Reviewing the Resource Potential of the Pennsylvanian Tyler Formation

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The dramatic upturn in oil production from the Bakken Formation in North Dakota during the last few years underscores the value of incorporating new models of geologic thought with advances in drilling and completion technology. The development of the Bakken Formation resulted from advances in drilling and completion technology that were originally developed to exploit regionally extensive gas resources known as basin-centered gas accumulations. The breakthrough in exploration thought that led to the development of petroleum from the Bakken Formation, was the realization that the same basic geologic principles used to explore for basin-centered gas resources also apply to oil.

Background

Four basic components contribute to the formation of a basin-centered petroleum accumulation (Schmoker, 2002; Law, 2002). The first and most important is the presence of a regionally extensive organic-rich source rock. The second involves thermal maturation of kerogen in the source rock to the point of oil generation. Third is the presence of a reservoir in contact with the oil-generating source rock and the fourth involves hydraulically isolating the source and reservoir with very poorly permeable rock.

The formation of an appropriate source rock is restricted to a specific set of depositional circumstances that include environments conducive to high rates of organic productivity that at the same time allow for the accumulation and preservation of dead organic matter. This organic matter consists of complex organic compounds containing carbon, hydrogen, and lesser amounts of oxygen and other elements. Oil-prone kerogen (Type I and II) contains organic compounds rich in hydrogen and relatively poor in oxygen. These organic compounds are derived primarily from planktonic, especially algal, sources associated with marine environments or freshwater lakes. Gas-prone kerogen (Type III and some Type II) consists mainly of organic matter from land plants, which is richer in oxygen and poorer in hydrogen than the organics found in more oil-prone kerogen types.

Maturation of source rocks involves heat-driven chemical reactions that convert solid kerogen into either oil and/or gas. Because temperatures increase with depth, the thermal maturity of a given kerogen is largely controlled by the burial history of the source rock. However, variations in crustal heat flow within a basin can significantly distort the simple depth-temperature relationship described by burial history alone. Combining a source rock's burial history with the appropriate heat flow can be, in the absence of better indicators, useful in estimating where and when a source rock has reached a level of maturation capable of oil generation. The reason for this is that as temperatures increase with burial depth, the rate that kerogen converts to oil also increases but at a much faster rate. At shallow depths and low temperatures kerogen forms oil at a negligible rate. At greater depths and higher temperatures the conversion occurs much more rapidly and continues to increase with temperature until oil generation slows as the reactive kerogen in the source becomes exhausted. As a result, there is a range of temperatures within which oil

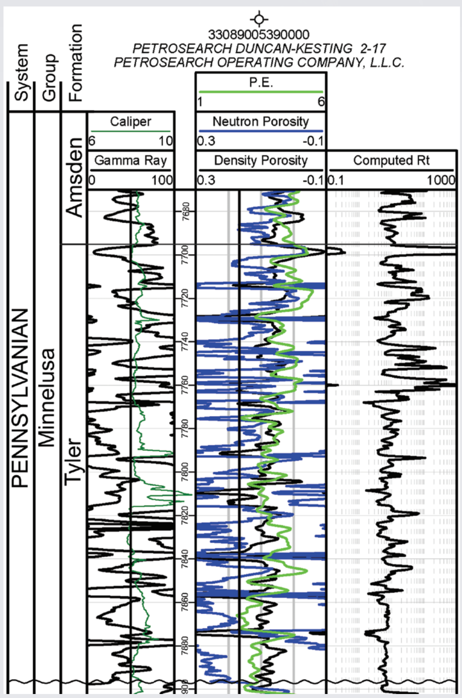

Figure 1. A set of wireline logs for the Tyler Formation from the Kesting #2-17 (API: 33-089-00539-00-00; NDIC: 14675) drilled in the SE NE, Sec. 17, T139N, R96W, Stark County, North Dakota.

 

Figure 2. Examples of core from the Government Taylor A-1. The core from a depth of 7,948 ft. (left) has a strong reddish hue that suggests that organic matter in this rock has been oxidized. The total organic carbon (TOC) in this sample is only 0.21%, indicating poor source rock quality. The dark gray to black core from the depth of 7,977 ft. (right) is an excellent, thermally mature, source rock with a TOC of 11.25%, a hydrogen index of 669 and a T_{max} of 446^{o}C. Width in photographs represent 3.25 inches of core.

generation is at its most intense. This temperature range, and the corresponding burial depths, is called the "oil window."

