# Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources—Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin

By Matthew D. Merrill, Ernie R. Slucher, Tina L. Roberts-Ashby, Peter D. Warwick, Madalyn S. Blondes, Philip A. Freeman, Steven M. Cahan, Christina A. DeVera, and Celeste D. Lohr

Chapter K of
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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; U.S. Congress, 2007) 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 storage of $CO_2$ is one possible way to mitigate its effects on climate change.

The methodology 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, an external panel of experts, and members of the public. During the implementation phase of the assessment (from 2010 to 2012), several practical steps were added to the assessment methodology of Brennan and others (2010). The details of the methodology used in the assessment are described in Blondes and others (2013). The assessment methodology is non-economic and is intended to be used at regional to sub-basinal scales.

The operational unit of the assessment is a storage assessment unit (SAU), which is 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; Blondes and others, 2013). 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; any formation water having a salinity less than 10,000 parts per million (ppm, which is equivalent to 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 (EPA) (2010) defines the lower limit of 10,000 ppm (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 ppm (mg/L) TDS are not assessed (Brennan and others, 2010; Blondes and others, 2013).

This report series contains a geologic description of each SAU identified within each report's assessed basins and focuses on particular characteristics specified in the methodology that influence the potential $CO_2$ storage resource. The geologic framework information contained in these reports was used to calculate a statistical Monte Carlo-based distribution of potential storage space in the various SAUs following Brennan and others (2010) and Blondes and others (2013). Assessment data, results, and summary can be found in the U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team's (2013a,b,c) reports. 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 | |
| Acre | 0.4047 | hectare (ha) |
| Acre | 0.004047 | square kilometer ($km^2$) |
| square mile ($mi^2$) | | 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 ($m^3$) |
| liter (L) | 0.2642 | gallon (gal) |

## Abbreviations

| | |
|---|---|
| $CO_2$ | carbon dioxide |
| EOR | enhanced oil recovery |
| mD | millidarcy |
| mg/L | milligrams per liter |
| NOGA | national oil and gas assessment |
| ppm | parts per million |
| SAU | storage assessment unit |
| TDS | total dissolved solids |
| USGS | U.S. Geological Survey |

# Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources—Permian and Palo Duro Basins and Bend Arch-Fort Worth Basin

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## Abstract

The U.S. Geological Survey has completed an assessment of the potential geologic carbon dioxide storage resource in the onshore areas of the United States. To provide geological context and input data sources for the resources numbers, framework documents are being prepared for all areas that were investigated as part of the national assessment. This report is the geologic framework document for the Permian and Palo Duro Basins, the combined Bend arch-Fort Worth Basin area, and subbasins therein of Texas, New Mexico, and Oklahoma. In addition to a summarization of the geology and petroleum resources of studied basins, the individual storage assessment units (SAUs) within the basins are described and explanations for their selection are presented. Though appendixes in the national assessment publications include the input values used to calculate the available storage resource, this framework document provides only the context and source of inputs selected by the assessment geologists. Spatial files of boundaries for the SAUs herein, as well as maps of the density of known well bores that penetrate the SAU seal, are available for download with the release of this report.

## Report Overview

This three-part chapter contains the geologic framework for three adjacent study areas in Texas, New Mexico and Oklahoma: the Permian Basin, the Palo Duro Basin, and the Bend arch-Fort Worth Basin area (fig. 1). Subbasins associated with these study areas are included in this report and addressed in the basin-specific sections. This report is a chapter of U.S. Geological Survey (USGS) Open-File Report 2012–1024—a multiple-chapter report that summarizes the geologic framework employed in the investigation of sedimentary basins in the United States for geologic carbon dioxide ($CO_2$) storage. Stratigraphic columns for the basins are presented specifically for the purpose of representing the storage units; these are not authoritative or comprehensive depictions of the full range of the geology in these basins. Figures showing the storage assessment unit boundaries also include well density information. This data may be used to infer the level of existing wells that have penetrated the proposed seal in a given storage assessment unit. Complete national assessment results, other basin-framework reports, and related $CO_2$ sequestration investigations by the USGS are available at http://energy.usgs.gov/HealthEnvironment/EnergyProductionUse/GeologicCO2Sequestration.aspx.

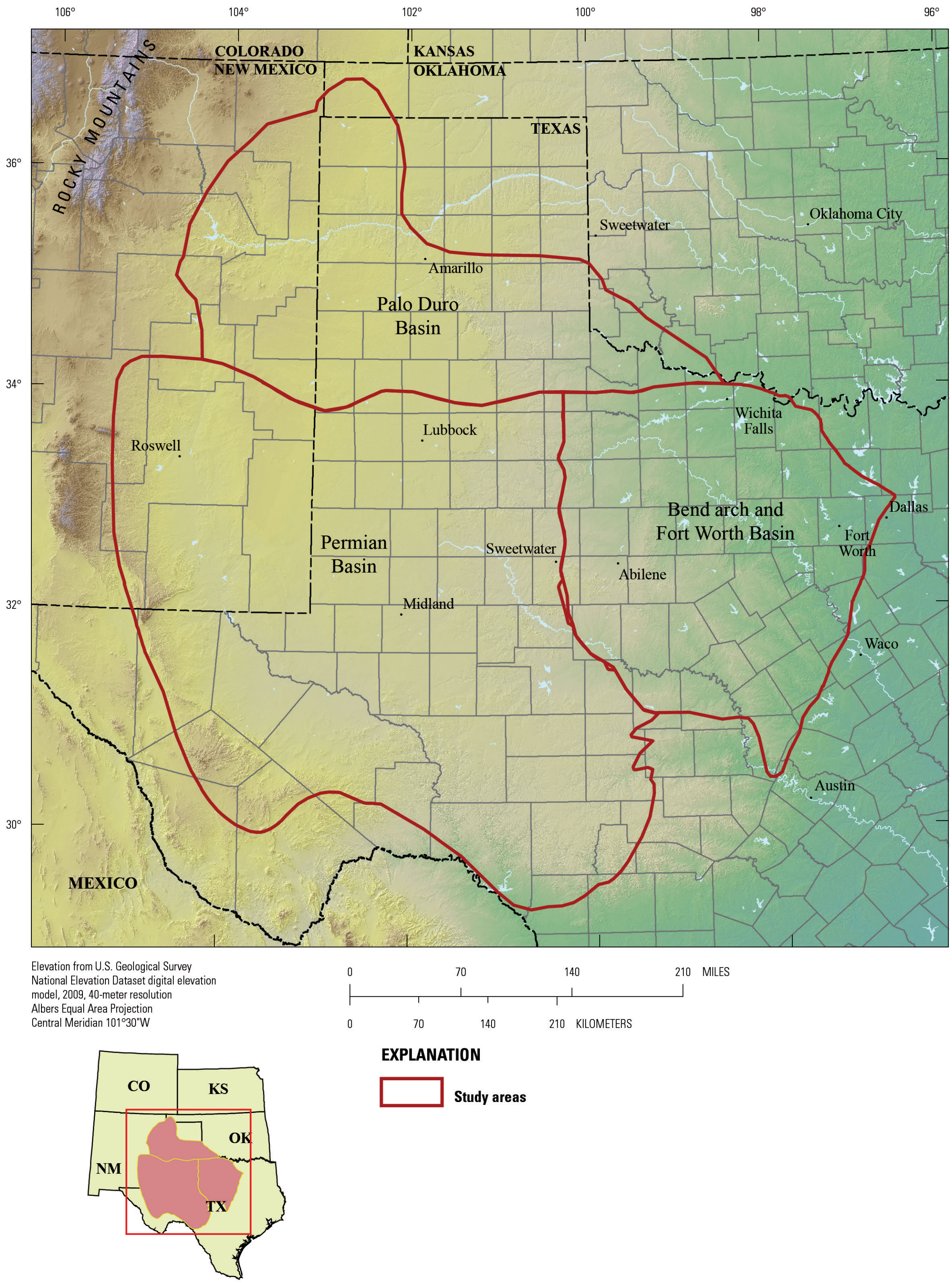


**Figure 1.** Map of the Permian and Palo Duro Basins and Bend arch-Fort Worth Basin in Texas, New Mexico, and Oklahoma. These areas were evaluated for their geologic carbon dioxide storage potential. Major structural features are presented in the basin-specific maps. Study areas are modified from U.S. Geological Survey national oil and gas assessment (NOGA) reports (Schenk and others, 2008; Pollastro and others, 2004; Ball and Henry, 1995).

# Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources—Permian Basin

By Ernie R. Slucher, Tina L. Roberts-Ashby, Peter D. Warwick, Madalyn S. Blondes, Philip A. Freeman, Steven M. Cahan, and Celeste D. Lohr

## Introduction

The present-day greater Permian Basin of west Texas and southeastern New Mexico consists of an area in excess of 86,000 square miles (Ball, 1995) (fig. 1). The basin developed in Late Mississippian and Early Pennsylvanian time along the southern margin of Laurentia as part of the Marathon-Ouachita-Sonora orogenic event (Dutton and others, 2005; Poole and others, 2005). A complex of discrete subbasins, shelves, and structurally uplifted platforms formed during this time and are major structural elements within the assessment study area (fig. 2). Notable features include the Midland and Delaware foreland basins, the foredeep Val Verde Basin, the structurally uplifted Central basin platform and associated Ozona arch, and the Northwest and Eastern shelves (Poole and others, 2005). The Matador uplift is an anticlinal trend separating the Midland and Palo Duro Basins. Prior to the development of these features, a broad cratonic sag termed the Tobosa Basin occurred in the region and centered mainly in the general vicinity of the later Delaware Basin (Galley, 1958; Dutton and others, 2005; Miall, 2008). The Tobosa Basin developed in the Late Cambrian, persisted through Late Devonian, and is defined by thickness and lithofacies distributions of lower and middle Paleozoic rocks (Galley, 1958).

In general, peripheral areas of the greater Permian Basin consist of the Eastern shelf on the east, the Northwest shelf to the north and northwest, and the Diablo platform on the west (fig. 2). The Marathon-Ouachita fold belt marks the southern limit of the Permian Basin (Oriel and others, 1967). Overall, the Delaware and Val Verde portions of the Permian Basin contain the deepest and thickest strata preserved in the basin (Galley, 1958; Hills, 1968).

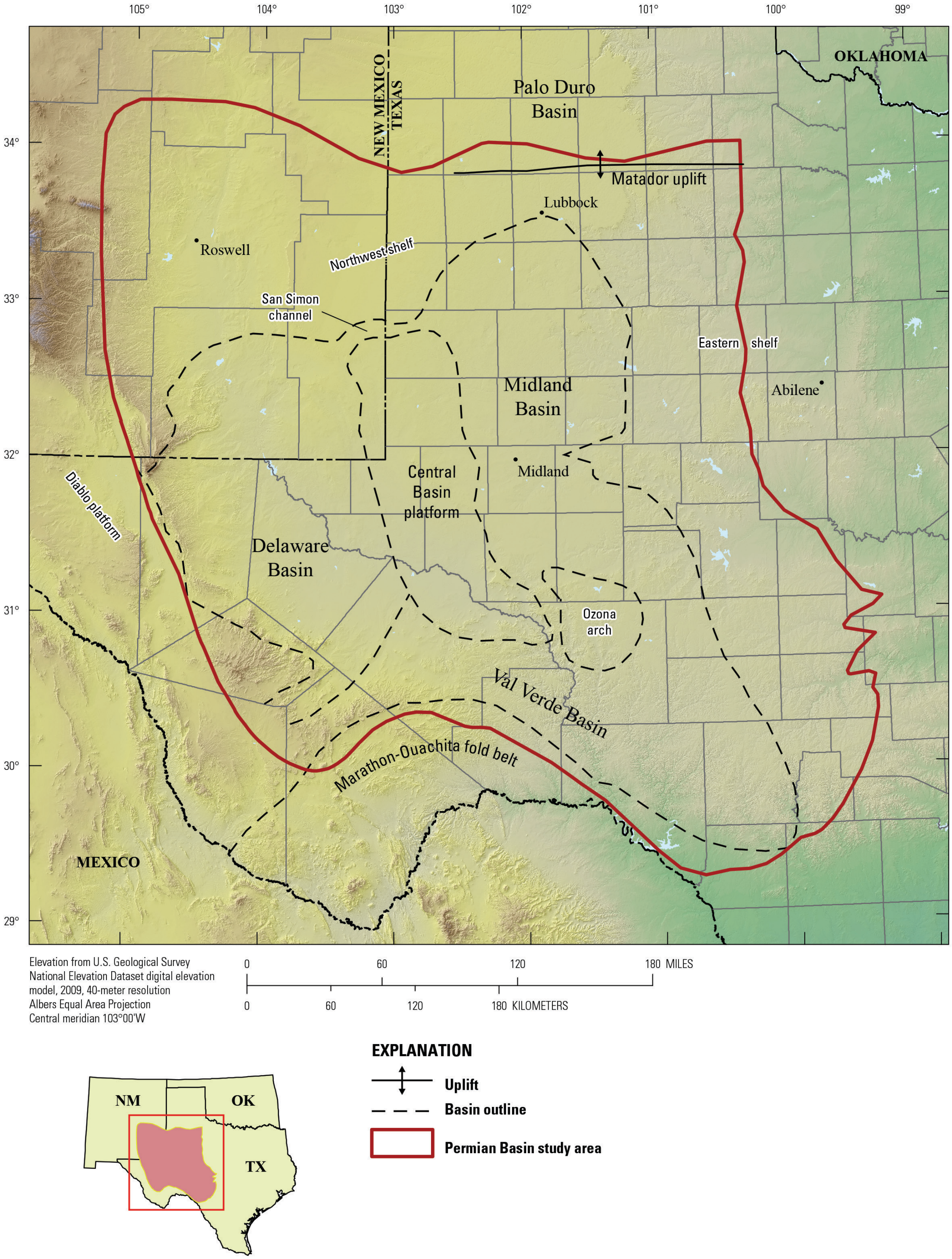


**Figure 2.** Map showing the Permian Basin study area, including major structural features (modified from Dutton and others, 2003, 2005). Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Schenk and others, 2008).

## Geologic History

Precambrian basement rocks that underwent multiple orogenic events approximately 1.7 to 1.0 billion years ago underlie the Permian Basin. Adams and Keller (1996) suggested reactivation of preexisting basement structures exerted control on the development of younger structures in the basin, as well as sedimentation. In general, following the breakup of Rodinia approximately 750 million years ago, a continental passive margin formed on the southward-facing edge of the North American plate (Laurentia) (Miall, 2008). Initial sedimentation across this platform consisted of, in most areas of the present-day Permian Basin, Upper Cambrian to Lower Ordovician siliciclastic rocks (fig. 3). Subsequent Ordovician and Silurian deposition consisted mainly of carbonates, with subordinate amounts of siliciclastic sediments. This interval was periodically influenced by tectonic and eustatic events producing regional unconformities, some characterized by extensive paleokarst, which preserved petrophysical properties required of storage reservoirs as discussed in this assessment (for example, the Ellenburger Group) (Dutton and others, 2005).

Following an extended period of erosion during most of the Devonian, the Upper Devonian and Lower Mississippian Woodford Shale were deposited (fig. 3). Deposition of the Woodford represents the final phase of sedimentation filling the Tobosa Basin (Galley, 1958). The southern margin of Laurentia remained a passive margin at least to Early Mississippian (Poole and others, 2005).

