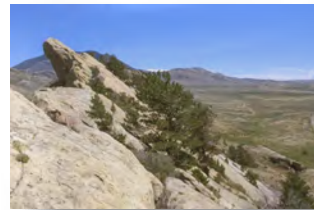
Chapter 9

Lewis Total Petroleum System of the Southwestern Wyoming Province, Wyoming, Colorado, and Utah



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Volume Title Page

By Robert D. Hettinger and Laura N.R. Roberts

Chapter 9 of

Petroleum Systems and Geologic Assessment of Oil and Gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah

By USGS Southwestern Wyoming Province Assessment Team

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Lewis Total Petroleum System of the Southwestern Wyoming Province, Wyoming, Colorado, and Utah

By Robert D. Hettinger and Laura N.R. Roberts

Abstract

The Lewis Total Petroleum System (TPS) within the Southwestern Wyoming Province of Wyoming, Colorado, Utah is a complex of marine strata that contains significant quantities of gas sourced from dominantly Type-III kerogen. Between 600 and 675 billion cubic feet of gas (BCFG) and minor amounts of oil have been produced since 1974. The source rock, reservoir rock, and seals are distributed throughout most of the Maastrichtian Lewis Shale, which was deposited about 71 to 68 million years ago (Ma) in the eastern half of the Greater Green River Basin. Previous investigations reveal that the sandstone reservoirs have a net thickness of as much as 600 feet. The sandstones were deposited in deltaic and turbidite systems, and some basin-floor sand lobes extend across as many as 30 townships. Gas generation began about 62 Ma, and peak gas generation and gas migration began about 52 Ma and probably persisted until about 5 Ma when the Lewis Shale attained its maximum depth of burial. Gas generation may be continuing at the present, but at a significantly reduced rate.

Two assessment units comprise the Lewis TPS: these are the Lewis Continuous Gas Assessment Unit (50370761) and the Lewis Conventional Oil and Gas Assessment Unit (50370701). The former encompasses approximately 3,310,000 acres and defines deeper basin regions that are characterized by an overpressured, gas-saturated basin-centered accumulation. The latter encompasses approximately 3,820,000 acres and defines shallower basin regions where gas accumulations are within conventional-style traps. The assessment of both units is based on stratigraphic and structural information and historical production data. Assessment results report hydrocarbon resources that have the potential to be produced in the next 30 years (about 2005–2035).

In area, about 18 to 69 percent of the Lewis Continuous Gas Assessment Unit has potential for additions to reserves in the next 30 years. These areas are estimated to contain between about 8,765 and 19,667 BCFG, with a calculated mean of about 13,536 BCFG. Gas discoveries in the next 30 years are likely to be similar in size to historical discoveries, but success ratios are expected to be significantly higher owing to improved exploration strategies, improved completion techniques, and an improved understanding of the basin-centered system. As such, individual untested cells are expected to range from 20 to 200 acres in size (with a mean of 103 acres), total recovery per cell is anticipated to range from 0.02 to 15 BCFG (with a median of 0.6 BCFG), and drilling success ratios are anticipated to range from 80 to 90 percent (with a median of 85 percent).

In contrast, most of the significant hydrocarbon accumulations in the Lewis Conventional Oil and Gas Assessment Unit might have already been found. However, in the next 30 years, the conventional assessment unit has the potential to provide between about 104 and 304 BCFG, with a calculated mean of about 195 BCFG. This undiscovered resource is anticipated to be distributed throughout 8 to 31 undiscovered gas accumulations (with a median of 18), and the accumulation sizes are expected to range from 3 to 90 BCFG (with a median of 8 BCFG).

Introduction

This report documents the rationale used to assess undiscovered hydrocarbon resources within the Lewis Total Petroleum System (TPS) (503707), which is complete with source rock, reservoir rock, and seals. The assessment was made using techniques and methodology described in Chapters 18–23 of this CD–ROM and is based on oil and gas field information provided by NRG Associates (2001), well history and production data by the IHS Energy Group (2001), and critical geologic input described in this report. Included are discussions on (1) stratigraphy of the Lewis Shale, (2) the Lewis TPS, (3) source rock maturation, (4) hydrocarbon migration, (5) hydrocarbon reservoirs, (6) hydrocarbon traps and seals, (7) assessment units, and (8) assessment results.

The Lewis TPS lies in the Southwestern Wyoming Province (5037), which encompasses the Greater Green River Basin (GGRB) of Colorado, Utah, and Wyoming (fig. 1). The GGRB is bounded by the Wind River and Granite Mountains uplifts to the north; the Rawlins, Sierra Madre, and Park uplifts to the east; the Axial arch and Uinta Mountains to the south; and the Wyoming thrust belt to the west (Roehler, 1992). Intrabasin uplifts include the Pinedale anticline; Moxa,

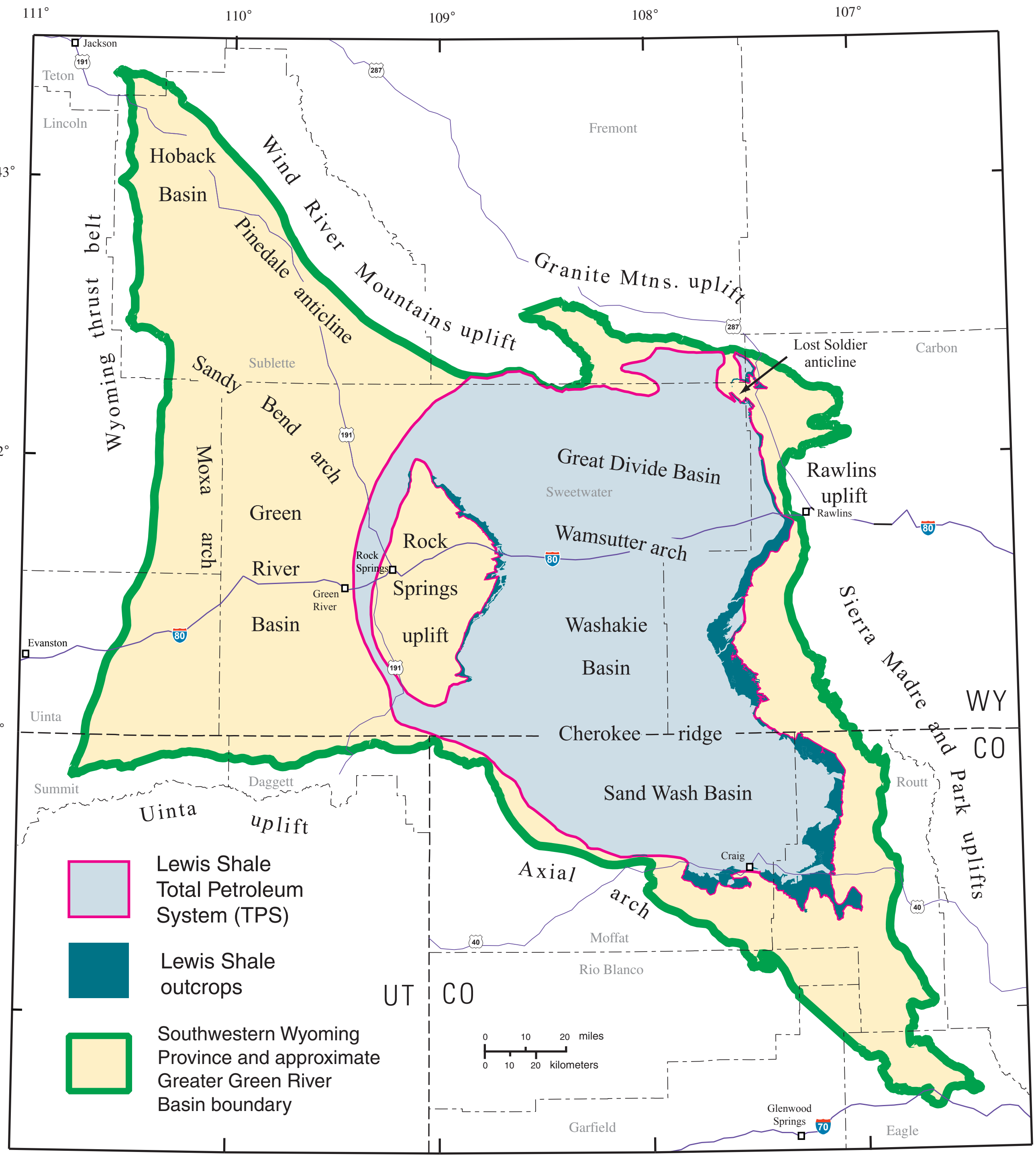

Figure 1. Location of the Lewis Total Petroleum System, Southwestern Wyoming Province, Greater Green River Basin. Lewis Shale outcrops are from Green (1992) and Green and Drouillard (1994).

Sandy Bend, and Wamsutter arches; Cherokee ridge; and Rock Springs uplift (Roehler, 1992). The Rock Springs uplift divides the GGRB, and subbasins in the eastern part include the Great Divide, Washakie, and Sand Wash Basins. The large basin-margin uplifts (Wind River, Granite Mountains, Uinta, Sierra Madre, and Park) are Laramide structures that developed in Late Cretaceous through Eocene time (Ryder, 1988, and references included therein). The Great Divide and Washakie Basins began to subside in Late Cretaceous time and continued to develop as the Axial arch, Cherokee ridge, and Wamsutter arch were uplifted during the Eocene (Ryder, 1988, and references included therein). The Rock Springs uplift was also uplifted between Maastrichtian and Paleocene time and had intermittent growth through at least the middle Eocene (Ryder, 1988; Kirschbaum and Nelson, 1988).

As much as 32,000 ft of Cambrian through Tertiary strata (fig. 2) is preserved in the GGRB (Law, 1996). Cretaceous deposits accumulated in alluvial, coastal plain, nearshore, and marine environments that prevailed along the western shoreline of the Western Interior Seaway. The Lewis TPS is composed of as much as 2,600 ft of Upper Cretaceous (Maastrichtian) strata that accumulated in nearshore and marine environments during the last major transgressive and regressive episode of the Western Interior Seaway (Gill and others, 1970). These strata are designated as the Lewis Shale (fig. 2), which is preserved in the Great Divide, Sand Wash, and Washakie Basins, along the Cherokee ridge, Wamsutter arch, and along the flanks of the Rock Springs uplift.

Owing to Laramide-age tectonics, the Lewis Shale subsided 7,000 to 10,000 ft below sea level in the subbasin centers and was uplifted 6,000 to 8,000 ft above sea level along the basin flanks (fig. 3). The Lewis Shale is overlain by as much as 12,000 to 16,000 ft of Upper Cretaceous through upper Eocene strata in the central regions of the Great Divide, Sand Wash, and Washakie Basins (fig. 4). An additional 3,000 to 3,500 ft of Oligocene through Miocene strata also accumulated above the Lewis but was removed by erosion during the Pliocene (Roberts and others, this CD–ROM). Subsidence and burial moved the Lewis Shale into the zone of hydrocarbon generation by early Paleocene time, peak gas generation was attained by early Eocene time, and gas generation might be continuing throughout most of the Lewis TPS (Roberts and others, Chapter 3, this CD–ROM). The more deeply buried regions of the Lewis TPS are within an overpressured and gas-saturated basin-centered gas system, which has been described in numerous papers referenced by Law (2002). Law and Spencer (1993) considered the GGRB to have one of the largest and better documented basin-centered gas accumulations in the United States.

Acknowledgments

The authors thank members of the U.S. Geological Survey (USGS) National Oil and Gas assessment team (Ron Charpentier, Troy Cook, Bob Crovelli, Tim Klett, and Chris Schenk) for significant discussions regarding the assessment of the Lewis Total Petroleum System. We also thank Troy Cook and Tim Klett (USGS) for graphs and interpretations of production data, Phil Nelson and Joyce Kibler (USGS) for information obtained from drill-stem tests, and Chris Anderson (contractor) for compiling and managing data in a Geographic Information System. Additional input was also provided from Tom Finn, Ed Johnson, Ron Johnson, Mark Kirschbaum, Mike Lewan, Paul Lillis, Phil Nelson, and Steve Roberts (USGS). We appreciate the comprehensive reviews by Chris Schenk and Ira Pasternack (Colorado School of Mines, Golden, Colo.) and editing by Katharine Varnes and Mary Kidd (USGS).

Stratigraphy of Lewis Shale

The Maastrichtian Lewis Shale was deposited when the third-order Bearpaw transgressive cycle of the Western Interior Seaway occupied the Hallville embayment, which was located between the present-day Axial arch, Granite Mountains uplift, and Rock Springs uplift (Roehler, 1990; McMillen and Winn, 1991). Lewis Shale deposition began when the seaway transgressed northwest into the Hallville embayment during the time of the *Baculites eliasi* biozone (Gill and others, 1970; Roehler, 1990). The seaway expanded farther into the embayment during the *Baculites baculu*s biozone, reached its maximum westward extent near the present-day western flank of the Rock Springs uplift during the *Baculites grandis* biozone, and withdrew from the embayment during the *Baculus clinolobatus* biozone (Gill and others, 1970; Roehler, 1990). Obradovich (1993) dated the biozones as follows: *Baculites eliasi* (about 71.0 Ma), *Baculites baculu*s (about 70.5 Ma), *Baculites grandis* biozone (about 70.0 Ma), and *Baculus clinolobatus* (about 69.4 Ma). The stratigraphic chart by Love and others (1993) implies a similar age of about 71–68 Ma for the Lewis Shale.

The Lewis Shale is about 2,600 ft thick in the southeastern Sand Wash Basin, 2,100 to 2,300 ft thick along the eastern margin of the Washakie and Great Divide Basins, and gradually thins to the north and west, toward its depositional pinch-out near the Rock Springs and Granite Mountains uplifts. The Lewis Shale is dominated by offshore marine strata, and its stratigraphic relations with adjacent formations are generally straightforward; shoreface deposits of the initial marine transgression are placed in the underlying Almond Formation, shoreface deposits of final marine regression are placed in the overlying Fox Hills Sandstone, and the ensuing succession of coastal-plain deposits is placed in the Maastrichtian Lance Formation. However, these stratigraphic relations become more complex in regions near the depositional pinch-out of the Lewis. For example, in the northern Great Divide Basin, the Lewis, Fox Hills, and Lance intertongue in a 1,000-ft-thick interval and shoreface deposits of the Fox Hills can be

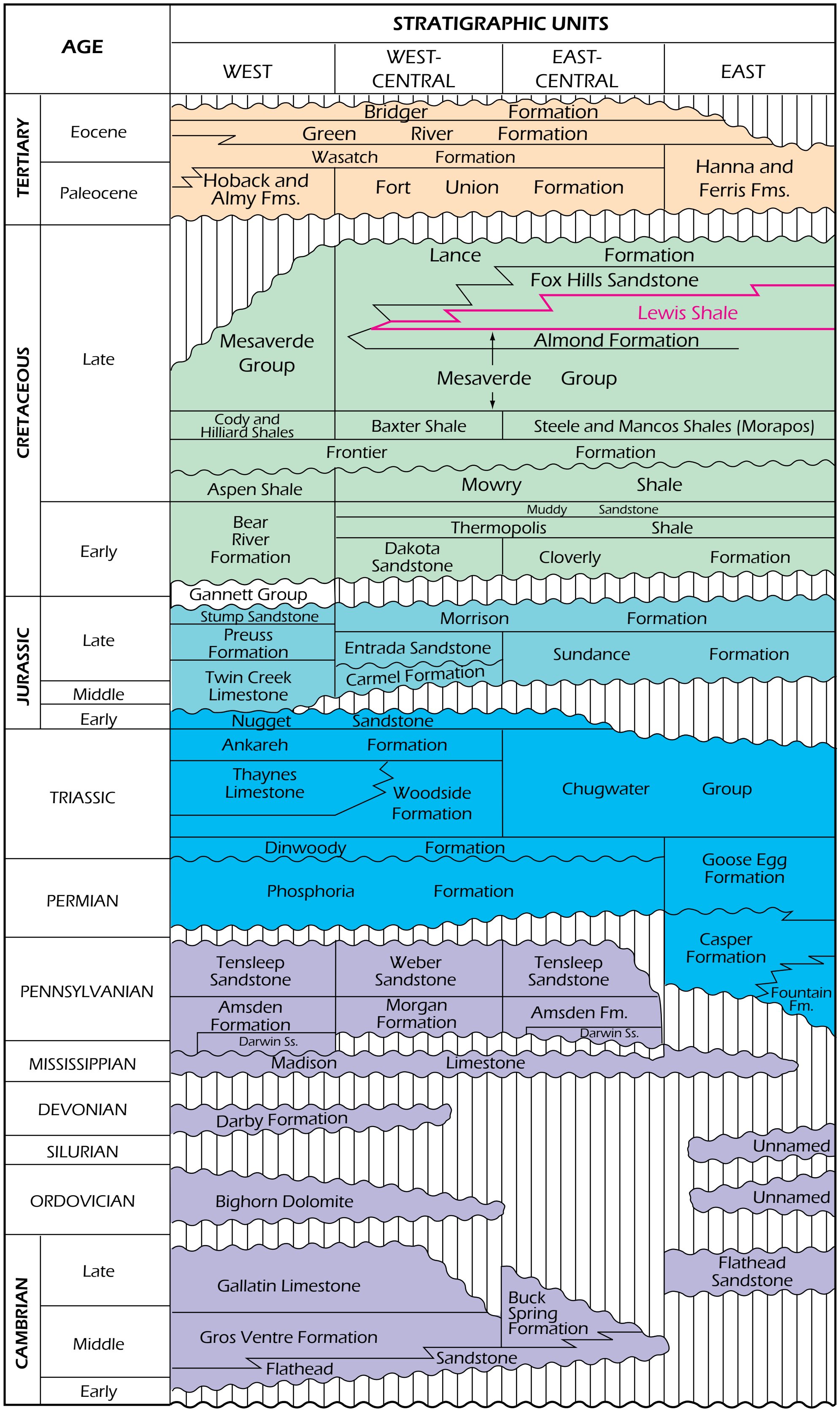

Figure 2. Chart showing formations and stratigraphic relations in the Southwestern Wyoming Province. The Lewis Total Petroleum System is outlined in red.

