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Potential for Deep Natural Gas Resources in Eastern Gulf of Mexico

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POTENTIAL FOR DEEP NATURAL GAS RESOURCES IN EASTERN GULF OF MEXICO

CONTRACT INFORMATION

Contract Number	DE-A121-83MC20422-5 MOD A044
Contractor	Branch of Petroleum Geology U.S. Geological Survey Box 25046, MS 971, DFC Denver, Colorado 80225
Contract Project Manager	Dudley D. Rice
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METC Project Manager	Charles W. Byrer
Period of Performance	October 1, 1990 to March 31, 1992

OBJECTIVE

The main purpose of the research is to evaluate the geological possibility that significant economically recoverable resources of natural gas exist in sedimentary basins of the United States at depths greater than 15,000 ft. While relatively unexplored, these gas resources may be large. The main objectives of the research are to determine the geologic factors that control deep gas accumulations in addition to the distribution and resource potential of these accumulations.

BACKGROUND INFORMATION

The United States is dependent upon oil and gas as its major sources of energy. However, fewer wells are being drilled today, the discovery rate of new oil and gas accumulations is declining, and oil production is decreasing in the United States, resulting in a growing dependency on imported sources. Future supplies of domestic oil and gas will result from improved recovery of discovered hydrocarbons and the development of unconventional resources. One important and essentially undeveloped source of gas is from deep sedimentary basins, the subject of this paper.

The Gulf of Mexico is one of the Nation's most important provinces for discovered and undiscovered hydrocarbons. In addition, the province has an enormous volume of sedimentary rocks deeper than 15,000 ft and has the best potential for deep gas resources. Interesting statistics from the NRG Associates Significant Fields (greater than one million barrels of oil equivalent-BOE) File for the deep (>14,000 ft) Gulf Coast Mesozoic producing region are summarized below. The Mesozoic producing region is important for deep gas and includes the East Texas, North Louisiana, and Mississippi salt basins, extending into southwest Alabama and the panhandle of Florida. One hundred and nine deep reservoirs in 97 fields are present in the Gulf Coast Mesozoic producing region with the earliest discovery occurring in 1944. Although a tremendous volume of sedimentary rocks deeper than 15,000 ft is present, the number of significant deep reservoirs decreases with increasing depth. Fifty-eight percent of the significant deep reservoirs are classified as gas; more deep oil reservoirs are present in the eastern part of the trend where the geothermal gradient is lower. For all depths, 64 percent of the deep reservoirs are clastic, whereas only 36 percent are carbonate. Most of the hydrocarbons in deep reservoirs are structurally trapped resulting from salt diapirism and syndepositional growth faulting.

PROJECT DESCRIPTION

The project work is focusing on the eastern Gulf of Mexico (onshore and offshore Mississippi, Alabama, and Florida or MAFLA); the study area includes the Mississippi salt basin (Fig. 1). In the MAFLA area, numerous deep wells have been drilled, commercial deep hydrocarbon production has been established, and sufficient samples and data are available at intermediate and greater depths to conduct studies. The knowledge gained from these studies will then be extrapolated to the unexplored deep parts of other basins that have deep potential.

The main focus of our studies will be on (1) geologic framework, (2) thermal maturity, (3) reservoir characterization, and (4) hydrocarbon generation and migration. This integrated approach will have direct bearing on the controls, distribution, resource potential, and exploitation and recovery of deep gas.

RESULTS

Geologic Framework

The northern Gulf of Mexico basin developed as a post-Paleozoic passive margin on the Ouachita fold belt that has been affected by extensional and gravitational faulting since Triassic time. The petroleum geology of the basin is summarized by Curtis (1991). Unlike other basins developed on passive continental margins, the Gulf basin is characterized by flowage of Jurassic salt which has resulted in abundant structural traps. Facies patterns and thickness variations reflect a depositional setting of rifted grabens, large-scale basin subsidence, and paleohighs (Fig. 1). Triassic and Jurassic strata are evaporitic, eolian, and fluvial-alluvial clastics and shallow-marine and peritidal carbonates. Lower Cretaceous strata are primarily fluvial-deltaic, and Upper Cretaceous strata are deltaic and marine shelf deposits. Marine transgression continued until Paleocene time, at which time a deltaic system prograded into the area from the northwest.

