An investigation into the water bearing sands of Offshore Mauritania, West Africa

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Abstract

The variation of the salinity value of water bearing sands can be an indicator of proximity to a geological salt structure known as a salt diapir. This paper presents the importance of the distance of wells to these structures for exploration and production of hydrocarbons, and suggests an alternative indirect method of obtaining the salinity values for the water bearing sands. With knowledge of the salinity values and the underlying geological structure, this project will aim to predict salinity values due to proximity to a salt diapir and hence have a direct impact on optimisation of drilling activities.

1.0 Background

1.1 Field Description

The Mauritanian basin off West Africa contains the Chinguetti, Tevet and Tiof oilfields and the Banda gas field. Woodside began exploring in Mauritania in 1999 and discovered the Chinguetti oil field in 2001, the Banda gas field in 2002, the Tiof oil field in 2003 and the Tevet oil field in 2004. The reservoir formation is sandstone with excellent properties. It exhibits porosities greater than 30% and permeability's greater than 1 Darcy. These sandstones were laid down in the Miocene age, which ranged between 23.7 – 5.3 million years ago. As this is a relatively young age, the environment was not that dissimilar to our own at present day. Thus the sands were deposited in water with a density and salinity similar to that of our seawater (roughly 28 kppm NaCl and a density of 1.02 g/cc at 20 °C). The Chinguetti field lies above a salt diapir, which is a geological structure that can influence the temperature and pressure of the immediate vicinity. Salt diapirs intrude sedimentary beds due to the salts lower density and thus create possible hydrocarbon traps within the sedimentary beds. A more in depth description of salt diapirs and their importance will be given later on in the paper.

1.2 Formation Water

The composition of formation water is very important when considering all aspects of the exploration, production and refining of hydrocarbons. For example, the composition of the formation water can tell us about the depositional environment of the reservoir rocks. The formation water composition is of particular interest for Mauritania as it can be an indication of the type of formations that may be nearby the sample site. A high salinity value (and a low salinity value) for formation water can be due to many factors. The main factor of concern for the Mauritania basin is the intrusion of a salt diapir. Other influences on the composition of formation water are the original depositional environment, underground aquifers in communication with one another and therefore mixing of two separate formation waters occurs. These other influences are not an issue for Mauritania; however, the reservoirs proximity to a salt diapir plays a major role in the composition of the formation waters composition.

1.3 Chinguetti Salt diapir.

Of particular interest is the Chinguetti oil field, which will be Mauritania's first oil project. It is located 90km southwest of Nouakchott, Mauritania in 800 metres of water. More importantly for this study, the Chinguetti oil field has a very close proximity to a salt diapir.
Salt diapirs can evolve from a mass of salt to a diapir and then to a smaller detached sheet. Since salt is less dense than other sediments, it flows upward, piercing the overlying material and, in some cases, forming traps in which hydrocarbons can accumulate.[4] This is illustrated in figure 1.

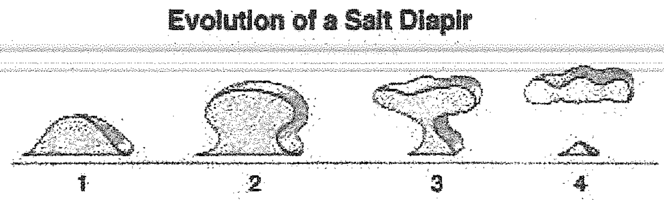

Figure 1: Evolution of a Salt diapir[4]

Hence the importance of salt diapirs to the exploration and production of hydrocarbons. This project will aim to characterise the salinity values obtained via wire-line formation testing and its relationship with the proximity to salt diapirs.

1.4 Chinguetti Wells

The Chinguetti field has had a large number of wells drilled into it. Of these wells, several are appropriate for this study. That is they contain clean water bearing sands. The petrophysical methods that have been chosen to carry out this study are such that only clean sands can be analysed. Those with high shale content (dirty sands) will not be appropriate. This is because porosity logs, e.g. neutron, density and sonic, and saturation logs, i.e. deep-resistivity, are affected by the shale and clay present in shaly sands. Thus, the following wells have been selected from the Chinguetti oil field:

Chinguetti	4-2
Chinguetti	8
Chinguetti	9
Chinguetti	10
Chinguetti	10 ST1
Chinguetti	13
Chinguetti	15

To ensure completeness and for comparison reasons the following wells will also be analysed for their salinity values relative to the Chinguetti field.

Banda 1	Tevet 1
Capitaine	Merou

Dorade 1	Tiof 5

2.0 Determining Water Composition

There are two basic of methods to determine the salinity of a formation water sample, the Direct method and the In-direct method. The direct methods require a sample of the formation water and subsequent physical analysis. The indirect method use in situ measurements to infer the salinity values.