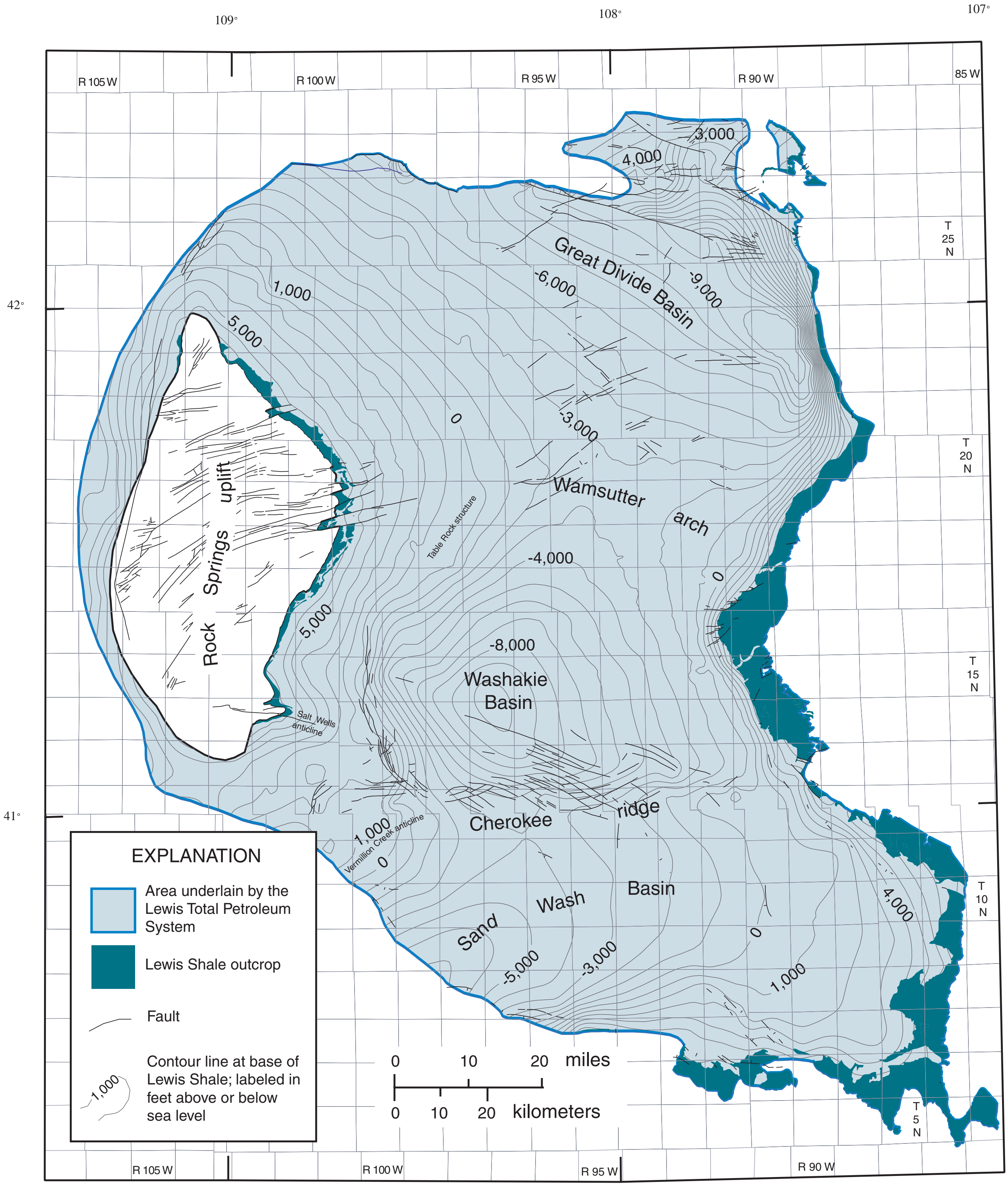

Figure 3. Structure contour map constructed on the base of the Lewis Shale. Elevations are based on outcrop information and data in the IHS Energy Group (2001) database from about 2,900 wells that penetrated the Lewis Shale. Lewis Shale outcrops are from Green (1992) and Green and Drouillard (1994). Contour interval 1,000 ft.

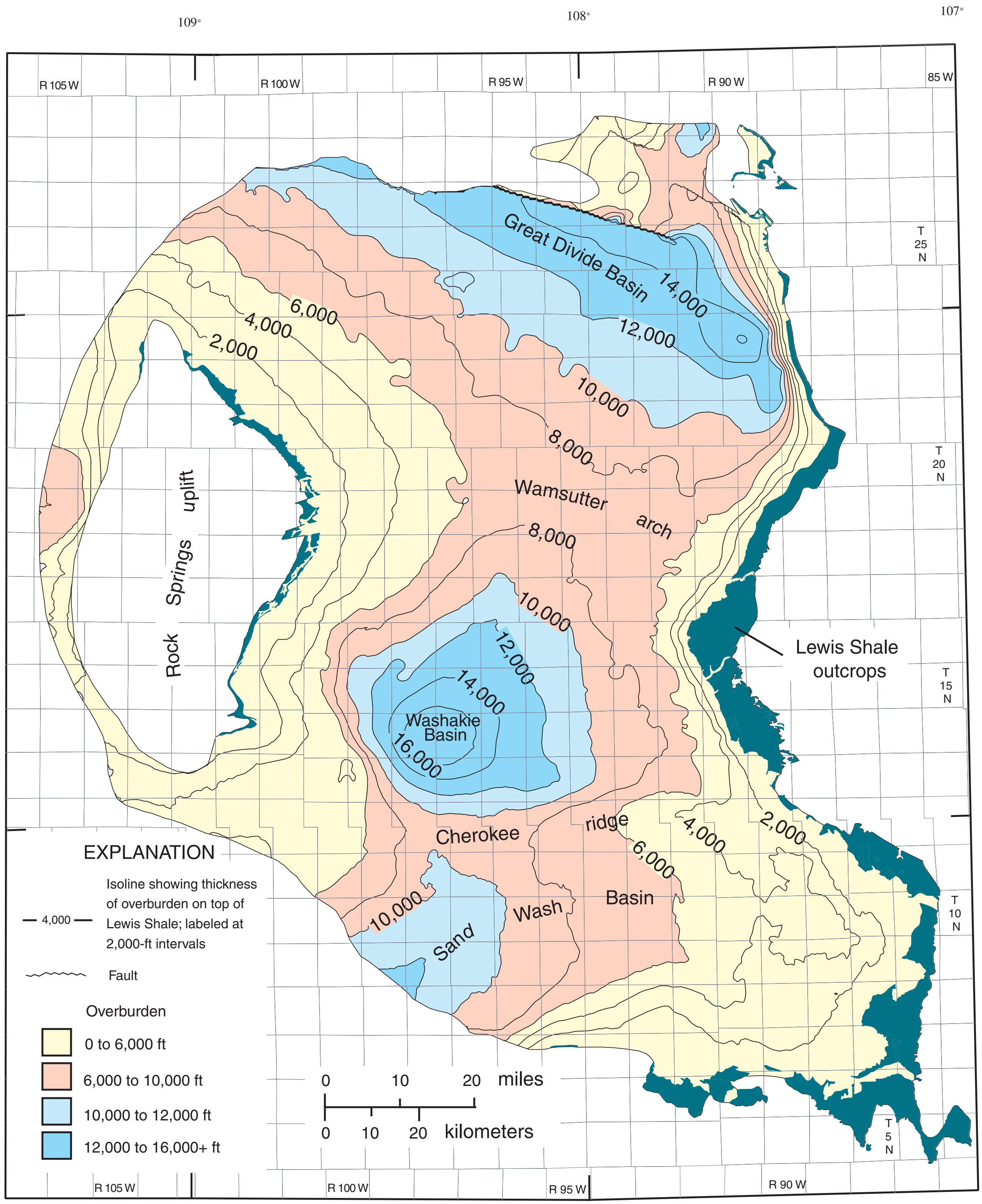

Figure 4. Overburden thickness on top of the Lewis Shale. Lewis Shale outcrops are from Green (1992) and Green and Drouillard (1994).

traced southward several townships where they are encased in offshore deposits of the Lewis (Ross and others, 1995; Weimer, 1970). In this report, the distal tongues of shoreface sandstone are included with the Lewis Shale, following the nomenclature of Gill and others (1970), Winn and others (1985), and Perman (1990).

The Lewis Shale is divided into a lower part, the Dad Sandstone Member, and an upper part (fig. 5), each containing various amounts of shale, siltstone, and very fine to medium-grained sandstone (Gill and others, 1970). The lower part of the Lewis Shale is composed of several hundred feet of black, organic-rich marine shale and includes the 30- to 120-ft-thick, informally named Asquith marker zone located about 100 to 700 ft above the basal Lewis contact. The Asquith has one of the highest gamma-ray log responses in the Lewis Shale and is interpreted as a third-order maximum flooding surface and condensed section that separates transgressive deposits from overlying highstand deposits in the third-order cycle (Pyles, 2000). The sandstone-dominated Dad Sandstone Member is as much as 1,400 ft thick in the eastern Washakie Basin but thins to the north, west, and south and is replaced by equivalent sandstone-dominated intervals that eventually pinch out into the undivided Lewis Shale. The laterally equivalent sandstones are commonly referred to informally as middle sandy member, middle Lewis sands, and lower Lewis sands; however, in this report they are simply considered part of the Dad Sandstone Member. The upper part of the Lewis Shale is composed of several hundred feet of silty to sandy marine shale and shoreface sandstone deposited during the late phase of the third-order highstand.

Depositional interpretations of the Lewis Shale have been refined by numerous sedimentological and stratigraphic investigations conducted since the 1970s. In brief, those studies show that the Lewis Shale represents deposition in deltaic, shelf, ramp-slope, and basin environments. A generalized paleogeographic map (fig. 6) depicts the approximate location of shoreface, shelf-ramp-slope, and deep-basin environments during deposition of the Dad Sandstone Member (time of *Baculites grandis*); the map is based on the collective studies cited in this paragraph. In general, the embayment was partially filled by deltaic systems sourced from the north and northeast (Asquith, 1970; Perman, 1990), southwest (Weimer, 1970; Roehler, 1990), and west (Hamzah, 2002). Sediment was transported into deeper marine basin environments by various gravity flow or turbidite-related processes (Winn and others, 1985, 1987; Cain, 1986; Van Horn and Shannon, 1989; Perman, 1990; McMillen and Winn, 1991; Robinson, 1993; Anderson, 1995; Ross and others, 1995; Hendricks, 1996; Witton, 1999; Pyles, 2000; Pyles and Slatt, 2000a; Dolloff and Lancaster, 2001; Parker and Bortz, 2001; Steinhoff and others, 2001; Zainal, 2001; Hamzah, 2002; Suryanto, 2003).

Additional sequence stratigraphic studies by Pyles (2000) and Pyles and Slatt, (2000a) demonstrated that the Lewis Shale contains numerous unconformity-bounded sequences deposited in response to rapid changes in relative sea level and sediment supply. As many as 21 sequences were interpreted along a 45-mi-long, dip-oriented cross section in the Great Divide and Washakie Basins (Pyles, 2000; Pyles and Slatt, 2000a), each consisting of highstand, transgressive, and lowstand systems tracts. The highstand systems tracts contain laterally continuous deposits of silty sandstone and shale that accumulated in shallower-water shoreface and offshore environments on the shelf and ramp-slope. Transgressive systems tracts contain mudrock that accumulated in nearshore and offshore environments, primarily on the shelf and slope. Lowstand systems tracts contain basin-floor fans, slope fans, and prograding complexes that accumulated primarily in deeper-water environments of the ramp-slope and basin. Pyles (2000) and Pyles and Slatt (2000a) described (1) basin-floor fans as consisting of laterally continuous, thick sandstones; (2) slope fans as consisting of discontinuous channel sandstones, thin-bedded continuous sandstones, and laterally continuous beds of mudstone; and (3) prograding complexes as consisting of thin-bedded sandstone and mudstone. Ongoing research by Pyles and Slatt (2002b) suggests that in addition to eustasy and sediment supply, cyclic sedimentation in the Lewis Shale was also controlled by variations in tectonic uplift along the northern border of the Great Divide Basin.

Lithostratigraphic correlations of the Lewis Shale are shown along a 140-mi-long cross section (pl. 1) that extends north to south through the Great Divide, Washakie, and Sand Wash Basins. The cross section orientation varies with respect to the orientation of the paleoshoreline and bathymetry. The northern part of the cross section is oriented approximately normal to the shelf, ramp-slope, and basin topography described in the Great Divide and Washakie Basins by Perman (1990). The bathymetry is revealed by laterally continuous clinoforms traced from shoreface deposits in the northern Great Divide Basin to deep-basin turbidites in the Washakie Basin. These correlations generally follow those of Winn and others (1985, 1987), Van Horn and Shannon (1989), Perman (1990), Ross and others (1995), Pyles (2000), Pyles and Slatt (2000a), Hamzah (2002), and Suryanto (2003). The southern part of the transect is oriented subparallel to the depositional system in the Sand Wash Basin, and correlations show horizontal to northward-dipping clinoforms. Based on the work of Haun (1961), Weimer (1970), Cain (1986), Roehler (1990), Dolloff and Lancaster (2001), and Zainal (2001), clinoforms in the Sand Wash Basin are interpreted to reflect a deltaic and turbidite system, sourced from the southwest, with deposition occurring on northeastward- and eastward-sloping shelf and deep basin topography.

Basin-Centered Gas System in the Greater Green River Basin

Paramount to the assessment of the Lewis TPS is an overpressured basin-centered gas system in the GGRB. Overpressured or anomalously pressured strata in the GGRB have been described in numerous studies, notably those by McPeek

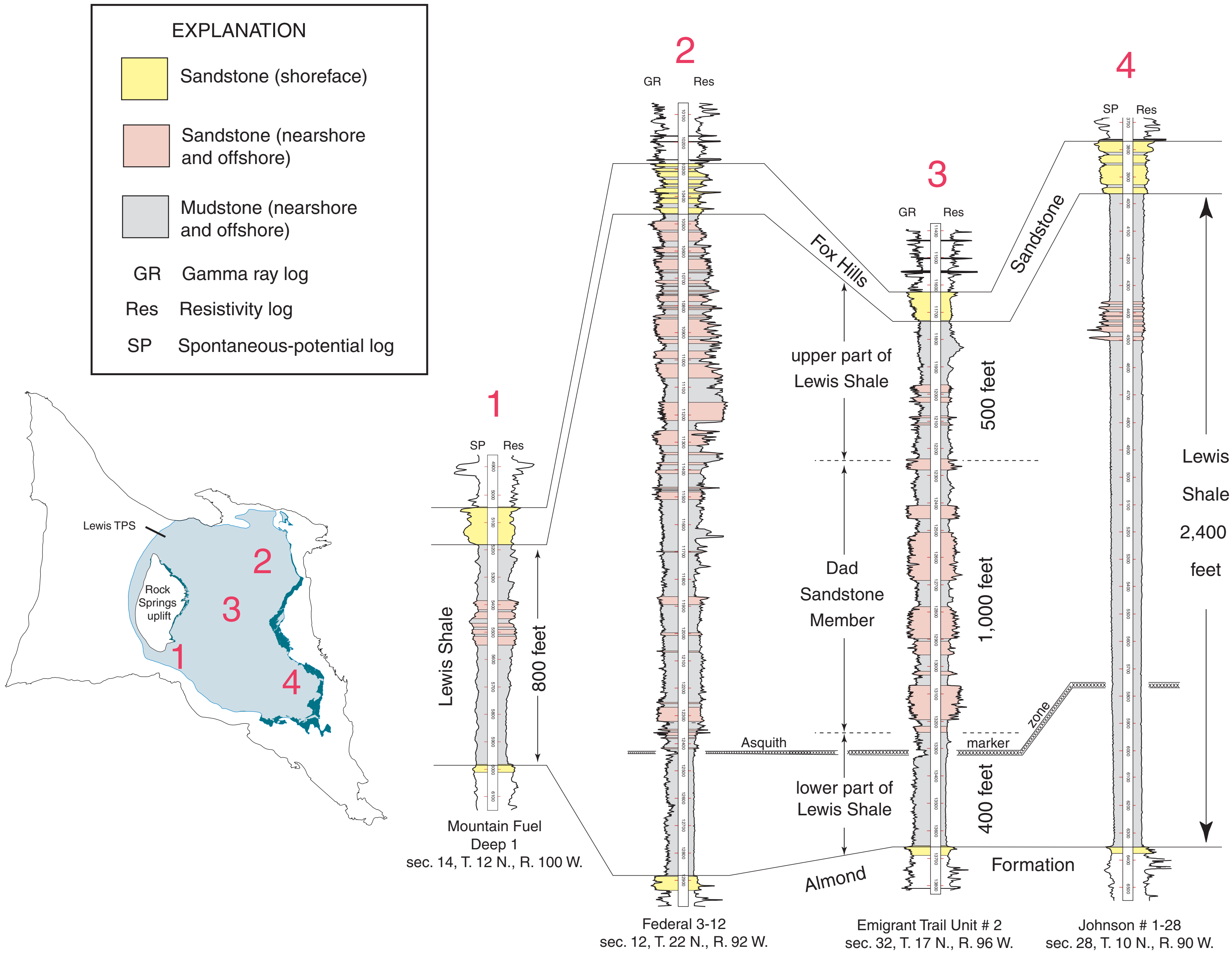

Figure 5. Geophysical log signatures of the Lewis Shale. The Lewis Shale pinches out at its depositional limit west of the Rock Springs uplift (west of locality 1) and is 2,000 to 2,600 feet thick in the Great Divide, Sand Wash, and Washakie Basins (localities 2, 3, and 4). The Lewis Shale is divided into an upper part, the Dad Sandstone Member, and a lower part in the Washakie Basin (locality 3).