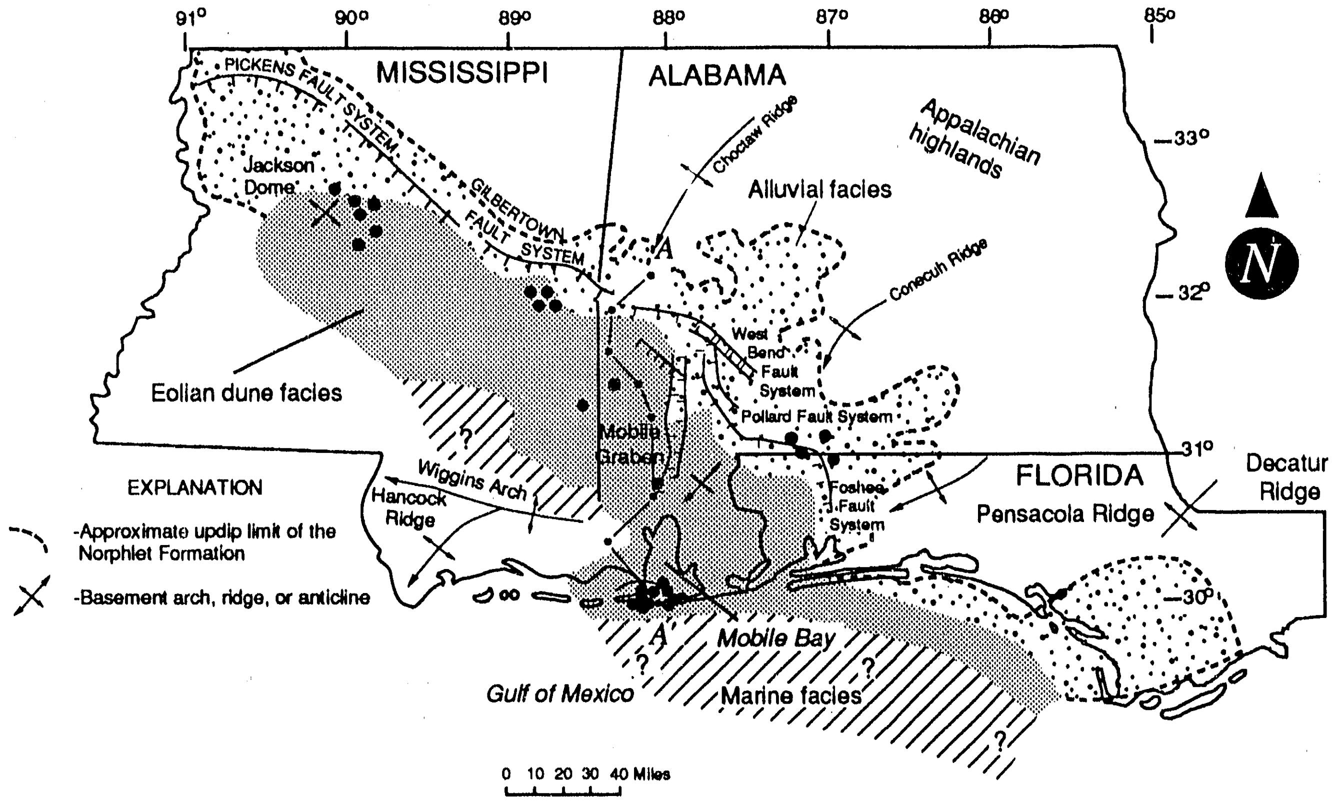

Figure 1. Index map of MAFLA showing major structural features, facies of Norphlet Formation, location of Norphlet fields (dots), and cross section A-A'. All of the fault zones make up the regional peripheral fault zone. From Schenk (1990).

The stratigraphic framework of the MAFLA area is illustrated in a regional north-south cross section which extends from northern edge of the Gulf basin to State waters of Mobile Bay on the south (Fig. 2). The northern edge of the Gulf basin coincides with the regional peripheral fault zone, the northern limit of Triassic normal-fault rifting, and the northern limit of the Middle and Upper Jurassic Louann Salt. In a southerly direction, the section including the Upper Jurassic Norphlet Formation through Cretaceous Trinity and Coahuila Groups thicken, whereas the rest of the Cretaceous strata on the cross-section shows no major thickness trends. In addition, the Jurassic and Cretaceous section becomes more deeply buried to the south because of the prograding Tertiary deltaic section. An unpublished section parallel to the basin margin in Alabama illustrates thickness variations attributed to basement highs.

A digital map for the area shown in Figure 1 has been prepared using the U.S. Geological Survey's ARC/INFO GIS system (Keighin and Schenk, 1992). At present, the map includes political boundaries and spatial (coordinate) data, geologic structure, such as faults and salt domes, and oil and gas fields. Other features with known latitude and longitude, such as oil and gas wells greater than 10,000 ft, 15,000 ft, and 20,000 ft, are being plotted on the base map.

Carbonates and sandstones of the Upper Jurassic Smackover and Norphlet Formations, respectively, are major reservoirs for hydrocarbons in the MAFLA area (Fig. 2). Petroleum geology of the Jurassic section in the MAFLA area is discussed by Mancini and Benson (1980), Mancini and others (1985), and Mink and others (1989,1990). Three hydrocarbon trends that parallel the northern edge of the basin-oil, wet gas and condensate, and dry gas—have been identified. The oil trend occurs updip of the peripheral fault zone, the dry gas trend is located south of the Wiggins Arch and partly offshore, and the wet gas and condensate trend is situated between the oil and dry gas trends (Fig. 1). The depth of produc-

