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**GEOLOGIC SETTING, PETROPHYSICAL CHARACTERISTICS,
AND REGIONAL HETEROGENEITY PATTERNS OF THE
SMACKOVER IN SOUTHWEST ALABAMA**

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EXECUTIVE SUMMARY

The Upper Jurassic Smackover Formation is found in an arcuate belt in the subsurface from south Texas to panhandle Florida. The Smackover is nowhere exposed at the surface, but age-equivalent strata crop out in northeastern Mexico. The Smackover is the most prolific hydrocarbon-producing formation in Alabama and is an important hydrocarbon reservoir from Florida to Texas.

Mesozoic and Cenozoic strata of the eastern Gulf Coastal Plain comprise a seaward-dipping and thickening wedge of sediments that blanketed the passive southern margin of the North American continent. The major positive basement elements that affected Mesozoic sedimentation in the eastern Gulf are the Wiggins arch, the Baldwin high, the Choctaw ridge complex, and the Conecuh ridge complex in southeast Mississippi and southwest Alabama and the Pensacola-Decatur ridge complex in southwest Georgia and northwest Florida. The Mississippi interior salt basin (MISB) of southern Mississippi and southwest Alabama was an actively subsiding depocenter throughout the Mesozoic and into the early Cenozoic. The Conecuh and Manila embayments and a basinal area south of the Baldwin high also were major sites of Mesozoic sedimentation. These negative structural features may have originated as rift grabens during the breakup of Pangea.

Movement of the Jurassic Louann Salt has resulted in a complex network of salt-related structural elements in southwest Alabama, including the regional peripheral fault trend, the Mobile graben, and numerous smaller features. Salt movement began in some areas as early as late Smackover time.

Pre-Jurassic and Jurassic geologic units found in the subsurface in the study area include pre-Mesozoic "basement" rocks; the Triassic-Lower Jurassic Eagle Mills Formation; the Jurassic Werner Formation, Louann Salt (including Pine Hill Anhydrite Member), Norphlet Formation (including Denkman Sandstone Member), Smackover Formation, and Haynesville Formation (including basal Buckner Anhydrite Member); and the Jurassic-Cretaceous Cotton Valley Group.

"Basement" denotes pre-Mesozoic sedimentary and crystalline rocks upon which basal Mesozoic strata were deposited. The Eagle Mills Formation is the oldest Mesozoic geologic unit in the study area; it is a nonmarine succession of red beds and associated diabase and basalt dikes and sills. The

overlying Werner Formation is dominated by anhydrite, but minor red, gray, and black shale, red sandstone, and conglomerate occur in the lower part of the unit. The Louann Salt conformably overlies the Werner Formation or, in the absence of the Werner, disconformably overlies the Eagle Mills Formation or basement rocks. In the study area, the Louann predominantly consists of silty, sandy, massive halite with intercalated anhydrite.

The Norphlet Formation (Oxfordian) conformably overlies the Pine Hill Anhydrite Member of the Louann Salt. Where the Pine Hill is absent, the contact may not be conformable. Where the Louann is absent, the Norphlet disconformably overlies older units. The Norphlet is dominated by alluvial-fan-, wadi-, playa-, and eolian deposits. Uppermost Norphlet strata were reworked by marine processes. The Norphlet is conformably overlain by the Smackover Formation. The contact is commonly abrupt, but is gradational over an interval of a few feet or less in parts of Mobile County, including Chunchula field, and in Barnett field on the Conecuh ridge complex.

The Smackover was deposited on a carbonate ramp, similar to that of the present-day Persian Gulf, in much of the Gulf-Coast region. However, in southwest Alabama, Smackover strata were deposited in four interconnected basins: the eastern part of the Mississippi interior salt basin, the Manila embayment (which contains two separate depocenters), the Conecuh embayment, and an unnamed basin south of the Baldwin high. The distribution of facies was more-closely controlled by local paleotopography than by southerly regional dip, as would have been the case in an unmodified ramp setting. High-energy facies were deposited in nearshore areas rimming exposed paleohighs and near the updip limit of Smackover deposition; lower energy strata were deposited in basin centers. Based on ammonites recovered from the lower portion of the unit, the Smackover has been assigned a late Oxfordian age. The Smackover ranges up to more than 550 feet thick in the study area.

Basal Smackover strata in Alabama contain laminar and domal stromatolites; these deposits probably formed in shallow water during the early stages of marine transgression. Middle Smackover strata are dominated by lime mudstone and pelletal or fossiliferous lime wackestone. These strata were deposited at and near the time of maximum transgression, and during and after a period of rapidly increasing water depth. Middle-Smackover lime mudstone is typically laminated and organic

rich. Upper Smackover strata were laid down during a relative-sea-level stillstand. Progradational strata of the upper Smackover are dominated by ooid grainstone and diverse peritidal carbonates on the flanks of the paleohighs, and by pelletal and oncoidal packstone and grainstone in the centers of the depositional basins. The Smackover locally contains substantial amounts of siliciclastic material, particularly near the Conecuh ridge and its associated small paleohighs (e.g., Barnett, North Wallers Creek, Uriah, Vocation, and Burnt Corn Creek fields), and in the Manila embayment. Diagenesis of Smackover reservoirs was dominated by the effects of (1) early cementation, (2) leaching of calcium-carbonate allochems, and (3) dolomitization, both mimetic and nonmimetic. The Smackover Formation is overlain in southwest Alabama by the Buckner Anhydrite Member of the Haynesville Formation, whose basal portion is dominated by subaqueous evaporites in depositional basins, and by peritidal- and supratidal evaporitic- and siliciclastic strata on the flanks and crests of paleohighs.

As of December, 1990, the Smackover had produced oil, condensate and/or natural gas from 73 established fields in Alabama. At that time, cumulative production from Smackover reservoirs in Alabama totaled over 113 million barrels (MMB) of oil (including Norphet oil production at South Womack Hill field, and minor amounts from a few other fields, which are not reported separately), 145 MMB of condensate (including Norphet condensate production at Hatter's Pond field, which is not reported separately), and 1.12 trillion cubic feet (TCF) of natural gas.

Smackover hydrocarbon traps in southwest Alabama can be characterized as structural or combination structural and stratigraphic traps. Many structural traps result from halokinesis of the Louann Salt, but basement-cored anticlinal traps are locally common. The Buckner Anhydrite Member of the Haynesville Formation commonly forms the seal. Combination traps generally involve porosity or permeability pinch-outs occurring on regional dip, on halokinetically-generated anticlines or structural noses, or on basement-related anticlines or faulted anticlines.

Microbially influenced laminated lime mudstone of the lower to middle Smackover Formation is the main source rock for the oil, condensate, and gas in Smackover reservoir rocks. Kerogen in Smackover laminated lime mudstone probably matured to liquid hydrocarbons from the early Cretaceous to the Tertiary. Structural growth of Smackover traps coincided with hydrocarbon

generation and migration from Smackover source rocks. Emplacement of liquid hydrocarbons in Smackover reservoirs was precisely controlled by relative timing of hydrocarbon generation and migration and trap formation and subsequent structural modification of the reservoir. For example, traps and seals that formed early contain oils most near the original composition of Smackover crude oil. Traps that formed later generally contain light oils or condensates. However, maturation and alteration of hydrocarbons in the reservoir can also generate condensates.

Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The most common Smackover reservoir rocks are nonskeletal grainstone. Mixed-particle grainstone/packstone is the second most common reservoir type in the Smackover of southwest Alabama. A third important kind of reservoir is microbial boundstone. A fourth reservoir type is crystalline dolostone. Quartzose sandstone, commonly dolomitic, forms permeable reservoirs locally in southern Monroe County.

The occurrence of reservoir-grade rocks (porosity at least 6% and permeability at least 0.1 md) in the Smackover Formation of southwest Alabama is dependent on (1) deposition of porous and permeable sediments in a variety of settings and (2) diagenetic processes which have preserved, enhanced, or created porosity and permeability both in originally permeable strata and in originally impermeable strata.

The most common kinds of pores in the Smackover are particle molds, secondary intraparticle (partial moldic) pores, intercrystalline pores, and interparticle pores. Less common, but significant, pore types are fractures and vugs. The various pore types lend different petrophysical characteristics to pore systems, and combinations of different kinds of pores in varying proportions create further effects. Interparticle pores are permeability enhancers, because they tend to form regular networks with abundant connections, and because they are interconnected by large pore throats. Fractures are even more effective permeability enhancers. Pore systems dominated by molds, vugs, and secondary intraparticle pores are not characterized by high permeability values because these pores tend to be poorly connected, and commonly by small pore throats. The most common kinds of molds are

oomolds and pelmolds. Secondary intraparticle pores differ from molds in being substantially smaller. Inter-crystalline pores form pore systems with variable permeability values, depending on crystal size. Inter-crystalline pores are commonly well connected by short and homogeneous pore throats, and the pores tend to be all about the same size and shape. Where inter-crystalline pores are large, homogeneous, and well connected, permeability values may be extremely high.

We classify Smackover reservoir rocks using capillary-pressure-curve shape. CP-curve shape summarizes a wealth of petrophysical information about reservoir rocks, including pore-throat-size distribution and estimates of recovery efficiency and permeability. CP-curve class 1 includes samples that have extremely leptokurtic pore-throat-size distributions and that exhibit little or no extrusion of mercury during pressure reduction. Samples assigned to CP-curve class 2 exhibit leptokurtic pore-throat-size distributions with minor fine tails, and there is little or no mercury extrusion during pressure reduction. CP-curve class 3 includes samples that have leptokurtic pore-throat-size distributions (generally steeper than those of class 2, but less steep than those of class 1). Samples assigned to this class exhibit as much as 60% mercury extrusion during pressure reduction. CP-curve class 4 includes samples that have mesokurtic pore-throat-size distributions (ranging from like those of class 2 to substantially more variable). These samples exhibit a prominent tail of small throats that accounts for as much as 25% of the pore volume, or a smooth reduction in volume of pores accessed through smaller and smaller throats over the entire range of pore-throat sizes. Samples assigned to this class extrude up to more than 25% of their mercury during pressure reduction. Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat-size distributions. CP curves assigned to this class are variable, as are porosity values, recovery efficiency values, and median throat sizes. On average, however, porosity values and throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40%. CP-curve class 6 includes marginal reservoir rocks; porosity values are less than 10% and the mean is about 6%. These samples have mesokurtic throat size distributions and entirely lack large throats (median throat sizes do not exceed 0.5 μm). Recovery efficiencies range between about 30 and 40%. CP-curve classes 7 and 8 include nonreservoir rocks. Progressing from class 1 to class 6, throat-size ranges for single samples increase and the proportions of dolomite and of

grainstone decrease. The lower class numbers correspond to reservoirs with higher porosity and permeability values.

Two possible methods of predicting permeability are discussed. The first is based on the relationship between microporosity, as measured from capillary-pressure data and as estimated by calibration of well logs, and permeability. The ultimate goal is to predict permeability values from well logs, or from limited amounts of other kinds of data. The second is by measuring median throat size, which is derived from capillary-pressure analysis. Small amounts of microporosity can dramatically depress permeability in the Smackover. It appears that small (centimeter-scale?) areas of small pores and small pore throats act as permeability baffles. The only petrophysical variable we investigated that is strongly correlated with permeability is median throat size (MTS). MTS is derived from capillary-pressure analysis, an expensive and time-consuming method which usually requires core samples. However, whereas permeability can only be measured in samples cut from cores, MTS can be calculated from analysis of cuttings. Therefore, permeability can be estimated from noncored intervals.

Pore systems in reservoir rocks of the Smackover Formation in southwest Alabama are dominated either by moldic plus secondary intraparticle pores or by intercrystalline pores. Intermediate pore systems are less common. Because the Smackover reservoir rocks we studied fall naturally into two distinct groups, we define two pore facies, which are rock units characterized by certain pore types or combinations of pore types, and by certain consequent pore-throat-size distributions. Pore facies also possess characteristic fluid-flow properties.

Reservoir rocks assigned to different pore facies are petrophysically, petrographically, and geographically distinct. Those assigned to the Moldic Pore Facies are dominated by moldic plus secondary intraparticle pores. Some samples contain up to about 20% interparticle pores. Reservoir rocks assigned to the Intercrystalline Pore Facies are dominated by intercrystalline pores. Moldic pore systems are products of primary sediment fabric, modified by (usually) fabric-selective dolomitization and by dissolution of unstable particles before, during, or after dolomitization. Intercrystalline pore systems are most strongly affected by pervasive fabric-destructive dolomitization, although primary

sediment fabric commonly has some effect on the final rock fabric. This means that geological models of environment of deposition and of diagenetic history are more likely to help interpretation of moldic reservoirs than of intercrystalline reservoirs. Moldic pore systems tend to have higher mean porosity values but lower maximum permeability values than intercrystalline pore systems. Moldic pore systems have more leptokurtic pore-throat-size distributions, but are fundamentally heterogeneous at microscopic scales because coarse and fine pores are found together. Intercrystalline pore systems are fundamentally homogeneous at this level, at least in the ideal case. Intercrystalline pore systems are more heterogeneous megascopically (vertically) and therefore have more potential for bypassing of potentially productive intervals. Also, high-permeability thief zones are more abundant in intercrystalline reservoirs. Intermediate samples resemble petrophysically the Intercrystalline Pore Facies, and occupy intermediate regions geographically. Because rocks of the Moldic and Intercrystalline pore facies are readily distinguishable, and exhibit quite different fluid-flow characteristics, the pore-facies classification proposed here may be a useful tool in planning development of Smackover fields in Alabama, and could probably be applied successfully to other porous and permeable carbonate units.

Quantitative measures of microscopic and megascopic reservoir heterogeneity are used to describe heterogeneity in Smackover hydrocarbon fields in southwest Alabama. Microscopic reservoir heterogeneity (μH) is $\{[(0.25\sigma\phi) + (\text{mean natural log of } K) + (1.5\sigma \text{ natural log of } K)]/3\}$. Megascopic heterogeneity (MH) is $\{[(\# \text{ of reservoir intervals}) + (\# \text{ of high-}K \text{ reservoir intervals}) + (\sigma \text{ of } \# \text{ of reservoir intervals})]\}$ where reservoir rock is defined as exhibiting permeability values ≥ 0.1 md and high- K reservoir rock exhibits permeability values ≥ 1.0 md. Both MH and μH are determined from core data and are estimates of vertical heterogeneity. The Dykstra-Parsons coefficient (DP) is a measure of microscopic heterogeneity that is partially independent of μH ($r^2 = 0.428$).

μH and MH are distributed in opposing patterns. μH generally decreases from northwest to southeast; highest values are found in the vicinity of the Choctaw ridge complex north of the MISB. Moderately high values typify the Manila embayment and the Conecuh ridge complex to the south, whereas lower values are found in the MISB, on the north flank of the Wiggins arch, and in the

Conecuh embayment. μH values are high in the Moldic Pore Facies and low in the Intercrystalline Pore Facies.

MH values are high on the north flank of the Wiggins arch, on the Conecuh ridge complex and in the Conecuh embayment. MH values are low near the Choctaw ridge complex. The Conecuh ridge is unique because it is characterized by high values of both μH and MH. Also, the low-relief salt-cored anticline that stretches southward from the vicinity of Silas field in southern Choctaw County to Chatom field in west-central Washington County is characterized by relatively high values of MH. Reservoirs belonging to the Moldic Pore Facies tend to be homogeneous with respect to MH, whereas reservoirs assigned to the Intercrystalline Pore Facies are characterized by relatively high values of MH.

The congruency of patterns of variation of μH and MH with pore-system characteristics (controlled by depositional patterns, dissolution, and dolomitization) and regional structural and paleogeographic trends suggests that reservoir heterogeneity characteristics are controlled by structural and paleogeographic setting, and by diagenesis. However, because contours of μH and MH are approximately normal to structure contours but parallel to Smackover thickness contours, it appears that depositional setting (or paleogeography) exerted more-stringent control on reservoir heterogeneity than did structural evolution.

The distribution of DP values is not related to pore-facies distribution; thus the DP coefficient is less useful for regional heterogeneity studies than is MH or μH .

Quantification of μH and MH regionally in the Smackover of southwest Alabama will facilitate EOR planning for fields that are still in the early stages of development. Prediction of reservoir heterogeneity characteristics will facilitate advance planning of production strategies and cost/benefit analyses for development of new fields. In addition, it will be possible to identify regions characterized by or containing unusually heterogeneous or unusually homogeneous reservoirs (microscopic, megascopic, or both).

Microscopic lateral heterogeneity (LH) was calculated for 12 of the largest Smackover fields. Relatively sophisticated parameters could not be applied to the Smackover of southwest Alabama

because the data are of poor quality. Instead, LH was estimated as a function of the difference between the residual variance about the porosity-permeability trend for single wells and that for entire fields. If a field is perfectly laterally homogeneous, then wells will not differ with respect to their porosity-permeability trends, and subtracting the field value from the average of values for single wells yields an LH estimate of zero. Conversely, if a field is highly heterogeneous laterally, then the field value will exhibit a high degree of scatter because wells with very different porosity-permeability relationships will have been lumped together. A high value of LH results. Analysis of the 12 fields for which sufficient data are available indicates that μH and LH covary. Also, gas-condensate fields are relatively laterally homogeneous, and oil fields are relatively laterally heterogeneous.

Appendix 1 is the final report on Subtask 2. This appendix consists of geological and engineering characterizations on each of the 73 Smackover fields discovered in southwest Alabama as of December 1990.

ABSTRACT

Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The most common Smackover reservoir rocks are nonskeletal grainstone, dominated by pellets, ooids, and oncoids, in order of decreasing abundance. Mixed-particle grainstone/packstone is the second most common reservoir type in the Smackover of southwest Alabama. A third important kind of reservoir is microbial boundstone. At least three kinds of microbial boundstone are common in the Smackover of southwest Alabama: laminar stromatolites, domal stromatolites, and "microstromatolites." The latter are small (commonly a few cm or less in the longest dimension), lensoid or domal, and are commonly clustered but not bound together. A fourth reservoir type is crystalline dolostone. Quartzose sandstone, commonly dolomitic, forms permeable reservoirs with interparticle pore systems locally in southern Monroe County (e.g., North Wallers Creek field).

The most common kinds of pores in the Smackover are particle molds, secondary intraparticle (partial moldic) pores, intercrystalline pores, and interparticle pores. Less common, but significant, pore types are fractures and vugs. The various pore types lend different petrophysical characteristics to pore systems, and combinations of different kinds of pores in varying proportions create further effects. Interparticle pores are permeability enhancers, because they tend to form regular networks with abundant connections, and because they are interconnected by large pore throats. Fractures are even more effective permeability enhancers. They are less likely to be cemented because they form later. Pore systems dominated by molds, vugs, and secondary intraparticle pores are not characterized by high permeability values because these pores tend to be poorly connected, and commonly by small pore throats. The most common kinds of molds are oomolds and pelmolds. Secondary intraparticle pores differ from molds in being much smaller. Intercrystalline pores form pore systems with variable permeability values, depending on crystal size. Intercrystalline pores are commonly well connected by short and homogeneous pore throats, and the pores tend to be all about the same size and shape.

Where intercrystalline pores are large, homogeneous, and well connected, permeability values may be extremely high.

We classify Smackover reservoir rocks using capillary-pressure-curve shape. CP-curve class 1 includes samples that have extremely leptokurtic pore-throat-size distributions and that exhibit little or no extrusion of mercury during pressure reduction. Samples assigned to CP-curve class 2 exhibit leptokurtic pore-throat-size distributions with minor fine tails, and there is little or no mercury extrusion during pressure reduction. CP-curve class 3 includes samples that have leptokurtic pore-throat-size distributions (generally steeper than those of class 2, but less steep than those of class 1). Samples assigned to this class exhibit as much as 60% mercury extrusion during pressure reduction. CP-curve class 4 includes samples that have mesokurtic pore-throat-size distributions (ranging from like those of class 2 to substantially more variable). These samples exhibit a prominent tail of small throats that accounts for as much as 25% of the pore volume, or a smooth reduction in volume of pores accessed through smaller and smaller throats over the entire range of pore-throat sizes. Samples assigned to this class extrude up to 25% or more of their mercury during pressure reduction. Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat-size distributions. CP curves assigned to this class are variable. These samples also have variable porosity values, recovery efficiency values, and median throat sizes. On average, however, porosity values and throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40%. CP-curve class 6 includes marginal reservoir rocks; porosity values are less than 10% and the mean is about 6%. These samples have mesokurtic throat size distributions and entirely lack large throats (median throat sizes do not exceed 0.5 μm). Recovery efficiencies range between about 30 and 40%. CP-curve classes 7 and 8 include nonreservoir rocks.

Progressing from class 1 to class 6, throat-size ranges for single samples increase, and the proportions of dolomite and of grainstone decrease. The lower class numbers correspond to reservoirs with higher porosity and permeability values.

Small amounts of microporosity can dramatically depress permeability in the Smackover. It appears that small (centimeter-scale?) areas of small pores and small pore throats act as permeability

baffles. Of the petrophysical variables investigated, only median throat size (MTS) is strongly correlated with permeability. Whereas permeability can only be measured in samples cut from cores, MTS can be calculated from analysis of cuttings. Therefore, permeability can be estimated from noncored intervals.

Pore systems in reservoir rocks of the Smackover Formation in southwest Alabama are dominated either by moldic plus secondary intraparticle pores or by intercrystalline pores. Intermediate pore systems are less common. Because the Smackover reservoir rocks we studied fall naturally into two distinct groups, we define two pore facies, rock units characterized by certain pore types or combinations of pore types, and by certain consequent pore-throat-size distributions. Pore facies also possess characteristic fluid-flow properties.

The Moldic and Intercrystalline pore facies are geographically segregated in the Smackover Formation in southwest Alabama. Reservoir rocks assigned to the Moldic Pore Facies are dominated by moldic plus secondary intraparticle pores. Some samples contain up to about 20% interparticle pores. Reservoir rocks assigned to the Intercrystalline Pore Facies are dominated by intercrystalline pores. Moldic pore systems are products of primary sediment fabric, modified by (usually) fabric-selective dolomitization and by dissolution of unstable particles before, during, or after dolomitization. Intercrystalline pore systems are most strongly affected by pervasive fabric-destructive dolomitization, although primary sediment fabric commonly has some effect on the final rock fabric. Moldic pore systems tend to have higher mean porosity values but lower maximum permeability values than intercrystalline pore systems. Moldic pore systems have more leptokurtic pore-throat-size distributions, but are fundamentally heterogeneous at microscopic levels because coarse and fine pores are mixed together. Intercrystalline pore systems are fundamentally homogeneous microscopically. Intercrystalline pore systems are more heterogeneous megascopically and therefore there is more potential for bypassing of potentially productive reservoir zones. Also, high-permeability thief zones are more likely in intercrystalline reservoirs. Intermediate samples resemble petrophysically the Intercrystalline Pore Facies, and occupy intermediate regions geographically.

Quantitative measures of microscopic and megascopic vertical reservoir heterogeneity are used to describe heterogeneity in Smackover hydrocarbon fields in southwest Alabama. Microscopic reservoir heterogeneity (μH) is $\{[(0.25\sigma\phi) + (\text{mean natural log of } K) + (1.5\sigma \text{ natural log of } K)]/3\}$. Megascopic heterogeneity (MH) is $\{[(\# \text{ of reservoir intervals}) + (\# \text{ of high-K reservoir intervals}) + (\sigma \text{ of } \# \text{ of reservoir intervals})]\}$ where reservoir rock is defined as exhibiting permeability values ≥ 0.1 md and high-K reservoir rock exhibits permeability values ≥ 1.0 md. μH and MH are distributed in opposing patterns. μH generally decreases from northwest to southeast. μH values are high in the Moldic Pore Facies and low in the Intercrystalline Pore Facies. The Conecuh ridge is unique because it is characterized by high values of both μH and MH. Reservoirs belonging to the Moldic Pore Facies tend to be homogeneous with respect to MH, whereas reservoirs assigned to the Intercrystalline Pore Facies are characterized by relatively high values of MH. The congruency of patterns of variation of μH and MH with pore-system characteristics (controlled by depositional patterns, dissolution, and dolomitization) and regional structural and paleogeographic trends suggests that reservoir heterogeneity characteristics are controlled by structural and paleogeographic setting, and by diagenesis. However, because contours of μH and MH are approximately normal to structure contours but parallel to Smackover thickness contours, it appears that depositional setting (or paleogeography) exerted more-stringent control on reservoir heterogeneity than did structural evolution. The distribution of DP values is not related to pore-facies distribution; thus DP is less useful for regional heterogeneity studies than is MH or μH . Microscopic lateral heterogeneity was calculated for 12 of the largest Smackover fields. Lateral heterogeneity was estimated as a function of the difference between the residual variance about the porosity-permeability trend for single wells and that for entire fields. μH and microscopic lateral heterogeneity covary. Also, gas-condensate fields are relatively laterally homogeneous, and oil fields are relatively laterally heterogeneous.

INTRODUCTION

ORGANIZATION OF THIS REPORT

This is the draft topical report on Subtasks 2 and 3 of DOE contract number DE-FG22-89BC14425, entitled "Establishment of an oil and gas database for increased recovery and characterization of oil and gas carbonate reservoir heterogeneity." This volume constitutes the final report on Subtask 3, which had as its primary goal the geological modeling of reservoir heterogeneity in Smackover reservoirs of southwest Alabama. This goal was interpreted to include a thorough analysis of Smackover reservoirs, which was required for an understanding of Smackover reservoir heterogeneity. Appendix 1 contains reservoir characterization packets on all 73 Smackover fields in Alabama (through December, 1990), which collectively constitute the final report on Subtask 2. Subtask 2 had as its primary aim the geological and engineering characterization of Smackover reservoirs in Alabama. A summary of findings of Subtask 2 follows this section. Reference in this report to specific Smackover fields is keyed to the location map (fig. 1) and accompanying table of fields (table 1).

This report is divided into six sections (including this brief introduction). Section two, entitled "Geologic setting," presents a concise summary of Jurassic paleogeography, structural setting, and stratigraphy in southwest Alabama. This section also includes a brief review of sedimentologic characteristics and stratigraphic framework of the Smackover, and a summary of the diagenetic processes that strongly affected Smackover reservoirs in Alabama.

Section three, entitled "Analytical methods," summarizes all nonroutine aspects of the analytical procedures used in this project. The major topics are thin-section description, analysis of commercial porosity and permeability data, capillary-pressure analysis, and field characterization.

"Smackover reservoir characteristics" are described in section four, which begins with a general summary of the petrographic characteristics of porous and permeable Smackover strata. This is followed by a more-detailed petrophysical description of Smackover reservoirs.

Figure 1.--Location map for all Smackover fields in Alabama.

Table 1.--Smackover fields in Alabama as of December, 1990

Field No.	Field Name	County	Hydrocarbon Type
1	Appleton	Escambia	Oil
2	Barlow Bend	Clarke and Monroe	Oil
3	Barnett	Conecuh and Escambia	Oil
4	Barrytown	Choctaw	Oil
5	Big Escambia Creek	Escambia	Condensate
6	Blacksher	Baldwin	Oil
7	Broken Leg Creek	Escambia	Oil
8	Bucatonna Creek	Choctaw	Oil
9	Burnt Corn Creek	Escambia	Oil
10	Chappell Hill	Choctaw	Oil
11	Chatom	Washington	Condensate
12	Choctaw Ridge	Choctaw	Oil
13	Churchula	Mobile	Oil/Condensate
14	Cold Creek	Mobile	Oil
15	Copeland Gas	Washington	Condensate
16	Crosbys Creek	Washington	Condensate
17	East Barnett	Conecuh and Escambia	Oil
18	East Huxford	Escambia	Oil
19	Fanny Church	Escambia	Oil
20	Gin Creek	Choctaw	Oil
21	Gulf Crest	Mobile	Oil
22	Hanberry Church	Escambia	Oil
23	Hatter's Pond	Mobile	Condensate
24	Healing Springs	Washington	Condensate
25	Huxford	Escambia	Oil
26	Little Escambia Creek	Escambia	Oil
27	Little Mill Creek	Choctaw	Oil
28	Little River	Baldwin and Monroe	Oil
29	Little Rock	Escambia	Condensate
30	Lovetts Creek	Monroe	Oil
31	Melvin	Choctaw	Oil
32	Mill Creek	Choctaw	Oil
33	Mineola	Monroe	Oil
34	Movico	Baldwin and Monroe	Oil
35	North Choctaw Ridge	Choctaw	Oil
36	North Smiths Church	Escambia	Oil
37	North Wallers Creek	Monroe	Oil
38	Northeast Barnett	Conecuh	Oil
39	Northwest Range	Conecuh	Oil
40	Pace Creek	Clarke	Oil
41	Palmers Crossroads	Monroe	Oil
42	Perdido	Baldwin and Escambia	Oil
43	Puss Cuss Creek	Choctaw	Oil
44	Red Creek	Washington	Condensate
45	Robinson Creek	Escambia	Oil
40	Pace Creek	Clarke	Oil

Table 1.—Smackover fields in Alabama as of December, 1990—Continued

Field No.	Field Name	County	Hydrocarbon Type
41	Palmers Crossroads	Monroe	Oil
42	Perdido	Baldwin and Escambia	Oil
43	Puss Cuss Creek	Choctaw	Oil
44	Red Creek	Washington	Condensate
45	Robinson Creek	Escambia	Oil
46	Silas	Choctaw	Oil
47	Sizemore Creek Gas	Escambia	Condensate
48	Smiths Church	Escambia	Condensate
49	South Burnt Corn Creek	Escambia	Oil
50	South Cold Creek	Mobile	Oil
51	South Vocation	Monroe	Oil
52	South Wild Fork Creek	Escambia	Condensate
53	South Womack Hill	Choctaw and Clarke	Oil
54	Southeast Chatom	Washington	Condensate
55	Southwest Barrytown	Choctaw	Oil
56	Souwilpa	Choctaw	Condensate
57	Stave Creek	Clarke	Oil
58	Sugar Ridge	Choctaw	Oil
59	Toxey	Choctaw	Oil
60	Turkey Creek	Choctaw and Clarke	Oil
61	Turnerville	Mobile	Oil
62	Uriah	Monroe	Oil
63	Vocation	Monroe	Oil
64	Wallace	Escambia	Oil
65	Waller's Creek	Monroe	Oil
66	West Appleton	Escambia	Oil
67	West Barrytown	Choctaw	Oil
68	West Bend	Choctaw and Clarke	Oil
69	West Okatuppa Creek	Choctaw	Oil
70	Wild Fork Creek	Escambia	Oil
71	Wimberly	Choctaw	Oil
72	Womack Hill	Choctaw and Clarke	Oil
73	Zion Chapel	Choctaw	Oil

Petrophysical classification of Smackover reservoirs is the subject of section five. The classification presented here is based upon a modified version of the genetic carbonate pore-type classification of Choquette and Pray (1970), and integrates pore types with porosity, permeability, and capillary-pressure data to create a unified reservoir classification.

The sixth and final section concerns reservoir heterogeneity. We develop numeric methods to rank Smackover fields from homogeneous to extremely heterogeneous. Three different measures of reservoir heterogeneity (two of microscopic reservoir heterogeneity and one of megascopic heterogeneity) are described and compared. We relate the distribution of heterogeneity values to the petrophysical classification presented in section five, to regional paleogeography, and to reservoir performance. Microscopic lateral heterogeneity is calculated for 12 large Smackover fields, and the implications of the results are discussed. Application of reservoir-heterogeneity analysis to individual field studies is the subject of the final topical report on Subtask 4 (previously submitted to DOE).

RESERVOIR CHARACTERIZATION OF SMACKOVER FIELDS

Appendix 1 is the final report on Subtask 2. The primary objective of Subtask 2 was the geological and engineering characterization of Smackover reservoirs in Alabama. Appendix 1 consists of geological and engineering descriptions of the 73 Smackover fields discovered in Alabama as of December 1990.

Appendix 1 is organized by field, in alphabetical order. For each field are presented index and structure maps, a type log, a structural cross section, a graph of production history, and a data sheet that includes such information as discovery well, number of producing wells, field averages for porosity and permeability, and trap type. A sample reservoir data sheet is included as figure 2. Additional kinds of information that are unavailable for some fields are included where possible. These include porosity vs. permeability plots, graphic core logs, descriptions of lithofacies containing reservoir rock (porosity at least 6%; permeability at least 0.1 md), paragenetic sequences, and ternary diagrams illustrating the relative abundances of major pore types (ternary pore plots).

**APT-1.--Reservoir characterization sheet, Smackover pool,
Appleton field, Escambia County, Alabama**

Discovery well

Operator: Texaco, U.S.A.

Permit number: 3854

Well Name: D.W. McMillan Trust 2-14 #1

Location: Sec. 2, T3N-R9E

Completion date: 10/19/83

Perforations: 12,902-12,938 ft

Initial flow rate: 661 bopd, 1,060 Mcfd,
16/64**Field data (as of 12/31/90)**

Number of wells within field limits: 7

Producing wells in pool: 4

Production wells in field: 4

Shut-in/Temp. abandoned wells: 0

Plugged and abandoned wells: 2

Salt water disposal wells: 1

Enhanced recovery wells: 0

Dry holes: 2

Drilling wells: 0

Unit spacing (acres): Unitized

Total field area (acres): ~840

Cumulative production

Condensate (bbl): 994,987

Gas (Mcf): 1,885,911

Water (bbl): 1,015,865

Reservoir data

Trap type: Structural

Reservoir structure: Anticline

Proven productive area (acres): 473

Average net pay thickness (feet): 39

Hydrocarbon type: Oil

Oil gravity (API): 52

Initial reservoir pressure (psia): 6,285

Current reservoir pressure (psia): 5,700

Reservoir drive: Solution gas/water

Type of enhanced recovery: none

Mean porosity (core) (%): 5.94

Porosity standard deviation (%): 3.75

Maximum porosity (%): 1.00

Minimum porosity (%): 14.30

Number of porosity analyses: 30

Geometric mean perm (core) (md): 0.69

Maximum permeability (md): 18.80

Minimum permeability (md): 0.01

Number of permeability analyses: 10

Dykstra-Parsons coefficient: na

Figure 2.--Sample reservoir data sheet from Appendix 1.

Appendix 1 is a reference to which the reader of this volume can refer for geological or engineering information about individual fields mentioned in this report, or about groups of fields described in this report as sharing similarities or exhibiting differences pertaining to their reservoir characteristics. The contents of Appendix 1 are briefly described in the following paragraphs. (In the methods section of this report, some aspects of data collection and preparation of figures in Appendix 1 are described.)

The reservoir characterization packets begin with index and structure maps. Most structure maps are drawn on the top of the Smackover Formation. Type logs were chosen for all fields on the basis of completeness and quality of the logs. If, for a given field, a core was described from a well having a complete and high-quality log, then that became the type log. Structural cross sections typically encompass all or part of the Haynesville Formation, and all units older than the Haynesville that were penetrated and logged.

Production graphs cover the entire history of all fields through December 1990. Production of all relevant fluids, as well as the number of producing wells, are recorded on these graphs. For unitized fields, the date of unitization is also indicated.

