A Publication of the
Gulf Coast Association of
Geological Societies
www.gcags.org

Geologic Models Underpinning the 2024 U.S. Geological Survey Assessment of Undiscovered Oil and Gas Resources in the Hosston and Travis Peak Formations of the Onshore Gulf Coast Region, U.S.A.

Lauri A. Burke, S. T. Paxton, S. A. Kinney, N. J. Gianoutsos, R. F. Dubiel, and J. K. Pitman

U.S. Geological Survey, MS 939 Box 25046 DFC, Denver, Colorado 80225–0046, U.S.A.

ABSTRACT

The Early Cretaceous (Berriasian–Hauterivian) Hosston Formation in Louisiana and eastward is time correlative to the Travis Peak Formation of Texas and southern Arkansas. The formation is a first-order clastic sequence with a regional carbonate transgressive surface as an upper contact. The Hosston and Travis Peak formations contain conventional natural gas and oil accumulations that have been produced for nearly a century. These mature reservoirs contain terrigenous fluvial-deltaic, shore-zone, and paralic deposits across the productive trend; organic-lean mudstone and siltstone lithologies are found outboard of the Lower Cretaceous shelf margin. Producing reservoirs exhibit normal pressure gradients from 0.43 to 0.55 psi/ft (9.7 to 12.4 kpa/m), depths from 4000 to over 20,000 ft (1220 to 6100 m), and temperatures from 150 to 385°F (65 to 196°C). Wells are primarily vertical completions. The number of new field wildcats has been declining since the late 1990s.

This paper presents comprehensive geologic models, which include lithofacies maps, structure and isopach maps, burial history models, regional seismic interpretations, and events charts that underpin the recently completed U.S. Geological Survey assessment of undiscovered, technically recoverable hydrocarbons within the Hosston and Travis Peak formations. This study also provides geographic and stratigraphic distributions of Hosston–Travis Peak reservoir properties, including geopressure, reservoir temperature, porosity, permeability, API gravity, and gas-oil ratios. Results indicate estimated undiscovered, technically recoverable mean resources of 28 million barrels of oil and 35.8 trillion cubic ft of gas in conventional and continuous accumulations within the Lower Cretaceous Hosston and Travis Peak formations of the onshore U.S. Gulf Coast region. Quantitative assessment results are detailed in U.S. Geological Survey Fact Sheet 2025–3021 and associated Data Release.

INTRODUCTION

The Early Cretaceous (Berriasian-Hauterivian; 130–115 Ma) Hosston Formation in Louisiana, Mississippi, and eastward is the correlative equivalent to the Travis Peak Formation of eastern Texas and southern Arkansas. The Hosston–Travis Peak (HTP) formations represents the second major clastic supersequence (after the Cotton Valley Formation) deposited in the northern Gulf of America Basin after Late Triassic continental rifting opened the basin (Salvador, 1991). The HTP lower contact is a sequence boundary and is unconformable in many locations. The upper contact is a transgressive surface on which regionally extensive platform carbonates of the Lower Cretaceous (Barremian-Aptian) Sligo and Pettet formations were deposited as sea level rose and flooded the continent. This 15 Ma depositional cycle includes substantial erosion associated with the regionally extensive Valanginian unconformity resulting from the Cretaceous sea level minima (Haq, 2013). The primary producing trend includes siliciclastic-rich strata of continental origin, predominantly from fluvial-deltaic and shore zone depositional environments.

This study aims to quantitatively assess undiscovered, technically recoverable oil and gas endowments within the HTP of the Gulf Coast region, as directed under the Energy Policy Act of 2005 and the Energy Policy and Conservation Act of 2000. This study area encompasses the HTP and Early Cretaceous time-equivalent strata within the Jurassic-Tertiary-Cretaceous composite total petroleum system (TPS; Dubiel et al., 2007) of the onshore Gulf Coast region (Fig. 1). This paper describes the regional geologic foundations for the resource assessment, characterizes all petroleum system elements, and synthesizes geologic models into unique assessment units (AUs) for the HTP and time-equivalent strata. Seven conventional AUs and one continu-

Manuscript received January 2, 2025; revised manuscript received May 9, 2025; manuscript accepted May 10, 2025.

GCAGS Journal, v. 14 (2025), p. 87–105.
https://doi.org/10.62371/STWR8033

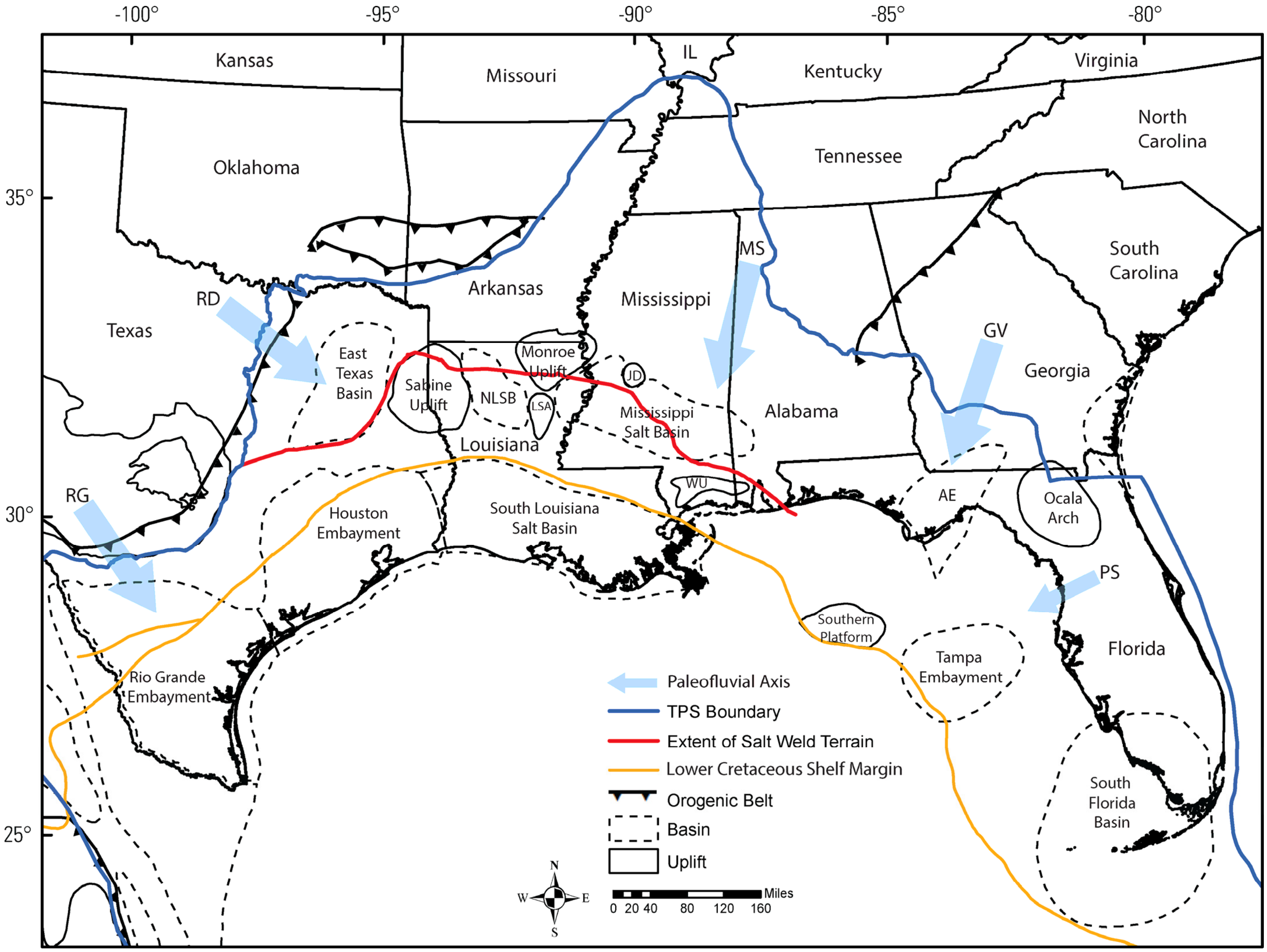


Figure 1A. Index map of the onshore Gulf Coast. (1) Paleofluvial axes for the ancestral Rio Grande (RG), Red (RD), Mississippi (MS), Grenville (GV), and Peninsular/Suwannee (PS) river systems during the Early Cretaceous, (2) total petroleum system (TPS) boundary, (3) the southernmost geographic extent of salt-weld terrain, (4) Lower Cretaceous shelf margin, (5) Appalachian-Ouachita orogenic belt, and (6) basins and uplifts, including the North Louisiana Salt Basin (NLSB), La Salle Arch (LSA), Wiggins Uplift (WU), Jackson Dome (JD), and Apalachicola Embayment (AE).

ous AU were quantitatively assessed (Burke et al., 2025a, 2025b). Results indicate estimated undiscovered, technically recoverable mean resources of 28 million barrels of oil and 35.8 trillion cubic ft of gas in conventional and continuous accumulations within the Lower Cretaceous Hosston and Travis Peak formations of the onshore U.S. Gulf Coast region.

BACKGROUND

The Western Interior Seaway (WIS) dominated western North America for over 100 million yr during the Jurassic and Cretaceous. However, during HTP depositional time (130–115 Ma), the southern terminus of the WIS generally coincided with the present-day Canadian border, and nutrient-rich waters of the Artic were not in communication with the Gulf of America water mass (Blakey and Rannye, 2018). Instead, the main influences on HTP erosion and deposition were sea-level fluctuations and continental drainage systems.

Substantial erosion of the HTP occurred during the Valanginian (128–123 Ma) global sea level minima of the Cretaceous (Haq, 2013). Consequently, HTP directly overlays Jurassic source rocks in several locations in northwestern portions of the TPS, based on subcrop maps in the vicinity of the ancestral Red River drainage (Paxton, 2022). We hypothesize that these eroded terrigenous siliciclastic sediments were transported over the Lower Cretaceous shelf margin and deposited onto the slope and deep basin environments. In further support, my interpretation of several regional reflection seismic lines, which are oriented dipwise and located downdip of the paleo Rio Grande, Red, and Mississippi River axes, show prominent seismic reflectors at the depth and thickness expected of the HTP. Seismic calibration is attained from eight wells with lithofacies interpretation of the HTP horizon. On the slope, this prominent reflector is laterally continuous and parallel. It exhibits high acoustic impedance contrast at the top, which may suggest direct-hydrocarbon indicators for natural gas charge. The HTP interval thickens basinward near the shelf margin, and the acoustic impedance contrast decreases in intensity, possibly due to mineral transition to a muddier slope lithology and/or a decrease in natural gas charge. On the basin floor, the time-equivalent HTP exhibits semi-continuous to discontinuous reflectors and decreases in thickness until finally terminating in a series of attenuated, rotated fault blocks at approximately 24,600 ft (7500 m) depth. These seismic features exhibit similar morphology to the intrabasinal tectonic structural features in the northern Gulf margin, especially salt-based detachment

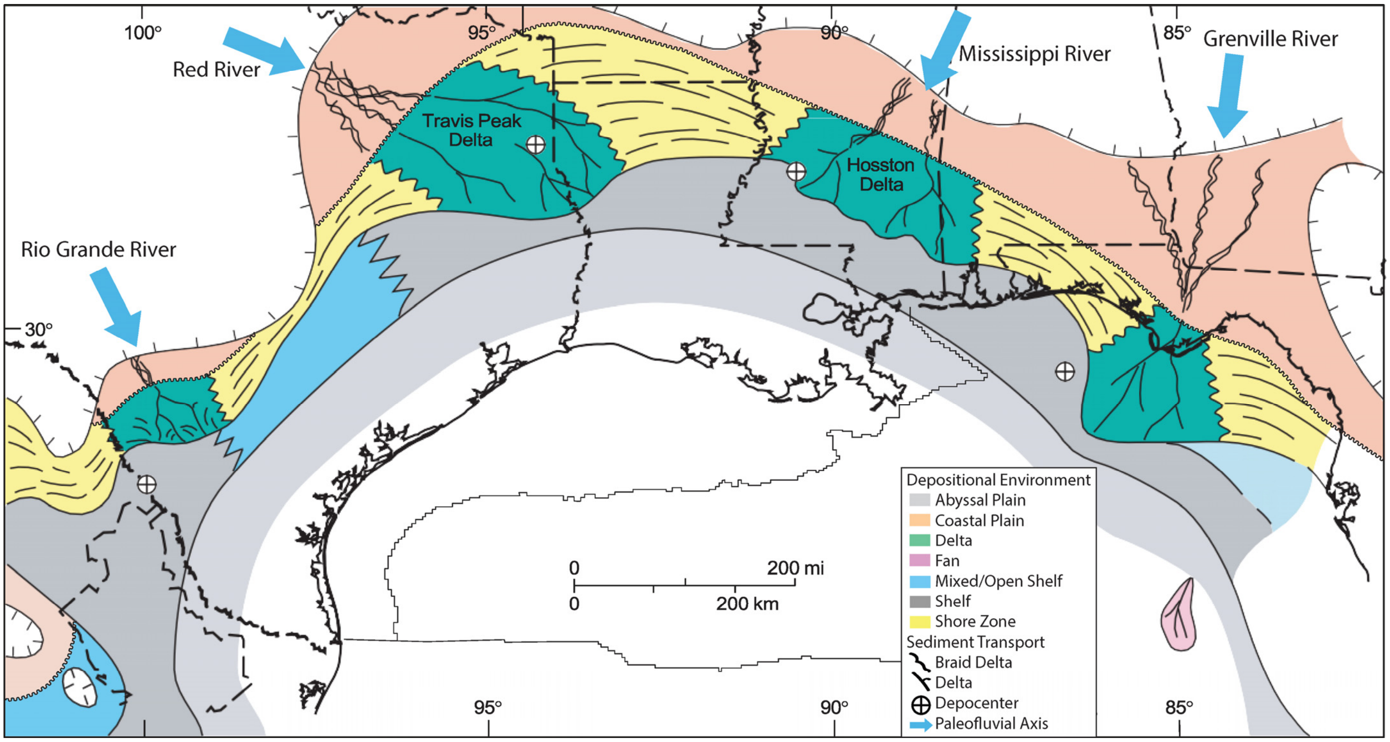


Figure 1B. Early Cretaceous principle fluvial systems and depositional environments over the Gulf Coast study area (modified after Galloway [2008] and Ewing and Galloway [2019]).

features, listric fault rollover systems, and salt-evacuation surfaces, as identified by Karlo and Shoup (2000; their figure 16.6B).

