

بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ



**SUDAN UNIVERSITY OF SCIENCE AND TECHNOLOGY**

**COLLEGE OF GRADUATE STUDIES**

**Analyses of Formation Damage Caused by  
Drilling Fluid in Bamboo field (Sudan)**

أقدم  
هذه الرسالة  
كجزء من متطلبات  
درجة الماجستير  
في هندسة الحفر  
(جامعة السودان للعلوم والتكنولوجيا)

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# الاستهلال

بِسْمِ اللّٰهِ الرَّحْمٰنِ الرَّحِیْمِ  
**(( قُلْ سَیْرُوا فِی الْاَرْضِ  
فَانظُرُوا كَیْفَ بَدَأَ الْخَلْقَ ثُمَّ  
اللّٰهُ یُنشِئُ النَّشْأَةَ الْاٰخِرَةَ اِنَّ  
اللّٰهَ عَلٰی كُلِّ شَیْءٍ قَدِیْرٌ ))**

صدق الله العظيم

( سورة العنكبوت الآیه 20 )

# **DEDICATION**

**To who suckled me her  
love and compassion to the  
symbol of love and healing  
balm to the heart as pure  
whiteness**

**My mother**

**To my, Family, Teachers &  
Friends**

**With gratitude and love**

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**Merciful god thanks and appreciation gave me the ability to complete this work. I assign appropriate credit to all who have contribute in some way to make this study in its final shape.**

**Second I would like to express my thanks and gratitude to my supervisor Dr. Ahmed who did not spare on Informing, advice, time, and close supervisions.**

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**Finally, I grant my thanks to all who enhanced me with help in this study.**

# Abstract

Formation Damage is any reduction in near well bore permeability which in this study is a result of any material from drilling and completion operations. In spite of many studies, there have been only a few reported attempts to mathematically model the pertinent processes.

This research applying the wojtanowicz et. al. model in Bamboo-Sudan oilfield to study the drilling fluid effects in the Bentiu reservoir formation (Units 1, 2, and 3) and the amount of formation damage for well (X West-4). Laboratory experiments were done to evaluate the mud cake thickness and the filtration. The correlation of experimental work and mathematical model was in great benefit by reducing the percentage of solids.

Formation damage mechanisms vary depending on the well operation types, reservoir and fluid conditions. The rock properties were the base for all calculations and assumptions done throughout the data evaluation and the constants determination. The wojtanowicz et al model and drilling fluid new design proposed considered as the optimum to use in bamboo field.

Foreign particles invasion damage to formation could be controlled by reducing of Barite solids from (4.76%) to (2.2%). The Pore Blockage by External Particles Diagnostic Chart for Unit-1, 2 and 3 were obtained assuring that the damage could be control and reduced by using the optimum concentration of barite (2.2%).

Finally, it is high recommended to continue searching on (apply  $\text{CaCO}_3$  in this work and study the effects of it, using local products (Arabic Gum, الزيتية, النباتات, ..., etc.) which have the same specifications with the imported additives).for the benefits of economical hazard reduction. Specially, in this study the reduction was 9.6% barite quantity in cubic meter (overall operation cost).

## □□□□□

- يمكن تعريف الضرر الطبقي علي انه التغيير في نفاذيه الطبقة القريبه من البئر الناتج من اي عمليات مثل الحفر, الاكمال, بالرغم من وجود العديد من الدراسات التجريبيه لكن هناك القليل من المحاولات للنماذج الرياضيه بالطرق المناسبه لدراسه مثل هذه العمليات .
- قد تم في هذا البحث تطبيق النموذج الرياضي لوجتانونيكر في احد الحقول السودانيه لمعرفة تأثير سائل الحفر المستخدم في منطقه المكمن علي النفاذيه وتحديد قيمه الضرر ومن ثم اجراء تجارب معمليه لتقليل نسبه المواد الصلبه في وبالم حافظه علي خواص سائل الحفر وبالتالي تقليل قيمه الضرر الناتج لعمليات الحفر المستقبليه.
- البحث يستعمل طريقه ووجتانونيكر في حقل بامبو في السودان لدراسه تأثير سائل الحفر في طبقة بانتيو وتقييم الضرر الطبقي للبئر (Xwest-4). تم اجراء تجارب معمليه لمعرفة سماكة كيكه الطين وفاقد الرشح, ومن ثم العلاقه بين التجارب المعمليه والنموذج الرياضى التي كانت ذات فائده جيده يمكن ان تساهم في تقليل نسبة المواد الصلبه.
- طرق حدوث الضرر الطبقي متنوعه تعتمد على العمليات المختلفه للبئر, وخواص المائع والمكمن . خواص الصخر ثابتة لكل الحسابات والفرضيات وذلك من خلال تحديد الثوابت وتقييم المعلومات (نموذج ووجتانونيكر) ايضاً التصميم الجديد لسائل الحفر المقترح ليستخدم في حقل بامبو .
- تم التحكم في الضرر الذي يسببه اجتياح الجزيئات للطبقة بواسطة تقليل نسبة البرايت من 4.7% الى 2.2%. الرسم التشخيصي لقلل المسام بواسطة الجزيئات الخارجيه للطبقات (الوحدات 1 و 2 و 3) الذي تم الحصول عليه يبين انه يمكن التحكم في الضرر وتقليله باستخدام تركيز البرايت (2.2%).
- اخيراً, نوصى بالمواصله في البحث ب(استخدام كربونات الكالسيوم في هذا العمل ودراسة تأثيرها, استخدام المنتجات المحليه مثل الصمغ العربى والزيوت النباتيه التي لها نفس مواصفات الاضافات المستورده). بالنسبه للمحازير الاقتصادية في هذه الدراسه قللت كمية البرايت مما ادي لتخفيض كلفه عمليه الحفر بنسبة 9.6% من التكلفة الكليه لحفر البئر.



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# CHAPTER 1

## 1. INTRODUCTION

Formation damage is a generic terminology referring to the impairment of the permeability of petroleum bearing formations by various adverse processes. It is an undesirable operational and economic problem that can occur during the various phases of oil and gas recovery from subsurface reservoirs including production, drilling, hydraulic fracturing, and workover operations, it occurs in petroleum-bearing formation by various mechanisms and/or processes, depending on the nature of the rock and fluids involved. The commonly occurring processes involving rock-fluid and fluid-fluid interactions and it is caused by chemical, biological, hydrodynamic, and thermal. Interactions of porous formation, particles, and fluids cause mechanical deformation of formation under stress and fluid shear. Formation damage indicators include permeability impairment, skin damage, and decrease of well performance.

Generally Formation Damage can be defined as any reduction in near well bore permeability which is the result of any material from drilling, completion, production, injection, attempted stimulation or any other well inter.

As expressed by Amaefule et al.<sup>1, 2</sup> "Formation damage is a great problem in the oil and gas industry. Bennion<sup>3</sup> described formation damage as: "The impairment of the invisible, by the inevitable and uncontrollable, resulting in an indeterminate reduction of the unquantifiable. Formation damage assessment, control, and remediation are among the most important issues to be resolved for efficient exploitation of hydrocarbon reservoirs .As expressed by Porter and Mungan<sup>4</sup>, formation damage is not necessarily reversible. Thus, it is better to avoid formation damage than try to restore formation permeability using costly

methods with uncertain successes in many cases. When a verified generalized formation damage model becomes available, it can be used to develop strategies to avoid or minimize formation damage.

To the researcher knowledge up to date, no modeling work has been reported for the prediction of the effects of dynamic mud filtration and filter cake on formation damage. However; this study will try to reduce the drilling mud damage as:

1. Development of formation damage control strategies.
2. Optimization of mud solids concentrations for prevention and/or reduction of the reservoir damage.

These tasks can be accomplished by means of:

1. Model assisted data analysis, laboratory test case studies, and extrapolation and scaling to conditions.
2. Design new drilling fluid and use different lab equipments to measure rheological properties and filtration tests.
3. Use the Wojtanowicz et al. model for particle invasion and bore blocking by fluid solids movement and capture to evaluate the permeability.
4. Combination between the formation damage and drilling fluid test.

## **CHAPTER 2**

### **2. LITERATURE REVIEW**

Formation damage is an exciting, challenging, and evolving field of research. In the past, numerous experimental and theoretical studies have been carried out for the purpose of understanding the factors and mechanisms that govern the phenomena involving formation damage. Although various results were obtained from these studies, a unified theory and approach still does not exist<sup>1</sup>.

A verified formation damage model and carefully planned laboratory and field tests can provide scientific guidance and help develop strategies to avoid or minimize formation damage. Properly designed experimental and analytical techniques, modeling and simulation approaches can help understanding, diagnosis, evaluation, prevention, remediation, and controlling of formation damage in oil and gas reservoirs<sup>1</sup>.