Another important consideration related to the burial history of a potential source rock is when the source rock entered or passed through the oil window. This is particularly important when the rocks that encase the source rock are too impermeable to allow generated oil to escape. When this happens pressure within the system builds up until fluids are either injected into the pore space of the surrounding rocks or the rocks fracture, releasing the trapped fluids. In either case, abnormally high pressure accumulates within and close to the source rocks. If the oil accumulation is encased in perfectly impermeable rock then pressures within the accumulation could persist for indefinite periods of time. However, in the absence of perfect impermeability, over-pressured conditions could be maintained as long as the source rocks are in the oil window where maturation and expulsion continuously recharges the system.

The question as to what constitutes a reservoir rock is evolving rapidly. This is primarily due to advances in drilling and completion technologies that has transformed yesterday's tombstone (rock with very little permeability) into today's highly productive reservoir. The ability to engineer a reservoir from almost any oil-

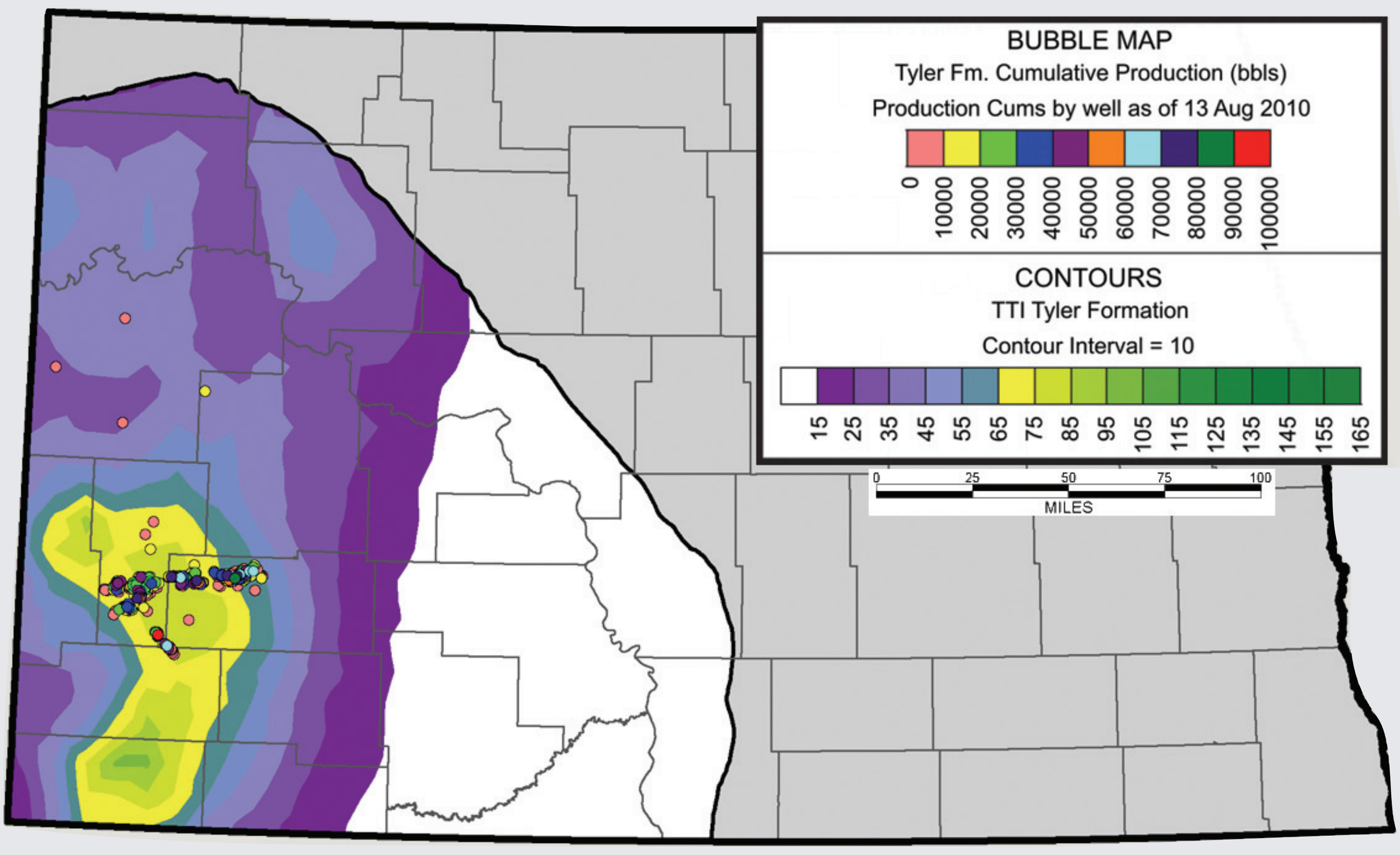

Figure 3. Index map of North Dakota showing the extent of the Tyler Formation. Areas in which the Tyler Formation are absent are in gray (modified from Anderson, 1974). The Time-Temperature Index calculated for the Tyler Formation (Lopatin, 1971; Waples, 1980) is keyed to the color bar in the upper right corner of the map. A TTI of 15 is the minimum level of maturation that could generate oil. A TTI of 75 corresponds with a level of maturation that could result in peak oil generation. Cumulative production statistics (barrels of oil) from the North Dakota Industrial Commission, are shown by the color of the circles centered on the wells that have and/or are producing oil from the Tyler Formation.

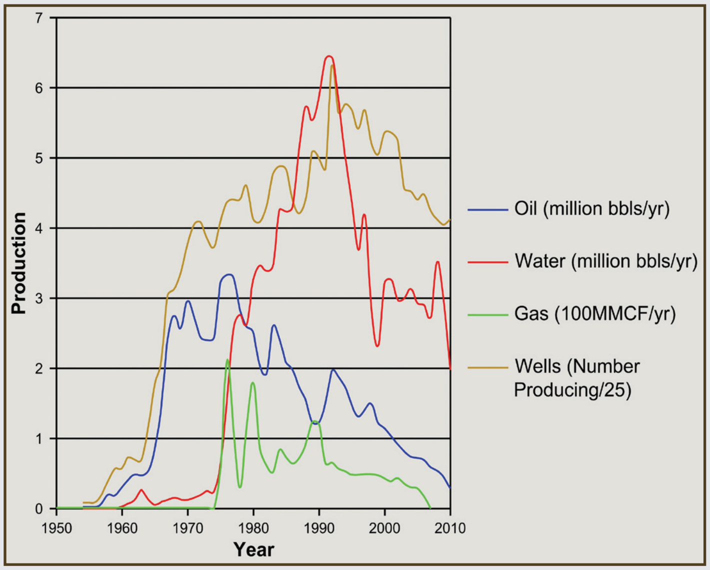

Figure 4. Annual production statistics for the Tyler Formation in North Dakota starting in 1954 and running through August 2010.

bearing formation may well be realized within the foreseeable future.

The Tyler Formation

