



## Amine Compound Replaces Potassium Chloride to Stabilize Kaolinite in the Magallanes Strait

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### Abstract

Potassium chloride has historically been used in drilling and drill-in fluids for stabilization of shale present within sandstones by minimizing shale swelling and dispersion. The Springhill sandstone formation encountered while drilling off-shore wells in the Magallanes Strait contains significant amount of kaolinite, which can lead to fines migration problems and formation damage.

During the planning stage return permeability tests were conducted to optimize the fluid design in the horizontal hole section. The tests showed that the addition of an amine compound to drill-in fluids improved return permeability values as compared with those obtained by using traditional potassium chloride salt. Also, the potassium chloride induced permeability damage as evident by low return permeability upon the test cores. This seems to be in agreement with references regarding mineralogical transformations made by potassium in kaolinite.

The return permeability tests were repeated and finally the amine compound was incorporated into the reservoir fluid formulation. Well productivities flow rates indicated that the drilling fluid prevented formation damage, thus confirming laboratory investigations. How amine chemistry interacts with clay chemistry is also discussed.

### Introduction

Potassium based drilling fluids have been used successfully for many years to drill through shale containing significant amounts of mixed-layer clays and illite.<sup>1,4</sup> The potassium ion is able to control the swelling tendency of mixed-layer clays and the dispersion of illite. Normally, the necessary potassium ion concentration is determined by the mixed-layer clay content of the shale and their cation exchange capacity.

Severe wellbore instability problems have been experienced during the last twenty years on wells in the basin on the eastern side of Andes Mountains in South American.

X-ray diffraction (XRD) mineralogical data (**Table 1**) on several troublesome shale formations in this area demonstrate the presence of significant amounts of

kaolin clay. Experience and laboratory data have shown potassium to have a very limited ability to stabilize shale containing kaolinite.<sup>5,6</sup> XRD mineralogical data shown in **Table 2** and **Table 3** from the Magallanes Strait and Ecuadorian productive sandstone indicate a significant amount of kaolinite.

In recent years the drilling industry has focused greater attention on this problem. Triaxial testing has been performed on shale samples exposed to KCl containing drilling fluids at elevated temperature and pressure. Kaolin containing shale exposure to KCl consistently produced a decrease in the rock strength.<sup>5,6</sup> Geochemical studies of the thermodynamic stability of shale forming minerals in contact with brines demonstrated that the potassium ion destabilizes kaolinite.

On the other hand less attention had been dedicated to the presence of kaolinite in reservoir sandstones and the effects of potassium exposure. Drill-in fluid design usually contains potassium chloride for inhibition regardless of the type of clay present inside the pores. This paper claims that potassium chloride is not a viable alternative while drilling sandstones containing kaolinite. The illitization of kaolinite is also a potential problem as it is while drilling kaolinite containing shales<sup>1</sup>. This paper focuses on a novel approach utilizing amine chemistry for preventing such problems.

The following is a list of formation damage mechanisms which may occur during drilling of horizontal wells:

1. Mud solids plugging
2. Mud filtrate and formation fluids incompatibility
3. Polymer screening and retention
4. Water blockage
5. Geomechanical stress alteration
6. Wettability alteration
7. Fines migration and clay swelling

The last problem addressed in this paper discusses that the use of potassium in the drill-in fluid formulation produces illitization of kaolinite.

Discussed in this paper are field and laboratory data collected from wells drilled with a drill-in fluid formulated with an amine salt compound for the stabilization of



### Suppression of Bentonite Hydration

With water in contact with bentonite, this clay exhibits hydration, swelling, viscosity with thixotropic properties and filtration/seepage loss control. While beneficial for an aqueous drilling fluid, such properties would be detrimental if drilling formations primarily of smectite clays.

Because laboratory results showed amine salts to reduce the cationic exchange capacities of water-sensitive clays, it follows that this characteristic would affect rheological/filtration control properties of bentonite slurries. Upon pre-treatment of the water with an amine salt, bentonite would hydrate less, thus minimizing viscosity build and filtration control.

One-bbl aliquots of deionized water were pretreated with 7 lb/bbl amine salt additive. While shearing, 35 lb/bbl of a commercial ground bentonite was added for a total shear time of 30 minutes. **Figure 2** illustrates resultant rheological/filtration control measurements of the treated clay slurry, as compared to the base with no treatment. Viscosity build-up was virtually nil with no filtration control evident. Generally, the cation sorption capacity of the clay decreased, indicating that presorbed amine salts blocked sorption sites for the methylene blue, thus to say blocking sorption sites for water molecules.

### Comparing Amine Salts to Potassium Chloride for Cation Exchange

Clay minerals have large cation exchange capacities, which enable them to be modified by a charged surfactant-type chemical to enhance their sorption of organic and anionic contaminants. In this study, the influence of amine salts is compared to potassium chloride upon bentonite was investigated.

Referring to one past study, the influence of quaternary ammonium surfactants on sorption of five metal cations ( $\text{Cs}^+$ ,  $\text{Sr}^{2+}$ ,  $\text{La}^{3+}$ ,  $\text{Pb}^{2+}$ , and  $\text{Zn}^{2+}$ ) onto a clinoptilolite zeolite was investigated. Generally, the metal cation sorption capacity and affinity for the zeolite decreased, indicating that presorbed charged surfactants blocked sorption sites for metal cations, as the surfactant loading on the zeolite increased. Sorption of charged surfactants on zeolite preloaded with different metal cations showed a strong correlation with the chain length of the surfactant tail group, while the roles of the charges and types of the metal cations were minimal. As the chain length increases, the critical micelle concentration decreases and the surfactant molecules become more hydrophobic, resulting in progressive bi-layer coverage. Desorption of presorbed metal cations by charged surfactants was strongly affected by the surfactant chain length and metal type. Numerous other studies have shown that specific amine chemistries exhibit different levels of effectiveness for cationic exchange efficiency upon clay surfaces.<sup>8, 15, 17, 19, 22</sup>

**Figure 3** shows comparative resultant data of an amine salt and potassium chloride in preventing hydration of bentonite. One-bbl aliquots of deionized water were pretreated with increasing increments of salt additive. 30 lb/bbl commercial bentonite was added and sheared 30 minutes. Rheological / filtration control properties were measured. Note that 3.5 lb/bbl amine salt was equivalent in performance to 20 lb/bbl potassium chloride.

### Depletion Rate of an Amine Salt

The Capillary Suction Testing (CST) equipment is used to measure the propensity of clay to swell once it is introduced to fresh water. Slurry of test clay or ground shale with distilled water is prepared. The instrumentation measures a recorded time of filtration, or dewatering of the clay slurry. The recorded time is directly related to the sample's swelling potential, i.e. the greater the time, the higher the swelling potential. This time can be reduced by adding halide salts, such as potassium chloride, to the slurry. In samples where the clays are predicted to swell, a salt may be added to the drilling fluid in a percentage determined by the CST to inhibit swelling. This instrument is applicable for evaluating the depletion rate or consumption of amine salts.<sup>10, 20</sup>

Incremental dosages of untreated Wyoming bentonite were added to deionized water pretreated with 6 lb/bbl amine salt. Solutions were sheared at 11,000 rpm for 2 minutes. CST measurements were determined, using the small funnel. **Figure 4** demonstrates resultant behavior of an amine salt when increasing the concentration of the reactive bentonite clay. Results showed a depletion rate of 1 lb amine salt per approximately 3.5 lb bentonite. Considering typical bentonite to have a MBT of about 80, whereas typical Gulf of Mexico gumbo to have an average MBT of approximately 20, the depletion rate in field operations would be 1 lb amine salt per 15 lb gumbo. Actual rates may be lower if applications are in high saline water-based drilling fluids or higher if extremely reactive shale is drilled.

