Review of Oil Families and Their Petroleum Systems of the Williston Basin[1]

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1. Manuscript received March 6, 2012; Accepted May 7, 2012
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ABSTRACT

The petroleum system concept was first applied in 1974 (Dow/Williams) to identify three oil systems in the Williston Basin, and recent studies have expanded the number to at least nine. This paper reviews the petroleum geochemistry, oil-oil, and oil-source correlations of the oil systems of the Williston Basin, providing a new perspective and some new findings. Petroleum systems with a known source (documented oil-source correlation) include the Red River (Ordovician), Winnipegosis (Devonian), Bakken (Devonian-Mississippian), Madison (Mississippian), and Tyler (Pennsylvanian) systems. Petroleum systems with an identified source rock but no documented oil-source correlation are considered hypothetical and include the Winnipeg (Ordovician), Duperow (Devonian), and Birdbear (Devonian). The Deadwood (Cambrian-Ordovician) petroleum system is speculative because a good oil-prone source rock has not been identified. The stratigraphic distribution of the oil families from each system is generally limited to the same formation from which they were sourced due to efficient seals and a paucity of vertical migration pathways, but some notable exceptions do occur.

Oil bulk properties such as API gravity, sulfur content, and pour point are much underutilized in the recent geochemical literature and are found to be useful here in differentiating oil families. The Red River petroleum system has two oil families that can be differentiated based on pour point. The oils in the Madison petroleum system can be divided into two families based on API gravity-sulfur content relationships, with one family derived from Type II-S kerogen and the other family derived from Type II kerogen with medium sulfur content. The Tyler petroleum system of the Williston Basin may be distinguished from the Heath-Tyler petroleum system in central Montana based on differences in geology and petroleum geochemistry, with Tyler petroleum system oils having a higher pour point and lower sulfur content.

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Lillis, Paul G., Review of oil families and their petroleum systems of the Williston Basin. *The Mountain Geologist*, v. 50, no. 1, p. 5-31. www.rmag.org

INTRODUCTION

The Williston Basin is a structural basin located in North Dakota, South Dakota, Montana, Saskatchewan and Manitoba that is a major producer of oil and gas (Fig. 1). The petroleum system concept was first applied by Dow and Williams in their classic 1974 papers defining three oil systems in the Williston Basin: Tyler, Bakken, and Winnipeg (Dow, 1974; Williams, 1974). Since then, the petroleum system concept has evolved (Magoon, 1988; Magoon and Dow, 1994), and recent work has defined at least nine oil systems in the basin (Fig. 2). The U.S. Geological Survey (USGS) adopted the concept for their energy resource assessments in 2000, proposing the term "Total Petroleum System" (TPS) to include areas outside of the boundary of a mapped petroleum system where geology suggests that undiscovered petroleum occurrences may exist (Magoon and Schmoker, 2000; Schmoker and Klett, 2003). The USGS completed a resource assessment of the undiscovered oil and gas potential of the United States portion of the Williston Basin in 2008 that was based on the TPS concept (Anna et al., 2008; Pollastro et al., 2008). This paper reviews the petroleum geochemistry, oil-oil, and oil-source correlations of the oil systems of the Williston Basin utilizing bulk and molecular geochemical data available in public databases (National Institute for Petroleum and Energy

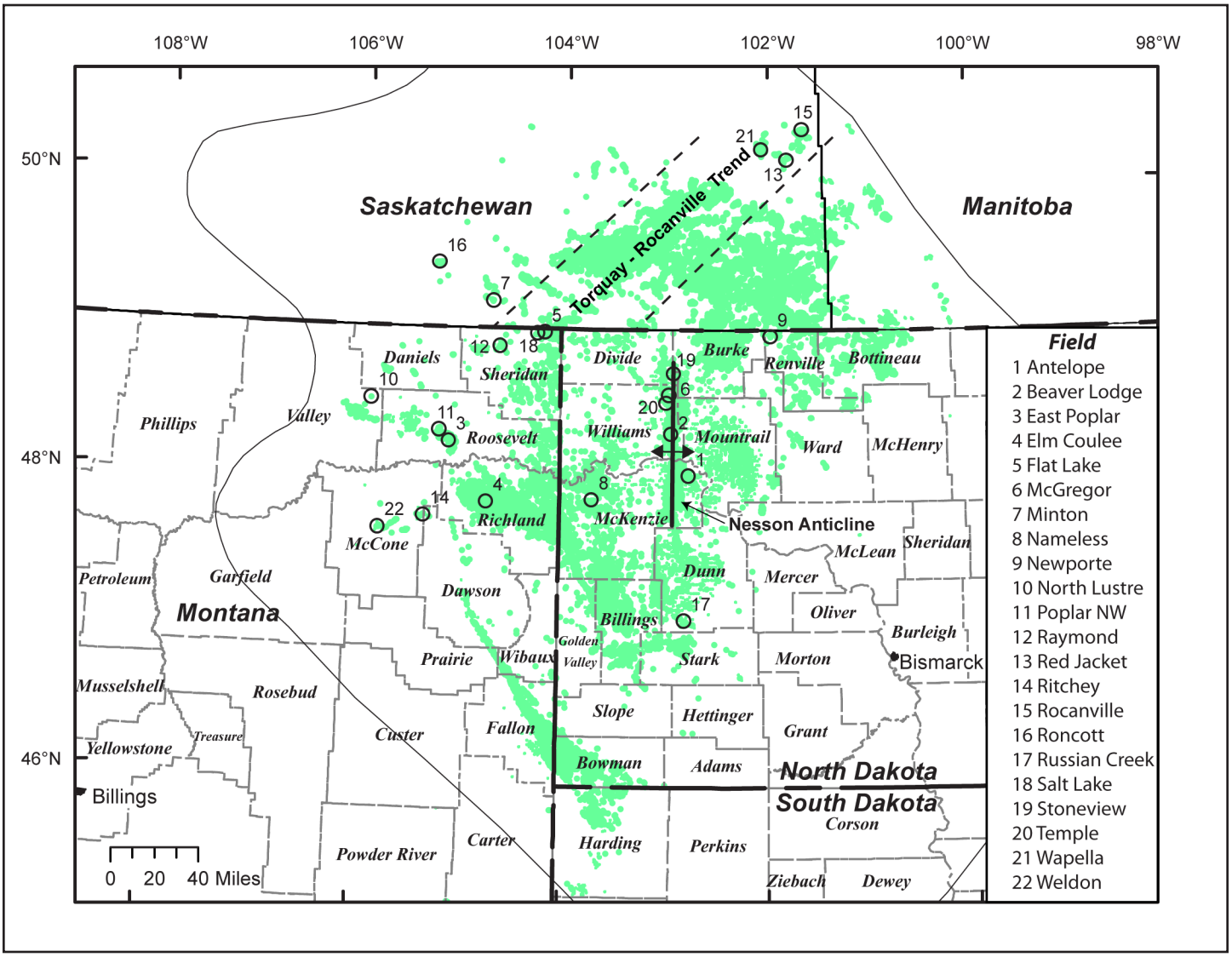


Figure 1. Map of the Williston Basin, United States and Canada, showing basin outline (modified from Kent and Christopher, 1994), counties, Torquay-Rocanville trend (Christopher, 1961; LeFever et al., 1991), Nesson Anticline, and oil fields in green. Numbered fields are listed alphabetically and discussed in the text.

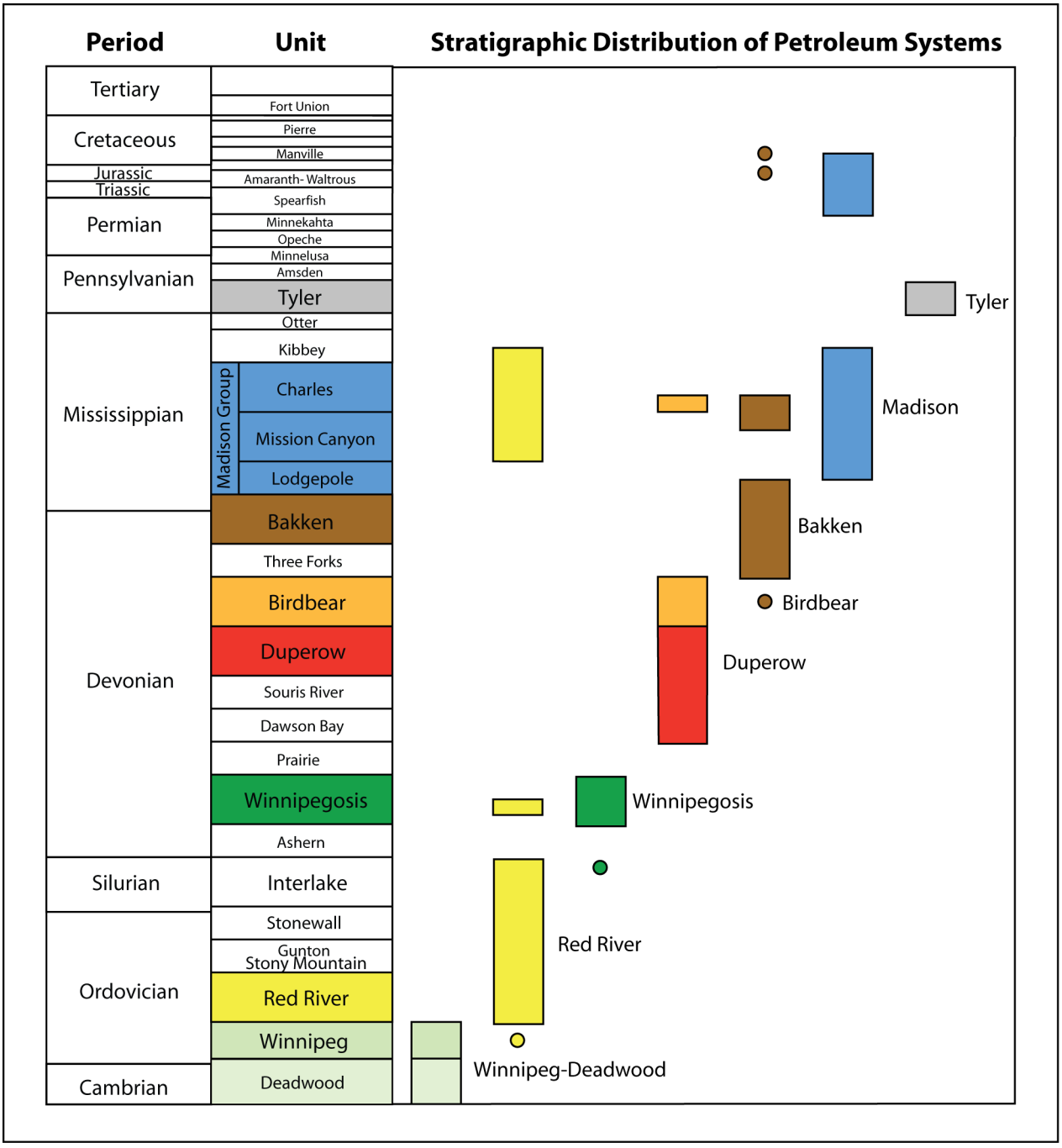


Figure 2. Stratigraphic column of the Williston Basin showing the petroleum systems in color (excluding gas systems) and the stratigraphic distribution of the petroleum system fluids. Circles represent minor occurrences or a single oil analysis. Systems without a documented oil-source correlation are considered hypothetical and include the Winnipeg, Duperow, and Birdbear. The Deadwood petroleum system is speculative because a good oil-prone source rock has not been identified.

Research, NIPER, 1995; North Dakota Geological Survey, NDGS, 2002; USGS, 2008) and data in cited publications. This paper emphasizes bulk oil properties, including American Petroleum Institute (API) gravity, sulfur (S) content, pour point, and stable carbon isotope values, which have been underappreciated in the recent geochemical literature and found to be quite useful here in differentiating oil families. For oil-oil correlation studies, bulk oil parameters have the advantage over molecular parameters (biomarkers) in cases where there is the possibility of mixed oil families, large maturity variations, or migration contamination (Hunt, 1996; Wilhelms and Larter, 2004; Curiale, 2008). However, the best correlation studies utilize both bulk and molecular parameters because bulk properties have the disadvantages of low specificity and nongenetic alteration (such as thermal maturity and biodegradation). Because this paper uses data compiled from multiple laboratories that may have differing analytical methods for a given measured parameter, potential correlation errors are possible though not likely.

API gravity and S content of crude oil are a function of the organic composition and thermal maturity of the source rock and of oil alteration effects such as biodegradation, water washing, and thermal cracking (Evans et al., 1971; Bailey et al., 1973; Granch and Posthuma, 1974; Baskin and Peters, 1992; Hunt, 1996). However, Orr (2001) has shown that the API gravity versus oil S content relationship is a function of the S content of the source kerogen (Fig. 3). Type II-S kerogen (atomic sulfur/carbon values greater than 0.04) is found in source rocks with low clay mineral content such as marine marlstones, whereas Type II kerogen is found in source rocks rich in clay minerals such as marine mudstones.

