Chapter 1

Geologic Assessment of Undiscovered Oil and Gas in the Powder River Basin Province, Wyoming and Montana

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By Lawrence O. Anna

Chapter 1 of
Total Petroleum Systems and Geologic Assessment of Oil and Gas Resources in the Powder River Basin Province, Wyoming and Montana

By U.S. Geological Survey Powder River Basin Assessment Team

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Geologic Assessment of Undiscovered Oil and Gas in the Powder River Basin Province, Wyoming and Montana

By Lawrence O. Anna

Abstract

The U.S. Geological Survey completed an assessment of the undiscovered oil and gas potential of the Powder River Basin in 2006. The assessment of undiscovered oil and gas used 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 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 Powder River Basin Province, six total petroleum systems, eight conventional assessment units, and three continuous assessment units were defined and the undiscovered oil and gas resources within each assessment unit quantitatively estimated.

Introduction

The U.S. Geological Survey (USGS) completed a quantitative estimate of the undiscovered oil and gas potential of the Powder River Basin (PRB) Province of northeastern Wyoming, southeastern Montana, and southwestern South Dakota in 2006 (fig. 1). The assessment of the province was based on geologic principles and applied the total petroleum system (TPS) concept. The TPS consists of one or more assessment units (AU), 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 to assess individually if each unit is sufficiently homogeneous in terms of geology, exploration considerations, and geologic risk. Using this geologic framework, the USGS (1) defined 6 TPSs and eight conventional AUs, and three continuous (or unconventional) AUs in the PRB; and (2) quantitatively estimated the undiscovered oil and gas resources in each. The TPSs, AUs, and resource assessments are described in detail herein.

An integral part of TPS and AU descriptions is an events chart that graphically portrays its temporal evolution. The principal components are (1) the intervals of time during which source, reservoir, and seal rocks were deposited; (2) the timing of hydrocarbon generation, migration, and accumulation; and (3) the period of time during which traps were formed. Such charts accompany each of the AU descriptions.

The PRB, located in northeastern Wyoming and southeastern Montana, developed during the Laramide orogeny similar to other Rocky Mountain foreland structural basins. The basin is asymmetric with the axis on the west side (fig. 2). The deepest part can be 17,000 ft or more to the top of the Precambrian basement. On the east flank, regional dip is about 100 ft/mi to the west but increases to about 500 ft/mi along the west limb of the Black Hills monocline; on the west flank, regional dip is about 500 ft/mi but decreases to less than 50 ft/mi north of the Wyoming-Montana border (figs. 1 and 3).

The boundaries of the basin are delineated by several uplifts including the Black Hills to the east (including the Fanny Peak monocline), the Hartville uplift and Laramie Range to the south, the Casper arch, Bighorn Mountains, and the Hardin platform on the west, and the Miles City arch, Bull Mountains, and Porcupine dome on the north (fig. 4). Except for the broad arching structures, most basin bounding features are hydrologic as well as structural boundaries. The province boundary was originally defined in the 1995 assessment of the PRB (Dolton and Fox, 1995) and was drawn on county lines that most closely followed geologic or basin boundaries.

In the PRB, numerous structures now observed at the surface originated as faults, shear zones, or zones of weakness in the basement rocks during Precambrian time and were rejuvenated during the Laramide orogeny, and by periodic recurrent movement throughout the Phanerozoic. In the PRB, most structures are oriented northwest-southeast and northeast-southwest, trends that probably influenced local

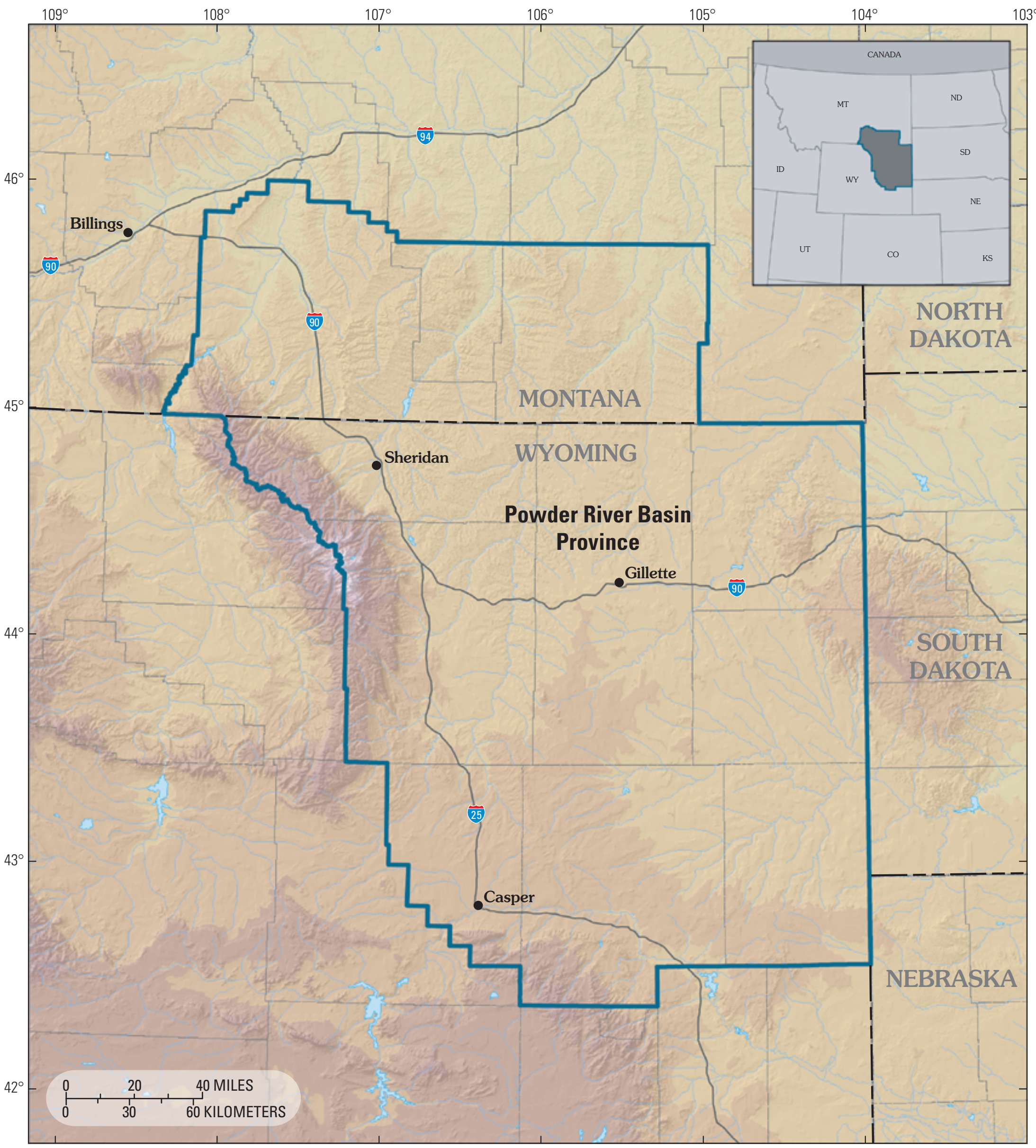


Figure 1. Map showing boundary of Powder River Basin Province in Wyoming and Montana. Province boundary is shown as heavy blue line.

and regional sedimentation patterns (Anna, 1986a, b). For example, the location of the shoreline during deposition of the Upper Minnelusa Sandstone was parallel to northeast-southwest-trending normal faults, with the downthrown side to the southeast toward an open sea. Upper Minnelusa oil fields are generally aligned with the prevailing trend, thereby reflecting the structural control on the orientation of reservoir rock deposition. The same structures also influenced drainage patterns on erosional surfaces during deposition of Cretaceous reservoirs.

Pennsylvanian-Permian Composite Total Petroleum System

The boundary of the Pennsylvanian-Permian Composite TPS (fig. 5) was determined from current and projected oil and gas production areas of the Minnelusa Formation, Tensleep Sandstone, and Leo Formation reservoirs within the interior of the basin (excluding the basin margin, which is a separate AU). Hydrocarbon source rock for these reservoirs is interpreted to be the Phosphoria Formation in western and central

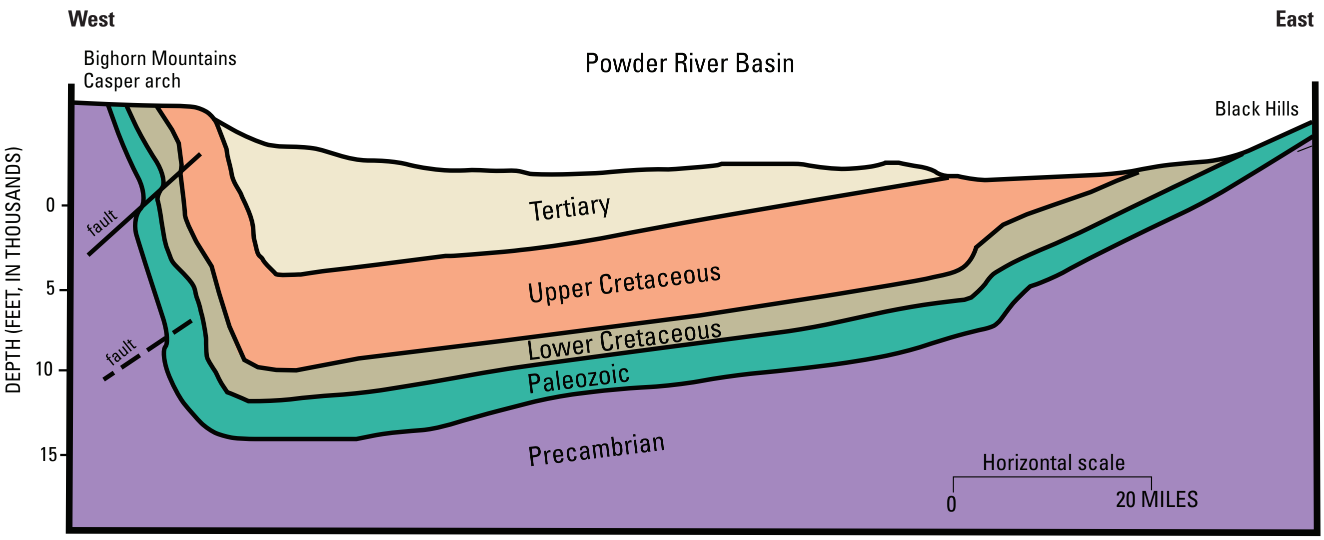


Figure 2. Generalized east-west cross section of Powder River Basin showing a west side basin axis. Black Hills monocline is shown in Cretaceous and Paleozoic rocks on east side of basin.

Wyoming and black shales of the Leo Formation in the southeast part of the basin. Because the pod of mature Phosphoria source rock is west of the PRB province, it is not included as part of this TPS.

Oil seeps were observed in Minnelusa Formation outcrops on the northwestern flank of the Black Hills uplift in the early 1900s. Subsequent drilling downdip from outcrops in 1906 established the first Minnelusa field (Rocky Ford), but it was soon abandoned. Since the initial discovery, exploration focused on structural closures near the Black Hills monocline and other surface exposed Laramide structures. In the 1940s and 1950s, seismic profiles helped expand exploration for deep structures not exposed at the surface. As the hunt for new structures declined, exploration for Minnelusa stratigraphic traps increased—a strategy that continues today.

The Minnelusa Formation, a name that was originally applied to Pennsylvanian and Lower Permian rocks in the Black Hills (fig. 6), is also applied to equivalent strata in the PRB and in parts of the Williston Basin. The Amsden Formation is applied to the Lower Pennsylvanian, and Tensleep Sandstone is applied to the Upper Pennsylvanian and Lower Permian in central, west, and northwestern Wyoming (fig. 6). These names generally have not been extended eastward into the PRB subsurface except along the west flank immediately adjacent to the Bighorn Mountain front.

Petroleum Source Rocks

It has long been established that the Phosphoria Formation generated considerable amounts of hydrocarbons that were trapped in numerous Paleozoic reservoirs in the north-central Rocky Mountains (for example, see Cheney and Sheldon, 1959; Sheldon, 1967; Claypool and others, 1978; Maughan, 1984), including the Minnelusa Formation and Tensleep Sandstone in the PRB (fig. 6). Although alternative sources of oil in Minnelusa and Tensleep reservoirs in the PRB have been proposed (William Barbat, consultant, written commun., 1983), most agree that the Phosphoria is the main source of oil, based on published geochemical evidence. Alternative hypotheses to long range migration include (1) locally derived oil from shales of the lower and middle parts of the Minnelusa Formation and (2) oil generation from organic-rich sabkhas and supratidal rocks contiguous to sandstone beds of the upper Minnelusa.

The Phosphoria Formation was deposited in a large, relatively shallow epicontinental embayment (called the Sublette Basin by Maughan, 1979) in what is now southern Idaho, southwestern Montana, western Wyoming, northwestern Colorado, northern Utah, and northeastern Nevada. The area consisted of a basin and slope surrounded on three sides by a carbonate platform. The basin and slope were covered by the Phosphoria sea in which were deposited phosphatic-rich beds of the Phosphoria; the Park City Formation, on the carbonate platform, consisted mostly of shelf carbonates. Several eustatic sea-level changes induced marine transgressions and regressions, forming complex depositional cycles resulting in interbedded strata of the Phosphoria and Park City Formations. The basin is interpreted to have covered about 100,000 mi^2 and to have had a maximum water depth of more than 800 ft (Maughan, 1984).

Maximum extent of the Phosphoria Formation and of the Phosphoria sea (fig. 7) is reflected by the distribution of the lower Meade Peak Phosphatic Shale Member and

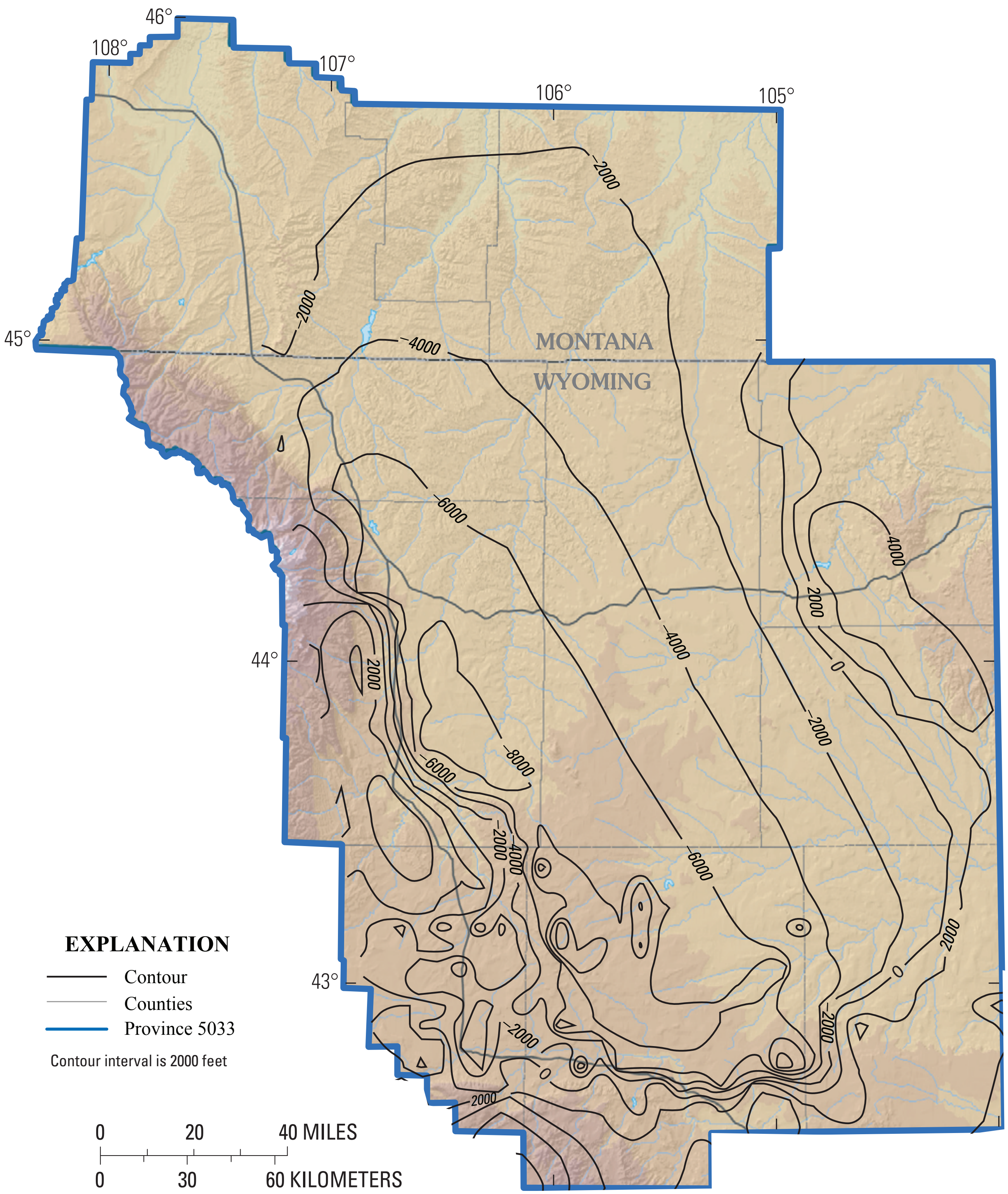


Figure 3. Map showing structure contours on top of Mowry Shale, Powder River Basin. Light gray lines are county lines. Contour interval is 2,000 feet. Basin bounding faults are not shown. Elevation data from IHS Energy Group, 2006. Province 5033 refers to code number assigned to Powder River Basin Province.

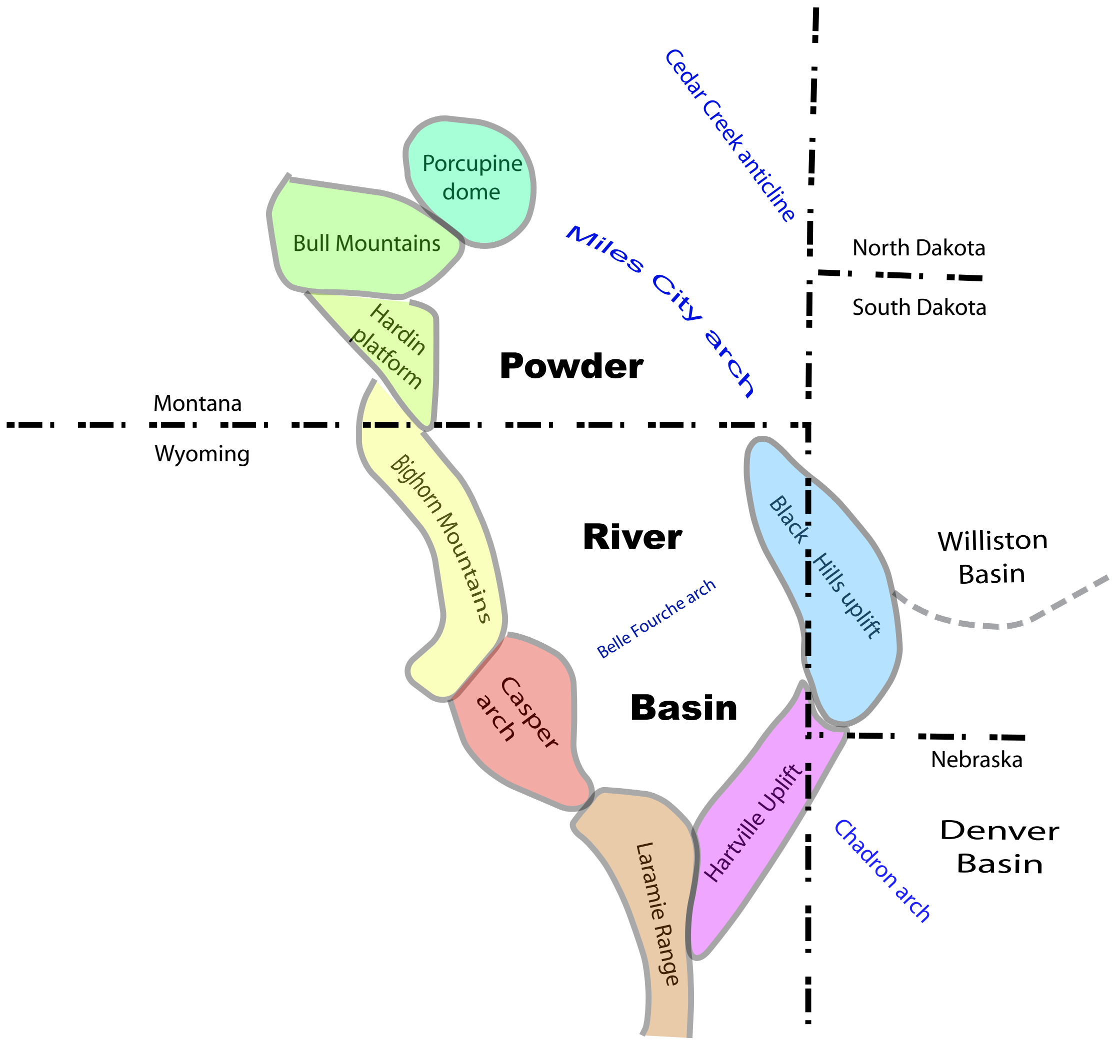


Figure 4. Generalized diagram showing major structural elements that border the Powder River Basin. Modified from Shurr and others (1988).

the upper Retort Phosphatic Shale Member. Both members are interpreted to be the main oil generation intervals in the Phosphoria.

The Meade Peak Phosphatic Shale and the Retort Phosphatic Shale Members were deposited in cold, nutrient-rich, oceanic water from the Cordilleran sea that upwelled into the relatively shallow Sublett Basin. The shale was enriched in phosphorite, possibly from a volcanic source to the west, which supported high organic productivity from the process of phosphogenesis (Johnson, 2003; Saltzman, 2003, describes the phosphogenesis process). As a result, the Meade Peak and Retort members have an average maximum total organic carbon (TOC) content of about 10 weight percent, and in the organically richest beds, as high as 30 weight percent (Maughan, 1984).

The Phosphoria Formation is generally considered to contain Type II organic matter that was incorporated in sediment that was deposited in a marine environment. Analysis of a single sample of the Retort member collected at its type locality in southwestern Montana indicates Type II organic matter (Lewan, 1985). The Phosphoria also generates oil with a high sulfur content that averages 2.1 weight percent (NRG Associates, 2006), a parameter that commonly distinguishes Phosphoria oil from low-sulfur Cretaceous oil.

Source rocks for oil in Leo Formation reservoirs in the southeastern part of the PRB are interpreted to originate locally and are interbedded with limestone and intertidal and eolian siliciclastics (Desmond and others, 1984; Ahlbrandt and others, 1994). TOC values range from less than 1 to 30 percent and average 5.5 percent (Ahlbrandt and others, 1994).

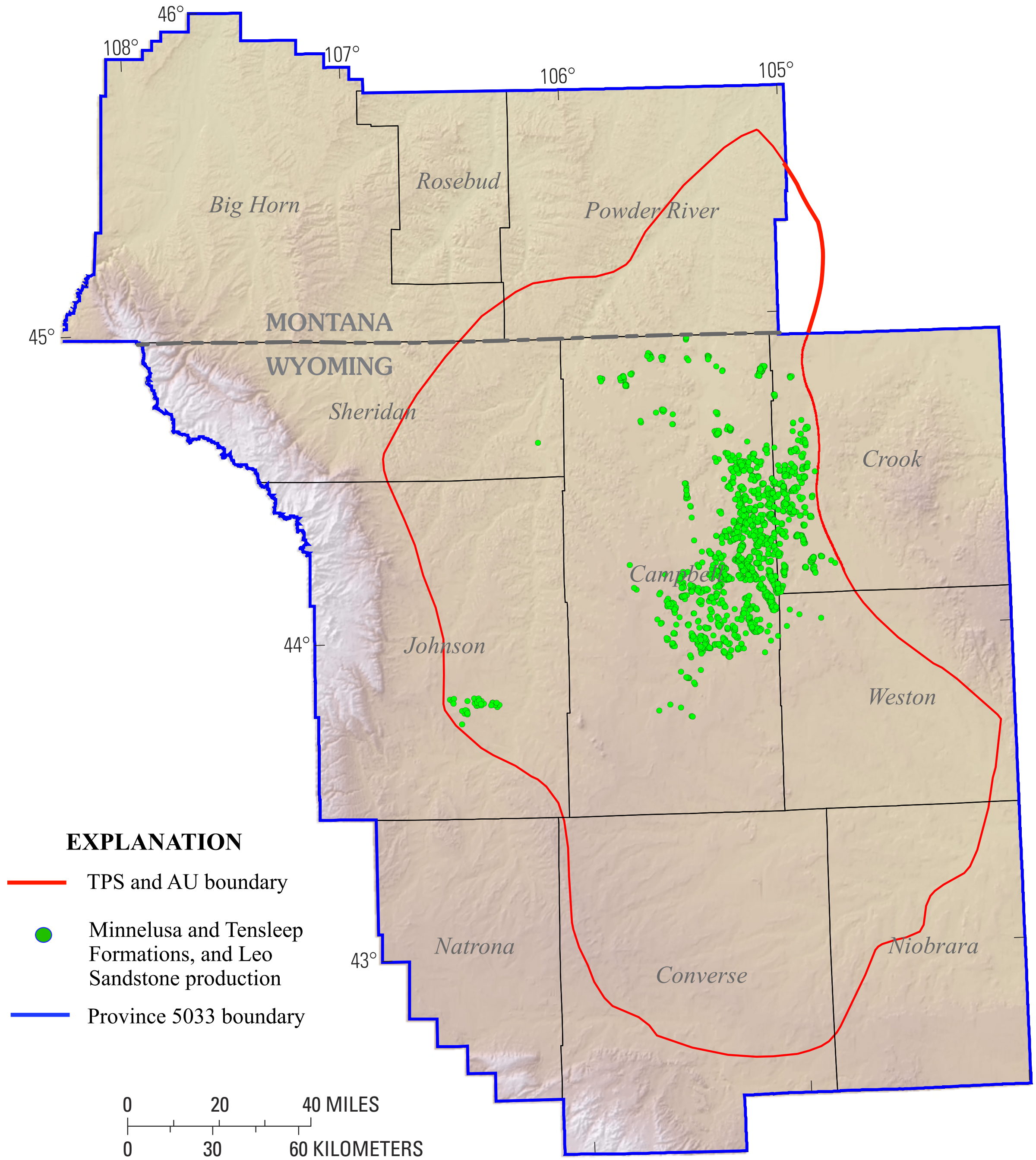


Figure 5. Map of Powder River Basin Province 5033 showing Minnelusa-Tensleep-Leo Assessment Unit (AU) boundary and hydrocarbon production. TPS, total petroleum system.

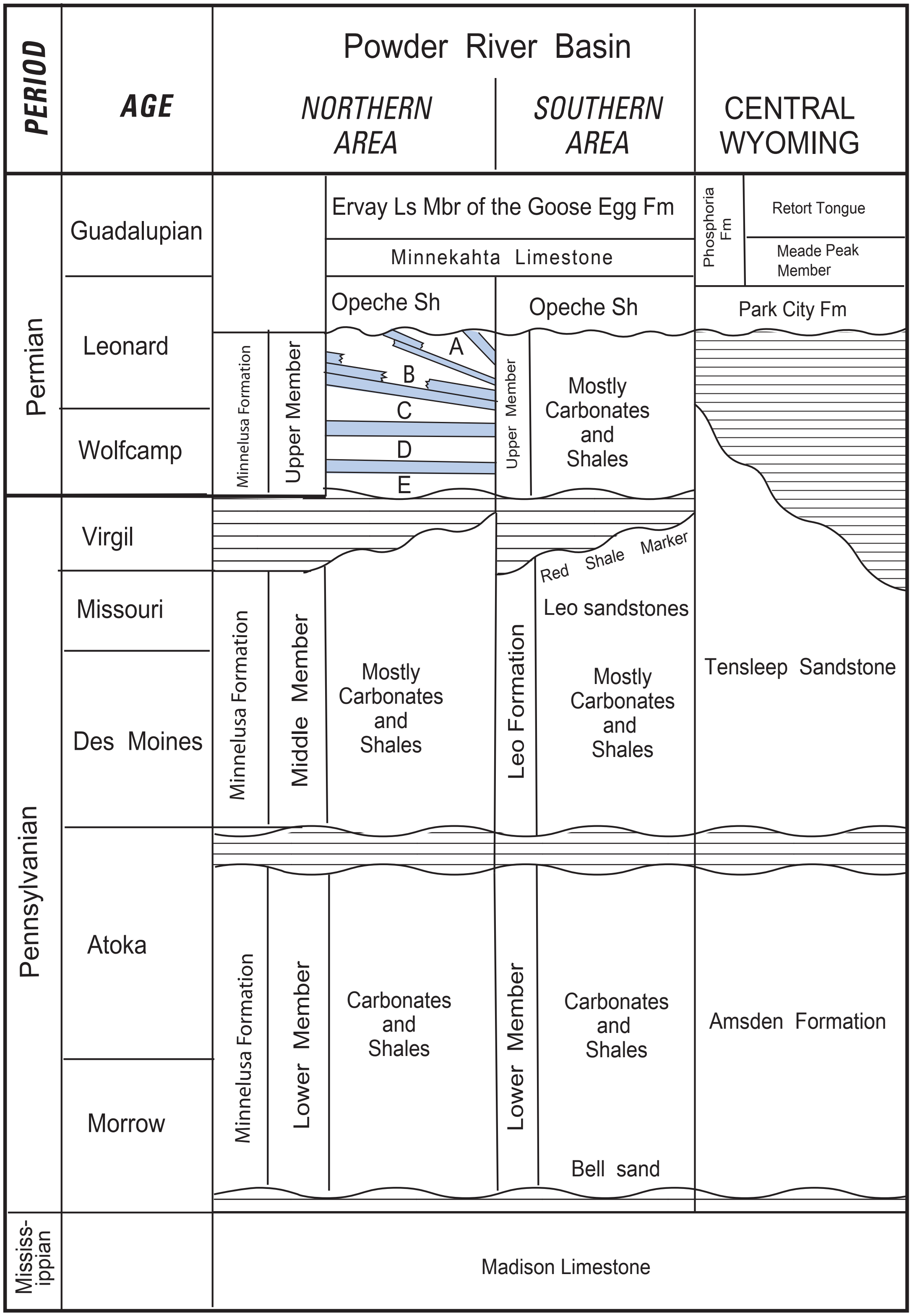


Figure 6. Stratigraphic column of Pennsylvanian and Permian strata in the Powder River Basin and central Wyoming. A–E units in upper part of the Minnelusa Formation are of informal usage. Gray pattern represents carbonate beds that separate units A–E. Fm, Formation; Sh, shale; TPS, total petroleum system; Ls, limestone; Mbr, member.

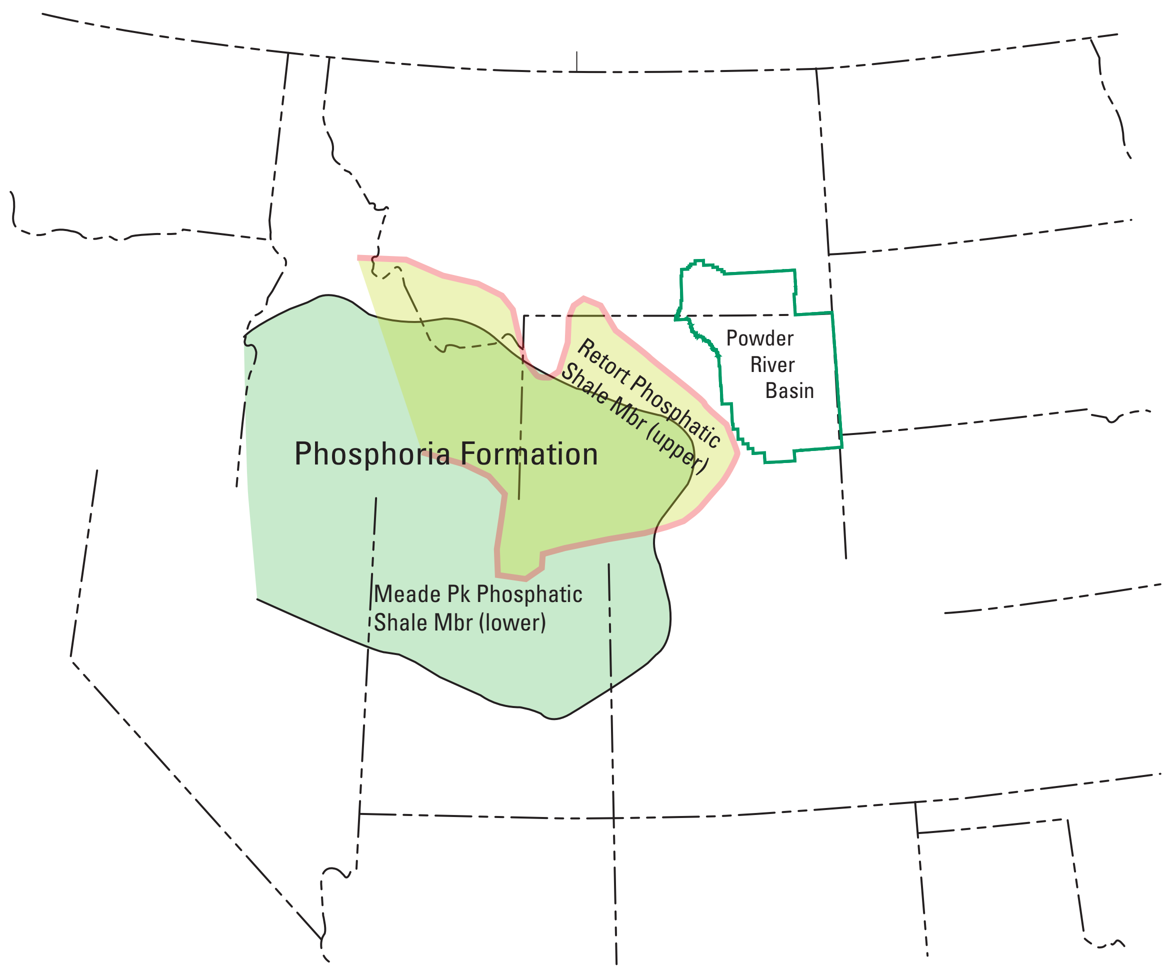


Figure 7. Map showing general location of the Phosphoria Formation deposition, including Meade Peak and Retort Phosphatic Shale Members in relation to the Powder River Basin. Mbr, member Modified from Maughan (1984).

Characteristics of Leo oil include 20° to 40° API gravity, varying amounts of hydrogen sulfide (H_2S) gas which can be as much as 40 percent, and low sulfur content (NRG Associates, 2006). The latter two constituents distinguish Leo oil from Phosphoria oil.

Source Rock Thermal Maturity

As part of the USGS oil and gas assessment of southwestern Wyoming, Nuccio and Roberts (2003) constructed burial-history curves for several locations. The modeled sites were calibrated with vitrinite reflectance (R_o) data from Cretaceous shales (sampled by Pawlewicz and Finn, 2002), whereby Phosphoria Formation oil generation results were projected from the calibrated burial curves. Results show that Phosphoria source rocks passed through the oil generation window no earlier than 88 Ma in the mid-Late Cretaceous.

According to Claypool and others (1978), hydrocarbon generation began in most areas of the former Sublette Basin when the Meade Peak Phosphatic Shale and the Retort Phosphatic Shale Members exceeded a burial depth of about 6,560 ft. Maughan (1984) reported that numerous samples collected from the Meade Peak had R_o measurements greater than 1.35 weight percent, indicating that most of the Phosphoria Formation has undergone complete transformation of kerogen to hydrocarbons. Maughan (1984) also reported that in some areas in the northwestern part of the former Sublette Basin the Meade Peak was immature, however, most of the Meade Peak in central Wyoming is considered mature. According to Maughan (1984), an increase in ambient temperature of the Meade Peak and Retort Members in the Overthrust Belt of western Wyoming and eastern Idaho resulting from thrust loading probably did not significantly increase hydrocarbon generation.

Many workers who have studied hydrocarbon generation in the Phosphoria Formation (for example, Sheldon [1967]; Stone [1967]; Claypool and others [1978]; Momper and Williams [1984]; and Burtner and Nigrini [1994]) reported that migration into the Weber and Tensleep Sandstones in western and central Wyoming took place during the Late Jurassic and Early Cretaceous. Fryberger and Koelmel (1986) interpreted Phosphoria-sourced oil to have migrated into the Weber in northwestern Colorado during the Early Cretaceous, and Britt and Howard (1982) concluded that in central Utah, Phosphoria oil began migrating during the middle part of the Cretaceous.

Based on the many contributions to the study of the maturation history of the Phosphoria Formation in this region, Johnson (2003) reported that Phosphoria source rocks in southeastern Idaho, where early Mesozoic overburden was the thickest, probably started generating oil at the beginning of the Early Cretaceous (based primarily on the work of Claypool and others, 1978). In the area of the Greater Green River Basin, Phosphoria source rocks were apparently not buried to a depth that would generate oil until the Late Cretaceous (based primarily on the work of Claypool and others, 1978; Roberts and others, 2003). Even though the earliest maturation of Phosphoria oil was in southeastern Idaho, Phosphoria oil from this area could have migrated eastward into central Wyoming and beyond.

Hydrocarbon Migration

Timing of migration of Minnelusa oil is an enigma, but Early to Late Cretaceous is most probable. Sevier orogeny thrusting during Early to middle Cretaceous in Idaho and Utah (Maughan, 1984) could have initiated eastward groundwater movement and oil migration similar to processes developed along thrust fronts in the Arkoma foreland basin and the Western Canadian Basin (Ge and Garven, 1992, 1994), respectively. This eastward movement could have also transported hydrocarbons to the PRB (Barbat, 1967) until intervening structures generated during the late Laramide orogeny changed hydraulic gradients and diverted flow paths away from the PRB.

Regional isopach maps of Middle Permian to Upper Jurassic strata show north-south to northwest-southeast orientations, indicating a structural trend in those directions. Isopach maps of Lower Cretaceous rocks, however, show a shift to east-west and northeast-southwest orientations. Therefore, in Early Cretaceous time the east to northeast direction may have been a conduit for oil migration for Phosphoria Formation oil into the PRB along the Belle Fourche arch (Slack, 1981). The oil may have migrated into the Minnelusa C, D, and E sands (Tensleep Sandstone equivalents, fig. 6) but migrated later into Minnelusa A and B sands. Some of the oil may have escaped to the surface or continued east past the present-day Black Hills, although evidence for that is lacking (Moore, 1986).

A geologic events chart (fig. 8) shows the elements that define the Minnelusa-Tensleep-Leo AU.

Reservoir Rocks

Reservoir rocks in the Pennsylvanian-Permian Composite TPS are in the Minnelusa and Leo Formations and Tensleep Sandstone. They are combined because of their similar ages, lithologic characteristics, and production histories.