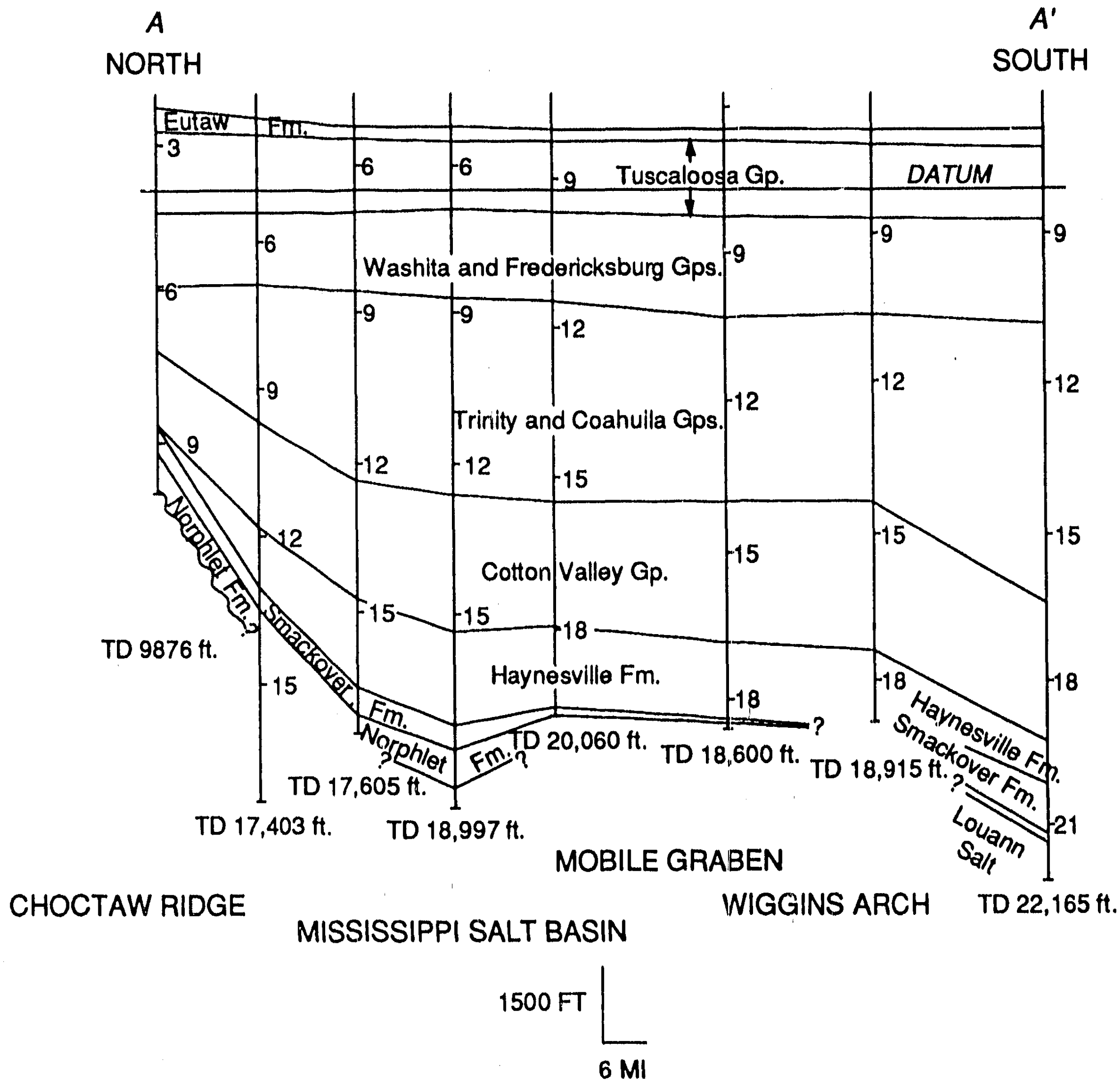

Figure 2. Generalized north-south cross section A-A' of pre-Selma Group Jurassic and Cretaceous strata, southwest Alabama. The Jurassic-Cretaceous boundary is near the top of the Cotton Valley Group. Line of section shown on Figure 1.

tion in these three trends increases in an offshore direction (Fig. 2). The major part of the production in the oil and wet gas and condensate trends is from carbonate reservoirs of the Smackover Formation. Production in the dry gas trend is from eolian sandstones of the Norphlet Formation at depths greater than 20,000 ft, and potential gas resources in the Norphlet are large. Initial production was established in the State and Federal waters of Mobile Bay, offshore Alabama; the most productive wells to date have recently been tested in offshore Mississippi.

Thermal Maturity

Thermal maturity influences many processes critical to deep gas accumulations, including generation and migration of hydrocarbons, and creation and preservation of reservoir properties. Figure 3 represents a preliminary attempt at relating thermal maturity, expressed as equivalent vitrinite reflectance (R_{oeq}), versus depth for five localities in the MAFLA area. The plots are derived from a combination of published and unpublished data that include vitrinite reflectance, bitumen reflectance, and Rock-Eval maximum-pyrolysis temperature (T_{max}). The R_{oeq} versus depth relations for these five localities are subject to modification as additional data become available.

The R_{oeq} versus depth trends show that thermal maturity increases steadily with depth (Fig. 3). Slopes are subparallel, except for curve 4. The steeper slope of curve 4 reflects the influence of the Jackson Dome, a Late Cretaceous subsurface igneous intrusion (Fig. 1). At a given depth, R_{oeq} tends to decrease from south to north (curves 2 to 1 and 3 to 5).

Figure 4 is a vitrinite reflectance (R_o) versus depth profile for the Exxon State Lease 624 No. 1 well located in State waters of Mobile Bay, offshore Alabama (Fig. 1). The well was drilled to a total depth of 22, 166 ft in the Louann Salt and produces dry gas from the Norphlet Formation. The R_o value at the surface is about 0.2 percent, indicating that the present depth of burial is maximum and that little or no erosion has occurred in this area. The R_o data suggest that two regression lines are possible; a single straight regression line and a two-segment regression line with a bend in the profile occurring at a depth of about 11,000 ft with a R_o value of 1.2 percent. The maximum R_o value at total depth of the well is 2.4 percent based on a two-segment profile and 3.7 percent based on a straight profile.

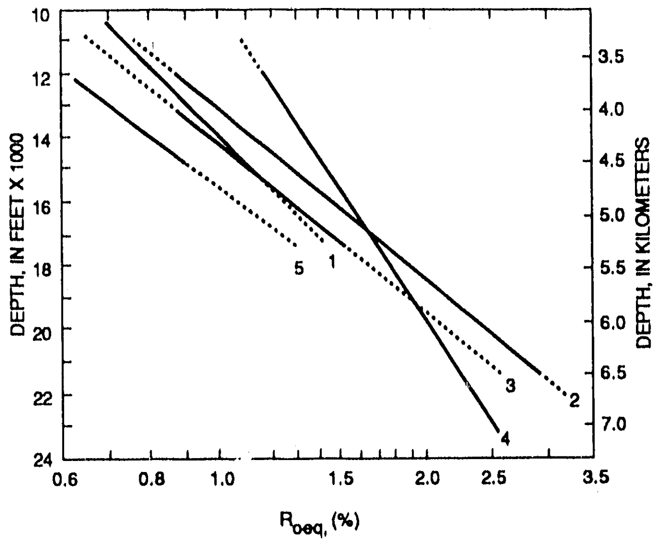

Figure 3. Preliminary trends of equivalent vitrinite reflectance (R_{oeq}) vs depth for five localities in MAFLA area. Trends represent: (1) along border of Alabama and Florida panhandle; (2) Mississippi and Alabama south of the Wiggins arch; (3) Mississippi salt basin; (4) east flank of Jackson Dome, Mississippi, and (5) Pickens-Gilbertown-Pollard fault zone near Mississippi-Alabama state line.

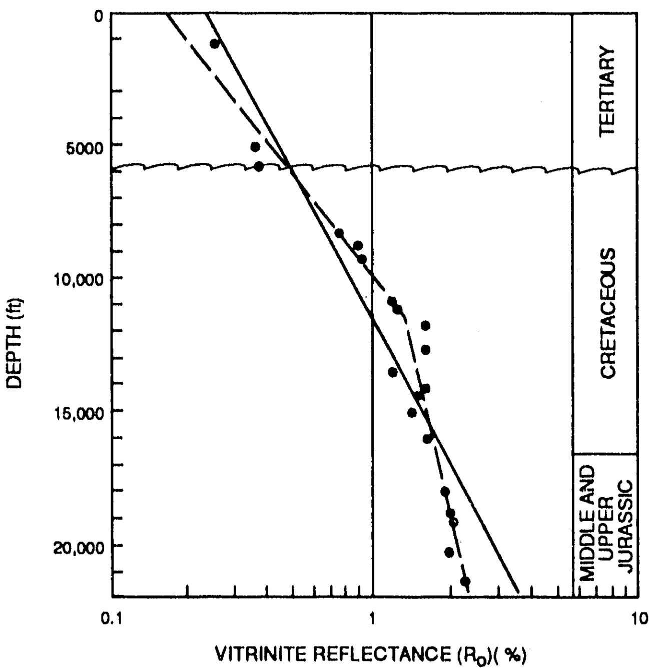

Figure 4. Vitrinite reflectance (R_0) vs depth profile of the Exxon State Lease 624 No. 1 well. Mobile Bay, offshore Alabama. Solid straight line is regression of all vitrinite reflectance data; dashed segmented line is regression of shallow and deep data.