Therefore, it is essential to develop experimental and analytical methods for understanding and preventing and/or controlling formation damage. The laboratory experiments are important steps in understanding the physical basis of formation damage phenomena. "From this experimental basis, realistic models which allow extrapolation outside the scaleable range may be constructed". These efforts are necessary to develop and verify accurate mathematical models and computer simulators that can be used for predicting and determining strategies to avoid and/or mitigate formation damage in petroleum reservoirs<sup>5</sup>. Planning and designing field test procedures for verification of the mathematical models are important. Once a model has been validated, it can be used for

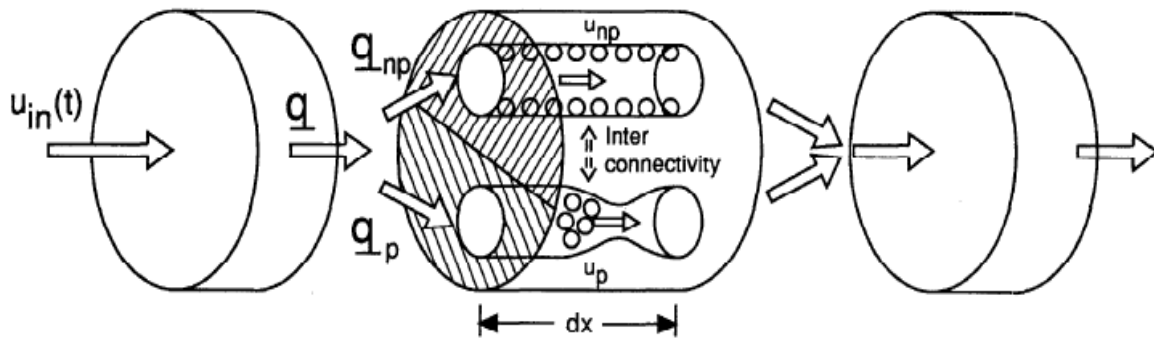
accurate simulation of the reservoir formation damage. Current techniques for reservoir characterization by history matching do not consider the alteration of the characteristics of reservoir formation during petroleum production. In reality, formation characteristics vary and a formation damage model can help to incorporate this variation into the history matching process for accurate characterization of reservoir systems and, hence, an accurate prediction of future performance.

## **2-1: The Mathematical Model**

### **2-1-1: Gruesbeck and Collins**

Gruesbeck and Collins<sup>6</sup> developed a partial differential model based on the concept of parallel flow of a suspension of particles through plugging and nonplugging pathways, as depicted in Figure 1-1. Relatively smooth and large diameter flowpaths mainly involve surface deposition and are considered nonplugging. Flowpaths that are highly tortuous and having significant variations in diameter are considered plugging. In the plugging pathways, retainment of particles occurs by jamming and blocking of pore throats when several particles approach narrow flow constrictions.

The model consisted of (1) a sequence of experiments using synthetic fines/porous-media systems to identify fundamental processes and to provide guidelines for a phenomenological description, (2) construction of a theoretical description of the deposition and entrainment process, and (3) controlled laboratory experiments using field cores and naturally occurring fines to verify results of the earlier studies.



**Figure (2-1): Plugged/ Non-plugged Paths Realization<sup>1</sup>.**

### 2-1-2: Cernansky and Siroky

Cernansky and Siroky<sup>7</sup> considered injection of a low particle concentration suspension at a constant rate into porous media made of a bed of filaments. Neglecting the diffusion of particles and the contribution of the small amount of particles in the flowing suspension, they expressed the total mass balance of particles similar to Gruesbeck and Collins<sup>3</sup> simplified mass balance equation. Thus, for incompressible liquid and particles and constant injection rate.

They expressed the net rate of particle deposition in porous media as the difference between the deposition by pore throat plugging and entrainment by hydrodynamic mobilization. Considering the critical shear stress necessary to mobilize the deposited particles in porous media.

Based on their experimental studies, Cernansky and Siroky<sup>4</sup> proposed an empirical permeability-porosity relationship as:

..... (2-1)

Where:

$\Phi_0$  is the initial porosity (%).

$\Phi$  is the porosity (%).

E and G are some empirical constants.

$k$  is the permeability (md).

$k_0$  is the initial permeability (md).

### 2-1-3: Khilar and Fogler

Khilar and Fogler<sup>8</sup> divided a core into  $n$ -compartments, Figure (2-2) the contents of these compartments are assumed well-mixed. Therefore, the composition of the flow stream leaving the compartments should be the same as the contents of the compartments. However, because particles having sizes comparable or larger than the pore throats are trapped within the porous media, the particle concentration of the stream leaving a compartment will be a fraction, of the concentration of the fluid in the compartment, (particle transport efficiency factor).

Pore surfaces are considered as the source of in-situ mobilized particles and the pore throats are assumed the locations of particle capture.

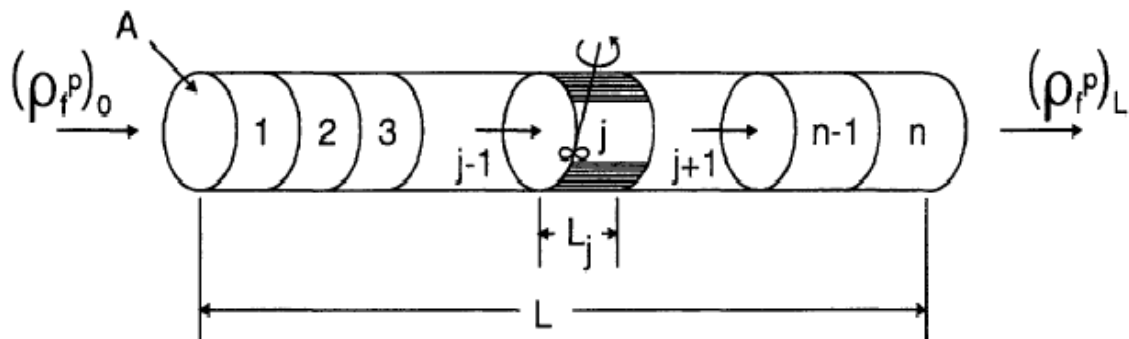


Figure (2-2). Continuously Stirred Compartments In Series Realization<sup>5</sup>.

### 2-1-4: Civan et al

Civan et al., Ohen and Civan<sup>9</sup> considered the formation damage by clayey formation swelling and migration of externally injected and indigeneous particles. They assumed constant physical properties of the particles and the

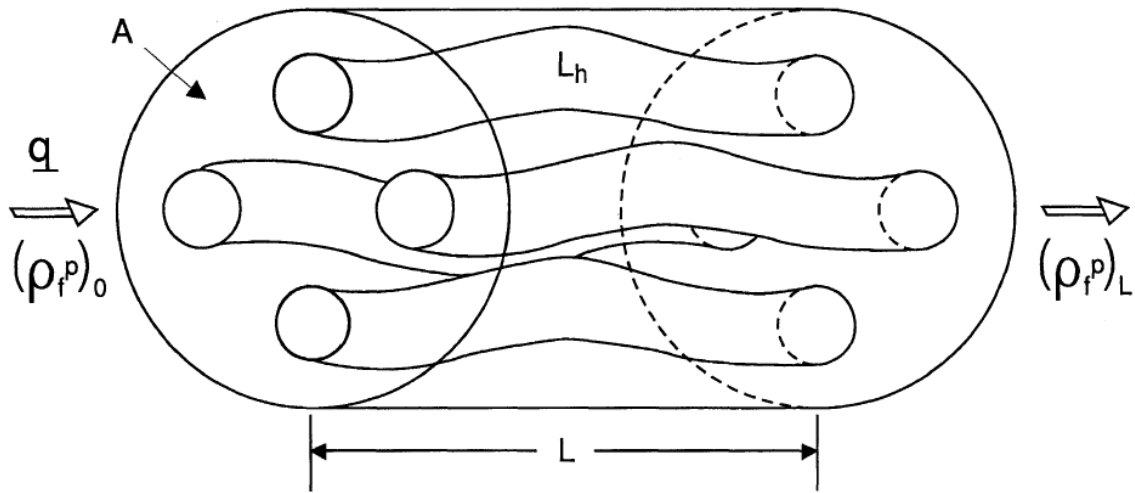


carrier fluid in the suspension. They also considered the effect of fluid acceleration during the narrowing of the flow passages by formation damage. Ohen and Civan<sup>9</sup> classified the indigeneous particles that are exposed to solution in the pore space in two groups: lump of total expansive (swelling, i.e. total authigenic clay that is smectitic) and lump of total nonexpansive (nonswelling) particles, because of the difference of their rates of mobilization and sweepage from the pore surface. They considered that the particles in the flowing suspension are made of a combination of the indigeneous particles of porous media entrained by the flowing suspension and the external particles introduced to the porous media via the injection of external fluids. They considered that the particles of the flowing suspension can be redeposited and reentrained during their migration through porous media and the rates of mobilization of the redeposited particles should obey a different order of magnitude than the indigeneous particles of the porous media. Further, they assumed that the deposition of the suspended particles over the indigeneous particles of the porous media blocks the indigeneous particles and limits their contact and interaction with the flowing suspension in the pore space. They<sup>9</sup> considered that the swelling clays of the porous media can absorb water and swell to reduce the porosity until they are mobilized by the flowing suspension. They assumed that permeability reduction is a result of the porosity reduction by net particle deposition and formation swelling and by formation plugging by size exclusion. The Ohen and Civan formulation is applicable for dilute and concentrated suspensions, whereas, Gruesbeck and Collins model applies to dilute suspensions<sup>6</sup>.

### **2-1-5: Wojtanowicz et al**

Wojtanowicz et al.<sup>10, 11</sup> considered a thin slice of a porous material and analyzed the various formation damage mechanisms assuming one distinct mechanism dominates at a certain condition. Porous medium is visualized as having tortuous pathways represented by  $N_h$  tubes of the same mean hydraulic

equivalent diameter,  $D_h$ , located between the inlet and outlet ports of the core, Figure (2-3). The cross sectional area of the core is  $A$  and the length is  $L$ . The tortuosity factor for the tubes is defined as the ratio of the actual tube length to the length of the core.