Porosity vs. permeability plots incorporate all available commercial porosity and permeability data from each field. The numbers of wells represented by each graph are indicated. In addition, if a core was described, and commercial porosity and permeability data were available for that core, then a separate graph was made using only the data from the described core. In most cases the graph for several wells combined exhibits more scatter than does the single-well graph for the same field. The difference in amount of scatter between the two graphs from a given field is a crude measure of lateral heterogeneity in that field (see section on lateral heterogeneity in this volume). For described cores that contain porous and permeable intervals, and for which commercial porosity and permeability data were available, additional porosity vs. permeability plots were constructed as follows. Reservoir lithofacies were identified from petrographic core description, and these were invariably found to differ petrophysically. Therefore, porosity vs. permeability plots for individual reservoir lithofacies were constructed. These graphs, in contrast to the other porosity vs. permeability

plots, exclude all nonreservoir rock (porosity < 6%; permeability < 0.1 md); they record only petrophysical variation within reservoir lithofacies. For many lithofacies porosity vs. permeability plots exhibit dramatically reduced variation in both petrophysical parameters when compared to the whole-core plots. This indicates that whereas the reservoir as a whole is variable, individual lithofacies (identified purely petrographically using a binocular microscope) are commonly remarkably homogeneous. Such lithofacies probably correspond to flow units. In principle, then, mapping of lithofacies permits mapping of flow units, at least for some fields.

The reservoir characterization data sheets include summary information about each field. Figure 2 is a sample reservoir characterization sheet.

The graphic core logs summarize the results of core description using a binocular microscope, supplemented, in some cases, by thin-section study. These figures are complex because they include a great deal of information. All symbols are explained at the beginning of Appendix 1.

The lithofacies descriptions correspond to the lithofacies mentioned above in connection with porosity-permeability plots. Estimates of relative abundances of pore types are based on visual inspection of cores and of thin sections, supplemented by point-counting of thin sections from 16 fields (see table 2).

Paragenetic sequences are based upon core description and thin-section study. They should be regarded as preliminary, because no detailed diagenetic studies have been completed. Where bars are solid, temporal overlaps between diagenetic processes are well supported. If one or both of the overlapping bars is (are) dashed, then the temporal relationship is conjectural.

Ternary pore plots are included for 16 fields. These are based upon point counts of petrographic thin sections. The method of ternary-pore-plot construction is described in this report, but see also Kopaska-Merkel and Mann (1991b).

Table 2.--Number of fields for which each kind of information is included in Appendix 1

Kind of Information	Number of fields
Index Map	73
Structure Map	73
Type Log	73
Cross Section	73
Production Graph	73
Phi vs. K Plot, whole core	52
Characterization Sheet	73
Graphic Core Log	38
Lithofacies Description	36
Phi vs. K Plot, lithofacies	28
Paragenetic Sequence	38
Ternary Pore Plot	16

GEOLOGIC SETTING

The Upper Jurassic Smackover Formation forms an arcuate belt in the subsurface from south Texas to panhandle Florida. The updip limit of Smackover strata passes offshore beneath the Florida panhandle. Age-equivalent strata in Mexico are assigned to the Zuloaga Formation. The Smackover is nowhere exposed at the surface, but the Zuloaga crops out in northeastern Mexico. Distal Smackover strata, which do not produce hydrocarbons, are found gulfward of productive nearshore facies, both onshore and offshore.

In this section, we review briefly the regional framework, structural and stratigraphic setting, and characteristics of Triassic and Jurassic strata in Alabama and surrounding areas. In section three, we describe analytical methods. Section four is a summary of Smackover reservoir characteristics. In section five Smackover reservoirs are classified petrophysically. Three different measures of vertical reservoir heterogeneity, and one of lateral heterogeneity, are presented in section six and are applied to Smackover fields in southwest Alabama.

REGIONAL FRAMEWORK

Southwest Alabama is part of the eastern Gulf Coastal Province of North America. This province includes that part of the Gulf Coastal Plain situated east of the Mississippi River and west of the Atlantic Coastal Plain, whose southwestern boundary is the northwest-southeast trending Ocala (or Peninsular) arch in Georgia and Florida (fig. 3). The northernmost extent of outcropping Upper Cretaceous or younger strata is the northern limit of the Coastal Plain, where coastal-plain strata unconformably overlie Paleozoic sedimentary and Precambrian and Paleozoic metamorphic and igneous rocks, most of which have been deformed. The southern limit of the Gulf Coastal Plain is the southernmost extent of the continental rise of the Gulf of Mexico (Murray and others, 1985).

Triassic through Lower Cretaceous strata, including the Jurassic Smackover Formation, occur only in the subsurface in the eastern Gulf (fig. 4). However, age-equivalent units are exposed on the Atlantic Coastal Plain (Triassic and Lower Cretaceous), in the western Gulf region (Lower Cretaceous), and in Mexico (Jurassic).

The Gulf of Mexico basin did not exist during the Late Paleozoic and early Mesozoic; no Upper Permian to Upper Triassic marine sediments have been found in the circum-Gulf region (Pindell, 1985). The Gulf area was part of the supercontinent of Pangea. Separation of the North American plate from the Afro-South American plate and the opening of the Gulf basin began with continental rifting in the Early Triassic (Wood and Walper, 1974; Murray and others, 1985; Wilson and Tew, 1985). Extensional faulting along the rifted margin of the basin generated a system of grabens and half grabens (Rainwater, 1967; Walper and Rowett, 1972; Beall, 1973; Smith and others, 1981; Mink and others, 1990). These newly formed basins became the loci of deposition of the basal Mesozoic strata: Triassic to Early Jurassic continental siliciclastic red beds and igneous intrusives of the Eagle Mills Formation (e.g., Todd and Mitchum, 1977). During the early stages of basin formation, it was intermittently invaded by marine waters. Restriction combined with an arid climate caused intense evaporation, and thick successions of evaporites were deposited during the early and middle Jurassic. The Gulf basin was essentially open by the middle Jurassic (Buffler and Sawyer, 1985), and the area

Figure 3.--Regional map showing major structural features of the eastern Gulf coast.

SERIES	STAGE	ROCK UNIT
Lower Cretaceous	Berriasian	Cotton Valley Group
----- ? -----	Tithonian	
Upper Jurassic	Kimmeridgian	Haynesville Formation
		Buckner Anhydrite Member
	Oxfordian	Smackover Formation
		Norphlet Formation
		Pine Hill Anhydrite Member
----- ? -----	----- ? -----	
Middle Jurassic	Callovian	Louann Salt
		Werner Formation
Lower Jurassic/ Upper Triassic		Eagle Mills Formation
		Undifferentiated Paleozoic and Proterozoic "basement" rocks

Figure 4.--Stratigraphic column in the eastern Gulf.

was dominated by normal marine and marginal marine conditions from the late Jurassic onward (Murray, 1961).

STRUCTURAL SETTING

Mesozoic and Cenozoic strata of the eastern Gulf Coastal Plain comprise a seaward-dipping and thickening wedge of sediment that blanketed the passive southern margin of North America. The following major kinds of structural elements, either alone or combined, have affected eastern Gulf Coastal Plain strata: (1) positive and negative basement features generated during continental collision and suturing or continental rifting; (2) features related to the movement of Jurassic salt; and (3) features associated with igneous activity (fig. 5).

The major positive basement elements that affected Mesozoic sedimentation in the eastern Gulf are the Wiggins arch, the Baldwin high, the Choctaw ridge complex, and the Conecuh ridge complex in southeast Mississippi and southwest Alabama and the Pensacola-Decatur ridge complex in southwest Georgia and northwest Florida. At least some of these features are related to the Appalachian fold and thrust belt that was generated in the Late Paleozoic by the collision of the North American and Afro-South American continental plates. The topography associated with the Appalachian trend significantly influenced the distribution of coastal plain sediments; positive areas were major sources of Jurassic and pre-Jurassic clastic sediments. Some of these positive basement elements (e.g., the Wiggins arch) may be isolated horst blocks of continental lithosphere formed during rifting of the Gulf basin (Smith and others, 1981; Miller, 1982).

The MISB of southern Mississippi and southwest Alabama, which was an actively subsiding depocenter throughout the Mesozoic and into the early Cenozoic, is a broad, prominent depression on the basement surface (Wilson, 1975). The post-Paleozoic succession in the basin is much thicker than in surrounding areas. The MISB overlies an area of attenuated granitic continental crust; crustal thinning resulted from extension of the lithosphere during rifting in the Triassic and Jurassic (Wilson, 1975). Crustal attenuation created a subsiding structural basin cratonward of the rifted and elevated continental margin (Wood and Walper, 1974).

Figure 5.—Major structural features of southwest Alabama (modified from Mancini and others, fig. 1, 1991).

The Conecuh and Manila embayments also were major sites of Mesozoic sedimentation (Mancini and Benson, 1980). The Manila embayment actually contained two separate depocenters during Smackover and Buckner deposition (fig. 6). These negative structural features may have originated as rift grabens during the breakup of Pangea (Miller, 1982).

Movement of the Jurassic Louann Salt has resulted in a complex network of salt-related structural elements in southwest Alabama. Martin (1978) attributed the structural fabric of most of the northern Gulf margin to salt movement. Rosenkrans and Marr (1967) stated that all structural anomalies associated with the Smackover and younger formations within salt basins were generated by salt flow. Salt-related structures include diapirs, massifs and related salt-cored anticlines, normal faults, and grabens. Structural elements in the study area resulting from salt movement include the regional peripheral fault trend, the Mobile graben, and numerous smaller features. Salt movement began in some areas as early as late Smackover time. Faults that cut the Jurassic section and extend upward into the Haynesville typically exhibited growth during deposition of the Haynesville-Smackover section. Development of salt structures has resulted in numerous petroleum traps (salt anticline, faulted salt anticline, and extensional fault traps) in southwest Alabama (Martin, 1978; Mink and others, 1985).

The regional peripheral fault trend comprises a group of extensional faults with many en echelon elements. This trend, referred to in the eastern Gulf as the Pickens, Gilbertown, West Bend, Pollard, Foshee, and Pensacola-Destin fault systems (Mancini and others, 1985; Kemmer, 1987), rims the Gulf basin and is one of the dominant structural trends in the region. The faults of the regional peripheral trend are generally parallel or subparallel to regional strike and approximately coincide with the updip limit of thick Jurassic salt. Most of the faults are normal, down-to-the-basin or antithetic faults that form grabens 5 to 8 miles across (Murray, 1961). Fault planes are listric and dip from roughly 35° to 70° (Murray, 1961). On major faults, displacements in the Jurassic section range from 200 feet to more than 2000 feet (Mancini and others, 1985).

The MISB is characterized by salt pillows and salt diapirs. Pillow features in the salt basin are generally confined to updip areas, whereas diapirs are found in the central portion of the basin

Figure 6.--Isopach map of Smackover Formation, southwest Alabama, showing major depocenters (Modified from Wilson, fig. 6, 1975, Mancini and Benson, fig. 3, 1980, and Geological Survey of Alabama, 1985b).

where both salt and overburden are thicker. The eastern limit of the MISB is a north-south trending basement paleohigh or salt ridge in eastern Washington County (fig. 6; Mancini and Benson, 1980). The Mobile graben, a major structural feature in southwest Alabama (fig. 7), could be considered the eastern limit of the MISB. However, Smackover and Buckner thickness patterns and log signatures indicate that an area west of the Mobile graben was part of the southwestern depocenter of the Manila embayment during the late Jurassic (fig. 6; e.g., Wilson, 1975; Mancini and Benson, 1980). The Mobile graben began to grow rapidly only after Smackover time. Thus, the original definition of the eastern boundary of the MISB (the north-south ridge in eastern Washington County; Mancini and Benson, 1980) is consistent with Smackover stratigraphy and is adopted here.

Numerous workers, using geophysical data and stratigraphic evidence from boreholes, have suggested that a rift-related trend of basement faults and grabens rims the Gulf of Mexico basin and underlies the inner Gulf Coastal Plain (Murray, 1961; Rainwater, 1967; Vernon, 1971; Woods and Addington, 1973; Sigsby, 1976; Martin, 1978; Miller, 1982; Kinsland, 1984; Klitgord and Popenoe, 1984; Klitgord and Schouten, 1986; Thomas, 1988). This inferred late Triassic to early Jurassic trend cuts pre-Mesozoic strata and is roughly coincident with the well-documented, salt-related regional peripheral fault trend, which dissects Jurassic through Miocene strata in Alabama (Martin, 1978). The faults of the regional basement rift trend may have controlled subsequent Jurassic and post-Jurassic faulting along the inner margin of the Gulf Coastal Plain.

Although the regional basement rift trend may have been reactivated and may have influenced movement of the Jurassic salt, it is important to clearly differentiate between the inferred regional basement rift trend that is genetically related to the Triassic-Early Jurassic breakup of Pangea and the opening of the Gulf, and the regional peripheral fault trend that is related to Late Jurassic to Miocene movement of the Louann Salt (Mink and others, 1990). Faults of the regional peripheral fault trend were active from the late Jurassic to the Miocene, with the maximum amount of displacement during the Cretaceous (Martin, 1978). By Cretaceous time, overburden was thick enough to produce large-scale halokinesis. In addition, many of the master and antithetic faults in the trend are listric and

Figure 7.--Regional structure map on top of Smackover Formation for southwest Alabama (Modified from Mancini and Benson, fig. 4, 1980, and Geological Survey of Alabama, 1985a).

terminate downward in the Louann Salt, indicating fault genesis at that stratigraphic level (Hughes, 1968; Moore, 1971; Sigsby, 1976; Martin, 1978; Kinsland, 1984).

STRATIGRAPHY

GENERAL INTRODUCTION

Pre-Jurassic and Jurassic geologic units found in the subsurface in the study area include pre-Mesozoic "basement" rocks; the Triassic-Lower Jurassic Eagle Mills Formation; the Jurassic Werner Formation, Louann Salt (including Pine Hill Anhydrite Member), Norphlet Formation (including Denkman Sandstone Member), Smackover Formation, and Haynesville Formation (including basal Buckner Anhydrite Member); and the Jurassic-Cretaceous Cotton Valley Group (fig. 4). None of these strata are exposed at the surface in the study area.

Jurassic strata underlying the U.S. Gulf coast contain huge volumes of evaporites: thick halite rock in the Louann and Haynesville, and anhydrite rock in the Werner, Pine Hill, and Haynesville. In addition, eolian strata dominate the Norphlet Formation in the eastern Gulf. Sabkhas and salinas are common in the upper Smackover (e.g., Barnett, Barrytown, Blacksher, Burnt Corn Creek, Chatom, and Zion Chapel fields; Appendix 1). Early diagenetic fabrics of carbonates of the Smackover and Haynesville formations suggest that meteoric diagenesis was limited. By contrast, indicators of arid-zone diagenesis, such as intrasedimentary penecontemporaneous discoidal gypsum crystals, tepee structures, and calcareous crusts (caliche) are widespread (e.g., Appleton, Barrytown, and Chappell Hill fields; see Appendix 1). Jurassic sediments in the study area were deposited in an arid setting.

"BASEMENT" ROCKS

"Basement" denotes pre-Mesozoic sedimentary and crystalline rocks upon which basal Mesozoic strata were deposited (fig. 4). An upper Paleozoic suture zone resulting from the collision of the North American and Afro-South American lithospheric plates trends generally east-west across the coastal plain of Alabama (Chowns and Williams, 1983; Horton and others, 1984; Dallmeyer, 1987). Along the suture zone, rocks of the Suwannee basement complex (interpreted as an accreted terrane,

a part of the Paleozoic Afro-South American plate that remained with North America during the early Mesozoic breakup of Pangea), and rocks of the problematic Wiggins basement complex (metamorphic rocks of late Pennsylvanian to early Permian age) meet the southwestern subsurface extension of the Appalachian Valley and Ridge and Piedmont provinces (Cagle and Khan, 1983; Chowns and Williams, 1983; Horton and others, 1984; Dallmeyer, 1987; Opdyke and others, 1987; Mink and others, 1990). The exact relationship across the Paleozoic suture zone is obscured by a cover of lower Mesozoic sedimentary and igneous strata deposited in the young Gulf of Mexico basin.

EAGLE MILLS FORMATION AND MESOZOIC IGNEOUS ROCKS

The Eagle Mills Formation is the oldest Mesozoic geologic unit in the study area, and its distribution and characteristics in Alabama are poorly known (Tolson and others, 1983). Nevertheless, some inferences may be made from scanty data from Alabama and more-abundant data from elsewhere in the Gulf coast (Tolson and others, 1983; Salvador, 1987) (fig. 4). The Eagle Mills is a nonmarine succession of red beds and associated diabase and basalt dikes and sills. The formation has been dated as Late Triassic to possibly Early Jurassic based on plant remains recovered from an exploration well in southern Arkansas (Scott and others, 1961). Isotopic data from igneous dikes and sills associated with red beds in the southwestern United States yield Early Jurassic dates (Chowns and Williams, 1983; Dooley and Wampler, 1983). Radiometric dating of basaltic intrusions in Eagle-Mills strata suggests a Late Triassic age (Baldwin and Adams, 1971).

The Eagle Mills Formation is discontinuously distributed, and abrupt changes in thickness are common (Tolson and others, 1983). These characteristics, along with rock composition and the nature of the rare fossils recovered from the unit, led Salvador (1987) to interpret Eagle Mills strata as continental deposits that filled actively subsiding grabens and half grabens that formed during rifting and opening of the Gulf of Mexico basin (e.g., Rainwater, 1967; Woods and Addington, 1973; Todd and Mitchum, 1977). Eagle Mills sediments were derived from the erosion of graben-bounding horst blocks and were deposited on alluvial fans, in river systems, on delta plains, and in lakes (Salvador, 1987).

WERNER FORMATION

The Werner Formation disconformably overlies the Eagle Mills Formation or, in the absence of Eagle Mills strata, basement rocks (fig. 4). The Werner formed during initial transgression of marine waters into the Gulf of Mexico basin (Tolson and others, 1983). The Werner is dominated by anhydrite, but minor red, gray, and black shale, red sandstone, and conglomerate occur in the lower part of the unit (Tolson and others, 1983; Salvador, 1987). The Werner is thick in grabens (up to about 1300 feet) and thin or absent on adjacent paleohighs (Tolson and others, 1983; Mink and others, 1990). In southwest Alabama, the Werner Formation is absent over portions of the Wiggins arch complex and the Choctaw, Conecuh and Pensacola-Decatur ridge complexes.

During Werner deposition, sea water probably reached the newly opening Gulf intermittently, forming large, shallow saline lakes in low areas, such as subsiding grabens (Salvador, 1987). Alternatively, the Werner could have been laid down in a deep-water evaporite basin (Schmalz, 1969). Evaporative concentration of the saline waters resulted in evaporite deposition. In most areas, the Werner is overlain by the Louann Salt. Locally, however, the two appear to be lateral equivalents, with halite deposits dominating the central portions of basins and evaporites found in marginal areas (Salvador, 1987). The Werner is inferred to be Callovian in age based on regional stratigraphic and paleogeographic relationships (Salvador, 1987), especially its apparent facies relationship to the Louann Salt.

LOUANN SALT

The Louann Salt conformably overlies the Werner Formation or, in the absence of the Werner, disconformably overlies the Eagle Mills Formation or basement rocks (fig. 4). The Louann has been estimated to cover as much as 180,000 square miles in the Gulf of Mexico region (Hazzard and others, 1947). The updip limit of thick Louann Salt deposition approximately coincides with the regional peripheral fault trend. In the study area, the Louann predominantly consists of silty, sandy, massive halite with intercalated anhydrite (Tolson and others, 1983). Locally, the Pine Hill Anhydrite Member occurs at the top of the Louann halite section (Oxley and Minihan, 1969; Tolson and others, 1983;

Mink and others, 1985). Depositional thicknesses of the Louann range up to thousands of feet (Wilson and Tew, 1985). All Jurassic units pinch out to zero thickness updip and on the flanks of some paleohighs. Thicker salt accumulations formed in basinal areas, especially in actively subsiding grabens, and the Louann is typically thin or absent over paleohighs, such as the Wiggins arch (e.g., Tolson and others, 1983; Mink and others, 1990).

The Louann Salt in the eastern Gulf is thickest in the Mississippi interior salt basin, where it may exceed 6000 feet in thickness (Wilson, 1975). In southwest Alabama, the Louann is widespread but thickness data are scanty because petroleum test wells rarely penetrate the full section of salt.

The Louann Salt, like the underlying Werner Formation, has been interpreted to have formed as the result of intermittent ponding and evaporation of sea water in differentially subsiding rift grabens (Salvador, 1987). The Louann is generally accepted to be Callovian to earliest Oxfordian in age, based on (1) sparse palynomorph data from a salt piercement structure in the Sigsbee Knolls area in the northwestern Gulf, thought to be of similar age to the Louann, and (2) regional stratigraphic and paleogeographic evidence (Kirkland and Gerhard, 1971; Salvador, 1987).

NORPHLET FORMATION

The Norphlet Formation (Oxfordian) conformably overlies the Pine Hill Anhydrite member of the Louann Salt (fig. 4). The contact may not be conformable where the Pine Hill is absent. Where the Louann is absent, the Norphlet disconformably overlies older units. The Norphlet is a regionally extensive, predominantly continental siliciclastic deposit that is found in the subsurface throughout most of the study area. The Norphlet is dominated by alluvial-fan-, wadi-, playa-, and eolian deposits. Sandstone reworked by marine processes makes up the uppermost part of the unit (Wilkerson, 1981; Mancini and others, 1984, 1985). In southwest Alabama, the Norphlet Formation ranges up to 800 feet in thickness. In the western Gulf the Norphlet is much thinner; a few tens of feet in east Texas.

Four Norphlet lithofacies are recognized in the study area: a discontinuous basal shale, a conglomeratic sandstone, red beds, and an upper quartzose sandstone (Denkman Sandstone Member of Tyrrell, 1972). Conglomeratic sandstone (fan deposits) dominates updip, red beds (wadi- and

alluvial plain deposits) are more prevalent in medial positions, and eolian sandstone is the major lithology in downdip positions, such as offshore (Mancini and others, 1985; Scott, 1986; Marzano and others, 1988; Dixon and others, 1989). Discontinuous lenses of black shale at the base of the Norphlet in southwest Alabama have been interpreted as lagoonal or mudflat deposits formed during retreat of the Louann sea (Mink and others, 1985). The uppermost Norphlet is a quartzose sandstone that was reworked in a nearshore marine environment.

During deposition of the Norphlet Formation the study area was dominated by a broad desert plain bordered on the north and east by highlands underlain by Proterozoic and Paleozoic rocks and on the south by the developing Gulf of Mexico basin. Major positive basement features such as the Wiggins arch were partially exposed at this time (Mancini and others, 1985).

The Norphlet is conformably overlain by the Smackover Formation. The contact is commonly abrupt, but is gradational over an interval of a few feet or less in parts of Mobile County (Tolson and others, 1983), including Churchula field, and in Barnett field on the Conecuh ridge.

SMACKOVER FORMATION

PALZOGEOGRAPHIC SETTING

The Smackover was deposited on a carbonate ramp, like that of the present-day Persian Gulf, in much of the Gulf-Coast region (Ahr, 1973; Mancini and Benson, 1980, 1981; Budd and Loucks, 1981; Moore, 1984). However, in southwest Alabama, deposition of Smackover strata was strongly affected by a system of preexisting ridges and basins (fig. 5). Smackover strata in southwest Alabama were deposited in five interconnected basins: the eastern part of the Mississippi interior salt basin, the Manila embayment (which contained two separate depocenters during Smackover deposition), the Conecuh embayment (Mancini and Benson, 1980, figs. 2 & 3), and a basinal area south of the Baldwin high. The distribution of facies was more-closely controlled by local paleotopography than by southerly regional dip, as would have been the case in an unmodified ramp setting. High-energy facies were deposited in nearshore areas rimming exposed paleohighs and near the updip limit of Smackover deposition; lower energy strata were deposited in basin centers (fig. 8).

Figure 8.--Map of minimum thickness of ooid grainstone in Smackover Formation, southwest Alabama (Dimensionless, contour interval=0.5). The value for Churchula field, Mobile County, is an average of 12 cores.

STRATIGRAPHY

The Smackover Formation conformably overlies the uppermost (marine) part of the Norphlet Formation. The Smackover is a platform carbonate that (together with the uppermost Norphlet) comprises the marine (lower) portion of a transgressive-regressive sequence. Absolute sea-level rose at a generally asymptotically decreasing rate during latest Norphlet-Smackover time, forming one half of a eustatic sea-level cycle (Vail and others, 1984; Moore, 1984; Meendsen and others, 1987; Benson, 1988; Mancini and others, 1990).

Based on ammonites recovered from the lower portion of the unit, the Smackover has been assigned a late Oxfordian age (Imlay, 1945). The Smackover ranges up to more than 550 feet thick in the study area (fig. 6) (Benson, 1985).

Basal Smackover strata in Alabama contain laminar and domal stromatolites; these deposits probably formed in shallow water during the early stages of a marine transgression. Middle Smackover strata are dominated by lime mudstone and pelletal or fossiliferous lime wackestone, deposited at and near the time of maximum transgression, and during and after a period of rapidly increasing water depth. Middle-Smackover lime mudstone is typically laminated and organic rich. These strata are inferred to be the source rocks from which most of the oil in Jurassic reservoirs in the study area was generated (Erdman and Morris, 1974; Mancini and Benson, 1980; Hughes, 1984; Oehler, 1984; Sassen and others, 1987; Sofer, 1988; Claypool and Mancini, 1989; Sassen, 1989). During middle Smackover time, prolific production of high-energy carbonate sediment on the flanks of the paleohighs initiated a progradational phase of Smackover deposition. Upper Smackover strata were laid down during a relative-sea-level stillstand. Progradational strata of the upper Smackover are dominated by ooid grainstone and diverse peritidal carbonates on the flanks of the paleohighs, and by pelletal and oncoidal packstone and grainstone in the centers of the depositional basins. Upper Smackover strata are generally arranged in a succession of stacked, upward-shallowing cycles that grade from subtidal strata at their bases to shallower subtidal to supratidal strata at their tops (Benson, 1988; Mancini and others, 1990a; Appendix 1). Exposure features, including hardened

crusts, mudcracks, fenestral fabric, dissolution fabrics, vadose pisoids, and pendant cement, are found at the tops of many cycles (i.e., Barrett, 1987; Benson, 1988; Mancini and others, 1990a; Appendix 1).

The Smackover locally contains substantial amounts of siliciclastic material, particularly near the Conecuh ridge and its associated small paleohighs (e.g., Barnett, North Wallers Creek, Uriah, Vocation, and Burnt Corn Creek fields). Also, terrigenous siliciclastic material is significant in the upper Smackover in parts of the Manila embayment (Wade and others, 1987). The upper Smackover is very argillaceous in the northern part of the embayment; in the southeastern part, several intervals of calcareous sandstone are interbedded with peloidal and oolitic packstone and grainstone (Wade and others, 1987).

Microbial boundstone is a significant component of upper Smackover strata on the north side of the Wiggins arch in Mobile County, Alabama, and on the Conecuh ridge complex in Baldwin County, Alabama (Baria and others, 1982; Benson, 1988). These strata are primarily composed of laminar, digitate, or domal stromatolitic cyanobacteria, along with foraminifers, sponges, and calcareous worm tubes (Benson, 1988).

DIAGENESIS

Smackover diagenesis was dominated by the effects of (1) early cementation, (2) leaching of calcium-carbonate allochems, and (3) dolomitization. Other diagenetic processes that significantly affected Smackover reservoir characteristics include pressure solution, dissolution of calcium-carbonate cement, late (post-dolomitization) calcite and anhydrite cementation, and fracturing, both tectonic and caused by collapse of partially dissolved rock frameworks.

Early marine-phreatic cementation in interparticle pore spaces in particle-supported Smackover carbonates was nearly ubiquitous. Marine-phreatic cement in the Alabama Smackover is fibrous pore-lining calcium carbonate that destroyed interparticle pore throats and in many cases filled primary interparticle pores, forming polygonal boundaries between opposing cement rims. At least some early marine-phreatic pore-lining cement in the Alabama Smackover was aragonitic, as indicated by square crystal terminations still preserved in partially filled primary interparticle pores. Marine-

phreatic cementation was suppressed in areas where meteoric waters are most likely to have reached upper Smackover strata (see fig. 36). Where primary interparticle pore space was destroyed by marine-phreatic cement, an initially highly permeable sediment was converted to a relatively impermeable (and nonporous) rock.

In many areas, early marine cementation was followed by leaching of ooids (Smackover ooids in Alabama were aragonitic) and other unstable particles. Oncoids tended to be partially dissolved by the formation of small vugs within them; pellets and mollusks were commonly entirely dissolved. This widespread particle dissolution vastly increased porosity values (to 40% or more) but had little direct effect on permeability. Reservoirs that have been cemented and leached, but not extensively dolomitized, are uncommon, and occur mainly in southern Choctaw County and northwestern Clarke County (e.g., some strata in Bucatunna Creek and Womack Hill fields; Appendix 1.) During deposition of upper Smackover strata in the eastern part of the MISB a minor relative sea-level drop initiated sabkha development on the crests of many topographic highs (e.g., Chatom and Zion Chapel fields; Appendix 1). These sabkha deposits (and associated salina deposits) contain significant amounts of anhydrite, and range up to a few tens of feet in thickness (fig. 9). They are commonly overlain by comparable or greater thicknesses of peritidal carbonates, including reservoir rock, laid down during and after a subsequent minor relative-sea-level rise. These in turn are overlain by massive anhydrite of the basal Buckner Anhydrite Member of the Haynesville Formation. The basal massive anhydrite was deposited subaqueously as a result of evaporative concentration of MISB waters (e.g., Mann, 1990).

Early dolomitization of uppermost Smackover strata by reflux of hypersaline brines was widespread, but of minor importance for reservoir evolution. Widespread formation of isotopically light (oxygen isotopes) dolomite in permeable Smackover strata caused extensive post-depositional alteration of Smackover strata (e.g., Benson and Mancini, 1984; Vinet, 1984; Barrett, 1987). This widespread Smackover dolomite, which is responsible for formation and/or preservation of many permeable Smackover pore systems, has been interpreted as mixed-water in origin (e.g., Vinet, 1984; Prather, 1992) or to have formed as a result of lateral migration of formation waters with focusing of flow over paleohighs (Barrett, 1987). Two different forms of isotopically light dolomite are common,

Figure 9.--East-west stratigraphic cross section, Mississippi interior salt basin, illustrating the localized development of sabkhas during late Smackover time on paleotopographic highs.

and likely represent the products of two different episodes of dolomitization. Some isotopically light Smackover dolostone is mimetic, which is to say it preserves clear evidence of primary sediment fabrics in the form of (1) inclusions within dolomite crystals, (2) dolomite crystal boundaries that mimic particle boundaries, (3) nondolomitized patches controlled by particle boundaries, and (4) relatively unaltered pores. Other isotopically light Smackover dolostone is nonmimetic, or fabric destructive. In these rocks, dolomite crystals did not honor particle boundaries, as can be seen clearly in (relatively rare) examples exhibiting faint bands of inclusions that outline particle boundaries and that are transgressed by dolomite crystals (fig. 10). In most Smackover fabric-destructive dolostone, no such bands of inclusions can be seen, and the primary fabric is indeterminable. Both mimetic and nonmimetic dolostone form excellent reservoirs in the Smackover. Their similarities and differences vis a vis reservoir characteristics and heterogeneity are discussed at length in subsequent sections.

Late baroque (saddle) dolomite is widespread but volumetrically insignificant in the Smackover. Other episodes of dolomitization may have also taken place (e.g., penecontemporaneous hypersaline dolomitization of lower Smackover strata in the Jay Field area of Alabama and Florida; Vinet, 1984).

Late-stage diagenetic processes that were widespread in the Alabama Smackover include stylolitic pressure solution and growth of replacive anhydrite laths. Other late diagenetic processes that were of at least local importance included dissolution of calcium-carbonate cement, dissolution or calcitization of dolomite, calcitization of anhydrite, pressure solution by particle interpenetration, post-dolomitization calcite and anhydrite cementation, and fracturing. Fracturing included both tectonic formation of fracture sets and crushing of dissolution-weakened rock components. These included cement frameworks around particle molds (see fig. 47) and dolomite cement crystals with their cores dissolved (see fig. 51B). Paragenetic sequences diagramed in Appendix 1 suggest the geographic and temporal distribution of these processes in the Alabama Smackover. Only pressure solution, calcite and anhydrite cementation, and tectonic fracturing exerted more than local effects on porosity and permeability of Smackover reservoirs.

Figure 10.--Planar-e dolostone in which dolomite-crystal boundaries do not correspond to particle boundaries (thin-section photomicrograph). Permit No. 3046, Little River field, Baldwin County, 15,035'.

BUCKNER ANHYDRITE

The Smackover Formation is overlain in southwest Alabama by the Buckner Anhydrite Member of the Haynesville Formation, whose basal portion is dominated by subaqueous evaporites (predominantly anhydrite and halite) in depositional basins, and by peritidal- and supratidal evaporitic- and siliciclastic strata on the flanks and crests of paleohighs (Dickinson, 1968; Harris and Dodman, 1982; Moore, 1984; Moore, 1986; Lowenstein, 1987; Mann, 1988, 1990). Deposition of the basal Buckner in the eastern part of the MISB was initiated by partial isolation of the eastern MISB and increase of salinity to the point of gypsum saturation (Mann, 1990). This chemical event involved a minor relative sea-level fall caused by a net evaporative water loss in the eastern MISB. Thus the massive anhydrite offlaps the underlying peritidal carbonates. Because its origin is a basin-wide (Alabama part of MISB) chemical event, the base of the massive Buckner saltern evaporite is a time plane (See Hardie and others (1978) and Kendall (1988) for discussion of this phenomenon). However, this time horizon may not be identifiable in basin marginal areas, where basal Buckner evaporites were deposited in sabkhas and salinas. On the crests of paleohighs, where uppermost Smackover strata include sabkhas and salinas, the base of the saltern may also be difficult to identify. In addition, halokinesis of the Louann Salt during Buckner time created high-frequency thickness variation in Buckner strata where underlying Smackover strata vary only slightly in thickness.

Analysis of well logs and cores suggests that similar processes operated in the Manila and Conecuh embayments. However, in the Manila embayment, a thin anhydrite interval is overlain by a thick sequence of halite (to the southwest) or sandstone (to the northeast). These two regions were separated during Smackover and Buckner time by a ridge that prevented sand from reaching the southwestern Manila embayment. The Buckner in the Conecuh embayment resembles that in the southwestern Manila embayment; up to about 50 feet of anhydrite is overlain by a thick halite succession. Thick sequences of halite in the Buckner of the Manila and Conecuh embayments suggest that these basins were deep enough to develop permanent haloclines during Buckner time. In the

Manila embayment, there appear to be two major areas of Buckner salt, whereas in the Conecuh embayment, salt was deposited primarily in small subbasins.

