Sudan University of Science and Technology

College of Graduate Study

Importance of Effect of Cyclic Steam Stimulation in the Reservoir Geomechanic and Deformation

(Case Study FC Oil Field)

اهمية تاثير التحفيز البخاري الدوري في الخواص الجيوميكانيكية و تشوه المكامن

(دراسة حالة حقل FC)

A Thesis Submitted in Partial Fulfillment of requirements for the degree of M. Sc in petroleum reservoir engineering

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الاستهلال

قال تعالى :

بسم الله الرحمن الرحيم

﴿ هُـوَ الَّـذِي خَلَـقَ السَّـمَاوَاتِ وَالْأَرْضَ فِي سِـتَّةِ أَيَّامٍ ثُمَّ اسْـتَوَى عَلَـى الْعَـرْشِ يَعْلَـمُ مَـا يَلِـجُ فِي الْأَرْضِ وَمَـا يَخْـرُجُ مِنْهَـا وَمَـا يَنـزِلُ مِـنَ السَّـمَاء وَمَـا يَعْـرُجُ فِيهَـا وَهُـوَ مَعَكُـمْ أَيْـنَ مَـا كُنـتُمْ وَاللَّهُ بِمَـا تَعْمَلُونَ بَصِيرٌ﴾

صدق الله العظيم

سورة الحديد الآية ﴿4﴾

Dedication

This research is dedicated to my wonderful parents, I dedicate it also to my brothers, friends, my future wife and everyone who suport me.

Acknowledgement

I have taken efforts in this project. However, it would not have been possible without the kind support and help of many individuals and organizations. I would like to extend my sincere thanks to all of them.

I am highly indebted to **Dr. Elham Mohamed, Eng. Mohanad Mahjoub , Eng.Ahmed Abuelgaz and Eng.Ahmed M. Salih** for their guidance and constant helping as well as for providing necessary information and data regarding the project & also for their support in completing the project.

My thanks and appreciations also go to my colleague and my students in developing the project and people who have willingly helped us out with their abilities.

التجريد

يعتبر الحقن الدوري للبخار من الطرق الفعالة للإستخلاص الحراري و ينشأ من هه العملية تغير في الخواص الجيوميكانيكة للطبقات ، هذا التاثير لم يؤخذ في الاعتبار في التطبيقات السابقة للحقن الدوري للبخار في السودان.

تم في هذا البحث حساب معاملات المرونة الديناميكية عن طريق بيانات تسجيلات الابار للبئر FC-18 بافتراض طريقة Brocher قابلة للتطبيق، و هذه الخواص المحسوبة تم إستخدامها في بناء نموذج جيوميكانيكي لهذة البئر بإحاثيات اسطوانية بإستخدام STAR Simulator و تمت مطابقة هذا النموذج ببيانات الإنتاج (معدل إنتاج الزيت ، معدل إنتاج الماء ، الإنتاج التراكمي) و تم التحصل علي نتائج مقبولة .

بالإضافة الي ذلك تم استخدام النموذج لمعرفة تأثير الحقن الدوري للبخار علي الخواص الجيوميكانيكية و اعتمدت عملية التقيم علي عدة عوامل مثل (معامل الامان، حالة الصخر الميكانيكية، الإنفعال الحجمي، الضغط المسامي، و الإجهادات).

إعتماداً علي عملية التقييم من المتوقع حدوث تشوهات، لذلك يوصي بتأكيد النتائج بتسجيلات الابار و إختبارات الشقوق.

ABSTRACT

Cyclic Steam Injection (CSI) is an effective thermal recovery process; this process may lead to change in the geo-mechanical characteristic of the rock, and deformation of the rock layers; this effect was not considered or studded before during the application of CSI in Sudan; the present study addressed the important of considering this effect as a case study in FC-18.

The dynamic elastic modules has been calculated using well logging data of FC-18 assuming Brocher method are applicable; those calculated parameter was used to build single well radial Geo-mechanical model Using STARS simulator. The model has been matched using different production data (oil rate, water rate and cumulative production); reasonable matching was achieved between the real data and the calculated data; then, the model was used to evaluate the effect of CSI on Geo-mechanical properties based on calculated parameter such as safety factor, yield state, volumetric strain, pore pressure and stresses.

Based on evaluation, deformation in FC-18 is expected and the image log and fracture identification test to confirm simulations results are required.

Keywords:

Cyclic Steam Injection, Elastic Module, Geo-mechanical Properties, Radial model, Deformation.