Pennsylvanian and Permian rocks in the PRB and adjacent areas can be divided into four unconformable depositional successions, two in each system (fig. 6). The Lower Pennsylvanian succession comprises sediments that record a transgression onto the continental shelf following differential epeirogenic uplift at the end of Mississippian (Chesterian) time. An epeirogenic disturbance in middle to late Atokan time interrupted deposition, developed an unconformity, and initiated the spread of fine-grained sand from a distant northwestern provenance. Another epeirogenic disturbance near the end of the Pennsylvanian into the Early Permian brought uplift in central Montana and southward through central Wyoming into north-central Colorado. The Lower Permian succession is composed of sandstone, carbonate, and evaporites deposited in an intracratonic basin east of this uplift. The Upper Permian is characterized by several transgressions across central Wyoming, during which sabkha, intertidal, and shallow subtidal-deposited red mudstone and evaporitic rocks were deposited in eastern Wyoming and adjacent areas (fig. 9).

Near Mayoworth, Wyoming, on the southwest flank of the basin, sandy dolomite beds that contain Wolfcampian fusulinids have been included in the Tensleep Sandstone (Verville, 1957). However, these strata lie unconformably above thick-bedded, massive to high-angle, cross-stratified sandstone typical of the Tensleep; lithologically, they resemble the Minnelusa and are assigned to the upper parts of the Minnelusa Formation (Verville, 1957). Equivalent strata of similar lithology are present in the upper part of the Casper Formation in the Laramie Range.

During the Permian, a shallow open sea existed southeast of the PRB at which intertidal and sabkha successions were deposited in the basin. The shoreline throughout the Early Permian frequently shifted positions in response to regional and local tectonism and to eustatic changes in sea level (fig. 9). These shoreline shifts gave rise to vertical cyclic sedimentation packages (or genetic units) informally defined as the A, B, C, D, and E zones of the upper member of the Minnelusa Formation (fig. 6; see next section). The shoreline probably extended to the northeast beyond the current Black Hills as well as to the southwest beyond the Casper arch (fig. 8). Following deposition of the upper A zone, a surface of erosion developed from a sea-level drop that eroded parts of the A and B zones (fig. 10).

Dolomites and evaporites of the A, B, and C zones of the Upper Minnelusa formed in a shallowing-upward

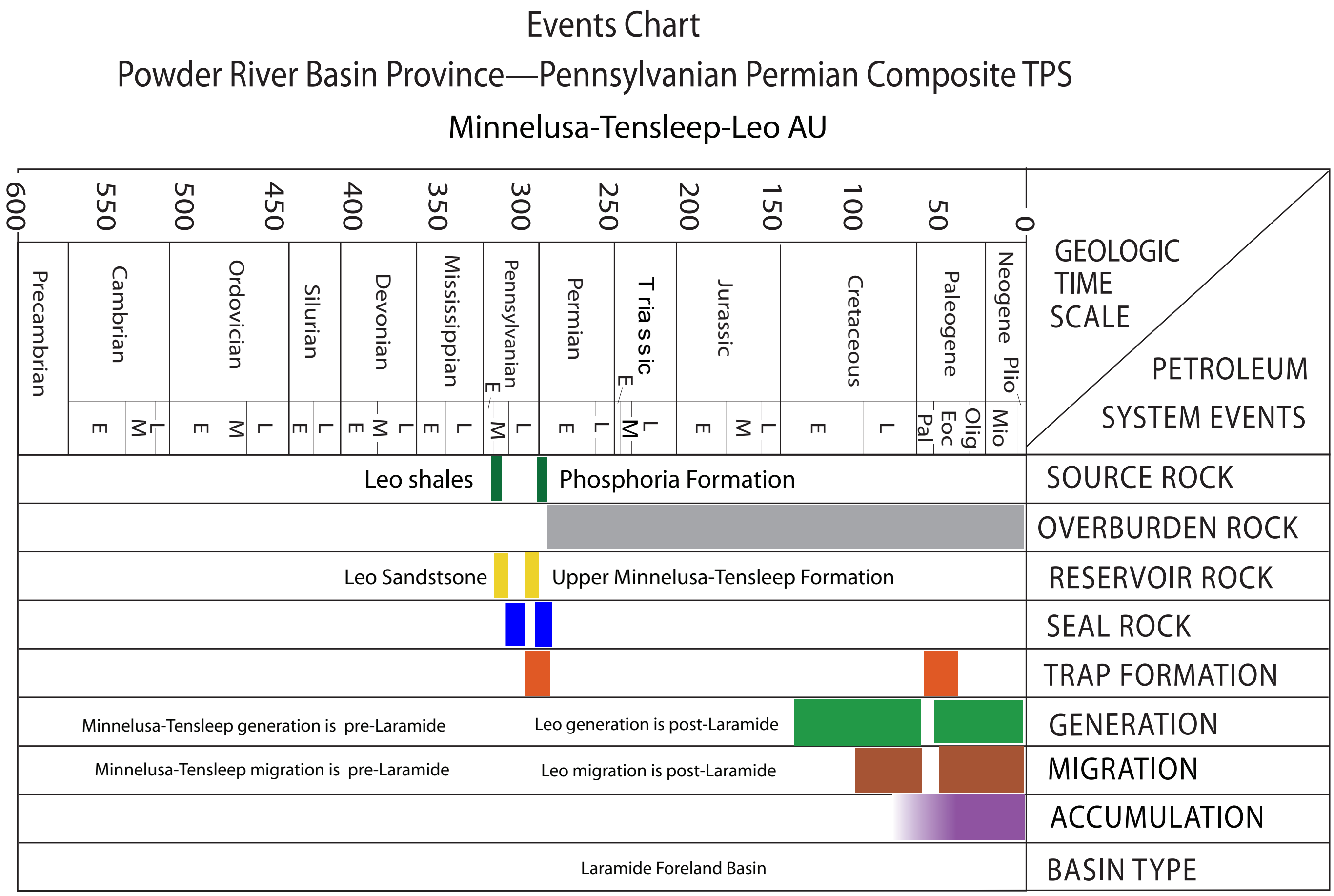


Figure 8. Events chart for the Minnelusa-Tensleep-Leo Assessment Unit (AU), Pennsylvanian-Permian Composite Total Petroleum System (TPS). Geologic time scale is in millions of years ago. E, early; M, middle; L, late; Plio, Pliocene; Mio, Miocene; Eoc, Eocene; Olig, Oligocene; Pal, Paleocene.

succession of intertidal and supratidal (sabkha) environments as regression of the sea continued to the southeast. Ensuing subaerial conditions resulted in the deposition of eolian sediments over the evaporite succession (fig. 11). The sea then transgressed rapidly to the northwest, depositing various assortments of limestone (which was diagenetically altered to dolomite), completing the depositional cycle. When the sea transgressed, the tops of the eolian deposits probably were reworked, preserving well sorted, high-porosity sands in topographically low areas. In addition, groundwater, which was oversaturated with cement-forming constituents, rose in fine-grained sand, but less so in coarse-grained sand due to capillary pressure creating vertical stratification of porosity. Therefore, in general, the upper parts of the A, B, and C sands are more porous and permeable than lower parts. In addition, freshwater may have flushed cements from the tops of zones.

As the Permian sea withdrew from the PRB, incised northwest-southeast drainage patterns developed on the Minnelusa surface. The incisement process eroded as much as 100 ft of the Minnelusa and to greater depths south and west of the main production fairway (fig. 10). Subsequently, a saline pan system consisting of lacustrine, alluvial, and evaporite deposits developed over most of the PRB and adjacent areas depositing the Opeche Shale (Benison and Goldstein, 2000). Conglomerates or evaporites were deposited in some incised valleys.

Minnelusa Formation

The Minnelusa Formation in the PRB can be divided informally into lower, middle, and upper members (fig. 6). The lower and middle members are Pennsylvanian in age and the upper unit is Permian. In the northern part of the basin the lower and middle members are mostly shales and carbonates; the shales have low potential as a source rock and the carbonates have low porosity and a low potential as a reservoir rock. In the western part of the basin and westward into

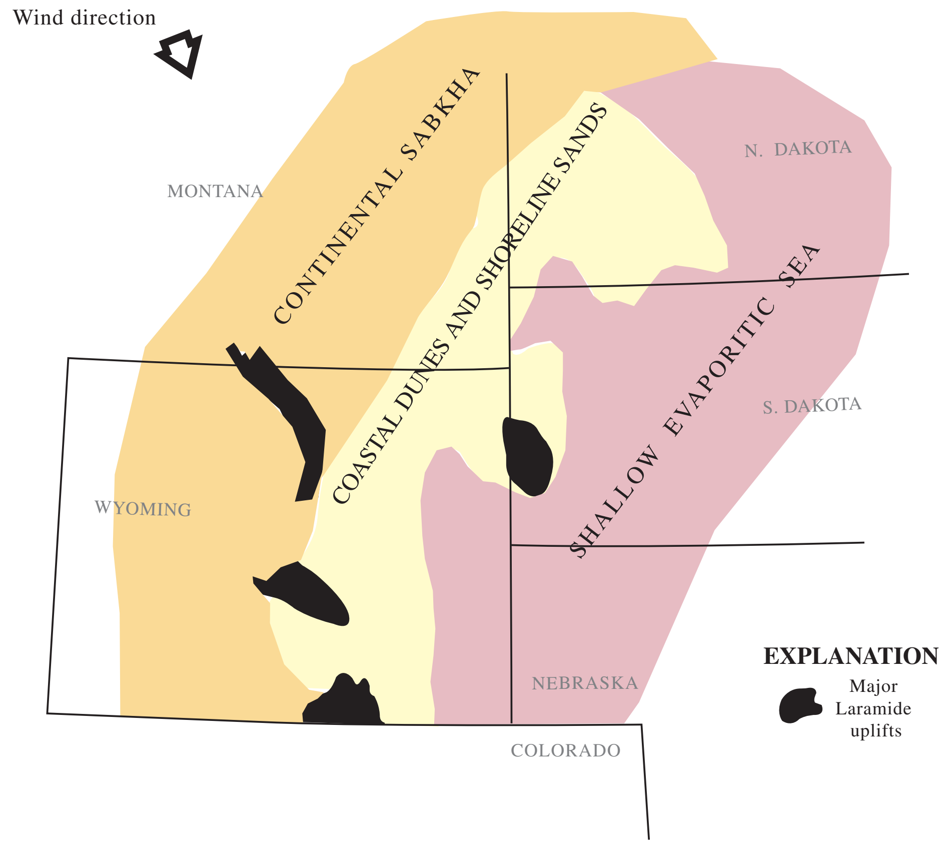


Figure 9. Generalized paleogeography of late Minnelusa time in parts of the Powder River Basin and adjacent areas.

central Wyoming, the Amsden Formation is equivalent to the lower member of the Minnelusa, and the Tensleep Sandstone is equivalent to the middle member of the Minnelusa and the lower part of Permian rocks (fig. 6). In the southern part of the PRB, intertidal and eolian siliciclastics of the Leo Formation, equivalent to the middle member of the Minnelusa (fig. 6), produce oil and gas. In the northern part of the PRB, the upper member of the Minnelusa, based on oil company terminology, is divided into five successions or cycles— A, B, C, D, and E, with E being the oldest cycle. Generally, each zone consists of a basal dolomite, succeeded by a thin evaporitic layer, another dolomite, and an upper sandstone. Each depositional cycle consists of dolomite, evaporitic succession and overlying sandstone (fig. 12). Lateral variation of the carbonate sand cycle is common and can make correlation difficult. In the western part of the basin the Tensleep is equivalent to the C, D, and E zones of the middle part of the Minnelusa.

The sandstones in the lower D and E zones are seldom penetrated because all production to date is from the upper Minnelusa A, B, or C zones. Where penetrated, however, the lower zones show varying degrees of sandstone porosity and thickness. For example, the D zone from the L.L. & E. #1 Flocchini well, T. 45 N., R. 72 W., sec. 1, has 35 ft of 18 percent porosity at 11,650 ft, whereas the Shell #34 Meadowlark well, T. 46 N., R. 73 W., sec. 28, has 14 ft of 7 percent porosity at 12,400 ft depth. Moore (1975) estimated an 8 percent maximum effective porosity at depths greater than 12,000 ft; on the west side of the basin Minnelusa reservoirs have significant amounts of oil with 9 percent porosity at 15,000 ft, but permeability is possibly fracture enhanced.

The A, B, and C zones are a complex succession of dolomite, evaporite, and sandstone (fig. 13). Of the three, the C zone is the most continuous, extending over the entire basin, exhibits the best lateral and vertical continuity, and has the best porosity and permeability. The sandstones generally increase in reservoir quality and quantity from south to north in the basin. Commonly, the top of the C zone is defined by the C marker bed (fig. 12), defined by sonic and gamma ray characteristics as a thin time-stratigraphic shale or bentonite bed. However, the marker loses its characteristics in places

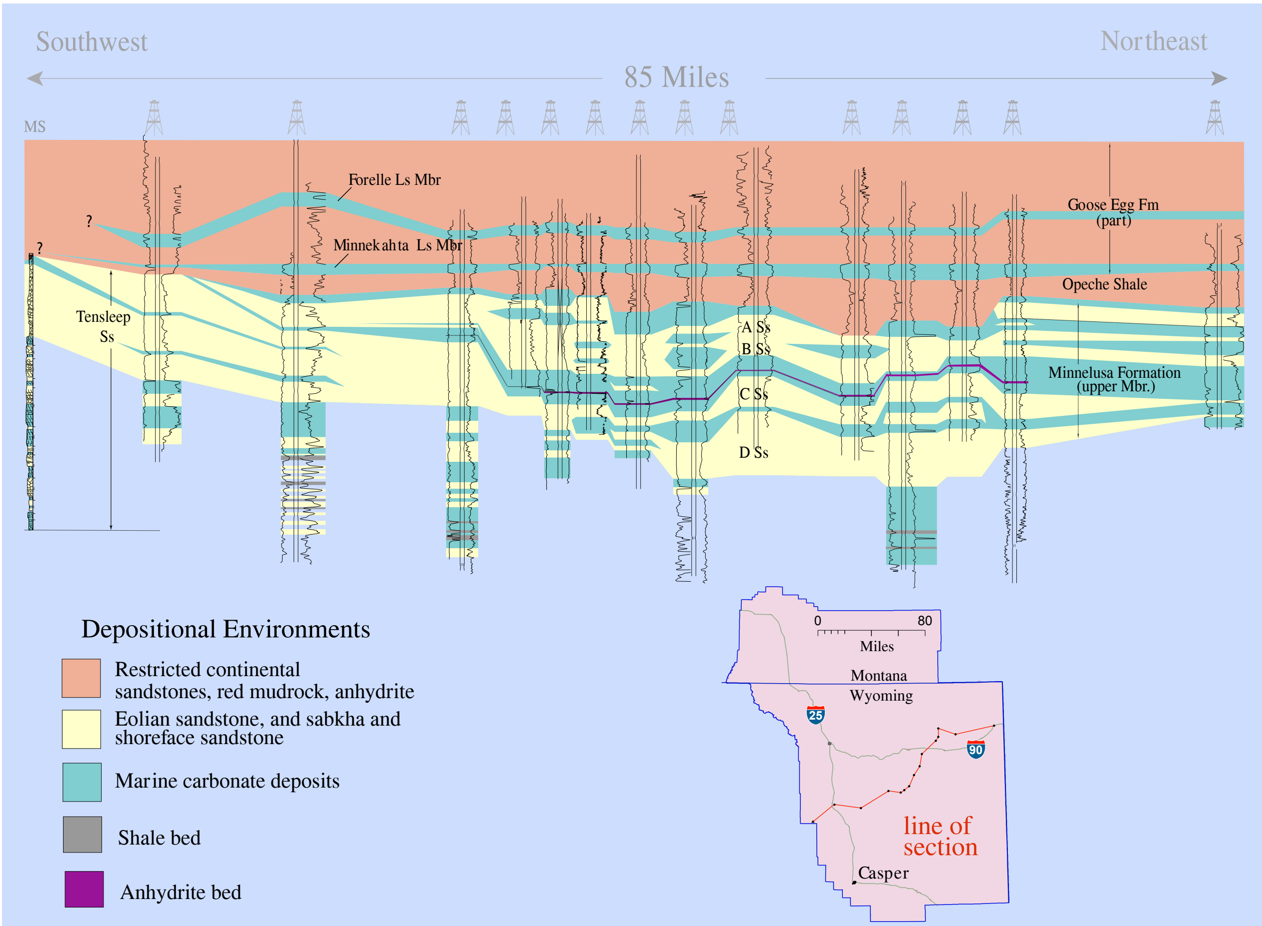


Figure 10. Southwest-northeast cross section of Permian strata in the Powder River Basin. (Click on image to open full size, high resolution image for viewing and printing).

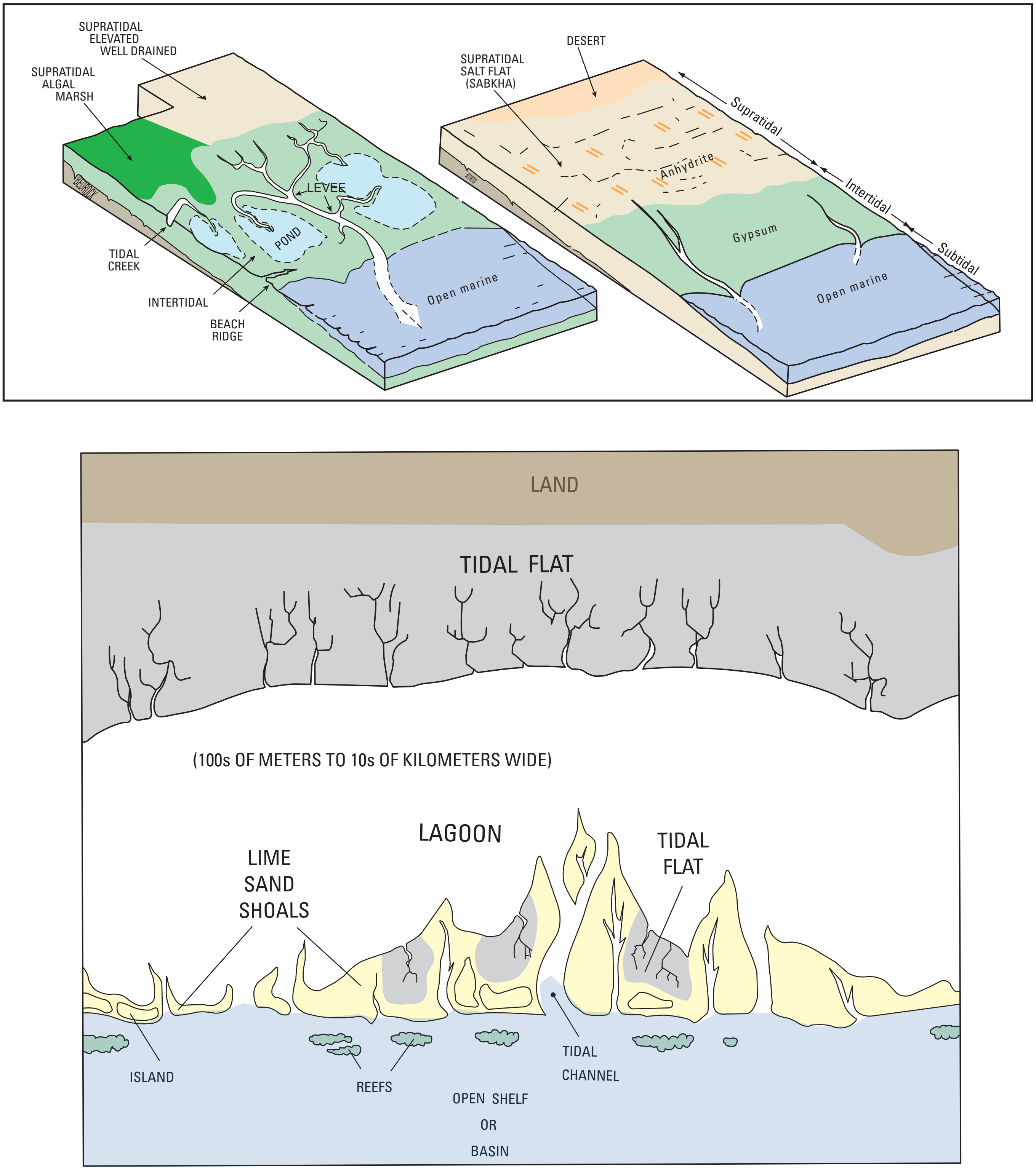


Figure 11. Diagram showing a time slice of generalized environments of deposition that comprise strata of the Minnelusa Formation in the Powder River Basin. Transgression and regression events form cyclic stacking patterns in the Minnelusa.

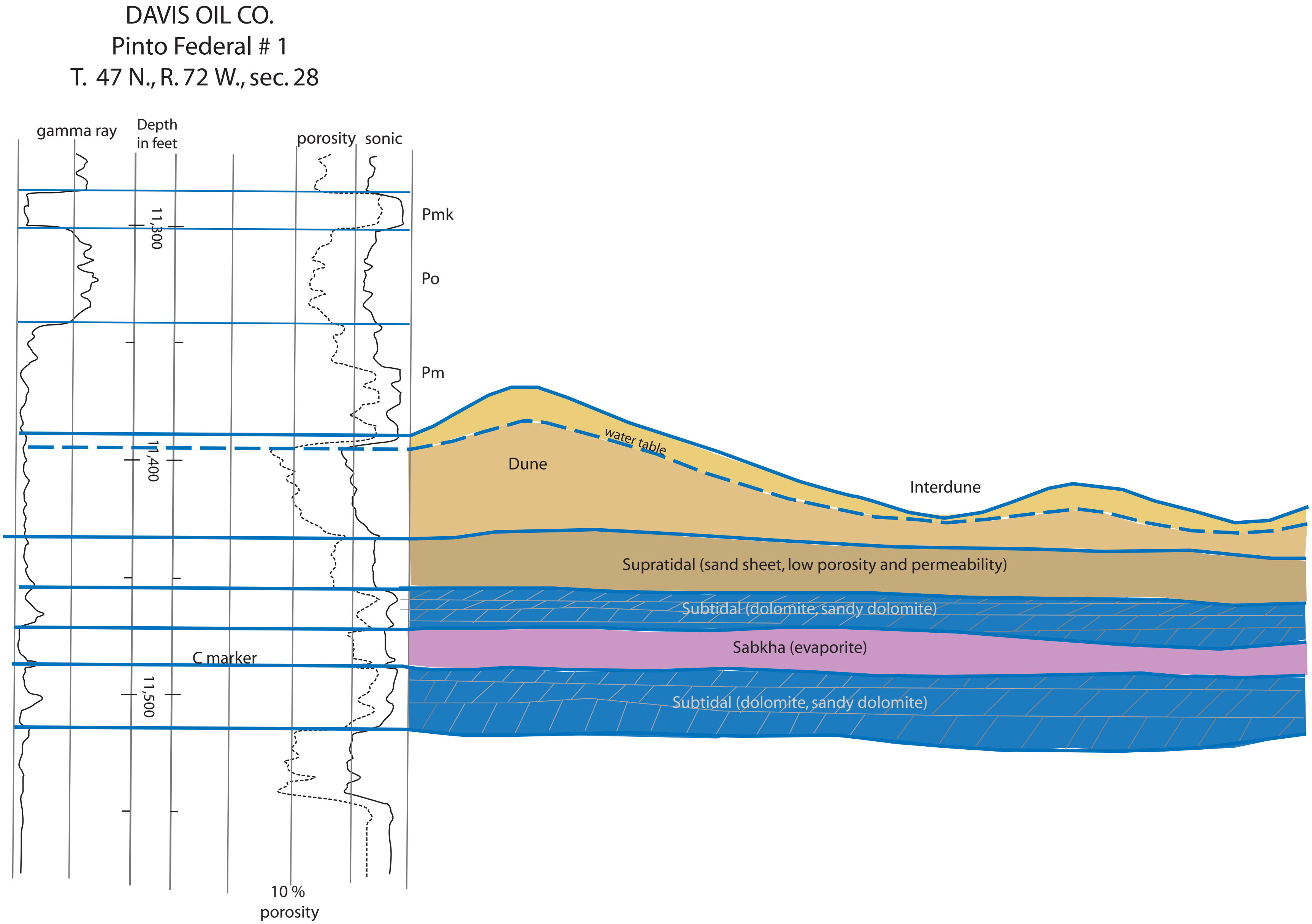


Figure 12. Diagram showing correlation of a geophysical log to a Minnelusa Formation depositional cycle. Pmk, Minnekahta Formation; Po, Opeche Formation; Pm, Minnelusa Formation.

to the west and south, but other time-stratigraphic markers maybe present. Many published reports use the Minnekahta Limestone as a time-stratigraphic marker to correlate and develop the stratigraphic framework of the Minnelusa and overlying formations.

Sea-level fall at the close of Minnelusa time exposed the Minnelusa surface to various amounts of incisement by fluvial processes, leaving isolated to partly isolated remnants of the A zone and B zones and, in places, incised into the C zone. The surface was covered with a saline pan system of bedded anhydrite and halite, red mudstone, siltstone, and thin sandy layers of the Opeche Shale (fig. 13; Benison and Goldstein, 2000).

In the PRB, the A, B, and C zones are all productive. The C zone is productive from several fields, the A and B zones are productive mainly in the eastern and northern part of the Minnelusa production fairway (fig. 14). In general, the B zone does not produce when a porous A zone is present, although both zones do produce in some fields. Most Minnelusa reservoirs are sandstone, although there is production from fractured dolomite facies in the Reno field on the west flank of the basin and from one well in the Bone Pile field in the production fairway. Best production practice includes at least 10 ft of net sand in a potential reservoir because half of such a bed will be cemented at the bottom and also possibly at the top. That would leave a minimum net pay of about 5 ft, which is adequate for a well to be economic with an active water drive.

Minnelusa Formation reservoirs are generally small (averaging four wells per field) but prolific. Production per field averages 3.7 MMBO (NRG Associates, 2006). Primary and secondary production averages 0.5 MMBO per well or more. Most fields have limited water drive because of the complex stratigraphy, but about 20 percent of the fields have an active water drive. Active water drive fields have the best production statistics and typically average 500 barrels per acre-ft.

Tensleep Sandstone

Tensleep Sandstone is the lateral equivalent of the Minnelusa Formation C, D, and E cycles. The term Tensleep originated in central Wyoming and carried eastward to the west margin of the PRB. The Minnelusa Formation designation originated in the Black Hills and was carried west into the PRB, up to the basin margin. The Tensleep has similar depositional and reservoir characteristics as the Minnelusa Formation; that is, it contains multiple boundaries in response to frequent and high-amplitude sea-level changes. A generalized upward succession of Tensleep strata consists of (1) thick marine carbonate beds; (2) thin, low porosity, interdune sandstone layers; (3) dominantly porous and permeable eolian crossbedded dune sandstones; and (4) thin, discontinuous carbonates. The siliciclastic units form the dominant reservoir, whereas dolomites, although vuggy, rarely produce because of low bulk permeability. Porosity and permeability distributions are constrained by succession boundaries, facies change, and diagenetic alteration.

Few wells produce from reservoirs designated as Tensleep in the Pennsylvanian-Permian Composite TPS. Most Upper Pennsylvanian and Permian production outside the main Minnelusa fairway is termed Minnelusa, not Tensleep, although Reno and Reno East fields, in the western part of the TPS, have been identified in the literature as both Tensleep and Minnelusa. Tensleep production in the Basin Margin TPS is from large anticlines such as those found at Teapot Dome and Salt Creek fields and from stratigraphic traps such as those at North Fork field and parts of Sussex field.

Leo Formation

The Middle Pennsylvanian Leo Formation is bounded by unconformities; it is confined to the southeastern part of the PRB, the Hartville uplift, and the northern Denver Basin. The Leo is underlain by the lower member of the Minnelusa Formation in places in the southeastern PRB and by the Amsden Formation in other parts of the basin, and is overlain by the upper member of the Minnelusa Formation (fig. 6).

The Leo Formation consists of six successions or cycles of shale, limestone, and intertidal and eolian siliciclastics (Desmond and others, 1984; Ahlbrandt and others, 1994). The successions are informally labeled in descending order as Leo 1–6. Siliciclastic intervals are also informally labeled Leo sands 1–6. Sandstone reservoir quality can vary greatly between cycles due to primary sedimentation patterns and diagenetic alteration. As a result, porosity can range from less than 5 to more than 20 percent over short distances. Thicknesses of each succession vary by tens of feet but commonly average about 50 ft, whereas thicknesses of the siliciclastic intervals range from a few feet to more than 30 ft.

Only minor amounts of oil are produced from the Leo Formation (NRG Associates, 2006) in the southeastern part of the TPS. The minor production appears to be trapped stratigraphically in a low-porosity (sonic log calculated), possibly fractured sandstone, although the type and location of lateral seals are unknown. Most Leo production is from basin margin anticlines in the southern and southeastern parts of the basin, including south of the Black Hills in South Dakota (fig. 4).

Traps and Seals

The Minnelusa Formation consists of several types of structural and stratigraphic traps (fig. 13). Trotter (1963) identified two types of structural traps: (1) four-way structural closure and (2) buried topography associated with an anticline. Trotter also identified four types of stratigraphic traps: (1) buried topography, (2) buried topography associated with a breached pre-Opeche structure, (3) updip porosity pinchout, and (4) facies change.

Van West (1972) mapped several Minnelusa Formation fields as to their trap type: topographic, permeability pinchout,

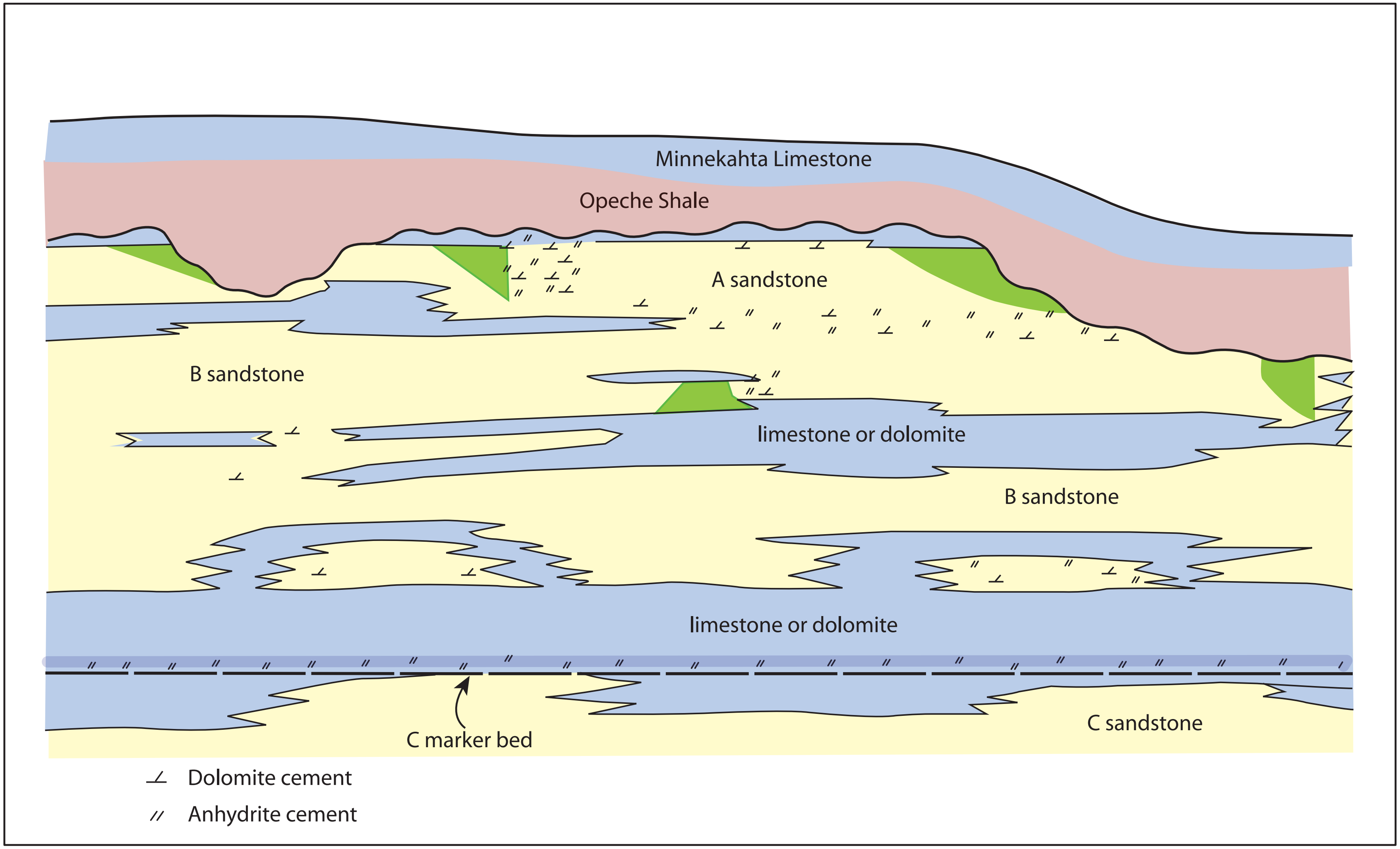


Figure 13. Generalized stratigraphic section of Minnelusa Formation A, B, and C zones. Green represents potential stratigraphic oil traps. C marker bed is defined by wireline log characteristics.

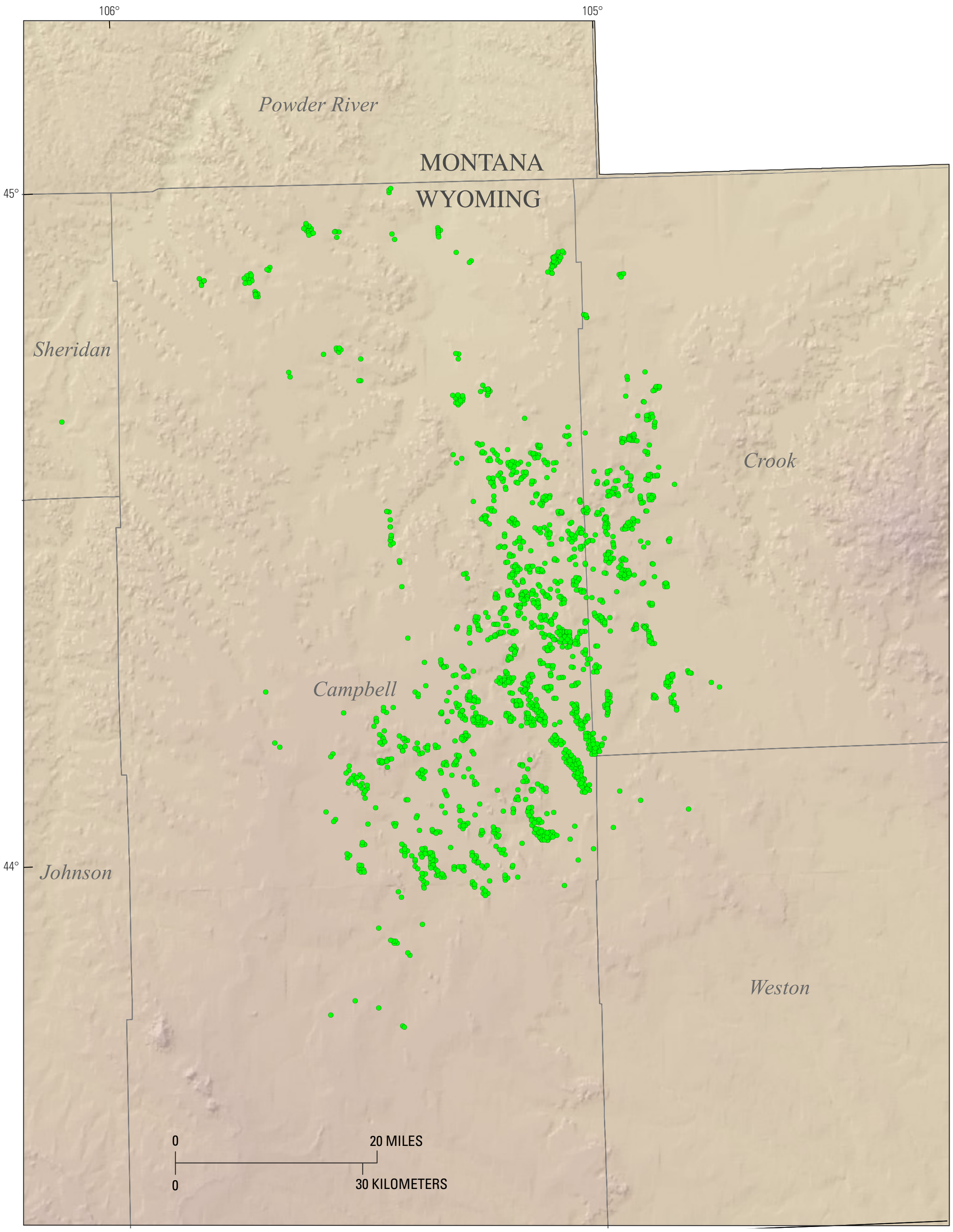


Figure 14. Map showing Minnelusa Formation production fairway and outlying fields in the Powder River Basin, Wyoming. Light gray lines are county boundaries.

or structural closure. Most trap types were either topographic or a permeability pinchout, with the larger fields being the topographic type. Most new field discoveries since Van West's publication in 1972 have been stratigraphic traps (NRG Associates, 2006).

Trapping mechanisms for the A and B zones of the upper member of the Minnelusa Formation are mostly controlled by pre-Opeche incisement. The incisement differentially erodes parts of unit A and locally unit B, leaving parts of A and B sands juxtaposed to Opeche shales and mudstones, an effective vertical and lateral seal (figs. 10, 13). The most effective trapping condition is where the A or B sandstones are eroded on the updip side. Because incisement patterns can be structurally influenced, their general pattern may be predictable. Van West (1972) published isopach maps of various Mississippian to Permian time intervals showing contours that trend northwest-southeast, similar to previously mapped structural trends.

Traps in the Tensleep Sandstone were identified from surface studies in the Bighorn Basin (Ciftci and others, 2004), which identified facies changes bounded with surfaces that segregated permeability and capillary pressure variations. These changes help compartmentalize and segregate fluids that help trap oil within the Tensleep.

Trap styles in Leo Formation reservoirs in this TPS are uncertain because of limited production, although probably both structural and stratigraphic types exist.

Mowry Total Petroleum System

This section describes the Mowry TPS, which includes three AUs in the PRB: (1) Lower Cretaceous Fall River-Lakota Sandstone AU, (conventional reservoirs); (2) Lower Cretaceous Muddy Sandstone AU (conventional reservoir); and (3) Mowry Shale AU, which is the main oil source for the TPS (continuous reservoir). Stratigraphic relations of the rocks composing these AUs are shown in figure 15.