Pour point is the temperature above which crude oil is liquid. Most oils have pour points less than 10°F (Fig. 4) and thus are liquid at room temperature. Non-biodegraded oils with a high pour point (greater than 30 to 50°F) have a high wax content, typically containing abundant normal paraffins ranging from C_{20} to C_{90+}. Waxy oils have long been known to be derived from terrestrial source rocks with higher land plant organic matter (Hedberg, 1968), but more recent studies suggest that marine and lacustrine source rocks with algal organic matter may also produce waxy oils (Moldowan et al., 1985; Hsieh and Philp, 2001; Philp et al., 2004). Sofer (1984) defined a linear relationship of the stable carbon isotopes ($\delta^{13}C$) of saturated and aromatic hydrocarbon fractions of petroleum that differentiates waxy oil from nonwaxy oil. The canonical variable (CV), defined as the perpendicular distance of a given sample's $\delta^{13}C$ values from Sofer's separating line, is greater

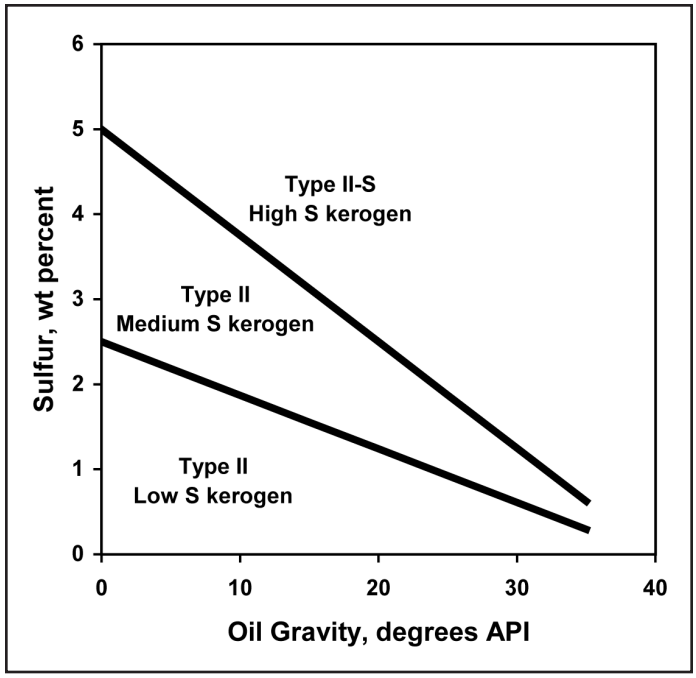


Figure 3. Plot of oil sulfur content versus oil gravity distinguishes the source kerogen sulfur content (Orr, 2001).

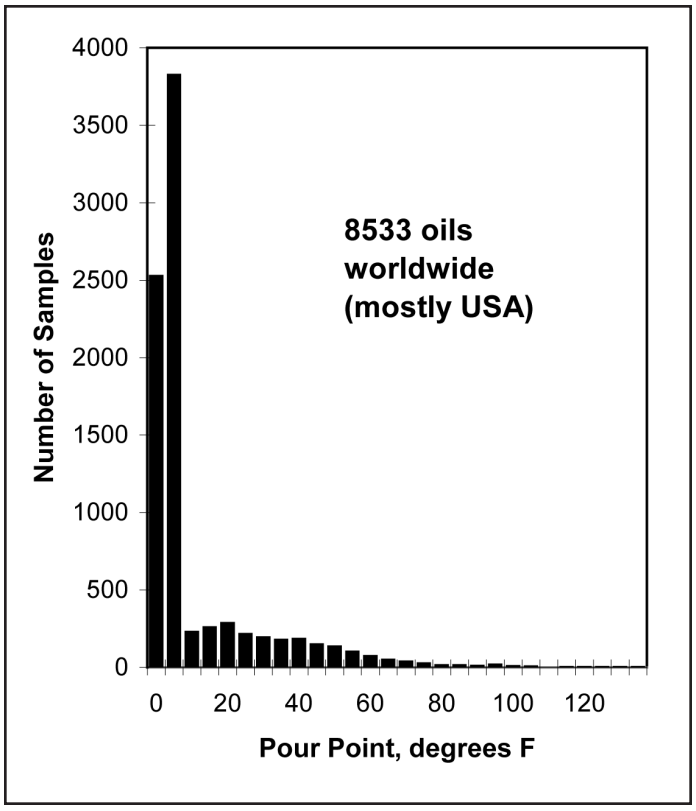


Figure 4. Histogram of crude oil pour point from 8,533 oils worldwide (mostly USA) showing that most oils have pour points below 10°F (data from NIPER, 1995). Non-biodegraded oils with a high pour point (greater than 30 to 50°F) have a high wax content (typically containing normal paraffins ranging from C_{20} to C_{90+}).

than 0.47 for waxy oils and less than 0.47 for nonwaxy oils. Thus both pour point and CV can be used to identify waxy oils and to discriminate oil families.

Source rocks are evaluated based on the quantity, quality, and thermal maturity of the organic matter component. Quantity is measured as total organic carbon content (TOC) in weight percent (wt %), and quality is a function of the hydrogen content of organic matter measured as atomic hydrogen/carbon ratio (H/C) by kerogen elemental analysis. Rock-Eval pyrolysis is an analytical technique commonly used in source rock evaluation (Espitalie et al., 1977; Peters, 1986). A powdered rock sample is heated in an inert gas atmosphere first isothermally, then at a programmed heating rate, yielding volatile organic compounds and other gases that are measured with a flame ionization detector and a thermal conductivity detector. Isothermal pyrolysis distills low molecular weight organic compounds (mostly hydrocarbons from C_1 to about C_{32}), and the products are expressed as S1 in milligrams of hydrocarbons per gram (mg HC/g) rock. Programmed heating distills heavier organic compounds and cracks the kerogen yielding organic compounds, carbon dioxide, and water, with the products measured as S2 in mg HC/g rock and S3 in mg CO_2/g rock. Tmax is the temperature (°C) at which the maximum amount of S2 hydrocarbons is generated, and is a function of kerogen type and thermal maturity. Parameters calculated from Rock-Eval pyrolysis include hydrogen index (HI), expressed as mg HC/g TOC, and oxygen index (OI), expressed as mg CO_2/g TOC, which are measures of kerogen quality. Production index (PI) is calculated as S1/(S1+S2) and is used as a thermal maturity and an oil stain/show indicator. Commonly used source rock evaluation criteria are presented in Peters (1986) and Peters and Cassa (1994). The kerogen types, I, II, and III, are defined by Tissot et al. (1974) based on atomic H/C and oxygen/carbon ratio (O/C), but in many studies the identification of kerogen type is based on Rock-Eval data (HI and OI) as a proxy and should be used with caution (Peters, 1986).

Figure 2 shows the stratigraphic distribution of the identified petroleum systems in the Williston Basin including Deadwood (Cambrian-Ordovician), Winnipeg (Ordovician), Red River (Ordovician), Winnipegosis (Devonian), Duperow (Devonian), Birdbear (Devonian), Bakken (Devonian-Mississippian), Madison (Mississippian), and Tyler (Pennsylvanian). Two gas systems, Pierre (Cretaceous) and Fort Union (Paleocene), have also been identified in the Williston Basin but are not discussed in this paper (see Anna, 2011 for more details). The stratigraphic distribution of the oil families from each system is generally limited to the same formation from which they were sourced due to efficient seals and a paucity of vertical migration pathways, but some exceptions do occur and will be discussed. This paper is focused on the characteristics, distribution, and origin of the oil families in the basin. Other elements of the petroleum system including seal, overburden rock, timing of generation, and trap formation are beyond the scope of this paper. For a detailed discussion of geology, critical TPS elements, TPS boundaries, and assessment units, see Anna (2011), Gaswirth et al. (2011), and Pollastro et al. (2011).

WILLISTON BASIN PETROLEUM SYSTEMS

Deadwood Petroleum System

A unique oil family has been produced from the Upper Cambrian-Lower Ordovician Deadwood Formation of the Newporte Field in Renville County, North Dakota (Zumberge, 1983; Fowler et al., 1998; Jarvie, 2001). Operators have also tested gas, condensate, and light oil from the Deadwood Formation from the Nesson Anticline area of North Dakota (Fig. 1). The oil from Newporte Field is a low S (less than 0.4 wt % S), moderate gravity (about 30° API), waxy oil (NDGS, 2002) similar in some respects to oils produced from the Ordovician Winnipeg Group in the Canadian Williston Basin (Smith and Bend, 2004). The dark-gray marine shale in the Deadwood Formation has been suggested to be the source of petroleum produced from the Newporte Field (Meissner et al., 1984; Peterson, 1988; Peterson, 1996; Jarvie, 2001) although Castaño et al. (1994) proposed that the source of the Deadwood oil is a shale unit within the Ordovician Winnipeg Group. Zumberge (1983) and Leenheer and Zumberge (1987) suggested a younger source for the Deadwood oil based on the oil containing higher plant biomarkers (which evolved since the Silurian). Fowler et al. (1998) proposed that the biomarkers in the oil indicate a lacustrine source.

Based on available TOC data, the source potential of the Deadwood Formation appears to be poor; Arneth (1984) reported TOC values from 0.04 to 0.35 wt %, and Seibel and Bend (2000) reported TOC values up to 0.8 wt %. Arneth and Matzigkeit (1986) reported one Deadwood Formation sample with an atomic H/C ratio of 1.24 interpreted to be Type I or II kerogen. However, until a potential source rock with higher TOC values (immature rocks with greater than 2 wt % TOC) is found, a Deadwood petroleum system is speculative.

Winnipeg Petroleum System

Oils produced from the Middle Ordovician Black Island Formation of the Winnipeg Group in the Canadian Williston Basin are a distinct family of waxy, high gravity (40-54° API) oils derived from an unknown marine shale source (Smith and Bend, 2004). In the U.S. Williston Basin, Win-

nipeg Group production is mostly gas and condensate but NDGS (2002) reports one oil from Newporte Field with gravity and S values similar to Deadwood reservoired oils from the same field (28.9° API, 0.16 wt % S). Jarvie (2001) correlated his W1 oil sample from a Winnipeg Formation production test in a Russian Creek Field well (Dunn County, North Dakota) (Fig. 1) to the oils from the Ordovician Red River Formation.

The Winnipeg Group was first proposed to be the source of oils produced from the Ordovician Red River Formation (Williams, 1974), but subsequent studies refuted this correlation and found that Red River oils are self-sourced (Brooks et al., 1987; Osadetz et al., 1992). Williams (1974) reported lean TOC values (0.05 to 0.74 wt %) from the Winnipeg Group in the U.S. Williston Basin. Osadetz and Snowdon (1995) reported TOC values ranging from 0.21 to 1.25 wt % and HI values ranging from 368 to 807 mg HC/g TOC from the Icebox Formation of the Winnipeg Group in Canada. However, one outlier has a TOC value of 10.41 wt % with a HI value of 924 mg HC/g TOC. The average values of TOC and HI of this dataset including the outlier (11 samples) are 1.55 wt % and 519 mg HC/g TOC, respectively (previously reported by Osadetz et al., 1992). Jarvie (2001) reported an average TOC of 1.68 wt % and average HI of 420 mg HC/g TOC from the Winnipeg in Hettinger and Phillips counties, North Dakota and Montana, respectively. Seibel and Bend (2001) reported that the Icebox Formation in southern Saskatchewan has TOC values that range from 1.0 to 11 wt % with HI values from 300 to 800 mg HC/g TOC, and Type I and Type II kerogen.

The Winnipeg petroleum system is hypothetical because there is no definitive oil-source correlation (Bend et al., 2005). The Icebox Formation of the Winnipeg Group is the most likely source because the unit has TOC values up to 11 wt % and has oil-prone kerogen (Seibel and Bend, 2001), and the main reservoir, Black Island Formation, immediately underlies the Icebox Formation. For the purposes of the USGS petroleum resource assessment of the U.S. portion of the Williston Basin in 2008, the Winnipeg-Deadwood TPS consists of source rocks within the Winnipeg Group and possibly the Deadwood Formation and petroleum found in both Winnipeg and Deadwood reservoir rocks (Anna et al., 2008; Anna, 2011).

Red River Petroleum System

The Red River oil family was first identified by Williams (1974) as "Type I" oils. This oil family was subsequently confirmed in other geochemical studies (Thode, 1981; Zumberge, 1983; Leenheer and Zumberge, 1987; Brooks et al., 1987) and was recognized as having a distinct Ordovician geochemical signature believed to be derived from kukersite, a kerogenite dominated by the alga *Gloeocapsomorpha prisca* (Reed et al., 1986; Hoffmann et al., 1987; Longman and Palmer, 1987). The gas chromatogram signature is characterized by an odd carbon number dominance in the C_9 to C_{19} n-alkanes and unusually low concentrations of C_{20}+ n-alkanes and acyclic isoprenoids, particularly pristane and phytane. Red River oils have a low S content ranging from zero to 0.6 wt % and display a wide range of maturities reflected in oil gravities ranging from the low 20's to the high 50's (Thode, 1981; NIPER, 1995; Jarvie, 2001; NDGS, 2002; USGS, 2008).

The Red River oil family is mainly produced from the informally named A through D zones (Sippel, 1998) within the upper Red River Formation, but the oil family is also found in the Ordovician Stony Mountain (Jarvie, 2001), Silurian Interlake (Williams, 1974; Jarvie, 2001), and Devonian Winnipegosis (Williams, 1974; Zumberge, 1983; Leenheer and Zumberge, 1987; Osadetz et al., 1992) formations and possibly in the Ordovician and Silurian Stonewall Formation (Fig. 2). Mixed Red River and Madison oil families have been identified in the Mississippian Kibbey Formation (Weldon Field) and Madison (Richey Field) reservoirs, McCone County, Montana (Williams, 1974; Price and LeFever, 1994; Jarvie, 2001) (Fig. 1).