### Laboratory Studies of an Amine Salt Application for Mud Program Designs

Several shale cutting samples from the Magallanes Strait, offshore Argentina, were submitted for the following:

- XRD analyses
- Standard MB analyses
- Amine salt consumption in freshwater, as shown by MB reduction in grinded cuttings (100-mesh) using a modified MB procedure.
- Static wafer tests in polymeric fluid formulations, comparing seawater, potassium chloride and sodium chloride, with/without the amine salt additive.

The cutting depths, labeled as received, were from a range of 817-832 m to 1497-1537 m.

Laboratory results indicated the XRD analyses for submitted samples with a composition range of 50 - 80% mixed layer clays, which were primarily 100% expandable. Kaolinite was not found. MB measurements noted the samples to be highly reactive, with a value range of 30 - 45.

**Figure 5** shows the test shale to readily consume the amine salt, as evident by the reduced MB value. Potassium chloride at 5% by weight, with/without amine salt at 7 lb/bbl, was most effective for reduction of MB value of the shale cuttings.

Unweighted polymeric fluids were prepared with different saline base waters and each batch contained equivalent treatments with PHPA, PAC, derivatized starch and xanthan gum. Shale wafers were prepared with the ground cuttings for immersion testing. In each instance, as compared to the base fluid, the amine salt provided enhanced shale stabilization. The best result was a fluid formulation with potassium chloride at 5% by weight and 7 lb/bbl amine salt; however, the 10% sodium chloride formulation was chosen for environmental considerations. Refer to Figure 5 for data information.

In another study several shale samples from Ecuador were evaluated for x-ray diffraction, with resultant data used to determine optimal drilling fluid designs. Analyses indicated the shale samples to have 25 - 35% quartz, 15 - 25% illite with 15 - 20% mixed layer of which 90% expandable clay, and 25 - 40% kaolinite.

The following fluid systems were lab-prepared for use in reconstituted shale wafer testing:

- Freshwater / aluminum complex
- Freshwater / aluminum complex with 3% - 6% potassium carbonate, as suggested by field operations
- Freshwater / amine salt with 3% potassium carbonate

Results showed the addition of potassium carbonate to be detrimental to the aluminum complex fluids. Because these shales contain a significant amount of kaolinite, a relatively high pH (11.5 - 12) with potassium would induce dispersive effects. Refer to **Figure 6** for additional the result summary of this test series. A low performance index indicates a more inhibitive fluid.

### The Poseidon Field

The Austral or Magallanes basin is located in the south extreme of South America and is limited by the Andean Patagonia west and Arco de Dungenes-Rio Chico in the east which isolated from Malvinas basin. The Poseidon field is located in the northeastern part of Tierra del Fuego Island. The field limits with Magallanes block in the east and Antares and Argos block in the south (**Figure 7**). The main objective of these wells is to reach the Springhill sandstones. This basin covers parts of Chile and Argentina and is being developed by

ENAP/Sipetrol. **Figure 8** presents a typical geological section for this field. **Figure 9** depicts typical well plans for the drilling operations.

The field is located in an area where sound environmental practices are required. All drilling fluids used must meet strict environmental criteria. Additionally, in order to minimize disposal costs, the need for treatment of wastes prior to disposal must be minimized.

### Drilling Fluid Design

A PHPA/potassium chloride system was planned for the deviated hole section. However, well bore problems were observed in the first two wells. Replacing potassium chloride with sodium chloride remedied this. The problem was related to the limitations of potassium chloride to stabilize kaolinite containing shale.

Special attention was dedicated to reservoir drill-in fluid design during the planning stage. Core samples from the potential productive formation were submitted by the operator for XRD analyses, shale dispersion test sand return permeability tests. Based on experience with similar sandstones in Venezuela, Colombia and Ecuador, XRD analysis of core samples was carried out (Table 1). Selected shale samples were then subjected to fluid compatibility studies. (**Figure 13**) In the Napo shale in particular, the laboratory performance of the aluminum complex is markedly superior to that of the potassium based system. The potassium nitrate system used for comparison is based on the drilling fluid in use at that time.

Minimizing formation damage in the production interval was the final and extremely important consideration. The approach here was to minimize fluid invasion by the use of correctly sized metamorphic calcium carbonate in a freshly prepared drill-in fluid.

### Laboratory Test

Two conventional cores from the SIPETROL CAM-XE-1 well in Chile were sent to Baker Hughes Drilling Fluids Houston Laboratory for x-ray diffraction analysis and oil return permeability testing with 10.2 lb/gal seawater-based drill in fluids. The cores are poorly consolidated, coarse-grained sandstones from 1661 (Core M-1) and 1662 (Core M-2) meters depth in the Springhill Formation.

After each core was analyzed by x-ray diffraction, attempts were made to cut one-inch diameter core plugs from each for return permeability testing in a Hassler Cell permeameter. The 1661m core was so poorly consolidated that no intact plug could be obtained, so two were cut from the 1662m M-2 sample. These plugs were also not well consolidated, and it was apparent they could not be placed in a Hassler Cell because they would fall apart when subjected to confining pressure.

Instead, each plug was placed atop a bed of 40/60 sand in an HTHP cell and surrounded with impermeable

cement, leaving one end of the core exposed. The core was saturated with a 42,000 ppm Cl<sup>-</sup> NaCl brine, then oil was flowed from the bottom of the cell upward through the core until irreducible water saturation was achieved, and initial permeability was calculated. The exposed end of the core was then exposed to the test drill-in fluid for two hours at 170° F and 1000 psi overbalance pressure. After this, oil flow was reestablished in the initial direction, breakout pressure was observed, and return oil permeability was determined when the flow rate stabilized.

X-ray diffraction analysis (Table 1) indicated both the M-1 and M-2 cores are similar, with quartz as the only framework grain type and abundant pore-filling authigenic kaolinite as the other significant component. Because there are no reactive clays present in these rocks, potassium chloride was not considered to be a necessary component in the drill-in fluids. The first fluid tested (Table 2) was a seawater-based Reservoir formulation with 103 lb/bbl CaCO<sub>3</sub>-20 for weighting and pore bridging. The results were unfavorable (Table 3), with an initial permeability of 2392 md and a return of 141 md (6%). Examination of the core afterwards revealed mud solids invasion throughout, suggesting the need for a coarser bridging material for this very high permeability sandstone. Another formulation with an equal mixture of regular and coarser (M-150) calcium carbonate (Table 2) was prepared and tested with much improved results as seen in Table 3. The 100 percent return indicated this to be the recommended drill-in fluid for this formation.

### Laboratory Results

The cores received for return permeability studies were highly fractured. For testing, the cores were consolidated to make core plugs. Results showed:

- The size particle distribution of calcium carbonate was selected while running the first two return permeability tests. Combinations of 50:50 coarse and regular calcium carbonate was required to obtain 100% return permeability by using an amine salt. The results are indicated in **Table 5**
- Typical fluid properties of field mud are presented in **Table 6**. The initial return permeability value of amine formulation was low due to non adequate bridging agent. The formulation was modified including coarse calcium carbonate obtaining good return permeability value (**Figure 10**).
- The formulation containing proper bridging agents and containing an amine salt was compared with formulations containing sodium chloride and potassium chloride. The presence of an amine salt produced better results as shown in **Figure 11**.
- The formulation containing the amine salt was tested at different permeabilities; consistent values of return permeability resulted as shown in **Figure 12**.
- Dispersion tests using core pieces exposed to

the amine salt fluid formulation indicated no adverse effects as shown in **Figure 13**.

### Drilling Practices

Improvements in drilling fluid design must go hand-in-hand with the adoption of good drilling practices. Step changes in performance are often achieved by the combination of fluid design changes and drilling practice changes.

