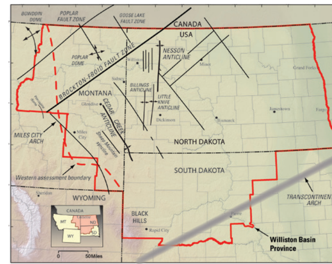
Chapter 3

Geologic Assessment of Undiscovered Oil and Gas in the Williston Basin Province, Montana, North Dakota, and South Dakota



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By Lawrence O. Anna

Chapter 3 of 7

Assessment of Undiscovered Oil and Gas Resources of the Williston Basin Province of North Dakota, Montana, and South Dakota, 2010

By U.S. Geological Survey Williston Basin Province Assessment Team

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Geologic Assessment of Undiscovered Oil and Gas in the Williston Basin Province, Montana, North Dakota, and South Dakota

By Lawrence O. Anna

Abstract

The U.S. Geological Survey completed an assessment of the undiscovered oil and gas potential of the Williston Basin Province in 2008. The assessment applied the total petroleum system concept, which includes mapping the distribution of potential source rocks and known petroleum accumulations, and determining the timing of petroleum generation and migration. Geologically based, it focuses on source rock and reservoir rock stratigraphy, timing of tectonic events and the configuration of resulting structures, formation of traps and seals, and burial history modeling. The total petroleum system is subdivided into assessment units based on similar geologic characteristics and accumulation and petroleum type. For the Williston Basin Province, 10 total petroleum systems, 13 conventional assessment units, and 6 continuous (or unconventional) assessment units were defined, and the undiscovered oil and gas resources within each assessment unit were quantitatively estimated.

Introduction

The U.S. Geological Survey (USGS) completed a quantitative estimate of the undiscovered oil and gas potential of the Williston Basin Province of North Dakota, eastern Montana, and northwestern South Dakota in 2008 (fig. 1). The assessment was based on geologic principles and applied the total petroleum system (TPS) concept. A TPS consists of one or more assessment units (AUs), the basic geologic unit that is assessed. An AU is a mappable part of a petroleum system in which discovered and undiscovered fields constitute a single, relatively homogeneous population. The assessment methodology was based on the simulation of the number and sizes of undiscovered fields. The TPS includes all genetically related petroleum within a limited mappable geologic space, along with other essential mappable geologic elements (reservoir, seal, and overburden rocks) that control the fundamental processes of generation, expulsion, migration, entrapment, and preservation of petroleum (Magoon and Dow, 1994). A TPS may equate to a single AU, or it may be subdivided into two or more AUs that are assessed individually if each unit is sufficiently homogeneous in terms of geology, exploration considerations, and geologic risk. Using this geologic framework, the USGS (1) defined 10 TPSs (fig. 2), 13 conventional AUs, and 6 continuous (or unconventional) AUs in the Williston Basin Province; and (2) quantitatively estimated the undiscovered oil and gas resources in each. This report, however, includes descriptions and assessment results for only 8 of the TPSs and the 11 AUs defined within them. The other two TPSs—the Bakken-Lodgepole and Madison—are described and assessed in other chapters of this CD-ROM.

The Williston Basin is a large intracratonic structural depression with over 16,000 ft of sediment deposited over Precambrian basement. The geographic extent covers North Dakota, eastern Montana, northwestern South Dakota, and southeastern Saskatchewan and southwestern Manitoba, Canada (fig. 1); however, only the U.S. part of the basin was included in the USGS's assessment. The structural basin is nearly symmetrical with the center in northwestern North Dakota, and the updip gradients of Paleozoic surfaces rise at about 50 ft/mi in all directions (fig. 3).

The physical boundaries of the basin are defined by the Canadian Shield to the northeast, a series of Laramide structures such as the Mile City arch, Black Hills uplift, Bowdoin dome, and Porcupine dome to the west and southwest, the Sweetgrass arch to the north and northwest, and the Transcontinental arch to the south and southeast. Within the basin there are several prominent structural features including the Nesson anticline, the Cedar Creek anticline, and Poplar dome (fig. 1).

The province boundary used in the USGS 1995 petroleum assessment of the Williston Basin (Peterson and Schmoker, 1995), and as used in this assessment, was drawn on county and State borders that were completely or partially within the geologically defined basin. The east boundary (North Dakota-Minnesota State boundary) and the south boundary (central South Dakota) are geologically defined as the eastern and southernmost subcrop of Paleozoic and Mesozoic formations. The west boundary in southeastern Montana is drawn near the east edges of several Laramide structural uplifts that geologically define the Williston Basin in that area. Some oil and gas fields, however, in the extreme

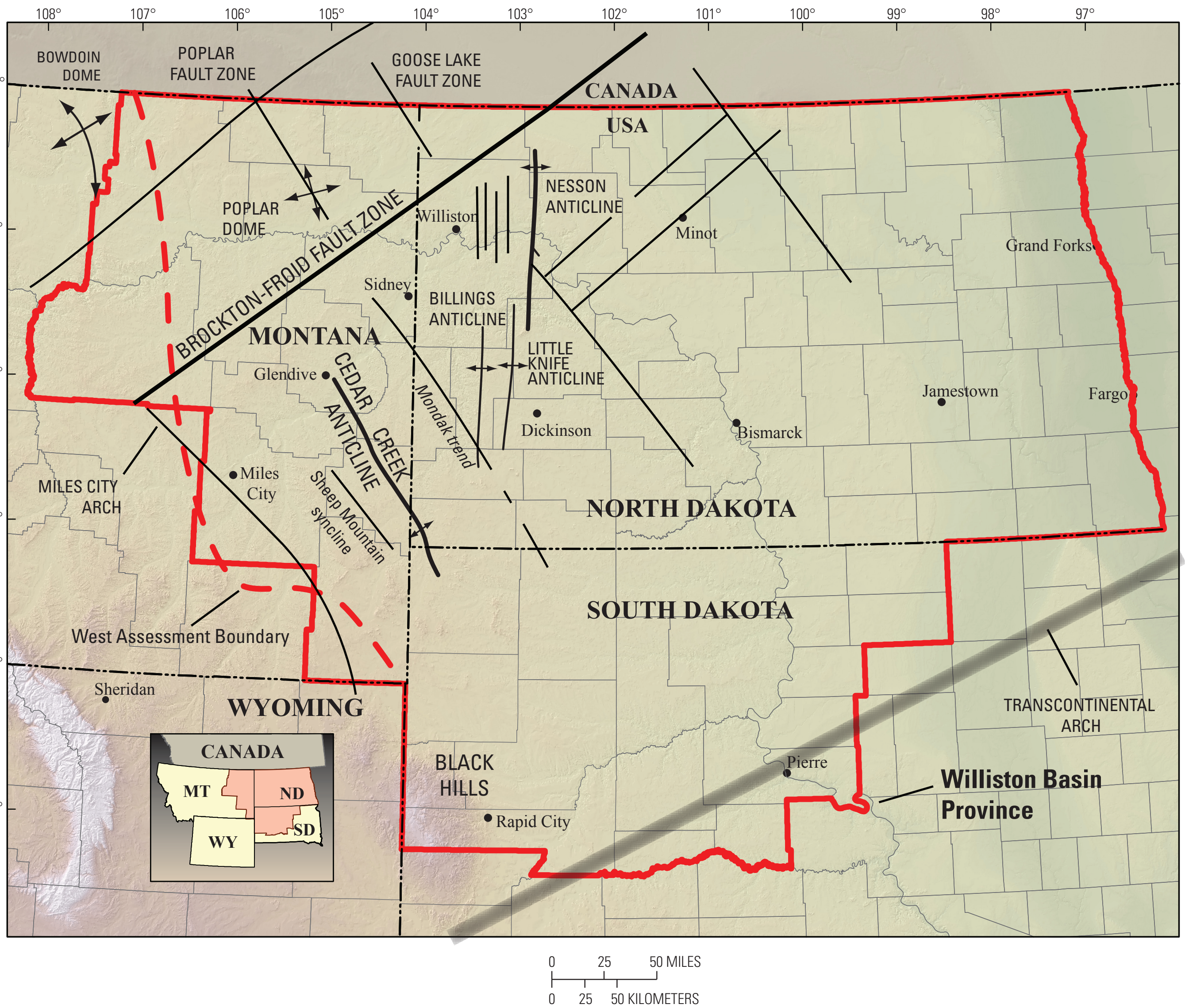

Figure 1. Outline of Williston Basin Province and major structural features.

western part of the province are considered to be part of the Powder River Basin or central Montana and were not included in the assessment of the Williston Basin Province. Therefore, a surrogate western assessment boundary was drawn to exclude those fields in that part of the province (fig. 1).

The oldest known hydrocarbon production in the Williston Basin was from a shallow gas discovery in Upper Cretaceous sandstone in 1913 and from an oil discovery in 1936, both on the Cedar Creek anticline (fig. 1). The Nesson and Cedar Creek anticlines were mapped from surface exposures in the early 1900s, and seismic profiles obtained in the 1940s and 1950s helped initiate and later expand exploration for structures not exposed at the surface. The first significant commercial oil production was in 1951, with the Amerada Hess Corporation Clarence Iverson #1 discovery on the Nesson anticline.

Winnipeg-Deadwood Total Petroleum System

The Winnipeg-Deadwood TPS, which includes the Winnipeg-Deadwood AU, is self-contained, in that hydrocarbons generated in the Upper Cambrian and Lower Ordovician Deadwood Formation and the Middle Ordovician Winnipeg Group have not migrated to other units. Well penetrations to the two units (some 650 wells) represent only 2 percent of all wells drilled in the Williston Basin. This scarcity of drilling can be attributed to the reservoirs being the deepest in the basin and the associated increase in risk for success. In comparison, there have been more than 8,000 penetrations into the overlying Ordovician Red River Formation, one of the primary targets in the basin.

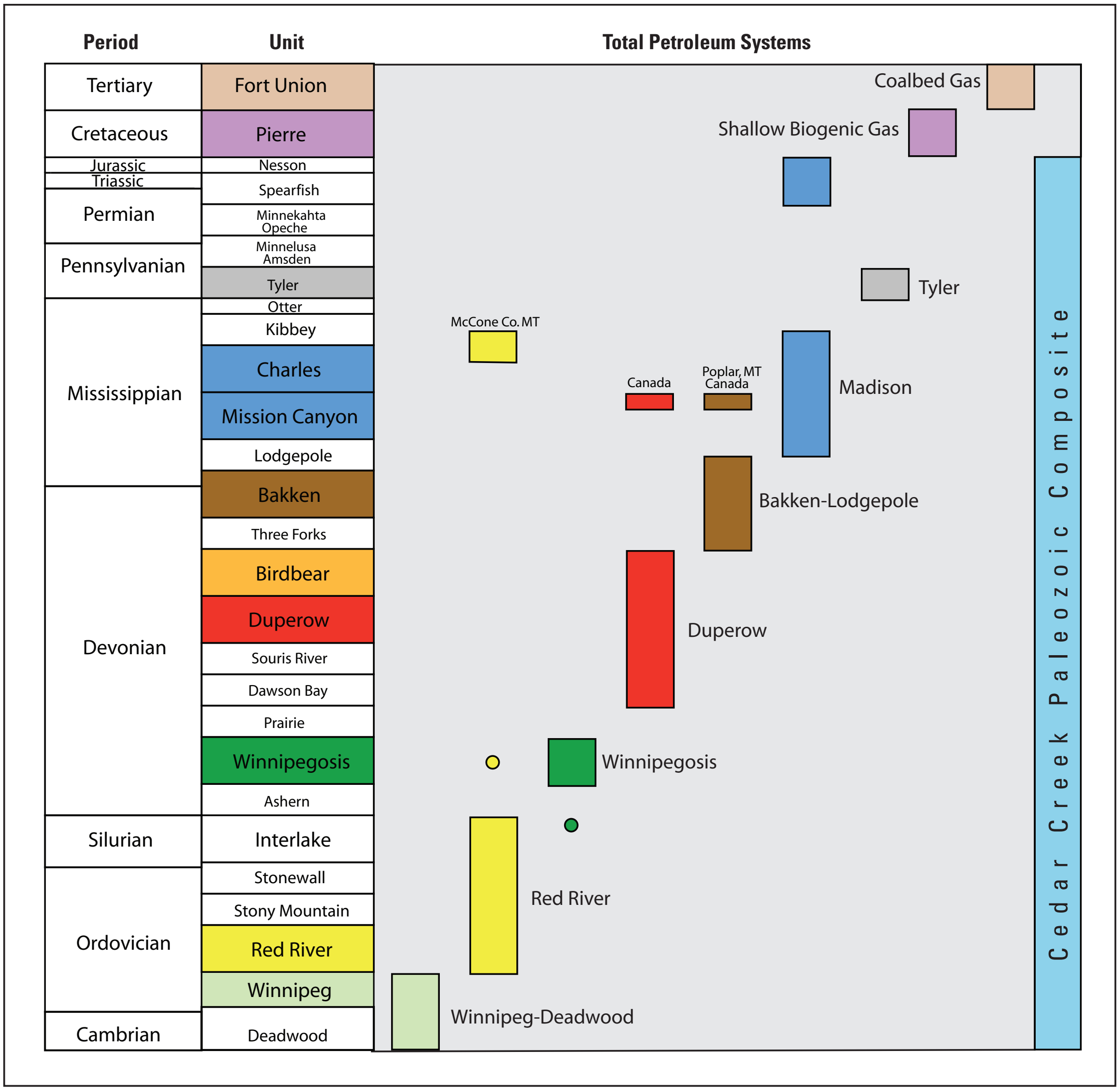

Figure 2. Diagram showing Williston Basin Total Petroleum Systems correlated to stratigraphic units and time periods within them.

Of the 650 Winnipeg-Deadwood wells, over half are located in the central and eastern part of the province, and only 18 have recorded initial production rates (IHS Energy Group, 2008) for a 3 percent success ratio. In the future, the success ratio should increase with increased understanding of the subsurface geology. There have been two major periods of drilling activity in this AU: in the 1950s during development of fields in the Nesson anticline and in the mid-1980s; both periods were followed by sharp declines. Average field depths have increased since the first discovery from less than 12,000 ft to approximately 15,000 ft (NRG Associates, Inc., 2008).

The TPS and AU boundaries are congruent and are located near the 8,000-ft-depth contour of the Winnipeg Group and the 200 °F subsurface temperature contour of the Winnipeg and Deadwood (fig. 4). On the east side of the basin, the AU boundary is drawn east of the 200 °F temperature contour to allow for some eastern and northeastern hydrocarbon migration (fig. 4). On the south side of the basin, the boundary matches the southern boundary of the primary reservoir, the Black Island Formation (fig. 5).

Petroleum Source Rocks

The Middle Ordovician Icebox Formation of the Winnipeg Group (fig. 5) is considered the primary source rock for hydrocarbons in Deadwood and Winnipeg reservoirs, although shales in the Black Island Formation also have hydrocarbon generation potential (Seibel and Bend, 2001). The Icebox Formation is one of three marine clastic shales in the basin (the Bakken and Tyler Formations are the other two); it also has appreciable thickness and could be considered

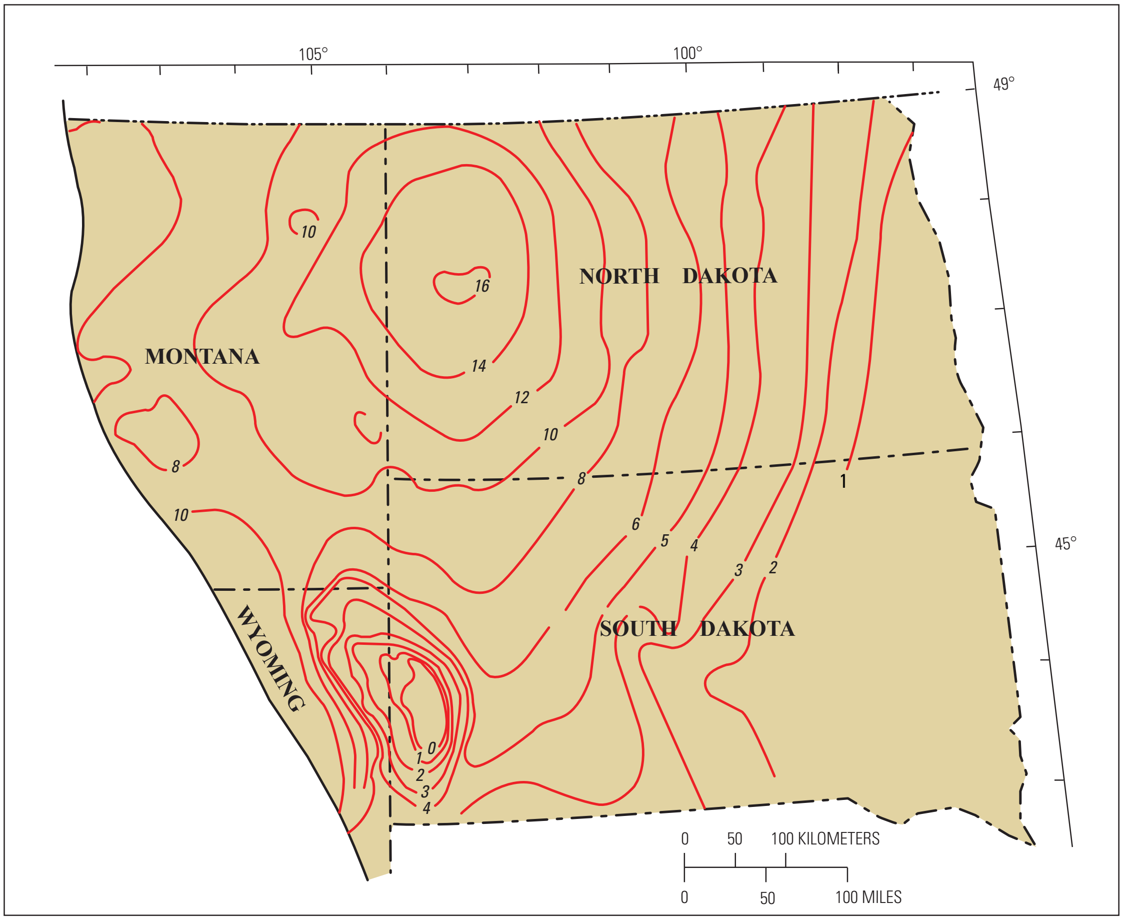

Figure 3. Structure contour map, top of the Ordovician Red River Formation, showing the general structural configuration of the Williston Basin. Contours are in thousands of feet and contour interval varies from 1,000 near the basin margin to 2,000 ft near the basin center.

a continuous-type reservoir. From limited geochemical data, shales of the Icebox can be characterized as a modest source rock with marine algal Type I and Type I/II kerogen. Other measured parameters include total organic carbon (TOC) that averages from less than 1 percent to as much as 11 percent, S2 (the amount of hydrocarbons produced from Rock-Eval experiments) that ranges from 2 to 85 mg/g of rock, hydrogen indices (HI) that range from 300 to 800, and zero sulfur (NRG Associates, Inc., 2008). All productive fields are categorized as gas (NRG Associates, Inc., 2008) and one well (Chimney and others, 1992) had a gas-oil ratio (GOR) of more than 26,900, but the average ratio for all Winnipeg-Deadwood AU fields is over 400,000 (NRG Associates, Inc., 2008).

There is uncertainty as to the origin of the oil and gas in the Red River Formation because Winnipeg shales were originally proposed to be the source (Williams, 1974; Dow, 1974); the Red River was later interpreted to be self-sourced (Osadetz and Snowdon, 1995; Smith and Bend, 2004). Jarvie (2001) reported that oil from reservoirs in Dunn County, North Dakota, correlated with Red River oil, but oil in the Deadwood Formation in the Newporte field, North Dakota, indicated that the oil was unique to Cambrian source rocks. P. Lillis (USGS, written commun., 2010) reviewed published data and concluded that the Winnipeg Shale was the sole source for petroleum in the Winnipeg-Deadwood AU.

The Icebox Formation of the Winnipeg Group overlies the Black Island Formation of the Winnipeg and in places underlies either the Roughlock Formation of the Winnipeg or the Red River Formation. The Winnipeg contact with the Red River is conformable, although the ratio of clastic rock (of the Winnipeg) to carbonate rock (of the Red River) varies vertically and laterally. Icebox thickness ranges from less than 80 ft near the basin margin to more than 160 ft in three depocenters—in the central part of the basin in northwestern North Dakota, another in southern Manitoba, Canada, and the third, although less distinct, in northwestern South Dakota (fig. 6). It is greenish-gray to dark gray, slightly to moderately bioturbated marine shale with thin discontinuous silty sandstone lenses near the base that intertongue with parts of the underlying Black Island Formation of the Winnipeg Group in the northern part of the province. There are also several thick sandstone lithosomes in the upper part of the Icebox

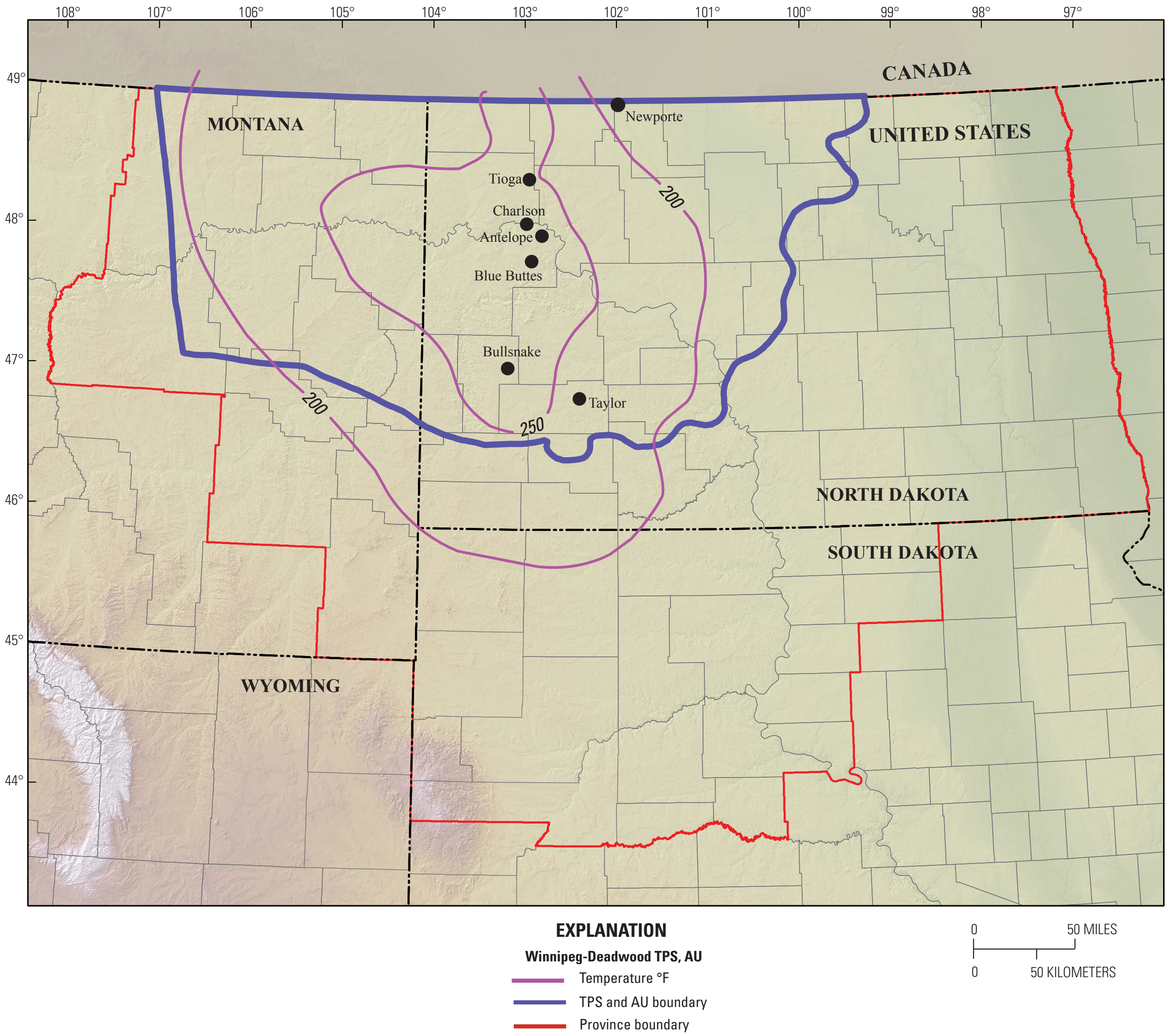

Figure 4. Area of the Winnipeg-Deadwood Total Petroleum System (TPS) and Assessment Unit (AU), temperature of the Deadwood-Winnipeg stratigraphic interval, and general location of Winnipeg and Deadwood oil and gas fields (solid dots).

Formation in the northeast part of the province (LeFever, 1996). Average Rock-Eval parameters are: S1, 0.21; S2, 11.6; S3, 0.42; TOC, 1.55; HI, 519; and oxygen index (OI), 44.7 (Osadetz and others, 1992).

Source Rock Thermal Maturity

Few data exist as to the thermal maturity of Winnipeg Group shales. Direct evidence includes temperatures from drill-stem tests in Deadwood and Winnipeg strata (fig. 4), but these are current temperatures and may not reflect maximum temperatures. The data show that temperatures are more than 250 °F near the center of the basin, and that temperature contours form a broad north–south trend with a westward shift toward the Poplar dome in Montana (fig. 1). The 200 °F contour is roughly parallel to the 250 °F contour, as well as to the 8,000-ft-depth contour to the top of the Winnipeg (figs. 3 and 4)—the approximate depth and temperature at which Winnipeg shales are thought to enter the oil generation window. However, Deadwood and Winnipeg fields, with drill-stem-test (DST) temperatures of more than 250 °F, are designated as gas with minor oil or condensate production (NRG Associates, Inc., 2008). Taylor field, with a temperature of less than 250 °F but more than 200 °F, produces some oil and condensate as well as gas. Newport field temperatures are less than 200 °F and produce a mix of gas, oil, and water. It is unclear whether the water originates from Cambrian sandstones or from underlying fractured Precambrian rocks.

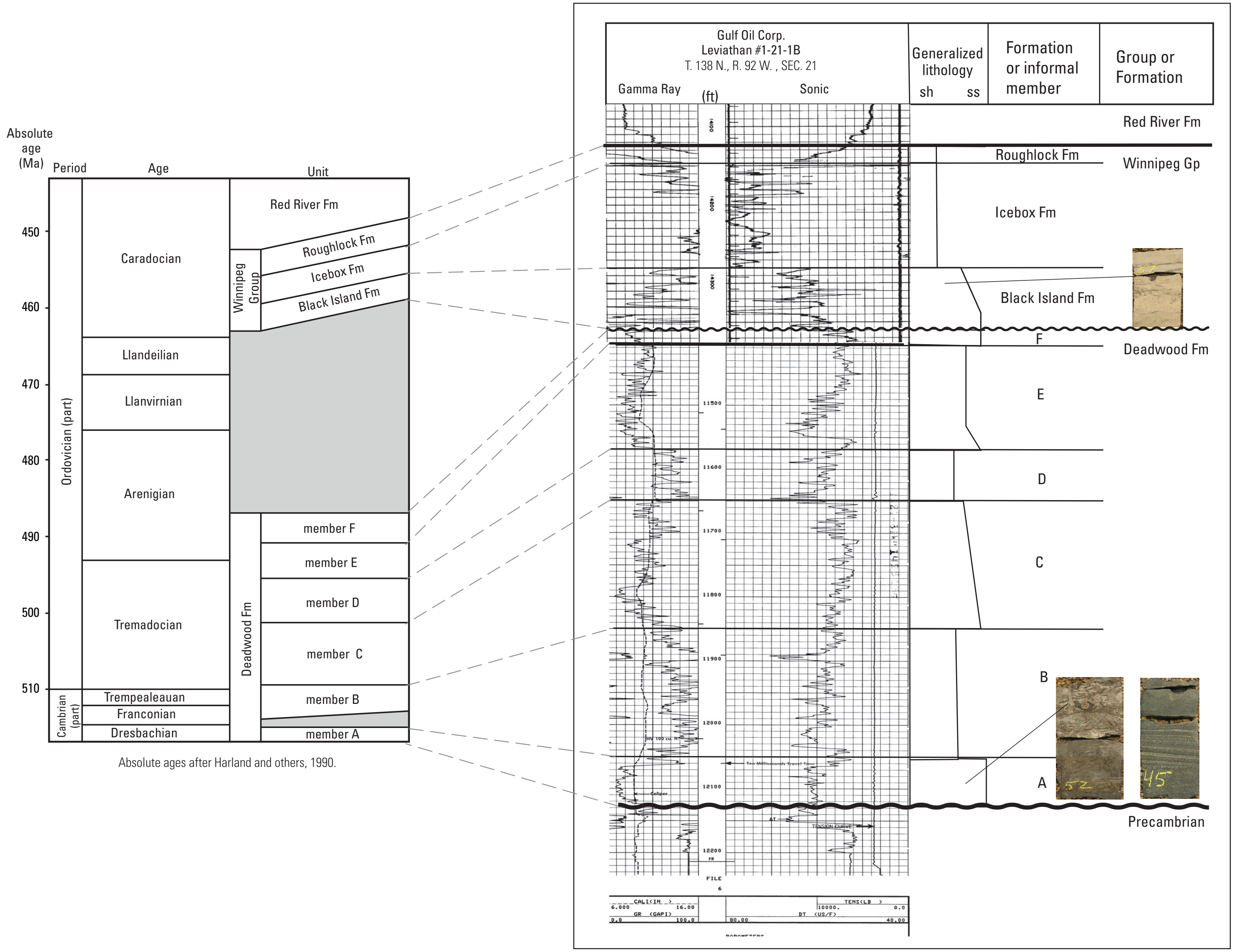

Figure 5. Correlation of a wireline log and lithology of the Cambrian-Ordovician Deadwood Formation and Ordovician Winnipeg Group to a stratigraphic chart. Core photographs are from North Dakota Oil and Gas Commission well number 7087 (North Dakota Oil and Gas Commission, 2009). Sh, shale; ss, sandstone; Gp, Group; Fm, Formation; Ma, million years ago.

Figure 6. Diagrams showing the thickness of the Ordovician Winnipeg Group. (*A*) Black Island Formation (isopach interval, 50 ft); (*B*) Icebox Formation (isopach interval, 20 ft). Modified from Lefever (1996). Colors are used to highlight thick and thin sections.

