Journal of Engineering and Engineering Technology

FORMATION DAMAGE MECHANISMS AND NUMERICAL SIMULATION OF PERMEABILITY IMPAIRMENT IN HORIZONTAL WELLS

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ABSTRACT

Puzzling circumstance associated with formation damage near wellbore occur frequently, resulting in permeability impairments and increased pressure losses. Potential damage phenomenon usually starts from drilling to completion via production and such mechanisms have been fully considered. Most of the existing tasks to mitigate the near oil wellbore damages involve use of empirical models, conducting experiments, frequent shut down of wells for proper well tests and pressure maintenance are highly expensive and time consuming. Permeability impairments have been simulated by modifying Darcy's equation to optimize reservoir pressure for improved near wellbore in horizontal wells. The model, transient linear partial differential equation (TLPDE) for impaired permeability is developed and numerically resolved using finite difference method. The model was implemented by writing codes in MATLAB language and the solution obtained was validated using synthetic/field data. The results obtained for TLPDE model indicated pressure depletion over time. This was also shown for every values of coefficient of anisotropy until 400 days when the anisotropy became insignificant approaching isotropy condition, suggesting permeability impairment. Numerical simulation proved to be effective in simulating near oil wellbore damages. This paper describes the detailed mechanisms of formation damage and provided a numerical approach to model impaired permeability in horizontal wells. This approach allowed us to study the impact of various damage mechanisms related to drilling, completion conditions and significant improvement of near oil wellbore for well performance.

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1.0   INTRODUCTION

Formation damage in oil and gas wells is any process that causes an undesirable reduction of permeability or a reduction in the natural inherent productivity of an oil producing formation (Civan, 2000). It is a condition most commonly caused by wellbore fluids used during drilling, well completions, work over operations and subsequent injection of water, steam, carbon dioxide or enhanced oil

recovery (Civan, 2015). Formation damage could also results into blockage of pore spaces, hindrance to flow assurance, high viscosity, pipelines corrosion, and slow down sweep efficiency. However, the current study overview the mechanisms of formation damage and also set to optimize reservoir pressure in a typical Brown Field using numerical and simulation approach for improved hydrocarbon recovery. Formation damage aims at disappointing production or injection results which related to a number of factors that may be difficult to diagnose. Reservoir engineers usually unjustly absorb the majority of the blame for poor results of many projects (Brant Bennion, 2002). This is difficult to quantify in many cases as to retrieve exact samples either by conducting experiment, detailed measurements and frequent shut down of wells for proper well test analysis on the area of interest, usually near wellbore which is several meters into the formation. This available information is to obtain a much better indication of the types of damage that may be sensitive to different reservoir pressure, thereby attempting to minimize or reduce these impairments.

1.1 Formation Damage Rationale

Beginning with the drilling process, formation damage can occur in the life of a well including completion, production, all through stimulation. It is a productivity killer. Adeosun *et al.,* (2020), stated that this problem is usually ignored due to a combination of ignorance and apathy that we don't care about formation damage in reservoirs, hence we fracture through it. In other publications, we have compared

fractured and unfractured horizontal well performance and the conclusion has been that in the case where a vertical well would result in a large dimensionless conductivity fractured and longitudinal fracture configuration for a horizontal well would be unattractive. It is also suggested that unfractured horizontal wells, drilled in a reservoir with vertical wells are fractured, and unlikely to be attractive and therefore, if drilled, such wells should be hydraulically fractured also. Exception to this is the case of extraordinary areal permeability anisotropy subjected to permeability impairment (Villegas *et a l* , 1996). In this case, most drilling and completion related to mechanisms of formation damage tend to be localized in the near wellbore region and may be relatively easily penetrated by a fracture treatment, and efforts may be to design a stimulation program that is compatible and non-damaging. In a situation where near wellbore damage is of prime importance, the issue of near wellbore and completion induced formation damage becomes very prominent in open hole completions as seen in Figure 1.

Mechanisms of Formation Damage

The chart in Figure 2 below summarized many of the common formation damage mechanisms in oil and gas wells. There are four primary mechanisms of formation damage viz mechanical, chemical, biological and thermal. Each mechanism can be further subdivided into sub-mechanisms to which a given reservoir may be prone to occur.
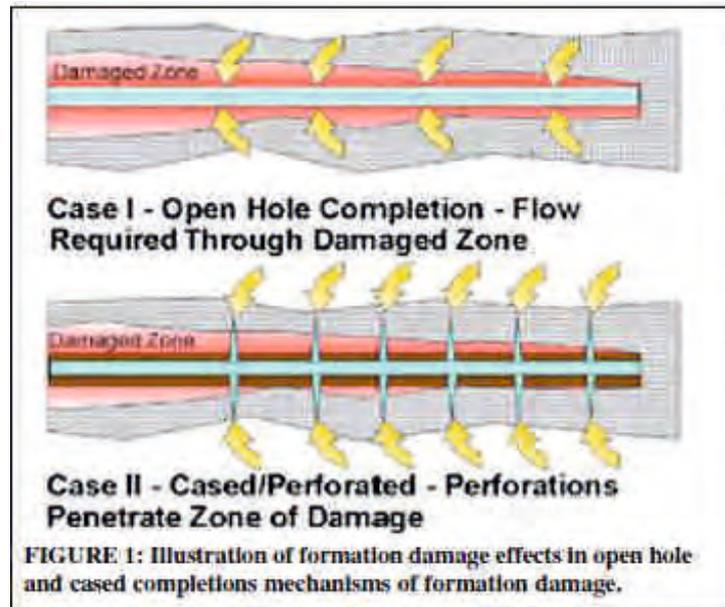
Figure 1: *Formation Damage Effects in Open and Cased hole Completions (Brant Bennion, 2002)*

Mechanical Formation Damage

Mechanical formation damage mechanisms are related to a direct, non-chemical interaction between the reservoir and fluids used to drill, or stimulate a well and the formation resulting in a reduction of permeability. Common mechanical impairment include:

Fines Migration

Fine particles migration refers to the development drilling induced damage, skin, completion and many other factors. Naturally it is due to the motion of particulates in the pore spaces system caused by high fluid shear rate (Amanda *et al.,* 2018). Fine particles migration causes numerous problems such as blockage of tiny pore throats of pore chamber in reservoirs when they are stuck because some of these tiny grains are larger than some pore throats. When this happens, flow paths of fluids in porous media are obstructed and permeability is adversely affected. Some of these nanoparticles are uncemented clays; namely: quartz, mica, anhydrite, rock fragments. Generally, fine migration tends to be more of an issue in clastic formations due to high concentration of potentially transported materials; as well as in carbonates where degree of cementation of mobile particles in the pores is essential. Fine particles migration is only apparent when the wetting phase of the reservoir is in motion. Whereas oil production can occur at high rates with limited or no fine particles migration (Abdullah, 2006).

