NORTH-CENTRAL MONTANA PROVINCE (028)

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With a section on the Northern Great Plains Shallow Biogenic Gas Plays
by Dudley D. Rice and Charles W. Spencer

INTRODUCTION

The North-Central Montana Province lies entirely within the State of Montana; it is approximately 250 mi long from east to west and 250 mi wide from north to south. The province includes both the North-Central and South-Central Montana Provinces of the previous petroleum assessment (Dyman, 1987; Maughan, 1989). It is bounded by the Montana Disturbed Belt to the west, Williston Basin to the east, Alberta Shelf and the United States–Canada border to the north, the Crazy Mountains Basin to the southwest, and the Powder River Basin to the southeast. Geologic features included in the province are the south Sweetgrass Arch (South Arch), Kevin-Sunburst and Bowdoin Domes, Central Montana Trough, and Bearpaw Uplift. The province has been actively explored for petroleum since 1903, when oil was discovered in adjoining Alberta, Canada (Medicine Hat field). Of the more than 170 discovered fields in the province, 58 are greater than 1 MMBO or equivalent 6 BCFG in size and are productive from an average depth of about 2,000 ft. The oldest significant (greater than 1 MMBO or 6 BCFG ultimate recoverable production) field is Bowdoin, which was discovered in 1913; it produces biogenic gas from low-permeability Cretaceous reservoirs. Cutbank oil field was discovered in 1926 and is the largest field in the province; it has an ultimate recoverable production of more than 210 MMBO from the Cretaceous Kootenai Formation sandstone and Madison Group carbonate.

Cumulative conventional production in the province is more than 440 MMBO and 1.1 TCFG. Late Precambrian through Tertiary strata occur in outcrop and in the subsurface in the province and are grouped into 10 conventional and unconventional plays. Conventional plays are Proterozoic (2801), Cambrian-Ordovician Sandstones (2802), Red River Carbonates (2803), Devonian-Mississippian Carbonates (2805), Tyler Sandstone (2806), Fractured-Faulted Carbonates in Anticlines (2807), Jurassic-Cretaceous Sandstones (2808) and Shallow Cretaceous Biogenic Gas Play (2809). Unconventional plays are Bakken Shale Fracture Systems Play (2804) and the Northern Great Plains Biogenic Gas Play, which is divided into High Potential Play (2810), Moderate Potential (Suffield Block Analog) Play (2811), and Low Potential Play (2812).

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CONVENTIONAL PLAYS

2801. PROTEROZOIC PLAY (HYPOTHETICAL)

Rocks of Proterozoic age form the basis for a poorly understood hypothetical play in the southernmost part of the North-Central Montana Province. Late Precambrian clastic and carbonate rocks of the Belt Supergroup are absent throughout most of north-central Montana, but occur in the subsurface along the southwestern and southern boundaries of the province within the Central Montana Trough. These Proterozoic metasedimentary rocks reach a maximum thickness of more than 20,000 ft in the western part of the Central Montana Trough to the south and more than 40,000 ft in the Montana Disturbed Belt to the west. Rocks in the southeastern part of the province less than 5,000 ft thick have been excluded from the play. Proterozoic rocks crop out in the Big Belt and Little Belt Mountains. Proterozoic rocks in play 2801 occur between about 3,000 and 12,000 or more ft.

Reservoirs: Potential Proterozoic reservoir rocks include limestone of the Newland Formation and limestone and sandstone of the Spokane, Greyson, and Helena Formations (part of Belt Supergroup in fig. 2) in both structural and stratigraphic traps.

Source rocks: Potential source rocks include interbedded shale, carbonate, and mudstone. Recent U.S. Geological Survey unpublished data suggest, however, that these rocks are poor source rocks with low genetic potentials, and they are overmature. Total organic carbon (TOC) values are generally less than 0.3 weight percent, and Tmax values are generally greater than 500^{o}C for samples taken in the Big Belt and Little Belt Mountains.

Exploration status and resource potential: Relatively few wells have penetrated these rocks and no known accumulations exist. Play attributes include a low probability of occurrence (probability=0.1) of source rocks of appropriate thermal maturity, but adequate reservoir rocks and traps are assumed present (probability=1.0). The play probability (probability of occurrence of an undiscovered accumulation of at least 1 MMBO or 6 BCFG) is therefore a low 0.1.

2802. CAMBRIAN–ORDOVICIAN SANDSTONES PLAY (HYPOTHETICAL)

The boundary of this hypothetical play is based on the distribution of Cambrian and Ordovician sandstone. Cambrian strata lie unconformably on Archean rocks across most of the province where Proterozoic Belt rocks are absent. The Middle to Late Cambrian eastward marine transgression in western and northern Montana resulted in deposition of the Flathead Sandstone and overlying marine fossiliferous shale and carbonate. Cambrian strata are approximately 1,000 ft thick in most of the province, but they thicken southward into the central Montana trough and to the west in the disturbed belt where Cambrian rocks are more than 2,000 ft thick. Cambrian strata thin to less than 500 ft along the flanks of the Sweetgrass Arch and are absent along part of its crest. Thinning also continues eastward across the North-Central Montana Province into the Williston Basin and the Black Hills region southeast of the province.

Ordovician strata are absent in the western and central part of the province due to pre- Late Devonian erosion, but strata thicken eastward into the Williston Basin, where they are more than 2,000 ft thick. Along the western margin of the Williston Basin, quartz-rich sandstone of the Lower Ordovician Winnipeg Formation is overlain by Middle to Upper Ordovician carbonate and evaporite strata.

