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# Optimized Salinity Delivers Improved Drilling Performance

**Juan Carlos Rojas, BP; David E. Clark, Baker Hughes Drilling Fluids; Bob Greene, Baker Hughes Drilling Fluids; Jianguo Zhang, Baker Atlas and Baker Hughes Drilling Fluids**

## Abstract

Non-aqueous drilling fluids are often chosen to drill troublesome shale formations since they will normally minimize wellbore instability problems. As the non-aqueous drilling fluid contacts the shale formations, the amount of change caused by the drilling process and resulting problems are increased or decreased by fluid capillary pressure, osmosis, ionic diffusion, hydraulic transport, and resulting hydration or dehydration pressure changes. Additionally, fluid penetration in fractured shale and weak bedding planes can accelerate problems with shale instability, as hydraulic support of the wellbore is lost and large blocks of fractured shale fall into the hole.

Gulf of Mexico experience has indicated that when drilling in highly faulted areas, oil and synthetic based fluids often do not prevent wellbore destabilization. This is evidenced by hole collapse, and the resulting difficulty with hole cleaning, tripping, logging and running casing.

It is known that the chemical, physical, and mechanical effects resulting from the interaction between the drilling fluid and the formation may degrade the stability of the borehole in the already weakened and stressed-fault interval. Commonly, the practice has been to increase the drilling fluid salt content to enhance the bore hole stability. The perception that low drilling fluid water activity is beneficial to wellbore strength needs to be revised.

A detailed laboratory and field investigation have demonstrated that the water activity of shale in the Gulf of Mexico is often much higher than perceived. This study and field investigation have shown that when drilling faulted or fractured shale the correct, not higher salt content in drilling fluids will reduce wellbore collapse problems and improve drilling performance. Field and laboratory data are presented to support the concept of raising activity to enhance borehole stability.

## Introduction

Wellbore instability in shales has plagued the oil and gas industry for many years [1-3]. This problem is caused by the stress concentration around the wellbore and the movement of water and ion into or out of shale formation as interaction with drilling fluid occurs. The stress distribution [4], petro-physical (permeability, saturation, porosity), chemical (membrane efficiency, water activity), and mechanical (strength, stiffness, Poisson's ratio) [5, 6] properties of the near wellbore formation maybe altered by this movement.

It is well-established that swelling and pore pressure increase, while strength and stiffness of the near wellbore formation decrease with the influx of water, which may cause wellbore instability problems [5, 6, 7, 8]. Additionally, fluid penetration in fractured shale and weak bedding planes can accelerate these problems, as hydraulic support of the wellbore is lost and large blocks of fractured shale fall into the hole [9].

On the other hand, it is generally accepted that the dehydration of shale is beneficial in terms of wellbore stability because this back flow reduces the near wellbore pore pressure and thereby "strengthens" the shale [1, 2, 10]. Although this dehydration is beneficial to improve wellbore stability when drilling soft, high water content Gumbo shale [1, 17], it is believed to be detrimental to wellbore stability in naturally fractured formation. The over-dehydration may cause the shale to shrink and increase tensile failure, especially in hard, naturally fractured shale formations [11]. This effect has been documented in many areas of the world and wellbore destabilization has been observed in several wells at Gulf of Mexico (GoM).

The drilling fluid design with respect to salinity is an important part of a "Stressed Shale Drilling Strategy". This paper will first present the field cases in Colombia and GoM which demonstrate that the decreased salinity, as part of the stressed shale drilling strategy, improved drilling operations. Then the results from shale core studies will be used to further justify these field observations.

## Colombia Field Experiences

The effect of oil-based mud (OBM) salinity has been very evident when drilling the highly stressed shale in Colombia. When drilling in the foothills of the Andes Mountains in the mid 1990's, numerous hole problems were encountered while drilling with oil-based muds through the highly stressed formations. Wellbore collapse was a common occurrence. Initially, attempts were made to improve well stability by increasing the $CaCl_2$ content of the internal phase from 25% to 35%. It was immediately noticed that the problems became even worse. Because the formations in Colombia were originally deposited in a freshwater environment, a decision was made to decrease the salinity of the OBM. Initially salinity was decreased to 15% $CaCl_2$ and an improvement in drilling conditions was observed. Wells were then drilled with 8% and to as low as 6% $CaCl_2$. The 6% was believed to be the optimum salt concentration. Future wells were drilled using 8% $CaCl_2$ as part of the stressed shale drilling strategy, with excellent success and minimal hole collapse. This approach remains in effect today.

## Gulf of Mexico Field Experiences

### *Deep Water*

Wellbore instability had plagued deep water operations in Mississippi Canyon. It was a major source of non productive time (NPT). The shale formations tend to become unstable, even when drilling with synthetic-based fluids. The resulting wellbore instability combined with the challenges of drilling in deep water has resulted in reduced drilling times, increased hole cleaning problems and excessive circulation times, hole pack-off, stuck BHA incidents and consequential sidetracks.

Well A is typical of drilling operations that began to have wellbore instability problems. It was drilled in 1,030 feet of water to a total depth of 18,370 feet (**Figure 1**). The original plan was to drill the well averaging 22.8 days per 10K feet, using a synthetic based drilling fluid with a 72/25 to 80/20 synthetic-brine ratio (SBR), and 25% $CaCl_2$ internal phase. As the well reached TD, wellbore instability problems resulted in the need to side track. Prior to the instability problems the well was drilled close to plan, with minimal drilling fluid losses. As instability occurred and the side track was drilled, in excess of 2,500 bbls of synthetic-based fluid was lost to the formations and drilling time was increased from the target of 23 days to 70 days / 10K feet. The wellbore instability problems resulted in an increased drilling fluid cost which was 75 percent above the target cost.

Well B was also drilled in Mississippi Canyon to a total depth of 18,610 feet in 6,828 feet of water using a synthetic based fluid with an average 76/24 SBR (**Figure 2**). The average $CaCl_2$ content was reduced and maintained in a range of 18 - 19.3% wt. Although there were some tight spots observed and a logging tool was stuck and recovered, no severe wellbore instability problems occurred. The well was drilled close the planned 28 days / 10K feet, at 29.9 days / 10K feet. The drilling fluid costs were 27 % below the target cost.

### *Continental Shelf*

A field in the West Delta of the Gulf of Mexico continental shelf had struggled with drilling wells efficiently. Problems drilling shale in this field were a major source of NPT. The resulting wellbore instability, combined with pressure depleted formations and challenging wellbore geometries, resulted in unnecessary trips, hole pack-off, stuck BHA incidents and consequential sidetracks.

Well C was typical of earlier fluid formulations (**Figure 3**). This fluid formulation consisted of a low toxicity mineral oil-based drilling fluid with 25% $CaCl_2$ brine as the internal phase. The well was drilled very quickly, without problems until a fault was drilled below 12,000 feet. The wellbore then collapsed and the hole was lost. A side tack was then drilled.

