Chapter 6

Deep Pressure Seal in the Lower Tuscaloosa Formation, Louisiana Gulf Coast

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ABSTRACT

Repeat formation tester (RFT) pore pressure measurements spanning a depth range of 5500–6060 m in the lower Tuscaloosa Formation (Upper Cretaceous) document a pressure discontinuity of >20 MPa at ~5680 m forming a pressure seal in two natural gas fields in the Tuscaloosa trend, Louisiana. In the Morganza field the depth to the top of overpressure varies by less than 30 m across two adjacent fault blocks, though equivalent strata are downthrown by 100 to 120 m. In contrast, the depth to the top of overpressure in the nearby Moore-Sams field rises slightly across the same fault. Therefore, the nearly horizontal top of overpressure does not appear to coincide with time- or lithostratigraphic boundaries.

The overpressures in all of the Moore-Sams and some of the Morganza fields wells follow a local hydrostatic gradient with increasing depth indicating that pore fluids below the pressure seal are in communication, and demonstrating that sandstone connectivity occurs below the pressure seal as well as above. In the remaining Morganza wells, overpressure increases with depth in a stair-step manner that may comprise offset local hydrostatic gradients, to magnitudes of 117 MPa at depths of 5.9 km. The occurrence of the pressure seal within interbedded sandstones and shales, where high sandstone connectivity is expected, suggests that the sandstones of the seal zone are unusually tight.

The above observations coupled with a petrographic study of sandstones from the vicinity of the pressure seal suggest that extreme compaction of the sandstones after dissolution of carbonate cements may have contributed to the low permeability indicated by the pressure data, and that the seal formed a kilometer or more shallower than it is today.

INTRODUCTION

The occurrence and maintenance of abnormally high fluid pressures in sedimentary basins is explained by processes that account for pore size reduction, pore fluid volume increase, and/or seal formation (see Gretener and Feng, 1985, for a review). Several pressure-generating mechanisms have been proposed for overpressures in sandstones such as thermal cracking of oil to gas (Hedberg, 1974), the migration of overpressured fluid into sandstones from undercompacted shales (Dickinson, 1953), the addition of pore water produced by the smectite to illite transformation (Powers, 1967; Perry and Hower, 1970, 1972), or the thermal expansion of pore water with burial (Barker, 1972). Additionally, the maintenance of abnormal pressure over geologic time requires either seals of extremely low permeability, the recharging of pressures by burial compaction and heating, or continuous addition of fluids by hydrocarbon generation or by topographically driven flow (Bradley, 1975; Gretener and Feng, 1985; Hunt, 1990).

Fluid flow models have reproduced observed pore pressures in sedimentary basins (England et al., 1987; Ungerer et al., 1987; Bethke et al., 1988; Mann and Mackenzie, 1990; Harrison and Summa, 1991). The pressure-generating mechanism in these models is shale compaction disequilibrium (Dickinson, 1953; Magara, 1971, 1978). Permeability barriers required to maintain overpressure in vertically flowing pore water require permeabilities in the nanodarcy range (Ungerer et al., 1987; Harrison and Summa, 1991; L. Cathles, 1991, personal communication), which for shales may require burial depths of at least 3 km (Gretener and Feng, 1985) and would exclude most siltstones and sandstones.

In the Tertiary section of the Gulf Coast basin the top of overpressure typically occurs near the base of massive deltaic sandstones at the contact with underlying marine shales (Dickinson, 1953; Wallace et al., 1979; Bruce, 1984). However, there remain some unusual hydrocarbon reservoirs where the present-day transition to overpressure occurs at unexplained permeability barriers that have either stopped migrating overpressured pore fluids or have sealed fluids that have subsequently expanded with heat or diagenesis (Bradley, 1975; Hunt, 1990). Very little is known about pressure seals within sandstones or sandstone-dominated sections (Jansa and Noguera Urrea, 1990; Tigert and Al-Shaieb, 1990; Moline et al., 1991; Weedman et al., 1992a, b), especially of the type that seal overpressured fluids with local hydrostatic gradients characteristic of the pressure compartments described by Powley (1990) and Hunt (1990).

The very porous sandstones (>25% porosity) of the deltaic portion (Smith, 1985) of the lower Tuscaloosa Formation (Upper Cretaceous) in Louisiana produce gas from 5400 to 6400 m depth. A transition to overpressure occurs within the formation in the study area including the Moore-Sams and Morganza fields (Figure 1). Less than 10 km up-dip from these fields, the formation is normally pressured, and less than 10 km down-dip it is entirely overpressured (McCulloh and Purcell, 1983). In this paper, we present closely spaced repeat formation tester (RFT) pore pressure measurements that constrain the geometry of the top of a pressure seal in the study area and use the data to assess pressure generation and seal formation mechanisms.