Collision of the North American plate (Laurentia) with the northwestward encroaching South American plate (Gondwana) in the Middle Mississippian created the Marathon-Ouachita-Sonora orogenic event (Poole and others, 2005). Evidence in the Marathon region south of the Permian Basin indicates that the orogenic event culminated by mid-Early Permian time (Poole and others, 2005). This event also initiated the development and configuration of most present-day structural elements that define the Permian Basin (fig. 2) and subsequent upper Paleozoic sedimentary rocks in the area of this assessment (fig. 3) (Dutton and others, 2005; Miall, 2008; Scholle and others, 2007). Sedimentation patterns related to differential subsidence, particularly from Wolfcampian through Guadalupian time, enhanced relief between the basins and surrounding shelf and platform areas so that with time, the difference in base-level between these depositional areas became more pronounced (Scholle and others, 2007). In general, uplifted platform and shelf regions of the Permian Basin were the sites of mostly carbonate shelf and marginal reef environments, whereas siliciclastic sediments were predominant in basin depositional systems. By Late Permian (Ochoan Series), open-marine environments within the basin ceased as Pangaea neared assembly, and several thousand feet of evaporite-rich sediments accumulated across the region (Galley, 1958; Oriel and others, 1967). Following the assembly of Pangaea and a period of erosion in the earliest Mesozoic, Upper Triassic continental sediments were deposited across the region (fig. 3). Later, a thin veneer of Cretaceous-age siliciclastic rocks were deposited, and the Late Cretaceous to middle Eocene Laramide orogeny and the Tertiary-age Basin and Range tectonic event altered southwestern areas of the greater Permian Basin (Galley, 1958). Trentham and others (2012) suggest that regional groundwater and petroleum reservoir systems within some areas of the Permian Basin also were altered by these events. Additional details on Paleozoic rocks specific to individual SAU discussions are presented later in this chapter.

## Stratigraphic and Assessment Divisions

Overall, the Permian Basin contains primarily a thick Paleozoic succession of mostly carbonate rocks with thinner but locally concentrated stratigraphic intervals of siliciclastic and evaporitic rocks (Galley, 1958; Dutton and others, 2005). Thickness of Paleozoic strata in the basin commonly exceeds 14,000 feet (ft), and may reach 25,000 ft thick in parts of the Delaware and Val Verde Basins (Galley, 1958; Oriel and others, 1967; Miall, 2008). Volumetrically, the majority of the Paleozoic succession is Late Pennsylvanian to Late Permian age (Galley, 1958).

The lithostratigraphy and hierarchy of nomenclature used to define Paleozoic rocks in the Permian Basin is both simple and complex (fig. 3) and can be divided into two specific intervals. In general, lower and middle Paleozoic nomenclature is straightforward and reflects sediments preserved on a passive continental margin and in the Tobosa Basin. Regionally applicable stratigraphic terms are applied with a high degree of uniformity across the greater Permian Basin for these rocks (fig. 3).

Conversely, upper Paleozoic lithostratigraphy, particularly of the Permian System, reflects the Late Mississippian to Early Pennsylvanian tectonic development of the previously noted structural elements in the Permian Basin (fig. 3). These features controlled, in part, a diverse mix of continental to deep-ocean basin depositional environments and resulted in a complex mosaic of lithofacies. This geologic complexity, combined with the initial development of a regional lithostratigraphic framework during the late 19th century and earliest 20th century (which preceded any major petroleum discoveries) and subsequent stratigraphic approaches over the last 100 years with the advent of petroleum exploitation, has spawned a great variety of stratigraphic schemes for the Permian Basin, most of which do not conform to any accepted or formal stratigraphic convention (Silver and Todd, 1969; Wright, 2011; Nelson and others, 2013). Some terms define lithostratigraphic units, others define dissimilar lithologies thought to be of equivalent age, and some unit names are simply provincial series assignments (for example, "Wolfcamp formation"), which may or may not be based on valid biostratigraphic control. Moreover, the current nomenclature includes both formal and informal terms, and in some instances, multiple rank identifiers define the same unit. For instance, the Leonardian Bone Spring of the Delaware Basin is formally recognized as the Bone Spring Limestone in the USGS Geologic Names Lexicon (GEOLEX, see http://ngmdb.usgs.gov/Geolex/geolex_home.html); however, Bone Spring Formation or Bone Spring basinal carbonate and sandstone are commonly used to define the unit in the Delaware Basin (Sarg, 1987; Dutton and others, 2005; Ruppel, 2009). The San Andres Limestone (or Formation) is another unit with multiple identifiers that also contains informally defined "upper" San Andres and "lower" San Andres internal divisions (Cowan and Harris, 1986; Dutton and others, 2005; see also fig. 3). In the Midland Basin, Spraberry sandstone historically defined an informal interval with economic interest (Oriel and others, 1967). Later, Hanford (1981) formally designated the unit as the Spraberry Formation; however, "sandstone" continues, or in some instances "trend" is used to identify rock of the interval (for examples see, Montgomery and others, 2000; Dutton and others, 2005; Schenk and others, 2008). Because of the multiplicity of stratigraphic nomenclature and rank assignments applied in different States and subregions of the Permian Basin, and for simplicity in presentation, the formation-rank term for formal units below group are not presented for Pennsylvanian, Permian, and Triassic units of figure 3. In general, the stratigraphic nomenclature presented here is a compilation based mostly on Ball (1995), Broadhead and others (2004), Dutton and others (2005), and Ruppel (2009).

## $CO_2$ Storage

For this assessment, two stratigraphic intervals, divisible into three SAUs, are identified with regionally extensive sealing rocks suitable for potential geologic storage of $CO_2$ within the Permian Basin. They are (1) the Lower Paleozoic Composite and (2) Lower Paleozoic Composite Deep SAUs and (3) the Permian Composite SAU. Descriptive summaries of these SAUs are presented herein. Geologic elements of each SAU are discussed, as is data employed in the methodology as defined in the Editors' Preface and Burruss and others (2009), Brennan and others (2010), and Blondes and others (2013). Also, factors and petrophysical properties related to geologic $CO_2$ storage and other geologic attributes that influence the potential $CO_2$ storage volumes are discussed in addition to the inputs for the calculations. Included also are estimates of the pore volume within structurally and (or) stratigraphically closed traps within specific SAUs. Complete national assessment results, of which this report is part of, and other information on $CO_2$ sequestration are available at
http://energy.usgs.gov/HealthEnvironment/EnergyProductionUse/GeologicCO2Sequestration.aspx.

## Petroleum Resources and $CO_2$-Enhanced Oil Recovery

Commercial quantities of petroleum were discovered in the Permian Basin in the first quarter of the 20th century. Since then, the greater Permian Basin has become one of the most important and prolific petroleum-producing basins in the United States. Overall, strata of Permian age account for nearly 75 percent of the cumulative petroleum production in the basin (Dutton and others, 2004). The 2007 USGS geologic assessments of undiscovered oil and gas resources of the Permian Basin (Schenk and others, 2008) suggest 747 million barrels of oil, 236 million barrels of natural gas liquids, and 5.2 trillion cubic feet of gas exist in undiscovered conventional oil and gas reservoirs occurring in 26 total petroleum system assessment units in Permian Basin rocks. This number of assessment units is appreciably larger than basins of similar size with similarly preserved strata and corroborates the lithologic complexities previously discussed. More recently, the Energy Information Administration (2009) ranks the Permian Basin first in proven reserves of crude oil and lease condensate and ninth in wet natural gas in the United States. The report also notes that the basin accounts for nearly one-quarter of the oil reserves in the United States, and that from 2008 to 2009, reserves calculations of this commodity increased by nearly 725 billion barrels of oil. The large accumulations of petroleum within the Permian Basin suggest that extensive pore volumes are accessible for the purpose of geologic $CO_2$ sequestration within existing and depleted oil and gas fields, with the additional possibility of traps uncharged with petroleum. However, a substantial amount of this recent reserve increase is from the newly exploited shale-oil reserves accessible using horizontal drilling and fracturing technologies. Use of $CO_2$-enhanced oil recovery (EOR) technology began in the Permian Basin in the early 1970s. Trentham and Melzer (2011) noted that approximately 3 billion cubic feet of $CO_2$ are processed daily in the basin for EOR, and in 2008 approximately 180,000 barrels of oil per day were produced via EOR in the basin.

An extensive literature beyond this introduction exists that discusses, at various levels of detail, attributes of the geology and petroleum plays within these economically important rocks. Examples include the studies by Ward and others (1986), Carr and Gardner (2000), Broadhead and others (2004), Xu (2010), as well as others (and the accumulation of references therein) and should be consulted for additional details.

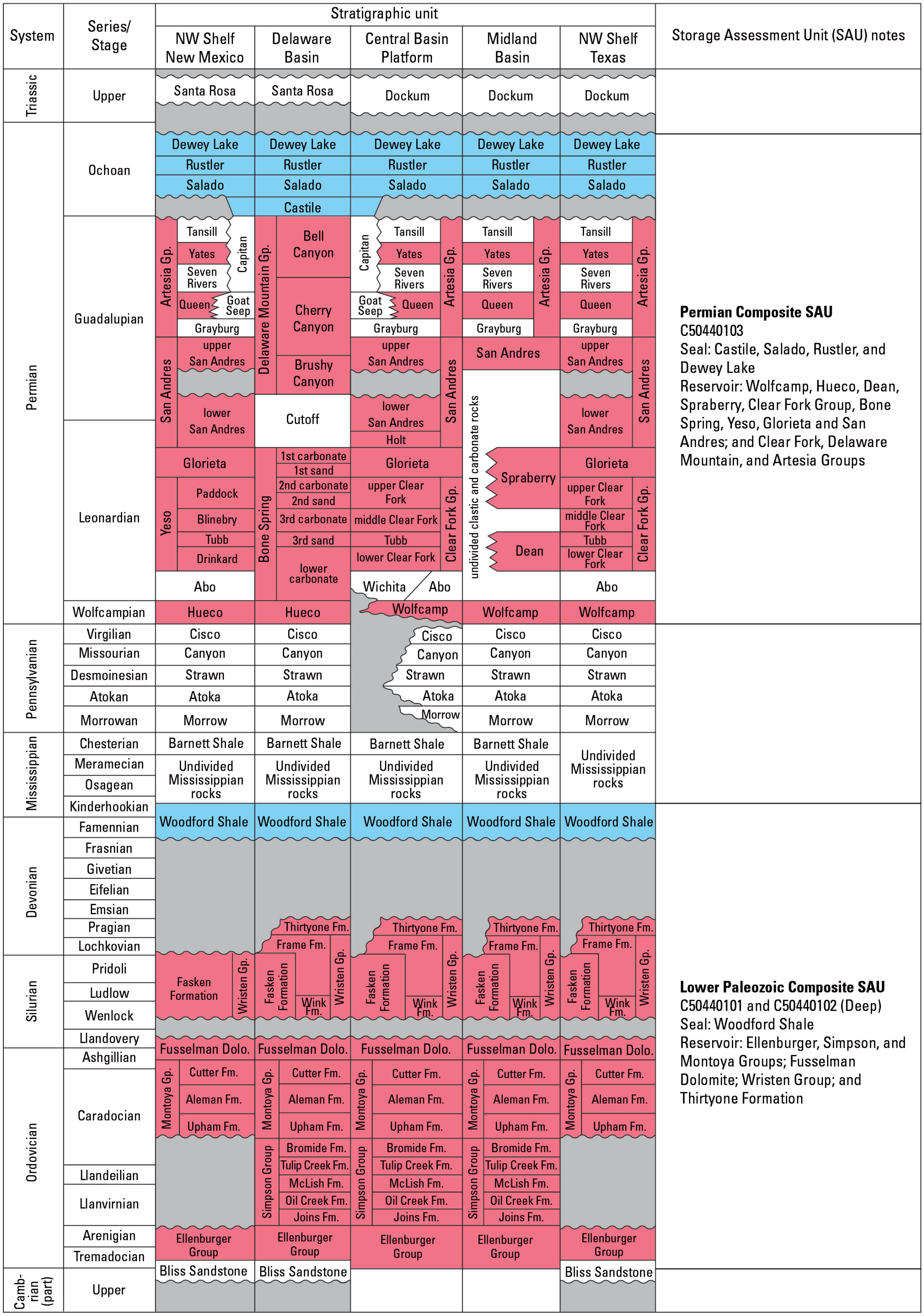


**Figure 3.** Generalized stratigraphic column of geologic units in the Paleozoic strata of the Permian Basin study area, Texas and New Mexico (modified from Ball, 1995; Dutton and others, 2005; Broadhead and others, 2004;

Ruppel, 2009). Because of the multiplicity of stratigraphic nomenclature and rank assignments applied in the different States and subregions of the Permian Basin, and for simplicity in presentation, the formation-rank term for formal units below group are not presented for Pennsylvanian, Permian, and Triassic units. The informal term Wolfcamp is used to refer to the undivided strata of the Wolfcampian Series; divisions of the Bone Spring and San Andres Limestones and Clear Fork Group (except for Tubb Formation) are informal. Storage assessment units (SAUs) consist of a reservoir (red) and regional seal (blue). Wavy lines indicate unconformable contacts, and gray areas represent unconformities or hiatuses. Only significant unconformities are shown. In some cases, divisions of units or lesser known correlative units are not shown. Gp., Group; Fm., Formation; Dolo., Dolostone.

### Lower Paleozoic Composite SAU C50440101 and Lower Paleozoic Composite Deep SAU C50440102

By Tina L. Roberts-Ashby and Peter D. Warwick

The lower Paleozoic rocks of the Permian Basin form a composite $CO_2$ storage reservoir that is composed of interbedded carbonate and siliciclastic rocks (fig. 3). From oldest to youngest, the lower Paleozoic composite reservoir consists of the Ordovician Ellenburger, Simpson, and Montoya Groups; Ordovician and Silurian Fusselman Dolostone; Silurian and Devonian Wristen Group; and the Devonian Thirtyone Formation.

The Ellenburger Group is one component of a massive Lower Ordovician carbonate platform that extended throughout large portions of the North American craton. During deposition of the Ellenburger Group, shallow-water carbonate sedimentation occurred on the shelf, while deep-water shale and carbonate accumulated on the shelf slope and in the basin (Loucks, 2008). Open-marine environments were typical of the outer shelf, and restricted-marine environments dominated the interior shelf (Loucks, 2008). The Ellenburger Group is composed largely of limestone and dolostone of various grain sizes and matrices that are interbedded with sandstone, conglomerate, and anhydrite of varying thickness.

The Simpson Group was deposited over the irregular, karstified surface of the Ellenburger Group during a marine transgression and is made up of the following formations, from oldest to youngest: Joins, Oil Creek, McLish, Tulip Creek, and Bromide Formations (Dutton and others, 2003, 2005; Jones, 2008a). The Oil Creek, McLish, and Tulip Creek Formations are clastic units containing sandstone and organic-rich shale that occur between the carbonate-dominated Joins and Bromide Formations.

The Montoya Group unconformably overlies the Simpson Group and was deposited on a shallow-water platform during Late Ordovician glacioeustasy changes (Jones, 2008b). The group consists of interbedded gravel conglomerate, sandstone, limestone, and dolostone, with some cherty and evaporitic layers (Jones, 2008b). From oldest to youngest, the group is made up of Upham, Aleman, and Cutter Formations.

The Fusselman Dolomite unconformably overlies the Montoya Group and is composed of shallow-water carbonate rocks that accumulated on a regionally extensive and relatively stable platform (Ruppel, 2008a). The formation primarily consists of ooid grainstone, fenestral mudstone, and pelmatazoan grainstone and packstone (Ruppel, 2008a).