One-dimensional burial-history modeling indicated that Winnipeg shales generated oil but not gas (table 1). Because this AU produces mostly gas, the input of Type II Woodford kinetics or constant heat flow into the model was probably not correct. Model output for one well located in southeast Dunn County, North Dakota, showed that generation started about 93 Ma, reached peak generation at about 58 Ma, and completed generation at 53 Ma. The other well, in western McLean County, North Dakota, started generating oil at 85 Ma, reached peak generation at 58 Ma, and currently has expelled 96 percent of its oil (table 1). Structurally, the top of the Winnipeg in the two wells is nearly at the same elevation; therefore, it is unclear why there are differences in the modeling results.

Hydrocarbon Migration

Although evidence is sparse, geochemical and physical data suggest that hydrocarbons generated in Winnipeg Group shales are confined to this AU, including the Black Island Formation and upper members of the Deadwood Formation. Most of the fluid migration appears to have been downward, although residual hydrocarbons probably still reside in Winnipeg shales. There is no evidence to support upward migration, in that (1) Winnipeg hydrocarbons have not been typed to Red River reservoirs, (2) the lower Red River Formation consists of thick successions of low-permeability limestone, and (3) the underlying permeable sandstone and the highly fractured and weathered Precambrian surface create a downward hydraulic gradient. Potentiometric surface maps (hydraulic gradient) of lower Paleozoic aquifers show hydraulic gradients to the north and northeast (Downey, 1984) suggesting lateral migration in those directions from a hydrocarbon-generation pod near the center of the Williston Basin.

Reservoir Rocks

Deadwood Formation

Deposition of the Deadwood Formation occurred with the initial marine transgression over an uneven Precambrian surface at the current site of the Williston Basin. The marine incursion progressed from west to east, and the Deadwood is thickest west of the province, although there is a local thick section in western North Dakota. The unit thins to an erosional edge to the east, northeast, and southeast, with thick and thin sections corresponding to Precambrian structural lows and highs, respectively. An unconformity at the end of Deadwood time (post-Sauk sequence, mid-Ordovician) eroded parts of the upper Deadwood as the basin started its initial subsidence (fig. 7).

The Deadwood Formation consists of siliciclastic marine sandstone, siltstone, and shale with minor amounts of thin carbonate rock, although, in general, sandstone is most prevalent in North and South Dakota, and a mix of sandstone and shale is more prevalent in Montana. The formation is divided into six informal members, named A through F in ascending order (LeFever, 1996) (fig. 5). The basal A member is transgressive marine sandstone, with variable amounts of glauconite, pyrite, and mica, and is commonly bioturbated, whereas the overlying B member represents a deeper water environment with interbedded sandstone, siltstone, and shale. The A and B members have the widest areal extent of all Deadwood members. Following a short regression, subsequent transgression deposited the C and D members that consisted of transgressive deposits of nearshore sandstone, siltstone, and minor limestone of the C member, and offshore deposits of the D member. Members E and F represent transgressive and regressive successions of shoreface and lagoon sandstone and in places, limestone

Table 1. Oil generation timing for six wells and several stratigraphic intervals in the Williston Basin. Because the kenetics for each interval is unknown, kenetic sensitivty was run for each interval. Measurements were made in the middle of the intervals. Model results from L.N.R. Roberts (USGS, written commun., 2008). A TR of 0.01 is the start of generation, 0.5 is peak generation, and 0.99 is end of generation.

[Ma, million years ago; TR, transformation ratio; max, maximum; Fm, Formation; sh, shale]

Source Rock	Well					
	6464	527	Robbins 1	7783	10606I	8225
Winnipeg w/Type-II Woodford kinetics						
Ma at start of oil (TR=0.01)	not drilled	not drilled	not drilled	85	93	not drilled
Ma at peak oil (TR= 0.50)				58	58	
Ma at end of oil (TR=0.99)				(max TR .96)	53	
Red River w/Type-I Green River kinetics						
Ma at start of oil (TR=0.01)	62	not drilled	not drilled	no oil	51	no oil
Ma at peak oil (TR= 0.50)	(max TR .28)				(max TR 0.04)	
Ma at end of oil (TR=0.99)						
Red River w/Type-II New Albany kinetics						
Ma at start of oil (TR=0.01)	75	not drilled	not drilled	56	59	50
Ma at peak oil (TR= 0.50)	55			(max TR 0.04)	(max TR 0.45)	(max TR 0.02)
Ma at end of oil (TR=0.99)	(max TR 0.98)					
Winnipegosis w/Type-II Woodford kinetics						
Ma at start of oil (TR=0.01)	84	not drilled	not drilled	68	62	no Winnipegosis Fm. present
Ma at peak oil (TR= 0.50)	62			(max TR 0.18)	51	
Ma at end of oil (TR=0.99)	51				(max TR 0.93)	
Duperow w/Type-II Woodford kinetics						
Ma at start of oil (TR=0.01)	78	96	98	60	60	68
Ma at peak oil (TR= 0.50)	57	70	71	(max TR 0.06)	45	(max TR 0.23)
Ma at end of oil (TR=0.99)	9	60	68		(max TR 0.67)	
Mission Canyon w/Type-IIS Phosphoria kinetics						
Ma at start of oil (TR=0.01)	135	153	144	80	85	89
Ma at peak oil (TR= 0.50)	72	82	83	52	56	68
Ma at end of oil (TR=0.99)	60	71	70	(max TR 0.80)	50	54
Charles/Ratcliff w/Type-II Alum Sh kinetics						
Ma at start of oil (TR=0.01)	71	80	79	52	57	67
Ma at peak oil (TR= 0.50)	49	61	67	(max TR 0.03)	(max TR 0.30)	(max TR 0.22)
Ma at end of oil (TR=0.99)	(max TR 0.81)	50	59			
Tyler/Heath w/Type-II Woodford kinetics						
Ma at start of oil (TR=0.01)	55	62	68	no oil	47	no Tyler Fm. present
Ma at peak oil (TR= 0.50)	(max TR 0.06)	(max TR 0.24)	56		(max TR 0.02)	
Ma at end of oil (TR=0.99)			46			

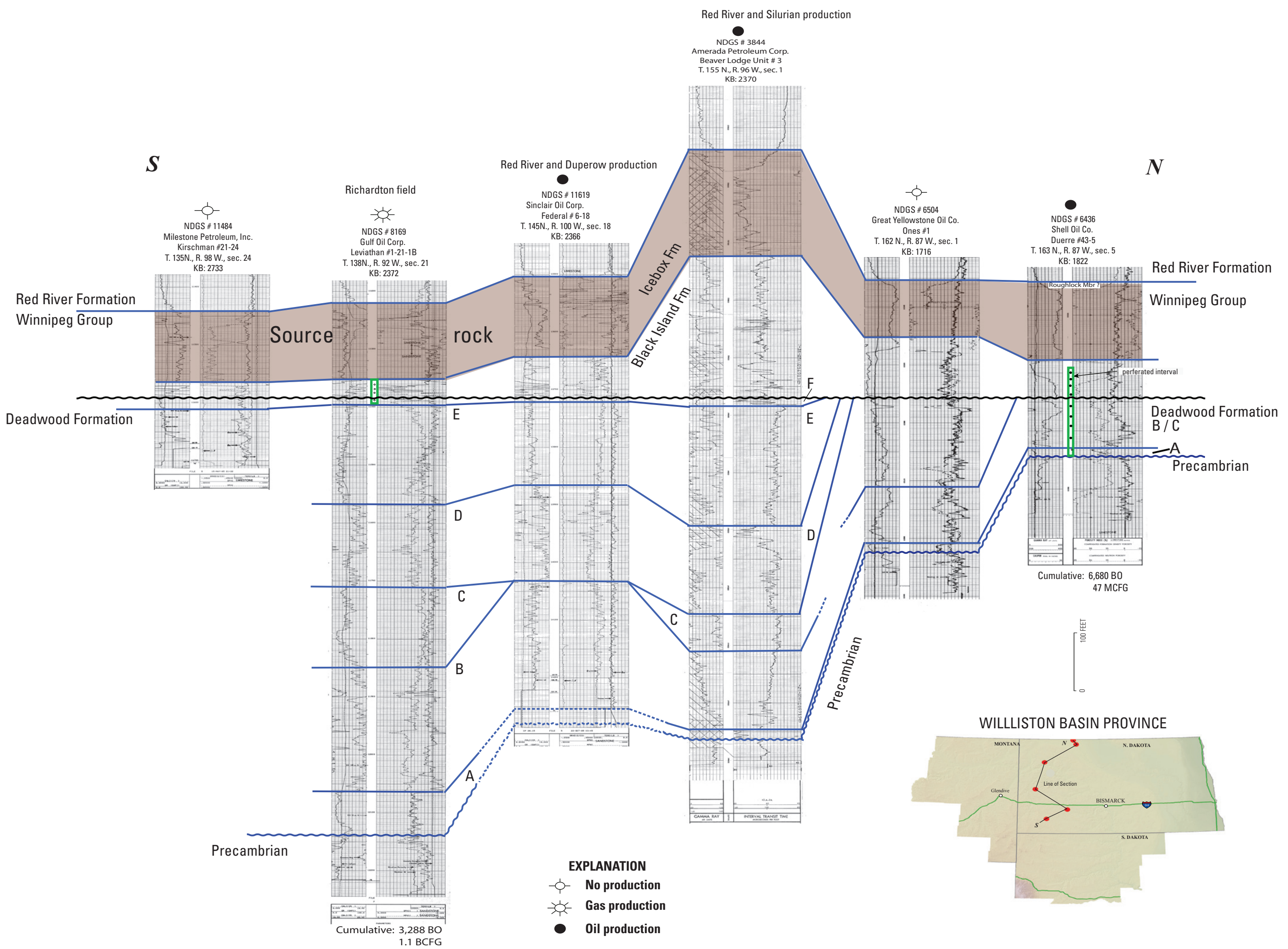

Figure 7. Wireline-log cross section of Deadwood-Winnipeg Assessment Unit strata. Letter designations (A–F) are informal members of the Deadwood Formation as shown in figure 5. Datum is the unconformity on top of the Deadwood Formation. NDGS, North Dakota Geological Survey; KB, kelly bushing (in feet); BO, barrels of oil; MCFG, thousand cubic feet of gas; BCFG, billion cubic feet of gas. (***Click here to open full-size, high-resolution image.***)

deposits. Parts of the F member were eroded during the post-Deadwood erosional event. Lateral extent of the C and D members is less than the A and B members, and the E and F members have the least lateral extent. Clean sandstone beds within the Deadwood have log-calculated porosities of 8 to 20 percent, and laterolog invasion profiles indicate some effective permeability (fig. 7).

Winnipeg Group

The Winnipeg Group is divided into three formations—Black Island, Icebox, and Roughlock—that represent a succession of transgressive deposits overlying unconformably on the Deadwood Formation. The Black Island Formation consists of transgressive deposits of sandstone with interbedded siltstone and shale in a nearshore environment. As sea level rose, shale of the Icebox Formation was deposited over the basin; then as sea level waned and clastic input started to decline, minor amounts of argillaceous limestone along with fine-grained clastic sediments that constitute the Roughlock Formation were deposited. Gradually, all clastic sedimentation ceased and carbonates of the overlying Red River Formation were deposited.

The sandstones of the Black Island Formation are the main producing reservoirs, although there may be some production from Deadwood sandstones, especially where sandstones of the A and B members lie closely beneath the unconformable contact with the Winnipeg Formation away from the basin center. Shale of the Icebox Formation is not only a petroleum source rock but could also be a fractured shale-gas reservoir in deep parts of the basin. However, no wells have yet targeted the Icebox as a potential continuous reservoir.

The Winnipeg Group reaches a maximum thickness of about 450 ft in the center of the Williston Basin (LeFever, 1996), with Black Island and Icebox Formations each reaching a maximum thickness of about 250 ft and 150 ft, respectively (fig. 6). The Roughlock Formation obtains a maximum thickness of more than 80 ft in the eastern part the basin. Depths of current fields range from less than 12,000 ft to as deep as 15,000 ft.

The transgressive sandstones of the Winnipeg Group have varying hydraulic characteristics. Porosities of clean sandstone may range from 8 to 20 percent with indications of possible permeability from laterolog invasion profiles. Porosity in bioturbated sandstone, however, is considerably lower than clean sandstone.

Traps and Seals

Traps in the Deadwood Formation and Winnipeg Group are difficult to characterize because there are few fields from which to establish trends. Most traps, however, appear to be structural with a minor stratigraphic component. Stratigraphic traps are probably rare in Deadwood and Winnipeg sandstones, as the reservoirs are commonly continuous.

Seals associated with Winnipeg-Deadwood reservoirs include shales of the Icebox Formation and the transition from shale to a limestone section between the Icebox and the overlying Red River Formation. Lateral seal potential is unknown because there are no known stratigraphic traps, so the potential for long-range migration is questionable.

Red River Total Petroleum System

The Red River TPS includes the Red River Fairway AU, the Red River Eastern Margin AU, and the Interlake-Stonewall-Stony Mountain AU (figs. 8 and 9), although there is some uncertainty as to whether Red River Formation oil migrated into the Interlake-Stonewall-Stony Mountain AU. The east boundary of the TPS is about 7,000 ft updip from the hydrocarbon generation window (within the 200 °F temperature contour; fig. 8). This boundary, which is also the east boundary of the Red River East Margin AU, is arbitrary, but allows for some eastward and northeastward migration. The west and southwest boundaries coincide closely with the Williston Basin Province boundary, but the area of the Cedar Creek Paleozoic Composite TPS boundary is excluded.

Well penetrations in this TPS represent 28 percent of all wells drilled in the Williston Basin, the predominance of which (8,000 wells, constituting 24 percent of the total) penetrate to the Red River Formation; this is a substantial increase over the total number of wells to the Winnipeg-Deadwood TPS. The Red River TPS established its carrying capacity as a reservoir with early production from the Nesson and Cedar Creek anticlines (fig. 1). The maximum number of Red River completions occurred in 1981 reaching nearly 280. Average field depth is about 13,000 ft and has varied only slightly since the first discovery (NRG Associates, Inc., 2008).

The Red River Formation consists of cyclic successions of thick limestone and dolomite that is more than 700 ft thick in the center of the basin and thins outward to a zero edge to the east and south. The formation consists of mostly marine limestone and becomes more dolomitic near the basin margin. The upper half of the formation is divided into four depositional cycles, cycles D through A, in ascending order. These cycles consist of a basal burrowed lime mudstone, a middle laminated dolostone, and an upper anhydrite. Petroleum source rocks are in the lower half of the formation (below the D interval) and consist of numerous thin organic-rich kerogenites.

Petroleum Source Rocks

Probable sources of oil in Red River TPS reservoirs are organic-rich zones that are mostly in or below the D interval of the Red River Formation (Kohm and Louden, 1988, their lower C zone; Longman and Palmer, 1987; Osedetz and others, 1992). These rocks were deposited in a shallowing-upward but deep-water anoxic shelf environment as algal-rich (*Gloeocapsamorphe prisca*) lime mudstones called kukersites or kerogenites. However, Carroll (1979) believed they were shallow intertidal pond deposits, which may have implications as to their lateral extent. The various cycles of kerogenites can be traced laterally within short distances, as in a field; however, they are not readily recognizable on geophysical logs, thus mapping their regional extent is controlled by the availability of core descriptions (fig. 10).

Mean values for Rock-Eval data (Osadetz and others, 1992) for Red River Formation source rocks (Canadian sample locations) are kerogen, Type I; S1, 1.24; S2, 77.33; S3, 1.00; TOC, 9.07 percent by weigh (ranges from 5 to 35 percent); HI, 728; and OI, 22.6. Burrus and others (1995) reported that Red River source rocks in Canada have a mean TOC of 8 percent by weight.

Dow (1974) did not recognize a Red River source and speculated that Red River reservoirs were sourced by the underlying Icebox Formation of the Winnipeg Group. However, later studies showed that the two oils are distinctive and each formation is self-sourced (Osadetz and Snowdon, 1995; Smith and Bend, 2004).

Source Rock Thermal Maturity

The thermal history of the Red River Formation source rocks is uncertain because there is little information as to its geochemical and kinetic parameters. Burial history modeling showed that the areal extent of thermal maturity of Red River source rocks was limited to the deepest parts of the Williston Basin at the Red River horizon (table 1), but DST measured temperatures (fig. 8) show an area having temperatures of more than 200 °F (temperature of oil generation) that is three times the area determined from burial history modeling. However, the temperatures are conservative because of the removal of approximately 2,000 ft of sediment in Neogene time.

Kerogenites apparently reached gas generation temperatures as there have been several gas discoveries in recent years at depths of more than 12,000 ft and within the temperature range of 250 °F to 300 °F. Produced gas from the Red River Formation generally carries large amounts of hydrogen sulfide

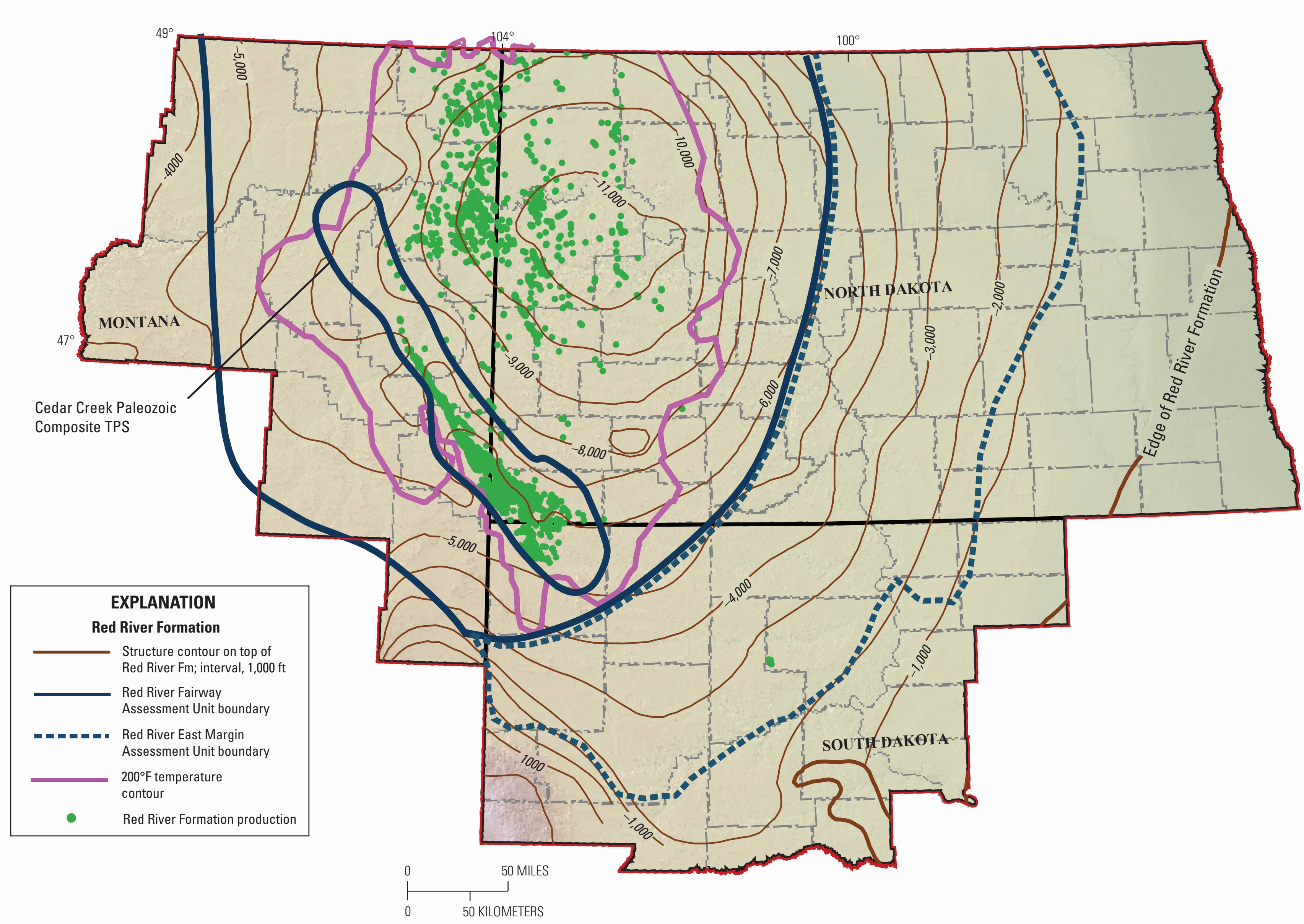

Figure 8. Williston Basin Province showing Red River Formation boundaries, assessment unit boundaries, general location of producing wells, and the 200°F temperature contour.

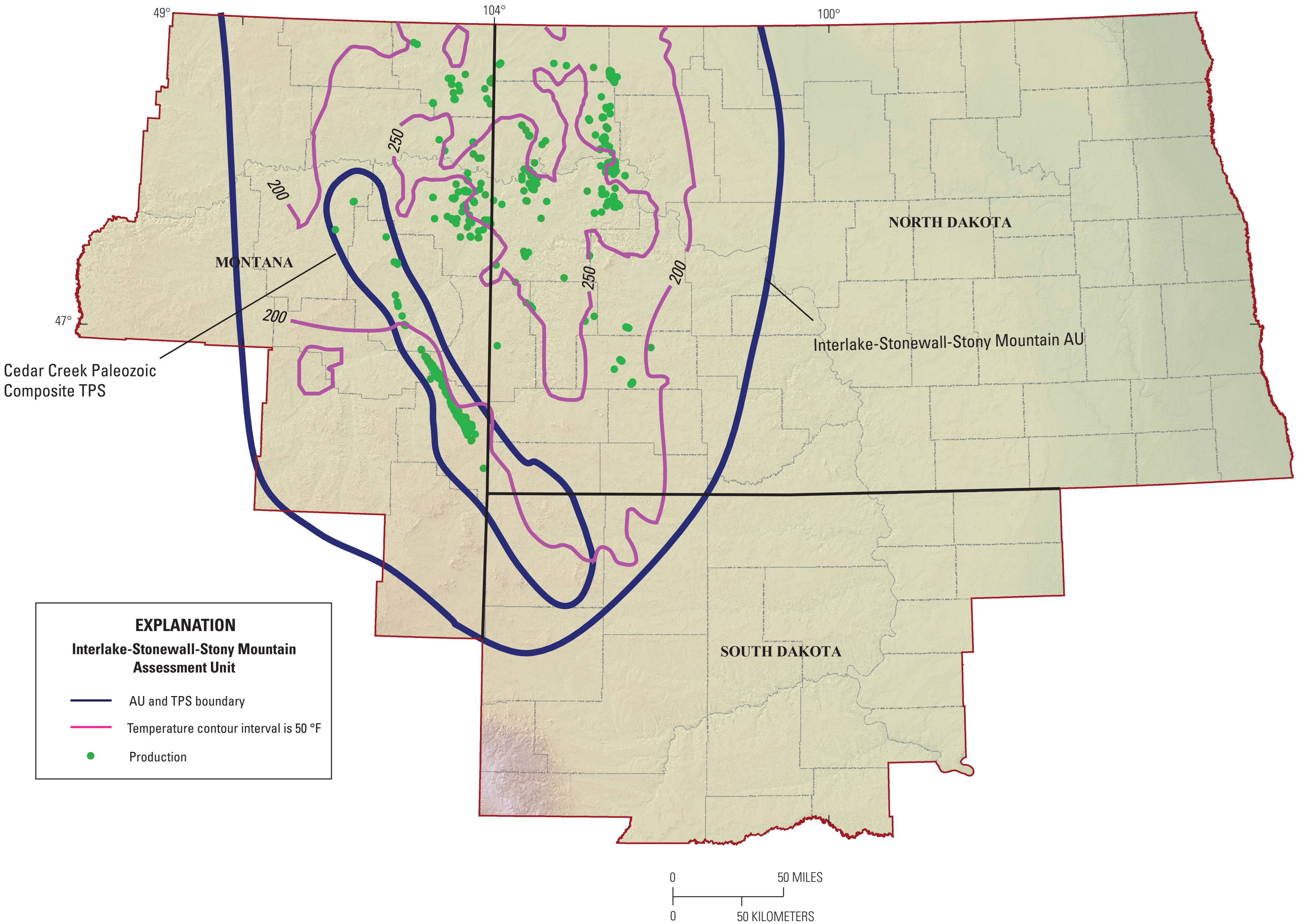

Figure 9. Williston Basin Province showing Interlake-Stonewall-Stony Mountain Assessment Unit production distribution, assessment unit boundary, and selected drill-stem-test-derived temperature.

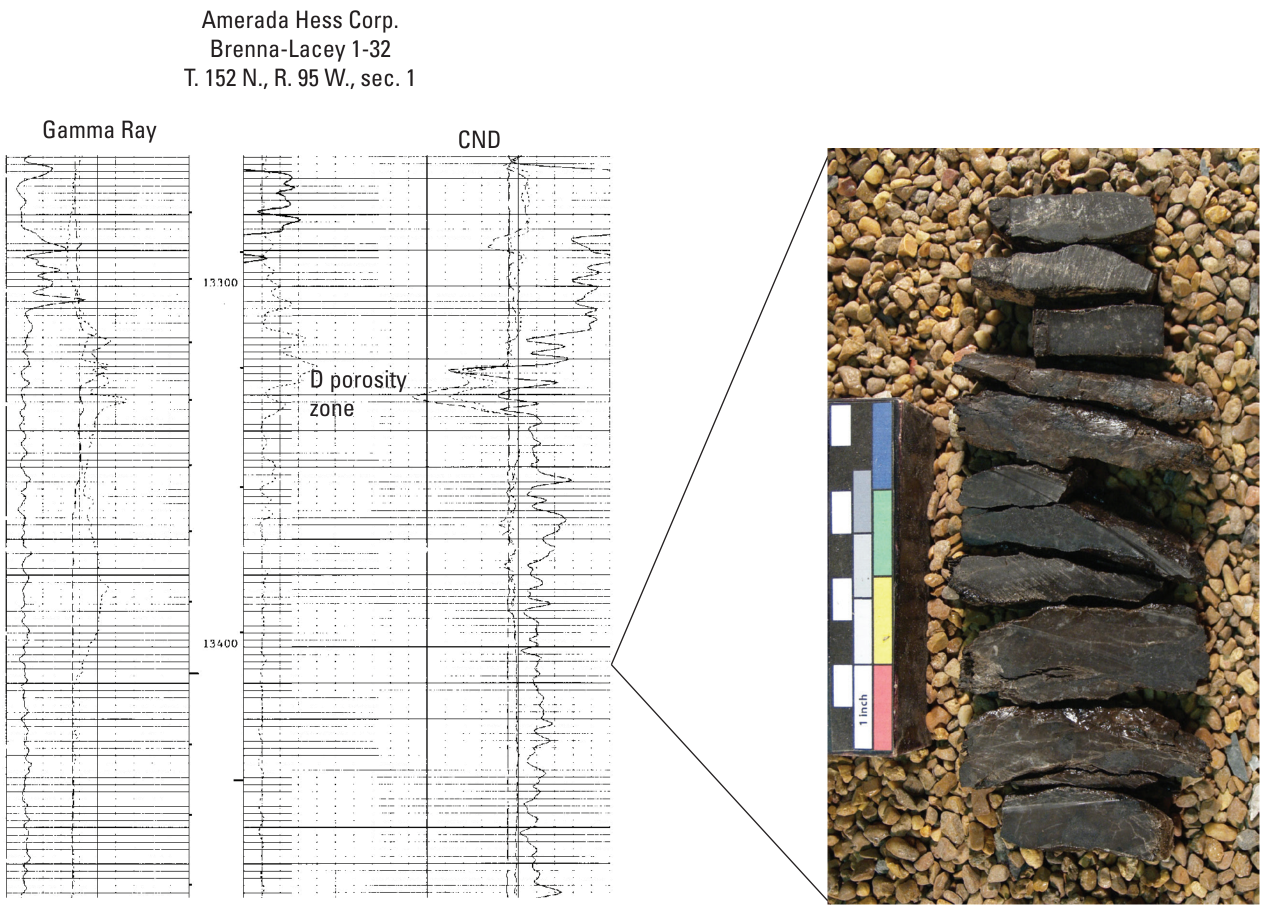

Figure 10. Diagram showing stratigraphic position of a possible Red River Formation source rock as interpreted from wireline logs.

gas (H_2S), which may be explained by (1) thermal cracking of sulfur-rich kerogen or oil, although this generally produces less than 2 percent H_2S, and it is unclear if temperatures were reached that would crack either kerogen or oil to gas; (2) bacterial sulfate reduction can produce as much as 10 percent H_2S because more than 10 percent is toxic to bacteria; and (3) concentrations of H_2S greater than 10 percent could be ascribed to thermochemical sulfate reduction (TSR), anhydrite being the source for sulfate. TSR tends to oxidize the longer alkane chains more rapidly than the shorter chains, which leads to the formation of dry gas; however, some Red River gases appear to be wet given the apparent extent of TSR (26 percent H_2S). The minimum temperature range for TSR is thought to be about 250 °F, and the maximum temperature for bacterial sulfate reduction is 175 °F, so this adds more support for the TSR interpretation. Because oils and kerogen in this area are low in sulfur, the bacterial sulfate reduction is not likely a contributor. Because of temperature conditions, the observed concentrations of H_2S, and the low-sulfur content of the oils and kerogen, indicates that the best explanation for gas in the Red River is the TSR process (Geoffrey Ellis, USGS, written commun., 2009).

The use of vitrinite reflectance (R_o) to predict source rock maturity is not reliable, given that few vitrinite substances are deposited in marine carbonate sediment. In addition, source rocks in the basin, like the Mississippian Bakken Formation, have suppressed vitrinite and are not reliable in predicting maturity. However, the use of calculated R_o equivalent indices, percent Rc (Smith and Bend, 2004), indicates that Red River oils in Canada are of low maturity, equivalent to an R_o of 0.62 percent. Dow (1974) determined that the top of the oil generation window was at –5,000-ft-subsea elevation and speculated that the critical depth for oil generation and expulsion is about 7,000 ft for most source rocks.

Hydrocarbon Migration

Hydrocarbon migration in the Red River Formation is poorly understood because the lateral distribution of source rock, kinetics, extent of hydrocarbon generation, hydraulic pressure potential, permeability trends, and possible buoyancy pathways are poorly understood. It is known, however, that there was long-range migration with the discovery of Red

River oil at Lantry field, some 100 mi southeast of the Cedar Creek anticline (fig. 1). Lantry field is a stratigraphic trap possibly due to a post-Silurian unconformity (fig. 11). Migration occurred from either buoyancy forces or from being "carried" in the direction of groundwater flow to the southeast, perpendicular to the present-day direction.

