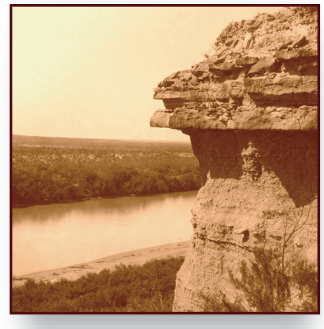
Chapter 2

2003 Geologic Assessment of Undiscovered Conventional Oil and Gas Resources in the Upper Cretaceous Navarro and Taylor Groups, Western Gulf Province, Texas



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By S.M. Condon and T.S. Dyman

Chapter 2 of

Petroleum Systems and Geologic Assessment of Undiscovered Oil and Gas, Navarro and Taylor Groups, Western Gulf Province, Texas

By U.S. Geological Survey Western Gulf Province Assessment Team

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2003 Geologic Assessment of Undiscovered Conventional Oil and Gas Resources in the Upper Cretaceous Navarro and Taylor Groups, Western Gulf Province, Texas

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Abstract

The Upper Cretaceous Navarro and Taylor Groups in the western part of the Western Gulf Province were assessed for undiscovered oil and gas resources in 2003. The area is part of the Smackover–Austin–Eagle Ford Composite Total Petroleum System. The rocks consist of, from youngest to oldest, the Escondido and Olmos Formations of the Navarro Group and the San Miguel Formation and the Anacacho Limestone of the Taylor Group (as well as the undivided Navarro Group and Taylor Group). Some units of the underlying Austin Group, including the "Dale Limestone" (a term of local usage that describes a subsurface unit), were also part of the assessment in some areas.

Within the total petroleum system, the primary source rocks comprise laminated carbonate mudstones and marine shales of the Upper Jurassic Smackover Formation, mixed carbonate and bioclastic deposits of the Upper Cretaceous Eagle Ford Group, and shelf carbonates of the Upper Cretaceous Austin Group. Possible secondary source rocks comprise the Upper Jurassic Bossier Shale and overlying shales within the Upper Jurassic to Lower Cretaceous Cotton Valley Group, Lower Cretaceous marine rocks, and the Upper Cretaceous Taylor Group.

Oil and gas were generated in the total petroleum system at different times because of variations in depth of burial, geothermal gradient, lithology, and organic-matter composition. A burial-history reconstruction, based on data from one well in the eastern part of the study area (Jasper County, Tex.), indicated that (1) the Smackover generated oil from about 117 to 103 million years ago (Ma) and generated gas from about 52 to 41 Ma and (2) the Austin and Eagle Ford Groups generated oil from about 42 to 28 Ma and generated gas from about 14 Ma to the present.

From the source rocks, oil and gas migrated upsection and updip along a pervasive system of faults and fractures as well as along bedding planes and within sandstone units. Types of traps include stratigraphic pinchouts, folds, faulted folds, and combinations of these. Seals consist of interbedded shales and mudstones and diagenetic cementation.

The area assessed is divided into five assessment units (AUs): (1) Travis Volcanic Mounds Oil (AU 50470201), (2) Uvalde Volcanic Mounds Gas and Oil (AU 50470202), (3) Navarro-Taylor Updip Oil and Gas (AU 50470203), (4) Navarro-Taylor Downdip Gas and Oil (AU 50470204), and (5) Navarro-Taylor Slope-Basin Gas (AU 50470205). Total estimated mean undiscovered conventional resources in the five assessment units combined are 33.22 million barrels of oil, 1,682.80 billion cubic feet of natural gas, and 34.26 million barrels of natural gas liquids.

Acknowledgments

We thank Richard Bain, ChevronTexaco North America Upstream, for discussing gas exploration in the Laredo area. Gary Lader of Swift Energy Company provided insights into the AWP oil and gas field. We thank Mike Lewan and Mark Pawlewicz, USGS, for their work on oil source rocks, for compiling burial-history data in the study area, and for meaningful discussions that helped to clarify some of the complex issues regarding hydrocarbon source rocks. Troy Cook, USGS, clarified the nature of several gas accumulations in the Western Gulf Province. We thank the assessment team of C.J. Schenk, T.R. Klett, R.R. Charpentier, T. Cook, R.M. Pollastro, and R.A. Crovelli, USGS; they helped guide our analysis of this area and calculated the final resource assessment numbers. USGS contractors Chris Anderson did GIS (geographic information system) processing and prepared working maps, and Heather Mitchell helped prepare contour-map figures. The manuscript was improved by the reviews of Laura Roberts, Ronald Johnson, and Douglas Nichols, USGS, and William Keefer, USGS (retired), and by the editing of USGS contractor Mary Eberle.

Introduction

Differences in Approach Between the 1995 and 2003 Assessments

Various regions of the United States are being reevaluated as a follow-up to the 1995 U.S. Geological Survey (USGS) national assessment of oil and gas resources; the results of these current studies are available at http://energy.cr.usgs.gov/oilgas/noga/nogaindex.htm. Within the Western Gulf Province, the area assessed in 2003 and discussed in this report is slightly larger than the area assessed in 1995 by Schenk and Viger (1996). As well, an area in the western part of the province was identified but not assessed in 1995 because the cut-off for field sizes at that time was larger (1 million barrels of oil equivalent [MMBOE]) than that used for this assessment (0.5 MMBOE) and there were no fields equal to or greater than 1 MMBOE in that play.

In the 2003 work reported here, assessment units have replaced plays as the basic level of assessment. A *play* was identified primarily by using similarities in petroleum reservoirs without applying a total petroleum system model. An *assessment unit* is "a mappable part of a total petroleum system in which discovered and undiscovered oil and gas accumulations constitute a single relatively homogeneous population such that the methodology of resource assessment is applicable" (Klett, 2004, p. 599); it is a three-dimensional entity, consisting of a contiguous geographic area and one or more geologic formations. The use of assessment units versus plays does not necessarily result in differences in assessed volumes of undiscovered resources, but applying the concept of total petroleum systems provides a unifying framework for identifying and analyzing accumulations (Klett, 2004; Klett and Le, this CD-ROM).

Another difference between the results presented in the *1995 National Assessment of United States Oil and Gas Resources* (Schenk and Viger, 1996) and the present assessment is the implementation in this report of the petroleum system model, as advocated by Magoon and Dow (1994). As currently used by geologists doing oil and gas assessments in the USGS, a total petroleum system includes all genetically related petroleum generated by a pod or by closely related pods of mature source rock. The system includes both shows and accumulations (discovered and undiscovered) and exists within a limited mappable geologic space. This space encompasses the essential mappable geologic elements (source, reservoir, seal, and overburden rocks) that control the fundamental processes of generation, expulsion, migration, entrapment, and preservation of petroleum (Klett, 2004; also see Klett and Le, this CD-ROM). Fundamentally, a total petroleum system consists of all areas to which hydrocarbons from related source rocks may have migrated after generation and expulsion and is commonly defined by the geographic extent of source and reservoir rocks. A composite total petroleum system is a mappable entity that is used when more than one source rock has charged the accumulations (Klett, 2004).

A further change in the assessment methodology involved the length of the forecast period. The 1995 assessment of undiscovered resources was based on a forecast time period through the use of an "ultimately recoverable" methodology, whereas in the 2003 assessment, a forecast span of 30 years was used for the estimate. A 30-year span indicates that the current assessment looks forward about one generation. Considering the many unforeseen developments in the petroleum industry over the past few decades, 30 years probably represents the maximum time period for a reliable forecast. Such a forecast span implies that certain resource categories will be excluded from the assessment, such as those requiring exploration in very deep water; no such constraints were placed on the 1995 assessment.

Therefore, although the geographic areas for both the 1995 and 2003 assessments are similar and the same stratigraphic interval was assessed, caution should be used when comparing these assessments. The 2003 assessment followed the new process involving (1) the consideration of petroleum systems instead of plays and (2) the incorporation of a shorter forecast period. The USGS was aware that these changes in the assessment process could affect the results and lead to differences with the previous assessment.

Geographic Setting of the Study Area

This report presents the results of a USGS assessment of the undiscovered oil and gas resources of selected Upper Cretaceous rocks in the Western Gulf Province, located in the northwest part of the Gulf of Mexico Basin (fig. 1). The geographical extent of the province was previously defined in earlier assessments of the Gulf Coast Region, most recently by Schenk and Viger (1996). As shown in figure 1, the entire province includes southeastern Texas and southern Louisiana as well as extending offshore about 10 mi from Texas and 3 mi from Louisiana. Although both southeastern Texas and southern Louisiana are within the Western Gulf Province, only that part of the province that lies in Texas was assessed in 2003. The Navarro and Taylor Group equivalents in southern Louisiana were excluded because they are deeply buried, and data were not available for assessment purposes.

As defined in this report, the study area extends from the Rio Grande River on the southwest, through south-central Texas, including the cities of San Antonio and Austin, to the eastern border of Texas (fig. 2). The study area encompasses approximately 45,000 mi^2 (29,000,000 acres). The study area stretches along the Rio Grande from Kinney County on the north through northern Zapata County on the south and from there to Newton County in the east. The northern boundary of the Western Gulf Province in Texas is drawn along county lines and separates this province from the Permian Basin, the Bend Arch–Fort Worth Basin, and the East Texas Basin Provinces.

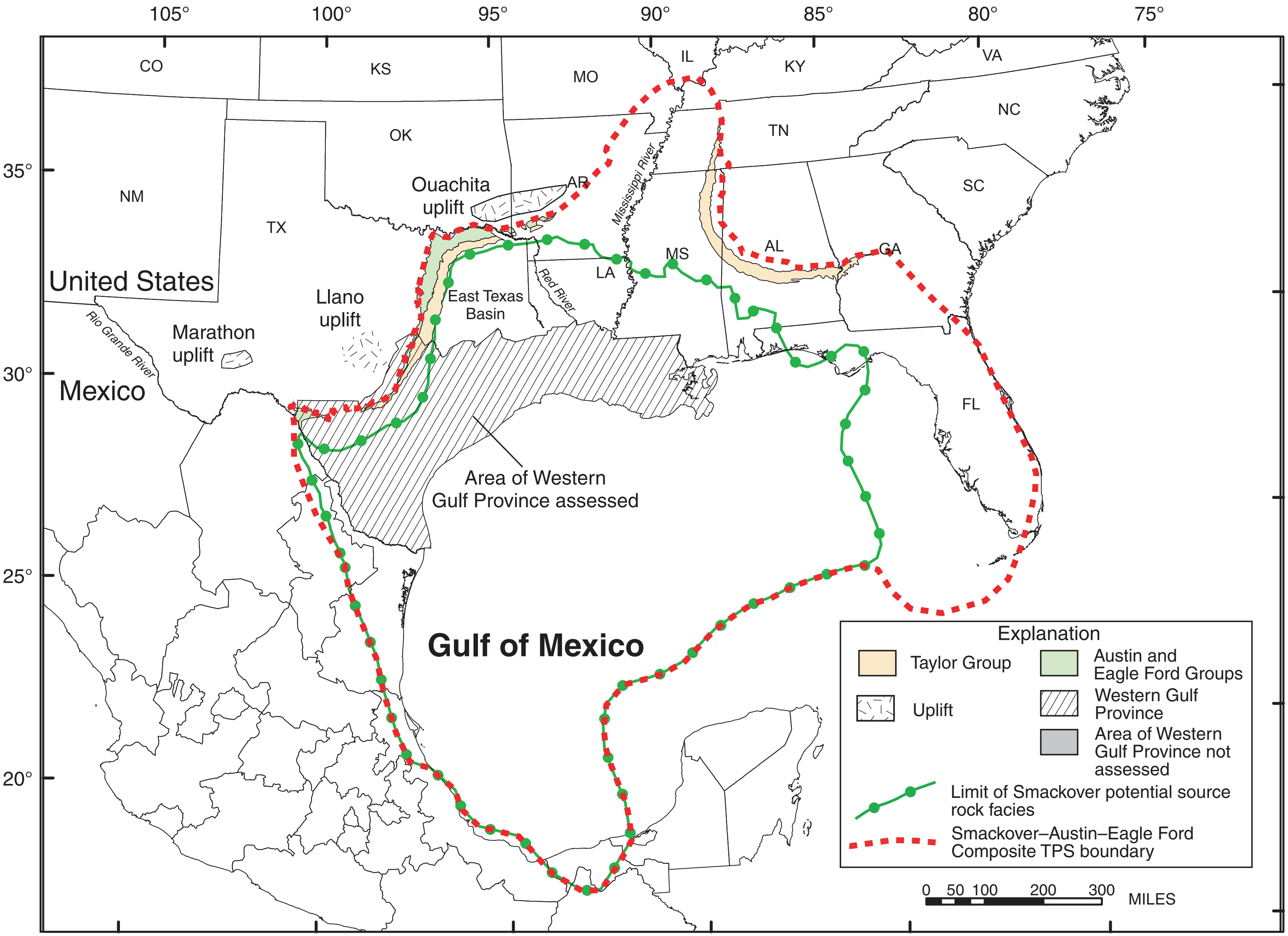

Figure 1. Map of the Gulf of Mexico region. The Western Gulf Province and the boundary of the Smackover–Austin–Eagle Ford Composite Total Petroleum System are shown. The extent of carbonate facies of the Smack
from Salvador (1987).

Overview of the Petroleum Resources in the Study Area

The Texas Bureau of Economic Geology previously defined hydrocarbon plays in the Olmos Formation in the Maverick Basin part of our study area (fig. 2) (Tyler and Ambrose, 1986). Bureau personnel did not calculate volumes of undiscovered resources, but their analysis was helpful in defining assessment units for our work. In the Maverick Basin, Tyler and Ambrose (1986) recognized five oil and gas plays: (1) volcanic mounds–related traps, (2) updip structural and stratigraphic traps, (3) deltaic and shore-zone sandstones and structural traps, (4) downdip deltaic and shelf tight-gas areas, and (5) shelf-edge traps. For the current study, we divided the province into assessment units, on the basis of additional drilling and resource development since the mid-1980s, and we extended the assessed area farther to the north and east of the Maverick Basin to include all potential reservoir rocks in the Navarro and Taylor Groups.

One aspect of our study was to look at the characteristics of known and potential oil or gas accumulations to determine whether they are discrete (conventional) or continuous (unconventional) as classified by Schmoker (1996), a distinction that is based on geologic parameters (rather than on government regulations relating to reservoir classification). It is important to distinguish between the two types because different assessment methodologies are used for each to estimate undiscovered resources. There are several distinguishing features of the end-member accumulation types, although there is probably a continuum between the types that can make classification difficult in some cases (Klett, 2004). Two lists of such distinguishing features, given in table 1, were drawn mainly from Spencer (1989), Schmoker (1996), Law (2002), and Bartberger and others (2003).

Oil and gas accumulations throughout the Western Gulf Province were evaluated by us with respect to the characteristics listed in table 1. Some existing accumulations had characteristics that clearly classified them as discrete, but others were more ambiguous. However, considering all of the factors, we decided that the discovered accumulations displayed characteristics that most closely fit the model for the discrete (conventional) category, and the assessment units were all assessed as such.

The geochemistry of oil samples collected from Cretaceous units in the Western Gulf Province indicates that part of the area has its hydrocarbon source in the Smackover Formation, but other parts have sources in the Austin and Eagle Ford Groups, or mixed Smackover and Austin–Eagle Ford sources (fig. 3) (Hood and others, 2002; M.D. Lewan, written commun., 2003). Because of these complexities, we decided to define a single composite total petroleum system for the province (fig. 1), more details of which are described in the section titled Smackover–Austin–Eagle Ford Composite Total Petroleum System.

Table 1. Comparison of characteristics of discrete and continuous oil and gas accumulations.

[Distinguishing features from Spencer (1989), Schmoker (1996), Law (2002), and Bartberger and others (2003). mD, millidarcy]

Discrete (conventional) accumulations	Continuous (unconventional) accumulations
• Well-defined stratigraphic and (or) structural traps	• Lack traditional seals or traps
• Hydrocarbon migration into traps from potentially distant source rocks	• Source rocks near reservoirs; migration distances commonly short
• Initial high production rates that decline as the wells mature	• Large in-place resources, but low well recoveries and production rates
• Normally pressured reservoirs	• Abnormal pressures (either underpressured or overpressured); thick sequences of reservoirs are gas-saturated
• Distinct hydrocarbon-water contacts	• Lack of hydrocarbon-water contacts
• Variable water production; water production can be high and commonly increases as wells mature	• Low or absent water production; accumulations occur downdip from water-saturated rocks and conventional fields
• Field boundaries delimited by water-saturated rocks	• Large geographic extent, commonly in the deeper central parts of basins
• Good reservoir porosity	• Low reservoir porosity; commonly less than 13 percent
• Good reservoir permeability	• Low reservoir permeabilities (<0.1 mD) reduce the ability of gas to migrate by buoyancy; natural or induced fractures are important for production
• Accumulations can occur in immature rocks because of migration	• Tops of accumulations are commonly within a narrow vitrinite reflectance (R_o) range of 0.75 to 0.9 percent

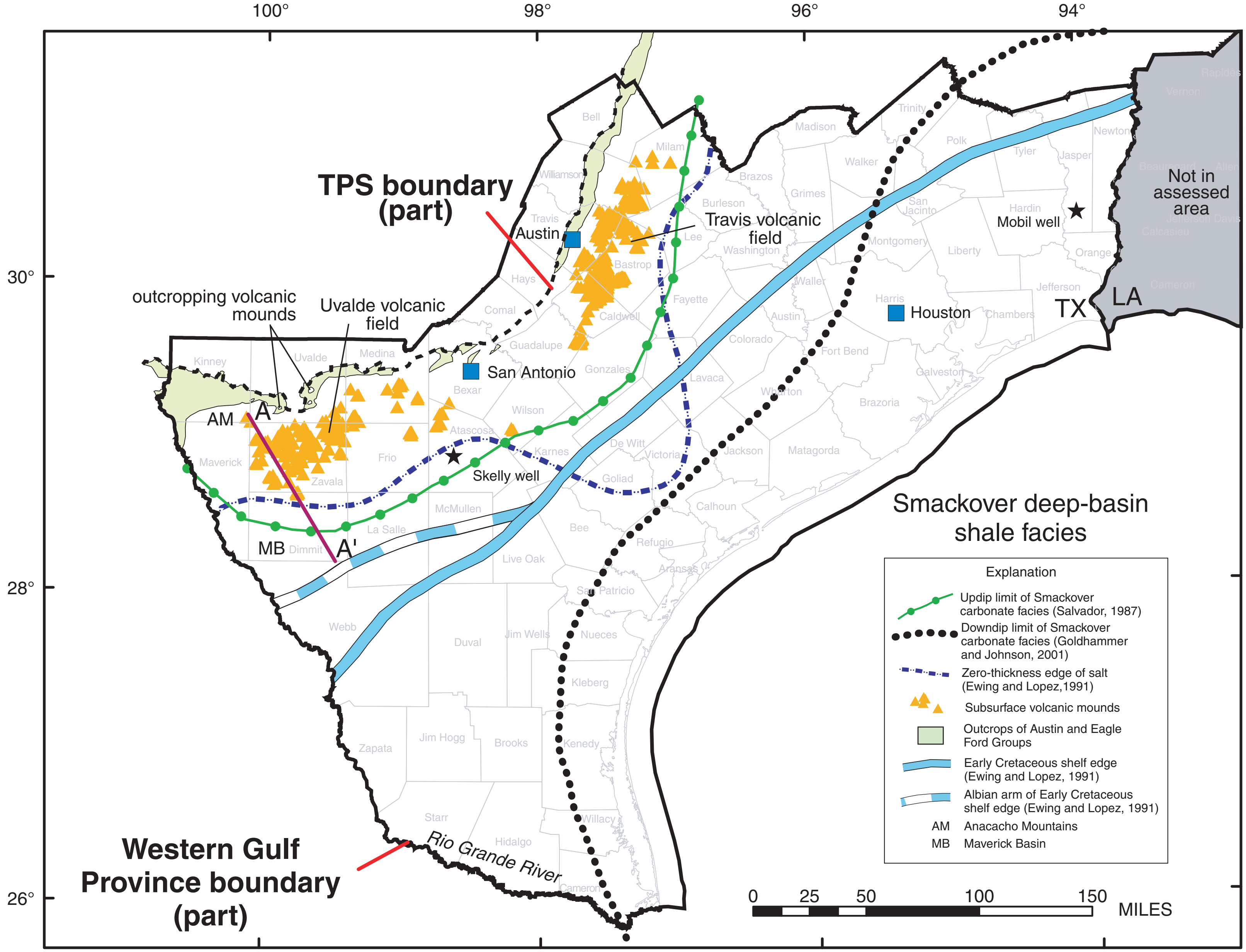

Figure 2. Map of the western part of the Western Gulf Province, showing the total petroleum system (TPS) boundary, outcrops of the Austin and Eagle Ford Groups, subsurface locations of volcanic mounds, zero-thickness edge of Jurassic salt, updip and downdip limits of Smackover carbonates, location of cross section A–A′ (see fig. 8), location of the Early Cretaceous shelf edge, and location of two wells for which burial history or timing of oil- and gas-generation charts were plotted. Locations of volcanic mounds are from IHS Energy Group (2003b).