The Cambrian-Ordovician Sandstones Play includes (1) Cambrian Flathead and equivalent sandstone throughout the province except along the crest of the Sweetgrass Arch, and (2) Ordovician Winnipeg Sandstone and its equivalent rocks along the western margin of the Williston Basin in the eastern part of the North-Central Montana Province. By the mid-1980's, more than 60 wells penetrated Cambrian strata in the region (Garcia-Ramirez and Helland, 1985), but facies relationships within these strata have not been well defined. No Cambrian production occurs in the province at this time.

Reservoirs: Reservoir and source-rock lithologies include quartz- and lithic-rich sandstone of the Flathead and Winnipeg Formations. The average depth to the top of the Cambrian where present varies from about 3,000–8,000 ft.

Source rocks: The best source rocks are dark-gray marine shale including the Cambrian Gordon and Switchback Shales and their equivalent rocks, and shale beds of the Red River Formation. At present, no geochemical data are available to determine thermal maturity, type of organic matter, and timing and migration of hydrocarbons for lower Paleozoic strata in the province. Kohm and Louden (1978), however, evaluated several kerogen samples from the Red River Formation in the Williston Basin. Total organic carbon (TOC) values there ranged from 1.8 to 14.0 weight percent, and source rocks were considered to be mature. Organic-geochemical data are not available for Cambrian shale, but these source rocks are generally considered poor to fair and assumed to be immature to marginally mature due to the shallow maximum burial depths.

Traps: Trapping mechanisms include permeability barriers in sandstone. Structural enhancement of existing traps may be common in areas of Laramide faulting and folding.

Exploration status: The first Winnipeg production in Montana was reported in 1986 by Amerada Hess in Roosevelt County in the western part of the Williston Basin east of the province. A wildcat well flowed about 3 MMCFG/D at a depth of 11,000 ft. Nyvatex Exploration reported high-gravity oil shows at a depth of 3,690 ft in the Flathead Formation in their Friedman 26-1XD well in Cascade County (sec. 26, T. 20 N., R. 2 E.) also drilled in 1986.

Resource potential: Play attributes include a moderate probability of occurrence (probability=0.5) of source rocks of appropriate richness, but adequate thermal maturity, reservoir rocks, and traps are assumed present (probability=1.0). The play probability (probability of occurrence of an undiscovered accumulation of 1 MMBO or 6 BCFG) is therefore 0.5. Undiscovered fields are presumed to be small.

2803. RED RIVER CARBONATES PLAY (HYPOTHETICAL)

Ordovician and Silurian strata are absent in the western and central part of the province due to pre-Late Devonian erosion associated with the central Montana Uplift, but where present, these strata thicken eastward from near the center of the province toward the Williston Basin, where they are more than 2,000 ft thick. Along the western margin of the Williston Basin, quartz- and lithic-rich sandstone of the Lower Ordovician Winnipeg Formation is overlain by Middle to Upper Ordovician carbonate and evaporite strata of the Red River, Stony Mountain, and Interlake Formations. The paleoequator passed through Montana during the Ordovician resulting in warm water and shallow marine to supratidal depositional environments. The Interlake Formation includes a Late Silurian upper portion composed of stromatolitic, oolitic, and bioclastic dolomite with paleosol and paleokarst horizons.

Reservoir rock lithologies of this hypothetical play include carbonate rocks of the Red River, Stony Mountain, and Interlake Formations. Source rocks include gray to green shale and carbonate rocks of post-Flathead Cambrian formations; and carbonate-evaporite rocks of the Red River, Stony Mountain, and Interlake Formations (Theodosis, 1955; Lochman-Balk, 1972). The best source rocks are dark-gray shale beds within the Red River Formation. Trapping mechanisms include permeability barriers in interbedded sandstone, increased porosity associated with selective dolomitization and solution brecciation, and facies changes in carbonate-evaporite cycles. Structural enhancement of existing traps may be common in areas of Laramide faulting and folding.

Reservoirs: Approximately 250 oil reservoirs produce from dolomite beds of the Red River and Stony Mountain Formations in the Williston Basin (Peterson, 1985), the closest being at Putnam field in Richland County, Montana, east of the province. Generally, reservoir rocks include tidal and subtidal bioclastic and laminated dolomite capped by anhydrite (Longman and others, 1983).

Source rocks: The average depth to the top of the Ordovician, where present, varies from approximately 3,000 to 7,500 ft. At present, no geochemical data are available to determine thermal maturity, type of organic matter, and timing and migration of hydrocarbons for lower Paleozoic strata in the province. Kohm and Louden (1978), however, evaluated several kerogen samples from the Red River Formation in the Williston Basin. TOC values there ranged from 1.8–14.0 weight percent, and source rocks were considered to be mature. However, in the central and eastern part of the North-Central Montana Province, these source rocks are more likely to be immature to marginally mature.

Traps: Trapping mechanisms include permeability barriers in interbedded sandstone, increased porosity associated with selective dolomitization and solution brecciation, and facies changes in carbonate-evaporite cycles. Structural enhancement of existing traps may be common in areas of Laramide faulting and folding.

Exploration status and resource potential: Play attributes include a moderate probability of occurrence (probability=0.75) of source rocks of appropriate richness, thermal maturity, and thickness, and adequate reservoir rocks and traps are assumed present (probability=1.0). The play probability (probability of occurrence of an undiscovered accumulation of 1 MMBO or 6 BCFG) is therefore 0.75. Undiscovered fields are considered to be small.

2805. DEVONIAN-MISSISSIPPIAN CARBONATES PLAY

The play is characterized primarily by oil accumulations in carbonate reservoirs of Devonian-Mississippian age in both structural and stratigraphic traps. The play includes (1) Devonian carbonate strata of the Souris River, Duperow, Nisku, Potlatch, and Three Forks Formations throughout the 250 x 150 mi area of the province; and (2) predominantly carbonate rocks of the Mississippian Madison Group. The play extends throughout the area of the province, although these rocks vary in reservoir quality and thickness. Devonian and Mississippian strata vary in total thickness from approximately 1,000–2,500 ft.