The Tyler Formation is the basal unit of the Minnelusa Group that together with the overlying Permian Opeche, Minnekahta, and Triassic Spearfish Formations makes up the Absaroka Sequence (fig. 1). The Tyler Formation consists of interbedded meter- to submeter-scale beds of shale, siltstone, limestone, local sandstone lenses, thin coal and, near the top, anhydrite-bearing red beds. In general, the Tyler shoals upward from dark carbonaceous shale and limestone at the base to reddish-hued shale, siltstones, dolostones and sandstones near the top. Faunal evidence indicates that the Tyler Formation is between 318.1 and 306.5 million years old (Pennsylvanian) and that deposition occurred in a deltaic setting that included offshore marine to nearshore, terrestrial, coal swamp environments (Grenda, 1977). The clastic sediments of the Tyler Formation originated in highlands south of the Williston Basin and spread over the eroded Mississippian surface that was flooded during the initial advance of the Absaroka Sea (Gerhard and Anderson, 1988). During this time the Williston Basin was situated in the tropics so that as the Absaroka Sea advanced and sediment supplies consequently diminished, these shallow marine waters generated huge amounts of organic matter that probably included Type II and maybe Type I kerogen. This material accumulated and is preserved in the various marine shales present in the Tyler Formation. The coals deposited just above sea level in the Tyler also contain significant amounts of organic carbon that is probably preserved in the form of Type III kerogen. The contact between the Tyler and the overlying Amsden Formation is gradational and may be difficult to identify, especially along the eastern margin of the Tyler where key marker horizons are absent.

Probably the most conspicuous aspect of the Tyler Formation is the distinct reddish color of the upper portion of the formation (fig. 2). Ziebarth (1972) thought that the reddish color was caused by iron that was oxidized by ground water shortly after deposition. Dow (1974) agreed noting that not only was the color of the formation influenced by oxidation, but that oxidation also destroyed much of the previously deposited organic matter. Dow suggested that the oil potential of the Tyler Formation should be directly related to the remaining thickness of the organic-rich, dark gray or black shale, most commonly found in the lower portion of the formation.