External Solids Entrainment

External solids entrainment is a common occurrence which happens during overbalanced drilling and completion due to the invasion of particulate matter suspended in drilling fluids which may be injected to the rock matrix surrounding the wellbore as well
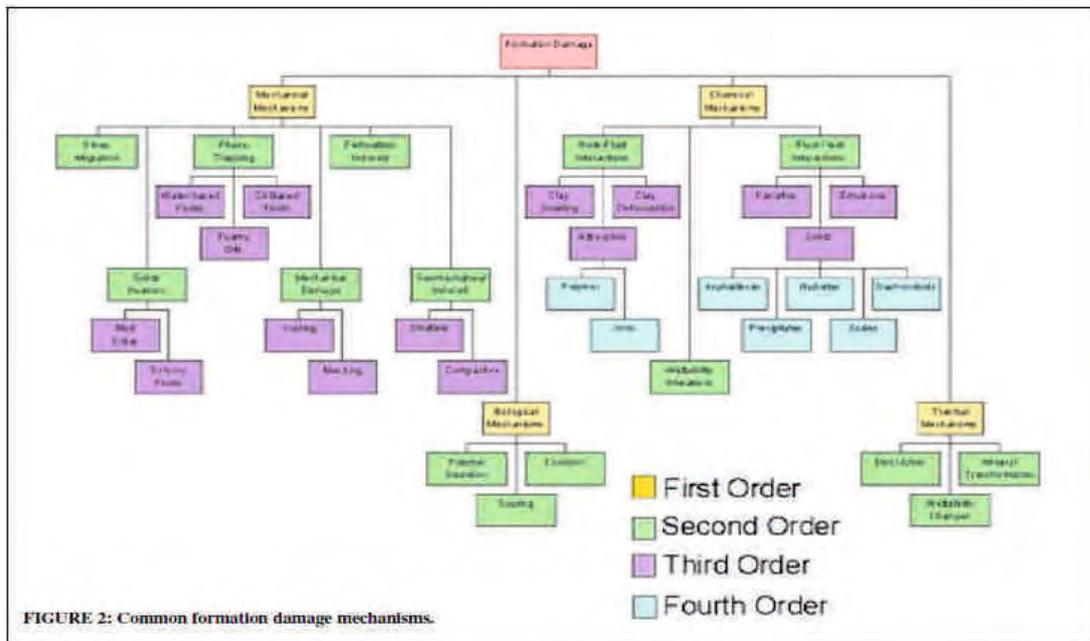
FIGURE 2: Common formation damage mechanisms.

as variety of suspended solids in drilling fluids (weighing agents, fluid loss control, and lost circulation materials) (Mattia Aleardi, 2018). In most formations, permeability is very high and the majority of this damage is confined to a region very close to the near-wellbore at least 1-3 cm in depth (Irene, 2013). The damage of this type is a major concern in formation capable of enhancing rapid formation of filter cake (Abdullah, 2006).

Drilling Mud (high viscosity)

Drilling-induced formation damage such as the presence of mud cake, phase trapping, polymer absorption/retention and asphaltene deposition should be taken into account especially high viscosity drilling fluids. If formation damage is not taken into account on these physical processes or only cake damage is considered, the oil production rate calculation could be very inaccurate with more than 20% error and could have a great impact on well productivity (Ding, 2009).

Phase Blocking and Trapping

Phase blocking and trapping are clastic formations which contains a high concentration of potentially mobile and particulates. These could also include clays such as kaolinite, detrital rock fragments and a combination of adverse capillary pressure and relative permeability effects. The basis of a phase trap is a transient or permanent increase in trapped fluid saturation either water or gas in the pore system surrounding the wellbore, causing a reduction in relative permeability to the phase desired to produce (Ahmed *et al.,* 2016). Frequent circumstances which may result in phase trapping include: invasion of water based fluids/filtrates into regions of low water saturation and resulting into trapping effects; invasion of oil-based fluids/filtrates into zones of low or zero oil saturation and resulting into trapping effects; production of high condensate type gases below the dew point pressure resulting in the accumulation and trapping in the near-wellbore, production

of black oils below the bubble point resulting in the release of gas from solution thereby creating foams; and injection of free gas or foams into a fluid saturated zone resulting in the creation of trapped critical gas saturation (Abdullah *et al.*, 2013).

Gazing

Gazing refers to the formation of crystalline particulates from aqueous solution of crystal growth and this may have direct damage to the well bore face caused by drill bits interactions or poorly rotating bits in a poor hole cutting situation, resulting in the working of cutting of fines particles into the formation face (Abdullah, 2006).

Geomechanics

The creation of a void/pore space in the reservoir matrix removes load-bearing rock and often results in the distortion of the geomechanical stress in a region directly adjacent to the wellbore. This results in a change of pore geometry and permeability character in the near-wellbore region (Abdullah *et al.*, 2013; Alvaro Chaueste, 2018).

Perforation Damage

The detonation of perforation charges may result in the creation of a crushed zone and generate mobile fines particles adjacent to the perforation tunnel, possibly reducing the permeability in the near-wellbore. The composition of perforating overbalanced may cause significant impact on damage effects (Abdullah, 2006).

Interfacial Coupling

Fluid flow has been shown to neglect the effect of interfacial coupling in porous media. (Ayodele *et al*, 2004) pointed out that the presence of one fluid affect the flow of the other fluids leading to interfacial coupling effects which may have a significant effect on the flow of the fluids. This problem is identified as damage effect when the transfer of viscous forces across the fluid-fluid interfaces exists (Ayodele *et al.*, 2004). At present, other unidentified coupling that come into play between two or more fluids flowing simultaneously through porous media are viscous and capillary couplings. These two constitute the major components of interfacial coupling. Viscous coupling refers to the viscous drag exerted by one fluid on the other fluid when they flow in the same porous medium while capillary coupling refers to the coupling that arises due to coupling of pressure across the interfaces of the fluids through the capillary pressure function (Abreu *et al*, 2007).

Heterogeneity

The flow patterns in horizontal well are completely different from a vertical well. Whilst vertical well has a uniform layer of cross bedded planes for which it penetrate in an orthogonal fashion (Pourafshary *et al.*, 2009); a horizontal well sources fluids from both vertical and horizontal direction and is much more radially affected by variations in vertical permeability of the reservoir (Abreu *et al.*, 2001; Vincent Artus *et al.*, 2004).

Sand Production

Sand control is a major problem that is usually

associated with production of heavy oils and bitumen from low API gravity crude oil reservoirs.This occurs in poorly cemented sandstones formation as a result of the combine effects of deformation and erosion phenomena in porous media. However, for sand production to occur, sand particles must be available to mobilize the interstitial fluid velocity in order to provide sufficient force to drag sand particles into the formation (Brant Bennion *et al.,* 1996; Civan, 2007).

