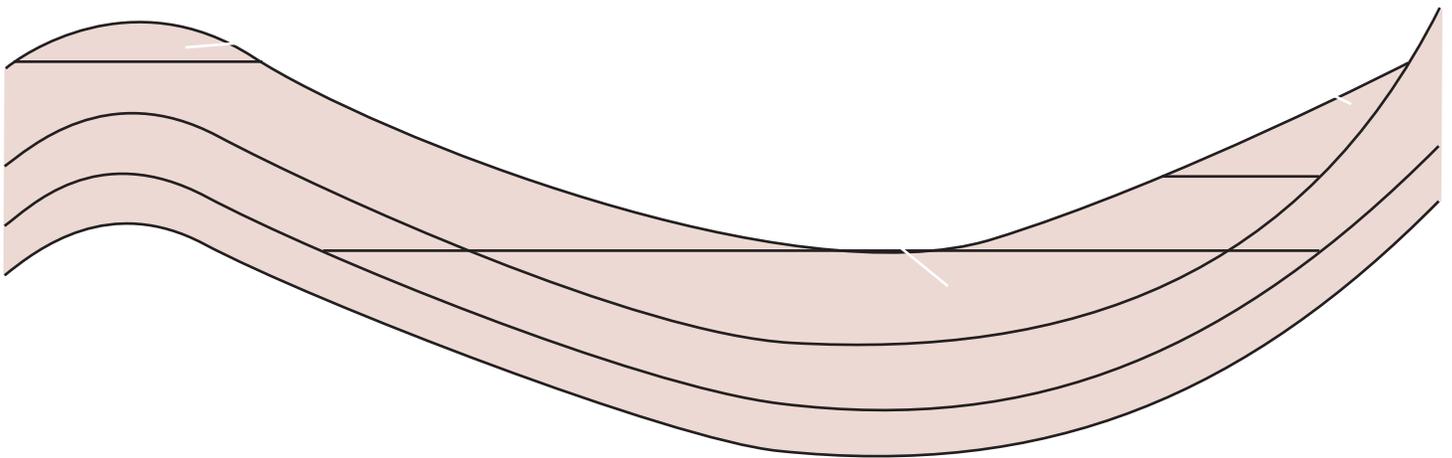


Potential for a Basin-Centered Gas Accumulation in Travis Peak (Hosston) Formation, Gulf Coast Basin, U.S.A

Geologic Studies of Basin-Centered Gas Systems

U.S. Geological Survey Bulletin 2184-E



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By Charles E. Bartberger, Thaddeus S. Dyman, *and* Steven M. Condon

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Edited by Vito F. Nuccio *and* Thaddeus S. Dyman

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Potential for a Basin-Centered Gas Accumulation in Travis Peak (Hosston) Formation, Gulf Coast Basin, U.S.A.

By Charles E. Bartberger, Thaddeus S. Dyman, and Steven M. Condon

Abstract

The potential of Lower Cretaceous sandstones of the Travis Peak Formation in the northern Gulf Coast Basin to harbor a basin-centered gas accumulation was evaluated by examining (1) the depositional and diagenetic history and reservoir properties of Travis Peak sandstones, (2) the presence and quality of source rocks for generating gas, (3) the burial and thermal history of source rocks and time of gas generation and migration relative to tectonic development of Travis Peak traps, (4) gas and water recoveries from drill-stem and formation tests, (5) the distribution of abnormal pressures based on shut-in-pressure data, and (6) the presence or absence of gas-water contacts associated with gas accumulations in Travis Peak sandstones.

The Travis Peak Formation (and correlative Hosston Formation) is a basinward-thickening wedge of terrigenous clastic sedimentary rocks that underlies the northern Gulf Coast Basin from eastern Texas across northern Louisiana to southern Mississippi. Clastic influx was focused in two main fluvial-deltaic depocenters—one located in northeastern Texas and the other in southeastern Mississippi and northeastern Louisiana. Across the main hydrocarbon-productive trend in eastern Texas and northern Louisiana, the Travis Peak Formation is about 2,000 ft thick.

Most Travis Peak hydrocarbon production in eastern Texas comes from drilling depths between 6,000 and 10,000 ft. Significant decrease in porosity and permeability occurs through that depth interval. Above 8,000-ft drilling depth in eastern Texas, Travis Peak sandstone matrix permeabilities often are significantly higher than the 0.1-millidarcy (mD) cutoff that characterizes tight-gas reservoirs. Below 8,000 ft, matrix permeability of Travis Peak sandstones is low because of pervasive quartz cementation, but abundant natural fractures impart significant fracture permeability.

Although pressure data within the middle and lower Travis Peak Formation are limited in eastern Texas, overpressured reservoirs caused by thermal generation of gas, typical of basin-centered gas accumulations, are not common in the Travis Peak Formation. Significant overpressure was found in only one Travis Peak sandstone reservoir in 1 of 24 oil and gas

fields examined across eastern Texas and northern Louisiana.

The presence of gas-water contacts is perhaps the most definitive criterion indicating that a gas accumulation is conventional rather than a “sweet spot” within a basin-centered gas accumulation. Hydrocarbon-water contacts within Travis Peak sandstone reservoirs were documented in 17 fields and probably occur in considerably more fields across the productive Travis Peak trend in eastern Texas and northern Louisiana. All known hydrocarbon-water contacts in Travis Peak reservoirs in eastern Texas, however, occur within sandstones in the upper 500 ft of the formation. Although no gas-water contacts have been reported within the lower three-fourths of the Travis Peak Formation in northeastern Texas, gas production from that interval is limited. The best available data suggest that most middle and lower Travis Peak sandstones are water bearing in northeastern Texas.

Insufficient hydrocarbon charge relative to permeability of Travis Peak reservoirs might be responsible for lack of overpressure and basin-centered gas within the Travis Peak Formation. Shales interbedded with Travis Peak sandstones in eastern Texas are primarily oxidized flood-plain deposits with insufficient organic-carbon content to be significant sources of oil and gas. The most likely source rocks for hydrocarbons in Travis Peak reservoirs are two stratigraphically lower units, the Jurassic-age Bossier Shale of the Cotton Valley Group, and laminated, lime mudstones of the Jurassic Smackover Formation. Hydrocarbon charge, therefore, might be sufficient for development of conventional gas accumulations, but it is insufficient for development of basin-centered gas as a result of the absence of proximal source rocks and a lack of effective migration pathways from stratigraphically or geographically distant source rocks.

Introduction

The U.S. Geological Survey (USGS) is reevaluating the potential for occurrence of continuous basin-centered gas accumulations in selected basins in the United States in order to accommodate changing geologic knowledge since completion of the USGS 1995 National Petroleum Assessment

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(Gautier and others, 1996). This effort, funded in part by the U.S. Department of Energy, might result in identification of new continuous-gas plays and petroleum systems or reevaluation of existing plays.

As part of the 1995 National Assessment of United States Oil and Gas Resources by the USGS, Schenk and Viger (1996) identified three conventional gas plays within the Travis Peak and Hosston Formations sandstone trend in eastern Texas and northern Louisiana. (The name Hosston Formation is used for rocks that are lithologically equivalent to the Travis Peak outside Texas.) This report reevaluates the 1995 USGS play definitions and parameters for establishing those plays through more extensive evaluation of data on reservoir properties, reservoir pressures, gas and water recoveries, gas-production rates, and gas-water contacts in Travis Peak (Hosston) sandstones. Data both favorable and unfavorable for the presence of continuous basin-centered gas accumulations are summarized. No attempt is made in this report, however, to identify new plays and petroleum systems or to estimate undiscovered gas resources for potential plays.

In 1982, under the auspices of its Tight Gas Sands Program, the Gas Research Institute (GRI) conducted a nationwide survey of low-permeability gas-bearing sandstones (Fracasso and others, 1988; Holditch, and others, 1988; Dutton, Laubach, Tye, and others, 1991). From that survey, the Lower Cretaceous Travis Peak Formation was one of two formations selected for comprehensive geologic and engineering research. The goals of this research were to develop knowledge to improve recovery of gas, and to reduce the costs of producing gas, from low-permeability sandstone reservoirs. The main emphasis was on developing more effective hydraulic-fracture treatments with anticipation of transferring this technology to other low-permeability gas reservoirs. As part of this research program, the Texas Bureau of Economic Geology (BEG) at the University of Texas in Austin conducted comprehensive geological analyses of the Travis Peak Formation from 1983 to 1986. The BEG focus was on depositional systems, sandstone diagenesis, natural fractures, source rocks, burial and thermal history, and structural evolution of the East Texas and Northern Louisiana Salt Basins and the Sabine uplift. Studies of reservoir-engineering properties and production characteristics of Travis Peak sandstones in selected gas fields also were conducted. Much of this research was based on core, wireline-log, and production data that GRI contractors collected from seven Travis Peak wells, with permission from operating companies. Results from this research prompted GRI to drill and complete three Staged Field Experiment (SFE) wells to test understandings developed and to acquire additional data (Dutton, Laubach, Tye, and others, 1991). SFE No. 1 was drilled in August 1986 in Waskom field, Harrison County, Texas, and SFE No. 2 was drilled in September 1987 in North Appleby field, Nacogdoches County, Texas. Research in these two wells focused on gas-productive sandstones near the top and base of the Travis Peak Formation. SFE No. 3 was drilled in September 1988 in Waskom field to attempt to apply technologies developed in the Travis Peak to low-permeability sandstones of the Cotton

Valley Group. As a result of research from this GRI Tight Gas Sands Program, a wealth of information on Travis Peak and Cotton Valley low-permeability sandstone reservoirs was published by both GRI and BEG. Those data and accompanying interpretations provide a significant part of the information used in this study to evaluate the potential for basin-centered gas in the Travis Peak.

Data Sources

Interpretations and conclusions presented in this report are based on data from published literature and limited conversations with industry personnel, together with geologic and engineering data accessible in a publicly available database from IHS Energy Group (PI/Dwights PLUS of Petroleum Information/Dwights, d.b.a. IHS Energy Group). PI/Dwights PLUS data evaluated for this report are current through February 2000. The primary data from PI/Dwights PLUS pertinent to this study are results of drill-stem and production tests in the Travis Peak Formation reported for individual wells. Because well-completion records depend on information provided by operators, well data in PI/Dwights PLUS might be incomplete.

Acknowledgments

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Continuous-Type Gas Accumulations

It is important to identify continuous-type gas accumulations because resource assessment for such gas accumulations is conducted using different methodology than that used for conventional fields (Schmoker, 1996). Continuous-gas accumulations generally occur within an extensive volume of reservoir rock that has spatial dimensions equal to or exceeding those of conventional hydrocarbon plays. The definition of continuous-gas accumulations used here is based

on geology rather than on government regulations defining low-permeability (tight) gas. Common geologic and production characteristics of continuous-gas accumulations include their occurrence downdip from water-saturated rocks, lack of conventional traps or seals, reservoir rocks with low matrix permeability, presence of abnormally pressured reservoirs, large in-place volumes of gas, and low recovery factors (Schmoker, 1996).

Continuous-gas plays were treated as a separate category in the U.S. Geological Survey 1995 National Petroleum Assessment and were assessed using a specialized methodology (Schmoker, 1996). These continuous plays are geologically diverse and fall into several categories including coal-bed gas, biogenic gas, fractured-shale gas, and basin-centered gas accumulations. This report focuses on the potential for basin-centered gas within Travis Peak Formation sandstones.

Basin-Centered Gas Accumulations

From studies of hydrocarbon-productive basins in the Rocky Mountain region, Law and Dickinson (1985) and Spencer (1987) identified characteristics of basin-centered gas accumulations that distinguish them from conventional ones. Basin-centered gas accumulations:

1. Are geographically large, spanning tens to hundreds of square miles in areal extent, typically occupying the central, deeper parts of sedimentary basins.
2. Occur in reservoirs having low permeability—generally less than 0.1 millidarcy (mD)—such that gas cannot migrate by buoyancy.
3. Lack downdip gas-water contacts because gas is not held in place by the buoyancy of water. Consequently, water production is low or absent. If water is produced, it is not associated with a distinct gas-water contact.
4. Commonly occur in abnormally pressured reservoirs (generally overpressured, but in places underpressured).
5. Contain primarily thermogenic gas, and, where overpressure is encountered, the overpressuring mechanism is thermal generation of gas.
6. Occur structurally downdip from water-bearing reservoirs that are normally pressured or locally underpressured.
7. Lack traditional seals and trapping mechanisms.
8. Have gas-prone source rocks proximal to the low-permeability reservoirs such that hydrocarbon migration distances are short.
9. Occur in settings such that the tops of the gas accumulations occur within a narrow range of thermal maturity, usually between a vitrinite reflectance (R_o) of 0.75 and 0.9 percent.

What causes a basin-centered, continuous-gas accumulation to form? The most common scenario involves low-permeability reservoirs in which overpressures develop in response to thermal generation of gas. Gas-prone source

rocks generally must be associated with, or are proximal to, low-permeability reservoirs, and this sequence of source and reservoir rock must be buried to a depth sufficient for the source rocks to generate gas. Overpressured reservoirs develop because the rate of thermal generation of gas exceeds the rate at which gas is lost updip by migration through the low-permeability reservoir. As overpressure develops, any free water in pores of the tight reservoir is forced out updip into higher permeability, normally pressured, water-bearing strata. Only bound, irreducible water remains in the tight-gas reservoir. Permeability is sufficiently low within the tight reservoir so that gas does not migrate through it by buoyancy as it does through conventional reservoirs with higher permeabilities (Gies, 1984; Spencer, 1987; Law and Spencer, 1993). Instead, gas migrates slowly through the tight-gas reservoir with movement caused by the pressure differential between the region of high-pressure gas generation and the normally pressured, higher permeability, water-bearing rocks updip where gas does migrate upward rapidly by buoyancy. Thus, because of its inherent low permeability, a basin-centered gas reservoir itself retards the upward migration of gas, in effect forming its own leaky seal, and maintaining overpressured conditions.

This scenario probably describes an ideal end-member situation. In some cases, for example, basin-centered gas accumulations have subnormal reservoir pressures resulting from significant tectonic uplift and erosion of overlying strata in the basin. For a basin that is tectonically active and in an intermediate stage of uplift, it might be possible to find a basin-centered gas accumulation with normally pressured reservoirs. It seems clear that particular gas accumulations might have only some of the characteristics for basin-centered gas described above and that differentiating between basin-centered and conventional accumulations often can be difficult and subjective. It is with this understanding that the potential for basin-centered gas in the Travis Peak Formation is evaluated.

Method for Evaluating Potential of Basin-Centered Gas in Sandstones of the Travis Peak Formation

One of the main requirements for the occurrence of a basin-centered, continuous-gas accumulation is the presence of a regional seal to trap gas in a large volume of rock across a widespread geographic area. In classic basin-centered gas accumulations (Law and Dickinson, 1985; Spencer, 1987; Law and Spencer, 1993), the regional seal is provided by the low-permeability of the reservoir itself, as described above. To evaluate the potential for a continuous-gas accumulation within the Travis Peak Formation, therefore, it is necessary to examine reservoir properties of Travis Peak sandstones across the northern Gulf Coast Basin. Because reservoir quality of Travis Peak sandstones is governed by diagenetic

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characteristics, which in turn are controlled primarily by depositional environment, it is helpful first to understand Travis Peak depositional systems and related diagenetic patterns.

Although gas production from Travis Peak sandstones seems to occur from discrete fields, it is necessary to determine if those fields are separate, conventional accumulations or so-called “sweet spots” within a regional, continuous-gas accumulation. Thus, it is essential to understand what characterizes the apparent productive limits of existing Travis Peak gas fields, including the presence or absence of gas-water contacts. Additionally, because continuous-gas accumulations commonly are characterized by overpressure associated with thermal generation of gas from source rocks that generally are proximal to low-permeability reservoirs, it is important to evaluate the presence and quality of potential source rocks, burial and thermal history of those source rocks, and reservoir-pressure data.

In northeastern Texas, the 2,000-ft-thick Travis Peak Formation is characterized by heterogeneities that require caution when evaluating the potential for basin-centered gas

accumulations. Because permeability decreases by four orders of magnitude across the productive depth range from (6,000 to 10,000 ft), it is inappropriate to characterize the entire Travis Peak Formation in a particular well using a single permeability value. Because of depositional heterogeneities, sandstones in the upper 300 ft of the Travis Peak commonly are isolated bodies encased in shales, whereas the bulk of the underlying Travis Peak consists of interconnected, multistory, multilateral sandstone bodies that lack regional shale barriers. Whereas a single fluid-pressure gradient might characterize much of the interconnected sandstone sequence, that gradient might be considerably different than the gradient for one of the isolated sandstone units in the upper Travis Peak, hence the difficulty in attempting to characterize the entire formation with one fluid-pressure gradient. Likewise, the presence of a gas-water contact within one upper Travis Peak sandstone reservoir in a particular Travis Peak field might not be characteristic of deeper Travis Peak reservoirs in the same area. Finally, because most Travis Peak hydrocarbon production in northeastern Texas is from sandstone reservoirs within the upper

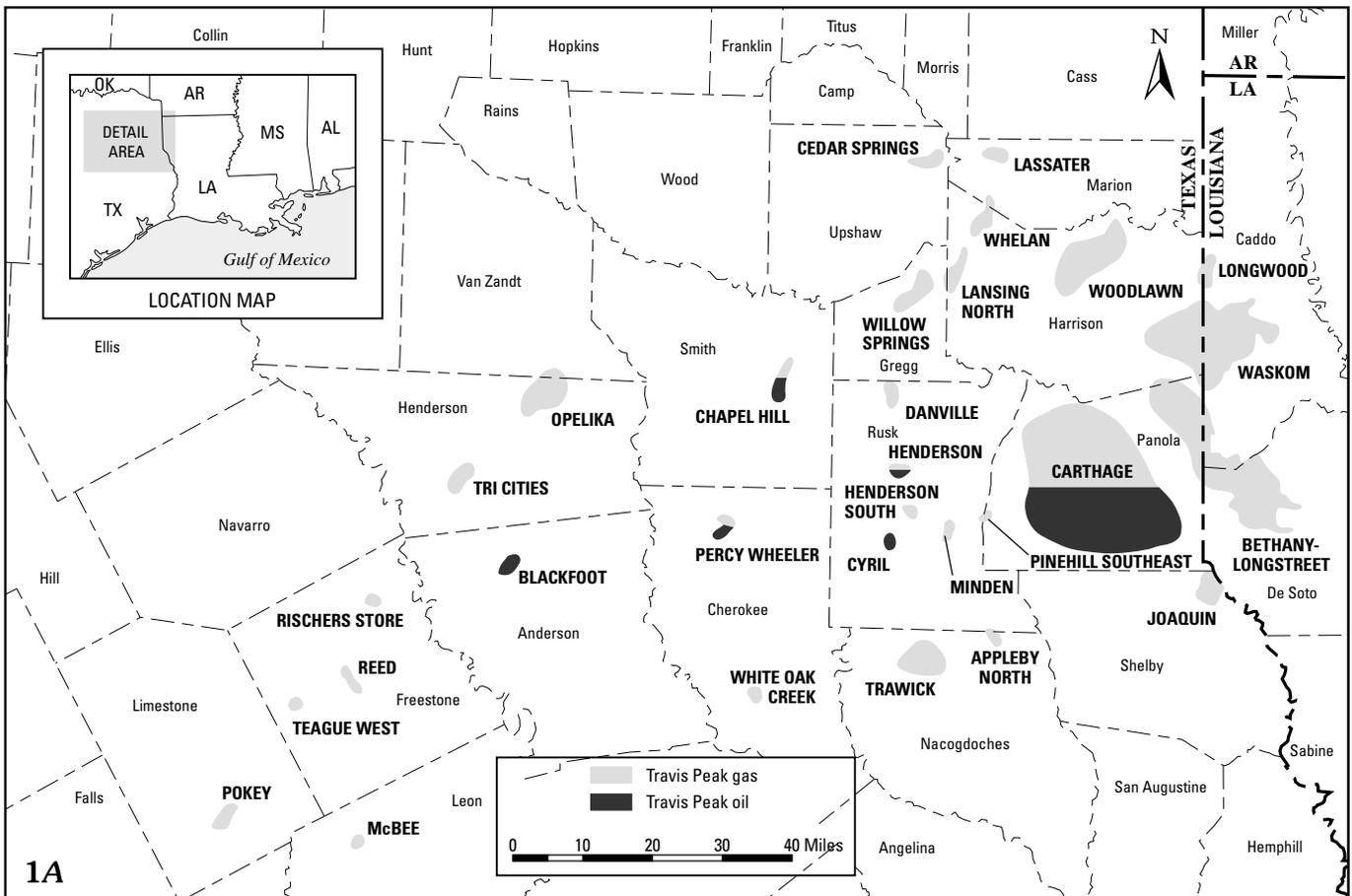


Figure 1A. Map of northeastern Texas showing major fields that have produced hydrocarbons from Travis Peak (Hosston) Formation sandstone reservoirs.

300 ft of the formation, significantly fewer data are available to characterize the lower three-fourths of the Travis Peak.