The Tyler Formation consists of a complex vertical distribution of rock types similar to other time-equivalent Pennsylvanian sections. The complex stacking patterns found in many Pennsylvanian rocks are often explained through various combinations of episodic sediment influx and basin subsidence, all within a global framework of frequently changing sea levels (Wilson, 1975).

The Tyler Formation covers roughly the southwestern third of North Dakota and extends to the west into Montana and to the south into South Dakota (fig. 3). The Tyler to the north and east pinches out along a subcrop formed by a pre-Mesozoic unconformity (Anderson, 1974). The maximum thickness of the Tyler is about 270 feet and is situated within a poorly defined depocenter in McKenzie County.

There is one significant difference between the depositional history of the Tyler Formation and the Bakken Formation. Deposition of the Tyler Formation occurred at or very near the surface and in part included terrestrial environments directly in contact with the atmosphere. As a result, organic matter in the Tyler Formation may have been, to some extent, modified by

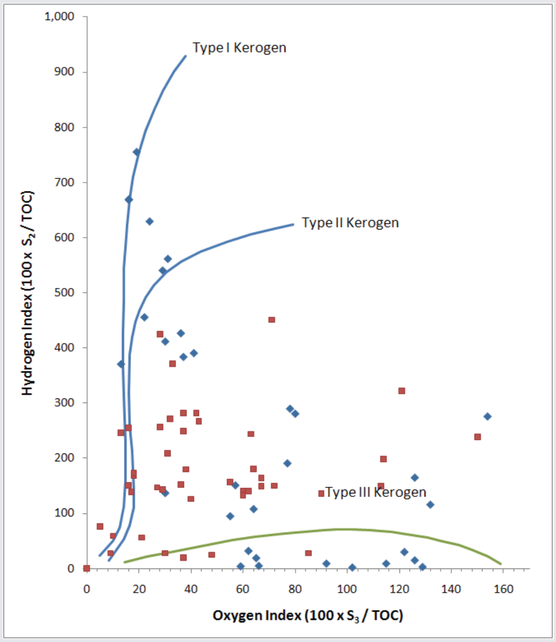

Figure 5. A modified Van Krevelen diagram that classifies kerogen on the basis of the Hydrogen Index (HI) and Oxygen Index (OI) derived from Rock Eval pyrolysis data. The blue diamonds represent the data from the Government Taylor A-1 (NDIC # 4627, SE¼ SE¼, Sec. 9, T139N, R103W) and the red squares refer to data from the State of North Dakota #41-36 (NDIC #: 4789, NE¼ NE¼, Sec. 36, T137N, R100W). These data suggest that kerogen within the Tyler Formation includes oil-prone Type I and Type II, gas-prone Type III as well as mixtures of both oil- and gas-prone kerogen.

oxidation. Over most, if not all, of its extent, the Bakken Formation was never directly exposed to subaerial conditions, so there was much less oxidative degradation of the accumulated organic matter before burial. The difference in the degree of oxidative degradation of organic matter could make the direct comparison of the two formations difficult and should be done with caution.

Oil production from the Tyler Formation was first established early in 1954 from the Dan Cheadle Unit #1 (NDIC #: 518, SE¼ NW¼, Sec. 9, T139N, R100W) drilled by Amerada-Hess and Northern Pacific in the Fryburg Field. This well initially produced 117 barrels (bbls) of oil per day with little water and no gas from a depth of 8,271 to 8,278 feet. The well was fraced with a 7,600 gallon diesel-sand slurry followed by a 3,000 gallon gel-sand mixture. The well was swabbed back and began to flow. According to the North Dakota Industrial Commission (NDIC) the Dan Cheadle Unit #1 was plugged and abandoned in 1974 after producing 74,691 bbls of oil and 13,156 bbls of water from the "Tyler pool."

As of August 2010 the Tyler Formation has produced over 83 million bbls. Tyler production peaked in 1976 when over 3.3 million bbls of oil were produced from 109 wells (fig. 4).

Oils from the Tyler tend to have lower gravities (Mean = 34.6^{o} API), higher viscosities (25 cp @ 100^{o}F), and more paraffin (Average = 29.5 wt. %) than other oils in the Williston Basin (North Dakota Geological Survey, 2002). Williams (1974) found that these oils are unique to the Tyler Formation and Dow (1974) concluded that the oil produced from the Tyler was self-sourced because of the similarity between the produced oils and the oil present in the shales.

