Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources—U.S. Gulf Coast

By Tina L. Roberts-Ashby, Sean T. Brennan, Marc L. Buursink, Jacob A. Covault, William H. Craddock, Ronald M. Drake II, Matthew D. Merrill, Ernie R. Slucher, Peter D. Warwick, Madalyn S. Blondes, Mayur A. Gosai, Philip A. Freeman, Steven M. Cahan, Christina A. DeVera, and Celeste D. Lohr

Chapter H of
Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources

Edited by Peter D. Warwick and Margo D. Corum

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Editors' Preface

By Peter D. Warwick and Margo D. Corum

The 2007 Energy Independence and Security Act (Public Law 110–140) directs the U.S. Geological Survey (USGS) to conduct a national assessment of potential geologic storage resources for carbon dioxide (CO_2) and to consult with other Federal and State agencies to locate the pertinent geological data needed for the assessment. The geologic sequestration of CO_2 is one possible way to mitigate its effects on climate change.

The methodology that is being used by the USGS for the assessment was described by Brennan and others (2010), who revised the methodology by Burruss and others (2009) according to comments from peer reviewers, members of the public, and experts on an external panel. The assessment methodology is non-economic and is intended to be used at regional to subbasinal scales.

The operational unit of the assessment is a storage assessment unit (SAU) composed of a porous storage formation with fluid flow and an overlying fine-grained sealing unit. Assessments are conducted at the SAU level and are aggregated to basinal and regional results. SAUs have a minimum depth of 3,000 feet (ft), which ensures that the CO_2 is in a supercritical state (and thus occupies less pore space than a gas). Standard SAUs have a maximum depth of 13,000 ft below the surface, a depth accessible with average injection pipeline pressures (Burruss and others, 2009; Brennan and others, 2010). Where geologic conditions favor CO_2 storage below 13,000 ft, an additional deep SAU is assessed.

The assessments are also constrained by the occurrence of relatively fresh formation water. Specifically, any formation water having a salinity less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS), regardless of depth, has the potential to be used as a potable water supply (U.S. Environmental Protection Agency, 2009). The U.S. Environmental Protection Agency (2008) has proposed the limit of 10,000 mg/L TDS for injection of CO_2. Therefore, the potential storage resources for CO_2 in formations where formation waters have salinities less than 10,000 mg/L TDS are not assessed (Brennan and others, 2010).

This report series contains geologic descriptions of each SAU identified within the assessed basins and focuses on the particular characteristics specified in the methodology that influence the potential CO_2 storage resource. Although assessment results are not contained in these reports, the geologic framework information will be used to calculate a statistical Monte Carlo-based distribution of potential storage space in the various SAUs following Brennan and others (2010). Figures in this report series show SAU boundaries and cell maps of well penetrations through the sealing unit into the top of the storage formation. Wells sharing the same well borehole are treated as a single penetration. Cell maps show the number of penetrating wells within one square mile and are derived from interpretations of incompletely attributed well data (IHS Energy Group, 2011; and other data as available), a digital compilation that is known not to include all drilling. The USGS does not expect to know the location of all wells and cannot guarantee the amount of drilling through specific formations in any given cell shown on cell maps.

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Contents

Figures

Conversion Factors

Multiply	By	To obtain
	Length	
inch (in.)	2.54	centimeter (cm)
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
	Area	
square foot (ft^2)	0.09290	square meter (m^2)
square foot (ft^2)	0.00002296	acre
square mile (mi^2)	2.59	square kilometer (km^2)
	Volume	
barrel (bbl), (petroleum, 1 barrel=42 gal)	0.1590	cubic meter (m^3)
cubic foot (ft^3)	0.02832	cubic meter (m^3)
1,000 cubic feet (MCF)	28.32	cubic meter (m^3)
cubic meter (m^3)	6.290	barrel (petroleum, 1 barrel = 42 gal)

Acronyms and Abbreviations

CO_2 carbon dioxide
EPA U.S. Environmental Protection Agency
mD millidarcy
mg/L milligrams per liter
MMBO million barrels of oil
SAU storage assessment unit
TDS total dissolved solids
USGS U.S. Geological Survey

Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources—U.S. Gulf Coast

By Tina L. Roberts-Ashby, Sean T. Brennan, Marc L. Buursink, Jacob A. Covault[1], William H. Craddock, Ronald M. Drake II, Matthew D. Merrill, Ernie R. Slucher, Peter D. Warwick, Madalyn S. Blondes, Mayur A. Gosai, Philip A. Freeman, Steven M. Cahan, Christina A. DeVera, and Celeste D. Lohr

Abstract

This report presents 27 storage assessment units (SAUs) within the United States (U.S.) Gulf Coast. The U.S. Gulf Coast contains a regionally extensive, thick succession of clastics, carbonates, salts, and other evaporites that were deposited in a highly cyclic depositional environment that was subjected to a fluctuating siliciclastic sediment supply and transgressive and regressive sea levels. At least nine major depositional packages contain porous strata that are potentially suitable for geologic carbon dioxide (CO_2) sequestration within the region. For each SAU identified within these packages, the areal distribution of porous rock that is suitable for geologic CO_2 sequestration is discussed, along with a description of the geologic characteristics that influence the potential CO_2 storage volume and reservoir performance. These characteristics include reservoir depth, gross thickness, net-porous thickness, porosity, permeability, and groundwater salinity. Additionally, a characterization of the overlying regional seal for each SAU is presented. On a case-by-case basis, strategies for estimating the pore volume existing within structurally and (or) stratigraphically closed traps are also presented. Geologic information presented in this report has been employed to calculate potential storage capacities for CO_2 sequestration in the SAUs that are assessed herein, although complete assessment results are not contained in this report.

Introduction

The area assessed within the Gulf of Mexico Basin and the surrounding region is identified in this paper as the United States (U.S.) Gulf Coast, which encompasses an area of approximately 148,049,000 acres and extends across southern, central, and eastern Texas; Louisiana; eastern and southern Arkansas; southeastern Missouri; southwestern Kentucky; western Tennessee; central and southern Mississippi; southern Alabama; the Florida panhandle; and the southwestern corner of Georgia (fig. 1). The U.S. Gulf Coast is a major petroleum-producing region of the United States, and includes the onshore portion of basins within the Gulf of Mexico down to the State-water lines, which mark the southern boundary of the Gulf Coast region study area. Study area boundaries are also delineated by the U.S.-Mexico international border (southwestern boundary); the updip limit of Cretaceous sedimentary rocks (northern boundary); and faults associated with the Ouachita orogenic belt (western boundary), the Ouachita Mountains (northern boundary), and the Appalachian Mountains (northeastern boundary; fig. 1). Sea-level oscillations had a major impact on sedimentation and the types of depositional environments that existed within the region. Additionally, fluctuations in clastic sediment supply associated with uplift and erosion of nearby mountain ranges, fluctuating channels and drainage systems, and changes in basin structure greatly affected sedimentation within the region, including the presence or absence and extent of carbonate environments.

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The Gulf of Mexico Basin and surrounding region within the U.S. Gulf Coast were originally formed as a result of crustal extension and expansion of the seafloor associated with the breakup of Pangea during Mesozoic time (Sawyer and others, 1991). The main depocenter of the Gulf Coast region, which is thought to underlie the southern Louisiana coastal plain and adjacent continental shelf, contains as much as 65,600 feet (ft) of rock that accumulated from the Jurassic through the Holocene (Galloway, 2011). The strata within the U.S. Gulf Coast is generally composed of sedimentary rocks that were largely deposited over a thick sequence of salt (Louann Salt) and other evaporites, especially in the northern and southern regions (Salvador, 1991a). The positions and trends of salt structures, which are dependent upon the basement faults together with gravity tectonic structures, affected sediment supply and distribution within the basins and had a major impact on the generation and mobilization of hydrocarbons within the region (Galloway, 2011).

The strata within the area of the U.S. Gulf Coast (figs. 2*A*, 2*B*, 2*C*, 2*D*, and 2*E*) can be divided into nine major depositional packages, which are composed of 28 composite depositional episodes, as outlined by Galloway (2011), and are separated by local and regional unconformities and (or) maximum-flooding disconformities. These depositional packages are useful for identifying prospective reservoir intervals and regional seals and are from oldest to youngest (1) a tectonostratigraphic megasequence of salts and other evaporites, siliclastics, and carbonates that includes the Upper Jurassic to Lower Cretaceous Louann Salt, Smackover Formation, and Cotton Valley Group; (2) pro-delta and fluvial-deltaic deposits of the Lower Cretaceous Hosston Formation, which was deposited following the cessation of seafloor spreading in the Gulf; (3) Lower Cretaceous carbonate-dominated sedimentation on a reef-rimmed carbonate margin; (4) Upper Cretaceous Tuscaloosa and Woodbine Formations deltaic deposits associated with prograding, rejuvenated clastic systems; (5) Upper Cretaceous carbonate, sandstone, basinal marl, and mudrock deposits that created a ramp-like shelf margin; (6) Paleocene-Eocene-Oligocene siliciclastic, volcanic ash, and volcaniclastic deposits associated with a prograding shelf and slope; (7) increased sediment supply leading to an extensive continental-margin progradation during the Miocene, in conjunction with a shift in the basin’s depocenter from the northwestern to the northeastern margin and the rejuvenation of the Appalachian and Cumberland Plateau uplands; (8) early Pliocene multi-sequence deposition associated with rapid, glacio-eustatic sea-level fluctuations; and (9) upper Pliocene and Quaternary fluvial-dominated delta and subjacent slope-apron-system deposits, as well as canyon excavation resulting from glacial meltwater surges (Salvador, 1991a; Dyman and Condon, 2006; Galloway, 2011).

The Gulf Coast is one of the most productive and heavily explored petroleum-producing regions in the United States, with basins that contain numerous mature oil and gas fields. Recently completed geologic assessments of undiscovered oil and gas resources conducted by the U.S. Geological Survey (USGS) present the extensive history of hydrocarbon production in the U.S. Gulf Coast region (Schenk and Viger, 1995a,b; USGS Cotton Valley Assessment Team, 2003; USGS Travis Peak-Hosston Assessment Team, 2003; USGS Navarro and Taylor Groups Assessment Team, 2004, 2006; USGS Gulf Coast Region Assessment Team, 2006; Dubiel and others, 2007a, 2011, 2012; Pitman and others, 2007; Pearson and others, 2011). The USGS estimates that approximately 1,482 million barrels of oil (MMBO), 153,290 billion cubic feet of gas, and approximately 5,168 million barrels of natural gas liquids remain undiscovered in the area of the Gulf Coast that was assessed in this report (USGS Cotton Valley Assessment Team, 2003; USGS Travis Peak-Hosston Assessment Team, 2003; USGS Navarro and Taylor Groups Assessment Team, 2004; Dubiel and others, 2007a, 2011; Pitman and others, 2007). Because the Gulf Coast has been one of the most productive regions within the U.S., pore volumes associated with existing and depleted oil and gas fields may be available for the purpose of geologic CO_2 sequestration, with the additional possibility of uncharged traps that have yet to be discovered. Non-petroleum-producing saline aquifers occur throughout the region as well, with total dissolved solid (TDS) concentrations exceeding 10,000 milligrams per liter (mg/L). These aquifers can provide additional porous storage space for CO_2 sequestration.

Numerous geochemically distinct hydrocarbon systems in the U.S. Gulf Coast are associated with unique source rocks and are confined to discrete stratigraphic intervals (Schenk and Viger, 1995a,b;

USGS Cotton Valley Assessment Team, 2003; USGS Travis Peak-Hosston Assessment Team, 2003; USGS Navarro and Taylor Groups Assessment Team, 2004, 2006; USGS Gulf Coast Region Assessment Team, 2006; Pitman and others, 2007; Dubiel and others, 2011, 2012; Pearson and others, 2011). This stratigraphic confinement of hydrocarbon systems is important to the potential for geologic CO_2 sequestration because it suggests the presence of several regional sealing units that are internal to basin fill within the region. The geographic extent of "regional" can vary from basin to basin within the United States. Within the U.S. Gulf Coast, "regional" is considered to be an area that typically extends across two or more States. Regional seals are essential components to CO_2 storage sites, and their likely presence in hydrocarbon systems of the U.S. Gulf Coast suggests the potential for containment of CO_2 over long periods of geologic time (that is, millennia), and a low risk of leakage from storage sites into overlying sources of drinking water or into the atmosphere (Wilson and others, 2003).

Multiple geologic units within the U.S. Gulf Coast meet the USGS criteria for conducting a regional assessment for CO_2 storage capacity and are confined to the first seven previously discussed depositional packages. The remaining two depositional packages (numbered 8 and 9), where they meet the USGS criteria, are for the most part present in Federal offshore waters and are the purview of the Bureau of Ocean Energy Management. It should be noted that each storage assessment unit (SAU) assigned to these geologic units has varying extent across the U.S. Gulf Coast region. The USGS-assessed reservoir units include (1) Upper Jurassic Norphlet Formation SAUs, (2) Upper Jurassic Smackover Formation SAUs, (3) Upper Jurassic Haynesville Formation SAUs, (4) Lower Cretaceous Sligo and Hosston Formations and Upper Jurassic and Lower Cretaceous Cotton Valley Group SAUs, (5) Lower Cretaceous Knowles and Winn Limestones and Calvin Sandstone SAU, (6) Lower Cretaceous Rodessa Formation and James Limestone SAUs, (7) Lower Cretaceous Fredericksburg Group and Rusk Formation SAU, (8) Lower Cretaceous Edwards, Glen Rose, and James Limestones SAU, (9) Lower Cretaceous Washita and Fredericksburg Groups, Rusk Formation, and James Limestone SAUs, (10) Upper Cretaceous Tuscaloosa and Woodbine Formations SAU, (11) Upper Cretaceous Navarro, Taylor, and Austin Groups SAU, (12) Paleogene Carrizo Sand and Wilcox Group SAU, (13) Paleogene Queen City Sand SAU, (14) Paleogene Sparta Sand SAU, (15) Paleogene Yegua and Cockfield Formations SAU, (16) Paleogene Frio and Vicksburg Formations SAU, (17) Neogene Lower Miocene I and II, Middle, and Upper Miocene SAUs, and (18) Paleogene and Neogene Tertiary slope and basin floor SAU (figs. 2*A*, 2*B*, 2*C*, 2*D*, and 2*E*).

In the following sections, the depositional setting, distribution, and stratigraphy of each prospective SAU is presented. Key information that provides the basis for calculating the capacity of each SAU for buoyant and residual CO_2 storage (as described in Burruss and others, 2009; Brennan and others, 2010; Blondes and others, 2013), as well as information that relates to the reservoir characteristics for each unit, is also summarized. Such key input parameters include depth from surface; area; gross thickness; net-porous-interval thickness, or the portion of the SAU gross thickness that contains porous rock identified as being sufficient for CO_2 storage; porosity of the net-porous-interval; and range of permeability for the entire SAU. Because the U.S. Environmental Protection Agency (EPA; 2009, 2013) stipulates that aquifers used for CO_2 sequestration must contain groundwater with a TDS concentration greater than 10,000 mg/L, regional trends in groundwater quality for an assessed area are characterized, and the area fraction of the SAU that is available for CO_2 storage is estimated. All parameters were estimated using a combination of proprietary databases (such as IHS Energy Group, 2010, 2011 and Nehring Associates, Inc., 2010); public and non-proprietary databases; and published literature, including isopachs, structure maps, and cross-sections.

Finally, in order to differentiate between the pore volume contained within buoyant traps and that contained within residual traps for the various SAUs (see Brennan and others, 2010; Blondes and others, 2013), the pore volume enclosed within buoyant traps, which are analogous to stratigraphic and (or) structural hydrocarbon traps, is defined. For each SAU, (a) minimum and (b) most likely pore volumes enclosed within buoyant traps were constrained on the basis of (1) the sum of the cumulative oil and gas production and the known hydrocarbon reserve volume and (2) the minimum buoyant pore volume plus the estimated volume of undiscovered resources (see Brennan and others, 2010; Blondes and others, 2013). Because this method was applied to all SAUs, it is not discussed on a case-by-case basis. An upper bound for enclosed pore volume was also determined for each unit, and methods for the various SAUs are discussed on a case-by-case basis. The information derived from the data sources and methods described in this report were used in accordance with the USGS Carbon Sequestration Assessment Methodology (Brennan and others, 2010; Blondes and others, 2013) to calculate the available storage space for CO_2 within each SAU.

Stratigraphic columns are provided that display the stratigraphy within the U.S. Gulf Coast study area, as well as that within each SAU that was identified for these rocks (figs. 2*A*, 2*B*, 2*C*, 2*D*, and 2*E*). These stratigraphic columns indicate stratigraphy variation from east to west across the study area; they do not display stratigraphic variation from updip to downdip. Additionally, the authors recognize that there is some contradiction in chronostratigraphy for Jurassic and Cretaceous units within the study area (see Swain, 1944; Goldhammer and Johnson, 2001; Mancini and Puckett, 2005; Mancini and others, 2008b; Rosen and Rosen, 2008). At this time, and until further investigation can be conducted, data and age of rocks presented by Goldhammer and Johnson (2001), Mancini and Puckett (2005), and Mancini and others (2008b) are adapted for this report.

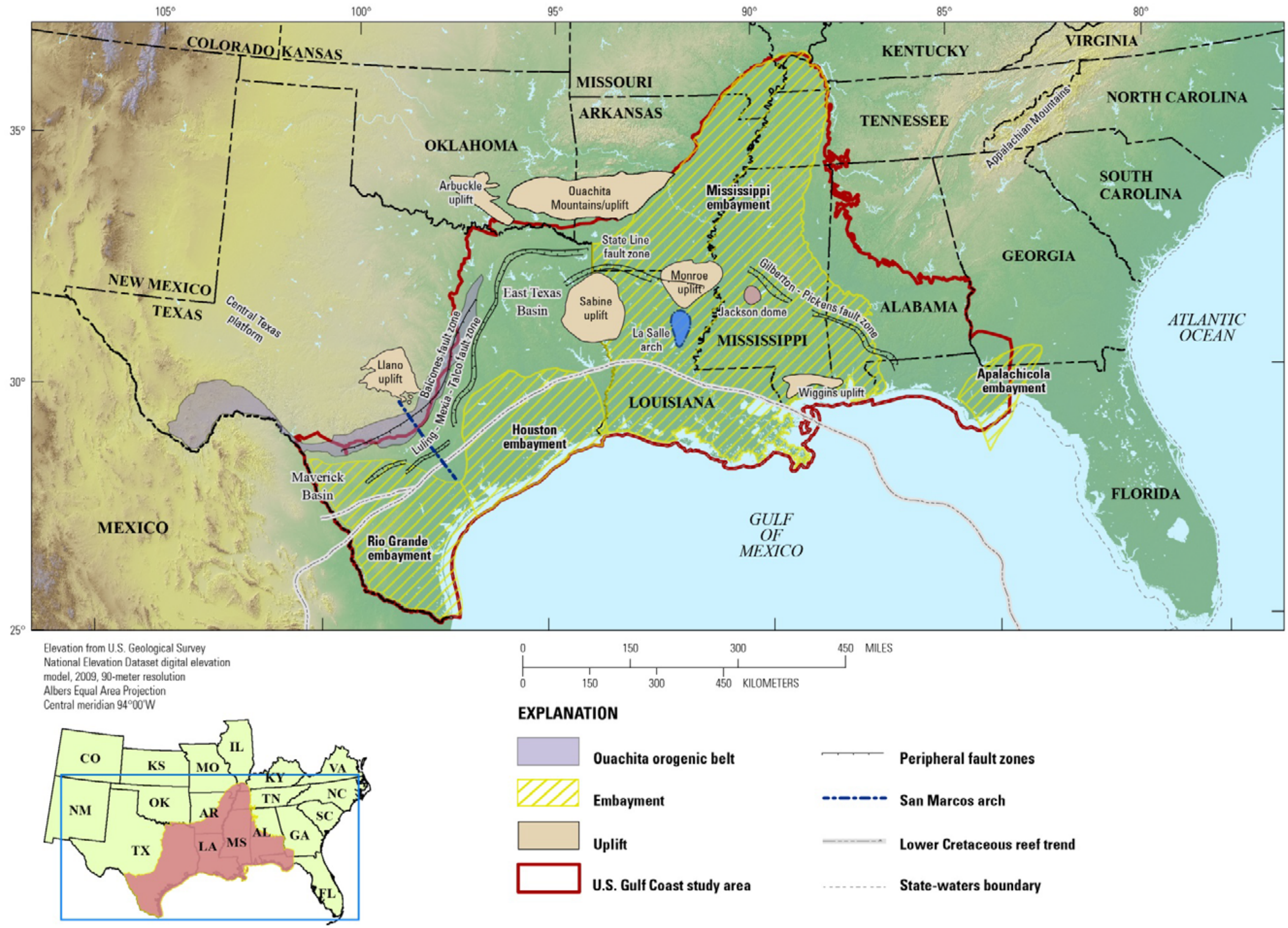

Figure 1. Geologic map of the U.S. Gulf Coast study area within the southern U.S. Major structural features adapted from Ewing and Lopez (1991) and Galloway (2011). In the inset on the lower left, area in red is the U.S. Gulf Coast study area.

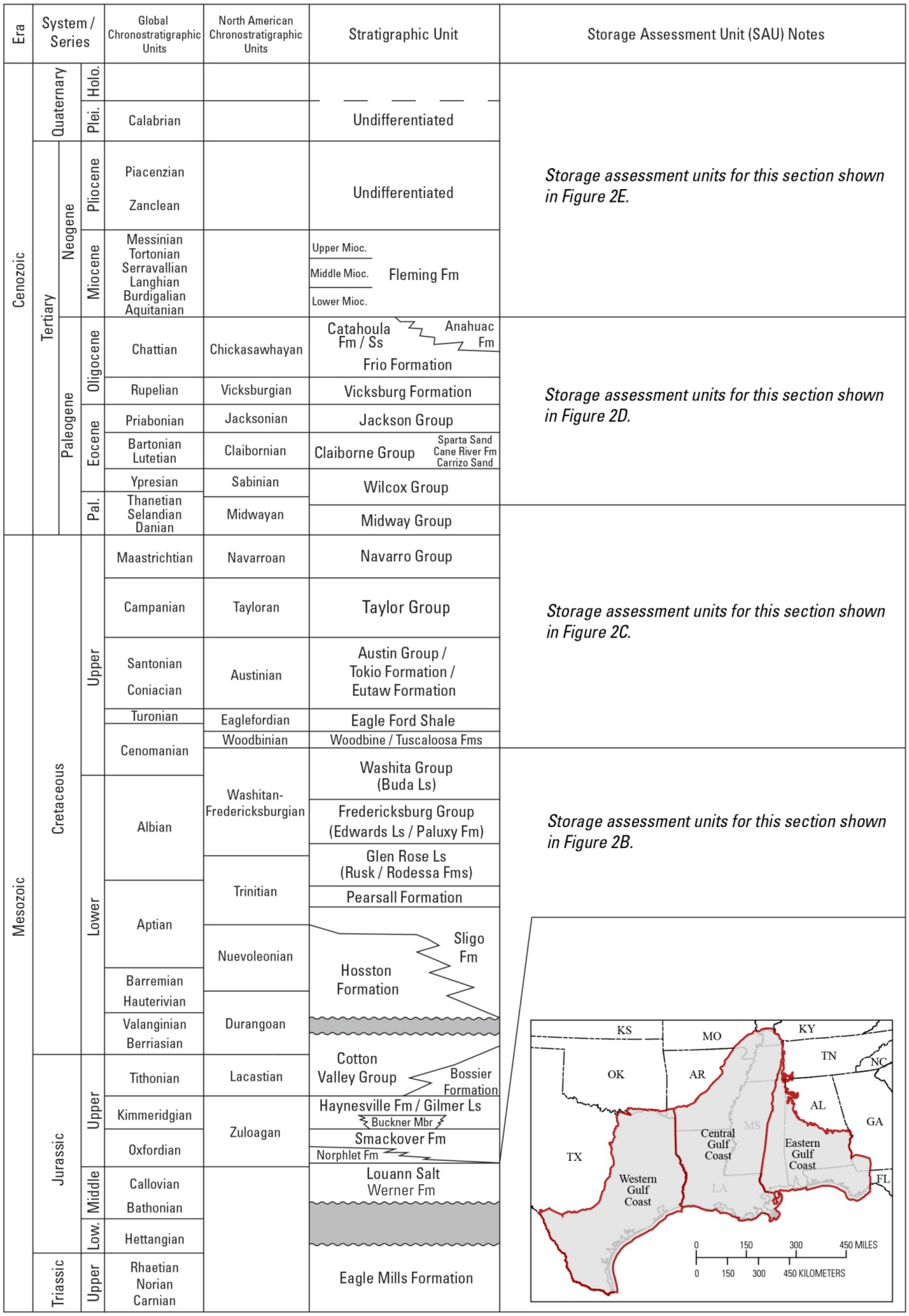

Figure 2A. Main stratigraphic column for the U.S. Gulf Coast study area. Wavy lines indicate unconformable contacts, and gray areas represent unconformities. Adapted from Salvador and Quezada-Muñeton (1991), Dubiel and others (2007a), Warwick and others (2007), and Mancini and others (2008b). Ls = Limestone; Fm = Formation; Mbr = Member.