In addition, a DST-derived temperature map of the Red River (fig. 8) shows that most Red River hydrocarbon generation occurred in the U.S. part of the Williston Basin; therefore, migration is the most probable method to source Red River reservoirs in southeastern Saskatchewan, Canada; the northernmost field is nearly 100 mi north of the International border.

Kahn and others (2006) reported that source rocks are absent east of the Nesson anticline (fig. 1) and that hydrocarbons generated in areas near or west of the Nesson anticline migrated to the north, west, and south, but not to the east. Several well reports (North Dakota Oil and Gas Commission, 2009), however, indicate free oil and minor gas in DST and mud logs and hydrocarbon shows in drill cuttings in the Red River Formation east of the Nesson anticline (eastern Dunn County, southwestern McLean County, and southeastern Mountrail County). It is unclear if these hydrocarbons migrated from the west or southwest or were generated locally. East of the Nesson anticline, a DST temperature map (fig. 8) shows that Red River Formation temperatures range from 200 °F to 275 °F, implying that Red River source rocks, if present, could be in the oil generation window.

Red River Formation oil migrated into units above the Red River Formation, including the Stony Mountain, Interlake, and Stonewall Formations (fig. 12). Although these formations, especially the Interlake, possibly contain strata and have a temperature range (fig. 9) that could generate oil, limited data indicate that these formations contain Red River oil. Migration paths from a Red River source to overlying reservoirs were probably complex; that is, hydrocarbons migrated vertically through faults or fracture networks, then horizontally through carrier beds.

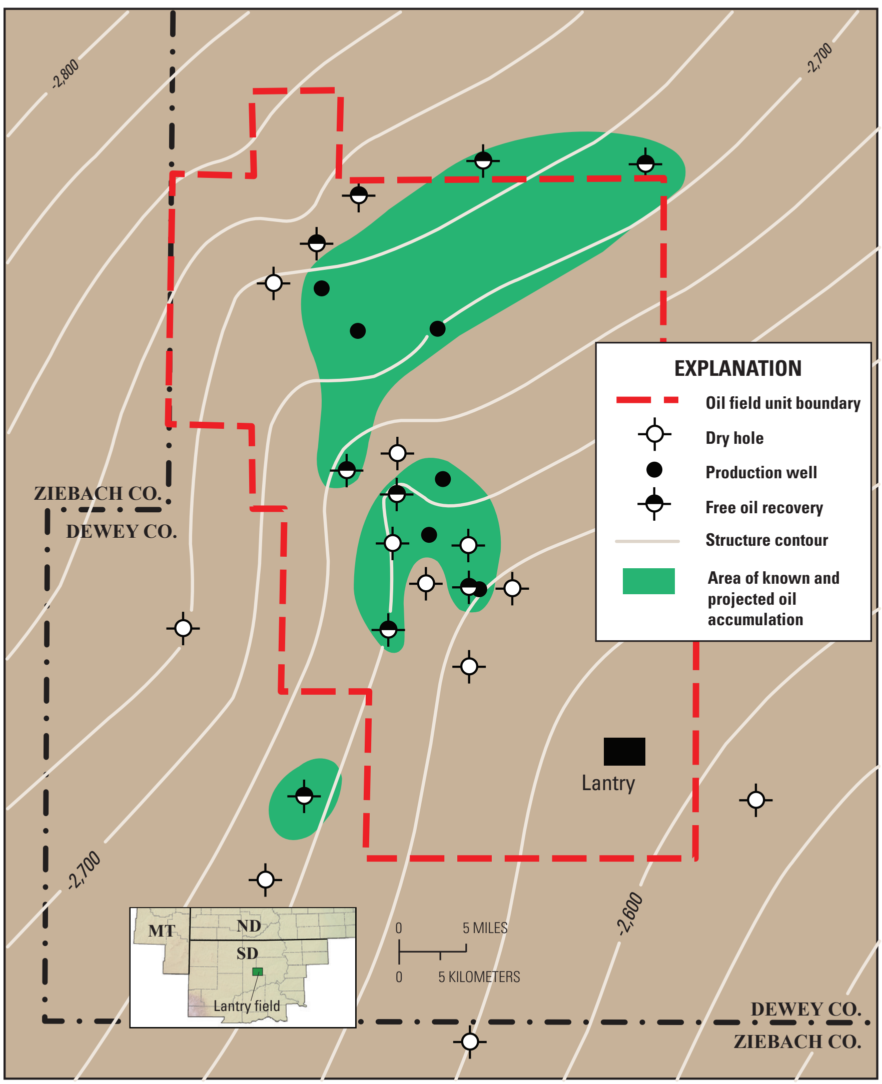

Figure 11. Lantry field with production from the Red River Formation.

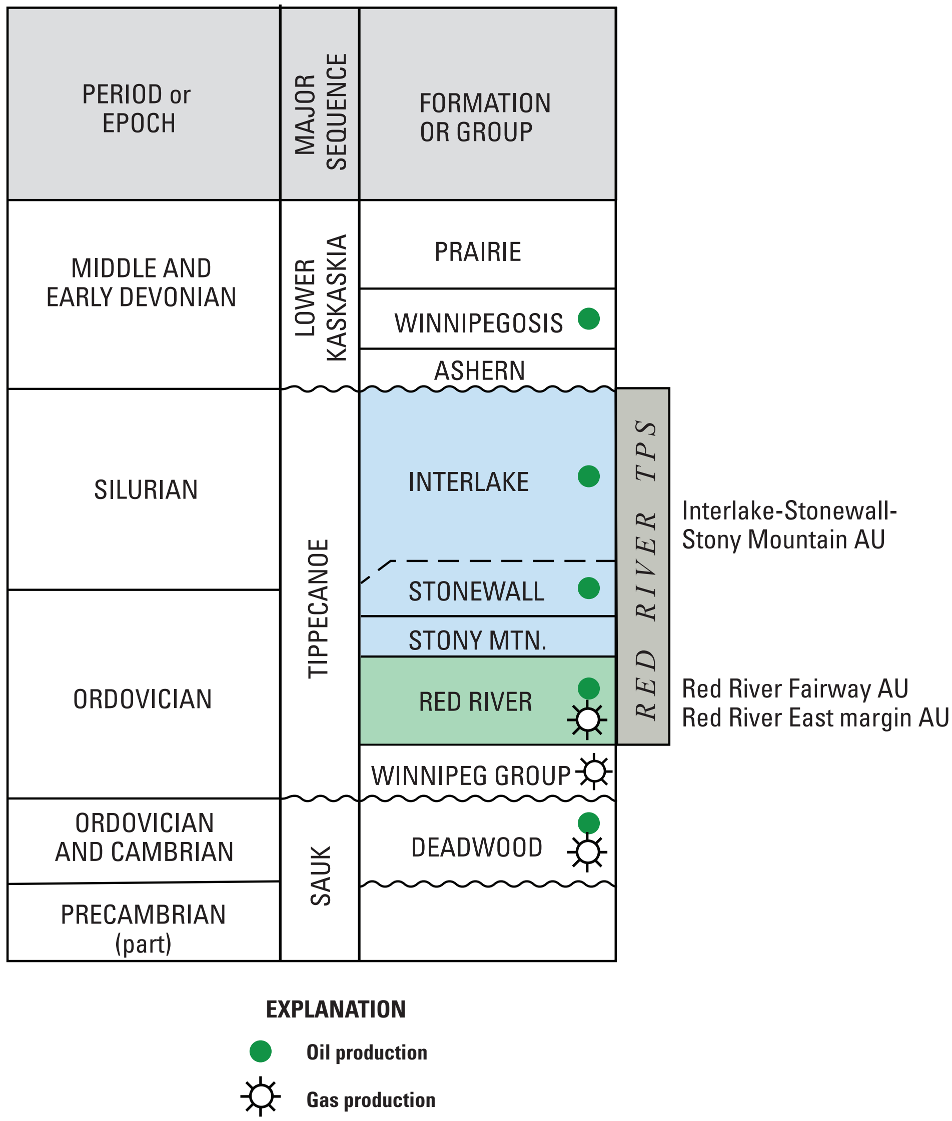

Figure 12. Stratigraphic chart showing units associated with the Red River Total Petroleum System (TPS) and associated assessment units (AU).

Red River Formation oil in the Cedar Creek anticline area (fig. 1) probably migrated to the southwest, updip from deeper parts of the basin, and then was rearranged by hydrodynamics created from structural adjustments during the Laramide orogeny. Further discussion on the Cedar Creek area is in the Cedar Creek Paleozoic Composite TPS section of this report.

Reservoir Rocks

Red River Formation

The Red River Formation has been extensively studied in the subsurface of the Williston Basin (Porter and Fuller, 1959; Kent, 1960; Kendall, 1976; Kohm and Louden, 1978; Carroll, 1979; Derby and Kilpatrick, 1985; Longman and others, 1983; Longman and Haidl, 1996; Canter and others, 2001). Cyclic successions of thick limestone and dolomite are more than 700 ft thick in the center of the basin and thin to zero to the east and south (fig. 13). The lower half of the formation consists of mostly marine limestone, deposited in subtidal to deep intertidal environments. At the periphery of the basin, the limestone becomes more dolomitic as the shelf became shallower (Foster, 1972). The upper half of the formation is divided into four depositional cycles, which are named D through A in ascending order. Each of these cycles consists of three parts: (1) a basal burrowed lime mudstone, deposited in a subtidal environment, (2) a middle laminated dolostone, deposited in a restricted intertidal to penesaline environment, and (3) an upper anhydrite, deposited in a restricted upper peritidal to penesaline environment but rarely a sabkha environment.

The main reservoir rock in the Red River Formation is in the middle laminated zone, and it has been debated as to whether it originated as an organic or inorganic sediment. Carroll (1979) and Derby and Kilpatrick (1985) interpreted it to be organic, deposited in a peritidal and restricted water

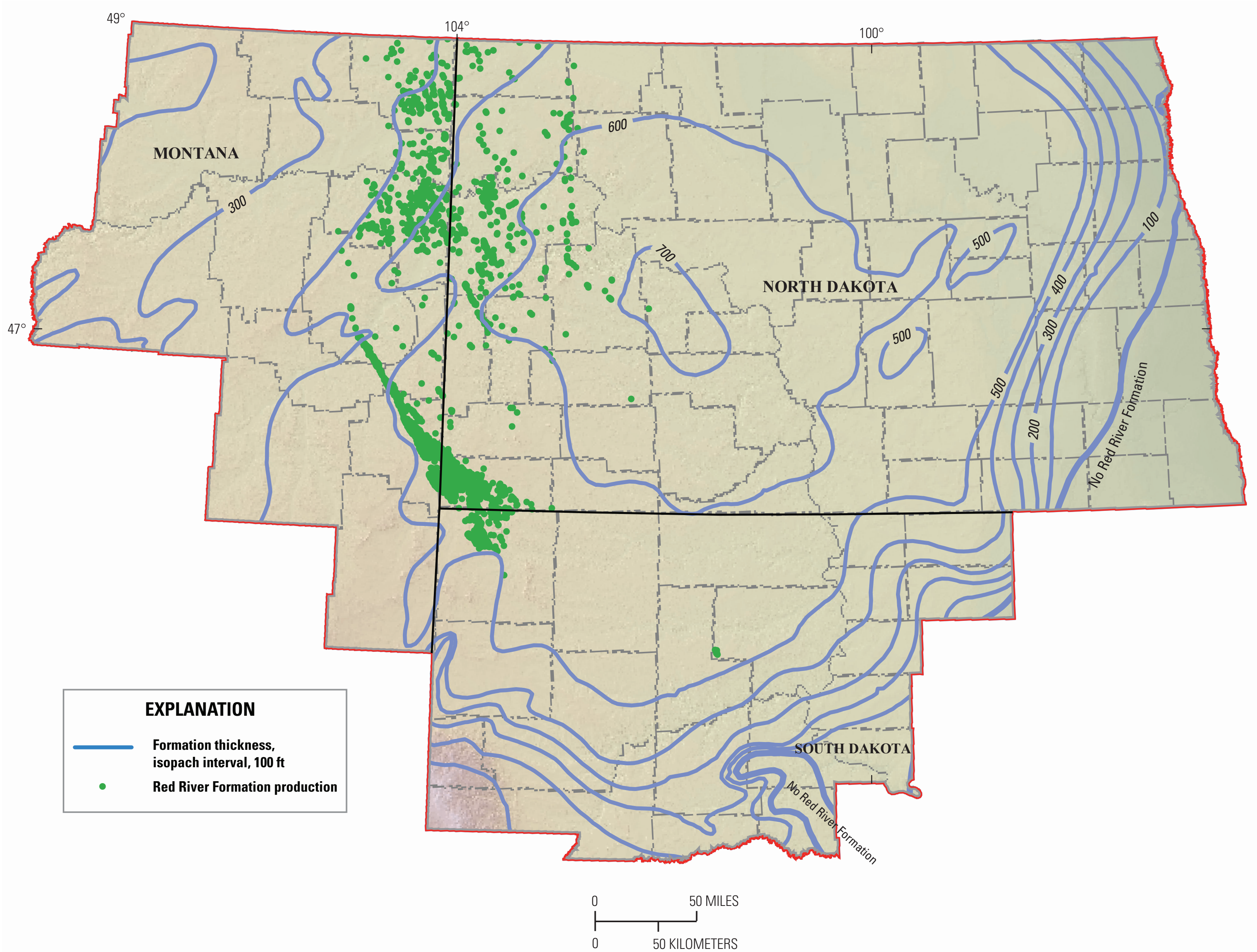

Figure 13. Red River Formation thickness and general location of production wells.

depth environment, whereas Kendall (1976), Kohm and Louden (1978), and Longman and others (1983) interpreted it to be inorganic, deposited in a high-salinity restricted subtidal environment.

Cycles in the upper Red River Formation are regionally extensive and various marker beds that define the cycles can be traced by wireline logs over most of the basin (fig. 14*A*, *B*, and *C*). However, detailed descriptions indicate substantial internal variability within each cycle, especially laminated or main reservoir intervals (Canter, 1998). The variability is due in part to dolomitization patterns, depositional facies, and paleostructural position.

Dolomitization patterns were controlled by paleostructure and possibly syndepositional structures and lesser amounts by present-day structure. Paleostructure was instrumental in determining water depths, thus producing restricting environments, and the location and character of faults and fracture networks helped facilitate downward migration of magnesium-concentrated brine. Dolomitization patterns are characterized as (1) cone shaped with nonporous cryptocrystalline dolomite at the top, funneling downward to lesser amounts of porous dolomite at depth (Longman and Haidl, 1996); (2) linear patterns of dolomite resulting from downward dolomitizing brines controlled by faults and fracture patterns (Kohm and Louden, 1978); and (3) a regional dolomitization pattern from flow pathways that promoted subsurface dolomitization. More specifically, the laminated zone C may be dolomitized over a large area, but the burrowed part is commonly not dolomitized or only partly dolomitized (Neese, 1985), and porosity in laminated parts of the C and D zones are typically the best developed on flanks of paleostructures (Neese, 1985; Carroll, 1978). Porosity can be developed by dissolution shortly after deposition or after deep burial especially in the D zone in the southwestern part of the basin where water depths were shallow over the Cedar Creek structural high and exposed to large quantities of meteoric water.

Hydraulic parameters in reservoir-quality rock are controlled in part by original rock fabric and subsequent diagenetic alteration (Canter and others, 2001); that is, the character of the original fabric controls crystal size and distribution that may control diagenetic alteration. Unimodal grain size contributes to good reservoir-quality rock because it creates the best porosity, permeability, and capillary pressure parameters. Bi- or multi-modal grain size, however, creates restricted pore throats, low fluid-entry pressures, and high irreducible-water saturations (Ruzyla and Friedman, 1982). Core-derived porosity values in good reservoir rock can range from less than 5 to more than 20 percent, and permeability can range from less than 1 to more than 400 millidarcies (mD), but commonly is less than 50 mD. Field-scale permeability, however, may be higher than core-scale permeability because of an increase in large-scale fracture permeability. Reservoirs with high irreducible-water saturations (small pore throats) tend to have permeabilities less than 10 mD.

Water production is variable, although reservoirs with water drives tend to produce more water than pressure depletion drives. Oil-water contacts are not always sharp but are commonly transitional because of the heterogeneous pore distribution in the reservoir and because of a diverse vertical porosity and permeability distribution.

Stony Mountain Formation

The Stony Mountain Formation, overlying the Red River Formation (fig. 15), is divided into the Stoughton and Gunton Members in ascending order. The contact of the Stoughton Member with the underlying Red River is sharp and may be the result of a minor unconformity, possibly from a regressive surface of erosion. The contact of the Gunton Member with the overlying Stonewall Formation appears to be conformable.

The Gunton Member consists of one depositional cycle, similar to the cycles of the Red River Formation, which includes (1) a lower subtidal burrowed lime mudstone with low porosity and permeability; (2) a middle laminated dolostone and boundstone, with fair to good porosity and permeability, deposited in a restricted intertidal to penesaline environment; and (3) an upper anhydrite, deposited in a restricted upper peritidal to penesaline environment.

The Stoughton Member, informally called the Stony Mountain shale by some workers, is a variegated, argillaceous dolomite with interbedded calcareous shale beds containing various percentages of shell fragments. Geophysical log characteristics indicate the member is shale (fig. 16*A* and *B*), although it has little potential as a source rock. This unit may act as a barrier to upward Red River oil and gas migration except along open faults and through fracture zones.

Stonewall Formation

The Stonewall Formation, similar to the carbonate successions of the upper Red River Formation and the Gunton Member of the Stony Mountain Formation, contains a basal burrowed limestone of low porosity and permeability, a middle porous and permeable burrowed and laminated dolostone, and an upper anhydrite or anhydritic mudstone. These cycles, however, are thinner than those in the Red River and are generally abbreviated and not well defined. This characteristic may create the potential for stratigraphic traps because of the lateral lithologic variability, but no such traps have been described. The best Stonewall production is on large structures such as the Nesson anticline, where the middle porosity zone thickens at the expense of the lower zone. Off structure,

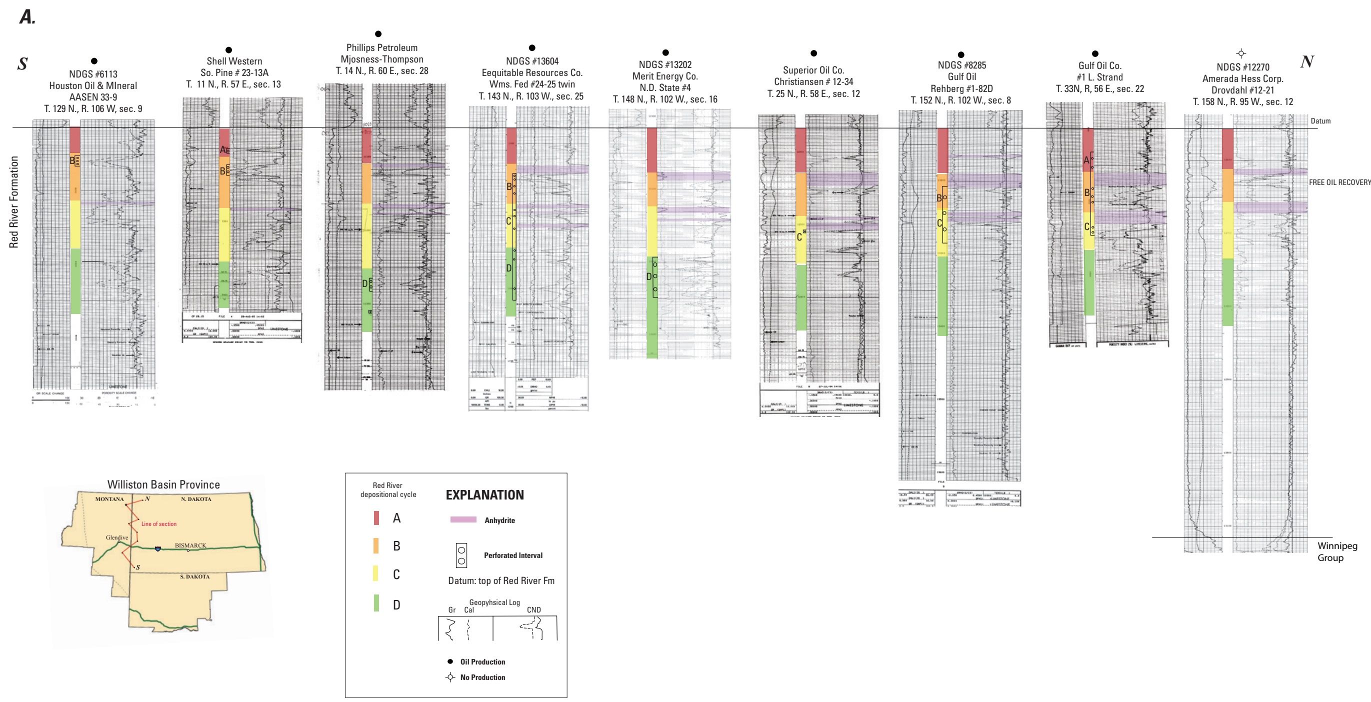

Figure 14. Wireline-log cross section of the Red River Formation showing depositional cycles across the Williston Basin. (*A*) North–south section; (*B*) west–east section north of Highway I-94; (*C*) west–east section south of Highway I–94. NDGS, North Dakota Geological Survey; GR, gamma ray; Cal, caliper; CND, compensated neutron density; DST, drill-stem test, KB, Kelly bushing elevation, in feet.
(***Click here to open full-size, high-resolution image.***)

the porosity zone remains a dolomite but its thickness and porosity decrease. It is unclear how and why better porosity zones are developed, although positive paleostructures possibly influenced primary sedimentation fabric, which in turn controlled selective dolomitization or dissolution.

Thickness of the Stonewall can be more than 120 ft at the center of basin (Carlson and Anderson, 1966) and thins toward the edge of the basin. Thinning occurs because of convergence.

Interlake Formation

The Silurian Interlake Formation (Roehl, 1967) records the deposition of the latest Tippecanoe sequence of Sloss (1963). The formation conformably overlies the Stonewall Formation (fig. 15), and a major unconformity separates the Interlake from the overlying Middle Devonian Ashern Formation. LoBue (1982) informally subdivided the Interlake Formation into three members and Megathan (1987) assigned group status to the Interlake and defined eight formations within it, although, Inden and others (1988) considered the Interlake to be a formation.

The Interlake Formation consists mostly of muddy dolostone and contains numerous, generally thin, shallowing upward, restricted marine cycles of thick dolomitic boundstone and thin dolomitic grainstone, packstone, and mudstone. The boundstone grades upward from algal boundstone to fenestral and algal laminae, to caliche crusts and pisolitic zones. Porosity is developed from fenestral structures and solution enlargement of original, commonly vuggy pore space. Nonporous zones developed from previous porous zones that became filled with fine-grained sediment, microcrystalline dolomitization, and secondary cement.

Reservoir characteristics are difficult to define and potential productive zones can be by-passed because of (1) a lack of distinctive log character from porous to nonporous zones; (2) homogeneous character in well cuttings; (3) high water saturations in productive zones; and (4) limited understanding of reservoirs types, salt plugging, and fracture characteristics (Inden and others, 1988). On the basis of limited data, porosity in reservoir rocks ranges from 5 to 24 percent (Inden and others, 1988), and nonreservoir rock porosity can be 10 percent or less. Bimodal porosity and small pore throats commonly result in low permeability, high capillary pressure, and high water saturations.

The upper Interlake Formation is productive along the Nesson anticline and the Mondak trend (fig. 1), but the controls on production are poorly understood. The middle Interlake Formation has minor production along the Mondak trend, and the lower Interlake produces from the Putnam zone (fig. 16*A* and *B*), informally named for the field from which it produces.

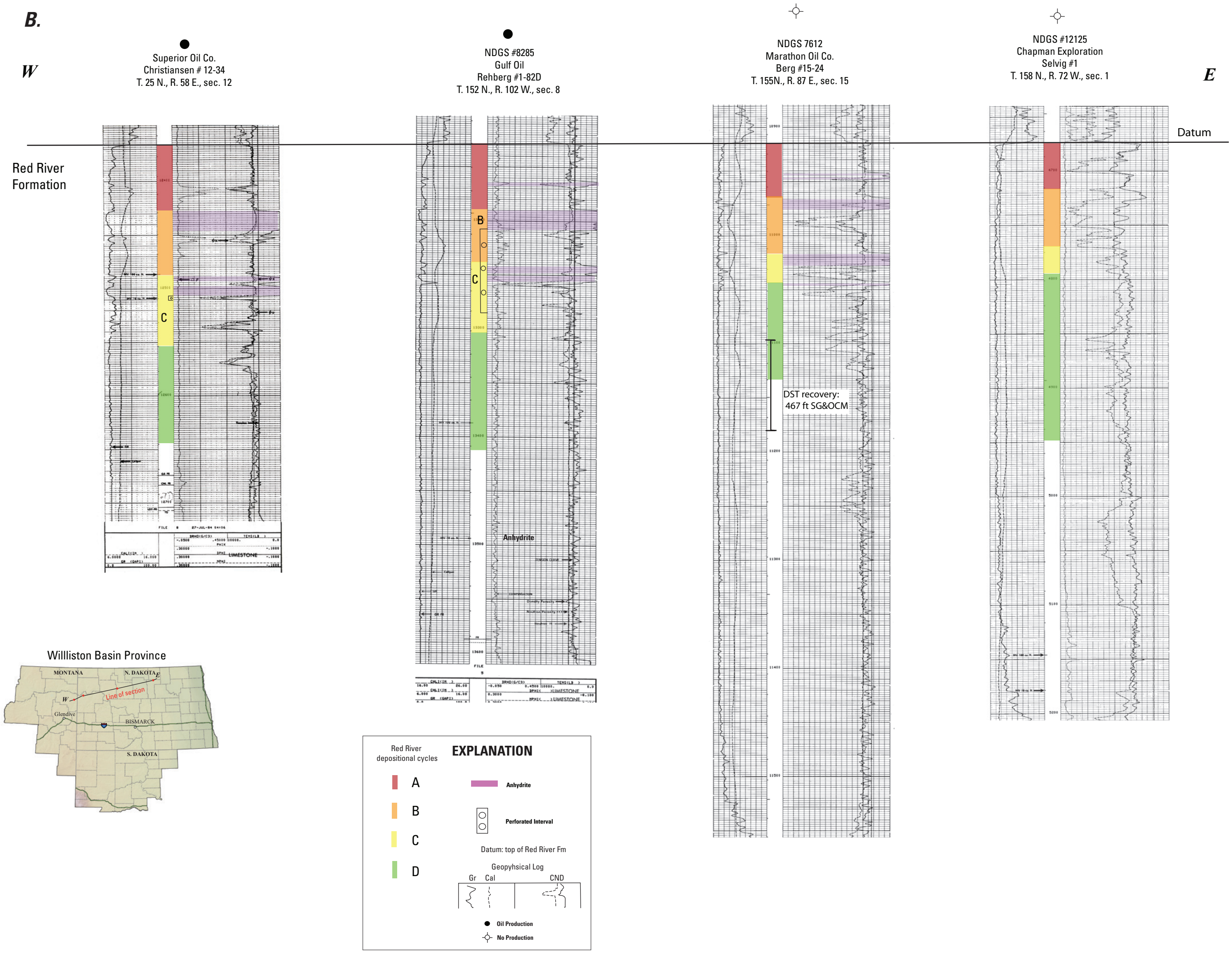

Figure 14. Wireline-log cross section of the Red River Formation showing depositional cycles across the Williston Basin. (*A*) North–south section; (*B*) west–east section north of Highway I-94; (*C*) west–east section south of Highway I–94. NDGS, North Dakota Geological Survey; GR, gamma ray; Cal, caliper; CND, compensated neutron density; DST, drill-stem test, KB, Kelly bushing elevation, in feet.—Continued (***Click here to open full-size, high-resolution image.)***

Traps and Seals

Traps in the Red River TPS can be characterized as structural with stratigraphic enhancement, although there are two fields with stratigraphic traps—Horse Creek in the Red River D zone and Cedar Hills in the Red River B zone (Longman and others, 1992). In the Red River Fairway AU (fig. 8), paleostructure is key to an understanding of the relation between structure and reservoir development where numerous small closures are superimposed on regional uplifted areas or structural noses. Paleostructures generally coincide with present-day structure, but in places they are offset or have an opposite direction of movement, which results in porosity changes on and off the flanks of structures. The potential for stratigraphic traps developed where paleostructure influenced sedimentation patterns, such as the location of shoal deposits that formed on structural highs. Although these deposits are thin and discontinuous, they are good reservoirs with lateral seals. For example, grain-supported porous beds in the laminated unit in the C zone of the Red River Formation are present over and adjacent to paleohighs. Red River C zones tend to produce on present-day structures, whereas Red River D zones, which are tight on the crest of anticlines, produce off present-day structures.

Winnipegosis Total Petroleum System

The Winnipegosis TPS and AU (fig. 17) are thought to be self-contained, in that hydrocarbons generated in this unit have not migrated to other units. The boundary of this TPS follows the coastal plain and shelf depositional environment interface of the Winnipegosis Formation.

C.