2.1 Direct Methods

At present salinity values are determined by chemical analysis carried out on samples obtained through Wire-line Formation Testers (WFT) and cores taken from wells. Another alternative is Drill-stem test.

2.1.1 Well Test

There are many types of well tests that can be carried out. For example, there is injection well testing, pressure transient well testing and pumping well testing. These are mainly methods to obtain pressure data, through build-up tests or fall off test. These types of tests are time consuming and should be used as a last resort to obtain a water sample. They are, however, the only real way to find how a well will perform and can give measurements of reservoir limits, permeability, and skin damage.

2.1.2 Core Samples

Core samples are taken in order to understand the composition and quality of the reservoir rock, inter-reservoir seals and the reservoir pore system. They are also used to obtain the rock properties by direct measurement in laboratories. Coring is typically performed between drilling operations and takes about a day to complete. The core is obtained using a special assembly on the drill pipe comprising of a core bit and core barrel. The main cost factor for coring is the rig time spent coring and the follow up investigations in the laboratories. Core analysis is complex and may require several different laboratories. Thus, it may be several months after the core is taken that a result is available.

2.1.3 Wire-Line Tester Background

The purpose of the wire-line or sidewall formation tester was initially to isolate a small portion of the borehole wall from the mud and extract a fluid sample. From this sample, the original formation tester could carry out pressure tests via a pressure gauge on the flow line. Thus, a flowing pressure curve could be recorded during draw down, as well as a build up curve when the sampling chamber was full. This original tester was invented around 1950 and had a sampling chamber size of 1 gallon (3.75 litres) or 2.75 gallons (10.4 litres).

For pressure measuring only, most of the tools available today collect two small 10 cm^3 samples in succession: the first one in16 s (0.63 cm^3/s) and the second in 8 s (1.25 cm^3/s) These samples are called "pre-tests' and are dumped in the borehole before proceeding to the next depth. The reason for the two flow-rates is to make two drawdown permeability calculations.

2.1.4 Current Formation Tester and Method for Obtaining Salinity Values.

The formation tester that has been used on the Chinguetti field and for all the Mauritanian wells is the Reservoir Characteristic Instrument (RCI) from Baker Hughes. The RCI is a modular formation testing and sampling tool designed to provide a more complete description of reservoir fluid and behaviour. The RCI's modularity provides the ability to test and sample fluids in a wide range of geological environments and borehole conditions. The tool has a fully controllable packer section for variable-volume and variable-rate draw down, small and large displacement pumps, a Multi Tank Carrier system for cost efficient sample recovery, and SampleView^{SM}, a near infrared analyser module for complete down hole fluid characterization.[1] The sample obtained then can be chemically analysed and the salinity value of the formation fluid can be determined. Alternatively, a core sample could be taken in the well. The core is then placed in a centrifuge where the formation fluid is spun out of the core, and again chemical analysis is carried out on the fluid to determine the salinity. Thus it is obvious that direct formation testing is a conventional method that is attractive to industry for its known accuracy and reliability.

2.2 Problems with the Direct Methods

This is a convenient method for obtaining the salinity of the formation fluid; however, there are several issues that arise whilst obtaining the fluid or core sample.

2.2.1 Cost

The issue of most concern to Oil and Gas companies is the time and cost of obtaining the sample. Not only does the sampling or coring cost the company to take place, but it also increases the rig time that is required (typically a day). The physical movement of the sample (transportation, maintenance, etc) or core and handling can also be expensive and damage may occur which will hinder the accuracy of the analysis.

2.2.2 Sample Contamination

As mentioned, it can be quite difficult to ensure that the sample has not been contaminated (by mud filtrate). The Chinguetti field, and the surrounding wells within the offshore Mauritania field, have been drilled using oil-based mud. Oil based muds are widely used in offshore drilling applications. Of concern however is the resulting contamination associated with obtaining high quality samples of formation hydrocarbons. The filtrate of an oil-based mud is highly soluble in crude oils; therefore, any contamination of the sample with oil based mud filtrate can significantly affect the composition and phase behaviour of the sample. This is of course a concern for sampling the hydrocarbons and due to the often high salinity of the oil-based mud can affect the chemical analysis of water samples if the suspended water phase is destablised.[3] This is less of a concern for water samples due to the immiscibility and opposing characteristics of oil and water. It is easy to see and disregard the affects of any filtrate that occurs within the water samples when analysing wire-line data because of the opposing characteristics. The oil based mud filtrate invasion is easily identified through the shallow resistivity curve. It will show a higher resistivity than the medium and deep resistivity curves indicating that the tester is responding to the filtrate and not the formation fluid.