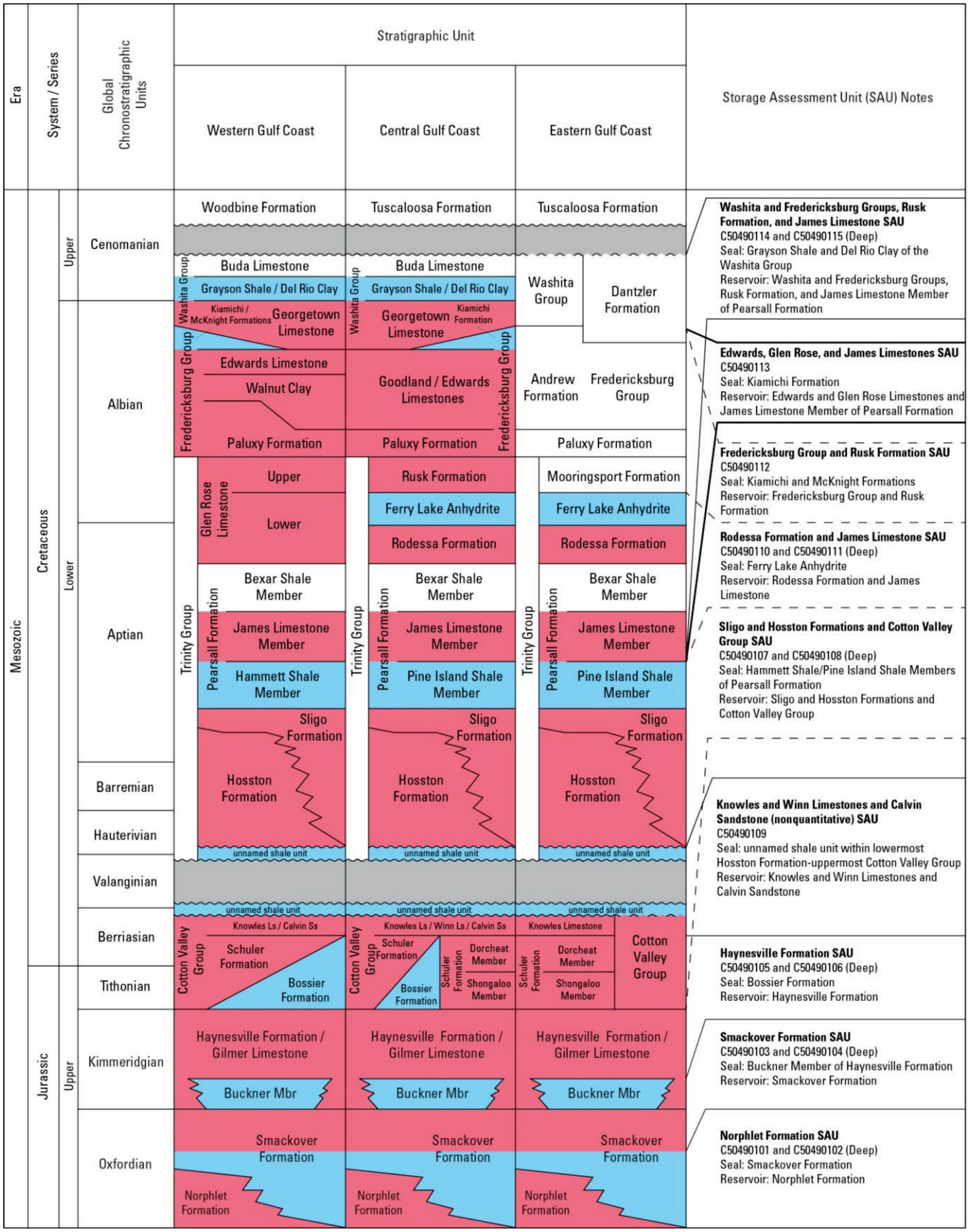

Figure 2B. Stratigraphic column displaying the east-west distribution of the Upper Jurassic and Cretaceous geologic units within the U.S. Gulf Coast study area. Storage assessment units consist of a reservoir (red) and regional seal (blue). Wavy lines indicate unconformable contacts, and gray areas represent unconformities. Adapted from Nehring (1991), Salvador and Quezada-Muñeton (1991), Goldhammer and Johnson (2001), Witrock and others (2003), Sweezey and Sullivan (2004), Mancini and Puckett (2005), Warwick and others (2007), Mancini and others (2008b), Valentine and Dennen (2012), and Walker and others (2012).

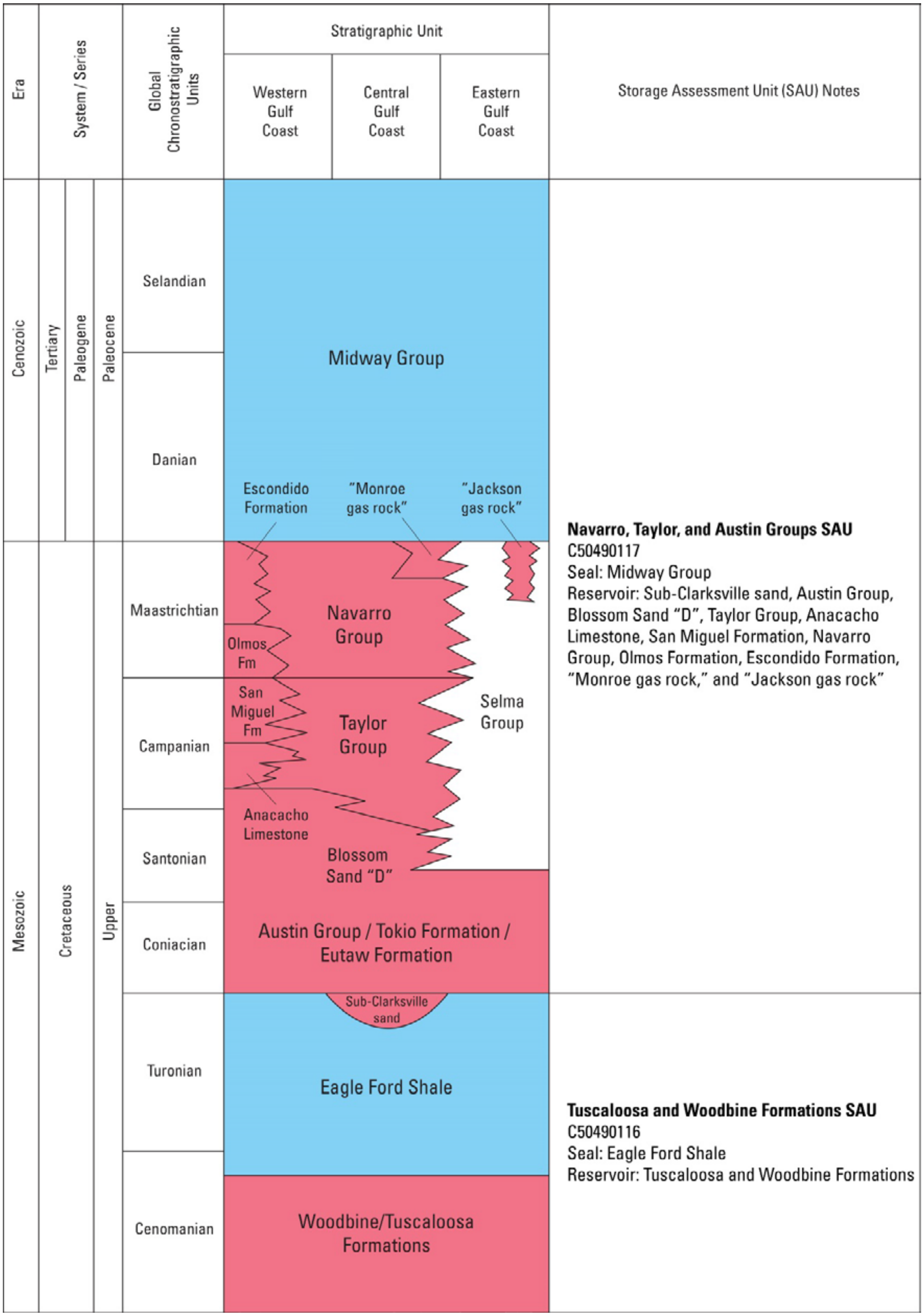

Figure 2C. Stratigraphic column displaying the east-west distribution of the Upper Cretaceous and lower Tertiary rocks within the U.S. Gulf Coast study area. Storage assessment units consist of a reservoir (red) and regional seal (blue). Wavy lines indicate unconformable contacts. Adapted from Salvador and Quezada-Muñeton (1991), Warwick and others (2007), and Mancini and others (2008b). Fm = Formation.

Figure 2D. Stratigraphic column displaying the east-west distribution of the Tertiary rocks within the U.S. Gulf Coast study area—Part 1. Storage assessment units consist of a reservoir (red) and regional seal (blue). Wavy lines indicate unconformable contacts. Adapted from Salvador and Quezada-Muñeton (1991), Galloway and others (1994), Lawless and others (1997), Warwick and others (1997, 2007), Witrock and others (2003), Dubiel and others (2007a), and Valentine and Dennen (2012), Walker and others (2012). Fm = Formation.

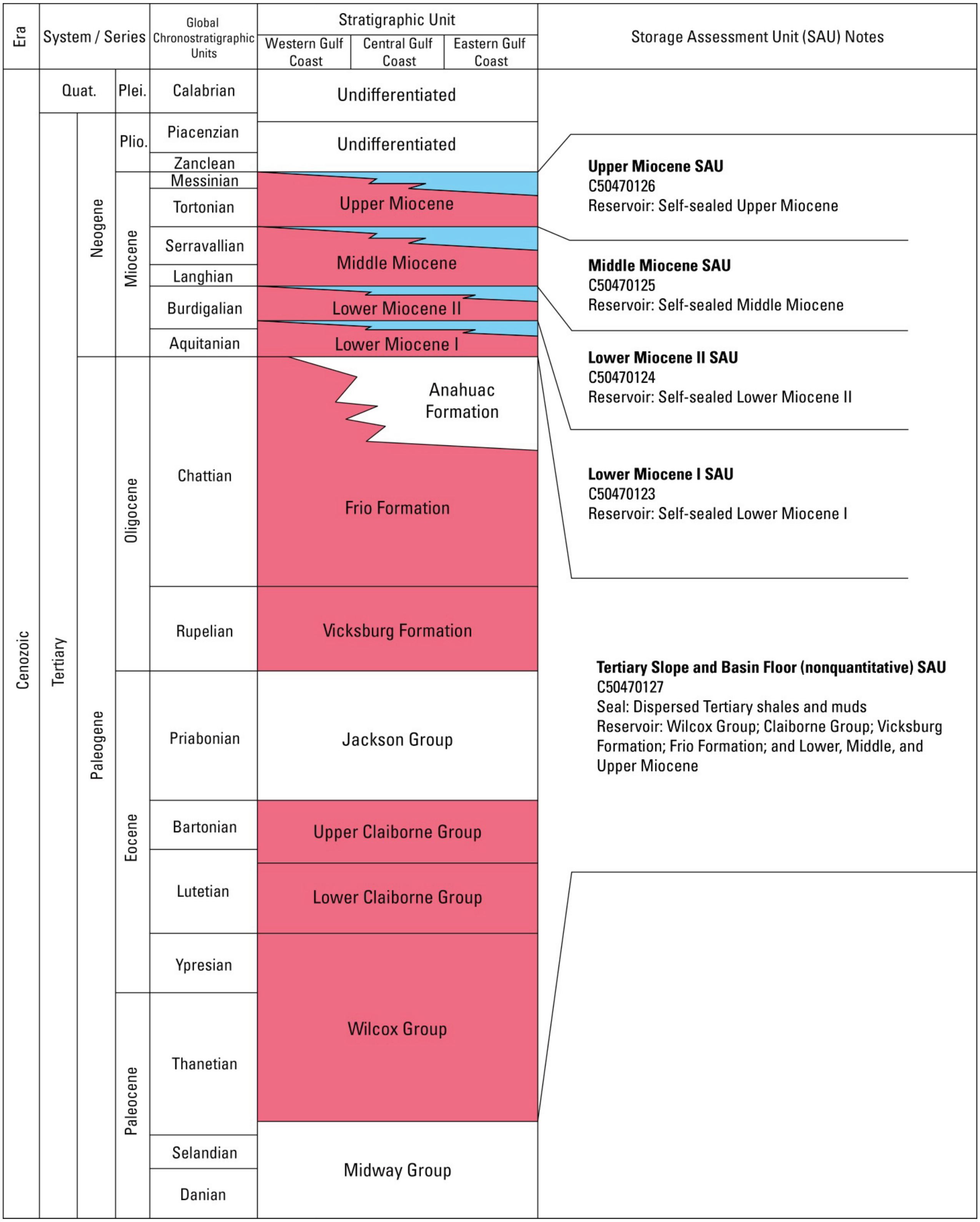

Figure 2E. Stratigraphic column displaying the east-west distribution of the Tertiary rocks within the U.S. Gulf Coast study area—Part 2. Storage assessment units consist of a reservoir (red) and regional seal (blue). Wavy lines indicate unconformable contacts. Adapted from Dubiel and others (2007a), Warwick and others (2007), and Mancini and others (2008b).

Norphlet Formation SAU C50490101 and Norphlet Formation Deep SAU C50490102

By Marc L. Buursink

The Norphlet Formation SAUs consist of those portions of the preserved Upper Jurassic (lower Oxfordian) siliciclastic lithology deemed suitable as reservoir rock for CO_2 sequestration that occurs beneath a regionally extensive seal in the U.S. Gulf Coast study area (figs. 1, 2*A*, and 2*B*). The Jurassic section in the northern basin of the U.S. Gulf Coast consists of siliciclastic, carbonate, and evaporite deposits, which accumulated after the break-up of Pangaea in continental to deeper marine environments, where the bathymetry was modified by salt tectonics or basement features (Mancini and others, 1990; Rhodes and Maxwell, 1993). The Norphlet Formation comprises sandstone, conglomeratic sandstone, and interbedded shale and siltstone deposited in eolian dune, alluvial fan, and fluvial and nearshore marine system environments (Salvador, 1991a; Mancini, 2010). Regionally, the lime mudstone of the lower portion of the Smackover Formation overlies the Norphlet Formation (Nehring, 1991; Salvador, 1991b) and functions as the sealing lithology (fig. 2*B*). The gray to black, carbonate mudstone and argillaceous limestone of the lower Smackover Formation were deposited in low-energy environments (Schenk and Viger, 1995a,b; Dubiel and others, 2011). Hydrocarbon exploration and exploitation in the Smackover Formation shales (Mancini and others, 2008a) may potentially compromise the seal for the Norphlet Formation CO_2 storage reservoir.

The Norphlet Formation SAU boundaries are constrained by the presence and depth below the surface of the top of the storage formation and by the presence and thickness of the regional seal. Formation picks for the Norphlet Formation, as reported in a commercial database (IHS Energy Group, 2011), helped define the top of each SAU. The SAU boundary interpretations were supported by (a) the Gulf of Mexico Basin geologic maps and cross sections in the Geological Society of America's Decade of North American Geology volume by Salvador (1991a,b), (b) the chapter and maps on the depositional evolution of the Gulf of Mexico by Galloway (2008), (c) the maps for reservoirs and petroleum systems of the Gulf Coast by Pitman (2011), and (d) formation tops (IHS Energy Group, 2011) differencing to obtain the regional seal thickness. Consequently, Norphlet Formation SAU C50490101 ranges between 3,000 and 13,000 ft in depth and has about a 29 million-acre most-likely area, whereas the Norphlet Formation Deep SAU C50490102 ranges between 13,000 and 22,000 ft and has about a 62 million-acre most-likely area (fig. 3). The larger Norphlet Formation Deep SAU extends from the U.S. and Mexico border toward the northeast and adjoins the Norphlet Formation SAU out to the Florida panhandle.

The thickness and facies distribution of the Norphlet Formation was affected by the paleo-topography of the U.S. Gulf Coast (Mancini and others, 1990; Rhodes and Maxwell, 1993). Regionally, the gross thicknesses range up to about 100 ft (Salvador, 1991b) onshore, whereas farther offshore, the thicknesses range from 600 to 800 ft (Mink and others, 1990). Analysis of the stratigraphy, net-to-gross ratio, and net-porous intervals of the Norphlet Formation within the SAUs were conducted using descriptions by Marzano (1988) and Bolin and others (1989); using cross sections by Hughes (1968) and Tew and others (1991); and were supplemented with sand and isopach maps by Schenk and Schmoker (1993) and Salvador (1987, 1991b), respectively. The Norphlet Formation SAU C50490101 average gross thickness ranges from 150 to 1,000 ft, with an average net-porous thickness between 100 and 300 ft. The Norphlet Formation Deep SAU C50490102 gross thickness ranges from 80 to 500 ft, with a net-porous thickness between 50 and 150 ft.

The Norphlet Formation is a productive oil and gas interval in the U.S. Gulf Coast, and reservoir-quality data are reported in multiple publications and databases. The first oil and gas discovery in the

Norphlet Formation was made in 1967, and since then 15 fields in mostly structural traps have produced 12 MMBO and 138 billion cubic feet of gas (Bearden and others, 2000). Despite relatively deep reservoirs, Norphlet Formation porosity is described as excellent (Bolin and others, 1989; Dixon and others, 1989). Published porosity and permeability values (Badon, 1975; Mancini, 2010) were compared to sandstone analogs (Nelson and Kibler, 2003; Ehrenberg and others, 2009), and average field values obtained from Nehring Associates, Inc. (2010) for the U.S. Gulf Coast study area were used for additional comparison. Based upon a review of these published results, the Norphlet Formation SAU C50490101 was assigned an average porosity range from 10 to 18 percent and a permeability range from 10 to 1,000 millidarcies (mD). The Norphlet Formation Deep SAU C50490102 was assigned an average porosity range from 5 to 15 percent and a permeability range from 1 to 900 mD.

Water-quality data obtained from a published database (Breit, 2002) indicates that saline formation waters (TDS >10,000 mg/L) are predominant within the Norphlet Formation SAUs; this is expected considering the storage formation overlies the Middle and Upper Jurassic Louann Salt (Galloway, 2008; Mancini, 2010). Only relatively small areas exist within the SAUs that contain groundwater with TDS values below the EPA underground sources of drinking water limit of 10,000 mg/L (EPA, 2009, 2010). Consequently, the storage formation areas with groundwater having TDS values below the 10,000 mg/L total TDS limit were delineated for each SAU and made up about 5 percent each of the estimated Norphlet Formation SAU and Norphlet Formation Deep SAU areas.

To create a probabilistic maximum for buoyant-trapping volume within each of the SAUs, first the Nehring Associates, Inc. (2010) field locations were plotted and the average field size was computed. The field locations and size were then extrapolated across the remaining SAU areas and summed to generate the probabilistic maximum. This estimate was made with the assumption that structural traps are dominant in the areas of the SAUs (Bearden and others, 2000).

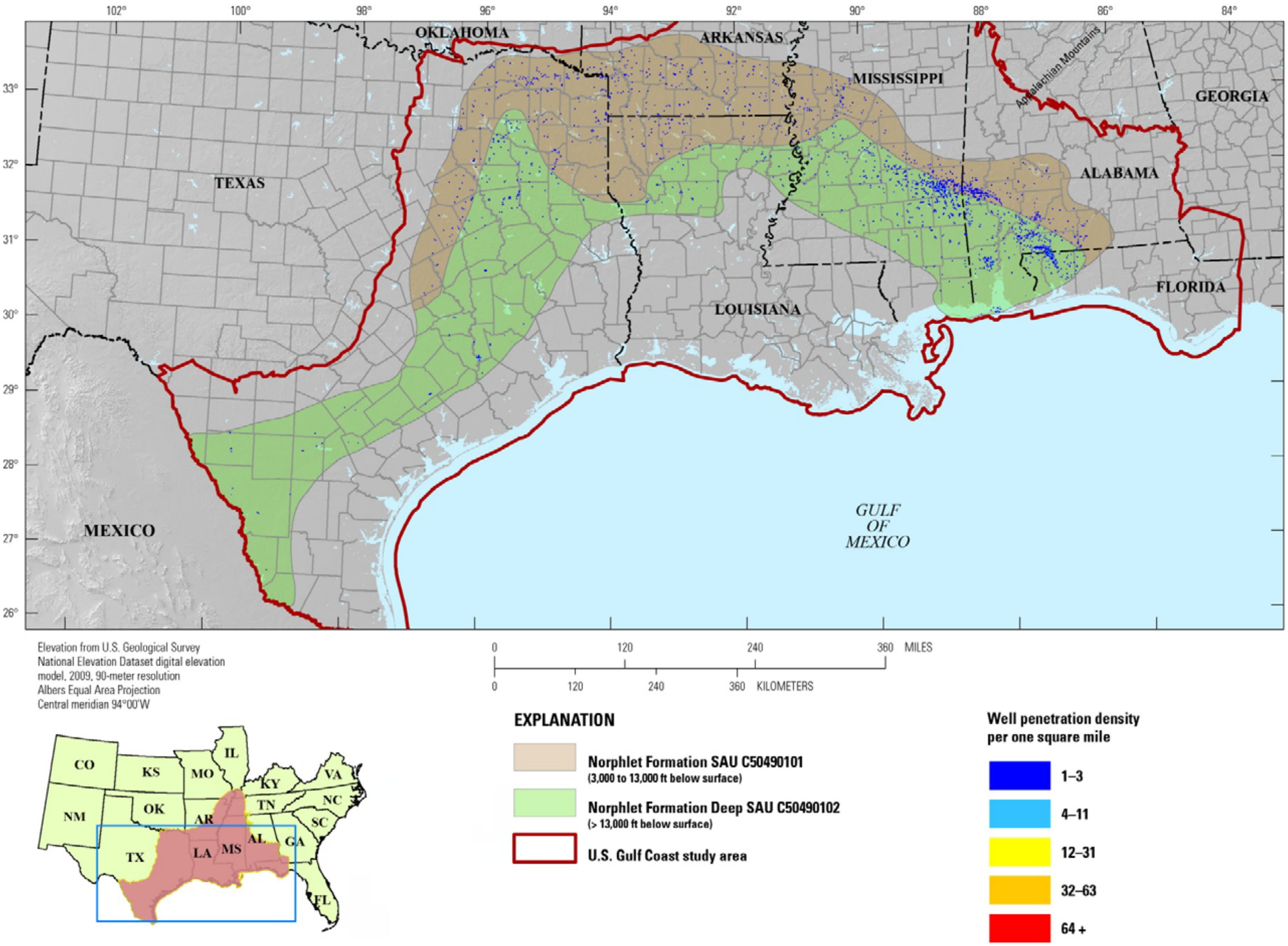

Figure 3. Map of the U.S. Geological Survey storage assessment unit (SAU) boundaries for the Norphlet Formation and Norphlet Formation Deep SAUs in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir-formation top.

Smackover Formation SAU C50490103 and Smackover Formation Deep SAU C50490104

By Marc L. Buursink

The Smackover Formation SAUs consist of those portions of the preserved Upper Jurassic (upper Oxfordian) carbonate lithology deemed suitable as reservoir rock for CO_2 sequestration that occurs beneath a regionally extensive Buckner Member of Haynesville Formation seal in the U.S. Gulf Coast study area (figs. 1, 2*A*, and 2*B*). The Jurassic section in the northern basin of the U.S. Gulf Coast consists of siliciclastic, carbonate, and evaporite deposits, which accumulated after the breakup of Pangaea in continental to deeper marine environments, where the bathymetry was modified by salt tectonics or basement features (Mancini and others, 1990; Rhodes and Maxwell, 1993). The Smackover Formation consists of coral-microbial and microbial buildups developed during the maximum marine transgression in the late Oxfordian, and higher energy nearshore and shoal deposits accumulated with a slowing of sea level rise (Mancini, 2010). The upper portion of the Smackover Formation consists of mostly grain-supported carbonates, including grainstones, packstones, and boundstones deposited in high-energy, shallow-water environments (Salvador, 1991b). Regionally, the anhydrite of the Buckner Member of Haynesville Formation and the undifferentiated mudstones of the lower portion of the Haynesville Formation overlie the Smackover Formation storage reservoir (Schenk and Viger, 1995b; Moore, 1997; Cicero and others, 2010) and function as the sealing lithology (fig. 2*B*). The Buckner Member accumulated on shoal-restricted, shallow, inner platforms (Galloway, 2008), and the Haynesville Formation mudstone was deposited as contemporaneous retrogradational and progradational facies across a restricted basin (Cicero and others, 2010). Hydrocarbon exploration and exploitation in the Haynesville Formation shales (U.S. Energy Information Administration, 2011) may potentially compromise the seal for the Smackover Formation CO_2 storage reservoir.

The Smackover Formation SAU boundaries are constrained by (a) the presence and depth below the surface of this storage-formation top, (b) by the presence and thickness of a regional seal, and (c) by the extent of the State waters. Formation picks for the Smackover Formation, as reported in a commercial database (IHS Energy Group, 2011), helped define the top of each SAU. These interpretations were supported by (a) the Gulf of Mexico Basin geologic maps and cross sections in the Geological Society of America's Decade of North American Geology volume by Salvador (1991a,b), (b) the chapter and maps on the depositional evolution of the Gulf of Mexico by Galloway (2008), (c) the maps for reservoirs and petroleum systems of the Gulf Coast by Pitman (2011), and (d) formation tops (IHS Energy Group, 2011) differencing to obtain the regional seal thickness. Consequently, Smackover Formation SAU C50490103 ranges from 3,000 to 13,000 ft in depth and has about a 31 million-acre most-likely area, whereas the Smackover Formation Deep SAU C50490104 ranges from 13,000 to 24,000 ft in depth and has about a 44 million-acre most-likely area (fig. 4). The Smackover Formation SAU and the Smackover Formation Deep SAU adjoin and extend from east Texas to the Florida panhandle and the edge of the State waters.

The Smackover Formation thickness is deformed by multiple extensional faults and grabens related to salt movement (Mancini and others, 1990). Regionally, the gross thickness of the Smackover Formation ranges from a few hundred feet (onshore and coastal areas of northeastern Gulf of Mexico) to over a thousand feet (south-southwest of coastal areas) (Mancini and others, 1990). Analysis of the stratigraphy, net-to-gross ratio, and net-porous intervals of the Smackover Formation within the SAUs were mainly conducted using data provided by Nehring (1991), Nehring Associates, Inc. (2010), and Fishman and others (2008), and were supplemented by isopach maps from Mancini and Benson (1980) and Cagle and Khan (1983). The Smackover Formation SAU C50490103 average gross thickness ranges from 100 to 500 ft, with an average net-porous thickness between 50 and 200 ft. The Smackover Formation Deep SAU C50490104 average gross thickness ranges from 80 to 400 ft, with an average net-porous thickness between 40 and 100 ft.

The Smackover Formation is a productive oil and gas interval in the U.S. Gulf Coast, and reservoir-quality data are reported in multiple publications and databases. The first oil and gas discovery in the Smackover Formation was made in 1963, and since then 82 fields in structural and combination traps have produced 258 MMBO and 1 trillion cubic feet of gas (Bearden and others, 2000). Diagenesis has affected reservoir porosity and permeability in the Smackover Formation (Moore, 1997; Fowler and Benson, 2000). More porous intervals in the Smackover Formation are found in fields that rim the northern margin of the Gulf of Mexico Basin (Nehring, 1991). Published porosity and permeability values (Fishman and others, 2008; Mancini, 2010) were compared to carbonate analogs (Murray, 1960; Ehrenberg and others, 2009), and average field values obtained from Nehring Associates, Inc. (2010) for the U.S. Gulf Coast study area were used for additional comparison. Based upon a review of these published results, the Smackover Formation SAU C50490103 was assigned an average porosity range from 10 to 20 percent and a permeability range from 0.1 to 1,000 mD. The Smackover Formation Deep SAU C50490104 was assigned an average porosity range from 8 to 15 percent and a permeability range from 0.01 to 500 mD.

Water-quality data obtained from a published database (Breit, 2002) indicates that saline formation waters (TDS >10,000 mg/L) are predominant within the Smackover Formation SAUs, and this is expected considering the storage formation overlies the Middle and Upper Jurassic Louann Salt and underlies evaporites of the Buckner Member of the Haynesville Formation (Galloway, 2008; Mancini, 2010). Only relatively small areas exist within the SAUs that contain groundwater with TDS values below the EPA underground sources of drinking water limit of 10,000 mg/L (EPA, 2009, 2010). Consequently, the storage formation areas with groundwater having TDS values below the 10,000 mg/L total TDS limit were delineated for each SAU and made up about 5 percent each of the estimated Smackover Formation SAU and Smackover Formation Deep SAU areas.

To create a probabilistic maximum for buoyant-trapping volume within each of the SAUs, first the Nehring Associates, Inc. (2010) field locations were plotted and the average field size was computed. The field locations and size were then extrapolated across the remaining SAU areas and summed to generate the probabilistic maximum. This estimate was made with the assumption that structural traps are dominant in the areas of the SAUs (Bearden and others, 2000).

