Reservoir characterization, modeling, and evaluation of Upper Jurassic Smackover microbial carbonate and associated facies in Little Cedar Creek field, southwest Alabama, eastern Gulf coastal plain of the United States

Sharbel Al Haddad and Ernest A. Mancini

ABSTRACT

An integrated field study of the microbial carbonate and associated reservoirs at Little Cedar Creek field in southwest Alabama, eastern Gulf coastal plain of the United States, provides an excellent opportunity to examine the spatial distribution of the sedimentary, petrophysical, and productivity trends in microbial reservoirs. This study includes characterizing the sedimentary, petrophysical, and hydrocarbon productivity characteristics of microbialites, developing a three-dimensional geologic reservoir model, and evaluating the hydrocarbon potential of these reservoirs. The lower reservoir comprises subtidal thrombolitic boundstone associated with microbial buildups oriented in a southwest to northeast direction over an area that encompasses 32 mi^2 (83 km^2). These buildups developed in clusters in the western, central, and northern parts of the field and attained thicknesses of 43 ft (13 m). The clusters are separated by interbuildup areas of microbialites of 7–9 ft (2–3 m) in thickness that are overlain by a thick section of nonreservoir microbially influenced lime mudstone and wackestone. Porosity in the microbial reservoirs includes depositional constructed void (intraframe) and diagenetic solution-enhanced void and vuggy pore types. This pore system provides for high permeability and connectivity in the reservoir beds. Permeability ranges to as much as 7953 md and porosity to as much as 20%. The

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microbial boundstone beds have high potential as hydrocarbon flow units; however, the buildup areas are separated by interbuildup areas associated with a thick section of low-permeability to nonreservoir beds that serve as potential baffles or barriers to flow. Much of the 17.2 million bbl oil produced from the field is from the microbial lithofacies. The results from the Little Cedar Creek field study have application in the design of improved development strategies for other fields producing from microbial carbonate reservoirs.

INTRODUCTION

With the recent discovery of microbial carbonate reservoirs along the South Atlantic margin, new emphasis is being given to further our understanding of the origin and development of microbial buildups, the nature of microbialite and associated facies, and the reservoir characteristics of microbial carbonate facies. Industry is particularly interested in the predictability of the spatial distribution of reservoir facies and their sedimentary, petrophysical, and hydrocarbon productivity characteristics and the ability to model trends in reservoir heterogeneity. In this regard, Upper Jurassic (Oxfordian) Smackover (Figure 1) microbial buildups are known to be productive oil and gas reservoirs in the eastern Gulf coastal plain of the United States. The hydrocarbon reservoir potential of these microbial carbonate facies was first recognized by Baria et al. (1982) and Crevello and Harris (1984). The sedimentary and reservoir characteristics of these deposits have been described by Markland (1992), Benson et al. (1996), Kopaska-Merkel (1998), Hart and Balch (2000), Parcell (2000), Mancini and Parcell (2001), Llinas (2004), Mancini et al. (2004b), Mancini et al. (2008), Ridgway (2010), Al Haddad (2012), and Mostafa (2013).

Mancini et al. (2004b) reported that Smackover microbial buildups commonly developed on elevated Paleozoic crystalline (igneous and metamorphic) paleotopographic features. These microbialites are commonly directly overlain by high-energy, nearshore, and shoal facies forming the Smackover boundstone-grainstone and packstone reservoir, and this Smackover reservoir is overlain by Buckner anhydrite beds of the Haynesville Formation (Benson et al., 1996). The anhydrites serve as the petroleum seal beds for these combination structural-stratigraphic traps, and the trapped hydrocarbons are sourced from Smackover basinal laminate beds that are rich in amorphous and microbial kerogen (Mancini et al., 2004b).

The exploration strategy to locate and delineate these microbial buildups has generally focused on identifying the paleotopographic highs associated with Paleozoic crystalline basement rocks on which the microbialites nucleated and developed (Mancini et al., 2004b). The use of three-dimensional (3-D) seismic reflection data provides the technology to identify the paleotopographic anomalies as exploration targets (Hart and Balch, 2000). The data are further used to predict whether potential reservoir facies developed on the crest or

System	Series	Group	Formation - Member
Cretaceous	Lower Cretaceous	Cotton Valley	Schuler Formation
Jurassic	Upper Jurassic		
		Louark	Haynesville Formation
			Buckner Member
			Smackover Formation
			Norphlet Formation
	Middle Jurassic		Louann Salt
			Werner Formation

Figure 1. Jurassic stratigraphy for southwest Alabama, eastern Gulf Coastal Plain.

flanks of a particular paleohigh. Unfortunately, the reservoirs discovered using this strategy, such as Appleton and Vocation fields (Figure 2), have produced less than 3 million bbl oil from 10 or fewer wells per field (Mancini et al., 2004b; field production records of the State Oil and Gas Board of Alabama [SOGBA], 2013a). Thus, the ability to study variation in the reservoir properties of microbialites and associated facies is limited.

However, with the discovery and subsequent continued development of Little Cedar Creek field in Conecuh County, southwest Alabama, an excellent opportunity to study the spatial distribution of sedimentary, petrophysical, heterogeneity, and productivity trends in microbial carbonate reservoirs is available. Little Cedar Creek field encompasses an area of 32 mi^2 (83 km^2) (Figure 3). Wire-line logs from 112 wells from the field area and core data for most of the wells drilled in the field area are available for this study.

The field was discovered by Hunt Oil Company in 1994 with the drilling and testing of the Hunt Oil Company 30–1 Cedar Creek Land and Timber Company well (SOGBA permit 10560). The well tested from perforations at 11,870–11,883 ft (3618–3622 m) in the upper reservoir in the Smackover Formation at 108 BOPD of 45° API oil. The SOGBA established the field in 1995. It was not until 2000 that a second well, Midroc Oil Company 19–5 Cedar Creek Land and Timber Company (11963), was drilled and tested at 250 BOPD. A third well, Midroc 20–12 Cedar Creek Land and Timber Company (12872) was drilled, cored, and tested (365 BOPD) in 2003. In December 2004, the western part of the Little Cedar Creek field was unitized with prospects for secondary recovery by waterflood and with an effective date of January 1, 2005. Midroc contracted with Pruet Production Company to operate its wells in the field in 2011. According to the field production records of the SOGBA, production from Little Cedar Creek field is 17.2 million bbl oil and 18.8 mmcf of natural gas with 92 wells producing from the upper and lower reservoirs as of January 2013.

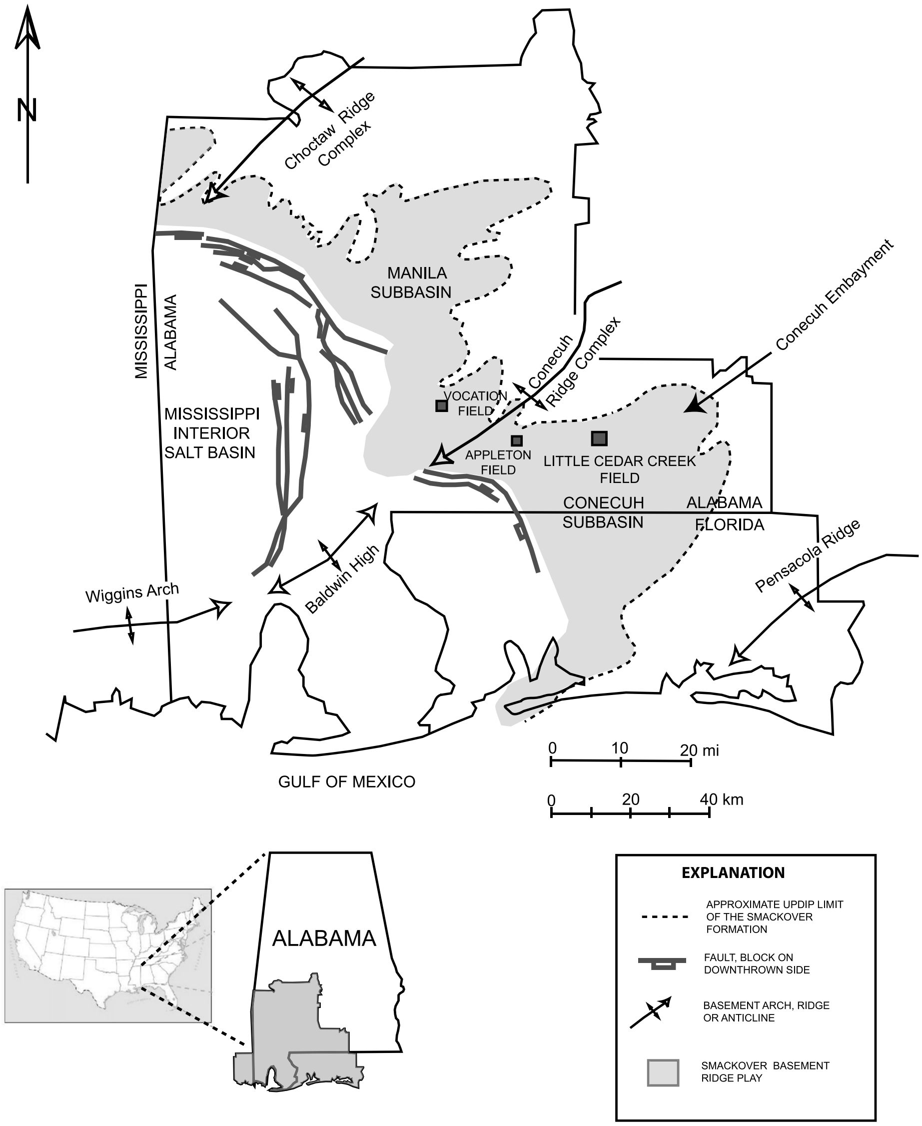
The description and characterization of the carbonate rocks in cores from early drilling in the field by Midroc provided evidence that the Smackover reservoirs in this field included microbialites (lower reservoir) and carbonate sand bodies (upper reservoir) associated with the approximate updip limit of Smackover deposition. Geologic studies of the field showed that these deposits did not accumulate directly on a localized Paleozoic basement paleohigh (Mancini et al., 2008).

The objective of this article is to present the results from an integrated field study of the microbial carbonate and associated reservoirs at Little Cedar Creek field to further the understanding of the spatial distribution of the sedimentary characteristics of microbial carbonate lithofacies; the petrophysical properties of microbial reservoirs; and the variability in the heterogeneity, connectivity, and productivity of microbial reservoirs. This field study includes characterizing the sedimentary, petrophysical, and hydrocarbon productivity characteristics of the reservoirs, developing a 3-D geologic reservoir model, and evaluating the hydrocarbon potential of these reservoirs to increase production from the field.

DEPOSITIONAL SETTING

The geologic history of the Little Cedar Creek field area is directly related to the evolution of the Conecuh embayment and the Conecuh ridge complex to the northwest and west and Pensacola ridge to the southeast and east of this embayment (Figure 2). These Paleozoic ridges are associated with the Appalachian structural trend and were paleohighs at the time of Smackover deposition (Mancini et al., 2004b). These ridges served as barriers

Figure 2. Location map showing major structural features in southwest Alabama, approximate updip limit of Smackover deposition, and the location of Appleton, Vocation, and Little Cedar Creek fields (modified from Mancini et al., 2008).



to ocean currents and wave energy producing a protected and at times restricted embayment area near the Smackover shoreline in the northern part of the Conecuh embayment area.

In this Conecuh embayment area, Smackover carbonates were deposited in an inner carbonate ramp setting, for the most part, under tranquil conditions in bays and lagoons subjected to periodic influxes of freshwater, terrestrial plant material, and terrigenous clay and silt (Figure 4). The distal part of the Smackover carbonate ramp has been described by Tew et al. (1993) from the offshore Alabama area south of the Wiggins arch.