METHODOLOGY

RFT pressure measurements used in this study were taken during the course of drilling wells in the early 1980s and have been graded by the authors using criteria described in Smolen (1977). Although the accuracy of the pressure gauge on the tool is reported as ±0.2 MPa (Smolen, 1977), pressure measurements in this study at the same depths vary as much as 2 MPa. Sand/shale ratios were estimated from gamma-ray logs by defining the 100% sandstone and 100% shale lines, and considering any unit registering 30% to the left of the shale line on the gamma-ray trace to be sandstone. Ratios were calculated every 30.5 m and averaged over the entire formation in the producing wells. The top of the lower Tuscaloosa Formation is identified and correlated by a distinctive, high-resistivity calcareous shale bed known as the Pilot, or Bain marker (Billingsley, 1980).

The term *overpressure* is used here to denote pore pressures above normal, i.e., greater than the hydrostatic pressure indicated by $\rho g h$, where ρ is the density of the pore fluid, g is gravity, and h is depth. Pressure gradients are calculated from the surface by dividing pore pressure by depth. Reference to local hydrostatic gradient means that pore pressures increase with depth at a rate that is parallel to the hydrostatic gradient to the ground surface and is interpreted to mean that the fluids in that interval are in hydraulic communication despite being overpressured.

Sandstones were sampled from available cores from these fields. The wells were cored above the pressure seal in the Ravenswood B and Butler wells from depths of 5483 m to 5613 m, and below the seal from the Fontaine well from depths of 5726 m to 5745 m. Discussion of these samples is given in more detail in Weedman et al. (1992a). A persistent problem in the study of pressure seals is the unavailability of core samples through the seal zone because of the hazardous nature of coring through a very high pressure gradient. Therefore, to infer the nature of the rocks in the seal zone we use indirect evidence such as pore pressure changes, differences in diagenesis of sandstones above and below the seal, and geophysical log characteristics.

RESULTS

A plot of all pressure data versus depth for both fields is shown in Figure 2. A transition from normal to overpressure occurs at about 5680 m near the top of the lower Tuscaloosa Formation. Other studies have documented a shallower transition zone, as well, in these and other Tuscaloosa trend fields (Matheny,

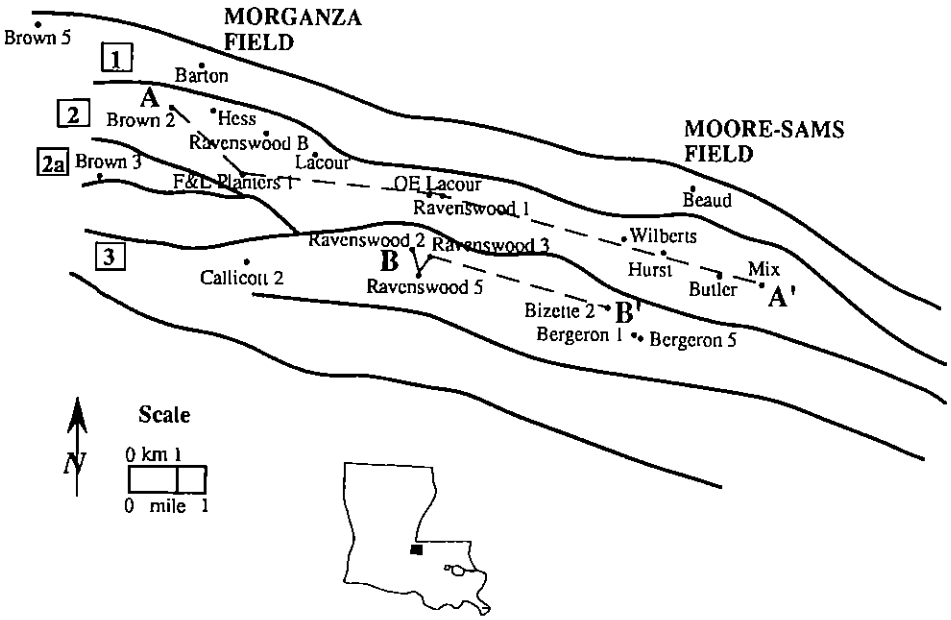

Figure 1. Map of the Morganza and Moore-Sams fields showing the locations of wells and the listric normal faults that subdivide the fields into fault blocks. Location in Louisiana shown in inset. Lines of cross section, A–A′ and B–B′, are shown for Figures 4 and 5 (after AMOCO map).