Geologic Setting for Travis Peak Formation in Northern Gulf Coast Basin

The Lower Cretaceous Travis Peak Formation is a basinward-thickening wedge of terrigenous clastic sedimentary rock that underlies the northern Gulf of Mexico coastal plain from eastern Texas across southern Arkansas and northern Louisiana into southern Mississippi, southern Alabama, and the Florida Panhandle. The thickness of the Travis Peak Formation ranges from less than 1,000 ft in southern Arkansas to more than 3,200 ft in north-central Louisiana. The downdip limit of the Travis Peak Formation has not been delineated by drilling to date. Travis Peak strata crop out in portions of Brown, Mills, McCulloch, San Saba, and Lampasas Counties in east-central Texas (Hartman and Scranton, 1992). Across

the hydrocarbon-productive trend of the Travis Peak Formation (figs. 1A, 1B, and 1C), the depth to top of the Travis Peak ranges from about 4,000 ft below sea level in southern Arkansas to more than 18,000 ft below sea level in north-central Louisiana and southern Mississippi (Saucier, 1985). Although Travis Peak sandstones produce gas from drilling depths in excess of 16,000 ft in southern Mississippi (Thomson, 1978), most Travis Peak production across the trend in eastern Texas and northern Louisiana is from drilling depths between 6,000 and 10,000 ft (Dutton and others, 1993). Travis Peak production across eastern Texas and northern Louisiana is primarily gas, but some fields also produce oil (figs. 1A and 1B).

The Travis Peak (Hosston) is the basal formation of the Lower Cretaceous Trinity Group, which overlies the Upper Jurassic and Lower Cretaceous Cotton Valley Group (fig. 2). The Cotton Valley Group and overlying Travis Peak Formation represent the first two major influxes of terrigenous clastic sediments into the Gulf Coast Basin following its initial formation during continental rifting in Late Triassic time (Salvador, 1987; Worrall and Snelson, 1989). The earliest sedimentary deposits in East Texas and Northern Louisiana Salt Basins (figs. 2 and 3)

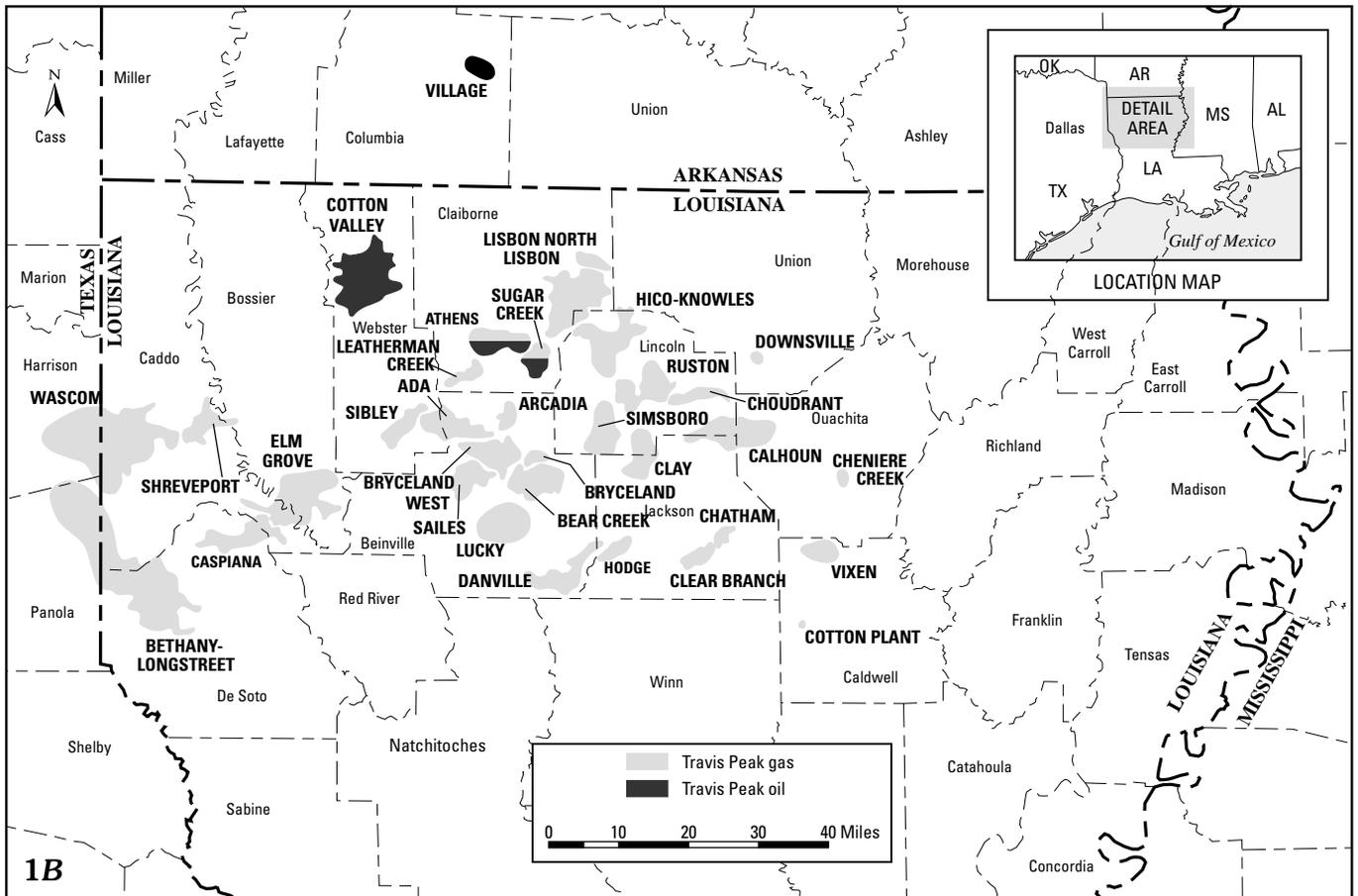


Figure 1B. Map of northern Louisiana and southern Arkansas showing major fields that have produced hydrocarbons from Travis Peak (Hosston) Formation reservoirs. Modified from Bebout and others (1992).

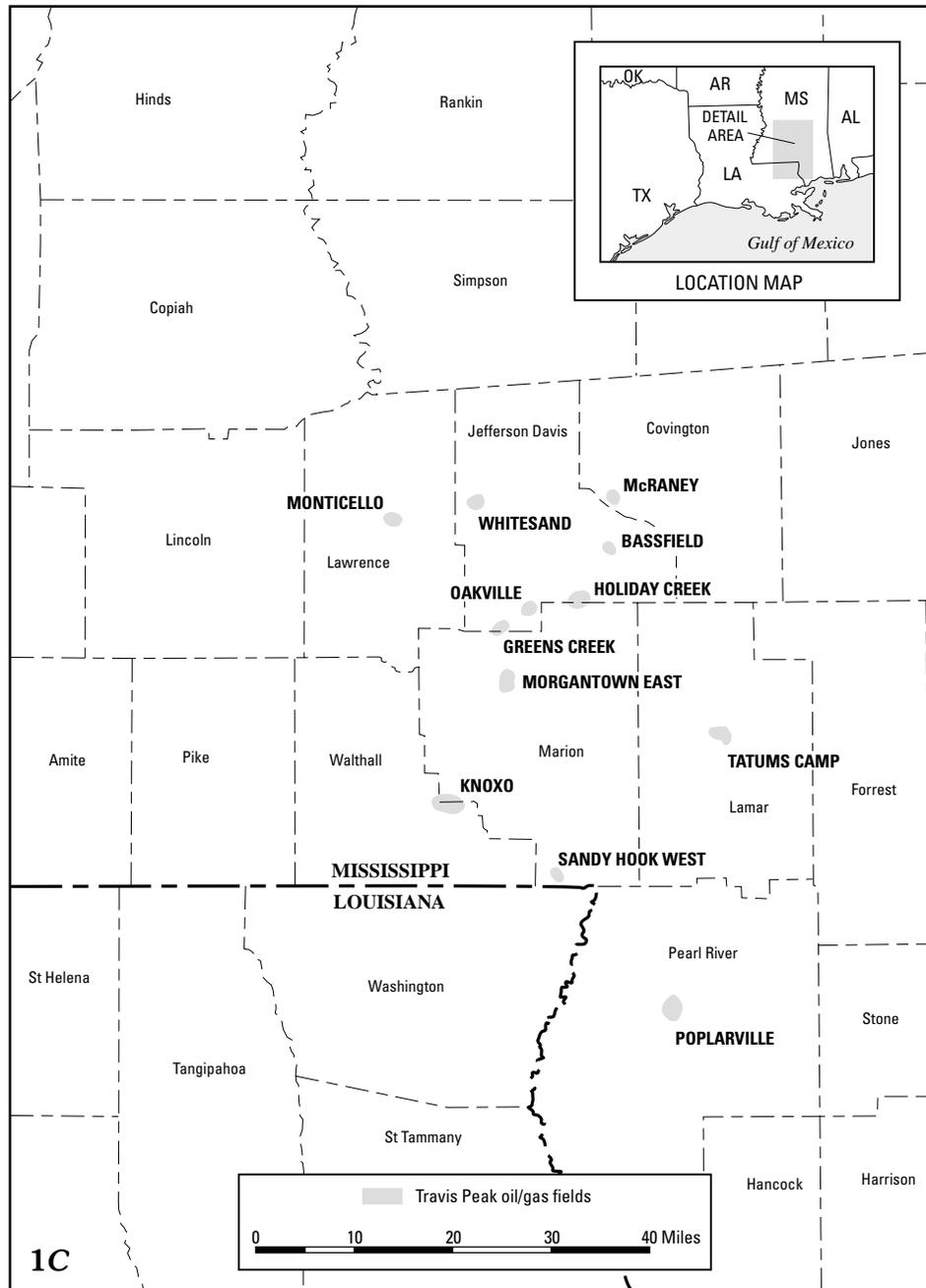


Figure 1C. Map of central Mississippi showing major fields that have produced hydrocarbons from Travis Peak (Hosston) Formation reservoirs. Modified from Bebout and others (1992).

include Upper Triassic and Lower Jurassic nonmarine red beds of the Eagle Mills Formation, the thick Middle Jurassic evaporite sequence known as the Werner Anhydrite and the Louann Salt, and the nonmarine Norphlet Formation. Following a major regional marine transgression across the Norphlet, regressive carbonates of the Upper Jurassic Smackover Formation were deposited and capped by red beds and evaporites of the Buckner Formation (fig. 2). A subsequent minor marine transgression is

recorded by the Gilmer Limestone (“Cotton Valley limestone”) in eastern Texas, although equivalent facies in northern Louisiana and Mississippi are terrigenous clastics known as the Haynesville Formation. The marine Bossier Shale, lowermost formation of the Cotton Valley Group (fig. 2), was deposited conformably atop the Gilmer-Haynesville, followed by progradation of the major fluvial-deltaic sequence known as the “Cotton Valley sandstone” or Schuler Formation (fig. 2).

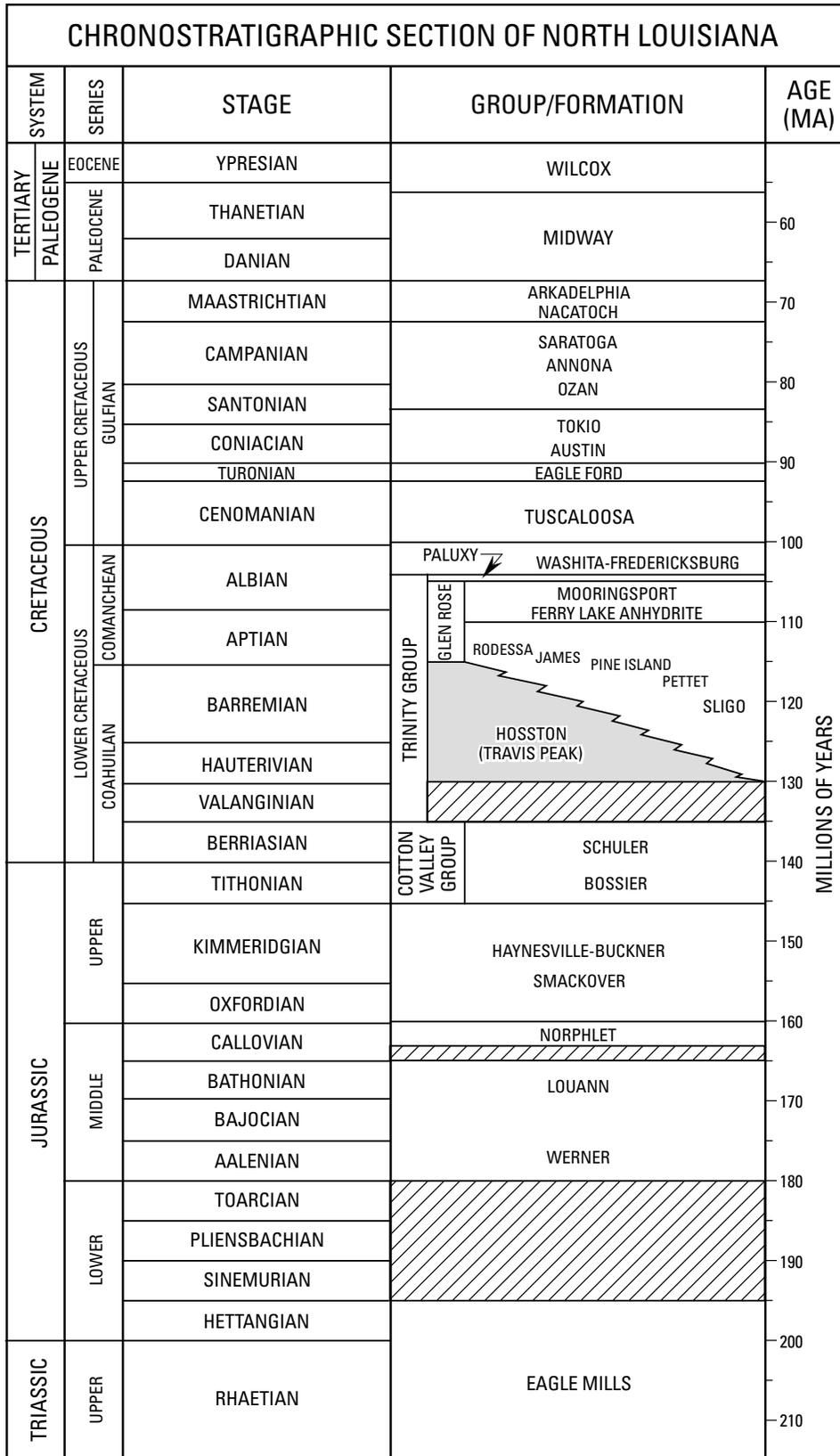


Figure 2. Chronostratigraphic section of northern Louisiana from Shreveport Geological Society (1987) showing general stratigraphic succession of selected units for northern Gulf Coast Basin. Travis Peak Formation, lowermost formation of the Trinity Group, is designated as Hosston Formation (shading) on this diagram. Upper contact of Travis Peak (Hosston) with overlying Sligo Formation carbonates is time transgressive.

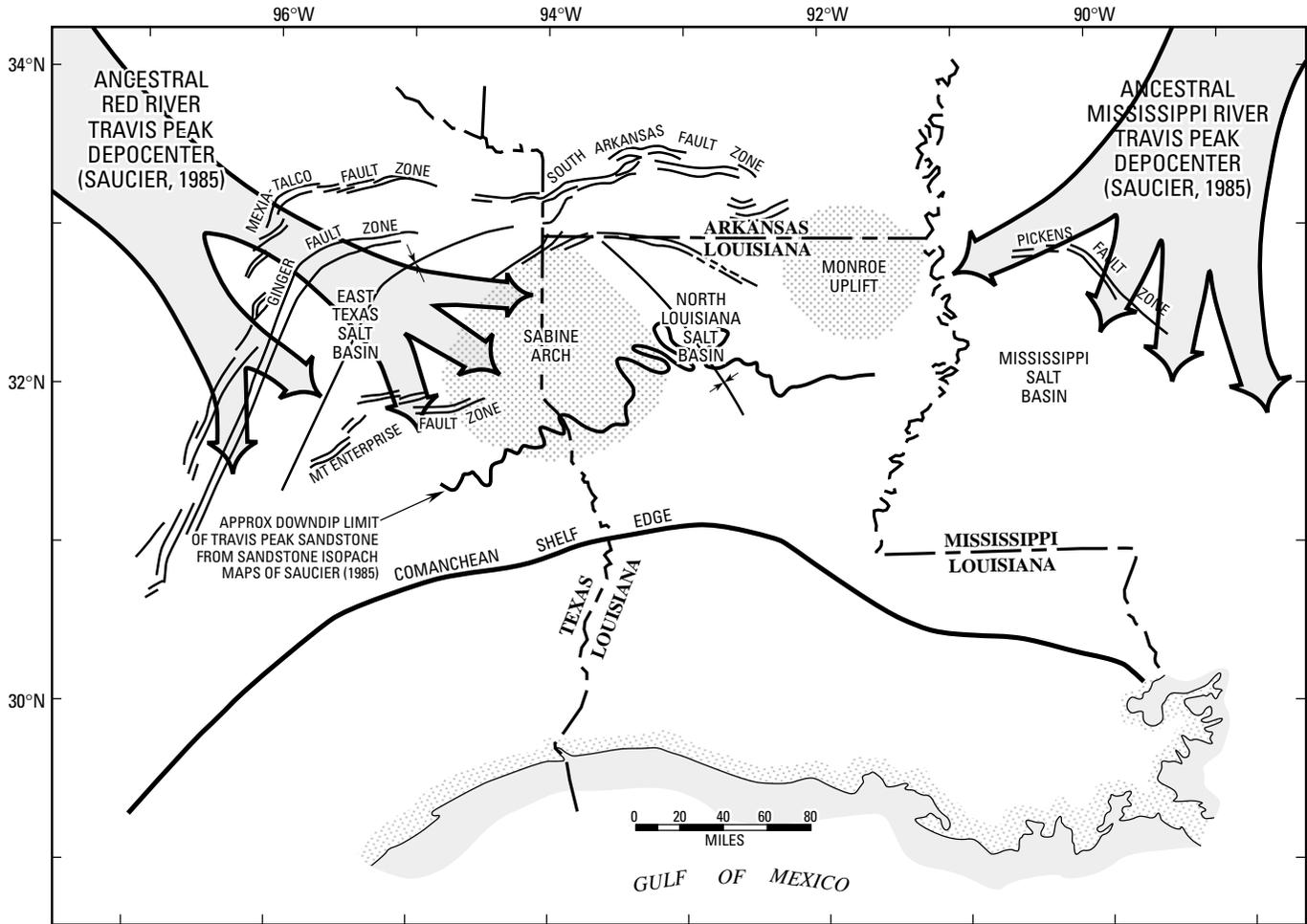


Figure 3. Index map of northern Gulf Coast Basin from Dutton and others (1993) showing major tectonic features, including Sabine arch and salt basins of eastern Texas, northern Louisiana, and Mississippi. Sabine and Monroe uplifts were not positive features during deposition of the Lower Cretaceous Travis Peak Formation. Movement of salt in the salt basins commenced during deposition of Upper Jurassic Smackover Formation carbonates and became more extensive with influx of thick sequence of Cotton Valley Group and Travis Peak Formation terrigenous clastic sediments.

A significant marine transgression that halted Cotton Valley fluvial-deltaic sedimentation is recorded by the Knowles Limestone, the uppermost formation of the Cotton Valley Group (fig. 4). Prodelta and fluvial-deltaic deposits of the Travis Peak Formation overlie the Knowles Limestone, recording the second major influx of terrigenous clastics into the northern Gulf Coast Basin. In updip regions of the Gulf Coast Basin, the Knowles Limestone pinches out, and Travis Peak fluvial-deltaic strata rest directly on Schuler fluvial deltaic units of the Cotton Valley Group (fig. 4). Whereas most workers consider the Knowles–Travis Peak contact to be conformable, controversy exists regarding the presence or absence of an unconformity between the updip Schuler and Travis Peak Formations. McFarlan (1977), Todd and Mitchum (1977), and Tye (1989) identify a major unconformity between the Schuler and Travis Peak, whereas Nichols and others (1968) and Saucier (1985) consider the contact to be conformable.

There is general agreement that the upper contact of the Travis Peak with overlying shallow-marine carbonates of the Sligo Formation (known as the Pettet Formation outside Texas) is conformable. Most of the 15-m.y. period of Travis Peak deposition occurred during a relative rise in sea level (McFarlan, 1977; Vail and others, 1977), and the Travis Peak–Sligo contact is a time-transgressive boundary with Sligo oolitic and micritic limestones onlapping Travis Peak paralic and marine clastics to the north out of the Gulf Coast Basin (Tye, 1991) (figs. 2 and 4).