2.2.3 Accessibility of Clean Sands

The well itself may not penetrate permeable water bearing sands. Chinguetti-1 is an example of this situation, where it only encountered oil-bearing sands before drilling into the salt diapir.

2.3 Indirect Methods

As mentioned previously, indirect methods utilise in situ well data in order to infer the salinity values. These methods include the use of wire-line log responses, catalogue and analogues and the method of inference. For example, if we know the pressure and depth data for a particular well, a Pressure-Depth graph will allow the calculation of the density of the formation fluid. From this we can then calculate the salinity of the formation fluid. Alternatively, we can assume a salinity level based on wells that have been drilled in singular nearby formations. This typically needs to be used in conjunction with other data, such as geological mapping and seismic to ensure its appropriateness and can often result in errors. The method that I propose to use is Wire-line log responses. Using the formations responses to certain tests, i.e. resistivity and gamma ray, water bearing sand sections can be identified and then analysed. Using known industry techniques and iterative methods, the formation water resistivity, density and thus salinity can be calculated.

3.0 Methodology

The methodology that has been used relies on the following: A porosity equation developed from first principles, Archie's Equation, a linear Thermal and Pressure Gradient and the linear dependency of salinity upon resistivity and temperature. An iterative method has also been developed which utilises brine density being a function of fluid salinity and formation temperature and pressure. A flow chart below outlines how each are related, and the iterative process involved.

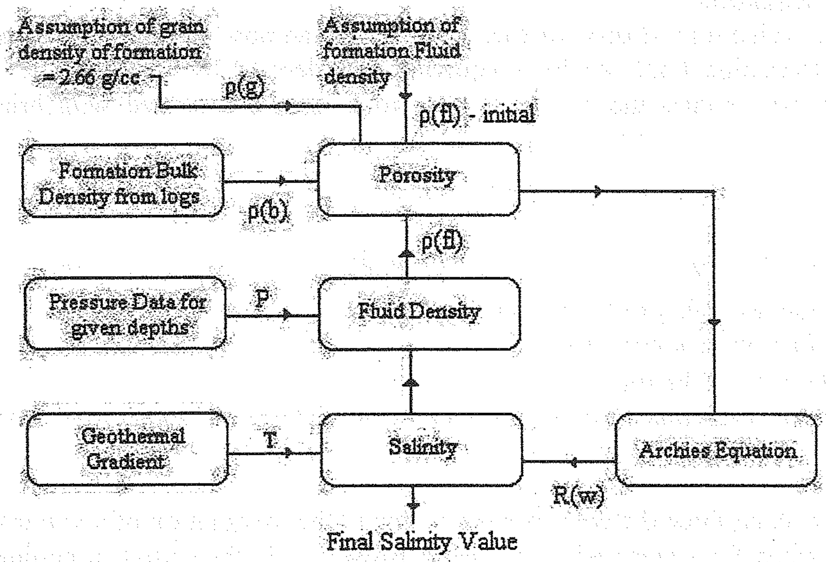

Figure 2: Determining Salinity Flow Chart

3.1 First Principles

Before we obtain the salinity values for formation water within the reservoirs, we need to obtain the porosity for each sample. To do this we need to go back to first principles to obtain an equation for the rocks porosity.

3.1.1 Porosity Equation

The porosity equation, shown below, has been derived from first principles. That is it has been derived using a general mass balance of the reservoir.

First principles: $$m_{bulk} = m_{matrix} + m_{fluid} \quad (1.)$$

Where m_{bulk} is the bulk mass of the sample

m_{matrix} is the mass of the rock matrix

and m_{fluid} is the mass of the formation fluid

Thus giving ➔ $$\phi = \frac{\rho_r - \rho_b}{\rho_r - \rho_f} \quad (2.)$$

Where ρ_r is the grain density, assumed in this case to be 2.66 g/cm^3 (obtained from core data)
ρ_b is the bulk density, which is measured via the wire-line density log
and ρ_f is the formation fluid density. This value has been set to values of 1, 1.1 and 1.2 g/cm^3 in order to account for the effect of salinity on the density of the formation fluid. Note: That within the iterative method, which will be described later, the formation fluid density is calculated and put back into the calculation to find salinity.

3.2 Extrapolation Method

The extrapolation method utilises a straight-line interpolation method that relates temperature, formation water resistivity and formation water salinity. From temperature data obtained during testing, a geothermal gradient can be calculated and applied for the wells. This allows us to obtain an exact temperature value for the individual sections of interest. We can then use Archie's equation to find the formation water resistivity.