The drilling team developed a set of drilling and tripping guidelines for high-angle wells. A principal part of the guidelines standardized the mud formulation to a non aqueous fluid system with reduced water phase salinity. It is believed that the decreased water phase salinity reduced shale dehydration and minimized wellbore destabilization. The reduced salinity was based upon good wellbore stability noted using 20% NaCl water-based drilling fluids. This approach is further supported by the fact that the produced water from this location averages 42,000 mg/l $Cl^-$, which would indicate a higher water activity for the shale than the typical 25% $CaCl_2$ OBM used on prior wells.

Well D (**Figure 4**) used a low toxicity mineral oil-based drilling fluid with a similar formulation and fluid properties to that used on Well C however the internal phase salinity was maintained in the range of 18 to 20 %, compared to 25 % on Well C. Well D experienced the best drilling performance in the field. The well was drilled at 13.38 days / 10 K feet, compared to an average of 19 days/10 K feet.

## Choosing the Optimal Internal Phase Salinity

### *Shale Activity in GoM*

It is difficult to obtain and preserve shale core necessary to make correct water activity measurements. Drill cuttings and cavings are often used to evaluate shale inhibition. However, cuttings and cavings are rapidly altered by drilling fluid chemistry making water activity measurements inaccurate. It can be assumed that the water activity of shale is in near equilibrium with interstitial water salinity of sandstone formations that border the formation. Using this understanding, it can be seen in **Figure 5** that salinity and, in all probability, shale $A_w$ **(Table 1)** will vary in GoM.

### *Prior Work on Ion and Water Movement in Shale*

Because water and ion transport simultaneously during shale/mud interactions, the effects of ion movement cannot be ignored. Researchers have studied the effects of ion movement on wellbore stability [11-14]. Gazaniol *et al.* (1995) suggested that shale failure can be caused by ionic diffusion due to the chemical alteration [12]. This chemical failure is delayed due the slow of the ionic diffusion. Horsrud *et al.* (1998) found that the adsorption of potassium ions caused shrinkage of shale in their lab. This shrinkage may accelerate tensile failure [11]. Simpson and Dearing (2000) studied the ionic diffusion on wellbore stability [13]. They suggested that the clay structure in the shale was altered by the invading ions due to the cation exchange reactions. It is also found in our lab that the water activity of shale decreased due to ion adsorption [14].

Therefore, water and ion movement should be controlled in order to improve wellbore stability in shales. The mechanisms for this movement, which include convective flow, capillary suction, diffusive flow and osmotic flow have been discussed in detail in the paper by Zhang *et al.*[14] Hale *et al.* (1993) argued that the hydraulic permeability of shales is extremely low, which is in a range of $10^{-7}$ to $10^{-12}$ darcy, and that oil will not enter the shale pores unless the differential pressure exceeds the minimum capillary entry pressure [5]. Furthermore, a semi-permeable membrane, although it is not perfect [15], which restricts the movement of ions, is formed when an OBM is used. Therefore, from the wellbore stability point of view, an oil based mud is superior over water-based mud (WBM) due to capillary effects and membrane properties.

When the differential pressure between an OBM and a pore fluid is below the minimum capillary entry pressure, water and ion movement can be controlled by the salinity of the OBM. The basic principle in designing an OBM is to adjust the salinity (activity) of the water phase so that there is no significant water transfer from the mud to the formation. Based on this principle, "balanced-activity" theory was developed by Chenevert [2]. It stated that the shale stability can be achieved by balancing the water activity of shale with that of an OBM. Many successful stories can be found by using balanced-activity OBM, including hard, illitic shales in West Texas and South Louisiana; soft, high montmorillonite content shale in offshore Louisiana [2].

Mondshine (1969) did pioneering work in determining the salinity of an OBM [16]. The principle for Mondshine's method is to use the osmotic pressure to balance the matrix stress. The matrix stress can be calculated by using the following equation:

$$\sigma = S_v - P_p \qquad (1)$$

where $\sigma$ is matrix stress; $S_v$ is overburden stress and $P_p$ is pore pressure.

The osmotic pressure of an OBM in contact with a shale formation is calculated by using the following equation [16]:

$$\pi = -RT(\phi_1 m_1 v_1 - \phi_2 m_2 v_2) \qquad (2)$$

In the above equation, $\pi$ is osmotic pressure; $R$ is gas law constant; $T$ is absolute temperature; $v$ is number of solute ions pre mole; $\phi$ is osmotic coefficient of the salt solution; $m_1$ is salt concentration in oil-mud water expressed as molality; and $m_2$ is salt concentration of shale formation water expressed as molality.

Based on the theory using osmotic pressure to balance matrix stress, Mondshine developed a graph to determine the $CaCl_2$ salinity of an oil-based mud [16], which is sown in **Figure 6**. In this graph, the effective matrix stress has been converted into depth by assuming that the overburden and pore pressure gradients are 1 psi/ft and 0.465 psi/ft respectively.

Two problems arise from Mondshine's early work: first, the water activity of pore fluid is different from the water activity of shale due to its negative surface charges and cation exchange capacity; and secondly, the assumption that the water-absorption force is equal to the effective compaction force that expelled water from the shale has not been supported. Therefore, when this technique is applied, very high salinity is required. For example, a preserved shale sample obtained from a BP well, was cored at about 17,050 feet. The measured activity of the shale was approximately 0.83. By using Figure 6, the minimum water phase salinity of an OBM is about 310,000 ppm (31 wt %, 0.62 $a_w$) by assuming the pore fluid is fresh water. If the salinity of pore fluid is considered, even higher salinity is needed.

Mondshine's technique was effective for the soft gumbo shale due to the fact that dehydration of the soft, high water content formation is beneficial to improve wellbore stability. The early successes drilling gumbo shale with OBM resulted in the routine use of 25 to 30% $CaCl_2$ internal phase emulsion-based fluids in the Gulf of Mexico. However, this perception needs to be revised when drilling naturally fractured, hard formations.

Based on "balanced-activity" theory, the water activity of a shale formation is balanced by the water activity of the drilling to avoid water movement during shale/mud interactions. The salinity of an OBM can be determined if the in-situ water activity is known by using the relationship between salt concentration and water activity, which is shown in **Figure 7**. However, it is very difficult, if it is not impossible to determine the in-situ water activity [8, 13].

For some time it has been known that the downhole activity of shale is different from the surface activity. Chenevert and Strassner (1975) found that the water activity of both argillaceous shales and salt solutions (NaCl and $CaCl_2$) increased with increasing temperature, and that the increase in water activity for shale is greater than that for salt solutions [17]. Based on the assumption that the dehydration is beneficial for wellbore stability, they claimed that these water activity changes did not cause wellbore instability problems.

Fonseca and Chenevert (1998) studied the effects of stress and temperature on water activity of shale by using the "Downhole Activity Cell" [18]. They found that the water activity of shales increased with increasing pressure and temperature [18]. Part of their results is shown in **Figure 8**.