The Wristen Group contains limestone and dolostone and consists of three formations that were deposited in shallow-water-platform (Fasken Formation) and deep-water, outer-platform to slope environments (Frame and Wink Formations) (Ruppel, 2008b). The Wristen unconformably overlies Fusselman Dolostone. The Thirtyone Formation conformably overlies the Wristen Group and was deposited during a regional marine transgression. The formation is composed of skeletal, shallow-water carbonates and bedded, commonly spiculitic, deep-water cherts (Ruppel and Barnaby, 2001).

The Upper Devonian to Lower Mississippian Woodford Shale unconformably overlies the Thirtyone Formation and forms the regional seal for the composite $CO_2$ storage reservoir. The relatively thick (as much as 600+ ft) shale unit is composed of highly radioactive, dark, fissile shale that becomes increasingly sandy in its northern extent, and the unit is thought to have been deposited in stagnant waters of a partly enclosed arm of the sea (Ellison, 1950; Amsden and others, 1967).

Two potential $CO_2$ storage reservoir units are identified in the lower Paleozoic rocks of the Permian Basin: (1) Lower Paleozoic Composite SAU C50440101 between 3,000- and 13,000-ft subsurface depth and (2) Lower Paleozoic Composite Deep SAU C50440102 below 13,000-ft subsurface depth (fig. 4). The Lower Paleozoic Composite SAU encompasses an area of about 11,484,000 acres (±10 percent) and the Lower Paleozoic Composite Deep SAU encompasses about 5,991,000 acres (±10 percent). Petroleum production within the area of the two SAUs is from the porous reservoirs of the Ellenburger Group; three sandstone members (Connell, Waddell, and McKee) in the basal portions of the

Oil Creek, McLish, and Tulip Creek Formations, respectively, of the Simpson Group; dolostone, grainstone, and packstone intervals of the Montoya Group and Fusselman Dolomite; Fasken Formation of the Wristen Group; and porous chert reservoirs of the Thirtyone Formation (Ruppel and Barnaby, 2001; Jones, 2008a,b; Loucks, 2008; Ruppel, 2008a,b).

The boundaries of the Lower Paleozoic SAUs are defined by the 3,000-ft and 13,000-ft reservoir-top depths taken from 9,306 well penetrations (IHS Energy Group, 2010) and the extent of the Woodford Shale seal where it is at least 100 ft thick and is predominantly shale with little sandstone. The rocks within the Lower Paleozoic SAUs deepen to the northwest and on average are 1,300–3,400 ft thick (SAU C50440101) and 1,200–3,100 ft thick (SAU C50440102), respectively, with a most likely thickness of 2,300 ft and 2,100 ft, as determined using published isopach maps (Ruppel and Hovorka, 1995; Ruppel and Barnaby, 2001; Jones, 2008b; Loucks, 2008; Ruppel, 2009).

The Ellenburger and Simpson Groups comprise the majority of the reservoir rock within the Lower Paleozoic SAUs. Diagenesis within the rocks of the Ellenburger Group has created a complex system of carbonate sequences that contain variable porosity and permeability both laterally and vertically. Dolomitization, karstification, and tectonic fracturing are the dominant diagenetic processes that affect reservoir quality in the group and have resulted in features such as large cave systems, dolines, karst towers, solution-collapsed zones, and large tectonic fractures (Loucks, 2008).

Reservoir-quality porosity in the Simpson Group is mainly confined to the sandstone members (Connell, Waddell, and McKee) (Jones, 2008a). Porosity in the remaining porous intervals of the lower Paleozoic rocks is variable and typically interparticle or intercrystalline. For the entire lower Paleozoic rock package, average porosity in the porous intervals decreases with depth, from 5 to 14 percent in the shallower Lower Paleozoic Composite SAU C50440101 to 3 to 7 percent in the Lower Paleozoic Composite Deep SAU C50440102 (Nehring Associates, Inc., 2010). Net-porous-interval thickness was estimated by first multiplying the weighted-average gross thickness of each group or formation within the Lower Paleozoic SAUs by an average net-porous to gross-thickness ratio, interpreted from geophysical logs for each reservoir interval. The final net-porous-interval thickness values for the Lower Paleozoic SAUs are the sum of each net-porous-interval thickness estimated for each group or formation within that SAU. This resulted in an average net-porous-interval thickness that ranges from 540 to 2,000 ft, with a most likely value of 930 ft, for the Lower Paleozoic Composite SAU C50440101 and an average net-porous-interval thickness of 480 to 1,200 ft, with a most likely value of 830 ft, for the Lower Paleozoic Composite Deep C50440102 SAU. Permeability in the Ellenburger Group is variable but mostly quite low due to the complexity and pervasiveness of diagenetic alterations. The sandstone intervals of the Simpson Group are typically clean; however, carbonate cementation reduces porosity and permeability in some regions (Jones, 2008a). Permeability in the remaining lower Paleozoic rocks is variable but typically low due to cementation. Average permeability in the lower Paleozoic rocks decreases with depth, from 0.01 to 5,517 millidarcy (mD), with a most likely value of 40 mD in the Lower Paleozoic Composite SAU, to 0.001 to 2,664 mD, with a most likely value of 20 mD, in the Lower Paleozoic Composite Deep SAU (Nehring Associates, Inc., 2010).

Water sampled from wells within the area of the Lower Paleozoic Composite SAU indicate saline formation waters throughout much of the SAU, with total dissolved solids (TDS) values well above the 10,000 parts per million (ppm) U.S. Environmental Protection Agency (EPA) limit (Breit, 2002). However, TDS values less than 10,000 ppm occur in the westernmost portion of the SAU, toward the Diablo platform, where the lower Paleozoic rocks approach the surface. Water sampled from wells within the area of the Lower Paleozoic Composite Deep SAU indicate saline formation waters (TDS >10,000 ppm) throughout the SAU (Breit, 2002). Because the Lower Paleozoic Composite Deep SAU does not appear to contain groundwater with TDS values less than 10,000 ppm, 100 percent of its area is considered suitable for subsurface storage of $CO_2$. However, because the westernmost portion of the Lower Paleozoic Composite SAU contains areas of low-salinity groundwater, we estimate that only about 90 percent of the SAU is suitable for $CO_2$ storage, with a minimum value of 70 percent and a maximum value of 95 percent.

Traps within the Lower Paleozoic SAUs are both structural and stratigraphic and can include simple anticlines, truncated flanks of anticlines, and permeability barriers (Dutton and others, 2004). In order to calculate the maximum buoyant pore volume within structural and stratigraphic closures for each Lower Paleozoic SAU, the known closure areas from the major petroleum-producing regions of 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 Lower Paleozoic SAU (Nehring Associates, Inc., 2010), with the assumption that there is potential for additional uncharged or undiscovered structural and stratigraphic closures outside of regions of historical hydrocarbon production.

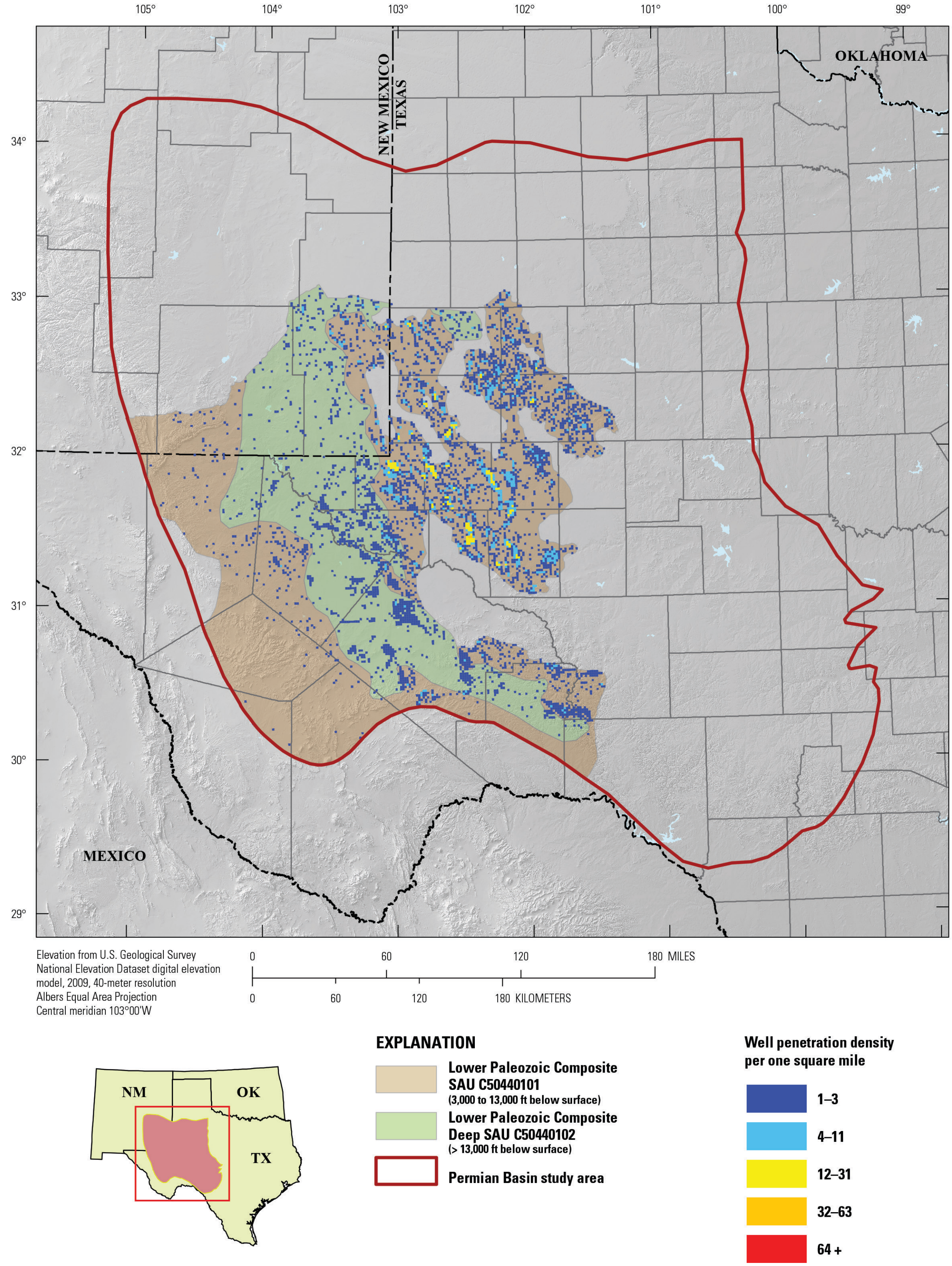


**Figure 4.** Map of the Lower Paleozoic Composite C50440101 and Lower Paleozoic Composite Deep C50440102 Storage Assessment Units (SAUs) in the Permian Basin. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the storage-formation top. Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Schenk and others, 2008).

## Permian Composite SAU C50440103

By Ernie R. Slucher

Permian strata in the Permian Basin consist of a diverse mix of facies deposited on and within a complex of shelves and subbasins (fig. 2). Preserved sedimentary rocks tend to be cyclic, reflecting the complex interaction of glacioeustastic events, regional tectonics, reciprocal sedimentation and sediment accumulation, facies migration, and diagenesis (Oriel and others, 1967; Scholle and Halley, 1980; Miall, 2008; Chen and others, 2013). The stratigraphic complexities of Permian strata is best demonstrated by the multitude of formal and informal stratigraphic units with multiple rank designations applied to the many rock-stratigraphic units occurring across the basin and discussed previously (Oriel and others, 1967; Ward and others, 1986; Dutton and others, 2004; Ruppel, 2008). Overall, however, four principal depositional settings existed during most of the Permian in the region: (1) platform or shelf, (2) platform margin, (3) platform slope, and (4) basin. In general, carbonate- or siliciclastic-dominated rocks exemplify most stratigraphic units formed during the Wolfcampian, Leonardian, and Guadalupian in these regions. For this assessment, the Wolfcampian, Leonardian, and Guadalupian Series contain all of the major geologic reservoirs in the basin and were combined into a composite SAU reservoir (fig. 3). The evaporite-dominated Ochoan Series forms the regional seal for the SAU.

In general, sediments of the lower Wolfcampian consisted predominately of black shale and dark argillaceous limestone. By the late Wolfcampian, carbonate sedimentation dominated on platform (shelf) and structurally uplifted areas, whereas the basins remained relatively sediment-starved regions of siliciclastic deposition (Silver and Todd, 1969; Dutton and others, 2005). During Leonardian time, and continuing throughout the Guadalupian, the base-level difference between shelf and basin areas became more pronounced, and a succession of facies developed from shelf to basin that represent aeolian, coastal, sabkhas, sandflats, lagoons, shallow-marine platform and back-reef, platform margin, reef, platform slope, turbidite and density flows, submarine fans, and hemipelagic basin environments (Ward and others, 1986; Ruppel, 2009). In general, during the Leonardian and early Guadalupian, platform areas were the site of mostly carbonate deposition with lesser amounts of siliciclastics, but by the late Guadalupian, increased siliciclastic and evaporate deposition was occurring (Galley, 1958; Ward and others, 1986). Seaward, platform margin areas were the site of carbonate shoal and reef facies deposition, whereas debris and density-flow deposits and turbidite and submarine fans of carbonate and siliciclastic sediments were deposited along the platform slope, extending some distance into the basin (Galley, 1958; Ward and others, 1986). In general, fine-grained siliciclastic sediment was the primary material deposited in the Delaware and Midland Basins, although near the end of the Guadalupian, the Midland Basin had filled, and deposition consisted of sediments similar to those on adjacent platforms (Oriel and others, 1967; Miall, 2007).

For this assessment, six major reservoir intervals within the Wolfcampian, Leonardian, and Guadalupian Series contain most of the reservoir storage in the SAU; they are, in descending order, the Yates and Queen of the Artesia Group, San Andres, Spraberry, Dean, undivided Wolfcampian, and equivalents to these units (Oriel and others, 1967; Dutton and others, 2004). Subordinate storage may exist in other units as well. Regionally, the overlying Ochoan Series functions as the seal of the SAU; it is a well-known interval of mostly rock salt and anhydrite several thousand feet thick (Galley, 1958; Pierce and Rich, 1962; Oriel and others, 1967).

The Permian Composite SAU encompasses approximately 6,168,000 acres (± 10 percent) that occur from 3,000 to 7,000 ft below the surface (fig. 5). The most likely depth to the top of the SAU is 5,250 ft. Units at the top of Guadalupian Series identified in borehole penetrations in the IHS Energy Group (2010, 2011) database were used to define the depth and boundary of the SAU. Although evaporitic facies exist in the Artesia Group or equivalent rocks (Guadalupian Series) on platform and shelf portions of the Permian Basin, that level of refinement of the SAU was not in line with the resolution dictated by this national assessment project. Had this been done, in all likelihood the spatial footprint, acreage, and storage resource of the SAU would have been larger than defined herein.