Water Flooding

Water flooding is one of the economically viable techniques for recovery of additional oil from matured fields. Likewise produced water re-injection (PWR1) is usually aimed to maintain high pressure to sweep oil towards the production well. However, the injected water will cause the pressure around the injection well bore to be much higher than that further away from the well. (Al-Marhoon *et al.,* 1998).

Underbalanced and Overbalanced Drilling

The used of water flooding frequently contain suspended fine particles which can be deposited over the injection formation face and inside the near wellbore formation to reduce the injectivity. Under-and over-balanced drilling have severe impact on productivity. Invasion of fluids and solids during the conventional over-balanced drilling reduce productivity and under-balanced drilling reduce invasion. During under-balanced operations, invasion of fluids and solids into the formation produced greater magnitude of improved productivity. Byme *et*

al., (2011), Brant Bennion *et al.,* (1996), Liu He *et al.,* (2013) and Zhangxin Chen (2007)

Chemical Formation Damage

Chemical formation damage mechanisms are the adverse rock-fluid and fluid-fluid interactions in the near wellbore region. Common causes of chemical impairment include:

Clay Swelling and Deflocculation

Clay swelling and deflocculation is usually accompany heavy oil producing formation contained in clastic formation also one of the severe causes of formation damage that involves the interaction and hydration of hydrophilic materials such as mixed layer clays which react with fresh and low salinity water. The expansion and sloughing of these clays can cause severe reductions in permeability depending on the amount of clays in the pore system (Jienian *et al.,* 2012). Clay deflocculation is caused by a disruption of the electrostatic force holding the surfaces of individual clay units that are attracted to each other in the pore system in a flocculated state. The problem is especially severe if the clay is lining in the pore throats and this result in a very large reduction in permeability (Brant Bennion *et al.,* 1997)

Chemical Adsorption and Dissolution

This may not necessarily be a significant problem if asphaltene are peptized. It is only when asphaltene are destabilized and flocculate from solution bodies that the formation is prone to permeability impairment. Polymers and other high

molecular weight materials present in some fluids may become bound adsorbed on the surface of the formation matrix and clays, these cause restrictions in flow area and hence permeability. Formation components having limited to high solubility in water based fluid can result in poor gauge formation or collapse in certain conditions and damaging fines particles (Louise Bailey *et al.,* 1999).

Deposition of inorganic and organic Micronics

Formation damage in oil bearing formation is caused by fluids and fine solid particles invasion from the wellbore into the formation during drilling and completion operations. Particles deposition in the near wellbore is more liable to well injectivity decline leading to a very significant reduction in productivity (Adinathan *et al.,* 1995). However, micronics size particles are of great practical importance because; they always remain in suspension in injection water because removing them is too expensive; are small enough to propagate at long distances; and are large enough to cause significant permeability reduction (Melvin Kome *et al.,* 2012).

Wettability Alteration

Wettability alteration is characterized by contact angle measurement. The observation of oil-wet contact and contact angle is more of water wetting phase. Oil wettability is caused by oil-wetted minerals, insoluble organic matter that created pore geometry effects which include alteration of poor connectivity, alteration of permeability and alteration of porosity (Ayorinde and John, 2018; Dake,

2000).

Paraffins and Waxes

Paraffins and waxes are more problematic in some situations with heavy oils and are control by reduction in temperature. Paraffins problem tends to be of production issue rather than down hole issue. Many oils exhibit low cloud point temperatures which can result in the precipitation of crystalline in non-alkane based solid hydrocarbons, or waxes, from solution in the oil. These solids can result in the formation of plugs of paraffin at or near the perforation. Wax deposition can be extremely damaging in many reservoirs (Santosh and Sharada, 2017).

Emulsions

Crude oil is seldom produced alone. It is generally commingled with water, which creates a number of problems during oil production. Produced water occurs in two ways: as free water and/or in the form of emulsions. Emulsions can be encountered in almost all phases of oil production and processing either as the water-in-oil emulsions (water droplets in a continuous oil phase) or oil-in-water emulsions (oil droplets in a continuous water phase) These type of emulsions can exhibit very high viscosity and hence may result in permeability exhibiting

emulsion blockage in the near-wellbore (Adeosun *et al* 2020; Deepa *et al.,* 2002; Ajay *et al.,* 2010).

Scale Formation

Scale is a result of the abnormal behavior of

calcium carbonate, unlike most substance, which dissolve better in hot water than in cold, calcium carbonate become less soluble as temperature increases. So when hard water is heated, the calcium carbonates can no longer stay dissolved but precipitates or fall out of the water-as a scale on the face of the wellbore. This is a common treatment in low permeability sandstones injection wells (Abdullah, 2006).

Biological Formation Damage

Biological formation damage refers to bacteria introduced into the formation at any time during drilling and completion and these problems created nutrient streams into a reservoir (Civan, 2007). Although most common associated with water injection operations, bacteria contamination has the potential to occur any time a water based fluid introduced into a formation. However, hot formations may result in a reduction in bottom hole temperature to the point where bacteria may survive and propagate for growth (Luis Javier, 2009). The three major damage mechanisms associated with bacteria entrainment include:

1. Plugging – Most bacteria secrete a viscous polysaccharide polymer as a byproduct of their life cycle which may adsorb and gradually plug the formation.

2. Corrosion – Some types of bacteria set up an electro kinetic hydrogen reduction reaction which can result in pitting and hydrogen stress cracking on metallic surfaces downhole in tubing or surface equipment.

3. Toxicity: A certain type of anaerobic bacteria, commonly referred to as sulfate reducing bacteria (SRB), reduce elemental sulfate which may be present in formation/injection water and create toxic hydrogen sulfide gas.

Thermal Formation Damage:

Thermal formation damage mechanisms refer formation damage to those associated with high temperature injection operations namely steam injection and in-situ combustion. These could result to:

Mineral Transformations

At temperatures in excess of approximately $200^{\circ}C$, the potential for mineral transformation is present with non-reactive clay species that may be catalyzed and form hydra table reactive products which swell, desegregate, and reduce permeability. These reactions are most pronounced at temperatures above $250^{\circ}C$ (Ding, 2002).

Mineral Dissolution

The dissolution of mineral may dissolve partially soluble carbonaceous or silicate material thereby releasing previously immobilized fines particles to migrate to pore throats and cause reduction in permeability and productivity. Mineral solubility increases with temperature. Long term dissolution may result in the release of encapsulated fines or subsequent precipitation of the dissolved species when the hot fluids move further into the reservoir or into production wells and cools (Huyt *et al.,* 2017).

Reduction in Absolute Permeability

Reduction in Absolute Permeability has been documented to occur under overburdened conditions at extreme temperatures (Corey, 2003). It is believed to be due to thermal induced grain expansion and subsequent pore constriction. Thermal stress cracking and damaging fines particles has also been observed at high temperatures in some isolated studies.