In stark contrast to modern-day continental-scale drainage patterns, most of the North American interior during the Early Cretaceous drained northward to the Boreal Sea through Western Canada foreland-basin systems (Blum and Pecha, 2014). Consequently, Gulf Coast drainage was limited to the area south of the Appalachian-Ouachita orogenic system. These sediments originated from the ancient (1.3–1.1 Ga) continental cratonic basement of the Laurentian-Grenville terrane, Laurentian margin, and peri-Gondwanan sutured terrane, along with younger (650–510 Ma) Gondwanan-Suwannee sutured terrane in Florida (Mueller et al., 2014). Four principal fluvial systems delivered these continental sediments to the northern Gulf of America during the Lower Cretaceous: the Rio Grande, Red, Mississippi, and Grenville Rivers. The Suwannee (or Peninsular) River had relatively minor sediment input axis in central Florida due to the limited geographic drainage area of relatively flat topography.

HTP depositional environments include paralic, fluvial-deltaic, shore zone, prodelta front, slope, and abyssal plain with, in general, terrigenous arkosic sandstone lithofacies transitioning into organic-lean mudstone lithofacies downdip of the main productive fairway. In Florida, continentally derived clastic lithofacies transition into shallow-water platform carbonates moving southward down the peninsula. Lithostratigraphic variations within the HTP are a function of higher-order eustatic fluctuations and the influence of local sediment influx rates. Although the HTP is not formally subdivided into stratigraphic members, four main divisions are recognized based on net-to-gross ratio, with most production originating from the upper 300 ft of the formation.

According to the literature (Dutton and Diggs, 1992; Dyman and Condon, 2006; Yamin, 2007; Lander and Laubach, 2015; Denny et al., 2020), the uppermost HTP section contains coastal plain, paralic, tidal-flat, and shallow marine deposits that experienced subsequent dolomitization reducing reservoir quality (porosity $\varphi = 3\%$; permeability $\kappa = 0.1$ mD). In the East Texas Basin, the upper to midsection contains extensively reworked shore zone and high-sinuosity channel sands that are fine-grained (0.14 to 0.21 mm), moderately well-sorted quartz arenites and subarkosic sandstones of adequate reservoir quality ($\varphi = 13\%$; $\kappa = 0.6$ mD). Further eastward, the Hosston lithofacies encompass extensively reworked shore zone clastics and fluvial-deltaic deposits at the terminus of the paleo Mississippi River. Most production comes from this portion of the formation, which exhibits higher porosity and pore connectivity. Quartz, followed by ankerite, is the most abundant porosity-occluding cement. Lower portions of the formation are comprised of low-sinuosity stacked channel sandstones and crevasse splays within flood-plain mudstones of continental origin; these sandstones are compacted and extensively quartz-cemented, resulting in lower reservoir quality ($\varphi < 4\%$; $\kappa < 0.1$ mD). The basal non-reservoir strata are highly compacted, extensively cemented deltaic fringe and marginal marine deposits from the initial progradation of the HTP.

The HTP generally deepens southward towards the Lower Cretaceous shelf margin and eastward towards the Mississippi Salt Basin (Figs. 2A and 2B). However, prominent basins and uplifts exhibit unique average depths to the top of the HTP: 14,000 ft (4300 m) average depth in the Mississippi Salt Basin; 10,000 ft (3050 m) average depth in the East Texas Basin and North Louisiana Salt Basin; 5000 ft (1530 m) average depth in the Sabine Uplift area; and 3500 ft (1,70 m) average depth in southern Arkansas. The influence of salt structures and diapers is visible in the HTP depth structure base map (stipple pattern; Fig. 2B), especially in southern Arkansas, along the northern margins of the East Texas Basin, Sabine Uplift area, and North Louisiana Salt Basin. Isopach thickness of the HTP averages 2000–2500 ft (610–760 m) regionally with localized areas over 3000 ft (915 m) (Fig. 2C). HTP in East Texas Basin (3500 ft [1070 m]) and Northern Louisiana Salt Basin (4000 ft [1220 m]) exhibit greater thicknesses as compared to the Sabine Uplift area (1500 ft [460 m]), which experienced substantial uplift and subsequent erosion

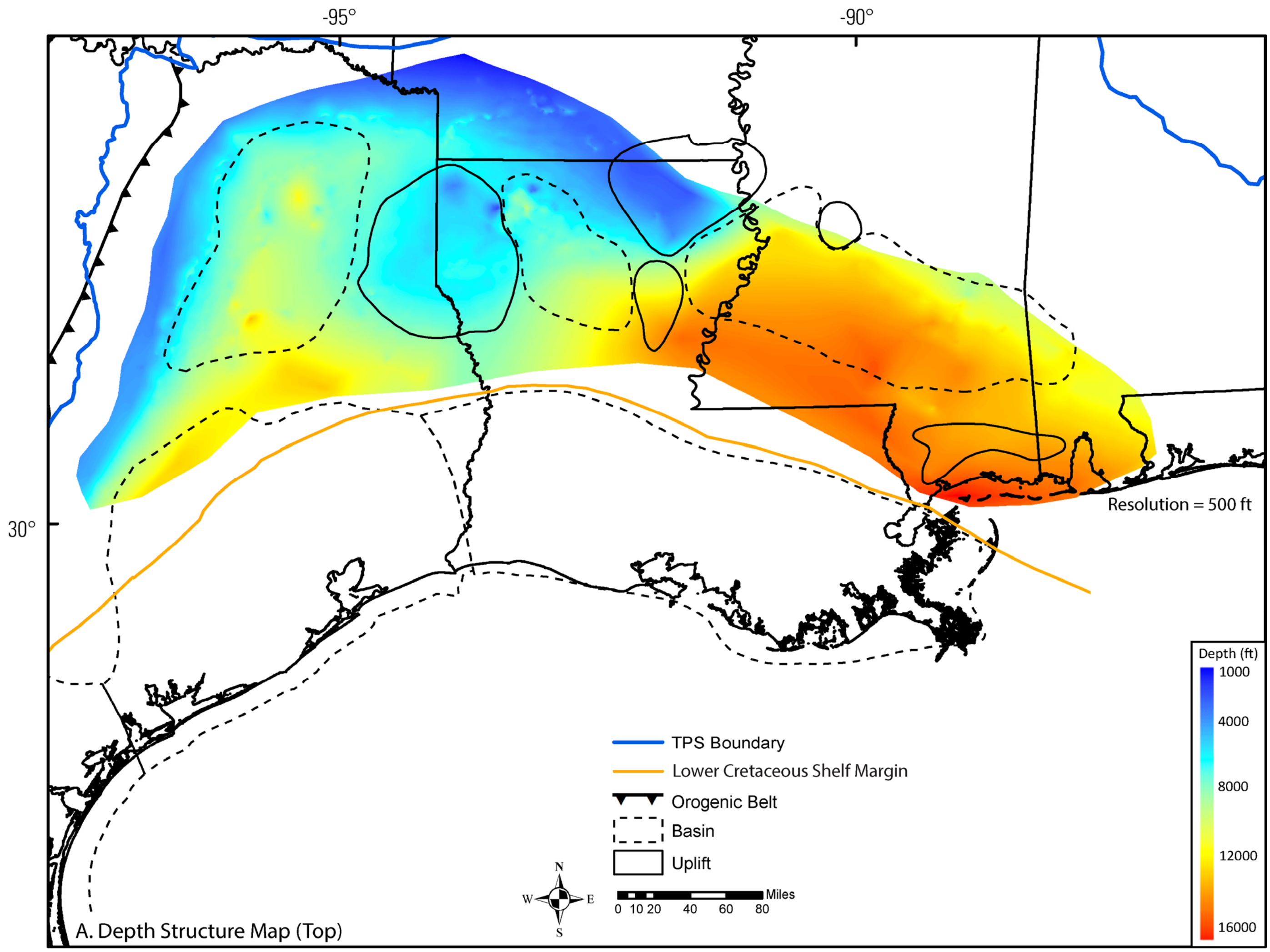


Figure 2A. Depth structure map (top) of the Hosston–Travis Peak formations over the main productive trend shows a general deepening southward and eastward.

(Laubach and Jackson, 1990). Notably, thick lobe-shaped physiographic features (6000 ft [1830 m]) are visible at the terminus of paleo Mississippi and Grenville River drainage axes and may represent clastic fluvial-deltaic deposits; our observations are corroborated with Snedden and Galloway's findings in this vicinity (Snedden and Galloway, 2019). The isopach map also highlights the presence of salt diapirs across southern Arkansas, the rim of the East Texas Basin, and the western half of the Sabine Uplift area. These salt-related features are associated with increased mobilization of Jurassic Louann Salt (Lopez, 1995) during HTP depositional loading and provide high-permeability conduits for secondary migration from underlying Jurassic source rocks.

In congruence with the structural architecture, HTP reservoir temperature generally increases southward and eastward, corresponding to a deepening of the formation (Figs. 2D and 3) (Burke et al., 2020). Reservoir temperatures can be divided into three separate thermal regimes. The coolest reservoir temperatures (110–150°F [43–65°C]) are found in southern Arkansas and portions of the Sabine Uplift area, which coincides with oil fields at shallower depths. Intermediate to higher reservoir temperatures (250–275°F [121–135°C]) are located at intermediate depths, for example, in the East Texas Basin, where localized temperature variation is likely due to the presence and influence of salt diapers and salt-cores structures. Maximum temperatures (325–350° F [163–177°C]) occur in deeper parts of the trend, such as the Mississippi Salt Basin and its vicinity, which corresponds to lower porosities and permeabilities as heat-dependent secondary mineralization of quartz occluded pore throats and reduced connectivity.

Producing reservoirs are predominantly hydrostatically pressured and range from 0.43–0.55 psi/ft (9.7–12.4 kpa/m) (Fig. 3). A few rare exceptions occur near normal faults in the East Texas Basin in which reservoir pressures slightly depart from the hydrostatic gradient and begin to approach the pressure transition zone at 0.70 psi/ft (15.8 kpa/m). Bartberger et al. (2003) and Dyman and Condon (2006) mapped oil-water contacts and gas-water contacts across the productive trend, supporting the HTP as a conventional play.

Porosity and permeability trends vary widely geographically and stratigraphically across the trend (Fig. 3). Higher average field porosities and permeabilities (φ = 18–30%; κ = 500–2000 mD) are observed in shallow (1000–6000 ft [305–1830 m]) producing oil fields in southern Arkansas and along the shallow northern-eastern flank of the Mississippi Salt Basin. These locations are also associated with regional fault zones and cooler geothermal gradients. Intermediate values (φ = 11–15%; κ = 80–200 mD) are prevalent in mid-depth (6000–10,000 ft [1830–3050

