian mound play of the North Dakota portion of the Williston Basin was one of the more active plays recently for the onshore U.S. There is a great deal of confusion regarding this play, including the source rock for the oil and reservoir characteristics. To prevent this confusion from spilling over to this discussion, we present an overview of the play in section 9.0. Fortunately, enough hard data exists that numerous firm conclusions can be drawn concerning this play:

As of 1995, there has been some discussion as to the source rock for the lower Lodgepole Waulsortian mound oils. However, the oils have been analyzed by different laboratories and have been found to belong within the Bakken oil family. That is to say, the lower Lodgepole oils were sourced by the Bakken shales. Moreover, both the lower Lodgepole oils, and the Bakken shales which sourced them, are only marginally-mature. Core analyses demonstrate that the characteristics of the lower Lodgepole reservoir rock for these Waulsortian mound oils are typical of that for all lower Lodgepole rocks throughout the Bakken HC kitchen, with low matrix porosity (2 to 6%) and very low matrix permeability (generally less than 0.1 millidarcies). However, in spite of these poor reservoir characteristics, the better wells of this play have very high initial potentials and also high cumulative productions. For example, the discovery well of the play, the Conoco Dickinson State # 74 was completed in February 1993 at an initial open-hole potential of over 8,000 barrels per day. From February 1993 to July 1996, this well produced over one million barrels of oil and was producing over 3% of Conoco's entire onshore U.S. oil production. These high productivities are entirely due to extensive tectonic fracturing overprinted in the rocks of the better lower Lodgepole wells, tectonic fracturing which has been caused by salt dissolution and collapse and has also overprinted any fracturing caused by HC generation in the Bakken shales at this site. In fact, salt collapse is most likely responsible for the entire play.

Lower Paleozoic salts (The Devonian Prairie Evaporite) lay beneath Bakken Source System rocks. These salts have been dissolved to varying degrees throughout the entire Williston Basin. When the Prairie Evaporite is so dissolved, a brine-filled cavern is created. Eventually the cavern cannot support the weight of the overlying column of rocks above it, and these overlying rocks thus collapse into the cavern. Fractures created by this collapse extend vertically above the collapse feature. Such fractures physically disrupt the Bakken shale, allowing oil expulsion to occur. These fractures also extend into lower Lodgepole limestones, both creating a reservoir, and a migration path from the Bakken shale to the reservoir, for the oils expelled from the Bakken shale. This then is the origin of the lower Lodgepole oil deposits.

In section 10.0, we present preliminary mass-balance calculations regarding the amount of oil generated by the Bakken shales in the Bakken HC kitchen of the Williston Basin (North Dakota and Montana). Our calculations suggest that 413 billion barrels of oil have been generated, with a potential upside of 503 billion barrels and a minimum of 271 billion barrels. These numbers are larger than three previously-published estimates of 92, 132, and 150 billion barrels. We discuss the inputs and assumptions, which go into our, and others, mass-balance calculations. We also discuss the limitations of the previously-published calculations, as well as the petroleum-geochemical limitations, which detract from the accuracy of any mass-balance calculations, including those herein.

For example, in the Bakken shales, large density differences exist between the shale mineral matter (about 2.72 g/cc) and the shale kerogen (about 1.40 g/cc). Because immature

Bakken shales have very high original total organic carbon (TOC) contents (16 to 40% TOC by weight), the shales, by volume, are composed of large amounts of OM. For example, 16 weight % TOC is equivalent to 31.35 volume % OM, and 40 weight % TOC is equivalent to 63.64 volume % OM. During intense oil generation, over 50% of the OM in the Bakken shales is converted to oil and gas, roughly in a 3.70 to 1 proportion. Consequently, Bakken shale TOC contents, thicknesses, and ROCK-EVAL hydrogen indices all dramatically decrease during intense HC generation.

To calculate the amount of oil generated by the Bakken shales, one must have starting and ending TOC contents, starting and ending ROCK-EVAL hydrogen indices, and ending shale thicknesses, which can be converted to starting shale thicknesses. In their calculations concerning the amount of oil generated by the Bakken shales, previous investigators did not take into account the decrease in either shale thicknesses or TOC contents during intense oil generation. These investigators also used unrealistically low starting TOC contents and low hydrogen index losses. Lastly, they also failed to account for the significant volume expansion of OM which occurs during the conversion of kerogen to oil and gas. When all these corrections are applied to the previous calculations, the 92 billion barrel estimate becomes 342 billion barrels and the 132 billion barrel estimate becomes 418 billion barrels.

Estimating the amount of oil generated by any source rock, including the Bakken shales, depends on ROCK-EVAL analyses from a number of samples of that rock. However, previous researchers using the ROCK-EVAL mass-balance approach made unrealistic assumptions. We refine the ROCK-EVAL mass-balance approach by taking into account various controlling parameters not considered by previous investigators. These topics, which are discussed in some detail, are: 1) the co-generation of natural gas with oil in source rocks; 2) the possible overestimation of oil generation potential in source rocks by the ROCK-EVAL instrument and; 3) the underestimation of oil generation potential by ROCK-EVAL in source rocks due to uptake of water by kerogen, via hydrolytic disproportionation of kerogen, during HC generation reactions. Hydrolytic disproportionation is an important, but generally unappreciated, reaction in petroleum geochemistry whereby water and OM (including HCS) chemically interact with each other by exchanging hydrogen and oxygen.

Estimates of in-place Bakken-shale-generated oil per township (36 sections or 36 $miles^2$, 93.2 $kilometers^2$) range from 1.55 to 3.14 billion barrels per township for Bakken shales presently 52 ft (15.8 m) thick, depending on starting TOC and ROCK-EVAL hydrogen-index values. These calculated amounts of generated oil might at first seem preposterous or unsupportable. However, other source-rock systems are known to have generated far more oil than the amounts calculated for the Bakken shales. Unlike all other cases involving these large amounts of generated oil, existing data document that none of this Bakken-shale-generated oil has been expelled from the Bakken Source System. Instead, this oil remains in place in the rocks directly adjacent to the two shales.

In section 11.0 we discuss three characteristics which may combine to make the Bakken Source System unique: First, the Williston Basin has had an extreme paleo-heat flow, in fact the highest paleo-heat flow we have observed in any sedimentary basin worldwide. Second, the Williston Basin has by far the best rock, oil, and well-history sample base in the world. Moreover, innumerable and varied analyses have been performed on these samples. Third, the Bakken source shales and reservoir rocks have unusual and beneficial relationships regarding oil recovery. These three characteristics could make the Bakken Source System unique compared to other possible analogous oil-resource bases worldwide.

1.0 INTRODUCTION

Because of the length of this paper, and the fact that a wider audience may read this paper compared to the typical scientific audience, several modifications not normally used in 'scientific writing' were employed to make this manuscript more reader-friendly: A more detailed and longer abstract than is normal has been presented. The text has been broken down into different sections, each dealing with a specific topic (or topics). At the head of each section, a synopsis of that section is presented. A decimal system has been employed with the headings and subheadings, for enhanced clarity.

In this paper, there has not been an entire conversion of English to metric units of measurement. In fact, most figures lack a metric scale. This lack of metric measurements reflects the majority of the research being based on cutting and core chips, which were originally measured using English Units of measurement. Conversion to metric units would only add unnecessary confusion to the paper. Moreover, this paper deals exclusively with the Williston basin, wherein the English scale of measurement is still employed. Lastly, different investigators have analyzed the same core (or cutting chips) samples in storage at the North Dakota State (NDGS) Core Repository at Grand Forks, ND, and to ensure accurate cross-reference of the resulting data, exact footages are necessary.

The purpose of this paper is to provide the evidence for, and some of the characteristics of, a very large unconventional, basin-centered, in-place resource base of high-quality oil, in the Williston Basin, first suggested by Price and LeFever (1992). Moreover, some misconceptions in the literature concerning this resource base will be addressed herein. It is one thing to identify the presence of large unconventional resource bases, it is quite another to effect their economic extraction. To quote Price and LeFever (1992, P. 213):

> "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."

Detailed research has been, and continues to be, carried out, largely based on production histories of Bakken-producing wells. These production histories, and much ancillary data, are on file with the NDGS in Bismarck, North Dakota. The synthesis of these data demonstrates that a number of parameters controlling the productivities of Bakken Source System wells have largely gone undetected by industry, thus supporting Price and LeFever's (1992) observation above. However, presentation of these findings is outside the scope of this present paper. These results will be presented in subsequent papers.

2.0 **THE WILLISTON BASIN**

2.01 **Synopsis**

The Williston Basin, the most structurally-simple oil-productive basin in the world, is characterized by unvarying flat-lying sediments. At this time, most (75%) of the conventional oil production of this basin is found in the Mississippian mid Madison limestones. Sediment age in the basin ranges from Cambrian to early Tertiary, with numerous unconformities present.

The lower Mississippian-upper Devonian Bakken Formation contains two black shales, the richest oil- source rocks in the basin, indeed, among the richest oil-source rocks worldwide. The rocks adjacent to the two Bakken shales are carbonate-rich, brittle, low-porosity, impermeable rocks which, with the two shales, form a tight, closed-fluid system: the Bakken Source System (Price and Le Fever, 1992).

Due to several unrelated circumstances, the North Dakota portion of the Williston basin has the best rock, oil, and well-history sample base worldwide. Because of this sample base, and the simple-geologic history of the basin, the Williston Basin is one of the best-studied petroleum basins, worldwide. The present research results largely because of this unique sample base.

2.02 **Background**

The Williston Basin is a large (340,000 mi^2; 880,596 km^2) cratonic basin covering parts of southwest Saskatchewan, southeast Manitoba, eastern Montana, and the western half of North Dakota (Fig. 1). Note that figure 1 was constructed to portray the hydrocarbon (HC) kitchen and principal occurrences of conventional oil deposits in the basin, and that the Williston Basin is actually much larger than shown. In Figure 1, contours in feet are on the top of the mid Mississippian Mission Canyon Formation, the principal oil reservoir of the basin. Characteristic of cratonic ("pancake") basins, the Williston Basin is structurally-simple, with no major faulting, and flat-lying sediments. In fact, the Williston Basin is structurally the simplest basin in the world with significant oil production, and this is a pivotal observation for the principal considerations of this paper. There is minor faulting along the west side of the Nesson anticline, on the Cedar Creek Anticline, and along the Weldon Brockton fault zone. However, the Cedar Creek Anticline is removed from, and plays no role in, our discussion.

The Mission Canyon reservoirs hold about 75% of the known basin's recoverable oil (Price, 1980a), with most of the remaining reserves in Lower Paleozoic reservoirs, principally along the Cedar Creek anticline. Minor Pennsylvanian Tyler sandstone production occurs in the center of the basin (Price, 1980a). The estimated ultimate recovery (EUR) of the basin is around 4.2 billion barrels from an estimated 11 to 14 billion barrels of in-place oil, 75% of that oil being on the Canadian side of the basin. The EUR numbers in Figure 1 (350 and 500 million barrels) are conservative. The stippled area of Figure 1 is where sediments are generally perceived to have been buried deeply enough, and have thus reached high enough burial temperatures, to have caused the deeper source rocks to generate oil and gas.

2.03 **Stratigraphy**

Figure 2 shows the generalized stratigraphy of the Williston Basin. From Figure 2, there has been ongoing sediment deposition in this basin from Cambrian to early Tertiary (Paleocene-Fort Union Group) time. However, major unconformities (wavy lines, Figure 2) are present, representing periods of nondeposition and/or basin uplift and erosion.

The youngest rocks (Fort Union to Montana Groups, Paleocene to Upper Cretaceous in age) are a series of lignites, siltstones, shales and sandstones, which neither contain commercial oil fields nor HC source rocks. The organic matter (OM) in the shales of this sequence is hydrogen- poor (Types III and IV) OM, which cannot form oil deposits. The Lower Cretaceous Colorado and Dakota Groups are a thick section of moderate to good oil source rocks with a hydrogen-rich marine-derived (Type II) OM and total organic carbon (TOC) contents ranging between 2 to 6 weight percent of the rock (unpublished data, this author). Very few sandstones are in this section of rocks, which have not been buried deep enough to generate oil in most parts of the basin.

Jurassic to Upper Mississippian rocks are a marine-derived sequence of shales, siltstones, sandstones, limestones, dolomites, and evaporites. Good source rocks and possible reservoir rocks are in this section. However, the only commercial oil deposits found to date in these rocks are in Pennsylvanian Tyler sandstones, which are stratigraphically-adjacent to the Tyler shale, a very good oil source rock. Nonetheless, these oil deposits make up only are an insignificant part of the basin's total reserves.

Middle to Lower Mississippian rocks are thick limestones which contain the principal oil reservoirs of the basin, the Mission Canyon Formation. The Charles and Lodgepole rocks are dense limestones with moderately-low to very low porosity, and extremely-low lateral and vertical permeabilities. No known source rocks have been documented in this section. The lowermost Lodgepole, the Bakken Formation, and the uppermost Three Forks Formation constitute the Bakken Source System (discussed below), and are the rocks of interest in this discussion.

Middle-Upper Devonian Nisku formation to Cambrian Deadwood Formation rocks contain a series of different source and reservoir rocks with significant proven and produced reserves. These rocks are mainly limestones and dolomites, with lesser evaporites, shales, and sandstones. The oils from these Lower Paleozoic rocks are compositionally-distinctive from the Bakken shale oils. These Lower Paleozoic oils and rocks will not be further considered here.

2.04 **The Bakken Source System**

The Bakken Source System (Fig. 3) consists of the upper and lower shale members of the Bakken Formation and a siltstone (middle member) between them. The lower Lodgepole limestone, above the Bakken Formation, and the upper Three Forks Shale, below the Bakken Formation, make up the rest of the Bakken Source System, as defined by Price and LeFever (1992). The two Bakken shales are grossly indistinguishable from one another by visual or microscopic examination, or by organic and inorganic geochemical analyses. Both shales are world-class source rocks with a marine-derived OM, starting TOC contents ranging between 12 to 36 weight percent of the rock and possibly averaging 25 to 28% over large areas of the basin. ROCK-EVAL analyses currently being carried out, will eventually define starting Bakken shale TOC contents. Published ROCK-EVAL analyses suggest on average that 58% of this carbon is convertible to oil and gas during deep burial and accompanying HC generation. However, ongoing, but yet incomplete, ROCK-EVAL, analyses suggest that this number may be slightly higher, perhaps as high as 65%.

Numerous varied analyses (core, petrographic, microscopic, etc.) demonstrate that, with the exception of the lowermost Lodgepole shale (discussed directly below), the rocks adjacent to the two Bakken shales are carbon-poor dense rocks with low porosities (2 to 10%, about 4% on average). None of these rocks have any fluid transmissibility, with numerous core analyses showing measured matrix permeabilities (vertical and lateral) of 0.005 to 0.01 millidarcies or less. The lower most Lodgepole is a dense limestone with a thin (one foot , 0.3 m or less) very organic-rich shale 6 to 10 ft (1.8 to 3 m) above the upper Bakken shale, with shallower rocks being a thick sequence of impermeable dense limestones. The middle Bakken siltstone can be broken in to smaller stratigraphic units based on depositional characteristics (LeFever et al., 1991). The Devonian Three Forks Formation is an alternating very fine-grained dolomite, dolomitic siltstone, and carbonate-rich shale.

Because they are carbonates, all three rocks adjacent to the two Bakken shales are brittle and thus easily fractured. Moreover, these are very organic-poor rocks with TOC contents of 0.1 to 0.3 weight percent of the rock, containing a degraded OM which cannot generate oil. In the Williston Basin, the Lodgepole Formation has a maximum thickness of about 800 ft (244 m), and the Three Forks Formation a maximum thickness of about 240 feet (73 m). The thickness of the Bakken Formation varies throughout the basin from 0 to 110 ft, (0 to 33.5 m). The upper Bakken shale varies from 0 to 30 ft (0 to 9 m), the lower Bakken shale from 0 to 46 ft (0 to 14 m) and the middle siltstone from 0 to 92 ft (0 to 28 m). In limited basin areas, the two shales summed, are slightly over 70 ft (21m) thick.

2.05 The Uniqueness of the Williston Basin Sample Base

Due to a fortuitous coincidence of natural and human-related circumstances, the Williston Basin by far has the best rock-sample base and well-history data base for any petroleum basin worldwide. These sample and data bases provide powerful vehicles with which to carry out this present petroleum-geological and geochemical research. The natural circumstances involve both the stratigraphic location of the Bakken shales, the richest source rock in the basin, above the significant Lower Paleozoic oil reservoirs. Thus, to test these Lower Paleozoic reservoirs, one must drill through the Bakken shales, thereby making samples of these shales available basin-wide. The largest of the two depocenters of the Williston basin is in North Dakota. Therefore, the processes of oil generation, expulsion from source rocks, and secondary migration from source rock to conventional oil deposits, have largely been centered in North Dakota.

The human-related circumstance is that commercial conventional oil deposits were discovered rather late (early 1950's) in the Williston Basin compared to other U.S. onshore basins. At this time, the state of North Dakota passed a law requiring a complete set of rock samples from every well drilled in North Dakota to be submitted to the North Dakota Geological Survey (NDGS) sample repository. Also, all electric logs run on the wells drilled in North Dakota, plus complete well histories from drilling through production, to plugging and abandonment had to be filed with the NDGS. Additionally, every time the drill penetrated the Bakken Source System, oil shows were encountered. These shows strongly suggested that a conventional oil deposit had been encountered. Consequently, the Bakken Source System was extensively cored throughout the years (over 110 wells) as explorationists searched for the oil reservoir they thought they had encountered. However, in all cases only tight, dense rocks were found in the cores. Much of this core was submitted to the NDGS sample repository. Lastly, large oil sample bases also exist for the Williston Basin. The end result is a detailed rock, oil-sample and well-information base for the over 13,500 wells drilled in North Dakota, a sample base unparalleled in any other major oil basin worldwide.

The Williston Basin also has had one of the simplest geologic histories of any basin with significant proven oil reserves, worldwide. This fact, and because it is also the structurally-simplest basin in the world with production, combined with the rock and oil sample base and the well-history information base, has resulted in the Williston Basin being one of the most-studied oil basins in existence, with important consequences: First, a vast amount of published and public domain geologic and geochemical data exist for this basin. This circumstance has enabled the present research to be carried out which would not have been possible in any other basin in the world. Second, early classic petroleum-geochemical studies in the Williston Basin established petroleum-geologic and geochemical paradigm regarding oil expulsion from source rocks and accumulation into conventional reservoirs.

3.0 CLASSIC PETROLEUM GEOLOGIC AND GEOCHEMICAL WILLISTON BASIN STUDIES

3.01 Synopsis

Early classic research by then Pan American (Amoco Oil Co.) personnel in the Williston Basin established important petroleum-geochemical concepts, now universally applied in oil exploration. However, these studies (Dow, 1974; and Williams, 1974) also concluded, incorrectly, that the richest oil source rocks in the Williston Basin, the Bakken shales, had sourced the most important conventional oil resource base in the basin, the oils in the mid Madison reservoirs (about 800 to 1,000 ft, 244 to 305 m, above the Bakken shales). Later work appeared to support the original Dow (1974) and Williams (1974) research, and led to the synthesis of the model of oil expulsion from source rocks and accumulation into traps, now universally accepted among oil explorationists, to wit:

1) The deepest parts of petroleum basin are open-fluid systems, where fluid movement is very easy.
2) Source rocks expel almost all of the oil that they generate.

3) Only a small fraction of this expelled oil is usually actually caught in commercial quantities in traps, e.g. most expelled oil is irrevocably lost over geologic time.

Countless analyses from the ROCK-EVAL instrument, the most widely used analytical instrument in petroleum geochemistry, appear to support the above model of oil expulsion and accumulation. Many of the concepts from the early Amoco work have stood the test of time, and remain unmodified to this day. However, as discussed in the next section, newer research conclusively demonstrates that the concept of the Bakken shales having sourced the mid Madison oils, is wrong.

3.02 **Williams-Dow**

Williams (1974) and Dow (1974) published companion papers resulting from a very large early research effort in the Williston Basin by the then Pan American (Amoco) Oil Company. These papers, more so than any others, laid the foundation for our present-day model of oil expulsion and accumulation. Moreover, arguably these two papers can be considered as either the, or amongst the, most classic papers in petroleum geochemistry (Price and McNeil, 1997). Williams (1974) geochemically analyzed 184 oil samples from the entire Williston Basin (North and South Dakota, Montana, Saskatchewan, and Manitoba) using: 1) carbon isotopic ratios of the oils; 2) n-paraffin patterns (gas-chromatographic analysis of the saturated HCS); 3) gasoline-range (C_4-C_7) HC gas-chromatographic "type" analysis; 4) optical-rotation analysis; and 5) the U.S. Bureau of Mines correlation index analysis (based on crude oil distillation characteristics). All of these analyses were state of the art in 1968 to 1972, when the study was actually performed. However, at this time, four of these analyses are no longer routinely used, as they are considered archaic and relatively uninformative. Be that as it may, based on these analyses, Williams (1974) concluded that three separate "oil families" existed in the Williston Basin (the Lower Paleozoic oils, the Mississippian mid Madison Group oils, and the Pennsylvanian Tyler oils). His conclusions are valid (with minor qualifications) to this day, being supported by present-day analyses of Williston Basin oils. (For clarification, an "oil family" is a suite of oils with the same, or very similar, physical and petroleum-geochemical characteristics, characteristics resulting from the origin of the oils from the same source rock(s). Oils having similar characteristics, because they have originated from the same source rock, are thus a "genetically-related family").

Williams (1974) also performed analyses on oil-like material (bitumen) removed from different organic-rich shales (source rocks) in the basin by the standard petroleum-geochemical analysis of solvent extraction, followed column chromatographic fraction separation and gas chromatography of the saturated-HCS. Given the similarity of analyses between each of the three oil families with specific bitumens extracted from certain shales, Williams (1974) matched each oil family with a given source rock. In others words, he "correlated" oils to their source rock. Williams (1974) correctly correlated the Pennsylvanian Tyler sandstone oils to the adjacent organic-rich Tyler shale, and also correlated the Lower Paleozoic oils to the Ordovician Winnipeg shale. Lastly, Williams (1974) correlated the principal conventional oil-resource base in the basin, the mid Madison oils, to the Bakken shales.

Williams (1974) provided the first examples of both grouping oils into families by detailed petroleum-geochemical analyses (oil-to-oil correlations) and of linking oils to their source rocks (oil-to-source rock correlation), the two most important functional tasks of present-day petroleum geochemistry. Williams (1974, p.1248-1249), also laid the foundation for "Petroleum Systems", which 22 years later, is finally being accepted as one of the major contributions of petroleum geochemistry to oil exploration: "It would be expected that the frequency of any given oil type would be greatest in those reservoirs closest to the source." The present-day application of Petroleum Systems to exploration is straight-forward: If you can't link your proposed trap by a fluid conduit (secondary-migration path) to a "mature" source rock, which has generated oil, you will likely drill a dry hole.

Dow (1974), in a companion paper to the Williams (1974) paper, first applied the then newly-conceived discipline of petroleum (organic) geochemistry to oil exploration, by relating the oil-to-source rock correlations, provided by Williams (1974), to thermal maturity, stratigraphic association, paleostructure, and carrier-bed isopach maps. Dow (1974) also first proposed constructing basinal-maturity maps and relating such maps to "carrier beds" (fluid transmissible units such as sandstones) which could carry generated oil from their source rocks to a trap, thereby forming a conventional oil deposit. Such maturity maps are then related to both basinal carrier-bed thickness (isopach) maps and to paleo-structure maps, which portray the structural configuration of the basin at the time of oil migration in the geologic past. By the inter-relationships of such maps, one could estimate the direction and amount, both vertically and laterally, of secondary oil migration from the source rocks. Thus, a possible subsurface distribution of oil deposits could be predicted to delineate sweet spots where exploration activity should be concentrated. Although this application of petroleum geochemistry to exploration was quite logical and a potentially very powerful tool, it was originally met with resistance among explorationists, and years passed before the concepts gained any degree of acceptance (W. Dow, DGSI, personal communication,10/96). In fact, it was only in the 1990's, with the publication of the AAPG Memoir 60 on Petroleum Systems (Magoon and Dow, 1994), that the concept of Petroleum Systems was finally accepted for the powerful tool that it is.

Dow (1974) also developed and first presented an oil expulsion and accumulation model, a model equivalent to the accepted present-day model. Dow (1974) also first recognized that the amount of oil generated in a basin is always much greater than the oil found in conventional accumulations. In his example, he theorized that the Bakken shales generated and expelled 10 billion barrels of oil, with only 3 billion barrels accumulated into conventional deposits. Although his concept was correct, the numbers Dow (1974) used were pessimistic. For example, calculations presented below demonstrate that the Bakken shales appear to have generated over 300 billion barrels of oil and between 8.25 to 10.5 billion barrels of mid Madison oil have been proven or produced. Lastly, Dow (1974), defined the controls of our first, best-known, and type-example of a Petroleum System: the Bakken/mid-Madison Petroleum System.

3.03 **Meissner**

Meissner (1978) in an elegant treatment of the Bakken Formation by stratigraphy, structural geology, petroleum geochemistry, fluid hydraulics, reservoir engineering, and production considerations, extended the earlier Dow (1974) and Williams (1974) research. Meissner (1978) noted that the Bakken Formation had significantly higher fluid pressure gradients, compared to all other rocks in the basin, whether above or below. Meissner (1978) correctly hypothesized that these abnormal-fluid-formation pressures (overpressures) resulted from oil generation in the Bakken shales. He hypothesized that during oil and gas generation, there is a net volume increase in the OM: the generated oils and gases occupy a greater volume than the original volume occupied by the solid OM (kerogen) in the shale before HC generation.

Thus, we have an expansion of material in a fixed volume, creating abnormally high pressures. Ungerer et al. (1987) later provided calculations validating Meissner's (1978) hypotheses on this matter. Meissner (1978) further postulated that these fluid overpressures fractured the rocks around the Bakken shales, in fact fracturing 800 to 1,500 ft (244 to 457 m) of dense impermeable limestone above the Bakken formation, so that Bakken-generated oil could reach the overlying mid Madison reservoirs. Meissner (1978) thus reinforced the earlier Dow (1974) and Williams (1974) work and models. Moreover, Meissner (1978) was the first to link oil expulsion as a direct consequence of oil generation. In other words, because of the volume expansion of OM during oil generation, and the resultant fluid overpressures, oil expulsion from source rocks occurs.

This early work by Dow (1974), Williams (1974), and Meissner (1978) resulted in the oil expulsion and accumulation model accepted today, with essentially no modifications.

3.04 Accepted Model of Oil Expulsion and Accumulation

Presently, by the oil expulsion and accumulation model nearly universally accepted in petroleum geology and geochemistry: 1) The deep parts of petroleum basins (depocenters) are considered to be open-fluid systems. 2) Thus, fluid movement between different rock units is easy. 3) Fluids are thought to be easily expelled from the deep basin. 4) Oil and gas expulsion from their source rocks is considered to be very efficient, with most (50 to 95%) generated HCS leaving their source rocks. 5) The more organic-rich the rock, the greater the loss, with rocks like the Bakken shales losing 95% or more of their generated HCS. 6) Oil accumulation into traps is thought to be very inefficient, with only 5%, or less in some cases, of the total oil expelled from source rocks being trapped in conventional oil deposits. 7) Almost all of the expelled oil is instead believed lost to dispersion, along the primary and secondary migration paths, or throughout the basin, or, most importantly, lost to surface leakage over geologic time. 8) Thus, almost all HCS generated from source rocks are believed to be irrevocably lost over geologic time. Lastly, it is also well known that good source rocks often generate several orders of magnitude more oil than found as commercial deposits in densely-explored basins (Hubbard et al., 1987; Espitalié et al., 1988; Demaison and Huizinga, 1991; Magoon and Valin, 1994).

This model of expulsion and accumulation (petroleum basin depocenters being open-fluid systems, very efficient oil expulsion, and very inefficient accumulation) has been discussed and supported by numerous investigators, including Price et al. (1984), Cooles et al. (1986); Leythaeuser et al. (1987); Mackenzie et al. (1987); Talukdar et al. (1987); Ungerer et al. (1987); Espitalié et al. (1988); and especially Miller (1992), and Magoon and Dow (1994). Moreover, the model also appears to receive support from ROCK-EVAL analyses of different source rocks worldwide, all as a function of variable maturity. Because ROCK-EVAL analyses are discussed throughout this document, we provide a review of the method for those unfamiliar with it. Those familiar with ROCK-EVAL should proceed to section 3.06.

3.05 **ROCK-EVAL**

ROCK-EVAL is a powerful inexpensive analytical-screening tool which provides critical petroleum-geochemical information, including the organic richness of a rock as related to the rock's capability to generate oil. ROCK-EVAL presently is by far the most widely-used analytical tool in petroleum geology and geochemistry. The analysis is based on progressively heating a small sample (200 milligrams or less) of powdered rock while passing an inert carrier gas over the sample during heating. During this progressive heating, a series of organic materials are distilled from the rock, and the carrier gas transports these products to a very sensitive detector (flame-ionization detector) which generates an electronic signal, the strength of which depends on the concentration of these distilled products in the carrier gas. Two of the signals, or peaks, of this analysis which we are concerned with are the "S_1" and "S_2" peaks, which are usually normalized to the rock weight to give a parts per million (ppm) value (to dry rock weight); or normalized to organic carbon to give the so-called HC index (milligrams S_1/grams of organic carbon), or the hydrogen index (milligrams S_2/grams of organic carbon).

The S_1 peak (Fig. 4) is the lower temperature peak of the two, being equivalent to oil-like HCS present in the rock. The S_1 peak is thus sometimes equated to the amount of HCS which can be extracted from finely-ground shale by solvent extraction. The S_2 peak is a measure of how much oil the solid OM (kerogen) in the rock can generate. At higher analytical temperatures during the ROCK-EVAL analysis, part of the kerogen in rocks thermally decomposes ("cracks") to oil-like components. This is analogous to heating oil shale to yield oil. As shown in Figure 4, at shallow burial when a rock is immature, the S_1 peak is small and the S_2 peak is large. With increasing burial, and thus increasing maturity, the kerogen in a rock is progressively converted to smaller molecules (oil-like material). Thus, the S_1 peak gets progressively larger and the S_2 peak gets progressively smaller. The transformation ratio (a.k.a., production index: $S_1/S_1 + S_2$) is a measure of these changes, and also is one of the maturity measurements (indices) that the ROCK-EVAL instrument provides. When a rock is immature, as shown in Figure 4, production index values are low (0.1 and less), because S_2 is high and S_1 is low. In deeply-buried rocks, the S_1 value is greater, and the S_2 value is much lower, leading to significantly higher production index values (0.5 to 0.9). Another maturity index that the ROCK-EVAL instrument supplies is the (pyrolysis) temperature at the maximum of the S_2 peak (T_{max}). Note in the left side of Figure 4 that the S_2 peak shifts to the right (higher analytical temperatures) as burial, and thus maturity, increases. Immature samples have T_{max} values of 380°to 400°C. Very-mature (deeply-buried) samples have T_{max} values of 460°C, although values as high as 600°C are possible.

As stated above, the S_2 peak when normalized to organic carbon yields the hydrogen index, and as the term implies it is a measure of the hydrogen richness of the kerogen in the rock. Due to variable depositional conditions, immature kerogens in different rocks can have variable chemical characteristics. Some OM is hydrogen-rich (ROCK-EVAL hydrogen indices of 450 to 900, Types I and II OM) and will thus generate substantial amounts of oil. Other OM is hydrogen-poor (hydrogen indices of 250 or less, Types III and IV OM), and is thought to principally generate gas, if anything at all. Thus, the hydrogen index is a crucially-important measurement in petroleum exploration. Rocks with starting hydrogen indices of 350 or more are viewed favorably as source rocks. Rocks with starting hydrogen indices of 500 or more are viewed especially favorably in this regard. Irrespective of the starting OM type (high or low hydrogen indices), the hydrogen indices of all OM types decrease with increasing maturation, as oil and gas are progressively generated. *Thus, decreasing hydrogen indices in a source rock are the most accurate maturation index possible.*

3.06 **ROCK-EVAL Data Supporting the Accepted Model of Oil Expulsion and Accumulation**

Let us return to the accepted model of oil expulsion and accumulation: 1) open-fluid systems in basin depocenters, 2) efficient oil expulsion from source rocks, and 3) inefficient accumulation, a model best portrayed by Figure 5 from England (1994), where only a small percentage of the oil generated in source rocks ever accumulates into traps. As stated, this model appears to be strongly supported by ROCK-EVAL analyses of numerous source rocks having wide-maturity ranges (immature to post-mature). This is because very large decreases in the oil-generation potential (hydrogen indices) of such rocks are measured with increasing maturity; however, these decreases are not matched by concurrent increases in the generated oil (HCS), as measured by either the ROCK-EVAL S_1 peak or by the somewhat equivalent analysis of solvent-extractable HCS. Thus, the only logical conclusion is that the generated HCS have been expelled from the source rock.

The example in Figure 6 of data taken from studies on HC generation in the Bakken shales by Webster (1984) and Price et al. (1984) appears to support this conclusion. The right side of Figure 6 shows ROCK-EVAL hydrogen indices for Bakken shales. Samples deeper than 9,000 ft (2.75 km) are from the high paleo geothermal gradient area of the Williston Basin. Notice that with increasing burial, the Bakken shale hydrogen indices strongly decrease, to values of 100 or less, as the rock goes through mainstage HC generation. However, concurrently the solvent-extractable C_{15}+ bitumen ("extractable oil") in the rock is invariant with depth. Note that the hydrogen index and bitumen are both normalized to organic carbon (by mg/gOC) and are thus directly comparable. The hydrogen-index scale in Figure 6, however, has a much greater numerical range than the scale for the C_{15}+ bitumen, 700 versus 180. Note that the deeper samples in the hydrogen index plot have lost at least 450 units of oil-generation potential. However, the solvent-extractable bitumen (generated oil, left side of Fig. 6) is invariant versus depth. Therefore, logically, the massive amounts of HCS which have been generated by the Bakken shales are no longer in the rock, and thus appear to have migrated.

4.0 PRESENT-DAY WILLISTON BASIN PETROLEUM-GEOCHEMICAL RESEARCH

4.01 Synopsis

The analytical instruments and methods available when Dow (1974) and Williams (1974) carried out their early (1968 to 1972) Williston Basin work are, understandably, archaic compared to today's tools. We also note that the analytical task petroleum geochemistry presently best carries out is determining if two or more oils have the same chemical fingerprints, and have thus been derived from the same source rock. State-of-the-art analyses, comparing oils produced directly from the Bakken Source System with mid Madison oils conclusively demonstrate that the two oil suites are different. In other words, the Bakken shales did not source the mid Madison oils. Moreover, no oil sourced from the Bakken shales has been found in a conventional oil reservoir on the U.S. side of the Williston Basin. That the richest source rock in the Williston Basin has contributed no oil to the conventional oil reservoirs there is a staggering conclusion, as related to petroleum geochemistry. Moreover, independent research demonstrates that the same situation exists in the Western Canadian (Alberta) Basin. The Williston and Alberta Basins are at the opposite ends of the spectrum regarding both basin-style and structural-intensity. That two such disparate basin styles have the same source rock-reservoir problem, in that the richest source rock in two basins contributes nothing to the conventional oil reservoirs in those basins, strongly suggests that the accepted model of oil expulsion and accumulation may be widely-inoperable.

In this light, an alternate model of expulsion and accumulation was proposed by Price (1994a), to wit:

1) The depocenters of petroleum basins are closed-fluid systems, where fluid movement is difficult or impossible.
2) Oil expulsion from source rock systems is far less common than generally believed.
3) Unless source rocks are physically disrupted by faulting, or salt or shale diapirism, or are directly adjacent to good fluid conduits, oil expulsion does not occur at all.
4) Therefore, most generated oil remains in or adjacent to its source rock.

This hypothesized alternate model of oil expulsion and accumulation is easily tested. If the model is valid, a strong correlation should exist between increasing structural intensity in the depocenters of petroleum basins with increasing amounts of recoverable conventional oils, for well-explored petroleum-bearing basins worldwide. A pronounced correlation between increasing basin richness and increasing deep-basin structural intensity does exist, suggesting that the alternate model of oil expulsion and accumulation is correct and that the accepted expulsion-accumulation model is invalid, or at least widely-inapplicable. This last conclusion has two profound implications for petroleum geology, one of which concerns us here: Namely, huge unconventional oil- resource bases should then exist as continuous-oil reservoirs in and around source rocks in the deep unstructured parts of some sedimentary basins. Research to date strongly suggests that such a resource base exists in the Bakken Source System of the Williston Basin: 200 to 400 billion barrels of low-sulfur ($\leq 0.1\%$), low-wax, 40°-45° API gravity oil in place. The second implication is that our models of oil expulsion and accumulation, used in both exploration and resource assessment, may be highly flawed.

4.02 **Introduction**

As stated above, the analytical techniques, and especially the analytical instruments, which Williams (1974) used between 1968 and 1972, to carry out his landmark Williston Basin research, were understandably primitive compared to the present-day techniques and instruments, which allow much deeper research insights to be obtained. In spite of the analytical revolution during the last 25 years, Williams' (1974) results stood the test of time, and in fact, were reinforced by other studies which reached the same conclusion: the Bakken shales were the source rocks for the mid Madison Williston Basin oils (Thode, 1981; Schmoker and Hester, 1983; Price et al. 1984; Leenheer, 1984; Webster, 1984; Leenheer and Zumberge, 1987). This situation persisted until the early 1990's.

Although petroleum geochemistry has significant limitations (Price and McNeil, 1997), one thing it does very well is to chemically match, or demonstrate the lack of a match, of oils with one another. Petroleum-geochemical tools can easily demonstrate whether or not a suite of oils belong to the same oil family.

4.03 **Bakken Oil to Mid Madison Oil Comparison**

Because of the intense Bakken shale horizontal drilling play which occurred on the American side of the Williston Basin from 1/1989 to 4/1993, a large number of oils were available produced directly from a source rock. Moreover, this sample base was augmented by scattered production throughout the basin from a number of vertical Bakken wells. Such a critical sample base, a suite of oils produced directly from a source rock, had previously never been available to petroleum geochemistry. Consequently, a large number of these oils (over 150) were collected, analyzed, and then compared to a large suite of mid Madison oils. The results (Price and LeFever, 1992, 1994) were startling: the Bakken and mid Madison oils were indisputably two different oil families. The Bakken shales in point of fact did not source the mid Madison oils. Moreover, the mid Madison oils had strong chemical characteristics diagnostic of a carbonate source, leading Price and LeFever (1994) to hypothesize that the oils had been sourced from marls (carbonate-rich shales) interbedded with the mid Madison reservoirs. Furthermore, those investigators found no Bakken oil in a conventional reservoir on the U.S. side of the basin and found no evidence that a mixing of Bakken and mid Madison oil had occurred anywhere in the basin. Concurrently, studies on the Canadian side of the Basin (Osadetz et al., 1992, 1994; Osadetz and Snowden, 1995) compared Canadian mid Madison oils to a few Canadian oils produced from the Bakken siltstone and reached the same conclusions: the mid Madison and Bakken oils are two different oil families, e.g., the Bakken shales did not source the mid Madison oils. The results from these different studies on both sides of the international border in the Williston Basin, have now been checked by a large number of other laboratories (various personal communications to L. C. Price), all with the same result: the Bakken and mid Madison oils are two separate and distinct oil families.

Several geologists (who will not be referenced here) have personally communicated to me that in their opinion the newer Bakken to mid-Madison oil comparisons are meaningless because the basic fingerprints of oils can be changed either after expulsion from a source rock during secondary migration or as oils reside in the reservoir. As such, in their opinion, because the original nature of an oil can be completely transformed, that oil can no longer be related to its source rock. Clearly, post-expulsion changes can occur to oils, for example, crude-oil degradation

(Price, 1980b), or evaporative fractionation (Silverman, 1965; Thompson, 1987). However, in even severe cases of alteration, the affected oils can usually be fingerprinted to an oil family. Although limited, to almost non-detectable, chemical alteration can occur to all oils in a reservoir, the proposition that the fundamental nature of an oil can be routinely altered by secondary migration or just by residing in the reservoir is unsubstantiated by any supporting data. In fact, the concept is antithetical to numerous large published data bases. Moreover, if this hypothesis were true, the very powerful tool of Petroleum Systems could not possibly even exist.

We will not discuss the detailed chemical differences between the Bakken and mid Madison oil families here, the appropriate references may be consulted. How the oils are different is not important for us; that they are different is of critical import. Nor will we discuss in detail how this obvious fact was missed for so long in petroleum geochemistry. This point has been addressed by the recent studies. We will note, however, that data were published in previous studies (Price et al., 1984; Leenheer, 1984; Leenheer and Zumberge, 1987) which clearly demonstrated that the Bakken shales did not source the mid Madison oils. However, these data at the time were misinterpreted to support existing paradigm that the Bakken shales sourced the mid-Madison oils. The immediate implications of the newer Bakken/mid Madison oil comparisons are staggering for petroleum geology and geochemistry. *That the organically-richest source rock in the Williston Basin has charged no oil into the Basin's primary reservoir is not a glitch in the model; it is a total breakdown of the model. Our accepted model of oil expulsion and accumulation is completely dysfunctional in the very basin from whence it originated.* This fact carries a serious question about the applicability of the model in general. Moreover, these source rock/reservoir problems are not unique.

4.04 Western Canadian Basin

Riediger et al. (1990) carried out petroleum-geochemical analyses on the Lower Jurassic Nordegg member of the Fernie Formation in the Western Canadian (Alberta) Basin. This is the richest, thickest, and most areally-extensive source rock in the Western Canadian Basin. Their research demonstrated that this shale sourced only a few small Triassic oil deposits and contributed nothing to either the large conventional oil deposits (46 billion barrels recoverable) or the massive tar sands (2.65 trillion barrels in place) in the basin. That the richest source rock in this basin sourced almost no oil in the basin is yet another complete breakdown of the accepted expulsion accumulation model. Moreover, the Western Canadian and Williston Basins, although areally contiguous, are at the opposite ends of the spectrum regarding structural styles and history of basinal evolution. Two such disparate basin styles having the same source rock/reservoir problem strongly suggests that the accepted oil expulsion and accumulation model may be far less applicable than previously thought, especially in tectonically-quiescent petroleum basins, such as the Williston.

4.05 **Alternate Oil Expulsion and Accumulation Model**

In light of the above, Price (1994a) proposed an alternate model for oil expulsion and accumulation:

1) The depocenters of petroleum basins are closed-fluid systems and fluid movement between different stratigraphic units is difficult.

2) Oil and gas expulsion is from source systems inefficient.

3) Unless source system rocks are physically disrupted by faulting or salt or shale diapirism, or are directly adjacent to good fluid conduits, expulsion, followed by secondary migration, does not occur at all.

4) Therefore, most generated HCS remain in or adjacent to their source rocks.

Also, Price (1994a) redefined primary migration and expulsion, two terms previously used interchangeably. Primary migration was defined as the movement of HCS from their generation site in a source rock to either another site within the source rock, or to rock directly adjacent to the source rock. Primary migration is viewed as a common occurrence. Expulsion was defined as movement of generated HCS from either the source rock, or from rocks adjacent to the source rock, into a fluid conduit to begin secondary migration towards a trap. Expulsion is viewed as a more uncommon occurrence.

4.06 **Basin Richness versus Structural Intensity**

Price (1994a) also hypothesized, that if points 1 to 3 (directly above, section 4.05) were true, then among productive oil basins there should be a strong positive correlation between increasing basin productivity and increasing structural disruption in the basin's depocenter where oil and gas are generated from source rocks (e.g., in the "HC kitchen"). Such a relationship was found (Figure 7).

In Figure 7, the estimated ultimate recovery (EUR) of oil, or oil-equivalent gas, is given for each basin class, with two examples of basins for each class in parenthesis. Average basin productivity is given for each basin type in millions of barrels of recoverable oil divided by thousands of square miles of basin area. This average figure was calculated by summing the productivities for all basins in a class and dividing by the number of basins in that class. The number of productive basins of each class is given in the far right column. As one goes down the chart, structural intensity of the basin depocenters containing the HC kitchens increases. Note in Figure 7, that the Williston and Los Angeles Basins are at opposite ends of the spectrum regarding productivity and structural intensity. The Los Angeles Basin is the most structurally-intense basin worldwide and it is also the most productive (7.692 billion barrels/1,000 miles^2). The Williston Basin is the least-structured basin in the world with significant oil reserves and it is the third-poorest basin in the world (12.3 million barrels/1,000 miles^2). Also note that the most intense-structural class of basins (wrench basins, of which Los Angeles is one) have 37 productive examples, contrasting with only four examples of productive (largely-unstructured) cratonic basins worldwide. Moreover, 44 very large cratonic basins exist worldwide which have no commercial oil production. Other qualifications and amplifications to Figure 7 are discussed in Price (1994a), and will not be discussed here. Suffice it to say that there is a strong relationship between basin richness and depocenter structural intensity for petroleum-bearing sedimentary basins worldwide. This relationship, combined with other points discussed in Price (1994a), are evidence which supports the alternative model of oil expulsion and accumulation outlined above.

4.07 **Implications of the Alternate Expulsion and Accumulation Model**

This alternative model of expulsion and accumulation carries major implications for three areas of petroleum geology: 1) resource assessment; 2) oil exploration for conventional HC deposits, especially in "frontier" (unexplored) basins; and 3) huge unconventional oil (and gas) resource bases which may exist in and adjacent to mature source rocks. Herein, we are not presently concerned with the first two areas. Regarding the third point, Price (1994a, p. 28-29) noted:

"If we assume that the hypothesis is correct that significant faulting of mature source rocks is necessary before the substantial expulsion of generated oil can occur, it then follows that most of the oil generated by mature source rocks in unfaulted basinal areas has remained in, or adjacent to, those source rocks. It is well known that mature source rocks in many basins have generated huge amounts of oil, which have either not been accounted for or have been attributed to leakage in previous mass-balance considerations. Thus, it may be concluded that very large in-place-oil-resource bases may exist in self-sourced, fractured, organic-rich shales. Furthermore, because hydrocarbon gases are cogenerated with C_{15}+ hydrocarbons in source rocks (Price and LeFever, 1992), part of this oil is mobile (from gas drive) and may perhaps be recoverable. This position is supported by the partial successes which have taken place in horizontal drilling programs in the shales of the Bakken formation (Williston Basin); Upper Cretaceous Niobrara Formation (Denver Basin-Stell and Brown, 1992; and Vincellette and Foster, 1992); and Middle Pennsylvanian Paradox Formation "Cane Creek" shales (Paradox Basin: Morgan, 1992; and Stell and Brown, 1992).

If such mobile and partially-recoverable oil-resource bases do exist, significant economic implications would follow for countries, which have large volumes of mature source rocks and import large quantities of oil. However, such unconventional oil-resource bases will not be recoverable by conventional drilling, completion, stimulation, maintenance, and production practices."

Because we are here concerned with an unconventional oil-resource base in the Bakken Source System, it is expedient to examine the characteristics of unconventional resources in general.

5.0 UNCONVENTIONAL ENERGY DEPOSITS

5.01 Synopsis

All unconventional-resource bases have various characteristics in common. Two of these characteristics immediately concern us here. First, the initial demonstration of economic exploitation of unconventional-resource bases is almost completely governed by technology. Second, unconventional resources which are economically produced due to technological advances can be monstrous in size. Many examples of varied unconventional resources exist where these parameters apply. Just one example is the bulk-tonnage, very low-grade gold deposits of northern Nevada (the "Carlin-type" gold deposits), which were once "unconventional" gold deposits, but are now considered eminently conventional. However, we are concerned here with unconventional energy deposits. Examples of unconventional, or once unconventional energy deposits are: 1) basin-centered gas deposits, 2) tight-sand gas deposits, 3) tar-sand deposits, 4) shale-gas deposits, and 5) coal-gas deposits. Significant differences exist, and are discussed below, between conventional oil and gas deposits versus unconventional oil and gas deposits found in "continuous reservoirs" over large areas in certain basins. Lastly, experience already gained from economic production of other unconventional-energy resources, provides insights regarding economic production of oil from the Bakken Source System continuous reservoirs.

5.02 **Introduction**

Figure 8 shows a resource triangle for oil, and the principles governing resource triangles apply to all resource bases, whether energy, gold, heavy metals, water, etc. First, as one goes down from the apex of the resource triangle, the grade (concentration) of the deposits decrease, as the resource bases become more dispersed. However, concurrently, the size of the resource base dramatically increases. Second, because the highest-grade deposits at the top of resource triangles are the easiest to extract, they yield the highest-profit margins. Thus, in the case of conventional oil deposits, the Saudi deposits (especially the Ghawar field) with their low lifting costs, would be at the apex of the triangle, above all other conventional oil deposits. Third, all deposits below "conventional" deposits are considered "unconventional" deposits until they can be produced at an economic profit, at which time they become conventional deposits. Very large tar-sand deposits have been known for some time, for example 2.65 trillion barrels in Western Canada (Masters, 1984a) and perhaps as much as 10 trillion barrels in Eastern Venezuela (Price, 1994a). However, economic recovery of such deposits has been hampered by the lack of a technological breakthrough regarding the production of the tar from these sands. The Syncrude (Western Canada) and Oriemulsion (Eastern Venezuela) processes are perhaps marginally-economic. Tight-sand gas deposits are also unconventional deposits and are also very large. For example, Law et al. (1989) estimated that the in-place tight-sand gas resource base of only the coarse-grained rocks of the Greater Green River Basin was between 3,611 to 6,837 trillion cubic feet. Similar tight-sand resource bases have been delineated for other basins also. However, the methods necessary for economic recovery of tight-sand gas deposits have not yet been delineated, or if delineated, have not been widely applied; although, research on the topic is proceeding.

5.03 **Antrim Shale Gas**

The Upper Devonian Antrim shale gas play of the northern Michigan Basin is of interest to this discussion, because this play demonstrates some characteristics common to all unconventional-resource bases, and concurrently has some strong parallels with the unconventional-oil resource base in the Bakken Source System. The following discussion is largely taken from Frantz (1996). As of January 1996, the Antrim shale-gas play had evolved from a resource base considered only marginally-economic in 1989, to perhaps the most intense gas play in the U.S., with over 4,300 wells producing 425 million cubic feet of gas per day. The known productive area was nearly 2.5 million acres and rapidly expanding, including into the southern part of the Michigan Basin in southern Michigan, Indiana, and Ohio. Moreover, Martini et al. (1996) note that a similar play was opened up in the Illinois Basin in northern Illinois with the Lower Mississippian-Upper Devonian New Albany shale (a time-stratigraphic equivalent of the Bakken shale).

Regarding the history of this play, prior to the 1970's, exploration wells in northern Michigan often encountered significant gas shows while drilling through the Antrim shale to reach deeper targets. However, tests of this zone only yielded strong water flows with minimal gas, and the zone was not considered economic. *This illustrates the prime characteristic of an unconventional energy resource base in a continuous reservoir: shows are encountered over large basinal areas, whenever the drill penetrates the continuous-reservoir unit.* An analogous situation exists with the Bakken Source System: ever since the Williston Basin was opened to exploration in the early 1950's, oil shows result whenever the Bakken Source System is drilled, (Price and LeFever, 1992, p. 201). Returning to the Antrim shale, by the late 1970's to early 1980's, several operators were producing gas at low rates (about 50,000 cubic feet/day per well) with high relative amounts of water using a simple form of gas lift. These low-rate producers were marginally-economic at best. The late 1980's Section 29 Federal Tax Credit, however, made the play economic and spurred a significant drilling boom (Fig. 9). However, when the Federal Tax Credit expired in 1992, note in Figure 9 that the number of new wells continued to steeply increase. This was because by this time the play had become a technological play, rather than a tax-credit play, wherein the operators had learned to economically produce the gas without the benefit of tax credits. A large part of the ascent on this "learning curve" was due to the Gas Research Institute (GRI), which instituted an aggressive research program with the operators in the play for improved drilling, completion, stimulation, and production practices to maximize production. Between this GRI research, and the operator's own experience, much better engineering and operating procedures were developed.

The technological stage of Antrim shale-gas development illustrates several points common to most unconventional-energy resource bases. First, the plays involving these resource bases most often are technological plays, in that different recovery approaches are attempted over a large area where the geology is constant, or nearly so. Moreover, application of variable drilling, completion, stimulation, and production practices result in variations in productivity between the different wells. Second, as is common to all unconventional-energy resource bases, application of production technology appropriate to the unique characteristics of the resource base under question is absolutely critical to the economic recovery of that resource base. If inappropriate recovery practices are applied, invariably production rates are poor and consequently the resource base is viewed as non-economic. This viewpoint was universal up until the mid 1980's regarding Antrim shale gas, and is now essentially universal regarding economic recovery of oil from the Bakken Source System. Another strong parallel exists between the Bakken Source System oil and Antrim shale gas plays. In both cases, geology is nearly constant and HC recovery is almost completely dependent on drilling, completion, stimulation, and production practices. As discussed below (section 8.0), contrary to the assumptions of other investigators, variation in local geology appears to have no control over well productivity in the Bakken Source System.

Let us consider some of the recovery practices necessary for economic production of Antrim shale gas. Antrim shales have high TOC contents and the gas in these shales is assumed to be principally adsorbed within the organic matrix of the shales. However, the gas also exists as a free-gas phase in both shale-matrix pore space and in shale fractures. Thus, Antrim shale-gas wells, like the coal-bed methane wells discussed below, must be dewatered to lower the reservoir pressure before the wells can produce. Lowering the reservoir pressure allows both the gas dispersed throughout the shales to be desorbed and form a free-gas phase and the existing free-gas phase to expand in volume. Thus, the critical-gas-saturation level for the shale is exceeded, and the gas can flow towards the well bore in economic quantities. (This point is discussed in detail in the "San Juan Basin Coal Gas" section (5.04), directly below.) Unless Antrim shale (and coal) gas wells are extensively dewatered, thus lowering their reservoir pressure, these wells will not economically produce gas. Thus, one who is unaware of this requirement for production, and attempts other inappropriate production techniques with unsuccessful results, would conclude that both these gas-resource bases are not producible and thus are non-economic.

Specific production procedures that GRI identified and helped implant in the Antrim shale gas play involved better dewatering procedures, cased-hole versus open-hole completions, dual-stage versus single-stage completions, fracing techniques and "ratholing" Antrim wells (drilling 100 to 400 ft (30 to 122 m) beyond the productive intervals to provide a sump for water to collect in, which helped with both dewatering and actual gas production). Other procedures were also implemented. These implementations increased gas-flow rates two to five times, tripled the economic value of the project, and added hundreds of billions of cubic feet of gas to the resource base. For example, in Figure 10, production rates are given for wells where all appropriate new technologies were applied, versus wells where no new technologies were applied (Antrim shale gas production comes from two intervals, the Lachine and Norwood, which may be completed in single or dual stage). The difference in results between the use, or non-use, of appropriate technology is appreciable (Fig. 10).

5.04 **San Juan Basin Coal Gas**

One would hardly envision another major unconventional-gas resource base being developed in the same area of a basin which previously had one developed in it. However, this is just what has occurred with the development of coal gas in the San Juan Basin (New Mexico and Colorado). Figure 11 shows the development of coal-gas production in the U.S. from 1982 to 1991. Note the explosive growth of coal-gas production in the San Juan Basin. This growth has continued. The San Juan Basin is one of the principal gas-producing basins in the U.S. and as of 1996, over 30% of the gas produced from this basin was coal gas. Palmer et al. (1993) provide a discussion of the history of coal-gas development, and coal-gas production in the San Juan and Black Warrior Basins was largely the result of serendipity, as is often the case with significant advances in HC exploration and production. From 1976 to 1977, to degasify an operating coal mine, 23 shallow open-hole wells were drilled in what then became the Oak Grove gas field. The next logical step was then to try to actually produce gas from coals away from operating mines. Thus, from 1979 to about 1990, a period of low-key experimentation followed in which different completion and stimulation techniques were tried with the Black Warrior Basin coals.

The principles of coal-gas production are much the same as those controlling production of gas from the Antrim shale. Coal gas is stored either absorbed on or in the coal matrix or as a free-gas phase in fractures. However, the free-gas is below the critical-gas-saturation level for the coal (Fig. 12). Thus, the reservoir pressure must be lowered in the coal allowing the gas to be desorbed from the coal, which increases the volume of the free-gas phase. This volume increase is also partly due to expansion of the pre-existing free-gas phase from the decrease in reservoir pressure. The resulting total volume increase in the free-gas phase eventually allows that part of the matrix porosity filled by gas to exceed the critical-gas-saturation limit for the coal, such that the gas flows towards the well bore.

The principals of two phase fluid flow (Fig. 12), can play pivotal roles in economic recovery of unconventional (and even conventional) HC resource bases. As shown in Figure 12, when two fluids are present in the same rock matrix, both fluids have critical-fluid-saturation levels which must be exceeded before the fluid under consideration can move through the rock. Thus, in the case of gas in Figure 12, at least 10% of the porosity must be filled with gas before gas can move through the rock. If the concentrations of both fluids under consideration (gas and water, Fig. 12) exceed their respective critical-fluid-saturation levels, then both fluids can move through the solid. However, their relative permeabilities are significantly reduced compared to what their permeabilities would be if only one fluid were in the solid alone. The Jamin effect (Hedberg, 1980) states that where two separate and immiscible fluids co-exist in a rock, and one phase (gas in Fig. 12) is below its critical-fluid-saturation level, a portion of that fluid may be in the form of immobile spherical globules, which cannot be distorted and which occupy a percentage of connecting pore throats. These globules thus decrease, or take to zero, the permeability of the rock with respect to the other fluid phase (stippled area, Fig. 12). Price and LeFever (1992) attributed a part of the poor productivities of some Bakken shale wells to the Jamin effect.

In addition to lowering the reservoir pressure so that coal gas can flow towards the well bore, coal-gas wells must be stimulated before they will economically produce. Different stimulation techniques have been tried and have been found to be effective in different basins, and in fact in different areas in the same basin. To quote Palmer et al. (1993, p. 305):

> "Coal bed methane wells usually require some kind of stimulation, because unstimulated flows of gas and water are often very low. This may reflect high positive skin factors of 3 to 30, presumably due to mud invasion, cement damage, or only a few effective perforations. Hydraulic fracturing is the most common form of stimulation. However, alternative "stimulation" techniques, such as the open hole cavity completion, have proved to be remarkably successful in coal beds in parts of the San Juan Basin."

The principal coal-gas stimulation procedures which have been extensively experimented with are: 1) open-hole cavitation, 2) gel-fracture treatments, 3) sand-water fracs, and 4) water-only fracs. Cavitation is a completion-stimulation procedure wherein the well is drilled and cased to the top of the productive coal interval. The bottom of the well is then drilled to the lower-most productive coal seam. Well formation pressure in the productive coal interval is then very rapidly lowered by opening flow to the atmosphere, thus setting up a large fluid-pressure gradient in the rocks immediately around the well bore. As a result, the coal fails and sloughs into the well bore. The well is shut in and formation pressure rebuilds and the process is repeated, in fact, repeated many times, perhaps 50 times in 8 to 10 days. Sloughing eventually subsides as the resulting 8 to 10 ft (2.4 to 3.0 m) diameter cavity stabilizes. The fragmentation and removal of the coal both reduce skin damage around the well bore and significantly increase the contact area of the producing coal with the well bore. Both effects dramatically increase production. Coal-bed methane wells in the so-called fairway zone of the San Juan Basin are only 3,000 ft (914 m) deep and often produce around 4 million cubic feet of gas per day.

Interestingly, properly-completed coal-bed methane wells typically demonstrate a negative-decline curve: that is, monthly gas production increases as the wells are first produced.

Wells outside the fairway zone cannot be completed by cavitation, because the coals will not slough into the well bore during pressure draw down. These wells must be completed and stimulated by other procedures. From much experience, it has been found that water-only fracs yield the best wells outside of the fairway zone in the San Juan Basin. Gelled-sand frac treatments, curiously, yield disappointing results. Although no explanation has been offered for this observation, we believe the cause could be due to the gelling agents used in the fracs. Gelling agents are moderately-reactive organic compounds. Coals contain many sites unsatisfied by chemical bonds, e.g. free-radical sites. The gelling agent thus could react with these sites, reducing permeability in the coal around the well bore. San Juan Basin coal bed methane wells have three pointed parallels with the Bakken Source System oil-resource base: Both geographic areas have "fairway areas" where production rates are believed to be optimal. Reservoir drive and mud damage play critical roles for production in both areas.

For many years, the strong gas shows encountered while drilling through mature coals, or the rocks adjacent to them, have been well known in many different areas. However, earlier attempts to produce the zones from which these shows originated, invariably resulted in weak water flows with very little, or no, gas. We note here that the shows always encountered while during through coals are caused by the drill bit physically disrupting the coals, and rocks vertically adjacent to the coals, liberating stored gas. Moreover, these ubiquitous shows are strong evidence supporting the alternate model of HC expulsion and accumulation, to wit: The large volume of HC gases remaining in these rocks can only result from inefficient HC expulsion.

5.05 **Discontinuous (Conventional) versus Continuous (Unconventional) HC Deposits**

Different investigators of the Energy Team at the U.S. Geological Survey have put significant research effort into unconventional-energy resource bases, especially gas resources. This research has led to delineation of some of the general characteristics of these different resource bases, which are perhaps best demonstrated by contrasting them with the characteristics of conventional oil or gas deposits: Conventional-HC deposits are found in discrete structural or stratigraphic traps, geographically-isolated from one another. Thus, the reservoir unit between separate deposits will either be tight (low porosity and permeability) or will be water-bearing. Porosities in conventional-oil deposits are 10 to 25%, and generally around at least 15%. Permeabilities in conventional-oil deposits are usually at least 10-50 millidarcies and sometimes much greater. Reservoir units are almost always sandstones, limestones and dolomites. HCS are stored almost completely in rock pore space (porosity) and travel through this matrix via permeability to the well bore. Reservoirs generally are open systems, many times with water drive for reservoir-pressure maintenance. However, conventional-HC reservoirs may also be highly-compartmentalized, and thus can be more closed-fluid systems. In oil deposits, oil-to-water ratios for produced fluids are generally 1 to 0.1, dramatically decreasing at the end of field life. Because of compartmentalization, some reservoirs, or some volumes of reservoirs, can be poorly-interconnected, with certain volumes of the reservoir being hydraulically isolated (compartmentalized) and not contributing to production. In a given basin, reserves of conventional fields have log-normal distributions, with most of the resource base being in a few large fields. Thus, most fields tend to be moderate to small in size. Discovery is always the most difficult aspect of conventional fields and once found, they are generally easily-produced by well-established procedures.

The most difficult aspect of unconventional-HC reservoirs for exploration personnel to grasp, is that these reservoirs are continuous, e.g. HCS will be found wherever a well is drilled over large areas of a given basin. Discovery is thus not a problem with unconventional-HC resource bases; however, production invariably is a problem, and most often is the limiting factor. This is because established production techniques or approaches almost never apply to these resource bases. Drilling, completion, stimulation, and maintenance techniques must be carefully tailored to the unique characteristics of each of these unconventional-resource bases. Moreover, the same resource base in different geologic settings can require completely different techniques. Porosities of the reservoir rocks of unconventional resource bases are perhaps 1 to 10% and generally 2 to 4%. Permeabilities are 0.01 to 0.1 millidarcies, or less. Thus, the rock matrix has little ability to transmit fluids. However, fractures usually play a critical role with unconventional-energy resources, and are most often the only, or principal avenue of, fluid transmission to the well bore. The reservoirs containing these unconventional resources are often closed-fluid systems, reservoir drive thus being a critical element of recovery. The above points are especially true of the Bakken Source System. In contrast to conventional deposits, the reservoirs of economically-producible unconventional-energy resource bases can be, but not always are, well-interconnected over large basinal areas. The concept of "sweet spots", which are volumes of rock with increased production capabilities compared to the average reservoir rocks of the unconventional-resource base, is usually an important consideration. Sweet spots generally result from intensified fracturing, or some other parameter, such as increased porosity and permeability, which increases fluid transmissibility.

6.0 CHARACTERISTICS, AND CAUSES THEREOF, OF BAKKEN SOURCE SYSTEM RESERVOIR ROCKS

6.01 Synopsis

Because of oil shows encountered whenever Bakken Source System rocks are penetrated by the drill, operators have cored these rocks in at least 107 wells in the North Dakota portion alone, of the Williston Basin. Moreover, at least 41 of these cores had traditional core analyses performed on them (porosity, permeability, residual oil and water, visual examination), analyses which were reported to the North Dakota Industrial Commission (NDIC), and hence are in public domain. A proprietary, unpublished, detailed, and pivotal, visual fracture study on 15 of these cored wells was carried out by Kathy Stolper (Petro Tech Associates, Houston, Texas) for Lake-Ronel Oil Company and was made available to this research effort. A *much* larger fracture study of Bakken Source System rocks is being carried out with Stolper Geologic. We have also carried out detailed ROCK-EVAL analyses on all five Bakken Source System rocks with spacings of 6 to 24 in (0.15-0.61m) between samples, for 26 geographically-separated wells.

Examples of conventional core analyses from Bakken Source System rocks from six different wells are presented herein. The conclusions drawn from these five examples apply to the entire sample base of all 41 cored wells. In basin areas where the Bakken shales are immature, the three adjacent reservoir rocks <u>always</u> have low matrix permeabilities (0.005 to 0.04 millidarcies) and zero to low residual-oil-saturation percentages. Moreover, these adjacent rocks have no, or only few, fractures. As the maturity of the Bakken shales increases, so does the percentage of residual oil and the incidence of fractures. Where the Bakken shales are both thick and mature, the three rocks adjacent to the two Bakken shales always have high residual-oil-saturation percentages and a very high incidence of fractures. These fractures dramatically increase the permeability of the rocks in which they occur. Both the fracturing and the high residual-oil-saturation percentages can only have been caused by HC generation in the organic-rich Bakken shales.

The close-spaced ROCK-EVAL analyses corroborate the results from the traditional core analyses, to wit: First, in basin areas where the Bakken shales are immature, the three rocks adjacent to the two Bakken shales are extremely organic-poor, and, throughout the Bakken HC kitchen, have no capability to generate indigenous HCS. Second, progressive movement of Bakken-shale-generated oil into the three rocks adjacent to the two Bakken shales occurred with increasing maturity of the Bakken shales. Third, samples of these three rocks from basinal areas where the shales are both thick and mature, always have very large increases in organic richness, compared to background values, due to massive injections of Bakken-shale-generated oil into them. However, concurrently the ROCK-EVAL analyses are both more precise and accurate than residual-oil analyses, and provide insights not otherwise possible. The most important of these is that the oil staining does not occur continuously in the reservoir zones, but instead is concentrated in zones of maximal fracturing. Thus, the oil resource base of the Bakken source System is concentrated rather than dispersed.

A detailed fracture study carried out on the rocks adjacent to the Bakken shales demonstrates that these are tight rocks with no fracturing in basinal areas where the Bakken shales are at shallow depths (3,000-4,000 ft; 915 to 1,220 m) and are thus immature. However, with increasing burial, and thus increasing Bakken shale maturity, horizontal fracturing commences and intensifies in the rocks adjacent to the shal this occurring before HC generation commences in the Bakken shales. On commencement of HC generation in the Bakken shales, and a loss of 50 to 75 from the starting values of the ROCK-EVAL hydrogen indices, the rocks adjacent to the shales are intensely horizontally fractured. In basin areas where the Bakken shales are post-mature, fracture intensity becomes extreme. These fractures are dominantly horizontal (99%+), unmineralized, and open, capable of taking up, and thus transmitting fluids. The fractures are caused by HC generation in the Bakken shales.

Calculations in this section demonstrate that the conversion of kerogen in source rocks to oil and gas during HC generation is a volume-expansive reaction. That is, the products of the reaction (oil and gas) take up more space than the reactants (kerogen). All the rocks of the Bakken Source System are "tight" with essentially no permeability and cannot, therefore, transmit fluids. Thus, during HC generation, the newly-generated oil and gas from the Bakken shales could not be transported from the shales, resulting in an expansion of material within a fixed volume. This expansion in turn created very high fluid pressures. These pressures compressed the kerogen in the Bakken shales, resulting in stored potential energy of compression. The pressures eventually became so high that the adjacent rocks were fractured, thereby relieving the accumulated stress in the system. However, the energy of compression stored within the Bakken shales actually created *super-lithostatic pressures* (pressures greater than the weight of the overlying column of rocks). The resulting expulsion of oil from the Bakken shales under these super-lithostatic pressure events created super-lithostatic fracturing events, resulting in extremely well-interconnected reservoirs in the three rocks adjacent to the two Bakken shales, with the Bakken-generated oil stored mainly in horizontal fractures.

Concurrently, rocks several hundred feet both above and below the Bakken Source System have dominantly vertical to off-vertical fractures which are cemented and completely closed, being unable to transmit fluids. These rocks thus form the upper and lower seals of the Bakken Source System, trapping the oil therein.

6.02 **Introduction**

Recall the observation above that every time the Bakken Source System is penetrated by the drill, even where the Bakken shales are only moderately-mature, an oil show results. These oil shows in turn have led to an extensive coring of Bakken Source System rocks as explorationists (unsucessfully) searched for the conventional oil resevoir thought to be holding this oil. In fact, by NDGS records, at least 107 wells have been so cored in North Dakota alone. Much of this core is in public domain at the NDGS core storage facility in Grand Forks, North Dakota. Furthermore, at least 41 of these 107 cores had traditional core analyses performed on them (porosity, permeability, and residual oil and water saturation analyses) by major oil field service companies (Core Labs, etc.) or by the in-house laboratories of major oil companies (Table 1). Lastly, detailed visual examination of the core of 15 of the Table 1 wells, was carried out by Petro Tech Associates, Houston, Texas for Lake-Ronel Oil Company. Pete Lake, the CEO of Lake-Ronel, graciously made this core study available to this research project.

All these data from wells throughout the North Dakota portion of the Williston Basin, provide an opportunity to understand characteristics of the Bakken Source System reservoir rocks, and the parameters controlling those characteristics. In this section, we discuss some of the results of our studies on these cores. However, before we do this, several points concerning the stratigraphy of the Bakken Source System rocks are addressed.

6.03 **Stratigraphy**

Please reference Figure 3 for the following discussion. Concerning Bakken Source System stratigraphy, five points are of interest for us: First, the two Bakken shales are very organic-rich with extremely high capacities for oil generation. Second, as will be demonstrated below, the three stratigraphic units immediately adjacent to the two Bakken shales (the Lodgepole limestone, the Bakken Siltstone, and the Three Forks shale) are very organic-poor. These three rocks cannot generate measurable oil. Third, the three rocks adjacent to the Bakken shales are both brittle from their carbonate- rich nature and have low matrix porosities and very low matrix permeabilities with no capacity to transmit fluids.

Critically, visual and electric-log examination reveals that the lower Lodgepole, middle Siltstone, and upper Three Forks rocks have no significant lateral-facies variations, with the same chemical and physical characteristics laterally over a large area of the Williston Basin, including all of the Bakken HC kitchen in both North Dakota and Montana.

The fifth point of interest in Figure 3 is the lowermost Lodgepole shale ("the false Bakken"), 6 to 10 ft (1.8 to 3.0 m) above the upper Bakken shale. The lowermost Lodgepole shale has been attributed as a source rock for both the mid Madison and Waulsortian mound oils (Montgomery, 1996). Because this rock is very much misunderstood, we will briefly review the lowermost Lodgepole shale here. The following discussion of the lowermost Lodgepole shale is based partially on various personal communications with J. LeFever (NDGS, Grand Forks, ND, 1984-1996).

6.04 **The Lowermost Lodgepole Shale**

The lithologic (physical) characteristics of the lowermost Lodgepole shale are superficially similar to those of the two Bakken shales, and perhaps the lowermost Lodgepole shale represents the last vestiges of Bakken shale deposition. The lowermost Lodgepole shale is considered by some explorationists to be 10 to 30 ft (3.0-10.1m) thick on the basis of electric-log response. However, the most organic-rich part of the lowermost Lodgepole shale, which gives a strong gamma-ray response, is much thinner (e.g., 1 to 3 ft, 0.3-1.1 m, Fig. 3). No previous published petroleum-geochemical analyses for this unit exists. However, analyses in Table 2 provide insight into understanding the unit.

In the NDGS # 8474 well (Tenneco Graham USA 1-15, Table 2), the most organic-rich part of the lowermost Lodgepole shale TOC $\geq$ 6.0%) is 0.5 to1.0 ft (0.15-0.3 m) thick. Note that TOC contents sharply decrease in samples above and below the rich interval (10,347.4 to 10,347.9 ft; 3,153.7 to 3,153.9 m). In NDGS # 8474, TOC contents slightly elevated over background are present only over a 7 ft (2.1 m) interval of 10,344.0 to 10,351.0 ft (3,152.7 to 3,154.8 m).

The Clarion Resources Slater-1 (NDGS # 8638, Table 2) is in Northwestern Ward County (Fig. 13) where the Bakken shales are much thicker (11 ft (3.4 m) of upper shale, 24 ft (7.3 m) of lower shale), compared to NDGS # 8474 (8 ft (2.4 m) of upper shale only). However, also notice that the lowermost Lodgepole shale in the Clarion well is much thinner (2 ft, (0.6 m); 7,878 to 7,880 ft (2,401.1 to 2,401.7 m) and much richer (TOC=26.59%) than in the NDGS # 8474 well. Preliminary data (electric-log mapping) suggests that the former observation may be a basin wide phenomenon (Julie LeFever, NDGS, personal communication; June, 1995). Thus, the lowermost Lodgepole shale thickens significantly towards the Bakken depositional edge, but is thin where the Bakken shales are thick (our main area of discussion). Thus, in the Bakken HC kitchen, any oil generated by the lowermost Lodgepole shale would be dwarfed by the oil generated by the <u>much</u> thicker Bakken shales. Many investigators and explorationists have elevated the lowermost Lodgepole shale to the status of a major player as a source rock in the Williston Basin. This is simply not the case. The lowermost Lodgepole shale is an inconsequential parameter in the Bakken Source System.

6.05 Traditional Core Analyses

6.051 Introduction

Six examples of traditional core analyses of Bakken Source System rocks are shown in Figures 14 to 19. Well locations are shown on Figure 13 by their NDGS numbers (8177, 8637, 7851, 8709, 11617, and 12494). These wells were chosen for discussion based on the thickness and maturity of the Bakken shales in each well. The conclusions drawn from these six wells are applicable across the Bakken HC kitchen of the Williston Basin.

6.052 NDGS # 8177 Immature Shales (Pre-HC Generation)

Well NDGS # 8177 (Marathon Dobrinski 18-44; Fig. 14) was drilled where the Bakken shales are immature (Fig. 13). ROCK-EVAL data from Price et al. (1984), as well as subsequent yet-unpublished ROCK-EVAL analyses, for NDGS # 8177 demonstrate that the two Bakken shales have a T_{max} range of 418° to 421°C. Unpublished saturated-HC gas chromatograms of this author from Soxhlet extractions of Bakken shales from this well also demonstrate that the shales have not yet begun mainstage HC generation. In fact, NDGS # 8177 represents the most immature locality for which residual-oil saturation percentage analyses are available for Bakken Source System rocks. ROCK-EVAL hydrogen indices for the Bakken shales in this well range from 550 to 675. Sixteen ft (4.9 m) of upper Bakken shale are present in this well with 10 ft (3.0 m) of lower shale. From Figure 14, siltstone porosities are low (ranging from 1.1 to 6.7%, and averaging around 3%). Siltstone permeabilities are <u>very</u> low, ranging from 0.01 to 0.05 millidarcies (md). Residual-oil saturations are also very low (1.7 to 4.4%), when even detected, for the most part, mainly adjacent to the two shales. ROCK-EVAL analyses of the NDGS # 8177 siltstones presented below (section 6.062) mirror the results of the residual-oil-saturation analyses, in that slightly-elevated values over background values of TOC and the S_1 and S_2 peaks are only found directly adjacent to the two shales.

The core analyses in Figure 14 demonstrate the tight nature (low porosities and permeabilities) of the siltstone. As will be seen below, these low porosities and permeabilities are characteristic of all three rocks adjacent to the two Bakken shales in all locations within and directly adjacent to the Bakken shale HC kitchen. The residual oil-saturation analyses of Figure 14 suggest a subtle, early migration of oil from the two Bakken shales into the immediately adjacent reservoir rocks, a migration which occurs in spite of the fact that the Bakken shales have not yet commenced HC generation. We attribute this migration to a fractionation of oil from the indigenous bitumen in the Bakken shales by the gas-driven bulk-phase expulsion mechanism proposed by Price and Clayton (1992). This point is further discussed below in section 6.063. However, it is important to note that most of the 24 ft (7.3 m) of the siltstone cored in Figure 14 has no measurable residual oil. The fracture study being carried out with Stolper Geologic revealed that fracturing was minimal in the siltstone of NDGS #8177, occurring principally for a distance of about 6 ft (1.8 m) below the bottom of the upper Bakken shale.

6.053 NDGS # 8637 Less Immature Shales (Pre-HC Generation)

Conventional core analyses are presented in Figure 15 for the Clarion-Pierce 1-18 (NDGS # 8637). The shales are 14 ft (4.3 m) thick in this well, with 6 ft (1.8 m) of upper shale and 8 ft (2.4 m) of lower shale), and are slightly more mature than those in NDGS # 8177. Bakken shale T_{max} values range from 425°C to 433°C in NDGS # 8637 versus 418° to 421° in NDGS # 8177, with ROCK-EVAL production indices of 0.060. However, saturated-HC gas chromatograms of extracted bitumen from Bakken shales from NDGS #8637 demonstrate that the Bakken shales in the well have not yet begun mainstage HC generation either. Bakken shale hydrogen indices in NDGS #8637 average 664. In Figure 15, siltstone porosities and permeabilites are equivalent to those found in the siltstones of NDGS # 8177. Thus in NDGS # 8637, porosities range from 0.6 to 6.2%, averaging around 2.5% (versus a 1.1 to 6.7% range, average 3%, in NDGS # 8177). *Matrix* permeabilites range from <0.01 to 0.06 millidarcies (md) in NDGS # 8637. However, note that higher permeability values are also present (0.42 to 62 millidarcies, md). Some of these higher values were noted to be associated with laminar fractures in the conventional core analysis. Unpublished detailed fracture analyses of this, and numerous other Bakken well(s), from the ongoing fracture study with Stolper Geologic, demonstrate that increased Bakken Source System permeability values over background (matrix) values are always associated with laminar fracturing (discussed below).

Note the significant increase in the percentages of residual-oil (dots) in the siltstones of NDGS # 8637 (Fig. 15) compared to the NDGS # 8177 siltstones (Fig. 14). Moreover, measurable oil saturations are scattered throughout the NDGS #8637 core, and not just adjacent to the two shales (Fig. 15). Thus, oil migrating into the siltstone apparently skips some vertical intervals and is injected into other intervals, which are more favorable conduits. Results from the ongoing fracture study with Stolper Geologic have demonstrated that vertical facies variations within each of the three rocks adjacent to the two shales determine which intervals within those rocks are more prone to be fractured and have oil emplaced in them. Three other observations are of interest: First, with one exception at 6,761.5 ft (2060.8 m), the horizontal fractures have the lowest (and in some cases, zero) oil saturations. We attribute this observation to the more permeable horizontal fractures (as compared to the unfractured rock matrix) allowing an easier, and at times, a total, escape of the migrated oil to the drilling mud, during the ascent of the core in the wellbore during coring operations. This point is discussed further in sections 6.072 and 6.076. Third, fracture analysis of the siltstones from NDGS #8637 and NDGS #8177 reveals that significantly increased horizontal fracturing is also present in the siltstone of NDGS #8637 compared to that in NDGS #8177. As discussed in sections 6.057 and 6.058 below, the association of increased residual-oil saturations and increased horizontal fracture intensity both result from the same cause, to wit: a super-lithostatic fracturing event caused by HC generation in, and HC migration from, the Bakken shales.

6.054 NDGS #7851 Immature Shales Just Having Commenced HC Generation

NDGS #7851 (Brooks Exploration 1-11 Rogstad) was drilled in a basin area where the hydrogen indices of the Bakken shales are near maximal (over 600), although the Bakken shales have just commenced HC generation. As such, ROCK-EVAL production indices for the NDGS #7851 Bakken shales range from 0.090 to 0.120 compared to values of 0.060 in the slightly less mature Bakken shales of NDGS #8637. The Bakken shales are also thick in NDGS #7851, with 15 ft (4.6 m) of upper shale and 32 ft (9.8 m) of lower shale.

In Figure 16, siltstone porosities in NDGS #7851 are slightly higher than in the previous cases, ranging between 3 to 7%, and averaging around 5%. However, permeabilities are still low, with all but three values being 0.06 md or less, and most values being 0.02 md and less. The highest values again are caused by laminar fractures. The most notable difference in Figure 16, compared to Figures 14 and 15, is the significantly-increased values of residual-oil saturation percentages. Thus, the NDGS #8177 siltstone (Fig. 14) had essentially zero residual-oil saturation values, (dots) and the NDGS #8637 siltstone had residual-oil saturation percentages (dots) largely ranging between 0 to 20% (with numerous zero values) with an average value of around 10%. In contrast, the siltstone in NDGS #7851 has residual-oil saturation percentages (dots) largely ranging between 10 to 45% (with no zero values), with an average of around 30%.

Our fracture study revealed that the incidence of horizontal fractures in the NDGS #7851 siltstones also increased over that found in the NDGS #8637 siltstones. The increases in both fracture intensity and residual oil saturation percentages coincide with the fact that the Bakken shales in NDGS #7851 are the most mature of the three wells we have discussed (Figs. 14 to 16). Moreover, the patterns of fracturing and residual-oil saturations observed in these three wells pertain to all other wells where the Bakken shales are immature, to wit: As maturity increases in the Bakken shales, residual-oil saturation percentages also increase in the three rocks adjacent to the two shales. This increase is from zero values where the shales are most immature, to uniform high values where the Bakken shales are still immature but have just begun HC generation, even though they have not lost detectable amounts of their ROCK-EVAL hydrogen indices. Concurrently, the incidence of horizontal fractures also increases in the rocks adjacent to the shales, with increasing Bakken shale maturity. These observations are related, and are both due to low-level HC generation in extremely organic-rich source rocks causing both abnormal fluid pressures from volume expansive reactions during HC generation and also a pervasive early movement of oil into the rocks adjacent to them. This migration would be driven by the mechanism proposed by Price and Clayton (1992), which is discussed below in section 6.063. The end result is a uniform saturation of oil in the porosities of the rocks adjacent to the Bakken shales, for significant vertical distances away from the Bakken shales, in cases where the Bakken shales have begun HC generation. The abnormal fluid pressures created by the volume expansive reactions during HC generation, and the fracturing resulting thereof, are discussed below in section 6.08.

An important conclusion can be drawn from Figures 14 to 16: The rocks adjacent to the Bakken shales have *very low* matrix permeabilities and low porosities. Over the entire U.S. side of the Williston Basin, where the Bakken shales are immature, the matrix of the three rocks adjacent to the two Bakken shales is "tight" with very limited capability for fluid transmission. As demonstrated below, where the Bakken shales are mature, the permeabilities of the three rocks adjacent to the two shales are even further decreased to values such that these rocks become incapable of significant fluid transmission. Because of these characteristics, the three units adjacent to the two shales are called "tombstones" by oil field personnel working in the Williston Basin (Brian Jones, then Halliburton Energy Services, personal communication; March, 1995).

6.055 NDGS # 8709 Thick Moderately-Mature Shales

The Shell Oil Co. Burbank 23-8 (NDGS # 8709) was drilled in a basin area (Fig. 13) where the Bakken shales are thick (22 ft (6.7 m) of upper shale, 17 ft (5.2 m) of lower shale and much more mature (ROCK-EVAL hydrogen indices 400) than the Bakken shales in Figures 14 to 16. In the previous three cases (Figs. 14 to 16), we have considered only the middle Bakken siltstone. However, the observations related to the siltstone also apply to the other two units (the Lodgepole limestone and the Three Forks shale) adjacent to the Bakken shales. These other two units are present in Figure 17 where porosities in all the rocks adjacent to the two Bakken shales in this well again are low to very low averaging about 1.5% for the Lodgepole, about 4.0% for the siltstone, and around 7.0% for the upper Three Forks interval. The porosity trends in Figure 17 are typical for essentially all of our area of discussion. Of the three rocks adjacent to the Bakken shales, the Lodgepole limestone usually has the lowest porosities, ranging from several tenths of a percent to 1 to 3%. The siltstone usually has higher porosities than Lodgepole rocks with averages of 4 to 6 percent. The uppermost Three Forks has the highest porosities (4 to 10% range, average of 6 to 7%) of the three rocks. However, occasionally siltstone and Three Forks porosities can be similar.