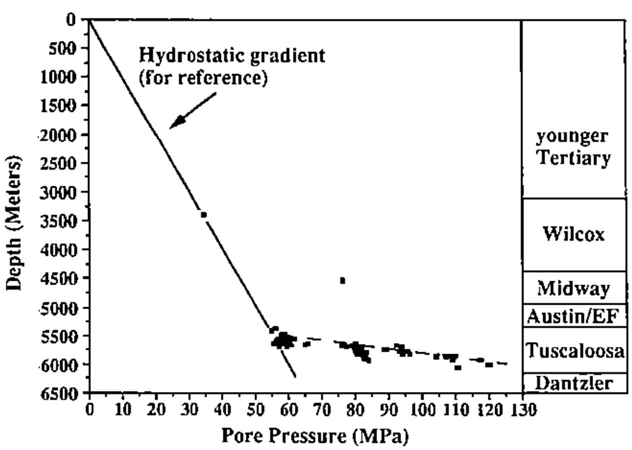

Figure 2. Plot of pressure vs. depth of all successful RFT data from the Morganza and Moore-Sams fields. Data indicate perhaps two overpressured zones separated by ~300 m of normally pressured fluids at 5350 m in the upper sandstones of the lower Tuscaloosa Formation. Approximate depths to formation tops shown at right; EF = Eagle Ford. N = 203 total data points, n = 5 at 3440 m, n = 3 at 4530 m. Data tables are given in Weedman et al. (1992b).

1979; Pankonien, 1979; Gill, 1980; McCulloh and Purcell, 1983; McCulloh, 1985) and an interval of normal pressure in between the two overpressured zones.

Moore-Sams Field

RFT pore pressure data from within the lower Tuscaloosa Formation in the Moore-Sams field are shown for three fault blocks (Figure 3A). All pore pressures in fault block 1 are normal, while below the transition zone pressures in blocks 2 and 3 follow a local hydrostatic gradient down to depths of 5850 m, reaching magnitudes of 82.6 MPa. In block 2, the transition zone from normal to overpressure occurs at 5728 ± 45 m, while in block 3 it occurs at 5674 ± 15 m; the top of the formation is displaced down-to-the-south across the fault separating blocks 2 and 3 by 105 m. Therefore, the transition zone is higher stratigraphically in fault block 3 than in 2, and the variation in the depth to the top of overpressure between fault blocks 2 and 3 is less than the displacement of the strata across the fault. Additionally, fluid communication in the overpressured zone below the pressure seal and across the fault is indicated by the nearly equal magnitude of pore pressures at the same depths on both sides of the fault.

Morganza Field

RFT pore pressure data from four fault blocks of the Morganza field are shown in Figure 3B. The pore pressures in the overpressured intervals in the Morganza field follow apparent local hydrostatic gradients, but increase as much as 26 MPa across certain shaly intervals. As for the Moore-Sams field, all pore pressure data from fault block 1 of the Morganza field are normal, while the overpressures encountered in fault blocks 2 and 3 reach a greater magnitude than in the Moore-Sams field, up to 117 MPa at depths of 5975 m. The variation in pore pressure over the depth range of 5675 to 5850 m suggests that several pressure seals may exist within this field, not only along faults (for example, between blocks 2 and 2A), but within fault blocks as well (blocks 2 and 3).

Pressure Seal Geometry

Both normal and overpressure RFT measurements are available for eight wells that constrain the depth and thickness of the pressure seal in the two fields.