The thick Middle Jurassic Louann Salt became mobile as a result of sediment loading and associated basinward tilting in Late Jurassic and Early Cretaceous time. Salt movement was initiated during Smackover carbonate deposition and became more extensive with influx of the thick sequence of Cotton Valley and Travis Peak clastics (McGowen and Harris, 1984). Many Cotton Valley and Travis Peak fields in eastern Texas,

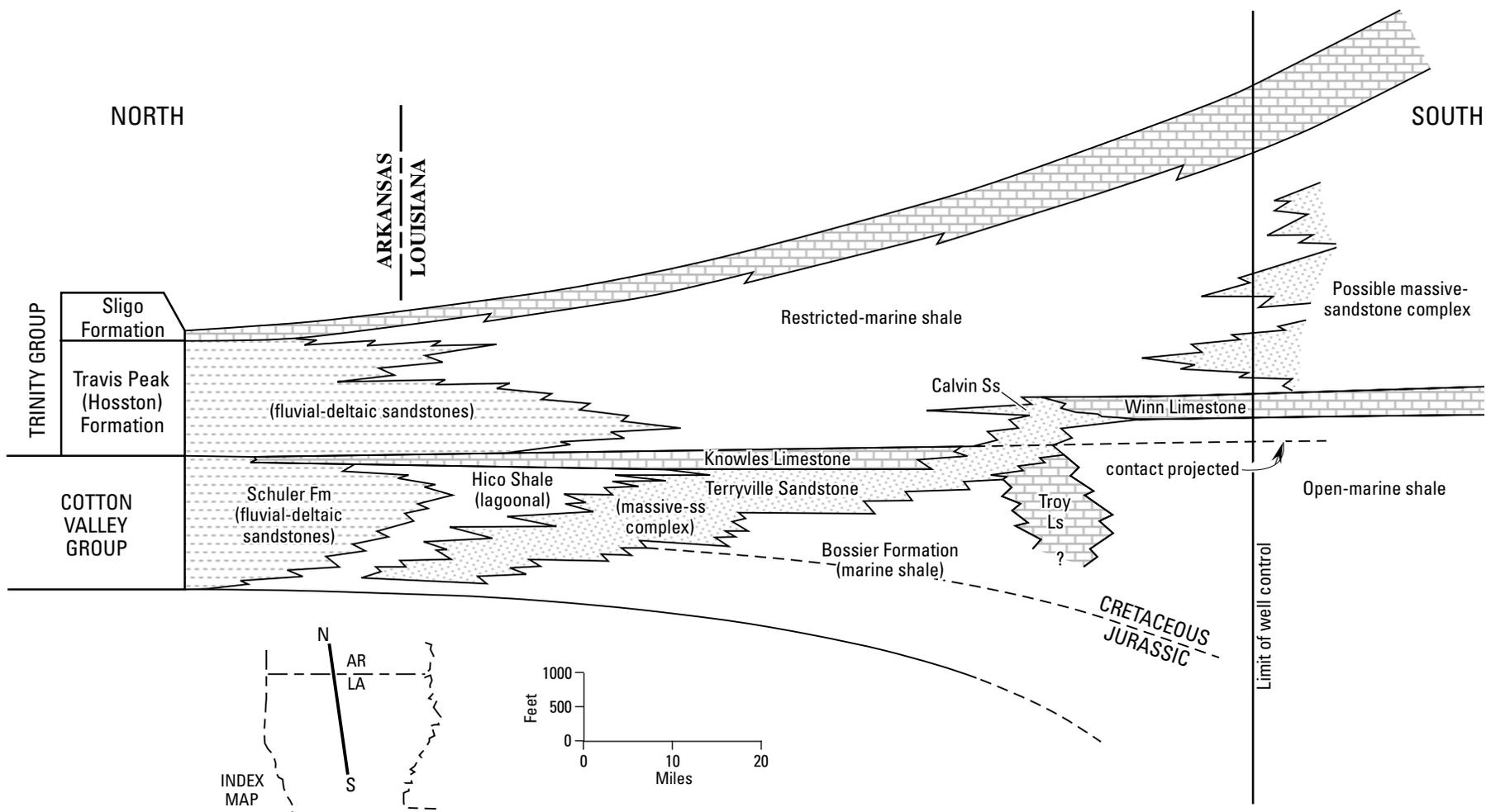


Figure 4. Diagrammatic north-south stratigraphic cross section across southern Arkansas and northern Louisiana showing depositional relationships among units of Cotton Valley Group and Travis Peak Formation (from Saucier, 1985). Datum is top of Cotton Valley Group. Relatively thick sequence of Cotton Valley (Terryville) Sandstone, interbedded shales, and Knowles Limestone separates Bossier Shale source rocks from Travis Peak sandstone reservoirs. Coleman and Coleman (1981) consider Calvin Sandstone and Winn Limestone to be part of Cotton Valley Group.

Louisiana, and Mississippi are structural or combination traps associated with deformed Louann Salt. Salt structures range from small, low-relief salt pillows to large, piercement domes (McGowen and Harris, 1984; Kisters and others, 1989).

The Sabine uplift (fig. 3) is a broad, low-relief, basement-cored arch separating the East Texas and Northern Louisiana Salt Basins. With vertical relief of 2,000 ft, the Sabine uplift has a closed area exceeding 2,500 mi² (Kisters and others, 1989). Isopach data across the uplift indicate that it was a positive feature during deposition of Louann Salt in the Jurassic but that main uplift occurred in late, mid-Cretaceous (101 to 98 Ma) and early Tertiary time (58 to 46 Ma) (Laubach and Jackson, 1990; Jackson and Laubach, 1991). As a high area during the past 60 m.y., the Sabine uplift has been a focal area for hydrocarbon migration in the northern Gulf Coast Basin during that time. Numerous smaller structural highs on the Sabine uplift in the form of domes, anticlines, and structural noses provide traps for hydrocarbon accumulations, including many oil and gas fields with Travis Peak reservoirs. Interpreta-

tions of the origins of these smaller structures have included salt deformation and small igneous intrusions, as summarized by Kisters and others (1989). Because the Louann Salt is thin across the Sabine uplift, Kisters and others (1989) suggested that most of the smaller structures across the Sabine uplift developed in association with igneous activity.

Travis Peak Formation Stratigraphy

The Travis Peak Formation is not divided formally into members. However, Saucier (1985) and Saucier and others (1985) distinguished three separate stratigraphic intervals within the Travis Peak across eastern Texas and northern Louisiana based on relative amounts of sandstone and shale, as reflected in the resistivity and gamma-ray character of sandstones on wireline logs. A thin, basal interval of mixed sandstones and shales interpreted as delta-fringe gradationally

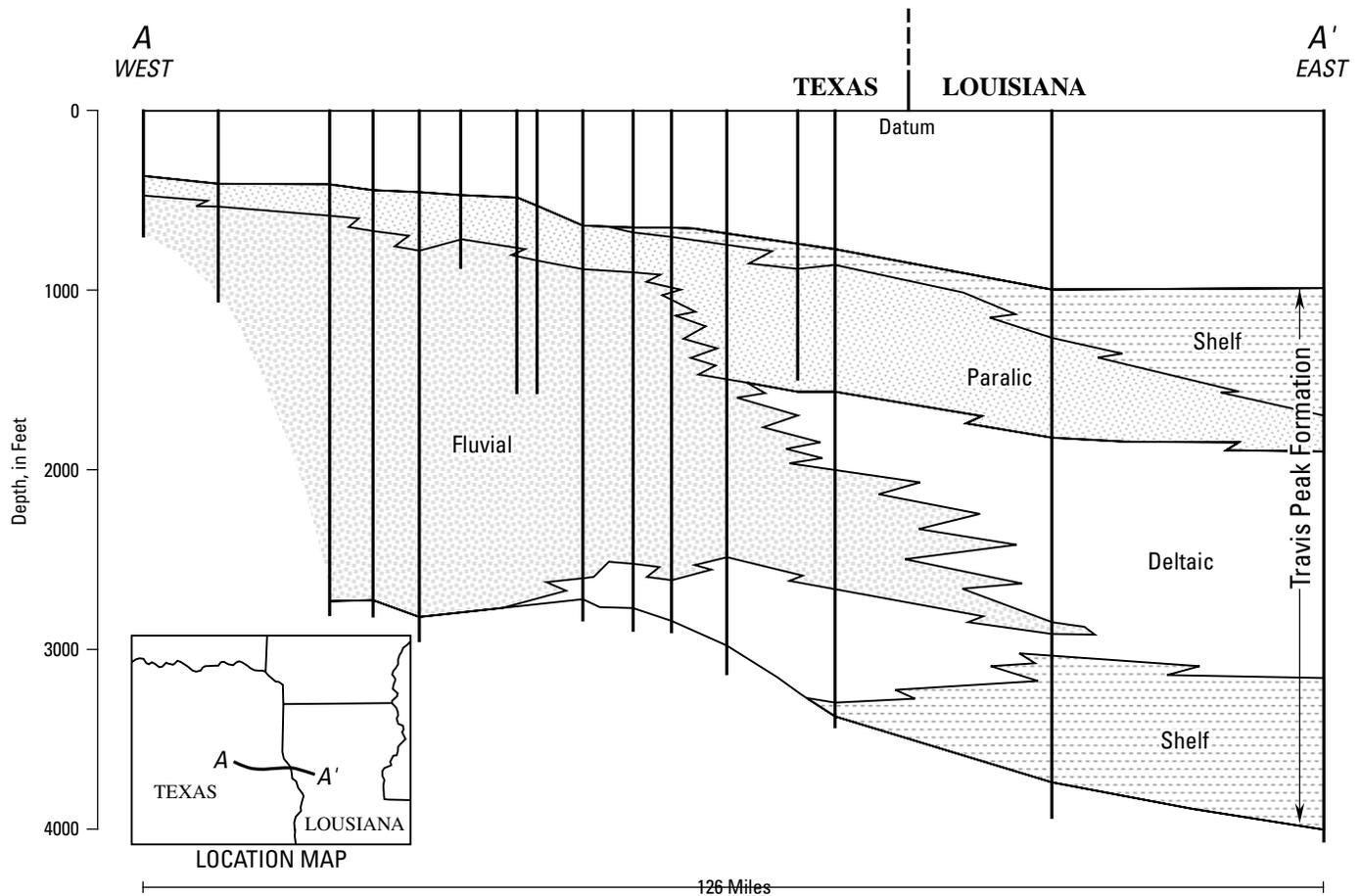


Figure 5. East-west stratigraphic cross section of Travis Peak Formation across northeastern Texas into western Louisiana showing major Travis Peak depositional systems (from Dutton, Laubach, and Tye, 1991). Cross section oriented parallel to depositional dip. Three-fold division of Travis Peak Formation across hydrocarbon-productive trend includes thin, basal deltaic unit overlain by thick fluvial sequence that grades upward into paralic deposits. Vertical lines represent locations of oil and gas wells. Datum is top of Pine Island Shale.

COMPOSITE LOG PROFILE OF TRAVIS PEAK FORMATION

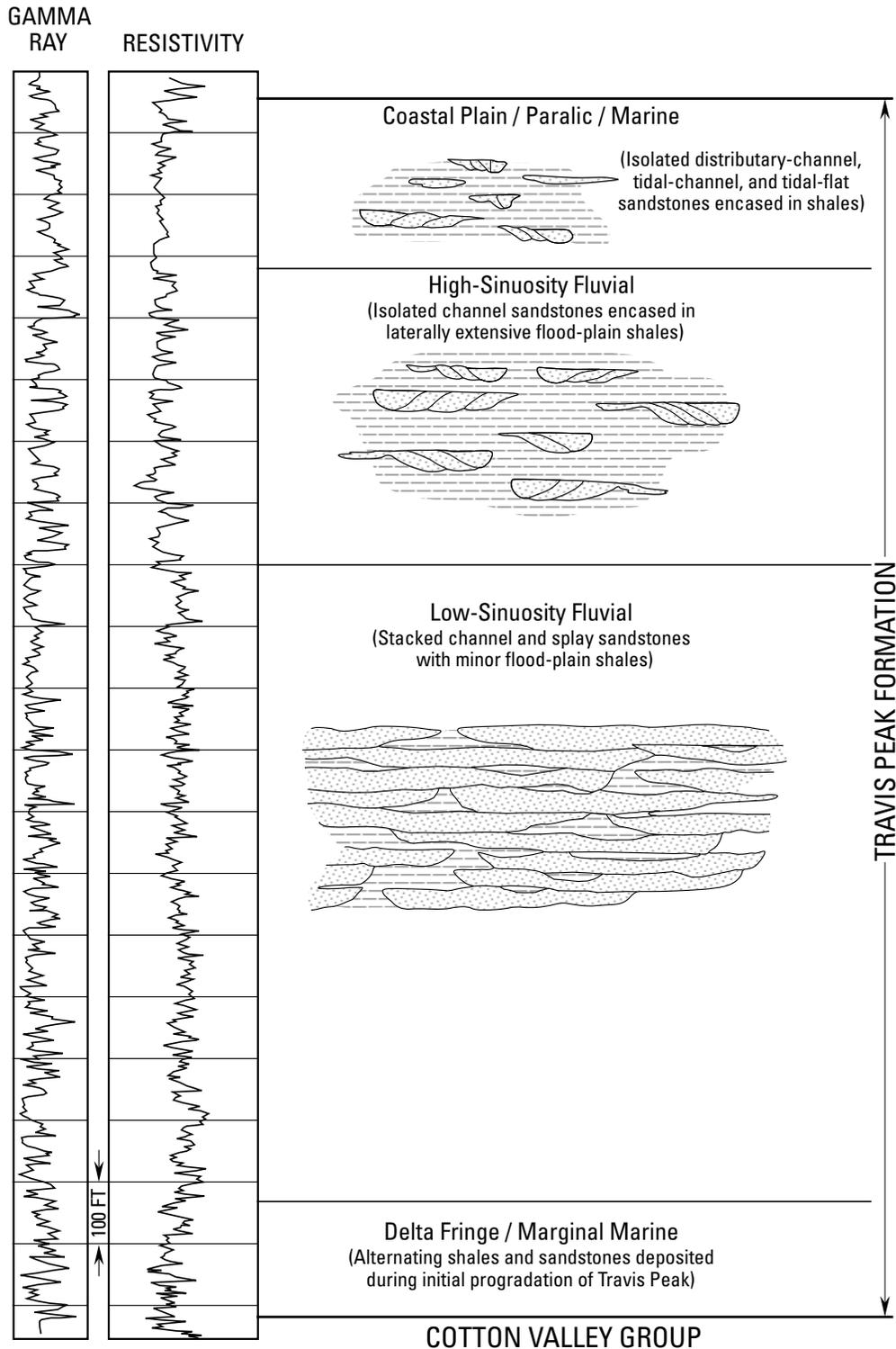


Figure 6. Composite wireline log showing gamma-ray and resistivity responses through complete section of Travis Peak Formation in eastern Texas (modified from Davies and others, 1991). Gamma-ray and resistivity character distinguish thin basal deltaic sequence, thick middle fluvial sequence, and thin upper paralic interval. Log responses within thick fluvial sequence also distinguish lower interval of stacked braided-channel sandstones with minor flood-plain mudstones from upper interval of meandering-channel sandstones encased in thicker overbank mudstones. Most Travis Peak hydrocarbon production in northeastern Texas comes from sandstones encased in shales within the upper 300 ft of the Travis Peak Formation. Depth increments on log are 100 ft.

is overlain by a thick, sandstone-rich sequence of fluvial and flood-plain deposits that grades upward into another interval of sandstone and mudstone interpreted as coastal-plain and paralic deposits (figs. 5 and 6) (Saucier, 1985; Fracasso and others, 1988; Tye, 1989, 1991). The middle fluvial–flood-plain interval, which is thickest and forms the bulk of the Travis Peak section, consists of stacked, aggradational, braided-channel sandstones that grade upward into more isolated meandering-channel sandstone deposits (fig. 6). Sandstones are interpreted as braided, based on blocky SP curves, bed forms observed in conventional cores, and sandstone-body geometry. Stacked, braided-channel units generally are 12 to 45 ft thick, but, because of the absence of preserved shales, amalgamated channel sandstones occur in places as massive sandstone units as much as 250 ft thick with blocky SP curves (Saucier, 1985). Serrated gamma-ray curves within such intervals reflect abundant shale rip-up clasts at the scoured bases of individual channels (Tye, 1989). Upward-fining sequences are not common and occur only where individual channel units are isolated by siltstones and (or) shales (Saucier, 1985).

This thick fluvial–flood-plain sequence gradationally overlies a much thinner sequence with considerably higher mudstone content in which discrete sandstones are separated by thicker mudstones. Sandstones in this lower Travis Peak sequence display a variety of upward-coarsening, upward-fining, and serrated SP signatures and are interpreted as delta-fringe deposits.

The thick, middle fluvial–flood-plain sequence grades upward into the third interval recognized by Saucier (1985), which forms the uppermost portion of the Travis Peak. Like the lower Travis Peak delta-fringe interval, this upper interval is characterized by discrete sandstones separated by thicker mudstones (fig. 6). Many sandstones in the upper interval display thin, spiky, upward-coarsening or upward-fining serrated SP signatures, which are interpreted as coastal-plain and paralic deposits. Upper Travis Peak paralic units are transgressive and step upward and landward with time (fig. 2) as they interfinger with, and are gradationally overlain by, shallow-marine shelf carbonates of the Sligo (Pettet) Formation (Fracasso and others, 1988). Sligo carbonates thin updip to the northwest as they lap onto Travis Peak paralic deposits. Contact of the Travis Peak with the overlying Sligo Formation, therefore, is time transgressive.

Travis Peak Formation Depositional Systems

Regional Framework

Following the regional marine transgression recorded by deposition of the Knowles Limestone at the close of Cotton Valley time, Travis Peak fluvial-deltaic systems began prograding basinward across surfaces of the Schuler and Knowles

Formations (fig. 4). Two main Travis Peak fluvial-deltaic depocenters (fig. 3) have been documented along the arcuate northern Gulf Coast Basin (Saucier, 1985; Tye, 1989). One depocenter was located in northeastern Texas where the ancestral Red River flowed into the area of the East Texas Salt Basin through a structural downwarp in the Ouachita thrust belt. The drainage area of the ancestral Red River most likely spanned a large part of the present-day Southwestern and Midwestern United States. Coarse clastic sediment probably was derived from highlands in western Utah and southern Arizona. Triassic red beds were exposed in the provenance area during Travis Peak time, and these might be the source of abundant red siltstones within the Travis Peak Formation in eastern Texas (Saucier, 1985).

The second Travis Peak depocenter was situated in southern Mississippi and northeastern Louisiana where the ancestral Mississippi River, which had developed as a major fluvial system during Cotton Valley time (Coleman and Coleman, 1981), continued to transport clastic sediments to elongate Travis Peak deltas in the northeastern Gulf Coast Basin (Reese, 1978; Saucier, 1985; Tye, 1989). Evidence for the presence of these two depocenters is provided by sandstone isopach patterns from Saucier (1985), who divided the Travis Peak section at its midpoint and mapped gross sandstone thickness of the lower and upper halves of the formation.

Across the Travis Peak hydrocarbon-productive trend in eastern Texas, the formation has been divided informally into three sequences based on relative amounts of sandstone and shale, as described above. However, because of rapid early progradation of Travis Peak fluvial-deltaic systems, the lowermost delta-fringe sequence is thin (figs. 5 and 6). With the bulk of the Travis Peak Formation deposited during a relative rise in sea level, the formation can be considered to be comprised of two main units: a lower aggradational to retrogradational fluvial sequence, and an upper retrogradational coastal-plain/paralic sequence.

Depositional Environments and Sand-Body Geometry

Lower Travis Peak Delta-Fringe Deposits

The basal 100 to 500 ft of the Travis Peak Formation across much of eastern Texas is characterized by discrete sandstones separated by thicker mudstones. Sandstones display upward-coarsening to upward-fining, spiky to serrated SP signatures, and are interpreted as representing distributary-channel, distributary-mouth-bar, delta-front, interdistributary-bar, and barrier-bar environments (Saucier, 1985). Upward in this section, sandstones become thicker and the log character changes from upward-coarsening to blocky, as depositional systems grade into the thick, massive, sandstone-rich fluvial section of the middle Travis Peak. Across much of eastern

Texas, lower Travis Peak delta-fringe deposits are absent, and Travis Peak fluvial sandstones directly overlie the Knowles Limestone or its updip fine-grained clastic equivalents (Saucier, 1985). This is because the stable Travis Peak shelf, which is underlain by continental crust, probably did not subside readily relative to the rate of lower Travis Peak deposition, and early Travis Peak rivers eroded and reworked their own delta-fringe deposits as Travis Peak fluvial-deltaic systems prograded seaward (Saucier, 1985). Little analysis is devoted to these lower delta-fringe sandstones in the Travis Peak literature, nor is any mention made of hydrocarbon production from them. Perhaps this is because they are absent across much of the updip portion of the East Texas Basin, and also, as discussed below in the section on diagenesis, reservoir properties of Travis Peak sandstones deteriorate significantly with depth.

Middle Travis Peak Fluvial Deposits

The middle Travis Peak sandstone-rich fluvial interval accounts for approximately three-fourths of the 2,000-ft thickness of the formation in eastern Texas (figs. 5 and 6). Travis Peak fluvial systems prograded rapidly seaward across the East Texas Basin, then slowly retreated landward, primarily in response to the relative rise in sea level that occurred during Early Cretaceous time (McFarlan, 1977; Todd and Mitchum, 1977; Tye, 1989, 1991). However, the thick sequence of Travis Peak fluvial sandstones and associated finer grained flood-plain deposits reflects deposition during a time when sediment supply and development of accommodation space (shelf subsidence) were in approximate balance. Although channel sandstones generally are stacked, amalgamated units with scoured basal contacts, there is little evidence of significant incision within the thick Travis Peak fluvial sequence (Davies and others, 1991).

The relative rise in sea level that occurred during Travis Peak time might have been responsible for an observed evolution in patterns of fluvial deposition from braided to meandering (fig. 6) (Tye, 1989, 1991). Regional stratigraphic studies across East Texas Basin suggest that early Travis Peak fluvial systems consisted of low-sinuosity, braided channels with bed-load movement of sand as the dominant sediment-transport mechanism. With relative rise in sea level, late Travis Peak fluvial systems evolved into higher sinuosity braided and meandering rivers that carried significantly larger volumes of mud in suspension, in addition to sand bed load. Data from cores indicate that channel sandstones comprise 65 percent of the total rock volume in the low-sinuosity fluvial section, with the remaining 35 percent being finer grained, argillaceous, crevasse-splay sandstones and overbank mudstones (Davies and others, 1991). In the higher sinuosity, meandering fluvial system, channel sandstones comprise only 30 percent of the section, with 70 percent of the rock volume consisting of fine-grained, argillaceous, overbank sandstones and flood-plain shales.