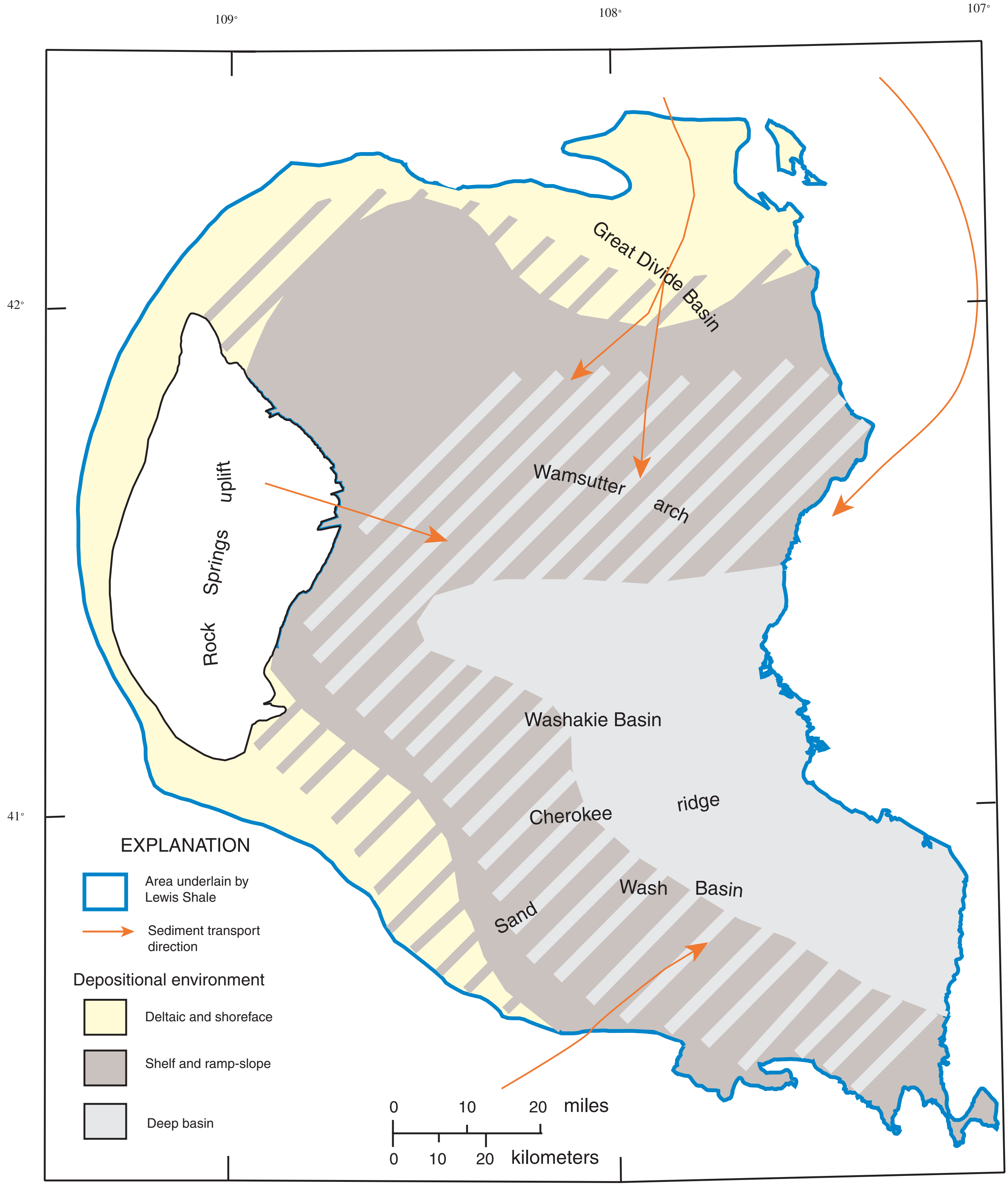

Figure 6. Generalized paleogeographic map of the region containing the Lewis Total Petroleum System. Map shows depositional environments that prevailed during deposition of the middle part of the Lewis Shale (time of *Baculites grandis*). Regions of deltaic, shoreface, shelf and ramp-slope, and deep-basin environments are shown. Hachures show where depositional environments overlap and intertongue due to transgressions and regressions of the shoreline.

(1981), Law (1984, 2002), Law and Dickinson (1985), Spencer (1987), Law and others (1989), Law and Spencer (1993), Surdam and others (1997), and Suryanto (2003). Law (2002) assigned a high level of certainty to a basin-centered gas system in the GGRB, and Law and Spencer (1993) considered the GGRB to have one of the largest and better documented basin-centered gas accumulations in the United States. The Lewis Shale has been included within the overpressured zone by all of the previously mentioned authors. The overpressured zone developed, and was maintained, because the rate of gas generation exceeded the rate of gas loss (Law and Dickinson, 1985; Law and others, 1989), and it is considered to be gas-saturated (Law, 2002). The system is further characterized by low permeability that developed because the remaining tightly bound water cannot remove dissolution products (Masters, 1979; Law and Dickinson, 1985; Law, 2002). Law (2000, 2002) lists the following characteristics as representative of the basin-centered gas system in the Greater Green River:

1. The absence of downdip water contacts.

2. Permeabilities less than 0.1 millidarcy (mD).

3. Pressure gradients from 0.5 to 0.9 pounds per square inch per foot (psi/ft).

4. Depths of 8,000 to 11,000 feet to the top of overpressuring.

5. Vitrinite thermal maturity levels of 0.7 to 0.9 percent R_o (and commonly 0.8 percent R_o) at the top of the basin-centered accumulation.

6. The presence of sweet spots, which are local areas of enhanced reservoir quality. In Great Divide Basin, the Lewis Shale contains sandstones that were cited specifically as examples of stratigraphic sweet spots (Law, 2002, p. 1913).

Lewis Total Petroleum System (503707)

The Lewis Total Petroleum System (TPS) is confined to strata assigned to the Upper Cretaceous Lewis Shale in the GGRB. The TPS is complete with source rock, reservoir rock, and reservoir seals. Principal reservoirs are turbidite sandstones in the Dad Sandstone Member, and some hydrocarbon production has also been reported from the lower part of the Lewis. The sandstone reservoirs are encased and sealed by clay-rich mudrock, and hydrocarbon is sourced from organic-rich marine mudrock, specifically in the lower part of the Lewis.

The Lewis TPS encompasses approximately 6,196,100 acres (about 9,680 mi^2) within the GGRB of the Southwestern Wyoming Province (fig. 1). The western boundary of the Lewis TPS is defined by the depositional pinch-out of the Lewis Shale as determined from drill-hole data. Its northern boundary is placed where the Lewis Shale is truncated by thrust faults along the southern limbs of the Wind River and Granite Mountains uplifts, as estimated from cross sections by Blackstone (1991). Similarly, the southern TPS boundary is placed where the Lewis Shale is truncated by faults along the Axial arch. Elsewhere, outcrops of the basal contact of the Lewis Shale define the TPS boundary. Excluded from the TPS are areas where the Lewis Shale has been removed by erosion within the core of the Rock Springs uplift, and areas where the Lewis grades into the Lance Formation near the Lost Solider anticline (fig. 1) as described by Reynolds (1966).

Although about 600 billion cubic feet of gas (BCFG) has been produced from the Lewis Shale (Doelger and others, 1999), its production is impossible to determine precisely due to commingling with other formations. Based on cumulative production from individual wells in the IHS Energy Group (2001) database, between 585 and 675 BCFG has been produced from the Lewis Shale; included is 585 BCFG from 435 wells where production was limited to the Lewis Shale and 90 BCFG from 102 wells where production was commingled with other formations. In addition, about 8.1 million barrels of oil and condensates has been produced from the Lewis Shale; included is 7.3 million barrels from wells where production was limited to the Lewis Shale and 0.8 million barrels from wells where production was commingled with other formations. The IHS Energy Group (2001) database does not include production before 1974; therefore, production from the Lewis Shale might exceed the amounts reported here.

The Lewis TPS is interpreted to contain both continuous and conventional hydrocarbon accumulations. The continuous accumulation is named the Lewis Continuous Gas Assessment Unit (50370761) and is located in deeper basin regions that are characterized by an overpressured, gas-saturated, basin-centered system (fig. 7). Conventional accumulations are in the Lewis Conventional Oil and Gas Assessment Unit (50370701) and are located in shallower basin regions where hydrocarbons have migrated from the overpressured zone and accumulated in conventional stratigraphic or structural traps (fig. 7). Due to the thickness of the Lewis Shale, its lower part may lie in the continuous assessment unit while its upper part may lie in the conventional assessment unit. Thus, the assessment units overlap along the basin flanks and intrabasin uplifts where the Lewis has partially emerged from the basin-centered gas system. Law and others (1989, their figs. 6, 7, and 8) depict similar overlapping relations of overpressured and normal-pressured strata in the GGRB. Hydrocarbon production in the overlap area was determined to be from either the conventional or continuous assessment unit, based on the depth of production.

Hydrocarbon Source Rocks

Both gas and oil have been produced from the Lewis TPS; however, the principal production is gas. Gas to oil ratios (cu ft/bo) reported for 14 fields range from about 9,400 to

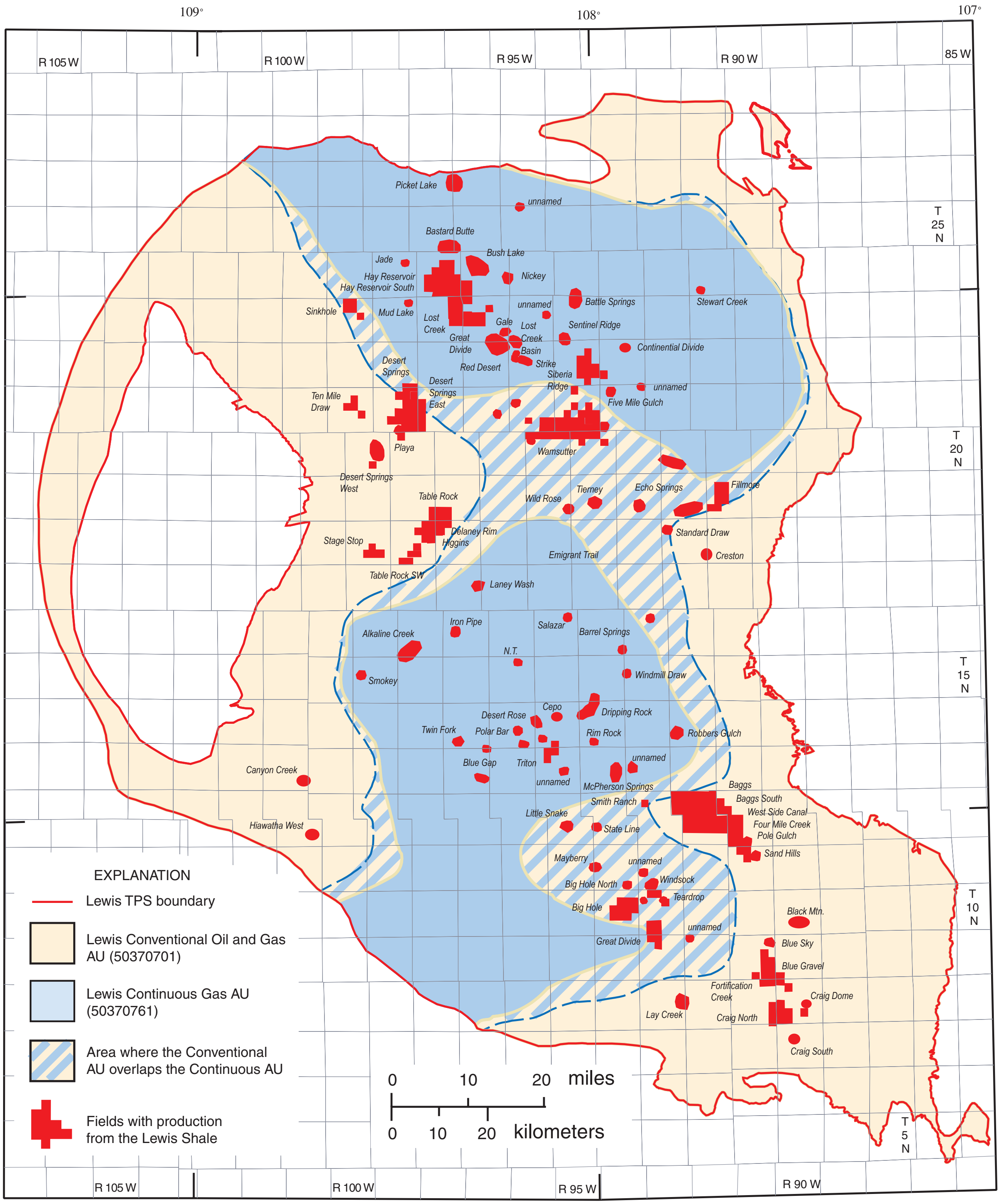

Figure 7. Location of assessment units (AU) in the Lewis Total Petroleum System (TPS). Included are the Lewis Conventional Oil and Gas AU (50370701) and the Lewis Continuous Gas AU (50370761). The two AUs overlap within the hachured area. Also shown are fields that have produced from the Lewis TPS. Field names are based on information from the IHS Energy Group (2001), Cardinal and Stewart (1979), and Miller and others (1992).

758,800, and 5 additional fields reported dry gas (Miller and others, 1992). Only one field (Stage Stop) reported a gas to oil ratio as low as 1,118 (Miller and others, 1992). The oil or condensates have American Petroleum Institute (API) gravity values that range from 36° to 62°, as reported for 21 fields described in Miller and others (1992); 6 fields have values from 36° to 44°, 11 fields have values from 45° to 55°, and 4 fields have values from 56° to 62°. Hunt (1997, p. 52) defines light oils as having API gravities from 31° to 55° and condensates as having API gravities greater than 55°.

Gas-charged sandstones in the Lewis are generally considered to have been sourced by mudrock in the Lewis Shale (Law, 1996); more specifically, the 30- to 120-ft-thick, organic-rich Asquith marker zone in the lower part of the Lewis Shale has been cited as a potential source rock (Pyles, 2000; Dolloff and Lancaster, 2001; Zainal, 2001; Hamzah, 2002). The Asquith marker is interpreted as a third-order condensed section that extends laterally across the entire GGRB region occupied by the Lewis Shale (Pyles, 2000). Gas might also have been sourced from additional thinner, fourth-order condensed sections distributed throughout the Lewis Shale (Pyles, 2000). One report by Meissner (1987) attributes gas to coal beds in the underlying Almond Formation. Although some petroleum in the Lewis Shale might have been derived from other formations (for example, oil produced from the Stage Stop field), the Lewis was considered to be a principally self-sourced petroleum system for the purpose of this assessment.

Values of total organic carbon (TOC) in the Lewis Shale have been measured from a limited number of core samples (Law, 1984; Pyles, 2000; Zainal, 2001). In the Great Divide Basin, core samples from the Amoco Production Company Champlin 276-D-1 well (sec. 13, T. 19 N., R. 92 W.) show that the Asquith marker zone has TOC values that range from 1.68 to 3.15 weight percent (Pyles, 2000). However, Ira Pasternack (written commun., 2003) reported that his review of Champlin core analyses revealed inconsistent results, possibly because random depth samples may not have detected TOC changes over short intervals. In the Sand Wash Basin, the Federal #1-14-28 well (sec. 28, T. 10 N., R. 93 W.) provided a sidewall core sample from the Asquith marker zone that had a TOC value of 2.30 weight percent (Zainal, 2001). Law (1984) reported TOC values for additional mudrock intervals in Lewis Shale in the Great Divide and Sand Wash Basins; 15 core samples from 5 wells had TOC values that ranged from 0.55 to 2.86 weight percent and averaged 1.33 weight percent.

Lewis Shale source rock has been characterized as containing Type-II and Type-III organic matter (Law and others, 1989; Pyles, 2000). According to Pyles (2000), both gas and oil were likely to have been generated from the Champlin 276-D core, and hydrocarbons were generated from Type-II and Type-III kerogen. However, nearly all samples from the Champlin core plot close to the Type-III kerogen path on a modified van Krevelen diagram shown by Pyles (2000, his figure 5.4). Law (1984, p. 484) described similar plots for marine and marginal marine samples in the GGRB (including those from the Lewis Shale) and considered the atomic H/C (hydrogen/carbon) ratios to be too low for Type-I and Type-II kerogens. In this report, the Lewis Shale source rock is considered to be primarily Type-III gas-prone on the basis of (1) high gas-to-oil ratios recorded from fields with Lewis Shale production, (2) the absence of major oil accumulations in the Lewis Shale, and (3) the close association of samples to the Type-III kerogen path on the modified van Krevelen diagram by Pyles (2000).

Source Rock Maturation

Source rock maturity in the Lewis TPS was determined from vitrinite reflectance (R_o) values provided by Law (1984) and Pawlewicz and Finn (2002). Roberts and others (this CD–ROM) suggested that gas generation from Type-III gas-prone source rock (1) began when R_o values of source rock attained 0.5 percent, (2) peaked when R_o values attained 0.8 percent, and (3) ended when R_o values exceeded 2.0 percent. Law (2002, and references included therein) used similar R_o values to signify the onset and peak generation of gas from Type-III source rock; he suggested that gas generation began when R_o values attained 0.6 percent, and peak gas generation occurred when R_o values attained 0.8 to 0.9 percent. The top of the overpressured zone in the GGRB was also considered to coincide with the peak gas generation and R_o values of about 0.8 percent (Law, 1984, 2002; Law and others, 1989; Law and Spencer, 1993).

Areas of thermal maturity in the Lewis TPS are depicted by R_o isolines at the base and top of the Lewis Shale (fig. 8). The isolines generally parallel the structural configuration of the basins and increase in value toward the basin centers, owing to greater burial depths and temperatures. R_o values range from less than 0.6 percent near the basin margins to as much as 1.1 percent in the Sand Wash Basin, 1.6 percent in the Great Divide Basin, and 2.0 percent in the Washakie Basin. Lewis Shale source rock is therefore considered to be thermally mature across large parts of the Lewis TPS. Following Roberts and others (Chapter 3, this CD–ROM): (1) gas generation has occurred in all areas where R_o values exceed 0.5 percent, (2) peak gas generation has occurred in all areas where R_o values exceed 0.8 percent, and (3) gas generation has ended in all areas where R_o values exceed 2.0 percent. Following Law (2002, and references included therein), the Lewis Shale is within the overpressured, basin-centered gas system where R_o values exceed 0.8 percent. Thus, the base of Lewis Shale is within the basin-centered gas system along a north-south-trending corridor that extends through the deeper regions of the Great Divide, Washakie, and Sand Wash Basins and over the Wamsutter arch and Cherokee ridge. The top of the Lewis Shale occupies a smaller region within the basin-centered gas system and emerges completely from the overpressured system along the Wamsutter arch.

Burial-history curves and analyses by Roberts and others (Chapter 3, this CD–ROM) provide additional information about the timing of thermal maturation in the Lewis Shale.

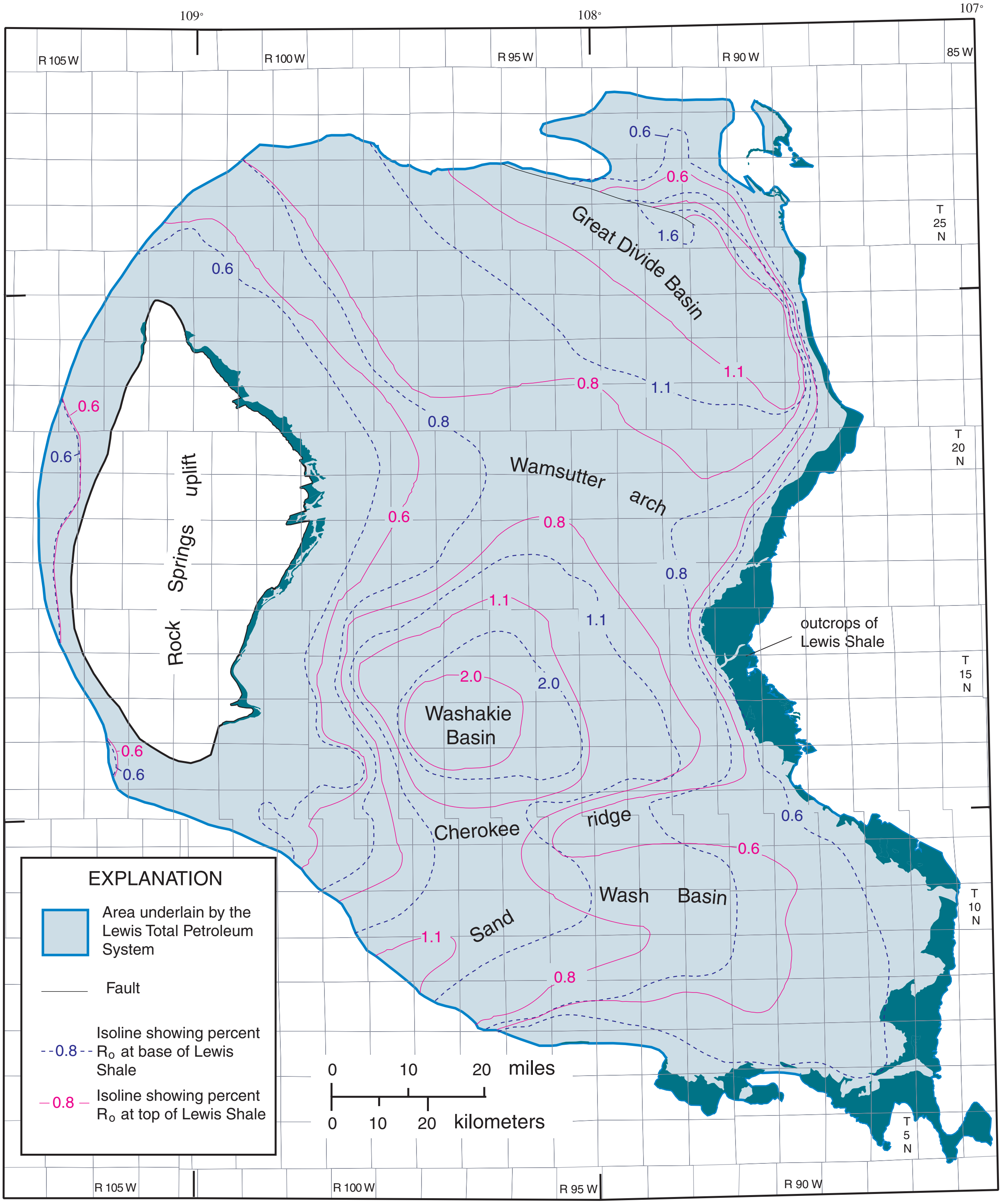

Figure 8. Thermal maturity of source rock of the Lewis Total Petroleum System. Vitrinite reflectance (R_0) isolines are shown at the base and top of Lewis Shale. Lewis Shale outcrops are from Green (1992) and Green and Drouillard (1994).