Reservoirs: Known reservoir rocks include (1) dolomite facies within carbonate-evaporite cycles of the Devonian Nisku Formation; and (2) oolitic and bioclastic carbonate banks and mounds and karst zones in the Mississippian Madison Group. Dolomitization, which may be associated with nearshore salinity variations within Devonian reservoirs, is greatest along a line trending northwestward from the Little Belt Mountains. Widespread paleokarst reservoirs in the middle and upper part of the Madison Group are the result of post-Mississippian erosion. In addition, dolomitized subtidal carbonate banks within the Madison Group are excellent reservoirs where they are interbedded with supratidal anhydrite. Productive zones vary from about 10 to 100 ft in thickness.

Source rocks: Source rocks include black organic-rich shale of the Bakken Shale, shale in the Three Forks Formation (Sappington Member), Lodgepole Limestone, and Heath Formation. The Heath is the uppermost unit in the Big Snowy Group, which overlies the Madison Group and occurs in the Central Montana Trough. Vitrinite reflectance values vary from 0.49–0.55 percent in Heath shale in southern Fergus County, Montana, indicating that they are thermally immature and are at or immediately below the oil generation window. Aram (1993) identified R_o values in the Heath of 0.69–0.84 percent and TOC values of up to 9 weight percent in Petroleum County and in Garfield County immediately east of the province. In the Williston Basin, organic matter in the Bakken Shale is primarily sapropelic kerogen and averages 11 weight percent total TOC. These source rocks are generally thermally mature to marginally mature in the central part of the play, but are often overmature in the disturbed belt to the west. In the western part of the play, Devonian and Mississippian hydrocarbons migrated eastward from source areas within the disturbed belt. Dolson and others (1993) identified a Bakken Shale source for Sun River (Madison) reservoirs along the Sweetgrass Arch. The Bakken Shale is thermally mature (R_o = 1.5 percent) in the thrust belt to the west and northwest, and oils may have migrated updip into traps along the arch.

Traps: Stratigraphic traps are the result of selective dolomitization of limestone, facies barriers in carbonate-evaporite sequences, and paleosol and karst systems. Most traps have been enhanced by Laramide folding and faulting. Oil found in several Jurassic Sawtooth reservoirs may have been generated in Mississippian source rocks in places where Jurassic reservoirs unconformably overlie Sun River (Madison) dolomite reservoirs. Many Madison Group traps (such as the Pondera field) are strongly influenced by Laramide faulting and folding. Drilling depths to the top of the Devonian vary from approximately 2,700–7,500 ft, but the average depth is about 3,000–4,000 ft. Evaporite and shale reservoir seals are present in the Devonian-Mississippian section.

Exploration status: Hydrocarbons have been produced in the play since 1922 when oil was discovered in the Madison at the Kevin-Sunburst field. Six reservoirs greater than 1 MMBO are identified for this play. Typical of these is Pondera field, discovered in 1927. It produces from a 15-ft-thick pay zone in a paleokarst dolomite reservoir in the Sun River at an average depth of 1,950 ft. Reservoir porosity in the field averages 16 percent and oil gravity is 34¡ API. A total of 360 wells had been completed in a field area of 7,600 acres, and greater than 35 MMBO had been produced to the end of 1990. The Mississippian section is moderately well explored in the northwestern part of the play, but Devonian production has been limited to two small Nisku wells in the Kevin-Sunburst field that each produce less than 20 BOPD. Oil shows have been reported in the Nisku from several wildcat wells in the southern part of the Sweetgrass Arch area in the 1980s.

Resource potential: Future potential is moderate for oil and low for gas, mainly in smaller fields. Larger structures have been drilled without success, but opportunity exists for small fields.

2806. TYLER SANDSTONE PLAY

The play is characterized by oil fields that produce from fluvial sandstone reservoirs of the Pennsylvanian Tyler Formation in stratigraphic traps that are modified by structure. The play lies entirely within the south-central part of the province in the Central Montana Trough and is defined by the occurrence of Tyler sandstone. The southern boundary of the play approximates the depositional boundary of the Tyler Formation along the Musselshell lineament. The play boundary is based on the thermal maturity of source rocks and the presence of appropriate reservoir rocks. The northern boundary is located at the erosional edge of Pennsylvanian rocks. The Tyler Formation does not occur everywhere within these boundaries, such as in the Little Belt, Big Snowy and Little Snowy Mountains, because of repeated tectonism in this structurally complex area, and the deposition and preservation of source beds, reservoirs, and trapping structures vary.

Reservoirs: Reservoirs are lenticular fluvial stream channels in valley-fill systems, deltaic sandstones, or shoreface sheet sandstones in the Pennsylvanian Tyler Formation. These reservoirs are generally less than 10 ft thick, although locally they range up to about 40 ft and are areally limited to tectonically controlled paleochannels within the Central Montana Trough. The reservoirs are commonly valley fills sealed by mudstone and claystone deposited coevally with the sandstone in overbank ponds and in coastal lakes. Reservoir porosity and permeability vary from poor to good. Reservoirs that occur in fractured or porous Pennsylvanian carbonate rocks are included in the Fractured-Faulted Carbonates in Anticlines Play (2807).