The PRB has a long history of oil production from Lower Cretaceous sandstone reservoirs (fig. 16). Muddy Sandstone oil production was first established in the late 1800s from Fiddlers Creek and Clareton fields immediately downdip from oil seeps on the east side of the basin. In the 1950s, Lower Cretaceous production was established in the deeper part of the basin while exploring for the Upper Minnelusa Formation. Some 85 percent of the fields are classified as oil (NRG Associates, Inc., 2006) whereas a few fields are classified as gas largely because of a limited volume of source rocks in the gas generation window. Most gas on the east side of the basin is associated gas, but in the deepest parts of the basin, where the Mowry Shale has reached gas generation temperatures, there are a few nonassociated gas fields (NRG Associates, Inc., 2006).

Petroleum Source Rocks

The Mowry Shale is considered the main hydrocarbon source for Lower Cretaceous reservoirs in the PRB, although minor quantities of hydrocarbons may be generated from the Lower Cretaceous Skull Creek Shale and Fuson Shale (fig. 15). The lower contact of the Mowry is the lowermost gamma ray kick just above a low resistivity zone, and the upper contact is the Clay Spur Bentonite Bed marking the base of the Frontier Formation (Burtner and Warner, 1984). The Mowry was deposited as dark brownish gray siliceous shale during maximum marine transgression that ranged from the end of the Lower Cretaceous Albian Stage to the lower part of the Upper Cretaceous Cenomanian Stage (Merewether, 1996). The shale is organic rich because of the preservation of organic material due to anoxic conditions and the lack of detrital sediment that would have inhibited organic input (Nixon, 1973; Byers and Larson, 1979). In the TPS, Mowry Shale thicknesses average about 250 ft and range from about 100 ft to more than 400 ft (Momper and Williams, 1984, their fig. 4). Three depositional units can be mapped within the Mowry (Byers and Larson, 1979) based on several bentonite markers that divide the unit into time stratigraphic intervals. The units are regionally persistent and lithologically distinctive (Merewether and others, 1977; Fox, 1993); therefore, the unit boundaries are isochronous and can be traced in the subsurface for long distances.

Geophysical log resistivities are commonly used to indicate lithology of the Mowry Shale. High resistivity indicates siliceous shale, sandy or silty shale, siltstone, or silty sandstone, whereas low resistivity indicates clay-rich shale and bentonite (Nixon, 1973). However, the presence of hydrocarbons may alter the resistivity signature; therefore, any lithologic interpretation should be made with caution.

The Mowry Shale has a TOC of 2 to more than 3 weight percent Type II and Type III kerogen (Nixon, 1973; Schrayer and Zarrella, 1963). Schrayer and Zarrella (1966) published maps of central Wyoming that showed Mowry TOC values increasing from west to east, with the highest values near the PRB west margin. Vertical profiles of Mowry TOC values, near Douglas, Wyoming (fig. 17), show values as much as 4 weight percent near the middle of the formation. These values may be conservative if the Mowry in this area has generated oil and therefore spent some of its original organic matter (Meissner, 1985). Heacock and Hood (1970) showed that the Mowry has one of the highest average TOC values for Cretaceous shales in the PRB. Momper and Williams (1984) reported that within the basin the Mowry Shale expelled about 11.9 BBO (billion barrels of oil) from an average of 3 weight percent TOC, which should be considered a maximum for the total fluid expulsion. That volume converts to an oil-generating capability of 105 barrels/acre-ft, with an expulsion efficiency of 6 to 8 percent. Cumulative known oil production from all reservoirs in the Mowry TPS (but not including basin margin Lower Cretaceous reservoirs) as of 2005 is about 630 MMBO (NRG associates, 2006), or 5 percent of the

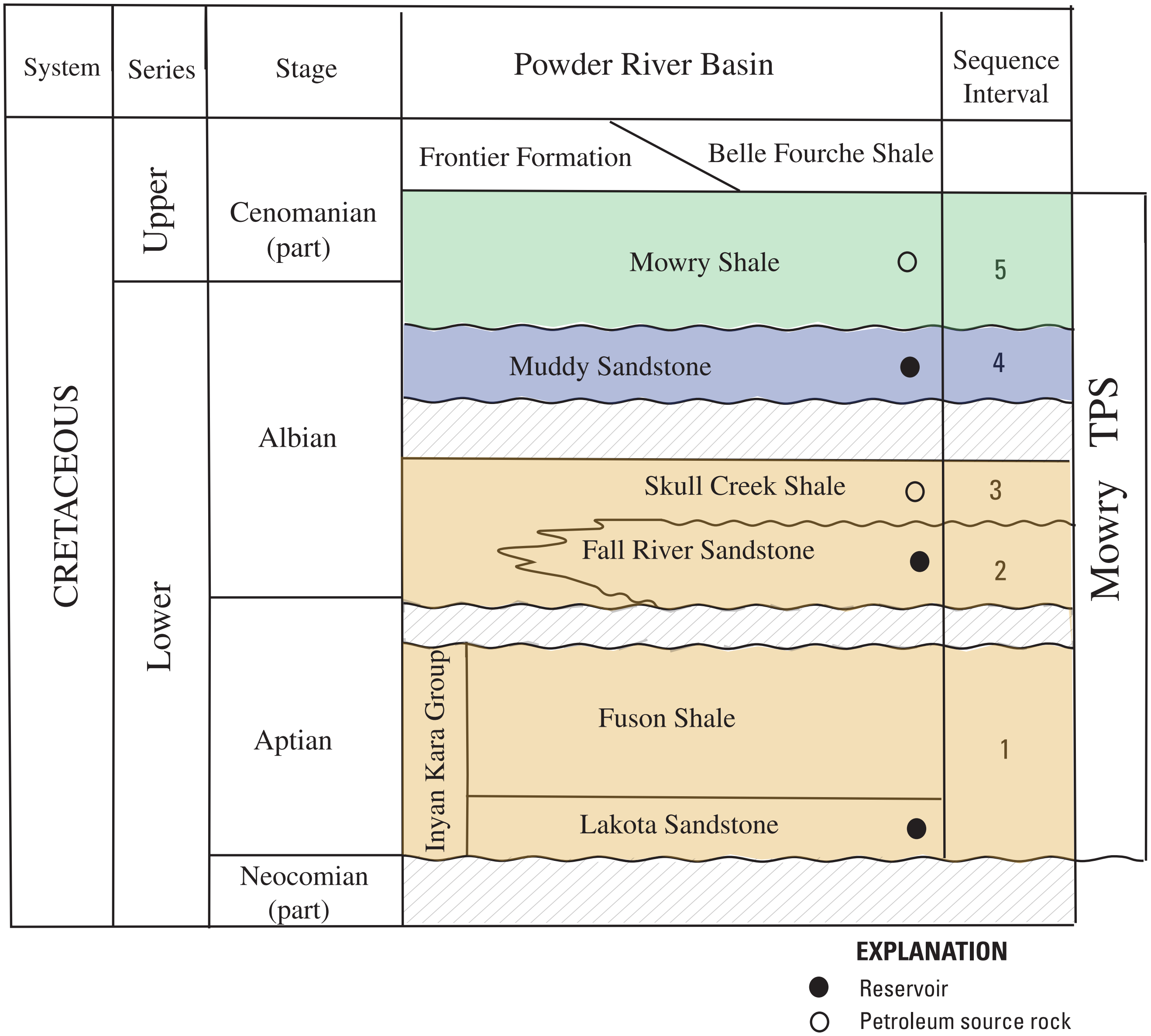


Figure 15. Stratigraphic column and succession intervals of Lower Cretaceous strata in the Powder River Basin including identification of the Mowry Total Petroleum System. TPS, total petroleum system.

11.9 billion barrels of expelled oil estimated by Momper and Williams (1984), for the Mowry source rocks. It should be noted that their amount does not include oil generated from the Fuson and Skull Creek Shales according to Momper and Williams (1984); the Fuson expelled a maximum of about 1 to 2 million barrels of waxy oil and minor amounts of gas, and the Skull Creek expelled a maximum of about 1 BBO from Type II organic matter.

Source Rock Thermal Maturity

Because of hydrocarbon mixtures, types, and temperatures, the Mowry Shale probably started generating hydrocarbons at depths exceeding 7,000 ft (Nixon, 1973). Basin and R_o modeling (described below) showed that significant hydrocarbon generation could have started at about 8,000 ft. Two one-dimensional burial history plots (using

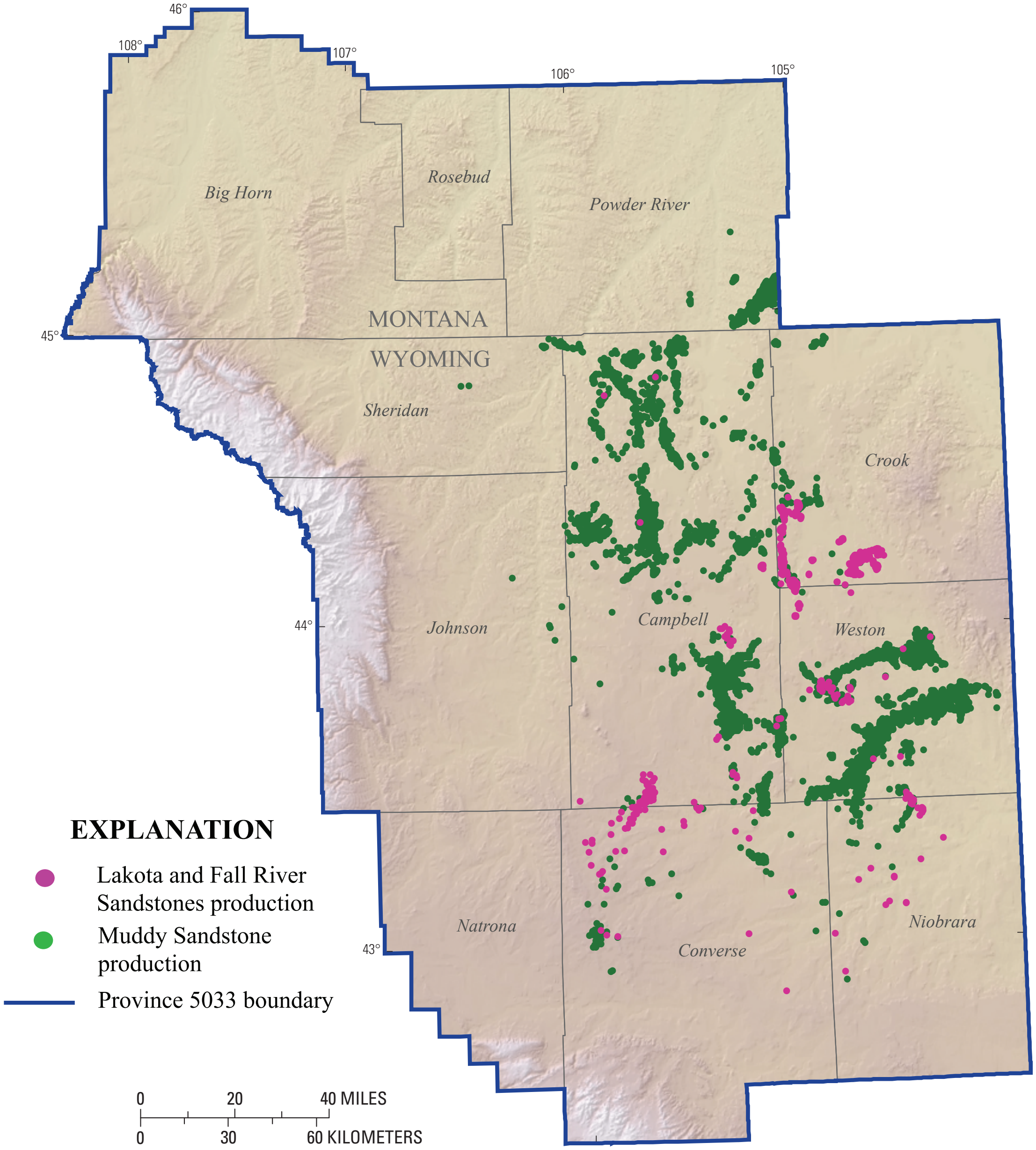


Figure 16. Map of Powder River Basin showing Lower Cretaceous production, including production from Fall River–Lakota Sandstones Assessment Unit and Muddy Sandstone Assessment Unit.

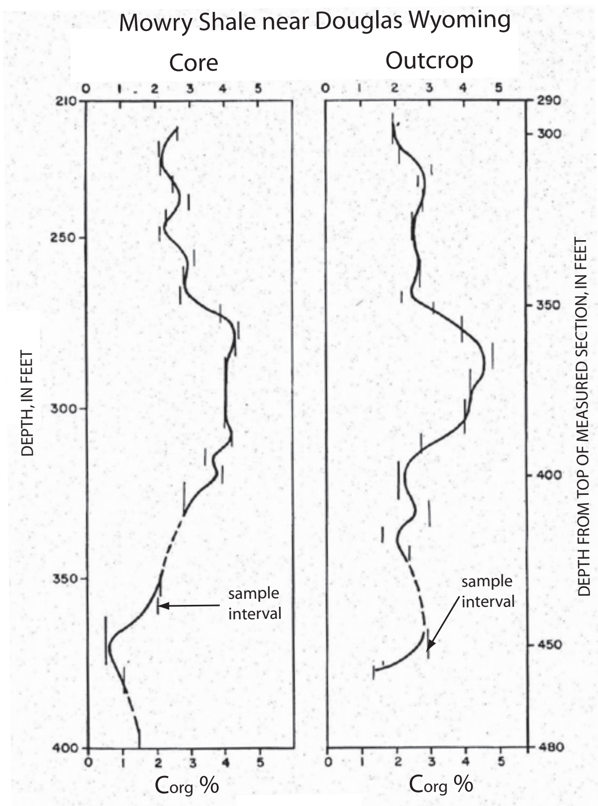


Figure 17. Core and outcrop vertical sections showing Mowry Shale total organic carbon values (C_{org} [%]) near Douglas, Wyoming.

PetroMod 1-D; Integrated Exploration Systems, 2002) were used to determine (1) the depth at which oil generation started, (2) the depth at which maximum oil generation occurred, and (3) the age range of petroleum generation. One model was derived for the east side of the basin and another for the west side, where formation depths and other input data were averaged from several sources. Therefore, the models reflect a general sense of burial and temperature history for each side of the basin. The models were calibrated to various sources of R_o data, including Higley and others (1997), Hunt (1979), and Surdam and others (1994). Although the models were not from a specific location, the output gives reasonable information about the basin's thermal history.

On the east side of the basin, results showed that (1) hydrocarbon generation started at the base of the Mowry Shale about 50 Ma at a depth of about 8,000 ft, at an R_o of 0.6 weight percent (fig. 18) which started formation overpressuring within the Mowry, and (2) R_o values for the Mowry have not yet reached more than 0.63 weight percent and are currently at about that value.

On the west side of the basin, modeling results showed that (1) hydrocarbon generation started at the base of the Mowry about 65 Ma at a depth of about 8,000 ft and at an R_o of 0.6 weight percent (fig. 19), which also started formation overpressuring; (2) the Mowry reached peak R_o of about 0.9 percent at about 25 Ma at a depth of about 13,000 ft and is currently at about 0.92 percent; and (3) R_o values would be entering the gas generation window at depths greater than 13,000 ft.

Hydrocarbon Migration

Buoyancy of fluids and pressure gradients are important to hydrocarbon migration because of oil being lighter and gas being much lighter than water, causing oil and gas, once they have been expelled, to move upgradient through porous and permeable carrier beds. However, if the buoyancy pressure is less than the capillarity of the carrier bed, the permeability barriers prevent migration until the pressure and capillarity reach equilibrium.

In the Mowry TPS, this process is common in that hydrocarbon production is located up structural gradient from the Mowry oil-generation kitchen located in the deep part of the basin (fig. 3). Oil migrates from the generation area toward the east where it is trapped in Lower Cretaceous reservoirs (fig. 20). The migration direction and rate was probably influenced by northeast-southwest-trending structures (Slack, 1981; Anna, 1986a, b; and Maughan and Perry, 1986). Conversely, the lack of production north of the generation area (fig. 20) could be explained as follows: (1) The area to the north is nearly parallel to the basin axis and not subject to buoyancy flow; (2) migration was confined to northeast-southwest-trending structures, even though present-day groundwater flow is both north and south out of the basin; (3) lack of quality reservoirs; and (4) a combination of the above. Geologically, there appears to be no ready explanation for the conspicuous absence of production in the Mowry kitchen area, although there have been a few recent discoveries (for example, African Swallow field trend) in the southwestern part of the basin.

Migration from the Mowry Shale into the Muddy Sandstone is a simple process because the Mowry directly overlies the Muddy. However, migration into the Fall River and Lakota Sandstones is a more arduous process because the Fuson and Skull Creek Shales are in between. Therefore, open fault and fracture zones served as vertical pathways for fluids to migrate from the Mowry to the Fall River-Lakota.

Plots of API gravity and gas/oil ratios (GOR) of several fields producing from Lower Cretaceous reservoirs show a general trend of decreasing values from west–to-east (fig. 21). This may indicate that the generated oil was being degraded along its west to east migration path, and that most of the oil was generated in the Mowry Shale at depths greater than 8,000 ft. Only along parts of the basin margin, however, is there some change in oil characteristics because of degradation (Wenger and Reid, 1961).

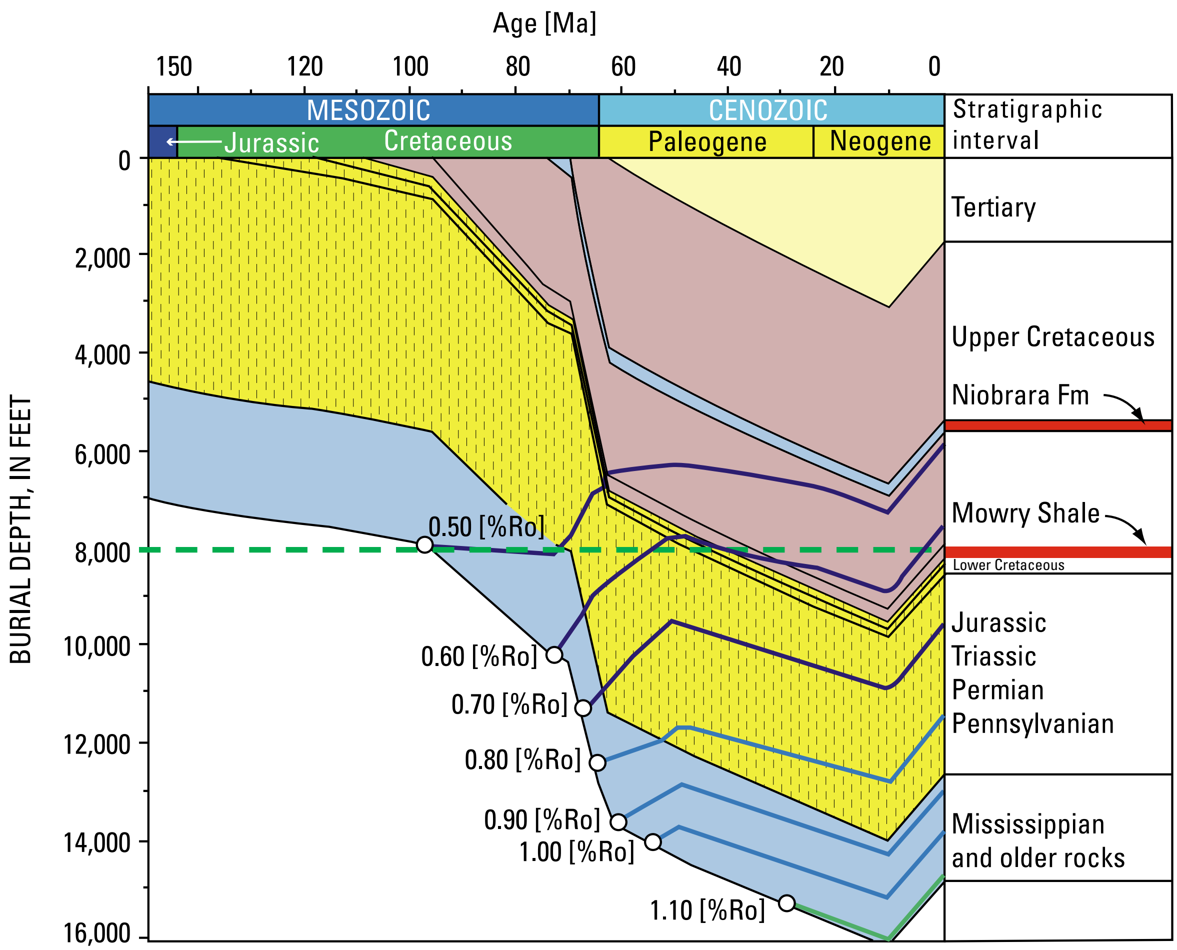


Figure 18. Burial history curve for east side of the Powder River Basin based on combined input and calibration data from several locations. The 8,000-foot datum marks the horizon below which Mowry Shale enters the oil generation window at about 42 million years ago. The Niobrara Formation does not enter the oil generation window over most of the east part of the basin. R_o, vitrinite reflectance; Fm, Formation; J, Jurassic; K, Cretaceous; Pg, Paleogene; Ng, Neogene.

A geologic events chart (fig. 22) shows elements that define the Fall River–Lakota Sandstones AU and the Muddy AU.

Reservoir Rocks

Fall River–Lakota Sandstones

Lower Cretaceous strata (Aptian and lower Albian) in the Rocky Mountain region are collectively called the Dakota Group, which is formally divided into a lower Inyan Kara Group and the overlying Fall River Sandstone. Some workers include the Skull Creek Shale and Muddy Sandstone in the Dakota Group, especially east of the Black Hills where the Skull Creek Shale thins and the Inyan Kara and the Muddy coalesce into one unit. Both the Fall River and Lakota produce oil and gas in the PRB, although cumulative production to date is only about 20 percent of that produced by the overlying Muddy. The lower production rates are probably because the Fall River and Lakota reservoir quality is more variable than the Muddy, and oil migration into the Fall River and Lakota from the Mowry Shale may not have been as efficient as into the Muddy (Dolson and Muller, 1994).

The Lower Cretaceous strata consist of four major and several minor stratigraphic intervals, separated in part by regional and local unconformities. The oldest major sequence overlies a regional unconformity that in places truncates Jurassic, Triassic, and, locally upper Paleozoic strata (Dolson and Muller, 1994). This succession consists of stacked conglomerates and coarse-grained sandstones separated by siltstones and mudstones of variable thicknesses of the Lakota Sandstone and the variegated shales and mudstones of the Fuson Shale.

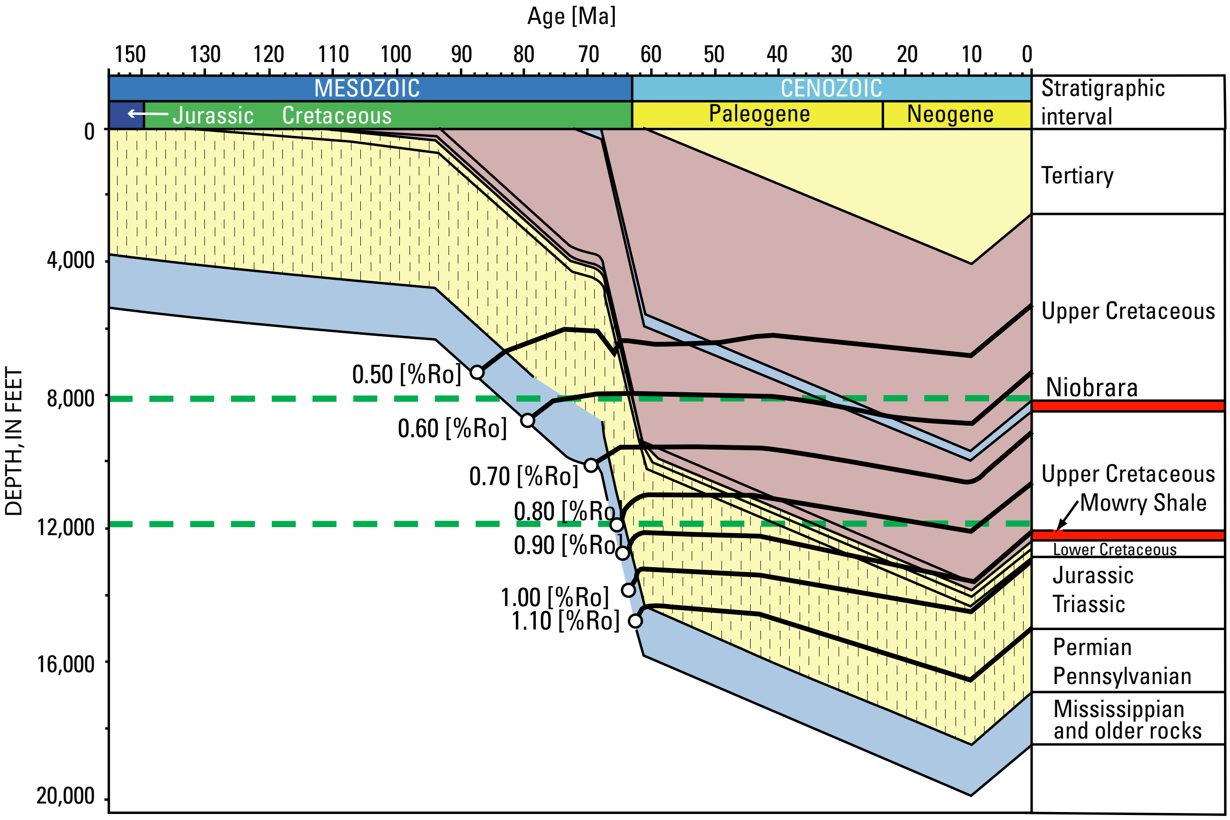


Figure 19. Burial history curve for west side of the Powder River Basin based on combined input and calibration data from several locations. The 8,000 foot datum marks horizon below which Niobrara Formation enters oil generation window at about 30 million years ago, and where the Mowry Shale enters the window at about 64 Ma. At 12,000 feet, the Mowry is currently at a vitrinite reflectance value of about 0.92 weight percent. J, Jurassic; K, Cretaceous; Pg, Paleogene; Ng, Neogene; Ma, mega-annum, before present; R_o, vitrinite reflectance.

The second major succession rests unconformably on the first and consists of the transgressive gray to black Skull Creek Shale. A third sequence, deposited during a lowstand event with widespread incisement into the Skull Creek, is represented by sandstone, siltstone, and mudstone of the Fall River Sandstone. A fourth succession also involved a major sea-level drop followed by incisement and the gradual fluvial and estuarine filling of channels characteristic of the Muddy Sandstone.

The Lakota Sandstone was deposited on an alluvial plain over a large area, not as a sheet deposit but as a large, north-trending drainage system associated with incised valleys on multiple surfaces (Meyers and others, 1992). Several successions of sandstone, siltstone, and shale make correlation of individual sandstones difficult and has led to misinterpretation of sandstone trends.

The Fall River Sandstone was deposited as a broad deltaic system that included incised valley and distributary fill, delta plain facies, and delta front facies (Rasmussen and others, 1985). Most Fall River production is from the incised valley and distributary systems, whereas minor production is from adjacent deltaic plain and delta front facies. Buck Draw field (Anderson and Harrison, 1997) is the largest Fall River oil producer (fig. 23). South of Buck Draw field, the width of the incisement decreases and the valley-fill sandstones have a lower sand/shale ratio than valley fill to the north. As a result, production volumes in that area are less than at Buck Draw. Rasmussen and others (1985) presented pictorially east-west cross sections of several north-trending incised valleys at various stratigraphic levels of the Fall River, indicating the possible abundance of reservoir-quality sandstones in the southern part of the basin.

Muddy Sandstone

The Muddy Sandstone is a prolific oil producer in several Rocky Mountain foreland basins, including the PRB. The Muddy consists of marine and nonmarine sandstone, siltstone,

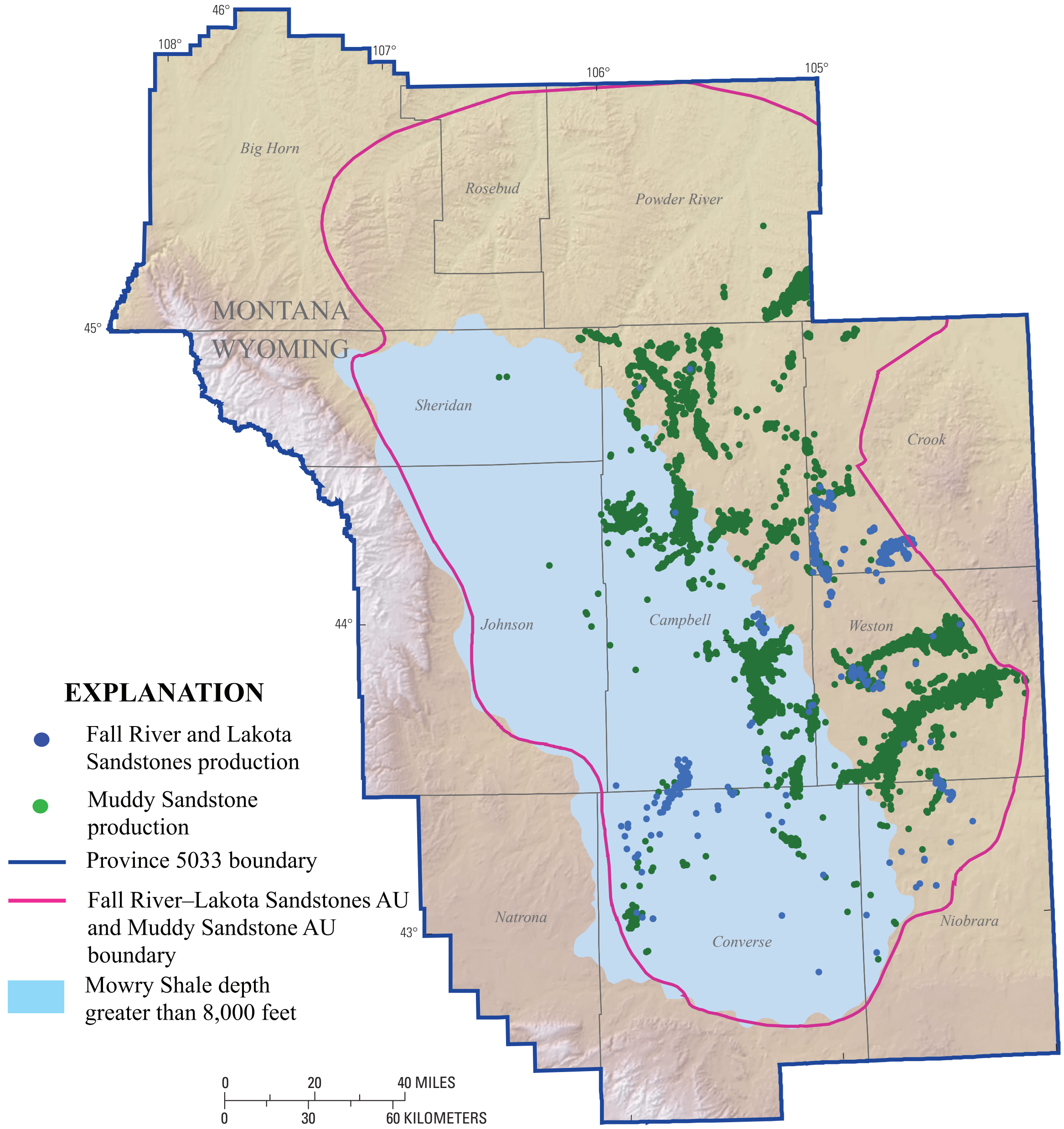


Figure 20. Map of Powder River Basin Province showing Lower Cretaceous production, area where depth to Mowry Shale is greater than 8,000 feet (blue area), and boundary of Mowry Total Petroleum System that also delineates the Fall River–Lakota Sandstones and Muddy Sandstone Assessment Units (AUs). Note that most of the current Lower Cretaceous production is east of the Mowry generation area. Province 5033 is code number for Powder River Basin Province.

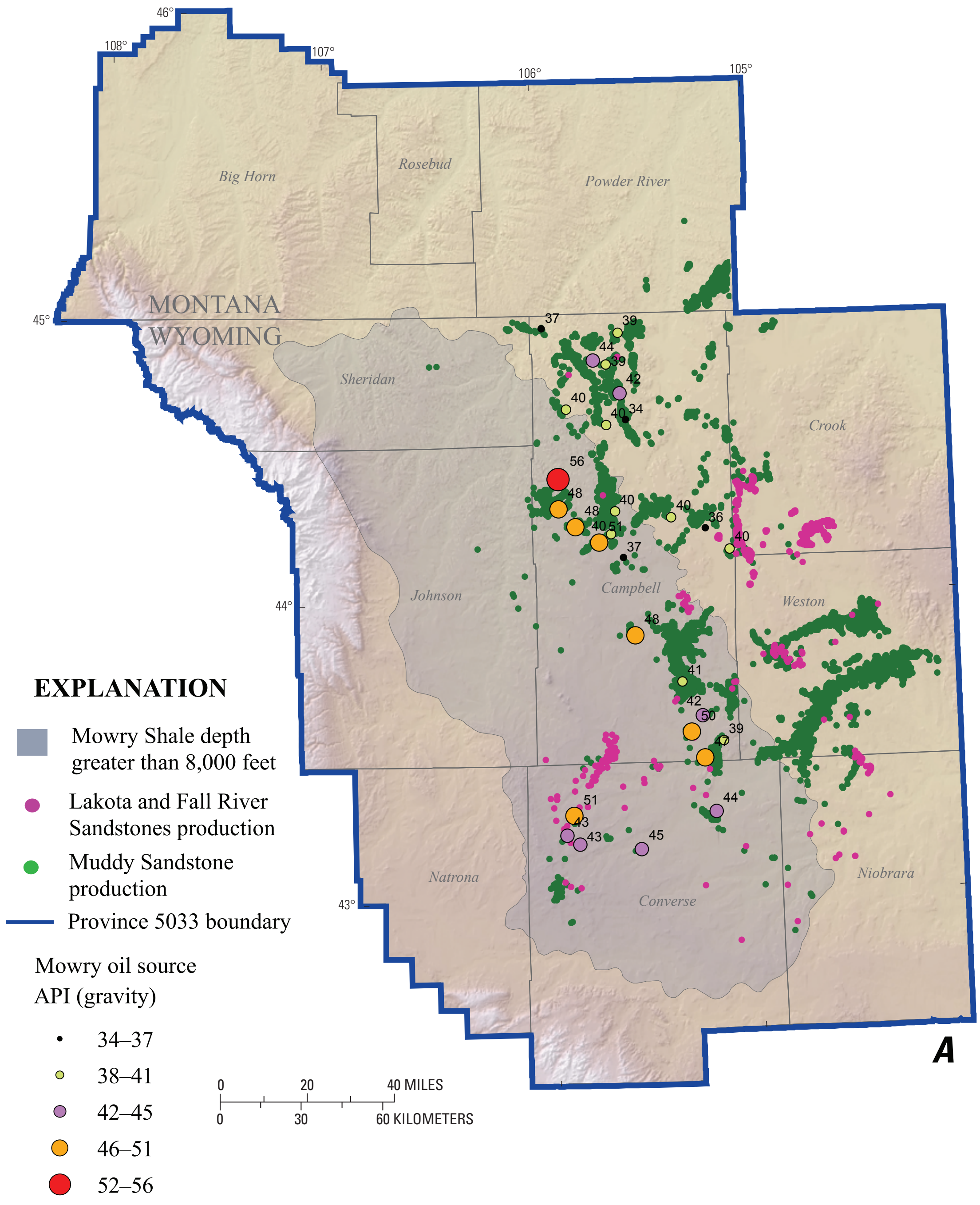


Figure 21. Maps of Powder River Basin Province showing Lower Cretaceous production, the area where depth to Mowry Shale is greater than 8,000 feet, (*A*) average API gravity for Lower Cretaceous fields, (*B*) average gas/oil ratio (GOR) for Lower Cretaceous fields. API and GOR data from NRG Associates, Inc. (2006). Province 5033 is code number for Powder River Basin Province.