**Figure (2-3). Hydraulic Tubes Realization Of Flow Paths<sup>11</sup>.**

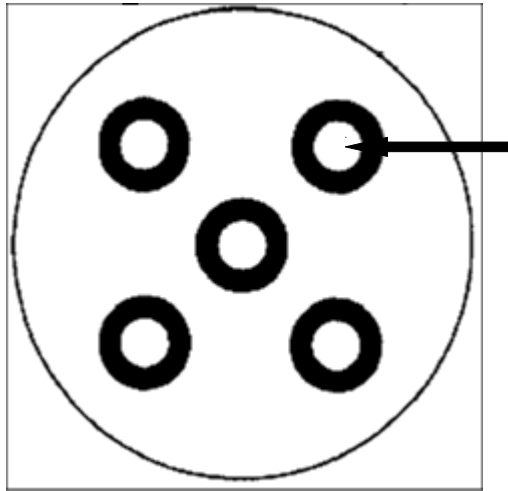
In this model, an intuitive guess is made on rock permeability as a function of the mobile solids concentration. This model, based on an exponential model of clay release and capture, was used to find correlations between the release/capture coefficients as well as the effects of temperature and flowrate. This model was used for simulation studies only without experimental verification<sup>10</sup>.

The approach applied in this model was to derive a mathematical theory concerning all types of mechanism of permeability damage and then analyze experimental data on permeability damage. A similar analysis was attempted for foreign particle capture alone<sup>10</sup>.

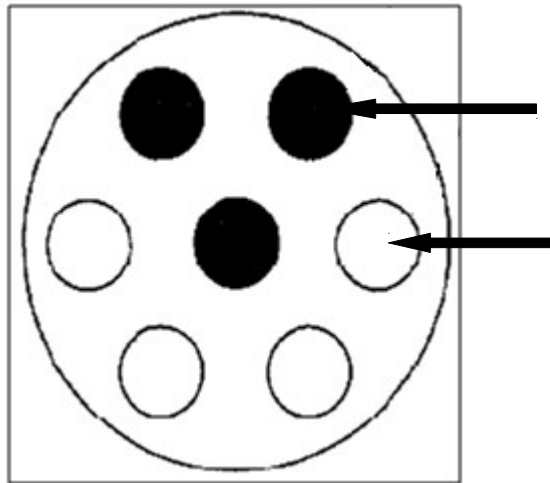
The permeability damage in porous media assumed to occur by three basic mechanisms:

1. Gradual Pore Blocking.

2. Single pore blocking (screening).
3. Cake formation near the inlet face of the porous media.



**Figure (2-4-a). Pore Surface Deposition<sup>1</sup>.**



**Figure (2-4-b). Pore Throat Plugging<sup>1</sup>.**

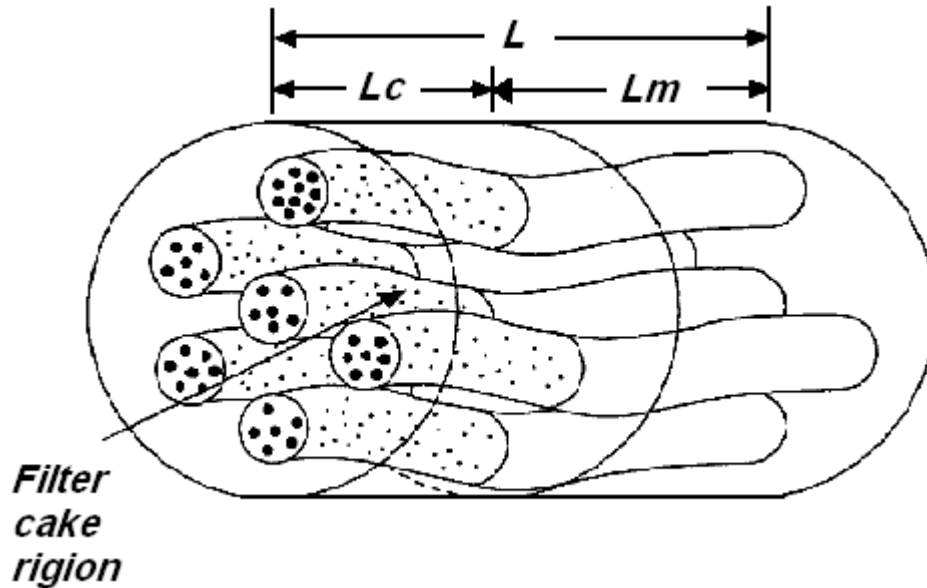


Figure (2-4-c). Pore Filling and Internal Filter Cake Formation<sup>1</sup>.

## 2-2: The Mud Damage Problem

Keelan and Koepf<sup>12</sup> explain that drilling mud's contain solid particles that form a filter cake over the wellbore wall, the filter cake restricts the mud flow into the near well bore formation, but some filtrate and fine particle invasion are unavoidable and usually occurs. The filtrate may react with the resident formation clays causing clay swelling, mobilization, and migration. The released particles and the fine particles carried into the formation by the filtrate can plug the pores and reduce permeability of the formation. The water-based filtrates increase the irreducible water saturation and create water block and hydrocarbon permeability reduction.

The understanding of well bore drilling mud invasion and mud cake formation and their impacts on formation damage is of continuing interest to the petroleum industry. In spite of many experimental studies, there have been only a few reported attempts to mathematically model the pertinent processes. Donaldson and Chemoglazov<sup>13</sup> proposed a model using empirical correlations for dispersion coefficient and mud fluid filtration rate. They considered a convection-dispersion transport of the soluble minerals of mud fluids in a single-

phase and radial flow system. Outmans<sup>14</sup> developed a model for calculation of mud filtration by considering the filter cake compressibility and porosity variation. Peng and Peden<sup>15</sup> developed a simplified filtration model considering the mud cake build-up and erosion at the formation face. Corapcioglu and Abboud<sup>16</sup> developed an elaborated cake filtration model considering the particle penetration at the cake surface.

Drilling mud pressure is usually maintained above formation pressure to prevent the reservoir fluid from flowing into well bore and causing the subsequent well blowout problems. Therefore, as a drillbit penetrates a petroleum bearing formation, the drilling mud invades the formation due to the positive differential pressure between the mud and reservoir fluids. However, the mud loss into the formation is usually limited unless the formation is highly permeable or heavily fractured. Particles smaller than the formation pores are introduced into the formation during mud spurt loss and they rapidly plug the formation around the well bore. Particles larger than the formation pores accumulate at the formation face initiating a mud cake build-up.

As the filtrate passes through the mud cake, its thickness increases by retaining the mud particles until a dynamic equilibrium is attained between the circulating mud and the mud cake.

Under these conditions the rate of deposition of mud particles on the mud cake by the fluid infiltration and rate of erosion of deposited particles by mud circulation are equalized and the infiltration rate and the cake thickness attain constant values. The increasing cake resistance limits the mud fluid infiltration into the reservoir formation<sup>17</sup>.

# CHAPTER 3

## 3. THE WOJTANOWICZ MODEL

Wojtanowicz et al. considered a thin slice of a porous material and analyzed the various formation damage mechanisms assuming one distinct mechanism dominates at a certain condition.

### 3-1 The Thin Slice Algebraic Model

Porous medium is visualized as having tortuous pathways represented by  $N_h$  tubes of the same mean hydraulic equivalent diameter,  $D_h$ , located between the inlet and outlet ports of the core, Figure (2-3). The cross sectional area of the core is  $A$  and the length is  $L$ . The tortuosity factor for the tubes is defined as the ratio of the actual tube length to the length of the core.

### 3-2: Consideration and assumption

1. Linear Laminar constant flow.
2. Homogeneous formation.
3. Incompressible particle and liquid sweepage of previously deposited particles on pore surface.
4. Particles deposition, throat blocking and filling on pore surface.
5. Empirical filtration rate expressions.
6. Cake incompressibility and Regular pore geometry.

..... (3-1)

Where:

The tortuosity factor

The cross-sectional area of the hydraulic tubes are approximated by

..... (3-2)

In which  $C_1$  is an empirical shape factor that incorporates the effect of deviation of the actual perimeter from a circular perimeter.

As a suspension of fine particles flows through the porous media, tubes having narrow constrictions are plugged and put out of service. If the number of nonplugged tubes at any given time is denoted by  $Nnp$  and the plugged tubes by  $Np$ , then the total number of tubes is given by:

..... (3-3)

The area open for flow is given by:

..... (3-4)

The Darcy and Hagen-Poiseuille equations given respectively by<sup>16</sup>:

..... (3-5)

And

..... (3-6)

Are considered as two alternative forms of the porous media momentum equations,  $q$  is the flowrate of the flowing phase and  $\Delta p$  is the pressure differentials across the thin core slice. Thus, equating Eqs. ( 3-1), (3-2), Eqs.

(3-5) and (3-6), the relationship between permeability,  $K$ , and open flow area,  $A$  is obtained as:

$$\dots\dots\dots (3-7)$$

In which the new constant is defined by:

$$\dots\dots\dots (3-8)$$

Gradual pore reduction is assumed to occur by deposition of particles smaller than pore throats on the pore surface to reduce the cross-sectional area,  $A$ , of the flow tubes gradually, Figure (2-4-a). Thus, the number of tubes open for flow,  $N_{np}$ , at any time remains the same as the total number of tubes,  $N_h$ , available.