In the Little Cedar Creek field area, late Oxfordian Smackover deposition (Figures 5, 6) began with a marine transgression resulting in the accumulation of subtidal lime mudstone and wackestone that disconformably overlie Norphlet alluvial and fluvial breccias, conglomerates, and sandstones (Mancini et al., 2008). The development of microbial carbonate buildups occurred in the early part of this marine transgression with microbe nucleation on localized firm to hard surfaces associated with wackestone to packstone deposition. The microbial (thrombolite, having a peloidal clotted fabric) boundstone buildups exhibit a southwest to northeast trend in the Little Cedar Creek field. The buildups are concentrated in three main areas of the field: western (field area approximately west of the R12E–R13E line), central (field area approximately east of the R12E–R13E line and south of the northern limit of the upper reservoir), and northern (essentially the field area north of the limit of the upper reservoir) parts (Figure 3). The greatest

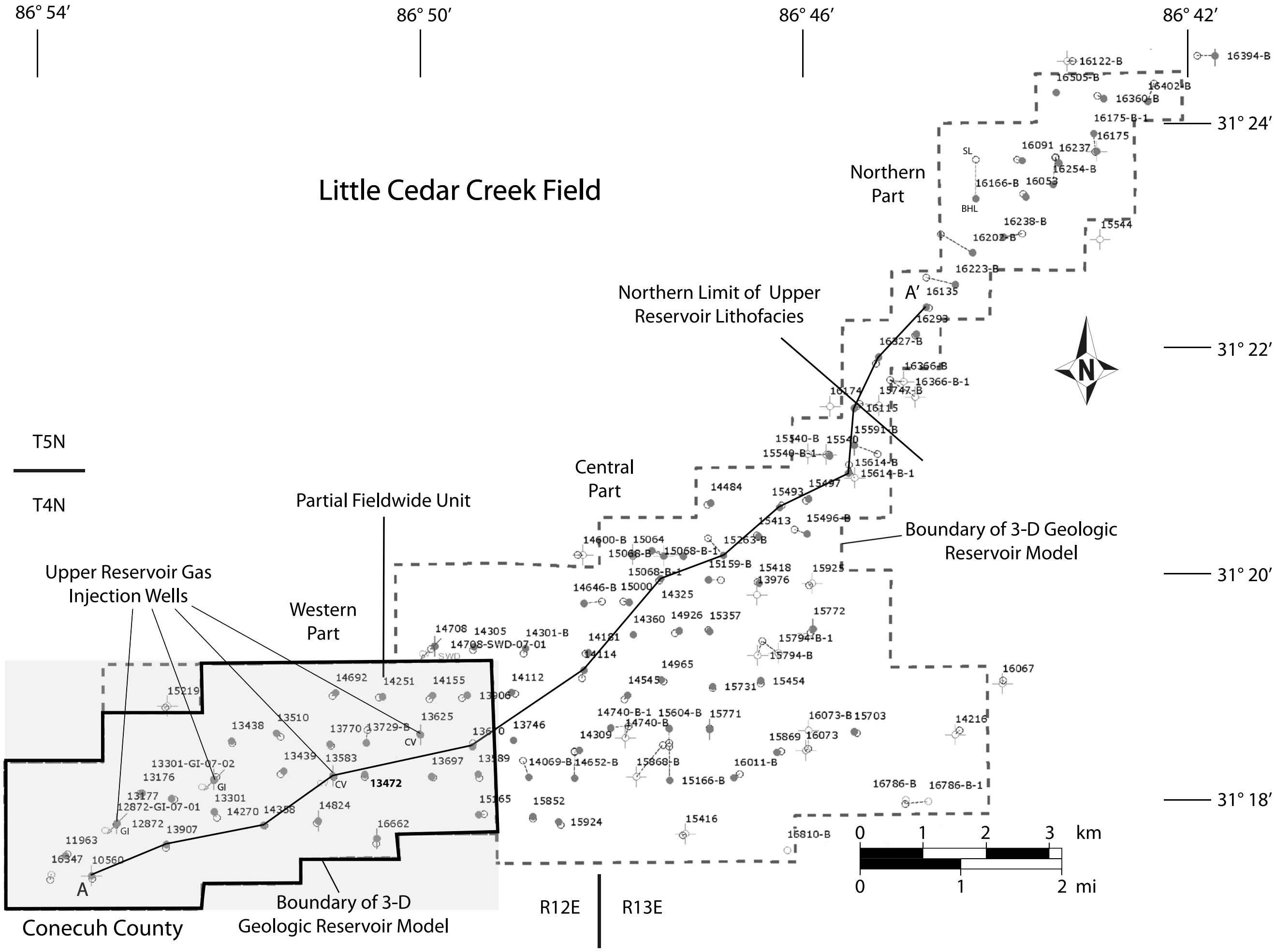


Figure 3. Location map for Little Cedar Creek field, partial fieldwide unit, outline of the boundary for the geologic model and field (modified from the Little Cedar Creek field map of the State Oil and Gas Board of Alabama, 2013b). The boundary for the three-dimensional (3-D) geologic reservoir model essentially corresponds to the field boundary (dashed line), which includes, in part, the boundary of the partial fieldwide unit (solid line) where this boundary is in common with the field boundary. Wells are identified by State Oil and Gas Board of Alabama permit numbers, such as the Midroc 22–2 Pugh well (13472). Note the line of section for stratigraphic cross section AA′, the location of well 13472, the approximate northern limit of the upper reservoir lithofacies, and the locations for the gas injection wells for the upper reservoir (S-3). GI = gas injection well; CV = conversion to gas injection well; SWD = salt-water disposal well; SL = surface location of well (unfilled circle); and BHL = bottom-hole location of well.

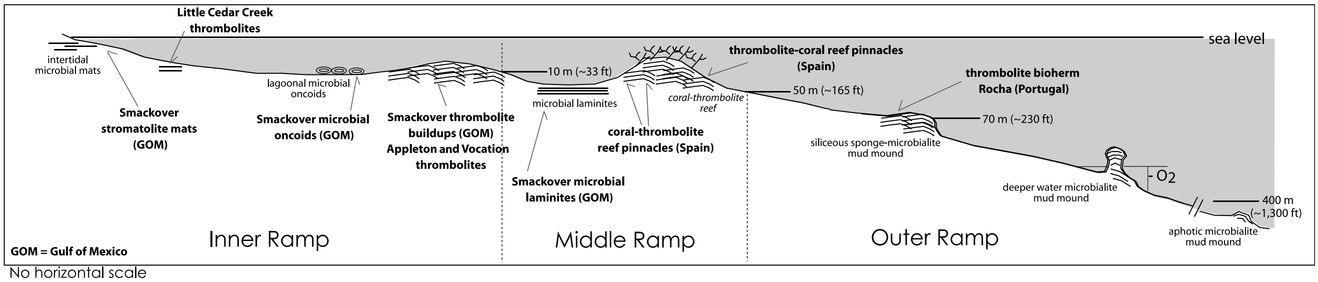
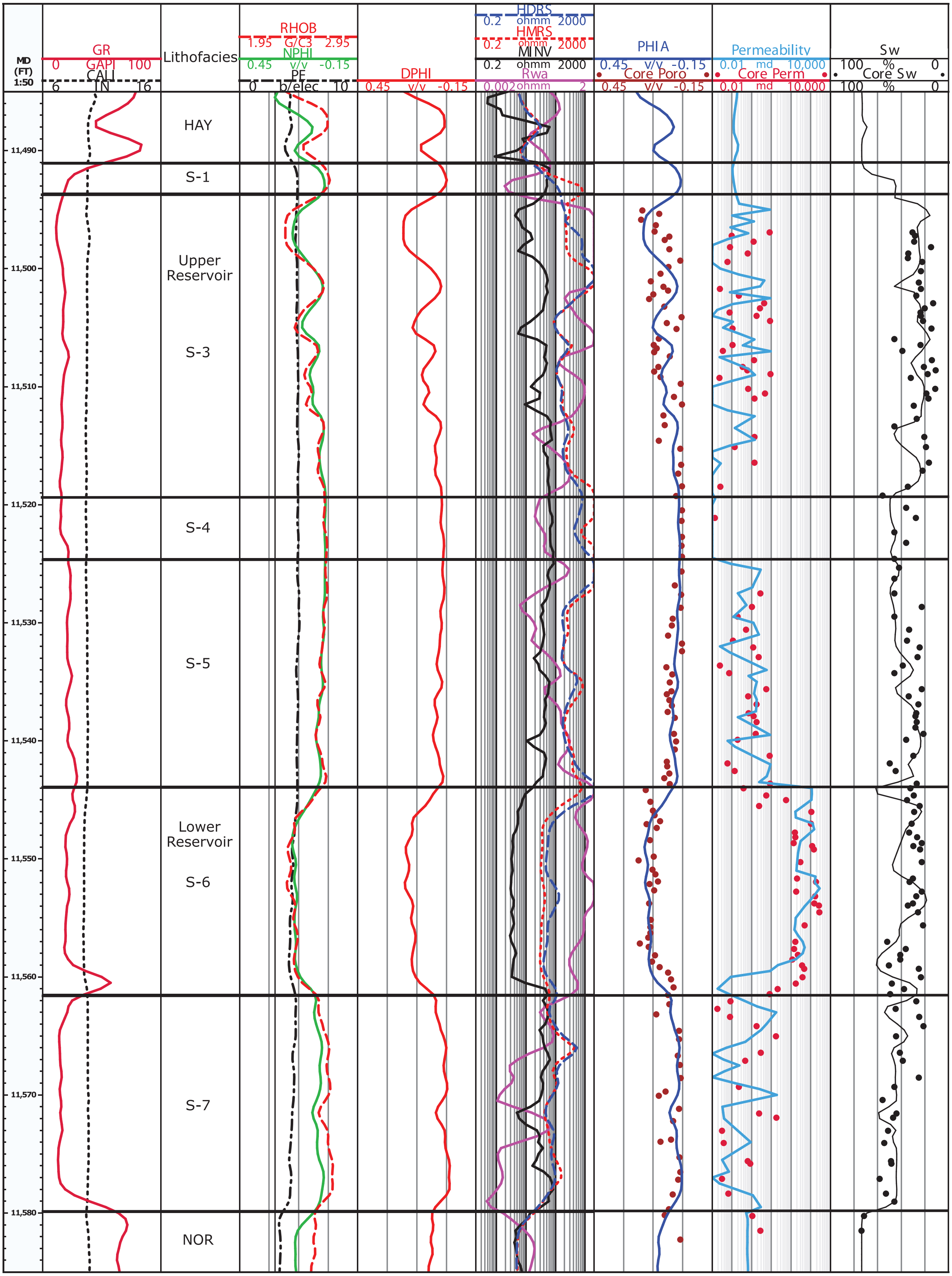


Figure 4. Generalized bathymetric diagram illustrating the distribution of microbial buildups on a carbonate ramp surface (modified from Mancini et al., 2004b). Note the inner to middle ramp settings for Upper Jurassic Smackover microbial growth and development in the northeastern Gulf of Mexico.


MD (FT) 1:50
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CALI
6 IN 16
Lithofacies
RHOB
1.95 G/C3 2.95
NPHI
0.45 v/v -0.15
PE
0 b/elec 10
DPHI
0.45 v/v -0.15
HDRS
0.2 ohmm 2000
HMRS
0.2 ohmm 2000
MINV
0.2 ohmm 2000
Rwa
0.002 ohmm 2
PHIA
0.45 v/v -0.15
Core Poro
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Permeability
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11,490
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HAY
S-1
Upper Reservoir
S-3
S-4
S-5
Lower Reservoir
S-6
S-7
NOR

areal distribution of microbial buildup is in the western part of the field (Figures 6B, 7). Buildups reach a thickness of 43 ft (13 m) in the field, whereas interbuildup areas are characterized by thicknesses of some 7–9 ft (2–3 m) of microbialite. With a combination of a reduction in the rate of sea level rise and influx of freshwater and clay and silt particles, microbial buildup slowed. Bioturbation of microbially influenced packstone beds capping the buildups followed, primarily in the western part of the field. The interbuildup areas are characterized by a thick section of microbially influenced lime mudstone and wackestone overlying the bioturbated packstone in much of the field. Lime mudstone of the microbially influenced beds directly overlies the boundstone of the microbial buildup lithofacies in the northern part of the field (Figure 7). Subtidal deposition continued with the accumulation of wackestone and lime mudstone. The subtidal wackestone-packstone-grainstone sequences overlying the lime mudstone and wackestone lithofacies represent a shift from transgression to regression and progradation in Smackover deposition in the embayment area (Mancini et al., 2008). With the loss of accommodation space and continued decrease in the rate of sea level rise, water depths decreased in this subtidal setting to the point where local marine currents and tides and wind patterns could produce a series of progradational ooid and peloid sand bodies in a carbonate bank setting. These marine carbonate sand belt buildups comprise as much as six wackestone-packstone-grainstone sequences (Figure 5). These features are characterized by an upper to middle buildup facies of ooid and peloidal grainstone to packstone, a lower margin buildup facies of peloidal packstone, and an interbuildup facies of wackestone. The carbonate bank complex extends from the western part of the field to the central part in a southwest to northeast direction. Buildup formation was best developed in the western and south-central parts of the field (Figures 6A, 7). Buildups attain a thickness of 26 ft (8 m) in the field. Interbuildup areas are characterized by a thickness of 4–8 ft (1–2 m) of packstone underlain by a thick section of wackestone. Carbonate bank facies have not been observed in the northern part of the field, suggesting that in this area, depositional conditions were not conducive for sand body accumulation or preservation (Figure 7). The carbonate bank deposits are overlain by peritidal lime mudstone that accumulated in bay and lagoonal environments. Tidal channels characterized by rudstone and floatstone occurred in this setting in association with the peritidal deposits (Ridgway, 2010). The Smackover peritidal carbonates are overlain by Haynesville argillaceous and andydrite beds (Mancini et al., 2008).

METHODOLOGY

Well logs, directional surveys, whole cores, conventional core analysis data, and well production information are used in this study and are available through the SOGBA. Because of seismic resolution issues caused by the reservoir thickness (4–43 ft [1–13 m]), operators in the field have developed the field based on a rigorous well coring program and without the use of extensive seismic data. Core and thin-section description in combination with gamma-ray signature, porosity and permeability values, and the relative position of the density and neutron porosity curves are used in characterizing the lithofacies in the Little Cedar Creek field (Figure 5).

Results from the formation evaluation and reservoir characterization studies are used to build the static model and to populate the grid with the petrophysical facies and lithofacies, which are a result of depositional and diagenetic processes. The stratigraphic grid is built to honor the geologic characteristics observed in the information and data from the field. Vertical facies trend curves and petrophysical data (porosity, permeability, and water saturation) are used in the modeling of the geologic properties.