Matrix permeabilities of the three rocks adjacent to the Bakken shales again are very low, largely 0.01 md or less. A limited number of samples from NDGS 8709 had permeabilities between 0.02 to 0.06, and a greater number of samples had permeabilities greater than 0.06 md, which are so-labeled in Figure 17. Both sets of these increased permeabilities are due to fracturing, many instances of which were so-labeled in the original core report on file with the NDGS. Seven sample points with such elevated values have no designation. These points do not represent samples with original elevated permeabilities. Rather, they are simply samples with unrecognized fractures.

Average matrix permeabilities for the siltstones in the three examples discussed above where the Bakken shales were immature were respectively 0.03 md for NDGS #8177 (Fig. 14), 0.03 md for NDGS #8637 (Fig. 15), and 0.025 md for NDGS #7851 (Fig. 16). However, the siltstone in NDGS #8709 (Fig. 17) has average matrix permeabilities (fracture permeabilities not being considered) of 0.01 md or less, as do the other two rocks adjacent to the Bakken shales. This observation holds true for all areas of the Williston Basin where the Bakken shales are mature, *matrix* permeabilities of the three rocks adjacent to the two shales consistently run 0.01 md or less. All higher permeabilities are fracture-enhanced. Thus, there has been a slight, but significant, permeability decrease in the reservoir rocks adjacent to the shales, with increasing Bakken shale maturity. This permeability decrease is most likely from precipitation of small amounts of carbonate minerals in pore throats, because porosities of the reservoir rocks are in the same range whether or not the adjacent Bakken shales are mature or immature.

NSGS #8709 was examined in our ongoing fracture study, and there was a several order of magnitudes increase in fracture intensity in the three reservoir rocks adjacent to the two shales in this well, compared to that observed in the rocks of NDGS #8637 and #7851. Moreover, the fractures observed in NDGS #8709 were dominantly (99.5%+) horizontal. Residual-oil saturation percentages in the NDGS #8709 siltstone also increased over previous examples, largely ranging from 22 to 60%, and averaging around 48% (Fig. 17), versus, for example, an average of 30% for NDGS #7851. Although we have been discussing the middle Bakken siltstone in the examples in Figures 14 to 17, the observations and conclusions we have drawn for this rock apply to the other two rocks (Lodgepole and Three Forks) adjacent to the two shales. Thus, elevated residual-oil saturation percentages are also present in Lodgepole and Three Forks rocks, especially in the Three Forks rocks with ranges between 20 to 100% and an average of around 65%. However, within any one of the stratigraphic units adjacent to the two shales, large variations in residual-oil saturation percentages (and fracturing) can be present, due to facies variations in each stratigraphic unit. Although each unit adjacent to the two shales has rather minimal lateral lithologic variation across the entire Williston Basin, significant vertical lithologic variation is always present in each of the three units.

Not only are high residual-oil-saturation percentages present in two of the three rocks adjacent to the two shales in NDGS #8709, with moderate values being in the lowermost

Lodgepole rocks, but the oil saturations are pervasive with no samples with zero, or near-zero, values. Moreover, the vertical intervals over which these high residual-oil saturations occur are large, for example 38 ft (11.6 m) of siltstone and 50 ft (15.2 m) of Three Forks. Furthermore, in the Three Forks shale, it is likely that these high values extend even further than 50 ft (15.2 m) from the Bakken shales.

The Bakken shales in NDGS #8709 have reached the middle of mainstage HC generation, wherein ROCK-EVAL hydrogen indices have decreased to 400 from original values of 625 or greater. Concurrently, massive fracturing of the three rocks adjacent to the two shales has occurred in this well, along with pervasive movement of oil into these three reservoir rocks, resulting in high residual-oil saturation percentages. As the Bakken shales reach even greater maturation ranks, where ROCK-EVAL hydrogen indices have further decreased to 50 to 100, these trends in the adjacent rocks continue.

6.056 NDGS # 12494 Thin Mature Shales

The Maxus Rauch Shapiro Fee 13-3 (NDGS # 12494, Fig. 18) was drilled in the Fairway (Fig. 13) where the Bakken shales are thin (2.7 ft (0.8 m) of upper shale only) and mature (ROCK-EVAL hydrogen indices about 150). Lodgepole porosities (Fig. 18) again are very low (0.1 to 3.1%). The vertical interval of Lodgepole limestone cored in NDGS #12494 (over 40 ft, 12.2 m) is much greater than that in NDGS #8709 (8 ft, 2.4 m; Fig. 17). As such, several different facies of Lodgepole rocks are present in Fig. 18. The Lodgepole interval above the top of the upper Bakken shale is a massive limestone with what appear to be incipient stylolitic features, sub-parallel to the horizontal axis. Fracturing in this facies of the Lodgepole is both weak, even in mature areas of the Bakken HC kitchen, and occurs along these stylolitic-like features. This "stylolite" facies of the Lodgepole is 10 to 20 ft (3.0 to 6.1 m) thick, depending on basinal location, and has the highest porosities (2 to 4%) of all Lodgepole rocks near the upper Bakken shale. The "stylolite facies", besides having the least fracturing of all Lodgepole rocks, also often has the highest residual-oil saturation percentages of all the different Lodgepole facies.

Above 10,500 ft (3,200 m) in Figure 18, one passes into Lodgepole rocks which are either massive with no depositional features, or have laminated bedding features developed in them. These two facies are interbedded with one another and both facies have very low porosities, with minimal ranges as low as 0.1 to 0.3% and maximal ranges of 1 to 1.5%. Because of the lower porosities, these rocks invariably have lower residual-oil saturation percentages (shown by triangles, Fig. 18) than the slightly deeper stylolite facies. The laminar Lodgepole facies can have extremely intense horizontal fracturing, where the Bakken shales are mature.

Siltstone and Three Forks porosities range between 0.8 to 5.6% and average about 3.4%. Matrix permeabilities for all three reservoir rocks are again very low, being 0.02 md or less. However, again matrix permeabilities are augmented by fractures, which although present, are not as prevalent as in the case of the NDGS #8709 well. Residual-oil saturation percentages are variable in the siltstone and Three Forks rocks, but tend to be highest nearest the shales.

We should note that there is inherent variability in the residual-oil analyses due to: 1) procedural differences between the laboratories, 2) how long the samples were analyzed after the core was taken, 3) the mud weights and other drilling conditions during the core operations, and 4) an inherent set of errors introduced into these analyses when analyzing Bakken Source System reservoir rocks by the accepted API (American Petroleum Institute) methods (API, 1998). However, these errors will not be discussed here. The second and third parameters have a dominant control on how much of the original in-place oil escapes from the core before analyses. Moreover, vertical facies variations within each of the three Bakken Source System reservoir units, variations which were touched on above, also control the residual-oil analyses. For example, more laminar vertical intervals fracture easily and more intensely than more massive intervals. Because of the higher fracture intensity over such intervals, escape of the original in-place oil is decidedly more facile from such laminated units.

Be all that as it may, residual-oil saturation percentages (and fracturing intensities) are decidedly lower in all the Fairway wells compared to wells from the Bakken HC kitchen where the Bakken shales are much thicker. This is because the Bakken shales in the Fairway area are much thinner and have lower starting TOCS and possibly lower starting hydrogen indices (Price et al., 1984, and unpublished data this author) than the much thicker shales in the Bakken HC kitchen proper. Thus, the thinner Fairway Bakken shales had decidely lower amounts of generated HCS, and thus produced much weaker fracture and oil-emplacement events than the thicker (and more organic-rich) shales in the Bakken HC kitchen proper. A comparison of the residual-oil saturations (both percentages and vertical extent), and the density of fractures noted in the core analyses of the last two wells (Figs. 17 and 18), both support his point. However, it should also be noted that the data from the Figure 18 NDGS #12494 well overstates this point. Most other Fairway wells with core analyses have higher residual-oil saturation percentages over greater vertical intervals than those in Figure 18.

6.057 NDGS # 11617 Thick Mature Shales

Conventional core analyses are shown in Figure 19 for NDGS # 11617 (the Cox and Berry, Hagen 1-13). The Bakken shales in this well are thick (22 ft (6.7 m) of upper shale, and 28 ft (8.5 m) of lower shale) and mature, with ROCK-EVAL hydrogen indices of around 140 (Fig. 13) and T_{max} values of 448°C. Porosities in the siltstone are low, ranging from 1.6 to 3.4% with all permeabilities less than 0.01 md. No horizontal fractures were noted in the siltstone. Moreover, our fracture study also demonstrates that this is a weakly-fractured zone, in spite of the high maturities and thickness of the shales. Notwithstanding this weak fracturing and complete lack of permeability in the siltstone, NDGS-11617 was sidetracked and perforated in the lower siltstone interval shown in Figure 19, and has produced over 140,000 barrels of oil, and is still producing.

In Figure 19, porostites in the Three Forks shale are low ranging from 2.9 to 5.0%. Matrix permeabilites are also low, largely less than 0.01 md, with higher values due to horizontal fractures. In fact, our ongoing fracture study has demonstrated the Three Forks shale in NDGS #11617 is intensely fractured. Elevated residual-oil saturations (dots) are uniformly present throughout the siltstone and Three Forks rocks. However, note that the residual-oil saturation percentages are reduced in both the siltstone and Three Forks rocks in NDGS #11617 (Fig. 19) compared to the values present for the same rocks in NDGS #8709 (Fig. 17). Thus, residual oil saturations in the siltstone in NDGS #11617 average around 30% (Fig. 19) versus 48% in NDGS #8709 (Fig. 17), and around 42% in the Three Forks in NDGS #11617 (Fig. 19) versus around 65% in NDGS #8709 (Fig. 17). This observation holds true at all locations in the Bakken HC kitchen for the three rocks adjacent to the two Bakken shales where the shales are both thick and mature and have ROCK-EVAL hydrogen indices less than 250, to wit: lower residual-oil-saturation percentages compared to those values in rocks where the shales are less mature (with ROCK-EVAL hydrogen indices of 350 to 500). There is at least one explanation for this:

Reservoir rocks in basinal positions with more mature Bakken shales have oils with higher gas-oil ratios compared to oils in basinal positions with less mature Bakken shales. The higher gas contents facilitate a greater loss of oil from the core to the drilling mud during the trip up the wellbore (discussed below).

Several observations concerning the data of Figure 19 should be stressed. First, note the very low matrix permeabilities of both the Bakken siltstone and the Three Forks shale (less than 0.01 md). Again, this is largely characteristic of the three rocks adjacent to the two Bakken shales where the shales have ROCK-EVAL hydrogen indices of 400 or less: a loss of what little matrix permeability was originally in these rocks. Second, as is typical of all basinal locations, the Three Forks shale has higher porosities than the siltstone. Lastly, the lack of fracturing in the lower part of the Bakken siltstone of NDGS #11617 warrants explanation. Fracture intensity of, and movement of oil into, the three rocks adjacent to the two Bakken shales are both related to Bakken shale maturity. However, the relationship is not perfect, and in basin areas where the Bakken shales are thick and mature, exceptions can exist with less intense fracturing occurring than expected. Also, more intense fracturing than expected can occur in areas where the Bakken shales are only moderately mature (ROCK-EVAL hydrogen indices of 400 to 500). However, in no case have we found significant fracturing occurring in the three rocks adjacent to the two Bakken shales, where those shales have not yet begun HC generation.

6.058 Discussion of Conventional Core Analyses

Important observations and implications result from the data of Figures 14 to 19. First, the rocks immediately adjacent to the two Bakken shales are "tight" with very low porosities and extremely low permeabilities. Moreover, in basin areas where the Bakken shales are mature

(ROCK-EVAL hydrogen indices of 250 and less), matrix permeabilities of the three rocks adjacent to the Bakken shales (the reservoir rocks) have largely decreased to less than 0.01 md. The matrix of these rocks has very limited capability for fluid transmission, especially where the Bakken shales are mature. Second, the distribution of both fractures and residual-oil saturations in the three rocks adjacent to the two Bakken shales offer significant insights into the circumstances involving HC expulsion from the Bakken shales and also carry significant implications for the unconventional oil-resource base proposed herein.

Core analyses of any of the three rocks adjacent to the Bakken shales from locations where the shales are immature invariably demonstrate a lack of, or only few, fractures. However, rocks from locations where the shales are marginally-mature and thick, to mature and thick to thin, have numerous fractures with enhanced permeabilities. For example, even though the Bakken shales in NDGS # 12494 (Fig. 18) are thin (2.7 ft, 0.8 m) the Bakken shales in NDGS #12494 are mature (ROCK-EVAL hydrogen index 150), thus the adjacent rocks have numerous fractures. However, shale thickness, in addition to maturity, is a key controlling parameter. Thus, the Bakken siltstone and Three Forks rocks in NDGS # 8709 (Fig. 17; 39 ft, 11.9 m of Bakken shale) are much more fractured than they are in NDGS # 12494 (Fig. 18; 2.7 ft, 0.8 m of Bakken shale). This despite the fact that the Bakken shales in NDGS # 12494 are considerably more mature (ROCK-EVAL hydrogen index 150) than they are in NDGS # 8709 (ROCK-EVAL hydrogen indices around 380-400). These observations are all due to, and explained by, super-lithostatic fracing events caused by HC generation in the Bakken shales, a topic discussed below in section 6.08.

6.06 **ROCK-EVAL Analysis of Immature Core Samples**

6.61 Introduction

Core samples from the many wells which were cored in the Bakken Source System provide a unique and key sample base with which to study the migration of Bakken-shale-sourced oil into the adjacent rocks, versus increasing maturity of the Bakken shales. Consequently, close spaced (6 to 24 inch (0.15 to 0.61 m) spacing) samples of Bakken shale, and more importantly of the reservoir rocks adjacent to the Bakken shales, have been taken and subjected to ROCK-EVAL analysis. The resulting data showed some of the same features as the residual-oil saturation measurements from conventional core analyses. However, because ROCK-EVAL is a more sensitive analytical method than residual-oil-saturation analysis, the ROCK-EVAL data provide even more information and insight to the points under consideration. In Figures 20 to 29, only the analyses for the Lodgepole, middle siltstone, or Three Forks rocks are presented. Data from analyses of the Bakken shales are not shown for two reasons: First, we are only interested in the ROCK-EVAL data pertaining to movement of oil into the rocks surrounding the Bakken shales, and thus ROCK-EVAL data from the Bakken shales add nothing to the discussion. Second, because the Bakken shales are so organic-rich, and the rocks adjacent to the shales are so organic-poor, the analytical data for both the Bakken shales and the reservoir rocks cannot be put on the same plots.

ROCK-EVAL analyses for eight of the 24 wells so analyzed thus far (Fig. 13 and Table 3) are shown in Figures 20 to 29. Figures 20 to 24 present ROCK-EVAL data from wells where the Bakken shales are immature.

6.062 NDGS # 8177

NDGS # 8177 (Marathon Oil, Dobrinski 18-44; Fig. 20) is the most immature of the wells analyzed. The Bakken shales in this well have not yet begun HC generation with average ROCK-EVAL T_{max} values of about 420°C and average production indices ($PI=S_1/S_1 + S_2$) of around 0.070. The middle siltstone was the only reservoir unit cored in this well. The contact between the upper Bakken shale and the middle siltstone is at 8,638.6 ft (2,632.9 m) and the contact between the siltstone and the lower Bakken shale is at 8,661.9 ft (2,640.0 m). In Figure 20 (as well as Figs. 21 to 27), TOC contents in weight percent of the rock, the S_1 ROCK-EVAL peak (equivalent to solvent-extractable HCS or free oil), and the S_2 ROCK-EVAL peak (equivalent to oil generation potential) are all plotted. S_1 and S_2 are plotted as parts per million (ppm) values on a dry-rock weight basis.

Note that a slight increase in values for all three parameters in Figure 20 occurs just below the upper shale over 8,638.6 to 8,641 ft (2,632.9 to 2,633.6 m), and just above the lower shale over 8,660 to 8,661.9 ft (2,639.4 to 2,640.0 m). These slightly-elevated values both are caused by the first stages of migration of oil from the Bakken shales to the adjacent rocks and mirror slightly-elevated values of residual-oil-saturation percentages measured in the siltstones of NDGS # 8177 (Fig. 14) over the same depth intervals. The TOC, S_1 and S_2 values between 8,643 to 8,658 ft (2,634.5 to 2,638.8 m), with the possible exception of the 8,654 ft (2,637.1 m) sample, may be taken as starting original (background) organic richness values for the siltstone. Thus, TOC contents range from 0.06 to 0.12%, averaging about 0.10%. S_1 values (free oil) range from 40 to 110 ppm, averaging about 80 ppm. S_2 values (the capacity of the rock to generate oil) range from 0 to 30 ppm, averaging less than 10 ppm. The ROCK-EVAL data of NDGS # 8177 allow four observations. First, the middle Bakken siltstone is a very organic-poor rock with near zero levels of indigenous HCS. Second, the very low ROCK-EVAL S_2 values of the siltstone demonstrate that this rock has no meaningful capacity to generate oil. Third, even when the Bakken shales are still very immature, we see oil beginning to move into the rocks adjacent to the Bakken shales, in this case, the siltstone. The fourth observation involves comparison of the ROCK-EVAL S_1 peak values (Fig. 20) for NDGS # 8177 siltstones to the conventional residual-oil analyses (Fig. 14) for the same rocks. In both cases (Figs. 14 and 20), an initial slight movement of oil from the shales into the siltstones is detected. Comparison of other Bakken Source System reservoir rocks from other wells, where both residual-oil saturation and ROCK-EVAL analyses are available, results in the same conclusion: The ROCK-EVAL S_1 peak has the same behavior as residual-oil. Thus ROCK-EVAL can be used to estimate residual-oil in cases where conventional-core analyses are not available for a given well.

6.063 Early Movement of Oil

This slight movement of oil from the Bakken shales into the immediately adjacent reservoir rocks, even though the shales have not yet begun HC generation, warrants comment. Solvent extraction of fine-grained rocks, to recover the indigenous HCS therein, involves grinding rocks to a powder, usually to 100 mesh, or less sieve size. However, Price and Clayton (1992) performed progressive long-term solvent extractions on a whole (unground) Bakken shale core sample, where that sample (NDGS # 105) was even more immature than the Bakken shales of NDGS # 8177. Their analyses demonstrated that a fractionation of bitumen to a more oil-like phase had occurred in the NDGS # 105 Bakken shale. This fractionated oil was hypothesized to be present in the cracks and parting laminae of these immature shales.

Price and Clayton (1992) attributed the bitumen fractionation they observed to the generation of carbon dioxide and HC gases (methane through the butanes) in small quantities, before mainstage HC generation commenced (Price, 1989a). They hypothesized that these generated gases had mobilized, and caused the fractionation of, the high concentrations of indigenous bitumen known to be present in the Bakken shales, even at immature ranks (Webster, 1984; Price et al., 1984). We will not discuss all aspects of the Price and Clayton (1992) paper here. However, Price and Clayton (1992) also hypothesized that if organic-rich shales (TOC≥10%, starting hydrogen indices ≥400) were directly adjacent to a good fluid conduit, or were faulted, then such shales would have the capability to form oil deposits, even though the shales had not begun HC generation. Thus, we attribute the slight increase in the ROCK-EVAL organic richness values in Figure 20 in the siltstones just above and below the two Bakken shales to the process documented and described by Price and Clayton (1992).

6.064 NDGS # 2618

The Bakken shales in well NDGS # 2618 (Pan American, Jacob Huber-1; Fig. 21) are slightly more mature than those in NDGS # 8177 (Fig. 20), with ROCK-EVAL T_{max} values around 428°C and ROCK-EVAL production indices averaging about 0.085. In Figure 21 (NDGS # 2618), TOC, and the S_1 and S_2 values (in ppm) for siltstone and Three Forks rocks are shown. In NDGS # 2618, the contact of the top of the Bakken siltstone with the bottom of the upper Bakken shale top with the siltstone is at 9,792 ft (2,984.5 m), and the first siltstone sample in Figure 21 is 9 ft (2.7 m) below this contact. Notice that the increase in TOC, S_1 and S_2 values from background levels in the two organic poor rocks (siltstone and Three Forks) adjacent to the lower Bakken shale is slightly larger than in the case of NDGS # 8177 (Fig.20). This slight increase, compared to the equivalent situation in NDGS # 8177 (Fig.20), is due to a slight increase in Bakken shale maturity in NDGS # 2618 (Fig. 21) compared to the Bakken shales in NDGS # 8177 (Fig.20).

As an aside, background TOC and S_2 values for the siltstone in NDGS # 2618 are considerably higher than they were in NDGS # 8177. In NDGS # 2618 (Fig. 21), background TOC values range from 0.13 to 0.41% and average around 0.30% versus an average background value of 0.10% for the siltstone in NDGS # 8177 (Fig. 20). Likewise, siltstone background S_2 values in NDGS # 2618 (Fig. 21) range between 120 to 200 ppm and average slightly less than 100 ppm, compared to the background siltstone values in NDGS # 8177 ranging from 0 to 30 ppm and averaging 10 ppm. On the other hand, S_1 values in the NDGS # 2618 siltstone (Fig. 21) are much lower (range 10 to 50 ppm, averaging slightly over 20 ppm) than in the NDGS # 8177 siltstone (Fig. 20, range 40 to 110 ppm, average 80 ppm).

The variations in background TOC, S_1 and S_2 values for the siltstone between these two wells are due to shortcomings of the ROCK-EVAL instrument. Although the instrument is a very powerful screening tool, there can be significant variability between different machines analyzing the same, or equivalent, samples, as is the case with the data of Figures 20 and 21. These limitations become more apparent with very organic-poor samples, such as the samples under discussion. Although the observed variations are large on a percentage-wise basis for essentially the same samples in Figures 20 and 21, for those experienced with ROCK-EVAL, the two sets of data both fall within the variability of the ROCK-EVAL instrument, and are in reality, identical. To wit: the siltstones in NDGS # 2618 (Fig. 21), as in NDGS # 8177 (Fig. 20), are very organic-poor and have essentially no ability to generate indigenous HCS.

Discounting the Three Forks samples between 9,836.9 to 9,838.5 ft (2,998.1 to 2,998.6 m) as stained due to migration of oil from the Bakken shales, we arrive at background Three Forks TOC values ranging between 0.37 to 0.74% and averaging around 0.50%, background S_1 values ranging between 10 to 20 ppm, and background S_2 values ranging between 50 to 130 ppm. However, analyses of Three Forks core samples from five other wells, where the Bakken shales are immature, suggest that the TOC values for the Three Forks in NDGS # 2618, like the NDGS # 2618 siltstone values, have been considerably exaggerated by the NDGS # 2618 ROCK-EVAL analyses. This conclusion is also supported by the data from NDGS #2010, discussed below (section 6.067). Be all that as it may, the data of Figure 21 demonstrate that Three Forks rocks, like the middle Bakken siltstone, are very organic-poor, with no meaningful capacity to generate indigenous HCS.

6.065 NDGS # 9001

ROCK-EVAL data are shown for siltstones from the NDGS # 9001 well bore in Figure 22. Bakken shales from NDGS # 9001 are yet slightly more mature than they were in NDGS # 2618 (Fig. 21), with T_{max} values averaging around 436°C. There is an increase in TOC (0.06 to 0.17%) and a pronounced increase in the S_1 peak values (from around 60 to a maximal value of 910 ppm) from the middle of the siltstone at about 7,400 ft (2,225.4 m) as one goes to shallower depths and approaches the upper Bakken shale. The S_1 peak (equivalent to free oil) demonstrates a much stronger increase in the siltstones near the Bakken shales of NDGS # 9001 (Fig. 22), than was observed in the previous two cases (Figs. 20 and 21). Moreover, the interval of significant staining (7,379.3 to 7,387 ft, 2,249.1 to 2,251.4 m; or 7.7 ft, 2.4 m) is also significantly larger than in the previous two cases. The S_2 values also increase somewhat as the bottom of the upper shale is approached. Likewise, as one passes from the middle of the siltstone at around 7,400 ft (2,225.4 m) downward toward the lower Bakken shale, S_1 and S_2 values sporadically increase, although the increase in S_1 values is not as strong as was the case in approaching the base of the upper Bakken shale. Thus, this well demonstrates that with slightly increasing maturity, compared to NDGS # 8177 (Fig. 20) and NDGS # 2618 (Fig. 21), a significantly stronger movement of oil from the Bakken shales has occurred to the adjacent reservoir rocks. Lastly, average background TOC, S_1 and S_2 values in the unstained portion of the siltstone from 7,393.5 ft (2,253.4 m) to 7,402 ft (2,256.0 m) of about 0.09%, 120 ppm, and 85 ppm respectively, again demonstrate the organic-poor nature of the siltstone. Zero S_2 values of many of the NDGS # 9001 siltstone samples (Fig. 22), further testify that this rock has little or no capacity to generate indigenous HCS.

6.066 NDGS # 8638

NDGS # 8638 (Fig. 23) is about the same maturity at NDGS # 9001 (Fig. 22). However, discussion of ROCK-EVAL data for NDGS # 8638 is included here because we can gauge background (starting) organic richness values for the Lodgepole limestone from this well. Several points are of interest in Figure 23. As in the case with NDGS # 9001 (Fig. 22), there is an increase in organic richness in the rocks nearest the Bakken shales. This increase, like the increase in the rocks of NDGS # 9001, also takes place over a larger depth interval than was the case with both NDGS # 8177 and # NDGS # 2618 (Figs. 20 and 21), because of the higher maturities of the Bakken shales in both NDGS # 9001 and NDGS # 8638. However these increased values are sporadic, with higher values interspersed with background values, an observation discussed further, below. Background TOC values for the Lodgepole limestone occur over the depth intervals 7,815 to 7,817 ft, 2,381.9 to 2,382.5 m; 7,872 to 7,877.8 ft, 2,399.3 to 2,401.0 m; and 7,881 to 7,884 ft, 2,402.0 to 2,402.9 m, and average around 0.12% (Fig. 23). Background S_1 and S_2 values for the Lodgepole limestone over these same depth intervals average around 80 ppm and 160 ppm respectively (Fig. 23). Thus, the Lodgepole limestone, like the Bakken siltstone and Three Forks shale is a very organic-poor rock with little or no capacity to generate significant amounts of indigenous HCS. Background TOC, S_1 and S_2 values for the siltstone in NDGS # 8638 (found over the depth interval 7,903 to 7,938 ft, 2,409.3 to 2,419.4 m; Fig. 23) average about 0.18%, 50 ppm, and 150 ppm respectively.

As an aside, note that in Figures 20 to 23, depth has no correlation to Bakken shale maturity. Thus, the Bakken shales in NDGS #2618 (Fig. 20) at 9,828 to 9,837 ft (2,995.4 to 2,998.2 m) are more immature than the shallower Bakken shales in both NDGS #9001 (around 7,400 ft, 2,255.4 m; Fig. 22) and in NDGS #8638 (7,889 to 7,898 ft, 2,404.4 to 2,407.2 m). For example, the Bakken shales in NDGS #2618 have ROCK-EVAL T_{max} values of 428 °C, versus T_{max} values of 436 °C in the shallower Bakken shales of NDGS #8638 and 9001. This is not a normal situation in sedimentary basins. However, Price et al. (1984) previously documented that paleo-geothermal gradients, and thus maturity, were not depth-dependent in the Williston Basin. Burrus et al. (1996) also noted that maturity was not depth-dependent in this basin. We will address this point further in section 7.0.

6.067 NDGS # 2010

Unfortunately no well penetrating the Bakken Source System has been continuously cored for 500 to 600 ft (152.4 to 182.9 m) such that 200 to 300 ft (61-91 m) of core in Lodgepole and Three Forks rocks are available for ROCK-EVAL analysis where the Bakken shales are immature. Thus, to extend the scope of the data in Figures 20 to 23, a large vertical interval (425 ft, 129.5 m) of cuttings chips were cleaned, picked, and analyzed by ROCK-EVAL, including 200 ft (61 m) of Lodgepole limestone and 150 ft (46 m) of Three Forks shale (Fig. 24). Moreover, the well (NDGS # 2010) location (Fig. 13) was chosen to both have immature Bakken shales and to also be removed from the location of other analyzed wells (Table 3) with immature Bakken shales. This was done to demonstrate that the organic-poor nature of the Lodgepole, siltstone, and Three Figure 24 near here. Forks rocks extends throughout the Bakken HC kitchen. The Bakken shales in NDGS # 2010 are at about the same maturity as the Bakken shales in NDGS # 9001 (Fig. 22) and NDGS # 8638 (Fig. 23) with ROCK-EVAL T_{max} values around 433°C and production indices of 0.051 to 0.112.

As an aside, some scientists and oil explorationists shun from ever using cuttings chips because of the problem of caving and possible contamination from organic-based drilling fluids. These points can be of concern. However, the five members of the Bakken Source System (Fig. 3, Lodgepole, siltstone, Three Forks, and two Bakken shales (the shales having identical lithologies) have very distinct lithologies, and thus it is easy to pick cavings from other units out of a given sample under a microscope after the sample has been cleaned. Also, most pre-1990 wells drilled in the Williston Basin were drilled with salt-saturated mud, because of the numerous evaporite sequences in the basin. Lastly, cuttings chips from wells drilled with organic-based drilling fluid are quite obvious with strong odors and thus sampling such wells can be avoided. Therefore, the data of Figure 24 are fully trustworthy.

Relevant observations can be drawn from the data of Figure 24. Both Lodgepole and Three Forks rocks are very organic-poor over large vertical intervals. For example, these rocks are characterized by total organic carbon (TOC) contents averaging around 0.1% and S_1 peak values averaging around 40 and 20 ppm respectively for the two rocks. S_2 peak values for these two rocks are also low, averaging around 150 ppm for the Lodgepole and 220 ppm for the Three Forks. The TOC, S_1 and S_2 values for the siltstone are noticeably elevated over those of the Lodgepole and Three Forks rocks in NDGS # 2010 (Fig. 24) as well as over the siltstones in Figures 20 to 23. This characteristic may be due to a change in the physical nature of the siltstone itself. As discussed below in section 8.06, LeFever et al. (1991) noted that the middle Bakken siltstone member in the northern Williston Basin in Saskatchewan and Manitoba (Canada) takes on characteristics of a sandstone, with increasing grain size, increasing porosities and permeabilities, and decreasing cementation in the porosity. Thus, fluid entry into this unit becomes easier in a northward direction in the Williston basin. NDGS # 2010 is very near the Canadian border (Fig. 13). Thus, the siltstones in this well may be sandier than siltstones more to the south in the basin depocenter. Therefore, the increased levels of organic richness in the NDGS # 2010 siltstones could be due to an enhanced early mobilization of indigenous (pre-mainstage generation) Bakken shale bitumen into these rocks (as discussed above).

Average starting organic richness (background) values for the Lodgepole, siltstone, and Three Forks rocks were compiled (Table 4) from Figures 20 to 24. These values were in turn averaged to arrive at background values for each rock. These background values are shown as dashed lines in the five subsequent figures (25 to 29) presenting ROCK-EVAL analyses of Lodgepole, siltstone, and Three Forks rocks from wells where the Bakken shales are mature.

6.07 **ROCK-EVAL Analyses of Mature Core Samples**

6.071 NDGS # 8474

The Tenneco Graham USA 1-15 (NDGS # 8474) is from an area of the basin where the Bakken shales are mature (Fig. 13) but relatively thin (8 ft, 2.4 m of upper shale, no lower shale). ROCK-EVAL hydrogen indices of the Bakken shales in this well are about 125, with T_{max} values of about 445°C. Background organic richness values are shown by lighter dashed lines in Figure 25. Significant increases in the organic richness, to levels substantially above background, are evident in the rocks adjacent to the Bakken shales. These increases in organic richness are caused by movement of Bakken-generated oil to the rocks adjacent to the mature Bakken shales.

Several other features are also evident in Figure 25. First, the increases in organic richness are sporadic, with background values being contiguous with significantly-elevated values. Concurrently, as one moves away (either up or down) from the Bakken shales, the organic richness generally decreases (with scatter) to background values. From these data, we may hypothesize that the super-lithostatic pressure injection of oil from the Bakken shales into the adjacent reservoir rocks appears to have been non-uniform. The conclusion of a non-uniform distribution of oil in the rocks adjacent to the two Bakken shales, especially where the Bakken shales are mature to moderately-mature, is supported by a very large body of ROCK-EVAL and residual-oil analyses. This body of analyses includes Figures 17-19 and 25-29, many other residual-oil analyses from conventional core analyses (Table 1), and thousands of additional ROCK-EVAL analyses of the rocks adjacent to the Bakken shales in the wells of Table 3, analyses which will not be shown here. A non-uniform distribution of oil in the rocks adjacent to the Bakken shales resulted because the very low matrix permeabilities of these rocks precluded migration of oil continuously through these rocks. Thus, the oil was emplaced in these rocks via a fracture network created by super-lithostatic fracturing events, in other words via a well-interconnected plumbing system versus a diffusive-based mechanism. Our ongoing fracture study demonstrates that fracturing intensity is dependent on lithologic facies variations. Thus, rocks which are prone to fracturing are the rocks which had oil injected into them from the Bakken shales. Important implications regarding possible oil recovery result from these considerations.

6.072 Oil Loss to the Drilling Mud During Drilling

Price and LeFever (1992) proposed that most of the oil generated by and remaining in and around the Bakken shales is lost to the drilling mud during the core or cutting-chip trip up the well bore during drilling operations. As Price and LeFever (1992) noted, gas-oil ratios of Bakken oils average around 1,100 standard cubic feet of gas per barrel of oil (SCF/Bbl). As core and/or cuttings chips ascend the well bore during drilling operations, they undergo large pressure decreases, from the very high formation pressures at depth (at least 7,900 psi in the Bakken Source System of theWilliston Basin) to atmospheric pressure (12 to 14.7 psi) at the well head. Because of this large pressure decrease, gas dissolved in the oil in Bakken reservoir rocks reaches bubble point and forms a free-gas phase in the oil. With further decrease in pressure, this free-gas phase greatly expands in volume and eventually explodes out of the rock, blowing any other gas and oil before it, into the drilling mud. Most of the oil in Bakken Source System rocks at depth is stored in fractures, with only a small percentage of the total oil in the negligible porosity of these rocks. Therefore, almost all the oil in these cracks is lost to the drilling mud during the core trip up the well bore, because this oil is so easily blown into the drilling mud.

Evidence supporting this large loss of the oil in Bakken Source System rocks to the drilling mud, losses on the order of at least 90-95%, will be discussed below (Section 6.076). However, for now, important implications result from this large loss of Bakken Source System oil to the drilling mud. First, this loss explains the observation that every time mature, to moderately-mature, Bakken Source System rocks are penetrated by the drill bit, an oil show is observed (Price and LeFever, 1992). Second, this loss also explains the high concentration of horizontal fractures observed in the organic-poor rocks adjacent to the Bakken shales in basinal areas where the Bakken shales are mature, as discussed above in section 6.05. All these fractures were filled with oil at depth and when the oil was lost to the drilling mud, these fractures may have even partially closed. Third, the increased organic richness of the Lodgepole, siltstone, and Three Forks rocks in Figure 25 represent only a fraction of what was present in the rocks at depth.

6.073 NDGS # 5088

NDGS # 5088 (Fig. 26) was drilled in an area of the basin (Fig. 13) where the Bakken shales are thick (17 ft (5.2 m) of upper shale and 47 ft (14.3 m) of lower shale), and are in the middle of mainstage HC generation, with ROCK-EVAL hydrogen indices of around 300 and T_{max} values of around 446°C. ROCK-EVAL TOC, S_1 and S_2 analyses are shown for 9 ft (2.7 m) of Lodgepole and for all of the siltstone (71 ft, 21 m) in NDGS # 5088 (Fig. 26). In most of the rocks of NDGS # 5088 (Fig. 26), TOC, S_1, and especially S_2 values, are significantly increased over the background levels (dashed line Fig. 26) found in immature rocks (Figs. 20 to 24). However, organic richness appears to have increased in the Lodgepole rocks more so than in the siltstone, in fact dramatically increased. The reason for this apparent differential increase in organic richness is partially due to the fact that Bakken oil does not escape to the drilling mud during coring as easily from the massive lower Lodgepole stylolite facies, which is largely unfractured, as it does from the much more fractured siltstone rocks. As in NDGS # 8474 (Fig. 25), the increases in organic richness in both Lodgepole and siltstone rocks are sporadic, with some rocks having background TOC, S_1, and S_2 values while contiguous samples may have significantly enriched values. The elevated S_2 values, and the fact that the S_2 values are consistently higher than the S_1 values, are both significant observations which are discussed directly below.

The vertical interval over which staining occurs in the reservoir rocks adjacent to the Bakken shales in NDGS # 5088 is significantly larger than in Figures 20 to 24, a trend due to the significant increase in the maturity of the Bakken shales in NDGS # 5088 (Fig. 26) compared to the previous examples with immature shales. Note also that the vertical interval of staining in NDGS # 5088 is larger than that in NDGS # 8474 (Fig. 25), even though the Bakken shales in NDGS # 8474 are significantly more mature than those in NDGS # 5088 (hydrogen indices of 125 versus 300). However, the Bakken shales in NDGS # 5088 are much thicker than those in NDGS # 8474 (71 ft, 22 m; versus 8ft, 2.4 m). Moreover, NDGS #8474 is in the Fairway (Fig. 13) and our very large, yet-unpublished, ROCK-EVAL data base for the Bakken shales demonstrates that the Bakken shales in the Bakken HC kitchen have significantly higher starting TOC contents compared to Bakken shales in the Fairway, which also have lower starting ROCK-EVAL hydrogen indices compared to kitchen shales. Thus, the NDGS # 5088 Bakken shales have generated much more oil than the thinner, but more mature, shales in NDGS # 8474. Shale thickness, maturity, and starting hydrogen indices and TOC contents of the Bakken shales all control the amount of oil generated, and expelled, by the shales.

6.074 Significance of Increased S_2 Values

Normally, the ROCK-EVAL S_2 signal is derived from the kerogen in shales. However, as Clementz (1979) noted, rocks which are stained by oil, such as the examples under discussion, invariably yield high values for the ROCK-EVAL S_2 peak. Clementz (1979) attributed such S_2 responses to high-molecular-weight HCS, resins, and asphaltenes, which had been dissolved in the oil, having precipitated out of the oil onto the rock surfaces. Because of their high molecular weight, these compounds are somewhat more analogous to kerogen than to HCS. In fact petroleum geochemists regard asphaltenes as small pieces of kerogen (Tissot and Welte, 1984). Thus, during ROCK-EVAL analysis, these compounds respond as the S_2 peak and do not contribute to the response making up the S_1 peak. From the data of Price and LeFever (1994), Bakken oils have negligible asphaltenes and 7 to 15 weight percent resins for the C_{14}+ fraction of oils. In light of these considerations, how the S_2 peaks of Figure 26 could be equal to or higher than the S_1 peaks in Figure 26 may at first appear to be a puzzle. This paradox is explained by the large loss of Bakken oil from these rocks to both the drilling mud and to evaporation during the time (10-35 years) the core has been stored since drilling operations. The large increases in the Figure 26 S_2 values over background values not only provide evidence of the loss of oil to the drilling mud, but these increased S_2 values also allow us to roughly quantify this loss.

The pressure and temperature decrease that core and cutting chips undergo during the trip up the well bore during drilling will cause some, but not all, resins entrained in the oil to precipitate onto the rock surfaces. For the sake of discussion, let us assume that 50% of the oil-entrained resins precipitate onto the rocks, although it could be as low as 20% very easily. In Figure 26, consider the siltstones over the 10,194 to 10,222 ft (3,107.0 to 3,115.5 m) interval. An average S_2 value, which is largely made up of precipitated resins from Bakken oil, for this interval would be around 500 ppm and an average S_1 value around 200 ppm. Let us double the 500 ppm value to 1,000 ppm to represent all the resins originally in place before drilling occurred. Assume that the C_{14}+ fraction of the in-place Bakken oils in the siltstone are composed of 10% resins (after the data of Price and LeFever, 1994). Thus, at a minimum, 10,000 ppm (1 weight percent, or about 3.25 volume percent, of the rock) of oil was originally in the rock at depth, versus the 200 ppm now in the rock, a loss of 98% of the oil. If we assume that the 500 ppm S_2 peak (resins) represents only 20% of the original resins in the rock, we arrive at 2,500 ppm total resins in the rock, with 25,000 ppm oil originally in the rock, representing a loss of 99.21% of the in place oil. Moreover, Hempel oil distillation analyses of Bakken oils on file with the NDGS demonstrate that Bakken oils have abnormally high concentrations of C_{14}- material, a fact also noted by Muscio (1995). For example 50-65% of Bakken oils are made up by the kerosene and lighter distillation fractions. Thus, by assuming, as we did above, that the resins make up 10% of the C_{14}+ fraction of Bakken oils, as opposed to only 5% of the whole oil (a more realistic estimate), we seriously underestimated the oil loss from the core. *Whatever the percentage loss of oil to the drilling mud (and evaporation), this loss is clearly very large.*

In Figure 26, note that over the 10,224 to 10,234 ft (3,116.1 to 3,119.2 m) interval, the TOC and S_1 values are near background values, which would lead to the conclusion that little or no Bakken oil was ever in these rocks. However, the S_2 values lead to an exactly opposite conclusion. The S_2 (resin) values over 10,224 to 10,234 ft (3,116.1 to 3,119.2 m) are above background, and by going through the above calculations, one again would arrive at large losses of oil from the rocks of this interval. These losses would have decreased the S_1 and TOC values to near background levels. We conclude that in the reservoir rocks of the Bakken Source System, where the Bakken shales are mature, at least three parameters control the amount of oil which is measured in these rocks by either traditional-core or ROCK-EVAL analysis: 1) the amount of oil originally injected into the rocks at depth, 2) the percentage loss of oil to the drilling mud, and 3) the percentage loss of oil to evaporation during storage.

6.075 NDGS # 1405

ROCK-EVAL S_1 and S_2 peak values (in ppm) and TOC contents are shown for siltstones and Three Forks rocks adjacent to the lower Bakken shale in well NDGS # 1405 (Fig. 27). Again, background (beginning) TOC, S_1 and S_2 values are shown by the light dashed lines. NDGS # 1405 was drilled in an area of the basin where the Bakken shales are both thick (23 ft, 7.0 m of upper shale, and 26 ft, 7.9 m of lower shale) and mature, with ROCK-EVAL hydrogen indices of around 100 and T_{max} values of 450°C. Thus, the Bakken shales in NDGS # 1405 have gone entirely through intense HC generation. This fact is reflected in the data of Figure 27, wherein the most significant increases in TOC, S_1 and S_2 values from background levels are present for the three wells discussed here (Figs. 25 to 27) with mature Bakken shales. These maximal increases are mainly due to the fact that of the three wells with mature Bakken shales we have discussed (Figs. 25 to 27), NDGS # 1405 had: 1) the second thickest shales, 2) by far the most mature shales, and 3) the highest starting TOC values (discussed below, section 10.05). In other words, the Bakken shales of NDGS # 1405 generated by far the most oil of the three examples. Nonetheless, evidence directly below in section 6.076, also demostrates that the siltstone and Three Forks rocks of NDGS # 1405 still have also lost massive amounts of their in-place oil to the drilling mud. The data of Figure 27 document a massive injection of oil into the organic-poor rocks adjacent to the two Bakken shales. *These data are replicated every time ROCK-EVAL analyses of these rocks are carried out where the samples are core from a well where the Bakken shales are thick and mature and were originally very organic rich.*

6.076 Evidence of Oil Loss to the Drilling Mud and Evaporation during Storage

Because of the loss of generated HCS from source rocks to the drilling mud during the trip up the wellbore, Price (1994c) proposed that our petroleum-geochemical laws and working models regarding HC generation and expulsion were based on analyses of perhaps less than 15% of the generated HCS present in organic-rich source rocks at depth, and that these models and laws should, at the least, be re-examined. Understandably, these proposals were not readily accepted by the general petroleum-geochemical community. In fact, numerous petroleum geochemists took the trouble to express their opinion that they believed the above hypotheses were erroneous. As an aside, as noted by Price and LeFever (1992), well-site geologists and drilling engineers have recognized the loss of generated HCS from core and cutting chips to the drilling mud for over fifty years. Such individuals do not consider the wellbore loss of generated HCS to drilling mud to be a hypothetical situation, but instead consider such losses to be reality, because they witness these events at well site. In fact, these losses are responsible for the HC (gas and/or oil) shows, which are evidenced every time either a reservoir bearing HCS or an organic-rich shale is penetrated by the drill.

Thus, the opinion of some/many? petroleum geochemists that any loss of generated HCS from source rocks to the drilling mud would be insignificant contradicts years of well-site observations. Moreover, this "hypothesis" (a wellbore loss of generated HCS to the drilling mud) could easily be tested by petroleum-geochemical analyses of core and cutting chips of rocks from the same depth interval. Thus, core would be expected to retain more generated oil than cuttings chips, because of the larger surface area of cuttings chips (per unit weight of rock), leading to greater HC losses from cuttings chips. Within cuttings chips from a given interval, with decreasing cuttings-chip size, HC losses should increase, again due to increasing surface area. Both ROCK-EVAL and solvent extraction are amenable to such analyses, and the S_1 pyrolysis peak would be the best ROCK-EVAL based index to use, because the S_1 peak is largely equivalent to solvent-extractable HCS or free oil (Price et al., 1984). Thus, a study was commenced to verify the "hypothesis" of wellbore loss of HCS to the drilling mud using rocks from different petroleum basins, including the Williston Basin. The outcome of this research did demonstrate, as expected, a massive loss of generated HCS from both source rocks and from the rocks adjacent to them to the drilling mud during drilling operations. However, all the results of all this research need not be presented here. Instead, we will examine some of the data taken from Bakken Source System rocks because these data provide much insight to storage of oil in, and possible recovery of oil from, the Bakken reservoir rocks.

During coring operations, cuttings chips are manufactured by the coring tool, just as they are by a drilling bit. However, in most wells, coring chips are not normally collected over a cored interval. Figures 28 and 29 represent ROCK-EVAL data from 2 Williston Basin wells (NDGS # 1405 and 4340) where coring chips were collected over the cored interval. In Figure 28, ROCK-EVAL analyses (TOC, and the S_1 and S_2 peaks in ppm) are shown for the Bakken siltstone from NDGS # 4340, which is from a part of the Bakken HC kitchen where the Bakken shales are both thick and mature: 20 ft (6.1 m) of upper shale and 36 ft (11.0 m) of lower shale with ROCK-EVAL hydrogen indices of 180. The siltstone coring chips were taken from the 9,906 to 9,969 ft

(3,019.2 to 3,038.4 m) depth interval and were sieved to different sizes and each sieve size was analyzed (Fig. 28). In rocks from other basins, decreasing cutting chip sieve size did, as expected, result in an increasing loss of HCS. However, with the Bakken Source System reservoir rocks, this relationship was sporadic. In Figure 28, TOC does demonstrate a decrease with decreasing chip size; however, the S_1 and S_2 peak values are both invariant, and very low, versus chip size. In the siltstone coring chips, TOC varies between 0.10 to 0.15%; the S_1 peak varies between 5 and 25 ppm; and the S_2 peak varies between 40 and 60 ppm. These values are equivalent to the organic richness background values found in siltstones adjacent to immature Bakken shales (Table 4), namely TOC=0.12%, S_1=67 ppm and S_2=86 ppm. Thus, the coring chips have essentially lost all their migrated oil to the drilling mud.

Close-spaced (foot by foot) analyses of the siltstone core from NDGS # 4340 have much higher levels of organic richness compared to the levels from the cuttings chips: TOC contents exceed 0.4%, S_1 peak values reach 1,930 ppm, and S_2 peak values reach 550 ppm. Again, the S_1 peak values in this analysis are the most meaningful, as they are largely equivalent to free oil. These two sets of analyses have been carried out on the same siltstone rocks from one wellbore, and the core-cutting chips have suffered a massive loss of HCS compared to the core, because of the much greater surface area of the coring chips compared to the core. One may attribute the stark differences in the ROCK-EVAL data of Figure 28 to differences in handling or storage between the core and coring chips of NDGS # 4340. However, these same results have been replicated in the analysis of Bakken Source System rocks from all other wells so analyzed, and the NDGS # 4340 core and core cuttings have been stored together at Grand Forks for over 25 years.

The close-spaced core ROCK-EVAL data of the bottom half of Figure 28, like the data of Fig. 27, document a massive injection of oil into the rocks adjacent to the two shales compared to starting organic richness values for these rocks (Table 4). This is the common situation when Bakken Source System reservoir rocks are analyzed where those rocks are from basin areas where the Bakken shales are both thick and mature.

Figure 29 presents ROCK-EVAL data for another example from NDGS # 1405, the Three Forks shale from 10,818 to 10,846 ft (3,297.2 to 3,305.7 m), where both close-spaced (foot by foot) core and the coring chips from the cored interval were analyzed by ROCK-EVAL. Again the coring chips from the 10,818 to 10,846 ft (3,297.2 to 3,305.7 m) depth interval were sieved to different sizes, which were then analyzed. Decreasing coring-chip size had no relation to the ROCK-EVAL measurements, all of which are invariant; and again are very low. As in the previous case, the TOC, and S_1 and S_2 peak values for the NDGS #1405 coring chips are all in the range for background values for organic richness of Three Forks rocks where Bakken shales are immature (Table 4). In contrast, ROCK-EVAL analyses for Three Forks core over the same depth interval as the coring chips, again demonstrate much greater organic richness than the values found in the coring chips (Fig. 29). The data of Figure 29 show once more that there has been a complete loss of Bakken-shale generated HCS from the Three Forks coring chips, compared to values found in core itself. Figures 28 and 29 both demonstrate that the coring chips have endured the loss of almost all the measurable HCS they once held. However, other analyses demonstrate that the core of Bakken Source System reservoir rocks has also had huge losses of HCS.

Figure 30 shows two gas chromatograms of saturated HCS, one from a Three Forks core composite from the depth interval of study in Figure 29, and another from a core composite of lower Bakken shale from the same well (NDGS # 1405). Whereas the lower Bakken shale sample has a full component of C_{15}- HCS, the Three Forks composite has lost all C_{15}- HCS. (The small peaks at elution times of 15 minutes and less are due to contamination from the solvents used to work the Three Forks core composite sample up). Although this complete loss of C_{15}- HCS from the Three Forks core sample has significant implications concerning production of oil from the Bakken Source System, we will not discuss this point here. Be that as it may, the Bakken shale saturated-HC gas chromatogram serves as a standard of comparison by which to measure the loss of HCS from the Three Forks core. The comparison demonstrates that the HC loss from the Three Forks core has been extreme in that all C_{15}- material has been lost and material up to n-C_{22} has been severely depleted.

Thus far we have extracted and analyzed over 80 Bakken Source System reservoir rocks from areas where the Bakken shales are mature and achieved results equivalent to those of Figure 30 in all the extracted samples. For example, in Figure 31, saturated-HC gas chromatograms are presented for a core composite of lower Bakken shale from 10,575 to 10,588 ft (3,223.1 to 3,227.0 m) as well as from core samples of Three Forks shale, Bakken siltstone, and lower Lodgepole limestone. All these core originated from NDGS # 607 (Fig. 13), a well where the Bakken shales are in the middle of mainstage HC generation, with ROCK-EVAL hydrogen indices of about 300, and thus there has been a massive movement of Bakken-shale generated oil to the rocks adjacent to the shales. Again, the core of rocks adjacent to the two Bakken shales have a complete loss of C_{15}- HCS compared to the Bakken Shale. The spike in the n-paraffins between n-C_{21} to n-C_{23} is caused by core-box wax, a contaminant from the boxes wherein the NDGS # 607 core was stored. Gas chromatography was also performed on the aromatic HCS with the same results as evidenced in Figures 30 and 31: A complete loss of C_{15}- to C_{16}- aromatic HCS from the rocks adjacent to the Bakken shales, compared to the Bakken shales, which retained these HCS.

Chromatograms identical to those from the reservoir rocks in Figures 30 and 31can be "manufactured" by evaporating Bakken whole oils, thus removing C_{20-} (and all C_{15}-) compounds. We are carrying out such evaporations, the first results of which are shown in the oil-whole gas chromatograms of Figure 32. Over each chromatogram, the weight-percent loss of the oil to evaporation is shown. Evaporation of the Figure 32 oil samples was achieved by weighing capped 2-dram vials containing the original oil before evaporation. The vials were then uncapped and allowed to passively evaporate in a fume hood , samples 32C and D also being evaporated on an N-EVAP (nitrogen evaporator). The whole-oil chromatograms of Figure 32 have much larger unresolved humps than the saturated-HC gas chromatograms of Figures 30 and 31. This is because the Figure 32 gas chromatograms contain the high molecular weight resin and asphaltene fractions, whereas those of Figures 30 and 31 do not.

The Figure 32D chromatogram has retained a percentage of the original amount of the C_{13} n-paraffin, whereas the Figure 30B Three Forks shale chromatogram has lost all C_{15}- material, and the Figure 31B to 31D chromatograms have lost all C_{14}- material. Thus, there has been a significantly greater loss of material in the reservoir rock gas chromatograms of Figures 30 and 31 than there has in the "manufactured" gas chromatogram of Figure 32D. The gas chromatograms of Figures 30 to 32 all demonstrate that a huge loss of the original oil has occurred, during coring operations, from the Bakken Source System reservoir rocks even within core samples.

Besides the loss in C_{20}-saturated and aromatic HCS, there has also been a loss of high-molecular weight (C_{20}+) saturated and aromatic HCS from the oils in the rocks adjacent to the Bakken shales, preferentially leaving the higher-molecular weight resins and asphaltenes in these rocks. In Table 5, the normalized percentages of the sum of the saturated and aromatic HCS and the sum of the resins and asphaltenes are given for the three rocks of NDGS # 607 adjacent to the two Bakken shales (Figs. 31B to D). The equivalent analysis is given for a Bakken oil (NDGS # 12728 from Price and LeFever, 1994) which has a similar maturity to the NDGS #607 samples (Fig. 31). Thus, the Bakken shales from well NDGS # 12728 have ROCK-EVAL indices of 268 and the Bakken shales in NDGS # 607 have hydrogen indices of around 300. Note the greater percentage of resins and asphaltenes (and consequently lower percentages of HCS) in the bitumens from the NDGS # 607 rocks, compared to the NDGS # 12728 oil. A preferential loss of HCS from and a preferential retention of the resins and asphaltenes in, the residual oil of NDGS # 607 has caused these differences. Carrying out calculations to restore the lost oil in the NDGS # 607 core samples to the compositional normalcy of a Bakken oil, suggests that losses of 95 to 99% of the oil originally in the rock have occurred. These calculations thus support the level of oil losses estimated on the basis of the ROCK-EVAL S_2 peak (Section 6.074). Moreover, similar numbers result when the same calculations are carried out for residual oils extracted from other core samples of Bakken Source System reservoir rocks from other wellbores.

6.8 **Evidence and Causes of Super-Lithostatic Fracturing**

Leigh C. Price and Kathy Stolper

In 1993, Lake-Ronel Oil Company, Tyler Texas commissioned Petro Tech Associates, Houston Texas, to carry out a visual fracture study of Bakken Source System rocks from 14 wells. Kathy Stolper, then with Petro Tech Associates, carried out the study and 616 ft (187.7 m) of core were examined. In 1995, a copy of the report was forwarded to the author and in 12/97 Pete Lake, CEO of Lake-Ronel, extended permission to the author to include that study in this report. On the basis of the original fracture study carried out for Lake-Ronel, a much larger fracture study was undertaken with Stolper Geologic (Evergreen, Colorado). Figures 33 to 35 are from the newer fracture study, and Figures 36 and 37 are from the Lake-Ronel study. A listing of all the wells examined in both the Lake-Ronel fracture study, and the ongoing much larger fracture study is presented in Table 6.

6.081 NDGS # 11397 and NDGS #4958 Immature Bakken Shales

The most immature well for which Bakken Source System core is available is NDGS #11397, the Amoco Daniel Anderson #1 (NESE sec. 17 T160N R73W). As is evident from Figure 13, this well is far out on the eastern flank of the Williston Basin. Consequently, the Bakken shales in NDGS #11397 are at shallow depths of burial, with the top of the upper Bakken shale at 3,307.75 ft (1,008.15 m). In this well, there are 22 ft (6.7 m) of upper shale and no lower shale, and 31 ft (9.4 m) of Lodgepole Limetone, 13 ft (4 m) of Bakken siltstone, and 50 ft (15 m) of Three Forks shale were cored. Thus we have substantial vertical intervals of cored reservoir rocks at very immature ranks in this well to serve as a standard of comparison against the same stratigraphic units from wells from more mature basinal settings.

Figure 33A presents the core analysis of 15 ft (4.6 m) of Lodgepole Limestone from 3,292 to 3,307 ft (1,003 to 1,008 m). Moderate fracturing is present over this interval, with many of the fractures being vertical or diagonal. Notice that all but one of the fractures have small X's through them. These X's signify closed calcite-cemented fractures, which thus have no capacity to take up fluids. One vertical open fracture (colored red) was present at just above 3,300 ft (1,006 m). The fracture analysis of figure 33A is representative of the fracturing in all the rocks adjacent to the Bakken shales in NDGS #11397: fractures completely closed by calcite cementation, most fractures being vertical or diagonal in orientation.

Traditional core analysis of the rocks in NDGS #11397 revealed zero residual-oil saturation percentages. ROCK-EVAL analysis also demonstrated that no oil staining was present in these rocks, with the rocks having the background values of Table 4. We demonstrated above, by both traditional core analyses (Figs. 14-16) and ROCK-EVAL analyses (Figs. 20-23), that a progressive movement of Bakken shale generated oil occurred into the rocks adjacent to the Bakken shales, with increasing maturity of the Bakken shales, in basinal areas where the Bakken shales had not yet begun HC generation. This same pattern is present in the development of fracturing in the rocks adjacent to the two Bakken shales, versus increasing Bakken shale maturity, for Bakken shales at pre-HC generation stages.

Figure 33B is the fracture analysis from the Bakken siltstone from NDGS # 4958 (F. M. Ingerson #2, SWNE sec. 2, T161N, R91W). The Bakken shales in this well are thick (10 ft, 3.05 m of upper shale; 26 ft, 7.92 m of lower shale) and immature with ROCK-EVAL hydrogen indices of 630, production indices of 0.060 and a T_{max} of 422°C. Although the Bakken shales in this well have not yet begun mainstage C_{15}+ HC generation, they are relatively more mature than those in NDGS #11397 because of the greater burial depth of the NDGS #4958 Bakken shales. Thus the upper Bakken shale in NDGS #4958 occurs over 7,570 to 7,580 ft (2,307 to 2,310 m) versus 3,307 to 3,329 ft (1,008 to 1,014 m) in NDGS #11397.

For the first 11.5 ft (3.5 m) of the NDGS # 4958 siltstone, below the bottom of the upper Bakken shale, moderate fracturing is present, and the fractures are exclusively horizontal. This most unusual pattern is repeated in all Bakken Source System reservoir rocks: dominant horizontal fractures, which are never mineralized. The reasons for, and implications of, these observations will be discussed below. Unlike the fractures in NDGS #11397, the fractures in NDGS #4958 are all open, and able to take up fluids, including water. Thus, after wetting the core and after unfractured core surfaces have dried, the fractures bleed water, allowing the fractures to be mapped. The reason for this behavior is discussed below in section 10.064. However, for now it is a critical observation that all the fractures of Figure 33B are open fractures, two types of which have been delineated. "Micro-closed" fractures (blue fractures in Fig. 33B) are closed to the naked eye but under magnification reveal themselves to be open, with fracture aperture widths of 5 to 30 micros. "Micro-open" fractures (red fractures in Fig. 33B) are open to the naked eye with aperture widths generally 30 microns or greater.

As one proceeds downhole from 7,591.5 ft (2,313.8 m), fracturing intensity strongly decreases, largely disappearing completely by 7,600 ft (2,316.4 m). Essentially the bottom 30.5 ft (9.30 m) of the siltstone in NDGS # 4958, from 7,592.5 to 7,623 ft (2,314.1 to 2,323.4 m), is unfractured. Note a small vertical extent of siltstone just above the top of the lower Bakken shale at 7,624 ft (2,323.7 m) that is also moderately fractured. These observations were repeated in the reservoir rocks from other wells with immature (pre-HC generation) Bakken shales that we have examined: In basin locations where the Bakken shales are immature and have not yet begun HC generation, the rocks adjacent to the shales have a low to moderate intensity of horizontal fractures for limited vertical distances contiguous to the two shales. Further from these vertically-limited zones of fracturing, the rocks will be largely unfractured.

This fracturing in Figure 33 is hypothesized to be a result of an early (pre-HC-generation) CO_2-driven expulsion of indigenous bitumen from the Bakken shales into the adjacent rocks. As discussed both below (section 10.064) and in Price et al. (1998), copious amounts of CO_2 are generated at immature ranks from highly organic-rich source rocks (such as the Bakken shales) by water chemically reacting with kerogen, with the hydrogen from this water hydrogenating the kerogen, and the oxygen from the water being given off as CO_2. Moreover, as discussed in Price (1989a), C_2 to C_4 HC gases are generated in small amounts (as normalized to TOC) in rocks with all OM types before mainstage C_{15}+ HC generation commences. However, in very high-TOC rocks, such as the Bakken shales, even though only small amounts of carbon-normalized gases are generated, the amounts of gas normalized per rock weight can be substantial. As discussed below (section 6.086), the uptake of water by kerogen and resulting generation of CO_2 and C_1 to C_4 HC gases is a volume expansive reaction (the products taking up a greater volume than the reactants). In closed-fluid systems, such as the Bakken source system, volume-expansive reactions create abnormally high fluid pressures. Thus, we hypothesize that the generation of CO_2 and the C_1 to C_4 HC gases by the Bakken shales in NDGS # 4958 created an abnormally-high fluid pressure situation which fractured the upper part of the Bakken siltstone (just below the bottom of the upper Bakken shale, Fig. 33) in that well.

Immature Bakken shales (at pre-HC generation ranks) have very high concentrations of indigenous bitumen (Price et al, 1984). The early-generated gases would collect bitumen molecularly-dispersed throughout the Bakken shales and effect a gas-driven bulk-phase migration of oil from the shales into the adjacent organic-poor rocks, thus explaining the elevated residual-oil analyses (Figs. 15 and 16) and the elevated ROCK-EVAL analyses (Figs. 22 and 23) in the organic-poor rocks adjacent to the upper or lower Bakken shales, even where the Bakken shales are still immature, not having begun HC generation. Therefore, the fracturing, and the movement of oil into the rocks adjacent to the two Bakken shales appear to be linked.

Again, note that the bottom of the siltstone (Fig. 33B) has no fractures except for a 4.5 inch (11.4 cm) interval just above the top of the lower Bakken shale. This pattern of fracturing is repeated in all the immature wells we have examined with core over this interval, which is moderate fracturing over the top intervals of the Bakken siltstone just below the bottom of the upper Bakken shale, and minimal or no fracturing at the bottom intervals of the Bakken siltstone just above the top of the lower Bakken shale. This observation is due to the fact that where the Bakken shales have not yet begun HC generation, essentially all the fracturing energy from the lower Bakken shale is directed downward towards the Three Forks Formation, leaving the bottom of the siltstone largely unfractured.

6.082 NDGS # 8824 Slightly Increased Bakken Shale Maturity

Figure 34 is the fracture analysis from the siltstone from NDGS # 8824 (Koch 2-28 NWNE sec. 28 T162N R89W). The Bakken shales in this well are thick (11 ft (3.4 m) of upper shale, and 18 ft (5.5 m) of lower shale) and immature with ROCK-EVAL production indices of 0.048 and a T_{max} value of 428°C. However, by the T_{max} values, the Bakken shales in NDGS # 8824 are slightly more mature than those in NDGS # 4958 (428° versus 422°C), which is reflected in the siltstone fracturing in NDGS # 8824. Note in Figure 34 that moderate fracture intensity in the NDGS # 8824 siltstone extends for 18.3 ft (5.6 m) over the interval 7,038.7 to 7,057 ft (2,145.3 to 2,150.9 m) below the bottom of the lower shale, with less intense fracturing from 7,057 to 7,064 ft (2,150.9 to 2,153.0 m) for a total fractured interval of 25.3 ft (7.71 m), versus 11.5 ft (3.5 m) of fracturing in NDGS #4958 siltstone. Thus, a slight increase in maturity (rank) leads to a significant increase in fracture intensity. Moreover, this interdependence of increasing fracture intensity with increasing rank of the Bakken shales was noted for all wells we examined wherein the Bakken shales are at immature ranks and have not yet begun HC generation.

Notice in Figures 33B and 34, that there are unfractured intervals intermingled with fractured zones. This observation pertains to all the other wells that we have examined (Table 6), including wells from basin areas where the Bakken shales are mature, and where the reservoir rocks are thus intensely fractured. The observation arises from the fact that within each of the units adjacent to the two shales, there are lithological variations which determine fracture propensity. The point will not be detailed here; however, the end result is that some zones in the rocks adjacent to the two shales will be preferentially fractured, whereas other zones will remain unfractured.

This lithologic control of fracturing was also reflected in the ROCK-EVAL analysis of reservoir rocks from wells where the Bakken shales had begun HC generation (Figs. 25 to 29). In those analyses, heavily-stained samples were interbedded with samples which had only moderate or no detectable oil staining. This variance in the ROCK-EVAL analyses could be attributed to differential loss of the migrated oil from the reservoir rocks to the drilling mud. However, that explanation is not believed to be the cause. Instead, we attribute the differences in the ROCK-EVAL analyses to the original migration of Bakken shale oil into the rocks adjacent to the shales. Comparison of the ROCK-EVAL analyses to both the fracture analysis and the lithology of the analyzed sample reveals that samples with more massive lithologies, which have less propensity to fracture, have lower values of oil staining than more fractured samples. Thus, the fracturing in, and oil migration into, the rocks adjacent to the two Bakken shales are linked, with the fractures serving as the pathways for oil migration. In this light, fractured intervals of reservoir rock will be heavily oil-stained, whereas unfractured intervals of rock will not be as stained, thus explaining the variance in the ROCK-EVAL analyses of Figures 25 to 29, a variance which is repeated in the reservoir rocks of all the other wells we have analyzed, including wells where the Bakken shales are mature (Table 3).

From the above discussion, it is obvious that the ROCK-EVAL S_1 peak analyses give a more realistic measurement of oil distribution in the Bakken Source System reservoir rocks than do the residual-oil saturation measurements from traditional core analyses. These latter analyses are performed and reported in such a manner that any measured oil is *assumed* to exist continuously throughout the analyzed sample (API, 1998). As such, residual-oil saturation analyses for Bakken Source System reservoir rocks portray reservoir rocks continuously stained by oil where the Bakken shales are thick and have begun HC generation (see Figures 16, 17, and 19). However, point by point ROCK-EVAL analyses demonstrate that the oil distribution is not a continuous saturation from a diffusive type of migration mechanism, but instead is variable, being a function of the associated fracturing. Whether or not Bakken Source System oil is diffused continuously throughout these low-porosity, low-permeability reservoir rocks (as suggested by traditional core analysis), or is concentrated along a very well interconnected fracture system is a pivotal point, because possible economic recovery of Bakken Source System oil hinges on this point.

We believe that ROCK-EVAL analyses of Bakken Source System reservoir rock core are more accurate than, and are thus preferred over, residual-oil saturation percentages from traditional core analyses. However, both types of analyses corroborate each other and document a massive migration of oil from the Bakken shales into the adjacent reservoir rocks. This migration is caused and accompanied by massive horizontal fracturing in these rocks.

6.83 NDGS #13098 Mature Shales-Bakken HC Kitchen

The NDGS #13098 (Oryx, Stenehjem 27-1, SWNE sec. 27, T150N, R97W) was drilled where the Bakken shales are thick (21.5 ft, 6.55 m of upper shale; 24.5 ft 7.47 m of lower shale) and ultra mature, with ROCK-EVAL hydrogen-indices of 50. Figure 35 presents the fracture analysis for 15 ft (4.6 m) of middle Bakken siltstone, which is representative of the total of 42.5 ft (13.0 m) of middle Bakken siltstone in this well. The fracturing in Figure 35 is an example of the end scale of the most intense fracturing of the Bakken Source system reservoir rocks encountered in our fracture study, regarding fracture continuity through the core, fracture aperture width, number of fractures per linear foot of core, and fracture interconnection.

Because of the greatly-increased fracture intensity in going from NDGS #8824 (Figs. 34A and B) to NDGS #13098 (Fig. 35), much smaller pen widths had to be used to map the fractures in the case of NDGS #13098. Thus the thinner lines in Figure 35 do not signify fractures with smaller aperture widths, in fact just the opposite is true as fracture aperture widths in the NDGS #13098 reservoir rocks often exceed 1 mm. The principal observation to be made regarding Figure 35, is that in all areas of the Williston Basin, where the Bakken are both thick and mature, the rocks adjacent to the Bakken shales usually are intensely laced with large open, unmineralized fractures, and the fractures are dominantly horizontal.

Again, note in Figure 35 that both moderately-fractured and unfractured intervals are present between the intensely-fractured intervals. The unfractured intervals are massive well-cemented sandstones interbedded with the more silty units. Thus even in basin areas where fracturing intensity in the Bakken Source System reservoir rocks is maximized, there is still a strong lithological control on fracturing, with the more massive lithologies being unfractured to only slightly-fractured.

6.084 NDGS #12160 Thin Moderately-Mature Shales

NDGS # 12160 (Meridian Oil Inc. 44-13, SESE sec. 13, T145N, R104W) was drilled in the Fairway area where the Bakken shales are thin (3ft, 0.9 m of upper shale, lower shale missing) and also are only moderately-mature (ROCK-EVAL hydrogen indices of 510). In Figures 33 to 35, we considered only the siltstone; however, Figure 36 demonstrates that the fractures present in the siltstone, and the intensity of these fractures, are also present in the other two reservoir rocks adjacent to the shales. Note that the Lodgepole interval between 10,754 to 10,757 ft (3,227.7 to 3,278.7 m) is intensely fractured. On the other hand, Lodgepole rocks from 10,759 to 10,767 ft (3,279.2 to 3,281.6 m) have only sparse or no fracturing. This again illustrates the point made above, that different intervals within any given unit adjacent to the two (or one) Bakken shales have different propensities to fracture, dependent on lithology. The massive basal Lodgepole (10,757.5 to 10,767 ft (3,278.7 to 3,281.6 m) in Fig. 36) has among the lowest fracture propensity of all the rock lithologies adjacent to the two Bakken shales. For the interval that was cored, the Three Forks Formation was comparatively intensely fractured. As with the previous wells, the fractures are dominantly horizontal, with no mineralization.

Another observation regarding NDGS #12160 is its cumulative production of Bakken oil, which was 82,861 barrels, an amount produced from a Fairway well with only 3 ft (0.91 m) of only moderately-mature Bakken shale (ROCK-EVAL hydrogen indices of 510). Moreover the fracture system which produced this oil was relatively weak compared to examples from the Bakken-shale HC kitchen proper, where the shales are thick and overmature. For example, compare the Fairway NDGS #12160 fracture system (Fig. 36) with the kitchen example (NDGS #13098, Fig. 35). The cumulative production from NDGS #12160 gives some indication of what the productive capability might be for a properly-drilled and completed well in the Bakken HC kitchen, where the shales are thick (40 ft, 12.2 m or more), mature (ROCK-EVAL hydrogen indices of 50 to 150), with higher starting TOC values and hydrogen indices compared to Fairway shales.

The observation regarding the fracture intensity in NDGS # 12160 applies to all the Fairway wells we examined in our fracture study (Table 6; NDGS #7579, 7851 7887, 8251, 8363, 8474, 8709, 8902, 9426, 9569, and 12160): Namely, the fracture intensity of the reservoir rocks from all these wells in as much less than that in wells from areas of the Bakken HC kitchen where the Bakken shales are both thick and mature ("the Bakken HC kitchen proper"). Thus, the fractures in Fairway rocks comparatively would have much smaller aperture widths (generally less than 30 microns), not take up fluids as well, and be much less concentrated (fractures/linear foot), than the fractures in rocks from the Bakken HC kitchen proper. This observation is because the fracturing event in the Fairway was significantly less intense than that in the Bakken-HC kitchen proper for different reasons. The most important of which is that Bakken shale HC generation (which causes the abnormal fluid pressures responsible for the fracturing) was significantly less intense in the Fairway area compared to the Bakken HC kitchen proper. This is because Fairway Bakken shales are much thinner, and had lower starting TOC contents and ROCK-EVAL hydrogen indices than "Bakken kitchen proper" shales. That in spite of these observations, there were numerous prolific productive wells in the Fairway again provides an indication of what properly-drilled and completed Bakken wells in the Bakken HC kitchen, with thick and mature shales, would be capable of.

6.085 NDGS #11689

In the original Lake-Ronel fracture study, sequences of rock in two wells (NDGS # 6437 and # 11689) were incorrectly identified as Bakken Source System rocks, and PetroTech was requested to analyze both sequences. However the "error" was beneficial, because it provided a standard of comparison of "normal fracturing" in the Williston Basin to the fracturing in Bakken Source System reservoir rocks. One of these rock sequences was 62ft (18.9 m) of rocks from 10,280 to 10,342 ft (3,133.2 to 3,152.1 m) in NDGS # 11689 (the Sonat 1-30 Glenn, NENW sec. 30 T155N R101W). This core was mislabeled during coring and is actually composed of Devonian Birdbear or Duperow Limestone, some 350 to 500 ft (107 to 152 m) below the bottom of the lower Bakken shale (Julie LeFever, NDGS Personal Communication 7/96). A 30 ft (9.1 m) portion of the analyzed interval from NDGS # 11689 is shown in Figure 37, and is representative both of the entire 62 ft (18.9 m) interval analyzed from NDGS # 11689 and of the entire 27 ft (8.23 m) non-Bakken interval analyzed from the other well: the Home Petroleum Marie Sherven #1 (NDGS # 6437, NWSW Sec. 26 T153N R95W). In the Sherven-1, the top of the upper Bakken shale is at 10,321 ft (3,145.7 m); however, upper Lodgepole rocks were cored from 10,070 to 10,097 ft (3,069.2 to 3,077.4 m), some 224 to 251 ft (68.3 to 76.5 m) above the top of the upper Bakken shale, and thus outside of the Bakken Source System. Both NDGS # 11689 and # 6437 are in the mature portion of the Williston Basin. The fracture analysis of Figure 37 is presented to demonstrate: 1) what the normal fracture pattern is for the carbonate-rich rocks sealing the Bakken Source System in the Williston basin, and 2) that the aberrant fracture pattern of Figures 33 to 36 is not pervasive throughout all deep Williston basin rocks. Indeed the fracture pattern in Figure 37 is typical for rocks in basins worldwide, including the deep rocks of the Williston Basin

An observation in Figure 37 is pivotal concerning the seal trapping Bakken-generated oil in the reservoir rocks adjacent to the Bakken shales. There are few open fractures in the rocks of Figure 37, those that are present being shown by the blue dotted lines. Moreover, these open fractures for the most part of discontinuous and isolated from one another. As an aside, the "micro-closed" (reddish orange) fractures of Figure 37 indeed are closed, and cannot take up water, unlike the "micro-closed" fractures of Bakken Source system rocks. The rocks of Figure 37 also have low matrix permeabilities (less than 0.01 millidarcies). Because of these characteristics, the rocks of Figure 37 have no capacity for fluid transmission and form the lower seal trapping Bakken Source System oil. The fracture analysis carried out on the NDGS #6437 middle Lodgepole core demonstrates that an analogous situation also creates a seal above the

Bakken Source system. The horizontal fracturing which stores Bakken Source System oil extends for some distance above and below the Bakken shales, at least 100 ft (30 m) in both directions. However, there are limits to this fracturing, and above and below this fracturing exist very effective seals.

In Figure 37, vertical or off-vertical fractures make up a dominant part of the fracture population, with only subordinate horizontal fractures. Moreover, most of the fractures are mineralized, with calcite, and/or dolomite and pyrite, in stark contrast to the completely non-mineralized, predominantly-horizontal fractures of the oil-wet Bakken Source System. To create a predominantly-horizontal fracture system, the earth's stress fields must either be suspended (which of course is impossible) or superceded, because the earth's existing stress fields dictate vertical, or off-vertical, fracture formation (William Perry, USGS Energy team, Personal Communication 8/96; Hills, 1963; Hobbs et al., 1976). Thus, dominantly-horizontal fracture patterns are normally considered physically impossible, because their existence demands that the weight of the overlying column of rocks would have to be exceeded. In other words, super-lithostatic pressures would have to be created.

Because horizontal fractures normally are considered geologically impossible, previous investigators who have observed them in core of the rocks adjacent to the Bakken shales have dismissed these fractures as due to dessication or man-made causes. In other words, these fractures could not have possibly been formed in situ at depth. Moreover, many of the fractures in these rocks are closed to the naked eye and are difficult to observe unless one is either specifically looking for them (which in previous investigations, was not the case) or is using the unorthodox wetting technique that we employ to map them. Thus, because of the unique nature of the fractures in the Bakken Source System reservoir rocks, those fractures previously went unrecognized. Consequently, industry never realized which rocks were holding the Bakken Source System oil, or how that oil was being held. Thus, although industry assumed that the oil was being held by *vertical fractures in the Bakken shales,* the oil is actually held in *horizontal fractures in the rocks adjacent to the Bakken shales.*

Lastly, the occurrence and intensity of the horizontal fractures in the Bakken Source System reservoir rocks have a strong positive correlation with the thickness and maturity of the Bakken shales. The abnormal pressures created by the Bakken shales during HC generation are the only explanation, of which we are aware, that can explain these fractures.

6.086 Causes of Super-Lithostatic Fracturing

As discussed above, Meissner (1978) insightfully first hypothesized that HC generation reactions are volume-expansive reactions: The products (oil and gas) of the reaction occupy a greater volume than the reactants (kerogen). Thus, when these reactions take place in closed-volume systems, abnormally-high pressures are generated, pressures significantly greater than the pressures along a hydrostatic-fluid-pressure gradient. Ungerer et al. (1987) later provided calculations supporting Meissner's (1978) hypothesis. The intensity of abnormal fluid pressures thus created by HC generation would depend on the organic richness, the thickness, and the maturity of the source rock. As noted, the Bakken shales are very organic-rich (world-class) source rocks. Moreover, the rocks adjacent to these shales are impermeable to fluid flow, especially where the Bakken shales are mature, forming a closed-fluid system, a fixed-volume reaction vessel for the Bakken shales, if you will. As HC generation proceeded in the Bakken shales, eventually the abnormal fluid pressures resulting from the HC-generation reactions exceeded fracture pressure, and the system failed.

Engineering and production data on file with the NDGS provide insight into the magnitude of the volume expansion of the OM during HC generation in the Bakken shales. NDGS production data demonstrate that gas/oil ratios for Bakken oils from mature basin areas, where the gas from the wells was not flared, are 1,100 standard cubic feet/barrel (SCF/Bbl) on average. This is in the range quoted by Price and LeFever (1992). Moreover, data provided by Price and Schoell (1995), and much more data on file with the NDGS, demonstrate that mature Bakken gases are very wet (around 71% C_1, 17% C_2, 8% C_3, and 4% C_4's, by volume), which equates to an average molecular weight of 25.26 grams (g)/mole for mature Bakken gases. By the ideal gas law, 1 mole of gas = 22.4 liters (L), and there are 28.316 L/SCF. Thus, 28.316 L/SCF x 1,100 SCF = 31.147 x 10^3 L÷22.4 L/Mole = 1.39 x 10^3 moles of gas in 1,100 SCF. In 1.39 x 10^3 moles of Bakken gas, there are 1.39 x 10^3 moles x 25.26 g/mole or 3.5123 x 10^4 g. Assume 42° API (0.815 g/cc specific) gravity Bakken oil. An American barrel of oil = 158.98 L or 158.98 x 10^3 cubmic centimeters (cc) x 0.815 g/cc = 129.57 x 10^3 g, versus 35.123 x 10^3 g of gas dissolved in that oil. Thus, 78.67% by weight of the products generated from Bakken kerogen are oil, and 21.33% by weight are C_1 to C_4 gases, which as we shall see, represents a huge volume expansion of OM during HC generation.

Kinghorn and Rahman (1983) have measured the specific gravities of various kerogens, including five immature type II kerogens with H/C ratios ranging from 1.23 to 1.46. These five samples of Kimmeridgian and Triassic shales are thus equivalent to the organic richness of the Bakken shales. The specific gravities of these five kerogen samples largely ranged between 1.34

to 1.45 g/cc. Thus we will assume a specific gravity of Bakken kerogen at immature ranks of 1.40 g/cc for our calculations. In contrast, 42° API gravity Bakken oil has a density of 0.815 g/cc. However, because so much gas is dissolved in the oil, the density of the fluids, even at the high pressures of reservoir conditions, is much less. A fluid recombination study (on file with NDGS) for the Federal DL-1 (NDGS-11292) allows us to estimate the percentage of this volume increase. The Federal DL-1 is a Fairway well which produced 221,668 Bbls of oil. Relavent data for the fluid recombination are: reservoir pressure and temperature 5800 psi (394.6 atm) 246°F (119°C) at 10,406-10,432 ft (3,171.6 to 3,179.5 m). Oil gravity was 43.6° API (0.8081 specific) with a gas/oil ratio of 1092 SCF/Bbl. The recombination analyses resulted in a calculated oil density of 0.6234 g/cc at reservoir conditions. This represents a 225% volume increase in going from kerogen at 1.40 g/cc to the reservoir fluids.

However, all of the products from the HC-generation reaction have not yet been considered. The other principal product would be spent kerogen, which, depending on the hydrogen-index loss, would have its density increased to values above the starting density of 1.4 g/cc. Let us assume for discussion that the hydrogen-index has been decreased from a starting average value of 625 to 100 (or a loss of 52.5% of the OM by weight). What would the ending density of the kerogen be? Kinghorn and Rahman (1983) give one example of a mature type II kerogen (their sample number 612), which has an estimated R_o value of 1.97%, an elemental kerogen H/C ratio of 0.37 and a density range of 1.53-1.65 gm/cc. However, this density value seems too low, especially compared to other of their samples, which are composed of type III OM, and which have elemental kerogen H/C ratios of 0.45 to 0.59, and density ranges of 1.65 to 1.81 g/cc. From Tissot and Welte's (1984) cross plot of kerogen elemental H/C ratios versus the

ROCK-EVAL hydrogen index (their Figure V. 1.11), a hydrogen index of 100 would correspond to an H/C ratio of 0.72. Thus, from the data of Kinghorn and Rahman's (1983) tables 3 and 5, we will assume that an elemental kerogen H/C ratio of 0.72 corresponds to a kerogen density of 1.75 gm/cc.

Therefore, a conversion of 1 g of Bakken kerogen (with an original volume of 0.7143 cc = 1g/1.4 g/cc) to generated products and kerogen with a hydrogen index of 100 would result in kerogen with a volume of 0.5714 cc, or a volume loss of 0.7143-0.5714/0.7143 = 20%. Hence, our volume increase of 225% must be reduced by 20%, or 0.8 x 225% = 180%, to take into account the increase in kerogen density. Likewise, this number (180%) must be further discounted because the Bakken shales decreased in thickness as HCS (oil and gas) were generated and expelled from the shales. This point is discussed in detail, with calculations, below in Section 10; however, we will go through a representative example here. Assume an immature shale with a starting TOC of 18%. 18.0 weight % TOC corresponds to 18.0%/0.844 = 21.33 weight % OM, because elemental analyses we have carried out on immature hydrogen-rich Bakken kerogen demonstrates that it is composed of 84.40% carbon on average. The volume percent occupied by the OM would be 21.33/1.4 g/cc/21.33/1.4 g/cc + (100-21.33)/2.72 g/cc, where 1.4 g/cc is the density of the kerogen, and 2.72 g/cc is the density of the mineral matter, or 34.49 volume percent. Assume a starting hydrogen index of 625 and a final hydrogen index of 100 in the mature shale, or a hydrogen index loss of 525, which would represent a loss of 52.5 weight percent of the OM during HC generation. Thus, 0.525 x 34.49 volume percent = 18.11% of the shale volume is lost to HC generation. Therefore, we must decrease our volume expansion estimate of 180% by 18.11%, to take into account the loss of shale thickness, leaving us with 147.4% volume expansion from HC generation.