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Nomenclature:

h_f is the convection of heat transfer coefficient.(Btu/ ft^3-hr °F)

T_0 is the initial temperature °F

T_f environmental temperature °F

T_{ref} is the reference temperature °F

ϑ_1, ϑ_2 *and* ϑ_3 are boundary condition first kind, second kind and third kind respectively

R_{so} *and* R_{sw} denote gas solubility in oil and water. (Scf/STB)

S_o , S_w *and* S_w denote oil, water and gas saturation respectively.

c_o , c_w *and* c_w denote oil, water and gas compressibility respectively (psi^{-1})

k_o , k_w *and* k_w denote oil, water and gas permeability respectively.(md)

k_x , k_y *and* k_z denote the permeability in x, y and z respectively. (md)

λ_t is total mobility term.

u_x , u_y *and* u_z denote the velocity in Cartesian coordinates x,y,z respectively.(ft/sec)

β_o , β_w *and* β_w denote oil, water and gas formation volume factor respectively.(bbl/STB)

[B] is the matrix shape function derivative

[N] is the matrix element shape function

{T} is the vector of nodal temperature

∅ denote porosity of porous media

c(x) is specific heat when pressure is constant

k(x) is the thermal conductivity (Btu/ ft-hr- °F)

n is the unit normal vector outward to the boundary

P is the pore pressure (psi)

q is prescribed heat flux (Btu/ ft^2-hr)

$Q(x,t)$ is heat generation/source per unit volume at the internal point x at time t

T is prescribed temperature °F

t is the time (sec)

$T(x,t)$ is tempreature field. °F

α is thermal expansion coefficient.($°F^{-1}$)

μ is the Poisson ratio (cp)

ρ(x) is mass density when pressure is constant (lb/ft^3) μ is the fluid viscosity (cp)

μ is the fluid viscosity (cp)

ρ denote density of the fluid (lb/ft^3)

CHAPTER 1

Introduction

1.1 Oil Recovery Methods:

Oil recovery methods can be divided into three major categories: primary, secondary and tertiary recovery (enhanced oil recovery), as show in figure 1.1. In the primary process, the oil is forced out of the petroleum reservoir by existing natural pressure of the trapped fluids in the reservoir. Primary oil recovery methods include solution-gas drive, gas-cap expansion, gravity drainage, rock expansion, water drive processes or their combination. With declining reservoir pressure, it becomes more difficult to get the hydrocarbons to the surface. Sometimes, artificial lift is required. On average, only 5-10% of original oil in place can be recovered by primary techniques. Over a period of oil production, the reservoir energy will fall, and at some point, there will be insufficient underground pressure to force the oil to the surface. When a large part of the crude oil in a reservoir cannot be recovered by primary methods, a method for recovering more of the oil left behind must be chosen. Most often, secondary recovery is accomplished by injecting gas or water into the reservoir to replace produced fluids and maintain or increase the reservoir pressure. Conversion of some production wells to injection wells and subsequent injection of gas or water for pressure maintenance in the reservoir has been designated as secondary oil recovery. The oil recovered by both primary and secondary processes ranges from 20 to 50% depending on the oil and reservoir properties.

The biggest portion of oil left behind after conventional oil recovery exhausted. Therefore, enhanced oil recovery methods must be applied if further oil is to be recovered. Enhanced oil recovery (Tertiary recovery) methods have focused on recovering the remaining oil from a reservoir that has been depleted of energy during the application of primary and secondary recovery methods.

Enhanced Oil Recovery (EOR): is the recovery of oil from the reservoir by the injecting of materials that not normally present in reservoir (Lake, 1989). The injected fluids interact with the reservoir rock and oil system to create conditions favorable for oil recovery.

Improved oil recovery (IOR) refers to any process or practice that improves oil recovery. IOR includes EOR processes and other practices such as water flooding, pressure maintenance, infill drilling, and horizontal wells.