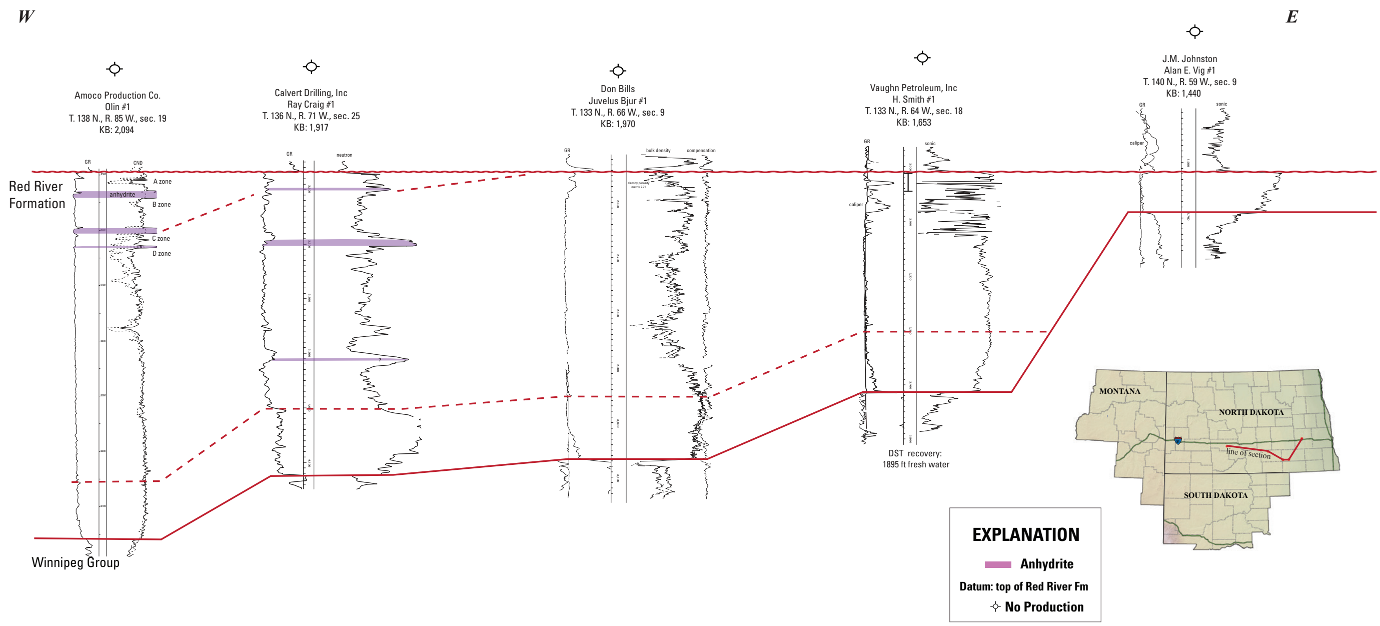

Figure 14. Wireline-log cross section of the Red River Formation showing depositional cycles across the Williston Basin. (*A*) North–south section; (*B*) west–east section north of Highway I-94; (*C*) west–east section south of Highway I–94. NDGS, North Dakota Geological Survey; GR, gamma ray; Cal, caliper; CND, compensated neutron density; DST, drill-stem test, KB, Kelly bushing elevation, in feet.—Continued (*Click here to open full-size, high-resolution image.*)

Well penetrations to the Winnipegosis Formation, numbering more than 9,500, represent 28 percent of all wells drilled in the Williston Basin. Only115 of these wells have a recorded initial production (IHS Energy Group, 2008), a success ratio of less than 1 percent, but this should increase as lower Paleozoic formations become primary targets. More than half of the producing wells were drilled in the 1980s, with only a few drilled in earlier years and some in the 1990s and later (IHS Energy Group, 2008). Average field depth is, and continues to be, about 11,000 ft.

Petroleum Source Rocks

Source rocks for the Winnipegosis TPS, primarily in the lower part of the Winnipegosis Formation, are thin, organic-rich, argillaceous limestone deposited in shallow parts of the Elk Point Basin platform (fig. 18). Organic-rich limy shale layers interbedded with limestone layers in the deeper parts of the basin platform, mostly in Canada, are also source rocks, but their total thickness is unknown.

Oil generated from Winnipegosis Formation source rocks has a chemical composition (Osadetz and others, 1992; Jarvie, 2001) that differs from oils in the underlying Red River TPS and the overlying Duperow TPS; however, the distinction is not great, and additional data are needed for more conclusive comparisons. Average geochemical parameters include TOC, 0.59 weight percent; HI, 120 mg HC/g TOC (Osadetz and Snowdon, 1995); and API, 35.7° (Osadetz and others, 1992).

The Ashern Formation (fig. 2) may be a hydrocarbon source, although in the U.S. part of the Williston Basin, the lithology of the Ashern is not as organic rich as it is in the Canadian part. The Ashern is a reddish (from reworked karsted Interlake Formation), fossil-poor dolostone in the lower part transitioning upward to a gray dolostone, with both parts having various amounts of interspersed and interbedded anhydrite.

Source Rock Thermal Maturity

The thermal maturity history of the Winnipegosis source rocks is uncertain because there is little information as to geochemical and kinetic parameters. Burial history modeling shows that the areal extent of thermal maturity of the Winnipegosis source rocks was limited to the deepest parts of the basin. Measured temperatures from DSTs show an area of temperatures 200 °F or greater (fig. 19) in northwestern North Dakota and northeast Montana, although the temperature may be conservative because of the removal of approximately 2,000 ft of sediment in the Neogene.

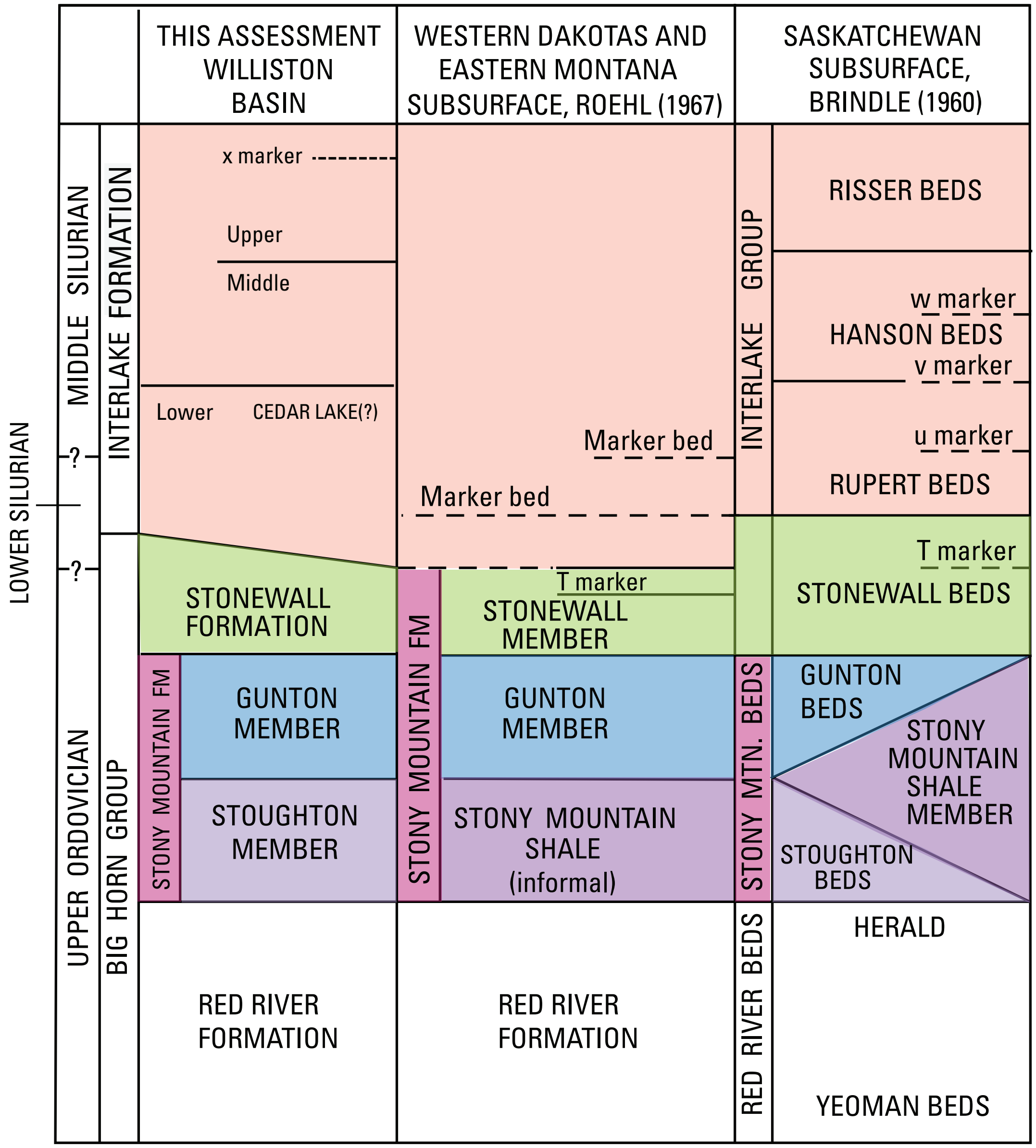

Figure 15. Correlation chart for the Upper Ordovician and Silurian Interlake-Stonewall-Stony Mountain Assessment Unit and the Red River Total Petroleum System.

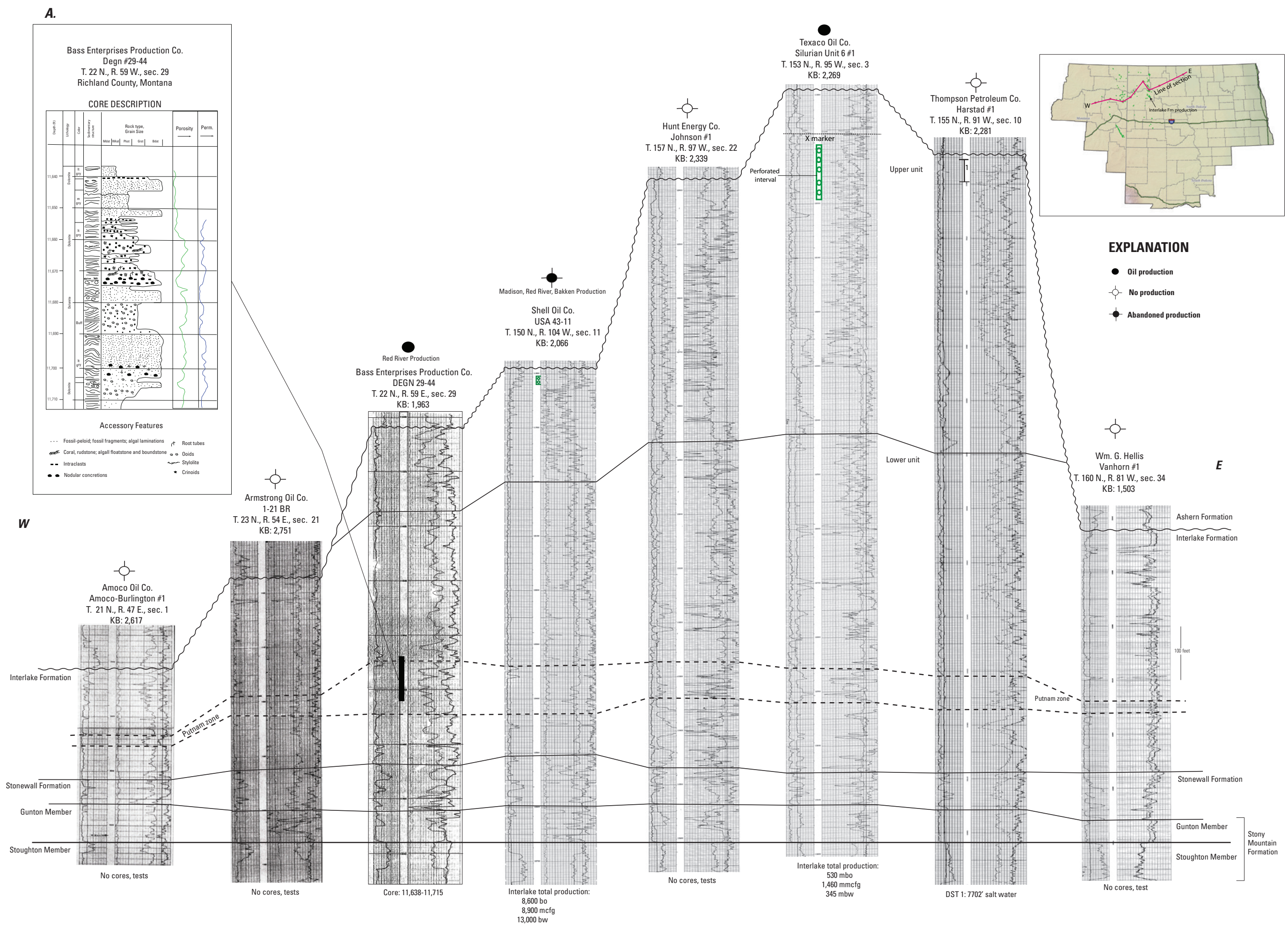

Figure 16. (*A*) West-east section; (*B*) North-south section. Wireline-log cross section showing formation contacts, producing intervals, and core description of the Interlake- Stonewall-Stony Mountain AU. Datum is on top of the Stoughton Member. Core description is modified from Inden and others (1988). In core description, porosity column is green where porosity is greatest. BO, barrels of oil; mcfg, thousand cubic feet of gas; bw, barrels of water; mbw, thousand barrels of water; DST, drill-stem test; KB, Kelly bushing elevation in feet; Mdst, mudstone; Wkst, wackestone; Pkst, packstone; Grst, grainstone; Bdst, boundstone.
(***Click here to open full-size, high-resolution image.)***

Hydrocarbon Migration

Hydrocarbon migration in the Winnipegosis Formation is poorly understood because the lateral distribution of source rock, kinetics and extent of hydrocarbon generation, hydraulic pressure potential, permeability trends, and possible buoyancy pathways are poorly understood. All Winnipegosis production is within the 200 °F contour or more (fig. 19), indicating that there was little if any lateral migration from the oil generating area. It is unclear if accumulations in Saskatchewan are from migrated or locally generated hydrocarbons because there is an area in Canada that is in the oil generation window with temperatures between 200° and 250 °F. There are thick and extensive zones of high porosity and permeable dolostone in the Winnipegosis that could act as carrier beds for hydrocarbons, in addition to major northeast-trending structural features that could provide pathways for significant hydrocarbon migration.

Reservoir Rocks

Winnipegosis Formation

The Middle Devonian Winnipegosis Formation of the Elk Point Group overlies the Ashern Formation and underlies the Prairie Formation (informally referred to by some workers as Prairie evaporite or salt) of the Elk Point Group (fig. 2). The Winnipegosis was deposited in the Elk Point Basin (fig. 18), a

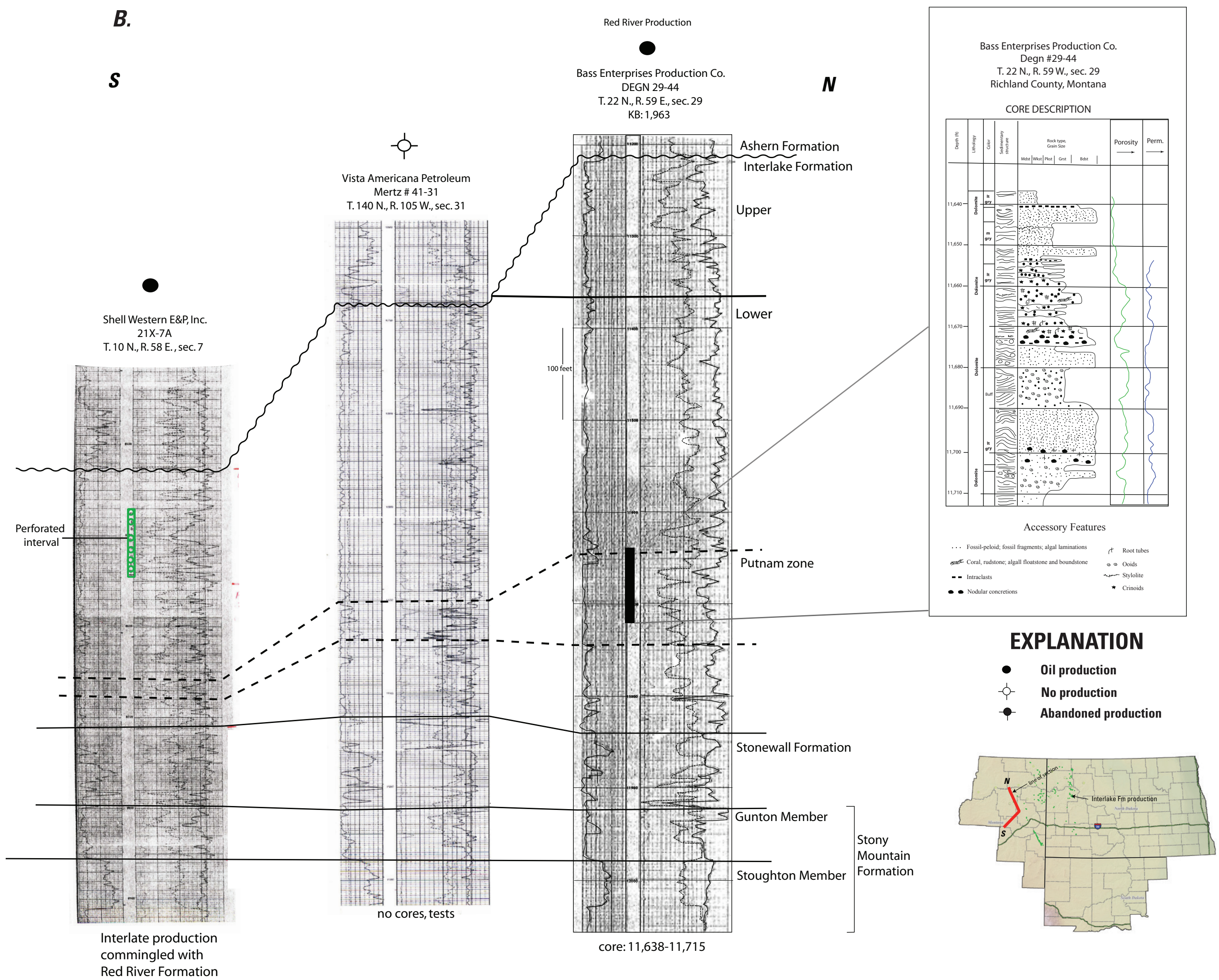

Figure 16. (*A*) West-east section; (*B*) North-south section. Wireline-log cross section showing formation contacts, producing intervals, and core description of the Interlake- Stonewall-Stony Mountain AU. Datum is on top of the Stoughton Member. Core description is modified from Inden and others (1988). In core description, porosity column is green where porosity is greatest. BO, barrels of oil; mcfg, thousand cubic feet of gas; bw, barrels of water; mbw, thousand barrels of water; DST, drill-stem test; KB, Kelly bushing elevation in feet; Mdst, mudstone; Wkst, wackestone; Pkst, packstone; Grst, grainstone; Bdst, boundstone.—Continued
(***Click here to open full-size, high-resolution image.***)

northwest–southeast trending platform with a carbonate shelf on the southwestern and southeastern part of the basin and a deeper carbonate shelf in the middle and northeastern part. The U.S. part consists mostly of a shallow, intertidal carbonate shelf and a small area of subtidal shelf. In the regressive phase of Winnipegosis deposition, which includes a restricted marine environment, numerous pinnacle reefs were deposited in deeper parts of the shelf. In addition, small patch reefs were deposited on slope breaks and on the shallow parts of the shelf (fig. 20). The pinnacle reefs are relatively small in lateral extend but can obtain heights of as much as 200 ft. Salts or evaporites of the Prairie Formation commonly encased all or parts of the reef. Structural highs formed by Precambrian basement highs may have helped colonize early reef growth. In the United States, the thickness of the Winnipegosis ranges from a zero edge to more than 350 ft in the center of the Williston Basin.

The Winnipegosis consists of seven time-stratigraphic progradational units that are arranged in landward-stepping, vertical stacking, and seaward-stepping geometric patterns,

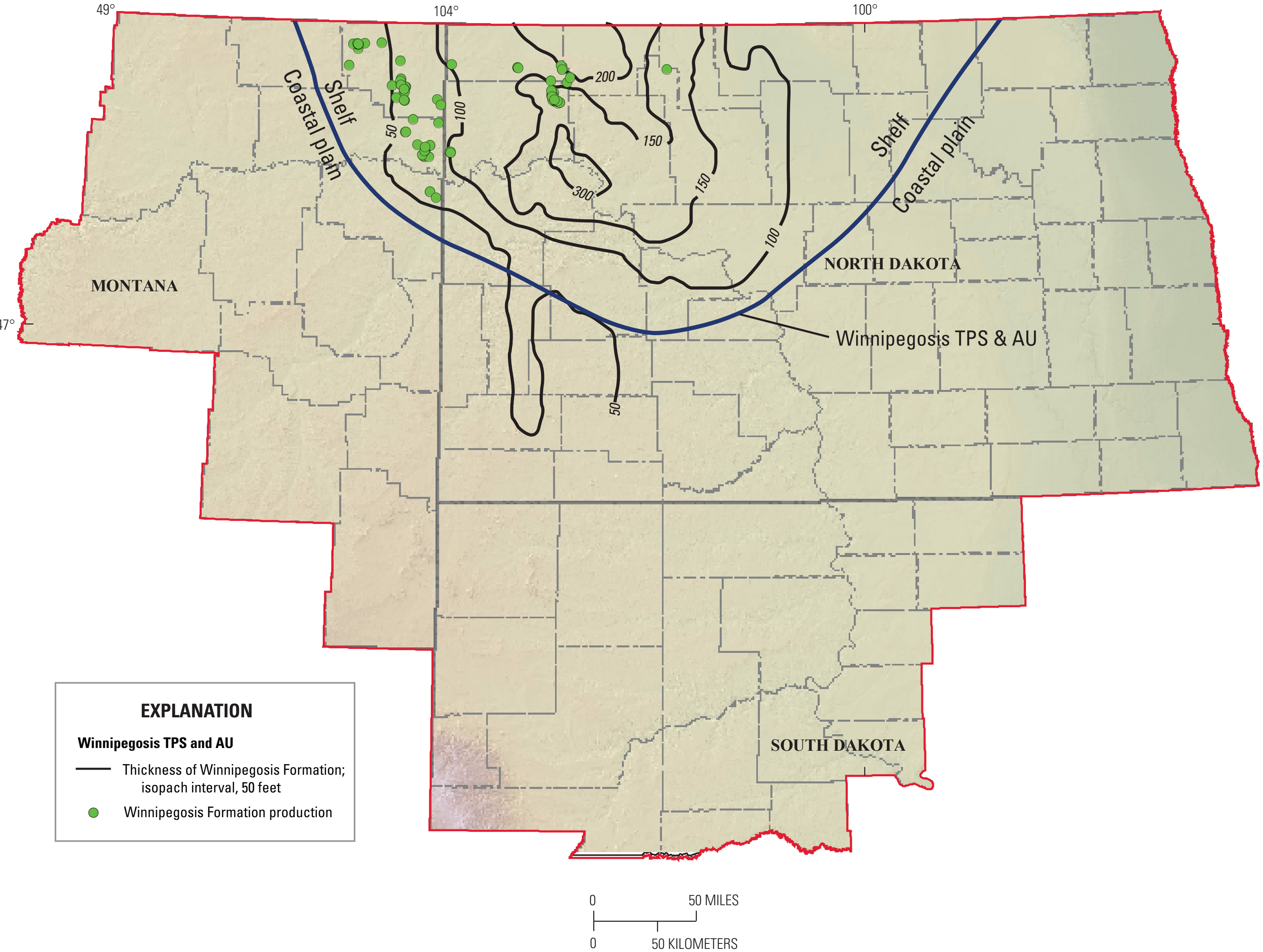

Figure 17. Boundary of Winnipegosis Assessment Unit, Total Petroleum System and approximate location of Winnipegosis Assessment Unit producing wells, and thickness of the Winnipegosis Formation.

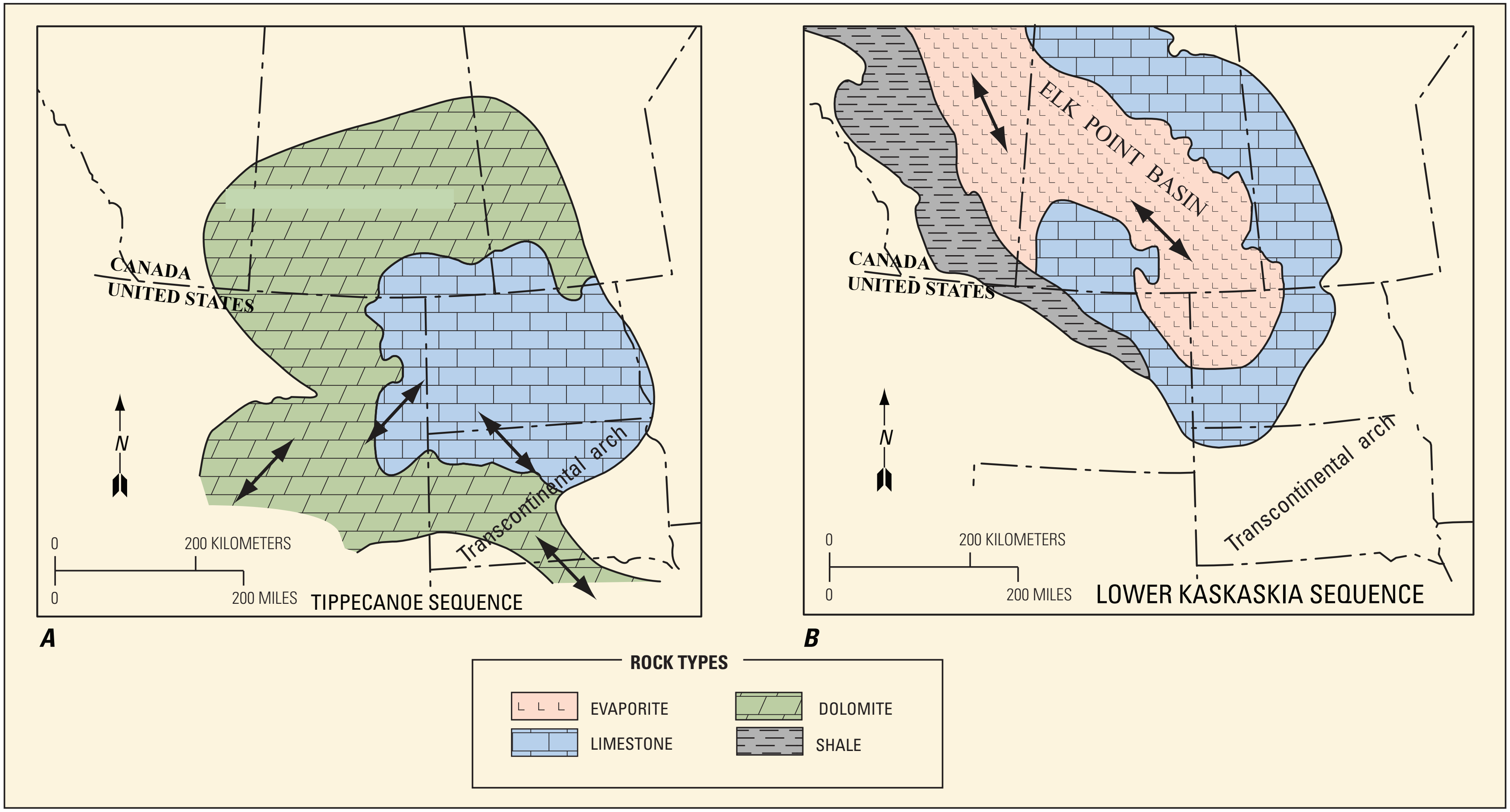

Figure 18. Williston Basin seaway connections and flow directions (double arrows) during (*A*) Ordovician and Silurian time with connections to the southwest and southeast and during (*B*) Devonian and Mississippian time with connection to the northwest.

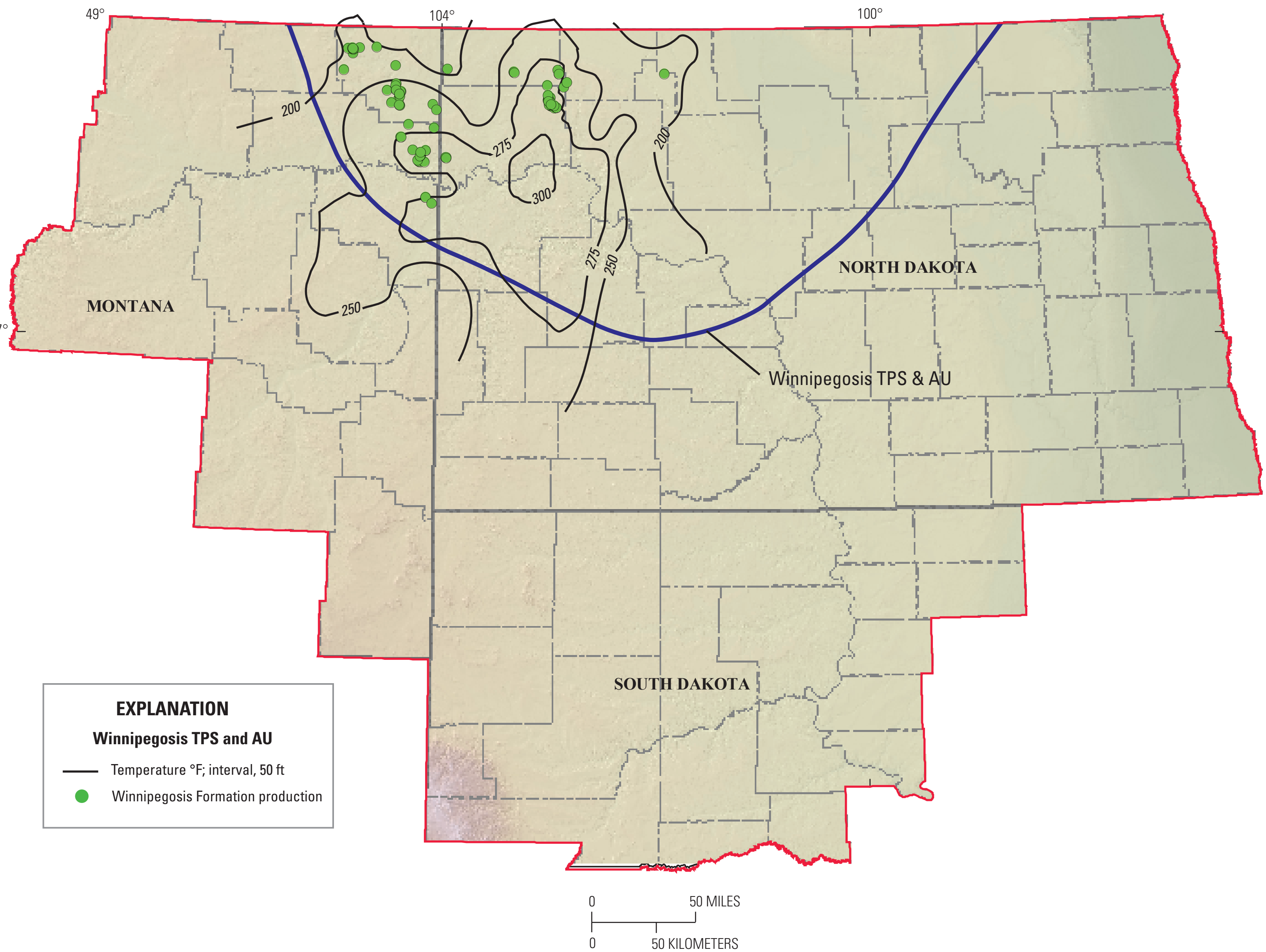

Figure 19. Winnipegosis Assessment Unit (AU) boundary, approximate location of producing wells, and drill-stem-test-derived temperature contours. TPS, total petroleum system.

