Capillary Seals as a Cause of Pressure Compartmentation in Sedimentary Basins

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Abstract

A new hypothesis that pressure compartmentation in basins can be caused by capillary seals is presented and discussed. Capillary seals form when a non-wetting fluid phase is generated within or introduced into grain-size layered sediments that are fine-grained enough that gravitational separation of the phases does not occur. Experiments show that such seals can be formed in the laboratory. These seals have many important implications: The changes in basin permeability that allow fluid overpressuring may occur when non-wetting phases are generated in the basin (CO_2 or hydrocarbon). Basin seals can be dynamic; they can move through the sediment column. Porosity profiles reflect such movement. Hydrocarbons and water may follow the trajectory of seal rupture and move along the same migration routes. The flow of both water and hydrocarbons may be directed to areas where the top of overpressure is covered by the least sediments. We have not proven the capillary seal hypothesis, but diverse evidence supports it and it has important implications.

Introduction

Objectives of this Paper

The purpose of this paper is to introduce a new concept of how pressures are compartmented in sedimentary basins by seals. The capillary seal hypothesis we present, despite considerable effort summarized here, remains a hypothesis. Because the idea has broad implications, many of which are directly relevant to the hydrocarbon industry, it seems useful to provide an overview of the concept and its implications. I give a brief history of the pressure compartmentation concept and then describe our capillary seal hypothesis, the steps we have taken to investigate it, and, most importantly, its implications. Three related papers follow this introduction to the concept and provide greater detail in selected areas. The first (Shosa and Cathles, 2001, this volume), demonstrates that capillary seals having the required properties can be produced in the laboratory. The second (Revil and Cathles, 2001, this volume), shows that porosity profiles in the Eugene Island South Addition Block 330 area suggest seal migration (through the sedimentary column), which is allowed if capillarity is responsible for sediment impermeability. The last paper (Erendi and Cathles, 2001, this volume) delimits the degree to which capillary sealing could inhibit oil recovery if gas exsolves during production. It further identifies remedial actions that could be taken.

A Short History of Basin Pressure Compartmentation

In the 1980's J. S. Bradley and D. E. Powley and others at Amoco developed a revolutionary view of fluid pressure in sedimentary basins (Hunt, 1990; Bradley and Powley, 1994). In this view, basin interiors are divided into compartments surrounded by seals. The compartment interiors have hydrostatic pressure gradients, so fluids can freely move within them, but the degree of overpressuring varies between compartments. The onset of overpressure (*i.e.*, the depth at which fluid pressure begins to exceed hydrostatic) is generally at about 3 km depth. The overpressured interiors of basins are overlain, underlain, and bounded laterally by strata having hydrostatic pore pressures. Pressure transition zones (seals) bound interior compartments, separating them from compartments having different levels of overpressure and preventing flow between compartments.

Powley recognized that a deficiency in Amoco's concept of pressure compartmentation was the lack of a fundamental scientific understanding of seals. He asked the Gas Research Institute to verify in the public literature that pressure compartments and seals exist, and to investigate the causes of this pressure compartmentation (Powley, 1987).

By the mid-nineties GRI and other investigators had documented pressure compartmentation, and a general consensus had developed that the migration and trapping of hydrocarbons in sedimentary basins was strongly influenced by thin (few hundred meters thick) vertical or horizontal, planar barriers called seals. Recent publications reflect this consensus (Bradley, 1975; Hunt, 1990; Powley, 1990; Bradley and Powley, 1994; Ortoleva, 1994; Surdam, 1997; Law, Ulmishak *et al.*, 1998; Mitchell and Graules, 1999). The current view of basin overpressuring is similar to Amoco's original synthesis, but there is a greater appreciation of the complexity of the compartmentation, and it is now recognized that the top of overpressure can be highly irregular. Typically, pore fluids in the upper few kilometers of basins are at hydrostatic pressures and fluid pressures increases at about 0.1 MPa/km. At a few kilometers depth the pressure typically increases sharply over a few 100 meters by ~2900 psi (20 MPa, 200 bars) to near lithostatic levels (*i.e.*, levels sufficient to nearly lift the overlying sediments and water and therefore near the maximum possible). Below this pressure transition zone, basin sediments are divided into pressure compartments. The pressure is not always hydrostatic within compartments. In some, pressure gradients follow lithostatic pressure, as if the sediments uniformly have very low permeability or are divided into so many small compartments that the hydrostatic pressure intervals are not apparent. The degree of overpressuring is different between compartments, the overpressured compartments exhibiting a wide range of spatial scales. Relatively thin impermeable "seals" separate the variously overpressured compartments. Compartments are nested within compartments in possibly fractal fashion.