Figure 5. Wireline-log suite for the Midroc 22–2 Pugh well, 13472, Little Cedar Creek field, illustrating the signatures for the Haynesville Formation (HAY), the Smackover lithofacies, S-1 to S-7, and the Norphlet Formation (NOR); comparison of porosity derived from core analysis compared to well-log analysis; comparison of permeability derived from core analysis compared to well-log analysis and use of neural networks; and comparison of water saturation derived from core analysis compared to well-log analysis and use of neural networks. S-1 = peritidal lime mudstone-dolomudstone and wackestone; S-3 = nearshore carbonate bank grainstone and packstone sand bodies and interbuildup wackestone; S-4 = subtidal wackestone and lime mudstone; S-5 = subtidal microbially influenced packstone, wackestone, and lime mudstone; S-6 = microbial (thrombolite) boundstone; and S-7 = transgressive lime mudstone-dolomudstone and wackestone. GR = gamma ray; CALI = caliper; RHOB = density; NPHI = neutron porosity; PE = photoelectric effect; DPHI = density porosity; HDRS = deep induction; HMRS = medium induction; MINV = microinverse resistivity; Rwa = water resistivity; PHIA = average porosity; and SW = water saturation. Note vertical heterogeneity in the sedimentary and petrophysical properties in the vertical sequence of the carbonate sand bodies in the upper reservoir (S-3). This well is located in Figure 3.

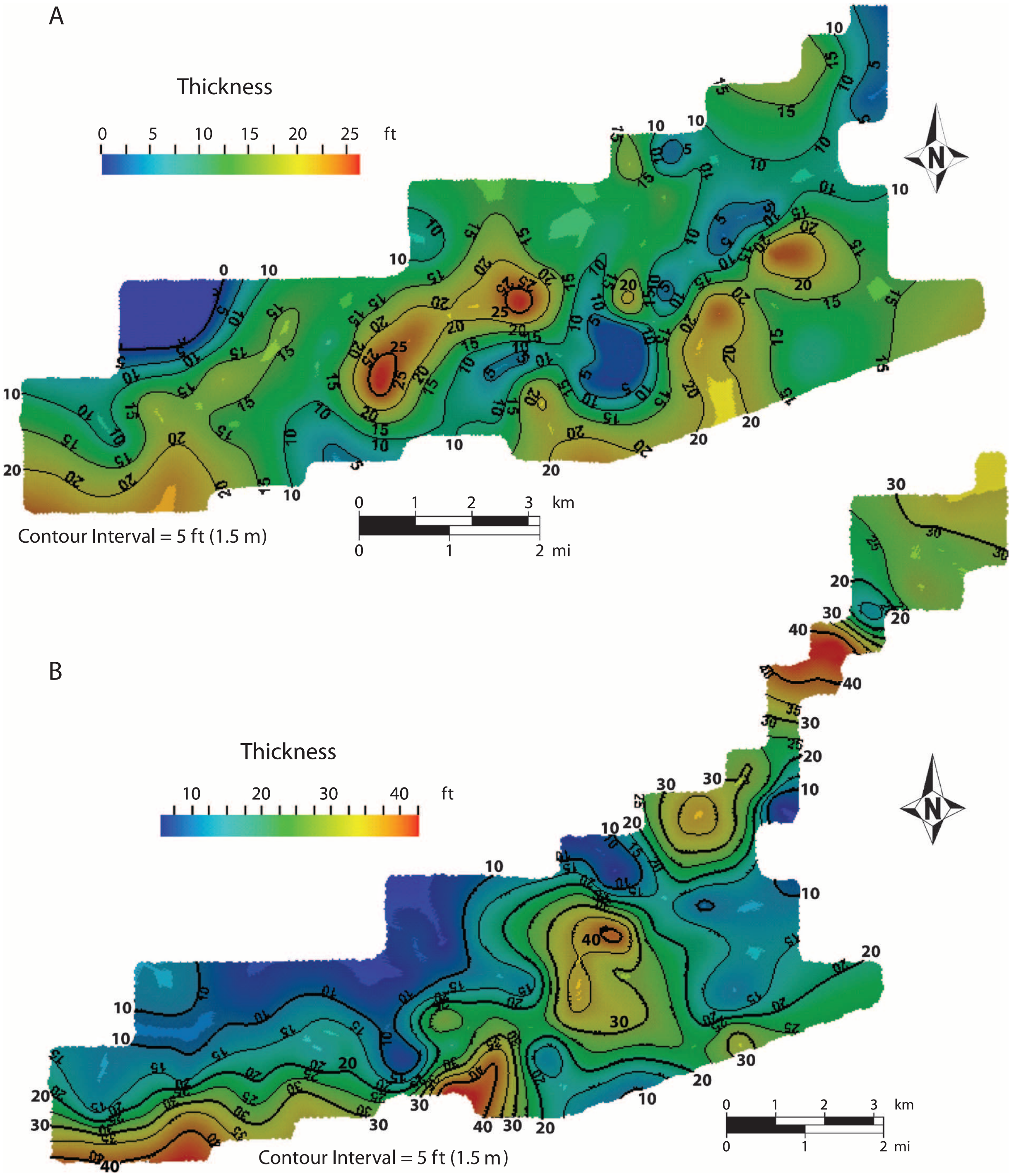

Figure 6. Thickness maps of the (A) upper grainstone-packstone reservoir (S-3) and (B) lower microbial boundstone reservoir (S-6). Note the southwest to northeast orientation of the S-6 reservoir as exhibited in clusters of microbial (thrombolite) boundstone buildups in three field areas, western, central, and northern parts of the field, and the thickness of as much as 43 ft (13 m) of boundstone in the microbial buildup areas. The orientation of the S-3 reservoir is shown in a series of progradational sand bodies in this carbonate bank setting from the western part of the field to the central part in a southwest to northeast direction and the thickness of as much as 26 ft (8 m) of grainstone-packstone in the marine carbonate sand belt buildup areas.

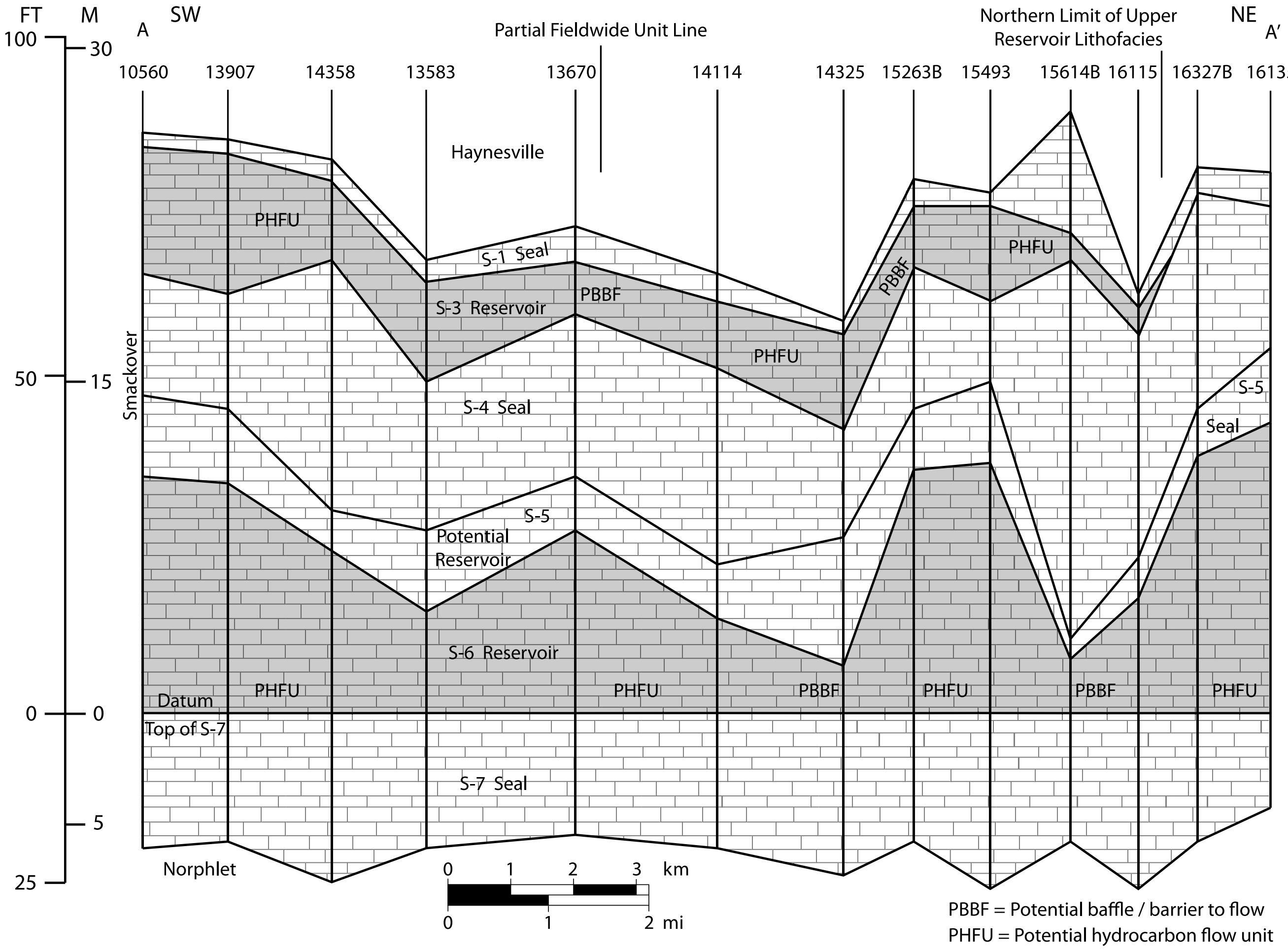

Figure 7. Stratigraphic cross section AA′ illustrating the areas of maximum extent and buildup of the marine carbonate sand belt buildups and interbuildup areas, the areas of maximum extent and buildup of microbial buildups and interbuildup areas, and the locations of potential hydrocarbon flow units and barriers or baffles to flow in the upper (S-3) and lower (S-6) reservoirs. S-1 = peritidal lime mudstone-dolomudstone and wackestone; S-3 = nearshore carbonate bank grainstone and packstone sand bodies and interbuildup wackestone; S-4 = subtidal wackestone and lime mudstone; S-5 = subtidal microbially influenced packstone, wackestone, and lime mudstone; S-6 = microbial (thrombolite) boundstone; and S-7 = transgressive lime mudstone-dolomudstone and wackestone. 10560 = Hunt 30–1 Cedar Creek Land and Timber Company well; 13907 = Midroc 20–15 Oliver well; 14358 = Midroc 21–10 Cedar Creek Land and Timber Company well; 13583 = Midroc 22–3 Pugh well; 13670 = Midroc 14–16 Tisdale well; 14114 = Midroc 13–1 McCreary well; 14325 = Sklar Exploration Company 7–2 Craft-Mack well; 15263B = Sklar 5–14 Craft-Ralls well; 15493 = Sklar 5–8 Craft-Ralls well; 15614B = Sklar 4–2 Craft-Rolls well; 16115 = Sklar 33–7 Craft-Ralls well; 16327B = Sklar 28–16 Craft-Ralls well; and 16135 = Sklar 27–6 Craft-Soterra LLC well. See Figure 3 for line of cross section and location of wells used in the cross section.

FORMATION EVALUATION

The objectives of the formation evaluation study in Little Cedar Creek field are to calculate representative petrophysical properties (porosity, permeability, and water saturation) of the reservoir rocks and to use these parameters to construct a 3-D geologic reservoir model. The logs most pertinent to the study are gamma ray, resistivity, neutron porosity, density porosity, photoelectric, and spontaneous potential. Available conventional core data analysis (porosity, air permeability, and water saturation) is also used in this study. Several log interpretation techniques and models are available for application to the data from this field (Asquith and Krygowski, 2004). Selection of the model depends on variables such as the dominant lithology present in the reservoir rocks, type of hydrocarbons in the pore spaces, and the types of data available.

Lithology Determination

The determination of the dominant reservoir lithology required to build the 3-D model is accomplished using neutron-density crossplots. These crossplots indicate that the dominant lithology is limestone in the Smackover Formation in the Little Cedar Creek field. However, this evaluation has shown that the S-5 and S-7 facies are dolomitic in the western part of the field (Midroc 16–14 Cedar Creek Land and Timber well, 13438). Moreover, dolomite is absent in these lithofacies in the central and northern parts of the field (Midroc 18–6 McCreary well, 14545 and Sklar 27–6 Craft-Soterra LLC well, 16135). This variation in lithology corresponds to a facies change as a result of depositional processes (packstone to lime mudstone) in combination with subsequent dolomitization of the packstone.

The presence of shale in a formation can adversely affect the response of the logging tools, especially the porosity tools (Asquith and Krygowski, 2004). Shale also has a high impact on permeability and water saturation calculations. However, the lithology evaluation performed for the Smackover Formation in this study showed that shale is absent in the Smackover Formation in the Little Cedar Creek field. Therefore, calculating the shale volume for the well logs in the field and correcting log-derived porosity values are not needed. Arithmetic average porosity (PHIA), defined as the average of porosities as determined from neutron and density logs, compared favorably to core measured porosity (Figure 5). Thus, derived PHIA logs are determined to be representative of the porosity in the Smackover Formation in the Little Cedar Creek field.