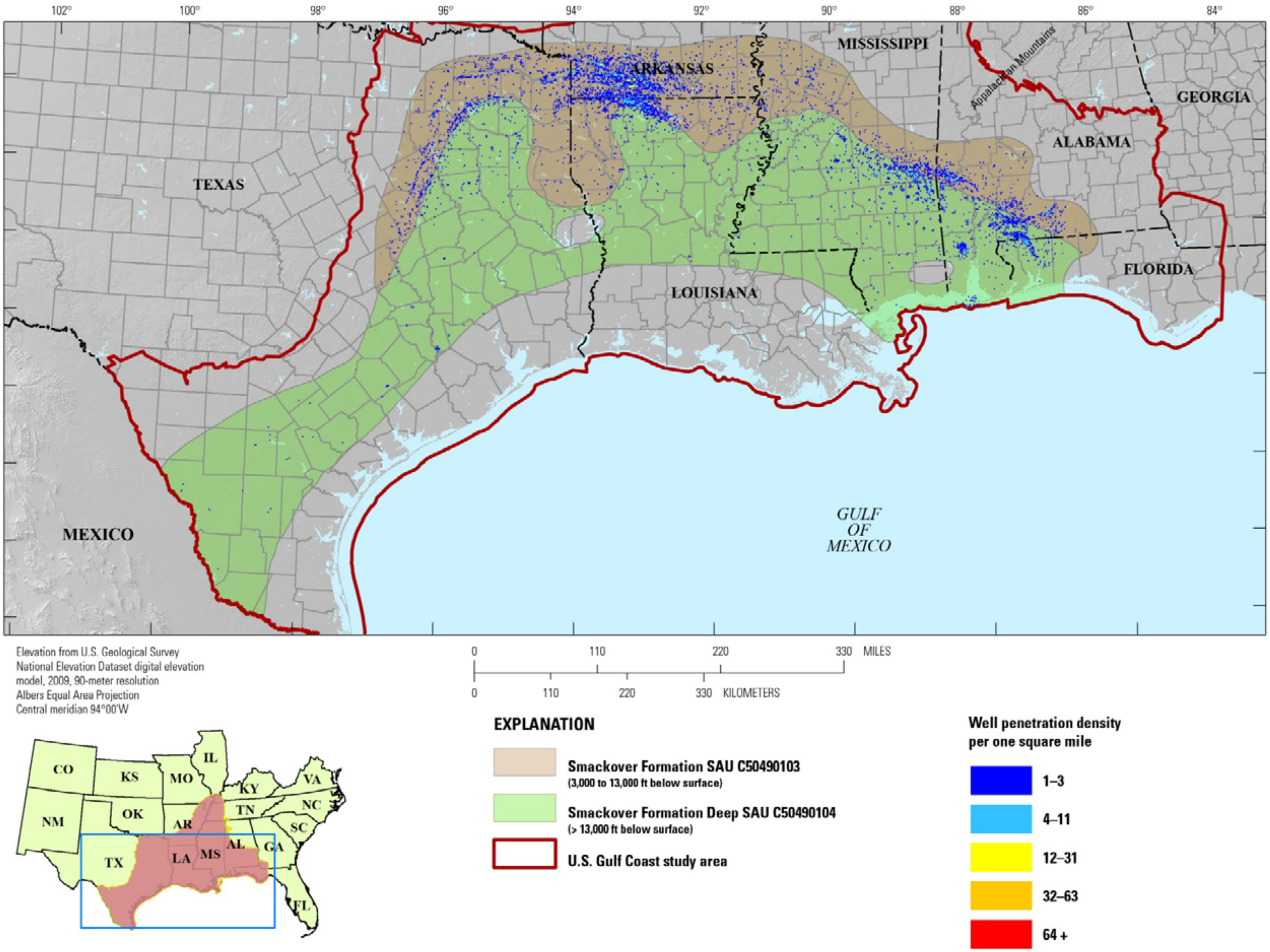

Figure 4. Map of the U.S. Geological Survey storage assessment unit (SAU) boundaries for the Smackover Formation and Smackover Formation Deep SAUs in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir-formation top.

Haynesville Formation SAU C50490105 and Haynesville Formation Deep SAU C50490106

By Tina L. Roberts-Ashby

The Upper Jurassic Haynesville Formation is a carbonate and siliclastic unit within the U.S. Gulf Coast (Forgotson and Forgotson, 1976) that forms a potential CO_2 storage reservoir that mainly extends across eastern Texas and into north-central Louisiana (figs. 2*A*, 2*B*, and 5). The carbonates within the Haynesville Formation have also been referred to as the Cotton Valley Lime/Limestone, Gilmer Limestone, or Buckner Limestone (Forgotson and Forgotson, 1976; Ahr, 1981; Nehring, 1991), and were generally deposited on a mature ramp in a shallow-water, marine-shoal environment, possibly during sea-level regression, and commonly over salt-supported structures (Ahr, 1981; Byram, 1988; Nehring, 1991). The Haynesville Formation carbonates have undergone little dolomitization (Ahr, 1981) and have varying lithology that includes dense, micritic limestones; oolitic and pseudo-oolitic limestones; argillaceous limestones; and pelletal grainstones and packstones (Forgotson and Forgotson, 1976; Ahr, 1981). The carbonate rocks within the Haynesville Formation grade into siliciclastics to the west, north, and northeast, and predominate in northeastern Louisiana, southeastern Arkansas, and central Mississippi (Forgotson and Forgotson, 1976; Salvador, 1991b). The Haynesville Formation siliciclastics include coarse sandstones and conglomerates, organic-rich shales, and calcareous shales that are terrigenous, non-marine, as well as near-shore and marginal-marine sediments that underwent some degree of marine reworking (Maher and others, 1968; Forgotson and Forgotson, 1976; Nehring, 1991; Salvador, 1991b; Mancini, 2010). Within the region of the CO_2 storage reservoir, the producing sandstones of the Haynesville Formation are concentrated in northern Louisiana. Depending upon location within the U.S. Gulf Coast, the Haynesville Formation carbonate and siliciclastic reservoirs are either underlain by the evaporites of the Buckner Member of the Haynesville Formation, or the evaporites of the Smackover Formation, and are overlain by the Upper Jurassic and Lower Cretaceous Bossier Formation (or Bossier Shale) of the Cotton Valley Group (fig. 2*B*; Maher and others, 1968; Forgotson and Forgotson, 1976). In the area of the potential CO_2 storage reservoir, the Bossier Formation forms the overlying seal and is predominantly a thick shale unit (Swain, 1944). The thickness of the Bossier Formation is variable throughout the U.S. Gulf Coast, especially in northern Louisiana, but can be as thick as 2,000 ft (Swain, 1944).

Two potential CO_2 storage reservoir units are identified in the Haynesville Formation of the U.S. Gulf Coast: (1) between 3,000 and 13,000 ft subsurface depth—Haynesville Formation C50490105, and (2) below 13,000 ft subsurface depth—Haynesville Formation Deep C50490106 (fig. 5). The Haynesville Formation SAU C50490105 encompasses an area of about 14,166,000 acres ($\pm$10 percent), and the Haynesville Formation Deep SAU C50490106 is about 8,771,000 acres ($\pm$ 10 percent).

The boundaries of the Haynesville Formation SAUs are defined by the 3,000-ft and 13,000-ft reservoir-top depths taken from 3,054 well penetrations (IHS Energy Group, 2010), faults associated with the Mexia-Talco fault zone, and the extent of the shales within the Bossier Formation seal (IHS Energy Group, 2010). The rocks within the Haynesville Formation SAUs deepen to the south, toward the Gulf of Mexico and Lower Cretaceous shelf margin, and on average are 300 to 750 ft thick (SAU C50490105) and 300 to 800 ft thick (SAU C50490106), with a most-likely thickness of 550 ft (SAU C50490105) and 600 ft (SAU C50490106), as determined by using the differences in depth-to-tops in 506 well penetrations located throughout the SAUs (IHS Energy Group, 2010).

Maximum porosity is highest within the sandstones and conglomerates of the Haynesville Formation (as much as 20 percent; Ahr, 1981); however, the majority of the Haynesville Formation SAUs are composed of carbonate rocks. Average porosity in the porous intervals of the Haynesville Formation decreases with depth from 7 to 14 percent in the Haynesville Formation SAU C50490105 to 3 to 11 percent in the Haynesville Formation Deep SAU C50490106 (Nehring Associates, Inc., 2010), which is primarily attributed to increased mudstone and micritic limestone content and cementation with depth in the carbonate rocks of the Haynesville Formation (Ahr, 1981). Net-porous-interval thickness was estimated by multiplying the total storage formation thickness by an average net porous thickness-to-gross thickness ratio, which was interpreted from geophysical logs. A net-to-gross ratio of 0.35 was used for the Haynesville Formation SAU C50490105 resulting in an average net-porous-interval thickness that ranges from 100 to 260 ft, with a most-likely value of 190 ft. A net-to-gross ratio of 0.30 was used for the Haynesville Formation Deep SAU C50490106 resulting in an average net-porous-interval thickness of 90 to 240 ft, with a most-likely value of 180 ft. Porosity in the carbonate rocks of the Haynesville Formation is typically intragranular, which formed by leaching and mineralogic stabilization of grains (Ahr, 1981; Nehring, 1991), and any intergranular pore space has, for the most part, been filled by carbonate cements, thereby decreasing porosity (Ahr, 1981; Nehring, 1991). Because most of the porosity in the carbonate rocks of the Haynesville Formation SAUs is intragranular, average permeability is quite low and the formation requires fracturing or acidization for optimal commercial petroleum production (Nehring, 1991). The permeability of the sandstones within the Haynesville Formation SAUs is generally good, however, it decreases with depth (Nehring, 1991; Ryder, 1996; Cicero and others, 2010). Average permeability in the Haynesville Formation decreases with depth from 0.01 to 500 mD, with a most-likely value of 0.5 mD in the Haynesville Formation SAU C50490105 to 0.005 to 200 mD, with a most-likely value of 0.3 mD in the Haynesville Formation Deep SAU C50490106 (Nehring Associates, Inc., 2010).

No major or minor potable-water aquifers in Texas occur within the Haynesville Formation (Ryder, 1996). Water sampled from two wells within the areas of the Haynesville Formation SAUs indicates saline formation waters, with TDS values well above 10,000 mg/L (Breit, 2002). Additionally, there are over 100 underground injection control wells within the Louisiana portion of the Haynesville Formation SAUs that are injecting "waste" (some of which is from oil and gas production) into subsurface depths of 3,000 ft to 11,000+ ft (Louisiana Department of Natural Resources, 2011), which indicates nonpotable, saline groundwater conditions. Because the Haynesville Formation SAU C50490105 does not appear to contain potable, freshwater (TDS <10,000 mg/L), 100 percent of its area is considered suitable for subsurface storage of CO_2. Furthermore, because salinity within the region increases with depth (Ryder, 1996), 100 percent of the Haynesville Formation Deep SAU C50490106 is expected to be entirely saline (TDS >10,000 mg/L) and suitable for geologic CO_2 storage, as well.

In order to calculate the maximum buoyant pore volume within structural and stratigraphic closures for each Haynesville Formation SAU, the known closure areas from the highly productive regions located throughout the Haynesville Formation SAUs were extrapolated and combined with upper bounds on regional reservoir thickness and porosity. The known closure areas were calculated by summing petroleum reservoir areas for each Haynesville Formation SAU (Nehring Associates, Inc., 2010). An assumption underlying this calculation is that there is potential for additional uncharged or undiscovered structural and stratigraphic closures outside of regions of historical hydrocarbon production.

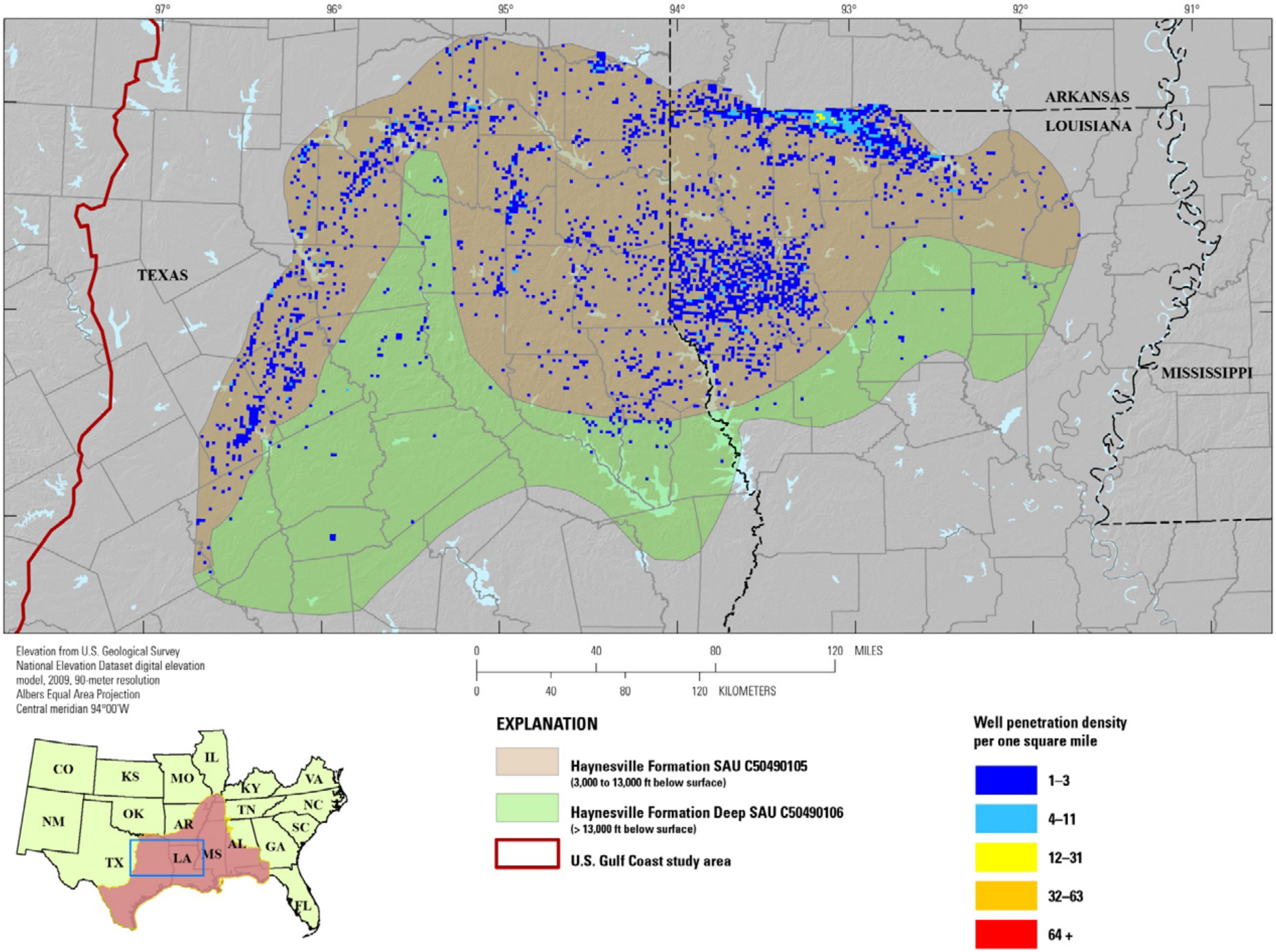

Figure 5. Map of the U.S. Geological Survey storage assessment unit (SAU) boundaries for the Haynesville Formation and Haynesville Formation Deep SAUs in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Sligo and Hosston Formations and Cotton Valley Group SAU C50490107 and Sligo and Hosston Formations and Cotton Valley Group Deep SAU C50490108

By Tina L. Roberts-Ashby

The Lower Cretaceous Sligo Formation and Hosston Formation of the Trinity Group, together with the Upper Jurassic and Lower Cretaceous Cotton Valley Group, make up a large storage reservoir identified as potentially suitable for CO_2 sequestration that extends across the entire U.S. Gulf Coast (figs. 2*A*, 2*B*, and 6). The Cotton Valley Group is generally composed of three formations (the Bossier Formation, Schuler Formation, and Knowles Limestone), although in some areas of the region, one unit may be missing or thin, and localized units may be included. The Bossier Formation is a thick shale unit that serves as the regional seal for the underlying Haynesville Formation SAUs and is therefore not included in the Sligo and Hosston Formations and Cotton Valley Group SAUs. The Schuler Formation is a progradational, fluvial-deltaic sequence composed of sandstone, siltstone, and some shales (Maher and others, 1968; Forgotson and Forgotson, 1976; Goldhammer and Johnson, 2001; Dyman and Condon, 2006; Mancini, 2010), and in some locations of the Gulf Coast is divided into the Shongaloo and Dorcheat Members (Goldhammer and Johnson, 2001; Mancini, 2010). The Shongaloo Member is a marginal-marine and coastal sandstone deposit, whereas the Dorcheat Member is composed of sandy shales, sandstones, and conglomerates associated with a maximum flooding surface (Mancini, 2010). The Knowles Limestone overlies the Schuler Formation across most of the U.S. Gulf Coast and is a carbonate unit, generally ~300 to 400 ft thick, that was deposited during a major sea level transgression that subsequently resulted in the cessation of fluvial-deltaic sedimentation in the Gulf of Mexico Basin (Herrmann and others, 1999; Ewing, 2001; Dyman and Condon, 2006). In some areas of the U.S. Gulf Coast, the mostly limestone unit contains relatively porous, storage-reservoir-quality rocks, especially in dolomitized regions, whereas other areas the limestones are cemented and tight, contain very little porosity and permeability, and contribute to the sealing of underlying sands (Coleman and Coleman, 1981; Cregg and Ahr, 1983; Mahbubullah, 1989). Predominantly, the Knowles Limestone is composed of a tight, argillaceous and calcite-cemented limestone with gray shales and is of low porosity and permeability (Coleman and Coleman, 1981; Cregg and Ahr, 1983; Herrmann and others, 1999). Seaward of the Knowles-Winn reef trend, few wells have penetrated the Knowles Limestone, and the reservoir quality of the unit is poorly characterized. Seaward of the Knowles-Winn reef trend, the Cotton Valley Group also contains a second carbonate unit with relatively good porosity but low permeability, known as the Winn Limestone, as well as a massive sand complex, known as the Calvin Sandstone (Coleman and Coleman, 1981; J. Coleman, USGS, written commun., 2011). Because the Knowles Limestone, Calvin Sandstone, and Winn Limestone do not occur or are of poor reservoir quality landward of the Knowles-Winn reef trend, they have minimal contribution to the total storage-reservoir interval within the Sligo and Hosston Formations and Cotton Valley Group SAUs within that region. However, seaward of the Knowles-Winn reef trend and up to the southern boundary of the SAUs, or the Lower Cretaceous reef trend (see figs. 1 and 6), the Knowles and Winn Limestones and Calvin Sandstone partially contribute to the porous intervals within the SAUs.

A pro-delta and fluvial-deltaic deposit, known as the Hosston Formation in Louisiana and the Travis Peak Formation in Texas and southern Arkansas, overlies the Cotton Valley Group throughout the U.S. Gulf Coast, with the exception of updip portions of the Gulf of Mexico Basin where the Knowles Limestone pinches out and the Hosston Formation directly overlies the Schuler Formation (Dyman and Condon, 2006). The Hosston/Travis Peak Formation is a thick wedge of terrigenous sedimentary rocks that marks the second major influx of siliciclastics to the northern Gulf of Mexico Basin (Dyman and Condon, 2006). The Sligo Formation conformably overlies the Hosston Formation and is predominantly composed of siliciclastics in Mississippi, Alabama, and Florida, whereas in Louisiana and Texas, the formation is predominantly composed of shelf-edge limestones (Rainwater, 1971; Ewing, 2001; Dyman and Condon, 2006). The shelf was eventually drowned by the black shales of the Lower Cretaceous Hammett Shale and Pine Island Shale Members of the Pearsall Formation (Trinity Group; Ewing, 2001), which can be hundreds of feet thick and forms the regional seal for the storage reservoir.

Two potential CO_2 storage reservoir units are identified in the Sligo and Hosston Formations and Cotton Valley Group within the U.S. Gulf Coast: (1) between 3,000 and 13,000 ft subsurface depth—Sligo and Hosston Formations and Cotton Valley Group C50490107, and (2) below 13,000 ft subsurface depth—Sligo and Hosston Formations and Cotton Valley Group Deep C50490108 (fig. 6). The Sligo and Hosston Formations and Cotton Valley Group SAU C50490107 encompasses an area of about 51,984,000 acres ($\pm$10 percent), and the Sligo and Hosston Formations and Cotton Valley Group Deep SAU C50490108 is about 20,937,000 acres ($\pm$10 percent).

The boundaries of the Sligo and Hosston Formations and Cotton Valley Group SAUs are defined by the 3,000-ft and 13,000-ft reservoir-top depths taken from 27,087 well penetrations (IHS Energy Group, 2010); the U.S.-Mexico international border; the U.S. Gulf Coast State-water lines; the Mexia-Talco, Gilbertown, and Pickens fault zones; areas where Lower Cretaceous rocks outcrop; the Lower Cretaceous reef trend/shelf margin, which marks the southern extent of a thick, continuous Hammett Shale and Pine Island Shale Members seal along the southern SAU boundary, in addition to the extent of which the Sligo and Hosston Formations and Cotton Valley Group have been explored and characterized to date (Dyman and Condon, 2006); and the extent of the continuous Hammett Shale and Pine Island Shale Members that is at least 50 ft thick, specifically along the northern boundary. The rocks within the Sligo and Hosston Formations and Cotton Valley Group SAUs deepen and thicken to the south and southeast toward the Gulf of Mexico and Lower Cretaceous shelf margin (fig. 6) and on average are 3,150 to 4,200 ft thick (SAU C50490107) and 4,300 to 6,000 ft thick (SAU C50490108), with a most-likely thickness of 3,750 ft (SAU C50490107) and 5,000 ft (SAU C50490108), as determined by using the differences in depths-to-tops in 4,861 well penetrations located throughout the SAUs (IHS Energy Group, 2010).

Average porosity in the porous intervals of the storage reservoir decreases with depth from 10 to 20 percent in the Sligo and Hosston Formations and Cotton Valley Group SAU C50490107 to 9 to 16 percent in the Sligo and Hosston Formations and Cotton Valley Group Deep SAU C50490108 (Nehring Associates, Inc., 2010). Net-porous-interval thickness was estimated by multiplying the total storage formation thickness by an average net-porous-thickness to gross-thickness ratio of 0.63, which was interpreted from geophysical logs. This resulted in an average net-porous-interval thickness that ranges from 2,000 to 2,650 ft, with a most-likely value of 2,400 ft for the Sligo and Hosston Formations and Cotton Valley Group SAU C50490107, and an average net-porous-interval thickness that ranges from 850 to 1,200 ft, with a most-likely value of 1,000 ft for the Sligo and Hosston Formations and Cotton Valley Group Deep SAU C50490108. Average permeability in the storage reservoirs decreases with depth from 0.1 to 3,300 mD, with a most-likely value of 35 mD in the Sligo and Hosston Formations and Cotton Valley Group SAU C50490107, to 0.05 to 200 mD, with a most-likely value of 8 mD in the Sligo and Hosston Formations and Cotton Valley Group Deep SAU C50490108 (Nehring Associates, Inc., 2010).

Two aquifers occur within the region of the Sligo and Hosston Formations and Cotton Valley Group SAUs, both of which contain saline water (TDS >10,000 mg/L) as well as fresh, potable water (TDS <10,000 mg/L), depending upon depth and location within the U.S. Gulf Coast: the Lower Trinity aquifer and the Southeastern Coastal Plain aquifer. According to cross-sections and regional maps (Renken, 1996; Ryder, 1996; George and others, 2011), only a small portion of the Sligo and Hosston Formations and Cotton Valley Group SAU C50490107, along its eastern boundary, potentially lies within the potable-water region of the Lower Trinity aquifer, and no portion of the Sligo and Hosston Formations and Cotton Valley Group Deep SAU C50490108 appears to be located within the aquifer's potable-water extent. No portion of either of the Sligo and Hosston Formations and Cotton Valley Group SAUs appears to be located within the freshwater region of the Southeastern Coastal Plain aquifer, according to regional aquifer contour maps (Miller, 1990). A nationwide database of TDS concentrations shows formation waters within the SAUs are predominantly saline (TDS >10,000 mg/L); however, there are some small regions that appear to contain freshwater (TDS <10,000 mg/L) within the SAU interval (Breit, 2002). For the Sligo and Hosston Formations and Cotton Valley Group SAU C50490107, because some small portions of the region contain accumulations of potentially potable water, 90 percent (at the mode, with a minimum of 75 percent and a maximum of 95 percent) of the SAU area is considered potentially suitable for geosequestration of CO_2. For the Sligo and Hosston Formations and Cotton Valley Group Deep SAU C50490108, significantly smaller portions of the region appear to contain accumulations of potentially potable water; therefore, most of the SAU area (most likely 95 percent, with a minimum of 95 percent and a maximum of 100 percent) is considered potentially suitable for geosequestration of CO_2.

In order to calculate the maximum buoyant pore volume within structural and stratigraphic closures for each Sligo and Hosston Formations and Cotton Valley Group SAU, the known closure areas from the highly productive regions located throughout the SAUs were extrapolated and combined with upper bounds on regional reservoir thickness and porosity. The known closure areas were calculated by summing petroleum reservoir areas for each Sligo and Hosston Formations and Cotton Valley Group SAU (Nehring Associates, Inc., 2010). An assumption underlying this calculation is that there is potential for additional uncharged or undiscovered structural and stratigraphic closures outside of regions of historical hydrocarbon production.