Burial-history curves were constructed for the Adobe Town well (sec. 20, T. 15 N., R. 97 W.), Bear 1 well (sec. 28, T. 7 N., R. 89 W.), and Eagles Nest well (sec. 29, T. 25 N., R. 91 W.), and results are summarized in figure 9. The Adobe Town and Eagles Nest wells are respectively located in the deepest parts of the Washakie and Great Divide Basins, where the base of the Lewis was drilled at depths of about 16,900 ft. In contrast, the Bear 1 well is on the southeast flank of the Sand Wash Basin where the base of the Lewis was drilled at a shallow depth of 3,580 ft.

The burial-history analyses of Roberts and others (Chapter 3, this CD–ROM) and R_o isoline configurations in figure 8 show that the Lewis Shale became thermally mature in the deep-basin areas first, about 62 Ma (during the early Paleocene) in the structural center of the Washakie Basin and about 56 Ma (during the late Paleocene) in the structural center of the Great Divide Basin. Gas generation probably began at a similar time in the structural center of the Sand Wash Basin, owing to its similar structural history with the Washakie Basin. The regions of gas generation expanded outward as the burial depth of the Lewis Shale increased through time. About 52 Ma to 50 Ma (during the early Eocene), the Lewis Shale was buried sufficiently to achieve peak gas generation in the deep-basin areas, and by 12 Ma (during the middle Miocene) the region of gas generation had expanded to shallower basin flanks, as determined from the burial-history curve of the Bear 1 well. The maximum areal extent of gas generation and peak gas generation was reached at the time of maximum burial of the Lewis Shale, about 5 Ma (late Miocene to early Pliocene). The isolines in figure 8 reflect R_o values attained at that time. The burial depth of the Lewis Shale has been reduced during the past 5 million years due to basin uplift and erosion of overburden. Although gas generation ended about 36 Ma (during the late Eocene) at the site of the Adobe Town well, the burial-history analyses suggest that gas generation might be ongoing where R_o values in the TPS lie between 0.5 and 2.0 percent, as shown in figure 8. However, ongoing gas generation is likely to be significantly reduced from the time when the Lewis Shale attained its maximum burial.

Hydrocarbon Migration

Hydrocarbon migration in the Lewis TPS is closely associated with the development of the overpressured, basin-centered gas system in the GGRB. Although the Lewis Shale began to generate gas during the Paleocene, significant gas migration probably did not begin until the Lewis Shale was buried sufficiently to generate large volumes of gas, whereby pore pressures were increased above regional hydrostatic pressures (Law and Dickinson, 1985, their discussion of stage III development of abnormally pressured gas accumulations). Those conditions were first attained in the early Eocene when the Lewis Shale attained peak gas generation. As overpressuring developed, both water and gas were forced into adjacent lower pressured strata, thereby charging conventional stratigraphic and structural traps that were already formed by Eocene time. Migration pathways probably either were oriented perpendicular to the structural configuration of the basins or followed fault planes and sandstones into updip regions along the basin flanks and intrabasin uplifts.

The basin-centered gas system is gas saturated, and fluid migration is generally limited to a few hundred feet (Law, 1984, 2002). Overpressuring is maintained because the rate of gas generation has exceeded the rate of gas loss, and water is prevented from reentering the overpressured zone as long as pore pressure remains higher than the regional hydrostatic pressure (Law and Dickinson, 1985). However, basin uplift and overburden erosion can disrupt temperature and pressure regimes and cause a reduction or cessation of gas generation (Law and Dickinson, 1985, their discussion of stage IV development). Therefore, an overpressured system can evolve into an underpressured system, thereby creating the potential for water to reenter the basin-centered gas system. Such conditions may have developed to some degree in the GGRB, owing to overburden removal since the Pliocene.

We suggest that gas migration was also influenced, or enhanced, by the expanding boundary of the basin-centered gas system. Overpressuring developed initially as isolated pods in the deeper regions of the Great Divide, Washakie, and Sand Wash Basins but extended subsequently across all three basins, owing to basin subsidence during the Eocene. As the basin-centered gas system grew in size, it may have encapsulated previously charged conventional stratigraphic traps. Therefore, the traps were charged before they were incorporated into the basin-centered gas system, and permeability was reduced. If correct, this model provides a mechanism for creating sweet spots, which Law (2002) considered to be characteristic of the basin-centered gas systems in the Greater Green River Basin.

Hydrocarbon Reservoir Rocks

Field reports described in Cardinal and Stewart (1979) and Miller and others (1992) show Lewis Shale production is from very fine to fine-grained and some medium-grained sandstone, with pay thicknesses ranging from about 5 to 100 ft for individual fields. Producing sandstones have porosity values that range from about 8 to 25 percent and permeability values that range from about 0.01 md to 50 md. Law and others (1989) estimated an average porosity of 8.0 percent for their Lewis Shale play located in the deeper part of the Great Divide, Sand Wash, and Washakie Basins. Hydraulic fracturing is commonly required for commercial production in reservoirs that have in-situ permeability less than 0.1 md (Law and others, 1989). Data compiled by the IHS Energy Group (2001) indicate that production depths range from about 2,400 to 17,200 ft, and pressure gradients range from 0.323 psi/ft to 0.64 psi/ft. The higher pressure gradients generally are in the deeper parts of the Lewis TPS.

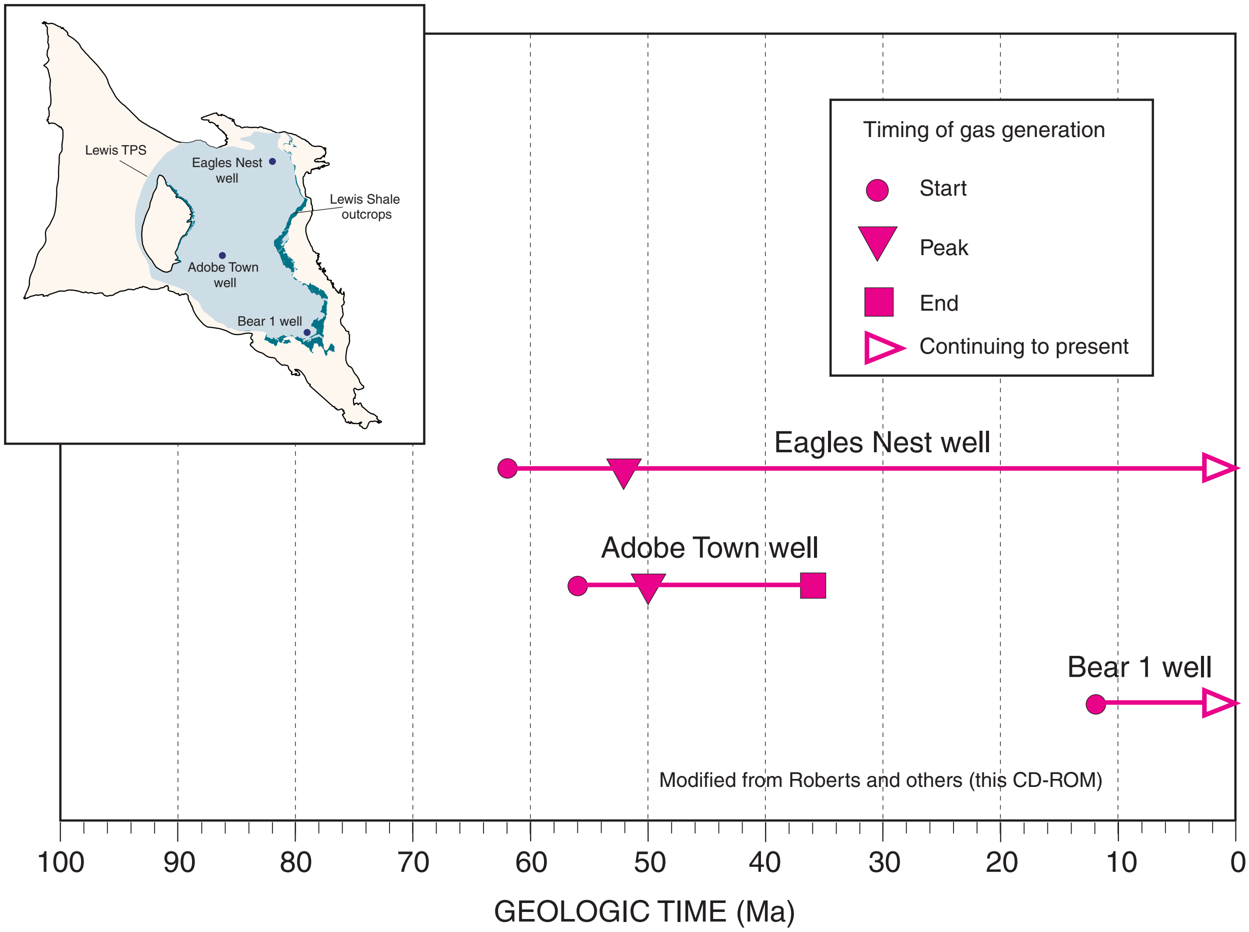

Figure 9. Timing of gas generation in the Lewis Shale. Time of gas generation was determined from burial-history curves constructed at the Adobe Town, Bear 1, and Eagles Nest wells (Roberts and others, Chapter 3, this CD–ROM). Well locations shown in inset map. The Adobe Town and Eagles Nest wells are in the deepest parts of the Washakie and Great Divide Basins, respectively. The Bear 1 well is on the southeast flank of the Sand Wash Basin. The present rate of gas generation in the Eagles Nest and Bear 1 wells is probably significantly reduced from the time when the Lewis Shale attained maximum burial, about 5 Ma.

Hydrocarbon reservoirs occur as sandstones bodies encased in Lewis Shale mudrock (Law, 1996). Individual sandstones are several feet to 100 ft thick and may be stacked in units as much as 350 ft thick. The cumulative thickness of sandstone ranges from 200 to 600 ft across much of the Lewis TPS (fig. 10) (Law, 1996; Law and others 1989, their fig. 14). Most of the reservoirs are in the Dad Sandstone Member, which is as much as 1,400 ft thick in the eastern Washakie Basin, but the Dad Sandstone Member eventually thins, splits, and pinches out into mudrock in the Lewis Shale, as demonstrated in the cross section on plate 1. The sandstone bodies are exposed on the eastern flanks of the Great Divide and Washakie Basins and are as much as 16,600 ft deep in the center of the Washakie Basin.

Numerous sedimentological and stratigraphic investigations provide information regarding the origin and continuity of the sandstone reservoirs in the Lewis Shale (see chapter section "Stratigraphy of Lewis Shale"). As previously described, sediment was sourced from the north, west, and south and was deposited in nearshore, deltaic, and turbidite systems that prevailed along the shelf, ramp-slope, and deep basin. Each depositional system contains numerous bodies of sand and mud. Steinhoff and others (2001) identified as many as 50 to 60 individual sand-lobe complexes and channels. The deep-basin deposits may have the best reservoir potential for stratigraphic trapping because they contain laterally continuous basin-floor sandstones overlain by deep-water shales that provide good seals (Pyles, 2000; Pyles and Slatt, 2000a). In contrast, nearshore deposits may have the poorest potential for stratigraphic trapping because the overlying seals are silty shales, which have poor sealing capacity (Pyles, 2000; Pyles and Slatt, 2000a). Dimensions of sandstone bodies in the turbidite systems are provided in the following examples:

1. Southwestern and southern part of the Great Divide Basin (examples from Van Horn and Shannon [1989] and Doelger and others [1999])—The Dad Sandstone Member contains multiple sandstone lobes that have been interpreted as base of slope fans by Van Horn

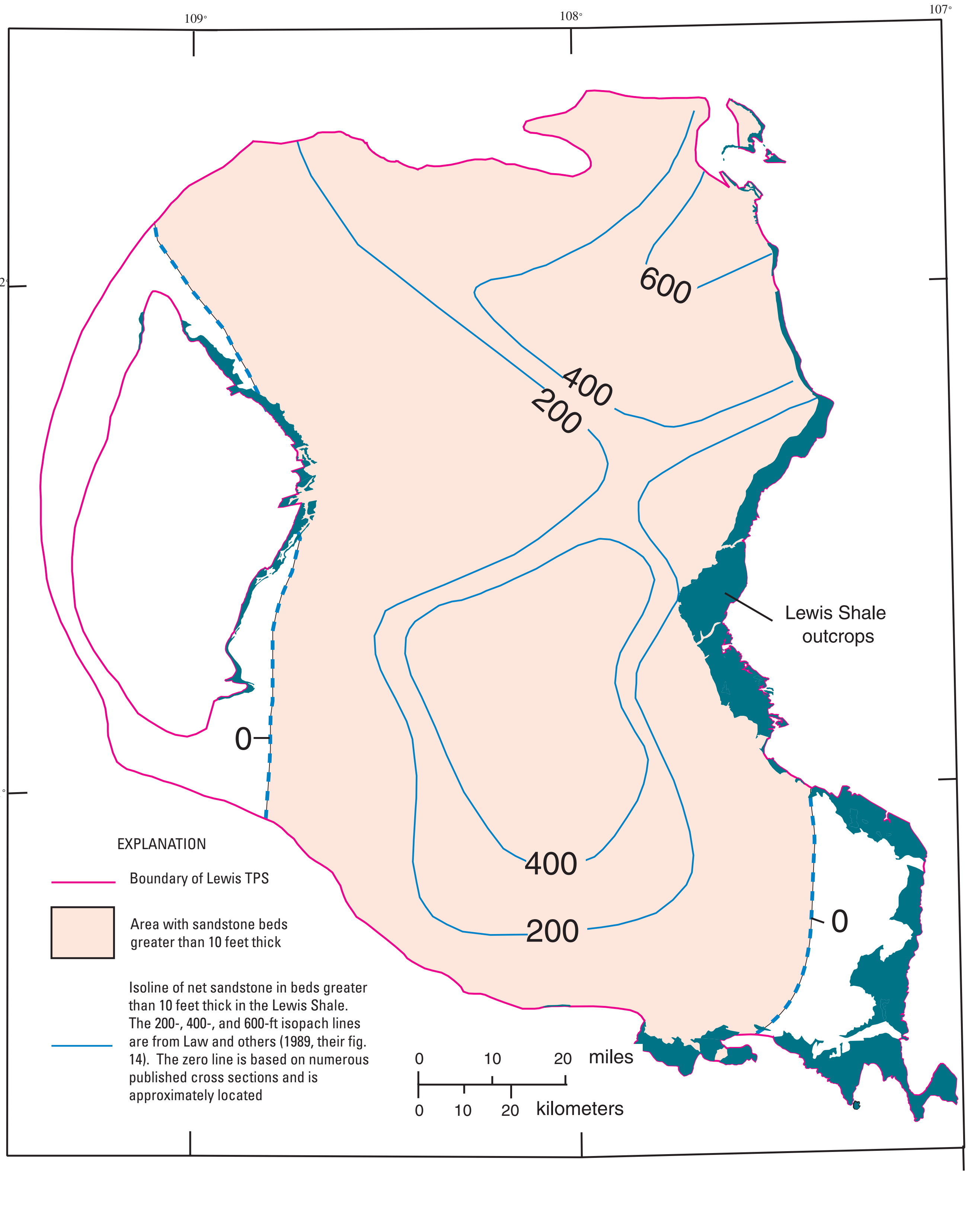

Figure 10. Net sandstone thickness in the Lewis Shale. Isopach lines represent net sandstone in beds greater than 10 feet thick. Modified from Law and others (1989, their figure 14). Lewis Shale outcrops are from Green (1992) and Green and Drouillard (1994).

and Shannon (1989). Individual sandstone lobes range from 20 to 350 ft thick, and some of the larger lobes extend across several townships. Feeder channels are 1 mi wide and several mi long (Van Horn and Shannon, 1989). Doelger and others (1999) describe several additional lobes of similar size along the southern flank of the Great Divide Basin.

2. Washakie Basin (examples from Witton [1999], Pyles [2000], and Hamzah [2002])—In the eastern Washakie Basin, Pyles (2000) and Witton (1999) interpreted basin-floor fans in the lower part of the Dad Sandstone Member, channel-fill sandstones in upper part of the Dad, and shingled turbidites in the upper part of the Lewis Shale. Basin-floor sand lobes were described as 5 to 12 ft thick and 1,000 to 2,000 ft long on outcrop and several miles long in the subsurface. Channel-fill sandstones were interpreted as slope deposits and were described as 5 to 50 ft thick and 12 to 470 ft wide. Shingled turbidites were interpreted as upper slope and outer shelf deposits and were described as 2 to 6 ft thick and as much 1 mi across. Hamzah (2002) and Suryanto (2003) identified about 13 sand sheets in the Dad Sandstone Member that extend, collectively, across most of the Washakie Basin. Individual sand lobes are as much as 250 ft thick and extend across as many as 20 to 30 townships (Hamzah, 2002; Suryanto, 2003).