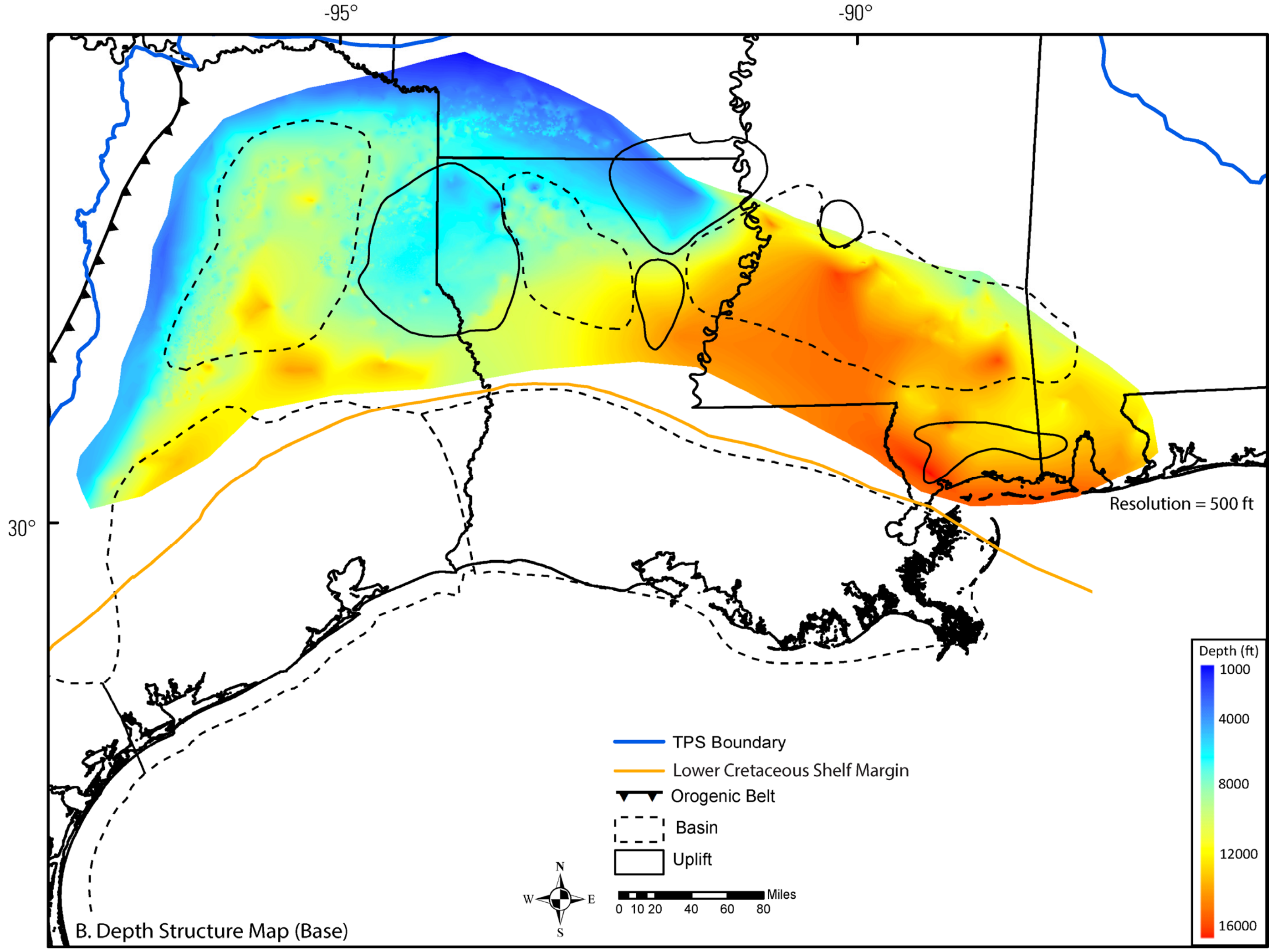


Figure 2B. Depth structure map (base) of the Hosston–Travis Peak formations over the main productive trend shows the deepening of the unit southward and eastward.

m]) gas fields across the productive trend and are attributed predominantly to matrix porosity and cooler geothermal gradients, which correspond to less quartz cementation. Lower reservoir quality (φ = 1–8 %; κ ≤ 25 mD) is found in deeper (10,000+ ft [3050+ m]) warmer gas fields along central and southern portions of the Mississippi Salt Basin, the eastern flank of the East Texas Basin, and western margins of the Sabine Uplift.

The porosity compaction curve in Figure 3 represents the maximum expected porosity during burial in the absence of pore-filling cement. Porosity generally decreases with depth and increasing temperatures; however, the Travis Peak exhibits a distinct porosity trend compared to the Hosston. This may be attributed, in part, to Hosston paralic and shore zone lithofacies containing comparatively higher mudstone volumes, resulting in lower matrix porosity and increased susceptibility to mechanical compaction. Additionally, deeper Hosston reservoirs, especially in the Mississippi Salt Basin, exhibit higher reservoir temperatures, which enhanced the catalyzation of secondary mineralization and pore-occluding cementation. However, deeper porosity preservation in Hosston and Travis Peak is due to chlorite coating of matrix porosity (Dutton and Diggs, 1992; Lander and Laubach, 2015; Denny et al., 2020).

Active Jurassic source rocks underlying the Gulf Coast region include the Smackover (Birdwell et al., 2024; Whidden et al., 2023), Bossier (Paxton et al., 2017a), and Haynesville formations (Paxton et al., 2017b). The Smackover contains amorphous-algal marine type IIS (oil-prone) kerogen and resides within the oil- or gas-generation window throughout most of the Gulf Coast productive trend (Fig. 4). The updip extent of the Smackover oil window roughly coincides with the northern extent of HTP oil production. In conjunction with fluid inclusion work, petrographic studies of microstructures suggest that large volumes of fluid migrated through the HTP formations via fractures that formed during burial and partly during uplift (Laubach, 1989; Lander and Laubach, 2015). Migration pathways from the underlying Jurassic source system into HTP reservoirs occurred primarily by buoyant migration through regional fault zones and fracture networks associated with Early Cretaceous mobilization of the Louann Salt and the ongoing downwarping of the Houston and Mississippi embayments. This included movement (1) along the Mexia-Talco Fault Zone across the northern and western boundaries of HTP-producing fields, (2) emplacement of structural folds associated with the deformation of salt pillows and salt domes, and (3) regional faulting that extends upward from the Smackover, Bossier, and Haynesville formations into the HTP formations. The geographic co-location of oil and gas fields and the mixed production characteristics (Fig. 4) suggest supplementary migration from fill-and-spill mechanisms within HTP carrier

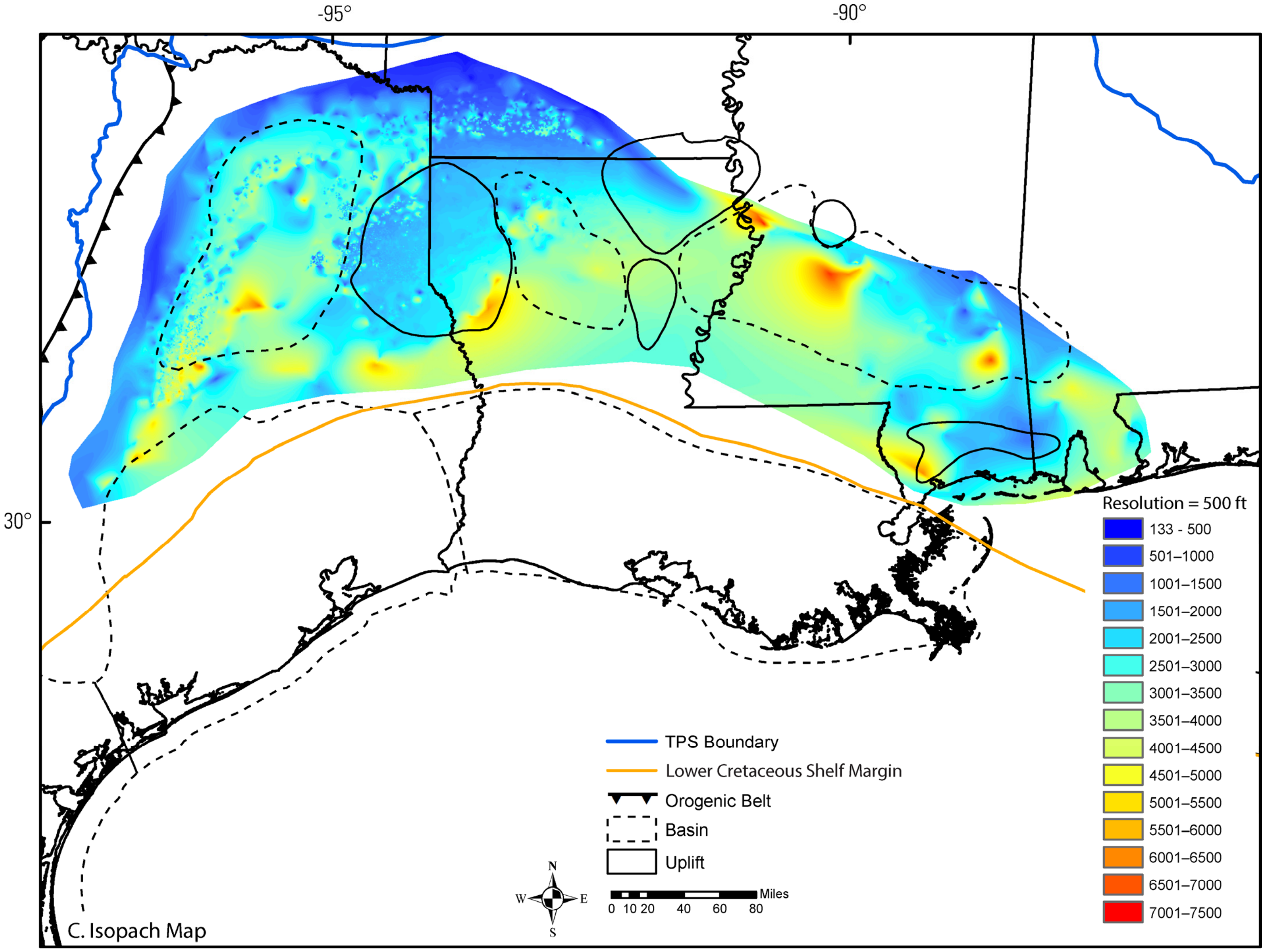


Figure 2C. Structure isopach map of the Hosston–Travis Peak formations over the main productive trend highlights the influence of salt diapirs (stippled pattern), especially in East Texas Basin, Sabine Uplift, North Louisiana Salt Basin, and vicinity. Note that lobe-shaped thickness variations (red contours) are present near the terminus of the ancestral Mississippi River within the Mississippi Salt Basin.

beds. These observations may also be attributed to the complex geometry of vitrinite reflectance Ro contours and subsequent intermixing of Smackover, Haynesville, and Bossier oils and gases, which is evident by the scatter cloud of API gravity data (Fig. 3).

METHODOLOGY

The USGS resource assessments use a geologic-based, peer-reviewed methodology (Charpentier and Klett, 2005; Klett et al., 2005; Schmoker, 2005; Schmoker and Klett, 2005) for the probabilistic determination of undiscovered petroleum accumulations. Assessments are predicated upon petroleum system science and geologic-based criteria for conventional and continuous resources to define each AU. An AU is defined as a mappable rock volume with geologically homogenous characteristics that is either predominantly oil-prone or gas-prone and is distinguishable from other AUs within a TPS (Schmoker and Klett, 2005). A TPS encompasses all genetically related petroleum in seeps, shows, and accumulations originating from a pod of active source rocks (Magoon and Schmoker, 2000). TPS elements include source rocks, reservoirs, traps, seals, overburden, and the geologic processes of hydrocarbon generation, expulsion, migration, accumulation, and preservation. Petroleum system science involves the characterization of each element, which includes but is not limited to: (1) source rock attributes of kerogen type, thermal maturity, organic richness, and geographic and stratigraphic extent, (2) reservoir geographic and stratigraphic extent, mineralogy, porosity, permeability, in-situ temperature, and reservoir pressure, (3) trap structural and stratigraphic type, timing of trap formation, deposition of seals, and seal integrity over geologic time, (4) overburden deposition, erosion, uplift, and emplacement of fault zones and fracture networks, (5) hydrocarbon generation based on kerogen type, hydrogen index, and transformation ratio, (6) primary migration due to pressure transfer mechanisms, (7) secondary migration arising from buoyancy and pressure transfer through higher permeability conduits and carrier beds, (8) accumulation with respect to trap and seal capacity, and (9) subsurface processes that may influence petroleum preservation through geologic time.

The assessment methodology distinguishes conventional from continuous resources using USGS–defined, geologic-based criteria (Schmoker, 2005; Schmoker and Klett, 2005). Several criteria are evaluated simultaneously to distinguish continuous from conventional resources. Key features for conventional re-