- It was identified by the operator that performing drill-out by using reservoir fluid containing calcium carbonate is a risk of having down hole tools plugging due to solids setting considering coarse calcium carbonate required for proper bridging.
- Changes were made to drill out cement by using seawater and displace 50 bbl of solids-free reservoir fluid to drill one meter of formation. A trip to be made for BHA and down hole tools and then displace to calcium carbonate reservoir fluid was done.
- Wiper trips were made every twenty-four hours of footage to the top of new hole and each 300 meters to the 7" casing shoe.
- Displacement reservoir fluid containing calcium carbonate for solids-free reservoir fluid of the same composition before running 4" liner.

### Drilling Fluids Maintenance

A series of lessons learned were captured and applied during 7 wells campaign for optimizing drill-in fluid performance.

- The MBT should be maintained less than 2.5 lb/bbl for minimizing formation damage. Additions of the amine salt (0.5 lb/bbl) were maintained along with dilution.
- Additions of 20 and 150 d50 sized calcium carbonate in a 1:1 ratio were maintained to meet the required density of 9.5 lb/bbl. 70 and 84 mesh screens were utilized to ensure having coarse calcium carbonate returned back into the system.
- Should sand content increase over 0.75%, 100-mesh screens were used for short periods of time in combination with hydro-cyclones for reducing sand content to desired values. Additional treatment with sized calcium carbonate was monitored.
- Calcium carbonate additions are not required while drilling inter-bedded shale sections.
- The API filtrate is to be kept below 4.0 cc by using modified starch additions.

### Comparative Performance

A total of seven wells were completed during this drilling campaign by using amine salt chemistry in the drill-in fluid formulation. **Table 7** and **Figure 14** documents the improvement in drilling performance on the Poseidon wells. The continual improvement is clear on wells 1 through 7. The performance was improved as

indicated by 75% reduction of days per 100 meters to drill the section from well 1 to well 7. The environmental performance was also improved due continuous decreasing of dilution rates and the subsequent volumes of waste generated during the operation.

The benefits were immediately evident in the drilling performance.

### Conclusions

- Use local regional knowledge when planning drilling campaigns.
- In the basin of the Magallanes the use of potassium as a shale inhibitor in reservoir fluid formulation is not recommended.
- Amine compounds successfully replace potassium to stabilize kaolinite present inside the cores for minimizing fines migration problem.
- By optimizing fluid design, drilling practices and well design significant cost savings were realized in the Poseidon campaign.
- Eliminating the destabilizing effects of drilling fluid chemistry minimized the risk of having fines migration and the subsequent formation impairment.

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### Nomenclature

*XRD* = X-Ray Diffraction

*PHPA* = Partially Hydrolyzed polyacrylamide

*CST* = capillary suction testing

*NT* = non-treated

*bbl* = barrel

*NPT* = non productive time

*ppm* = parts per million

*lb/gal* = pounds per gallon

*cp* = centipoise

*MBT* = methylene blue test

*md* = millidarcy

*ECD* = Equivalent Circulating Density

*AFE* = Authorization For Expenditure

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**Table 1: X-Ray Diffraction Results on South American Shale**

| Formation  | Area      | Quartz, % | Calcite, % | Illite, % | Mixed Layer, % | Chlorite, % | Kaolinite, % |
|------------|-----------|-----------|------------|-----------|----------------|-------------|--------------|
| Tiyuyaco   | Ecuador   | 5 – 10    | 0          | 10 – 15   | 30 – 35        | 0           | 45 - 50      |
| Tena       | Ecuador   | 15 – 20   | 0          | 25 – 30   | 30 – 35        | 10 – 15     | 10 – 15      |
| Honda      | Colombia  | 15        | 0          | 15        | 57             | 0           | 13           |
| Barsalozza | Colombia  | 57        | 0          | 3         | 20             | 0           | 20           |
| Carbonera  | Colombia  | 10 – 15   | 0          | 15 - 20   | 25 - 30        | 15 - 20     | 25 - 30      |
| Misoa      | Venezuela | 5 - 10    |            | 10 - 15   | 35 - 40        |             | 45 - 50      |
| La Rosa    | Venezuela | < 5       |            | 20 - 25   | 25 - 30        | 5 - 10      | 30 - 35      |
| Napo       | Ecuador   | <5        | <5         | 15 – 20   | 35 – 40        | 0           | 35 - 40      |

**Table 2: X-Ray Diffraction Results on Core Samples from Off-set Well, Argentina**

| Formation  | Depth, meter | Quartz, % | Calcite, % | Illite, % | Mixed Layer, % | Chlorite, % | Kaolinite, % |
|------------|--------------|-----------|------------|-----------|----------------|-------------|--------------|
| Springhill | 1661         | 50 – 55   | 0          | 0         | 0              | 5 – 10      | 35 - 40      |
| Springhill | 1662         | 60 – 65   | 0          | 0         | 0              | 5 – 10      | 30 - 35      |

**Table 3: X-Ray Diffraction Results from Cores in Ecuador**

| Formation | Depth, feet | Quartz, % | Calcite, % | Illite, % | Mixed Layer, % | Chlorite, % | Kaolinite, % |
|-----------|-------------|-----------|------------|-----------|----------------|-------------|--------------|
| Napo      | Core 1      | 30 – 35   | 0          | 15 – 20   | 5-10           | 0           | 40 – 45      |
| Napo      | Core 2      | 15 – 20   | 0          | 35 – 40   | 0              | 0           | 45 – 50      |

**Table 4: Laboratory Fluid Composition and Properties**

| Fluid                           | 1     | 2     | 3     | 4     |
|---------------------------------|-------|-------|-------|-------|
| Seawater, bbl                   | 0.87  | 0.87  | 0.97  | 0.97  |
| NaCl, lb/bbl                    |       |       |       |       |
| KCl, Lb/bbl                     |       |       | 10.5  | 14.3  |
| Polymer Blend, lb/bbl           | 7.5   | 7.5   | 7.5   | 7.5   |
| CaCO <sub>3</sub> -20, lb/bbl   | 103   | 51.5  | 51.5  | 51.5  |
| CaCO <sub>3</sub> - 150, lb/bbl | 1.0   | 51.5  | 51.5  | 51.5  |
| Amine shale inhibitor, lb/bbl   | 2.0   | 2.0   |       |       |
| <b>Properties at 120°</b>       |       |       |       |       |
| 600 rpm                         | 55    | 53    | 76    | 65    |
| 300 rpm                         | 38    | 37    | 57    | 48    |
| 200 rpm                         | 32    | 31    | 50    | 37    |
| 100 rpm                         | 24    | 25    | 41    | 30    |
| 6 rpm                           | 11    | 12    | 20    | 20    |
| 3 rpm                           | 9     | 11    | 16    | 17    |
| Plastic viscosity, cp           | 17    | 16    | 19    | 17    |
| Yield point, lb/100 sq ft       | 21    | 21    | 38    | 31    |
| 10-sec/10 min gel, lb/100 sq ft | 11/16 | 13/15 | 16/20 | 13/15 |
| Fluid Loss,cc                   | 3.7   | 3.6   | 3.8   | 3.7   |

**Table 5: Return Permeability Increase with Amine CaCO<sub>3</sub> Optimization**

|                                   |       |      |      |      |
|-----------------------------------|-------|------|------|------|
| Seawater, bbl                     | 0.87  | 0.87 | 0.97 | 0.97 |
| NaCl, lb/bbl                      |       |      |      |      |
| KCl, Lb/bbl                       |       |      | 10.5 | 14.4 |
| Polymer Blend, lb/bbl             | 7.5   | 7.5  | 7.5  | 7.5  |
| CaCO <sub>3</sub> -20, lb/bbl     | 103   | 51.5 | 51.5 | 51.5 |
| CaCO <sub>3</sub> - 150, lb/bbl   | 1.0   | 51.5 | 51.5 | 51.5 |
| Amine shale inhibitor, lb/bbl     | 2.0   | 2.0  |      |      |
| <b>Return Permeability values</b> |       |      |      |      |
| Initial Permeability, md          | 2,391 | 888  | 1730 | 4342 |
| Final Permeability, md            | 141   | 892  | 286  | 2243 |
| Return Permeability (%)           | 6     | 100  | 16   | 52   |