As assessed, most potential storage is in the Delaware Basin and northwestern Midland Basin, with subordinate potential in marginal areas of the Central Basin platform and Northwest shelf (figs. 2 and 5). As defined and investigated, the overall most likely gross thickness of Permian units in the SAU ranges from 6,500 to 8,500 ft, with a most likely thickness of 7,500 ft (IHS Energy Group, 2010, 2011). Within the SAU, the minimum, maximum, and most likely net-porous thickness within the major stratigraphic units considered to be extensive reservoirs is 300, 900, and 600 ft, respectively (IHS Energy Group, 2010, 2011). Petrophysical data in Nehring and Associates, Inc. (2010) databases and data provided by the Texas Bureau of Economic Geology on both carbonate and clastic lithologies within the Wolfcampian, Leonardian, and Guadalupian Series indicate the overall mean minimum and maximum porosity values range from 8 to 21 percent, with a most likely porosity of 14 percent (Nehring and Associates, Inc., 2010). 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. In general, however, the porosity distribution patterns suggest that the upper percentile values occur mainly in sandstone, whereas the lower percentile values tend to occur within carbonate rock. Permeability values from the same data set range from 0.01 to 1,200 millidarcys (mD), with a most likely value of 11 mD. Overall, specific reservoir intervals commonly contain a wide range of petrophysical values at individual field scale because of complex interactions of lithotypes, cements, and intercalated shale (Dutton and others, 2004; Ruppel, 2009).

Groundwater chemistry data of units within the Permian Composite SAU indicate a dominantly saline groundwater system exists throughout the region (Breit, 2002; Scholle and others, 2007; Nehring Associates, Inc., 2010). Nevertheless, small areas of groundwater salinities below 10,000 milligrams per liter may exist locally along the SAU margin between the Delaware Basin and Central Basin platform and in the trend of reef facies along the Delaware Basin margin. Excluding such areas from our assessment, the minimum, maximum, and most likely area of the SAU available for storage is 80, 95, and 90 percent, respectively. The methodology of Brennan and others (2010) and implementation guide of Blondes and others (2013) were used to determine the minimum and central tendency buoyant-trapping pore volumes and the maximum buoyant-trapping pore volume available for $CO_2$ storage.

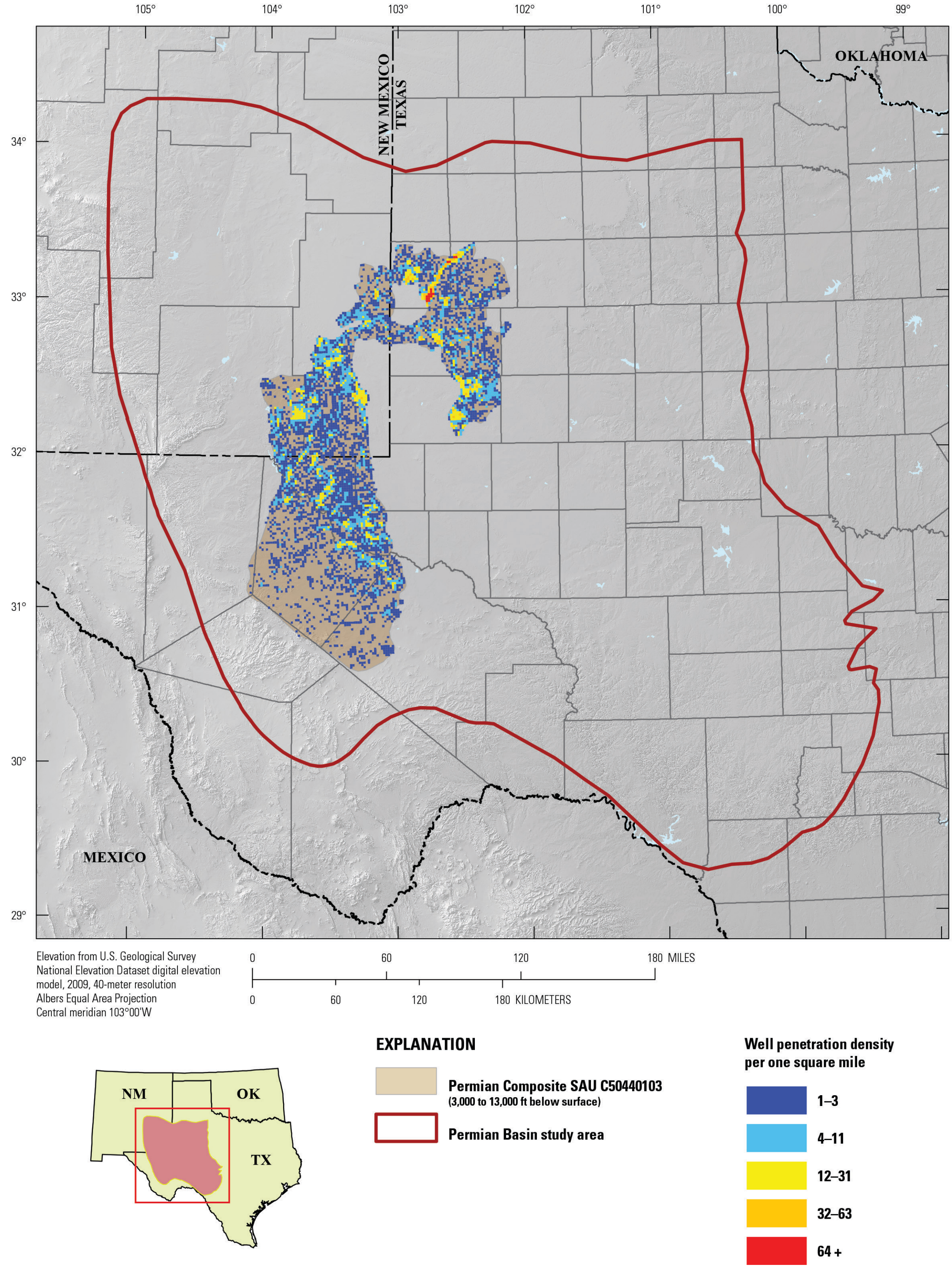


**Figure 5.** Map of the Permian Composite C50440103 Storage Assessment Unit (SAU) in the Permian Basin. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the storage-formation top. Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Schenk and others, 2008).

# Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources—Palo Duro Basin

By Matthew D. Merrill, Madalyn S. Blondes, Philip A. Freeman, Steven M. Cahan, and Christina A. DeVera

## Introduction

The Texas Panhandle region, encompassing the northernmost rectangular extent of Texas and neighboring areas in New Mexico and Oklahoma, includes five sedimentary basins: Palo Duro, Dalhart, Tucumcari, Hollis-Hardeman, and Anadarko. This summary discusses the USGS assessment of the potential carbon dioxide storage resource available in the Palo Duro, Dalhart, Tucumcari, and Hollis-Hardeman Basins. In the northern panhandle, the Dalhart Basin is separated from the Anadarko to the east by the Cimarron arch and from the Palo Duro Basin by the Texas portion of the Bravo dome and to a lesser extent the Amarillo-Wichita uplift (fig. 6). In New Mexico and south of the Bravo dome is the Tucumcari Basin. The Amarillo-Wichita uplift separates the Anadarko Basin to the north from the Palo Duro and Hollis-Hardeman Basins to the south. The Matador uplift, a faulted anticline of low relief, separates the southern margin of the Palo Duro Basin from the northern Midland Basin, and its eastern extension, the Red River uplift, marks the southern boundary of the Hollis-Hardeman Basin, with the Bend arch-Fort Worth Basin to the southeast. A subtle structural high trending roughly along a southern projection of the eastern edge of the Texas Panhandle separates the Palo Duro on the west from the Hollis-Hardeman on the east. For the purposes of this assessment, the term Palo Duro Basin is used to refer to the entire study area that encompasses the Dalhart, Hollis-Hardeman, Tucumcari, and Palo Duro Basins.

## Geologic History

Following the rifting of the Pannotia megacontinent that split Laurentia (North America) from Gondwana in the Neoproterozoic and Early Cambrian (Scotese, 2009), the present-day Palo Duro Basin area was part of a broad passive margin on the edge of the North American craton, a setting shared by the Permian and Fort Worth Basins to the south (fig. 1). The structural foundations of the current basin are products of the late Paleozoic Ancestral Rocky Mountains orogeny. However, sedimentary deposits present in the Palo Duro do record the time prior to the tectonic collisions that shaped the subsurface. Major basement structures, such as the northwest-trending Amarillo and Wichita Mountains uplift (hereafter Amarillo-Wichita uplift), were produced during the Ancestral Rocky Mountains orogeny through inversion of the Cambrian Southern Oklahoma aulacogen (fig. 6). Smaller associated uplifts and basins on folds striking to the southeast of the Amarillo-Wichita uplift may be secondary folds produced by shear movement along the uplift (Nicholson, 1960).

Structurally the Precambrian basement in the Palo Duro Basin reaches depths of 10,000 ft below the surface, with an east–west basin axis in the eastern part of the basin and a northwest–southeast axis in the western part of the basin (Dutton and others, 1979). Structure contour maps from Dutton and others (1979) and Ruppel (1985) show that the basin is deepest in the south, bordering the Matador uplift. Depth to basement, relative to sea level, in the Dalhart Basin is about 5,200 ft, and 6,400 ft in the Hollis-Hardeman Basin; these are shallower than the southern Palo Duro Basin proper at 7,200 ft below sea level (Dutton and others, 1979). Faults in the region generally trend northwest–southeast except along the Matador uplift, where some west-trending faults are present (Ruppel, 1985).

Sedimentary rocks in the basin are predominantly Paleozoic age (fig. 7) though they are capped in places by post-orogenic Triassic rocks of the Dockum Group (Dutton and others, 1979). Major erosion during the Middle Devonian removed most, if not all Ordovician, Silurian, and Devonian age rocks in the region (Ruppel, 1985). Ellenburger Group carbonates (equivalent in part to the Arbuckle Group in the

Anadarko Basin) are present in the basin; however, the Ellenburger carbonates have been removed from two Ordovician structural highs, the Texas arch, an early Paleozoic feature occurring northwest to southeast across the basin, and the Amarillo-Wichita uplift (Soderstrom, 1968; Ruppel, 1985). Lower Mississippian Kinderhookian sandstone is only locally preserved in the Palo Duro and Dalhart Basins. The overlying shallow-water Mississippian carbonate rocks are separated into the Osagean, Meramecian, and Chesterian Series and are found in varying thicknesses across the Palo Duro Basin (Ruppel, 1985) (fig. 7).

Initial stages of Ancestral Rocky Mountains deformation probably began in the Late Mississippian; this is reflected in the higher clastic content within the Chesterian Series and the presence of limestone conglomerates (Handford and Dutton, 1980; Ruppel, 1985). A central deep basin flanked by shallow-water shelves and uplifts to the north, east, and west existed during the Pennsylvanian and Early Permian in the Palo Duro Basin, and they were the sites of shelf-margin carbonate, basin shale, and peritidal dolomite deposition (Handford and Dutton, 1980). A general shift from shallow seas to an evaporitic sabkha environment began in the middle Permian. During the Permian, a basinward (southerly) facies shift of supratidal to subtidal deposits is evident with rare carbonate rocks to the north and extensive, thick salt deposits throughout the section (Presley, 1979). The Upper Triassic Dockum Group, a continental clastic deposit, is the only significant Mesozoic rock unit in the basin, and it post-dates Ancestral Rocky Mountains deformation (Dutton and others, 1979). The Tucumcari Basin in New Mexico exhibits similarly restricted preservation of Mesozoic units (Broadhead and King, 1988).

## Resource Extraction

The central Palo Duro Basin does not produce significant oil or gas. Production is concentrated on the flanks of Bravo dome, which separates the Dalhart Basin from the Palo Duro Basin proper, and on the Matador uplift south of the basin. Pre-Pennsylvanian source rock potential in the Palo Duro is medium to low because of low (or marginal) thermal maturity of carbonate source rocks; moreover, average total organic content is below levels normally associated with source rocks (Ruppel, 1985). Conversely, Pennsylvanian shale source rocks appear to be more mature than the pre-Pennsylvanian carbonates, possibly due to greater thresholds for hydrocarbon generation in carbonates (Ruppel, 1985; Henry, 1988). In light of underwhelming source rock potential in the Palo Duro, the presence of 95 percent of the basin's oil on the Matador uplift has been explained by Rose (1986a) as Permian (Midland) Basin oil that has migrated into the Palo Duro.

## $CO_2$ Storage

There are three SAUs in the Palo Duro Basin $CO_2$ Storage Assessment, they include: Basin Center Paleozoic Composite C50430101, Basin Flank Paleozoic Composite C50430102, and the Basin Center Permian C50430103. The extent of the storage formations are defined by the geologic characteristics of the reservoirs and overlying seals and depth that they occur as described in Burruss and others (2009) and Brennan and others (2010). The following sections describe each of the storage assessment units defined in the Palo Duro Basin.

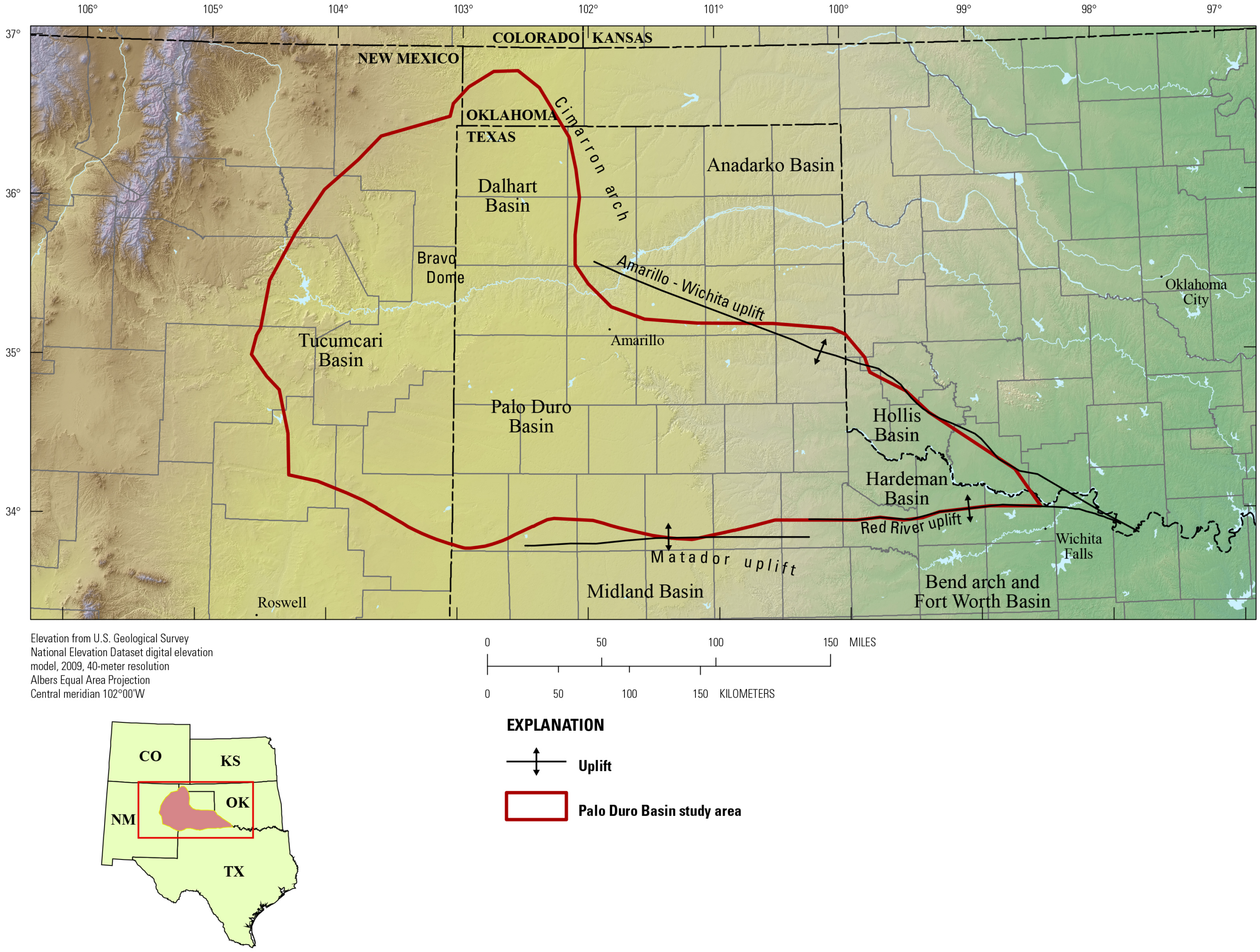


**Figure 6.** Map of the Palo Duro Basin study area, including major structural features (Nicholson, 1960; Ruppel, 1985; Broadhead and King, 1988). Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Ball and Henry, 1995).