Another aspect of this creation of abnormal fluid pressures by HC generation in the Bakken shales, and most likely in some other source rocks, has gone unappreciated by previous workers. As demonstrated above, the Bakken shales have very high volume percentages of OM, because of the density differences between kerogen versus the mineral matter in the shales. For example, starting TOC contents of Bakken shales, generally range between 15 to 25% (or higher) by weight. As discussed above, kerogens in immature Bakken shales with high hydrogen indices are composed of 84.4% carbon. Thus, TOC contents of 15 to 25 weight % convert to OM contents of 15/0.844 to 25/0.844 or 17.77 to 29.62 weight % OM. As also discussed above, in the Bakken shales, the OM (kerogen) has a density of about 1.4 g/cc and the mineral matter, on average, has a density of 2.72 g/cc. Thus, an OM content of 17.77 weight percent, would convert to a OM content of 17.77/1.4 g/cc/17.77/1.4 g/cc + 100-17.77/2.72 g/cc, or 29.57 volume percent. Likewise an OM content of 29.62 weight percent is equivalent to 44.98 volume percent. Thus, immature Bakken shales are composed of 30 to 45% volume % kerogen. Kerogen is highly compressible compared to solid mineral matter. Therefore, a large percentage of the energy manufactured by the abnormal fluid pressures created from HC generation would have been stored in compressing the kerogen in the Bakken shales. Only when the kerogen reached its limits of compression, could the abnormal fluid pressures from the HC generation process build up to, and exceed, fracturing pressures.

However, when fracturing pressures were finally exceeded and rock failure did occur, much more energy was released than as originally perceived by Meissner (1978), and subsequent investigators, because of the large amount of potential energy stored in the compressed kerogen. Thus, at rock failure, this energy of compression would have been instantaneously released, temporarily generating fluid pressures significantly above lithostatic fluid pressures. Therefore, a super-lithostatic fracturing event would have been created, resulting in much more intense fracturing than originally perceived. Meissner (1978), and later Momper (1980), envisioned such pressure buildups, and subsequent oil-expulsion events, to progressively take place as a series of episodic pulses as HC generation proceeded. We agree. The end result of these super-lithostatic episodic-fracture events generated by the Bakken shales would be well-interconnected reservoirs in the rocks adjacent to the two Bakken shales. Moreover, the oil generated by the Bakken shales would be principally stored in, and transmitted by, the fracture network thus created.

6.087 Consequences of Super-Lithostatic Fracturing

Late-stage infill development drilling in large old onshore U.S. oil fields has demonstrated that many (most?) conventional sandstone and carbonate reservoirs are "compartmentalized" (Longacre et al., 1996). That is, certain parts of the reservoir are not in fluid communication with other parts of the reservoir, and the reservoir is made up of separate fluid compartments. Therefore, some late-stage infill wells encounter "virgin" reservoir fluid pressures (fluid pressures equivalent to those measured when the field was first discovered). Hence, industry has come to realize that conventional oil reservoirs are much more heterogeneous than first suspected.

However, bottom-hole pressures and well histories (neither of which will be discussed in this paper) for many Bakken producing wells on file with the NDGS and the North Dakota Industrial Commission (NDIC) suggest that the "reservoir" rocks for the Bakken oil may be among the best-interconnected reservoirs in the world. This might be expected, because every drop of oil in these reservoir rocks had to have been fed by interconnected fracture systems emanating from, and leading back to, the Bakken shales. This is because the very low fluid transmissibility in the matrix of the Bakken Source System reservoir rocks dictate that fractures leading back to the shales are the only possible avenue of fluid transport. The thickness and organic richness of the Bakken shales, the brittle nature of the reservoir rocks, and the super-lithostatic episodic oil-expulsion events from the Bakken shales all would suggest that the fractured reservoirs of the Bakken Source System would be well-interconnected over very large areas. The bottom-hole pressure and well-history evidence, referred to above, demonstrate that these expectations are, in fact, reality. Significant implications thus result concerning optimum methods for economic recovery of the in-place unconventional Bakken Source System oil-resource base.

The high residual-oil saturation percentages of Figures 17 and 19 provide evidence of the episodic super-lithostatic expulsion events discussed above. Given the tight nature of the rocks adjacent to the Bakken shales, there is no known mechanism by which the residual oil of Figures 17 and 19 could have been introduced into the porosity of these rocks. This is especially true considering that water was already present in this porosity before the oil was introduced. The presence of this oil could be partially explained by super-lithostatic pressure injection events occurring during the expulsion of oil from the Bakken shales.

By the above discussion, the energy of a Bakken shale fracturing event is expected to be partially dependent on Bakken shale thickness. This is because thick shales would store more energy of compression than thin shales. Thus, increasing fracture intensity and increasing residual-oil saturations should be linked to shale thickness. This expected pattern of increasing fracturing and residual-oil concentrations, versus Bakken shale thickness and maturity, are present in all wells for which conventional core analyses are available and/or which have been examined in our ongoing fracture study. As noted above, reservoir rocks associated with thick mature Bakken shales have significantly more intense fracturing and higher residual-oil concentrations compared to reservoir rocks in the Fairway at the same maturity, but where the Bakken shales are much thinner.

6.088 IFP's Position of Hydraulic Fracturing

Some investigators, especially those at the Institut Francais du Petrole (IFP), have taken the position that HC generation, even in extremely rich source rocks such as the Bakken shales, is incapable of creating enough of a volume expansion to create high enough pressures to fracture rocks, much less to create superlithostatic pressures. Thus, Burruss and Rudiewicz (1994, p. 3/4) note, "Hydraulic fracturing seems to be less frequent than often thought. Calculated P/S ratio very rarely exceeds 0.90 during the development of a sedimentary basin, even if rocks have low permeabilities, like compacted shales. This means that hydraulic fracturing is an efficient expulsion accelerator only if extensional tectonics prevails." Burrus et al. (1996, p. 287) also concluded that,

> "Despite the low permeabilities and the development of overpressures, mature Bakken shales do not seem to have reached hydraulic fractionation thresholds, except locally in regions of extensional tectonic stress. Hydraulic fracturing cannot be viewed as a pervasive mechanism driving Bakken oil expulsion."

The opinions of Burrus and coworkers concerning the ability of rich source rocks to effect hydraulic fracturing are completely antithetical to a very large body of data from the Bakken

Source System. These data demonstrate that a large volume increase occurred during HC generation in the Bakken shales. This large volume increase in turn created super-lithostatic fluid pressures, which in turn effected massive "geologically impossible" horizontal hydraulic fracturing in the rocks adjacent to the Bakken shales. The intensity of this fracturing is in turn directly linked to Bakken shale maturity and thickness. Lastly, we note that the opinionsof Burrus and coworkers on the topic of rich source rocks causing hydraulic fracturing are unsubstantiated by hard data from the natural system, but instead derived from models. As will be discussed below, original erroneous inputs to these models yielded results copesetic with preconceived conclusions of Burrus and coworkers.

6.089 Bakken Soruce System Oil to Water Ratios

Table 7 presents oil and water cumulative production data, and oil to water ratios, for Fairway horizontal wells which produced over 100,000 barrels of oil. Oil to water ratios range between 60 to 1350 for all but one case, with most of the values ranging between 200-800 with a median value of around 300. Such elevated oil to water ratios are both unheard of in conventional oil fields and provide testimony that a very unusual situation exists in the reservoirs holding this oil, towit: The Bakken Source System is a completely oil-wet system. Price and LeFever (1992) previously pointed this fact out and provided data supporting their conclusion (their table 3).

This system is water starved for several reasons: First, the Bakken Source System is a huge closed-fluid compartment which outside water has no access to. Second, as discussed below in section 7.102, what water was originally in the system was consumed by the Bakken shales as they generated HCS. Third, an oil only phase was generated by, and migrated from, the Bakken shales to create the fractures it the rocks adjacent to the shales, fractures that store the oil. Thus, these fractures since their creation have only been exposed to oil, and have never seen water. What water is coproduced with the Bakken oil is either: 1) dissolved in the Bakken oil, exsolving during production, or 2) produced from the matrix porosity of the reservoir rocks (Figs. 14-19).

The oil-wet nature of the Bakken Source System carries two important implications: First, industry has generally failed to recognize that this system is oil-wet. Consequently, the possible damage which could occur to Bakken Source System reservoirs during aqueous-based completions or workovers has gone unappreciated. Second, the very unusual oil-wet nature of the Bakken Source system provides important evidence of some of the process controls responsible for the origin of this system, controls which are discussed below.

6.09 **Implications to Source Rock Expulsion**

The research we have carried out on the Bakken Source System has three important applications. First, it documents the existence of this very large unconventional oil resource base, which is the principal point of this paper. Second, it provides detailed information about, and characteristics of, the large in-place oil-resource base of the Bakken Source System, information which may aid in the economic recovery of the resource base. Third, and this is the point which concerns us here, is that such research also provides us with possibly important insights to process controls of the origin of conventional oil (and gas) deposits, in other words, how petroleum systems work, including the largest remaining enigma of petroleum systems: source rock expulsion.

To briefly review, as discussed above in section 3.04, the accepted, and nearly universal, view of source-rock expulsion and oil and gas accumulation into conventional deposits is that expulsion is very efficient and accumulation into traps is very inefficient. Cooles et al. (1986)

quantified this viewpoint with an expulsion model that is nearly universally employed in the oil industry. By this model, 80-95% of the HCS generated by even moderately-rich source rocks are thought to be expelled from their source systems, and most of the expelled HCS are lost over geologic time, usually only a small percent accumulating into traps. This model is widely used in petroleum-geochemical modeling for both petroleum exploration and resource assessment. Interestingly, the foundation for the model can be directly traced back to the papers of Dow (1974) and Williams (1974) both of which involved the assumption of efficient oil expulsion from the Bakken shales, which were proposed to have sourced the conventional mid-Madison oil deposits in the Basin. However, later comparison of mid-Mississippian Madison oils to Bakken oils in the Williston Basin (Price and LeFever, 1994) revealed that these were two separate oil families, sourced by two different source rocks.

In light of these observations, Price and LeFever (1994) concluded that the accepted model of source rock expulsion was dysfunctional in the very basin from which was originally derived, and Price (1994a) proposed an alternate model of expulsion and accumulation (discussed in section 4.06). To briefly reiterate that model: Petroleum depocenters are closed-fluid systems where expulsion of oil and gas from source rocks is difficult and is therefore highly inefficient, in contrast to the accepted viewpoint. Moreover, source rocks must be physically disrupted, or be directly adjacent to a good conduit, for significant source-rock expulsion to occur at all.

The work carried out on the reservoir rocks adjacent to the Bakken shales (conventional core and ROCK-EVAL analyses, and fracture description) allow us to gauge, in this case, how far the natural system departs from accepted models regarding source rock expulsion. Data presented below in section 10.05, allow the deduction that in the two principal Bakken HC kitchens of

North Dakota and Montana where shales are thick and mature, starting TOC contents were a little under 30% by weight of the rock. In these two principal HC kitchens, large areas exist where ROCK-EVAL hydrogen indices of the Bakken shales range from 50 to 150. As also discussed below, average starting ROCK-EVAL hydrogen indices of the Bakken shale were 625, with a range of 550 to 800. Thus, the argument can be made that the Bakken shales are either the, or one of the, world's richest source rocks, where large volumes of a rock have gone completely through mainstage generation.

Both the traditional core and ROCK-EVAL analyses demonstrate a basin-wide movement of oil from the Bakken shales into the adjacent rocks, a movement which commences at pre-HC generation stages of Bakken shale maturity. Moreover, by the time the Bakken shales commenced HC generation, the rocks adjacent to the shales had been heavily stained with migrated oil from the Bakken shales, continuously for at least 50 ft (15 m) above and below the shales. This is an important observation, because it corroborates the hypothesis of Price and Clayton (1992) that organic-rich source rocks at immature (pre-HC generation ranks) are capable of sourcing commercial deposits, if a viable secondary-migration path exists between the source rock and reservoir. This possibility has important exploration and resource-assessment implications.

Once the Bakken shales commenced mainstage C^{15}+ HC generation and lost values of 50 to 75 from their starting hydrogen indices, the rocks adjacent to the shales were pervasively fractured for distances of at least 80 to 100 ft (24 to 30 m) from the shales. This fracturing was caused by the abnormal pressures created by the volume expansion of OM during HC generation. Moreover, the fractures thus generated are almost all horizontal fractures, a most unusual situation. As the Bakken shales proceeded through HC generation, the concentration (fractures per foot), intensity (aperture width and length), and the vertical distribution of fractures both above and below the shales, all increased. *Although the Bakken shales, arguably the richest source rocks in the world, caused all these events, the shales never expelled any oil into a conventional deposit.*

The behavior of the Bakken shales in this regard is a *serious* contradiction to the accepted model that source rock expulsion is very efficient. In fact, in the case of the Bakken Source System, quite the opposite is true, source-system expulsion has been perfectly inefficient. One may only conclude that the accepted model of source rock expulsion is highly flawed and requires significant correction. This correction is all the more important because assumptions about the most important aspects of petroleum systems, the amount of oil a source system expels, are made on the basis of this model Moreover, these assumptions have a profound affect on both HC exploration and resource assessment.

6.10 Discussion and Conclusions: Bakken Reservoir Rocks

Both traditional core analyses (porosity, permeability, residual-oil saturations, and visual observations) and several types of petroleum-geochemical analyses document a massive injection of oil generated by the Bakken shales into the organic-poor rocks adjacent to the shales basin-wide, wherever the Bakken shales were marginally-mature to mature. The presence of mobile oil in the Bakken Source System is also evidenced by the oil shows encountered every time these rocks are penetrated by the drill bit where the Bakken shales are at least marginally-mature. Theoretical considerations suggest that the expulsion of oil from the Bakken shales to the adjacent reservoir rocks occurred via episodic super-lithostatic pressure events, events which also created a massively-fractured, well-interconnected reservoir. Both high residual-oil saturations and high ROCK-EVAL S_1 and S_2 peak values in the adjacent rocks, rocks with very low porosities and permeabilities, are further evidence of, and could only have been accomplished by, such events. These residual-oil saturations and ROCK-EVAL analyses thus provide evidence for super-lithostatic fracturing, *as does the almost exclusive horizontal fracture pattern in the reservoir rocks adjacent to the Bakken shales as documented by our large fracture study.* The conclusion follows that an unconventional in-place oil-resource base of monstrous proportions exists in basin-wide "continuous reservoirs" in the Williston Basin.

Due to the low porosities and very low permeabilities of the three reservoir rocks adjacent to the Bakken shales, the only avenue of transport by which this injection of oil into these three rocks could have occurred is via fractures created by the explosive super-lithostatic oil expulsion events from the Bakken shales. The brittle nature of the reservoir rocks adjacent to the Bakken shales probably assisted in this fracturing process. Also, because of the very low matrix permeabilities of these rocks, any oil which migrated into the "reservoir" rocks from the Bakken shales had to migrate along a fracture, or series of fractures, which is (are) connected from the present residence site of the oil continuously back to the Bakken shales. Five important implications follow:

- <u>First,</u> most of the Bakken oil resource base is in fractures in the "reservoir" rocks adjacent to the shales and only a fraction of the oil is stored in the porosity of these rocks. Thus, the oil resource is highly concentrated in fractures, as opposed to the usual situation in conventional sandstone or carbonate reservoirs, where the oil is dispersed, and intermingled with water, throughout the rock porosity.

- Second, because of the very high energy of the fracture events, the fracture networks should be very well interconnected over large areas of the basin, essentially continuously interconnected. In fact, these fracture networks may constitute one of the most homogeneous reservoirs in the world, in strong contrast to the heterogeneous nature of many conventional carbonate, and especially sandstone, reservoirs. Production histories and reservoir pressure data for Bakken-producing wells document that well-connected reservoirs do exist over great lateral distances. As discussed below, SEM analyses demonstrate that these fracture networks are also very well interconnected at the local level.
- Third, such homogeneous noncompartmentalized reservoir carries the implication that some form of pressure maintenance would be an appropriate recovery processes to be used with the Bakken oil-resource base.
- The fourth implication is the expectation that the Bakken Source System should be an oil-wet system, with little or no mobile water. Existing production data (Table 7) corroborate this expectation
- The fifth, and last, implication involves the place of residence of Bakken Source System oil. Industry considered the two Bakken shales to hold the bulk of the producible oil in vertical fractures. However, Price and LeFever (1992) pointed out that most "Bakken" vertical wells were actually perforated

in one, or all three, of the rocks adjacent to the Bakken shales, as well as in the shales themselves. Actually, NDGS records reveal that no productive vertical wells have been perforated exclusively in the Bakken shales. As such, Price and LeFever (1992) suggested that a significant percentage of the Bakken Source System oil-resource base may be present in the brittle rocks adjacent to the two shales. *However, we hypothesize here that episodic, super-lithostatic pressure oil-expulsion events from the Bakken shale would result in most of oil resource base being emplaced in horizontal fractures in the rocks adjacent to the Bakken shales. Pivotal approaches for recovery of Bakken oil would result from this scenario.*

7.0 **WILLISTON BASIN MATURITY AND HEAT FLOW**

7.01 **Synopsis**

Vitrinite reflectance (R_o) and ROCK-EVAL T_{max} values, especially of coals, are the very best maturity indices in petroleum geochemistry with which to estimate the maximum paleo temperatures (rank) to which a rock has been buried. Previously-published R_o profiles versus depth suggested very high paleo temperatures existed in the Williston Basin. These previously-published R_o versus depth profiles have been further augmented, including ROCK-EVAL analysis of coal samples in the shallowest samples. The new data corroborates the previous findings: extreme paleo-geothermal gradients once existed in the Williston Basin. Moreover, the heat flow causing these gradients had to occur in Eocene or younger time.

Other evidence also exists that extreme heat flows previously occurred in the Williston Basin. Moreover, other investigators have also hypothesized high paleo-heat flows from completely separate lines of research. However, still other investigators, dealing with computer modeling, have simply assumed, with no supporting data, that heat flows have been constant through geologic time at the moderate present-day levels of the Williston Basin. These assumptions, made simply to facilitate construction of the computer models, are unsubstantiated because they lack data supporting the assumption.

The Williston Basin has been significantly cooled by strong cross-basinal meteoric-water recharge, via five aquifers of variable geologic age (Tertiary to Cambrian). This cooling explains today's moderate burial temperatures in the Williston Basin.

Marine-derived, hydrogen-rich OM requires far higher burial temperatures than generally recognized to initiate and sustain mainstage HC generation. The reasons for this are discussed in this section. A consequence of this suppression of organic metamorphism is that the extreme paleo-heat flows (and resulting extreme burial temperatures) in the Williston Basin become pivotal to our discussion. Specifically, the Bakken shales, which are world class source rocks, have generated hundreds of billions of barrels of oil and created superlative oil reservoirs in the rocks adjacent to the two shales, all at shallow burial depths (9,000 to 11,500 ft; 2,743.1 to 3,505.0 m). Similar oil-resource bases in other basins worldwide, will occur only at depths of 20,000 to 30,000 ft (6,095.7 to 9,143.6 m) because of the lower present-day or paleo-geothermal gradients in these basins. Thus, other resource bases in basins other than the Williston, and which are similar to the Bakken Source System oil resource base, will not be economically-competitive to the Bakken resource base, specifically regarding recovery costs. In fact, these other resource bases will likely not be economic at all, at today's oil price.

7.02 **Introduction**

Source rock maturity is a key petroleum-geochemical measurement, absolutely necessary to assess the extent of HC generation in a rock. The very best gauge of source rock maturity is to measure the change in the HC generation capacity of a source rock, by measuring the ROCK-EVAL hydrogen indices of a source rock or the kerogen elemental hydrogen to carbon (H/C) ratio, versus progressive burial. Such an example is given in Figure 13, which is being updated with over 1300 ROCK-EVAL analyses of Bakken shales from both North Dakota and Montana to construct a much more detailed ROCK-EVAL hydrogen-index map than that of Figure 13. The finished detailed hydrogen index map, combined with maps of total Bakken shale thickness and starting (pre-HC generation) TOC values (also ROCK-EVAL derived numbers), will eventually all be used to carry out mass-balance calculations of how much oil has been generated per unit area, for the entire Bakken kitchen.

In most cases, it is not possible to construct such detailed ROCK-EVAL hydrogen-index maps, because the source rock of interest is buried too deeply, and therefore appropriate rock samples are not available for analysis. Thus, the maturity of the source rock of interest must be *indirectly estimated* from maturity profiles versus depth at different basin sites, using any one of a myriad of different possible maturity measurements (maturity indices). In these cases, values of the maturity index under study are plotted versus depth, and the resulting trend is extrapolated to the depth of the source rock. As discussed below, there are limitations and pitfalls with this approach. Although many different maturity indices are available, the premier petroleum-geochemical maturation index is vitrinite reflectance (R_o) with the ROCK-EVAL T_{max}

measurement (especially of coals) being the second-most preferred index. All other maturity indices are second tier, and are usually related back to R_o. We provide a brief explanation of R_o in Section 7.03. For those familiar with R_o, please proceed to section 7.04.

7.03 **Vitrinite Reflectance (R_o)**

Pieces of different parts of woody plants (plant macerals) are commonly deposited and preserved with sediments, much like fossils, which, in fact is what these plant fragments are. One type of these plant pieces, or macerals, is vitrinite which is made of pieces of the vascular framework that provides support for plants, the "rebar" of plants. Vitrinite, as it is progressively buried to higher burial temperatures, increasingly gains the ability to reflect light. This ability is gauged by measuring the percentage of light reflected back when light is shone on vitrinite particles, hence the term "vitrinite reflectance". R_o is expressed in percent, and R_o values for vitrinite with no or little (less than 500 ft; 152.4 m) of burial, range between 0.20 to 0.29%, generally being around 0.25%. R_o values of 0.6% are equated to the beginning of intense oil generation. R_o=0.9% is thought to be the onset of C_{15}+ HC (oil) thermal destruction, and $R_o \geq$ 1.35% is taken as the complete destruction of oil (C_{15} + HCS).

However, all these observations and values have significant qualifications, because R_o, like ROCK-EVAL, has significant limitations, many of which are discussed in Barker and Pawlewicz (1986). The most severe limitation, which concerns us here, is the suppression of R_o in hydrogen-rich OM, a widespread problem first pointed out by Price and Barker (1985). Vitrinite in shales with hydrogen-rich OM (that is, oil source rocks) matures at significantly slower rates than does vitrinite in shales with oxygen-rich (humic) OM, the type of OM that comprises most coals. Thus, vitrinite in a rock with hydrogen-rich (marine) OM will have a lower

R_o value than vitrinite in a rock with oxygen-rich (terrestrial or humic) OM, where both rocks are buried under identical conditions. *Therefore, reliable R_o measurements can be obtained only from vitrinite in rocks with oxygen-rich OM. R_o values from coals are regarded as the most reliable values possible.* However, even vitrinite in coals is subject to suppression, in coals with higher hydrogen contents (Newman et al., 1997). R_o values are generally plotted on a logarithmic scale versus depth (in feet or meters) on an arithmetic scale. When so plotted, R_o values from rocks with oxygen-rich OM will yield a straight line (when the geothermal (or paleo-geothermal) gradient is constant), with high R_o versus depth correlation coefficients resulting (generally $r^2 \geq 0.90$) from regression analysis.

7.04 **Williston Basin R_o Profiles**

7.041 NDGS # 6464

Price et al. (1984) presented R_o profiles for two wells from the Williston Basin, one of which is reproduced in Figure 38. As Price et al. (1984) noted, the shallower rocks in the Williston Basin with oxygen-rich OM yield steep R_o profiles versus depth, which implies that a high paleo- geothermal gradient existed in this basin. Price et al. (1984) also noted that the rate of R_o increase, versus depth, decreases dramatically in the Jurassic and older rocks (Fig. 38), rocks which have a marine, more hydrogen-rich OM. This R_o decrease is due to R_o suppression, as discussed above. Note in Figure 38 that an R_o value of 1.0% is reached by 5,500 ft (1,676.3 m). R_o=1.0% is considered to be a high value in petroleum geochemistry. By comparison, in the U.S. onshore and offshore Gulf Coast, R_o values of 1.0% are reached between 15,000 to 25,000 ft (4,571.8 to 7,619.6 m) of burial, depending on geothermal gradients, burial times, and other factors. For example, an R_o profile, versus depth, from the offshore Texas Gulf Coast COST-1 well is shown in Figure 39. This is an area of moderately-high geothermal gradients (for the Gulf Coast) and R_o=1.0% is reached at about 16,405 ft (5,000 m) at a burial temperature of around 194°C. Thus, the R_o value of 1.0% at 5,500 ft (1,676.3 m) in Figure 38 demonstrates that an extremely-high paleo-geothermal gradient once existed in the Williston Basin.

7.042 NDGS #607

We have expanded the database of Price et al. (1984) regarding R_o profiles versus depth in the Williston Basin. In Figure 40, well locations with these R_o profiles (determined from cuttings chips) are overlain on the ROCK-EVAL hydrogen-index map of Price et al. (1984). Table 8 lists the newer wells (location, well name, and operator). Two examples of R_o profiles from Table 8 are shown in Figures 41 and 42. The R_o profile versus depth for the NDGS # 607 well (Fig. 41) has the same general features as that of the NDGS # 6464 well (Fig. 38). To wit: the R_o profile again is very steep and R_o=1.0% is reached by 5,300 ft (1,615.4 m) in NDGS # 607 (versus 5,500 ft; 1,676.3 m in NDGS # 6464). Thus, the gradients of the two R_o profiles, and therefore of the two paleo-geothermal gradients, for the two wells are similar and very high. Extrapolating the R_o profile in Figure 41 (dashed line) to R_o=0.25% (the approximate value for zero burial) suggests that 450 ft (137 m) of sediment has been eroded from this site in the Williston Basin. Carrying out the same exercise for NDGS # 6464 (not shown in Figure 38) suggests that 1,000 ft (304.8 m) of erosion has occurred at that site.

Coal deposits, some significant, occur from the Eocene Bear Den Member of the Golden Valley Formation down to the uppermost Cretaceous Hell Creek Formation. As mentioned above, *R_o and ROCK-EVAL T_{max} measurements of coals are the most reliable petroleum-geochemical maturity indices possible.* Coals from the shallower NDGS # 607 samples were subjected to ROCK-EVAL and R_o analyses. These samples are shown by triangles in Figure 41. ROCK-EVAL T_{max} values (in °C) are shown for each of the coal samples (triangles) in Figure 41 (and 42). Note the orderly increase of R_o and T_{max} values in these coals versus depth (Fig. 41). These data thus corroborate the above conclusion that an extreme paleo-geothermal gradient once existed in the Williston Basin. R_o values from deeper shales with oxygen-rich OM (dots in Fig. 41) fall on the same R_o gradient versus depth as do the coals, with a linear regression value (correlation coefficient) of r^2=0.993. In Figure 41, at about 5,100 ft (1,554.4 m) in passing from the shallower rocks with terrestrial OM deeper into marine rocks with hydrogen-rich OM, R_o values are significantly suppressed compared to shallower values, and actually exhibit decreases, corroborating the previous findings of Price et al. (1984) in this regard.

Price et al. (1984) also noted that the R_o profiles from the shallower rocks in the Williston Basin could not simply be linearly-extrapolated to the depths at which Bakken shales occur, to obtain an R_o estimate for the Bakken shales equivalent to what would be determined for oxygen-rich OM at that depth. This is because, compared to values in the shallower rocks, the thermal conductivity of the sedimentary column increases with depth in the Swift Formation and older rocks, and especially in Madison Group rocks, due to evaporites and limestones in the section. Because of this increased thermal conductivity, paleo-geothermal gradients would decrease in these rocks. This point was also noted by Burrus et al. (1996). However, whatever the properly-calibrated Bakken R_o values in the NDGS # 607 would be, they are *clearly much higher* than those suppressed R_o values actually measured in the shales.

7.043 NDGS #527

Another R_o profile versus depth from the Williston Basin is shown in Figure 42 for the well NDGS # 527, and the same features present in Figures 38 and 41 are in Figure 42: a very steep R_o profile versus depth in the shallow rocks with oxygen-rich OM and a strong suppression of R_o values in the deeper rocks. However, note that R_o=1.0% is reached at a shallower depth, 3,900 ft (1,188.7 m), than in the two previous cases: 5,300 ft (1,615.4 m) in NDGS # 607 (Fig. 41) and 5,500 ft (1,676.3 m) in NDGS # 6464 (Figure 38). This shallower depth for R_o=1.0% in NDGS # 527 reflects the fact that this well is located in the highest paleo-geothermal gradient (most mature) area of the Williston basin. Again, the coals in NDGS # 527 (Fig. 42) have an orderly increase of both R_o and T_{max} values with increasing depth. Extrapolation of the R_o profile in Figure 42 to R_o=0.25% (dashed line) demonstrates that only 300 ft (914 m) of sediment have been eroded from this area of the basin. The coal with the 387°C T_{max} value (Fig. 42) is from the very uppermost Paleocene to lowermost Eocene Bear Den member of the Golden Valley Formation. The R_o value of this sample clearly lies on the R_o gradient of Figure 42. Thus, the paleo-heat flow event responsible for the R_o gradient of Figure 42 had to be Eocene or younger.

The R_o and T_{max} profiles for the coals of Figures 41 and 42, as stated, demonstrate that extreme paleo-geothermal gradients once existed in the Williston Basin. In fact, we have never seen higher maturity gradients (published or unpublished) for any petroleum-producing basin worldwide. This is not to say that higher gradients do not exist. But at the very least, the Williston Basin has experienced some of the highest heat flows known in oil-bearing sedimentary basins.

7.044 All Analyzed Wells

The R_o profiles for all the wells of Table 8 are shown in Figure 43. Again, the location of these wells are given in Figure 40. Linear-regression-analysis correlation coefficients for each profile, and the estimated amount of erosion at each well site, are also given in Table 8. We wish to stress four points from the data of Figure 43 and Table 8. First, there is a continuum of gradients for the R_o profiles, instead of R_o versus depth profiles which overlie each other. Second, the gradients range from extreme (NDGS # 527), to very high (NDGS # 2010 and # 7020), even the lowest gradients in Figure 38 (NDGS # 2010 and # 7020) being atypically high, compared to the norm in sedimentary basins. For example, in NDGS #2010 and #7020, R_o values of 0.55% are reached around 5,000 ft (1,523.9 m). In the Texas Gulf Coast COST-1 well (Fig. 39), $R_o = 0.55\%$ is reached around 10,170 ft (3,100 m), and the COST-1 well had a geothermal gradient significantly above the Gulf Coast average. The data of Figure 43 thus demonstrate that variable heat flows, ranging from very high to extreme, existed throughout the Williston Basin. The third point is that the regression coefficients of the R_o values to their respective regression lines for each gradient are high (Table 8). Thus, the R_o values making up each line have tight distributions to the lines, and the data sets are quite dependable. Fourth, only moderate erosion has taken place in the North Dakota portion of the Williston Basin (Table 8). Taking the average of the erosion estimates of Table 8 (including the two negative values), yields an average erosion of 470 ft (143 m), which is taken as a representative value for the North Dakota portion of the Williston Basin.

7.05 **Corroborating Evidence**

Other petroleum-geochemical evidence of high heat flow in the Williston Basin also exits. For example, ROCK-EVAL T_{max} values for the most mature Bakken shales in Price et al. (1984) range up to 454°C, and are, at a minimum, commonly 449° to 452°C. If one applies a ROCK-EVAL (burial history) kinetics modeling program to these mature Bakken shales, using (correct) starting T_{max} values of 390°C, it becomes quite evident that present-day Williston Basin burial temperatures are wholly inadequate to account for these observed Bakken shale maturities. However, we will not discuss those calculations here.

Another line of evidence of extreme paleo heat flow, is that some shales from the Jurassic Swift, and older formations in the most mature areas of the Williston Basin have developed very large sericite (mica) flakes from shale recrystallization. Such sericite development is characteristic of burial temperatures of at least 225° to 250°C, far higher than today's burial temperatures.

7.06 **Discussion**

Controversy exists concerning heat flow in the Williston Basin. Based on theoretical considerations, previous investigators, including Combs 12and Simmons (1973), and Scattolini (1977), inferred high paleo heat flows in the Williston Basin. Price et al. (1984), as noted, provided evidence, in the form of several R_o profiles versus depth, of extremely-high, but laterally- variable, paleo heat flows in the Williston Basin. Although R_o is the premier petroleum geochemical maturity index, the conclusions of Price et al. (1984) regarding paleo-heat flow and maturity in deep Williston Basin rocks were not widely-accepted, because the measured R_o gradients were so high. However, other work by Majorowicz et al. (1986, 1988) corroborated the results of Price et al. (1984). Later investigators (Gosnold and Huang, 1987; Gosnold, 1990; and Burrus et al., 1995, 1996), using computer models, rejected the data from the natural system of the Price et al. (1984) and Majorowicz (1986, 1988) studies, and *inferred* constant and moderate heat flows through the Williston Basin through geologic time. These, in our opinion, erroneous assumptions were made to simplify the computer modeling. Burrus et al. (1995, 1996) on the basis of their computer models predicted two different heat flows in the Williston Basin, one moderately higher than the other, but both far lower than those required by the R_o profiles presented by Price et al. (1984).

Our data (Figs. 41 to 43, and the accompanying discussion thereof) clearly support the earlier conclusions of Price et al. (1984) and Majorowicz et al. (1986, 1988), and concurrently are at complete odds with the conclusions of Burrus et al. (1995, 1996) on the topic. Let us return to Figure 43, and note the continuum of variable R_o gradients therein. Figure 43 thus supports the finding of Price et al. (1984) of laterally-variable paleo-heat flows across the Williston Basin and <u>conflicts</u> with the predictions of Burrus et al. (1995, 1996) that only two heat flows (one moderately-higher than the other) are/were present in the Williston Basin.

The question obviously arises as to what geologic event caused the extreme heat flow in the Williston Basin. Price et al. (1984) hypothesized that this event was a rift, or aborted rift, associated with the thick Cretaceous-Paleocene sediment infilling of the basin. Shepard (1991) later theorized that an abnormally-high Paleocene heat flow would have resulted from events associated with the Cretaceous to lower Tertiary Laramide structuring of the Rocky Mountains. This extreme heat flow would have also been aided by the intersection of the two Precambrian rifts, the Montana Aulacogen and the Trans Hudson rift, near the Williston Basin depocenter.

Shepard (1991) also stressed that maturation and HC generation in the Bakken shales was caused by punctuated diagenesis rather than by "burial diagenesis." Shepard's (1991) observation here is pivotal.

"Burial diagenesis" results from the gradual increase in burial temperatures as sedimentation slowly progresses, burying older sediments deeper and deeper. "Punctuated diagenesis" is a term first coined by Morton (1985) in his study of the Oligocene Frio Formation of the Texas Gulf Coast. This type of maturation is caused by a sharp, abnormally-high heat flow from any number of possible geologic tectonic events. Such sudden high heat flows dramatically increase sediment burial temperatures, causing changes in rock diagenesis and organic maturation to occur over short geologic time periods, in contrast to the tens or hundreds of millions of years thought to be required by burial diagnesis.

We have gathered much additional data (not shown here) supporting the hypotheses of Price et al. (1984) and Shepard (1991) regarding the cause of the extreme paleo heat flow in the Williston Basin. However, that data will neither be presented nor discussed here. For the present discussion, what caused this heat flow is not important. Rather, the critical point is that it did occur, because the results and implications of this extreme heat flow in the Williston Basin have pivotal implications regarding the Bakken Source System.

As an aside, Price (1983) first pointed out that conclusive evidence existed in numerous sedimentary basins worldwide that these basins had been affected by different geologic tectonic events resulting in geologically-brief high heat flows in those basins. Although he did not use the term "punctuated diagenesis", Price (1983) first documented the widespread occurrence of this type of organic maturation and rock diagenesis in sedimentary basins. All geologic terrains, including sedimentary basins, are well-known to be affected by such tetonic thermal geologic events. Such events, in fact, are a natural consequence of chaos theory, which governs all aspects of nature (Gleick, 1987). However, unpredictable chaotic major geologic events in sedimentary basins (punctuated diagenesis) have no niche in computer models of basin evolution, which historically only model burial diagenesis. Therefore, such events are regarded as never, or rarely, occurring in sedimentary basins by many basin modelers. For example, to quote Burrus and Rudkiewicz (1994, p. 114), "Detailed investigations of past thermal histories in various basins carried out at IFP (such as Paris Basin, France; Williston Basin, USA/Canada; Mahakam Delta, Indonesia; Viking Graben, North Sea) indicate that crustal heat flow has not varied much with time. Observed present-day temperatures and organic mineral paleothermometers can in most cases be accounted for by time-invariant crustal heat flow. This tends to disprove the concept of "tectono thermal" event referred to". This preconceived approach concerning computer models then is the underlying reason for the inaccurate misrepresentation of paleo-heat flow in the Williston Basin by Burrus et al. (1996). Contrary to the opinion of Burrus and Rudkiewicz (1994), the observed present-day temperatures of the Williston Basin can in no way account for the R_o profiles (an "organic-paleothermometer") there.

7.07 **Basin Cooling**

As stated, present-day burial temperatures are far too low to have caused the maturity trends in the Williston Basin. Thus, significant cooling must have recently occurred in the basin, and evidence of this cooling should be evident. Indeed such evidence is present. Figure 44, after Meissner (1978), shows formation fluid pressures versus depth for wells in the Antelope Field (Fig. 1), McKenzie County, North Dakota. Note that the hydrostatic fluid pressure gradient is

0.53 pounds per square inch per foot (psi/ft). All stratigraphic units, except Bakken Source System rocks, are subnormally-pressured (less than hydrostatic pressures). Dickey and Cox (1977) correctly noted that there are only two possible causes for subnormal pressures in petroleum basins: 1) a decline in the geothermal gradient of the basin, and/or 2) substantial uplift and sediment erosion, or both.

We have demonstrated above (Fig. 43, Table 8, and accompanying discussion) that only minimal erosion has occurred in the Williston Basin. Moreover, this erosion is too small to have resulted in the basin cooling recorded in Figure 44. Thus, a decrease in the geothermal gradient is the only other possible cause of the subnormal-fluid pressures of Figure 44. However, the severity of basin cooling which had to occur is not reflected by the measured formation fluid pressure gradients, which are only moderately below the expected values. Thus, it seems that the agent that caused a decrease in the paleo-geothermal gradient had to also cause a recharge of formation waters.

That agent is meteoric water recharge, which has been documented as a major influence in the Williston Basin by a number of workers, including Downey (1984), Mitsdarffer (1985), DeMis (1987), Downey et al. (1987), Hannon (1987), Berg et al. (1994), and DeMis (1995). Those investigations will not be discussed in detail here except to note that they documented from Eocene to Recent time, that the Williston Basin has been in a state of strong hydrodynamic flow, with at least five different aquifers, ranging from Cambrian-Ordovician to Recent, serving as fluid conduits (Fig. 45). These investigations also documented that the middle-lower Mississippian to Devonian rocks (including Bakken Source System rocks) have acted as strong aquitards (confining layers or closed-fluid systems) to this cross-basinal meteoric water flow. The

Tertiary uplift of both the Black Hills and Bighorn Mountains, and exposure of the older rocks as aquifers to highland meteoric water recharge, allowed this strong cross-basinal meteoric-water flow to occur. Moreover, the intensified precipitation, which occurred during glacial periods, would have strengthened this process. Because at least five aquifers, interbedded with aquitards, existed from crystalline basement to surface (Fig. 45), the large amount of heat-stored in the basin's rocks from the extreme post-Paleocene heat flow was effectively and geologically quickly, transmitted out of the basin.

Concurrently, this meteoric recharge increased formation-fluid pressures in the aquifers to values greater than they otherwise would have been if only basin cooling occurred, which would have caused a severe thermal contraction of fluids and solids in the basin, resulting in much lower formation-fluid pressures than those recorded in Figure 44.

7.08 **Maturity versus Rank**

As Price and McNeil (1997) noted, the difference between rank and maturity is not widely recognized in petroleum geochemistry, even though the distinction between the two has been delineated for some time (Suggate, 1959), and has been stressed by different studies and different investigators including Suggate (1990), Suggate and Boudou (1993), and Price and McNeil (1997). Rank refers to the actual burial conditions to which a given rock has been exposed. Maturity is an inferred estimate of those burial conditions, arrived at by measuring changes in given chemically or physically-based parameters, or characteristics, of that rock, in other words by measuring a "maturity index". Examples of widely-employed maturity indices are: R_o, the ROCK-EVAL T_{max} value, the smectite to illite clay transformation, or biomarker ratios. However, differences between maturity and rank can arise because two different rocks buried under the same conditions, in other words, buried at the same rank, can have far different maturities. Thus, at times maturity measurements can be only inexact estimates of rank, and in fact can be meaningless. The distinction between rank and maturity is more throughly discussed in Newman et al. (1997, p. 142-146).

The most-recognized example of such variation in maturity between different rocks buried at the same rank is the suppression of R_o values in rocks with hydrogen-rich OM, as discussed above. The optimum approach to standardize R_o maturity measurements, is to take R_o readings only from rocks with hydrogen-poor Type III OM, or from coals with starting hydrogen indices of 200 or less, and to construct maturity versus depth profiles which can be extrapolated, or interpolated, into rocks with more hydrogen-rich OM. Fang and Jianyu (1992, p. 433) summarize the problem concisely,

> "Vitrinites deposited in different redox conditions, and thus with different initial hydrogen contents and kinetics, may yield very different reflectance values at the same regional rank. The same R_o values will not always reflect the same time-temperature histories, whereas different R_o values will not always indicate different organic maturity levels. Only the reflectance values of equivalent vitrinites (vitrinites which are similar to the telocollinites in "normal coals" in initial compositions and kinetics) are comparable in determining basin-by-basin thermal histories."

Suggate (1959) developed the concept of Suggate Rank to deal with the problem of variable maturity at a given rank in different OM types, and later amplified his approach Suggate and Lowry (1982), Suggate (1990), and Suggate and Boudou (1993). However, petroleum geochemistry has not taken advantage of Suggate's efforts in this regard.

7.09 **Suppression of Organic Metamorphism in Hydrogen-Rich OM**

7.091 Introduction

As mentioned above, Price and Barker (1985) were the first to point out the widespread suppression of R_o in rocks with hydrogen-rich OM. Numerous other investigators have since documented the effect, although many of the studies have involved coals (Fang and Jianyu, 1992; Suggate and Boudou, 1993; Sykes et al., 1994; and Newman et al., 1997). Several studies have involved marine-derived source rocks including Scotchman (1991), Lo (1993), and Snowdon (1995). Although most investigators believe that suppression of organic-geochemical maturity indices is limited to R_o, Snowdon (1995) demonstrated significant suppression of ROCK-EVAL T_{max} values with increasing kerogen hydrogen richness, for shales at the same rank. Lastly, some investigators, including Lo (1993), have concluded that although there is a suppression of R_o with increasing kerogen hydrogen richness, the effect is not large. We stress two points here, both of which are amplified on below: First, all maturity indices (and not just R_o), and indeed all aspects of organic metamorphism including HC generation, are suppressed at a given rank with increasing kerogen hydrogen richness. Second, the magnitude of the suppression can be *quite* large, and thus is not a trivial effect.

7.092 Examples/Consequences of Suppression of Organic Metamorphism

The suppression of all aspects of organic metamorphism, including HC generation, in hydrogen-rich OM has been discussed by Price (1991, 1997), Price, et al. (submitted), and Price (submitted) with examples given. This suppression has been documented in numerous petroleum basins, including Los Angeles, Ventura, Southern San Joaquin Valley, West Texas Permian, Anadarko, South Texas Gulf Coast, and the Williston Basin. Figure 46 presents data from the Los Angeles and Southern San Joaquin Valley Basins, wherein 3 maturity indices are plotted versus the ROCK-EVAL hydrogen index of the rock, for shales with burial temperatures between 180° to 200°C. Two of the indices in Figure 46 (the ROCK-EVAL production index (transformation ratio) and the ROCK-EVAL S_1 peak normalized to organic carbon, mg/gOC) are direct measurements of HC generation. Many of the samples in Figure 46 have low hydrogen indices, which result from two causes: 1) the original hydrogen indices of the rocks were low from deposition of hydrogen-poor OM; and 2) the orignally low hydrogen indices were further decreased from the OM in these rocks having substantiallly gone through HC generation. Note the presence of transformation ratios of 0.3 to 0.7 and carbon-normalized S_1 values of up to 120 in Figure 46 for rocks with hydrogen indices of 200 or less. Such transformtion ratios and S_1 values are quite high, being indicative of rocks which have largely gone through HC generation.

On the other hand, the samples at the high end (right-hand side) of the hydrogen-index scale have not even commenced HC generation, with low carbon-normalized S_1 values and low transformation ratios (10 to 40 mg/gOC, and 0.01 to 0.08, respectively). Thus the two end-member OM types in Figure 46, which have been buried at the same rank, have *vastly* different maturities. The hydrogen-poor kerogens have largely gone through HC generation and the hydrogen-rich kerogens have not yet even begun HC generation, not subtle differences. Moreover, R_o demonstrates similar behavior, with the shales with hydrogen-poor OM having R_o values of 1.1 to 1.2%, while shales with hydrogen-rich OM buried at the same rank have R_o values of 0.22 to 0.35% again *vastly* different maturities.

Recall the R_o versus depth profiles of Figures 38, 41, and 42. The R_o values for the Bakken shales in all 3 figures are *highly* suppressed from any reasonable extrapolation of the trends established in the shallower rocks with hydrogen-poor OM. Very few petroleum geochemists have recognized the magnitude of the suppression of all aspects of organic metamorphism in hydrogen-rich OM. It is generally thought that when the even effect occurs, it is of only minor consequence. This is not the case at all.

The principal consequence of this suppression of organic metamorphism in hydrogen-rich OM is that *far higher* burial temperatures are required for hydrogen-rich kerogen (type I/II OM, starting hydrogen indices ≥550) to commence, much less go through HC generation, then are portrayed by accepted petroleum-geochemical models. For example, from existing data it appears that minimal burial temperatures of 200°-250°C may be necessary just to *commence* HC generation in the most hydrogen-rich OM. Moreover, as the original hydrogen richness of the OM increases, so do the temperatures required to initiate mainstage HC generation. Although almost all petroleum geochemists would find these to be outrageous proposals, they are supported by a large data base from Nature. Figure 47 is ROCK-EVAL and R_o data for shales with hydrogen-rich OM from the Wilmington field, Los Angeles Basin. As is evident from Figure 47, all aspects of organic metamorphism are strongly suppressed in the OM of these rocks. HC generation has not even commenced by 200 ° C in the deepest shales, which have ROCK-EVAL hydrogen indices ranging between 450 to 650, averaging around 550. In contrast to the data of Figure 47, Price et al. (submitted) demonstrate that in shales with hydrogen-poor OM, HC generation commences at 120 ° C in the Los Angeles Basin as judged by the first significant increase in the ROCK-EVAL production indices.

An example intermediate between the above two cases of hydrogen-poor and hydrogen-rich OM in the Los Angeles Basin is found in the deep shales with hydrogen-rich OM of the Ventura Avenue Field, in the Ventura Basin, adjacent to the Los Angeles Basin. As judged by the first significant increase in both the ROCK-EVAL S_1 peak and production indices in Figure 48, HC generation commences at a depth of 6,149 m and at burial temperature of 196.7 °C there. The pre HC generation ROCK-EVAL hydrogen indices of these deep shales range between 300 to 540 and average 430. Because the deep Ventura Avenue Field shales have less hydrogen-rich OM than the deep shales in the Wilmington Field, HC generation commences in the former case but not the latter, in spite of the fact that in both cases, the burial histories of the rocks are the same. The only significant variable between the two cases is hydrogen-richness variation in the OM.

As discussed below, starting ROCK-EVAL hydrogen indices for the Bakken shales range between 550 to 800, and average around 625. Thus even higher burial temperatures (beyond 200 °C), than was the case for the Ventura Avenue Field, would be needed to initiate mainstage HC generation in the Bakken shales. Because such high burial temperatures are required for the more hydrogen-rich OM even to commence HC generation, such OM must be buried very deeply, 20,000 to 30,000 ft (6,095 to 9,145 m), for the range of heat flows normally found in sedimentary basins, to achieve the high degree of HC generation found in the Bakken shales of North Dakota (Fig. 3) (and Montana). *Thus, almost all in-place unconventional oil-resource bases equivalent to that of the Bakken Source System will only be found at depths which currently preclude economic production of the resource base.*

Another possibility exists, which is having analogous oil-resource bases in basins with paleo-heat flows equivalent to that of the Williston Basin. However, we are aware of only one other petroleum-bearing basin worldwide which has had a paleo-geothermal gradient even comparable to the lowest gradients in the HC kitchen of the Williston Basin, and that is the northern part of the San Juan Basin. However, that part of the San Juan basin has been strongly uplifted and eroded as is evident in Figure 49, where 6,200 ft (1,889.7 m) of sediment is estimated to have been eroded, based on extrapolating the R_o versus depth profile to 0.25%. In Figure 49 before erosion occurred, an R_o value of 1.0% would have occurred at a burial depth of 7,200 ft (2,194.4 m). By contrast, the lowest paleo-geothermal gradient in the Bakken HC kitchen (where the shales have commenced HC generation) resulted in an (extrapolated) R_o value of 1.0% by 7,100 ft (2,164.0 m) in NDGS # 7783 (Fig. 43).

Moreover, the San Juan Basin R_o profile (Fig. 49) demonstrates another important point: Regions of sedimentary basins with even moderately high present-day or paleo-geothermal gradients, much less extreme gradients, *usually* (the Williston Basin being an exception) are tectonically disrupted. Tectonic disruption of source rocks precludes the possibility of basin-centered continuous-reservoir oil-resource bases in closed-fluid systems (Price, 1994a). Lastly, we are not aware of any sedimentary basin worldwide with a *present-day* heat flow high enough to effect R_o versus depth profiles comparable to those in Figure 43. However, even if a basin, or basins, existed with such a high present-day heat flow and with an in-place basin-centered oil-resource base akin to that in the Bakken Source System, production of that resource base would be difficult to impossible, because of the very high burial temperatures which would be involved, burial temperatures significantly higher than industry's current upper operating limits.

The above discussion highlights how a number of different parameters (pivotally, including an extreme paleo-heat flow) have coalesced to make the Bakken Source System possibly a unique, but at the least a very rare, occurrence worldwide in sedimentary basins. Clearly, a large number of other basin-centered, continuous-reservoir, unconventional oil resource bases will be present in many sedimentary basins. However, these oil-resource bases will be buried so deep that the extreme pressures and temperatures at which they exist will preclude their possible *economic* recovery for the foreseeable future. If the in-place oil-resource base of the Bakken Source System can be economically produced, then industry will commence a search for similar plays in other sedimentary basins, at moderate depths (5,000 to 15,000 ft; 1,523.9 to 4,571.8 m). Such a search will produce occasional moderate successes. However, the far greater part of this effort would be expected to result in failure. Oil-resource bases of the magnitude of that in the Bakken Source System simply will not be found at producible depths.

7.10 **Causes of Suppressed Organic Metamorphism in Hydrogen-Rich OM**

7.101 Controlling Parameters of Organic Metamorphism

It is not sufficient to state that organic metamorphism is suppressed in hydrogen-rich kerogens, without touching on the causes of this suppresion, which in turn, a-priori, must involve some discussion of the parameters which control organic metamorphism in general, including HC generation. By conventional wisdom (Hunt, 1979; Tissot and Welte, 1984), organic metamorphism proceeds by first-order reactions. Thus geologic time and burial temperature are thought to be the primary controls. Moreover, C_{15}+ HCS are thought to have limited thermal stability in Nature, being destroyed by 150°-200°C. However, a large body of data collected by this author (Price, 1982, 1983, 1985 , 1988, 1993, 1997, and submitted; Price et al., 1979, 1981, 1984, and submitted; Price and Clayton, 1990; and Price and Wenger, 1992) *strongly* contradicts existing paradigm while concurrently pointing to alternate reaction controls. Moreover, other investigators have also presented petroleum-geochemical data antithetical to accepted models (reviewed in Price, 1991 and 1997).

Although it is outside the scope of this paper to present an extended discussion of the alternate parameters controlling organic metamorphism, we can simply touch on each of these controls. As discussed in Price (1983, 1985), laboratory experiments clearly demonstrate that HC-generation and destruction reactions are not first-order reactions at all, but are higher-ordered reactions. Thus, time cannot be substituted for temperature in Arrhenius equations and geologic time would have no, or only minimal, control in organic-metamorphism. Open-fluid systems which allow product escape, allow organic metamorphic reactions to proceed further than they would in closed-fluid systems where products are retained. Because basin depocenters appear to be largely closed-fluid systems (Price, 1994a), the effects this control could be pronounced. Increasing fluid pressure can dramatically suppress organic metamorphism (Price and Wenger, 1992). Other studies which have documented this effect are reviewed in both Price and Wenger (1992) and Fang and Jianyu (1992). Temperature remains as one of the two principal controls of organic metamorphism.

The last, least-recognized, and with temperature, the other of the two most important controls of organic metamorphism, is water. The importance of water in both HC generation and organic metamorphism has been stressed by Price et al. (1979), Siskin and Katritzky (1991), Price (1993, 1997), Stalker et al. (1994), Helgeson et al. (1993), and Lewan (1997). The pronounced effect of water on organic metamorphism appears to be at least partly the result of the hydrolytic disproportionation of OM.

7.102 Hydrolytic Disproportionation of OM

The hypothesis of the hydrolytic disproportionation of OM (Shock, 1988; Helgeson, 1991; Helgeson et al., 1993) although generally unrecognized, appears to be a geologic agent of the magnitude (Price et al., 1998). As reviewed in Price (1994b), experiments carried out by other investigators involving other research topics, inadvertently demonstrated the existence of the process. Moreover, compelling experimental evidence, specifically designed to test the validity of the hypothesis, strongly supports the hypothesis. For example, Seewald (1994) provided strong experimental evidence supporting the concept.

As defined by Helgeson (1991) and Helgeson et al. (1993), water disproportionates and enters into aqueous-based redox reactions with OM in the natural system, with some organic species being oxidized and other organic species being reduced (hydrogenated). The end products of the reaction are CO_2 and CH_4, and the reaction is governed by, and helps set, the redox potential of the system. Thus OM, water, and mineral species are in metastable equilibrium with one another. The hydrolytic disproportionation of OM plays dominant roles in many geologic settings besides sedimentary basins. However, the process also plays several key petroleum-geochemical roles which bear on this, and other, discussions in this paper. One of these roles is the hydrogenation of kerogen by water during HC-generation.

Aqueous-pyrolysis experiments simulating HC-generation (Price, 1989a,b; Wenger and Price, 1991; Price and Wenger, 1992) generate much more CO_2 than can possibly be accounted for, considering the original oxygen content of the kerogen. Moreover, the same effect occurs in hydrous-pyrolysis experiments (Lundegard and Senftle, 1987; Barth et al., 1989; Lewan, 1992).

It appears that this effect is present in all HC-generation experiments carried out in closed, water-wet systems. Examples of this excess CO_2 from the HC-generation experiments of Wenger and Price (1991) are shown in Figure 50.

In Figure 50, the amounts of CO_2 generated from three different OM types (type I, Eocene Green River shale; type II-S, Permian Phosphoria shale; and type II/III Pennsylvanian Anna shale) are shown. In all three cases, 100% equals the maximum amount of CO_2 possible, given the original oxygen content of the kerogen. Kerogen oxygen contents were determined by both ROCK-EVAL oxygen indices and kerogen elemental analyses. In all cases, any CO_2 contributions from carbonate minerals during the experiments have been subtracted from the Figure 50 values. In the Figure 50 rocks, mainstage pyrolytic C_{15}+ HC generation commences at 250°C (275°C for the Green River shale) and is largely complete by 320°C. Experimental temperatures of 350°C and higher represent mainstage C_8+ HC thermal destruction. From Figure 50, excess CO_2 is generated before mainstage C_{15}+ HC generation even commences, and during both mainstage HC generation and the HC destruction phase.

These results can only be explained by water reacting with kerogen, with the oxygen from the water going to CO_2 and the hydrogen from water hydrogenating the kerogen. The kerogen after such hydrogenation would end up with more HC generation potential than suggested by original ROCK-EVAL or elemental-kerogen analyses. ROCK-EVAL analyses of all six of the rocks studied by Wenger and Price (1991) confirm this suggestion: Hydrogen indices of reacted rocks increase over those of the starting samples, where the experimental temperatures are below those of the commencement of mainstage pyrolytic HC generation. The experimental results of Hoering (1968, 1984) are also explained by hydrolytic disproportionation of OM and thus also support the Figure 50 data. Moreover, other investigators have called for water hydrogenating kerogen, and producing excess CO_2, based on their respective experimental results (Lewan, 1992, 1997), including oxygen-isotope labeling (Stalker, et al., 1994).

From these results and considerations, the chemical addition of water to kerogen during HC generation appears to be an integral part of the process. Indeed, thermodynamic calculations suggest that if water is withdrawn from kerogen during HC generation in the natural system, all reactions will cease, no matter what the burial temperature (H. Helgeson, various personal communications, 1992-1998). Our data suggest that to some extent this is true, thus partially explaining the suppression of organic metamorphism in hydrogen-rich OM. This is because organic-rich rocks with hydrogen-rich OM, such as the Bakken shales, have far less water available for HC-generation reactions, than do lower TOC shales with hydrogen-poor OM.

7.103 Water Availability versus OM type

Hydrogen-poor (type III or terrestrial) OM tends to be found in deltaic depositional settings, with the Gulf Coast Neogene sediments being the type example, wherein high concentrations of swelling clays (montmorillonite or smectite) are codeposited with the OM. Moreover, OM (TOC) concentrations in these shales generally range from 0.3 to 3.0%, with an average value at the lower end of that range, especially for the Gulf Coast Neogene shales. The Gulf Coast Neogene shales also have exceedingly low ROCK-EVAL starting hydrogen indices, 60-90, Price (1991). Also, low concentrations of indigenous bitumen (25-100 ppm, dry rock weight) are deposited in these rocks. Mass balance calculations (Price, 1991) strongly suggest that at no time during the entire HC generation sequence are enough C_{15}+ HCS generated such that an oil-only phase can be created in the porosity of such shales. This is partly due to the fact that abnormally-high porosities (10-20%) are retained to great depths in the shales of these depositional environments, mainly due to the extremely-high fluid pressure gradients, gradients which approach lithostatic which are developed in these depositional environments. Please see Price (1976, p. 223-233) for a fuller discussion of these observations regarding fluid pressures and porosities in deeply-buried shales in deltaic settings.

Swelling clays begin to convert to ordered (illite) clays at about the temperatures at which HC generation commences in hydrogen-poor OM in the natural system (100°-120°C). Thus, between the high porosities in the shales containing hydrogen-poor OM, and the large amount of water supplied by the smectite to illite clay transformation, *excess water is available to hydrogen-poor kerogen at all stages of HC generation.* However, the situation in high TOC rocks with hydrogen-rich OM, such as the Bakken shales, is vastly different. Conventional core analyses on file with the NDGS reveal that the Bakken shales have very low matrix permeabilities (generally 0.01 millidarcies or less, not shown here). Muscio (1995) reports Bakken shale permeabilities measured at high confining pressures in the 10's to 100's nanodarcy range. Moreover, porosity in the Bakken shales has been theorized to have high residual-oil saturations, 40 to 90%, which is reflected by the early build up of electric-log resistivity (Fig. 51) first pointed out by Meissner (1978). In Figure 51, resistivity values in the Bakken shales first go to infinite values by 7,000 ft (2,133.5 m). However, extractable bitumen contents are largely invariant versus depth, precluding the shallow increases in resistivity as due to HC generation in the Bakken shales. This conclusion is corroborated by the large petroleum-geochemical data base of Price et al. (1984), which led those authors to conclude that C_{15}+ HC generation commenced at around 8,000 ft (2,438.3 m) in the high geothermal gradient area of the Bakken shale HC kitchen.

Thus, the increases in resistivity in Figure 51 at shallower depths must be due to a factor, or factors, other than HC generation. We hypothesize that those factors are: 1*) a decrease in shale conductivity* as shale pore water is consumed by Bakken shale kerogen, and 2) a redistribution of indigenous shale bitumen by the large amounts of CO_2 generated by the Bakken shales as the shales react with pore water (Fig. 50). Thus, by the above scenario, the original pore waters in the Bakken shales would not be lost to compaction, but instead would be consumed by the kerogen in the shales. This loss of water from the porosity of the Bakken shales would dramatically decrease electric-log conductivity, *or increase resistivity*. Concurrently, the very large amounts of CO_2, and lessor amounts of HC gases, being generated by the shales at immature (pre-HC-generation) ranks would redistribute indigenous bitumen molecularly dispersed throughout the shales, partly by a gas phase migration, a hypothesis corroborated by Price and Clayton (1992). An oil-like phase would thus be emplaced in the porosity of the Bakken shales, replacing the water which was incorporated into the shale kerogen, thus increasing Bakken shale resistivity. All this would occur before mainstage HC generation ever commenced in the Bakken shales.

When HC generation did commence in the Bakken shales, little or no water would have been available to drive the generation reactions, reactions which would thus be suppressed, in spite of the high ranks to which the shales were buried. This is because by Figure 50, water is a necessary reactant at all stages of HC generation. If a required reactant in a reaction is unavailable, the reaction is impeded or halted. Moreover, as discussed below, the three stratigraphic units sandwiching the two Bakken shales are thick, impermeable ("tombstone") rocks incapable of transmitting fluids. Furthermore, as discussed above (section 2.0), there is a dearth of significant tectonic faulting and fracturing in the Williston Basin. Thus, no avenue of fluid transport to bring water to the Bakken shales was present on a widespread basis in the Williston Basin during HC generation in the Bakken shales, leading to a significant suppression of organic metamorphism.

Comparing the situation in the Bakken shales to that of rocks with type III/IV OM, we have two opposite ends of the spectrum of total water availability to HC generation potential. Thus, with the Bakken shales we have huge HC generation potential with beginning (pre-HC-generation) ROCK-EVAL hydrogen indices and TOC's averaging over 600 and 20%, respectively (L. C. Price, unpublished data). However, the Bakken shales have no swelling clays to yield a late-stage water pulse, and their porosity is essentially filled with oil before HC generation even commences. Thus, the Bakken shales would have minute ratios of available water to HC generation potential, per unit weight of rock. By contrast, Gulf Coast Neogene shales have low starting average ROCK-EVAL hydrogen indices and TOC's (60 to 90 and 0.3%, respectively; Price, 1991). These deltaic shales also have high water-filled porosities (10-20%), and high contents of swelling clays and as such have very high ratios of available water to HC generation potential, allowing HC generation reactions to proceed in a normal fashion. In contrast, the low ratios of water to HC generation potential for the Bakken shales, by the theory of hydrolytic disporportionation of OM, could *strongly suppress* HC-generation reactions (Personal Communication, Hal Helgeson, U. C. Berkeley, 6/1991).

As noted by Price and McNeil (1998), another cause of suppression of organic metamorphism in hydrogen-rich OM are the types of carbon-oxygen bonds therein, compared to the carbon-oxygen bonds in hydrogen-poor (type III/IV) OM. Siskin and Katritzy (1991) note that carbon-oxygen crosslinked bonds must be broken if coals and kerogens are to be converted to oil and gas. As one passes from hydrogen-rich OM to hydrogen-poor organic matter, the oxygen-carbon bonds change from esters to exclusively carboxylic-acids. Esters have much higher bond strengths than carboxylic acids (Roberts and Caserio, 1964). Thus, hydrogen-rich (more ester-rich) OM requires higher ranks to react than does hydrogen-poor (carboxylic-acid-rich) OM. To further compound the situation, Siskin and Katritzky (1991) note that ester bonds are cleaved much easier in water than in dry situations (such as could partially be present in high-TOC rocks with hydrogen-rich OM).

Lastly, as discussed in Price (1993, 1997), product removal also likely plays a role in suppressing organic metamorphism. Low-TOC rocks with low concentrations of indigenous HCS, low HC generation potential, and high porosity will never build up high concentrations of HCS around their kerogens at any time during the HC generation process. In contrast, high TOC rocks with high original concentrations of indigenous bitumen (2,000 to 6,000 ppm), high HC generation potentials, and porosities which become oil-filled long before HC generation commences, in other words rocks like the Bakken shales, will have high concentrations of HCS around their kerogen at all stages, and even before commencement, of HC generation. As Helgeson et al. (1993) note, even though the process of hydrolytic disporporitonation of OM (one aspect of which is organic metamorphism) is, overall, irreversible, there are many intermediate products in the process which may take part in reversible reactions. By Le Chatelier's principle (Sienko and Plane, 1961), lack of product removal can create an impediment to a reversible reaction, especially where solids are reacting to partly form gas products, such as with (solid) kerogen converting to liquids (oil) and HC gases and CO_2.

From the above discussions, it appears that several different parameters combine to strongly suppress organic metamorphism in hydrogen-rich OM compared to hydrogen-poor OM.

7.11 **Conclusions and Implications**

Numerous R_o profiles, including R_o and ROCK-EVAL T_{max} values for coals, demonstrate that a large part of the Williston Basin depocenter in North Dakota has experienced extremely high heat flows and, consequently, extremely high paleo-geothermal gradients in the geologic past (Eocene or post-Eocene time). In fact, these are the highest paleo-geothermal gradients we have observed in any oil-bearing sedimentary basin worldwide. Subsequently, in the recent geologic past, most of this heat was removed from the basin by strong cross-basinal meteoric-water recharge, via five known aquifers, thus explaining today's more moderate burial temperatures in the Williston Basin.

These unusually high heat flows are pivotal to our discussion, as they have caused some of the richest source rocks in the world, the two Bakken shales, to have completely gone through HC generation over large basinal areas. As a consequence, hundreds of billion of barrels of oil were generated at shallow depths (9000 to 11,500 ft; 2743.1 to 3505.0 m) and injected into well-interconnected reservoirs in the three rocks adjacent to the two Bakken shales, reservoirs created by the HC generation process itself. Detailed maturity maps are being constructed which will allow tight delineation of the Bakken HC kitchen. For a number of different reasons, all aspects of organic metamorphism, including HC generation, are strongly suppressed in hydrogen-rich OM compared to hydrogen-poor OM at the same ranks. Thus, the extreme Williston Basin heat flows have caused HC generation to occur at much shallower depths than normally would be the case. For example, similar oil-resource bases in other basins will occur only depths of 20,000 to 30,000 ft (6,095.7 to 9,143.6 m), because of the high ranks required to initiate and sustain HC generation in rocks with hydrogen-rich OM. In fact, we are not aware of another basin worldwide where this type of oil resource could occur at the shallower depths characteristic of the Williston Basin. Thus, the oil-resource base in the Williston Basin will have far lower recovery costs than other analogous resource bases worldwide.

8.0 RECENT PUBLICATIONS

8.01 Synopsis

Four investigations have reached conclusions divergent from those of this paper regarding the fate and recoverability of the oil generated by the Bakken shales. Each of these studies are discussed in some detail in this section.

Burrus et al. (1996), in a computerized model of the Williston Basin, concluded that the heat flow, and therefore the geothermal gradients of the Williston Basin, had been constant through geologic time at today's moderate values. They further concluded that abnormal fluid pressures never occurred from HC generation in the Bakken shales and therefore, that no hydraulic fracturing of any Bakken Source System rocks had occurred. Lastly, and critically, Burrus et al. (1996) concluded that all the oil generated by the Bakken shales had been dispersed throughout the Williston Basin in porous and permeable Lodgepole limestones. Moreover, this Bakken-generated oil was theorized to be at irreducible-oil saturations in the Lodgepole limestone, too low to be analytically detectable.

We demonstrate that because of the assumptions that Burrus et al. (1996) put into their computer model, their model yielded erroneous results. In one such example, Burrus et al. (1996) assumed an average lateral permeability of 40 millidarcies in the Lodgepole limestone. This assumed value is 4,000 times greater than actual measured average lateral-matrix permeabilities from hundreds of core analyses from numerous wells throughout the Williston Basin. We also compare the predictions from the model of Burrus et al. (1996) to actual observations based on large data bases from Bakken Source System rocks. These checks reveal that the key predictions of Burrus et al. (1996) are most often diametrically opposed to observed data, and thus are erroneous predictions.

Schmoker (1996) observed marked heterogeneities in the oil productivities of Williston Basin Bakken wells at both local and regional levels. Local production heterogeneities (e.g., where two spatially-close wells have produced vastly different amounts of oil) were assumed to be due to heterogeneities (changes) in reservoir geology between the two wells over short lateral distances. However, no proof was offered to support this assumption. We have demonstrated above that reservoir geology is largely constant over our entire area of discussion in the Williston Basin. Schmoker's (1996) assumption on this point is unsubstantiated and controverts the observed reality of Nature. Schmoker (1996) also hypothesized that the cause of the highest Bakken well productivities concentrated in the Fairway area is due to a regional geologic change compared to the rest of the Williston Basin. This regional geologic variation was hypothesized to have resulted in significantly improved reservoir properties, thus explaining the elevated productivities of Bakken Fairway wells, compared to Bakken wells in other basin areas. We provide evidence that Schmoker's (1996) hypotheses on these matters are incorrect.

I concur with Schmoker (1996) that pronounced local and regional production heterogeneities are present between Bakken wells throughout our area of discussion. However, a large body of data I have assembled, which will not be discussed here, *strongly suggests* that these production heterogeneities are mostly due to variable drilling, completion, stimulation, and maintenance procedures applied to different Bakken wells. Inappropriate procedures result in bad wells. Application of procedures appropriate to the unique characteristics of the Bakken Source System result in productive wells.

American Hunter, then a Canadian Hunter subsidiary, put a substantial effort, but unsuccessful, into the Bakken horizontal play, at least as measured by dollars. Only one publication (Carlisle, et al. 1992) came out of the American-Canadian Hunter effort in the Bakken Source System, and the principal conclusion of that publication concerns us, to wit: that the Fairway area of the Williston Basin in North Dakota has the most productive wells because that is where the Bakken shales are most mature and therefore have the best reservoir qualities. This conclusion was based on analyses of Bakken produced oils to determine oil maturity. However, their oil sample base was small (only 5 samples) and biased. We demonstrate that the Fairway area does not have the most mature Bakken shales in the Williston Basin, and that the conclusion of Carlisle et al. (1992) on this matter in incorrect. Moreover, Carlisle et al. (1996) assumed that the Bakken shales are the principal (only?) reservoir for the Bakken oils. We believe that this erroneous assumption is the principal reason for American Hunter's lack of success in their effort in the Bakken horizontal drilling play.

Four small conventional oil fields are present in the middle Bakken siltstone in Canada. Also, the middle Bakken siltstone takes on sandier characteristics in Canada, compared to Bakken siltstones on the American side of the Williston Basin. These facts led LeFever et al. (1991) to propose long-distance lateral (secondary) migration of oil generated by Bakken shales, from the Bakken HC kitchen far south on the American side of the Williston Basin, northward into Canada.

The siltstone itself was proposed to have served as the conduit for this migration. We demonstrate that this proposed lateral migration of Bakken shale generated oil is not possible given observed data. The Bakken siltstone does in fact take on sandier characteristics in a northward direction into Canada. However, siltstone core analyses are available from eight wells on the American side of the basin near the Canadian border, and these analyses demonstrate that even at these northern locations, the middle Bakken siltstone is still a tight rock with very low permeabilities (less than 0.1millidarcies). As such, these more northern siltstones are still incapable of transmitting fluids. Also, oil distribution patterns in siltstones on the American side of the basin could not possibly result from secondary migration of oil. Thus, we do not concur with the hypothesis of LeFever et al. (1991) of long-lateral migration of Bakken oil through the Bakken siltstone.

Instead, we believe that the Canadian Bakken siltstone oil pools most likely originated by a fractionation of indigenous bitumen to an oil-like phase within the Bakken shales. Previous research has demonstrated that this fractionation occurs in Bakken shales, even at very immature ranks. When adequate conduits are directly adjacent to rich source rocks, then expulsion of such fractionated oil to the more porous rock may occur. This is the situation in Canada, where immature, rich Bakken shales are directly adjacent to a moderately-transmissible fluid conduit, the Bakken siltstone, a siltstone that actually has become poor quality sandstone in Canada. Thus, the Bakken siltstone oil pools in Canada could have had a local origin. Moreover, this model of a local origin is supported by molecular differences between American Bakken produced oils and Canadian Bakken siltstone oils.

8.02 **Burrus et al. (1996)**

Burrus et al. (1995, 1996) in a petroleum-geochemical computer modeling study of the Williston Basin, reached far different conclusions than ours, regarding the geologic history of the Williston Basin and the oil generated by the Bakken shales. Because Burrus et al. (1996) is an expansion of Burrus et al. (1995), we only consider Burrus et al. (1996) here. Their principal conclusion, which here concerns us, is that the oil generated by the Bakken shales is dispersed throughout the Lodgepole limestone at very low concentrations and therefore is not an economic resource base. This is exactly opposite of our conclusion that an eminently-recoverable, concentrated-oil-resource base exists in the rocks adjacent to the two shales. We will examine how Burrus et al. (1996) arrived at their conclusion.

As stated above (Section 2.05), a massive amount of petroleum-geologic and geochemical data exists for the Williston Basin, including all the relevant publications discussed above and the NDGS public well file at Bismarck, North Dakota. However, Burrus et al. (1996) opted not to use these data bases and instead made some curious assumptions regarding inputs to their computer model. The most pivotal assumption regards the porosity and permeability values they *assumed* for the Lodgepole limestone: average porosities of 10%, lateral permeabilities of 40 millidarcies, and vertical permeabilities of 0.04 millidarcies. These assumed porosity and lateral-permeability values are much higher than the actual values measured in Lodgepole cores from a number of wells (Table 1, Figures 17 and 18). Measured Lodgepole porosities largely range from 0.1 to 0.3% to maximum values of perhaps 2 to 4%. Measured lateral permeabilities in unfractured Lodgepole rocks are 0.005 (or less) to 0.01 millidarcies, with occasional values up to 0.04

millidarcies. These measured porosity and permeability values do not support the assumptions of Burrus et al. (1996). We will demonstrate below that the measured (real) permeability values of Lodgepole rocks negate the validity of the entire model of Burrus et al. (1996), and that the predictions of their model are at complete odds with the observations (real data) from the Williston Basin.

There is a second problem with the lateral (40 millidarcies) and vertical permeabilities (0.04 millidarcies) assumed by Burrus et al. (1996). Limestones usually do not have such anisotropic permeabilities, where permeabilities are so much higher in one direction than the other, except in the case of solution or karst formation, neither of which is applicable to the Lodgepole limestone. Although we did not discuss vertical permeabilities in Section 6.05 above, they are usually of the same order of magnitude as the lateral permeabilities in Figures 14 to 19, for all three rocks adjacent to the Bakken shales, including the Lodgepole limestone. The reason that Burrus et al. (1996) assumed these unrealistic anisotropic differences in Lodgepole limestone lateral and vertical permeabilities is discussed below.

Because of the assumed high lateral permeabilities for the Lodgepole limestone, the model of Burrus et al. (1996) predicted that all oil generated by the Bakken shales would be quickly transported from the Bakken shales with two results. First, the Bakken-generated oil would be dispersed throughout the Williston Basin at small concentrations constituting a non-recoverable oil-resource base. Second, because Lodgepole rocks were so transmissible to fluids, abnormal-fluid pressures could not possibly build up from HC generation in the Bakken shales. Thus Bakken Source System rocks could not possibly have been fractured from HC generation in the Bakken shales. Burrus et al. (1996) also "proved", by modeling Bakken shale maturities using

ROCK-EVAL reaction kinetics, that the heat flow and geothermal gradients in the Williston Basin had been constant through geologic time at today's moderate values.

Let us consider this latter "proof" of Burrus et al. (1996). ROCK-EVAL kinetics is a standard maturity modeling technique, used throughout the petroleum industry. Basin thermal histories may be estimated from the technique by comparing expected ROCK-EVAL T_{max} values of a given rock, calculated from known burial histories and burial temperatures of that rock, to ROCK-EVAL T_{max} values actually measured for that rock. When calculated, T_{max} values are about equal to measured values, it is generally assumed that geothermal gradients (heat flow) have been constant through geologic time for that rock. Calculated T_{max} values that are considerably less than measured values suggest, on the other hand, that paleo-geothermal gradients have been higher in the geologic past.

As discussed above in Section 3.05 on ROCK-EVAL, starting T_{max} values for rocks buried no more than 500 ft (152 m) vary between 380° to 400°C, with values generally around 390°C (see Figs. 4 and 42). Because Bakken shales obviously do not exist beyond their depositional edge (Fig. 1), the shallowest Bakken shales on the U.S. side of the Williston basin available for analysis are at about 4,000 ft (1,219.1 m) of burial. Immature Bakken shales buried between 4,000 to 7,500 ft (1,219.1 to 2,285.9 m) generally have T_{max} values between 410° to 415°C, based on the large data base published by Price et al. (1984). However, we stress that the starting T_{max} values of these samples, before they were buried to the 4,000 to 7,500 ft (1,219.1 to 2,285.9 m) range, would have been around 390°C. Thus, 390°C is the correct starting T_{max} value for the Bakken shales, as it is for almost all other rocks.

However, when a starting T_{max} value of 390°C is used for the Bakken shales, the ROCK-EVAL kinetics program calculates that the present-day geothermal gradients in the Williston Basin would have to be at least doubled to account for the high T_{max} values (up to 455°C) of the more deeply-buried Bakken shales. This estimate is based on petroleum-geochemical model computer calculations by Jerry Sweeny of the Lawrence Laboratory using the ROCK-EVAL kinetics program he developed, which perhaps is the most widely used one in the petroleum industry. The Sweeny program is also very similar to the Institut Francais du Pétrole (IFP) ROCK-EVAL kinetics program used by Burrus et al. (1996) in their calculations. As discussed below (Section 8.03), Burrus et al. (1996) believed that high paleo-heat flows could not possibly have existed in the Williston Basin. To circumvent the problem of possible higher paleo-heat flows in theWilliston Basin, Burrus et al. (1996, p. 274) simply assumed that starting (original) T_{max} values for the Bakken. shales were 421° to 428°C. By making this unrealistic assumption, Burrus et al. (1996) were able to attribute observed maturities in the Bakken shales solely to the present-day heat flow of the Williston Basin. In our opinion, it is unrealistic to assume computer-input values, which are much different than the actual measured values, for a system, such that a desired result is obtained.

Let us compare some of the key predictions of the model of Burrus et al. (1996) against observed data for that system regarding the Bakken Source System. First, Burrus et al. (1996) concluded that Bakken Source System rocks could not be hydraulically-fractured by abnormal-fluid pressures from HC generation in the Bakken shales. We presented a large body of evidence above (Sections 6.05 and 6.08) that Bakken Source System rocks have been fractured by *super-lithostatic-pressure* fracture events caused by HC generation in the Bakken shales and the resulting abnormal-fluid pressures thereof. In fact, the very unusual predominantly-horizontal fractures in the Bakken Source System rocks can *only* be explained by these super-lithostatic pressures, and the resulting hydraulic frac events. This first prediction from the model of Burrus et al. (1996) is clearly erroneous.

From their model, Burrus et al. (1996) also concluded that the oil generated by the Bakken shales was laterally-dispersed at very low concentrations throughout the Lodgepole limestone, and contrary to the conclusions of Price and LeFever (1992), no producible oil existed in these rocks. Moreover, Burrus et al. (1996, p. 284) predicted that oil saturations in Lodgepole rocks were at near irreducible saturations between 2.0 to 3.0% of the rock porosity; and that, "Oils dispersed in Lodgepole and Madison systems are thus predicted to have concentrations too low to be detectable." Data we presented previously (Figs. 14 to 19) demonstrate that residual-oil saturations in the three rocks adjacent to the two Bakken shales (including the Lodgepole limestone) are far above 2.0 to 3.0% of the rock porosity, where the Bakken shales are thick and mature. Moreover, many other wells with core analyses where the Bakken shales are mature (Table 1) replicate the results shown in Figures 14 to 19. Furthermore, the prediction that oil concentrations in the Lodgepole are "too low to be detectable" is not borne out by the ROCK-EVAL data of Figures 20 to 29, nor by a very large ROCK-EVAL database from other wells that we have analyzed (Fig. 13, Table 3).

These above two predictions, as well as other predictions (which we will not discuss here) from the model of Burrus et al. (1996) for the Williston Basin are erroneous. In fact, the predictions are generally exactly the opposite of reality, as delineated by hard data for this basin. We make two other observations concerning Burrus et al. (1996). First, the key inputs for any computer model predetermine the output of the simulated model. The key inputs (assumptions) of the Burrus et al. (1996) Williston Basin model are completely at odds with available data, published and otherwise in public domain. These assumptions never should have been made. Second, very specific predictions resulted from the Burrus et al. (1996) computer simulation. These predictions could have easily been checked against available data. That such checks were not carried out is curious, to say the least. Other errors exist in the input, assumptions, and conclusions of the model of Burrus et al. (1996). However, these errors do not directly relate to our discussion and thus will not be detailed here.

8.03 **Reasons for the Burrus et al. (1996) Model**

Petroleum basins may be viewed in principally two ways: First, they can be entities which evolve through geologic time with large variations in heat flows (and thus geothermal gradients), water flows, subsidence rates, etc. Second, and this is the view of the Institut Francais du Pètrol (IFP), petroleum basins are largely constant through time with no or few changes other than constant burial. This IFP position was outlined by Burrus and Rudkiewicz (1994, p. 1/4) in discussing advances by the IFP in petroleum-geochemical computer modeling.

> "Detailed investigations of past thermal histories in various basins carried out at IFP (such as Paris Basin, France; Williston Basin, USA/Canada; Mahakam delta, Indonesia; Viking Graben, North Sea) indicate that crustal heat flow has not varied much with time. Observed present day temperatures and organic and mineral paleothermometers can in most cases be accounted for by time invariant crustal heat flow. This tends to disprove the concept of "tectono thermal" event often referred to."

Burrus and Rudkiewicz (1994, p. 3/4) also outlined the IFP's position on fracturing caused by the expansion of OM during HC generation. They acknowledged that different investigators (including Murray, 1968; Finch, 1969; and Meissner, 1978) had previously discussed fracturing in and around the Bakken shales. However, Burrus et al. (1996, p. 279) maintained that this previous work was based on only inference and that there was no hard evidence of this fracturing. Because their simulated model "predicted" no fracturing, they concluded that no fracturing was/is present in these rocks. By Figures 35 and 36, intense horizontal fracturing, which could only have been caused by OM volume expansion during HC generation, is clearly rampant throughout these rocks where the Bakken shales are mature, contrary to the opinions of Burrus et al. (1996).

8.04 **Schmoker (1996)**

Schmoker (1996) drew some conclusions about the oil resource base in the Bakken Source System which parallel our own conclusions. However, he concurrently drew other conclusions opposed to some of our conclusions. Thus, some explanation of these two viewpoints is warranted.

In concurrence with our view, Schmoker (1996, p. 7) recognized that the Bakken Source System oil-resource base was contained in a continuous reservoir,

> "The Bakken Formation in North Dakota and Montana provides an excellent example of a continuous oil accumulation. Throughout a region of approximately 17,800 mi^2 (46,100 km^2), cells of the Bakken formation are charged with oil."

Schmoker (1996) subdivided the Bakken continuous oil accumulation of North Dakota and Montana into three distinct areas (Fig. 52) based on production histories of Bakken wells therein. These areas in order of decreasing productivities, are: the Fairway area, the intermediate area, and the outlying area. Schmoker (1996), like many other investigators, considered the Antelope Field to be a unique entity which would not be repeated elsewhere in the basin. As an aside, we do not agree with this viewpoint concerning the "uniqueness" of the Antelope field, however, the reasons for our viewpoint on this matter will not be detailed here.

Schmoker's (1996) estimated ultimate recovery (EUR) probability distributions for Fairway wells show that the median Fairway well (50th percentile well) produces 89,000 barrels of oil, whereas the median well of the intermediate area produces 18,000 barrels of oil. The total production attributed to the 8,854 mi^2 (22,932 km^2) of the outlying area as of 7/94 was only 5,755 barrels of oil. Thus, these EUR values presented by Schmoker (1996) certainly do appear to demonstrate apparent greater productivities of Bakken wells in the Fairway area.

Schmoker (1996) assumed that the Bakken shales were the principal (only?) reservoir rock for the Bakken oils. We do not agree with this assumption and have conclusive evidence to the contrary, which will not be detailed here. Schmoker (1996) noted, as we have also found, that even within the Fairway area, productivities of vertical Bakken wells can be highly variable over short lateral distances. Schmoker (1996, p. 5) attributed this production heterogeneity as due to variations in geology over short lateral distances: "The underlying assumption is that production heterogeneity is a true measure of reservoir heterogeneity." This is a logical assumption; however Schmoker (1996) presented no data to support his assumption.