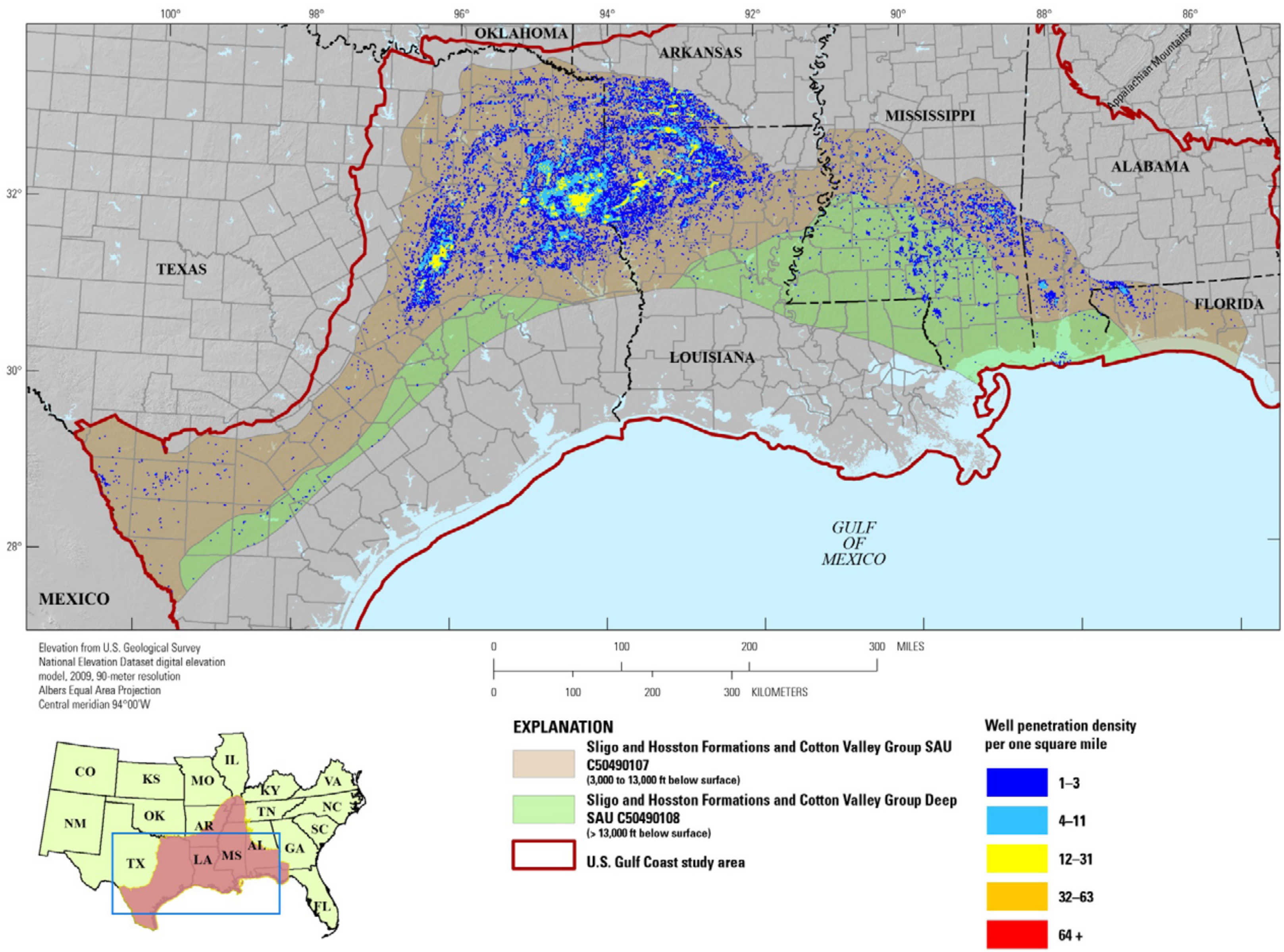

Figure 6. Map of the U.S. Geological Survey storage assessment unit (SAU) boundaries for the Sligo and Hosston Formations and Cotton Valley Group and Sligo and Hosston Formations and Cotton Valley Group Deep SAUs in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Knowles and Winn Limestones and Calvin Sandstone SAU C50490109

By Tina L. Roberts-Ashby

Seaward of the Knowles-Winn reef trend, the Lower Cretaceous interval of the upper portion of the Cotton Valley Group is composed of, from oldest to youngest, the Knowles Limestone, Calvin Sandstone, and Winn Limestone (figs. 2*A* and 2*B*). These geologic units are included in the Sligo and Hosston Formations and Cotton Valley Group SAUs of the U.S. Gulf Coast, with a southern extent up to the Lower Cretaceous reef trend/shelf margin, where there is a known, continuous shale seal (Hammett Shale and Pine Island Shale Members) within the Pearsall Formation. However, from the Lower Cretaceous reef trend/shelf margin seaward to the State-water lines within the U.S. Gulf Coast, this portion of the Cotton Valley Group is identified as the Knowles and Winn Limestones and Calvin Sandstone SAU C50490109 (fig. 7). The units collectively comprise a storage reservoir that is potentially suitable for subsurface storage of CO_2 in the U.S. Gulf Coast, based upon knowledge of the rocks landward of the reef trend, but that has no well-drilling or exploration, thereby hindering the ability to accurately characterize the reservoir rocks and presence of a regional seal.

The Knowles and Winn Limestones and Calvin Sandstone SAU C50490109 is overlain by an unnamed shale unit within the lowermost Hosston Formation and uppermost Cotton Valley Group that has been eroded and is not present north of the Knowles-Winn reef trend, where the Sligo and Hosston Formations and Cotton Valley Group SAUs are located (Coleman and Coleman, 1981; Dyman and Condon, 2006; J. Coleman, USGS, written commun., 2011). This shale could potentially serve as a seal for the Knowles and Winn Limestones and Calvin Sandstone SAU C50490109; however, due to lack of drilling and exploration activity in the region of the SAU, the thickness and extent of this potential shale seal cannot be characterized. The Knowles and Winn Limestones and Calvin Sandstone SAU C50490109 encompasses an area of approximately 65,023,000 acres that could potentially serve as a CO_2 geosequestration reservoir; however, because the CO_2 storage reservoir assessment methodology (Brennan and others, 2010) requires a continuously thick, well-documented, and mappable regional seal, this SAU was not quantitatively assessed.

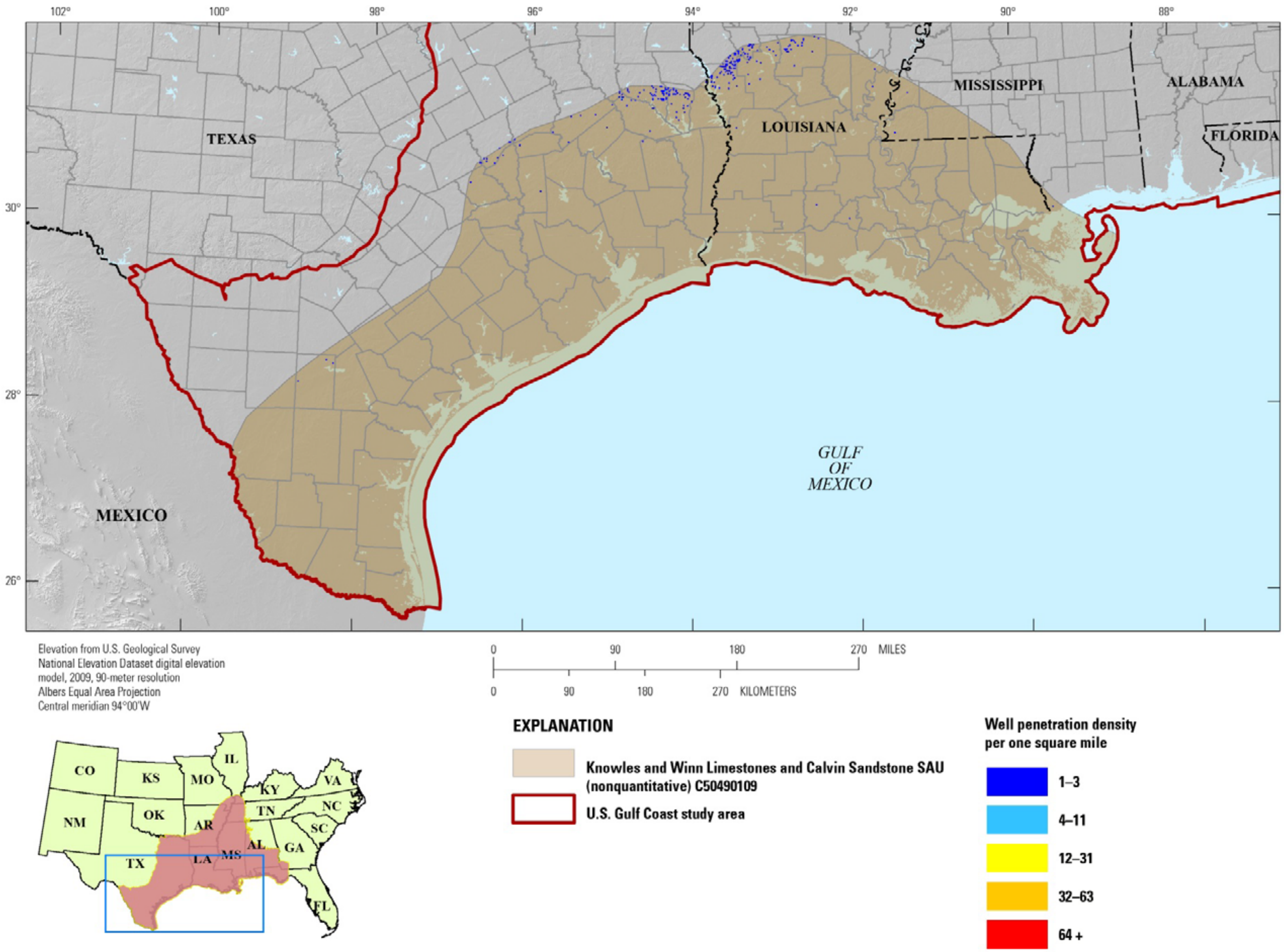

Figure 7. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Knowles and Winn Limestones and Calvin Sandstone SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Rodessa Formation and James Limestone SAU C50490110 and Rodessa Formation and James Limestone Deep SAU C50490111

By Peter D. Warwick

The northern part of the U.S. Gulf Coast is located in the southeastern part of the United States (fig. 1). To define the region margin for this assessment, the Upper Jurassic-Cretaceous-Tertiary Composite Total Petroleum System boundary was used from the most recent USGS national oil and gas assessment of the basin (Dubiel and others, 2007b, 2011). The USGS recently assessed the Rodessa Formation and James Limestone Member of the Pearsall Formation intervals for hydrocarbon resources, and the geologic data used in that study (Dubiel and others, 2011, 2012; Warwick, 2011) were incorporated into the current CO_2 storage assessment and report. The Rodessa Formation (equivalent to the lower Glen Rose Formation) and the underlying James Limestone Member, both Early Cretaceous in age (figs. 2*A* and 2*B*), are composed of interbedded intervals of predominately limestone and carbonate mudstone that are locally dolomitized and have variable porosity and permeability (Galloway and others, 1983; Mancini and others, 2001, 2008a; Montgomery and others, 2002). The rocks within the Rodessa-James interval were deposited in back-reef-lagoon, patch-reef, reef, and fore-reef environments that developed during the Early Cretaceous sea-level high stands and associated carbonate platform depositional environments (McFarlan and Menes, 1991; Yurewicz and others, 1993; Mancini and others, 2001, 2008a; Kerans and Loucks, 2002). The Rodessa Formation consists of gray, arenaceous, argillaceous, oolitic, skeletal limestone interbedded with a few thin sandstone and shale layers (Weeks, 1938; Roberts and Lock, 1988; Keith and Pittman, 1983). The James Limestone Member is composed of lithofacies ranging from deeper water, low-energy wackestones and packstones to shallower water, higher energy hydrozoa/cryptalgal stromatolite bindstones and requinid/coral packstones, grainstones, and boundstones (Loucks and others, 1996). Reservoir rock characteristics within both intervals are associated with rudist reef facies composed of grainstones, boundstones, and patch reef distributions controlled by salt or other paleostructural highs, creating a combination of stratigraphic and structural traps (Galloway and others, 1983; Loucks and others, 1996; Petty, 1999). Some of these areas have developed significant secondary moldic porosity from subaerial exposure and dissolution by meteoric diagenesis. Platform patch reef and reef development along the Lower Cretaceous shelf break have been the targets for petroleum exploration since the early part of the twentieth century (Sams, 1982; Galloway and others, 1983; Keith and Pittman, 1983; Petty, 1999; Mancini and others, 2001, 2008a; Loucks, 2002; Montgomery and others, 2002; Kerans and Loucks, 2002).

The sealing unit for the Rodessa Formation and James Limestone standard and deep SAUs is the Ferry Lake Anhydrite (also Lower Cretaceous; figs. 2*A* and 2*B*; Pittman, 1985; Petty, 1995). The Ferry Lake Anhydrite is composed of alternating intervals of limestone, claystone, gypsum, and anhydrite of variable thickness, with individual beds ranging from a few feet near the outcrop to tens of feet thick in the central part of the depositional area in northeastern Texas and northwestern Louisiana. Some anhydrite intervals can be correlated across several States (Pittman, 1985). The Ferry Lake and its equivalent intervals outcrop in southern Arkansas and extend into the subsurface across northeastern Texas, northern Louisiana, southern Mississippi, southern Alabama, and the Florida panhandle. In southern Florida, the Ferry Lake has been correlated with the Punta Gorda Formation (Pittman, 1985). The total Ferry Lake Anhydrite thickness ranges from about 50 ft near the northern outcrop belt to more than 400 ft in northeastern Louisiana, and thins basinward to about 200 ft before it merges with the Glen

Rose Lower Cretaceous shelf margin (Forgotson, 1963; Keith and Pittman, 1983; Pittman, 1985; Petty, 1995).

The Rodessa Formation and James Limestone SAU C50490110 and Rodessa Formation and James Limestone Deep SAU C50490111 boundaries are based on the depth from the land surface to the top of the Rodessa Formation interval, and define three areas where the top of the SAU is either between 3,000 and 13,000 ft, or 13,000 ft and greater (fig. 8). The Rodessa Formation and James Limestone standard and deep SAU areas were determined from formation tops in the IHS Energy Group (2010) commercial database and by georeferencing and digitizing lithofacies maps of the interval by Forgotson (1963). The gross thickness of the Rodessa Formation and James Limestone Member in the area of the SAUs ranges from 450 to 900 ft, with a most-likely thickness of 600 ft for the standard SAU and 700 ft for the deep SAU (data from IHS Energy Group, 2010). Available data (Forgotson, 1963; Galloway and others, 1983; Esposito and others, 2008; Webster and others, 2008; IHS Energy Group, 2010; and Nehring Associates, Inc., 2010) suggest the net-porous interval for both Rodessa Formation and James Limestone SAUs ranges from 30 to 115 ft, with a most-likely value of 40 ft.

Data from Galloway and others (1983) and Nehring Associates, Inc. (2010) suggest porosity for the net-porous interval of the Rodessa Formation and James Limestone standard SAU ranges from 12 percent to 20 percent, with a most-likely value of 16 percent. For the Rodessa Formation and James Limestone deep SAU, the porosity ranges from 6 percent to 13 percent, with a most-likely value of 10 percent. Permeability of the Rodessa Formation and James Limestone standard SAU is primarily in the range of less than 0.2 mD to 2,000 mD, with about 70 mD for the most-likely value (Nehring Associates, Inc., 2010). Permeability of the Rodessa Formation and James Limestone deep SAU is estimated to be in the range of less than 0.05 mD to 100 mD, with about 10 mD for the most-likely value (Nehring Associates, Inc., 2010).

Water-quality data (Breit, 2002; USGS, 2010) suggest that there is a mix of both fresh (TDS <10,000 mg/L) and saline water (TDS >10,000 mg/L) within the SAU intervals. For the Rodessa Formation and James Limestone standard SAU, approximately 80 percent (the most-likely value; with a minimum of 80 percent and maximum of 100 percent) of the area volume may contain saline water suitable for subsurface storage of CO_2. For the Rodessa Formation and James Limestone deep SAU, 100 percent (the most-likely value; with a minimum of 100 percent and maximum of 100 percent) of the area volume may contain saline water.

Approximately 1 percent of the area for the Rodessa Formation and James Limestone standard and deep SAUs is estimated to contain structural and stratigraphic closures associated with patch- or barrier-reef development; therefore, 1 percent of the SAU area may be used to estimate the size of the SAUs pore buoyant volume. The attributes described herein will be used in accordance with the USGS Carbon Sequestration Assessment Methodology (Brennen and others, 2010) to calculate the available storage space for CO_2 within the Rodessa Formation and James Limestone standard and deep SAUs.

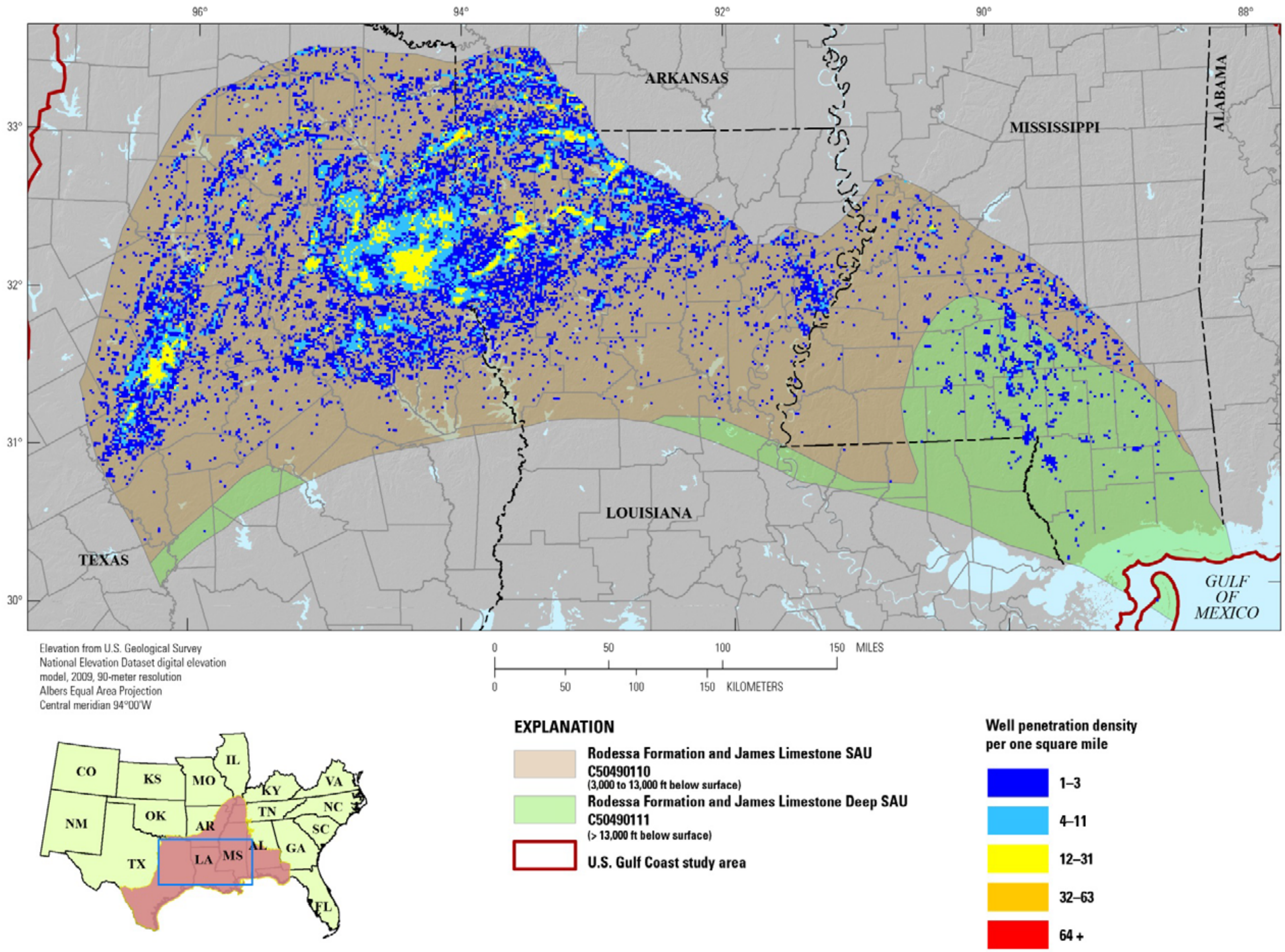

Figure 8. Map of the U.S. Geological Survey storage assessment unit (SAU) boundaries for the Rodessa Formation and James Limestone and Rodessa Formation and James Limestone Deep SAUs in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Fredericksburg Group and Rusk Formation SAU C50490112

Edwards, Glen Rose, and James Limestones SAU C50490113

Washita and Fredericksburg Groups, Rusk Formation, and James Limestone SAU C50490114

Washita and Fredericksburg Groups, Rusk Formation, and James Limestone Deep SAU C50490115

By Sean T. Brennan

The SAUs discussed in this section are comprised of Lower Cretaceous deposits that occur within the western U.S. Gulf Coast (fig. 1). Because there is significant overlap within the strata of the SAUs, the delineation of which strata are within a given SAU is based on the extent of the overlying regional seal. This introductory section describes only the depositional setting during the Early Cretaceous and provides a description of the strata therein (fig. 2*B*) and is followed by descriptions of the individual SAUs and their characteristics in subsequent chapters.

These Lower Cretaceous SAUs are all located almost entirely within the State of Texas (figs. 9–11), and within these specific SAUs the formations were deposited in a broad platform in the north-central through the southern margins and basins on the eastern and southwestern margins. These basins were the Maverick Basin to the southwest, which is located within the Rio Grande embayment, and the East Texas Basin to the east (fig. 1; Rose, 1972; Galloway, 2008). The platform was once the Central Texas Platform and the southern margin was the Comanchean (Aptian and Albian) Cretaceous reef trend (Rose, 1972), which was dominated by the Stuart City reef trend during the Early Cretaceous (Bebout and Loucks, 1974; Scott, 1990; Galloway, 2008).

The strata within these SAUs are Aptian to Albian in age (Mancini and others, 2008b), and all lie stratigraphically above the Hosston and Sligo Formations (fig. 2*B*). The deposition of the Sligo Formation terminated with relative sea level rise, leading to deposition of the deep water Pine Island Shale Member of the Pearsall Formation (Galloway, 2008). This rise in relative sea level was followed by a brief shoaling event, which was on the order of one to two million years (Galloway, 2008) leading to the deposition of the James Limestone Member of the Pearsall Formation (also referred to as the Cow Creek Limestone in the Maverick Basin region; Loucks, 2002). James Limestone Member deposition was terminated by another relative sea level rise, which led to the deposition of the Bexar Shale Member of the Pearsall Formation (Galloway, 2008). There is evidence of shoaling facies within the James Limestone and Bexar Shale Members that are composed of packstones and grainstones, which, due to diagenetic leaching of carbonate grains, has created high-porosity zones within these otherwise fine-grained, low-porosity rocks (Galloway, 2008).

During the flooding event that led to the deposition of the Bexar Shale Member, the Stuart City reef trend began to establish itself along the drowned Sligo reef trend (Bebout and Loucks, 1974; Scott, 1990; Galloway, 2008). This reef trend wrapped around the Maverick Basin (Rose, 1972; Talbert and Atchley, 2000) and is referred to as the Devils River trend along the northern border of the basin (Rose, 1972; Loucks, 2002; Galloway, 2008), creating a restricted basin that was bounded on the southern, eastern, and northern margins by the reef (Winker and Buffler, 1988) and along its eastern edge by the Central Texas Platform (Galloway, 2008).

Within the SAUs, the Glen Rose Limestone overlies the Pearsall Formation (fig. 2*B*). In the western Gulf Coast, the Glen Rose Limestone is divided into lower and upper parts, with the lower part of the Glen Rose Limestone equivalent to the Rodessa Formation and Ferry Lake Anhydrite of the central and eastern Gulf Coast (Imlay, 1945), and the upper part of the Glen Rose Limestone equivalent to the Rusk and Mooringsport Formations of the central and eastern Gulf Coast (fig. 2*B*; Forgotson, 1963). In the East Texas Basin and eastward from that basin, the upper and lower Glen Rose Limestone are separated by a massive anhydrite within the Ferry Lake Anhydrite (Galloway, 2008). This anhydrite forms the regional seal for the Rodessa Formation and James Limestone SAU C50490110 and the Rodessa Formation and James Limestone Deep SAU C50490111 (fig. 8; also see Rodessa Formation and James Limestone SAU of this chapter). Within the regions outlined by SAUs C50190110 and C50490110 (fig. 8), the Rodessa Formation and James Limestone Member are excluded from the SAUs described in this section.

The facies of the lower Glen Rose Limestone represent back-reef depositional environments that exhibit fabrics from mudstones through grainstones. This variation in the limestone leads to varied zones of high porosity within the formation. Furthermore, there are patch reefs common within the lower Glen Rose Limestone in the Maverick Basin (Scott, 2004; Aconcha, 2008). These patch reefs are approximately 35 m high, with diameters of about 1 kilometer (Aconcha, 2008). High-porosity zones within the James Limestone Member are common within the patch reefs (Scott, 2004; Aconcha, 2008). Although the upper Glen Rose Limestone is similar to the lower Glen Rose Limestone, patch-reefs are not present (Kerans and Loucks, 2003). However, diagenetically altered dolomite zones (Scott, 2004) that may result from hydrothermal alteration (Loucks and Kerans, 2003) are similar in shape to the patch-reefs. These zones are approximately 30 ft high with areal extents similar to the patch-reefs (Loucks and Kerans, 2003; Scott, 2004).

The deposition of the Glen Rose Limestone was terminated by a relative rise in sea level, followed by deposition of Fredericksburg Group-age strata, which consist of a combination of carbonate and siliciclastic deposits. The siliciclastic deposits overlie the upper Glen Rose Limestone primarily in the East Texas Basin (Galloway, 2008) and are the result of terrigenous influx from the progradation of a deltaic complex sourced from the Arbuckle-Ouachita uplift (Seni, 1981) into the northern shore of the East Texas Basin (Galloway, 2008). These clastic sediments form the Paluxy Formation. While the Paluxy Formation was deposited within the northern East Texas Basin along the southern margin, the back-reef/shelf sediments of the Edwards Limestone were being deposited. The limestone units of the Fredericksburg depositional event comprise predominantly low-porosity limestones interspersed with some high-porosity zones (Dyer and Bartolini, 2004). The Paluxy Formation was overlain by the transgressive shelf carbonates of the Edwards Limestone and the equivalent Goodland Limestone (Galloway, 2008), which is a low-porosity limestone. During this time, the Maverick Basin became highly restricted, which led to the deposition of the evaporitic McKnight Formation (Galloway, 2008). Additionally, the clay-rich, deep-water Kiamichi Formation was being deposited in the East Texas Basin and the Maverick Basin (Galloway, 2008). The Kiamichi Formation alone forms the regional seal for the Fredericksburg Group and Rusk Formation SAU C50490112 in the East Texas Basin, whereas the Kiamichi and McKnight Formations form the regional seal for the Edwards, Glen Rose, and James Limestones SAU C50490113 in the Maverick Basin. The Kiamichi Formation is not thick enough, nor consistently present, over the entire Central Texas platform to be considered a regional seal, which is why it is only recognized as a regional seal within the East Texas and Maverick Basins.

The Fredericksburg Group depositional event is overlain by the deposits of the Washita Group depositional event (Galloway, 2008). The major unit at the base of the Washita Group that overlies the Fredericksburg deposits is the Georgetown Limestone. The Washita Group deposits are broadly similar to the underlying Fredericksburg carbonate units, though with more shale intercalated with the carbonates (Galloway, 2008). The Washita Group deposits consist of widespread platform carbonates bounded to the south by the continued aggradation of the Stuart City reef trend (Galloway, 2008). The shoaling along the back-reef continued to be a locus of grainstone deposition, and subsequent diagenetic activity created highly porous zones in this region (Mancini and Scott, 2006). The Georgetown Limestone is overlain by the Grayson Shale and Del Rio Clay, also of the Washita Group, which are clay-rich units that form the regional seal for the Washita and Fredericksburg Groups, Rusk Formation, and James Limestone SAU C50490114 and the Washita and Fredericksburg Groups, Rusk Formation, and James Limestone Deep SAU C50490115.

Fredericksburg Group and Rusk Formation SAU C50490112

The Fredericksburg Group and Rusk Formation SAU C50490112 is located entirely within the East Texas Basin of the U.S. Gulf Coast (fig. 9). The regional seal is the clay-rich Kiamichi Formation (Dennen and Hackley, 2012) that is described as a distal turbiditic deposit (Scott and others, 1975). The Kiamichi Formation is between 10 and 150 ft thick in outcrops throughout the U.S. Gulf Coast region (Hill, 1891; Wilmarth, 1938; Leggat, 1957; Shelburne, 1959; Fox and Hopkins, 1960; Perkins, 1960; Freeman, 1964; Barnes, 1967a,b, 1972; Brown, 1971) and is 90 ft thick in the subsurface along the western margin of the East Texas Basin (Branson, 1950). The area of the SAU is approximately 16,600,000 acres and is based on the extent and depth of the base of the Kiamichi Formation.