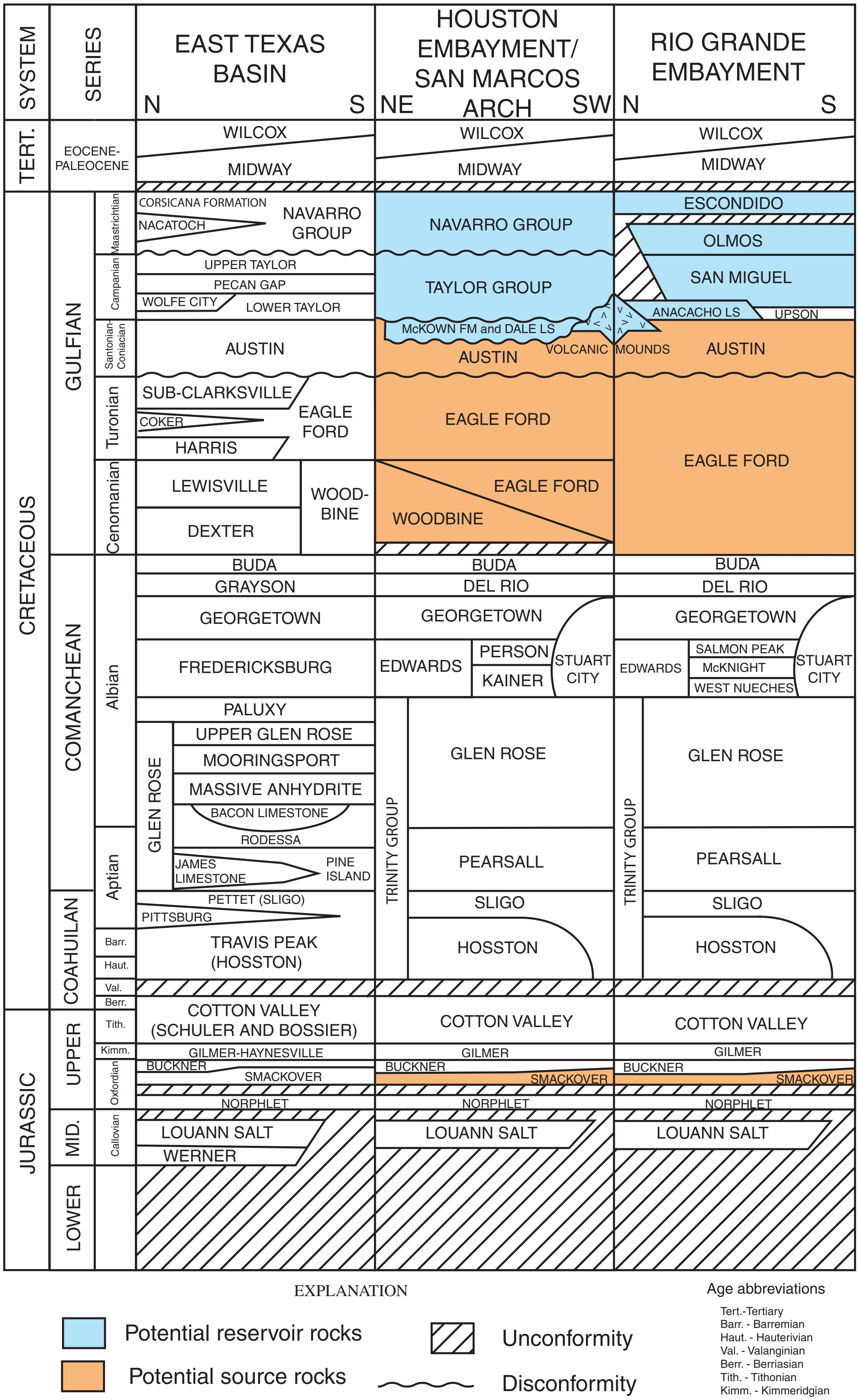

Figure 3. Columnar sections of Jurassic and Cretaceous stratigraphic units in southern and eastern Texas (modified from Kosters and others, 1989).

The Smackover–Austin–Eagle Ford Composite Total Petroleum System was divided into five assessment units (AUs): (1) Travis Volcanic Mounds Oil (AU 50470201), (2) Uvalde Volcanic Mounds Gas and Oil (AU 50470202), (3) Navarro-Taylor Updip Oil and Gas (AU 50470203), (4) Navarro-Taylor Downdip Gas and Oil (AU 50470204), and (5) Navarro-Taylor Slope-Basin Gas (AU 50470205). These assessment units are described in more detail in the section titled Assessment of Oil and Gas Resources. Future assessments of older or younger geologic units within this total petroleum system will define additional assessment units.

The mean volumes of estimated undiscovered resources in 2003 are 33.22 million barrels of oil (MMBO), 1,682.80 billion cubic feet of natural gas (BCFG), and 34.26 million barrels of natural gas liquids (MMBNGL) (table 2). Total cumulative production to date from the assessed formations in over 11,000 leases is about 443 MMBO and 2,000 BCFG (table 3).

Data Sources

Primary data sources for our assessment are commercial databases from IHS Energy Group (2003a, 2003b), dba PI/Dwights PLUS on CD. Well-production data are current as of February 2003, and well-completion data are current as of May 2003. Production data are available for more than 11,000 leases for the units assessed in the Western Gulf Province, and data for nearly 21,000 wells have been reported, such as formation tops, drill-stem tests, and initial production tests.

Another primary source for gas and oil field data is NRG Associates (2001), which provided information on the dates of discovery and sizes of gas and oil fields, trends of increasing or decreasing field volumes, gas-oil ratios, and API oil-gravity values (see chapter by Klett and Le, this CD-ROM). Other important sources of information included published literature on the structure, stratigraphy, and oil and gas geology of the region as well as discussions with industry and government personnel.

Structural Setting

The Gulf of Mexico has had a complex structural history that was comprehensively reviewed in a volume edited by Salvador (1991b). A brief summary of the structural history of

Table 2. Assessment Results Summary, Smackover–Austin–Eagle Ford Composite Total Petroleum System (504702).

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MAS, minimum accumulation size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one accumulation equal to or greater than the MAS. Accum., accumulation. Results shown are fully risked estimates. For gas accumulations, all liquids are included as natural gas liquids (NGL). F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable]

Code and Accumulation Type	MAS	Prob. (0-1)	Total undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
50470201	Travis Volcanic Mounds Oil Assessment Unit													
Oil	0.5	1.00	1.25	2.73	4.81	2.85	0.28	0.66	1.30	0.71	0.01	0.03	0.07	0.04
Gas	3.0						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total		1.00	1.25	2.73	4.81	2.85	0.28	0.66	1.30	0.71	0.01	0.03	0.07	0.04
50470202	Uvalde Volcanic Mounds Gas and Oil Assessment Unit													
Oil	0.5	1.00	1.27	2.41	3.97	2.48	1.29	2.83	5.20	2.97	0.06	0.14	0.28	0.15
Gas	3.0						14.33	35.40	61.71	36.38	0.20	0.52	1.00	0.55
Total		1.00	1.27	2.41	3.97	2.48	15.62	38.23	66.91	39.35	0.25	0.65	1.28	0.69
50470203	Navarro-Taylor Updip Oil and Gas Assessment Unit													
Oil	0.5	1.00	6.78	19.41	40.58	21.02	9.43	28.37	64.58	31.58	0.26	0.83	2.02	0.95
Gas	3.0						60.96	167.86	342.17	180.56	1.01	2.93	6.57	3.25
Total		1.00	6.78	19.41	40.58	21.02	70.38	196.23	406.75	212.14	1.27	3.76	8.60	4.20
50470204	Navarro-Taylor Downdip Gas and Oil Assessment Unit													
Oil	0.5	1.00	1.91	5.95	15.06	6.88	17.44	58.22	156.48	68.72	0.48	1.70	4.90	2.06
Gas	3.0						158.43	425.92	749.36	436.91	2.95	8.26	16.30	8.76
Total		1.00	1.91	5.95	15.06	6.88	175.88	484.14	905.84	505.63	3.44	9.96	21.20	10.82
50470205	Navarro-Taylor Slope-Basin Gas Assessment Unit													
Oil	0.5	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	3.0						239.07	868.58	1785.68	924.96	4.48	16.84	38.16	18.52
Total		1.00	0.00	0.00	0.00	0.00	239.07	868.58	1,785.68	924.96	4.48	16.84	38.16	18.52
504702	**Total: Conventional undiscovered resources in the Smackover-Austin-Eagle Ford Composite Total Petroleum System**													
Oil	0.5	1.00	11.21	30.51	64.41	33.22	28.45	90.09	227.55	103.99	0.82	2.69	7.27	3.20
Gas	3.0						472.79	1497.75	2938.92	1578.81	8.64	28.55	62.04	31.07
Total		1.00	11.21	30.51	64.41	33.22	501.24	1,587.84	3,166.47	1,682.80	9.45	31.25	69.31	34.26

Table 3. Total oil and gas production, Smackover–Austin–Eagle Ford Composite Total Petroleum System.

[Production data are from the formations that compose the five assessment units (IHS Energy Group, 2003a). Data are current through February 2003]

Producing unit	Produced oil (MMBO)[1]	Produced gas (BCFG)[2]	Approximate no. of leases[3]
Escondido Formation	4	75	450
Olmos Formation	110	1,227	3,700
San Miguel Formation	142	414	1,050
Anacacho and Dale Limestones	11	7	770
Undivided Navarro Group	144	186	4,600
Undivided Taylor Group	29	133	800
Austin Chalk associated with volcanic mounds	2.5	<1	50
Totals	442.5	2,042	11,420

[1]Million barrels of oil.

[2]Billion cubic feet of gas.

[3]Production from a single well may be divided into multiple leases if the well produces from more than one reservoir or has changed operators.

the region is presented here, drawn largely from papers by Salvador (1987, 1991a), Ewing (1991), and others that are cited.

In the Late Proterozoic, between about 800 and 650 Ma, the supercontinent Rodinia began to break up, in part in the area of the present-day Gulf Coast (Salvador, 1991a; Adams, 1993; Dehler, 1998). Several failed rifts, or aulacogens, formed during this 150-m.y. interval. They have been variously named the Texas lineament or Delaware rift along the present Rio Grande River, the Wichita lineament or Southern Oklahoma aulacogen along the present Red River, and the Mississippi lineament or Reelfoot rift along the present Mississippi River (fig. 1) (Albritton and Smith, 1957; Beall, 1973; Wood and Walper, 1974; Thomas, 1991; Salvador, 1991a; Adams, 1993).

In the Pennsylvanian and Permian Periods, the supercontinent Pangea coalesced. An outcome of this event was a collision of the African, South American, and North American plates that resulted in folding, northward and northwestward thrust faulting, and uplift of Paleozoic rocks along the sutured margin. The Ouachita uplift of Oklahoma and Arkansas and the Marathon uplift of west Texas formed as a result (fig. 1). A zone of compressed Paleozoic rocks—the Ouachita orogenic belt—connects these uplifts and curves along the Llano uplift (fig. 4) in the northwestern part of the study area (Ewing, 1991).

In the Late Triassic, South America and Africa separated from North America as Pangea began to break up. A series of rift basins formed along the new North American continental margin (Salvador, 1987; Jacques and Clegg, 2002). The present Gulf of Mexico occupies an area where the continental crust was stretched and thinned; it may have been the site of a continental rift basin. In the Middle Jurassic, seawater periodically flooded the area that would become the Gulf of Mexico Basin and deposited thick sequences of salt (Salvador, 1987).

The Gulf of Mexico opened in the Late Jurassic, and oceanic crust was extruded along a spreading center in the central gulf (Buffler and Sawyer, 1985; Salvador, 1987, 1991a; Pindell and Kennan, 2000, 2001; Jacques and Clegg, 2002). Rifting divided the area underlain by Middle Jurassic salt into two parts separated by oceanic crust, but Upper Jurassic carbonate and clastic units were deposited over the entire basin (Buffler and Sawyer, 1985). The Upper Jurassic Smackover Formation, consisting of shelf carbonates and deeper marine shales, was deposited at this time and later became an important hydrocarbon source rock.

The Cretaceous Period was a time of relative tectonic stability in the northern Gulf of Mexico Basin (Salvador, 1991a). For most of the Early Cretaceous, the Gulf Seaway was separated from the Western Interior Seaway, but in the late Early to Late Cretaceous, a connection was established through northwestern Texas to link the two bodies of water (Stephenson and Reeside, 1938; Roberts and Kirschbaum, 1995). In the Early Cretaceous, shelf-edge reefs developed along the break between the continental shelf and the Gulf of Mexico Basin. These reefs remained in a fairly stable geographic position through the Early Cretaceous, only diverging to any large extent in the western part of the study area (Goldhammer and Johnson, 2001) (figs. 2, 4). It should be noted that the divergent shelf-edge reefs shown in plan view in figures 2 and 4 were not contemporaneous. The southern branch of the reef is late Aptian in age, and the northern branch is late Albian in age (Goldhammer and Johnson, 2001). The late Aptian reef-building event was followed by a marine transgression that deposited lime mudstone and shale. The late Albian reef then formed landward and stratigraphically above the position of the earlier reef. The shelf edge also influenced the deposition of Upper Cretaceous units, including the Austin and Eagle Ford Groups and younger units, but reefs did not form in the Late Cretaceous (Salvador, 1991a; Sohl and others, 1991). In the Late Cretaceous, the Maverick Basin area (fig. 4) developed as a depocenter having a higher percentage of sandy sediment compared to the sedimentary material deposited elsewhere in the Western Gulf Province in the Late Cretaceous. Deltas formed on the shelf areas (Weise, 1980), and shelf-slope and basin turbidites formed along the shelf edge (Dennis, 1987; Salvador, 1991a; Bain, 2003).

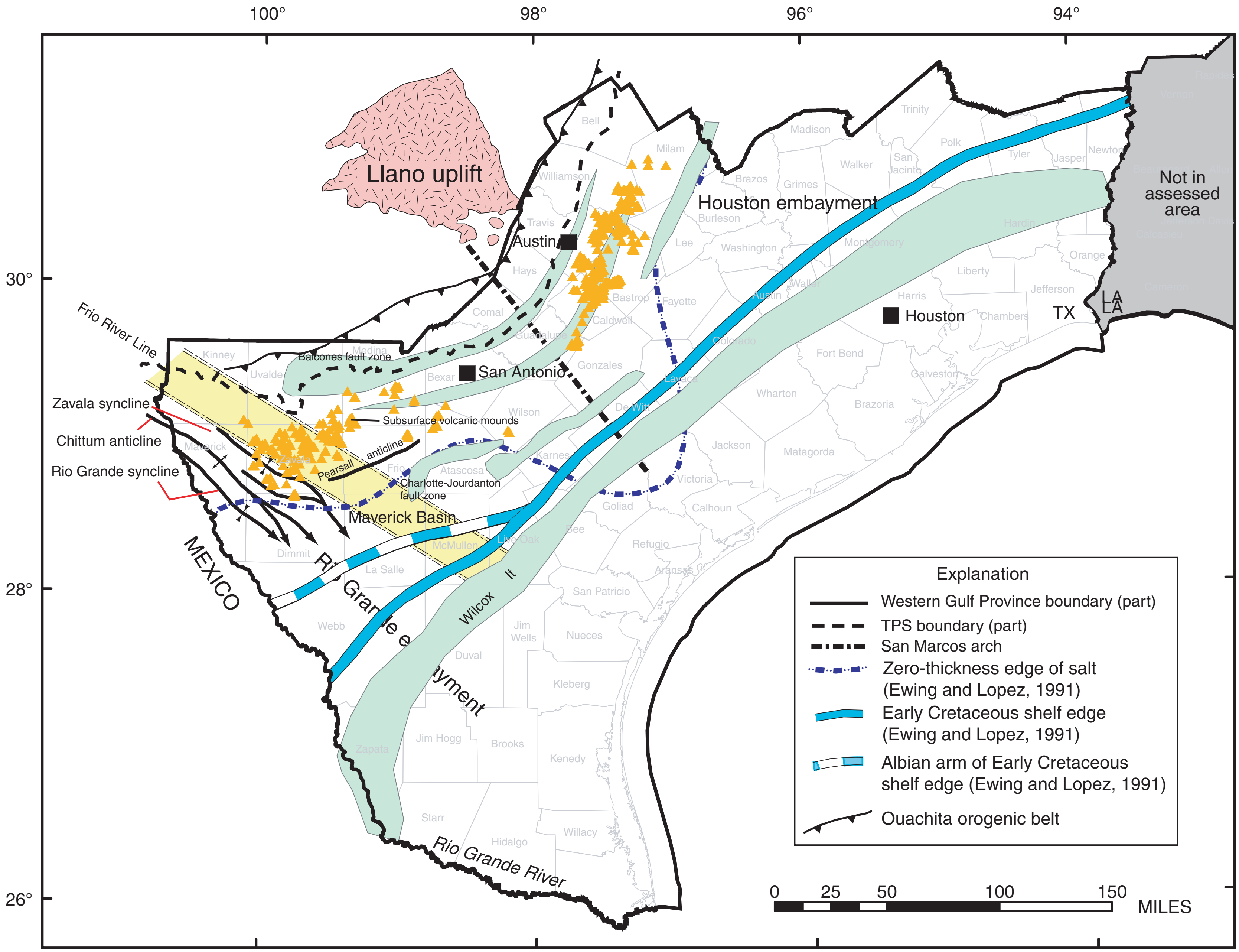

Figure 4. Map of the western part of the Western Gulf Province, showing main structural features. Fault trends and fold axes are modified from Fowler (1956); locations of subsurface volcanic mounds are from IHS Energy Group (2003b).

In the latest Cretaceous and early Tertiary, the Laramide orogeny affected the western side of the study area. Northeastward-directed compression resulted in a series of anticlines, synclines, and basins in northeastern Mexico and in the western Maverick Basin (fig. 4), as described by Ewing (1991). Main sediment sources were from the southwest and northwest at this time, as opposed to mainly northwestern sources earlier in the Cretaceous. Less important source areas probably were in the southern Appalachian region.

In the middle to late Tertiary and Quaternary, a thick sequence of clastic sediments accumulated in the Gulf of Mexico Basin (Galloway and others, 2000). Much sediment bypassed shelf areas, where there had previously been Cretaceous deltaic and shallow-marine shelf deposition, and was deposited farther out in the gulf. Rapid accumulation of Tertiary sediments created a series of growth-fault belts that parallel the Gulf Coast. According to Grabowski (1984), the main locus of sedimentation in the Texas Gulf Coast area shifted southeastward in the Miocene, resulting in relatively thin Pliocene and younger units in the study area. Only minor uplift and erosion of the area have occurred since the Pliocene.

Structural Features

There are several main structural features within, or adjacent to, the western part of the Western Gulf Province (Ewing, 1991). Just northwest of the province boundary is the elevated Llano uplift (fig. 4), an area of outcropping Proterozoic rocks that apparently acted as a buttress during compressional tectonics of the Ouachita orogeny in Pennsylvanian and Permian time. The Ouachita orogenic belt curves along the south and east sides of the Llano uplift and consists of faulted and folded Paleozoic rocks. The San Marcos arch is a subsurface extension of the Llano uplift that extends southeastward toward the gulf (fig. 4). Several Jurassic and Cretaceous stratigraphic units thin or are absent over the arch, indicating periodic uplift during the Jurassic and Cretaceous. The uplifted area of the arch is broadly outlined by the zero edge of Middle Jurassic salt, as shown in figures 2 and 4.

Southwest of the San Marcos arch is the Rio Grande embayment (fig. 4), which extends into northeastern Mexico (Ewing, 1991) and is generally aligned with the northwest-trending Precambrian Texas lineament along the Rio Grande River. The Maverick Basin occupies a part of the Rio Grande embayment in the west-central part of the study area (fig. 4). The Maverick Basin began subsiding in the late Early Cretaceous and responded as a foreland basin to Laramide tectonism in the Late Cretaceous to early Tertiary.

The Houston embayment is on the northeast side of the San Marcos arch, in a structural setting similar to that of the Rio Grande embayment (fig. 4). It is a southern extension of the East Texas Basin (fig. 1) and is a structural low whose origin was probably influenced by the Precambrian Wichita lineament. In the Late Cretaceous, the Houston embayment subsided less than the Rio Grande embayment, and Upper Cretaceous rocks there contain more shale and carbonates and less sandstone in comparison with time-equivalent rocks in the Maverick Basin.

The Pearsall anticline, located southwest of San Antonio (fig. 4), is thought to be older than other folds in the Maverick Basin. Fowler (1956) noted that this fold, being subparallel to the fault zones in the region, was the only fold having this orientation in south-central Texas. Faults that formed contemporaneously with the Pearsall anticline affected deposition of rocks as old as the Austin Group (Fowler, 1956), and the relationships indicate that the fold could be as old as Jurassic (Ewing, 1987).

Most of the folds in the western part of the Maverick Basin are of Late Cretaceous to Tertiary age and are the result of Laramide compression (Ewing, 1991). The main folds in the western part of the basin are the Rio Grande and Zavala synclines, separated by the southeastward-plunging Chittum anticline (fig. 4). Only the western part of the study area was affected to any large degree by Laramide compression, and prominent folds are not present on the San Marcos arch or in the Houston embayment.

A structural feature having a northwest-southeast orientation in the western part of the Western Gulf Province was named the “Frio River Line” (fig. 4) by Ewing (1987) and was thought to be a boundary between two areas having different structural and stratigraphic histories. Several attributes of the area support such an interpretation of the Frio River Line: (1) the line marks the western end of the Balcones, Luling, and Charlotte-Jourdanton fault zones (fig. 4); (2) Laramide folds exist only southwest of the line; (3) igneous intrusions are mainly within or northeast of the line; and (4) there is a divergence of the Early Cretaceous reef trends at the line. Ewing (1987, 1991) proposed a Paleozoic to Mesozoic origin for the Frio River Line, thus implying that it was not related to the earlier Proterozoic development of the Texas lineament in the area, but instead resulted from structural adjustments related to coalescence of the plates to form Pangea or to its subsequent disruption.

Faults are common throughout the study area and are grouped in several major zones that parallel the Ouachita orogenic belt (fig. 4) (Weeks, 1945; Fowler, 1956; Matthews, 1986; Ewing, 1987, 1991). The Balcones fault zone is farthest to the northwest and marks the craton margin of the central United States. Faults in the Balcones fault zone are normal, have down-to-the-southeast displacements that can exceed 1,600 ft, and extend at least to and possibly into basement rocks of Paleozoic age. The fault zone is mapped from about Williamson County (north of Austin) southwest to Uvalde County (west of San Antonio).