In the absence of structuring and laterally variable stratigraphy, such as is the case in Williston Basin, there are only three possible controls on reservoir heterogeneity: porosity, permeability, and natural fracture density. The large number of wells with core analyses (Table

1), representative examples of which are shown in Figures 14 to 19 (and 54), demonstrate that matrix porosity and permeability of all the Bakken Source System rocks, including the two Bakken shales, remain constant, and low, over the entire Fairway and intermediate areas of Figure 52. There is no detectable difference in the porosities and permeabilities of Bakken Source System rocks in wells with high cumulative productions, compared to that in wells with low, or no, cumulative productions. Regarding fracture density, our large ongoing fracture study has involved a number of wells from the Fairway (Table 6) with variable cumulative productions. Again, we have not recognized any detectable increase in fracture intensity in Fairway wells with high cumulative productions compared to that in wells with low or no cumulative productions. Thus, geologic variation does not appear to be the explanation for production heterogeneity in Bakken wells over short lateral distances.

Schmoker (1996) is eminently correct in noting that large production heterogeneities are present over short distances between Bakken wells, and this is a pivotal observation. However, his assumption that these production heterogeneities result from geological heterogeneity is not supported by a large body of geologic data. There is, of course, a cause for these production heterogeneities, and we touch on it below.

Schmoker (1996) also tried to explain the differences in production charcteristics between the different regions of the Williston Basin (Figure 52). He attributed the better production of the Fairway area to three possible favorable characteristics of this area:

1) increasing fracture density towards the southwest depositional edge of the Bakken shale due to thinning of the Bakken shales in that direction;

2) better developed fracture density along a hinge line between the "southwest shelf area" and the Williston Basin depocenter; and

3) the Fairway area being the most thermally-mature area of the Williston Basin, resulting in improved reservoir quality in that direction.

Of the three possibilities, Schmoker (1996) preferred the third. Because of the wealth of data available for this basin, all three hypotheses can be rigidly evaluated; although Schmoker (1996) declined to do this. As we will demonstrate, available data reveal that all three of these possibilities are untenable.

The first possibility was that the Bakken shales become more fractured towards their depositional edge in the Fairway area, because they become thinner and therefore more brittle. This is a repeated theme among explorationists involved with the Bakken shales. However, we are aware of no published evidence that ductility or brittleness of a solid varies as a function of thickness, where the range of thickness is from 25 ft (9.2 m, the average thickness of one of the Bakken shales in the depocenter of the Bakken kitchen) to 6 ft (1.8 m, the average thickness of the upper Bakken shale in the Fairway). *In fact, the Bakken shales, no matter how thick, are always a very plastic rock, much more like bedded salt or "silly putty", than an indurated rock.* The very plastic Bakken shales, *especially the Bakken shales in the Fairway,* have been known to flow through perforations and up the sides of cemented well casings (various personal communications, Brian Jones, then Halliburton, 1992-1997). Thus the plastic nature of this rock has not dramatically changed in the Fairway.

The second possibility that Schmoker (1996) raised involved fracturing due to a hinge-line in the Williston Basin. A hinge-line is that area of an *asymmetric basin*, between the "shelf" of a basin, where the sediments are flat-lying and thin, and the depocenter of the basin, where sediment thickness is greatest. An example of an asymmetric basin is the mid-continent Anadarko Basin. Symmetric cratonic basins do not have hinge-lines. Moreover there is no southwest shelf area in the Williston Basin (Fig. 1). Thus, the "southwest hinge-line" of the Williston Basin, and any possible fracturing caused by such an entity, are really non-existent features. This is confirmed by our ongoing fracture study (Table 6), a study which clearly demonstrates that in point of fact fracturing intensity is significantly *less intense* in the Fairway compared to the fracturing in the center of the Bakken HC kitchen (Schmoker's (1996) intermediate area and part of his outlying area, Fig. 52). This is expected, if the fracturing is a result of fluid overpressuring from expansion of OM during HC generation (as discussed above in section 6.08). This is because the shales in the Bakken HC kitchen are much thicker and have significantly higher starting TOC contents than Fairway Bakken shales.

The third explanation Schmoker (1996) provided, maximum Bakken shale maturity in the Fairway area, is the easiest to evaluate of the three. As discussed above, the optimum measurement of source rock maturity is a map of ROCK-EVAL hydrogen-index values (Fig. 13), where samples are available to do this. Such maps are uncommon, because rarely is a suite of a given source rock available throughout a basin, so that such a map may be constructed. However, such maps are powerful tools, because actual hydrogen index decreases are directly measured, rather than inferred from indirect measurements of source-rock maturity such as R_o or biomarker ratios. Schmoker (1996) referenced Price et al. (1984), thus he apparently knew that the Figure 13 map existed. Instead Schmoker (1996) chose to use indirect source-rock maturity measurements: vitrinite reflectance (R_o) and biomarker ratios (diasterane-to-sterane ratios). Although R_o is the premier-petroleum geochemical maturity index, direct measurements of source rock maturity from the ROCK-EVAL hydrogen index are a much preferred method. Moreover, as discussed above, R_o values are highly suppressed in the hydrogen-rich OM of the Bakken shales, and which R_o values correspond to which stage of HC generation are unknown. Thus, the use of Bakken shale R_o data is fraught with difficulty. The use of biomarker ratios is even more difficult because these ratios are very imprecise when applied as maturity indices.

The data of Figure 13 clearly demonstrate that the Fairway area (shaded) does not have the most mature Bakken shales in the Williston Basin. Large areas of the Bakken HC Kitchen have shales with equivalent maturities to those of the Fairway. Moreover, the entire western part of the Fairway (Fig. 13) has moderately-mature to mid-mature Bakken shales (ROCK-EVAL hydrogen-indices of 300 to 580). A much larger (yet unpublished) Bakken shale hydrogen-index map confirms this aspect of the Fairway based on the more limited data base of Figure 13 from Price et al. (1984). Schmoker's (1996) conclusions regarding Bakken shale maturity do not agree with a very large data base of measured Bakken shale maturities. Again, Schmoker (1996) is certainly correct in his observation that there are pronounced local and regional production heterogeneities between producing Bakken Source System wells. However, his *assumption* is quite incorrect, in my opinion, that these production heterogeneities are due to variations in local and regional geology in the Williston Basin.

As stated above, yet unpublished research that we have carried out strongly suggests that the cause of the production heterogeneities in Bakken wells is almost due entirely to variations in drilling, completion, stimulation, and maintenance procedures of different Bakken wells. These points will be presented in future papers. Recall our discussion above in Section 5.0

(Unconventional Energy Deposits), wherein we stressed that recovery techniques applied to each unconventional energy resource must be appropriate to the unique characteristics of that resource base. If this is not the case, economic retrieval of the resource base in question will not occur. Our research on this matter demonstrates that economic retrieval, per well, of Bakken Source System oil appear to be completely dependent on applying appropriate (currently existing) recovery techniques. As of yet, aside from salt collapse structures (which are rare), local variations in geology have not had any measurable effect on productivities of Bakken Source System wells.

8.05 **Carlisle et al. (1992)**

Recall that the Canadian Hunter Company was briefly mentioned in Section 5.04. Canadian Hunter, at one time, had assembled perhaps one of the best research teams in the entire oil industry involved with exploitation of unconventional HC resource bases. American Hunter was a company formed and owned by Canadian Hunter, to attempt exploitation of the Bakken oil resource base in North Dakota. Although they only drilled seven wells in North Dakota, American Hunter was one of the biggest players in the Bakken Horizontal drilling play, as measured by total dollars spent. Carlisle et al. (1992) was the only publication which came out of the American Hunter Experience. Much of this discussion in this section is via personal communications from Hans von der Dick, a member of the American Hunter team and a co-author on Carlisle et al. (1992), a paper discussed directly below.

Canadian Hunter, after discovering and bringing onto production the super-giant Elmworth basin-centered gas field in the deep Canadian Alberta Basin, recognized the continuous-oil resource base in the Bakken Source System, and thus formed the American Hunter team. They also logically reasoned that if some horizontal Bakken shale wells were such good producers where the Bakken shales were thin in the Fairway area, where almost all the horizontal wells were being drilled at the time, then horizontal Bakken wells should produce much better where the shales were thick. Based on our studies, this assumption with qualifications, one of which is critical, is valid. Moreover, with this assumption, American Hunter possibly came closer to successful exploitation of the Bakken Source System than any other recent exploration group. However, there are caveats to this system which American Hunter did not recognize and which doomed their effort to failure.

With minimal background scientific research (all literature research), American Hunter leased a large part of the Williston Basin where the Bakken shales were both thick and mature. Thirty million dollars were spent on this lease program. Still without background research, seven horizontal wells were drilled in the middle of thick Bakken shales. Because these wells were drilled in an area of abnormally high Bakken formation fluid pressures, the wells were expensive. All seven wells had minuscule initial productions and were absolute economic failures. Only during the drilling of the last well was a research program initiated.

Carlisle et al. (1992) was part of the outcome of this research. However, the research came too late, because the failure of the Bakken program helped to cause reorganization of Canadian Hunter. The purpose of research thus mainly was post mortem to answer the question, "Why had the American Hunter Bakken horizontal drilling program failed, and why were the only successful horizontal Bakken wells in the Fairway area".

In American Hunter's post mortem research, it was assumed that the Bakken shales themselves were the principal reservoir rocks for Bakken oil. Consequently, the research in

Carlisle et al. (1992) was designed to support that premise. We have presented evidence above (Figs. 14 to 36, and the accompanying discussions), that the rocks adjacent to the two shales are important unrecognized reservoirs for this oil. The assumption that the two shales are the only (or principal) Bakken oil reservoirs is, in our opinion, incorrect, and this is the major reason for the American Hunter Bakken failure. In fact, our research conclusively demonstrates that the Bakken shales are incapable of producing commercial amounts of oil anywhere in the Bakken Source System kitchen. However, this point will not be detailed here.

Carlisle et al. (1992) also assumed that because the shales were the oil reservoirs, that variation in shale porosity, permeability and fracturing density, all controlled oil production. Logically, they further assumed that increasing shale maturity increased the values of these parameters, thus improving production capabilities. Carlisle et al. (1992) then proceeded to "prove" that the Fairway area was the most mature area of the basin. This was done by using published vitrinite reflectance (R_o) data from the Bakken shales (Webster, 1984; and Dembicki and Pirkle, 1985), and biomarker analyses (diasterane to sterane ratios) from five Bakken oils. Two of the oils used in the biomarker analysis were from the mature area of the Fairway (please recall that, as stated above, part of the Fairway in North Dakota actually has only moderately-mature shales, Fig. 13). The other three oils were from poor producing wells in basinal areas where the Bakken shales are marginally mature. *Oils from areas where the Bakken shales are thick and mature were not analyzed.* On the basis of this small, and biased, sample population, Carlisle et al. (1992) concluded that the oils from the Fairway area were the most mature Bakken oils in the basin, thus demonstrating (to them) that the Fairway area was the most mature area of the basin.

However, if one immature Bakken oil from the Fairway area had been analyzed along with one Bakken oil from where the Bakken shales are thick and mature, then this conclusion would have been untenable. Two such analyses are presented in Price and LeFever (1994, their Fig. 27, NDGS #1350, and NDGS #12779). NDGS #12779 is an oil from an immature part of the Fairway and consequently has a significantly lower diasterane to sterane ratio than the other Fairway examples provided by Carlisle et al. (1992). NDGS #1350 originates where the shales are thick (22 feet of upper shale, 26 feet of lower shale) and mature (ROCK-EVAL hydrogen indices around 170). NDGS # 1350 also has a very high diasterane to sterane ratio. Had these two, or other similar, oils been included in the data set of Carlisle et al. (1992), then those investigators never could have drawn the conclusions they did, regarding oil maturity of Bakken shales in the Fairway.

Again, like Schmoker (1996), Carlisle et al. (1992) did not elect to utilize the Bakken shale ROCK- EVAL hydrogen-index map of Price et al. (1984, our modified Fig. 13). To repeat, hydrogen index maps are the final word or "bible" on shale maturities. All other maturity parameters, including R_o and biomarker analyses, are indirect measurements of shale maturity and are related back to such maps. The data of Figure 13 do not support the conclusion of Carlisle et al. (1992) that the Fairway has the most mature Bakken shales in the basin, and in fact, disprove Carlisle's et al. (1992) conclusion on this matter on two counts. First, there is a large area of the basin where Bakken shales are as, or more, mature than the Bakken shales of the shaded Fairway area in Figure 13. Second, as previously demonstrated, a large part of the Fairway (the left hand area of the Fairway with elevated ROCK-EVAL hydrogen indices, Fig. 13), has only moderately mature Bakken shales. Price and LeFever (1994) present further data supporting this observation, and as stated above, we possess a much larger, yet unpublished, data base (not shown here) also supporting this observation. Thus, all of the Fairway area is not even mature, contrary to the opinion of Carlisle et al. (1992).

The two principal conclusions of Carlisle et al. (1992) relating to our discussion are, first, that the Bakken shales are the principal (or only) reservoir of the Bakken Source System (actually this was an assumption by Carlisle et al. (1992), and second, that the Fairway is the most productive area of the Williston Basin for Bakken wells because the Bakken shales are most mature there. Published, and much more unpublished, data demonstrate that these conclusions (assumptions) are quite simply incorrect.

8.06 **LeFever et al. (1991)**

If you recall, in our discussion in Section 6.067, we noted that the middle Bakken siltstone increasingly takes on sandier characteristics in going northward towards Canada from the southern limit of Bakken deposition in middle southern North Dakota. Moreover, four "conventional" oil fields in Canada (Hummingbird, Roncott, Rocanville, and Daly) produce oil from the middle Bakken siltstone member. These fields are shown in Figure 53 with other single Bakken siltstone wells in Canada plus Bakken siltstone shows in both the U.S. and Canada. These three facts e.g., 1) the siltstone becoming sandier northward, 2) the four Canadian Bakken siltstone oil pools, and 3) the many Bakken siltstone oil shows of Figure 53, all led LeFever et al. (1991) to propose a long-distance lateral migration of Bakken oil generated on the U.S. side of the Williston Basin, south of the Missouri river, to the Canadian siltstone pools. This entails a maximum migration distance of 188 mi (302 km) to the Daly field. The siltstone itself was proposed to have served as the conduit of fluid transmission. LeFever et al. (1991), on the basis of this scenario, also logically proposed a large unrecognized conventional oil play in the middle Bakken siltstone in the northern Williston Basin. This proposal would appear to be supported by the numerous oil shows which occur whenever the siltstone, or the other two rocks adjacent to the Bakken shales, are drilled. Some of these shows are documented by Figure 53. However, this proposed long-distance oil migration in the siltstone would appear to contradict data presented above which demonstrate that Bakken Source System rocks, when immature, have very low porosities and permeabilities, and are incapable of laterally transmitting fluids. Thus, the study by LeFever et al. (1991) must be discussed. Moreover, the origin of the Canadian pools in the Bakken siltstone must be explained.

However, before proceeding, a few details of these four Canadian Bakken siltstone fields are in order. First, the total recoverable reserves of all four fields are estimated at 2.14 million barrels (LeFever et al., 1991). Thus, these are not large fields. Porosities and permeabilities in these fields have wide ranges; some values are characteristic of good fluid conduits, others are not. For example, siltstone porosities in the Rocanville field average 20% and permeabilities range from 30 to 1000 and average 65 millidarcies. Thus, the middle Bakken siltstone at Rocanville is actually a high quality sandstone. In contrast, average porosity and permeability values for the Bakken siltstone at the Hummingbird field are only 9% and 5 millidarcies respectively. Roncott siltstone porosity averages 14% but permeabilities are low, ranging from 0.75 to 75 and averaging 6 millidarcies. No permeabilities were given for the Daly field; however, porosities averaged between 15 to 17%.

Figure 54 presents porosity, permeability, and percent residual oil and water saturations for NDGS # 8697 (Clarion Resources Pullen 1-33, NENE sec 33 159N 88W). NDGS # 8697 is somewhat near two of the four wells LeFever et al. (1991) used in the construction of their geologic fence (their Fig. 4) on the U.S. side of the basin: NDGS # 8637 (sec 19 161N 87W) and NDGS # 8819 (sec 32 T162N R89W). Porosities in the NDGS # 8697 Bakken siltstone range from 2.8 to 10.3% and average between 7 to 8%. As shown in Table 9, these are measurably higher ranges and averages than found in the siltstones from the 6 wells of Figures 14 to 19, most of which are further south in the basin (Fig. 13). Thus, NDGS # 7851 (Fig. 16) siltstones had porosities between 3.2 to 6.8%, averaging around 5.8%. Siltstones from NDGS # 8709 (Fig. 17) had porosities between 0.5 to 6.0%, averaging about 4.5%, while NDGS # 12494 (Fig. 18) siltstone porosities ranged between 0.8 to 5.6%, averaging about 3.25%. Siltstone porosities in NDGS #11617 (Fig. 19) ranged between 1.6 to 3.7%, averaging around 2.8%, whereas all NDGS #11617 permeability measurements were less than 0.01 millidarcy. Original matrix (unfractured) permeabilities for the siltstones of the wells of Figures 14 to 19 are, for the most part, less than, or equal to, 0.01 millidarcies. The siltstone permeabilities of NDGS # 8697 are still low (Fig. 54), but are noticeably higher than the values of Figures 14 to 19. These increases are due to the siltstone becoming sandier in a northward direction. For example, in NDGS # 8697 (Fig. 54), only one siltstone sample has a value of 0.01 millidarcy, with most other samples ranging between 0.02 to 0.09 millidarcies. The higher values (0.20 to 2.7 millidarcies) in some siltstone samples from NDGS # 8697 over 7,689 to 7,700 ft (2,343.5 to 2,346.8 m) are due to laminar fractures created by HC generation in the upper Bakken shale.

Conversely, well NDGS # 8637 (Fig. 15) one of the wells in the geologic fence of LeFever et al. 1991), and a well slightly to the south of NDGS # 8697 (Fig. 13) does not show the siltstone to be that much more "sandy" than more southern wells. Average permeability (0.035

millidarcies) is slightly higher than the other Table 9 wells, but is still very low. However, average porosity (2.8%) is the lowest of all the Table 9 wells. From these data from NDGS # 8637, we may conclude that the increase in sandiness of the middle siltstone in a northward direction although real, is sporadic.

Let us return to the siltstone in NDGS # 8697. In spite of the higher matrix (non-fracture) permeabilities therein, the siltstone in NDGS # 8697 may hardly be considered a fluid conduit. Table 1 lists the wells with core analyses of Bakken Source System rocks. Six other wells in Table 1 lie in the northern portions of the U.S. side of the Williston Basin (NDGS # 3007, # 8638, # 8699, # 8824, # 8850, and # 13318), and have siltstone core analyses. These core analyses demonstrate that the siltstones in all these wells are tight with very low permeabilities, equivalent to, or less than, the values found in NDGS # 8697 (Fig. 54). A large number of siltstone core analyses from wells in northern U.S. area of the Williston Basin thus demonstrate that the Bakken siltstones there simply do not have the capability to laterally transport significant volumes of oil that LeFever et al (1991) postulated.

Moreover, the residual-oil distributions of Figure 54 (and Fig. 22) also argue against the proposal of LeFever et al. (1991). To wit, long distance lateral migration of oil through fluid conduits (secondary migration) is thought to take place in only limited volumes of the fluid conduit, where the top of the conduit contacts a seal or aquitard (England, 1994, and references therein). This migration pattern is caused by buoyancy forces. In our case, secondary-oil migration would occur at the top of the Bakken siltstone where it contacts the bottom of the upper Bakken shales. Thus, the residual oil in Figure 54 over 7,689 to 7,695 ft (2,343.5 to 2,345.3 m) could be explained by secondary migration. However, the residual oil at the bottom of the siltstone between 7,708 to 7,712 ft (2,349.3 to 2,350.5 m), just above the top of the lower Bakken shale, cannot be explained by, and argues against secondary-oil migration. Moreover, this same pattern was observed in the ROCK-EVAL data of Figure 22 for well NDGS # 9001, also in the northern U.S. portion of the Williston Basin.

We have previously discussed above how this oil has a local origin, moving from the Bakken shales not only into the siltstone, but into all three rocks adjacent to the Bakken shales, as Bakken shale maturity progressively increases. Residual-oil saturation and ROCK-EVAL analyses for NDGS # 8177 (Figs. 14 and 20 respectively) also have this oil-distribution pattern, a pattern which negates the possibility of secondary migration. Lastly, we presented siltstone residual-oil saturations where the Bakken shales are mature (Figs. 16 and 19), and ROCK-EVAL analyses of siltstones where the Bakken shales are mature (Figs. 25 to 27. Moreover, ROCK-EVAL analyses exist of siltstones from other wells where the Bakken shales are mature (Fig. 13, Table 3), as do residual-oil saturation analyses (Table 2). All these analyses demonstrate that the oil staining in the Bakken siltstone, where the Bakken shales are mature, occurs over the entire interval of the siltstone and not just at the top of the siltstone, as would be expected if the oil were due to lateral migration in the siltstone. This oil-distribution pattern in the siltstone, in cases where the Bakken shales are mature, demonstrates that the oil has been emplaced into the siltstone from the adjacent Bakken shales, rather than having migrated laterally through the siltstone, as LeFever et al. (1991) proposed.

Thus, for three reasons, we do not agree with the hypothesis of LeFever et al. (1991) that the origin of the Canadian Bakken siltstone oils is due to long-lateral migration of Bakken oil generated in the Bakken kitchen on the U.S. side of the basin: First, the Bakken siltstone on the

U.S. side of the basin is incapable of laterally transmitting significant amounts of fluids. Second, residual-oil distribution patterns in the siltstone where the Bakken shales are immature could not have originated from lateral migration. Third, residual-oil saturation patterns in the siltstone where the Bakken shales are mature could not have originated from lateral migration either. The question then of course poses itself: If these Canadian Bakken siltstone oil pools (Fig. 53) did not originate from lateral migration of Bakken oil generated in the U.S., how did the oil pools originate? After all, the Bakken shales on the Canadian side of the Williston Basin appear to be too shallow and too immature to have sourced these Bakken siltstone oils. The answer to this question follows:

As discussed briefly in section 6.063, laboratory solvent extractions to recover bitumen from source rocks are always carried out using rocks ground to a fine powder. However, Price and Clayton (1992) carried out a whole-rock extraction, wherein the rock was not ground, and only a small part of the total bitumen was removed by successive immersions of the whole rock in an organic solvent (dichloromethane). The rock they used was Bakken shale from well NDGS # 105 (Fig. 13). This is one of the most immature wells for which Bakken shale core is available on the U.S. side of the basin. ROCK- EVAL T_{max} values for the Bakken shales from this well average 417°, with average ROCK-EVAL production indices of 0.04. Price and Clayton (1992) found that the first extracts recovered from the whole rock were more oil-like than the later extracts, the first extracts having higher contents of saturated and aromatic HCS and lower contents of resins and asphaltenes. Moreover, the first extracts were also significantly more oil-like, and compositionally-different, than the bitumen extracts from the powdered rock. Such extractions have been carried out on five other more mature samples of Bakken shale, and the original results of Price and Clayton (1992) were repeated and reinforced in the more mature rocks (L. Price, unpublished data).

These subsequent analyses, like the analyses of Price and Clayton (1992), demonstrated that the bitumen within these rocks had undergone fractionations (compositional changes) to a more oil-like phase. However, that this fractionation had occurred in the Bakken shales of NDGS # 105 was especially surprising, because these shales are so immature, and nowhere close to commencing mainstage HC generation. Price and Clayton (1992) attributed this fractionation to a gas-driven bulk-phase rearrangement of indigenous shale bitumen within the shales by HC gases, and especially carbon dioxide, which is known to be generated in significant quantities long before mainstage HC generation commences. However, how this fractionation occurs is not important for our discussion, that it does occur is important.

Price and Clayton's (1992) paper carried a number of important petroleum-geochemical implications which we will not discuss here, save one. Price and Clayton (1992) postulated that based on their findings, immature (pre-HC generation) organic-rich source rocks (total organic carbon ≥10%, with hydrogen-rich OM) would have the capability to form small oil deposits if such rocks were either faulted or were positioned directly adjacent to good fluid conduits. This is because either faulting or adequate fluid transmissibility would allow a fractionated oil-like bitumen to move from the source rock to an adjacent reservoir to possibly form oil deposits. Several oil deposits at immature ranks have been found in different basins and apparently have originated from this process (J. Clayton, personal communication, March, 1996). We believe that the Canadian Bakken siltstone fields have originated from the above process, to wit: Oil-like bitumen fractionated and moved from very rich immature Bakken shales into a moderate to good fluid conduit, the (sandy) Bakken middle member on the Canadian side of the Williston Basin.

Comparison of the physical characteristics of Bakken oils produced from the American side of the Williston Basin with the four Canadian Bakken siltstone oils supports an origin of the Canadian oils by the process outlined by Price and Clayton (1992). Concurrently, this comparison also argues against an origin of the Canadian Bakken siltstone oils by long-lateral secondary-oil migration, as proposed by LeFever (1991) et al.:

Bakken Canadian siltstone oils are physically-different than the Bakken oils from the U.S. side of the basin. The API gravities of the four Canadian Bakken oils (Fig. 53) range between 30° to 35° (0.875 to 0.850 gm/cc), except for Daly at 40.2° API (0.824 gm/cc), and the oils are opaque to transmitted light. The API gravity of Bakken oils on the U.S. side of the basin almost never fall below 40° API (0.825 gm/cc) and are always translucent to very translucent to transmitted light. Moreover, analyses of the Canadian Bakken siltstone oils in Osadetz et al. (1994), compared to analyses of Bakken oils from the American side of the basin (Price and LeFever, 1994), demonstrate that these four Canadian Bakken oils have different compositions at the molecular level compared to Bakken oils from the American side of the Williston Basin. For instance, see the examples given in Price and LeFever (1994). Secondary (lateral) migration can be called upon to produce gross physical changes within oils, for example, decreasing both the API gravities and translucencies of the oils with increasing secondary migration. However, secondary migration will not result in changes at the molecular level such as documented in these two (Canadian and American) suites of Bakken oils. In other words, these two oil suites are actually different oil families, and the Canadian Bakken siltstone oils thus appear have been sourced variations may be present between Bakken shales on the American and Canadian sides of the Williston Basin. Such facies variations might be expected in the Bakken shales, based on the facies variation in the Bakken siltstone between the American and Canadian portions of the Williston Basin.

Lastly, it is difficult to accept the argument that lateral migration has so severely altered the API gravity of these Bakken oils. The Stoneview field (Fig. 53, caption) has the northernmost Bakken siltstone production on the U.S. side of the Williston Basin, and is near the Canadian border. However, it should be noted that the Stoneview Bakken siltstone production is unconventional fracture production from the siltstone, in contrast to the conventional production from the sandy Bakken middle member on the Canadian side of the basin. The API gravity for Stoneview Bakken oils varies from 40.8° to 44.0° (0.821 to 0.805 gm/cc). The Hummingbird Bakken pool is 60 mi (96.5 km) west northwest from Stoneview and has an API gravity of 35.0° (0.850 gm/cc) while Daly is 110 mi (177 km) from Stoneview and has an API gravity of 40.2° (0.825 gm/cc). It is paradoxical that a migration of 60 mi (96.5 km) Stoneview to Hummingbird) could result in a decrease in API gravity of 5° to 9° API (0.029 to 0.045 gm/cc), whereas Daly, which is almost twice as far from Stoneview as Hummingbird is, has a *higher* API gravity oil than Hummingbird (40.2° versus 35.0° API, 0.825 versus 0.850 gm/cc). This oil-gravity distribution is unlikely if lateral migration is causing these gravity differences between U.S. and Canadian Bakken oils.

Thus, in summary, there are numerous observations within both the rocks and oils of the northern Williston Basin which strongly suggest that the Canadian oil pools in the Bakken siltstone cannot be due to long lateral (secondary) migration as proposed by LeFever et al. (1991).

Concurrently, these same observations, and other observations made above in this document, all support a local origin of these Canadian siltstone oils from Bakken shales near the oil pools by the mechanism proposed by Price and Clayton (1992). This process also explains the origin of the oils within the lower Lodgepole play, as of 1995-1996, a very active play in the Williston Basin but currently (9/99) less so.

9.0 THE LOWER LODGEPOLE WAULSORTIAN MOUND PLAY

9.01 Synopsis

The lower Lodgepole Waulsortian mound play of the North Dakota portion of the Williston Basin was one of the more active plays recently for the onshore U.S. However, there is a great deal of confusion regarding this play, including the source rock for the oil, and the reservoir characteristics. To prevent this confusion from spilling over to this discussion, we present an overview of the play here. Fortunately, enough hard data exist that numerous conclusions can be drawn concerning this play.

There is some discussion as to the source rock for the lower Lodgepole Waulsortian mound oils. However, the oils have been analyzed by different laboratories and have been found to belong within the Bakken oil family. Moreover, both the lower Lodgepole oils, and the Bakken shales which sourced them, are only marginally-mature in the original discovery area (near Dickinson, Stark County, North Dakota). Core analyses demonstrate that the lower Lodgepole reservoir rock for these Waulsortian mound oils is typical of that for all lower Lodgepole rocks throughout the area of discussion, with low matrix porosity (2 to 6%) and very low matrix permeability (generally less than 0.1 millidarcies). However, in spite of these poor reservoir characteristics, the better wells of this play have very high initial potentials and cumulative productions. For example, the discovery well of the play, the Conoco Dickinson State # 74 was brought in, in February 1993, at an initial-open-hole potential of over 8,000 barrels per day. From Feb 1993 to July 1996, this well produced over one million barrels of oil and was producing over 3% of Conoco's entire onshore U.S. oil production. These high productivities are due to extensive tectonic fracturing in the rocks of the better lower Lodgepole wells. This tectonic fracturing has been caused by salt dissolution and collapse, and has been overprinted on the fracturing caused by HC generation in the Bakken shales. In our opinion, salt collapse is most likely responsible for the entire "Waulsortian Mound" play.

Lower Paleozoic salts (the Devonian Prairie Evaporite) lay beneath Bakken Source System rocks. These salts have been dissolved to varying degrees throughout the entire Williston Basin. When the Prairie Evaporite is dissolved, a brine-filled cavern is created. Eventually the cavern cannot support the weight of the overlying column of rocks above it and these rocks thus collapse into the cavern. Fractures created by the collapse extend vertically above the collapse feature. Such fractures physically disrupted the Bakken shale allowing oil expulsion to occur. These fractures also extended into lower Lodgepole limestones creating both a reservoir and a migration path from the Bakken shale. This then appears to be the origin of the lower Lodgepole oil deposits. As an aside, salt solution and collapse is the only geologic variable we have yet identified which affects the otherwise constant geology of the Bakken Source System.

9.02 **Introduction**

The lower Lodgepole Waulsortian mound play recently was one of the more active oil exploration plays of the onshore U.S. This play was kindled in February 1993, by the Conoco Dickinson State # 74 (Fig. 13, NDGS # 13447 (DS # 74), and Fig. 55) which had an initial potential of over 2,000 barrels of oil/day (over 8,000 barrels/day open hole). At one time, this single well was making over 3% of Conoco's entire onshore U.S. oil production and to June 27, 1996 has produced 1,050,431 barrels of oil. The well produced no water until the Dickinson field was unitized for a waterflood operation in March 1995, and has since produced 74,030 barrels of water. The flames of the play were fanned into a fire when Duncan Oil brought in the 1-11 Knopik (Fig. 55), again at over 8,000 barrels/day open-hole potential. By this time, the exploration community had accepted the hypothesis (first published by Burke and Diehl, 1993) of a ring of Waulsortian mounds ringing the east side of the Williston Basin depocenter.

Waulsortian mounds are ill-defined lower Paleozoic bioherms largely composed of bryozoans, crinoids, and cyanobacteria. There is much confusion regarding the play, especially given the amount of information available for the Williston Basin. Explanations and hypotheses have been fashioned which directly contradict known data. For example, there is no agreement on the source rock for the oil. There is also much debate about how the oil is stored in the reservoir, and in fact about the mounds themselves. Thus, Randy Burke who first (in print at least) proposed the existence of Waulsortian mounds (Burke and Diehl, 1993), later questioned whether the mounds exist at all. Fortunately, there is enough hard data publicly available to provide significant insight to the Waulsortian mound play.

9.03 **The Source Rock**

The source of the Waulsortian mound oil has been attributed either to the Bakken shales or to a non-existent shale in the lower third of the Lodgepole formation, which is thought to be 150 to 300 ft (45.7 to 91.4 m) above the Bakken Formation. With no supporting data, a number of explorationists discuss, and take the existence of this source rock for granted. Unfortunately, only a few wells exist on the U.S. side of the basin that have the lower third of the Lodgepole limestone, which is proposed to contain this source rock, and the proposed source rock is not present in these wells.

Although adequate samples of any given source rock may not be available for study, the existence of a source rock, of significant thickness, basinwide, can be easily checked by electric well logs. Formation density and gamma ray logs are especially useful. Dembicki and Pirkle (1985) provide both references and a discussion of this approach. Organic-rich source rocks are readily apparent from large increases (kicks) in gamma ray logs. Electric logs from North Dakota wells both in the Bakken shale HC and adjacent to the kitchen in an eastward direction provide no evidence of an organic-rich rock in the lower third of the Lodgepole limestone, or for that matter, anywhere in the Lodgepole limestone. A middle Lodgepole shale does exist, and is used as a log marker throughout the U.S. side of the Williston Basin. However, this is not an organic-rich rock, and also is not the lower Lodgepole source rock which has been inferred to exist by different explorationists and researchers. Thus, the inferred lower Lodgepole source rock cannot be documented by electric logs. That is to say, the rock simply does not exist, or if it does exist, it is less than 1 foot (0.3 m) thick and sporadic in occurrence.

LeFever et al. (1995) present analyses of the Dickinson State # 74 oil and conclude that it is clearly Bakken-generated oil. W. Dow (oral communication, June, 1996) has analyzed two samples of lower Lodgepole Waulsortian mound oils from North Dakota (one of which was the Dickinson State # 74), and also concluded both oils are Bakken-sourced. I have also analyzed two samples of these lower Lodgepole oils and found them to be Bakken-generated oils, without question (unpublished data). Thus, although some consider otherwise, or consider the question as unanswered, the lower Lodgepole oils were clearly generated by the Bakken shales.

There is another line of evidence as to the source of the lower Lodgepole oils. Lower Lodgepole wells always have high oil-to-water cumulative production ratios (see Table 1, Montgomery, 1996). For example, the Dickinson State # 74 well produced around 700,000 barrels of oil *and no water*, before water flooding operations began. High oil-to-water cumulative production ratios are a telling characteristic of oils produced from Bakken Source System rocks (Table 7, and Price and LeFever, 1992). Thus, the high oil to water ratios of the productive lower Lodgepole wells strongly suggest that the oil in question has been generated by the Bakken shales.

9.04 **Oil/Source-Rock Maturity**

The maturity of the oils is also a relevant point. LeFever et al. (1995) state that the Bakken shales at Dickinson State # 74 are immature to marginally-mature, with ROCK-EVAL hydrogen indices of around 500. This agrees with our analysis which put the Bakken shale ROCK-EVAL hydrogen indices at this site at about 535. It should be noted that the data of Price et al. (1984) suggest that the hydrogen indices at the State # 74 well would be about 350 (Fig. 13). This discrepancy arises because the Price et al. (1984) hydrogen index map is based on a relatively small number of samples, with no samples in the area under discussion. Our much more detailed hydrogen-index map (not shown here), agrees with the assessment of LeFever et al. (1995). It is not surprising, then, that these Bakken-generated lower Lodgepole oils are immature, as LeFever et al. (1995) have also noted. We will not detail here the petroleum-geochemical characteristics which make these oils immature, except to note that these oils have significantly lower gas-oil ratios, 450-800 standard cubic feet of gas per barrel of oil (SCF/Bbl), versus the norm (about 1,100 SCF/Bbl). These lower gas-oil ratios result from the marginally-mature Bakken shales of Stark County not having had generated as much gas as do more mature Bakken shales.

The marginally-mature nature of the Bakken shale at Dickinson, and therefore of the lower Lodgepole oil, raises three questions. First, how did these immature shales source this much oil, such that a single well has a cumulative production of over one million barrels of oil? Second, how did the oil move from the source rock to the reservoir, where the bottom of the oil column is 150 ft (45.7 m) above the top of the upper Bakken shale? (In the State # 74, there is also 150 ft (45.7 m) of productive reservoir above this 150 foot (45.7 m) water leg.) Third, how will these shale maturities affect the possible extension of this play? To answer these questions, we must understand how these oil deposits originate. The first step to this understanding is to review what is known about the reservoir rocks.

9.05 **Reservoir Porosity and Permeability**

Porosities of these rocks have been highly overstated in review articles. For example, Burke and Diehl (1993) called for porosities of up to 15% in Waulsortian mounds in general. Montgomery (1996, p. 801) states, "Log and core analyses indicate porosities in the range of 2.5 to 13.8%.....". However, Conoco personnel in testifying before the Oil and Gas Board of the North Dakota Industrial Commission concerning the Dickinson State # 74 well, stated that maximum porosities calculated from electric logs were 5 to 6%. Unfortunately, there is no Lodgepole core from this well because the well was a bailout of a deeper (Silurian) test, and thus the well was not cored. However, the North Dakota State Geological Survey (NDGS) made thin sections from cuttings chips of the reservoir interval. Point counting these thin sections reveals average porosities of 2 to 3% for the State # 74 well (Julie LeFever, NDGS and Geoff Matthews, then Lake-Ronel Oil Company, personal communications, 6/96).

The second-most productive well in the Dickinson unit (Fig. 55), and in the entire play, is the Kadrmas # 75 (NDGS # 13574), with a cumulative production with 324,000 barrels of oil (to 6/27/96) from the lower Lodgepole over 9,722 to 9,824 ft (2,63.1 to 2,944.2 m). Of this 102 ft (31.1 m) of productive interval, only 21 ft (6.4 m) of core could be recovered (discussed below) from 9,750 to 9,771 ft (2,971.6 to 2,978.1 m). Core analyses of these rocks (not shown here, on file with the NDGS, Table 1) demonstrate that the porosity in this core ranged from 1.5 to 6.3%, with one sample at 9.4%. The average porosity was 3.7%. Note that the porosities of these lower Lodgepole rocks are, however, greater than the porosities of the lower Lodgepole rocks of Figures 17 and 18, which can be as low as a few tenths of a percent. Part, if not all, of this porosity increase is due to an increase in vugs in the limestones (J. LeFever, NDGS, personal communication 6/96). However, these vugs are not well interconnected and thus this matrix porosity increase is not all that useful.

Montgomery (1996, p. 801) in further describing the lower Lodgepole reservoir rocks notes that these rocks are characterized by:

"....matrix permeabilities generally less than 1 md. (millidarcy).

Reservoir quality is due either to good interconnection within vug-bearing intervals, or vertical fracturing, or both."

This statement by Montgomery (1996) about interconnection within vug bearing intervals, is problematical. If such good interconnection is present, it is reflected by elevated permeability values--this is what permeability measures and means. Low fluid conductivity (bad porosity interconnection) results in the low permeability measurements of rocks. The lack of interconnection in these rocks is also reflected by the observation that unless a vug is connected to a fracture, that vug contains no oil-staining (J. LeFever NDGS, personal communication 6/96). This later observation is in turn reflected by residual-oil saturation from core analyses of the Kadrmas # 75 reservoir rock (not shown here, on file with the NDGS, Table 1), percentages which range from zero to 13.8% and average 3.7%, with 7 of the 21 samples having zero values. Montgomery (1996) is correct about matrix permeabilities being generally less than 1.0 millidarcy. They are in fact generally less than 0.1 millidarcy. However, fracturing which is both measured and seen in the core can vastly increase these matrix permeabilities.

By now it is rather obvious that something strange is afoot. How can reservoir rocks with 2 to 4% porosity and matrix permeabilities of less than 0.1 millidarcy have initial open-hole potentials of over 8,000 barrels/day with cumulative productions of 250,000 to 1,000,000 barrels of oil? They, of course, cannot. Moreover, it is difficult, with such porosities and permeabilities, to see how these rocks could even be considered bioherms in the first place.

Those not enamored with the Waulsortian mound hypothesis early on recognized that these rocks were highly fractured, along with several other interesting observations: First, these "Waulsortian mound" rocks were some of the cleanest limestones in the Williston Basin (an observation readily apparent on electric well logs, as noted by Montgomery, 1996). Second, although some intervals of the Waulsortian mounds were fossiliferous, other intervals were not. This last feature is characteristic of lower Lodgepole rocks throughout the Williston Basin. These Waulsortian mound rocks, in point of fact, are not detectably more fossiliferous than Lodgepole rocks of the same stratigraphic interval from elsewhere in the basin. Montgomery (1996, his Figures 7 and 9) unfortunately overstates the case regarding the fossil-rich nature of these bioherms, by portraying two fossil rich rocks as representative of the whole productive interval, which they are not. Some investigators and explorationists familiar with both the lower Lodgepole play and the rocks involving the play doubt that the proposed Waulsortian mounds even exist in the Williston Basin. Waulsortian mounds may or may not exist, but if they do, they are not the parameter controlling this oil production.

9.06 **Fracturing**

It has become increasingly apparent to those studying the problem that intense fracturing is the principal control for the high productivities in these fields. Indeed, we believe that intense fracturing allowed the formation of these oil deposits in the first place. Note that the cleaner a limestone is, the more brittle it is, which only intensifies accompanying fracturing. Burke and Diehl (1994), in an apparent reversal of their original Waulsortian mound hypothesis (Burke and Diehl, 1993), listed seven reasons pointing to intense fracturing being present in the lower Lodgepole limestones in productive "Waulsortian Mound" wells:

1) such fractures are invariably present and observed in recovered core;
2) during coring, the drill string encounters significantly increased torque and the core barrel often jams;
3) recoveries of cored intervals are very low, often 20 to 30%, a characteristic of highly fractured rocks;
4) permeability measurements are highly variable and vertical permeabilities are often much greater than horizontal permeabilities;

5) lost circulation is frequent during drilling and coring;

6) neutron density electric logs are not repeatable (characteristic of highly fractured intervals);

7) effective measured system (not rock matrix) permeabilities at well bottom are very high (500 to 1,000 millidarcies).

The question now arises as to what caused this intense fracturing, especially in a basin noted for its structural quiescence. LeFever et al. (1995) proposed salt dissolution, and subsequent collapse of the overlying sediments into the leached salt cavern, as the principal cause of this fracturing. The following discussion is largely taken from LeFever et al. (1995).

9.07 **Salt Collapse**

The Devonian Prairie Evaporite is up to 638 ft (194.4 m) thick in North Dakota and has been subjected to intense dissolution throughout the Williston Basin. In fact, it is now missing entirely from the area of the basin involved with the lower Lodgepole play. Salt solution and collapse have long been recognized as resulting in complex structuring in the sediments above the salt in limited areas of the Williston Basin. These two processes are also recognized as long-occurring, but episodic, through time at any given site. Salt collapse, in point of fact, is the premier structural agent in the structurally-quiescent Williston Basin, and is the one geologic variable, we have thus far identified, which affects the otherwise constant geology of the Bakken Source System. LeFever et al. (1995) were the first to recognize that the Bakken shale was significantly thickened below the most productive wells of the Waulsortian mound play. Conversely, dry holes, or marginally-economic wells, had no such thickening of Bakken shale. Montgomery (1996, p.799) also discussed this thickening of the Bakken shale under productive wells. The Waulsortian mound play is in an area (Fig. 55) of the Williston Basin near the depositional edge of the Bakken formation. Hence, before the Waulsortian mound wells, this area of the basin had no recognized lower Bakken shale. Moreover, the upper Bakken shale was only thought to be 2-4 ft (0.6-1.2 m) thick therein, based on electric-log readings from many wells in this area. However at the State # 74 well, the upper Bakken shale had merged with the lowermost Lodgepole shale, which is missing in this well, and the upper Bakken shale was 40 ft (12.2 m) thick, an order of magnitude thicker than it should be. LeFever et al. (1995) also noted that productive "Waulsortian mound" wells always had one or more Mesozoic units above the Bakken Source System rocks and Madison Group carbonates, both of which were also anomalously thick. Such variable sediment thickening at one site through time is clear evidence of episodic salt collapse over geologic time.

Multiple generations of cement are also present in the lower Lodgepole reservoirs, another characteristic of episodic salt solution. The salt collapse episodes are initiated by hot waters moving up a lineament into the Prairie salts. These waters dissolve the Prairie salts, forming a brine-filled cavern. Eventually, the weight of the overlying sediments becomes too much for the cavern to support, and some of the sediment column collapses into the cavern, injecting the brine upward or downward, resulting in a cementation event in the thus fractured rocks. The sediment collapse into the brine cavern therefore causes sagging and intense fracturing to extend into other sediments much higher above the salt collapse (e.g., the Bakken Source System rocks). Multiple collapse events, with multiple brine injections, thus lead to multiple generations of cement.

The timing of oil generation in the Bakken shales relative to the timing of an episodic salt-collapse event is irrelevant as related to the possible formation of an oil deposit. However, we would guess in the area of Stark County involving the lower Lodgepole play, that complete dissolution of the Prairie Evaporite took place before the large early Tertiary heat pulse which we believe occurred in the Williston Basin. In either case (pre- or post-HC generation salt collapse), a fluid-transport avenue is available to move oil generated from the physically-disrupted (intensely fractured to, in some cases, perhaps rubbleized) marginally-mature Bakken shale source rocks, to the fractured lower Lodgepole limestone reservoir. However, in an area where the Bakken shales normally would be thin, such as Stark County, the timing of Bakken shale deposition relative to an episodic salt collapse event might be critical: If Bakken shale deposition did not occur during such an event, then these marginally-mature source rocks would not have reached the inordinate thickness necessary to yield meaningful oil deposits.

The limited positive results of the lower Lodgepole play offer important evidence of the potential of the Bakken Source System throughout the Bakken HC kitchen of the Williston Basin. Montgomery (1996, p. 797) estimates per-well recoveries for the better wells of the lower Lodgepole play at 500,000 to 3,000,000 barrels of oil. We believe that the two Dickinson unit wells, the State # 74 and Kadrmas # 75, will eventually both reach 2.0 to 3.0 million barrel cumulative oil productions before abandonment. However, the reasons for this opinion will be discussed here. The lower Lodgepole play demonstrates that marginally-mature thick Bakken shales are capable of generating oil deposits with wells of 324,000 to possibly 3,000,000 barrel cumulative productions. One may only imagine what correctly completed wells, where thick Bakken shales are present and fully mature, are capable of producing. However, most of these more mature thick shales will not have the vertical fracturing from the salt-collapse sweet-spot overprint of the Stark County area of Figure 55. On the other hand, thick and mature Bakken shales will have created their own fracture network from intense HC generation, and thus might be expected to have productivities similar to the better lower Lodgepole wells in and around Dickinson (Fig. 55).

10.0 MASS BALANCE ESTIMATES OF BAKKEN-GENERATED OIL

10.01 Synopsis

Mass balance calculations regarding the amount of oil generated by the Bakken shales in our area of discussion in the Bakken HC kitchen of Montana and North Dakota suggest that 413 billion barrels of oil have been generated with a potential upside of 503 billion barrels and a minimum of 271 billion barrels. These numbers are larger than three previously-published estimates of 92, 132, and 150 billion barrels. In this section, we discuss the inputs and assumptions which go into our mass-balance calculations. We also discuss the limitations of the previously-published calculations, as well as the petroleum-geochemical limitations which detract from the accuracy of any mass-balance calculations, such as the ones we carry out here.

In the Bakken shales, large density differences exist between the shale mineral matter (about 2.72 g/cc, grams/cubic centimeter and the shale kerogen about 1.40 g/cc). Because immature Bakken shales have very high original TOC contents (16 to 40% TOC by weight), the shales, by volume, are composed of large amounts of OM (organic matter). For example, 16 weight % TOC is equivalent to 31.35 volume % OM, and 40 weight % TOC is equivalent to 63.64 volume % OM. During intense oil generation, over 50% of the OM in the Bakken shales can be converted to oil and gas, roughly in a 3.7 to 1 proportion. Consequently, Bakken shale TOC contents, thicknesses, and ROCK-EVAL hydrogen indices, all dramatically decrease.

To calculate the amount of oil generated by the Bakken shales, one must have starting and ending TOC contents, starting and ending ROCK-EVAL hydrogen indices, and ending shale thicknesses, which can be converted to starting shale thicknesses. In their calculations concerning the amount of oil generated by the Bakken shales, previous investigators did not take the decrease in either shale thicknesses or TOC contents into account during intense oil generation. Those investigators also used unrealistically low starting TOC contents and unrealistically low-hydrogen index losses. Lastly, they also failed to account for the significant volume expansion of OM that occurs during the conversion of solid OM into oil and gas. When all these corrections are applied to the previous calculations, the 92 billion barrel estimate becomes 342 billion barrels and the 132 billion barrel estimate becomes 418 billion barrels.

To calculate the amount of oil generated by any source rock, including the Bakken shales, one must have ROCK-EVAL analyses from a number of samples of that rock. Such analyses exist for the Bakken shales. However, previous researchers using the ROCK-EVAL mass-balance approach have made simplistic and, unfortunately, erroneous assumptions. We refine the ROCK-EVAL mass-balance approach by taking into account various controlling parameters not considered by previous investigators. These topics, which are discussed in some detail in this section, are:

1) the cogeneration of natural gas with oil in source rocks,
2) the overestimation of oil generation potential in source rocks by the ROCK-EVAL instrument, and

3) the underestimation of oil generation potential in source rocks due to uptake of water by kerogen via hydrolytic disproportionation of kerogen during HC generation reactions.

Estimates of in-place Bakken shale generated oil per township-range (36 sections, or 36 miles^2, 93.2 km^2) vary from 1.55 to 3.14 billion barrels per township-range, for Bakken shales presently 52 ft thick (15.8 m) thick, depending on starting TOC and ROCK-EVAL hydrogen index values. These calculated amounts of generated oil may at first seem preposterous or unsupportable. However, other source-rock systems are known to have generated far more than the amounts we calculate for the Bakken shales. However, unlike all other cases involving these large amounts of generated oil, we know for a fact that none of this Bakken-shale generated oil has been expelled from the Bakken Source System. Instead, this oil remains in place, in the Bakken Source System.

10.02 **Introduction**

Three previous publications have presented mass-balance estimates of the amount of oil generated by the Bakken shales: Schmoker and Hester (1983), Webster (1984), and Artindale (1990). The first two are published papers and thus their estimates (132 and 92 billion barrels, respectively) may be evaluated. Artindale (1990) gives an estimate of 150 billion barrels but is an abstract. Thus, we cannot evaluate the (American Hunter) estimate.

Our current estimate of Bakken generated oil in the Williston Basin is 413 billion barrels, with a potential upside of 503 billion barrels and a minimum at 271 billion barrels. In this section, we discuss the inputs to our calculations, provide a critical analysis of previous estimates, and discuss the limitations of any mass-balance calculations concerned with generated oil. *At the* *outset, we stress that there are severe limitations within petroleum geochemistry which limit the accuracy of any mass-balance calculations, including the ones we carry out here.*

10.03 **Inputs and Assumptions**

Three parameters must be considered for any mass-balance calculations on the amount of oil that the Bakken shales have generated: 1) the total organic carbon (TOC) content of the shales, 2) the thickness[1] of the shales, and 3) the percent of organic carbon in the shales which is converted to oil.

This third input can only be obtained from ROCK-EVAL analyses. It would seem that the first and second inputs would be straight-forward, but they are not. For example, Schmoker and Hester (1983) in their estimates of Bakken generated oil, averaged all their total organic carbon (TOC) measurements for Bakken shales and arrived at an average TOC value of 12.1% for the

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[1]Carlisle et al. (1992) noted that the basal lower Bakken shale has a mappable unit of decidely lower TOC values (1 to 2%) compared to the Bakken shales as a whole. They believe that these basal low TOC shales are largely west of the Nesson Anticline. We have seen the same feature in our large ROCK-EVAL data base. However, this characteristic of the lower Bakken shale is also present in numerous wells east (and even far east) of the Nesson Anticline. Moreover, this characteristic appears to be of random occurrence, based on closed-spaced (3"-12", 7.6-30.5 cm) ROCK-EVAL analyses of Bakken-shale core. This lower TOC basal unit gives a significantly lower gamma ray response than the richer Bakken shales and has not been used in our mass-balance calculations. Most probably these rocks were not included in the calculations of other investigators either.

upper Bakken shale and 11.5% for the lower Bakken shale. This is an erroneous approach. For any mass-balance calculations, no matter what the approach, we need an estimate of *starting* TOC values before HC generation, not the average TOC values of mature and immature Bakken shales throughout the basin. Webster (1984) also used average TOC, and not starting TOC values in his calculations. Using basin-wide average TOC values, as opposed to starting values, results in calculated values of generated oil far lower than actual generated amounts.

Shale thickness is also a problem. Bakken shale thicknesses are easily measured from electric-log gamma-ray responses, and we have detailed compilations of the thickness of upper and lower Bakken shales for both the Montana and North Dakota portions of the Williston Basin for the most organic-rich part of the shale. However, contrary to the assumptions of Schmoker and Hester (1983) and Webster (1984), today's electric-log measured thickness values for mature Bakken shales are not representative of the shale thicknesses during HC generation.

During HC generation, both ROCK EVAL hydrogen indices and TOC values strongly decrease. For example, consider a shale with starting hydrogen indices of 575 decreasing to values of 50 after HC generation, a decrease of 525 or 52.5% of the OM in the rock. Oil is composed of about 85% carbon by weight (Hunt, 1979), and from the Bakken Source System gas-compositional data of Price and Schoell (1995), Bakken gases would be composed of around 82% carbon by weight. As discussed above (Section 6.086), 78.7% of Bakken generated products are oil, and 21.3% are gas. Thus, the total Bakken generated products (oil and gas) would contain 0.787 x 85% + 0.213 x 82%, or 84.4% carbon by weight. Therefore, a hydrogen index loss of 525 (or 52.5% of the OM) would also result in an organic carbon loss of .844 x 52.5%, or 44.3%. As discussed above, because of the density differences between kerogen (about 1.4 g/cc, grams/cc) and mineral matter (on average assume 2.72 g/cc) in the Bakken shales, the shale OM occupies a greater volume than suggested by the (weight percent) TOC values. For example, a shale with a starting TOC content of 20% would have 20%/0.844 (the percent carbon in the kerogen) or 23.7% OM by weight. In 100g of this shale, the OM would have a volume of 23.7g/1.40g/cc or 16.9cc, whereas the mineral matter would have a volume of 100g-23.7g - 72.3g/2.72g/cc or 26.6cc. Thus the OM in a shale with a 20% TOC value would comprise 16.9cc/16.9cc + 26.6cc, or 38.8 volume percent of the rock. If 52.5% of the OM is lost during hydrocarbon generation, then 0.525 x 38.8% = 20.40% of the shale volume would also lost. Thus, a mature shale with hydrogen indices of 50, that is 40 ft (12.2 m) thick today, actually would have been 40 ft x 1.2040 = 48.2 ft (14.7 m) thick, before HC generation. None of the previous mass-balance calculations took into account that the thickness of Bakken shales decrease with increasing HC generation.

Lastly, there is a density change of the OM in going from kerogen to oil due to the OM volume increase during HC generation, an increase which was discussed above in section 6.086, which concerned the creation of our fractured reservoir in the rocks adjacent to the Bakken shales. This OM volume increase also enters into our mass balance calculations.

API gravity of Bakken oils on the U.S. side of the Williston Basin ranges between 40° to 47° (0.825 to 0.793 g/cc) and averages around 42° (0.815 g/cc). Kerogen has a specific density of around 1.4 g/cc. Previous mass-balance calculations have simply assumed a conversion of kerogen to oil on an equal volume basis. However, in reality, 1 cc (1.4 g) of Bakken shale kerogen completely converted to Bakken oil would yield 1.718 cc of Bakken oil. Moreover, the reservoir fluid recombination study for the Federal DL-1 well (NDGS-11292 discussed in section 6.086 above) demonstrates that when the generated gas dissolved in the oil is also considered, that the combined generated fluid would actually have a density of 0.6234 g/cc, representing a 225% volume increase in products over reactants during HC generation in the Bakken shales. Because this volume shift was not considered by previous investigators, they have thus further underestimated the amount (volume in barrels) of oil generated from the Bakken shales.

10.04 **Schmoker and Hester (1983), Webster (1984)**

Schmoker and Hester (1983) and Webster (1984) carried out their mass-balance calculations differently, but ended up with nearly the same estimates (132 billion versus 92.3 billion barrels of generated oil, respectively). However, as stated above, both sets of mass-balance calculations have what we consider to be significant errors in their assumptions. Schmoker and Hester (1983) assumed a loss of 16.7% of the Bakken OM throughout what they deemed was the mature area of the basin. Multiplying this percentage loss (which would be equivalent to a hydrogen index loss of 167) by their average TOC values (12.1% for the upper shale and 11.5% for the lower shale) and by the shale thicknesses, resulted in the 132 billion barrel estimate of Schmoker and Hester (1983). However, their TOC values, hydrogen-index decrease, and shale thicknesses are all much too low. Our large ROCK-EVAL base (which is still being acquired, and is thus yet unpublished) demonstrates average starting TOC values for immature Bakken shales ranging between 17-20% (with limited areas of much higher values). So we will increase the starting TOC values by 18.5/11.8%, or 56.8%. Likewise we will increase starting shale thicknesses on average by 20%. Average hydrogen-index losses will be increased from 167 to 334. Similarly, we must take the volume shift into account in going from kerogen to oil and gas. From Section 6.086, we calculated a volume increase of 180% in going from a shale with an original TOC of 18.0% and a hydrogen index of 625, to a shale with a TOC of 12.0% and a hydrogen index of 100, for a hydrogen-index loss of 525. However, in this case, our (average) hydrogen-index loss is assumed to be only 334, so the volume shift will be smaller, or 334/525 x 180% = 114.5%. Thus, Schmoker and Hester's (1983) estimate becomes (334/167+0.568+ 0.20) x 132 x 1.145 = 418 billion barrels of generated oil.

Webster's (1984) approach was more detailed than that of Schmoker and Hester (1983). He assumed starting Bakken shale ROCK-EVAL hydrogen indices of 500. Moreover, Webster (1984) broke the Williston Basin into four generation stages (A-D), with progressive hydrogen-index losses of 100, based on a limited sample base of measured hydrogen indices. Thus, stage A had a hydrogen index loss of 100, while stage D had a hydrogen-index loss of 400. Webster assumed a starting TOC value of 10% for the lower Bakken shale (based on averaged measured values) and used starting TOC values ranging from 1.0% to 17.05% for the upper Bakken shale. Of his 21 TOC values for the upper Bakken shale, 9 TOC values were less than 5%, 9 values were between 5 to 12.4%, and 3 were greater than or equal to 12.4%. (Rick Webster's original calculations were supplied to us via a written communication.). Our large ROCK-EVAL data base demonstrates that Webster's TOC values are much too low (discussed below, section 10.05). If his TOC values are adjusted upward, to reflect the correct situation, and a starting hydrogen index of 575 is used (such that his hydrogen index loss cells now become 175, 275, 375, and 475), then a volume of 342 billion barrels of generated oil results from Webster's method. However, the loss of shale thickness and the volume increase of kerogen going to oil and gas still need to be taken into account, but will not be done so here. Moreover, Webster (1984) only considered the North Dakota portion of the Bakken HC kitchen, excluding a substantial Bakken HC kitchen in Montana.

Further refinement of the calculations of Schmoker and Hester (1983) and Webster (1984) would result in more precise estimates. However, that is outside the scope and intent of this discussion. The objective of these adjustments to the previous mass-balance calculations of the amount of generated Bakken oil is to demonstrate that appropriate modifications, which reflect the reality of Nature, to these previous calculations, result in *much* larger estimates of generated oil.

10.05 **Starting TOC Contents**

Our large ROCK-EVAL data base for the Bakken shales (which is still being collected) demonstrates that immature Bakken shales having hydrogen indices of 575 or greater, and ringing the Bakken shale HC kitchen, have TOC values ranging between 15 to 25%, averaging a little under 18%. Thus, for discussion, we can take 18% as the average starting TOC value for the Bakken shales, based on the TOC values found in immature Bakken shales today. However, even 18% is shown to be a conservative estimate by other considerations.

First, assume that a starting 18% TOC rock, having starting hydrogen indices of 625, goes through HC generation and ends up with hydrogen indices of 100. What is the TOC value of the rock which we would then expect? From considerations above (Section 10.03), the generated products (oil and gas) would contain an 84.4% organic carbon by weight. The hydrogen-index loss would be 525, or 52.5% of the OM, of which 84.4% (the carbon content of the generated products) would be due to organic carbon loss. Thus, a hydrogen index loss of 525 (or 52.5% of the OM) would correspond to 0.844 x 52.5% = 44.3% of a TOC loss. Therefore, 18.0% x (1-0.443) = 10.03%, which would be the TOC value expected after HC generation. Our large ROCK- EVAL data base demonstrates that mature Bakken shales with hydrogen indices of 50 to 150 have TOC values ranging between 6.5 to 20%, perhaps averaging between 9 to 10%. Similar values are found in the more limited ROCK-EVAL data base of Price et al. (1984). However, most of the lower TOC values in our data base (6.5-12%) are from at or near the depositional edge of the Bakken shales, where shales are both thin and to the south of the Bakken HC kitchens in North Dakota and Montana. In these HC kitchens, the Bakken shales are both thick and mature (ROCK-EVAL hydrogen indices of 50 to 150), with average TOC values of about 15% (Fig. 56). This observation suggests average starting Bakken shale TOC's of 14.0/0.557 = 25.13% for the Bakken shales in the HC kitchens of Montana and North Dakota, assuming final ROCK-EVAL hydrogen indices of 100.

Thus, besides shale thickness and maturity, starting TOC values also control the amount of oil generated by the Bakken shales, and thus the size of the resource base.

10.06 **Estimated Amounts of Generated Oil**

10.061 ROCK-EVAL

Any estimate of the amount of oil generated by the Bakken shales must involve ROCK-EVAL analyses, there is simply no other way to carry out such mass-balance calculations. Based on our large ROCK-EVAL data base (which is still being collated), we can demonstrate an average starting hydrogen index of 625 for the Bakken shales of the Bakken HC kitchen, as discussed below (section 10.064).

We have an areally dense sample grid of Bakken shales for the Bakken HC kitchens in North Dakota and Montana, on which we ran ROCK-EVAL analyses. From these analyses, we have constructed a preliminary maturity map showing final (measured) hydrogen index values for the Bakken shales in the HC kitchen. As an aside, while our map (not shown here) has the same general features as the hydrogen-index maturity map of Price et al. (1984, their Fig. 5, our modified Fig. 13), there are differences in details. By subtracting the final (measured) hydrogen index values from the starting value (625), the hydrogen-index loss may be estimated. There is one question with this approach: What does this number mean?

Cooles et al. (1986) were perhaps the first investigators to attempt detailed mass-balance calculations of the amount of oil generated and expelled by a given source rock using ROCK-EVAL analyses. Cooles et al. (1986) simply assumed that the amount of oil expelled by a source rock was equal to the difference of the original HC plus hydrogen indices of a rock ($S_1/TOC_o + S_2/TOC_o$), and the final (measured) HC and hydrogen indices of a rock ($S_1/TOC_x + S_2/TOC_x$). For example, assume an average starting hydrogen index of 625 and an average starting HC index (S_1 peak/TOC) of 5. Thus the total is $S_1/TOC + S_2/TOC = 630$. Assume a mature Bakken shale with a final hydrogen index of 150, and a (S_1) HC index of 25. Thus $S_{1x} + S_{2x} = 175$, and the total amount of oil generated is assumed to be 630 - 175 = 455 milligrams of oil/gram of organic carbon. Then by knowing both the original TOC content and the thickness of the rock, seemingly- accurate mass-balance calculations would yield the total amount of oil generated. However, there are at least two problems with this approach.

First, no supporting evidence has ever been provided by anybody demonstrating that this mathematical approach is valid, e.g., that the hydrogen-index loss is directly equal to the amount of oil generated. Second, volumes of published data from both analyses of source rocks from Nature and from HC generation experiments carried out with source rocks in closed, pressurized, water-wet systems inside stainless-steel reaction vessels demonstrate that significant amounts of HC gases (and especially CO_2) are generated during, and even before, mainstage oil generation. These observations are in direct conflict with most petroleum-geochemical computer models involving HC generation, which assume that no, or negligible, HC gas is cogenerated with oil. Thus, the assumption that all of the ROCK-EVAL hydrogen-index loss is assumed to be directly converted to oil in the ROCK-EVAL method of Cooles et al. (1986) is clearly incorrect.

There is no single multiplier that can be used to correct for this cogeneration of gas with oil, for several reasons. First, from the experiments of Wenger and Price (1991) and Price and Wenger (1992), the composition of gas (% methane, % ethane, % propane, etc.) varies with the different OM types found in different rocks. Also, the composition of generated gas varies with the maturity of the rock under study. Lastly, a major component of the gas is carbon dioxide (CO_2), through all stages of HC generation. This is not a HC gas, so a part of the carbon in the kerogen does not even go towards the manufacture of HCS. As discussed above (Section 6.086), given the average gas-oil ratio (1100 SCF/barrel of oil) and gas composition for oils produced from the mature portion of the Bakken HC kitchen, 21.3% of the hydrogen-index loss would go towards the production of HC gases and not oil. Thus 21.3% of the starting ROCK-EVAL hydrogen index (625) must be discounted for the production of HC gas alone from the Bakken shales.

10.062 Closed System Measurements

As stated above, ROCK-EVAL is a very powerful tool for low-cost analytical screening of large numbers of samples. However, ROCK-EVAL analytical conditions are completely unlike the conditions involved with HC generation in the natural system. In Nature, HC generation takes place in pressurized, water-wet, closed-systems (no, or little, product escape), with low oxygen fugacities, occurring over geologic time. ROCK-EVAL analyses take place instantly in open (immediate product escape), dry, low pressure systems, possibly with moderate oxygen fugacities.

Petroleum-geochemical computer modelers have assumed that ROCK-EVAL analysis directly replicates HC generation in Nature and thus analyses from the instrument are a one on one facsimile of natural HC generation. This is, of course, an incorrect assumption, as has been noted by a number of different investigators, including Price (1994b) and Lewan (1995). However, HC-generation reactions can be, and extensively have been, carried out in stainless steel, closed, pressure vessels where water content, pressure, the pressuring medium, and oxygen (and thus hydrogen) fugacities can all be controlled. There are many different variants of this approach, and of course, some advocates of each experimental approach insist their technique, and no other, is correct. In truth, all of these systems probably mimic Nature about equally regarding HC generation, with no one method being vastly superior to another, and no one system exactly duplicating the natural process. *Be that as it may, all of these systems mimic HC generation in Nature much better than the ROCK-EVAL instrument does.*

These closed-system experimental approaches are especially valuable, because all the products of HC generation reactions may be trapped and analyzed. In contrast, source rocks from the natural system do not contain all the products from natural HC generation reactions, because the generated gases and light HCS are very mobile and migrate (at least short distances) from their generation sites. Moreover, we have presented data above (Section 6.076) demonstrating that there is a huge loss of generated HCS (including heavier HCS) to the drilling mud during the rock trip up the well bore in drilling operations. Closed-system experimental approaches also allow researchers to vary parameters controlling HC generation reactions over wide ranges, such as experimental temperature, and closely examine the effects of varying these parameters on these reactions, using the same starting rock. This is most advantageous, because rock suites from the natural system are rarely (if ever) complete over the entire range of the variable of interest. For example, complete suites of a given rock versus burial temperature are almost never available from Nature (the Bakken shales being an exception) because either, or both, ultra mature or very immature examples from the suite will be missing. There are many other advantages to the closed-system experimental approach which we will not outline here. However, we note that the closed system approach is especially powerful when the results from these experiments can be compared to similar analyses from complete, or nearly complete, suites of rock and oil samples from Nature, such as Bakken shales and oils.

Lewan (1985) developed a variant of this closed-system approach ("hydrous pyrolysis") whereby at the end of his experiments a free-floating crude oil, generated by, and expelled from, rock chips under a layer of water, is found on top of this water. Lewan (1985) maintains that his approach is perhaps the best possible closed-system technique, because it not only closely replicates natural HC generation but also replicates oil expulsion. His point is well-taken; however, it is unproven that hydrous pyrolysis more closely replicates natural HC generation than other variants of the closed-system approach. Moreover, it has not yet been demonstrated that hydrous pyrolysis closely replicates natural oil expulsion from source rocks. Be that as it may, Lewan (1995) has noted that in his experiments he obtains only about 40% of the expelled oil predicted by ROCK-EVAL analyses. Thus, he believes that the ROCK-EVAL hydrogen-index loss should be discounted by 40% in using ROCK-EVAL data to estimate amounts of generated oil. Although, again, his point is well-taken, it is again unproven that the ROCK-EVAL hydrogen index loss should be discounted by 40%. This is because, as stated above, it has never been conclusively demonstrated that hydrous pyrolysis closely replicates natural HC generation or natural source-rock expulsion. To present just one example, the important process of hydrolytic disproportionation of kerogen (discussed below, Section 10.064) would be minimized in all closed-system experimental approaches, because of their very rapid approach to high experimental temperatures, as opposed to the gradual heating which takes place in Nature from gradual burial. Hydrous pyrolysis may, or may not, be the best of all closed-system experimental methods with which to replicate natural HC generation and expulsion processes. However, even if hydrous pyrolysis is the best available closed-system experiment approach, it does not follow, that hydrous pyrolysis is exactly replicating nature regarding HC generation and expulsion. This uncertainty is compounded by the fact that, in Nature, both primary migration (the original movement of HCS from their generation site) and source rock expulsion (the expulsion of HCS from their source system into a trap or a conduit for secondary migration) are the two least understood processes concerning the formation of HC deposits.

Lewan (1995) also maintains that hydrous pyrolysis may exaggerate the amount of petroleum expelled by perhaps as much as a factor of 2, because hydrous pyrolysis would minimize the process of crosslinking during HC generation, which he maintains is primarily a free-radical based reaction. Herein, the carbon molecules of higher-molecular weight compounds in bitumen are cross-linked with the carbon in kerogen such that the TOC content in source rocks increases with increasing maturity, at higher maturities. Lewan (1995) proposed that high contents of water, such as are present in hydrous pyrolysis, prevent such crosslinking by shutting down free-radical sites. The Bakken shales are an excellent candidate to test the cross linking hypothesis, because the shales exist in a closed-fluid system, where the access of water is minimized. Geographically-close Bakken shales, which cut across large ranges of hydrogen indices ≥625 to 50, demonstrate a continuous TOC decrease versus increasing maturity. This observation suggests that the process of crosslinking is minimized, if it occurs at all, in the Bakken Source System.

Although closed-volume, pressurized, water-wet experiments replicate natural HC generation much closer than the ROCK-EVAL analysis, data from all these experiments demonstrate that they are not reproducing Nature at 100%. Thus, the generated products in all these experiments are much higher in resins and asphaltenes than are mature oils and bitumens in Nature. This is an important difference between the two. A solution to this problem of inexact replication of the natural system is to check trends or results from such experiments against data from Nature, to see if previously unrecognized similar trends are present in the natural system. Important, but previously-unrecognized aspects of natural HC generation have thus been characeterized by different investigators in this manner.

The above discussion should highlight that carrying out mass-balance calculations on expelled oil from source rocks is fraught with unknowns, and that such calculations are in reality only estimates. More insight to the topic could be achieved by cross comparing all the generated products from closed-system experiments, such as hydrous pyrolysis (expelled oil, fractionated oil remaining in the source rock, and molecularly-dispersed bitumen) with oils, stains in reservoir rocks, and source-rock bitumens in samples from the natural system for one source system. This would allow a more realistic appraisal of closed-system experiments to be made as a mimic of the natural system. The Bakken Source System rocks and fluids would be a prime applicant with which to carry out this pivotal research.

To return to our discussion, just how much the ROCK-EVAL hydrogen-index should be discounted is unknown, and presently there is absolutely no way to determine what it should be, or even if it should be discounted at all. Clearly, in the case of the Bakken shales, the original hydrogen-index values should be discounted by at least 21.3% to account for the HC generation capacity which goes towards the generation of HC gases. In addition, we will discount the difference between average original (625) and final hydrogen indices by another 10%, which is an arbitrary number, to account for a further possible overestimation of HC generation potential by the ROCK-EVAL instrument.

10.063 HC Generation Models

As discussed above (Section 7.101), the accepted view of HC generation in Nature (Tissot and Welte, 1984) is that HC generation reactions proceed by first-order reaction kinetics where geologic (burial) time may be substituted for burial temperature in Arrhenius equations. Burial temperature is viewed as the principal controlling parameter in HC-generation reactions, with geologic time playing an important, but secondary, role. Thus, both increasing burial temperatures and increasing geologic time are viewed as driving, or increasing the extent of these reactions. Models based on this view predict that HC generation commences over a rather moderate range of burial temperatures (60° to 120°C depending on the burial time), or at maturation ranks corresponding to vitrinite reflectance (R_o) values of 0.6%. Oil is also viewed as being thermally unstable, being destroyed by burial temperatures of 150° to 200°C, depending on the burial time and whose model is being used. This first-order reaction concept is especially amenable to modeling by computer, an example being the Burrus et al. (1996) model for the Williston Basin.

Another viewpoint (Price, 1993, and references therein) is that HC-generation reactions are not first-order reactions at all, but are higher-ordered reactions. Thus, geologic time plays no, or only a minimal, role in HC-generation reactions, and increasing burial temperature is the principal drive of these reactions. We will not discuss this viewpoint in detail here, except to note three points. First, this viewpoint allows for substantially greater HC thermal stabilities than the accepted models. Second, this viewpoint also predicts substantially different reaction kinetics between different OM types (hydrogen-rich versus hydrogen-poor OM). Thus, the hydrogen-rich OM in oil source rocks, such as the Bakken shales, is thought to require substantially higher burial temperatures to commence mainstage HC generation compared to less hydrogen-rich (Type III or terrestrial) OM. Third, although all of them will not be outlined here, other parameters are also thought to play important roles, but secondary to temperature, in HC generation reactions. One of these parameters is water:

10.064 Hydrolytic Disproportionation of OM

There is a third viewpoint (Helgeson et al., 1993) concerning natural HC generation of relevance to our discussion regarding mass-balance calculations of the oil generated by the Bakken shales. By this view, the principal control of HC generation reactions is the decreasing chemical activity of oxygen (oxygen fugacity) which is inversely proportional to the increasing chemical activity of hydrogen (hydrogen fugacity). Increasing temperature is perceived only as a facilitator, allowing these reactions to proceed. We note that oxygen fugacity strongly decreases (hydrogen fugacity strongly increases) with increasing sediment depth, paralleling the increase in burial temperature. Thus, it is quite difficult to unweave the relative contributions of decreasing oxygen fugacity and increasing burial temperature from each other. The concept was discussed in some detail above (Section 7.102), and Price (1994b) and Price et al. (1998) provide an overview of the concept. Helgeson et al. (1993) termed this process, "hydrolytic disproportionation" of OM.

The characteristic of hydrolytic disproportionation of OM of interest to our mass-balance estimates of the amount of generated Bakken oil, is that during HC generation, kerogen chemically takes up large amounts of water, giving off the excess oxygen as carbon dioxide and using the hydrogen in the generation of HCS. Thus, more HCS are generated from this process than would be originally indicated by the ROCK-EVAL hydrogen indices of immature rocks. This point was discussed above in Section 7.102. The amount of excess HCS this uptake of water by kerogen is generating is unknown, but it is significant. Carbon dioxide is the single most abundant compound generated in all HC generation experiments carried out in closed pressure vessels. Moreover, between 200 to 800% more CO_2 is generated in these experiments (depending on OM type and experimental temperature) than can be accounted for by the original oxygen content of the OM (Fig. 50).

Indirect evidence of this uptake of water by Bakken shale kerogen is present in previous data we presented. In the conventional core analyses of Figures16 to 19, we provided evidence of high-residual oil saturation percentages in the small amounts of porosity of the reservoir rocks adjacent to Bakken shales, in basin locations where the Bakken shales are mature. This residual oil was attributed above to a super-lithostatic injection of oil into this porosity. However, this is only a part of the explanation. Before this oil was injected into this porosity, the porosity was filled with water. If the water remained in the porosity, these rocks would have been rubbleized during the injection event. Thus, we are left with only two possible explanations:

1) excess porosity was created, 2) some of the water in this porosity was removed. Both explanations contribute. Let us consider the second possibility first:

How could this second possibility, the removal of some of the original water, have taken place? Previous studies of oil and HC solubilities in water (Price, 1976, 1981) have demonstrated that oil is not dissolved in large amounts in water at temperatures below 275°C. However, water, under the same conditions, is about 100 times more soluble in oil, than oil is in water (Lewan, 1991). Thus, newly-generated Bakken oil, which would have little or no dissolved water in it after expulsion, and traveling along the fracture network created in the rocks adjacent to the Bakken shales, would eventually come to rest, and be in contact with, some porosity containing only water. The oil would be strongly undersaturated with respect to water, and some of the water in the porosity would thus be dissolved in the oil. However, other oil more "upstream" towards the Bakken shales, or perhaps still in the Bakken shales, would still be undersaturated with respect to water, and a concentration gradient of water in the oil would be established. Thus, this water would migrate down the concentration gradient towards water-undersaturated oil. Eventually this migrating water would make contact with, and be incorporated into, Bakken shale kerogen during the HC generation process. Thus we propose that some of the oil in the porosity of the rocks adjacent to the Bakken shales arrived there by "chemically eating" the existing water, while the whole system was under super lithostatic pressure. We note that as unlikely as this scenario may first appear, there is no other known or reasonable explanation for the presence of this oil in the porosity of the rocks adjacent to the Bakken shales. Moreover, petrographic analyses of the horizontal fracture system in the reservoir rocks adjacent to the two Bakken shales supports the widespread occurrence of the hydrolytic disproportionation of OM throughout the Bakken Source System:

Among the tools used to study the fracture system was impregnating three samples of Three Forks shale (from the Texaco Hovde-1 NDGS #2828) and two samples of middle Bakken siltstone from the Maxus Carus Fee 21-19, NDGS #12785) with rhodamine B dyed epoxy. These samples were subjected to autofluorescent illumination under magnification, a process which delineates both open fractures and any other porosity, or microporosity, in the samples. In all cases, there were significant zones of microporosity developed adjacent to the fractures. The investigators of this study noted, "Porosity is enhanced along fracture walls probably as a result of circulating, slightly acidic formation waters prior to hydrocarbon influx. Porosity tends to occur in patches, but within these patches the pore system, although extremely small, appears to be well interconnected. An abundance of open microfractures helps to link up patches of microporosity". (RMGEL, 1998, unpaginated). Two points in this quote warrant comment. First, the reservoir rocks adjacent to the two shales are tight, impervious ("tombstone") rocks, which at no time after the fractures were created, were subject to circulation of "slightly acidic formation waters". Moreover, because the fractures were created by the emplacement of the oil itself, they did not even exist prior to "HC influx". Yet the observations of the investigators are real and valid: petrographic analyses did reveal that areas of these carbonate-rich rocks adjacent to fractures, were etched by weak acid, creating secondary micro-porosity. How is this paradox possible?

Recall the discussion on the hydrolytic disproportionation of OM above in Section 7.102. Besides increasing the hydrogen content of kerogen, another possible consequence of the hydrolytic disproportionation of OM can be the creation of secondary porosity. As discussed in

Price et al. (1998), the principal cause of the hydrolytic disproportionation of OM is either water or OM flowing post each other. When this occurs, the water and OM (in this case fluid oil and gas) undergo a series of aqueous-based redox reactions which oxidize the HCS. One of the principal intermediate products from these reactions are organic acids with the CO_2 as an end product (Helgeson et al., 1993; Price et al., 1998). Water will disproportionate with CO_2 to also form acidic solutions. Thus as Bakken-generated oil flowed through fractures in the reservoir rocks adjacent to the two shales, the oil came into contact with water in the porosity of these rocks (Figs. 14-19). The ensuing redox reactions between the oil (and gas) and water created organic acids and CO_2, which in turn reacted with the minerals in the reservoir rocks, creating the secondary microporosity delineated by the RMGEL (1998) investigation.

The analytical method used to delineate and map the fracture system provides further insight to it. A sawn core face is soaked in water and the excess water is then removed with an absorbent cotton bath towel, leaving a damp surface. This surface will shortly air dry, or the process may be speeded up by blowing on the rock face. However, when horizontal fractures are present in the rock, they continue to bleed water after the rest of the rock surface has dried. This behavior is most unusual and previously had not been observed in any other of the many fracture systems studied by Stolper Geologic. This ability to absorb and bleed water arises from the microporosity developed adjacent to the fractures. Coring-induced, or other man-made fractures in these rocks do not have this ability. Thus our observations dovetail those of RMGEL (1998) and document that the secondary microporosity is adjacent to all horizontal microfractures in the Bakken Source system reservoir rocks.

The microporosity adjacent to the fracture walls carries another important implication. Some investigators having been shown or told of the horizontal fractures in the Bakken Source System reservoir rocks have immediately attributed the fractures to shale dehydration, being coring-induced, or to expansion (or contraction) from pressure release, etc. Such immediate explanations understandable, given that horizontal fracture systems are of course usually geologically impossible, due to the earth's stress fields. The explanation of shale dehydration is most unlikely, because the Bakken Source System reservoir rocks are dense carbonate-rich rocks, which may (or may not) have weak laminations. However, in no way may any of these rocks be considered shales, and that includes the ill-named "Three Forks shale". Moreover, all three reservoir rocks have only minute amounts of water remaining in their porosity. Induced fractures are present in the Bakken Source system reservoir rocks; however, they are readily apparent. Moreover, scanning electron microscopy (SEM) demonstrates profound textural differences between naturally-occurring and induced fractures (one difference being no adjacent microporosity development adjacent to induced fractures). *In fact, the secondary microporosity ubiquitously adjacent to the horizontal fractures dictates that the fractures could only have been generated in situ in the natural system.*

Thus, we believe that the residual oil in the porosity of the Bakken Source System reservoir rocks, as measured by traditional core analyses, was emplaced there by two mechanisms: 1) solution of pore water into the newly migrated Bakken oil, and 2) creation of secondary microporosity in the reservoir rocks in areas directly adjacent to the fractures which were created by the migrating oil.

Other evidence, which both supports the occurrence of hydrolytic disproportionation of kerogen in the Bakken HC kitchen, and also strongly enters into the mass-balance calculations under consideration, exists in the large Bakken shale ROCK-EVAL data base being assembled. That data base demonstrates that in proceeding from east to west, hydrogen indices in the Bakken shales which are immature and have not commenced HC generation demonstrate a continual, but scattered, increase in values. This increase maximizes in a swath perhaps 15 mi (24 km) wide just east of the 500 hydrogen-index contour of Figure 13 (not shown in Fig. 13). Within the entire length of the swath from Canada south to the depositional edge of the Bakken shale in Stark Co., Bakken shales exist with highly-elevated hydrogen indices (575 to a maximum value of 810, most values in the 600-650 range) compared to more eastern Bakken shales. This zone of elevated hydrogen-index values could be attributed to facies shifts from changing original depositional conditions; however, analyses to date (kerogen maceral analysis and qualitative analysis of the saturated and aromatic HCS and biomarkers) do not support this hypothesis. Moreover, as noted by Price et al. (1984), when facies shifts do occur in the Bakken shales, qualitative differences manifest themselves in the shale bitumen. Analyses we have performed support that observation of Price et al. (1984); however, those analyses will not be discussed here. Thus, we attribute this north-south trend of elevated ROCK-EVAL indices to the process of kerogen being hydrogenated via water incorporation by hydrolytic disproportionation of OM. As an aside, as one proceeds slightly to the west of this zone, commencement of intense HC generation occurs, and Bakken shale hydrogen-indices rapidly decline from this maxima.

Evidence of a pronounced hydrogen enrichment of kerogen by the hydrolytic disproportionation of OM has been published in other studies. Figure 57, from Price (1997) and after Bertrand (1984), is a plot of R_o versus the ROCK-EVAL hydrogen index, for coals from worldwide localities. The relevant feature of Figure 57 is the strong increase in the hydrogen indices over $R_o = 0.2$ to 0.6%, with the mean hydrogen index at $R_o = 0.2\%$ being around 150 versus around 230 at $R_o = 0.6\%$. The strong decrease in hydrogen indices at R_o values above 0.7%, is due to the commencement of intense HC generation. The pronounced increase (over 50%) in hydrogen indices at immature (pre-HC-generation) ranks in Figure 57 supports the laboratory obsersvations of a pronounced hydrogen enrichment of kerogen via reactions with water. Moreover, a similar large data base from coals presented by TeichmÜller and Durand (1983) also shows a pronounced increase in ROCK-EVAL hydrogen indices over immature ranks, as does a smaller data base of New Zealand coals (Suggate and Boudou, 1993).

