Journal of Nature Science and Sustainable Technology
Volume 9, Number 3
ISSN: 1933-0324

CLASSICAL MODELLING OF THE EFFECT OF HETEROGENEITY ON RESERVOIR PERFORMANCE OF AGBADA FORMATION

Sarah A. Akintola, Oluwatoyin O. Akinsete* and Okon G. Akan
Department of Petroleum Engineering, University of Ibadan, Nigeria

ABSTRACT

Understanding the basic mechanisms that govern flow of hydrocarbon in any given reservoir situation is necessary in developing reliable methods of predicting behaviour in that reservoir. Most reservoirs in Agbada Formation of the Niger Delta Basin are anisotropic and therefore heterogeneous, which is a vital parameter in the efficient production of hydrocarbons. This work looked at the effect of permeability anisotropy (K_v/K_h) or heterogeneous distribution and its effects on reservoir performance using windows based IPM-MBAL petroleum engineering software. Results analysis revealed that anisotropy makes reservoir production modelling more realistic than the isotropic scenarios, and degree of heterogeneity improves oil recovery from the reservoir (K_v/K_h = 1, R.F = 49.31%; K_v/K_h = 0.1, R.F = 49.95%; K_v/K_h = 0.001, R.F = 50.60%; K_v/K_h = 0.0001, R.F = 51.24%). Reservoir heterogeneity should be included in reservoir modelling practices because it has a significant effect on hydrocarbon production.

Keywords: Modelling, Heterogeneous reservoir, Permeability anisotropy, Reservoir performance, Oil recovery

NOMENCLATURE

B_g	Gas formation volume factor (bbl/Scf)
B_{gi}	Initial gas formation volume factor (bbl/Scf)
B_o	Oil formation volume factor (bbl/STB)
B_{oi}	Initial oil formation volume factor (bbl/STB)
B_t	Two phase formation volume factor (bbl/STB)
C_f	Formation compressibility (psi^{-1})
C_w	Water compressibility (psi^{-1})
G_P	Cumulative gas produced (Scf)

* Corresponding Author: kunle2223@yahoo.com

K_h	Horizontal permeability (md)
K_v	Vertical permeability (md)
m	Ratio of reservoir initial gas-cap volume to initial oil volume
N	Initial oil in place (STB)
N_P	Cumulative oil produced (STB)
P	Volumetric average reservoir pressure
P_i	Initial reservoir pressure (psi)
R_P	Cumulative gas-oil ratio (Scf/STB)
R_s	Gas solubility (Scf/STB)
R_{si}	Initial gas solubility (Scf/STB)
W_e	Cumulative water influx (bbl)
W_P	Cumulative water produced (bbl)
ΔP	Change in reservoir pressure (psi)

INTRODUCTION

Petroleum in the Niger Delta is produced from sandstone and unconsolidated sedimentary structure formed as a complex regressive offlap sequence of clastic sediments varying in thickness from 9,000 – 12,000 meters.

Short and Stauble (1967) divided the tertiary deltaic complex into three major facies units – Akata, Agbada and Benin Formations. The Agbada formation consists mainly of sands, sandstones and silt-stones, it is the main hydrocarbon reservoir in the delta. Log responses in the Agbada formation show changes related to upward coarsening of barrier sands accompanied by increase in permeability. The vertical permeability of barrier bar sand reservoirs is often broken up by clay streaks. The Niger Delta complex is also characterized by growth fault structures called rollover anticlines, the Agbada formation is the most affected by growth faulting given rise to heterogeneity of the formation.

Reservoir heterogeneity is the degree of diversity of elements making up a reservoir while anisotropy is the characteristic of having physical properties that differ when measured in different directions.

Anisotropy is a fundamental property of sedimentological formations, it is inherent in deposition which is a dynamic process and affects heterogeneous material – the sediments being deposited. It is defined as the ratio of vertical permeability to horizontal permeability. Permeability, a property of the rock, is controlled by the rock fabric through which the fluids in the reservoirs flow. It is a function of size, shape and distribution of pore channels which are in-turn related to grain sizes, surface textures and packing arrangements and it is a directional quantity. In as much as rock formations are anisotropic, and therefore heterogeneous, permeabilities are similarly anisotropic in the horizontal and vertical directions.