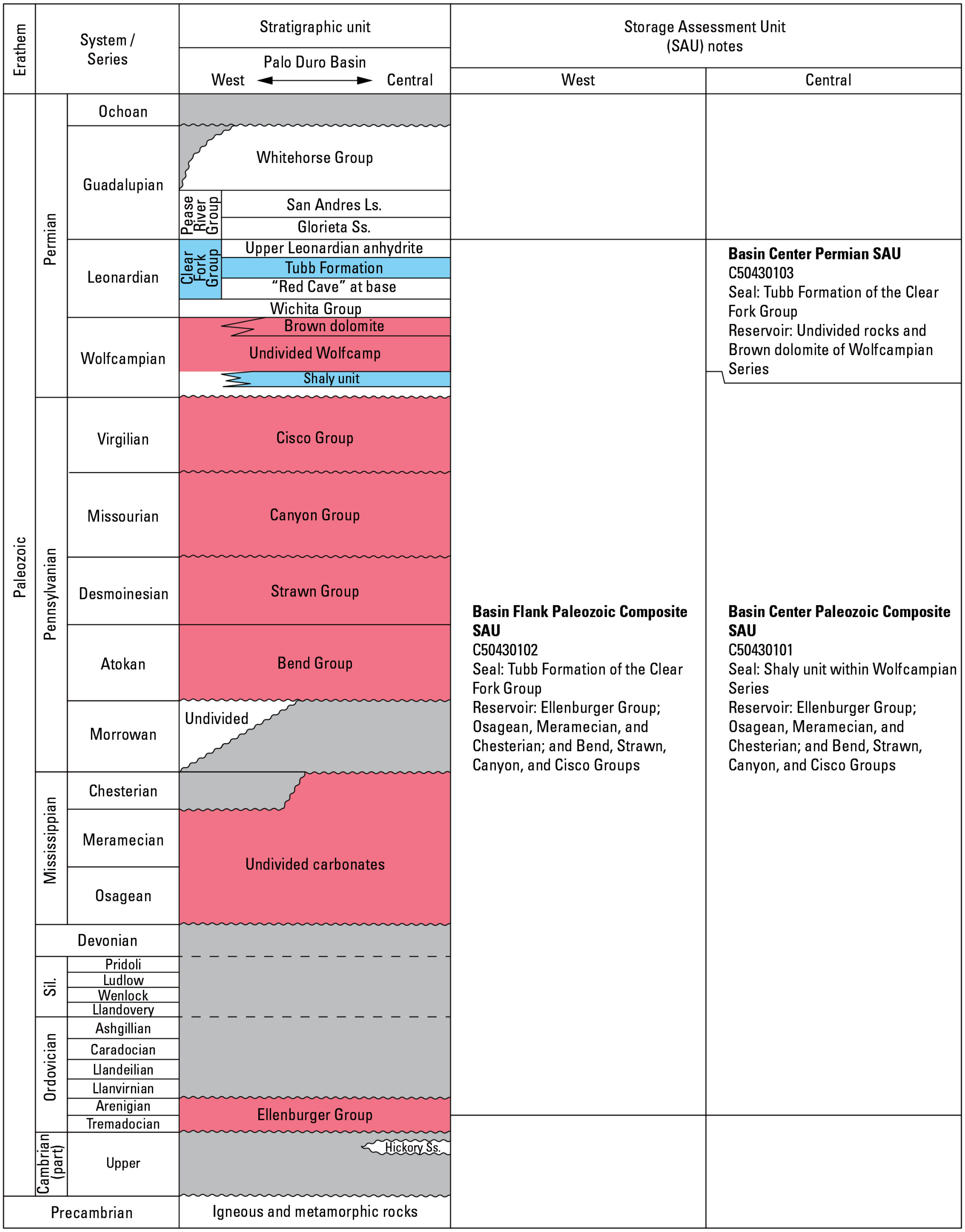


**Figure 7.** Generalized stratigraphic column of Paleozoic geologic units in the Palo Duro Basin study area (modified from Nicholson, 1960). Mesozoic and Tertiary rocks are not present in the storage assessment units (SAUs) of this assessment and are therefore not included in the stratigraphic column. Red Cave, Brown dolomite, and shaly unit are informal units within the Permian. SAUs consist of a reservoir (red) and regional seal (blue). Wavy lines indicate unconformable contacts, and gray areas represent unconformities or hiatuses. In some cases, subdivisions of units or lesser known correlative units are not shown. Ls., Limestone; Fm., Formation; Ss., Sandstone.

## Basin Center Paleozoic Composite SAU C50430101

By Matthew D. Merrill

The Basin Center Paleozoic Composite SAU (C50430101) includes the following pre-Permian reservoirs in the center of the Palo Duro Basin: Ordovician Ellenburger Group; Osagean, Meramecian, and Chesterian carbonates; and the Pennsylvanian Bend, Strawn, Canyon, and Cisco Groups (fig. 7).

The Lower Ordovician Ellenbuger Group contains fine- to coarse-grained, sucrosic to rhombic dolomite with rare limestone (Ruppel, 1985). Mississippian rocks unconformably overlie the Ellenberger. The Kinderhookian Series is only present in western Palo Duro; these rocks are fine-grained quartz sandstones that are commonly interbedded with shales and limestones (Ruppel, 1985). Osagean rocks are gray to brown argillaceous, cherty limestones and dolomites (Ruppel, 1985). White to buff-colored, fine- to medium-grained limestone with abundant chert and ooids occurs in the Meramecian Series (Ruppel, 1985). Chesterian limestones are similar to those of the Meramecian; however, they are more fossiliferous and cherts are rare.

Handford and Dutton (1980) note that the Pennsylvanian and Early Permian have not been satisfactorily divided into formations; instead they discuss the geology of the Pennsylvanian in terms of depositional environments. Rose (1986b) takes a similar route; however, in addition to depositional environments, his description of the geology incorporates group divisions of the Pennsylvanian to facilitate discussion of the interval; such format is used in this description. “Granite wash” sandstones and associated deltaic deposits shed from topographic highs during the Morrowan and Atokan exhibit reservoir properties but are not present within the SAUs of this assessment. The Strawn Group contains shallow marine limestone and dolomite. Canyon Group deposits are shelfal limestones and dolomites on the edge of the deep central basin in the Palo Duro. Deeper units include limestone and shales. Cisco Group rocks represent the main unit in the basin center; the deposits are marine shales with marginal silt and sandstones. Lower Permian Wolfcampian deposits include marine calcareous shale (shaly unit in fig. 7) in the basin center, which serves as a confining seal for this SAU. Additional lithologies in the Wolfcampian include porous dolomites and limestones on the shelf edge (Rose, 1986b). SAU boundaries generally follow the shelf margin outline as defined by Handford and Dutton (1980). However, based on interpretations of work by Conti and others (1988), the SAU has been bisected along a roughly north to south direction to avoid including areas where the sealing formation, the lower Wolfcampian, has shale thicknesses less than 200 ft (fig. 8). In its entirety, the SAU occupies approximately 4,467,000 acres in the center of the basin study area.

Reservoir depths, as interpolated from formation tops in proprietary databases, for the Basin Center Paleozoic Composite SAU range from 3,000 to 8,400 ft, with an average depth of approximately 6,500 ft below surface (IHS, 2010). Total and net-porous thicknesses were calculated in a geographic information system (GIS) using published thickness-contour maps from Ruppel (1985) for the pre-Pennsylvanian units and Handford and Dutton (1980), Handford (1980), Dutton and others (1982), and Conti and others (1988) for the Bend through Cisco Groups in the Pennsylvanian. Thickness values were summed from the GIS comprising the publications mentioned above for the composite of reservoir formations. Thicknesses ranged from 1,750 to 2,900 ft, and the thicknesses of the porous interval, also known as the net thickness, was considerably less ranging from 50 to 230 ft, with a most likely value of 125 ft. Due to a lack of available porous reservoir thickness for the Ellenburger Group, the Ellenburger in the nearby Fort Worth Basin, where more data were available, was used as an analog.

Porosity values for the net thickness of the multiple reservoir formations were again derived from the work of Ruppel (1985) for the Ordovician and Mississippian strata and Handford and Dutton (1980) for the Pennsylvanian. Additional porosity information was also gleaned from average reservoir porosities from proprietary databases (Nehring Associates, Inc., 2010). Values of 10 to 18 percent porosity, with a central tendency of 13 percent, were used to represent the reservoirs. Permeabilities from drill stem tests and core analyses reported by Smith (1983) for all the reservoirs included in the SAU ranged from 0.04 to 1,600 mD, with a most likely value of 90 mD.

Water salinity information in the Palo Duro Basin is limited to the southern and northern areas where hydrocarbon exploration occurs. Although few data points fell within the SAU itself, TDS contents of 10s to 100s of thousands of parts per million indicate groundwater at depth is highly saline (Breit, 2002). Potential structural closures for storage in the SAU were inferred from maps of the depth to the Pennsylvanian section from sea level (Rose, 1986b).

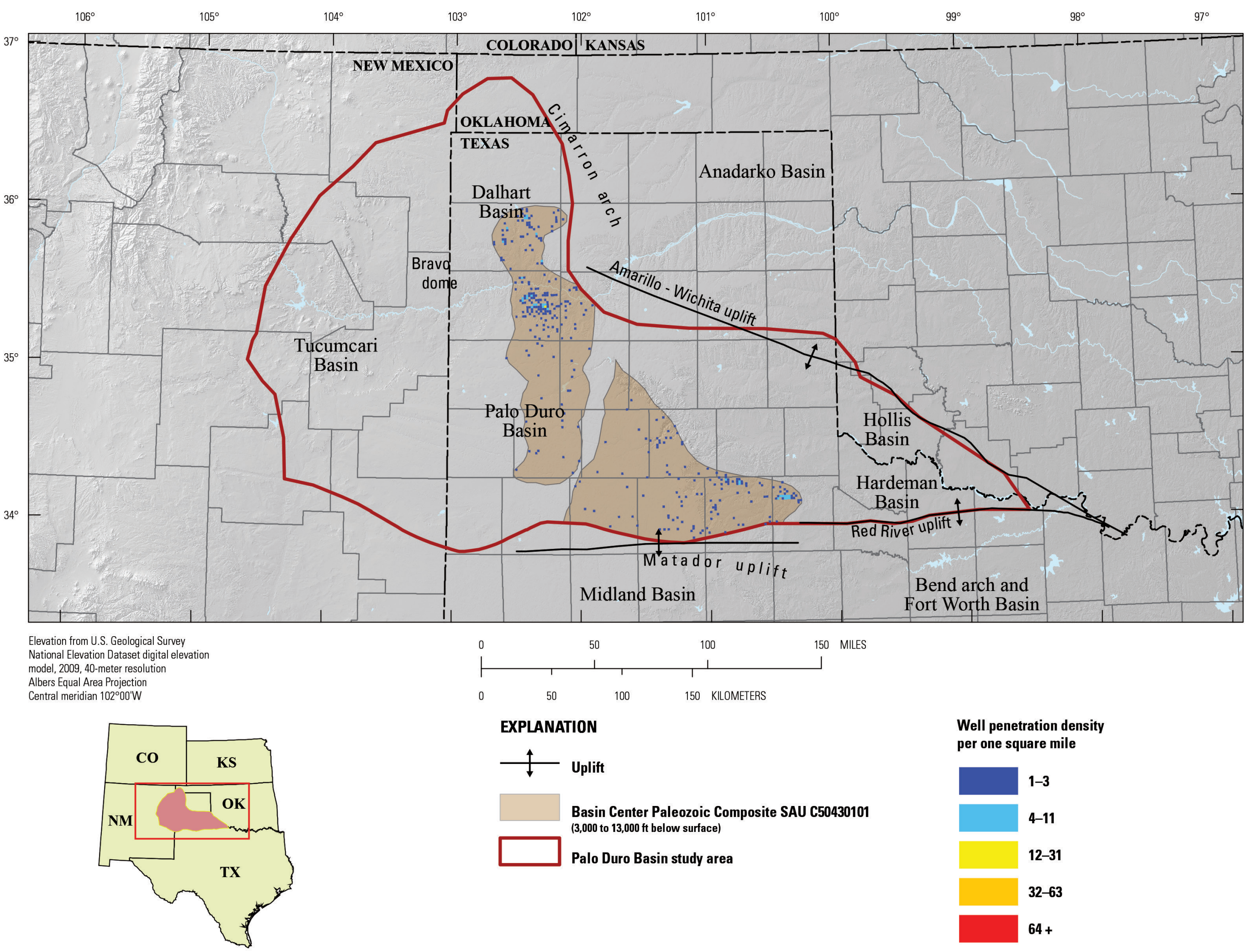


**Figure 8.** Map of the Basin Center Paleozoic Composite C50430101 Storage Assessment Unit (SAU) in the Palo Duro Basin. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the storage-formation top. Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Ball and Henry, 1995).

## Basin Flank Paleozoic Composite SAU C50430102

By Matthew D. Merrill

The Basin Flank Paleozoic Composite SAU contains the same reservoir formations as the previously discussed Basin Center Paleozoic Composite SAU (C50430101), with the exception of the Upper Mississippian Chesterian Series, which is absent in the area of this SAU (Ruppel, 1985) (fig. 7). A substantial shale and red-bed deposit, the Tubb Formation of the Clear Fork Group, in the Leonardian Series provides the seal for this SAU. Additional potential confining layers of salt and anhydrite occur in the Wichita Group and the informal Red Cave unit at the base of the Clear Fork (Rose, 1986b). The western boundary of the previously described Basin Center Paleozoic Composite SAU defines the eastern side of this SAU. Western and northern sides are defined by the gradation of shale to sand in the Tubb Formation extending to the west out of the Palo Duro Basin (Dutton and others, 1979). Total acreage for the SAU is 3,058,000 acres, and its depth from the surface ranges from 3,300 to 5,600 ft; the average depth across the SAU is 4,800 ft (IHS, 2010) (fig. 9).

Reservoir characteristics from the multiple potential storage formations in the SAU were all determined using mapping calculations in GIS-based compiled maps from Ruppel (1985) for the pre-Pennsylvanian formations and Handford and Dutton (1980), Handford (1980), Dutton and others (1982), and Conti and others (1988) for the Pennsylvanian and Permian. Thicknesses for the composite of reservoirs in the SAU range from 2,800 to 4,100 ft; however, the net-porous thickness is between 150 and 300 ft, with a most likely value of 250 ft. Availability porosity data were limited to only the eastern half of the SAU, nearest to the Basin Center SAU; this partial geographic coverage of data is considered representative of the SAU and was used to create a distribution of the entire SAU. The data were similar in range to the basin center SAU with a minimum porosity of 10 percent, a maximum of 18 percent, and an average value of 13 percent (Ruppel, 1985; Handford and Dutton, 1980). Permeability across the many reservoir formations ranged from 0.03 mD to 1,600 mD; an average value across the compiled data points was 77 mD (Smith, 1983). Relying on the same evidence as mentioned in the above description of the Basin Center SAU, the water quality in this SAU is highly saline (Breit, 2002). Potential structural closures for storage in the SAU were inferred from maps of the depth from sea level to the Pennsylvanian section (Rose, 1986b).