Whereas Tye (1989, 1991) suggests that Travis Peak fluvial systems evolved from low to high sinuosity with time, Davies and others (1991) report that channel type varies more with geographic position within the Travis Peak depocenter. They suggest that high-sinuosity channels comprise the bulk of the fluvial section on the northeastern flank of the Travis Peak depocenter, whereas low-sinuosity channels predominate in central portions of the depocenter. Davies and others (1991), however, admit that distinguishing between high- and low-sinuosity channel systems using wireline logs alone is difficult in the absence of core data, and they recognize that most of the 2,000-ft Travis Peak section in East Texas Basin is not cored. Evolution of fluvial systems from low to high sinuosity with time is consistent with the documented relative rise in sea level, gradation of fluvial deposits into paralic deposits in the upper Travis Peak, and culmination of the transgression with deposition of Sligo carbonates. Marzo and others (1988) showed that, in moving from proximal to distal positions within a fluvial-sheet sandstone sequence, amalgamated sandstone bodies become less connected and more separated by mudstones. Vertical change from stacked braided-channel sandstones to meandering-channel sandstones isolated within flood-plain shales in the Travis Peak Formation would therefore be expected at any given location in the East Texas Basin as a result of landward displacement of fluvial-deltaic facies during the overall Travis Peak transgression.

Low-Sinuosity Fluvial System

Within the Travis Peak low-sinuosity fluvial system, average thickness of individual channel sandstones is 8 ft (Davies and others, 1991). Abandoned-channel deposits of gray-black shale that cap channel sandstones are not common and, where present, are only a few inches thick. Because channel sandstones reflect successive flood events and tend to accumulate in vertical or en-echelon patterns, solitary channel deposits are rare. Although channels have scoured basal contacts, significant amounts of incision have not been observed. Basal-lag conglomerates with black-shale clasts are thin and generally occur only above underlying channels that are capped by thin abandonment units. Travis Peak amalgamated channel-sandstone units range from 12 to 45 ft thick and consist of two to five stacked channels (Davies and others, 1991). In places, massive sandstone units are as much as 250 ft thick (Saucier, 1985). Sedimentary structures consist predominantly of planar cross-stratification and horizontal laminations, with minor amounts of ripples (Tye, 1991; Davies and others, 1991). Because of the low amount of mud transported as suspended load, mud drapes are not common. Main barriers to flow that might compartmentalize these reservoir sandstones, therefore, are zones where porosity is occluded as a result of extensive quartz cementation. Stacked channel-sandstone sequences are capped by red and gray flood-plain mudstones and siltstones that commonly show evidence of roots and would seem to provide top seals. However, lateral switching in conjunction with vertical and en-echelon stacking of channels

results in multilateral and multistory sandstone units that span wide geographic areas and probably have complex interconnections with respect to pressure communication and fluid migration.

Low-sinuosity channels are broad, tabular sandstone bodies, with thickness-to-width ratios of approximately 1:800 (Tye, 1991; Dutton, Laubach, Tye, and others, 1991). At North Appleby field in Nacogdoches County, Texas, Tye (1991) found channel-belt widths ranging from 3 to 6 miles. In a gas-productive zone at the base of the low-sinuosity fluvial section at North Appleby field, Tye (1991) reported average thickness of stacked channel-belt sandstones to be 26 ft and average channel-belt width to be 4.5 miles. Patterns of channel avulsion in low-sinuosity rivers tend to result in preservation of long sandstone bodies; Davies and others (1991) demonstrated that Travis Peak channel-belt sandstone bodies commonly span areas of 5,000 acres or more. Tye (1991) reports individual productive channel-belt sandstone bodies can cover 25,000 acres.

High-Sinuosity Fluvial System

High-sinuosity channel deposits in the Travis Peak Formation commonly include both a lower sandstone unit that accumulated as a migrating point-bar deposit in an active channel and an overlying mudstone plug deposited in the abandoned-channel stage (Davies and others, 1991). Point-bar sandstone thickness in the Travis Peak commonly is 12 to 15 ft, with the lower 8 to 10 ft consisting of relatively clean, trough-crossbedded sandstone overlain by a thinner sequence of finer grained, often shaly, rippled sandstone with mudstone drapes. Mudstone drapes are deposited during periods of normal, low-velocity flow between flood events, and collectively they can compartmentalize the upper parts of point-bar sandstone units. Eventual cut-off of meanders by channel avulsion during floods resulted in isolation of point-bar sandstone units. Although high-sinuosity channel sandstone units in the Travis Peak locally exhibit vertical stacking or cross-cutting of successive units, most such point-bar sandstones are isolated from each other by overbank mudstones and siltstones, which comprise 70 percent of the high-sinuosity sequence (Davies and others, 1991). High-sinuosity Travis Peak fluvial-channel deposits generally have thickness-to-width ratios of 1:100 (Dutton, Laubach, Tye, and others, 1991, Dutton, Laubach, and Tye, 1991). Estimates of the size of fully developed Travis Peak point-bar units are approximately 300 acres, a figure that agrees closely with drainage areas predicted from GRI reservoir-engineering simulations (Davies and others, 1991).

Upper Travis Peak Coastal-Plain and Paralic Deposits

Cores from the upper Travis Peak interval reveal a diverse assemblage of environments within the Travis Peak Formation, and this diversity manifests itself along depositional dip from northwest to southeast across eastern Texas into

northern Louisiana (Tye, 1989). In updip regions, sandstones represent meandering-channel and overbank, crevasse-splay deposits, and they grade downdip into distributary-channel, distributary-mouth-bar, delta-front, and interdistributary-bar deposits. Farther downdip, sandstones were deposited in estuarine, tidal-flat, tidal-channel, and marine settings. Point-bar sandstones in updip coastal-plain settings are slightly thinner (5 to 15 ft thick) than those in the underlying high-sinuosity channel sequence but exhibit similar characteristics, including isolation from each other within overbank mudstone deposits (Tye, 1989). Farther downdip, blocky to upward-fining sandstones 10 to 25 ft thick display trough and ripple cross-bedding with abundant burrows, flaser bedding, bidirectional cross-stratification (indicative of tidal currents), coal streaks and organic debris, and, in places, bivalve and gastropod shell fragments (Tye, 1989). These sandstones are interpreted as deposits from distributary-mouth bars and tidal and estuarine channels. Thinner sandstones with spiky log character are believed to have accumulated in tidal-flat settings. Almost all of these sandstones are isolated within mudstones.

Diagenesis of Sandstones of the Travis Peak Formation

Burial History

Following deposition, Travis Peak sediments experienced progressively deeper burial in eastern Texas until late mid-Cretaceous time, when the Sabine arch was uplifted and eroded (Jackson and Laubach, 1991; Dutton and Diggs, 1992). Prior to this late mid-Cretaceous uplift, total burial depth and depth from surface were identical because Travis Peak strata were essentially horizontal. As renewed burial commenced in Late Cretaceous time, the Travis Peak was buried less deeply on the flanks of the Sabine uplift and more deeply in the adjacent salt basins. Burial continued into the early Tertiary when a second period of uplift and erosion resulted in removal of 1,500 ft of section across most of northeastern Texas (Jackson and Laubach, 1991; Dutton and Diggs, 1992). Consequently, maximum burial depth for the Travis Peak at any given locale in northeastern Texas is 1,500 ft greater than present burial depth.

Sandstone Composition

In northeastern Texas, most Travis Peak sandstones are fine-grained to very fine grained quartz arenites and subarkoses. Average framework composition is 95 percent quartz, 4 percent feldspar, and 1 percent rock fragments (Dutton and Diggs, 1992). Dutton and Diggs (1992) defined clean sandstones as those with less than 2 percent detrital clay matrix. The average grain size of clean fluvial sandstones is 0.15 mm as compared to 0.12 mm for clean paralic sandstones.

Compaction and Cementation

In northeastern Texas, Travis Peak sandstones have had a complex diagenetic history involving (1) mechanical compaction, (2) precipitation of cements and authigenic minerals, including dolomite, quartz, illite, chlorite, and ankerite, (3) generation of secondary porosity through dissolution of feldspar, and (4) formation of reservoir bitumen (Dutton and Diggs, 1992). Loss of primary sandstone porosity in near-surface settings following deposition was negligible in most fluvial sandstones. Minor loss of porosity occurred in paralic sandstones from precipitation of dolomite cement. From surface to a burial depth of about 3,000 ft, Travis Peak sandstones lost primary porosity mainly through mechanical compaction. Potential further compaction was halted by extensive quartz cementation that occurred between burial depths of 3,000 and 5,000 ft. The next significant diagenetic event was the creation of secondary porosity through dissolution of feldspar. Additional minor porosity reduction occurred to a depth of 7,500 ft from precipitation of authigenic chlorite, illite, and ankerite. Sandstones on higher parts of the Sabine uplift did not experience further porosity reduction from cementation. However, in Travis Peak sandstones buried below 8,000 ft on the western flank of the uplift, a second episode of extensive quartz cementation occurred in which silica was generated from pressure solution associated with development of stylolites.

Reservoir Bitumen

A late-stage diagenetic event that significantly reduced porosity and permeability in some Travis Peak sandstones in northeastern Texas was the formation of reservoir bitumen (Dutton, Laubach, Tye, and others, 1991; Lomando, 1992). Reservoir bitumen is a solid hydrocarbon that lines and fills both primary and secondary pores in some Travis Peak sandstones. Formation of reservoir bitumen occurred after precipitation of quartz and ankerite cement (Dutton, Laubach, Tye, and others, 1991), and its occurrence is limited to sandstones within the upper 300 ft of the Travis Peak Formation, which are primarily paralic sandstones. Geochemical analyses suggest that reservoir bitumen formed from deasphalting of oil trapped in pores of upper Travis Peak sandstones (Rogers and others, 1974; Dutton, Laubach, Tye, and others, 1991). The oil probably was similar to oil currently being produced from some Travis Peak sandstone reservoirs in fields in northeastern Texas. According to Tissot and Welte (1978), deasphalting commonly occurs in medium to heavy oil when large amounts of gas dissolve into the oil. Gas that dissolves into an oil to cause deasphalting can be generated from thermal alteration of the oil itself, or from introduction of new gas from outside the reservoir. The level of kerogen maturity in mudstones interbedded with Travis Peak sandstone reservoirs suggests that oils in Travis Peak sandstones were subjected to temperatures sufficient to generate gas internally (Dutton, 1987).

Among sandstones in the upper Travis Peak that contain

reservoir bitumen, average and maximum volumes of bitumen are 4 percent and 19 percent, respectively. Samples examined by Dutton, Laubach, Tye, and others (1991) that contain reservoir bitumen had an average porosity of 7.5 percent prior to formation of bitumen. Formation of reservoir bitumen reduced that average porosity to 3.5 percent, a loss of 55 percent of the pre-bitumen pore space. Within the paralic facies, where most of the reservoir bitumen occurs, permeability patterns probably controlled the pore spaces into which oil originally migrated and in which reservoir bitumen eventually formed. Crossbedded and rippled sandstones that are clean and well-sorted contain large volumes of reservoir bitumen, whereas burrowed, shaly, poorly sorted sandstones have little or no reservoir bitumen. Consequently, many sandstone intervals that had the highest porosity and permeability following compaction and cementation now have little or no porosity because of formation of reservoir bitumen.

Dutton, Laubach, Tye, and others (1991) provide a specific example that demonstrates the deleterious effect of reservoir bitumen on porosity, permeability, and wireline-log measurement of porosity. They describe a Travis Peak sandstone that has no reservoir bitumen from a depth of 8,216.5 ft in a particular well as having 11.6 percent porosity as measured by porosimeter, in-situ permeability of 22.5 mD, and average grain density of 2.65 g/cm³. Less than 1 ft below, at 8,217.2 ft, the sandstone contains reservoir bitumen and has porosimeter porosity of 5.4 percent, permeability of 0.0004 mD, and average grain density of 2.51 g/cm³. Not only does reservoir bitumen significantly reduce porosity and permeability, but it dramatically affects porosity measurements from a neutron-density log. Although porosimeter porosity in the sandstone at 8,217.2 ft was measured as 5.4 percent, porosity determined from a neutron-density log was 13 percent. Overestimation of porosity with a neutron-density log occurs because (1) density of reservoir bitumen is approximately the same as density of drilling-mud filtrate, which penetrates sandstone pores during drilling, and (2) 90 to 99 percent of reservoir bitumen is measured as porosity by a neutron log because of the hydrogen content of the bitumen.

Porosity

Porosity and permeability of Travis Peak reservoir sandstones are controlled directly by diagenetic factors described above. Most hydrocarbon production from Travis Peak sandstones in northeastern Texas is from drilling depths between 6,000 and 10,000 ft, and sandstone porosity decreases significantly with depth through that interval (Dutton and Diggs, 1992). Average porosity of clean Travis Peak sandstones decreases from 16.6 percent at 6,000 ft to 5.0 percent at 10,000 ft. For all Travis Peak sandstones (clean and shaly), average porosity decreases from 10.6 percent at 6,000 ft to 4.4 percent at 10,000 ft (fig. 7). Decrease in porosity from 6,000 to 10,000 ft is not caused by increased compaction (Dutton, Laubach, Tye, and others, 1991; Dutton and Diggs,

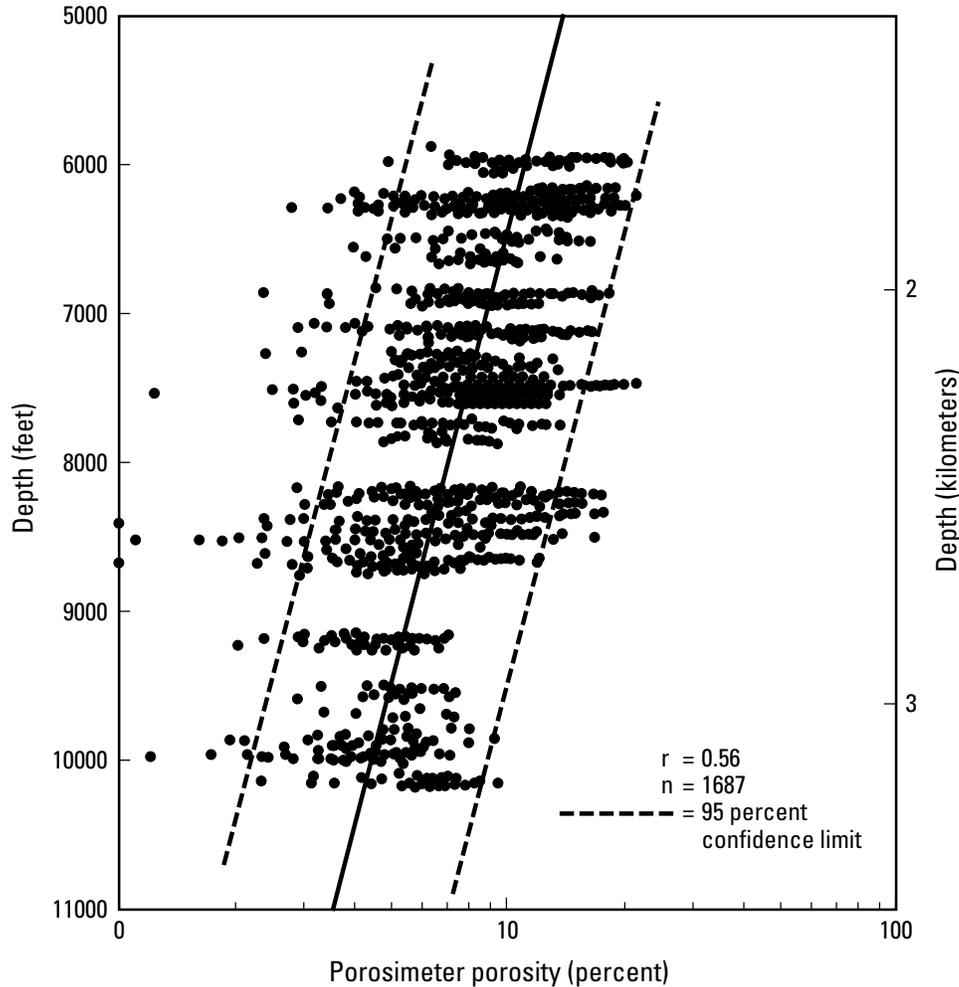


Figure 7. Semi-log plot of porosity versus depth for 1,687 Travis Peak Formation sandstone samples from wells in eastern Texas (from Dutton, Laubach, Tye, and others, 1991). Samples include both clean and shaly sandstones.

1992). Decrease in porosity with depth results primarily from (1) increasing amount of quartz cement, and (2) decrease in amount of secondary porosity. Secondary porosity was generated almost exclusively from dissolution of feldspar, and original feldspar content of Travis Peak sandstones decreases systematically with depth (Dutton and Diggs, 1992). High initial porosity together with high degree of connectivity of multilateral, multistory, braided-channel sandstones permitted large volumes of diagenetic fluids to move through the thick Travis Peak fluvial-sandstone sequence. As a result, the thick fluvial section lost most of its primary porosity to extensive quartz cementation. However, because sandstones in the upper 300 ft of the Travis Peak are encased in mudstones, smaller volumes of diagenetic fluids moved through those sandstones, and they commonly retain significant primary porosity (Dutton and Land, 1988).

Within Travis Peak fluvial-sandstone reservoirs at North Appleby field, Tye (1991) reported that the greatest thickness of porous sandstone generally occurs in the widest portions of channel belts, and the highest porosities occur within 3 to 5 ft upward from the base of channels.

Permeability

According to Dutton and Diggs (1992), average stressed permeability of clean Travis Peak sandstones in northeastern Texas decreases by four orders of magnitude, from 10 mD at 6,000 ft to 0.001 mD at 10,000 ft. For all sandstones, average stressed permeability declines from 0.8 mD at 6,000 ft to 0.0004 mD at 10,000 ft (fig. 8). Decrease in permeability from 6,000 to 10,000 ft primarily is a function of (1) decrease

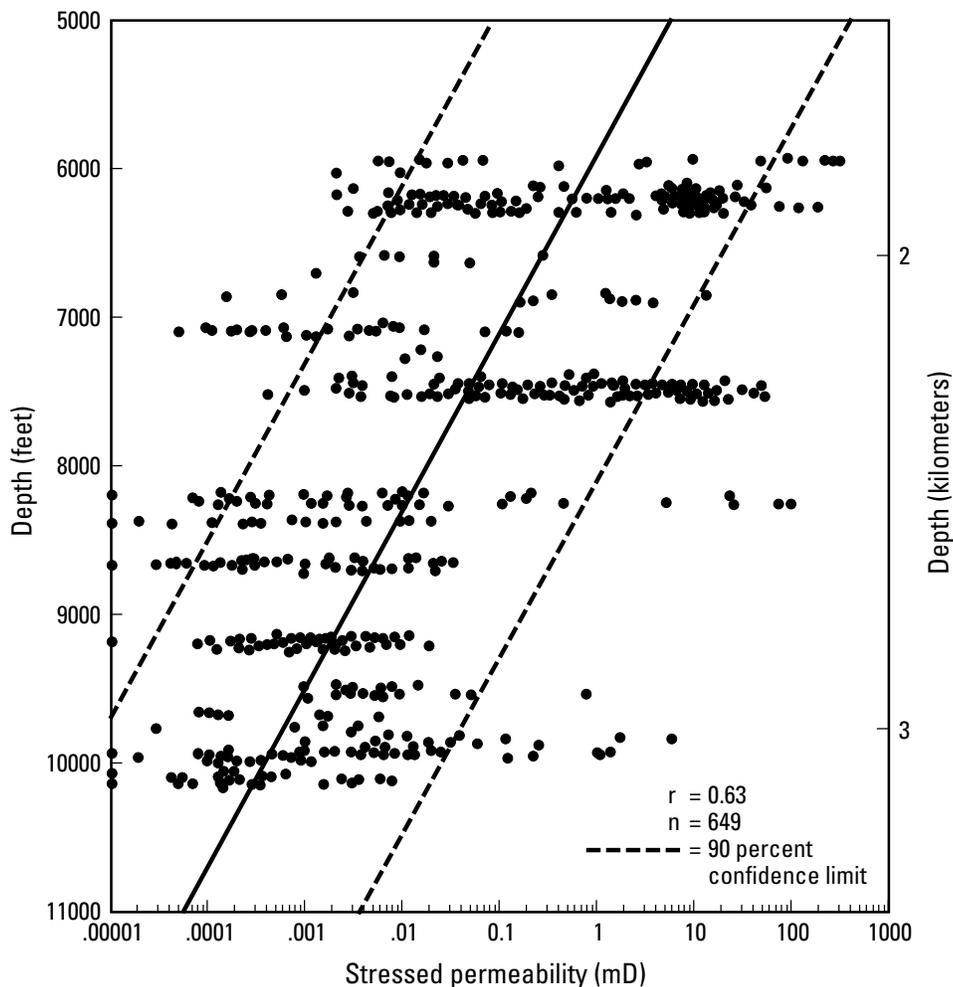


Figure 8. Semi-log plot of stressed permeability versus depth for 649 Travis Peak Formation sandstone samples from wells in eastern Texas (from Dutton, Laubach, Tye, and others, 1991). Samples include both clean and shaly sandstones. Note that in addition to decrease in permeability with depth, permeability also varies by four orders of magnitude at any given depth.

in porosity, which in turn is caused principally by increasing quartz cement, and (2) increasing overburden pressure that closes narrow pore throats. Although this latter effect has a significant impact on permeability, it has little effect on porosity.