Reservoir anisotropy occurs at several scales, Weber and Van Geuns (1989) proposed three major reservoir architectural types: Layer Cake type, Jigsaw Puzzle type and Labyrinth type. Reservoirs can be described as one of these or as combination of these types. They also stipulated that degree of anisotropy increases from Layer-cake to Labyrinth reservoir types. Since permeability of a rock is dependent upon the rock fabric, hence, any meaningful description of permeability anisotropy must take account of the rock in terms of fabric to architecture; hence reservoir anisotropy is described as heterogeneity.

LITERATURE REVIEW

Ahmed (2000) quantitatively described two types of heterogeneity Areal heterogeneity and Vertical heterogeneity by geostatistical methods in the petroleum industry. Other authors such as Law (1944), Clelland (1986) and Jensen et al. (1987) analyzed reservoir permeability statistically. As shown in Table 1, Jensen et al. (1987) described how permeability distributions can be classified into; stratified or layered and serial while Clelland (1986) recognized a random distribution class. In this work, heterogeneity will be described using permeability property of reservoir. There are several methods of obtaining permeability anisotropy such as core analysis, well testing techniques, wireline formation tester measurements, log data analysis, etc. Several logging tools have been developed in the petroleum industry to assist in the direct and indirect estimation of anisotropy and permeability. This progress has been well documented by several prolific authors over the last two decades. The tools used for the estimation of permeability and permeability anisotropy include the straddle-packer formation tester as detailed by Renzo et al. (2007). The tool performs its function from transient measurements of pressure acquired with a wireline straddle-packer formation tester. The method developed using the tool incorporates the physics of two-phase, axisymmetric, immiscible flow to simulate measurements and is combined with a nonlinear minimization algorithm for history matching purposes, as well as the process of mud-cake build-up and invasion.

Table 1. Permeability distribution and types of averaging

Permeability Distribution	Averaging Type	Geological Setting	Flow Direction
Stratified	Arithmetic Mean	Layered barrier Sands	Parallel to layering (K_h)
Serial	Harmonic Mean	Layered barrier Sands	Normal to layering (K_v)
Random	Geometric Mean	Bioturbated Sands	Parallel or normal

Core analysis is one of the traditional ways of measuring permeability directly on a sample of rock. Orientation of the plug determines whether horizontal or vertical permeabilities are to be measured. Average permeability can be computed along the well if measurements are made on samples taken per foot travelled. Harmonic averaging is used for estimating the vertical permeability to account for variations in vertical displacement between plugs, while arithmetic averaging is made for horizontal permeability. Cosan et al. (1994) stated that in the use of cores for anisotropy determination, there must be an absence of impermeable barriers such as stylolites or shales. In the presence of these barriers, vertical permeability measurements are 10 to 100 times lower, thus making data on a reservoir scale unacceptable.

Colley et al. (1992) presented a means of permeability anisotropy estimation is vertical interference testing using the Modular Formation Dynamics Tester tool which estimates vertical anisotropy in the near wellbore i.e., approximately within 15 feet. This tool uses various combinations of probes and packers, allowing open hole vertical interference tests to be performed faster and at lower costs.

The effects of heterogeneity of reservoir rocks on fluid displacement efficiency remains a very important unsolved problem in this period of rapidly growing application of fluid injection for increased recovery of oil. Hypotheses of reservoirs ranging from non-connecting layers characterized by permeability frequency distribution, irrespective of spatial origin of cores, to reservoirs too heterogeneous they are nearly homogeneous have been offered as basis for evaluation of actual oil recovery projects. Lincoln and Aelie (1962) are of the opinion that flow through a heterogeneous reservoir having major variances in permeability should be non-uniform. Walter (1982) supported this by stating that effluent streams regressing from a right-cylindrical anisotropic core media will not be uniformly distributed. Walter further expounded that if the mean dimensions of fracture created local heterogeneous domains were small enough in comparison to the dimensions of the entire domain of fluid flow, then their random distribution on a large scale would often result in an averaging-out effect termed anisotropy. He further stated that horizontal wells are good ways to take advantage of natural heterogeneities and effort should be made to create such heterogeneities if absent in a given reservoir.