Permeability Calculation

Core permeability is commonly measured in the laboratory using air as flowing fluid. The available core analysis reports for the Little Cedar Creek field indicate that permeability was measured by air. Klinkenberg (1941) reported that permeability measurements made with air as flowing fluid are always greater than liquid permeability. Klinkenberg proposed an equation for calculating liquid permeability from air permeability. However, the values necessary to perform the Klinkenberg correction for air permeability were not available for this study. Therefore, air permeability (K_{air}) is used in this study. According to the Halliburton's Open Hole Log Analysis and Formation Evaluation (2004), the Klinkenberg correction would not have a major impact on the permeability values in the Little Cedar Creek field study because most of the permeability values are low.

In noncored wells, permeability is most commonly estimated from well logs using either an empirical relationship or some form of linear regression. In siliciclastic reservoirs, typically, a linear relationship exists between porosity and the logarithm of permeability plotted against each other in crossplots. This relationship is caused by the fact that permeability in sandstones is directly related to depositional porosity, which is mostly intergranular porosity. However, in carbonates, diagenesis, grain-size distribution, cementation, and pore-type distribution alter this relationship, making the prediction of permeability more difficult. In the last few years, parametric (multilinear and nonlinear models) and nonparametric statistical regressions have been proposed to overcome this problem (Avila et al., 2002; Lee et al., 2002; Mathisen et al., 2003; Mancini et al., 2004a). Whereas parametric regression techniques require a priori assumptions regarding functional forms, nonparametric approaches, such as alternating conditional expectations (ACE) and artificial neural networks (ANN), are successful in overcoming the limitations of the conventional multilinear regressions methods (Avila et al., 2002; Lee et al., 2002; Mathisen et al., 2003; Mancini et al., 2004a). In addition, several approaches (Abbaszadeh et al., 1996) have used lithofacies information derived from cores to identify hydraulic flow units (HFUs). Other approaches have used pore type characterization and permeability-porosity transforms to predict permeability in complex carbonate reservoirs (Lonoy, 2006). In the Little Cedar Creek field, conventional linear regression techniques fail to accurately predict permeability because of reservoir heterogeneity and a porosity-permeability mismatch (i.e., low permeability in regions exhibiting high porosity and vice versa). Therefore, in this study, neural networks are used to predict permeability.

Neural Networks

Rogers et al. (1995) proposed ANN to predict permeability in wells in the Smackover in Big Escambia Creek field in southern Alabama. They used backpropagation artificial neural networks (BPANNs) to accurately predict permeability using minimal data. The availability of a large amount of core and wireline-log data in Little Cedar Creek field makes the use of ANN a good approach for permeability estimation. A neural network has been described as a "massively parallel-distributed processor made up of simple processing units called neurons" by Bhatt (2002, p. 7). These neurons have a natural tendency for storing experiential knowledge and making this knowledge available for use (Bhatt, 2002). That is, the neural networks act like a human brain that can store knowledge and then use it when needed. Neural networks are applied in a wide variety of disciplines to solve problems such as classification, feature extraction, diagnosis, function approximation, and optimization (Bhatt, 2002). They are superior to other methods under the conditions that (1) the data on which a conclusion is based are fuzzy, (2) the patterns important to the required decision are subtle or deeply hidden, (3) the data have significant unpredictable nonlinearity, and (4) the data are chaotic (in a mathematical sense). Most of the above apply in the Little Cedar Creek field case. The multilayer perception (MLP) networks (a variant of BPANN) approach is used in this study. Multilayer perception networks are currently the most widely used neural networks because they are characterized by their ability to classify patterns having nonlinearly separable boundaries (Bhatt, 2002). The MLP approach is an example of supervised learning that is conducted through backpropagation. The operation consists of an input layer, an internal layer of hidden neurons, and an output layer. The network is provided with training and validation data sets of known inputs and outputs. In the learning phase, random weights are applied to the input variables in the hidden layer, and the network is adjusted to minimize the convergence error (root mean square error) with the validation data set and the convergence error with the training data set. Once the network has finished learning, it starts the training process where the weight values of the middle hidden layer(s) are adjusted by comparing the results of the network to the desired outputs and updating the weight values by backpropagation to produce better outputs (Rogers et al., 1995; Bhatt, 2002). This process is iterative. However, some considerations need to be applied so that the network is not overtrained. The optimum output is obtained when the convergence errors on both the validation data set and the training data set are minimal. The advantage of using MLP is the ability of the networks to solve problems stochastically and the nonlinear relationship it generates between inputs and outputs. Moreover, the approach does not require any a priori assumption or relationship to be made with the data.

Permeability Prediction

To predict permeability from well logs in the Little Cedar Creek field, cored wells are used to construct training and validation data sets. Available well logs of gamma ray (GR), deep resistivity (ILD or HDRS), average porosity (PHIA), spontaneous potential (SP), and photoelectric effect (PEF) are used as the input variables (Figure 5). The optimal number of hidden layers of a permeability neural network should be confined to a range of 8–12, which would keep the variance and bias at their minimum (Bhatt, 2002). Moreover, the optimal number of training patterns should be in excess of 100 to ensure negligible errors in the data caused by moderate noise (Bhatt, 2002).

In the Little Cedar Creek field, 10 hidden layers are used, and the process of iteration is used to obtain the minimum value of convergence. The modeled (output) permeability is shown for the lithofacies in Figure 5. The output matches the core data very well, keeping in mind that according to Bhatt (2002), there will never be a perfect match because of errors in the original data that would have resulted from measurement conditions, resolution, spatial sampling, and anisotropy. The availability of core data for most of the wells in the field provides for the reconstruction of the permeability log in the cored interval using the original core data, while predicting the permeability values in the noncored interval. This process reduces the uncertainty associated with the neural network prediction and results in improved modeling of permeability in the field. The modeled (predicted) permeability can then be used as a training and validation data set for noncored wells. In total, 80 of the 112 wells studied were found to have a high level of confidence in predicting permeability using an ANN approach.

Water Saturation Prediction

Special core analysis data (SCAL) and, thus, the electrical parameters (m = cementation exponent of the rock, n = the saturation exponent, and a = tortuosity factor) were not available for this study. Therefore, an MLP networks approach was used to predict and model water saturation in the field. The input logs used in this case are gamma ray (GR), deep resistivity (ILD or HDRS), average porosity (PHIA), and apparent water resistivity (R_{wa}) provided by the operator. The apparent water resistivity has a unique signature in the reservoirs that can be used to properly train and model the water saturation

(Figure 5). By using the MLP approach, the modeled water saturation from cored wells can be used as a training and validation data set to predict water saturation in noncored wells. The modeled water saturation logs that were used to train the network match the core data very well. The availability of core data for most of the wells in the field provides for the reconstruction of the water saturation log in the cored interval using the original core data while predicting the water saturation values in the noncored interval. This process reduces the uncertainty associated with the neural network prediction and results in improved modeling of water saturation in the field.

RESERVOIR CHARACTERIZATION

Sedimentary Characteristics

In the Little Cedar Creek field area, the Smackover Formation ranges 40 to 148 ft (12 to 45 m) thick. The Smackover Formation in the area is divided into seven distinct lithofacies (Mancini et al, 2008; Ridgway, 2010). Beginning from the top of the Smackover Formation, the facies are (S-1) peritidal lime mudstone-dolomudstone and wackestone; (S-2) tidal-channel rudstone and floatstone; (S-3) nearshore carbonate bank grainstone and packstone sand bodies characterized by ooids, peloids, microbial coated grains and intraclasts, and interbuildup wackestone (Figures 8A–D, 9A, B); (S-4) subtidal wackestone and lime mudstone; (S-5) subtidal bioturbated microbially influenced packstone (Figures 8E, 9C), wackestone and lime mudstone; (S-6) microbial (thrombolite) boundstone (Figures 8F–I, 9D); and (S-7) transgressive lime mudstone-dolomudstone and wackestone. The carbonate bank grainstone and packstone lithofacies (S-3) are the upper reservoir beds, and the microbial boundstone lithofacies (S-6) are the lower reservoir beds. The bioturbated packstone of the microbially influenced lithofacies (S-5) has some reservoir potential chiefly in the western part of the field. However, the distribution of this packstone is limited and discontinuous and, therefore, is difficult to predict and model. The Haynesville argillaceous beds and upper Smackover lime mudstone-dolostone and wackestone (S-1) serve as the top seal beds (Figures 5, 7). The middle Smackover wackestone and lime mudstone (S-4) act as the top seal beds for the lower microbial reservoir and serve as a barrier to flow between the lower and upper reservoirs as evidenced by different reservoir pressures for the two reservoirs. The lower Smackover lime mudstone-dolostone and wackestone act as the base seal beds. See Mancini et al. (2006), Ridgway (2010), and Breeden (2013) for a detailed description of the Smackover lithofacies in the Little Cedar Creek field area.

The petroleum trap in this field is an updip (near the depositional limit of Smackover carbonates) stratigraphic trap consisting of a change in lithofacies from subtidal microbial boundstone and carbonate bank grainstone and packstone to bay and lagoonal lime mudstone and wackestone toward the northeastern end of the field, near the Smackover shoreline (Figure 2). Structural maps drawn on top of the Smackover (Figure 10) and Norphlet (Figure 11) formations show uniform dip to the southwest at a rate of 150–200 ft/mi (46–61 m/km). To date, no faulting, structural closure, or localized paleotopographic highs have been observed in Little Cedar Creek field, meaning that no paleohighs similar to Appleton or Vocation fields were available to serve as effective combination traps in this field. The oil–water contact or highest known water in the field is recognized by the SOGBA at a subsea depth of 11,365 ft (3464 m) in the induction log for the Midroc 21–1 McCreary well (#13439). The hydrocarbons trapped in Little Cedar Creek probably are not sourced from the lime mudstone lithofacies in the field area but rather from Smackover basinal laminate beds rich in amorphous and microbial kerogen south of the field area (Mancini et al., 2008).

Petrophysical Characteristics

The primary control on reservoir architecture in the Little Cedar Creek field is the depositional fabric of the reservoir facies with dissolution and, to some degree, dolomitization events having significant influence on enhancing reservoir quality by enlarging primary interparticle and constructed void (associated with microbial growth fabrics) pore types and forming and enlarging secondary intraparticle, grain moldic, and vuggy pore types. Although dolomitization and the creation of intercrystalline pores are not pervasive in this field as in other fields producing from microbial carbonate and associated reservoirs, such as Appleton and Vocation fields (Mancini et al., 2000, 2004b), partial dolomitization of a reservoir can act to stabilize the lithology of a reservoir and can serve to reduce the potential for later porosity loss because of compaction (Benson, 1985). Dissolution processes also have the effect of expanding existing pore throats and enhancing permeability (Benson, 1985).