Thermal Degradation

Over $200^{\circ}C$ thermal reactions of sulfur-bearing compounds in oil and rock, as well as carbonate reactions, may result in the production of large concentrations of hydrogen sulfide, carbon dioxide and mercaptans (Ding, 2011).

Formation Damage in Horizontal Wells

Horizontal wells have adverse effects that are more pronounced or magnified in potential deeper invasion depth near the wellbore. Some effects are the failure or loss of effective length of horizontal wells results in wellbore collapse and geomechanical issues. Mechanical damage usually produces a significant barrier to flow in horizontal open hole with shallow uncemented liner completions (Civan, 2003). Typical horizontal well and non-uniform cleanup is obtained due to permeability variation which may result to majority of the production coming from a small portion of the horizontal wellbore and the inability to remove invasive damage. Damage effects tend to increase the severity of horizontal to vertical permeability ratio. The natural high vertical permeability tends to reduce the severity of damage effects in a horizontal well situation. Anisotropic flow effects associated with variation in horizontal to vertical permeability ratio has impact on the flow of horizontal wells (Brant and Bennion, 2002). Fracture along a horizontal well poses far smaller pressure drops than those of the fracture intersecting a vertical well and numerical simulation corroborate the semi-analytical solution for the problem of formation damage in horizontal wells. In the absence of chemical interactions between filtrate and fluids in place, this induces an adverse water/oil relative permeability effects which is additional permeability impairment. Numerical approach is usually used to evaluate wettability, capillary pressure, initial and irreducible fluid saturation, relative permeability and critical velocity.

Modeling Impaired permeability for Horizontal Wells

A technical definition of permeability impairment would be any degradation/reduction of permeability which occurs in low oil and gas producing zones, technically, this may include all of the above mechanisms. It is known to be a major indicator of formation damage. Horizontal wells are more productive in thin bedded reservoir than in thick ones. In a thick bedded reservoir, a horizontal well behaves like a vertical well because of the small exposure of the wellbore to the formation. Economides *et al.*, (1996); Economides and Brand, (1991) provided the fundamental equation for a constant pressure of ellipsoid at steady-state production given as

$$q = \frac{hk_H(p_e - p_{wf})}{141.2B\mu \ln(\Gamma_1\Gamma_2)} \qquad (1)$$

Where $\Gamma_1 = \frac{a+\sqrt{a^2-(L/2)^2}}{L/2}$, $\Gamma_2 = \left[\frac{\beta h}{r_w(\beta+1)}\right]^{\left(\frac{\beta h}{L}\right)}$

$$\beta = \left(\frac{k_h}{k_v}\right)^{0.5} , \quad k_H = \beta^2 k_V$$

$$a = \frac{L}{2}\left[0.5 + \left(0.24 + \left(\frac{r_{ev}}{L/2}\right)^4\right)^{0.5}\right]^{0.5}$$

For such horizontal well with a length L, penetrating a reservoir with layered sediments of thin bedded sand-shale pay zone thickness h, the larger half axis a of the horizontal drainage shape is an ellipsoid formed around a horizontal well within an equivalent radius r_{ev} and parallel to the x-direction with length L=2a. Reservoir pressure is initially constant at time t=0 and uniformly distributed within the reservoir. Economides *et al.*, (1996) flow rate in Equation 2.

$$q = V_x = \frac{hk_H(p_e - p_{wf})}{141.2B\mu \ln(\Gamma_1\Gamma_2)} = -\frac{hk_H\Delta p}{141.2B\mu \ln(\Gamma_1\Gamma_2)} \quad , P_{wf} > P_e \qquad (2)$$

Mathematical Model Formulation

The model equation for impaired permeability is formulated by modifying the Darcy equation with the assumptions that the formation is homogeneous with varying layer thickness, small pressure gradient and application of Darcy law, the flow is horizontal x-y plane and gravity force is negligible. Principle of conservation of mass for a representative control volume Figure (3) that include properties, mechanical energy and fluid dynamic forces as (Rate of mass into the formation) − (Rate of mass out of the formation) + (Rate of generation in the formation) + (Rate of consumption in the formation) + (Fluid normal force on control surface) + (Fluid tangential force on control surface) + (Gravity on control volume) + (Mechanical force on control volume) = (Rate of accumulation in the formation) (Adeosun *et al*, 2009).
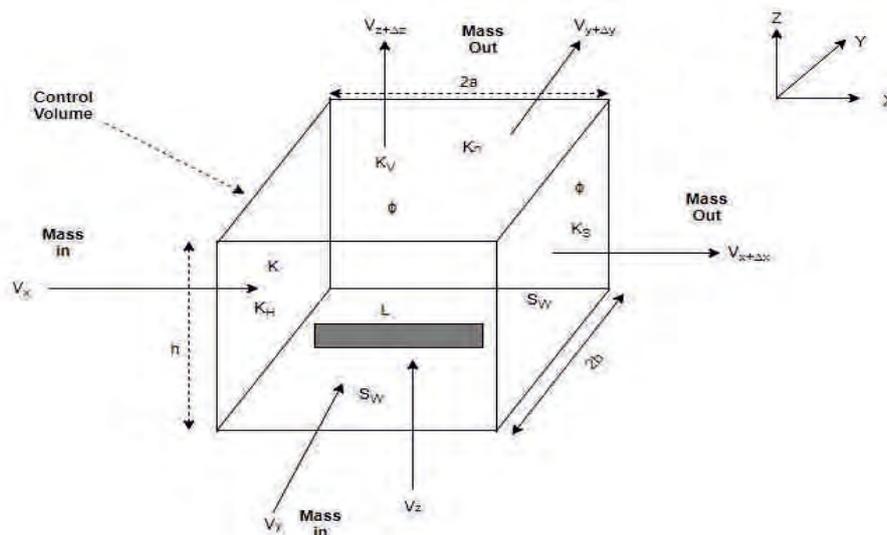

Figure 3: Control Volume Representative

The material balance equation assumes rate of mass generation, consumption, fluid forces and gravity are neglected in this formulation.