Examination of other R_0 profiles in Mississippi and Alabama indicates that the two-segment profile is probably more representative of the trend. In similar appearing R_0 profiles in the Rocky Mountain region, Law and others (1989) attributed the steep-sloping segment to convective heat transfer processes related to the presence of abnormally high formation pressures and vertically flowing formation fluids. Other possible explanations include changes of organic matter type and suppression of thermal maturity due to abnormally high formation pressure. The origin of the two-segment profile in the MAFLA area is uncertain and under investigation because thermal maturity is a dominant control of deep gas processes and accumulations.

A preliminary burial and thermal history reconstruction for strata in the Exxon State Lease 624 No. 1 well is shown in Figure 5. Based on a present-day thermal gradient of 1.35° F/ 100 ft remaining constant through geologic time, the Louann Salt entered the oil window about 120 m.y. ago during deposition of the Trinity Group. With continued burial, the top of the oil window moved to stratigraphically younger units and is currently in the Cretaceous Fredericksburg and Washita Groups at a depth of about 10,200 ft. However, preliminary thermal modeling of this well indicates that the present-day thermal gradient of 1.35° F, or even higher gradients of 1.4 to 1.5° F as reported by Wilson and Tew (1985), are insufficient to achieve the measured level of thermal maturity. Therefore, paleotemperatures, at some time, were higher than present-day temperatures are.

Reservoir Characterization

As stated earlier, sandstones of the Norphlet Formation are major reservoirs for hydrocarbons in the MAFLA area and are particularly important for deep dry gas in the Mobile Bay area. Two main facies are commonly recognized in the Norphlet Formation as summarized by Schenk (1990). Conglomerate and red-colored sandstones, siltstones, and shales are found updip and along the margins of some of the basement uplifts and together they are identified as the alluvial facies on Figure 1. The conglomerate was deposited in proximal alluvial fan and wadi environments adjacent to basement uplifts and adjacent highlands. The redbed facies occurs downdip from the conglomerate, and is interpreted to be distal alluvial fan and fluvial/wadi sediments.

The major offshore accumulations of deep dry gas are produced from the eolian facies of the Norphlet (Fig. 1). The eolian facies is dominated

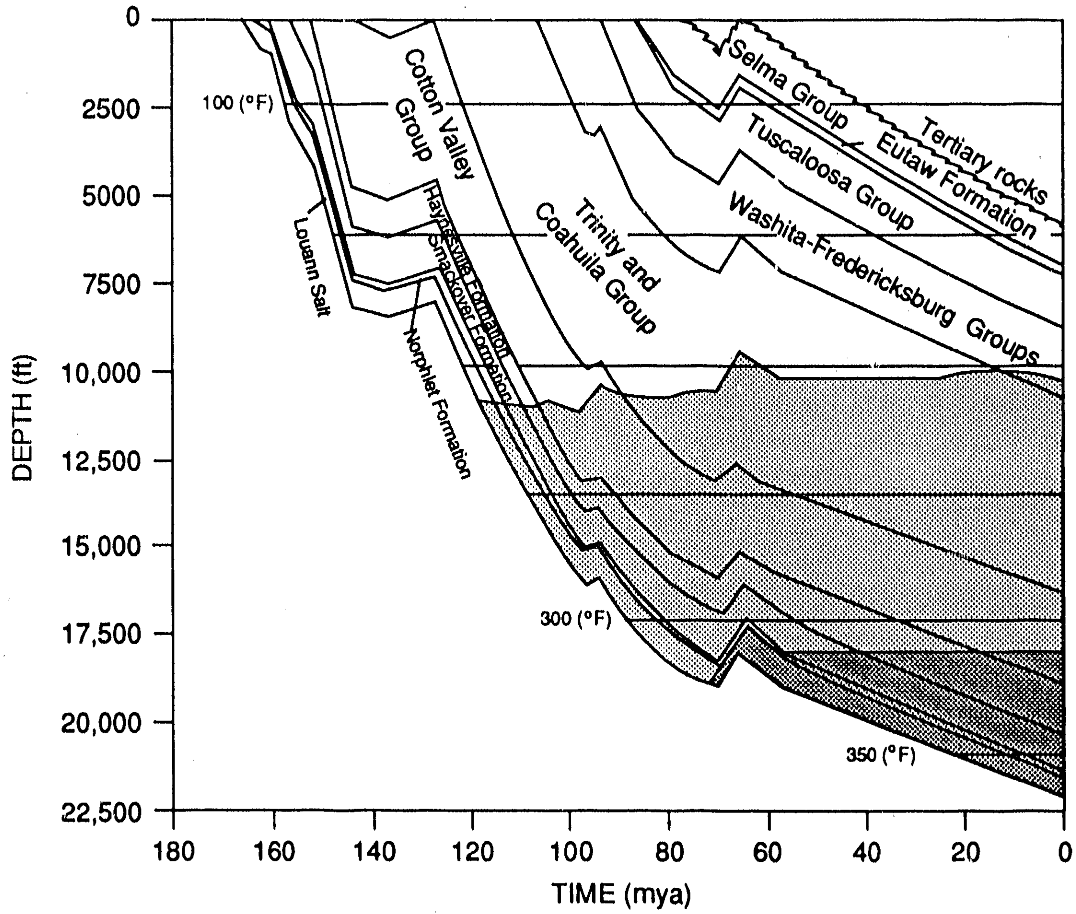

Figure 5. Preliminary burial and thermal history reconstruction of Exxon State Lease 624 No. 1 well, Mobile Bay, offshore Alabama. Light shaded pattern represents area within the oil window (catagenesis); dark shaded pattern represents area within gas window (metagenesis).

by sandstone with inversely graded eolian ripple strata, and high-angle eolian avalanche strata. These sandstones also contain interdune, playa, and wadi deposits. The upper part of the Norphlet Formation in the Mobile Bay area is commonly described as massive and is interpreted to represent reworking of the eolian sand by marine waters associated with the Smackover transgression.