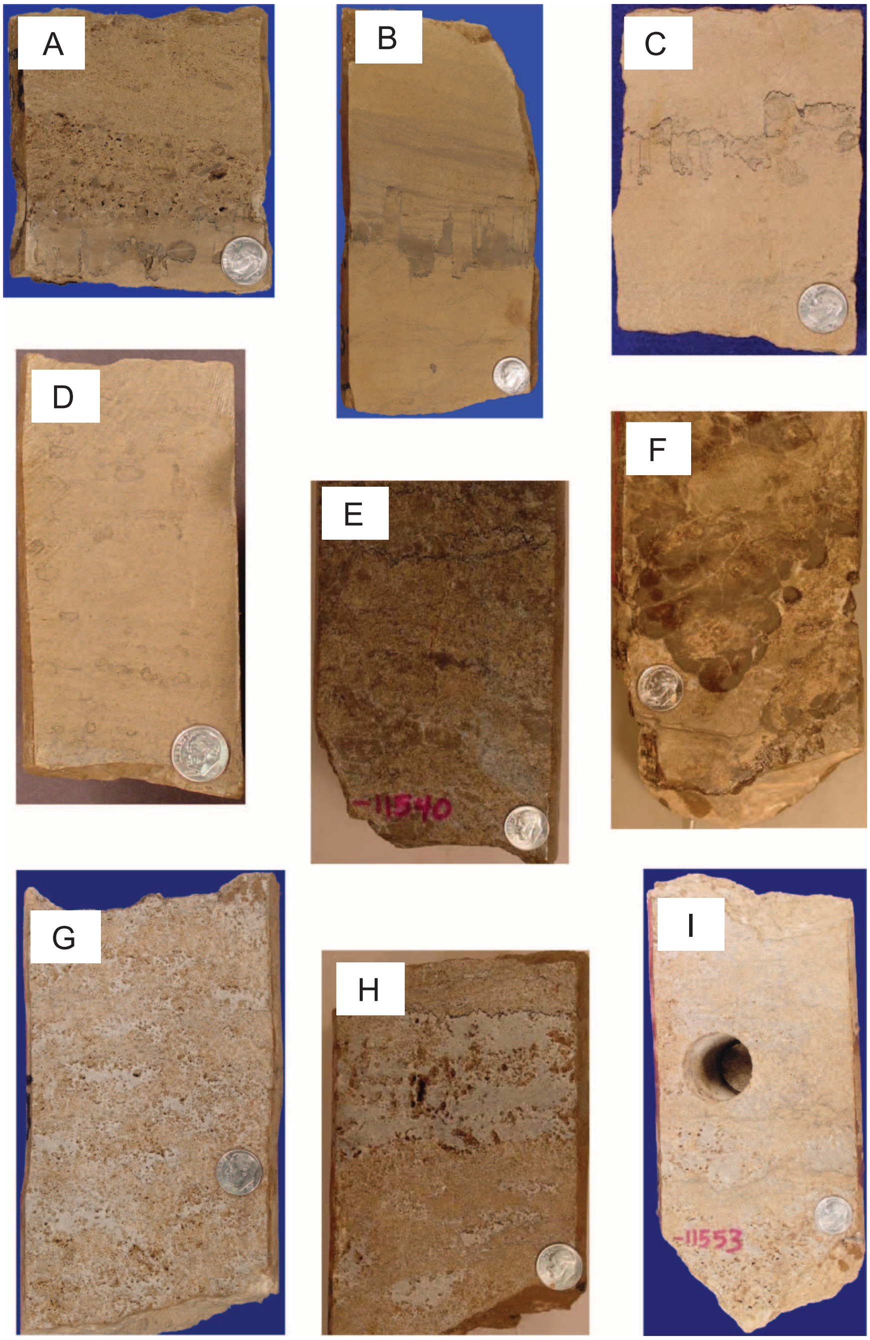

Figure 8. Core photographs of Smackover lithofacies in the Little Cedar Creek field. (A) S-3 leached grainstone, upper to middle facies of a marine carbonate sand belt buildup, Midroc Exploration Company 12–16 McCreary well, 14181, depth 11,238 ft (3425 m); (B) S-3 cross-bedded grainstone, upper to middle facies of a buildup, Midroc 12–16 McCreary well, 14181, depth 11,237 ft (3425 m); (C) S-3 ooid grainstone, upper to middle facies of a buildup, Midroc 22–2 Pugh well, 13472, depth 11,495 ft (3504 m); (D) S-3 peloidal packstone, lower margin facies of a buildup, Midroc 22–2 Pugh well, 13472, depth 11,512 ft (3509 m); (E) S-5 microbially influenced packstone, bioturbated facies overlying a microbial buildup, Midroc 22–2 Pugh well, 13472, depth 11,540 ft (3517 m); (F) S-6 thrombolitic boundstone, microbial buildup facies, Midroc 12–16 McCreary well, 14181, depth 11,282 ft (3439 m); (G) S-6 leached boundstone, microbial buildup facies, Midroc 20–12 Cedar Creek Land and Timber well, 12872, depth 11,881 ft (3621 m); (H) S-6 highly leached boundstone, microbial buildup facies, Midroc 20–12 Cedar Creek Land and Timber 20–12 well, 12872, depth 11,880 ft (3621 m); and (I) S-6 leached and pelodial boundstone, microbial buildup facies, Midroc 22–2 Pugh well, 13472, depth 11,553 ft (3521 m). Diameter of coin is 18 mm (0.71 in.). Photographs (C)–(E) and (I) are located in Figure 5. See Figure 3 for the location of these well cores. Core photographs, except for (D), are from Mancini et al. (2006, 2008). Core photographs (A)–(C), (F)–(G), and (I) are republished by permission of the Gulf Coast Association of Geological Societies, whose permission is required for further publication use.

Porosity in the upper grainstone-packstone reservoir facies (S-3) consists of primary interparticle and secondary solution-enhanced interparticle, intraparticle, vuggy, and grain moldic pore types (Ridgway, 2010; Breeden, 2013). In this reservoir interval, ooid content increases, and the degree of microbial influence decreases upward, resulting in a sequence consisting of upper grainstone high in ooid content; middle grainstone with differing amounts of ooids, peloids, microbe-coated grains, and intraclasts; and lower packstone-wackestone beds with peloids and a large number of microbe-coated grains (Breeden, 2013). These different textures reflect subenvironments of a marine carbonate sand belt buildup in a carbonate bank setting: upper crestal buildup grainstone beds rich in ooids that are totally to partially leached and partially dolomitized with some vugs; middle or

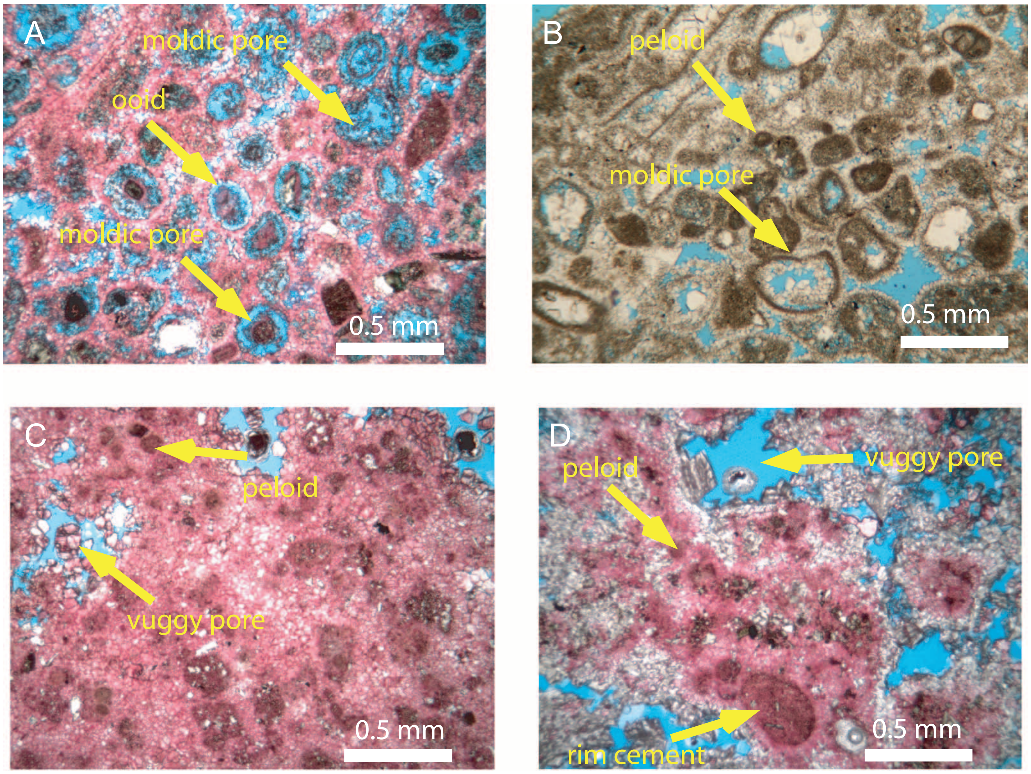

Figure 9. Photomicrographs of the Smackover lithofacies in the Midroc 22–2 Pugh well, 13472 in the Little Cedar Creek field: (A) S-3 leached ooid grainstone showing grain moldic pores, depth 11,495 ft (3504 m); (B) S-3 leached peloid packstone showing grain moldic pores, depth 11,512 ft (3509 m); (C) S-5 bioturbated microbially influenced packstone showing peloids and vuggy pores, depth 11,542 ft (3518 m); and (D) leached thrombolitic boundstone showing vuggy pores, depth 11,553 ft (3521 m). Samples (A), (C)–(D) were stained with Alizarin red S. Photomicrographs are located in Figure 5. Photomicrographs, except for (B), are from Mancini et al. (2006, 2008). Photomicrographs (A) and (C)–(D) are republished by permission of the Gulf Coast Association of Geological Societies, whose permission is required for further publication use.

main buildup grainstone to packstone beds containing a mixture of ooids, peloids, microbe-coated grains, and intraclasts; and lower margin buildup packstone beds with peloids and an abundance of microbe-coated grains (Figure 9A, B). According to the carbonate genetic porosity classification of Ahr (2008), these reservoir facies are classified as hybrid 1 because they include both depositional and diagenetic pore types.

Porosity in the lower microbial boundstone (S-6) includes primary constructed voids or intraframe pore types associated with the microbial growth framework and secondary solution-enhanced void and vuggy pore types (Figure 9D). The bioturbated microbially influenced packstone (S-5) includes interparticle, grain moldic, and vuggy pore types (Figure 9C). The microbial (thrombolite) boundstone principally contains vugs that have resulted from leaching and are partially dolomitized. According to the carbonate genetic porosity classification of Ahr (2008), these reservoir facies are classified as hybrid 1 because they include both depositional and diagenetic pore types. Dissolution is, however, more reprevalent in the lower boundstone-packstone reservoir as compared to the upper grainstone-packstone reservoir.

The fundamental building blocks of reservoir architecture are the pore systems, including pore topology and geometry and pore-throat-size distribution (Ahr and Hammel, 1999). Thus, the amount, kind, and spatial distribution of reservoir heterogeneity are a function of pore origin, geometry, and distribution. According to Kopaska-Merkel and Hall (1993), pore systems affect not only hydrocarbon storage and flow but also reservoir producibility and flow-unit quality. Therefore, the pore systems of the Little Cedar Creek reservoir intervals and their characteristics are extremely crucial. Pore-throat-size distribution is a crucial factor in controlling permeability because the smallest pore throats serve as the bottlenecks that impact the rate at which fluid can pass through a rock (Ahr and Hammel, 1999).

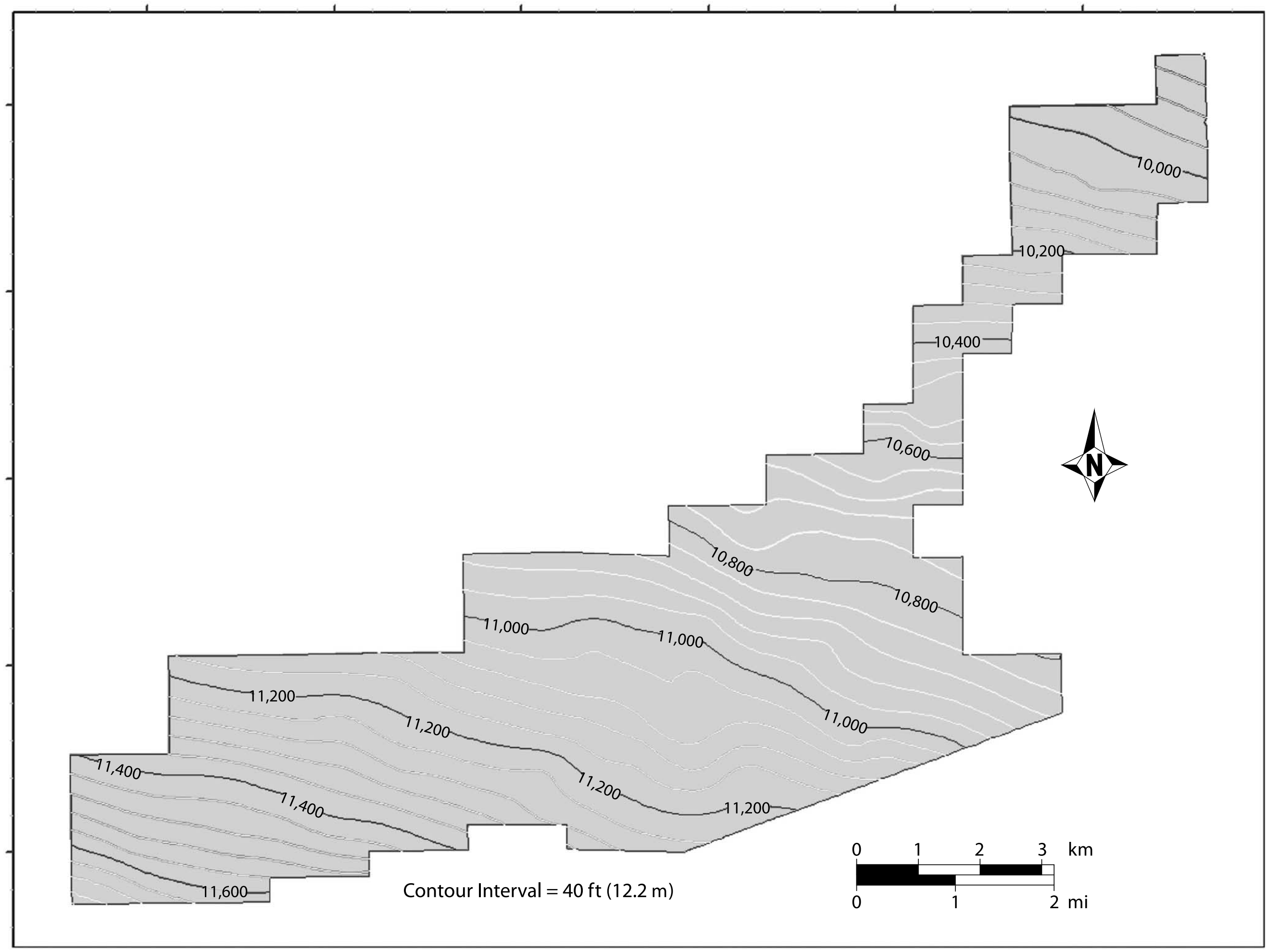

Figure 10. Structure map on top of the Smackover Formation, Little Cedar Creek field. Note uniform dip to the southwest at a rate of 150–200 ft/mi (46–61 m/km).