3. Sand Wash Basin (examples by Cain [1986] and Zainal [2001])—Cain (1986) described linear sandstone bodies in the Dad Sandstone Member in the east-central Sand Wash Basin. She interpreted that sand was transported by northeast-flowing turbidity currents and deposited in channels on the middle and upper slope. Channels were described as 100 to 260 ft thick and 2.8 mi wide. Zainal (2001) described five sand lobes in the lower part of the Lewis Shale in the central Sand Wash Basin and interpreted a south and southwest source. Individual lobes were described as 20 to 130 ft thick and one to three townships wide.

Hydrocarbon Traps and Seals

Hydrocarbon production in the Lewis Shale is from conventional-style structural and (or) stratigraphic traps and the basin-centered gas system. Stratigraphic traps occur where sandstone beds pinch out updip into less permeable mudrock; for example, at toes of prograding clinoforms folded upward along the basin flanks. Stratigraphic traps initially developed about 71 to 68 Ma during deposition of the Lewis Shale and were structurally enhanced about 67 to 37 Ma as a result of Laramide deformation. Structural traps also developed during Laramide-aged deformation and formed where reservoirs were folded over closed anticlines or truncated by faults. Areas with the best potential for stratigraphic trapping are shown in figure 11, and structural deformation is inferred from structure contours in figure 3. Stratigraphic and structural traps were sealed by mudrock in the Lewis Shale. The most effective seals are clay-rich mudstones deposited below storm-wave base, and the least effective seals are silty and sandy mudstones deposited near turbidity currents and above storm-wave base in nearshore environments (Almon and others, 2002; Pyles, 2000; Pyles and Slatt, 2000a).

The basin-centered gas system extends across lithologic and stratigraphic boundaries and has no recognizable seal (Law and others, 1989). A water-block (capillary) trap, however, might form a seal that extends over the basin-centered accumulation (Masters, 1979; Law, 2002). Water-block traps develop as water is expelled from the low-permeability overpressured system and forced updip into overlying strata. Masters (1979) demonstrated that at 65-percent water saturation, rock is nearly impervious to gas flow in low-permeability strata. The proposed water trap in the Lewis TPS initiated at the time of peak gas generation (about 52 Ma, during the early Eocene) and expanded to its maximum size when the Lewis Shale attained its maximum burial, about 5 Ma.

Total Petroleum System Event Summary

Events charts (fig. 12) similar to those used by Magoon and Dow (1994) relate the timing of essential elements in the Lewis TPS; included is the timing of (1) depositional elements, (2) trap formation, (3) hydrocarbon generation, and (4) hydrocarbon migration. The timing of trap formation and hydrocarbon processes is only generally shown because it is related to the rate and duration of basin tectonics. An events chart for the Lewis Conventional Oil and Gas Assessment Unit (50370701) is shown in figure 12*A*, and the events chart for the Lewis Continuous Gas Assessment Unit (50370761) is shown in figure 12*B*.

Conventional and continuous accumulations in the Lewis TPS contain the same depositional elements. Deposition of rock units, source and reservoir rocks, and lithologic seals occurred about 71 to 68 Ma, during the Maastrichtian Stage of the Late Cretaceous. Those essential elements are included within the Lewis Shale; the source rock is organic-rich mudrock, principal reservoir rock is sandstone in the Dad Sandstone Member, and seals are provided by clay-rich mudrock. Overburden required for source rock maturation includes all strata above the base of the Lewis Shale. Overburden accumulated from Maastrichtian through Miocene time; but upper Eocene through Miocene strata subsequently were removed by erosion during the Pliocene.

Stratigraphic and structural traps are associated primarily with conventional accumulations but also provide sweet spots in the continuous accumulation. Stratigraphic traps formed during deposition of the Lewis Shale and were enhanced by Laramide deformation during Late Cretaceous through late Eocene time. Structural traps also formed during Laramide tectonism. Water-block traps are associated with the continuous accumulation

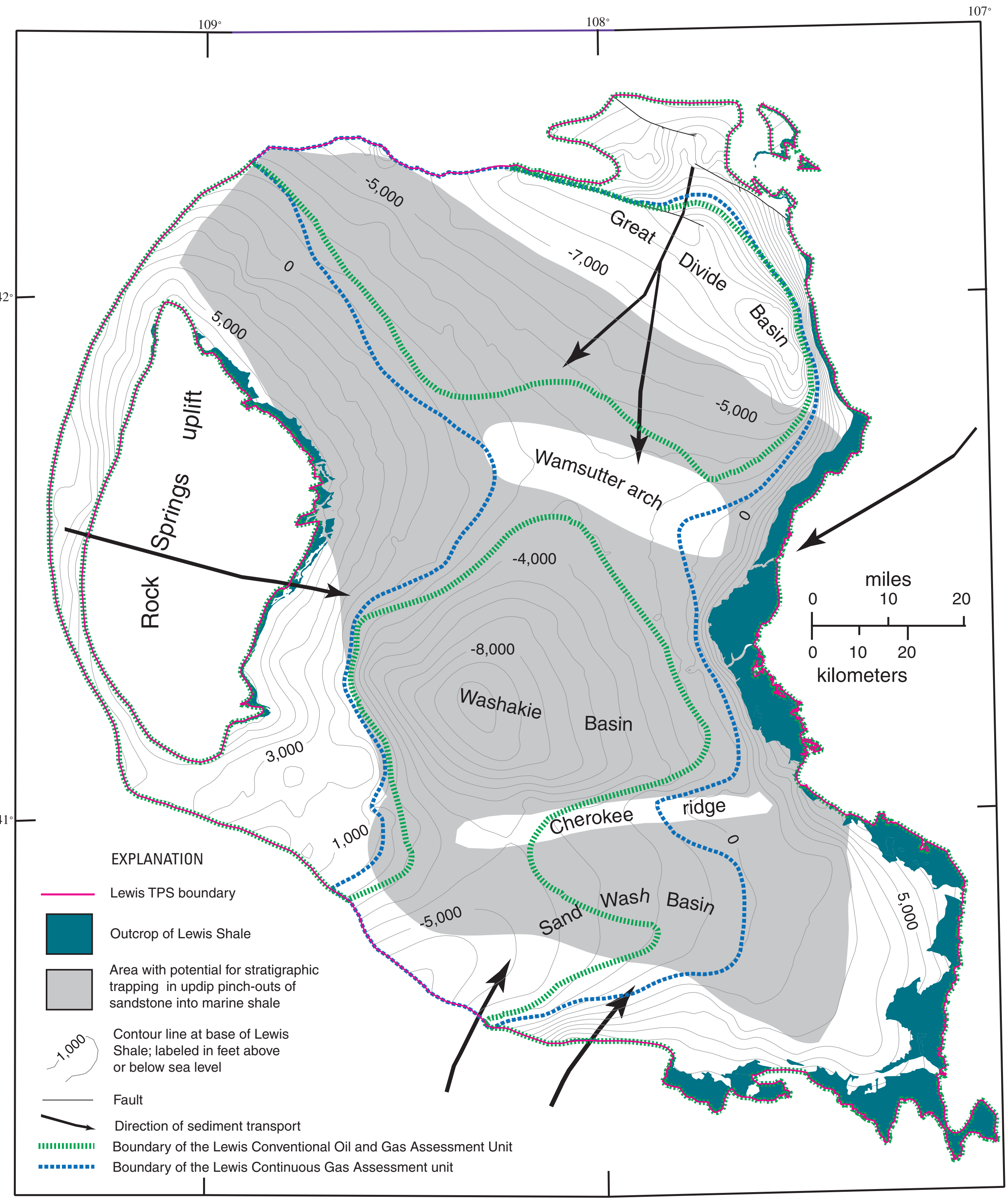

Figure 11. Areas of Lewis Shale that have potential for stratigraphic traps. The traps form where sandstones pinch out updip into shale, and areas with the best potential are located along the upturned basin flanks. Lewis Shale outcrops are from Green (1992) and Green and Drouillard (1994).

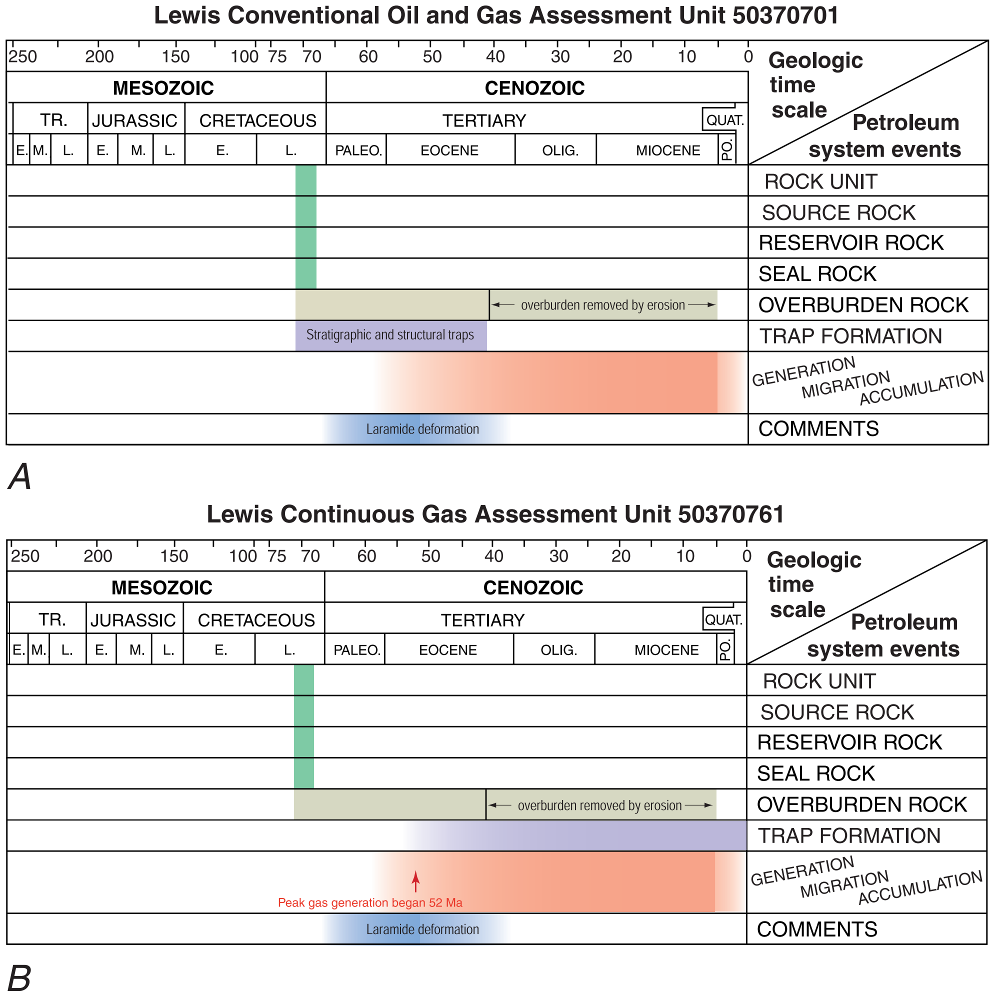

Figure 12. Event charts showing timing of key events in the Lewis Total Petroleum System. *A*, Lewis Conventional Oil and Gas Assessment Unit (50370701). *B*, Lewis Continuous Gas Assessment Unit (50370761). Abbreviations: Triassic (TR.), Paleocene (PALEO.), Oligocene (OLIG.), Quaternary (QUAT.), Pliocene (PO.), early (E.), middle (M.), late (L.)

and began to develop about 52 Ma (during the early Eocene) when the source rock first attained peak gas generation in deeper basin areas. The development of water-block trapping is thought to have continued until the end of the Miocene when the Lewis Shale attained its maximum burial depth. However, basin uplift and erosion of overburden during the Pliocene may have disrupted the water-block seal.

Gas generation began about 62 Ma, (during the early Paleocene) and may be continuing throughout much of the Lewis TPS. Gas migration began about 52 Ma (during the early Eocene) when source rock initially attained peak gas generation and pore pressures were elevated above regional hydrostatic pressures, thus forcing fluids to migrate from the overpressured zone. Some of the gas migrated into conventional-style traps within the Lewis Conventional Oil and Gas Assessment Unit. However, water-block traps sealed most of the thermogenic gas into the basin-centered gas system of the Lewis Continuous Gas Assessment Unit. Peak gas generation and migration are thought to have continued along the upper boundary of the Lewis Continuous Gas Assessment Unit until the basin dynamics were disrupted during uplift about 5 Ma (near the Miocene and Pliocene boundary). The rate of gas generation at the present time is likely to be significantly less than it was prior to 5 Ma.

Assessment Units in the Lewis Total Petroleum System

The Lewis TPS of the Southwestern Wyoming Province includes the Lewis Continuous Gas Assessment Unit (50370761) and the Lewis Conventional Oil and Gas Assessment Unit (50370701). The continuous assessment unit lies within the overpressured, gas-saturated, basin-centered gas accumulation of the GGRB. The conventional assessment unit overlies the basin-centered gas accumulation and occupies areas in the Lewis TPS where gas has migrated and accumulated in conventional stratigraphic or structural traps. Well-history files by the IHS Energy Group (2001) show about 530 wells in the Lewis TPS with Lewis hydrocarbon production;

included are about 300 in the conventional assessment unit and about 230 in the continuous assessment unit. The number of wells is approximate, as some have been recompleted and therefore have been reported more than one time. The wells are distributed throughout about 84 fields, and individual fields contain 1 to 60 wells with Lewis production (table 1, fig. 7). About 38 fields are in the conventional assessment unit, and 46 fields are in the continuous assessment unit. Most of the Lewis production has been from the Desert Springs and Hay Reservoir fields; since 1974 these two fields have collectively produced about 297 BCFG and 3.6 million barrels oil (MMBO) and condensate, as summed from the IHS Energy Group (2001) database. That amount represents about 50 percent of the total hydrocarbon production from the Lewis TPS (see chapter section "Lewis Total Petroleum System (503707)." The Desert Springs field is in the conventional assessment unit and has produced about 164 BCFG and 1.4 MMBO and condensate from the Lewis Shale since 1974. The Hay Reservoir field is in the continuous assessment unit and has produced about 133 BCFG and 2.2 MMBO and condensate from the Lewis Shale since 1974.

Lewis Continuous Gas Assessment Unit (50370761)

The Lewis Continuous Gas Assessment Unit of the Southwestern Wyoming Province (fig. 13) encompasses approximately 3,310,000 acres (about 5,170 mi^2) where the Lewis Shale has attained thermal maturation levels that exceed 0.8 percent R_o. At these thermal maturation levels, the Lewis Shale is thought to be within the basin-centered gas system described by Law (2002). The assessment unit boundary is defined by the Lewis TPS boundary and the 0.8 percent R_o isoline at the base of the Lewis Shale. Field data in Miller and others (1992) and NRG Associates (2001) indicate that the continuous assessment unit (table 2) has characteristics that are generally consistent with those described for basin-centered gas system, which are summarized in the section of this report regarding the Lewis Total Petroleum System. However, the assessment unit has some higher permeabilities and lower pressure gradients, which can be attributed to disrupted basin dynamics as described by Law and Dickinson (1985, their discussion of stage IV development of abnormally pressured gas accumulations).

Sandstone is distributed across most of the Lewis Continuous Gas Assessment Unit, and the net sandstone thickness ranges from about 200 to 600 ft (fig. 10). Although these reservoirs are assumed to be gas saturated, better production occurs where gas accumulations have been enhanced in sweet spots, and hydraulic fracturing is commonly required for economic production. Controlling mechanisms for sweet spots include structural features, fracture systems, and facies relations (Hendricks, 1995). Examples of stratigraphic sweet spots may include productive overpressured sand lobes in the Great Divide and Hay Reservoir fields that pinch out updip into marine shale along the southern limb of the Great Divide Basin (Van Horn and Shannon, 1989). About 70 percent of the continuous assessment unit is located where there is potential for similar stratigraphic sweet spots (fig. 11).

Historical Drilling, Success Ratios, and Production

The Lewis Continuous Gas Assessment Unit is underexplored and underdeveloped. We consider the Lewis Shale to have been tested in only 539 drill holes in the assessment unit where information is provided regarding the potential for hydrocarbon production. Each tested well is considered to be a tested cell. Included are 209 wells with Lewis production, and 330 abandoned wells that penetrated the Lewis (fig. 14) (IHS Energy Group, 2001). The abandoned wells include 42 that terminated in the Lewis Shale and 288 that terminated below the Lewis; none of the abandoned wells were considered to have potential for Lewis production. Although the Lewis Shale has been penetrated by an additional 1,077 wells in the assessment unit, the wells targeted deeper formations, and hydrocarbon tests were not reported for the Lewis (IHS Energy Group, 2001) (fig. 14). Although some of these deeper wells might have a potential to be recompleted in the Lewis, none were counted as tested Lewis cells because the potential for Lewis production could not be evaluated. (Drill-hole tallies in this paragraph do not include wells that terminated less than about 200 ft below the top of the Lewis Shale or wells that produced from conventional accumulations where the assessment units overlap [see fig. 7]. Adjustments were also made to account for wells that were listed more than one time in the well-history file.)

The drainage area (cell size) for wells with Lewis production is estimated to range from about 100 to 640 acres, based on well spacings in some of the larger fields, but some wells have recently been drilled on 80-acre centers, or less. The tested area is about 55,500 acres, the product of 539 tested wells and a calculated median cell size of 103 acres. Therefore, approximately 98.3 percent of the Lewis Continuous Gas Assessment Unit remains untested. It is important to note that the percentage of untested area would not have changed significantly had all 1,616 wells described in the previous paragraph been considered as tested Lewis cells; the untested area would have been about 95 percent rather than 98 percent, as reported.

The historical drilling success ratio for the continuous assessment unit is estimated to be 36 percent. The ratio is based on the 539 tested wells and compares 196 wells with successful Lewis production and 343 wells with unsuccessful production. Unsuccessful wells include the 330 abandoned drill holes as well as 13 drill holes where Lewis production was less than 0.02 BCFG (the minimum total recovery considered for reserve calculations in this assessment) (fig. 14). Before 1975, only 14 wells in the continuous assessment unit reported Lewis production. Wells with Lewis production

Table 1. Fields that have produced gas and (or) oil from the Lewis Total Petroleum System.