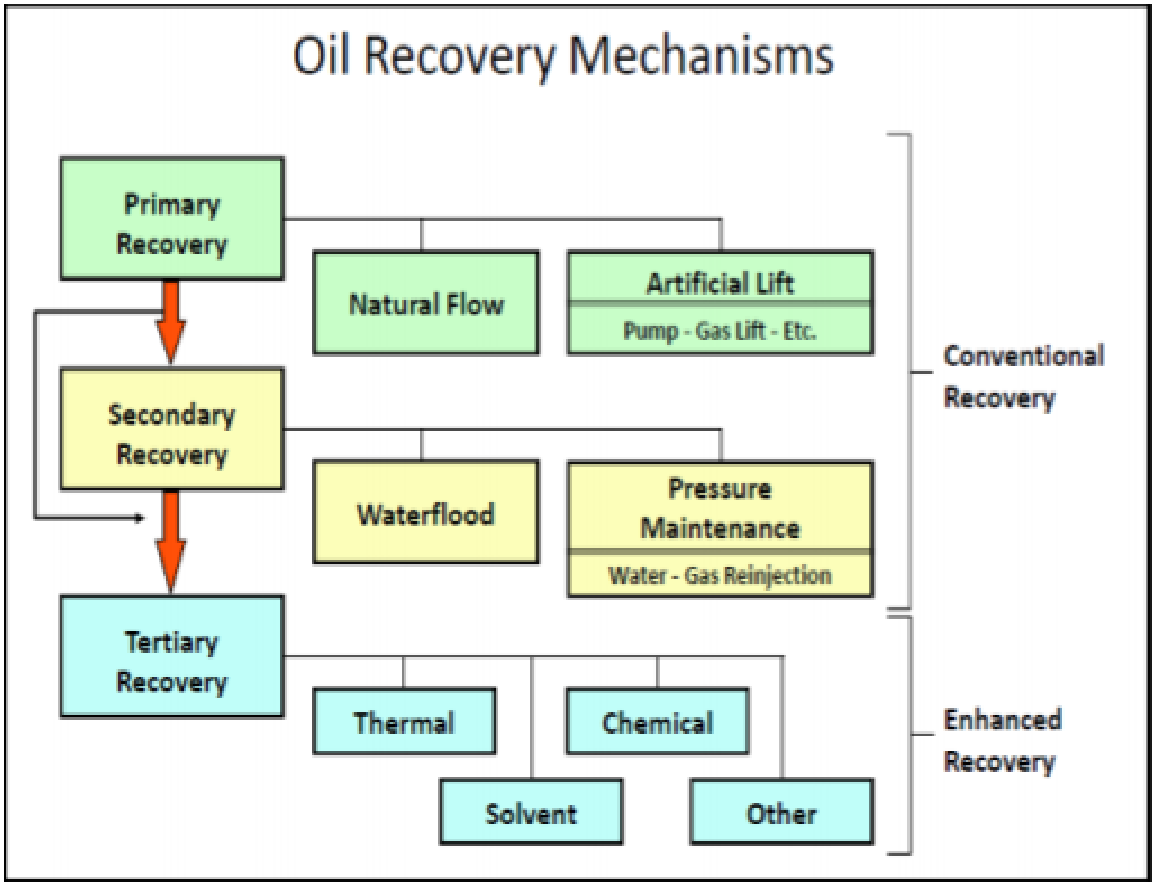

Figure1.1. Oil recovery methods (Oil and Gas Journal, 1990)

1.2 Problem Statement:

Cyclic Steam Injection (CSI) is an effective thermal recovery process. Every stimulation that is performed in the reservoir has consequences; introducing heat into the formation by CSI produces stress and deformation in oil sand formations , this process will lead to change the geo-mechanical characteristic of the layers ; it is very important to mention that a enormous of CSI modeling applications in literature they are neglect the geo-mechanical effect on the process; therefore a geo-mechanics effect should be taking into consideration in order to model accurate effect of CSI in the reservoir formation. This study focusing on showing the importance of Geo-mechanics effects on the modeling of CSI.

1.3 Objectives:

The main objective of this research is to illustrate the importance of Geo-mechanic characteristics on the modeling of CSI.

As the research case study of FC-18 specific objective fall into the following points:

1. To calculate Dynamic elastic modules for FC-18.
2. To build Geo-mechanic model for FC-18 based on dynamic elastic modules.
3. To evaluate the current state of CSI in FC-18 based on Geo-mechanical effect.

1.4 Methodology:

In order to achieve the above mentioned objectives STARS simulator is used in this study.

1.5 Outlines:

In chapter2 of this research a review of history of CSI and theoretical background of recovery methods will be done; then in chapter3 an introduction of finite element method and equation that control flow and elastic module equation will be discussed in details; in chapter4 of this research a results of calculating elastic properties and Geo-mechanical model and evaluation of current state of CSI will be discussed in details finally a conclusion and recommendation will be made in chapter5.

CHAPTER 2

Literature Review and Theoretical Background

2.1. Literature Review:

CSI was first utilized accidentally in Venezuela in 1959.By that time, one of the steam injector wells started to produce, after a blowout, in much preferable condition over the encompassing production wells (Trebolle and Chalot, 1993).

From that point forward, this has been applied in many fields, for example, Bolivar Coastal and Santa Barbara in Venezuela (Valera et al., 1999), Cold Lake Oil Sands in Canada, Xinjiang and Liaohe in China (Liguo et al., 2012), Midway sunset in California (Jones et al., 1990), among other heavy oil fields.

At the beginning stages of CSI application, CSI was considered as an old school oil production method in which operations are in front of research improvements (Ramey et al., 1969). Clarifying CSI processes, depended on field experiences instead of research work.

There are a lot of unknowns about the process parameters, for example, the quantity of stimulation cycles, well orientation and number of wells, working condition, the expansion of water cut, among others. Therefore, on early CSI field applications, the procedure was performed as trial and error field scale experiment (Ramey, 1967).

After many research studies and field experiences, important technology problem was reduced. To start with, the quantity of stimulation cycles increases by time. By 1974, CSI has average of three stimulation cycles with a maximum reported of 22 (Ali et al., 1974). In 1990, in the Midway Sunset field, California, there was already a well with 39 cycles.

Also, out of 1500 wells, there were 75 wells with more than 30 cycles, and 350 wells with more than 20 cycles (Jones et al., 1990). This increment in the quantity of cycles was accomplished by getting better understanding of steam properties, reservoir characteristics, and injection conditions.