The variations in the composition of Red River oils likely reflect, in addition to the effects of maturity, contributions from multiple Ordovician organic facies. Grantham and Wakefield (1988) observed 2 to 4 parts per thousand (‰) differences in the stable carbon isotope ($\delta^{13}C$) composition between Red River zones C and D (their Table 1). In North Dakota, the composition variations are stratigraphically controlled in that low wax (low pour point) oils are predominantly produced from zones C and D of the Red River Formation, whereas high wax (high pour point) oils are produced predominantly from zone B of the Red River Formation, and Stonewall, Stony Mountain (Gunton Member), and Silurian Interlake Formation reservoirs (Fig. 5). Compared to other Red River oils, one waxy Red River oil sample from Dunn County, North Dakota (Zumberge, 1983; Longman and Palmer, 1987) has a relatively low $\delta^{13}C$ saturated hydrocarbon value (-30.4 ‰) and a high CV (0.88) consistent with the waxy nature of the oil (Sofer, 1984). Jacobson et al. (1988) characterized two Ordovician organic facies in Iowa (Assemblages A and B) that they believe explain variations in local Ordovician oil composition. Assemblage A (dominated by the alga *G. prisca*) is the source of low-wax oils with the distinct Ordovician geochemical signature described previously, and Assemblage B (dominated by amorphous kerogen) is the source of waxy oils containing conspicuous amounts of isoprenoids including pristane and phytane. Guthrie and Pratt (1995) correlated two Ordovician oil families in the Illinois Basin to Ordovician Assemblage A and B organic facies (as defined by Jacobson et al., 1988), respectively, based on stable carbon isotope, normal alkane, and bio-

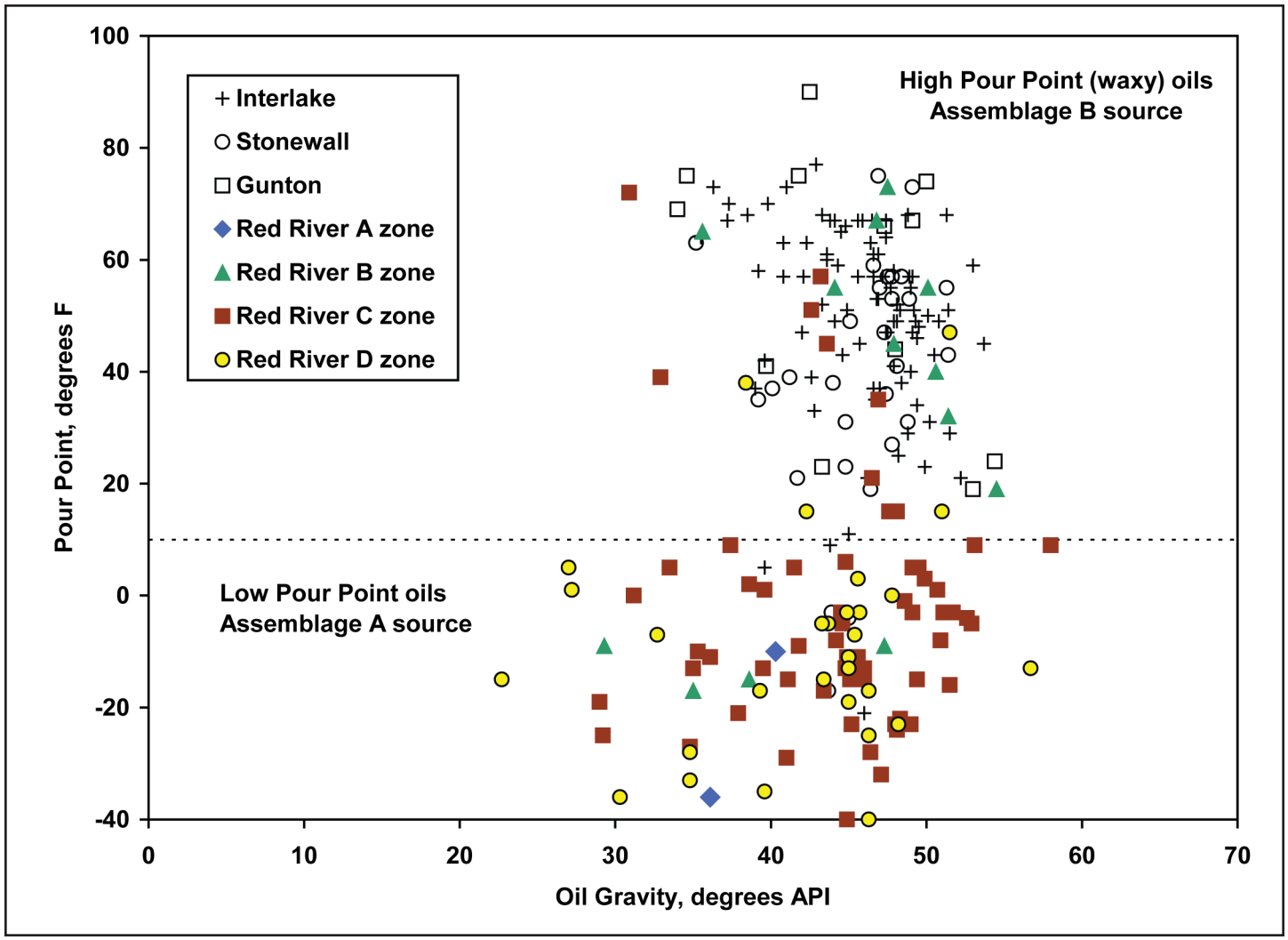


Figure 5. Plot of pour point versus oil gravity for the Red River petroleum system oils from the various reservoirs in North Dakota (data from NDGS, 2002). High pour point (waxy) oils are produced from zone B of the Red River Formation, Stonewall, Stony Mountain (Gunton Member), and Interlake reservoirs. The low-wax and high-wax oil families may be derived from Assemblage A (dominated by the alga *G. prisca*) and Assemblage B (dominated by amorphous kerogen) organic facies, respectively (after Jacobson et al., 1988). Dividing line of 10°F is derived from Figure 4.

marker compositions. Similarly, the Red River petroleum system in the Williston Basin has low-wax and high-wax oil families that might be derived from organic facies like Assemblage A (dominated by the alga *G. prisca*) and Assemblage B (amorphous organic matter), respectively.

Williams (1974) correlated his "Type I" (Red River) oils to source rocks in the Winnipeg Group although he recognized that the Winnipeg TOC values were low, and using Williams' study, Dow (1974) defined the Winnipeg-Red River oil system (petroleum system). However, subsequent geological studies suggested that kerogenites in the lower Red River Formation might be the source of Red River oil (Kendall, 1976; Kohm and Louden, 1978, 1982). Most of the Red River Formation is marine limestone and dolomite with lean TOC values ranging from 0.14 to 0.54 wt % (Williams, 1974), but Kohm and Louden (1982) reported kerogenite beds in the lower Red River Formation with TOC values between 9 and 14 wt %. Kukersite or kerogenite beds in the Yeoman Formation in the Canadian Williston Basin (equivalent to the lower part of the Red River Formation), although quite thin, are organic-rich and consist of Type I organic matter based on HI values and petrographic examination. Osadetz and Snowdon (1995) reported Yeoman kukersite TOC values ranging from 0.55 to 34.94 wt % with an average of 9.07 wt %, and HI values ranging from 131 to 1013 mg HC/g TOC with an average of 728 (62 samples). Fowler et al. (1998) recognized two kukersite facies in the Yeoman in southeastern Saskatchewan consisting of

stromatolitic kukersites with greater than 10 wt % TOC content and HI values greater than 800 mg HC/g TOC, and thicker kukersite beds with lower TOC content (3 to 5 wt %) and HI values (<700 mg HC/g TOC). Stasiuk (1994) identified two types of alginite macerals in the Yeoman Formation consisting of disseminated and stromatolitic varieties of *G. prisca* and an amorphous kerogen with a significant contribution of filamentous alginite, similar to Assemblage A and B organic facies of Jacobson et al. (1988), respectively.

The Red River petroleum system has a known level of certainty because Osadetz et al. (1992) correlated the kukersites in the Yeoman and the Stony Mountain formations to the Red River oil family. The system has low-wax and high-wax oil families with the former most likely derived from Assemblage A (dominated by the alga *G. prisca*) organic facies. The high-wax oils found in the Upper Ordovician Stony Mountain, Ordovician and Silurian Stonewall, and Silurian Interlake reservoirs of North Dakota might be derived from Assemblage B (dominated by amorphous kerogen) organic facies within the Red River or Stony Mountain formations, analogous to the Ordovician organic facies in Iowa (Jacobson et al., 1988) and the Illinois Basin (Guthrie and Pratt, 1995), but the correlation remains to be established.

Winnipegosis Petroleum System

The oils produced from the Devonian Winnipegosis Formation were first recognized as a distinct genetic oil family "D" in the Canadian Williston Basin (Brooks et al., 1988; Osadetz et al., 1991; Osadetz et al., 1992). The correlation of this oil family was expanded to oil production in the U.S. Williston Basin by Obermajer et al. (1998, 2000) and Jarvie (2001). In North Dakota, Winnipegosis oils are waxy (pour points mostly between 37 and 77°F) with a range in gravity from 27 to 51° API and S content from 0.09 to 0.67 wt % (NDGS, 2002). Sulfur and pour point data are not available for Winnipegosis oil production in Montana and Canada.

The Winnipegosis oil family is limited stratigraphically to Winnipegosis reservoir rocks, although there is evidence that some Winnipegosis oil has migrated into the underlying Silurian Interlake (Jarvie, 2001, sample IN4 from Nameless field in McKenzie County, North Dakota) (Fig. 1). The overlying Devonian Prairie Formation is a good regional seal and likely prevented Winnipegosis oil from migrating into younger reservoirs (Dow, 1974; Burrus et al., 1996a). Osadetz et al. (1992) subdivided oil family D into D1 and D2 (based on normal alkane/acyclic isoprenoid values) and proposed that D1 oils were derived from a different facies of the Winnipegosis Formation and migrated up to younger reservoirs (Birdbear Formation and the Ratcliffe interval of the Charles Formation). However, Obermajer et al. (1999) discounted the D1 family correlation to a Winnipegosis source (based on the distribution of C_7 alkanes, C_{13}-C_{30} normal alkanes and steranes) and instead suggested a mixed source or an unidentified source for the D1 family (possibly the Upper Devonian Birdbear Formation).

The richest source rocks in the Winnipegosis Formation are the informally named Brightholme member, which is a basinal facies distal to the platform carbonate and pinnacle reef facies (Osadetz and Snowdon, 1995). They report TOC values ranging from 0.3 to 45.92 wt % with an average of 7.38 wt %, and HI values ranging from 26 to 802 mg HC/g TOC with an average of 515 mg HC/g TOC (94 samples). The platform carbonate facies also contains organic-rich source rocks (Osadetz et al., 1992; Osadetz and Snowdon, 1995; Fowler et al., 2001). The upper and lower member platform facies have TOC values ranging from 0.4 to 3.4 wt % and HI values ranging from 37 to 870 mg HC/g TOC. Wardlaw and Reinson (1971) reported TOC values ranging from 0.12 to 4.96 wt % from the lower member platform facies. Osadetz and Snowdon (1995) believe that the Winnipegosis source rocks contain Type I and Type II kerogen based on Rock-Eval and visual kerogen analyses.

Osadetz et al. (1992) correlated the Winnipegosis oil family D2 to the Brightholme source facies in the Winnipegosis Formation in the Canadian Williston Basin. Thus, the Winnipegosis petroleum system has a known level of certainty. Although most oils produced from the Winnipegosis Formation are likely self-sourced, some Red River Formation-sourced oils have migrated up into Winnipegosis reservoirs in a few cases (Raymond Field in Sheridan County, Montana, Zumberge, 1983; Minton Field, Saskatchewan, Osadetz et al., 1992).

Duperow Petroleum System

A distinct oil family produced from the Upper Devonian Duperow Formation was recognized in the U.S. portion of the Williston Basin (Zumberge, 1983; Leenheer and Zumberge, 1987; Grantham and Wakefield, 1988; Jarvie, 2001). In Canada, very little Duperow Formation production exists. In North Dakota, Duperow oils are generally waxy, moderate gravity, low S oils with average values of pour point, gravity and S content of 55°F, 38.7° API, and 0.2 wt %, respectively, based on 122 samples (NIPER, 1995; Jarvie, 2001; NDGS, 2002). The stable carbon isotope values of three Duperow oils exhibit high CV values (2 to 3.6) consistent with the waxy nature of the oil family (Sofer, 1984).

The stratigraphic distribution of the Duperow oil family beyond the Duperow Formation is unclear because Jarvie (2001) tentatively interprets mixed Duperow oils in Red River, Interlake, and Madison reservoirs (his samples R8,

R10, R12, IN4, M2, M4 and M30). More bulk and molecular geochemical data are needed to confirm these tentative correlations. Oils produced from reservoirs in the Devonian Dawson Bay and Souris River formations are more likely derived from the Duperow Formation because the underlying Devonian Prairie Formation provides a regional seal (Fig. 2) and the oils share similar geochemical properties with Duperow oils. For example, oils produced from Dawson Bay reservoirs have bulk properties (average pour point is 57°F and average S content is 0.2 wt % from 12 analyses; NDGS 2002) similar to Duperow oils. The C_7 hydrocarbon data (Jarvie, 2001, sample DB1) of an oil sample from the Dawson Bay Formation in Temple Field, North Dakota (Fig. 1) correlates with the Duperow oil family.

The Duperow Formation has been suggested as an oil source by Gerhard et al. (1982), Grantham and Wakefield (1988), Peterson (1988), Fowler et al. (2001), and Jarvie (2001). Total organic carbon values reported by Li et al. (1998a) on four Duperow Formation samples from well core in southeastern Saskatchewan are lean (0.34 to 2.15 wt %). However, Duperow samples from eastern Saskatchewan reported by Fowler et al. (2003) have TOC values ranging from 0.15 to 3.43 wt % with HI values ranging from 89 to 544 mg HC/g TOC, and one outlier sample has a TOC value of 47.8 wt % with a HI value of 384 mg HC/g TOC. Tmax values (420 to 437°C) indicate that the samples are immature. Duperow Formation source rocks in the U.S. Williston Basin have been identified by Jarvie (2001), with TOC values averaging 3.02 wt % and HI values averaging 342 mg HC/g TOC. However, no oil-source correlation between the Duperow source rocks and oils has been performed, so the Duperow petroleum system remains hypothetical.

The correlation issue is further complicated by the possibility that other Upper Devonian formations are potential source rocks that may have contributed to the reservoirs of the same age. In a report by Fowler et al. (2003), Dawson Bay samples from Saskatchewan range in TOC from 0.4 to 9.25 wt % with HI values ranging from 82 to 596 mg HC/g TOC, but only four of 21 samples have oil-prone characteristics (TOC > 2 wt % and HI > 250 mg HC/g TOC). Meissner et al. (1984) suggested that the Souris River Formation might be the source of oils in the Duperow Formation. The Souris River Formation in Saskatchewan contains source beds with organic-rich Type I and II organic matter but the beds are very thin and thermally immature (Fowler et al., 2001; Fowler et al., 2003).

In summary, the hypothetical Duperow petroleum system contains waxy low S oils found in the Dawson Bay, Souris River and Duperow reservoirs that might be derived from the Duperow Formation, but more research is needed to prove these correlations or identify separate petroleum systems for the Dawson Bay and Souris River. Due to the uncertainty of the oil-oil correlations within these Upper Devonian reservoirs, the Duperow TPS in the USGS petroleum resource assessment of the U.S. portion of the Williston Basin in 2008 also included oils in the Birdbear Formation (Anna et al., 2008; Anna, 2011).