According to Mancini et al. (2000), permeability is directly related to the pore system and degree of heterogeneity inherent to Smackover reservoirs. These authors found that, in general, the more homogeneous (minimum variability in reservoir architecture and pore systems) the reservoir, the greater the oil and gas recovery from that reservoir.

The pore system of the upper grainstone-packstone reservoir interval is dominated by grain moldic and solution-enhanced interparticle pore types, although certain grainstone beds in this interval are characterized by a pore system having a high percent of interparticle or vuggy pores. The pore system of the upper reservoir interval overall is characterized by pores of variable size that are poorly connected by narrow pore throats. Pore size is dependent on the size of the carbonate grain that was leached. However, the pore system of the lower microbial reservoir pore system is dominated by vuggy and solution-enhanced void pore types and is characterized by more large-size pores that are interconnected by larger and more uniform pore throats. In addition, such a pore system provides for higher connectivity in carbonate reservoirs and higher permeability (Lucia, 1999; Jennings and Lucia, 2001; Mancini et al., 2004a). In the Little Cedar Creek field, boundstone hydrocarbon flow units (reservoir intervals of high porosity, permeability, and connectivity) in the lower microbial reservoir (S-6) dominated by vuggy and solution-enhanced void pore types have high hydrocarbon productivity throughout the field as evidenced by the 2-yr cumulative oil production per well for wells producing only from this reservoir as recorded in the SOGBA production records for Little Cedar Creek field. For wells in the three parts of the field, the highest 2-yr cumulative oil production per well totals are as follows: northern part, Sklar 27–6 Craft-Soterra LLC well, 16135,

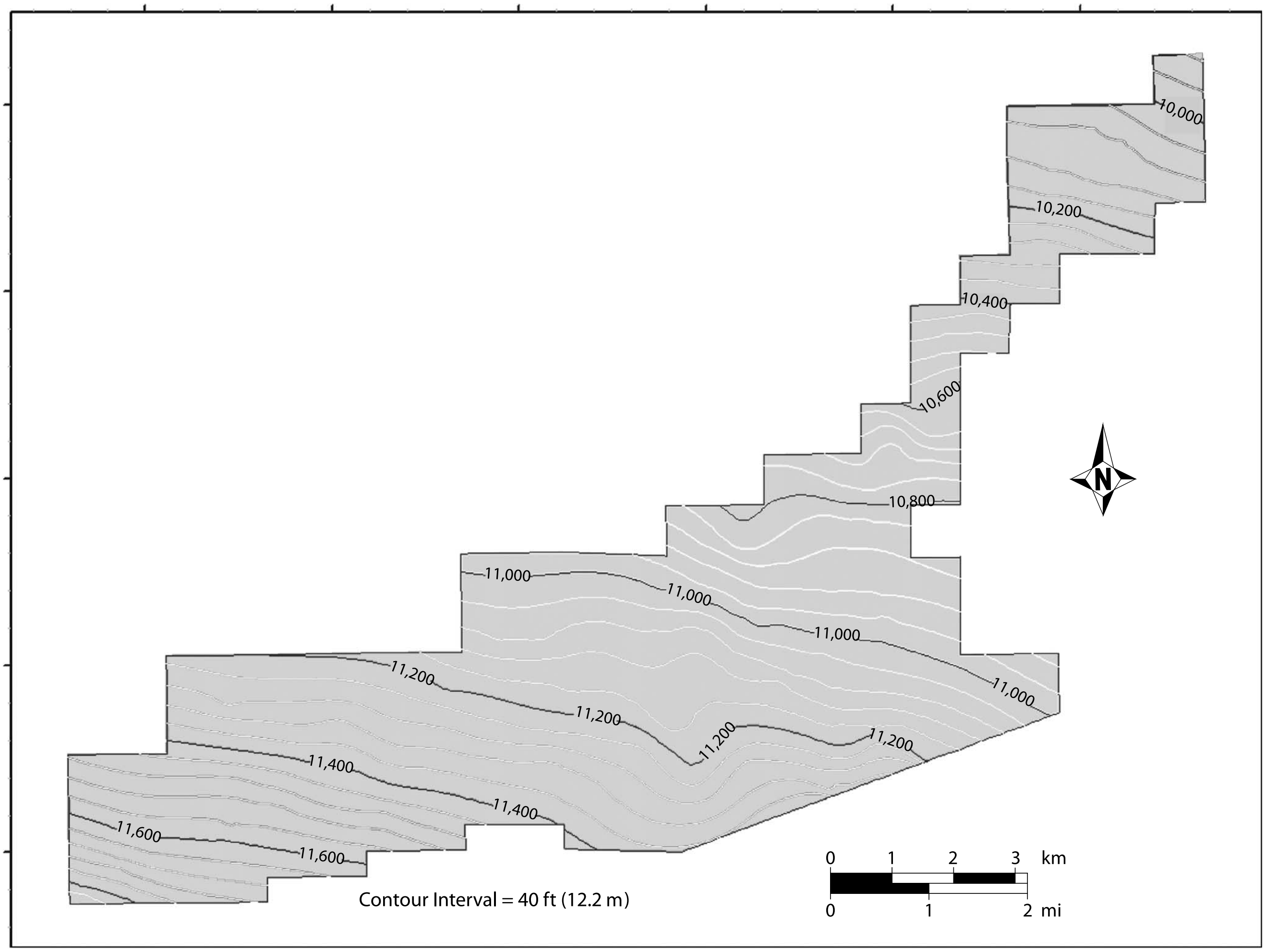

Figure 11. Structure map on top of the Norphlet Formation, Little Cedar Creek field. Note uniform dip to the southwest at a rate of 150–200 ft/mi (46–61 m/km).

271,524 bbl; central part, Midroc 18–6 McCreary well, 14545, 265,159 bbl; and western part, Midroc 24–3 Tisdale well, 14069B, 229,306 bbl. The high productivity of this reservoir is attributed to a pore system characterized by a higher percentage of large-size pores interconnected by larger and more uniform pore throats. However, the 2-yr cumulative oil production per well from wells completed solely in the upper reservoir interval (S-3) is less than that of the lower reservoir (SOGBA, 2013a). The highest 2-yr cumulative oil production per well total in the field for this reservoir, prior to gas injection, is 95,921 bbl of oil from the Midroc 20–7 Cedar Creek Land and Timber well, 13177 from the western part of the field. The lower hydrocarbon productivity of this reservoir is attributed to its pore system, which comprises a higher percentage of small-size pores that are not as well connected because of a system of narrower and less uniform pore throats. In addition, potential barriers (intervals of nonreservoir grade rock) and baffles (intervals of low permeability and connectivity) to flow potentially are present in both the lower and upper reservoir intervals. Potential lateral barriers or baffles to flow can develop in the S-6 reservoir interval. The interbuildup areas are characterized by a thick section of microbially influenced lime mudstone and wackestone (Figure 7). With the S-3 reservoir interval, a thick section of wackestone characterizes the interbuildup areas and represents a potential baffle or barrier to flow in this reservoir interval. The vertical heterogeneity within the upper wackestone-packstone-grainstone sequences and the discontinuity and limited areal extent of specific beds in a given sequence laterally may result in potential vertical and lateral baffles to flow in the S-3 reservoir interval (Figures 5, 7).

Table 1. Parameters Used to Construct the Stratigraphic Grid of the Little Cedar Creek Field 3-D Geologic Reservoir Model

	Stratigraphic Unit	Layering	Build Cells	Vertical Number of Cells	Vertical Cell Thickness, ft (m)
Top of Smackover	S-1	Conformable	Yes	10	2 (0.6)
	S-3	Baselap	Yes	27	2 (0.6)
	S-4	Conformable	Yes	10	7 (2.1)
	S-5	Conformable	Yes	12	2 (0.6)
	S-6	Conformable	Yes	25	2 (0.6)
	S-7	Conformable	Yes	10	5.5 (1.7)
Base of Smackover	Norphlet	Conformable	No		

THREE-DIMENSIONAL GEOLOGIC RESERVOIR MODEL

In constructing the boundaries for the 3-D geologic reservoir model, we use the geographic boundaries for the Little Cedar Creek field as established by the SOGBA (Figure 3) in combination with changes in reservoir characteristics caused by depositional and diagenetic processes that resulted in dry holes or noncommercial wells.

Thus, the field and model are bounded on the west and along the northwest and the southeast margins by the reservoir lithofacies being absent or not economically producible.

Stratigraphic Model

To construct the stratigraphic grid, well locations, well surveys, and well tops are imported into Paradigm's SKUA© modeling package. The stratigraphic and sedimentologic information obtained from the reservoir characterization studies (wireline log, core data analysis, and thin-section analysis, cross sections, and thickness maps) are incorporated into the 3-D geologic reservoir model. The final grid of this model is shown in Figure 3. The grid incorporates six subhorizontal stratigraphic horizons and excludes the S-2 lithofacies surface, which is observed in only two wells in the field (Table 1). Vertical layering is conformable between lithofacies, except for the S-3 lithofacies surface that is set as baselap to truncate (pinch out) the surface in the northeastern part of the field where this lithofacies is absent because of a depositional change in lithofacies. The vertical number of cells and vertical cell thickness are shown in Table 1. Horizontally, the cells widths are 250 × 250 ft (76 × 76 m). The model is oriented with a 65° northeast trend to reflect the depositional strike of the field and the depositional pattern observed in the thickness maps of the S-3 and S-6 lithofacies (Figure 6).

Lithofacies Model

Truncated Gaussian simulation is used to model the lithofacies in the Little Cedar Creek field. Pixel-based simulation (sequential indicator simulation [SIS] and truncated Gaussian simulation [TGS]) methods are preferred in modeling carbonate environments. The primary data inputs to run a TGS are (1) upscaled lithofacies data blocked into the grid from facies logs, (2) the order of the lithofacies in the model or vertical succession of lithofacies, (3) one variogram that is used for all lithofacies, and (4) the global fraction and trend of each lithofacies. Secondary data input includes vertical lithofacies proportion curves (VPCs) and 3-D or 2-D trend maps. In the Little Cedar Creek field, the facies logs are generated from the lithofacies that are picked on each well log (S-1 to S-7) and observed from core studies where each lithofacies is coded to a number to create the discrete facies logs. An experimental variogram is computed from the facies logs, and then the variogram model is adjusted to obtain horizontal and vertical ranges for the lithofacies. A spherical isotropic variogram model with 5300 ft (1615 m) in R1 (maximum) and R2 (minimum) ranges and 21 ft (6.4 m) is used for the vertical range. No trend is used in the variogram; however, the horizontal variogram model is fitted to the experimental in the 0°, 60°, 90°, and 120° directions to capture probable microbial buildup orientations and diagenetic trends observed in the data. Vertical facies proportion curves are obtained from data analysis and are used to constrain the model.