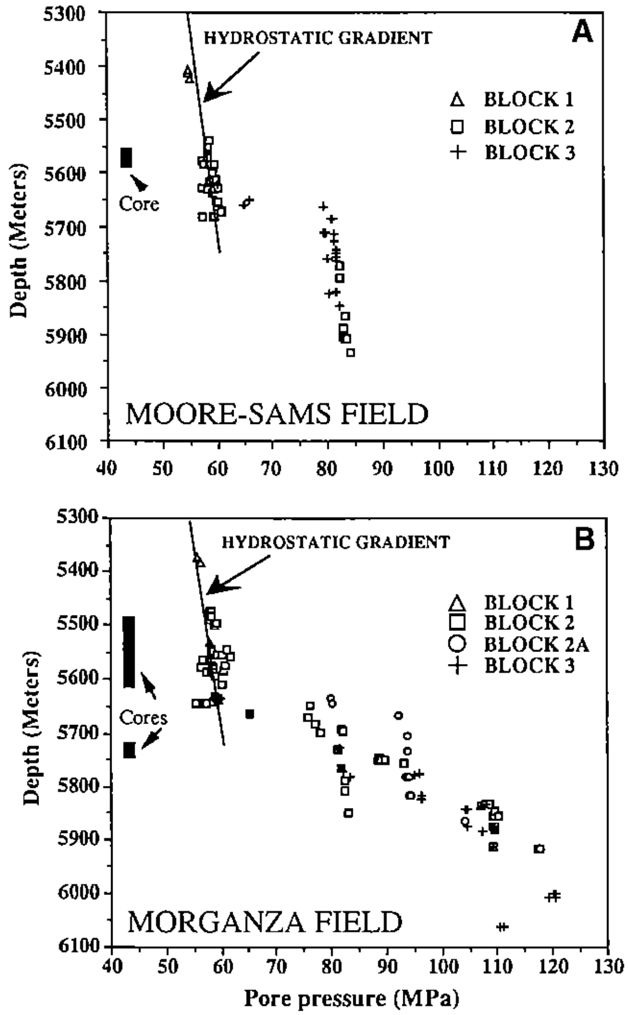

Figure 3. Plot of pressure vs. depth of RFT data. The hydrostatic gradient to the surface is shown for reference. (A) Pressure vs. depth in the Moore-Sams field from the fault blocks listed at upper right. Core taken from interval indicated. (B) Pressure vs. depth in the Morganza field from fault blocks listed at upper right. Cores taken from the intervals indicated.

Cross sections of those wells from fault blocks 2 and 3 are shown in Figures 4 and 5, respectively. The shaded pressure seal interval, constrained by the deepest normal pressure and the shallowest RFT overpressure measurements, is characterized by interbedded sandstone and shale.

Comparison of the Bizette 2 with the Mix well (Figures 4 and 5) shows that the pressure seal is in the middle part of the lower Tuscaloosa Formation in fault block 2 and in the upper part of the formation in fault block 3. The pressure seal in the Mix well occurs within a thick shale interval that may be correlated from across both fields. However, the pressure data show that this apparently laterally extensive shale, indicated in Figures 4 and 5 by a dashed line, is not the pressure seal in the other wells.

The maximum possible thickness of the pressure seal in block 2 varies from 28 m (OE Lacour) to 137 m (F&L Planters), and in block 3 varies from 67 m (Bizette 2) to 131 m (Ravenswood 5). In fault block 3 of both fields, the depth to the top of the pressure seal is consistent from well to well, varying from ~5620 m (Bizette 2) to ~5640 m (Ravenswood 5). It is possible that the seal is less than 28 m thick throughout the fields. The upper part of the pressure seal zone in nearly all wells in Figures 4 and 5 is characterized by high resistivity in both the sandstones and shales. High resistivity is generally attributed to the presence of hydrocarbons or extremely low porosity, or both. Below the resistivity maximum, but in the seal zone, there is a sharp decline in resistivity, indicating either increased porosity or more conductive pore fluids, or both. This resistivity signature of the top of overpressure, due to the assumed undercompacted state of the sediments, was first described by Hottman and Johnson (1965) and is used in the Tuscaloosa trend, as well as in most of the Gulf Coast, to anticipate the onset of overpressure (Gill, 1980).

DISCUSSION

The pressure transition zone in the study area is unusual in that it is nearly horizontal, contains sandstones and shales, is thin (28 m in one well), and appears to cross-cut stratigraphic boundaries. This horizontality could reflect the greatest depth at which interconnected, normally pressured sandstones are juxtaposed at faults of the type of situation described by Mann and Mackenzie (1990)—an interpretation that requires a laterally extensive, low-permeability shale that reaches from fault to fault to vertically isolate normal from overpressured sandstones. The lithology at the transition zone is not a thick shale but a zone of interbedded (~3 m thick) sandstone and shale, typically upward-coarsening. Evidence from gamma-ray logs suggests that the only thick shale that might extend from fault to fault, the shale break at 5700 m in block 2 and at 5900 m in block 3, clearly is not the seal in most of the wells (Figure 4). We think that correlation across these distances in deltaic intervals is difficult and perhaps unreliable with log data alone. If the thick shale shown in the Mix well with shading (Figure 4) is continuous to the west as indicated, it clearly does not form the pressure seal in wells to the west. However, if the thick shale at the Mix well is not laterally continuous as indicated, then it must pinch out to the west. In either case, a thick shale does not form the pressure seal in any well but perhaps the Mix well, where the shale coincides with the pressure transition as indicated by the RFT measurements.