Continuity equation

$$\frac{\partial \rho V_x}{\partial x} + \frac{\partial \rho V_y}{\partial y} = -\frac{\partial(\rho\phi)}{\partial t} \quad (3)$$

Equation of State

The equation of state assumed a fluid constant compressibility defined by

$$c = -\frac{1}{v}\frac{dv}{dp} = \frac{1}{\rho}\frac{\partial\rho}{\partial p}$$

$$c\rho dp = d\rho \Rightarrow C_t = c\rho = \frac{\partial\rho}{\partial p} \quad (4)$$

From equation (3)

$$\frac{\partial(\phi\rho)}{\partial t} = \phi\frac{\partial\rho}{\partial p}\cdot\frac{\partial p}{\partial t} + \rho\frac{\partial\phi}{\partial t}$$

Hawkins's equation (1956).

$$s_d = \left(\frac{K_n}{k_s} - 1\right)\ln\left(\frac{r_s}{r_w}\right) \quad (5)$$

$$s_f = \left(\frac{K_n}{k_s} - 1\right) \quad (6)$$

The contrast reveals the extent of permeability damage between k_s and k_n. However, If a well is neither damage nor stimulated $k_s = k_n$ and S_f=0 (Civan, 2015).

$$\rho\frac{(k_n - k_s)}{\mu k_s}\frac{\partial^2 p}{\partial x^2} + \rho\frac{(k_n - k_s)}{\mu k_s}\frac{\partial^2 p}{\partial y^2}$$

$$= \phi\frac{\partial\rho}{\partial p}\cdot\frac{\partial p}{\partial t} + \rho\frac{\partial\phi}{\partial t} \quad (7)$$

$$\frac{(k_n - k_s)}{\mu k_s}\left[\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2}\right] = \phi c_t\frac{\partial p}{\partial t}$$

$$\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} = \frac{\phi\mu c_t k_s}{(k_n - k_s)}\frac{\partial p}{\partial t} \quad (8)$$

Darcy equation

$$V_x = -\frac{k}{\mu}\frac{\partial p}{\partial x} = -\frac{k\Delta p}{\mu} \quad (9)$$

Equate equation (2) and)(9

$$V_x = -\frac{k\Delta p}{\mu} = -\frac{hk_H\Delta p}{141.2B\mu\ln(\Gamma_1\Gamma_2)} \quad (10)$$

$$k = \frac{hk_H\Delta p}{141.2B\ln(\Gamma_1\Gamma_2)} \quad (11)$$

Civan, (2007) considered the effect of skin factor on porous and permeable layered sediments formation for as low as possible for a tolerance interval of (0≤S_f≤1.45). If the thin bedded layer thickness is a multiplicity of (h), then the accurate value of skin factor postulated theoretically and experimentally by Civan, (2006, 2007) assumed a value of S_f=1.45. Hence

$$k = \frac{k_n - k_s}{k_s} = \frac{hk_H\Delta p}{141.2B\ln(\Gamma_1\Gamma_2)} \quad (12)$$

Substituting the equation (12) into equation (8), we have

$$\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} = \frac{141.2\phi\mu c_t B\ln(\Gamma_1\Gamma_2)}{hk_H}\frac{\partial p}{\partial t}$$
$$(13)$$

Thus the modified Darcy equation for horizontal well with the skin factor S_f is given by

$$q = V_x = -\frac{hk_H}{141.2\mu Bs_f\ln[\Gamma_1\Gamma_2]}\frac{\partial p}{\partial x} \quad (14)$$

Equation (15) is the transient diffusivity partial differential equation for horizontal wells with initial and boundary conditions

given below

$$\frac{\partial^2 p(x,t)}{\partial x^2} + \frac{\partial^2 p(y,t)}{\partial y^2} =$$

$$\frac{141.2\phi\mu B c_t s_f \ln(\Gamma_1\Gamma_2)}{hk_H}\frac{\partial p}{\partial t} \quad (15)$$

$$\frac{\partial p}{\partial x}(x,t) = 0 \ at \quad \begin{cases} y = 0 \\ y = b \end{cases} \quad t > 0$$

$$\frac{\partial p}{\partial y}(y,t) = 0 \ at \quad \begin{cases} x = 0 \\ x = a \end{cases} \quad t > 0$$

Initial reservoir conditions

$$p(x,y,0) = P_0 \ in \quad \begin{cases} 0 \le x \le a \\ 0 \le y \le b \end{cases} \quad t = 0$$

Method of Solution

The use of finite difference as method of solution allows the degree of exactness to depend largely on the discretization techniques. The method also allowed some degree of freedom in determining the availability of input data for desired flow characteristics. Dirichlet boundary conditions was used as presented above with initial condition *p(x,y,t=0)=5000 psi*. The solution will be observed with simulation conducted for 500 days with and without injection run. Equ.(15) with its boundary conditions was discretized by using finite forward difference employing the alternating direction implicit (ADI).

$$\left(\frac{P_{i+1,j}^k - 2P_{i,j}^k + P_{i-1j}^k}{\Delta x^2}\right)\left(\frac{P_{i,j+1}^{k+1} - 2P_{i,j}^{k+1} + P_{i,j-1}^{k+1}}{\Delta y^2}\right) = \lambda\left(\frac{P_{i,j}^{k+1} - P_{i,j}^k}{\Delta t}\right)$$

$$\left(\frac{p_{i,j+1}^{k+1} - 2p_{i,j}^{k+1} + p_{i,j-1}^{k+1}}{\Delta y^2}\right) + q_{wi} = \frac{\lambda}{\Delta t}\left(p_{i,j}^{k+1} - p_{i,j}^k\right) - \left(\frac{P_{i+1,j}^k - 2P_{i,j}^k + P_{i-1,j}^k}{\Delta x^2}\right)$$

$$\frac{\Delta t}{\Delta y^2}\left(P_{i,j+1}^{k+1} - 2P_{i,j}^{k+1} + P_{i,j-1}^{k+1}\right) - \lambda P_{i,j}^{k+} = -\lambda P_{i,j}^k - \frac{\Delta t}{\Delta x^2}\left(P_{i+1,j}^k - 2P_{i,j}^k + P_{i-1,j}^k\right)$$

Let $\ r_y = \frac{\Delta t}{\Delta y^2}$ and $r_x = \frac{\Delta t}{\Delta x^2}$

$$r_y P_{i,j+1}^{k+1} - (2r_y + \lambda)P_{i,j}^{k+1} + r_y P_{i,j-1}^{k+1} = -\lambda P_{i,j}^k - r_x\left(P_{i+1,j}^k - 2P_{i,j}^k + P_{i-1,j}^k\right) \quad (16)$$

All the terms on the left hand side are unknowns while those on the right hand side are known − initial conditions and upwardly solved variables. Equation (16) solves for the temporal pressure variation along the y-axis

since all the terms on the LHS are known. The discrete equation below solves for the x-direction. Similarly, at the next iteration time, the other direction is solved for, using the solution obtained for direction.