3.2.1 Archie's Equation

With the calculated value for porosity for each section, we can now use Archie's equation to find the resistivity of the formation fluid. Archie's equation was derived by G. Archie in 1942 and is an empirical equation that relates the resistivity of a rock sample saturated with brine to the rocks porosity. Archie's equation is shown below:

$$R_t = \frac{a.R_w}{\phi^m} \qquad 3.$$

Rearranging equation 3 gives:

$$R_w = a.R_t.\phi^m \qquad 4.$$

Where R_t is the true resistivity of the formation
R_w is the formation water resistivity
ϕ is the porosity of the rock
and a & m are the cementation exponents. These are determined experimentally and have been taken to be 1 and 2 respectively.

Since we have calculated three different porosities due to the assumption of a variable fluid density, we obtain three values for water resistivity. Each resistivity is then used in conjunction with the temperature at the sample depth to approximate a value for the salinity of the sample. This is a graphical method known as the "Resistivity of equivalent NaCl solutions" and again is a widely accepted method of determining salinity levels. This graph can be found in the Baker Hughes: Baker Atlas Log Interpretation Charts.

3.3 An Iterative Method

The extrapolation method can be then verified via an iterative method that utilises formation fluid density being dependant on pressure, temperature and salinity. Through the previous method, a value for salinity is determined and then used to obtain a new value for the formation fluid density. This new fluid density is then used to re-calculate the salinity. We can continue this step, recalculating the formation fluid density and thus obtaining a more accurate value for the salinity. The extrapolation method utilises temperature and resistivity data to obtain the salinity of the formation water, where as the iterative method includes pressure and a more precise value for the assumed value of the formation water density. It is important to note that an initial fluid density of 1 g/cc has been assumed. Also, that within each method a constant thermal gradient and pressure gradient has been assumed and has been found using data obtained through wire-line testing. This has allowed interpolation or extrapolation to obtain either pressure or temperature data for the given depths.

3.4 Proximity to a Salt Diapir

The varying salinity values, as mentioned, can be dependant upon the distance to a salt diapir. Thus the next stage in the investigation is to link the salinity variations to the proximity to the salt geological structure. This will be carried out with knowledge of the direction and depth of the wells in question and the position of the underlying salt diapir. This is sensitive information and thus will not be presented at this time.

4.0 Early Results and Further Work

4.1 Salinity results.

Thus far, all of the salinity values that are required have been obtained. The ranges of which are tabulated below for each well.

The Chinguetti Wells:

Well	Salinity Range	Method used to obtain salinity
Chinguetti 4-2	22 – 90	Iterative Method
Chinguetti 8	11 – 240	Archie's Equation
Chinguetti 9	132 – 250	Archie's Equation
Chinguetti10	16.5 – 160	Archie's Equation
Chinguetti10 ST1	42 – 130	Archie's Equation
Chinguetti 13	42 – 125	Archie's Equation
Chinguetti 15	46 – 270	Archie's Equation

And the other Mauritania Wells:

Well	Salinity Range	Method used to obtain salinity
Banda 1	18 – 35	Iterative Method
Capitaine	32 – 115	Archie's Equation
Dorade 1	39 – 80	Archie's Equation
Tevet 1	10.5 - 40	Iterative Method
Tiof 5	17 – 240	Archie's Equation
Merou	76 – 270	Iterative Method

4.2 Salt Diapir Proximity

This work is yet to be completed, however will be completed within the next month. This data will hopefully give an insight to the field for Woodside that they are yet to have. It will also help them with future developments that are situated on or near salt diapirs, and thus allow them to compensate. Again, I hope that this will benchmark the accuracy and reliability of such an indirect but convenient method comparing its outcomes with experimental results. Using the known depth and direction of the wells studied, and the height of the apex of the salt diapir it is possible to characterise the salinity range of the area. Thus, knowing the distance from a saline point source, which is the apex of the diapir, it will be possible to predict a salinity range for a proposed well. This will be shown graphically and compared with the control wells outside of the Chinguetti field. Thus the wells that are some distance from the Chinguetti field, such as Banda, will allow a comparison.

4.3 Engineering Applications

A focus on the engineering applications of the outcome will be applied, in particular a drilling engineering viewpoint. A known value for the salt concentration in the area will allow for an optimisation of salt concentration in drilling fluids and thus enhance well-bore stability, and minimize failure during drilling operations in that region. This will ultimately bring down the time spent drilling and therefore the drilling costs. Also of interest is the formation of scale and corrosion of the drill bit and drill string due to the high salinity of the formation. Thus, an appropriate selection of material can be used in order to withstand the estimated corrosion.

5.0 References

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