Figure 58 presents a large ROCK-EVAL data base for shales with type IV/III and III OM from the Los Angeles Basin. Again there is a pronounced increase in the ROCK-EVAL hydrogen-index over immature ranks (burial temperatures of 40° to 100°C) and beyond. CIHG in Figure 58 refers to the commencement of intense HC generation, as determined by the TOC-normalized S_1 ROCK-EVAL peak. Lastly, aqueous pyrolysis laboratory experiments carried out by Wenger and Price (1991) and Price and Wenger (1992) on six rocks with different OM types also demonstrated this phenomenon. In the lower-temperature, pre-HC-generation, experiments, ROCK-EVAL hydrogen indices significantly increased, with increasing reaction temperature, relative to values for the unreacted rocks.

Thus, both data from the natural system and from laboratory experiments support a hydrogen-enrichment of kerogen by water via hydrolytic disproportionation of OM. A small part of this hydrogen enrichment is due to some of the original oxygen in the kerogen being given off as CO_2. However, mass-balance calculations demonstrate that this loss of carbon and oxygen can account for only a minor part (5 to 15%) of the increase in hydrogen indices. The topic of the hydrolytic disproportionation of OM has been discussed at such length because it plays two key roles in Bakken Source system oil-resource base: First, it significantly increases the HC generation potential of the Bakken shales by increasing kerogen hydrogen richness. Second, it dramatically enhances the reservoir characteristics of the rocks adjacent to the Bakken shales, increasing the oil-storage capacity of these rocks through the creation of secondary microporosity adjacent to the fractures. Also, reservoir productivity is increased by increasing the interconnection of oil-bearing areas within the reservoirs.

10.065 The Present Estimate of Bakken-Generated Oil

Returning to our mass-balance considerations, as stated, we do not know how much excess oil is created by the uptake of water by kerogen during HC generation via hydrolytic disproportionation of kerogen, outside of the fact that it is significant. As a "blue-sky" estimate, we will assume that the excess oil thus created offsets 33% of the loss in ROCK-EVAL hydrogen indices from the generation of HC gases.

Let us review our other inputs: First, based on our large ROCK-EVAL data base, starting average TOC contents are conservatively assumed at 22%. Recall from our discussion above (section 10.05), that based on the data of Figure 56, average starting TOC contents of Bakken shales in the most mature part of the Bakken HC kitchen were back-calculated as 25.1%. Second, shale thicknesses are restored to original values before HC generation occurred. Third, the difference of average starting (625) and final hydrogen indices is discounted to 90% to account for a possible optimistic estimate of oil generation capacity by the ROCK-EVAL instrument. Fourth, we assume that 21.3% of the oil generation potential of the Bakken shales goes towards cogeneration of HC gases with oil. As stated directly above, we further assume that 33% of this loss in actual oil generation capacity is offset by the excess oil generated because of uptake of water by the Bakken shale kerogen during HC generation. This results in a total discount of 0.758 of the difference between the starting and ending ROCK-EVAL hydrogen indices. Fifth, as discussed above in section 6.086, we account for the volume shift in converting kerogen to oil by dividing the original density (1.4 g/cc) of immature Bakken kerogen before HC generation by 0.815 g/cc (the density of 42° API gravity Bakken oil). We then discount that number (1.4 g/cc/0.815 g/cc = 1.72) by 20% to take into account the increase in the density of spent Bakken kerogen (to an assumed density of 1.75 g/cc), for a final multiplier of 1.374 times the difference between starting and ending hydrogen indices.

ROCK-EVAL hydrogen indices and TOC contents from a dense sample grid of Bakken shales throughout the Bakken HC kitchen will eventually yield detailed hydrogen-index and TOC maps. Through a series of cells throughout the Bakken shale HC kitchen, the amount of oil generated by each cell can be calculated, given the original (restored) shale thicknesses and final hydrogen-index values. Such calculations have been carried out on an older data base of Bakken shale ROCK-EVAL data much larger than that in Price et al. (1984), but smaller than that we are currently working on, for preliminary estimates of the amount of oil generated by the Bakken shales. However, the details of these calculations, with older accompanying maps, will not be presented here for two reasons. First, this would significantly increase the length of this article. Second, another set of calculations will be carried out, with more detailed maps, once all the ongoing ROCK-EVAL analyses of Bakken shales are complete.

By the above mass-balance approach, we calculate that the Bakken shales have generated 413 billion barrels of oil. By changing some of the basic assumptions, we believe the lowest possible number to be 271 billion barrels with an ultimate ceiling of 503 billion barrels of oil. Moreover, as will be discussed in future publications, we believe that at least 50% of this in-place oil (206.5 billion barrels) may be recoverable at less than $12 per barrel oil prices. Let us put this 206.5 billion barrel number in perspective. The proven recoverable reserves of the U.S. presently are 25 billion barrels. 206.5 billion barrels is also significantly larger than the largest known oil field in the world (Ghawar field, Saudi Arabia at 100 billion barrels recoverable).

10.066 Small-Scale Estimates

The magnitude of this in-place oil-resource base is also demonstrated by calculating the amount of oil contained in 10 sections (10 square miles) using two different sets of assumptions. In these calculations, for simplicity, we will use only English units of measurements. In the first (conservative) case, we assume a starting TOC of 16%, starting hydrogen indices of 575, and ending hydrogen indices of 125, for a now 52.0 ft thick section of Bakken shales that were, as deomonstrated directly below, therefore originally 59.3 ft thick. The hydrogen index loss is 575-125=450, which we discount by 24.19% (.758 x 450) to 341.2 from both the over-estimation of oil generation potential by the ROCK-EVAL instrument and the percentage of the Bakken shale generation potential (21.3%) which goes towards generating HC gases. Again, 33% of the amount of gas generation, is assumed to be offset by the excess oil generated by the kerogen from water uptake via hydrolytic disproportionation of kerogen during HC generation. Shale with 16.0% TOC would have 16.0%/0.844 (the percent carbon in the kerogen) or 18.96 weight % OM.

The OM (kerogen) would have a density of 1.4 g/cc, and the mineral matter a density of 2.72 g/cc. Thus the OM would make up

$$\frac{18.96\text{ g}/1.4\text{ g/cc}}{18.96\text{ g}/1.4\text{ g/cc} + (100\text{g}-18.96\text{ g})/2.72\text{ g/cc}}$$

or $$\frac{13.54\text{ cc}}{13.54\text{ cc} + 29.79\text{ cc}} = 31.35 \text{ volume \% of the rock}$$

Thus, 31.25 volume % x 45.0% (the hydrogen index loss) = the volume of the shale converted to oil = 14.06%. Shales now 52.0 ft thick would originally have been 114.06% x 52.0 = 59.3 ft thick.

1 Barrel of oil (42 gallons) = 5.6146 ft^3/barrel

1 Section = 1 $mile^2$ = $(5{,}280\text{ ft})^2 = 2.788 \times 10^7\text{ ft}^2$

The multiplier for the volume shift of kerogen converting to oil is 1.374.

The unit conversion of shale to oil = 31.25 volume % OM x 34.12% (HI loss (450) x 0.758) = 0.1066.

One section of this mature Bakken shale has generated:

$(59.3\text{ ft})\ (2.788\text{x}10^7\text{ ft}^2)(0.1066)\ (1.374)/(5.6146\text{ ft}^3/\text{Bbl}) = 43.1 \times 10^6$ Bbls/section

or, 431,000,000 barrels of oil in 10 sections, or 1.55 billion barrels of oil per township (36 sections).

Let us consider a second, less conservative, but still realistic case. Assume a starting TOC of 25%, starting hydrogen indices of 625, ending hydrogen indices of 50, for a now 52.0 ft thick section of Bakken shales. The hydrogen index loss is 625-50=575, which we discount by 0.758 (0.758 x 575) to 435.8 from the over-estimation of oil generation potential by the ROCK-EVAL instrument and from failing to account for gas generation. Converting the weight percent TOC to weight percent OM: 25.0/0.844 or 29.6 weight percent OM, and applying the calculations as above,

$$\frac{29.6\ g/1.4\ g/cc}{29.7\ /1.4\ g/cc + (100\ g\text{-}29.6\ g)/2.72\ g/cc}$$

$$\text{or, } \frac{21.14\ cc}{21.14\ cc + 25.88\ cc} = 44.96$$

Thus, 0.4496 x 57.5 (the hydrogen-index loss) = 25.85%, or the volume of shale lost to HC generation. Shales now 52.0 ft thick would originally have been 52.0 x 1.2585 = 65.4 ft thick. After discounting the ROCK-EVAL hydrogen-index loss (0.758 x 0.575 = 0.4359), we would have a unit conversion of shale to oil of 0.4496 volume % OM x 0.4359 = 0.1959. Thus, one section of this mature Bakken shale would be calculated to have generated (65.4) (2.788 x 10^7 ft^2 (0.1959) (1.374/(5.6146$^{ft3}/_{bbl}$) = 87.4 x 10^6 bbl of oil per section or, 3.14 billion barrels of oil per township (36 sections).

10.067 Comparisons to Other Oil Source Systems

The potential in-place oil estimates in Sections 10.065 and 10.066 at first no doubt appear to be unrealistic. However, as Price (1994a) noted, it is well known that good source rocks often have been calculated to have generated several orders of magnitude more oil than found as conventional deposits in a basin. This point is illustrated by the data of Table 10 from Magoon and Valin (1994) in the authoritative AAPG Memoir 60 on Petroleum Systems. Some source-rock systems are capable, by the data of Table 10, of generating a trillion barrels of oil. However, more impressive evidence from Nature exists of even larger generative capabilities. As discussed above in Section 5.02, very large tar sand deposits have been delineated in Western Canada (2.65

trillion barrels) and in Eastern Venezuela (perhaps as much as 10 trillion barrels). Although now tar, the oil in both areas was first expelled as a mature light oil, most of which has been lost over geologic time. We may conservatively triple the amount of tar to represent the original amount of expelled oil. This results in only the tar sands representing 7.95 trillion barrels of oil expelled in Western Canada and 30 trillion barrels of oil expelled in eastern Venezuela. Moreover, oil in conventional deposits, and oil lost to dispersion and seepage over geologic time would still have to be added, to arrive at the amounts of total expelled oil in both basins. By these comparisons, the calculated amount of generated Bakken oil (413 billion barrels) does not appear to be so outrageous.

The depocenters of both the Western Canadian (Alberta) and Eastern Venezuelan Basins are highly structured, which has no doubt helped in the expulsion of the HCS to form the tar sands there. High oil expulsion efficiencies from source rocks were probably operative in both cases. We note that the large amount of oil calculated to be generated by the Bakken shales has a unique characteristic compared to the many other cases of large calculated amounts of generated oil from source rocks. Due to the unrivaled sample bases in the Williston Basin, as discussed in section 4.03, we know for a certainty, that none of this Bakken-generated oil has been lost from the basin. All this generated oil remains in the Bakken shales and in the rocks adjacent to them at relatively shallow burial depths (9,000 to 11,500 ft; 2743 to 3505 m). This is a given. There is no other basin worldwide, where we may presently draw this conclusion. This certain knowledge that 413 billion barrels of in-place oil exists in the Bakken Source System rocks in the Williston Basin presents the oil industry with an unparalleled "exploration" opportunity.

11.0 OTHER CONSIDERATIONS

11.01 Synopsis

In this section, we consider several unrelated topics which combine to make the Bakken Source System a unique, or at least a very rare, entity. First, the extreme paleo-heat flow in the Williston Basin has resulted in the Bakken shales generating a huge oil-resource base at relatively shallow depths (9,000 to 11,500 ft; 2743.1 to 3505.0 m). The hydrogen-rich OM of oil source rocks (such as the OM in the Bakken shales) requires significantly higher burial temperatures to initiate and pass through intense oil generation than generally recognized by the oil industry. Thus, in most basins, unconventional oil-resource bases analogous to the Bakken oil-resource base will be at depths of 20,000 to 30,000 ft (6,095.7 to 9.143.6 m). Therefore, prohibiitively-deep, expensive, and mechanically-difficult wells (because of the high burial temperatures and very high fluid pressures) will be required to recover analogous unconventional-oil-resource bases in other basins.

Three other characteristics also contribute to the uniqueness of the Bakken Source System resource base:

- First, a very large sample base exists in the public domain covering the oil kitchen of the Bakken Source System in North Dakota and Montana. Moreover, a very detailed well-history sample base exists for all Bakken-producing wells of North Dakota. These well histories provide pivotal insight on proper recovery procedures for Bakken Source System oil.

- Second, a large number of varied analyses have been performed on many of the above samples. Such very large sample bases and the analyses thereof, will be absolutely necessary for the delineation and recovery of analogous unconventional oil-resource bases in other sedimentary basins. However, similar dense sample bases, with corresponding analyses, simply do not exist for other basins.
- The third characteristic is the positioning of world-class source rocks between several hundred ft (60-90 m) (both up and down) of tight impermeable rocks which cannot transmit fluids. Although this association is not unique, it is uncommon. Usually fluid transmissible carrier beds are found within several hundred ft (60-90 m) of source rocks. These carrier beds drain off significant percentages of generated oil, thus dispersing the resource base. Completely closed-fluid systems, like the Bakken Source system, are the exception and not the rule.

Bakken Source System oil is among the highest quality oil in the world, being 40° to 42° API gravity (0.825 to 0.815 specific gravity), low sulfur (0.1 weight percent), low wax, and very low in asphaltenes. This naphthene-aromatic-based oil also has high concentrations of gasoline through the diesel distillates (Fig. 31).

11.02 **Introduction**

Three unusual characteristics of the Bakken Source System each imparts a degree of uniqueness to the Bakken Source System. All three characteristics combined may make the Bakken Source System a unique feature among petroleum basins worldwide, based on currently-available information. Because of the uniqueness of the Bakken Source System, unconventional oil-resource base analogous to the Bakken Source System in other sedimentary basins will not presently be economically viable.

11.03 **The Uniqueness of the Bakken Source System**

11.031 Williston Basin Paleo-Heat Flow

The paleo-heat flow in the Williston Basin, a topic of some discussion above, has far-reaching economic implications. These implications revolve around the burial temperatures that are necessary for oil-source rocks with hydrogen-rich OM to commence and go through mainstage HC generation. As stated above, the oil industry generally believes that intense HC generation begins in all source rocks at between 60° to 120°C, or at a vitrinite reflectance (R_o) of 0.6%, depending on the burial time. This is not at all the case, because the hydrogen-rich OM comprising oil-source rocks requires far higher ranks than $R_o = 0.6\%$, as would be read in coals or type III OM, to initiate mainstage HC generation. This concept, and the data supporting it, was discussed above. Although this hypothesis (and the associated data) have not been accepted by the oil industry, an important implication results from this hypothesis regarding analogous basin-centered unconventional-oil deposits in basins other than the Williston. Thus, in the case of normal to moderately-high present-day and paleo-geothermal gradients, great depths of burial (20,000 to 30,000 ft, 6.095.7 to 9,143.6 m, or greater) are required for source rocks with hydrogen-rich OM to enter into and pass substantially through mainstage HC generation. Consequently, very deep and expensive wells will be required to recover unconventional-oil resource bases generated by such source rocks. Not only will these other wells be more expensive than Bakken wells, they will also be much more difficult to drill, because of the higher fluid pressures and temperatures at these greater depths. By contrast, the Bakken oil-resource base is contained entirely between 9,000 to 11,500 ft (2,743.1 to 3.505.0 m). As stated above, the paleo-geothermal gradients in the Williston Basin are the highest paleo-(or present-day) geothermal gradients that we have observed in any basin worldwide. We are unaware of any other basin in the world where analogous oil-resource bases could exist at such shallow depths, in a largely unstructured basin, such as the Williston Basin.

11.032 The Unparalleled Williston Basin Sample Base

To restate the point made in section 2.05, the uniqueness of the Williston Basin sample base is paramount. There is no other basin worldwide, of which we are aware, that has a fraction of the Williston Basin sample base in existence, much less available in the public domain. Moreover, the completeness of the sample and well-history databases for every well drilled in North Dakota, is also unique. Even if comparable sample bases exist (which to our knowledge, they do not), an equivalent level of sample analyses (analyses costing millions of dollars), most of which is in the public domain, certainly does not yet exist. A level of analyses comparable to that of the Williston Basin will be necessary before this type of play can be applied in any other basin, even discounting depth of production considerations.

11.033 The Source-Reservoir Relationship

The two Bakken shales may not be the best oil-source rocks in the world, but they are in the top 3 or 4 of the world for oil-generation capability on a volume per volume basis of rock. Thus, we have two world-class source rocks encased in a thick sequence of tight impermeable rocks (the Lodgepole limestone, Bakken siltstone, and Three Forks shale) which, without fracturing, are incapable of fluid transmission. The Williston Basin is the least-faulted oil-productive basin in the world (Price, 1994a). There are simply no avenues of transport to move

Bakken-generated oil out of the immediate vicinity of the source rock. Moreover, the brittle carbonate-rich rocks adjacent to the Bakken shales have been transformed into highly-fractured, well-interconnected, world-class reservoirs.

This advantageous association of world-class source rocks with a closed-fluid system, where excellent well-interconnected reservoir rocks are "manufactured" during HC generation, and yet no oil is lost from the system, may not be unique. However, it is most uncommon. More often than not, an adequate fluid conduit will be present within 200 ft (61.0 m) of a source rock, and eventually HC-generation-induced fracturing will reach that conduit. This will drain a significant part of any oil resource from in and around the source rock. Also, the depocenters of most other petroleum basins in the world are much more faulted than the Williston Basin depocenter. Such faults provide excellent fluid conduits to drain oil generated by source rocks. Lastly, the stratigraphic association of the two Bakken shales, two thick world-class source rocks, with the adjacent brittle tight reservoir rocks is uncommon. More often that not, rich source rocks are encased by other less-organic-rich shales. In this situation, the generated oil is in a "reservoir" composed of shales, rocks which tend to be plastic even when not organic-rich. Thus, economic recovery of oil generated by the organic-rich source rock portion of the shale sequence would be difficult, because no solid reservoir rock would be present in such other systems. Other times, thin rich source rocks tend to alternate with potentially good reservoir rocks, such as sandstones or perhaps carbonates. Examples are the Pennsylvanian Cane Creek shales of the Paradox Basin, Colorado and Utah, or the upper Cretaceous Niobrara shales of the Rocky Mountain region, U.S. In these cases, we have thin sandstone or limestone reservoir rocks in separate fluid compartments, isolated from each other by the source rocks, which act as fluid aquitards. Such situations would obviously greatly complicate economic recovery of the oil generated by the source shales. To be sure, there will be other cases where large areas of other basins will also have advantageous unconventional oil-source reservoir systems. These systems will, however, be deeply buried.

Thus, the three attributes discussed above (the extreme paleo-heat flow through the Williston Basin, the truly unique sample base, and the unusual source-reservoir relationship) all combine to make the Bakken Source System unconventional oil-resource base possibly unequaled worldwide regarding potential economic oil recovery. There is no other apparent sedimentary basin in the world where analogous oil-resource bases will be so easily recovered.

11.04 **Additional Positive Aspects of the Bakken Source System**

Consider the oil itself. This is among the highest-quality oil in the world. The entire Bakken Source System resource base is made up of 40° to 47° API (0.825 to 0.792 specific) gravity (generally 40° to 42° API gravity; 0.825 to 0.815 specific gravity), low sulfur (0.1 weight percent) oil. The oil is also low in waxes and very low in asphaltenes (generally much less than 0.25 weight percent asphaltenes. Muscio (1995) has noted that the Bakken shale OM (at least on the American side of the Williston Basin) is very unusual, in that it generates an oil with high concentrations of lower-molecular weight (C_{15}-) compounds. The end result is oil high in gasoline to diesel range distillates.

11.05 **Oil Recovery**

It is one thing to propose, or even prove, the existence of a large in-place HC resource base. However, it is yet another to economically affect its recovery. For example, the existence of the super-giant, in-place oil-shale resource base of the Eocene Green River oil shale (U.S.) is beyond debate. However, based on the detailed research carried out to date on these oil shales, it appears that the resource base will not be economically produced in the foreseable future. Notwithstanding, we believe that this will not be the case with the basin-centered oil-resource base of the Bakken Source System.

Detailed examination and synthesis of drilling, completion, stimulation, and maintenance records have been (and are still being) carried out for all producing, and non-producing, Bakken wells of North Dakota. Other ancillary, but related, studies also have been (and are being) carried out. From these completed and ongoing studies, over fifteen separate parameters controlling production of Bakken Source System oil have thus far been identified. Ignorance of any of these parameters can make a Bakken well non-productive. From existing production and well-history records, it appears that no operator has been cognizant of more than 3 or 4 of these parameters at any one time. Existing records also suggest that proper application of these parameters will routinely result in wells with very high open-hole initial productive potentials, and thus very high cumulative productions. Moreover, because the oil resource base is in a continuous and very well interconnected reservoir, dry holes should not be a problem during development. In addition, research to date also strongly suggests that high percentage (at least 50%) of the in-place oil can be economically recovered, even at $12/barrel oil prices.

However, discussion of these topics is outside the scope of this paper, whose main purpose is to demonstrate the existence of, and provide evidence for, the basin-centered oil-resource base in the Bakken Source System continuously throughout the Bakken HC kitchen in the Williston Basin (northwestern North Dakota and northeastern Montana). Discussion of the parameters affecting productivity of Bakken Source System wells would triple the size of this report, and thus these topics will be covered in future publications.

12.0 **CONCLUSIONS**

1) The Williston Basin is structurally the most simple basin worldwide with significant oil production, with minor faulting, an uncomplicated geologic history, and flat-lying sediments.

2) The Bakken shales, the richest source rocks in the basin, are among the richest source rocks worldwide.

3) The rocks adjacent to the two Bakken shales (the lower Lodgepole Limestone, the Bakken siltstone, and the Three Forks Shale) are dense, carbonate-rich, impervious, brittle rocks, which, with the Bakken shales, form a closed-fluid system: The Bakken Source System.

4) The Williston Basin is one of the best-studied and well-documented basins worldwide with public domain information.

5) The North Dakota portion of the Williston Basin, which has the larger of the two Bakken HC kitchens in the basin, has the best rock and oil sample base and well-history file for any basin, worldwide.

6) Thus, process controls of HC generation, source-rock expulsion, and oil accumulation may be studied to a detail not possible in many other petroleum basins.

7) Early classic research in the Williston Basin, which identified the Bakken shales as the source rocks for the mid-Madison oils (the largest conventional oil resource in the basin), is the foundation for our present-day model of source-rock expulsion and HC accumulation into traps:

   (A) Petroleum-basin depocenters are open-fluid systems, where fluid movement is easy.

   (B) Rich source rocks expel almost all the oil they generateOnly a small amount of expelled oil is caught in traps, the remainder being lost over geologic time.

(C) Only a small amount of expelled oil is caught in traps, the remainder being lost over geologic time.

8) ROCK-EVAL analyses of rich source rocks from basins worldwide appear to support the accepted model of HC expulsion and accumulation: Large decreases in the ROCK-EVAL S_2 peak are not matched by concurrent increases in the S_1 peak or Soxhlet-extractable HCS, thus leading to the conclusion that the generated HCS were expelled from the source rock.

9) Present-day accurate analyses and comparison of mid-Madison and Bakken-produced oils demonstrate that they are two different oil families, e.g. - the Bakken shales did not source the mid-Madison oils, a startling petroleum-geochemical conclusion.

10) That the richest source rock in the Williston Basin did not source the most important conventional oil resource there, and in fact sourced no conventional oil deposits, is a complete breakdown of the accepted model of HC expulsion and accumulation, a model which is thus dysfunctional in the very basin in which it was originally derived.

11) A similar situation exists in the Western Canadian Alberta Basin, a basin at the opposite end of the spectrum regarding both structural style and structural intensity, compared to the Williston Basin. In the Alberta Basin, the richest source there has made no detectable contribution to either the conventional deposits or the tar sands in that basin.

12) These observations in the Alberta and Williston Basins strongly suggest that the accepted model of HC expulsion and accumulation is far less applicable than previously thought, and that an alternate model of HC expulsion and accumulation should be seriously considered.

(A) Petroleum basin depocenters are closed-fluid systems where fluid movement between aquitards is difficult.

(B) Oil and gas expulsion from source systems is inefficient.

(C) Unless source systems are physically disrupted by faulting or salt or shale diapirism, or are directly adjacent to good fluid conduits, source-system expulsion does not occur at all.

(D) Thus, most generated HCS remain in and around their source rocks.

13) This model redefines primary migration and source rock expulsion, which previously often were considered equivalent. Primary migration is the original movement of HCS from their generation site to another site in the source rock, or to rock directly adjacent to the source rock (e.g., to another source-system rock). Primary migration is of common occurrence. Source-system expulsion is the movement of generated HCS from any source-system rock, including the source rock, to a secondary-migration conduit, or to a trap, and is of less common occurrence than primary migration.

14) A strong correlation exists between petroleum-basin productivity and structural intensity in the HC kitchens of basin depocenters (source-rock disruption), which is persuasive support for the alternate model of expulsion and accumulation.

15) Traditional core analyses of the three rocks adjacent to the two Bakken shales (the Lodgepole Limestone, the Bakken siltstone, and the Three Forks Shale, e.g., the Bakken Source System reservoir rocks) reveal that these rocks:

(A) are tight with low porosity and permeability and are incapable of transmitting fluids;

(B) have zero residual-oil saturation percentages, and no visible fractures, in basin areas where the Bakken shales are immature;

(C) have increased residual-oil saturation percentages and increased fracture incidence in the rocks directly adjacent to the two shales, in basin areas with increasing Bakken-shale maturity, but before the Bakken shales have begun HC generation;

(D) have moderate residual-oil saturation percentages (20-30% on average) continuously through them, by the time HC generation just commences in the Bakken shales;

(E) have high values of residual-oil saturation percentages (50-70% on average), and a dramatically-increased fracture incidence, in basin areas where the Bakken shales have lost values of 100-200 from their starting ROCK-EVAL hydrogen indices.

16) Where the Bakken shales are immature, and have not yet begun HC generation, a strong correlation exists between increasing Bakken shale maturity with increasing fracture incidence and increasing residual-oil saturation percentages in the reservoir rocks

17) In areas where the Bakken shales are mature (ROCK-EVAL hydrogen indices ≥200), but thin (<6 ft, 1.8 m), both the vertical extent and absolute values of residual-oil saturation percentages and fracture incidence in the reservoir rocks, all dramatically decrease, compared to that in reservoir rocks in areas with thicker shales of the same, or even less, maturity.

18) Both this movement of oil into, and associated fracturing in, the Bakken Source System reservoir rocks were caused by a volume expansion of OM during HC generation in the Bakken shales. This volume expansion of generated fluids, combined with the compressibility of the Bakken shales, created super-lithostatic pressures driving both the primary migration of the oil from the Bakken shales to the reservoir rocks and the fracturing in the reservoir rocks.

19) Where the Bakken shales are both thick (<15 ft, 4.6 m) and mature (ROCK-EVAL hydrogen indices ≤250), the reservoir rocks have reduced residual-oil saturation percentages (15-40%), compared to values (50-70%) from reservoir rocks where the Bakken shales are less mature. This observation is attributed to higher gas-oil ratios in the oils from more mature basinal areas, and thus a greater loss of reservoired HCS to the drilling mud during coring operations.

20) Porosity is invariant in the three reservoir rocks adjacent to the two shales versus increasing maturity, once the Bakken shales have been buried to 6,000 ft (1,828.7 m). This unusual observation is attributed to the fact that the Bakken Source System is oil-wet with only small amounts of water in the matrix porosity of the reservoir rocks, and no water in the fractures, which contain only oil. Thus, aqueous-based porosity-reducing reactions could not occur.

21) Matrix permeability in the reservoir rocks does decrease with increasing Bakken shale maturity from values of 0.01-0.06 md where the Bakken shales are immature, to values of ≤0.01 md to 0.01 md where the shales are mature. One of the principal causes of this decrease is believed to be CO_2, formed as a product of the hydrolytic disproportionation of Bakken shale kerogen, causing carbonate precipitation in the porosity of pore throats of the reservoir rocks, thus reducing permeability at nearly constant porosity.

22) The ROCK-EVAL S_1 peak mirrors residual-oil saturation percentages from traditional core analyses of Bakken Source System reservoir rocks.

23) ROCK-EVAL analyses of Bakken Source System reservoir rocks corroborate all the observations made on the basis of traditional core analyses of these rocks, and concurrently provide insights not possible with traditional core analyses.

24) ROCK-EVAL analyses of the Bakken Source System reservoir rocks:

(A) not only establish the organic-poor nature of these rocks in basin areas where the Bakken shales are immature, but also establish the background organic richness levels of these rocks;

(B) document a non-uniform distribution of oil in the reservoir rocks in basin areas where the Bakken shales are mature, as opposed to a uniform distribution of equal concentrations of oil.

25) Thus, the ROCK-EVAL S_1 peak is a more accurate and detailed measurement of oil staining than residual-oil saturation percentages from traditional core analysis.

26) The non-uniform distribution of oil in the reservoir rocks is attributed to the fact that the oil was emplaced in these rocks via fractures making up a well-defined plumbing system as, opposed to dissemination from a diffusive type of migration mechanism, which has pivotal implications regarding recovery of the resource base.

27) Large losses of Bakken Source System oil (estimated at 90 to 99%+) have occurred from the reservoir rocks both to the drilling mud during coring and to evaporation during storage.

28) <u>All</u> measurable migrated oil has been lost from cuttings chips of reservoir rocks due to the much higher ratios of rock-surface area to rock volume in cuttings chips, compared to core.

29) All C_{14}- to C_{16}- fractions of the migrated oil are lost from core of reservoir rocks, in all analyzed samples.

30) These losses account for the oil shows recorded whenever mature Bakken Source System rocks are drilled, and are attributed to the fact that the oil can easily escape from the fractures holding the oil.

31) Bakken Source System reservoir rocks, at basin sites where the Bakken shales are immature and are at shallow burial depths (3,000 to 4,000 ft.; 914.3 to 1,219.1 m), have closed, cemented, early-diagenetic fractures which have no capability to take up or transmit fluids.

32) With progressive burial to about 6,000 ft (1,828.7 m), volume-expansive kerogen maturation reactions occur in the Bakken shale kerogen at pre-HC generation ranks, causing moderate fracturing in the reservoir rocks directly adjacent to the Bakken shales. These fractures are dominantly horizontal, and are never mineralized.

33) Fracture intensity in the reservoir rocks, regarding fracture length, fracture aperature width, and vertical extent and concentration of the fractures, all increase with increasing Bakken shale maturity.

34) This fracturing is caused by, and thus accompanies, migration of oil into the adjacent reservoir rocks from the Bakken shales. Therefore, increasing fracture intensity has close correlations with increasing residual-oil saturation percentages, and increasing ROCK-EVAL derived organic richnesses.

35) Fracturing intensity of the reservoir rocks is governed by lithology, being minimized in more massive sub units of the three reservoir rocks.

36) Because organic richnesses in the reservoir rocks, as measured by ROCK-EVAL, has a positive correlation with fracture intensity, organic-richness in minimized in zones with minimal fracturing. This is expected, since fractures served as the migration avenues for the oil.

37) In basin areas where the Bakken shales are thick and mature (hydrogen-indices ≤400), fracturing can be extreme: increased fracture lengths and aperature widths, and high numbers

of fractures per vertical feet of core. Oil concentrations, as measured by ROCK-EVAL or traditional core analyses, are also high in these areas.

38) Mainstage HC-generation reactions are volume expansive. In the case of the Bakken shales, there is a volume increase of around 150%, depending on starting hydrogen indices and starting TOC values. Moreover, because the Bakken Source system is a closed-fluid system, fluid-volume expansions create high fluid pressures.

39) OM is compressible, and the Bakken shales have high volume percentages of OM. Thus the high fluid pressures created by HC generation in the Bakken shales compressed Bakken shale kerogen, resulting in stored energy of compression. When the Bakken Source system did reach fracture pressure, this stored energy of compression was released and the system went super-lithostatic, resulting in an explosive oil migration from the Bakken shales to, and the creation of an extensive *horizontal* fracture network in, the rocks adjacent to the Bakken shales.

40) A well-interconnected fracture system would be expected by these events. Production histories and bottom-hole pressure histories of Bakken producing wells confirm this expectation.

41) Shale thickness and maturity, and starting TOC and ROCK-EVAL hydrogen index values all combine to determine the intensity of both the fracturing events and the migration of oil from the Bakken shales.

42) Fracture intensity and oil staining are minimized in Bakken Source System reservoir rocks of the Fairway, because the Bakken shales there are thinner, with lower original TOC contents compared to Bakken shales from Bakken HC kitchen proper. Also, a large area of the

Fairway has only moderately-mature shales. Nonetheless, many prolific Bakken wells are located in the Fairway, suggesting that correctly-completed and produced wells in the Bakken-HC kitchen proper would have even greater producibilities.

43) Because the fractures in Bakken Source System reservoir rocks are so geologically-unusual, previous investigators did not recognize these fractures as naturally-occurring in these rocks. Moreover, the oil industry previously *assumed* that Bakken-generated oil was held in vertical fractures in the Bakken shales, as opposed to the real situation: horizontal fractures in the rocks adjacent to the shales.

44) Dense, low-porosity, low-permeability, carbonate-rich rocks, with completely-closed and cemented fractures, several hundred feet above and below the Bakken Source System, form very effective vertical seals, trapping Bakken Source System oil. Unlike the fractures in Bakken Source System reservoir rocks, the fractures in the sealing rocks are largely vertical and off-vertical fractures, and are highly mineralized, which are the normal characteristics of fractures in sedimentary basins.

45) The Bakken Source System is oil-wet with oil to water ratios largely ranging between 200 to 800. This explains, among other things, the lack of post HC-migration mineralization in the fractures of the reservoir rocks, fractures which were created by oil migration from the Bakken shales.

46) The data from traditional core analyses (especially residual-oil saturation percentages), ROCK-EVAL analyses, and our ongoing fracture study all demonstrate that HC expulsion was very inefficient from the Bakken Source System, in fact "perfectly inefficient", contrary to accepted models of oil expulsion and accumulation. This conclusion has profound

consequences for both HC exploration and resource assessment, both of which employ an expulsion and accumulation model based on efficient source-rock expulsion.

47) Residual-oil saturation percentages, ROCK-EVAL analyses, Soxhlet extractions, and our fracture study all as applied to Bakken Source System reservoir rocks, demonstrate the existence of mobile oil in well-fractured reservoir rocks over a large area of northeastern Montana and northwestern North Dakota making up a very large in-place oil resource base in continuous reservoirs over this area.

48) Most of this oil is both in fractures and in secondary microporosity directly adjacent to the fractures, in a well-connected fracture system. Only a small part of the oil appears to be dispersed in the original matrix porosity of the reservoir rocks. Thus, this resource base appears to be highly concentrated along permeable pathways, as opposed to being dispersed over large volumes of rock.

49) Therefore, reservoir pressure maintenance would appear to be a necessary and integral part of any attempted recovery of this resource base.

50) Previously published R_o profiles, newer R_o profiles presented herein, and T_{max} profiles of coals, all versus depth, demonstrate that a spectrum of very high to extreme paleogeothermal gradients, of Eocene age or younger, existed in the Williston Basin.

51) These gradients were probably due to an aborted rift event. Whatever the cause, these heat flows are a classic example of punctuated diagenesis.

52) The R_o profiles suggest that little erosion (500 ft, 152.4 m, or less) has occurred throughout the North Dakota portion of the Williston Basin.

53) The Williston Basin has been significantly cooled in the recent geologic past via cross-basinal meteoric water flow through five aquifers, probably during the last glacial periods.

54) The difference between rank and maturity is not appreciated or well-understood in the petroleum geosciences. Two rocks at the same rank can have vastly different maturities, depending on the maturity index being employed. R_o suppression in hydrogen-rich OM is the most widely recognized example of this.

55) However, all aspects of organic metamorphism, including HC generation, are strongly suppressed in hydrogen-rich OM, compared to the case in hydrogen-poor OM at the same ranks.. Examples of this suppression exist in basins worldwide.

56) The causes of this suppression, probably in combination, are:

A) the absence of sufficient volumes of water, a required reactant during HC generation reactions, in high-TOC rocks with hydrogen-rich OM;

B) much stronger carbon-oxygen bonds (esters, aldehydes, etc.) in hydrogen-rich OM, compared to the carbon-oxygen bonds in hydrogen-poor OM (mainly carboxylic acids); and

C) the lack of product removal in high TOC shales with hydrogen-rich OM, compared to low TOC shales with hydrogen poor OM.

57) Almost all other petroleum basins have had much lower heat flows than the extreme paleo heat flows of the Williston Basin. Thus, resource bases analogous to that of the Bakken Source System will be found only at much greater depths in other basins, because of the high burial temperatures necessary to initiate and sustain HC generation in hydrogen-rich OM.

58) The hydrolytic disproportionation of OM, wherein water and OM chemically interact with one another via aqueous-based redox reactions, is a generally-unrecognized geologic agent of the first magnitude which has played three critical roles in the Bakken Source System:

59) First, the HC generation potential of Bakken shale kerogens was increased by water reacting with the kerogen before and during HC generation. The excess hydrogen from the water hydrogenated the kerogen. The excess oxygen from the water was given off as CO_2, which formed pore-plugging carbonate cements which helping to seal the Bakken Source System into a closed-fluid system.

60) Numerous examples exist of immature shales, at pre-HC generation ranks, including the Bakken shales, whose ROCK-EVAL hydrogen indices continuously increase with increasing maturity, before mainstage HC generation commences, due to kerogen hydrogenation by water.

61) The second critical role occurred later during mainstage HC generation, wherein HC generation reactions were suppressed in the Bakken shales from the lack of available water to react with Bakken shale kerogen.

62) Third, hydrolytic disproportionation of newly-migrated Bakken oil occurred in the reservoir rocks adjacent to the Bakken shales by the pore water of these rocks, creating organic acids and CO_2. These products in turn created secondary microporosity immediately adjacent to the fractures, microporosity which helped to store the migrated oil which thus would be readily-deliverable to the fractures during production.

63) This secondary microporosity also provides irrefutable evidence that the horizontal fractures in the Bakken reservoir rocks were formed at depth in-situ, and are not induced fractures.

64) Published computer models of the Bakken Source System are based on erroneous assumptions and yield predictions diametrically-opposed to volumes of data from the System. These computer models are thus unrealistic.

65) Large production heterogeneities exist at the local and regional levels for Bakken wells in the Williston Basin. These heterogeneities have been assumed to be due to variations in geology at both the local and regional levels. However, geologic variation between wells is insignificant and thus cannot be responsible for these production heterogeneities.

66) A large amount of geologic data from the Bakken Source System demonstrates that geologic variation on either the local or regional level, is insignificant and thus cannot be responsible for these production heterogeneities.

67) Instead, these production heterogeneities are attributed here to the only other possible explanation: differences in drilling, completion, stimulation, and maintenance techniques between wells. Wells with high cumulative productions have had techniques applied which are appropriate to the unique characteristics of the Bakken Source System. Wells with low cumulative productions have had inappropriate techniques applied, causing extensive formation damage. Comparisons of well histories for wells with pronounced production heterogeneities strongly support this promise.

68) The Fairway Bakken shales are not the most mature Bakken shales of the Bakken HC kitchen. In fact, a significant area of the Fairway with productive wells has only moderately-mature shales (ROCK-EVAL hydrogen indices of 450-580).

69) Thus, shale maturity does not explain the relatively high productivity of the Fairway on a regional level.

70) The Bakken shales are not the reservoirs for Bakken Source System oil, and in fact hold no producible oil.

71) The small Bakken middle siltstone oil pools of the Canadian portion of the Williston Basin most probably originated from local sourcing by bitumen fractionation and pre-HC generation expulsion from immature Bakken shales into the more sandy Canadian Bakken siltstones. Long lateral secondary migration of this oil is considered unlikely.

72) The source rock for the lower Lodgepole "Waulsortian Mound" productive wells on the east flank of the Williston Basin (Stark Co., North Dakota) is the Bakken shale. The productive area of this play is most probably due to salt solution and collapse. This play will be of only limited extent. Moreover, Waulsortian Mounds may not even exist in this area of the Williston Basin.

73) Previous mass-balance calculations of the amount of oil generated by the Bakken shales used incorrect inputs and assumptions, thus the calculated amounts of oil (92 and 132 billion barrels) are too low.

74) Realistic inputs and assumptions to such mass-balance calculations involve using:

(A) average *starting* TOCS, and not average TOCS;

(B) restored starting shale thicknesses, before shale-volume loss due to HC generation;

(C) calculations to account for the density change of kerogen going to oil and gas during HC generation reactions (roughly a 150% increase in volume);

(D) appropriate ROCK-EVAL hydrogen-index losses (average starting values of 625 minus present-day measured values).

75) When realistic inputs and assumptions are applied to the previous mass-balance calculations, the 92 billion barrel estimate becomes 342 billion barrels and the 132 billion barrel estimate becomes 418 billion barrels.

76) The Cooles et al. (1986) approach to HC-generation mass-balance calculations using ROCK-EVAL derived numbers is unrealistic because at the minimum it does not take into account that a significant part of source-rock HC-generation potential (21.3% in the case of the Bakken shales) goes towards the generation of HC gases and not oil.

77) Closed-system, water-wet, pressurized HC-generation laboratory experiments are much better representations of HC generation in Nature than ROCK-EVAL analyses.

78) However, some products from all closed-system, water-wet experiments, have significant differences with those from HC generation in Nature. For example, the products from laboratory reactions are much richer in resins and asphaltenes. Thus, even these laboratory experiments do not faithfully reproduce natural HC generation. Consequently many unknowns exist concerning process controls of HC generation and expulsion in Nature.

79) Therefore, any mass-balance calculations regarding amounts of generated oil from a given source rock, including those of this paper, are inexact due to severe limitations of knowledge of all the process controls of HC generation and expulsion.

80) Our preliminary estimate of the amount of oil generated by the Bakken shales in the Bakken-HC kitchen of northwestern North Dakota and northeastern Montana, after accounting for all known relevant parameters, is 413 billion barrels, with an ultimate oiling of 503 billion barrels, and a floor of 271 billion barrels.

81) Different parameters have coalesced in the Williston Basin to possibly make the large in-place unconventional oil-resource base there, and its ease of recovery, unique, or at least very unusual, on a worldwide basis. These factors are: an extremely rich source rock; extremely-high basin heat flows; no structuring basinwide; brittle, thick, impermeable carbonate-rich rocks which sandwich the source rocks and serve as both reservoir and seal; and an unparalleled rock, oil, and well-history sample base.

82) Detailed analysis of Bakken well-history files, besides documenting that production techniques appear to be completely responsible for production heterogeneiities, have revealed at least 15 separate parameters controlling Bakken production. The results of this analysis thus strongly suggest that the in-place Bakken Source System oil resource base is eminently producible at current oil prices using existing technology. These results will be published in future papers.

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Table 1

List of wells on which traditional core analyses (porosity, permeability, and residual oil) were performed on Bakken Source System rocks in the North Dakota portion of the Williston Basin. In the "Units Analyzed" and "Stratigraphic Tops" columns, LP is Lodgepole limestone; US is upper Bakken shale; SS is Bakken siltstone; LS is lower Bakken shale; and F is Three Forks shale. HI is the ROCK-EVAL hydrogen index, indicating the maturity of the Bakken shales in a given well. Cored intervals taken from drillers depths. Stratigraphic tops are from electric log. DD≠LD is drilling depths not equal to logged depths. Well locations and names are in Table 11. In the "HI" column, values of 625+ signify Bakken shales which have not yet begun HC generation, and whose real HI values may actually range from 550-800.

WELL	CORED INTERVAL		STRATIGRAPHIC TOPS				UNITS	HI	DD/LD
NDGS #	TOP	BOTTOM	US	SS	LS	TF	ANALYZED		
1779	10,530	10,555	10,443	10,462	10,504	10,529	TF	150	
1780	10,365	10,390	10,282	10,302	10,347	10,372	TF	100	DD≠LD
1890	10,549	10,579	10,457	10,477	10,520	10,546	TF	180	
1987	10,521	10,546	10,424	10,444	10,489	10,514	TF	200	
2308	10,643	10,681	10,548	10,568	10,610	10,641	TF	200	
2828	11,132	11,190	11,049	11,069	11,113	11,142	TF	115	
3007	9,409	9,433	9,402	9,414	9,476	9,506	SS	230	
3167	10,198	10,287	10,180	10,201	10,244	10,268	SS,3F	114	
4297	9,895	9,910	9,905	9,926	9,990	10,025	SS	190	DD≠LD
4958	7,577	7,624	7,570	7,580	7,622	7,648	SS	625+	
5656	9,634	9,674	9,626	9,639	9,667	9,723	SS	321	
7494	10,959	11,019	10,945	10,956	10,982	10,983	LP→TF	100	
7851	9,386	9,451	9,370	9,385	9,418	9,450	SS	610	
7887	10,720	10,838	10,791	10,801	10,808	10,810	LP→TF	80	
8177	8,629	8,667	8,620	8,636	8,660	8,670	US→LS	625+	
8251	10,358	10,405	10,387	10,394	-	10,401	LP→TF	125	
8363	10,327	10,374	10,349	10,356	-	10,366	LP→TF	133	
8474	10,331	10,394	10,366	10,374	10,379	10,380	LP→TF	125	
8637	6,760	6,790	6,750	6,756	6,779	6,787	SS/LS	625+	
8638	7,872	7,938	7,882	7,893	7,940	7,964	SS	625+	
8697	7,685	7,716	7,680	7,691	7,714	7,732	US/LS	625+	DD≠LD
8699	7,651	7,691	7,650	7,660	7,690	7,709	SS	625+	
8709	10,510	10,640	10,504	10,526	10,565	10,582	LP→TF	380	DD≠LD
8819	7,169	7,230	7,156	7,167	7,205	7,223	SS	625+	
8824	7,014	7,073	7,026	7,038	-	7,077	LP→SS	625+	
8850	7,397	7,455	7,389	7,400	7,454	7,478	SS	625+	
8902	10,546	10,622	10,587	10,594	-	10,601	LP→TF	500	
9351	10,425	10,487	10,463	10,472	10,483	10,484	LP→TF	125	DD≠LD
9707	10,375	10,555	10,424	10,440	10,474	10,502	LP→TF	452	
10077	10,750	10,799	10,768	10,776	10,784	10,785	LP→TF	130	
10989	10,715	10,749	10,731	10,739	10,746	10,748	LP→TF	125	
11397	3,277	3,334	3,310	3,332	-	3,392	LP	625+	
11617	10,363	10,423	10,309	10,331	10,377	10,405	SS→TF	150	DD≠LD
12019	10,570	10,615	10,516	10,536	10,580	10,606	LS/TF	200	
12033	10,649	10,679	10,579	10,598	10,642	10,672	TF	270	
12160	10,754	10,782	10,780	10,785	-	10,790	LP→3F	500	DD≠LD
12494	10,470	10,531	10,511	10,516	-	10,523	LP→TF	150	
12558	10,470	10,530	10,519	-	-	10,522	LP→TF	150	DD≠LD
12886	10,479	10,581	10,518	10,526	10,529	10,532	LP→TF	150	
13098	10,888	11,045	10,916	10,936	10,976	11,004	LP→TF	80	DD≠LD
13318	8,842	8,865	8,829	8,841	8,913	8,946	SS	220	DD≠LD
M-1	7,749	7,778	-	-	-	-	SS	550	

Table 2

ROCK-EVAL data for the rocks in, and around, the false Bakken (lowermost Lodgepole) shale of NDGS 8474 and NDGS #8638. TOC is total organic carbon content in weight percent; PI is the production index ($S_1/S_1 + S_2$) and T_{max} is ROCK EVAL T_{max} in °C. In well NDGS #8474, elevated TOC values (TOC ≥0.80), generally depressed PI values (with scatter), and elevated T_{max} values (generally 442° to 450°C, compared to T_{max} values of 365° to 439°C in the adjacent rocks) all define the organic-rich portion of the lower Lodgepole shale (10,346.4 to 10,351 ft; 3,153.4 to 3,154.8 m). Note that the highest TOC values (TOC ≥6.0% occur over an even more limited interval. In well NDGS #8638, T_{max}, PI, and especially TOC, values define an even more vertically-limited interval of organic rich lower Lodgepole shale. Note that unrealistically-high (>450°C) or unrealistically low (<430°C) T_{max} values can be characteristic of the low TOC rocks of Table 1. Well locations and data are in Table 11.

NDGS #8474

Depth	TOC	PI	T_{max}
10331.0	0.33	0.575	431
10331.8	0.55	0.439	435
10332.0	0.13	0.429	432
10332.7	0.66	0.412	439
10333.0	0.11	0.364	415
10333.6	0.15	0.400	423
10334.1	0.15	0.417	389
10334.7	0.15	0.400	428
10335.0	0.13	0.556	425
10335.7	0.16	0.450	437
10336.1	0.22	0.517	433
10336.1	0.40	0.484	432
10337.4	0.32	0.603	429
10338.0	0.28	0.529	427
10338.1	0.40	0.361	430
10339.0	0.33	0.300	430
10339.8	0.54	0.438	365
10340.2	0.43	0.425	428
10340.7	0.46	0.269	427
10341.0	0.54	0.256	430
10341.6	0.55	0.310	430
10342.1	0.58	0.477	439
10342.6	0.60	0.404	437
10343.0	0.51	0.406	433
10343.6	0.54	0.417	432
10344.0	0.62	0.283	430
10344.6	0.70	0.375	429
10345.0	0.44	0.389	425
10345.6	0.52	0.361	423
10346.0	0.70	0.319	428
10346.6	1.17	0.500	444
10347.4	6.03	0.211	450
10347.9	6.35	0.204	449
10348.0	3.70	0.300	449
10348.7	1.36	0.479	442
10349.0	0.81	0.644	438
10350.0	2.27	0.406	446
10350.5	1.95	0.384	448
10351.0	0.72	0.670	442
10351.9	0.55	0.724	428

NDGS #8638

Depth	TOC	PI	T_{max}
7815.0	0.12	0.15	569
7816.0	0.13	0.10	575
7817.0	0.43	0.45	423
7872.0	0.17	0.32	423
7872.1	0.14	0.39	418
7874.0	0.07	0.50	414
7875.0	0.22	0.15	416
7875.1	0.03	0.50	414
7877.8	0.10	0.39	431
7878.0	26.59	0.02	434
7879.0	0.52	0.26	414
7880.0	0.52	0.41	427
7881.0	0.19	0.32	422
7882.0	0.01	0.36	424
7882.1	0.07	0.35	429
7884.2	0.04	0.68	346
7885.1	0.16	0.45	348
7886.2	0.23	0.49	295
7887.0	0.39	0.52	375
7887.6	0.11	0.45	286
7888.0	0.21	0.52	288
7888.6	0.25	0.50	422
7888.9	0.31	0.25	404
7898.6	0.30	0.19	440
7899.0	0.31	0.46	282
7899.6	0.20	0.24	330
7900.0	0.32	0.51	285

Table 3

List of wells with close-spaced (foot by foot, or less) ROCK-EVAL analyses of Bakken Source System rocks. Locations of wells are also shown in Figure 13. In "Units Analyzed" column, LP is Lodgepole limestone, US is upper Bakken shale; SS is Bakken siltstone; LS is lower Bakken shale; TF is Three Forks shale. Interval analyzed taken from drillers depths. Stratigraphic tops are from electric-log readings. Well locations and data are in Table 11. Drillers depths do not necessarily equal electric-log depths.

WELL	STRATIGRAPHIC TOPS				UNITS	INTERVAL
NDGS	US	SS	LS	TF	ANALYZED	ANALYZEXD
505	10,036	10,048	10,070	10,076	LP/SS/TF	9803-10290
527	11,194	11,216	11,253	11,275	SS/LS/TF	11225-11340
545	10,838	10,854	10,886	10,895	LP/SS/TF	10808-10870
607	10,509	10,521	10,574	10,607	LP/US/SS/LS/TF	10416-10471
						10508-10792
1202	10,266	10,288	10,330	10,356	3F	10343-10385
1254	10,373	10,393	10,434	10,458	3F	10455-10480
1405	10,737	10,760	10,794	10,822	SS/LS/TF	10770.75-10846
2618	9,778	9,792	9,826	9,838	SS/LS/TF	9801-9842.5
3007	9,402	9,414	9,476	9,506	SS	9414-9433
4340	9,886	9,907	9,966	10,011	US/SS/LS/TF	9886-10060
5088	10,160	10,169	10,240	10,290	LP/US/SS/LS	10145-10277
7579	10,852	10,857	-	10,864	LP/US/SS/TF	10830-10885
7851	9,370	9,385	9,418	9,450	SS	9386-9416
8069	9,157	9,174	9,207	9,236	US/SS/LS	9157-9216
8177	8,620	8,636	8,660	8,670	US/SS/LS	8630-8668
8474	10,366	10,374	10,379	10,380	LP/US/SS/LS/TF	10331-10394
8637	6,750	6,756	6,779	6,787	US/SS/LS	6760-6790
8638	7,882	7,893	7,940	7,964	LP/US/SS	7815-7937
8697	7,680	7,691	7,714	7,732	US/LS	7685.25-7688.6
						7713.2-7715.1
8699	7,650	7,660	7,690	7,709	US/SS/LS	7651-7691.5
9001	7,375	7,379	7,415	7,460	US/SS	7375-7415
11617	10,309	10,331	10,377	10,405	SS/LS/TF	10363-10423
12162	10,722	10,731	-	10,745	US/SS	10722-10737
12786	9,265	9,273	9,320	9,350	US/SS/LS	9265-9349
M-2	10,532	10,542	-	?	SS/TF	10557-10630

Table 4

Background (starting) organic richness values as determined by ROCK-EVAL analyses of Lodgepole limestone, Bakken siltstone, and Three Forks shale rocks from the wells of Figures 20 to 24 (and other wells not considered here). TOC is total organic carbon content in weight percent. S_1 and S_2 are values of the ROCK EVAL S_1 and S_2 pyrolysis peaks in parts per million (ppm) dry rock weight. "Average background values" are those values appearing as light dashed lines in Figures 25 to 27. Well locations and data are in Table 11.

WELL	LODGEPOLE			SILTSTONE			THREE FORKS		
NDGS #	TOC	S_1	S_2	TOC	S_1	S_2	TOC	S_1	S_2
8638	0.12	80	160	0.18	50	150	-	-	-
9001	-	-	-	0.09	120	85	-	-	-
2618	-	-	-	0.30*	20	100	0.50	15	80
8177	-	-	-	0.10	80	10	-	-	-
2010	0.10	30	150	- -	-	-	0.10	40	200
average background values	0.11	55	155	0.12	67	86	0.30	27	140

*not used in calculation of average values

Table 5

Normalized percentage of column chromatography fractions from bitumen (dead oil) extracted from core samples of Lodgepole limestone (LP; 10,497-10499 ft; 3,199.3-3,199.9 m); Bakken siltstone (SS; 10,554-10,558 ft; 3,216.7-3,217.9 m), and Three Forks shale (3F; 10,619-10,622 ft; 3,236.5-3,237.4 m) and from a Bakken oil sample (NDGS 12728, from Price and LeFever, 1994, their Table 3). LP is the Lodgepole Limestone, SS is the Bakken siltstone, and 3F is the Three Forks shale.

SATURATED AND AROMATIC HCS	RESINS AND ASPHALTENES	
68.71	31.45	NDGS 607 LP
62.41	37.59	NDGS 607 SS
68.36	31.28	NDGS 607 3F
85.80	14.20	NDGS 12728 (OIL)

Table 6

Wells with core of Bakken Source System reservoir rocks which were subjected to fracture analysis and mapping by Stolper Geologic. NDGS number is the NDGS permit number of the well. ROCK-EVAL hydrogen index is the hydrogen index of the Bakken shales from the well in question; "PRE HC GEN" refers to shales which have not yet begun HC generation and whose hydrogen indices can vary from 550-750. Well locations are given as quarter-quarter section-township-range. "Feet of Bakken Shale" is the thickness of upper and lower (when present) Bakken shales, in feet, in the well in question. Cumulative oil production is the barrels of oil produced, if production was present; FWY refers to a well in the Fairway, and ANT to a well in the Antelope Field. "Interval Cored in Feet" are the drilling depths (which may not agree with electric log depths) over which Bakken Source system core was taking in a given well. "Units Studied" are the stratigraphic units available from a given well which were subjected to fracture analysis and mapping.

NDGS Number	Rock Eval Hydrogen Index	Location Quarter Quarter Section-Township-Range	Feet of Bakken Shales	Cumulative Oil Production	Interval Cored in Feet	Units Studied
33	110	SWSE 12-149-98	21'US 25'LS	--	11,022-11,140	3F
105	PRE HC GEN	SWNE 2-153-85	12'US 8'LS	--	7,522-7,612	SS
527	50-70	NWNE 13-148-98	22'US 22'LS	--	11,225-11,340	SS,3F
607	400	SWNE 24-149-93	14'US 26'LS	--	10,508-10,681	LP,SS,3F
793	590 (Lost 25-75)	SENW 22-149-91	20'US 30'LS	--	9,992-10,072	LP,SS,3F
1202	125-150	SWNW 6-152-94	22'US 26'LS	619,302(ANT)	10,267-10,385	SS,3F
1254	125-150	SWSE 17-152-94	20'US 24'LS	28,018(ANT)	10,450-10,485	3F
1343	125-150	NWSW 7-152-94	20'US 22'LS	62(ANT)	10,341-10,349	3F
1405	110	NWNE 27-150-96	23'US 30'LS	--	10,759-10,874	SS,3F
1606	110	NESW 35-150-97	20'US 28'LS	--	10,945-11,002	3F
1679	135	SWSE 10-153-96	21'US 29'LS	--	10,003-10,055	3F
1858	120	NWNE 25-150-96	20'US 22'LS	--	10,963-10,993	3F
1886	150	NWSE 33-153-94	21'US 32'LS	62,068(ANT)	10,701-10,735	3F
2226	120	SWNW18-153-94	25'US 32'LS	--	10,578-10,616	3F
2383	120-125	NWNE 30-150-94	16'US 23'LS	--	10,570-10,801	3F
2602	115	SWNE 6-153-95	23'US 30'LS	--	9,789-9,846	3F
2618	PRE HC GEN	SWSE 15-145-91	14'US 12'LS	--	9,794-9,844	SS,3F
2828	115	NWNW 15-154-98	20'US 29'LS	--	11,132-11,190	3F
2967	105	NWSE 3-152-96	20'US 24'LS	--	10,238-10,340	SS,3F
3007	230	SENE 30-159-95	12'US 30'LS	--	9,409-9,433	SS
3167	114	SESW 31-153-95	21'US 22'LS	--	10,198-10,287	SS,3F
3363	115	NWSE 19-157-96	15'US 24'LS	--	10,213-10,244	3F
4113	343	SENW 4-150-93	17'US 26'LS	--	10,725-10,760	3F
4264	95-105	NENW 3-153-95	24'US 31'LS	--	10,023-10,071	3F
4340	100-150	SWSW 2-154-95	20'US 26'LS	--	9,886-10,060	SS,3F
4790	PRE HC GEN	SESE 20-159-81	12'US 14'LS	--	5,484-5,544	3F
4958	PRE HC GEN	SWNE 2-161-91	10'US 26'LS	--	7,577-7,624	SS
5088	300	NENW 35-156-93	17'US 47'LS	--	10,145-10,321	SS,3F
5656	321	SWSW 3-157-95	13'US 26'LS	6,362	9,634-9,674	SS
6082	120	SENW 18-145-97	12'US 7'LS	--	-- --	
6437	--	NWSW 26-153-95		--	-- --	
7579	520	SENE 24-145-104	5'US --	219,050(FWY)	10,852-10,855	SS,3F
7851	600-620 (Lost 25-50)	NESE 11-155-91	15'US 32'LS	1,375	9,386-9,451	SS
7887	80	SWNE 17-142-100	10'US 2'LS	--	10,720-10,818	LP,SS,3F
8069	600-625(Lost 25-50)	SESE 12-154-90	18'US 29'LS	--	9,157-9,206	SS
8177	PRE HC GEN (690)	SESE 18-151-87	16'US 10'LS	--	8,629-8,667	SS
8251	125	SWSE 24-143-102	7'US --	41,471 (FWY)	10,358-10,405	LP,SS,3F

TABLE 6 (CONT.)

8363	133	NWNE 23-143-102	7'US --	92,938 (FWY)	10,327-10,374	LP,SS,3F
8474	125	NESW 15-144-102	8'US 1'LS	165,717 (FWY)	10,331-10,394	LP,SS,3F
8637	PRE HC GEN	SENE 18-161-87	6'US 8'LS	--	6,760-6,790	SS
8709	380	NESW 8-147-93	22'US 17'LS	5,916	10,510-10,640	SS,3F
8824	PRE HC GEN	NWNE 28-162-89	12'US 18'LS	--	7,014-7,073	SS
8850	PRE HC GEN (695)	SWSE 29-163-92	11'US 24'LS	--	7,397-7,455	SS
8902	500	NWSE 23-146-104	7'US --	306(FWY)	10,546-10,622	LP,SS,3F
9426	125	SWSE 12-144-102	9'US --	105,565 (FWY)	10,799-10,859	LP,SS,3F
9569	62	SESE 34-145-100	11'US --	--	10,931-10,963	SS
9707	452	SWNE 4-148-92	16'US 28'LS	318	10,375-10,555	LP,SS,3F
9793	100-150	SENE 30-152-100	18'US 11'LS	--	10,798-10,857	LP,SS
11397	PRE HC GEN, Most Immature Well	NESE 17-160-73	22'US --	--	3,277-3,392	LP,SS,3F
11617	150	SESW 13-153-95	22'US 28'LS	130,000+	10,363-10,423	SS,3F
11689	--	NENW 30-155-101				
12019	200	SENE 33-152-94	20'US 26'LS	92,582 (ANT)	10,570-10,615	3F
12160	500	SESE 13-145-104	5'US	82,861 (FWY)	10,754-10,782	LP,SS,3F
12033	212	NENE 30-151-93	19'US 30'LS	--	10,649-10,679	3F
12772	91	NWNE 12-146-99	13'US 6'LS	--	11,210-11,330	LP,SS,3F
12785	62	NENW 19-147-96	15'US 17'LS	1,467	11,260-11,366	LP,SS,3F
12786	620 (Lost 25-50)	NESW 25-156-91	8'US 31'LS		9,265-9,350	SS
12807	300-350	NWSE 36-154-93	17'US 49'LS	658	10,368-10,506	LP,SS
13098	80	SWNE 27-150-97	20'US 28'LS	--	10,888-11,045	LP,SS,3F
13318	220	11,160-95	12'US 33'LS	--	8,842-8,865	SS
12162	120	NWSW 21-143-101	9'US	31,024 (FWY)	10,722-10,737	SS
M-3	315	13-23-56	2'US	--	10,561-10,621	LP,SS,3F
M-4	218	24-24-54	11'US	?	9,986-10,045	LP,SS,3F
M-5	390-410	2-30-58	12'US 8'LS	--	9,875-9,927	LP,SS,3F

Table 7. Cumulative oil (Cum. Oil), Cumulative water (Cum. Water), and cumulative oil to water ratios (Oil/Water) for horizontal wells in the Fairway and which produced over 100,000 barrels of oil. NDGS well numbers, well name, and field are also given.

Well No.	Well Name	Field	Cum. Oil	Cum. Water	Oil/Water
6662	Bicentennial Fed. #11-26H	Bicentennial	123161	110	1119.65
8644	Devils Pass Fed. #44-34H	Devils Pass	182723	1020	179.14
9240	MOI #33-19	Bicentennial	167543	600	279.24
9660	MOI #31-29H	Bicentennial	124067	272	456.13
11877	MOI #44-35H	Elkhorn Ranch	220961	3079	71.76
12275	MOI #34-29	Elkhorn Ranch	181075	765	236.70
12533	MOI #21-33H	Rough Rider	124581	670	185.94
12542	MOI #41-27H	Bicentennial	180358	136	1326.16
12570	MOI #44-7H	Pierre Creek	236562	509	464.76
12584	MOI #12-33H	Elkhorn Ranch	225156	786	286.46
12599	MOI #44-25H	Elkhorn Ranch	113186	418	270.78
12641	MOI #14-27H	Rough Rider	223469	26677	8.38
12682	State #36-44H2	Buckhorn	130567	0	0.00
12705	MOI #33-29H	Bicentennial	145759	266	547.97
12736	MOI #13-3H	Elkhorn Ranch	167888	2055	81.70
12788	Sidewinder #1-7	Ash Coulee	188063	689	272.95
12802	MOI #14-21H	Roosevelt	127680	466	273.99
12813	Karla #21-16H	Ash Coulee	18145	215	84.40
12814	Short Com. #3	Elkhorn Ranch	177958	1063	167.41
12823	MOI Roosevelt #31-29H	Roosevelt	119504	2065	57.87
12852	R.K.E. #44-16H	Rough Rider	100644	443	227.19
12865	MOI #44-19H	Roosevelt	111080	1530	72.60
12870	Bicentennial Fed. #41-11H	Bicentennial	119055	88	1352.90
12874	MOI Stillwater #21-23H	DeMores	222563	627	354.96
12884	MOI Buckhorn #41-35H	Buckhorn	161745	400	404.36
12886	Connell #24-27	Buckhorn	181220	3617	50.10
12887	Ketch #1-17	Ash Coulee	178527	612	291.71
12891	Elkhorn State #6	Elkhorn Ranch	125842	1651	76.22
12897	MOI Rough Rider #42-11H	Rough Rider	190968	788	242.35
12920	Nautilus #1-11	Ash Coulee	167771	637	263.38
12964	C. Wolf #1-14	Ash Coulee	145940	435	335.49
12968	MOI Rough Rider #41-17H	Rough Rider	117354	273	429.87
13027	Titan #1-28	Roosevelt	104579	377	277.40
13051	MOI Rough Rider #31-19H	Rough Rider	71203	173	411.58
13071	MOI Flat Top Butte #22-5H	Flat Top Butte	159641	603	264.74
13112	Elkhorn Federal "A" #7	Elkhorn Ranch	109148	838	130.25
13120	MOI DeMores #11-25H	DeMores	171572	221	776.34
13165	MOI Rough Rider #44-7H	Rough Rider	107626	323	333.21
13178	MOI Rough Rider #14-21H	Rough Rider	159478	435	366.62
13228	Morgan Draw Fed. B #3	Morgan Draw	136175	708	192.34
13281	F.T. Butte Trotter #1	Flat Top Butte	129506	422	306.89
13301	Rough Rider #31-26H	Rough Rider	135260	240	563.58
13334	Pierre Creek Fed. # 31-1H	Pierre Creek	120871	372	324.92
13411	Nelson Federal #31-26H	Pierre Creek	102394	120	853.28
13459	Flat Top Butte Federal #32	Flat Top Butte	99985	1205	82.98

Table 8

List of wells with vitrinite reflectance (R_o) analyses (profiles). The correlation coefficient (r^2) for linear regression of the R_o data versus burial depth, the estimated feet of sediment lost to erosion (by extrapolation of the regression line to R_o = 0.25%), and the depth to R_o = 1.0% are all given, for each well. Well locations and data are in Table 11.

WELL NDGS NUMBER	r^2	Erosion Feet	Erosion Meters	Depth to R_o = 1.0% Feet	Depth to R_o = 1.0% Meters
25	0.929	100	30	5,070	1,545
527	0.933	300	91	4,000	1,220
607	0.993	450	137	5,530	1,685
2010	0.955	1,500	457	9,900	3,020
2615	0.930	-450	-137	5,530	1,685
6464	0.950	1,000	305	5,530	1,685
6616	0.923	1,350	411	6,100	1,860
7020	0.860	-570	-173	8,850	2,700
7783	0.879	550	168	7,120	2,170

Table 10

Proven recoverable oil and calculated generated (expelled) oil in billions of barrels for the source rocks of four different petroleum systems. Data from Magoon and Valin (1994).

SOURCE ROCK	BASIN	RECOVERABLE OIL Billions of Bbls	GENERATED OIL Billions of Bbls
Ellesmerian	North Slope	12.88	1,431.00
Mandel (Jurassic)	North Sea Central Graben	6.54	1,090.00
Akata	Niger Delta	0.76	94.75
Tuxedni	Cook Inlet	1.18	29.50

Table 11. List of all wells discussed in this paper. NDGS # is the North Dakota Geological Survey unique number for that well. Well name, API number, and well location are also given.

NDGS#	Well Name	API#	Location		NDGS#	Well Name	API#	Location	
25	Clarence Iverson #1 (BLSU-407)	033-105-00004	SWSW sec 6	T155N-R95W	8251	Chambers Citgo #1-24	033-007-00645	SWSE sec 24	T143N-R102W
33	Benhomer Risser #1	033-053-00001	NENE sec 28	T158N-R72W	8363	23-143-102 BN #1	033-007-00666	NWNE sec 23	T143N-R102W
105	Walter & Ingeberg #1	033-101-00006	SWNE sec 2	T153N-R85W	8474	Graham USA #1-15	033-007-00690	NESW sec15	T144N-R102W
505	F-42 6P Dvorak	033-025-00002	SENE sec 6	T141N-R94W	8542	Graham #1-12	033-007-00700	SENE sec 12	T144N-R102W
527	Rough Creek Unit #1	033-053-00026	NWNE sec 13	T148N-R98W	8637	Pierce #1-18	033-075-00873	SENE sec 18	T161N-R87W
545	F.G. Hoehn A#1	033-053-00030	NESE sec 13	T152N-R102W	8638	Slater #1-24	033-013-00853	SWSW sec 24	T161N-R91W
607	Kennedy Federal #32-24-D	033-025-00003	SWNE sec 24	T149N-R93W	8697	Pullen #1-33	033-101-00272	NENE sec 33	T159N-R88W
793	Soloman Bird Bear	033-025-00005	SENW sec 22	T149N-R91W	8699	Flecten #1-20	033-101-00273	NENE sec 20	T160N-R89W
1202	1 Jens Strand	033-053-00144	SWNW sec 6	T152N-R94W	8709	Burbank BIA #23-8	033-025-00232	NESW sec 8	T147N-R93W
1254	Gilbert T. Rhode #1	033-053-00159	SWSE sec 17	T152N-R94W	8819	Mertes #1-32	033-013-00862	SWNW sec 32	T162N-R89W
1343	3 H.G. Price	033-053-00203	NWSW sec7	T152N-R94W	8824	Koch #2-28	033-013-00864	NWNE sec 28	T162N-R89W
1350	Brenna Lacey #1 (AMU-G521)	033-053-00206	NENE sec 1	T152N-R95W	8850	Nelson #1-29	033-013-00867	SWSE sec 29	T163N-R92W
1405	Catherine E. Peck #2	033-053-00226	NWNE sec 27	T150N-R96W	8869	Federal #2-4	033-007-00741	SWSW sec 2	T144N-R102W
1606	1 H.H. Shelvik Tract 1	033-053-00285	NESW sec 35	T150N-R97W	8874	Federal #10-1	033-007-00742	NESE sec 10	T144N-R102W
1679	1 C.C Mogen Tract 1	033-053-00295	SWSE sec 10	T153N-R96W	8902	USA #33-23-154	033-053-01391	NWSE sec 23	T146N-R104W
1779	Harvey Hopkins #3	033-053-00322	NWNE sec 17	T152N-R94W	9001	Negaard #1	033-013-00877	NWSE sec 21	T163N-R93W
1780	George C. Lewis #3 (AMU K-5111)	033-053-00323	SENE sec 18	T152N-R94W	9127	Federal #6-4	033-007-00781	NESW sec 6	T144N-R101W
1858	Minnie Kummert 1 #1	033-053-00342	NWNE sec 25	T150N-R96W	9240	MOI #33-19H	033-053-01459	NWSE sec 19	T145N-R103W
1886	John Dinwoodie #1	033-053-00347	NWSE sec 35	T153N-R94W	9351	Federal F-6-144-101 #3	033-007-00820	NWSE sec 6	T144N-R101W
1890	Rose Hopkins Hand #1	033-053-00348	SWSW sec 16	T152N-R94W	9425	Federal #11-1	033-007-00829	NENW sec 11	T144N-R102W
1987	Woodrow Star #1A	033-053-00014	SWSE sec 21	T152N-R94W	9426	Federal #12-1	033-007-00830	SWSE sec 12	T144N-R102W
2010	Dallas D. Moore #1	033-023-00024	NWNE sec 7	T163N-R102W	9492	Federal #19-1	033-007-00843	SESW sec 19	T144N-R101W
2226	USA Thomas #1	033-053-00393	SWNW sec 18	T153N-R94W	9569	1 Fed. DG	033-053-01536	SESE sec 34	T145N-R100W
2308	Drags Wolf Heirs #1	033-053-00402	SWNW sec 27	T152N-R94W	9707	Young Bear BIA #32-4	033-025-00347	SWNE sec 4	T148N-R92W
2383	Lawrence Birds Bill #1	033-053-00411	NWNE sec 30	T150N-R94W	9793	Schmitz 8-30	033-053-01599	SENE sec 30	T152N-R100W
2602	5 S.A. Garland	033-053-00449	SWNE sec 6	T153N-R95W	10077	Federal #11-4	033-007-00914	NWNE sec 11	T144N-R102W
2615	Jack Dvirnak #1	033-025-00016	NENE sec 20	T146N-R96W	10989	Federal #12-12	033-007-01014	SWNW sec 12	T144N-R102W
2618	Jacob Huber #1	033-025-00017	SWSE sec 15	T145N-R91W	11257	Federal # 1-29	033-053-01979	NESE sec 29	T145N-R101W
2828	L.J. Hovde #1	033-105-00591	NWNW sec 15	T154N-R98W	11292	Federal DL #1	033-007-01039	SWNE sec 8	T142N-R102W
2967	2 A.S. Wisness	033-053-00493	NWSE sec 35	T152N-R96W	11397	Daniel Anderson #1	033-079-00049	NESE sec 17	T160N-R73W
3007	Hamlet Unit #2	033-105-00606	CNE sec 30	T159N-R95W	11617	Hagen #1-13	033-053-02076	SESW sec 13	T153N-R95W
3167	1 W. Quale	033-053-00509	SESW sec 31	T153N-R95W	11689	Glen #1-30	033-105-01209	NENW sec 30	T155N-R101W
3363	1 Clarence Pederson	033-105-00633	NWSE sec 19	T157N-R96W	12019	Rose #1	033-053-02163	SENE sec 33	T152N-R94W
4113	1A Fort Berthold Allottee	033-061-00179	SENW sec 4	T150N-R93W	12033	Shobe #1	033-061-00344	NENE sec 30	T151N-R93W
4264	Amerada-Gov't Dorough A3	033-053-00562	NENW sec 35	T153N-R95W	12160	MOI #44-13	033-053-02188	SESE sec 13	T145N-R104W
4297	B.E. Hove #1	033-105-00665	SWNE sec 2	T154N-R95W	12162	MOI #13-21	033-007-01119	NWSW sec 21	T143N-R101W
4340	Marmon Clifford 31	033-105-00068	SWSW sec 2	T154N-R95W	12331	MOI # 44-27	033-007-01140	SESE sec 27	T143N-R102W
4790	ABRA Steen #1	033-009-01034	SESE sec 20	T159N-R81W	12494	Rauch-Shapiro-Fee #13-3	033-007-01154	NWSW sec 3	T142N-R102W
4958	Florence M. Ingerson #2	033-013-00715	SWNE sec 2	T161N-R91W	12558	Crooked Creel State #31-16	033-007-01162	NWNE sec 16	T142N-R102W
5088	L. Texel #21-35	033-061-00187	NENW sec 35	T156N-R93W	12570	MOI #44-7H	033-053-02265	SESE sec 7	T146N-R102W
5656	H. Borstad #1	033-105-00732	SWSW sec 3	T157N-R95W	12772	AHEL Grassy Butte 12 #31 H3	033-053-02308	NWNE sec 12	T146N-R99W
5919	Sonflot Heirs Unit #1	033-013-00749	SESW sec 30	T161N-R94W	12779	Beaver Valley Ranch #34-21H	033-053-02310	SWSE sec 21	T146N-R104W
6082	Martin Weber 1-18-1C	033-025-00067	SENW sec 18	T145N-R97W	12785	Carus Fee #21-19	033-025-00447	NENW sec 19	T147N-R96W
6437	Marie Sherven #1	033-053-00744	NWSW sec 26	T153N-R95W	12786	Laredo #26-1	033-061-00394	SWNE sec 26	T156N-R91W
6464	GPE-ALAQ 19-147-95 BN #1	033-025-00112	NWSE sec 19	T147N-R95W	12807	AHEL et al Sanish 36-44 H4	033-061-00398	NWSESE sec 36	T154N-R93W
6616	FLB #1-26	033-053-00797	NENW sec 26	T153N-R101W	12886	Connell #24-27	033-007-01213	SESW sec 27	T144N-R102W
7020	William Steckler #1	033-037-00023	SENE sec 5	T137N-R88W	12979	Gudbranson #1	033-053-02338	NWSE sec 34	T152N-R94W
7128	Blacktail Federal #1-20	033-007-00393	SWSE sec 20	T143N-R101W	13098	Stenejhem HD #1-27	033-053-02357	NESE sec 27	T150N-R97W
7494	BN Depco #15-22	033-053-01030	SENW sec 15	T146N-R101W	13318	Watterud "A" #17	033-023-00412	SESW sec 11	T160N-R95W
7579	USA # 42-24A	033-053-01058	SENE sec 24	T145N-R104W	13447	Dickinson State #74	033-089-00397	SWNW sec 32	T140N-R96W
7590	USA #43-27A	033-053-01062	NESE sec 27	T146N-R104W	13574	Kadramas #75	033-089-00400	NWSE sec 31	T140N-R96W
7690	Blacktail Federal #3-19	033-007-00552	SWSW sec 19	T143N-R101W	M-1	Wascana Joyes State 5H		NENE sec 16	T37N-R57E
7783	Tribal #1-1	033-055-00024	SENW sec 1	T151N-R90W	M-2	Sun Dennis Dynneson-1	25-083-0501200	SWSE sec 30	T24N-R58E
7851	1-11 Rogstad	033-061-00252	NESE ec 11	T155N-R91W	M-3	AHEL Nevins-1		SESW sec 13	T23N-R56E
7887	Mee USA #3-17	033-007-00581	SWNE sec 17	T142N-R100W	M-4	Balcron Naira 44-24	25-083-2177500	SESE sec 24	T24N-R54E
8069	Jensen #12-44	033-061-00257	SESE sec 12	T154N-R90W	M-5	Oryx Big Sky-1	25-085-2156700	NWSE sec 2	T30N-R58E
8177	Dobrinski #18-44	033-101-00260	SESE sec 18	T151N-R87W					

FIGURES

Figure 13. Map showing contours to the top of the Mississippian-Devonian Bakken Formation (thinner lines). Datum is sea level, thus this map does not represent a sediment-burial map. Contour interval is 500 ft (152 m) except for the 8,750 and 9,000 ft (2666.9 to 2743.1 m) contours. ROCK-EVAL hydrogen-index contours (thicker lines) of the Bakken shales are from Price et al. (1984). Locations of wells with close-spaced (foot by foot) ROCK-EVAL analysis of core samples of Bakken Source System rocks (Table 3) are shown by: larger dots NDGS numbers and "RE" (e.g., 9001RE, "ROCK-EVAL"). Locations of wells discussed in Figures (14 to 19 and 33 to 37) are also shown by larger dots and NDGS numbers. Stark County is labeled, as is the discovery well for the lower Lodgepole Waulsortian mound play, the Dickinson State #74, as designated by the NDGS number (13447) and (DS-74). The approximate leasing trend for the Waulsortian mound play is shown by the stippling, trending roughly north south. The Fairway area is shown by stippling in the lower left hand corner of the map. Dashed line is the depositional edge of the upper Bakken shale.

Figure 14. Plot of porosity in volume percent of rock, permeability in millidarcies, and residual oil and water saturation percentages, all versus depth, for the Bakken silltstone in NDGS #8177 (Marathon Dobrinski 18-44, SESE sec 18 T151N R87W). The upper and lower Bakken shales are shown by stippling. Residual-oil saturations are shown by circles. Residual-water saturations are shown by squares.

Figure 15. Plot of porosity in volume percent of rock, permeability in millidarcies, and residual-oil and water saturation percentages, all versus depth, for the Bakken siltstone in NDGS #8637 (Clarion Resources Inc. Pierce 1-18, SENE sec 18 T161N R87W). The upper and lower Bakken shales are shown by stippling. Residual oil saturations are shown by circles. Residual water saturations are shown by squares. Numbers in the far right of the permeability plot are offscale permeability values. "F" is a fracture as noted in the core analysis.

Figure 16. Plot of porosity in volume percent of rock, permeability in millidarcies, and residual-oil and water saturation percentages, all versus depth, for the Bakken siltstone in NDGS #7851 (Brooks Exploration, Rogstad 1-11, NESE sec 11 T155N R91W). The lower Bakken shale is shown by stippling. Residual-oil saturations are shown by circles. Residual-water saturations are shown by squares. Numbers in the far right of the permeability plot are offscale permeability values.

Figure 17. Plot of porosity in volume percent of rock, permeability in millidarcies, and residual oil and water saturation percentages, all versus depth for all three rocks (Lodgepole limestone, Bakken siltstone, and Three Forks shale) adjacent to the upper and lower Bakken shales in NDGS #8709 (Burbank BIA #23-8, NESW sec 8 T147N R93W). Note the breaks in the depth scale at the upper and lower Bakken shales. Both Bakken shales are designated by stippling. "CVF" is closed vertical fracture. "F" is an undesignated fracture. The numbers at the far right of the permeability plot are offscale permeability

values in millidarcies. Residual-water saturations are shown by circles; residual-oil saturations are shown by triangles. Depths are driller's depths. The 10.6 value in the porosity plot just below the lower Bakken shale is an offscale porosity value.

Figure 18. Plot of porosity in volume of percent of rock, permeability in millidarcies, and residual oil and water saturation percentages, all versus depth, for all three rocks (Lodgepole limestone, Bakken siltstone, and Three Forks shale) adjacent to the upper Bakken shale in NDGS #12494 (Rauch-Shapiro-Fee #13-3, NWSW sec 3 T142N R102W). Note that the lower Bakken shale is not present in this well. The upper Bakken shale is designated by stippling. "LF" is a laminar fracture and "HF" is a horizontal fracture, as noted in the core analysis. Residual-water saturations are shown by circles; residual-oil saturations are shown by triangles. Depths are driller's depths.

Figure 19. Plot of porosity in volume percent of rock, permeability in millidarcies, and residual-oil and water saturation percentages, all versus depth, for the Bakken siltstone and Three Forks shale in NDGS #11617 (Cox and Berry Hagen 1-13, SESW sec 13 T153N R95W). The top of the lower Bakken shale is at 10,377 ft (3,162.8 m) and the top of the Three Forks shale is at 10,405 ft (3,171.3 m). Note the break in the vertical scale over the lower Bakken shale. Residual-oil saturations are shown by circles. Residual water saturations are shown by squares. Numbers in the far right of the permeability plot are offscale permeability values.

Figure 20. ROCK-EVAL analysis, versus depth, for the middle Bakken siltstone from NDGS #8177 (Dobrinski #18-24, SESE sec 18 T151N R87W). The upper and lower Bakken shales are shown by stippling. TOC is total organic carbon content in weight percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 peaks in parts per million (ppm) dry rock weight. The S_1 peak is analogous to solvent-extractable HCS (free oil). The S_2 peak measures oil-generation potential. Depths are driller's depths.

Figure 21. ROCK-EVAL analyses, versus depth, for the middle Bakken siltstone and Three Forks shale from NDGS #2618 (Jacob Huber #1, SWSE sec 15 T145N R91W). The lower Bakken shale is shown by stippling. TOC is total organic carbon content in weight percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 peaks in parts per million (ppm) dry rock weight. Note the break in the depth scale for the lower Bakken shale. Depths are driller's depths.

Figure 22. ROCK-EVAL analyses, versus depth, for the middle Bakken siltstone from NDGS #9001 (Negaard #1, NWNE sec 21 T163N R93W). The upper and lower Bakken shales are shown by stippling. TOC is total organic carbon content in weight percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 peaks in parts per million (ppm) dry rock weight. Depths are driller's depths.

Figure 23. ROCK-EVAL analyses, versus depth for the Lodgepole limestone and Bakken siltstone from NDGS #8638 (Slater #1-24, SWSW sec 24 T161N R91W). The false Bakken (lowermost Lodgepole) shale and upper Bakken shale are shown by stippling. TOC is total organic carbon content in weight

percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 peaks in parts per million (ppm) dry rock weight. Depths are driller's depths. Note the break in the vertical scale over the upper Bakken shale and above the false Bakken.