Second, well orientation and number of wells were enhancing by time. In Trinidad and Tobago, slim hole injectors, insulated tubing and packers, and limited entry perforations have been utilized to combat gravity segregation consequences (Khan, 1992). Also, steam was injected with foam diverting agents to control water breakthrough resulting from high injectivity. What's more, in the cold Lake oil sands, Canada, steam distribution in horizontal wells was enhanced by utilizing screen section, which facilitated contact between the well and the reservoir. Additionally, inside these screen section, small flow orifices were utilized to control the flow between the inward pipe and the reservoir to enhance oil production and reduce steam consumption (Oil and Gas Journal report by Bob Tippee, 2012).

In China, the most up to data strategies and tecniques utilized as a part of CSI include: high efficient steam injection via automatic controlling steam generation, protecting surface pipeline and multi zone steam injection; and in addition artificial lifting, sand control, CSI with chemical additives, reentry drilling technology, and process control system (Haiyan et al., 2005).Furthermore, steam distribution has been enhanced by utilizing separated zone steam injection techniques such as selected, double and multi zone injection, either sequentially or simultaneously.

This technique showed, in field testing to 76 wells of the Liaohe oil field, an increase up to 70% of the steam zone (Liguo et al., 2012).

Also, as well in horizontal well, the tubing and annulus of a similar well have been applied to inject to in the toe and heel separately (Liguo et al., 2012). Third, operate condition of pressure and temperature have adjusted to each case based on reservoir properties and well design.

In the cold Lake field, CSI has been accomplished by injection at pressures sufficiently high to fracture the formation (Beattie et al., 1991). In California, specifically in Potter sands in the Midway Sunset field, sequential steaming process was implemented. This approach included heating the reservoir rather than heating each well separately (Jones et al., 1990). The wells were stimulated in rows from down to up plunge of the reservoir.

Utilizing this methodology, the production per well increased up to rate of 30% per year (Jones et al., 1990). Another technique, in pilot stage and successfully stimulated, is the utilization of Top Injection Bottom Production (TINBOP) whose principle is to inject steam at the highest point of the reservoir utilizing the short well string and produced from the bottom of the reservoir utilizing the long well string. (Morlot et al.,2007).Simulation studies conducted by Morlot et al. showed TINBOP increased oil recovery by 57 to 93%, compared to conventional CSI (Morlot et al., 2007).

One feature of this method is that there is no soaking period. Fourth, the increase of water cut is additionally tended to. In CSI, each succeeding cycle normally increase water cuts (Ali et al., 1974). Therefore, in the late 70's there was a trend to convert these operations into steam drives due to the decrmentin oil recovery (Prats, 1978). This trend has changed in the last years with the utilization of chemical additives on CSI. As of late, there have been important progresses in oil recovery utilizing chemical addition. Although CSI increases oil recovery, chemical addition with CSI increases it even further (Ramey et al., 1967). These days, in CSI processes, co injection of steam with gels, foams, and surfactants, among different chemicals, are utilized to increase oil production and reduce water production. In Russia, specifically in the Permian Carboniferous reservoir of the Usinsk field, gels and foams have been injected with CSI from 2007 to 2011, and an increase of 20-30% oil rate and decreased 33-35% water cut (Taraskin et al., 2012) have been observed.

In Canada, Liquid Addition to Steam for Enhancing Recovery (LASER) has been field tested for a single cycle at Cold Lake field. Past work showed that, if successful, the LASER process could increase the recovery factor by 3 – 6% OOIP (Leaute et al., 2007).

Additionally in Canada, different process have been tested to increase CSI performance, for example, air injection, accomplishing 15% incremental in addition to the 12-20% recovery with high pressure CSI (Jiang et al., 2010), and biodiesel and carbamide injection (Babadagli et al., 2010 and Zhang et al., 2009), both utilized as surfactants to enhance the CSI efficiency. The field tests in Henan Oil Field, China, utilizing carbamide increase oil recovery by 7% and decrease Residual Oil Saturation (SOR) nearly by 1% (Zhang et al., 2009). Too, in the Bachaquero field in Venezuela, an ionic alkylaryl sulfonate surfactant (LAAS) has been utilized to generate foams that enhance steam distribution all the more equally in the reservoir by restricting steam to the areas with higher permeability.

This technique has improved the production per cycle from 15 to 40% (Valera et al., 1999). Additionally, solvents have been utilized to improve steam injectivity by removing organic from the rock and changing its wettability in Costa Bolivar, Zulia, Venezuela (Mendez et al., 1992). finally, wettability changes in CSI because of temperature increment have been studies by several authors with various result.