SMACKOVER PETROLEUM GEOLOGY

GENERAL

Commercial quantities of hydrocarbons were first discovered in the Smackover Formation in Alabama at Toxey field, Choctaw County, in 1967. The Smackover has subsequently proven to be the most prolific hydrocarbon-producing reservoir in southwest Alabama. As of December, 1990, the Smackover had produced oil, condensate and/or natural gas from 73 established fields in southwest Alabama, from the counties of Baldwin, Choctaw, Clarke, Conecuh, Escambia, Mobile, Monroe, and Washington. At that time, cumulative production from Smackover reservoirs in Alabama totaled over 113 million barrels (MMB) of oil (including condensate production from Chunchula field and minor Norphlet oil production from several fields), 145 MMB of condensate (including Norphlet condensate production from Hatter's Pond field, which is not reported separately), and 1.12 trillion cubic feet (TCF) of natural gas.

HYDROCARBON TRAPS AND SEALS

Smackover hydrocarbon traps in southwest Alabama are structural or combination structural and stratigraphic traps (Mancini and others, 1990a). Many structural traps result from halokinesis of the Louann Salt. Salt movement has produced salt anticlines, faulted salt anticlines, diapirs, and extensional faults which form hydrocarbon traps. The Buckner Anhydrite Member of the Haynesville Formation seals most Smackover traps in Alabama. Basement-related structural traps are common in Monroe, Conecuh, and Escambia counties. Typically, these traps are anticlines developed over basement paleohighs. The Buckner is the seal for most of these basement-related traps as well.

Combination traps generally involve porosity or permeability pinch-outs on regional dip or on halokinetically-generated anticlines or structural noses. Porosity and permeability pinch-outs on basement-related anticlines or faulted anticlines are also recognized in the study area.

OIL GEOCHEMISTRY

Microbially influenced laminated lime mudstone of the Smackover Formation is the main source rock for the oil, condensate, and gas in Smackover reservoir rocks (Erdman and Morris, 1974; Mancini and Benson, 1980; Hughes, 1984; Oehler, 1984; Sassen and others, 1987; Sofer, 1988; Claypool and Mancini, 1989; Sassen, 1989). Although laminated lime mudstone occurs throughout the Smackover, in the MISB only the laminated lime mudstone of the lower to middle Smackover contains sufficient organic matter to be considered hydrocarbon source rock (Oehler, 1984; Claypool and Mancini, 1989; Sassen, 1989).

Laminated lime mudstone of the lower to middle Smackover in the MISB was deposited under low-energy conditions in intertidal to subtidal settings during a marine transgression. Similar strata in the lower to upper Smackover in the Manila and Conecuh embayments accumulated in similar settings and also contain sufficient amounts of organic matter to be hydrocarbon source rock.

The depositional and post-depositional (diagenetic and thermal) histories of Smackover carbonates were favorable for the generation and migration of hydrocarbons. Lower to middle Smackover lime mudstone accumulated as transgressive to condensed-section deposits in the LZAGC-4.1 depositional sequence (Mancini and others, 1990b). Condensed-section deposits are generally fine textured and rich in organic matter (Sarg, 1988; Loutit and others, 1988). Pressure solution concentrated organic matter along stylolites in the Smackover. The Smackover was subjected to high temperatures early in its burial history. This resulted in the generation and migration of liquid hydrocarbons from Smackover source rocks during the Cretaceous (Nunn and Sassen, 1986). Diagenetic processes (e.g., chemical compaction, dissolution) and fracturing associated with salt movement enhanced migration pathways. Impermeable evaporite strata overlying Smackover reservoirs acted as effective seal rocks.

Although originating from a common carbonate source, the crude oils and condensates from Smackover fields in southwest Alabama differ subtly in gross composition (Claypool and Mancini, 1989). This variation suggests that the oils originated from a common marine source but under

somewhat different environmental conditions, and were later subjected to progressively increasing degrees of thermal alteration. These crude oils and condensates have compelling similarities in molecular and isotopic compositions indicating a close genetic relationship (Claypool and Mancini, 1989). However, at a given level of API gravity, crude oils from the MISB are higher in sulfur than oils from the Manila and Conecuh embayments. The MISB oils also have pristane/phytane ratios of less than one and saturated and aromatic hydrocarbon fractions with $\delta^{13}\text{C}$ differences of almost zero. Conversely, Smackover oils from the Manila and Conecuh embayments generally have pristane/phytane ratios of greater than one and aromatic hydrocarbons that are about 1‰ heavier in $\delta^{13}\text{C}$ than the saturated hydrocarbons. The $\text{C}_{15}+$ fractions of oils from the MISB are enriched in aromatic hydrocarbons compared with those from the Manila and Conecuh embayments. These subtle differences may reflect differing environmental conditions, such as higher salinity, lower oxygen content, and less influx of clay minerals and terrigenous organic matter in the MISB (Claypool and Mancini, 1989).

Thermal cracking of liquid hydrocarbons results in their conversion to gas. Ultimately, with increasing thermal maturity, crude oil in carbonate reservoir rocks which contain sulfate will be destroyed; methane, nonhydrocarbon gases, and pyrobitumen are the end products (Orr, 1974; Sassen, 1988). The carbon-isotope ratios of Smackover oils and condensates show a depth-related increase due to thermal transformation.

Hydrocarbon liquids from condensate fields appear to have reacted with sulfur. The condensates form two groups: low-sulfur and high-sulfur condensates. Compared with low-sulfur condensates (0.1 to 0.2% sulfur), the high-sulfur condensates (1.0 to 1.4%) have more positive $\delta^{34}\text{S}$ and $\delta^{13}\text{C}$ values, lower saturated to aromatic hydrocarbon ratios, higher gas content, lower $\text{C}_{15}+$ content, and lower API gravities (Claypool and Mancini, 1989). These differences are consistent with partial reaction of high-sulfur condensates with sulfur or sulfur compounds derived from thermochemical reduction of evaporitic sulfate (Claypool and Mancini, 1989). The reaction is selective, resulting in preferential removal of saturates. This sulfate reduction in combination with hydrocarbon oxidation results in the production of carbon dioxide, methane, hydrogen sulfide, and sulfur compounds and an

increase in aromatic hydrocarbons. The source of the sulfate probably was the plentiful Jurassic anhydrite whose $\delta^{34}\text{S}$ values range from 16 to 24‰ (Claypool and Mancini, 1989). Variation in the extent of sulfate reduction may result from variation in mineralogy, thickness, and flow characteristics of Jurassic strata (Claypool and Mancini, 1989) or may be related to variable H_2S flux away from Smackover reservoirs (Wade and Moore, 1990).

HYDROCARBON MIGRATION AND ENTRAPMENT

Kerogen in Smackover laminated lime mudstone probably matured to liquid hydrocarbons beginning in the early Cretaceous and continuing into the Tertiary (Mancini and others, 1985; Nunn and Sassen, 1986). Jurassic temperature gradients were about $33^\circ/\text{km}$, more than twice the modern gradient (Nunn and Sassen, 1986). Hence, Jurassic strata have probably been close to their current temperatures (90 to 170°C) for the last 100 million years (Nunn, 1984).

Smackover petroleum traps are principally salt-related structural traps. Salt movement was initiated in basinal areas in late Smackover/Haynesville time and continued into the Tertiary in updip areas and along the regional peripheral fault trend (Martin, 1978; Bearden and Mink, 1989). Structural growth coincided with hydrocarbon generation and migration from Smackover source rocks. Emplacement of liquid hydrocarbons in Smackover reservoirs was precisely controlled by relative timing of hydrocarbon generation and migration on the one hand, and trap formation and subsequent structural modification of the reservoir on the other. For example, traps and seals that formed early contain oils near the original composition of Smackover crude oil. Traps that formed later generally contain light oils or condensates. However, maturation and alteration of hydrocarbons in the reservoir can also generate condensates.

HYDROCARBON TRENDS

Hydrocarbon types, in conjunction with basinal position and relationship to regional structural features, can be used to delineate three Jurassic hydrocarbon trends in Mississippi, Alabama, and

Florida (Mink and others, 1985). The three trends are an updip oil trend, an intermediate oil and gas condensate trend, and a downdip gas trend (fig. 11).

The oil trend is north of the regional peripheral fault trend. The principal petroleum traps in this trend include structural (salt related and paleohighs) and combination traps. Haynesville, Smackover and Norphlet fields produce chiefly low to medium gravity oil.

The oil and gas condensate trend lies between the regional peripheral fault trend and the Wiggins arch. The principal petroleum traps are salt-related anticlines and extensional faults and combination traps. Most Jurassic fields in the tri-state area are located in this trend, with fields established in the Cotton Valley, Haynesville, Smackover, and Norphlet. Production from the trend is chiefly medium to high gravity oil, condensate, and gas.

The deep natural gas trend is found south of the Wiggins arch. The principal hydrocarbon traps are salt anticlines. Fields in this trend produce methane gas from the Cotton Valley and Norphlet formations.

A more detailed analysis of the relationship between trap type, basinal position, and hydrocarbon type in the Smackover of Alabama, Mississippi, and the Florida panhandle was published by Mancini and others (1991).

ANALYTICAL METHODS

INTRODUCTION

A comprehensive battery of analytical methods has been employed to characterize Smackover fields. Some of these methods require no specific comment, whereas others may be either unfamiliar to some readers, or may be sufficiently variable in how they are applied by different researchers that our particular approach needs to be outlined. In addition to describing details of our analytical procedures, in this section we provide notes on conventions used in illustrations in the field characterizations (Appendix 1).

Figure 11.--Hydrocarbon trends, southwest Alabama area (modified from Mink and others, 1985).

THIN-SECTION DESCRIPTION

In addition to standard petrographic study, some thin sections have been point counted. These point-count data have been used to generate graphs known as ternary pore plots (Kopaska-Merkel and Mann, 1991b), and have been combined with capillary-pressure data and subjected to statistical analysis, as described elsewhere in this report.

PORE TYPES

All descriptions of pore systems in this report use a genetic classification that is a modification of that of Choquette and Pray (1970). For the most part, the modifications are straightforward and self-evident. Two possible exceptions concern secondary intraparticle pores and intershard pores.

Secondary intraparticle pores did not exist when sediment was initially deposited, they exist only within single particles (do not transect particle boundaries), and are individually smaller than 1/2 of the particle size. If a single secondary intraparticle pore occupies more than 1/2 of the area of the particle, then it is regarded as a particle mold. Secondary intraparticle pores in the Smackover consist mainly of three kinds: (1) small vugs that lie entirely within partially dissolved particles; (2) polygonal pores between dolomite crystals within particles that were partially replaced by planar-e unimodal dolomite (Sibley and Gregg, 1987) before dissolution of remnant calcium carbonate; and (3) reduced molds that have been nearly occluded by late cementation. Secondary intraparticle pores are akin to moldic pores (and are classified with them on ternary pore plots, described below) because, like moldic pores, they do not form a continuous network. Secondary intraparticle pores are found within former particles, and are separated from one another by whatever occupies the spaces between the former particles. In the Smackover, this intervening material is commonly marine-phreatic calcium-carbonate cement, microspar, dolomite, or anhydrite cement. See section on genetic pore classification for further discussion.

A "perfect" particle-moldic pore system consists of delicate cement frameworks that are susceptible to collapse under lithostatic pressure. If this happens, collapsed-moldic fabrics form (Kopaska-Merkel and Mann, 1991a, b). Extreme cases may yield cement-shard diagenetic grainstone,

in which the rock consists primarily of fragments, or shards, of cement. Such rocks may be exceedingly permeable, because they can develop highly interconnected pore systems with intershard porosity (see figs. 31 and 47), which is characterized by large pore throats.

POINT COUNTING

At least 200 points were counted on each thin section. Additional points were counted on some thin sections because either (1) porosity was low and therefore the absolute number of points encountering pores was low, or (2) some common pore type was obviously grossly underrepresented in the counted points. Points were counted on a grid, and each intersection was counted. Visual inspection of thin sections, as well as comparison of incremental counts of a single thin section at 50-count intervals, indicate that only the most uncommon pore types are missed in these counts, and that the pore types are counted in the proper proportions. Only in the case of fracture porosity does the underrepresentation of uncommon pore types present a potentially significant problem for interpretation of reservoir characteristics in the Smackover. Microporosity was not considered because it cannot be counted in standard petrographic thin sections.

TERNARY PORE PLOTS

Ternary diagrams commonly are used to summarize geological data. Sedimentary-rock classifications based upon ternary diagrams date back to the sandstone classification of Krynine (1948). Despite widespread use of ternary diagrams in geology, the most widely accepted carbonate-rock classifications, those of Folk (1959), Dunham (1962), and Choquette and Pray (1970) are essentially tabular. The immense power of ternary diagrams for clearly and simply summarizing data suggests that they can play a greater role than heretofore in the classification of carbonate rocks.

In this report, we construct ternary diagrams of carbonate pore types using point-count data from thin sections, following the method of Kopaska-Merkel and Mann (1990, 1991a, b). Pores are classified genetically as described above and in a later section of this report. Ternary diagrams are constructed such that the three apices together account for most of the pores observed in a

carbonate rock unit. This approach simplifies the interpretation of pore systems, by focusing on only three major components and by displaying these data on a simple graphic plot that makes trends and clustering of samples obvious. These ternary diagrams whose apices are pore types are called ternary pore plots.

For this report, the three apices of ternary pore plots were chosen as follows: (1) moldic plus secondary intraparticle porosity, (2) interparticle porosity, and (3) intercrystalline porosity. These are the most-common kinds of pores in the Smackover in Alabama (Kopaska-Merkel, 1990), and account for more than 95% of total porosity in the thin sections studied (Kopaska-Merkel and Mann, 1991a). These three apices were chosen specifically for the data set used in this study. Other carbonate rock units might have different dominant pore types, in which case, different apices might be more suitable.

In the Smackover of Alabama the Interparticle-Moldic axis corresponds to a trend from little cementation or dissolution to increasing amounts of dissolution and of cementation (see fig. 41). The Moldic-Intercrystalline axis corresponds to destruction of depositional fabric by nonfabric-selective dolomitization. Thus, an alteration gradient may be envisaged going from minimum alteration (Interparticle apex) to significant alteration (Moldic apex) to maximum alteration (Intercrystalline apex). The Interparticle-Intercrystalline axis is a region of no data because it corresponds to a "forbidden" diagenetic history in which fabric-destructive dolomitization would occur without leaching of calcium carbonate. Samples plotting at the Intercrystalline apex commonly retain no vestige of their primary porosity or depositional fabric (rarely, ghosts are visible using a white card or fluorescence microscopy).

COMMERCIAL POROSITY AND PERMEABILITY DATA

Most of the petrophysical data available for the Smackover consist of commercial "core analyses," which include both porosity and permeability analyses. We first discuss limitations that affect both kinds of data. We then discuss some special problems of porosity data.

LIMITATIONS OF SAMPLING

Most of these data are sampled at one-foot intervals. These samples may be random with respect to reservoir properties, but commonly an effort is made to sample small areas that appear more permeable and more porous than neighboring areas. Thus, reservoir quality is overestimated. In addition, the one-foot sampling interval means that stratigraphic variations in reservoir quality that have recurrence intervals of less than one foot will not be observable with any reliability. Put these two facts together, and one realizes that if high-permeability and low-permeability strata that are less than one foot thick are intimately intercalated, then the commercial data will give a very poor picture of reservoir homogeneity. Conversely, if relatively homogeneous intervals are thicker than one foot, the commercial porosity and permeability data probably represent accurately the scale and nature of reservoir heterogeneity.

Are Smackover reservoir strata homogeneous on a vertical scale of one foot? The answer is "sometimes yes, sometimes no." Some Smackover reservoirs appear homogeneous when slabbed core is examined with a binocular microscope, whereas others are clearly heterogeneous. Gin Creek field (Permit No. 3312; figure GC-7 in Appendix 1) is one example in which dramatically different strata that are commonly less than one foot thick are intercalated. High-porosity laminae that may be as thin as one inch or thinner are sandwiched between tight laminae of similar thicknesses in this core and in many others examined in the course of this study. Figure 12 is a thin-section photomicrograph of the boundary between two adjacent layers of obviously differing petrophysical characteristics.

We can also study this question quantitatively, by collecting samples for capillary-pressure or for permeability analysis that are more closely spaced than one foot apart. The best sort of samples for this purpose are replicate samples collected from as near to the same spot as possible. Analysis of 7 pairs of replicate capillary-pressure samples from North Choctaw Ridge field (Permit No. 1878, Choctaw County) reveals that variation within pairs is considerable, and can exceed the standard deviation for the entire data set from this core (fig. 13).

Figure 12.—Small-scale reservoir heterogeneity in laminated pellet dolograins. Dark areas are pelmolds; white patches are pelmolds filled with anhydrite cement. Tight areas contained pellets that were not dissolved. Thin-section photomicrograph, Permit No. 2478, Healing Springs field, Washington County, 16,024'.

Figure 13.--Variation of petrophysical parameters for 7 pairs of replicate samples; North Choctaw Ridge field, Choctaw County. Solid vertical bars=range of difference between replicate samples; horizontal bars=mean difference between replicate samples; dashed vertical bars=magnitude of one standard deviation for a given parameter for all samples. Thus, for all 29 samples, the standard deviation of median throat size is 2.24 μm , whereas the mean difference between replicate samples is 0.92 μm .

Another way to look at this same problem is to examine samples collected from different locations within a single reservoir. Thirty sets of samples were collected from a visually homogeneous 30-foot interval of ooid dolograine and lesser pellet dolograine in Silas field (Permit No. 2205, Choctaw County; see fig. SIL-7 in Appendix 1), all except the base of which was dominated by particle moldic porosity (see Silas field in Appendix 1). Permeability and Median Throat Size (MTS) (derived from capillary-pressure data, see below) were measured. As expected, these two variables are positively correlated (r^2 between MTS and $\log_{10}$ permeability = 0.51). These data (fig. 14) suggest that a single interval of Smackover reservoir rock can vary by more than 1 order of magnitude in permeability, and by 2 to 3 micrometers in MTS. Also, the seemingly homogeneous reservoir interval contains at least 5 impermeable zones and is not at all homogeneous. Adjacent samples differ by as much as the entire range of variation for the whole data set (except for the bottom two samples, which contain substantial amounts of intercrystalline porosity). This phenomenon is analogous to the nugget effect in fractal statistics: an irreducible minimum level of variation applies over a wide range of spatial scales (in this case, the range is from a few inches to 30 feet).

In conclusion, it appears that at least some Smackover reservoirs exhibit a high and consistent degree of variation in permeability and in MTS on scales of fractions of an inch to tens of feet. Therefore, commercial core-analysis data probably successfully capture the range of petrophysical variation for reservoir intervals considered as wholes. However, the high degree of local variation permits the appearance of false trends in commercial core-analysis data and prevents commercial data from capturing the true complexity of porosity and permeability variation. Where there is significant stratigraphic variation in petrophysical parameters with periods of less than one foot within reservoir intervals, as in Silas and North Choctaw Ridge fields, it will not be resolvable using commercial core-analysis data. We have observed in cores and in thin sections juxtaposition of impermeable and nonporous strata with permeable and porous strata, where all laminae are substantially thinner than one foot. Although we have recognized the fine scale of porosity and permeability heterogeneity that characterizes some Smackover reservoirs, this phenomenon cannot yet be quantified, because to do so requires extremely closely spaced sampling.

Figure 14.--Small-scale heterogeneity, Permit No. 2205, Silas field, Choctaw County. Gas permeability values measured at the Geological Survey of Alabama; median throat size calculated from mercury porosimetry performed at the Geological Survey of Alabama. These data were collected from 30 pairs of samples. Large dots=ooid dolograins, medium-size dots=mixed ooid-pellet dolograins, small dots=pellet dolograins. Data points falling on the Y axis of the permeability plot represent permeability values too low to measure. Further discussion in text.

ACCURACY OF POROSITY DETERMINATIONS

Capillary-pressure data derived from any high-pressure mercury porosimeter (see below) permit calculation of porosity values that are commonly considerably more accurate than are commercial mercury-based "porosity" data (measured by service companies on a contract basis). Most commercial "porosity" values are measured using mercury capillary-pressure devices commonly called "porometers". These devices inject mercury into samples by applying outside pressure just as the Autopore II 9220 does. However, "porometers" are only capable of attaining capillary pressures of 6000 psia (41 MPa) air-Hg or less. Most such devices have a maximum capillary pressure of only 1000 psia (6.8 MPa), and this is the maximum value attained in most analyses of rocks from south Alabama. A capillary pressure of 1000 psia (41 MPa) is equivalent to a pore-throat size of about 0.09 micrometers, which is nearly 30 times the size of the smallest pore throat measurable at 30,000 psia (207 MPa) (Kopaska-Merkel, 1991). More importantly, as shown by Kopaska-Merkel and Amthor (1988), as much as 70% of porosity is invisible to analyses which terminate at 5000 psia (34 MPa), and as much as 100% percent of porosity is invisible to analyses which terminate at 2000 psia (13.6 MPa) (Kopaska-Merkel and Amthor, 1988, their figure 3, p. 59). Routine porosity measurements miss substantial amounts of macroporosity. All such data should be regarded as "minimum" porosity values, not as "porosity" values, and they are of severely limited utility if, as is commonly the case, the experimental conditions are not reported. Porosity data collected using helium are substantially more accurate, and may even be significantly more accurate than high-pressure mercury porosity data.

There are further implications of the limited pressure ranges used in commercial "porosity" determinations. Stratigraphic changes in reported "porosity" values may simply reflect changes in the proportion of throats that are too small to measure, and not true changes in porosity. Looked at another way, the amount or proportion of effective porosity (under subsurface conditions) that is invisible to a commercial "porosity" analysis, varies with the pore-throat-size distribution. "Porosity" values that are depressed by this effect should be associated with lower permeability values, because permeability and pore-throat size are commonly positively correlated. This is also exactly what one

would expect if porosity were truly lower, because porosity and permeability are at least weakly positively correlated for most rock units. If subsurface pressures and hydrocarbon densities, viscosities, contact angles, and interfacial tensions are known, then high-pressure capillary-pressure data can be used to calculate effective porosity values that are specific for a given field. In other words, one can determine the minimum pore-throat size accessible to the oil in that field under subsurface conditions (e.g., Schowalter, 1979; Jennings, 1987). This, in turn, yields the relationship between the commercial "porosity" values calculated from wells in a certain field, and the true effective-porosity values for that field.

CALCULATION OF HETEROGENEITY FROM COMMERCIAL DATA

For the purposes of calculating microscopic vertical heterogeneity (μH) and megascopic vertical heterogeneity (MH), only reservoir rocks were analyzed. Reservoir rock exhibits permeability values ≥ 0.1 md, and porosity values $\geq 6\%$. The 3 parameters needed to calculate μH were calculated in a perfectly straight-forward fashion. For calculation of MH, numbers of reservoir intervals were calculated by counting a reservoir interval that is partially represented in a core as one interval. Calculation of the standard deviation of the number of reservoir intervals required at least 2 cores per field. Microscopic lateral heterogeneity (LH) was calculated using all nonzero paired porosity and permeability analyses, because low-permeability and low-porosity samples help define the porosity-permeability trends used to calculate LH. This procedure obviously requires the assumption that all samples from the Smackover in a single field belong, in some sense at least, to a common "population." This seems to be true, because fieldwide porosity-permeability plots commonly show strong correlations and linear trends, whereas lumping several fields together tends to eliminate these trends. The different parts of a reservoir resemble one another more closely than they do parts of other reservoirs. (See section on reservoir heterogeneity for further discussion.)

CAPILLARY-PRESSURE ANALYSIS

The following sections briefly cover some aspects of capillary-pressure analysis. Further discussion of these topics appears in Kopaska-Merkel (1991).

THEORY

The pore system in a rock consists of two elements: the main open spaces (pores) and the smaller channels (pore throats or throats) connecting the pores. The definition is simple, but the total characterization of pore systems is difficult because of their complexity. Pore-system geometry and topology control the movement and distribution of fluids within porous media such as hydrocarbon reservoirs. Using capillary-pressure curves derived from mercury porosimetry, one can derive petrophysical parameters such as throat-size distribution, "effective" porosity, and recovery efficiency (Purcell, 1949; Smith, 1966; Dullien and Dhawan, 1974; Wardlaw, 1976; Schowalter, 1979; Van Brakel and others, 1981; Wardlaw and McKellar, 1981; Lucia, 1983; Jennings, 1987; Amthor and others, 1988; Wardlaw and others, 1988; Kopaska-Merkel and Friedman, 1989). Permeability may be estimated from capillary-pressure data (Jennings, 1987) but only if throats are large and well-"sorted", microporosity is negligible, and permeability is greater than approximately 1 md.

Before briefly discussing the method of mercury porosimetry, a distinction must be made between wetting- and nonwetting fluids. All fluids experience surface tension, the stress on the surface of a liquid caused by Van der Waals forces that are not opposed by intermolecular agitation (Levorsen, 1967; p. 442). The surface tension of a fluid, as well as its interfacial tension with coexisting fluids, determines its contact angle with the surface of its enclosing porous medium (e.g., sedimentary rock). If the fluid adheres strongly to the rock surface, then the contact angle (measured through the fluid) is low, and the rock-fluid contact is classified as wetting. If the fluid is repelled by the rock surface and the contact angle is high, then the contact is nonwetting. Wetting fluids coat the rock surfaces and flow readily through any openings sufficiently larger than their component molecules. Nonwetting fluids "bead up" on rock surfaces, and are subject to capillary forces, which means that pressure must be applied to force them through small openings. The pressure required is

inversely proportional to the size of the opening. Because mercury porosimetry makes use of a nonwetting fluid (mercury) and subjects it to pressure in order to induce capillarity, this method produces information directly relevant to the behavior of nonwetting fluids. In natural rock systems, either water or petroleum may behave as a nonwetting fluid, depending on the composition of the rock matrix, any organic- or inorganic coatings on the rock, coexisting fluids, fluid characteristics, and the characteristics of other materials mixed with any of the fluids (e.g., detergents). Siliciclastic rocks are commonly water-wet, whereas carbonate rocks may be either oil- or water-wet. See Levorsen (1967), Wardlaw (1976, 1980), Good and Mikhail (1981), Yu and Wardlaw (1986a, b), and Yu and others (1986) for more-detailed discussions.

Mercury porosimetry involves measuring the volume distribution of pore throats. Pore throats constitute only a small fraction of the total pore-system volume. However, most mercury porosimetry studies give information on only the pore throats (Wardlaw, 1976), not the pores, because the method depends on the forcing of mercury into the small voids within the rock. The smallest voids (throats) control access to the larger ones (pores) because higher pressures are needed to force mercury or other nonwetting fluids into smaller spaces (principle of capillarity; see, e.g., Purcell, 1949). The pore throats are the bottlenecks in the pore system; their critical capillary pressures must be exceeded for mercury or other nonwetting fluids to enter the pores they surround. For an infinite sample with a spatially homogeneous pore system, the total volume of mercury intruded at a given pressure is precisely related to the number of throats of corresponding size. Thus, a graph of cumulative mercury-intrusion volume vs. capillary pressure is equivalent to cumulative mercury-intrusion volume vs. pore-throat size. More precisely, the experimentally derived number associated with pore throats of a given size, is the total volume of pore space filled through throats of that size. (Note that this is not the case if equilibrium is not achieved before each data point is collected; a finite amount of time, commonly a few 10s of seconds to a few minutes, is required for pores and throats to fill.) Mercury porosimetry is the only analytical method that routinely yields quantitative information about the size distribution of pore throats. If throats are large, then image analysis,

which can produce quantitative information about pore shapes and -sizes, can also yield reliable information about throats.

The particular pore-throat size (calculated) corresponding to a given pressure (measured) depends on the model of throat geometry used (Wardlaw and Taylor, 1976; Dullien, 1979), as well as on mercury contact angle and on the values for interfacial tension of mercury and air. A model commonly used in studies of carbonate rocks is that of Wardlaw (1976; Wardlaw and Taylor, 1976) in which throats are assumed to be sheetlike (Wardlaw, 1976). This model is preferred for studies of most carbonate rocks for reasons discussed by Kopaska-Merkel and Friedman (1989; see also Kopaska-Merkel, 1987, p. 128, his figures 3-4 to 3-6). However, the model may be inappropriate for pore systems dominated by interparticle porosity (typical of many siliciclastic rocks). For samples dominated by interparticle porosity, the correct pore-throat sizes may be as much as twice the values derived from eq. (1). No Smackover reservoirs are dominated by interparticle pores. In the model used for carbonates, throat size (d) is calculated by the equation

$$d = (-2\gamma \cos\theta)/p, \quad \text{eq. (1)}$$

where γ is the interfacial tension (485 dynes/cm for Hg/vacuum), θ is the contact angle (130° for Hg/vacuum, measured in Hg) and p is the pressure in psia. A contact angle of 130° is preferred for reasons discussed by Kopaska-Merkel and Friedman (1989), although values as high as 180° have been used by others. For throats with subcircular cross-sections (e.g., interparticle porosity), eq. (2) is chosen:

$$d = (-4\gamma \cos\theta)/p. \quad \text{eq. (2)}$$

The porosimeter used at the Geological Survey of Alabama (GSA) is a Micromeritics Autopore II 9220; data are reduced using RUN92, v. 2.03, the program supplied with the machine (Micromeritics Instrument Corporation, 1987). The Autopore II 9220 can generate an experimental pressure range of 1.5 to 60,000 psia (0.01 to 414 MPa), greater than that used in any published studies known to us. Rock samples are generally tested at high pressures to (1) duplicate subsurface conditions at realistic depths and (2) evaluate the full range of available porosity in the rocks studied, some of which contain large pore-system volumes that would remain undetected at substantially lower pressures. A

pressure of 20,000 psia (138 MPa) air-Hg is the maximum pressure normally attained at the GSA. This pressure corresponds to a throat size of 0.0045 micrometers ($45\text{\AA}$) if throats are sheetlike. This is comparable to the sizes of some oil molecules. Therefore, high capillary pressures generate information on all pores available to most oils. A pressure of 30,000 psia (207 MPa) air-Hg equals roughly 6000 psia (41 MPa) air-brine in nature, which is comparable to the hydrostatic pressure at a depth of 2.5 mi (13,200 ft; 4.2 km) or less (Purcell, 1949; Smith, 1966; Schowalter, 1979). Thus the experimental pressure range covers a range of hydrostatic pressures comparable to that experienced in the subsurface by rocks of economic interest in Alabama. For some purposes, pressures significantly greater than 20,000 psia (138 MPa) might be desirable. Use of mercury capillary pressures as high as 30,000 psia (207 MPa) does not normally damage the pore systems of rock samples (Kopaska-Merkel and Amthor, 1988). However, friable samples may implode even at low pressures, yielding a characteristic dip in the cumulative intrusion capillary-pressure curve (Kopaska-Merkel, 1991). Even samples that do not collapse during mercury porosimetry become contaminated with mercury and therefore cannot be used afterward for any other kind of analysis.

When a pressure gradient is applied to a reservoir containing a nonwetting fluid (such as petroleum), that fluid will move in a predictable way that is governed by capillary forces. However, if the pore system contains larger and smaller elements (pores and throats) as is always the case in natural systems, the stress put on the continuous body of nonwetting fluid will not be equal everywhere. Regions where the diameter of the pore system changes suddenly and dramatically (boundaries between large pores and small throats) are regions of maximum stress on the nonwetting fluid. At these locations, the nonwetting phase may rupture, and blobs of nonwetting fluid may become isolated, surrounded by wetting phase. This process of rupture of nonwetting phase is known as "snap-off". Isolated blobs of nonwetting fluid are insulated from capillary forces and will not move under the influence of an applied pressure gradient. Thus, the sizes of pores and throats critically affect producibility of nonwetting fluids. This discussion is condensed and modified from Levorsen (1967), Dullien (1979), Wardlaw (1976, 1980), Wardlaw and Taylor (1976), Wardlaw

and McKellar (1981), Yu and Wardlaw (1986a, b) and Yu and others (1986), which should be consulted for further information.

Recovery efficiency (RE), as measured by mercury porosimetry, is not necessarily the same parameter as recovery efficiency of in-situ hydrocarbons from the subsurface. This is the result of three effects. One is simply that mercury is almost a perfectly nonwetting fluid in a two-fluid system (mercury plus mercury vapor), whereas natural subsurface systems may involve more than two fluids, and these may be partially wetting. The second effect is a result of hysteresis in the response of mercury to pressure changes. A pore throat that is intruded by mercury at a certain pressure will be vacated at a slightly lower pressure. This process is commonly attributed to a difference between advancing and receding mercury contact angles. Receding contact angles are inferred to be less than advancing contact angles (e.g., Micromeritics Instrument Corporation, 1987; Wardlaw and others, 1988). This effect is probably minor, and although it is not a function of pore-system characteristics, it occurs both in porosimeters and in rock reservoirs, so it may not introduce bias. The third effect is caused by the fact that capillary-pressure analyses begin at a pressure of about 1.5 psia, whereas they terminate at atmospheric pressure; about 14.7 psia. Thus, pore throats filled at pressures between 1.5 and 14.7 psia cannot be vacated during pressure reduction. The effect of wettability on RE is variable, but both of the other two effects tend to reduce recovery from large throats. Because RE from large throats only is affected, the difference between initial- and final pressures in mercury-porosimetry analyses can create an inverse relationship between RE and MTS (and also porosity, which is commonly correlated with MTS) that is unrelated to characteristics of the pore system. There is also an inverse relationship between RE and MTS (and porosity) that does result from pore-system characteristics. MTS and porosity are correlated with the aspect ratio (pore size/throat size). This is because as pore- and throat sizes increase, the variances in these parameters also increase. Small pores have a smaller maximum possible aspect ratio. Also, large pores in carbonates tend to be moldic pores, which commonly have very high aspect ratios. High aspect ratios promote snap-off and nonwetting-fluid trapping. Therefore, if MTS and porosity values are high, the aspect ratio is likely to be high, and RE will be low. However, an inverse relationship between RE and MTS that is a result

primarily of low recovery from pore throats filled at pressures below 15 psia is artifactual. Such a relationship that results from recovery from throats filled at pressures greater than 15 psia may indicate differences in aspect ratio.

The raw data generated by capillary-pressure analysis using mercury porosimetry consist of paired pressure- and capacitance readings. The capacitance readings are converted to volumes of mercury with negligible error (Kopaska-Merkel, 1988). The major variable that alters capacitance during an analysis is the movement of mercury into and out of the sample (Micromeritics Instrument Corporation, 1987), which is the variable one generally wants to measure. Expansion and contraction of mercury with changes of temperature are the largest sources of error (changes in mercury volume not related to intrusion or extrusion of mercury into or out of the sample), and are dealt with using blank analyses (see Kopaska-Merkel, 1991).

Pressure readings are converted to pore-throat sizes as explained above. The resultant pore-throat-size- and volume readings yield a detailed- and accurate picture of the aggregate pore volumes accessed through pore throats of a wide range of sizes. This is not the same as permeability. Permeability is a measure of how fast a particular fluid can flow through a sample's pore system. For example, permeability is an important indicator of the rate at which drinking water or petroleum could be produced from an aquifer or petroleum reservoir rock. The pore-throat-size distribution is one of the important factors determining permeability, because the smallest pore throats (in cross-sectional area) that occur in continuous paths through the rock are the bottlenecks that determine the rate at which fluid can pass through the rock. But this is not the whole story. In a natural rock system, multiple fluids may coexist in the reservoir, and they may interact with each other, and with the rock matrix itself, in complex ways. The size distribution of pore throats and the pore-throat-size ratio affect how subsurface fluids will behave, and control to what degree and under what circumstances nonwetting fluids will become trapped.