Hewett (1986) in his investigation on fractal distribution effects on fluid transport stated that fluid flow in heterogeneous porous media showed that their transport properties were determined by the structure of spatial correlations in the permeability distribution. Also, when the range of these correlations were comparable to or larger than the fluid flow path, solutions of the convective-dispersion equation with an effective dispersivity augmented to account for the dispersive effects of reservoir heterogeneity do not provide accurate predictions of the transport characteristics of the medium. Gaten et al. (1991) studied the effect of anisotropy on well performance prediction and discovered that for fractures that grow in the direction of high permeability, as the permeability anisotropy increased, cumulative production to a given time decreased. Wannell and Colley (1993) further expounded that at low values of anisotropy, significant reserves are trapped behind the rising aquifer. While at the other extreme, high anisotropy does not allow recovery of gas from un-perforated layers. They also stated that reserves were maximised when the anisotropy was small enough to retard water influx but high enough to allow drainage of the un-perforated layers. Furthermore the anisotropy would determine the optimum perforating policy to be adopted. If low, only upper layers would be perforated to avoid water coning but allow the drainage of un-perforated layers. If high, would require more perforations to effectively drain the field.

Grammer et al. (2004) showed that fluid flow in reservoirs were affected by heterogeneity at a range of scales, from sub-metre up to 10's of metre, but that predominant control was exerted by bedding, pore fluid changes and diagenetic effects at the metre-scale. Georgi et al. (2002) stated that it was difficult to directly measure or determine permeability anisotropy, but was possible to measure resistivity anisotropy with new wireline, multi-component induction hardware. From which permeability anisotropy can be estimated. They showed numerically and theoretically for 2D structures that resistivity and permeability anisotropy were identical for cells with inverse property contrasts. They also concluded that the relationship between resistivity and permeability anisotropy was not trivial, but controlled by the spatial distribution of the pore-space on the small scale and the spatial distribution of the sand bodies and gaps in the shale barriers on larger reservoir scales respectively.

Brad and Chuck (2008) showed the possibility of using cross-well seismic data to characterize lateral variations in reservoir stratigraphy and for qualitative and quantitative mapping of stochastic reservoir heterogeneity. They further stated that well log and surface seismic data had limitations that controlled resolution. Well log sample less than 1m vertical resolution whereas seismic data has 30 – 50m vertical resolution at the reservoir interval. Simon et al. (1996) developed a high resolution permeability predictor using correlated Formation Micro-Imager (FMI) and probe permeability measurements in order to accurately quantify reservoir heterogeneity in the near wellbore region. This is possible because the FMI combined with probe measurements allow sampling of the reservoir at individual lamina scale at which the reservoir properties are effectively homogeneous and are able to resolve those elements of the reservoir that, although being thin, contribute significantly to larger scale reservoir heterogeneity and anisotropy.

THEORETICAL FRAMEWORK

The fundamental principle behind the IPM-MBAL software is the Material Balance Equation (MBE) principle, which states that, the mass of hydrocarbons initially in-place is equal to sum of the mass produced and mass remaining in the reservoir (Kleppe, 2014) i.e.

$$M_j = \Delta M + M \tag{1}$$

The MBE calculation is considered as zero dimension, i.e. a tank of constant volume. The pressure in the tank model is defined by the volumetric average pressure;

$$\overline{P} = \frac{\int_{V_j} PdV}{V_j} \tag{2}$$

The initial oil in place calculation is given as (Ahmed, 2000):

$$N = \frac{N_P\left(B_t + \left(R_P - R_{Si}\right)B_g\right) - \left(W_e - W_P B_w\right)}{\left(B_t - B_{ti}\right) + mB_{ti}\left(\frac{B_g}{B_{gi}} - 1\right) + B_{ti}\left(1+m\right)\left(\frac{S_{wi}C_w + C_f}{1 - S_{wi}}\right)\Delta P} \tag{3}$$