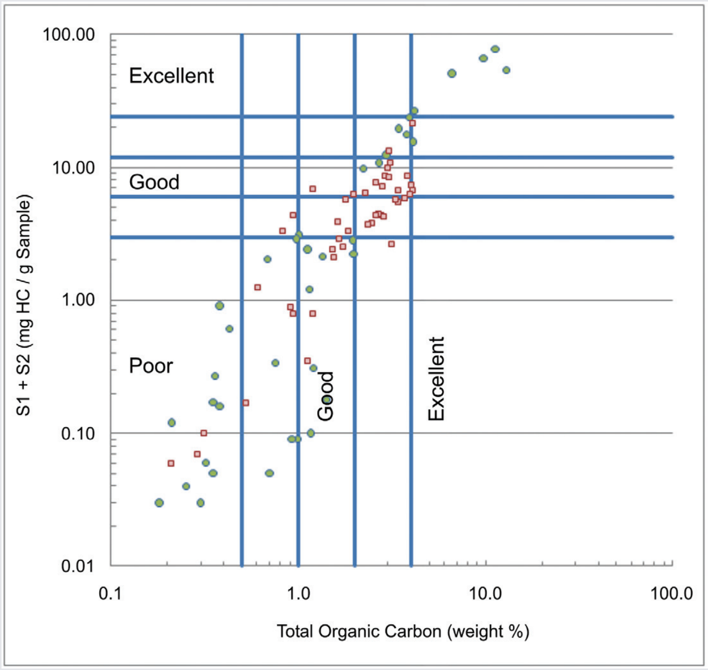

Figure 6. A kerogen quality diagram (Dembicki, 2009) constructed from the Total Organic Carbon (TOC) versus the mass of existing (S1) and potential (S2) hydrocarbons contained in samples of the Tyler Formation. The samples are from the Government Taylor A-1 (green circles) and the State of North Dakota #41-36 (red squares).

The organic geochemistry of the Tyler Formation is poorly documented. Only two wells have data on file with the NDIC that can be used to evaluate how much, what type, and how mature the organic carbon in the Tyler Formation is. The two wells are: Mule Creek Oil Company's Government Taylor A-1 in eastern Golden Valley County and Shell Oil Company's State of North Dakota #41-36 in western Billings County. Both wells are located close to established production and appear, on the basis of the Time Temperature Index, to be within the oil window (fig. 3).

A total of 82 samples from these two wells were analyzed by Rock Eval pyrolysis. Rock Eval pyrolysis measures the mass of oil present in a sample (S1) as well as the mass of kerogen that is capable of generating oil (S2). The compounds measured as S1 and S2 consist primarily of hydrogen and carbon. The total mass of S2 relative to the total amount of organic carbon in the sample (TOC) approximates the amount of hydrogen in the kerogen that is bonded to carbon. The ratio (100 X S2)/TOC is called the Hydrogen Index or HI. Rock Eval also measures the mass of carbon dioxide produced during pyrolysis. The amount of carbon dioxide generated during pyrolysis (S3) relative to the total organic carbon content (TOC) approximates how much of the carbon present in a sample's kerogen is bonded to oxygen. The ratio of (100 X S3) to TOC is called the Oxygen Index or OI. The Hydrogen Index and Oxygen Index taken together can be used to classify kerogen into types that are prone to generating oil (Type I), oil and gas (Type II) or gas only (Type III). Figure 5 shows that the samples collected from the Tyler Formation include kerogen that is oil-prone (Type I or Type II), gas-prone (Type III) and mixtures of these types. The range of kerogen types present in the Tyler Formation is in marked contrast to the Bakken Formation. Kerogen in the Bakken Formation rarely contains enough organically bound oxygen to be classified as Type III (Nordeng et al., 2010). The oxygen-bearing organic compounds that differentiate Type III kerogen from Types I and II are probably derived from the preserved remains of land plants that make up the thin coals in the Tyler Formation.

Over half of the samples analyzed contain good to excellent amounts of total organic carbon (TOC) with over one-third of the samples containing kerogen with good to excellent quantities of hydrogen-rich (Type I and/or Type II), organic carbon (fig. 6). The level of organic maturity of these kerogens, especially the Type I and Type II kerogens, can also be determined by Rock Eval pyrolysis. Specifically, it is given as the pyrolysis temperature that corresponds to the greatest release of S2 hydrocarbons. This temperature, called T_{max}, is frequently used as a measure of organic maturity. As a rule of thumb, a T_{max} of about 435^{o}C marks the lower threshold that corresponds to a level of thermal maturity capable of oil generation. Most of the samples analyzed have T_{max} values within the range expected for oil generating source rocks (fig. 7).