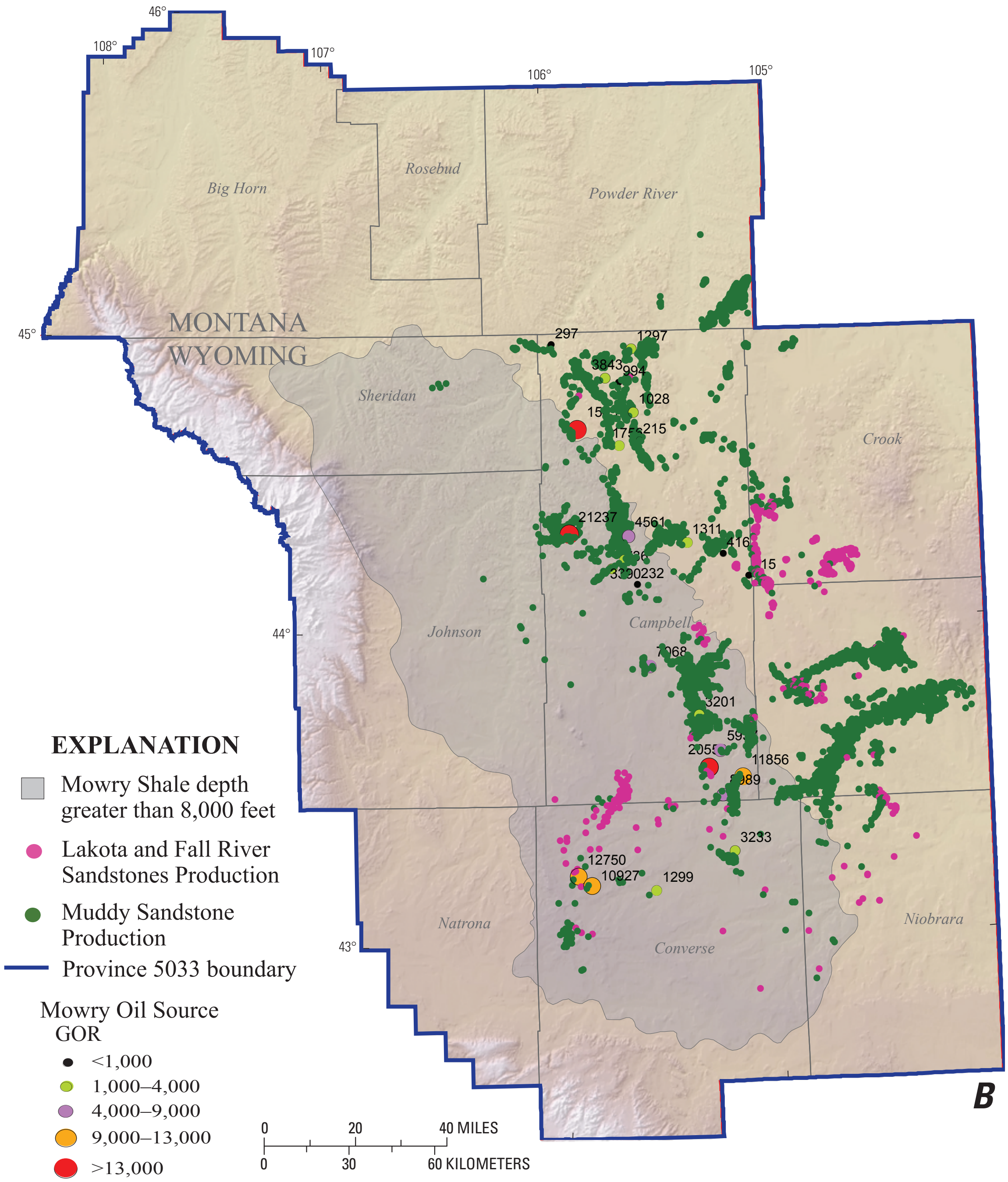


Figure 21. Maps of Powder River Basin Province showing Lower Cretaceous production, the area where depth to Mowry Shale is greater than 8,000 feet, (*A*) average API gravity for Lower Cretaceous fields, (*B*) average gas/oil ratio (GOR) for Lower Cretaceous fields. API and GOR data from NRG Associates, Inc. (2006). Province 5033 is code number for Powder River Basin Province.—Continued

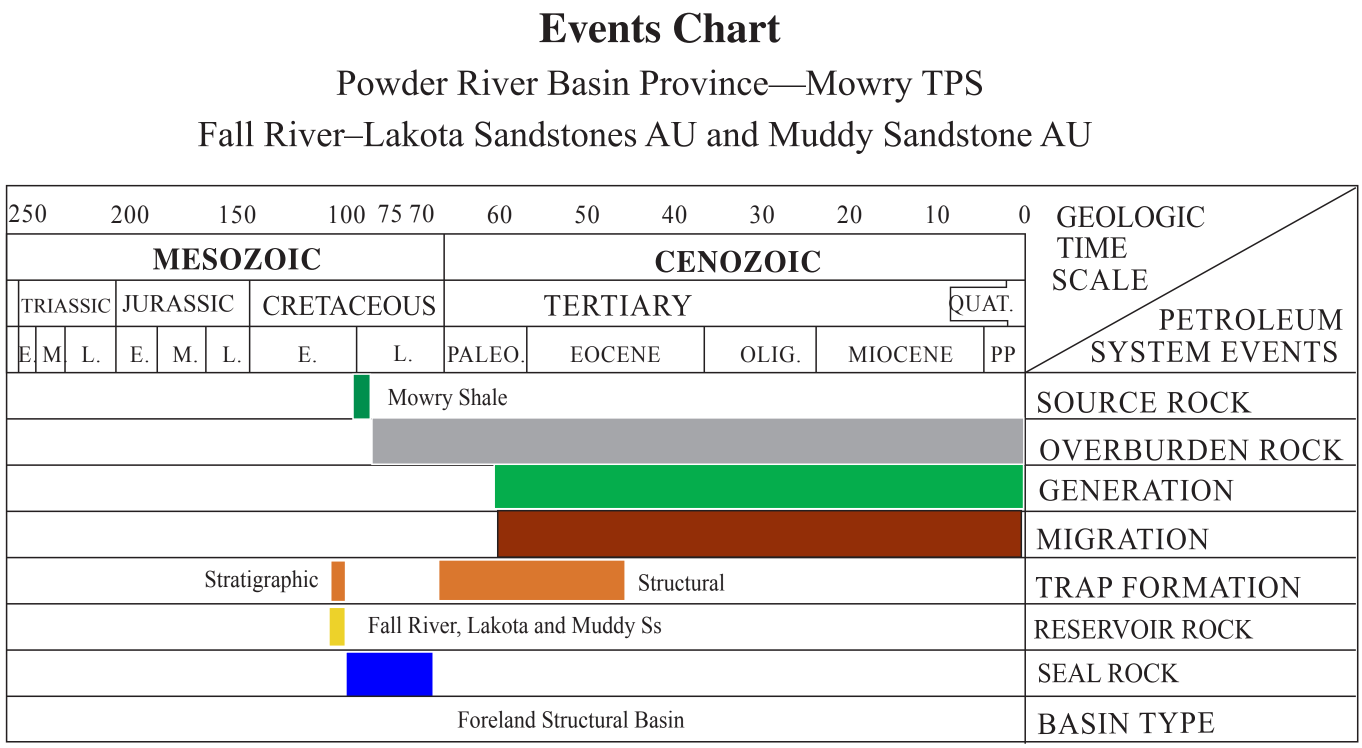


Figure 22. Events chart for Fall River–Lakota Sandstones and Muddy Sandstone Assessment Units (AUs) in the Mowry Total Petroleum System (TPS). Ss, sandstone; Quat, Quaternary; PP, Plio-Pleistocene; Olig., Oligocene; Paleo., Paleocene; E., early; M., middle; L., late.

and mudstone deposited in a variety of sedimentary environments. In the PRB, the two main producing intervals consist of valley-fill fluvial and estuarine sandstones and transgressive nearshore marine sandstones. Fluvial strata are common on the east side of the basin, whereas estuarine strata are common on the west side. Transgressive nearshore marine sandstones are associated with incised valley systems, most commonly in the central and western parts of the basin. As a result, most Muddy production is associated with incised valley systems in stratigraphic traps and in some structural traps, although rarely is the Muddy a pure structural trap.

The regional paleotopographic setting of the Muddy described by Dolson and others (1991) helped to integrate numerous smaller scale studies (Donovan, 1995; Gustason, 1988; Martinsen, 1994); Waring, 1975; Weimer and others, 1982, 1988; Wheeler and others, 1988) into a comprehensive understanding of a complex depositional system. Simply stated, during regression of the Mowry sea, sediments of the Muddy interval (fig. 24) were first deposited as part of a highstand systems tract (HST) as widespread, but thin, argillaceous and bioturbated sands and silts. This very fine grained unit generally has low porosity and permeability and is not considered an exploration target. A lowstand systems tract (LST) then developed at maximum Mowry regression, resulting in incised valleys into the exposed Muddy surface (Dolson and others, 1991). The transgressive systems tract of the incised valley fill unconformably overlies one or more of the following successions: fluvial deposits of sandstone, siltstone, and mudstone overlain by estuarine deposits of sandstone and capped by thin, transgressive sandstone. Some authors (Wheeler and others, 1988, and Gustason, 1988) have applied formation names to particular unconformity-bound sandstone intervals for a particular field or area.

Fluvial deposits are most prevalent on the east side of the PRB proximal to the Mowry sea but are thin to absent on the west side. Fluvial deposits contain various amounts of sandstone but are sand rich on the east side, with sand percentage gradually decreasing to the west. Estuarine deposits are mostly siltstone and mudstone dominated with limited but variable amounts of sandstone. Sandstone percentage in the estuarine deposits also diminishes to the west. A major transgressive event deposited mostly fine grained, well-sorted sandstone over the Muddy surface, more so in topographically low areas coincident with the incised fluvial systems (fig. 25). As the transgression progressed, sand on topographic highs was eroded, whereas sand in topographic lows was preserved. These sandstones can be excellent

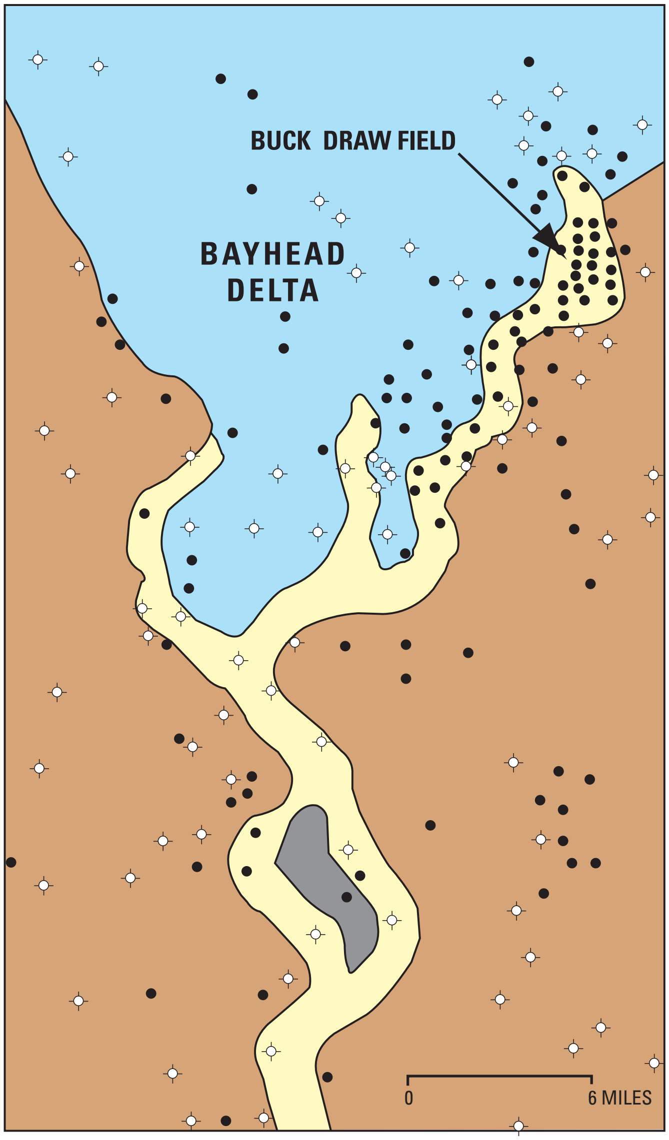


Figure 23. Map showing relation between Fall River Sandstone delta system and Fall River production at Buck Draw field, Powder River Basin, Wyoming. Blue, water; yellow, fluvial system; brown, delta plain; gray, interfluvial island; solid dots, oil wells, open circles, dry holes. Diagram modified from Anderson and Harrison (1997).

reservoirs as evidenced by high production rates from African Swallow and Sand Dunes fields (fig. 25).

On the east side of the basin, in normal or underpressured sections, reservoir-quality sandstones have porosity exceeding 20 percent and permeability ranging from 100 to more than 1,000 millidarcies (mD). On the west side, in overpressured sections, reservoir quality sandstone has porosity of 10 to 15 percent and permeability less than 200 mD.

Traps and Seals

Traps in Lower Cretaceous strata in the PRB can be characterized as stratigraphic and a combination of stratigraphic and structural enhancement. Stratigraphic traps are the most common type and are associated with incised valley systems, a diversity of lithologies, and juxtaposed pattern of sandstones, siltstones, and shales in the valley systems; that is, the oil-bearing reservoir sandstones are enclosed in low-porosity and low-permeability siltstones, shales, or mudstones that create a barrier to oil migration. Porosity reduction owing to increased clay content in reservoirs may also be a factor in some cases, but diagenetic alteration in forming potential traps is rare.

Structural traps are a result of Laramide deformation that created numerous structural types at various scales. Most structures were created before oil was generated and migrated from Lower Cretaceous source rocks (fig. 22). As a result, oil migration into potential stratigraphic and structural traps was done in an efficient manner.

Mowry TPS as a Continuous Reservoir

The Mowry Shale is a self-contained petroleum system, in that it is a hydrocarbon source rock not only for other Lower Cretaceous reservoirs but also for intraformational reservoir, which is typical of a continuous (or unconventional) petroleum system. Production from the Mowry is enhanced by fracture permeability and storage, but there is a possibility that thin siltstones may be present, similar to siltstones and sandstones mapped in the Bighorn Basin to the west of the PRB (Davis and Byers, 1989). The siltstones could increase porosity and storage, which would supply oil to Mowry fracture networks.

Mowry Shale thicknesses range from about 100 ft to more than 400 ft and average about 250 ft (Momper and Williams, 1984, their fig. 4). Three main depositional units can be mapped within the formation (Byers and Larson, 1979), all bounded by bentonite beds that divide the unit into time-stratigraphic intervals. The units are regionally persistent and lithologically distinctive (Merewether and others, 1977; Fox, 1993). Geophysical log resistivities are commonly used to identify lithologic type—high resistivity indicates siliceous, sandy or silty shale, and siltstone or silty sandstone; and low resistivity indicates clay-rich shale and bentonite (Nixon, 1973). However, the presence of hydrocarbons may alter the resistivity signature, so lithologic interpretation should be made with caution.

Most continuous reservoirs have sweet spots where production may be enhanced by an increase in secondary porosity or permeability. Several sweet spots associated with major lineaments and lineament zones were identified within the Mowry Shale (Slack, 1981; Anna, 1986a, 1986b; Maughan and Perry, 1986). The lineaments in figure 26 are assumed to be associated with zones of structural deformation and could be areas of enhanced secondary porosity and permeability

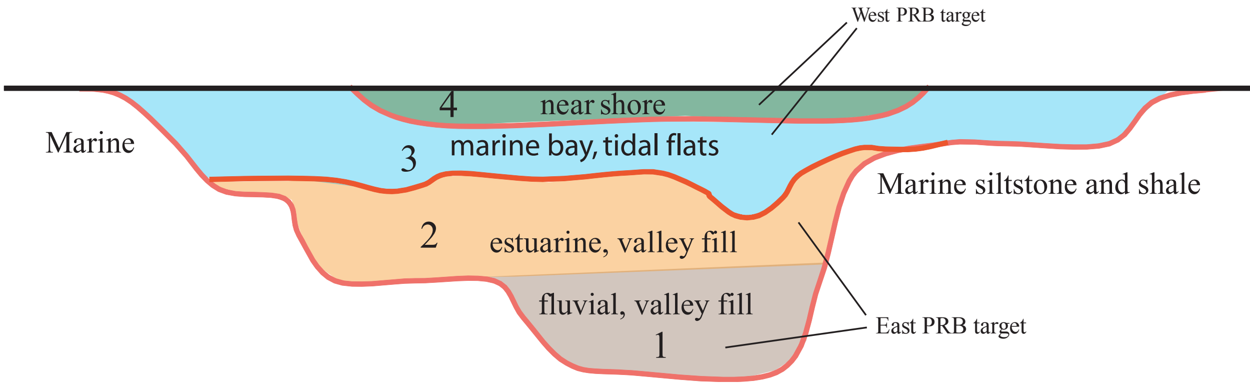


Figure 24. Generalized cross section of Muddy Sandstone depositional environments and successions in the Powder River Basin (PRB). All lines mark unconformities. Estuarine and valley fill are production targets on east side of basin, whereas the nearshore and marine bay and tidal flats are targets on the west side. Diagram and concept modified from Weimer and others (1982).

in the formation. For example, lineaments that coincide with the Belle Fourche arch (fig. 4) may represent areas of increased fracture intensity along the arch because of flexing or enhanced stress, or they may coincide with folds where fractures developed as a mechanical response to folding. Most current Mowry production, but not all, is within sweet spot areas as shown in figure 26. The correlation may be considered circumstantial because the lack of control may not be statistically significant, or alternatively, the plotted lineament locations do not represent all structural zones.

Niobrara Total Petroleum System (TPS)

The Niobrara TPS in the PRB includes (1) three conventional AUs: (a) the Frontier-Turner Sandstones AU, (b) the Sussex-Shannon Sandstones AU, and (c) the Mesaverde-Lewis Sandstones AU; and (2) one continuous AU, the Niobrara AU (fig. 27). The Niobrara TPS (fig. 28) consists of Upper Cretaceous marine-dominated siliciclastic reservoirs whose environments of deposition range from proximal and distal delta to marine shelf systems. Numerous sea-level changes produced transgressive and regressive systems tracts, initiated regional and local lowstand unconformities, and deposited shallow nearshore marine sandstones and mudstones capped by transgressive deepwater marine shales.

The basin has long produced hydrocarbons from Upper Cretaceous sandstone reservoirs (fig. 28). Production was first established in the late 1950s with the discovery of Dead Horse Creek field followed by several discoveries in the 1970s of stratigraphic traps which became recognized as important exploration objectives.

Over 95 percent of the fields from Upper Cretaceous reservoirs are classified as oil (NRG Associates, Inc., 2006), because source rocks never reached temperatures to generate large amounts of gas. Most reservoirs produce associated gas, whereas only source rocks in the deepest part of the basin may have reached temperatures to be in the gas-generation window.

Source Rocks

Carbonates of the Niobrara Formation are considered to be the primary hydrocarbon source for Upper Cretaceous reservoirs in the PRB, although a minor amount may have been generated from thick, areally extensive, younger Cretaceous marine shales. The formation was deposited in latest Turonian to early Campanian time as pelagic carbonate in a large but shallow interior seaway, with water depths ranging from 200 ft to more than 500 ft, similar to depositional environments of the Upper Cretaceous Austin Chalk of the Gulf Coast. The sea covered a broad, stable platform over the western flank of the North American craton during a sea-level rise and represented a major and one of the most prolonged highstands in the Cretaceous. On a regional basis, the Niobrara Formation is composed of both allochems and matrix components. The primary allochems are chalk pellets, inoceramid and oyster shell fragments, and forams; the primary matrix components are mud, clay, and silt. As a result, the formation is usually classified as (1) chalk (with greater than 95 percent carbonate), (2) chalky marl (with 65 to 95 percent carbonate), (3) marl (with 35 to 65 percent carbonate), (4) marly shale (with 5 to 35 percent carbonate), and (5) shale (with less than 5 percent carbonate). Megascopically, there is little difference between the components except for color and organic content. The Niobrara can be classified as very fine

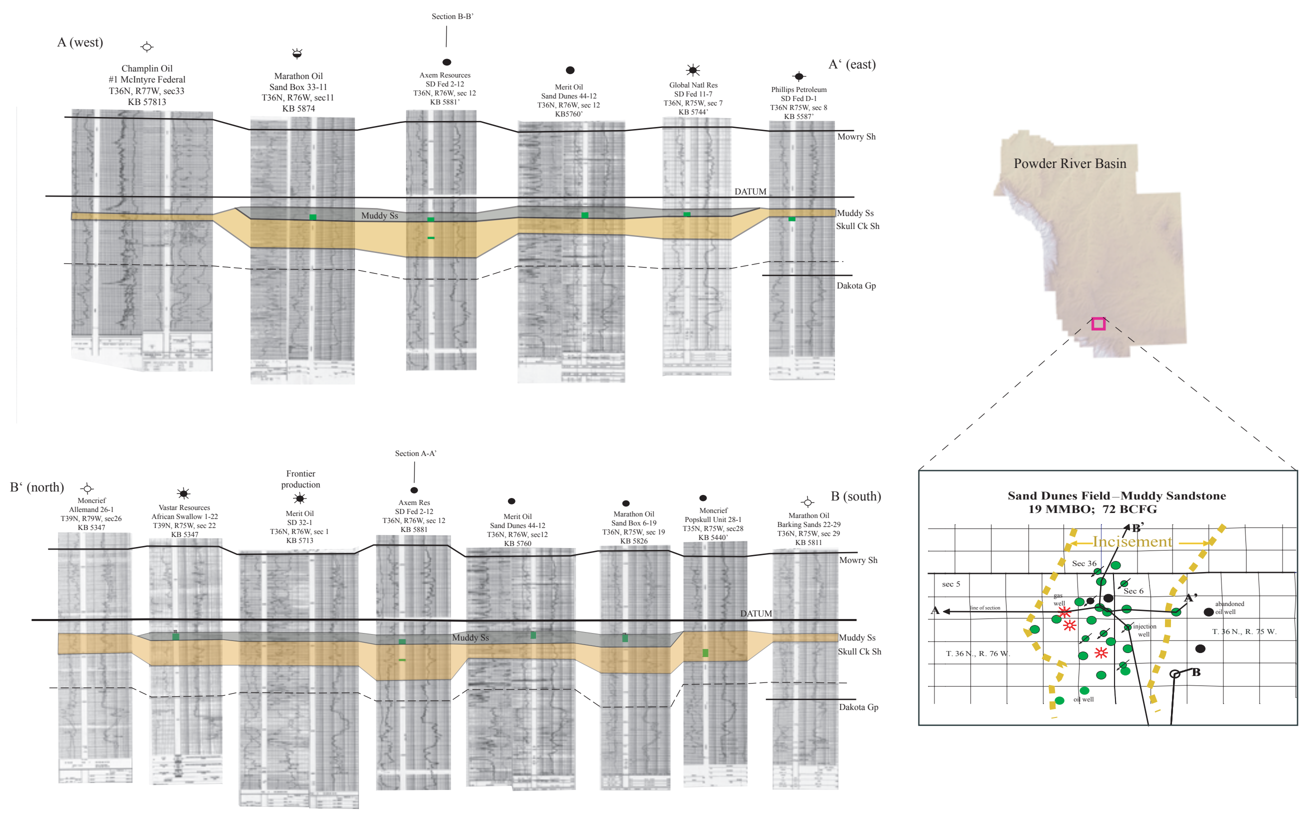


Figure 25. Cross sections of Muddy Sandstone interval, Sand Dunes field, Powder River Basin. (Click on image to open full size, high resolution image for viewing and printing).

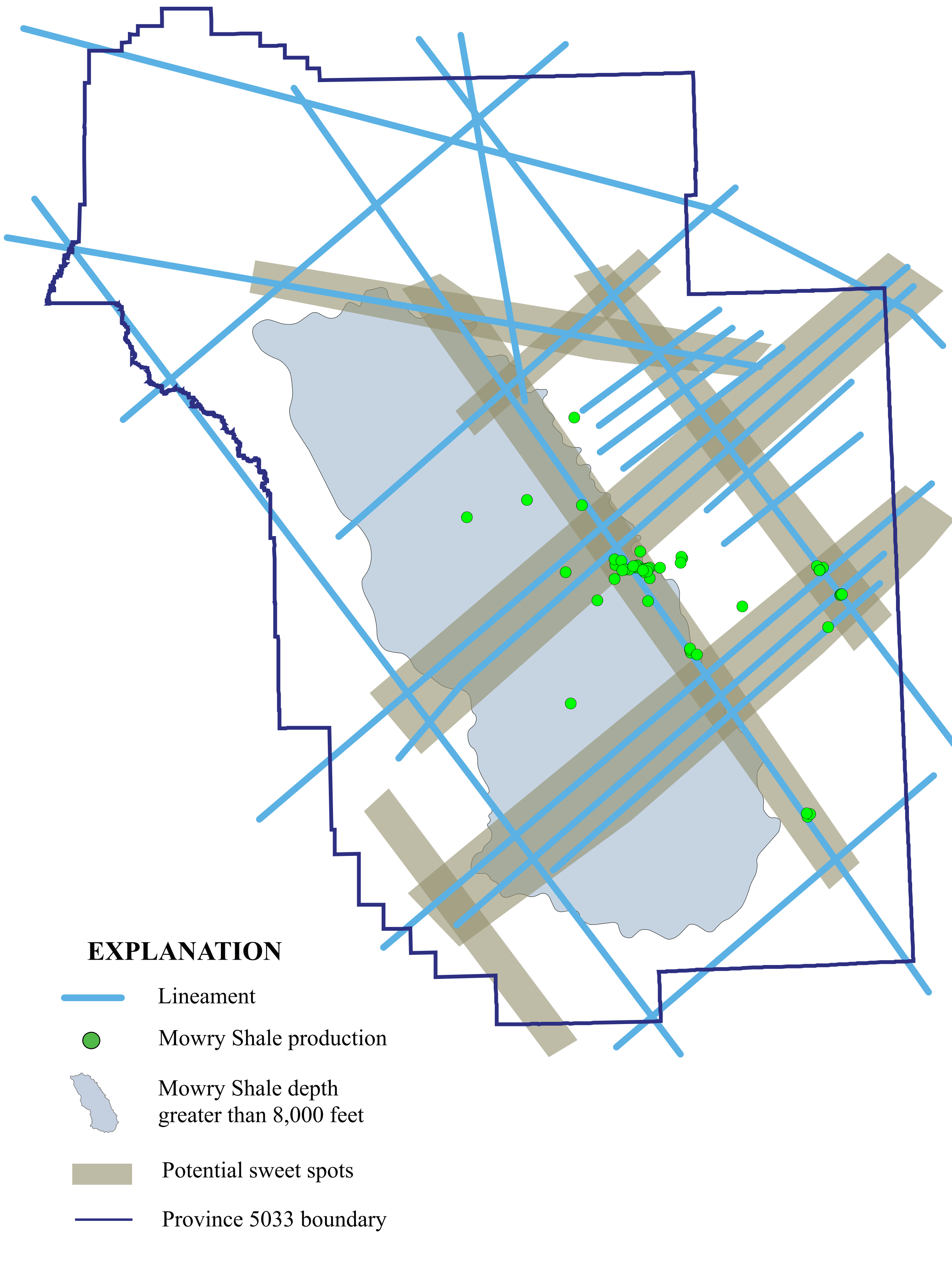


Figure 26. Map of Powder River Basin Province showing Mowry Shale potential sweet spots derived from the congregation of published lineament and lineament zones, and current production from the Mowry Shale, Powder River Basin.

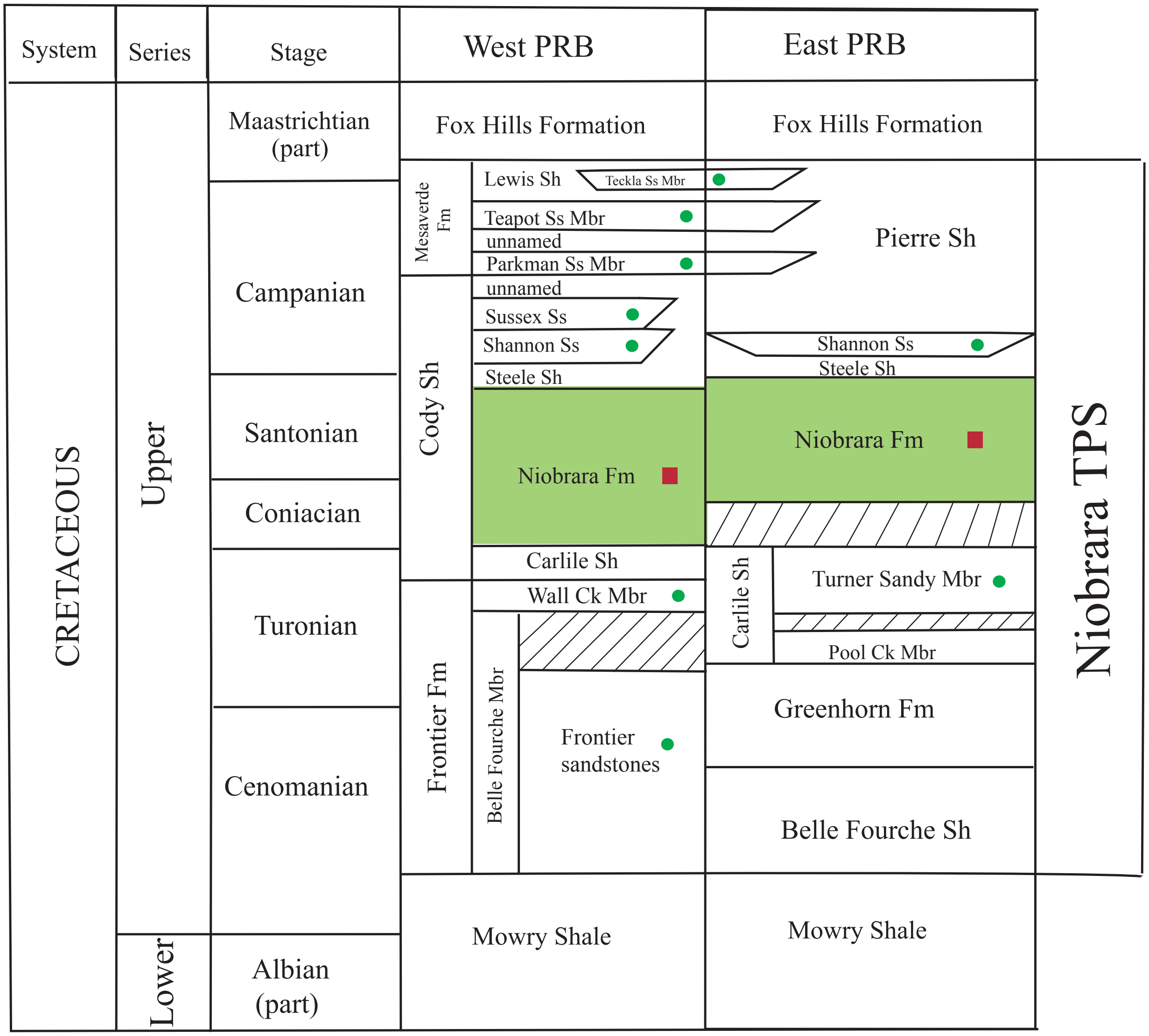


Figure 27. Stratigraphic column of Upper Cretaceous strata in the Powder River Basin (PRB). Niobrara Formation source rock is highlighted and the units defining the Niobrara Total Petroleum System (TPS) are identified. Mbr, member; Ck, Creek; Fm, formation; Sh, shale; Ss, sandstone.

grained and well sorted with pore throat sizes of less than 1 micrometer; hence, matrix permeability is low, generally less than 0.01 mD. Matrix porosity can be as high as 20 percent, typically averages 10 percent, and is a function of depth and shale content, both of which increase to the west in the basin.

The formation is divided into two members, the Fort Hays Limestone Member at the base and the overlying Smoky Hill Member. The Fort Hays Limestone Member is mostly carbonate and is defined as a chalk, whereas the Smoky Hill Member has more varied lithology and has the best source rock potential. Longman and others (1998) and Landon and others (2001) divided the formation into nine intervals because of the formation's cyclic nature, with the lowest interval corresponding to the Fort Hays Limestone Member. The lithologic characteristics of both members are regionally persistent and can be traced by wireline logs in the subsurface for large distances.

Merewether and others (1977) and Fox (1993) developed several regional cross sections across the PRB. Their mapping shows that the Niobrara is underlain by the Carlile Shale on the west side and by the Turner Sandy Member, equivalent to the Ferron Sandstone in Utah and the Codell Sandstone in Colorado, on the east side. Overlying the formation on the west side is the Fishtooth Sandstone and on the east side is the Pierre Shale. In general, the Niobrara is part of an extensive and thick Upper Cretaceous marine system, consisting mostly

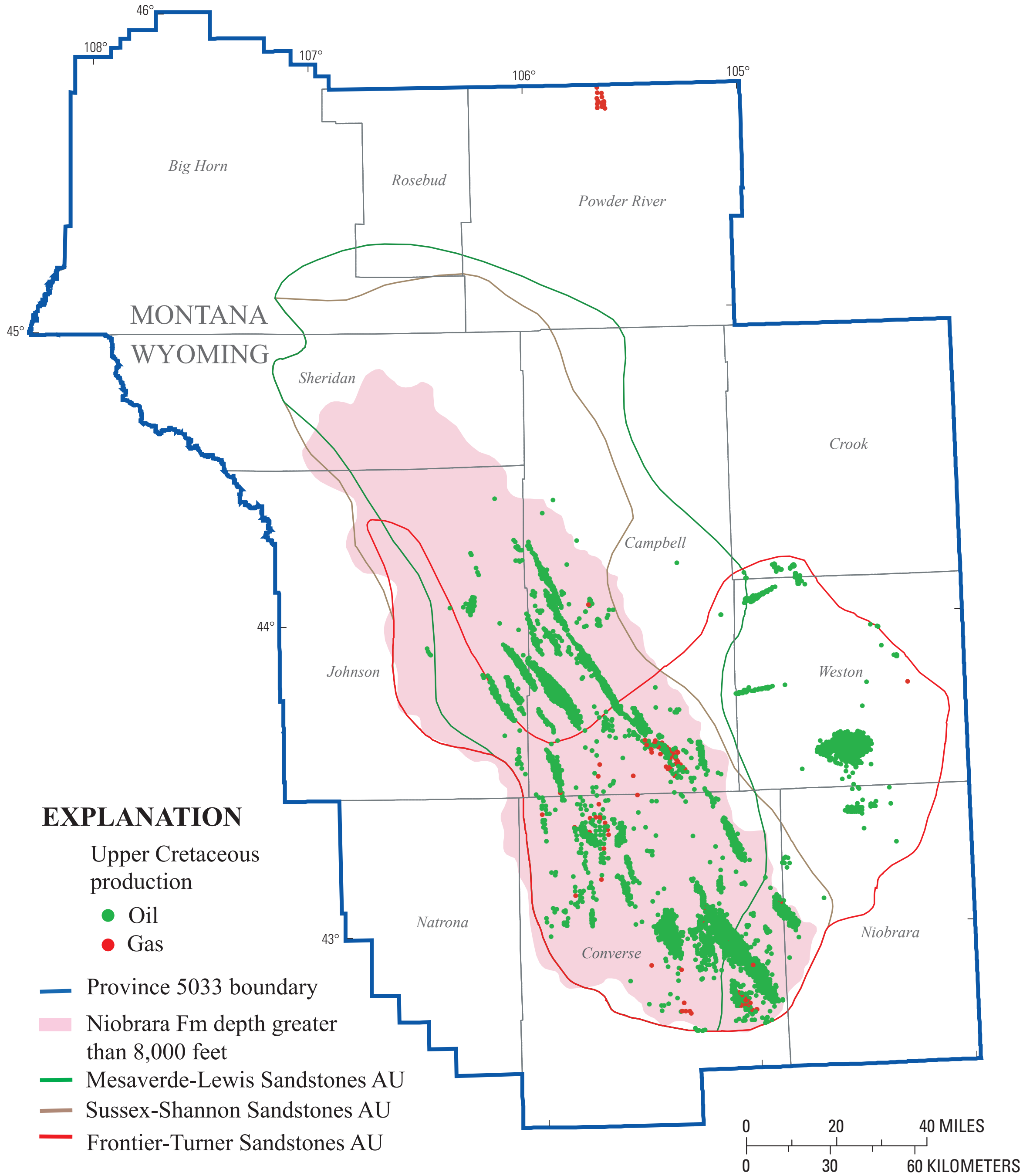


Figure 28. Map showing Upper Cretaceous oil and gas production, area where depth to Niobrara Formation is greater than 8,000 feet, and boundaries of assessment units (AU) within the Niobrara Total Petroleum System in the Powder River Basin Province. Most Upper Cretaceous production is within area where Niobrara Formation is more than 8,000 feet deep.

of shale and carbonate with thin, low-permeability, shallow marine sandstones. Thicknesses average about 400 ft and range from less than 50 ft to more than 600 ft; within the AU boundary, average thicknesses are less than 400 ft, ranging from about 300 to 500 ft.

Wireline resistivity logs of the Niobrara Formation are used to indicate hydrocarbon richness because hydrocarbons are a nonconducting fluid (Smagala and others, 1984). Accordingly, as oil saturation increases (as more hydrocarbons fill fractures) resistivity also increases. As Longman and others (1998) and Landon and others (2001) have indicated, individual deposition cycles must be mapped separately to accurately compare resistivity patterns. Mapping maximum resistivity of the total formation as an exploration tool can give misleading results.

The Niobrara Formation averages more than 3 weight percent TOC of Type II kerogen in the PRB; Landon and others (2001) reported TOC values exceeding 7 weight percent in areas adjacent to the PRB. According to Heacock and Hood (1970), the formation has the highest averages of TOC of all the Upper Cretaceous rocks in the basin. The organic matter is mostly concentrated in thin, dark, and shaly laminae, whereas the chalky intervals have low TOC consisting of 1 to 2 weight percent. Because the Niobrara becomes more shaly on the west side of the basin, TOC values may increase to the west. Owing to kerogen type and temperature, hydrocarbons probably did not start generating and migrating until the formation had reached a burial depth of at least 7,000 ft. Modeling of basin structural, depositional, and thermal histories shows that significant hydrocarbon generation could have started with about 8,000 ft of overburden (fig. 28).

Source Rock Thermal Maturity

Thermal maturity of the Niobrara Formation was evaluated using standard methods including R_o and depth plots, Rock-Eval pyrolysis data, correlation of resistivity and R_o, and constructing burial history models for the east and west sides of the basin. Published R_o data were not conclusive because vertical depth profiles rarely fit a normal (linear) profile. Rock-Eval pyrolysis data were sporadic and also not conclusive. Smagala and others (1984) correlated R_o and resistivity as a semilog plot, and suggested that there is a correlation between in-situ generated hydrocarbons and high electrical resistivity of hydrocarbons. However, if the data are normalized to a constant temperature, the trend line flattens, indicating that there is a range of resistivity to identify a particular level of maturity and that the technique should be used only empirically.

The software PetroMod1D (Integrated Exploration Systems, 2002) was used to model burial-history curves for the Niobrara TPS and the Mowry TPS. Results show that (1) on the east side of the basin, the Niobrara Formation did not reach thermal maturity (fig. 18); (2) on the west side of the basin, hydrocarbon generation started at about 30 Ma at a depth of about 8,000 ft (fig. 19) and at an R_o of 0.6 weight percent; (3) at the base of the formation the Niobrara reached a maximum R_o of about 0.68 percent at about 10 Ma, at a depth of about 9,700 ft; and (4) R_o is currently at about 0.68 percent. These modeled R_o values indicate that the Niobrara probably did not reach thermal maturation to generate nonassociated gas but could reach gas-generating temperatures in the deepest parts of the basin.

Geologic events charts (fig. 29) show the elements that define the Frontier-Turner Sandstones AU, the Sussex-Shannon Sandstones AU, and the Mesaverde-Lewis Sandstones AU.