For a combination drive reservoir, the relative magnitude of each of the driving mechanism to production is given as:

$$DDI + SDI + WDI + EDT = 1 \tag{4}$$

where,

$$DDI = \frac{N\left(B_t - B_{ti}\right)}{N_P\left(B_t + \left(R_P - R_{si}\right)B_g\right)} \tag{5}$$

$$SDI = \frac{NmB_{ti}\left(B_g - B_{gi}\right)}{N_P B_{gi}\left(B_t + \left(R_P - R_{si}\right)B_g\right)} \tag{6}$$

$$WDI = \frac{W_e - W_P B_w}{N_P\left(B_t + (R_P - R_{si})B_g\right)} \tag{7}$$

$$EDI = \frac{NB_{oi}(1+m)\left(\frac{C_w S_{wi} + C_f}{1 - S_{wi}}\right)(P_i - P)}{N_P\left(B_t + (R_P - R_{si})B_g\right)} \tag{8}$$

RESULTS AND DISCUSSIONS

Reservoir and fluid properties used in this study are listed in Table 2. Figure 1 is a plot of reservoir pressures versus oil recovery factor. The plot is generally trending downwards with maximum values of reservoir pressures as 2400psig for K_v/K_h values of 1, 0.1, 0.01, 0.001 and 0.0001. All K_v/K_h values have maximum oil recovery factors ranging from (49.3 – 51.2%). K_v/K_h of 1 has the lowest recovery factor of 49.31%. From Figures 1 and 2, it is seen that vertical anisotropy improves oil recovery. This is seen by the values of oil recovery for different values of vertical anisotropy at a fixed reservoir pressure of 2035.1psig. Table 3 and Figure 2 summarises the effects of vertical anisotropy on reservoir oil recovery factor. Oil recovery factor increases as anisotropy increases.

Table 2. Reservoir and Fluid Input Data

Reservoir Properties		Fluid Properties	
T (°F)	133	API gravity	35.4
P (psia)	2405	Specific gravity	0.689
Porosity	0.412	GOR(scf/stb)	489
C_f (psi^{-1})	3.2E-06	Water salinity (ppm)	100,000
m	2.186		
N (MMSTB)	20.4059		
k (md)	300		
S_{wc}	0.476		

Table 3. Oil Recovery Factor at different values of K_v/K_h

K_v/K_h	Oil recovery factor (%)	Reservoir Pressure
1	49.31	2035
0.1	49.93	2035
0.001	50.60	2035
0.0001	51.24	2035