Simpson *et al.* (1998, 2000) also established in their lab that a fluid and a shale having the same activities at ambient conditions did not have equal activities under down hole stress and temperature [13, 19]. For example, the test showed that a simulated interstitial water having an ambient activity of 0.89 $a_w$ showed no evidence of osmotic force when in contact with the Cretaceous shale at down hole conditions, even though the ambient activity of the shale was 0.78 $a_w$. It was also shown that a Pleistocene with a surface activity of 0.89 $a_w$ had the equivalent of 0.95 $a_w$ under downhole conditions.

In summary, the downhole activity is different from that measured at surface; normally it is higher than that measured at surface. This means that if the salinity of an OBM is determined to be at equilibrium with the shale based on the surface measurements, dehydration of the downhole formation can be expected. Although this dehydration is benefit to improve wellbore stability in soft, high water content Gumbo shale, it is believed to be detrimental to wellbore stability in naturally fractured formation

## Shales and Test Fluids

Preserved Pierre II shale core and a preserved core from a BP GoM deepwater well, were used in this study. The BP shale was cored from a depth of 17,055.1 to 17,055.9 feet. The knowledge gleaned from the CT scans allowed the selection of the best preserved core and minimized the exposure time of the shale to atmospheric conditions (**Figures 9, 10, 11).** It has fractures and cracks extended in different directions; some fractures are intersected.

**Figure 12** shows the effect of salinity of synthetic-based muds on the generation of the fracture in BP shale cores. It is easily observed that fractures began to occur as the shale was exposed to fluids with internal phase salinity above 15 wt%. Numerous cracks were generated after the salinity was increased to 25 wt% $CaCl_2$.

The mineralogical composition of the shale cores was determined by X-ray fraction and the water activity was measured by using Aqua Alb Series 3TE water activity meter [24].

### *Water Activity Results*

The preserved shale core was removed from its wax-sealed protective metal sampling tube and visually inspected for integrity. It was noted that the shale core sample tested appeared to be one complete un-fractured core sample. The complete shale core was then submersed in mineral oil to prevent dehydration prior to collecting the actual shale samples for water activity measurement.

An approximately one inch thick slice was cut from the core at approximately 17,055.30' with a chop saw and three samples were manually collected from the center of the slice to ensure undisturbed representative shale samples. Sample #1 was collected near the surface of the core, sample #2 was collected at an intermediate depth between the core surface and the core center, and sample #3 was collected at the center of the core. Each shale sample was placed in an Aqua Lab disposable sample cup with lid in preparation for water activity measurement. The water activity measurements indicated an activity range of 082 at the core surface, 0.81 at an intermediate point and 0.85 at the core center. This indicates that the shale water activity was probably reduced during the coring action by means of contact with the emulsion-based drilling fluid, which had an activity of .78. The center measurement was the closest to the natural activity of the shale. **Table 2** presents results for water activities of the collected samples, which fell between the activity of 19 and 21.5% $CaCl_2$.

### *Water Content*

The native water content was determined by drying a sample at 200°F (93°C) overnight. The results for mineralogical composition, water content and water activity are shown in **Table 3**. It is seen that BP shale is reactive shale consisting of high content of swelling clay.

A section of preserved shale was removed from the storage can, and immediately cut into pieces of 0.5"X0.75"X1.0". All cut samples were carefully preserved using established techniques developed by Chenevert (1997) to avoid alteration by atmospheric humidity [20].

$CaCl_2$ and NaCl brines and synthetic-based invert solution (SBS) were used for testing. The SBS consisted of synthetic-base oil (16-18 IO), emulsifier and brine. The oil-water ratio (OWR) is 80/20. Its composition and equivalent water activity at room temperature are listed in **Table 4**.

Gravimetric-Swelling Test (GST) was run for these two shales to quantitatively determine water and ion movement when a shale sample interacts with a solution [21]. During GST, a sample was placed in a small plastic bag and was positioned between the movable anvil and stationary anvil of a swelling transducer. A 50 ml solution was then poured into the plastic bag and the bag was sealed immediately. The swelling or shrinkage was recorded continuously until equilibrium was reached. In this test, it seems that the equilibrium took about 48 hours.

## Results and Discussions

### *Effects of Salinity on Water/Ions Movement for Pierre II Shale*

The effect of salt concentration on water/ion movement for Pierre II exposed to $CaCl_2$ solutions for 48 hours is shown in **Figure 13**. It is seen that when the salt concentration increases, water is removed due to osmotic effects and ions are added because of ionic diffusion. The mechanisms for water and ion movement can be reviewed in AADE-06-DF-HO-37[14].

As shown in **Figure 13**, the net transport including both water and ion, increases with increasing $CaCl_2$ concentration. This result agrees with immersion test by Santos et *al.* [22], who observed that the weight increase to shale from a salt solution is higher than that from water. However, they accredited the weight change only to water movement and probably reached the wrong conclusion: “Even with a very low activity, the calcium chloride solution was not able to drive water from the shale”. When measurements of osmosis and diffusion are considered, there can be a net weight gain, even when the shale is dehydrated. From **Figure 13**, it is observed that when the Pierre II shale was immersed into 24.8 wt% $CaCl_2$ (0.85 $a_w$) solution for 48 hours, the net weight gain was 2.4 wt%; while it lost 2.1 wt% water.

The influence of salt concentration on water and ion movement when Pierre II sample was immersed to NaCl solutions is shown in **Figure 14.** Once again, the water is removed due to osmotic effect and ions are added due to the ionic diffusion when Pierre II shale was exposed to high salinity NaCl solutions.

The effect of $CaCl_2$ concentration on water and ion movement when Pierre II was exposed to synthetic-based solution is shown in **Figure 15**.

It is seen that when the salinity of the SBS is high enough (greater than 4 wt%), water was removed from Pierre II shale. Compared with exposure to the $CaCl_2$ solution (**Figure 13**), **Figure 15** also exhibits that the amount of ion movement is very small when the Pierre II shale was immersed into SBS, even at very high salinity (24.8 wt%). For example, when Pierre II shale was immersed into 24.8 wt% water-based $CaCl_2$ (0.75 $a_w$) solution for 48 hours, it gained 4.4 wt % ions. However, when it exposed the SBS with the same salinity, it only gained 0.1 wt% ions. This clearly demonstrates that the oil-based solution used in our tests acted as a near-perfect semi-permeable membrane, which allows the movement of water and restricts the movement of ions.

### *Effect of Water Activity on Water Movement for Pierre II Shale*

Converting the salt concentration into water activity by using the relationship between water activity and salt concentration, as shown in **Figure 7**, we get the effects of water activity on water movement for both water-based and synthetic-based solutions, which are shown in **Figure 16**. Just as expected, water is removed at the lower water activity for both solutions. It is interesting the amount of water movement is different when Pierre II was immersed into NaCl and $CaCl_2$ water-based solutions with the same water activity. At the same water activity, the amount of water removed by $CaCl_2$ is larger than that by NaCl solution. This is because the water activity of the Pierre II shale has been changed due to the water/ion movement. This result is exactly the same as obtained with the Pierre I shale [14].