$$\left(\frac{P_{i+1,j}^{k+1} - 2P_{i,j}^{k+1} + P_{i-1,j}^{k+1}}{\Delta x^2}\right) + \left(\frac{P_{i,j+1}^k - 2P_{i,j}^k + P_{i,j-1}^k}{\Delta y^2}\right) = \lambda\left(\frac{P_{i,j}^{k+2} - P_{i,j}^k}{\Delta t}\right)$$

$$\left(\frac{P_{i+1,j}^{k+2} - 2P_{i,j}^{k+2} + P_{i-1,j}^{k+2}}{\Delta x^2}\right) = \lambda\left(\frac{P_{i,j}^{k+2} - P_{i,j}^{k+1}}{\Delta t}\right) - \left(\frac{P_{i,j+1}^{k+1} - 2P_{i,j}^{k+1} + P_{i,j-1}^{k+1}}{\Delta y^2}\right)$$

$$\frac{t}{\Delta x^2}\left(P_{i+1,j}^{k+2} - 2P_{i,j}^{k+2} + P_{i-1,j}^{k+2}\right) = \lambda\left(P_{i,j}^{k+2} - P_{i,j}^{k+1}\right) - \frac{t}{\Delta y^2}\left(P_{i,j+1}^{k+1} - 2P_{i,j}^{k+1} + P_{i,j-1}^{k+1}\right)$$

$$r_x\left(P_{i+1,j}^{k+2} - 2P_{i,j}^{k+2} + P_{i-1,j}^{k+2}\right) - \lambda P_{i,j}^{k+2} = -\lambda P_{i,j}^{k+1} - r_y\left(P_{i,j+1}^{k+1} - 2P_{i,j}^{k+1} + P_{i,j-1}^{k+1}\right)$$

$$\left(r_x P_{i+1,j}^{k+2} - (2r_x + \lambda)P_{i,j}^{k+2} + r_x P_{i-1,j}^{k+2}\right) = -\lambda P_{i,j}^{k+1} - r_y\left(P_{i,j+1}^{k+1} - 2P_{i,j}^{k+1} + P_{i,j-1}^{k+1}\right) \qquad (17)$$

Where

$$\Delta t = \frac{T}{N} \quad , \qquad \Delta x = \left(x_f - x_0\right), \qquad \Delta y = \left(y_f - y_0\right)$$

T = Total simulation time, N = Number of discrete time steps used for simulation, X-Y coordinates of the reservoir

3.0 RESULTS AND DISCUSSION

The solution equation (16 and 17) was implemented on MATLAB and was validated using field data sets from a Brown Field in Niger Delta (See Appendix 1). The synthetic data was perturbed with Gaussian noise of ±10% during the simulation conducted for 500days at different time steps without injection. The validation was also carried out on anisotropic values of 0.1, 0.5, 1.0, for 700 days with skin factor values of 0, 0.5, 1.0, 1.45, and 1.50 for different values of horizontal permeability (K_H) of 100mD to 700mD respectively. The results generated pressure depletion that shows that the energy of the reservoir depends on the initial pressure during production and pressure changes in the reservoir usually prone to depletion on reservoir surface distance with initial pressure of 5000 *psi*. Figure (4) shows the reservoir has initial pressure of 5000 psi. This was the prediction of the reservoir at the start of production, the pressure suddenly diminished to 4,999.4 *psi*. Figure (5-9) revealed the sensitivity to pressure change along horizontal well (x- direction). Pressure variation in these figures began to decrease with response to

surface distance in the sequence 4,429.7 *psi*, 3,895.4 *psi*, 3,289.2 *psi*, 2,719 psi and 2,148 psi. These results also show the influence of water coning on breakthrough time. The effect of this was that the critical oil production for horizontal wells in an oil reservoir underlain by water prolongs water free oil production. Another significant effect of water coning was that the critical oil production was high for thin bed reservoirs as thin bed drained oil initially faster in horizontal wells than thick reservoirs. This implies there were incremental gains in the reservoir for thin bed reservoir which produce oil more than thick beds reservoirs. Figure (5-9) show that there was an early onset of water coning everywhere in the reservoir and eventually water breakthrough into the wellbore at low production rate. This implies that pressure drop increases for a long period of water coning with reducing sweep efficiency as shown in the Figure (9).

Horizontal Well Pressure with Anisotropy

Figure (10) shows the pressure response simulated for Equations (16 and 17) were used for three different anisotropic factor values and the result obtained shows that pressure for high anisotropic value exhibits high sensitivity to pressure change than those with low anisotropic values. This increase in anisotropic ratio causes an increase in the
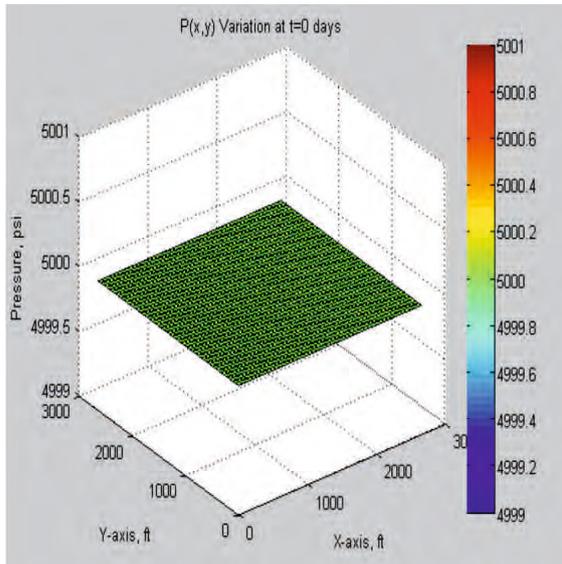
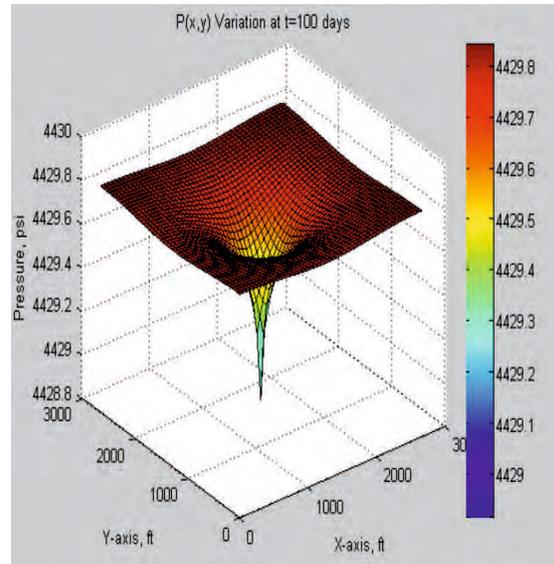*Figure 4: Pressure variation with distance at time t=0 day for equ.(16 and 17)*

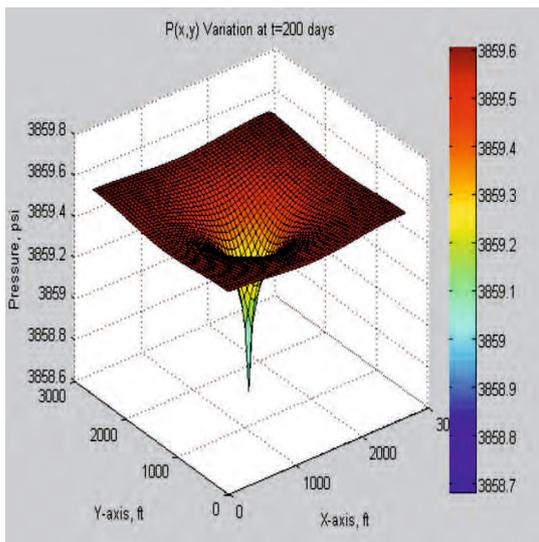*Figure 5: Pressure variation with distance at time t=100 days for equ.(16 and 17)*