MEASUREMENT ACCURACY AND PRECISION

Volume changes greater than 0.0015 cc may be measured with the Autopore II 9220 (Kopaska-Merkel, 1988; 1991). For comparison, a small (2.5039 g) sample of dolostone from the Smackover Formation in Lovetts Creek Field (Monroe County) yielded a total intrusion (to 20,000 psia or 138 MPa) of 0.1092 cc, or nearly 73 times the minimum measurable volume change. See Kopaska-Merkel (1991) for further discussion of aspects of measurement, including calibration and equilibration.

SAMPLING

In most cases, sample size and -shape are of no real concern for mercury porosimetry. This is because the boundary effect, although ubiquitous, generally affects only a small portion of the sample. The boundary effect results from two related phenomena: (1) transected pores and (2) asymmetry of the pore system surrounding a given pore. Transected pores are pores that are cut by the sample surface. These pores are directly exposed to the enclosing mercury, and are not filled through pore throats. They fill almost as soon as the sample chamber is flooded with mercury, and before significant pressure is applied. However, if they fill at pressures greater than the initial filling pressure (typically 1.5 psia) then they are counted as pores that are accessed through very large throats (up to about 60 micrometers across).

The pore system surrounding a given pore in a sample is asymmetrical. In the subsurface, a pore is surrounded by a pore system that is practically infinite, unless that pore is very close to a flow-unit boundary, or to a well bore or open fracture. However, in a sample, one side of a pore faces the center of the sample, but the other side faces the sample surface. The movement of fluid through a pore system is a Markovian process (e.g., Harper, 1984). That is, the rate at which fluid can reach a pore is not merely a function of how swiftly it can pass through the pore throat that opens directly into that pore. The rate at which the fluid can reach that closest pore throat, through more-distant pores and throats, must also be considered. If the pore is only a few throat lengths from the sample surface, then one of the "pore throats" is the sea of mercury surrounding the entire sample, and mercury can penetrate surficial pore throats in almost no time at all. This effect is greatly reduced if

the pore in question is far from the sample surface. If the sample is thick, and most pores are therefore far from the sample surface, then the boundary effect is small.

How far is "far"? According to Larson and Morrow (1981), who experimented with glass spheres, a sample thickness of 30 throat diameters is sufficient to render the boundary effect negligible. Figure 15 illustrates the relationship between pore-throat sizes reported in the literature and sample thicknesses. It is clear that for samples thicker than about 1 mm, the boundary effect is insignificant for nearly all rock samples. Only well cuttings commonly are less than 1 mm in thickness, and even with well cuttings, many rocks will contain throats small enough to permit the boundary effect to be ignored (Kopaska-Merkel, 1988, 1991). Experimental data also indicate that capillary-pressure analyses of well cuttings can yield accurate results (Purcell, 1949; Ghosh and others, 1987; Kopaska-Merkel, 1988).

SAMPLE PREPARATION

A number of sample-preparation procedures are suitable for mercury porosimetry (Kopaska-Merkel and others, 1987; Kopaska-Merkel, 1991). Cleaning of very small fragments, such as well cuttings, was discussed by Kopaska-Merkel (1988). The various procedures that are in common use all yield essentially the same result (Ghosh and Friedman, 1989). However, more-stringent procedures are needed with dirty samples. The goal in every case is to remove particles adhering to the samples, and to remove fluids that may be contained within the samples. When the sample-preparation process is complete, the sample should be clean and dry inside and out. After the sample is clean, it should not be touched with the fingers because the oils on human hands alter the surface properties of samples and affect mercury intrusion.

REPLICATE SAMPLING AND THE STUDY OF RESERVOIR HETEROGENEITY

SCALES OF CARBONATE RESERVOIR HETEROGENEITY

All reservoirs are heterogeneous. One needs to know the nature and scale of heterogeneity that affects fluid behavior. Because the size distribution of pore throats in a reservoir controls the

Figure 15.--Relationship between pore-throat size and sample thickness.

behavior of nonwetting fluids in the reservoir, capillary-pressure data are critical to an understanding of the reservoir's production potential. Variations in pore-throat size not apparent in core- or thin-section studies may control trapping of oil or condensate in heterogeneous reservoirs.

Mercury porosimetry is well suited to the study of differences among units measured in cm or meters, just as image-analysis using a scanning-electron microscope is suited to analysis of heterogeneity on scales of microns to mm, and log analysis can discriminate between units with thicknesses of about a meter or greater. At the scale at which mercury porosimetry is most effective at defining heterogeneity, many siliciclastic reservoir rocks are remarkably uniform. Many siliciclastic reservoirs consist of fairly homogeneous flow units with stratigraphic thicknesses ranging from a few tens of cm to hundreds of meters. By contrast, carbonate reservoirs commonly exhibit considerable variation over shorter distances in petrophysical parameters measurable by capillary-pressure analysis (e.g., recovery efficiency, effective porosity, and throat-size distribution). Cm- to m-scale variation in petrophysical parameters in carbonate rocks results from the interaction of two factors that play a more-important role in the genesis of carbonate reservoirs: environmental patchiness and diagenetic modification of porosity (e.g., Boggs, 1987).

The first of these two factors is the tendency of carbonate sedimentary environments to be composed of petrophysically distinct "microfacies" that may be patchy on a small scale. Environmentally-controlled patchiness in carbonate rocks is exemplified by a lithosome consisting of patch reefs decimeters to tens of meters across and decimeters to meters thick embedded within lagoonal or shelf deposits. The patch reefs themselves are heterogeneous, being composed of a complex framework of porous skeletons, laminated encrustations, borings, carbonate cements, and intercalated sediments with a wide variety of particle sizes (See e.g., Wilson [1975] and Flügel [1982] for discussions of carbonate facies and microfacies.). Microfacies development in carbonates produces a marked primary variation in petrophysical parameters on scales ranging from cm to tens of meters measured perpendicular to depositional surfaces and decimeters to tens of kilometers measured parallel to depositional surfaces.

The second factor causing cm- to m-scale heterogeneity in carbonate reservoirs is diagenesis; in particular the processes of dissolution and dolomitization. Both processes are sensitive to preexisting variation in mineralogy, fabric, pore-system characteristics, the nature and distribution of organic matter in the sediment, and water chemistry. The first four of these parameters are known to vary substantially over distances as short as a few micrometers and it appears that pore-water chemistry is similarly heterogeneous (e.g., Garrett and others, 1971; Scoffin, 1972; Sansone and others, 1988). Therefore, dissolution and dolomitization of carbonate minerals, as well as dissolution of associated sulfate minerals, can contribute reservoir heterogeneity at scales readily studied by capillary-pressure analysis.

Because carbonate reservoir rocks may exhibit significant variation in petrophysical parameters at all scales readily amenable to study by mercury porosimetry, detailed sampling programs may be valuable in studies of carbonate rocks. Published data that would permit a quantitative analysis of the scales of petrophysical heterogeneity in reservoir rocks are scanty. Commercial porosity and permeability data demonstrate huge variations in these parameters from foot to foot in many reservoirs (but see following section).

To understand the significance of spatial variation in capillary-pressure data, both within and between reservoirs, it is necessary to understand the scale of variation that can be expected to occur among adjacent samples within a single flow unit or reservoir lithofacies. This expected within-facies scale of variation will of course be different for different petrofacies. If two samples that are assigned to different reservoir lithofacies are subjected to mercury porosimetry and yield visibly different results, but no baseline data on within-facies heterogeneity have been collected, then the petrophysical differences between the two samples are uninterpretable. Knowledge of the "background noise" of within-facies variation permits interpretation of the significance of the petrophysical differences between samples assigned to different facies.

PUBLISHED STUDIES OF REPLICATE SAMPLES

Published capillary-pressure data collected from replicate- and closely-spaced samples of carbonate reservoir rocks provide the beginnings of the database needed for the development of accurate models of reservoir heterogeneity (e.g., Kopaska-Merkel and Amthor, 1988; Kopaska-Merkel, 1991). These data indicate considerable variation in porosity, MTS, and RE between some pairs of adjacent samples (cylindrical plugs drilled from a single hole and then divided in half). Other pairs of adjacent samples do not differ substantially in these parameters.

REPLICATE SAMPLING IN THE ALABAMA SMACKOVER

Studies of replicate and closely spaced samples from the Smackover of Alabama suggest that samples collected from the "same" location can differ in permeability or in MTS by nearly the total range of variation for samples from a given core (see figs. 13 and 14). In the case of permeability analyses, replicate samples are collected by drilling a long plug into a core and then cutting it in half. Hence, measurements of horizontal permeability come from samples collected at the same stratigraphic horizon and whose nearer ends are separated by the thickness of a saw blade. Replicate capillary-pressure samples are collected by cutting a rectangle about the size and shape of a small thin-section billet, and then slicing it in half the long way. The implications of replicate sampling for reservoir heterogeneity in the Smackover were discussed in the section entitled "Commercial Porosity and Permeability Data."

FIELD CHARACTERIZATIONS

CONVENTIONS USED ON GRAPHS, TABLES, AND SCHEMATIC ILLUSTRATIONS

This section includes brief discussions of the various kinds of illustrations included in the field characterizations (Appendix 1), and is primarily intended to explain the basis for each kind of figure in terms of (1) kinds of data, (2) kinds of statistical manipulation, and especially (3) the limits of reliable interpretation.

GRAPHS OF POROSITY VS. NATURAL LOG OF PERMEABILITY

Porosity vs. natural log of permeability plots are based exclusively on commercial porosity and permeability data. Plots for entire fields or for entire cores include all data except samples for which permeability was reported as "0" or as "<0.01 md," because these represent cases in which permeability values were too low to measure accurately. If these values had been included, then the trends would be biased, as they would consist of high-permeability values measured with high accuracy, combined with low-permeability values, measured with low accuracy. The regression lines are automatically calculated, and do not necessarily have any statistical validity. The r^2 values listed on each plot should be consulted, along with common sense, to determine which regression equations have any meaning. A good rule of thumb is that if r^2 is much less than 0.50, for the sample sizes typical of these data, then the regression equation is at best a poor approximation.

The plots for individual reservoir lithofacies are constructed slightly differently. On these plots, the standard reservoir cutoffs of 0.1 md permeability and 6% porosity are used. These plots show relationships only for actual reservoir rock. In some cases, reservoir rocks are genetically related to intercalated subreservoir rocks, hence this truncation of the plots drastically lowers r^2 . In other cases, two distinct rock types are intercalated, and using the reservoir cutoffs might increase r^2 of the regression equations by excluding one of the two rock types.

GRAPHIC CORE LOGS

The graphic core logs are based entirely on description of slabbed cores using binocular microscopes. Samples for thin sections and for other kinds of analyses were chosen during core description.

LITHOFACIES DESCRIPTIONS

Lithofacies descriptions are based primarily on description of slabbed cores. Petrographic thin sections, where available, were used to refine and modify interpretations based on core description. Point-count data were used to correct estimates of pore-type proportions. Lithofacies are rock units

that can be classified simply using the scheme of Dunham (1962), and that exhibit characteristic pore types (as viewed through a binocular microscope). In other words, lithofacies are relatively homogeneous petrographically and petrophysically (the former by design; the latter because pore throats vary in conjunction with pore-type variation).

PARAGENETIC SEQUENCES

Paragenetic sequences should be regarded as approximations, as many are based primarily on core descriptions. Thin-section data are incorporated where available. Solid bars indicate greater levels of confidence than dashed bars. However, dashed bars indicate only uncertainty about relative timing, not about whether a given process took place.

TERNARY PORE PLOTS

All ternary pore plots have grid lines marked at ten-percent intervals. Depths of samples are indicated where there is sufficient space on the plot.

SMACKOVER RESERVOIR CHARACTERISTICS

In this section we describe Smackover reservoirs petrographically and petrophysically. We use the Dunham classification (1962), which is both genetic and descriptive, and the Sibley and Gregg (1987) classification, which is descriptive, to describe Smackover reservoir rocks petrographically. We then describe Smackover pore systems, which directly control rock petrophysical characteristics, using the genetic classification of Choquette and Pray (1970). We describe the typical ranges of, and relationships among, such petrophysical parameters as permeability, porosity, pore-throat size, and hydraulic radius for the Smackover in southwest Alabama. We also describe reservoirs that are not typical.

In the last part of this section we discuss the prediction of porosity and of permeability using various methods.

GENERAL CHARACTERISTICS OF SMACKOVER RESERVOIRS

In this section we describe Smackover reservoirs in sufficient detail to lay the groundwork for subsequent discussions of petrophysics, petrophysical classification, and heterogeneity classification. We begin by describing Smackover carbonate reservoirs within the framework of the major structural features that influenced Smackover deposition and diagenesis in southwest Alabama: the adjacent portions of the North American continent, the basins, the paleohighs, and the peripheral fault system. We then look more closely at Smackover pore systems.

CARBONATE ROCK TYPES

Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The first group are conveniently classified using the scheme of Dunham (1962), whereas the latter ("crystalline dolostone" to Dunham) can be characterized in more detail following Sibley and Gregg (1987). We begin by classifying Smackover reservoirs in this way, although we plan to focus directly on pore systems in subsequent portions of this report, because the Dunham classification is simple to apply and the categories are directly related to depositional settings.

The most common Smackover reservoir rocks are nonskeletal grainstone, dominated by pellets, ooids, and oncoids, in order of decreasing abundance. Generally, either ooids or pellets are dominant, though both ooid grainstone and pellet grainstone may be found in a single core (e.g., Silas field, Choctaw County). Oncoids are associated either with ooids or with pellets. The pellets are either small, nondescript ellipsoids of the type commonly ascribed to small gastropods (locally abundant in the Smackover) or polychaetes, or (less commonly) the large, distinctive *Favreina* pellets that are made by callianassid shrimp. *Favreina* pellets are widespread, and locally abundant but are much less important to reservoir development than are the small pellets. This is because *Favreina* pellets (1) are less abundant, (2) less commonly form grainstone, and (3) less commonly are dissolved to form molds. Micritic ellipsoids that are all the same size and shape are clearly pellets. Many other micritic ellipsoids

are probably pellets, but are called peloids if their origin is in doubt (Friedman and others, 1992). Skeletal particles (the most common are indeterminate mollusk fragments, cerithid gastropods, and echinoderm ossicles), as well as intraclasts and (locally) vadose pisolites, are locally common in the nonskeletal grainstone. High-energy ooid grainstone is most abundant in the upper Smackover on the crests and flanks of paleohighs, and in southern Choctaw County, on the proximal portion of a large Smackover carbonate ramp. Pellet grainstone is most abundant within the basins, especially the MISB (e.g., Chatom field, Washington County).

Mixed-particle grainstone/packstone is the second common reservoir type in the Smackover of southwest Alabama. These lower energy strata are compositionally variable and commonly grade upward into grainstone *sensu stricto*. Mixed-particle grainstone/packstone is either dominated by ooids or by pellets, as is the grainstone. Skeletal material is both more abundant and more diverse than in the nonskeletal grainstone. Less abundant fossil types include encrusting foraminifers, other foraminifers, coral fragments, and sponge fragments.

A third important reservoir rock type is microbial boundstone. There are at least three common kinds of microbial boundstone in the Smackover of southwest Alabama. These are laminar stromatolites, domal stromatolites, and "microstromatolites." The latter are small (commonly a few cm or less in the longest dimension), lensoid or domal, and are commonly found in groups. They are distinct from the first two kinds of stromatolites, which are wider than cores (2 to 3 in.) and may form true reefs up to several feet thick. Boundstone is commonly associated with pelletal and/or oncoidal packstone and grainstone and with exposure surfaces. Microbial boundstone is most abundant on the southeastern flank of the Manila embayment, where individual microbial reefs exceed 1 meter in thickness (e.g., Lovetts Creek, Vocation, and Little Escambia Creek fields).

A fourth reservoir-rock type is crystalline dolostone. Permeable Smackover dolostone in southwest Alabama is commonly either planar-e or planar-s (Sibley and Gregg, 1987). These rocks are finely crystalline, coarsely crystalline, or exhibit polymodal or platykurtic crystal-size distributions. This has not been investigated quantitatively.

The preceding summary of Smackover reservoir-rock characteristics comes from new observations supplemented by descriptions published by Mancini and Benson (1980, 1981), Benson and Mancini (1982, 1984), and Benson (1985, 1988).

SILICICLASTIC SMACKOVER RESERVOIRS

Quartzose sandstone, commonly dolomitic, with abundant but subordinate feldspar, forms permeable reservoirs locally in southern Monroe County (e.g., North Wallers Creek field). Porosity is primarily interparticle. Evidently, the sand was shed in abundance from emergent islands and/or from the nearby North American landmass, overwhelming the autochthonous carbonate sediment sources. Quartzose sandstone has also been found in the upper Smackover of the northern Manila embayment, which contains no Smackover fields. Because this study concerns carbonate reservoirs only, the uncommon siliciclastic reservoirs are not described further.

SMACKOVER PORE SYSTEMS

The occurrence of reservoir-grade rocks (porosity at least 6% and permeability at least 0.1 md) in the Smackover Formation of southwest Alabama is dependent on (1) deposition of porous and permeable sediments in a variety of settings and (2) diagenetic processes which have preserved, enhanced, or created porosity and permeability both in originally permeable strata and in originally impermeable strata.

It is instructive to consider first the kinds of pores (classified using a modified form of the scheme of Choquette and Pray, 1970) that are common in Smackover pore systems, and then to discuss the kinds of porous and permeable pore systems that compose (with their host rocks) Smackover reservoirs. The genetic pore classification is described first, followed by a discussion of Smackover pore types.

GENETIC PORE CLASSIFICATION

The study of pore systems is fraught with difficulties, not least of which is the often bewildering array of shapes and sizes of pores. Before one can classify pore systems, one must be able to classify

pores. We do so genetically, using a modified form of the classification of Choquette and Pray (1970). We make three modifications to their classification (fig. 16). First, we add modifiers indicating the nature of the precursory material to moldic and intraparticle pores. Thus, for example, what Choquette and Pray would call simply moldic porosity we call oomoldic porosity. (Choquette and Pray suggested this informally in the appendix to their 1970 paper, and many workers have followed the suggestion.)

Our second modification concerns partial molds. Choquette and Pray mentioned in a figure caption that some molds are incomplete, but did not classify partial molds as separate pore types. We do so, calling them secondary intraparticle pores, for two reasons. First, moldic and secondary intraparticle pores are not simply mixed together at random. On the contrary, some reservoir rocks contain very few secondary intraparticle pores, but an abundance of particle molds. Other reservoir rocks are dominated by recrystallized particles filled with secondary intraparticle pores, but molds are quite rare. In some reservoir rocks, ooids become molds, whereas co-occurring pellets are transformed into ellipsoidal "sacks" of secondary intraparticle pores. Second, molds and secondary intraparticle pores differ systematically in their petrophysical characteristics (explained more fully in a later section). Because of these two differences, moldic and secondary intraparticle pores are recognized explicitly as distinct pore types.

For our third modification, we further divide secondary intraparticle pores into three kinds: cement-reduced moldic pores (recognized by Choquette and Pray, 1970), and two other kinds not recognized by Choquette and Pray. The second kind is formed by the partial dissolution of particles, in which either very small vugs are scattered through particles, certain regions of particles are systematically dissolved (e.g., certain concentric laminae within ooids), or single vugs form within the particles, without dissolving as much as half of the particles. This kind of pore is termed a microvuggy secondary intraparticle pore. The third kind of secondary intraparticle pore that is commonly found in Smackover reservoir rocks is formed by the partial dolomitization and partial dissolution of a particle. Commonly, partial dolomitization occurs first, and a framework of euhedral dolomite crystals is formed, in which the intercrystalline spaces are filled by relict calcium carbonate. Subsequently, if the

Pore Type Classification	
Primary	Secondary
<p>Interparticle</p> <p>Fenestral</p> <p>Shelter</p>	<p>Secondary intraparticle</p> <p>(modified by particle type)</p> <p>Microvuggy</p> <p>Intercrystalline</p> <p>Moldic</p> <p>(modified by particle type)</p> <p>Cement moldic</p> <p>Particle moldic</p> <p>Vuggy</p> <p>Intershard</p> <p>Fracture</p> <p>Intercrystalline</p>

Figure 16.--Genetic pore classification (modified from Choquette and Pray, 1970).

relict calcium carbonate is dissolved, intercrystalline secondary intraparticle porosity is created. These fabrics are commonly restricted to the interiors of particles, and do not transgress particle boundaries.

UTILITY OF GENETIC PORE CLASSIFICATION

We use a genetic pore classification for two reasons. The most important reason is that genetically different pore types tend to differ in shape, size, distribution, and connectivity, which means that a genetic classification captures those aspects of pore systems that control fluid flow. The other reason we prefer a genetic classification is that genetic pore types are directly related to primary sediment fabrics and to diagenetic processes (such as particle dissolution). This connection between pore types, deposition, and diagenesis maximizes our ability to predict pore-system distribution by relating it to geologic models of the depositional setting and of diagenetic processes.

SMACKOVER PORE TYPES

The most common kinds of pores in the Smackover are particle molds, secondary intraparticle pores, intercrystalline pores, and interparticle pores. Less-common, but significant, pore types are fractures, vugs, and cement molds. The various pore types lend different petrophysical characteristics to pore systems, and combinations of different kinds of pores in varying proportions create further effects.

Interparticle pores are permeability enhancers, because they tend to form regular networks with abundant connections, and because they are connected by large pore throats. The permeability of primary interparticle pore systems is readily destroyed by the precipitation of pore-rimming marine-phreatic cement. Fractures are even more effective permeability enhancers. They are less likely to be cemented because they form later.

Pore systems dominated by molds, vugs, and secondary intraparticle pores are not characterized by high permeability values because these pores tend to be poorly connected, and commonly by small pore throats. The most common kinds of molds are oomolds and pelmolds. Mollusk fragments commonly form molds. Oncoids, echinoderm ossicles, intraclasts, and *Favreina* pellets rarely form

molds. Secondary intraparticle pores are most common in ooids and in oncoids, less common in small pellets. *Favreina* also form secondary intraparticle pores, but are less common than the other particle types.

Secondary intraparticle pores resemble molds in being separated from one another by pore systems having different characteristics (the former interparticle spaces). Secondary intraparticle pores are small clusters of small pores, surrounded by pore systems that may be finer or coarser. By contrast, molds are individual large pores surrounded by finer pore systems. Cement-reduced molds are uncommon but widespread in the Alabama Smackover; microvuggy and intercrystalline secondary intraparticle pores are both abundant and widespread.

Intercrystalline pores typify pore systems whose permeability values depend on crystal size. Intercrystalline pores are commonly well connected by short and homogeneous pore throats, and the pores tend to be all about the same size and shape. Where intercrystalline pores are large, homogeneous, and well connected, permeability values may be extremely high.

Cement molds are not widespread, but locally compose up to 15% of pore systems (e.g., see fig. 30). However, they have little effect on permeability except where the dissolved cement had occluded primary interparticle pore throats. The most common (or at least most readily identified) kinds of cement molds in the Smackover of Alabama are dissolved meniscus or pore-lining calcium-carbonate cement (see fig. 51A) and molds formed by dissolution of the cores of dolomite cement crystals (see fig. 51B).

Uncommon Smackover pore types include fenestral, fossomoldic, shelter, intershard, and stylolitic pores. These pore types can be significant locally, especially intershard pores (see fig. 47). Intershard pores result from partial crushing of moldic pore systems, and form highly permeable networks.

DIAGENESIS OF SMACKOVER PORE SYSTEMS

Smackover reservoirs can be differentiated on the basis of degree of preservation of depositional fabric (or conversely, the degree of alteration of depositional fabric by diagenesis). The most common mode of fabric destruction in the Smackover is nonfabric-selective dolomitization. The important

kinds of Smackover reservoirs are reviewed below, beginning with those least modified by diagenesis and proceeding to those most altered.

The least altered reservoirs are oolitic, oncoidal, and pelletal grainstone, partially or nondolomitized, characterized by complex pore systems with abundant interparticle pores. The other common pore types in these reservoirs are particle moldic, secondary intraparticle, and (locally) cement moldic. These reservoirs exhibit high permeability values because of the abundance of interparticle pores.

Slightly more altered reservoirs are as above, but lack substantial amounts of interparticle porosity. These reservoirs are considered to be more-highly altered because the interparticle pores inherited from the precursor sediment have been largely obliterated. These reservoirs are less permeable than those described above.

Reservoirs assigned to the next category are largely or entirely dolomitized. These strata retain clear evidence of depositional fabric, may be characterized by abundant interparticle pores, and contain relatively few intercrystalline pores. Reservoirs with abundant interparticle pores are highly permeable; those with fewer interparticle pores are less so. The process of dolomitization itself has little effect on the porosity and permeability of these reservoirs (Kopaska-Merkel and Mann, 1991b). The pore types and petrophysical characteristics differ only slightly between nondolomitized and dolomitized moldic and secondary intraparticle reservoirs, though dolomitized examples are far more abundant and widespread in the Alabama Smackover. An uncommon but dramatic kind of reservoir in this category is pellet or ooid dolograinstone in which the pellets or ooids are entirely dissolved away and the rock consists of dolomitized interparticle cement. These pore systems can exhibit porosity values greater than 40%, but permeability values are low. If a pure-moldic reservoir is partially crushed, microfractures create intershard porosity and enhance permeability.

More highly altered reservoirs are dolostone which retains evidence of depositional fabric, but contains progressively greater proportions of intercrystalline and unspecified outsize pores, and progressively lesser proportions of other pore types. Permeability values are variable.

Even more highly altered reservoirs retain vestiges of depositional fabric, but an unequivocal assignment using the classification of Dunham (1962) cannot be made. These include completely or largely dolomitized oolitic and pelletal rocks that contain recognizable particles, but have been partially converted to homogeneous crystalline dolostone. The pore systems of these rocks are dominated by intercrystalline pores, but contain substantial proportions of molds, vugs, and unspecified outsize pores. With greater degree of alteration, the molds and vugs vanish, and the outsize pores are progressively less identifiable as to origin. These reservoirs are characterized by highly variable permeability values, depending primarily on dolomite crystal size and shape, which control the sizes of intercrystalline pore throats.

Another rock type assigned to this alteration category is microbial doloboundstone. These rocks are locally abundant in the lower part of the Smackover, and are dominated by intercrystalline and vuggy pores. Shelter porosity may be common, and fracture porosity is widespread. The volume of fracture porosity is small, but fractures have a dramatic effect on permeability values. Thus, reservoirs of this type are among the most permeable in the Smackover.

The most highly altered Smackover reservoirs are devoid of recognizable depositional fabric and contain pore systems dominated by intercrystalline pores. These reservoirs exhibit variable permeability values; highest where the rock fabric is coarse, crystal size is unimodal, and crystals are euhedral.

Smackover pore types and pore systems have now been described in sufficient detail to move on to the topic of reservoir-rock petrophysics. The subject of the relative abundance of pore- and pore-system types is deferred to the section on petrophysical reservoir classification.

PETROPHYSICAL CHARACTERISTICS OF SMACKOVER RESERVOIRS

CAPILLARY-PRESSURE CHARACTERISTICS

Capillary-pressure data were collected on 274 samples taken from 20 cores from 15 Smackover fields (table 3). Lithologically similar samples yield similar capillary-pressure (CP) curves. Because capillary-pressure-curve shape is a direct function of the pore-throat-size distribution (see methods

section), similarity of CP curves indicates similarity of pore-throat sizes. For example, many samples from moldic reservoirs that retain substantial amounts of primary interparticle porosity tend to exhibit leptokurtic unimodal throat-size distributions. This means that nearly all pores are accessed through large throats of a very restricted size range. These pore throats appear to result from a combination of (1) incomplete cement coatings on the particles (now molds), (2) open primary pores that originally formed a highly permeable network, and (3) interconnection of neighboring particle molds resulting from partial crushing of the rigid cement framework. The effect is to render the small throats between dolomite crystals irrelevant; fluid flow is controlled by the much larger throats between interparticle pores and perhaps by microfractures of about the same width.

Reservoir rocks can be classified on the basis of capillary-pressure-curve shape, using a descriptive approach applied by Amthor and others (1988) to the Lower Paleozoic Hunton group of the Anadarko basin, and to the Ordovician Ellenburger Formation of west Texas. This same approach was used to develop petrofacies classifications of the Hunton Group (Kopaska-Merkel and Friedman, 1989) and of post-Paleozoic strata from the Exmouth Plateau and Argo Abyssal Plain.

CP CURVE CLASSIFICATION

In this section we classify Smackover reservoir rocks based upon CP-curve shape. We discuss CP curves separately to draw attention to the wealth of petrophysical information that CP-curve shape summarizes, including pore-throat-size distribution and estimates of recovery efficiency and permeability. New samples for which CP curves have been generated (and this is possible with cuttings if core is not available; Kopaska-Merkel, 1988) can be confidently classified. Class membership is readily determinable from standard CP graphs, but carries with it information about petrophysical parameters such as porosity, permeability, and pore-throat-size distribution. In a subsequent section we present an integrated petrophysical classification of Smackover reservoirs that includes CP-curve shape as well as petrophysical and petrographic parameters.

Table 3.--Summary of capillary-pressure samples used in this report (Porosity estimates based on 20,000 psia (air-Hg) maximum pressure)

Field Name	Permit No.	Depth	Median throat size	Recovery efficiency	Porosity
Appleton	6247	12,976.4	2.7855	0.0359	0.117
Appleton	6247	12,979.3	2.63	0.0463	0.029
Appleton	6247	12,978.8	0.3671	0.0829	0.051
Appleton	6247	12,981.8	0.3688	0.1061	0.069
Barrytown	1818	11,834	1.4934	0.1702	0.2231
Barrytown	1818	11,832.5	1.0871	0.1636	0.1792
Barrytown	1818	11,833.5	1.5435	0.1794	0.2056
Barrytown	1818	11,834.5	1.3083	0.1811	0.1554
Barrytown	1818	11,838	4.2017	0.03	0.217
Blacksher	5242	15,564.8	4.137	0.0811	0.1505
Blacksher	5242	15,568.3	1.4237	0.1198	0.1061
Blacksher	5242	15,584.6	5.3264	0.0783	0.2229
Blacksher	5242	15,584.6	5.7611	0.0338	0.2186
Blacksher	5242	15,590.2	1.7601	0.0831	0.0953
Blacksher	5242	15,592.5	0.5209	0.2554	0.1109
Churchula	1973	18,432	0.9881	0.1359	0.1346
Churchula	1973	18,435	1.319	0.1821	0.1526
Churchula	1973	18,458	0.1851	0.2727	0.0641
Churchula	1973	18,462	0.0138	0.4043	0.0127
Churchula	1973	18,463	1.2368	0.1475	0.1362
Churchula	1973	18,464	1.2404	0.1235	0.1206
Churchula	1973	18,466	1.5455	0.1152	0.1356
Churchula	1973	18,468.5	1.0116	0.1632	0.1297
Churchula	1973	18,470	0.1824	0.1341	0.0724
Churchula	1973	18,471.5	0.1206	0.1744	0.0467
Churchula	1973	18,472	0.9413	0.1458	0.0902
Churchula	1973	18,473.5	1.6784	0.1009	0.1099
Churchula	2120	18,384	2.4828	0.1105	0.1372
Churchula	2120	18,413.5	1.7491	0.1463	0.1662
Churchula	2120	18,419	2.3762	0.1257	0.1646
Churchula	2120	18,421	2.067	0.1195	0.1616
Churchula	2120	18,428	2.3566	0.1037	0.176
Churchula	2120	18,434	2.0842	0.126	0.18
Churchula	2120	18,446	2.3147	0.1225	0.1118
Churchula	2120	18,516	2.2591	0.0991	0.132
Churchula	2355	18,476	1.0408	0.1426	0.1485
Churchula	2355	18,477	1.2501	0.0995	0.1503
Churchula	2355	18,479	1.2244	0.1521	0.1476
Churchula	2355	18,479	1.2815	0.1547	0.1518

Table 3.--Summary of capillary-pressure samples used in this report (Porosity estimates based on 20,000 psia (air-Hg) maximum pressure)—Continued

Field Name	Permit No.	Depth	Median throat size	Recovery efficiency	Porosity
Churchula	2355	18,487	0.0493	0.434	0.0148
Churchula	2355	18,505.3	1.8461	0.1033	0.1814
Churchula	2355	18,509.3	0.0251	0.1765	0.0093
Churchula	2355	18,512	0.029	0.2453	0.0145
Churchula	2355	18,512	0.0274	0.087	0.0063
Churchula	2355	18,515.8	0.0254	0.3636	0.0093
Churchula	2355	18,518	0.112	0	0.003
Churchula	2355	18,520	0.0901	0.3387	0.0171
Churchula	2355	18,527	0.0304	0.3539	0.0192
Churchula	2355	18,529.5	0.0461	0.1515	0.0094
Churchula	2584	18,473	1.6121	0.1277	0.1434
Churchula	2584	18,480	1.0036	0.1365	0.1117
Churchula	2584	18,486	0.247	0.2928	0.058
Churchula	2584	18,492	2.0377	0.0958	0.0913
Churchula	2584	18,493	1.6427	0.1022	0.093
Churchula	2584	18,496	1.3982	0.0912	0.077
Churchula	2584	18,497	0.9637	0.1	0.0711
Churchula	2584	18,499	2.7441	0.1073	0.1274
Churchula	2584	18,501	1.996	0.0655	0.0863
Churchula	2584	18,502	1.16	0.0785	0.0741
Churchula	2678	18,483	1.6458	0.0864	0.129
Churchula	2678	18,485	0.0693	0.1644	0.0761
Churchula	2678	18,488	1.5899	0.1306	0.145
Churchula	2678	18,489	1.9354	0.058	0.1313
Churchula	2678	18,490	1.1583	0.1385	0.1213
Churchula	2678	18,491.5	1.5354	0.1093	0.1314
Churchula	2678	18,493	1.64	0.0892	0.1165
Churchula	2678	18,495	1.9821	0.0907	0.1358
Churchula	2678	18,496	1.3412	0.129	0.1294
Churchula	2678	18,498	1.5617	0.0876	0.1279
Churchula	2678	18,500	2.6559	0.0961	0.1377
Churchula	2678	18,502	1.3089	0.108	0.1158
Churchula	2678	18,504	1.1135	0.1304	0.1046
Churchula	2678	18,506	3.3522	0.0661	0.1017
Churchula	2678	18,508	2.6727	0.0303	0.1084
Churchula	2678	18,509	2.8782	0.08	0.1341
Churchula	2678	18,511	2.8061	0.0397	0.1294
Churchula	2678	18,513	2.5363	0.0681	0.1498
Churchula	2678	18,515	1.0963	0.1258	0.1201
Churchula	2678	18,518	0.156	0.2213	0.0624

Table 3.—Summary of capillary-pressure samples used in this report (Porosity estimates based on 20,000 psia (air-Hg) maximum pressure)—Continued