### *Effects of Salt Concentration on Water and ion Movement for BP Shale*

The effect salt concentration on water and ion movement when BP shale was immersed into water-based $CaCl_2$ solutions is shown in **Figure 17**. It is shown that water influx decreases, while ion adsorption increases with increasing $CaCl_2$ concentration. Different from the results of Pierre II shale, the BP shale still absorbed water, even when the water activity of the water-based $CaCl_2$ solution (0.75 aw) is lower than that for BP shale (0.82 $a_w$). This may be caused by the de-saturation of the BP shale during coring and processing [20]. The de-saturation caused capillary suction when it immersed into water-based solutions [14, 21, 22].

The effect of $CaCl_2$ concentration on water and ion movement when BP shale was immersed into the SBS is shown in **Figure 18**. It is shown that water began to be removed when the $CaCl_2$ concentration was increased to about 18 wt % (0.86 $a_w$). This “0” water movement at 18% $CaCl_2$ concentration validates the gravimetric test with the water activity measurements using the chilled mirror water activity measurement. It is also seen that the amount of ion movement during shale/mud interaction is very small, nearly no transport. This further demonstrates that the SBS in our test acted as a near-perfect semi-permeable membrane.

### *Effects of Water-based and Synthetic-based Solutions on Water Movement for BP shale*

**Figure 19** shows the effect of water activity of the water-based and synthetic-based solutions on water movement for the BP shale. It is seen that the amount of water movement for water-based solution is much higher than that for the SBS. As expected, this demonstrates that the oil-based solution is superior in wellbore stability than water-based solution because it can minimize the water and ion movement when it interacts with formations.

## Conclusions

1. The SBS in the test acts as a near-perfect semi-permeable membrane, which allows the flow of water and restricts the flow of ions in shale.
2. Gulf of Mexico field experiences demonstrate that properly decrease the salinity of oil-based mud can improve wellbore stability in naturally fractured shale formations.
3. Field cases and lab results showed that down-hole water activity of the formation is higher than that measured at surface. Therefore salinity selections based the surface measurement cause dehydration of formation. This dehydration is detriment to wellbore stability in naturally fractured shale formations.

4. Produced water salinity measurements can be used as an indication of the level of shale water activity.
5. The proper design of oil-based drilling fluid salinity is an important part of a “Stressed Shale Drilling Strategy”.

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## Nomenclatures*

$m_1$ = Salt concentration in oil-mud water expressed as molality

$m_2$ = Salt concentration of shale formation water expressed as molality

$P_p$ = Pore pressure [=] m/L-$t^2$

$R$ = Gas law constant, $8.314\times10^3 kg\cdot m^2/S^2\cdot Kg-mole\cdot K$

$S_v$ = Over-burden stress[=] m/L-$t^2$

$T$ = Absolute temperature [=] T

$v$ = Number of solute ions pre mole

$\sigma$ = Matrix stress [=] m/L-$t^2$

$\pi$ = Osmotic pressure [=] m/L-$t^2$

$\phi$ = Osmotic coefficient of the salt solution, dimensionless

* [=] means has unit of, L is a length unit; m mass; t time; and T temperature.

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**Table 1 - Effect of salt on water activity**

| % Wt NaCl | Chlorides (mg/l) | $A_w$ |
|---|---|---|
| **1** | **6,108** | **0.996** |
| **5** | **31,421** | **0.970** |
| **10** | **65,062** | **0.935** |
| **15** | **101,087** | **0.892** |
| **20** | **139,489** | **0.839** |

**Table 2 - Core sample activity**

| Shale Sample # | Sample Location | Water Activity ($a_w$) |
|---|---|---|
| 1 | Surface | 0.82 |
| 2 | Intermediate | 0.81 |
| 3 | Center | 0.85 |

**Table 3 - Mineralogical composition, water content, and water activity of Pierre II and BP Shale.**

| Constituent | | Pierre II (% weight) | BP shale (% weight) |
|---|---|---|---|
| Quartz | | 15-20 | 15-20 |
| Feldspar | | 1-2 | |
| Clay | Chlorite | | - |
| | Kaolinite | 5-10 | 10-15 |
| | Illite | 20-25 | 25-30 |
| | Smectite | | - |
| | Mixed layer | 50-55 | 35-40 |
| | Total | 75-90 | 70-85 |
| Expandable Layers in Mixed Layer | | 70-80 % | > 95 % |
| Water Content (wt%) | | 17.7 | 8.25 |
| Water activity | | 0.98 | 0.82 |

**Table 4 - Composition of SBS.**

| Salt type | Emulsifier (lb/bbl) | Organic clay (lb/bbl) | Wt % of salt | Water activity |
|---|---|---|---|---|
| --- | 6 | 2 | 0 | 1 |
| $CaCl_2$ | 6 | 2 | 10 | 0.95 |
| $CaCl_2$ | 6 | 2 | 18.8 | 0.85 |
| $CaCl_2$ | 6 | 2 | 24.8 | 0.75 |
| NaCl | 6 | 2 | 8 | 0.95 |
| NaCl | 6 | 2 | 19 | 0.85 |
| NaCl | 6 | 2 | 26 | 0.75 |