The Norphlet sandstones are subarkosic to arkosic in composition. The bulk mineral composition of productive Norphlet sandstones at two areas in Alabama was determined by X-ray powder diffraction; onshore near the Florida Panhandle at depths of 15,100 to 15,600 ft and in State waters of Mobile Bay, offshore Alabama at depths of 20,100 to 22,200 ft. The mean bulk composition, in weight percent, of onshore samples is 58 percent quartz, 26 percent feldspar, 11 percent clay minerals, 4 percent carbonate, and 1 percent pyrite. In contrast, the mean bulk composition of Mobile Bay samples is 65 percent quartz, 28 percent feldspar, 4 percent clay minerals, and less than 1 percent carbonate and pyrite.

The most significant difference in the bulk-mineral composition between the two groups is the amount, as discussed previously, and the type of clays. Clay minerals in the Norphlet sandstones are illite, chlorite, and mixed-layer illite/smectite (I/S). The I/S is of the illitic and ordered variety common to deeply buried rocks (Pollastro, 1991). The mean clay-mineral composition of the onshore samples is 90 percent illite, 9 percent I/S, and 1 percent chlorite. In contrast, the samples from Mobile Bay contain mostly chlorite (82 percent) with some illite (15 percent) and I/S (3 percent). The relation between the amount and type of clay minerals is demonstrated in Figure 6. The primary differences in the sandstones between these two areas, particularly the clay fraction, suggest that tectonic setting, provenance, and depositional environment were important factors in controlling their composition.

The porosity of sandstones has been shown to correlate with time-temperature exposure (Schmoker and Gautier, 1988; Schmoker and

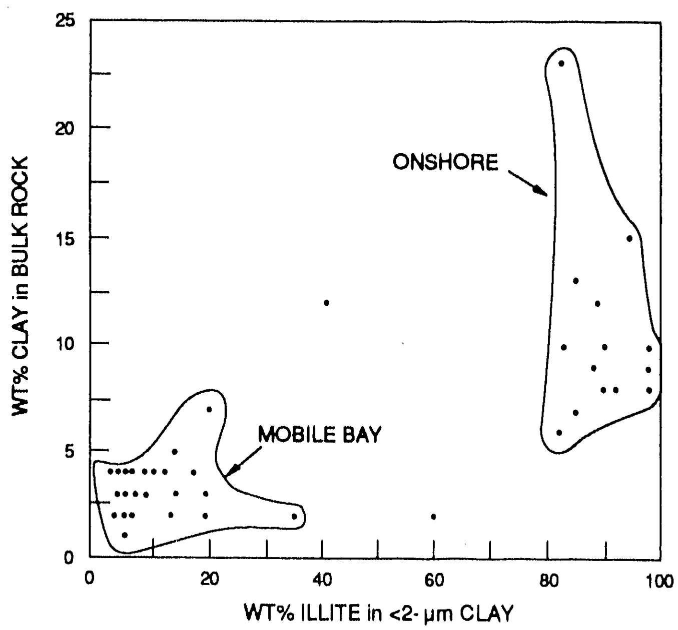

Figure 6. Plot of weight percent of clay minerals in bulk rock vs relative weight percent of illite in sandstones, Norphlet Formation. Note separation of samples from onshore and Mobile Bay areas.

Higley, 1991). A measure of integrated thermal history, such as vitrinite reflectance (R_0), is thus a useful parameter for empirical porosity prediction. Based on Figure 3, R_{oeq} of the Norphlet Formation ranges from about 0.65 percent near the Pickens-Gilbertown-Pollard fault zone to 3.0 or higher in Federal waters, offshore Alabama. Core-plug porosity data for the Norphlet Formation that span this R_{oeq} range have been gathered from a number of locations. Preliminary interpretation suggests that, at a given level of thermal maturity, porosities of the Norphlet Formation are significantly higher than porosities of most other sandstones around the world.

Figure 7 is a sketch illustrating the higher than expected porosity values for the Norphlet. The "type curve" in this figure is a porosity-R_{oeq} curve considered to be representative of sandstones in general (Schmoker and Gautier, 1989). The hachured zone depicts the porosity range of the Norphlet Formation as a function of thermal maturity. The key point is that Norphlet porosities are high, compared to typical sandstones, not just offshore, but throughout the MAFLA area.

Preservation of sandstone porosity in Norphlet sandstones has been cited in the literature as a function of (1) overpressuring, (2) inhibition of diagenesis by the presence of hydrocarbons, (3) inhibition of quartz diagenesis by the presence of chlorite clay cement, (4) the general lack of pore fluid volume required to cement the sandstones with quartz following mechanical compaction, and (5) early cementation and subsequent dissolution of evaporitic cements (carbonates, anhydrite, and halite). Each of these are discussed separately.

Overpressuring was cited by Dixon and others (1989) as acting to forestall compaction and preserve a few percent porosity in Norphlet sandstones. Compilations of pressure data for this project illustrate that nearly all onshore Norphlet fields are only slightly overpressured, with the exception being a few fields proximal to the Jackson Dome. Offshore, overpressuring may be more important, and may actually preserve a few percent of Norphlet sandstone porosity. The majority of Norphlet porosity onshore, however, is not due to overpressuring.