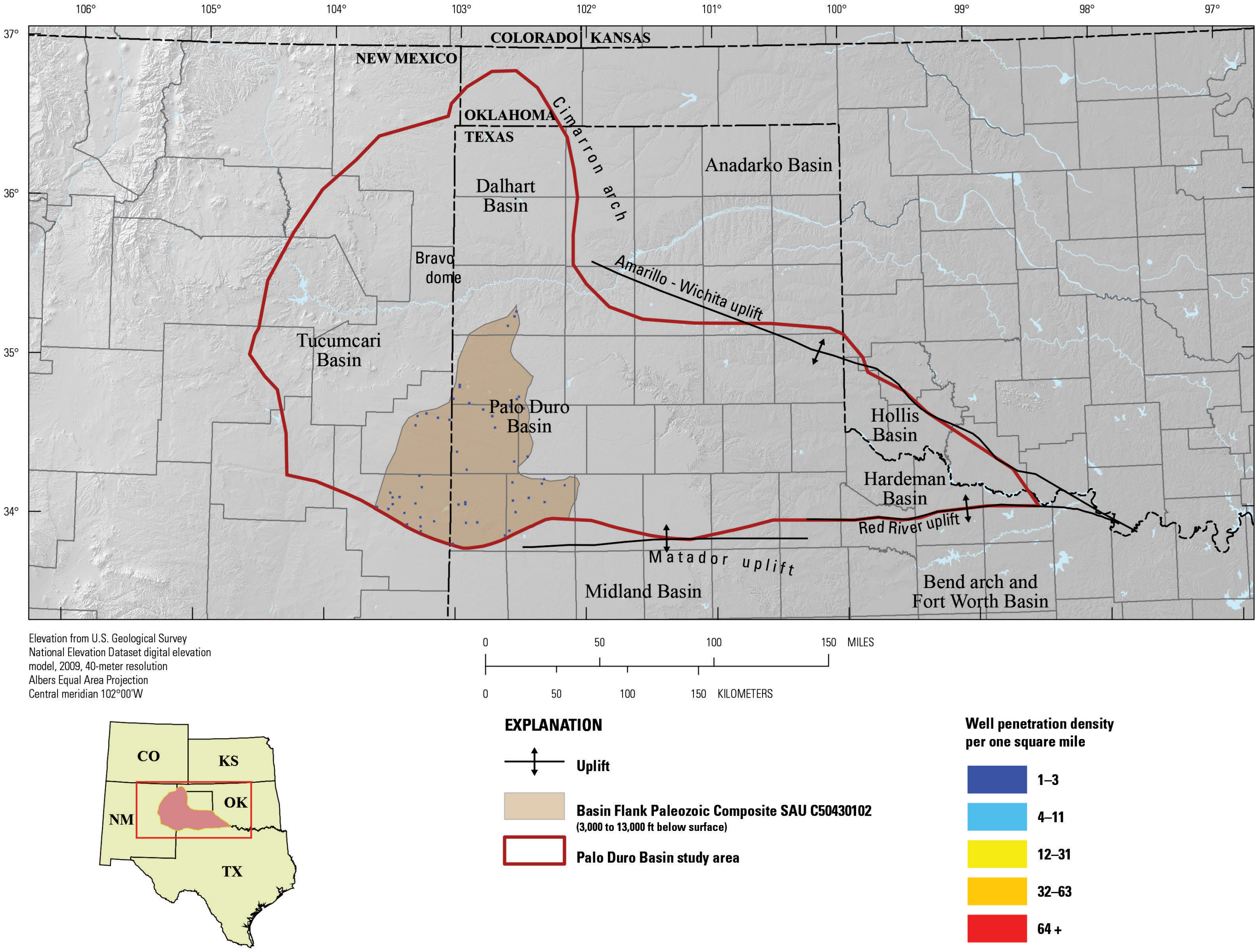


**Figure 9.** Map of the Basin Flank Paleozoic Composite C50430102 Storage Assessment Unit (SAU) in the Palo Duro Basin. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the storage-formation top. Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Ball and Henry, 1995).

## Basin Center Permian SAU C50430103

By Matthew D. Merrill

The Basin Center Permian SAU overlaps with much of the core of the Basin Center Paleozoic Composite SAU (fig. 10). Potential storage formations in the SAU are limited to the Wolfcampian Series. Lower Wolfcampian rocks are shale-rich basin deposits that resemble the lithology of the underlying Cisco Group. During late Wolfcampian time, the basin shelf-edge migrated southward burying basinal siliciclastic sediments beneath highly porous limestone and dolomite shelf deposits (Rose, 1986b). These porous units are storage reservoirs of the SAU. Boundaries for the SAU include the Matador uplift to the south and the Anadarko Basin to the north. The western and eastern extents of the SAU are based on two properties: (1) the dimensions of the clastic-rich basin during Wolfcampian time (Handford and Dutton, 1980) and (2) the extent of the shale within the confining Tubb Formation (Dutton and others, 1979) at a minimum of 3,000-ft depth from surface; the same seal as used in the Basin Flank Paleozoic SAU. The SAU covers 4,275,000 acres. Depth to the SAU ranges from 3,000 to 5,500 ft; the reservoir is deepest to the southwest and shallowest along the northern and western extent of the SAU (IHS, 2010) (fig. 10).

Thicknesses for the Wolfcampian in the SAU range from 1,800 to 3,000 ft; however, the majority of this lithology is not particularly porous. The thicknesses of the porous rock, as calculated from maps of porous dolomite and specifically from an informal unit called the Brown dolomite, range from 200 to 500 ft (Conti and others, 1988) (fig. 9). The most likely thickness for potential storage is 300 ft. Porosity data in the Wolfcampian reservoirs show a higher maximum and average in comparison to the other SAUs in the basin; the range is 10 to 20 percent with an average of 15 percent (Rose, 1986b; Conti and others, 1988). Permeability, as indicated by available data, on the other hand is lower than in the composite SAUs. An average value of 20 mD is bracketed by a minimum of 0.03 mD and a maximum of 262 mD (Smith, 1983; Conti and others, 1988). Potential structural closures for storage in the SAU were inferred from maps of the depth from sea level to the Tubb Formation (Rose, 1986b). Formation-water data indicate that the groundwater is highly saline, similar to that in the other two SAUs (Breit, 2002).

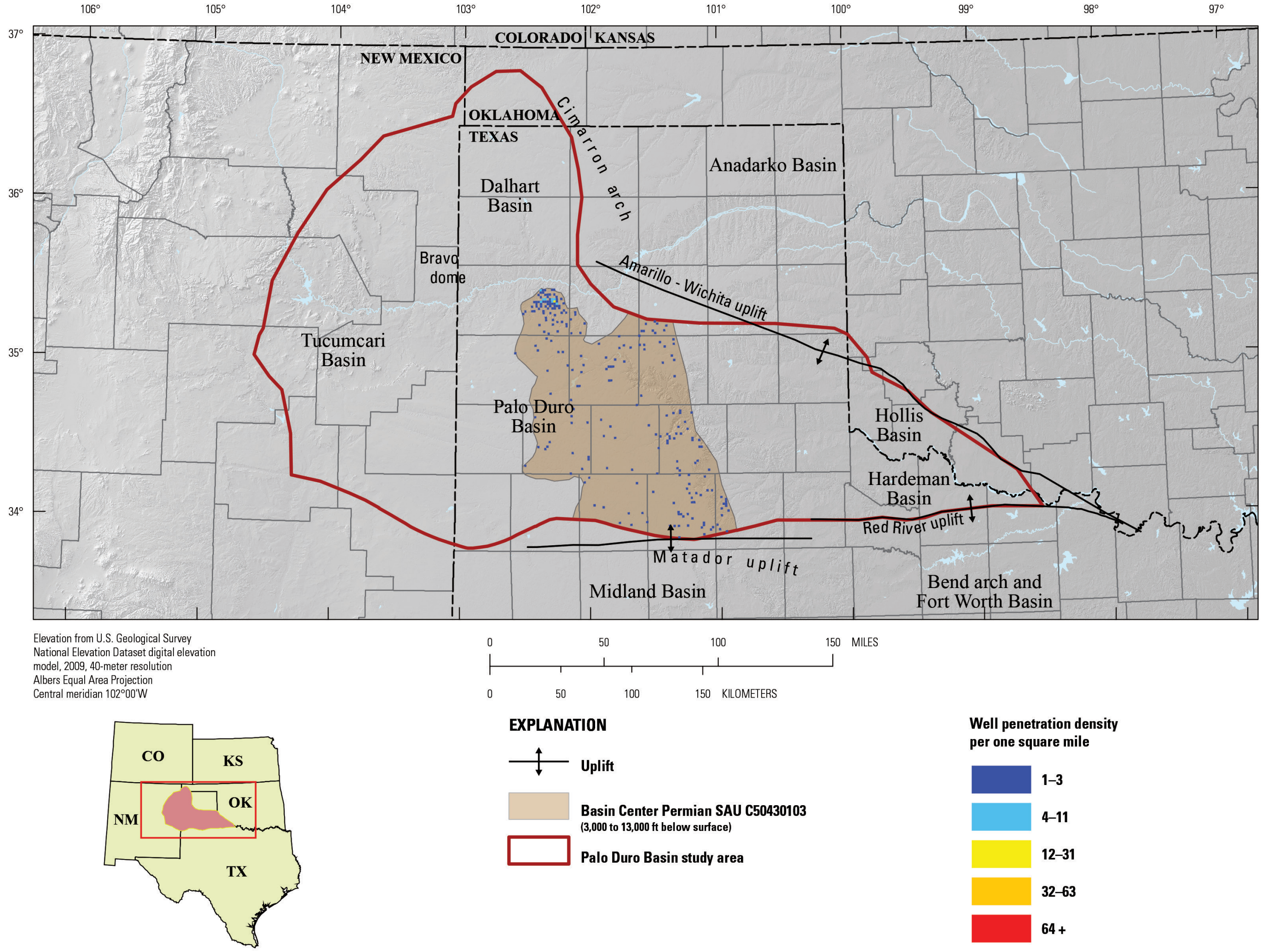


**Figure 10.** Map of the Basin Center Permian C50430103 Storage Assessment Unit (SAU) in the Palo Duro Basin. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the storage-formation top. Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Ball and Henry, 1995).

# Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources—Bend Arch-Fort Worth Basin

By Matthew D. Merrill, Tina Roberts-Ashby, Madalyn S. Blondes, Philip A. Freeman, Steven M. Cahan, and Christina A. DeVera

## Introduction

The Bend arch-Fort Worth Basin study area (hereafter the Fort Worth Basin) in central Texas (fig. 11) contains Cambrian to Pennsylvanian strata deposited on a passive continental margin, followed by tectonic plate convergence, then a divergent plate tectonic event. Oil and gas exploration began in the early 1900s and currently the basin is well-known for the production of unconventional natural gas resources from the Barnett Shale using hydraulic fracturing and horizontal wells (Pollastro, 2007). A combination of available geologic data, existing infrastructure, and mature petroleum fields make the basin an attractive target for carbon dioxide storage investigation. The basin is an asymmetrical northeastward dipping feature with a relatively flat western region called the Eastern shelf that is separated from the steeper dipping eastern side by the roughly north- to south-trending structural Bend arch (fig. 11). The western basin margin abuts the Midland Basin of the west Texas Permian Basin study area. To the north, the basin is separated from the Hardeman Basin by the Red River uplift, and northeastward it is bound by the Muenster arch. The eastern edge of the basin is marked by the Ouachita fold and thrust front and its associated structures. The Llano uplift and Concho platform are outside the basin and delineate the southern and southwestern boundaries, respectively.

## Geologic History

The basin as defined today developed as the Ouachita fold and thrust front (hereafter the Ouachita front) formed through convergence and collision between Laurentia (North America) and Gondwana (the African and South American continents) in Early Pennsylvanian—the process that formed the mega-continent of Pangaea (Thompson, 1988). The geologic history of the basin's sediments began prior to basin formation, that is, when Neoproterozoic rifting of a continent called Pannotia separated the North American continent Laurentia from Gondwana. This formed the Wichita (or Southern Oklahoma) aulacogen, a northwest-trending feature in basement rocks in the Texas and Oklahoma border region (Walper, 1982), and also initiated the development of the Iapetus Ocean (Walper, 1982; Scotese, 2009).

Subsequent marine transgression of the Iapetus Ocean flooded the Laurentia cratonic margins resulting in deposition of Upper Cambrian Riley and Wilberns Formations carbonate sediments (fig. 12). As the seas extended farther inland, the Ordovician Ellenberger Group (and regional equivalents) was deposited across the region (fig. 11) (Cloud and Barnes, 1957). Direct impacts of the massive Taconic orogeny along the northeastern North American craton did not reach the Fort Worth Basin area during the Ordovician; instead, changes in cratonic stresses may have resulted in the formation of positive structural features called the Texas arch or Concho platform in the Fort Worth area (Walper, 1982). Deposition of Silurian and Devonian sediments continued northeast of the Fort Worth Basin in the Southern Oklahoma Basin and to the southwest in the passive margin that is today's Permian Basin; however, sediments deposited during this period in the Fort Worth Basin, if any, were subsequently eroded as uplifting continued (Turner, 1957; Walper, 1982).

In the middle Paleozoic, the subduction that accompanied the closing of the Iapetus Ocean produced a subduction complex of thrusted sedimentary basin fill that would eventually be called the Ouachita front. As noted by Flippin (1982), this feature has been called many names including the Ouachita foldbelt, Ouachita tectonic belt, Ouachita-Marathon overthrust, and Llanoria structural belt. The modern exposed portion of the front remains in the core of the Ouachita Mountains of southwestern

Oklahoma and northwestern Arkansas. Upper Ordovician through Devonian deposits are recorded in the Ouachita front. In Mississippian time, the Ouachita front had consumed the marginal basin landward of the volcanic arc and reached the cratonic margin. Subducting continental lithosphere hinged at a fulcrum point west of the subduction complex; this hingeline, where the crust was bending downward, moved westward in step with landward movement of the Ouachita front.

Marine transgressions in the Late Mississippian resulted in the formation of the Barnett Shale and Comyn Formation (fig. 12). Although more carbonate-rich sediments were deposited in the shallow western areas, in the east, shale and sandstone of the Barnett reflect its proximity to the deepening trench and eroding Ouachita front (Walper, 1982). Continued western migration of the hingeline and subduction of the shelf margin in the Pennsylvanian produced shallow-water deposits to the west, notably the Comyn Formation, Marble Falls Limestone, and Big Saline Formation and informal Caddo limestone. To the east, in deeper waters, black shales were deposited, including the informal Pregnant shale and Smithwick Shale, and nearest the fold belt, gray shales and sandstones were deposited in westward prograding fluvial deltaic environments called informally the Atoka clastics (Pollastro and others, 2007). Subsidence decreased in the Fort Worth Basin as plate convergence ceased in late Atokan through early Desmoinesian time; however, the Ouachita front served as a source of sediment supply until early Missourian time (Walper, 1982; Thompson, 1988). Western migration of the basin margin halted once it reached the Concho platform; however, continued overthrusting of the Ouachita front and uplift of the Llano region, combined with the stalled western margin migration, shifted the basinal trough northwestward toward the Muenster arch during the time of deposition of the Strawn Group (Walper, 1982). Cycles of marine transgressions and uplifts of buoyant post-convergent crust resulted in cycles of carbonate and clastic sediments. An increase in subsidence of the Permian Basin to the west and a decrease to the east in the Fort Worth Basin created a new hingeline between the two areas; that hinge is referred to as the Bend arch and as mentioned above, defines the western boundary of the modern Fort Worth Basin.