Hence,

$$\dots\dots\dots (3-9)$$

Then, using Eq. 3-9 and eliminating  $A$  between Eqs. 3-4 and 3-7 leads to the following equation for the permeability to open flow area relationship during the surface deposition of particles:

$$\dots\dots\dots (3-10)$$

In which the new constant is defined by:

$$\dots\dots\dots (3-11)$$

The instantaneous porosity of a given cross-sectional area is given by:



..... (3-12)

$\phi_0$ , are denoting the initial and instantaneous porosity values;  $\phi$  is the fractional bulk volume of porous media occupied by the deposited particles, given by:

..... (3-13)

$m_p$  = the mass of particles retained per unit volume of porous media.  
= the particle grain density. For convenience, these quantities can be expressed in terms of initial and instantaneous open flow areas,  $A_{fo}$  and  $A_f$  and the area covered by the particle deposits,  $A_p$ , as:

..... (3-14)

..... (3-15)

..... (3-16)

Substituting Eqs. (3-14) through (3-16), Eqs. (3-12) and (3-13) become, respectively:

..... (3-17)

..... (3-18)

The particle mass balance for a thin core slice is given by:

..... (3-19)

Subject to the initial conditions:

$$\dots\dots\dots (3-20)$$

And are the particle mass concentrations in the flowing phase at the inlet and outlet of the core. Wojtanowicz et al<sup>10</sup>. Omitted the accumulation of particles in the thin core slice and simplified Eq. (3-19) to express the concentration of particles leaving a thin section by:

$$\dots\dots\dots (3-21)$$

The rate of particle retention on the pore surface is assumed proportional to the particle mass concentrations in the flowing phase according to:

$$\dots\dots\dots (3-22)$$

The rate of entrainment of the surface deposited particles by the flowing phase is assumed proportional to the mass of particles available on the pore surface according to:

$$\dots\dots\dots (3-23)$$

Then, the net rate of deposition is given as the difference between the retention and entrainment rates as:

$$\dots\dots\dots (3-24)$$

Subject to the initial condition given by:

$$\dots\dots\dots (3-25)$$

Gradual pore reduction by surface deposition occurs when the particles of the injected suspension are smaller than the pore constrictions. Assume that the surface deposition is the dominant mechanism compared to the entrainment. Then, the solution of Eqs. (3-24) and (3-25) yields:

$$\dots\dots\dots (3-26)$$

A substitution of Eq. (3-26) into Eq. (3-18) leads to the following expression for the area occupied by the surface deposits:

$$\dots\dots\dots (3-27)$$

Substitution of Eqs. (3-10) and (3-27) into Eq. (3-17) yields the following diagnostic equation:

$$\dots\dots\dots (3-28)$$

In which the empirical constant is given by:

$$\dots\dots\dots (3-29)$$

### **3-3 Equation to calculate permeability<sup>18, 19</sup>**

$$\dots\dots\dots (3-30)$$

$$\dots\dots\dots (3-31)$$

..... (3-32)

..... (3-33)

..... (3-34)

..... (3-35)

..... (3-36)

..... (3-37)

..... (3-38)

**Where:**

K is permeability (md).

C is a constant, normally about 20.

$\Delta R$  is change in resistivity (ohm-m).

$\Delta D$  is the change in depth corresponding to  $\Delta R$  (ft).

$R_o$  is the 100% water-saturated formation resistivity (ohm-m).

$e_w$  is formation water density( $g/cm^3$ ).

$e_h$  is hydrocarbon density ( $g/cm^3$ ).

$\phi$  is porosity(%).

$\rho_p$  is bulk density( $g/cm^3$ ).

F is the formation resistivity factor.

$R_w$  is the formation water resistivity (ohm-m).

$R_t$  is the true formation resistivity (ohm-m).

$S_{wi}$  is irreducible water saturation.

$S_w$  is actual water saturation.

$K_{ro}$  is the relative permeability of oil.

$K_r$  is effective permeability (md).

# CHAPTER 4

## 4. GEOLOGY

### 4-1: Geological Objective

X West-4 has been classified as an Appraisal well. The main objective of this well was to penetrate deep into the Bentiu and Aradeiba formations.

### 4-2: Litho Profile

Umm Ruwaba Sandstone, Zeraf Sandstone, Adok Shale, Nayil Shale, Amal Sandstone, Baraka Sandstone, Ghazal Shale/Sandstone, Zarqa Shale, Aradeiba Upper Shale, Aradeiba Main Sand, Aradeiba Lower Shale, Aradeiba 'E' Sand and Bentiu Sandstone (Unit 1, 2 and 3) formations were encountered while drilling the well X West-4. Geological samples examined indicated the lithology in the area as sandstone and claystone.

#### **4-2-1 Bentiu sandstone unit-1 (1253 m to 1361 m) E-log top: 1250.5 mKB**

Sandstone (1253m - 1261m) : transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, trace coarse grained, subangular to subrounded, trace angular, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace mica, trace chlorite, fair porosity, minor light brown oil staining, common even bright yellow direct fluorescence, minor fast streaming bright milky white cut fluorescence, trace light brown residual oil with common interbedded Claystone: reddish brown, grey to greenish grey, firm, occasionally moderately hard, subblocky, occasionally silty, sandy, earthy, trace micromicaceous, slightly calcareous.

Sandstone (1261m - 1272m) : transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, trace coarse grained, subangular to subrounded, trace angular, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace mica, trace chlorite, fair to good porosity, common light brown oil staining, common even bright yellow direct fluorescence, occasionally fast streaming bright milky white cut fluorescence, trace light brown residual oil with common interbedded Claystone: reddish brown to brown, light grey to greenish grey, firm, moderately hard, subblocky, trace fissile, trace silty, earthy, trace micromicaceous.

Sandstone (1272m - 1278m): transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, trace angular, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace mica, fair to good porosity, abundant light brown oil staining, common even faint yellow direct fluorescence, common fast blooming faint milky white cut fluorescence, minor medium brown residual oil.

Sandstone (1278m - 1288m) : transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, trace angular, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace mica, fair to good porosity, abundant light brown oil staining, common even faint yellow direct fluorescence, common fast blooming faint milky white cut fluorescence, minor medium brown residual oil.

Sandstone (1288m - 1297m) : transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, trace angular, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace mica, fair

to good porosity, abundant light brown oil staining, common even faint yellow direct fluorescence, abundant fast blooming faint milky white cut fluorescence, occasionally light brown residual oil.

Sandstone (1297m - 1307m): transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, trace angular, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace mica, fair to good porosity, minor light brown oil staining, common even faint yellow direct fluorescence, minor slow streaming faint milky white cut fluorescence, rare light brown residual oil.

Sandstone (1307m - 1314m): transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, trace rounded, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace pyrite, fair porosity, occasionally light brown oil staining, occasionally even dull yellow direct fluorescence, minor fast streaming bright milky white cut fluorescence, rare light brown residual oil with occasionally interbedded Claystone: grey to greenish grey, trace reddish brown, firm, occasionally moderately hard, subblocky, trace silty, sandy, trace micromicaceous.

Sandstone (1314m - 1323m): transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, trace rounded, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace pyrite, fair porosity, occasionally light brown oil staining, occasionally even dull yellow direct fluorescence, minor fast streaming bright milky white cut fluorescence, rare light brown residual oil with common interbedded Claystone: grey to



greenish grey, trace reddish brown, firm, occasionally hard subblocky, trace silty, sandy, trace micromicaceous.

Sandstone (1323m - 1340m): transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, minor coarse grained, subrounded to rounded, moderately sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace chlorite, fair porosity, occasionally light brown oil staining, minor even dull yellow direct fluorescence, common fast streaming dull milky white cut fluorescence, occasionally light brown residual oil.

Sandstone(1340m - 1350m): transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, trace rounded, well sorted, quartz, trace kaolinitic matrix, trace pyrite, trace calcareous cement, trace calcite mineral, fair porosity, trace light brown oil staining, trace patchy dull yellow direct fluorescence, common fast streaming dull milky white cut fluorescence, rare light brown residual oil.

Sandstone (1350m - 1361m): transparent to translucent, unconsolidated, trace poorly consolidated, predominantly medium grained, occasionally coarse grained, subangular to subrounded, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace calcite mineral, trace pyrite, fair porosity, no shows with common interbedded Claystone: reddish brown, grey to greenish grey, firm, moderately hard, trace silty, earthy, trace micromicaceous.

#### **4-2-2 Bentiu sandstone unit-2 (1361 m to 1440 m) E-log top: 1360 mKB**

Sandstone (1361m - 1374m): translucent to transparent, unconsolidated, trace poorly consolidated, predominantly medium grained, minor fine to very fine grained, subrounded to subangular, well sorted, quartz, trace kaolinitic

matrix, occasionally calcareous cement, trace calcite with mineral fluorescence, trace mica, good to fair porosity, trace light brown oil staining, common even dull yellow direct fluorescence, moderately blooming bright light yellow cut fluorescence, no visible residual oil with minor interbedded Claystone: reddish brown, light grey to greenish grey, subblocky, trace silty, trace sandy, earthy, trace micromicaceous.