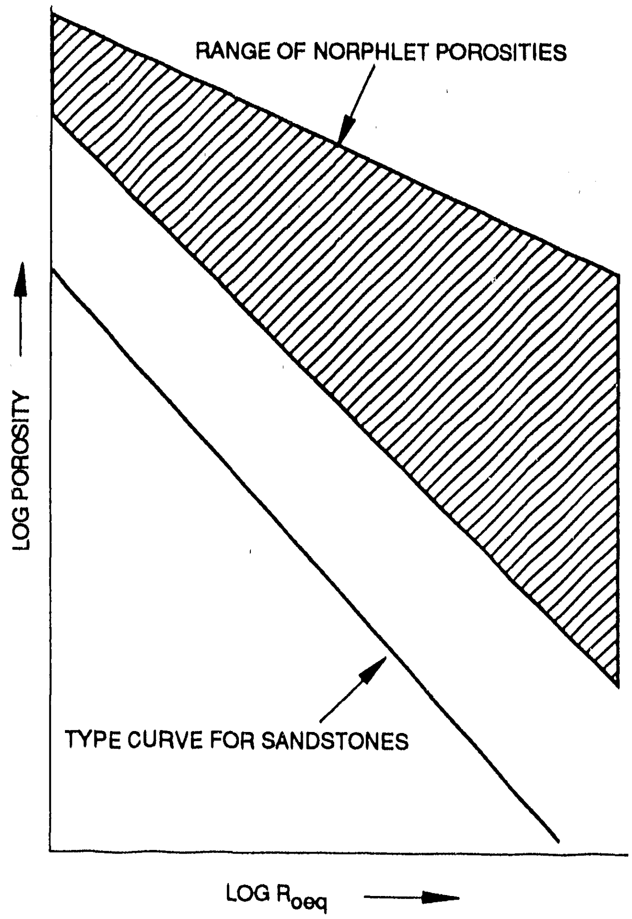

Figure 7. Preliminary interpretation of thermal maturity vs Norphlet porosity for MAFLA region. Porosities of Norphlet Formation are higher than porosities of sandstones in general (type curve, from Schmoker and Gautier, 1989), when compared on basis of thermal maturity (equivalent vitrinite reflectance, R_{oeq}), over a wide range of thermal maturity.

Dixon and others (1989) also concluded that diagenesis was inhibited by the presence of hydrocarbons in the pore spaces, resulting in porosity preservation. However, many wells onshore have encountered Norphlet sandstone reservoirs that are water-wet; little of the porous sandstone had ever contained hydrocarbons, questioning the general application of the role of hydrocarbons in preserving Norphlet porosity.

Chlorite clay has been cited as a cause of porosity preservation generally through the inhibition of quartz cementation, which then leaves pores relatively open (Thompson and Stancliffe, 1990). As discussed previously, chlorite is the dominant clay type in the Mobile Bay area, although the total clay content is relatively low compared to onshore. In this study, many examples of quartz cementation subsequent to chlorite growth have been documented; again, the general application of the role of chlorite in porosity preservation is suspect. Samples from offshore wells with abundant chlorite have, in some cases, contained quartz cement (Fig. 8).

Ajdukiewicz and others (1991) concluded that pore fluid migration through Norphlet sandstones was inadequate to cement the sandstones with quartz, and this lack of cementation was the main reason for preservation of deep porosity. This concept deserves more study, as Norphlet sandstones may have been somewhat isolated from fluid flow by the underlying Louann Salt, However, as discussed with chlorite, many samples from both onshore and offshore wells exhibit quartz cement, indicating that fluids were moving through the Norphlet sandstone; chlorite and other cements also document fluid movement. Although the general application of this cause is suspect, the amount of pore fluids moving through the Norphlet may have been less than that of similar sandstones in other basins. More work, especially diagenetic modeling, is needed to focus on this problem.

Finally, several studies have focused on the dynamics of early evaporitic cements as a prime cause of excellent Norphlet porosity. The interpretation of the importance of early cements has polarized; Dixon and others (1989) concluded that early cements were of minor importance to deep porosity preservation, whereas Lock and Broussard (1989) felt that early cements were critical to porosity preservation. Our studies have shown that dolomite, calcite, anhydrite, and halite were early cements, as have other studies (Marzano and others, 1988), and that halite in particular is considered to be more significant than generally realized in porosity preservation (Hartman, 1968). Halite was observed in samples from several wells in the area extending from the Jackson Dome to southwest Alabama. Halite is easily removed from core samples during normal preparation processes; if samples are prepared with oil rather than water, more halite was observed (Fig. 8). Thus, the amount of halite in core samples may have been artificially low due to sample preservation. Halite appears to have formed before chlorite, and before significant quartz cementation. Halite does not grow pseudomorphically within a pore system; that is, halite does not peripherally replace framework minerals, so its removal leaves no trace of its former presence, unlike carbonates or anhydrite. Work continues on the significance of halite in porosity preservation.

To sum up, each of these five factors may be important locally, but focus is being placed on the regional aspects and importance of the dynamics of early cementation and late dissolution as the main causes of porosity preservation in the Norphlet Formation.

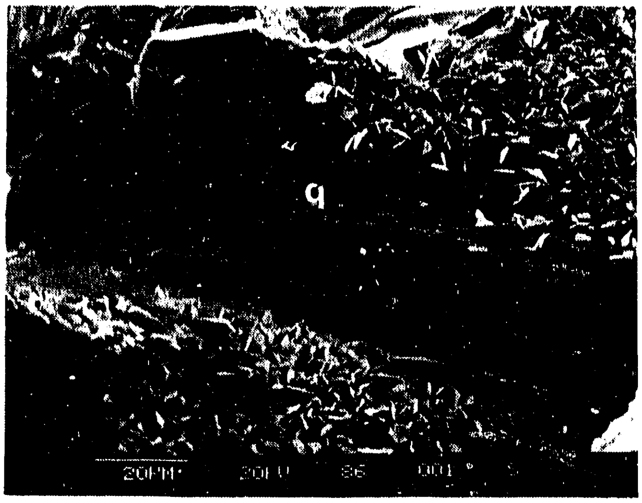

Figure 8. (A) Quartz cement (q) grew subsequent to chlorite cement in some Norphlet Formation sandstones, questioning the general application of the idea that chlorite inhibited further diagenesis. Exxon State Lease 534 well, Mobile Bay, offshore Alabama, 20,486 ft. (B) Early halite cement (h) is present in several wells, and may be more pervasive in onshore Norphlet sandstones than previously realized. Halite occurs before chlorite cement. Hughes-Eastern Marie Strickland well, Escambia County, Alabama, 14,920 ft.

Source Rocks

The productive area of the Norphlet Formation in MAFLA (Fig. 1) is characterized by oxidizing eolian and alluvial, and transgressive marine depositional environments. Adequate hydrocarbon source rocks have not been identified in the Norphlet in its main productive area, which is south of the Wiggins Arch.

The underlying Middle and Upper Jurassic Louann Salt forms a permeability barrier that seemingly rules out hydrocarbon migration into the Norphlet from older formations. The Norphlet is overlain by the Smackover Formation, which in turn is overlain by the Haynesville Formation. Evaporites in the lower part of the Haynesville Formation form an upper seal that appears to prevent hydrocarbon migration into the Norphlet-Smackover system from younger formations.