Weber's (1982) investigation of shale length (lateral extent) as a function of depositional environment suggests that in the delta front environment laterally continuous shales typically have a length that is smaller than the distance from fault to fault in the Moore-Sams and Morganza fields (2–5 km), suggesting further that a shale bed is an unlikely candidate for a pressure seal in the study area.

A study of sandstone diagenesis from above and below the pressure seal of cores from the Ravens-

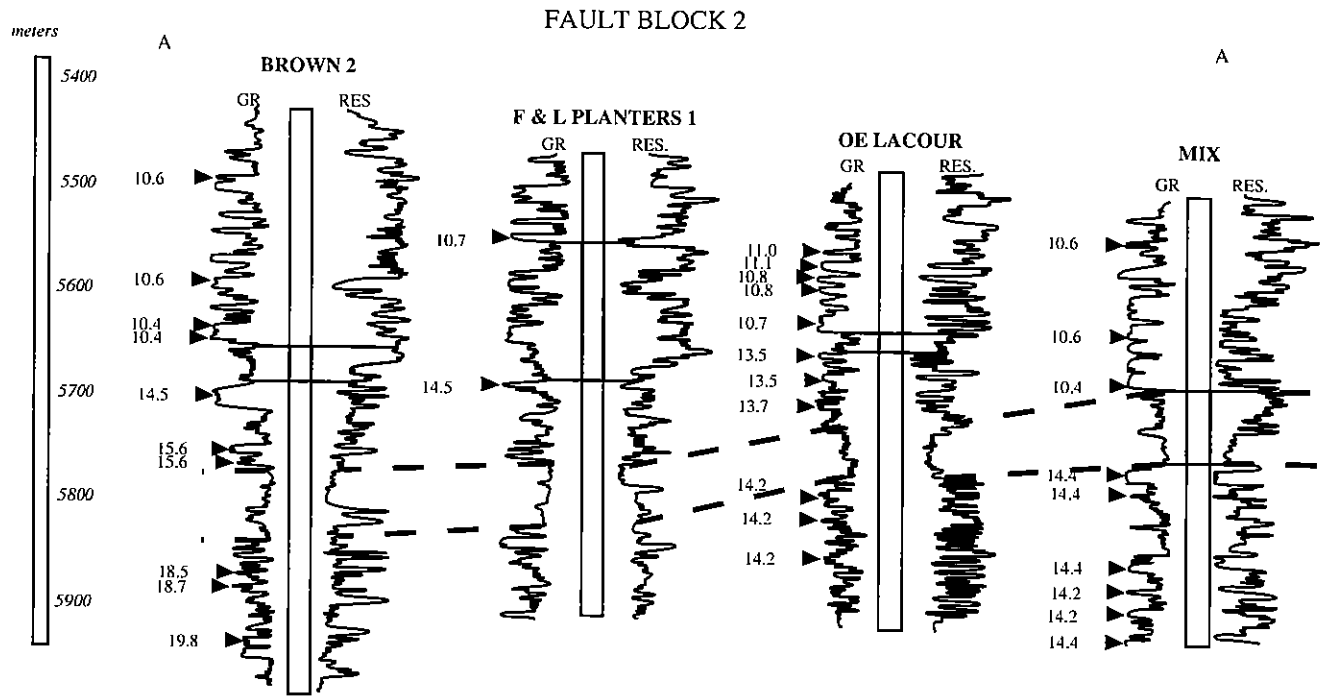

Figure 4. Cross section A–A′ of wells for which normal and abnormal pressures were measured in fault block 2. Line of cross section is shown in Figure 1. Arrows indicate measurement location, numbers are pressure gradients in MPa/km or KPa/m. The logs are gamma ray on the left and resistivity on the right. The logs begin at the top of the lower Tuscaloosa Formation at the Bain Marker bed and extend to the bottom of the well. The depths between the deepest normal pressure measurement and the shallowest overpressure measurement are shaded. A thick shale is correlated (dashed line) and may be the only laterally extensive shale in the two fields.