The Luling fault zone is parallel to, and lies southeast of, the Balcones fault zone. The Luling faults are normal and have down-to-the-northwest displacements—opposite to the displacements of the Balcones faults—ranging from about 1,000 to 2,000 ft. Thus the combined Balcones-Luling faults bound a broad down-dropped graben. The Luling faults are also thought to extend at least to Paleozoic basement rocks, but the faults’ association with volcanic mounds of the Travis volcanic field east of Austin implies much deeper seated faulting (see discussion of the volcanic mounds in the section on reservoir rocks).

The Charlotte-Jourdanton fault zone is of more limited size, extending from southeast Frio County across Atascosa

County to southwestern Wilson County (fig. 4). This fault zone is composed of parallel sets of normal faults along which movements of opposite sense have occurred to form a graben; displacements are 500–700 ft. The Charlotte-Jourdanton fault zone is related in an en echelon fashion to the structurally similar Karnes fault zone and graben system that extends northeastward from Atascosa County through Gonzales County and just crosses into Lavaca County. Farther north, beyond the San Marcos arch, the Mexia-Talco fault zone extends from Bastrop County northward through Milam County and out of the study area (fig. 4).

The five fault zones (Balcones, Luling, Charlotte-Jourdanton, Karnes, Mexia-Talco) are thought to have first developed in the Late Cretaceous on the basis of abnormal thicknesses of stratigraphic units on the downthrown sides of fault blocks (Fowler, 1956). Thick Upper Jurassic rocks on the downthrown side of the Mexia-Talco fault zone may indicate even earlier movement (Ewing, 1991). Early Late Cretaceous movement on some faults may have also accompanied emplacement of volcanic mounds in the area east of Austin. However, major movement on all the faults is thought to have occurred in the Miocene during a period of regional uplift and extension (Weeks, 1945; Ewing, 1987, 1991).

A wide zone of growth faults extends southeast from the Early Cretaceous shelf edge to the Texas coast and into the Gulf of Mexico. The strike of the faults is subparallel to the shelf edge, and most of them lie outside the assessed area, but the Wilcox fault zone, which is the northwesternmost of these fault zones, lies partially within the study area (fig. 4). Growth faults are also present along the northern branch of the Cretaceous shelf edge in northern Webb County (Snedden and Jumper, 1990). The processes by which the growth faults developed is complex, as discussed by Ewing (1991), but all are related to the wedge of clastic sediments that prograded southeastward from the shelf edge into the Gulf of Mexico Basin between the Late Cretaceous and the present. The Wilcox and younger fault zones developed mainly in Paleocene and younger strata and do not involve rocks updip of the Early Cretaceous shelf edge. Wilcox faults are characterized as “deep listric” (Ewing, 1991), are thought to sole out in lower Tertiary or Upper Cretaceous rocks, and do not extend to Paleozoic basement rocks as do the previously described normal faults.

General Stratigraphy

The oldest rocks in the region of the Western Gulf Province are of Proterozoic age and crop out in the Llano uplift (fig. 4) (Schruben and others, 1998). The uplift is composed of a complex assemblage of metasedimentary rocks and granite, divided into about equal parts of granite, gneiss, and schist (Meuhlberger and others, 1967). Surrounding the uplift are outcrops of deformed Paleozoic rocks of Cambrian, Ordovician, and Pennsylvanian age (Schruben and others, 1998). Paleozoic rocks are presumed to underlie most or all of our study area, but little is known of them because of a lack of deep drilling.

Rocks above the Paleozoic basement wrap around the Llano uplift, generally striking parallel to the northwest boundary of the Western Gulf Province. The rocks dip variably southeastward toward the Texas coastline; older rocks crop out in the northwest, and younger rocks crop out in the southeast. In the western part of the study area, the post-Paleozoic section ranges in thickness from about 1,500 ft in updip areas to more than 26,000 ft downdip near the Early Cretaceous shelf edge. Basinward from the shelf edge, the stratigraphic section thickens in a short distance to more than 32,000 ft (Ewing, 1991). Triassic or Jurassic rocks are not exposed in the study area (Schruben and others, 1998), and no Triassic rocks were identified from well records in the study area (IHS Energy Group, 2003b). Jurassic rocks are present in the subsurface (IHS Energy Group, 2003b), but pinch out updip and are overlapped by the Lower Cretaceous Trinity Group (Travis Peak [and time-equivalent Hosston] through Glen Rose Formations) (fig. 3). A thick sequence of Lower Cretaceous rocks—some of which produce oil and gas (Schenk and Viger, 1996)—underlies the assessed formations, but these older rocks are not discussed here because their evaluation was outside the scope of the present assessment.

The formations included in the assessment units are of Late Cretaceous age and consist mainly of the Taylor and Navarro Groups—from oldest to youngest, the Anacacho Limestone and the San Miguel, Olmos, and Escondido Formations, as well as the undivided Navarro and Taylor Groups (fig. 3). In limited areas, the undivided Austin Group and the “Dale Limestone” of Thompson (1986), which is an Anacacho equivalent that is part of the Austin Group, were included in the assessment units. In these limited areas, the Austin and Dale are associated with Cretaceous volcanic mounds, which are described in the section on reservoir rocks. Regionally, the sequence of rocks from the top of the Navarro to the top of the Austin is as much as 5,500 ft thick, but typically ranges from 300 to 3,600 ft (IHS Energy Group, 2003b). Ranges of thicknesses of this sequence in specific areas are less than 500–5,500 ft in the Maverick Basin, 300–1,500 ft over the San Marcos arch, about 1,000–2,000 ft north of Houston, and 2,500–3,000 ft in a northwest-trending belt between Houston and Austin. Details of individual units are discussed later in the context of the total petroleum system.

Smackover–Austin–Eagle Ford Composite Total Petroleum System

Key elements of the Smackover–Austin–Eagle Ford Composite Total Petroleum System are the following:

- Source rocks of appropriate lithology and sufficient thermal maturity to generate hydrocarbons, primarily consisting of the shelf carbonates and deep-marine shales of the Smackover Formation, shelf carbonates of the Austin Group, and shelf carbonates and organic shales of the Eagle Ford Group, as well as several other secondary potential sources.

- Migration pathways, including upward migration through faults and fractures and updip migration along disconformities and through sandstone beds.
- Reservoir rocks, consisting primarily of sandstones of the Navarro and Taylor Groups and carbonates of the Anacacho and Dale Limestones and the Austin Group.
- Traps and seals, including stratigraphic pinchouts, folds, structural drapes over volcanic mounds, and combinations of these features, along with enclosing shale or mudstone beds and tight sealing of some beds by diagenetic cement.

Determination of Boundary

The extent of the Smackover–Austin–Eagle Ford Composite Total Petroleum System is shown in figure 1. Several criteria, mainly the distribution of potential source and reservoir rocks, were used to determine the boundary. Onshore, the total petroleum system boundary from the Rio Grande River to western Georgia is drawn at the updip pinchout of the Austin and Eagle Ford Groups, and equivalent units, as identified in outcrops (fig. 1; Schruben and others, 1998). The boundary was projected around the Mississippi embayment on the basis of limited outcrops of younger formations. In southeastern Georgia and Florida, the total petroleum system boundary encompasses wells in which tops are reported for the Austin, Eagle Ford, and equivalent units (IHS Energy Group, 2003b).

In the Gulf of Mexico, most of the southern boundary of the total petroleum system is established by Oxfordian paleogeography interpreted by Salvador (1987) (where the dashed red line coincides with the green line in fig. 1). The short boundary line extending from the southern Florida coast to the west is speculative, but strata of the Smackover, Austin, and Eagle Ford are not thought to extend southeast of this line segment on the basis of scant well and seismic data (Salvador, 1987). Along the Mexican coast, the total petroleum system boundary is approximately drawn to reflect the distribution of potential source rocks equivalent to both the Smackover Formation and the Austin and Eagle Ford Groups.

Hydrocarbon Source Rocks

The interpreted distribution of potential source rocks in the Upper Jurassic Smackover Formation is shown by the green line in figure 1. Although little is known about the Smackover in the deep central part of the Gulf of Mexico (Salvador, 1987), the formation is thought to extend across the center of the Gulf of Mexico Basin on the basis of seismic interpretations (Buffler and Sawyer, 1985, their fig. 8). Note that in the onshore parts of the United States and in the Gulf of Mexico Basin offshore of western Florida, the younger Austin and Eagle Ford extend beyond the limit of the Smackover.

A study by Hood and others (2002) distinguished several hydrocarbon systems in the Gulf Coast Region on the basis of geochemical compositions of sampled oil, including systems involving important source rock sequences in Upper Jurassic, Upper Cretaceous, and lower Tertiary strata. Three of these systems are in our study area: (1) the undifferentiated Cretaceous hydrocarbon system, (2) the Turonian (Upper Cretaceous) hydrocarbon system, and (3) the lower Tertiary terrestrial hydrocarbon system. In another study by M.D. Lewan (written commun., 2003), oils with geochemical characteristics indicating a Jurassic Smackover (Oxfordian) source were identified in Upper Cretaceous reservoirs in the western part of the Western Gulf Province, and oils with mixed Jurassic and Cretaceous sources were identified in the central Maverick Basin. It should be noted that the oil samples studied by both Hood and others (2002) and M.D. Lewan (written commun., 2003) were obtained mainly from the Austin Group and Tertiary reservoir rocks, not from reservoirs studied for this assessment, so conclusions about the source of oil in the assessed units in this report are indirect.

For our study, it is thought that there are three main sources of oil and gas in the assessed formations: Upper Jurassic Smackover Formation and Upper Cretaceous Austin and Eagle Ford Groups. Oils thought to have a Smackover source are mainly found in the far western part of the study area, and oils thought to have an Eagle Ford or Austin source are located in the north-central part; oils having a mixed Smackover–Austin–Eagle Ford origin are produced in the central part of the Maverick Basin (M.D. Lewan, written commun., 2003).

Smackover Formation

No oil or gas production has been reported from the Upper Jurassic (Oxfordian) Smackover Formation in the Texas part of the Western Gulf Province (IHS Energy Group, 2003a), and the unit has not been studied or described in that area. However, published reports on the Smackover elsewhere in the Gulf Coast Region (for example, Oehler, 1984; Sassen and others, 1987; Claypool and Mancini, 1989; Mancini and others, 1990, 1993; Lewan, 2002) indicate that oil and gas were generated from algal-rich calcareous mudstones from the lower and middle Smackover. The lower part is composed of intertidal to subtidal laminated carbonate mudstone and peloidal and oncolitic wackestone and packstone deposited under a transgressive regime; the middle part consists of a condensed section of subtidal laminated carbonaceous mudstone interbedded with peloidal and skeletal wackestone and packstone (Mancini and others, 1990). Total organic carbon (TOC) in these strata has been variously reported as (1) ranging from 0.1 to 1.0 weight percent and averaging 0.5 weight percent (Oehler, 1984); (2) averaging 0.51 weight percent (Sassen and others, 1987); and (3) averaging 0.81 weight percent

(Mancini and others, 1993). In addition, TOC in samples analyzed by Claypool and Mancini (1989) was reported to range from 0.04 to 1.74 weight percent and average 0.48 weight percent; however, these samples were from the upper, less organic-rich part of the Smackover as well as from the lower and middle parts. The API gravity of oil and condensate in 38 Smackover samples analyzed by Claypool and Mancini (1989) ranged from 17.1° to 56° (average 34.3°); their sulfur contents ranged from 0.1 to 5.2 percent (average 0.97 percent). Oils thought to be derived from the Smackover are enriched in sulfur and display characteristic geochemical properties that distinguish them from other oils in the Gulf Coast Region (Mancini and others, 1993; Hood and others, 2002).

The paleogeographic reconstruction of Salvador (1987) implied that facies favorable for hydrocarbon generation in southwestern Alabama extend westward into the Western Gulf Province. Conditions favoring the accumulation and preservation of organic matter in the Smackover include deposition of the types of facies indicative of intertidal to subtidal environments characterized by low-energy, hypersaline, and anoxic conditions (Mancini and others, 1993). Parts of the Smackover that were deposited in higher energy environments closer to the paleoshoreline received a greater influx of terrestrial sediment and organic matter and have a poor hydrocarbon-generating potential (Sassen and others, 1987). Figure 1 shows the extent of potential source rock facies in the Smackover. Figure 2 shows the updip limit of the carbonate facies in the Smackover that is thought to comprise the favorable hydrocarbon-generating strata in the lower and middle parts of the unit. The downdip extent of Smackover shelf carbonates in the study area is also shown in figure 2. Basinward (seaward) of this line, the formation consists of deeper water argillaceous limestones and shales, the hydrocarbon-generating potential of which is not known; however, such strata in the central parts of the Gulf of Mexico Basin cannot be ruled out as a contributing source for updip accumulations.

In the study area there are only six wells with tops recorded for the Smackover Formation (IHS Energy Group, 2003b). In those wells, the formation ranges from 460 to 570 ft thick and is currently at depths generally between 12,000 and 16,000 ft. In updip areas, where the carbonate facies of the Smackover is absent, the noncarbonate facies is truncated in the subsurface at about the position of the Luling fault zone (figs. 2, 4) (Ewing, 1991).

Eagle Ford Group

The Eagle Ford Group is of Late Cretaceous (Cenomanian-Turonian) age (fig. 3) and consists of (1) organic-rich, pyritic, and fossiliferous marine shales and bituminous claystone in the lower part that were deposited during a transgressive episode; (2) a condensed section of pyritic, phosphatic, and bentonitic shale beds in the middle part; and (3) shales, limestones, and carbonaceous siltstones in the upper part that were laid down during a regressive highstand (Dawson, 2000). The lower shales and condensed middle section were deposited in low-energy, poorly oxygenated environments below wave base, and the upper part was deposited in high-energy, well-oxygenated, nearshore environments (Liro and others, 1994; Dawson, 2000).

The organic-rich lower shales and condensed section have the highest hydrocarbon-generating potential of any part of the Eagle Ford Group (Dawson, 2000). Outcrop samples of this interval near Austin were reported to have average TOC contents of 5.15 weight percent, and those at a locality north of Austin (outside the study area) averaged between 2.43 and 4.87 weight percent. Sulfur content at both localities averaged about 1.3 percent (Liro and others, 1994). Differences in organic-matter type were detected when plotting pristane/nC_{17} against phytane/nC_{18} (Liro and others, 1994). Samples from north of Austin were interpreted as having well-preserved, oil-prone marine organic matter, whereas those from nearer Austin had a mixed marine and terrestrial, gas- and oil-prone signature; the differences possibly reflect deposition in a subsiding basin versus deposition over an arch, although most samples were consistent with Type II kerogen (Liro and others, 1994).

The Eagle Ford crops out irregularly along the northwest side of the study area, where its basal contact also marks the northwest boundary of the total petroleum system (figs. 1, 2). It is present throughout the subsurface of the region, at least as far downdip as the Early Cretaceous shelf edge. The group is of variable thickness, depending on its position relative to the San Marcos arch (fig. 4). North of the study area, the exposed thickness of the unit exceeds 200 ft, but it thins to 45 ft in outcrops farther south near Austin on the north flank of the San Marcos arch (Dawson, 2000). In the subsurface, the Eagle Ford is thickest (500–600 ft) in Maverick, Zavala, and Dimmit Counties in the Maverick Basin and in Brazos County in the northeast. Reported thicknesses are commonly less than 10 ft over the crest of the San Marcos arch (IHS Energy Group, 2003b).

Austin Group

The Upper Cretaceous (Coniacian-Santonian) Austin Group disconformably overlies the Eagle Ford Group. The Austin has been divided into a number of lithologically distinct formations, which consist of a sequence of recrystallized, fossiliferous, interbedded chalks, marls, and black shales (Hinds and Berg, 1990; Berg and Gangi, 1999). Updip parts were deposited in shallow-marine shelf and normal-marine environments that were well oxygenated and thus are relatively lean in organic matter. Downdip parts are darker, less fossiliferous, and less bioturbated than updip parts and contain higher amounts of organic matter (Grabowski, 1984; Dawson and others, 1995); this facies was deposited below wave base in outer-shelf and upper-slope environments in nearly anoxic conditions (Grabowski, 1984; Dawson and others, 1995).

The Austin Group is considered an important hydrocarbon source rock in the Western Gulf Province (Snyder and Craft, 1977; Grabowski, 1981, 1984; Hunt and McNichol, 1984; Hinds and Berg, 1990; Dawson and others, 1995; Berg and Gangi, 1999). The Austin's TOC is related to burial depth because of pressure solution and removal of some of the limestone as burial depth increases. Those Austin rocks that were buried the deepest have TOC contents as high as 21.8 weight percent (Dawson and others, 1995), but TOC contents greater than 1.5 weight percent are present in all parts of the Austin, regardless of lithology or depth (Grabowski, 1984). Kerogen is considered to be Type I, Type II, or intermediate between Types II and III and is thought to originate from marine plankton and algae (Grabowski, 1981, 1984; Hunt and McNichol, 1984; Dawson and others, 1995). Although Type III organic matter generally indicates a continental source, oxidized marine organic matter can also have a Type III signature (Dawson and others, 1995). The API gravity of most produced oil from the Austin ranges between 30° and 39° (Grabowski, 1984).

The Austin crops out along the northwest side of the study area (figs. 1, 2) and is present in the subsurface downdip at least to the Early Cretaceous shelf edge; equivalent organic shales are in downdip areas beyond the shelf edge. Reported thicknesses are as much as 1,550 ft; the average thickness is 333 ft as recorded in nearly 2,500 wells (IHS Energy Group, 2003b). The unit is thickest in the Maverick Basin, thins over the San Marcos arch, is relatively thick just northeast of the arch, and again thins in the area north of Houston (IHS Energy Group, 2003b). No subsurface thickness data are available for the area southeast of the shelf edge.

Figure 5 is an isopach map of the combined Austin and Eagle Ford Groups in the study area. Combined thicknesses are as much as 1,750 ft and average 383 ft in the more than 2,300 wells listed by IHS Energy Group (2003b). The combined units are thickest in the Maverick Basin, on the northeast flank of the San Marcos arch, and in the central Houston embayment. They are thinnest over the crest of the San Marcos arch and in an arcuate area from eastern Milam to Lavaca Counties (fig. 5).

Other Potential Source Rocks

Other potential hydrocarbon source rocks in the Gulf Coast Region include (1) the Jurassic Bossier Shale and shales above the Bossier within the Jurassic and Cretaceous Cotton Valley Group (fig. 3) (Hood and others, 2002; Bartberger and others, 2002, 2003); (2) organic-rich shales within the lower part of the Cretaceous Taylor Group (fig. 3) (Simmons, 1967; Ewing and Caran, 1982); (3) organic-rich shales deposited downdip from Lower Cretaceous shelf formations (Moredock and Van Siclen, 1964; Hood and others, 2002); and (4) Eocene organic-rich shales (Hood and others, 2002). The Eocene rocks are gas prone owing to the presence of terrestrial organic matter (Hood and others, 2002); however, the potential for upward migration of gas from this source along listric faults bordering the Early Cretaceous shelf edge and accumulation of the gas in Upper Cretaceous reservoirs has not been adequately studied.

The Upper Cretaceous Olmos Formation (fig. 3) includes coal at outcrops in Maverick County that extends southeastward into the subsurface of the Maverick Basin (Barker and others, 2003). The coal pinches out at the outcrop just northeast of the Chittum anticline (fig. 4) and extends a short distance in the subsurface in Zavala and Dimmit Counties, but is absent in other parts of the study area. The maximum depth of the coal is about 2,500 ft, and the coal has generated a mixture of biogenic and thermogenic gas (Barker and others, 2003). The limited geographic extent of Olmos coal removes it from consideration as an important source rock in the study area, and its potential as a coal-bed methane resource was not evaluated.

Source Rock Thermal Maturity

The Smackover Formation became mature and is inferred to have generated and expelled hydrocarbons as it reached burial depths greater than 9,000 ft in southwestern Alabama (Claypool and Mancini, 1989). Within the Western Gulf Province study area, the formation is generally between about 12,000 and 16,000 ft deep in the few wells in which a top is reported. In the Skelly Oil Company Bertha M. Winkler No. 1 well (fig. 2), for example, it is at a depth of greater than 15,000 ft—more than 8,300 ft below the top of the Austin. Lewan (2002) presented data on the timing of oil and gas generation for the Smackover in the central Gulf Coast area of southern Louisiana and adjacent areas; several of his data points lie within or adjacent to the eastern part of our study area, in positions both updip and downdip of the Cretaceous shelf edge. He (Lewan, 2002) concluded that (1) oil generation began between 120 and 59 Ma and ended between 104 and 44 Ma, depending on location, and (2) gas generation began between 55 and 31 Ma and ended between 25 Ma and the present. Thus, wherever favorable laminated carbonate mudstones are present within the Smackover, the formation is thought to be a potential source rock for both oil and gas, as shown by the boundaries in figures 1 and 2.