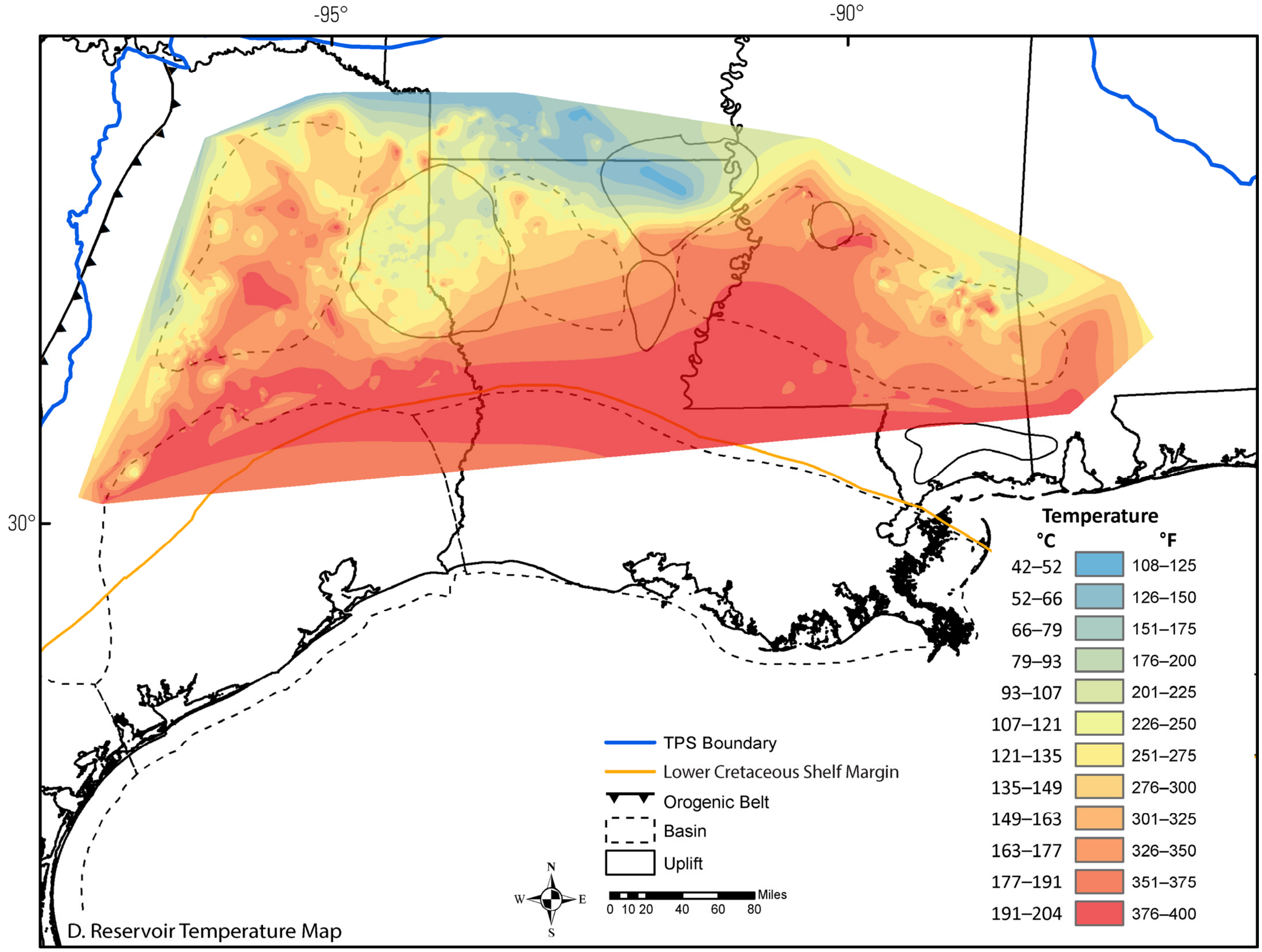
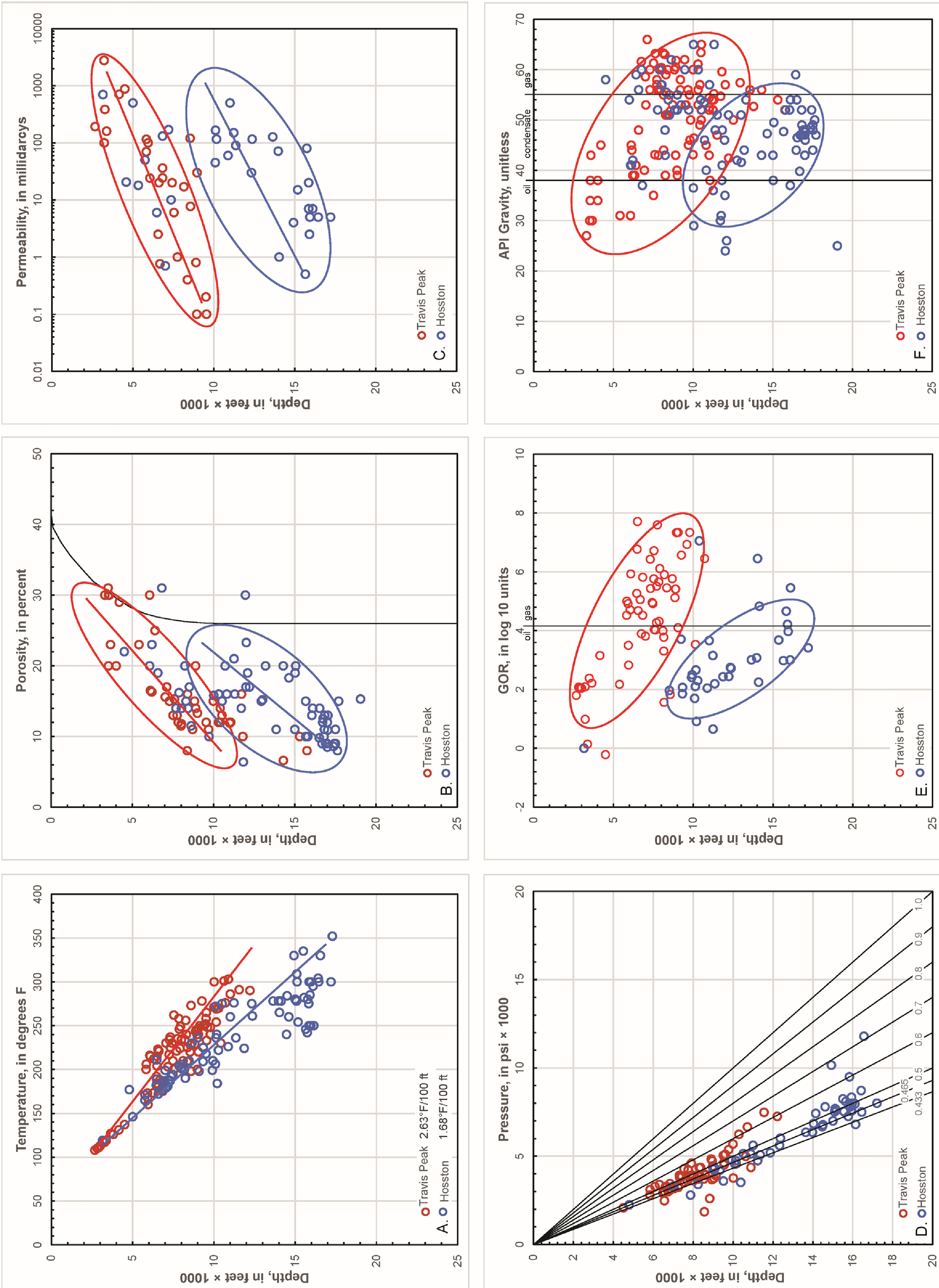


Figure 2D. **Reservoir temperature distribution of the Hosston–Travis Peak formations over the main productive trend across the Gulf Coast region.**

sources include discrete accumulations typically associated with structural and stratigraphic traps and seals, and oil-water and gas-water contacts may be present due to hydrocarbon buoyancy with respect to pore waters (Schmoker and Klett, 2005). Strong indicators for conventional resources may involve higher water saturations, higher water production originating from the rock matrix as opposed to fault-related water production, higher porosities, and a range of permeability values, some of which may be lower than 0.1 mD. Moderate indicators may include vertical or directional well completion practices and dry holes often associated with in-fill drilling or expansion of known fields and existing wells. Only fields above minimum size (0.5 million barrels for oil; 3 billion cubic ft for gas fields) are considered in the calculations.

In contrast, continuous resources exhibit lower relative permeabilities (often below 0.1 mD), resulting in higher capillary entry pressures that serve as the trapping mechanism. Thus, hydrocarbon accumulations are distributed continuously across the play, irrespective of traps (Schmoker, 2005). Continuous resources exhibit lower permeabilities and porosities, resulting in higher capillary entry pressures that serve as the trapping mechanism. Continuous resources often exhibit higher irreducible water saturations, and wettability is often heterogeneous down to the mineral grain scale. Oil-water and gas-water contacts are markedly absent. Wells are commonly horizontal, and completions may contain multiple hydraulic fracture stages. Dry holes may be distributed somewhat randomly across the play instead of within discrete accumulations due to factors involving, for example, localized porosity and permeability heterogeneity. Reservoirs are often overpressured, although this is not a requisite condition for a continuous resource. Large volumes of produced waters, if encountered, are typically associated with fault zones instead of originating from the matrix porosity. Continuous plays are often geographically extensive and typically reside within deeper portions of the basin.

A resource assessment begins with characterizing the regional tectonic setting, basin history, and framework geology, followed by characterizing all petroleum system elements. Geologic models are developed from the synthesis of these multidisciplinary data types. Production characteristics for each AU are used to calculate estimated ultimate recovery (EUR) for input into a Monte Carlo simulation that provides a probability distribution of undiscovered petroleum resource volumes remaining in the subsurface. Fractiles for F95, F50, and F5 express uncertainty about the undiscovered resource volume. The F95 fractile, for example, represents a 95% chance of that volume of hydrocarbons remaining in the subsurface; other fractiles are expressed similarly.


Permeability, in millidarcys
Depth, in feet × 1000
C.
Travis Peak
Hosston
API Gravity, unitless
gas
condensate
oil
F.
Porosity, in percent
B.
GOR, in log 10 units
E.
Temperature, in degrees F
A.
Travis Peak 2.63°F/100 ft
Hosston 1.68°F/100 ft
Pressure, in psi × 1000
D.
0.433
0.465
0.5
0.6
0.7
0.8
0.9
1.0

(FACING PAGE) Figure 3. Rock and fluid properties as a function of depth show distinct trends between the Travis Peak (red circles) and Hosston (blue circles), including (A) reservoir temperature, (B) porosity, (C) permeability, (D) reservoir pressure, (E) gas-oil-ratio (GOR), and (F) API gravity. Individual data points represent field-wide averages.

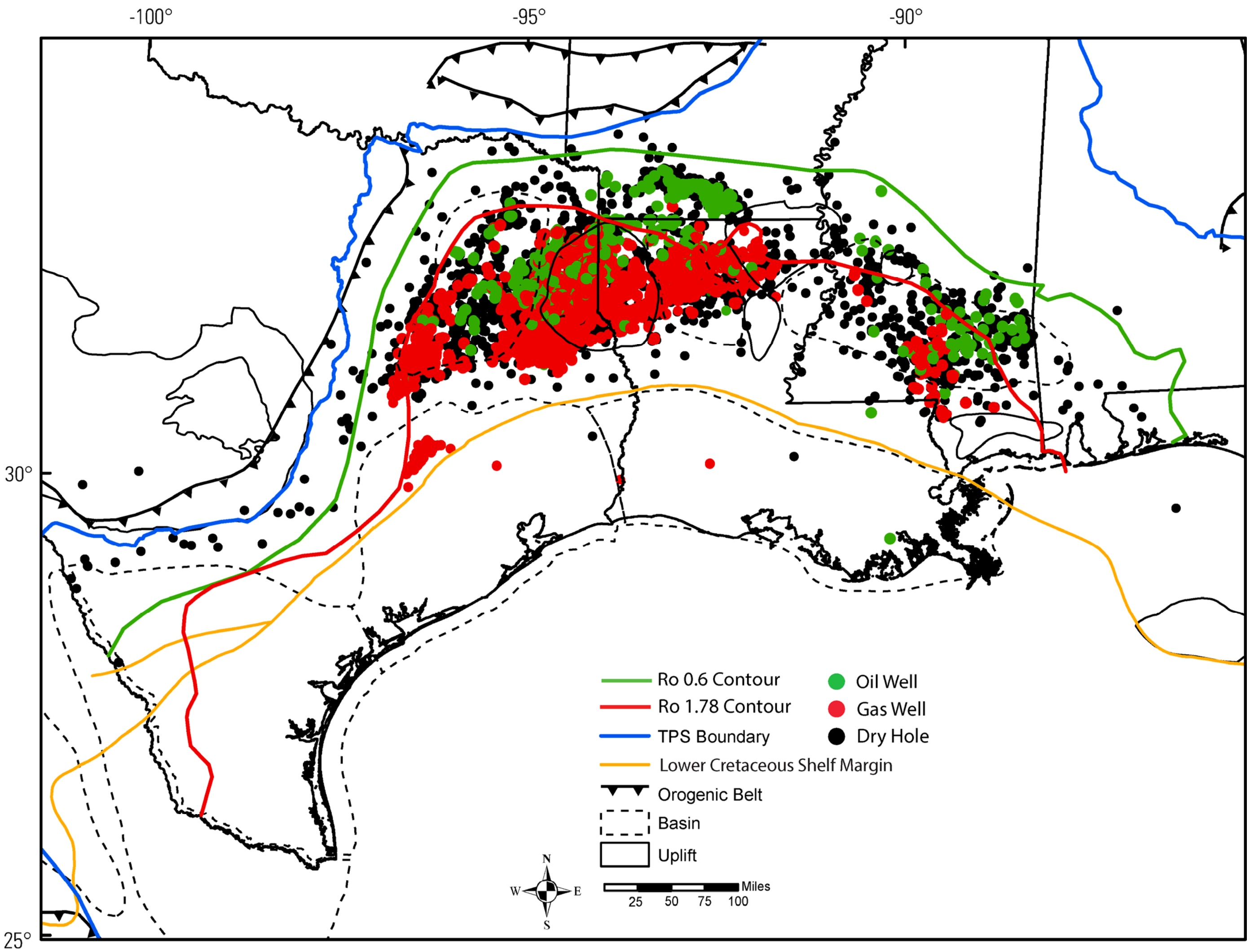


Figure 4. Hosston–Travis Peak oil production (green circles), natural gas production (red circles), and dry holes (black circles) in relation to thermal maturity contours for the Smackover oil-window (R_o [vitrinite reflectance] = 0.6; green contour) and the Smackover gas-window (R_o = 1.78; red contour).

GEOLOGIC MODELS

The study area for the HTP undiscovered resource assessment is given by the solid blue line (Fig. 1A) representing the Upper Jurassic-Cretaceous-Tertiary Composite TPS Boundary (Warwick et al., 2007) to the north, the Mexico border to the west, and the Gulf Coast shoreline approximating the State waters extent of the USGS purview. The geographic distribution of lithofacies over the study area (Fig. 1B) (Ewing and Galloway, 2019) includes coastal plain, fluvial-deltaic, shore zone, shallow marine, shelfal, and abyssal plain lithofacies.