Production is from the Lewis Continuous Gas Assessment Unit or Lewis Conventional Oil and Gas Assessment Unit, as indicated. The number of wells with Lewis Shale production is based on information in the IHS Energy Group (2001) well-history file (if available); otherwise, the number of wells is from the production file. Sources of data are the IHS Energy Group (2001), Cardinal and Stewart (1979), and Miller and others (1992). Field locations are shown in figure 7. CONT. AU, continuous assessment unit; CONV. AU, conventional assessment unit]

Field Name	Location	Wells	CONT. AU (50370761)	CONV. AU (50370701)	Field Name	Location	Wells	CONT. AU (50370761)	CONV. AU (50370701)
ALKALINE CRK.	16N, 98W	2	X		LAY CREEK	8N, 93W	1		X
BAGGS	12N, 92W	1		X	LITTLE SNAKE	12N, 95W	1		X
BAGGS S	12N, 92W	19		X	LOST CREEK	23N, 97W	3	X	
BARREL SPRINGS	16N, 93W	2	X		LOST CREEK BASIN	22-23N, 95W	2	X	
BASTARD BUTTE	25N, 97W	3	X		MAYBERRY	11N, 94W	1		X
BATTLE SPRINGS	23-24N, 94W	2	X		MCPHERSON SPGS	13N, 94W	2	X	
BIG HOLE	10N, 94W	12	X		MUD LAKE	23N, 98W	1	X	
BIG HOLE N	11N, 94W	1		X	NICKEY	24N, 96W	1	X	
BLACK MTN.	10N, 90W	3		X	N.T.	15N, 96W	1	X	
BLUE GAP	14N, 91-93W	3	X		PICKET LAKE	26N, 96-97W	5	X	
BLUE GRAVEL	9N, 90-91W	30		X	PLAYA	20N, 99W	7		X
BLUE SKY	9N, 91W	1		X	POLAR BAR	14N, 96W	2	X	
BUSH LAKE	24N, 96W	3	X		POLE GULCH	12N, 92W	4		X
CANYON CRK.	13N, 101W	1		X	RED DESERT	22N, 96W	5	X	
CEPO	14N, 95W	1	X		RIM ROCK UNIT	14N, 95W	1	X	
CONTINENTAL DIVIDE	22N, 93W	1	X		ROBBERS GULCH	14N, 92W	1	X	
CRAIG DOME	8N, 90W	1		X	SALAZAR	16N, 95W	1	X	
CRAIG NORTH	8N, 90/91W	19		X	SAND HILLS	11-12N, 91W	3		X
CRAIG SOUTH	7N, 90W	1		X	SENTINEL RIDGE	23N, 94W	1	X	
CRESTON	18N, 92W	1		X	SIBERIA RIDGE	21-22N, 94W	43	X	
DELANEY RIM	18N, 97/98W	6		X	SINK HOLE	23N, 99W	12	X	
DESERT ROSE	14N, 96W	1	X		SMITH RANCH	12N, 93W	2		X
DESERT SPRINGS	20-21N, 97-98W	21		X	SMOKEY	15N, 99W	1	X	
DESERT SPRINGS E	21N, 97-98W	2		X	STAGE STOP	18N, 99W	12		X
DESERT SPRINGS W	20N, 99W	1		X	STANDARD DRAW	18N, 92W	1	X	
DRIPPING ROCK	14-15N, 94W	3	X		STATE LINE	12N, 94W	1		X
ECHO SPRINGS	19-20N, 92-93W	5		X	STEWART CREEK	24N, 91W	1	X	
EMIGRANT TRAIL	17-18N, 95W	1	X		STRIKE	22N, 95W	2	X	
FILLMORE	19N, 91W	6		X	TABLE ROCK	18-19N, 97-98W	34		X
FIVE MILE GULCH	20-21N, 93W	2	X		TABLE ROCK SW	18N, 98W	4		X
FORTIFICATION CK	8-9N, 91W	2		X	TEARDROP	10N, 93W	2		X
FOUR MILE CRK.	11-12N, 91W	2		X	TEN MILE DRAW	21N, 99W	4		X
GALE	23N, 96W	1	X		TIERNEY	19N, 94W	1	X	
GREAT DIVIDE (C0)	9-10N, 93W	11	X		TRITON	13-14N, 95W	5	X	
GREAT DIVIDE (WY)	23N, 96W	8	X		TWIN FORK	14N, 97W	1	X	
HAY RESERVOIR	23-24N, 96-97W	60	X		UNNAMED (4 fields)	9N, 92W; 10N, 93W; 11N, 93W; 21N, 96W	1 each		X
HAY RESERVOIR S	23N, 97W	1	X		UNNAMED (7 fields)	13N, 93W; 13N, 95W; 14N, 95W; 21N, 93W; 22N, 95W; 23N, 95W; 25N, 95W	1 each	X	
HIAWATHA WEST	12N, 100-101W	1		X	WAMSUTTER	20-21N, 93-95W	53		X
HIGGINS	18N, 98W	3		X	WEST SIDE CANAL	11-12N, 91-92W	34		X
IRON PIPE	16N, 97W	1	X		WILD ROSE	19N, 95W	1	X	
JADE	24N, 98W	1	X		WINDMILL DRAW	15N, 93-94W	1	X	
LANEY WASH	17N, 97W	1	X		WINDSOCK	11N, 93 W	4		X

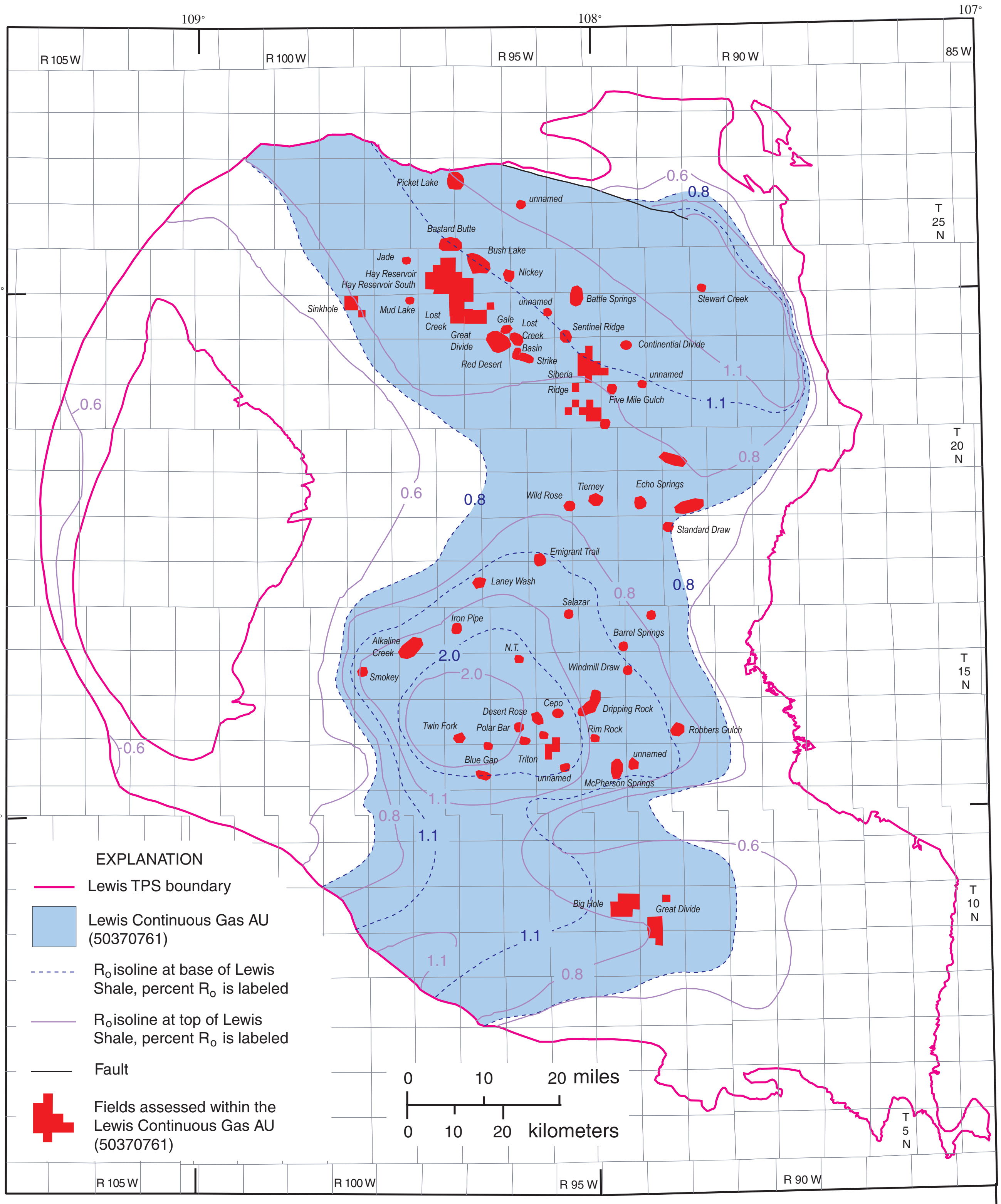

Figure 13. Lewis Continuous Gas Assessment Unit (AU) (50370761). Shown are R_o isolines at the base and top of the Lewis Shale and fields that have produced from the AU. The AU boundary is defined by the 0.8-percent R_o isoline at the base of the Lewis Shale and by the boundary of the Lewis Total Petroleum System.

Table 2. Reservoir characteristics for selected fields that have produced from the Lewis Continuous Gas Assessment Unit.

[Number of wells is from the IHS Energy Group (2001) well-history file (if available); otherwise the number of wells is from the production file. Depth of upper reservoir is approximate and based either on field data in Miller and others (1992) or the average depth of the upper perforated zone reported in the IHS Energy Group (2001) production file. Pressure gradients were calculated from pressure and reservoir depths reported in Miller and others (1992) (one asterisk), NRG Associates (2001) (two asterisks). Hydrocarbon/water contacts are reported as they were described in Miller and others (1992). All other information is from field reports in Miller and others (1992). Blanks indicate no information was available. ft, feet; grad., gradients; %, percent; mD, millidarcies; press., pressure; psi, pounds per square inch; psi/ft, pounds per square inch per foot; <, less than]

Field name	No. wells	Depth of upper reservoir (ft)	Porosity (%)	Permeability (mD)	Pay (ft)	Press. (psi)	Press. grad. (psi/ft)	Hydrocarbon/ water contact
Alkaline Creek	2	11,800			22			
Bastard Butte	3	10,900			16			
Battle Springs	2	11,900	14		39	6,170	0.519*	Unknown
Blue Gap	3	8,800			20			
Continental Divide	1	11,800	0-15		22			Variable
Desert Rose	1	13,600			34			
Dripping Rock	3	11,200	8		74			
Emigrant Trail	1	10,300	9		61			Unknown
Five Mile Gulch	2	9,600	8	< 0.1	26	4,814	0.502*	None
Great Divide (WY)	8	9,800	9	0.1	25		0.650**	Not applicable
Hay Reservoir	60	10,000	9	0.1	30	6,343	0.634*	Not applicable
Laney Wash	1	11,300			40			
Lost Creek Basin	2	9,500			20			
Nickey	1	11,500			21			
N.T.	1	12,900			69			
Picket Lake	5	13,500	14		31	8,500	0.630*	Unknown
Red Desert	5	9,700			15			Not applicable
Rim Rock Unit	1	13,300			46			
Sentinel Ridge	1	11,400	11	0.13	26			
Sinkhole	12	6,800	13	2.18	12	3,200	0.471*	Unknown
Triton	5	13,000			27		0.498**	
Twin Fork	1	17,200			10			

increased strikingly after 1976 owing to the discovery of Hay Reservoir field in the Great Divide Basin. From 1976 through 1999, successful Lewis completions ranged from 0 to 23 wells per year and averaged 8 wells per year.

A distribution curve (fig. 15A) shows the estimated ultimate recovery (EUR) for 196 wells where Lewis production is expected to exceed 0.02 BCFG. The EUR values were generated using decline curve analyses based on data in the IHS Energy Group (2001) production files. EUR values range from about 0.02 BCFG to 17 BCFG, with a median of 0.6 BCFG. Production depths range from about 6,600 to 18,700 ft, with a median depth of about 10,500 ft, as determined from data compiled by the IHS Energy Group (2001).

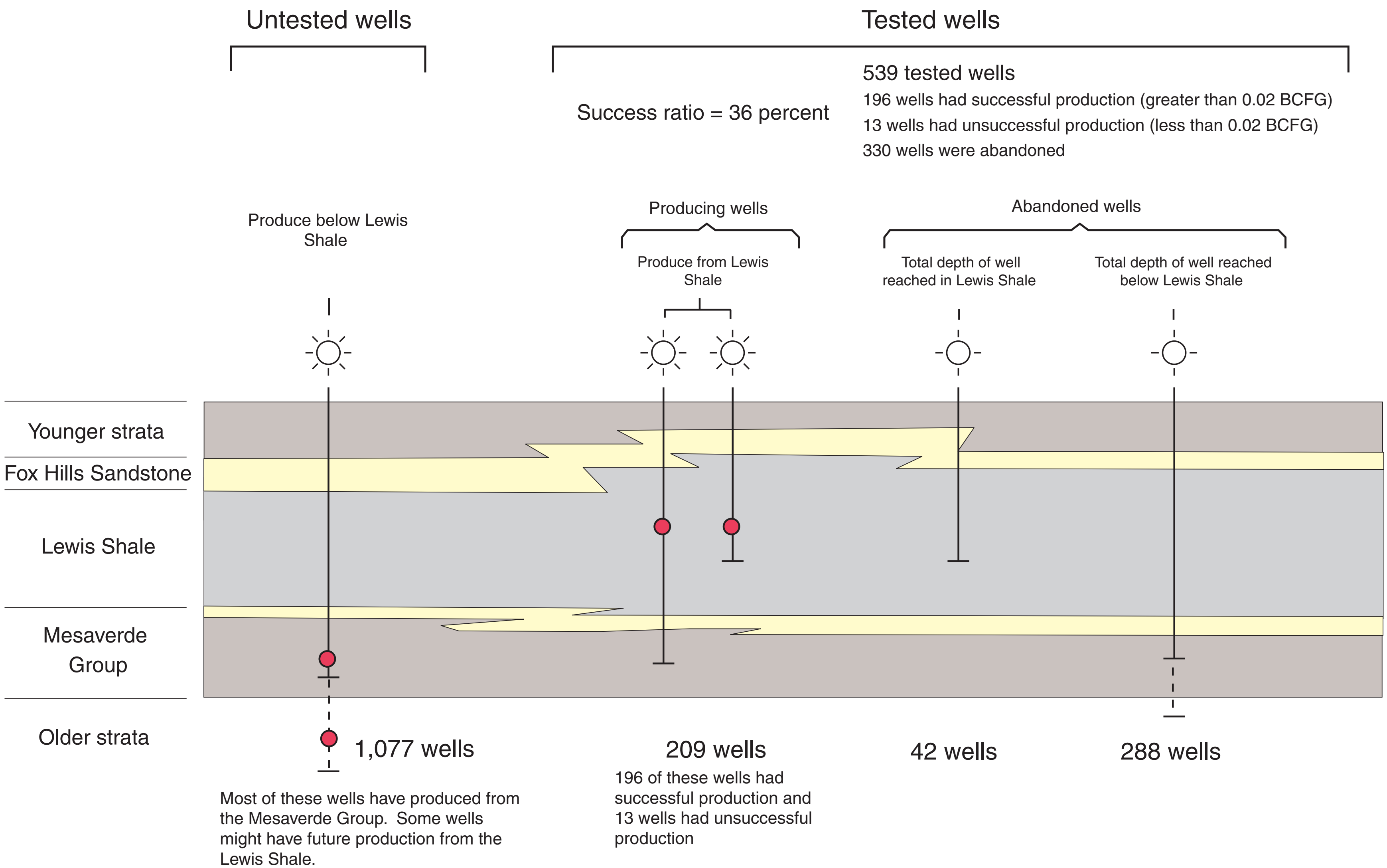

Figure 14. Tested wells in Lewis Continuous Gas Assessment Unit (AU). The Lewis Shale has been drilled by 1,616 wells in the AU, but it is considered to have been tested by only 539 wells. Tested wells include 209 with Lewis production, and 330 that were abandoned. Only 196 of the producing wells exceed the minimum total recovery (0.02 BCFG) considered in this assessment. Therefore, a success ratio of 36 percent was determined based on 196 wells with successful Lewis production and 343 wells with unsuccessful production. Drill holes with unsuccessful production include the 330 abandoned wells and 13 wells where Lewis production was less than 0.02 BCFG. The remaining 1,077 wells reported production from below the Lewis Shale; these drill holes were not counted as tested Lewis wells because information regarding the Lewis was generally not available. The well count is based on data by the IHS Energy Group (2001). [BCFG, billion cubic feet of gas.]

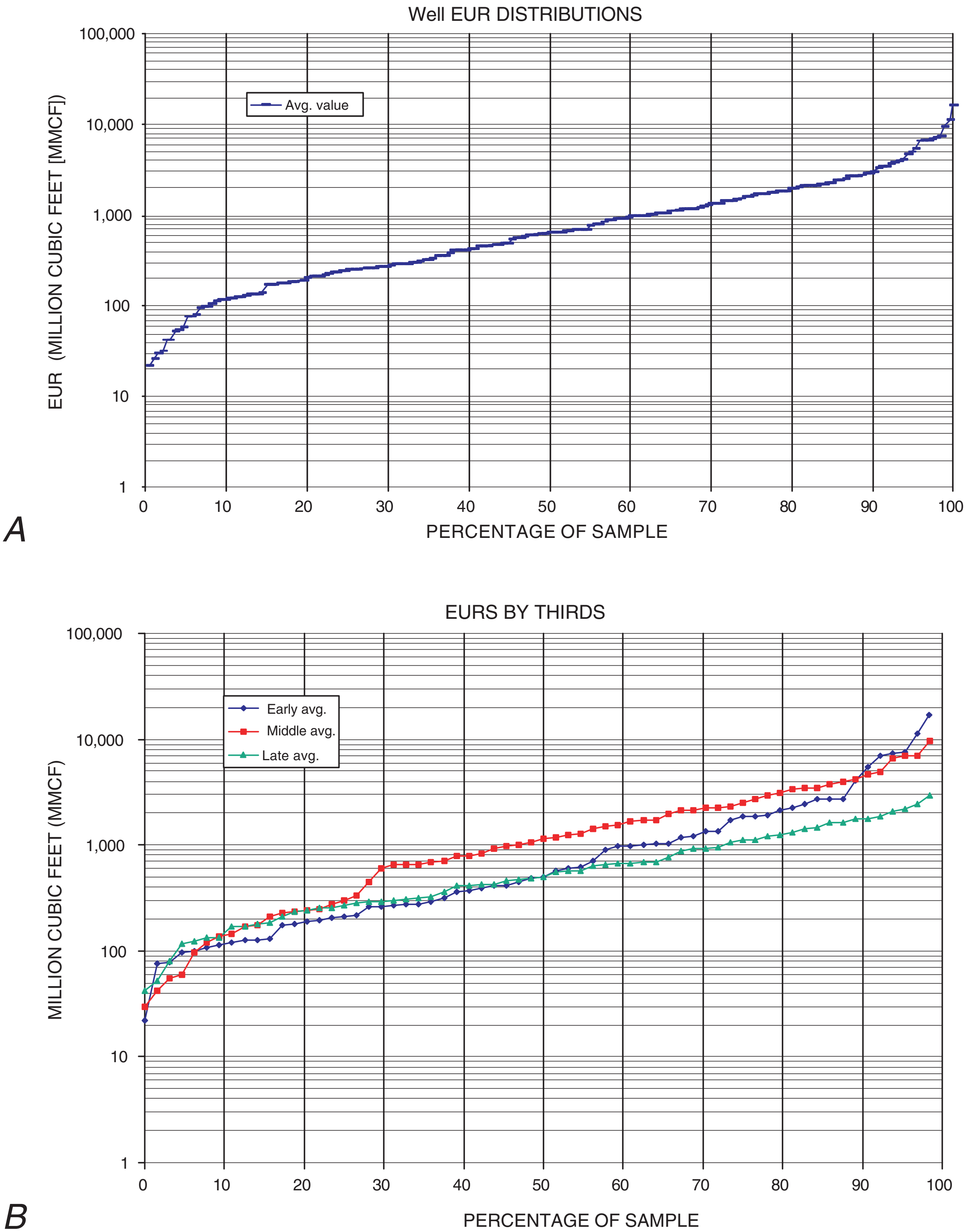

Figure 15. Distribution of estimated ultimate recoveries (EURs) for wells in the Lewis Continuous Gas Assessment Unit. *A*, Estimated ultimate recovery for all wells where production from the Lewis Shale is expected to exceed 0.02 BCFG (billion cubic feet of gas). *B*, Distribution of EUR through time for all wells where production from the Lewis Shale is expected to exceed 0.02 BCFG; each curve represents one-third of the producing Lewis wells grouped according to their completion dates. Distribution curves in *A* and *B* are based on data from the IHS Energy Group (2001). Graphs provided by Troy Cook (U.S. Geological Survey), and EUR values were generated using decline curve analyses. [MMCF, million cubic feet gas.]