Source rocks: Source rocks are organic carbon-rich mudstone and limestone of shallow lagoonal deposits in the underlying Mississippian Heath Formation that are areally restricted to the Central Montana Trough. Aram (1993) identified R_o values of 0.69 to 0.84 percent and TOC values of up to 9 weight percent for Heath shale in Petroleum County. Maturation of hydrocarbons has been variable, owing to local differences in time and depth of burial because of tectonic complexities within the region. Thermal maturation probably occurred during maximum burial prior to Late Cretaceous uplift in some areas, and during Late Cretaceous and Paleocene downwarping in other areas. Migration of oil into reservoirs occurred where source and reservoir rocks were in direct contact, or by fracture communication. Some oil has likely been derived from carbonaceous mudstone beds that are indigenous to the Tyler, but these are low-grade source rocks in that much of the organic matter is of terrestrial plant origin and low in hydrogen. Catagenesis has varied because tectonism has been episodically recurrent in the Central Montana Trough and Heath source rocks have been differentially buried. These strata are thermally immature adjacent to the Little Snowy Mountains, in contrast to areas south and east of these mountains where oil generation occurred.

Traps: Tyler sandstone production is limited to the south-central part of the North-Central Montana Province. Fields occur mainly in structurally enhanced stratigraphic traps resulting from sandstone deposition in fluvial valley-fill systems. The sandstone is encased in fine-grained overbank sediments and further localized by structural folds and faults. Seals are mudstone and claystone within the Tyler. Drilling depths range from about 2,000–5,500 ft.

Exploration status and resource potential: Discovery of oil in the Tyler Formation first occurred in 1948 at Big Wall field in Musselshell County. Twenty-nine additional fields have been discovered in the play. Approximately 80 MMBO has been produced from Tyler reservoirs in the play, and the largest field is Sumatra in Rosebud County, which has a cumulative production of about 43 MMBO through 1986. Sparsely drilled areas of the play are not considered to have as much potential as the already productive areas, because of shallow burial and thermal immaturity of organic-rich shale in the Heath. Although the western area of the play has not been adequately tested, the future potential of the play is for oil, and the probability of finding new resources in fluvial-deltaic reservoirs is estimated to be low to moderate for predominantly small fields.

2807. FRACTURED-FAULTED CARBONATES IN ANTICLINES PLAY

The play is characterized primarily by oil accumulations in carbonate reservoirs of Devonian through Cretaceous age in structural traps controlled by the distribution of fracture systems generated during Laramide and post-Laramide structural events. The play includes carbonate rocks of the (1) Devonian Souris River, Duperow, Nisku, Potlatch, and Three Forks Formations; (2) Mississippian Madison Group; and (3) Jurassic Piper, and Cretaceous Greenhorn and Niobrara Formations. The play extends throughout the area of the province although rocks vary in reservoir quality and thickness. Cretaceous limestone is missing along part of the Sweetgrass Arch. The play does not include stratigraphically or structurally trapped oil and gas where carbonate facies play an important role in trapping hydrocarbons.

Reservoirs: Known reservoirs include carbonate rocks of many different facies, as structure controls the distribution of trap types.

Source rocks: Source rocks include organic-rich shale of the Bakken Shale, shale in the Three Forks Formation (Sappington Member), Lodgepole Limestone, and Heath Formations (Cole and Daniel, 1984). Vitrinite reflectance varies from 0.49 to 0.55 percent in Heath shale in southern Fergus County, indicating that the source rocks are thermally immature and are at or immediately below the oil generation window. Aram (1993) identified R_o values of 0.69 to 0.84 percent and TOC values of up to 9 weight percent for Heath shale, and R_o values of 0.49 to 0.66 percent and TOC values of up to 2 weight percent for the Mowry Shale in Petroleum County and in Garfield County immediately east of the province. TOC values average 2.4 weight percent for the Marias River Shale (Cone Member) in the disturbed belt near Glacier National Park in Glacier County, and vitrinite reflectance values average 0.6 percent along the crest of the Sweetgrass Arch. In the Williston Basin, organic matter in the Bakken Shale is primarily sapropelic kerogen and averages 11 weight percent TOC. These source rocks are generally thermally mature to immature in the central part of the play, but are mature to overmature in the disturbed belt to the west. In the western part of the play, Devonian and Mississippian hydrocarbons migrated eastward from source areas within the disturbed belt. Dolson and others (1993) identified a Bakken Shale source for Sun River reservoirs along the Sweetgrass Arch. The Bakken Shale is thermally mature (R_o = 1.5 percent) in the disturbed belt to the west and northwest, and oils may have migrated updip into traps along the arch.

Traps: Most traps are controlled by Laramide folding and faulting. Oil being produced from several Jurassic fields may have been generated in Mississippian source rocks in places where Jurassic reservoirs unconformably overlie Sun River (Madison) dolomite reservoirs. Average drilling depth to the top of the Devonian varies from approximately 2,700–7,500 ft. Drilling depths to fractured Cretaceous reservoirs are usually less than 3,000 ft. Evaporite and shale sealing beds are present in the Devonian-Mississippian section. Cretaceous reservoirs are generally sealed by impermeable shales.

Exploration status and resource potential: Hydrocarbons have not been produced in this play within the province, but have been produced immediately west of the province since the 1980's with the discovery of a Cone Member (Marias River Shale = Greenhorn Limestone) reservoir at East Glacier field along the eastern margin of the disturbed belt. At Cat Creek field, a small Piper limestone reservoir has produced oil from a single well. Aram (1993) has argued that this small reservoir may actually be related to a leaky Swift sandstone reservoir. Potential for undiscovered accumulations may be greatest in the disturbed belt to the west of the province where larger undrilled structures exist. Some potential exists in the southern part of the province for small fields.