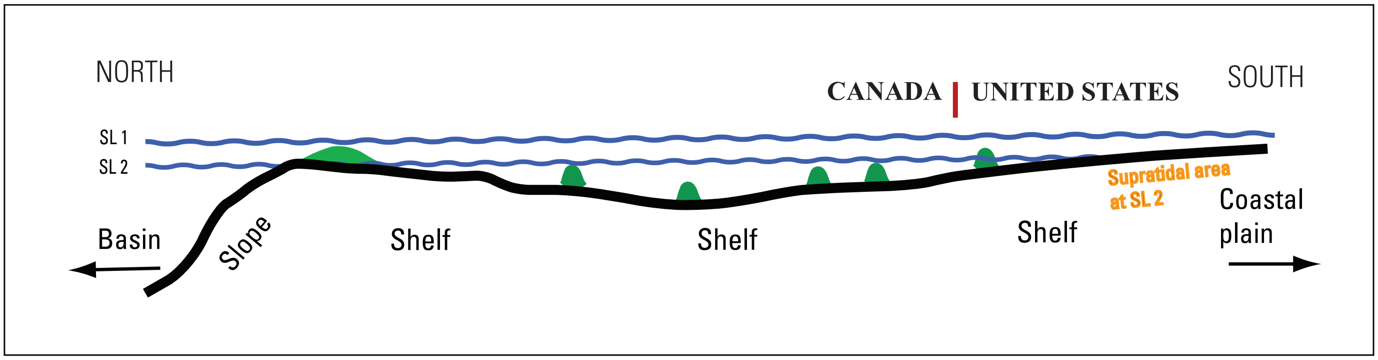

Figure 20. Diagrammatic cross section showing possible Winnipegosis Formation paleogeography with a systematic drop in sea level. At sea level time 1(SL 1), there is open marine circulation in the Elk Point Basin. At sea level time 2 (SL 2), Elk Point Basin marine water is restricted creating possible supratidal conditions in the U.S. part of the basin. Green features represent pinnacle or patch reefs.

which reflect changes in relative sea level (Shanley and Cross, 1988). Sea level drop restricted basin-water volume and salinity, which was especially evident in the U.S. part of the basin because intertidal environments were located on the shallow slope of the shelf (fig. 20). In addition, parts of the shelf margin were subaerially exposed while other parts were being extensively dolomitized. With a sea level rise, open marine limestone facies were deposited, including stromatoporoid patch reefs and local grainstone shoals. As a result, there are various successions of limestone, dolostone, and evaporite that were deposited in shallow, middle, and deep shelf environments (fig. 21).

Hydrocarbon production in the United States is concentrated in two areas, one is along the Nesson anticline and the other is in northeastern Montana (fig. 17). Nesson anticline production is from thin dolomites, whereas in northeastern Montana, production roughly parallels the shelf edge and is from random thin zones of high porosity in thick dolomites.

Traps and Seals

Traps can be characterized as structural because relatively thick continuous units of porous dolomite need full closure or structural nosing on mounds with lateral and downdip porosity reduction. Stratigraphic traps may form in the bioherm buildups, although there is currently no known hydrocarbon accumulation in reefs or mounds.

On the west side of the basin, hydrocarbon production is from intertidal shelf deposits of porous dolomite, and pay zones are associated with the best porosity. Overlying seals are usually anhydrite, but can be tight dolomite (fig. 21). The overlying Prairie Formation is a regional seal that contains tens of feet of salt and interbedded salt and anhydrite. Lateral seals consist of either tight dolomite or tight limestone.

Duperow Total Petroleum System

The Duperow TPS comprises two AUs—Dawson Bay-Souris River AU (fig. 22) and Duperow-Birdbear AU (fig. 23). The stratigraphic sequence includes Souris River, Duperow, and Birdbear Formations, which are combined because they have similar depositional, lithologic, and trapping characteristics. The boundary of the AU is arbitrarily drawn to the east of, and generally parallel to the 650-HI contour of the Bakken Formation (fig. 22); the subcrop limits of the Dawson Bay Formation to the south and southeast, is contiguous with the Cedar Creek Paleozoic Composite TPS (fig. 8) to the southwest, and parallels the western assessment boundary (fig. 1) to the northwest (fig. 22). The boundary of the Duperow-Birdbear AU is similarly constructed (fig. 23).

Source Rock

The Duperow TPS is distinct from other TPSs in the province because hydrocarbons produced from the Duperow, Birdbear, Dawson Bay, and Souris River Formations are chemically different from Winnipegosis oils (Obermajer and others, 1999), although the distinction is subtle. As in other lower Paleozoic petroleum systems in the Williston Basin, source rocks within the TPS cannot be identified with certainty. The most likely sources are from algal and organic-rich limy mudstones in transgressive units of the Duperow and Birdbear Formations, with less likely sources within the Souris River or Dawson Bay Formations. Without more definitive data, it is not possible to make meaningful estimates of the volume of hydrocarbons that may have been generated or the amount of remaining hydrocarbons that can be technically recoverable in the future.

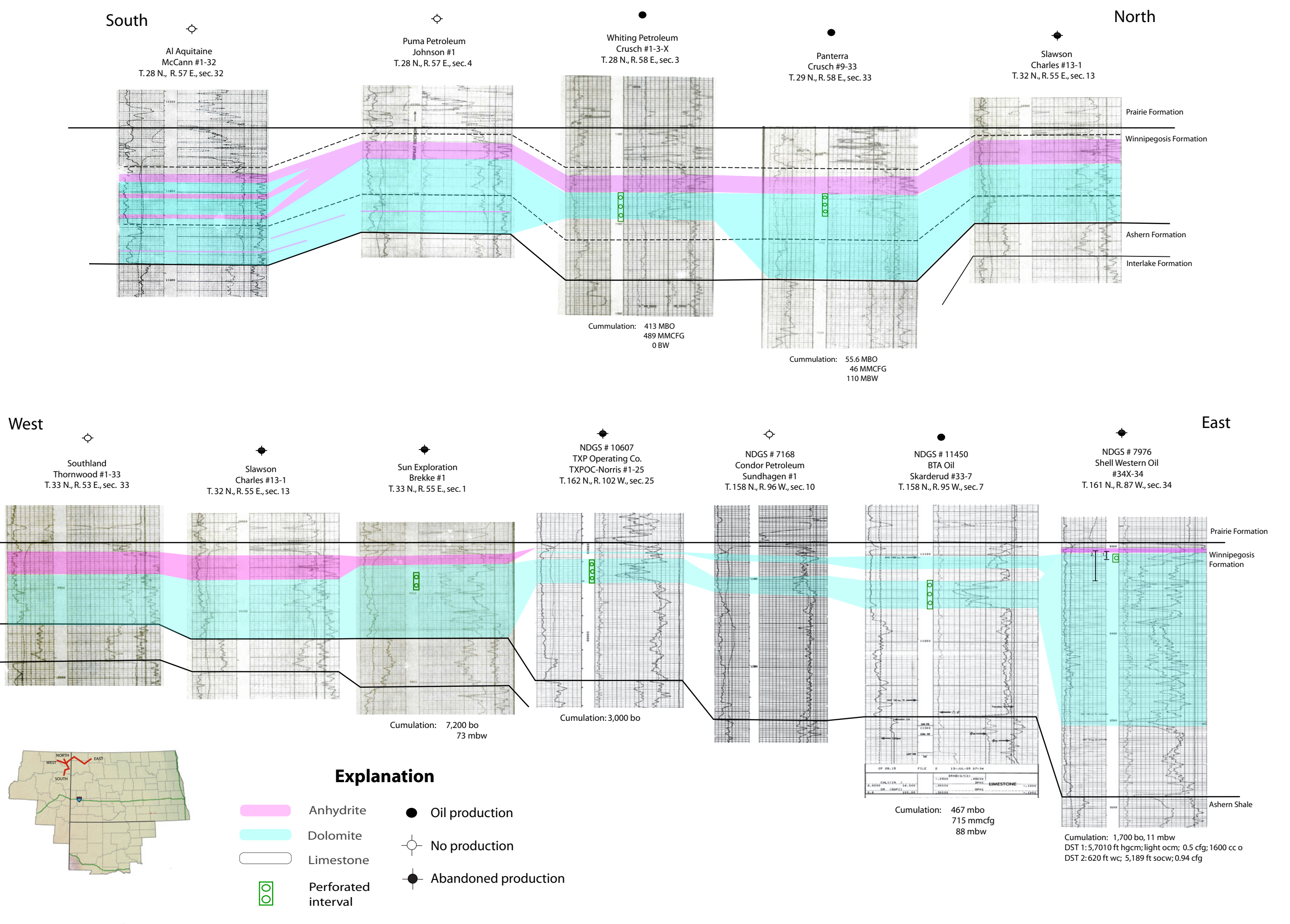

Figure 21. Wireline-log cross section of Winnipegosis Formation in the northwestern part of the Williston Basin showing relation between oil production and dolomite distribution. All wireline logs have gamma ray in the left track and compensated neutron density in the right track. Prairie Formation consists mostly of salt and anhydrite. NDGS, North Dakota Geological Survey; bo, barrels of oil;, mbo, thousand barrels of oil, MBW, thousand barrels of water; mmcfg, million cubic feet of gas; DST, drill-stem test; HGCM, heavily gas cut mud; CFG, cubic feet of gas; CC O, cubic centimeters of oil; WC, water cushion; SOCW, slightly oil cut water.
(*Click here to open full-size, high-resolution image.)*

Thermal Maturity

Temperature or other maturity indicators for this TPS are lacking; therefore, maturity indicators of the Bakken Formation, a few hundred feet above the stratigraphic units of this TPS, were used as a surrogate (figs. 22 and 23). The process was to determine the ratio of calibrated hydrogen index (HI) to the atomic hydrogen/carbon (H/C) ratio for the Bakken, then to calibrate HI to the transformation ration (TR), which was generated from one-dimensional burial history models (Pollastro and others, 2008). The calibration indicated that the 650-HI contour for the Bakken (fig. 22) was the best indicator as to the start of hydrocarbon generation for Type II kerogen, and therefore, it was used as a general indicator of the oil generation area of the Duperow Formation. All hydrocarbon production from the Duperow is west of this line.

Hydrocarbon Migration

The lateral migration potential of this TPS could not be determined, because all known hydrocarbon accumulations are within the mapped oil generation area (figs. 22 and 23). Therefore, it is unknown if lateral migration took place outside the oil generation area. The exact source rock locations are not known for this TPS; therefore, vertical migration probably takes place within the TPS, but it is unknown if migration is out of the TPS. Like other lower Paleozoic systems, vertical migration probably occurs in faults, fracture systems, or zones of weakness and not through rock matrix. The migration pathways are probably nonlinear, similar to stair steps. Of course, the Prairie Formation is a barrier to downward vertical flow, except where it is missing or where salt has been locally dissolved.

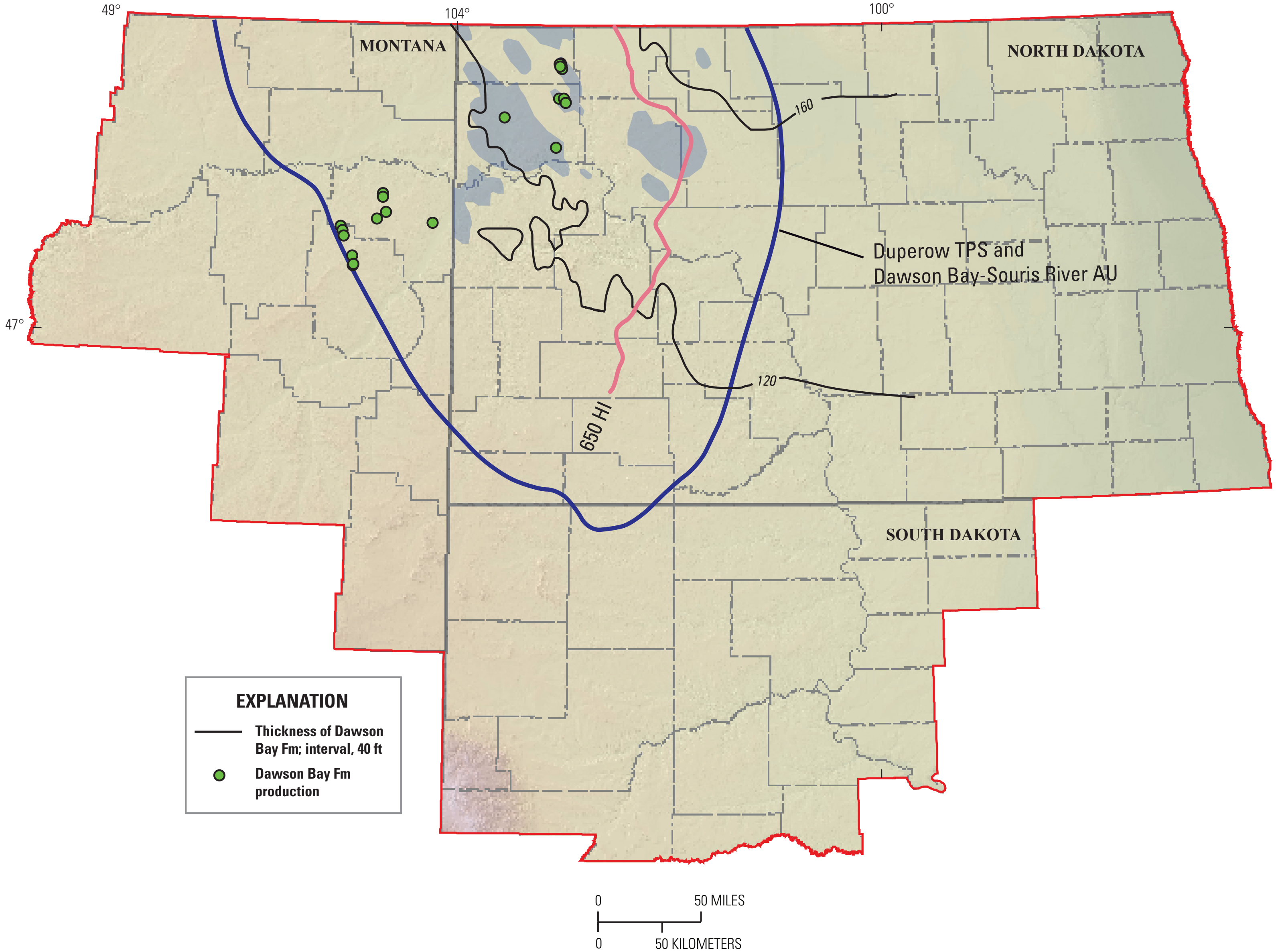

Figure 22. Dawson Bay Formation thickness (black lines), approximate location of producing wells (green dots), and porosity zones (blue areas; North Dakota only) (mapped by Dean, 1983). Bakken Formation's 650-hydrogen-index (HI) contour (pink) acts as a surrogate eastern oil generation boundary and Dawson Bay-Souris River Assessment Unit (AU) boundary (red line). Producing wells outside the AU boundary are part of the Cedar Creek Paleozoic Composite Total Petroleum System (TPS).

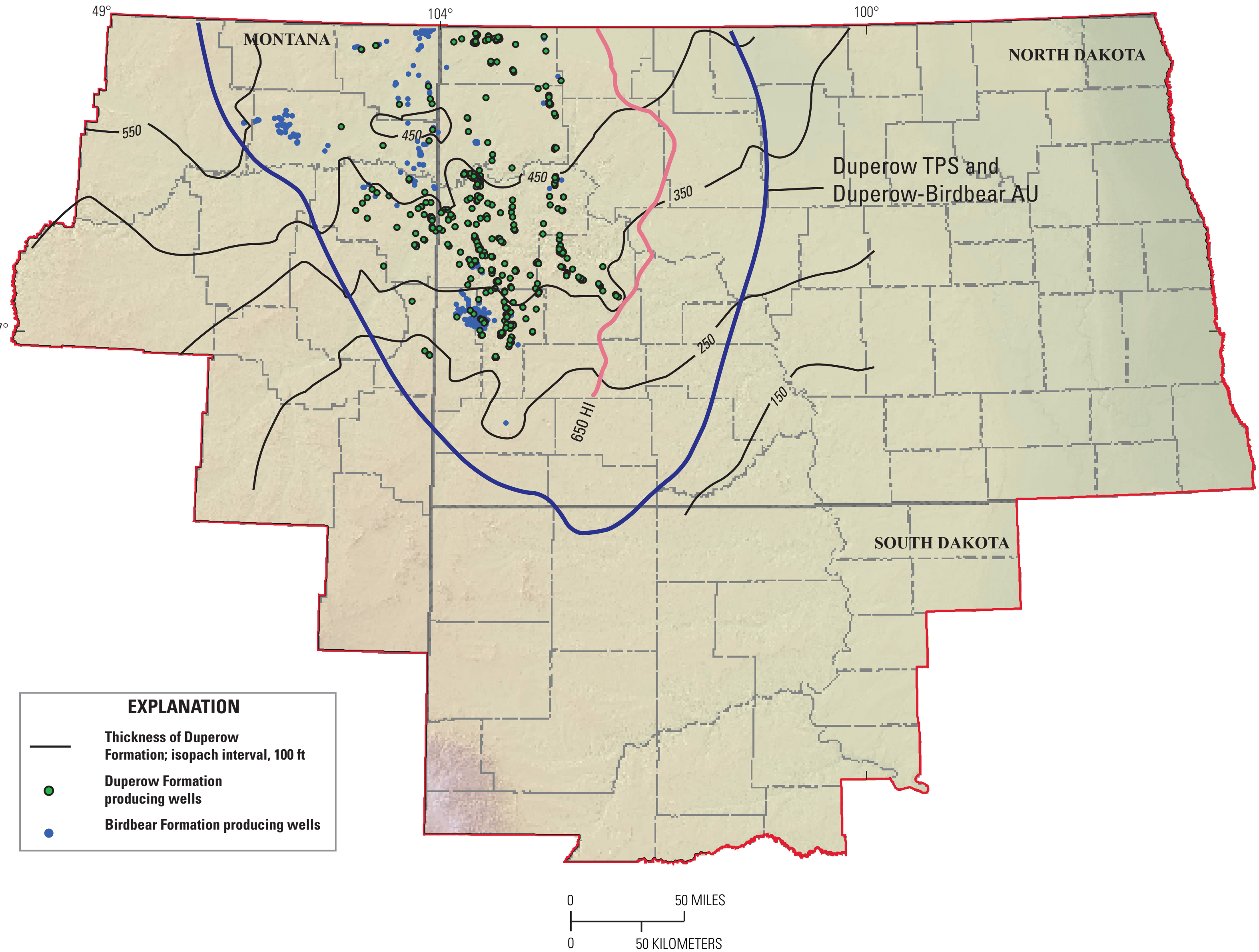

Figure 23. The boundary of Duperow Total Petroleum System (TPS) and Duperow-Birdbear Assessment Unit (AU), approximate location of producing wells, 650-hydrogen-index (HI) contour for the Bakken Formation, which serves as the eastern oil generation boundary for the Duperow Formation, and Duperow thickness. (Note that the depocenter for the Duperow is in Saskatchewan, Canada.)

Reservoir Rocks

Dawson Bay Formation

Following the deposition of the Winnipegosis Formation, a short-lived regression resulted in a restricted marine environment in the Elk Point Basin (fig. 18). As a result, over 500 ft of salt and evaporite were deposited as the Prairie Formation. Normal marine conditions were later re-established during a transgressive event and the Dawson Bay was deposited on a stable, low-relief shelf. The formation consists of stromatoporoid-dominated patch reefs in the lower part of the section and was later dolomitized with more than 50 percent dolomite in the middle to upper parts of the formation. Anhydrite is also present in the upper part (fig. 24), indicating renewed restriction of the seaway. Porosity is generally developed in northwest–southeast linear trends (Dean, 1983) that are possibly related to thickness (fig. 22), original rock fabric, and dolomitization trends, although porosity can be occluded by salt and anhydrite plugging.

The Dawson Bay Formation appears to be hydrocarbon rich, because, although there are few producing wells, the average per-well production exceeds the overall basin average. Although most of the higher production is limited to the Nesson anticline, it is unclear if the lack of significant production from other areas is due to low generation volume, scarcity of traps, and (or) low porosity and permeability.

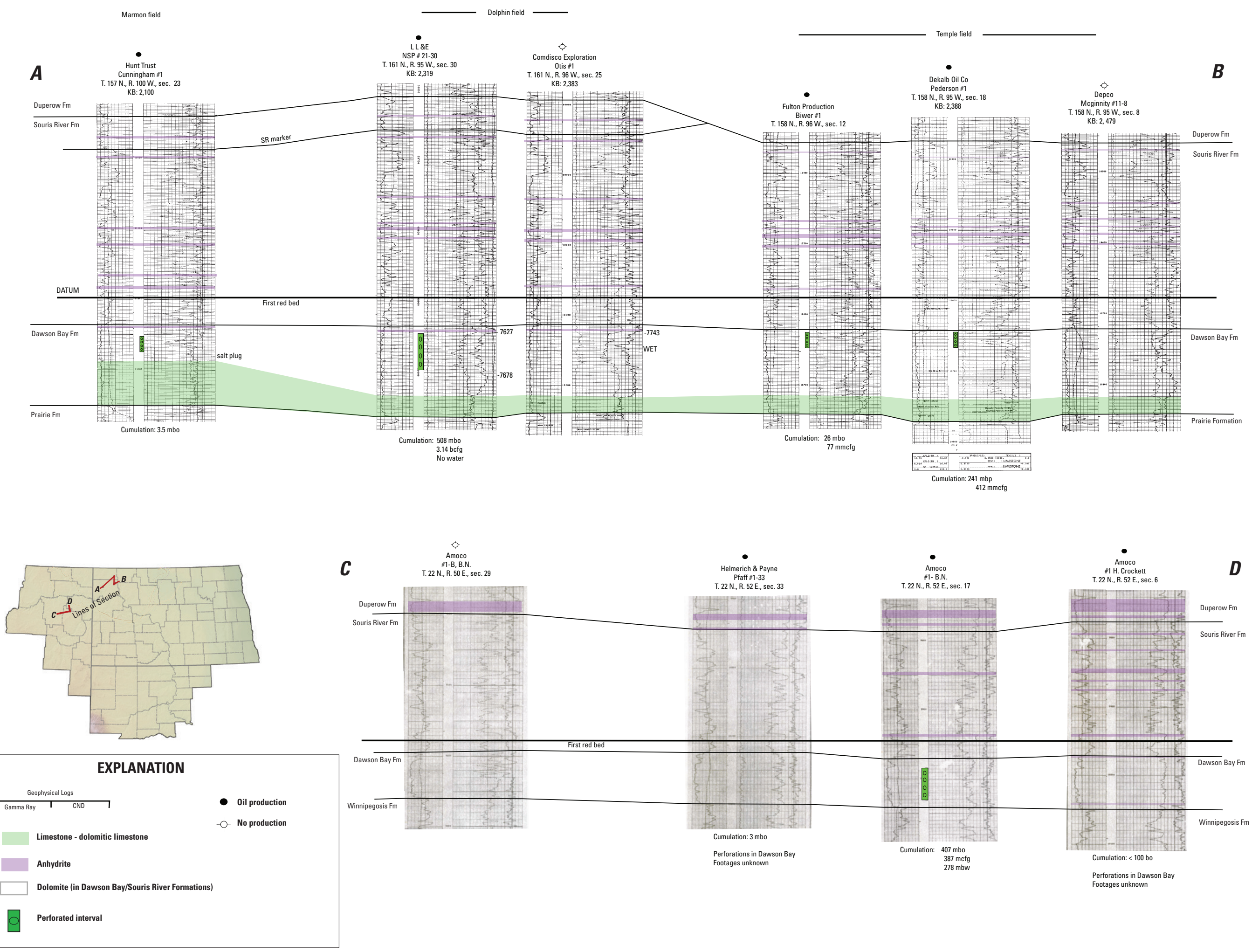

Figure 24. Wireline-log cross section of the Dawson Bay-Souris River Assessment Unit. Prairie Formation salt is dissolved and is missing from cross section *C–D* owing to dissolution along line of section. Geophysical logs are gamma ray–compensated neutron density (CND). SR marker, Souris River Formation marker bed; Fm, Formation; mbo, thousand barrels of oil; bcfg, billion cubic feet of gas; mmcfg, million cubic feet of gas; MBW, thousand barrels of water; KB, Kelly bushing elevation in feet; LL&E, Louisiana Land and Exploration Company.
(***Click here to open full-size, high-resolution image.)***

Souris River Formation

The Souris River Formation conformably overlies the Dawson Bay Formation and has similar lithology as the Dawson Bay, although it is slightly thicker and has numerous interbedded thin dolomite and anhydrite, but porosity is often salt-plugged. The Souris River is not considered to be an important oil producing interval, and it appears to have little future potential. Currently, one well is producing in Dolphin field, but the specific amounts of hydrocarbons attributed to the formation have not been reported, although it is possibly pooled with the overlying Duperow along the Nesson anticline. Two additional wells produced a few thousand barrels of oil from the Souris River.

Duperow Formation

The Upper Devonian Duperow Formation was deposited over a broad shallow marine shelf (Elk Point Basin; fig. 18) that extended into the Provinces of Saskatchewan, Manitoba, and Alberta, Canada. The formation consists of numerous shoaling and or brining-upward cycles as 2nd-order regressive cycles. However, 3rd- and 4th-order cycles show evidence of a more restricted environment. The base of each 2nd-order cycle consists of subtidal to normal marine limy wackestone and packstone, with normal marine fossils, including a local stromatoporoid limestone that was dolomitized in places. The middle part of the cycle consists of a restricted marine carbonate, which is a burrowed dolomitic mudstone or grainstone containing a restricted marine fauna and stromatoporoid beds. These units have the best porosity and permeability and are the main pay zones of the Duperow; the dolomitization appears to be diagenetic, not primary. The top of the cycle consists of supratidal to hypersaline nodular and mosaic-bedded anhydrite overlain with thin, supratidal siliciclastic and dolomitic mudstones. The siliciclastic part has an increased gamma ray signature and is used as a timeline boundary (fig. 25). Lateral distribution of this facies can be variable and is thought to be structurally controlled.

Thickness of the Duperow Formation ranges from less than 100 ft in the southern, southeastern, and eastern parts of the basin, to more than 450 ft along the Canadian border in northwest North Dakota and northeast Montana (fig. 23). The thickness contours follow a general east–west trend, but in Canada, the contours curve northward, then parallel the axis of the Elk Point Basin.

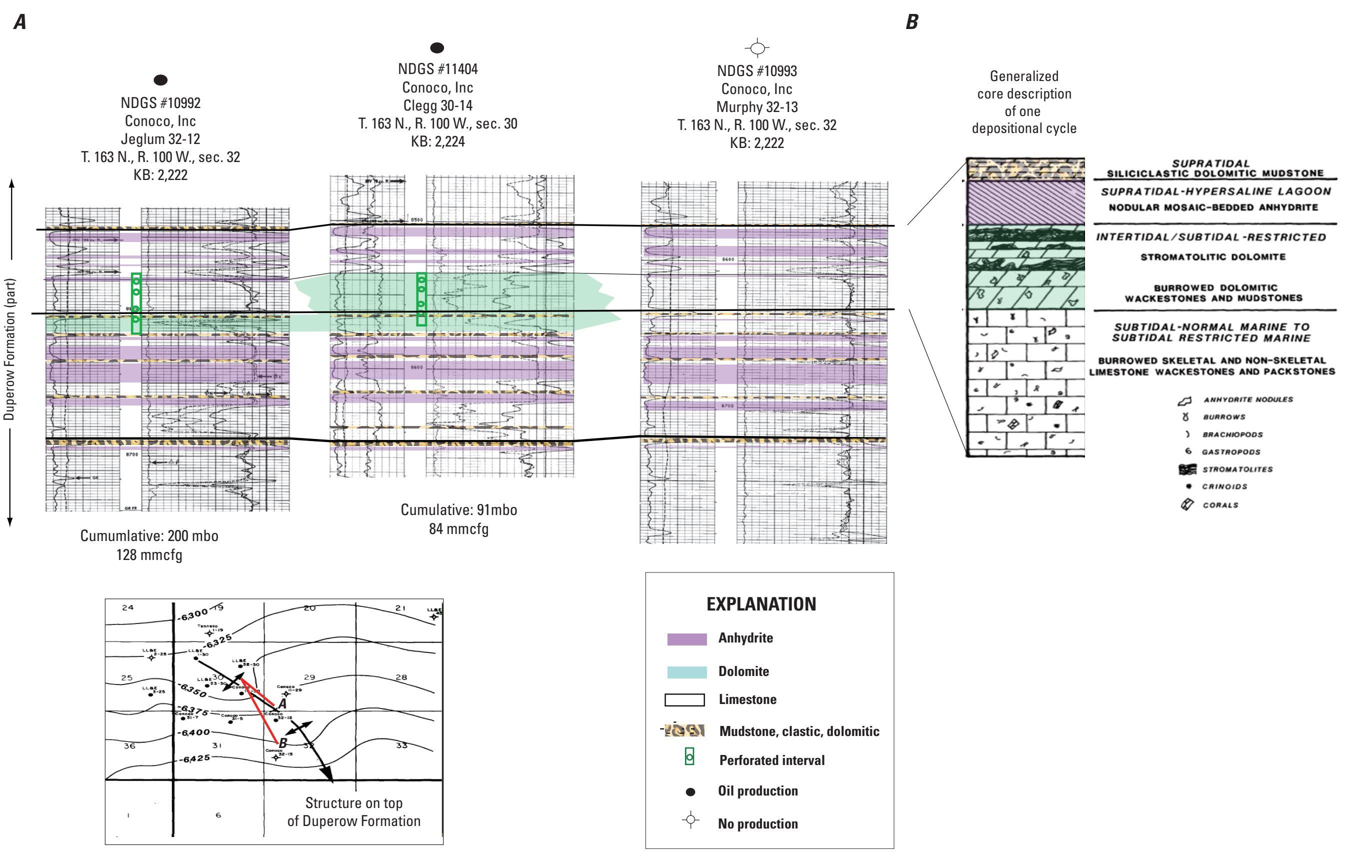

Figure 25. Wireline-log cross section (*A*–*B*) of Duperow Formation showing lateral variation of anhydrite, dolomite, and limestone intervals. Core description is from Weinzapfel and Neese (1986). Red line in insert is line of section. Datum is an internal mudstone that marks a time-stratigraphic flooding surface. Geophysical logs are gamma ray–compensated neutron density (CND); KB, Kelly bushing elevation in feet; mbo, thousand barrels of oil; mmcfg, million cubic feet of gas.
(*Click here to open full-size, high-resolution image.)*

Birdbear Formation

The Birdbear Formation represents one of the 3rd-order sequences within the overall Devonian transgressive-regressive sequence. Specifically, it includes the later stages of the Late Devonian regression and the deposition of Upper Devonian carbonates in a shallow seaway, stretching from North Dakota into the Alberta Basin (Birdbear Formation is called Nisku Formation in Canada). The formation consists of a single shoaling-upward carbonate-evaporite couplet that persists over a broad area. It is informally divided into two zones, a lower B and an upper A (fig. 26). There are three 4th-order dolostone-anhydrite couplets in the A zone and one in the B zone.