Field Name	Permit No.	Depth	Median throat size	Recovery efficiency	Porosity
Chunchula	2678	18,531	0.3683	0.1803	0.0938
Chunchula	2678	18,533	0.3664	0.1571	0.0974
Chunchula	2678	18,535	0.1917	0.1359	0.0801
Chunchula	2739	18,459	0.3349	0.3159	0.0872
Chunchula	2739	18,463	1.9552	0.0835	0.1478
Chunchula	2739	18,465.5	1.7205	0.1048	0.1481
Chunchula	2739	18,466	1.7143	0.0742	0.1528
Chunchula	2739	18,469	3.0432	0.081	0.184
Chunchula	2739	18,470	1.8436	0.123	0.1376
Chunchula	2739	18,471	2.8417	0.1072	0.1367
Chunchula	2739	18,473	1.9059	0.1183	0.1505
Chunchula	2739	18,474	2.4749	0.0873	0.1364
Chunchula	2739	18,476	0.8081	0.1978	0.1127
Chunchula	2739	18,480	0.0514	0.2987	0.021
Chunchula	2739	18,486	0.2854	0.2037	0.1094
Chunchula	2739	18,488	0.4853	0.2154	0.1274
Chunchula	2739	18,490	0.6352	0.1751	0.1344
Chunchula	2739	18,490	0.6464	0.1788	0.1394
Chunchula	2739	18,491.9	1.2116	0.1275	0.1456
Chunchula	2739	18,492.5	1.1157	0.1551	0.1484
Chunchula	2739	18,494.8	1.2652	0.1123	0.1557
Chunchula	2355B	18,802	0.8271	0.2193	0.1362
Chunchula	2355B	18,803	1.3121	0.1709	0.134
Chunchula	2355B	18,804	1.1346	0.1387	0.1406
Chunchula	2355B	18,805	1.4003	0.1697	0.1562
Chunchula	2355B	18,806	1.3646	0.1817	0.1727
Chunchula	2355B	18,811	1.1085	0.2342	0.1568
Chunchula	2355B	18,813	0.728	0.2296	0.139
Crosbys Creek	5115	16,384.7	0.6398	0	0.1346
Crosbys Creek	5115	16,385.8	0.3945	0	0.1792
Crosbys Creek	5115	16,389.9	0.4246	0	0.1823
Crosbys Creek	5115	16,393	1.401	0.0188	0.2482
Crosbys Creek	5115	16,394.6	0.573	0.0139	0.2454
Crosbys Creek	5115	16,398.1	0.9646	0.0374	0.164
Crosbys Creek	5115	16,402	2.4726	0.0047	0.1724
Crosbys Creek	5115	16,404.9	0.999	0.0231	0.2413
Crosbys Creek	5115	16,406.2	0.9672	0.0169	0.3187
Huxford	4577	14,546.6	7.7083	0.0815	0.1037
Huxford	4577	14,550.2	4.0796	0.0263	0.0958
Huxford	4577	14,552.1	4.0772	0.0505	0.0768

Table 3.—Summary of capillary-pressure samples used in this report (Porosity estimates based on 20,000 psia (air-Hg) maximum pressure)—Continued

Field Name	Permit No.	Depth	Median throat size	Recovery efficiency	Porosity
Huxford	4577	14,559	2.155	0	0.0726
Huxford	4577	14,559.3	0.5462	0.1117	0.0481
Huxford	4577	14,562.3	2.856	0.1116	0.1075
Huxford	4577	14,557.5	4.6467	0.058	0.0966
Little Escambia Creek	1654	15,152	1.5051	0.181	0.1707
Little Escambia Creek	1654	15,155	0.6914	0.188	0.1605
Little Escambia Creek	1654	15,155.5	0.8829	0.1768	0.1625
Little Escambia Creek	1654	15,170	3.0071	0.073	0.122
Little Escambia Creek	1654	15,170	2.7806	0.134	0.1371
Little Escambia Creek	1654	15,176.4	2.9108	0.103	0.1575
Little Escambia Creek	1654	15,176.4	2.8678	0.0362	0.1558
Little Escambia Creek	1654	15,177	3.0693	0.1746	0.1423
Little Escambia Creek	1654	15,190	0.83	0.2543	0.1389
Little Escambia Creek	1654	15,192	0.4585	0.8815	0.0326
Little Escambia Creek	1654	15,204	0.371	0.2953	0.0894
Little Escambia Creek	1654	15,230	0.1191	0.125	0.0464
Little Escambia Creek	1654	15,283	1.6092	0.3874	0.1205
Little Escambia Creek	1654	15,283.7	1.2279	0.4084	0.1043
Little Escambia Creek	1654	15,288.5	0.2658	0.2687	0.0953
Little Escambia Creek	1654	15,295	0.0176	0.1882	0.0244
Little Escambia Creek	1654	15,431	0.0797	0.2188	0.0352
Little Escambia Creek	1654	15,433.8	0.0525	0.2273	0.035
Little Escambia Creek	1654	15,433.8	0.0543	0.2	0.0341
Little Escambia Creek	1654	15,434.3	0.0545	0.2478	0.0601
Little Escambia Creek	1654	15,434.5	0.0561	0.1856	0.0379
Little Escambia Creek	1654	15,440	0.0159	0.1556	0.0250
Lovetts Creek	3535	13,336.6	2.1448	0.094	0.109
North Choctaw Ridge	1878	11,755	5.1919	0.132	0.0773
North Choctaw Ridge	1878	11,755	2.7708	0.0672	0.1901
North Choctaw Ridge	1878	11,758	1.2365	0.27	0.089
North Choctaw Ridge	1878	11,758	1.9187	0.121	0.1341
North Choctaw Ridge	1878	11,758.5	2.0854	0.0709	0.1536
North Choctaw Ridge	1878	11,759	1.1398	0.1491	0.1022
North Choctaw Ridge	1878	11,759	1.1914	0.1728	0.1086
North Choctaw Ridge	1878	11,762	2.7908	0.1028	0.2233
North Choctaw Ridge	1878	11,762	4.579	0.003	0.1657
North Choctaw Ridge	1878	11,764.5	1.6218	0.0898	0.2509
North Choctaw Ridge	1878	11,764.5	1.6811	0.1094	0.2550
North Choctaw Ridge	1878	11,765	3.8453	0.1165	0.2357
North Choctaw Ridge	1878	11,765	5.391	0.367	0.1888

Table 3.--Summary of capillary-pressure samples used in this report (Porosity estimates based on 20,000 psia (air-Hg) maximum pressure)—Continued

Field Name	Permit No.	Depth	Median throat size	Recovery efficiency	Porosity
North Choctaw Ridge	1878	11,766	0.7237	0.0104	0.1988
North Choctaw Ridge	1878	11,775	5.28	0.0576	0.2746
North Choctaw Ridge	1878	11,778	7.2477	0.33	0.1769
North Choctaw Ridge	1878	11,778	6.5654	0.224	0.1743
North Choctaw Ridge	1878	11,782.4	2.1463	0.0406	0.2078
North Choctaw Ridge	1878	11,782.4	2.2933	0.0609	0.2186
North Choctaw Ridge	1878	11,783	5.5281	0.022	0.2249
North Choctaw Ridge	1878	11,783	4.84	0.165	0.2533
North Choctaw Ridge	1878	11,785	5.7697	0.018	0.1606
North Choctaw Ridge	1878	11,785	5.7471	0.191	0.205
North Choctaw Ridge	1878	11,785.8	4.8821	0.0431	0.2966
North Choctaw Ridge	1878	11,789	2.7802	0.004	0.1736
North Choctaw Ridge	1878	11,789	3.6497	0.008	0.1485
North Choctaw Ridge	1878	11,794	4.9208	0.05	0.2609
North Choctaw Ridge	1878	11,794	4.9699	0.0557	0.2503
North Choctaw Ridge	1878	11,796	3.5543	0.106	0.1735
North Choctaw Ridge	1878	11,798.2	4.3497	0.001	0.1698
North Choctaw Ridge	1878	11,798.8	4.7327	0.0034	0.1331
North Choctaw Ridge	1878	11,805.5	1.4214	0.2480	0.1550
North Choctaw Ridge	1878	11,805.5	1.2804	0.391	0.1529
North Choctaw Ridge	1878	11,816	0.7625	0.5	0.1277
North Choctaw Ridge	1878	11,816	0.8367	0.514	0.1307
North Choctaw Ridge	1878	11,818.5	0.4472	0.182	0.0664
North Choctaw Ridge	1878	11,818.5	0.3487	0.1156	0.0586
North Choctaw Ridge	1878	11,824	0.9184	0.2405	0.1049
North Choctaw Ridge	1878	11,824	0.6923	0.259	0.0893
North Choctaw Ridge	1878	11,828	1.8038	0.204	0.1826
North Choctaw Ridge	1878	11,828	1.8716	0.215	0.1853
North Choctaw Ridge	1878	11,833.9	0.8541	0.5696	0.1478
North Choctaw Ridge	1878	11,833.9	0.8404	0.5437	0.1452
North Choctaw Ridge	1878	11,834	0.984	0.4226	0.1741
North Choctaw Ridge	1878	11,834	0.9506	0.4801	0.1825
North Choctaw Ridge	1878	11,834.8	0.5325	0.1519	0.1755
North Choctaw Ridge	1878	11,834.8	1.6149	0.244	0.1616
North Choctaw Ridge	1878	11,836	1.2249	0.411	0.1566
North Choctaw Ridge	1878	11,837	1.4275	0.1662	0.1528
North Choctaw Ridge	1878	11,837	1.7161	0.1383	0.1470
North Choctaw Ridge	1878	11,837 6	1.3729	0.4476	0.1641
North Choctaw Ridge	1878	11,839	0.0306	0.0960	0.0347
North Choctaw Ridge	1878	11,839	0.0466	0.1135	0.0366

Table 3.--Summary of capillary-pressure samples used in this report (Porosity estimates based on 20,000 psia (air-Hg) maximum pressure)—Continued

Field Name	Permit No.	Depth	Median throat size	Recovery efficiency	Porosity
Perdido	4696	16,534.6	1.8882	0.0969	0.0995
Perdido	4696	16,541.5	0.2833	0.14	0.066
Perdido	4696	16,544.9	1.2669	0.1609	0.1096
Perdido	4696	16,546.1	2.1579	0.1423	0.1186
Silas	2205	13,601.4	1.1014	0.2947	0.1262
Silas	2205	13,602	1.5689	0.0417	0.1388
Silas	2205	13,602.9	0.5744	0.0186	0.2132
Silas	2205	13,603.8	0.8067	0.0144	0.2126
Silas	2205	13,604	2.0483	0	0.2222
Silas	2205	13,605.5	2.1368	0	0.2005
Silas	2205	13,607	2.5286	0	0.2376
Silas	2205	13,609	2.6178	0.0134	0.2132
Silas	2205	13,610	1.3675	0.0343	0.2209
Silas	2205	13,611.5	0.463	0.0154	0.2366
Silas	2205	13,612.3	1.5388	0.0061	0.245
Silas	2205	13,613	1.8856	0	0.2103
Silas	2205	13,614	2.6736	0.0363	0.1808
Silas	2205	13,615.7	2.0423	0.0045	0.2378
Silas	2205	13,615.8	0.7069	0	0.2251
Silas	2205	13,617.3	0.2543	0	0.2153
Silas	2205	13,617.7	2.47	0	0.2004
Silas	2205	13,618.9	1.9437	0	0.1027
Silas	2205	13,619	1.3178	0.0196	0.1865
Silas	2205	13,619.8	0.682	0	0.119
Silas	2205	13,621.6	1.6929	0	0.2416
Silas	2205	13,622	0.2848	0.0283	0.2782
Silas	2205	13,623	2.4534	0	0.1773
Silas	2205	13,625.8	0.4468	0.0157	0.1584
Silas	2205	13,626	0.71	0	0.3272
Silas	2205	13,626.5	0.2535	0.0017	0.336
Silas	2205	13,628.7	0.8164	0	0.2969
Silas	2205	13,630.2	2.7384	0.1446	0.2255
Sugar Ridge	1903	11,719.2	0.0266	0.02	0.1405
Sugar Ridge	1903	11,721	1.5004	0.0827	0.157
Sugar Ridge	1903	11,721.5	1.576	0.0683	0.1728
Sugar Ridge	1903	11,723	0.6521	0.0664	0.117
Sugar Ridge	1903	11,723.9	2.3442	0.0868	0.1487
Sugar Ridge	1903	11,725.5	2.9298	0.1059	0.1539
Sugar Ridge	1903	11,737	0.8179	0.2051	0.117
Uriah	1571	14,055.5	0.1137	0.3882	0.0222

Table 3.--Summary of capillary-pressure samples used in this report (Porosity estimates based on 20,000 psia (air-Hg) maximum pressure)—Continued

Field Name	Permit No.	Depth	Median throat size	Recovery efficiency	Porosity
Uriah	1571	14,062.5	4.2904	0.106	0.1102
Uriah	1571	14,072.5	1.6005	0.1314	0.0942
Uriah	1571	14,087.3	3.581	0.1196	0.1275
Uriah	1571	14,107	0.14	0.375	0.0503
Uriah	1571	14,114.5	3.5583	0.1059	0.1088
Uriah	1571	14,128.3	0.0203	0.2857	0.0135
Uriah	1571	14,146.7	0.4714	0.1013	0.0601
Uriah	1571	14,148.3	4.5513	0.0442	0.1896
Uriah	1571	14,155.5	0.5437	0.1	0.0578
Uriah	1571	14,161.1	0.7087	0.1783	0.0811
Uriah	1571	14,167.7	1.922	0.1783	0.1194
Uriah	1571	14,170.5	0.5999	0.081	0.0817
Uriah	1571	14,173.5	0.4884	0.0759	0.0749
Uriah	1571	14,182.4	0.1107	0.1367	0.0383
Uriah	1571	14,192.5	0.1035	0.4296	0.0379
Uriah	1571	14,195	0.0981	0.375	0.0344
Womack Hill	2327	11,436.1	0.751	0.2104	0.0888
Womack Hill	2327	11,437.8	0.0349	0.1472	0.0524
Womack Hill	2327	11,440.4	2.2203	0.1594	0.1518
Womack Hill	2327	11,442.2	0.264	0.2424	0.0768
Womack Hill	2327	11,445.8	0.026	0.2273	0.0237
Zion Chapel	2372	14,023.6	0.0501	0.1359	0.0288
Zion Chapel	2372	14,023.6	0.0456	0	0.0262
Zion Chapel	2372	14,023.6	0.0449	0.0588	0.0285
Zion Chapel	2372	14,028.4	1.7803	0.0484	0.1489
Zion Chapel	2372	14,028.4	1.7502	0.1645	0.1511
Zion Chapel	2372	14,028.4	1.8502	0.1593	0.1479
Zion Chapel	2372	14,029.5	2.0551	0.1407	0.1561
Zion Chapel	2372	14,029.5	2.1823	0.1486	0.1636
Zion Chapel	2372	14,029.5	2.0776	0.1594	0.163
Zion Chapel	2372	14,029.5	2.0324	0.1602	0.159
Zion Chapel	2372	14,031.7	2.1653	0.1363	0.1458
Zion Chapel	2372	14,031.7	2.2591	0.1359	0.1509
Zion Chapel	2372	14,033.2	1.166	0.181	0.127
Zion Chapel	2372	14,033.2	1.1651	0.1992	0.1257
Zion Chapel	2372	14,058.1	0.0478	0.0595	0.0685

Smackover CP curves are classified into 8 groups; 5 correspond to reservoir rocks, 1 to borderline reservoir rocks (porosity and permeability values near or below the cutoffs of 6% and 0.1 md, respectively), and 2 to nonreservoir rocks (table 4).

Table 4.—Classification of capillary-pressure curves by shape

Class	Throat-size distribution	Median throat size	Recovery efficiency
1	Extremely leptokurtic	Very large (2.70 ± 1.67)	Low (0.02 ± 0.03)
2	Leptokurtic	Large (1.85 ± 1.52)	Low (0.02 ± 0.02)
3	Leptokurtic	Large (2.32 ± 1.48)	High (0.21 ± 0.14)
4	Mesokurtic	Large (1.56 ± 0.89)	Intermediate (0.13 ± 0.05)
5	Platykurtic or polymodal	Intermediate (1.11 ± 1.14)	Intermediate (0.13 ± 0.11)
6	Mesokurtic	Small (0.22 ± 0.10)	High (0.31 ± 0.06)
7	Leptokurtic	Very small (0.04 ± 0.03)	High (0.31 ± 0.09)
8	Leptokurtic	Very small (0.08 ± 0.10)	Intermediate (0.14 ± 0.06)

CP-curve class 1 includes samples with extremely leptokurtic pore-throat-size distributions that exhibit little or no extrusion of mercury during pressure reduction. Essentially all of the porosity in each of these samples is accessed through throats of a single narrow size range. Samples assigned to this class tend to have large median pore throats and high porosity values; most are ooid dolograins or pellet dolograins with abundant moldic porosity and many contain substantial amounts of interparticle porosity (fig. 17). Evidently, the pore throats that control fluid movement over distances as great as a few mm are the preserved segments of interparticle porosity and microfractures that formed during partial crushing of the dolomitized cement framework after particle dissolution (fig. 18).

Samples assigned to CP-curve class 2 exhibit leptokurtic pore-throat-size distributions with minor fine tails, and there is little or no mercury extrusion during pressure reduction. Most of the porosity in each of these samples is accessed through throats of a single narrow size range. However, smaller throats are involved in the filling and drainage of roughly 10 to 20% of the pore system in these samples. The smaller throats may form a discrete group, or may encompass a broad range of sizes (fig.

Figure 17.—CP-curve class 1. Example from Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,789'. In this and other CP curves, pore-throat radius is calculated from capillary pressure as explained in section 3.

Figure 18.--Simplified paragenetic sequence of moldic reservoir assigned to CP-curve class 1.

19). Samples assigned to this class have large median pore throats, but typically not so large as those of samples assigned to class 1. Porosity values are as high as or higher than those characteristic of class 1. Most samples assigned to this class are pelletal and oolitic dolograins, similar to those assigned to class 1; most exhibit either pure moldic pore systems or contain substantial amounts of interparticle porosity. A few contain nearly pure intercrystalline pore systems.

CP-curve class 3 includes samples that have leptokurtic pore-throat-size distributions (generally steeper than those of class 2, but less steep than those of class 1). If a fine tail is present, the volume of pore space associated with each incrementally smaller throat size decreases smoothly, and collectively these smaller throats commonly account for 10% or less of the pore system. Samples assigned to this class commonly exhibit a substantial amount of mercury extrusion during pressure reduction; as much as 60% in rare cases (fig. 20). Samples assigned to this class have median throats slightly larger, on the average, than those of samples assigned to class 2, but substantially smaller than those of samples assigned to class 1. Porosity values are measurably lower than for classes 1 and 2. Whereas the first two CP-curve-shape classes are dominated by oolitic and pelletal dolograins, samples assigned to this class are more diverse. They include a wide variety of dolograins, partially dolomitized grains, packstone, and wackestone, crystalline dolomite, and other rock types. This is by far the most-abundant CP-curve type among our samples.

CP-curve class 4 includes samples that have mesokurtic pore-throat-size distributions (ranging from like those of class 2, to substantially more variable). Many of these samples exhibit a prominent tail of small throats that accounts for as much as 30% of the pore volume. Many samples, rather than exhibiting a discrete fine tail, exhibit a smooth reduction in volume of pores accessed through smaller and smaller throats over the entire range of pore-throat sizes. Samples assigned to this class extrude up to 25% or more of their mercury during pressure reduction (fig. 21). Median throat sizes and porosity values are lower than in classes 1, 2, and 3. Samples assigned to class 4, like those of class 3, are petrographically diverse. Diverse dolograins, partially dolomitized grains and packstone, and crystalline dolomite are the most common rock types assigned to class 4. These samples differ from those assigned to class 3 primarily in having a broader range of pore-throat-sizes through which

Figure 19.--CP-curve class 2. (a) Example from Permit No. 4577, Huxford field, Escambia County, 14,552.1'. Smaller pore throats encompass a discrete size group. (b) Example from Permit No. 2205, Silas field, Choctaw County, 13,613'. Smaller pore throats smoothly decrease in abundance with decreasing size. See caption to figure 17 for general comments.

Figure 20.--CP-curve class 3. Example from Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,837.6'. See caption to figure 17 for general comments.

Figure 21.--CP-curve class 4. Example from Permit No. 2327, Womack Hill field, Clarke County, 11,436.1'. See caption to figure 17 for general comments.

substantial volumes of porosity are accessed. The diversity of rock types suggests that there are at least several proximate causes of this broadened pore-throat-size range. Many of these samples are dominated by intercrystalline pores. We infer from the mesokurtic pore-throat-size distributions that these samples exhibit polymodal dolomite-crystal-size distributions. Other samples assigned to this class typically contain mixed pore systems in which secondary intraparticle pores and intercrystalline pores are abundant, which probably explains the mesokurtic pore-throat-size distributions in these samples.

Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat-size distributions. CP curves assigned to this class are variable. These samples also have variable porosity values, recovery efficiency values, and median throat sizes. On average, however, porosity values and median throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40% (fig. 22). Samples assigned to class 5 are petrographically diverse; this class specifically differs from classes 1 through 4 in including abundant dolomitized boundstone, in addition to dolograinstone, dolopackstone, and other rock types.

CP-curve class 6 includes samples that are only marginal reservoir rocks; porosity values are less than 10% and the mean porosity value is about 6%. These samples have mesokurtic throat-size distributions but entirely lack large throats (MTS does not exceed 0.5 Mm). RE ranges between about 30 and 40% (fig. 23). These samples include microcrystalline carbonate (e.g., lime mudstone and peloid wackestone), of which some are dolomitized, and crystalline dolostone.

CP-curve classes 7 and 8 include nonreservoir rocks and are not described here (see table 4).

Progressing from class 1 to class 6, several trends are evident. Porosity values and throat sizes decrease (table 4), throat-size ranges for single samples increase (on a log scale; table 4), and the proportions of dolomite and of grainstone also decrease. The lower class numbers correspond to more-productive reservoirs.

The CP-curve classification presented here differs from, but is consistent with the design of, those previously devised by Amthor and others (1988) and Kopaska-Merkel and Friedman (1989). The categories used in this report are compared to those used by Kopaska-Merkel and Friedman (1989) in

Figure 22.--CP-curve class 5. (a) Platykurtic example from Permit No. 6247, Appleton field, Escambia County, 12,978.8'. (b) Polymodal example from Permit No. 2205, Silas field, Choctaw County, 13,601.4'. See caption to figure 17 for general comments.

Figure 23.--CP-curve class 6. Example from Permit No. 1654, Little Escambia Creek field, Escambia County, 15,288.5'. See caption to figure 17 for general comments.

Figure 24.--Porosity vs. median throat size for all Smackover data.

table 5. In essence, we here subdivide two of Kopaska-Merkel and Friedman's categories, and we have not observed samples like those assigned to their category V (which were nonreservoir rocks).

Table 5.--Comparison of capillary-pressure curve classification of this paper with that of Kopaska-Merkel and Friedman, 1989.

This paper	Kopaska-Merkel and Freidman
1	IB
2	IB
3	IA
4	IA
5	II
6	III
7	IV
8	IV

TYPICAL AND ATYPICAL RESERVOIRS

Despite our division of Smackover reservoir rocks into 6 groups based on CP-curve shape, CP data can also be used to show that most Smackover reservoir rocks form a homogeneous group characterized by well-defined trends. Using this approach, the differences between CP-curve-shape classes are ignored and overall similarities become apparent. This exercise is instructive, because it permits generalizations to be made about petrographic characteristics of the entire "trend." If porosity is compared to MTS (fig. 24), a general trend characterizes most Smackover reservoirs. The greater the porosity, the larger the MTS. For unimodal distributions of roughly similar shape (and most Smackover reservoir rocks exhibit CP curves that are of roughly similar shape) median throat size is a fairly unbiased comparative measure of throat size.

Although most Smackover reservoir rocks fit the trend just described, in which MTS and porosity are proportional to one another and positively correlated, there are some exceptions. A group of 15 outliers have unusually low values of MTS (fig. 24). These samples exhibit porosity values of 18% or more but MTS values are no greater than 1 micrometer. Eleven of these samples come from reservoirs

characterized by nearly pure moldic porosity (with or without interparticle porosity) in which the particle molds are poorly connected. These samples are assigned to CP-curve classes 1 and 2. By contrast with these "perfect" moldic reservoirs, moldic reservoirs that have experienced partial crushing of the rock framework and development of microfractures, which are common in the Smackover of Alabama, fit the general trend illustrated by figure 24 (see fig. 47). The occurrence of noncrushed moldic pore systems within a reservoir interval creates heterogeneity by the development of relatively impermeable high-porosity zones. These zones are commonly no greater than a few cm thick, and their lateral extents are probably several meters or less. The other four samples with unexpectedly small median throats are assigned to CP-curve class 5. These four samples resemble one another petrographically; they are all ooid dolograstone or pellet ooid dolograstone. However, the four CP curves are dissimilar, ranging from gradational to bimodal with a coarse tail, to bimodal with a fine tail. It is not clear what factors, if any, tie these four samples to one another or to the other 11 outliers.

POROSITY AND PERMEABILITY DATA

PREDICTING POROSITY

Porosity prediction is fairly straightforward, depending as it does on both core analyses and well-log interpretations. On a regional scale it is possible to construct a map of average porosity values (one such is presented as figure 55). On a field scale, porosity is best predicted using a geostatistical technique that preserves as much as possible the variance structure of the data. Hierarchical conditional simulation was applied to porosity data in Chunchula field, and the results are reported in the final report on Subtask 4, already submitted to DOE. This subject is not treated further here.

PREDICTING PERMEABILITY

Petrophysical data (porosity, permeability, and capillary-pressure analyses) have been analyzed statistically and compared to other kinds of data (e.g., petrographic) in order to predict permeability. The first step was to look for regularities in the petrophysical data. On a regional scale, Smackover

reservoir characteristics are remarkably consistent. When a single reservoir is studied (e.g., Silas field in Choctaw County; see Appendix 1) atypical samples are readily distinguished (fig. 25). This graph shows that rock units that were identified as significantly different by visual core description exhibit distinct petrophysical characteristics. This confirms that flow units can be identified by visual core description. As we would like to model the 3D distribution of flow units using readily acquired data, the congruence between lithofacies identified in core and petrophysical characteristics is encouraging. Because lithofacies dominated by moldic pores are strongly controlled by depositional fabric, a detailed facies-analytic approach using cores and logs might help refine engineering models of flow-unit distribution by constraining the shapes, sizes, and relative positions of reservoir bodies with moldic pore systems. Such an approach is unlikely to be successful in reservoirs with intercrystalline pore systems because they commonly bear an indeterminable relationship to depositional fabric.

Two possible methods of predicting permeability present themselves. The first is based on the relationship between microporosity, as measured from capillary-pressure data and as estimated by calibration of well logs, and permeability. The ultimate goal is to predict permeability values from well logs, or from limited amounts of other kinds of data. The other way to predict permeability is by measuring MTS, which is derived from capillary-pressure analysis.

FROM MEDIAN THROAT SIZE

One approach to predicting porosity and permeability, stochastic modeling, has been applied to Chunchula field, Mobile County, as explained in the final report on Subtask 4. Another approach is to predict permeability deterministically, using geological or engineering data. Of all of the variables we have investigated, only MTS is strongly correlated with permeability (fig. 26). MTS is derived from capillary-pressure analysis. This method requires expensive and time-consuming studies of rock samples, commonly from cores. However, whereas permeability can only be measured in samples cut from cores, MTS can be calculated from capillary-pressure analysis of cuttings (Purcell, 1949; Kopaska-

Merkel, 1988). Therefore, permeability can be estimated from noncored intervals using this method. As explained in the methods section, this approach is unusable if the pore throats are too large.

If a reservoir simulation is planned in a field for which only some wells have been cored, MTS values from capillary-pressure analysis of cuttings can be used to derive permeability values to plug into the locations of noncored wells. This increases the size and accuracy of the dataset to be input to geostatistical models that will provide the grid-block numbers for the simulation. Permeability can also be estimated in noncored wells if permeability can be calibrated to well logs. Even if well logs are successfully calibrated to permeability, the MTS method provides an independent estimate; the two estimates can be used to check each other.

Permeability can also be calculated from capillary-pressure data in other ways (e.g., Jennings, 1987; Ma and others, 1991) but these are not appropriate for a regional study like this one.

Influence of Microporosity

Small amounts of microporosity can dramatically depress permeability in Smackover reservoir rocks (fig. 27). It appears that small (centimeter-scale?) areas of small pores and small pore throats act as permeability baffles. Thus, by understanding the distribution of microporosity one might be able to predict permeability variation.

At least in some cores, the proportion of "microporosity" (defined as pores intruded at pressures greater than 1000 psia) is roughly inversely proportional to permeability (see fig. 27). However, in other cores, this is not true, and there is no overall relationship for all samples between these two variables. Perhaps some kinds of microporosity influence permeability and others do not. This presents several questions which are, at the present time, unanswered. What kinds of microporosity affect permeability? In what kinds of pore systems or depositional facies do they occur? Can the distribution of microporosity that affects permeability be calibrated to well-log response?

Another aspect of this problem is the question of the distribution of bound water relative to "microporosity." S_w values can be measured and related to pore-throat-size distributions to study the pore-throat size that would separate "true" micropores, those that will not contain movable

hydrocarbons, from those slightly larger pores that are small, but that may contain movable hydrocarbons.

PETROPHYSICAL RESERVOIR CLASSIFICATION

STATEMENT OF PURPOSE

We classify Smackover reservoir rocks petrophysically in order to identify groups of reservoirs that are expected to respond similarly to attempts to produce reservoir fluids. In doing so we must direct our attention to pore systems, the networks of holes in the rock. In other words, we find that it is much more useful to look at what is not there, than at what is there. The shapes, sizes, distribution, surface textures, and connectivity of pores (as well as temperature, pressure, and fluid characteristics) control fluid behavior in reservoirs.

The pore systems of reservoir rocks are the end products of a long and complicated series of processes beginning with sediment deposition and continuing through burial diagenesis (fig. 28). Pore-system geometry and topology exert greater control on the hydrocarbon-production potential of reservoir rocks (especially permeability and nonwetting-fluid trapping) than any features of the rock matrix.

CLASSIFICATION OF PORES

The genetic pore classification of Choquette and Pray (1970), and our modifications to it, were described in the earlier section on genetic pore classification.

DOMINANT PORE TYPES IN THE SMACKOVER OF SOUTHWEST ALABAMA

The three most-common kinds of pores in the Smackover in Alabama are (1) moldic plus secondary intraparticle pores, (2) interparticle pores, (3) intercrystalline pores (Kopaska-Merkel, 1990). Together, these three pore types account for more than 95% of total porosity in the thin sections studied (Kopaska-Merkel and Mann, 1991a) (table 6).

Figure 25.--Median throat size vs. hydraulic radius, Silas field.

Figure 26.--Median throat size vs. natural log of permeability, all data.

Figure 27.--Example of inverse relationship between permeability and microporosity, Churchill field. Permeability and "microporosity" are plotted versus depth.

Figure 28.--Flow chart of important diagenetic processes that affected Smackover pore systems after sediment deposition.

The lumping of all particle molds together in one group, regardless of the nature of the particles from which the molds were derived, honors petrophysical similarities and differences among reservoir-rock samples. Samples from different reservoirs that have similar pore types have similar fluid-flow characteristics. Least-squares regression lines of porosity on natural log of permeability from two cores from different fields, both characterized by moldic pore systems, are nearly identical in slope and intercept (fig. 29A and B). By contrast, sets of samples characterized by different pore types exhibit differing slopes and/or intercepts on porosity-permeability plots (fig. 29C). The similarities between figures 29A and 29B are all the more remarkable because the core in B is dominated by pellet dolograinstone and the core in A contains abundant ooids. Ooids differ mineralogically from pellets (aragonite vs. calcite in the Smackover of Alabama) and are substantially larger (ooid diameters are 600 to > 1000 μm ; 5 to 10 times pellet diameters). Thus, both susceptibility to dissolution and initial permeability values are dramatically different for ooid grainstone and pellet grainstone. Reservoir rocks that are generally classified in different "trends", because they differ in depositional fabric and original mineralogy (e.g., aragonitic ooids vs. calcitic pellets) and come from different paleogeographic settings (e.g., Chatom and Gin Creek fields, Washington and Choctaw counties respectively; Mancini and Benson, 1980) may nevertheless exhibit pore systems that we lump together. This is justified because the petrophysical similarity between samples that is congruent with the pore-type classification is more significant to fluid-flow characteristics than are depositional differences.

Just as particle type may not strongly influence reservoir characteristics, the process of dolomitization per se does not necessarily cause a change in pore types. Dolostone and limestone both exhibit moldic pore systems. More importantly, petrophysical characteristics such as permeability and porosity also may be conserved through dolomitization. An oomoldic dolograinstone is petrophysically nearly identical to an oomoldic lime grainstone.