2808. JURASSIC-CRETACEOUS SANDSTONES PLAY

The play is defined by oil and gas accumulations mainly in stratigraphic traps locally affected by structure, and in fluvial and deltaic sandstone reservoirs of Jurassic and Cretaceous age. The play covers most of the area of the province except for the Little Belt Mountains. It includes predominantly clastic rocks of the Jurassic Sawtooth, Swift, and Morrison Formations, Lower Cretaceous Kootenai Formation, Lower and Upper Cretaceous Colorado Group, and Upper Cretaceous Montana Group. These strata vary in thickness from approximately 1,500 to 3,000 ft in the play, but they are thin on the Sweetgrass Arch. Cretaceous strata are absent in the play from the southern part of the Sweetgrass Arch to the Little Belt Mountains, and their zero edge forms the southwestern boundary of the play. The base of the Jurassic section varies in depth from 1,000–5,000 ft. Jurassic and Cretaceous strata are combined in the play because of similarities in depositional environment and facies, trapping mechanisms, and source rocks.

Reservoirs: The best reservoir rocks include fluvial to nearshore marine sandstone of the Swift, Sawtooth, Morrison, Kootenai, Blackleaf, and Marias River Formations and their stratigraphic equivalents. Valley-fill fluvial channels form major reservoirs at Cutbank field along the updip end of the Sweetgrass Arch. Jurassic reservoirs of the Sawtooth and Swift Formations occur in generally lenticular, laterally discontinuous marine sandstone. Permeability barriers associated with environments of deposition, diagenetic alteration of sandstones, and Laramide folding and faulting strongly affect the quality of reservoirs. Kootenai sandstone reservoirs (2nd and 3rd Cat Creek sands of drillers' usage) are well developed and of good quality where they are adjacent to and sealed by flood plain and interdistributary mudstone. Fluvial and deltaic sandstone of the Blackleaf Formation (Vaughn Member) in the western part of the play and to the south in southwestern Montana is volcanic rich and forms poor reservoirs.

Source rocks: The most important source rocks are dark-gray phosphatic shale of Jurassic age, and Cretaceous dark-gray shale in the Kootenai, Blackleaf, and Marias River Formations and their stratigraphic equivalents (Hayes, 1984). Generally, the organic material in these shale beds is thermally immature except where buried to greater depths near the disturbed belt or very near Tertiary intrusive and volcanic rocks. TOC values average 2.4 weight percent for the Cone Member of the Marias River Shale in the disturbed belt near Glacier National Park in Glacier County, and vitrinite reflectance values average 0.6 percent along the crest of the Sweetgrass Arch. Dolson and others (1993) identified Bakken Shale source rocks for Cretaceous reservoirs along the Sweetgrass Arch. The Bakken Shale is thermally mature (R_o= 1.5 percent) in the disturbed belt to the west, and hydrocarbons probably migrated updip into shallow Cretaceous reservoirs along the axis of the Sweetgrass Arch.

Traps: Most reservoir traps are stratigraphic but are structurally enhanced in the northwestern part of the province; they were filled with hydrocarbons migrating updip from source rocks in deeper parts of the disturbed belt. The relative importance of stratigraphic versus structural factors in trap definition for Jurassic and Cretaceous reservoirs is difficult to define. Updip shale beds form effective seals in the Jurassic-Cretaceous section. Drilling depths range from less than 1,000–6,000 ft.

Exploration status: The play has been moderately explored, in part, because of early attention to surface oil seeps and subsequent discoveries at shallow depths (usually less than 2,500 ft). Thirty-five significant oil and gas reservoirs have been found in the play since the 1919 discovery at the Cat Creek field. Cutbank field in Glacier and Toole Counties is one of the largest fields in the play. The field was discovered in 1926 and has produced more than 100 MMBO and 300 BCFG from fluvial and deltaic sandstone reservoirs of the Kootenai Formation (Cutbank sandstone). One hundred eighty-seven wells produce from an average depth of 3,300 ft in the field, which covers more than 65,000 acres. The most productive gas reservoir, the Cutbank sandstone, was deposited in a widespread fluvial channel system; the sandstone pinches out against Jurassic strata on the east to form a large valley-fill trap. Sandstone reservoirs of the Blackleaf Formation are generally less productive than sandstone reservoirs in the Kootenai Formation.

Resource potential: Future potential is estimated to be low for oil and moderate for gas because all the large stratigraphic and structural traps have been defined by exploration through the years. Future exploration opportunities exist for small reservoirs.

2809. SHALLOW CRETACEOUS BIOGENIC GAS PLAY

Late Cretaceous source rocks were generally not buried deep enough for oil generation in the North-Central Montana Province. Most Late Cretaceous natural gas is methane-rich biogenic gas formed from the breakdown of organic matter by anaerobic bacteria at relatively low temperatures. Some biogenic gas in Montana occurs in widely dispersed continuous-type accumulations in low-permeability reservoirs with hydrodynamic control; this resource is considered unconventional (continuous-type). However, only conventional undiscovered accumulations in water-driven, structurally and stratigraphically trapped reservoirs are included in this play.