The Anadarko basin provides perhaps the best single example of pressure compartmentation. The overpressured zone in the Anadarko has been described (Al-Shaieb, 1994; Al-Shaieb *et al.*, 1994a) as a megacompartment complex, a term which elegantly emphasizes the complex honeycomb structure of the overpressuring.

The Problematic Nature of Lithologic Seals

The nature of the seals that separate pressure compartments is still unclear. The previous view that fluid overpressures develop by burying very impermeable sediments (Gibson, 1958; Bredehoeft and Hanshaw, 1968; Hanshaw and Bredehoeft, 1968; Bethke, 1986) can be modified slightly to accommodate pressure compartmentation. Lithologic strata such as condensed shales could have permeabilities low enough that the sediments below them become overpressured as they are buried. Several problems remain, however. The natures of seals that form the sides of pressure compartments are not explained by this view. Neither is it clear that very low permeability sediments are common enough in basins to account for all the required seals. Also, it is not immediately apparent how well the impermeability of lithologic seals can withstand fracturing and faulting. Finally, compartment tops and bottoms do not always follow lithology.

Consider first the permeability issue. It is generally agreed that to reach overpressure basins must have bulk permeabilities less than ~$10^{-21}m^2$ (Deming, 1994). Relying on a small fraction of basin sediments to seal the basin means, of course, that these sediments must have even lower permeability. Neuzil (1994) has compiled permeability data from laboratory measurements that show that it is unusual for unfractured sediments to have permeabilities as low as $10^{-21}m^2$. Although the samples measured could have lower permeabilities *in situ*, and lithologic sealing certainly cannot be ruled out, it is nevertheless disconcerting, given the widespread occurrence of overpressuring in basins, that sediment permeabilities in the required range are not more easily demonstrated in the laboratory. (See also Revil and Cathles, 1998)

It is also problematic for a simple lithologic view of sealing that some seals clearly crosscut lithology. In the offshore Louisiana portion of the Gulf of Mexico, for example, the top of overpressure shallows from ~18,000 ft near the coast to ~2000 ft or less off the shelf edge, while strata generally dip the opposite direction. In addition the top of overpressure there is a highly irregular surface. Changes in depth of 9000 ft over 15 km are not unusual. Seals thus clearly cut stratigraphy and lithology cannot be the whole explanation for the overpressure topography. Faults seem to form side seals and account for some of it, but the criteria for faults acting as seals are not clear. Some faults are seals and others are not while some side seals do not appear to be related to faults.

Many explanations have been offered for reduced sediment permeability. It might be reduced by compaction (Hunt, 1990), inorganic cementation (Tigert and Al-Shaieb, 1990; Al-Shaieb *et al.*, 1994a, b; Quin and Ortoleva, 1994), the precipitation of solid hydrocarbon residues (Whelan *et al.*, 1994b), or by the introduction of a non-wetting fluid phase (Benzing and Shook, 1996). Iverson *et al.* (1994) suggested capillary phenomena could be important in trapping gas in the overpressured parts of the Alberta Basin. Threshold or entry pressure had been recognized as important in trapping oil and gas since at least the late 1970’s (*e.g.*, Schowalter, 1979).