The drilling depth to, or thickness of overburden rocks on, the Austin Group is shown in figure 6. The depth range is 0 to about 16,500 ft, and the mean depth is about 5,700 ft over the entire area (IHS Energy Group, 2003b). The Austin dips southward and southeastward from outcrops in the East Texas Basin and Llano uplift areas and is overlain by progressively younger Cretaceous and Tertiary units in the downdip direction. Well data are not generally available basinward (seaward) of the position of the Early Cretaceous shelf edge. A burial-history chart for the Skelly Oil Company Bertha M. Winkler No. 1 well, central Atascosa County (figs. 2, 5), is shown in figure 7. This reconstruction shows that maximum burial at that location occurred in the Eocene, at about 40 Ma, followed by relatively minor uplift and erosion. The location of the Mobil Oil Corporation Atlantic Richfield sec. 77 No. 1 well is also plotted in figures 2 and 5. Lewan (2002) interpreted the timing of oil and gas generation in both the Smackover and

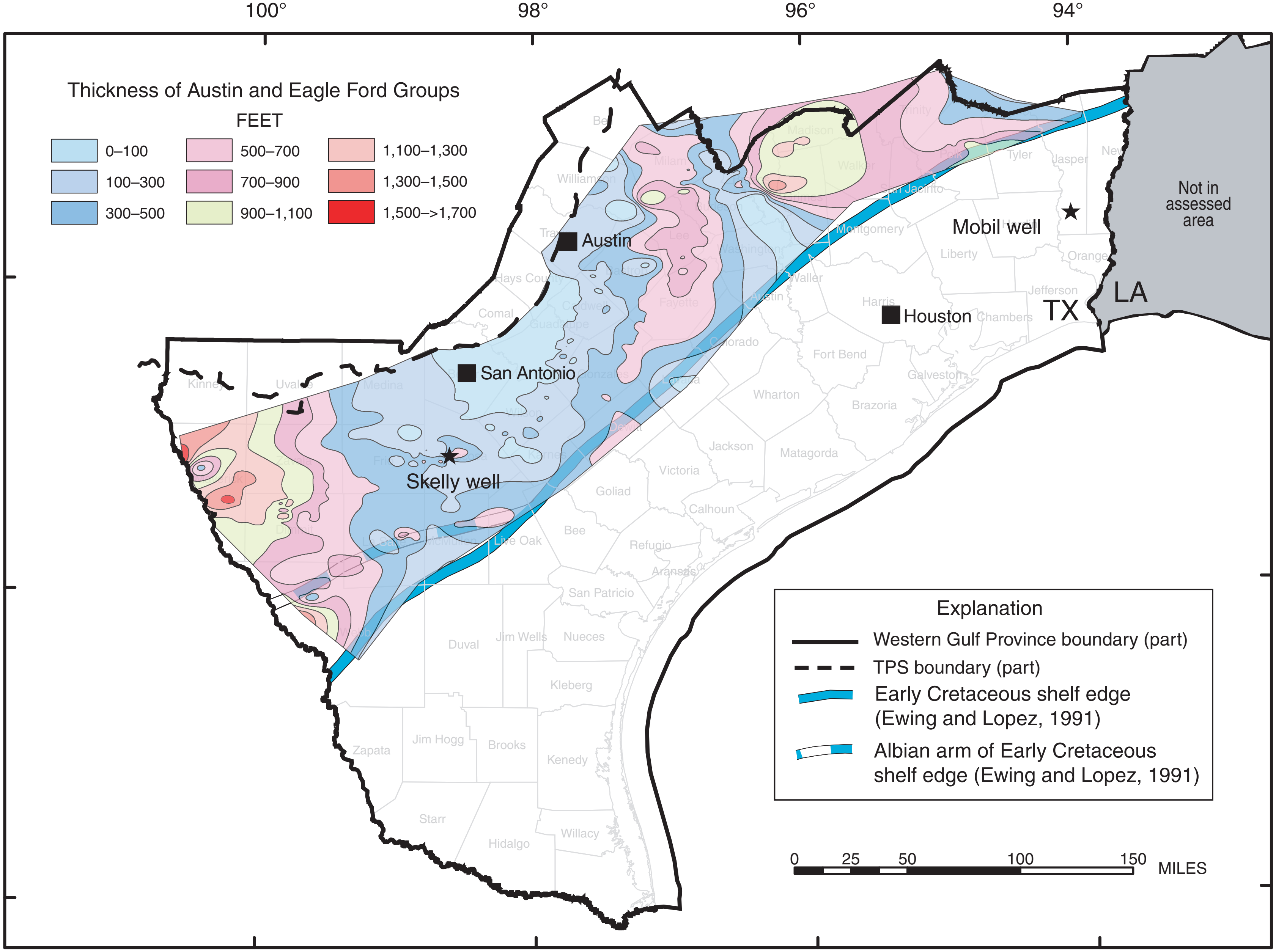

Figure 5. Isopach map of the interval from the top of the Austin Group to the base of the Eagle Ford Group in the western part of the Western Gulf Province. Data are from IHS Energy Group (2003b).

Turonian rocks in this well, and we used his interpretations in our analysis of assessment units in this report.

It has been suggested that hydrocarbon generation in the Austin Group occurred at relatively shallow depths. In southeastern Texas (specifically in Burleson County), Grabowski (1981) inferred that peak oil generation occurred in the depth range of 6,000–8,000 ft and peak gas generation was below 8,000 ft. Hunt and McNichol (1984) examined Austin core from various wells in the region and determined that the deepest samples (at about 9,000 ft) had passed through the oil window and are in the beginning of the thermogenic gas window; Hunt and McNichol also considered a depth of 6,000 ft as the threshold for main hydrocarbon generation in the Austin. Dawson and others (1995) estimated an oil-generation depth of 6,700 ft, based on several geochemical indicators, and concluded that the base of the oil window could be as deep as 12,500 ft.

Lewan's (2002) data for the Eagle Ford show that the Turonian rocks generated both oil and gas in downdip areas, but that the rocks are immature for both oil and gas in all but one updip well; in that well, the rocks were interpreted to have started generating oil, but are not yet at the peak for oil generation. Lewan (2002) further interpreted that, depending on location, (1) oil generation in the Eagle Ford started between 42 and 26 Ma and ended between 31 Ma and the present and (2) gas generation began between 28 and 14 Ma and ended between 22 Ma and the present.

The overburden-thickness map of the Austin (fig. 6) can be used as a general guide in estimating areas where the Austin and underlying Eagle Ford source rocks are buried deeply enough to have started generating hydrocarbons, on the basis of depth estimates of the various investigators already cited herein. Source rocks in the Austin and Eagle Ford are thought to be mature in areas deeper than the zone between the 6,000- and 8,000-ft contours. However, depth of burial is only one of several important factors to be considered in estimating maturity, others being (1) varying regional geothermal gradients across the area, which generally increase to the west within the contoured area (Bodner and others, 1985); (2) source rock lithologic variations; (3) variable thickness of source rock intervals; and (4) differences in organic-matter composition. Rather than using the overburden map (fig. 6) to predict where hydrocarbon generation may have occurred, the map may actually be more useful in eliminating areas that are too immature.

Thermal maturity of the Austin and Eagle Ford Groups, as well as the Smackover, may have been enhanced by intrusive igneous activity in parts of the Western Gulf Province (fig. 2). Minor contact metamorphism of the Austin was noted by Hutchinson (1994b), but what is more important, the geothermal gradient in some areas may have been increased by the proximity of magma chambers.

Hydrocarbon Migration

Virtually all of the oil and gas in the Navarro and Taylor Groups migrated from underlying units, thought to be the Upper Jurassic Smackover Formation and the Upper Cretaceous Austin and Eagle Ford Groups, although the exact mechanism of migration is uncertain. Most natural gas is thought to have been generated through the cracking of already-generated oil, not by primary generation from source rocks (Lewan and Henry, 2001). Thus, migration distances for gas could have been less than for oil. Migration can be broken down into three parts: (1) expulsion from source rocks, (2) migration from source rocks to reservoir rocks, and (3) migration within reservoir rocks. All three processes may occur in combination after generation, expulsion, and migration began.

In clastic source rocks, such as the organic shales of the Eagle Ford Group, mechanical compaction is thought to be the primary mechanism for expulsion of hydrocarbons (Nordgard Bolas and others, 2004). In low-permeability carbonate source rocks, such as the Smackover and Austin, compaction coupled with fracturing probably created the necessary conditions. Microfracturing in the Austin has been documented by Berg and Gangi (1999) and was interpreted to have resulted from the oil-generating process. Tectonic fractures are also pervasive in the Austin (Stowell, 2001), in sets striking northwest and northeast (Hinds and Berg, 1990). Such fractures, as well as microfractures, were observed in the Smackover Formation in other areas (Llinas, 2002), so similar fracturing of the Smackover in the study area can be reasonably assumed.

Vertical migration of hydrocarbons from the Smackover Formation into Navarro and Taylor reservoirs probably required other pathways in addition to fractures, as thick shales in the Jurassic and Cretaceous Cotton Valley Group, Lower Cretaceous Travis Peak (Hosston) Formation, and other Lower Cretaceous marine formations would have inhibited propagation of continuous fractures through the entire sedimentary section. Thus, larger features such as faults would seem to be necessary to permit vertical migration. For example, the Smackover is truncated updip at about the position of the Luling fault zone (fig. 4) (Ewing, 1991), and the faults in that fault zone may form important migration routes for Smackover-generated oil or gas. The same reasoning may also apply to the Charlotte-Jourdanton, Karnes, and Mexia-Talco fault zones (fig. 4), but in these cases a component of upward migration would also be necessary to move the hydrocarbons into shallow Upper Cretaceous reservoirs. Regionally recognized unconformities, such as those at the base of the Eagle Ford and at the base of the Escondido Formation (figs. 3, 8) could be avenues of upward migration. Sequence-boundary disconformities and transgressive erosion surfaces within Cretaceous rocks could also be potential routes of migration.

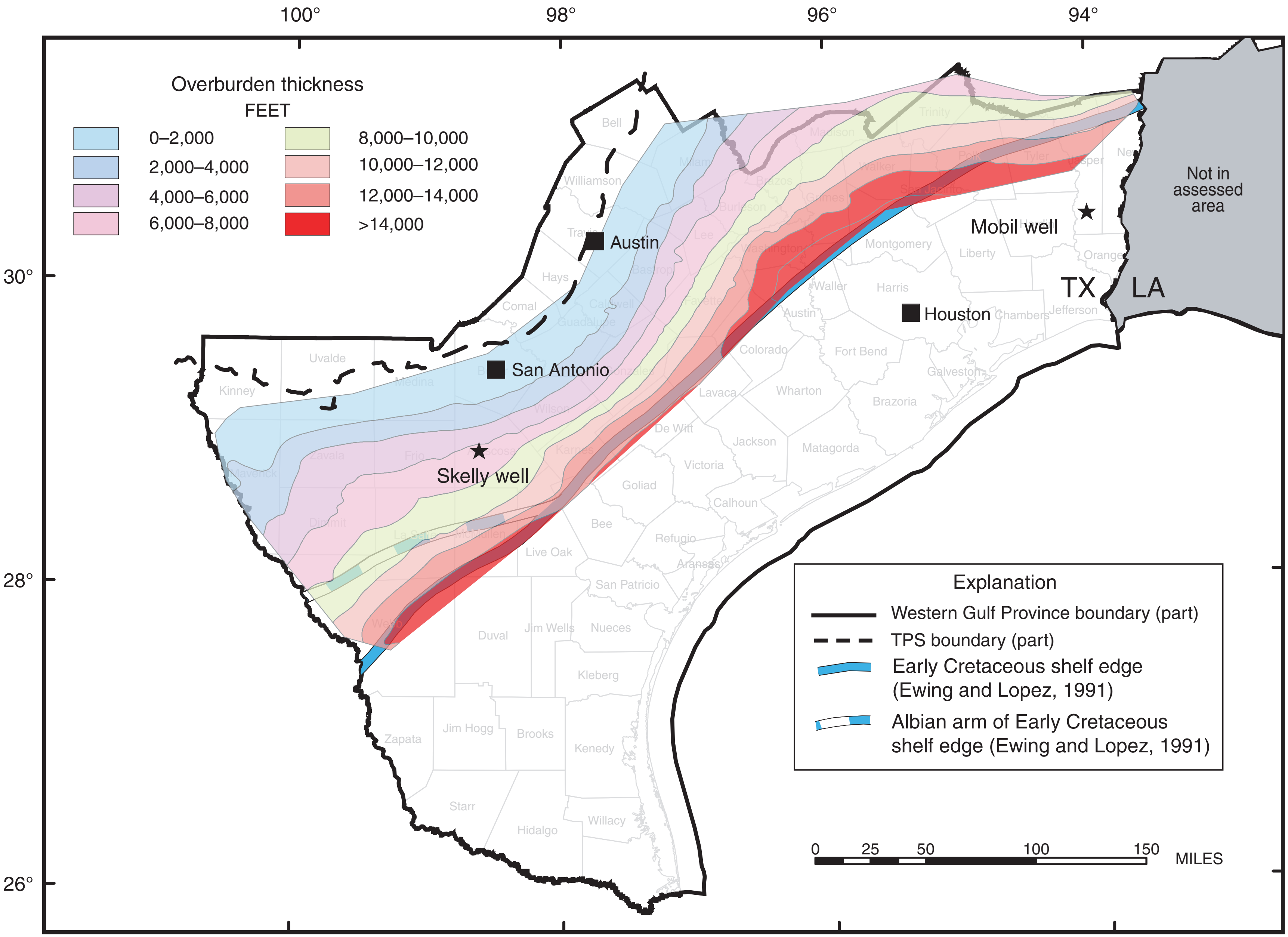

Figure 6. Overburden map of the interval from the ground surface to the top of the Austin Group in the western part of the Western Gulf Province. Data are from IHS Energy Group (2003b).

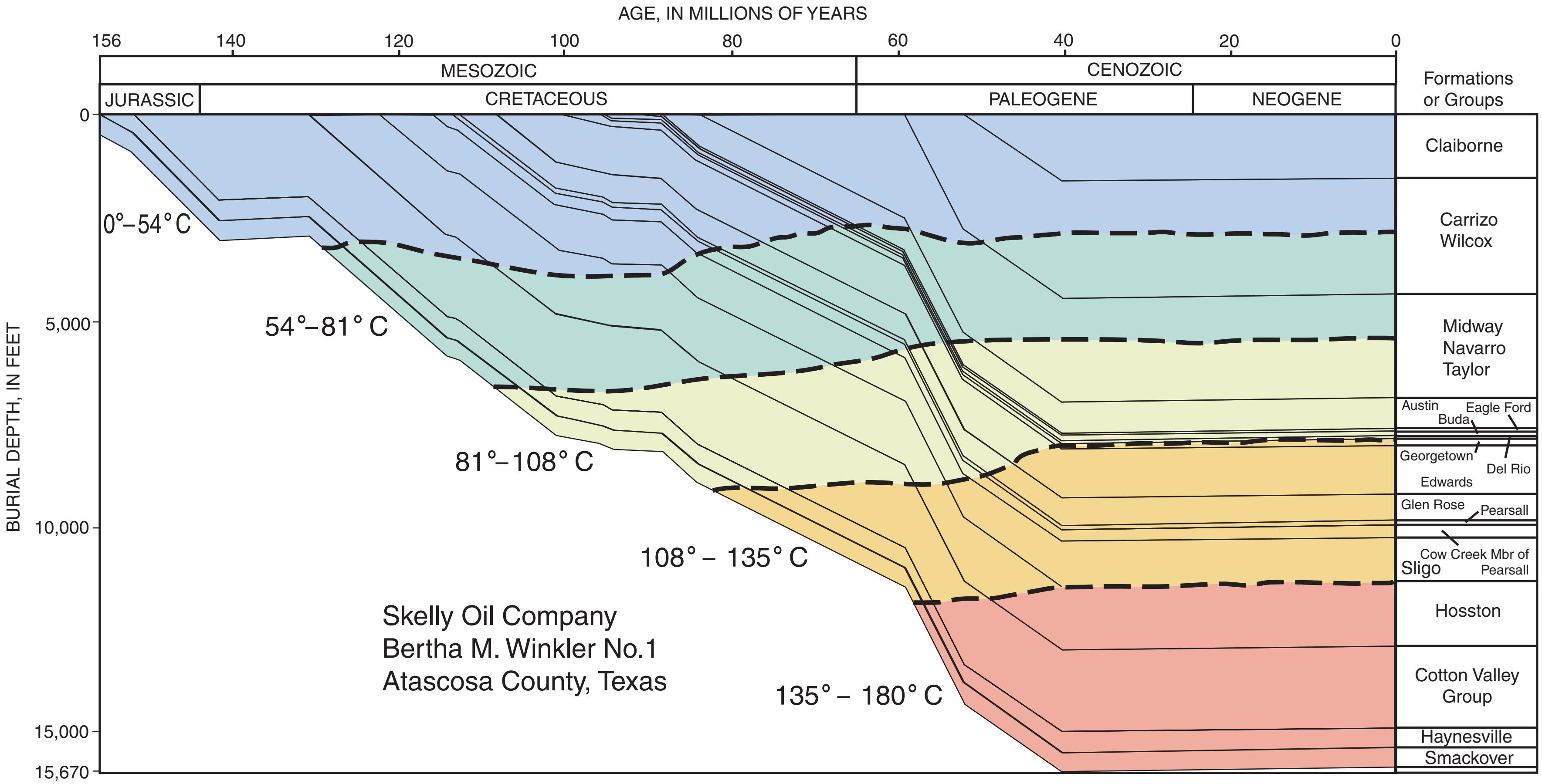

Figure 7. Burial-history chart of the Skelly Oil Company Bertha M. Winkler No. 1 well, Atascosa County, redrawn from a plot provided by M. Pawlewicz (written commun., 2004) that was created with Integrated Exploration Systems (IES) software. Color bars indicate temperature profiles that were generated by assuming a geothermal gradient of 34.2° C/km. Location of the well is shown in figures 2, 5, 6, 9, and 10.

Migration of oil or gas from Austin and Eagle Ford strata into Navarro and Taylor reservoirs poses fewer problems in interpreting source than migration from the Smackover, inasmuch as the Taylor Group lies directly above the Austin and vertical movement through fractures seems a reasonable mechanism for migration. Fractures in the Austin are in clusters spaced between about 3 and 150 ft, are partially open, and have permeabilities exceeding 7 D (darcy) (Stowell, 2001). Migration from downdip Austin and Eagle Ford sources to updip reservoirs was probably necessary, but fractures and disconformities between and within the units are also available pathways, as indicated by oil staining along microfractures and stylolites (Dawson and others, 1995). Additionally, vertical migration probably occurred in the Balcones, Luling, Charlotte-Jourdanton, and other fault zones.

Little has been published on natural fracturing of reservoir rocks in either the Navarro or Taylor Groups, including the Anacacho Limestone and the San Miguel, Olmos, and Escondido Formations. A photograph of an Anacacho open-pit asphalt mine (Wilson and Wilson, 1984) shows some vertical fractures in exposed walls of limestone—features that are not uncommon for this lithology. Diagenesis of sandstone reservoirs has resulted in precipitation of void-filling cements that reduces permeability (see following section on reservoir rocks), so induced fracturing is necessary in many areas for recovery of economic amounts of gas or oil.

Reservoir Rocks

Austin Chalk

As described previously under the heading Hydrocarbon Source Rocks, the Austin Chalk is that part of the Austin Group consisting of an argillaceous, compacted, foraminiferal biomicrite (Dawson and others, 1995). Overall, its reservoir properties vary greatly with geographic location and depth of burial, but the strata are considered tight in most areas. On the San Marcos arch, for example, porosity averages between 15 and 30 percent, and permeabilities are between 0.5 and 5.0 mD (Scholle and Cloud, 1977); off the structure, however, porosity and permeability decrease to 10 percent or less and 0.5 mD or less, respectively (Snyder and Craft, 1977; Hinds and Berg, 1990). The causes of the reduction in porosity and permeability are carbonate recrystallization, which resulted from compaction and pressure solution, and crystallization of secondary ferroan calcite as cement (Dravis, 1981). The Austin is extensively fractured, containing both tectonic fractures and microfractures, the latter resulting from hydrocarbon generation (Snyder and Craft, 1977; Berg and Gangi, 1999). For our study, the Austin Chalk was considered as a reservoir only in limited areas where the unit has been further fractured by extrusion of and structural adjustments over volcanic mounds (fig. 8). The databases we used (IHS Energy Group, 2003a, 2003b) showed Austin production in association with volcanic mounds in about 50 leases (out of a total of more than 22,600 whose wells reach the Austin). In our study, we considered the Austin to be more important as a source rock than as a reservoir.

Volcanic Mounds

In late Austin to early Taylor time (Santonian to Campanian), a series of submarine volcanoes erupted along a 250-mi-long belt in what is now south-central Texas, forming three main groups of seamounts and volcanic islands on the shallow Cretaceous shelf (fig. 2). Stratigraphic relationships indicate that some volcanism extended into Navarro time (Maastrichtian), but most activity was earlier (Spencer, 1969; Ewing and Caran, 1982).

The northeastern group of volcanic mounds, named the Travis volcanic field, extends across Caldwell, Bastrop, Travis, Williamson, Milam, and Guadalupe Counties along a north-northeast–trending zone lying just east of the city of Austin (fig. 2). Of the approximately 70 known individual volcanic mounds in this area, a few are exposed, but most have been enclosed and buried by the Austin and Taylor Groups (Matthews, 1986).

A central group of volcanic mounds (unnamed) is in Wilson, Bexar, Atascosa, Frio, and Medina Counties in the area south of San Antonio (fig. 2); only a few have been discovered, all in the subsurface. Stratigraphic relationships indicate that these mounds are slightly older than those in the Travis volcanic field, as evidenced by their being buried and overlain by Austin Group rocks rather than the younger Taylor Group (Matthews, 1986).

Farther southwest, the Uvalde volcanic field is centered in Zavala County but also extends into Uvalde, Medina, Frio, Dimmit, Maverick, and Kinney Counties (fig. 2); most exposures of volcanic mounds are in this area (Spencer, 1969). An aeromagnetic survey over the Uvalde volcanic field located more than 200 shallow igneous rock masses, most of which are in the subsurface (Miggins and others, 2002). These mounds appear to be younger on average than those of the northeastern and central areas because overlying rocks as young as the Escondido Formation contain bentonitic clay, presumed to be altered pyroclastic material (Welder and Reeves, 1964).

The volcanic rocks in all three areas consist of olivine nephelinite, basanite, alkali basalt, and phonolite (Spencer, 1969). They are characterized by high magnesium and nickel contents and have inclusions of mantle xenoliths, attesting to their deep source (Wittke and Mack, 1993). Although the chemistry of the volcanic centers is similar to that of ocean-island basalts (Wittke and Mack, 1993), neither active rifting nor plume activity has so far been interpreted in the Western Gulf Province in the Late Cretaceous. Instead, the region has been considered as part of a passive continental margin (Ewing and Caran, 1982).