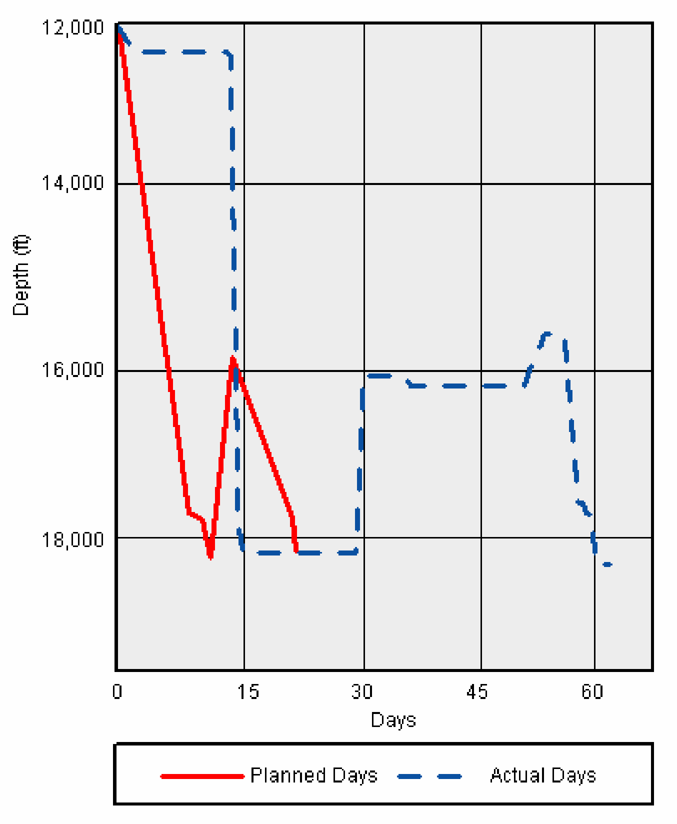

**Figure 1 – Days vs. depth of Well A in GoM Shelf.**

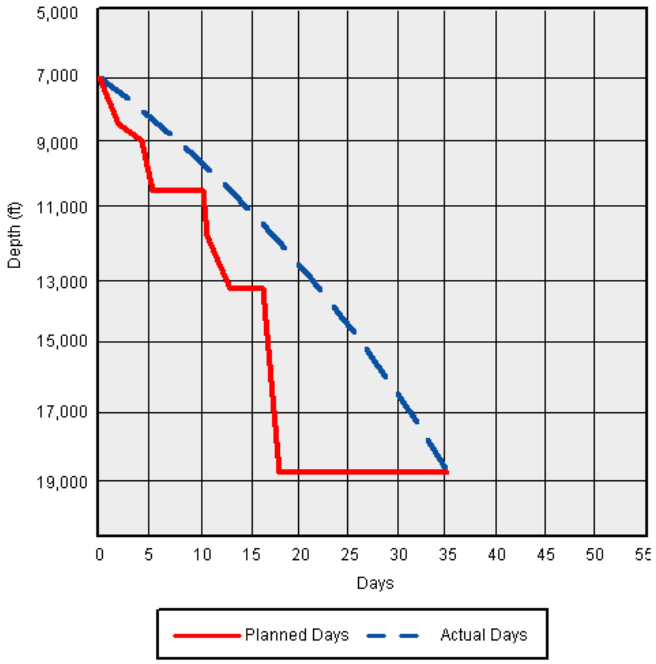

**Figure 2 – Days vs. depth of Well B in GoM Shelf.**

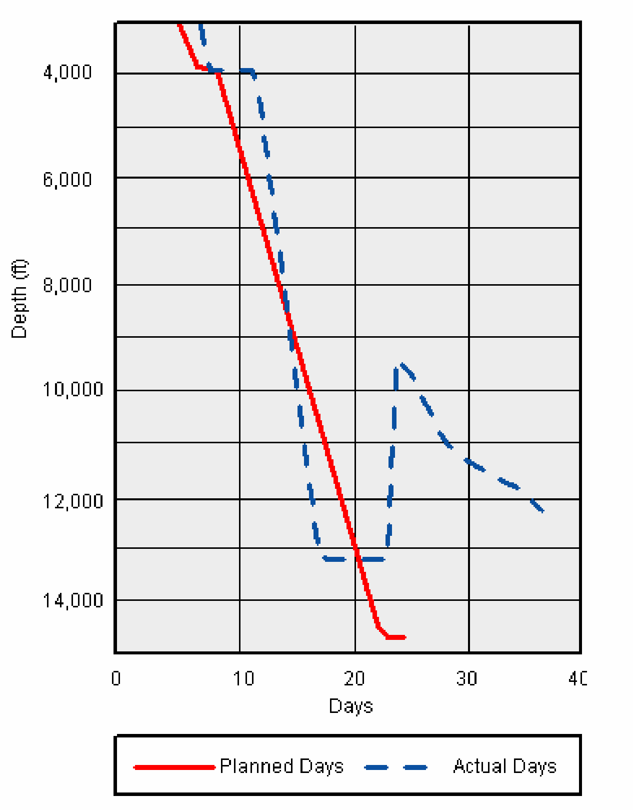

**Figure 3 – Days vs. depth of Well C in GoM Deepwater.**

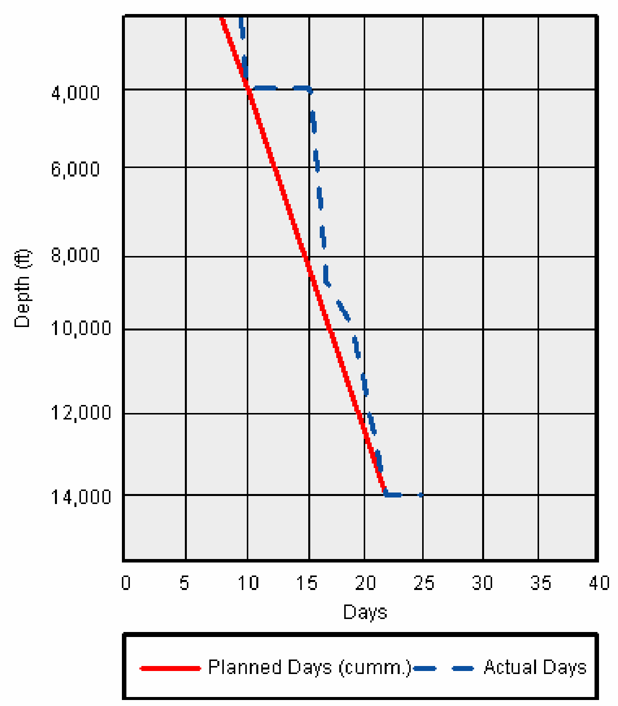

**Figure 4 – Days vs. depth of Well D in GoM Deepwater.**

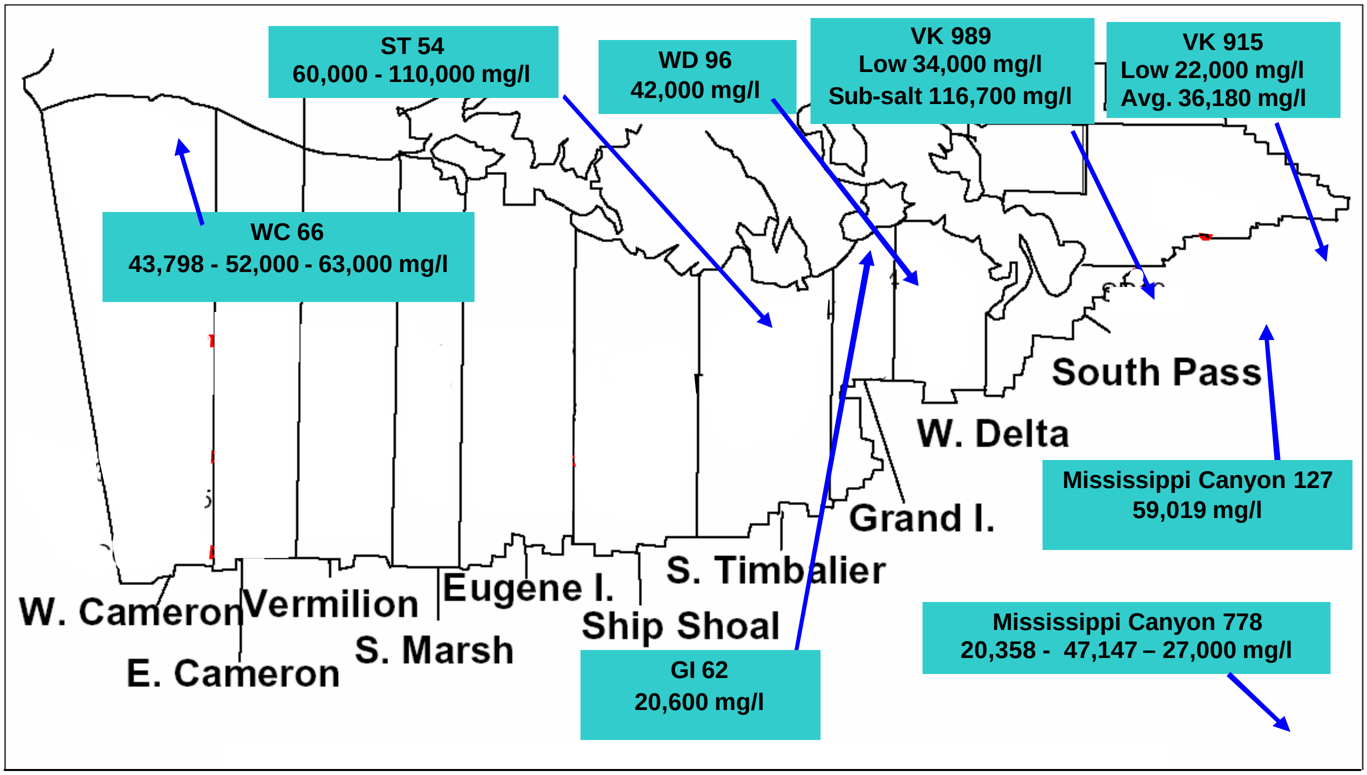