Petroleum System Elements of Coastal Plain Facies

All petroleum system elements are present or possible within the northern bounding coastal plain facies. The source is the thermally mature, underlying Smackover Formation, which resides in the oil- and wet-gas-generation windows throughout this area. Updip and northward petroleum migration is predominantly through fault zones and fracture networks associated with salt movement and coastal plain subsidence. However, the proximity of this AU to the highly-faulted Ouachita orogenic belt may have enabled petroleum to bypass HTP reservoirs and ultimately accumulate in reservoirs further updip and upsection. The coastal plain lithofacies contains Early to Late Jurassic pre–Eagle Mills fill and pre-Callovian salt basin-fill deposits of continental origin that were reworked by the fluvial-deltaic and shore zone systems (Ewing and Galloway, 2019; Galloway, 2008). Accordingly, reservoir lithofacies in this region are a collection of lower-quality, poorly sorted, subangular to subrounded, terrigenous clastics.

USGS subcrop maps (Paxton and Kinney, 2022) derived from formation tops (S&P Global Commodity Insights, 2024) show evidence of fluvial incision and subsequent headward erosion of the HTP coastal plain lithofacies in northwestern portions of the study area, especially in the vicinity of the ancestral Red River drainage and northwestern East Texas Basin. Incision down to Jurassic source rocks is evident in these locations, with HTP and Cotton Valley formations. Sediments are likely transported downdip and ultimately deposited as sandy basin-floor fan complexes (BFFs). Carbonate seals of the Aptian Sligo and Pettet formations were deposited atop HTP coastal plain strata as sea level continued to rise and flood the continent. However, carbonate seals in the northern parts of the study area may be relatively thin due to shallower water depths and less accommodation space during deposition. As a consequence, carbonate seals in these areas may have ruptured due to Early Cretaceous mobilization of the Louann Salt.

Petroleum Systems Elements of the Productive Fairway

The main productive fairway, spanning the East Texas Basin, Sabine Uplift, and North Louisiana Salt Basin, produces conventional natural gas and some oil from hydrostatically pressured reservoir sandstones of continental origin. Reservoirs over the productive trend contain reworked shore zone lithofacies and stacked fluvial-deltaic deposystems associated with the Rio Grande, Red, Mississippi, and Grenville river systems, which drained limited terrain south of the Appalachian-Ouachita orogenic system. Over the main productive fairway, hydrocarbons migrated from thermally mature source rocks in the underlying Jurassic Smackover, Bossier, and Haynesville formations (Birdwell et al., 2024; Whidden et al., 2023). Updip migration was facilitated by higher porosity and permeability fairways associated with salt-related features and regional fracture networks resulting from the ongoing movement of the Louann Salt and downwarping of the Gulf coastal plain. Supplemental migration may have also occurred within HTP carrier beds through fill and spill mechanisms (this study), as evidenced by intermixed oil and gas production, especially in the East Texas Basin and the Sabine Uplift, along with wide-ranging API gravity values. Travis Peak and Hosston exhibit different trapping mechanisms across the productive trend. Travis Peak producing fields are associated with a combination of trap types, notably salt drape structures, salt diapirs, and salt ridges, especially in the East Texas Basin and western flank of the Sabine Uplift. Travis Peak also contains deltaic and fluvial stratigraphic traps and anticlinal structural closures toward the central portions of the Sabine Uplift area. Trapping mechanisms for Hosston reservoirs are predominantly anticline structural traps, with salt-related traps and normal fault structural traps in the producing fields of southern Arkansas and southern Mississippi. Regionally extensive and stratigraphically thick carbonate seals of the Aptian Sligo and Pettet formations were deposited atop the HTP as sea level rose and flooded the low-lying portions of the coastal plain. Production drive mechanisms are mainly pressure depletion due to reservoir compaction; water drive is an intermediate drive mechanism, followed by solution gas drive, gas cap expansion, and gravity drainage (S&P Global, 2024).

Petroleum Systems Elements of Slope and Abyssal Plain

A working petroleum system is predicted south of the Lower Cretaceous shelf margin. We interpreted HTP time-equivalent strata downdip of the Lower Cretaceous shelf margin and into the deep basin based on several regional 2D reflection seismic lines with well control; results were corroborated with Snedden and Galloway (2019). Based on our interpretations, the HTP exhibits laterally continuous reflectors on the shelf. Near the shelf margin, the HTP thickens basinward, and the acoustic impedance contrast decreases due to a lithologic transition to a muddier lithology and/or less natural gas charge. On the basin floor, Lower Cretaceous time-equivalent HTP strata exhibit semi-continuous to discontinuous reflectors. The downdip termination of these strata in the abyssal plain coincides with large-scale intrabasinal tectonic structural features that we interpreted as salt-based detachment features and rotated fault blocks based on seismic geomorphology identified by Karlo and Shoup (2000, their figure 16.6B).

Our geologic model predicts predominantly low-permeability, organic-lean, fine-grained mudstone lithofacies, prodelta siltstones, and claystones on the slope and abyssal plain depositional environments. Additionally, due to regionally extensive Valanginian erosion of continental strata, massive terrigenous siliciclastic strata may have been deposited beyond the Lower Cretaceous shelf margin during the Early Cretaceous. Potential occurrences of sandy BFFs downdip of the Mississippi, Red, and Rio Grande River systems are predicted, with the greatest potential aligned with the Early Jurassic Mississippi Canyon axis. Furthermore, age-equivalent BFFs have been identified offshore Florida downdip of the Suwannee River (Galloway, 2019; Snedden and Galloway, 2019). Sandy BFFs and low-permeability age-equivalent strata may harbor continuous resources because the Smackover resides within the gas-generation window over the geographic extent of this area (Birdwell et al., 2024; Whidden et al., 2023).

Petroleum Systems Elements in Florida

Elements of a Lower Cretaceous working petroleum system are present or possible in northern and western Florida. HTP-time equivalent reservoir lithofacies include coastal plain strata, fluvial-deltaic deposits from the Peninsular River, and siliciclastics transitioning to shallow-water and platform carbonates in southern Florida (Bovay, 2015; Snedden and Galloway, 2019). Thermally mature source rocks are unknown or absent across most of this area, which may be due to sparse exploration; only one dry hole exists near the Grenville River depocenter in offshore Florida (Bovay, 2015; Snedden and Galloway, 2019; S&P Global Commodity Insights, 2024). In the South Florida Basin, active source rocks include the Wood River, Bone Island, Pumpkin Bay, Dollar Bay, and Sunniland formations, which are Lower Cretaceous, fine-grained, organic-rich carbonates containing high-sulfur, algal marine Type IIS (oil-prone) kerogen (Pollastro et al., 2001). Two wells in the Sunniland trend (>15,000 ft [>4570 m]) in the South Florida Basin have gas shows, and the literature suggests potential gas in the Upper Jurassic to Lower Cretaceous Wood River Formation (Roberts-Ashby et al., 2016; Pollastro et al., 2001; McFarlan and Menes, 1991). Aside from unknown or undiscovered source rocks, hypothetical long-distance migration from the Smackover to the Grenville fluvial-deltaic lithofacies in the Florida panhandle may be possible; however, well control is absent. Stratigraphic, structural, and combination traps will likely exist across the area. Aptian carbonates of the Sligo Formation and numerous anhydrite seals exist as facies transition from terrestrial to carbonate moving southward; for example, the Punta Gorda Anhydrite is a regional seal in the South Florida Basin.

Events Charts and Burial History Models

Events charts were constructed for the Travis Peak Formation in the East Texas Basin (Fig. 5A) and the Hosston Formation in the Sabine Uplift area of Louisiana (Fig. 5B). For both locations, source rocks were deposited during the Late Jurassic, and oil generation began early in HTP depositional history when higher porosity was mainly intact. The ongoing mobilization of the Louann Salt created fractures that facilitated migration and normal faulting that formed traps. Lower Cretaceous carbonate seals of the Sligo and Pettet formations were deposited atop the HTP as sea level rose. Petroleum accumulation continued unin-

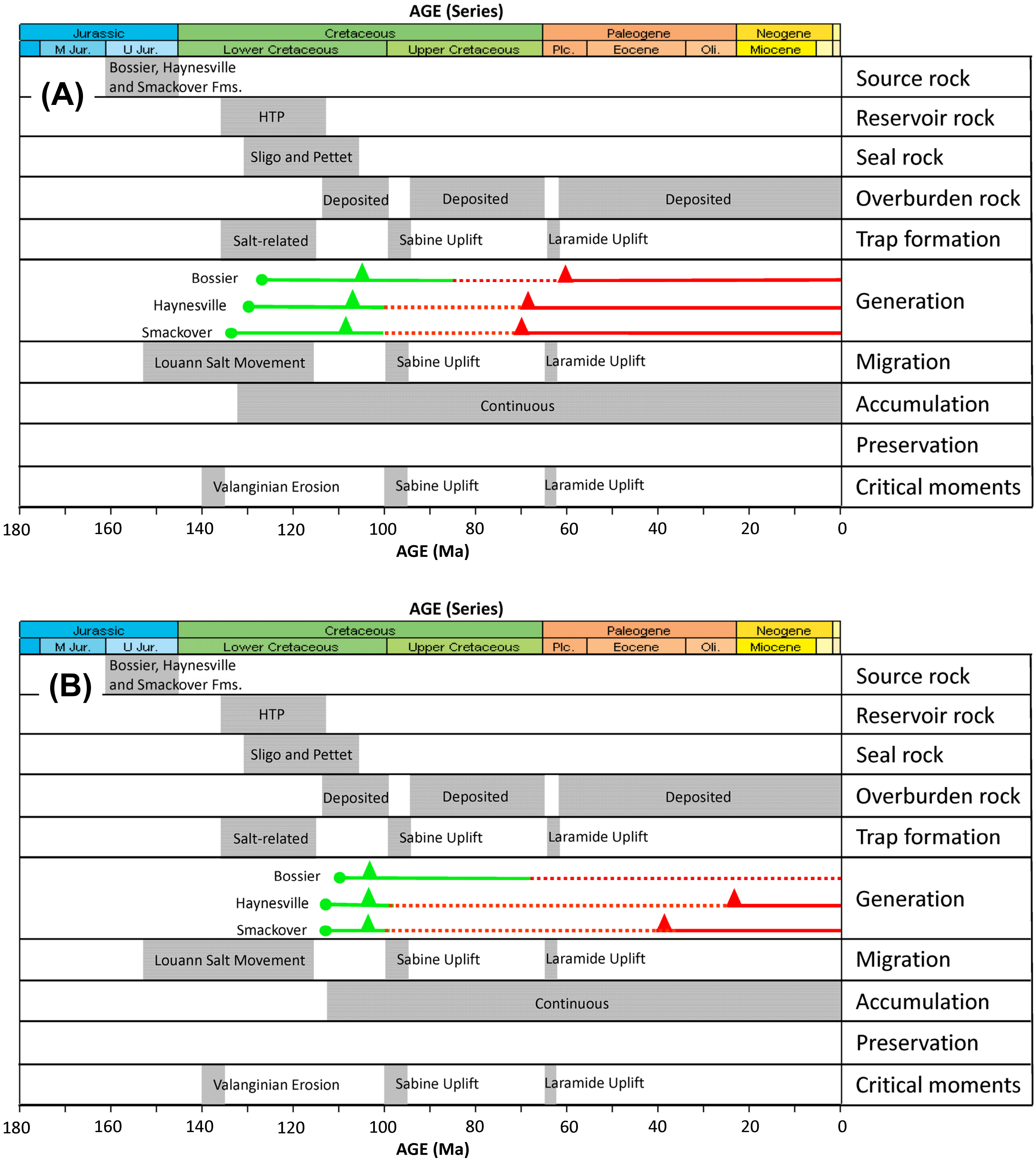


Figure 5. (A) Timing and events charts for petroleum system elements of the Travis Peak Formation in the East Texas Basin. Beginning of oil generation (green circle); peak oil generation (green triangle); beginning of natural gas generation (red dashed line); peak gas generation (red triangle). (B) Timing and events charts for petroleum system elements of the Hosston Formation in the Sabine Uplift area. Beginning of oil generation (green circle); peak oil generation (green triangle); beginning of natural gas generation (red dashed line); peak gas generation (red triangle). M. Jur. is Middle Jurassic; U. Jur. is Upper Jurassic; Plc. is Paleocene; and Oli. is Oligocene.

terrupted through the present day without incident to petroleum preservation. This temporal sequence of events is appropriate for a world-class petroleum system.

Three 1D burial history models were generated for the East Texas Basin, eastern Sabine, and western Sabine (Figs. 6A–6C) from available well data. The Ashland No. 1 well in the East Texas Basin was modeled to investigate reservoir quality and mineral precipitation over time. Oil generation (130–80 Ma) began when Travis Peak (yellow) was shallow in burial depth with higher porosity intact. Gas generation occurred between 100–40 Ma and may be overmature today. According to the available published research (Dutton and Diggs, 1992; Lander and Laubach, 2015; Denny et al., 2020), quartz cementation precipitated from meteoric water during early burial and from stylolites during deeper burial. The initial quartz cementation phase was followed by orthoclase dissolution and albitization of plagioclase. Ankerite precipitation occurred after this, followed by additional quartz cementation continuing to the present day with reservoir temperatures around 260°F (127°C).

Burial history for Foster No. 1 well in the eastern Sabine shows the Hosston (yellow) experienced rapid burial followed by a period of uplift on the Sabine (100–95 Ma). The Jurassic source system in this location generated oil between 120–60 Ma. At the onset of oil generation, the Hosston was still at a shallower depth with higher porosity mostly intact, which is favorable for oil moving into the reservoir. At maximum burial (11,000 ft [3350 m]; 100 Ma), gas generation began and continues today. This well currently produces gas and wet gas condensate.