Reservoirs: The Shallow Cretaceous Biogenic Gas Play is characterized by accumulations in shallow reservoirs in predominantly clastic rocks of the Upper Cretaceous Montana Group (for example, Eagle Sandstone), although similar reservoirs occur in the lower Upper Cretaceous upper part of the Blackleaf Formation and equivalent strata (for example, Mowry Shale and Muddy Sandstone). Boundaries of the play are defined by the distribution of Late Cretaceous predominantly marine sandstone and siltstone as defined by Rice and Shurr (1980). Montana Group rocks are generally absent due to Tertiary erosion along the axis of the Sweetgrass Arch in the northwestern part of the province. The western boundary of the play extends along a north-south line defining the western limit of Late Cretaceous strata. Late Cretaceous strata vary in thickness from about 1,000 to more than 3,000 ft within the play area. Sandstone reservoirs vary from less than about 1,000 ft to about 4,000 ft deep. The best gas accumulations are in late Cretaceous reservoirs in permeable shoreface and shelf sandstone. Tiger Ridge field in Hill and Blaine Counties produces gas from regressive shoreface sandstone reservoirs in the Eagle Sandstone that are in part fault controlled. At Bowdoin Dome in Phillips County, production is from thin-bedded, low-permeability sandstone reservoirs in the Carlile Shale; however, reservoirs at Bowdoin are considered unconventional for this assessment. Reservoirs in low-permeability marine chalk of the Greenhorn Formation, which is approximately equivalent to the Marias River Shale, produce some gas at the north end of Bowdoin field and are also considered unconventional for this assessment.

Traps: Stratigraphic trapping of gas within both clastic and carbonate reservoirs may be due to permeability barriers related to facies changes, and to the distribution of fracture systems. Many stratigraphic traps are, in part, structurally controlled, such as at Bowes field.

Exploration status: Currently, seven significant fields produce biogenic gas from Late Cretaceous reservoirs in north-central Montana. Of these seven, at least four have a poorly-developed to well-developed water drive system; these include Sherard, Leroy, Tiger Ridge, and Battle Creek fields. Tiger Ridge field in Blaine and Hill Counties is a representative example of the Shallow Cretaceous Biogenic Gas Play. The field was discovered in 1966 as the result of an offset from a dry hole that bottomed in the Madison Group. At present, more than 80 wells produce methane-rich gas (94 percent methane) from the Eagle Sandstone and Judith River Formation in a field area of approximately 115,000 acres. Production occurs at an average depth of 1,000 ft in a 135-ft thick pay zone that has an average porosity of 26 percent. Tiger Ridge has an ultimate production of 760 BCFG which represents about 30 percent of the entire province (2.1 TCFG) based on data for significant fields.

Resource potential: The play is moderately explored in the more favorable areas, and the future potential for undiscovered gas is fair. Currently, limitations exist because of economic considerations associated with biogenic-rich reservoirs and because of the existing pipeline and transportation infrastructure; many potential reservoirs are considered unconventional (continuous-type). Many of the larger structures are well drilled, but possibilities exist for small reservoirs.

UNCONVENTIONAL PLAYS

Continuous-Type

2804. BAKKEN SHALE FRACTURE SYSTEMS PLAY (HYPOTHETICAL)

The Late Devonian Three Forks Formation is overlain by organic-rich black shale and thin shallow-water fine-grained sandstone and siltstone of the Bakken Shale in the northern part of the province. The Bakken represents an interruption in carbonate deposition associated with Early Mississippian marine transgression and is regionally equivalent to the Pilot Shale of the Great Basin and the Ekshaw Shale of Alberta. Although the Bakken is more than 100 ft thick in the northeastern part of the province and in the Williston Basin, it is thin or absent on the Sweetgrass Arch and south. This hypothetical play is defined as an analog to known production in the Williston Basin, but no production has been identified in the Bakken Shale within the North-Central Montana Province. The undiscovered resource in this province is considered an unconventional continuous-type accumulation.

Dolson and others (1993) identified a Bakken Shale source for Sun River (Madison) reservoirs along the Sweetgrass Arch. The Bakken Shale is thermally mature (R_o= 1.5 percent) in the disturbed belt to the west and northwest, and oil may have migrated updip into traps along the arch. However, data show that thermal maturities decrease rapidly away from the thrust belt and are less than R_o= 0.6 percent near Cutbank field.

The play boundary is defined on the basis of more than 0.6 percent R_o regardless of thickness. The Bakken Shale is present over much of north-central Montana but is thermally immature. The play extends from the Canadian border southward through Cutbank field southeastward to northwestern Meagher County. The Bakken Formation and its equivalent rocks occur between about 1,500 and 6,000 ft deep in play 2804. The Bakken may be an important source rock for other plays in north-central Montana.

Northern Great Plains Shallow Biogenic Gas

By Dudley D. Rice and Charles W. Spencer

Major resources of natural gas of biogenic origin occur in continuous-type (tight) Upper Cretaceous offshore sandstone, siltstone, shale, and chalk in the northern Great Plains (Rice and Shurr, 1980). The overall distribution of this gas includes parts of Provinces 028, 031, and 033.

The reservoirs occur at depths of less than 4,000 ft and most of the resource is at depths of less than 2,000 ft. The gas is underpressured. This gas resource has been extensively developed in Canada over an area of more than 8,000 sq mi on the Alberta Shelf in Alberta and Saskatchewan and estimated ultimate recoveries (EUR) average about 2 BCFG/sq mi (Rice and Shurr, 1980; Suffield Evaluation Comm., 1974). The potentially productive facies extends continuously across Saskatchewan and into the Bowdoin Dome area of northeast Montana (Rice, 1981). Figure 2 shows correlation in reservoirs in southeastern Alberta and Bowdoin field. The top of Bowdoin Dome has some conventional and near-conventional "sweet spot" sandstones that have been productive since 1929. The Bowdoin field is larger than the Bowdoin Dome structure and does not have gas/water contacts, but some average sandstones porosities are as high as 15 to 17 percent. Porosities are mostly in the range of 6 to 14 percent. All reservoirs have calculated in-situ permeabilities to gas of less than 0.1 md (Rice and others, 1990).