Figure 24. ROCK-EVAL analyses, versus depth, for cuttings chips, of the Lodgepole limestone, Bakken siltstone, and Three Forks shale from NDGS #2010 (Dallas D. Moore #1, NWNE sec 7 T163N R102W). The upper and lower Bakken shales are shown by stippling. TOC is total organic carbon content in weight percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 peaks per million (ppm) dry rock weight.

Figure 25. ROCK-EVAL analyses, versus depth, for the Lodgepole limestone, Bakken siltstone, and Three Forks shale from NDGS #8474 (Graham USA #1-15, NESW sec 15 T144N R102W). The false Bakken (lowermost Lodgepole shale) and upper Bakken shale are shown by stippling. The line at 10,375 ft (3,162.1 m) is the contact between the Bakken siltstone and the Three Forks shale. The dashed vertical lines are background (starting) TOC, S_1, and S_2 values for each stratigraphic unit. TOC is total organic carbon content in weight percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 pyrolysis peaks in parts per million (ppm) dry rock weight. Depths are driller's depths.

Figure 26. ROCK-EVAL analyses, versus depth, for the Lodgepole limestone and Bakken siltstone from NDGS #5088 (L. Texel #21-35, NENW sec 35 T156N R93W). The upper and lower Bakken shales are shown by stippling. Note the break in the depth scale at the upper Bakken shale. The dashed vertical

lines are background (starting) TOC, S_1, and S_2 values for each stratigraphic unit. TOC is total organic carbon content in weight percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 pyrolysis peaks in parts per million, dry rock weight. Depths are driller's depths.

Figure 27. ROCK-EVAL analyses, versus depth, for the Bakken siltstone and Three Forks shale from NDGS # 1405 (Catherine E. Peck #2, NWNE sec 27 T150N R96W). The lower Bakken shale is shown by stippling. Note the break in the depth scale at the lower Bakken shale. The dashed vertical lines are background (starting)TOC, S_1 and S_2 values for both stratigraphic units. The numbers in the S_1 plot just below the lower Bakken shale are offscale S_1 values. TOC is total organic carbon content in weight percent. S_1 and S_2 ppm are the ROCK-EVAL S_1 and S_2 pyrolysis peaks in parts per million, dry rock weight. Depths are driller's depths.

Figure 28. ROCK-EVAL analyses (total organic carbon (TOC) content, and the S_1 and S_2 peaks in ppm, parts per million, dry rock weight) for close-spaced core (6"-18", 0.15-0.46 m) and core-cutting chips (of variable sieve sizes) of the Bakken siltstone from NDGS #4340 (Pan Am, C. Marmon-1, SWSW sec 2 T154N R95W). The numbers at the far right in the S_1 and S_2 plots for the core samples are offscale values. The bottom of the upper and the top of the lower Bakken shales are shown by stippling in the close-spaced core plot.

Figure 29. ROCK-EVAL analyses (total organic carbon (TOC) content, and the S_1 and S_2 peaks in ppm (parts per million, dry rock weight) for close-spaced core

(6"-18", 0.15-0.46 m) and core-cutting chips (of variable sieve sizes) of the Three Forks shale from NDGS #1405 (Amerada Catherine Peck #2, NWNE sec 27 T150N R96W). The numbers at the far right in the TOC, and S_1 and S_2 plots for the core samples are offscale values. The bottom of the lower Bakken shale is shown by stippling in the close-spaced core plot.

Figure 30. Saturated-HC gas chromatograms of core composites of lower Bakken shale and Three Forks shale from NDGS #1405 (Catherine E. Peck #2, NWNE sec 27 T150N R96W). PRIS is pristane; PHY is phytane. Selected n-paraffins (usually every fifth n-paraffin) are designated by "C" and their respective carbon number. Peaks eluting before 15 minutes in the chromatogram of the Three Forks shale are contamination from the solvents used to extract and process the sample.

Figure 31. Saturated-HC gas chromatograms from the lower Bakken shale, Lodgepole limestone, middle Bakken siltstone, and Three Forks shale from NDGS #607 (Kennedy Federal 32-24-D SWNE sec 24 T149N R93W). PRIS is pristane; PHY is phytane. Selected n-paraffins (usually every fifth n-paraffin) are designated by "C" and their respective carbon number.

Figure 32. Whole-oil gas chromatograms for the original oil (32A) and evaporated samples (32B to 32D) of Bakken oil produced from a 1998 recompletion attempt of the Three Forks shale over 11,128-11,168 ft (3,391.6-3,403.8 m) in the Johnsrud 1-31 (NDGS #11630, SWSE sec 31 T151N R98W). Every

fifth n-paraffin is labeled (n-C10 etc.). Percent weight loss from evaporation is shown for each chromatogram.

Figure 33A. Work sheets from fracture analysis for 15 ft (4.6 m) of lower Lodgepole Limestone just above the top of the Bakken shale at 3,307.75 ft (1008.15 m, core depths and not electric-log depths), from NDGS #11397 (Daniel Anderson-1, NENE sec 17 T160N R73W). Permeability plugs cut from the core are shown by circles, crescents, half circles, ellipses or half ellipses. Black dashed lines are induced fractures (from coring, hammer blows, etc.). Solid black lines are saw cuts. Intervals with missing core are shown by cross hachures. Blue lines with Xs through them are early-formed completely-closed, cemented fractures which cannot absorb water. Red lines are open fractures which can take up fluids. Anlaysis by Stolper Geologic.

Figure 33B. Fracture analysis of the Bakken siltstone from NDGS #4958 (EOG Ingerson-2, SWNE sec 2 T161N R91W). Intervals with missing core are shown by black line or boxes with X's through them. Blue lines ("Micro-Closed") are fractures closed to the naked eye, which under magnification are open fractures. Red lines ("Micro-Open") are fractures open to the unassisted eye. Both types of fractures absorb water. Analysis by Stolper Geologic.

Figure 34A and B. Work sheets from fracture analysis of the Bakken siltstone in NDGS #8824 (C & K Koch 2-28, NWNE sec 28 T162N R89W). Permeability plugs cut from the core are shown by rectangles, one half-circle, and one circle. Black-dashed lines are induced fractures (from coring, hammer blows, etc.).

Intervals with missing core are shown by cross hachures. Blue lines are fractures closed to the naked eye, which under magnification are open fractures. Red lines are fractures open to the unassisted eye. Both types of fractures absorb water. Analysis by Stolper Geologic.

Figure 35. Fracture analysis of the Bakken siltstone from NDGS #13098 (Oryx Stenehjem 27-1, SWNE sec 27 T150N R97W). Blue lines are fractures closed to the unassisted eye, which under magnification are open fractures. Red lines are fractures open to the unassisted eye. Black dashed lines are induced fractures (hammer blows). Analysis by Stolper Geologic.

Figure 36. Fracture analysis of Bakken Source System core from NDGS #12160 (Meridian Oil MOI 44-13, SESE sec 13 T145N R104N). In this case, red lines ("Micro-Closed") are fractures closed to the unassisted eye, which under magnification are open. Dotted dark blue times ("Micro-Open") are fractures open to the unassisted eye. Both types of fractures absorb water. Intervals with missing core are shown by boxes with X's through them. From Bolger and Stolper (1993), analysis by Kathy Stolper.

Figure 37. Fracture analysis of middle Devonian Birdbear or Duperow limestone from NDGS #11689 (Sonat 1-30 Glenn, NENW sec 30 T155N R101W). Reddish-orange lines ("Micro-Closed") are fractures completely closed under magnification and partially to totally calcite-cemented. Dotted dark blue lines ("Micro-Open") are fractures open either under magnification or to the unassisted eye. Dashed green leins are (cemented) closed fractures, which to

the unassisted eye are mineralized (calcite, dolomite, or pyrite). Boxes with X's through them are intervals with missing core. Intervals with rubblelized core, and which thus could not be analyzed, are shown by interlocked black curved lines. From Bolger and Stolper (1993), analysis by Kathy Stolper.

Figure 38. Vitrinite relfectance (R_o) profile, versus depth, for the rocks (cuttings chips) of NDGS #6464 (Gas Producing Enterprises ALAQ 19-147-95 BN#1, NWSE sec 19 T147N R95W). $r^2 = 0.95$ is the correlation coefficient from linear regression analysis of the R_o data versus depth. The solid line is the regression line. Geologic ages and major stratigraphic units are shown. FM is formation, GRP is group. Taken from Price et al. (1984).

Figure 39. Vitrinite reflectance (R_o) profile, versus depth, for rocks from the COST-1 offshore Texas Gulf Coast stratigraphic test. Data from Huc and Hunt (1980) and Waples (1981).

Figure 40. Map showing location of wells (as designated by larger dots and NDGS well numbers) with vitrinite reflectance versus depth profiles (Figures 38, and 41-43). See Figure 13 caption for details of this base map, which is from Price et al. (1984).

Figure 41. Vitrinite reflectance (R_o) versus depth profile for of NDGS #607 (Kennedy Federal #32-24-D, SWNE sec 24, T149N R93W). Coals are shown by triangles. Rocks with hydrogen-poor (terrestrial) OM are shown by dots. Marine rocks with hydrogen rich organic matter are shown by squares. Three Bakken shale samples are so labeled (BAKKEN). The correlation coefficient

(r^2) of the R_o data versus depth (the regression line from 0 to about 5,000 ft (1,523.9 m) is high (0.993). The wavy line at about 5,100 ft (1.554.4 m) shows the transition from hydrogen-poor to marine OM. The numbers (in °C) on the triangles are ROCK-EVAL T_{max} values. Stratigraphy is shown on the right of the figure. "IK" is Inyan Kara. Extension of the solid line to R_o = 0.25% suggests 450 ft (137 m) of erosion at this site.

Figure 42. Vitrinite reflectance (R_o) profile for rocks of NDGS #527 (Rough Creek Unit #1, NWNE sec 13, T148N R98W). Coals are shown by triangles. Rocks with hydrogen-poor (terrestrial) OM are shown by squares. Three Bakken shale samples are so marked (BAKKEN). The correlation coefficient (r^2) of the R_o data versus depth (the regression line from 0 to about 4,500 ft; 1,3771.5 m) is 0.933. The wavy line at about 4,800 ft (1,463.0 m) shows the transition from hydrogen-poor to marine organic matter. The numbers (in °C) on the triangles are ROCK-EVAL T_{max} values. The 435°C value applies to both the triangles at that depth. Stratigraphy is shown on the right of the figure. "IK" is Inyan Kara. Extension of the solid line to R_o = 0.25% suggests 300 ft (91.4 m) of erosion at this site.

Figure 43. Linear regression lines from vitrinite reflectance (R_o) profiles versus depth from wells at different sites (Fig. 40) in the North Dakota portion of the Williston Basin. The numbers on the profiles are NDGS well numbers The data sets are equivalent to those shown in Figures 38, 41, and 42. Correlation coefficients and estimates of erosion at each site, are shown in Table 8.

Figure 44. Measured formation fluid pressures for a well in the Antelope Field. Note that all stratigraphic units have fluid pressures below the hydrostatic gradient, except the Bakken formation, which is overpressured. After Meissner (1978).

Figure 45. Diagrammatic cross section from a Williston Basin groundwater recharge area (Big Horn Mountains) to a groundwater discharge area (Red River of the North) showing relationship of aquifers and confining layers in the northern Great Plains, Montana and North Dakota. Note that the Bakken Source System rocks are an aquitard (closed-fluid system). After Downey et al. (1987).

Figure 46. Plot of R_o, and the ROCK-EVAL production index, and S_2 peak normalized to organic carbon (mg/gOC) all versus the ROCK-EVAL hydrogen index for rocks at equilibrium burial temperatures of 180 to 199.9 °C. Samples are from the Wilmington field, the northwest plunge of the Santa Fe Springs field (Houghton Community-1), and the Apex-1 in the Los Angeles Basin; and the KCLA 72-4 wellbore, Paloma Field, Southern San Joaquin Valley Basin. The curved line in the R_o plot results from logarithmic regression analysis of the data and has a correlation coefficient of $r^2 = 0.867$ to the data. The lines in the S_1 pyrolysis peak and production index plots define the principal trends of the data. After Price et al. (submitted).

Figure 47. Plot of TOC (total organic carbon), the TOC-normalized (milligrams per gram, mg/gOC) S_1, S_2 (HI-hydrogen index), S_3 (OI-oxygen index) ROCK-

EVAL peaks, the ROCK-EVAL production index (PI) and T_{max}, and R_o versus burial temperature in °C and depth in kilometers for shales from various wells in the Wilmington field, Los Angeles Basin. Trends are defined by solid lines. Crosses are immature (pre-HC generation) sample with large amounts of indigenous or stained HCS. The sample with 184 to the far right of the S_1 plot is the S_1 value of that sample. From Price et al. (submitted).

Figure 48. Plot of TOC (total organic carbon) content, and the ROCK-EVAL: S_1 pyrolysis peak normalized to organic carbon (mg/gOC), hydrogen index, and production index (S_1/S_1+S_2), for shales from the Shell Taylor 653, Ventura Avenue Field, Ventura Basin, all versus burial temperature in °C and depth in kilomters. Dots are samples from cuttings chips, triangles are samples from core.

Figure 49. R_o versus depth profile for the Natomas North America Anderson 1-12 in the Ignacio Field (SWNE sec 12 T34N R8W), La Plata Co., Colorado. The data have a correlation coefficient (r^2) of 0.993 to the solid line. The dashed portion of the line extrapolates to $R_o = 0.25\%$ to estimate the amount of erosion at this location.

Figure 50. Percent of CO_2 generated over what was possible, based on the original oxygen content of the kerogens, for three rocks on which aqueous pyrolysis experiments were performed.

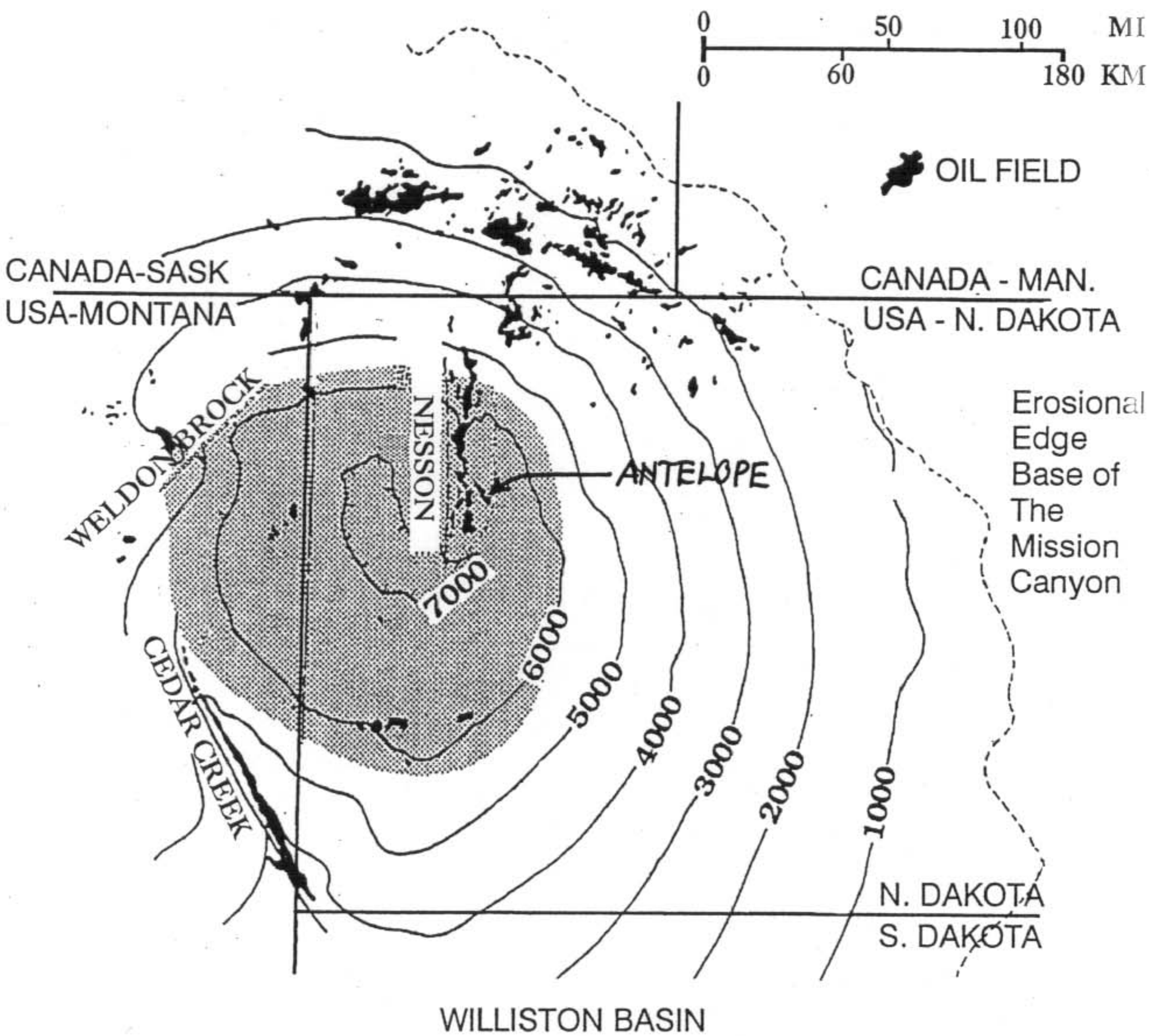
Figure 51. Plots of electrical wire-line log resistivity values in ohm-meters (after Meissner, 1978) and milligrams of C_{15}+ bitumen per gram of orgnaic carbon (mg C_{15}+ bitumen/gOC, after Webster, 1984; and Price et al., 1984) both versus depth, for Bakken shales, Williston Basin.

Figure 52. Map of the Bakken continuous oil accumulation, as defined by Schmoker (1996), showing his three subdivisions: outlying, intermediate, and fairway areas. After Schmoker (1996).

Figure 53. Map showing principal structural features of the Greater Williston Basin as related to oil production and shows from the middle Bakken siltstone member. After LeFever et al.. (1991). Stoneview field is at the north end of the Nesson anticline near the "143m OCM" D.S.T. oil show.

Figure 54. Plot of porosity, in volume percent of rock, permeability in millidarcies, and residual oil and water saturation percentages, all versus depth, for Bakken siltstone rocks, from NDGS #8697 (Pullen #1-33, NENE sec 33 T159N R88W). The numbers to the right of the permeability plot are offscale permeability values. The other two numbers for these sample points (e.g., 0.8/90° at 7,689 ft; 2,343.5 m) are permeability measurements taken 90° to maximum permeability measurements. "ND" is no data. Circles are residual water saturation percentages, and triangles are residual oil saturation percentages.

FIG. 1



0
50
100
MI
0
60
180
KM
OIL FIELD
CANADA-SASK
USA-MONTANA
CANADA - MAN.
USA - N. DAKOTA
WELDON BROCK
NESSON
ANTELOPE
Erosional Edge Base of The Mission Canyon
7000
6000
5000
4000
3000
2000
1000
CEDAR CREEK
N. DAKOTA
S. DAKOTA
WILLISTON BASIN

FIG. 2

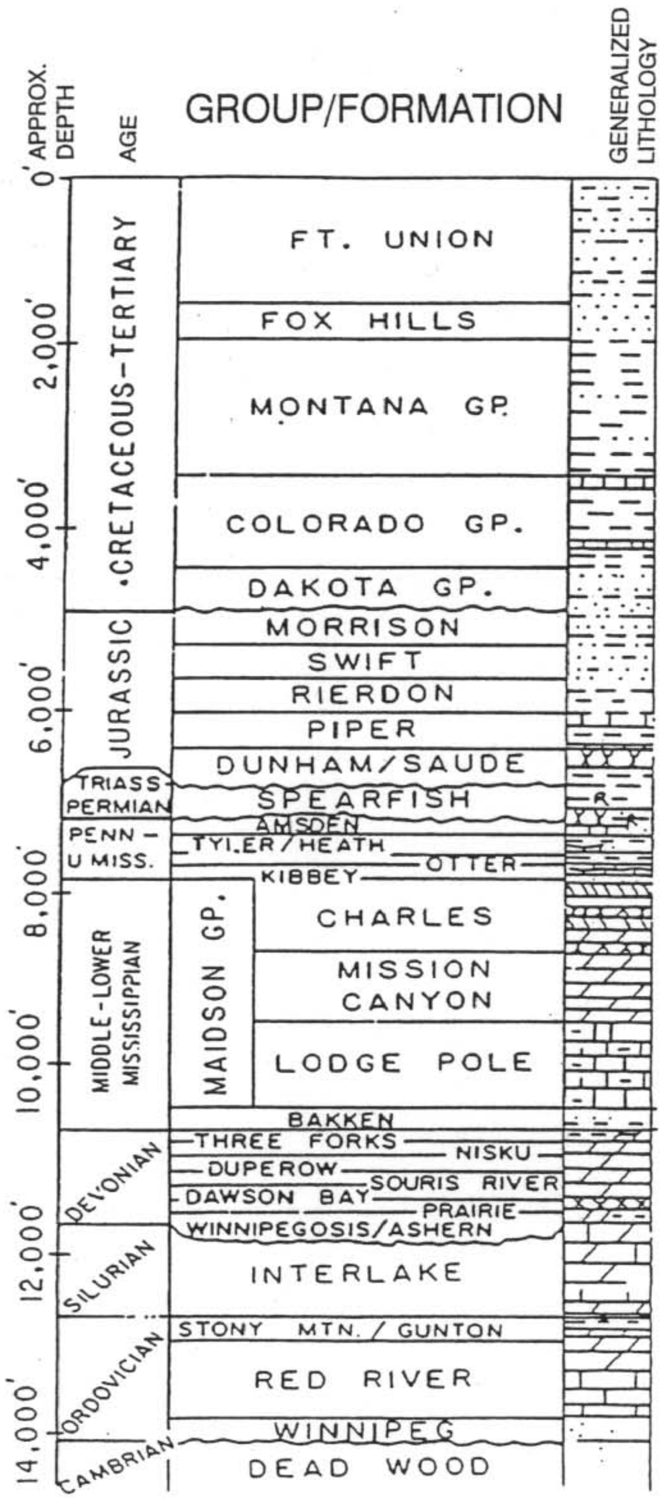
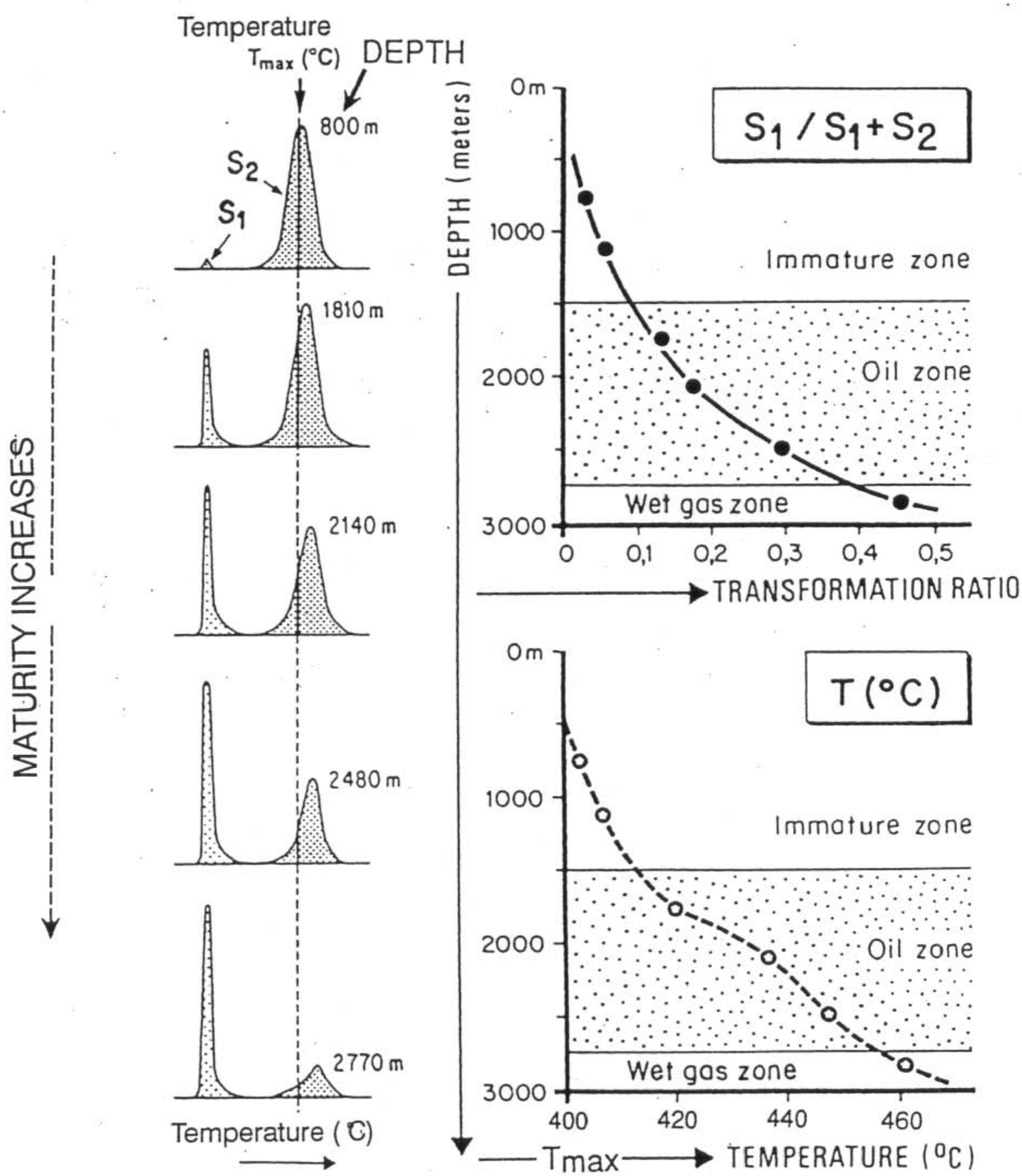

APPROX. DEPTH
AGE
GROUP/FORMATION
GENERALIZED LITHOLOGY
0'
2,000'
4,000'
6,000'
8,000'
10,000'
12,000'
14,000'
CRETACEOUS-TERTIARY
JURASSIC
TRIASS
PERMIAN
PENN - U MISS.
MIDDLE-LOWER MISSISSIPPIAN
DEVONIAN
SILURIAN
ORDOVICIAN
CAMBRIAN
FT. UNION
FOX HILLS
MONTANA GP.
COLORADO GP.
DAKOTA GP.
MORRISON
SWIFT
RIERDON
PIPER
DUNHAM/SAUDE
SPEARFISH
AMSDEN
TYLER/HEATH
OTTER
KIBBEY
MAIDSON GP.
CHARLES
MISSION CANYON
LODGE POLE
BAKKEN
THREE FORKS
NISKU
DUPEROW
SOURIS RIVER
DAWSON BAY
PRAIRIE
WINNIPEGOSIS/ASHERN
INTERLAKE
STONY MTN. / GUNTON
RED RIVER
WINNIPEG
DEAD WOOD

FIG. 3

BAKKEN SOURCE SYSTEM			
UNIT THICKNESS	TOTAL ORGANIC CARBON CONTENT	STRATIGRAPHIC UNIT	LITHOLOGY
800 feet	0.10% - 0.30%	LODGEPOLE	LIMESTONE
1 to 3 feet	8.00% - 26.00%	FALSE BAKKEN	SHALE
6 to 12 feet	0.10% - 0.30%	LODGEPOLE (lowermost)	LIMESTONE
0.5 to 30 feet	10.00% - 36.00%	UPPER BAKKEN	SHALE
10 to 92 feet	0.20% - 0.30%	MIDDLE BAKKEN	SILTSTONE
0.5 to 46 feet	10.00% - 36.00%	LOWER BAKKEN	SHALE
240 feet	0.10% - 0.30%	THREE FORKS	SHALE

FIG. 4



Temperature
T_{max} (°C)
DEPTH
800 m
S_2
S_1
1810 m
2140 m
2480 m
2770 m
Temperature (°C)
MATURITY INCREASES
DEPTH (meters)
$S_1 / S_1 + S_2$
0m
1000
2000
3000
Immature zone
Oil zone
Wet gas zone
0
0,1
0,2
0,3
0,4
0,5
TRANSFORMATION RATIO
T (°C)
0m
1000
2000
3000
Immature zone
Oil zone
Wet gas zone
400
420
440
460
Tmax
TEMPERATURE (°C)

FIG. 5

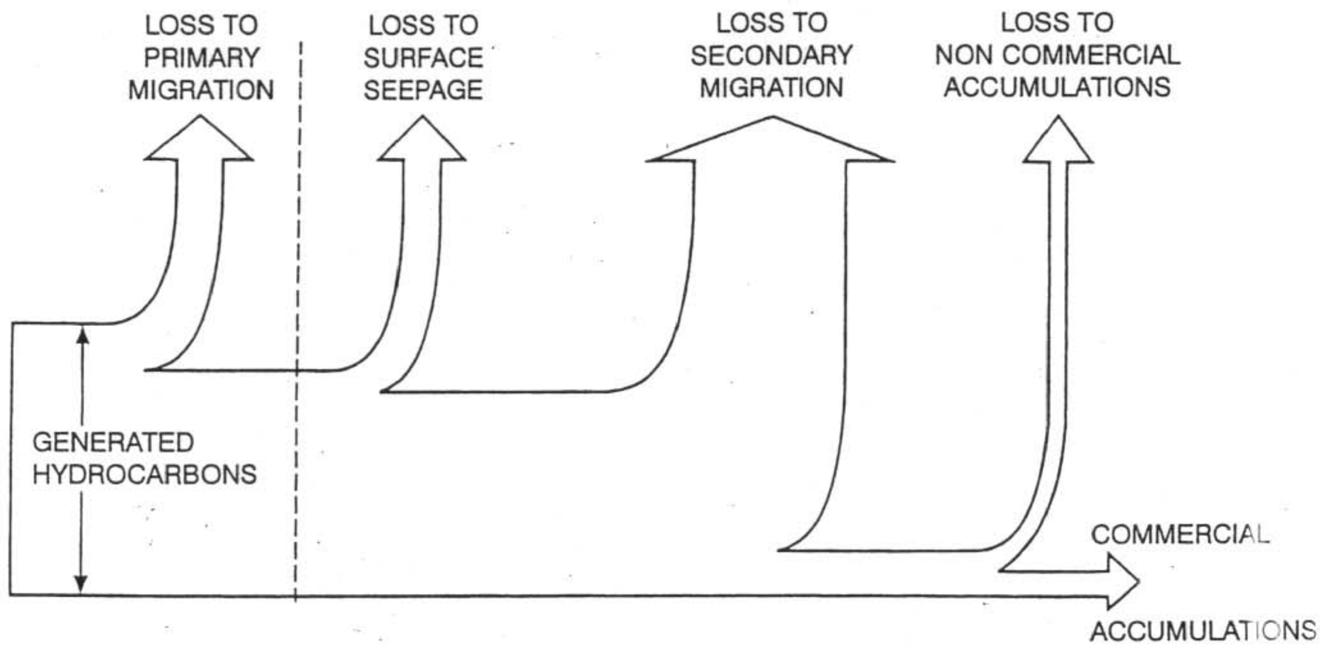

LOSS TO PRIMARY MIGRATION
LOSS TO SURFACE SEEPAGE
LOSS TO SECONDARY MIGRATION
LOSS TO NON COMMERCIAL ACCUMULATIONS
GENERATED HYDROCARBONS
COMMERCIAL
ACCUMULATIONS

FIG. 6

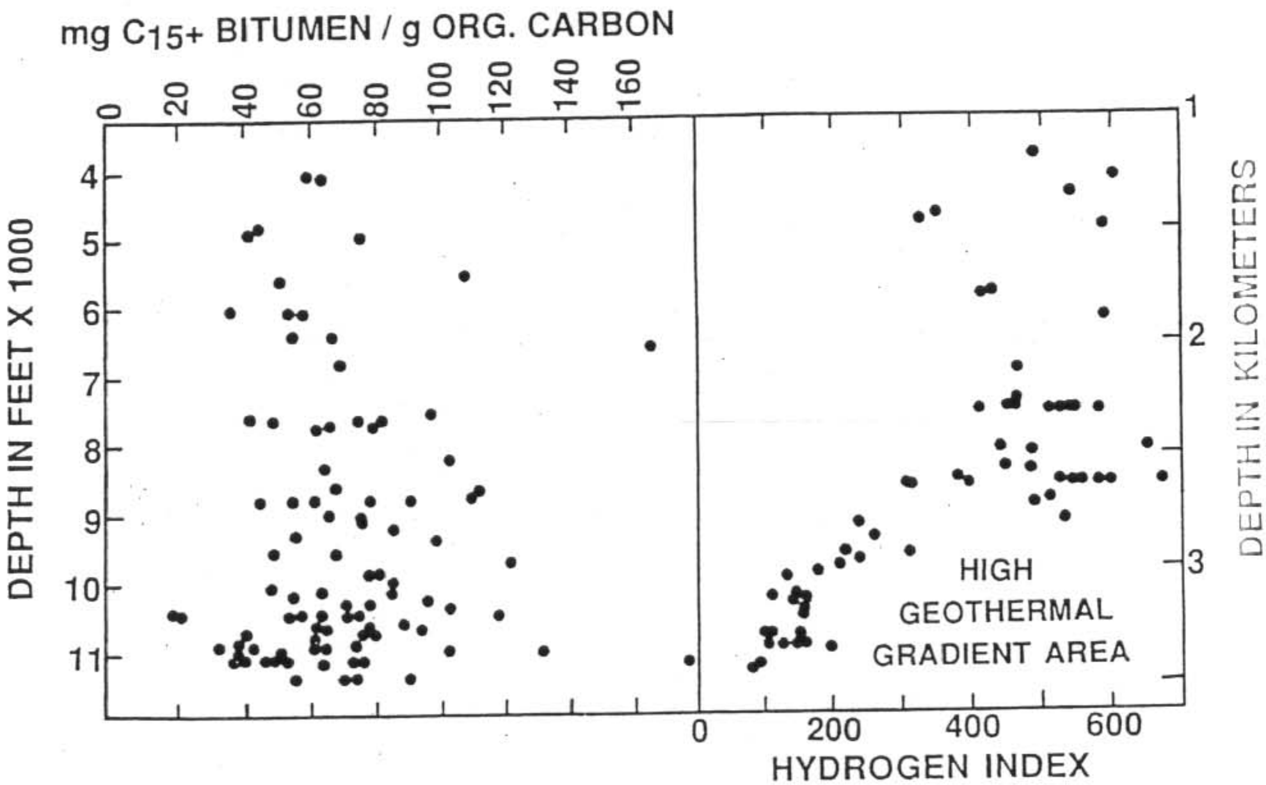
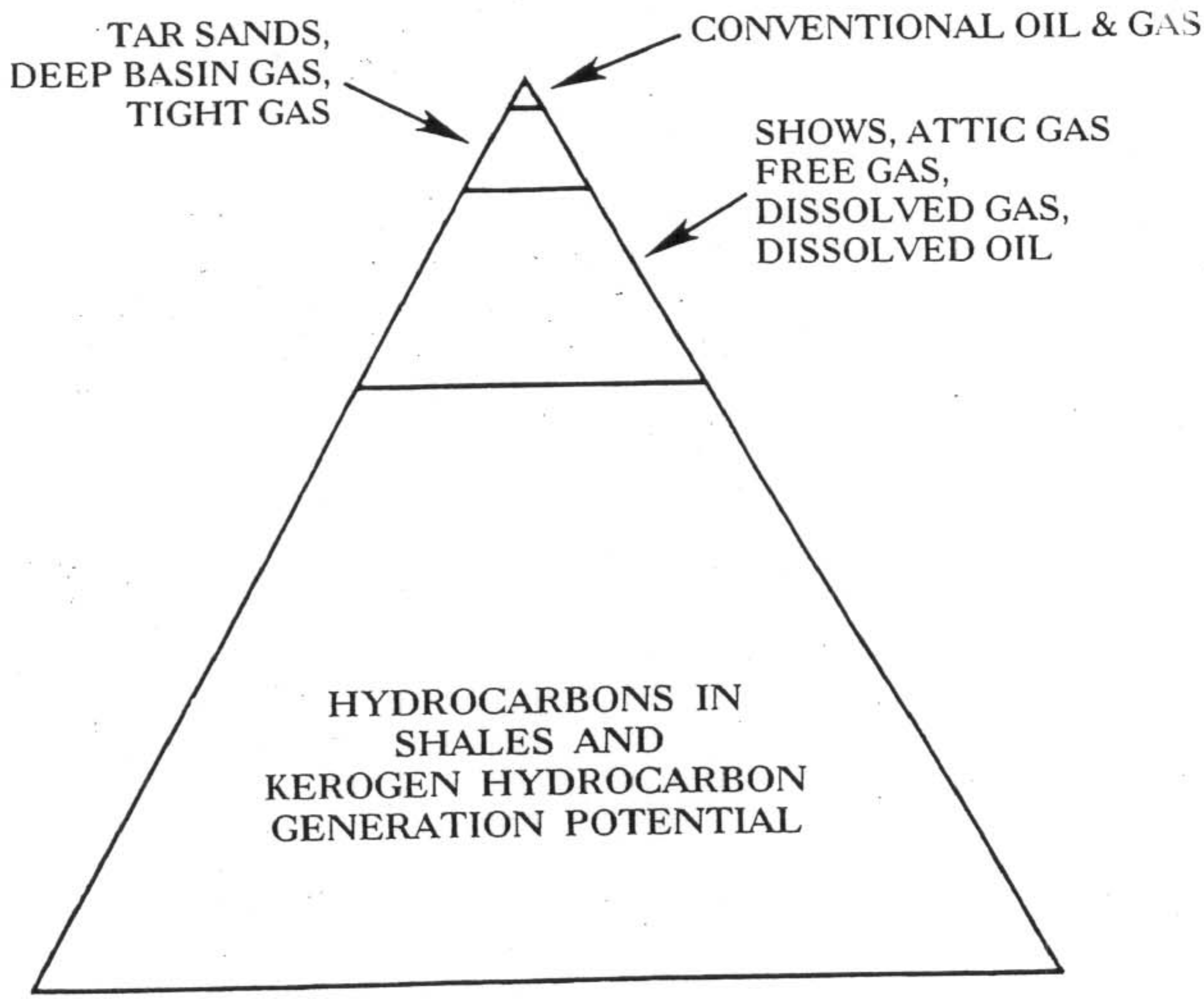

mg C_{15}+ BITUMEN / g ORG. CARBON
0
20
40
60
80
100
120
140
160
DEPTH IN FEET X 1000
4
5
6
7
8
9
10
11
DEPTH IN KILOMETERS
1
2
3
HIGH
GEOTHERMAL
GRADIENT AREA
0
200
400
600
HYDROGEN INDEX

FIG. 7

BASIN TYPE (EXAMPLES)	EUR 10^9 bbls	RICHNESS 10^6 BBLS/ 10^3 MI^2	# PROD. BAS.
CRATONIC (PARIS, WILLISTON)	7.08	9.34	4 (44 lub)
ASYMMETRIC-CRATONIC (DENVER, PARADOX)	25.75	80.5	10
PASSIVE-MARGIN (GABON, NW AUSTRALIA)	17.0	71.5	10
COMPRESSIVE-TROUGHS OR FOLD BELTS (PO VALLEY, WIND RIVER)	4.00	102.8	12
RIFT-ABORTED RIFT (SUEZ, NORTH SEA)	413.5	335	18
GRABENS ONLY SUEZ	7.10	1,365	
VIKING	30	1,875	
FORELAND-FOLDBELT (PERSIAN GULF-ALBERTA)	990.5	250	21
DELTAS (MAHAKAM, MISSISSIPPI)	103	818	8
DOWNWARP (GREATER GULF COAST)	170	476	5
WRENCH (LOS ANGELES, MARACAIBO)	156.5	1,126	37

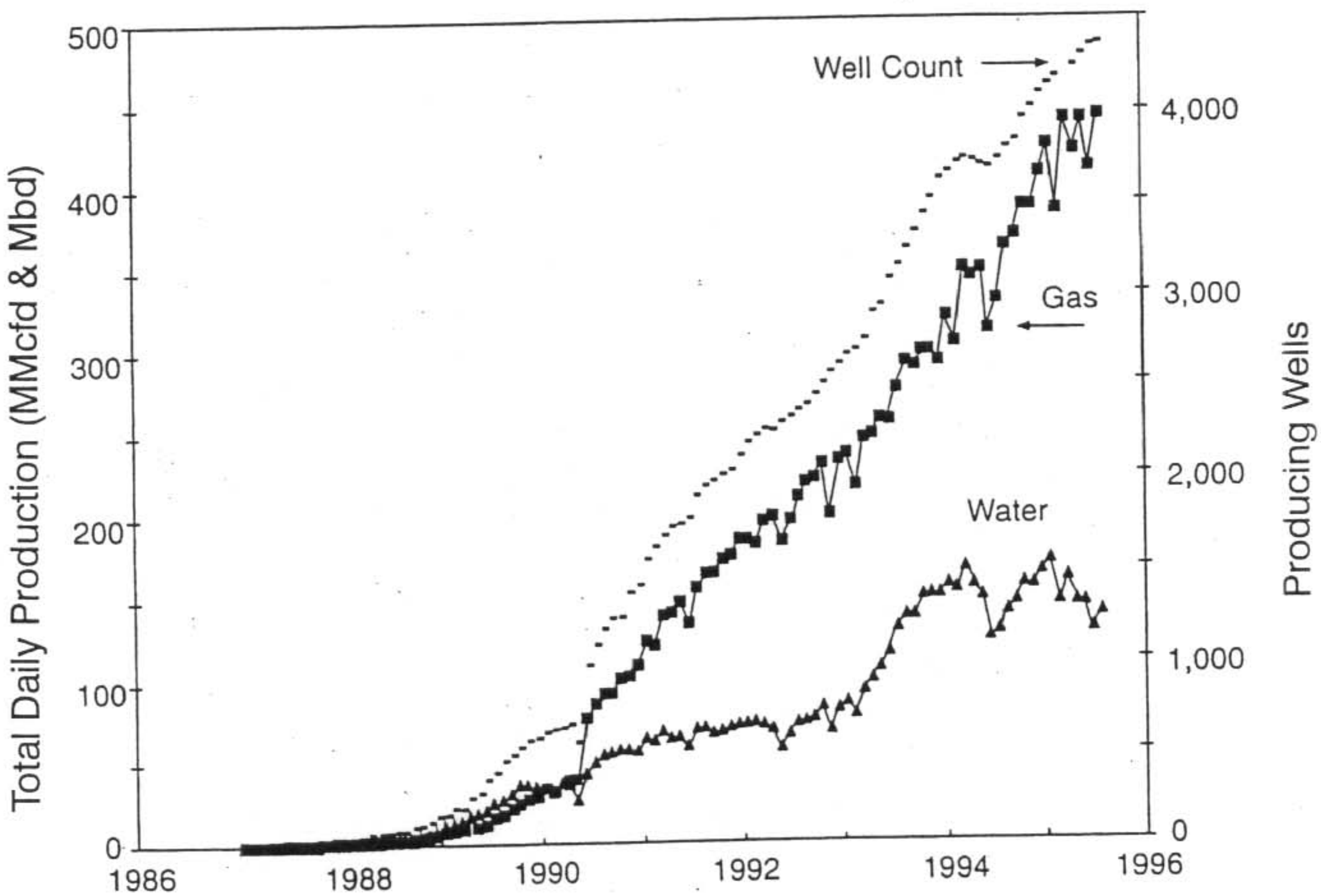
INCREASING STRUCTURAL INTENSITY

FIG. 8



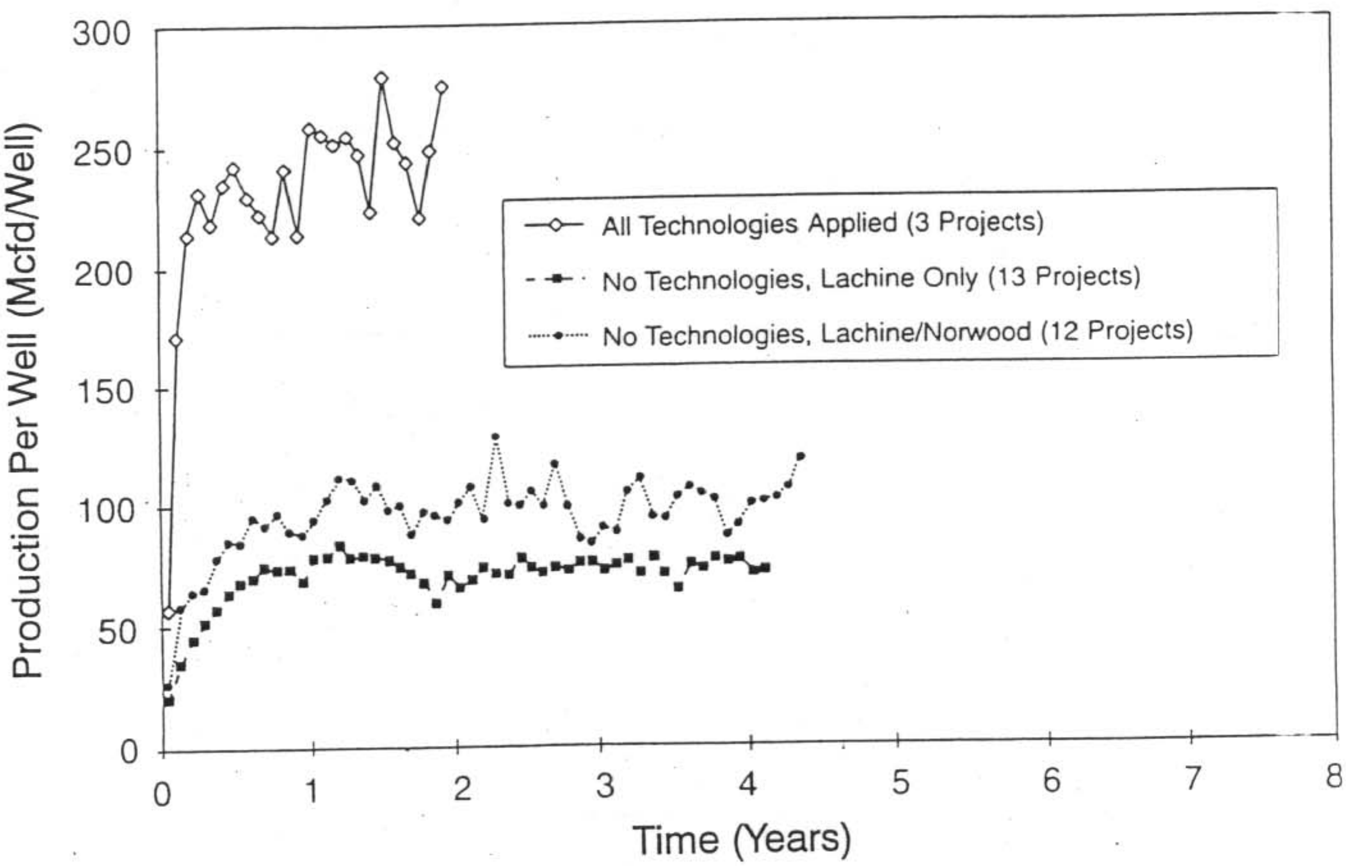
TAR SANDS,
DEEP BASIN GAS,
TIGHT GAS
CONVENTIONAL OIL & GAS
SHOWS, ATTIC GAS
FREE GAS,
DISSOLVED GAS,
DISSOLVED OIL
HYDROCARBONS IN
SHALES AND
KEROGEN HYDROCARBON
GENERATION POTENTIAL

FIG. 9



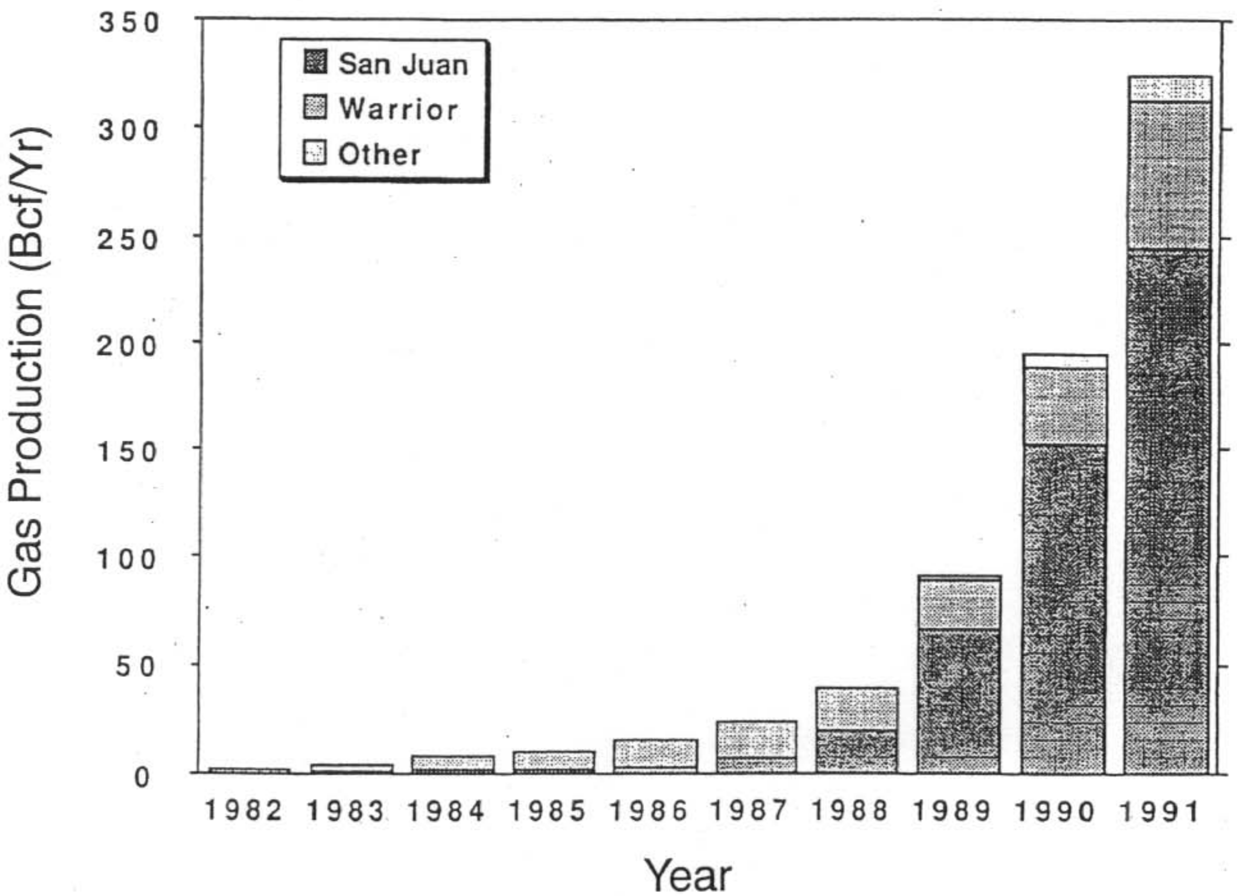
Well Count
Gas
Water
Total Daily Production (MMcfd & Mbd)
Producing Wells
500
400
300
200
100
0
4,000
3,000
2,000
1,000
0
1986
1988
1990
1992
1994
1996

FIG. 10



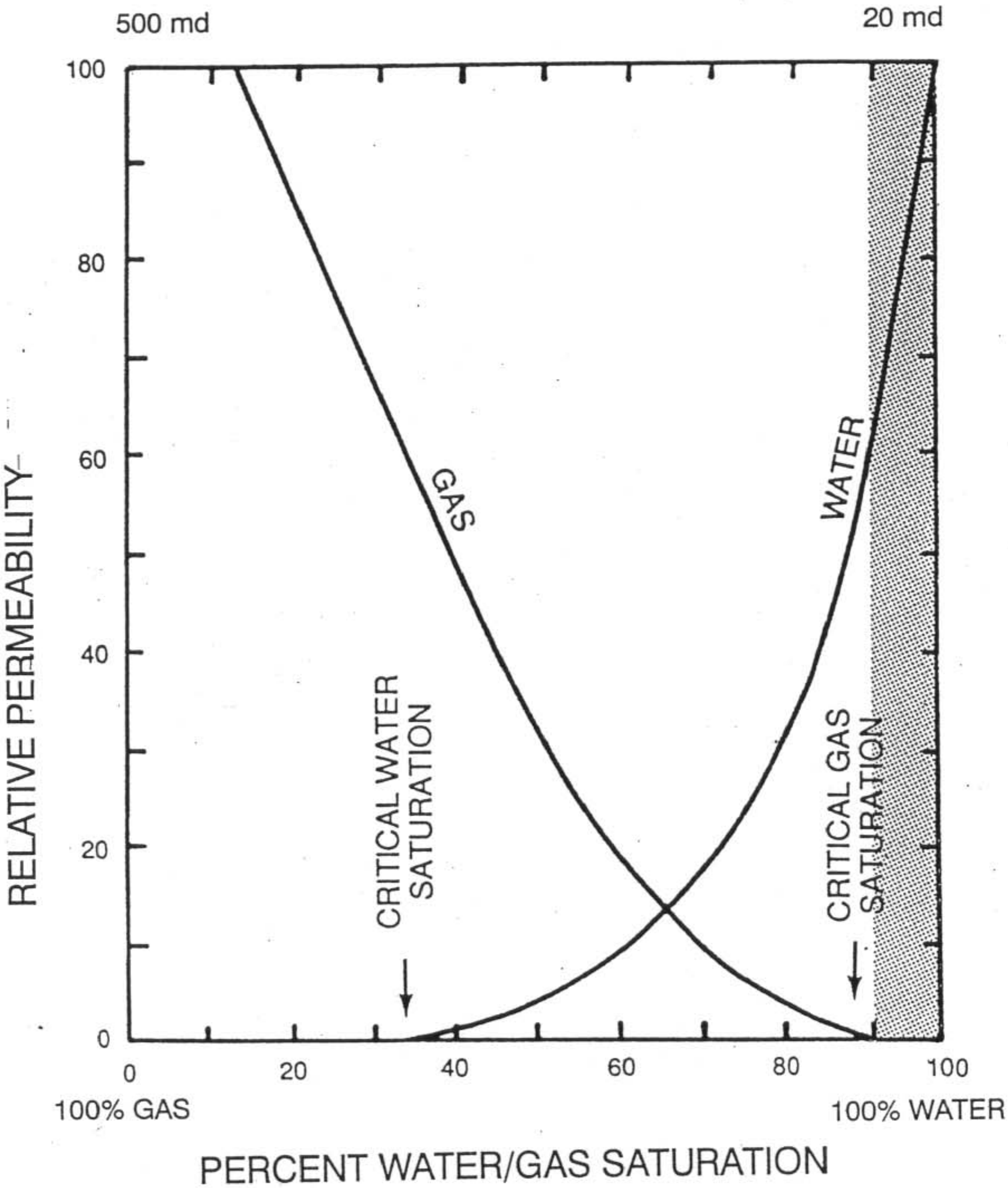
300
250
200
150
100
50
0
Production Per Well (Mcfd/Well)
0
1
2
3
4
5
6
7
8
Time (Years)
All Technologies Applied (3 Projects)
No Technologies, Lachine Only (13 Projects)
No Technologies, Lachine/Norwood (12 Projects)

FIG. 11



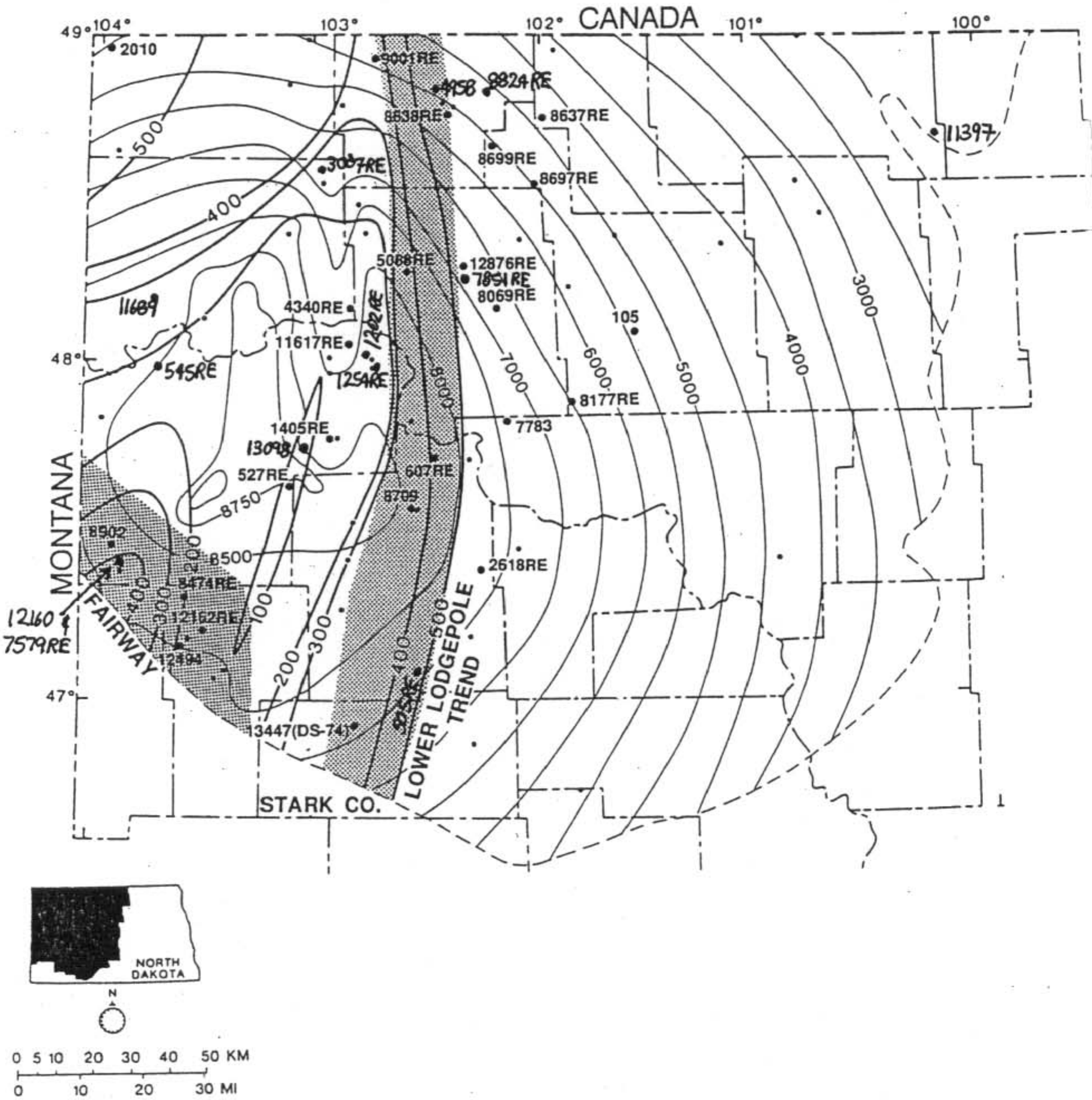
San Juan
Warrior
Other
350
300
250
200
150
100
50
0
Gas Production (Bcf/Yr)
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
Year

FIG. 12



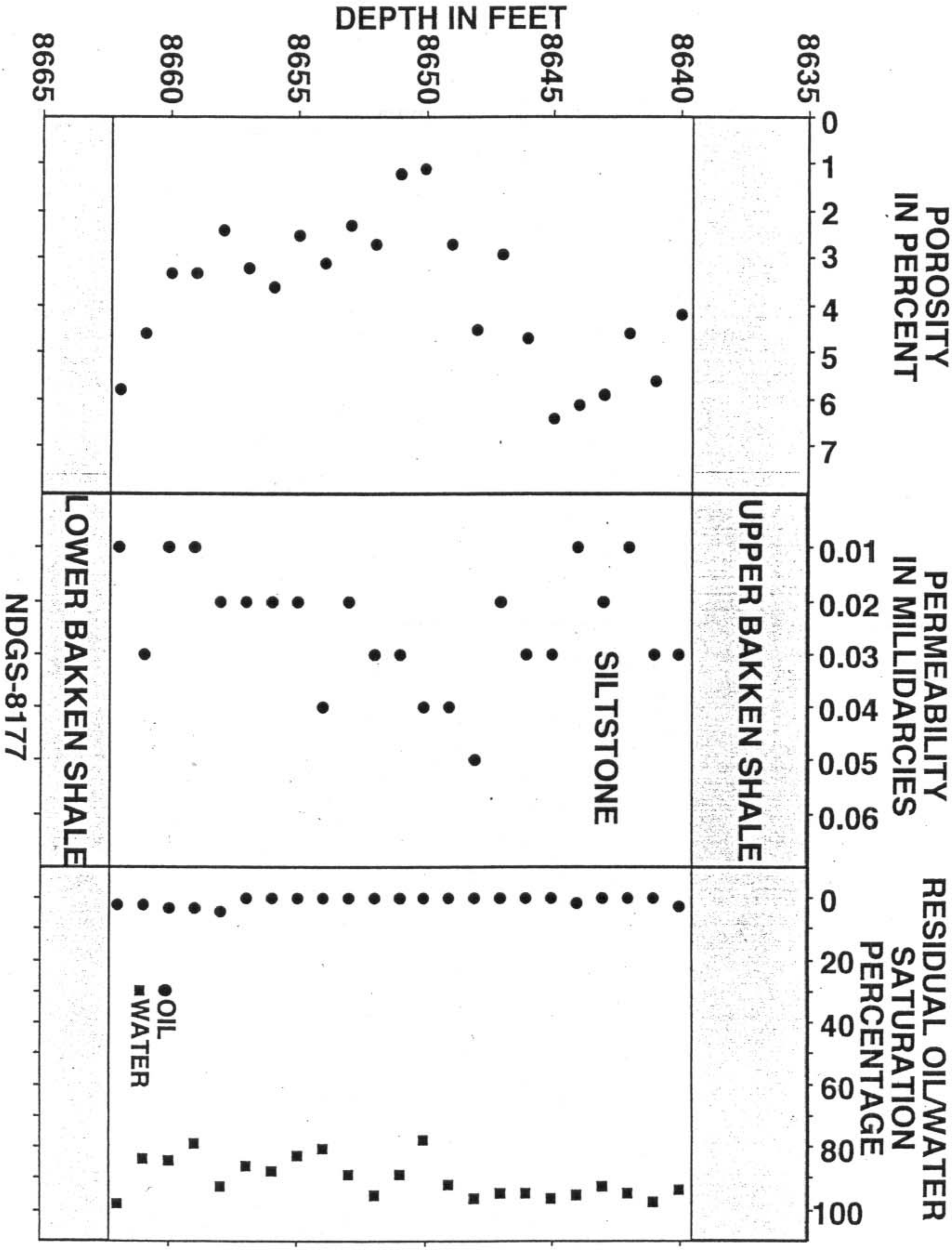
500 md
20 md
100
80
60
40
20
0
RELATIVE PERMEABILITY
GAS
WATER
CRITICAL WATER SATURATION
CRITICAL GAS SATURATION
0
20
40
60
80
100
100% GAS
100% WATER
PERCENT WATER/GAS SATURATION

FIG. 13



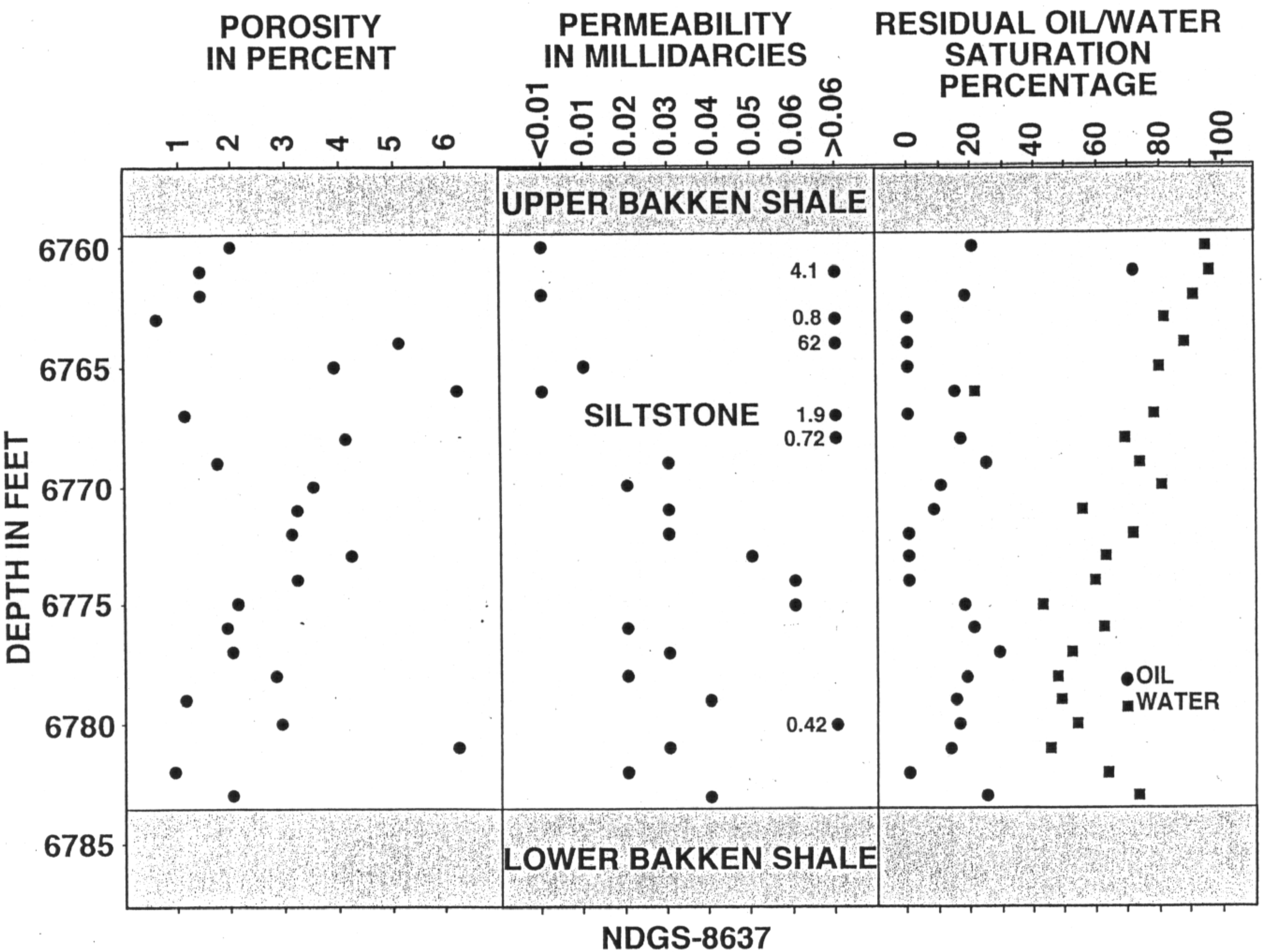
CANADA
MONTANA
49°
48°
47°
104°
103°
102°
101°
100°
2010
9001RE
4158
8824RE
8637RE
8638RE
8699RE
8697RE
11397
3007RE
500
400
5088RE
12876RE
7851RE
8069RE
11689
4340RE
1202RE
105
11617RE
545RE
1254RE
8000
7000
6000
5000
4000
3000
8177RE
7783
1405RE
13098
607RE
527RE
8709
8750
8502
8500
200
2618RE
8474RE
12160
7579RE
12162RE
12494
FAIRWAY
100
300
200
300
400
500
LOWER LODGEPOLE TREND
13447(DS-74)
STARK CO.
NORTH DAKOTA
N
0 5 10 20 30 40 50 KM
0 10 20 30 MI

FIG. 14



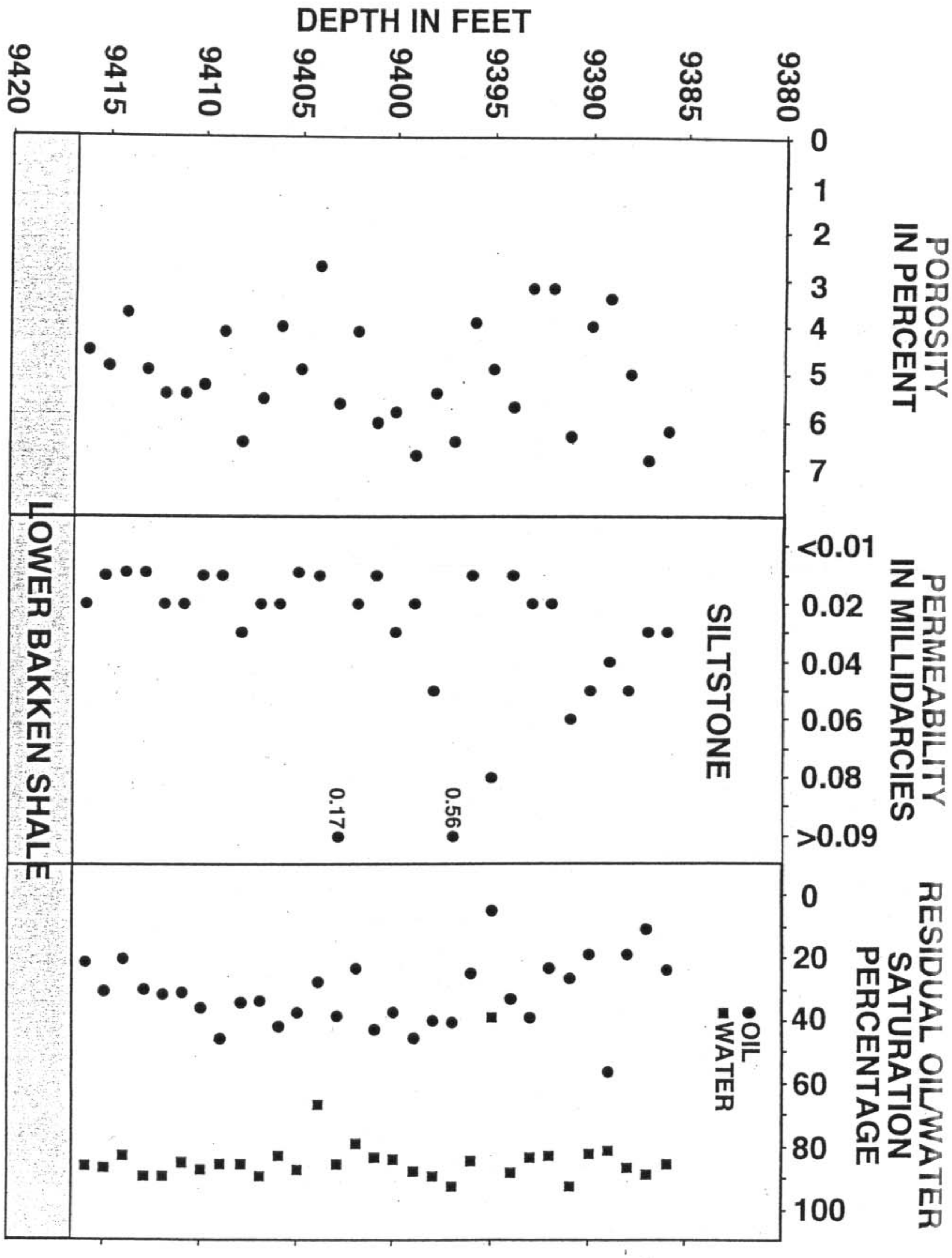
DEPTH IN FEET
8665
8660
8655
8650
8645
8640
8635
POROSITY IN PERCENT
0
1
2
3
4
5
6
7
PERMEABILITY IN MILLIDARCIES
0.01
0.02
0.03
0.04
0.05
0.06
RESIDUAL OIL/WATER SATURATION PERCENTAGE
0
20
40
60
80
100
UPPER BAKKEN SHALE
SILTSTONE
LOWER BAKKEN SHALE
OIL
WATER
NDGS-8177

FIG. 15



POROSITY IN PERCENT
PERMEABILITY IN MILLIDARCIES
RESIDUAL OIL/WATER SATURATION PERCENTAGE
1 2 3 4 5 6
<0.01 0.01 0.02 0.03 0.04 0.05 0.06 >0.06
0 20 40 60 80 100
UPPER BAKKEN SHALE
SILTSTONE
LOWER BAKKEN SHALE
4.1
0.8
62
1.9
0.72
0.42
OIL
WATER
DEPTH IN FEET
6760
6765
6770
6775
6780
6785
NDGS-8637

FIG. 16



DEPTH IN FEET
9420
9415
9410
9405
9400
9395
9390
9385
9380
POROSITY IN PERCENT
0
1
2
3
4
5
6
7
PERMEABILITY IN MILLIDARCIES
<0.01
0.02
0.04
0.06
0.08
>0.09
0.17
0.56
SILTSTONE
RESIDUAL OIL/WATER SATURATION PERCENTAGE
0
20
40
60
80
100
●OIL
■WATER
LOWER BAKKEN SHALE
NDGS-7851

FIG. 17

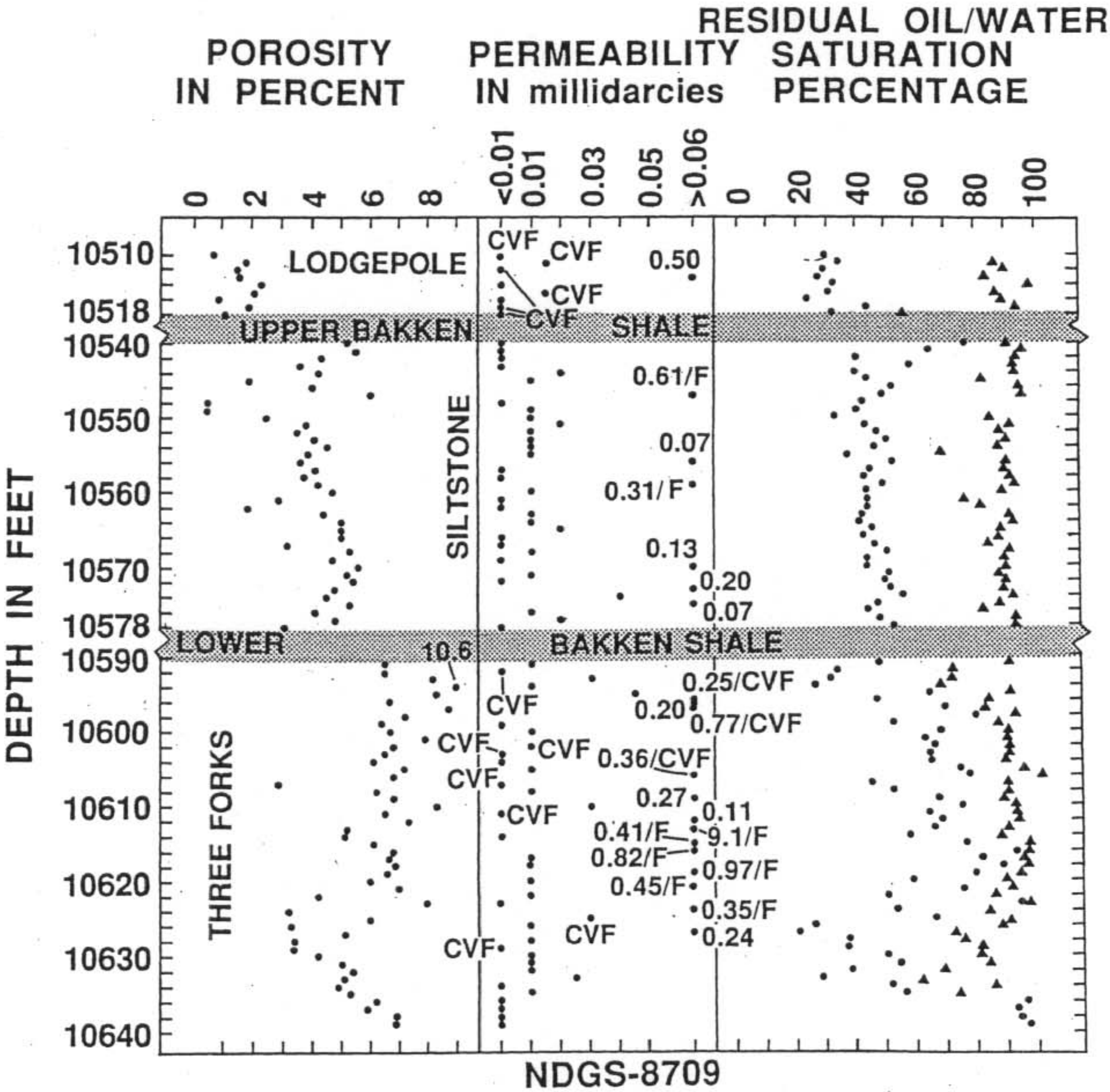
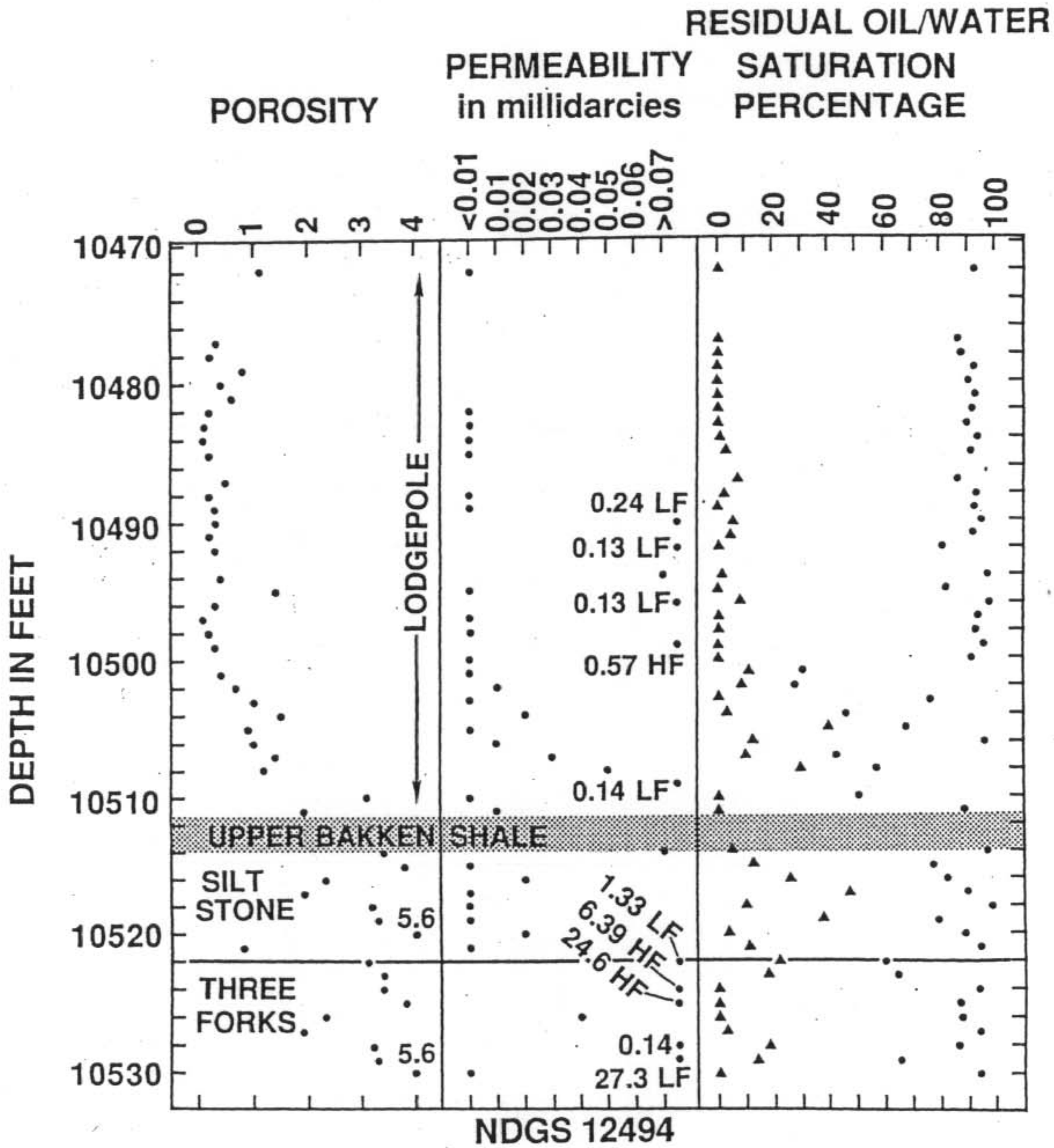
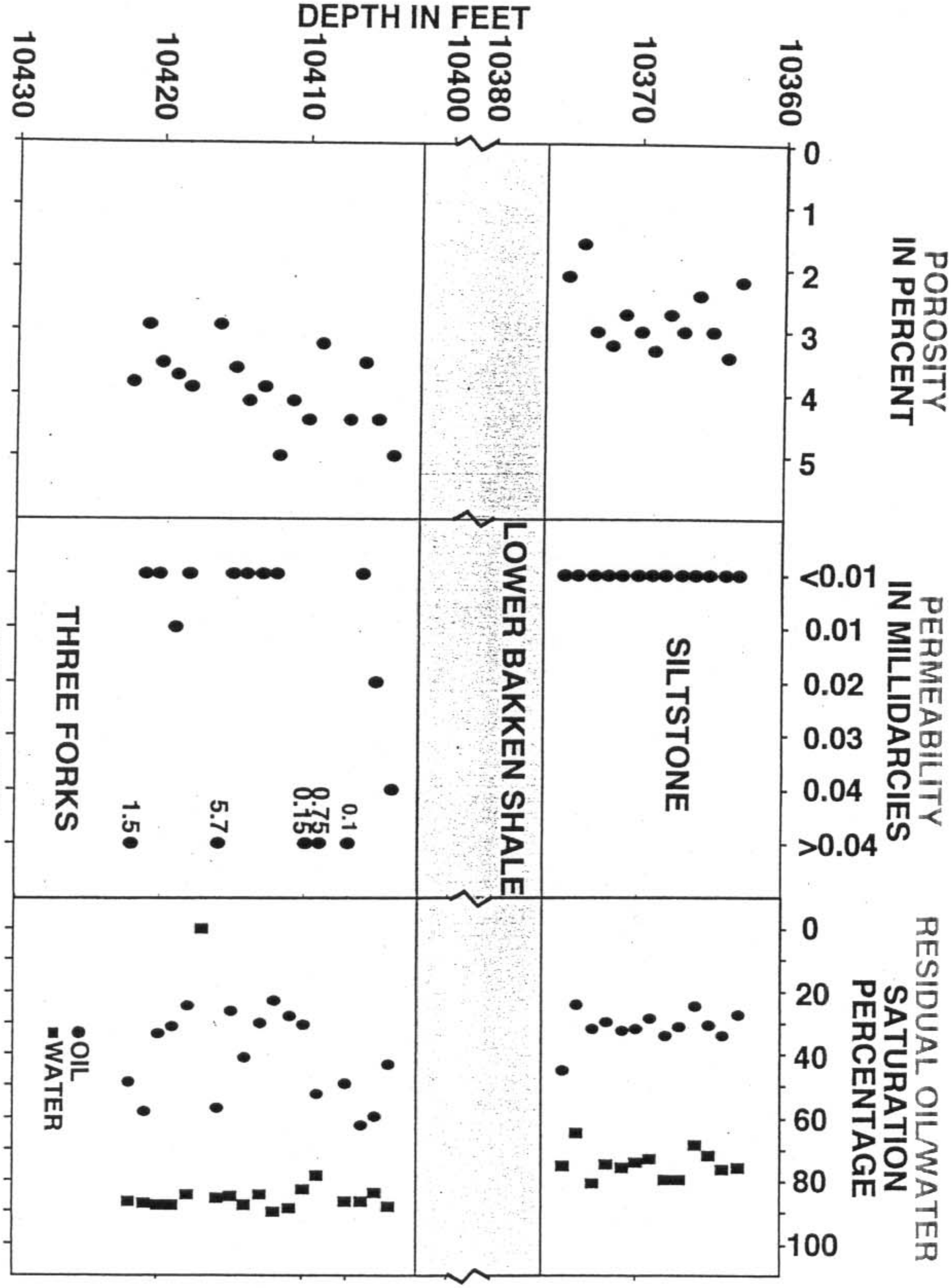