At any given depth within the Travis Peak Formation in northeastern Texas, permeability ranges over approximately four orders of magnitude. Also, at any given depth, average permeability is 10 times greater in clean, fluvial sandstones than in clean, paralic sandstones. According to Dutton and Diggs (1992), inferior permeability of clean, paralic sandstones probably can be attributed to three factors. First, because paralic sandstones are finer grained, they had poorer permeability than coarser grained fluvial sandstones at the time of deposition. Second, although paralic sandstones and fluvial sandstones contain similar amounts of quartz cement, paralic sandstones contain an average of 7 percent more total

cement because they have significantly larger volumes of authigenic dolomite, ankerite, illite and chlorite, as well as more reservoir bitumen. Third, much of the porosity in paralic sandstones is secondary porosity and microporosity associated with authigenic illite and chlorite that occurs within secondary pores. Secondary porosity and microporosity both contribute significantly less to permeability than does primary porosity, in which pores are better connected.

Hydrocarbon Production

Although clean, paralic Travis Peak Formation sandstones have an order of magnitude poorer permeability than clean, fluvial sandstones at any given depth, most hydrocar-

bon production from the Travis Peak in eastern Texas has come from paralic and high-sinuosity fluvial sandstones in the upper 300 ft of the formation (Fracasso and others, 1988; Dutton, Laubach, Tye, and others, 1991; Dutton and others, 1993). Concentration of producible hydrocarbons in sandstones in the upper part of the formation probably results from the absence of effective traps and seals in the underlying sandstone-rich, low-sinuosity fluvial sequence. Multi-story and multilateral fluvial-channel belts within the fluvial sequence afford a highly interconnected network of channel sandstones that provides effective migration pathways for hydrocarbons. Additionally, hydrocarbon migration through this sandstone network is enhanced by the presence of natural fractures, which are significantly more abundant in the quartz-cemented, sandstone-rich, low-sinuosity fluvial sequence than in overlying paralic sandstones (Dutton, Laubach, Tye, and others, 1991). Consequently, hydrocarbons migrating upward into the Travis Peak Formation may have passed through the sandstone-rich fluvial section before being trapped within upper Travis Peak paralic and high-sinuosity, fluvial sandstones, which are encased in mudstones that provide effective hydrocarbon seals. Main reservoirs within the paralic sequence include tidal-channel and tidal-flat sandstones along with high-sinuosity, fluvial-channel sandstones deposited in coastal-plain settings (Tye, 1989; Dutton, Laubach, and Tye, 1991)

Most Travis Peak hydrocarbon production comes from (1) structural, combination, or stratigraphic traps associated with low-relief closures or structural noses on the crest and flanks of the Sabine uplift, and (2) structural or combination traps associated with salt structures in the East Texas and Northern Louisiana Salt Basins (Kosters and others, 1989; Dutton, Laubach, and Tye, 1991). Combination and stratigraphic traps occur where fluvial sandstones pinch out into flood-plain mudstones or where paralic sandstones pinch out into tidal-flat, estuarine, or shallow-marine mudstones across closures, noses, or on regional dip.

According to Fracasso and others (1988), wells on the western flanks of structures in northeastern Texas generally require hydraulic-fracture treatments to produce commercially from Travis Peak sandstone reservoirs, whereas wells on the eastern flanks typically flow gas at commercial rates without stimulation. These trends reflect a general east-to-west deterioration in Travis Peak sandstone porosity and permeability across structures. These east-west patterns in reservoir quality of upper Travis Peak paralic sandstones are not related to depositional facies changes. According to Fracasso and others (1988), these patterns are attributed to control by structures on regional flow of diagenetic fluids; this resulted in cementation being fostered on western flanks, or inhibited on eastern flanks, or both.

Source Rocks

In a study of diagenesis and burial history of the Travis Peak Formation in eastern Texas, Dutton (1987) showed that

shales interbedded with Travis Peak sandstone reservoirs were deposited in fluvial-deltaic settings where organic matter commonly was oxidized and not preserved. With measured values of total organic carbon (TOC) in Travis Peak shales generally less than 0.5 percent, these shales would not be considered as potential hydrocarbon source rocks, according to Tissot and Welte (1978). Dutton (1987) suggested that the most likely sources for hydrocarbons in Travis Peak reservoirs in eastern Texas are (1) prodelta and basinal marine shales of the Jurassic Bossier Shale, basal formation of the Cotton Valley Group, and (2) laminated, lime mudstones of the lower member of the Jurassic Smackover Formation (fig. 3). Sassen and Moore (1988) demonstrated that Smackover carbonate mudstones are a significant hydrocarbon source rock in Mississippi and Alabama. Wescott and Hood (1991) documented the Bossier Shale as a major source rock in eastern Texas. Presley and Reed (1984) suggested that gray to black shales interbedded with Cotton Valley sandstones could be a significant source for gas as could the underlying Bossier Shale. In summary, despite limited source-rock data, it seems likely that significant hydrocarbon source rocks occur in the Bossier Shale of the Cotton Valley Group, which underlies the Travis Peak Formation, and also in stratigraphically lower Smackover carbonate mudstones (fig. 2).

Burial and Thermal History

Vitrinite reflectance (R_o) is a measure of thermal maturity of source rocks based on diagenesis of vitrinite, a type of kerogen derived from terrestrial woody plant material. In studying diagenesis and burial history of the Travis Peak Formation in eastern Texas, Dutton (1987) reported that measured R_o values for Travis Peak shales generally range from 1.0 to 1.2 percent, indicating that these rocks have passed through the oil window ($R_o = 0.6$ to 1.0 percent), and are approaching the level of onset of dry-gas generation ($R_o = 1.2$ percent) (Dow, 1978). Maximum R_o of 1.8 percent was measured in the deepest sample from a downdip well in Nacogdoches County, Texas. Despite relatively high thermal maturity levels reached by Travis Peak shales, the small amount and gas-prone nature of organic matter in these shales precludes generation of oil, although minor amounts of gas might have been generated (Dutton, 1987).

In the absence of actual measurements of R_o , values of R_o can be estimated by plotting burial depth of a given source rock interval versus time in conjunction with an estimated paleogeothermal gradient (Lopatin, 1971; Waples, 1980). Dutton (1987) presented burial-history curves for the tops of the Travis Peak, Cotton Valley, Bossier, and Smackover for seven wells on the crest and western flank of the Sabine uplift. The burial-history curves show total overburden thickness through time and use present-day compacted thicknesses of stratigraphic units. Sediment compaction through time was considered insignificant because of

absence of thick shale units in the stratigraphic section. Loss of sedimentary section associated with late mid-Cretaceous and mid-Eocene erosional events was accounted for in the burial-history curves.

Dutton (1987) provided justification for using the average present-day geothermal gradient of 2.1°F/100 ft for the paleogeothermal gradient for the five northernmost wells. Paleogeothermal gradients in the two southern wells probably were elevated temporarily because of proximity to the area of initial continental rifting in the Triassic. Based on the crustal extension model of Royden and others (1980), Dutton (1987) estimated values for elevated paleogeothermal gradients for these two wells for 80 m.y. following the onset of rifting; after that, the value reverts to the present-day gradient for the past 100 m.y.

Using estimated paleogeothermal gradients in conjunction with burial-history curves, Dutton (1987) found that calculated values of R_0 for Travis Peak shales agree well with measured values. Because of this agreement, Dutton (1987) used the same method to calculate R_0 values for tops of the Cotton Valley, Bossier, and Smackover in eastern Texas. Estimated R_0 values for the Bossier Shale and Smackover in seven wells range from 1.8 to 3.1 percent and 2.2 to 4.0 percent, respectively, suggesting that these rocks reached a stage of thermal maturity in which dry gas was generated. Assuming that high-quality, gas-prone source rocks occur within these two formations, it is likely that one or both of these units generated gas found in Travis Peak reservoirs.

No such regional source-rock and thermal-maturity analysis is known for the Travis Peak (Hosston) Formation in northern Louisiana. Scardina (1981) presented burial-history data for the Cotton Valley Group but included no information on geothermal gradients and thermal history of rock units. Present-day reservoir temperatures in Travis Peak sandstones of both eastern Texas and northern Louisiana range from 200° to 250°F (table 1). It is likely that Bossier and Smackover source rocks in northern Louisiana have experienced a thermal history relatively similar to their stratigraphic counterparts in eastern Texas and, therefore, may be sources for Travis Peak gas in northern Louisiana. Herrmann and others (1991) presented a burial-history plot for Ruston field in northern Louisiana. At Ruston field, they suggested that Smackover gas was derived locally from Smackover lime mudstones and Cotton Valley gas from Cotton Valley and Bossier shales. Their burial-history plot shows that onset of generation of gas from Smackover and Cotton Valley source rocks at Ruston field occurred about 80 Ma and 45 Ma, respectively. These estimates are reasonably consistent with Dutton's (1987) date of 57 Ma for onset of generation of dry gas from the Bossier Shale in eastern Texas. Most salt structures in the East Texas Salt Basin were growing during Travis Peak deposition (McGowen and Harris, 1984) and presumably they were growing in the Northern Louisiana Salt Basin, as well. Therefore, these structures would have provided traps for hydrocarbons generated from Smackover, Bossier, and Cotton Valley source rocks. Also, as noted earlier in this report, the Sabine uplift has

been a positive feature for the past 60 m.y. (Kosters and others, 1989; Jackson and Laubach, 1991). It therefore would have been a focal area for gas migrating from Smackover, Bossier, and Cotton Valley source rocks in the East Texas and Northern Louisiana Salt Basins.

Abnormally Pressured Reservoirs

Pore pressure or reservoir pressure commonly is reported as a fluid-pressure gradient (FPG) in pounds per square inch/foot (psi/ft). The normal FPG is 0.43 psi/ft in freshwater reservoirs and 0.50 psi/ft in reservoirs with very saline waters (Spencer, 1987). In his study of abnormally high pressure gradients in basin-centered gas accumulations in Rocky Mountain basins, Spencer (1987) considered reservoirs to be significantly overpressured if FPGs exceed 0.50 psi/ft where waters are fresh to moderately saline, and exceed 0.55 psi/ft where waters are very saline. With formation-water salinity of Travis Peak sandstone reservoirs about 170,000 parts per million (ppm) total dissolved solids (TDS) (Dutton and others, 1993), salinity is considered high, and these reservoirs should be considered to be significantly overpressured if their FPGs exceed 0.55 psi/ft.

FPGs for Travis Peak sandstone reservoirs for various oil and gas fields in northeastern Texas and northern Louisiana (table 1; figs. 9 and 10) were calculated from initial shut-in pressures reported in Herald (1951), Shreveport Geological Society Reference Reports (1946, 1947, 1951, 1953, 1958, 1963, 1987), Kosters and others (1989), Shoemaker (1989), and Bebout and others (1992). Multiple FPG values for a specific field (figs. 9 and 10; table 1) refer to FPGs calculated for different, stacked Travis Peak sandstone reservoirs in that field. Most calculated FPGs are between 0.41 and 0.49 psi/ft (table 1; figs. 9 and 10). Higher FPGs were encountered in three fields in northeastern Texas (fig. 9): 0.53 psi/ft at Tri-Cities and Percy-Wheeler fields, and 0.54 psi/ft at Carthage field. A gradient of 0.79 psi/ft was calculated for one Travis Peak sandstone reservoir in Clear Branch field in northern Louisiana, although gradients in three other Travis Peak reservoirs within that same field were 0.47, 0.48, and 0.48 psi/ft (table 1, fig. 10). A number of other fields scattered geographically across northeastern Texas and northern Louisiana exhibit below-normal FPGs ranging from 0.36 to 0.38 psi/ft. The lowest FPG in the Travis Peak field trend is 0.27 psi/ft in Village field, Columbia County, Arkansas (table 1; fig. 10).

In northern Louisiana where Travis Peak hydrocarbon production comes from various interdeltic sandstones throughout the Travis Peak section, shut-in-pressure data are available from a variety of depths. In northeastern Texas, however, most production comes from sandstone reservoirs in the upper 300 ft of the Travis Peak Formation. Consequently, shut-in-pressure data are abundant for the upper 300 to 500 ft of the Travis Peak, but data are limited in the lower three-fourths of the formation, which include the thick fluvial

Table 1 (below and on facing page). Data for Travis Peak Formation fields in Texas, Louisiana, and Arkansas.

[Data primarily from Shreveport Geological Society Reference Reports, Herald (1951), Kusters and others (1989), Shoemaker (1989), and Bebout and others (1992). Field, name of field producing from Travis Peak sandstones; Discovery date, date of discovery of oil or gas in particular Travis Peak sandstone; Trap, trapping mechanism for field (Struct, structural trap; Strat, stratigraphic trap; Comb, combination structural and stratigraphic trap; A, anticline; FA, faulted anticline; FC, facies change (sandstone pinch-out); N, structural nose; FN, faulted structural nose); Depth, depth, in feet, to particular productive Travis Peak sandstone reservoir; Porosity, sandstone porosity (decimal); BHT, bottom-hole temperature (°F); BHP, bottom-hole pressure (psi); FPG, Fluid-pressure gradient (psi/ft); Sw, water saturation (decimal); Fluid contacts, gas-oil, oil-water, and gas-water contacts (GOC, gas-oil contact; OWC, oil-water contact; GWC, gas-water contact); IP, initial production rate for specific Travis Peak sandstone reservoirs (MCFD, thousand cubic feet per day (gas)); BOPD, barrels of oil per day; BCPD, barrels of condensate per day; BWPD, barrels of water per day; avg, average of values; N. res., north reservoir; S. res., south reservoir; Pos., position of reservoir within Travis Peak Formation (L, lower; U, upper; uL, upper part of lower); Ext., extension. Blank spaces indicate no data]

Field	County	State	Discovery date	Trap	Depth (feet)	Porosity (decimal)	Permeability (mD)	BHT (°F)
Appleby North	Nacogdoches	TX		Strat (FC)	8,872	0.11	0.015 (avg)	254
Bethany	Panola, Harrison	TX	1940	Comb (FA, FC)	6,024			
			1948		6,300	0.15	115	206
Blackfoot	Anderson	TX	1948	Comb (A, FC)	9,918			
Carthage	Panola	TX	1942	Struct (A)	6,128			
			1944		6,439			
			1945		6,230	0.15	10.8	
Cedar Springs	Upshur	TX	1967	Struct (A)	8,960	0.10		240
Chapel Hill	Smith	TX	1947	Comb (A, FC)				
Cyril	Rusk	TX	1963	Strat (FC)	7,650	0.09–0.18	<1 to 200	200
Danville	Rusk	TX	1959	Comb (FA, FC)	7,606			
Henderson	Rusk	TX	1950	Struct (A)	7,457	0.18	72	185
Henderson South	Rusk	TX	1946	Struct (A)				
Joaquin	Shelby	TX	1968	Struct (A)	6,300			
Lansing North	Harrison	TX	1950	Struct (A)	7,606			
Lassater	Marion	TX	1948	Struct (A)	9,035			
Longwood	Harrison	TX	1948	Comb (N, FC)				
McBee	Leon	TX	1955	Comb (N, FC)	10,100	0.07–0.10		216
Minden	Rusk	TX	1953	Comb (N, FC)	7,372			
Opelika	Henderson, Van Zandt	TX	1944	Strat (FC)?				
Percy Wheeler	Cherokee	TX	Gas 1979	Comb (FN, FC)	9,100	0.10 (avg)	0.076 (avg)	245
			Oil 1980	Comb (FN, FC)	9,159			
Pinehill Southeast	Rusk, Panola	TX		Strat (FC)	7,155	0.08	1.3 (avg)	199
Pokey	Limestone	TX	1959	Strat (FC)	7,084	0.08–0.20		190
Reed	Freestone	TX	1945					
Rischers Store	Freestone	TX	1967	Comb (A, FC)	7,236	0.10–0.23		240
Teague West	Freestone	TX	1951	Comb (FC, FA)	7,680			
Trawick	Nacogdoches, Rusk	TX	1963	Comb (A, FC)	8,561	0.08–0.12	0.1 (avg)	
Tri-Cities	Henderson	TX	1950	Comb (FC, FA)	8,496	0.10	0.01 to 85	240
Waskom	Harrison	TX	1939	Comb (A, FC)	6,185			
			1973		7,404	0.17	65	198
Whelan	Harrison	TX	1946	Comb (FC, FA)	8,036	0.13	0.05 to 83	220
White Oak Creek	Cherokee	TX	1976	Srtuct (FA)	10,024			
Willow Springs	Gregg	TX	1954	Struct (A)	7,812	0.13	20 (1.48 avg)	229
Woodlawn	Harrison	TX						
Ada-Sibley	Webster	LA	1951	Struct (FA)	6,900	0.19	131	
Arcadia	Bienville	LA	1965	Srtuct (FA)	7,050			
Athens	Claiborne	LA	1941	Comb (FA, FC)	6,172			
			1943		6,400			
			1948		7,240			
			1949		7,696			
			1949		6,314			
Bear Creek-Bryceland	Bienville	LA	1937	Comb (A, FC)	7,240	0.16	170	
Bethany-Longstreet	DeSoto, Caddo	LA	1954	Struct (A)	7,000			
Bryceland West	Bienville	LA	1952	Comb (FA, FC)	6,900			
Calhoun	Ouachita	LA	1936	Comb (FA, FC)	6,900			

Table 1. Data for Travis Peak Formation fields in Texas, Louisiana, and Arkansas—Continued.

BHP (psi)	FPG (psi/ft)	Pos	Sw	Fluid contacts	IP (MCFD)	IP (BOPD)	IP (BCPD)	IP (BWPD)
3,890	0.44	L	0.28					
2,295	0.38	U			60,000		720	
3,113	0.49	uL	0.34					
		U		Elevation of bottom of oil -9,589		63		
				Lenticular sandstones w/ complex GWCs	5,900	147.5		
						26.7		
3,350	0.54	U	0.24					
4,409	0.49	L	0.30					
		U		Elevation of bottom of gas -7835				
3,550	0.46	U	0.25 to 0.55	OWC -7,125 N. res.; GOC -7,100, OWC -7,125 S. res.		20		
3,186	0.43	U	0.26	GOC -6,995; OWC -7,005	1,500	49		
		U		Elevation of bottom of gas -7,020	655		13	
				Lowest gas -7,314	2,100			
				Lowest gas -8,730	2,540		243.7	
				Lowest gas -5,754				
3,625	0.36	U	0.31 to 0.38		1,650			
4,843	0.53	U	0.33		3,200			
					180	62		23
3,071	0.43	U	0.42					
3,250	0.46	U	0.36 to 0.45		4,700			
		U		Elevation of bottom of gas -7,860				
3,000	0.41	U	< 0.45		1,900		43	
3,720	0.43	uL	0.20 to 0.45		7,600			
4,500	0.53	U	0.32					
		U		GWC -5,880	5,040			
2,795	0.38	L						
3,076	0.38	uL						
3,421	0.44	uL						
					8,000		192	
					4,000		20	
					11,600		23	
						118		
						68		
				Multiple sands with separate GWCs	5,000 to 165,000			
				Flank wells tested water without gas				

Table 1 (below and on facing page). Data for Travis Peak Formation fields in Texas, Louisiana, and Arkansas—*Continued*.

Field	County	State	Discovery date	Trap	Depth (feet)	Porosity (decimal)	Permeability (mD)	BHT (°F)
Caspiana	DeSoto, Caddo	LA						
Chatham	Jackson	LA	1945		9,620			
Chenier Creek	Ouachita	LA	1949	Comb (N, FC)	7,782	0.16	6	211
Choudrant	Lincoln	LA	1959	Struct (A)	8,568	0.19	250	
Clay	Lincoln	LA	1958	Struct (A)	7,305			
Clear Branch	Jackson	LA	1975	Comb (N, FC)	9,000	0.07	3.8	191
					10,000	0.08	1.4	205
					10,100	0.07	0.6	218
					11,900	0.05	0.3	282
Cotton Plant	Caldwell	LA	1984	Comb (N, FC)	10,200	0.15	166	258
					10,600	0.13		272
Cotton Valley	Webster	LA	1936	Struct (A)	5,550			
Danville	Bienville	LA	1966	Struct (A)	7,700			
Downsville	Union	LA	1948	Comb (A, FC)	7,390			
			1962	Comb (A, FC)	7,819			
			1978	Comb (A, FC)	7,652	0.17		177
Driscoll	Bienville	LA	1937	Struct (A)	7,200			
Elm Grove	Bossier	LA	1975	Struct (FA)	5,852			
Elm Grove (Ext.)	Caddo, Bossier	LA	1984	Struct (FA)	5,956			
Hico-Knowles	Lincoln	LA	1959	Comb (A, FC)	6,600			
Hodge	Jackson	LA	1961	Struct (A)	7,900			
Holly	DeSoto	LA	1974	Strat (FC)	7,000			
Leatherman Creek	Claiborne	LA	1975	Comb (FA, FC)	8,387–9,614	0.10	0.7	215
Lisbon	Claiborne	LA	1941	Strat (FC)	5,100	0.23	500	
Lisbon North	Claiborne	LA	1941	Struct (A)	5,112			
Lucky	Bienville	LA	1943	Struct (FA)	7,900	0.15		
Ruston	Lincoln	LA	1943	Comb (A, FC)	5,896			
			1944		5,745			
Sailes	Bienville	LA	1945	Comb (FA, FC)	8,847	0.14		
Shreveport	Caddo, Bossier	LA	1951	Struct (A)	6,238			
Simsboro	Lincoln	LA	1936	Struct (FA)	6,571	0.22	500	
			1951	Struct (FA)	8,069	0.15	2 to 50	
Sugar Creek	Claiborne	LA	1936	Comb (FA, FC)	5,600	0.19	65	
			1937		5,718			
Vixen	Caldwell	LA	1945	Struct (A)	9,700			
Waskom	Caddo	LA		Comb (A, FC)				
Village	Columbia	AR	1946	Struct (A)	4,800	0.26	706	

sequence that characterizes the bulk of the Travis Peak in northeastern Texas. Calculated FPGs from sandstone reservoirs at depths of 500 or more ft below the top of the Travis Peak are normal at North Appleby, Bethany, Cedar Springs, and Trawick fields and subnormal at Waskom and Whelan fields (table 1, fig. 9). Reservoirs in the middle and lower Travis Peak section at Woodlawn and Carthage fields also are normally pressured, according to Al Brake (BP Amoco engineer, oral commun., 2000), who reports no knowledge of any significant overpressure in Travis Peak reservoirs at any depth within the formation in northeastern Texas. The best available data, therefore, suggest that Travis Peak reservoirs are not significantly overpressured in northeastern Texas.