Almost no wildcat drilling for the biogenic gas play has occurred.. There are two reasons for this lack of activity: (1) a large field must be established before a gathering system and pipeline connection can be made, and (2) gas-filled reservoirs are not recognized. Low reservoir pressure, thin interbedded shale, siltstone, and sandstone, and high silt and clay content of sandstones cause difficulty in recognizing potential pays on borehole geophysical logs (Rice and Shurr, 1980; Gautier and Rice, 1982; Rice and others, 1990).

The northern Great Plains shallow biogenic gas resource has been subdivided into three plays on the basis of established production, mapping of various facies across the region, and relative potential among the plays. The best reservoir quality occurs in "sweet spots," such as Bowdoin Dome and the Cedar Creek anticline (Play 2810), which are paleopositives where sandstones are better developed. The next best reservoir quality occurs in facies similar to those producing in Canada on the Alberta Shelf (Play 2811). The lowest potential is for undiscovered biogenic gas in areas of poorer well control and considerable distance from known production or gas recoveries on drillstem tests (Play 2812).

2810. NORTHERN GREAT PLAINS BIOGENIC GAS-HIGH POTENTIAL PLAY (HYPOTHETICAL)

This play is confirmed and is based on better quality reservoirs associated with paleopositive features, such as Bowdoin Dome and the Cedar Creek anticline, and with other shoaling areas where thicker shelf tight sandstone deposits may occur. These thicker sandstone reservoir areas have higher estimated ultimate recoveries for individual wells. The play limits are based on pinchout of shelf sandstones and siltstones.

Reservoirs: Reservoirs are marine-shelf sandstone and siltstone and laminated very fine sandstone, siltstone, and organic-rich shale. Porosity in this play varies from as much as 20 percent to about 6 percent. Average porosity is about 12 percent. Permeabilities to gas at in-situ conditions are < 0.1 mD.

Source rocks: Source rocks are marine shales interbedded with reservoir rocks. Organic richness averages about 2 percent total organic carbon (Rice and others, 1990). The source rocks are thermally immature with respect to thermogenic hydrocarbon generation.

Timing and migration: Timing is not important inasmuch as the methane gas began to be generated soon after burial because it was the product of methanogenic bacteria activity (Rice and Shurr, 1980). This activity continued as long as temperature, pore space, and availability of CO_2 for respiration were optimum. The methane went into solution in formation water and was then exsolved out of solution into a free-gas phase after uplift and cooling.

Traps: Traps are micro-stratigraphic over much of the play area. There are structural modifications at areas such as Bowdoin Dome and Cedar Creek anticline. The gas is trapped by changes in capillary pressure and pore sizes. Once the gas was exsolved out of the pore water, it was preferentially trapped in the relatively coarser clastics and cannot migrate out of the reservoir except by diffusion.

Exploration status and resource potential: A high degree of development has occurred in the Bowdoin area, which has experienced significant field growth since gas prices increased in the late 1970's. Other than the presently developed areas, relatively little exploration activity has taken place on this shallow reservoir. These underpressured, tight, shallow gas reservoirs look poor on well logs and do not generally yield gas shows when drilled; hence, they are bypassed when drilling for deeper targets.

2811. NORTHERN GREAT PLAINS BIOGENIC GAS-MEDIUM POTENTIAL PLAY (HYPOTHETICAL)

This play is confirmed using the Alberta Shelf production as an analog. The play is limited eastward by depth and loss of shelf sandstone and siltstone. It is limited on the west by facies change into conventional reservoirs (shoreline sandstones and continental deposits) and updip water. The trend of the play is based on interpretation of regional facies mapping (Rice and Shurr, 1980; Gautier and Rice, 1982).

Reservoirs: The reservoirs are similar to those in play 2810, except thick (> 20 ft) sandstone buildups are not generally expected. Average reservoir porosity ranges from 6 to about 12 percent with a gross interval porosity of about 8 to 10 percent. It should be noted that individual sandstone and siltstone laminae may have as much as 25 percent porosity. This porosity can be seen in thin section but cannot be accurately analyzed by conventional core analysis.

Source rocks: Source rocks are marine shales interbedded with reservoir rocks. Organic richness averages about 2 percent total organic carbon (Rice and others, 1990). The source rocks are thermally immature.

Timing and migration: Timing is not important inasmuch as the methane gas began to be generated soon after burial because it was the product of methanogenic bacteria activity (Rice and Shurr, 1980). This activity continued as long as temperature, pore space, and availability of CO_2 for respiration were optimum. The methane went into solution in formation water and was then exsolved out of solution into a free-gas phase after uplift and cooling.

Traps: Traps are micro-stratigraphic over much of the play area. The gas is trapped by changes in capillary pressure and pore sizes. Once the gas was exsolved out of the pore water, it was preferentially trapped in the relatively coarser clastics and cannot migrate out of the reservoir except by diffusion.

Exploration status and resource potential: The play is relatively unexplored in the United States by wells drilled with a biogenic-gas objective. Many wildcat wells are being drilled in Canada where the play concepts are now well recognized.

2812. NORTHERN GREAT PLAINS BIOGENIC GAS-LOW POTENTIAL (HYPOTHETICAL)

This play is hypothetical but has a high probability that it exists. It encompasses those areas where marine-shelf sandstone and siltstone sequences are thinner and more poorly developed than in Play 2811. The general trend limits of this play are based on interpretation of regional facies mapping by Rice and Shurr (1980).

Reservoirs: The reservoirs are the same as in Play 2811 except sandstone and siltstone strata are somewhat thinner in the overall rock sequence.

Source rocks: Source rocks are marine shales interbedded with reservoir rocks. Organic richness averages about 2 percent total organic carbon (Rice and others, 1990). The source rocks are thermally immature.