Table 6.--Point-count data (points encountering rock not identified as to kind of constituent)

Field	Permit No.	Sample Depth	Oo-molds	Pel-molds	Onco-molds	Particle Molds	Fav-reina Molds	Fosso-molds	All Particle Molds	Cement Molds	Inter-line	Inter-particle	Vuggy	Fracture	Inter-shard
Barnett	1827	13429.5	0	0	0	0	0	0	0	0	16	0	0	0	0
Barnett	1827	13431.3	0	0	0	0	0	0	0	0	21	0	0	0	0
Barnett	1827	13439.5	0	0	0	0	0	0	0	1	19	0	0	0	0
Barnett	1827	13442	0	0	0	0	0	0	0	0	34	0	0	0	0
Barnett	1827	13456.5	0	0	0	0	0	0	0	0	20	0	0	0	0
Barnett	1827	13464.3	0	0	0	0	0	0	0	0	27	0	0	0	0
Barnett	1827	13467.4	0	0	0	0	0	0	0	0	30	0	0	0	0
Big Escambia Creek	4727	15693	0	0	0	0	0	0	0	0	17	0	0	0	0
Big Escambia Creek	4727	15715.5	0	0	0	0	0	0	0	0	45	0	0	0	0
Blacksher	5242	15560.9	0	0	0	0	0	0	0	4	3	8	2	0	0
Blacksher	5242	15560.9	0	0	0	0	0	0	0	3	1	5	0	0	0
Blacksher	5242	15563.4	0	0	0	0	0	0	0	0	18	3	2	0	0
Blacksher	5242	15563.4	0	0	0	0	0	0	0	1	15	5	0	0	0
Blacksher	5242	15565.7	0	0	0	0	0	0	0	0	3	16	0	0	0
Blacksher	5242	15568.3	5	2	0	0	0	0	7	0	0	1	0	0	0
Blacksher	5242	15584.6	0	0	0	0	0	0	0	0	61	0	0	0	0
Blacksher	5242	15590.1	0	0	0	0	0	0	0	0	37	0	0	0	0
Blacksher	5242	15592.5	0	1	0	0	0	0	1	0	0	0	0	0	0
Blacksher	5242	15564.8	0	0	0	0	0	0	0	0	0	15	3	0	0
Bucatanua Creek	2753	12269.5	65	2	1	2	0	0	70	0	1	13	4	0	0
Bucatanua Creek	2753	12272	68	4	0	1	0	0	73	0	1	4	1	2	0
Chappell Hill	2426	11392	0	0	0	1	0	0	1	0	30	0	0	0	0
Chappell Hill	2426	11408	0	0	0	1	0	0	1	0	15	0	0	0	0
Chatom	7044	16019	0	48	0	0	0	0	48	0	3	0	0	0	0
Chatom	7044	16021	0	46	0	0	0	0	46	0	7	0	0	0	0
Chatom	7044	16024	0	54	0	0	0	0	54	0	6	0	0	0	0
Chatom	7044	16025	0	31	0	0	0	0	31	0	7	0	0	0	0
Chatom	7044	16074	0	0	0	0	1	0	1	0	37	0	0	0	0
Churchula	2085	18414	0	2	0	0	0	0	2	0	23	0	0	0	0
Churchula	2085	18418	0	1	0	0	0	0	1	0	38	0	0	0	0
Churchula	2085	18422.5	0	6	0	0	0	0	6	0	36	0	0	0	0
Churchula	2085	18451	0	1	0	0	0	0	1	0	21	0	0	0	0
Churchula	2085	18462	0	0	0	0	0	0	0	0	16	0	0	0	0
Churchula	2085	18547.9	0	7	0	0	0	0	7	0	21	0	0	0	0
Churchula	2085	18554.1	0	0	0	0	0	0	0	0	23	0	0	0	0
Churchula	2085	18562.9	0	8	0	0	0	0	8	0	39	0	0	0	0
Churchula	2085	18563.9	0	7	0	0	0	0	7	0	42	0	0	0	0

Table 6.--Point-count data (points encountering rock not identified as to kind of constituent)—Continued

Field	Permit No.	Sample Depth	Oo-molds	Pel-molds	Onco-molds	Particle Molds	Fav-reina Molds	Fosso-molds	All Particle Molds	Cement Molds	Inter-xtline	Inter-particle	Vuggy	Frac-ture	Inter-shard
Churchula	2085	18414	0	2	0	0	0	0	2	0	23	0	0	0	0
Churchula	2085	18418	0	1	0	0	0	0	1	0	38	0	0	0	0
Churchula	2085	18422.5	0	6	0	0	0	0	6	0	36	0	0	0	0
Churchula	2085	18451	0	1	0	0	0	0	1	0	21	0	0	0	0
Churchula	2085	18462	0	0	0	0	0	0	0	0	16	0	0	0	0
Churchula	2252	18547.9	0	7	0	0	0	0	7	0	21	0	0	0	0
Churchula	2252	18554.1	0	0	0	0	0	0	0	0	23	0	0	0	0
Churchula	2252	18562.9	0	8	0	0	0	0	8	0	39	0	0	0	0
Churchula	2252	18563.9	0	7	0	0	0	0	7	0	42	0	0	0	0
Churchula	2252	18597.5	0	4	0	0	0	0	4	0	37	0	0	0	0
Churchula	2252	18618.5	0	0	0	0	0	0	0	0	34	0	0	0	0
Gin Creek	3312	13446.9	0	56	0	0	0	0	56	0	5	9	2	0	0
Gin Creek	3312	13454.5	2	0	0	0	0	0	2	0	3	11	0	0	0
Gin Creek	3312	13458	1	4	0	0	0	0	5	0	2	5	0	0	0
Gin Creek	3312	13462.1	1	19	0	3	0	0	23	0	3	0	2	0	0
Gin Creek	3312	13475.2	39	1	0	0	0	0	40	0	0	0	0	1	0
Hatter's Pond	6846	18057	0	0	0	3	0	0	3	0	28	0	0	0	0
Hatter's Pond	6846	18067.9	0	0	0	9	0	0	9	0	13	0	3	0	0
Hatter's Pond	6846	18072.8	0	0	0	11	0	0	11	0	22	0	4	0	0
Hatter's Pond	6846	18074	0	0	0	11	0	0	11	0	25	0	4	0	0
Hatter's Pond	6846	18077	0	0	0	14	0	0	14	0	21	5	6	1	0
Hatter's Pond	6846	18078	0	0	0	10	0	0	10	0	15	0	1	0	0
Hatter's Pond	6846	18084	0	12	0	0	0	3	15	0	10	0	3	0	0
Hatter's Pond	6846	18105.7	0	0	0	0	0	0	0	0	32	0	1	0	0
Hatter's Pond	6846	18115	0	0	0	1	0	0	1	0	20	0	0	0	0
Hatter's Pond	6846	18140.5	0	0	0	4	0	0	4	0	30	0	12	0	0
Hatter's Pond	6846	18146	0	0	0	3	0	0	3	0	25	0	0	0	0
Hatter's Pond	6846	18153.9	0	0	0	2	0	0	2	0	31	0	2	0	0
Huxford	4577	14546.6	0	0	0	0	0	0	0	0	16	10	0	0	0
Huxford	4577	14550.2	0	0	0	0	0	0	0	0	24	0	0	0	0
Huxford	4577	14552.1	0	0	0	0	0	0	0	0	18	0	0	0	0
Huxford	4577	14557.5	0	0	0	0	0	0	0	0	19	0	0	0	0
Huxford	4577	14559.3	0	0	0	0	0	0	0	0	3	0	0	0	0
Huxford	4577	14562.3	0	0	0	4	0	0	4	0	22	0	1	0	0
Huxford	4577	14564.9	0	0	0	0	0	0	0	0	1	15	0	0	0
Huxford	4577	14599	0	9	0	0	0	0	9	0	8	0	0	0	0
Little River	3046	14494.5	0	2	0	0	0	0	2	0	25	0	0	0	0
Little River	3046	14995.5	0	7	0	4	0	0	11	0	9	2	3	0	0
Little River	3046	15000.1	0	0	0	0	0	0	0	0	17	0	0	0	0
Little River	3046	15008.5	0	0	0	0	0	0	0	0	34	1	0	0	0

Table 6.--Point-count data (points encountering rock not identified as to kind of constituent)—Continued

Field	Permit No.	Sample Depth	Oo-molds	Pel-molds	Onco-molds	Particle Molds	Fav-reina Molds	Fosso-molds	All Particle Molds	Cement Molds	Inter-xtline	Inter-particle	Vuggy	Fracture	Inter-shard
Little River	3046	15033	2	0	0	1	0	0	3	0	15	0	6	0	0
Little River	3046	15040.2	0	0	0	0	0	0	0	0	9	0	0	0	0
Little River	3046	15041.5	0	4	0	1	0	0	5	0	4	1	0	0	0
Little River	3046	15044.7	0	0	0	0	0	0	0	0	19	0	0	0	0
Lovetts Creek	3535	13448.2	0	1	0	0	0	0	1	0	14	0	0	1	0
Lovetts Creek	3535	13203.5	0	0	0	0	0	0	0	0	7	0	0	0	0
Lovetts Creek	3535	13335.2	0	0	0	4	0	0	4	0	1	17	1	0	0
Lovetts Creek	3535	13339.4	0	0	0	3	0	0	3	0	15	2	1	1	0
Lovetts Creek	3535	13370.5	0	0	0	5	0	0	5	0	4	0	0	1	0
Lovetts Creek	3535	13379.9	0	0	0	7	0	0	7	0	19	4	0	0	0
Lovetts Creek	3535	13481.1	0	2	0	4	0	0	6	0	19	3	0	1	0
Lovetts Creek	3535	13490.5	0	0	0	3	0	0	3	0	19	15	0	0	0
N. Choctaw Ridge	1878	11755.7	0	0	3	3	0	0	6	9	0	10	0	0	0
N. Choctaw Ridge	1878	11759	3	0	0	2	0	0	5	0	5	10	2	0	0
N. Choctaw Ridge	1878	11765.5	26	0	1	1	0	0	28	0	2	27	0	0	0
N. Choctaw Ridge	1878	11766	56	57	0	1	0	0	114	0	1	5	0	2	0
N. Choctaw Ridge	1878	11782.5	22	21	0	1	0	0	44	0	6	10	7	1	0
N. Choctaw Ridge	1878	11782.6	12	3	0	7	0	0	22	0	16	9	10	0	0
N. Choctaw Ridge	1878	11782.6	0	16	0	0	0	0	16	0	50	0	8	0	0
N. Choctaw Ridge	1878	11789	19	5	0	0	0	0	24	0	6	9	0	0	0
N. Choctaw Ridge	1878	11799	1	0	0	0	0	0	1	0	4	27	1	0	0
N. Choctaw Ridge	1878	11800	0	0	0	0	0	0	0	0	28	0	0	0	0
N. Choctaw Ridge	1878	11801	0	0	0	0	0	0	0	0	40	0	0	0	0
N. Choctaw Ridge	1878	11824	0	0	0	0	0	0	0	0	43	0	3	5	0
N. Choctaw Ridge	1878	11837	0	0	0	0	0	0	0	0	54	0	2	0	0
Silas	2205	13601.4	0	5	0	0	0	0	5	0	8	6	0	0	2
Silas	2205	13602	0	2	0	0	0	0	2	0	3	5	0	1	10
Silas	2205	13602.9	0	50	0	0	0	0	50	0	2	0	0	0	0
Silas	2205	13603.8	2	22	0	0	0	0	24	0	3	2	0	0	0
Silas	2205	13604	12	4	0	0	0	0	16	0	2	4	0	0	1
Silas	2205	13605.5	5	9	0	0	0	0	14	0	1	10	0	0	2
Silas	2205	13607	13	7	0	0	0	0	20	0	1	12	0	1	0

The inclusion of secondary intraparticle pores with moldic pores requires some explanation. Secondary intraparticle pores in the Smackover consist mainly of three kinds: (1) small vugs that lie entirely within partially dissolved particles (fig. 30) or partial molds that conform to the internal fabrics of original particles (fig. 31); (2) polygonal pores between dolomite crystals within particles that were partially replaced by planar-e unimodal dolomite (Sibley and Gregg, 1987) before dissolution of remnant calcium carbonate (fig. 32); and (3) reduced molds that have been nearly occluded by late cementation (these are uncommon in the Alabama Smackover). Secondary intraparticle pores are classified with molds because, like molds, they do not form a continuous network. Secondary intraparticle pores, like molds, are found within former particles and are separated from one another by whatever occupies the spaces between the former particles. In the Smackover, this intervening material is commonly marine-phreatic calcium-carbonate cement (fig. 33), microspar (fig. 34), dolomite, or anhydrite cement.

By contrast with secondary intraparticle pores and molds, interparticle pores are large and form well-connected networks. Because interparticle pores, where they occur, tend to be found with moldic and/or secondary intraparticle pores, they add a high-permeability pore-system element to the essentially low-permeability moldic or secondary-intraparticle pore system (fig. 35). Thus, even the addition of 5 to 10% interparticle pores can dramatically increase the permeability of a moldic (or secondary intraparticle) pore system. However, the situation just described only obtains if the primary interparticle pores have not been significantly affected by the formation of pore-rimming cement. In tropical shallow-marine settings, high-permeability carbonate sands tend to be quickly cemented by marine-phreatic cements (e.g., Friedman and others, 1992). These cements typically consist of blades or fibers of aragonite or of high-magnesian calcite that radiate outward from and completely coat all exposed particle surfaces (e.g., Longman, 1980). A relatively modest amount of pore-rimming marine-phreatic cement will block pore throats quite effectively (fig. 33). If, however, marine sediments come under the influence of meteoric waters before cementation in the marine environment, then meteoric-phreatic cement may form, and it is far less effective at blocking pore throats (Longman, 1980; Halley and Harris, 1979, fig. 7). (One reason for this is that the low concentration of calcium and

Figure 29.--Porosity vs. natural log of permeability, bivariate plots with least-squares regression lines and equations. Plots are based on commercial porosity and permeability data collected at one-foot intervals. (a) Permit No. 3312, Gin Creek field, Choctaw County; (b) Permit No. 7044, Chatom field, Washington County. The regression lines are virtually coincident. (c) Permit No. 3535, Lovetts Creek field, Monroe County. The intercrystalline-dominated pore-system in this core is very different from the moldic pore systems of the first two cores. The slope and intercept of the regression line for this data set are quite different from those in A and B.

Figure 30.--Secondary intraparticle pores (upper arrow) that are small vugs lying entirely within partially dissolved particles. This view also includes meniscus-cement-moldic porosity (1), pore-rimming-cement-moldic porosity (lower arrow), and interparticle porosity (2). Thin-section photomicrograph, Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,755.5'.

Figure 31.--Secondary intraparticle pores that are partial molds conforming to the internal fabric of the original particle. Note ooid on left side of photomicrograph in which certain concentric laminae have been selectively dissolved. Also note partially collapsed fabric in center of photomicrograph. Black areas are pores. Thin-section photomicrograph, Permit No. 2753, Bucatunna Creek field, Choctaw County, 12,272'.

Figure 32.--Secondary intraparticle pores that are polygonal intercrystalline pores between dolomite crystals within ooid in center of photomicrograph. The ooid was partially replaced by planar-e dolomite before dissolution of remnant calcium carbonate caused collapse of the dolomite crystals into the bottom of the mold and formation of a geopetal fabric. Dark areas are pores. Thin-section photomicrograph of ooid dolograins, Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,782.9'.

Figure 33.--Marine-phreatic pore-rimming cement blocking primary interparticle pore throats and separating ooids with secondary intraparticle porosity. Dark areas are pores; white blotch in center is incompletely stained epoxy in large interparticle pore. Thin-section photomicrograph, Permit No. 2753, Bucatunna Creek field, Choctaw County, 12,261'.

Figure 34.—Microspar between particle molds in pellet grainstone. This is an inverted fabric, in which former particles have become secondary porosity and former primary interparticle pores now are filled with calcium carbonate. Thin-section photomicrograph, Permit No. 3312, Gin Creek field, Choctaw County, 13,462.1'. Dark areas are porosity, mostly pelmoldic.

Figure 35.—Well-connected interparticle porosity (1) associated with moldic (2) and secondary intraparticle (arrow) porosity in pellet ooid grainstone. Interparticle pores add a high-permeability element to a fundamentally low-permeability secondary pore system. Thin-section photomicrograph, Permit No. 2753, Bucatunna Creek field, Choctaw County, 12,272'. Dark areas are pores; white blotch in right is porosity filled with incompletely stained epoxy.

bicarbonate in meteoric water does not permit rapid precipitation of calcium carbonate.) Well-preserved interparticle porosity that has not been severely affected by early cementation is restricted to regions close to sources of meteoric water: the updip areas and the tops of some paleohighs (fig. 36).

Intercrystalline pores, though commonly smaller than interparticle pores, also form well-connected networks. In the ideal case, dolomite crystals are all about the same size and shape and therefore the pores among them are as well (fig. 37). In reality, there are commonly patches of coarser or finer dolomite crystals, or the crystals may vary continuously in size and/or shape. Measurements of 162 dolomite crystals in a fairly homogeneous dolostone from Chunchula field (Mobile County) revealed substantial variation in crystal size (fig. 38) but most crystals were < 60 micrometers across.

POINT-COUNT DATA

Pore types and their relative proportions in reservoir rocks were determined by point counting petrographic thin sections. We counted 134 thin sections from 18 cores (fig. 39). Only the data from points encountering porosity are treated in this report (table 6). The number of points that encountered porosity in a single thin section ranged from 12 to 144 (mean = 55).

TERNARY PORE PLOTS

Ternary diagrams commonly are used to summarize geological data. Sedimentary-rock classifications based upon ternary diagrams date back to the sandstone classification of Krynine (1948). Other sandstone classifications, essentially modifications of Krynine's, are also based on ternary diagrams (e.g., Gilbert, 1954; McBride, 1963; Folk and others, 1970). Ternary diagrams have even been used to classify mixtures of terrigenous siliciclastic and carbonate sediment (e.g., Friedman and others, 1992). In the earliest instance we know of in which ternary diagrams were used specifically to study porosity, Pittman (1979) estimated the relative proportions of interparticle pores, dissolutional pores, and micropores in sandstone.

Figure 36.--Locations of cores with significant interparticle porosity in the Smackover Formation (as determined from thin-section study). The updip limit of the Smackover Formation and the 100' isopach of the Smackover are shown to illustrate the proximity of most samples to the Smackover subcrop. Only the sample from Stave Creek field (Clarke County) is far from the Smackover subcrop. This field is located on a high-relief paleohigh that grew rapidly during Haynesville time (Bolin and others, 1989). The Smackover in this field is not capped by a thick massive anhydrite unit as is typical in much of southwest Alabama. Therefore meteoric water could have reached the Smackover from a local source during subaerial exposure in Haynesville time.

Figure 37.--Example of Intercrystalline Pore Facies. Planar-e dolostone. Dark areas are pores. Permit No. 6846, Hatter's Pond Field, Mobile County, 18,152.9'.

Figure 38.--Dolomite crystal size from a single thin section of the Smackover from Churchula field, Mobile County. Crystals measured with a micrometer eyepiece using a petrographic microscope.

Figure 39.—Location of point-counted thin sections. Numbers inside circles refer to fields (see location map, fig. 1). Numbers outside circles indicate numbers of thin sections point-counted from each location. Empty circle is a wildcat well.

Despite widespread use of ternary diagrams in geology, and specifically in rock classification, the most widely accepted carbonate-rock classifications, those of Folk (1959), Dunham (1962), and Choquette and Pray (1970), are essentially tabular. (Folk published a ternary diagram in 1959 depicting the three basic limestone families of his carbonate-rock classification, but this mode of presentation was subordinate to the tabular format.) The dearth of carbonate-rock classifications based upon ternary diagrams may be an accident of history, or may result from the greater petrographic complexity of carbonate rocks, as compared to sandstone. The immense power of ternary diagrams for clearly and simply summarizing data suggests that they can play a greater role than heretofore in the classification of carbonate rocks. We use ternary diagrams to classify carbonate pore types, as described in the following figure.

Ternary diagrams whose apices are pore types (ternary pore plots; Kopaska-Merkel and Mann, 1990, 1991a, b) are constructed such that the three apices together account for most of the pores observed in a carbonate rock unit (fig. 40). This approach simplifies the interpretation of pore systems, by focusing on only three major components and by displaying these data on a simple graphic plot that makes trends and clustering of samples obvious. Ternary pore plots provide information on the shapes and origins of pore-system elements.

For this study the three apices of ternary pore plots were chosen as follows: (1) moldic plus secondary intraparticle, (2) interparticle, and (3) intercrystalline (fig. 40). Most Smackover reservoir rocks fall close to either the moldic apex or the intercrystalline apex of ternary pore plots, with most of the remaining pore systems falling between these two extremes (fig. 41). The spectrum of Smackover pore systems is not a continuum, but represents partial mixing of two distinct end members (fig. 42). This suggests that Smackover pore systems can be profitably classified according to their positions in moldic-intercrystalline porosity space. We classify Smackover reservoir rocks into Moldic and Intercrystalline pore facies based on associations of pore types that are genetically related and petrophysically similar.

Figure 40.--Ternary pore plot of samples from Permit No. 1878, North Choctaw Ridge field, Choctaw County. In this, and in all but one of the ternary pore plots in this report, the apices of the plots are moldic + secondary intraparticle; interparticle; and intercrystalline pores. See text for further discussion.

Figure 41.-- Ternary pore plot of all point-count data used in this study. Each point represents a summation of 200 or more points from a single thin section.

Figure 42.-- Ternary pore plot that illustrates preponderance of end-member samples (See figure 41.) Each cell of the ternary pore plot is coded according to the density of points falling within it. Points cluster at the moldic and intercrystalline apices, and to a lesser extent, along the boundary of the plot between those two apices.

PORE FACIES

Two distinct but partially intergrading pore facies are recognized in the Smackover of southwestern Alabama: the Moldic Pore Facies and the Intercrystalline Pore Facies (fig. 43; Kopaska-Merkel and Mann, 1991b). These pore facies are defined on the basis of the relative proportions of particle molds (assumed to include secondary intraparticle pores unless stated otherwise) and intercrystalline pores, which together account for greater than 85% of the total porosity in the Smackover of southwest Alabama (Kopaska-Merkel and Mann, 1991b). An arbitrary percentage of 60% of the dominant pore type has been selected as the boundary for pore facies. Most samples we studied plot close to either the moldic or the intercrystalline apex of a ternary pore plot; intermediates are underrepresented (fig. 41). Thus, the two pore facies are not end-members on a continuum, but are distinct entities. Pore systems that are intermediate in pore-type composition, and hence cannot be assigned to either pore facies, are discussed in a later section.

MOLDIC PORE FACIES

The Moldic Pore Facies is volumetrically dominated by particle molds (fig. 44) and plots near the particle-moldic apex on a ternary pore plot (fig. 45). It typically forms in particle-supported carbonate rocks that have been partially to wholly cemented in the shallow-marine-phreatic diagenetic environment (summarized by Longman, 1980) and whose particles have undergone partial to complete dissolution. Peloidal and oolitic grainstone are the most common particle-supported rocks in the Smackover. Most reservoirs assigned to the Moldic Pore Facies have been partially to entirely fabric-selectively (mimetically) dolomitized. Dolomitization of calcium-carbonate cement before dissolution of unstable particles was common in the Moldic Pore Facies. (Particle molds in the Moldic Pore Facies do not contain centripetal dolomite cement fabrics, but do commonly contain geopetal dolomite silt or porous frameworks of dolomite crystals that do not exhibit cement-like fabrics; see fig. 32.) However, dolomitization per se had little effect on pore-system characteristics. This

Figure 43.--Map of southwest Alabama showing the distribution of the Moldic and Intercrystalline pore facies, as well as regions characterized either by mixed pore systems, or by the co-occurrence of the two pore facies. The areas of no data contain few Smackover penetrations. Wells 1571 (Uriah field, Monroe County) and 7589 (North Wallers Creek field, Monroe County) contain quartzose sandstone reservoirs. (Modified from Kopaska-Merkel and Mann, 1991b.)

Figure 44.--Example of pore system dominated by moldic and interparticle pores. This rock consists primarily of dolomitized pore-rimming cement that forms a "dolomite-sponge" fabric. Partially dolomitized ooids and peloids now consist of porous dolomite-crystal frameworks enclosing secondary-intraparticle pores. Small interparticle pores were entirely filled with cement, whereas large interparticle pores were only rimmed with cement, and considerable interparticle porosity remains (e.g., letter "i" on figure). Dark areas are pores. Thin-section photomicrograph of peloid ooid dolograins from lithofacies 1 in Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,766'.

Figure 45.--Ternary pore plot of example of Moldic Pore Facies. Permit No. 2205, Silas Field, Choctaw County. One sample from the base of the permeable interval is dominated by intercrystalline pores.

decoupling of fabric-selective dolomitization from pore-system modification is typical of the Moldic Pore Facies.

Petrophysically the Moldic Pore Facies is characterized by large pores, determined by former particle sizes (fig. 44), and relatively high pore/throat size (aspect) ratios. Pore size and shape are determined by the former particle boundaries; pores are commonly spherical to elliptical and several hundred micrometers across because the most common particles were peloids and ooids. Throat size and shape, by contrast, are determined by the characteristics of the rock framework. Chief among these factors is dolomite crystal size. Relatively large pores commonly translate into relatively large pore volumes for reservoirs dominated by moldic porosity. However, high aspect ratios, and the decoupling of porosity and throat size, mean that permeability values increase only slightly with increasing porosity values. This is illustrated by a porosity-permeability plot in which the slope of the least-squares regression line is low (fig. 46). Pore-throat shapes are variable, but sheetlike throats are most common.

Samples of reservoir strata assigned to the Moldic Pore Facies tend to yield CP curves of classes 1 and 3. These CP-curve classes are characterized by leptokurtic throat-size distributions, by very large median throats, and by variable recovery efficiencies. Particle-moldic pore systems, consisting of delicate cement frameworks, are highly susceptible to collapse (possibly under the influence of tectonic stresses) and concomitant formation of collapsed-moldic fabrics (figs. 31 and 47). In extreme cases, cement-shard diagenetic grainstone may form, in which the rock consists primarily of fragments, or shards, of cement. Such rocks may be exceedingly permeable, because the intershard porosity can develop highly interconnected pore systems, which characteristically have large pore throats.

INTERCRYSTALLINE PORE FACIES

The Intercrystalline Pore Facies is volumetrically dominated by intercrystalline pores (fig. 37) and plots near the intercrystalline apex of a ternary pore plot (fig. 48). It typifies strata that have been pervasively nonfabric-selectively dolomitized. Primary rock fabric has little influence on the

Figure 46.--Moldic Pore Facies, plot of porosity vs. natural log of permeability. Slope of regression line is less than for the Intercrystalline Pore Facies. Permit No. 2426, Chappell Hill Field, Choctaw County.

Figure 47.--Collapsed moldic fabric (center of photomicrograph) in ooid dolograins. Ooids, some with secondary intraparticle porosity, are separated by pore-rimming cement and relict interparticle porosity, most clearly seen on lower part of photomicrograph. Dark areas are pores. Thin-section photomicrograph, Permit No. 3312, Gin Creek field, Choctaw County, 13,454.5'.

Figure 48.--Ternary pore plot of example of Intercrystalline Pore Facies. Permit No. 6846, Hatter's Pond Field, Mobile County.

distribution of intercrystalline porosity. (Subtle variation in dolomite-crystal size is commonly observed, and may result from effects of primary rock fabric.) Dolomite in the Intercrystalline Pore Facies is predominantly planar-e or planar-s, so pores are commonly polygonal and pore throats sheet-like.

Pore volume in the Intercrystalline Pore Facies is typically less than in the Moldic Pore Facies. However the aspect ratio is also smaller, and a certain porosity value in the Intercrystalline Pore Facies typically corresponds to a higher permeability than in the Moldic Pore Facies. (Wardlaw and Cassan [1979] showed that a large aspect ratio strongly and adversely affects flow of nonwetting fluids.) Although the range of porosity and mean porosity of the Intercrystalline Pore Facies is less than that of the Moldic Pore Facies, the mean maximum permeability and maximum permeability range is higher in the Intercrystalline Pore Facies (fig. 49). The slopes of least-squares regression lines of porosity on natural log of permeability are high (fig. 50) for the Intercrystalline Pore Facies.

Samples from reservoirs assigned to the Intercrystalline Pore Facies typically yield CP curves in class 4, which is characterized by mesokurtic throat-size distributions, large median throats, and intermediate recovery efficiencies. The differences between the two facies are much greater if samples with significant interparticle porosity are excluded from the Moldic Pore Facies (fig. 49). (This point is discussed further in the section on heterogeneity within the moldic pore facies.)

DISCUSSION OF PORE FACIES

COMPARISON OF PORE-FACIES CHARACTERISTICS

The two pore facies exhibit substantially different petrophysical characteristics (fig. 49). The mean slope of regression lines of porosity on natural log of permeability for the Intercrystalline Pore Facies is 0.47, with a range of 0.19 to 0.90 (fig. 50). The mean slope for the Moldic Pore Facies is 0.22 with a range of 0.18 to 0.27 (fig. 46). The higher slopes for the Intercrystalline Pore Facies mean that in this pore facies permeability values may be more readily predicted from porosity data. Porosity values are commonly higher in the Moldic Pore Facies, which has a range of mean porosity of 10.2 to 28.0%

Figure 49.--Summary of some statistical parameters for Moldic and Intercrystalline pore facies, for examples that contain mixtures of substantial proportions of both major pore types, and for the Moldic Pore Facies excluding all examples that contain substantial proportions of interparticle pores. Horizontal bars are means, wide vertical bars are one standard deviation, and narrow vertical bars are ranges. Further discussion in text.

Figure 50.--Intercrystalline Pore Facies, plot of porosity vs. natural log of permeability. Slope of regression line is higher than for the Moldic Pore Facies. Permit No. 4727, Big Escambia Creek Field, Escambia County, lithofacies 1.

compared to 9.6 to 20.5% for the Intercrystalline Pore Facies. Greater hydrocarbon volumes can be stored in reservoirs dominated by the Moldic Pore Facies, but connectivity is better in the Intercrystalline Pore Facies. The mean maximum permeability for the Intercrystalline Pore Facies is 130 md; the corresponding value is 91 md for the Moldic Pore Facies. High-permeability fluid conduits are more common in the Intercrystalline Pore Facies than in the Moldic Pore Facies.

In addition to the differences just mentioned, the Moldic and Intercrystalline pore facies exhibit distinctly different CP curves. Moldic Pore Facies CP curves (classes 1 and 3) are characterized by leptokurtic throat-size distributions, very large median throats, and variable recovery efficiencies, whereas Intercrystalline Pore Facies curves (class 4) commonly exhibit mesokurtic throat-size distributions, large median throats, and intermediate recovery efficiencies. Thus, the most obvious difference is in the kurtosis of the throat-size distribution, but median throat size differs as well.

This analysis is supported by data reported by Melas and Friedman (1992) from Jay-Little Escambia Creek (LEC) field, Escambia county, Florida. (Jay-LEC is a single reservoir, but Melas and Friedman only studied the Florida portion, which is named Jay field.) Most of the Smackover reservoir in Jay-LEC field is dominated by intercrystalline pores and probably would be assigned to the Intercrystalline Pore Facies. Moldic pores are common in a restricted interval in at least one well (Melas and Friedman, 1992). Capillary-pressure curves of class 4 appear to characterize the volumetrically dominant intercrystalline portion of the Jay-LEC field reservoir (e.g., Melas and Friedman, 1992, fig. 12). A CP curve of class 2, which is similar to class 4, was also observed by Melas and Friedman (1992, fig. 16, B). The minor moldic reservoir facies in Jay-LEC field is characterized by CP curves of class 3 (Melas and Friedman, 1992, fig. 17, B). The relationship between CP-curve shape and pore facies in Jay-LEC field appears to be completely consistent with that observed for Smackover reservoirs in Alabama.

Moldic and secondary intraparticle pores differ fundamentally from intercrystalline pores. This difference has a major effect on fluid-flow properties of pore systems dominated by one or the other of these two kinds of pores. Moldic (and secondary intraparticle) pore systems are heterogeneous on a microscopic scale because they consist of large pores (or clusters of relatively large pores) that are connected to one another by distinctly different (commonly finer) pore systems. The large pores are

the particle molds, and the fine pores are found in the material that has filled the original interparticle primary porosity. In the Smackover, this material is commonly either dolomitized carbonate cement (by far the most common), dolomitized lime mud, or calcium carbonate cement (fig. 34). Note that pore sizes, but not necessarily pore-throat sizes, are inherently heterogeneous in the Moldic Pore Facies. By contrast, intercrystalline pore systems are essentially homogeneous, because they are developed in rock fabrics that tend to consist of unimodal leptokurtic distributions of dolomite crystals that are all about the same shape (figs. 37 and 38). Moldic pore systems have a significant potential for trapping hydrocarbons within the large molds, because the high aspect ratio (pore/throat size ratio) at the interface between the molds and the surrounding much-smaller intercrystalline pores puts stress on the continuous nonwetting phase (oil, in water-wet reservoirs) (Yu and Wardlaw, 1986a). This facilitates rupture of the continuous nonwetting phase, and isolated oil globules left behind in particle molds are permanently trapped. By contrast, in intercrystalline pore systems, aspect ratios are relatively low and uniform, and the potential for trapping is thereby diminished.

The range of slopes of regression lines of porosity on natural log of permeability for the Intercrystalline Pore Facies is much greater than for the Moldic Pore Facies. We suggest that the relationship between permeability and porosity is less variable in the Moldic Pore Facies because fewer processes (i.e., cementation and dissolution) operate to produce the Moldic Pore Facies, whereas a third process, nonfabric-selective dolomitization, is also important in the evolution of Interparticle Pore Facies. Dolomitization, as mentioned earlier, has had little effect on pore-system characteristics of the Moldic Pore Facies. Furthermore, depositional lithofacies may be less variable in the Moldic Pore Facies. The Moldic Pore Facies is dominated by oolitic and peloidal grainstone, so the aspect ratio in this pore facies is relatively invariant. In the Intercrystalline Pore Facies, however, all primary rock fabrics from mud-supported to particle-supported may be nonfabric-selectively dolomitized, producing a wide range in dolomite-crystal size. Crystal size variation produces wide variation in pore sizes and probably in aspect ratios in the Interparticle Pore Facies.

HETEROGENEITY WITHIN THE MOLDIC PORE FACIES

All high-permeability examples of the Moldic Pore Facies contain substantial amounts of interparticle porosity. Interparticle pores are remnants of the primary rock-pore system that is commonly destroyed by marine-phreatic rim cementation in the Smackover of Alabama. As rim cement increases in thickness pore throats are closed off and permeability is rapidly reduced. However, if marine-phreatic cementation is prevented, or is interrupted at an early stage, commonly by exposure of the rocks to meteoric water, the coating of rim cement is thin and permeability values remain high. The results of the preservation of primary interparticle pore throats are dramatically shown in figure 49. The entire Moldic Pore Facies has a mean porosity of approximately 18%. Excluding samples containing significant interparticle porosity, the mean porosity is reduced only to about 16%. However, mean maximum permeability is reduced by a factor of 3 and maximum permeability is reduced by a factor of 4 if samples having significant interparticle porosity are excluded. Clearly, high permeability values in the Moldic Pore Facies are a function of the preservation of interparticle porosity. All but one of the samples containing significant interparticle porosity are found near the Smackover subcrop (fig. 36). The only example known to us of a Smackover reservoir with a considerable amount of primary interparticle porosity that is far from the Smackover subcrop is Stave Creek field, Clarke County, which is located on the crest of a high-relief structure that appears to have grown rapidly during Haynesville time (Bolin and others, 1989, p. 157, cross section). (The remainder of the Moldic Pore Facies is characterized by permeability values substantially less than those of the Intercrystalline Pore Facies; fig. 49.)

INTERMEDIATE PORE SYSTEMS

The two pore facies commonly intergrade to form mixtures, in which no pore type composes more than 60% of the total porosity. These mixtures are of two kinds. One kind of intermediate pore system consists of thin (mm to m) layers characterized by either moldic or intercrystalline pores, intercalated with layers dominated by the other major pore type. These "intermediate" pore systems

are heterogeneous on a macroscopic scale (levels 3 or 4; fig. 53 in this report), but on a microscopic scale they can be assigned to one pore facies or the other. The second kind of intermediate pore system is macroscopically homogeneous, but is heterogeneous at level 5, consisting of intimately commingled moldic, secondary intraparticle, and intercrystalline pores. These rocks are referred to as having mixed pore systems. For mapping purposes in the Smackover in southwest Alabama the two kinds of intermediate pore systems can be lumped together as belonging to an informal "intermediate pore facies", though to some extent this must obscure petrophysical differences between the two kinds of intermediate pore systems. In strata having mixed pore systems, "isolated" particle molds are commonly connected by networks of intercrystalline pores which control fluid-flow over macroscopic distances (see fig. 12). Intermediate pore systems must experience a similar effect on a larger spatial scale.

Intermediate pore systems petrophysically resemble the Intercrystalline Pore Facies in many ways. The slopes of regression lines of porosity on natural log of permeability for intermediate pore systems are similar to those for the Intercrystalline Pore Facies; figure 49. Maximum permeability values for intermediate pore systems are depressed, perhaps because the co-occurrence of pores and throats of varying sizes and shapes interferes with efficient drainage of fluids. Mean porosity values are lower in intermediate pore systems for reasons yet unknown.