None of these proposals is fully satisfactory as a general explanation of pressure compartmentation. Inorganic sedimentation requires the expulsion of unreasonably large volumes of pore fluid. Organic pore plugging is not observed and could be of only marginal effectiveness unless very viscous components such as asphaltines are involved. It is unlikely these could be precipitated extensively enough and in sufficient quantity to allow compartmentation of an entire basin. Relative permeability effects could at most reduce the permeability of shales to both hydrocarbon and aqueous phases by a factor of 4, which is insufficient. Although capillary seals of the type described by Schowalter (1979) and Iverson *et al.* (1994) work well as a hydrocarbon trapping mechanism, they cannot work on all sides of an overpressured compartment. Oil or gas can be trapped beneath water-saturated shale if the oil and gas entry pressures are not exceeded, but water below the oil-water contact is free to move through the seal where the two come into contact. Hydrocarbon entry pressure, as traditionally envisioned, thus cannot form an overpressured compartment in which both hydrocarbons and water are overpressured. Even if one of the above mechanisms could be effective, maintenance of the very low required permeabilities over 1000’s of km^2 in basin sediments that are undergoing active deformation and faulting remains a major concern.

Capillary Seals

Capillary seals have not been seen as a means of rendering large volumes of sediment impermeable, because, on the relatively large scale at which hydrocarbons are trapped, the scale most familiar to petroleum geologists, water and hydrocarbon phases gravitationally segregate and the two fluid phases required to produce flow barriers are present only where hydrocarbons are trapped. On a finer scale, the gravitational segregation might be much less effective, however. If two phases occupied the pores of finely layered fine-grained sediment, gravitational segregation could be very slow. A layer of gas in fine sediments abutting a finer layer might not gravitationally segregate at all. Each gas bubble might lodge sufficiently against overlying grains as to be immobile. If the non-wetting phase blocked each pore of the finer layer, the flow of both phases would be blocked so long as the capillary entry pressure of the non-wetting phase was not exceeded. The flow inhibition could be additive over multiple fine layers in a fine-grained section, and volumetrically minor amounts of hydrocarbon would be needed if the hydrocarbons were strategically allocated. The capillary barriers would superficially appear to be lithologic barriers because they would tend to form in fine-grained units, but they would have properties that are different and important.

Capillary Seals in the Laboratory

We investigated the formation of capillary seals in the laboratory. The experiments are described in detail in an accompanying paper (Shosa and Cathles, 2001, this volume). The experiments were carried out in a ~50 cm long, 1.27 cm inner diameter stainless steel tube packed with 45 micron quartz containing 2 to 8, 1 cm thick layers of 2 micron quartz. Flow blockage arose when the gas saturation of the coarser sediments reached about 50%. The flow blockage survived the forced throughput of at least 12 pore volumes of two-phase fluid. When re-pressurized, blockage disappeared, and the flow was again single phase Darcy flow.

Analysis of the experiments shows that 1 cm thick layers of fine (2 micron grains) quartz particles enclosed in coarser grains have permeabilities of ~7.4 millidarcies when only water is present. However, the effective layer permeabilities drop to less than 1.2 nanodarcies (a decrease of $>10^7$) when gas is introduced. Temperature dependence of the flow blockage, and the fact it can be described by the well-known Laplace capillary formula (which relates capillary entry pressure to grain size and interfacial tension but not to permeability) indicates capillary blockage.

Capillary barriers can survive a good deal of fluid throughput because the strong capillary suction of the fine layers for the wetting phase expels the gas phase and pinches off any gas channels through the fine layers as soon as the pressure drop across the layer is reduced below that required to drive flow across the layer. We argue in Shosa and Cathles (2001, this volume) that the leakage of the water phase is zero, and that the capillary barriers allow no flow of either phase until the threshold pressure is exceeded. In any case, the equivalent permeability of the 2μm layers (<1.4 nanodarcies) is very close to that required to produce the sealing observed in sedimentary basins. The fact that each capillary barrier at each fine layer is independent of the others so that the blockage at each layer is additive means that basin seals restraining 100's of bars of overpressure could be constructed of hundreds of fine sediment layers, each with a few bar capillary pressure drop, as in our experiments.