Hydrocarbon Migration

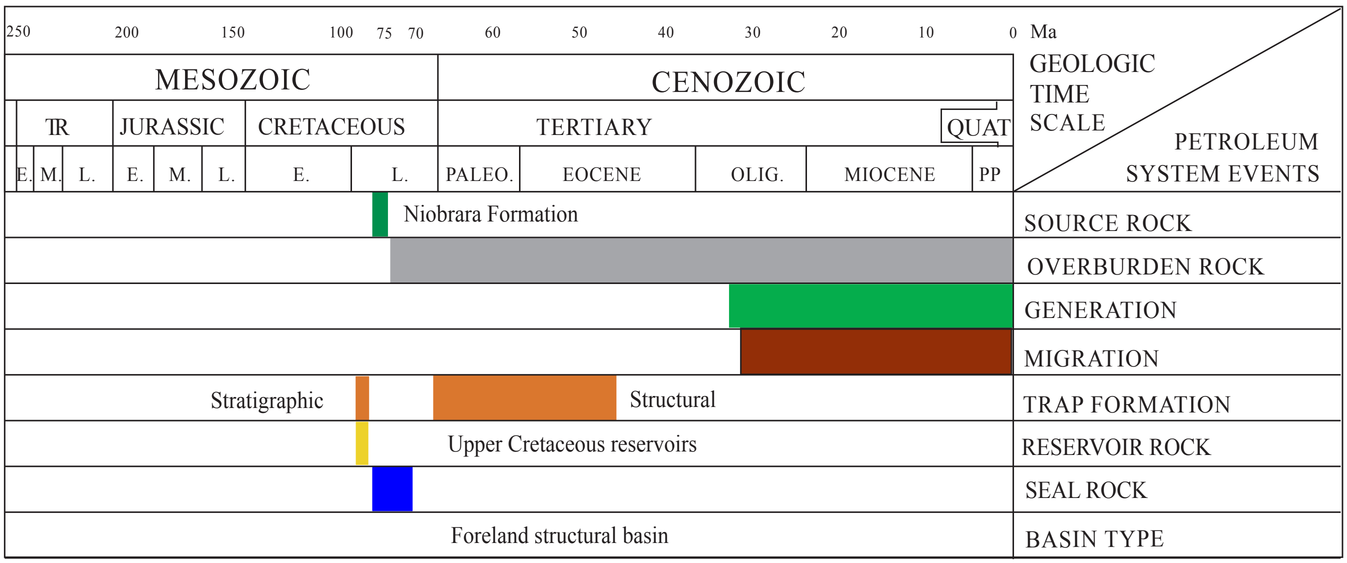
Unlike the Mowry TPS, Niobrara TPS production is almost exclusively confined to the Niobrara hydrocarbon generation area, indicating that most Niobrara migration has been vertical (fig. 27). The exception is that a few fields (Finn-Shurley, Todd, Coyote Creek South, and other small fields) on the east side of the basin produce almost exclusively from the Turner Sandy Member. The Turner in that area was sourced either by Niobrara oil migrating from the west or by Mowry oil migrating vertically through connected faults or fracture zones associated with the Belle Fourche arch.

The lack of production in the northern part of the Niobrara hydrocarbon generation area (fig. 27) could be explained similarly by the following reasons: (1) northward migration would be along strike, therefore, not subject to buoyancy flow; (2) the northeast-trending structures confined migration parallel to the structures, even though present-day groundwater flow is north in the north half of the basin and south in the south half of the basin; (3) lack of quality reservoirs; (4) the area is underpressured or has normal pressure, so there is a lack of pressure or hydraulic gradients to "push" hydrocarbons into potential reservoirs; or (5) various combinations of the above reasons.

Because all Upper Cretaceous reservoirs are encased in marine shale, even as much as several hundred feet, the most plausible explanation appears to be that vertical fault and fracture pathways in shale connect the Niobrara both to underlying and overlying reservoirs. Most rock fracture and fault lengths (or size) follow a power law distribution (meaning many short lengths and few long lengths) with the long lengths forming connected pathways. In addition, the longer lengths help connect shorter lengths to increase effective storage and pathways to a well bore (Dershowitz and others, 1999).

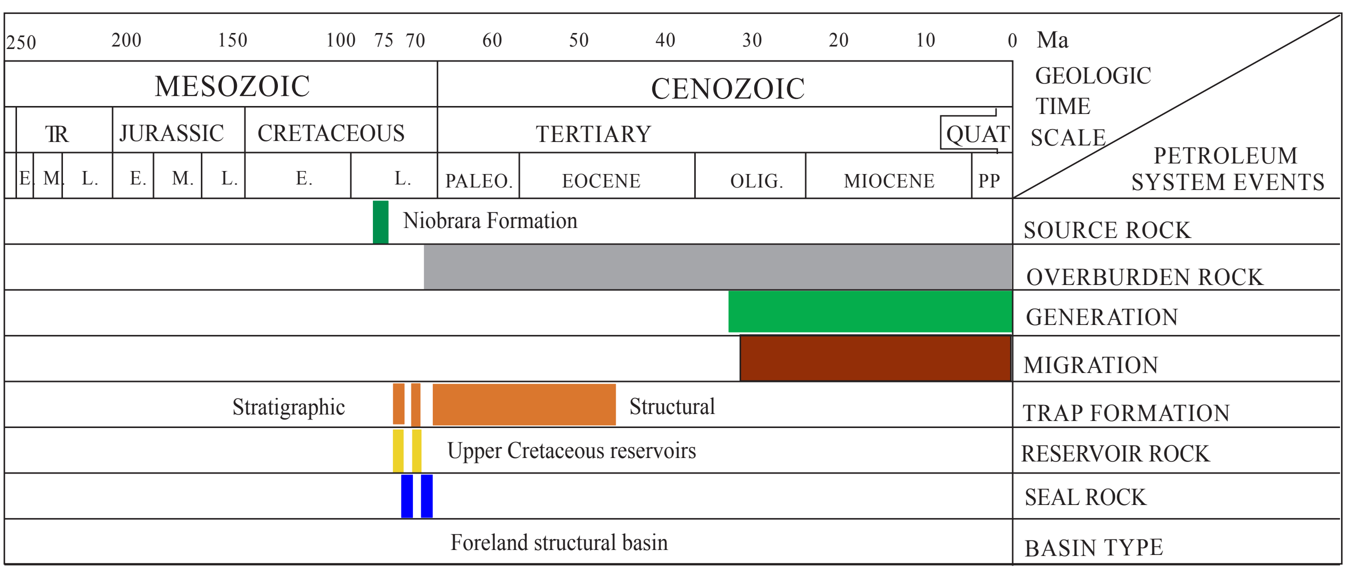
Plots of API gravity and gas/oil ratios (GOR) of Upper Cretaceous oils show a northwest-southeast trend; GOR values decrease sharply northwest and southeast from the Belle Fourche arch, and API values decrease only northwest of the arch (fig. 30). Additionally, oil from fields east of the Niobrara generation area (for example, Finn-Shurley field) have similar API values as does the south half of the Niobrara

Events Chart
Powder River Basin Province—Niobrara TPS
Frontier-Turner Sandstones AU



A

Events Chart
Powder River Basin Province—Niobrara TPS
Sussex-Shannon Sandstones AU



B

Figure 29. Events chart for assessment units (AU) in the Niobrara Total Petroleum System (TPS) in the Powder River Basin, Wyoming. (*A*) Frontier-Turner Sandstones Assessment Unit; (*B*) Sussex-Shannon Sandstones Assessment Unit; and (*C*) Mesaverde-Lewis Sandstones Assessment Unit. Geologic time scale is in millions of years. Quat., Quaternary; PP., Plio-Pleistocene; Olig., Oligocene; Paleo., Paleocene; E., Early; M., Middle; L., Late.; TR., Triassic.

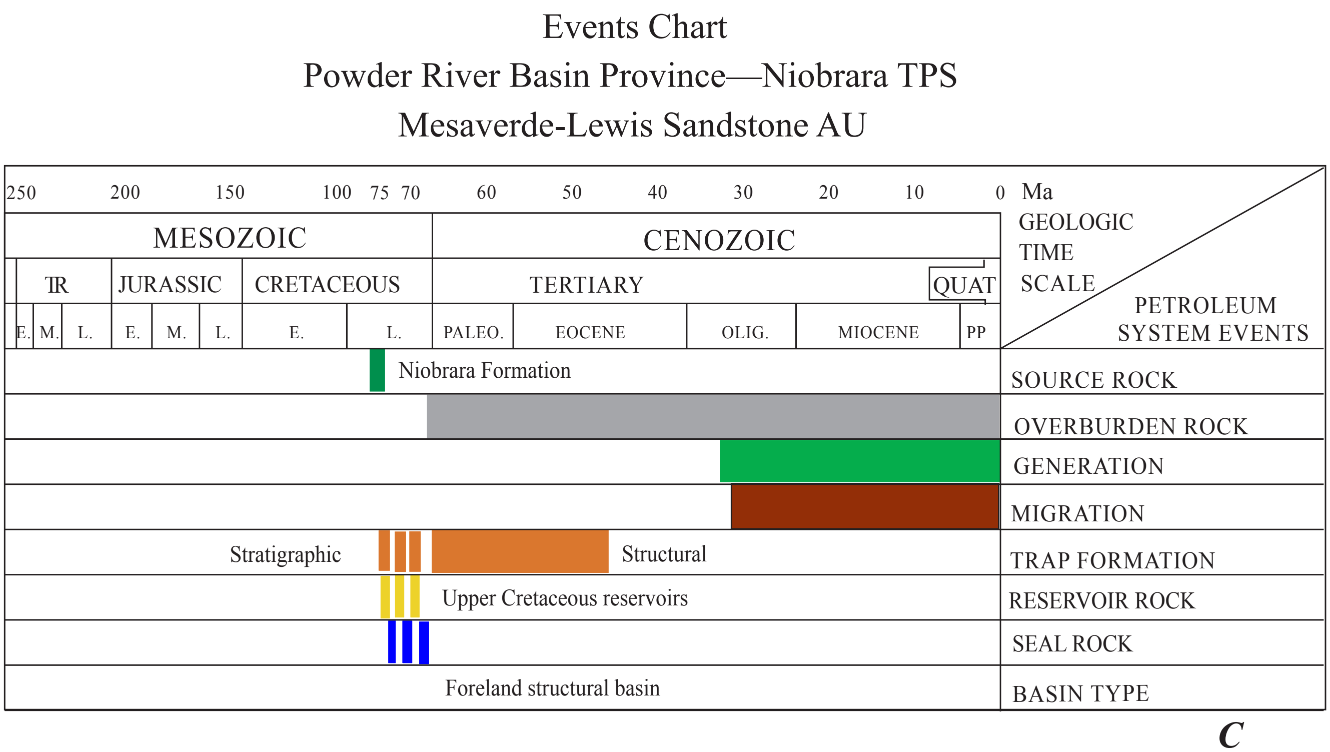


Figure 29. Events chart for assessment units (AU) in the Niobrara Total Petroleum System (TPS) in the Powder River Basin, Wyoming. (*A*) Frontier-Turner Sandstones Assessment Unit; (*B*) Sussex-Shannon Sandstones Assessment Unit; and (*C*) Mesaverde-Lewis Sandstones Assessment Unit. Geologic time scale is in millions of years. Quat., Quaternary; PP., Plio-Pleistocene; Olig., Oligocene; Paleo., Paleocene; E., Early; M., Middle; L., Late.; TR., Triassic.—Continued

generation area, but GOR values are similar to those northwest and southeast of the Belle Fourche arch in south-central Campbell County (figs. 4, 30). In the vicinity of the arch, API and GOR values are both high; northwest of the arch API and GOR values are both low, and southeast of the arch and east of the generation area, values are high for API but low for GOR. Because there is little hydraulic potential to migrate oil from the Niobrara generation area eastward toward the Finn-Shurley and nearby fields, there is the possibility that those fields were sourced through vertical migration. Interpretation of the API and GOR data is not conclusive but suggests that Upper Cretaceous fields are producing oil that is similar to Niobrara-generated oil. The data also show that pathways from the generation area to the eastern fields were relatively direct, not the tortuous routes commonly found in fractured shale (Neuzil, 1986).

Reservoir Rocks

Frontier Formation

The Upper Cretaceous Frontier Formation was deposited as an eastward-prograding clastic wedge into a foreland basin in response to the Sevier orogenic disturbance in Late Cretaceous Cenomanian to Turonian time. Proximal lithologies of the clastic wedge include coarse-grained nonmarine fluvial strata incised into marine strata, whereas distal lithologies include marine nearshore strata. The Frontier overlies the Mowry Shale and underlies the Cody Shale; the base and top of the Frontier are marked by the Clay Spur Bentonite Bed and an unnamed bentonite, respectively. Ammonite zones that bracket the Frontier include *Calycoceras gilberti* at the base and *Scaphites nigricollensis* at the top (Merewether and others, 1976, 1979).

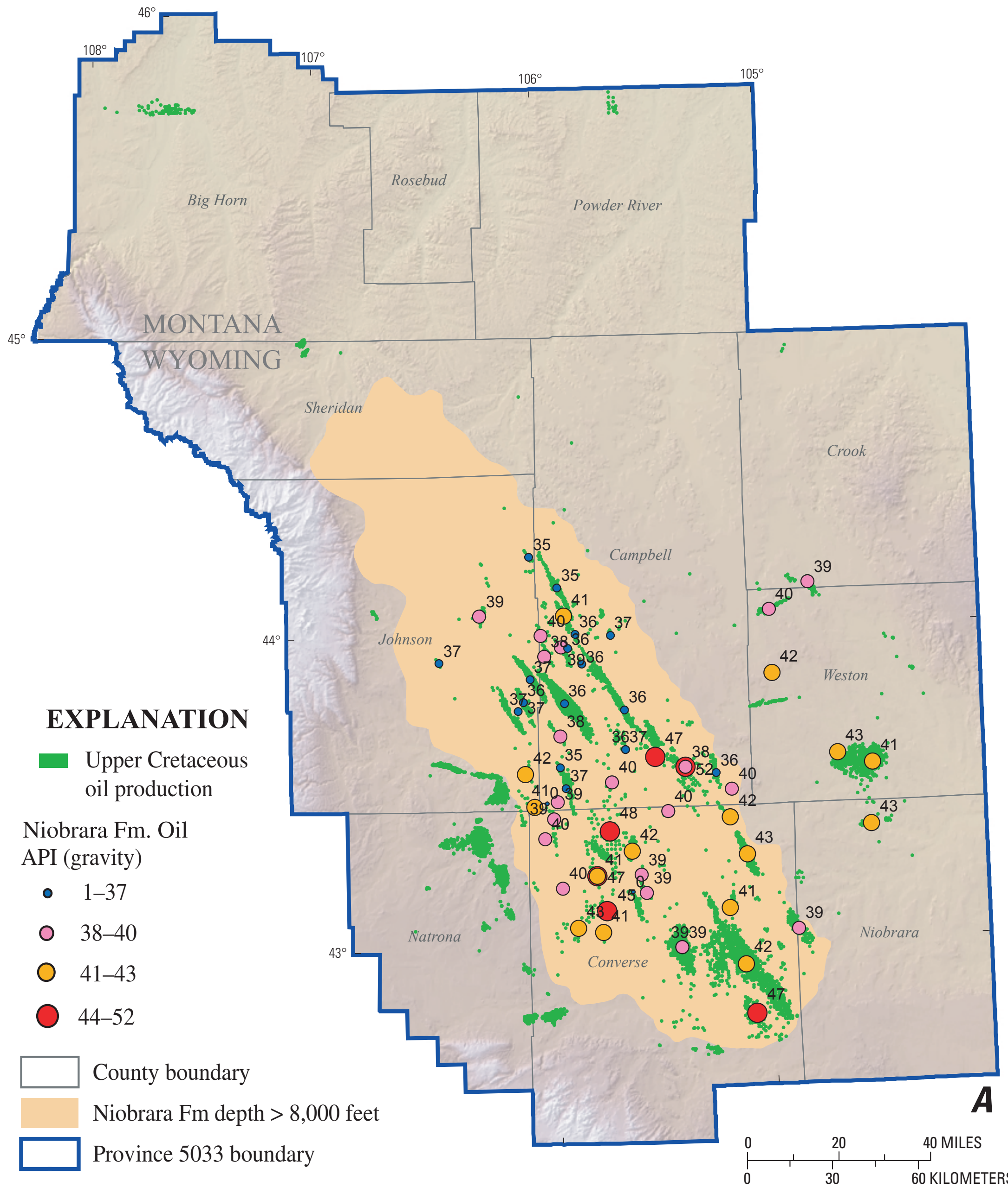


Figure 30. Map of Powder River Basin Province showing Upper Cretaceous production, area where depth to Niobrara Formation is greater than 8,000 feet. (*A*) average API gravity for Upper Cretaceous fields; (*B*) average gas/oil ratio (GOR) for Upper Cretaceous fields. API and GOR data from NRG Associates, Inc. (2006).

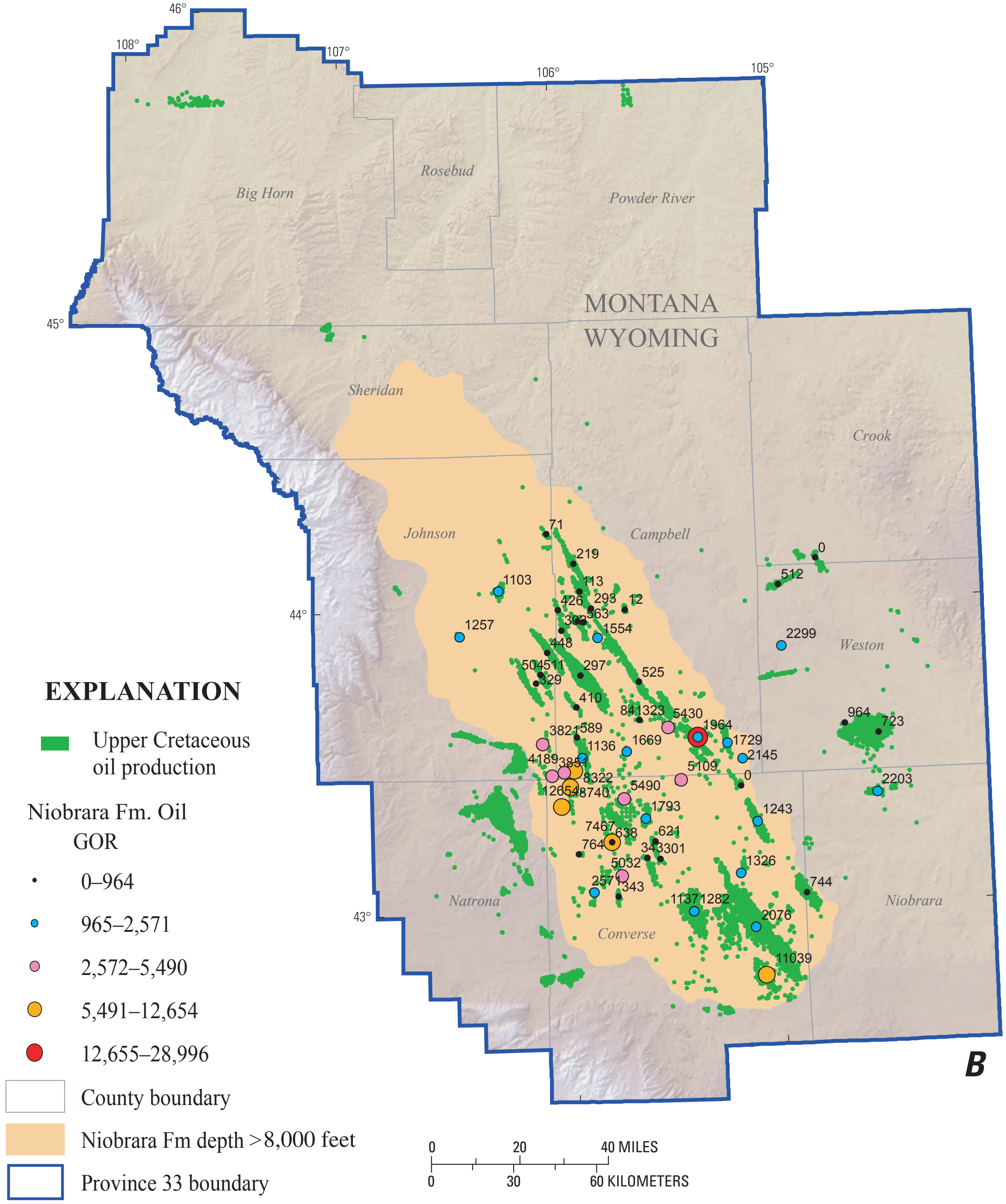


Figure 30. Map of Powder River Basin Province showing Upper Cretaceous production, area where depth to Niobrara Formation is greater than 8,000 feet. (*A*) average API gravity for Upper Cretaceous fields; (*B*) average gas/oil ratio (GOR) for Upper Cretaceous fields. API and GOR data from NRG Associates, Inc. (2006).—Continued

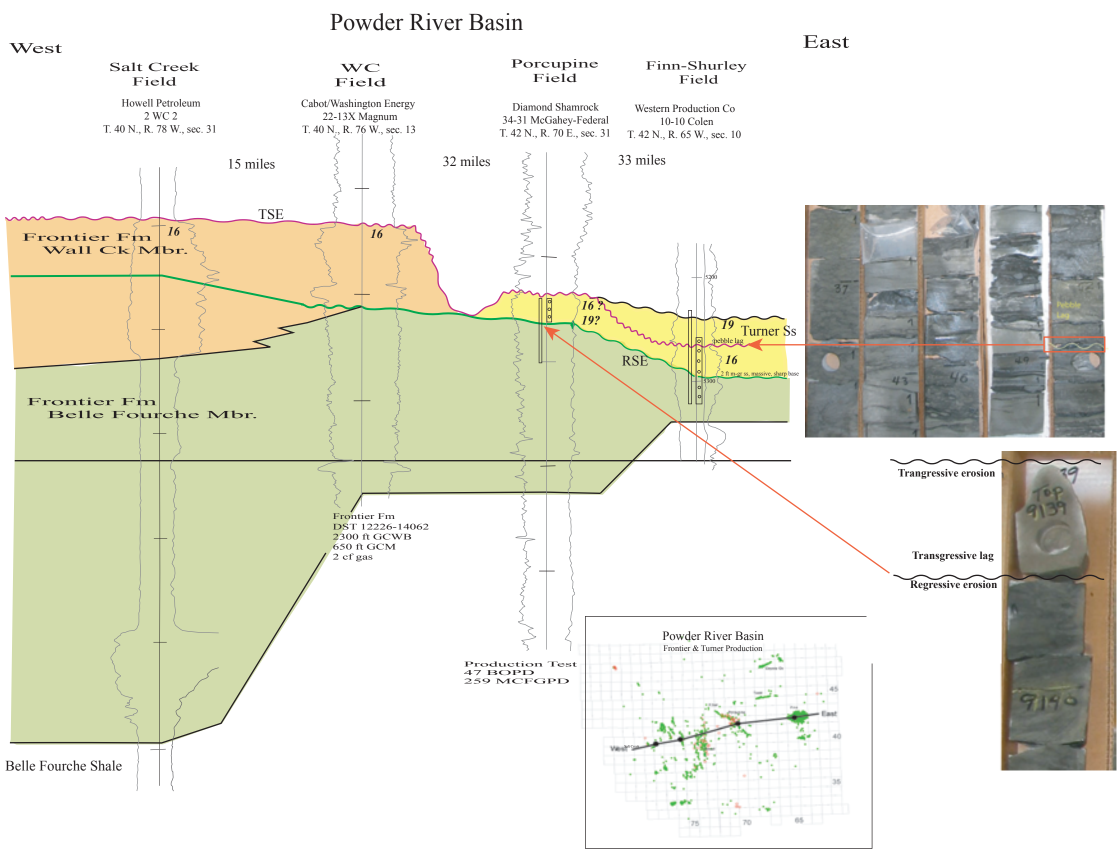


Figure 31. West-east cross section of the Frontier Formation and Turner Sandy Member interval, Powder River Basin. (Click on image to open full size, high resolution image for viewing and printing).

In the PRB there are three members of the Frontier Formation —the lower Belle Fourche Member, the middle Emigrant Gap Member (Merewether, 1996) called the unnamed member by Merewether and others, 1976), and the upper Wall Creek Sandstone Member. Fine-grained rocks compose about half of the total interval and include laminated to variably bioturbated shales and siltstones with several bentonite beds that are regionally persistent. Facies and geometry of sandstones indicate probable deposition as delta lobes (for example, Coleman and Wright, 1975; Bhattacharya and Walker, 1992; Johnson and Baldwin, 1996; Bhattacharya and Willis, 2001). The deltas were probably truncated at the top during transgression, as evidenced by a lack of subaerial exposure, presence of topset lags, and truncated inclined beds.

Belle Fourche Member

The Belle Fourche Member is generally confined to the southwestern part of the basin. It is divided into four internal successions, informally termed 1st through 4th Frontier (Merewether and others, 1979). Numerous environments of deposition have been recognized on the basis of having various percentages of fluvial, estuarine, nearshore, and deepwater strata (Barlow and Haun, 1966; Merewether and others, 1979; Tillman and Merewether, 1994; Bhattacharya and Willis, 2001). In the PRB all four successions have similar sedimentation characteristics, including (1) coarsening upward from marine shale to nearshore marine sandstone and (2) eroded tops capped with a coarse-grained lag over an erosional surface.

Individual sandstones consist of very fine to fine-grained siliciclastics with planar to low-angle cross stratification. Sandstone thicknesses range from 50 ft in the southwestern part of the basin to a zero edge toward the east and southeast. Unlike the Wall Creek Sandstone Member, there is not a basinward sandstone equivalent of the Belle Fourche Member. Sandstones within the interval have similar reservoir parameters including porosity that ranges from 5 to15 percent and permeability that ranges from 1 to less than 100 mD.

Emigrant Gap Member

The Emigrant Gap Member (unit five of Merewether and others, 1979; Ryer, 1993) is a single succession bounded by unconformities with extensive top truncation. The member has limited extent compared with other Frontier Formation members. The Emigrant Gap has been mapped as two elongated, but narrow packages of sandstone, siltstone, and mudstone, one trending east-west near Casper, Wyoming, and another northwest-southeast between Buffalo and Kaycee, Wyoming. The member can be as much as 90 ft thick, with maximum sandstone thicknesses of 30 ft. Subsurface hydraulic characteristics of this member are not known.

Wall Creek Sandstone Member

The Wall Creek Sandstone Member (units six, seven, and eight of Merewether and others, 1979) disconformably overlies the Emigrant Gap Member and the Belle Fourche Member where the Emigrant Gap Member is absent. The Wall Creek consists of several successions of coarsening-upward mudstone, siltstone, and sandstone in a prograding deltaic environment. Several sea-level falls might have caused top truncation of some beds and consequent progradation of delta lobes eastward into the basin interior. The sandstones are generally well sorted and fine to locally medium grained, with varying amounts of detrital clay. Porosity values of sandstones range from near zero to 20 percent, with hydrocarbon-producing sandstones having porosities between 10 to 20 percent. Permeability of sandstones from some facies can be as much as 100 mD but averages much less than 100 mD.

The Wall Creek Sandstone Member thicknesses are as much as 400 ft in western Converse County and eastern Natrona County, Wyoming. Thickness trends appear to align east-west, although erosional surfaces within the Wall Creek Sandstone Member may preclude making meaningful interpretations of original depositional trends. In addition, the dominant paleocurrent directions are southeast, indicating a general progradation in that direction (Merewether and others, 1979).

Turner Sandy Member

The Turner Sandy Member of the Carlile Shale (fig. 27) is generally linked to the Frontier Formation as a stratigraphic or chronographic equivalent, although there is little direct confirming evidence. Weimer and Flexer (1985) described the Turner as being a brackish to marine deposit in northeast-trending valleys with the lower part deposited in tidal flat and estuary environments. Rice and Keighin (1989) inferred that the lower part was deposited as an elongated sand body in a shelf depression, whereas Merewether and others (1979) suggested that the Turner was deposited from Wall Creek sands carried by tidal currents to an open shelf, although postdeposition transgression removed or reworked various parts.

Based on this detailed mapping of the Frontier Formation on the southwest side of the basin, Bhattacharya and Willis (2001) inferred that sea-level falls induced a progradation of Frontier delta sands basinward to the east and southeast, which then became detached from the main body and were deposited onto a previous offshore shelf during a regressive lowstand; this is similar to a process described by Plint (1988). Subsequent transgressions created surfaces that eroded sediment from bathymetric highs while reworking but preserving sand in low areas. Some or most of the original connection between the Turner and the Frontier was eroded over bathymetric highs, the Turner being preserved in bathymetric lows (fig. 31). Cores of the Turner from a well in the Finn-Shurley field showed the presence of two erosion surfaces, one at the base of the Wall Creek Sandstone Member marked by medium-grained, sharp-based sandstone and another halfway up from the base of the Wall Creek, marked by a thin pebble lag (fig. 31). Turner cores from the Porcupine Field (west of Finn-Shurley field) showed the presence of an erosional surface at the base of the Wall Creek, marked by medium-grained, sharp-based sandstone over a thin pebble lag.

In places, the Turner Sandy Member is more than 70 ft thick in the Finn-Shurley field but thins to less than 20 ft to the west and east. Core plugs in sandstone at Finn-Shurley field had measured permeability exceeding 2 darcies from medium-grained, clean, well-sorted sand. Core plugs from Porcupine field have measured permeability of more than 10 mD from slightly argillaceous, fine-grained sandstone but less than 10 mD from argillaceous, fine-grained, and slightly bioturbated sandstone.

Cody Shale

Shannon Sandstone Member

The Shannon Sandstone Member of the Upper Cretaceous Cody Shale was deposited as clean to argillaceous sand during early Campanian time in southeastern Montana, northeastern Wyoming, and northwestern South Dakota. Shannon Sandstones form conspicuous northwest-southeast-trending linear sand ridges; individual units are as much as 50 ft thick, thousands of feet in width, and tens of miles in length. Both the Shannon and the overlying Sussex Sandstone Member represent distal ends of a transgressive-regressive wedge of a deltaic system to the north and northwest along the west margin of the Cretaceous seaway. One interpretation is that they were deposited as shelf sands or offshore bars, encased in marine shales, because of their classic upward coarsening grain size from a muddy shelf base, to fine- to medium-grained, well-sorted, clean and porous, cross- to planar-bedded sandstone at the top. Other interpretations include their being reworked delta systems, or they are incised nearshore and valley complexes, both of which require progradation events from a sea-level lowstand that created a variety of disconformities at the top and base (Bergman and Walker, 1995). An alternative interpretation for the origin of the Shannon might be similar to that of the Turner—that is, the depositional processes involved a transgressive ravinement surface upon which sand was preserved in bathymetric lows but eroded sediment over highs, the pattern of which may have been structurally controlled in part.

Shannon Sandstone Member porosity ranges from near zero in argillaceous and bioturbated silt and sandy layers to over 20 percent in clean, well-sorted, medium-grained sandstone. Permeability ranges from less than 1 mD to more than 100 mD, with a mean of 20 mD.

Sussex Sandstone Member

The Sussex Sandstone Member of the Cody Shale was deposited during early Campanian time and was separated from the underlying Shannon Sandstone Member by tens of feet of marine shale. The member is informally subdivided into three units (Anderman, 1976): a lower B sandstone, a middle marine shale, and an upper A sandstone. Similar to the Shannon, the Sussex was originally interpreted to be deposited as a middle shelf bar in moderate to deep water, with the sand being transported across the shelf bottom from nearshore sand accumulations. Sandstone body geometry similar to the Shannon, is dominated by northwest-southeast-trending linear sandstone units, tens of miles long, 2–3 miles wide, and tens of feet thick. Sussex production tends to cluster about two areas, one along the House Creek–Porcupine field trend and the other farther west along the Spearhead Ranch–Scott field trend (fig. 32). Production tends to cluster along a single trend represented by the Hartzog Draw, Pine Tree, and Jepson fields (fig. 33), with most production being west and north of Sussex Sandstone Member production.

The top of the reservoir B sandstone is approximately 20 to 60 ft below the Ardmore Bentonite Bed of the Steele Shale, based on correlation of well logs and core studies. Higley and others (1997) interpreted the B sandstone to have originated as a series of probable midshelf sand-ridge deposits in the Cretaceous epicontinental seaway (fig. 34). At House Creek field, for example, there are such units composing B sandstone. Higley and others (1997) inferred that a transgression during deposition created the westward (landward) backstepping stacked sand ridges, followed by a regression marked by a disconformity at the top of the sandstone identified by thin chert-pebble sandstone (Higley, 1992).

Interridge lithologies consist mainly of burrowed and intact mudstone laminae, interbedded mudstone, and burrowed, fine-grained sandstone. These lithologies are effective permeability barriers, resulting in small reservoir compartments; this may be a cause for low production volumes.

Thicknesses of the Sussex B sandstone vary from a few feet to more than 50 ft depending on the number of stacked ridges and the amount of erosion that occurred both internally and at the top of the sequence. The Sussex A sandstone has a similar depositional history but is thinner and more discontinuous except at the Triangle U field where it is thicker and more continuous than the underlying Sussex B sandstone. At the Triangle U field, the A sandstone has permeability ranging from 2.5 to 77 mD, with an average porosity of 13.5 percent, whereas the B sand has both lower permeability (0.01 to 5.4 mD) and a porosity average less than 10 percent (Smith and Larsen, 1997).

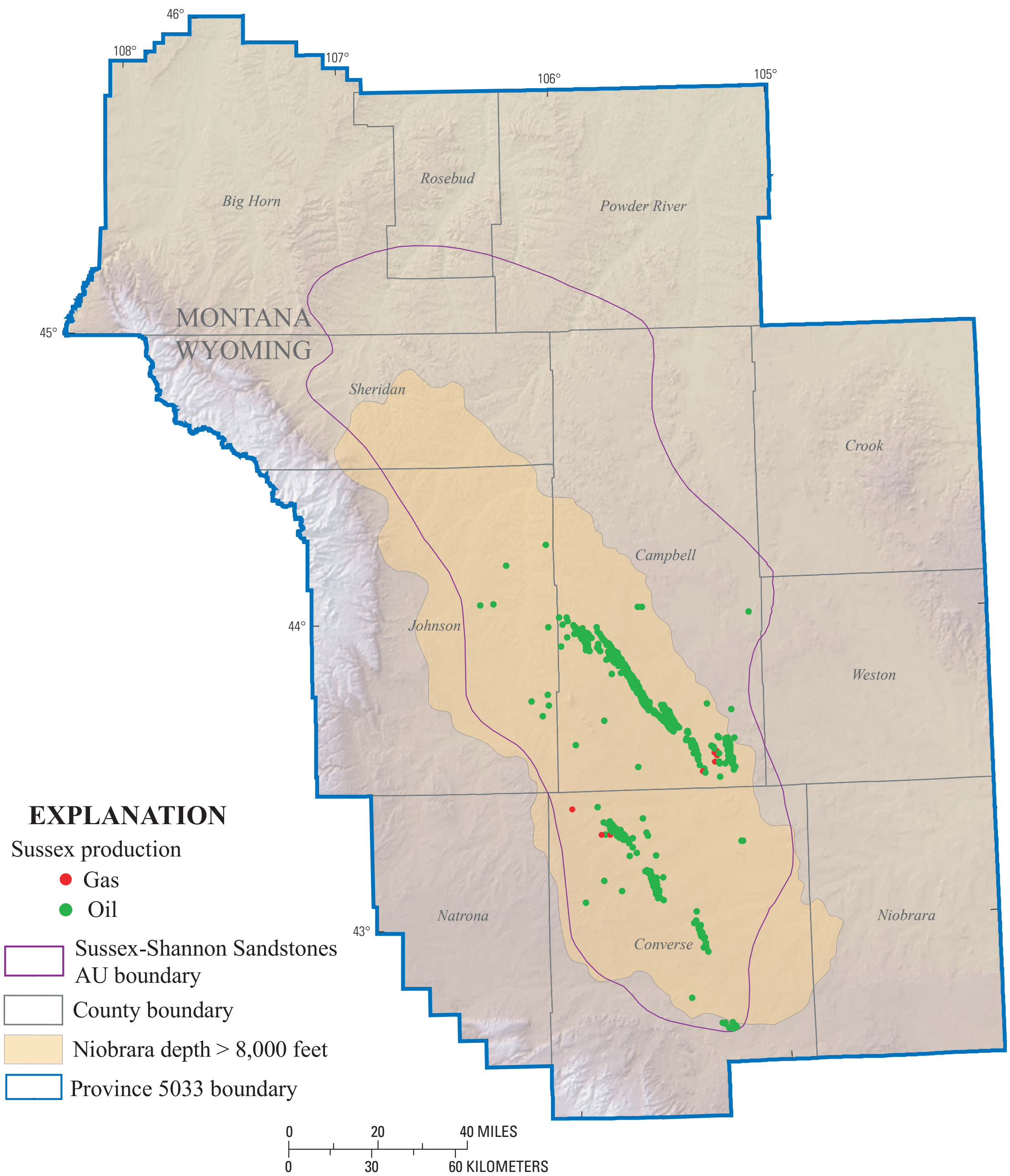


Figure 32. Map of Powder River Basin Province showing Sussex Sandstone Member oil and gas production, Sussex-Shannon Sandstones Assessment Unit (AU) boundary, and area where depth to Niobrara Formation is more than 8,000 feet.

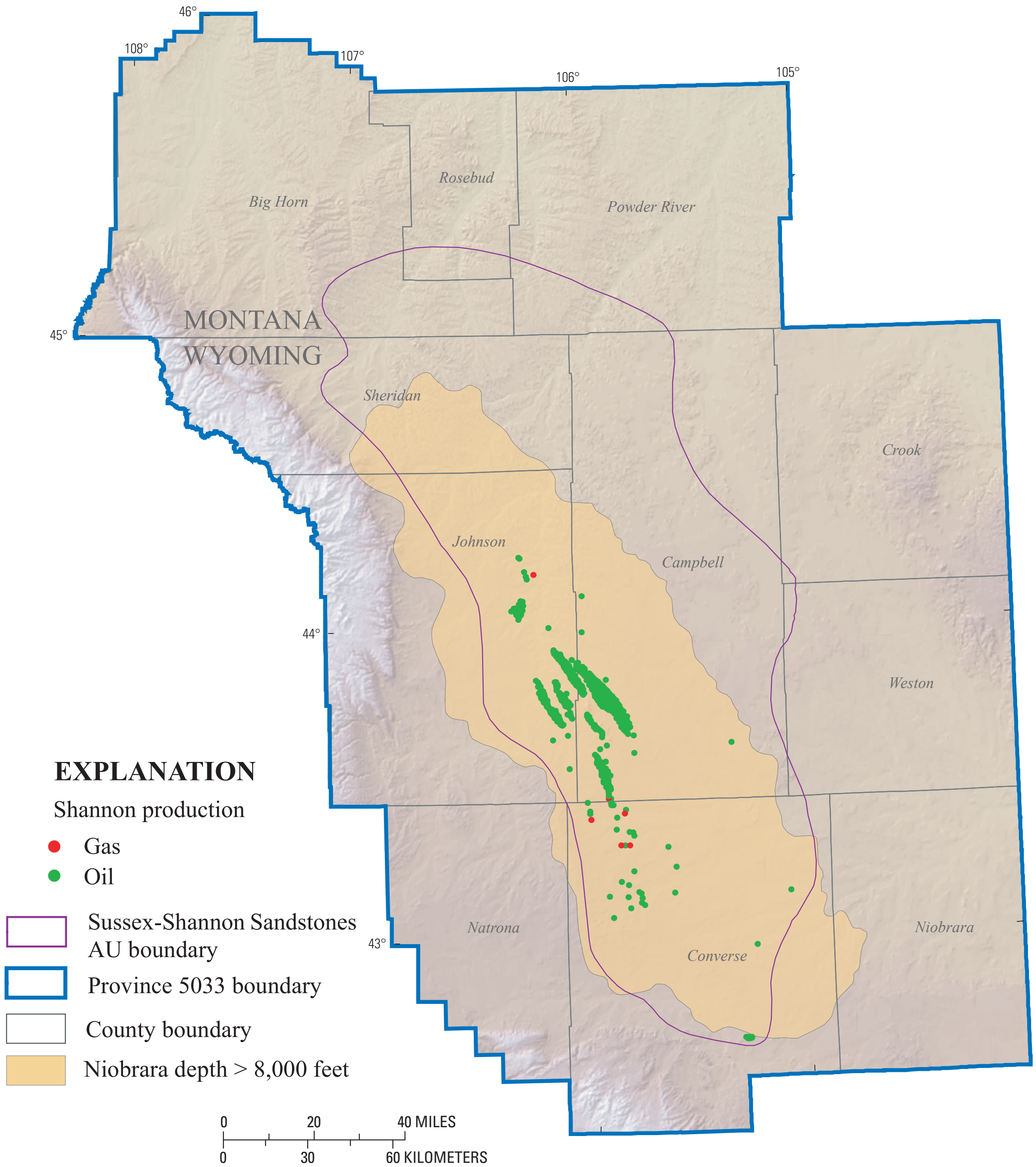


Figure 33. Map of Powder River Basin Province showing Shannon Sandstone Member oil and gas production, Sussex-Shannon Sandstones Assessment Unit (AU) boundary, and area where depth to Niobrara Formation is more than 8,000 feet.