Hydrocarbon-Water Contacts

Based on data for various Travis Peak oil and gas fields reported primarily by the Shreveport Geological Society (1946, 1947, 1951, 1953, 1958, 1963, 1987), East Texas Geological Society (Shoemaker, 1989), and Texas Bureau of Economic Geology (Herald, 1951), hydrocarbon-water contacts have been documented in Travis Peak sandstone reservoirs in 13 fields across eastern Texas and northern Louisiana (figs. 11 and 12). Field reports edited by Herald (1951) do not use the terms “gas-water contact” or “oil-water contact” but do report “elevation of bottom of oil or gas” and “lowest oil or gas.” It

Table 1. Data for Travis Peak Formation fields in Texas, Louisiana, and Arkansas—*Continued.*

BHP (psi)	FPG (psi/ft)	Pos	Sw	Fluid contacts	IP (MCFD)	IP (BOPD)	IP (BCPD)	IP (BWPD)
				Flank wells tested water without gas				
3,700	0.38				8,000			
3,050	0.39		0.34	Flank wells tested water without gas	2,700		2.7	0
4,190	0.47		0.53		4,088		2	
4,785	0.48		0.37					
4,865	0.48		0.38					
9,450	0.79		0.31					
4,884	0.48			GWC –10,163 & –10,592	3,803			
5,078	0.48				4,569			
						240		
3,375	0.46				4,093		4.5	
3,840	0.49				4,100		16.4	
3,550	0.46		0.25	GWC –7,441	2,000		6	
					25,000			
2,739	0.46				2,675			0
	0.47		0.30		5,585		24	
					3,840		56	
2,800	0.35				2,000			
2,400	0.41			Multiple sands with separate GWCs	45,000			
					25,000			
			0.3		432			
					2,080			
				Multiple sands with separate GWCs	67,634			
					16,500			
2,300	0.41				20,000			
				Multiple sands with separate GWCs & OWCs		205		
3,600	0.37				9,000			
1,300	0.27							

seems likely that “lowest gas” refers to the lowest elevation gas had been encountered by drilling at the time the report was written, whereas “elevation of bottom of gas” refers to an actual gas/water contact. Supporting that interpretation is the fact that the term “elevation of bottom of gas” clearly was used to indicate elevation of a gas-oil contact at Henderson field (Herald, 1951). If this interpretation of “elevation of bottom of gas” is correct, hydrocarbon-water contacts are documented in Travis Peak sandstone reservoirs in four additional fields (Herald, 1951), as indicated in table 1 and shown by dashed field outlines in figure 11.

Most Travis Peak production in northeastern Texas comes from the upper 300 ft of the formation, and hydrocarbon-water

contacts documented in Travis Peak sandstone reservoirs in the seven Texas fields (table 1; fig. 11) all occur within reservoirs in that upper part of the formation. No documentation of hydrocarbon-water contacts in middle or lower Travis Peak reservoirs in northeastern Texas has been found. At North Appleby field, Nacogdoches County, Texas, Tye (1991) reported that gas seems to be present throughout the Travis Peak section, though not necessarily in commercial amounts, and a discrete gas-water contact does not exist within the Travis Peak.

An attempt was made to document the presence or absence of hydrocarbon-water contacts in additional Travis Peak fields through analysis of data from drill-stem tests

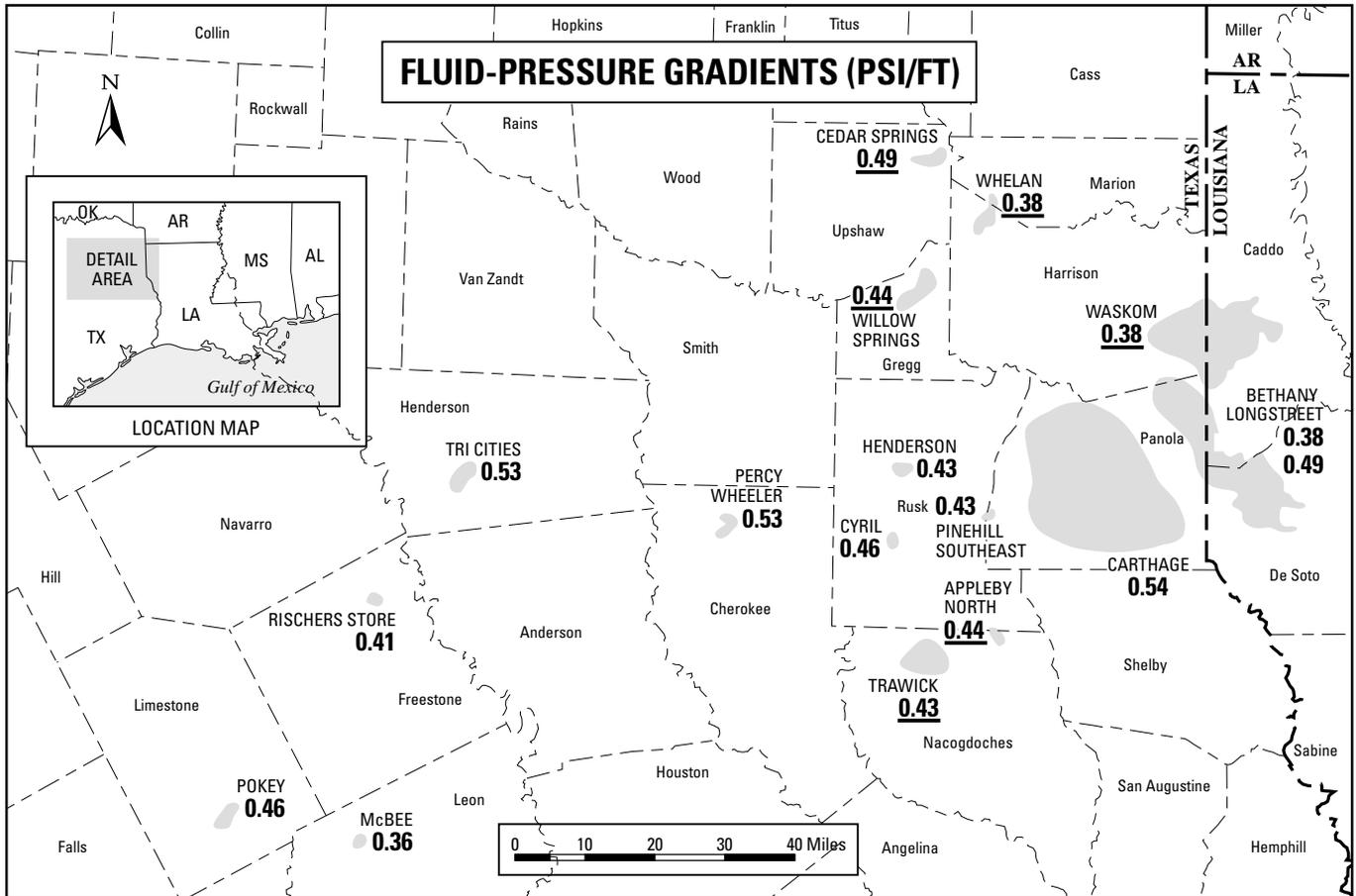


Figure 9. Map of northeastern Texas showing fluid-pressure gradients (FPG) (psi/ft) calculated from original shut-in pressures in Travis Peak Formation sandstone reservoirs. Multiple pressure-gradient values for a particular field are gradients calculated for different stacked sandstone reservoirs in that field. Shut-in pressure data are shown in table 1 along with sources for those data. Underlined FPG values indicate those from depths 500 ft or deeper below top of Travis Peak Formation.

(DSTs) and production tests. The goal was to determine if fields that produce gas from Travis Peak sandstones are flanked by dry holes that tested water only without gas, indicative of presence of a gas-water contact. A data set of wells penetrating the Travis Peak and Cotton Valley Group across much of northeastern Texas and northern Louisiana was extracted from a database provided by IHS Energy Group (petroROM Version 3.43) for analysis of DST and production-test data using ArcView software (Environmental Systems Research Institute, Inc., version 3.2). Well data were sorted and displayed in map view using ArcView software such that wells that produce from Travis Peak sandstones could be distinguished from Travis Peak dry holes with tests. While viewing the map display, we could examine test results from any particular well.

Reconnaissance analysis of test data show that water was recovered without gas from production tests or DSTs in Travis Peak sandstone reservoirs in wells on one or more flanks of Bethany-Longstreet, Cheniere Creek, and Caspiana fields in northern Louisiana (fig. 12). These data indicate presence of

gas-water contacts within Travis Peak sandstone reservoirs in those fields.

In summary, hydrocarbon-water contacts have been documented in Travis Peak sandstone reservoirs at various depths within the formation in northern Louisiana and within the upper 300 ft of the formation in northeastern Texas. Although data from the middle and lower Travis Peak section in northeastern Texas are limited, no hydrocarbon-water contacts have been reported from that interval in northeastern Texas.

Discussion of Evidence For and Against Basin-Centered Gas

Source Rocks and Burial and Thermal History

Source rocks responsible for generating gas in basin-centered gas accumulations commonly are in strati-

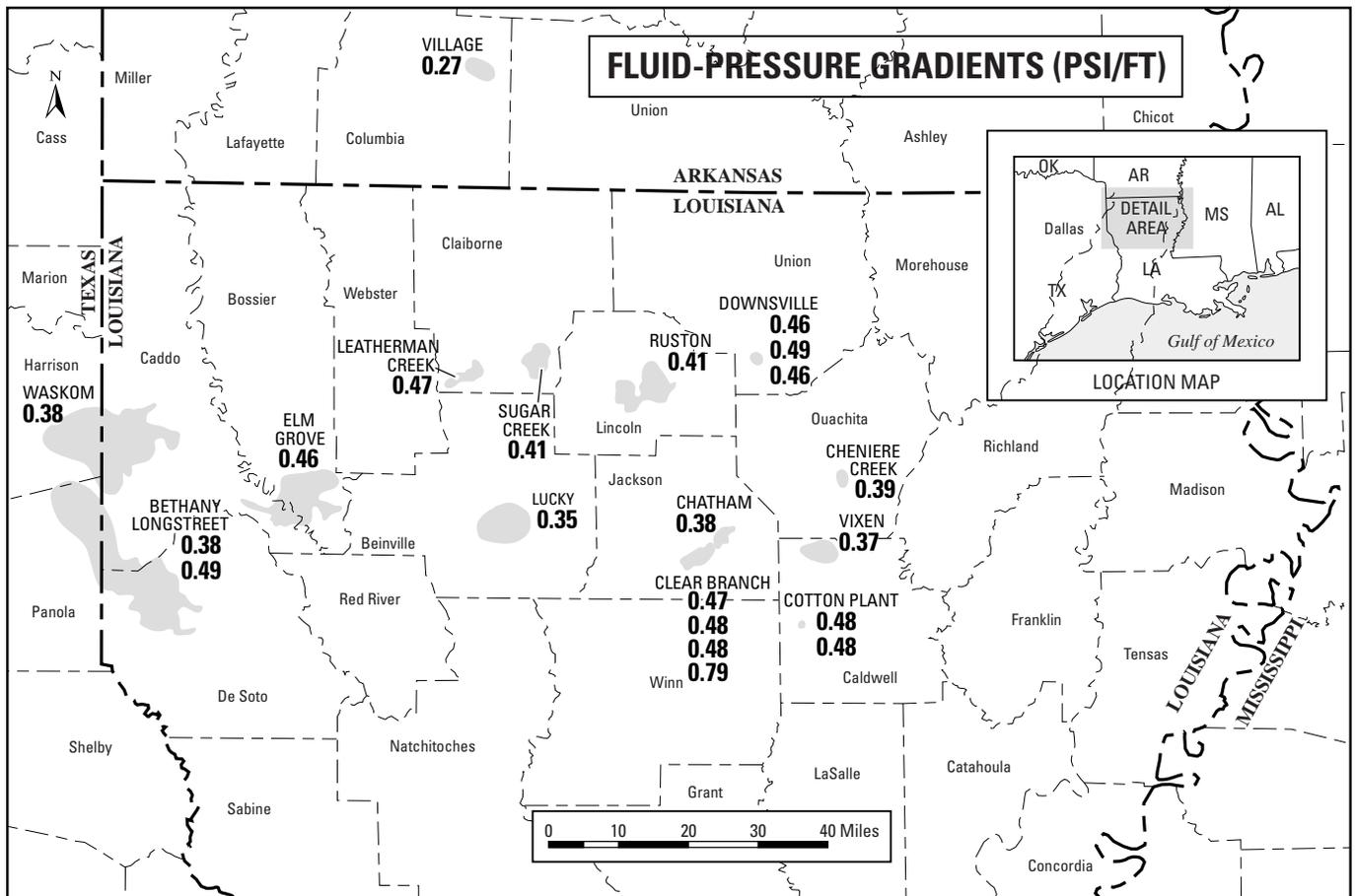


Figure 10. Map of northern Louisiana showing fluid-pressure gradients (psi/ft) calculated from original shut-in pressures in Travis Peak Formation sandstone reservoirs. Multiple pressure-gradient values for a particular field are gradients calculated for different stacked sandstone reservoirs in that field. Shut-in pressure data are shown in table 1 along with sources for those data.

graphic proximity to low-permeability reservoirs that hold the gas. As described above, shales interbedded with Travis Peak sandstone reservoirs in northeastern Texas have passed through the oil window and are approaching the level of onset of dry-gas generation. However, these shales are primarily oxidized flood-plain shales with TOC content generally less than 0.5 percent, and therefore are not considered as potential hydrocarbon source rocks (Tissot and Welte, 1978; Dutton, 1987). Dutton (1987) suggested that Travis Peak marine shales depositionally downdip from the Travis Peak hydrocarbon-productive trend probably have higher TOC content and thus might be potential source rocks. Because these marine shales occur primarily in Louisiana, Dutton (1987) expressed concern about long lateral migration distances that would be required to move hydrocarbons from these shales to updip Travis Peak sandstone reservoirs in eastern Texas. Dutton (1987) concluded that the marine Bossier Shale, which is the lowermost formation of the Cotton Valley Group, and Smackover laminated lime mudstones, which lie below the Bossier Shale (fig. 2) are the source rocks most likely to have generated hydrocarbons produced

from Travis Peak reservoirs in eastern Texas. Gray to black marine shales interbedded with Cotton Valley sandstones also might be potential source rocks. As discussed above, burial- and thermal-history data for the northern Gulf Coast Basin suggest that burial depths of Bossier and Smackover source rocks, in conjunction with the regional geothermal gradient, have been sufficient to generate dry gas. Also, as described above, time of generation of most of this gas postdates development of both the Sabine uplift and structures in the East Texas and Northern Louisiana Salt Basins. Available data, therefore, provide a reasonable scenario for charging Travis Peak sandstone reservoirs with oil and gas. Postulated Bossier Shale source rocks, however, are separated stratigraphically from Travis Peak sandstone reservoirs by at least 1,000 ft of tight Cotton Valley sandstones and interbedded shales, and also by the tight Knowles Limestone across much of the area (fig. 4). Potential Smackover source rocks are stratigraphically lower yet, and are separated from the Bossier by Haynesville/Buckner units, which include anhydrite. Although a reasonable scenario can be established for charging Travis Peak sandstone reservoirs with gas derived

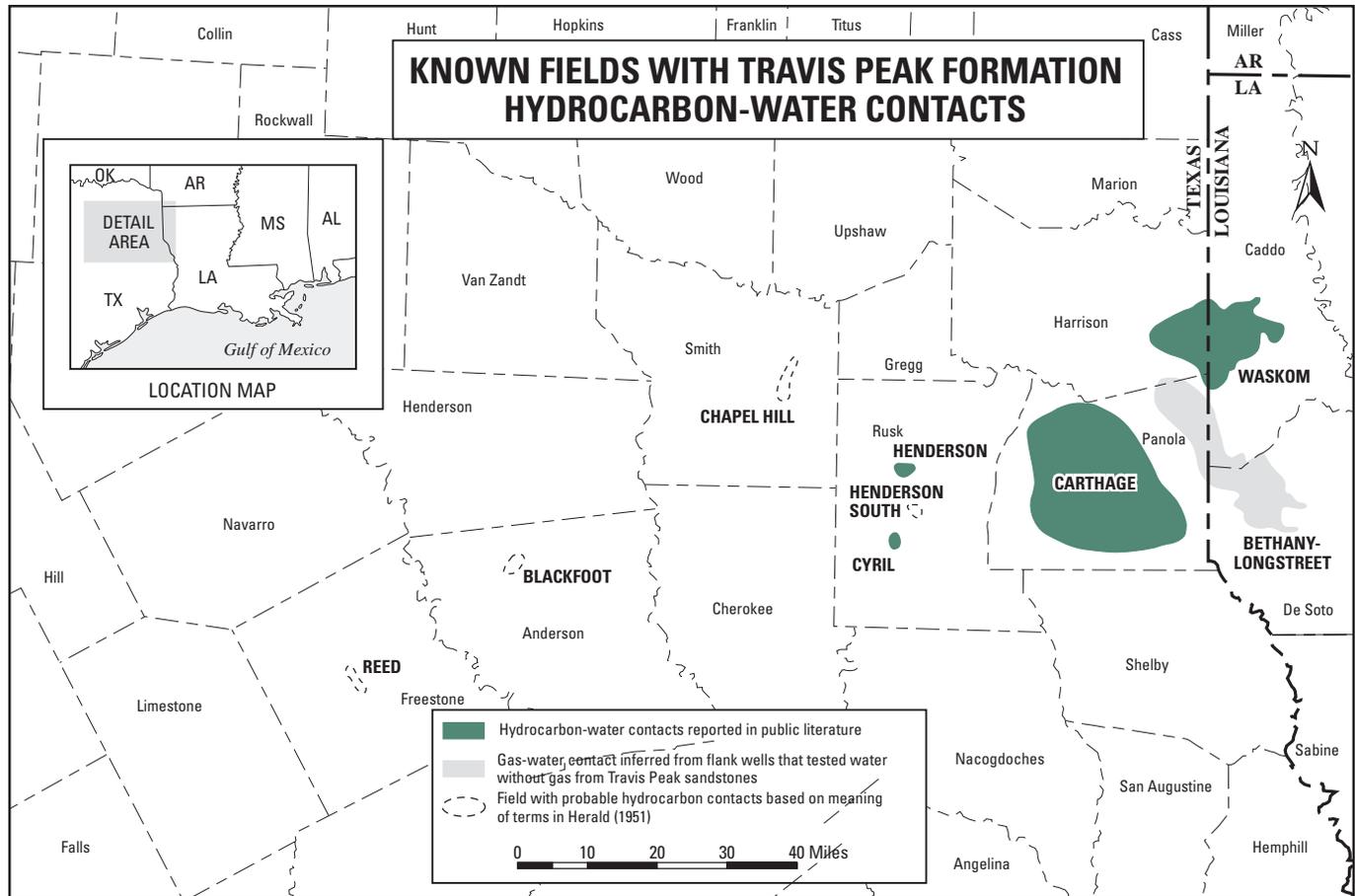


Figure 11. Map of northeastern Texas showing fields in which hydrocarbon-water contacts have been identified in Travis Peak Formation sandstone reservoirs. Dark shading indicates fields in which Travis Peak hydrocarbon-water contacts have been reported in publicly available literature (see table 1). Light shading indicates fields in which gas-water contacts are inferred based on presence of flank wells that tested water only, without gas, identified from IHS Energy data (PI/Dwights Plus of Petroleum Information/Dwights, d.b.a. IHS Energy Group). Fields with dashed outlines are those that probably have gas-water or oil-water contacts, depending on meaning of terms “elevation of bottom of gas” and “elevation of bottom of oil,” as reported in Herald (1951) and discussed in this report. All Travis Peak hydrocarbon-water contacts in these fields occur within sandstone reservoirs in the upper 300 to 500 ft of the Travis Peak Formation.

from stratigraphically lower source rocks, abundant gas-prone source rocks are not proximal to those reservoirs. This is not characteristic, in general, of classic basin-centered gas accumulations.