**Figure 5 - Production water chloride content in GoM.**

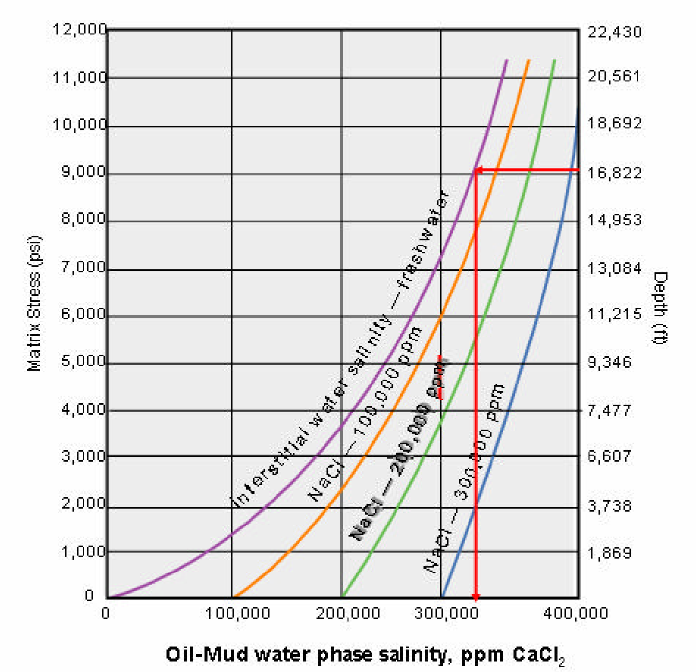

**Figure 6 - Determination of salinity for an OBM (after Mondshine, 1969 [16]).**

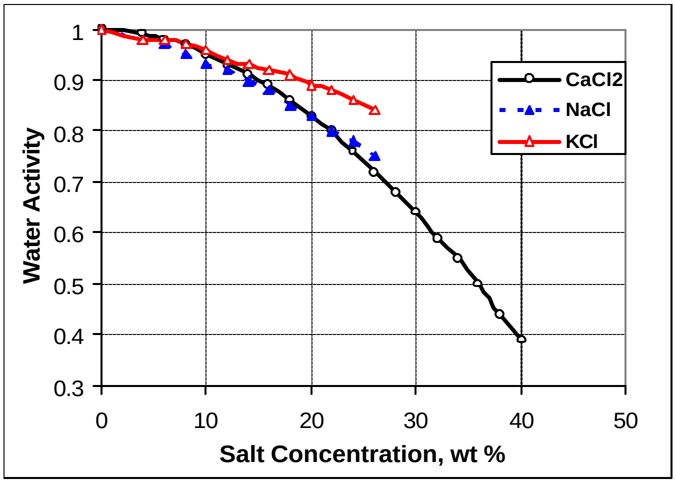

Figure 7 – Relationship between salinity and water activity at room temperature.

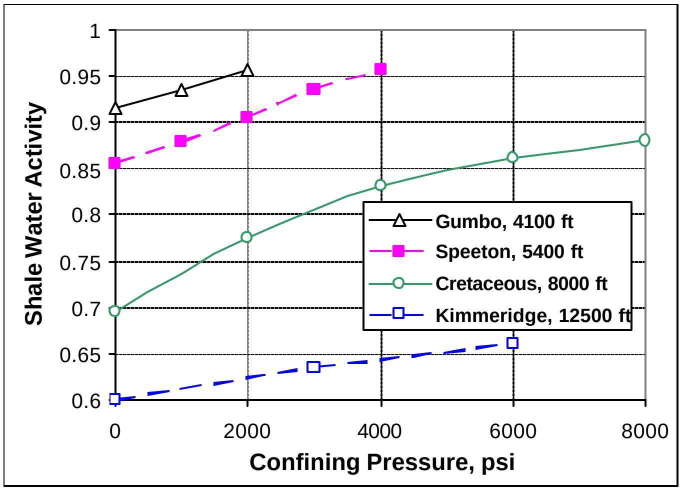

Figure 8 - Effects of confining pressure on water activity of shale (after Fonseca and Chenevert, 1998[18]).