The A zone consists of two to three thin dolostone beds with porosity developed from dolomitization that averages more than 10 percent, but is commonly occluded by salt plugging. The B zone is tens of feet thick with porosity developed in a dolomitized stromatoporoid bank and amphiporia bank facies. Best porosity (as much as 20 percent) is developed in the upper part of the B zone where the zone is fairly persistent (LeFever, 2009), whereas porosity in the lower part is laterally variable. The lower part of the B zone consists of open marine to intertidal, variably fossiliferous limestone and dolomitic limestone.

Where the A zone is thin, reservoir-quality porosity is lacking, especially along basin margins or where structure influenced thickness patterns. Thickness of the Birdbear is more than 100 ft along the Canadian border and thins to a zero edge parallel to the Elk Point Basin edge (fig. 27).

Traps and Seals

Traps in the Duperow TPS include (1) large closed structures such as the Nesson anticline (fig. 1); (2) structural highs developed from differential salt dissolution; (3) porosity that is draped over a structural nose, such as the Billings nose, Billings anticline, and the Mondak trend (fig. 1); and (4) rare unconformity stratigraphic traps. Structural closures on the Nesson anticline are sites of some of the best production in the Williston Basin because the fold that developed the anticline helped to create reservoir conditions within the affected rocks that favored large hydrocarbon accumulations.

Small structural positive areas were developed from a two-stage salt dissolution process (fig. 28), especially in the Prairie Formation, as well as from thinner discontinuous salt beds such as the Flat Lake Halite. Salt dissolution typically generated structures with three-way closure and with variable orientations. Patterns of salt dissolution may be structurally controlled with the first phase of dissolution located near faults or fracture networks that act as conduits. Smaller structures were possibly created from basement-involved movement and often have three- and four-way closure.

Stratigraphic traps may occur in the Dawson Bay Formation because northwest–southeast trending zones of porosity parallel structural contours, which indicate a potential for the development of updip porosity pinchout.

Top seals to reservoirs are anhydrite, salt, cryptocrystalline dolomite, or anhydritic dolostone. In general, the lack of top seals is not a concern in the Williston Basin, because of the numerous depositional cycles that are capped by anhydrite or salt. Lateral seals are developed from either halite plugging or lateral porosity reduction from either diagenetic porosity reduction or primary fabric change, such as a facies change from intertidal dolomite to subtidal limestone (Weinzapfel and Neese, 1986).

Cedar Creek Paleozoic Composite Total Petroleum System

The Cedar Creek Paleozoic Composite TPS was separated from other petroleum systems in the Williston Basin because the anticlinal structure (figs. 1 and 29) has multiple stacked pay zones, and there are two or more oil types that have migrated into the TPS area. The multiple pay zones include the Ordovician Red River and Stony Mountain Formations, Silurian Interlake Formation, and Mississippian Lodgepole Limestone of the Madison Group, undivided Madison Group, and Kibbey Sandstone (fig. 2). Source rocks in Red River and Madison strata have generated oil that has migrated updip to the southwest into the Cedar Creek area. The percentage of each oil type that may have migrated vertically into other reservoirs such as the Interlake or Kibbey is not known. Although there is no clear evidence, oil from other source rocks may have also migrated into various reservoirs along the structure. Shallow biogenic gas in Upper Cretaceous reservoirs along the Cedar Creek trend is part of the Shallow Biogenic Gas TPS and is segregated from deeper oil production.

The boundary of the Cedar Creek Paleozoic Composite TPS is several townships to the northeast and southeast of the Cedar Creek structure to include oil that has migrated down the structural nose due to hydrodynamic forces. The boundary is also extended from the structure to the northwest to include fields such as Cow Creek and Weldon fields that produce lower Paleozoic oil in upper Paleozoic reservoirs.

Oil from the Cedar Creek anticline was first discovered in 1951. In the early stages of development, there was a clear distinction of field boundaries, but currently field boundaries are contiguous and there is nearly continuous production along the anticline.

The structural history of the Cedar Creek anticline is long and complex, and it had an important influence on depositional environments, sedimentation patterns, stratigraphic juxtapositions, and fluid migration patterns. From early Paleozoic through mid-Tertiary time, there were four major periods of tectonism (Clement, 1987): (1) Early Devonian uplift and fault movement initiated north and east tilting of the main Cedar Creek block; (2) Late Devonian fault movement and uplift created a broad northwest–southeast trending anticline with structural closures; (3) Late Mississippian to Triassic normal faults formed along parts of ancestral master faults and subsidiary

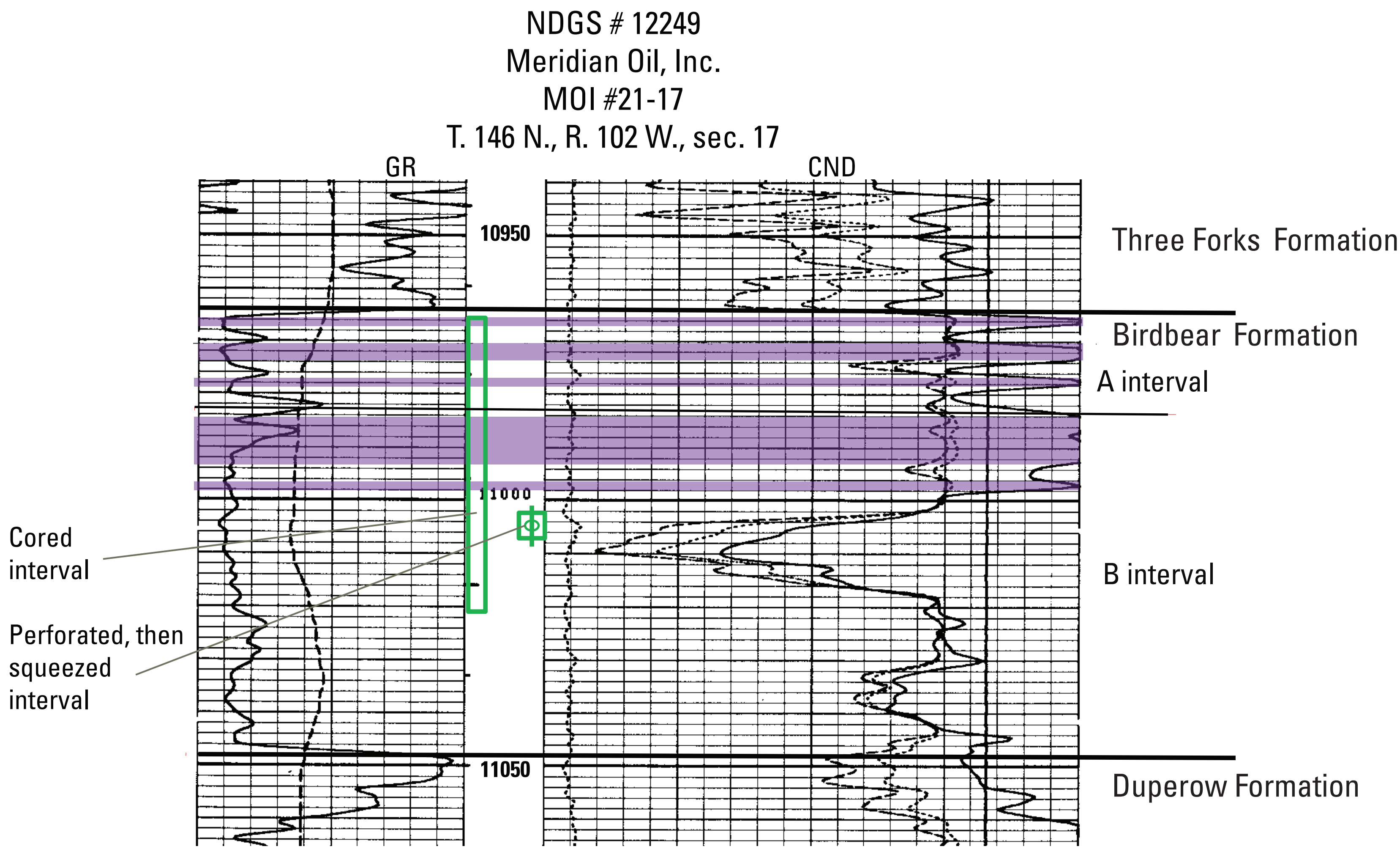

Figure 26. Wireline log showing stratigraphic relations of the Birdbear Formation A and B intervals. There are good oil shows in the B-interval porosity zone and in the middle porosity zone of the A interval. Cored interval (green column) is from 10,964–11,024 ft. The one perforated interval (symbol to left of CND log) was squeezed after a production test of 71 barrels of oil. Well was completed in the Red River Formation. Purple intervals are anhydrite. GR, gamma ray; CND, compensated neutron density.

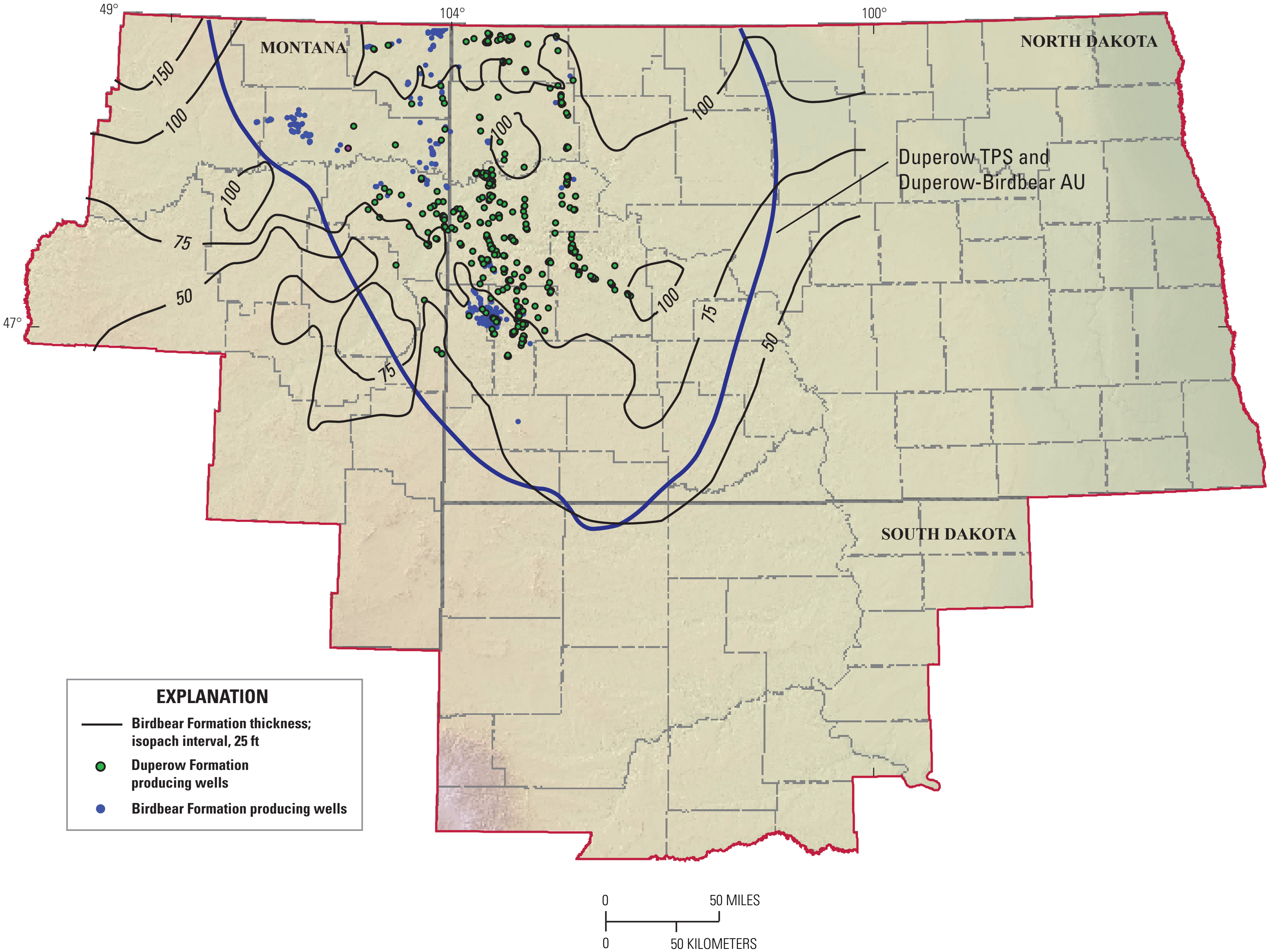

Figure 27. Boundary of Duperow Total Petroleum System (TPS) and Duperow-Birdbear Assessment Unit (AU) (blue line), approximate location of producing wells, and Birdbear Formation thickness.

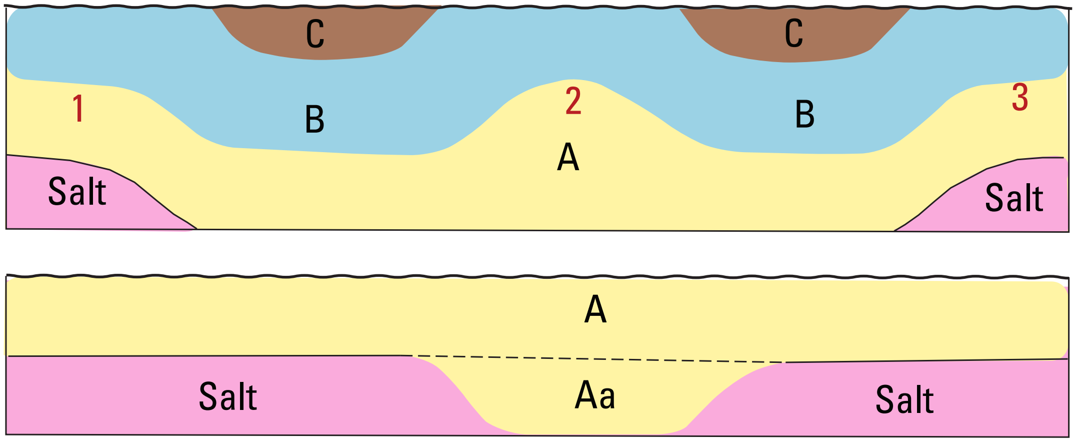

Figure 28. Diagram showing two-phase salt-dissolution model. A, B, C, Aa, and salt are hypothetical depositional units. In the bottom panel, salt dissolution is penecontemporaneous with deposition of unit Aa, and compensatory thickening occurs. In the top panel, there is continued salt dissolution with thicks developed in younger units. Stratigraphically higher intervals developed in areas 1, 2, and 3. Modified after Rogers and others (1985).

faults; and (4) post-Paleocene uplift of the Cedar Creek block caused major flexuring, drape folding, and minor fault adjustments. Subsidiary structures parallel to Cedar Creek anticline formed southwest of the main trend and were then uplifted, creating traps for shallow biogenic gas.

Thermal Maturity and Hydrocarbon Migration

Burial history and thermal modeling of the Williston Basin indicated that Paleozoic source rocks in the Cedar Creek anticline area were not in the oil generation window. Source rocks in the Red River Formation and Madison Group generated oil in deeper parts of the basin that migrated in Late Cretaceous time into Cedar Creek structural closures and fault induced dip slopes (Clement, 1987). Late Mississippian to Triassic normal faults that formed along parts of the northwest–southeast trending Cedar Creek master faults were probably migration pathways for oil to redistribute vertically and laterally along the Cedar Creek trend.

Traps and Seals

The Cedar Creek structural trend is the most prominent trap for this TPS. The trend consists not only of anticlinal closures, but there are also numerous fault traps associated with horsts and grabens, and, to a minor degree, erosional unconformities helped to form paleoclosures. Hydrocarbon production commonly aligns more with the paleo-structures than present-day closures. Hydrodynamics also played a role in moving oil off structure to the northeast and causing a lowering of oil-water contacts.

Tyler Total Petroleum System

The Tyler TPS boundary includes the oil generation area of the Lower Pennsylvanian Tyler Formation source rocks, the north and northeast subcrop limits of the Tyler, and the possible migration limits of hydrocarbons (fig. 30). This TPS is self-contained, meaning that the hydrocarbons generated in this system have not migrated to other units; therefore, the Tyler Sandstone AU is the only assessment unit within this TPS. Hydrocarbon accumulations in the Tyler are concentrated along the basin axis mainly in the southwestern part of North Dakota (fig. 30), which is updip (south) along the basin axis (see fig. 8), but there may be a Tyler shale resource play as a continuous oil reservoir in the central part of the basin.

Petroleum Source Rocks

In the early development of petroleum resources in the basin, only three source rock intervals were recognized (Dow 1974; Williams, 1974)—shales of the Tyler Formation being one of the three, and the Bakken and Winnipeg Formations the other two. Williams (1974, his fig. 16) made a distinction between Tyler Formation shale (which correlated with Tyler oil) and Heath Formation shale because there was no correlation between Heath oil and Heath shale. However, it is unclear where the samples were taken stratigraphically because the Heath Formation is mostly absent in the basin.

Tyler Formation shales are thickest in the central part of the basin and thin toward the margin (Dow, 1974). Organic richness of the Tyler correlates with the percent oxidation of the shales, where percent oxidation is inversely proportional to organic richness (Dow, 1974). Most of the oxidation is

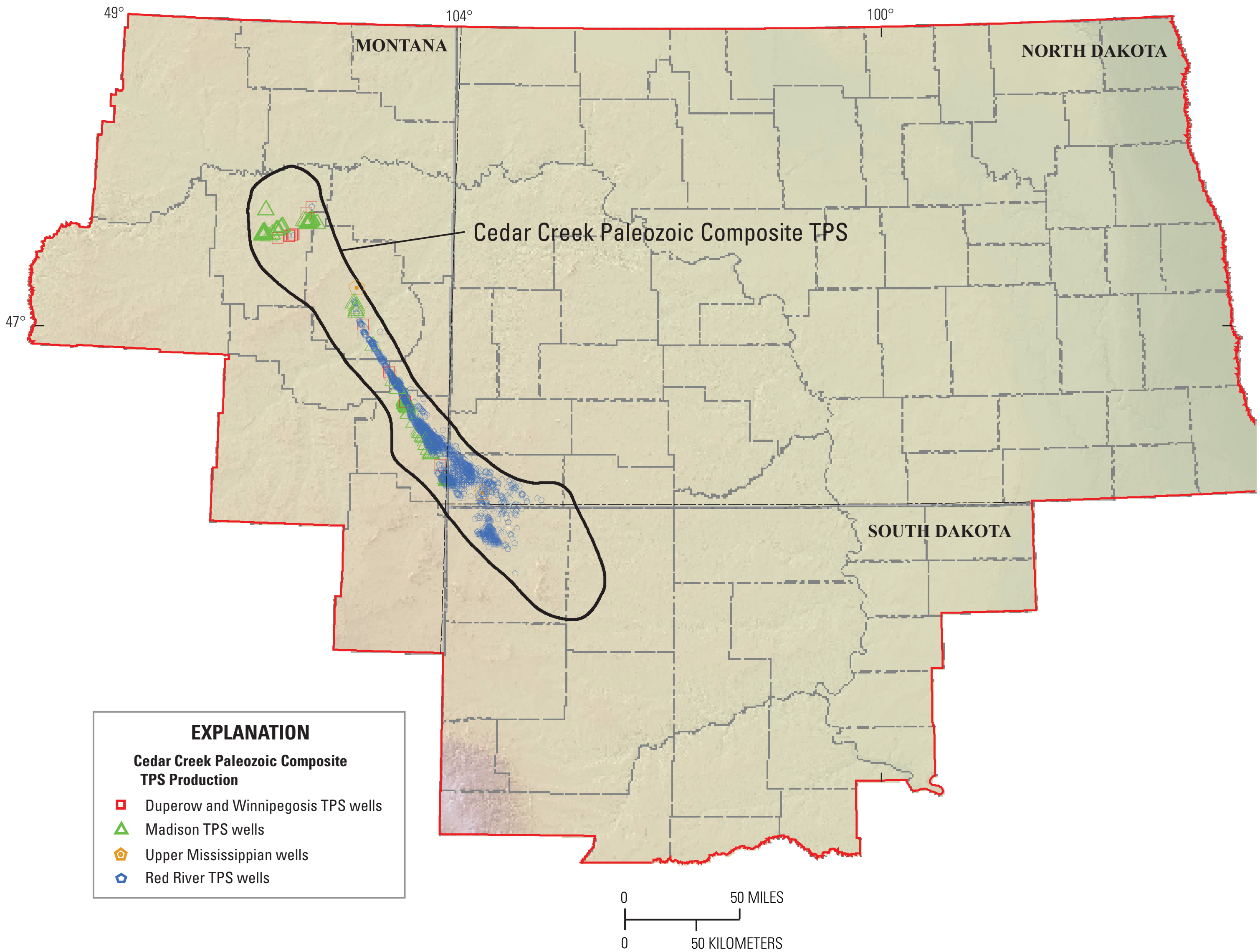

Figure 29. Cedar Creek Paleozoic Composite Total Petroleum System (TPS) showing approximate boundary and the location of producing wells.

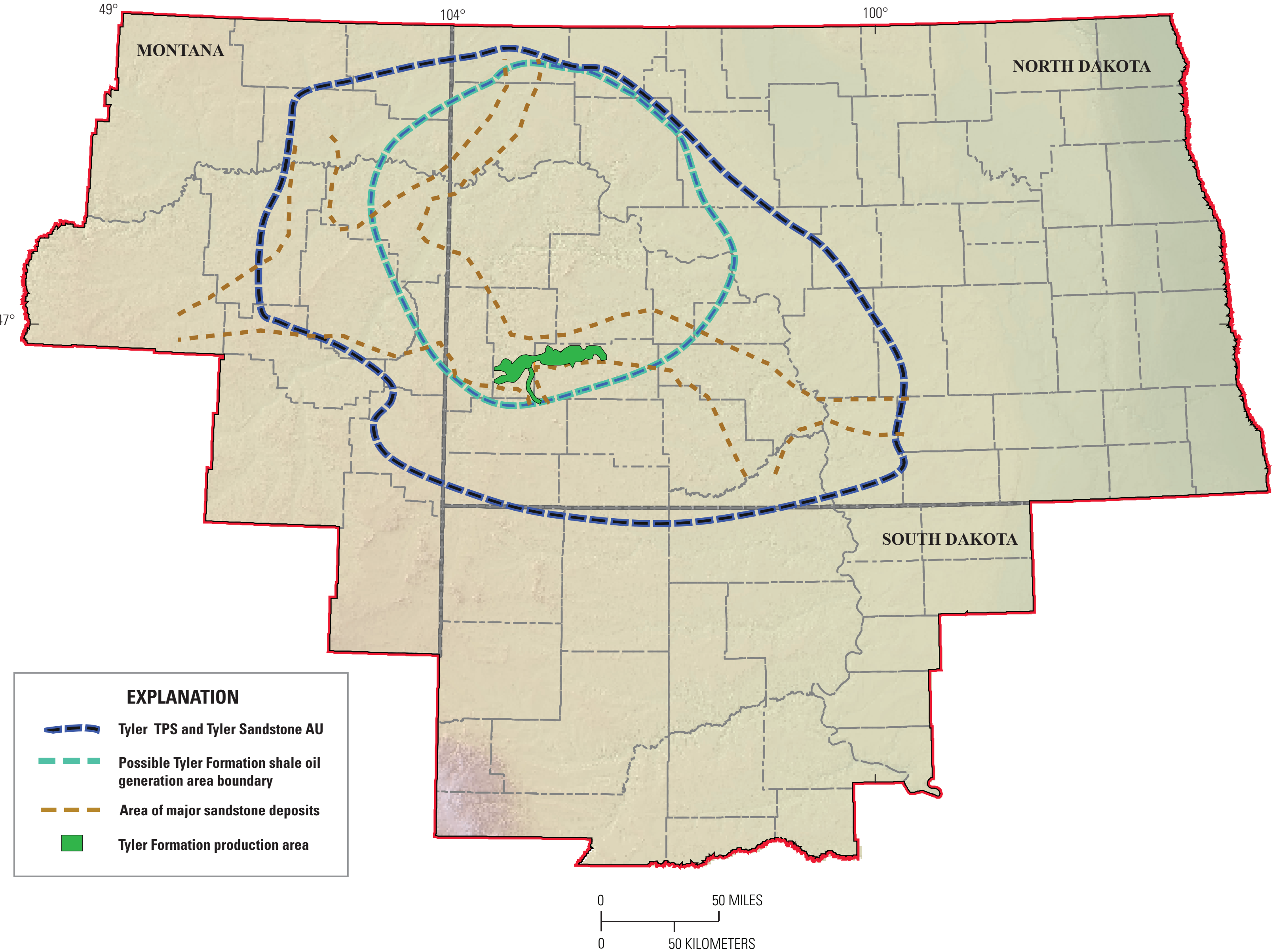

Figure 30. Boundary of Tyler Total Petroleum System (TPS), Tyler Sandstone Assessment Unit (AU) , and the area of major Tyler Formation sandstone deposits defined by Maughan (1984).

toward the basin edge, and the lowest oxidation percentage is in a north–south trend in western North Dakota and South Dakota, as well as in a zone that surrounds and is parallel to the Brockton-Froid fault zone in northeastern Montana (fig. 1).

Tyler oil TOC ranges from 0.2 to 9.1 weight percent. (Note: Williams (1974) reported the Tyler to range from 0.2 to 3.6 TOC and the Heath Formation to range from 0.67 to 9.1 TOC, but this report does not separate Heath from Tyler.) Tyler shale extracts indicate that kerogen is Type III and the C4 to C7 oil fractions are also Type III, which is distinct from Madison Group and Bakken Formation Type II oil and Winnipeg Formation Type I oil. Tyler oil API ranges from 27° to 37° and sulfur from 0.2 to 1.2 percent.

Source Rock Thermal Maturity

Thermal maturity information indicates that Tyler Formation shales entered the hydrocarbon generation window at a depth of about 8,000 ft (Dow, 1974); maximum depth is about 9,000 ft, which would be in the oil generation window. Burial history plots indicate that the shales entered the oil generation window at about 60 Ma and only one well, at Poplar field, had complete oil transformation at 49 Ma. These results however, may be modified because the burial history model used Type II Woodford Shale kinetics, whereas Tyler shale is a Type III kerogen (Dow, 1974; Williams, 1974).

Hydrocarbon Migration

Hydrocarbon migration in the Tyler Formation appears to be limited. There have been some oil shows outside of its hydrocarbon generation area, but no production. Furthermore, the Tyler is truncated to the north and northeast, which limits the areal distribution of Tyler reservoir rocks.

Reservoir Rocks

Tyler Formation

The most prominent Tyler Formation reservoir is in southwestern North Dakota; it is the lithostratigraphic equivalent to the upper part of the Tyler Formation (Maughan, 1984) in central Montana (fig. 30). The lower part (Stonehouse Canyon Member) in central Montana is not present in the Williston Basin. The Tyler in the Williston Basin is overlain by the Pennsylvanian Amsden Formation that consists of limestone, siltstone, and mudstone and is considered a regional seal to Tyler reservoirs. The Tyler is underlain by the Upper Mississippian Otter Formation (fig. 2) because the normally intervening Heath Formation is mostly absent in the basin.

The Tyler consists of three parasequences of fluvial-deltaic deposits (Sturm, 1987; Sturm and Peterson, 1994) (fig. 31); the upper sequence contains the thickest and laterally most persistent sandstones, whereas the middle and lower sequences consist of mostly shale and siltstone with minor amounts of sandstone. Land (1979) described the upper sequence as originating as barrier islands along regressive shorelines, with coarsening-upward successions capped with coal and mudstones deposited in a marsh facies. Landward (south), shoreline sandstones interfinger with thin limestones, black shales, and oxidized mudstones deposited in marsh, lagoon, and mudflat environments (Land, 1979). Quandt (1997) reported that the upper Tyler in southwestern North Dakota is absent in northwestern North Dakota, although it is unclear if he was referring to just the upper parasequence or a larger part of the formation. Quandt (1997) implied that the lower Tyler sandstones are distinct and separated from the upper parasequence sandstones.

Fluvial channels containing reservoir quality sandstones are in the upper and middle sequence (fig. 32*B*, the Cardinal Petroleum, Fritz A, 1-R well). Only one of the fluvial channels connected to the paleoshoreline is productive, but other channels probably exist.

Upward-coarsening sandstones have permeability values ranging from 0.1 to 10 mD, whereas channel sandstones have permeabilities ranging from 10 to 700 mD. The permeability is affected by a wide variety of diagenetic alterations, including paleosol development, feldspar dissolution, clay conversion, and inclusion of nodular limestone within pore space.

Traps and Seals

Hydrocarbons in Tyler Formation reservoirs have accumulated mostly in stratigraphic traps formed by updip diagenetic reduction of porosity and permeability and by sandstone bodies encased in tight shales and mudstones (Land, 1979). There may have also been minor structural control on stratigraphic entrapment, especially those that were active during deposition, which controlled rock fabric types. Also, some structures that were reactivated during oil migration may have formed small structural traps. Although detailed structure contour maps show numerous gently plunging structural noses, plots of cumulative production per well show no correlation to structural features or geographic position.

Shallow Biogenic Gas Total Petroleum System

Continuous shallow biogenic gas resources in the Williston Basin can be categorized into three types: (1) gas that was generated in place shortly after deposition of the potential reservoir; (2) gas that was generated in place long after the reservoir rock was deposited; and (3) gas that is produced from microbial processes by conventional or continuous methods, but later migrated into structural or stratigraphic traps. Reservoirs associated with the first and second types are generally low-permeability sandstones or siltstones.