Birdbear Petroleum System

Several studies have suggested that the Devonian Birdbear Formation in the Williston Basin contains a distinct oil family. Using biomarker (tricyclic diterpanes and steranes) and stable carbon isotope compositions, Zumberge (1983) and Leenheer and Zumberge (1987) identified a distinct oil type from the Birdbear Formation they called "group 4." Osadetz et al. (1992) defined a family of oils in Birdbear and Ratcliffe (interval of the Charles Formation) reservoirs as their oil family D1, and the Birdbear oils in their study were later correlated with six other Birdbear oil samples by Obermajer et al. (1999). Based on fluorescence properties of fluid inclusions, Stasiuk et al. (1998) recognized three types of oil in the Birdbear Formation.

Oils produced from the Birdbear Formation in North Dakota (mostly McKenzie and Williams counties) have fairly uniform bulk properties (low S content and pour point) more suggestive of a single source rather than mixed source; 31 of 38 oil samples have pour points less than 0°F with a mean value of -25°F, and S contents less than 0.25 wt % with a mean value of 0.2 wt % (NDGS, 2002). Similarly, nine oils from the Birdbear Formation in southeastern Saskatchewan have a fairly uniform gasoline-range hydrocarbon and biomarker composition more consistent with a single source (Obermajer et al., 1999).

The Birdbear Formation has long been recognized as a possible oil-prone source rock in the Williston Basin (Gerhard et al., 1982; Arneth and Matzigkeit, 1986; Peterson, 1996; Obermajer et al., 1999). Fowler et al. (2001) reported that the Birdbear in Saskatchewan contains source rocks with Type I kerogen and TOC values up to 6 wt % and Type II kerogen with TOC values up to 17 wt %, but four Birdbear samples they analyzed from the U.S. have no source rock potential (TOC values between 0.2 and 0.6 wt %).

Oils produced from the Birdbear Formation have been suggested to be derived from the Winnipegosis Formation (Osadetz et al., 1992) or the Bakken Formation (Dow, 1974; Brooks et al., 1987; Jarvie, 2001). However, Obermajer et al. (1999) discounted the Birdbear oil correlation to a Winnipegosis source (based on the distribution of C_7 alkanes, C_{13}-C_{30} normal alkanes and steranes) and instead suggested Birdbear oils are a mixture of hydrocarbons from multiple Middle-Upper Devonian sources (although a Birdbear source was strongly suspected). Fowler et al. (2001) believe there is a strong possibility that the Birdbear oils in southeastern Saskatchewan are sourced from the Birdbear

Formation based on similar geochemical characteristics of Birdbear rock extracts and oils produced from Birdbear reservoirs. The Nisku petroleum system, which is the stratigraphic equivalent of the Birdbear Formation, has been identified in east-central Alberta (Creaney et al., 1994). However, without a definitive oil-source correlation, the Birdbear petroleum system in the Williston Basin is considered to be hypothetical.

Bakken Petroleum System

The Upper Devonian and Lower Mississippian Bakken Formation has long been known to be a world-class source rock in the Williston Basin (Murray, 1968; Williams, 1974; Dow, 1974; Meissner, 1978; Schmoker and Hester, 1983; Arneth, 1984; Leenheer, 1984; Price et al., 1984; Webster, 1984; Dembicki and Pirkle, 1985; Osadetz and Snowdon, 1995). In his classic geochemical study, Williams (1974) identified the Bakken as a major source rock for the oils found in Mississippian Madison Group reservoirs (as well as Devonian and Triassic-Jurassic reservoirs) in the Williston Basin, and based on this study, Dow (1974) proposed the Bakken-Madison oil system (petroleum system). The Bakken-Madison petroleum system of Williams (1974) was supported by Thode (1981) who used sulfur isotopes to correlate the Madison oil family to the Lower Member of the Bakken, and by Leenheer and Zumberge (1987) who used biomarkers and stable carbon isotopes to correlate Madison oils to the Upper and Lower members of the Bakken.

Brooks et al. (1987) first recognized the genetic difference between the oils produced from Madison and Bakken reservoirs based on biomarker geochemistry. The low pristane/phytane and diasterane/sterane values and high norhopane/hopane values in the Madison-reservoired oils indicate a carbonate source deposited in an anoxic water column, whereas Bakken-reservoired oils have high diasterane/sterane values indicating an argillaceous source rock. They proposed that the oils found in the Madison are not Bakken-sourced but instead are derived from source rocks within the Madison Group. In addition, they suggested a Bakken source for the oils found in Bakken reservoirs. Grantham and Wakefield (1988) differentiated oils derived from Bakken and Mission Canyon (Madison Group) sources in their study of sterane biomarkers in petroleum. Osadetz et al. (1992) correlated the Bakken-reservoired oils in the Canadian Williston Basin to Bakken source rocks based on biomarker signatures. All subsequent geochemical studies have supported the Canadian Bakken oil-source correlation of Osadetz et al. (1992) (for example, Jiang et al., 2001; Jiang and Li, 2002), and extended the correlation into the U.S. Williston Basin (for example, Price and LeFever, 1992, 1994; Obermajer et al., 1998; Jarvie, 2001).

In addition to biomarker geochemistry, the Bakken oil family can generally be distinguished from the Madison oil family based on S content (Obermajer et al., 2000; Jarvie, 2001). The Bakken oils produced from Bakken and Lodgepole (Waulsortian mounds) reservoirs in North Dakota are moderate to high gravity (26 to 46° API) with low S contents (less than 0.35 wt %) (NIPER, 1995; Jarvie, 2001; NDGS, 2002; USGS, 2008). Madison-sourced oils generally have higher S content (0.2 wt % to over 3.6 wt %). Bakken oils generally have very low pour points (average -25°F based on 40 samples), whereas Madison oils have moderately high pour points (average 38°F based on 570 samples; NDGS, 2002). Numerous studies have also used light hydrocarbons (gasoline range) in conjunction with other molecular parameters to distinguish the Bakken oil family and identify examples of mixing with the Madison oil family (Obermajer et al., 1998; Obermajer et al., 2000; Jarvie, 2001; Jiang and Li, 2002; Chen et al., 2009).

Until Elm Coulee Field in Montana (Fig. 1) was discovered in 2000, Bakken-sourced oil fields were few and limited in size. Bakken oil had been discovered in the 1950s from Bakken fractured shale and Pronghorn Member sandstone (formerly called Sanish) in Antelope Field, North Dakota, and from Middle Member Bakken sandstone in Rocanville and Roncott fields, Saskatchewan (Murray, 1968; LeFever, 1991). Bakken oil was first discovered in Montana in 1970 in the Salt Lake Field, Sheridan County (Hanson and Long, 1991). Since 1987, advances in drilling and completion techniques (horizontal wells and multi-stage hydraulic fracturing) eventually led to significant Bakken discoveries (Elm Coulee Field has an estimated ultimate recovery over 200 million barrels; Sonnenberg and Pramudito, 2009), and the number of wells completed in the Bakken has risen dramatically (less than 130 wells in 1987 to over 4000 wells in 2011).

Although the earliest production of Bakken-sourced oil came from sandstones in the Pronghorn Member (Sanish) and the fractured shales of the Lower and Upper members of the Bakken, most Bakken oil production now comes from the sandstones, siltstones, and dolostones of the Middle Member of the Bakken Formation. In recent years (since 2004) the underlying Devonian Three Forks Formation (Torquay Formation equivalent in part) has become a significant oil producer of presumed Bakken-sourced oil in Manitoba, Saskatchewan and North Dakota (Kreis et al., 2006; Nicolas, 2006; Bottjer et al., 2011; Sonnenberg, 2011). Oil produced from the upper portion of the Three Forks Formation correlates with the Lower Member of the Bakken Formation based on biomarker and stable carbon isotope analyses (John Zumberge, 2012, GeoMark, oral comm.)

In addition to the Bakken and Three Forks reservoirs, Bakken-sourced oil has been identified in other reservoirs ranging from Devonian to Cretaceous (Fig. 2). Brooks et al.

(1987) suggested that oils in the Devonian Birdbear Formation (Nisku Formation equivalent) in southeastern Saskatchewan may be derived from the Bakken, but these oils are more likely derived from source rocks within the Birdbear (Obermajer et al., 1999; Fowler et al., 2001). Jarvie (2001) identified Bakken-sourced oils in the Birdbear (Nisku) Formation west of Poplar Dome in Roosevelt County, Montana. In the U.S. part of the Williston Basin, Bakken-sourced oil is not generally found in Madison reservoirs with a few notable exceptions: mixed Bakken and Madison oil families in North Lustre, East Poplar, Poplar Northwest, Beaver Lodge, McGregor, and Stoneview fields (Burrus et al., 1996b; Jarvie, 2001; Jiang and Li, 2002) (Fig. 1), and Bakken oil in the Waulsortian mounds in the Lodgepole Formation (Montgomery, 1996; Jarvie et al., 1997; Obermajer et al., 2000; Jarvie, 2001). Bakken oil has migrated from mature Bakken source rocks in the U.S. into the immature Bakken reservoirs in the Canadian Williston Basin (Osadetz et al., 1992; Burrus et al., 1996a; Li et al., 1998b; Kreis et al., 2006) and vertically into Madison reservoirs along the northeast striking Torquay-Rocanville trend (Jiang and Li, 2002; Chen et al., 2009). Chen et al. (2009) also identified Bakken-sourced oil in Jurassic (Red Jacket Field) and Cretaceous (Wapella Field) reservoirs along this trend in eastern Saskatchewan (Fig. 1).

The Bakken Formation was defined in the subsurface of the Williston Basin, North Dakota by Nordquist (1953) and subdivided into three informal members: lower and upper member organic-rich mudstones deposited in a restricted marine basin under largely anoxic conditions, and a middle member consisting of various lithologies including sandstone, siltstone, dolomite, and mudstone deposited in a shallow marine environment (LeFever et al., 1991; Smith and Bustin, 2000). Recently the nomenclature has been revised, formalizing the three members and adding the underlying "Sanish" as a fourth member called the Pronghorn Member (LeFever et al., 2011). Numerous studies have documented the organic richness and oil-prone character of the Lower and Upper mudstone members of the Bakken using TOC and Rock-Eval HI, as well as visual kerogen analysis (Table 1). Also summarized on Table 1 are data from the USGS (2008) mostly from studies by the late Leigh C. Price (USGS, Denver, CO). The Upper and Lower members have very similar organic richness (aver-

TABLE 1
Total organic carbon and hydrogen index values of the Bakken Formation, Williston Basin

Member	TOC average	TOC range	HI average	HI range	No. Smpl.	Reference
Undifferentiated	3.84	0.65 - 10.33			26	Williams (1974)
Upper	16.38	0.58 - 24.73			12	Leenheer (1984)
Lower	12.23	6.45 - 17.14			13	Price et al. (1984)
Undifferentiated	11.46	1.80 - 21.82	355	74 - 886	171	Price et al. (1984)
Upper *(immature)*	14.22	6.82 - 21.82	488	170 - 672	27	Price et al. (1984)
Lower *(immature)*	13.43	6.99 - 21.28	518	318 - 886	26	Price et al. (1984)
Undifferentiated	11.33	5.25 - 18.69		82 - 672		Webster (1984)
Undifferentiated	12.2	3.0 - 21.0		96 - 572	42	Muscio et al. (1994)
Upper	17.63	0.41 - 31.89	410	1 - 689	29	Osadetz and Snowden (1995)
Lower	11.77	0.47 - 29.75	399	6 - 827	31	Osadetz and Snowden (1995)
Upper	10	up to 35	565	up to 1050		Smith and Bustin (2000)
Lower	8	up to 20	615	up to 1150		Smith and Bustin (2000)
Upper+Lower+undiff.	13.73	0.11 - 41.92	306	16 -1126	1694	USGS (2008)
Upper	14.37	0.29 - 33.99	318	18 - 803	769	USGS (2008)
Upper *(immature)*	17.08	5.67 - 33.99	510	142 - 773	239	USGS (2008)
Lower	13.26	0.48 - 35.74	289	27 -1126	750	USGS (2008)
Lower *(immature)*	15.05	3.10 - 35.74	491	93 -1126	171	USGS (2008)
Middle	0.26	0.00 - 1.17	231	0 -1400	602	USGS (2008)

TOC, total organic carbon in wt %. HI, hydrogen index in mg HC /g TOC. No. Smpl., number of samples. Smith and Bustin (2000) data are from unpublished Ph.D. dissertation of Smith (1996). See Figure 6 for definition of *immature*.

age immature TOC, upper = 17.08 wt %, lower = 15.05 wt %) and kerogen quality (average immature HI, upper = 510, lower = 491). In contrast, the Middle Member (siltstone) has very low organic carbon content, averaging less than 0.3 wt %.