The Carthage No. 9 well was modeled in the western Sabine and indicates that the Travis Peak experienced rapid burial during the Early Cretaceous. The Jurassic source system in this location began oil generation around 115 Ma and continues today. At the onset of oil generation, the Travis Peak was still at shallower depths with higher porosity mostly intact. As the system was buried deeper over time, gas generation began in lower portions of the source system around 60 Ma and continues today. This well produces oil and gas today.

ASSESSMENT UNIT BOUNDARIES

Hosston and Travis Peak AUs, in relation to physiographic and geologic features within the Jurassic-Cretaceous-Tertiary composite TPS of the onshore Gulf Coast region, are shown in Figure 7. An AU boundary defines the geologic extent of the petroleum system elements that compose the geologic model describing a given AU (Schmoker, 2005; Schmoker and Klett, 2005). All petroleum system elements, which include source rocks, migration pathways, reservoirs, traps, and seals, have been characterized and evaluated for the Hosston and Travis Peak formations, resulting in one continuous and seven conventional AUs (Fig. 7).

The Hosston–Travis Peak Updip Oil AU is defined by the character and geometry of the coastal plain lithofacies, which contains poorly sorted, subangular to well-rounded, terrigenous clastics of the Eagle Mills Formation and pre-Callovian salt basin fill deposits that were extensively reworked by the four principle fluvial systems of the Early Cretaceous (Snedden and Galloway, 2019). This lithofacies exhibits low-to-moderate porosity and permeability, resulting in a lower-quality reservoir than neighboring AUs. This AU contains zero producing fields or wells of minimum size, and only a handful of dry holes are located within this area. The northern boundary of this AU is defined by the TPS boundary or the regional extent of the coastal plain lithofacies. The regional extent of known source rocks marks the eastern AU boundary, and the U.S.-Mexico border represents the western boundary of this AU.

The Travis Peak Delta Oil and Gas AU is located in the vicinity of the East Texas Basin and encompasses the sand-rich, fluvial-deltaic lithofacies of the paleo Travis Peak Delta at the downdip terminus of the ancestral Red River. AU boundaries are based on the lithofacies change from fluvial-deltaic to coastal plain facies to the north and from fluvial-deltaic to shore zone lithofacies to the east. The southern boundary is defined by the geographic extent of salt-weld terrain, which facilitated secondary oil migration from underlying Jurassic source rocks. Secondary migration was facilitated by the emplacement of higher porosity-permeability fairways created by the mobilization of the Jurassic Louann Salt concurrent with HTP deposition. Salt-related structural traps (namely salt diapir, salt drape, and salt flank) are the predominant trapping mechanism within this AU, followed by fluvial-deltaic stratigraphic traps, anticline structural closures, and isolated incidences of carbonate reef margin traps. Geographically extensive platform carbonates of the Sligo and Pettet formations generally form the regional seal.

The Hosston Shore Zone Oil and Gas AU is a relatively shallow, oil-producing area in southern Arkansas and northern Louisiana that encompasses the siliciclastic-rich, shore zone lithofacies located east of the Travis Peak Delta and west of the Hosston Delta. The northern boundary coincides with the geographic extent of the shore zone lithofacies before changing to the coastal plain facies. The southern boundary is defined by the southern extent of salt-weld terrain, which provided high-permeability pathways for the migration of underlying Jurassic-sourced oils. Secondary migration is through higher porosity-permeability fairways created by the mobilization of Louann Salt, especially associated with salt welds. Normal fault closures and salt-related traps are the main trapping mechanisms within this AU; isolated carbonate reef margin traps are found in the eastern portion of the AU. Reservoir temperatures are cooler due to the shallower reservoir depths, resulting in higher porosities. Massive platform carbonates of the Pettet Formation form the regional seal for this AU.

The Hosston Delta Oil and Gas AU encompasses the northern portions of the Mississippi Salt Basin, southern Alabama, a portion of the Florida Panhandle, and State waters. This AU includes fluvial-deltaic lithofacies of the Hosston Delta from the ancestral Mississippi River, plus the progradational shore zone facies further south and eastward to the State waters. The eastern boundary is defined by the geographic extent of known source rocks, which includes the underlying Smackover residing within the oil-generation window. The western boundary coincides with the transition to shore zone lithofacies and the northern boundary is defined by the change to coastal plain lithofacies. The geographic extent of salt weld terrain defines the southern boundary. Updip migration from oil-generating source rocks is through higher porosity-permeability pathways created by salt movement, especially through fault and fracture networks associated with salt welds. Trap architecture mainly involves anticline structural closures along with salt-drape and salt-diapir traps that occur throughout the AU, with limited instances of normal faulting traps in the northeastern area of the Mississippi Salt Basin. In general, stratigraphically thick Pettet carbonates form the regional seal.

The Hosston–Travis Peak Middip Gas and Oil AU is geographically extensive across the productive trend and encompasses northern portions of the Rio Grande Embayment, San Marcos Arch, northern Houston Embayment, Sabine Uplift area, North Louisiana Salt Basin, Monroe Uplift, southern portions of Mississippi Salt Basin, and territory basinward toward the Lower Cretaceous shelf margin. The extent of salt weld terrain defines the northern boundary. The Lower Cretaceous shelf margin and State waters delineate the southern boundary. The fluvial-deltaic lithofacies transition associated with the Rio Grande River system defines the western boundary. Reservoir lithofacies vary greatly across the geographic extent of this AU and include fluvial-deltaic sandstones, shore zone sandstones, pro-delta lithofacies, and organic-lean shelfal deposits. The Jurassic source system includes underlying thermally mature source rocks of the

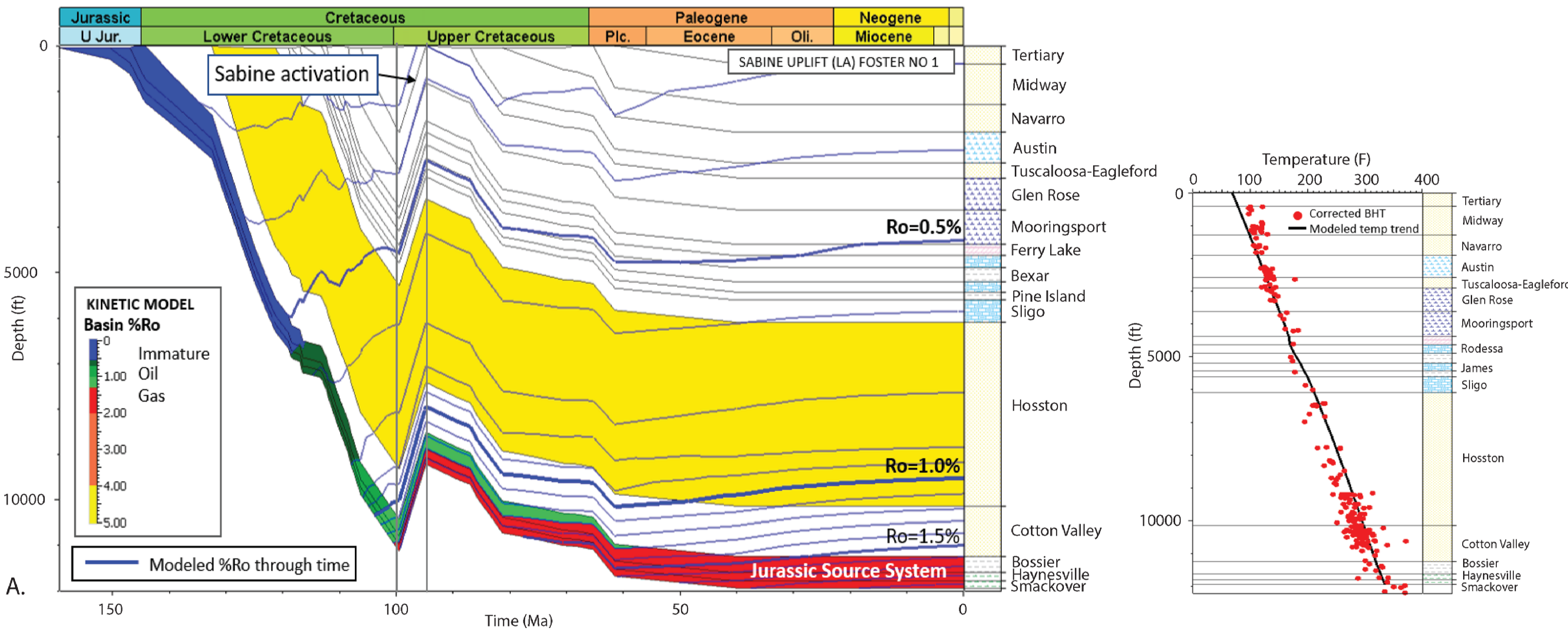


Figure 6A. Burial history model and associated temperature calibration data for Foster No. 1 well in the eastern Sabine Uplift area. Hosston is highlighted in yellow.

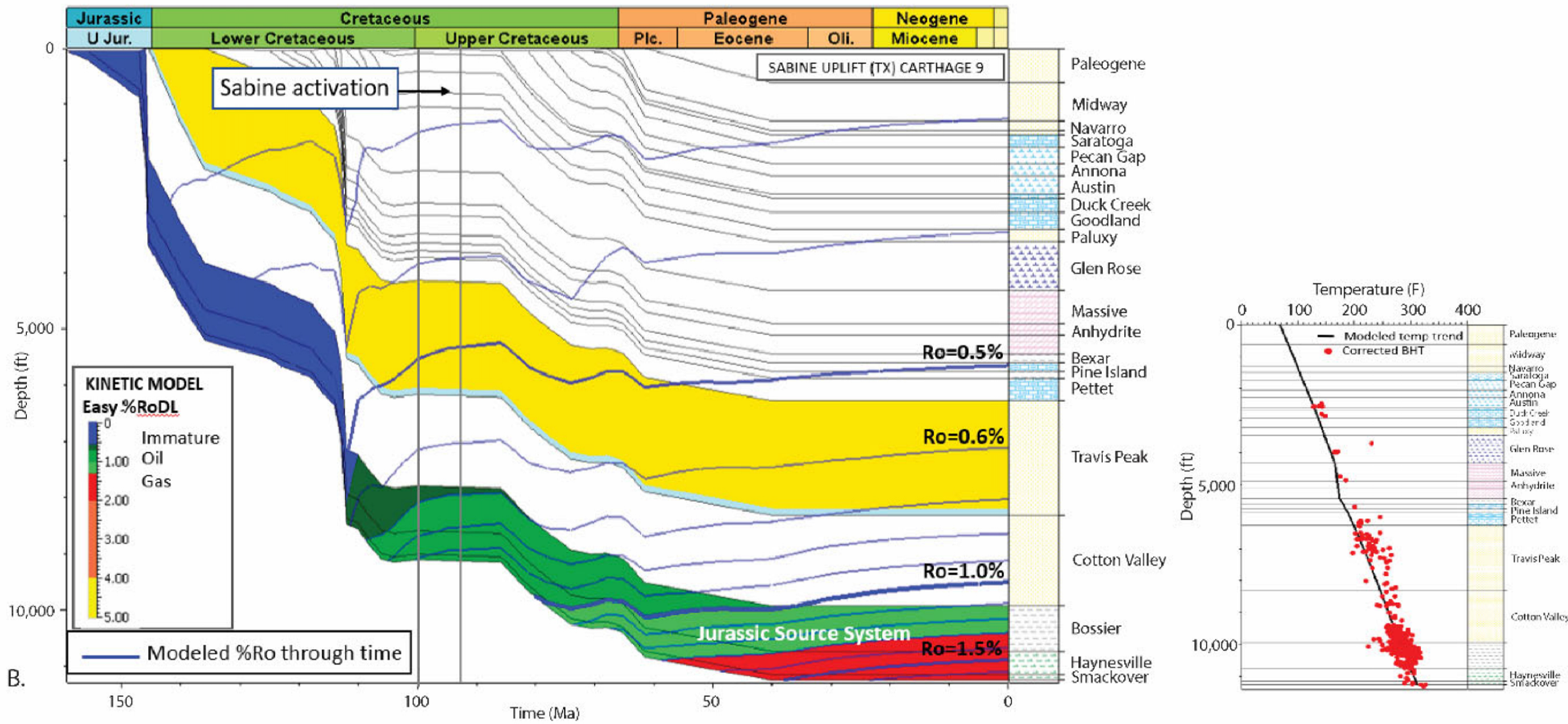


Figure 6B. Burial history model and associated temperature calibration data for Carthage No. 9 well in the western Sabine Uplift area. Travis Peak is highlighted in yellow.