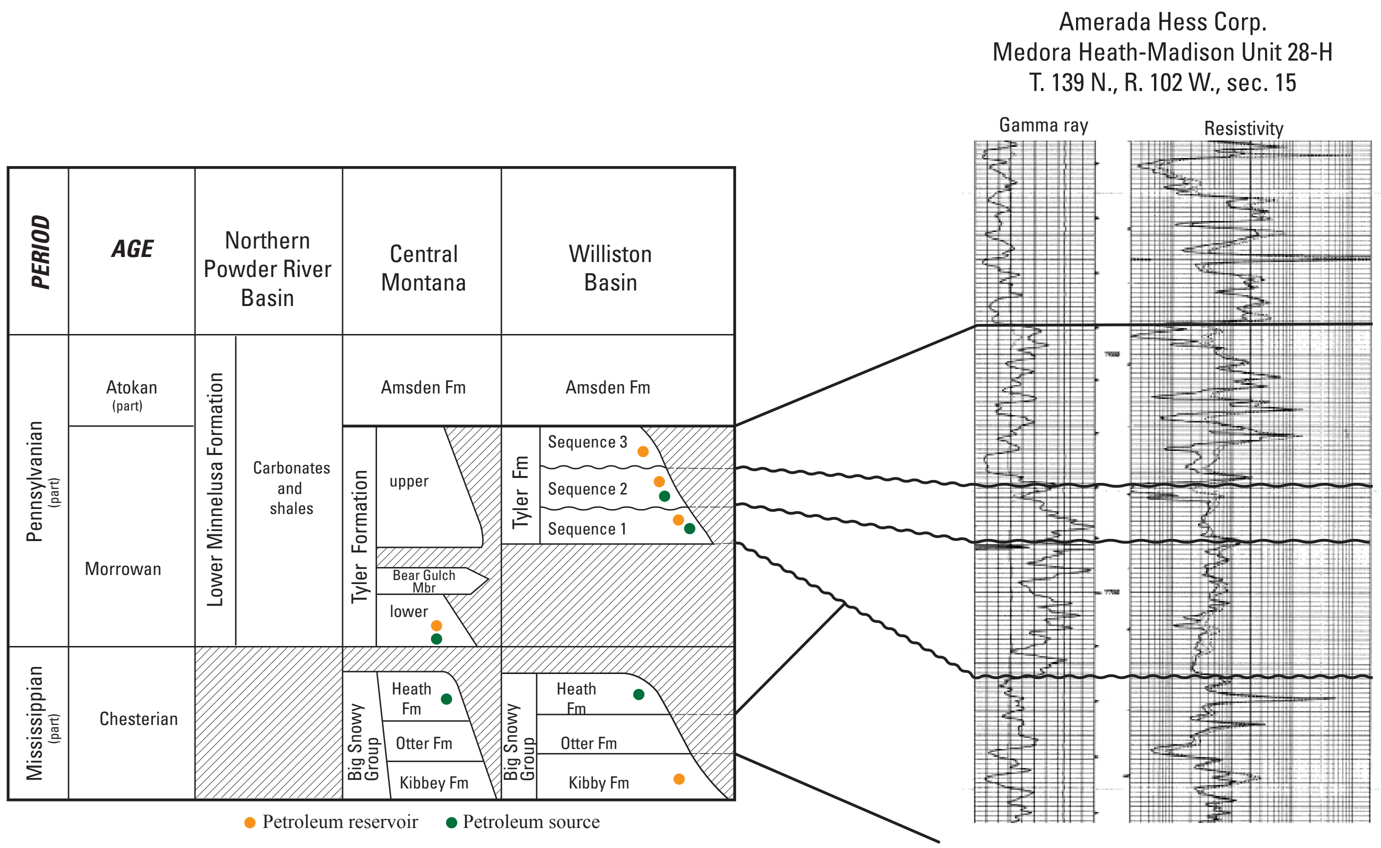

Figure 31. Diagram showing stratigraphic chart of the Tyler Formation and its correlation with a wireline log, also on cross section *C–D*, figure 32A. Note that the Heath Formation is missing in the example log. Fm, Formation; Mbr, Member.

Gas production areas are located near the basin margin, but only economic quantities are in the southwest part of the basin (fig. 33). The Souris River area, in the northeastern part of the basin, produces biogenic gas from glacial drift deposits and Upper Cretaceous rocks. Gas from the low-permeability drift deposits is generated in organic-rich Cretaceous rocks, such as the Niobrara Formation or the Pierre Shale, and then migrates upward through fractures or faults. Apparently, the generation of gas, or at least the gas migration, did not occur until the groundwater had time to circulate through the fractured rock beneath the drift (Shurr, 1998). In this area, associated groundwater contains high values of nitrogen (calculated as a ratio to methane: $(N_2/(N_2+CH_4)*100))$ indicating that groundwater assisted in migration of the gas (Clayton, 1992).

Gas accumulations in the eastern and southeastern part of the Williston Basin in the LaMoure and Pierre gas areas (fig. 33) are from hydrodynamic trapping in the Dakota Sandstone, where groundwater-flow paths converge with migration pathways for biogenic gas and possibly minor amounts of thermogenic gas. As the hydraulic head in the Dakota is reduced, the volume of gas accumulation decreases accordingly. Gas production currently is minimal and is used only in local markets.

Early generation gas in Cretaceous sandstone and siltstone reservoirs on the southwest margin of the basin is produced in conventional structures, although there may be a continuous component between structures due to redistribution of the gas by hydrodynamic forces. The main reservoirs in the Cedar Creek anticline area are the Shannon Member of the Eagle Sandstone and the overlying Judith River Formation (fig. 34). Both are marine siltstones and sandy siltstones that were deposited on a shelf edge near the basin slope, and are time equivalents to parts of the Pierre Shale that were deposited in a deep basin environment to the east. The main reservoir in the West Short Pine Hills area (fig. 33) is the Shannon Member, a marine sandstone to silty sandstone deposited on the shelf edge with good reservoir porosity and moderate permeability.

Coalbed Gas Total Petroleum System

The boundary of the Coalbed Gas TPS and the Fort Union Coalbed Gas AU in the Williston Basin is the areal extent of the Fort Union Formation (fig. 35). The Paleocene Fort Union Formation consists of, in ascending order, the Ludlow, Tongue River, and Sentinel Butte Members (fig. 36).

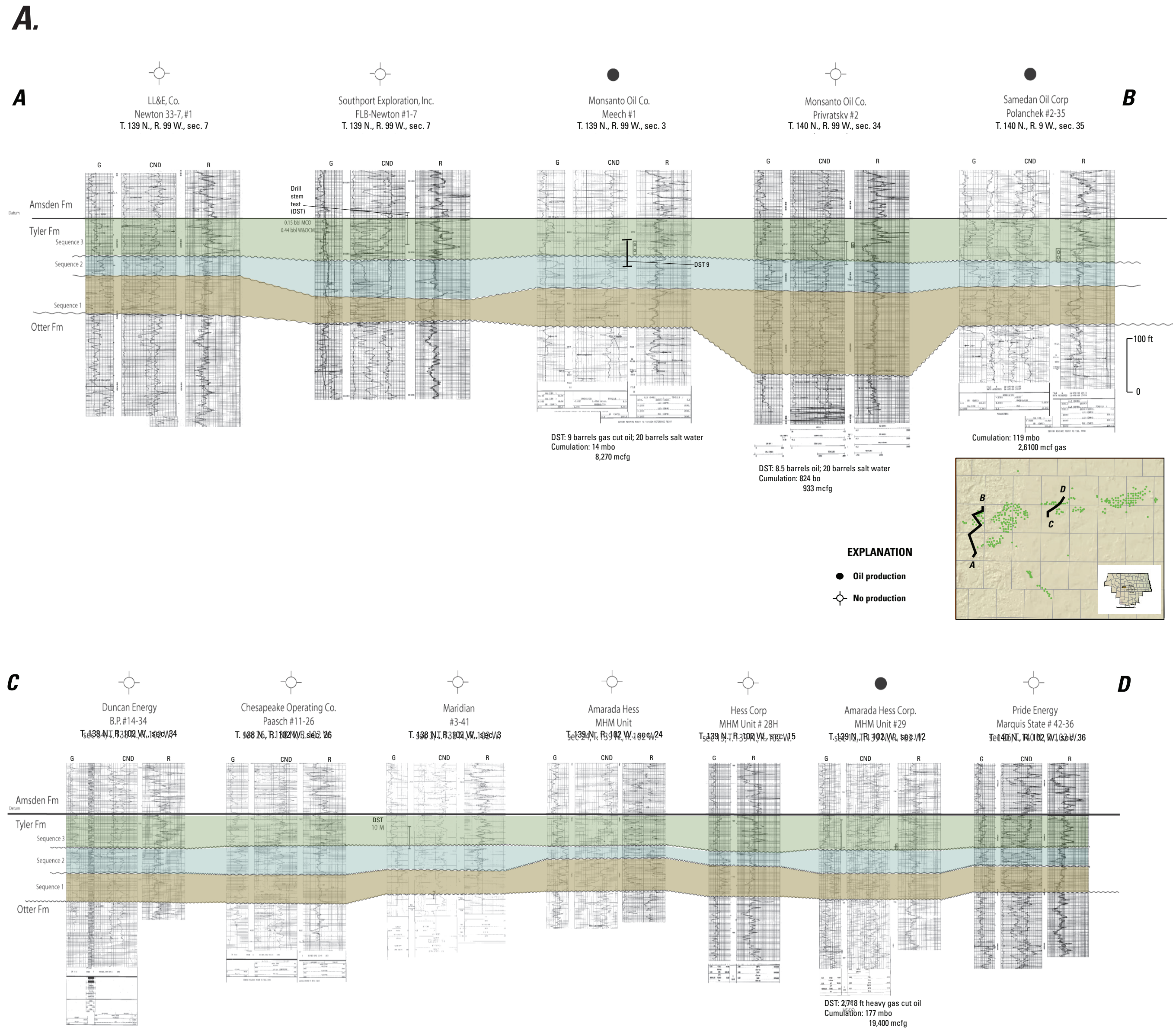

Figure 32. Wireline-log cross section of the Tyler Formation showing stratigraphic relations of sequences 1 through 3 and production intervals. (*A*) A–B and C–D sections; (*B*) E–F and G–H sections. G, gamma ray; R, resistivity; CND, compensated neutron density; and DST, drill-stem test; KB, Kelly bushing elevation in feet; mcfg, thousand cubic feet of gas; bo, barrels of oil; mbo, thousand barrels of oil. (***Click here to open full-size, high-resolution image.)***

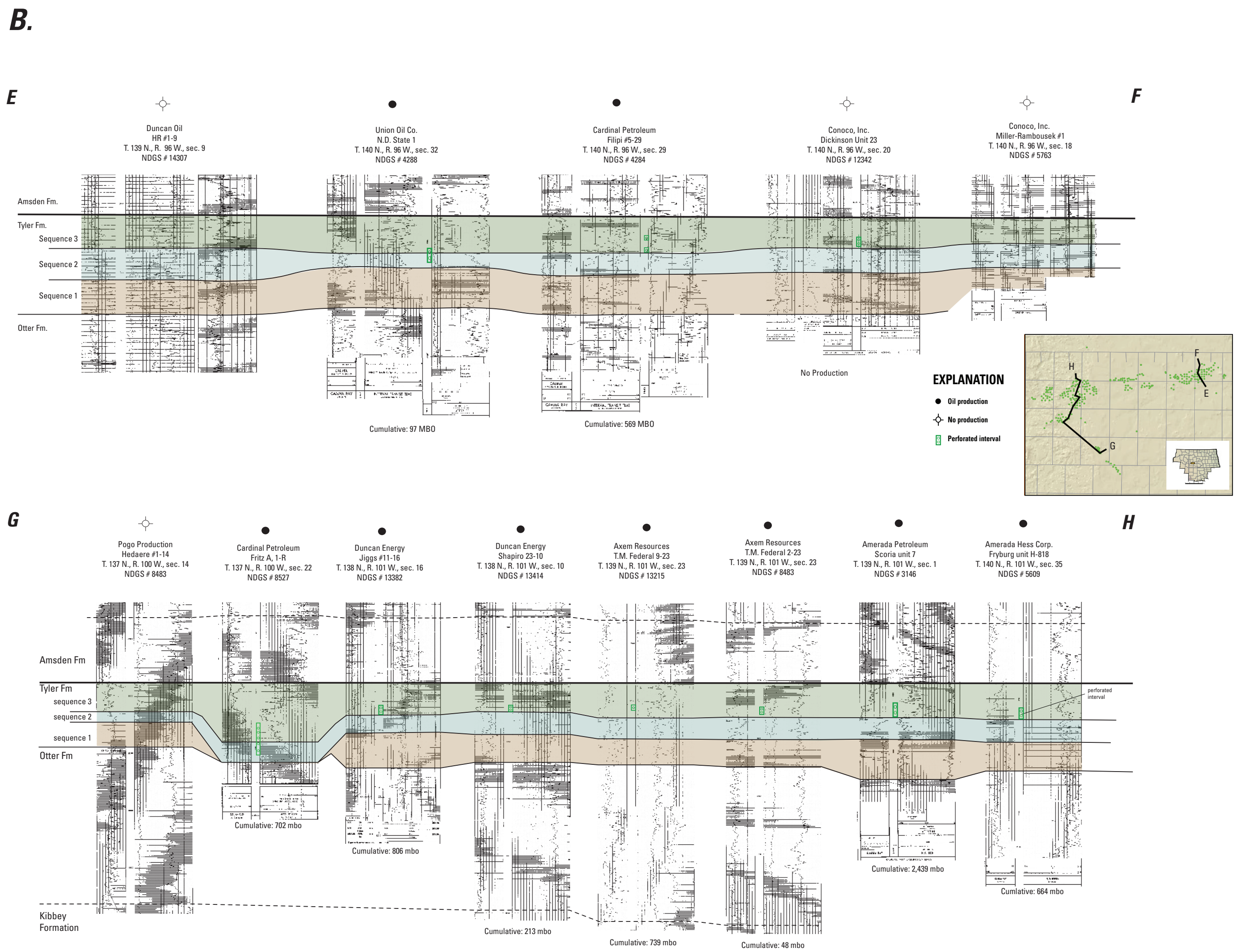

Figure 32. Wireline-log cross section of the Tyler Formation showing stratigraphic relations of sequences 1 through 3 and production intervals. (*A*) A–B and C–D sections; (*B*) E–F and G–H sections. G, gamma ray; R, resistivity; CND, compensated neutron density; and DST, drill-stem test; KB, Kelly bushing elevation in feet; mcfg, thousand cubic feet of gas; bo, barrels of oil; mbo, thousand barrels of oil. (***Click here to open full-size, high-resolution image.***)

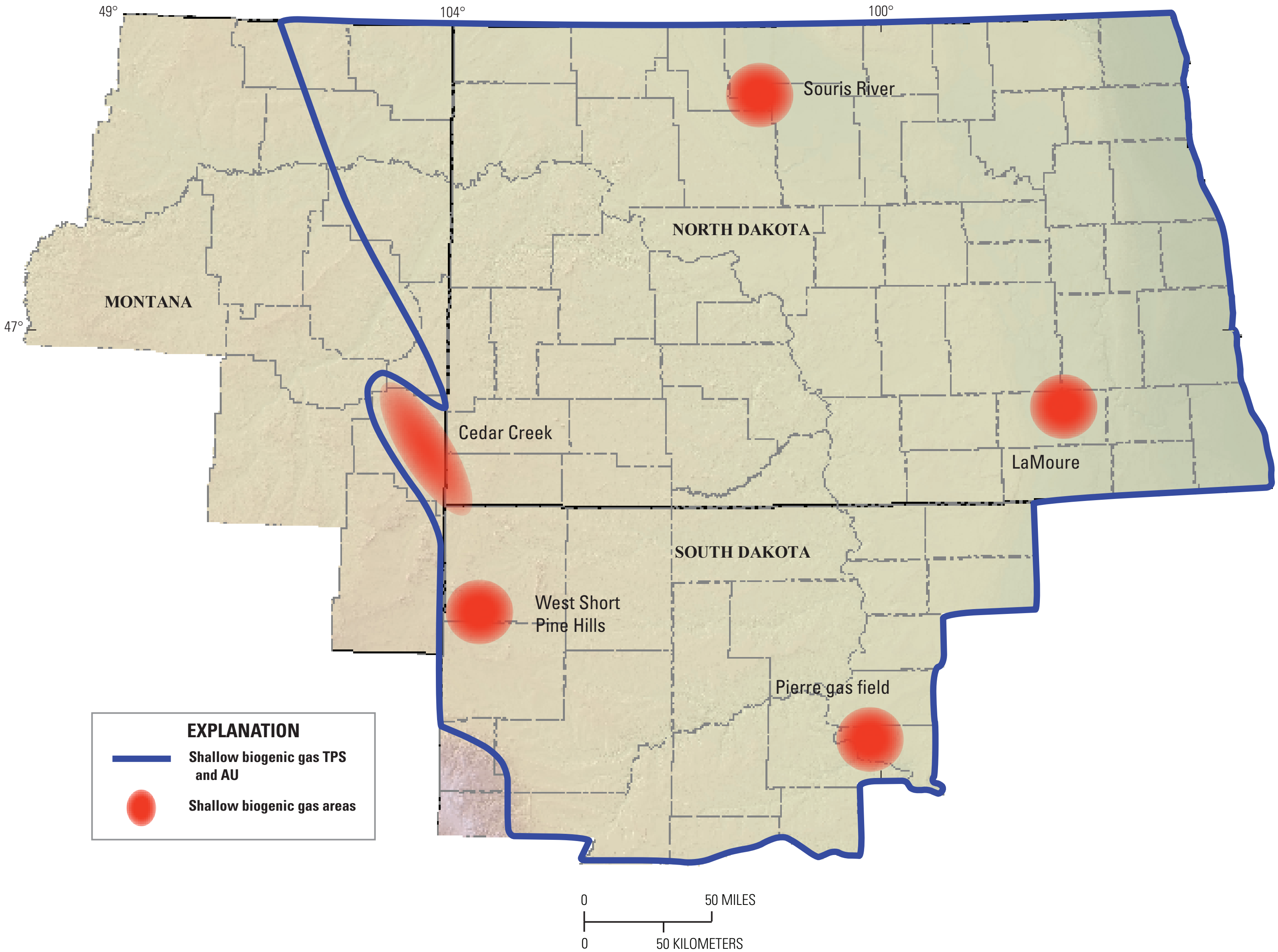

Figure 33. Shallow Biogenic Gas Total Petroleum System (TPS) and Assessment Unit (AU) showing approximate location of gas producing areas. Only the Cedar Creek and West Short Pine Hills areas have economic quantities of gas. Areas west of the TPS and AU boundary in Montana were assessed separately (Ridgley, 2008).

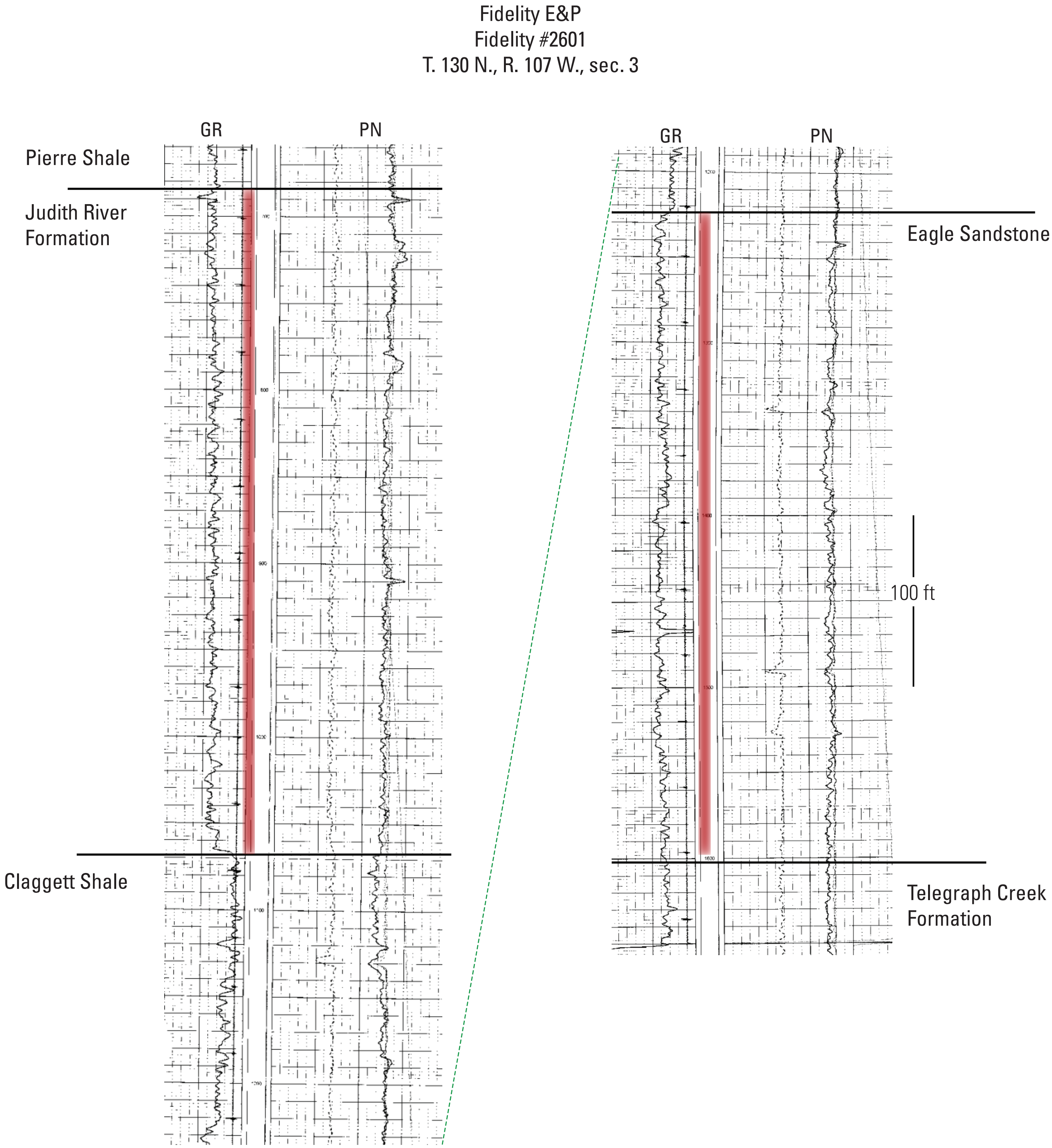

Figure 34. Wireline logs showing gas producing intervals (vertical red line) in the Upper Cretaceous Judith River Formation and Eagle Sandstone in the Shallow Biogenic Gas Total Petroleum System and Assessment Unit. Depth of deepest producing intervals is 1,600 ft. GR, gamma ray; PN, pulsed neutron.

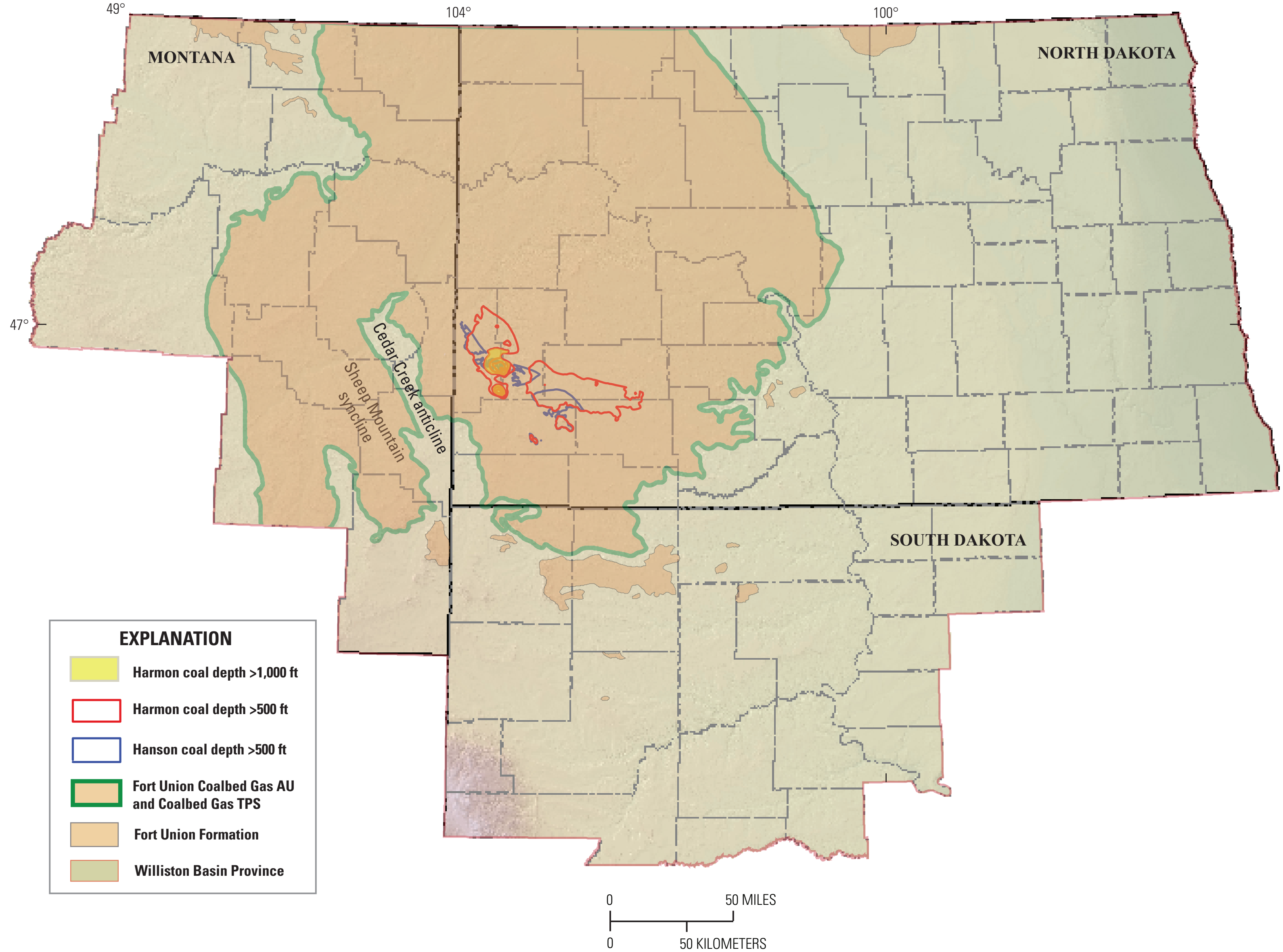

Figure 35. Outline of the Coalbed Gas Total Petroleum System (TPS) and Fort Union Coalbed Gas Assessment Unit (AU), areas where depths to the Harmon and Hanson coalbeds, the two main coalbeds in the Williston Basin, are more than 500 ft, and where the depth to the Harmon coalbeds are greater than 1,000 ft. No data were available from Montana or South Dakota. Coal in the Sheep Mountain syncline, southwest of the Cedar Creek anticline (fig. 1), may also reach depths of more than 500 feet. Coal data are from Flores (1999).

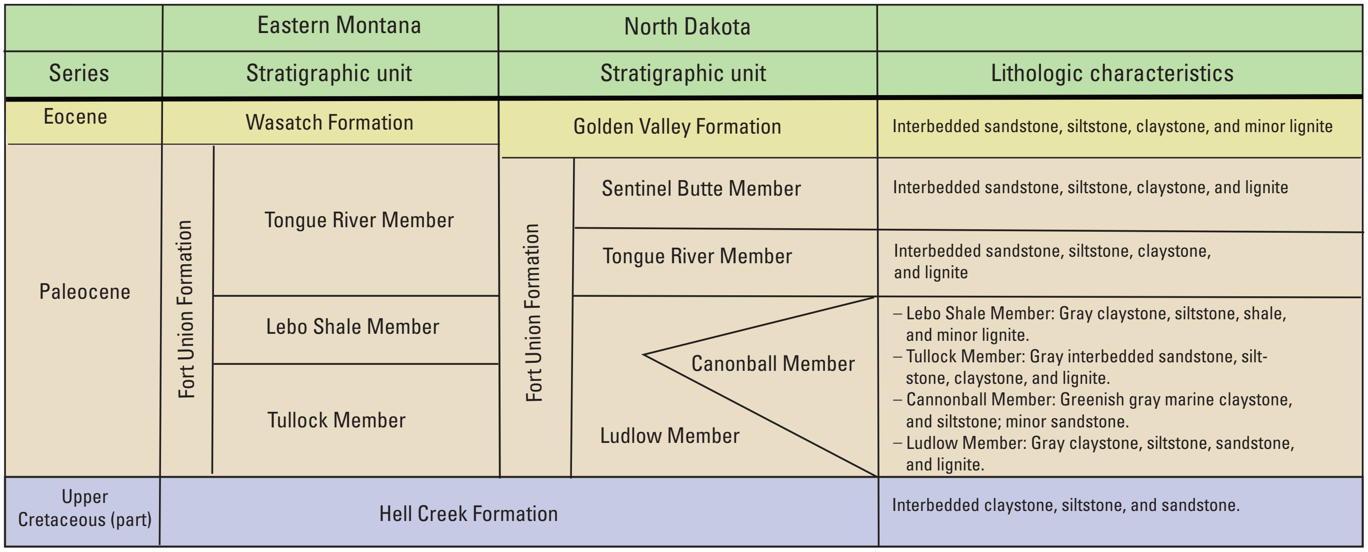

Figure 36. Stratigraphic chart showing Upper Cretaceous (part), Paleocene, and Eocene stratigraphy and associated lithologic characteristics.

Most mined coal in the basin is from the Sentinel Butte and Tongue River Members, although the Ludlow may also have some coal. Average thickness of coal beds is 5 ft, with a few more than 20 ft thick over an extended area (Murphy and Goven, 1998). Most locations in the basin have several stacked coal beds that are stratigraphically equivalent to the lower Fort Union Formation T-Cross coal and Big Dirty coal in southeastern Montana (Warwick and others, 2004). Heating value of the coal in the basin is reported to be from 6,500–9,500 BTU/lb, equivalent to lignite to sub-bituminous rank (Flores, 1999), although most of the coal has collectively been called lignite.