The igneous activity was estimated to have occurred between 86 and 63 Ma (Baldwin and Adams, 1971). More

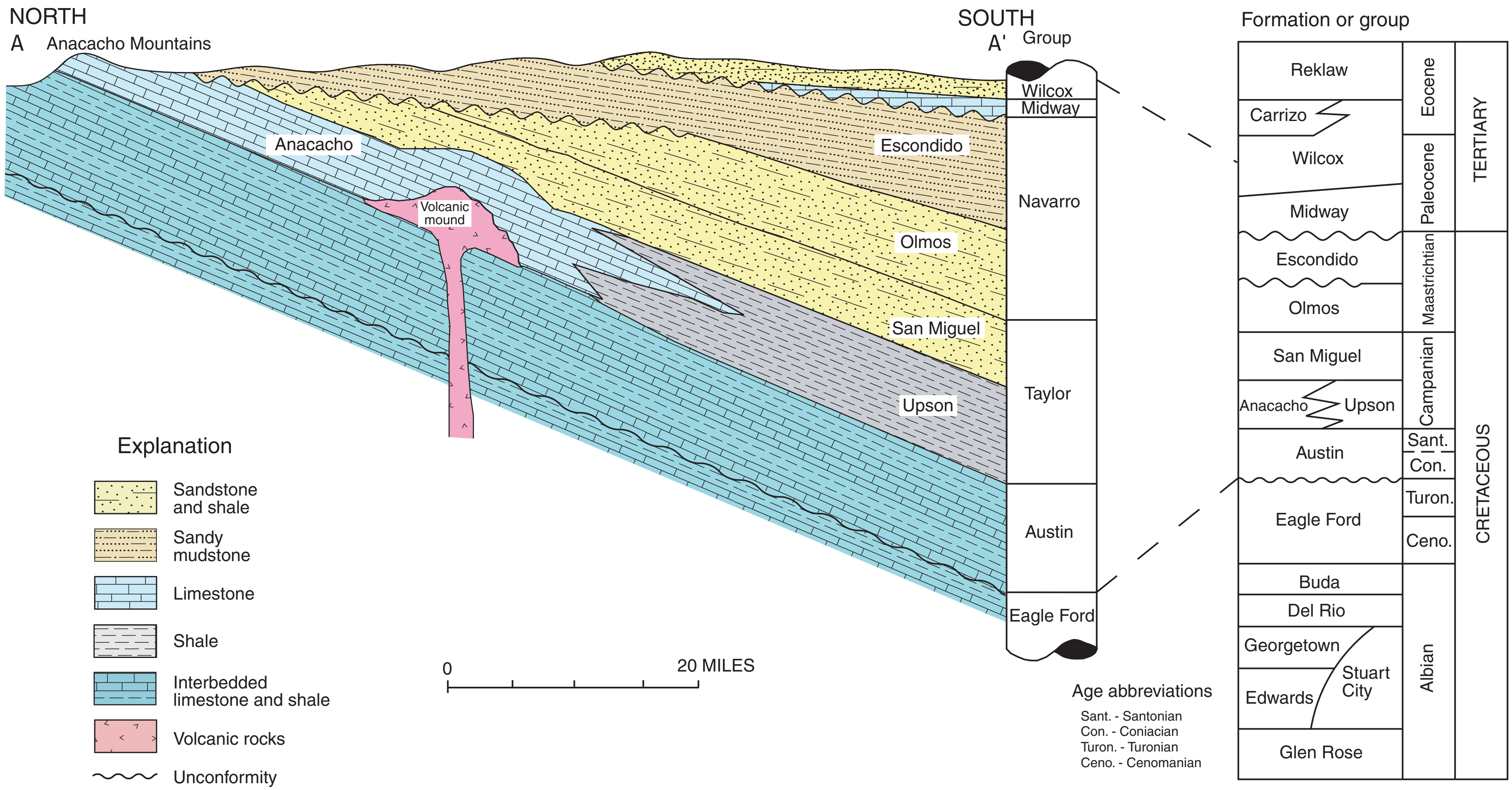

Figure 8. Diagrammatic northwest-southeast cross section through the Maverick Basin (modified from Tyler and Ambrose, 1986). Location of cross section is shown in figure 2.

recent argon-argon dating of four samples from the Uvalde area yielded a range of 78–71 Ma (Miggins and others, 2002).

Travis volcanic mounds are associated with the Luling fault zone (fig. 4) and are strongly aligned with the fault trends (Simmons, 1967; Matthews, 1986). Some mounds are directly linked with faults, so an Austin age (at a minimum) is indicated for at least some of the faults (Ewing and Caran, 1982). Barker and Young (1979), on the basis of a petrologic study of one mound near Austin, concluded that the source of the magma was at a minimum depth of 35 ± 10 mi (60 ± 15 km), indicating ascent along deep-seated faults.

In contrast, the Uvalde volcanic centers are not clearly aligned with faults, although some that outcrop in Uvalde County are within the Balcones fault zone. Some individual mounds are elongated along Balcones faults, but others are elongated subparallel to the axis of the northwest-trending Rio Grande embayment and to the Frio River Line (fig. 4). Massive igneous rocks of variable composition, formed by magmatic differentiation, are more abundant in this area, indicating a possibly shallower and longer lived magma chamber than the one situated in the Travis area (Ewing and Caran, 1982).

Magma is inferred to have moved upward along faults and fractures and to have reacted explosively with seawater at or below the water-sediment interface in the Austin-Taylor sea (Ewing and Caran, 1982). Rock fragments and glass shards were ejected into the sea and air, craters were formed on the seafloor, surrounding country rock was fractured, and ash and tuff mounds were built up around the feeder plugs. In some cases, continued eruptions built the mounds above sea level and created tuff cones as much as 3.5 mi in diameter and 1,000 ft high (Simmons, 1967; Martinez and others, 1991; Hutchinson, 1994b; Cearley, 1999), although most rose only 150–300 ft above the seafloor (Ewing and Caran, 1982). The tuff cones were initially described as “serpentine” by Collingwood and Rettger (1926), but Greenwood (1956) used the more accurate term “palagonite tuff” for the devitrified basaltic glass that constitutes most of the mounds (Hutchinson, 1994b).

After deposition, the mounds were subjected to reworking by wave action and mass wasting and were gradually buried by fine-grained marine sediments of the upper part of the Austin Group and the Taylor Group (Roy and others, 1981; Ewing and Caran, 1982). Much of the volcanic material has been altered to smectite clays and zeolites (Matthews, 1986). Some mounds are fringed with reef and shallow-marine shelf bioclastic deposits of the Anacacho Limestone in the Uvalde area and similar facies of the McKown Formation and Dale Limestone in the Travis area (fig. 2), indicating that the mounds were emergent or only slightly below sea level. Prevailing winds or ocean currents from the northeast redistributed the pyroclastic material, which led to preferential development of shoals and reefs on the southwestern sides of the mounds (Luttrell, 1977; Roy and others, 1981). Where basal San Miguel or Taylor sandstones overlie the mounds, the sandstones are composed of reworked volcanic material (Cearley, 1999).

Hydrocarbons have been produced from several reservoirs associated with the volcanic mounds. Production has been from the igneous rocks in the mounds themselves, from Austin Group rocks below the mounds, and from the contact between the mounds and the Austin (Sellards, 1932; Martinez and others, 1991; Hutchinson, 1994a, 1994b). Much of the production in the Travis volcanic field is from the volcanic mounds (Matthews, 1986); more limited production is from the overlying Taylor Group, although the database we used reported production as being from the Austin, Dale, and Taylor (IHS Energy Group, 2003a).

Anacacho and Dale Limestones

Seamounts and emergent volcanic mounds on the Cretaceous shelf became the sites of fringing-reef carbonates in late Austin through Taylor time (Santonian to Campanian) (Luttrell, 1977; Matthews, 1986). Later, the carbonates coalesced and spread across shallow-marine shelf areas away from the mounds.

Anacacho Limestone of the Rio Grande Embayment

In the Maverick Basin, these fringing-reef carbonates are named the Anacacho Limestone and are considered to be the basal formation of the Taylor Group. The main area of outcrop of the Anacacho Limestone is in the Anacacho Mountains of southeastern Kinney County, in the northwest corner of the study area (fig. 2). The Anacacho Limestone is also exposed in scattered outcrops eastward from there through Uvalde and Medina Counties.

The Anacacho consists of biohermal reef rock and reworked skeletal debris, mollusk shells, foraminifera, and other microorganism remains in a chalky or coarsely crystalline matrix that indicates deposition in water depths of less than 150 ft (Hartville, 1959; Wilson, 1986). Some of the debris was redeposited in beds displaying cross-bedding, indicating high-energy environments. The transport of material was from the northeast to the southwest (Wilson, 1986; Roy and others, 1981). The Anacacho is interbedded with bentonitic clay beds and grades westward and southward into the Upson Clay, a distal equivalent unit in the Taylor Group (Hartville, 1959) (fig. 8). The Anacacho was deposited over an area approximately 100 mi east-west by 25 mi north-south and reaches a maximum thickness of about 800 ft (Wilson and Wilson, 1984). The mean thickness of the formation in nearly 900 wells is about 275 ft. In the subsurface, it is thickest in north-central Frio County and southern Zavala County and thinnest on the southwest flank of the San Marcos arch in northern Karnes County and southwestern Gonzales County (fig. 4) (IHS Energy Group, 2003b).

During burial and compaction, primary porosity of the Anacacho Limestone was reduced, and fractures and stylolites formed (Wilson and Wilson, 1984). Exposure to ground-water circulation created secondary porosity, which averages about 15 percent, but can range as high as 43 percent (Wilson and Wilson, 1984; Hartville, 1959). Asphalt-bearing Anacacho has been mined, crushed, and used as road metal in some areas of the northern Maverick Basin (Wilson and Wilson, 1984).

Oil and gas are produced from the Anacacho Limestone from Zavala County through Wilson County. Main oil production is from Fairfield, Somerset, and Taylor-Ina fields in Bexar, Atascosa, and Medina Counties (fig. 9). Gas production is relatively minor from Shaw, Benton City, and Hog & Frog fields in Atascosa and Uvalde Counties.

McKown Formation and Dale Limestone

In the area east of Austin, Texas, such volcanic mound–flanking carbonates are known as the McKown Formation in outcrops of the Austin Group (Ewing and Caran, 1982) and as the Dale Limestone in the subsurface (the Dale Limestone is an informal term discussed by Thompson, 1986). Both the McKown and Dale conformably overlie the Austin Chalk and are considered to be part of the Austin Group. The McKown crops out in exposures east of Austin in Travis County.

The Dale Limestone, which is recognized in the Travis volcanic field east of Austin, is associated more closely with individual volcanic mounds than is the Anacacho and grades laterally into marls or into other Dale carbonate buildups on adjacent mounds (Thompson, 1986). Dale carbonates are at several stratigraphic horizons on the flanks of mounds, reflecting alternating conditions of volcanism and reef growth. The Dale has reported thicknesses of as much as 423 ft and a mean thickness of about 58 ft (IHS Energy Group, 2003b). The unit is thickest just east of Austin in eastern Travis County and thins in Williamson, Bastrop, and Caldwell Counties. It is not recognized on or southwest of the San Marcos arch. At Bateman field (fig. 9), the Dale has an average porosity of 13 percent and an average permeability of 0.22 mD (Thompson, 1986). Production from the Dale Limestone is primarily oil, from Buchanan, Bateman, Luling-Branyon, Lytton Springs, and other small fields, mostly in Caldwell and Bastrop Counties (fig. 9).

Taylor and Navarro Groups

The main reservoir rocks in the study area consist of Upper Cretaceous (Campanian to Maastrichtian) strata, which include the San Miguel, Olmos, and Escondido Formations and the Anacacho Limestone (figs. 3, 8). Most of the Navarro and Taylor strata are composed of alternating sandstones, mudstones, and shales that were deposited in deltaic or shallow-marine shelf environments. The San Miguel and Olmos have the highest percentages of coarse clastic components; the Escondido has a higher percentage of mudrocks. The Navarro and Taylor Groups are divided into constituent formations mostly in the western part of the study area in the Maverick Basin, but are undivided in areas on and northeast of the San Marcos arch within the study area.

San Miguel Formation

The San Miguel is the upper formation of the Taylor Group in the Maverick Basin and conformably overlies the Anacacho Limestone or Upson Clay (fig. 3). Exposed mainly in Maverick County on the Chittum anticline, the formation is composed of several progradational sequences that were deposited during a time of relative sea-level rise and transgression in the Late Cretaceous (Weise, 1980). Weise (1980) identified two depocenters in the Maverick Basin where clastic rocks of the San Miguel accumulated. The western depocenter is represented by nine couplets related to regressive-transgressive cycles, and the eastern depocenter contains several sandstone bodies grouped into a single unit. The two depocenters are inferred to have had different source areas—the western one had sediment input from the northwest, and the eastern area had sediment input from the north.

The San Miguel consists of a series of stacked, massive to cross-bedded sandstone bodies, sandy to argillaceous limestones, thin argillaceous and calcareous sandstones, and mudrocks. Some sandstones are fossiliferous and contain an abundant shallow-marine fauna (Stephenson, 1931). In core samples, Lewis (1977) noted black shale, which could be a minor source rock for hydrocarbons.

San Miguel sandstones have been studied and described in detail by several investigators, including Layden (1976), Lewis (1977), Weise (1980), Jacka (1982), and Tyler and others (1987). The composite sandstone bodies described by Weise (1980) are in units that trend north to northeast; their lengths range from about 35 to 60 mi, their widths range from 8 to 40 mi, and net sandstone thicknesses range from 80 to 160 ft. Regionally, thicknesses of the San Miguel are as much as 1,500 ft; mean thickness is 575 ft in 521 wells (IHS Energy Group, 2003b). In the subsurface, the San Miguel is thickest in southwestern Zavala County and thins to the southeast, east, and northeast. Northeastward thinning is probably due, in part, to truncation by an unconformity at the base of the overlying Escondido Formation (fig. 8).

Sandstones were deposited by prograding deltas and then were reworked by waves, longshore currents, and marine transgressions. Upper-prodelta, lower-shoreface, and upper-shoreface deposits are preserved. The tops of progradational depositional sequences have been removed by erosion during subsequent marine transgression (Weise, 1980). Delta-plain deposits, such as lignites or coals, have not been identified in the San Miguel.

Grain sizes in individual sandstone beds coarsen upward from coarse silt to very fine or fine sand at the top (Weise, 1980). Porosity also increases upward within the sandstone beds and ranges from 10 to 30 percent. Updip sandstones in Zavala County average 27 percent porosity and 100 mD; in southern Zavala County, porosity decreases to an average of 21 percent, and permeability decreases to 30 mD (Lewis, 1977). Farther south, in Big Wells field in northeastern Dimmit County and southeastern Zavala County, porosity averages 19 to 21 percent and permeability averages 6 to 7 mD (Layden, 1976; Tyler and others, 1987).

Much of the original porosity of the sandstone beds was occluded by kaolinite or calcite cement (Jacka, 1982). Merritt (1980) examined San Miguel sandstones in adjacent parts of

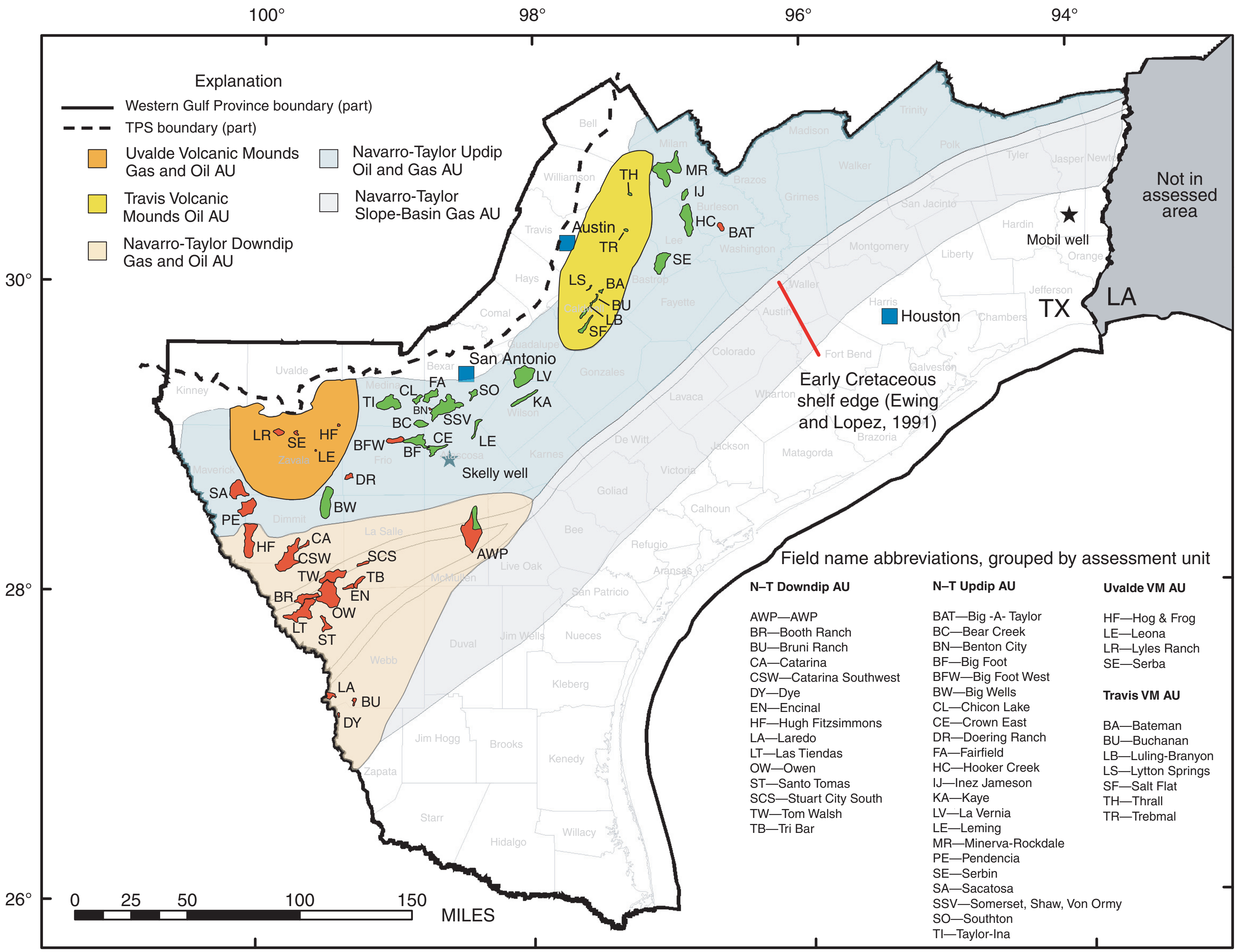

Figure 9. Map of the western part of the Western Gulf Province showing oil and gas fields mentioned in the text. Fields colored red produce mainly gas; fields colored green produce mainly oil. Well data are from IHS Energy Group (2003b).

northeastern Mexico and recognized a seven-step diagenetic history. Her study identified calcite cement as the primary cause (along with compaction) for the loss of primary porosity. Two periods of calcite dissolution created secondary porosity, which was subsequently partly filled by late-stage cements.

Most oil production in the San Miguel Formation is concentrated in east-central Maverick County and western and eastern Dimmit County in Sacatosa, Hugh Fitzsimmons, and Big Wells fields (fig. 9); scattered small fields produce from the formation throughout Zavala County. Gas production is mainly in northern Webb County in Catarina Southwest field, in Doering Ranch field in western Frio County, and in small fields scattered throughout Zavala County.

Olmos Formation

Snedden and Kersey (1982) noted that the Olmos Formation was originally assigned to the Maastrichtian Navarro Group by Stephenson (1931), based on studies of macrofossils at outcrops in Maverick County. Later, Spencer (1965) placed the Olmos in the Campanian Taylor Group, on the basis of the presence of the foraminifer *Lituola taylorensis* in a marker bed approximately 200 ft above the Olmos, which Frizzell (1954) found only in the Taylor Group. Later reports (Weise, 1980; Tyler and Ambrose, 1986) continued to assign the Olmos to the Taylor, although the top of the Olmos came to be recognized as coincident with the *Lituola taylorensis* horizon (Tyler and Ambrose, 1986). Complicating this arrangement, Young and others (1977) noted *Lituola taylorensis* in the Corsicana Formation, which is still considered to be part of the Navarro Group. Further clouding the issue, Snedden and Jumper (1990) even considered the underlying San Miguel Formation to be Maastrichtian. The USGS currently assigns the Olmos to the Navarro Group (http://ngmdb.usgs.gov/Geolex/geolex_home.html), and we include it in the Navarro in this report to conform with accepted USGS usage (figs. 3, 8).

The Olmos Formation is similar in many respects to the underlying San Miguel Formation. It crops out mainly in Maverick County, where it conformably overlies the San Miguel, and was also deposited in two main depocenters in the Maverick Basin having northwestern and northern sources (Tyler and Ambrose, 1986). The Olmos Formation in the western depocenter was divided into five sandstone units, which generally coarsen upward and are each less than 150 ft thick, separated by shale breaks (Tyler and Ambrose, 1986). The formation in the eastern depocenter was divided into three sandstone units, which also coarsen upward and range in thickness from about 30 to 200 ft.

Sandstone bodies of the lower three units in the western area are elongate southeastward (downdip) and reflect rapid progradation of the deltaic system toward the shelf edge. Only the distal end of the third unit is modified by wave action or longshore currents. This phase of deposition was followed by marine transgression and onlap of the upper two units, and sandstone bodies in these units are more closely aligned with the strike of the shoreline, indicating increased reworking by waves and longshore currents. Deposition in the eastern area started later than in the west, and the three depositional units there are roughly equivalent to the upper three units in the west. The first two units in the east were interpreted as wave-modified deltas, and the upper unit as a fluvial-dominated, but also wave-modified delta (Tyler and Ambrose, 1986).