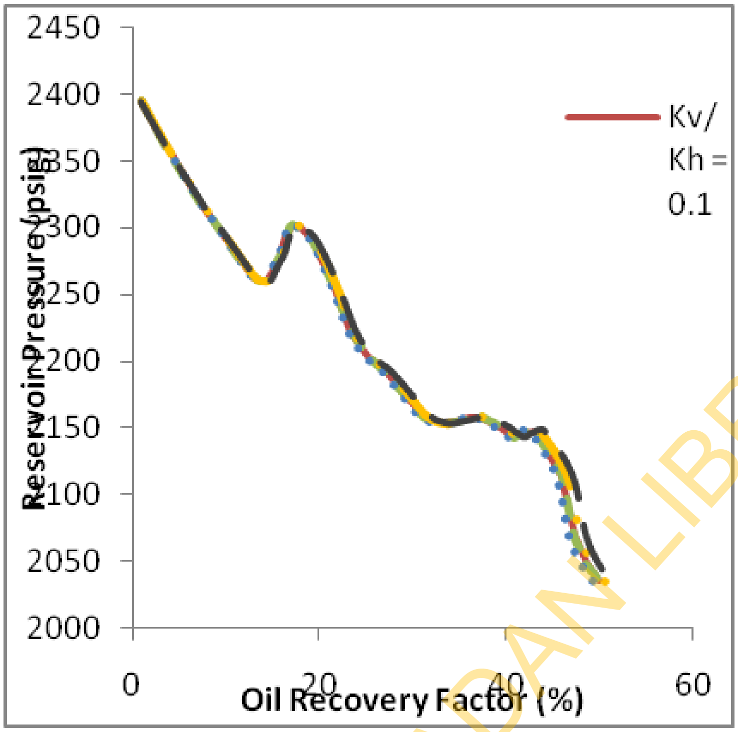

Figure 1. Reservoir Pressure versus Oil Recovery Factor.

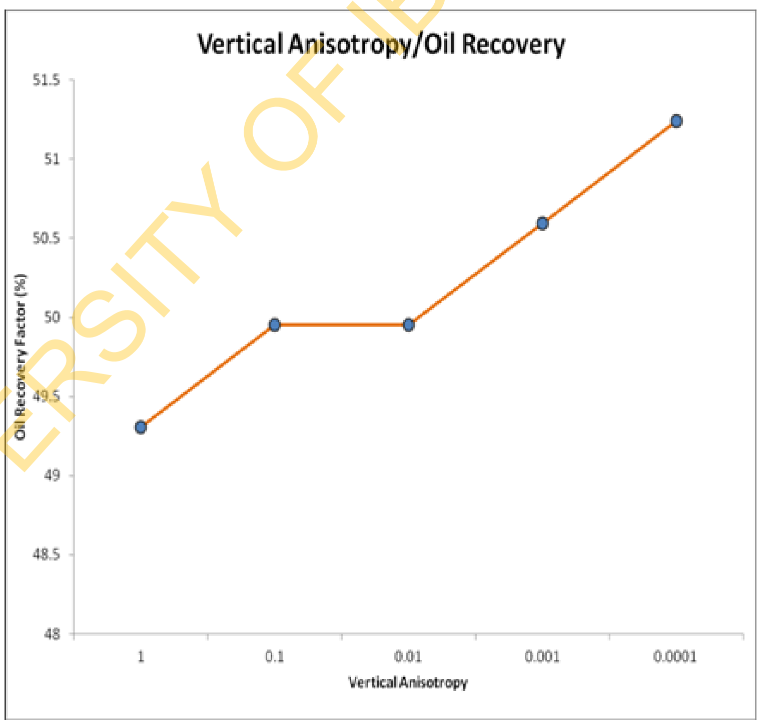

Figure 2. Vertical Anisotropy versus Oil Recovery Factor.

Values of produced GOR are plotted against reservoir's oil recovery factor Figure 3. The curve is trending upward, showing ever increasing values of GOR with increases in oil recovery factor.

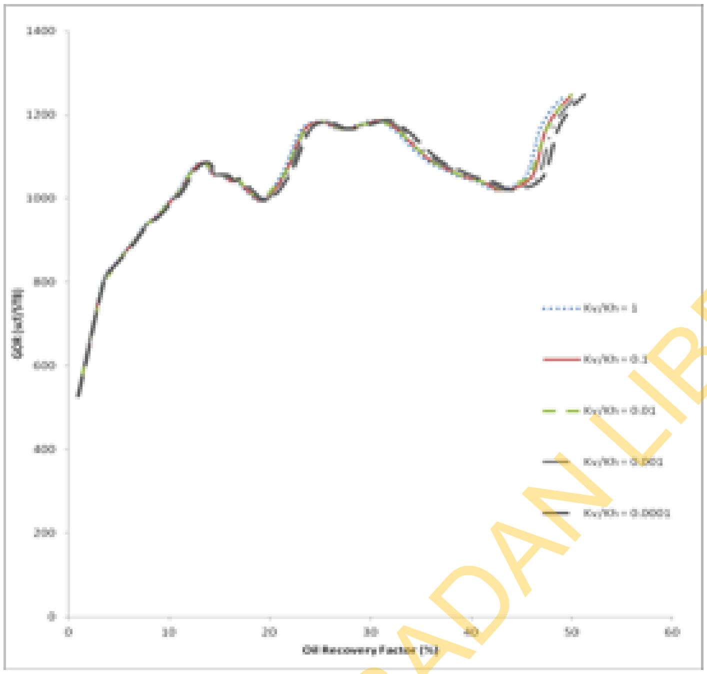

Figure 3. GOR versus Oil Recovery Factor Plot.