Our experiments, unfortunately, did not directly address the gravitational segregation of phases. The tube was vertical, with flow from bottom to top. However, an experience we had preparing the experiments does address this issue to some degree. To test the plumbing at the start of our experimentation, we decided to measure flow through a tube filled entirely with 45 μm quartz grains. The tube was loaded by pouring small quantities of 45 μm grains into the tube, tamping the sediment with a dowel, and poring in another small amount. We found, to our surprise, that even with a 600 psi pressure drop across the tube, we could induce no flow of water though it. At first we thought the plumbing was clogged, but disconnecting the entire downstream plumbing system (so the tube was open to the atmosphere) did not cure the blockage. We believe that the flow blockage was capillary in nature, with the barriers arising where the grains were more closely packed. To avoid this problem we adopted the procedure described in (Shosa and Cathles, 2001, this volume) of loading the tube, introducing CO_2, evacuating it again, and finally filling it with water. With this procedure we had no blockage of single-phase flow, and could control the capillary blockage by controlling total pressure. This experience suggests capillary flow barriers can be produced very easily in sediments. Since the tube in this case was horizontal, gravity segregation was clearly not rapid on laboratory timescales in sediments composed of 45 μm particles.

Capillary Compartmentation in Basins

Basin fill almost always consists of interlayered fine- and coarse-grained sediments, and basins frequently generate non-aqueous gases and fluids. Our experiments suggest that capillary seals and pressure compartmentation in basins should be common. They show that the seals that divide the interior of basins into pressure compartments could be capillary seals. Whether, and under what circumstances they are remains to be demonstrated.

Capillary seals would have several important properties. If capillary seals were responsible for pressure compartmentation, basins would be effectively self-sealing. The decompression of gas-saturated waters would lead to the exsolution of gas, which would produce capillary barriers to the flow (a leaky seal). The seal thickness would increase, adding capillary barriers, until flow stopped. Gas-charged waters would be directed to areas where seals had not yet formed or were in need of repair. Basins would thus be self-sealing. Capillary seals would also be durable. Under natural conditions grain-size contrasts and presence of two fluid phases would be difficult to change. Hence, the seals, if ruptured by faulting or fracturing, should re-heal as soon as the tectonic disturbance ends. This has led to the use of capillary barriers in hazardous waste containment strategies (*e.g.*, references in Oldenberg and Pruess, 1993).

There is another consequence of our hypothetical capillary sealing that is of conceptual significance. Hydrocarbons typically mature at sufficient depth that the gas and oil products of maturation form a supercritical mixture. At some point, as this supercritical mixture migrates upward toward the surface, and pressure and temperature are reduced, the supercritical gas-oil mixture undergoes a phase separation which produces distinct gas and oil phases. In the Gulf of Mexico, this phase separation seems to be broadly coincident with the transition from hydrostatic to near lithostatic pressures at the so-called top of overpressure or TOOP (Meulbroek, 1997). Most of the oil in sedimentary basins is trapped near or in this transition zone (Leach, 1993). Gas/water interfacial tension is about twice oil/water or supercritical gas-oil/water. Thus, the capillary pressure barrier at each fine-coarse interface would be about twice as strong where gas is present as a free phase compared to locations where only oil or supercritical gas-oil is present. The depths where gas separates from supercritical gas-oil is where the capillary barriers are toughest, all other factors equal. The deeper interior, where gas and oil have not phase-separated, would be more weakly pressure compartmented if capillary effects were the cause of compartmentation. The result can be thought of as an orange. The overpressured interior is weakly compartmented like the interior of an orange. The top of overpressure, where the hydrocarbon phase breaks down to separate gas and oil phases is more resistive to rupture and represents the rind of the orange.

Implications of Capillary Sealing

The capillary seal hypothesis has many implications.