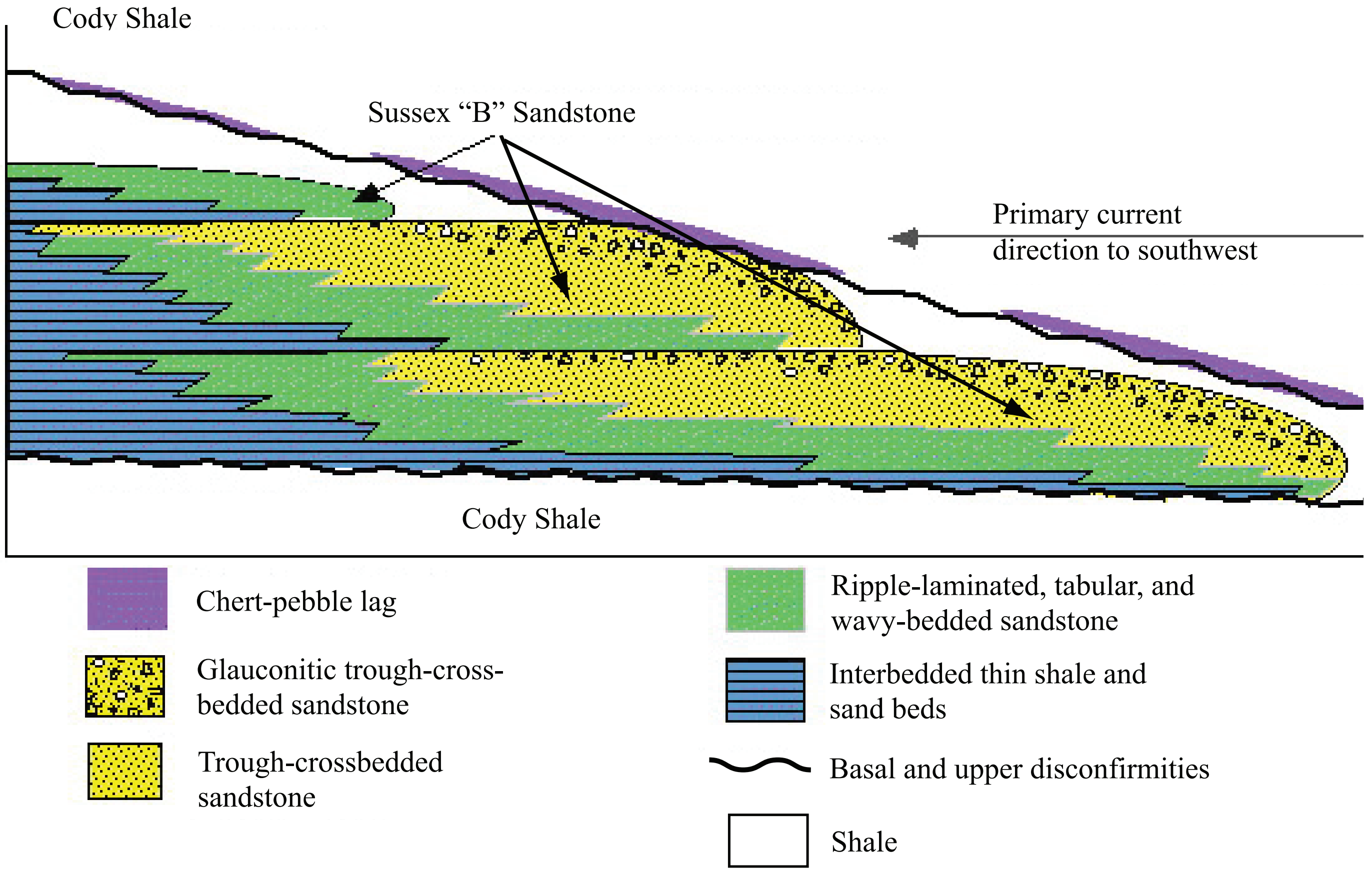


Figure 34. Generalized cross section showing generalized facies distribution of the Sussex "B" sandstone, Powder River Basin. Modified from Higley and others (1997).

Mesaverde Formation

Parkman Sandstone Member

The Parkman Sandstone Member of the Upper Cretaceous Mesaverde Formation (fig. 27) is the oldest sandstone member in a widespread cycle of Late Cretaceous regression and transgression following the long period of predominantly marine deposition represented by the thick Steele Shale (or Cody Shale to the west of the PRB). The member consists of a progradational delta complex that overlies the extensive marine shelf deposits of the Steele Shale. Lithologies include (1) prodelta shale and siltstone interbedded locally with very fine grained, well-sorted sandstone; (2) nearshore deposits of coarsening-upward successions of medium-grained sandstone with interbedded siltstone; and (3) terrigenous deposits of carbonaceous to lignitic silt and mudstone. Depth to Parkman reservoirs range from 5,000 ft to more than 9,500 ft near the Basin axis (Dolton and Fox, 1995).

Van Wagoner and others (1990) divided the Parkman Sandstone Member into one progradational parasequence and the overlying Teapot Sandstone Member into two sequences. The lower Parkman appears to step basinward to the east, producing in the subsurface a well-log pattern characteristic of a progradational succession. Based on faunal zones, the member's basinward time equivalent is the Red Bird Silty Member of the Pierre Shale. The top of the Parkman interval is bounded by a flooding surface caused by an abrupt increase in water depth recognized in well-log correlations as a planar surface (Van Wagoner and others (1990). Within each succession are minor flooding surfaces that create laterally variable units of interbedded mudstones and siltstones.

Teapot Sandstone Member

The Teapot Sandstone Member was named after Teapot Rock, a prominent cliff-forming feature north of Casper, Wyoming. The nearby type section (Curry, 1976a) includes both marine and nonmarine sandstones, coals, and other associated lithologies. Curry (1976a) described the Teapot, from base to top, as 255–275 ft of lower prodelta shale, 55–70 ft of delta front strata, and 40–50 ft of nonmarine delta plain strata.

The prodelta section is dark-colored shale, with a regional unconformity at the base (Gill and Cobban, 1973; Krystinik and DeJarnett, 1995). The delta front strata consist of coarsening upward, lightly burrowed, thin sandstone laminations with low to medium cross stratification in places; fine-grained intervals are interpreted as lower shoreface. Geophysical logs indicate that if the contact with the underlying prodelta shale is sharp, as in WC and Mikes Draw fields, the unit is generally a thick sandstone (average thickness 30 ft) with good log-calculated porosity. If the contact is gradational, only the top few feet of the delta-front strata are sand rich, with variable log-calculated porosity. This interval is overlain by horizontal laminated and oxidized medium-grained sandstone interpreted as nearshore to beach with exposed root zones at the top. The delta-front facies contributes most of the oil production.

The delta plain deposits consist of a variety of lithologies including distributary and overbank sandstone and siltstone, carbonaceous material including plant impressions, and thin discontinuous lignitic zones.

The Teapot Sandstone Member is composed of two progradational intervals (Van Wagoner and others, 1990). The upper boundary of the lower interval is terminated by a major erosional event and a slight basinward shift in facies. The overlying set is composed of two intervals separated by a marine-flooding surface—shallow-marine sandstones below the boundary and deeper water mudstones above. The member's basinward time equivalent is an unnamed shale of the Pierre Shale.

Lewis Shale

Teckla Sandstone Member

The Teckla Sandstone Member of the Lewis Shale is an Upper Cretaceous (uppermost Campanian, *Baculites eliasi zone*) marine sandstone and shale unit that is a secondary exploration target in the middle and southern parts of the PRB (fig. 35). The Teckla is part of a regressive-transgressive interval within the thick marine Lewis Shale, which is a time equivalent of the Bearpaw Shale of Montana and the upper part of the Pierre Shale of southern Wyoming and eastern Colorado. The Lewis Shale thickens from less than 300 ft in the northern part of the Basin to more than 1,500 ft in the southern part (Fox and Higley, 1996b).

The reference section for the Teckla Sandstone Member is the Gulf Oil Corporation, no. 1 Government-Teckla well, in southeastern Campbell County, Wyoming (T. 41 N., R. 70 W., sec. 10). At the reference section, the Teckla is divided into three members: a lower 44-ft sandstone (informally called the Teckla B sand), a middle 38-ft bentonitic shale (informally called the Kara shale bed), and an upper 112-ft sandstone (informally called the Teckla A sand) (Runge and others, 1973). According to Runge and others (1973), the contacts at the base and top of the Teckla are conformable, with no apparent discontinuity.

The Teckla Sandstone Member is part of a northeast-prograding delta system with a north-northwest-trending strand line. At various times, the delta system migrated from northwest to southeast along the strand line. The northwestern part of the system was not extensive and had little sediment capacity with low accommodation space. The southeastern delta, in contrast, had more sediment capacity and more accommodation space. As a result, the Teckla in the southern part of the PRB has good reservoir-quality sandstones. At its reference section, the Teckla consists of a regressive delta front sandstone (Teckla B) overlain by the Kara shale bed, representing a short transgressive event; this was followed by another regressive event that deposited the Teckla A delta front sandstone. West of the reference section, delta plain units were deposited and overlie parts of the Lewis Shale where the Teckla is absent. From geophysical log interpretations, the delta plain deposits appear to consist of thin channel and overbank sandstone and interchannel mudstone and siltstone. The deposits trend north-northwest and are thickest in the southwestern part of the basin, with thicknesses as much as 600 ft but thinning to the east and north. The sandstones east of the reference section average 15-percent porosity and about 30-mD permeability, although the best permeability is usually less than 100 mD. Teckla delta-front sandstones gradually interfinger with the prodelta facies consisting of thin siltstone and shale. The prodelta facies has a similar trend as the delta-front interval.

Traps and Seals

Traps in the Niobrara TPS can be characterized mostly as stratigraphic with structural enhancement in places, but only rarely with four-way structural closure. Most commonly, oil is trapped because reservoir-quality sandstones are adjacent to low-porosity and low-permeability siltstones, shales, or mudstones that were deposited during repeated transgressions, thereby creating permeability barriers to oil migration. Diagenetic alteration that reduced porosity is rare as a trapping mechanism. Stratigraphic traps due to incised valley systems are also rare although bathymetric low areas in foreland basins may trap and help preserve sand deposits during ravinement processes. Low areas in a subtidal setting may be structurally controlled similar to incised valley systems in a supratidal setting.

Structural traps are a result of Laramide deformation that created numerous structural styles and types at various scales. Most structures in the basin were created prior to oil migration. Moore (1985) interpreted an east-west seismic line on the west side of the basin that showed potential fault traps involving the Frontier Formation as well as older rocks.

Poison Draw field is the largest field that produces oil from the Teckla Sandstone Member; there, the reservoir is a complex unit of deltaic strandline sandstones in which oil is

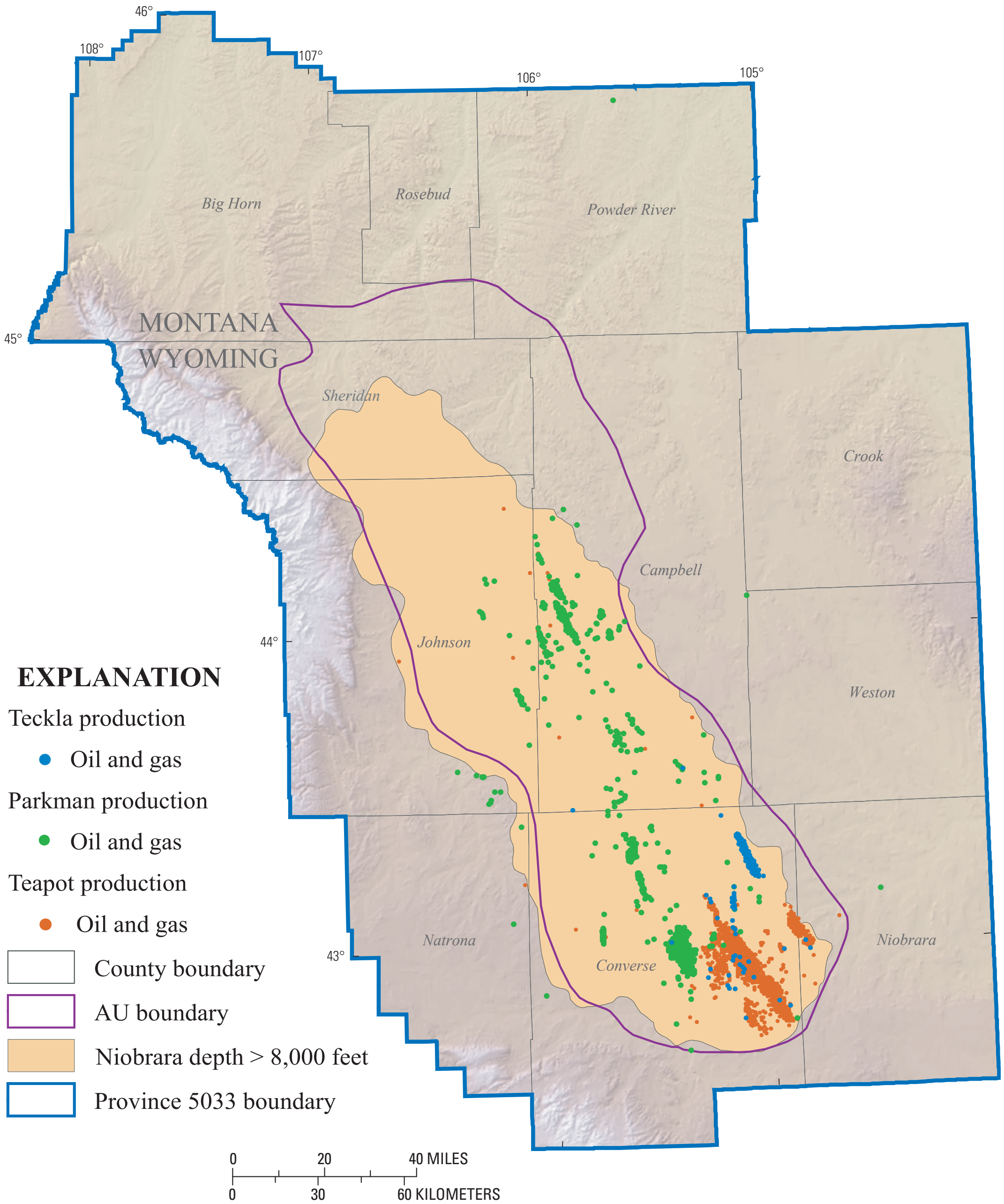


Figure 35. Map of Powder River Basin Province showing oil and gas production of Parkman Sandstone and Teapot Sandstone Members of Mesaverde Formation and Teckla Sandstone Member of Lewis Shale of the Mesaverde-Lewis Conventional Oil and Gas Assessment Unit (AU), and the area where depth to Niobrara Formation is more than 8,000 feet.

trapped by an updip loss of porosity because of an increase in siltstone and shale. The complexity is attested to by the presence of multiple oil/water contacts. One of the largest Teapot Sandstone Member producing fields, Well Draw, is a large, northwest-trending stratigraphic trap formed by an updip facies change from porous shallow-water marine sandstone into tight, offshore siltstone and shale. The Parkman Sandstone Member characteristically produces oil from accumulations trapped within northwest-trending marine bar sandstones (fig. 35), as at Dead Horse Creek–Barber Creek field.

Niobrara Total Petroleum System as a Continuous Reservoir

The Niobrara Formation is in part a self-contained petroleum system in that it is a hydrocarbon source rock as well as also containing reservoir rocks, a relation that is typical of a continuous petroleum system. In the PRB, Niobrara thicknesses range from 50 ft near the Black Hills to about 450 ft thick in the deepest parts of the basin, to a maximum of 600 ft along the west flank of the basin; basinwide average is about 400 ft (Fox and Higley, 1996b, map J).

Niobrara production is delivered through a network of fractures and faults, although the true nature of the networks is as yet not well known in detail, such as fracture intensity or connectivity, which control rates and distribution of fluids. Connectivity is best defined by fracture and fault orientation, length (or size in three dimensions), and intensity. Numerous studies (for example, Slack, 1981; Anna, 1986a, 1986b; Marrs and others, 1984; Martinsen and Marrs, 1985; Maughan and Perry, 1986; Mitchell and Rogers, 1993) have shown that the pervasive regional structural orientations in the PRB are northwest-southeast and northeast-southwest. Different orientations may exist, especially when associated with local stress systems, but they are minor contributors to the regional fracture and fault connectivity patterns. Fracture and fault lengths are difficult to measure, although partial length distributions can be expanded through statistical methods and used to eliminate censoring and bias from mapping. Conventional wisdom associates high fracture density with an increase in reservoir permeability, which may be true locally, but only if fracture length improves the connectivity of a given area (commonly called percolation theory).

Most locally generated fractures are connected by a regional system that enhances reservoir permeability (except possibly in coals). Geologic sweet spots in the Niobrara, therefore, should be determined first by mapping regional structural trends and secondly, by mapping local structural features such as fractures related to folding. For example, outcrop maps and horizontal well formation microimager (FMI) well log images of Austin Chalk in south Texas reveal that fracture spacing ranges from several fractures to only a single fracture per foot for distances of hundreds of feet; the several fractures per foot could be considered a sweet spot (Fett, 1991). Sweet spots are not necessarily fault related but commonly are part of one structural event (Fett, 1991). Rates and cumulative production in the Austin Chalk point to large rock volumes being drained, indicating that 3-dimensional flow is probably taking place in large fractures connected to small but numerous fractures.

There appears to be no correlation, however, when comparing sweet spot zones (mapped as lineaments) and current Niobrara Formation production in the PRB (fig. 36). This discrepancy may be due to several factors: (1) Niobrara production rates are not dependent on fractures and faults; (2) “sweet spot” areas are incorrectly mapped; (3) there is not sufficient control to make a valid comparison; (4) there is a bias in targeting other reservoirs as the primary objective rather than the Niobrara; therefore, its potential has not been established; (5) the Niobrara is used as a bailout zone, independent of fracture potential; and (6) increased shale content in the western part of the basin may increase fracture length but decrease spacing compared with the chalky and brittle intervals of the Niobrara. Therefore, “sweet spots” may have different characteristics in shale intervals than in chalk intervals.

Production data (IHS Energy Group, 2006) indicate that the Niobrara Formation from 34 wells has cumulative production of almost 600,000 barrels of oil (BO), 1.9 billion cubic feet of gas (BCFG) over a 30-year reporting period. However, few individual Niobrara wells have estimated ultimate recoveries (EUR) of over 100 MBO, with most accumulations of less than 50 MBO. Individual well-production plots indicate that most Niobrara wells produce little if any water from either oil or gas wells. Most operators target mid- to upper Niobrara strata. Lower zones are also a target but are not as laterally persistent as other zones, a condition that may form potential stratigraphic traps (Mitchell and Rogers, 1993).

Water saturations (Sw) in chalk reservoirs that produce commercial quantities of oil are commonly less than 50 percent (for example, the mean Sw for deep Denver Basin Niobrara is 0.39 ± 0.1). Intervals with water saturations above 50 percent are generally marginal or noneconomic. However, chalky intervals with high pore surface area may produce economic quantities of oil at saturations greater than 50 percent.

Paleozoic-Mesozoic Composite Total Petroleum System

The Paleozoic-Mesozoic Composite TPS, which includes approximately 8,500 mi^2, is characterized by oil and gas accumulations in Laramide structures along the south and west margins of the PRB. This also constitutes the Basin Margin AU (fig. 37; Dolton and Fox, 1995),which can be described as the upthrown side of several coalesced major basement-involved faults (fig. 38), similar to those described by Stone (2002), although some faults are not exposed at the surface. In those cases, the inner boundary of the TPS and AU is marked by the fold axes of monoclines resulting from basement offset, such as the monoclines at Sussex field and the east side of the

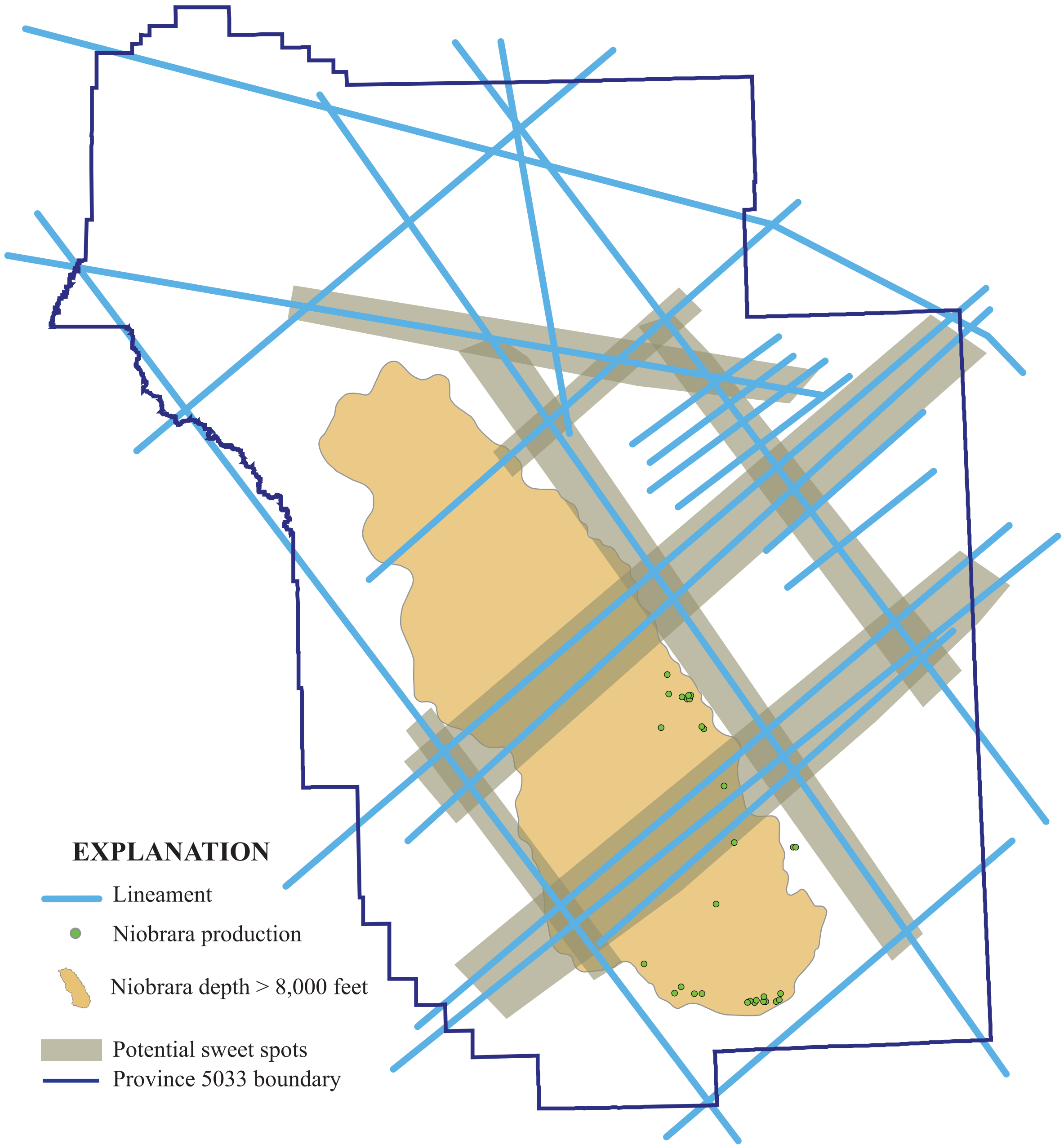


Figure 36. Map of the Powder River Basin Province showing Niobrara Formation potential sweet spots derived from published lineament and lineament zones, and current production from the Niobrara Formation.

Figure 37. Map of the Powder River Basin Province showing oil and gas production and boundary of the Basin Margin Assessment Unit (AU).

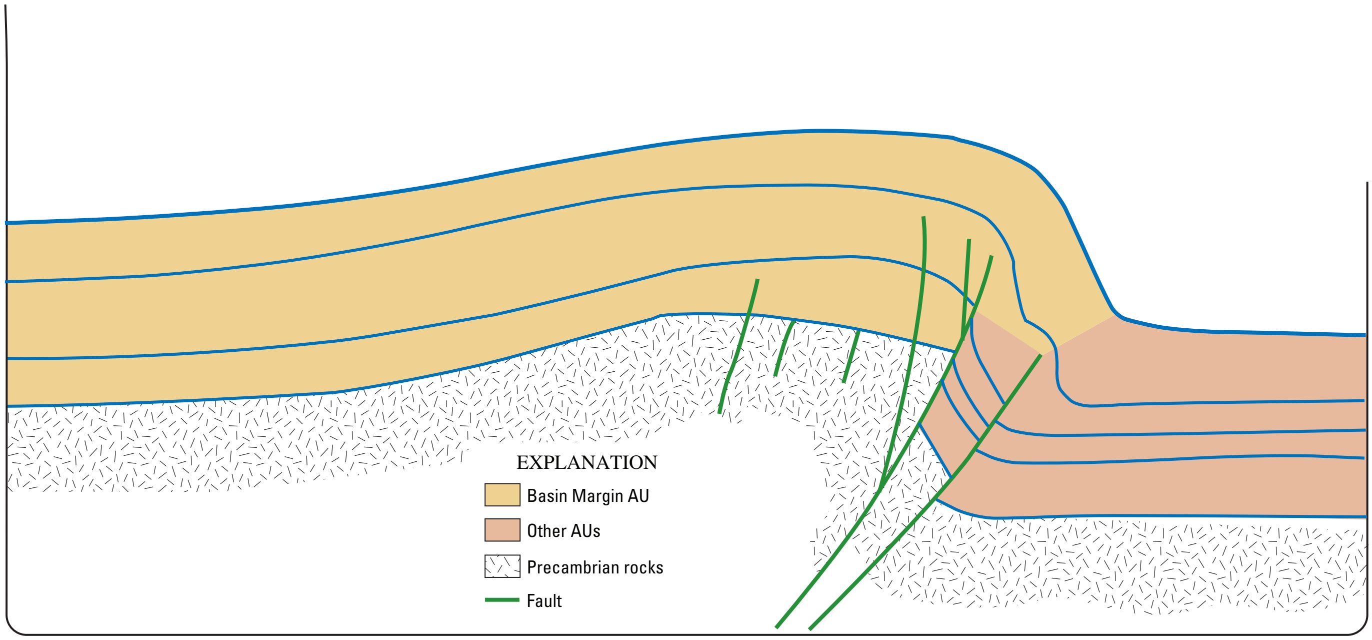


Figure 38. Generalized cross section of basin margin thrusting showing structural positions of Basin Margin Assessment Unit (AU) and adjacent assessment units. Diagram modified from Stone (2002).

Casper arch. The outer boundary of the TPS and AU is defined by mountain ranges or where the Phanerozoic section is thin or absent, although the northwest boundary is somewhat arbitrary and is not clearly defined.

Some of the major boundary structures include the Casper thrust, Laramie Range fault, Hartville fault, Bighorn Mountain front fault, and a basement-involved thrust on the east side of the Casper arch. Smaller or antithetic structures are commonly force folds that are associated with faults at depth, some with four-way closure, three-way closure, or simple compression or buckle folds and associated tension faults. The combination of structural and stratigraphic traps are generally confined to Cretaceous reservoirs such as Sussex and Glenrock South fields, but reservoirs in large structural traps such as Salt Creek and Teapot Dome fields may be compartmentalized, with the oil and gas confined to specific parts of the structure due to spatial changes of porosity and permeability. Reservoirs range from Mississippian carbonates to Upper Cretaceous siliciclastics and fractured shale.

Oil was first discovered in this TPS in the late 1880s at the Salt Creek field, although commercial production was not established until the 1920s. In its early history, the Salt Creek field was one of the major oil producers in the United States. Other discoveries soon followed, including Big Muddy, Cole Creek, North Fork, and Lance Creek, with the discovery wells being drilled on mappable surface structures.

Petroleum Source Rocks

Source rocks in the TPS include the same source rocks as were described for other TPSs in the PRB described in this report: (1) for Paleozoic reservoirs, organic-rich rocks of the Permian Phosphoria Formation from west of the province, and black shales of the Pennsylvanian Leo Sandstone within the province; and (2) for Lower and Upper Cretaceous reservoirs, the Mowry Shale and Niobrara Formation, respectively. Cretaceous and Paleozoic reservoirs have distinct oil types related to their different sources—gravities of oils in Cretaceous rocks are typically 30°–44° API, with less than 1 percent sulfur, whereas the Paleozoic oils are typically 20°–35° API, with 1 to 4 percent sulfur (fig. 39) (NRG Associates, 2006).

Clayton and others (1997) reported that the Pennsylvanian Leo Sandstone oil is easily distinguished from Minnelusa and Cretaceous oil on the basis of chemical and isotopic compositions. In addition, analyses of Leo gases indicate that the gas was generated at low temperatures and migrated short distances. Clayton and others (1997) also observed that (1) oil and gas in Leo reservoirs at Lance Creek (southeastern PRB) are derived from Cretaceous source rocks; (2) oil produced from the Jurassic Canyon Springs Sandstone Member is derived from Leo shales, and (3) gas has a Cretaceous rather than a Leo source.

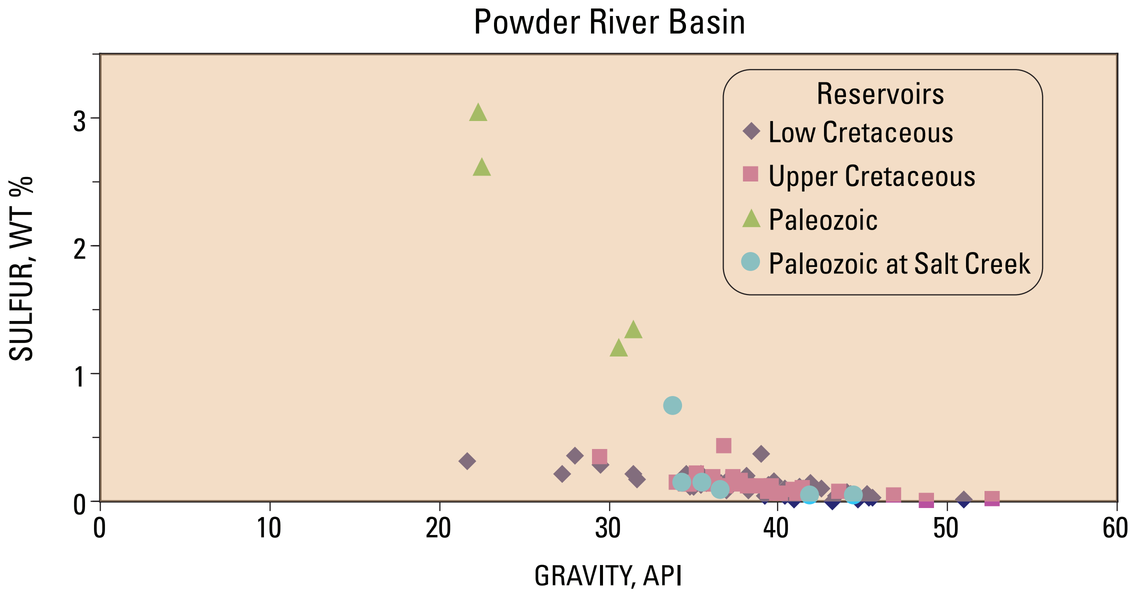


Figure 39. Chart comparing sulfur and gravity values of Powder River Basin oil reservoirs. Paleozoic reservoirs are high in sulfur, whereas Lower and Upper Cretaceous and Jurassic reservoirs have low sulfur. One Jurassic sample may have a Paleozoic oil component. Data are from Wenger and Reid (1961), Coleman and others, (1978). wt %, weight percent.

Because Cretaceous source rocks (Mowry Shale and Niobrara Formation) are too shallow to generate hydrocarbons in the basin margin of depths less than 4,000 ft, Cretaceous hydrocarbons must have migrated short distances from the Mowry and Niobrara hydrocarbon generating area (figs. 20 and 27, respectively) through basin margin faults into Leo and Jurassic reservoirs at Lance Creek field and possibly in other places. Dennen and others (2005) in their study of oil and gas compositions in Teapot Dome field interpreted that two oil types were represented, one coming from Cretaceous reservoirs and the other from Pennsylvanian Tensleep Sandstone reservoirs. They concluded that Cretaceous oils are less mature, show more evidence of secondary biodegradation, and have a mixed terrestrial and marine kerogen source. In addition, Cretaceous oils can be separated into three different groups, Upper Cretaceous sandstone reservoirs, Upper Cretaceous shale reservoirs, and Lower Cretaceous sandstone reservoirs, although the distinctions are minor. In contrast, the Pennsylvanian Tensleep oil is more mature, less biodegraded, has high sulfur content, shows evidence of water washing, and has a marine kerogen source.

Hydrocarbon degradation of Cretaceous oil at the Teapot Dome Field appears to vary as a function of depth. Hydrocarbons from the southern and deeper parts of the field, for example, are less degraded than the northern and shallow parts. Pennsylvanian oil does not appear to show variation within the field or in adjacent fields. According to Dennen and others (2005), molecular and isotopic compositions of gases indicate that thermogenic gases may have been altered by two different microbial processes—methanogenesis and secondary bacterial alteration, processes that may occur in several locations around the basin margin.

Source Rock Thermal Maturity

Significant amounts of hydrocarbons have not been generated in the basin margin areas because most if not all source rocks are too shallow for the maturation level to have reached the oil generation window. There may be circumstances where local pockets of source rock entered the oil generation window because they are in a downthrown fault block (fig. 38) or near a localized high thermal source. These possibilities were not considered in this assessment.

Hydrocarbon Migration

Mowry Shale source rock probably began expelling oil in Paleocene time, although the timing of oil migration into Laramide structures along the basin margin is uncertain. Major migration routes appear to trend eastward (fig. 20) rather than toward the south and west into the basin margins. The volume of Mowry oil that may have migrated toward these margins has not been determined, but steep updip gradients between the axial part of the PRB and the west margin may have provided sufficient buoyancy force to induce Mowry oil migration. Oil typing at Teapot Dome field (anticlinal trap with multiple stacked reservoirs; Dennen and others, 2005) indicated that Mowry oil was the dominant oil type in several Cretaceous reservoirs at Teapot Dome field and that Niobrara oil made only a minor contribution. Because Niobrara oil generation started in late Eocene time, Mowry oil could have migrated into basin margin structures before Niobrara generation, excluding Niobrara oil, although some oil mixing may have occurred. Results of oil typing at Teapot Dome field are also assumed to be indicative of the type of oil that is present in other basin margin fields with multiple stacked reservoirs, especially on the west side of the basin, but data are lacking.

Basin margin production from Mississippian Madison Limestone, Permian Tensleep and Minnelusa Sandstones, and Jurassic Sundance Sandstone reservoirs is from long-range oil migration from the Phosphoria Formation to the west prior to the formation of Laramide structures (Barbat, 1967). During the Laramide orogeny, oil was redistributed from stratigraphic traps or carrier beds into present-day structures (Moore, 1986). Alternative migration models indicate that Tensleep and Minnelusa oil was most likely generated locally because redistributed Phosphoria oil is not a viable model.

Basin margin production on the south side includes sandstone reservoirs in the Leo and Sundance Formations. The oil was generated in the organic-rich shales of the Leo in the deep part of the basin, then migrated south along fault and fracture networks. Generation and migration probably were in early to mid-Paleocene time, which postdates Cretaceous generation and migration into Sundance reservoirs at Red Bird field (Clayton and others, 1997).

A geologic events chart (fig. 40) shows the elements that define the Basin Margin AU.

Reservoir Rocks

Most of the reservoirs discussed earlier for other TPSs are also Basin Margin AU reservoirs, including sandstones of the Lower Cretaceous Muddy and Dakota Formations, sandstones of the Upper Cretaceous Frontier Formation, Sussex and Shannon Sandstone Members of the Steele Shale, and the Pennsylvanian-Permian Tensleep Sandstone. Differences exist, however, with respect to structural position, hydraulic fluid potential, and depth. In some places fractured shales of Cretaceous age are also productive, as is the Mississippian Madison Limestone in the northwestern part of this TPS at Soap Creek Field. Multiple pay zones in anticlinal traps are common; fine-grained rocks intercalated with the reservoirs provide seals. A regional seal of Permian-Triassic red beds separates Paleozoic and Mesozoic reservoirs in most fields.

Traps and Seals

Traps are commonly anticlines that rim the south and west margins of the basin. Most structures are relatively simple folds, reverse-faulted at depth, but with tension faults on their crests (Stone, 2002). Fault closures, particularly on plunging anticlinal noses, also produce, as do combination stratigraphic and structural traps such as Sussex and Glenrock South fields. Seals are commonly interreservoir shales or low-porosity siliciclastics.

Tertiary-Upper Cretaceous Coalbed Methane Total Petroleum System

Conventional accumulations of coalbed methane (CBM) are contained in sandstones interbedded with coal beds in the upper part of the Tertiary Fort Union Formation in the PRB; the assessed sandstones are within the Eastern Basin Margin Upper Fort Union Sandstone AU. Gas production from coals and contiguous sandstones has been described in detail (Flores, 2004; U.S. Geological Survey, 2004) and will not be discussed further in this report.