wood B, Butler, and Fontaine wells demonstrates that the pressure transition zone separates sandstone strata of unusually high secondary porosity of up to 26% (Weedman et al., 1992a). In addition, pressure data show that there is sufficient sandstone connectivity below the seal to maintain a local hydrostatic gradient in the overpressured zone, a characteristic of a pressure compartment (Hunt, 1990; Powley, 1990). The rocks that form the seal and maintain a pressure discontinuity of >20 MPa over a depth range of 28 to 137 m are interbedded thin (~3 m) sandstones and shales. King (1990) has shown by three-dimensional modeling of hypothetical random networks of sandbodies in shale that within an interval where the net to gross ratio (sand/sand + shale) is 0.8, the connected sand fraction approaches 100%. The producing wells of the lower Tuscaloosa Formation have sand/shale ratios of at least 4:1 or a net to gross value of 0.8. This observation suggests to us that while the thin sandstones in the seal zone were probably interconnected with sandstones above and below when deposited, they are now very tight with sufficiently low permeability to act with the shales as a pressure seal that maintains the pressure anomaly.

Compaction parameters of packing density and packing proximity were measured on three sandstone populations in the vicinity of the pressure seal: normally pressured with >18% cement, normally pressured with <10% cement, and overpressured with <10% cement. Packing proximity is the percentage of grain contacts along a traverse that are in grain-to-grain contact; packing density is the percentage of a traverse that is occupied by framework grains and not cements or pore spaces. We have presented evidence elsewhere that the samples with less than 10% cement had lost a previous carbonate cement by dissolution (Weedman et al., 1992a). Results show that the packing of framework grains is similar between normally pressured, cemented sandstones and overpressured, low-cement sandstones, while normally pressured, low-cement sandstones exhibit as much as 20% greater compaction compared to the other two populations (Figure 6). These results suggest to us that the compaction of framework grains resumed after decementation in the normally pressured zone but was inhibited below the pressure seal because of high fluid pressures. Therefore, the pressure seal became effective in isolating porous and interconnected sandstones soon after the dissolution of grain-supporting calcite cement, and a process analogous to shale undercompaction can exist in overpressured sandstones. In addition, small samples of cuttings taken from within the seal zone, where cores are unavailable, show extensive pressure solution and fitted textures that would, if as extensive as suspected, provide permeability barriers within the thin sandstones of the seal zone (Albrecht, 1992; Weedman et al., 1992a). If observed in only one well, the highly compacted textures may be interpreted as fault gouge; however, cuttings were examined from three