Porosity and Permeability

Continuous, basin-centered gas accumulations commonly involve a large volume of gas-saturated reservoir rock in which presence of gas cuts across stratigraphic units. Such gas accumulations require a regional seal to trap gas, and that seal characteristically is provided by the inherent low permeability of reservoir rocks themselves. Thus, continuous-gas reservoirs characteristically have low permeability, and when reservoirs are sandstones, they generally are referred to as tight-gas sandstones.

As discussed in the Introduction, the Travis Peak Forma-

tion was selected by GRI as one of two low-permeability formations for comprehensive geologic and engineering studies under auspices of its Tight Gas Sands Program. Also, Travis Peak sandstones have been designated as “tight” by the Federal Energy Regulatory Commission (FERC) in selected areas of northeastern Texas, northern Louisiana, and in one well in Jefferson Davis County, Mississippi (Dutton and others, 1993). That Travis Peak sandstones have been designated “tight” only in selected areas and not universally across the northern Gulf Coast Basin, however, reflects the relatively high permeability of Travis Peak sandstone reservoirs locally and significant variation of permeability with depth (fig. 8) and geographically across the northern Gulf Coast Basin (figs. 13 and 14).

As shown in figure 8, permeability of Travis Peak sandstones in northeastern Texas varies significantly with depth. Above 7,500 ft, numerous Travis Peak sandstone samples exhibit permeability values above 0.1 mD, the general permeability cutoff for designation as a tight-gas sandstone. At

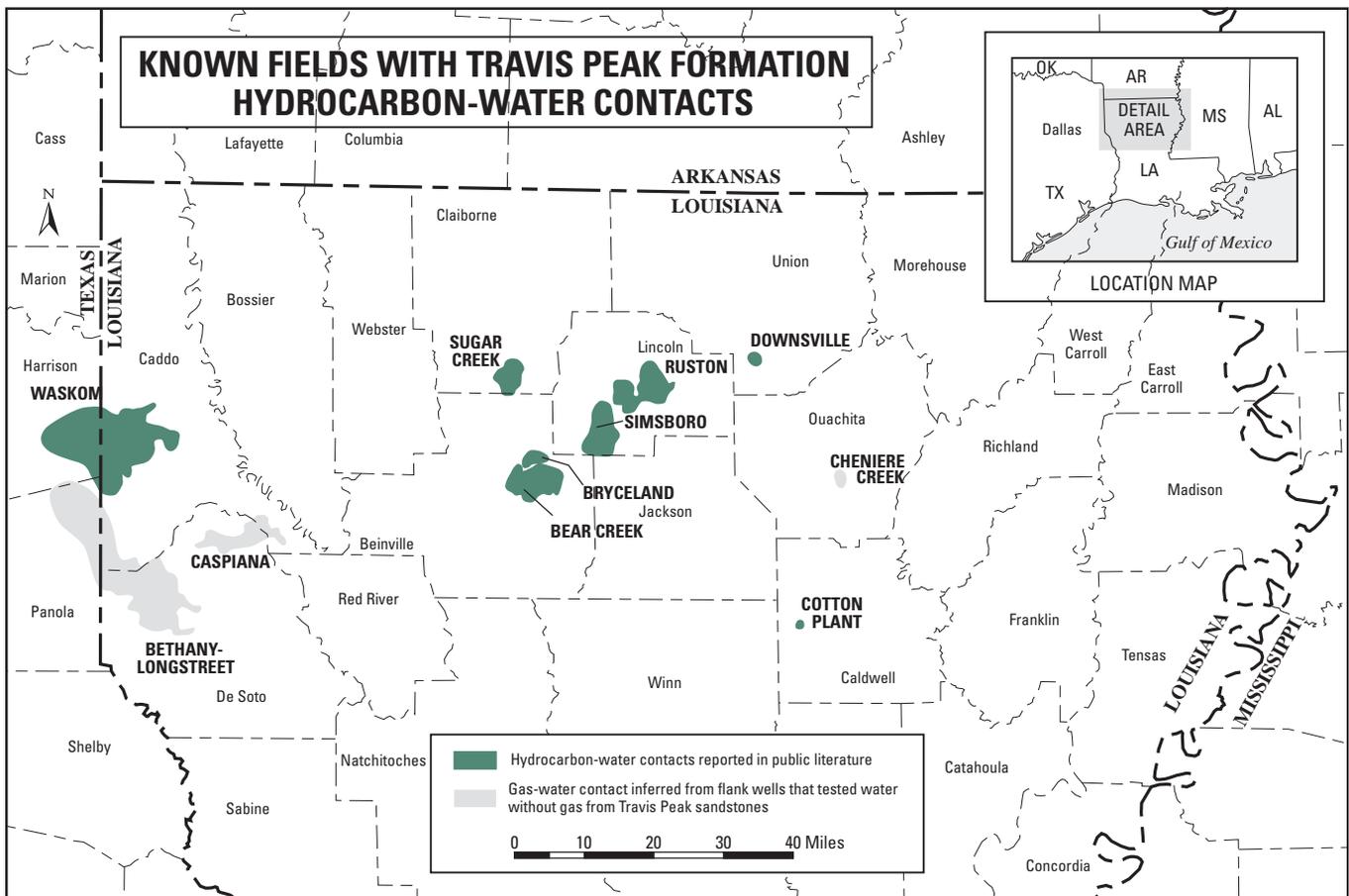


Figure 12. Map of northern Louisiana showing fields in which hydrocarbon-water contacts have been identified in Travis Peak (Hosston) Formation sandstone reservoirs. Dark shading indicates fields in which Travis Peak hydrocarbon-water contacts have been reported in publicly available literature (see table 1). Light shading indicates fields in which gas-water contacts are inferred based on presence of flank wells that tested water only, without gas, identified from IHS Energy data (PI/Dwights Plus of Petroleum Information/Dwights, d.b.a. IHS Energy Group).

depths less than 6,000 ft, permeability can exceed 100 mD. As discussed above, the decrease in permeability of Travis Peak sandstones by four orders of magnitude from 6,000 to 10,000 ft in northeastern Texas is controlled primarily by the volume of quartz cement. Such variation with depth probably explains much of the apparent geographic variation in permeability of Travis Peak sandstones (figs. 13 and 14). Multiple values of permeability for a given field refer to measurements from different, stacked Travis Peak sandstones within that field. For many fields (figs. 13 and 14), a range of measured permeability values is given, probably reflecting primarily variation of sandstone permeability with depth within those fields. Abundance of high-permeability sandstones, especially in upper portions of the Travis Peak Formation, is not characteristic of reservoirs that harbor basin-centered gas accumulations. This is because such higher permeability reservoirs cannot provide their own internal, albeit leaky, seal for gas.

Although sandstones throughout the entire Travis Peak Formation reportedly are charged with gas in some Travis Peak

fields, though not necessarily in commercial quantities (Davies and others, 1991; Tye, 1991; Dutton and others, 1993), gas production comes primarily from sandstones in the upper 300 ft of the formation (Fracasso and others, 1988; Al Brake, BP Amoco engineer, oral commun., 2000). To some degree, this might be a function of higher permeability of upper Travis Peak sandstones, which results in preferential completion of upper Travis Peak zones by operators. However, Fracasso and others (1988) suggested that hydrocarbons tend to be concentrated in upper Travis Peak sandstones because these sandstones are encased in shales that provide effective traps. Underlying low-sinuosity fluvial sandstones, comprising the bulk of the Travis Peak Formation, form a highly interconnected reservoir not only by virtue of their inherent multistory, multilateral sand-body geometries but also because of the abundance of natural vertical fractures within the highly quartz cemented, fluvial-sandstone sequence. Thus, the thick fluvial sequence seems to provide an effective upward migration pathway for gas. Data from Woodlawn field in Harrison County, Texas, corroborate this interpretation.

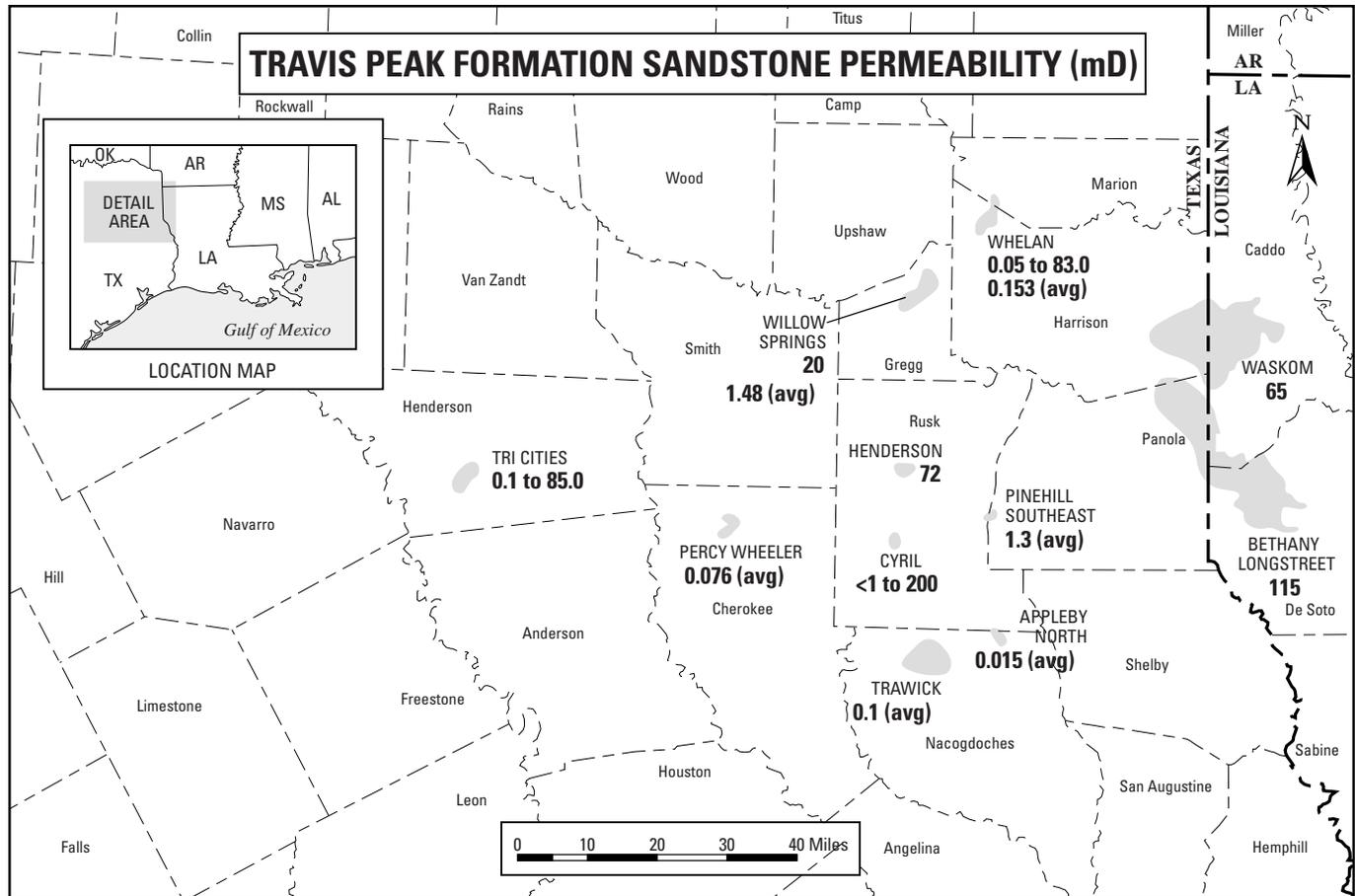


Figure 13. Map of northeastern Texas showing measured and average (avg) values of permeability for productive Travis Peak Formation sandstones in various fields. Multiple values of permeability for a particular field are measured values for different stacked sandstone reservoirs in that field. Permeability data are shown in table 1 along with sources for those data.

According to Al Brake (BP Amoco engineer, oral commun., 2000), mud-log gas shows are prominent in sandstones within the upper 500 ft of the Travis Peak at Woodlawn field but are generally absent in sandstones throughout the middle and lower Travis Peak. Completion attempts within the few thin middle and lower Travis Peak zones that exhibit gas shows and higher resistivities generally yield marginal to noncommercial quantities of gas before depleting and (or) giving way to water production (Al Brake, BP Amoco engineer, oral commun., 2000).

In summary, permeability within much of the Travis Peak Formation is significantly higher than the 0.1-mD cutoff value defining tight-gas sandstones. Traps for much of the gas in Travis Peak sandstone reservoirs are provided by mudstones that encase sandstone units in the upper portions of the formation rather than by inherent low permeability of the sandstone reservoirs. Travis Peak sandstone reservoirs exhibit reservoir properties and trapping patterns that are not entirely characteristic of basin-centered gas reservoirs, in which inherent, ubiquitous, low-permeability provides a seal for thermally generated gas.

Abnormally Pressured Reservoirs

Based on the fluid-pressure-gradient cutoff value of 0.55 psi/ft, above which Spencer (1987) considered reservoirs with highly saline waters to be significantly overpressured, virtually all Travis Peak sandstone reservoirs across northeastern Texas and northern Louisiana are normally pressured (figs. 9 and 10). Some Travis Peak reservoirs have slightly elevated FPGs, between 0.43 and 0.54 psi/ft, and a few exhibit subnormal FPGs, between 0.36 and 0.38 psi/ft. Based on data from 24 Travis Peak fields, the only Travis Peak sandstone reservoir that is significantly overpressured is one with an FPG of 0.79 psi/ft in Clear Branch field, Jackson Parish, Louisiana (fig. 9). Three shallower Travis Peak sandstone reservoirs in Clear Branch field, however, have normal FPGs of 0.47 to 0.48 psi/ft (fig. 9). Although pressure-gradient data for Travis Peak reservoirs in northern Louisiana come from various depths throughout the Travis Peak Formation, most pressure data for Travis Peak reservoirs in northeastern Texas are from sandstones within the upper 300 ft of the formation. Of 17 FPG values for

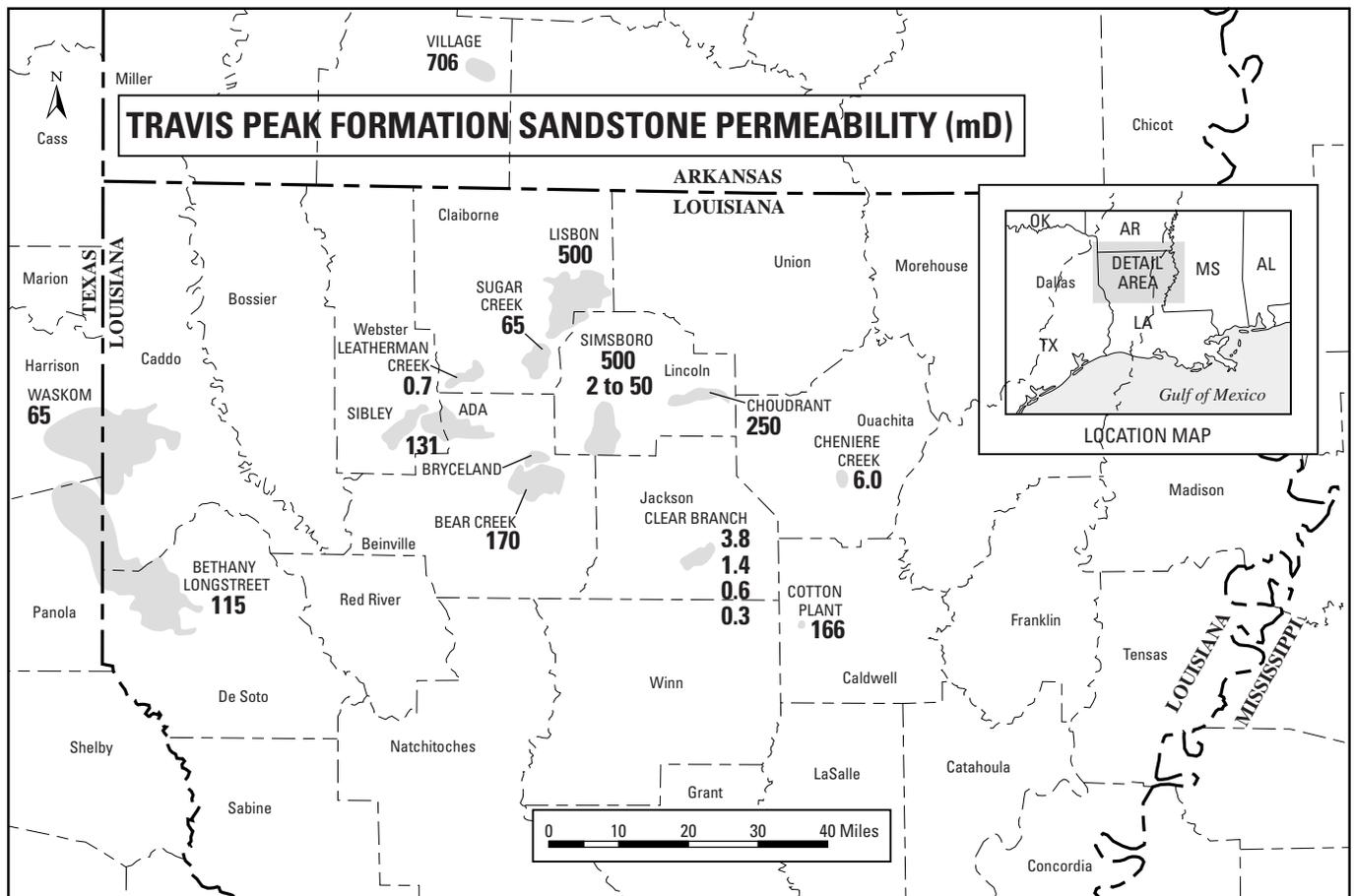


Figure 14. Map of northern Louisiana showing measured values of permeability for productive Travis Peak Formation sandstones in various fields. Multiple values of permeability for a particular field are measured values for different stacked sandstone reservoirs in that field. Permeability data are shown in table 1 along with sources for those data.

Travis Peak reservoirs in northeastern Texas, six are believed to be from reservoirs at depths of 500 ft or greater below top of the Travis Peak (table 1 and fig. 9). Four of these six FPGs are normal, and two are subnormal. Al Brake (BP Amoco engineer, oral commun., 2000) identified two additional fields in northeastern Texas, Woodlawn and Carthage fields, where Travis Peak reservoirs exhibit normal FPGs throughout the formation. Al Brake is not aware of any significantly overpressured Travis Peak reservoirs in northeastern Texas. Available data, therefore, suggest the absence of significantly overpressured reservoirs throughout the Travis Peak Formation in northeastern Texas. If overpressured reservoirs do occur within the middle and lower Travis Peak Formation in northeastern Texas, they probably are a local phenomenon without regional extent.

A number of Travis Peak reservoirs exhibit subnormal FPGs (0.27 to 0.38 psi/ft) (figs. 9 and 10). It is possible that these lower FPGs represent errors in measurement or lack of development of equilibrium conditions during tests in low-permeability rock. Also it is possible that a subnormal FPG for

a particular sandstone reservoir reflects depletion of pressure caused by hydrocarbon production from another Travis Peak sandstone that is in pressure communication with the apparently subnormally pressured interval. However, if one assumes that all the subnormal FPG values shown in figures 9 and 10 reflect original, virgin pressures unaffected by depletion, one might argue that they represent pressure declines associated with Tertiary uplift and erosion. If that were true, perhaps many Travis Peak reservoirs that today are normally pressured or slightly overpressured might have been significantly overpressured prior to Tertiary uplift and erosion.

During Tertiary uplift between 58 and 46 Ma, approximately 1,500 ft of strata were removed across much of northeastern Texas (Dutton, 1987; Laubach and Jackson, 1990; Jackson and Laubach, 1991). However, if much of the gas found in Travis Peak reservoirs was derived from Bossier Shale source rocks, migration of that gas into Travis Peak sandstones probably commenced between 57 and 45 Ma (Dutton, 1987; Hermann and others, 1991). Therefore, most of the thermally generated gas that presumably would have

caused development of overpressured reservoirs probably migrated into Travis Peak reservoirs following Tertiary uplift. If Tertiary uplift and erosion resulted in pressure reduction within Travis Peak sandstone reservoirs, subsequent introduction of thermally generated gas has not been able to produce significant widespread overpressure within those reservoirs. Perhaps most subnormal FPGs calculated for Travis Peak reservoirs reflect (1) depletion of pressure caused by hydrocarbon production from another Travis Peak sandstone reservoir that is in pressure communication with the apparently subnormally pressured reservoir interval or (2) lack of pressure buildup to equilibrium conditions during the pressure test. The best available data indicate that widespread, abnormally high pressure gradients caused by thermal generation of gas that is typical of basin-centered gas accumulations does not occur within the Travis Peak Formation. Stated another way, the occurrence of normally pressured, gas-charged sandstone reservoirs throughout most of the Travis Peak Formation across the northern Gulf Coast Basin suggests that a significant basin-centered accumulation is not present within the Travis Peak.

It is interesting to speculate on the absence of widespread overpressured reservoirs in the Travis Peak across eastern Texas and northern Louisiana. Perhaps there is insufficient hydrocarbon charge associated with absence of proximal source rocks or with poor migration pathways from stratigraphically or geographically distant source rocks. Additionally, relatively high matrix and fracture permeability of significant volumes of Travis Peak sandstone reservoirs might prevent the Travis Peak Formation as a whole from retarding upward migration of gas sufficiently to enable abnormally high pressures to develop. The lack of regional overpressures within the Travis Peak Formation could be explained by insufficient hydrocarbon charge relative to effectiveness of Travis Peak sandstone reservoirs to transmit, rather than retard the flow of, gas.