POROSITY IN PERCENT
PERMEABILITY IN millidarcies
RESIDUAL OIL/WATER SATURATION PERCENTAGE
0 2 4 6 8
<0.01 0.01 0.03 0.05 >0.06
0 20 40 60 80 100
DEPTH IN FEET
10510
10518
10540
10550
10560
10570
10578
10590
10600
10610
10620
10630
10640
LODGEPOLE
UPPER BAKKEN SHALE
SILTSTONE
LOWER BAKKEN SHALE
THREE FORKS
CVF
0.50
0.61/F
0.07
0.31/F
0.13
0.20
10.6
0.25/CVF
0.77/CVF
0.36/CVF
0.27
0.11
0.41/F
9.1/F
0.82/F
0.97/F
0.45/F
0.35/F
0.24
NDGS-8709

FIG. 18



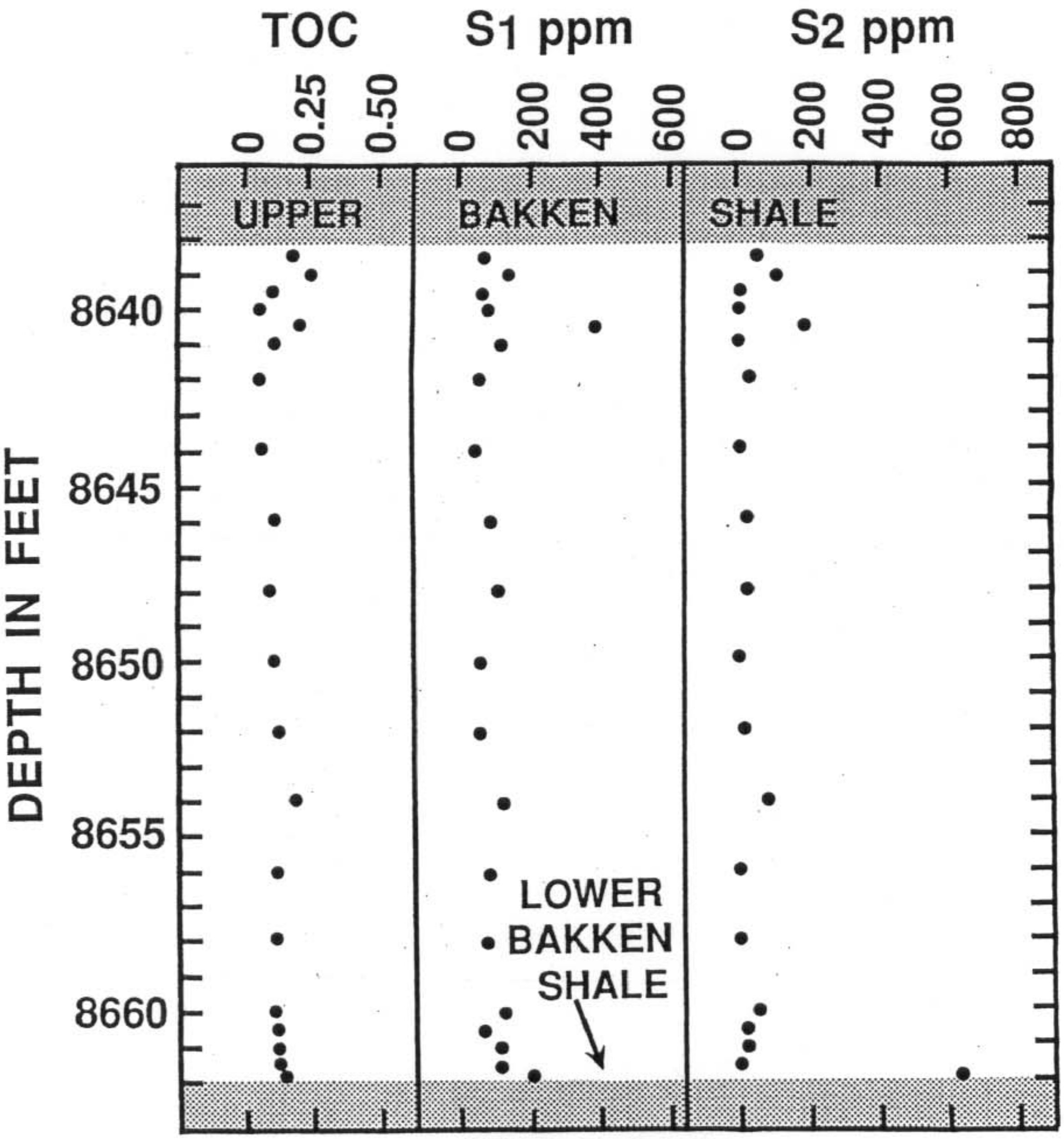
POROSITY
PERMEABILITY in millidarcies
RESIDUAL OIL/WATER SATURATION PERCENTAGE
0 1 2 3 4
<0.01 0.01 0.02 0.03 0.04 0.05 0.06 >0.07
0 20 40 60 80 100
DEPTH IN FEET
10470
10480
10490
10500
10510
10520
10530
LODGEPOLE
0.24 LF
0.13 LF
0.13 LF
0.57 HF
0.14 LF
UPPER BAKKEN SHALE
SILT STONE
5.6
1.33 LF
6.39 HF
24.6 HF
THREE FORKS
5.6
0.14
27.3 LF
NDGS 12494

FIG. 19



DEPTH IN FEET
10360
10370
10380
10400
10410
10420
10430
POROSITY IN PERCENT
0
1
2
3
4
5
PERMEABILITY IN MILLIDARCIES
<0.01
0.01
0.02
0.03
0.04
>0.04
RESIDUAL OIL/WATER SATURATION PERCENTAGE
0
20
40
60
80
100
SILTSTONE
LOWER BAKKEN SHALE
THREE FORKS
0.1
5.7
1.5
●OIL
■WATER
NDGS-11617

FIG. 20



NDGS 8177

FIG. 21

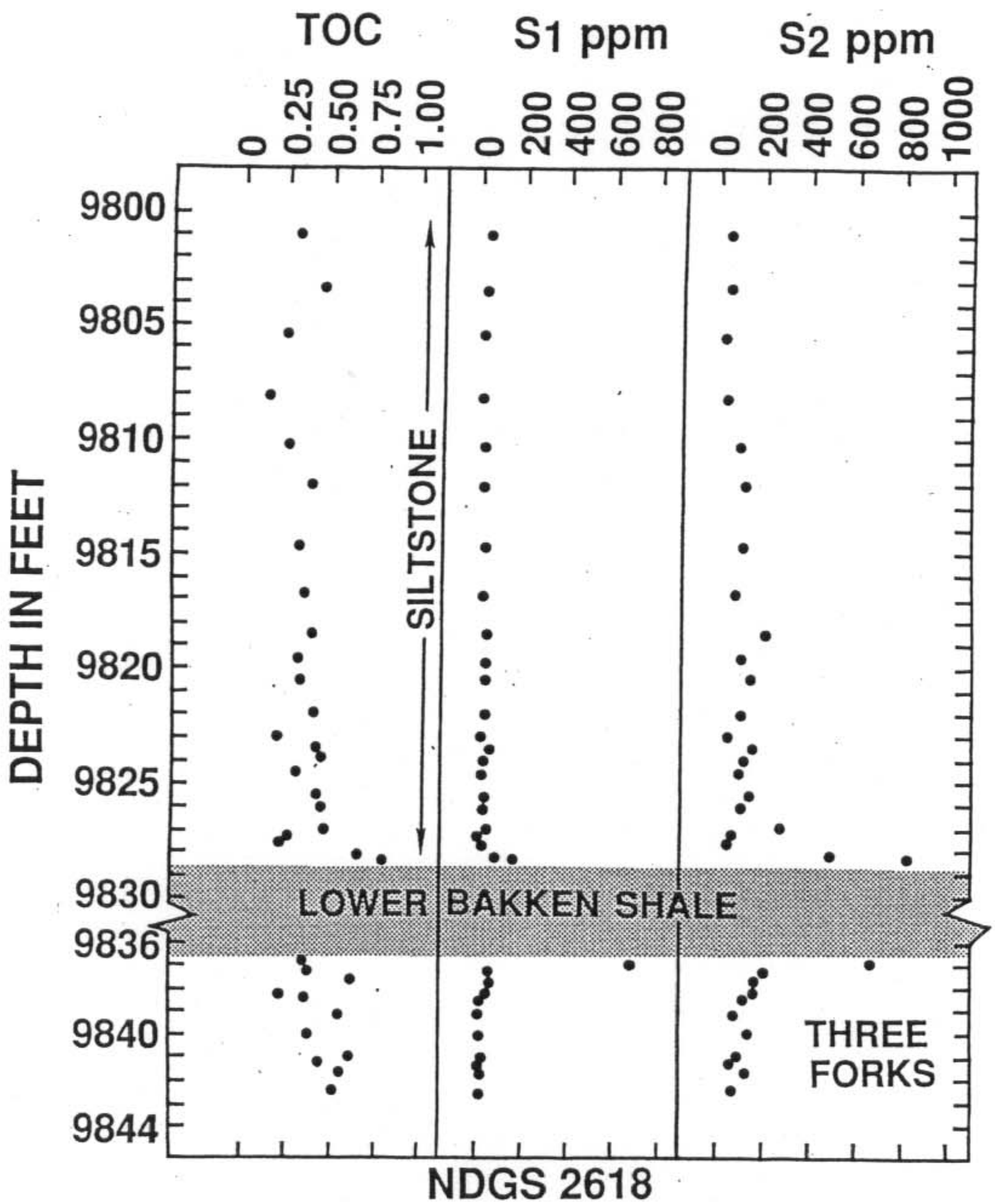

TOC
S1 ppm
S2 ppm
0 0.25 0.50 0.75 1.00
0 200 400 600 800
0 200 400 600 800 1000
DEPTH IN FEET
9800
9805
9810
9815
9820
9825
9830
9836
9840
9844
SILTSTONE
LOWER BAKKEN SHALE
THREE FORKS
NDGS 2618

FIG. 22

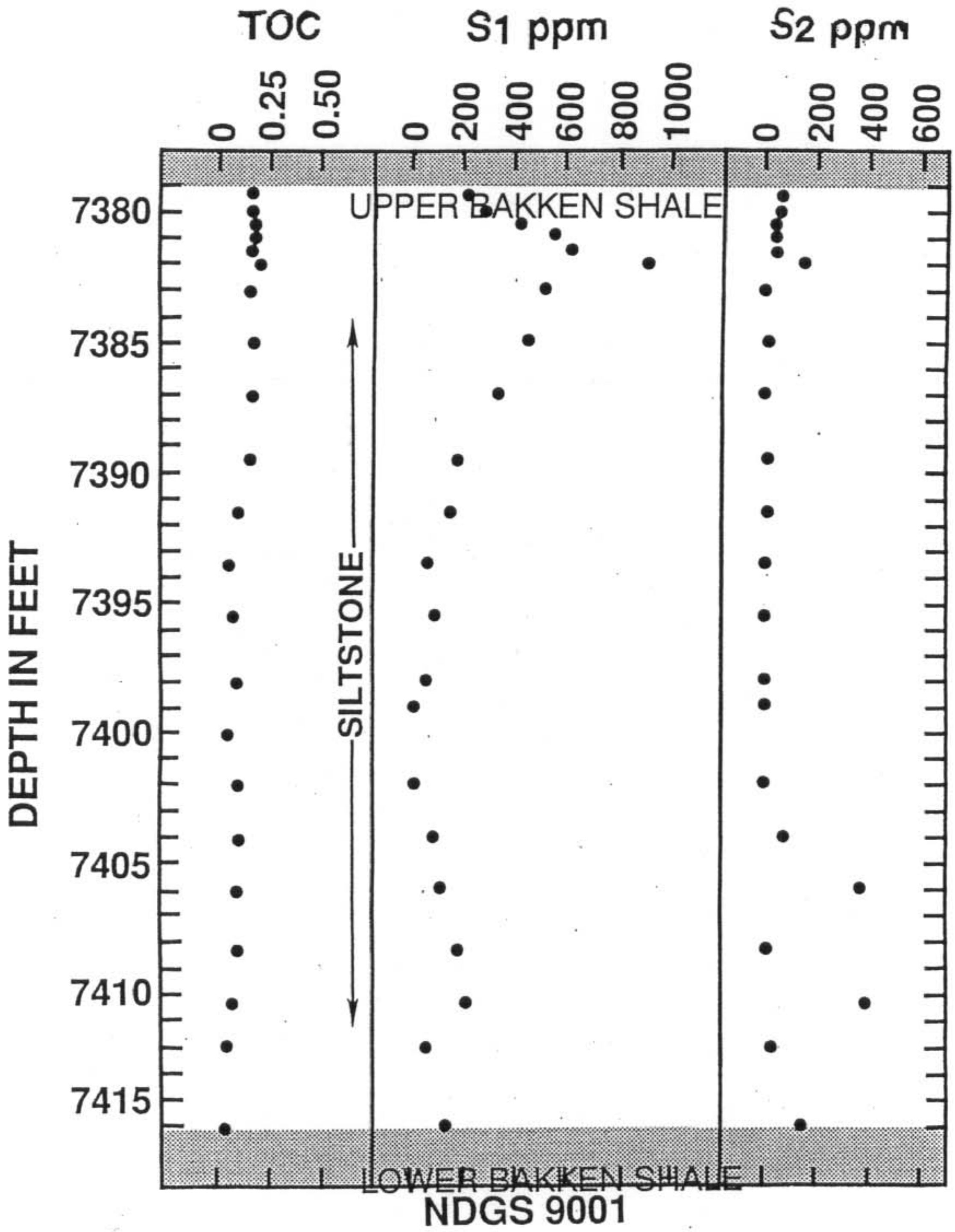

TOC
S1 ppm
S2 ppm
0
0.25
0.50
0
200
400
600
800
1000
0
200
400
600
UPPER BAKKEN SHALE
SILTSTONE
LOWER BAKKEN SHALE
DEPTH IN FEET
7380
7385
7390
7395
7400
7405
7410
7415
NDGS 9001

FIG. 23

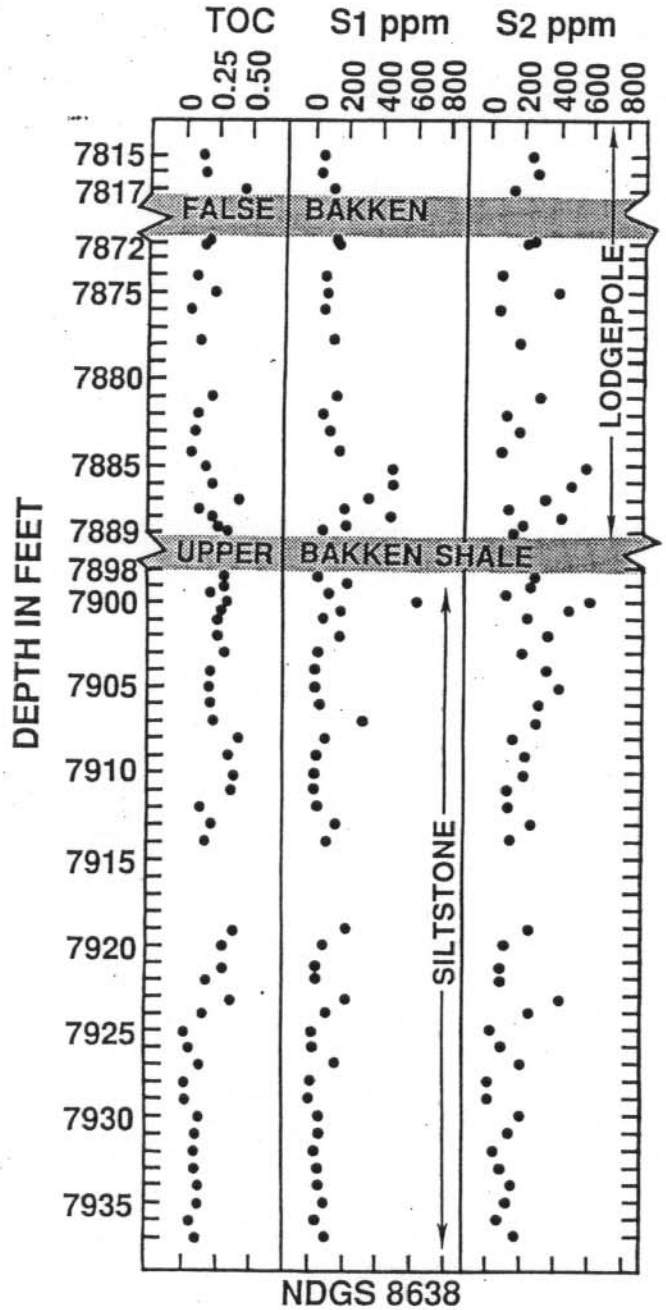

TOC
S1 ppm
S2 ppm
0
0.25
0.50
0
200
400
600
800
0
200
400
600
800
7815
7817
7872
7875
7880
7885
7889
7898
7900
7905
7910
7915
7920
7925
7930
7935
DEPTH IN FEET
FALSE BAKKEN
UPPER BAKKEN SHALE
LODGEPOLE
SILTSTONE
NDGS 8638

FIG. 24

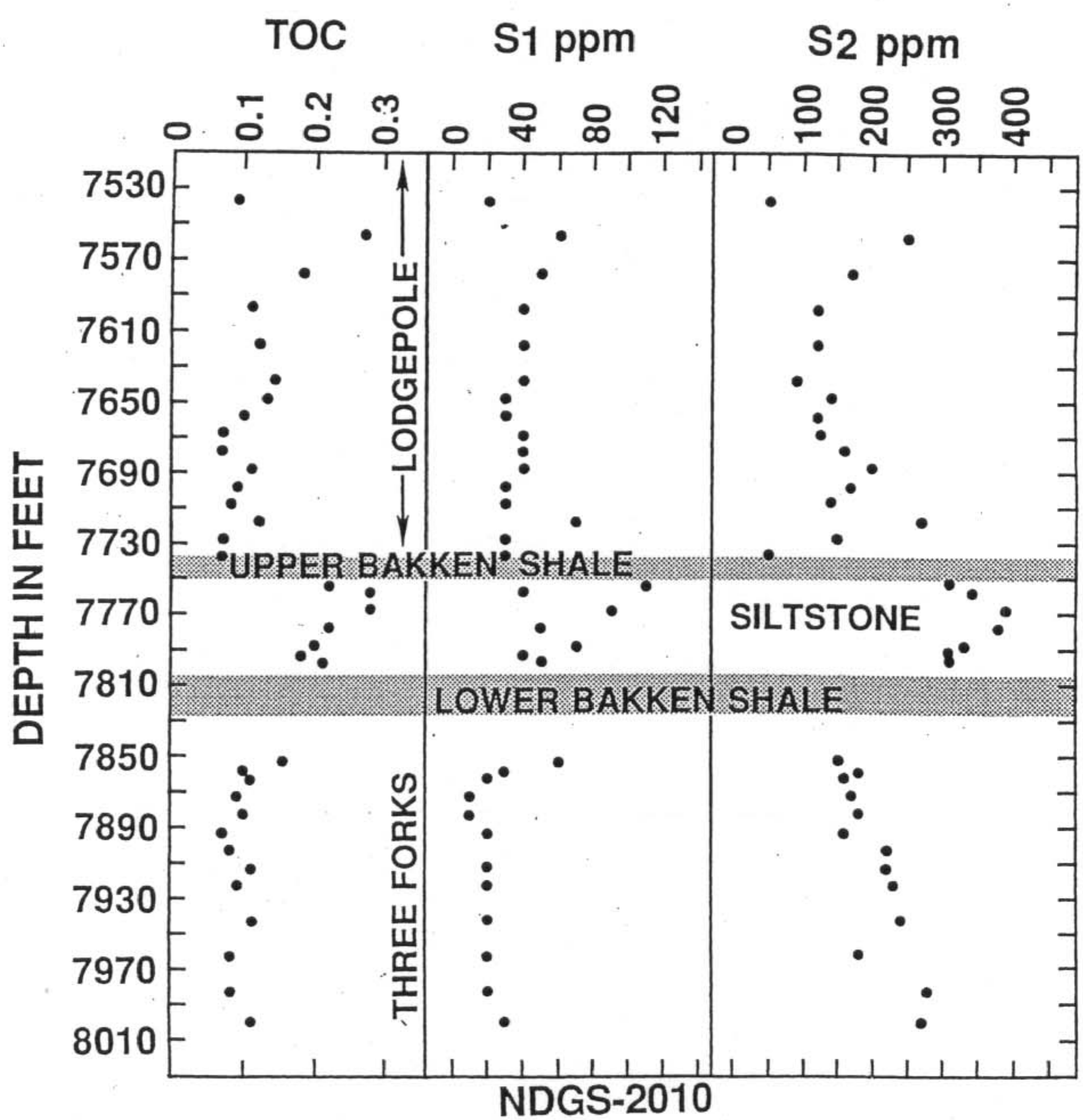

TOC
S1 ppm
S2 ppm
0
0.1
0.2
0.3
0
40
80
120
0
100
200
300
400
DEPTH IN FEET
7530
7570
7610
7650
7690
7730
7770
7810
7850
7890
7930
7970
8010
LODGEPOLE
'UPPER BAKKEN' SHALE
SILTSTONE
LOWER BAKKEN SHALE
THREE FORKS
NDGS-2010

FIG. 25

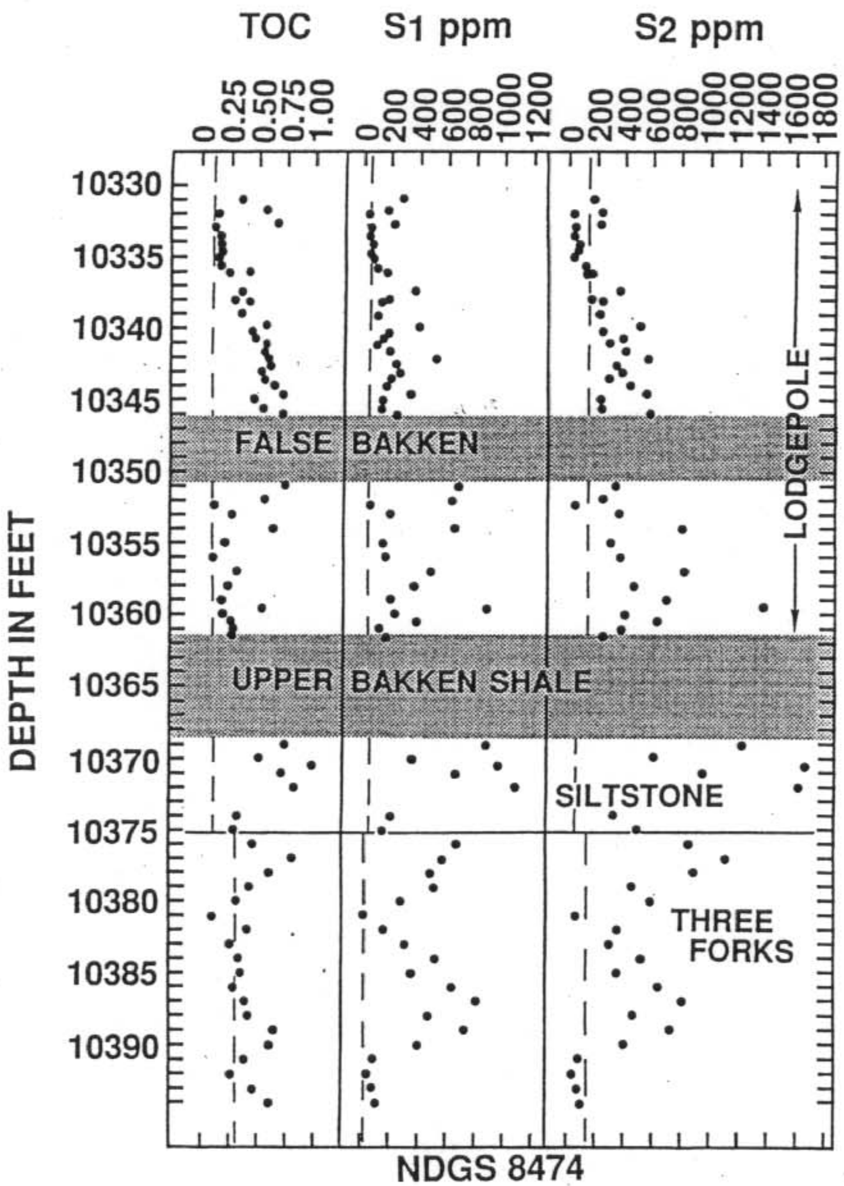
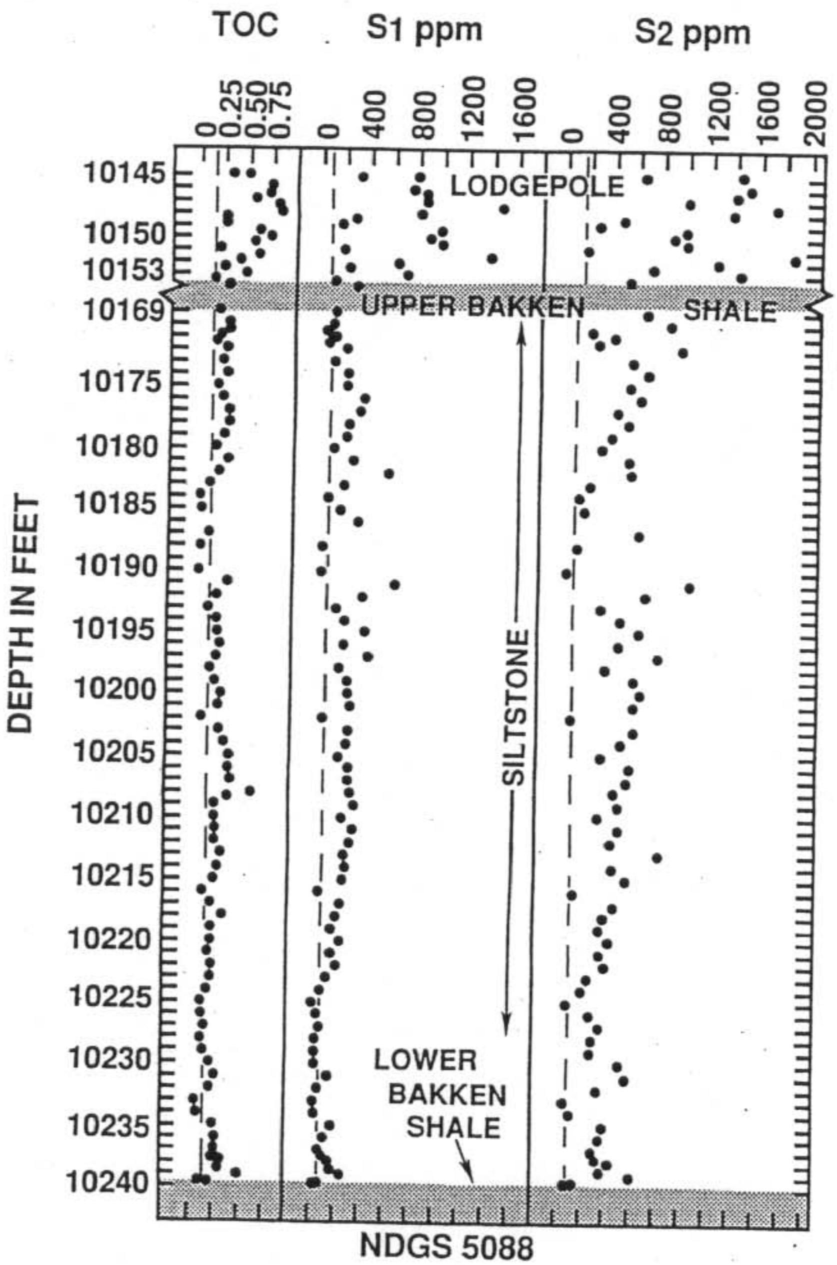

TOC
S1 ppm
S2 ppm
0 0.25 0.50 0.75 1.00
0 200 400 600 800 1000 1200
0 200 400 600 800 1000 1200 1400 1600 1800
DEPTH IN FEET
10330
10335
10340
10345
10350
10355
10360
10365
10370
10375
10380
10385
10390
FALSE BAKKEN
UPPER BAKKEN SHALE
LODGEPOLE
SILTSTONE
THREE FORKS
NDGS 8474

FIG. 26



TOC
S1 ppm
S2 ppm
0
0.25
0.50
0.75
0
400
800
1200
1600
0
400
800
1200
1600
2000
DEPTH IN FEET
10145
10150
10153
10169
10175
10180
10185
10190
10195
10200
10205
10210
10215
10220
10225
10230
10235
10240
LODGEPOLE
UPPER BAKKEN SHALE
SILTSTONE
LOWER BAKKEN SHALE
NDGS 5088

FIG. 27

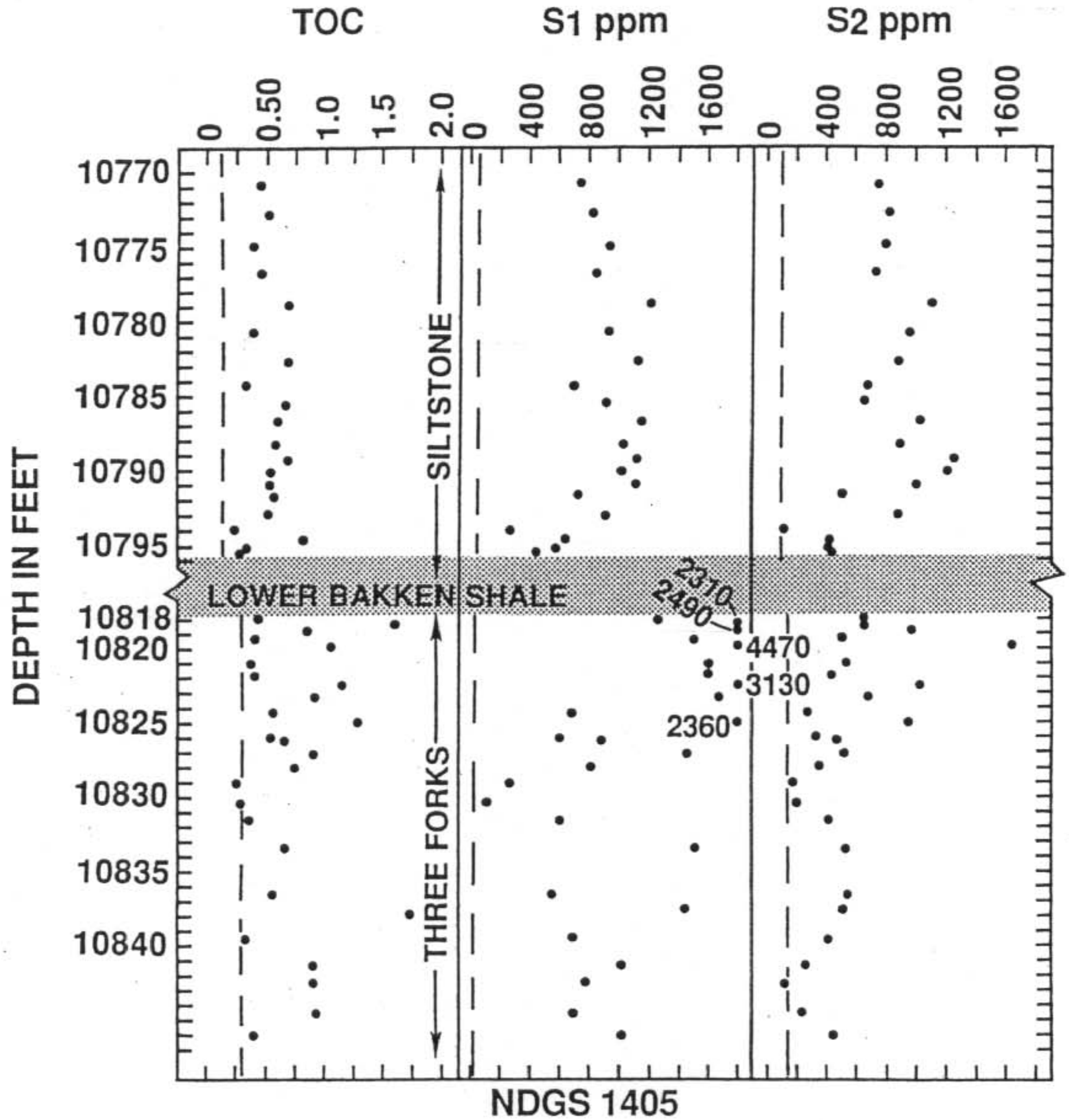

TOC
S1 ppm
S2 ppm
0
0.50
1.0
1.5
2.0
0
400
800
1200
1600
0
400
800
1200
1600
DEPTH IN FEET
10770
10775
10780
10785
10790
10795
10818
10820
10825
10830
10835
10840
SILTSTONE
LOWER BAKKEN SHALE
THREE FORKS
2310
2490
4470
3130
2360
NDGS 1405

FIG. 28

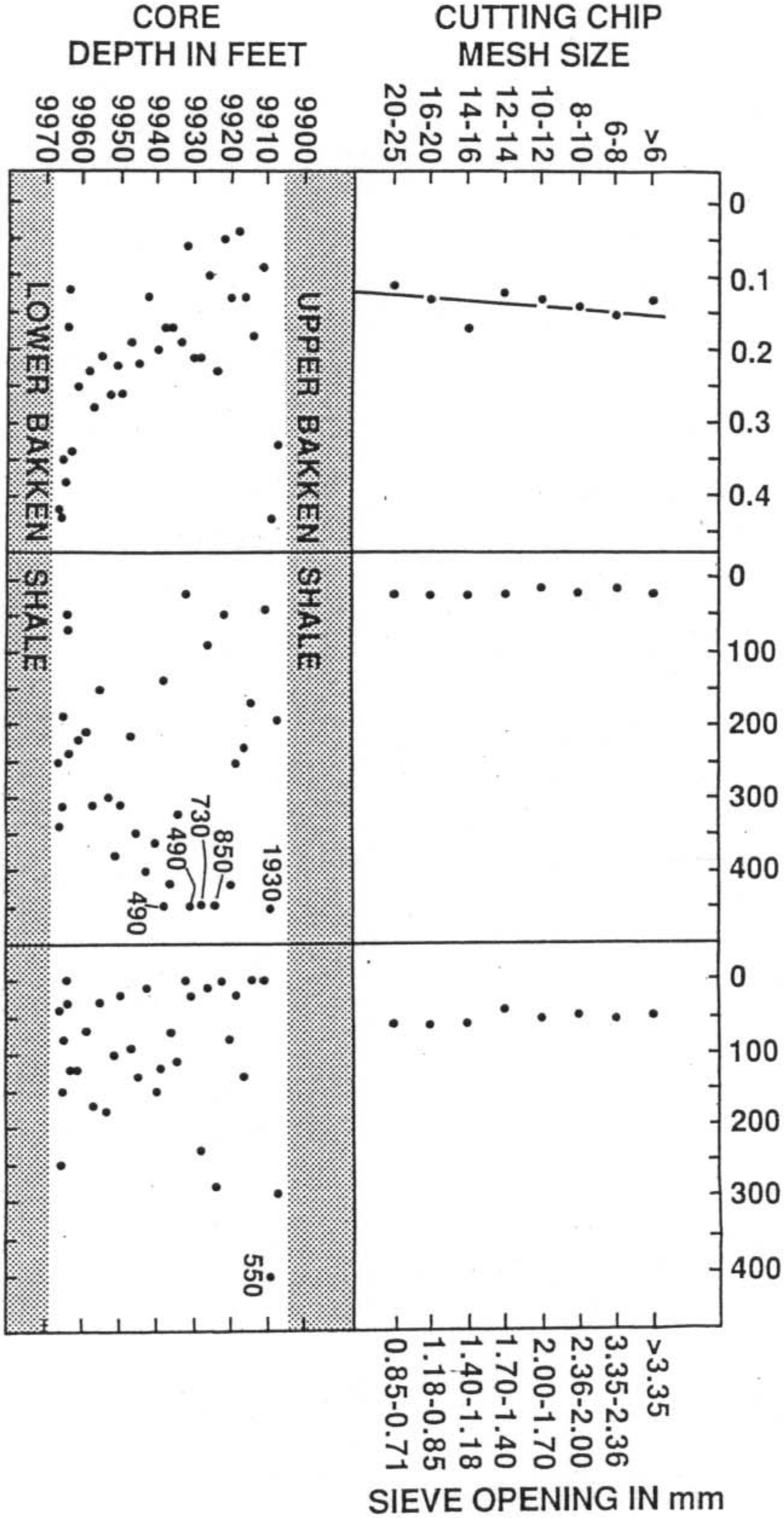

CORE
DEPTH IN FEET
CUTTING CHIP
MESH SIZE
9970
9960
9950
9940
9930
9920
9910
9900
20-25
16-20
14-16
12-14
10-12
8-10
6-8
>6
TOC
0
0.1
0.2
0.3
0.4
S1 ppm
0
100
200
300
400
S2 ppm
0
100
200
300
400
UPPER BAKKEN SHALE
LOWER BAKKEN SHALE
NDGS-4340 SILTSTONE
1930
850
730
490
490
550
0.85-0.71
1.18-0.85
1.40-1.18
1.70-1.40
2.00-1.70
2.36-2.00
3.35-2.36
>3.35
SIEVE OPENING IN mm

FIG. 29

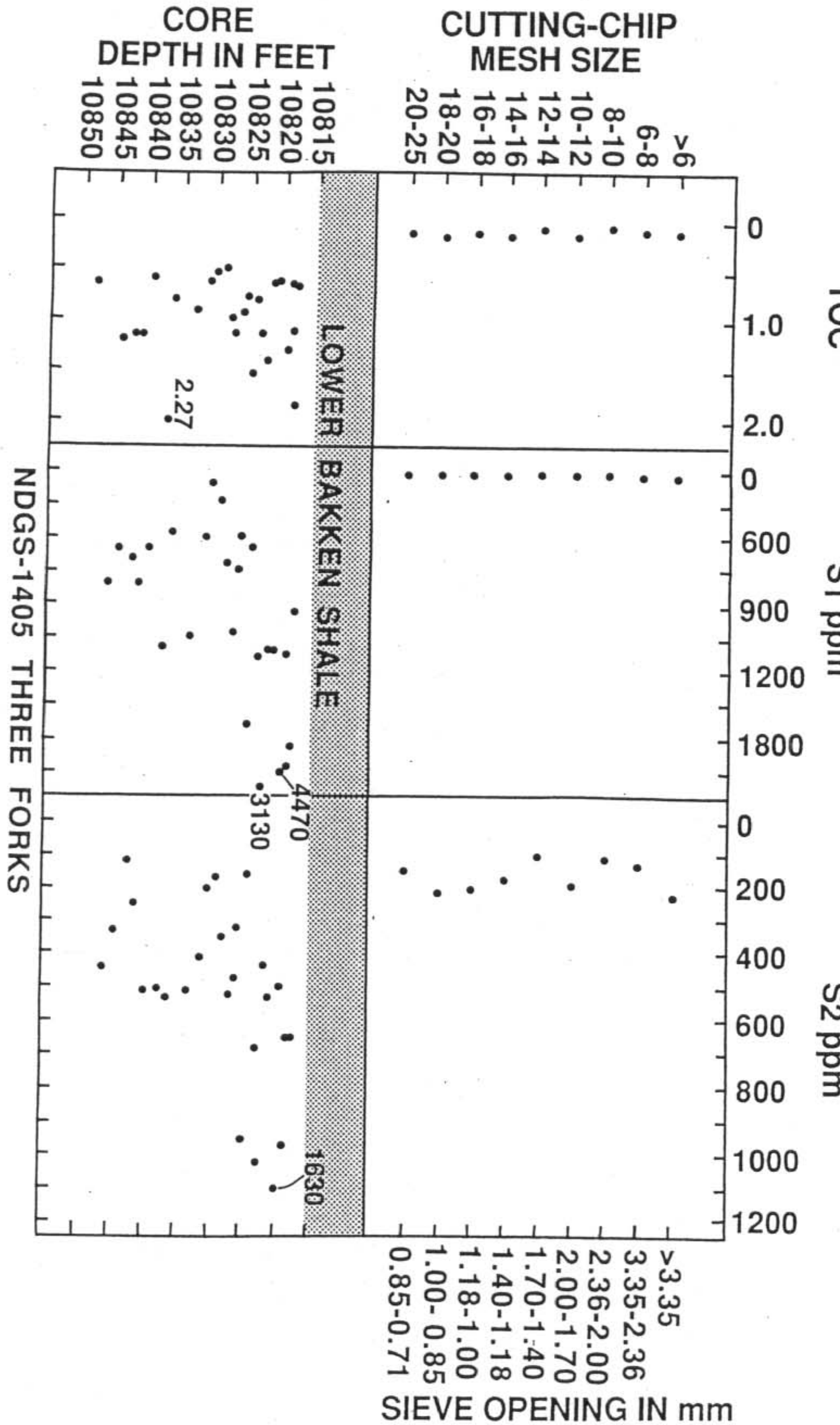
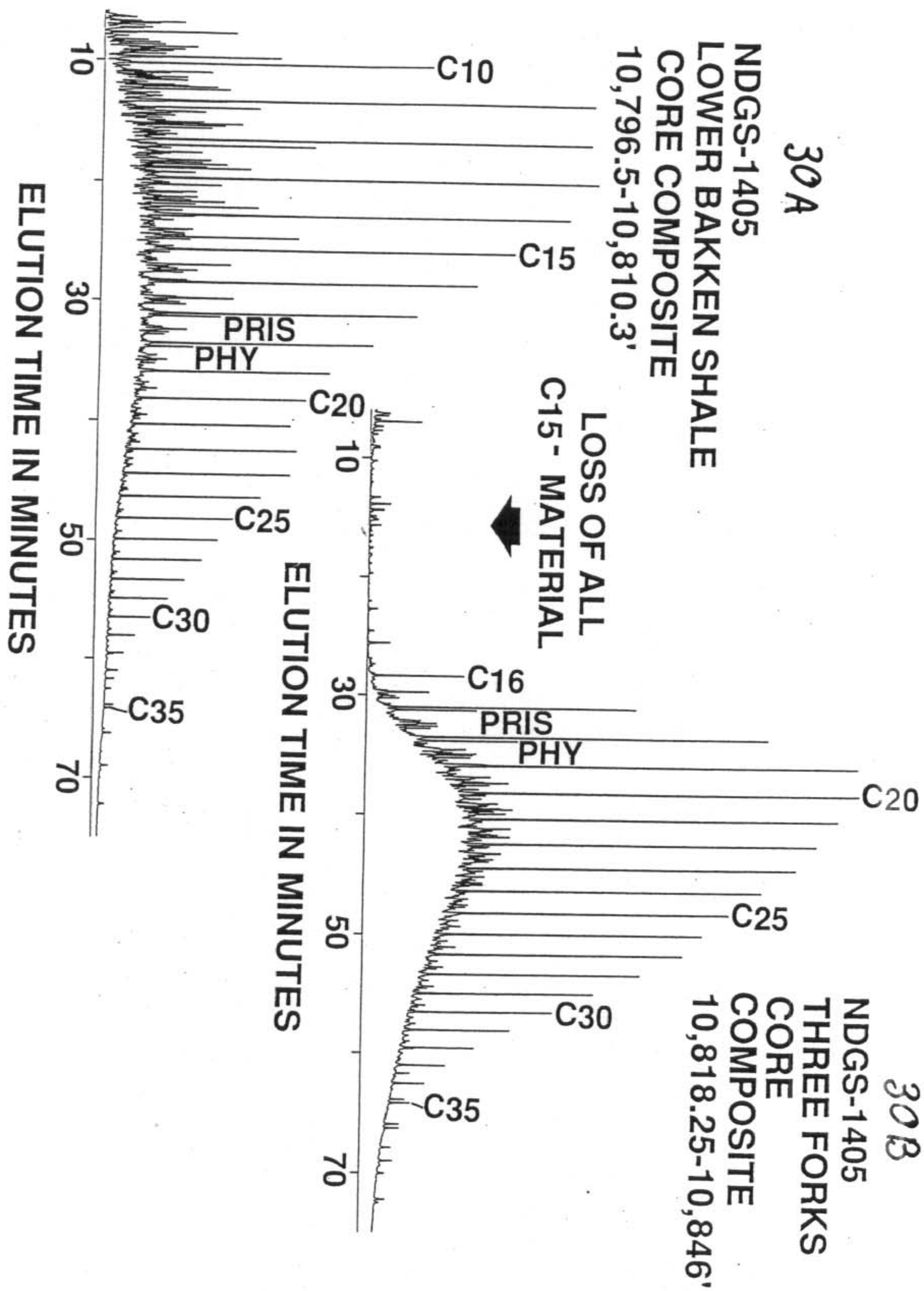

CORE DEPTH IN FEET
10850 10845 10840 10835 10830 10825 10820 10815
CUTTING-CHIP MESH SIZE
20-25 18-20 16-18 14-16 12-14 10-12 8-10 6-8 >6
TOC
0 1.0 2.0
2.27
S1 ppm
0 600 900 1200 1800
4470
3130
S2 ppm
0 200 400 600 800 1000 1200
1630
LOWER BAKKEN SHALE
NDGS-1405 THREE FORKS
0.85-0.71 1.00-0.85 1.18-1.00 1.40-1.18 1.70-1.40 2.00-1.70 2.36-2.00 3.35-2.36 >3.35
SIEVE OPENING IN mm

FIG 30


30A
NDGS-1405
LOWER BAKKEN SHALE
CORE COMPOSITE
10,796.5-10,810.3'
C10
C15
PRIS
PHY
C20
C25
C30
C35
10
30
50
70
ELUTION TIME IN MINUTES
LOSS OF ALL
C15- MATERIAL
30B
NDGS-1405
THREE FORKS
CORE
COMPOSITE
10,818.25-10,846'
C16
PRIS
PHY
C20
C25
C30
C35
10
30
50
70
ELUTION TIME IN MINUTES

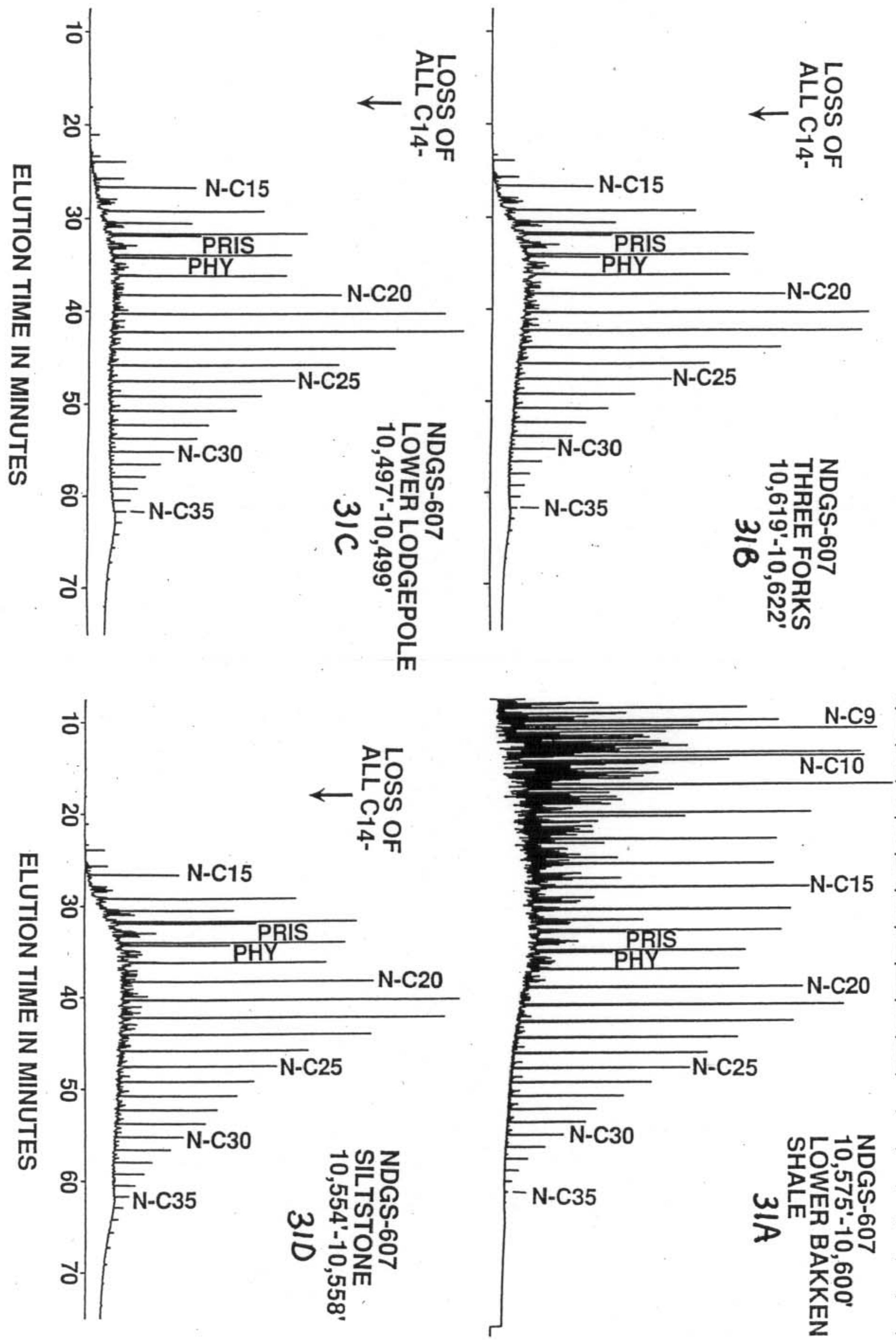
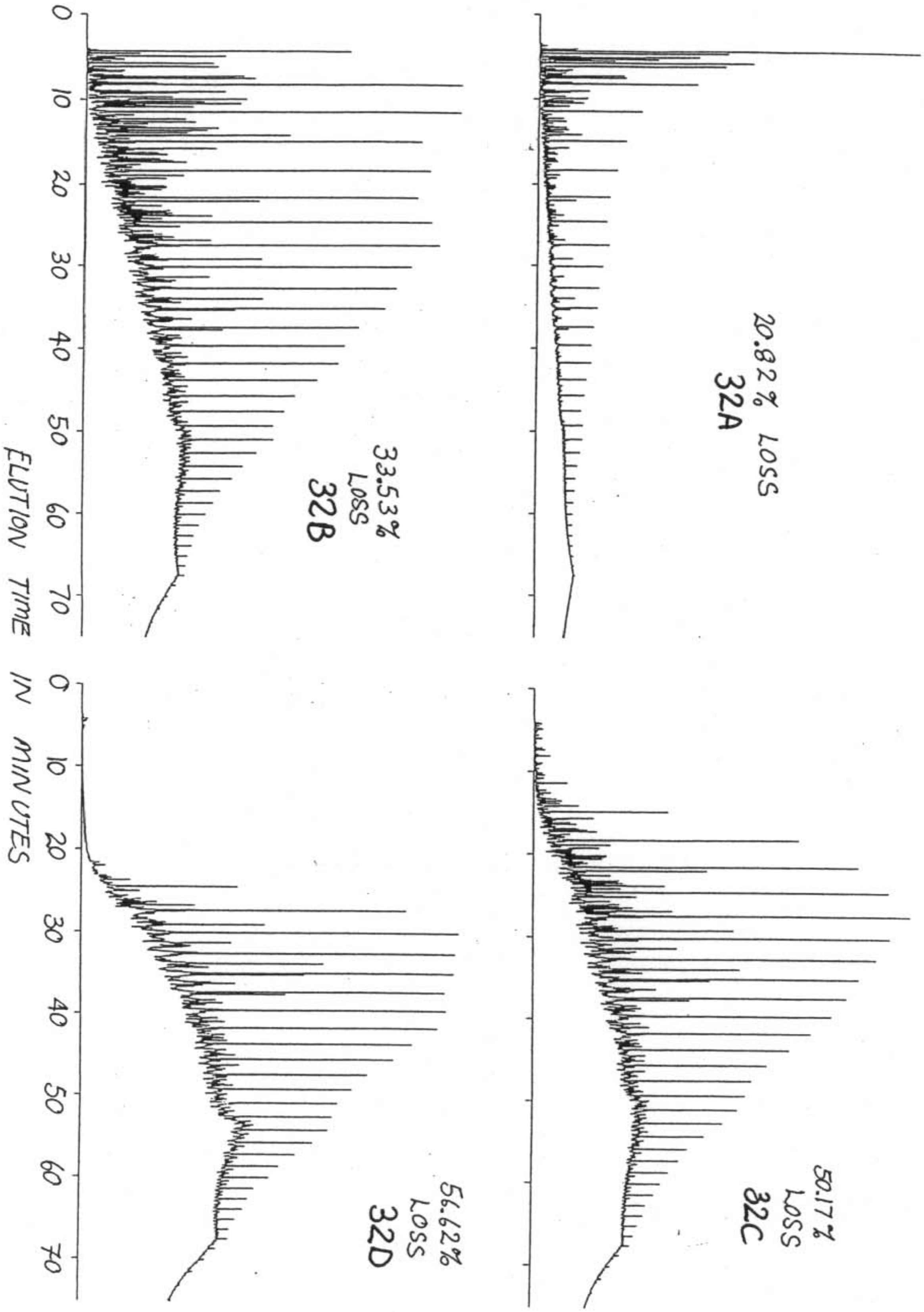

NDGS-607
10,575'-10,600'
LOWER BAKKEN
SHALE
31A
N-C9
N-C10
N-C15
PRIS
PHY
N-C20
N-C25
N-C30
N-C35
NDGS-607
THREE FORKS
10,619'-10,622'
31B
LOSS OF
ALL C14-
N-C15
PRIS
PHY
N-C20
N-C25
N-C30
N-C35
NDGS-607
LOWER LODGEPOLE
10,497'-10,499'
31C
LOSS OF
ALL C14-
N-C15
PRIS
PHY
N-C20
N-C25
N-C30
N-C35
10
20
30
40
50
60
70
ELUTION TIME IN MINUTES
NDGS-607
SILTSTONE
10,554'-10,558'
31D
LOSS OF
ALL C14-
N-C15
PRIS
PHY
N-C20
N-C25
N-C30
N-C35
10
20
30
40
50
60
70
ELUTION TIME IN MINUTES

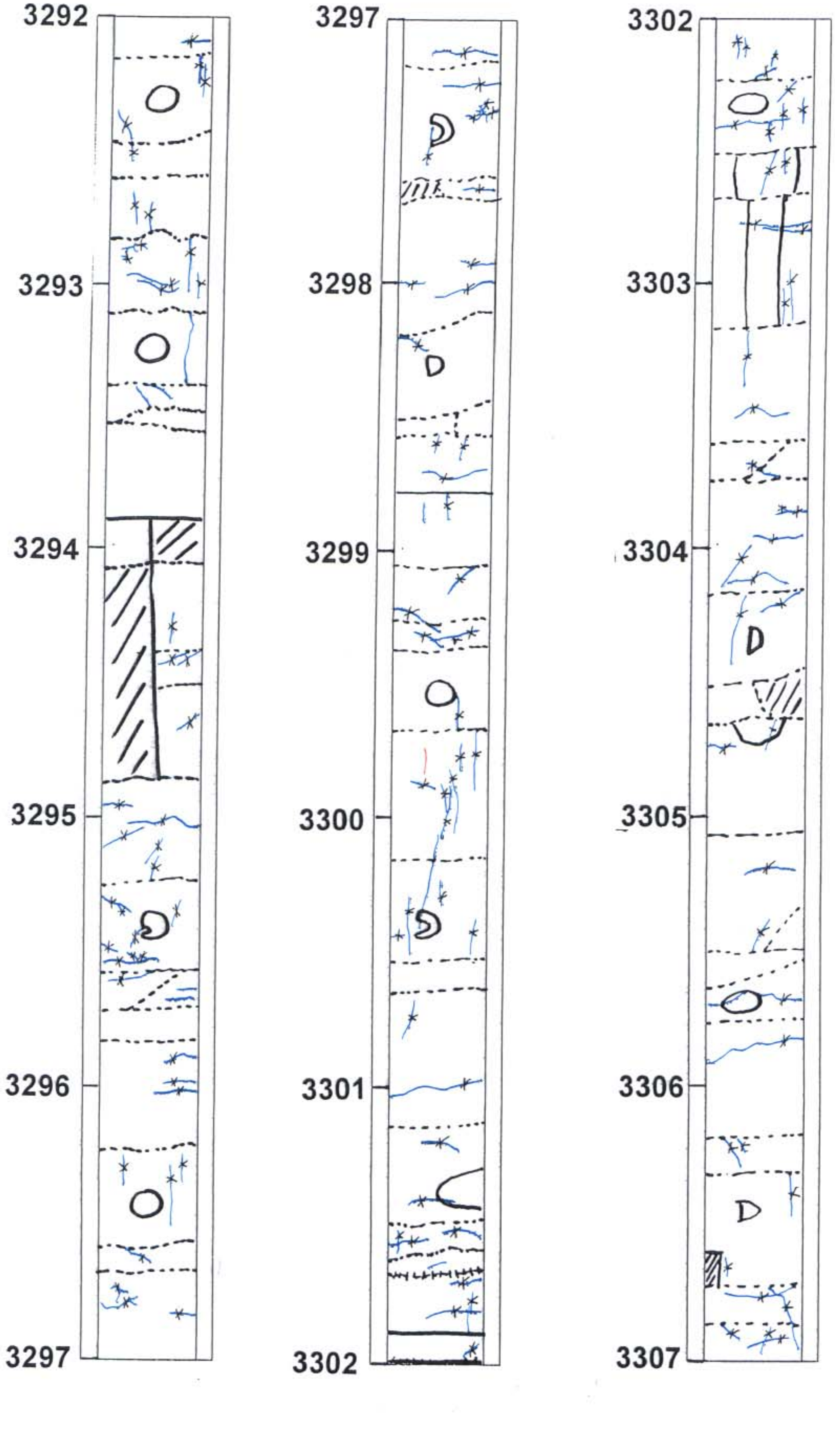
FIG. 31

FIG. 32



20.82% LOSS
32A
33.53% LOSS
32B
50.17% LOSS
32C
56.62% LOSS
32D
0
10
20
30
40
50
60
70
ELUTION TIME IN MINUTES

FIG. 33A
NDGS 11397 LODGEPOLE LIMESTONE



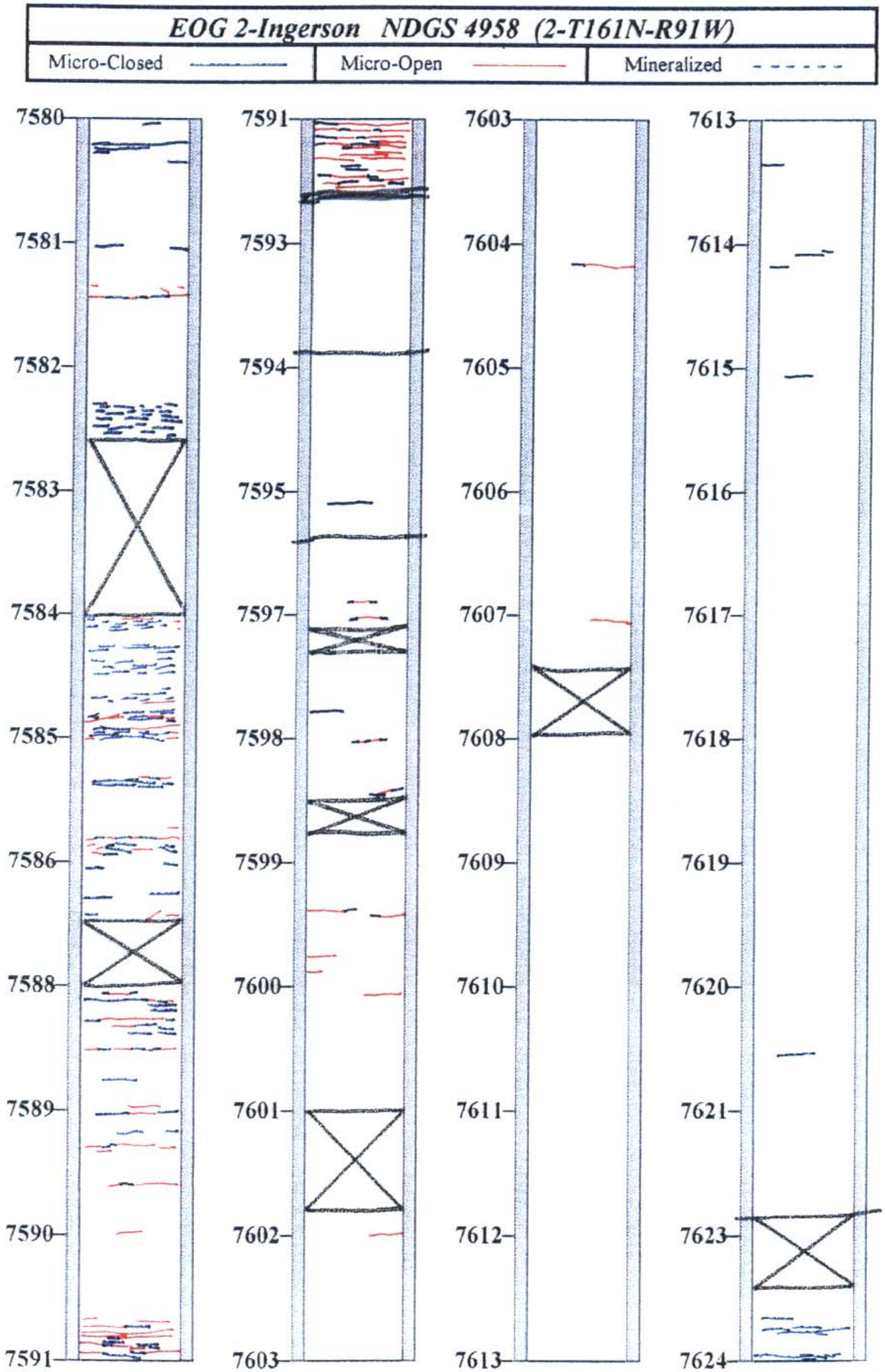

EOG 2-Ingerson NDGS 4958 (2-T161N-R91W)
Micro-Closed
Micro-Open
Mineralized
7580
7581
7582
7583
7584
7585
7586
7588
7589
7590
7591
7591
7593
7594
7595
7597
7598
7599
7600
7601
7602
7603
7603
7604
7605
7606
7607
7608
7609
7610
7611
7612
7613
7613
7614
7615
7616
7617
7618
7619
7620
7621
7623
7624

FIG. 33B

FIG. 34A

NDGS 8824 SILTSTONE

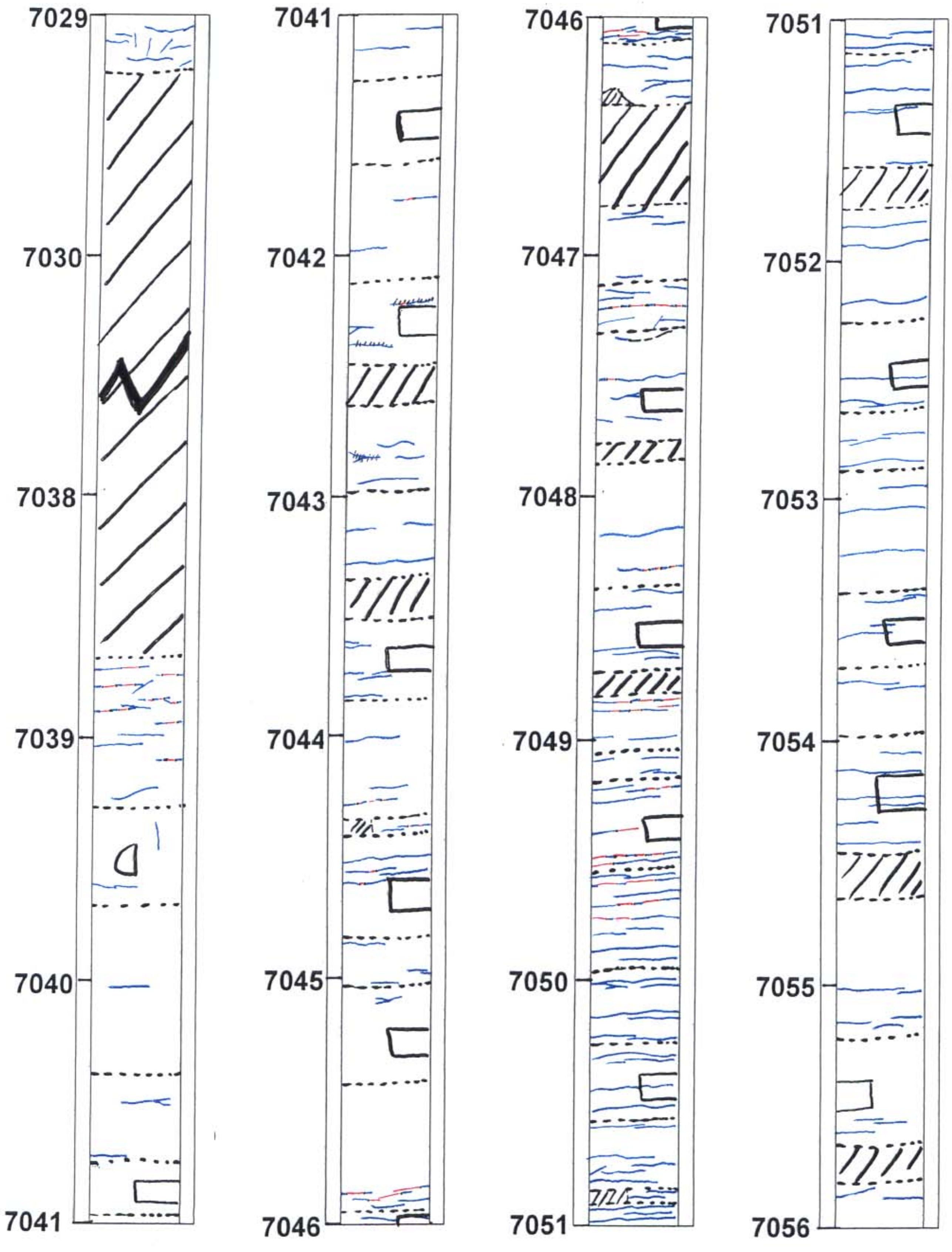


FIG. 34B
NDGS 8824 SILTSTONE

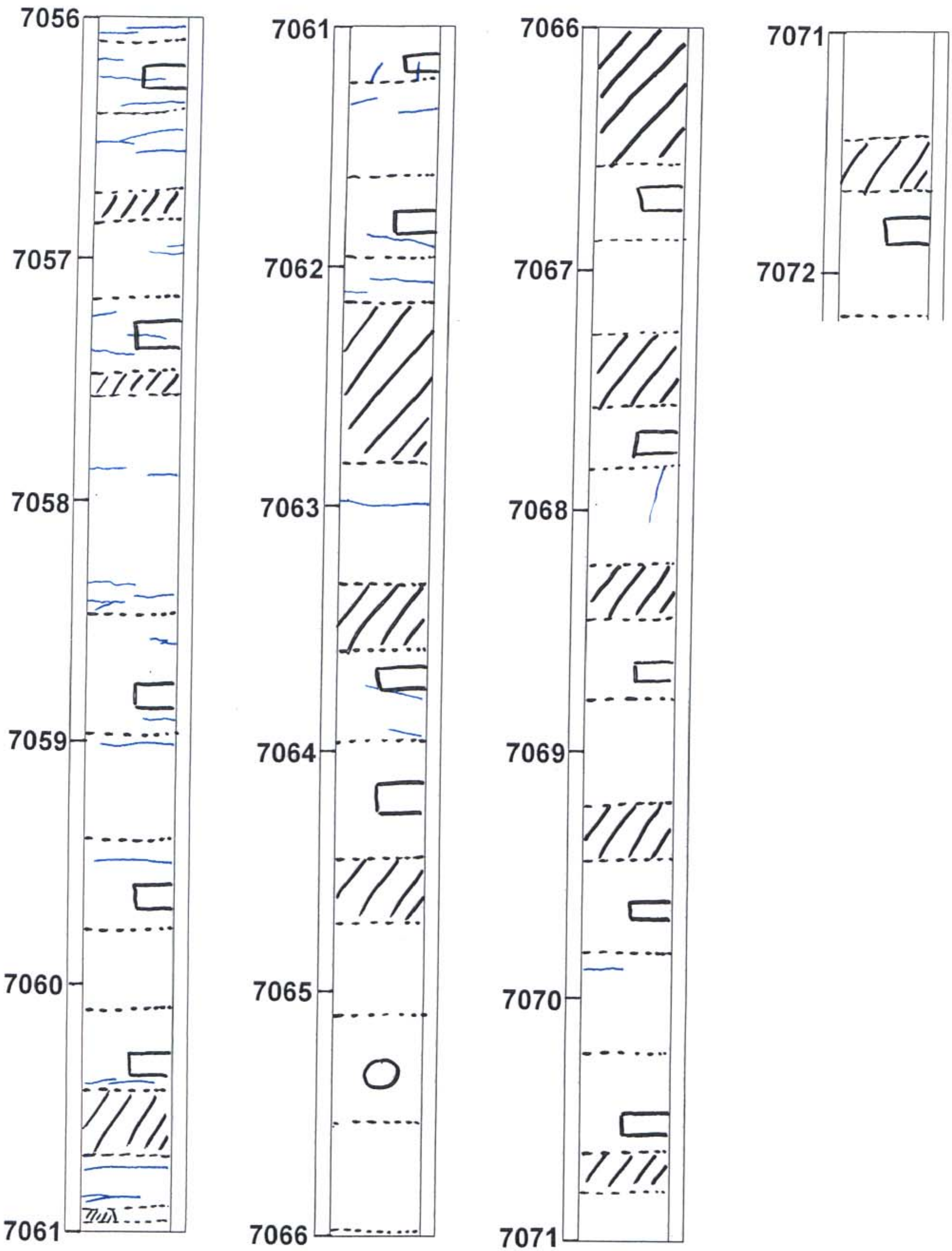
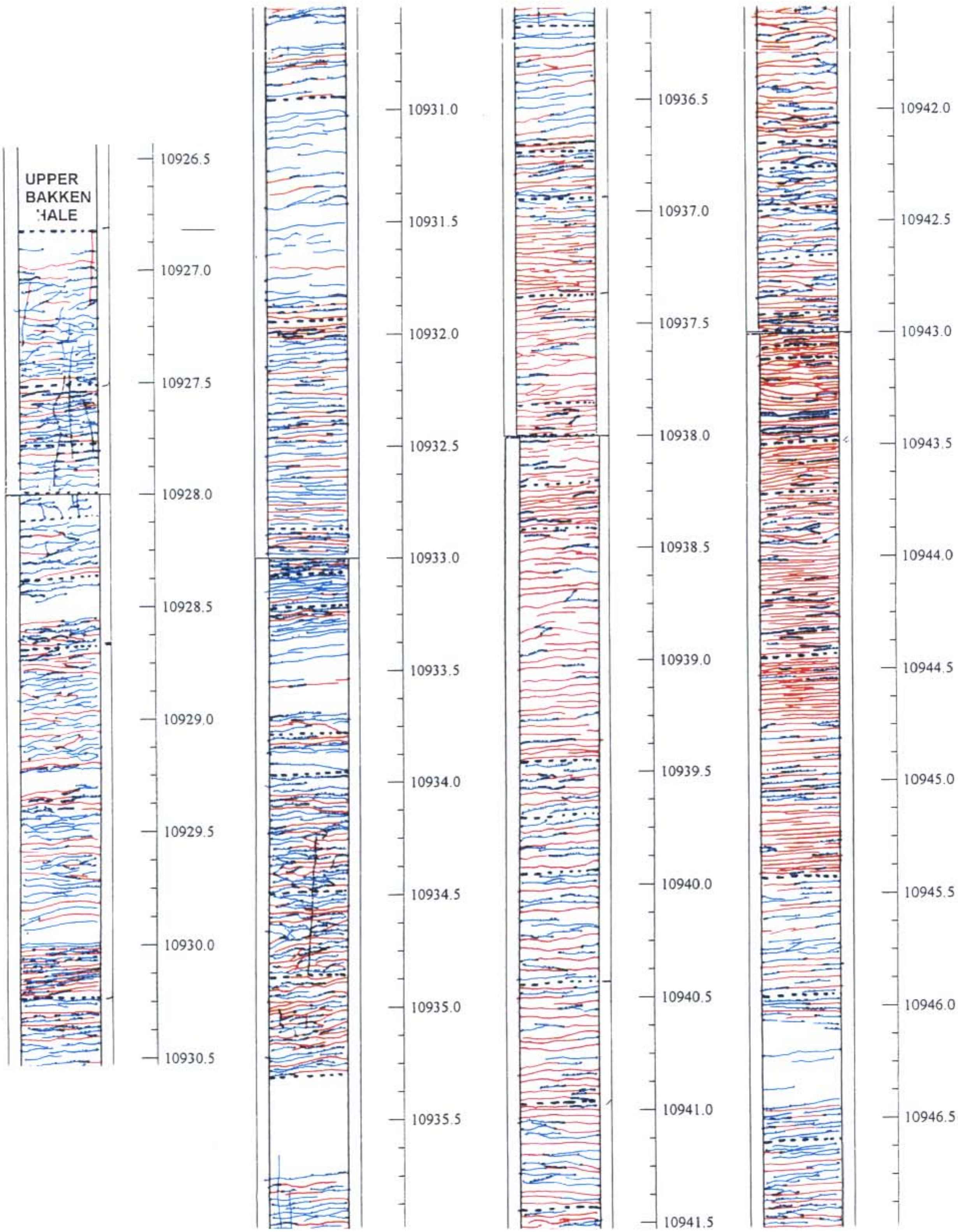


FIG. 35

NDGS 13098 SILTSTONE



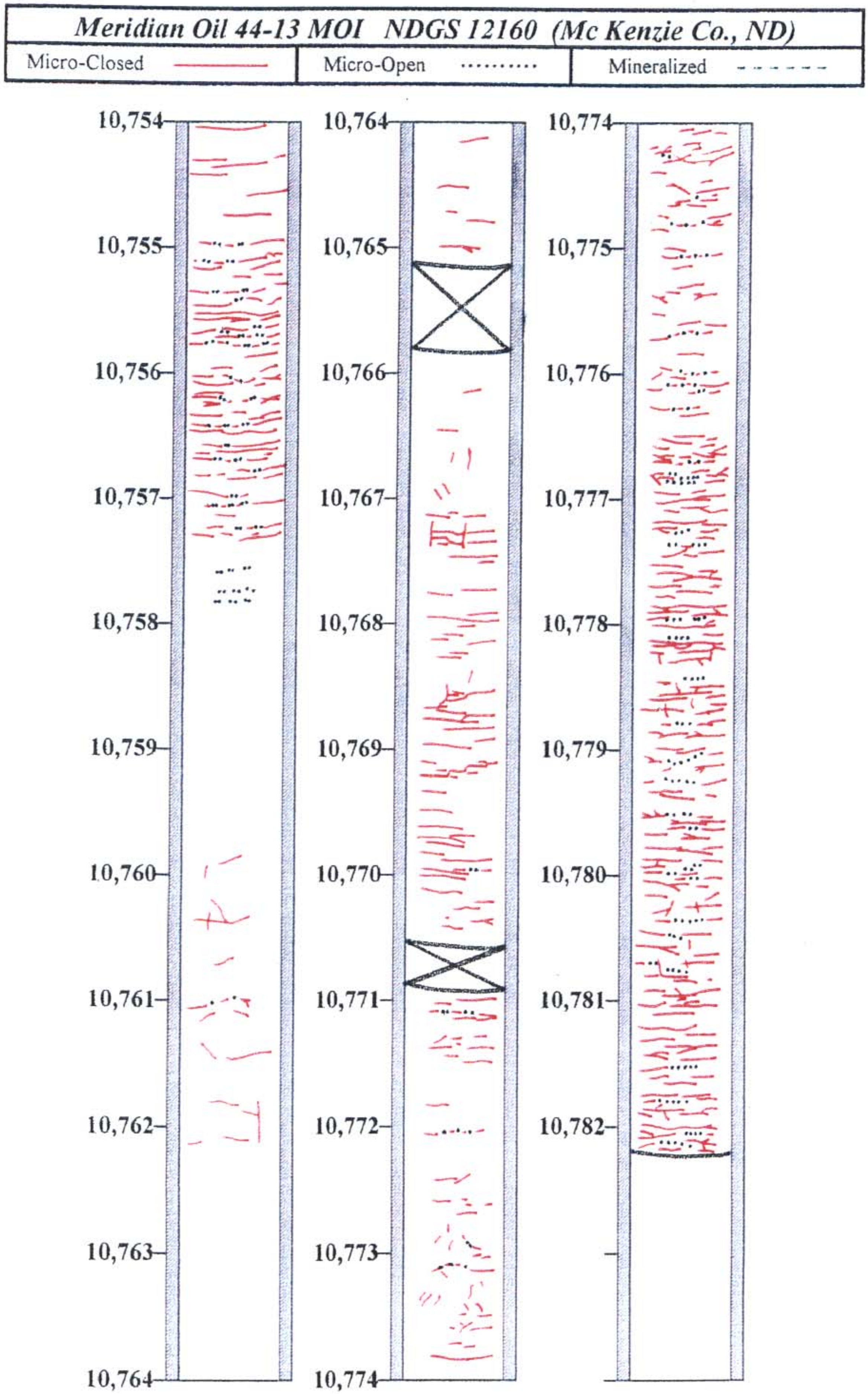

Meridian Oil 44-13 MOI NDGS 12160 (Mc Kenzie Co., ND)
Micro-Closed
Micro-Open
Mineralized
10,754
10,755
10,756
10,757
10,758
10,759
10,760
10,761
10,762
10,763
10,764
10,764
10,765
10,766
10,767
10,768
10,769
10,770
10,771
10,772
10,773
10,774
10,774
10,775
10,776
10,777
10,778
10,779
10,780
10,781
10,782

FIG. 36

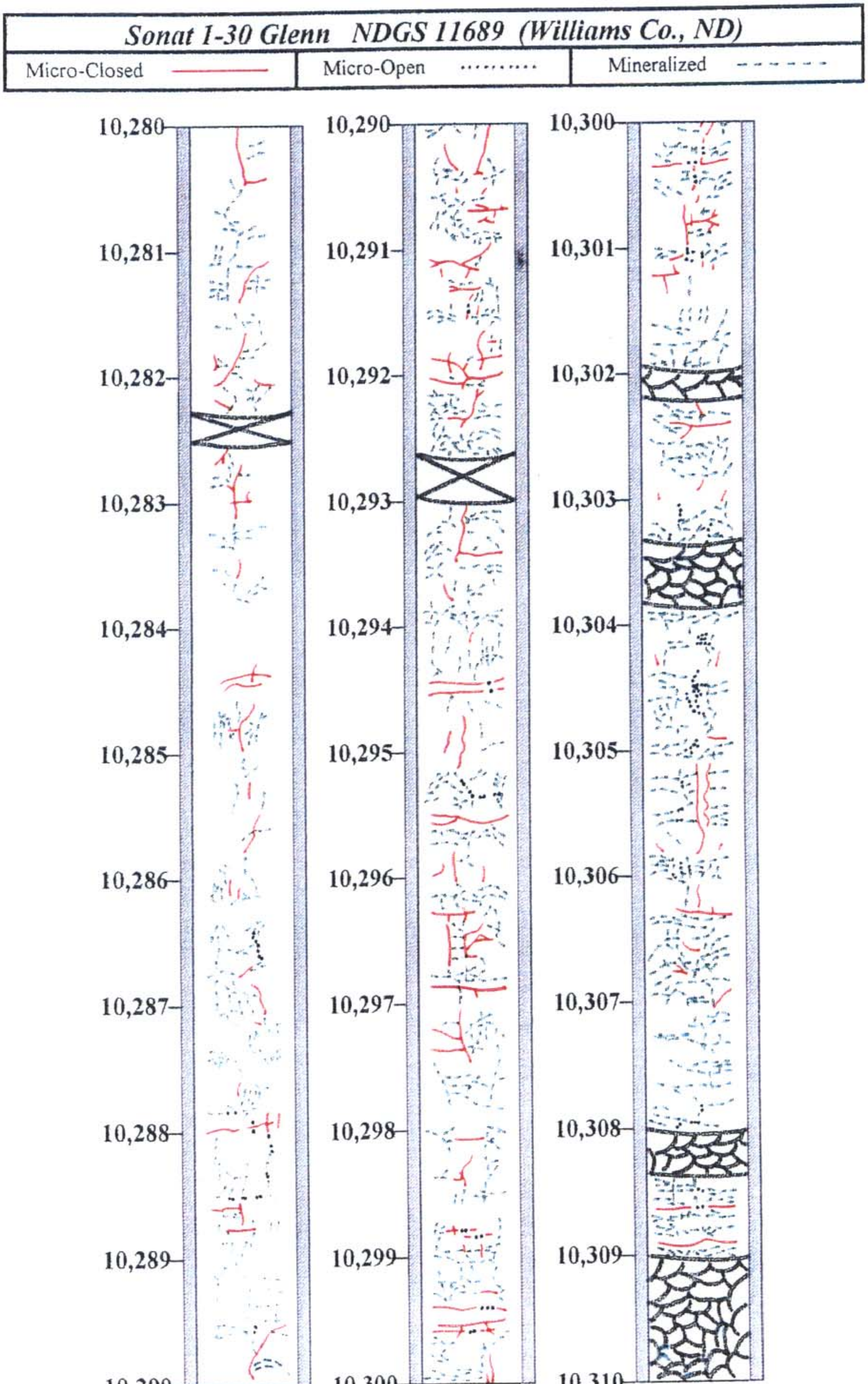
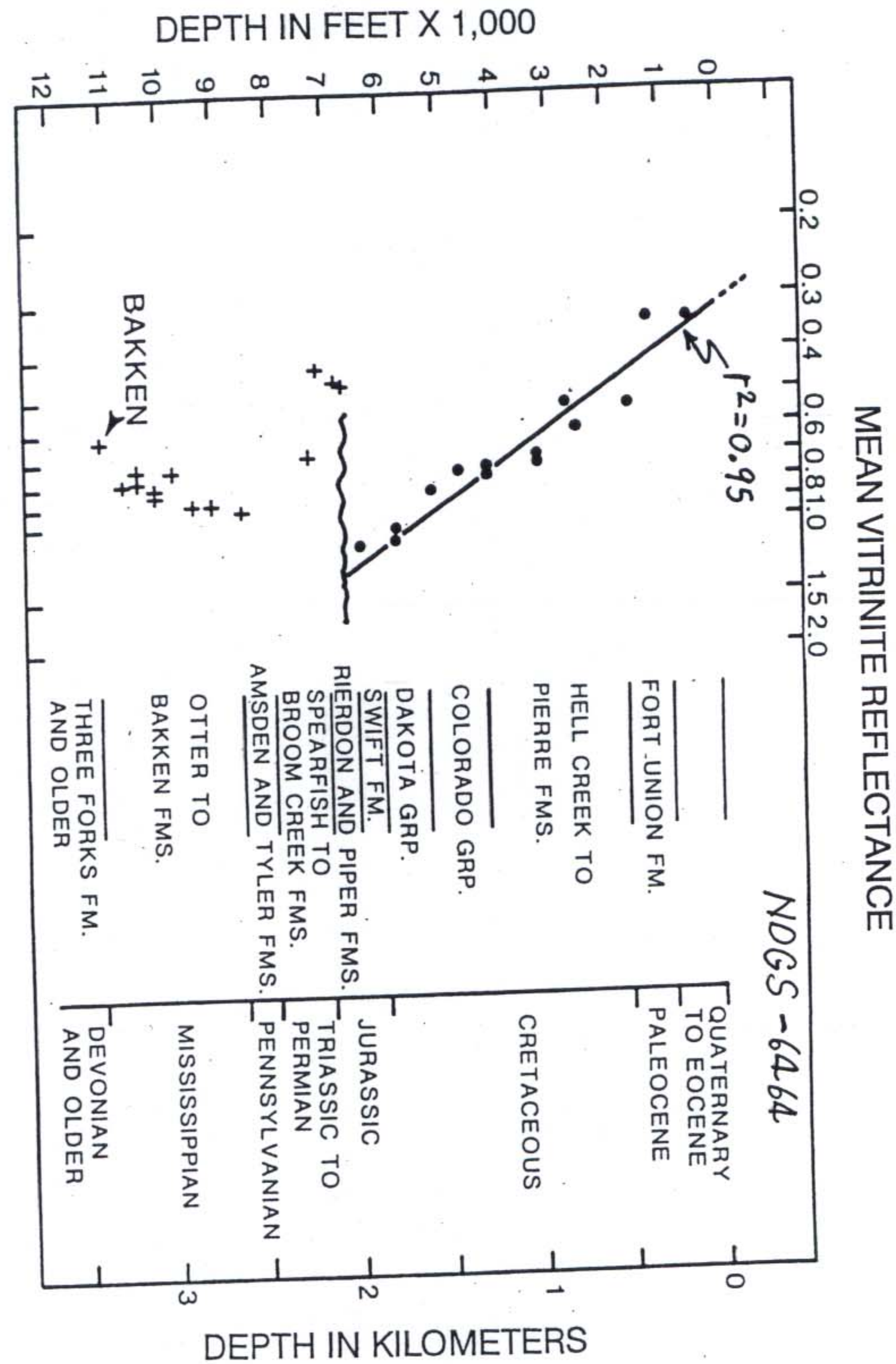