1. Since it ties basin permeability to the generation and migration of hydrocarbons, basin permeability becomes time-dependent. Top seals, in particular, can migrate upwards through the sediment column with time at variable rates, and will affect the porosity profile in predictable and interpretable ways. The generation of hydrocarbons could fundamentally alter and greatly reduce the permeability of a basin.
2. Grain size contrasts are more important than either grain size itself or intrinsic permeability in controlling flow in the overpressured parts of basins.
3. Since the top of overpressure, where hydrocarbon phases separate, hosts the toughest seals (the orange rind), flow from the interior of a basin will tend to be directed to topographic highs in the top of overpressure. The lithostatic stress is least at highs covered by thinner layers of sediment. As fluid pressures build, these will be the first locations to rupture (hydrofracture). Reduction of pressure under topographic-highs will ultimately trigger a cascade of ruptures in the weaker seals separating underlying and adjacent pressure compartments. The result is that hydrocarbons and water will move toward, and leak from, topographic highs in the top of overpressure.
4. Fluid flow in a pressure-compartmented basin will follow an idiosyncratic rule set regardless of the cause of compartmentation. Flow of all phases will occur from one compartment to another when and where the seal of a compartment leaks. The proportions of phases moving between compartments may of course be different than their proportion in the compartment, but all fluid phases will move along the same rupture path. This common flow will, in general, not coincide with either the pressure-directed flow predicted by Darcy's law, or the largely vertical buoyancy-driven flow of hydrocarbons (diverted by capillary barriers) envisioned by many petroleum geologists.
5. Although, the amount of gas or liquid hydrocarbon required to form a capillary seal could be quite small, since only the areas immediately adjacent to fine-coarse interfaces need contain a non-aqueous phase, the effect of even a small amount of gas on sonic velocity and of gas and oil on the thermal conductivity of a sediment is dramatic. For a constant heat flow, the thermal gradient could easily be doubled where sediments contain pore gas (Somerton, 1992). Thus, if the top of overpressure seal is a hydrocarbon capillary seal, the thermal gradient should increase dramatically there,

and the sonic velocity should drop. The thermal gradient often doubles at the top of overpressure in the Gulf of Mexico (Jones, 1975), and a drop in sonic velocity greater than can be accounted for by the change in porosity at the top of overpressure (Jaio and Surdam, 1997; Surdam *et al.*, 1997) has been used for many years as one means to predict the top of overpressure ahead of the drill bit.

6. The thermal history of a basin could be affected by hydrocarbon generation and migration if capillary sealing traps gas within the sediments in a distributed fashion and thermal conductivity is affected.
7. Seals should be inorganically altered where they leak because the chemistry of pore waters, buffered by sediment minerals, will change as fluid pressure and temperature drop across the seal. This is the opposite of the usual interpretation of seal alteration. Alteration does not indicate seals are well constructed and intact, it reflects and measures seal leakage.
8. The cumulative pattern of basin dewatering can be constrained if top seal alteration can be mapped. Alteration should directly measure the cumulative pore fluid mass flux through a seal.
9. The invulnerability of capillary seals to permanent rupture could allow gas to be trapped in basins for very long times, perhaps explaining the phenomena of basin-center gas.

Testing the Capillary Seal Hypothesis

The implications listed above allow the capillary seal hypothesis to be tested, and could certainly be important to hydrocarbon exploration if the hypothesis is both valid and significant in real basins. With support from the Gas Research Institute we have undertaken to test as many of the implications as possible.

The Top of Overpressure

The “orange” model described above proposes that the top of overpressure is broadly coincident with the depth at which super-critical gas-oil segregates into distinct gas and oil phases. To explore this possibility we carried out flash calculations as a function of maturity for type 2 kerogen (Cathles, 1996; Meulbroek, 1997). The composition of the hydrocarbon fluid was predicted as a function of maturity using the LLNL maturation model for type 2 kerogens. A Redlich-Kwong-Soave equation of state was used to determine the fugacity of each of 33 components in a hydrocarbon fluid. A Prausnitz fluid phase equilibria model was then used to determine the bubble point depth as a function of maturity. Our calculations show that, at the depth at which supercritical gas-oil exsolves, a distinct vapor phase increases from 1 to 2 km depth with increasing source maturity. This is much less than the 0 to 6 km increase in top of overpressure observed in the offshore Louisiana Gulf of Mexico.