The kerogen type in the Upper and Lower Bakken members is considered to be mostly Type II, although interpretations are generally inferred from Rock-Eval or visual kerogen data rather than measured atomic H/C and O/C ratios of immature kerogen (Stasiuk et al., 1990; Osadetz et al., 1992; Price and LeFever, 1992; Requejo et al., 1992; Muscio et al., 1994; Osadetz and Snowdon, 1995; Burrus et al., 1996a; Jiang et al., 2001). Jones (1980) reports an atomic H/C ratio of 1.23 (Type II) from immature Bakken kerogen. Arneth and Matzigkeit (1986) report Type II kerogen for the Bakken based on atomic H/C ratios of 1.15 and 1.19 of "mature" samples (H/C diminishes with increasing maturity and hydrocarbon generation). Several studies have proposed that the Bakken Formation contains some Type I kerogen based on Rock-Eval pyrolysis data (Price and LeFever, 1992; Osadetz and Snowdon, 1995; Smith and Bustin, 1996; Stasiuk and Fowler, 2004; Sonnenberg and Pramudito, 2009), which is supported by the Rock-Eval HI versus OI plots of immature Bakken samples in this study (Fig. 6). However, plots of HI versus Tmax shows that the Upper and Lower members of the Bakken Formation generally follow the Type II kerogen maturation trend based on the slope of the data (Fig. 7). The wider band of data in the Lower Member suggests more heterogeneity of kerogen type than the Upper Member. The hydrocarbon generation kinetic distribution (activation energy) derived from Rock-Eval pyrolysis for the Bakken (Upper Member) is consistent with Type II kerogen (Burrus et al., 1996a). In kerogen maceral studies, Leenheer (1984) describes the Upper and Lower members of the Bakken as mostly amorphous kerogen and exinite, which is oil-prone, and the Middle Member as mostly vitrinitic material, which is gas-prone. In the Bakken in Saskatchewan Stasiuk et al. (1990) have identified mostly amorphous kerogen (bituminite), with some marine algi-

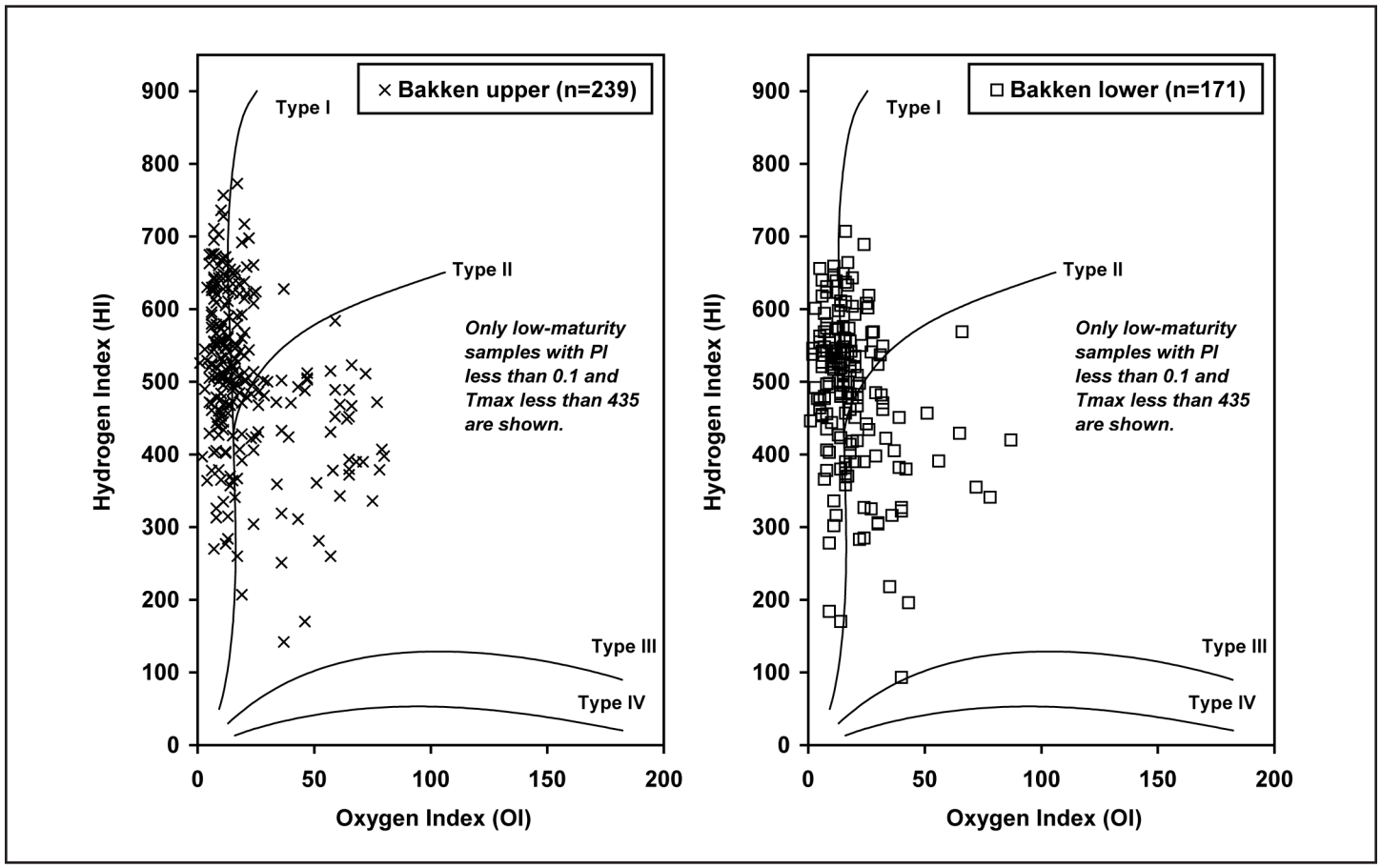


Figure 6. Plots of Rock-Eval pyrolysis hydrogen index (HI) versus oxygen index (OI) of low-maturity samples of the Upper and Lower members of the Bakken Formation, North Dakota and Montana (data from USGS, 2008), showing that much of the Bakken plots on the Type I kerogen curve. Only samples with a Tmax less than 435°C and production indices (PI) less than 0.1 are shown (low-maturity). Kerogen type curves are from Hunt (1996, p. 343).

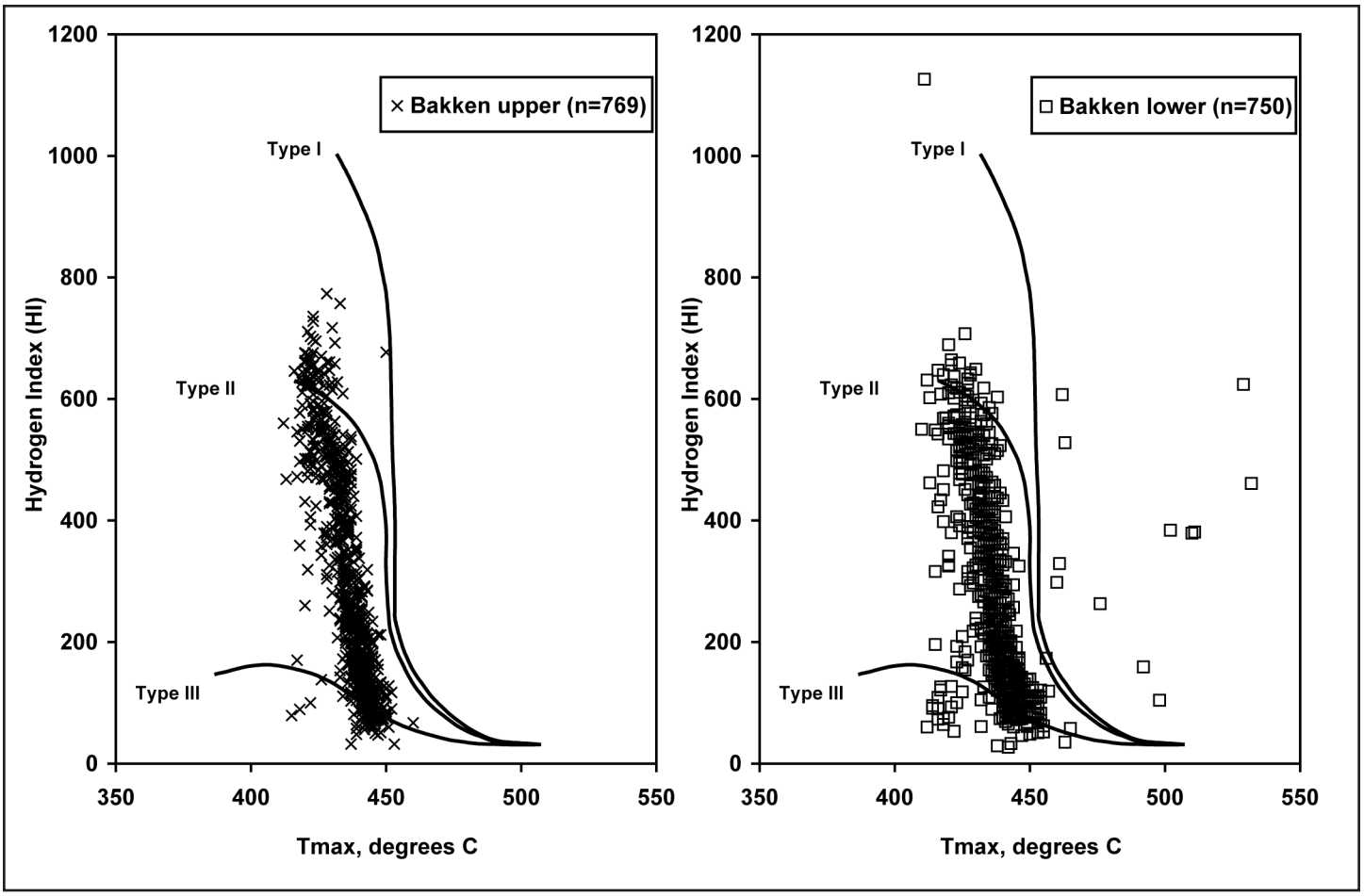


Figure 7. Plots of Rock-Eval pyrolysis hydrogen index versus Tmax of samples of Upper and Lower members of the Bakken Formation, North Dakota and Montana (data from USGS, 2008), showing that the Bakken has a Type II kerogen maturation trend. Samples of all maturities are shown. Maturation lines of kerogen types (Type I, Type II, Type III) are from Mukhopadhyay et al. (1995).

nite (*Leiosphaeridia* and *Tasmanites* planktonic green algae), and lesser amounts of acritarchs, terrestrial sporinite, and minor vitrinite and inertinite. In Canada, Bakken Formation organic facies as defined using macerals, inorganic microfossils, and organic-inorganic microtextures can be distinguished from the Upper Devonian and Lower Mississippian Exshaw Formation, with the former containing deep to intermediate water depth organic facies, and the latter containing siliceous microfossil-enriched and shallow-water organic facies (Stasiuk and Fowler, 2004).

In summary, the Bakken petroleum system consists of world-class source rock (Upper and Lower members of the Bakken Formation) containing Type II kerogen that has generated low S, low pour point, moderate to high gravity oil in the Williston Basin (mostly generated in the U.S. portion of the basin). Bakken-sourced oil is produced throughout the Williston Basin predominantly from the Middle Member of the Bakken Formation, but in recent years the underlying Devonian Three Forks Formation has also become a significant oil producer. In addition, Bakken oil has been produced from the Waulsortian mounds in the Lodgepole Formation in North Dakota, and from Mississippian Madison, Jurassic and Cretaceous reservoirs, mostly in the Canadian Williston Basin.

Madison Petroleum System

The Mississippian Madison Group consists of the Lodgepole, Mission Canyon, and Charles formations (Fig. 2), and accounts for the majority of the historic oil production in the Williston Basin (as of 2011). Oils produced from Madison Group reservoirs were first characterized as a distinct oil family by Williams (1974) who ascribed the source to be the Bakken Formation. Although some early studies supported this oil-source correlation (Thode, 1981; Zumberge, 1983; Leenheer and Zumberge, 1987), all subsequent studies have supported a self-sourced Madison

petroleum system including Brooks et al. (1987), Grantham and Wakefield (1988), Osadetz et al. (1991, 1992, 1994), Price and LeFever (1992, 1994), Obermajer et al. (1998), Peterson (1996), Burrus et al. (1996b), Jarvie and Walker (1997), Obermajer et al. (2000), Jiang et al. (2001), Jarvie (2001), Jiang and Li (2002), Chen et al. (2009), and Gaswirth et al. (2010). A notable exception is the Bakken-sourced oils reservoired in Waulsortian-type carbonate mud mounds in the Lodgepole Formation in the U.S. portion of the Williston Basin (Montgomery, 1996; Jarvie and Walker, 1997; Jarvie et al., 1997; Jarvie, 2001; Gaswirth et al., 2010).

The geochemical composition of Madison oils, although somewhat variable, is characterized by high S content, low pristane/phytane and diasterane/sterane values, and high norhopane/hopane values indicative of a carbonate source rock (Brooks et al., 1987; Osadetz et al., 1992, 1994; Price and LeFever, 1994; Jarvie, 2001). Madison oils are notably paraffinic (Price and LeFever, 1992) with pour points of North Dakota oils averaging 38°F and ranging up to 98°F based on 570 samples (NDGS, 2002). Sulfur content of Madison oils ranges from 0.2 to 3.6 wt % with a range of gravity from 15 to 48° API. The wide variation in Madison oil geochemistry, not only S content but also biomarker and gasoline-range hydrocarbon content, reflects the organic facies variation of source rocks within the Madison Group (Price and LeFever, 1994; Jarvie, 2001; Gaswirth et al., 2010).

In North Dakota, the Mission Canyon and Charles formations are divided into informal units (Fig. 8), and the oils produced from these units have distinct sulfur-gravity trends reflecting local source rocks. Figure 9 shows the sulfur-gravity values of oils from the informal Wayne, Glenburn, Mohall, Sherwood, Bluell, and Coteau intervals of the Mission Canyon Formation indicating a Type II-S kerogen source (Orr, 2001). Figure 10 shows sulfur-gravity values of oils produced from the Charles Formation, and the informal Nesson, Tilston and Landa intervals of the Mission Canyon Formation reflecting locally sourced Type II kerogen with medium sulfur content. Geographically the oils reflecting a Type II-S source are generally found in Mission Canyon reservoirs east of the Nesson Anticline (Fig. 1) and in the Lodgepole, Mission Canyon and Charles formations in the Canadian Williston Basin (Fig. 11).