Sandstone (1374m - 1383m): translucent, occasionally transparent, rare poorly consolidated, predominantly medium grained, trace fine grained, subrounded to subangular, well sorted, quartz, trace calcareous cement, trace calcite with mineral fluorescence, good porosity, trace light brown oil staining, minor spotty dull yellow direct fluorescence, fast streaming dull light yellow cut fluorescence, no visible residual oil with minor interbedded Claystone: greenish grey to grey, reddish brown, soft to firm, trace moderately hard, subblocky to blocky, earthy, minor sandy, trace silty, trace micromicaceous.

Sandstone (1383m - 1393m): translucent, occasionally transparent, unconsolidated, rare poorly consolidated, predominantly medium grained, trace fine grained, subrounded to subangular, trace rounded, well sorted, quartz, trace calcareous cement, trace calcite with mineral fluorescence, good porosity, no visible oil staining, occasionally spotty faint light yellow direct fluorescence, slow streaming faint light yellow cut fluorescence, no visible residual oil, with common interbedded Claystone: brown to reddish brown, greenish grey, soft to moderately hard, subblocky to blocky, earthy, minor sandy, trace silty, trace micromicaceous.

Claystone (1393m - 1402m): brown to reddish brown, greenish grey, soft to moderately hard, subblocky to blocky, earthy, minor sandy, occasionally silty, trace micromicaceous, rare chlorite with minor interbedded Sandstone:

translucent to transparent, unconsolidated, rare porosity consolidated, medium to fine grained, subrounded to subangular, moderately sorted, quartz, trace calcareous cement, trace calcite with mineral fluorescence, good to fair porosity, no visible oil staining, rare spotty faint light yellow direct fluorescence, very slow streaming, faint light yellow cut fluorescence, no visible residual oil.

Sandstone (1402m - 1415m): translucent to transparent, unconsolidated, rare poorly consolidated, predominantly medium grained, minor fine grained, subrounded to subangular, well sorted, quartz, trace calcareous cement, good porosity, trace light brown oil staining, common patchy bright light yellow direct fluorescence, slow to moderately blooming bright milky white cut fluorescence, no visible residual oil with common interbedded Claystone: brown to reddish brown, greenish grey, soft to moderately hard, subblocky to blocky, earthy, trace sandy, trace silty, trace micromicaceous.

Sandstone (1415m - 1430m): translucent to transparent, unconsolidated, rare poorly consolidated, predominantly medium grained, occasionally fine grained, subrounded to subangular, trace rounded, well sorted, quartz, trace calcareous cement, trace mica, good porosity, trace light brown oil staining, common even bright light yellow direct fluorescence,

moderately blooming bright milky white cut fluorescence, no visible residual oil.

Sandstone (1430m - 1440m): translucent to transparent, unconsolidated, rare poorly consolidated, medium to coarse grained, subangular to subrounded occasionally rounded, moderately sorted, quartz, trace calcareous cement, rare mica, good porosity, rare light brown oil staining, minor spotty dull light yellow direct fluorescence, slow streaming faint light yellow cut fluorescence, no visible residual oil with common interbedded Claystone: brown to reddish brown,

greenish grey, soft, trace moderately hard, subblocky, earthy, minor sandy, trace silty, rare micromicaceous.

#### **4-2-3 Bentiu sandstone unit- 3 (1440 m to 1550 m) E-log top: 1437 mKB**

Sandstone (1440m - 1455m): light brown to brown, transparent to translucent, unconsolidated, predominantly medium grained, occasionally fine grained, subrounded to subangular, well sorted, quartz, trace mica, good porosity, abundant dark brown oil staining, abundant even dull light yellow direct fluorescence, fast blooming bright milky white cut fluorescence, dark brown residual oil.

Sandstone (1455m - 1460m): translucent to transparent, light brown, unconsolidated, medium grained, trace fine to coarse grained, subrounded to subangular, minor rounded, well sorted, quartz, rare mica, good porosity, common light brown to brown oil staining, common even bright light yellow direct fluorescence, moderately blooming bright milky white cut fluorescence, light brown residual oil with minor interbedded Claystone: brown to reddish brown, greenish grey, soft, subblocky, earthy, minor sandy, trace micromicaceous.

Sandstone (1460m - 1465m): translucent to transparent, light brown, unconsolidated, medium grained, trace fine to coarse grained, subrounded to subangular, minor rounded, well sorted, quartz, rare mica, good porosity, common light brown to brown oil staining, common even bright light yellow direct fluorescence, moderately blooming bright milky white white cut fluorescence, light brown residual oil.

Sandstone (1465m - 1475m): translucent to transparent, unconsolidated, medium to coarse grained, subrounded to rounded, occasionally subangular, moderately sorted, quartz, good porosity, trace light brown oil staining, common

even bright light yellow direct fluorescence, moderately blooming bright milky white white cut fluorescence, no visible residual oil.

Sandstone (1475m - 1480m): translucent to transparent, unconsolidated, medium to coarse grained, subrounded to rounded, occasionally subangular, moderately sorted, quartz, good porosity, trace light brown oil staining, common even bright light yellow direct fluorescence, slow blooming bright milky white cut fluorescence, no visible residual oil.

Sandstone (1480m - 1485m): translucent-transparent, unconsolidated, coarse grained, occasionally medium grained, subrounded to rounded, trace subangular, well sorted, quartz, rare pyrite, good porosity, trace light brown oil staining, abundant patchy dull light yellow direct fluorescence, fast streaming bright light yellow cut fluorescence, no visible residual oil.

Sandstone (1485m - 1490m): translucent to transparent, unconsolidated, coarse grained to medium grained, occasionally fine grained, subrounded to subangular, minor rounded, moderately sorted, quartz, good to fair porosity, trace light brown oil staining, minor patchy bright light yellow direct fluorescence, moderately streaming bright light yellow cut fluorescence, no visible residual oil with common interbedded Claystone : grey to greenish grey, occasionally reddish brown, soft to firm, trace moderately hard, subblocky to blocky, trace subfissile, earthy, trace sandy, trace silty, trace micromicaceous, slightly calcareous.

Sandstone (1490m - 1510m): translucent, occasionally transparent, unconsolidated, medium grained, minor fine to very fine grained, subrounded to rounded, trace subangular, well sorted, quartz, trace mica, trace chlorite, rare pyrite, good porosity, rare light brown oil staining, minor spotty dull yellow

direct fluorescence, slow streaming faint light yellow cut fluorescence, no visible residual oil.

Sandstone (1510m - 1515m): translucent to transparent, unconsolidated, medium to coarse grained, minor fine grained, subrounded to rounded, trace subangular, moderately sorted, quartz, trace mica, good porosity, no visible oil staining, trace spotty dull yellow direct fluorescence, slow streaming bright light yellow cut fluorescence, no visible residual oil with minor interbedded Claystone: grey to greenish grey, minor reddish brown, soft to moderately hard, subblocky, earthy minor sandy, rare silty, trace micromicaceous.

Sandstone (1515m - 1531m): transparent to translucent, unconsolidated, predominantly medium grained, minor fine grained, trace coarse grained, subrounded to rounded, trace subangular, well sorted, quartz, rare mica, good to fair porosity, no shows.

Sandstone (1531m - 1540m): translucent to transparent, unconsolidated, medium to coarse grained, occasionally fine, subrounded to rounded, minor subangular, moderately sorted, quartz, trace mica, rare pyrite, good to fair porosity, no shows with common interbedded Claystone: grey, trace reddish brown, firm, occasionally moderately hard, subblocky, trace silty, sandy, earthy, slightly calcareous.

Sandstone (1540m - 1550m): transparent to translucent, unconsolidated, occasionally poorly consolidated, predominantly medium, occasionally coarse grained, subangular to subrounded, well sorted, quartz, trace kaolinitic matrix, trace calcareous cement, trace pyrite, trace chlorite, occasionally calcite mineral, fair porosity, no shows with common interbedded Claystone: reddish brown to

brown, minor grey, firm, occasionally moderately hard, subblocky, trace blocky, trace fissile, trace silty, earthy, trace micromicaceous, slightly calcareous.