The accuracy of our estimate depends on the accuracy and adequacy of the LLNL model. The LLNL maturation model certainly has deficiencies, especially for calculating phase properties. Its 33 chemical components, although a large number of variables for maturation modeling, is small compared to the thousands of components in natural oil. Its failure to simulate wet gas cracking certainly reduces the calculated bubble point depth range to some degree. The LLNL model is, however, well tested against hydrous pyrolysis and other laboratory experiments. We believe, but cannot prove, that the bubble point calculations based on it are broadly reliable. If the bubble point depths we calculate are broadly realistic, the existence of gas caps associated with low to moderate maturity oils at depths below 2 km in the Gulf of Mexico implies that the oils must have been altered in some way. The simplest explanation is that these gas caps reflect the introduction of a dry gas produced deeper in the basin, rather than phase fractionation. Keith Thompson (private communication to Peter Meulbroek, 1996) previously arrived at this same conclusion by the same logic.

There is strong evidence for the late introduction of dry gas. The gas in Eugene Island Block 330 is more mature than the oils (equivalent vitrinite maturity of 1.5% compared to 0.8% for the oils; Whelan *et al.*, 1994a). Furthermore, the departure of Eugene Island Block 330 oils from their unaltered (Kissin) compositions suggests that these oils have been chemically altered (“washed”) by interaction with dry gas. Equation of state simulations of this washing show that both the depth of washing and the number of moles of dry gas that has washed each mole of oil can be determined from the break number at which the n-alkane oil composition departs from the unaltered Kissin trend and the extent of this departure. It can also be inferred from changes in aromaticity (or paraffinicity) of the oil. (Meulbroek, 1998). We find that 12 to 15 moles of dry gas must have interacted with and washed the Eugene Island oils at close to the present depth of the deepest sand in the area to explain their alteration.

The situation is similar at Texaco's offshore Tiger Shoals Field near the Louisiana coast, where over 90% of the n-alkanes in the oil have been carried off by gas. The washing again occurred at a depth similar to that of the deepest sand in the area. At South Marsh Island Block 9, about 50% of the n-alkanes have been removed. Near the shelf (at Jolliet, for example), no gas washing is evident. From what we can tell from 219 oil analyses in a 120 x 130 km transect in the South Marsh, Eugene, and Ship Shoal blocks in offshore Louisiana, the pattern of washing is remarkably coherent spatially (Losh, Cathles *et al.*, 2001).

The picture that emerges on the Louisiana shelf is one of ongoing gas (and oil) leakage. The leakage generally occurs at the margins of salt withdrawal mini-basins, as in the Eugene Island Block 330 area (Alexander and Flemings, 1995). Broadly, oil and gas production appear often to be near topographic highs in the top of overpressure. However, the overpressure highs are not controlled by hydrocarbon chemistry. Conceivably, this could have been the case initially, but persistent gas venting has since changed the gas-oil ratio to the opposite of that predicted. The vents are areas of excess gas where phase separation could occur at greater depths. The hydrocarbon leak zones and protuberances in the top of overpressure appear therefore to be related to differential salt movement, not hydrocarbon chemistry. The introduction of gas in these persistent vents may change the permeability of sediments but this is not the factor that controls the location of the vents. If the orange model is valid, it must be changed to a spiked orange model, where the orange rind has spikes with weak, rupture-prone central cores located where the orange has persistently leaked.