**Table 6: Typical Drill-in Fluid properties**

| Interval                                   | 6 1/8"                   | 6 1/8"                   | 6 1/8"                   |
|--|--------------------------|--------------------------|--------------------------|
| Fluid Type                                 | CaCO <sub>3</sub> /Amine | CaCO <sub>3</sub> /Amine | CaCO <sub>3</sub> /Amine |
| Depth, meter                               | 2,025                    | 2,229                    | 2,546                    |
| Hole angle, degrees                        | 88.5                     | 89.6                     | 90.6                     |
| Dilution rate, bbl/m                       | 8.57                     | 4.29                     | 3.03                     |
| <b>Fluid Formulation</b>                   |                          |                          |                          |
| Polymer Blend, lb/bbl                      | 42                       | 40.54                    | 35.23                    |
| Amine inhibitor, lb/bbl                    | 1.73                     | 2.78                     | 2.56                     |
| Xanthan gum, lb/bbl                        | 0.38                     | 0.42                     | 0.48                     |
| Ca carbonate 20, lb/bbl                    | 20.0                     | 23.56                    | 19.08                    |
| Ca Carbonate 150, lb/bbl                   | 20.0                     | 22.17                    | 19.06                    |
| <b>Fluid Properties, typical</b>           |                          |                          |                          |
| Density, lb/gal                            | 9.3                      | 9.4                      | 9.5                      |
| Plastic viscosity, cp                      | 23                       | 18                       | 16                       |
| Yield point, lb/100 sq ft                  | 28                       | 25                       | 25                       |
| Gels, 10-sec/10-min/30-min<br>lb/100 sq ft | 12 / 18 / 22             | 12 / 14 / 18             | 12 / 17 / 20             |
| API Filtrate, ml/30 min                    | 5.6                      | 4.4                      | 4.2                      |
| MBT, lb/bbl                                | 0                        | 2.5                      | 2.5                      |
| Solids, vol %                              | 6                        | 6                        | 6                        |
| pH   | 10.5                     | 9.6                      | 9.6                      |

**Table 7: Drilling Performance Horizontal Hole Section**

| Drilling Information Reservoir Section | 1     | 2    | 3    | 4    | 5    | 6    | 7    |
|--|-------|------|------|------|------|------|------|
| Interval, meters                       | 137   | 159  | 522  | 178  | 689  | 307  | 722  |
| Inclination, degrees                   | 73.5  | 65.1 | 90.6 | 96.4 | 92.4 | 91.8 | 91.2 |
| NPT, hours                             | 42.8  | 0    | 0    | 0    | 0    | 0    | 0    |
| Time, days                             | 13.7  | 10   | 11.2 | 9.2  | 18.3 | 18.1 | 18.6 |
| <b>Performance Indicators</b>          |       |      |      |      |      |      |      |
| Days per 100 meters                    | 10    | 6.35 | 2.15 | 5.17 | 2.66 | 5.92 | 2.58 |
| Dilution Rate, bbl/meter               | 12.84 | 8.77 | 3.02 | 6.74 | 3.41 | 6.23 | 3.91 |
| Cost per meter                         | 553   | 268  | 172  | 295  | 253  | 235  | 196  |

Note: The actual costs above have been multiplied by a factor in order to preserve confidential data.

Figure 1: MBT Determinations of 20 lb/bbl NT bentonite slurry w/ increasing amine salt additive content

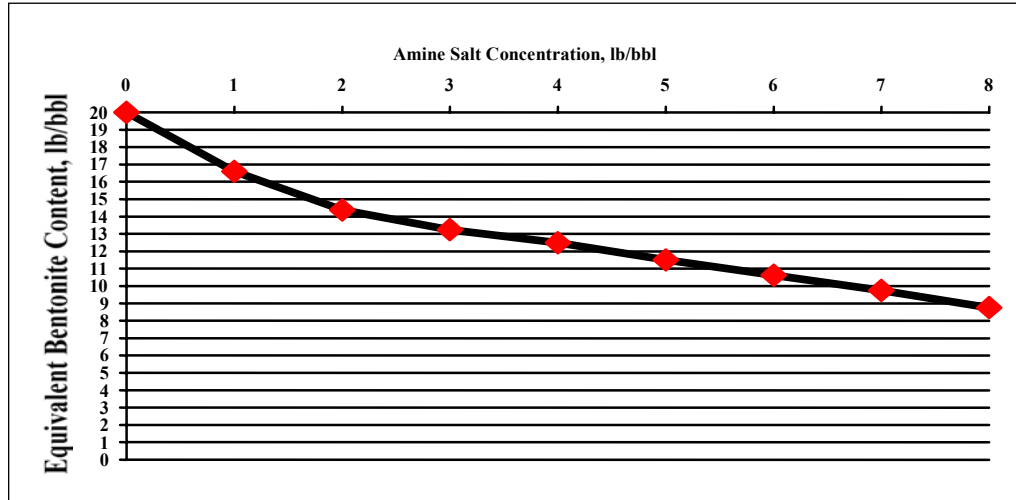
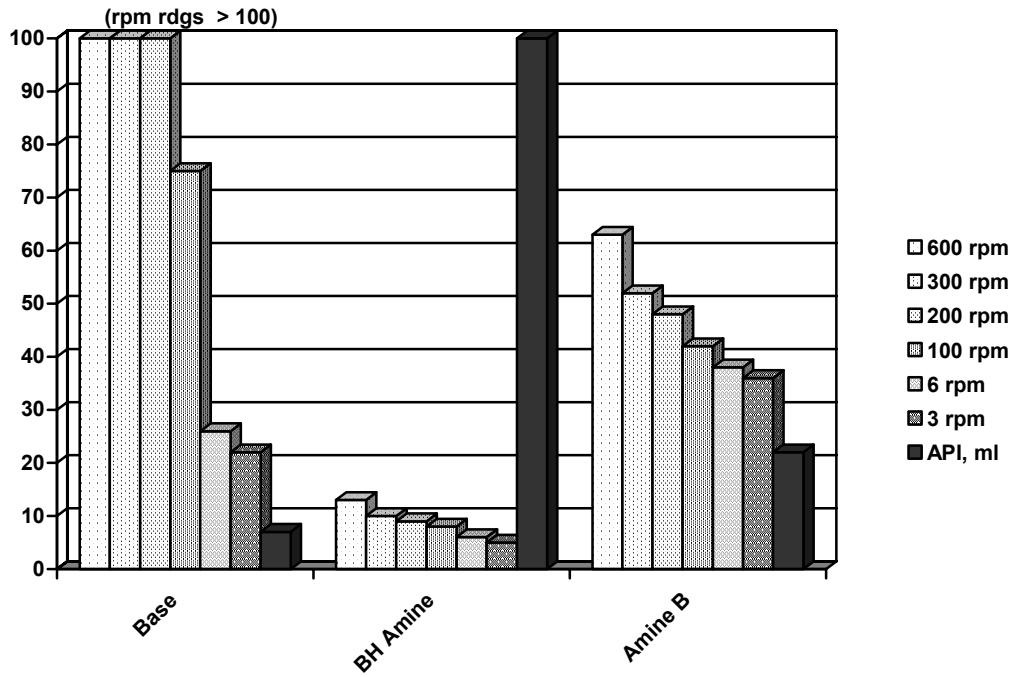
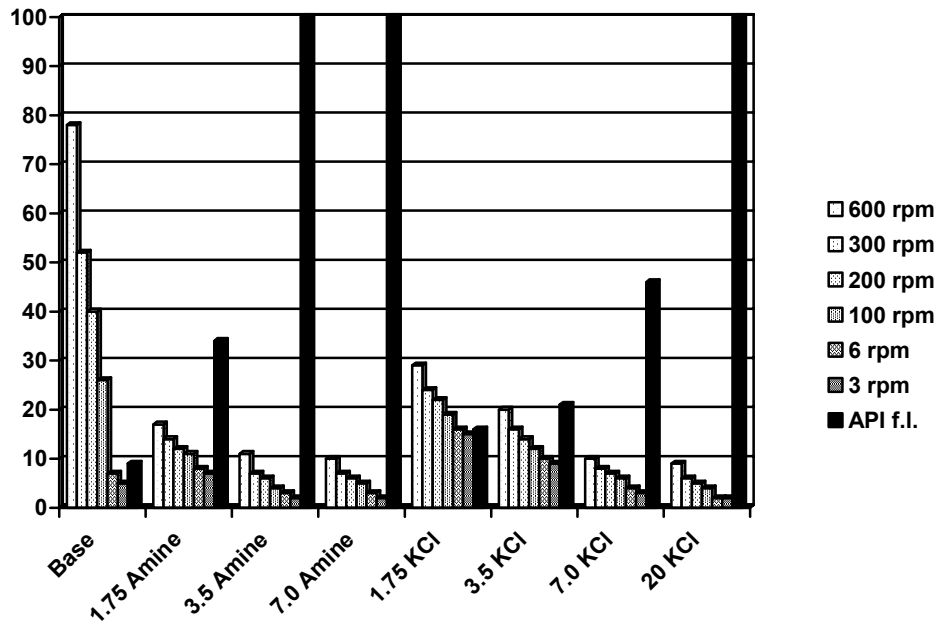