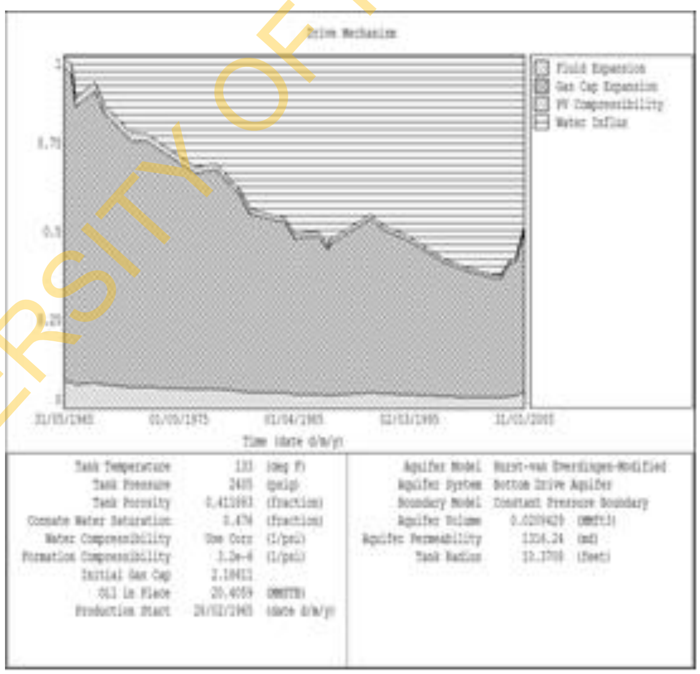

Figure 4. Energy Plot of Reservoir Drive Mechanism.

At different values of K_v/K_h, different values of GOR with respect to oil recovery factor are observed. At isotropic reservoir conditions (K_v/K_h =1) lower values of GOR are observed as compared to other values of anisotropy, K_v/K_h of 0.1, 0.01, 0.001, and 0.0001.

The curve depicted by Figure 3 is generally upward trending with peak values of GORs of 1247.0scf/STB at K_v/K_h of 0.0001 (51.24% oil recovery factor), 0.001 (50.60% oil recovery factor), 0.01 (49.95% oil recovery factor), 0.1 (49.95% oil recovery factor), 1 (49.31% oil recovery factor, 1049.1scf/STB) respectively. Minimum value of GOR is seen at all values of K_v/K_h (526.94scf/STB).