On one hand, there is a line of thought which assures that as temperature increases, the system oil water rock becomes more water wet (Prats, 1985, Schembre et al., 2006, Kovscek et al., 2008, and Poston et al., 1970). Then again, another tendency advocates that the system becomes more oil wet as temperature increases (Rao and Karyampudi,1999, Escrochi et al., 2008, and Rao, 1999); additionally, there is a third line of thought clarifying that wettability is independent of temperature changes (Miller and Ramey, 1985, and Pollkar et al., 1989. studies with Diatomaceous rocks and Berea sandstones directed by Schembre et al., 2006, showed that both diatomaceous and Berea cores become more waterwet as temperature increments (from 100 to 200°C).

This behavior was attributed to fines detachment, in low saltiness and high pH steam condensate fluid, which stabilizes a thin water film that covers the rock surface avoiding contact with the oil phase. This fines separation dependon temperature and mineralogy; for instance, wettability changes reached faster in silica than that in clays (Schembre et al., 2006). Furthermore, Poston et al., 1970, conducted similar studies utilizing unconsolidated sands from Houston sands and Midway Sunset field, California, achieving the conclusion that increasing temperature (from 25 to 150°C) is determined in improving water wetness in the unconsolidated sands. On the other hand, Raoand Karyampudi, 1999, andRao,1999, conducted CSI lab and field test in the heavy oil and bitumen Elk Point Cummings formation, Canada. Their results showed that at high temperatures (162 to 196– °C), the formation, which is mainly silica (87%), becoming oil wet. In addition, they additionally discover that salt deposition, mainly calcium carbonate (CaCO3), in one of the core layers prevented oil wet behavior at high temperatures, changing the wettability to water wet.

This effect was proved in core flooding and field test in which increase in oil rate and reduce in water cut were seen (from 22 BPD and 83% in the fourth cycle to 51 BPD and 77% in the five cycle) (Rao and Karyampudi, 1999).

Wettability inversion effect at high temperatures is additionally attriduted to asphaltene precipitation. Utilizing Athabasca bitumen and live oil sample with 5% and 3.17% asphaltene separately, Escrochi et al., 2008, showed that from 150 to 400 °C the system shifted to oil wet until asphaltene precipitation was finished and after that wettability was changed to water wet. Moreover, in the literature results showed that temperature don't affect wettability during CSI, and Miller and Ramey, 1985 tested the unconsolidated Ottawa Silica Sand and a consolidated Berea Sandstone with temperatures from 25 to 150° C, concluding that there were not changes in residual saturation that imply variance in wettability.

Similar result were come to in the unconsolidated silica sands at 125 to 175 °C by Pollkar et al., 1989.Consequently, when CSI is applied, there are distinctive positions in depicting wettability mechanism and their change with temperature.

However, it is important to point out that these results mainly depend on chemical properties of fluid injected ,asphaltene content and the mineralogy of the reservoir. From early stages until today, CSI has evolved significantly from a process discovered by chance where trial and error governed the operations with minimal number of cycles and low recovery factor to state of the art applications with an great variety, of chemical additives and well geometries which increment the quantity of cycles and ultimate oil recovery.

However, more research should be done in evaluating wettability changes at field scale to determine the factors that influence early water break and reduced oil production at various Mineralogy and injection temperatures

2.2. The Heavy Oil:

Heavy oil is described as crude having API gravity less than 20 ranges. trendy exercise within the U.S. additionally uses this gravity definition. The API gravity, even though, does not absolutely describe the go with the flow characteristics of the crude; this is better represented by way of the oil viscosity. In case , a few heavy crudes however have a low enormously viscosity at reservoir temperature when in comparison with a few lighter crudes, nd the maximum vital factor within the monetary exploitation of the reserve is the go with the flow fee an awful lot greater than the oil gravity, it is proposed that heavy oil sand .e., the ones requisite stimulation with the aid of warmness or by way of different way to be described as crudes with viscosities more than 100 cp [greater than 100 mPas] at reservoir conditions heavy oils normally have high asphalting, sulphur, and metal contents compared with traditional oils. The non-hydrocarbon components have a tendency to increase with lowering API gravity, which, in mixture with reducing portions of lighter ends, reduces the marketplace cost of the crude. (Briggs, P. J., Baron, P. R., Fulleylove, R. J., & Wright, M. S. (1988, February 1).

Goodarzi et al., (2009) outline heavy as the elegance of oils have viscosity ranging from 50 cp to 5000 cp. The excessive viscosity made restriction to the easy waft of oil at the reservoir temperature and stress. Figure2.1 is a graph pertaining to viscosity and API ratings and it showed truly that the heavy oil region lies within the high viscosity variety.

Ancheyta and Speight (2007) define heavy oil as a viscous kind of petroleum that incorporates a higher stage of sulfur as compared to standard petroleum that happens in comparable locations.

Meyer et al., (2007) explained that the oil turns into heavy due to eradication of light fractions via herbal methods after evolution from the natural supply materials. A excessive percentage of asphaltic molecules and with substitution in the carbon community of heteroatom's together with nitrogen, sulfur, and oxygen also play an critical function in making the oil heavy. consequently, heavy oil, no matter supply, constantly contains the heavy fractions of asphaltenes, heavy steel, sulphur, and nitrogen.