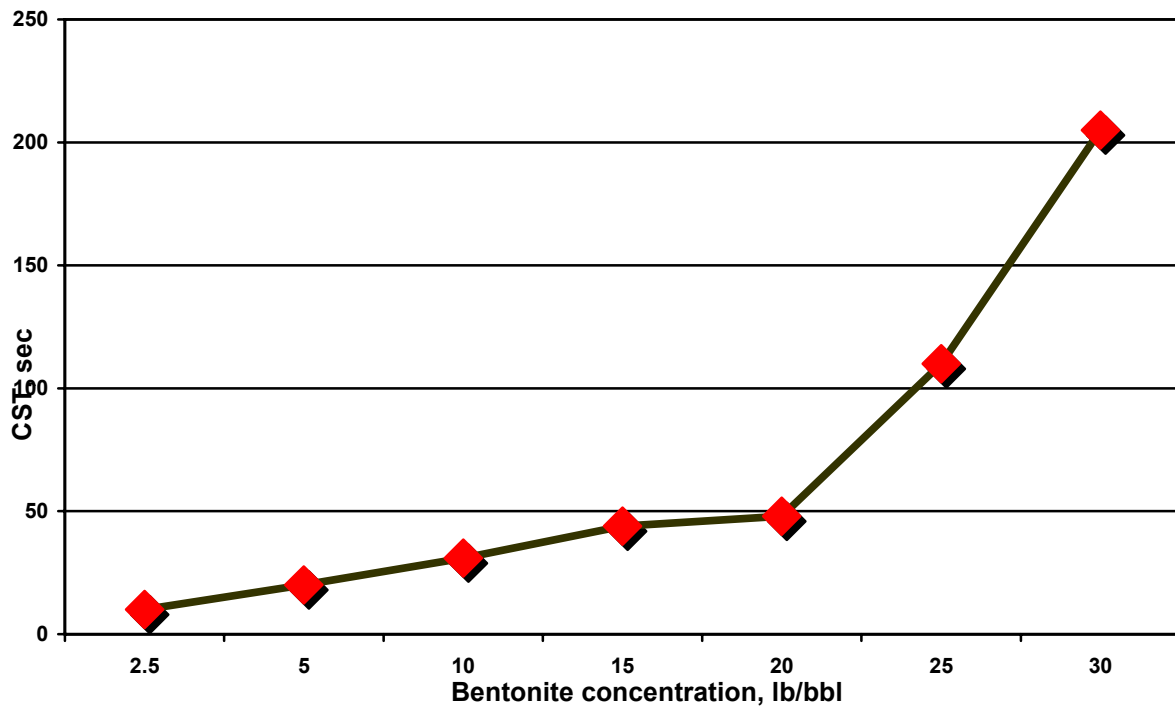
Figure 2: Suppression of Bentonite Hydration



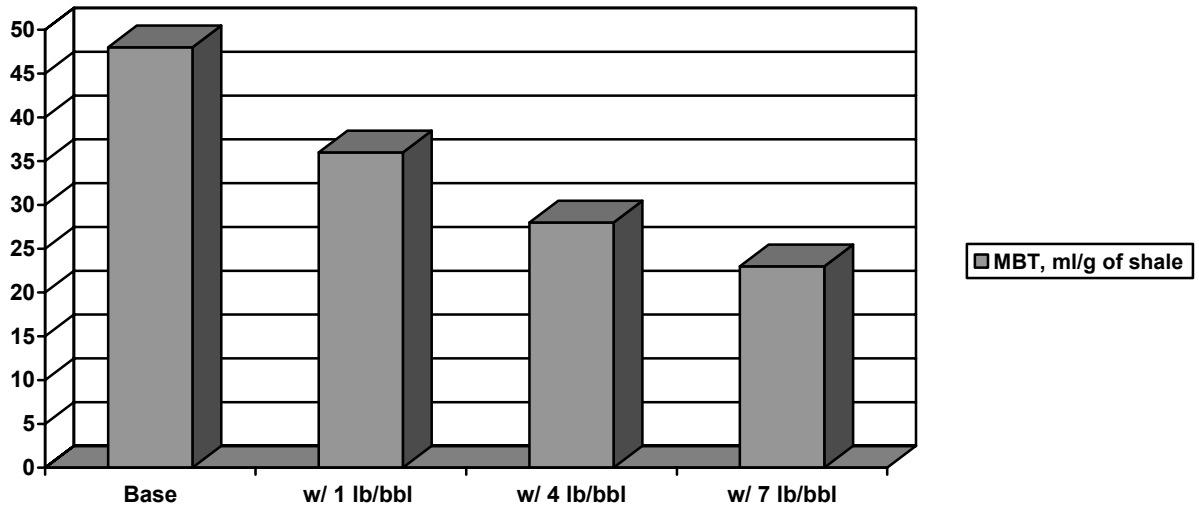
**Figure 3: Suppression of Bentonite Hydration – Amine Salt vs. Potassium Chloride**



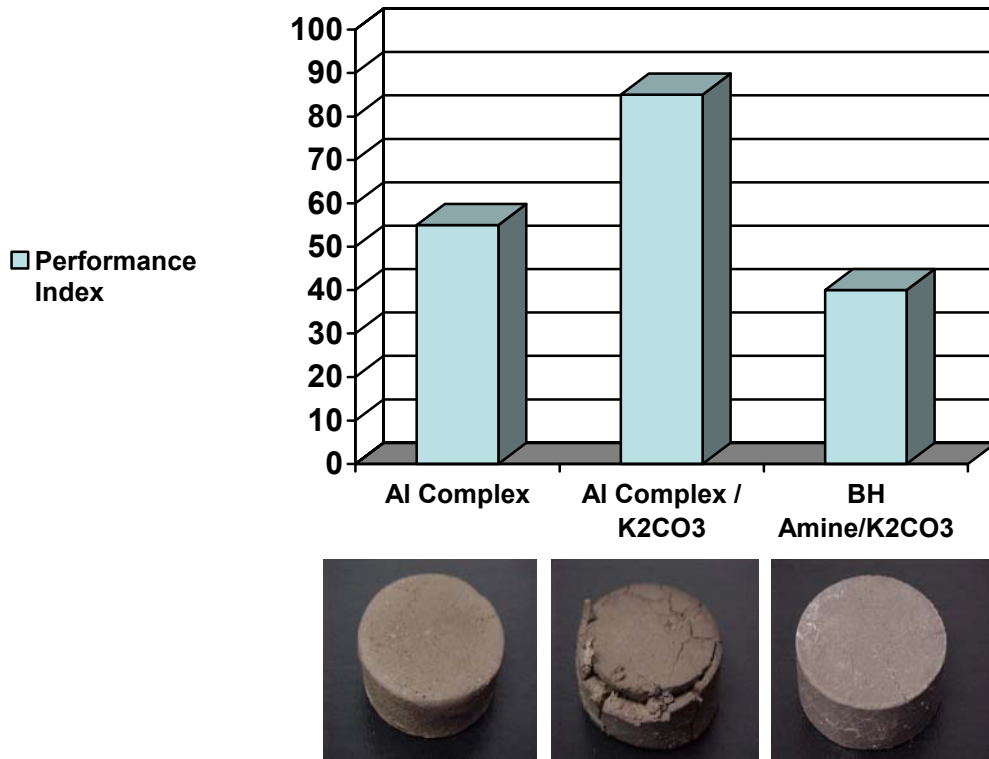
**Figure 4: CST Study of Amine Depletion on Reactive Clay**