The stratigraphic distribution of Madison-sourced oils in the U.S. portion of the Williston Basin is largely limited to the Mission Canyon and Charles formations. Oils in Lodgepole reservoirs (Waulsortian mounds) in North Dakota are derived from the Bakken Formation as reflected by their low S content (Fig. 11) and biomarker composition (Jarvie and Walker, 1997; Jarvie et al., 1997; Jarvie, 2001). Significant Madison oil family production also comes from the Permian-Triassic Spearfish Formation in Bottineau County, North Dakota along the northeastern boundary of the

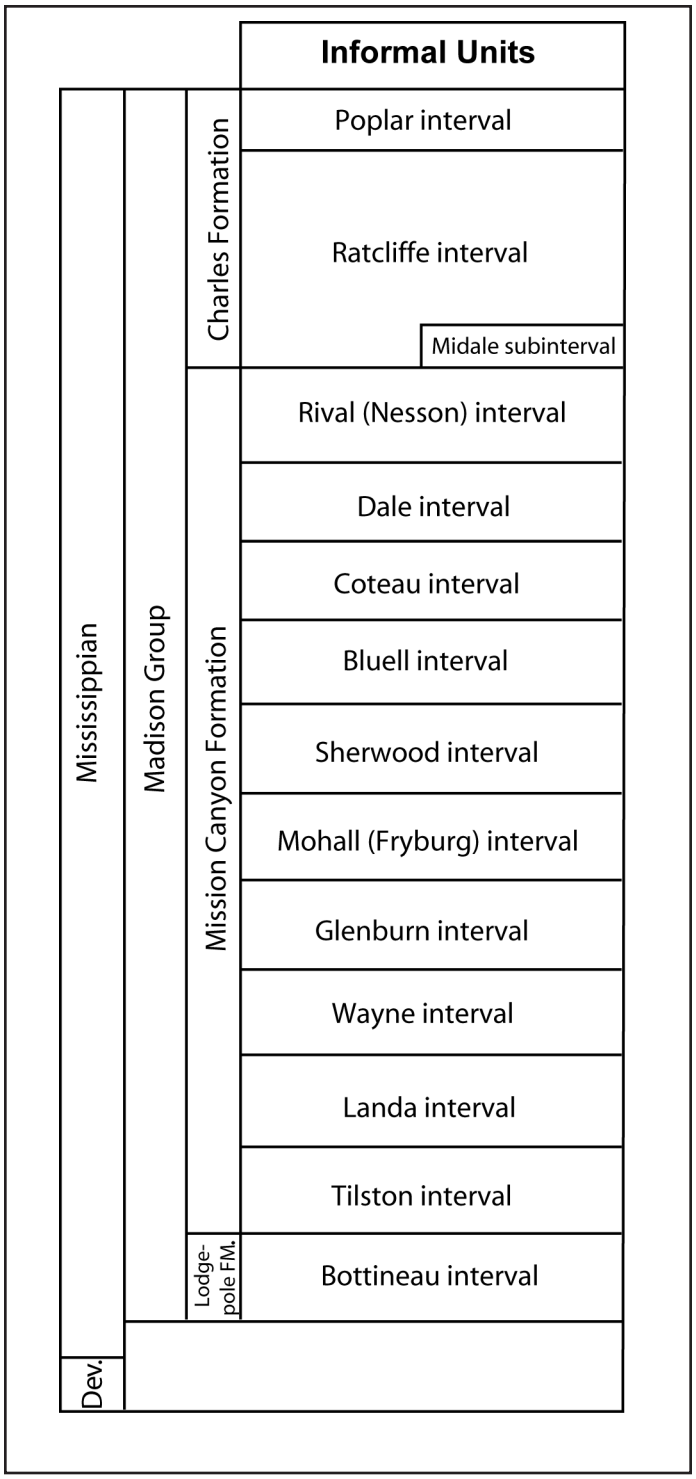


Figure 8. Informal stratigraphic units in the Madison Group, North Dakota. Modified from Hendricks (1988) and Lindsay (1988).

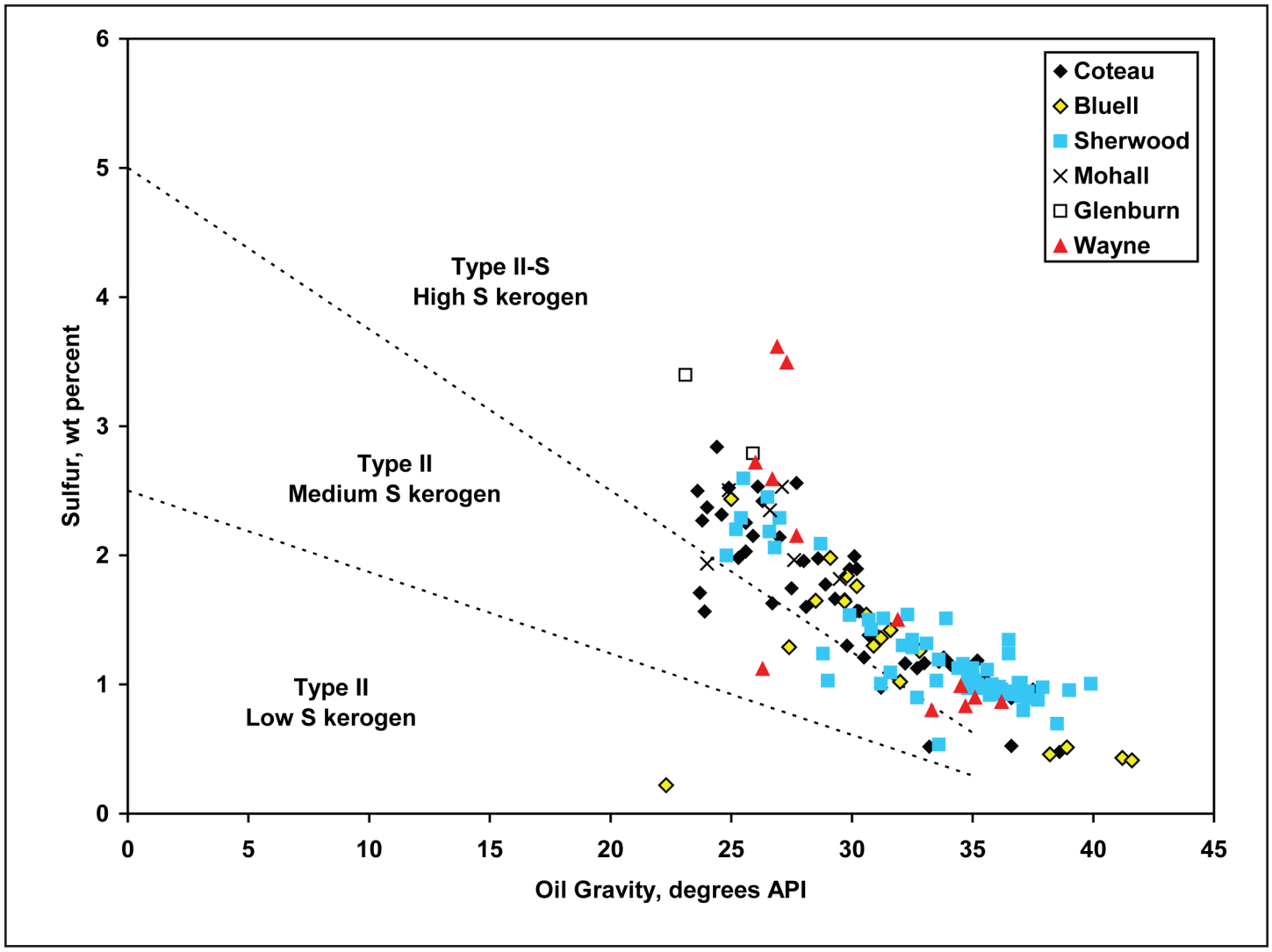


Figure 9. Plot of sulfur content versus oil gravity of Madison Group oils in North Dakota mostly derived from Type II-S kerogen (data from NIPER, 1995; NDGS, 2002; Jarvie, 2001; USGS, 2008). Symbol names are informal stratigraphic units in the Madison Group (Fig. 8). Kerogen type lines are from Orr (2001).

basin (Williams, 1974; Jarvie, 2001) (Fig. 1). Sulfur-gravity data from the Spearfish Formation in North Dakota plot in the Type II-S region on Figure 11 similar to Mission Canyon/Charles oils from Canada, consistent with a Madison Group source. In Weldon Field, Montana, Madison oil has been identified in the Mississippian Kibbey Formation (Williams, 1974). In the Canadian Williston Basin, Madison oils are produced from the Mississippian Lodgepole, Mission Canyon, and Charles formations, the Triassic-Jurassic Waltrous and Amaranth formations, the Jurassic Shaunavon, Gravelbourg, and Melita formations, and the Lower Cretaceous Manville Group (Brooks et al., 1987; Osadetz et al., 1992, 1994; Jiang and Li, 2002; Chen et al., 2009; Nicolas, 2009; Manitoba IEM, 2011).

Mixing of oil families is not common in the Williston Basin. However, mixed Bakken and Madison oils have been recognized in Madison reservoirs in Montana (North Lustre, East Poplar, and Poplar Northwest fields), in the Nesson Anticline of North Dakota (McGregor Field, Beaver Lodge Field, Stoneview Field), and in several fields in Canada along the northeast striking Torquay-Rocanville trend (Fig. 1) (Burrus et al., 1996b; Jarvie, 2001; Jiang and Li, 2002; Chen et al., 2009). Oil in the Mission Canyon Formation in Ritchey Field, (McCone County, Montana) is thought to be a mix of Madison- and Red River-sourced oils (Price and LeFever, 1994; Jarvie, 2001). The Madison (Charles) reservoir in Flat Lake Field on the Montana-Saskatchewan border may contain a mixture of Madison

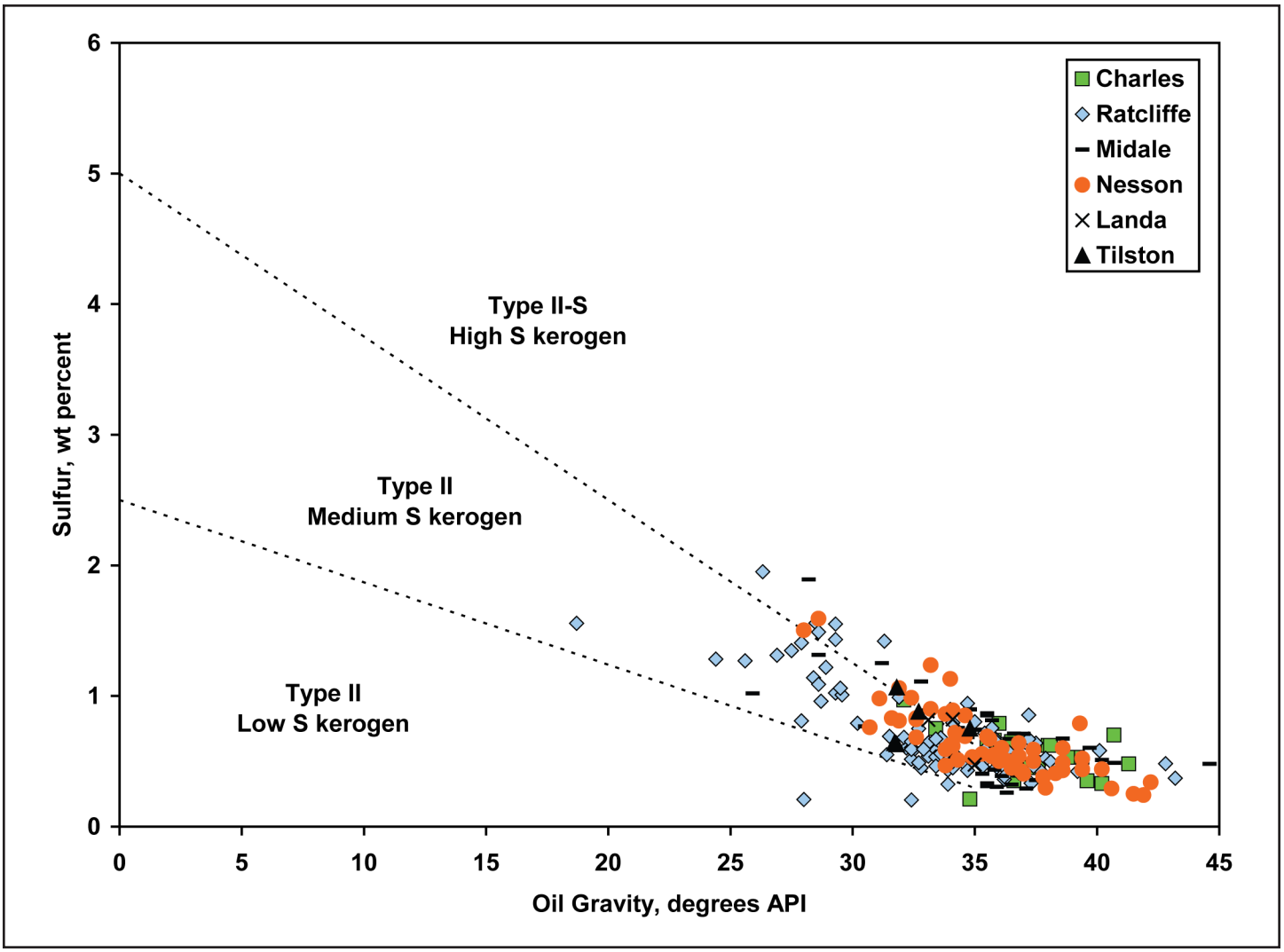


Figure 10. Plot of sulfur content versus oil gravity of Madison Group oils in North Dakota mostly derived from Type II kerogen with medium sulfur content (data from NIPER, 1995; NDGS, 2002; Jarvie, 2001; USGS, 2008). Symbol names other than the Charles Formation are informal stratigraphic units in the Madison Group (Fig. 8). Kerogen type lines are from Orr (2001).

and Birdbear oils (D1 Family of Osadetz et al., 1992; Price and LeFever, 1994).

Source rocks for the Madison petroleum system have been found in the Lodgepole and Mission Canyon formations. Williams (1974) suggested that the Lodgepole Formation in the Williston Basin is a possible oil source based on TOC values of 26 mature samples ranging from 0.03 to 0.89 wt %. Osadetz and Snowdon (1995) reported that the Lodgepole Formation in the Canadian Williston Basin has TOC values ranging from 0.37 to 15.62 wt % with an average of 5.49 wt %, and HI values ranging from 11 to 659 mg HC/g TOC with an average of 401 mg HC/g TOC (based on 23 samples). Jiang et al. (2001) described six Lodgepole samples from Osadetz and Snowdon (1995) and four new samples with TOC values ranging from 2.05 to 10.21 wt % and HI values ranging from 520 to 627 mg HC/g TOC (their samples 34-37). However, there is uncertainty about the chronostratigraphic position of some of these samples, and they may actually be part of the Tilston interval of the lower Mission Canyon Formation (Jarvie, 2001; Jiang et al., 2001). The organic matter in the Lodgepole source rocks in Canada has been considered to be Type II kerogen (Osadetz and Snowdon, 1995; Jiang et al., 2001) but the sulfur-gravity relationships of produced oils suggest a Type II-S source (Fig. 11).