Perhaps because of a lack of other candidates, algal carbonate mudstones of the Smackover are commonly assumed to be the source rocks for hydrocarbons in Norphlet reservoirs (Sassen and others, 1987; Claypool and Mancini, 1989). This assumption is qualitative, however, and has not been documented by mass-balance calculations. Measured total organic carbon (TOC) values of selected Smackover samples from wells in Alabama rarely exceed 1.0 percent and more typically are 0.2 to 0.3 percent (Claypool and Mancini, 1989). The volume represented by these nonrandom samples is unknown, but possibly quite small.

Drilling results indicate that onshore Norphlet hydrocarbon potential is limited by adequate onshore source rocks. Many salt-related structures with large closure are wet and others have only a thin hydrocarbon column in the Norphlet (Bolin and others, 1989). Smackover production demonstrates that migrating oil and gas could reach these structures and that they are sealed. These circumstances suggest that the supply of hydrocarbons in onshore areas is generally insufficient to charge Norphlet traps.

In sharp contrast, offshore salt-related structures in the Norphlet contain very large volumes of hydrocarbons. Mancini and others (1987) estimated the total reserves in the State waters of Alabama to range from a low of 4.3 to a high of 7.1 TCF. T.J. Woods (Gas Research Institute, personal commun., 1992) estimated the gas resources of the Norphlet in the MAFLA area to be in the range of tens of TCF based on recent discoveries. The generalization can thus be made that the hydrocarbon potential of the Norphlet in offshore areas is not limited by source rocks.

A hypothesis that explains the difference in onshore and offshore hydrocarbon abundance in the Norphlet is that the principal source rocks for the major offshore Norphlet gas accumulations are not algal carbonate mudstones of the Smackover, but rather downdip, more distal, undifferentiated Norphlet-Smackover equivalent marine facies as suggested on Figure 1. Such facies, with a thickness of at least 1,100 ft, were encountered in a well located approximately 20 mi offshore, south of the Alabama-Florida state line (Mink and others, 1990).

According to this hypothesis, the large offshore Norphlet fields are charged by hydrocarbons generated and expelled from roughly age-equivalent, downdip, marine facies. The Wiggins arch-Conecuh ridge system (Fig. 1), over which the Norphlet thins or pinches out, tends to block the updip migration of these hydrocarbons into onshore areas. The availability of hydrocarbons in onshore areas is thus severely restricted compared to offshore areas, and may depend on the sourcerock potential of the Smackover, which appears to be quite limited overall.

This hypothesis explains the regional hydrocarbon distribution in the Norphlet Formation of the MAFLA area and could be incorporated into exploration, development, and resource assessment strategies. Quantitative geochemical investigations of source rock potentials, source rock volumes, and petroleum types are needed to support or discredit this hypothesis. More broadly, such studies are needed to better understand the Norphlet-Smackover system of the MAFLA area.

Natural Gases

Thirty gas samples from the MAFLA area were analyzed for molecular and isotopic composition. The samples are from Norphlet and Smackover reservoirs in the oil, wet gas and condensate, and dry gas trends.

The gas samples become chemically drier (C_{2+} values of 49 to 0 percent) and isotopically heavier (methane $\partial^{13}C$ values of -55 to - 21 ‰) with increasing depth of burial (11,400 to 23,600 ft) and increasing level of thermal maturity. Based on composition, two groups of gases can be distinguished; one with samples from the oil and wet gas and condensate trends and one with samples from the dry gas trend (Fig. 9). The gases from the oil and wet gas and condensate trends are chemically wet (C_{2+} values greater than 15 percent) and isotopically light (methane $\partial^{13}C$ values less than -41 ‰); this composition indicates generation during catagenesis. In contrast, the gases from the dry gas trend are easily distinguished by their dryness (C_{2+} values less than 1 percent) and enrichment of heavy ^{13}C isotope in the methane component (methane $\partial^{13}C$ values greater than -38 ‰). The dry gases were generated at high levels of thermal maturity (metagenesis) and resulted mainly from thermal cracking of oils and heavier hydrocarbons generated from marine source rocks.

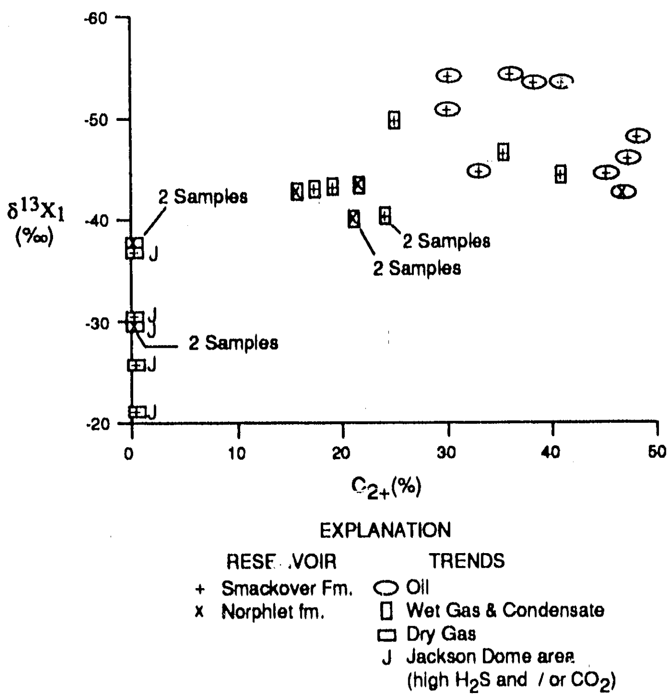

Figure 9. Plot of methane $\partial^{13}C$ vs C_{2+} for gas samples from MAFLA area

Nonhydrocarbon gases, such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) make up a significant component of many of the gases produced from Jurassic reservoirs. The highest values of CO_2 (as much as 99 percent) and H_2S (as much as 45 percent) are in the vicinity of the Jackson Dome. Gases with these high CO_2 and H_2S contents are dry and are associated with the isotopically heaviest methane (methane $\partial^{13}C$ values greater than -36.9 ‰) (Fig. 9). Many of the gases from all three producing trends have at least some CO_2 and H_2S, which is a concern in the drilling, production, and marketing of the gas. The CO_2 is probably derived from the high-temperature decomposition of carbonate rocks (Hunt, 1979), such as those in the Smackover Formation, and the presence of CO_2 results in dilution of the hydrocarbon gases. The H_2S probably resulted from thermochemical sulfate reduction at high temperatures (Orr, 1977), with the source of the sulfate being anhydrite in the overlying Haynesville Formation. Unfortunately, methane can be destroyed by reactions with H_2S and sulfur compounds.