The reservoir strata below the Kiamichi Formation that are within this SAU include the Fredericksburg Group and the Rusk Formation. Within the East Texas Basin, the Fredericksburg Group is composed of the Goodland Limestone, the Edwards Limestone, the Walnut Clay, and the Paluxy Formation (fig. 2*B*; Mancini and others, 2008b; Galloway, 2008). The Edwards Limestone is predominantly present in the southern region of the SAU, along the Stuart City reef trend (Galloway and others, 1983), whereas the Paluxy Formation is thickest in the northern region of the SAU, where the delta front prograded into the East Texas Basin, sourced from the Arbuckle-Ouachita uplift to the north (fig. 1; Seni, 1981; McFarlan and Menes, 1991; Galloway, 2008). The deeper water Goodland Limestone overlies the Paluxy Formation and becomes thicker northward as the clastic input from the Paluxy delta decreased (Galloway, 2008). The thickness of this depositional package ranges between 1,300 and 2,300 ft within the Fredericksburg Group and Rusk Formation SAU C50490112.

The extent of the stratigraphic components of the Fredericksburg Group and Rusk Formation SAU C50490112, and the patchy distribution of the porous zones within the carbonates, made it difficult to estimate the net-porous thickness of the SAU. The percentage of the SAU where either formations were present, or where shoals were likely to be found, were used to decrease the thickness of those porous units to arrive at a reasonable range of thicknesses that best represented the range of potential average values. Specifically, the net-porous thickness was assumed to range between 100 and 250 ft across the East Texas Basin. The range of porosity values within the various facies of the SAU made determining the range of average porosity difficult because the porosity within the Paluxy Formation sandstones is significantly higher than the porosity of the shoaling facies within the limestone units. Since the net-porous thickness within the Fredericksburg Group and Rusk Formation SAU C50490112 is dominated by the Paluxy Formation, the porosity values were skewed to the higher side, ranging from 10 to 18 percent and favoring the values of the Paluxy Formation (Nehring Associates, Inc., 2010). The permeability values ranged from 0.1 to 4,000 mD, with a central tendency value of 100 mD (Nehring Associates, Inc., 2010).

Water-quality data indicate that all formations within this SAU contain waters with salinity values in excess of the 10,000 ppm TDS threshold (Breit, 2002). Buoyant-storage values were based on both produced volumes and known reserves of oil and gas (Nehring Associates, Inc., 2010); undiscovered resource estimates (Dubiel and others, 2011); and estimates of the areas and thicknesses of structural, stratigraphic, and diagenetic traps.

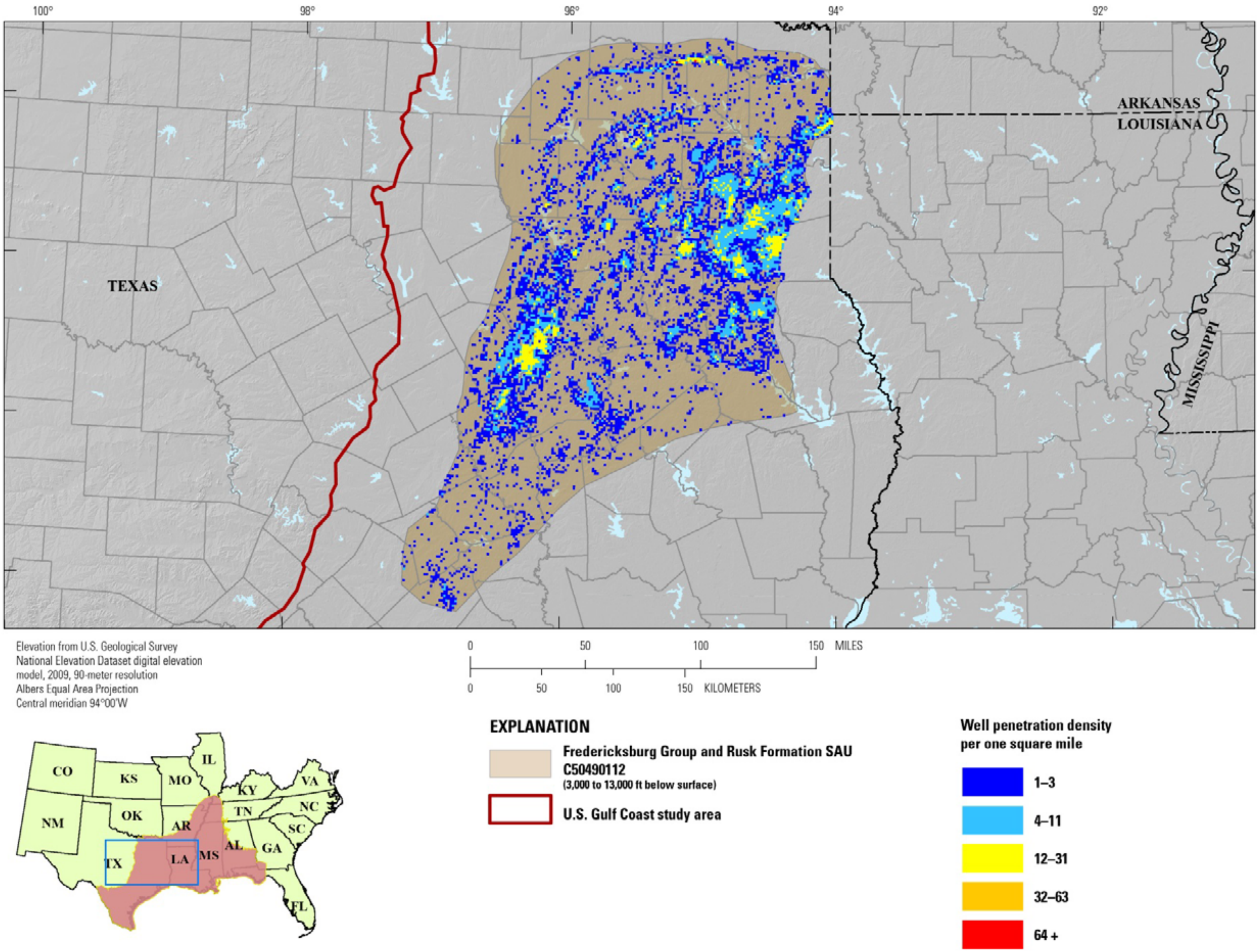

Figure 9. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Fredericksburg Group and Rusk Formation SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Edwards, Glen Rose, and James Limestones SAU C50490113

The Edwards, Glen Rose, and James Limestones SAU C50490113 is located entirely within the Maverick Basin and within the westernmost portion of the U.S. Gulf Coast (fig. 10). The regional sealing units for the SAU are the McKnight Formation, a 100- to 150-ft thick argillaceous, evaporitic unit (Galloway, 2008; Dennen and Hackley, 2012) and the Kiamichi Formation (fig. 2*B*). The area of the SAU is 3,500,000 acres, which is defined by the extent (Dennen and Hackley, 2012) and depth (IHS Energy Group, 2010) of the McKnight Formation.

The strata below the McKnight and Kiamichi Formations in the Edwards, Glen Rose, and James Limestones SAU C50490113 are the Edwards Limestone, which is thickest along the southern edge of the Maverick Basin, near the Stuart City reef trend (Galloway, 2008); the Glen Rose Limestone, which also thickens near the Stuart City reef trend; and the Pearsall Formation, which contains the Pine Island Shale, Cow Creek Limestone (and its correlative James Limestone Member), and Bexar Shale Members. The average total thickness of this stratigraphic package ranges from 2,400 to 3,900 ft. The irregular distribution of porous zones within the limestone units of the SAU made estimation of the average net-porous thickness problematic. The porous zones primarily exist in the patch reefs of the Glen Rose Limestone, the shelfward shoals of the Pearsall Formation members (primarily the Cow Creek Limestone and Bexar Shale Members), and the porous back-reef deposits of the Edwards Limestone. The thickness of these porous zones, coupled with the likely percentage of the SAU that each covered, was used to estimate the average net-porous thickness across the SAU. The average porosity of these net-porous zones is estimated to range from 5 to 15 percent (Nehring Associates, Inc., 2010). The permeability values are estimated to range from 0.01 to 500 mD, with a central tendency value of 4 mD (Nehring Associates, Inc., 2010). Water-quality data indicate that all formations within the Edwards, Glen Rose, and James Limestones SAU C50490113 contain waters with salinity values in excess of the 10,000 ppm TDS threshold (Breit, 2002). Buoyant-storage values were based on known oil and gas reserve values (Nehring Associates, Inc., 2010);undiscovered resource estimates (Dubiel and others, 2011); and estimates of the areas and thicknesses of structural, stratigraphic, and diagenetic traps.

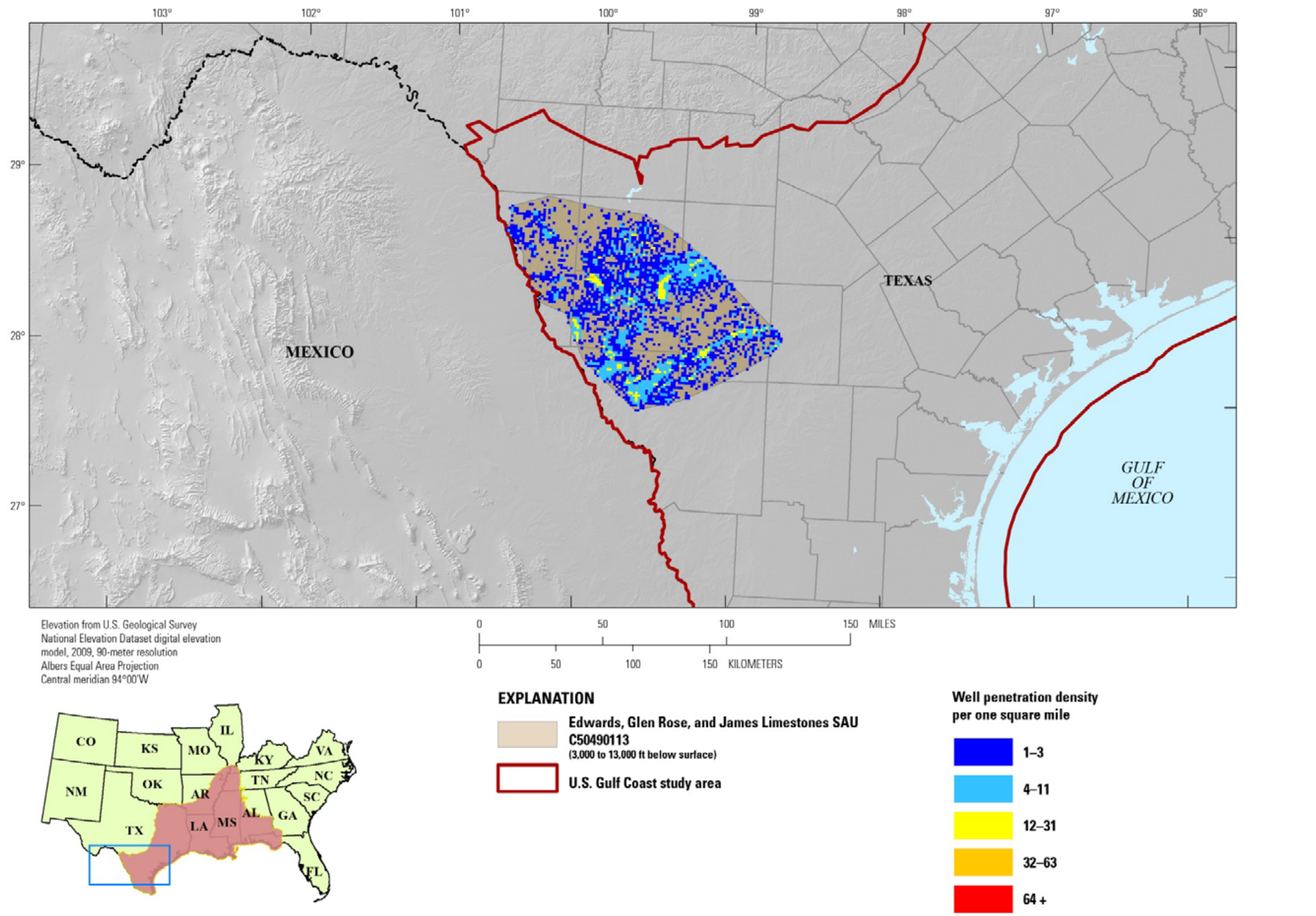

Figure 10. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Edwards, Glen Rose, and James Limestones SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Washita and Fredericksburg Groups, Rusk Formation, and James Limestone SAU C50490114 and Washita and Fredericksburg Groups, Rusk Formation, and James Limestone Deep SAU C50490115

The Washita and Fredericksburg Groups, Rusk Formation, and James Limestone SAU C50490114 and Washita and Fredericksburg Groups, Rusk Formation, and James Limestone Deep SAU C50490115 (hereafter the "standard" and "deep" SAUs, respectively) extend from the eastern edge of East Texas Basin, across the Central Texas platform, and to the western edge of the Maverick Basin (fig. 11). The regional sealing units for the SAUs are the clay-rich, fossiliferous Grayson Shale and Del Rio Clay, which combined are 80 to 100 ft thick in the area of the SAUs (Dennen and Hackley, 2012). The areas are 24,100,000 acres and 4,110,000 acres for the standard and deep SAUs, respectively. The extent of the standard SAU is defined by the extent and depth to the base of the Grayson Shale and Del Rio Clay (IHS Energy Group, 2010; Dennen and Hackley, 2012). The depth of the standard SAU ranges from 3,000 to 13,000 ft, and the top of the deep SAU ranges from 13,000 to 17,100 ft deep (IHS Energy Group, 2010).

The stratigraphic units that compose the Washita and Fredericksburg Groups, Rusk Formation, and James Limestone SAU C50490114 and Washita and Fredericksburg Groups, Rusk Formation, and James Limestone Deep SAU C50490115 consist of the entire Lower Cretaceous package of rock discussed in the introduction above. However, this total stratigraphic package is only considered within the Central Texas platform because there are additional regional seals below the Grayson Shale and Del Rio Clay in the Maverick and East Texas Basins. Therefore, within these small basins, the strata included within these SAUs are the Georgetown Limestone of the Washita Group and any equivalent strata. Using these parameters, it was determined that the average gross thickness of the SAUs ranges from 400 to 700 ft for the standard SAU and 800 to 1,400 ft for the deep SAU.

The net-porous thickness primarily comes from the porous zones within the Georgetown Limestone and any equivalent units (Mancini and Scott, 2006), with some contribution from the Edwards Limestone near the Stuart City reef trend and the patch reefs of the Glen Rose Limestone. The average net-porous-thickness values calculated from the thickness and distribution of the porous intervals of these formations indicate that the thickness for the standard SAU ranges from 30 to 120 ft, and the deep SAU ranges from 50 to 150 ft. The average porosity for the net-porous intervals is 5 to 15 percent for the standard SAU and 2 to 8 percent for the deep SAU (Nehring Associates, Inc., 2010). The permeability ranges from 0.1 to 100 mD, with a central tendency of 5 mD for the standard SAU, and from 0.1 to 10 mD, with a central tendency of 1 mD for the deep SAU (Nehring Associates, Inc., 2010). Water-quality data indicate that all formations within the Washita and Fredericksburg Groups, Rusk Formation, and James Limestone SAU C50490114 and Washita and Fredericksburg Groups, Rusk Formation, and James Limestone Deep SAU C50490115 contain waters with salinity values in excess of the 10,000 ppm TDS threshold (Breit, 2002). Buoyant-storage values were based on known oil and gas reserve values (Nehring Associates, Inc., 2010); undiscovered resource estimates (Dubiel and others, 2011); and estimates of the areas and thicknesses of structural, stratigraphic, and diagenetic traps.

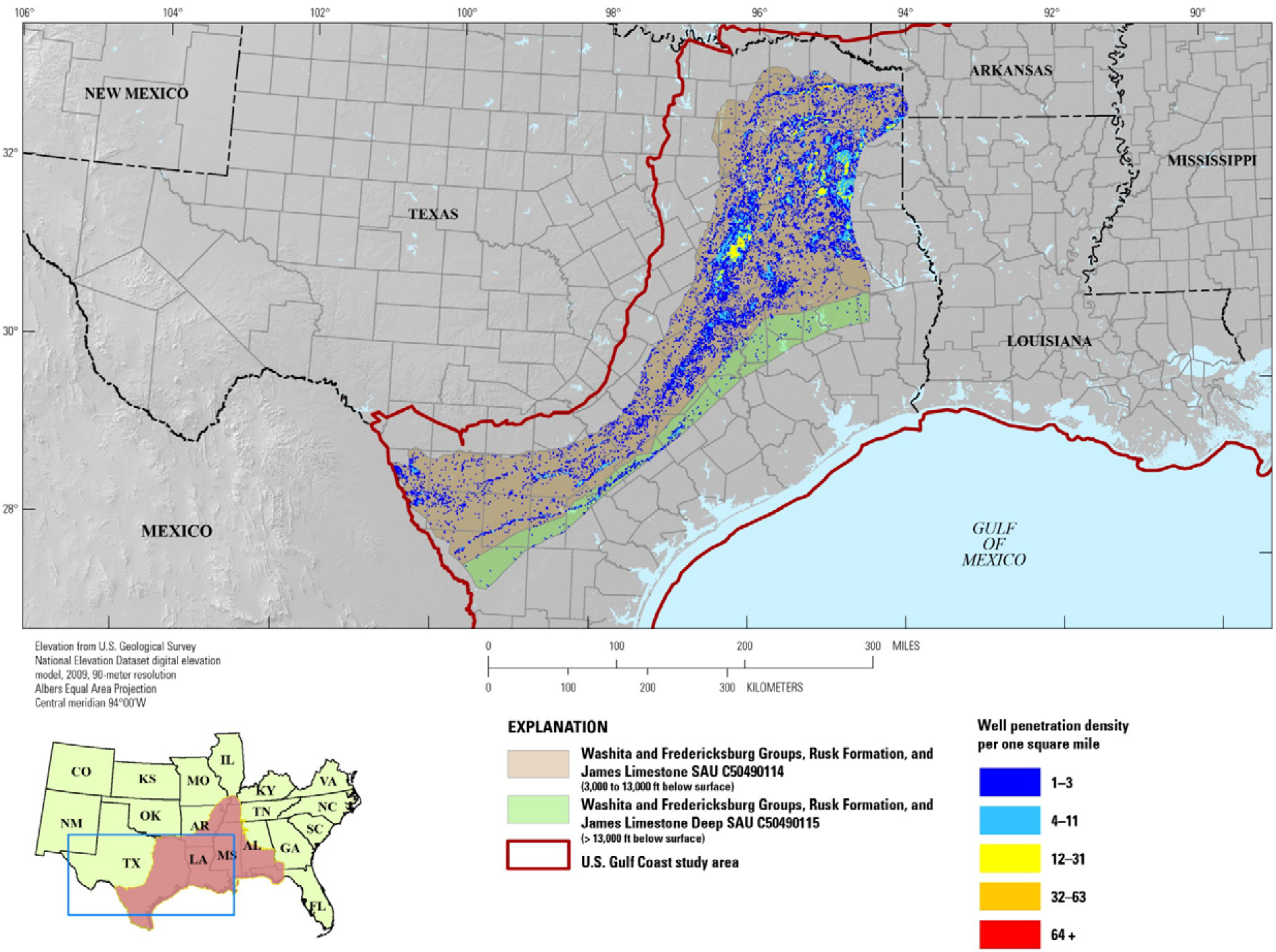

Figure 11. Map of the U.S. Geological Survey storage assessment unit (SAU) boundaries for the Washita and Fredericksburg Groups, Rusk Formation, and James Limestone and Washita and Fredericksburg Groups, Rusk Formation, and James Limestone Deep SAUs in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Tuscaloosa and Woodbine Formations SAU C50490116

By Ronald M. Drake II

The Woodbine Formation in Texas and the Tuscaloosa Formation in Louisiana are laterally equivalent units composed of interbedded conglomerate, sandstone, and shale (Pitman and others, 2007). In Louisiana, the upper part of the Tuscaloosa Formation is predominantly a marine shale unit that forms the regional seal for the reservoirs within the lower part of the Tuscaloosa Formation. These upper Tuscaloosa Formation shales correlate with the marine shales of the Eagle Ford Group in Texas, which overlies the Woodbine Formation and forms the regional seal for the underlying Woodbine Formation reservoirs. The marine shales of the Eagle Ford Group and upper Tuscaloosa Formation are 120 to 800 ft thick (U.S. Department of Energy, 2011).

The boundaries for the Woodbine and Tuscaloosa Formations SAU C50490116 are based upon interpretations of formation-top picks from a commercial database (IHS Energy Group, 2010) that are between 3,000 and 13,000 ft below the surface and from the Cretaceous shelf margin as depicted from Galloway and others (1991), which marks the southern boundary of the SAU. Within the Woodbine and Tuscaloosa Formations SAU C50490116, the average depth to the top of the SAU is 5,165 ft. The area of the SAU is about 82,823,000 acres. The most common formation thickness ranges from 450 to 800 ft and the most-likely thickness is 600 ft. The net-porous-sand thicknesses were determined by applying a net-to-gross ratio of 1:4, as determined from geophysical logs, and from the net-sand map provided in Petty (1997). Average net-porous-interval thickness ranges from 100 to 250 ft, and the most-likely net-porous thickness is 150 ft.

Porosity and permeability data were obtained from a proprietary database (Nehring Associates, Inc., 2010) and the 1995 USGS national oil and gas assessment report (Schenk and Viger, 1995a). The most-likely porosity values for the Woodbine and Tuscaloosa Formations SAU C50490116 are 15–29 percent, with a mode of 25 percent. Average permeabilities for the Woodbine and Tuscaloosa Formations SAU C50490116 range from 0.2 mD to 5,000 mD, with a most-likely value of 200 mD.

Water-quality data were compiled from several sources, including the USGS National Water Inventory System database and the produced-water database of "Breit" (2002). The water-quality data for the Woodbine and Tuscaloosa Formations were plotted on a map of the SAU, and areas were identified within the SAU that contained high concentrations of TDS. The results show that areas with high TDS (>10,000 mg/L) measurements are intermixed with areas of low TDS (<10,000 mg/L) measurements within the Woodbine and Tuscaloosa Formations; however, data indicate that the majority of the SAU (about 95 percent) contains pore water with TDS values that are greater than 10,000 mg/L.

In order to calculate the maximum buoyant pore volume within structural and stratigraphic closures for the Woodbine and Tuscaloosa Formations SAU C50490116, the known closure areas from the highly productive regions located throughout the SAU were extrapolated and combined with upper bounds on regional reservoir thickness and porosity. The known closure areas were calculated by summing petroleum reservoir areas for the SAU (Nehring Associates, Inc., 2010). An assumption underlying this calculation is that there is potential for additional uncharged or undiscovered structural and stratigraphic closures outside of regions of historical hydrocarbon production.

The boundaries, thicknesses, rock properties, and water-quality information mentioned above will be used in accordance with the USGS Carbon Sequestration Assessment Methodology (Brennan and others, 2010) to calculate the available storage space within the Woodbine and Tuscaloosa Formations SAU C50490116.

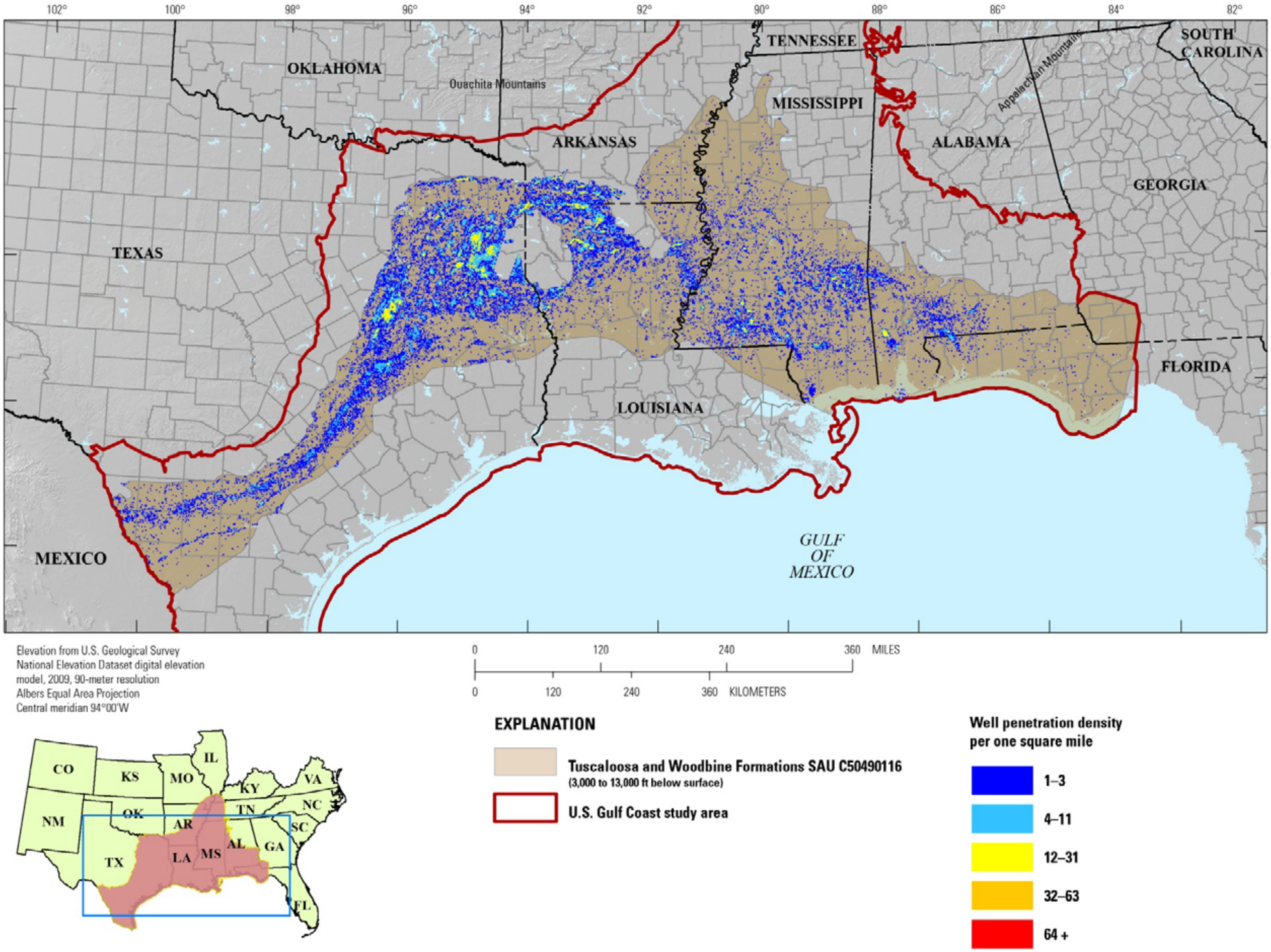

Figure 12. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Woodbine and Tuscaloosa Formations SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Navarro, Taylor, and Austin Groups SAU C50490117

By Ernie R. Slucher

The Upper Cretaceous Navarro, Taylor, and Austin Groups SAU C50490117 is a composite assessment unit containing multiple formations with potential storage reservoirs in the subsurface of the U.S. Gulf Coast. In most areas of the SAU west of the Mississippi River, the Navarro, Taylor, and Austin Groups are formally recognized, whereas in eastern areas, comparable rocks are mainly in the Eutaw Formation and Selma Group (fig. 2*C*). Overall, rocks within the SAU chronicle a period of relative sea-level highstand, with some eustacy fluctuation, when both marine carbonate-dominated and nonmarine and marine clastic-dominated depositional systems occurred. Regional deposition patterns during this time reflect mainly crustal subsidence and uplifts, loading subsidence in subbasins, and local plutonic and volcanic events in response to Laramide tectonics and overall motion of the North American tectonic plate (King, 1994; Galloway, 2008; Mancini and others, 2008b; Pearson, 2010). Potential storage units within the SAU vary based upon location within the Gulf Coast. For instance, in the Rio Grande embayment area of Texas (figs. 1, 2*C*, and 13), stratigraphic units included in the SAU are the Anacacho Limestone and San Miguel Formation of the Taylor Group and the Olmos and Escondido Formations of the Navarro Group. In the Houston embayment region, units consist mainly of the Tokio Formation and the informal Blossom Sand “D” unit of the Austin Group (as identified in the IHS Energy 2011 dataset), as well as the informal sub-Clarksville sand (Condon and Dyman, 2003)—the latter, even though it occurs below the Austin Group, is at the top of the Eagle Ford Shale, which is the seal of the immediately underlying Tuscaloosa and Woodbine Formations SAU, and could not be included in that assessment (see Tuscaloosa and Woodbine Formations SAU C50470116, this volume; figs. 1, 2*C*, and 13). In the region of the Mississippi embayment, the Eutaw Formation, “Monroe gas rock” and “Jackson gas rock” of local usage (Fergus, 1935; Saunders and Harrelson, 1992), and the Tokio Formation of the Austin Group are potential storage units (figs. 1, 2*C*, and 13). Collectively, most storage potential in the SAU is within deltaic, shoreface, and marine-shelf-sandstone portions of the Olmos and Escondido Formations of the Navarro Group, the San Miguel Formation of the Taylor Group, the Blossom Sand “D” unit of the Austin Group, the Eutaw Formation, and the sub-Clarksville sand (Dubroff, 1987; Ewing, 2009a; Nehring Associates, Inc., 2010). Subordinate storage potential exists locally in shoaling shelf-carbonate rocks of the Anacacho Limestone (C. Swezey, USGS, written commun., 2011) and “Monroe gas rock,” and where shoal/reefal carbonate and tuffaceous rocks of the “Jackson gas rock” and Anacacho Limestone formed in areas over igneous plutons or around volcanic vents of Campanian and Maastrichtian age (Ewing and Caran, 1982; Harrelson, 1989; Ewing, 2009b). The thick, widespread, and clay-rich Midway Group overlies the uppermost units of the SAU throughout its extent, forming the regional seal. The Midway Group is a transgressive unit deposited during a period of reduced sediment influx to the Gulf Coast (Salvador, 1991a).