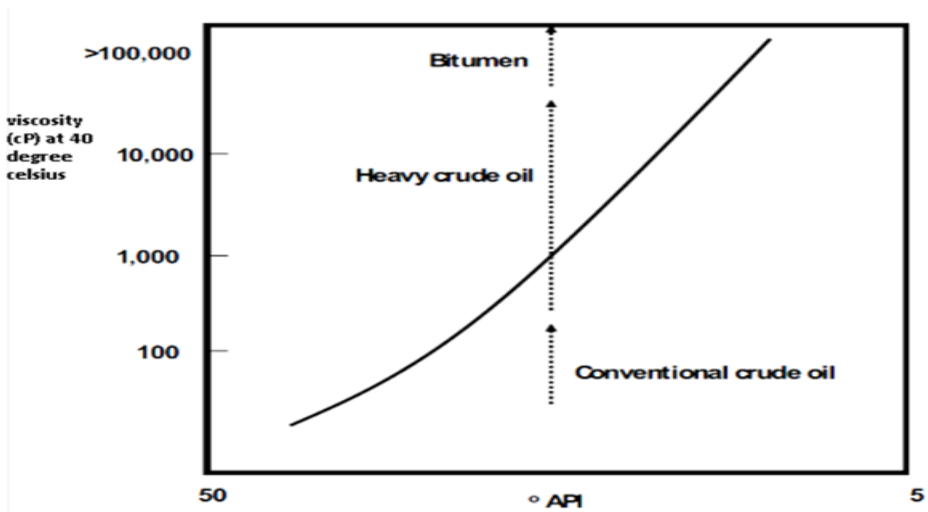

Figure 2.1: General relationship of viscosity to API gravity (Thomas, 2008).

The reservoirs of heavy engine oil are shallow (as much as one thousand meters below the top line) for this it has low tank warmness range (40-60 °C) and less effective. Low sedimentary overburden will relieve the biodegradation, and the prevalence of beneath aquifers further facilitates the system. As said previously the less powerful seal is because of the reduced seal strain, which would possibly reason the dissolved gases to go away the olive oil, growing its viscosity. The tank lithology is normally sandstones transferred as turbidity with excessive porosity and permeability; the raised viscosity is paid out with the aid of high permeability

Hydrocarbon resources of heavy petrol and petrol sands are nearly 3 instances the traditional oil set up in around the arena trillion barrels of olive oil exists inside the natural oils sands of Alberta and in Canada the contribution of heavy petrol and engine oil sands sources is 20% of the entire general oil improvement. Farouq Ali and Meldau (1999)

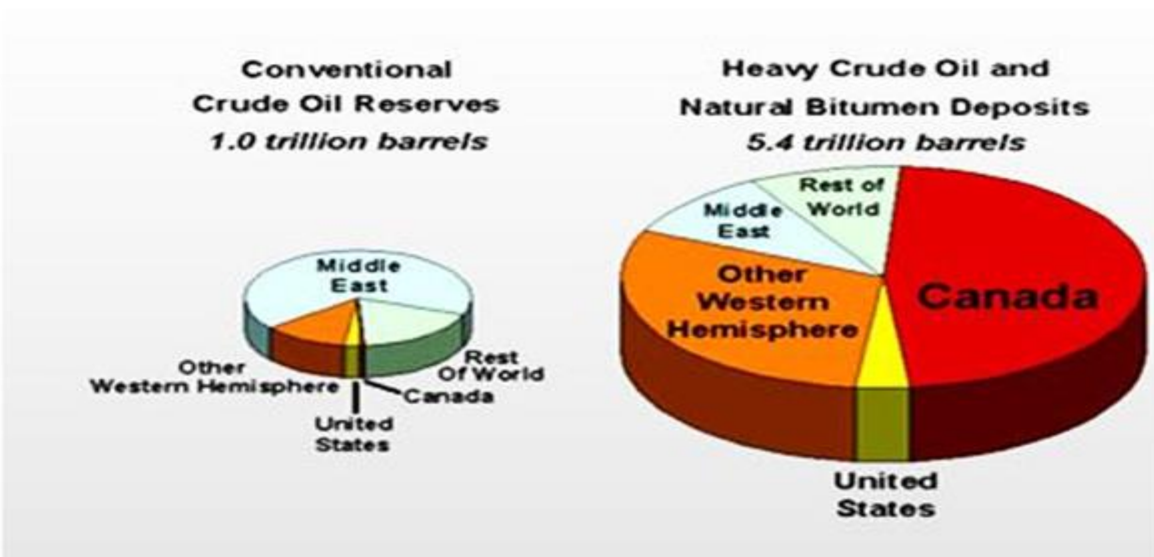

Figure 2.2: Distribution of conventional crude oil and heavy hydrocarbon (Herron, 2000)