Seal Migration and its Effect on Porosity

If sediment impermeability results from capillary sealing when a non-aqueous phase is introduced (rather than just resulting from the intrinsic impermeability of the sediments), the stratigraphic position of the top of overpressure can change as sedimentation proceeds. Changes in pore fluid overpressure directly affect compaction. It follows that we can look to porosity profiles to test whether seals have migrated.

We have done this in the Eugene Island South Addition Block 330 area. Our investigation of the porosity profiles in 89 wells (40 in detail) is reported in Revil and Cathles (2001). By comparing mud weights and fluid overpressure predicted from porosity, we show that in this area, the departure of shale porosity from the trend expected under hydrostatic conditions is caused by pore pressure in excess of hydrostatic. The departure of shale porosity from the hydrostatic compaction trend is thus a useful definition of the top of overpressure. This porosity-determined top of overpressure is largely coincident with the 1.27 Ma *Helicosphaera sellii* condensed shale, but in one area the top of overpressure cuts across 2 sands to rise over 500 m above this stratum.

Porosity profiles vary coherently over the area studied. There are regions where the porosity increases sharply at the top of overpressure, and then declines parallel to the hydrostatic compaction trend (which we call the "fixed" seal profile), regions where porosity is constant over a substantial depth interval below the top of overpressure (which we call a "migrating" seal profile), regions where one type of profile overlies the other, and profiles that are intermediate between "fixed" and "migrating". We interpret these profiles using a set of end-member analytical models. The "fixed" seal profiles could result if a stratum such as the *H. sellii* shale became impermeable at about 550 m depth. The "migrating" seal profiles could be produced if hydrocarbons leaked steadily, introducing capillary sealant at about the rate of sedimentation, so that the depth of the top of overpressure remained at a constant depth below the surface, and the porosity captured in compartments was constant.

Changes in venting rates are inferred from the seal profiles. Where venting waned, migrating seals are buried. Seals migrating upward faster than the sedimentation rate indicate rapid venting. We discuss one example where a fixed seal formed at 550 m in the *H. sellii* stratum about 1 Ma before present, began leaking at ~0.7 Ma when *H. sellii* was at 1430 m depth, and continued leaking to present, producing a constant porosity ("migrating" seal compartment) between 1430 m and 2020 m depth, the present depth of the *H. sellii* shale. Seal profiles of the "fixed" (where porosity increases and then declines parallel to the hydrostatic compaction trend) and "migrating" type (where porosity is constant over a depth interval) have been known for decades (*e.g.*, Jones, 1978), but have never to our knowledge been interpreted in the detailed fashion described here.

Alternative interpretations are of course possible. Two points are important: First, porosity profiles at Eugene Island have the form expected if sediment impermeability is dynamic. Secondly, a great deal of useful information on hydrocarbon venting could be obtained from porosity profiles in shale if in fact the introduction of hydrocarbons causes the sediments to become impermeable.

Inorganic Alteration of Seals

Basin pore fluids are in chemical equilibrium with minerals they contact in the sediment. Independent variables are pressure, temperature, and salinity (*e.g.*, Hanor, 1994). If a seal leaks, the pore fluids will experience changing temperature and pressure as they move across the seal. Attendant changes in the fluid chemistry drive chemical and mineralogical alteration of the sediments. The intensity of this alteration should be directly related to the amount of fluid leakage. Hence, mapping inorganic alteration along the top of overpressure should provide a map of fluid leakage.

We have developed methods for calculating the alteration that leakage could produce in a seal (Shosa, 2000). We find the intensity of alteration is related to the salinity of the fluid vented. One weight percent alteration will result if brines of 1 molal salinity vent uniformly across a 5 m portion of a seal with a pressure gradient of 500 bars/km and a temperature gradient of 50°C/km. For focused leakage, the intensity of alteration could thus be quite large. The proportions of alteration minerals change with the fraction of gas vented with the brine, and with the steepness of the pressure gradient across the seal.