## Resource Extraction

Oil discoveries first occurred in the Fort Worth Basin in the early 1900s, and by 1960 the basin was under fully developed mature production (Pollastro, 2007). Exploration focusing on Pennsylvanian age conventional reservoirs led to cumulative output of 2 billion barrels of oil and 8 trillion cubic feet of gas by 1990 (Pollastro, 2007). Evidence of hydrocarbons in the Barnett Shale fueled well-completion research that in the mid-1990s resulted in booming commercial production of natural gas from the Barnett Shale (Montgomery and others, 2005). In 2004, the Newark East field in the northeastern part of the basin became the second largest gas field in the United States (Pollastro, 2007).

## $CO_2$ Storage

Two SAUs were assessed in the Bend arch-Fort Worth Basin: the Chappel Limestone and Ellenburger Group SAU (C50450101) and the Bend Group and Comyn Formation SAU (C50450102). The following sections discuss the specific geology of the storage and sealing formations as well as the reasoning for the boundaries of the SAUs. Sources for various geologic characteristics used in the assessment process are provided as well. Of particular note is a brief mention of the Barnett Shale as a sealing formation. The hydraulic fracturing and horizontal wells that have turned the Barnett Shale into a major gas producer may also have implications for carbon dioxide retention. Although this report in no way attempts to investigate the issue of seal integrity in the presence of gas extraction using hydraulic fracturing, it is important to recognize the potential complications for $CO_2$ storage as implementation of this extraction technology increases.

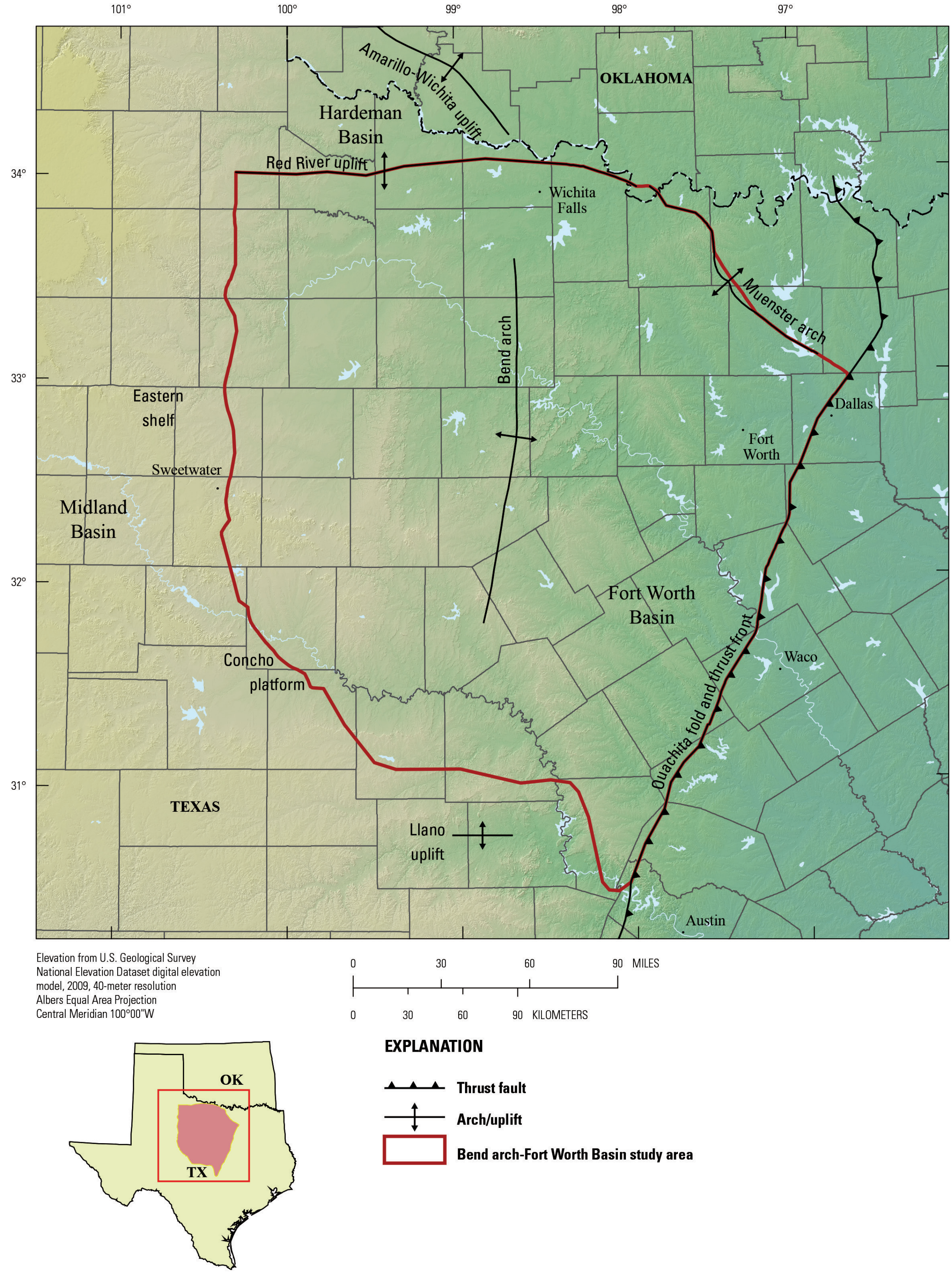


**Figure 11.** Map of the Bend arch-Fort Worth Basin study area, including major structural features (Pollastro, 2007). Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Pollastro and others, 2004).

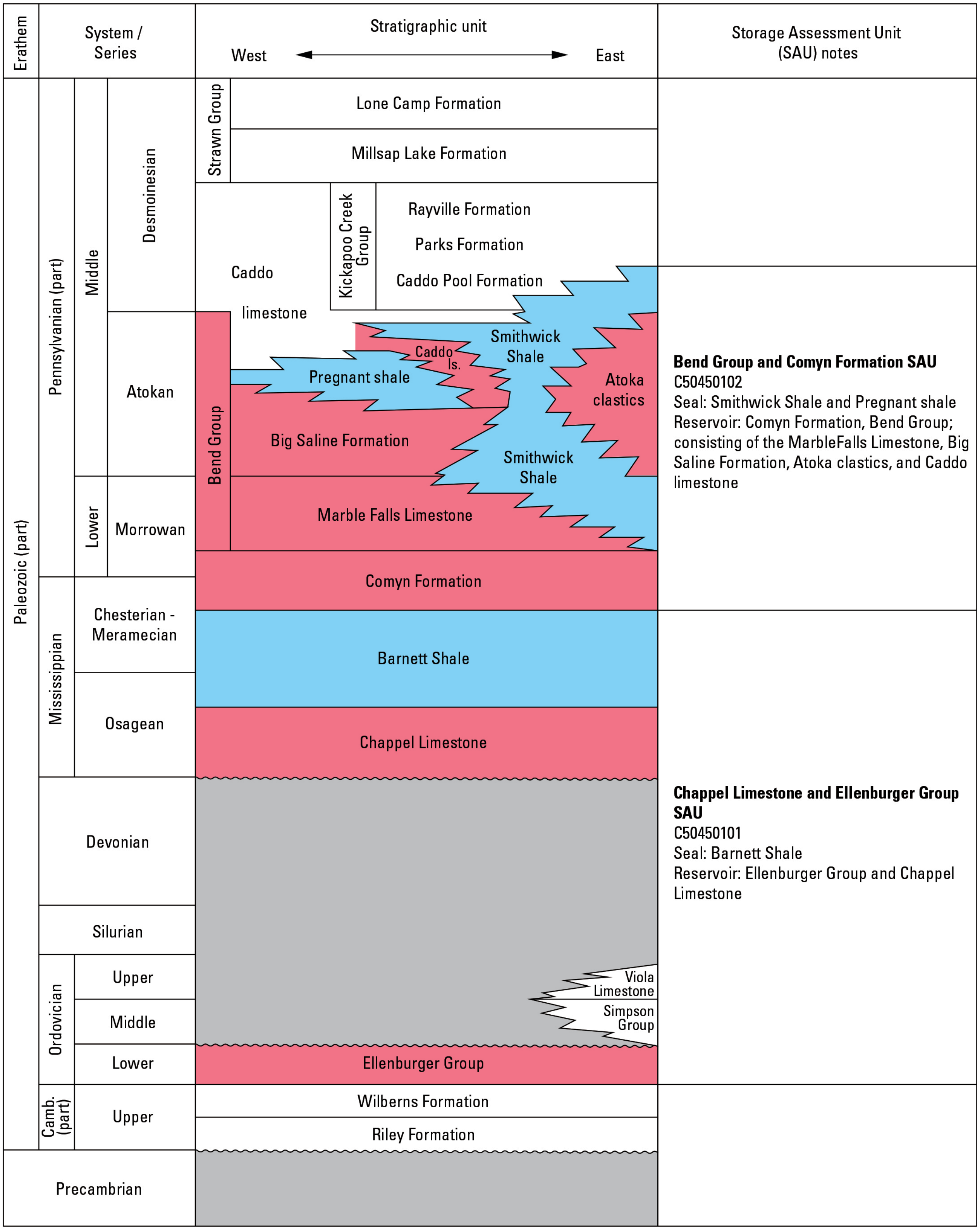


**Figure 12.** Generalized stratigraphic column of geologic units in the Bend arch-Fort Worth Basin study area (modified from Flippin, 1982 and Pollastro, 2007). Storage assessment units (SAUs) consist of a reservoir (red) and regional seal (blue). Pregnant shale and Atoka clastics are informal units within the Atokan Series. Caddo limestone is an informal unit within the Middle Pennsylvanian. Wavy lines indicate unconformable contacts, and gray areas represent unconformities or hiatuses. In some cases, subdivisions of units or lesser known correlative units are not shown.

## Chappel Limestone and Ellenburger Group SAU C50450101

By Matthew D. Merrill

The Chappel Limestone and Ellenburger Group SAU (C50450101) (fig. 13) is one of two SAUs in the combined Bend arch-Fort Worth Basin study area. Paleozoic rocks from the Lower Ordovician Ellenburger Group up through the Lower Mississippian Chappel Limestone serve as the reservoirs for this SAU (fig. 12). Specifically, the majority of the potential storage space in this SAU is provided by the dolostones and limestones of the Ellenburger Group. These rocks consist of aphanitic gray limestone and microcrystalline to coarsely crystalline dolostone, with finer textures often encountered in the upper part of the section (Collier, 1983). Fossils are uncommon in the Ellenburger, with mollusks being the more common of those fossils present (Collier, 1983). Using paleontology and sedimentary evidence, Cloud and Barnes (1957) suggested that shallow warm seas that deepened to the north and east are the most probable depositional environment. Post-depositional erosion removed the Middle Ordovician Simpson Group and Upper Ordovician Viola Limestone from most of the basin except its northern margin, near the Muenster arch. Silurian and Devonian strata are absent throughout the study area (Turner, 1957). Thus, the Lower Mississippian Chappel Limestone overlies the Ellenburger unconformably in most locations.

The Chappel Limestone is present mostly in the western part of the SAU where shallower platform environments persisted. Reef mounds and reefal debris deposits characterize the thin and discontinuous Chappel Limestone. Thickness ranges from 0 to 45 ft in outcrop for the crinoidal limestone; however, reef masses can reach 500 ft thick (Turner, 1957). The Osagean to Chesterian Barnett Shale forms the seal on top of this SAU. The Barnett consists of interbedded shale and limestone; higher limestone abundance is found in the north, and the predominantly shale-rich sections that form the seal are greater in thickness to the south and west (Montgomery and others, 2005).

Advances in hydraulic fracturing technologies and subsequent production success have brought the Fort Worth Basin's Barnett Shale to the forefront of the petroleum industry (Pollastro, 2007). The process of hydraulic fracturing could possibly compromise the confinement properties of a SAU seal. Based on the extent of currently known gas wells, it is assumed that the entirety of the potential seal for the SAU is not compromised. However, due to ongoing exploration and fracturing in the Barnett Shale, any potential sequestration of $CO_2$ below the Barnett Shale would require significant competency testing and injection engineering. This reality may make the Chappel Limestone a less than ideal target for storage.

Boundaries within the study area for the SAU are based on two factors: a minimum depth of 3,000 ft from the surface to the top of the storage units and a minimum thickness of 100 ft of Barnett Shale. To the north, the Anadarko Basin study area forms the border as does the Ouachita front to the east. To the south, the 3,000-ft-depth limit set by the assessment methodology (Brennan and others, 2010) bounds the SAU. The SAU was further restricted to areas where the Barnett Shale is thicker than 100 ft. This restriction defines the western edge of the SAU (Pollastro and others, 2007). In total, the area of the SAU is 10,848,000 acres (fig. 13). The SAU is deepest in the north and east and shallows to the south and west; ranges for the mean depth to the top of the storage formation are from 3,000 to 10,000 ft (IHS, 2011). The most common depth is 4,500 ft from the surface. Total thickness of the reservoir formations is essentially the thickness of the Ellenburger, as contributions from the Chappel Limestone are only significant in the west. Isopachs from Collier (1983) provide the most complete Ellenburger thickness data across the basin. With small additions made for the Chappel, total thickness distribution values were a minimum mean thickness of 1,000 ft and a maximum of 3,000 ft; the porous portion of this thickness was 200 to 800 feet. The latter net-porous thicknesses are based on a combination of net-thickness measurements in proprietary databases (Nehring Associates, Inc., 2010) and 20 well log analyses conducted looking at porosity variations for the entire storage interval. Porosity in the SAU is predominantly found within dolostone of the Ellenburger, and though porosities are lower than other Fort Worth Basin limestone and sandstone units, the Ellenburger dolostone contains between 5 and 15 percent porosity with a common mean value of 10 percent (Nehring Associates, Inc., 2010). Permeability data from the same proprietary database, in addition to Ellenburger reservoir characteristics from the Hardeman Basin to the north (Ahr and Walters, 1985), indicated that a range of 0.01 to 1,000 mD and an average value of 0.1 mD best reflect the variation in the storage formation.

Water in the SAU is highly saline, with TDS content for the groundwater ranging from 50,000 ppm to 300,000 ppm (Breit, 2002), which is far above the upper limit set by the EPA of 10,000 ppm TDS for potential underground sources of drinking water (U.S. Environmental Protection Agency, 2010).