### 4-3: Well profile:

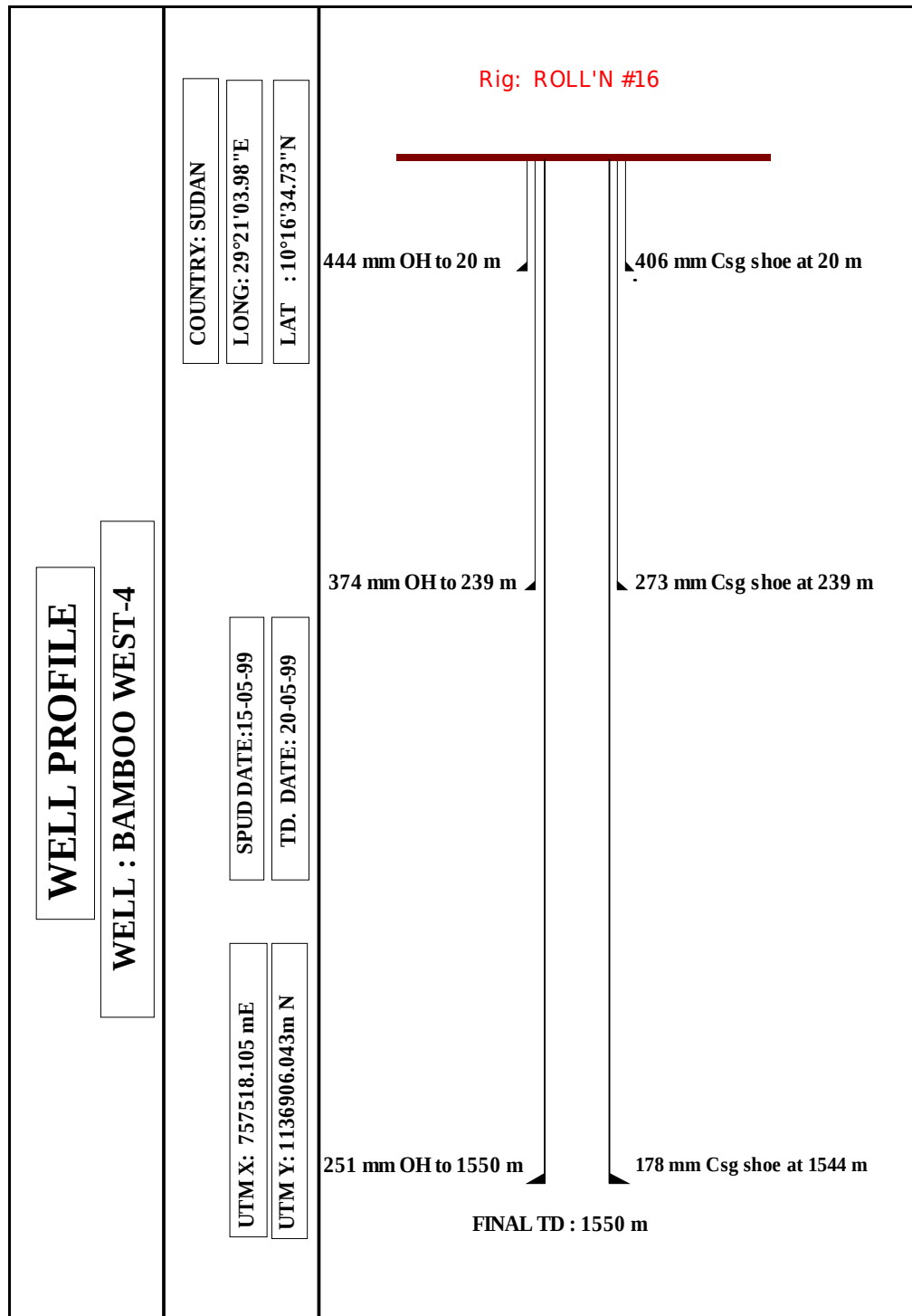


Fig (4-1): Well Profile.



## 4-4: Operational Data and Daily Drilling Report:

From well profile and Daily Drilling Report for X (west-4) well obtained the total Volume of The Well and mud Properties, Table (4-1), Table (4-2) and the logs data were taken from the las.file, fig (4-2).

**Table (4-1): Total Volume Of The Well From Well Profile.**

Depth (m)	Hole volume (bbl)	Surface volume (bbl)	Total volume (bbl)
1373	528	500	1028
1550	563	500	1063

**Table (4-2): Mud Properties.**

Properties	unit-1	unit-2	unit-3
M.W	1200	1955	1250
P.V	15	15	18
Y.P	10.1	10.1	9.6
Gel	2.8/5.6	2.8/4.8	3.1/5.6
PH	12	12	12
Filtrate(API)	5	4.5	4
Concentration of barite(kg/bbl)	8.754863813	11.28880527	11.28880527

### Where:

M.W is the weight of mud ( $\text{kg/m}^3$ ).

P.V is the plastic viscosity (cp).

Y.P is the yield point (pa).

Gel is gel strings (0 min/10 min).

```

Bamboo_W04.las - Notepad
File Edit Format View Help

~Version Information
VERS .      2.0                :CWLs Log Ascii Standard - Version 2.0
WRAP .      NO                :One line per depth step

~Well Information Block
#MNEM,UNIT  Data Type          Information
#-----
STRT .M     1533.90600         :START DEPTH
STOP .M     1.21920           :STOP DEPTH
STEP .M     -0.15240          :INCREMENT
NULL .      -999.25           :NULL DATA VALUE
COMP .      GNPOC             :COMPANY
WELL .      BAMBOO WEST-4     :WELL
FLD .      Sudan              :FIELD
LOC .      :                  :LOCATION
PROV .      SUDAN             :PROVINCE
STAT .      SUDAN             :STATE
CNTY .      RIG 16           :COUNTRY
CTRY .      :                  :COUNTRY
DATE .      :                  :DATE
UWI .      BAMBOO WEST-4     :UNIQUE WELL UWI
LIC .      :                  :LICENSE NUMBER
API .      :                  :API NUMBER
SRVC .      SLB               :SERVICE COMPANY

~Parameter Information Block
#MNEM,UNIT  Value             Description
#-----
~Curve Information Block
#MNEM,UNIT  API Code          Curve  Description
#-----
DEPT .M     :0                Index
GR .GAPI    :1                Gamma Ray
SP .MV      :2                Spontaneous Potential
CALI .IN     :3                Caliper
LLD .OHMM   :4                Laterolog Deep Resistivity
LLS .OHMM   :5                Laterolog Shallow Resistivity
MSFL .OHMM  :6                Micro-spherically-focused Resistivity
RHOB .G/C3  :7                Bulk Density
DRHO .G/C3  :8                Bulk Density Correction
PEF .       :9                Photoelectric Factor
NPHI .V/V   :10               Thermal Neutron Porosity (original Ratio Method) in Selected Lithology
DT .US/F    :11               Delta-T (also called slowness or Interval Transit Time)

~Ascii Data Section
1533.90600 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000
1533.75360 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000
1533.60120 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000
1533.44880 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000
1533.29640 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000
1533.14400 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000 -999.25000

```

Figure (4-2): Well Wire Line Loge Las.File

# CHAPTER 5

## 5. WOJTANOWICZ ET AL VERFICATIONS AND LAP TESTS APPLICATION

In general, number of mechanisms acting together with different relative contributions effects resulted as formation damage. This study analyses the Bamboo Field- Bentiu Formation potential damage mechanisms under certain conditions using Wojtanowicz et al model and the practical lab technique to dominant X (west-4) well data.

### 5-1: Bentiu permeability

The X(west-4) well wire line log las.file was used to calculate the permeability of mentioned reservoir formation (1257 to 1533m) using Equations (3-30) to (3-35) which have been depicted in Appendix (A) and Figure (5-1). The permeability diagram showed not homogeneous relation as three units [1257-1361m, 1361-1440m and 1440-1533m]. The average permeability for each unit was observed, then the relative permeability for unit-1, unit-2 and unit-3 were calculated using Equation (3-36) and (3-37), table (5-1).

**Figure (5-1): Bentiu Formation Permeability VS Depth.**

**Table (5-1): Bentiu Formation Average and Relative Permeability.**

<b>Depth( m)</b>	<b>K(md)</b>	<b>Averag eK</b>	<b>S<sub>wi</sub>(%)</b>	<b>K<sub>ro</sub></b>	<b>K<sub>r</sub>(md)</b>
<b>unit-1</b>		<b>353.9</b>	<b>1.749</b>	<b>0.028</b>	<b>10.00642</b>

			<b>331</b>	<b>275</b>	<b>316</b>
<b>1258-1361</b>	<b>353.9</b>				
<b>unit-2</b>		<b>181.6505</b>	<b>1.998945</b>	<b>0.028419</b>	<b>5.16224938</b>
<b>1361-1405</b>	<b>1.72</b>				
<b>1406-1411</b>	<b>117.652</b>				
<b>1412-1429</b>	<b>13.3</b>				
<b>1430-1440</b>	<b>593.93</b>				
<b>unit-3</b>		<b>36.39333</b>	<b>2.757045</b>	<b>0.028864</b>	<b>1.05045487</b>
<b>1440-1453</b>	<b>3.24</b>				
<b>1453-1458</b>	<b>105</b>				
<b>1458-1533</b>	<b>0.94</b>				

By knowing the formation permeability and the drilling operation conditions especially the drilling mud to use the study was focused on three different barite concentrated fluids. The first, with concentration of 4.76% (the base mud used in the well), the second, with concentration of 2.2%, and lastly the third, with concentration of 0.88%.

The study was designed according to the verification of the quality fluid test into two parts (theoretical analysis of formation damage and mud cake thickness evaluation). The ongoing analytical evaluation following the steps below for the three different barite concentrations:

1. Laboratory tests evaluating volumetric (Quantity) and Laboratory tests evaluating Gravimetric (Quality) methods, table (5-2) and table (5-3).

A- Rheological tests, tables (5-4) and (5-5).

B- filtrations tests, tables (5-6) and (5-7).

2. Calculate the constant ( $C_5$ ), table (5-8), (5-10) and (5-12).
3. Calculate of  $\sqrt{k/k_i}$ , table (5-9), (5-11) and (5-13).
4. Gradual pore external Particles blockage diagnostic chart.
5. Formation damage and filtrations test combination.