Snedden and Kersey (1982), Snedden and Jumper (1990), Tyler and Ambrose (1986), and Conrad and others (1990) identified a complex assemblage of lithofacies within the Olmos, representing a range of deltaic environments. Lithologies comprise minor coal, shale, siltstone, and locally fossiliferous sandstone beds. Environments of deposition include tidal and distributary channels, crevasse splays and levees, interdistributary freshwater marshes and shallow-marine lagoons, storm-caused washover fans, abandoned distributary channels, interdistributary and prodelta bays, middle- to outer-shelf sand shoals, and barrier bars and islands deposited under a transgressive regime.

Sandstone bodies lying downdip in northern Webb County are thinner than the lobate sand bodies farther northwest in Maverick and Dimmit Counties, averaging only about 2 ft thick, have a sheet-like geometry, display many characteristics of turbidites, and were interpreted as having been deposited by density currents by Snedden and Kersey (1982).

The Olmos at the AWP field in McMullen County (fig. 9) has some features in common with the lower shelf sandstones and turbidites in northern Webb County (Dennis, 1987), in that deltaic sands prograded from the north and accumulated along the shelf edge. Movement on a basinward-sloping syndepositional fault that paralleled the shelf edge apparently caused the sands to fail and slump down the shelf-edge slope. The sands were redeposited on the slope and at the base of the slope in sheets. This process resulted in sand accumulations in three distinct depositional settings within the field: (1) delta-front deposits, on the updip side of the slope; (2) slope or proximal ramp deposits, extending as much as 3 mi beyond the shelf edge; and (3) basin-plain deposits, extending as much as 5 mi farther to the south (Dennis, 1987). The sandstones in the updip and slope settings have higher average porosity (20 percent), higher permeability (1 mD), less clay content, and thinner interbedded shales compared to the distal basin-plain sandstones, which have porosities near 10 percent and permeabilities near 0.01 mD.

Regionally, porosity of Olmos sandstones ranges from 9 to 28 percent, averaging about 24 percent, and permeabilities range from 0.01 to 422 mD, averaging about 83 mD (Tyler and Ambrose, 1986; Dennis, 1987). The reservoirs are normally pressured to slightly underpressured, having average fluid-pressure gradients ranging from 0.36 pounds per square inch per foot (psi/ft) to 0.43 psi/ft. Regionally, net sandstone thicknesses range from about 60 to 150 ft in depositional packages that vary from 15 to 75 mi in length and 20 to 60 mi in width. Subsurface thicknesses of the Olmos are as much as 1,600 ft; the mean of its thickness as determined from 1,350 wells is 695 ft (IHS Energy Group, 2003b). The unit is thickest along the United States–Mexico border and thins to the north and east.

In adjacent areas of northeastern Mexico, the Olmos Formation is interpreted to have had the same diagenetic history as the San Miguel Formation (Merritt, 1980), in that primary porosity was largely destroyed by compaction and precipitation of calcite and other early cements. Two periods of dissolution created secondary porosity, which was partially filled by late-stage cements.

Much of the oil from the Olmos has been produced from a four-county area just southwest of San Antonio. Fields in Bexar, Medina, Atascosa, and Frio Counties include Taylor-Ina, Von Ormy, Somerset, Bear Creek, and Big Foot, among many others (fig. 9). The AWP field, one of the larger oil producers, is in eastern McMullen County. Gas from the Olmos is produced mainly from Tri Bar, Tom Walsh, Booth Ranch, Owen, Las Tiendas, and Hugh Fitzsimmons fields, in northern Webb, western Dimmit, southern La Salle, and southern Maverick Counties, as well as from scattered small fields in Uvalde County. Big Foot West field in Frio County, and the AWP field in McMullen County also produce gas from the Olmos.

Escondido Formation

The Escondido Formation is the uppermost unit of the Navarro Group in the Maverick Basin. It is separated from the underlying Olmos Formation by a transgression-caused erosion surface and is overlain unconformably by the Paleocene Midway and Wilcox Groups (figs. 3, 8). The lower part of the unit consists of fossiliferous mudstone; medium- to thick-bedded, fine-grained sandstone beds that are generally less than 75 ft thick; and argillaceous, fossiliferous limestone (Pessagno, 1969; Cooper, 1971). Sandstone beds in the middle part of the formation are more lenticular, have higher porosity, and are coarser grained than the basal sandstones (Pessagno, 1969). There are also shell breccias in the middle part that are as thick as 40 ft (Pessagno, 1969). The upper part of the Escondido comprises glauconitic, calcareous, sandy mudstone and siltstone, argillaceous limestone, and fine-grained sandstone (Pessagno, 1969; Cooper, 1971). (Note: The upper part of the Escondido and basal limestone and shale beds of the Midway Group are pictured on the cover of this report.)

Mudstones in the Escondido were considered to be deposits of coastal bays and lagoons, whereas the sandstone beds were interpreted as shoreface deposits and shallow-marine shelf bars (Cooper, 1971, 1973). Applying the principles of sequence stratigraphy, Snedden (1991) divided the formation into a series of progradational, shallowing-upward parasequences deposited in a transgressive systems tract. In addition to the basal marine flooding surface that separates the Escondido from the underlying Olmos, four other shale-sandstone couplets within the Escondido are each overlain by flooding surfaces and thus form parasequences. Interpreted environments of deposition comprise open marine, ebb-tidal delta, shoreface, and marginal marine (Snedden, 1991). McDonald (1986) identified shallow-marine shelf bars in the subsurface of Wilson, Bexar, and Atascosa Counties.

In exposures along the Rio Grande River, the Escondido is approximately 900 ft thick (Cooper, 1971). It can be traced as a distinct formation eastward to about San Antonio, but from there northward it is included in the undivided Navarro Group. In the subsurface of the Maverick Basin, maximum thickness is about 2,550 ft; mean thickness is 923 ft in about 2,500 wells (IHS Energy Group, 2003b). The Escondido is thickest in northeastern Webb and southwestern LaSalle Counties and thins northward.

Sidewall-core analyses were reported by McDonald (1986) for two Escondido wells in Leming field. In one well, sandstone porosity ranged from 15.9 to 30.7 percent and averaged 22.9 percent; permeability ranged from 0 to 1,295 mD and averaged 143 mD (19 samples). The other well reported porosity from 15.5 to 25.5 percent and averaged 19.2 percent; permeability ranged from 0 to 54 mD and averaged 9.6 mD (15 samples). Net sandstone thickness in Leming field is as much as 20 ft (McDonald, 1986).

Most oil production from the Escondido Formation has been in Bexar, Medina, and Atascosa Counties, south and southwest of San Antonio (fig. 9). Main fields are Von Ormy, Southton, Chicon Lake, and Leming. Most gas production has been from three areas: (1) northern Zavala County, in small fields such as Serba and Lyles Ranch; (2) southern Maverick and western Dimmit Counties, in the Pendencia field; and (3) northern Webb and southwestern LaSalle Counties, in the Santo Tomas, Tom Walsh, Encinal, Tri Bar, and Stuart City South fields. This latter area corresponds closely with the area of the thickest Escondido in the subsurface.

Undivided Taylor Group

In general, the Taylor Group is not subdivided outside the Maverick Basin in areas northeast of Atascosa County on and northeast of the San Marcos arch. However, well operators have reported Taylor tops as far west as the Rio Grande River in Maverick and Webb Counties, so the unit can be mapped regionally in the subsurface. Young (1965) divided the Taylor into several formations in central Texas, including the northeastern part of the study area. However, the databases we used are based on operator-reported formation tops, which exclude the formations proposed by Young (1965).

In the northeastern part of the study area, the Taylor disconformably overlies the Austin Chalk, the Dale Limestone and McKown Formation, or the Cretaceous volcanic mounds (the outcrop areas of these underlying units are shown in fig. 2). The base of the Taylor is marked by a transgression-caused erosion surface. It is overlain by a condensed bed (Bottjer and Bryant, 1980), which, in turn, is overlain by an ostracode-bearing calcareous claystone that was in large part derived from volcanic ash (Young and others, 1977; Ross and Maddocks, 1983). The upper part of the Taylor rests disconformably on the lower part, contains an abundant marine fauna, and is composed of argillaceous marl that grades upward into calcareous claystone (Chimene and Maddocks, 1984).

The abundance of marine fossils and the lithology of the Taylor Group in the northeastern part of the study area implies a marine origin, probably a shallow shelf. A package of four "mini-shelves" at the base of the upper Taylor wedges out downdip, and each wedge overlaps the next in the downdip direction (Tucker and Hencey, 1987). Tucker and Hencey (1987) interpreted these features as distal deltaic deposits; the downdip pinchout, the lobate shape of the units in plan view, and their position above a disconformity also suggests that they may represent lowstand systems tracts. The disconformity between the lower and upper parts of the Taylor appears to represent a marine flooding surface between two parasequences.

Over the entire study area, the thickness of the Taylor Group is as much as 3,480 ft; the mean of its thickness as determined from 3,039 wells is 757 ft (IHS Energy Group, 2003b). The thickest sections are in northern Webb, northeastern Colorado, Austin, and Polk Counties, and the thinnest are over the San Marcos arch and generally in the highest updip parts of the region. The lower Taylor thins over volcanic mounds in the area east of Austin (Tucker and Hencey, 1987).

Oil production is reported from the Taylor mainly in Serbin field in Bastrop and Lee Counties in the northeast and in Sacatosa field in eastern Maverick County. There is scattered oil production across Zavala through Caldwell Counties, mainly concentrated in Caldwell County in the Salt Flat, Luling-Branyon, and Buchanan fields. Gas production has been from northern Webb, Zavala, Burleson, and Washington Counties. Most gas fields are small, the largest ones being Catarina Southwest and Big -A- Taylor; some gas also is produced from Serbin field (fig. 9) in Bastrop and Lee Counties.

Undivided Navarro Group

The final reservoir unit to be considered is the undivided Navarro Group. Like the undivided Taylor Group, the Navarro is recognized mainly outside the Maverick Basin, although tops are reported for the unit across the entire region. The Navarro disconformably overlies the Taylor Group; its basal bed consists of a phosphatic, glauconitic, sandy marl (Dane and Stephenson, 1927; Tucker and Hencey, 1987). The rest of the unit is composed of interbedded (1) medium to dark gray, calcareous, highly fossiliferous shale, (2) local siltstone beds, and (3) thin, silty sandstones. A disconformity in about the middle of the sequence is overlain by sandy beds that pinch out downdip (Tucker and Hencey, 1987). Tucker and Hencey (1987) also noted that the upper two thirds of the Navarro are composed of a series of upward-coarsening shale-sandstone couplets, similar to the parasequences described for the Escondido Formation by Snedden (1991).

In the northeastern part of the study area, the Navarro was interpreted as a shelf deposit (Tucker and Hencey, 1987). Patterson and Scott (1984) identified shallow-marine shelf sandbars in the upper part that form linear sand-rich belts 3–20 ft thick, 17–20 mi wide, and 27–30 mi long. These sand ridges were deposited 21–40 mi out on the shelf, and their sources were updip deltas.

Data from some 85 wells drilled in a new downdip gas exploration play in southern Webb and northern Zapata Counties show the presence of a thin (average thickness, 10 ft), discontinuous, clean, highly permeable sandstone, encased in deep-water pelagic shales, in the uppermost part of the Navarro. Bain (2003) interpreted the sandstone lobe as a basin-floor turbidite, on the basis of its log character and position within neritic to middle-bathyal shales downdip from the Cretaceous shelf edge.

In the subsurface, the Navarro reaches a maximum reported thickness of 2,150 ft, and the mean of its thickness as determined from 1,880 wells is 630 ft (IHS Energy Group, 2003b). Thickest sections are in a band from southern Zavala to central Atascosa County, in northwestern Burleson, southeastern Milam, and eastern Lee Counties, and in Brazos and Grimes Counties. Thinnest sections are over the San Marcos arch and in a region encompassing San Jacinto, Polk, and Tyler Counties.

Data on reservoir properties of the Navarro are not generally available. Tyler and Ambrose (1986) reported Navarro porosities ranging from 22 to 34 percent and averaging about 27 percent. Permeabilities range from 2 to 24 mD and average about 19 mD. Reservoirs are normally pressured to slightly underpressured, averaging 0.41 psi/ft.

Oil production has been mainly from Minerva-Rockdale, Inez Jameson, and Hooker Creek fields in Milam, Burleson, and Lee Counties, in the area where the Navarro is thick, and in a broad area south of San Antonio from Medina and Frio Counties across Atascosa, Bexar, Burleson, and Wilson Counties to Guadalupe County, including Big Foot, Crown East, Somerset, Von Ormy, Kaye, and La Vernia fields (fig. 9). Gas production is scattered across the study area, mostly in association with oil fields, except for production in Webb and Zapata Counties. Fields in that area are Laredo, Dye, and Bruni Ranch.

The Navarro Group is overlain by Tertiary rocks of Paleocene through Pliocene age as well as by Pleistocene and Holocene unconsolidated units (Schruben and others, 1998). Most sediments that were deposited during this time interval bypassed the shelf and accumulated in slope and basin settings (Galloway and others, 2000). The Tertiary strata thin to a zero-thickness edge in updip parts of the study area, but thicken to between 10,000 and 14,000 ft along the downdip side of the assessed area (IHS Energy Group, 2003b).

Traps and Seals

Hydrocarbon traps in the study area are stratigraphic, structural, or a combination of the two. Stratigraphic traps are formed by pinchouts of reservoir sandstones into finer grained mudrocks or by truncation beneath disconformities. Examples of the first type include the potential for pinchouts of (1) deltaic fluvial channels into levee and swamp-overbank mudstones, (2) crevasse-splay sandstones into swamp deposits, (3) shoreface sandstones into marginal-marine lagoons and offshore shales, (4) longshore current–modified distributary-mouth bars into prodelta shales, (5) barrier islands or shallow-marine shelf sand bars into marine shales, (6) porous reef carbonates into enclosing shales in places where the Anacacho Limestone and Dale Limestone rim volcanic mounds, and (7) offlapping lowstand-systems-tract sandstones or turbidites into basin shales. Conditions favored the development of stratigraphic traps in the deltaic deposits of the San Miguel, Olmos, and Escondido Formations, and undivided Navarro and Taylor Groups at various places in the study area. Examples of stratigraphic traps formed by truncation beneath disconformities are the erosion of various shoreline sandstones by sequence boundaries, a well-known example of which is the unconformity at the base of the Escondido Formation, as shown in figure 8.

Structural-trap types in the study area comprise anticlines, domes, and faults. Folds are relatively rare in the study area, the main ones being the Chittum and Pearsall anticlines (fig. 4). Faults are prevalent in the Balcones, Luling, Charlotte-Jourdanton, Karnes, and Mexia-Talco fault zones, as well as in the Wilcox fault zone and other isolated locations along the downdip side of the Early Cretaceous shelf edge where accumulating sediments produced growth faults. Fields associated with structural traps include Crown East, Big Foot, Leming, and Big Foot West (fig. 9).

In a few places, combination stratigraphic-structural traps formed where sandstones pinch out over structures. This type of trap developed mainly in areas where volcanic mounds are present. In those areas, sediments of the Taylor Group were compacted during and after deposition, but there was less compaction over the tops of the underlying volcanic rocks, and a paleo-topographic high was created over the mounds. Sandstones in the Taylor and younger units drape over the mounds and even pinch out toward the top of the mounds. Additionally, faulting adjacent to the mounds can accompany compaction, further contributing to trap formation.

Seals in the study area consist of mudrocks—terrestrial-levee and swamp-overbank deposits, marginal-marine lagoonal mudstones, and marine shales. Fine-grained strata are interbedded with more porous reservoirs, so that vertical sequences of stacked reservoirs, traps, and seals were formed. In some areas, diagenesis of the reservoir rocks produced tightly cemented zones that may also act as local seals.

Assessment of Oil and Gas Resources

Our study within the Western Gulf Province included the Smackover–Austin–Eagle Ford Composite Total Petroleum System and the five assessment units (AUs) within it: (1) Travis Volcanic Mounds Oil (AU 50470201), (2) Uvalde Volcanic Mounds Gas and Oil (AU 50470202), (3) Navarro-Taylor Updip Oil and Gas (AU 50470203), (4) Navarro-Taylor Downdip Gas and Oil (AU 50470204), and (5) Navarro-Taylor Slope-Basin Gas (AU 50470205) (figs. 9, 10). (Note: Coal-bed gas and tar sands were not assessed.) Each assessment unit is defined on the basis of geologic characteristics and conditions favorable for hydrocarbon generation and accumulation—such as source, reservoir, and seal rocks; burial, thermal, and migration histories; and trapping mechanisms—that combine to distinguish it from other assessment units.

Following a numbering system established by the USGS to facilitate petroleum resource assessment (U.S. Geological Survey, 2000), the unique number assigned to the Smackover–Austin–Eagle Ford Composite Total Petroleum System is 504702, of which “5” denotes the region (North America), “047” denotes the province, and “02” denotes the total petroleum system. The Smackover–Austin–Eagle Ford Composite Total Petroleum System is numbered “02” because the Western Gulf Province contains another total petroleum system, the Tuscaloosa-Woodbine, numbered 504701. The assessment units in the Smackover–Austin–Eagle Ford, in turn, are numbered AU 504702<u>01</u> through AU 504702<u>05</u>, respectively (see the previous paragraph and Klett and Le, this CD-ROM).

A thorough analysis of all the available geologic data, as well as petroleum exploration and development information, was presented to a review panel for a final determination of the criteria and boundaries to be used for each of the assessment units. In addition, estimates of the sizes and numbers of undiscovered oil and gas accumulations, based on a tabulation of existing field and well records provided by Klett and Le (this CD-ROM), were presented on input-data forms to the review panel. These input-data forms (see Klett and Le, this CD-ROM) constitute the basis for estimating hydrocarbon resources in the assessment unit. The default minimum accumulation size that has potential for additions to reserves is 0.5 million barrels of oil equivalent (MMBOE). Other data compiled or calculated for each assessment unit to aid in the final estimate of undiscovered resources include gas-oil ratios, natural gas liquids to gas ratios, API gravity, sulfur content, and drilling depth. Additionally, allocations of undiscovered resources were calculated for Federal, State, and private lands and for various ecosystem regions. All such data are available on the completed input-data forms for the individual assessment units (see Klett and Le, this CD-ROM). In Texas, spacing of wells is governed by the Railroad Commission of Texas Statewide Rule 37, which prohibits siting wells within 1,200 ft of each other if they are either completed in or projected to be drilled to the same horizon. This rule effectively establishes a minimum spacing of 40 acres, although exceptions are routinely applied for and granted with sufficient geologic justification.

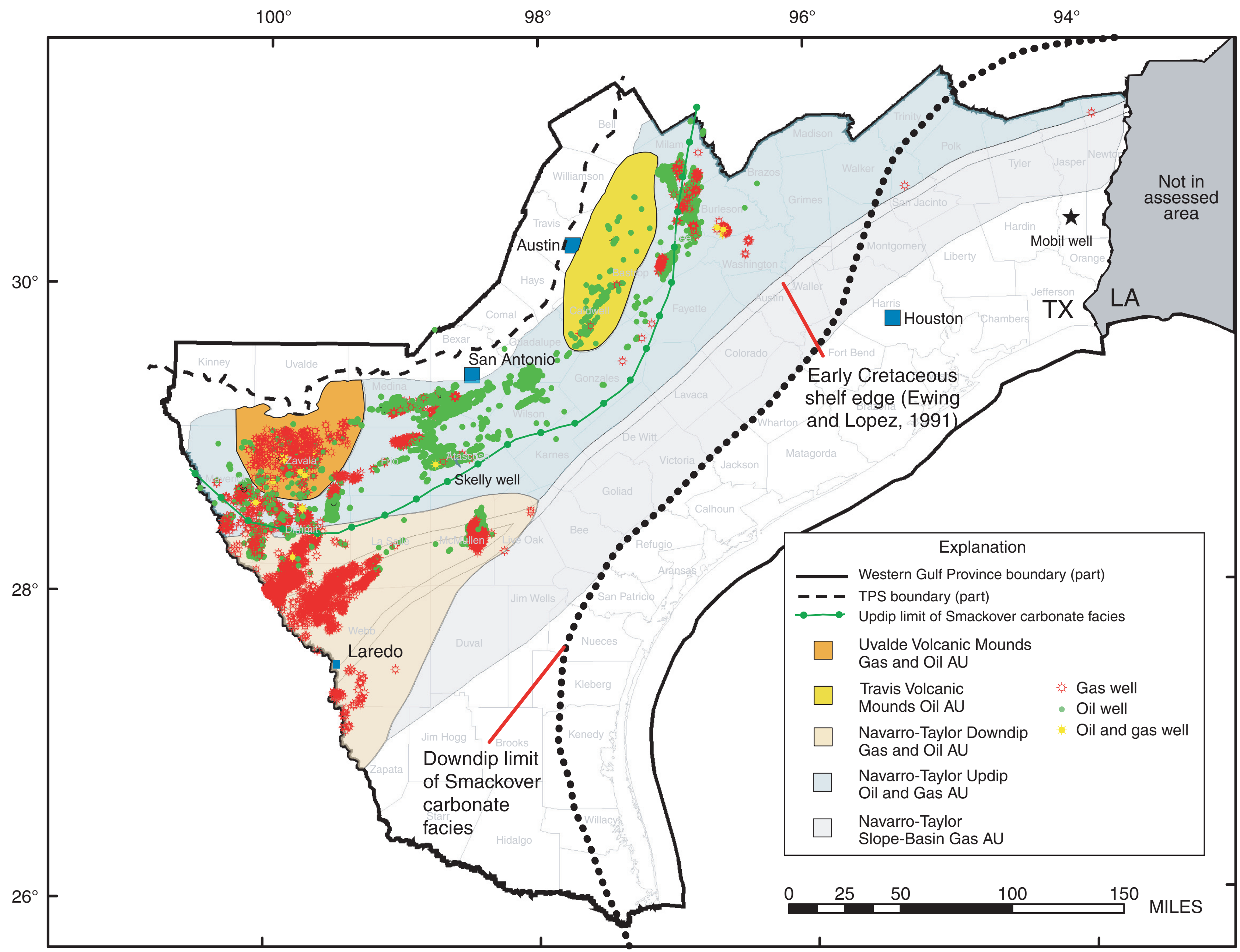

Figure 10. Map of the western part of the Western Gulf Province showing assessment units and areas of oil and gas production. Red symbols represent gas production; green symbols represent oil production; yellow symbols represent gas and oil production. Well data are from IHS Energy Group (2003b).