Sonat 1-30 Glenn NDGS 11689 (Williams Co., ND)
Micro-Closed
Micro-Open
Mineralized
10,280
10,281
10,282
10,283
10,284
10,285
10,286
10,287
10,288
10,289
10,290
10,291
10,292
10,293
10,294
10,295
10,296
10,297
10,298
10,299
10,300
10,301
10,302
10,303
10,304
10,305
10,306
10,307
10,308
10,309
10,310

FIG. 37

FIG 38



MEAN VITRINITE REFLECTANCE
0.2 0.3 0.4 0.6 0.8 1.0 1.5 2.0
DEPTH IN FEET X 1,000
0 1 2 3 4 5 6 7 8 9 10 11 12
DEPTH IN KILOMETERS
0 1 2 3
$r^2 = 0.95$
NDGS - 6464
BAKKEN
FORT UNION FM.
HELL CREEK TO
PIERRE FMS.
COLORADO GRP.
DAKOTA GRP.
SWIFT FM.
RIERDON AND PIPER FMS.
SPEARFISH TO
BROOM CREEK FMS.
AMSDEN AND TYLER FMS.
OTTER TO
BAKKEN FMS.
THREE FORKS FM.
AND OLDER
QUATERNARY
TO EOCENE
PALEOCENE
CRETACEOUS
JURASSIC
TRIASSIC TO
PERMIAN
PENNSYLVANIAN
MISSISSIPPIAN
DEVONIAN
AND OLDER

FIG. 39

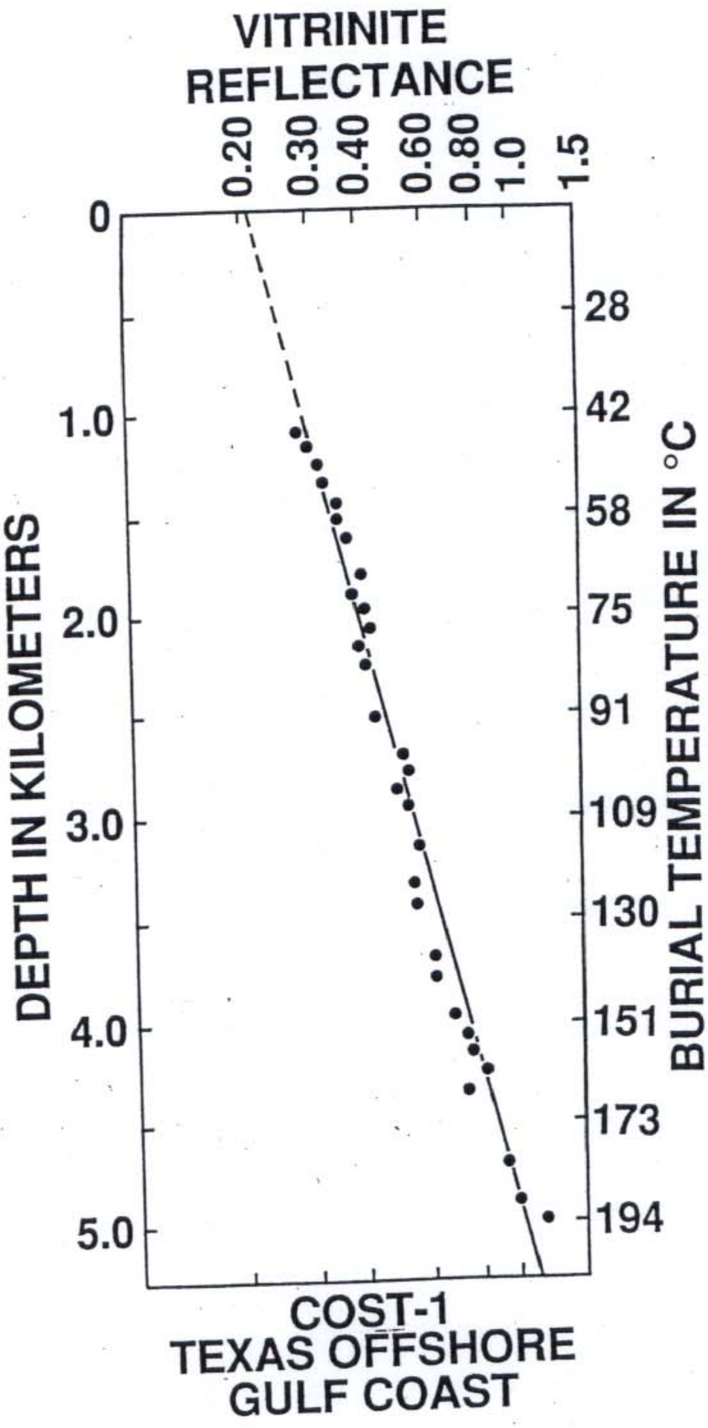
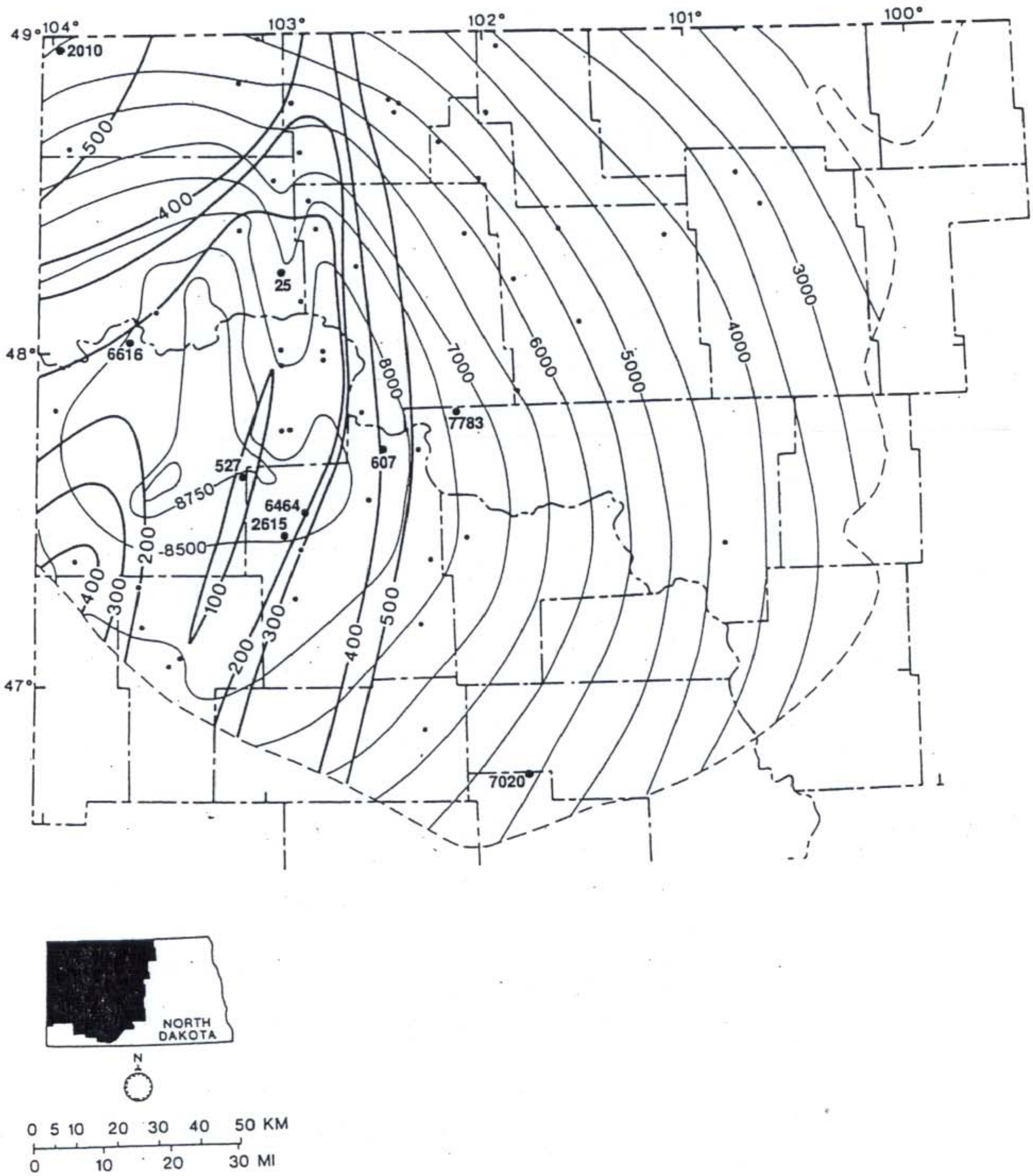
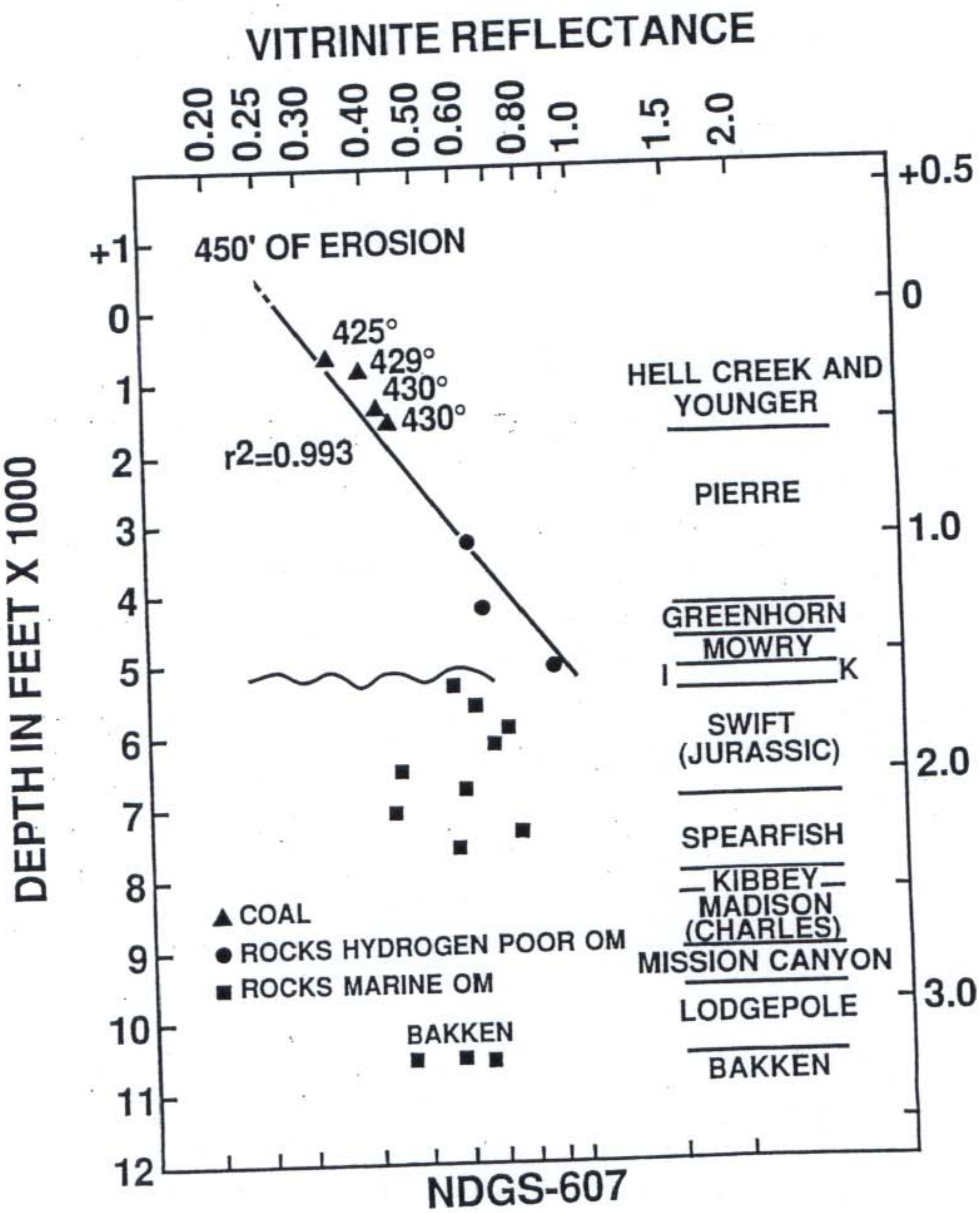

VITRINITE
REFLECTANCE
0.20
0.30
0.40
0.60
0.80
1.0
1.5
0
1.0
2.0
3.0
4.0
5.0
DEPTH IN KILOMETERS
28
42
58
75
91
109
130
151
173
194
BURIAL TEMPERATURE IN °C
COST-1
TEXAS OFFSHORE
GULF COAST

FIG. 40



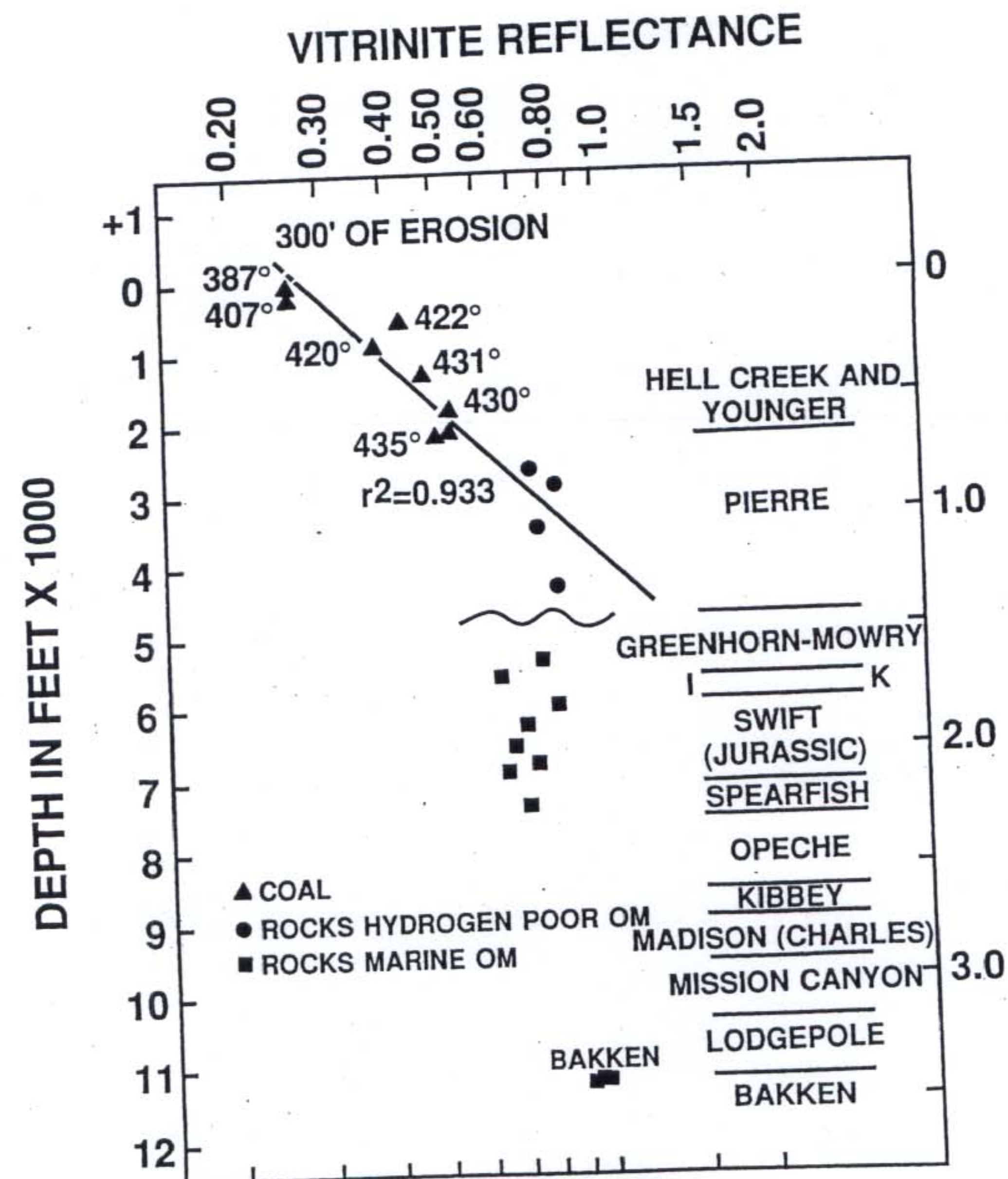
49°
104°
103°
102°
101°
100°
48°
47°
2010
500
400
25
6616
8000
7000
6000
5000
4000
3000
7783
607
527
8750
6464
2615
8500
200
400
300
100
200
300
400
500
7020
NORTH DAKOTA
N
0 5 10 20 30 40 50 KM
0 10 20 30 MI

FIG. 41



VITRINITE REFLECTANCE
0.20
0.25
0.30
0.40
0.50
0.60
0.80
1.0
1.5
2.0
+0.5
+1
450' OF EROSION
0
425°
429°
430°
430°
HELL CREEK AND
YOUNGER
1
2
r2=0.993
PIERRE
3
1.0
4
GREENHORN
MOWRY
5
I
K
SWIFT
(JURASSIC)
6
2.0
7
SPEARFISH
8
KIBBEY
MADISON
(CHARLES)
COAL
ROCKS HYDROGEN POOR OM
ROCKS MARINE OM
9
MISSION CANYON
3.0
LODGEPOLE
10
BAKKEN
BAKKEN
11
12
NDGS-607
DEPTH IN FEET X 1000
DEPTH IN KILOMETERS

FIG. 42



NDGS-527

FIG. 43

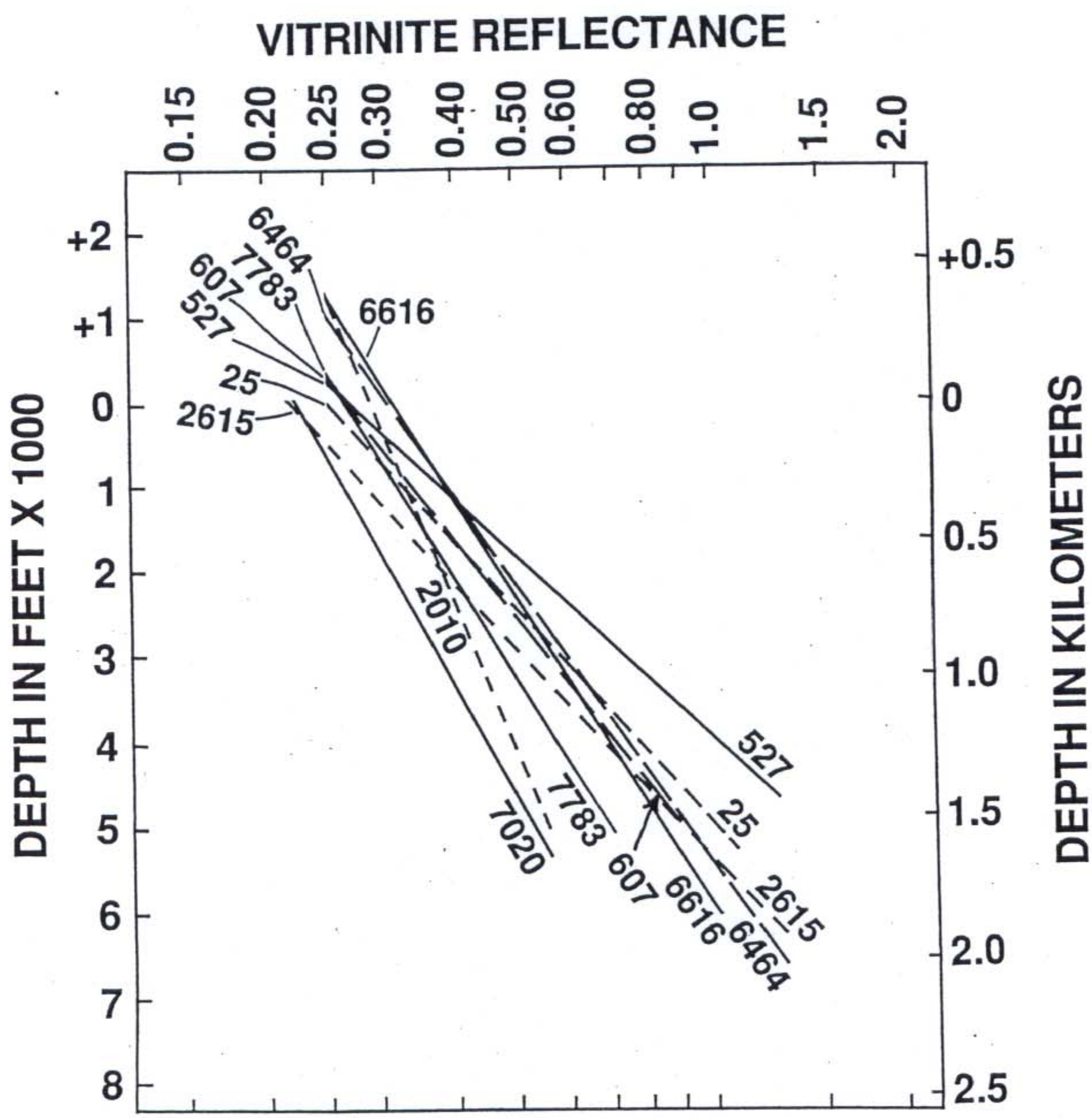

VITRINITE REFLECTANCE
0.15
0.20
0.25
0.30
0.40
0.50
0.60
0.80
1.0
1.5
2.0
DEPTH IN FEET X 1000
+2
+1
0
1
2
3
4
5
6
7
8
DEPTH IN KILOMETERS
+0.5
0
0.5
1.0
1.5
2.0
2.5
6464
7783
607
527
25
2615
6616
2010
7020
7783
607
6616
6464
527
25
2615

FIG. 44

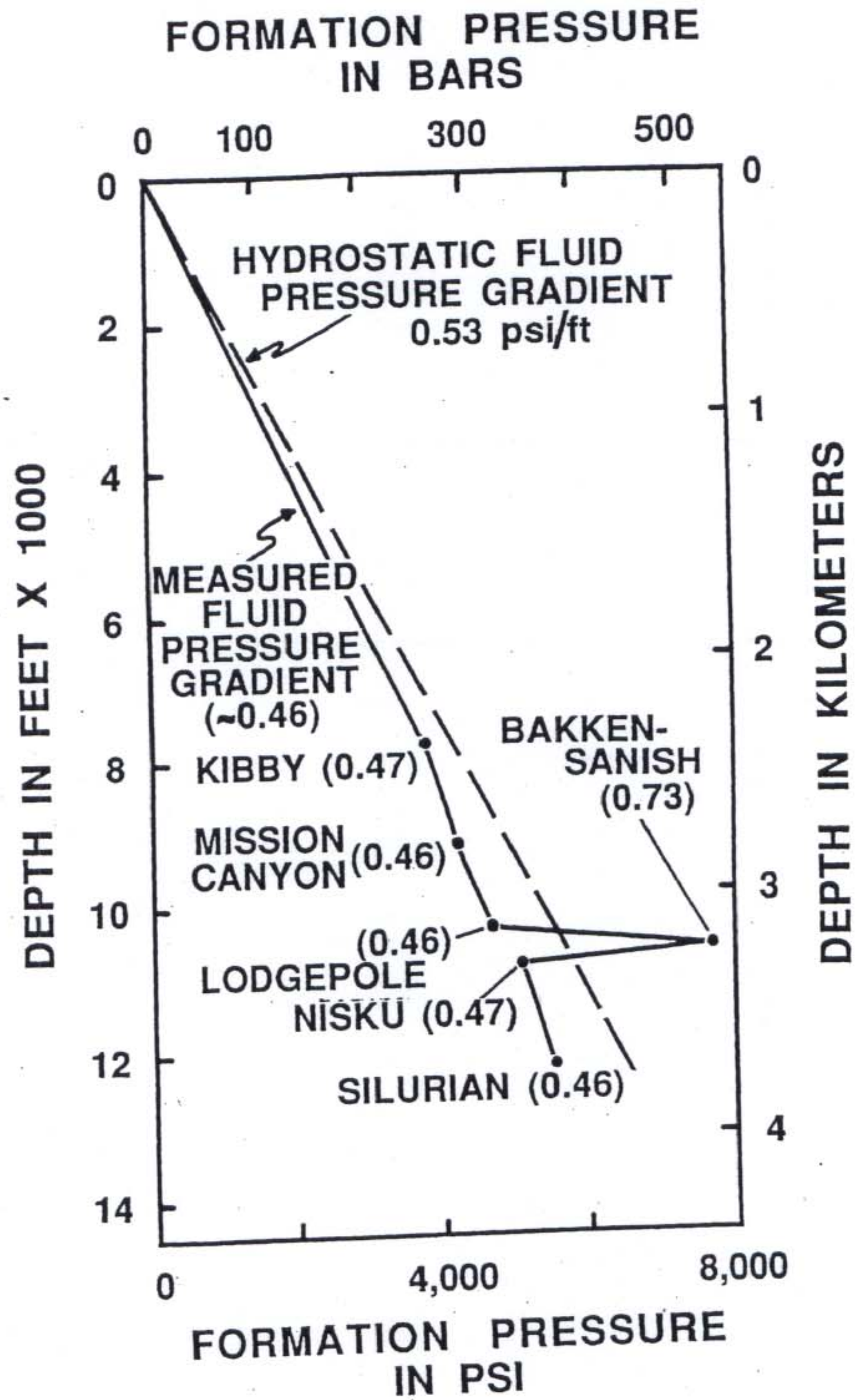
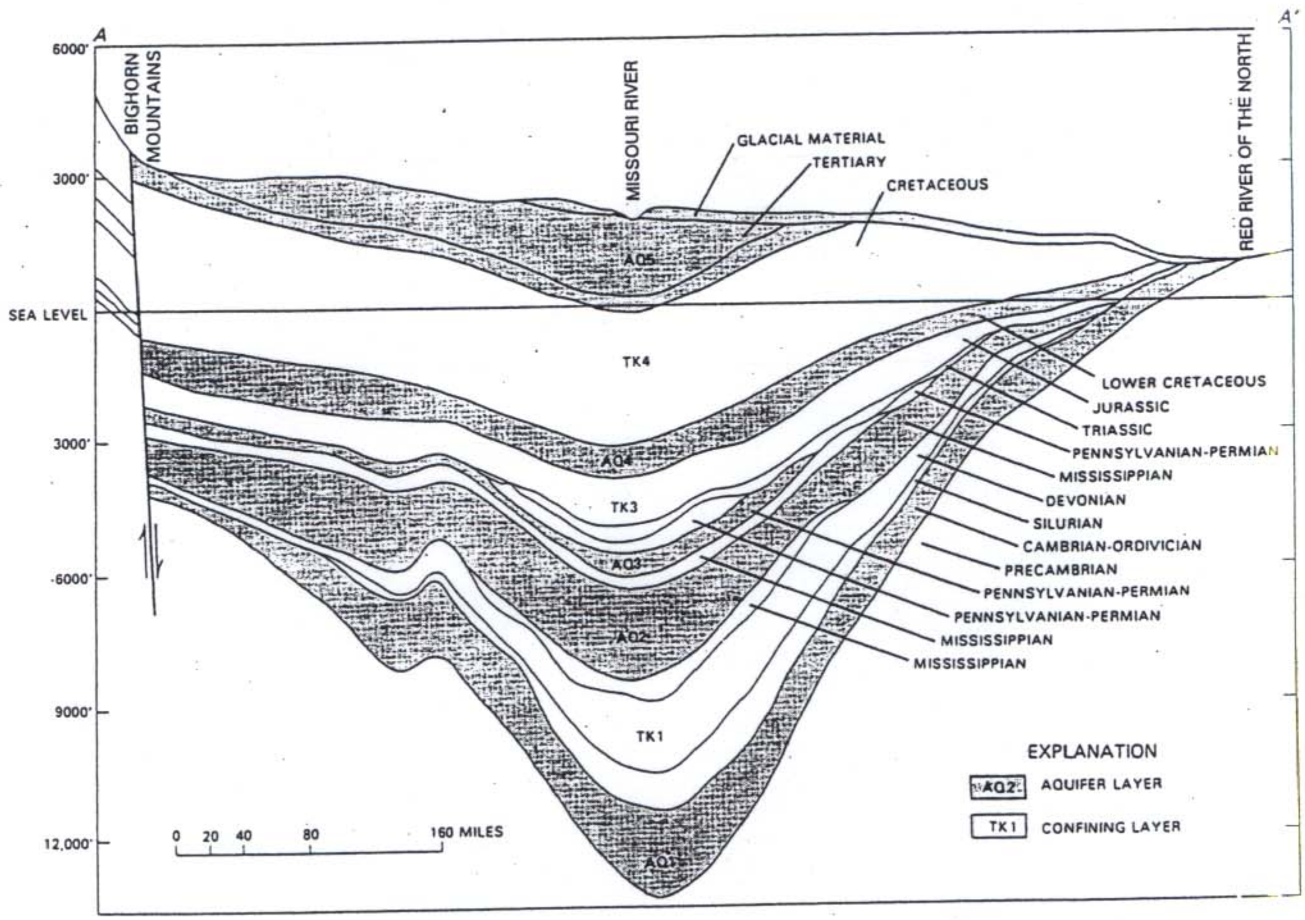
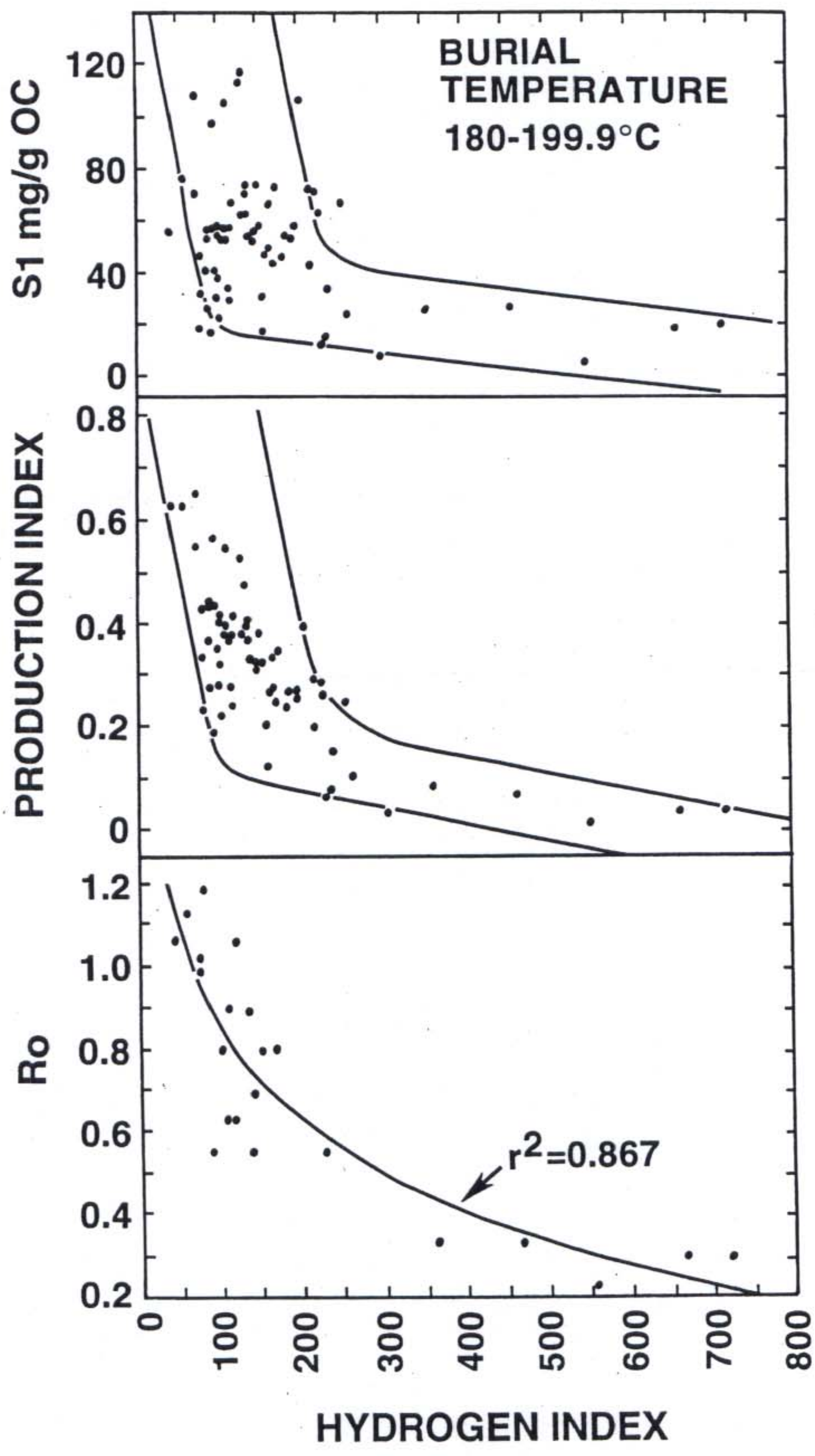

FORMATION PRESSURE IN BARS
0
100
300
500
0
2
4
6
8
10
12
14
HYDROSTATIC FLUID PRESSURE GRADIENT 0.53 psi/ft
MEASURED FLUID PRESSURE GRADIENT (~0.46)
KIBBY (0.47)
MISSION CANYON (0.46)
(0.46)
LODGEPOLE
NISKU (0.47)
SILURIAN (0.46)
BAKKEN-SANISH (0.73)
0
1
2
3
4
DEPTH IN FEET X 1000
DEPTH IN KILOMETERS
0
4,000
8,000
FORMATION PRESSURE IN PSI

FIG. 45



A
A'
6000'
3000'
SEA LEVEL
3000'
6000'
9000'
12,000'
BIGHORN MOUNTAINS
MISSOURI RIVER
RED RIVER OF THE NORTH
GLACIAL MATERIAL
TERTIARY
CRETACEOUS
AQ5
TK4
AQ4
TK3
AQ3
AQ2
TK1
AQ1
LOWER CRETACEOUS
JURASSIC
TRIASSIC
PENNSYLVANIAN-PERMIAN
MISSISSIPPIAN
DEVONIAN
SILURIAN
CAMBRIAN-ORDIVICIAN
PRECAMBRIAN
PENNSYLVANIAN-PERMIAN
PENNSYLVANIAN-PERMIAN
MISSISSIPPIAN
MISSISSIPPIAN
0 20 40 80 160 MILES
EXPLANATION
AQ2 AQUIFER LAYER
TK1 CONFINING LAYER

FIG. 46



BURIAL
TEMPERATURE
180-199.9°C
S1 mg/g OC
120
80
40
0
PRODUCTION INDEX
0.8
0.6
0.4
0.2
0
Ro
1.2
1.0
0.8
0.6
0.4
0.2
r^2=0.867
0
100
200
300
400
500
600
700
800
HYDROGEN INDEX

FIG. 47

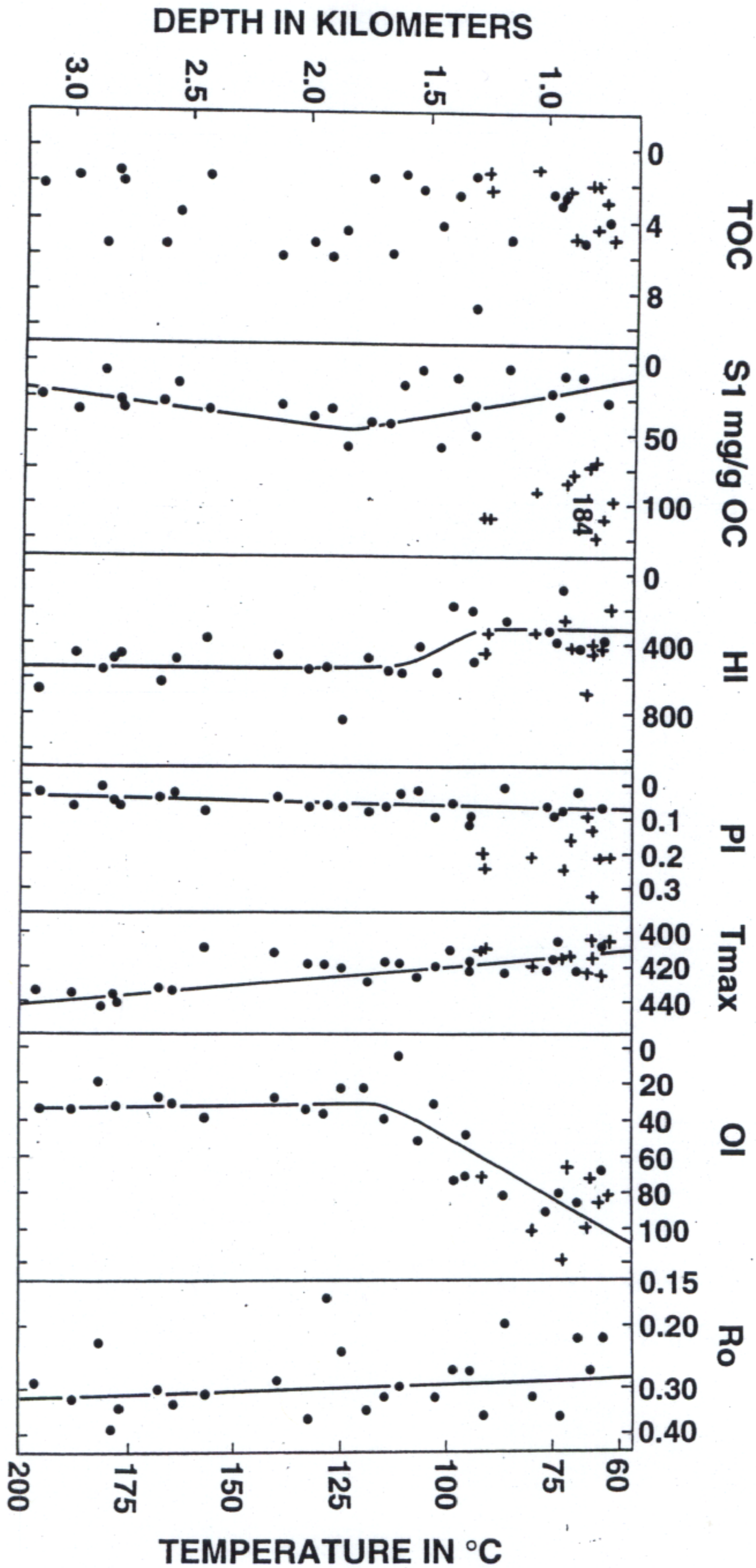

DEPTH IN KILOMETERS
3.0
2.5
2.0
1.5
1.0
TOC
S1 mg/g OC
HI
PI
Tmax
OI
Ro
184
TEMPERATURE IN °C
200
175
150
125
100
75
60

FIG.48

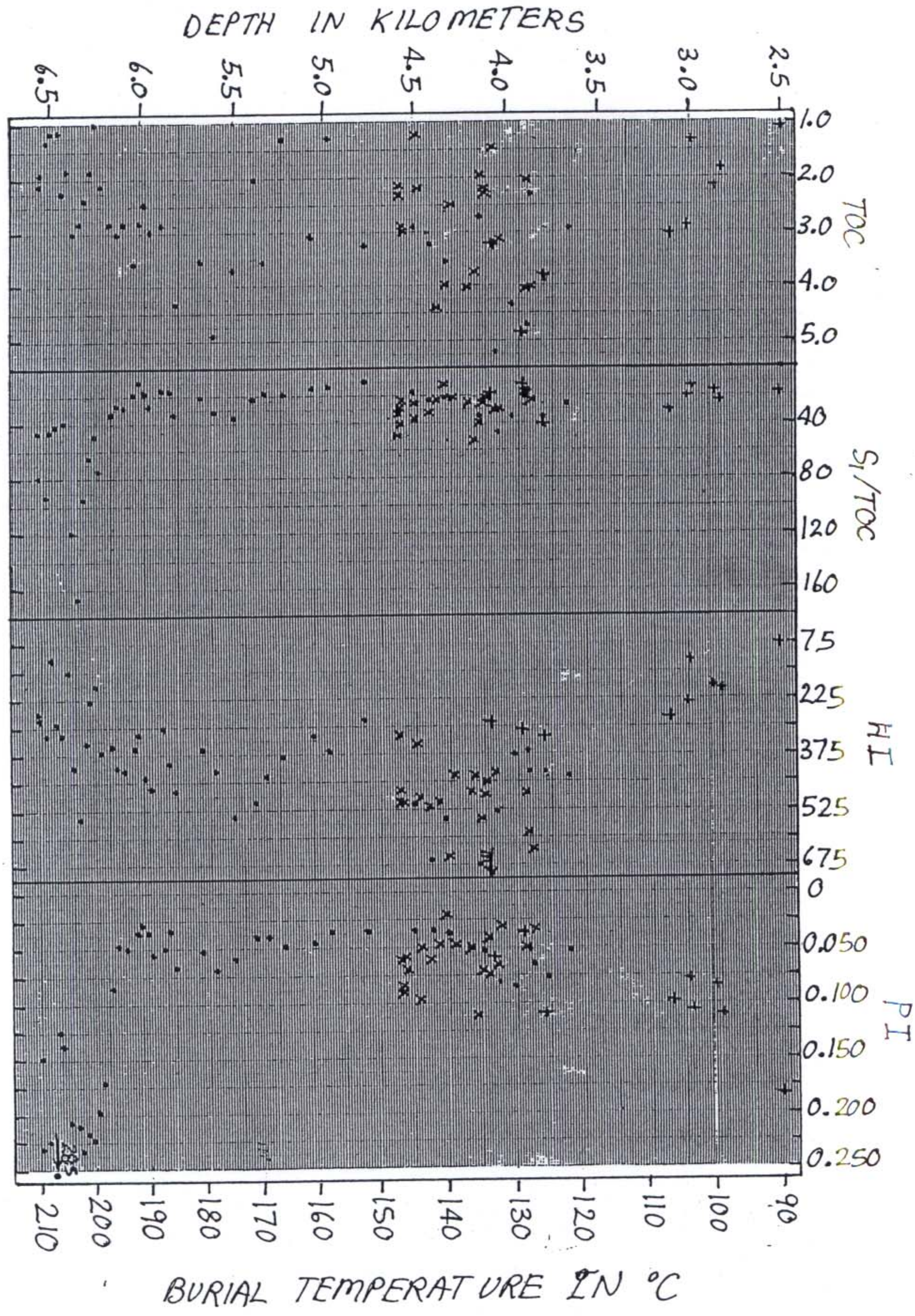
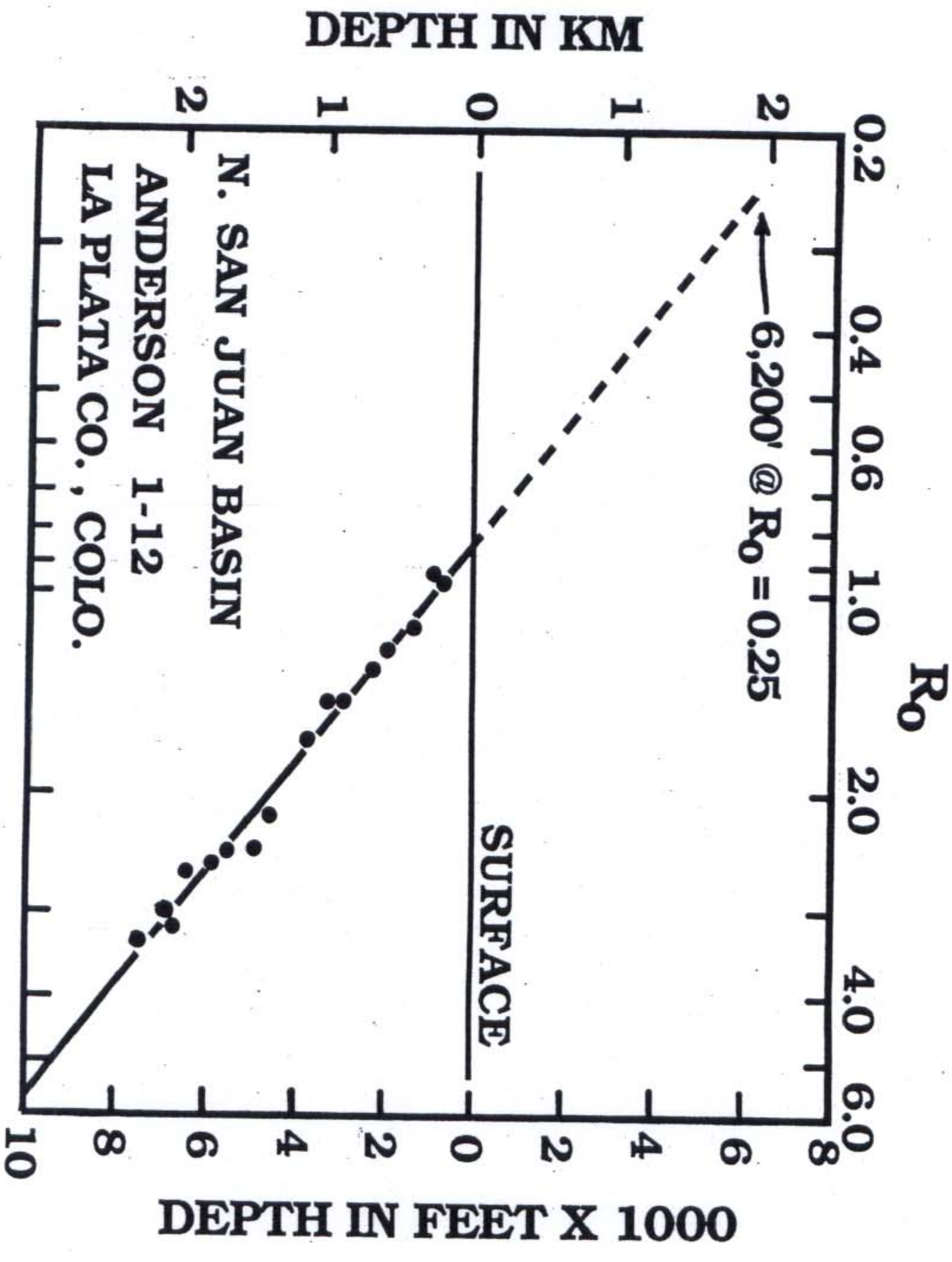
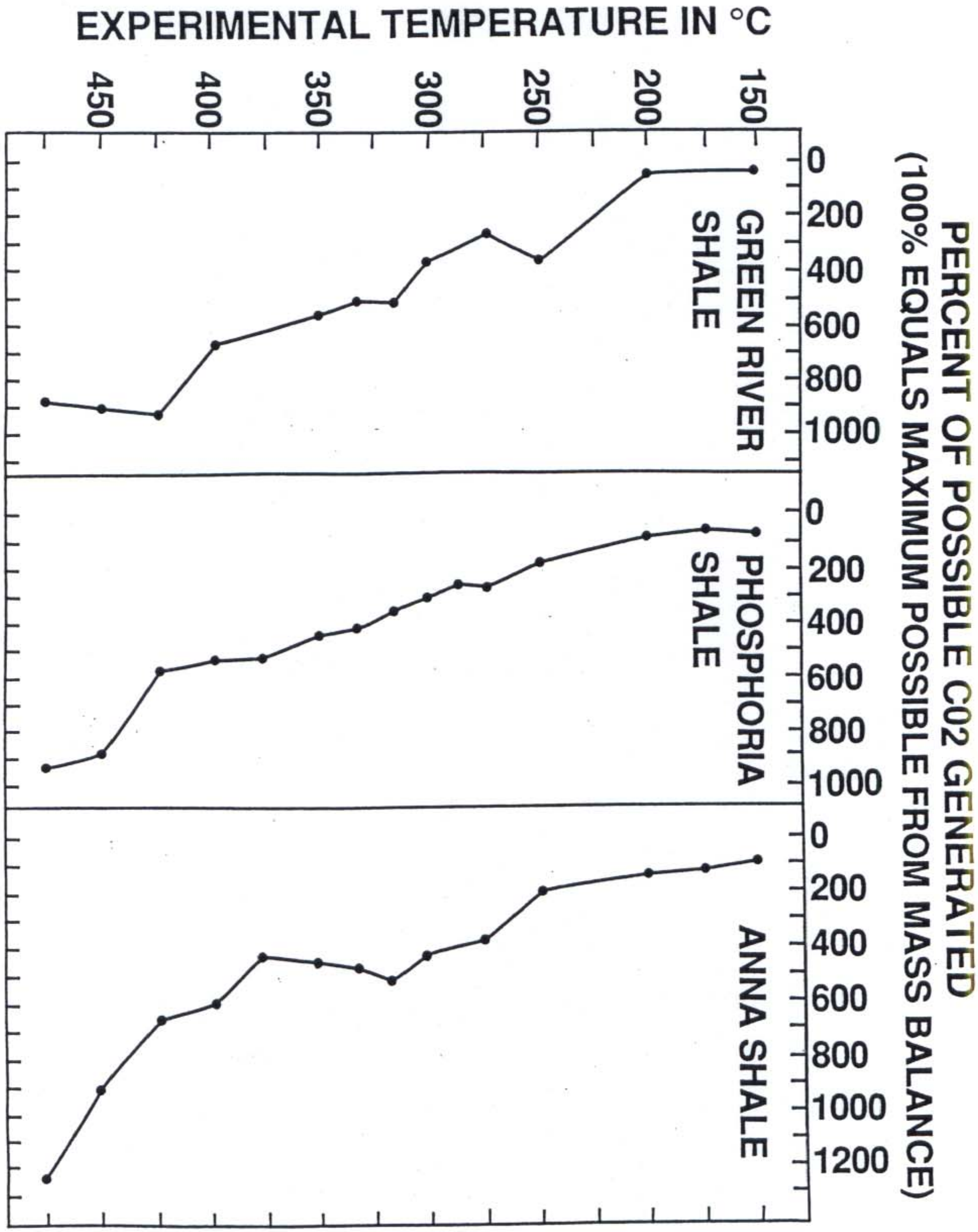

DEPTH IN KILOMETERS
6.5 6.0 5.5 5.0 4.5 4.0 3.5 3.0 2.5
1.0 2.0 3.0 4.0 5.0
TOC
40 80 120 160
S1/TOC
75 225 375 525 675
HI
0 0.050 0.100 0.150 0.200 0.250
PI
210 200 190 180 170 160 150 140 130 120 110 100 90
BURIAL TEMPERATURE IN °C

FIG. 49



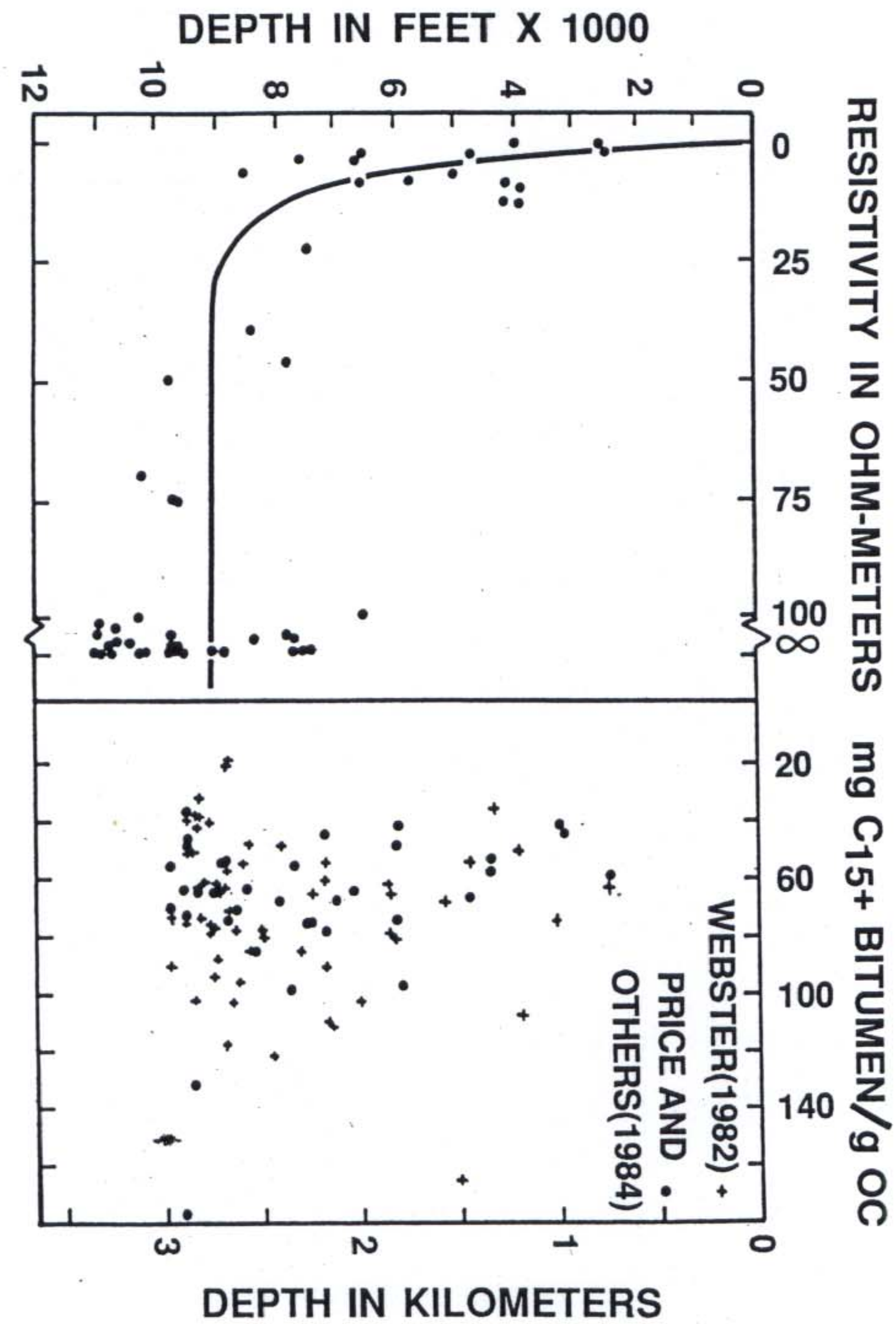
DEPTH IN KM
DEPTH IN FEET X 1000
R_o
0.2
0.4
0.6
1.0
2.0
4.0
6.0
2
1
0
1
2
8
6
4
2
0
2
4
6
8
10
6,200' @ R_o = 0.25
SURFACE
N. SAN JUAN BASIN
ANDERSON 1-12
LA PLATA CO., COLO.

FIG. 50



EXPERIMENTAL TEMPERATURE IN °C
450
400
350
300
250
200
150
PERCENT OF POSSIBLE C02 GENERATED
(100% EQUALS MAXIMUM POSSIBLE FROM MASS BALANCE)
0
200
400
600
800
1000
1200
GREEN RIVER SHALE
PHOSPHORIA SHALE
ANNA SHALE

FIG. 51



DEPTH IN FEET X 1000
RESISTIVITY IN OHM-METERS
mg C_{15+} BITUMEN/g OC
WEBSTER(1982) +
PRICE AND OTHERS(1984) •
DEPTH IN KILOMETERS

FIG. 52

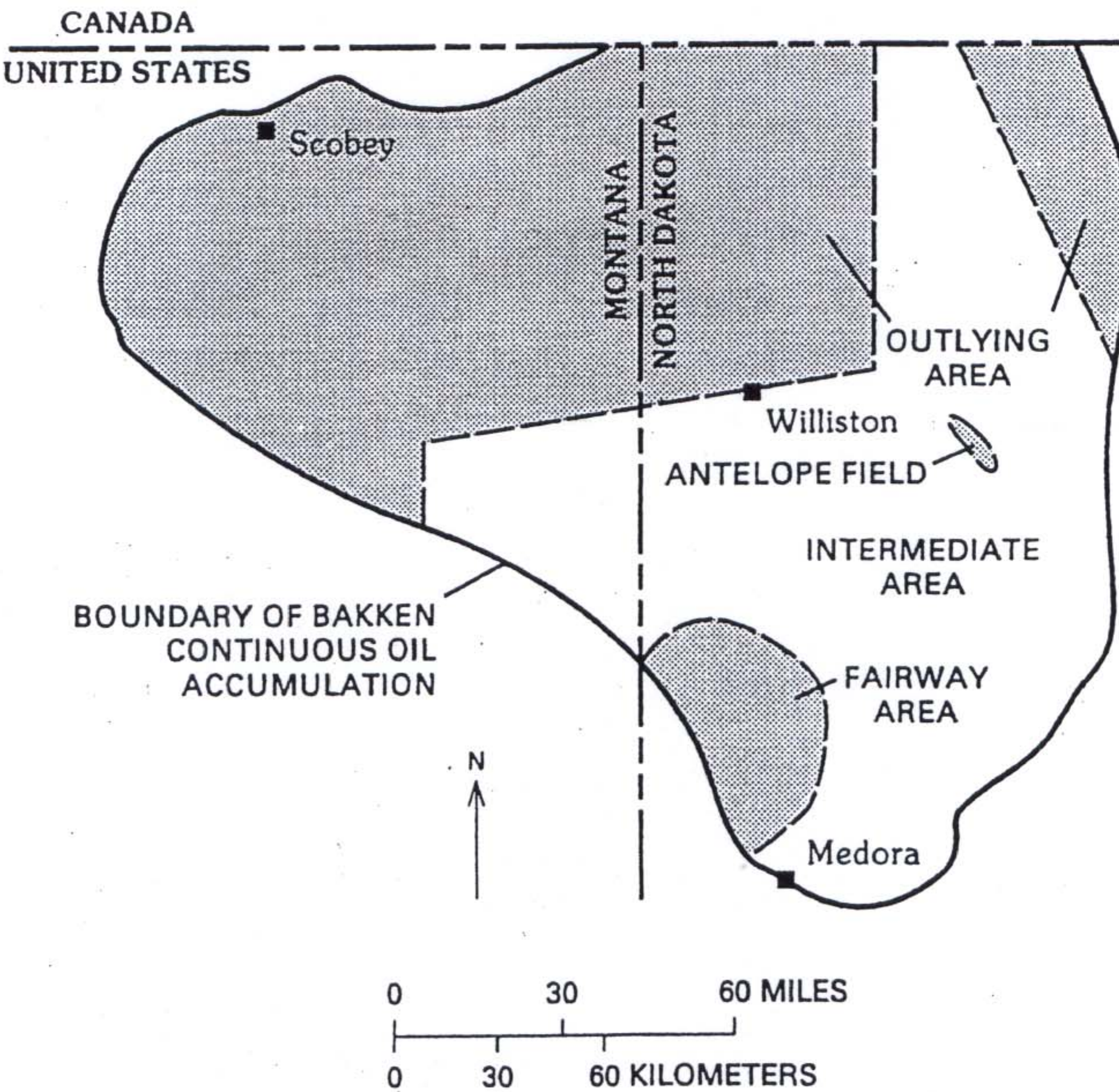

CANADA
UNITED STATES
Scobey
MONTANA
NORTH DAKOTA
OUTLYING AREA
Williston
ANTELOPE FIELD
INTERMEDIATE AREA
BOUNDARY OF BAKKEN CONTINUOUS OIL ACCUMULATION
FAIRWAY AREA
N
Medora
0
30
60 MILES
0
30
60 KILOMETERS

FIG. 53

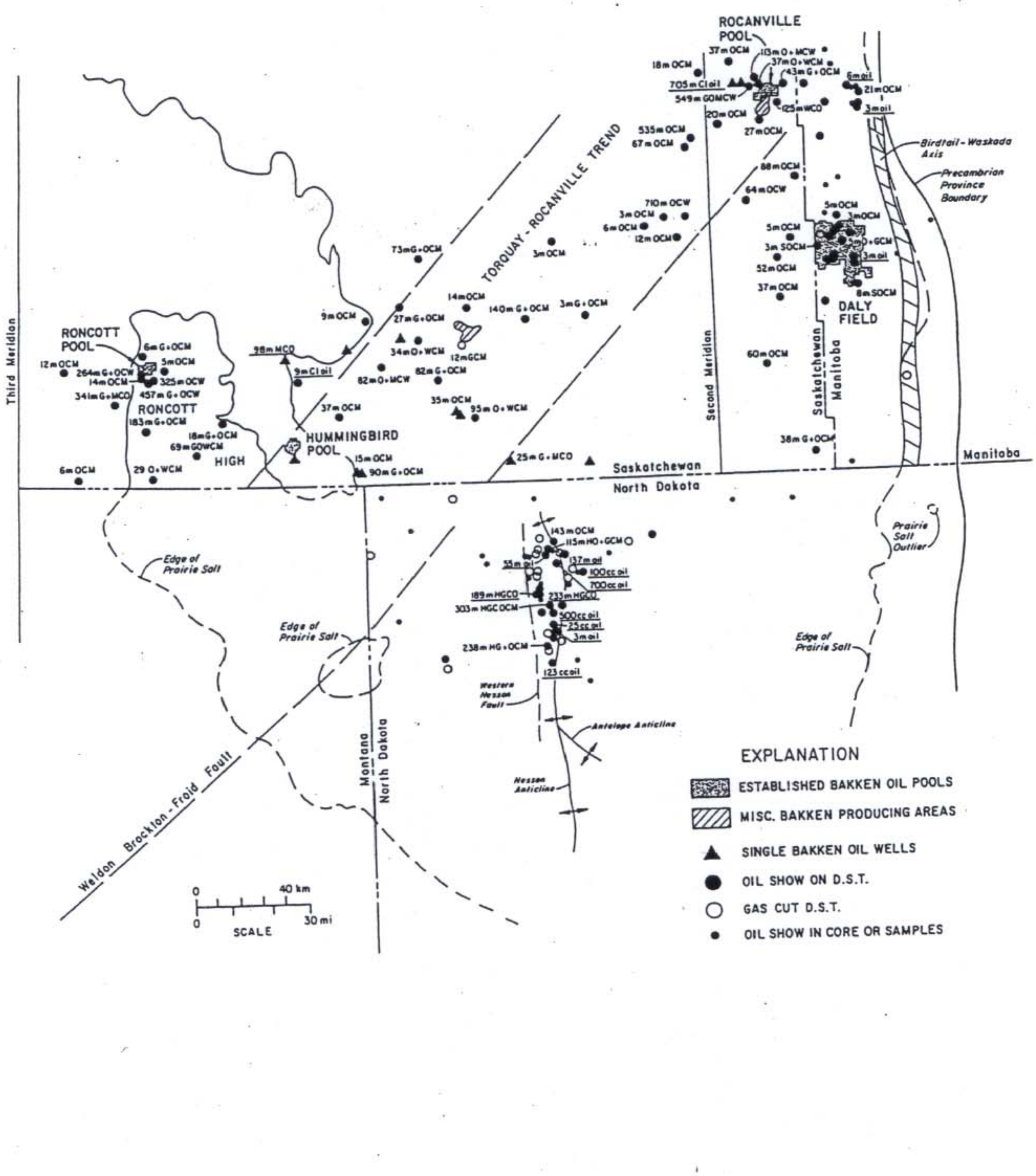

ROCANVILLE POOL
TORQUAY - ROCANVILLE TREND
RONCOTT POOL
RONCOTT HIGH
HUMMINGBIRD POOL
DALY FIELD
Third Meridian
Second Meridian
Saskatchewan
Manitoba
Saskatchewan
North Dakota
Montana
North Dakota
Birdtail - Waskada Axis
Precambrian Province Boundary
Prairie Salt Outlier
Edge of Prairie Salt
Edge of Prairie Salt
Edge of Prairie Salt
Western Nesson Fault
Antelope Anticline
Nesson Anticline
Weldon Brockton - Froid Fault
0 40 km
0 30 mi
SCALE
EXPLANATION
ESTABLISHED BAKKEN OIL POOLS
MISC. BAKKEN PRODUCING AREAS
SINGLE BAKKEN OIL WELLS
OIL SHOW ON D.S.T.
GAS CUT D.S.T.
OIL SHOW IN CORE OR SAMPLES

FIG. 54

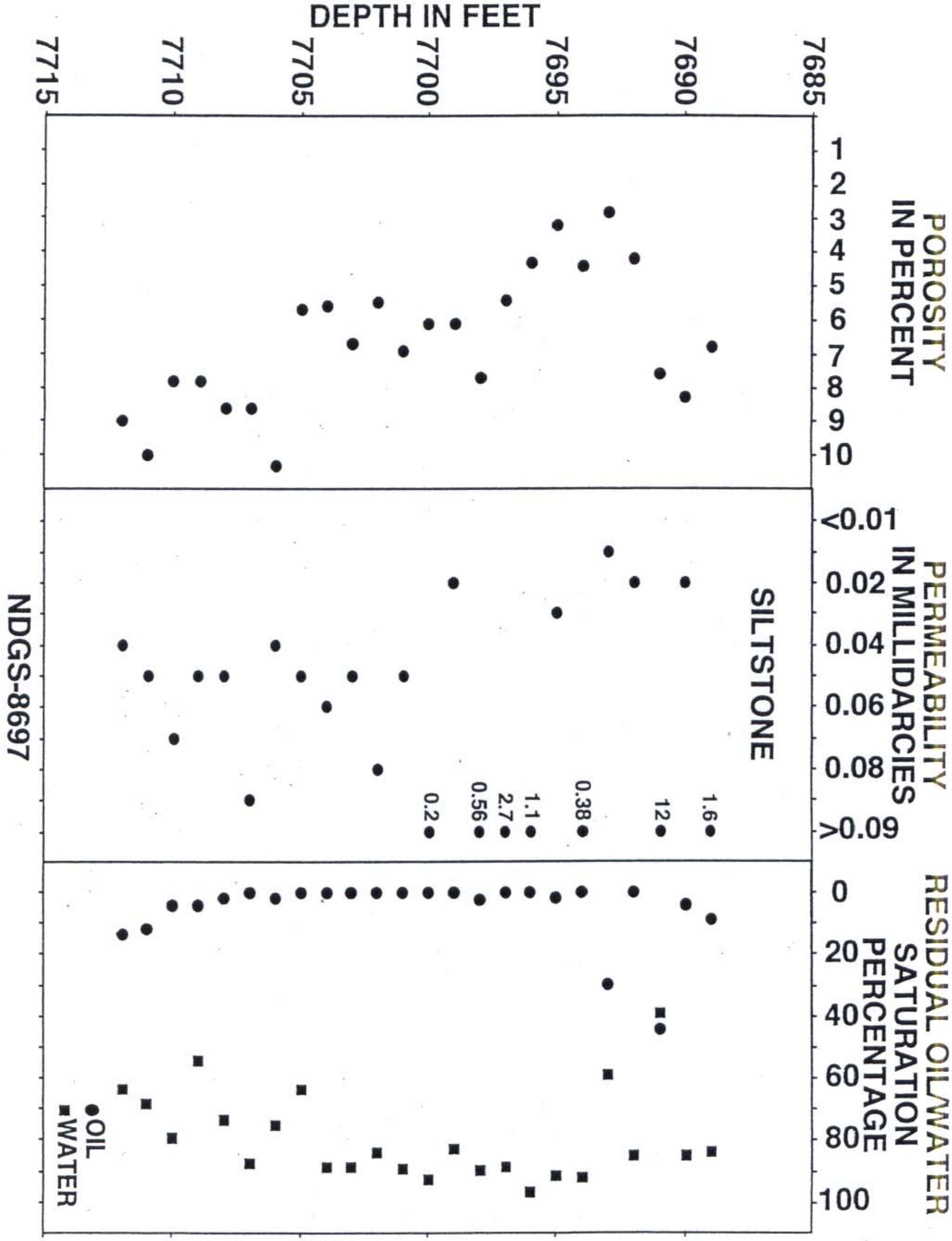
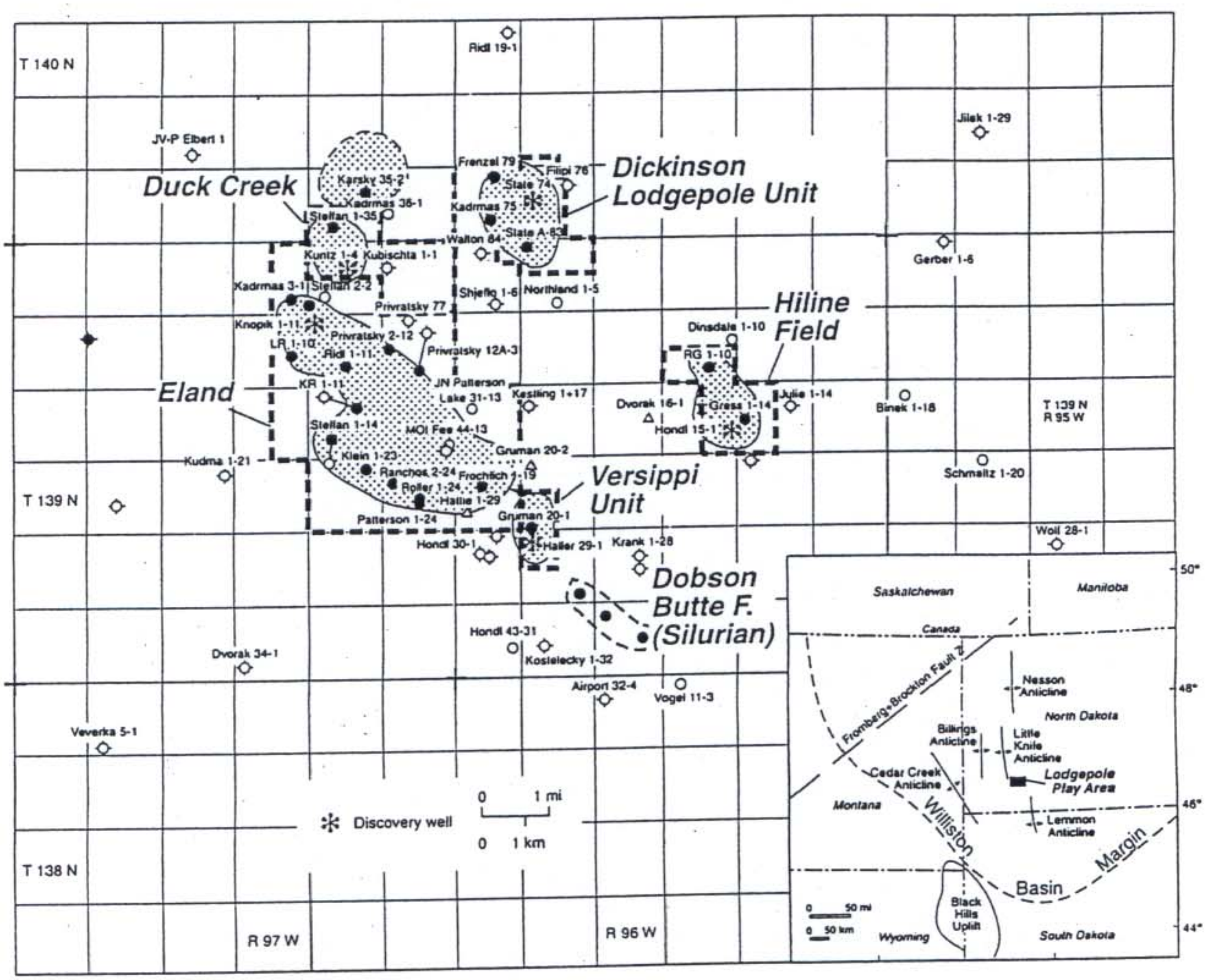
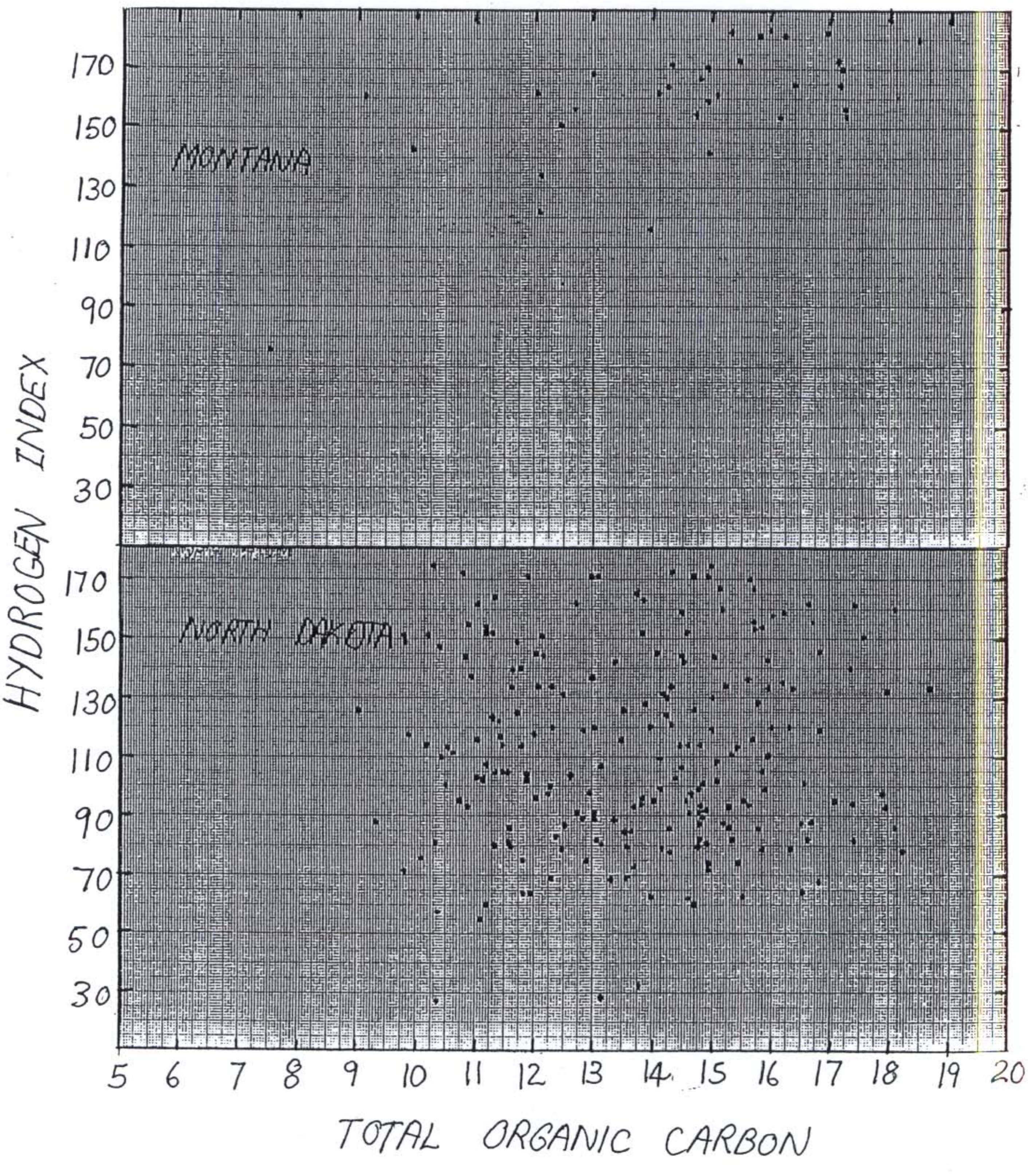

DEPTH IN FEET
7685
7690
7695
7700
7705
7710
7715
POROSITY IN PERCENT
1
2
3
4
5
6
7
8
9
10
PERMEABILITY IN MILLIDARCIES
<0.01
0.02
0.04
0.06
0.08
>0.09
1.6
12
0.38
1.1
2.7
0.56
0.2
SILTSTONE
RESIDUAL OIL/WATER SATURATION PERCENTAGE
0
20
40
60
80
100
OIL
WATER
NDGS-8697

FIG. 55



T 140 N
T 139 N
T 138 N
T 139 N R 95 W
R 97 W
R 96 W
Duck Creek
Dickinson Lodgepole Unit
Hiline Field
Eland
Versippi Unit
Dobson Butte F. (Silurian)
Discovery well
0 1 mi
0 1 km
Ridl 19-1
JV-P Elbert 1
Jilek 1-29
Gerber 1-6
Dinsdale 1-10
RG 1-10
Julie 1-14
Binek 1-18
Dvorak 16-1
Gress 1-14
Hondl 15-1
Schmaltz 1-20
Woll 28-1
Kudma 1-21
Krank 1-28
Hondl 43-31
Kostelecky 1-32
Airport 32-4
Vogel 11-3
Dvorak 34-1
Veverka 5-1
Saskatchewan
Manitoba
Canada
Montana
North Dakota
South Dakota
Wyoming
Nesson Anticline
Billings Anticline
Little Knife Anticline
Cedar Creek Anticline
Lodgepole Play Area
Lemmon Anticline
Williston Basin Margin
Black Hills Uplift
50 mi
50 km

FIG. 56



MONTANA
NORTH DAKOTA
HYDROGEN INDEX
170
150
130
110
90
70
50
30
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
TOTAL ORGANIC CARBON

FIG. 57

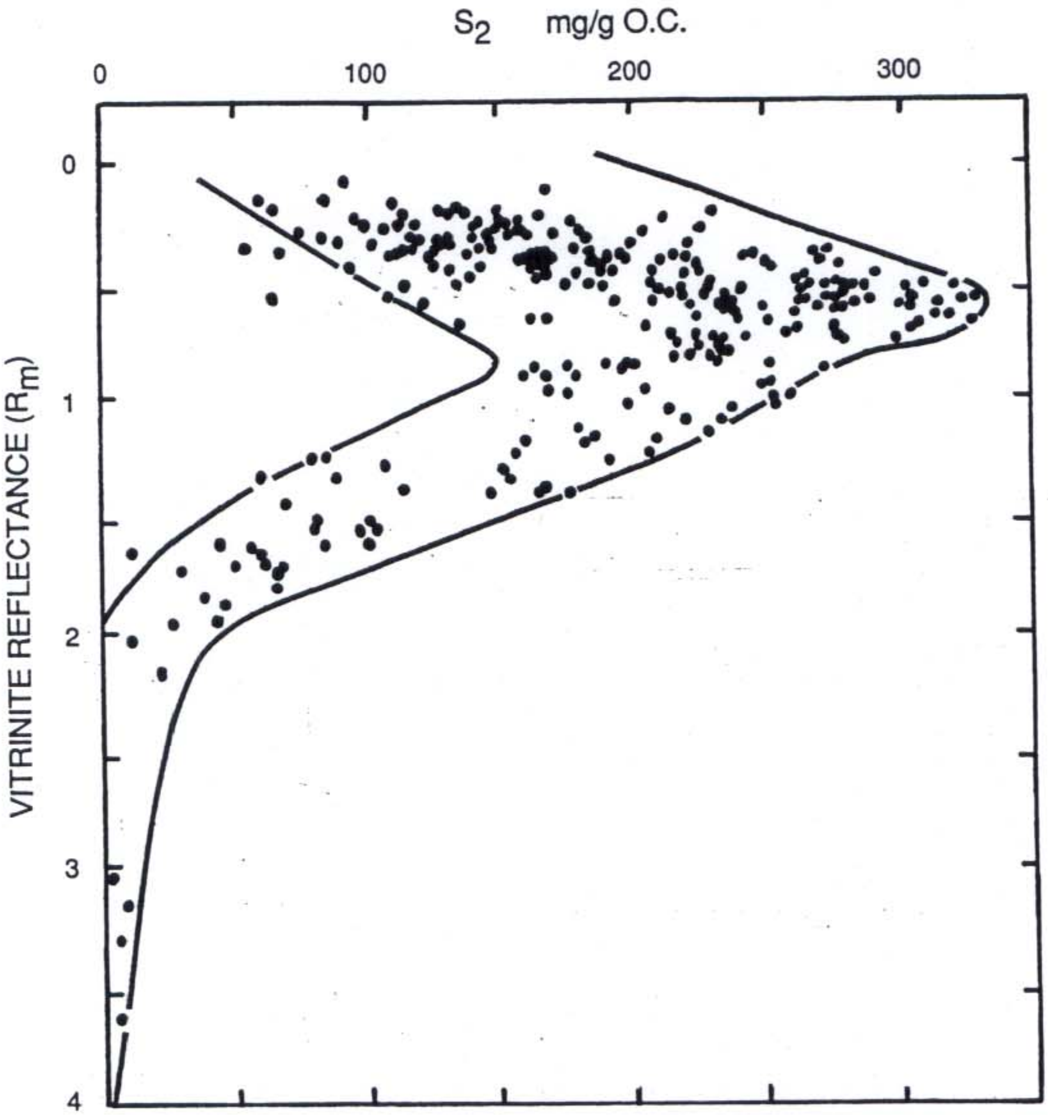
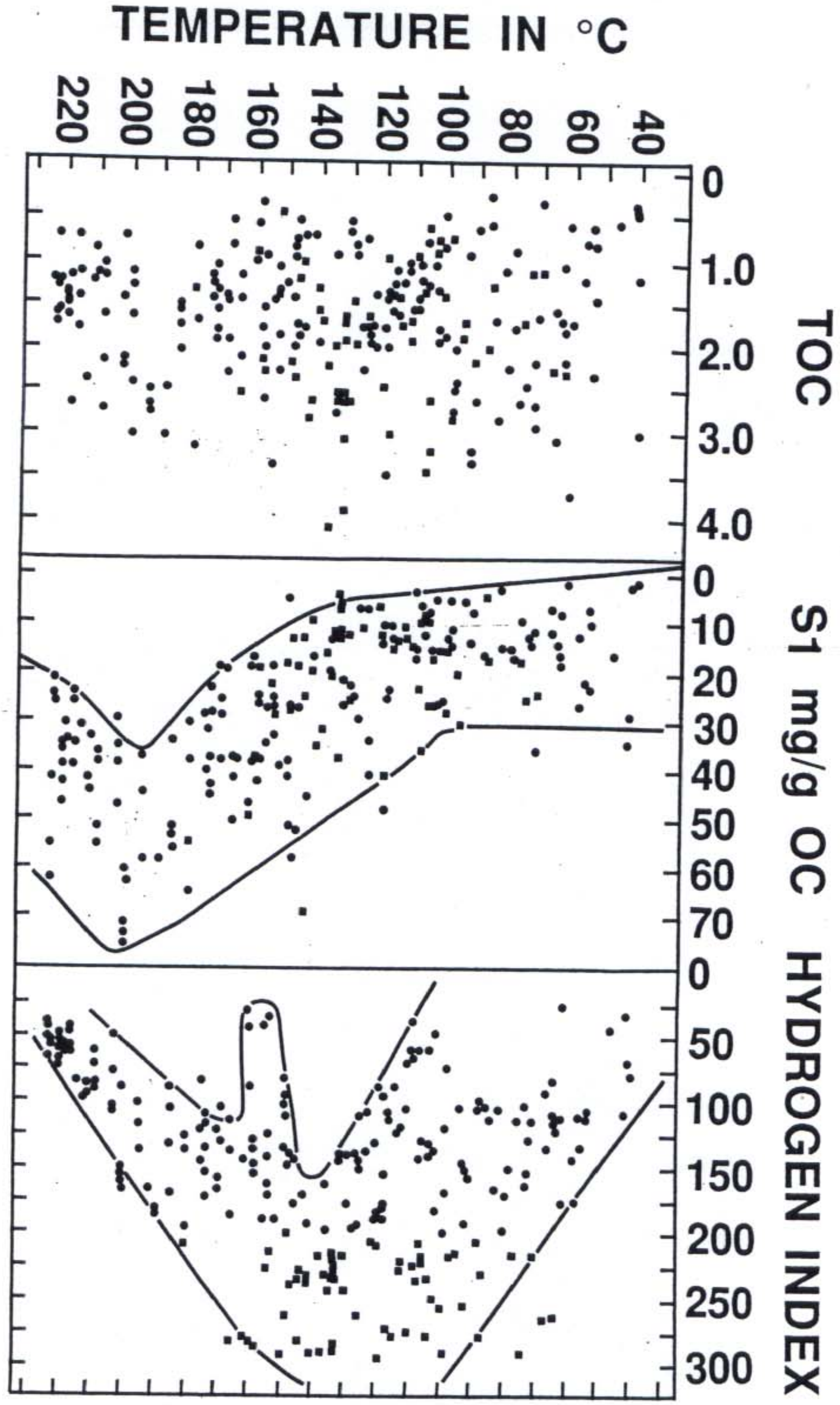


FIG. 58



TEMPERATURE IN °C
220
200
180
160
140
120
100
80
60
40
TOC
0
1.0
2.0
3.0
4.0
S1 mg/g OC
0
10
20
30
40
50
60
70
HYDROGEN INDEX
0
50
100
150
200
250
300