Restriction of reservoir bitumen in Travis Peak sandstones to reservoirs in the uppermost 300 ft of the formation might be significant in understanding hydrocarbon charge. Reservoir bitumen probably formed in pores of Travis Peak sandstones from deasphalting of oil caused by dissolution of gas in the oil. Was oil present throughout most of the Travis Peak Formation, and were sufficient quantities of gas developed, or introduced, only in the upper 300 ft of the Travis Peak to promote deasphalting there? Or was oil that experienced deasphalting originally present only in sandstones within the uppermost 300 ft of the formation, reflecting limited charge of oil into the Travis Peak? The latter explanation seems more logical, because, even within upper Travis Peak sandstones, bitumen occurs only in clean, well-sorted, rippled and cross-bedded sandstones. The absence of bitumen in burrowed, shaly, poorly sorted sandstones in the upper Travis Peak suggests that charge was insufficient to drive oil through smaller pore throats. Thus, with respect to the oil phase, hydrocarbon charge seems to be limited.

An additional question concerns the source of gas that promoted deasphalting of Travis Peak oil to produce reser-

voir bitumen. Was the gas generated in place through thermal alteration of Travis Peak oil, or was it introduced from some external source? The answer is unknown, although the level of kerogen maturity in mudstones interbedded with Travis Peak sandstone reservoirs suggests that oils in Travis Peak sandstones were subjected to temperatures sufficient to generate gas internally (Dutton, 1987). However, the extensive volume of gas within Travis Peak reservoirs regionally might suggest that much of that gas was derived from an external source, presumably the Bossier Shale or Smackover laminated lime mudstones, or both. Thus, there might have been a two-phase migration of hydrocarbons into Travis Peak reservoirs, perhaps similar to that described in general terms by Gussow (1954). As Bossier and Smackover source rocks were buried, they first generated oil, some of which might have migrated into Travis Peak sandstones where it was trapped. With continued burial, Bossier and Smackover source rocks reached the gas window, spawning an episode of gas generation that might be continuing today. This later gas might have caused deasphalting of previously emplaced oil in Travis Peak sandstones, as well as displacement of oil from some Travis Peak reservoirs. However, as evidence seems to suggest a limited charge of oil into Travis Peak reservoirs, perhaps gas charge also is sufficiently limited relative to transmissibility of Travis Peak sandstone reservoirs to prohibit development of regionally overpressured reservoirs and accompanying basin-centered gas.

Hydrocarbon-Water Contacts

Perhaps the most definitive criterion for establishing the presence of a basin-centered gas accumulation is absence of gas-water contacts. Gas-water contacts are distinctive features of conventional gas accumulations. The presence of a gas-water contact indicates a change from gas-saturated to water-saturated porosity within a particular reservoir unit. This implies that a well drilled into that reservoir structurally below the gas-water contact should encounter only water, thereby demonstrating the absence of a continuous-gas accumulation in that immediate area. Documentation of the occurrence of gas-water contacts within a particular stratigraphic unit in various gas fields distributed across a particular basin argues strongly against presence of a continuous- or basin-centered gas accumulation within that particular interval in the basin.

Hydrocarbon-water contacts have been documented within Travis Peak sandstone reservoirs in 13 fields (figs. 11 and 12) across eastern Texas and northern Louisiana. As discussed above and as indicated by dashed field outlines in figure 11, four additional Travis Peak fields probably also have hydrocarbon-water contacts, depending upon interpretation of the term "elevation of bottom of gas" as reported by Herald (1951). Data for many Travis Peak fields presented in Shreveport Geological Society Reference Reports (1946, 1947, 1951, 1953, 1958, 1963, 1987) and Shoemaker (1989) either do not mention hydrocarbon-water contacts or report that none were encountered. However, because many of those reports

were prepared not long after fields were discovered, sufficient development drilling may not have occurred to encounter hydrocarbon-water contacts. In other cases, fluid contacts were not included as part of the field description. Lack of reported Travis Peak hydrocarbon-water contacts in such field reports, therefore, should not be interpreted as absence of oil-water or gas-water contacts in those fields. Consequently, it is likely that considerably more of the Travis Peak fields (figs. 1A and 1B) have hydrocarbon-water contacts than illustrated in figures 11 and 12.

Supporting that inference is the inferred presence of Travis Peak gas-water contacts at fields such as Bethany-Longstreet and Cheniere Creek in northern Louisiana (fig. 12) based on recoveries of water without gas from production tests and DSTs of Travis Peak sandstone reservoirs on the flanks of those fields. Although water recoveries from flank wells suggest the presence of gas-water contacts within Travis Peak reservoirs in those fields, gas-water contacts were not reported for Travis Peak reservoirs in those fields in Shreveport Geological Society Reference Reports (1963, 1987).

As discussed above, all hydrocarbon-water contacts within Travis Peak sandstone reservoirs in fields in northeastern Texas documented in this report (table 1 and figure 11) occur in the upper 300 ft of the Travis Peak Formation. No documented hydrocarbon-water contacts in middle or lower Travis Peak reservoirs in northeastern Texas have been found. At Woodlawn field in Harrison County, Texas, a discrete gas-water contact has not been identified in the lower Travis Peak Formation. However, commercial gas production from the middle and lower Travis Peak section at Woodlawn field is limited, and most of that interval at Woodlawn field is considered water bearing, according to Al Brake (BP Amoco engineer, oral commun., 2000). In addition to sandstones within the upper 500 ft of the Travis Peak, a deeper sandstone interval about 200 ft above the bottom of the Travis Peak Formation produces gas in commercial quantities at Woodlawn field. BP refers to this deeper productive interval at Woodlawn field informally as the McGee sandstone. Al Brake reports that the bulk of the Travis Peak section between the McGee sandstone and productive sandstones in the upper 500 ft of the Travis Peak lacks mud-log gas shows and is not considered productive. Locally within the middle and lower Travis Peak interval at Woodlawn field, Al Brake reports that scattered 10- or 12-ft sandstones locally exhibit high resistivity within the upper 1 to 3 ft accompanied by mud-log gas shows, but show lower resistivity below with no mud-log gas shows. Some of these thin, high-resistivity intervals have been perforated and tested. Typical cumulative production from one of these thin intervals ranges from insignificant to a maximum of only about 0.1 BCFG before the zone depletes and gives way to water production. Based on general lack of mud-log gas shows, scattered presence of only thin 1- to 3-ft, high-resistivity, gas-bearing zones, and limited recovery of gas throughout the bulk of the Travis Peak section between the deeper McGee sandstone and the uppermost 500 ft of the formation, Al Brake (BP Amoco engineer, oral commun., 2000) considers the middle

and lower Travis Peak interval at Woodlawn field to be largely water bearing. If these reservoir and production characteristics are typical of other Travis Peak fields, this information from Woodlawn field tends to confirm the interpretation of Fracasso and others (1988) that commercial quantities of hydrocarbons in Travis Peak sandstones are concentrated within the sandstones in the upper 300 ft of the formation.

Patterns of gas occurrence and production at Woodlawn field might have significance in understanding Travis Peak gas reservoirs at North Appleby field in Nacogdoches County, Texas. According to Tye (1991), gas occurs throughout the Travis Peak Formation at North Appleby field, though not necessarily in commercial amounts, and a discrete gas-water contact reportedly is not present. As at Woodlawn field however, sandstone reservoirs throughout the Travis Peak Formation at North Appleby field, are normally pressured (Lin and Finley, 1985), which is not typical of basin-centered gas accumulations. Furthermore, although most of the Travis Peak section at North Appleby field reportedly is gas charged, perforations in the field well shown by Tye (1991) are limited to only a few sandstones that are capped by thicker shale units. Perforated sandstones in this well are restricted to two zones, one within the upper 500 ft of the Travis Peak between depths of 8,200 and 8,500 ft, and a second zone about 200 ft from the bottom of the formation between depths of 9,800 and 10,000 ft. This pattern of perforations is strikingly similar to that described by Al Brake for Travis Peak sandstones at Woodlawn field. Although cores were cut in several intervals within the thick intervening fluvial-sandstone section in that well at North Appleby field, no zones were perforated between 8,500 ft and 9,800 ft. Examination of production-test data from other wells in North Appleby field indicates that most perforations are restricted to the upper 500 ft of the Travis Peak section. Only two other wells in North Appleby field were found with perforations in the deeper interval about 200 ft from the base of the Travis Peak. Initial-production rates of 72 and 114 thousand cubic ft of gas per day (MCFD) from lower Travis Peak perforations in these two wells suggest that this deeper zone at North Appleby field probably is marginally commercial to noncommercial. Restriction of perforations within the middle and lower Travis Peak Formation at North Appleby field to one zone about 200 ft from the bottom of the Travis Peak shows striking resemblance to the pattern observed at Woodlawn field, where the normally pressured middle and lower Travis Peak section reportedly is largely water bearing. Although mud-log data from wells in North Appleby field were not available for this study, one might wonder if the bulk of the middle and lower Travis Peak section there lacks gas shows and largely is water bearing despite the report of being gas charged by Tye (1991). Tye's report that the middle and lower Travis Peak Formation at North Appleby field is gas charged was based on personal communication to him with no supporting data and was accompanied by the qualification that gas might not be present in commercial quantities throughout the section. Such qualification bears some resemblance to the situation described by Al Brake at Woodlawn field, where scattered thin, highly resistive zones in the middle and

lower Travis Peak produce small amounts of gas before depleting and yielding water. Finally, in considering the potential for basin-centered gas, it is significant that, despite the lack of documented gas-water contacts within the middle and lower Travis Peak at Woodlawn and North Appleby fields, the entire Travis Peak interval at both fields reportedly is normally pressured.

In summary, hydrocarbon-water contacts in Travis Peak sandstone reservoirs have been documented at various depths within the Travis Peak Formation in nine fields in northern Louisiana. In northeastern Texas, hydrocarbon-water contacts have been reported within Travis Peak sandstone reservoirs in eight fields, but these all occur within the upper 300 to 500 ft of the Travis Peak Formation. Rather than being clustered in a small area, however, these fields with documented hydrocarbon-water contacts are widely distributed across the eastern-Texas and northern-Louisiana Travis Peak productive trend. Wide distribution of such conventional hydrocarbon accumulations with hydrocarbon-water contacts suggests the absence of significant basin-centered gas accumulations within the entire Travis Peak Formation in northern Louisiana and within the upper 500 ft of the Travis Peak Formation in northeastern Texas. Data on hydrocarbon-water contacts in the lower three-fourths of the Travis Peak section in northeastern Texas are limited and less conclusive. At fields such as North Appleby and Woodlawn in northeastern Texas, clearly defined gas-water contacts reportedly are not present or have not been identified. Travis Peak reservoirs at North Appleby and Woodlawn fields, however, are normally pressured, which is not characteristic of basin-centered gas accumulations. The best available data suggest that the lower three-fourths of the Travis Peak Formation across much of northeastern Texas is characterized by a general lack of mud-log gas shows and by only a few gas-charged sandstones that yield marginal to noncommercial gas production before depleting and giving way to water production. Operators consequently seem to focus efforts on Travis Peak completions within sandstone reservoirs in the uppermost 300 to 500 ft of the Travis Peak Formation, resulting in limited data in the lower three-fourths of the formation. Although pressure data from depths below 500 ft of top of the Travis Peak are limited, data from eight fields indicate normal or subnormal FPGs and suggest absence of significant overpressure throughout the Travis Peak Formation in northeastern Texas. In the absence of documented gas-water contacts below 500 ft of top of the Travis Peak Formation in northeastern Texas, limited data indicating presence of abundant water-bearing sandstones and a lack of significant overpressured reservoirs together suggest absence of widespread basin-centered gas accumulations within the middle and lower Travis Peak.

Conclusions

1. The Travis Peak (Hosston) Formation is a Lower Cretaceous basinward-thickening wedge of terrigenous clastic sedimentary rocks that underlies the northern

Gulf Coast Basin from eastern Texas across northern Louisiana into southern Mississippi and eastward. Clastic influx was focused in two main fluvial-deltaic depocenters associated with the ancestral Red River in northeastern Texas and the ancestral Mississippi River in southern Mississippi and northeastern Louisiana.

2. Across its hydrocarbon-productive trend in northeastern Texas, the Travis Peak Formation is divided into three informal units based on relative amounts of sandstone and shale. A thin lower interval consists of mixed sandstones and shales interpreted as delta-fringe deposits. It is gradationally overlain by a thick, sandstone-rich sequence that forms the bulk of the Travis Peak section comprised primarily of stacked, braided-channel sandstones grading upward into meandering-channel deposits. The third and uppermost interval consists of mixed sandstone and mudstone interpreted as coastal-plain, paralic, and marine deposits. Upward stratigraphic evolution from braided through meandering fluvial systems to paralic and marine strata reflects an overall transgression and relative rise in sea level that occurred during Travis Peak deposition.
3. Most hydrocarbon production from the Travis Peak Formation in northeastern Texas and northern Louisiana is from drilling depths of 6,000 to 10,000 ft. Throughout that interval, porosity and permeability of Travis Peak sandstones decrease significantly with depth. In northeastern Texas, average porosity of clean Travis Peak sandstones decreases from 16.6 percent at 6,000 ft to 5.0 percent at 10,000 ft. Average stressed permeability of clean sandstones decreases by four orders of magnitude from 10 mD at 6,000 ft to 0.001 mD at 10,000 ft. Decrease in porosity with depth results primarily from (a) increasing amount of quartz cement, and (b) decrease in amount of secondary porosity, which was derived almost exclusively from dissolution of feldspar. Decrease in permeability with depth occurs mainly because of (a) decrease in porosity, which in turn is caused principally by increasing quartz cement, and (b) increasing overburden pressure that closes small-diameter pore throats.
4. Reservoir properties of many Travis Peak sandstones are significantly better than those characteristic of basin-centered gas reservoirs in which inherent, ubiquitous, low-permeability provides an internal, leaky seal for thermally generated gas. Although Travis Peak sandstones have received "tight-gas" designation across selected portions of eastern Texas and northern Louisiana, at depths less than 7,500 ft in northeastern Texas, the sandstones often exhibit permeabilities well above the 0.1-mD cutoff for qualification as a tight-gas reservoir. At depths less than 6,000 ft, permeability can exceed 100 mD. At depths below 8,000 ft, where matrix permeability generally is less than 0.1 mD as a result of extensive quartz cementation, natural fractures are common, imparting fracture permeability to

the reservoir. In northern Louisiana where interdeltaic sandstones are separated by shale intervals, hydrocarbon production comes from sandstones throughout the Travis Peak. In northeastern Texas, most production of oil and gas from the Travis Peak comes from sandstone reservoirs in the upper 300 ft of the formation. This seems to reflect a concentration of hydrocarbons in the upper Travis Peak, though in some fields, sandstones throughout the Travis Peak Formation reportedly are gas charged. Concentration of oil and gas probably occurs in upper Travis Peak sandstones because these meandering-channel, tidal-channel, and tidal-flat sandstones are encased in thick shales that provide effective seals. Underlying low-sinuosity fluvial sandstones, comprising the bulk of the Travis Peak Formation, form a highly interconnected network because of their inherent multistory, multilateral sand-body geometries; there is also an abundance of natural vertical fractures within the highly quartz-cemented sequence. Thus, the thick fluvial sequence with its lack of thick, widespread shale barriers seems to provide an effective upward-migration pathway for gas rather than affording inherent sealing capabilities typical of reservoirs harboring basin-centered gas accumulations.

5. Source rocks generating the hydrocarbons produced from Travis Peak sandstone reservoirs are not proximal to those reservoirs. Vitrinite reflectance (R_o) of Travis Peak shales interbedded with reservoir sandstones in eastern Texas indicate that they have passed through the oil window and are approaching the onset of dry-gas generation. However, these shales are primarily oxidized flood-plain shales with total organic carbon content less than 0.5 percent and consequently are not considered likely sources of oil and gas. Travis Peak marine shales depositionally down-dip in the Gulf Coast Basin in central Louisiana might have generated hydrocarbons, but relatively long distance lateral migration would be necessary. Most likely source rocks for gas and oil produced from Travis Peak sandstones are the Jurassic Bossier Shale of the underlying Cotton Valley Group and stratigraphically lower, laminated, carbonate mudstones of the Jurassic Smackover Formation. Burial- and thermal-history data for eastern Texas and northern Louisiana suggest that onset of dry-gas generation from Smackover mudstones and the Bossier Shale occurred about 80 Ma and 57 Ma, respectively. The Bossier Shale, however, is separated from Travis Peak reservoirs by at least 1,000 ft of tight Cotton Valley sandstones and interbedded shales, and also by the tight Knowles Limestone, across much of the area.
6. Unlike basin-centered gas reservoirs, which generally are abnormally pressured, Travis Peak sandstone reservoirs across eastern Texas and northern Louisiana commonly are normally pressured. Of 24 fields for which pressure data are reported here, only one has a Travis Peak reservoir that is considered significantly overpressured, i.e., with FPG greater than 0.55 psi/ft. At Clear Branch field, Louisiana, one sandstone has a FPG = 0.79 psi/ft, but three other Travis Peak sandstone reservoirs within that field are normally pressured. In northern Louisiana, pressure data are available from sandstones throughout the Travis Peak, whereas in northeastern Texas, most available pressure data are from reservoirs in the upper 300 to 500 ft of the Travis Peak Formation. Limited data from the lower three-fourths of the Travis Peak in northeastern Texas suggest absence of significant overpressures in that interval, too. Some fields exhibit underpressured reservoirs, with FPGs ranging from 0.27 to 0.38 psi/ft. If these data are accurate, they might suggest pressure decrease associated with Tertiary uplift and erosion across northeastern Texas. Most of the gas presumably generated from Bossier and Smackover source rocks probably migrated into Travis Peak reservoirs following Tertiary uplift. If Tertiary uplift and erosion resulted in pressure reduction within Travis Peak sandstone reservoirs, subsequent introduction of thermally generated gas has not been able to produce significant widespread overpressured reservoirs. Thus, Travis Peak reservoirs across the northern Gulf Coast Basin are characterized by normal to slightly below normal pressures. Widespread abnormally high pressure caused by thermal generation of gas that is typical of basin-centered gas accumulations does not occur within the Travis Peak Formation.
7. The presence of a gas-water contact perhaps is the most definitive criterion suggesting that a gas accumulation is conventional rather than a "sweet spot" within a basin-centered, continuous-gas accumulation. Hydrocarbon-water contacts within Travis Peak sandstone reservoirs have been documented in nine fields in northern Louisiana and eight fields in northeastern Texas. In all eight fields in northeastern Texas, however, hydrocarbon-water contacts occur in sandstone reservoirs in the uppermost 300 to 500 ft of the Travis Peak Formation. In northeastern Texas, no documented gas-water contacts have been found in Travis Peak reservoirs in the lower three-fourths of the formation. In a few Travis Peak fields, such as North Appleby field, Nacogdoches County, Texas, gas reportedly is present, though not always in commercial amounts, in sandstones throughout the Travis Peak Formation, and a discrete gas-water contact reportedly is not present. However, Travis Peak reservoirs at North Appleby field are normally pressured. Perhaps vertically extensive gas-water transition zones with poorly defined gas-water contacts occur in some Travis Peak reservoirs such as those at North Appleby field, as is characteristic of normally pressured conventional gas accumulations in low-permeability reservoirs. Alternatively, the pattern of perforated intervals at North Appleby field is similar to that at Woodlawn field, Harrison County,

Texas, where most of the middle and lower Travis Peak section reportedly is water bearing. Fields with clearly documented hydrocarbon-water contacts throughout the Travis Peak in Louisiana and within the upper 300 to 500 ft of the formation in northeastern Texas are distributed widely across the Travis Peak productive trend. Wide distribution of conventional hydrocarbon accumulations with discrete hydrocarbon-water contacts indicates absence of a significant basin-centered gas accumulation within the Travis Peak Formation in Louisiana, and within the upper 300 to 500 ft of the Travis Peak in northeastern Texas.

8. Insufficient hydrocarbon charge together with sufficiently high reservoir permeability might explain why Travis Peak sandstone reservoirs generally are normally pressured and commonly exhibit discrete hydrocarbon-water contacts. Perhaps lack of proximal source rocks and lack of effective migration pathways from stratigraphically or geographically distant source rocks result in insufficient hydrocarbon charge. Furthermore, Travis Peak sandstone reservoirs might have sufficiently high matrix and fracture permeability through sufficient stratigraphic thickness and across sufficient geographic extent to allow upward migration of gas, to the degree that abnormally high pressure and basin-centered gas cannot develop. Most Travis Peak hydrocarbon accumulations in northeastern Texas occur in the uppermost 300 to 500 ft of the formation within sandstones that are encased completely in marine shale.
9. Lack of proximal source rocks, the relative abundance of reservoir sandstone with significant matrix and fracture permeability, and especially the abundance of normally pressured reservoirs together with widespread presence of hydrocarbon-water contacts suggest that basin-centered gas is absent or insignificant within the Travis Peak Formation. If any areas of continuous gas occur within the Travis Peak Formation, they probably occur within the lower three-fourths of the Travis Peak in northeastern Texas, southwest of the Sabine uplift, and probably are not sufficiently large to have a significant impact on hydrocarbon resource assessment for the Travis Peak.

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