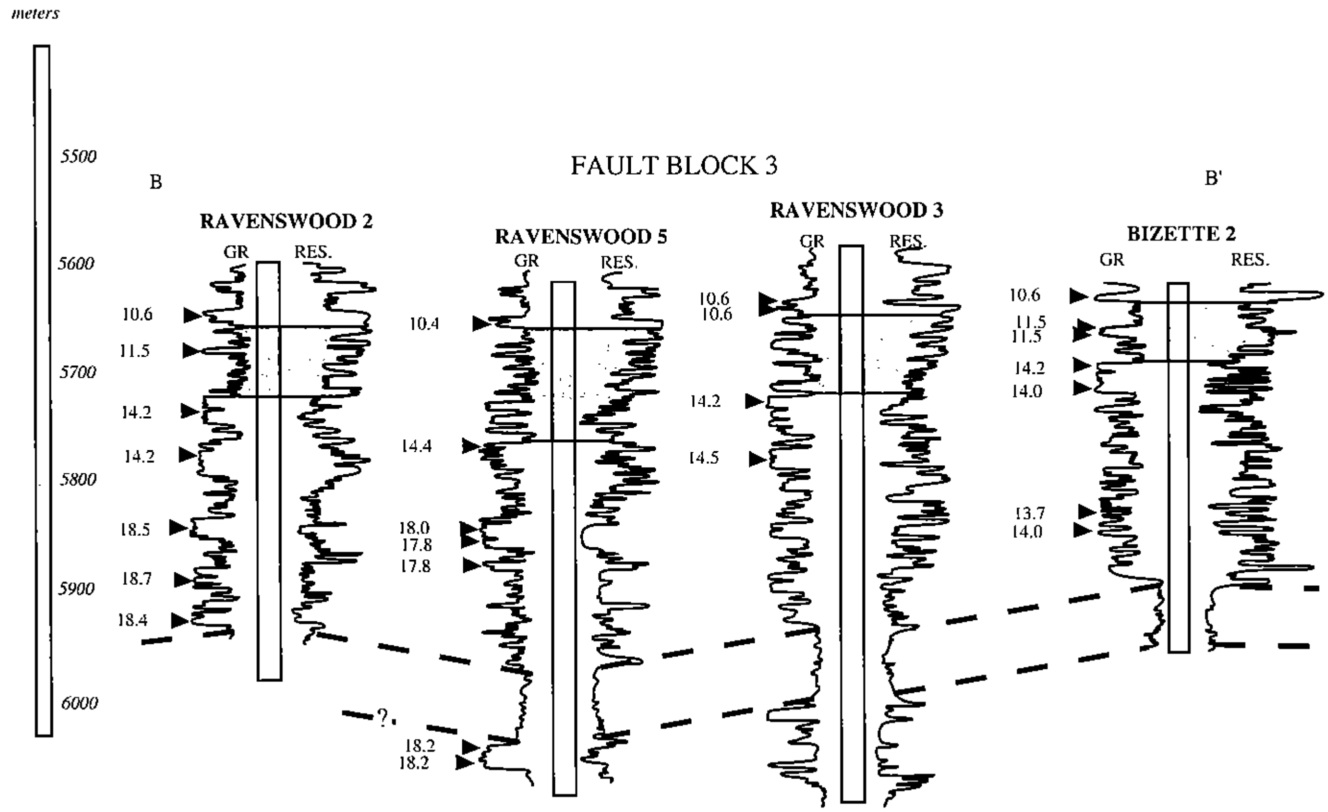

Figure 5. Cross section B–B′ of wells for which normal and abnormal pressures were measured in fault block 3. Line of cross section is shown in Figure 2. Arrows indicate measurement location, numbers are pressure gradients in MPa/km. The logs are gamma ray on the left and resistivity on the right. The logs begin at the top of the lower Tuscaloosa Formation at the Bain Marker bed and extend to the bottom of the well. The depths between the deepest normal pressure measurement and the shallowest overpressure measurement are shaded. The shale that is correlated may be the only laterally extensive shale in the two fields.

widely spaced wells (Brown 2, Ravenswood 5, and V.J. Hurst; see Figure 1) and the pressure solution texture was observed only within the seal zone as defined by RFT pressure data (Albrecht, 1992). If this compaction texture is the consequence of faulting, the fault must be nearly horizontal across the two fields.

In several studies of sandstones from the Gulf Coast Tertiary, calcite cements are thought to have been dissolved in reservoirs at temperatures of 75° to 125°C (Franks and Forester, 1984). Assuming a geothermal gradient of 25°C for the study area, that depth today would be between 2 and 4 km. Superimposing that depth interval on a simple burial history curve for a well in the Moore-Sams field, Figure 7, suggests that the pressure seal within the lower Tuscaloosa Formation could be as old as 30 million years. Bethke (1989) and Harrison and Summa (1991) calculate that the onset of overpressures in Late Cretaceous rocks at the depths and approximate strike location of the study area commenced in about Oligocene time, which is consistent with the above estimate based on petrography.

There may be multiple sources for the overpressured fluids in these fields. Organic-rich shales in the lower Tuscaloosa Formation, thought to be the source rocks for these reservoirs (Sassen, 1990), are deep enough to produce gas (Hunt, 1979). In addition, the shale resistivity declines across the pressure seal zone suggest that the overpressured shales are still undercompacted and could be a source of overpressured fluids to the sandstones. If the pressure seal formed at a kilometer or more shallower depth than it is today, as suggested by compaction differences of sandstones in the vicinity of the seal, some of the overpressure could be attributed to aquathermal pressuring or to trapped pore fluids generated by clay diagenesis at shallower depths.

None of the popular pressure-generation mechanisms can explain the maintenance of such a high pressure discontinuity (>20 MPa) for the amount of time indicated from petrography. We think that, in the absence of a laterally extensive thick shale, a sealing mechanism is required to explain the pressure anomaly and observed grain packing, and propose the process of secondary compaction of high porosity sandstones.