Nearly 2.0 × 10^{12} barrels (0.3 × 10^{12}m3) of conventional oil and 5.0 × 10^{12} barrels (0.8 × 10^{12} m3) of heavy oil will stay in reservoirs worldwide after conventional restoration strategies have been exhausted. lots of this oil might be recovered through greater Oil recovery (EOR) methods, which can be a part of the overall scheme of advanced Oil recovery (IOR) the selection of the method and the predicted restoration depends on many issues, monetary in addition to technological. (Thomas 2008)

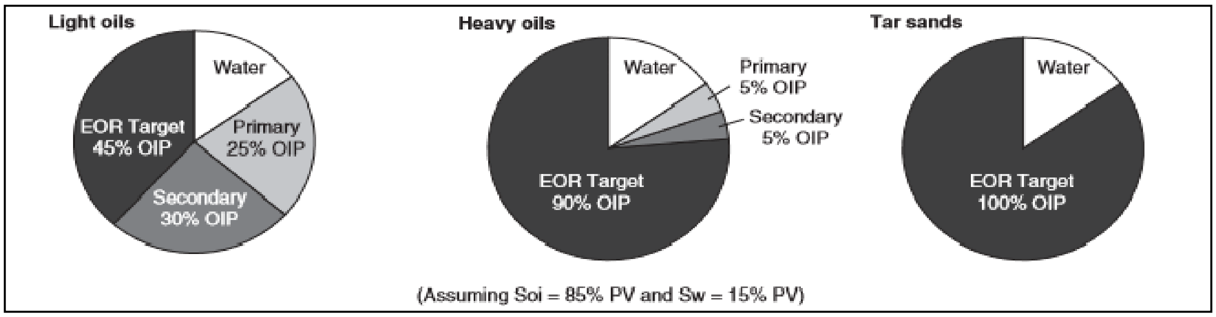

Figure 2.3: EOR target for different hydrocarbons. (Thomas 2008)

Many EOR techniques have been used inside the past, with various degrees of achievement, for the recuperation of light and heavy oils, as well as tar sands. Thermal methods are mostly supposed for heavy oils. (Thomas 2008)

The well production, lifting, and transportation of heavy oil and their viscous emulsions are a big task for this greater hard hydrocarbon useful resource. Honestly put, the viscous nature of those fluids restricts the practical quotes of producing and shifting heavy oil fluids will increase the electricity costs required to accomplish this, thereby increasing the general fee of manufacturing this hydrocarbon.

Thinking about high viscosity of heavy oil, thermal recuperation techniques appear the right answer for development of shallow heavy oil fields.

2.3. Enhanced oil recovery methods:

EOR methods generally can be classified into two major groups: thermal and non-thermal processes Each main group has a different EOR processes. Each technique has different concepts but similar objective which is to recover remaining oil and improving the recovery rate (Green and Willhite, 1998).

EOR refers to the recovery of oil through the injection of fluids and energy not normally present in the reservoir. The injected fluids must accomplish one of the objectives as follows:

A. Boost the natural energy in the reservoir

B. Interact with the reservoir rock/oil system to create conditions favorable for remaining oil recovery.

C. Reduction of the interfacial tension between the displacing fluid and oil.

D. Increase the capillary number.

E. Reduce capillary forces.

F. Increase the drive water viscosity.

G. Provide mobility-control.

H. Oil swelling.

I. Oil viscosity reduction.

J. Alteration of the reservoir rock wettability.

EOR processes are very sensitive to oil prices. The price of oil on a sustainable basis must exceed the cost of the injecting plus operating costs by a sizeable margin for an EOR process to be considered economical. For this reason, an EOR process must be efficient in terms of cost per barrel of oil recovered and also effective in substantially increasing the volume of oil recovered beyond the current recovery process. Economic evaluation is the key important step in the selection of an EOR process and is emphasized throughout the selection process.

An EOR process was deemed successful only if it was both an engineering and an economic success (Iyoho, 1978). The goal of EOR processes are to mobilize the oil left behind after conventional methods and to increase the overall oil displacement efficiency, which is a function of microscopic and macroscopic displacement efficiency (Green & Willhite, 1998). Oil displacement efficiency is increased by decreasing oil viscosity (Thermal and miscible flood) or by reducing capillary forces or interfacial tension

Microscopic efficiency refers to the mobilization of oil at the pore scale and measures the effectiveness of the displacing fluid in moving the oil at those places the displacing fluid contacts the oil. Microscopic efficiency can be increased by reducing capillary forces or interfacial tension between the displacing fluid and oil or by decreasing the oil viscosity (Satter et al., 2008). Macroscopic or volumetric displacement efficiency refers to the effectiveness of the displacing fluid in contacting the reservoir in a volumetric sense. Volumetric displacement efficiency also known as conformance indicates the effectiveness of the displacing fluid in sweeping out the volume of a reservoir, both areal and vertically, as well as how effectively the displacing fluid moves the displaced oil toward production wells (Green & Willhite, 1998).