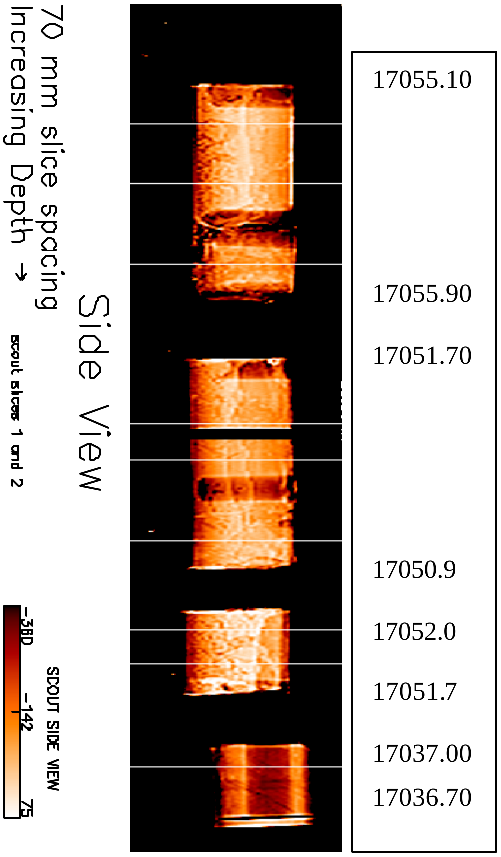

Figure 9 CAT scan view 1 of preserved BP Shale

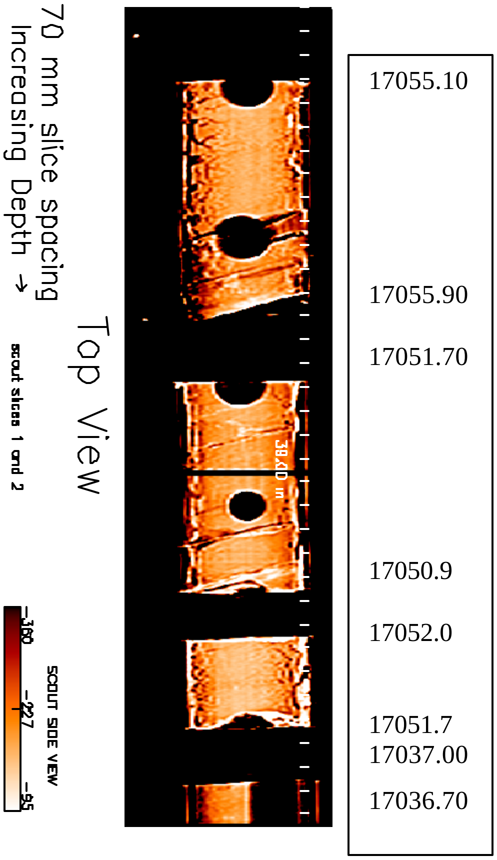

Figure 10 - CAT scan view 2 of preserved BP Shale

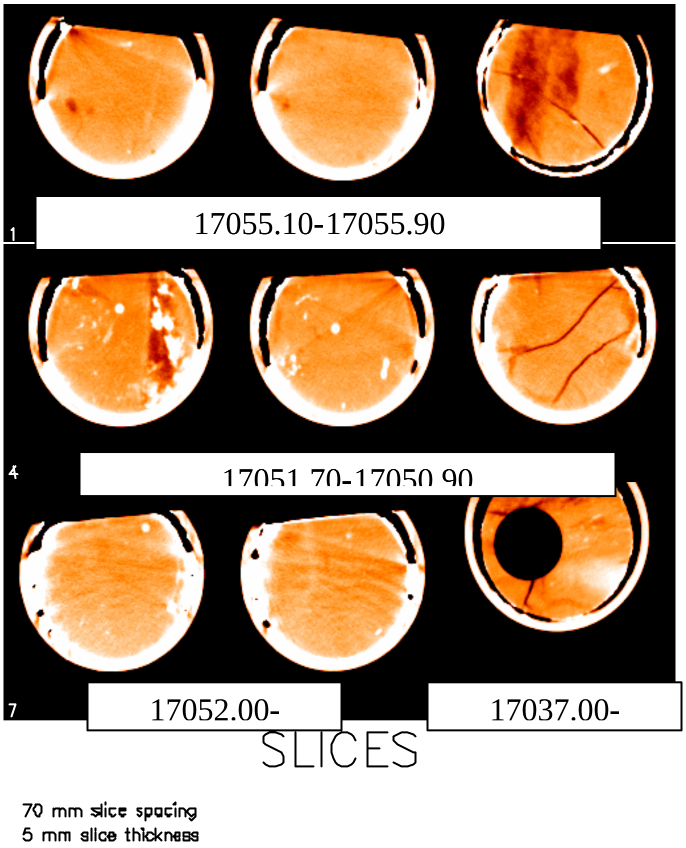

Figure 11 - CAT scan view 3 of preserved BP Shale

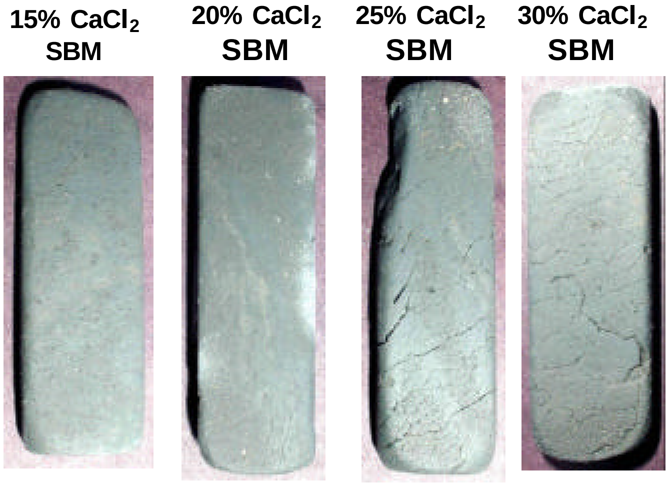

**Figure 12 – BP preserved core pieces immersed in synthetic –based drilling fluid exhibit increasing shrinkage and cracking as the fluid activity is decreased.**

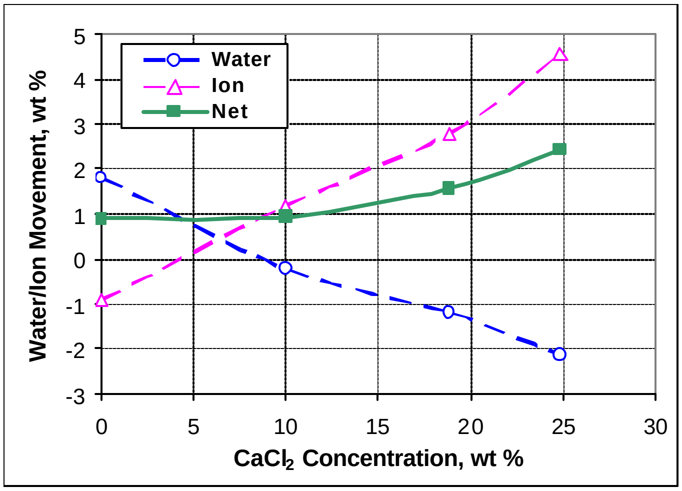

**Figure 13 - Effect of $CaCl_2$ concentration on water and ion movement when Pierre II shale immersed into $CaCl_2$ solution.**