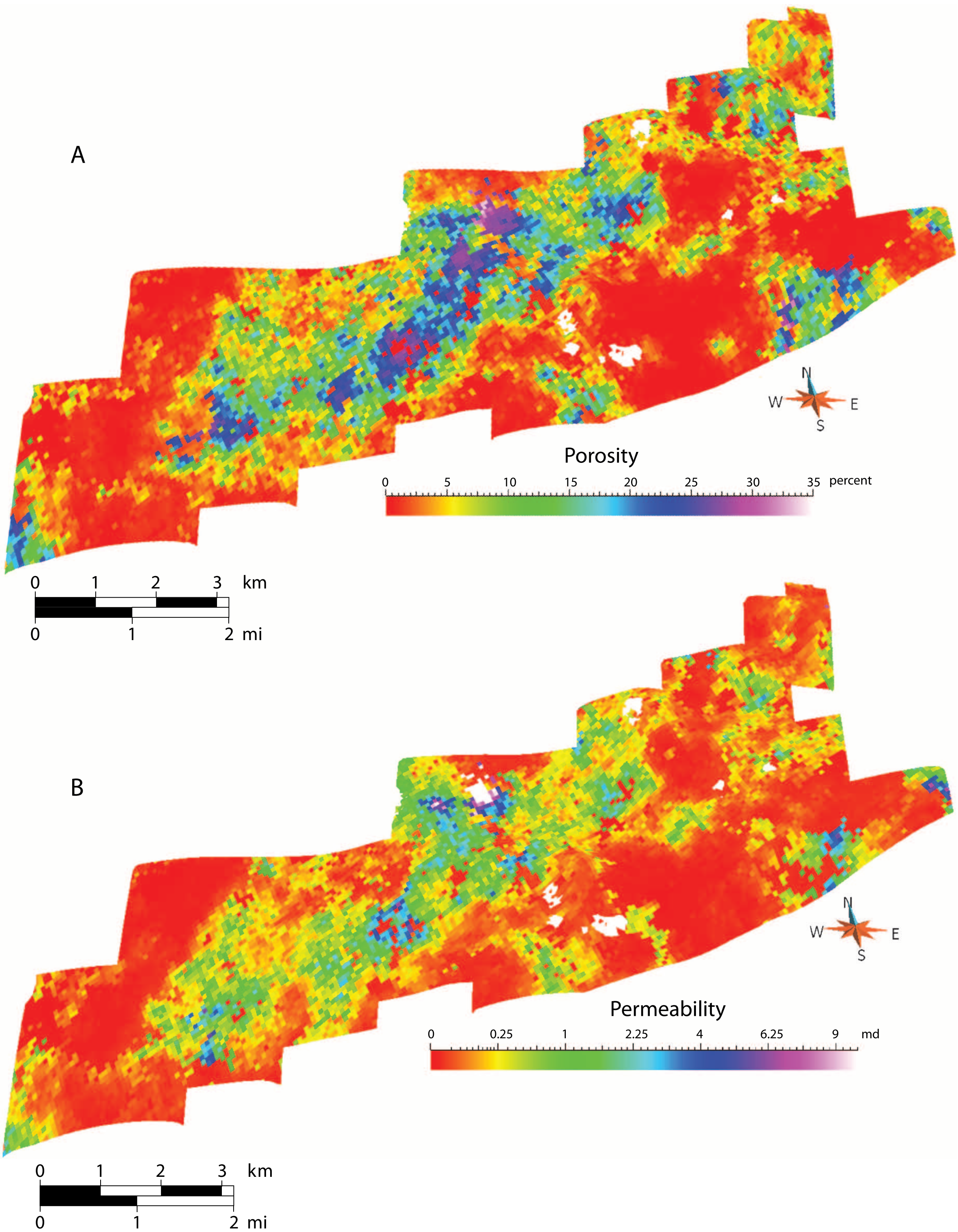

Figure 12. Spatial distribution of porosity (A) and permeability (B) on the top of the S-3 reservoir layer in the 3-D geologic reservoir model of Little Cedar Creek field. Note the overall elongated and heterogenous southwest to northeast trend in porosity and permeability extending from the western part to the central part of the field and the smaller but comparable trend in the south-central part of the field. These trends compare favorably with the orientation and distribution of the carbonate sand bodies observed in the thickness map for the S-3 lithofacies illustrated in Figure 6A. The internal variability in the porosity and permeability trends correspond to the areas of carbonate sand belt buildup and interbuildup areas showing that the buildup areas represent potential hydrocarbon flow units (higher permeability values) and the interbuildup areas represent potential baffles or barriers to flow. This relationship is also seen in Figure 7.

In general, wells are drilled in areas with the greatest probability for high hydrocarbon production (cores are taken preferentially from quality reservoir rock). Such data collection practices lead to optimal economic practices and result in the greatest amount of data coming from parts of the field that are the most economically viable. Therefore, subsequent bias for oversampling occurs for certain areas and undersampling results for other areas. During the process of analyzing the data, we use declustering techniques to remove sampling bias and to establish unbiased statistics. Ten simulations are then performed using the TGS technique to build the lithofacies model.

Porosity Model

In the Little Cedar Creek field, the depositional lithofacies govern the porosity distribution, and diagenesis was lithofacies selective (Ridgway, 2010). Thus, the porosity model in the Little Cedar Creek field should be lithofacies constrained. Sequential Gaussian simulation (SGS) is a geostatistical simulation technique used to model porosity in this field. The SGS technique is applied to interpolate data between wells and to obtain multiple realizations. One variogram is required for the SGS simulations. The experimental variogram displays cyclicity in the vertical direction. The cyclicity is a product of microbial buildup, development, and the resulting heterogeneity in the field. A spherical isotropic variogram model with 7962 ft (2427 m) in R1 (maximum) range and R2 (minimum) range and 25 ft (7.6 m) for the vertical range is used. No trend is used in the variogram, but the horizontal variogram model is fitted to the experimental data in the 0°, 60°, 90°, and 120° directions. Average porosity logs (PHIA) from wells are blocked to the grid cells using arithmetic mean, and 10 simulations per lithofacies are then performed using the SGS technique to obtain the porosity model (Figures 12A, 13A). Well-log analysis and modeling indicate that porosity ranges from 0% to 33% with a mean of 7.6% in the upper reservoir (Figure 14A), and porosity ranges from 0% to 20% with a mean of 5.7% in the lower reservoir (Figure 14C). Based on the producibility of these reservoirs, the unit operator used a cutoff of 10% for porosity for the upper reservoir and a cutoff of 6% for porosity for the lower reservoir in determining the net hydrocarbon pore volume component of the allocation formula for partial field unitization according to the SOGBA (2004) hearings.

Permeability Model

Permeability is a difficult reservoir parameter to model because it is highly variable and is characterized by extreme values. Extreme low values in a lithofacies potentially result in a baffle or barrier to flow, whereas extreme high values in a lithofacies have the potential to facilitate flow and serve as a flow conduit. The direction of flow and local pressure conditions are also important parameters. The permeability distribution commonly has a highly skewed histogram and, thus, cannot be linearly averaged. Typically, the logarithm of permeability is used because of the skewed nature and approximately log-normal character of the permeability histograms. Moreover, the models of permeability also consider any relationship with porosity. Sequential Gaussian simulation with collocated cokriging is a technique that can consider a statistical relationship between two variables. The statistical relationship is a simple correlation between porosity and logarithm of permeability. In the Little Cedar Creek field, the semilog relationship between porosity and permeability was obtained by plotting the predicted permeability versus core porosity on a semilog plot. However, correlation values should be used with caution with the reservoirs in this field because of the highly variable porosity-permeability relationship in these heterogeneous but interconnected pore system networks characterized by a tortuous flow pathway system. Geometric and power averaging methods are recommended to upscale (block) permeability from wells into the grid. The geometric mean method is used in this study because this method is sensitive to low values of permeability. Ten nested (porosity and facies) simulation runs are performed using SGS with collocated cokriging to generate a permeability model. The model honors the modeled variogram, has the observed correlation with the porosity, and matches the permeability data from wells. Well-log analysis and modeling indicate permeability ranges from 0 to 452 md with a median of 1 md in the upper reservoir (Figure 14B), and permeability ranges from 0 to 7953 md with a median of 1 md in the lower reservoir (Figure 14D).

The upper and lower reservoirs have a southwest-northeast orientation that corresponds to the depositional topographic trend of the Smackover Formation during the Late Jurassic (Figures 10, 11). The reservoirs include several potential hydraulic (hydrocarbon) flow units characterized by higher permeability values (Figures 12B, 13B). The potential flow units of the

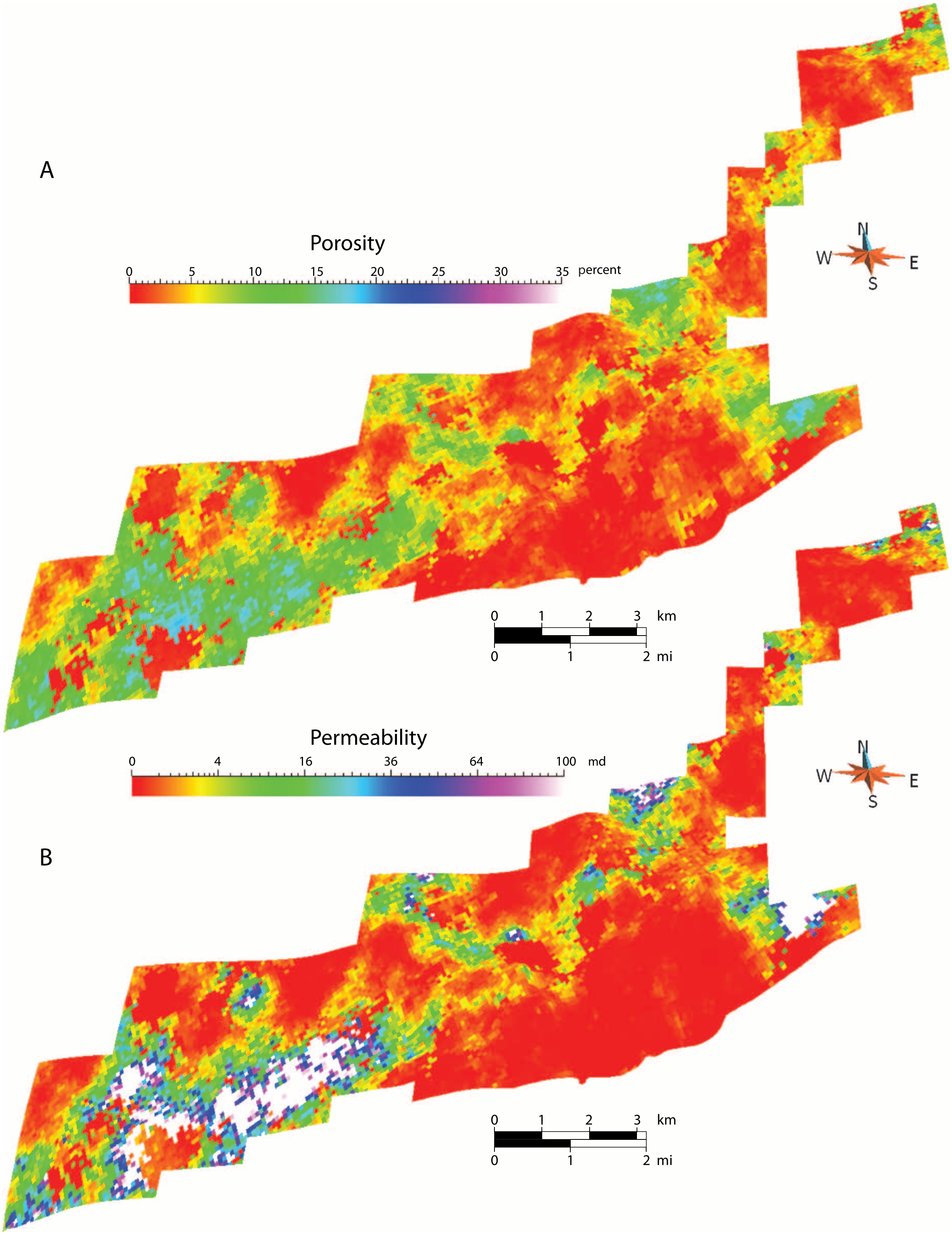

Figure 13. Spatial distribution of porosity (A) and permeability (B) on the top of the S-6 reservoir layer in the 3-D geologic reservoir model of Little Cedar Creek field. Note the overall southwest to northeast heterogeneous trend in porosity and permeability extending from the western part through the central part to the northern part of the field. This trend compares favorably with the orientation and distribution of the three clusters of microbial carbonate buildups observed in the thickness map for the S-6 lithofacies illustrated in Figure 6B. The internal variability in the porosity and permeability trends corresponds to the areas of microbial buildup and interbuildup areas showing that the buildup areas represent potential hydrocarbon flow units (higher permeability values) and the interbuildup areas represent potential barriers or baffles to flow. This relationship is also seen in Figure 7.

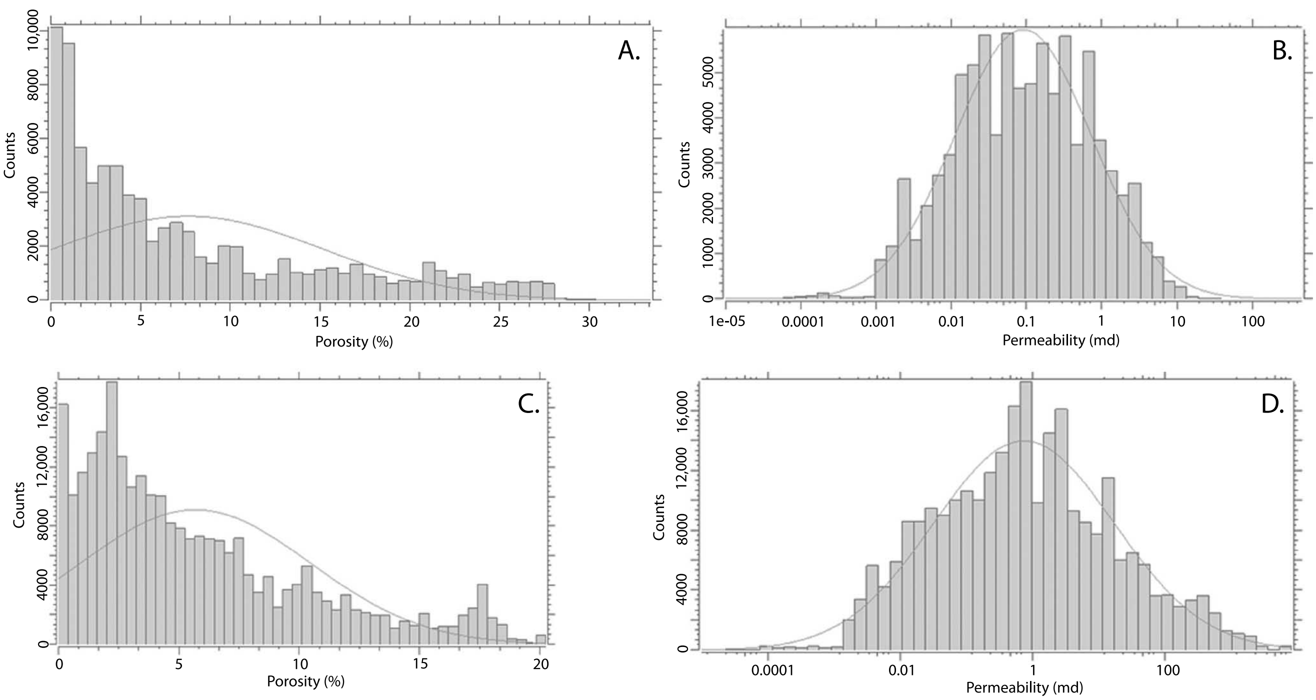

Figure 14. Histograms illustrating the petrophysical properties of the upper (S-3) and lower (S-6) reservoirs as determined from well-log analysis and modeling at Little Cedar Creek field: (A) S-3 porosity, 88,334 samples; (B) S-3 permeability; (C) S-6 porosity, 267,425 samples, and S-6 permeability.

upper reservoir interval extend mainly from the southwest to the northeast where the S-3 lithofacies is truncated (lithologic pinch-out) because of a facies change (Figures 3, 6A, 7). In the western to central part of field, the potential hydrocarbon flow units are separated by lower porosity and permeability zones, which indicate interbuildup areas that have the potential to serve as baffles to flow (Figure 12B). The permeability maps for the S-6 beds of the lower reservoir interval show a potential main hydrocarbon flow unit that is located in the western part of the field with other localized potential hydrocarbon flow units in the central and northern parts of the field (Figures 7, 13B). These potential hydrocarbon flow units correspond to the field areas characterized by major microbial buildups (Figures 6B, 7). The potential flow units are separated by lower permeability zones, which indicate interbuildup areas that have the potential to act as baffles to flow.