In North Dakota, a thin (3- to 6-foot thick) shaley limestone and calcareous claystone found 5 to 20 feet above the base of the Lodgepole is a potential source rock with TOC values up to 8 wt % (Price and LeFever, 1994) and is sometimes called “false Bakken” (Hansen and Long, 1991;

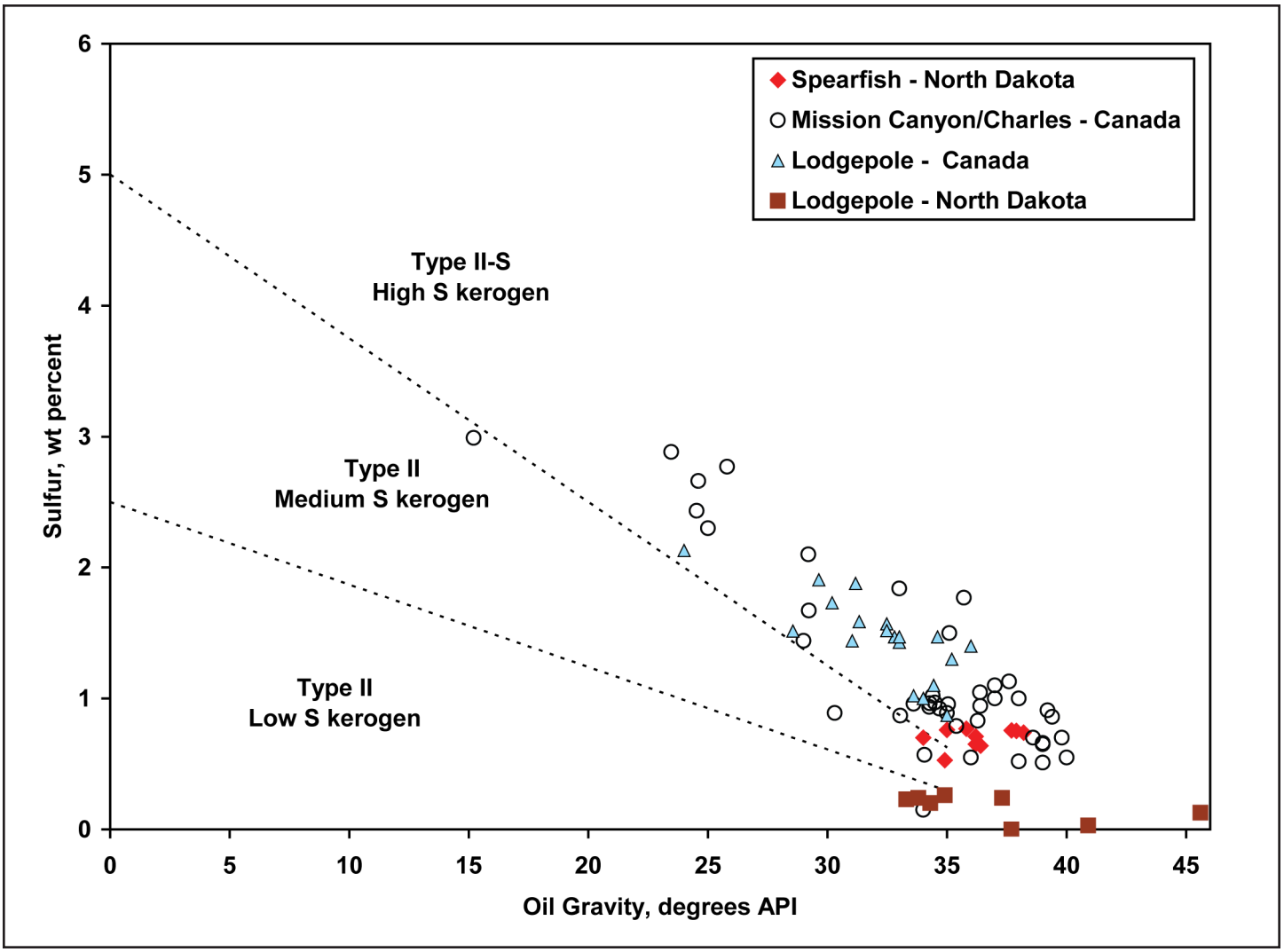


Figure 11. Plot of sulfur content versus oil gravity of oils in Lodgepole Formation reservoirs in Canada (Madison Group Type II-S source), Mission Canyon/Charles Formation reservoirs in Canada (Madison Group Type II-S source), Spearfish Formation reservoirs in North Dakota (Madison Group Type II-S source), and Lodgepole reservoirs in North Dakota (Bakken Formation source). Data are from Hodgson (1954), Bailey et al. (1973), Thode (1981), NDGS (2002) and USGS (2008). Kerogen type lines are from Orr (2001).

LeFever, 1991). Jarvie et al. (1996) determined that the "false Bakken" has geochemical characteristics similar to the Bakken Formation and different from the informal Scallion unit of the Lodgepole Formation. USGS (2008) Rock-Eval data from the Lodgepole Formation in the U.S. Williston Basin shows that except for the aforementioned "false Bakken" shale, most of the lower Lodgepole samples are not oil-prone source rocks (TOC < 2 wt %).

Three organic-rich intervals (up to 14 wt % TOC) were found in the Mission Canyon Formation in a well in Sheridan County, Montana (Jarvie and Walker, 1997). Jarvie (2001) reports average source rock values as follows: lower Mission Canyon, TOC of 1.96 wt % and HI of 394 mg HC/g TOC; middle Mission Canyon, TOC of 8.50 wt % and HI of 300 mg HC/g TOC; upper Mission Canyon, TOC of 1.92 wt % and HI of 273 mg HC/g TOC; Ratcliffe, TOC of 1.83 wt % and HI of 378 mg HC/g TOC.

Early oil-source correlations attributed the Madison oil family to the Bakken Formation (Williams, 1974; Thode, 1981; Leenheer and Zumberge, 1987). However, all subsequent studies since Brooks et al. (1987) have supported a self-sourced Madison petroleum system. Osadetz et al. (1992) correlated Madison oils to source rocks in the Lodgepole Formation in Saskatchewan, and Jarvie and Walker (1997) correlated Madison oils to Mission Canyon source rocks in the U.S. Williston Basin based on light hydrocarbon and biomarker composition. Therefore, the Madison petroleum system has a known level of certainty.

In summary, the Madison petroleum system consists of marine carbonate source rocks in the Lodgepole and Mission Canyon formations that have generated oil with up to 3.6 wt % S. These oils can be divided into two oil families based on sulfur-gravity values that are a function of kerogen type (Type II or Type II-S). Madison-sourced oils in the U.S. portion of the Williston Basin are produced predominantly from the Mission Canyon, Charles, and Spearfish formations. In the Canadian Williston Basin, Madison oils are produced from the Mississippian Lodgepole, Mission Canyon, and Charles formations, the Triassic-Jurassic Waltrous and Amaranth formations, the Jurassic Shaunavon, Gravelbourg, and Melita formations, and the Lower Cretaceous Manville Group. Future oil-source rock correlation studies may document multiple petroleum systems within the formations of the Madison Group as suggested by Jarvie (2001) and references therein.

Tyler Petroleum System

The Tyler petroleum system of the Williston Basin was first identified by Williams (1974) and Dow (1974) but has drawn little attention of geochemists since then. Thode (1981) included three Tyler Formation oils in his study of sulfur isotopes in crude oils of the Williston Basin. In contrast, the Heath-Tyler petroleum system in central Montana (Musselshell and Rosebud counties) has been studied in detail and is well established in the literature (Rinaldi, 1988; Aram, 1993; Cole and Drozd, 1994; Jarvie, 2001; Obermajer et al., 2002; Bennett and Olsen, 2007). A genetic link between the Heath-Tyler petroleum system in central Montana and the Tyler petroleum system in the Williston Basin has been inferred in some studies (for example, Meissner et al., 1984; Jarvie, 2001). However, it is not clear whether the Mississippian Heath Formation exists in the Williston Basin. Willis (1959) uses the term "Tyler-Heath" for rocks in the Williston Basin that may be equivalent, in part, to the Heath Formation of central Montana. Ziebarth (1964) suggests that in the Williston Basin the Heath Formation exists only in northwest North Dakota. Williams (1974) and Jarvie (2001) report on Heath source rock samples from the Williston Basin (unspecified location). Other references, however, suggest that the Heath Formation is generally missing in the Williston Basin except in the western margin of the basin in northeastern Montana (Grenda, 1978, 1992; Bluemle et al., 1981; Maughan, 1984; Sturm, 1987; Peterson, 1996; Murphy et al., 2009; Manitoba IEM, 2011). The term "Heath" as applied to strata in North Dakota by some studies is probably Pennsylvanian Tyler Formation or Mississippian Otter Formation (Ziebarth, 1962; Maughan, 1984).

To date there are no published geochemical studies that correlate Heath-Tyler oils from central Montana to Tyler oils in the Williston Basin. However, in this study, the gravity-sulfur relationships of oils from the two areas suggest that most of the Tyler oils in the Williston Basin are derived from clay-rich source rocks with low-S kerogen, whereas some of the central Montana Heath-Tyler oils are derived from clay-poor marine source rocks containing kerogen with medium S content (Fig. 12). Furthermore, the Tyler oils in North Dakota generally have a higher pour point from higher wax content consistent with a deltaic swamp or lacustrine source (Fig. 13). The waxy, low S Tyler oil family is predominantly found in Lower Pennsylvanian Tyler Formation sandstones (Williams, 1974), which includes the so-called "Heath" reservoirs. Geographically, Tyler oil production is limited primarily to Billings, Slope, and Stark counties, North Dakota (Fig. 1).

Tyler and "Heath" source rocks in the Williston Basin were first characterized by Williams (1974). He describes the Tyler as having TOC ranging from 0.2 to 3.6 wt % with an average of 0.8 wt % (41 samples), and "Heath" with TOC ranging from 0.67 to 9.07 wt % with an average of 2.68 wt % (34 samples). Arneth (1984) reports two Tyler calcareous shale samples with TOC values of 2.64 and 5.38 wt %. Jarvie (2001) reports that the Tyler Formation has an average TOC and HI of 6.08 wt % and 174 mg HC/g TOC, respectively, and the "Heath" has an average of 5.83 wt % and 268 mg HC/g TOC (unknown number of samples or maturity). It is uncertain whether the so-called "Heath" samples are actually Heath or Tyler Formation. Recent source rock studies (Nordeng and Nesheim, 2010; Nesheim and Nordeng, 2011) show that the Tyler Formation in the Williston Basin has a highly variable source rock composition reflecting a range of depositional environments in a fluviodeltaic system. TOC values range from 0.07 to over 33 wt % (one outlier has 66 wt % TOC) with an average of 3.6 wt % (108 samples), and HI values suggesting Type I, II and III kerogen (Fig. 14). The highly variable kerogen composition may explain some of the observed scatter in S (Fig. 12) and pour point (Fig. 13) values.

The Tyler oil family was correlated with Tyler source rocks based on light hydrocarbon geochemistry and stable carbon isotopes (Williams, 1974), but the correlation has yet to be confirmed in subsequent geochemical studies. Numerous studies have concurred with this interpretation (Maughan, 1984; Gerhard et al., 1991) although Meissner et al. (1984), Peterson (1996), Jarvie and Inden (1997), and Jarvie (2001) have suggested both Tyler and Heath formations are possible sources of Tyler oils. Nevertheless, the Tyler petroleum system is considered to have a known level of certainty based on aforementioned oil-source correlation and the apparent self-sourced nature of the system.

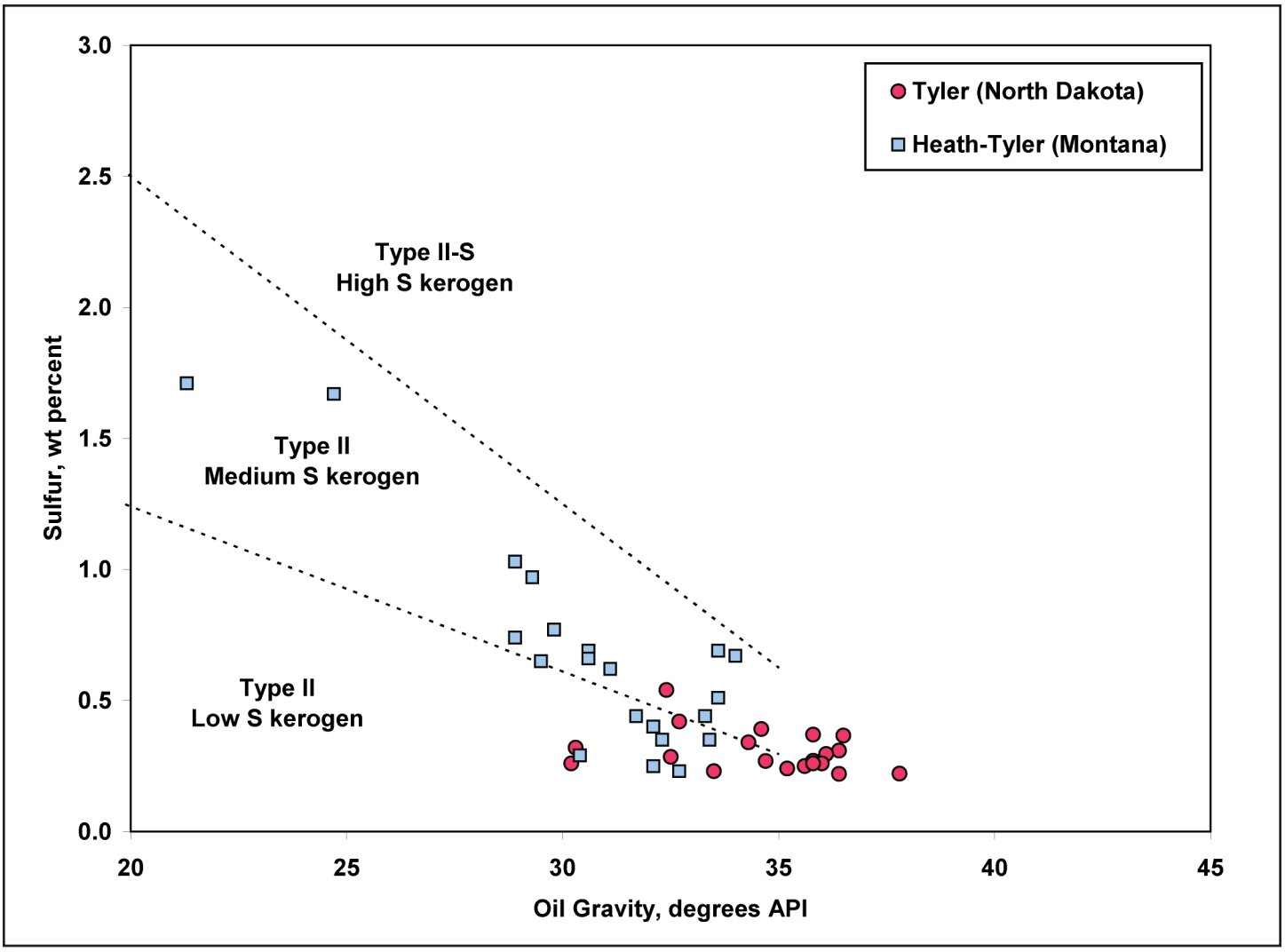


Figure 12. Plot of sulfur content versus oil gravity of Tyler Formation oils in central Montana and North Dakota showing that the Tyler petroleum system of the Williston Basin has oils derived from low-sulfur kerogen and might be distinct from the Heath-Tyler petroleum system in central Montana. Data are from Cole and Drozd (1994), NIPER (1995), Jarvie (2001), Thode (1981) and NDGS (2002). Kerogen type lines are from Orr (2001).