CP curves derived from samples exhibiting intermediate pore systems span a range of shapes that encompass those of both Moldic and Intercrystalline pore facies (classes 3 and 4 are both common). Whereas in many respects intermediate pore systems resemble the pore systems of reservoirs assigned to the Intercrystalline Pore Facies, in CP-curve shape they resemble both end-members. In addition, representatives of CP-curve class 5 are common in samples with intermediate pore systems. These curves are platykurtic or polymodal, with intermediate throat sizes and recovery efficiencies. These curves evidently result from mixtures at core-plug scales of two or more kinds of pore system.

GEOGRAPHIC SEGREGATION OF PORE FACIES

Because pore types are determined by original depositional patterns (modified by diagenesis), rocks classified by dominant pore types are spatially segregated; this was demonstrated for the Smackover of Alabama by Benson (1985) and is confirmed by our work reported here and in Kopaska-Merkel and Mann (1991b). The spatial segregation of pore types permits mapping of pore facies. The Moldic Pore Facies dominates to the northwest (Choctaw, western Clarke, and Washington counties) and the Intercrystalline Pore Facies to the south and east (Mobile, Monroe, Baldwin, Escambia, and Conecuh counties) (fig. 43). Pore-facies distributions overlap in some areas (e.g., western Monroe County) and multiple pore facies occur in many Smackover fields. Areas characterized by the co-occurrence of the two pore facies are assigned to the informal "intermediate pore facies". Also assigned to this informal "pore facies" are reservoir rocks characterized by mixed pore systems (see fig. 12).

The distribution of pore facies in the Smackover of southwest Alabama is congruent with variation in petrophysical parameters (e.g., average porosity, maximum permeability, pore-throat-size distribution [CP-curve shape]) as is implied by the petrophysical differences between the pore facies. Pore-facies distribution is also congruent with variation in heterogeneity values (discussed in a following section), and with the distribution of large-scale paleogeographic features (see fig. 5).

AN ALTERNATE TERNARY-PORE-PLOT CONSTRUCTION SCHEME

The three apices used to construct ternary pore plots collectively account for over 95% of all pores in these samples (Kopaska-Merkel and Mann, 1991a). These apices also represent three end-members of a multidimensional continuum of diagenetic alteration. Interparticle pores dominate unaltered or slightly altered pore systems in particle-supported rocks. (End-member interparticle pore systems are uncommon in the Smackover.) Moldic pores dominate pore systems primarily affected by cementation and by leaching of unstable allochems. Because many allochems in the Smackover are aragonitic ooids, this kind of pore system characterizes many Smackover reservoirs. Rocks that experienced only partial cementation before leaching are characterized by both moldic and (lesser) interparticle pores. The third (intercrystalline) apex represents the ultimate result of pervasive and

fabric-independent (fabric-destructive) dolomitization. This process is common in the Smackover and in many other carbonate units.

Of course, there are complicating factors. Cement molds (fig. 51) represent one such complication, though one that has little effect on permeability. By contrast, other unusual diagenetic effects can greatly affect fluid-flow characteristics. One example is that of a "perfect" particle-moldic pore system characterized by high porosity values and relatively low permeability values.

Any three kinds of pores could be used to define the apices of a ternary pore plot. Other carbonate rock units might exhibit pore systems quite different from those of the Smackover. Or, one might wish to study only certain kinds of pores, even though other pores might predominate in a rock unit. One example of such an approach is presented here (fig. 52). The apices of the ternary pore plot in figure 52 are constructed as follows. The moldic apex of the other ternary pore plots is divided into "true" moldic porosity, in which at least 50% of the area of a former particle is occupied by a single large pore, and secondary intraparticle porosity, which represents all other kinds of intraparticle pores. The third apex corresponds to vuggy pores, *sensu stricto*. Most data points fall somewhere on or near the moldic-secondary intraparticle axis with a few along the moldic-vuggy axis. The secondary intraparticle-vuggy axis, and the central part of the triangle, are essentially empty. This is presumably because most dissolutional pores either occur in rocks characterized by the formation of small intraparticle pores, or else particles tend to be completely dissolved away. Only in the latter case are larger dissolutional pores, which might be identifiable as vugs, common. Molds and secondary intraparticle pores are abundant in the Smackover, as indicated by the clustering of data points near the moldic apex of figure 41. No Smackover pore systems are dominated by vuggy pores. Of course, this is in part an artifact of our pore classification, because small dissolutional pores that lie entirely within single particles are classified as secondary intraparticle pores. These pores probably do not differ fundamentally in the manner of their formation from pores that transgress particle boundaries and are therefore called vugs. Still, the distinction made here may be useful.

All dissolutional pores tend to be "isolated"; that is, they are connected to relatively small-bore pore systems. However, data points near the secondary-intraparticle apex represent smaller pores

Figure 51.--Cement-moldic porosity. Dark areas are pores. A) Example of complex pore system in pisoid dolograinstone. This rock contains interparticle (1), cement-moldic (right arrow), and microvuggy secondary intraparticle (left arrow) porosity. Three generations of pore-rimming cement formed. Subsequently, the second generation of cement dissolved. By contrast, the first and third cement generations resisted dissolution. These cements were evidently more stable chemically than that of generation two, which may have consisted of aragonite. Thin-section photomicrograph, Permit No. 1878, North Choctaw Ridge field, Choctaw County, 11,755.7' B) Crystalline dolostone in which some euhedral dolomite cement crystals have had their cores dissolved. Molds and partial molds of dolomite crystals are commonly filled with calcite cement. Thin-section photomicrograph, Permit No. 4577, Huxford field, Escambia County, 14,552.1'.

Figure 52.--Ternary pore plot of Smackover data illustrating alternate classification of carbonate pore types. In this diagram, the three apices are defined as follows: True moldic=all dissolutional intraparticle pores individually constituting at least 50% of the original particle area; secondary intraparticle=all dissolutional intraparticle pores individually constituting less than 50% of the original particle area; and vuggy=dissolutional pores that are not confined to single particles.

than those plotting near the other apices. The former typify pore systems characterized by relatively small aspect ratios. Conversely, molds or vugs typify pore systems with high aspect ratios. Aspect ratios strongly affect the extrusion or trapping of nonwetting fluids (e.g., Wardlaw, 1976; Wardlaw and Taylor, 1976; Yu and others, 1986). For a given rock unit, relative aspect ratios could be estimated by observing the positions of data points on ternary pore plots with suitable apices if aspect ratios for different kinds of pore systems in that unit were known. In addition, porosity values are commonly higher in moldic-dominated pore systems than in secondary-intraparticle-dominated pore systems. Porosity values for vuggy rocks depend on the size and abundance of vugs, which are commonly strongly affected by preexisting rock fabric.

RESERVOIR HETEROGENEITY

A QUANTITATIVE APPROACH TO RESERVOIR HETEROGENEITY ESTIMATION

The ultimate volume of hydrocarbons recovered from a reservoir is strongly affected by the 3D shape (at all scales larger than the size of a small pore throat, about $0.01\ \mu\text{m}$) of the hydrocarbon-bearing pore system in that reservoir. Spatial variability within the pore system (reservoir heterogeneity) can have a significant effect on the ultimate volume of hydrocarbons recovered. Reservoirs that have little internal variability may produce up to 80% of the original oil in place (OOIP); more heterogeneous reservoirs tend to produce less (Geological Survey of Alabama, 1990). During primary recovery, extremely heterogeneous reservoirs may produce as little as 10% of the OOIP.

Geologic heterogeneity that controls the distribution and migration of oil within a reservoir is created by the same processes that molded the reservoir itself. Reservoir heterogeneity may be depositional, diagenetic, or structural and may occur on a variety of scales ranging from that of individual pores to field-wide. Five levels of heterogeneity are based on the areal extent of units considered to be internally homogeneous (fig. 53) (Moore and Kugler, 1990, fig. 2, p. 3). At the largest scale, level 1, a reservoir is surrounded by nonreservoir rock. Features that affect fluid flow over distances greater than the average well spacing within a single reservoir are the homogeneous units of level 2 heterogeneity. Level 3 heterogeneity consists of differences between features that have areal extents less than the average well spacing in the region under consideration but considerably greater than the diameter of a well bore. Level 4 heterogeneity is concerned with features at the scale of a well bore or core. Level 5 heterogeneity occurs at scales of hundreds of pores and pore throats down to that of a single pore. When quantifying reservoir heterogeneity, one must account for heterogeneity at both large and small scales, because the two are not necessarily covariant.

Because pore-system topology, the proximate control of reservoir heterogeneity, is a product of the depositional, diagenetic, and structural history of a given reservoir, reservoirs with similar histories may have similar amounts and kinds of heterogeneity. Classification of reservoirs into trends on the basis of similarities in depositional, diagenetic, and structural histories may be useful in predicting reservoir heterogeneity.

Reservoirs formed in different geologic settings exhibit different rock fabrics, and therefore, different hydrocarbon-recovery factors. Carbonate rock units tend to be less-efficient hydrocarbon producers than siliciclastic rock units (Tyler, 1988). This is because carbonate reservoirs tend to be more complex. Among carbonate reservoirs, the products of some depositional and diagenetic settings are more homogeneous (and produce a higher percentage of their contained hydrocarbons) than others (Tyler, 1988). In other words, carbonate rock bodies differ systematically in the presence, abundance, and distribution of features that affect fluid flow.

Figure 53. Levels of heterogeneity (Moore and Kugler, 1990, fig. 2, p. 3).

Finley and others (1988) ranked carbonate reservoirs formed in depositional settings ranging from supratidal flats to deep ocean basins on a scale of reservoir complexity from 1 to 10. Twelve categories were defined primarily on the basis of depositional setting. Diagenesis was considered as a factor affecting heterogeneity in three categories. The classification was based upon interpretations of rock characteristics. Smackover reservoirs in southwest Alabama can be assigned to at least four categories: evaporitic flats, dolomitized restricted platforms, open shelves, and oolitic bars and barriers.

One of the attractions of a depositional-setting based reservoir heterogeneity classification is the common perception that environment of deposition is easier to predict than what might be termed "diagenetic facies." In a general sense this is true, but, as we have seen, strata deposited under similar conditions can and do develop extremely different pore systems. This is one of the limitations of a reservoir heterogeneity classification based on depositional setting. Reservoir heterogeneity is more accurately described by a classification based directly on the physical characteristics of the reservoir. This is the approach taken in the pore-facies classification presented in an earlier section of this report.

A disadvantage of the classification of Finley and others (1988) is that it consists of a fixed number of discrete categories. These categories were chosen by examination of a training set, a set of reservoirs that were deposited in a variety of depositional settings. The categories of which the classification is composed were named on the basis of what was found in the training set (450 oil reservoirs from Texas). When such a classification is applied to a new data set it may need to be modified to accommodate characteristics of the new data that were not found in the training set.

The classification of Finley and others (1988) was subsequently modified, and data from New Mexico and Oklahoma were added to the training set (ICF, 1989; DOE, 1990). The classification was further modified for the TORIS database by the Reservoir Classification Task Force (1990; figure 54). Smackover reservoirs in Alabama fall into the restricted shelf category in the revised classification (they were assigned to four different categories in the original classification of Finley and others, 1988). This twice-revised classification is currently undergoing review by the DOE and by others, and

I. Depositional Systems

Lacustrine

Peritidal

Supratidal

Intertidal

Subtidal

Shallow Shelf

Open Shelf

Restricted Shelf

Shelf Margin

Rimmed Shelf

Ramp

Reefs

Pinnacle Reefs

Bioherms

Atolls

Slope/Basin

Debris Fans

Turbidite Fans

Mounds

Basin

Drowned Shelf

Deep Basin

II. Diagenetic Overprint

Compaction/Cementation

Grain Enhancement

Dolomitization

Dolomitization (Evaporite)

Massive Dissolution

Silicification

III. Structural Compartmentalization

Natural Fracture Porosity

Unstructured

Faulted (normal, reverse, or strike-slip)

Fault/Fold (normal, reverse, or strike-slip)

Folded

Figure 54.--Classification of carbonate reservoir heterogeneity used in TORIS database.

additional revisions to the classification may be required (DOE, 1990). The instability of the classification, in which a given reservoir may change its pigeonhole each time the classification is revised, provides opportunities for error. Further, whenever a revision is implemented, the existing literature becomes obsolete.

The pore-facies classification described in this report was developed, like that of Finley and others (1988), using a training set. However, the pore-facies classification is based upon published criteria (pore types; Kopaska-Merkel and Mann, 1991b). By contrast, the classification of Finley and others (1988) is based upon interpretations of depositional setting that have not been published. Although the pore-facies classification would be of limited value in classifying reservoirs that are not dominated by moldic and/or intercrystalline pores, such reservoirs are uncommon, and the pore-facies classification is probably widely applicable.

In this section we define two semi-independent vertical heterogeneity parameters, megascopic heterogeneity and microscopic heterogeneity, and use them to describe the distribution of vertical reservoir heterogeneity in Smackover hydrocarbon fields in southwest Alabama. We also describe the distribution of the Dykstra-Parsons coefficient, which is a measure of microscopic heterogeneity, and compare these results to those of the other two measures. All three heterogeneity measures measure different aspects of reservoir heterogeneity (see figs. 56, 57, and 60); hence, all three may be of value in evaluating reservoir heterogeneity. These heterogeneity estimates, in combination with the pore-facies classification, provide simple estimates of the kinds and amounts of heterogeneity in Smackover reservoirs. Because all three components of heterogeneity (μH , MH , and DP coefficient) are distributed nonrandomly, the heterogeneity characteristics of a potential Smackover reservoir can be predicted in advance of the drill. We also define a measure of lateral heterogeneity, and relate variation in lateral heterogeneity to vertical heterogeneity, hydrocarbon type, and well spacing. These heterogeneity measures may be applicable to Smackover reservoirs outside Alabama, and to other carbonate reservoirs as well.

Once the heterogeneity characteristics of a reservoir have been estimated, more-detailed studies are required to identify the specific features that cause heterogeneity and to map their distribution in

three dimensions. This is the subject of the Chunchula field study, described in the final report on Subtask 4, which has already been submitted to DOE. When heterogeneity can be mapped in detail it becomes possible to locate uncontacted reservoir compartments, to target infill wells, to better identify the limits of the reservoir and locate step-out wells, and to define flow paths that will benefit enhanced-recovery programs. A better understanding of the factors controlling the distribution and movement of hydrocarbons in Smackover reservoirs will also help in identifying the most-profitable development strategies. Efficient recovery of hydrocarbons depends on detailed knowledge of the reservoir.

VERTICAL RESERVOIR HETEROGENEITY

INTRODUCTION AND DISCUSSION OF PARAMETERS

Vertical heterogeneity in a carbonate reservoir is determined by the number and distribution of features occurring on a wide variety of scales. A ranking scheme for reservoir heterogeneity should ideally consider all possible features. From a practical standpoint, the scheme should use data that are readily available. Toward this end, the ranking scheme proposed here relies heavily on data obtainable from porosity logs and through core analysis. Because permeability distribution is absolutely critical to reservoir performance, permeability data are used to estimate reservoir heterogeneity. If porosity logs have been calibrated to permeability using core data, then porosity logs as well as core data can be used to estimate heterogeneity. Another method is to estimate permeability from MTS using CP analyses of cuttings.

Because the distribution of reservoir heterogeneity is nonrandom, heterogeneity values in regions for which permeability data are not available can be predicted from reservoir-heterogeneity maps using geostatistics. (An example of this approach is described in the final report on Subtask 4, already submitted to DOE.)

For the purpose of this study, reservoir rocks were defined to include all strata having porosity values $\geq 6\%$ and permeability values ≥ 0.1 md. Six parameters that appear to have the greatest influence on reservoir heterogeneity were measured or calculated for all fields for which we had the

necessary data. (Additional parameters were also calculated but yielded no additional information.)

These six parameters are:

1. Average Number of Reservoir Intervals (by well)
2. Average Number of High-Permeability Reservoir Intervals (by well)
3. Standard Deviation of Number of Reservoir Intervals (by well)
4. Standard Deviation of Porosity
5. Mean Permeability
6. Standard Deviation of the Natural Log of Permeability

The first three parameters were used to calculate megascopic reservoir heterogeneity (MH); the last three were used for microscopic reservoir heterogeneity (μH). All six parameters could be calculated for 31 fields: parameters 4 through 6 could be calculated for an additional 22 fields, making a total of 53 fields for which μH could be calculated (table 7). (Fewer fields provided MH values because at least 2 wells are needed to calculate parameter 3.) We separate microscopic- and megascopic reservoir heterogeneity because, as will be seen below, their spatial distributions are almost diametrically opposed. If the two scales of heterogeneity were measured by a single equation, then their opposite distributions would be obscured.

Before describing the results of our heterogeneity calculations, we discuss why we chose the parameters we used in the equations. We begin with MH.

The equation for megascopic reservoir heterogeneity (MH) employs the first three parameters listed above: $[(\# \text{ of reservoir intervals}) + (\# \text{ of high-K reservoir intervals}) + (\sigma \text{ of } \# \text{ of reservoir intervals})]$. Many other parameters could be employed to calculate MH, such as average reservoir-interval thickness, average thickness of high-permeability reservoir intervals, standard deviation of the number of high-permeability reservoir intervals, standard deviation of reservoir-interval thickness, or numbers or thicknesses of very-high-permeability reservoir intervals (e.g., greater than 10 md permeability, greater than 100 md permeability, etc.). None of these parameters were used to calculate MH for two reasons. First, all the parameters listed, as well as innumerable others like them, are closely correlated with parameters 1, 2, and 3. Thus, adding them to the equation for MH would

Table 7.--Parameters used to calculate reservoir heterogeneity and three reservoir heterogeneity factors

Field	mean phi	sd phi	mean ln k	sd ln k	μH	MH	#res. int.	#high k res.	stdev # res.	DP coeff.
Appleton	10.6	3.1	1.25	1.39	1.37					0.96
Barlow Bend	12.6	5.6	0	2.99	2.30					0.95
Barnett	9.7	2.5	0.22	2.16	1.36	8.34	3.67	2.33	2.34	0.88
Barrytown	18.9	4.2	2.02	0.97	1.51	3.25	1.5	0.75	1	0.63
Big Escambia Creek	14.1	4.5	0.64	2.03	1.60	10.1	4.7	2.63	2.71	0.92
Blacksher	11.6	4.27	1.19	2.41	1.96	13.5	5.29	3.71	4.46	0.95
Broken Leg Creek	11.7	3.2	1.5	2.12	1.83					0.94
Bucatunna Creek	18	5.6	0.46	1.2	1.22	6.62	1.5	3	2.12	0.76
Chappell Hill	16.2	4.9	1.29	1.65	1.66	4.91	2.67	1.67	0.58	
Chatom	20.7	6.24	1.62	0.54	1.83	9.54	4.5	3.75	1.29	0.93
Choctaw Ridge	19.4	5	3.06	1.62	2.25	3.16	1.4	0.8	0.96	0.80
Churchula	12.9	3.6	0.44	1.69	1.29	5.66	2.75	1.64	1.27	0.87
Cold Creek	9.9	3.7	0.01	1.85	1.24	9.65	4	3	2.65	0.86
Copeland	15.6	5.8	0.69	1.6	1.51					0.82
Crosbys Creek	21.4	9.2	-0.52	1.33	1.26	5.73	2	2	1.73	0.79
Fanny Church	12.7	3.7	0.18	1.96	1.35	10.2	4.88	1.53	3.82	0.85
Hatter's Pond	13.4	4	0.99	1.75	1.54	7.17	2.68	2.32	2.17	0.90
Huxford	9.8	2.5	2.04	2.36	2.07	10.5	4.75	2.75	2.99	0.91
Little Escambia Creek	12.7	3.9	0.07	1.95	1.32	9.54	4	1.8	3.74	0.90
Little Mill Creek	24.1	5.8	4.6	2.41	3.22		1	0		0.92
Little River	11.8	4.3	1.68	2.61	2.22					0.96
Lovetts Creek	9.5	2.4	0.81	1.66	1.30	12	4.4	3.6	3.97	0.91
Melvin	20.3	3.4	3.32	1.47	2.13					0.83
Mill Creek	20.6	5.8	2.82	2.15	2.50	2.11	1	0.4	0.71	0.89
Mineola	14.6	3.4	3.01	1.52	2.05					
Movico	17.2	4.8	2.81	1.46	2.07	2.21	1.5	0		0.91
North Choctaw Ridge	20.3	5.6	2.68	1.43	2.08	3.89	1.89	1.22	0.78	0.95
North Wallers Creek	12.9	2.8	2.12	1.62	1.75					.954
Northwest Range	9.2	2.0	0.56	1.77	1.24					
Pace Creek	17.3	7.18	2.56	2.66	2.78					
Palmer's Crossroads	16.3	5.3	2.29	2.20	2.31					.955
Perdido	10	1.6	0.2	1.34	0.87	3.91	1.33	2	0.58	0.84
Puss Cuss	21.3	7.4	1.79	1.49	1.96					0.78
Red Creek	19.6	7.8	1.28	1.95	2.05		1	1		0.93
Robinson Creek	10.4	4.3	0.3	2.01	1.46					
Southeast Chatom	22.4	6.7	0.76	1.66	1.64	6.5	3	3.5	0	0.87

Table 7.--Parameters used to calculate reservoir heterogeneity and three reservoir heterogeneity factors—
Continued

Field	mean phi	sd phi	mean ln k	sd ln k	μH	MH	#res. int.	#high k res.	stdev # res.	DP coeff.
Silas	15.9	6.7	0.44	1.99	1.70	7.8	3	1.33	3.46	0.87
Sizemore Creek	13.5	4.4	0.19	2.2	1.53					0.87
Stave Creek	15.9	4.4	2.1	1.94	2.04	6.98	2.33	2.33	2.31	0.92
Sugar Ridge	19.5	7.1	2.22	1.69	2.18	6.13	3	1.5	1.63	0.96
Southwest Barrytown	17	6.1	2.05	2.5	2.44					0.74
Turkey Creek	20.6	4.4	3.85	1.12	2.21					0.69
Uriah	10.8	2.9	2.83	2.09	2.23					0.78
Vocation	12.4	3.9	2.52	2.11	2.22	9.61	3.92	3.08	2.61	0.97
Wallace	9.5	2.51	-0.3	1.71	0.96					
Walters Creek	12.7	3.8	1.16	1.98	1.69	4.49	1.67	1.67	1.15	0.92
West Appleton	13.3	4.6	3.02	1.86	2.32					
West Barrytown	18.9	3.6	2.72	1.32	1.87	5.39	2.25	1.25	1.89	0.74
West Bend	14.8	3.7	1.32	1.94	1.72	5.96	2.25	2	1.71	0.95
Wild Fork Creek	11.2	2.5	0.9	1.25	1.13					0.77
Wimberly	19.8	6.6	2.11	1.59	2.05	4.53	2.33	0.67	1.53	0.80
Womack Hill	18.5	4.4	2.28	1.48	1.87	6.14	2.58	1.79	1.77	0.96
Zion Chapel	19.5	7.4	1.98	1.64	2.10	4.53	2.33	0.67	1.53	0.82

scarcely reduce the unexplained variance in MH. The effort of collecting the additional data would yield little return. Second, the three parameters we chose were those for which the largest number of fields possessed the requisite data for the calculation of MH. Addition or substitution of any of the alternative parameters listed above would have greatly reduced the number of fields for which MH could be calculated.

The equation for microscopic reservoir heterogeneity employs the last three of the six parameters listed above: $(\mu H) = \{[(0.25\sigma\phi) + (\text{mean of natural log of } K) + (1.5\sigma \text{ of natural log of } K)]/3\}$. As with MH, other parameters could have been used, such as maximum porosity, maximum permeability, and mean porosity. However, in the calculation of μH it is important to include only appropriate parameters. For example, mean porosity has been used by others to calculate reservoir heterogeneity. But mean porosity is not directly related to the ability of the formation to produce hydrocarbons efficiently. It is not how much of a rock is empty space that determines how easy it is to remove the contained fluids, but rather how variable and how coarse the pore system is. Some of the most-variable pore systems on a microscopic level (level 5) are moldic pore systems, because of their

inherent bimodality and high aspect ratios (discussed in previous sections). Moldic reservoirs are also the most porous (fig. 55). However, some relatively low-porosity pore systems are also quite variable, because of high-amplitude variations in both porosity and permeability. Yet another problem with using mean porosity is that, despite the differences between high-porosity pore systems and highly-variable pore systems, mean porosity is strongly correlated with standard deviation of porosity ($r^2 = 0.64$). Therefore, only one of these two parameters should be used to avoid unintentional weighting of the result. It is more appropriate to use the standard deviation of porosity, which is directly related to variation in pore-system characteristics. Maximum porosity and maximum permeability are highly unstable measurements, because they are strongly affected by single outlying data points; for this reason, these two parameters were rejected.

μH is not, strictly speaking, a measure of vertical heterogeneity, because data from all wells within a field are lumped together to generate this parameter. However, because wells are thousands of feet apart whereas samples from a single core are 1 foot apart, μH is more strongly affected by vertical heterogeneity than by lateral heterogeneity. μH is primarily a measure of one aspect of vertical heterogeneity.

Another kind of parameter might be used to estimate microscopic heterogeneity. This class of parameters includes median pore-throat size and other measures of pore-throat size distribution, that are derived from capillary-pressure measurements. However, these data are expensive to collect and are generally available only from a few wells. For this reason, we do not use them to estimate heterogeneity. If large amounts of capillary-pressure data are available, then some measures of the dispersion of pore-throat sizes could be useful in estimating microscopic heterogeneity, for they are directly related to the efficiency of production of nonwetting fluids.

MEGASCOPIC RESERVOIR HETEROGENEITY

The numbers of reservoir intervals, numbers of high-permeability reservoir intervals, and the standard deviation of the numbers of reservoir intervals measure large-scale (levels 3 and 4; see fig. 53) heterogeneity defined by depositional, diagenetic, and structural setting. These three parameters

Figure 55.—Map of average porosity of Smackover fields in southwest Alabama. Average porosity values are highest in southern Choctaw County, and substantially lower to the south and east on the north flank of the Wiggins arch and the Conecuh ridge complex, and in the Conecuh embayment. The distribution of average porosity values closely parallels the distribution of reservoir types in the Smackover (compare fig. 43, which shows the distribution of pore facies in Smackover reservoirs). Moldic reservoirs, which are less-severely altered than intercrystalline reservoirs, are, on the average, more porous. Porosity in percent; contour interval = 5%. Dots are Smackover fields (see fig. 53). Data taken from Bolin and others, 1989.

are summed in the calculation of megascopic reservoir heterogeneity (MH): $[(\# \text{ of reservoir intervals}) + (\# \text{ of high-K reservoir intervals}) + (\sigma \text{ of } \# \text{ of reservoir intervals})]$.

Reservoirs belonging to the Moldic Pore Facies tend to be vertically homogeneous at large scales (low values of MH), whereas reservoirs assigned to the Intercrystalline Pore Facies are characterized by relatively high values of MH. It may be that intercrystalline reservoirs are heterogeneous at large scales because the process of nonfabric-selective dolomitization was patchy on a vertical scale of meters to tens of meters. (It was also patchy horizontally as indicated by lateral variation in petrographic parameters within Chunchula field, Mobile County. See the final report on Subtask 4, already submitted to DOE, for further discussion.) By contrast, moldic reservoirs are relatively homogeneous vertically at meter- to decameter scales, indicating that sedimentary features such as dunes, bars, beach foreshores, spits, and channels (at least some of which have been recognized in cores of moldic reservoirs; see Appendix 1) may have exerted relatively little influence on reservoir heterogeneity. Hence, carbonate depositional microfacies patterns may be crude predictors of reservoir distribution.

The distribution of MH values is shown by figure 56. MH values are high on the north flank of the Wiggins arch, on the Conecuh ridge complex and in the Conecuh embayment. MH values are low near the Choctaw ridge complex. The Conecuh ridge complex is characterized by high values of both microscopic and megascopic heterogeneity; it is the only major structural feature to be so blessed. Also, a low-relief paleogeographic high, a salt-cored anticline that began growing in latest Smackover time (see fig. 9), that stretches southward from the vicinity of Silas field in southern Choctaw County to Chatom field in west-central Washington County (see fig. 1), is characterized by relatively high values of MH.

The linear zone of high-MH fields that stretches northward from Chatom field in the center of the MISB to Silas field in southern Choctaw County (see fig. 1) coincides with a salt-cored anticline. This anticline did not exist during most of Smackover time, for it is superimposed on a thick westward-thickening wedge of Smackover strata (see fig. 6). There is no thinning of Smackover strata that would suggest either a paleohigh or differential uplift along this salt-cored anticline during most of

Figure 56.--Map of megascopic reservoir heterogeneity (MH) of Smackover fields, southwest Alabama. The geographic pattern of MH variation is roughly opposite to that of microscopic reservoir heterogeneity. High values characterize the entire southern part of the study area except just south of the Baldwin high. A slender promontory of heterogeneous reservoirs projects northward from the central part of the Mississippi interior salt basin towards the Choctaw ridge complex. This area is the site of a linear salt ridge that already possessed significant relief during earliest Buckner time (see discussion of Smackover sabkhas in section on geologic setting). Dimensionless; contour interval=2.5. MH is calculated from commercial permeability data.

Smackover time. However, the crest of the salt-cored anticline is marked by the development of sabhkas on local highs during latest Smackover time (see fig. 9). Typically, 10 feet or less of sabkha deposits are overlain by 20 to 40 feet of peritidal carbonates, including reservoir rock, which in turn are overlain by basal Buckner saltern deposits. These relationships indicate that the salt-cored anticline began to form in latest Smackover time.

MICROSCOPIC RESERVOIR HETEROGENEITY

Microscopic reservoir heterogeneity (μH) is based upon the standard deviation of porosity, the mean of natural log of permeability, and the standard deviation of natural log of permeability: $\{[(0.25\sigma\phi) + (\text{mean of natural log of } K) + (1.5\sigma \text{ of natural log of } K)]/3\}$. These parameters all measure variation in pore system characteristics at small scales (level 5 heterogeneity; see fig. 53). In the equation for μH , the standard deviation of porosity is multiplied by 0.25. This fractional weighting is performed because (1) porosity values cover a wider range than do values of the natural log of permeability (table 7), and (2) porosity variation is less critical to reservoir heterogeneity (has a lesser effect on producibility of hydrocarbons) than the permeability value. Hydrocarbon production efficiency is more sensitive to variation in permeability than to variation in porosity. Similarly, the standard deviation of natural log of permeability is multiplied by 1.5, which increases its contribution to μH . This is because changes in the amount of variation in permeability have a greater effect on hydrocarbon production, through mechanisms such as bypassing of oil in regions of lower permeability, than does a simple shift in permeability distribution.

The distribution of μH values in the Smackover of southwest Alabama is shown by figure 57. In the following paragraphs, we discuss the pattern of μH variation in more detail.

μH values are high in moldic reservoirs and low in intercrystalline reservoirs. This may result from the fundamentally heterogeneous nature of moldic pore systems (in which large pores are juxtaposed with small throats) vs. the fundamentally homogeneous nature of intercrystalline pore systems. However, the definition of μH contains no reference to pore type. μH is simply a function of porosity and permeability variation. Perusal of figs. 55, 58, and 59 reveals that high values of porosity and

Figure 57.—Map of microscopic reservoir heterogeneity (μH) of Smackover fields, southwest Alabama. μH is highest in southern Choctaw County, and diminishes smoothly to the south and east. Uniformly low values typify the north flank of the Wiggins arch and the Conecuh embayment. High-frequency variation in μH in southern Choctaw County may be related to the effects of paleotopography (the Choctaw ridge complex) on petrophysical characteristics of Smackover reservoirs. Dimensionless; contour interval=0.5. μH is calculated from commercial porosity and permeability analyses of core plugs.

permeability, but not of the standard deviation of permeability, are responsible for the high values of μH in the northwestern part of the study area.

Movico and Hatter's Pond fields (Baldwin plus Mobile and Mobile counties, respectively; see fig. 1) have substantially higher values of μH than do nearby fields. Movico reservoir differs from its neighbors in other ways as well: MH (fig. 57), thickness of the Smackover (fig. 6), average porosity (fig. 55), mean K (fig. 58), and σ of K (fig. 59). Both Movico and Hatter's Pond fields differ from their neighbors in their values of the Dykstra-Parsons coefficient (fig. 60) and of the standard deviation of porosity (fig. 61). These two fields are structurally different from their neighbors (being associated with the Mobile graben). They are also the most easterly of the fields on the north flank of the Wiggins arch, which may be significant if regional paleogeography had a noticeable effect on pore-system development. Whatever the cause(s), fields associated with the southern part of the Mobile graben, especially Movico field, exhibit dramatically different reservoir characteristics from nearby fields on the north-facing distally-steepened ramp that forms the north flank of the Wiggins arch. Specifically, the ramp fields are less porous and less permeable, but also less heterogeneous, than the Mobile graben fields.

Smackover reservoirs in southern Choctaw County display regional patterns of μH that seem to be controlled by paleogeographic setting. Two north-south regions of high and low μH cut across the peripheral fault trend (fig. 57), but are subparallel to the buried Choctaw ridge complex immediately to the north (Wilson and others, 1980). The region characterized by higher values of μH overlies a basement ridge, and the region characterized by lower values of μH overlies a trough on the basement surface (fig. 57; Wilson and others, 1980).

Uriah and Palmers Crossroads fields are neighbors characterized by high values of μH . Another field in this area, North Wallers Creek field, has a moderately high value of μH . The reservoir at Uriah field consists of intercalated sandstone and dolostone, that at Palmers Crossroads field contains both carbonate and siliciclastic components (based on interpretation of geophysical logs), and that at North Wallers Creek field is dolomitic sandstone. A nearby field, Barnett, contains intercalated dolomitic sandstone and dolostone, but the reservoir consists entirely of dolostone. It seems that a

Figure 58.--Map of mean permeability of Smackover fields, southwest Alabama. The distribution of mean permeability is similar to that of average porosity (fig. 55). The most obvious difference is the presence of a low-amplitude permeability high along the Baldwin high and the Conecuh ridge complex. Natural log of permeability (in md); contour interval=1.0. Data taken from commercial permeability analyses of core plugs.

Figure 59.--Map of standard deviation of permeability of Smackover fields, southwest Alabama. Interestingly, this map does not show the same pattern as do the maps of mean permeability and maximum permeability. On the contrary, a large area of highly variable permeability values occupies at least part of the Manila embayment, the Conecuh ridge, and the northern part of the Conecuh embayment. A small region of moderately high values is found in southwestern Choctaw County, but for the most part this region is characterized by low values of permeability standard deviation. Similarly, the Mississippi interior salt basin and the north flank of the Wiggins arch are characterized by uniformly low values of permeability standard deviation. Natural log permeability (in md); contour interval=0.5). Data taken from commercial permeability analyses of core plugs.

Figure 60.-Map of Dykstra-Parsons coefficient for Smackover fields in southwest Alabama. The DP coefficient appears to be strongly controlled by paleotopographic patterns; note especially the high values concentrated along the Conecuh ridge and the southwesterly trends in southern Choctaw County, which parallel underlying basement topography. Dimensionless; contour interval=0.05. The DP coefficient is calculated from commercial permeability analyses of core plugs.