Cretaceous Biogenic Gas Total Petroleum System

Small quantities of what is considered to be biogenic gas are currently produced from shallow low-permeability Cretaceous reservoirs around the edges of the PRB; ratios of methane to $C_2 + C_3$ gas indicate a biogenic origin, but the evidence is not totally conclusive as to whether part of the gas mix is thermogenic. No isotope values of the gas are known to have been published. The assessed strata are within the Shallow Continuous Biogenic Gas AU. The gas is sourced and trapped as continuous-type accumulations, although structure and hydrodynamics may help concentrate the gas. Generation of biogenic gas is from methogenesis—that is, the methane is a product of O_2 depletion and sulfate reduction in the presence of organic matter in strata that can carry sufficient O_2 in the system. However, in a continuous-type system, a reservoir must allow gas to be trapped from capillary retention and buoyancy effects. Therefore, Cretaceous marine facies including fractured shales and shelf sandstones are well suited to trap biogenic gas in unconventional accumulations. Most Upper Cretaceous marine reservoirs are characterized by thin, discontinuous, low-permeability silty sandstones and silty or marly shales. The organic content of the shales can vary from less than 1 to more than 4 TOC by weight.

Depth range for biogenic gas production must be above the depth needed to generate thermogenic hydrocarbons. The R_o at which no thermogenic generation could occur was modeled as 0.40, which corresponds to a maximum depth of 3,400 ft. At such shallow depths, biogenic gas does not accumulate because of leakage and groundwater flushing, but it is also dependent on the type of seal rock.

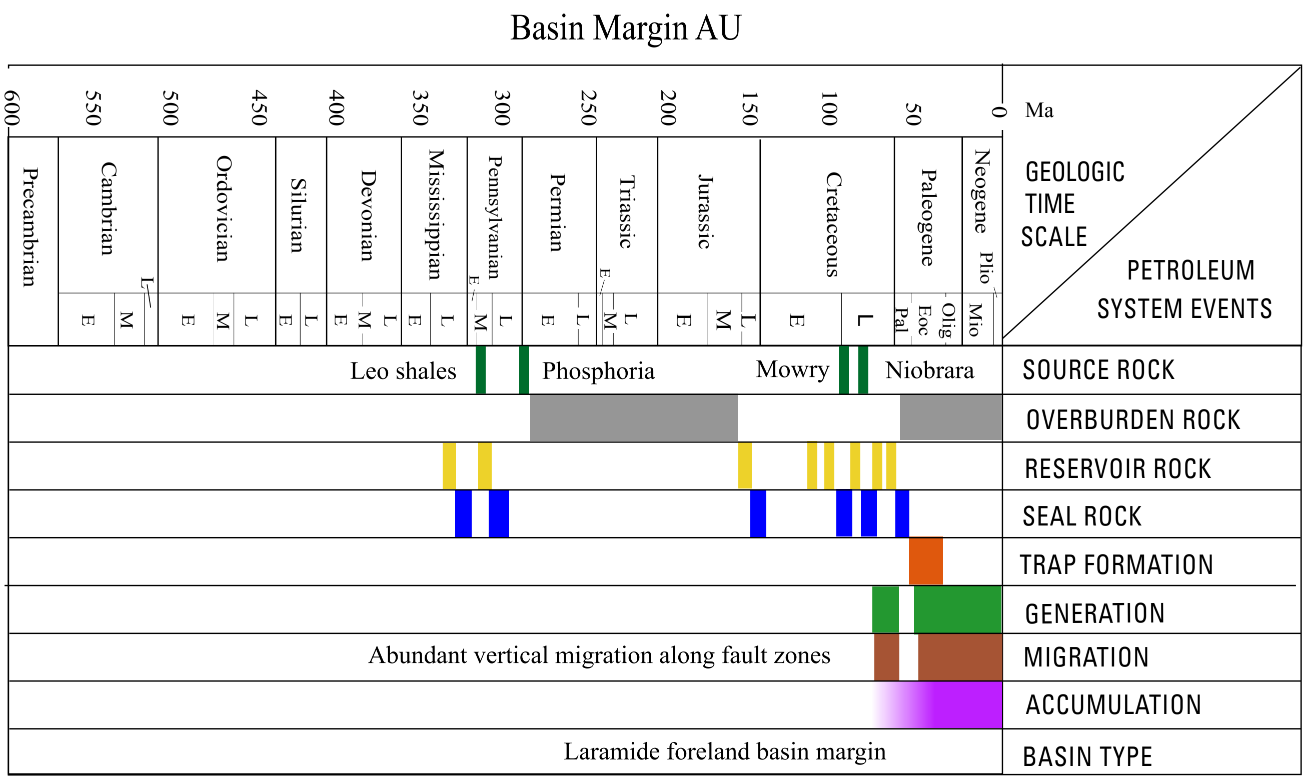


Figure 40. Events chart of the Basin Margin Assessment Unit (AU) of the Paleozoic-Mesozoic Composite Total Petroleum System (TPS) showing multiple reservoirs, sources, and seals. Geologic time scale is in millions of years. Plio, Pliocene; Mio, Miocene; Olig, Oligocene; Paleo, Paleocene; Eoc, Eocene; E, Early; M, Middle; L, Late.

Assessment of Undiscovered Petroleum Resource

Petroleum exploration in the PRB has been long and successful since oil was first discovered in the late 1800s. The basin has thick, organic-rich petroleum source rocks, a variety of reservoir rocks, and numerous types of traps ranging from large surface-exposed anticlines, topographically carved paleo sand dunes, incised channel sandstones, and overpressured tight marine sandstones. Over the years, 68,000 wells have been drilled in the basin, of which some 36,000 are currently producing or have produced in the past (IHS Energy Group, 2006).

The range of undiscovered oil and gas resources estimated for the 6 TPSs and their contained AUs in this assessment (table 1) reflects the mature exploration and production of the basin. That is, the range in the estimated amounts of technically recoverable new, undiscovered resources is relatively small because of the limited areas of the PRB that contain favorable conditions for hydrocarbon accumulation and as yet are untested. However, there is the potential for a moderate number of new oil and gas discoveries (fields containing a minimum of 5 million barrels of oil equivalent (MMBOE), especially on the west side of 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 503301 is assigned to the Tertiary–Upper Cretaceous Coalbed Methane TPS, in which “5” denotes the region (North America), “033” denotes the PRB province, and “01” 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 in the PRB is as follows:

503305 Pennsylvanian-Permian Composite TPS
50330501 Minnelusa-Tensleep-Leo AU
503302 Mowry TPS
50330201 Fall River–Lakota Sandstones AU
50330202 Muddy Sandstone AU
50330261 Mowry Continuous Oil AU
503303 Niobrara TPS
50330301 Frontier-Turner Sandstones AU
50330302 Sussex-Shannon Sandstones AU
50330303 Mesaverde-Lewis Sandstones AU
50330361 Niobrara Continuous Oil AU
503304 Cretaceous Biogenic Gas TPS
50330461 Shallow Continuous Biogenic Gas AU
503306 Paleozoic-Mesozoic Composite TPS
50330601 Basin Margin AU

Table 1. Powder River 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 fields, all liquids are included under the NGL (natural gas liquids) category. F95 denotes a 95-percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. CBG, coal-bed gas. Gray shading indicates not applicable]

Total Petroleum Systems (TPS) and Assessment Units (AU)	Field type	Total undiscovered resources: Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Conventional Oil and Gas Resources													
Pennsylvanian-Permian Composite TPS													
Minnelusa-Tensleep-Leo AU	Oil	21.38	56.48	112.13	60.51	0.87	2.52	5.85	2.83	0.02	0.08	0.25	0.10
	Gas					3.34	7.26	13.39	7.32	0.17	0.41	0.86	0.44
Mowry TPS													
Fall River-Lakota Sandstone AU	Oil	18.14	58.58	127.53	64.05	18.58	64.98	162.77	74.70	1.03	3.81	10.25	4.48
	Gas					104.85	507.46	1,257.06	574.51	9.72	49.36	131.97	57.47
Muddy Sandstone AU	Oil	10.95	40.62	106.81	47.34	31.03	122.43	360.08	149.14	2.71	10.89	32.87	13.43
	Gas					52.61	214.07	564.62	248.77	4.93	20.79	58.58	24.85
Niobrara TPS													
Frontier-Turner Sandstones AU	Oil	2.46	9.12	21.37	10.18	8.72	34.44	93.45	40.47	0.59	2.41	6.97	2.91
Sussex-Shannon Sandstones AU	Oil	2.75	7.97	16.98	8.67	2.25	7.09	17.30	8.09	0.17	0.55	1.45	0.65
Mesaverde-Lewis Sandstones AU	Oil	1.55	5.19	13.20	6.00	1.90	6.97	19.84	8.41	0.13	0.48	1.44	0.59
Tertiary-Upper Cretaceous Coalbed Methane TPS													
Eastern Basin Margin Upper Fort Union Sandstone AU	Gas					0.00	0.00	107.43	27.37	0.00	0.00	0.00	0.00
Paleozoic-Mesozoic TPS													
Basin Margin AU	Oil	4.79	16.30	36.76	17.93	3.46	12.58	32.89	14.66	0.11	0.44	1.23	0.53
Total Conventional Resources		**62.02**	**194.26**	**434.78**	**214.68**	**227.61**	**979.80**	**2,634.68**	**1,156.27**	**19.58**	**89.22**	**245.87**	**105.45**
Continuous Oil and Gas Resources													
Tertiary-Upper Cretaceous Coalbed Methane TPS													
Wasatch Formation AU	CBG					1,011.94	1,815.71	3,257.89	1,934.09	0.00	0.00	0.00	0.00
Upper Fort Union Formation AU	CBG					7,232.13	11,635.87	18,721.10	12,132.50	0.00	0.00	0.00	0.00
Lower Fort Union-Lance Formation AU	CBG					0.00	171.67	440.90	197.90	0.00	0.00	0.00	0.00
Mowry TPS													
Mowry Continuous Oil AU	Oil	116.99	189.32	306.38	197.61	103.35	185.50	332.95	197.61	5.56	10.91	21.37	11.86
Niobrara TPS													
Niobrara Continuous Oil AU	Oil	135.53	217.49	349.03	226.67	119.54	213.10	379.87	226.67	6.43	12.53	24.40	13.60
Cretaceous Biogenic Gas TPS													
Shallow Continuous Biogenic Gas AU	Gas					341.92	712.15	1,483.26	786.64	0.00	0.00	0.00	0.00
Total Continuous Resources		**252.52**	**406.81**	**655.41**	**424.28**	**8,808.88**	**14,734.00**	**24,615.97**	**15,475.41**	**11.99**	**23.44**	**45.77**	**25.46**
Total Undiscovered Oil and Gas Resources		**314.54**	**601.07**	**1,090.19**	**638.96**	**9,036.49**	**15,713.80**	**27,250.65**	**16,631.68**	**31.57**	**112.66**	**291.64**	**130.91**

503301 Tertiary-Upper Cretaceous Coalbed Methane TPS

50330101 Eastern Basin Margin Upper Fort Union Sandstone AU

A thorough analysis of all the available geologic data, as well as performance and development information, was presented earlier 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 assessment unit 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 Appendixes A–J. The form is organized into six major sections. The source of the known accumulation data is the Nehring database (NRG Associates, 2006) which provides accumulation size data for most fields in the United States.

Assessment of Undiscovered Petroleum Resources in Conventional Assessment Units

Minnelusa-Tensleep-Leo AU (50330501)

The Minnelusa-Tensleep-Leo AU includes most of the interior part of the PRB. The Tensleep and Leo Sandstones are located on the west and southeast edges of the AU, respectively (fig. 5). Tensleep Sandstone nomenclature is problematic as some operators use the term Minnelusa and some use Tensleep for the same unit, especially on the west side of the basin. Although Tensleep is stratigraphically equivalent to the lower part of the upper Minnelusa Sandstone (fig. 6), for this assessment Minnelusa and Tensleep were used interchangeably. The Minnelusa-Tensleep reservoirs are the most prolific oil producers in the PRB, with most of the production in this AU; Leo sandstones contribute little production.

The Minnelusa-Tensleep-Leo units have production of more than 600 million barrels of oil (MMBO) from approximately 1,700 producing wells in 167 fields (NRG Associates, 2006). In addition, some 7,000 wells have penetrated all or parts of the Minnelusa-Tensleep-Leo section (IHS Energy Group, 2006), which includes more than 3,700 new field wildcats (NRG Associates, 2006). Field size ranges from less than 0.5 to 48 MMBO with a mean and median of 3.7 and 2.0 MMBO, respectively. The average field depth exceeds 8,000 ft and ranges from 4,000 ft to more than 14,000 ft, although most production is from less than 12,000 ft. Oil gravity in most fields ranges from 20º to 30º API gravity but can range from 15º to 50º API gravity.

Input values for the Assessment Data Form to assess this AU are shown in Appendix A. We estimated the number of undiscovered oil accumulations in this assessment unit to be a minimum of 5, a maximum of 65, and a mode of 18. There have been 167 new oil field discoveries since the first economic discovery in 1957, and 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 5 new oil fields above the minimum of 0.5 MMBO. The maximum estimate of 65 undiscovered fields is a reflection of the large geographic size of the AU and the large undrilled area for possible new Leo Sandstone discoveries in combination structural and stratigraphic traps. New Minnelusa and Tensleep Sandstone oil field discoveries will probably be small. Few new fields will be discovered on the west side of the basin because of the lack of structural traps and the low stratigraphic trap potential in the Tensleep and Minnelusa Formations.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.5 MMBO, and a maximum of 20 MMBO. The default minimum size of 0.5 MMBO 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 fields will 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 probability that a larger discovery is remote.

Although there has not been a gas discovery in this AU, a potential increase in drilling depths will increase the probability of a discovery in the future. Therefore, we estimated the number of undiscovered gas accumulations is a minimum of 1, a maximum of 3, and a mode of 1.

Sizes of undiscovered gas accumulations are estimated to be a minimum of 3 billion cubic feet of gas (BCFG), a maximum of 20 BCFG, and a median of 4 BCFG. It is estimated that there will be at least one new gas field discovery equal 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 40 percent of the assessed gas will be from associated gas production.

Mean estimates of undiscovered resources for the Minnelusa-Tensleep-Leo AU are 60.5 MMBO, 10.1 BCFG (2.8 BCFG from associated gas), and 0.54 MMBNGL (table 1). Table 1 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered to be limited because, although parts of the AU are mature, other parts are sparsely drilled but have limited trapping potential.

Fall River–Lakota Sandstones AU (50330201)

The Fall River–Lakota Sandstone AU (about 13.6 million acres) covers most of the interior part of the PRB; its outline is based on the distribution of Fall River–Lakota sandstones that have the potential to accumulate oil and gas, although most of the production is located in the southern part of the AU (fig. 20). The AU does not include the large structural features at the basin margin, which is a separate AU. As explained in the Mowry TPS section of this report, Fall River and Lakota nomenclature is problematic because some operators use the terms interchangeably; in addition, the term Dakota is also used, perhaps as a matter of convenience in cases where there is uncertainty in stratigraphic correlation.

Fall River–Lakota Sandstone stratigraphic units have accumulated more than 100 MMBO and 10.6 BCFG from approximately 500 producing wells in 18 oil fields and 3 gas fields (NRG Associates, 2006). In addition, 10,000 wells or more have penetrated all or parts of the Fall River–Lakota section (IHS Energy Group, 2006), which includes some 4,700 new field wildcats (NRG Associates, 2006). However, not all new field wildcats had the Fall River–Lakota section as the primary target.

Current and past oil production volumes compared with field size can be classified as bimodal, with field sizes of 4 to 8 MMBO producing about 34 MMBO and field sizes of 16 to 32 MMBO producing in excess of 40 MMBO; these totals account for more than 74 percent of all Fall River–Lakota production in the AU. All gas volumes are produced from field sizes that range from 3 to 6 BCFG.

The average field depth is about 6,000 ft, ranging from less than 1,000 ft to more than 12,000 ft. Several recent field discoveries exceed 12,000-ft depth, a trend that may continue. Gravity in most fields ranges from 20° to 30° API units but can range from 15° to 50° API gravity.

Input values for the Assessment Data Form to assess this AU are shown in Appendix B. The number of undiscovered oil accumulations in this assessment unit is estimated to be a minimum of 2, a maximum of 50, and a mode of 10. There have been 38 new oil field discoveries since the first economic discovery in 1949 and, although there has been no new field discovery (above the minimum size) since 1985 (NRG Associates, 2006), it is considered a likely possibility that at least 2 new oil fields above the minimum of 0.5 MMBO will be discovered. The maximum estimate of 50 undiscovered fields is a reflection of the large geographic size of the AU and the large undrilled area yet to be tested for Fall River and Lakota Sandstone accumulations. New oil field discoveries will be small fields, most of which will be discovered on the west side of the basin in narrow, overpressured channel systems. The biggest risk for exploration is in locating channel systems with porous and permeable sandstone.

Sizes of undiscovered oil accumulations are estimated at a minimum of 0.5 MMBO, a median of 2.5 MMBO, and a maximum of 20 MMBO. The default minimum size of 0.5 MMBO reflects that there will be one new field that exceeds the minimum size and that most discoveries will be small. A median size of 2.5 MMBO, which is the long-term trend of new field discovery size, was used although the last two new field discoveries were substantially greater than 3 MMBO. A maximum size of 20 MMBO reflects the maturity of the AU, but the probability of such a large discovery is remote.

Although only three new gas fields have been discovered in this AU, the probable increase in drilling depths will increase the probability of a gas discovery in the future. Therefore, estimated number of undiscovered gas accumulation is a minimum of 1, a maximum of 75, and a mode of 7. The skewed distribution indicates the uncertainty in estimating the number of new fields.

Estimated sizes of undiscovered gas accumulations were 3 BCFG (the minimum field size to assess), a maximum of 200 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. The numbers reflect the probability that the gas field discoveries will be relatively small. About 10 percent of the assessed gas will be from associated gas produced with oil.

Mean estimates of undiscovered resources for the Fall River–Lakota Sandstone AU are 64.1 MMBO, 649.2 BCFG (74.7 BCFG from associated gas), and 61.9 MMBNGL (table 1). Table 1 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered to be uncertain because, although there have been a substantial number of well penetrations in the AU, a significant percentage of channel systems remain untested or undertested.

Muddy Sandstone AU (50330202)

The Muddy Sandstone AU (about 13.9 million acres) covers most of the interior part of the PRB; its outline is based on the distribution of Muddy Sandstone reservoirs that are either currently producing and (or) have the potential to accumulate oil and gas in the future. Muddy production is located in the east-central part of the basin with several new field discoveries in the southwestern part of the basin (fig. 20), and since the last USGS assessment (Dolton and Fox, 1995) most new production is from reserve growth of existing fields. The AU does not include the large structural features at the basin margin, which is a separate AU. This report uses the term Muddy Sandstone for all marine and nonmarine facies below the Mowry Shale and above the Skull Creek Shale.

Muddy Sandstone reservoirs have produced over 530 MMBO and 192 BCFG from approximately 3,600 producing wells in 79 oil fields and 8 gas fields. In addition, some 14,000 wells have penetrated all or part of the Muddy Sandstone section (IHS Energy Group, 2006), which includes more than

7,000 new field wildcats (NRG Associates, 2006), not all of which had the Muddy as the primary drilling target.

Oil production volumes compared to field size were classified as bimodal with field sizes of 16 to 32 MMBO producing a total of more than 140 MMBO and those in the 128 to 256 MMBO category producing a total of more than 130 MMB0; these amounts account for more than 50 percent of all Muddy production in the AU. All other field size classes have less than 80 MMBO (NRG Associates, 2006). Gas production indicates that the largest field size class is 48 to 96 BCFG (NRG Associates, 2006).

The depth of new field discoveries has increased since the first Muddy discovery in the 1940s. The average depth then was about 4,000 ft compared to the average depth of more than 10,000 ft in the 1990s. Recently, several new field discoveries exceed the 12,000-ft depth, a trend that will probably continue. Oil gravity ranges between 15° and 65° API with a mean of 40 API. GOR ranges from less than 10 to over 2,500 with a mean of 1,200. Input values for the Assessment Data Form to assess this AU are shown in Appendix C. The number of undiscovered oil accumulations is estimated to be a minimum of 2, a maximum of 30, and a mode of 10. There have been 79 new oil field discoveries since the first economic discovery in 1944, and although there has been no new field discovery (above the minimum size) since 1998 (NRG Associates, 2006), it is a likely possibility that at least 2 new oil fields above the minimum of 0.5 MMBO will be discovered. The maximum estimate of 30 undiscovered fields is a reflection of the large geographic size of the assessment unit and the large undrilled area yet to be tested for new Muddy Sandstone accumulations in combination structural and stratigraphic traps. This is the potential for new Muddy oil discoveries to be made on the west side of the basin in narrow, overpressured channel systems, but the biggest risk will be to locate channel systems containing porous and permeable sandstone.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.5 MMBO, and a maximum of 100 MMBO. The default minimum size of 0.5 MMBO reflects a potential that there will be one field discovered greater than the minimum size but that most new fields will be small. A median size of 1.5 MMBO was used, which is considered the long-term trend new field size. A maximum size of 100 MMBO reflects the upside potential of the AU and that there is the potential for a large field size discovery.

Although only eight new gas fields have been discovered in this AU, there is an increase in probability of new field wildcats being drilled to deeper depths, which will increase the probability of gas discoveries in the future. Therefore, the estimated number of undiscovered gas accumulations is a minimum of 2, a maximum of 30, and a mode of 6. Sizes of undiscovered gas accumulations were estimated to be 3 BCFG (the minimum field size to assess), a maximum of 450 BCFG, and a median of 10 BCFG. At least one new gas field discovery is estimated to be equal to or greater than the minimum size of 3 BCFG. The numbers reflect the probability that the gas field discoveries will be relatively small. About 60 percent of the assessed gas is estimated to be from associated gas production.

Mean estimates of undiscovered resources for the Muddy Assessment Unit are 47.3 MMBO, 398 BCFG (149.1 BCFG from associated gas), and 38.3 MMBNGL (table 1). Table 1 also shows a resource breakdown into the F95, F50, and F5 fractiles. Although there have been a substantial number of well penetrations in the Muddy Sandstone, large areas remain in which there may be channel systems that are untested or undertested, especially on the west side of the PRB.

Frontier-Turner Sandstones AU (50330301)

The Frontier-Turner Sandstones AU (about 4.8 million acres) covers most of the south-central part of the PRB, and its outline is based on the distribution of reservoirs in the Frontier Formation and the Turner Sandy Member of the Carlile Shale that are currently producing oil and gas and have the potential for future production. Frontier production is located in the west side of the basin but does not include production from basin margin fields such as Salt Creek and Teapot Dome fields. Most Frontier production since the last USGS assessment of the PRB (Dolton and Fox, 1995) is from infield completions and from two new field discoveries with marginal Frontier production. Turner production is located in the east-central part of the basin (fig. 41) with new production from infield drilling and field extension. The K-bar field is a new field discovery since the last USGS assessment (Dolton and Fox, 1995), and Brooks Draw field has limited Turner production.

As explained in the Niobrara TPS section of this report, Frontier Formation and Turner Sandy Member (of the Carlile Shale) nomenclature is commonly used interchangeably for the same lithostratigraphic interval. In this report a distinction is made between the Turner and the Frontier, in that the Turner is treated as a time equivalent of the Wall Creek Member of the Frontier (fig. 27) having been deposited in a lowstand setting east of the Wall Creek highstand location. In places, the Wall Creek and the Turner are separated physically and hydraulically by a ravinement surface of erosion (fig. 31).

Frontier Formation and Turner Sandy Member reservoirs in this AU have produced some 74 MMBO and 289 BCFG from approximately 1,100 producing wells in 13 oil fields, 11 oil and gas fields, and 1 gas field. In addition, more than 4,500 wells have penetrated all or part of the Frontier-Turner section in this AU (IHS Energy Group, 2006), which includes some 1,500 new field wildcats (NRG Associates, 2006).

Most oil production from Frontier-Turner reservoirs is produced from one field size class, that of 16 to 32 MMBO with a total volume of 44 MMBO. Smaller field size classes produce the remaining oil of 30 MMBO (NRG Associates, 2006). Gas production is from one field, Porcupine, which has produced 39 BCFG; all other gas production is from associated gas (NRG Associates, 2006).

Since the discovery of Frontier-Turner production in the early 1900s, production depth from new field discoveries in the 1960s averaged 4,500 ft; but since the 1970s depths have

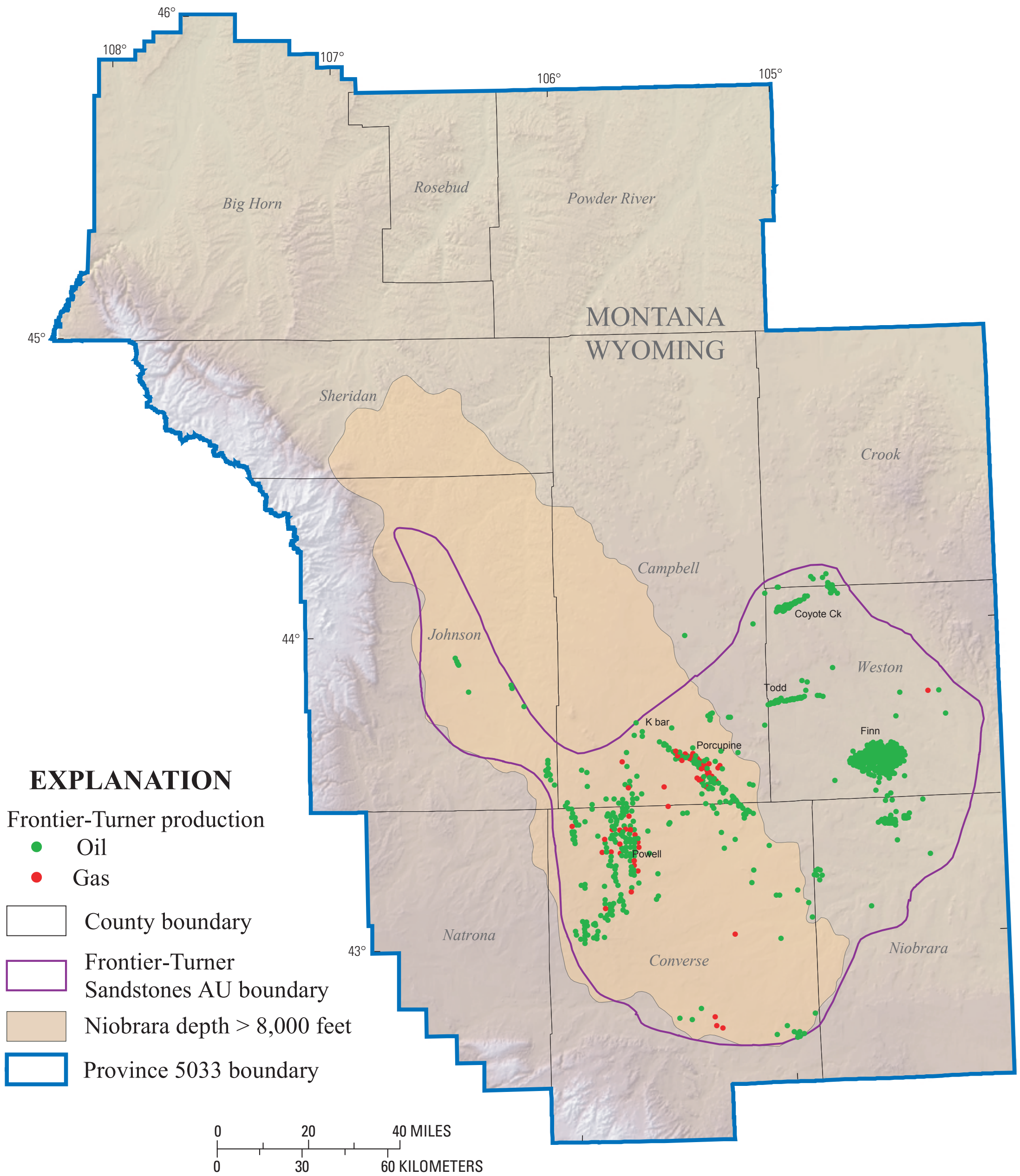


Figure 41. Map of the Powder River Basin showing oil and gas production of Frontier Formation and Turner Sandy Member of the Carlile Shale. The Frontier and Turner were combined into the Frontier-Turner Sandstones Assessment Unit (AU). Major fields are labeled.

ranged from about 6,000 ft to more than 12,000 ft. Wells in the most recent discovery K-Bar field in 1997 have an average depth exceeding10,000 ft (NRG Associates, 2006). Oil gravity ranges from 30º to 52º API with a mean of 40º API. GORs range from less than 500 cfg/bo to more than 29,000 cfg/bo with a mean of 5,000 cfg/bo.

Input values for the Assessment Data Form to assess this AU are shown in Appendix D. Estimated number of undiscovered oil accumulations are a minimum of 1, a maximum of 20, and a mode of 3. There have been 24 new oil field discoveries and, although there has not been a new field discovery (above the minimum size) since 1997 (NRG Associates, 2006), it is considered a likely possibility that at least 1 new oil field above the minimum of 0.5 MMBO will be discovered. The maximum estimate of 20 undiscovered fields is a reflection of some areas with few wells that could have tested the Frontier and Turner reservoirs in combination structural and stratigraphic traps. New Frontier-Turner oil discoveries will be in the deeper parts of the basin in overpressured reservoirs; the biggest challenge is searching out porous and permeable sandstone in overpressured compartments.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1 MMBO, and a maximum of 10 MMBO. The minimum size of 0.5 MMBO reflects what is considered to be the potential for discovering one field greater than the minimum size; however, most new fields are thought to be small. A median size of 1 MMBO, which is an average volume for new field size for the most recent discoveries, was used although the range of most recent discoveries is between 3 and 0.5 MMBO. A maximum size of 10 MMBO is established as the upside potential of the AU, but there is considerable uncertainty as to the discovery of a large field.

There has been only one new gas field discovered in this AU, and the probability of new gas fields being discovered is limited because the potential gas generation volume in Niobrara source rocks is areally restricted. Therefore, the number of undiscovered gas accumulations greater than the minimum is estimated as 0. Mean estimates of undiscovered resources for the Frontier-Turner Sandstones AU are 10.2 MMBO, 40.5 BCFG, and 2.9 MMBNGL (table 1). Table 1 also shows a resource breakdown into the F95, F50, and F5 fractiles.

Sussex-Shannon Sandstones AU (50330302)

The Sussex-Shannon Sandstones AU (about 6.6 million acres) covers most of the central part of the PRB, and its north-south outline is based on the distribution of reservoirs in the Sussex and Shannon Sandstone Members of the Cody Shale that are currently producing and have potential for future discoveries. Sussex production is located in the eastern and southwestern parts of the AU, whereas Shannon production is in the west-central part. The Sussex and Shannon Sandstone Members are combined in this AU because they have similar reservoir characteristics and production styles and histories.

The Sussex Sandstone Member has been informally subdivided into three units (Anderman, 1976), a lower B sand, a middle marine shale, and an upper A sand; both the A and B sands are productive. The Shannon Sandstone Member is one unit consisting of a lower silt unit overlain by interbedded sandstones that are commonly truncated at the top. The reservoirs are northwest-southeast-trending linear sandstone bodies, tens of miles long, 2–3 miles wide, and tens of feet thick; however, the sandstones thin to the north and east from current production. Sussex production tends to cluster in two areas, one along the House Creek–Porcupine field trend and the other farther west along the Spearhead Ranch–Scott field trend (fig. 32). Shannon production tends to cluster in one trend, including the Hartzog Draw, Pine Tree, and Jepson fields (fig. 33). Most of the Shannon production lies west of the main area of Sussex production to the north but follows along trend of the Sussex to the south.

Sussex and Shannon reservoirs have produced some 216 MMBO and 98 BCFG from approximately 1,200 producing wells in 17 oil fields. Only associated gas is produced, with no designated gas fields. In total, more than 5,000 wells have penetrated these sandstone units in this AU (IHS Energy Group, 2006), which includes 3,500 or more new field wildcats (NRG Associates, 2006).

Most oil production from Sussex and Shannon reservoirs is from one field size class, which is in the range of 64 to 128 MMBO, with a total volume of 120 MMBO. Smaller field size classes produce the remaining 96 MMBO (NRG Associates, 2006). Oil volumes compared to accumulation size classes follow a power law distribution.

Since the early discovery of Sussex and Shannon production in the late 1960s to the present, production depths from new field discoveries averaged 9,000 ft and ranged from about 7,000 to 10,200 ft. During this period, there has been a general trend toward drilling to greater depths to reach the reservoirs (NRG Associates, 2006). Oil gravity ranges between 30° and 45° API with a mean of 35°. GOR ranges from less than 200 cfg/bo to more than 2,500 cfg/bo with a mean of 500 cfg/bo.

Input values for the Assessment Data Form to assess this AU are shown in Appendix E. Estimated numbers of undiscovered oil accumulations are a minimum of 1, a maximum of 10, and a mode of 3. There have been 17 new oil field discoveries, and although there has not been a new field discovery (above the minimum size) since 1994 (NRG Associates, 2006), it is likely that at least 1 new oil field above the minimum of 0.5 MMBO will be discovered. The maximum estimate of 10 undiscovered fields is a reflection of some areas with few wells that could have tested the Sussex and Shannon in combination stratigraphic traps. Growth in oil reservoirs will be mostly from infield drilling and field extensions. New fields and field growth may be in deeper parts of the basin, but also possibly in shallower parts. The highest potential for new field discoveries is believed to be in exploring for porous and permeable sandstone in overpressured compartments.

Estimated sizes of undiscovered oil accumulations include a minimum of 0.5 MMBO, a median of 1.5 MMBO, and a maximum of 12 MMBO. The default minimum size of 0.5 MMBO reflects that there will be the discovery of one field greater than the minimum size but that most fields will be small. A median size of 1.5 MMBO was used, which is an average volume for field sizes for the most recent discoveries. A maximum size of 12 MMBO reflects some possible upside potential of the AU, but there is much doubt that a large volume field will be discovered.

There have been no new gas fields discovered in this AU, and the probability of new gas fields being discovered is low because gas generation potential in Niobrara source rocks is limited. Therefore, the number of undiscovered gas accumulations was estimated to be 0. We estimate that most of the assessed gas will be from associated gas production.

Mean estimates of undiscovered resources for the Sussex-Shannon Sandstones AU are 8.7 MMBO, 8.1 BCFG, and 0.65 MMBNGL (table 1). Table 1 also shows a resource breakdown into the F95, F50, and F5 fractiles.

Mesaverde-Lewis Sandstones AU (50330303)

The Mesaverde-Lewis Sandstones AU (about 6.1 million acres) covers most of the central part of the PRB, and its north south outline is based on the distribution of Mesaverde-Lewis Sandstone reservoirs that are currently producing and have the potential for future production. Reservoirs include the Parkman Sandstone and the Teapot Sandstone Members of the Mesaverde Formation and the Teckla Sandstone Member of the Lewis Shale (fig. 27); they are combined in a single AU because they have similar reservoir characteristics, production style and type, and depositional history. Production of the Teckla and Teapot sandstones is limited to the southern part of the basin, whereas Parkman production is distributed in the southern and central parts.

In general, most Mesaverde and Lewis fields produce modest volumes of oil from several multipay fields, although a few fields produce large volumes of oil (there are no designated gas fields; NRG Associates, 2006). For example, (1) the Parkman produces large quantities of oil from the Empire, Dead Horse, and Scott fields; (2) the Teapot has production from Flat Top, Kaye, Mikes Draw, and Well Draw fields; and (3) the Teckla has excellent production from Poison Draw field. Some wells have good initial production but have steep declines. The modest production from these reservoirs is indicative of their high clay content and low permeability. A few wells have low initial production rates with flat declines, although it is unclear if these wells are pressure depleted because of multiple pay zones. Most units within the Teapot, Parkman, and Teckla Sandstones have an average reservoir thickness of 10 to 150 ft, with a porosity and permeability range of 12 to 18 percent and 2 to 34 mD, respectively; some beds may have permeabilities exceeding 100 mD.

Mesaverde-Lewis Sandstone reservoirs in this AU have produced in excess of 126 MMBO and 187 BCFG from some 1,500 producing wells in 19 oil fields. Only oil with associated gas is produced from the 19 oil fields; there are no designated gas fields (NRG Associates, 2006). In addition, more than 5,100 wells have been drilled through the Mesaverde-Lewis interval to reach deeper targets (IHS Energy Group, 2006), which includes 2,100 new field wildcats (NRG Associates, 2006). Most oil production from Mesaverde-Lewis reservoirs is produced from two field size classes—16 to 32 MMBO and 32 to 64 MMBO—with a total volume of 88 MMBO. Five other field size classes from 0.5 to 16 MMBO produce the remaining 38 MMBO (NRG Associates, 2006).

Since the discovery of Mesaverde-Lewis production in the late 1950s at Dead Horse field, production depths from new field discoveries have averaged about 7,300 ft and ranged from about 5,500 to 9,500 ft. The historical trend, although short, is flat (NRG Associates, 2006). Oil gravity ranges from 35° to 47° API gravity per field with a mean of 39°. GOR ranges from less than 10 cfg/bo to more than 11,000 cfg/bo with a mean of 1,200 cfg/bo. Input values for the Assessment Data Form to assess this AU are shown in Appendix F. The number of undiscovered oil accumulations in this assessment unit was estimated to be a minimum of 1, a maximum of 10, and a mode of 2. There have been 19 new oil field discoveries, and although there has not been a new field discovery above the minimum size of 0.5 MMBO since 1980 (NRG Associates, 2006), it is a likely possibility that at least 1 new oil field above the minimum will be discovered. The maximum estimate of 10 undiscovered fields is a reflection of some areas with wells that could have tested sandstones in the Mesaverde-Lewis interval in combination stratigraphic traps, but failed to do so. New Mesaverde-Lewis oil discoveries will probably be mostly small fields in deeper parts of the basin, although the potential in shallower parts of the basin should not be overlooked. Exploration efforts should focus on finding porous and permeable sandstones with updip pinchouts.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.5 MMBO, and a maximum of 10 MMBO. The default minimum size of 0.5 MMBO reflects a potential for one field to be discovered that is greater than the minimum size, but most discovered fields are expected to be small. A median size of 1.5 MMBO was used, which is an average volume for a new field size based on the most recent discoveries in the AU. A maximum size of 10 MMBO reflects some upside potential of the AU, especially because there are three fields that have produced more than 20 MMBO; but there is large uncertainty in discovering a new large-volume field.

There have been no new gas fields discovered in this AU, and the probability of new gas fields being discovered in limited because gas generation in Niobrara source rocks is limited. Therefore, the number of undiscovered gas accumulations was a minimum of 0, a maximum of 7, and a mode of 1. Estimated sizes of undiscovered gas accumulations are 3 BCFG (the minimum field size to assess), a maximum of 10 BCFG, and a median of 3.5 BCFG. There is a potential for at least one new gas field to be discovered equal to or greater than the minimum size of 3 BCFG because a large area in the northern part of the basin remains to be tested. The assigned numbers reflect the probability that future discoveries will be relatively small. Most of the assessed gas will be from gas associated with oil production.