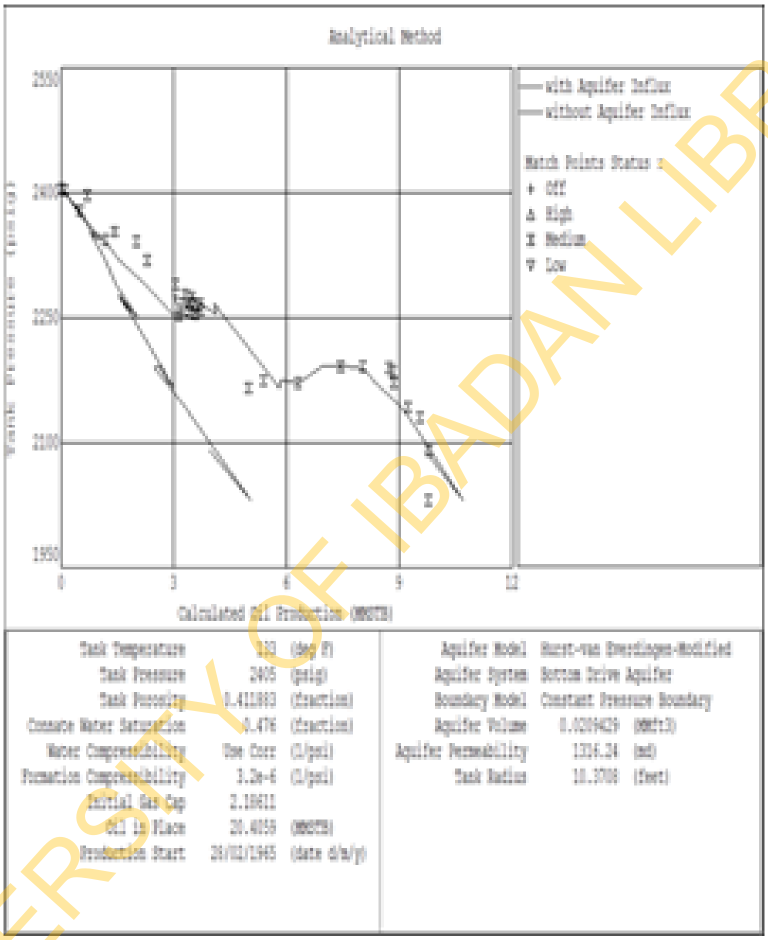

Figure 5. Pressure profile of oil production for heterogeneous case (K_v/K_h = 0.0001).

This is because, regardless of isotropic conditions or otherwise, all production will have a common starting point or origin. Also, the difference in recovery values for the isotropic scenario and the heterogeneous scenarios is about 1.9368%. Figure 4 shows the effect of heterogeneous on the reservoir drive. Figures 5 also showed that heterogeneity of the reservoir improves hydrocarbon production from 0 – 10.8MMSTB (for Aquifer Influx), 0 – 4.97MMSTB (without Aquifer Influx) as compared to Figure 6 the isotropic scenario of 0 – 2.46MMSTB

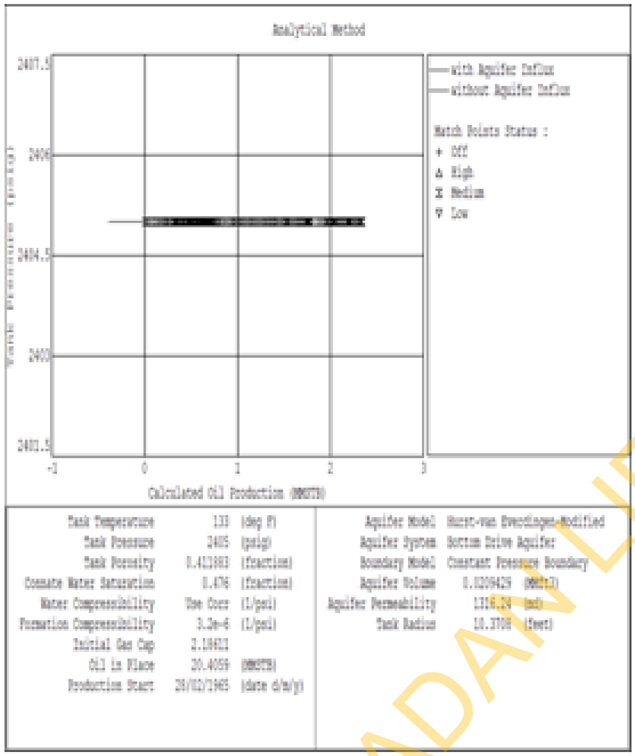

Figure 6. Pressure profile of oil production for isotropic case ($K_v/K_h = 1$).

Conclusion

In this study, the result demonstrated that:

1. Vertical anisotropy makes production modelling more realistic than it would if considered isotropic.
2. Good vertical permeability will permit production of oil to the wellbore with less bypassing of gas.
3. Heterogeneity effect on production performance is minimal in the short term development planning of a reservoir, but can be considerate when undergoing strategic long term planning.
4. Reservoir heterogeneity should be included in reservoir modelling practices because it has a significant effect on hydrocarbon production.