The Navarro, Taylor, and Austin Groups SAU C50490117 encompasses approximately 45,262,000 acres that occur between 3,000 and 13,000 ft below the surface, with the most-likely depth to the top of the SAU being approximately 5,250 ft. The boundary, thickness, and petrophysical properties of the SAU were defined and categorized primarily by IHS Energy Group (2010, 2011) data on the top of the Navarro Group or equivalent chronostratigraphic units; the distribution of stratigraphic units with storage potential across the region; and other available data resources (Snedden and Kersey, 1982; Dubroff, 1987; Tyler and others, 1987; Bebout and others, 1992; Clark, 1995; Greer, 1995; Condon and Dyman, 2003; Collins, 2008; Ewing, 2009a; Nehring Associates, Inc., 2010; P. Nelson, USGS, written commun., 2011). These data indicate the most-likely range of total SAU thickness is from 1,000 to 2,200 ft, with 1,600 ft being the regional average. Accessed data suggest that porous intervals of the SAU in total have a minimum, maximum, and most likely net-porous thickness that is available for potential storage of CO_2 of 50, 150, and 100 ft, respectively. Porosity and permeability values within the SAU vary spatially across the SAU because of the multiplicity of formations representing various depositional environments composing the interval. Nevertheless, petrophysical data obtained on all units identified as a potential storage reservoir within the SAU indicate overall mean porosity values range from 12 to 26 percent, with 21 percent being the most likely, and permeability values range from 0.1 to 600 mD, with a most-likely value of 250 mD.

The methodology defined by Brennan and others (2010) was used to determine the minimum and central tendency buoyant trapping pore volumes. The maximum buoyant-trapping pore volume is based on (1) the combined area of structural reservoir traps at the top of the SAU, as interpreted mainly from data obtained from IHS Energy Group (2010, 2011); (2) the maximum net-porous interval thickness; (3) the maximum mean porosity value; and (4) known petroleum production and projected resource estimates (Condon and Dyman, 2003; Nehring Associates, Inc., 2010; Dubiel and others, 2011).

Data on salinity of groundwater within the Navarro, Taylor, and Austin Groups SAU C50490117 suggest TDS values exceed 10,000 mg/L throughout most of the region (Breit, 2002; Kharaka and Hanor, 2007); however, some regional studies (Nordstrom, 1982; Webb, 1984; Miller, 1990) suggest areas of low salinity may exist locally along the updip margin of the SAU, thus limiting the most-likely area available for CO_2 storage by about 5 percent.

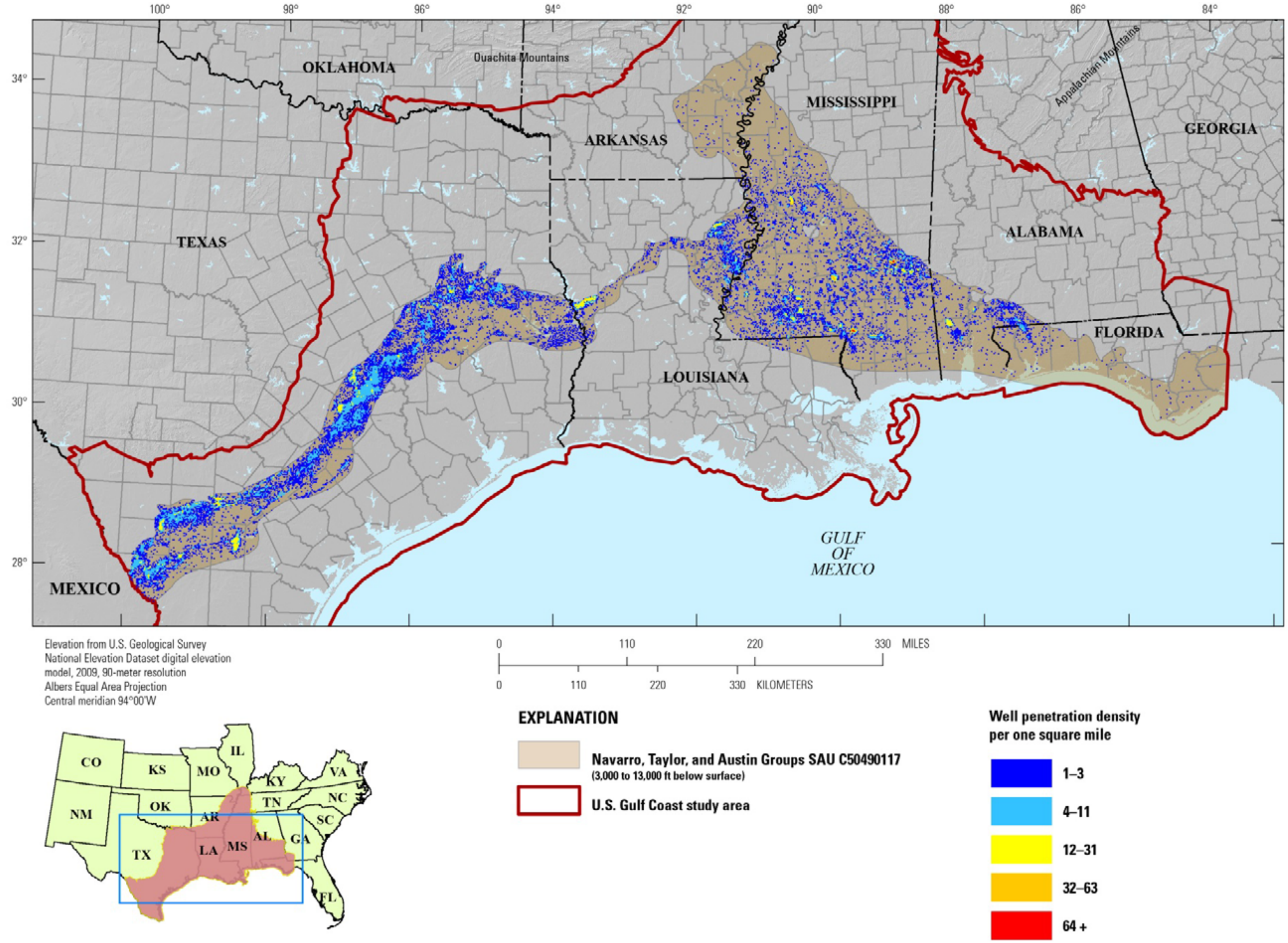

Figure 13. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Navarro, Taylor, and Austin Groups SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Carrizo Sand and Wilcox Group SAU C50470118

By Matthew D. Merrill

The Carrizo Sand and Wilcox Group form an SAU that contains thick sand sequences of nearshore and deltaic deposits. According to Galloway (1968), numerous principal-component facies of delta systems are exhibited in the formations, ranging from bar sands, mud and silt-bay facies, channels, pro-delta muds, deltaic-plain, destructional-phase marine transgressive sand, and mud-lignite facies. Source material for the sediments originated in the southern Rocky Mountains and Great Plains and entered the U.S. Gulf Coast at the Houston embayment on the west (Galloway and others, 1991) and flowed from Appalachian Mountains and entered the U.S. Gulf Coast on the east (Adams, 1928; Galloway, 2008). The Carrizo Sand and Wilcox Group SAU (fig. 2*D*) extends from Texas to Alabama (fig. 14) and is sealed by a thick, regional seal that consists of the shales of the Reklaw, Cane River, and Tallahatta Formations (fig. 2*D*). The Paleocene lower part of the Wilcox Group and Eocene upper part of the Wilcox Group are separated by the Big Shale Member in portions of south Texas, Louisiana, and Mississippi (fig. 2*D*; Galloway, 1968; Tye and others, 1991). The continuous extent of the Big Shale Member is limited to central Louisiana and Mississippi; middle Wilcox Group shales in Texas are generally valley-fill deposits that are not correlative across the U.S. Gulf Coast (Dingus and Galloway, 1990; Echols and Goddard, 1992). In keeping with the regional- to basinal-scale defined in the methodology, the middle Wilcox Group shales are not included as confining layers, and both the lower and upper parts of the Wilcox Group and Carrizo Sand (and their equivalents in Mississippi; Fillon and others, 1998) are included in the same SAU.

The Carrizo Sand and Wilcox Group SAU C50470118 has an area of about 36,695,000 acres (fig. 14). The boundaries of the SAU are as follows: the northern boundary of the SAU is the 3,000-ft depth-to-Wilcox contour; the western edge is the Texas and Mexico international border; the eastern edge is the State-waters line in western Alabama and all of coastal Mississippi and easternmost Louisiana; and the southern boundary of the SAU is an interpolated 13,000-ft depth-to-Wilcox contour. In the western Gulf Coast region, 41,000 individual depth-to-top-of-interval records were employed to produce the boundary of the 3,000- to 13,000-ft depth-to-top of the SAU (IHS Energy Group, 2011). Additionally, interval top-depths from 4,400 of these records were used to create an isopach map that indicates the SAU has a range of average gross thicknesses that is from 3,000 to 5,000 ft, with a most-likely value of 4,000 ft. Combining published net-sand isopachs of various reservoir intervals resulted in a net-porous thickness map for the SAU that has an average range of 600 to 1,400 ft, centered on 900 ft (Galloway, 1968; Fisher and McGowen, 1969; Hamlin, 1983; Tye and others, 1991; Tyler and Scott, 1999). Average porosity for the sands in the reservoir intervals of the SAU ranges from 16 to 28 percent (Grubbs, 1953; Nehring Associates, Inc., 2010) and permeability ranges from 0.1 to 1,200 mD, with most likely values around 20 percent and 70 mD, respectively (Nehring Associates, Inc., 2010). Salinity maps from Pettijohn and others (1988) and data from the USGS produced-water database (Breit, 2002) covered the majority of the SAU and revealed that much of the SAU is greater than the 10,000 mg/L TDS limit for CO_2 storage consideration; however, approximately 15 percent of the area of the SAU may incorporate areas of fresh water (TDS <10,000 mg/L).

In order to calculate the maximum buoyant pore volume within structural and stratigraphic closures for the Carrizo Sand and Wilcox Group SAU C50470118, the known closure areas from the highly productive regions located throughout the SAU were extrapolated and combined with upper bounds on regional reservoir thickness and porosity. The known closure areas were calculated by summing petroleum reservoir areas for the SAU (Nehring Associates, Inc., 2010). An assumption underlying this calculation is that there is potential for additional uncharged or undiscovered structural and stratigraphic closures outside of regions of historical hydrocarbon production.

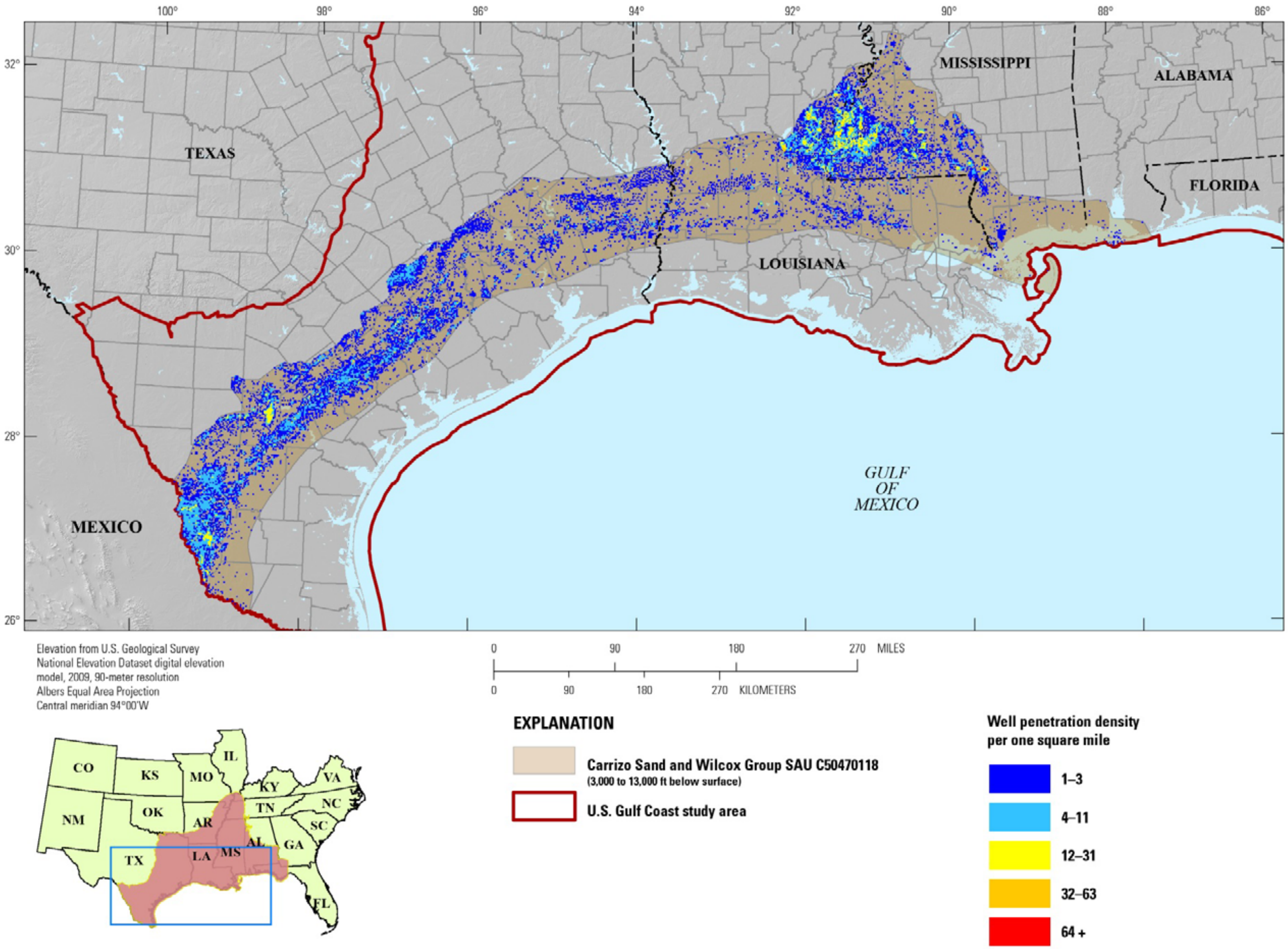

Figure 14. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Carrizo Sand and Wilcox Group SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Queen City Sand SAU C50470119

By Matthew D. Merrill

The middle Eocene Queen City Sand is a deltaic and strand-plain sandstone unit that exists in the subsurface of the Texas Gulf Coast region, occurring between the more massive Sparta Sand and sands of the Wilcox Group (fig. 2*D*). Guevara and Garcia (1972) describe the Queen City Sand as a sandy, non-fossiliferous to sparsely fossiliferous unit. In south Texas, the sands represent a highly destructive delta facies, whereas in east Texas they represent a highly constructive delta facies. In central Texas, the Queen City Sand represents a strand-plain. Guevera and Garcia (1972) and Hobday and others (1979) provide detailed discussions of facies groups beyond the three basic environments mentioned above. Facies deposition occurred during progradation across shallow shelf muds and glauconitic sands of the Reklaw Formation. The Queen City Sand is overlain by similar shales and glauconitic sands of the Weches Formation (Guevara and Garcia, 1972), which forms the regional seal for the SAU. Sediment-source areas for the Queen City Sand were located primarily to the northwest, though small influxes from the northeast were also possible (Hobday and others, 1979). Deposition of this minor terrigenous clastic wedge is limited to Texas, as lithologies grade into the shales of the Cane River Formation in western Louisiana.

The Queen City Sand SAU C50470119 covers an area of 13,042,000 acres, (±10 percent) (fig. 15). The SAU is bounded on the northwestern side by the 3,000-ft depth requirement for an SAU; on the southwestern side by the U.S.-Mexico international border; on the southeast side by a zero net-sand isopach-line truncation, as determined from Guevara and Garcia (1972); and on the northeast side by the extent of the formation. Formation records obtained from the IHS Energy Group (2010) database indicate that the regional seal for the SAU, the Weches Formation, is present over the entire SAU.

Depths from surface in the SAU range from 3,000 to 12,500 ft. Mean gross Queen City Sand thickness, calculated from well-top-depth differencing, ranges from 600 to 1,400 ft, with most likely values around 1,100 ft (IHS Energy Group, 2011). Mean net-sand thicknesses in the SAU, determined from isopachs presented in Guevara and Garcia (1972), range from 20 to 150 ft, with a most-likely value of 50 ft. Data from 15 producing reservoirs in the Nehring Associates, Inc. (2010) database indicate that mean porosity in the net sands ranges from 22 to 30 percent. Permeability data from the same database show typical values for deltaic sandstones with an absolute range of 0.1 to 1,200 mD and common values around 70 mD.

Water quality in the Queen City Sand SAU C50470119 is both fresh (TDS <10,000 mg/L) and saline (TDS >10,000 mg/L). Maps by Pettijohn and others (1988) and produced-waters information from Breit (2002) indicate that approximately 60 percent of the area within the SAU contains saline groundwater and therefore is a viable CO_2 storage option.

In order to calculate the maximum buoyant pore volume within structural and stratigraphic closures for the Queen City Sand SAU C50470119, the known closure areas from the highly productive regions located throughout the SAU were extrapolated and combined with upper bounds on regional reservoir thickness and porosity. The known closure areas were calculated by summing petroleum reservoir areas for the SAU (Nehring Associates, Inc., 2010). An assumption underlying this calculation is that there is potential for additional uncharged or undiscovered structural and stratigraphic closures outside of regions of historical hydrocarbon production.

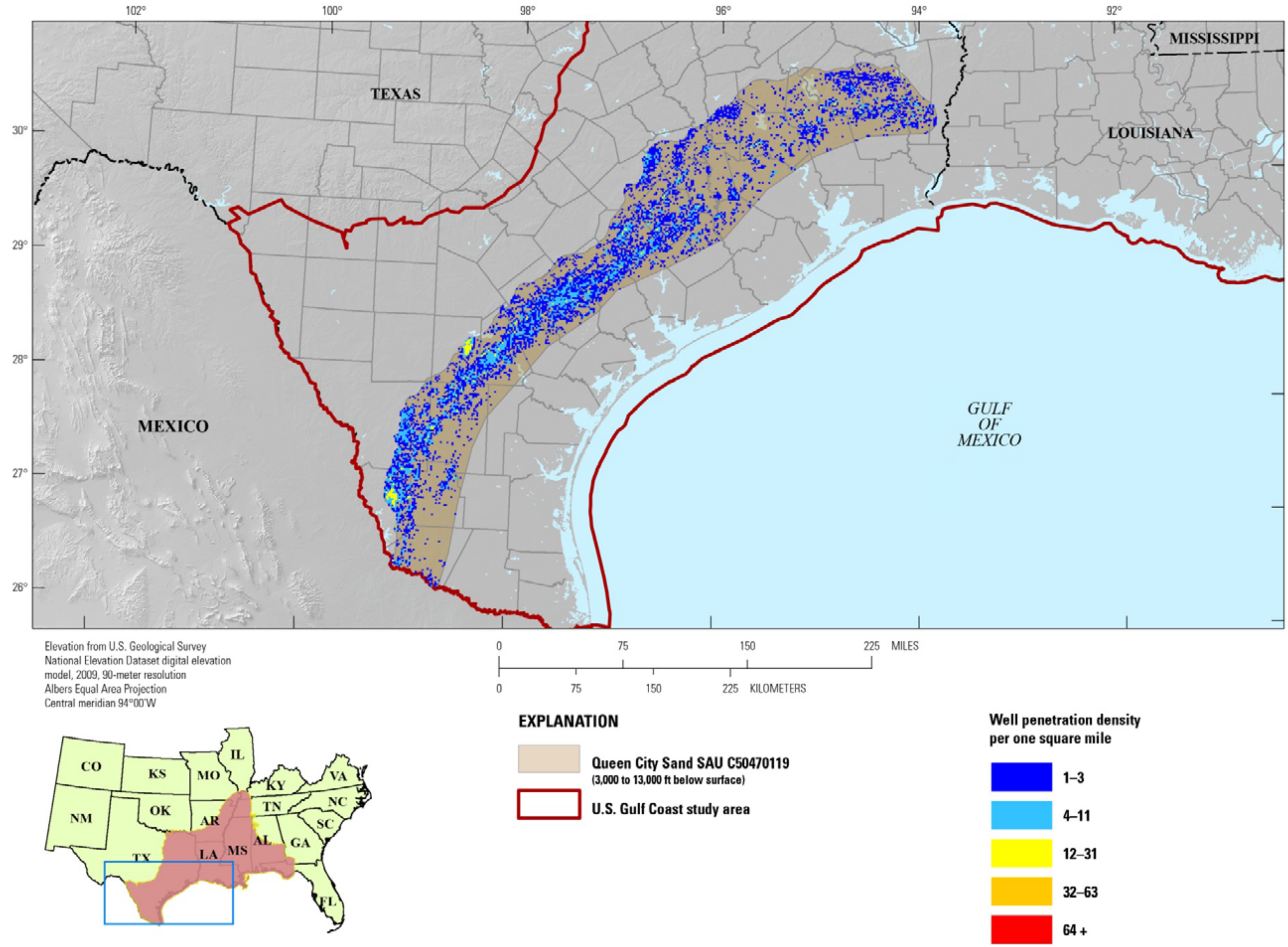

Figure 15. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Queen City Sand SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Sparta Sand SAU C50470120

By Jacob A. Covault

The middle Eocene Sparta Sand is approximately 500 ft thick on average and predominantly includes fine-grained, siliciclastic sandstone interbedded with mudstone (figs. 2*D* and 16; Payne, 1968; Ricoy and Brown, 1977; Hackley and Ewing, 2010; Hackley, 2012). The Sparta Sand is the middle part of the Claiborne Group, which comprises lower, middle, and upper sandstone reservoirs separated by finer-grained units. The relatively fine-grained Weches Formation underlies the Sparta Sand, which is capped by the fine-grained Cook Mountain Formation and foresets of the overlying Yegua (in Texas) and Cockfield (in Louisiana and Mississippi) Formations (Ricoy and Brown, 1977; Lawless and others, 1997; Galloway, 2008; Hackley and Ewing, 2010; Hackley, 2012). The Cook Mountain Formation is relatively fine grained and is hundreds of feet thick in east Texas (Wendlandt and Knebel, 1926; Hackley, 2012); however, it is characterized as sandstone-rich in south Texas and Mexico (Trowbridge, 1932; Kane and Gierhart, 1935). The Cook Mountain Formation and the overlying fine-grained foresets of the Yegua and Cockfield Formations form the sealing units for the underlying Sparta Sand. The Sparta Sand and overlying Cook Mountain Formation couplet has been interpreted to represent a landward retreat of depositional environments from predominantly coarse-grained, deltaic, and barrier-bar systems (Sparta Sand) to a finer grained, fully marine system (Cook Mountain Formation) in the Paleogene Gulf of Mexico (Ricoy and Brown, 1977; Galloway and others, 2000; Galloway, 2008). The overlying Yegua and Cockfield Formations have been interpreted to represent progradation of a fluvial-dominated delta system across the submerged Sparta Sand and Cook Mountain Formation (Galloway, 2008). Fine-grained mudstone is interpreted to compose the prodelta foresets of the Yegua and Cockfield progradational delta system, following the fluvial-dominated delta facies model of Berg (1982).

The Sparta Sand SAU C50470121 is a potential reservoir unit for CO_2 storage in the U.S. Gulf Coast at subsurface depths from 3,000 to 12,000 ft (fig. 16). The SAU boundary is defined by the 3,000-ft drilling depth based on more than 9,000 well penetrations (IHS Energy Group, 2011), the middle Eocene Sparta continental-shelf edge defined by Galloway (2005), and the extent of shallow-marine sandstone mapped by Ricoy and Brown (1977). The range of total storage formation thickness for the reservoir unit was determined by tops-differencing from nearly 700 well penetrations of the top of the Sparta Sand to the top of the Weches Formation (IHS Energy Group, 2011), as well as by review of regional studies of the Sparta Sand (Todd and Roper, 1940; Payne, 1968; Hackley, 2012). The thickness of the net-porous interval was determined from net-sandstone to gross-stratigraphic thickness and net-sandstone thickness maps by Ricoy and Brown (1977) and Payne (1968). Average porosity ranges from 20 to 35 percent, and average permeability ranges from 0.1 to greater than 1,000 mD (Nehring, 1991; Nehring Associates, Inc., 2010).