The Time-Temperature Index map (TTI) of the Tyler Formation (fig. 3) indicates that, based on modern heat flow measurements and basin subsidence histories derived from stratigraphic thicknesses, a significant part of the Tyler Formation within the Williston Basin should be capable of generating oil. The organic maturation (T_{max}) measurements from the Government Taylor #A-1 and the State of North Dakota #41-36 as well as all of the known Tyler production

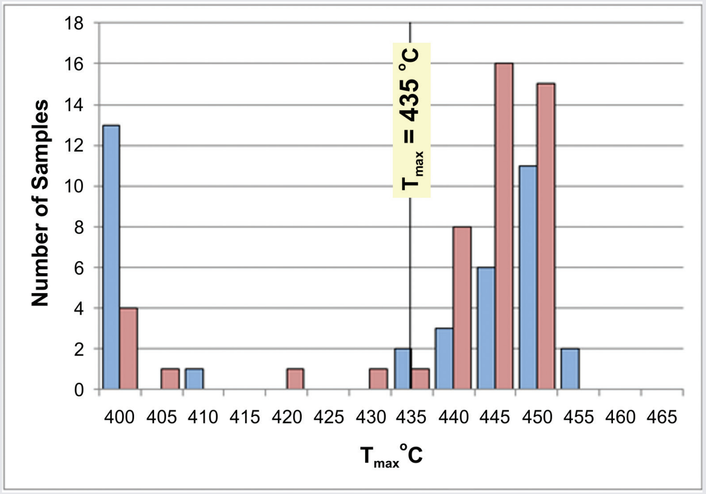

Figure 7. A frequency diagram showing that most of the samples of the Tyler Formation collected from the Government Taylor A-1 (red), and the state of North Dakota #41-36 (blue) have been thermally matured beyond the threshold that marks the onset of oil generation (T_{max}~435°C).

coincide with Time-Temperature Indices that predict a level of thermal maturity that should generate oil. The TTI map is only capable of estimating the thermal maturity of a particular horizon and does not include any reference to kerogen quality. It is only the coincidence of a favorable thermal history with a high quality kerogen that should be considered potentially productive.

Hydraulic isolation is another key element that Schmoker (2002) attributed to basin-centered petroleum accumulations. Meissner (1978) recognized the importance of over-pressured conditions in the Bakken Formation in the Williston Basin. This occurs because the rocks that encase the source beds lack sufficient permeability to allow petroleum generated within the source beds to escape and migrate away. As a result, pressures within the source beds and associated reservoir rocks exhibit abnormally high or low formation pressure relative to the pressure expected in a reservoir that is in hydraulic communication with the overlying rocks. The "expected" pressure usually refers to the "hydrostatic condition," which is equal to the pressure exerted by a column of water that extends from the surface to the depth that the pressure is measured. When this is the case, the ratio of the formation pressure to the depth of the formation is a constant known as the hydrostatic gradient. The hydrostatic gradient varies depending on the amount of dissolved material in the water from 0.43 psi/ft. for fresh water to 0.49 psi/ft. for a salt saturated brine. Therefore, abnormally low or high pressure would yield hydraulic gradients (pressure/depth) that lie outside this range.

Modestly over-pressurized reservoir conditions in the Tyler Formation were apparently present in several fields prior to production (Nordeng and Neshiem, 2010). Over-pressurized conditions suggest that oil generation has been intense enough to "charge" the formation and that the rocks that encase the Tyler are too impermeable to allow the over-pressure to dissipate. This situation indicates that the Tyler Formation is, at least partially, hydraulically isolated, and tends to confirm Dow's argument that the oil present in the lenticular sandstone reservoirs of the Tyler Formation came from the surrounding shale.

The limited data available today suggest the Tyler Formation is a regionally extensive unit that may contain good to excellent quantities of oil-prone kerogen that is sufficiently mature to generate oil within a hydraulically compartmentalized environment. If so, then the Tyler Formation possesses the elements needed to qualify as a basin-centered petroleum accumulation. However, even though the Tyler Formation may be within the oil window on a regional scale, the amount and type of organic matter that could be converted into oil or gas is largely unknown. To address this question the North Dakota Geological Survey is undertaking a program of sampling and analysis that will provide a picture of the regional distribution of organic carbon (TOC) as well as the types of kerogen that are present in the Tyler Formation.

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