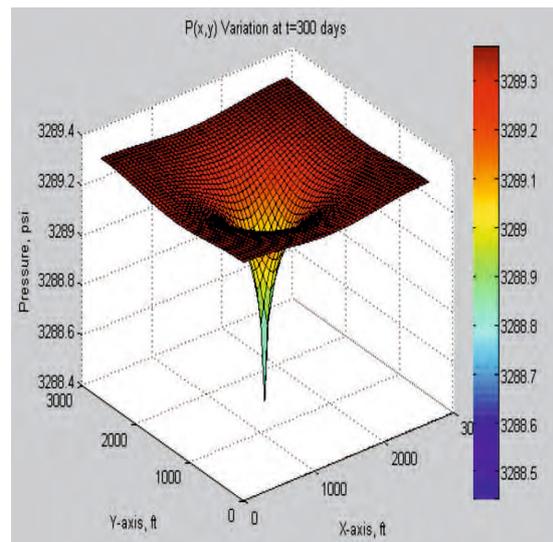*Figure 6: Pressure variation with distance at time t = 200 days for equ. (16 and 17)*

Figure 7: Pressure variation with distance at time t=300 days for equ.(16 and 17)

magnitude of pressure differential. The late-time for pressure build up at a picked time of 400 days shows the pick point for each pressure response. This effect was enhanced when horizontal well for a given long period of time produced its fluids. The effect was also emphasized when high permeability formation exhibited thin beds reservoirs. This is an important technical issue since pressure

drop are often influenced by skin effects, anisotropic effects and noise effects, thereby decreasing the reliability to estimate and predict production outcome.

Figure (11) shows the plot of the modified Darcy flow rate Equation (14) as a function of horizontal permeability for various values of skin factors. This figure shows the influence of
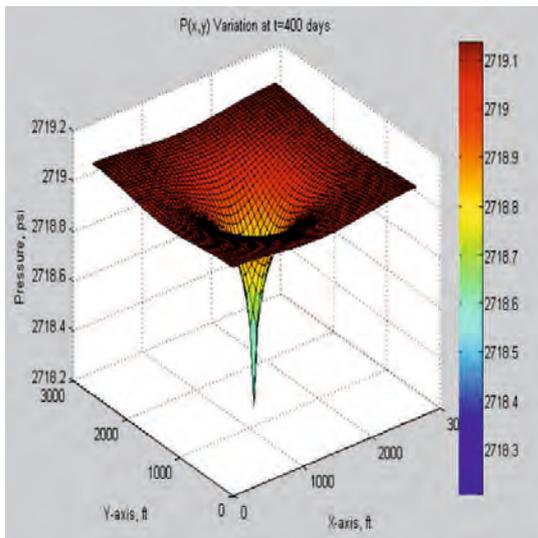
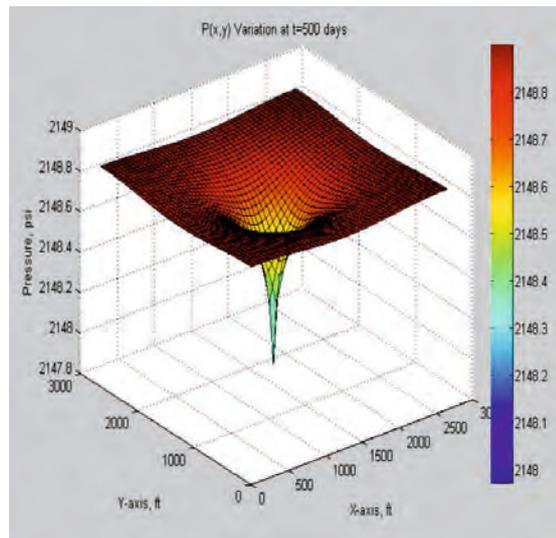*Figure 8: Pressure variation with distance at time t=400 days for equ.(16 and 17)*

Figure 9: Pressure variation with distance at time t=500 days for equ.(16 and 17)

flow rate was quite significant and as a results, horizontal permeability increases monotonically with increasing flow rate. This effect was due to the dominant influence of horizontal permeability in horizontal wells. Monotonic increasing of horizontal permeability with flow rate was clearly seen for various values of skin factors. Horizontal

wells with very long well length and average skin values interval $0 \leq S_f \leq 1.50$ postulated by Civan, (2007) gave a maximum horizontal permeability. The peak pressure resurfaces again in this figure when horizontal permeability attained maximum value and consequently high productivity as a result of producing from horizontal wells.
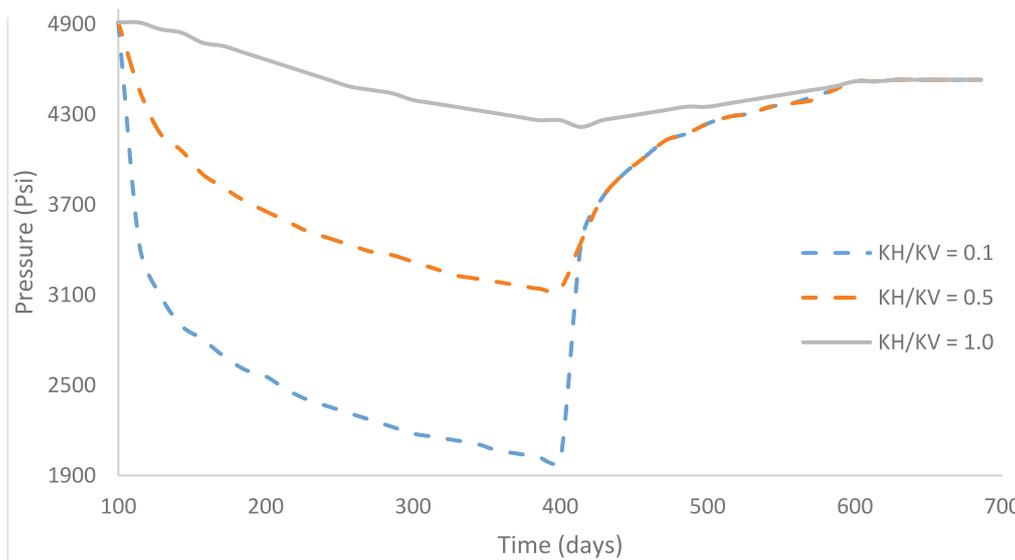