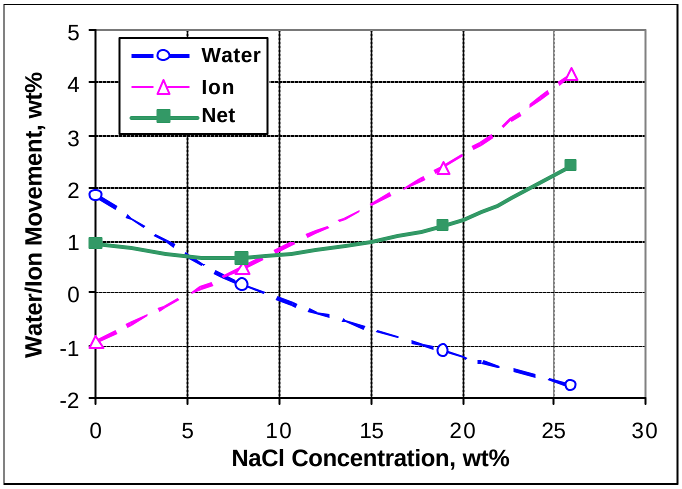

**Figure 14 - Effect of NaCl concentration on water and ion movement when Pierre II shale immersed into NaCl solution.**

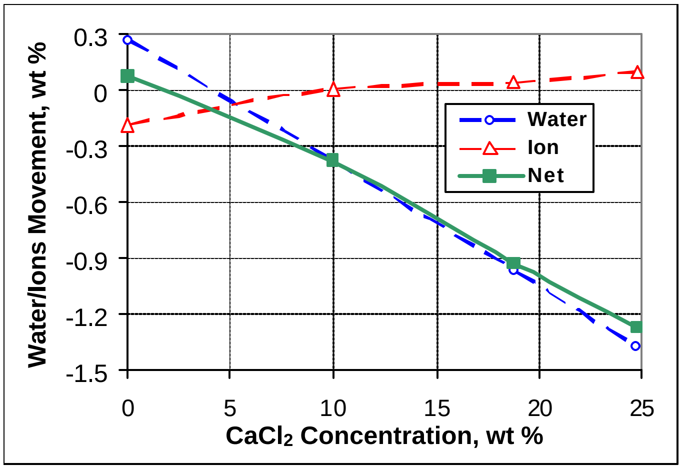

**Figure 15 - Effect of $CaCl_2$ concentration on water and ion movement when Pierre II shale immersed into SBS (SWR: 80/20).**

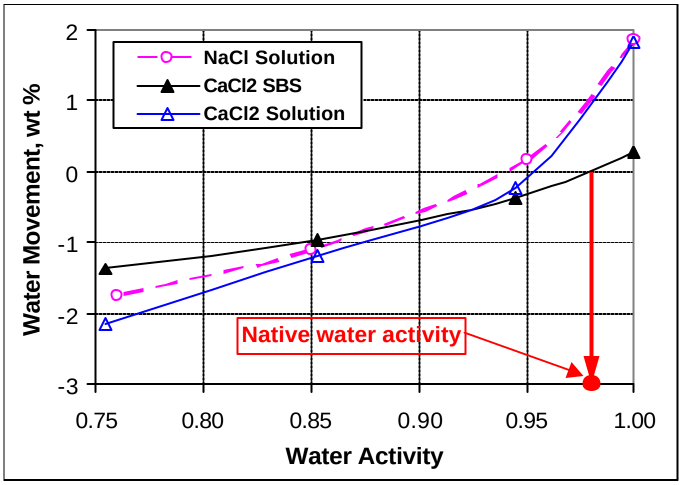

**Figure 16 – Effect of water activity on water movement in Pierre II Shale**

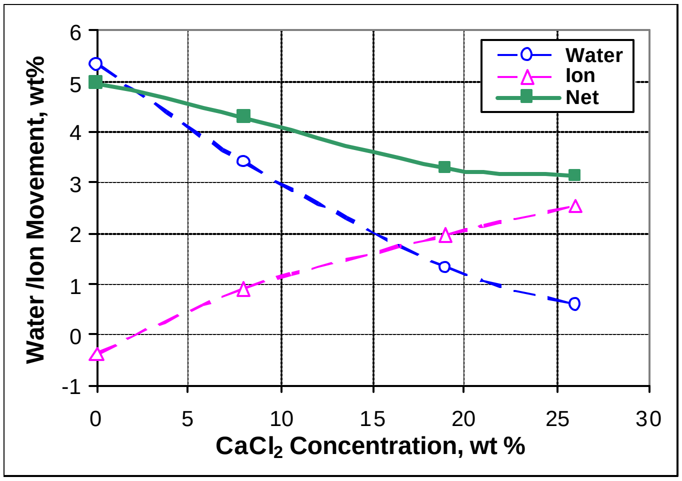

**Figure 17 - Effect of $CaCl_2$ concentration on water and ion movement when BP shale immersed into $CaCl_2$ solution.**

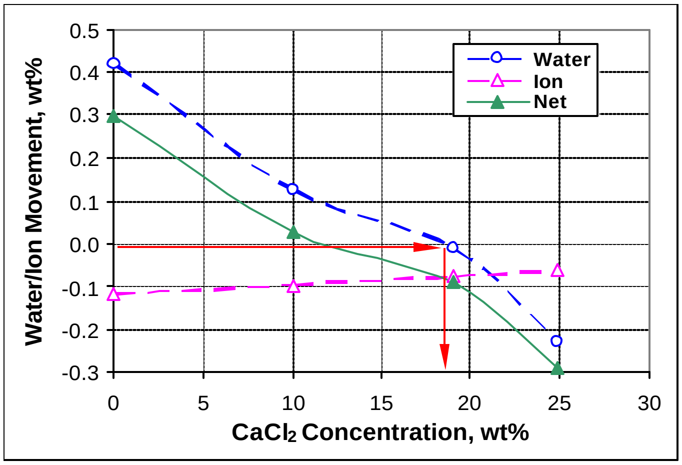

**Figure 18 - Effect of $CaCl_2$ concentration on water and ion movement for BP shale exposed to SBS (SWR: 80/20).**

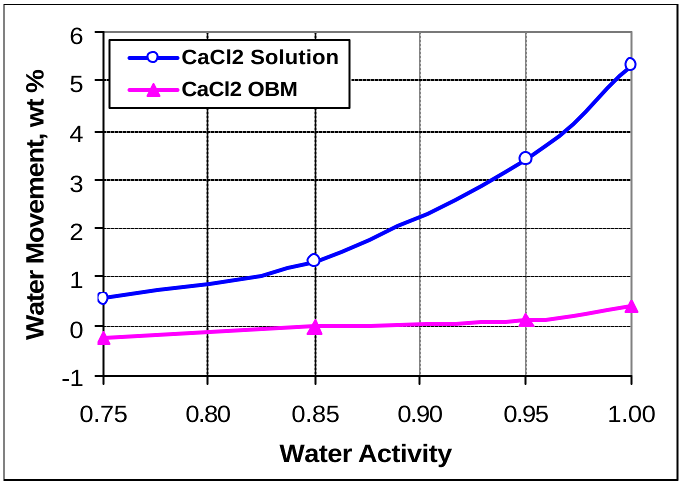

**Figure 19 – Effect of brine and synthetic-based solutions on water movement for BP shale.**