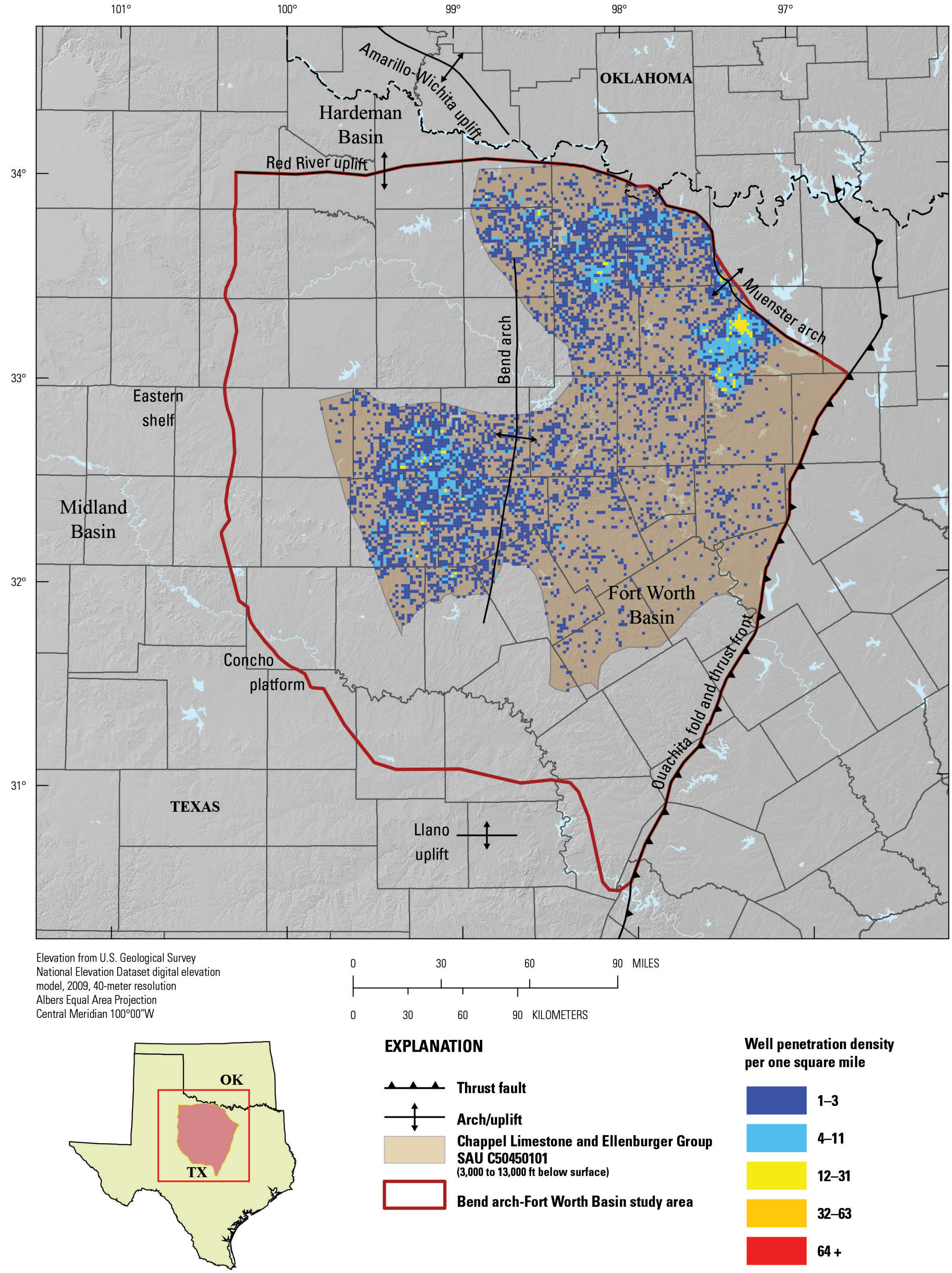


**Figure 13.** Map of the Chappel Limestone and Ellenburger Group C50450101 Storage Assessment Unit (SAU) in the Bend arch-Fort Worth Basin. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the storage-formation top. Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Pollastro and others, 2004).

## Bend Group and Comyn Formation SAU C50450102

By Tina L. Roberts-Ashby

The Upper Mississippian and Lower Pennsylvanian Comyn Formation and Lower and Middle Pennsylvanian Bend Group of the Bend arch-Fort Worth Basin form a composite $CO_2$ storage reservoir composed of a mixture of carbonate and siliciclastic rocks (figs. 12 and 14). The Comyn Formation is composed of massively bedded, dense, dark, oolitic limestone with interbedded shale deposited in a neritic environment on the marginal section of the North American craton (Browning, 1982; Flippin, 1982; Namy, 1982; Ruppel, 1989).

The Bend Group overlies the Comyn Formation and consists of rocks of the Morrowan and Atokan Series in the Lower and Middle Pennsylvanian, respectively. The group consists of complexly intertonguing formations that include the Morrowan Marble Falls Limestone, the Atokan Big Saline Formation, the Smithwick Shale, multiple additional clastic rock units of the Atokan and Morrowan age, and portions of the informal Caddo limestone.

The Marble Falls Limestone directly overlies the Comyn Formation, and the two are often indistinguishable except in regions where shale occurs between the two (Flippin, 1982). Rocks of the formation are largely composed of dark, dense, finely crystalline limestone that is interbedded in some locations with thin, fissile shale (Flippin, 1982). The Marble Falls Limestone was deposited on a southeast-sloping shelf near the western portion of the Fort Worth Basin, across the Llano uplift, and into the adjacent Kerr Basin to the east. The Marble Falls Limestone is overlain by clastic and carbonate rock sequences of the Atokan Series deposited in westward-prograding fluvial-deltaic and transgressive carbonate-bank environments (Cleaves, 1982; Flippin, 1982).

The Big Saline Formation makes up the carbonate rocks of the Atokan Series and consists of two carbonate-bank complexes that trend northeast–southwest (Namy, 1982). The limestones of the Big Saline Formation are differentiated from those of the underlying Marble Falls Limestone by increased siliciclastic content consisting of thin layers of fissile shale and fine- to medium-grained sandstone (Flippin, 1982). The Big Saline Formation grades into a thick facies of conglomerates within the Atokan Series (informally called Bend conglomerate or Atoka conglomerate) that consist of silty shale, limestone, and poorly sorted fine- to coarse-grained and friable sand (Browning, 1982; Flippin, 1982; Glover, 1982). Other clastic facies of the Atokan Series include fine- to coarse-grained sandstone (informally called Atoka clastics) and shale (Smithwick Shale [also informally called Atoka shale and Pregnant shale]). The Atoka clastics consist of moderately to poorly sorted, micaceous, arkosic sandstone probably derived from the erosion of highlands formed by the Ouachita orogeny and are interbedded with shale indicative of fluvial-deltaic, nearshore deposition (Flippin, 1982).

The Smithwick Shale is likely a deep-water deposit that is more than 400 ft thick, composed of a sequence of black, fossiliferous, and finely laminated shale with very thin lenses of sandstone (Flippin, 1982). The Pregnant shale was deposited in pro-delta and distal-delta environments and consists of relatively thick (up to 150 ft) shale and siltstone with some interbedded sandstone lenses of varying thickness and extent (Collins and others, 1992). The Smithwick Shale and Pregnant shale form a regional, composite sealing unit for the Mississippian and Pennsylvanian Bend Group and Comyn Formation SAU in the Bend arch-Fort Worth Basin. Approximately 70 percent of the storage reservoir contains the Caddo limestone; however, this is limited to the area of the basin where the formation occurs between the Smithwick-Pregnant shale seal (fig. 12), which varies throughout the region due to complexity of deposition of the Mississippian and Pennsylvanian rocks.

The Caddo limestone is primarily a shelf carbonate with occasional, massive reef buildups and varies in color (cream to dark gray) and texture (crystalline, to fossiliferous, to micritic) (Browning, 1982; Martin, 1982). As shown in figure 12, the Caddo overlies and intertongues with Atokan shales.

The Bend Group and Comyn Formation SAU (C50450102), in the Mississippian and Pennsylvanian rocks of the Bend arch-Forth Worth Basin, occurs between 3,000- and 13,000-ft subsurface depths (fig. 14). The SAU encompasses an area of about 17,326,000 acres ($\pm$10 percent). Petroleum production within the area of the SAU is from the Comyn Formation; Marble Falls Limestone; Big Saline Formation; conglomerate and lenticular, clean sandstone within the Bend conglomerate; and the Caddo limestone, particularly where fracture-porosity and reef buildup are abundant (Browning, 1982; Flippin, 1982; Glover, 1982; Martin, 1982; Namy, 1982; Ball and Perry, 1996; Nehring Associates, Inc., 2010).

The boundary of the Bend and Comyn SAU is defined by the 3,000-ft reservoir-top depth taken from over 20,000 well penetrations (IHS Energy Group, 2010; Nehring Associates, Inc., 2010) and from regional cross sections (Lahti and Huber, 1982; Erlich and Coleman, 2005), the Muenster arch and associated fault system, the Ouachita front and associated fault systems, and the lateral extent of the Smithwick-Pregnant shale seal where it is at least 50 ft thick, as determined using formation-tops differencing from 194 wells (IHS Energy Group, 2010). The rocks within the SAU deepen eastward, toward the Ouachita front, and thicken to the north and west where the Caddo limestone is included within the reservoir rocks of the SAU. On average, the gross thickness of the Bend Group and Comyn Formation SAU is 200–600 ft thick, with a most likely thickness of 400 ft, as determined using formation-tops differencing from 6,703 well penetrations located throughout the SAU (IHS Energy Group, 2010).

Porosity and permeability in the reservoir rocks of the Bend Group and Comyn Formation SAU are variable due to the various facies distributions within the SAU; both porosity and permeability can be quite low within the fine-grained strata or quite high in areas with abundant reef buildup and fracture and karst porosity. In areas where permeability is low, acidization or hydraulic fracturing is often required for commercial petroleum production (Glover, 1982). Average porosity in the porous intervals of the Bend Group and Comyn Formation SAU is 10 to 17 percent, with a most likely value of 12 percent (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 0.52 that was interpreted from geophysical logs. This resulted in an average net-porous-interval thickness that ranges from 100 to 300 ft, with a most likely value of 200 ft for the Bend Group and Comyn Formation SAU. Average permeability in the SAU is 0.01–3,000 mD, with a most likely value of 25 mD (Nehring Associates, Inc., 2010).

Wells sampled within the confines of the SAU indicate formation waters have TDS values that are saline (TDS >10,000 ppm), with values up to 120,000 ppm in some locations (Breit, 2002), which exceeds the 10,000 ppm lower limit emplaced by the EPA for $CO_2$ storage reservoirs. Additionally, the Railroad Commission of Texas online database showed underground injection control (UIC) wells in every county within the SAU injecting waste water into the storage reservoir intervals of the SAU (http://www.rrc.state.tx.us/about-us/resource-center/research/online-research-queries/). Therefore, from the standpoint of water quality, 100 percent of the Bend Group and Comyn Formation SAU is expected to be suitable for geosequestration of $CO_2$.

Traps within the Bend Group and Comyn Formation SAU are both structural and stratigraphic within the reservoir rocks of the Comyn Formation, Marble Falls Limestone, and Caddo limestone, whereas stratigraphic traps dominate the Atokan clastic reservoirs (Flippin, 1982). Trapping structures include simple anticlines and fault-bounded anticlines; stratigraphic traps include pinch-outs that are facies-controlled or a result of truncation (Ball and Perry, 1996). In order to calculate the maximum buoyant pore volume within structural and stratigraphic closures for the Bend Group and Comyn Formation SAU, 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.

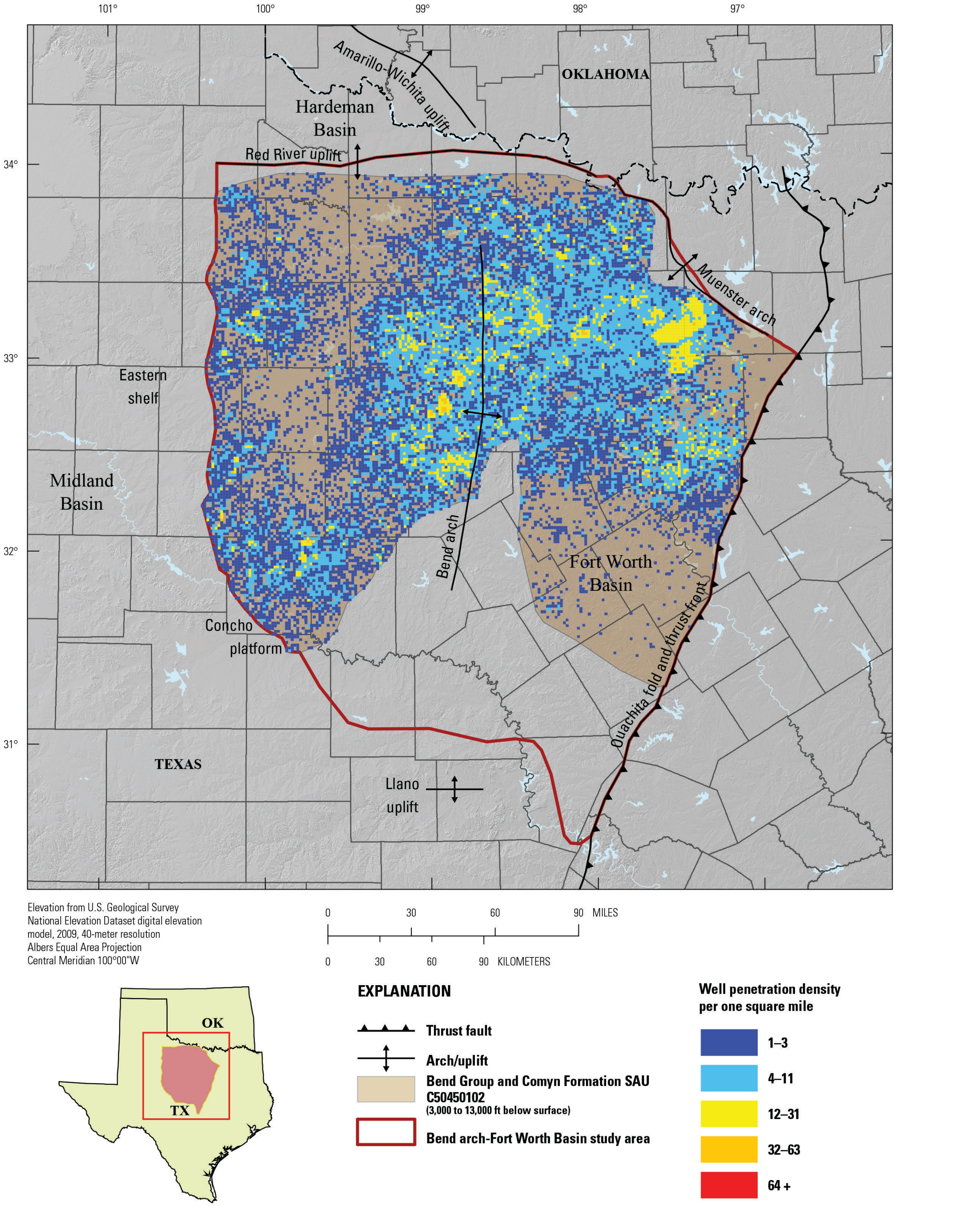


**Figure 14.** Map of the Bend Group and Comyn Formation C50450102 Storage Assessment Unit (SAU) in the Bend arch-Fort Worth Basin. Grid cells (one square mile) represent counts of wells derived from ENERDEQ well database (IHS Energy Group, 2011) that have penetrated the storage-formation top. Study area boundaries were modified from the U.S. Geological Survey national oil and gas assessment (NOGA) (Pollastro and others, 2004).

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