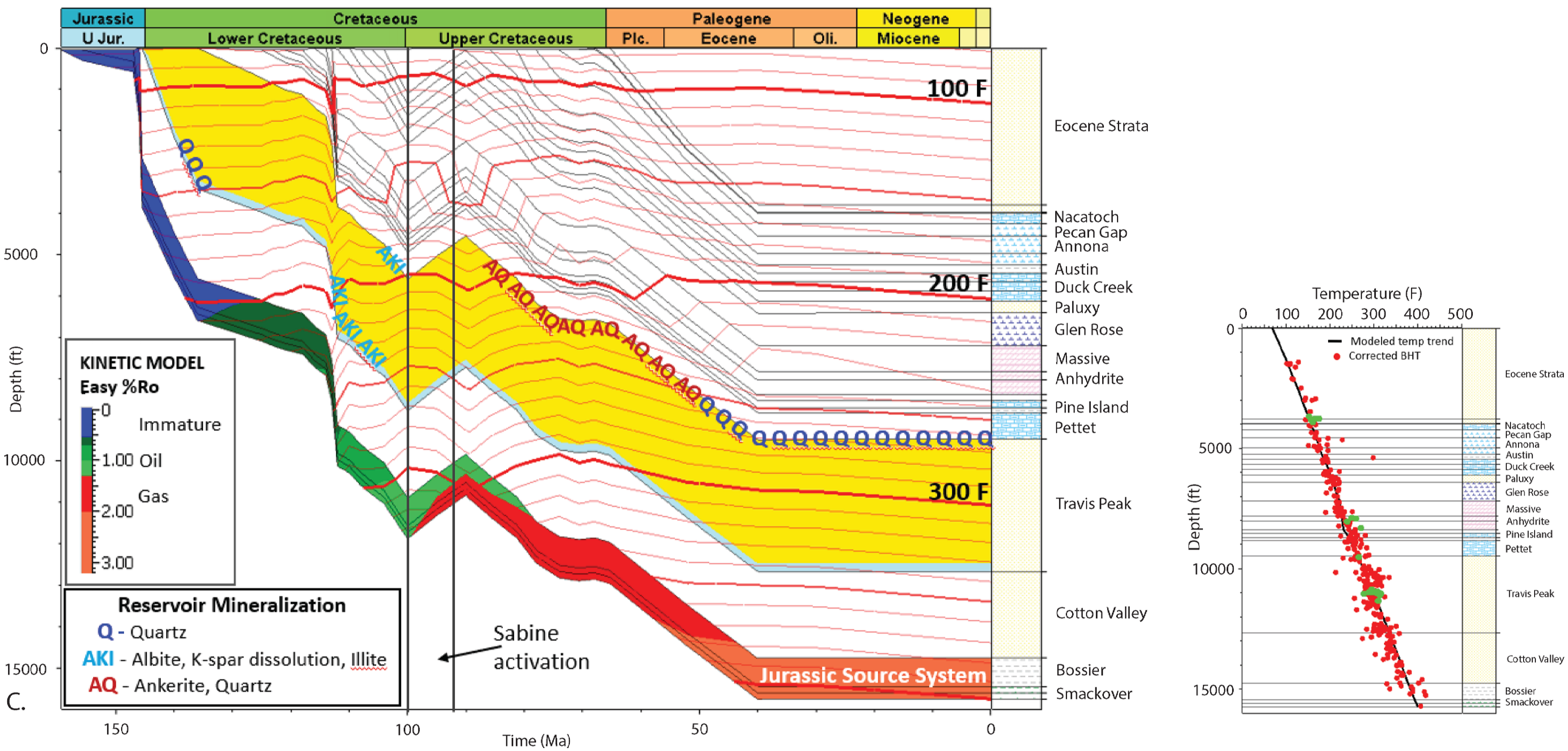


Figure 6C. Burial history model and associated temperature calibration data for Ashland No. 1 well in the East Texas Basin. Travis Peak is highlighted in yellow. Timing and depth of pore-occluding mineralization (modified after Dutton and Diggs [1992]) is denoted for quartz precipitation (Q), albite, potassium- feldspar dissolution, and illite formation (AKI), and ankerite and quartz precipitation (AQ).

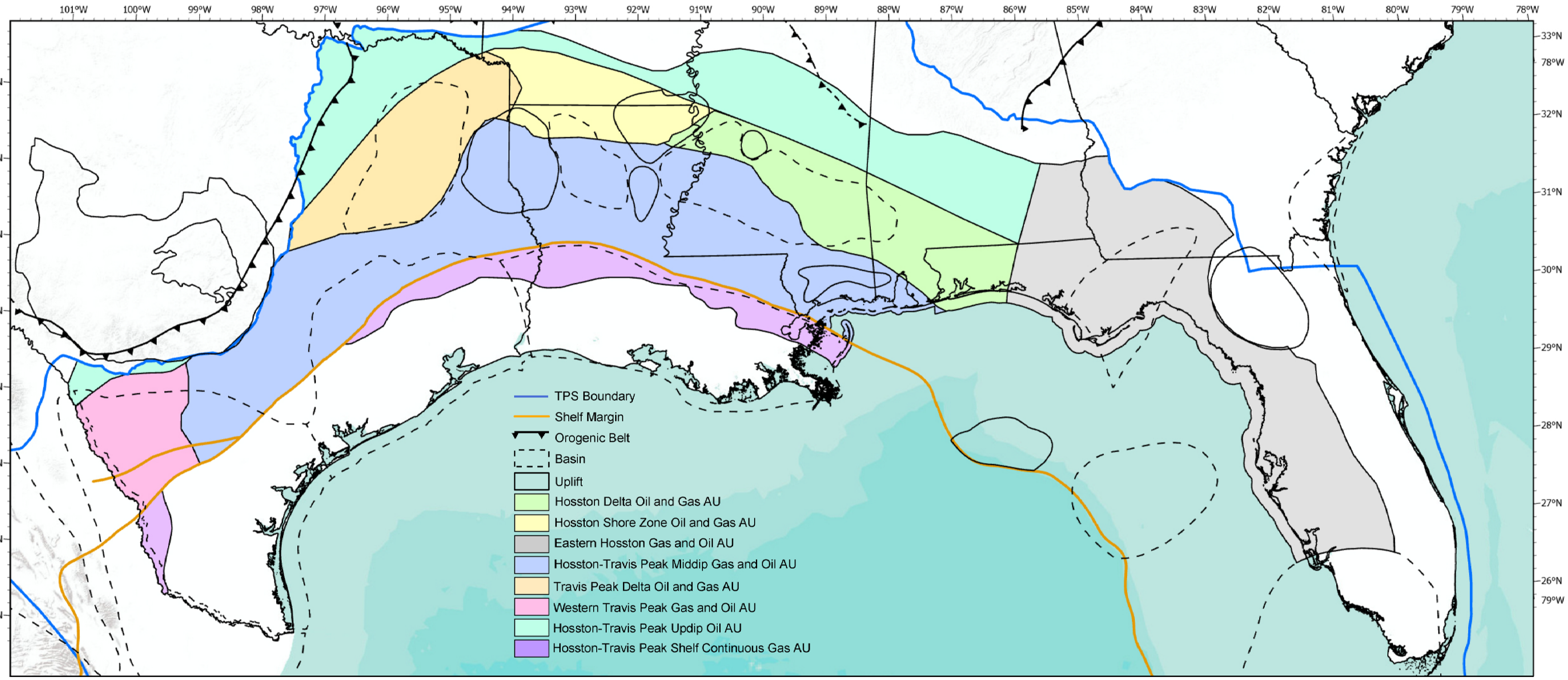


Figure 7. Hosston–Travis Peak Formation assessment units (AUs) within the Jurassic-Cretaceous-Tertiary composite total petroleum system (TSP; blue line) of the onshore Gulf Coast region. The fully risked, estimated mean totals for conventional and continuous oil and gas resources are 28 million barrels of oil, 35.8 trillion cubic ft of gas, and 156 million barrels of natural gas liquids. Further explanation for key input data and assessment results are provided in the USGS Fact Sheet (Burke et al., 2025a) and associated USGS Data Release (Burke et al., 2025b).

Smackover, Haynesville, and Bossier formations. Buoyant migration is through a variety of higher permeability conduits, including salt-related fracture networks and along regional fault zones. As a supplemental mechanism, spill and fill migration through HTP carrier beds may have occurred; the evidence is based on our observations of production data (co-location of oil and gas fields and intermixing of oil and gas production; see Figure 4), the complex oil-generation windows of the underlying Jurassic source system, and the API gravity data indicating migrated oils from multiple source rocks. Structural and stratigraphic traps occur across this AU, including anticline closure, normal fault-related, salt-drape, salt-diapir, and fluvial-deltaic structural traps. Regionally extensive carbonates of the Sligo and Pettet formations form the regional seal.

The Western Travis Peak Gas and Oil AU is located in the vicinity of the Rio Grande Embayment. Lithofacies include fluvial-deltaic, shore-zone, and shelf deposits. The northern AU boundary represents the lithofacies change from the Rio Grande fluvial-deltaic system to coastal plain lithofacies. The western boundary is the U.S.-Mexico border, which notably contains the ancestral Rio Grande depocenter. The eastern boundary is the downdip continuation of the lithofacies change from fluvial-deltaic and shore zone facies in the north and shelf to open-marine deposits further downdip. The Lower Cretaceous shelf margin forms the southern boundary. Source rocks are in the oil- and gas-window across this area. HTP strata were interpreted on regional seismic 2D lines in this area. However, well data are sparse to non-existent here. HTP reservoirs may have experienced localized erosion areas during the Valanginian sea-level minima and possibly again when the WIS connected to the Gulf of America watermass later in the Cretaceous. Buoyant migration of Smackover oils is through fault zones and fracture networks. Spill and fill migration may have also occurred through porous HTP carrier beds. A high probability for structural and stratigraphic traps, with less potential for salt-related traps, exists within this AU. A few dry holes have been drilled into the coastal plain lithofacies in the northern portion of the AU. However, proximity to the highly faulted orogenic belt may have enabled hydrocarbons to bypass through the HTP and ultimately accumulate in stratigraphically younger reservoirs further updip. Furthermore, in the northern portions of this AU, we posit that sealing Pettet carbonates may be thinner and more easily fractured due to shallower water depths and less accommodation space during deposition. Zero HTP wells have been drilled further south in this AU or near the depocenter, where the potential exists for a working petroleum system.

Eastern Hosston Gas and Oil AU includes southern Alabama, southwestern Georgia, the Florida panhandle to the Ocala Arch, the western Florida peninsula down to the South Florida Basin, and the associated State waters. The western AU boundary is defined by the geographic extent of known source rocks; the Smackover resides within the oil window in a small portion of the Florida panhandle. The northern boundary coincides with the TPS boundary. The Ocala Arch and Florida Peninsular Arch mark the eastern boundary. State waters and the South Florida Basin rim represent the southern boundary. Underlying thermally mature source rocks may be absent across the vast majority of this AU. One dry hole near the Grenville depocenter in Federal waters has been studied in conjunction with seismic data by Snedden and Galloway (2019). The potential exists for long-distance migration from the Smackover or active source rocks in the South Florida Basin, which was assessed by the USGS in 2016 and 2001 (Roberts-Ashby et al., 2016; Pollastro et al., 2001). Reservoir lithofacies may include coastal plain strata, fluvial-deltaic facies from the Peninsular River, and facies transitioning to shallow-water carbonates in southern Florida (Bovay, 2015; Snedden and Galloway, 2019). Sealing formations may include the carbonates of the Sligo and Pettet as well as numerous massive anhydrite seals as the depositional environment transitions from terrestrial to carbonate moving southward (for example, the Punta Gorda Anhydrite regional seal in South Florida Basin). Across this geographically extensive AU, numerous stratigraphic and structural traps are likely to exist.

The Hosston–Travis Peak Shelf Continuous Gas AU is bound by the Lower Cretaceous shelf margin to the north, State waters to the east, the international border in the west, and the 230°C isotherm representing the technically recoverable limit for continuous resources. All elements of a working petroleum system are present in this AU. The Smackover is within the gas-generation window throughout this AU. Based on my interpretations of the regional 2D seismic lines and corroborated by other published research (Snedden and Galloway, 2019), HTP-time equivalent strata exist on the slope and into the deep basin. Our geologic model predicts finer-grained, organic-lean mudstones and siltstones of continental origin in this AU. The potential exists for sand-rich basin floor fans that were sequestered down submarine canyons aligned with paleo-fluvial axes of the Rio Grande, Red, Mississippi, and Grenville Rivers. High-permeability fairways for migration of Smackover gas may include intrabasinal tectonic features identified on USGS Gulf Span 2D seismic lines, such as salt-detachment features and rotated fault blocks. The low-permeability matrix serves as the trapping and sealing mechanism for these continuous plays.

CONCLUSIONS AND ASSESSMENT RESULTS

Using a geologic-based methodology, the USGS quantitatively assessed undiscovered, technically recoverable resources within seven conventional and one continuous assessment units within the Lower Cretaceous Hosston–Travis Peak formations of the U.S. Gulf Coast region. The fully risked, estimated mean totals for conventional and continuous oil and gas resources are 28 million barrels of oil , with an F95–F5 range from13 to 59 million barrels of oil; 35.8 trillion cubic ft of gas, with an F95–F5 range from 8.8 to 74.85 trillion cubic ft of gas; and 156 million barrels of natural gas liquids, with an F95–F5 range from 40 to 336 million barrels of natural gas liquids. Further explanation of key input data and assessment results for each AU is provided in the USGS Fact Sheet 2025–3021 (Burke et al., 2025a) and associated USGS Data Release (Burke et al., 2025b). Data for this paper are located in the associated USGS Data Release (Burke, 2025).

ACKNOWLEDGMENTS

The authors wish to acknowledge the USGS Gulf Coast Geologic Energy and Assessment Research Team members and the USGS Central Energy Resources Science Center. The USGS Energy Resources Program provided all research funding.

NON-ENDORSEMENT

REFERENCES CITED

Bartberger, C. E., T. S. Dyman, and S. M. Condon, 2003, Potential for a basin-centered gas accumulation in Travis Peak (Hosston) Formation, Gulf Coast Basin, U.S.A.: U.S. Geological Survey Bulletin 2184-E, 18 p., <https://pubs.usgs.gov/bul/b2184-b>.