Lewis Conventional Oil And Gas Assessment Unit (50370701)

The Lewis Conventional Oil and Gas Assessment Unit (fig. 16) encompasses about 3,820,000 acres (about 5,970 mi^2) of the Lewis TPS where thermal maturation is below the level required for peak gas generation, that is, less than 0.8 percent R_o. The conventional assessment unit overlies the basin-centered gas accumulation, and hydrocarbon production is from conventional stratigraphic or structural traps with discrete gas/water contacts. Most of the gas in the conventional assessment unit is interpreted to have migrated from the basin-centered accumulation (that is, the Lewis Continuous Gas Assessment Unit). The assessment unit boundary is defined by the Lewis TPS boundary and the 0.8 percent R_o isoline at the top of the Lewis Shale. The conventional assessment unit is generally characterized by field pressure gradients of less than 0.5 psi/ft and reservoir permeabilities greater than 1 mD (table 3). Hydrocarbon/water contacts are also reported in several fields; however, they are absent in the Baggs South field and have not been determined in several additional fields (table 3).

Historical Drilling and Production

Approximately 300 wells have produced gas and(or) oil from 38 fields in the assessment unit (table 1). Production depths range from about 3,100 to 8,400 ft, and the producing intervals have ranged from about 4 to 55 ft thick (tables 1 and 3). Sandstone reservoirs are greater than 10 ft thick throughout about 80 percent of the assessment unit. As much as 400 ft of net sandstone is found along the Wamsutter arch, Cherokee ridge, and eastern flank of the Great Divide Basin; however, the net thickness is generally less than 200 ft throughout most of the assessment unit, and sandstone is generally absent in the eastern part of the Sand Wash Basin and in areas surrounding the Rock Springs uplift (fig. 10).

Trapping mechanisms are both stratigraphic and structural. Stratigraphic traps have been reported at the Desert Springs, Echo Springs, Fillmore, Little Snake, Playa, Smith Ranch, Stage Stop, State Line, Ten Mile Draw, and Wamsutter fields where sandstone beds pinch out updip into mudrock along the basin flanks (Miller and others, 1992). Structural traps have been found where the sandstone reservoirs are either folded over closed anticlines or truncated by faults. Combinations of stratigraphic and structural traps have been reported at the Baggs South and West Side Canal fields (along the Cherokee ridge), the Higgins, Table Rock, and Table Rock Southwest fields (along the Table Rock structure), and the Hiawatha West field (along the Vermillion Creek anticline) (figs. 3 and 16) (Miller and others, 1992).

Only 11 discovered accumulations (fields) in the conventional assessment unit have produced, or are expected to produce, more than 3 BCFG or 0.5 million barrels of oil equivalent (MMBOE), which is the minimum grown accumulation considered in this assessment. These include 10 fields where gas is the major constituent and oil is a co-product, and 1 field where oil is the major constituent and gas is a co-product. The gas fields were discovered between 1954 and 1997 and include the Baggs/West Side Canal, Blue Gravel, Craig North, Delaney Rim, Desert Springs, Echo Springs, Table Rock, Ten Mile Draw, Wamsutter, and Windsock. The single oil field is Stage Stop, which was discovered in 1966. A general decline in gas-field discoveries and grown accumulation size is illustrated in figure 17*A*. Nine gas fields were discovered between 1954 and 1979, and 18 years passed before another gas field was discovered in 1997. Similarly, most of the larger accumulations (greater than 95 BCFG, grown) were discovered before 1964, and most of the smaller accumulations (less than 13 BCFG, grown) were discovered after 1968. Therefore, only one large field has been discovered in the past 36 years (as of December 1999). The general decline with time in size of grown gas accumulations is also shown in figure 17*B*, where the first half of field discoveries, by completion date, are compared to the second half of field discoveries. Grown gas accumulations in the first half range from about 12 to 300 BCFG and have a median of 93.7 BCFG. By comparison, the grown gas accumulations in the second half discovered are significantly smaller; they range from about 8 to 100 BCFG and have a median of 9.9 BCFG.

Assessment Results for the Lewis Total Petroleum System (503707)

The Lewis TPS (503707) is estimated to contain a mean of about 13,730 BCFG in undiscovered gas resources that have a potential for additions to reserves in the next 30 years (table 4). That value represents the summation of calculated mean values determined for the Lewis Continuous Gas Assessment Unit and the Lewis Conventional Oil and Gas Assessment Unit, which constitute the TPS. The two assessment units were evaluated using geologic concepts described in this report and methodology procedures described in Chapters 18 through 23 of this CD–ROM. Results of both assessment units are shown in table 4. Basic input data for the Lewis Continuous Gas Assessment Unit are provided in Appendix A, and basic input data for the Lewis Conventional Oil and Gas Assessment Unit are provided in Appendix B. The following sections describe the rationale of the critical input data.

Lewis Continuous Gas Assessment Unit (50370761)

Total Assessment-Unit Area

The median total assessment unit area is 3,310,000 acres, as determined from the Lewis TPS boundary and the intersection of the Lewis Shale base and the subsurface elevation of

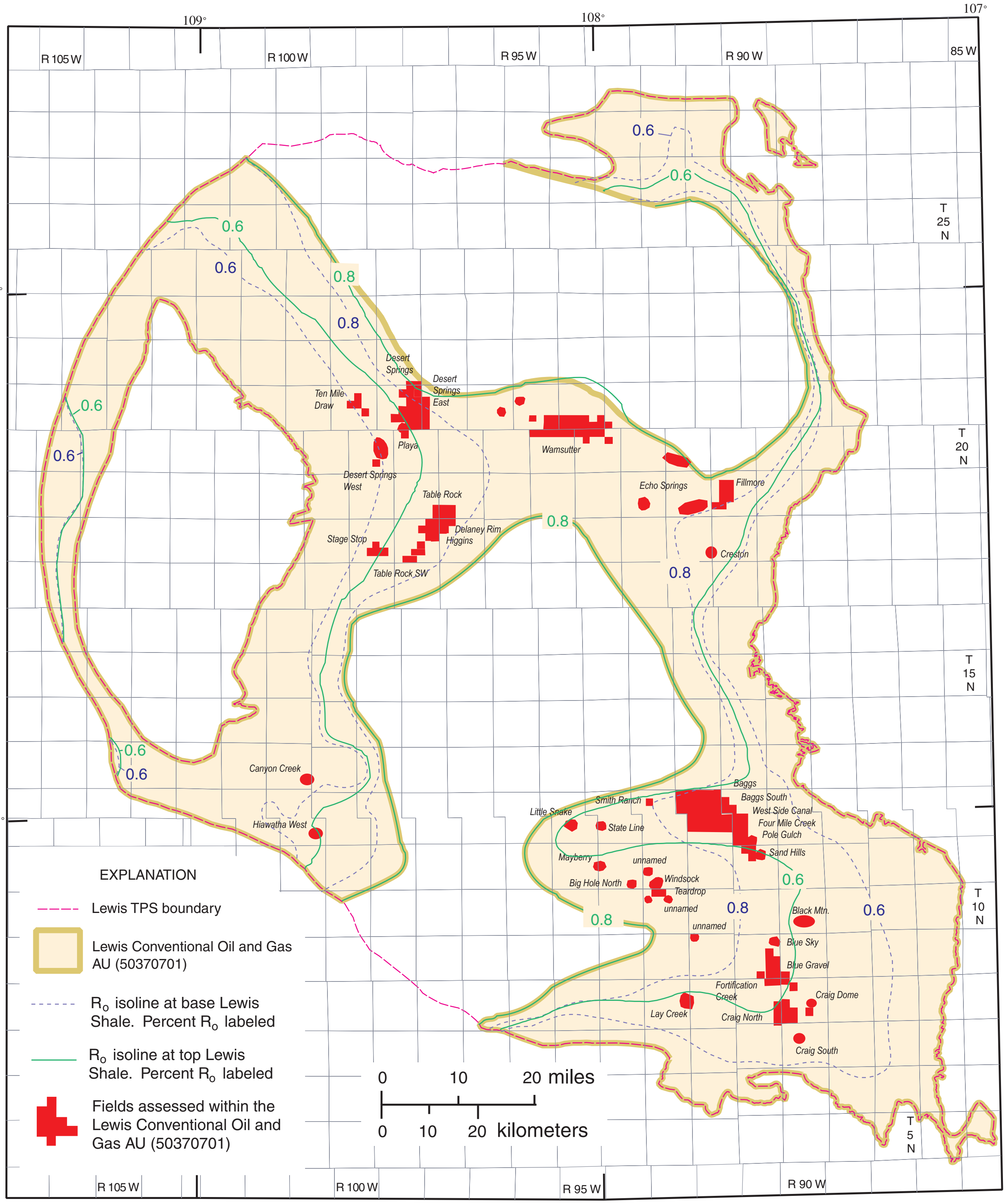

Figure 16. Lewis Conventional Oil and Gas Assessment Unit (AU) (50370701). Shown are R_o isolines at the base and top of the Lewis Shale and fields that have produced from the AU. The AU boundary is defined in general by the 0.8-percent R_o isoline at the top of the Lewis Shale and the boundary of the Lewis Total Petroleum System. The AU boundary diverges from the 0.8-percent R_o line, locally, to avoid gas fields in the adjoining Lewis Continuous Gas AU.

Table 3. Reservoir characteristics for selected fields that have produced from the Lewis Conventional Oil and Gas Assessment Unit.

The number of wells is from the IHS Energy Group (2001) well-history file (if available); otherwise the number of wells is from the production file. The approximate depth to top of reservoir is based on field data in Miller and others (1992) or average depth of upper perforated zone reported in the IHS Energy Group (2001) production file. Pressure gradients were calculated from pressure and reservoir depths reported in Miller and others (1992) (one asterisk), NRG Associates (2001) (two asterisks), and IHS Energy Group (2001) (three asterisks). Hydrocarbon/water contacts refer to feet above sea level and are reported as described in Miller and others (1992). Average porosity, permeability, and pay are from field reports in Miller and others (1992). Blanks indicate no information was available. ft, feet; res, reservoirs; %, percent; mD, millidarcies; psi/ft, pounds per square inch per foot; Avg., average]

Field	No. wells (Lewis Shale)	Trap type	Depth to top Lewis res. (ft)	Depth to 0.8 R_o (ft)	Pressure gradient (psi/ft)	Hydrocarbon/ water contact	Avg. porosity (%)	Avg. permeability (mD)	Avg. pay (ft)
Baggs South	20	stratigraphic/ structural	4,700	7,700	0.486**	none	25	10.8	18
Big Hole North	1		7,400	7,600					
Black Mountain	3		4,600	9,400	0.333***				
Blue Gravel	30		4,100	7,200	0.428**				
Blue Sky	1		3,900	7,600					
Craig Dome	1		3,100	7,000					
Craig North	19		3,100	6,600	0.399**				
Craig South	1			6,400					
Creston	1			7,300					
Delaney Rim	6	stratigraphic	6,900	7,400	0.397**				58
Desert Springs	24	stratigraphic	5,200	5,500	0.460*	1,000 ft +	16.7	7.9	15
Fillmore	6	stratigraphic	7,700	7,900	0.387*	unknown	15		23
Fortification Creek	2		4,700	6,900					
Four Mile Creek	2		4,200	8,800					
Hiawatha West	1	stratigraphic/ structural	4,500	5,400	0.445*	unknown	about 10		76
Higgins	3	stratigraphic/ structural	5,800	7,500					
Lay Creek	1			5,600					
Mayberry	1			7,600					
Playa	7	stratigraphic	3,500	4,900	0.417*	3,200 ft +	about 21		9
Pole Gulch	4		4,500	7,700					
Sand Hills	3		4,200	8,500					
Smith Ranch	2	stratigraphic	5,500	7,200	0.408*	not defined	13	0.1	24
Stage Stop	12	stratigraphic	4,900	6,100	0.415**	1,760 ft +	16	50	4 to 55
State Line	1	stratigraphic	7,200	7,300	0.357***				
Table Rock	34	stratigraphic/ structural	6,200	7,300	0.389*	yes (Robinson, 1993)	18	about 1.7	20
Table Rock SW	4	stratigraphic/ structural	5,700	7,200					
Teardrop	2		7,400	7,700					
Ten Mile Draw	4	stratigraphic	3,800	5,500	0.412**	3,075 ft +	about 25	70	8
Wamsutter	53	stratigraphic	8,400	8,700	0.476*	not determined	about 10	0.25	21
West Side Canal	34	stratigraphic/ structural	4,000	8,200	0.472*	variable	16.1	1.1	21
Windsock	4		7,300	7,700					

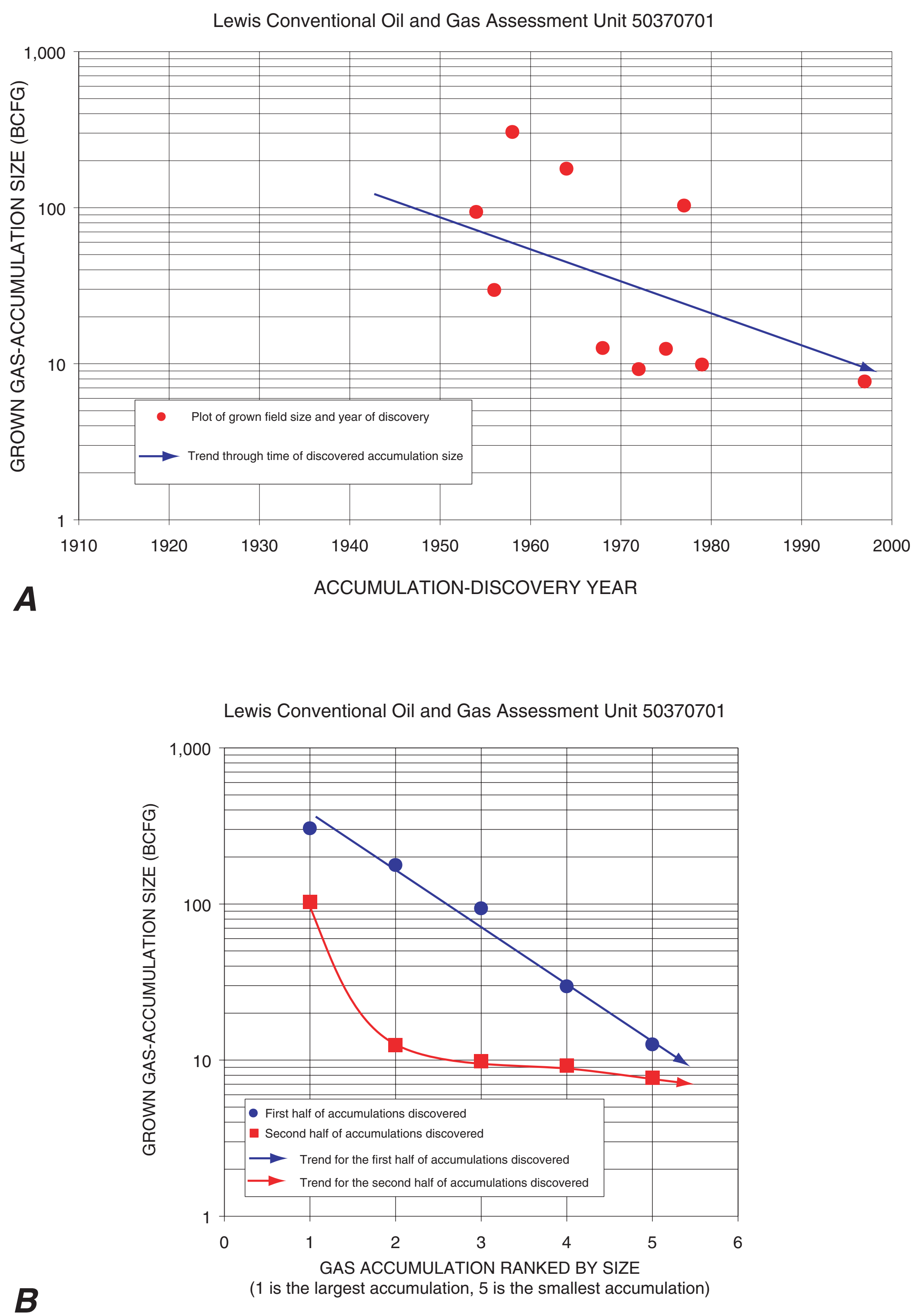

Figure 17. Trends through time of gas accumulation discoveries in the Lewis Conventional Oil and Gas Assessment Unit (50370701). Fields shown in graphs have exceeded the minimum grown size (3 BCFG). *A*, Graph of grown gas-accumulation size relative to accumulation-discovery year. *B*, Graph comparing grown gas accumulations for the first and second halves of discovered fields divided according to completion dates. Distribution curves are based on data from NRG Associates (2001). Graphs provided by Tim Klett (U.S. Geological Survey). [BCFG, billion cubic feet of gas.]

Table 4. Undiscovered resources in the Lewis Total Petroleum System (503707), Southwestern Wyoming Province (5037).

[Results shown are fully risked estimates. All liquids are included under the natural gas liquids category. F95 denotes a 95-percent chance of discovering at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable. BCFG, billion cubic feet of gas; MMBO, million barrels of oil; MMBNGL, million barrels of natural gas liquids]

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
Lewis TPS													
Lewis Conventional Oil and Gas AU	**Gas**					103.70	188.90	304.00	194.60	3.70	7.40	13.30	7.80
Total conventional resources						**103.70**	**188.90**	**304.00**	**194.60**	**3.70**	**7.40**	**13.30**	**7.80**
Lewis Continuous Gas AU	**Gas**					8,764.90	13,132.80	19,677.40	13,535.70	305.00	514.70	868.70	541.40
Total continuous resources						**8,764.90**	**13,132.80**	**19,677.40**	**13,535.70**	**305.00**	**514.70**	**868.70**	**541.40**
Total conventional and continuous resources						**8,868.60**	**13,321.70**	**19,981.40**	**13,730.30**	**308.70**	**522.10**	**882.00**	**549.20**

the 0.8-percent R_o (see report section "Lewis Continuous Gas Assessment Unit"). The assessment-unit area has an uncertainty of plus or minus 10 percent, which reflects a lack of precision regarding the elevation and intersection of the two surfaces. The boundary also reflects a lack of precision regarding the extent of Lewis Shale that lies below hanging walls of thrust faults located near the northern and southern boundaries of the TPS.