Timing and migration: Timing is not important inasmuch as the methane gas began to be generated soon after burial because it was the product of methanogenic bacteria activity (Rice and Shurr, 1980). This activity continued as long as temperature, pore space, and availability of CO_2 for respiration were optimum. The methane went into solution in formation water and was then exsolved out of solution into a free-gas phase after uplift and cooling.

Traps: Traps are micro-stratigraphic over much of the play area. The gas is trapped by changes in capillary pressure and pore sizes. Once the gas was exsolved out of the pore water, it was preferentially trapped in the relatively coarser clastics and cannot migrate out of the reservoir except by diffusion.

Exploration status and resource potential: This play is relatively unexplored in the United States by wells drilled with a biogenic gas objective. Many wildcat wells are being drilled in Canada where the play concepts are now well recognized.

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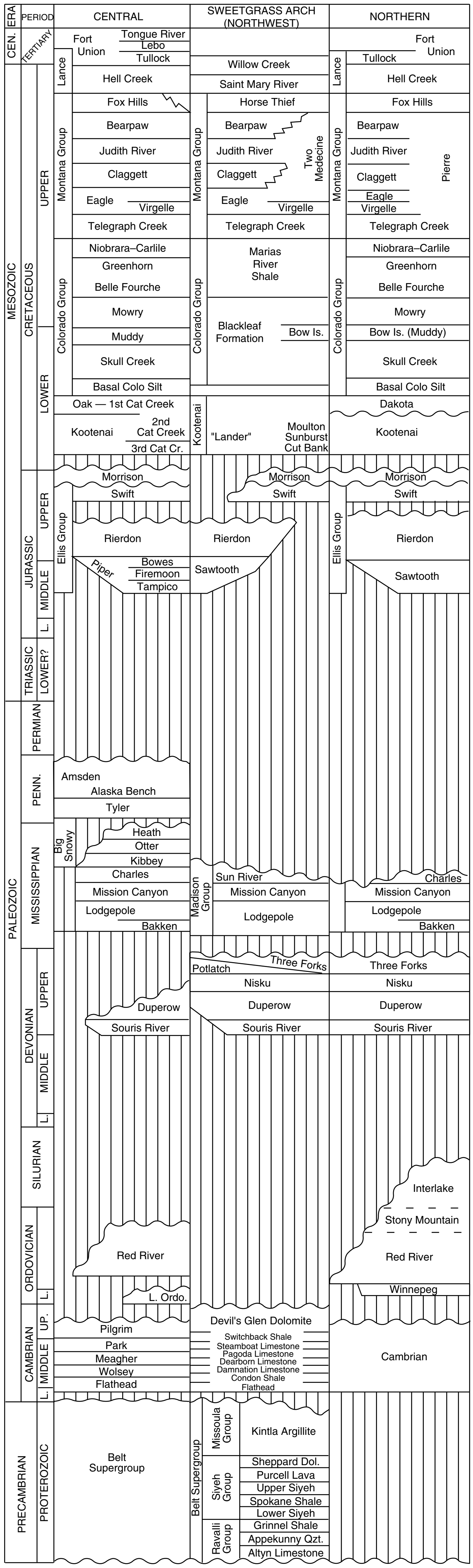
ERA
PERIOD
CENTRAL
SWEETGRASS ARCH (NORTHWEST)
NORTHERN
CEN.
TERTIARY
MESOZOIC
CRETACEOUS
UPPER
LOWER
JURASSIC
UPPER
MIDDLE
L.
TRIASSIC
LOWER?
PALEOZOIC
PERMIAN
PENN.
MISSISSIPPIAN
DEVONIAN
UPPER
MIDDLE
L.
SILURIAN
ORDOVICIAN
L.
CAMBRIAN
UP.
MIDDLE
L.
PRECAMBRIAN
PROTEROZOIC
Fort Union
Tongue River
Lebo
Tullock
Lance
Hell Creek
Fox Hills
Montana Group
Bearpaw
Judith River
Claggett
Eagle
Virgelle
Telegraph Creek
Colorado Group
Niobrara–Carlile
Greenhorn
Belle Fourche
Mowry
Muddy
Skull Creek
Basal Colo Silt
Oak — 1st Cat Creek
Kootenai
2nd Cat Creek
3rd Cat Cr.
Morrison
Swift
Ellis Group
Rierdon
Piper
Bowes
Firemoon
Tampico
Amsden
Alaska Bench
Tyler
Big Snowy
Heath
Otter
Kibbey
Charles
Mission Canyon
Lodgepole
Bakken
Duperow
Souris River
Red River
L. Ordo.
Pilgrim
Park
Meagher
Wolsey
Flathead
Belt Supergroup
Willow Creek
Saint Mary River
Horse Thief
Bearpaw
Judith River
Claggett
Eagle
Virgelle
Two Medicine
Telegraph Creek
Marias River Shale
Blackleaf Formation
Bow Is.
Kootenai
"Lander"
Moulton
Sunburst
Cut Bank
Morrison
Swift
Rierdon
Sawtooth
Sun River
Madison Group
Mission Canyon
Lodgepole
Three Forks
Potlatch
Nisku
Duperow
Souris River
Devil's Glen Dolomite
Switchback Shale
Steamboat Limestone
Pagoda Limestone
Dearborn Limestone
Damnation Limestone
Condon Shale
Flathead
Belt Supergroup
Missoula Group
Kintla Argillite
Siyeh Group
Sheppard Dol.
Purcell Lava
Upper Siyeh
Spokane Shale
Lower Siyeh
Ravalli Group
Grinnel Shale
Appekunny Qzt.
Altyn Limestone
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Lodgepole
Bakken
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Nisku
Duperow
Souris River
Interlake
Stony Mountain
Red River
Winnepeg
Cambrian