Liquid Hydrocarbons

Twenty-six liquid samples, including both medium-gravity oils and condensates, from southwest Alabama were analyzed. The samples are from all major producing intervals, but most are from Jurassic reservoirs to depths of about 18,000 ft. Stable carbon isotope ratios ($\partial^{13}C$) of the aromatic and saturated hydrocarbon fractions range from -25.5 to -22.0 ‰. These values are within the range of $\partial^{13}C$ values reported by Sofer (1984) for oils derived from marine organic matter. Oils and condensates produced from Cretaceous reservoirs are depleted in ^{12}C by about 1.0 ‰ relative to Jurassic oils and condensates. The difference in carbon isotope ratios between aromatic and saturated hydrocarbons ($\partial^{13}C_{aromatic}$-$\partial^{13}C_{saturated}$, or Δ) is generally about 1.0 for Jurassic oils (Smackover Formation) and about 0.5 for oils from the Mississippi salt basin. That is, the aromatic hydrocarbons are isotopically heavier (more ^{13}C-enriched) than the saturated hydrocarbons. Δ values for Cretaceous liquids are quite variable and do not show any systematic trend. The isotope data indicate that at least two source rocks have generated and expelled the liquids in these Cretaceous and Jurassic reservoirs.

The whole-oil gas chromatography (GC) analyses show that the relative amounts of toluene (normalized to C_7 compounds) generally increase with increasing depth of the producing reservoir to about 13,000 ft. No systematic relation between depth and toluene is evident in samples from reservoirs deeper than 13,000 ft. Heptane values (Thompson, 1987) are from 27 to 48 (Fig. 10). According to Thompson's (1987) interpretation, oils with heptane values in the range of 17 to 30 are considered mature (catagenesis) and values greater than 30 are typical of supermature oils and condensates (metagenesis).

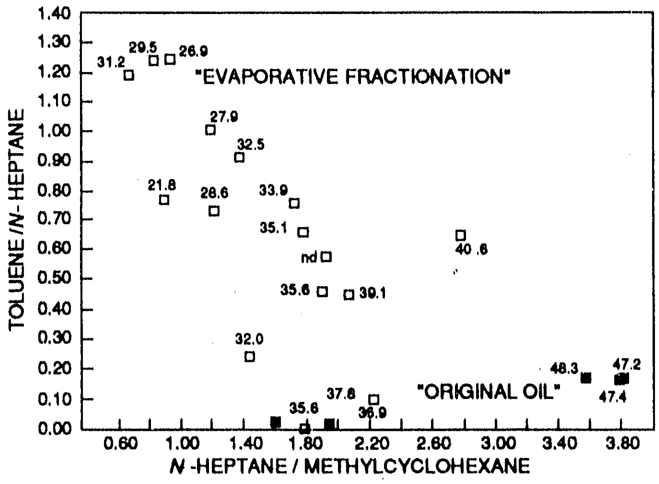

Figure 10. Toluene/heptane vs heptane/methylcyclohexane ratios for oils and condensates of southwest Alabama. Jurassic liquids are open squares; Cretaceous samples are solid squares. Numbers refer to heptane values (100 X heptane (Σ cyclohexane through methylcyclohexane) (Thompson, 1987).

All liquids, except three from the Jurassic, have API gravities greater than 40°, but only five of the Jurassic oils have heptane values significantly into the supermature range (greater than about 35) according to Thompson's criterion. The combination of high API gravity and relatively low heptane values (mature) could be explained by evaportive fractionation. Evaporative fractionation is a process whereby normal oils yield condensates which are enriched in toluene (Thompson, 1987). The high toluene/heptane ratios of some of the Jurassic oils and condensates that have heptane values less than about 30 would be consistent with Thompson's hypothesis (Fig. 10). Condensates are usually attributed to generation by thermal cracking of pre-existing oil at elevated temperatures. Evaporative fractionation does not require high-temperature cracking to generate condensates. In the present study, a combination of thermal cracking and evaporative fractionation is possible because high heptane values and the distribution of alkanes, not shown here, suggests that at least some condensates are very mature.

SUMMARY

Natural gas from deep (>15,000 ft) sedimentary basins in the United States is an important source of hydrocarbons. The Gulf of Mexico is one of the Nation's most important provinces for discovered and undiscovered hydrocarbons, including deep gas. Major resources of deep gas are present in eolian sandstone reservoirs of the Upper Jurassic Norphlet Formation in the MAFLA area and are being studied for this project.

Thermal maturity is a major control of deep gas processes and accumulations. Thermal gradients vary throughout the MAFLA area, but are highest south of the Wiggins arch where the best deep gas potential exists. Thermal modeling indicates that paleotemperatures were higher than present-day temperatures are.

At a given level of thermal maturity, porosity values for the Norphlet are significantly higher than those of most sandstones around the world. These high values may be related to (1) early cementation and subsequent dissolution of evaporitic cements (carbonates, anhydrite, and halite), (2) inhibition of quartz diagenesis by the presence of chlorite clay cement, which is prevalent in offshore Mobile Bay, (3) overpressuring, (4) inhibition of diagenesis by the presence of hydrocarbons, and (5) the general lack of pore fluid volume required to cement the sandstones.

The source for onshore Jurassic hydrocarbons, which are mostly in carbonate reservoirs in the upper part of the Smackover Formation, is probably algal carbonate mudstones in the lower part of the Smackover. However, these carbonate source rocks are probably inadequate to charge the major accumulations of deep, dry gas in the Norphlet in the Mobile Bay area, offshore Alabama and Mississippi. Downdip, more distal, marine facies containing type II kerogen of the undifferentiated Norphlet and Smackover interval are postulated to be the source for these offshore accumulations.

Gases in deep reservoirs of the Norphlet are distinguished by their dryness and enrichment in heavy isotope ^{13}C indicating generation at high levels of thermal maturity (metagenesis). Gases in Jurassic reservoirs of MAFLA contain varying amounts of CO_2 and H_2S, which have an inorganic origin, and present problems in drilling, production, and marketing. Geochemical data indicate that liquids in deep Jurassic and Cretaceous reservoirs may have at least two sources. In addition, the condensates may have resulted from either (1) high-temperature cracking of heavier hydrocarbons, or (2) evaporative fractionation.

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