Figure 10: Pressure variation with time for values of $\frac{k_V}{k_H}=0.1$, $\frac{k_V}{k_H}=0.5$, $\frac{k_V}{k_H}=1.0$ for equ.(14)
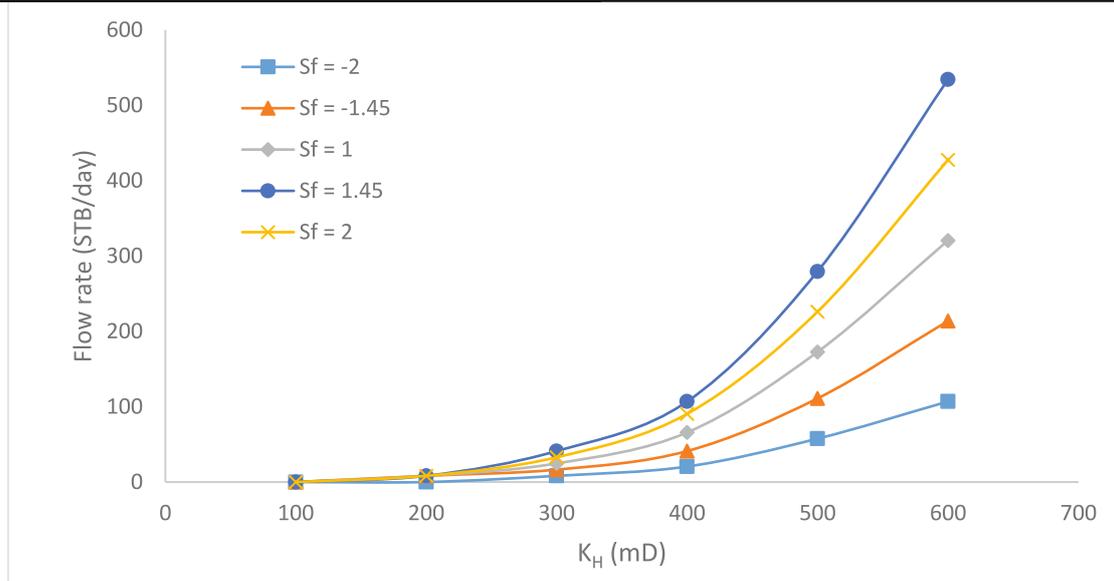
Figure 11: Pressure variation with horizontal permeability k_H at different skin factor values of $S_f = 2$, $S_f = -1.45$, $S_f = 1$, $S_f = 1.45$ and $S_f = 2$ for equ. (14).

CONCLUSION

A wide range of different potential types of formation damage mechanisms have been discussed for the near oil wellbore damages, specifically, fine particles migration, phase blocking and trapping, loss of reservoir properties, gazing, sand intrusion, water flooding, clay swelling, paraffin's and waxes, scale formation, emulsion problem, mineral dissolution and mud filtrate invasion are all impaired phenomenon concerning formation damage. A small bit of knowledge on these mechanisms can go a long way towards allowing engineers to make informed decisions as to the best practices to drill, complete and optimize sweep efficiency.

Permeability impairments have been simulated by formulating model involving modification of Darcy's equation in an attempt to optimize the reservoir pressure for improved near oil wellbore in horizontal wells. The model, transient linear partial differential equation (TLPDE) for impaired permeability in horizontal wells was numerically resolved using Finite difference method. The TLPDE model indicated pressure depletion prior to permeability impairment which justifies the distribution of permeability in relevant direction with horizontal permeability (k_H) which is considered truly representative of permeability anisotropy under the influence of skin effects.

Numerical simulation has therefore proved to be effective mathematical tool in simulating near wellbore damages. The models formulated indicate pressure depletion over time but increases thereafter, resulting to significant improvement of near oil wellbore recovery.

Nomenclature

a   Tortuosity factor, p Pressure, t Time

C_t Total compressibility, p_{wf} flowing pressure at reservoir condition, μ Viscocity

h formation pay zone thickness, p_e Well bone pressure, ϕ Porosity

k Permeability, q Darcy flow rate, $(x, y,)$ Coordinate system

k_H Horizontal permeability, r_w Well bone radius, Δp Change in pressure

k_v Vertical permeability, r_s Extent drainage radius, β Anisotropy factor

k_s Skin permeability, r_e Drainage radius, (Γ_1, Γ_2) Constant denotation

k_n Normal permeability, r_{ev} Equivalent radius, V_y Flow rate in y-direction

L Length, α Half-axis ellipsoid, V_x Flow rate in x-direction

S_f Skin factor, S_d Skin damage,

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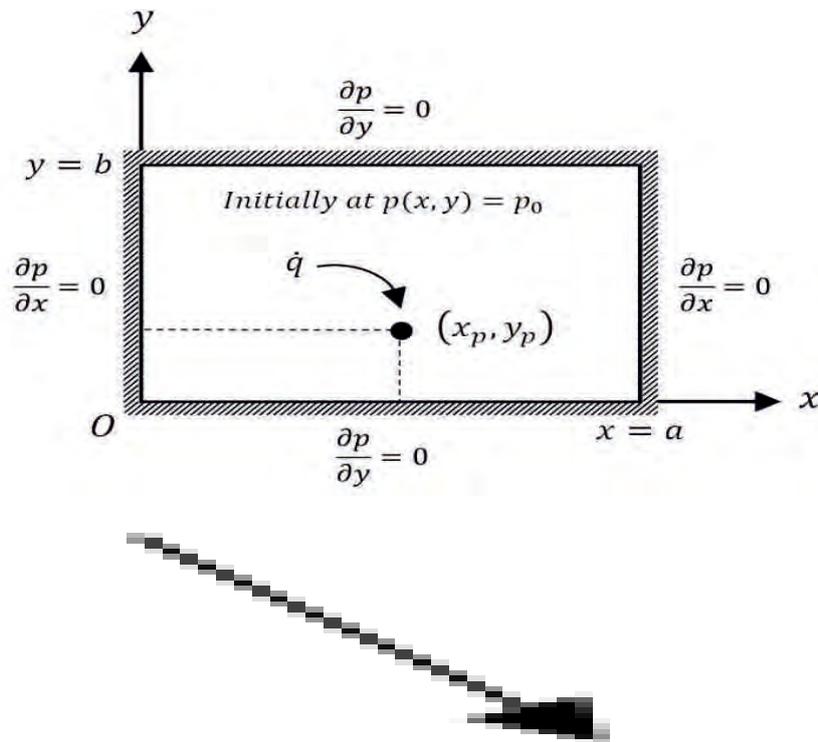
Appendix 1

Figure A: Schematic of a rectangular reservoir with initial and boundary conditions

Table A: Data set for the case study and unit system

Parameter	FIELD	SI
ϕ	20%	20%
μ	0.33 cp	3.3×10^{-4} Pa.s
c_t	$1.0 \times 10^{-6}(kgf/cm^2)^{-1}$	$2.18 \times 10^{-9} \, Pa^{-1}$
K	$1.5mD$	$1.48 \times 10^{-15}m^2$
P	$5000psi$	$490.35MP_a$
Gaussian Noise	$\mp10\%$	$\mp10\%$
a	$2,000ft$	$609.6m$
b	$2,000ft$	$609.6m$