CONCLUSIONS

Repeat formation pressure data across a pressure transition zone in the deep Tuscaloosa trend have been evaluated to document the geometry and lithology of

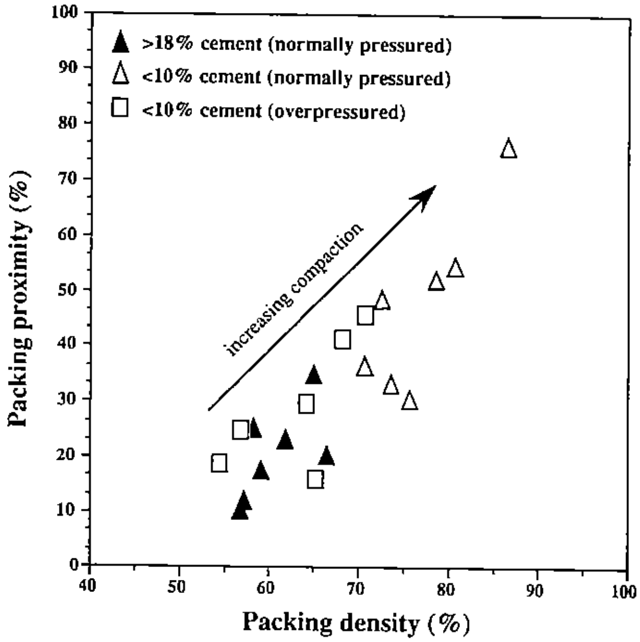

Figure 6. Packing proximity vs. packing density for 20 thin sections cut perpendicular to bedding. The sandstones that have suffered the greatest compaction (Δ) are normally pressured and have <10% cement, due to dissolution of calcite cement. Normally pressured sandstones with >18% cement (▲) are compacted to a degree similar to overpressured sandstones with <10% cement (□). This plot documents secondary compaction after secondary porosity and the inhibition of compaction by overpressured pore fluids below the pressure seal.

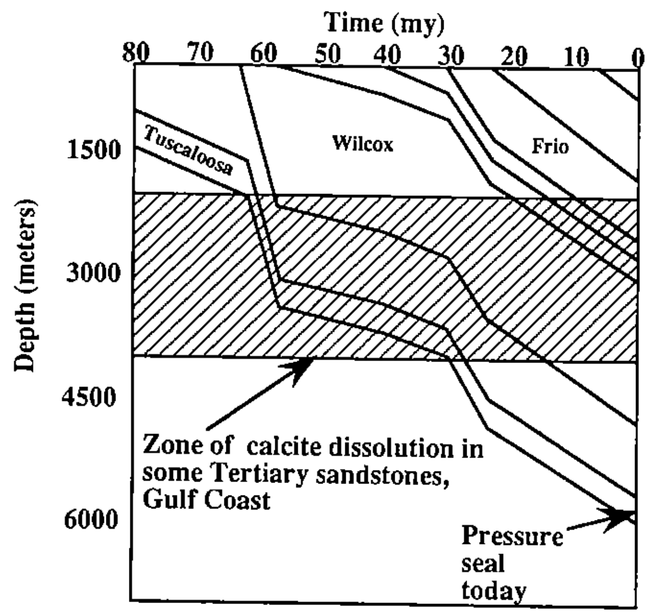

Figure 7. Simple burial history curve for the V.J. Hurst well in the Moore-Sams field from the present day to approximately 80 m.y. ago (compaction has been neglected). Lower Tuscaloosa (Upper Cretaceous), Wilcox (Eocene), and Frio (Oligocene) clastic wedges are identified. The depths at which temperatures range from 75° to 125°C, the temperature range of calcite dissolution in the Tertiary of the Gulf Coast according to data from Franks and Forester (1984), are approximated with diagonal lines; these depths are derived using a geothermal gradient of 25°C/km. The lower Tuscaloosa Formation may have been in this temperature range from approximately 30 to 60 million years ago.

the seal zone. The pressure seal is nearly horizontal and does not follow a laterally continuous lithologic horizon but is characterized by thinly bedded sandstones and shales. While horizontality may be controlled by the juxtaposition of normally pressured sandstones across growth faults, the problem of characterizing a pressure seal remains. The only potentially laterally extensive shale in the formation forms the pressure seal only in one well. Without high resolution pressure data, the pressure seal may have been attributed to that shale; pressure data shown in Figures 4 and 5 demonstrate that it is not.

An alternative interpretation is that the high sandstone secondary porosity has collapsed in places producing zones of extensive pressure solution and extremely low permeability. This compaction has been documented above the seal but can only be inferred from cuttings within the seal zone. Where those collapsed sandstones are interbedded with shales on a fine scale, there may be sufficiently low permeability to maintain a pressure anomaly of >20 MPa. Diagenetic study of core and cuttings from the vicinity of the pressure seal coupled with burial history suggests that the seal may have formed as long as 30 million years ago and subsided to the present depth of ~5.6 km.

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