Again there are many potential complications not the least of which is the stoichiometry of the mineral buffer. To predict or interpret mineral change properly, the stoichiometry of the mineral buffer at a particular site would need to be determined. Moreover, to be useful, the intensity of alteration would need to be related to seismic signatures. It would be infeasible to map mineralogic changes over broad areas in any other fashion. This might be difficult to do, but the reasonable prospect of seismically mapping a direct measure of fluid movements in a basin might warrant the initiation of a serous development effort. The cause of sealing need not be capillary blockage for this approach to be valid. Inorganic alteration should quantitatively reflect fluid throughput in almost any other kind of seal provided the pressure and temperature gradients across the seal remain intact as it leaks.

Models of Capillary Seals

We have tried to simulate capillary seals numerically using standard two phase flow equations (Erendi, 2000). We can duplicate the classic Buckley-Leverett two phase test case, and simulate the expulsion of gas (and imbibition of water) from a fine layer where the gas saturation in the fine and adjacent coarse layers was initially the same (0.5 in our calculations). However, the calculations become unstable when we try to simulate two-phase flow across such a fine layer (*e.g.*, when we try to simulate Shosa's experiments). Others have experienced similar difficulties (Langtangen *et. al.*, 1992; Chang and Yortsos, 1992). To date, we have been unable to obtain useful results, despite considerable effort, but we are continuing to pursue a modeling solution using a variety of techniques. Currently, gas lattice dynamic approaches show the most promise.

We have investigated the impact capillary barriers might have on oil production if gas exsolves from oil during production. Interfacial tensions between oil and gas could turn grain size contrasts in a sand reservoir into flow barriers, and this would inhibit production. The concluding equations derived in Shosa and Cathles (2001, this volume) are used to address the magnitude of this effect in Erendi and Cathles (2001, this volume). In these papers we show that, contrary to intuition, the greatest production inhibition will occur in the most productive wells (because more capillary barriers are encountered by the wider draw-down cone).

An interesting aspect of this kind of production inhibition is that it can be reclaimed by waiting for pressure to recover (whereupon gas will redissolve and the barriers will disappear) or by introducing surfactants to reduce the oil-gas interfacial tension that creates the barriers to flow.

Conclusions

Capillary seals can form in layered coarse- and fine-grained sediments when more than one fluid phase is present. These capillary seals may be a cause of overpressuring and pressure compartmentation in basins. Capillary effects are considered to produce the very low permeability (sub-nanodarcy) self-healing, ubiquitous (at each fine layer) barriers needed to make basin seals. Capillary sealing can account for both pressure compartmentation below the top of overpressure and the top of overpressure itself.

We articulate four major groups of corollaries that have commercial implications:

1. The capillary seal hypothesis links major permeability changes in a basin to hydrocarbon generation.
2. With capillary (or non-capillary) compartmentation, the flow paths of water, oil and gas in the overpressured interiors of basins will follow a common rupture trajectory. Hydrocarbons and water will move together from one pressure compartment to another when and where the bounding seals rupture.
3. The interfacial tension of gas-water is about twice that of oil-water or supercritical gas/oil-water. The toughest capillary barriers will form where hydrocarbons first become sub-critical and gas and oil separate as distinct phases from supercritical gas-oil. Because of this relatively tough outer capillary skin, the flow of all phases should be preferentially directed toward topographic highs in the top of overpressure surface where hydrofracturing will occur first as overpressures increase.
4. Capillary seals are dynamic. They can turn on and off when hydrocarbon phases are introduced or removed. Seals can shift positions relative to stratigraphy. They need not remain attached to a particular stratum or fault. The history of fluid venting is recorded in porosity-depth profiles in shales and in the inorganic alteration of the seals.

We have not been successful in proving that capillary seals exists in the offshore Louisiana Gulf of Mexico basin. Certain evidence (temperature and sonic gradients near the top of overpressure and porosity profiles) are encouraging, suggesting seal migration and the re-healing nature of capillary seals. The implications of capillary sealing are intriguing and potentially important and we hope this encourages others to try to prove or disprove the ideas presented.

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