RESERVOIR EVALUATION

The results from the reservoir characterization, formation evaluation, 3-D geologic reservoir modeling, and production data analysis studies can be used to evaluate the hydrocarbon productivity of the microbial carbonate and associated reservoirs at Little Cedar Creek field and to assist in the design of a strategic reservoirwide field development plan. This integrated field study can serve as an effective management tool for making decisions regarding field operations, such as the drilling and spacing of infill wells and the initiation of secondary recovery projects, including the placement of related injection wells. The knowledge gained regarding the lateral and vertical heterogeneity of the sedimentary and petrophysical characteristics of these heterogeneous reservoirs and associated facies and the nature of the resulting pore systems, flow units, and potential barriers or baffles to flow is important to operating the Little Cedar Creek field in an efficient manner.

The two reservoirs in this field are separate and distinct, having different fluid compositions and maximum measured reservoir pressures (5391 psig for the upper reservoir and 5122 psig for the lower reservoir) (SOGBA, 2004). The operator concluded that the field was producing under a solution-gas drive mechanism and determined that unitization of the western part of the field and implementation of a secondary waterflood project for the reservoirs in the unit area were justified. The unitization and enhanced recovery project were projected to increase the ultimate recovery of hydrocarbons from the field, and the cost for unit operations was estimated not to exceed the value of the additional hydrocarbons recovered from the field. The creation of the unit also provides for the drilling of wells at optimum geologic locations in the unit area. In October 2007, Midroc Operating Company implemented a secondary recovery program involving gas injection in the unitized part of the field as a result of simulation modeling (SOGBA, 2007). This enhanced recovery project targeted the upper reservoir in the field. The lower microbial reservoir was not part of this project.

Upper Grainstone-Packstone Reservoir

The upper grainstone-packstone reservoir (S-3) consists of a series of progradational ooid and peloid sand bodies (Figure 8A–D) that extend from the western part of the field to the central part in a southwest to northeast direction. This reservoir is absent in the northern part of the field (Figure 3). These carbonate sand belt buildups comprise as much as six wackestone-packstone-grainstone sequences (Figure 5) and attain thicknesses of 26 ft (8 m) (Figure 6A). In interbuildup areas, the sand bodies have a thickness of 4–8 ft (1–2 m) and are underlain by a thick section of wackestone (Figure 7). Porosity consists of primary interparticle and secondary solution-enhanced interparticle, intraparticle, vuggy, and grain moldic (Figure 9A) pore types and ranges 0%–33% with a mean of 7.6% (Figure 14A). Permeability is critical to the low productivity of this reservoir and ranges 0–452 md with a median of 1 md (Figure 14C).

The secondary recovery program of injecting natural gas into the upper reservoir using two injection wells (Midroc 20–12 Cedar Creek Land and Timber well, 12872, and Midroc 21–4 Cedar Creek Land and Timber well, 13301) has proven successful (SOGBA, 2013a). According to hearing records SOGBA (2007), this gas injection program was selected for enhanced recovery in the upper reservoir instead of the original water injection project because of low permeability in this reservoir and because of the nature of the solution-gas drive in the reservoir. The operator is converting two additional wells (Midroc 22–3 Pugh well, 13583, and Midroc 14–12 Price well, 13625) to injection wells in the partial fieldwide unit (Figure 3).

The results from our field study provide support for the decision by the operator to use gas injection in the upper reservoir to recover undrained hydrocarbons. The sedimentary and petrophysical characteristics of the S-3 reservoir interval and associated pore system dominated by grain moldic and solution-enhanced interparticle pore types produce a compartmentalized reservoir having high porosity (Figure 14A) but low permeability (Figure 14C), connectivity (Figure 12B), and hydrocarbon productivity. This reservoir interval has high vertical (Figure 5) and lateral (Figures 6A, 12) heterogeneity that results in a complex of potential local flow units separated by baffles to flow and, in some cases, flow barriers (Figure 7).

The upper reservoir carbonate sand belt buildup areas serve as potential heterogeneous hydrocarbon flow units, and the interbuildup areas containing a thick section of low-permeability to nonreservoir rock serve as potential baffles or barriers to flow (Figure 7). As a result of the high sedimentary and petrophysical variability within the S-3 reservoir interval, high potential exists for the formation of local flow units associated with drainage areas having reduced communication. Although the gas injection program is increasing production from the S-3 reservoir as evidenced in the production records of the State Oil and Gas Board, the implementation of a strategic in-fill well drilling program probably would facilitate the recovery of uncontacted hydrocarbons. Thus, a strategy of drilling new wells in the carbonate sand belt buildup areas is applicable in the western and south-central parts of the field. New wells completed in this reservoir should be drilled on a lesser spacing than 160 ac (53 ha) because of the inherent compartmentalization in this reservoir as a result of lower permeability and connectivity (Figures 7, 12B).

Lower Microbial Boundstone Reservoir

The lower boundstone reservoir (S-6) comprises subtidal thrombolitic boundstone (Figure 8F–I) associated with microbial buildups oriented in a southwest to northeast direction. These buildups developed in clusters in the western, central, and northern parts of the field and attain thicknesses of 43 ft (13 m) (Figure 6B). The clusters are separated by interbuildup areas characterized by a thickness of 7–9 ft (2–3 m) of microbialites that are overlain by a thick section of microbial-influenced lime mudstone and wackestone (Figure 7). Porosity in the microbial reservoirs includes depositional constructed void (intraframe) and diagenetic solution-enhanced void and vuggy pore types (Figure 9D). This pore system provides for high permeability and connectivity in the reservoir beds (Figure 13B). Permeability ranges to as much as 7953 md (Figure 14D) and porosity to as much as 20% (Figure 14B).

The lower microbial boundstone reservoir (S-6) is a candidate for secondary recovery operations in the Little Cedar Creek field to increase the ultimate recovery of hydrocarbons from the field (SOGBA, 2004). However, the sedimentary, petrophysical, and hydrocarbon productivity characteristics of the S-6 reservoir are more favorable for the recovery of hydrocarbons than the S-3 reservoir. The boundstone flow units associated with the microbial buildups are dominated by vuggy and solution-enhanced void pore types and represent a thick and more continuous, laterally (Figure 7) and vertically (Figure 5), reservoir interval of high porosity (Figure 14B), permeability (Figure 14D), and connectivity (Figures 7, 13B). Wells completed in this reservoir have higher hydrocarbon productivity compared to wells completed in the upper reservoir. Therefore, further simulation modeling should provide guidance in selecting the preferred secondary recovery project, water or gas injection, for the lower reservoir.

The S-6 reservoir beds of the microbial buildups with high permeability and connectivity have potential as quality hydrocarbon flow units; however, the buildup areas are separated by interbuildup areas characterized by a thick section of low permeability to nonreservoir rock that serves as a potential baffle or barrier to flow (Figures 7, 13). Thus, the microbial boundstone reservoir dominated by a vuggy and solution-enhanced void pore system has potential for the recovery of remaining hydrocarbons in the interwell areas associated with microbial buildups (Figure 6B). These undrained hydrocarbons probably, in part, can be recovered through a strategic well-drilling program. The strategy of drilling new wells in the microbial buildup areas is applicable throughout the field as evidenced by the high hydrocarbon productivity in wells in the western, central, and northern parts of the field. New wells completed in this reservoir can be drilled on a greater spacing than the upper reservoir because of the higher permeability, connectivity, and productivity of the S-6 reservoir.

CONCLUSIONS

1. An integrated field study of the microbial carbonate and associated reservoirs at Little Cedar Creek field in southwest Alabama, eastern Gulf coastal plain of the United States provides information to further the understanding of the spatial distribution of the sedimentary, petrophysical, and hydrocarbon productivity trends in microbial reservoirs.
2. The petroleum trap in Little Cedar Creek field is an updip stratigraphic trap consisting of a change in Upper Jurassic Smackover lithofacies from carbonate bank grainstone and packstone and subtidal microbial boundstone to bay and lagoonal lime mudstone and wackestone toward the northeastern end of the field, near the Smackover shoreline. Structural maps drawn on top of the Smackover and Norphlet formations show uniform dip to the southwest at a rate of 150–200 ft/mi (46–61 m/km). To date, no faulting, structural closure, or localized paleotopographic highs have been observed in this field. The hydrocarbons trapped in Little Cedar Creek probably are not sourced from the lime mudstone lithofacies in the field area but rather from Smackover basinal laminate beds rich in amorphous and microbial kerogen south of the field area.
3. The Smackover Formation in the field area can be divided into lithofacies, including two reservoir units and three seal rock units. Beginning from the top of the Smackover Formation, the facies are (S-1) peritidal lime mudstone-dolomudstone and wackestone (top seal along with the Haynesville argillaceous beds); (S-2) tidal-channel rudstone and floatstone; (S-3) nearshore carbonate bank grainstone and packstone sand bodies (upper reservoir) and interbuildup wackestone; (S-4) subtidal wackestone and lime mudstone (top seal for the lower reservoir); (S-5) subtidal bioturbated microbially influenced packstone (potential local reservoir), wackestone, and lime mudstone (potential seal beds in parts of the field); (S-6) microbial (thrombolite) boundstone (lower reservoir); and (S-7) transgressive lime mudstone-dolomudstone and wackestone (base seal rocks).
4. The upper reservoir consists of a series of progradational ooid and peloid sand bodies in a carbonate bank setting. The carbonate bank complex extends from the western part of the field to the central part in a southwest to northeast direction. These marine carbonate sand belt buildups comprise as much as six wackestone-packstone-grainstone sequences and attain thicknesses of 26 ft (8 m). In interbuildup areas, the sand bodies have a thickness of 4–8 ft (1–2 m) and are underlain by a thick section of wackestone. Porosity consists of primary interparticle and secondary solution-enhanced interparticle, intraparticle, vuggy, and grain moldic pore types and ranges 0%–33% with a mean of 7.6%. Permeability is critical to the low

productivity of this reservoir and ranges 0–452 md with a median of 1 md. Carbonate sand belt buildup areas serve as potential heterogeneous hydrocarbon flow units, and the interbuildup areas containing a thick section of low-permeability to nonreservoir rock serve as potential baffles or barriers to flow.

5. The lower reservoir comprises subtidal thrombolitic boundstone associated with microbial buildups oriented in a southwest to northeast direction over an area that encompasses 32 mi^2 (83 km^2). These buildups developed in clusters in the western, central, and northern parts of the field and attained thicknesses of 43 ft (13 m). The clusters are separated by interbuildup areas characterized by a thickness of 7–9 ft (2–3 m) of microbialites that are overlain by a thick section of microbial-influenced lime mudstone and wackestone. Porosity in the microbial reservoirs includes depositional constructed void (intraframe) and diagenetic solution-enhanced void and vuggy pore types. This pore system provides for high permeability and connectivity in the reservoir beds. Permeability ranges to as much as 7953 md and porosity to as much as 20%. These strata have high potential as hydrocarbon flow units; however, the buildup areas are separated by interbuildup areas characterized by a thick section of low-permeability to nonreservoir rock that serves as a potential baffle or barrier to flow. The microbialites are the major reservoir in the field.
6. To increase the ultimate recovery of hydrocarbons from Little Cedar Creek field, the differences in the sedimentary, petrophysical, and hydrocarbon productivity parameters in the lower and upper reservoirs should be considered. For example, the boundstone flow units associated with microbial buildups represent a thick and more continuous (laterally and vertically) reservoir interval of high porosity, permeability, and connectivity. Wells completed in this heterogeneous reservoir have higher hydrocarbon productivity. However, the grainstone-packstone flow units associated with carbonate sand belt buildups represent a thinner and more variable (laterally and vertically) reservoir interval of high porosity but lower permeability and connectivity. Wells completed in this highly heterogeneous reservoir interval have lower hydrocarbon productivity. Thus, a strategic infill well drilling program in the field requires drilling upper reservoir wells on lesser spacing than lower reservoir wells because the flow units associated with the upper reservoir tend to be more local and compartmentalized.
7. The results from the Little Cedar Creek field study have application in the design of improved development strategies for other fields producing from microbial carbonate reservoirs.

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