**Figure 5: Resultant MB Measurements of Grinded Shale Cutting Samples, Dispersed in Freshwater with Increasing Amine Salt Dosages (Cuttings from 1197 – 1247 m)**



**Figure 6: Comparative Evaluations of Aluminum Complex Fluids and an Amine Salt Fluid, with and without Potassium Carbonate, for Shale from Ecuador**



\*\* Performance Index is the sum of % hardness change, % swelling and % hydration. A high PI denotes poor performance while a low PI indicates more effective wafer preservation.

Figure 7: Location of Magallanes Project

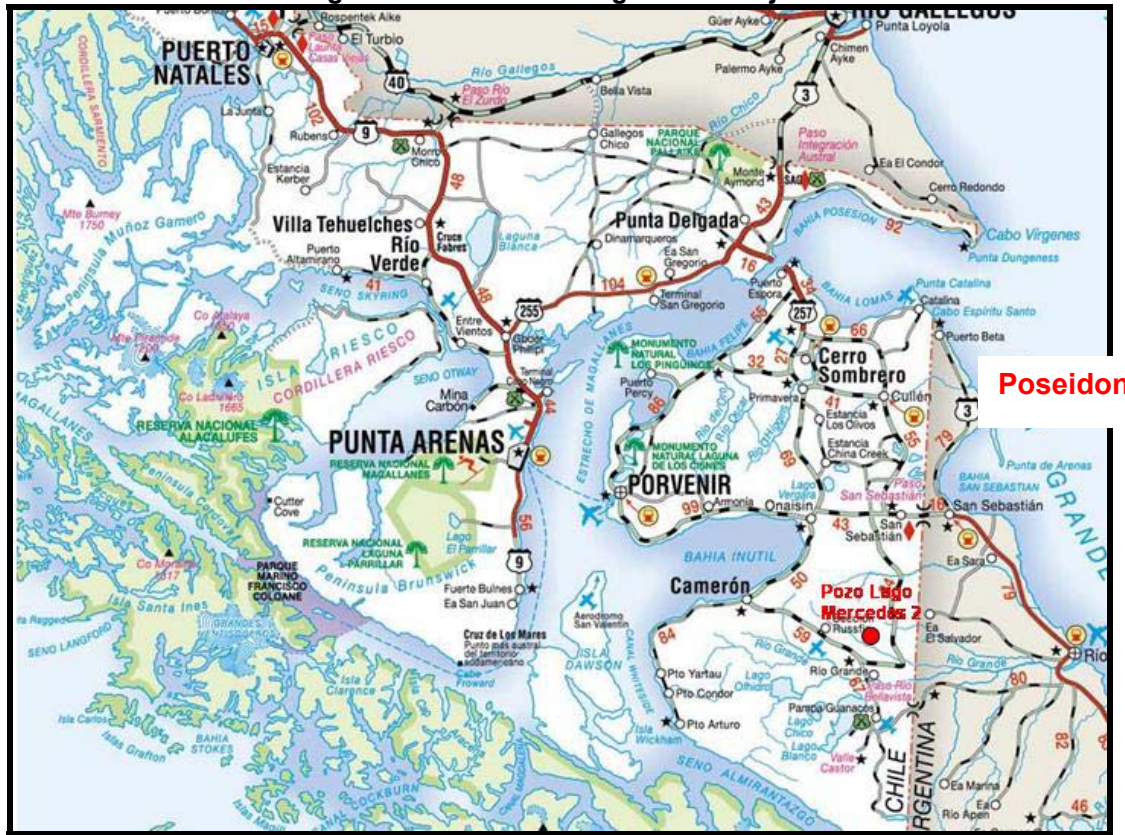


Figure 8: Typical Geological Section

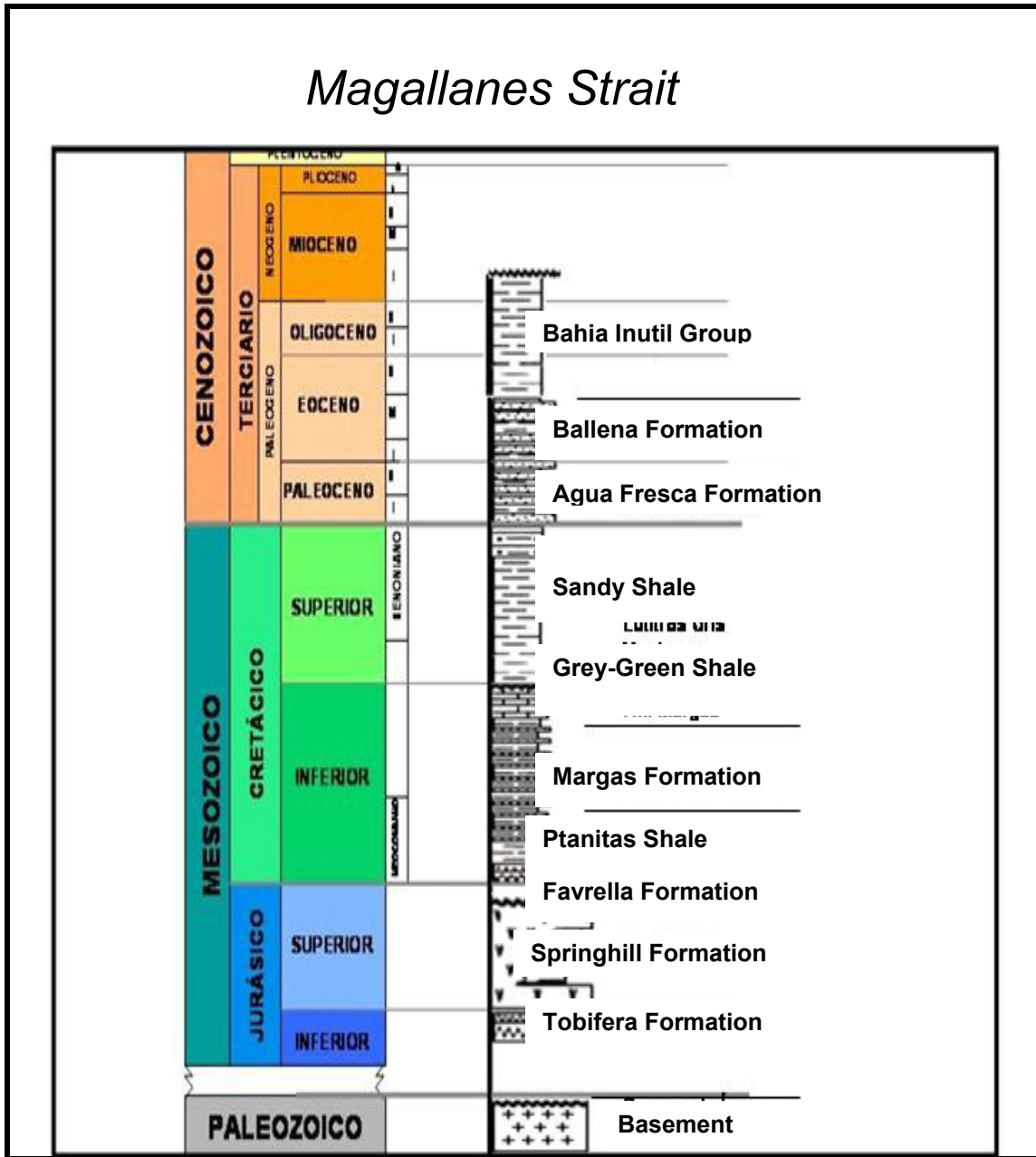
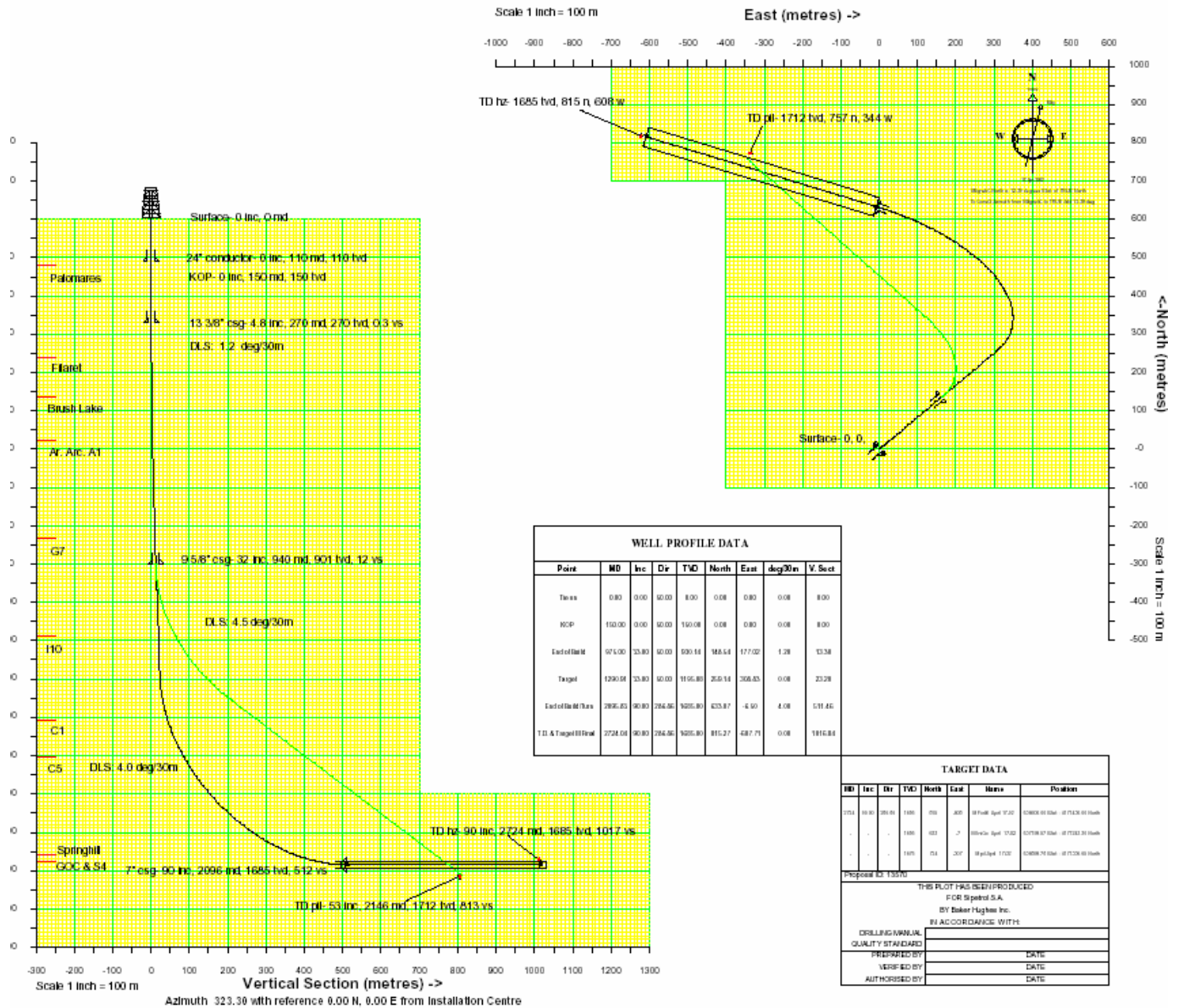
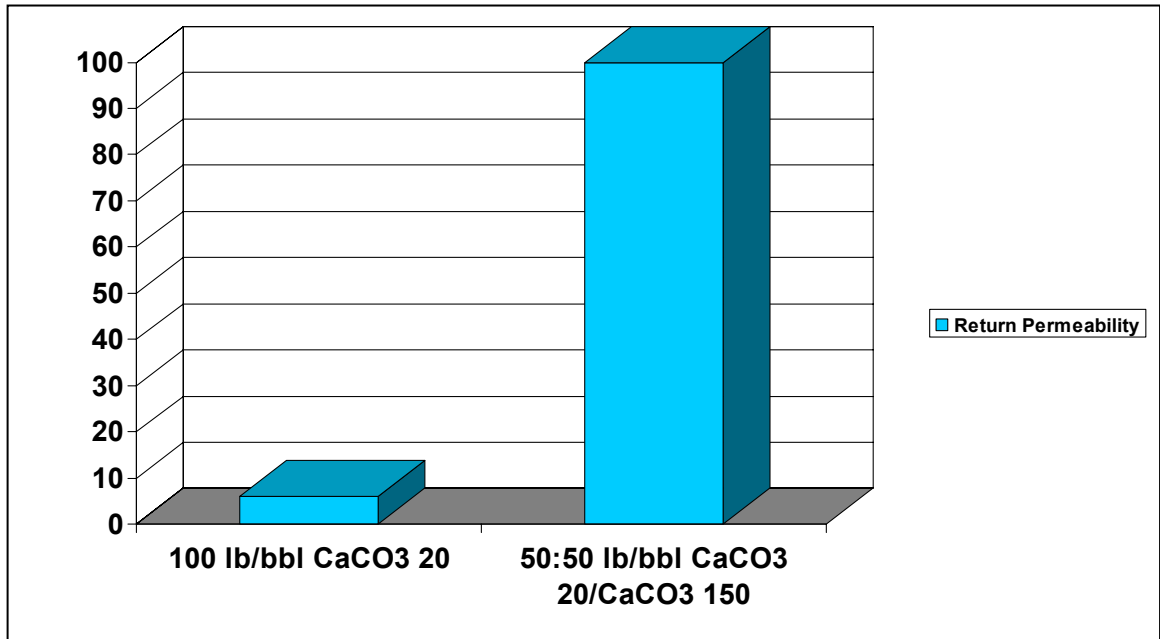