Mean estimates of undiscovered resources for the Mesaverde-Lewis Sandstones Assessment Unit are 6.0 MMBO, 8.4 BCFG, and 0.6 MMBNGL (table 1). Table 1 also shows a resource breakdown into the F95, F50, and F5 fractiles.

Basin Margin AU (50330601)

The Basin Margin AU (about 5.45 million acres) includes the structurally upthrown parts of the western and southern rims of the PRB. Reservoirs include the same Paleozoic and Mesozoic strata that produce in the central part of the basin and are described in previous sections.

The production history of most Basin Margin fields show relatively small declines over decades of production, although some low-volume fields show some erratic production histories, and others show modest production increases over short time intervals due to secondary recovery. Most fields have a strong water drive, whereas some have solution gas drives, and a few have only solution gas drives.

Basin margin fields have produced the greatest volumes of oil in the PRB, owing to stacked pay zones trapped in structural closures; cumulative production exceeds 1,300 MMBO and 1,050 BCFG from more than 2 wells in 45 oil fields. Only associated gas is produced, and there are no designated gas fields. In addition, some 2,000 new-field wildcats have been drilled in this AU (NRG Associates, 2006).

Most oil production is from a field size class of 512 to 1,024 MMBO with a total volume of more than 700 MMBO. The giant Salt Creek field has produced more than 735 MMBO (NRG Associates, 2006), which is more than 6 times as much oil as the next largest producer, the Meadow Creek–Sussex field complex. Five other field size classes, ranging from 0.5 to 128 MMBO, produce the remaining oil of 590 MMBO (NRG Associates, 2006).

Since the early discovery of production in the early 1900s at Salt Creek field, depths of new field discoveries ranged from 150 to 10,000 ft and averaged 4,500 ft. In addition, there is a slight trend toward deeper field depths over time (NRG Associates, 2006). Oil gravity ranges from 15° to 50° API gravity per field with a mean of 33°. GOR ranges from less than 10 cfg/bo to more than 16,000 cfg/bo with a mean of 900 cfg/bo.

Input values for the Assessment Data Form to assess this AU are shown in Appendix G. Estimated numbers of undiscovered oil accumulations are a minimum of 1, a maximum of 20, and a mode of 5. Although there has not been a new field discovery (above the minimum size) since 1998 (NRG Associates, 2006), it is estimated that at least 1 new oil field above the minimum of 0.5 MMBO will be discovered. The maximum estimate of 20 undiscovered fields reflects the potential for new discoveries in stratigraphic traps and combinations of structural and stratigraphic traps, especially through the testing of new pay zones in some of the more recent discoveries, and additional exploration that helps to define such structural and stratigraphic traps.

Estimated sizes of undiscovered oil accumulations are a minimum of 0.5 MMBO, a median of 1.5 MMBO, and a maximum of 20 MMBO. The default minimum size of 0.5 MMBO reflects the potential for one field to be discovered that is greater than the minimum size; however, most new fields probably will be small. A median size of 1.5 MMBO was used, based on an average volume of the most recent discoveries. Although the potential is low for discovering a new large-volume field, a maximum size of 20 MMBO reflects at least some potential, especially because 20 MMBO is an average field for this AU.

There have been no new gas fields discovered in this AU, and the probability of new gas fields being discovered is low because gas generation or gas migration potential is limited. Therefore, the number of undiscovered gas accumulations was estimated to be 0. Most of the assessed gas will be from gas associated with oil production.

Mean estimates of undiscovered resources for the Basin Margin Assessment Unit are 17.9 MMBO, 14.7 BCFG, and 0.53 MMBNGL (table 1). Table 1 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered to be limited but uncertain because a large area in the northern part of the basin remains to be evaluated.

Eastern Basin Margin Upper Fort Union Sandstone AU (50330101)

Eastern Basin Margin Upper Fort Union Sandstone AU is a conventional AU with coalbed methane (CBM) contained in sandstones (not in coals) interbedded with coal in the upper part of the Paleocene Fort Union Formation. The fluvial channel sandstones, which have a gross thickness of as much as 300 ft, are mainly in the Tongue River Member. Gas may migrate from the interbedded coals into sandstones when gas is being desorbed during pressure-reducing events (Flores, 2004), such as erosion of overlying sediments.

Mean estimates of undiscovered resources for the Eastern Basin Margin Upper Fort Union Sandstone Assessment Unit are 0 MMBO, 27.4 BCFG, and 0 MMBNGL. These data were reported by Flores (2004) and are incorporated in table 1.

Conventional Assessment Summary

The Powder River Basin Province is a productive hydrocarbon province, with reservoirs that range in age from Mississippian through Paleocene. There are two excellent Cretaceous source rocks—Mowry Shale and Niobrara Formation—that have generated billions of barrels of oil and gas equivalent (Momper and Williams, 1984); the Permian Phosphoria Formation also has generated large amounts of oil, some of which migrated into Paleozoic reservoirs.

Although the province has been extensively drilled, especially on the east and south sides of the basin, untested and undertested sections remain that likely will produce in the future. This assessment calculated that, in the future, there will be 25 percent more oil and almost 100 percent more gas discovered in the province than has been recovered as of 2006. New production will likely come from infill and new pay zones discovered in old fields, especially on the east side of the basin, and new field discoveries will likely come from deep reservoirs on the west side of the basin. The number and sizes of new field discoveries will be relatively small compared to historical numbers, and gas discoveries will outperform oil discoveries.

Mean estimates of total conventional undiscovered resources for the PRB Province are 215 MMBO, 1,156 BCFG of associated and nonassociated gas, and 105 MMBNGL (table 1).

Assessment of Undiscovered Petroleum Resources in Continuous Assessment Units

Mowry Continuous Oil AU (50330261)

The methods used to assess a continuous type play apply 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 drainage area, and the production history of analog fields.

Estimated ultimate recovery (EUR) plots for the Mowry Continuous AU were developed from modeled production decline curves; the production data were taken from Integrated Exploration Systems (2002). Cumulative probability production curves were generated to determine the total possible recovery per cell for untested cells. Data were used from the Upper Cretaceous Mowry Shale producing fields with vertical wells in the PRB and from Devonian-Mississippian Bakken Shale (upper and lower members) fields in the Williston Basin in North Dakota with vertical wells. The cell size applied had a median value of 0.25 MMBO, a minimum value of 0.02 MMBO, and a maximum value of 0.35 MMBO. Production from several fields in the PRB that produce from the Mowry were used in the probability plots including Maysdorf, Krejci, Lonetree Creek, Breen, Am-Kirk, Big Hand, Dillinger Ranch East, and Lightning Creek fields (Wyoming Oil and Gas Conservation Commission, 2003).

The Mowry Continuous Oil AU was characterized as a continuous reservoir with lateral limits confined to geologic sweet spots identified by the location of lineaments and faults (fig. 26). An upper limit of 8,000 ft corresponds to the upper boundary of overpressuring caused by hydrocarbon generation (Surdam and others, 1994). There may have been some migration in the Mowry at depths less than 8,000 ft, but in that case the reservoir is probably normally pressured to underpressured, and hydrocarbon extraction may not have occurred. There is no known lower depth limit, but it could be as much as 15,000 ft.

Thousands of wells have been drilled through the Mowry Shale, but only a few have been drill-stem or production tested. The formation commonly has hydrocarbon shows but is commonly considered a secondary option for completion. Because fractured shale reservoirs require special completion techniques that are being improved, the Mowry as a primary objective will probably be more successful than in the past; hence, its past history may not reflect future upside potential.

Of the 6.3 million acres in the AU, 3.2 million acres, or 50.3 percent, are within zones of high potential or sweet spots. Despite uncertainties in the mapping of lineament sand interpreting the structural forms, the minimum, maximum, and median percentages of untested assessment areas that have the potential for additions to reserves were calculated (above 0.02 MBO per well minimum cutoff). The minimum value is 8 percent, maximum value is 45 percent, and the median value is 25 percent (see Appendix H). Minimum value was calculated on the basis of the assumption that only 10 percent of the sweet spot area would be productive and have a 90-percent success ratio—that is, the sweet spots would be confined to a small area, but the area would have a high probability of success. The maximum value was based on similar assumptions, but reversed—that is, 90 percent of sweet spots would be productive, but with only a 10-percent probability of success. The median value was calculated with a 50-percent sweet spot productive area and a 50-percent probability of success. The values were also based on a 270-acre median cell size. Mean estimate of undiscovered resources for the Mowry AU is 198 MMBO, 198 BCFG, and 11.9 MMBNGL (table 1).

Niobrara Continuous Oil AU (50330361)

The method used to assess a continuous-type play applies a cell-based grid that uses a probability of ultimate gas recovery in each cell. The size of each cell was based on geologic controls, drainage area, and production history of analog fields.

Estimated ultimate recovery (EUR) plots for the Niobrara Continuous Oil AU were developed from modeled production decline curves, and the production data were taken from an Integrated Exploration Systems (2002) database. Cumulative probability production curves were generated to determine the total recovery per cell for untested cells. Data were used from fields producing from the Upper Cretaceous Niobrara Formation in the PRB and from vertical wells in the Silo field in the Denver Basin in southeastern Wyoming. The cell size had a median value of 0.028 MMBO, a minimum value of 0.02 MMBO and a maximum value of 0.5 MMBO. Several fields in the PRB producing from the Mowry were also used in the calculations, including Highlight, Payne, East Fork, and Shawnee fields (Wyoming Oil and Gas Conservation Commission, 2003).

The Niobrara Continuous Oil AU was characterized as a continuous unit with estimated recoverable areas limited to sweet spots identified by the location of lineaments and faults (fig. 36). A depth of 8,000 ft was determined as the upper extent of overpressuring caused by hydrocarbon generation (Surdam and others, 1994), and this could extend to depths as much as 14,000 ft. There may be some migration in the Niobrara at depths shallower than 8,000 ft, but this would be under normally pressured or underpressured conditions. Of the thousands of wells that have been drilled through the Niobrara Formation, only a few have been drill-stem tested or production tested in the PRB even though the formation usually has hydrocarbon shows. Past histories of Niobrara production may therefore not be indicative of future potential, especially in view of the new and improved techniques now becoming available to better evaluate the economic viability of fractured carbonate and carbonaceous shale reservoirs.

Of the 4.6 million acres in the Niobrara Continuous Oil AU, 2.5 million acres, or 54.5 percent, are within zones mapped as high potential or sweet spots. Despite the uncertainties inherent in the mapping of lineaments and interpreting their structural characteristics, estimates were made of the minimum, maximum, and median percentages of untested areas that have the potential for additions to reserves from wells capable of producing at least 20,000 barrels of oil (BO) in the next 30 years. These estimates are: minimum, 8 percent; maximum, 45 percent; and median, 25 percent. The minimum value was calculated on the basis of the assumption that 10 percent of a given sweet spot area would be productive, and would have a 90-percent success ratio. The maximum value was calculated on the basis of similar assumptions, but reversed—90 percent of sweet spots would be productive but with only a 10-percent probability of success. The median value was calculated with a 50-percent sweet spot productive area and a 50-percent probability of success. The values also were based on a 130-acre median cell-size area.

Estimated ultimate recoveries (EUR) in the Niobrara Continuous Oil AU were based on current production statistics reported by IHS Energy Group (2006). Cumulative probability production curves were generated to determine the total recovery per cell for untested cells. Data were used from vertical Niobrara producing wells in the PRB and from vertical Niobrara wells in the Silo field in the northern Denver Basin of southeastern Wyoming. Median value of 0.28 MMBO was selected at 50-percent probability, minimum value of 0.02 MMBO at the 12-percent probability, and the maximum value of 0.5 MMBO at 100-percent probability. Fields with Niobrara Formation production that were used in the probability plots include Goer Draw, WC, K-Bar, Big Muddy, Haps Draw, Orpha, Payne, Si Tanka, Rocky Hill, Shawnee, and Highlight fields (Wyoming Oil and Gas Conservation Commission, 2003). The values were also based on a 130-acre median cell size. Input values for the Assessment Data Form to assess this AU are shown in Appendix I.

Mean estimates of undiscovered resources for the Niobrara AU are 227 MMBO, 227 BCFG, and 13.6 MMBNGL (table 1).

Shallow Continuous Biogenic Gas AU (50330461)

Methods used to assess a continuous-type play applies a cell-based grid that uses a probability of ultimate gas recovery in each cell. The size of each cell was based on geologic controls, drainage area, and production history of analog fields.

The Cretaceous biogenic gas AU was characterized as hypothetical with potential production in Cretaceous sandstone and siltstone but with lateral and vertical limits that trap gas in place. An upper depth limit was arbitrary, but 300 ft of overburden could possibly prevent upward leakage. The lower limit was determined to be 3,400 ft where above that, only biogenic gas would be generated.

Estimated ultimate recovery (EUR) plots for the Shallow Continuous Biogenic Gas AU were developed from modeled production decline curves (production data from Integrated Exploration Systems, 2002). Cumulative probability production curves were generated to determine the total recovery per untested cells. Data were used from current producing fields in and adjacent to the PRB including the West Short Pine Hills field in Harding County, South Dakota. The cell size had a median value of 0.08 BCFG, a minimum value of 0.01 BCFG, and a maximum value of 1.5 BCFG. Some of the fields that were used in the analysis are Hardin, Lilscom Creek, Pumpkin Creek, Gaslight, Hammond, and Ardmore fields (Wyoming Oil and Gas Conservation Commission, 2003; George Shurr, written commun., 1999). Because of the uncertainty associated with the origin of the gas in these fields, this AU was assessed as a hypothetical AU. Input values for the Data Form to assess this AU are shown in Appendix J.

Of the 19.7 million acres (median) in the play area, 6.14 million acres, or 31.2 percent, are within zones of high potential or sweet spots. Despite uncertainties in the mapping of lineaments and interpreting their structural characteristics, calculations were made of the minimum, maximum, and median percentages of untested assessment areas that have the potential for additions to reserves (> 0.01 BCFG per well minimum cutoff) in the next 30 years. The resulting estimates were 1,12.5, and 5 percent, respectively (Appendix J). Minimum value was calculated based on the assumption that only 10 percent of the sweet spot area would be productive, but with a 90-percent success ratio. Maximum value was based on similar assumptions, but reversed—90 percent of sweet spots would be productive, with a 10 percent probability of success. The median value was calculated with a 50-percent sweet spot productive area and a 50-percent probability of success. The values were also based on a 160-acre median cell size. Mean estimate of undiscovered resources for the Cretaceous continuous Biogenic Gas AU is 787 BCFG (table 1).

Assessment Summary

Continuous hydrocarbon accumulations in the PRB are difficult to assess because the strata involved typically have been thought of as source rocks rather than also being reservoirs that are a primary exploration target. Historically, well testing of fractured shale and limy shale reservoirs indicate poor production performance because of little fluid recovery, even with mud log shows. New completion techniques should help production performance for these reservoirs in structurally enhanced areas.

Mean estimates of continuous undiscovered resource for the basin are 424 MMBO, 1,211 BCFG (excludes CBG resources), and 25.5 MMBNGL (table 1).

Comparison of Results of 1995 and 2005 Assessments

A comparison between the 1995 and 2006 USGS resource estimates for the Powder River Basin Province shows an appreciable change in the estimated size of the undiscovered oil and gas resource. In 1995, Dolton and Fox (1995), using a play concept, estimated a total mean undiscovered oil and gas resource of 1,131 MMBO and 983 BCFG for 11 conventional and 1 continuous play in the PRB Province. In 2006, for the assessment discussed in this report using the total petroleum system concept, a mean resource of 639 MMBO and 2,368 BCFG (excluding coalbed gas) was calculated for the 11 assessment units in 6 TPSs. It should be noted that in the 1995 assessment the Mowry and Niobrara continuous AUs were not assessed. Considering differences in methodology, the 2006 estimates reflect a notable decrease in oil resource estimates, the difference being in the respective assessed value for the Minnelusa-Tensleep-Leo s AU. The 2006 assessed value had only a mean of 60 MMBO, whereas the 1995 assessment of the same units calculated a much larger combined value of 604 MMBO. The 1995 assessment speculated that the vast untested acreage in the western and southern parts of the basin where Minnelusa-Tensleep-Leo are present would eventually produce significant amounts of oil. However, in the present assessment, much less was estimated for the same untested area because of a perceived lack of potential traps.

Gas resource for this assessment was significantly higher than the 1995 assessment—2,368 BCFG compared to 938 BCFG— mainly due to an increase in estimated volumes of gas in the continuous Mowry and Niobrara reservoir systems, as well as biogenic gas (excluding CBM reservoirs). Conventional gas was assessed at 1,156 BCFG compared with the 1995 assessment of 1,011 BCFG.

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Appendixes

Appendix A. Basic input data for the Minnelusa-Tensleep-Leo Sandstones Assessment Unit (50330501). SEVENTH APPROXIMATION DATA FORM (NOGA, Version 6, 4-9-2003). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	L.O. Anna	Date:	30-May-06
Region:	North America	Number:	5
Province:	Powder River Basin	Number:	5033
Total Petroleum System:	Pennsylvanian-Permian Composite	Number:	503305
Assessment Unit:	Minnelusa-Tensleep-Leo Sandstones	Number:	50330501
Based on Data as of:	IHS Energy (2006) and NRG (2005, data current through 2003), Wyoming Oil and Gas Conservation Commission		
Notes from Assessor:			

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 163 Gas: 0
Established (>13 accums.) X Frontier (1-13 accums.) ____ Hypothetical (no accums.) ____

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd 3.74 2nd 3rd 3.37 3rd 3rd 1.6
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum siz	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0)	5	mode	18	maximum	65
Gas Accumulations:	minimum (>0)	1	mode	1	maximum	3

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum	0.5	median	1.5	maximum	20
Gas in Gas Accumulations (bcfg):	minimum	3	median	4	maximum	20

Assessment Unit (name, no.)
Minnelusa-Tensleep-Leo Sandstones, 50330501

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	20	40	80
NGL/gas ratio (bngl/mmcfg)	10	20	80

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)	30	60	90
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	15	25	45
Sulfur content of oil (%)	0.5	2.8	4
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	500		2750		4700

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)	1	5	15
CO_2 content (%)	0.5	4.5	12
Hydrogen-sulfide content (%)	0.1	2	50
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	2000		3100		4800

Appendix B. Basic input data for the Fall River-Lakota Sandstones Assessment Unit (50330202). SEVENTH APPROXIMATION DATA FORM (NOGA, Version 6, 4-9-2003). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	L.O. Anna	Date:	31-May-06
Region:	North America	Number:	5
Province:	Powder River Basin	Number:	5033
Total Petroleum System:	Mowry	Number:	503302
Assessment Unit:	Fall River-Lakota Sandstones	Number:	50330201
Based on Data as of:	IHS Energy (2006) and NRG (2005, data current through 2003), Wyoming Oil and Gas Conservation Commission		
Notes from Assessor:	NRG reservoir growth function, 30 years		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 18 Gas: 3
Established (>13 accums.) X Frontier (1-13 accums.) ____ Hypothetical (no accums.) ____

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd 5.52 2nd 3rd 4.46 3rd 3rd 3.89
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0)	2	mode	10	maximum	50
Gas Accumulations:	minimum (>0)	1	mode	7	maximum	75

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum	0.5	median	2.5	maximum	20
Gas in Gas Accumulations (bcfg):	minimum	3	median	15	maximum	200

Assessment Unit (name, no.)
Fall River-Lakota Sandstones, 50330201

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	500	1000	2000
NGL/gas ratio (bngl/mmcfg)	30	60	90

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)	50	100	150
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	20	38	50
Sulfur content of oil (%)	0	0.1	0.3
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	500		3500		4300

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)	0.1	0.4	2
CO_2 content (%)	0.1	0.5	2.7
Hydrogen-sulfide content (%)	0	0	0
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	500		3600		4600

Appendix C. Basic input data for the Muddy Sandstone Assessment Unit (50330202). SEVENTH APPROXIMATION DATA FORM (NOGA, Version 6, 4-9-2003). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	L.O. Anna	Date:	31-May-06
Region:	North America	Number:	5
Province:	Powder River Basin	Number:	5033
Total Petroleum System:	Mowry	Number:	503302
Assessment Unit:	Muddy Sandstones	Number:	50330202
Based on Data as of:	IHS Energy (2006) and NRG (2005, data current through 2003), Wyoming Oil and Gas Conservation Commission		
Notes from Assessor :	NRG reservoir growth function, 30 years		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 60 Gas: 8
Established (>13 accums.) X Frontier (1-13 accums.) ____ Hypothetical (no accums.) ____

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd 2.36 2nd 3rd 2.9 3rd 3rd 1.03
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd 39.32 2nd 3rd 9.07 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0) 2	mode 10	maximum 30
Gas Accumulations:	minimum (>0) 2	mode 6	maximum 30

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum 0.5	median 1.5	maximum 100
Gas in Gas Accumulations (bcfg):	minimum 3	median 10	maximum 450

Assessment Unit (name, no.)
Muddy Sandstones, 50330202

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	1350	2700	5400
NGL/gas ratio (bngl/mmcfg)	60	90	120

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)	50	100	150
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	25	40	55
Sulfur content of oil (%)	0	0.1	0.35
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	600		3600		4600

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)	0.1	0.5	5
CO_2 content (%)	0.1	0.9	2.2
Hydrogen-sulfide content (%)	0	0	0
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	1000		3900		4600

Appendix D. Basic input data for the Frontier-Turner Sandstones Assessment Unit (50330301). SEVENTH APPROXIMATION DATA FORM (NOGA, Version 6, 4-9-2003). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	L.O. Anna	Date:	31-May-06
Region:	North America	Number:	5
Province:	Powder River Basin	Number:	5033
Total Petroleum System:	Niobrara	Number:	503303
Assessment Unit:	Frontier-Turner Sandstones	Number:	50330301
Based on Data as of:	IHS Energy (2006) and NRG (2005, data current through 2003), Wyoming Oil and Gas Conservation Commission		
Notes from Assessor:	NRG reservoir growth function, 30 years		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 21 Gas: 1
Established (>13 accums.) X Frontier (1-13 accums.) ___ Hypothetical (no accums.) ___

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd 2.15 2nd 3rd 1.16 3rd 3rd 0.88
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ___ 2nd 3rd ___ 3rd 3rd ___

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0)	1	mode	3	maximum	20
Gas Accumulations:	minimum (>0)	0	mode	0	maximum	0

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum	0.5	median	1	maximum	10
Gas in Gas Accumulations (bcfg):	minimum		median		maximum	

Assessment Unit (name, no.)
Frontier-Turner Sandstones, 50330301

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	1700	3400	6800
NGL/gas ratio (bngl/mmcfg)	36	72	108

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)			
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	35	40	50
Sulfur content of oil (%)	0	0.1	0.3
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	800		3600		3900

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)			
CO_2 content (%)			
Hydrogen-sulfide content (%)			
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)					

Appendix E. Basic input data for the Sussex-Shannon Sandstones Assessment Unit (50330302). SEVENTH APPROXIMATION DATA FORM(NOGA, Version 6, 4-9-2003). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	L.O. Anna	Date:	31-May-06
Region:	North America	Number:	5
Province:	Powder River Basin	Number:	5033
Total Petroleum System:	Niobrara	Number:	503303
Assessment Unit:	Sussex-Shannon Sandstones	Number:	50330302
Based on Data as of:	IHS Energy (2006) and NRG (2005, data current through 2003), Wyoming Oil and Gas Conservation Commission		
Notes from Assessor:	NRG reservoir growth function, 30 years		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 17 Gas: 0
Established (>13 accums.) X Frontier (1-13 accums.) ____ Hypothetical (no accums.) ____

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd 6.51 2nd 3rd 6.04 3rd 3rd 1.62
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0)	1	mode	3	maximum	10
Gas Accumulations:	minimum (>0)	0	mode	0	maximum	0

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum	0.5	median	1.5	maximum	12
Gas in Gas Accumulations (bcfg):	minimum		median		maximum	

Assessment Unit (name, no.)
Sussex-Shannon Sandstones, 50330302

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	400	800	1600
NGL/gas ratio (bngl/mmcfg)	40	80	120

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)			
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	F75	mode	F25	maximum
API gravity (degrees)	30		35		45
Sulfur content of oil (%)	0		0.17		0.25
Depth (m) of water (if applicable)					
Drilling Depth (m)	2100		2800		3500

Gas Accumulations:	minimum	F75	mode	F25	maximum
Inert gas content (%)					
CO_2 content (%)					
Hydrogen-sulfide content (%)					
Depth (m) of water (if applicable)					
Drilling Depth (m)					

Appendix F. Basic input data for the Mesaverde-Lewis conventional oil and gas Assessment Unit (50330303). SEVENTH APPROXIMATION DATA FORM(NOGA, Version 6, 4-9-2003). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrles of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids; Comm., Commission]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	Lawrence O. Anna	Date:	
Region:	North America	Number:	5
Province:	Powder River Basin	Number:	5033
Total Petroleum System:	Niobrara	Number:	503303
Assessment Unit:	Mesaverde - Lewis conventional oil & gas	Number:	50330303
Based on Data as of:	PI/Dwights 2006, Wyo Oil & Gas Convervation Comm., Nehring Data base		
Notes from Assessor:	Well Draw field as analog		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) or Gas (≥20,000 cfg/bo overall) oil

What is the minimum accumulation size? 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 19 Gas: 0
Established (>13 accums.) x Frontier (1-13 accums.) Hypothetical (no accums.)

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd 2.44 2nd 3rd 1.77 3rd 3rd 1.19
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd 2nd 3rd 3rd 3rd

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. CHARGE: Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. ROCKS: Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. TIMING OF GEOLOGIC EVENTS: Favorable timing for an undiscovered accum. ≥ minimum size:	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0)	1	mode	2	maximum	10
Gas Accumulations:	minimum (>0)	0	mode	1	maximum	7

Sizes of Undiscovered Accumulations: What are the sizes (grown) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum	0.5	median	1.5	maximum	10
Gas in Gas Accumulations (bcfg):	minimum	3	median	3.5	maximum	10

Assessment Unit (name, no.)
Mesaverde-Lewis Conventional oil & gas 50330303

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	10	400	12,000
NGL/gas ratio (bngl/mmcfg)	10	80	200

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)	50	300	750
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	35	39	50
Sulfur content of oil (%)	0.01	0.09	0.25
Depth (m) of water (if applicable)	300	2800	3100

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	1200		2300		3050

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)	0.1	0.7	2.7
CO_2 content (%)	0.1	0.4	0.7
Hydrogen-sulfide content (%)	0	0	0
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	1900		2400		3100

Appendix G. Basic input data for the Basin Margin Assessment Unit (50330601). SEVENTH APPROXIMATION DATA FORM (NOGA, Version 6, 4-9-2003). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	L.O. Anna	Date:	31-May-06
Region:	North America	Number:	5
Province:	Powder River Basin	Number:	5033
Total Petroleum System:	Paleozoic-Mesozoic Composite	Number:	503306
Assessment Unit:	Basin Margin	Number:	50330601
Based on Data as of:	IHS Energy (2006) and NRG (2005, data current through 2003), Wyoming Oil and Gas Conservation Commission		
Notes from Assessor:	NRG reservoir growth function, 30 years		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 41 Gas: 0
Established (>13 accums.) X Frontier (1-13 accums.) ____ Hypothetical (no accums.) ____

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd 8.31 2nd 3rd 10.44 3rd 3rd 1.88
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0)	1	mode	5	maximum	20
Gas Accumulations:	minimum (>0)	0	mode	0	maximum	0

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum	0.5	median	1.5	maximum	20
Gas in Gas Accumulations (bcfg):	minimum		median		maximum	

Assessment Unit (name, no.)
Basin Margin, 50330601

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	350	700	1400
NGL/gas ratio (bngl/mmcfg)	18	36	54

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)			
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	15	33	50
Sulfur content of oil (%)	0	0.5	4
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	250		1800		3200

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)			
CO_2 content (%)			
Hydrogen-sulfide content (%)			
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)					

Appendix H. Basic input data for the Mowry Continuous Oil Assessment Unit (50330261). FORSPAN ASSESSMENET MODEL FOR CONTINUOUS ACCUMULATIONS (NOGA, Version 7, 6-30-2000). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

***FORSPAN* ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATIONS--BASIC INPUT DATA FORM (NOGA, Version 7, 6-30-00)**

IDENTIFICATION INFORMATION

Assessment Geologist:…	L.O. Anna	Date:	8/5/2002
Region:……………………	North America	Number:	5
Province:…………………	Powder River Basin	Number:	5033
Total Petroleum System:.	Mowry	Number:	503302
Assessment Unit:……….	Mowry Continuous Oil	Number:	50330261
Based on Data as of:……	PI/Dwights 2001, Wyoming Oil and Gas Conservation Commission		
Notes from Assessor…..	1- to 2-well (Mowry) fields in basin and Bakken Shale as analogs		
	Based on EURs and drainage areas of vertical wells		
	Future success ratio: 50%		

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-Unit type: Oil (<20,000 cfg/bo) **or Gas** (≥20,000 cfg/bo) Oil
What is the minimum total recovery per cell?… 0.002 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 62
Number of tested cells with total recovery per cell ≥ minimum: …….. 31
Established (>24 cells ≥ min.) X Frontier (1-24 cells) ____ Hypothetical (no cells) ____
Median total recovery per cell (for cells ≥ min.): (mmbo for oil A.U.; bcfg for gas A.U.)
1st 3rd discovered ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an untested cell with total recovery ≥ minimum ……	1.0
2. **ROCKS:** Adequate reservoirs, traps, seals for an untested cell with total recovery ≥ minimum.	1.0
3. **TIMING:** Favorable geologic timing for an untested cell with total recovery ≥ minimum………..	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……………….. 1.0

4. **ACCESS:** Adequate location for necessary petroleum-related activities for an untested cell with total recovery ≥ minimum ……… 1.0

NO. OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES IN THE NEXT 30 YEARS

1. Total assessment-unit area (acres): (uncertainty of a fixed value)
minimum 6,009,000 median 6,325,000 maximum 6,641,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres):
(values are inherently variable) minimum 40 median 270 maximum 640

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
minimum 99.6 median 99.7 maximum 99.8

4. Percentage of untested assessment-unit area that has potential for additions to reserves in next 30 years (%): (a necessary criterion is that total recovery per cell ≥ minimum)
(uncertainty of a fixed value) minimum 8 median 25 maximum 45

Assessment Unit (name, no.)
Mowry Continuous Oil, 50330261

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves in next 30 years:
(values are inherently variable)

	minimum	median	maximum
(mmbo for oil A.U.; bcfg for gas A.U.)	0.002	0.025	0.35

AVERAGE COPRODUCT RATIOS FOR UNTESTED CELLS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil assessment unit:	minimum	median	maximum
Gas/oil ratio (cfg/bo)…………………………...…….	500	1000	1500
NGL/gas ratio (bngl/mmcfg)…………………….….	30	60	90
Gas assessment unit:			
Liquids/gas ratio (bliq/mmcfg)….……………..…….			

SELECTED ANCILLARY DATA FOR UNTESTED CELLS
(values are inherently variable)

Oil assessment unit:	minimum	median	maximum
API gravity of oil (degrees)………….………….	35	40	45
Sulfur content of oil (%)……………………...…	0	0.5	2
Drilling depth (m) ……………..…………….……	2400	2900	4300
Depth (m) of water (if applicable)……………….			
Gas assessment unit:			
Inert-gas content (%)……………………......…..			
CO_2 content (%)……………………………..…...			
Hydrogen-sulfide content (%)……………...…….			
Drilling depth (m)………………………………….			
Depth (m) of water (if applicable)……………….			

Appendix I. Basic input data for the Niobrara Continuous Oil Assessment Unit (50330361). FORSPAN ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATION (NOGA, Version 7, 6-3-2000). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

_FORSPAN_ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATIONS--BASIC INPUT DATA FORM (NOGA, Version 7, 6-30-00)

IDENTIFICATION INFORMATION

Assessment Geologist:…	L.O. Anna	Date:	8/6/2002
Region:……………………	North America	Number:	5
Province:…………………	Powder River Basin	Number:	5033
Total Petroleum System:..	Niobrara	Number:	503303
Assessment Unit:……….	Niobrara Continuous Oil	Number:	50330361
Based on Data as of:……	PI/Dwights 2001, Wyoming Oil and Gas Conservation Commission		
Notes from Assessor…..	1- to 2-well (Niobrara) fields in basin and Silo Field as analogs Based on EURs and drainage areas of vertical wells Future success ratio: 60%		

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-Unit type: **Oil** (<20,000 cfg/bo) **or** **Gas** (≥20,000 cfg/bo) Oil
What is the minimum total recovery per cell? 0.002 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 43
Number of tested cells with total recovery per cell ≥ minimum: ……... 25
Established (>24 cells ≥ min.) X Frontier (1-24 cells) ____ Hypothetical (no cells) ____
Median total recovery per cell (for cells ≥ min.): (mmbo for oil A.U.; bcfg for gas A.U.)
1st 3rd discovered ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an untested cell with total recovery ≥ minimum ……	1.0
2. **ROCKS:** Adequate reservoirs, traps, seals for an untested cell with total recovery ≥ minimum.	1.0
3. **TIMING:** Favorable geologic timing for an untested cell with total recovery ≥ minimum………..	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……….......……. 1.0

4. **ACCESS:** Adequate location for necessary petroleum-related activities for an untested cell with total recovery ≥ minimum ……………………………………………………………… 1.0

NO. OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES IN THE NEXT 30 YEARS

1. Total assessment-unit area (acres): (uncertainty of a fixed value)
   minimum 4,372,000 median 4,602,000 maximum 4,832,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres):
   (values are inherently variable) minimum 10 median 130 maximum 320

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
   minimum 99.77 median 99.87 maximum 99.97

4. Percentage of untested assessment-unit area that has potential for additions to reserves in next 30 years (%): (a necessary criterion is that total recovery per cell ≥ minimum)
   (uncertainty of a fixed value) minimum 4.1 median 16.4 maximum 27.2

Assessment Unit (name, no.)
Niobrara Continuous Oil, 50330361

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves in next 30 years:
(values are inherently variable)
(mmbo for oil A.U.; bcfg for gas A.U.) minimum 0.002 median 0.028 maximum 0.5

AVERAGE COPRODUCT RATIOS FOR UNTESTED CELLS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil assessment unit:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………...…….	500	1000	1500
NGL/gas ratio (bngl/mmcfg)…………………..….	30	60	90
Gas assessment unit:			
Liquids/gas ratio (bliq/mmcfg)….……………..……			

SELECTED ANCILLARY DATA FOR UNTESTED CELLS
(values are inherently variable)

Oil assessment unit:	minimum	median	maximum
API gravity of oil (degrees)………….………….	34	39	45
Sulfur content of oil (%)………………………...….	0.02	0.1	0.5
Drilling depth (m) ……………...…………….……	2400	2900	4000
Depth (m) of water (if applicable)……………….			
Gas assessment unit:			
Inert-gas content (%)……………………….....…..			
CO_2 content (%)……………………………….…..			
Hydrogen-sulfide content (%)……………...…….			
Drilling depth (m)………………………………….			
Depth (m) of water (if applicable)……………….			

Appendix J. Basic input data for the Shallow Continuous Biogenic Gas Assessment Unit (50330461). FORSPAN ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATION (NOGA, Version 7, 6-3-2000). [AU, assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bng/mmcfg, barrels of natural gas liquids per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; min, minimum; mmboe, million barrels of oil equivalent; ngl, natural gas liquids]

***FORSPAN* ASSESSMENT MODEL FOR CONTINUOUS ACCUMULATIONS--BASIC INPUT DATA FORM (NOGA, Version 7, 6-30-00)**

IDENTIFICATION INFORMATION

Assessment Geologist:…	L.O. Anna	Date:	8/6/2002
Region:……………………	North America	Number:	5
Province:…………………	Powder River Basin	Number:	5033
Total Petroleum System:.	Cretaceous Biogenic Gas	Number:	503304
Assessment Unit:……….	Shallow Continuous Biogenic Gas	Number:	50330461
Based on Data as of:……	PI/Dwights 2001		
Notes from Assessor…..	West Short Pine Hills Field as analog		
	Future success ratio: 40%		

CHARACTERISTICS OF ASSESSMENT UNIT

Assessment-Unit type: Oil (<20,000 cfg/bo) **or Gas** (≥20,000 cfg/bo) Gas
What is the minimum total recovery per cell? 0.01 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 0
Number of tested cells with total recovery per cell ≥ minimum: ……... 0
Established (>24 cells ≥ min.) ____ Frontier (1-24 cells) ____ Hypothetical (no cells) X
Median total recovery per cell (for cells ≥ min.): (mmbo for oil A.U.; bcfg for gas A.U.)
1st 3rd discovered ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an untested cell with total recovery ≥ minimum ……	1.0
2. **ROCKS:** Adequate reservoirs, traps, seals for an untested cell with total recovery ≥ minimum.	1.0
3. **TIMING:** Favorable geologic timing for an untested cell with total recovery ≥ minimum………..	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……….......……. 1.0

4. **ACCESS:** Adequate location for necessary petroleum-related activities for an untested cell with total recovery ≥ minimum ……………………………………………………………… 1.0

NO. OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES IN THE NEXT 30 YEARS

1. Total assessment-unit area (acres): (uncertainty of a fixed value)
minimum 18,726,000 median 19,712,000 maximum 20,698,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres):
(values are inherently variable) minimum 40 median 160 maximum 320

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
minimum 100 median 100 maximum 100

4. Percentage of untested assessment-unit area that has potential for additions to reserves in next 30 years (%): (a necessary criterion is that total recovery per cell ≥ minimum)
(uncertainty of a fixed value) minimum 1 median 5 maximum 12.5

Assessment Unit (name, no.)
Shallow Continuous Biogenic Gas, 50330461

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves in next 30 years:
(values are inherently variable)

	minimum	median	maximum
(mmbo for oil A.U.; bcfg for gas A.U.)	0.01	0.08	1.5

AVERAGE COPRODUCT RATIOS FOR UNTESTED CELLS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil assessment unit:	minimum	median	maximum
Gas/oil ratio (cfg/bo)………………………..…….			
NGL/gas ratio (bngl/mmcfg)………………….……			
Gas assessment unit:			
Liquids/gas ratio (bliq/mmcfg)….………….……	0	0	0

SELECTED ANCILLARY DATA FOR UNTESTED CELLS
(values are inherently variable)

Oil assessment unit:	minimum	median	maximum
API gravity of oil (degrees)…………….………….			
Sulfur content of oil (%)………………………...…			
Drilling depth (m) ……………...…………….……			
Depth (m) of water (if applicable)……………….			
Gas assessment unit:			
Inert-gas content (%)……………………….....…..			
CO_2 content (%)……………………………….....….	0.00	0.20	0.30
Hydrogen-sulfide content (%)……………...…….	0.00	0.00	0.00
Drilling depth (m)………………………………….	200	600	1040
Depth (m) of water (if applicable)……………….			

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