Area Per Cell of Untested Cells Having Potential for Additions to Reserves in the Next 30 Years

In the next 30 years, the area per cell of untested cells having potential for additions to reserves is estimated to range from 20 to 200 acres, with a median of 100 acres and a calculated mean of 103 acres. These values reflect the current well spacings and account for a trend to drill at closer spacings in some of the larger fields. The area per cell for untested cells is supported by volumetric calculations that use reservoir rock properties (table 2) and predicted future EUR values.

Percentage of the Total Assessment-Unit Area that is Untested

Approximately 55,500 acres of the assessment unit has been tested (based on a calculated mean cell size of 103 acres), and 98.3 percent of the assessment unit remains untested (see chapter section "Lewis Continuous Gas Assessment Unit"). These data strongly suggest that the Lewis Continuous Gas Assessment Unit is underexplored and underdeveloped.

Future Success Ratios for Untested Cells Having Potential for Additions to Reserves in the Next 30 Years

Success ratios in the next 30 years are anticipated to be between 80 and 90 percent, with a calculated mean of 85 percent. Future success ratios are predicted to be significantly higher than historical success ratios because of improved exploration strategies, completion techniques, and understanding of the basin-centered gas system.

Percentage of Untested Assessment-Unit Area that has Potential for Additions to Reserves in the Next 30 Years

Three scenarios were considered for the untested assessment-unit area that might have potential for additions to reserves; they are described as follows:

1. The minimum scenario assumes future contributions will come from the expansion of areas that have existing (current) production, and as much as 20 percent of the assessment unit is estimated to fit these criteria. Assuming a drilling success ratio of 90 percent, approximately 18 percent of the untested assessment-unit area is considered to have potential for additions to reserves in the next 30 years.

2. The median scenario assumes about 49 percent of the assessment unit is underlain by laterally extensive sandstone lobes where gas accumulation is enhanced within fracture-controlled, structural-controlled, or

facies-controlled sweet spots. The accumulations include base of slope and deep basin fans, as well as additional fans that are likely to be located along sediment-transport pathways. Assuming a drilling success ratio of 85 percent, approximately 42 percent of the untested assessment-unit area has potential for additions to reserves in the next 30 years.

3. The maximum scenario assumes about 85 percent of the assessment unit is underlain by sandstones, as indicated by the total sandstone isopach map (fig. 10) and depositional models by Perman (1990), Ross and others (1995), Pyles (2000), Pyles and Slatt, (2000a), Zainal (2001), Hamzah (2002), and Suryanto (2003). A significant amount of the sandstones is likely to be gas saturated or gas charged (Law, 2002). Assuming a drilling success ratio of 80 percent, approximately 69 percent of the untested assessment-unit area has potential for additions to reserves in the next 30 years.

Total Recovery per Cell for Untested Cells Having Potential for Additions to Reserves in the Next 30 Years

The total recovery per cell for untested cells is estimated from EUR distribution curves shown in figures 15*A* and 15*B*. The curves are based on 196 wells where Lewis Shale production exceeded 0.02 BCFG (see chapter section “Lewis Continuous Gas Assessment Unit [50370761]”). Figure 15*A* shows the EUR distribution for all 196 wells, and values range from about 0.02 to 17 BCFG, and the median value is about 0.6 BCFG. The increase in EUR through time is demonstrated by three curves (fig. 15*B*); each curve represents one-third of the producing Lewis wells, which have been grouped according to their completion dates. The earliest group of wells has EUR values that range from 0.02 to 17 BCFG, with a median of 0.5 BCFG. The middle group of wells has EUR values that range from 0.03 BCFG to 10 BCFG, with a median of 1 BCFG. The latest group of wells has EUR values that range from 0.04 BCFG to 3 BCFG, with a median of 0.5 BCFG. These curves show that higher EUR values are associated with the early and middle groups, and wells with lower EUR values are associated with the latest group. The three curves suggest the best discoveries have already been made.

The EUR distribution curves in figures 15*A* and 15*B* suggest that future discoveries in the Lewis Continuous Gas Assessment Unit are likely to be similar to historical discoveries. The total recovery per cell, for untested cells having potential for additions to reserves in the next 30 years, is estimated to range from 0.02 to 15 BCFG, with a median of 0.6 BCFG. The anticipated maximum value of 15 BCFG is slightly lower than the historical maximum value of 17 BCFG because the largest discoveries might already have been found.

Assessment Results

The Lewis Continuous Gas Assessment Unit is estimated to contain about 13,535.7 BCFG in undiscovered gas resources that have a potential for additions to reserves in the next 30 years (table 4). This value represents the calculated mean using methodology and basic input data discussed in this report (see methodology Chapters18 through 23 of this CD–ROM). There is a 95-percent chance the assessment unit has at least 8,764.9 BCFG, a 50-percent chance it has 13,132.8 BCFG, and a 5-percent chance it has as much as 19,677.4 BCFG. It is important to note that these reported values reflect recoveries as low as 0.02 BCFG, which are currently subeconomic. Likewise, the Lewis Continuous Gas Assessment Unit is estimated to have a mean value of about 541.4 million barrels of natural gas liquids (MMBNGL) in undiscovered natural gas liquids resources. There is a 95-percent chance the assessment unit has at least 305.0 MMBNGL, a 50-percent chance it has about 514.7 MMBNGL, and a 5-percent chance it has as much as 868.7 MMBNGL. Oil co-products associated with the undiscovered accumulations were assessed as natural gas liquids.

Lewis Conventional Oil and Gas Assessment Unit (50370701)

The evaluation of undiscovered accumulations in the Lewis Conventional Oil and Gas Assessment Unit of the Southwestern Wyoming Province was influenced strongly by historical trends of discovered accumulations (fields) that exceed the minimum grown size of 3 BCFG, or 0.5 MMBOE, considered in this assessment. Only 11 known accumulations meet those criteria (see report section “Lewis Conventional Oil and Gas Assessment Unit [50370701]”). Ten fields had gas as a major constituent; oil was a major constituent in only one field, discovered in 1966. Therefore, undiscovered accumulations are likely to be gas. In this assessment unit, oil co-products associated with undiscovered accumulations were assessed as natural gas liquids.

Historical trends indicate that most of the significant gas accumulations in the assessment unit might already have been discovered. Plots of the 10 discovered gas accumulations reveal the discovery rate and size of accumulation have experienced an overall decline through time (fig. 17). Most of the larger accumulations were discovered before 1964 (fig. 17*A*). Furthermore, the median size (grown) of 9.9 BCFG for the second half of discovered accumulations is significantly smaller than the median size (grown) of 93.7 BCFG for the first half (fig. 17*B*). Still, additional gas accumulations might be found in undiscovered stratigraphic and (or) structural traps. Undiscovered stratigraphic traps are likely to exist along most of the basin flanks, and undiscovered structural closures of low relief might be found along the Cherokee ridge, Salt Wells anticline, Vermillion Creek anticline, Wamsutter arch (fig. 3), or elsewhere in the assessment unit.

Structural traps might also be discovered under the hanging walls of basin margin thrust faults, or adjacent to normal faults that cut the Cherokee ridge and eastern plunging nose of the Rock Springs uplift.

On the basis of historical drilling, sandstone distribution, and structural configuration of the Lewis TPS, the assessment unit is expected to have 8 to 31 undiscovered gas accumulations, with a median of 18. These may include 8 to 25 in small stratigraphic traps, 1 to 5 in medium-sized stratigraphic or structural traps, and (or) 1 in a large structural trap. Undiscovered accumulations are expected to range from 3 to 90 BCFG, with median of 8 BCFG.

Assessment Results

The Lewis Conventional Oil and Gas Assessment Unit is estimated to contain about 194.6 BCFG at the mean in undiscovered gas resources that have a potential for additions to reserves in the next 30 years (table 4). There is a 95-percent chance that the assessment unit has at least 103.7 BCFG, a 50-percent chance that it has 188.9 BCFG, and a 5-percent chance that it has as much as 304.0 BCFG. Likewise, the conventional assessment unit is estimated to have a mean of 7.80 MMBNGL in undiscovered natural gas liquids resources. There is a 95-percent chance that the assessment unit has at least 3.70 MMBNGL, a 50-percent chance that it has 7.40 MMBNGL, and a 5-percent chance that it has as much as 13.30 MMBNGL.

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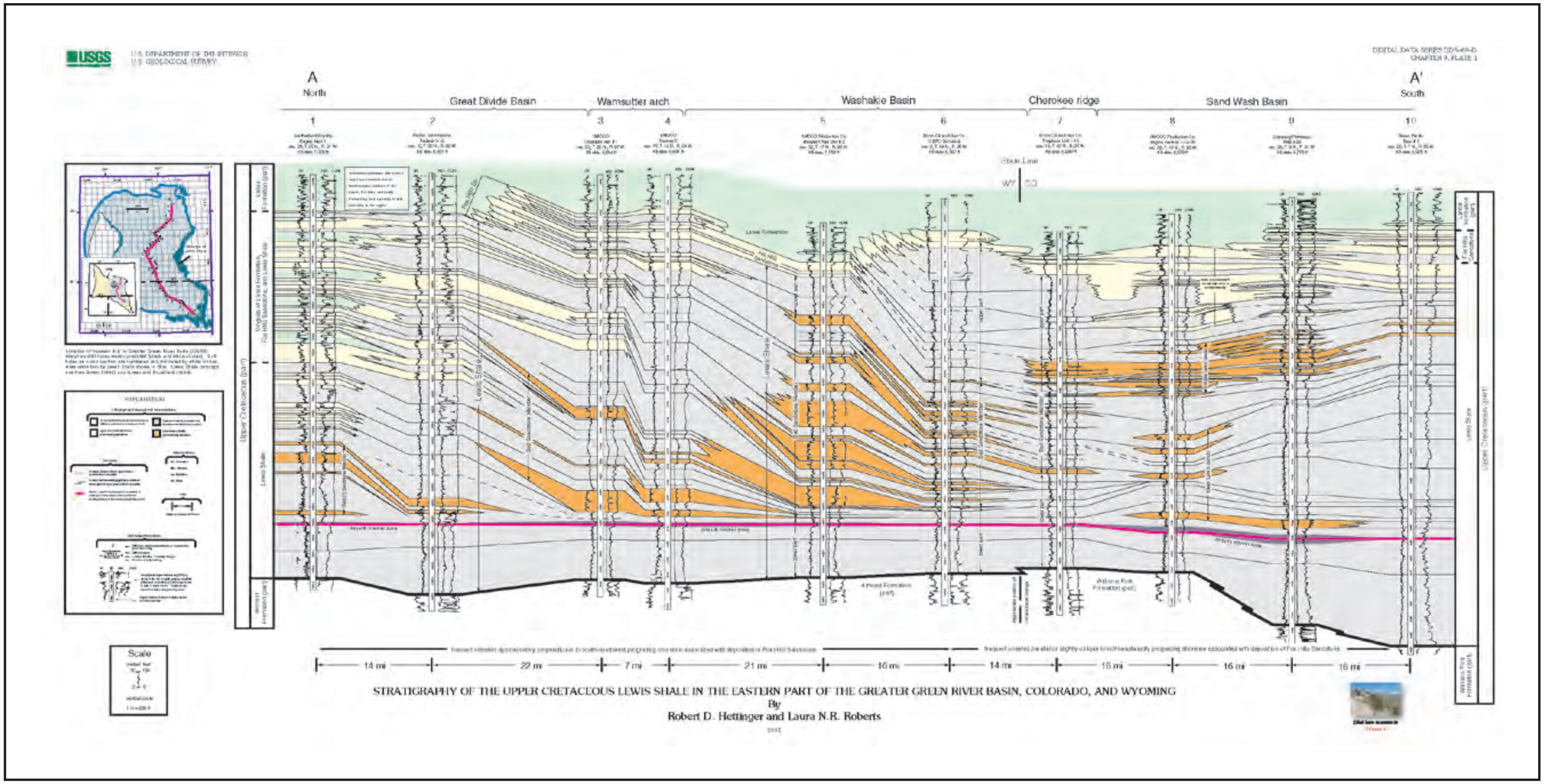


Plate 1. Stratigraphy of the Upper Cretaceous Lewis Shale in the eastern part of the Greater Green River Basin, Colorado and Wyoming.

Appendix A. Basic input data for the Lewis Continuous Gas Assessment Unit (50370761) FORSPAN ASSESSMENT MODEL. [A.U., assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bngl/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; mmbo, million barrels of oil; ngl, natural gas liquids]

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

IDENTIFICATION INFORMATION

Assessment Geologist:…	R.D. Hettinger	Date:	8/23/2002
Region:……………………	North America	Number:	5
Province:………………….	Southwestern Wyoming	Number:	5037
Total Petroleum System:.	Lewis	Number:	503707
Assessment Unit:……….	Lewis Continuous Gas	Number:	50370761
Based on Data as of:……	IHS Energy Group, 2001, NRG 2001 (data current through 1999), Wyoming Oil and Gas Conservation Commission		
Notes from Assessor…..			

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?… 0.02 (mmbo for oil A.U.; bcfg for gas A.U.)
Number of tested cells:………… 539
Number of tested cells with total recovery per cell ≥ minimum: ……... 196
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 0.5 2nd 3rd 1.1 3rd 3rd 0.5

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 2,979,000 median 3,310,000 maximum 3,641,000

2. Area per cell of untested cells having potential for additions to reserves in next 30 years (acres):
(values are inherently variable)
calculated mean 103 minimum 20 median 100 maximum 200

3. Percentage of total assessment-unit area that is untested (%): (uncertainty of a fixed value)
minimum 96.6 median 98.3 maximum 99.7

Appendix A. Basic input data for the Lewis Continuous Gas Assessment Unit (50370761) FORSPAN ASSESSMENT MODEL. [A.U., assessment unit; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bngl/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; mmbo, million barrels of oil; ngl, natural gas liquids]—Continued

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 18 median 42 maximum 69

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 0.02 median 0.6 maximum 15

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)……………………	20	40	60

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 (%)………………………	0.10	0.90	17.00
CO_2 content (%)………………………………	0.50	0.90	1.30
Hydrogen-sulfide content (%)…………………	0.00	0.00	0.00
Drilling depth (m)………………………………	2000	3200	5700
Depth (m) of water (if applicable)………………			

Success ratios:	calculated mean	minimum	median	maximum
Future success ratio (%)..	85	80	85	90

Historic success ratio, tested cells (%) 36

Appendix B. Basic input data for the Lewis Conventional Oil and Gas Assessment Unit (50370701) SEVENTH APPROXIMATION DATA FORM (NOGA, Version 5, 6–30–01). [accums., accumulations; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bngl/mmcfg, barrels of natural gas liquids per million cubic feet of gas; bo/mmcfg, barrels oil per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; max., maximum; med., median; min., minimum; MMBOE, million barrels of oil equivalent; ngl, natural gas liquids]

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (NOGA, Version 5, 6-30-01)

IDENTIFICATION INFORMATION

Assessment Geologist:……	R.D. Hettinger	Date:	8/23/2002
Region:………………………	North America	Number:	5
Province:……………………	Southwestern Wyoming	Number:	5037
Total Petroleum System:….	Lewis	Number:	503707
Assessment Unit:…………	Lewis Conventional Oil and Gas	Number:	50370701
Based on Data as of:………	NRG 2001 (data current through 1999), IHS Energy Group, 2001, Wyoming Oil and Gas Conservation Commission		
Notes from Assessor………	NRG Reservoir Lower 48 growth function		

CHARACTERISTICS OF ASSESSMENT UNIT

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

What is the minimum accumulation size?……………. 0.5 mmboe grown
(the smallest accumulation that has potential to be added to reserves in the next 30 years)

No. of discovered accums exceeding minimum size:………………. Oil: 1 Gas: 10
Established (>13 accums.) ______ Frontier (1-13 accums.) X Hypothetical (no accums.) ______

Median size (grown) of discovered oil accumulation (mmbo):
1st 3rd ______ 2nd 3rd ______ 3rd 3rd ______
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd 93.7 2nd 3rd 9.9 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. ≥ min. size……………………	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ min. size………………	1.0

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

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered accumulation ≥ minimum size………………………………………………………………………………… 1.0

Appendix B. Basic input data for the Lewis Conventional Oil and Gas Assessment Unit (50370701) SEVENTH APPROXIMATION DATA FORM (NOGA, Version 5, 6–30–01). [accums., accumulations; bcfg, billion cubic feet of gas; bliq/mmcfg, barrels of liquid per million cubic feet of gas; bngl/mmcfg, barrels of natural gas liquids per million cubic feet of gas; bo/mmcfg, barrels oil per million cubic feet of gas; cfg/bo, cubic feet of gas per barrel of oil; m, meters; max., maximum; med., median; min., minimum; MMBOE, million barrels of oil equivalent; ngl, natural gas liquids]—Continued

UNDISCOVERED ACCUMULATIONS

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

Oil Accumulations:……………………….min. no. (>0)	0	med. no.	0	max. no.	0
Gas Accumulations:……………………..min. no. (>0)	8	med. no.	18	max. no.	31

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):…………..min. size		med. size		max. size	
Gas in Gas Accumulations (bcfg):…………min. size	3	med. size	8	max. size	90

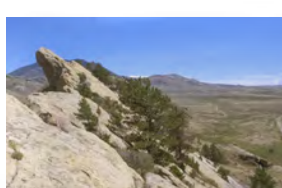
Assessment Unit (name, no.)
Lewis Conventional Oil and Gas, Assessment Unit 50370701

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

Oil Accumulations:	minimum	median	maximum
Gas/oil ratio (cfg/bo)…………………………………			
NGL/gas ratio (bngl/mmcfg)…………………………			
Gas Accumulations:	**minimum**	**median**	**maximum**
Liquids/gas ratio (bliq/mmcfg)………………………	20	40	60
Oil/gas ratio (bo/mmcfg)…………………………………			

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

Oil Accumulations:	minimum	median	maximum
API gravity (degrees)…………………………………			
Sulfur content of oil (%)……………………………			
Drilling Depth (m)………………………………………			
Depth (m) of water (if applicable)…………………			
Gas Accumulations:	**minimum**	**median**	**maximum**
Inert gas content (%)…………………………………	0.5	0.8	3.1
CO_2 content (%)………………………………………	0.1	0.2	0.4
Hydrogen-sulfide content (%)………………………	0	0	0
Drilling Depth (m)………………………………………	860	1,638	2,591
Depth (m) of water (if applicable)…………………			



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