Figure 61.--Map of standard deviation of porosity of Smackover fields, southwest Alabama. Standard deviation of porosity is strongly affected by paleotopography, but generally decreases from northwest to southeast. This is similar to the pattern exhibited by average porosity. Porosity in percent; contour interval = 1.0. Standard deviation of porosity is calculated from commercial porosity analyses of core plugs.

local source of quartzose sand in this area created several heterogeneous reservoirs consisting of mixed siliciclastic and carbonate strata. The updip parts of the Manila embayment contain substantial admixtures of quartzose sand. Where sand and carbonate are commingled, μH values are likely to be high. If there are areas within the updip part of the Manila embayment where quartzose sandstone dominates the reservoir, then μH values may be low in these areas.

Various petrographic parameters show different relationships to paleotopography, present structure, and to each other. For example, average porosity (fig. 55) and standard deviation of porosity (fig. 61) display very similar patterns that are unlike those of the other parameters. Standard deviation of porosity (fig. 61) shows very strong control by paleotopography. The distribution of maximum permeability (fig. 62) is also sensitive to paleotopographic control. Inspection of the maps presented in this section shows that each aspect of the pore system has responded to the various controlling factors in subtly different ways. Thus, heterogeneity measures that encompass multiple parameters may better represent overall heterogeneity than any one of the individual parameters.

RELATIONSHIP BETWEEN MH AND μH

The pattern of variation in μH is roughly opposite to that of MH. μH values generally decrease from northwest to southeast. The Conecuh ridge complex is roughly the southeastern limit of high values of μH . This inverse relationship between MH and μH is not surprising if one recalls that moldic reservoirs are inherently heterogeneous on a microscopic scale, but are characterized by relatively few and homogeneous flow units. By contrast, intercrystalline reservoirs are inherently homogeneous microscopically, but are relatively heterogeneous megascopically (Kopaska-Merkel and Mann, 1991b). This relationship between μH and MH has implications for reservoir development. One should not expect to find reservoirs that are homogeneous at all scales in the Smackover of southwest Alabama. Instead, the reservoir modeler should expect to face significant variation in reservoir heterogeneity on at least two scales, but the magnitude of the problem at one scale may be inversely proportional to that at the other scale. Because the most-common EOR methods that are used in the Alabama Smackover are waterflooding and various types of gas injection (Masingill, 1990), MH may

Figure 62.--Map of maximum permeability of Smackover fields, southwest Alabama. This map shows two areas characterized by high values of maximum permeability: one in southern Choctaw County overlying the southerly extension of the Choctaw ridge complex, and one overlying the western end of the Conecuh ridge complex. The high-permeability intervals in southern Choctaw County are characterized by reservoir strata are cross laminated or (less commonly) laminated, and exhibit pore systems dominated by moldic pores but containing 10 percent or more interparticle porosity. By contrast, the high-permeability reservoirs found overlying the western part of the Conecuh ridge complex are highly altered planar-e and planar-s dolostones. The pore systems are almost pure intercrystalline. Natural log of permeability (in md); contour interval 1.0. Data taken from commercial permeability analyses of core plugs.

be more important in the short term than μH . This is because injection-type EOR processes are adversely affected by large-scale permeability heterogeneity (e.g., Thomas and Bibby, 1991).

The congruency of the patterns of variation of μH and MH with pore-system characteristics (controlled by depositional patterns, and modulated by dissolution and dolomitization), and with regional structural and paleogeographic trends, suggests that reservoir heterogeneity characteristics are controlled by structural and paleogeographic setting, and by diagenesis. However, because contours of μH and MH are approximately normal to structure contours but subparallel to Smackover thickness contours, it appears that depositional setting (or paleogeography) exerted more-stringent control on reservoir heterogeneity than did structural evolution. The detailed patterns of μH variation in southern Choctaw County suggest control by NE-SW trending paleotopography, whereas the pattern of MH variation in the same area suggest control by the E-W trending peripheral fault trend. The Mobile graben appears unrelated to μH variation, probably because its major growth occurred after Smackover deposition.

DYKSTRA-PARSONS COEFFICIENT

The Dykstra-Parsons coefficient, like μH , is not, strictly speaking, a measure of vertical heterogeneity, for it is commonly applied to an entire field. The DP coefficient measures overall heterogeneity, both vertical and lateral together. However, because wells are far apart and permeability samples within a core are spaced 1 foot apart, the DP coefficient, like μH , is primarily a measure of vertical heterogeneity. The DP coefficient was devised to evaluate the probability of success of waterflooding (Dykstra and Parsons, 1950). The DP coefficient is $[(\log \text{mean } K) - (\log K @ -1 \sigma)] / \log \text{mean } K$. (Other formulations yield essentially the same result.) Thus, if there is no variation of permeability, the standard deviation of K is zero, and the DP coefficient is also zero. The maximum value of the DP coefficient, 1.0, corresponds to the condition of maximum heterogeneity (Craig, 1971). The DP coefficient is a measure of microscopic heterogeneity, as is μH , but the two have contrasting distributions (fig. 60). The DP coefficient is partially correlated with μH ($r^2 = 0.428$). The distribution of DP coefficient values is also dramatically different from the distribution of σ natural

log of K values (fig. 59), though the former is essentially a normalized version of the latter. The distribution of the DP coefficient, unlike those of MH and μH , bears no obvious relationship to pore-facies distribution. Also, the pattern of DP coefficient variation is more complex. Hence, it is more difficult to predict the DP coefficient value in advance of the drill. We recommend therefore that μH , rather than the DP coefficient, be used to represent microscopic heterogeneity if only one microheterogeneity parameter is to be used.

LATERAL RESERVOIR HETEROGENEITY

Accurate evaluation of lateral heterogeneity is difficult. Data for a single field typically consist of a small number of wells distributed over an area of several square miles. For Smackover fields in Alabama, typical well spacing is 160 acres. By contrast, many reservoir heterogeneity studies have dealt with fields characterized by spacings of 40 ac., 20 ac., or even less (e.g., Honarpour and others, 1991). Virtually no data are available for well separation distances of less than about 1500 feet. Spatial correlation over distances on the order of 2000 to 10,000 feet are amenable to study for most fields.

Because of the sampling constraints outlined above, there have been few published attempts at defining lateral heterogeneity. One simple technique involves calculation of reservoir continuity between well pairs (George and Stiles, 1978). The technique involves determination of reservoir continuity (in %) between each possible pair of wells within a field area. These data are then plotted against the distance between the wells in each pair. Wells close together are expected to have a high continuity index and the index is expected to decrease as the distance between wells increases. The rate of this decrease is a measure of reservoir continuity which is, in turn, a measure of lateral heterogeneity.

Though the technique is simple, it has important limitations. Accurate correlation of specific reservoir zones is essential. In fields with few or widely spaced wells, this can be a problem. Also, the position of the wells relative to one another within the field is important. Significant differences are expected in the continuity between wells oriented parallel to depositional strike and those oriented

perpendicular to strike. Finally, the correlation indices are strongly influenced by the shape of the reservoir; irregularly shaped reservoirs have different continuity-distance relationships in different directions.

The continuity-index technique was applied to 9 Smackover fields in Alabama (Geological Survey of Alabama, 1990). The continuity index was plotted against the distance between wells for all well pairs within each field. These crossplots (included in Geological Survey of Alabama, 1990) appear to show a decrease in continuity index with increasing distance. Some Smackover reservoirs exhibit a pronounced preferred orientation of continuity index, whereas others do not (Geological Survey of Alabama, 1990). Different reservoir intervals within a single field tend to have similar continuity vs. distance relationships but the relationships vary substantially from field to field.

The technique described above, although it is one of the few geologically-based techniques available, is ineffective in evaluating the lateral continuity of reservoirs in the Smackover Formation of southwest Alabama. The small number of wells and the large distances between wells in most fields make the reliability of correlations of reservoir intervals between wells questionable and prevent the evaluation of correlations over short distances (generally less than 1500 feet). For most fields continuity-distance plots show a high degree of scatter, and estimates of the correlation distance are problematic at best. Also, reservoir shape strongly affects continuity data. For these reasons, the lateral continuity ranking provided by the technique is a poor estimate of reservoir continuity.

Even if the technique were more accurate, it only measures 3D continuity of the reservoir. It cannot account for internal barriers to lateral fluid flow. A reservoir may have excellent overall lateral continuity but contain numerous barriers to lateral fluid flow and thus be laterally heterogeneous. Conversely, another reservoir may have less lateral continuity but lack internal barriers to fluid flow; thus, lateral heterogeneity values are low.

A cruder method of assessing lateral reservoir heterogeneity was also attempted. This is necessary where data are insufficient for more-sophisticated techniques. The method involves comparing porosity-permeability plots for single wells to similar plots from multiple wells from the same field.

Thus, this is a way to measure microscopic lateral heterogeneity. If lateral heterogeneity is significant then r^2 will be lower for the multi-well plots. This is because when wells with different porosity-permeability characteristics are lumped together, variance increases and r^2 decreases.

The method was applied as follows. Only wells with at least 30 non-zero permeability analyses were counted, and only fields with at least 4 wells satisfying the first criterion were included. These restrictions were necessary because small data sets would severely bias results. Short cores have a high probability of yielding biased samples from vertically heterogeneous reservoirs, and if too-few cores are included in the multi-well calculations, then even if lateral heterogeneity is significant, it cannot be detected. Twelve fields met these criteria (table 8).

Table 8.--Lateral heterogeneity in 12 Smackover fields

Field	Normalized lateral heterogeneity	μH	Acreage	Spacing	Fluid type
Big Escambia Creek	0.1	1.6	15858	640	gas-condensate
Churchula	0.1	1.29	22113	640	gas-condensate
Hatter's Pond	0.1	1.54	6418	640	gas-condensate
Chatom	0.5	1.83	2080	640	gas-condensate
Womack Hill	0.6	1.87	1719	100	oil
Barnett	0.8	1.36	1237	160	oil
Blacksher	1	1.96	1123	160	oil
Fanny Church	1.3	1.35	653	160	oil
Vocation	1.3	2.22	775	160	oil
North Choctaw Ridge	1.4	2.08	779	80	oil
Sugar Ridge	4.3	2.18	249	140	oil
Lovetts Creek	4.9	1.3	202	160	oil

Only the larger Smackover fields met the necessary criteria, but these are the very fields for which lateral heterogeneity (LH) is of interest, because EOR projects are not economically feasible for small fields. Table 8 includes all parameters we studied that exhibit any relationship to LH. $LH = [((\text{average } r^2 \text{ for single wells in field} - \text{fieldwide } r^2) + 1) / \text{field acreage}] * 1000$. LH is normalized by division by the field area (in acres); the result is multiplied by 1000 simply for convenience. LH is most strongly related to μH : the average value of μH for the six fields with the highest values of LH is 1.85, vs. 1.58 for the six fields with the lowest values of LH. LH is also correlated with both hydrocarbon type (oil vs.

gas-condensate) and (inversely) with spacing. Spacing and hydrocarbon type are obviously related to one another; with the exception of Movico Field, which is a special case, only gas-condensate fields are drilled on 640-acre spacing, vs. 80 to 160 acres for most oil fields. Therefore the relationship between LH and spacing is probably a function of that between LH and hydrocarbon type. There is no evidence that LH is related to pore facies. The important results of this analysis are three.

First, LH and μH are positively correlated, which means that, at least for the Smackover in Alabama, vertical and lateral microscopic heterogeneity are correlated with one another. This is important because it is easier to estimate vertical heterogeneity and therefore lateral heterogeneity can be predicted from it. Second, large gas-condensate fields are laterally homogeneous whereas (relatively) large oil fields are more laterally heterogeneous. This suggests that for the oil fields, bypassing of mobile oil is a real possibility. Third, LH, a new, simple measure of microscopic lateral heterogeneity, may be a valuable tool for characterization of reservoir heterogeneity where more-sophisticated methods cannot be applied because of insufficient data. LH can be used as a modifying factor for economic analyses of EOR feasibility.

Lateral heterogeneity may be better assessed by direct measurement of well to well fluid flow (e.g., tracer studies or pulse testing). Unfortunately, these kinds of data are generally not available for the Smackover in southwest Alabama. One approach that is applicable to the Smackover of southwest Alabama is the calculation of drainage areas for individual wells based on pressure and/or production data. This technique was used to define lateral heterogeneity in Churchula field, Mobile County (final report on Subtask 4 already submitted to DOE). Lateral heterogeneity can also be investigated using conditional simulation, but for this technique the dearth of data for short distances is a severe problem. This technique has been applied to Churchula field.

PREDICTION OF RESERVOIR HETEROGENEITY

It is desirable to estimate reservoir heterogeneity early in the field-development process. The goal is to use the estimate of the amount and kind of heterogeneity in preparing the field-development plan from as early a stage as possible. Ideally, then, the heterogeneity characteristics of the reservoir

would be known with some accuracy in advance of the drill. One would also like to be able to refine this estimate substantially after drilling only one or a few wells.

Using the heterogeneity parameters presented here the nature and degree of heterogeneity can be predicted by reference to the reservoir-heterogeneity maps (figs. 56, 57, and 60) or to the pore-facies map (fig. 43) (which may contain information where the heterogeneity maps contain none). Alternatively, the pore facies in the target area may be calculated and the heterogeneity values predicted from the known relationships between pore facies and heterogeneity. The mean values of μH and MH for the Moldic Pore Facies are 1.96 and 5.48, whereas the same values for the Intercrystalline Pore Facies are 1.62 and 8.26 (table 9). Values of μH and MH for intermediate pore

Table 9.—Heterogeneity characteristics of Smackover pore facies

Pore facies	μH				MH			
	Range	Mean	Standard Deviation	N	Range	Mean	Standard Deviation	N
Moldic	1.22-3.22	1.96	0.42	24	2.11-9.54	5.48	1.63	17
Intermediate	0.87-2.30	1.65	0.45	15	2.21-13.46	8.39	3.89	9
Intercrystalline	1.24-2.22	1.62	0.42	6	5.66-10.49	8.26	1.93	5

systems are nearly identical to those for the Intercrystalline Pore Facies. If a well is drilled and no core is cut, then the pore-system characteristics can be determined from cuttings (including capillary-pressure data; Kopaska-Merkel, 1988). In this way, pore facies can be used to predict heterogeneity where no measurement of permeability is possible and hence MH and μH cannot be calculated.

HETEROGENEITY AND PRIMARY RECOVERY

All four heterogeneity measures are essentially uncorrelated with primary recovery factor (PRF) (fig. 63). One cannot predict PRF in the Alabama Smackover using any known measure of reservoir heterogeneity. We suggest that primary recovery is controlled chiefly by other factors, and therefore is inherently not predictable from heterogeneity information.

The only parameter we measured that shows a significant relationship to PRF is MTS (fig. 64). If the indicated positive relationship between MTS and PRF can be relied upon (bearing in mind the

Figure 63.--Bivariate plots of three measures of reservoir heterogeneity vs. primary recovery factor. (a) DP coefficient, (b) MH, and (c) μH . None of the three heterogeneity factors exhibit a significant correlation with primary recovery factor.

Figure 64.--Bivariate plot of MTS and PRF. Only eight fields have both adequate CP data (≥ 8 samples) to calculate mean MTS and a reliable PRF. $R^2 = 0.645$, which is probably significant even given the small sample size. See text for further discussion.

small sample size) then the implications are profound. No other petrophysical parameter, even with many more samples (e.g., permeability) shows a significant relationship to PRF (fig. 63). It appears that the single most important factor controlling PRF is the size distribution of pore-throats through which the oil must flow. PRF prediction can best be made from capillary-pressure data. However, because this inference is supported by scanty data, skepticism is required. Further research, specifically collection of additional CP data, is planned. The results will show whether the relationship between MTS and PRF is robust.

HETEROGENEITY AND SECONDARY RECOVERY

Theoretically, reservoir heterogeneity has a strong influence on reservoir performance. In particular, heterogeneous reservoirs should contain, after primary recovery, zones of uncontacted mobile oil, that can be recovered by infill drilling or by application of other EOR methods. We should like to be able to say which Smackover reservoirs, or which kinds of Smackover reservoirs, if any, are amenable to substantially improved recovery, and by which methods. Unfortunately, the available data are scanty.

Six Smackover fields in Alabama are currently undergoing secondary fluid injection, but only three of these fields are sufficiently mature to yield reasonable estimates of secondary recovery factors. Clearly, this data set is too small to permit any general conclusions to be drawn.

Another way to look at the efficiency with which fields are drained is to compare well spacing to primary recovery. If well spacing is variable, but in every case sufficient to drain all recoverable oil from a reservoir, then well spacing should not be correlated with recovery factor. However, if some fields have well spacings too great for efficient exploitation, then some of the fields with larger well spacings should tend to have lower primary recovery factors.

This question has been investigated, with inconclusive results. Recovery factor is only weakly correlated with well spacing. If one compares recovery factor to well spacing graphically (fig. 65) it is obvious that there are too few fields with well spacings greater than 160 ac. to clarify the relationship. In short, it is not possible to say, using this approach, whether any Smackover fields in

Alabama could benefit from infill drilling. A regional predictive model cannot yet be formulated. Detailed field studies are required to determine whether infill drilling might be beneficial. More detailed analyses of the potential benefits of infill drilling in the Alabama Smackover are described in the final reports on Subtasks 4, 5, and 6.

SUMMARY AND CONCLUSIONS

The Upper Jurassic Smackover Formation is found in an arcuate belt in the subsurface from south Texas to panhandle Florida. The Smackover is nowhere exposed at the surface, but age-equivalent strata crop out in northeastern Mexico. The Smackover is the most prolific hydrocarbon-producing formation in Alabama and is an important hydrocarbon reservoir from Florida to Texas.

Mesozoic and Cenozoic strata of the eastern Gulf Coastal Plain comprise a seaward-dipping and thickening wedge of sediments that blanketed the passive southern margin of the North American continent. The major positive basement elements that affected Mesozoic sedimentation in the eastern Gulf are the Wiggins arch, the Baldwin high, the Choctaw ridge complex, and the Conecuh ridge complex in southeast Mississippi and southwest Alabama and the Pensacola-Decatur ridge complex in southwest Georgia and northwest Florida. The MISB of southern Mississippi and southwest Alabama was an actively subsiding depocenter throughout the Mesozoic and into the early Cenozoic. The Conecuh and Manila embayments and a basinal area south of the Baldwin high also were major sites of Mesozoic sedimentation. These negative structural features may have originated as rift grabens during the breakup of Pangea.

Movement of the Jurassic Louann Salt has resulted in a complex network of salt-related structural elements in southwest Alabama, including the regional peripheral fault trend, the Mobile graben, and numerous smaller features. Salt movement began in some areas as early as late Smackover time.

Pre-Jurassic and Jurassic geologic units found in the subsurface in the study area include pre-Mesozoic "basement" rocks; the Triassic-Lower Jurassic Eagle Mills Formation; the Jurassic Werner Formation, Louann Salt (including Pine Hill Anhydrite Member), Norphlet Formation (including

Denkman Sandstone Member), Smackover Formation, and Haynesville Formation (including basal Buckner Anhydrite Member); and the Jurassic-Cretaceous Cotton Valley Group.

"Basement" denotes pre-Mesozoic sedimentary and crystalline rocks upon which basal Mesozoic strata were deposited. The Eagle Mills Formation is the oldest Mesozoic geologic unit in the study area; it is a nonmarine succession of red beds and associated diabase and basalt dikes and sills. The overlying Werner Formation is dominated by anhydrite, but minor red, gray, and black shale, red sandstone, and conglomerate occur in the lower part of the unit. The Louann Salt conformably overlies the Werner Formation or, in the absence of the Werner, disconformably overlies the Eagle Mills Formation or basement rocks. In the study area, the Louann predominantly consists of silty, sandy, massive halite with intercalated anhydrite.

The Norphlet Formation (Oxfordian) conformably overlies the Pine Hill Anhydrite member of the Louann Salt. Where the Pine Hill is absent, the contact may not be conformable. Where the Louann is absent, the Norphlet disconformably overlies older units. The Norphlet is dominated by alluvial-fan-, wadi-, playa-, and eolian deposits. Uppermost Norphlet strata were reworked by marine processes. The Norphlet is conformably overlain by the Smackover Formation. The contact is commonly abrupt, but is gradational over an interval of a few feet or less in parts of Mobile County, including Churchula field, and in Barnett field on the Conecuh ridge complex.

The Smackover was deposited on a carbonate ramp, similar to that of the present-day Persian Gulf, in much of the Gulf-Coast region. However, in southwest Alabama, Smackover strata were deposited in four interconnected basins: the eastern part of the Mississippi interior salt basin, the Manila embayment (which contains two separate Smackover depocenters), the Conecuh embayment, and an unnamed basin south of the Baldwin high. The distribution of facies was more-closely controlled by local paleotopography than by southerly regional dip, as would have been the case in an unmodified ramp setting. High-energy facies were deposited in nearshore areas rimming exposed paleohighs and near the updip limit of Smackover deposition; lower energy strata were deposited in basin centers. Based on ammonites recovered from the lower portion of the unit, the Smackover has

been assigned a late Oxfordian age. The Smackover ranges up to more than 550 feet thick in the study area.

Basal Smackover strata in Alabama contain laminar and domal stromatolites; these deposits probably formed in shallow water during the early stages of marine transgression. Middle Smackover strata are dominated by lime mudstone and pelletal or fossiliferous lime wackestone. These strata were deposited at and near the time of maximum transgression, and during and after a period of rapidly increasing water depth. Middle-Smackover lime mudstone is typically laminated and organic rich. Upper Smackover strata were laid down during a relative-sea-level stillstand. Progradational strata of the upper Smackover are dominated by ooid grainstone and diverse peritidal carbonates on the flanks of the paleohighs, and by pelletal and oncoidal packstone and grainstone in the centers of the depositional basins. The Smackover locally contains substantial amounts of siliciclastic material, particularly near the Conecuh ridge and its associated small paleohighs (e.g., Barnett, North Wallers Creek, Uriah, Vocation, and Burnt Corn Creek fields), and in the Manila embayment. Diagenesis of Smackover reservoirs was dominated by the effects of (1) early cementation, (2) leaching of calcium-carbonate allochems, and (3) dolomitization, both mimetic and nonmimetic. The Smackover Formation is overlain in southwest Alabama by the Buckner Anhydrite Member of the Haynesville Formation, whose basal portion is dominated by subaqueous evaporites in depositional basins, and by peritidal- and supratidal evaporitic- and siliciclastic strata on the flanks and crests of paleohighs.

As of December, 1990, the Smackover had produced oil, condensate and/or natural gas from 73 established fields in Alabama. At that time, cumulative production from Smackover reservoirs in Alabama totaled over 113 million barrels (MMB) of oil (including Norphlet oil from South Womack Hill and a few other fields), 145 MMB of condensate (including Norphlet condensate production at Hatter's Pond field, which is not reported separately), and 1.12 trillion cubic feet (TCF) of natural gas.

Smackover hydrocarbon traps in southwest Alabama can be characterized as structural or combination structural and stratigraphic traps. Many structural traps result from halokinesis of the Louann Salt, but basement-cored anticlinal traps are locally common. The Buckner Anhydrite Member of the Haynesville Formation commonly forms the seal. Combination traps generally involve porosity

or permeability pinch-outs occurring on regional dip, on halokinetically-generated anticlines or structural noses, or on basement-related anticlines or faulted anticlines.

Microbially influenced laminated lime mudstone of the lower to middle Smackover Formation is the main source rock for the oil, condensate, and gas in Smackover reservoir rocks. Kerogen in Smackover laminated lime mudstone probably matured to liquid hydrocarbons from the early Cretaceous to the Tertiary. Structural growth of Smackover traps coincided with hydrocarbon generation and migration from Smackover source rocks. Emplacement of liquid hydrocarbons in Smackover reservoirs was precisely controlled by relative timing of hydrocarbon generation and migration and trap formation and subsequent structural modification of the reservoir. For example, traps and seals that formed early contain oils most near the original composition of Smackover crude oil. Traps that formed later generally contain light oils or condensates. However, maturation and alteration of hydrocarbons in the reservoir can also generate condensates.

Most Smackover reservoirs originated as nearshore-marine carbonate sediments with minor admixtures of noncarbonate material. Some of these reservoirs preserve abundant evidence of their environment of deposition. Others have been highly altered and their origins are unclear. The most common Smackover reservoir rocks are nonskeletal grainstone. Mixed-particle grainstone/packstone is the second most common reservoir type in the Smackover of southwest Alabama. A third important kind of reservoir is microbial boundstone. A fourth reservoir type is crystalline dolostone. Quartzose sandstone, commonly dolomitic, forms permeable reservoirs locally in southern Monroe County.

The occurrence of reservoir-grade rocks (porosity at least 6% and permeability at least 0.1 md) in the Smackover Formation of southwest Alabama is dependent on (1) deposition of porous and permeable sediments in a variety of settings and (2) diagenetic processes which have preserved, enhanced, or created porosity and permeability both in originally permeable strata and in originally impermeable strata.

The most common kinds of pores in the Smackover are particle molds, secondary intraparticle (partial moldic) pores, intercrystalline pores, and interparticle pores. Less common, but significant, pore types are fractures and vugs. The various pore types lend different petrophysical characteristics

to pore systems, and combinations of different kinds of pores in varying proportions create further effects. Interparticle pores are permeability enhancers, because they tend to form regular networks with abundant connections, and because they are interconnected by large pore throats. Fractures are even more effective permeability enhancers. Pore systems dominated by molds, vugs, and secondary intraparticle pores are not characterized by high permeability values because these pores tend to be poorly connected, and commonly by small pore throats. The most common kinds of molds are oomolds and pelmolds. Secondary intraparticle pores differ from molds in being substantially smaller. Intercrystalline pores form pore systems with variable permeability values, depending on crystal size. Intercrystalline pores are commonly well connected by short and homogeneous pore throats, and the pores tend to be all about the same size and shape. Where intercrystalline pores are large, homogeneous, and well connected, permeability values may be extremely high.

We classify Smackover reservoir rocks using capillary-pressure-curve shape. CP-curve shape summarizes a wealth of petrophysical information about reservoir rocks, including pore-throat-size distribution and estimates of recovery efficiency and permeability. CP-curve class 1 includes samples that have extremely leptokurtic pore-throat-size distributions and that exhibit little or no extrusion of mercury during pressure reduction. Samples assigned to CP-curve class 2 exhibit leptokurtic pore-throat-size distributions with minor fine tails, and there is little or no mercury extrusion during pressure reduction. CP-curve class 3 includes samples that have leptokurtic pore-throat-size distributions (generally steeper than those of class 2, but less steep than those of class 1). Samples assigned to this class exhibit as much as 60% mercury extrusion during pressure reduction. CP-curve class 4 includes samples that have mesokurtic pore-throat-size distributions (ranging from like those of class 2 to substantially more variable). These samples exhibit a prominent tail of small throats that accounts for as much as 25% of the pore volume, or a smooth reduction in volume of pores accessed through smaller and smaller throats over the entire range of pore-throat sizes. Samples assigned to this class extrude up to more than 25% of their mercury during pressure reduction. Samples assigned to CP-curve class 5 exhibit platykurtic or polymodal pore-throat-size distributions. CP curves assigned to this class are variable, as are porosity values, recovery efficiency values, and median throat sizes. On

average, however, porosity values and throat sizes are smaller than for classes 1 through 4; recovery efficiencies range up to about 40%. CP-curve class 6 includes marginal reservoir rocks; porosity values are less than 10% and the mean is about 6%. These samples have mesokurtic throat size distributions and entirely lack large throats (median throat sizes do not exceed 0.5 Mm). Recovery efficiencies range between about 30 and 40%. CP-curve classes 7 and 8 include nonreservoir rocks. Progressing from class 1 to class 6, throat-size ranges for single samples increase and the proportions of dolomite and of grainstone decrease. The lower class numbers correspond to reservoirs with higher porosity and permeability values.

Two possible methods of predicting permeability are discussed. The first is based on the relationship between microporosity, as measured from capillary-pressure data and as estimated by calibration of well logs, and permeability. The ultimate goal is to predict permeability values from well logs, or from limited amounts of other kinds of data. The second is by measuring MTS, which is derived from capillary-pressure analysis. Small amounts of microporosity can dramatically depress permeability in the Smackover. It appears that small (centimeter-scale?) areas of small pores and small pore throats act as permeability baffles. The only petrophysical variable we investigated that is strongly correlated with permeability is MTS. MTS is derived from capillary-pressure analysis, an expensive and time-consuming method which usually requires core samples. However, whereas permeability can only be measured in samples cut from cores, MTS can be calculated from analysis of cuttings. Therefore, permeability can be estimated from noncored intervals.

Pore systems in reservoir rocks of the Smackover Formation in southwest Alabama are dominated either by moldic plus secondary intraparticle pores or by intercrystalline pores. Intermediate pore systems are less common. Because the Smackover reservoir rocks we studied fall naturally into two distinct groups, we define two pore facies, which are rock units characterized by certain pore types or combinations of pore types, and by certain consequent pore-throat-size distributions. Pore facies also possess characteristic fluid-flow properties.

Reservoir rocks assigned to different pore facies are petrophysically, petrographically, and geographically distinct. Those assigned to the Moldic Pore Facies are dominated by moldic plus

secondary intraparticle pores. Some samples contain up to about 20% interparticle pores. Reservoir rocks assigned to the Intercrystalline Pore Facies are dominated by intercrystalline pores. Moldic pore systems are products of primary sediment fabric, modified by (usually) fabric-selective dolomitization and by dissolution of unstable particles either during or after dolomitization. Intercrystalline pore systems are most strongly affected by pervasive fabric-destructive dolomitization, although primary sediment fabric commonly has some effect on the final rock fabric. This means that geological models of environment of deposition and of diagenetic history are more likely to help interpretation of moldic reservoirs than of intercrystalline reservoirs. Moldic pore systems tend to have higher mean porosity values but lower maximum permeability values than intercrystalline pore systems. Moldic pore systems have more leptokurtic pore-throat-size distributions, but are fundamentally heterogeneous at microscopic scales because coarse and fine pores are found together. Intercrystalline pore systems are fundamentally homogeneous at this level, at least in the ideal case. Intercrystalline pore systems are more heterogeneous megascopically (vertically) and therefore have more potential for bypassing of potentially productive intervals. Also, high-permeability thief zones are more abundant in intercrystalline reservoirs. Intermediate samples resemble petrophysically the Intercrystalline Pore Facies, and occupy intermediate regions geographically. Because rocks of the Moldic and Intercrystalline pore facies are readily distinguishable, and exhibit quite different fluid-flow characteristics, the pore-facies classification proposed here may be a useful tool in planning development of Smackover fields in Alabama, and could probably be applied successfully to other porous and permeable carbonate units.

Quantitative measures of microscopic and megascopic reservoir heterogeneity are used to describe heterogeneity in Smackover hydrocarbon fields in southwest Alabama. Microscopic reservoir heterogeneity (μH) is $\{[(0.25\phi) + (\text{mean natural log of } K) + (1.5\sigma \text{ natural log of } K)]/3\}$. Megascopic heterogeneity (MH) is $\{[(\# \text{ of reservoir intervals}) + (\# \text{ of high-}K \text{ reservoir intervals}) + (\sigma \text{ of } \# \text{ of reservoir intervals})]\}$ where reservoir rock is defined as exhibiting permeability values ≥ 0.1 md and high- K reservoir rock exhibits permeability values ≥ 1.0 md. Both MH and μH are determined from core data

and are estimates of vertical heterogeneity. The Dykstra-Parsons coefficient is a measure of microscopic heterogeneity that is partially independent of μH ($r^2 = 0.428$).

μH and MH are distributed in opposing patterns. μH generally decreases from northwest to southeast; highest values are found in the vicinity of the Choctaw ridge complex north of the MISB. Moderately high values typify the Manila embayment and the Conecuh ridge complex to the south, whereas lower values are found in the MISB, on the north flank of the Wiggins arch, and in the Conecuh embayment. μH values are high in the Moldic Pore Facies and low in the Intercrystalline Pore Facies.

MH values are high on the north flank of the Wiggins arch, on the Conecuh ridge complex and in the Conecuh embayment. MH values are low near the Choctaw ridge complex. The Conecuh ridge is unique because it is characterized by high values of both μH and MH. Also, the low-relief salt-cored anticline that stretches southward from the vicinity of Silas field in southern Choctaw County to Chatom field in west-central Washington County is characterized by relatively high values of MH. Reservoirs belonging to the Moldic Pore Facies tend to be homogeneous with respect to MH, whereas reservoirs assigned to the Intercrystalline Pore Facies are characterized by relatively high values of MH.

The congruency of patterns of variation of μH and MH with pore-system characteristics (controlled by depositional patterns, dissolution, and dolomitization) and regional structural and paleogeographic trends suggests that reservoir heterogeneity characteristics are controlled by structural and paleogeographic setting, and by diagenesis. However, because contours of μH and MH are approximately normal to structure contours but parallel to Smackover thickness contours, it appears that depositional setting (or paleogeography) exerted more-stringent control on reservoir heterogeneity than did structural evolution. The distribution of DP coefficient values is not related to pore-facies distribution; thus the DP coefficient is less useful for regional heterogeneity studies than is MH or μH .

Microscopic lateral heterogeneity (LH) was calculated for 12 of the largest Smackover fields. Relatively sophisticated parameters could not be applied to the Smackover of southwest Alabama

because the data are of poor quality. Instead, LH was estimated as a function of the difference between the residual variance about the porosity-permeability trend for single wells and that for entire fields. If a field is perfectly laterally homogeneous, then wells will not differ with respect to their porosity-permeability trends, and subtracting the field value from the average of values for single wells yields an LH estimate of zero. Conversely, if a field is highly heterogeneous laterally, then the field value will exhibit a high degree of scatter because wells with very different porosity-permeability relationships will have been lumped together. A high value of LH results. Analysis of the 12 fields for which sufficient data are available indicates that μH and LH covary. Also, gas-condensate fields are relatively laterally homogeneous, and oil fields are relatively laterally heterogeneous.

Quantification of μH and MH regionally in the Smackover of southwest Alabama will facilitate EOR planning for fields that are still in the early stages of development. Prediction of reservoir heterogeneity characteristics will facilitate advance planning of production strategies and cost/benefit analyses for development of new fields. In addition, it will be possible to identify regions characterized by or containing unusually heterogeneous or unusually homogeneous reservoirs (microscopic, megascopic, or both) and to flag areas likely to present unusually minor or severe development problems. These regional relationships can be used as a guide when making geologic models of individual reservoirs. The relationship between pore facies, μH , and MH will permit prediction of 3D continuity and porosity and permeability characteristics of reservoirs using an integrated geological/engineering approach. For fields assigned to the Moldic Pore Facies, a more-detailed geological analysis of the depositional environments and diagenetic history of reservoir strata can be achieved. This may permit a more-detailed assessment of the shapes and distributions of flow units and of the distribution of permeability baffles and barriers. For intercrystalline reservoirs, a stochastic approach to modeling reservoir porosity and permeability characteristics is preferable, like that outlined in the report on Subtask 4, section on geostatistics.

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