Birdwell, J. E., K. J. Whidden, S. T. Paxton, S. A. Kinney, R. D. Gardner, J. K. Pitman, K. L. French, T. J. Mercier, C. A. Woodall, H. M. Leathers-Miller, and C. J. Schenk, 2024, Assessment of undiscovered, technically recoverable conventional oil and gas resources in the Upper Jurassic Smackover Formation, U.S. Gulf Coast, 2022: U.S. Geological Survey Fact Sheet 2023–3046, 4 p., <https://doi.org/10.3133/fs20233046>.

Blakey, R. C. and W. D. Ranney, 2018, Ancient landscapes of western North America: a geologic history with paleogeographic maps, Springer, p. 103–130, <https://doi.org/10.1007/978-3-319-59636-5>.

Blum, M. and M. Pecha, 2014, Mid-Cretaceous to Paleocene North American drainage reorganization from detrital zircons: Geology, v. 42, p. 607–607, <https://doi.org/10.1130/G35513.1>.

Bovay, A. C., 2015, New models of early Cretaceous source-to-sink pathways in the eastern Gulf of Mexico: Austin, Texas: M.S. Thesis, University of Texas at Austin, 88 p.

Burke, L. A., O. N. Pearson, and S. A. Kinney, 2020, New method for correcting bottomhole temperatures acquired from wireline logging measurements and calibrated for the onshore Gulf of Mexico Basin, U.S.A.: U.S. Geological Survey Open-File Report 2019–1143, 12 p., <https://doi.org/10.3133/ofr20191143>.

Burke, L. A., 2025, USGS data release of geologic models underpinning the 2024 U.S. Geological Survey assessment of undiscovered oil, natural gas, geothermal, and CO2 storage resources in the Hosston and Travis Peak formations of the onshore Gulf Coast region, U.S.A.: U.S. Geological Survey Data Release, <https://doi.org/10.5066/P13TGX26>.

Burke, L. A., S. T. Paxton, S. A. Kinney, N. J. Gianoutsos, R. F. Dubiel, J. K. Pitman, C. J. Schenk, T. M. Mercier, P. A. Le, and H. M. Leathers-Miller, 2025a, U.S. Gulf Coast Petroleum Systems Project assessment of undiscovered oil and gas resources in the Lower Cretaceous Hosston and Travis Peak formations, U.S. Gulf Coast, 2024: U.S. Geological Survey Fact Sheet 2025–3021, 4 p., <https://doi.org/10.3133/fs20253021>.

Burke, L. A., S. T. Paxton, S. A. Kinney, N. J. Gianoutsos, R. F. Dubiel, J. K. Pitman, C. J. Schenk, T. M. Mercier, P. A. Le, and H. M. Leathers-Miller, 2025b, USGS National and Global Oil and Gas Assessment Project—Gulf Coast Mesozoic Province, Lower Cretaceous Travis Peak and Hosston formations: Assessment unit boundaries, assessment input forms, and fact sheet data tables: U.S. Geological Survey Data Release, <https://doi.org/10.5066/P1JPWRAY>.

Charpentier, R. R., and T. R. Klett, 2005, A Monte Carlo simulation method for the assessment of undiscovered, conventional oil and gas, *in* Petroleum systems and geological assessment of oil and gas in the southwestern Wyoming province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series DDS–69–D, 8 p., <https://certmapper.cr.usgs.gov/data/noga00/natl/text/CH_21.pdf>.

Denny, A. C., A. Fall, I. J. Orland, J. W. Valley, P. Eichhubl, and S. E. Laubach, 2020, A history of pore water oxygen isotope evolution in the Cretaceous Travis Peak Formation in East Texas: Geological Society of America Bulletin, v. 132, p. 1626–1638, <https://doi.org/10.1130/B35291.1>.

Dubiel, R. F., J. K. Pitman, O. N. Pearson, P. D. Warwick, A. W. Karlsen, J. L. Coleman, P. C. Hackley, D. O. Hayba, S. M. Swanson, R. R. Charpentier, T. A. Cook, T. R. Klett, R. M. Pollastro, and C. J. Schenk, 2007, Assessment of undiscovered oil and gas resources in Tertiary Strata of the Gulf Coast, 2007: U.S. Geological Survey Fact Sheet 2007–3066, 4 p., <https://pubs.usgs.gov/fs/2007/3066/pdf/FS07-3066_508.pdf>.

Dutton, S. P., and T. N. Diggs, 1992, Evolution of porosity and permeability in the Lower Cretaceous Travis Peak Formation, East Texas: American Association of Petroleum Geologists Bulletin Bull., v. 76, p. 252–269, <https://doi.org/10.1306/BDFF87C2-1718-11D7-8645000102C1865D>.

Dyman, T. S., and S. M. Condon, 2006, Assessment of undiscovered conventional oil and gas resources—Lower Cretaceous Travis Peak and Hosston formations, Jurassic Smackover Interior Salt Basins Total Petroleum System, in the East Texas Basin and Louisiana-Mississippi salt basins provinces: U.S. Geological Survey Digital Data Series DDS–69–E–5, 39 p., <https://doi.org/10.3133/ds69E_chapter5>.

Ewing, T. E., and W. E. Galloway, 2019, Evolution of the northern Gulf of Mexico sedimentary basin, *in* A. D. Miall, ed., The sedimentary basins of the United States and Canada (2nd ed.): Elsevier, p. 627–694, <https://doi.org/10.1016/B978-0-444-63895-3.00016-4>.

Galloway, W. E., 2008, Depositional evolution of the Gulf of Mexico sedimentary basin: Sedimentary Basins of the World, v. 5, p. 505–549, <https://doi.org/10.1016/S1874-5997(08)00015-4>.

Haq, B. U., 2013, Cretaceous eustasy revisited: Global and planetary change, v. 113, p. 44–58, <https://doi.org/10.1016/j.gloplacha.2013.12.007>.

Jackson, M. L. W., and S. E. Laubach, 1991, Structural history and origin of the Sabine Arch, East Texas and northwest Louisiana: Bureau of Economic Geology Geological Circular 91–3, 47 p.

Karlo, J. F., and R. C. Shoup, 2000, Classifications of syndepositional systems and tectonic provinces of the northern Gulf of Mexico: American Association of Petroleum Geologists Search and Discover Article 30004, <https://www.searchanddiscovery.com/documents/karlo/index.htm>.

Klett, T. R., J. W. Schmoker, and R. R. Charpentier, 2005, U.S. Geological Survey input-data form and operational procedure for the assessment of conventional petroleum accumulations, *in* Petroleum systems and geological assessment of oil and gas in the southwestern Wyoming province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series DDS–69–D, 10 p., <https://certmapper.cr.usgs.gov/data/noga00/natl/text/CH_20.pdf>.

Lander R. H., and S. E. Laubach, 2015, Insights into rates of fracture growth and sealing from a model for quartz cementation in fractured sandstones: Geological Society of America Bulletin, v. 127, p. 516–538, <https://doi.org/10.1130/B31092.1>.

Laubach, S. E., 1989, Fracture analysis of the Travis Peak Formation, Western flank of the Sabine Arch, East Texas: Bureau of Economic Geology Report of Investigations 185, 55 p.

Laubach, S. E., and M. L. Jackson, 1990, Origin of arches in the northwestern Gulf of Mexico Basin: Geology, v. 18, p. 595–598, <https://doi.org/10.1130/0091-7613(1990)018<0595:OOAITN>2.3.CO;2>.

Lopez, J. A., 1995, Salt tectonism of the U.S. Gulf Coast Basin: New Orleans Geological Society, scale 1:1,524,000. <https://archives.datapages.com/data/nogs/data/006/006034/pdfs/0001.pdf>.

Magoon, L. B., and J. W. Schmoker, 2000, The total petroleum system—The natural fluid network that constrains the assessment unit: U.S. Geological Survey Digital Data Series DDS–60, 30 p., <https://certmapper.cr.usgs.gov/data/PubArchives/wecont/chaps/ps.pdf>.

McFarlan, E., and L. S. Menes, 1991, Lower Cretaceous, *in* A. Salvador, ed., The geology of North America, v. J: The Gulf of Mexico Basin: Geological Society of America, p. 181–204, <https://doi.org/10.1130/DNAG-GNA-J.181>.

Mueller, P. A., A. L. Heatherington, D. A. Foster, W. A. Thomas, and J. L. Wooden, 2014, The Suwannee suture: significance for Gondwana-Laurentia terrane transfer and formation of Pangaea: Gondwana Research, v. 26, p. 365–373, <https://doi.org/10.1016/j.gr.2013.06.018>.

Paxton, S. T., 2022, Subcrop map series of Travis Peak and Hosston formations based on formation tops from S&P Global Commodity Insights, 2024: Written communication, June 17, 2022.

Paxton, S. T., J. K. Pitman, S. A. Kinney, N. J. Gianoutsos, O. N. Pearson, K. J. Whidden, R. F. Dubiel, C. J. Schenk, L. A. Burke, T. R. Klett, H. M. Leathers-Miller, T. J. Mercier, S. S. Haines, B. A. Varela, P. A. Le, T. M. Finn, S. B. Gaswirth, S. J. Hawkins, K. R. Marra, and M. E. Tennyson, 2017a, Assessment of undiscovered oil and gas resources in the Bossier Formation, U.S. Gulf Coast, 2016: U.S. Geological Survey Fact Sheet 2017–3015, 2 p., <https://doi.org/10.3133/fs20173015>.

Paxton, S. T., J. K. Pitman, S. A. Kinney, N. J. Gianoutsos, O. N. Pearson, K. J. Whidden, R. F. Dubiel, C. J. Schenk, L. A. Burke, T. R. Klett, H. M. Leathers-Miller, T. J. Mercier, S. S. Haines, B. A. Varela, P. A. Le, T. M. Finn, S. B. Gaswirth, S. J. Hawkins, K. R. Marra, and M. E. Tennyson, 2017b, Assessment of undiscovered oil and gas resources in the Haynesville Formation, U.S. Gulf Coast, 2016: U.S. Geological Survey Fact Sheet 2017–3016, 2 p., <https://doi.org/10.3133/fs20173016>.

Pollastro, R. M., C. J. Schenk, and R. R. Charpentier, 2001, Assessment of undiscovered oil and gas in the onshore and state waters portion of the South Florida Basin, Florida—USGS Province 50: U.S. Geological Survey Digital Data Series 69–A, 75 p., <https://certmapper.cr.usgs.gov/data/noga00/prov50/text/pr50_2001.pdf>.

Roberts-Ashby, T. L., P. C. Hackley, C. D. Lohr, C. J. Schenk, T. J. Mercier, K. J. Whidden, P. A. Le, M. E. Tennyson, S. B. Gaswirth, C. A. Woodall, M. E. Brownfield, H. M. Leathers-Miller, K. R. Marra, and T. M. Finn, 2016, Assessment of undiscovered oil and gas resources in the South Florida Basin, 2016: U.S. Geological Survey Fact Sheet 2018–3074, 4 p., <https://doi.org/10.3133/fs20183074>.

S&P Global Commodity Insights, 2024, Enerdeq US well history and production database: S&P Global Commodity Insights, <https://spglobal.com/commodityinsights>. [Available from S&P Global Commodity Insights, 15 Inverness Way East, Englewood, CO 80112.]

Salvador, A., 1991, Origin and development of the Gulf of Mexico Basin, *in* A. Salvador, ed., The geology of North America, v. J: The Gulf of Mexico Basin: Geological Society of America, p. 389–444, <https://doi.org/10.1130/DNAG-GNA-J.389>.

Schmoker, J. W., 2005, U.S. Geological Survey assessment concepts for continuous petroleum accumulations, *in* Petroleum systems and geological assessment of oil and gas in the southwestern Wyoming province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series DDS–69–D, 10 p., <https://certmapper.cr.usgs.gov/data/noga00/natl/text/CH_13.pdf>.

Schmoker, J. W., and T. R. Klett, 2005, U.S. Geological Survey assessment concepts for conventional petroleum accumulations, *in* Petroleum systems and geological assessment of oil and gas in the southwestern Wyoming province, Wyoming, Colorado, and Utah: U.S. Geological Survey Digital Data Series DDS–69–D, 9 p., <https://certmapper.cr.usgs.gov/data/noga00/natl/text/CH_19.pdf>.

Snedden, J. W., and W. E. Galloway, 2019, The Gulf of Mexico sedimentary basin—Depositional evolution and petroleum applications: U.K., Cambridge University Press, 326 p., <https://doi.org/10.1017/9781108292795>.

Warwick, P. D., A. W. Karlsen, J. L. Coleman, P. C. Hackley, D. O. Hayba, and S. M. Swanson, 2007, Assessment of undiscovered oil and gas resources in Tertiary strata of the Gulf Coast, 2007: U.S. Geological Survey Fact Sheet 2007–3066, 4 p., <https://pubs.usgs.gov/fs/2007/3066/pdf/FS07-3066_508.pdf>.

Whidden, K. J., J. E. Birdwell, R. D. Gardner, S. A. Kinney, S. T. Paxton, J. P. Pitman, and C. J. Schenk, 2023, Assessment of continuous oil and gas resources in the Upper Jurassic Smackover Formation of the onshore U.S. Gulf Coast, 2022: U.S. Geological Survey Fact Sheet 2023–3021, 4 p., <https://doi.org/10.3133/fs20233021>.

Yamin, L., 2007, Evaluation of Travis Peak gas reservoirs, west margin of the East Texas Basin: M.S. Thesis, Texas A&M University, 116 p.