**Table (5-2): Volumetric Method Fluids Design (kg/m<sup>3</sup>).**

type of fluid	barite	idpac	idpac*xl	idvis	lime	IDFLO	kcl
fluid-1-a(1)	54.7	0.912	0.912	1.22	1.37	3.8	0.17
fluid-2-a(2)	25	1.995	1.995	2.669	2.997	8.314	0.373
fluid-3-a(4)	10	4.98864	4.98864	6.6734	7.4939	20.786	0.9299

**Table (5-3): Gravimetric Method Fluids Design (kg/m<sup>3</sup>).**

type of fluid	barite	idpac	idpac*xl	idvis	lime	IDFLO	kcl
fluid-1-b(1)	54.7	0.912	0.912	1.22	1.37	3.8	0.17
fluid-2-b(3)	25	0.912	0.912	1.22	6.7	8.28	0.17
fluid-3-b(5)	10	0.912	0.912	1.22	34.2	8.28	0.17

**Table (5-4): Volumetric Fluids Properties.**

type of fluid	M.W(kg/m3)	P.V(cp)	Y.P(pa)	Gel(0/10)	PH	Filtrate(API)
fluid-1-a(1)	1200	15	10.1	2.8/5.6	12	6.6
fluid-2-a(2)	1170	11	12	4.8/7.1	12	6.2
fluid-3-a(4)	1160	21	27	5.8/7.6	12	6.6

**Table (5-5): Gravimetric Fluids Properties.**

type of fluid	M.W(kg/m3)	P.V(cp)	Y.P(pa)	Gel(0/10)	PH	Filtrate(API)
fluid-1-b(1)	1200	15	10.1	2.8/5.6	12	6.6
fluid-2-b(3)	1200	15	10.1	2.8/5.6	12	4.5

<b>fluid-3-b(5)</b>	<b>1200</b>	<b>15</b>	<b>10.1</b>	<b>2.8/5.1</b>	<b>12</b>	<b>24.8</b>
---------------------	-------------	-----------	-------------	----------------	-----------	-------------

Comparing the properties of fluids in the table (5-4) with the base mud; showed insignificances of the rheological and the huge difference in operating hydraulics properties. In the same time, comparing the base mud properties to the fluids in the table (5-5); the properties were sensed very close to the base mud rheology and hydraulics.

Here in this study the decision was to consider the **GRAVIMETRIC (QUALITY)** to obtain the desired mud properties. The less damage of drilling fluid to formation is the optimum fluid program to use.

## 5-2: Fluids Filter Evaluation

Evaluations of other fluids and tests were referred to the fluid-1 (base mud). The filter loss tests, table (5-6) and figure (5-2), showed the significances of fluid-2-b (3) with lower loss vise versa fluid-3-b (5), appendix (B - A).

The smirched filter papers were cared out of cell and marked, appendix (B -B); the created cake was measured to a sure the significances of fluid-2-b (3), table (5-7) and figure (5-3). The thick mud cake was noticed for fluid 3-b (5) beside the not homogenous diagnosis.

**Table (5-6): Water Loss (ml).**

<b>number of fluid</b>	<b>at 7.5 min</b>	<b>at 15 min</b>	<b>at 22.5 min</b>	<b>at 30 min</b>
<b>Fluid 1-b(1)</b>	<b>1</b>	<b>6</b>	<b>6</b>	<b>6.6</b>
<b>Fluid 2-b(3)</b>	<b>3</b>	<b>3</b>	<b>3</b>	<b>4.5</b>
<b>Fluid 3-b(5)</b>	<b>17</b>	<b>18.4</b>	<b>18.8</b>	<b>24.8</b>

**Figure (5-2): Water Loss at Different Time.**

**Table (5-7): Thickness of Mud Cake (inch).**

number of fluid	at 7.5 min	at 15 min	at 22.5 min	at 30 min
Fluid 1-b (1)	0.009	0.011	0.01	0.01
Fluid 2-b (3)	0.011	0.012	0.012	0.012
Fluid 3-b (5)	0.007	0.031	0.019	0.0075

**Figure (5-3): Mud Cake Thickness at Different Time.**

### 5-3: Gradual bore blocking mechanism

For Bentiu formation as have been mentioned above, the study divided it into three main units considered as internal layers (unit-1, unit-2, unit-3). The fluids used to penetrate the formation are quantified as above (fluid-1, fluid-2 and fluid-3). Then the damage by the three fluid types over specified 100 minutes period was theoretically identified using Wojtanowicz et. al.

#### 5-3-1 Unit-1 identifications

Using the equation (3-29) the constant  $C_5$ , at different barite Concentration of (54.7, 25, 10) ( $\text{kg/m}^3$ ) was calculated as shown in table (5-8). The resulted  $C_5$  were used to calculate  $\sqrt{k/k_i}$  by using equation (3-28), table (5-9). To this point the damage view is cleared as the Diagnostic plot, figure (5-4). fluid (1-b) ( $54.7\text{kg/m}^3$ ) showed very high invasion and severe formation damage .vise versa fluid (3-b) ( $10 \text{ kg/m}^3$ ) gave very low formation damage but is high filtration rate, fig(5-2).the fluid 2-b was essential with medium damaged (near to fluid (1-a) ) and less filtration rate comparing to fluid (1-a ) (best condition ).



**Table (5-8): Barite Concentration With Drilling Mud For Unit-1.**

<b>Fluid type</b>	<b>Concentration volume (%)</b>	<b>Concentration (kg/m3)</b>	<b>C<sub>5</sub></b>
<b>Fluid-1-b</b>	<b>4.76</b>	<b>54.7</b>	<b>0.00851</b>
<b>Fluid-2-b</b>	<b>2.2</b>	<b>25</b>	<b>0.00389</b>
<b>Fluid-3-b</b>	<b>0.88</b>	<b>10</b>	<b>0.001556</b>

**Table (5-9): Unit-1 Invasion and Damage.**

<b>time</b>	<b><math>\sqrt{k/k_i}</math></b>	<b><math>\sqrt{k/k_i}</math></b>	<b><math>\sqrt{k/k_i}</math></b>
<b>0</b>	<b>1</b>	<b>1</b>	<b>1</b>
<b>5</b>	<b>0.95745</b>	<b>0.98055</b>	<b>0.99222</b>
<b>10</b>	<b>0.9149</b>	<b>0.9611</b>	<b>0.98444</b>
<b>15</b>	<b>0.87235</b>	<b>0.94165</b>	<b>0.97666</b>
<b>20</b>	<b>0.8298</b>	<b>0.9222</b>	<b>0.96888</b>
<b>25</b>	<b>0.78725</b>	<b>0.90275</b>	<b>0.9611</b>
<b>30</b>	<b>0.7447</b>	<b>0.8833</b>	<b>0.95332</b>
<b>35</b>	<b>0.70215</b>	<b>0.86385</b>	<b>0.94554</b>
<b>40</b>	<b>0.6596</b>	<b>0.8444</b>	<b>0.93776</b>
<b>45</b>	<b>0.61705</b>	<b>0.82495</b>	<b>0.92998</b>
<b>50</b>	<b>0.5745</b>	<b>0.8055</b>	<b>0.9222</b>
<b>55</b>	<b>0.53195</b>	<b>0.78605</b>	<b>0.91442</b>
<b>60</b>	<b>0.4894</b>	<b>0.7666</b>	<b>0.90664</b>
<b>65</b>	<b>0.44685</b>	<b>0.74715</b>	<b>0.89886</b>

<b>70</b>	<b>0.4043</b>	<b>0.7277</b>	<b>0.89108</b>
<b>75</b>	<b>0.36175</b>	<b>0.70825</b>	<b>0.8833</b>
<b>80</b>	<b>0.3192</b>	<b>0.6888</b>	<b>0.87552</b>
<b>85</b>	<b>0.27665</b>	<b>0.66935</b>	<b>0.86774</b>
<b>90</b>	<b>0.2341</b>	<b>0.6499</b>	<b>0.85996</b>
<b>95</b>	<b>0.19155</b>	<b>0.63045</b>	<b>0.85218</b>
<b>100</b>	<b>0.149</b>	<b>0.611</b>	<b>0.8444</b>

**Figure (5-4): Gradual Pore Blockage By External Particles Diagnostic Chart For Unit-1.**

### 5-3-2 Unit-2 Identifications

Using the equation (3-29) the constant  $C_5$ , at different barite Concentration of (70.6, 32.6, 13.05) ( $\text{kg/m}^3$ ) was calculated as shown in table (5-10). The resulted  $C_5$  were used to calculate  $\sqrt{k/k_i}$  by using equation (5-28), table (5-11). To this point the damage view is cleared as the Diagnostic plot, figure (5-5); fluid(1-b) ( $70.6\text{kg/m}^3$ ) showed very high invasion and severe formation damage .vise versa fluid(3-b) ( $13.05 \text{ kg/m}^3$ ) gave very low formation damage but is high filtration rate, fig(5-2).the fluid 2-b was essential with medium damaged (near to fluid (1-a) ) and less filtration rate comparing to fluid (1-a ) (best condition ).