CONCLUSIONS

This paper reviews the petroleum geochemistry, oil-oil, and oil-source correlations of the oil systems of the Williston Basin, which includes the Deadwood (Cambrian-Ordovician), Winnipeg (Ordovician), Red River (Ordovician), Winnipegosis (Devonian), Duperow (Devonian), Birdbear (Devonian), Bakken (Devonian-Mississippian), Madison (Mississippian), and Tyler (Pennsylvanian) petroleum systems. The stratigraphic distribution of the oil families from each system is generally limited to the same formation from which they were sourced, but some exceptions do occur. These systems, summarized in Table 2, were used to define and map the total petroleum systems for the USGS petroleum resource assessment of the U.S. portion of the Williston Basin in 2008 (Anna et al., 2008; Pollastro et al., 2008).

Some of the new findings in this study:

The Red River petroleum system in the Williston Basin has low-wax and high-wax oil families that may be derived from Assemblage A (dominated by the alga *G. prisca*) and Assemblage B (dominated by amorphous kerogen) organic facies, respectively. The high wax (high pour point) oils are produced mainly from zone B of the Red River Formation, Stonewall, Stony Mountain (Gunton Member), and Silurian Interlake reservoirs.

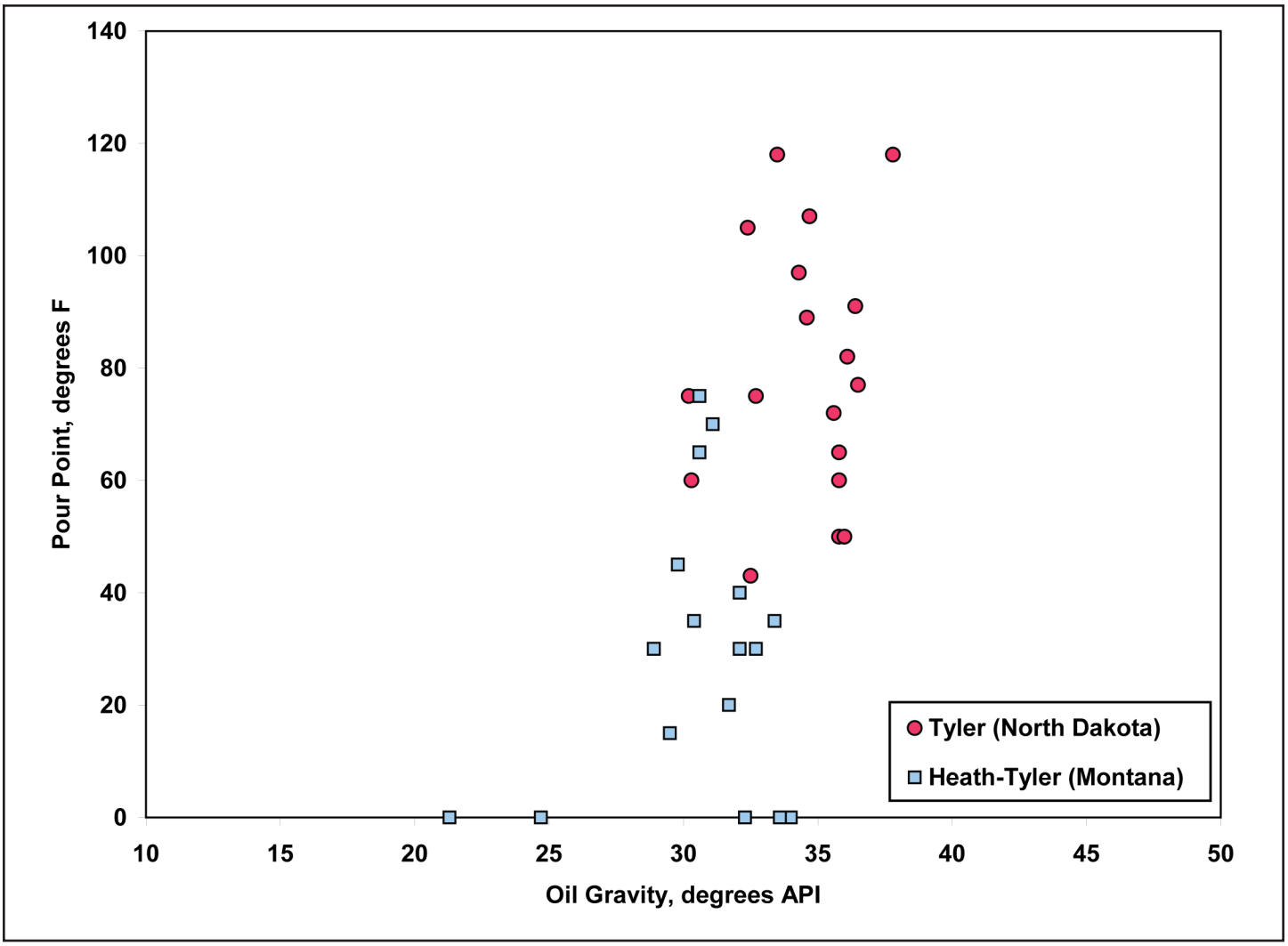
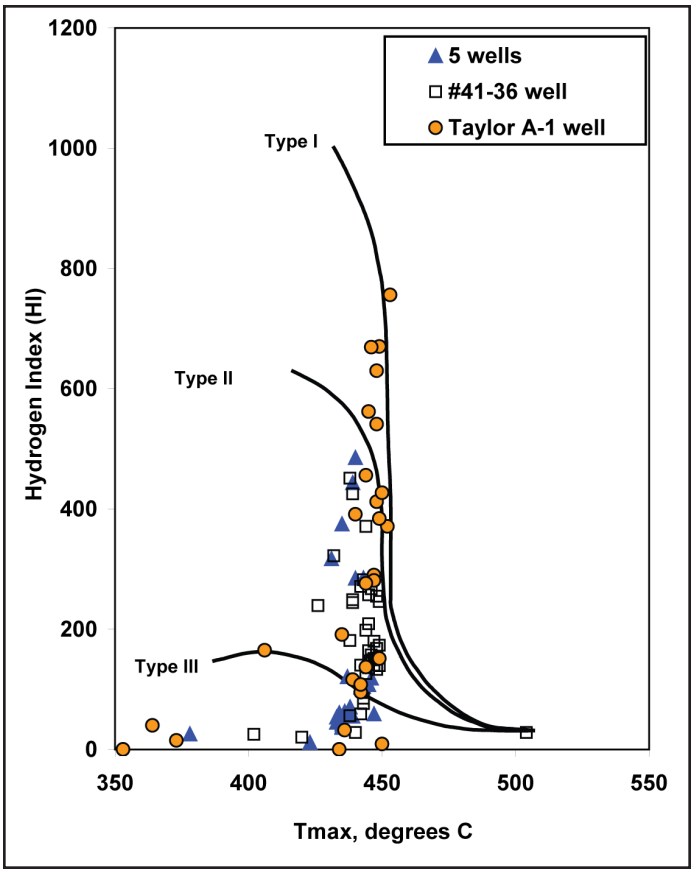


Figure 13. Plot of pour point versus oil gravity of Tyler Formation oils in central Montana and North Dakota showing that the Tyler petroleum system of the Williston Basin has high pour point oils and might be distinct from the Heath-Tyler petroleum system in central Montana. Data are from NDGS (2002) and NIPER (1995). Pour point values of 0°F were reported by NIPER (1995) as "less than 5°F".

Some studies have suggested that the Bakken Formation contains Type I, as well as Type II kerogen, based on Rock-Eval data (HI versus OI). Although this interpretation has been confirmed in this study with a large dataset of immature Bakken samples (n = 410), a plot of HI versus Tmax from Rock-Eval analysis shows that the Bakken generally follows the Type II kerogen maturity trend. Interpretations of kerogen type based on Rock-Eval pyrolysis data should be used with caution.

Oils in the Madison petroleum system of the Williston Basin can be divided into two oil families based on API gravity-sulfur content relationships, indicating that Madison Group source rocks contain spatially separated organic facies distributions of Type II-S kerogen and Type II kerogen with medium sulfur content.

The Tyler petroleum system of the Williston Basin may be distinct from the Heath-Tyler petroleum system in central Montana based on differences in geology and petroleum geochemistry with Tyler petroleum system oils having a higher pour point and lower sulfur content.



(Left) Figure 14. Plot of Rock-Eval pyrolysis hydrogen index versus Tmax of the Tyler Formation, North Dakota (data from Nordeng and Nesheim, 2010; and Nesheim and Nordeng, 2011) showing that the formation contains Type I, Type II and Type III kerogen. Maturation lines of kerogen types (Type I, Type II, Type III) are from Mukhopadhyay et al. (1995). The API numbers of the five wells are: 33105011220000, 33025004190000, 33025005660000, 33053004610000, 33053027940000. The API number of the Government Taylor A-1 well is 33033000180000. The API number of the #41-36 well is 33007001350000.

TABLE 2
Summary of the Petroleum Systems of the Williston Basin (excluding gas systems)

Petroleum System	Age	Level of Certainty	Oil Character	TOC max	Kerogen Type
Deadwood	Cambrian-Ord.	speculative	low S, high Pp	---	---
Winnipeg	Ordovician	hypothetical	low S, high Pp	11	I II
Red River	Ordovician	known	low S, low Pp	35	I
Assem. B	Ordovician	hypothetical	low S, high Pp	5	II
Winnipegosis	Devonian	known	low S, high Pp	46	I II
Duperow	Devonian	hypothetical	low S, high Pp	4	II
Birdbear	Devonian	hypothetical	low S, low Pp	17	I II III
Bakken	Devonian-Miss.	known	low S, low Pp	42	II
Madison	Mississippian	known	medium S, low-high Pp	14	II
Type II-S	Mississippian	known	high S, high Pp	16	II-S
Tyler	Pennsylvanian	known	low S, high Pp	33	I II III

Assem. B, Assemblage B subsystem of Red River after Jacobson et al. (1988). Type II-S subsystem of the Madison based on oil gravity/sulfur relationship (Orr, 2001). Ord., Ordovician. Miss., Mississippian. Level of Certainty: known, documented oil-source rock correlation; hypothetical, undocumented oil-source rock correlation; speculative, undocumented potential source rock. S, sulfur content defined in Figure 3 by Orr (2001). Pp, pour point, high Pp >30-50°F. TOC max, maximum reported total organic carbon value in wt % (see text for more details). Kerogen type (except Type II-S) is defined by Tissot et al., (1974) based on atomic H/C and O/C, but in many cases kerogen type is interpreted based on Rock-Eval pyrolysis data (Peters, 1986) and should be used with caution.

ACKNOWLEDGMENTS

I would like to acknowledge the collaboration, discussion and guidance from the geologists of the USGS Williston Basin Province assessment team (Lawrence O. Anna, Stephanie B. Gaswirth, Richard M. Pollastro, Laura N.R. Roberts, and Michael D. Lewan). Augusta Warden (USGS, Denver, CO) provided API gravity and sulfur analyses of over 40 crude oils. Fruitful discussions and digital data from their publications were provided by Stephan H. Nordeng and Julie A. LeFever (North Dakota Geological Survey), and Daniel M. Jarvie (Worldwide Geochemistry). Constructive reviews were provided by Michael D. Lewan, Debra K. Higley, and Lawrence O. Anna (USGS); Janell D. Edman (consultant); John Curtis (Colorado School of Mines); and Mel Klinger and Joyce Trygstad Nelson (RMAG).

Any use of trade, firm, or product names is for descriptive purposes only and does not imply endorsement by the U.S. Government.

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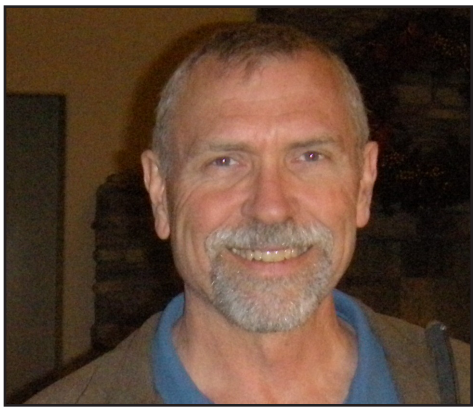

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