Travis Volcanic Mounds Oil Assessment Unit (AU 50470201)

The Travis Volcanic Mounds Oil Assessment Unit is a northeast-southwest–oriented oval area just east of Austin, Texas, covering approximately 1.5 million acres (fig. 10). It encompasses the area where there are Cretaceous volcanic mounds, commonly called "serpentine plugs." Earliest oil production in this area was from a volcanic mound in Thrall field in Williamson County in 1915 (Matthews, 1986). Most field development in the assessment unit was completed by the mid-1930s, but there has been production to the present time in Trebmal field in Bastrop County. The area is mature with respect to drilling for oil and gas resources.

Production has been mainly in the south-central part of the assessment unit (fig. 10). Drilling depths are relatively shallow, increasing from about 300 to 4,400 ft toward the southeast, which reflects the southeast dip of the reservoirs. To date, more than 1 million barrels of oil (MMBO) and nearly 220 million cubic feet of gas (MMCFG) have been produced from the assessed formations in the assessment unit (IHS Energy Group, 2003a). Most wells are classified as oil, but some gas wells are in the southern third of the assessment unit. For our study, we defined dry holes for each assessment unit as wells that reached total depth in the assessed formations and were classified as dry and abandoned (D&A) in the well database. Dry holes are distributed relatively evenly throughout the assessment unit, but in some places are clustered around volcanic mounds. Minimum well spacing, as in other areas, is 40 acres. Figure 11 is an events chart that shows the elements of the geologic model that describe this assessment unit. Key features are summarized in the following sections.

Source

No oil samples from accumulations in the assessment unit have been analyzed, so the source of the oil is unknown. Samples from the underlying Austin Chalk on the northeastern side of the San Marcos arch have a geochemical signature characteristic of Eagle Ford oils and unlike that of Smackover oils (Hood and others, 2002), and the Austin and Eagle Ford Groups are the presumed main source rocks for oil and gas. The Smackover could also be a source of gas, but its role remains uncertain owing to the lack of geochemical data.

Maturity

Just basinward of the Early Cretaceous shelf edge in the eastern part of the study area, Turonian source rocks penetrated in the Mobil well (fig. 10) were interpreted to have generated oil from 42 to 28 Ma and to have generated gas from 14 Ma to the present (Lewan, 2002). The Austin and Eagle Ford are present at similar depths downdip from the Travis Volcanic Mounds Oil Assessment Unit and could have started generating oil and gas at approximately the same time intervals. In the Mobil well, the Smackover generated oil from 117 to 103 Ma and gas from 52 to 41 Ma (Lewan, 2002). Maturity of source rocks within the assessment unit may have been enhanced locally by the igneous intrusions, but it is not known whether the elevated geothermal gradients would have been sufficient to generate oil or gas, given their shallow depth of burial.

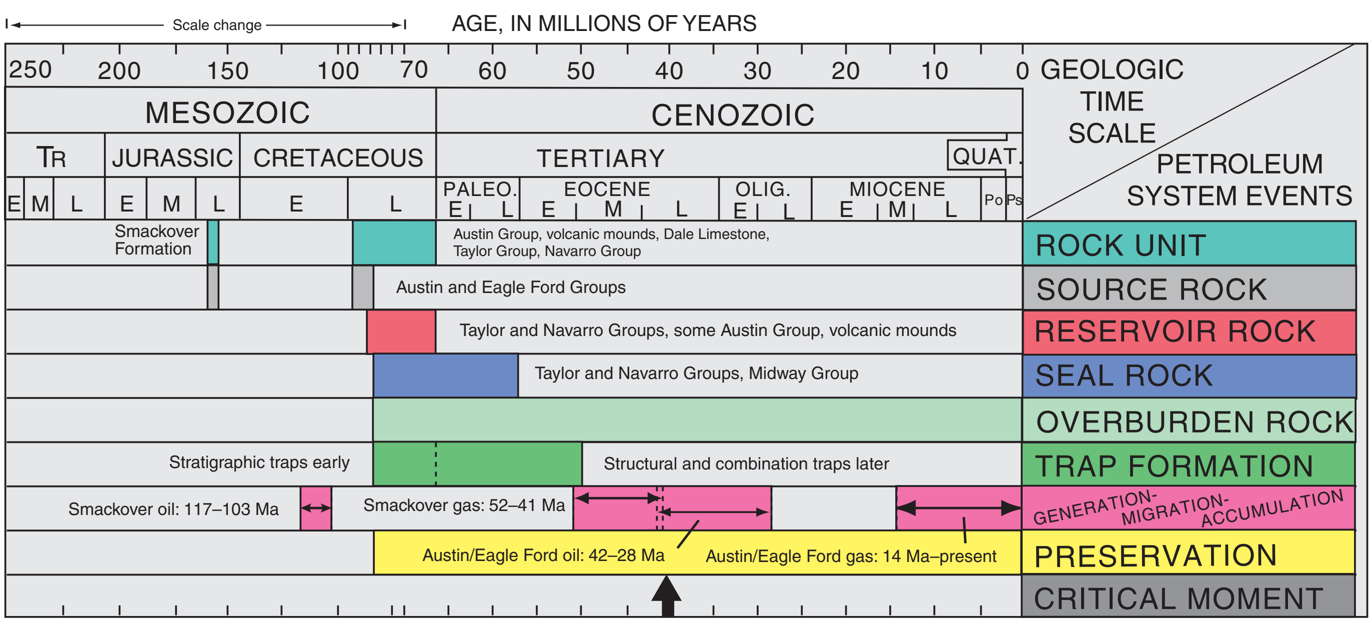

Figure 11. Events chart showing timing of key elements of the Smackover–Austin–Eagle Ford Composite Total Petroleum System. The critical moment is defined as the point in time (marked by arrow) that best depicts the generation-migration-accumulation of most hydrocarbons in the Smackover–Austin–Eagle Ford Composite Total Petroleum System (Magoon and Dow, 1994).

Migration

The center of the Travis Volcanic Mounds Oil Assessment Unit lies about 60 mi northwest of the Early Cretaceous shelf edge, so this is considered a minimum migration distance if the source of the oil was the Austin and Eagle Ford Groups. Updip migration was probably in the northwest-southeast–oriented fracture system in the Austin or along disconformities within and between the Austin and Eagle Ford. The assessment unit is closely associated with the Luling fault zone (fig. 4), and these faults could have provided pathways for the upward migration of Austin hydrocarbons. Gas could also have migrated from Smackover source rocks along the Early Cretaceous shelf edge.

Reservoirs

Most production has been from the Dale Limestone and the undivided Taylor Group, but some minor production has been reported from the undivided Navarro Group and the Austin Chalk. Although some production from the volcanic mounds was reported by Sellards (1932) and Matthews (1986), the databases we used indicated that this production was from the Taylor.

Traps and Seals

Production is associated primarily with volcanic mounds. Traps are mainly stratigraphic and form in bioclastic reefs that surround the mounds and in lower Taylor sandstones that overlie the mounds. There is some production from structural traps where sandstones drape over the mounds or from combination traps where sandstones pinch out on the flanks of paleo-topographic highs over the mounds. The Austin Chalk is also productive where fractured during emplacement of the volcanic mounds. Seals are mainly marls in the lower part of the Taylor Group.

Known oil fields have characteristics that identify them as conventional accumulations. They are located in well-defined areas in discrete stratigraphic, structural, or combination traps. Coproduced water is present in variable amounts (Matthews, 1986), and fields display distinct oil-water contacts. The shallow depth of the accumulations implies that migration from a distant source was important and that there was little or no generation of oil or gas within the assessment unit.

Estimated Resources

The assessment unit is considered as established and has 14 oil fields that equal or exceed the minimum accumulation size; there are no gas fields (see Klett and Le, this CD-ROM). The median sizes of previously discovered accumulations, when divided into thirds (by early, middle, and late initial dates of production) are 13.5, 6.0, and 1.9 MMBO (Klett and Le, this CD-ROM), indicating a large reduction in discovered accumulation size through time. However, conditions are deemed favorable for the assessment unit to contain one or more undiscovered hydrocarbon accumulations equal to or greater than the minimum field size of 0.5 MMBOE, as explained next.

In this assessment unit, we estimate the number of undiscovered oil accumulations to be a minimum of one, a maximum of five, and a mode of two. Only two oil fields have been discovered since 1950 that have production above the minimum of 0.5 MMBOE. All previous discoveries were between 1915 and 1933. Although the area is in a mature stage of exploration, we think there is a potential for at least one more oil field discovery above the minimum size, given the number of volcanic mounds and the potentially favorable area between the mounds. At the maximum, we allowed for the possibility of five more discoveries, based on finding or drilling volcanic mounds in areas downdip of present production or between mounds. We selected a mode of only two undiscovered fields because this is a maturely explored area.

In terms of the sizes of undiscovered oil accumulations, we estimate (1) a minimum size of 0.5 MMBO based on the minimum allowed at the current cutoff; (2) a maximum size of 3 MMBO, because the last discovered field was about that size; and (3) a median size of 1 MMBO, which reflects a decrease from the 1.9 MMBO reported for the last third of the discovered accumulations. As indicated by the trend of thirds, the size of discovered fields has been decreasing since the 1930s, and we expect that trend to continue.

Mean estimates of undiscovered resources for the Travis Volcanic Mounds Oil Assessment Unit are 2.85 MMBO, 0.71 BCFG, and 0.04 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future discoveries is considered to be low, on the basis of the maturity of exploration and the lack of discoveries since 1980. Future resource estimates will likely be a result of growth of previously discovered fields. The best areas for new discoveries will most likely be between volcanic mounds in sparsely drilled areas.

Uvalde Volcanic Mounds Gas and Oil Assessment Unit (AU 50470202)

The Uvalde Volcanic Mounds Gas and Oil Assessment Unit is a semicircular area southwest of San Antonio, Texas, that covers approximately 1.3 million acres (fig. 10). It is similar to the Travis Volcanic Mounds Oil Assessment Unit in that it also encompasses an area where there are Cretaceous volcanic mounds. Earliest production was from a mound in Medina County in 1919 (Matthews, 1986). Production has continued in small fields throughout the assessment unit, most recently from Leona field in Zavala County. This area is also in a mature stage of exploration, but slightly less so than the Travis area.

Production has been mainly in the southwestern and central parts of the assessment unit (fig. 10). Drilling depths are between 400 and 6,000 ft, becoming deeper toward the south. Production to date has been about 12.5 MMBO and 180 BCFG (IHS Energy Group, 2003a). Most wells are classified as gas producers, and they are clustered in the central part of the assessment unit. Oil is also produced across the entire assessment unit, but production is concentrated in the southern half of Zavala County. Dry holes are scattered fairly evenly across the assessment unit with the exception of a 6- to 10-mi zone along the north edge, where there has been little drilling. Minimum well spacing, as in other areas, is 40 acres. The events chart (fig. 11) shows the elements of the geologic model that describe this assessment unit. Key features are summarized in the following sections.

Source

No oil samples have been analyzed, so the source of the oil is unknown. Samples from the underlying Austin Chalk in nearby areas have a geochemical signature that possibly indicates a mixing of high-sulfur Smackover oil and low- to moderate-sulfur Austin–Eagle Ford oil (M.D. Lewan, written commun., 2003); therefore, a mixed source is thought to be likely.

Maturity

Just basinward of the Early Cretaceous shelf edge in the eastern part of the study area (fig. 10), Turonian source rocks penetrated in the Mobil well were interpreted to have generated oil from 42 to 28 Ma and gas from 14 Ma to the present (Lewan, 2002). The Austin and Eagle Ford are present at similar depths downdip from the Uvalde Volcanic Mounds Gas and Oil Assessment Unit and could have started generating oil and gas at approximately the same times. The Smackover was calculated to have generated oil from 117 to 103 Ma and gas from 52 to 41 Ma in the Mobil well (Lewan, 2002) and could have been a downdip source for oil or gas. Maturity of source rocks within the assessment unit may have been enhanced locally by the igneous intrusions, but it is not known whether elevated geothermal gradients would have been sufficient to generate oil or gas.

Migration

The center of the Uvalde Volcanic Mounds Gas and Oil Assessment Unit lies about 80–85 mi from the southernmost Early Cretaceous shelf edge, so this is considered a minimum migration distance if the source of oil is the Austin and Eagle Ford Groups. Updip migration was probably in the northwest-southeast–oriented fracture system in the Austin or along disconformities within and between the Austin and Eagle Ford. The assessment unit is at the western ends of the Balcones and Luling fault zones (fig. 4), and these faults could have facilitated migration from the Austin and Eagle Ford into stratigraphically higher reservoirs.

Reservoirs

Production has been from all units in the Navarro and Taylor Groups. The San Miguel Formation has the highest percentage of gas- and oil-producing wells, followed by the Olmos Formation. Only a few wells associated with volcanic mounds produce from the Austin Chalk.

Traps and Seals

Production is closely associated with volcanic mounds. Traps are mainly stratigraphic and form in bioclastic reefs that surround the mounds and in sandstones of the Navarro and Taylor Groups that overlie the mounds. Structural traps, where sandstones drape over the mounds, or combination traps, where sandstones pinch out on the flanks of paleo-topographic highs over the mounds, are also important. Minor production is from the Austin Chalk that was fractured during emplacement of the volcanic mounds. Seals are mainly mudrocks in the Navarro Group or Taylor Group.

The oil and gas fields in this assessment unit have characteristics that identify them as conventional accumulations. They are located in well-defined areas in discrete stratigraphic, structural, or combination traps. Drill-stem tests indicate variable amounts of water production (IHS Energy Group, 2003b), and fields display distinct oil-water contacts. The shallow depth of the accumulations implies that migration from a distant source was important and that there was little or no generation of oil or gas within the assessment unit itself.

Estimated Resources

The assessment unit is considered established and has 8 oil and 13 gas fields that equal or exceed the minimum accumulation size (see Klett and Le, this CD-ROM). The median size of previously discovered oil accumulations, when divided into halves (by early and late initial dates of production), is 1.4 and 0.7 MMBO; gas data for halves is 7.5 and 9.0 BCFG (see plots in Klett and Le, this CD-ROM). (Note: data are usually divided into thirds, except when there are not enough data points to make a meaningful plot. In that case, the data are divided into halves, plotted by the initial date of production.)

The essential elements for the generation, migration, and trapping of hydrocarbons appear to favor the assessment unit's having a minimum of at least one, a maximum of five, and a mode of three undiscovered oil accumulations at the cutoff size of 0.5 MMBOE. Although there was an upward trend in the number of oil discoveries from 1953 to 1980, no discovery since 1980 has produced more than 0.5 MMBOE. The minimum of one future discovery was considered a viable number because the area is mature for exploration. We estimated a maximum of five new discoveries on the basis of the potential for drilling additional volcanic mounds or areas between mounds. The mode value of three reflects our opinion that the possibilities are low for future oil field discoveries above the minimum of 0.5 MMBOE.

In the Uvalde Volcanic Mounds Gas and Oil Assessment Unit, sizes of estimated undiscovered oil accumulations were a minimum of 0.5 MMBO, a maximum of 3 MMBO, and a median of 0.75 MMBO. The default minimum for oil discoveries, 0.5 MMBO, was used because of the past low production volumes from individual small fields. Since 1975 the largest oil field discovery was just over 3 MMBO, and thus that value was used as the maximum. The decrease from 1.4 to 0.7 MMBO in the halves data indicates that future discoveries are probably going to be closer to the minimum than the maximum, so we used 0.75 MMBO as the median size for undiscovered oil fields.

We estimate a minimum of 1, a maximum of 10, and a mode of 5 undiscovered gas accumulations. The fields database (NRG Associates, 2001) shows a fairly steady increase in gas discoveries through time, punctuated by periods without discoveries. The last discoveries were in the early 1990s. We concluded that there was a possibility of finding at least one more gas field above the minimum of 3 BCFG (0.5 MMBOE). There have been six gas field discoveries above the minimum field size since 1980, and with the currently renewed interest in natural gas, we think that there could be as many as 10 new discoveries using currently available technology. We chose a mode of five undiscovered accumulations, which reflects the slow, but steady trend of gas discoveries since 1975.

The sizes of estimated undiscovered gas fields are a minimum of 3 BCFG, a maximum of 30 BCFG, and a median of 6 BCFG. A size of 3 BCFG is the minimum cutoff value for a gas field, which we also used as the minimum. Except for one field of more than 60 BCFG, all have been less than 30 BCFG, a value that we used for the maximum undiscovered field size. The trend of the halves in the period of record has actually increased from 7.5 to 9 BCFG. The last two discoveries were markedly smaller, however, so we used a value of 6 BCFG as the median size of undiscovered gas fields.

Mean estimates of undiscovered resources for the Uvalde Volcanic Mounds Gas and Oil Assessment Unit are 2.48 MMBO, 39.35 BCFG, and 0.69 MMBNGL (table 2). Table 2 also shows a breakdown into the F95, F50, and F5 fractiles. The potential for future discoveries is considered to be relatively low on the basis of the maturity of exploration and the lack of discoveries since the early 1990s. Future resource estimates will likely be a result of field growth of previously discovered accumulations. The best areas for new discoveries may be between volcanic mounds where there has been less drilling to date.

Navarro-Taylor Updip Oil and Gas Assessment Unit (AU 50470203)

The Navarro-Taylor Updip Oil and Gas Assessment Unit is an irregular area that extends across the entire width of the study area from the Rio Grande River to the eastern Texas State line. The assessment unit encompasses some 12.3 million acres (fig. 10). On the updip side of the assessment unit, the boundary was drawn along the outcrop of Navarro and Taylor rocks, except in places where the Travis Volcanic Mounds Oil Assessment Unit and the Uvalde Volcanic Mounds Gas and Oil Assessment Unit occupy that position. The downdip boundary was drawn along the Early Cretaceous shelf edge for most of its extent and along the border with the Navarro-Taylor Downdip Gas and Oil Assessment Unit from about Live Oak County to the Rio Grande. The earliest reported production was in 1920 in Fairfield field in Medina County and was from the Escondido and undivided Navarro Group (IHS Energy Group, 2003b). Most production since about 2003 has been in Sacatosa field in Maverick County, but there is also scattered current production across the entire area. Updip parts of the assessment unit are considered mature for exploration, but downdip parts have not been well explored.

Production is predominantly from three clusters of fields: (1) in southern Maverick and northern Dimmit Counties, (2) over a wide area southwest and southeast of San Antonio, and (3) an area east and northeast of Austin (fig. 10). Drilling depths range from less than 1,000 ft in parts of Maverick County to about 12,000 ft along the shelf edge. An exception is in Newton County, where the top of the Taylor is encountered at about 15,000 ft. To date, total production from the assessed formations is about 220 MMBO and 500 BCFG (IHS Energy Group, 2003a). In general, the western part of the assessment unit has produced mainly gas, although mainly oil was produced at Big Wells field in northeastern Dimmit County. The central and north-central parts of the assessment unit have produced mainly oil; exceptions include Big Foot West field in Frio County, Somerset field in Bexar County, and Big -A- Taylor field in Burleson County, which are gas producers. A relatively dense distribution of dry holes exists within and surrounding the three main producing areas; however, there are few wildcat wells in western Frio County and in a zone 25–50 mi wide that borders the Early Cretaceous shelf edge. The minimum well spacing allowed is 40 acres; Big Wells field was developed on 80-acre spacing. The events chart (fig. 11) shows the elements of the geologic model that describe this assessment unit. Key features are summarized in the following sections.

Source

No oil samples have been analyzed, so the source of the oil is unknown. Geochemical analyses of oil in the Austin Chalk indicate a probable Smackover source in Maverick County, an Eagle Ford source and possibly an Austin source northeast of the San Marcos arch, and mixed Smackover, Eagle Ford, and Austin sources in the central and northern Maverick Basin (Hood and others, 2002; M.D. Lewan, written commun., 2003).

Maturity

Just basinward of the Early Cretaceous shelf edge in the eastern part of the study area, Turonian source rocks penetrated in the Mobil well (fig. 10) were interpreted to have generated oil from 42 to 28 Ma and gas from 14 Ma to the present (Lewan, 2002). The Austin and Eagle Ford are present at similar depths downdip from the Navarro-Taylor Updip Oil and Gas Assessment Unit and could have started generating oil and gas at approximately the same times. The Smackover was calculated to have generated oil between 117 and 103 Ma and gas between 52 and 41 Ma in the Mobil well (Lewan, 2002).

Migration

Updip migration from the Austin and Eagle Ford was probably in the northwest-southeast–oriented fracture system in the Austin or along disconformities within and between the Austin and Eagle Ford. The Luling, Charlotte-Jourdanton, Karnes, and Mexia-Talco fault zones (fig. 4) could also have served as migration pathways for Austin, Eagle Ford, or Smackover hydrocarbons.

Reservoirs

All of the assessed formations other than the Austin Chalk and Dale Limestone produce oil and gas. Production volume is largest from the undivided Navarro Group, which has produced mainly oil in Milam, Burleson, and Lee Counties in the north-central part of the assessment unit and in a broad area southwest and southeast of San Antonio (IHS Energy Group, 2003a). The San Miguel Formation has produced mainly oil in the western part of the assessment unit, and the Olmos and Escondido Formations have produced oil southwest of San Antonio and gas in the western part of the assessment unit. The Anacacho Limestone has also produced mainly oil southwest of San Antonio.