**Table (5-10): Barite Concentration With Drilling Mud For Unit-2.**

Type of fluid	Concentration volume (%)	Concentration ( $\text{kg/m}^3$ )	$C_5$
Fluid-1-b	4.76	70.6	0.0079
Fluid-2-b	2.2	32.6	0.0037
Fluid-3-b	0.88	13.05	0.0015

**Table (5-11): Unit-2 Invasion and Damage.**

time	$\sqrt{k/k_i}$	$\sqrt{k/k_i}$	$\sqrt{k/k_i}$
0	1	1	1
5	0.962	0.982455	0.992975
10	0.924	0.96491	0.98595
15	0.886	0.947365	0.978925

<b>20</b>	<b>0.848</b>	<b>0.92982</b>	<b>0.9719</b>
<b>25</b>	<b>0.81</b>	<b>0.912275</b>	<b>0.964875</b>
<b>30</b>	<b>0.772</b>	<b>0.89473</b>	<b>0.95785</b>
<b>35</b>	<b>0.734</b>	<b>0.877185</b>	<b>0.950825</b>
<b>40</b>	<b>0.696</b>	<b>0.85964</b>	<b>0.9438</b>
<b>45</b>	<b>0.658</b>	<b>0.842095</b>	<b>0.936775</b>
<b>50</b>	<b>0.62</b>	<b>0.82455</b>	<b>0.92975</b>
<b>55</b>	<b>0.582</b>	<b>0.807005</b>	<b>0.922725</b>
<b>60</b>	<b>0.544</b>	<b>0.78946</b>	<b>0.9157</b>
<b>65</b>	<b>0.506</b>	<b>0.771915</b>	<b>0.908675</b>
<b>70</b>	<b>0.468</b>	<b>0.75437</b>	<b>0.90165</b>
<b>75</b>	<b>0.43</b>	<b>0.736825</b>	<b>0.894625</b>
<b>80</b>	<b>0.392</b>	<b>0.71928</b>	<b>0.8876</b>
<b>85</b>	<b>0.354</b>	<b>0.701735</b>	<b>0.880575</b>
<b>90</b>	<b>0.316</b>	<b>0.68419</b>	<b>0.87355</b>
<b>95</b>	<b>0.278</b>	<b>0.666645</b>	<b>0.866525</b>
<b>100</b>	<b>0.24</b>	<b>0.6491</b>	<b>0.8595</b>

**Figure (5-5): Gradual Pore Blockage By External Particles Diagnostic Chart for Unit-2.**

### **5-3-3 Unit-3 Identifications**

Using the equation (3-29) the constant  $C_5$ , at different barite Concentration of (88.19, 40.76, 16.3) ( $\text{kg/m}^3$ ) was calculated as shown in table (5-12). The resulted  $C_5$  were used to calculate  $\sqrt{k/k_i}$  by using equation (3-28), table (5-13). To this point the damage view is cleared as the Diagnostic plot, figure (5-6) ;fluid(1-b) ( $88.19\text{kg/m}^3$ ) showed very high invasion and severe formation damage .vise versa fluid(3-b) ( $16.3 \text{ kg/m}^3$ ) gave very low formation damage but is high

filtration rate, fig(5-2).the fluid 2-b was essential with medium damaged (near to fluid (1-a) ) and less filtration rate comparing to fluid (1-a) (best condition ).

**Table (5-12): Barite Concentration With Drilling Mud for Unit-3.**

Type of fluid	Concentration volume%	Concentration (kg/m <sup>3</sup> )	C <sub>5</sub>
Fluid-1-b	4.76	88.19	0.0045
Fluid-2-b	2.2	40.76	0.0021
Fluid-3-b	0.88	16.3	0.0008

**Table (5-13): Unit-3 Invasion and Damage.**

Time	$\sqrt{k/k_i}$	$\sqrt{k/k_i}$	$\sqrt{k/k_i}$
0	1	1	1
5	0.99312	0.99682	0.99873
10	0.98624	0.99364	0.99746
15	0.97936	0.99046	0.99619
20	0.97248	0.98728	0.99492
25	0.9656	0.9841	0.99365
30	0.95872	0.98092	0.99238
35	0.95184	0.97774	0.99111
40	0.94496	0.97456	0.98984
45	0.93808	0.97138	0.98857
50	0.9312	0.9682	0.9873
55	0.92432	0.96502	0.98603
60	0.91744	0.96184	0.98476
65	0.91056	0.95866	0.98349
70	0.90368	0.95548	0.98222
75	0.8968	0.9523	0.98095
80	0.88992	0.94912	0.97968
85	0.88304	0.94594	0.97841
90	0.87616	0.94276	0.97714
95	0.86928	0.93958	0.97587

<b>100</b>	<b>0.8624</b>	<b>0.9364</b>	<b>0.9746</b>
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**Figure (5-6): Gradual Pore Blockage By External Particles Diagnostic Chart for Unit-3.**

## 5-4: Result and Discussions

In the past, numerous experimental and theoretical studies have been carried out to understand the formation damage phenomena. Although various results were obtained from these studies, a unified theory and approach still does not exist<sup>1</sup>. From our investigations and analysis this type of work is the first to be done in the Sudan oilfields; despite the difficulties the search has found but it considered meaningful outcomes.

### The enrich results showed:

The theory of wojtanowicz et al for particle invasion and bore blocking by fluid solids movement and capture in unity formation showed dramatically diagnostic plots proved the applicability for analyzing data on permeability damage in bamboo field.

Foreign particles invasion are time and total solids concentration dependent as the lab tests prove that, table (5-14).

**Table (5-14): The drilling fluid formation damage.**

<b>Barite concentration (%)</b>	<b>damage(%) at 7.5 (min)</b>	<b>damage(%) at 15 (min)</b>	<b>damage(%) at 22.5 (min)</b>	<b>damage (%) at 30 (min)</b>	<b>C<sub>5</sub></b>
<b>unit-1</b>					
<b>4.76</b>	12.4	23.9	34.6	44.5	<b>0.00851</b>
<b>2.2</b>	5.7	11.3	16.7	21.9	<b>0.00389</b>
<b>0.88</b>	2.3	4.6	6.8	9.1	<b>0.00155</b>

					<b>6</b>
<b>unit-2</b>					
<b>4.76</b>	11.4	22.2	32.3	41.7	<b>0.0079</b>
<b>2.2</b>	5.4	10.7	15.9	20.9	<b>0.0037</b>
<b>0.88</b>	2.2	4.4	6.6	8.7	<b>0.0015</b>
<b>unit-3</b>					
<b>4.76</b>	6.6	13	19.2	25.2	<b>0.0045</b>
<b>2.2</b>	3.1	6.2	9.2	12.2	<b>0.0021</b>
<b>0.88</b>	1.1	2.3	3.5	4.7	<b>0.0008</b>

The mechanism by which particle were mobilized and captured, however, varied with the type of drilling fluids. Thus, the drilling fluid compatibility with a formation can be quantified by values of release and capture coefficients.

The formation damage caused by foreign particles invasion, reduced by decrease the concentration of barite in drilling fluid to 2.2% which was the optimum to use.

# CHAPTER 6

## 6. CONCLUSIONS AND RECOMMENDATIONS

### 6-1: Conclusions

- 1- The wojtanowicz et al model was selected in the mean of simplicity and ease of use. The proposed drilling fluid new design considered as the optimum to used in bamboo field.
- 2- Foreign particles invasion damage to formation could be controlled by reducing of Barite solids concentration from (4.76%) to (2.2%).
- 3- The rock properties were the base for all calculations and assumptions done throughout the data evaluation and the constants determination. However the core area was taken the same as the wojtanowicz et al.
- 4- The whole core area to the porous channel area gave the constants  $C_1$  to  $C_5$ ; those are quantified and qualified by the assurance of the logging operation data.
- 5- The  $\sqrt{k/k_i}$  was calculated at the concentrations of barite (4.76, 2.2 and 0.88) for unit1, 2 and 3. Then the Gradual Pore Blockage By External Particles Diagnostic Chart for Unit-1, 2 and 3 were obtained.
- 6- Fig. (5-4), (5-5) and (5-6) assured that the External Particles Gradual Pore Blockage damage could be control and reduced by using the optimum concentration of barite (2.2%). In spite of the increase in other additives quantity; the investigations showed cost reduction.
- 7- The GRAVIMETRIC (QUALITY) method of combining the mud solid concentrations was used. The parallel quantities have to be the best in obtaining the mud properties.



- 8- Comparing the water loss and mud cake thickness illustrated in the lab for the three fluids; in the studied case the optimum fluid was fluid (2-b); appendix (B-B).
- 9- The cost/environment is the main headache to all in oil industry; in this study the combination of lab experimental with the theoretical models developed a successfully outputs with great benefits of high cost cut (9.6% solid decrease) and environment risk.

## 6-2: Recommendation

1. The applied type of work through out other Sudan oilfields will pave the quality management for the operations and cut the economical alerts. Not to forget the environment this is a global concern in today.
2. Further developments in this work may include velocity and temperature effects as well as conversion of the linear model into a radial geometry, utilizing a constant pressure filtration rather than a constant rate of flow as used in these experiments.
3. The permeability damage in porous media is assumed to occur by three basic mechanisms as Gradual pore blocking by surface deposition, Single pore blocking by screening and Pore volume fills by straining. This study deepens the first gradual blocking **it is highly recommended** to run the single screening and bore fills blocking investigations.
4. The Sudan country has a lot of  $\text{CaCO}_3$  source area it is highly recommended to apply this type of work and study the effects of  $\text{CaCO}_3$ . The  $\text{CaCO}_3$  is environmental friend and the use of it will decrease the overall drilling operation high cost.
5. It is also high consideration to the local products (Arabic Gum, الزيت النباتية, ..., etc.) which have the same specifications with the imported additives.

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## **APPENDIX (A)**

**Bamboo reservoir formation permeability for (1257  
to1533m)**