Water-quality measurements indicate that groundwater in the formation is predominantly saline (>10,000 mg/L TDS; Pettijohn and others, 1988; Breit, 2002). The minimum and most likely buoyant-trapping pore volumes were determined using methods described in Brennan and others (2010). Maximum buoyant-trapping pore volume was calculated from the product of (1) the combined areas of Sparta Sand structural reservoir traps and reservoirs of producing fields (Nehring Associates, Inc., 2010), (2) the maximum net-porous-interval thickness, and (3) the maximum porosity. Sparta Sand structural reservoir traps include rollover anticlines downthrown to growth faults and broad stratal upwarping over areas influenced by salt tectonics (Nicot and Havorka, 2009; Hackley, 2012). Combined structural-stratigraphic traps against salt diapirs were not considered as a result of limited subsurface data to illustrate closure geometry.

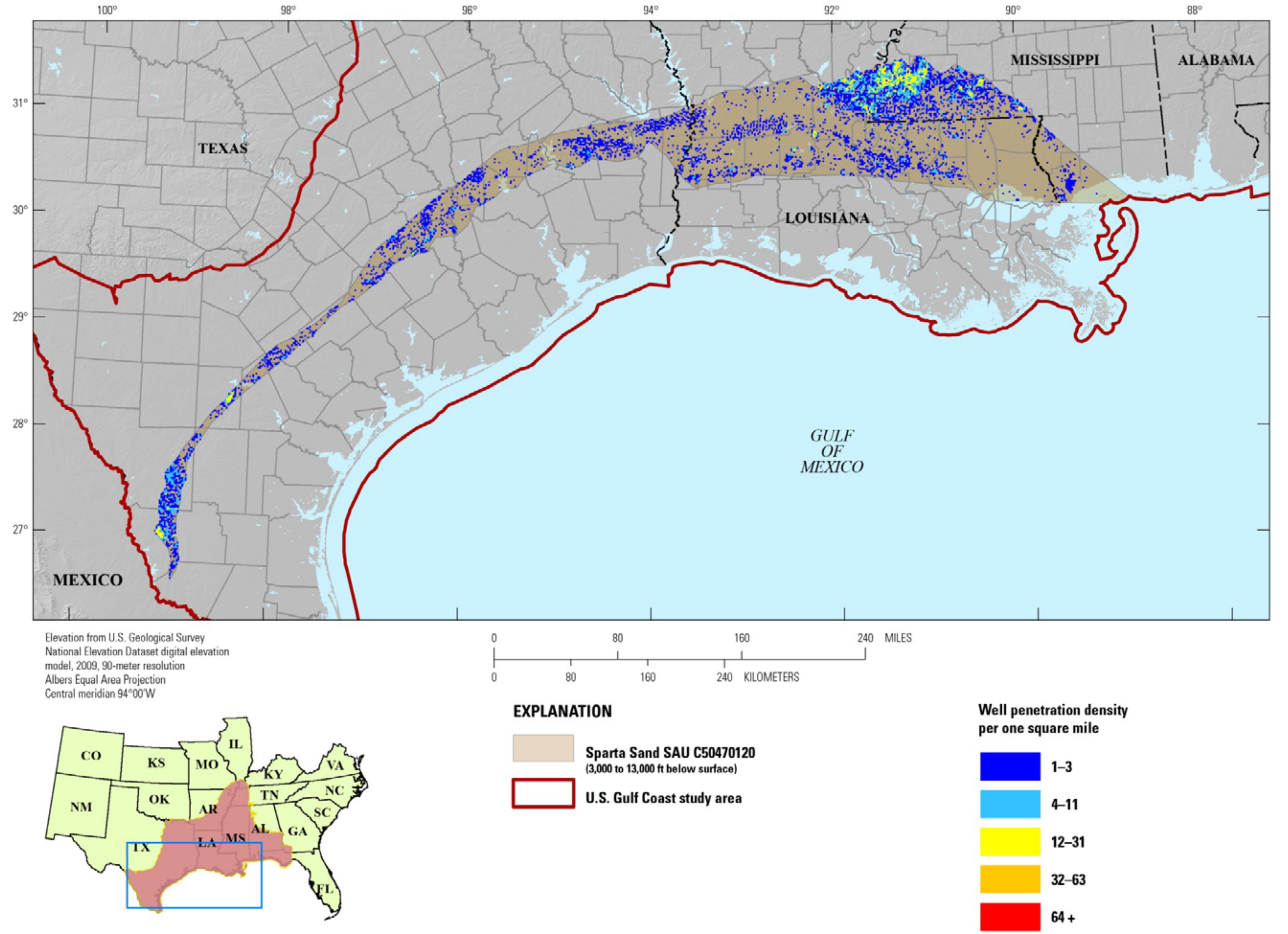

Figure 16. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Sparta Sand SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Yegua and Cockfield Formations SAU C50470121

By Jacob A. Covault

The middle and upper Eocene Yegua and Cockfield Formations are approximately 700 ft thick on average and include siliciclastic sandstone interbedded with mudstone and volcanic ash beds (figs. 2*D* and 17) (Galloway, 2008; Hackley, 2012). The Yegua and Cockfield Formations compose the uppermost part of the Claiborne Group, which comprises lower, middle, and upper sandstone reservoirs separated by finer grained units (Hackley and Ewing, 2010; Hackley, 2012). The upper Claiborne unit is referred to as the Yegua Formation in Texas and the Cockfield Formation in Louisiana and Mississippi. The Yegua and Cockfield Formations are underlain by the relatively fine-grained Cook Mountain Formation and are overlain by the fine-grained Moodys Branch Formation and equivalents within the Jackson Group (Lawless and others, 1997; Galloway, 2008; Hackley and Ewing, 2010; Hackley, 2012). Proprietary well-penetration data (IHS Energy Group, 2011) indicate that the Moodys Branch Formation is restricted to east Texas, Louisiana, and Mississippi. Subsurface stratigraphic correlations by Galloway and others (1994) support a regionally extensive interpretation of the Moodys Branch Formation and temporally equivalent fine-grained strata (Galloway and others, 2000). The Moodys Branch Formation and the overlying fine-grained facies of the Jackson Group form the sealing units for the underlying Yegua and Cockfield Formations (Hackley, 2012). The succession from the Yegua and Cockfield Formations into the overlying fine-grained units have been interpreted to represent a landward retreat of depositional environments from predominantly coarse-grained, nonmarine fluvial, shallow-marine deltaic, and continental-shelf systems (Yegua and Cockfield Formations) to a finer grained, fully marine system (Moodys Branch Formation) in the Paleogene Gulf of Mexico (Fisher, 1969; Galloway and others, 2000; Galloway, 2008; Hackley, 2012). The overlying Jackson Group has been interpreted to represent an extensive, mud-rich shelf system in the central Gulf of Mexico and into the Mississippi Embayment (Galloway and others, 2000; Hackley and Ewing, 2010; Hackley, 2012).

The Yegua and Cockfield Formations SAU C50470122 SAU is a potential reservoir unit for CO_2 storage in the U.S. Gulf Coast at depths from 3,000 to 11,000 ft (fig. 17). The SAU boundary is defined by the 3,000-ft drilling depth from nearly 10,000 well penetrations (IHS Energy Group, 2011) and the middle and upper Eocene Yegua shelf edge and associated extent of shallow-marine sandstone (Galloway and others, 2000; Galloway, 2005, 2008; see also Hackley, 2012). The range of total storage formation thickness for the reservoir unit was determined by tops-differencing from nearly 1,000 well penetrations of the top of the Yegua and Cockfield Formations to the top of the Cook Mountain Formation (IHS Energy Group, 2011), as well as by review of regional studies of the Yegua Formation (Davies and Ethridge, 1971; Galloway and others, 1994; Hackley, 2012). The thickness of the net-porous interval was determined from a net-sandstone thickness map by Fisher (1969; see also Hackley, 2012). Average porosity ranges from 10 to 40 percent, and average permeability ranges from 0.1 to greater than 3,000 mD (Nehring, 1991; Nehring Associates, Inc., 2010). Reservoir data provided by Nehring Associates, Inc. (2010) indicates that Yegua Formation reservoirs have a median porosity of 30 percent and a median permeability of 175 mD.

Water-quality measurements indicate that groundwater in the Yegua and Cockfield Formations is predominantly saline (>10,000 mg/L TDS) (Pettijohn and others, 1988; Breit, 2002). The minimum and central tendency buoyant-trapping pore volumes were determined using methods described in Brennan and others (2010). Maximum buoyant-trapping pore volume was calculated from the product of (1) the combined areas of Yegua and Cockfield structural reservoir traps and reservoirs of producing fields

(Nehring Associates, Inc., 2010), (2) the maximum net-porous-interval thickness, and (3) the maximum porosity. Yegua and Cockfield structural reservoir traps include rollover anticlines downthrown to growth faults and broad stratal upwarping over areas influenced by salt tectonics (Nicot and Havorka, 2009; Hackley, 2012). Combined structural-stratigraphic traps against salt diapirs were not considered as a result of limited subsurface data to illustrate closure geometry.

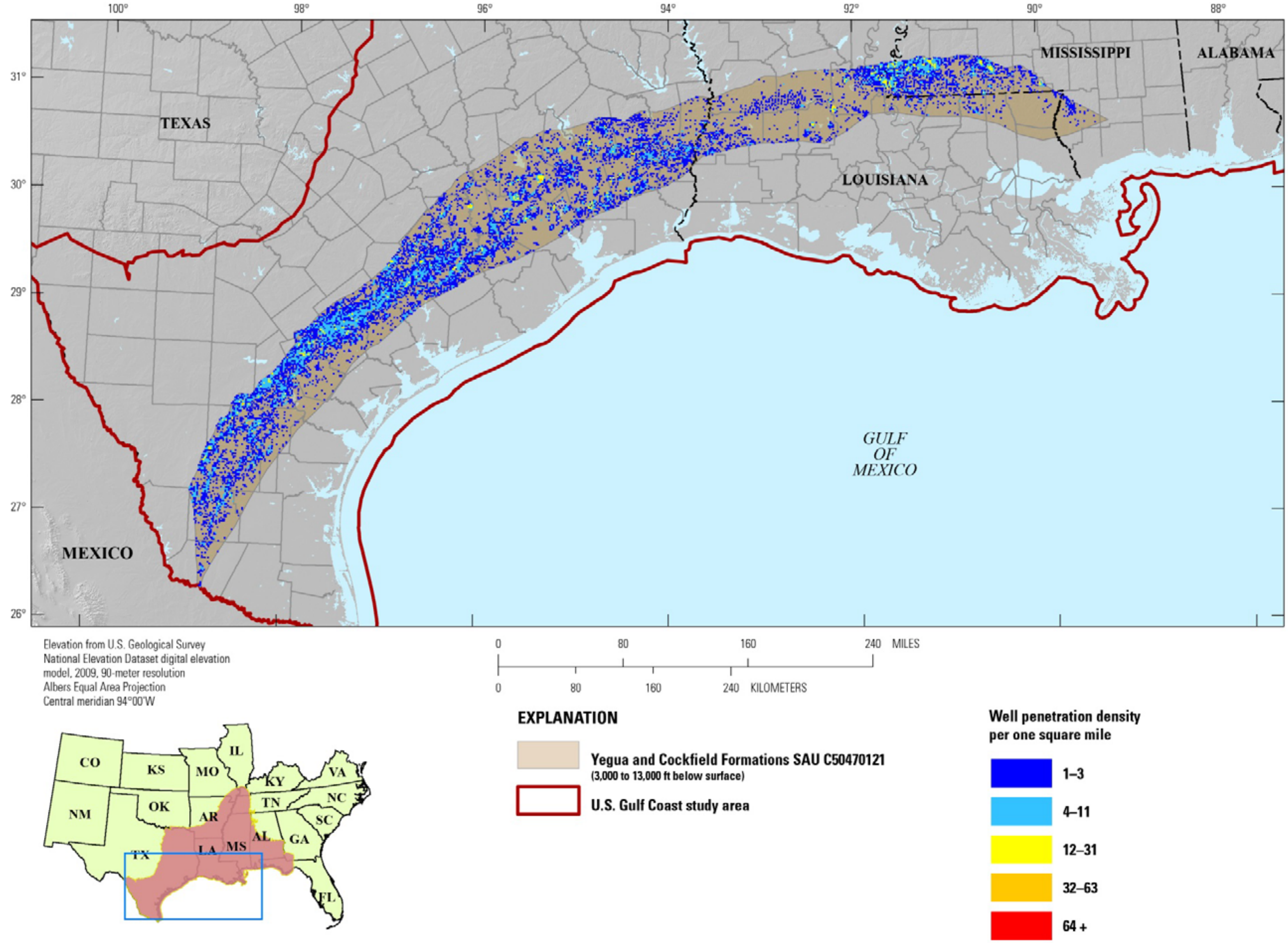

Figure 17. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Yegua and Cockfield Formations SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Frio and Vicksburg Formations SAU C50470122

By William H. Craddock

The Frio and Vicksburg Formations (fig. 2*D*) are a southeast-dipping package of siliciclastic sediment that was deposited along the Gulf of Mexico continental margin during the Oligocene Epoch (Galloway and others, 2000). Four primary depocenters were involved in deposition of the Vicksburg through Frio stratigraphic package. From the west to east along the continental margin, these are the Norias delta, the Norma delta, the Houston delta, and the Mississippi delta (see Galloway and others, 2000). Vicksburg through Frio strata were deposited in a wide variety of depositional environments, including distributary channel, delta plain, delta, interdeltaic embayment, and continental shelf (Galloway and others, 1982; Combes, 1993; Galloway and others, 2000). The largest single sediment source was the Norias-Norma system, and deltas associated with this system are characterized by wave dominated environments. To the east, the Houston and Mississippi systems are characterized by fluvially dominated deltas (Galloway and others, 2000). During deposition of the Vicksburg through Frio interval, sedimentary systems originating in the western portion of the basin, and eventually those originating in the east-central portion of the basin, prograded across the Gulf of Mexico continental shelf and onto the continental slope. High sediment fluxes and rapid progradation of depositional systems in the western part of the basin are thought to relate to erosion of sediment source areas in northeastern Mexico and the southwestern United States (Yurewicz and others, 1997). Progradation of depositional systems across the continental shelf in the early Oligocene was followed by sustained systems tract retreat during the late Oligocene (Galloway and others, 2000). The retrogradational systems tract that overlies the Vicksburg and Frio Formations is known regionally as the Anahuac Formation, which typically comprises fine-grained, open-marine deposits (Galloway and others, 2000). Regionally, the Anahuac Formation is several hundreds of feet thick, perhaps approaching 1,000 ft in some locations, such that it should form a robust top-seal for prospective CO_2 storage in a Vicksburg-Frio reservoir (Williamson, 1959; Stoudt and others, 1990; Galloway and others, 1994).

The perimeter of the Frio and Vicksburg Formations SAU C50470122 is defined by several geologic and political boundaries, including the 3,000- and 13,000-ft overburden contours, the updip limit of fine-grained Anahuac strata that define the regional top-seal, the downdip limit of coarse-grained Vicksburg through Frio strata that form the reservoir interval, the U.S.-Mexico international border, and State-water boundaries (fig. 18; see Brennan and others, 2010). Overburden contours were generated using a database of stratigraphic information from boreholes around the region (IHS Energy Group, 2011). The 3,000- and 13,000-ft contours define parts of the updip and downdip SAU boundaries, respectively. The areal distribution of laterally continuous, shale-prone Anahuac deposits is difficult to define at the spatial scale of the entire U.S. Gulf Coast. In order to approximate this, we used a shoreline reconstruction for the late Oligocene marine transgression that corresponds to the deposition of the Anahuac Formation (Rainwater, 1964). Comparison of the position of the Anahuac shoreline (Rainwater, 1964) and several regional cross sections that extend across the Texas and Louisiana coastal plain (Stoudt and others, 1990; Galloway and others, 1994) suggest that the shorelines are often reasonably good indicators of the updip limit of laterally continuous, fine-grained, marine strata. The updip seal boundary is subject to an estimated approximately 20 miles of uncertainty, at most. Notably, the updip shale limit shifts toward the northern basin margin in the eastern Gulf Coast reflecting the fact that coarse-grained sediment flux into the Mississippi embayment was relatively low compared to the Norias-Norma system to the west (Rainwater, 1964; Galloway and others, 2000). Because of this pattern, the updip SAU limit is defined by the 3,000-ft overburden contour in the eastern part of the basin and the top-seal limit in the western part of the basin. We define a downdip limit of Vicksburg through Frio sand/sandstone, which corresponds to the position of the ultimate Oligocene shelf margin (Galloway and others, 2000). In addition to the ultimate Oligocene continental shelf margin, the downdip SAU limit is also partially defined by the 13,000-ft overburden contour and the State-waters boundary. The eastern limit of the SAU is defined by the gradual transition between siliciclastic rocks in Louisiana and Oligocene carbonates in the Florida panhandle region (Galloway and others, 2000). The southwestern limit of the SAU is defined by the international border between Texas and Mexico. The SAU has a total area of 23,653,000 acres (±10 percent).

The gross thickness of the Vicksburg through Frio stratigraphic package was determined by contouring stratigraphic thickness measurements from borehole stratigraphy (IHS Energy Group, 2011). Averaged across the basin, gross thickness appears to be between 2,700 and 1,100 ft. Generally, gross thickness increases in the basinward direction (see Stoudt and others, 1990) and is relatively large, approaching 7,000 ft, at major sediment outlets, such as the Norias-Norma delta and the Houston delta. In between these deltas, the formations thin to about 1,000 to 3,000 ft of net-sandstone thickness. Net thickness was determined from a variety of data sources, including net-sandstone isolith maps (Bebout and others, 1975; Bebout and others, 1976) and net-to-gross factors that were applied to the gross-thickness isopach map (Burke, 1958; IHS Energy Group, 2011). The highest net-sandstone thicknesses are associated with the Norias-Norma delta systems, where net thickness may be in excess of 3,000 ft. Net Oligocene-sandstone thicknesses generally decrease to the east and basinward, and near the downdip edge of the SAU in Louisiana and eastern Texas, there may be very little (perhaps tens of feet) net sandstone. At a regional scale, the net thickness of porous reservoir rock is on the order of 900 ± 600 ft.

In order to characterize the porosity and permeability of the Vicksburg and Frio Formations at the scale of the entire U.S. Gulf Coast, petroleum-reservoir-averaged porosity measurements were plotted against reservoir depth for Paleogene sandstone reservoirs on the Gulf of Mexico coastal plain (Nehring Associates, Inc., 2010). The plot contains 1,358 petroleum-reservoir-averaged porosity measurements (Nehring Associates, Inc., 2010), and it suggests that within the SAU depth range, average reservoir porosity is 22 ± 4 percent. This number is in reasonable agreement with other studies of Frio sandstone porosity from various swaths of the Texas coastal plain (Maxwell, 1964; Loucks and others, 1979; Galloway and others, 1982). A similar dataset of 1,035 petroleum-reservoir-averaged permeability measurements was compiled for Paleogene sandstones of the Gulf coastal plain (Nehring Associates, Inc., 2010). This dataset suggests that the permeability of the Frio Formation ranges from 0.1 to 3,000 mD, with a most-likely value of approximately 200 mD.

Regional analysis of the salinity of formation waters for various Tertiary formations of the Gulf of Mexico coastal plain shows that salinity within the SAU increases with increasing burial depth, as well as down the depositional dip of the basin (Pettijohn and others, 1988). The Frio and Vicksburg Formations SAU is located entirely downdip of the area that contains formation waters with TDS concentrations <10,000 mg/L, such that the viable storage area does not appear to be significantly limited by the presence of potable formation waters.

In order to approximate the maximum volume that is available for storing CO_2 in buoyant traps (see Brennan and others, 2010), the area of structural and (or) stratigraphic enclosures was combined with the most-likely values for net-sandstone thickness and porosity. The vast majority of traps within this interval appear to be either structural or combination structural-stratigraphic traps (Nehring Associates, Inc., 2010), such that it may be reasonable to combine the enclosed area with the entire net sandstone thickness. The area of enclosed pore volume was approximated by combining the number of petroleum fields with an estimate of a most-common reservoir size (Nehring Associates, Inc., 2010).

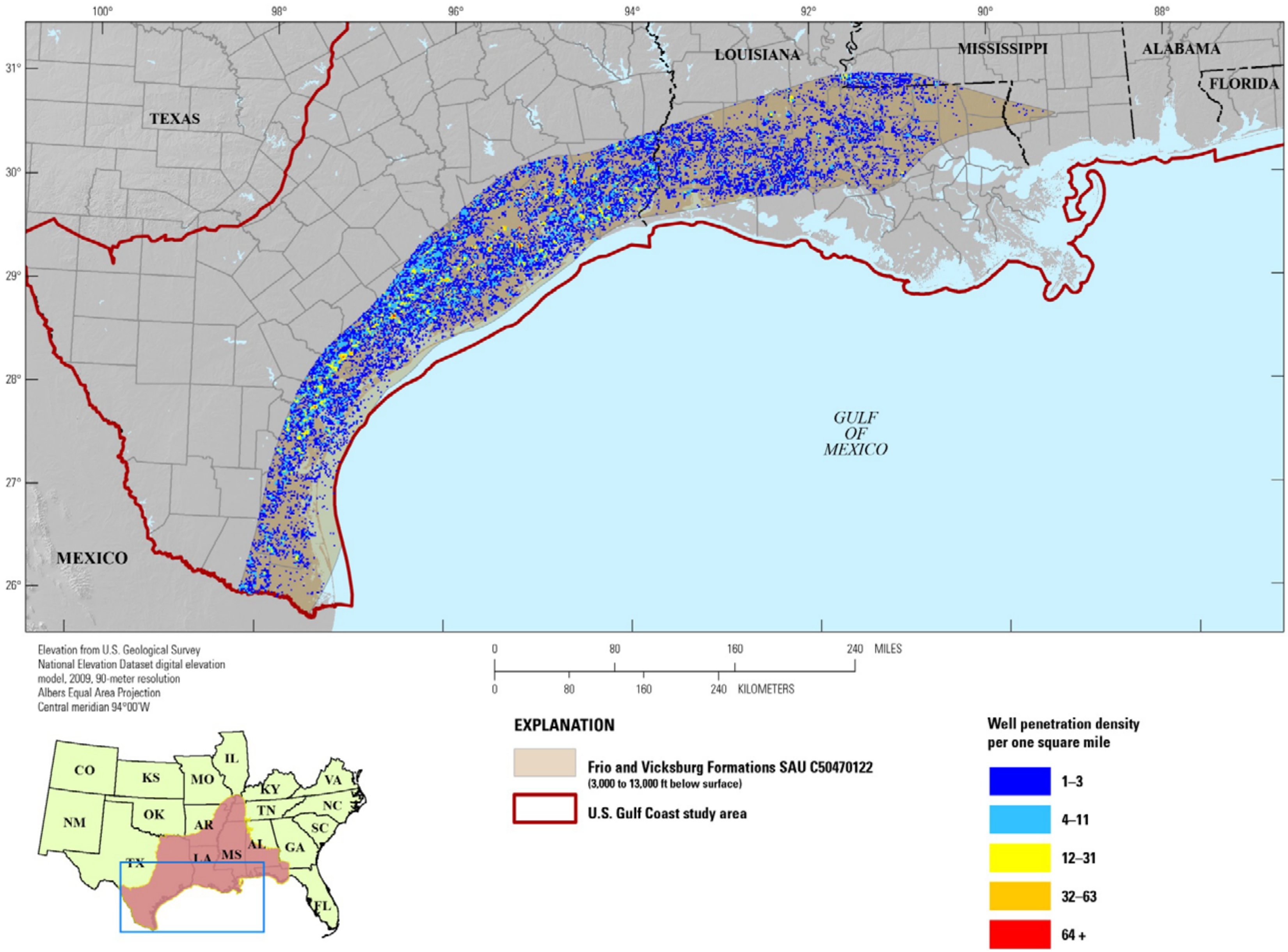

Figure 18. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Frio and Vicksburg Formations SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Lower Miocene I SAU C50470123, Lower Miocene II SAU C50470124, Middle Miocene SAU C50470125, and Upper Miocene SAU C50470126

By William H. Craddock

Miocene strata (fig. 2*E*) deposited along the Gulf of Mexico continental margin dip gently to the southeast and expand in the basinward direction. Five primary depocenters were involved in deposition of the Miocene strata. From west to east, these include the Norma delta, the North Padre delta, the Corsair delta, the Calcasieu delta, and the Mississippi delta (Galloway and others, 2000). The strata were deposited in a wide variety of depositional settings, including distributary channel, delta plain, delta, interdeltaic embayment, continental shelf, and upper continental slope (Galloway and others, 2000). A detailed review of the Miocene depositional history is beyond the scope of this report, and readers are referred to a recent review by Galloway and others (2000) for additional details. However, some key geologic observations relating to this stratigraphic package are highlighted herein. Firstly, relative to the Oligocene, sediment influx into the western portion of the basin tapered, whereas sediment influx into the eastern portion of the basin (particularly the Mississippi River axes) accelerated (Galloway and others, 2000). Generally speaking, progradation of the continental shelf across the south Texas continental margin was modest, approximately a few tens of miles over the course of the Miocene. In contrast, the Louisiana continental shelf margin prograded basinward by more than 100 miles. To the east of Louisiana, the continental shelf was largely sediment starved in the early Miocene, but sediment supply accelerated during the middle and late Miocene causing deltaic systems to advance rapidly to the continental shelf margin over spatial scales similar to the central Mississippi axis (Galloway and others, 2000). Secondly, fluctuations in eustatic sea level during the Miocene exerted a first-order influence on the evolving paleogeography of the region (Galloway and others, 2000; Miller and others, 2005). We defined four retrogradational packages deposited during major transgressions, and they serve as fine-grained regional sealing units and subdivide the Miocene section into four SAUs (adapted from Galloway and others, 2000): Lower Miocene I SAU C50470123, Lower Miocene II SAU C50470124; Middle Miocene SAU C50470125, and Upper Miocene SAU C50470126 (figs. 19 to 22).

The perimeter of the various Miocene SAUs is defined by several parameters, which include 3,000- and 13,000-ft overburden contours, the updip limit of shale-prone strata in the sealing units, the downdip limit of continental shelf deposits, the U.S.-Mexico international border, and State-water boundaries (figs. 19 to 22; see Brennan and others, 2010). Overburden contours were adapted from a recent USGS undiscovered oil and gas assessment of the Miocene strata of the Gulf coastal plain, and the 3,000- and 13,000-ft contours define parts of the updip and downdip SAU boundaries, respectively (R. Dubiel, USGS, written commun., 2011). The landward limit of the shale-prone packages that separate the Miocene stratigraphic packages were adapted from a reconstruction of Oligocene and Miocene shorelines during major marine transgressions in the Oligocene and Miocene (Rainwater, 1964). Comparison of the position of these shorelines with regional cross sections (Doyle, 1979; Stoudt and others, 1990) suggests that the shorelines accurately define the updip limit of homogeneous, fine-grained strata. Additionally, these shale-prone stratigraphic intervals should act as robust regional seals. The updip seal boundary is estimated to have about 20 miles of uncertainty, at most. Paleogeographic reconstructions of ultimate continental shelf edges during the various Miocene progradational events were used to define the basinward limit of sandstone reservoir rock because it was assumed that a transition from relatively coarse-grained to fine-grained rocks occurs along the continental shelf-slope boundary (Galloway and others, 2000). The Lower Miocene SAU boundaries are generally defined by top-seal limits along their updip edges and State-water boundaries and (or) 13,000-ft overburden contours along their downdip edges. The Middle and Upper Miocene SAUs are defined almost entirely by the updip top-seal limit and the State-water boundaries. Due to the fact that the top-seal limits nearly overlap the Texas State-waters boundary for the Middle and Upper Miocene SAUs, the majority of the area of these SAUs is situated along the Louisiana coast, and narrow, disconnected sections of the SAUs extend along the Texas State-waters boundary. In stratigraphic order (older to younger), these SAUs cover areas of 8,432,000 acres, 9,924,000 acres, 3,619,000 acres, and 1,933,000 acres. We consider the uncertainty on these area measurements to be about 10 percent.