Traps and Seals

The large number of reservoirs and the size of the assessment unit engender a variety of traps. Pinchouts of sandstones into mudrocks are important in the deltaic and shallow-marine shelf depositional environments of most of the reservoirs, as is truncation of sandstones by disconformities. Structural traps are present in the Chittum and Pearsall anticlines and in numerous fault zones. Seals are mainly terrestrial, marginal-marine, or marine mudrocks.

Oil and gas fields have characteristics that identify them as conventional accumulations. They are in well-defined areas in discrete stratigraphic, structural, or combination traps. Drill-stem tests indicate variable amounts of water production (IHS Energy Group, 2003b), and fields display distinct oil-water contacts; water saturations average 39–47 percent (Tyler and Ambrose, 1986). The reservoirs are normally pressured to slightly underpressured.

Estimated Resources

The assessment unit contains 47 oil and 6 gas fields that exceed the minimum accumulation size (see Klett and Le, this CD-ROM). The median size of previously discovered oil accumulations, when divided into thirds (by early, middle, and late initial dates of production) is 3.8, 1.9, and 1.7 MMBO; gas data for halves is 22.4 and 6.3 BCFG (see Klett and Le, this CD-ROM). The assessment unit was determined to have adequate reservoirs, traps, and seals, as well as a favorable history of hydrocarbon generation, for there to be one or more undiscovered accumulations equal to or greater than the minimum size of 0.5 MMBOE.

Accordingly, we estimated the numbers of undiscovered oil accumulations to be a minimum of 2, a maximum of 20, and a mode of 7. There have been eight new oil field discoveries since 1975, and, although the rate of discoveries has decreased, we think it a likely possibility that at least two new oil fields above the minimum of 0.5 MMBO will be discovered. The maximum estimate of 20 undiscovered fields is a reflection of the large geographic size of the assessment unit, the variety of possible traps, and the size of the gaps between currently producing areas. A lack of good reservoir facies in the northeast part of the assessment unit may limit the number of undiscovered fields in that area. The mode of seven undiscovered fields is at the low end of the range and reflects the facts that already-discovered oil fields are in the updip, more maturely explored parts of the assessment unit and that there is less probability of oil discoveries in the downdip parts of the assessment unit.

We estimated the sizes of undiscovered oil accumulations to be a minimum of 0.5 MMBO, a maximum of 25 MMBO, and a median of 1.5 MMBO. The default minimum size of 0.5 MMBO was used in anticipation that undiscovered fields will be small. The size of the largest existing oil field is about 85 MMBO, and there have been four additional fields greater than 35 MMBO, although the historical trend has been toward smaller field sizes. We used a maximum value of 25 MMBO to reflect the possibility that one or more relatively large fields in the unexplored, updip parts of the assessment unit will be discovered. The thirds data show a historical decline in oil field sizes, and our value of 1.5 at the median is slightly less than the last third of the period of record.

The numbers of undiscovered gas accumulations were estimated to be a minimum of 3, a maximum of 35, and a mode of 10. To date, much gas production has been associated gas in fields designated as oil fields in the updip part of the assessment unit, so the historical production data are skewed toward oil. We think there is a greater potential for gas discoveries in the downdip part of the assessment unit and that the likelihood is great enough to merit a minimum higher than just a single undiscovered field; therefore, we chose three as the minimum number. As indicated by the distribution of dry holes, the assessment unit is underexplored in the downdip, deeper part of the region. We consider this area to have good potential for future discoveries, so assigned a maximum estimate of 35 undiscovered fields. We chose a mode of 10 undiscovered fields to indicate our opinion that the area has potential, but the fact that good reservoir rocks are less abundant in the downdip facies of the Navarro and Taylor Groups potentially limits the possibilities for new gas discoveries.

The sizes of undiscovered gas fields are a minimum of 3 BCFG, a maximum of 120 BCFG, and a median of 8 BCFG. The minimum-size undiscovered field was set at the minimum (3 BCFG), allowing for the possibility of small fields. Historically, resources in one-third of the discovered fields have been slightly more than the 3 BCFG cutoff. Much of the downdip part of the assessment unit is untested for gas, but the presence of gas in the deep Austin Chalk indicates a potential for important gas resources in those strata. We estimated a maximum of 120 BCFG for a field in this underexplored area. Data indicate that the median size of discovered gas accumulations decreased from 22.4 BCFG in the first half of the development period to 6.3 BCFG in the second half. We conservatively assigned a median size of undiscovered fields at 8 BCFG, which is slightly larger than the median for the second half of historic production.

Mean estimates of undiscovered resources for the Navarro-Taylor Updip Oil and Gas Assessment Unit are 21.02 MMBO, 212.14 BCFG, and 4.20 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered to be moderate on the basis of the maturity of exploration within the assessment unit and the decrease in discoveries since the mid-1980s. Our study indicated a good potential for future gas discoveries, especially in downdip parts of the assessment unit where reservoir quality decreases and conditions become less favorable for oil accumulations.

Navarro-Taylor Downdip Gas and Oil Assessment Unit (AU 50470204)

The Navarro-Taylor Downdip Gas and Oil Assessment Unit is a triangular area of approximately 4.6 million acres. It borders the Rio Grande River with one vertex in southern Maverick County, one in west-central Zapata County, and the third in northwestern Bee County (fig. 10). In southern Maverick and central Dimmit Counties, the boundary was drawn to include the “downdip deltaic and shelf tight gas area” of Tyler and Ambrose (1986). The small “bump” in the boundary at the Maverick-Dimmit County line was drawn to take in the entire Hugh Fitzsimmons field (HF in fig. 9). The southeastern boundary was drawn to encompass the known downdip gas accumulations in the Laredo area (fig. 10) and also wells having known potential reservoir rocks. The assessment unit was extended northeastward to include the AWP field (fig. 9) because of similarities of that field with other fields to the west.

The earliest reported production was in Catarina field (fig. 9), southern Dimmit County, in 1948, from Navarro Group strata (IHS Energy Group, 2003b). Production has continued to the present, mainly in LaSalle and Webb Counties. Drilling depths range from about 1,600 to 13,000 ft, increasing to the southeast. To date, cumulative production has reached about 48 MMBO and 1,100 BCFG (IHS Energy Group, 2003a). Production has primarily been in (1) the northern half of the assessment unit from the Hugh Fitzsimmons, Catarina, and Catarina Southwest fields (fig. 9) that have produced both oil and gas and (2) a complex of fields in northern Webb County that have produced mainly gas. The AWP field, at the edge of the Early Cretaceous shelf, produced oil early in its history and later produced gas in a step-out to the south. The most recent drilling has been in southern Webb and northern Zapata Counties where small, relatively deep (to about 10,500 ft) gas fields have been discovered. Notable gaps in production have been in northeastern Webb County, southeastern LaSalle County, southwestern McMullen County, and northwestern Duval County. Dry holes are mainly clustered around areas of past and current production, not in the less-explored parts of the assessment unit. Well spacing is limited to 40 acres. The events chart (fig. 11) shows the elements of the geologic model that describe this assessment unit. Key features are summarized in the following sections.

Source

No oil samples have been analyzed, but geochemical analyses of oil in the Austin Chalk indicate a probable Smackover source in Maverick County and mixed Smackover, Eagle Ford, and Austin sources in the central part of the Maverick Basin, including the areas of scattered oil production in Dimmit, LaSalle, and McMullen Counties (Hood and others, 2002; M.D. Lewan, written commun., 2003). The source of the gas is uncertain, because little gas has been produced from the Austin Chalk in this area (IHS Energy Group, 2003a). As noted previously in the section titled Other Potential Source Rocks, coal in the Olmos Formation pinches out in southwestern Dimmit County; therefore we do not consider coal to be an important source of gas. The Smackover remains a possible gas source, but there is no reported production from the Smackover. Among other possible sources are pelagic shales encasing reservoirs in part of the assessment unit and deeply buried Eocene rocks (Hood and others, 2002), but neither has been confirmed.

Maturity

Definitive data regarding the maturation history of potential source rocks are lacking, but by analogy, the Smackover, Austin, and Eagle Ford source rocks possibly generated gas at about the same time period as discussed previously in this report for the Mobil well in Jasper County (fig. 10), that is, (1) the Smackover generated oil from 117 to 103 Ma and gas from 52 to 41 Ma and (2) Turonian rocks generated oil from 42 to 28 Ma and gas from 14 Ma to the present (Lewan, 2002). The thermal gradient increases slightly from east to west across the study area (Bodner and others, 1985), so this western area may have started generating hydrocarbons somewhat earlier than areas to the east. The question remains as to why little gas has been produced from the Austin in this area, because the Austin does produce abundant gas in a comparable geologic setting in fields to the northeast and should be mature enough to have produced gas in this assessment unit. Either the Austin and Eagle Ford have not generated gas in this assessment unit, which is unlikely, or their potential has not been adequately explored. The Smackover, being more deeply buried than the Austin, should also have produced gas in this area.

Migration

If hydrocarbons were generated by Austin and Eagle Ford strata, updip migration was probably in the northwest-southeast–oriented fracture system in the Austin or along disconformities within and between the Austin and Eagle Ford. Snedden and Jumper (1990) noted the presence of normal faults along the northern branch of the Early Cretaceous shelf edge, which could have been conduits for hydrocarbons from the Austin, Eagle Ford, or Smackover. Faults in the Wilcox fault zone southeast of the shelf edge in southeastern Webb County (fig. 4) could also be migration pathways.

Reservoirs

All the assessed formations other than the Anacacho and Dale Limestones and Austin Chalk produce oil and (or) gas. Production is most abundant from the Olmos Formation, which has produced mainly gas except at the AWP field where it has also produced oil. The Escondido Formation has produced mainly gas in northern Webb County. The Navarro Group has produced some gas in northern Webb County, but the developing turbidite exploration play in southern Webb and northern Zapata Counties has been drilled most recently. The San Miguel and undivided Taylor Group have produced the least amount of oil or gas.

Traps and Seals

Traps in the northwestern part of the assessment unit are mainly stratigraphic, formed by sandstone pinchouts in deltaic and shallow-marine shelf environments. Some traps southeast of the shelf edge have been interpreted as turbidites, and these also pinch out into mudrocks. In general, sandstone reservoirs have been subjected to severe diagenesis, resulting in generally low permeabilities. The AWP field is a complex trap, consisting of updip deltaic sandstones and downdip turbidites that pinch out into pelagic shales. The small fields in southern Webb and northern Zapata Counties also are considered turbidites and likewise pinch out into marine shales. Seals are thus mainly mudrocks in the Navarro and Taylor Groups deposited in deltaic, slope, and basin environments.

The oil and gas fields have characteristics that identify them as conventional accumulations; they are mainly discrete stratigraphic traps. Porosity and permeability are variable, depending on diagenesis of the reservoir rocks. Water saturation is high, averaging 62 percent (Tyler and Ambrose, 1986).

Estimated Resources

The assessment unit is considered established, and has 3 oil and 26 gas fields that exceed the minimum accumulation size (see Klett and Le, this CD-ROM). The median size of previously discovered gas accumulations, when divided into thirds (by early, middle, and late initial dates of production) is 63.2, 21.4, and 10.3 BCFG (see Klett and Le, this CD-ROM). There were not enough control points to plot oil-accumulation thirds or halves. The assessment unit was determined to have a potential for hosting one or more undiscovered accumulations equal to or greater than the minimum size on the basis of the presence of adequate reservoirs, traps, and seals and having favorable conditions for hydrocarbon generation.

We estimated the numbers of undiscovered oil accumulations to be (1) a minimum of one on the basis that the assessment unit is not particularly oil prone; (2) a maximum of seven, because the northern part of the assessment unit is on the thermally less-mature shelf, which we considered to present the possibility for as many as seven undiscovered oil fields in that area; and (3) a mode of two, which reflects our overall determination that there is a low probability of new oil discoveries.

The sizes of estimated undiscovered oil accumulations were a minimum of 0.5 MMBO, a maximum of 20 MMBO, and a median of 1.5 MMBO. The AWP field has produced about 40 MMBO (IHS Energy Group, 2003a), but this amount is considered anomalous. Therefore, we chose a value of 20 MMBO as a maximum undiscovered field size and a value of 1.5 MMBO for the median size. We do not anticipate important oil discoveries in this assessment unit.

The numbers of undiscovered gas accumulations are a minimum of 3, a maximum of 40, and a mode of 20. There have been two periods of rapid gas development in the assessment unit, probably relating to changing completion and recovery technologies. We think that the assessment unit has good potential for future gas discoveries and assigned a minimum of three undiscovered fields to this assessment unit. However, the latest model (Bain, 2003) for gas exploration predicts small, isolated sandstone bodies deposited in turbidites and encased in deep-basin shales, and the potential exists for a large number of these small sand bodies situated along the shelf edges in the assessment unit. For this reason, we assigned to the assessment unit a maximum of 40 undiscovered gas fields, primarily in this environment, and a mode of 20 undiscovered fields.

The sizes of undiscovered gas fields are a minimum of 3 BCFG, a maximum of 200 BCFG, and a median of 15 BCFG. The cutoff value of 3 BCFG was used for the minimum, allowing for the possibility of some small undiscovered fields. Las

Tiendas field has produced in excess of 260 BCFG, but the next largest field has produced less than 182 BCFG, and most other discovered fields have produced less than 100 BCFG. Our estimate of a maximum of 200 BCFG reflects the historical data. The thirds data indicate a decrease to a median size of about 10 BCFG for discovered fields; however, the turbidite plays are a fairly recent exploration model for this assessment unit, and we think that the median size of undiscovered fields will be higher than the historical decline indicates. Nevertheless, we kept the median size at 15 BCFG, because the geologic model indicates that the undiscovered fields will probably be isolated and relatively small.

Mean estimates of undiscovered resources for the Navarro-Taylor Downdip Gas and Oil Assessment Unit are 6.88 MMBO, 505.63 BCFG, and 10.82 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered to be low on the basis of the maturity of exploration for oil in updip areas and the lack of discoveries since 1981. On the other hand, we consider the potential to be favorable for future gas discoveries in turbidite sandstones, especially in downdip parts of the assessment unit.

Navarro-Taylor Slope-Basin Gas Assessment Unit (AU 50470205)

The Navarro-Taylor Slope-Basin Gas Assessment Unit is an arcuate area some 400 mi long and 30–40 mi wide, extending from central Zapata County to the eastern Texas State line (fig. 10) and containing approximately 9 million acres, which makes it the second largest assessment unit within the Smackover–Austin–Eagle Ford Composite Total Petroleum System. Except for the southwest end of the assessment unit, the updip boundary is drawn along the Early Cretaceous shelf edge. Potential reservoir rocks were identified in southern Tyler County about 30 mi southeast of the shelf edge, so the downdip boundary of the assessment unit was projected this same distance southeastward from the shelf edge. The central part of the southeast boundary was also drawn to coincide with the downdip limit of Smackover carbonate rocks (fig. 10).

This assessment unit is hypothetical, in that there is no existing production from the Taylor or Navarro Groups. It was defined because of the likely presence of source rocks and reservoirs and because certain comparisons can be made with the Navarro-Taylor Downdip Gas and Oil Assessment Unit. Projected depths of reservoir rocks range from about 12,000 to nearly 23,000 ft; thus we think that mainly gas would be produced. There have been a few wildcat wells drilled along the shelf edge, all of them dry holes. The events chart (fig. 11) shows the elements of the geologic model that describe this assessment unit. Key features are summarized in the following sections.

Source

There are more potential sources for hydrocarbons in this assessment unit than in any of the other four. Although most Austin production has been updip from the Early Cretaceous shelf edge, in the past some production, mainly gas, existed on the downdip side. In the downdip areas, the Austin would be expected to grade into organic shales, similar to the underlying Eagle Ford Group. North and east of Houston, the Smackover Formation also consists of deep-water shales, whereas southwest of Houston, it is made up of laminated carbonate mudstones that are known producers in other areas. Lower Cretaceous rocks—composed of deltaic clastic components and shallow-marine shelf carbonates northwest of the shelf edge—also grade into organic shales southeast of the shelf edge, making them possible sources of hydrocarbons. As noted previously in this report, in the Laredo area, pelagic shales that encase turbidite reservoirs are also potential source rocks, as are deeply buried Eocene strata about which little is yet known.

Maturity

In the Mobil well in Jasper County, (1) the Austin and Eagle Ford Groups generated oil from 42 to 28 Ma and gas from 14 Ma to the present, and (2) the Smackover Formation generated oil from 117 to 103 Ma and gas from 52 to 41 Ma (Lewan, 2002). Similar maturities and times of hydrocarbon generation probably also apply to areas within this assessment unit.

Migration

The Wilcox fault zone (fig. 4) consists of individual faults that mainly sole out into Tertiary or Upper Cretaceous rocks (Ewing, 1991). However, some faults may extend deeper, at least into Lower Cretaceous rocks (Ewing, 1991), and these could form migration pathways from Austin and Eagle Ford source rocks into the Upper Cretaceous reservoirs. Fractures within the Austin are probably not as well developed in the basin-slope area compared to areas farther updip, in that the updip strata are composed of more brittle carbonate facies. Faults are not known to extend downward far enough to cut the Smackover Formation.

Reservoirs

Wells having recorded formation tops for the undivided Navarro and Taylor Groups are in the northeast part of the assessment unit, mainly in San Jacinto, Polk, Jasper, and Newton Counties (IHS Energy Group, 2003b). In the Navarro-Taylor Downdip Gas and Oil Assessment Unit, the Navarro was identified in wells in southern Webb and northern Zapata Counties, downdip of the Early Cretaceous shelf edge (Bain, 2003). In the AWP field (fig. 9), the Olmos Formation was interpreted as deposited along and downdip of the Early Cretaceous shelf edge (Dennis, 1987). We anticipate that more detailed exploration along and downdip from the shelf edge will lead to recognition of Navarro and Taylor sandstones in more basin-slope areas.

Traps and Seals

In the Laredo area (fig. 10), thin, porous Navarro turbidite sandstones pinch out into pelagic shales (Bain, 2003). Reservoir sandstones in the Olmos Formation also pinch out into deep-basin shales in the downdip part of the AWP field (Dennis, 1987). We think that these types of traps and seals formed along the shelf edge in many additional locations.

This assessment unit was assessed by using the methodology for conventional accumulations because of anticipated similarities to the permeable turbidite reservoirs in the Laredo area. Additional exploratory data might show that the area has features characteristic of continuous accumulations.

Estimated Resources

Although no fields have been discovered, the assessment unit was considered to have adequate reservoirs, traps, and seals and a capability for generating hydrocarbons that could lead to one or more undiscovered accumulations (see Klett and Le, this CD-ROM).

On the basis of this perceived potential, we estimate the numbers for undiscovered gas accumulations to be (1) a minimum of 1, in view of the hypothetical nature of the assessment unit; (2) a maximum of 100, based on the assessment unit's large areal extent; and (3) a mode of 35, because of a limiting factor imposed by the particular kinds of strata involved. The potential for undiscovered accumulations is not equally distributed throughout the assessment unit because of preferential sandstone development in the Maverick Basin rather than in areas affected by the San Marcos arch.

In this assessment unit, sizes of estimated undiscovered gas accumulations were a minimum of 3 BCFG, a maximum of 500 BCFG, and a median of 10 BCFG. An end-member analog for this assessment unit would be the AWP field, which lies along the shelf edge. We used a value of 500 BCFG to approximate the barrels of oil equivalent of this field at the maximum for the assessment unit. However, we chose a value of 10 BCFG at the median for undiscovered fields, which reflects the isolated and restricted size of sandstone bodies that likely hold undiscovered gas resources in the assessment unit.

Mean estimates of undiscovered resources are 924.96 BCFG and 18.52 MMBNGL (table 2). Table 2 also shows a resource breakdown into the F95, F50, and F5 fractiles. The potential for future oil discoveries is considered to be low because of the depth of potential source rocks and reservoirs. We think that there is good potential for future gas discoveries, especially along the northwestern boundary of the assessment unit.

Comparison of Results of 1995 and 2003 Assessments

A comparison between the 1995 and 2003 USGS resource estimates for the Upper Cretaceous rocks of the Western Gulf Province shows an appreciable change in the estimated size of the undiscovered resource. In 1995, Schenk and Viger (1996) estimated a total mean undiscovered oil and gas resource of 270.3 MMBO and 826 BCFG for three conventional plays in the Upper Cretaceous Navarro and Taylor Groups in the Western Gulf Province. A fourth play—the Upper Cretaceous Volcanic Mounds Oil and Gas Play—was not assessed because no fields exceeded the minimum size of 1 MMBOE. In 2003, a mean resource of 33.3 MMBO and 1,683 BCFG was estimated for the five assessment units we have discussed.

Even considering differences in methodology, the 2003 estimates reflect a notable change of thinking in the 10 years since the 1995 assessment. During that 10-year period, cumulative oil and gas production for all of the Upper Cretaceous reservoirs associated with the plays assessed in 1995 amounted to 5 MMBO and 243 BCFG. This 10-year cumulative production profile represents only 1.8 percent of the undiscovered oil but nearly 30 percent of the undiscovered gas estimated in 1995. The production data indicate that additions to oil reserves estimates in 1995 were overly optimistic. In 2003, an order-of-magnitude less of undiscovered oil was estimated for the equivalent assessment units, whereas gas estimates were higher by a factor of two. These changes reflect a shift in perception from an abundance of oil to an abundance of gas. Much of the difference in the gas estimate (an additional 925 BCFG) reflects the addition of a new assessment unit, the Navarro-Taylor Slope-Basin Gas Assessment Unit, a hypothetical gas assessment unit not identified in 1995.

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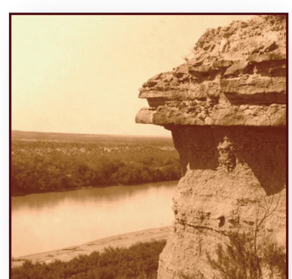

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