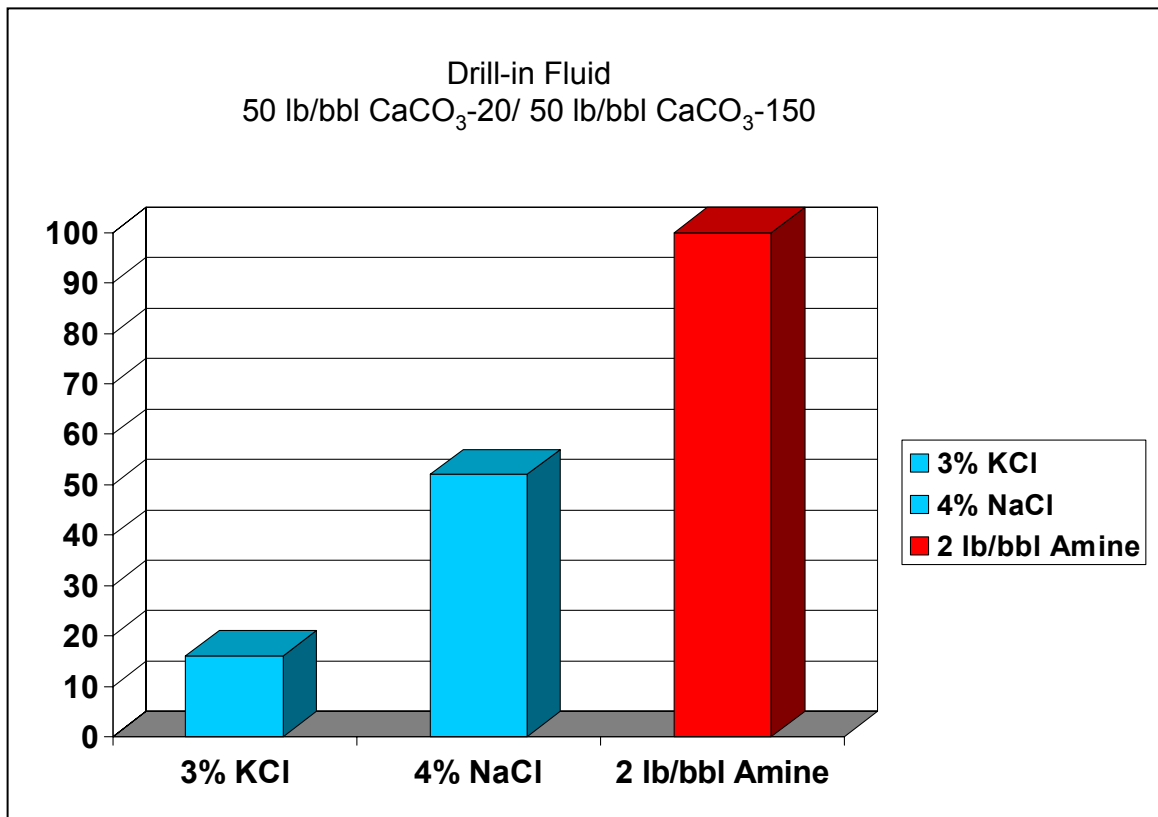
Figure 9: Typical Well Path

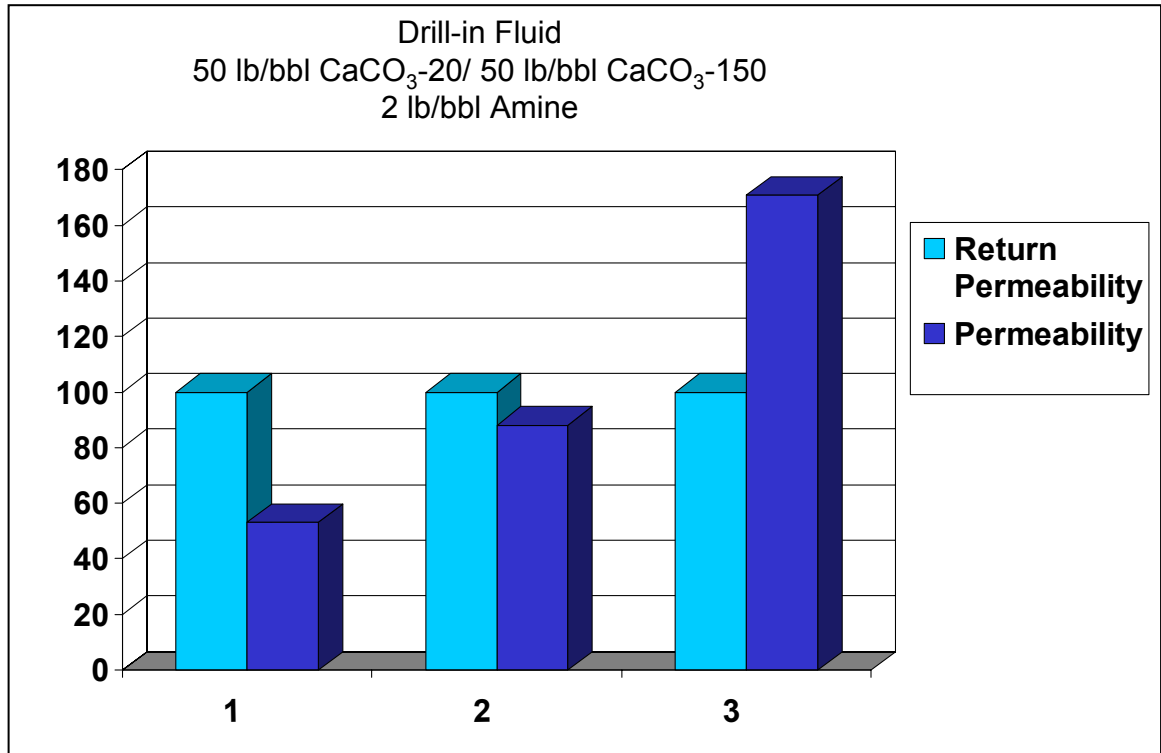
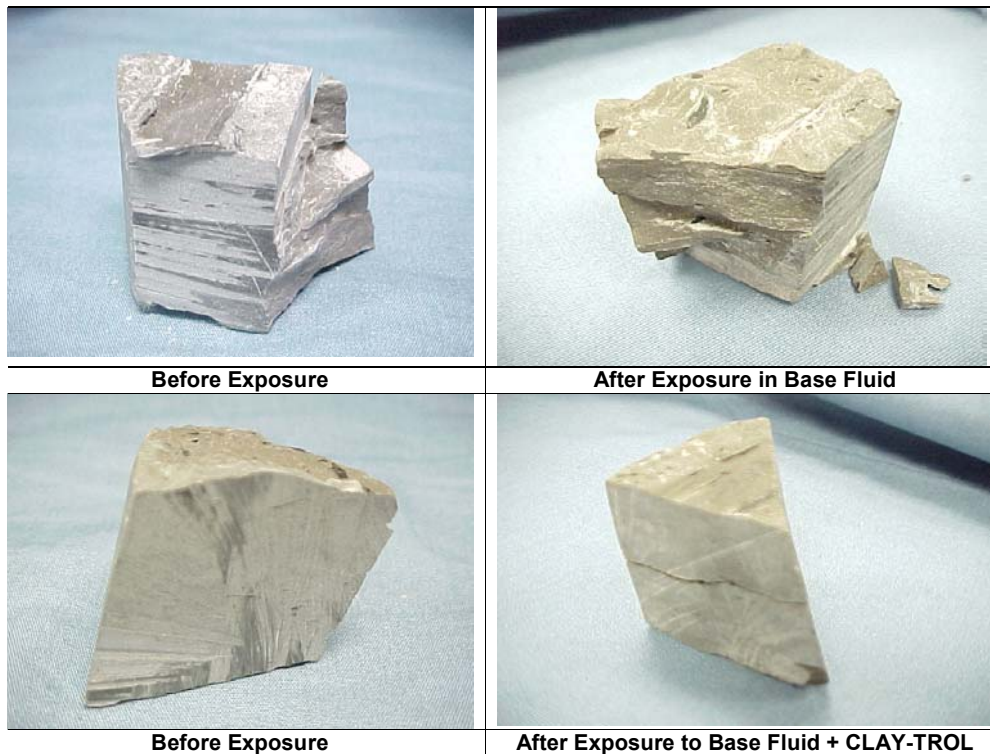


**Figure 10: Return Permeability and Calcium Carbonate Particle Size**



**Figure 11: Return Permeability Amine vs KCl & NaCl**



**Figure 12: Return Permeability with Amine at Different Permeability****Figure 13: Core samples exposure to Amine Drill-in Fluid**

Actual shale before and after exposure to the 10.2 lb/gal Drill-in fluid and the base fluid with Amine Salt

**Figure 14: Horizontal Section Well Performance**