References

Ahmed, T. (2000). *Reservoir Engineering Handbook*. 2nd ed. Butterworth–Heinemann, Texas, 222–224.

Brad, B. and Chuck, H. (2008). Characterization of Reservoir Heterogeneity: An Investigation of the Role of Cross-Well Reflection Data. *CSEG Recorder*. Pages 31–37.

Clelland, W. (1986). Porosity and Permeability Averaging for Simulation Purposes. RKRS.

Colley, N., Ireland T., Reignier P., Richard S., Joseph J., Zimmerman T., Traboulay I and Hastings S. (1992). The MDT Tool: A Wireline Testing Breakthrough. Oilfield Review 4. Number 2, pages 58 – 65.

Cosan, A., Nick, C., Greig, C., Emmanuel, E., Mick, W., Peter, G., Frank, H., Jeffrey, J., Adriano, M. and Julian, P. (1994). *Measuring Permeability Anisotropy: The Latest Approach.* Oilfield Review.

Gatens, J. M., Lee, W. J., Hopkins, C. W., Lancaster, D. E. and Holditch, S. A. (1991). The Effect of Permeability Anisotropy on the Evaluation and Design of Hydraulic Fracture Treatments and Well Performance. *Paper SPE* 21501, pages 211–222.

Georgi, D., Bespalov, A. and Tabarovsky, L. (2002). On the Relationship between Resistivity and Permeability Anisotropy. *Paper SPE* 77715.

Grammer G. M., Harris P. M. and Eberli G. P. (2004). Integration Of Outcrop And Modern Analogs In Reservoir Modelling: Overview With Examples From The Bahamas In Integration Of Outcrops And Modern Analogs In Reservoir Modelling. *AAPG Memoir* 80, 1 – 22.

Hewett T.A (1986). Fractal Distributions of Reservoir Heterogeneity and their Influence on Fluid Transport. *Paper SPE* 15386.

Jensen, J. L., Hinkley, D. V. and Lake, L. W. (1987). A statistical Study of Reservoir Permeability: distributions, correlations and averages. SPE Foundation Evaluation, pp. 461-468.

Kleppe, J. (2014) TPG4150 Reservoir Recovery Techniques 2014: Material Balance Equation. http://www.ipt.ntnu.no/~kleppe/TPG4150/matbal.pdf.

Law, J. (1944). Statistical Approach to the Interstitial Heterogeneity of Sand Reservoirs. Trans. *AIME* 155, pp 202-222.

Lincoln, F. E and Arlie, M. S. (1962). Some Field Observations of Heterogeneity of Reservoir Rocks and Its Effects on Oil Displacement Efficiency, *paper SPE* 282, pages 61 – 70.

Renzo, A., Carlos, T., Hee – Jae, L., Faruk, O. A. and James, S. (2007). Estimation of Permeability and Permeability Anisotropy from Straddle – Packer Formation – Tester, Measurements Based on the Physics of Two – Phase Immiscible Flow and Invasion. Journal of Society of Petroleum Engineers, *Paper SPE* 95897. Pages 339 – 354.

Short, K. C. and Stauble, A. J. (1967). Outline of Geology of Niger Delta: *American Association of Petroleum Geologists Bulletin*, v. 51, p. 761-779.

Simon, T., Patrick, C., and Jerry, J. (1996). Permeability And Anisotropy Characterization In The Near Wellbore: A Numerical Model Using The Probe Permeameter And Micro-Resistivity Image Data. Paper SPWLA 37th Annual Logging Symposium.

Walter, R. (1982). Permeability Anisotropy in Low Permeability Formations. *Paper SPE-AIME* 10810. Pages 195 – 198.

Wannell, M.J and Colley, N. M. (1993). The Use of a New Technique to Determine Permeability Anisotropy. *Paper SPE* 26801, pages 489 – 495.

Weber, K. J. and Van Geuns, L. C. (1989). Framework for Constructing Clastic Reservoir Simulation Models, *SPE* 19582.