Currently the Fort Union Coalbed Gas AU is considered to be a hypothetical conventional assessment unit because there are no producing wells or fields. However, coal-seam fires have been detected and there have been multiple gas shows from shallow wells in coal, from sandstones that are contiguous to coal beds, and from clinkered outcrops. There have been a few canister retrievals for measuring gas content, but these are too few to produce meaningful statistical data on gas volumes. Stricker (2006) published gas yields on three test wells at depths ranging from 167 ft to more than 900 ft. An average of about five canister tests were conducted for each well; only two canisters were from coals that were more than 20 ft thick, and the remaining tests were from thinner coals. Total gas content per canister ranged from 0.3 to 2.6 standard cubic feet per short ton. Isotherm plots indicated that the Williston Basin isotherms are about one-half the values collected from Powder River Basin coals (Flores, 1999). However, there are so few data that a statistical comparison is questionable.

Numerous hydraulic well tests from the Harmon coal in western North Dakota (Horak, 1983) were converted to permeability and then cross plotted with depth. Using regression analysis, a permeability of about 16 mD at 1,000-ft depth was calculated which is well within the range of coal permeability as defined by Lauback and others (1997, their fig. 3).

Methane gas of biogenic origin was in all captured canisters (Stricker and others, 2006), so it is assumed that the gas is pervasive throughout the Williston Basin Fort Union coals. The volume of coalbed gas per ton has not been determined, but for this study it is assumed that the best potential for significant volumes of gas is where coals more than 10 ft thick are buried to depths exceeding 500 ft. The 10-ft cutoff is used because thinner beds have less gas per volume of coal than thicker beds. Also, thin coals are commonly more compartmentalized than thicker coals because cleats are less connected (Anna, 2003). Those areas where coal is more than 500 ft deep and more than 10 ft thick were outlined in North Dakota (Stricker, 2006), and this was used to form the boundary of the Fort Union Coalbed Gas AU in North Dakota (fig. 35). In addition, the Sheep Mountain syncline southwest of the Cedar Creek anticline in Montana (fig. 1) was included as part of the AU because the syncline has Fort Union strata that are deeper than 500 ft and may contain coal that is sub-bituminous in rank.

Assessment of Undiscovered Petroleum by Assessment Unit

Petroleum exploration in the Williston Basin has been long and successful since non-commercial oil was first discovered in the late 1920s along the Cedar Creek anticline. The basin has thick sections of carbonate rock, displaying many 3rd- and 4th-order carbonate depositional cycles, including thin organic-rich source beds and a variety of reservoir rocks.

Also, there are numerous types of traps ranging from large surface anticlines to small structural blocks related to basement block deformation. Over time 33,000 wells have been drilled, of which more than 19,000 are currently producing or have produced in the past (IHS Energy Group, 2008).

The range of undiscovered oil and gas resources estimated for the eight TPSs and their contained AUs in this assessment (table 1) reflects a mature stage of exploration and production within the basin. Consequently, the range of estimated amounts of technically recoverable new, undiscovered resources is relatively small because yet-to-be tested areas that may contain favorable conditions for hydrocarbon accumulation are limited. However, there is potential for a moderate number of new oil and gas discoveries—that is, fields containing a minimum of 0.5 million barrels of oil equivalent (MMBOE) throughout the basin.

Following a numbering system established by the USGS to facilitate petroleum resource assessment (U.S. Geological Survey, 2000), unique six-digit numbers are assigned to TPSs—for example, the number 503102 is assigned to the Winnipeg-Deadwood TPS, in which “5” denotes the region (North America), “031” denotes the Williston Basin Province, and “02” denotes the specific TPS. Assessment units are also uniquely numbered (8 digits) (for reference see Klett and Le, this CD-ROM). The numbering system established for TPSs and AUs that are the subject of this report is as follows:

- 503102 Winnipeg-Deadwood TPS
  50310201 Winnipeg-Deadwood AU
  50310261 Winnipeg-Icebox Continuous Gas
  (not assessed)

- 503103 Red River TPS
  50310301 Red River Fairway AU
  50310302 Red River East Margin AU
  50310303 Interlake-Stonewall-Stony Mountain AU

- 503104 Winnipegosis TPS
  50310401 Winnipegosis AU

- 503105 Duperow TPS
  50310501 Dawson Bay-Souris River AU
  50310502 Duperow-Birdbear AU

- 503106 Cedar Creek Paleozoic Composite TPS
  50310601 Cedar Creek Structural AU

- 503108 Tyler TPS
  50310801 Tyler Sandstone AU
  50310861 Tyler Shale Continuous Oil AU
  (not assessed)

- 503109 Shallow Biogenic Gas TPS
  0310901 Shallow Biogenic Gas AU

- 503110 Coalbed Gas TPS
  50311801 Ft. Union Coalbed Gas AU

A thorough analysis of all the available geologic data, as well as performance and development information, were presented earlier in this study to a review panel for a final determination of the criteria and boundaries to be used for each of the AUs. In addition, estimates of the sizes and numbers of undiscovered oil and gas accumulations, based on a tabulation of existing field and well records provided by Klett and Le (this CD-ROM), were presented on input-data forms to the review panel. These input-data forms (see Klett and Le, this CD-ROM) constitute the basis for estimating undiscovered hydrocarbon resources in each AU. The default minimum accumulation size that has potential for additions to reserves is 0.5 million barrels of oil equivalent (MMBOE). Other data compiled or calculated for each AU to aid in the final estimate of undiscovered resources include gas/oil ratios, natural gas liquids to gas ratios, API gravity, sulfur content, and drilling depth. Additionally, allocations of undiscovered resources were calculated for Federal, State, and private lands and for various ecosystem regions. All such data are available on the completed input-data forms for the individual AUs (see Klett and Le, this CD-ROM). The input form, a Seventh Approximation Data Form for Conventional Assessment Units, v. 6, developed by Charpentier and Klett (2005), is shown in Chapter 7. The form is organized into six major sections. The source of the known accumulation data is the Nehring database (NRG Associates, Inc., 2008), which provides accumulation-size data for most fields in the United States.

Conventional Assessment Units

Winnipeg-Deadwood AU

The Winnipeg-Deadwood AU covers about two-thirds of the province area (31 million acres) (fig. 4); Winnipeg-Deadwood reservoirs have accumulated more than 52 billion cubic feet of gas (BCFG) and a minor amount of oil from some five gas fields (NRG Associates, Inc., 2008). In addition, more than 800 wells have penetrated all or parts of the Winnipeg-Deadwood section (IHS Energy Group, 2008), which includes some 390 new field wildcats (NRG Associates, Inc., 2008). Approximately 50 percent of all Winnipeg-Deadwood penetrations are new field wildcats and consist of only 2 percent of total Williston Basin wells.

Current and past gas production volumes compared with field size can be classified as bimodal, with field sizes ranging from 6 to 12 thousand cubic feet of gas (MCFG) and from 24 to 48 MCFG. There is no oil production reported, because all field production has been below the 0.5 million barrels of oil (MMBO) cut off. The average field depth is about 14,000 ft, ranging from less than 12,000 ft to more than 14,700 ft.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The number of undiscovered oil accumulations (≥0.5 MMBO) is estimated to be a minimum of one, a maximum of eight, and a mode of two. There have been four new gas field discoveries since the first economic discovery in 1981 (the last was in 1997) and none have produced oil above the minimum size of 0.5 MMBO (which is equivalent to 3.0 BCFG), (NRG Associates, Inc., 2008); it is considered a likely possibility that at least two new gas fields above the minimum size will be discovered. The maximum estimate of 15 undiscovered gas fields is a reflection of the large geographic size of the AU and the large undrilled area that is yet to be tested. The mode estimate is six new field discoveries.

Estimated sizes of undiscovered gas accumulations were 3 BCFG (the minimum field size to assess), a maximum of 300 BCFG, and a median of 15 BCFG. It is estimated that there will be at least one new gas field discovery equal to or greater than the minimum size of 3 BCFG, which reflects the probability that future gas field discoveries will be relatively small. About 6 percent of the assessed gas will be from associated gas produced with oil.

Sizes of undiscovered oil accumulations are estimated at a minimum of 0.5 MMBO, a median of 1.0 MMBO, and a maximum of 10 MMBO. The AU probability of 1.0 reflects that there will be one new field that exceeds the minimum size and that most future discoveries will be small. A median size of 1.0 MMBO is the trend of new field discovery size. A maximum size of 10 MMBO reflects the possibility of finding a large field because of the large undrilled area of the AU, but the probability of such a large discovery is remote.

The greatest risk for exploration is in locating porous and permeable sandstones associated with paleostructure and present-day structure.

Mean estimates of undiscovered resources for the Winnipeg-Deadwood AU are 5.0 MMBO, 189 BCFG (11 BCFG from associated gas), and 9 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future gas discoveries is good because the source rock for this AU is mostly in the gas generation window. The minor potential for oil is expected to be around the edges of the generation window.

Red River Fairway AU

The Red River Fairway AU includes about 33.8 million acres (fig. 8). It has produced more than 135 million barrels of oil (MMBO) from approximately 1,700 producing wells in 140 fields (NRG Associates, Inc., 2008). In addition, there have been more than 1,700 new field wildcats (NRG Associates, Inc., 2008). Field size ranges from less than 0.5 to as much as 9.5 MMBO with a mean and median of 1.8 and 1.1 MMBO, respectively. The average field depth exceeds 12,000 ft and ranges from about 8,200 ft to more than 14,000 ft. Oil gravity in most fields range from 40° to 50° API but can be as low as 23° or as high as 63° API.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered oil accumulations is a minimum of 5, a maximum of 50, and a mode of 20. There have been 101 new oil field discoveries since the first economic discovery in 1957; although there has not been a new field discovery (above the minimum size of 0.5 MMBO) since 1998, a likely possibility exists for the discovery of at least five new oil fields above the minimum. The maximum estimate of 50 undiscovered fields is a reflection of the large geographic size of the AU and the large undrilled area for possible new discoveries in structural and combination structural-stratigraphic traps. New Red River oil field discoveries will probably be small.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.0 MMBO, and a maximum of 7 MMBO. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 1.0 MMBO was used to reflect the probability that most of the undiscovered fields will also be relatively small, which is the trend over the last several years. A maximum size of 7 MMBO reflects the maturity of the AU and is indicative of the probability that a larger discovery is remote.

Although there have been few gas discoveries in this AU, an increase in drilling depths will increase the probability of more discoveries in the future. Therefore, the number of undiscovered gas accumulations is estimated to be a minimum of 3, a maximum of 40, and a mode of 10.

Sizes of undiscovered gas accumulations are estimated to be a minimum of 3 BCFG, a maximum of 50 BCFG, and a median of 8 BCFG. It is estimated that there will be at least one new gas field discovery equal to or greater than the minimum size of 3 BCFG, but the overall numbers reflect the probability that the gas field discoveries will be relatively small. About 15 percent of the assessed gas will be from associated gas production.

Mean estimates of undiscovered resources for the Red River Fairway AU are 30 MMBO, 197 BCFG (30 BCFG from associated gas), and 36 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered optimistic because, although parts of the AU are mature, other parts are sparsely drilled or old structures have only shallow production. Well spacing is 160 acres.

Red River East Margin AU

The Red River East Margin AU covers 0.12 million acres (fig. 8). Only about 100 wells have penetrated strata in this AU (IHS Energy Group, 2008), which includes the Lantry field (fig. 11). The Red River Formation has produced only 0.15 MMBO from two wells in the Lantry field (IHS Energy Group, 2008), despite 20 attempted well completions. The oil has been typed to a Red River origin (Bogle and others, 1998). Drilling depth is approximately 5,000 ft. Oil gravity is low with some degradation, water cuts are high, and gas-oil ratios are low (Bogle, 1998).

Table 2. Williston Basin Province assessment results.

[MMBO, million barrels of oil; BCFG, billion cubic feet of gas; MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas accumulations, all liquids are included as NGL (natural gas liquids). F95 represents a 95-percent chance of at least the amount tabulated; other fractiles are defined similarly. TPS, total petroleum system; AU, assessment unit. Gray shading indicates not applicable]

Total Petroleum System and Assessment Unit	Field Type	*Total Undiscovered Resources*											
		Oil (MMBO)				*Gas (BCFG)*				*NGL (MMBNGL)*			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Continuous Oil and Gas Resources													
Coalbed Gas TPS													
Fort Union Coalbed Gas AU	***Gas***					368	791	1,701	882	0	0	0	0
Total Continuous Resources									**882**				
Conventional Oil and Gas Resources													
Winnipeg–Deadwood TPS													
Winnipeg–Deadwood AU	***Oil***	1	4	10	5	3	9	24	11	0	0	1	0
	Gas					56	161	358	178	3	8	20	9
Red River TPS													
Red River Fairway AU	***Oil***	12	29	51	30	11	28	55	30	1	3	6	3
	Gas					58	155	314	167	11	30	67	33
Red River East Margin AU	***Oil***	0	2	4	2	0	0	1	0	0	0	0	0
	Gas					0	0	0	0	0	0	0	0
Interlake–Stonewall–Stony Mountain AU	***Oil***	9	22	44	24	8	22	47	24	1	2	5	2
	Gas					0	0	0	0	0	0	0	0
Winnipegosis TPS													
Winnipegosis AU	***Oil***	4	11	22	11	2	6	14	7	0	1	1	1
	Gas					0	0	0	0	0	0	0	0
Duperow TPS													
Dawson Bay–Souris River AU	***Oil***	2	5	12	6	1	3	6	3	0	0	0	0
	Gas					0	0	0	0	0	0	0	0
Duperow–Birdbear AU	***Oil***	13	26	44	27	9	20	38	22	1	2	4	2
	Gas					0	0	0	0	0	0	0	0
Cedar Creek Paleozoic Composite TPS													
Cedar Creek Structural AU	***Oil***	6	19	41	20	3	12	28	13	0	1	2	1
	Gas					0	0	0	0	0	0	0	0
Tyler TPS													
Tyler Sandstone AU	***Oil***	4	14	31	15	1	3	7	3	0	0	0	0
	Gas					0	0	0	0	0	0	0	0
Shallow Biogenic Gas TPS													
Shallow Biogenic Gas AU	***Gas***					48	418	1,091	475	0	0	0	0
Total Conventional Resources					**140**				**933**				**51**

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered oil accumulations in this assessment unit is a minimum of one, a maximum of five, and a mode of two. There has been only one new oil field discovery, but no discovery above the minimum of 0.5 MMBO. There is a 0.8 possibility that at least one more oil field above the minimum of 0.5 MMBO exists. The maximum estimate of five and the mode estimate of two for undiscovered fields is a reflection of the large geographic size of the AU and the large undrilled area for possible new discoveries in combination structural-stratigraphic traps. New Red River oil field discoveries will probably be small.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 0.75 MMBO, and a maximum of 5 MMBO. A median size of 0.75 MMBO was also used to reflect the probability that most of the fields will be relatively small. A maximum size of 5 MMBO reflects the large untested area of the AU and is indicative of the low probability for a larger discovery.

There has not been a gas discovery in this AU, and geologic conditions indicate little or no new gas field potential.

Mean estimates of undiscovered resources for the Red River East Margin AU are 2 MMBO (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered remote because, although one field has been discovered, it is unknown if oil has migrated to the eastern part of the basin, and the potential for traps is possible but unknown.

Interlake-Stonewall-Stony Mountain AU

The Interlake-Stonewall-Stony Mountain AU, about 33.8 million acres (fig. 9), has produced more than 80 MMBO and 270 MCFG from approximately 290 producing wells in 29 fields (NRG Associates, Inc., 2008). In addition, there has been more than 1,850 new field wildcats in this AU (NRG Associates, Inc., 2008). Field sizes range from less than 0.5 to 18.5 MMBO with a mean and median of 3.1 and 1.5 MMBO, respectively. The average field depth is slightly less than 12,000 ft and ranges from about 10,000 ft to nearly 14,000 ft. Oil gravity in most fields ranges from 40° to 50° API gravity but can range from 30° to 55° API gravity. Gas-oil ratio averages about 1,500 cubic feet of gas per barrel of oil.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered oil accumulations in this assessment unit is a minimum of 3, a maximum of 30, and a mode of 10. There have been 29 new oil field discoveries since the first economic discovery in 1960; although there has not been a new field discovery (above the minimum size) since year 2000, a likely possibility exists for the discovery of at least three new oil fields above the minimum of 0.5 MMBO. The maximum estimate of 30 undiscovered fields is a reflection of the large geographic size of the AU and the large undrilled area for possible new discoveries in structural and combination structural-stratigraphic traps. New oil field discoveries will probably be small.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.25 MMBO, and a maximum of 15 MMBO. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 1.25 MMBO was used to reflect the probability that most of the undiscovered fields will also be relatively small, which is the trend over the last several years. A maximum size of 15 MMBO reflects the maturity of the AU and is indicative of the small probability of a larger discovery.

Because there has been only one gas discovery in this AU, there is little, if any, potential for new gas discoveries; therefore, the gas resource for this AU that was assessed was from associated gas.

Mean estimates of undiscovered resources for the Interlake-Stonewall-Stony Mountain AU are 24 MMBO, 24 BCFG (from associated gas), and 2 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is highly dependent on reservoir quality and trapping conditions, which are uncertain, and the potential is also questionable because oil generated in the Red River Formation must migrate into overlying reservoirs.

Winnipegosis AU

The Winnipegosis AU covers 17.8 million acres (fig. 17). It has produced more than 13 MMBO and 16 million cubic feet (MCF) of associated gas from approximately 115 producing wells in 11 fields (NRG Associates, Inc., 2008). In addition, there has been more than 1,260 new field wildcats (NRG Associates, Inc., 2008). Field size ranges from less than 0.5 to 7 MMBO with a mean and median of 2.6 and 1.2 MMBO, respectively. The average field is nearly 12,000 ft deep and ranges from about 9,000 ft to more than 11,000 ft. Oil gravity in most fields ranges from 40° to 50° API gravity but can range from 35° to 50° API gravity. Gas-oil ratio averages about 600 cubic feet of gas per barrel of oil.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered oil accumulations is a minimum of 1, a maximum of 14, and a mode of 5. There have been 11 new oil field discoveries since the first economic discovery in 1971; although there have not been any discoveries above the minimum size since 2000, a likely possibility exists for the discovery of at least one new oil field above the minimum of 0.5 MMBO. The maximum estimate of 14 undiscovered fields is a reflection of the geographic size of the AU and the large undrilled area for possible new discoveries in pinnacle reefs and from structural and combination structural-stratigraphic traps. New oil field discoveries will probably be small.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.3 MMBO, and a maximum of 15 MMBO. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 1.3 MMBO was used to reflect the probability that most of the undiscovered fields will also be relatively small, which is the trend over the last several years. A maximum size of 15 MMBO reflects the maturity of the AU and is indicative of the small probability of a larger discovery.

Because there are no gas discoveries in this AU, the potential for a new gas discovery is remote; therefore, the gas resource for this AU that was assessed was from associated gas.

Mean estimates of undiscovered resources for the Winipegosis AU are 11 MMBO, 7 BCFG (from associated gas), and 1 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is guarded by uncertain reservoir quality, especially in pinnacle reefs, and trapping conditions.

Dawson Bay-Souris River AU

The Dawson Bay-Souris River AU, covering about 23.3 million acres (fig. 22), has produced 5 million barrels of oil (MMBO) and 1.5 MCF of associated gas from approximately 32 producing wells in 3 fields (NRG Associates, Inc., 2008). In addition, there have been more than 1,800 new field wildcats in this AU (NRG Associates, Inc., 2008). Field size ranges from less than 0.5 to 3.6 MMBO, with a mean field depth of more than 10,000 ft. Oil gravity in most fields ranges from 40° to 50° API gravity and averages 45° API gravity. Gas-oil ratio averages about 500 cubic feet of gas per barrel of oil.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered oil accumulations in this assessment unit is a minimum of 1, a maximum of 15, and a mode of 3. There have been three new oil field discoveries since the first economic discovery in 1980; although there has not been a new field discovery (above the minimum size) since 1995, a likely possibility exists for the discovery of at least one new oil field above the minimum of 0.5 MMBO. The maximum estimate of 15 undiscovered fields is a reflection of the geographic size of the AU and the large undrilled area for possible new discoveries from structural and combination structural-stratigraphic traps. New oil field discoveries will probably be small.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 0.75 MMBO, and a maximum of 8 MMBO. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 0.75 MMBO was used to reflect the probability that most of the undiscovered fields will also be relatively small, which is the trend over the last several years. A maximum size of 8 MMBO reflects the maturity of exploration within the AU and is indicative of the small probability of a larger discovery.

Because there have been no gas discoveries in this AU, there is little, if any, potential for new gas and new natural gas liquids discoveries, therefore, the gas resource that was assessed was from associated gas.

Mean estimates of undiscovered resources for the Dawson Bay-Souris River AU are 6 MMBO and 3 BCFG (from associated gas) (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered guarded because of uncertain reservoir quality and trapping opportunities.

Duperow-Birdbear AU

The Duperow-Birdbear AU covers 23.3 million acres (fig. 23), and has produced more than 200 MMBO and 170 billion cubic feet (BCF) of associated gas from approximately 600 producing wells in 79 fields (NRG Associates, Inc., 2008). In addition, there has been more than 2,400 new field wildcats (NRG Associates, Inc., 2008). Field size ranges from less than 0.5 to as much as 83 MMBO and averages about 2 MMBO, with a mean field depth of about 11,000 ft. Oil gravity in most fields ranges from 40° to 50° API gravity and averages 43° API gravity. Gas-oil ratio averages about 800 cubic feet of gas per barrel of oil.

Input values for the Assessment Data Form to assess this assessment unit are shown in Chapter 7. The estimated number of undiscovered oil accumulations in this assessment unit is a minimum of 5, a maximum of 28, and a mode of 13. There have been 79 new oil field discoveries since the first economic discovery in 1951; although there has not been a new field discovery (above the minimum size) since 2003, a likely possibility exists for the discovery of at least five new oil fields above the minimum of 0.5 MMBO. The maximum estimate of 28 undiscovered fields is a reflection of the geographic size of the AU and the large undrilled area for possible new discoveries from structural and combination structural-stratigraphic traps. New oil field discoveries will probably be small.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.4 MMBO, and a maximum of 12 MMBO. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 1.4 MMBO was used to reflect the probability that most of the undiscovered fields will also be relatively small, which is the trend over the last several years. A maximum size of 12 MMBO reflects the maturity of the AU and is indicative of the small probability of a larger discovery unless fields with shallow production on large structures are drilled deeper.

Because there have been no gas discoveries in this AU, the potential for new gas and new natural gas liquids discoveries is remote; therefore, the gas resource for this AU that was assessed was from associated gas.

Mean estimates of undiscovered resources for the Duperow-Birdbear AU are 27 MMBO, 22 BCFG (from associated gas), and 2 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered optimistic because of good reservoir quality, trapping opportunities, and horizontal drilling techniques.

Cedar Creek Structural AU

The Cedar Creek Structural AU covers a small part of the province area (4.5 million acres), but it has produced more than 320 million barrels of oil (MMBO) and 360 BCF of associated gas from more than 600 producing wells in 35 fields (NRG Associates, Inc., 2008). Field size ranges from less than 0.6 to as much as 167 MMBO and averages about 11.2 MMBO with a mean field depth of about 9,000 ft. Oil gravity in most fields ranges from 30° to 40° API gravity, averaging 33° API gravity. Gas-oil ratio averages about 600 cubic feet of gas per barrel of oil.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered oil accumulations in this assessment unit is a minimum of 1, a maximum of 20, and a mode of 5. There have been 29 new oil field discoveries since the first economic discovery in 1915; although there has not been a new field discovery (above the minimum size) since 1997, a likely possibility exists for the discovery of at least one new oil field above the minimum of 0.5 MMBO. The maximum estimate of 20 undiscovered fields is a reflection of the undrilled area for possible new discoveries from structural and combination structural-stratigraphic traps.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.75 MMBO, and a maximum of 20 MMBO. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 1.75 MMBO likewise reflects the probability that most of the undiscovered fields will also be relatively small, which is the trend over the last several years. A maximum size of 20 MMBO reflects the maturity of the AU and is indicative of the small probability of a larger discovery.

Because there have been no gas discoveries in this AU, the potential new gas and new natural gas liquids discoveries is remote; therefore, the gas resource for this AU that was assessed was from associated gas.

Mean estimates of undiscovered resources for the Cedar Creek Structural AU are 20 MMBO, 13 BCFG (from associated gas), and 1 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered optimistic because of good reservoir quality and trapping opportunities, and the use of horizontal drilling techniques.

Tyler Sandstone AU

The Tyler Sandstone AU covers 24.6 million acres (fig. 30), and has produced more than 84 MMBO and 22 BCFG of associated gas from approximately 330 producing wells in 11 fields (NRG Associates, Inc., 2008). In addition, there have been more than 4,000 new field wildcats (NRG Associates, Inc., 2008). Field size ranges from less than 1.1 to as much as 26.7 MMBO and averages about 7.7 MMBO with a mean field depth of about 8,000 ft. Oil gravity in most fields ranges from 30° to 40° API gravity, and averages 36° API gravity. Gas-oil ratio averages about 200 cubic feet of gas per barrel of oil.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered oil accumulations is a minimum of 1, a maximum of 20, and a mode of 4. There have been 11 new oil field discoveries since the first economic discovery in 1954; although there has not been a new field discovery (above the minimum size) since 1992, a likely possibility exists for the discovery of at least one new oil field above the minimum of 0.5 MMBO. The maximum estimate of 20 undiscovered fields is a reflection of the geographic size of the AU and the large undrilled area for possible new discoveries from structural and combination structural-stratigraphic traps, as well as new continuous reservoir discoveries. New oil field discoveries will probably be small.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.5 MMBO, and a maximum of 12 MMBO. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 1.5 MMBO was used to reflect the probability that most of the undiscovered fields will also be relatively small, which is the trend over the last several years. A maximum size of 12 MMBO reflects the maturity of the AU and is indicative of the small probability of a larger discovery unless fields with channel sandstone reservoirs are discovered.

Because there has been no gas discoveries in this AU, the potential new gas and new natural gas liquids discoveries is remote; therefore, the gas resource for this AU that was assessed was from associated gas.

Mean estimates of undiscovered resources for the Tyler Sandstone AU are 15 MMBO, and 3 BCFG (from associated gas; table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered guarded because of reservoir quality, trapping opportunities, and continuous reservoir potential is hypothetical.

Shallow Biogenic Gas AU

The Shallow Biogenic Gas AU covers some 71.8 million acres. The AU has produced more than 80 BCFG of biogenic gas from approximately 1,200 producing wells in six fields (NRG Associates, Inc., 2008). In addition, there have been more than 450 new field wildcats in this AU (NRG Associates, Inc., 2008). Field size ranges from less than 3.4 to 41 MMCFG and averages about 16 MMCFG with a mean field depth of about 1,100 ft. There were minimum amounts of inert gas and CO_2, and no hydrogen sulfide.

Input values for the Assessment Data Form to assess this AU are shown in Chapter 7. The estimated number of undiscovered gas accumulations is a minimum of 1, a maximum of 200, and a mode of 3. There have been six new oil field discoveries since the first one in 1915, but none above the minimum size since 1998. However, it is considered likely that at least one new oil field above the minimum will be found. The maximum estimate of 200 undiscovered fields is a reflection of the geographic size of the AU and the large undrilled area for possible new discoveries from structural and combination structural-stratigraphic traps. New gas field discoveries will probably be small.

Estimated sizes of undiscovered gas accumulations are a minimum of 3.0 BCFG, a median of 6 BCFG, and a maximum of 35 BCFG. The AU probability of 1.0 reflects that there will be one field greater than the minimum size and that most discovered fields are small. A median size of 6 BCFG was used to reflect the probability that most of the undiscovered fields will also be relatively small, although there are few data points to establish a trend. A maximum size of 35 BCFG reflects the small probability of a large field discovery.

Because there are no oil discoveries in this AU, the oil resource for this AU was not assessed.

Undiscovered resources for the Shallow Biogenic Gas AU are estimated at a mean of 475 BCFG (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future gas discoveries is considered optimistic because of reservoir quality, large regional extent, and trapping opportunities.

Continuous Assessment Units

Fort Union Coalbed Gas AU

The Fort Union Coalbed Gas AU (fig. 35) is hypothetical because there are no known gas producing wells (NRG Associates, Inc., 2008); however, there are reported gas shows in shallow groundwater wells and shallow coal mines.

The method to assess a continuous-type play applies a cell-based grid that assigns a probability of ultimate gas recovery in each cell. The size of each cell is based on geologic controls, extent of gas drainage area, and the production history of analog fields in other provinces.

The method includes a determination of the mode, minimum, and maximum percentages of untested assessment areas that have the potential for additions to reserves (above the minimum of 0.02 BCFG). At the mode there are 27,363,000 untested acres in the AU; at the minimum 24,627,000 untested acres; and at the maximum 30,100,000 acres.

Area per cell of untested cells having potential for additions to reserves is estimated at a minimum of 40 acres, a mode of 100 acres, and a maximum of 180 acres (appendix K). The percentage of total AU area that is untested is 100 percent. The total recovery per cell for untested cells having potential for additions to reserves is estimated at a minimum of 0.02 BCF, a median of 0.085 BCF, and a maximum of 1 BCFG.

Mean estimate of undiscovered gas resources for the Fort Union Coalbed Gas AU is 882 BCFG (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles.

Assessment Summary

The Williston Basin Province has been a prolific hydrocarbon province since the 1950s, with reservoirs ranging in age from Cambrian through Paleogene. The basin has generated billions of barrels of oil and several trillion cubic of gas, and produced over 3.2 billion barrels of oil equivalent that has accumulated in ten TPSs.

Although the province has been widely drilled, especially in the central part of the basin, there remain untested and undertested sections that likely will produce in the future. This assessment calculated that, in the future, there may be 142 percent more oil and 132 percent more gas in the province than has been discovered as of 2006. Excluding the Bakken Formation, there may be 7.2 percent more oil and 65 percent more gas. New production will likely come from infill and new pay zones discovered in old fields, especially deep pay zones in fields with existing shallow production. The number and sizes of new field discoveries will be relatively small, although not all of the large structures in the basin have deep well tests.

Mean estimates of total conventional undiscovered resources for those AUs of the Williston Basin Province presented in this chapter (excluding the Bakken Formation) are 140 MMBO, 933 BCF of associated and nonassociated gas, and 51 MMBNGL (table 2).

Mean estimates of continuous hydrocarbon accumulations (excluding the Bakken Formation) in the basin include only coalbed-gas production of 882 BCFG. New completion and drilling techniques should help production performance in deep coal beds.

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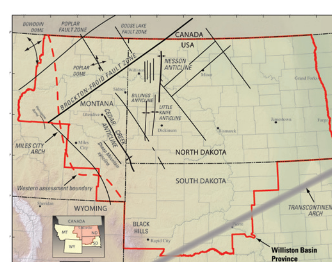

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