A variety of data were aggregated in order to determine the gross thickness of the storage reservoirs, as well as the net-sandstone thicknesses within the reservoirs. The data include gross formation isopachs and percent-sand contours from a USGS Miocene undiscovered oil and gas assessment (R. Dubiel, USGS, written commun., 2011), gross-formation thickness and net-to-gross contours for the Texas coastal region (Doyle, 1979), and net-sandstone isolith maps for the southern Texas coastal region (Morton and others, 1988). Generally speaking, the highest gross and net thicknesses correspond to the major deltaic axes, and the central Mississippi River depocenter is typically much thicker than depocenters to the west. Between the major depocenters, gross and net-sandstone thicknesses decrease dramatically. For the Lower Miocene I SAU, gross thickness appears to average 1,500 ± 500 ft. Maximum thicknesses are associated with the Mississippi delta and may be as much as 8,000 ft near the downdip edge of the SAU, although gross thickness of 1,000 ft or more is observed across the Texas State-waters region, on average. Net-sandstone thickness appears to average 600 ± 300 ft across this SAU. Again, maximum thicknesses are associated with the Mississippi delta, and they may exceed 1,500 ft. Along the Corsair delta in Texas, net-sandstone thickness may approach 400 ft. For the Lower Miocene II SAU, gross-thickness estimates average 1,600 ± 300 ft, with thicknesses in excess of 6,000 ft in the Mississippi delta, thicknesses of thousands of feet in the Corsair delta, and thin zones located away from the major depocenters. Net-sandstone thicknesses for this SAU are 550 ± 200 ft. The updip portion of the Mississippi delta area may have aggregate sandstone thickness >1,000 ft, whereas the thickest sandstone accumulations in Texas, along the Corsair delta, approaches 1,000 ft. An average gross thickness of 3,200 ± 900 ft was estimated for the Middle Miocene SAU, with thicknesses in excess of 6,000 ft at the Mississippi delta and thicknesses of hundreds of feet in the narrow swaths of the SAU that are located along the Texas State-waters boundary. Net-sandstone thickness estimates are 480 ± 140 ft, with thicknesses approaching 1,000 ft in the Mississippi delta and thicknesses of hundreds of feet across offshore Texas. Finally, the average gross thickness of the Upper Miocene SAU is estimated to be 5,400 ± 1,000 ft, with thicknesses in excess of 10,000 ft at the Mississippi delta, and thicknesses in excess of 1,000 ft at the Norma delta. The average net-sandstone thickness of the Upper Miocene SAU is 1,500 ± 400 ft, with thicknesses in excess of 3,000 ft at the Mississippi delta and in excess of 1,000 ft at the Norma delta.

The Nehring Associates, Inc. (2010) production database was used to characterize the porosity and permeability of the Miocene SAUs. From this database of 432 petroleum-reservoir-averaged porosity measurements, a basin-wide, sandstone compaction curve for Neogene sandstone reservoirs around the Gulf Coast region was generated. The database suggests relatively high porosities at any given burial depth in comparison to underlying Paleogene strata. Given that the distribution of burial depths is relatively even across the region, a mean burial depth of 8,000 ft was assumed for all SAUs to estimate regional porosity directly from the Neogene compaction curve. Within the SAUs, regional reservoir porosity appears to be approximately 28 ± 4 percent. Permeability was estimated from 259 petroleum reservoirs on the coastal plain. Similar to porosity, regional permeability appears to be high, with a most-likely value of about 500 mD (Nehring Associates, Inc., 2010). Similar to other geologic formations, permeability varies over a wide range, and individual petroleum reservoirs may exhibit permeability as low as 20 mD and as high as 8,000 mD.

Regional analysis of the salinity of formation waters for various Tertiary formations of the Gulf coastal plain has shown that salinity tends to increase with increasing burial depth, as well as down the depositional dip of the basin (Pettijohn and others, 1988). In general, the Miocene SAUs are located in zones of high salinity, with TDS values well in excess of 10,000 mg/L. The highest potential for groundwater accumulations with TDS <10,000 mg/L in any of the Miocene SAUs appears to be within the far eastern margin of the Lower Miocene II SAU (Pettijohn and others, 1988), although this potentially saline area appears to encompass no more than 10 percent of the SAU area.

In order to approximate the maximum volume that is available for storing CO_2 in buoyant traps (see Brennan and others, 2010), the area of structural and (or) stratigraphic enclosures was combined with the probable net-sandstone thickness and porosity of the various Miocene stratigraphic intervals. The approach to this calculation is identical to the approach used for the Frio and Vicksburg Formations SAU.

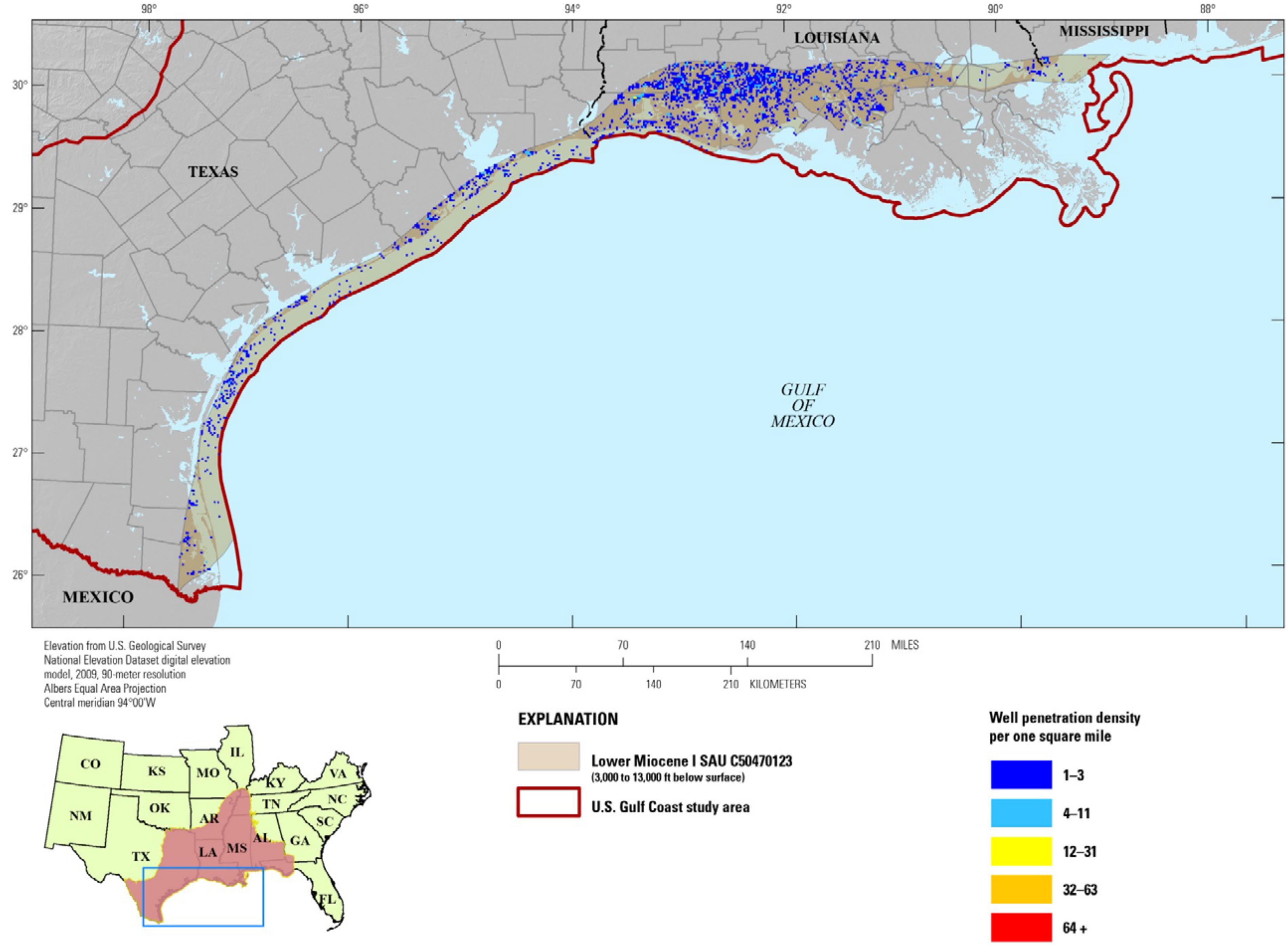

Figure 19. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Lower Miocene I SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

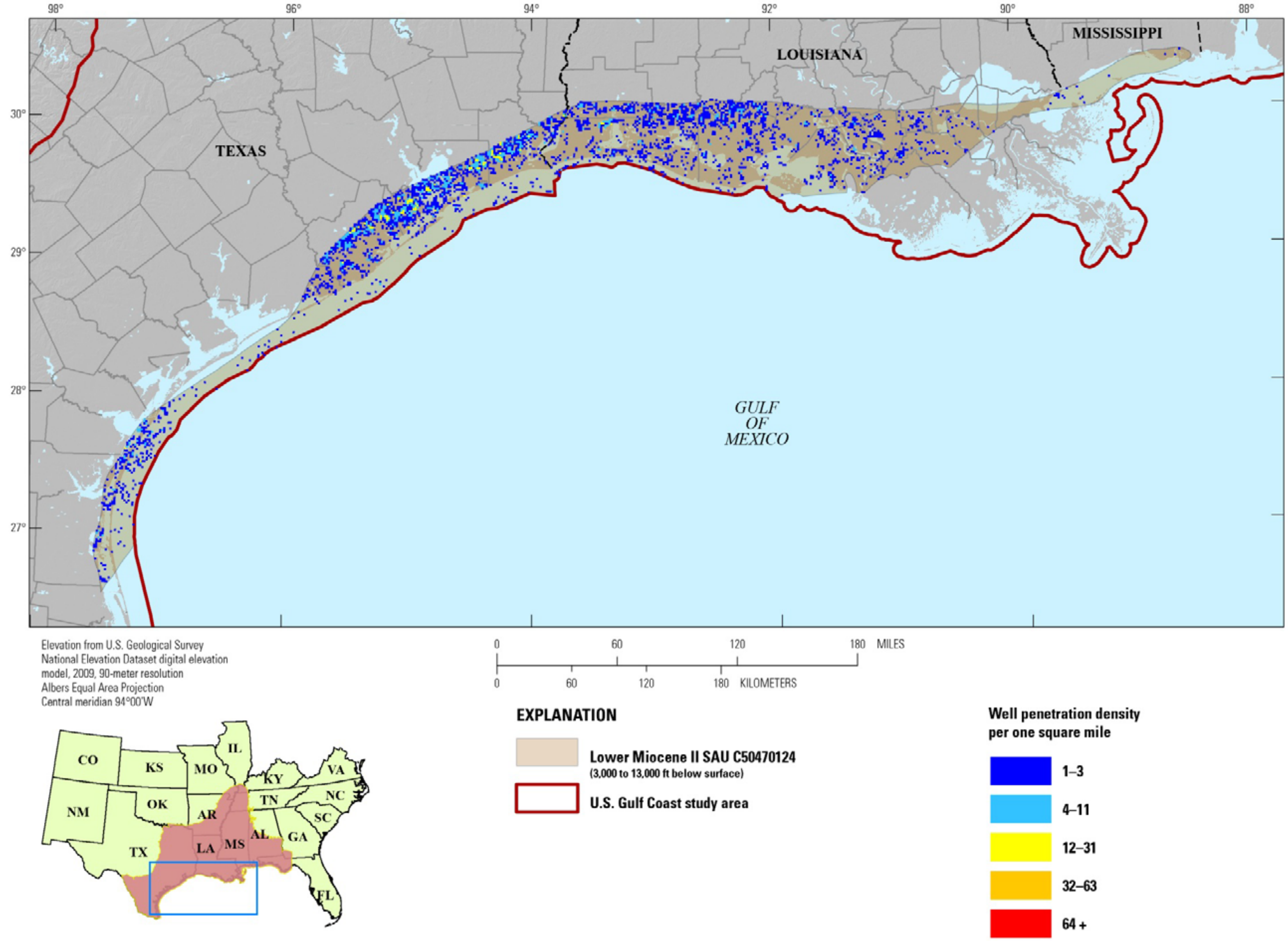

Figure 20. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Lower Miocene II SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

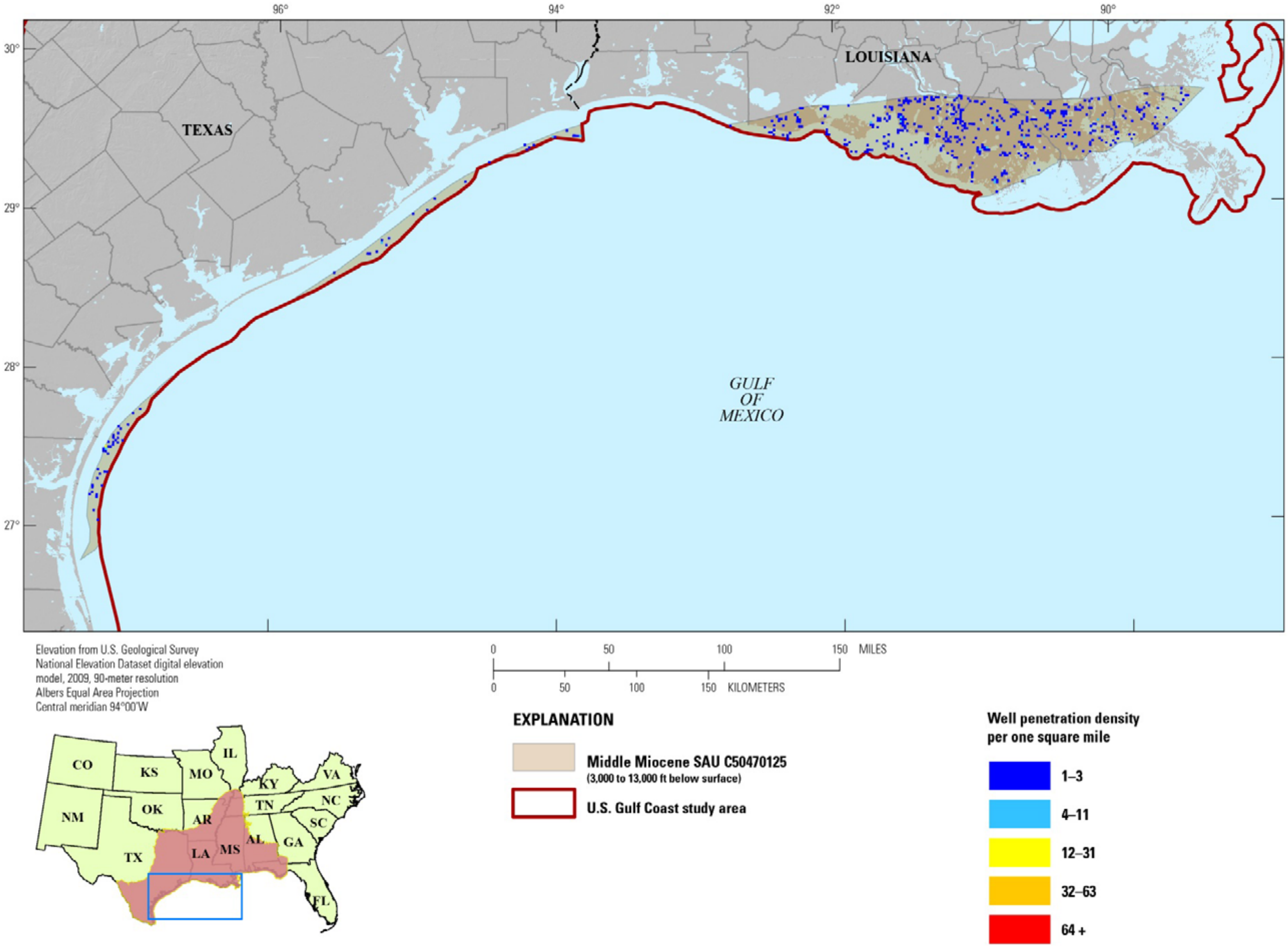

Figure 21. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Middle Miocene SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

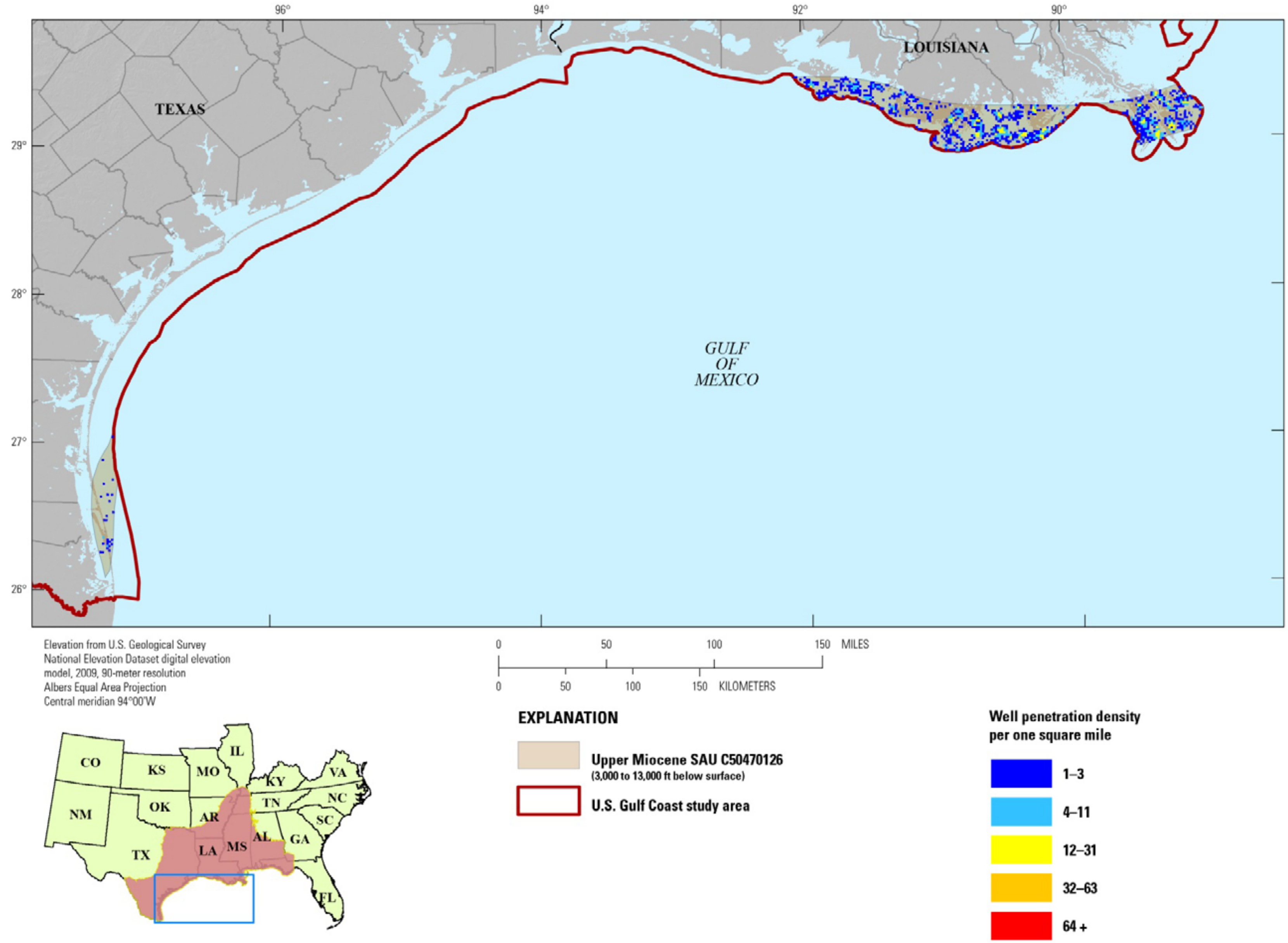

Figure 22. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Upper Miocene SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

Tertiary Slope and Basin Floor SAU C50470127

By Matthew D. Merrill, William H. Craddock, and Tina L. Roberts-Ashby

The Tertiary Slope and Basin Floor SAU C50470127 is a nonquantitative SAU that includes continental-slope and basin-floor deposits, situated downdip of the ultimate continental shelf margins for the various Tertiary depositional episodes in the Gulf Coast region (Ewing and Lopez, 1991; Galloway and others, 2000). Since continental slope deposits tend to be muddy and lack good reservoir quality, the best opportunity for reservoir rock in the Tertiary Slope and Basin Floor SAU C50470127 is probably in submarine canyon and upper slope channel-fill deposits, which tend to be coarse grained, thereby enhancing the potential for increased storage reservoir quality. Additionally, these channel fills tend to be located closer to the base of the continental slope or local salt diaper bathymetry inversions, such that there is potentially a better chance for reservoir rock in relatively downdip regions, as updip of the continental slope, canyon channel-fills are generally sites of erosion and (or) bypass. Additionally, basin-floor fans and wide basin-floor aprons could act as potential storage reservoirs for CO_2 sequestration within this SAU. The Tertiary Slope and Basin Floor SAU C50470127 is hypothetically composed of the lower Tertiary Wilcox Group and Carrizo Sand through the Miocene-age sands (fig. 2*E*) at depths greater than 13,000 ft below the surface. For further information on the lithology and depositional environments of the stratigraphic units that comprise this SAU, see descriptions for SAUs C50470118 through C50470126 of this report. The regional seal that potentially overlies this SAU is poorly understood; however, it is assumed to be fine, terrestrial, basin-floor deposits of Tertiary age.

The Tertiary Slope and Basin Floor SAU C50470127 has an area of around 28,949,000 acres (fig. 23). The boundaries of the SAU extend from the Upper Cretaceous Stuart City reef margin in the north, a boundary that also coincides with the southern or downdip limit of the Carrizo Sand and Wilcox Group SAU C50470118, to the downdip direction and up to the State-waters boundary off the coasts of Texas and Louisiana. The western limit of the SAU is the U.S.-Mexico international border, and the eastern boundary is marked by the Federal-State-waters boundary in the Mississippi delta region of Louisiana.

Based upon water-quality data (Breit, 2002) and regional groundwater studies (Pettijohn and others, 1988), the SAU is thought to contain exclusively saline waters (TDS >10,000 mg/L). Although the Tertiary Slope and Basin Floor SAU C50470127 probably has significant potential to serve as a CO_2 storage reservoir, data availability for all of the reservoir units within the SAU, as well as data needed to characterize the seal, are limited; therefore, the Tertiary Slope and Basin Floor SAU C50470127 is a nonquantitatively assessed SAU.

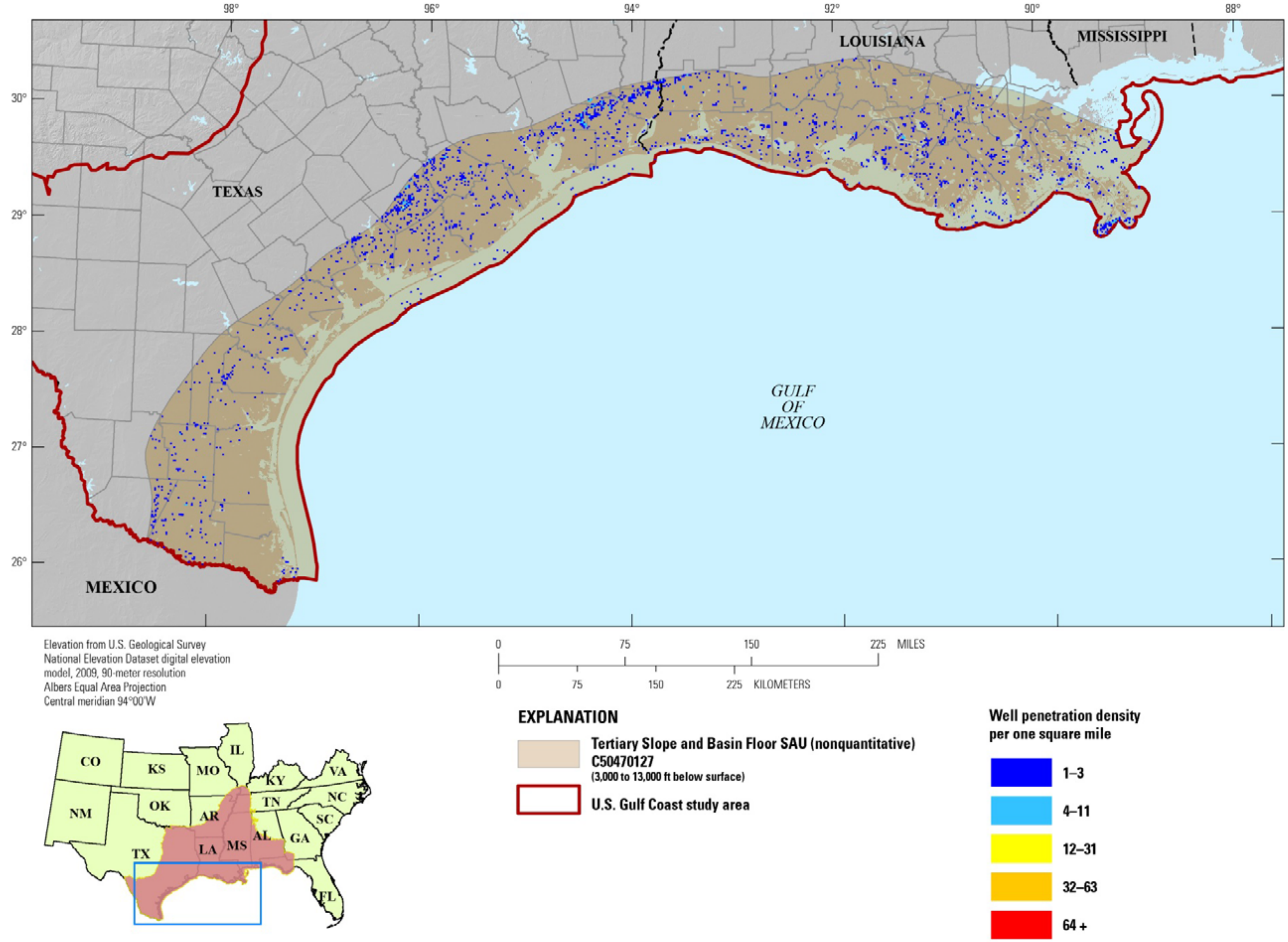

Figure 23. Map of the U.S. Geological Survey storage assessment unit (SAU) boundary for the Tertiary Slope and Basin Floor SAU in the U.S. Gulf Coast. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the reservoir formation top.

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