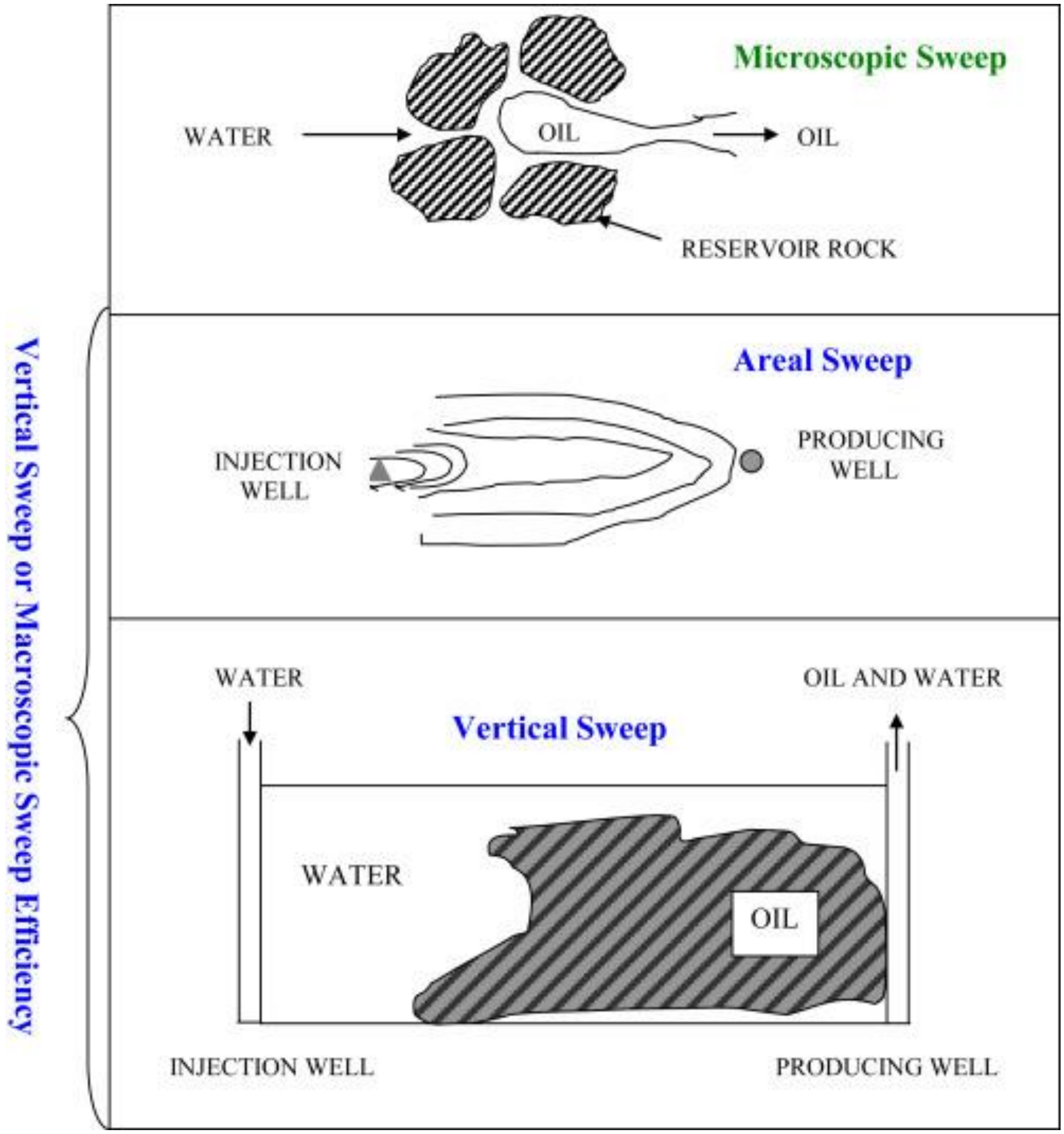

Figure2.4: Schematics of microscopic and macroscopic sweep efficiencies (Lyons and Plisga, 2005)

2.4. Thermal EOR methods:

Thermal EOR processes are defined to include all processes that supply heat energy to the reservoir and enhancing the ability of oil to flow by reducing its viscosity. Thermal recovery processes are globally the most advanced EOR processes. The key of thermal recovery is the use of heat to lower the viscosity of oil and reduces mobility ratio, therefore, increases the productivity and recovery. The oil caused to flow by the supply of thermal energy is produced through production wells. When heated, oil becomes less viscous and flows more easily. Because this is an important property of oil, considerable effort has been devoted to the development of techniques that involve the introduction of heat into a reservoir to improve recovery of the heavier, more viscous crude oils. The viscosity of oils dramatically decreases as temperature increases, and the purpose of all thermal oil recovery processes is therefore to heat the oil to make it flow easier. Figure 2.6 shows the sensitivity of viscosity to temperature for several grades of oil and water. The sharp decrease of crude oils viscosity with temperature, especially for the heavier crude, largely explains why thermal EOR has been so popular.

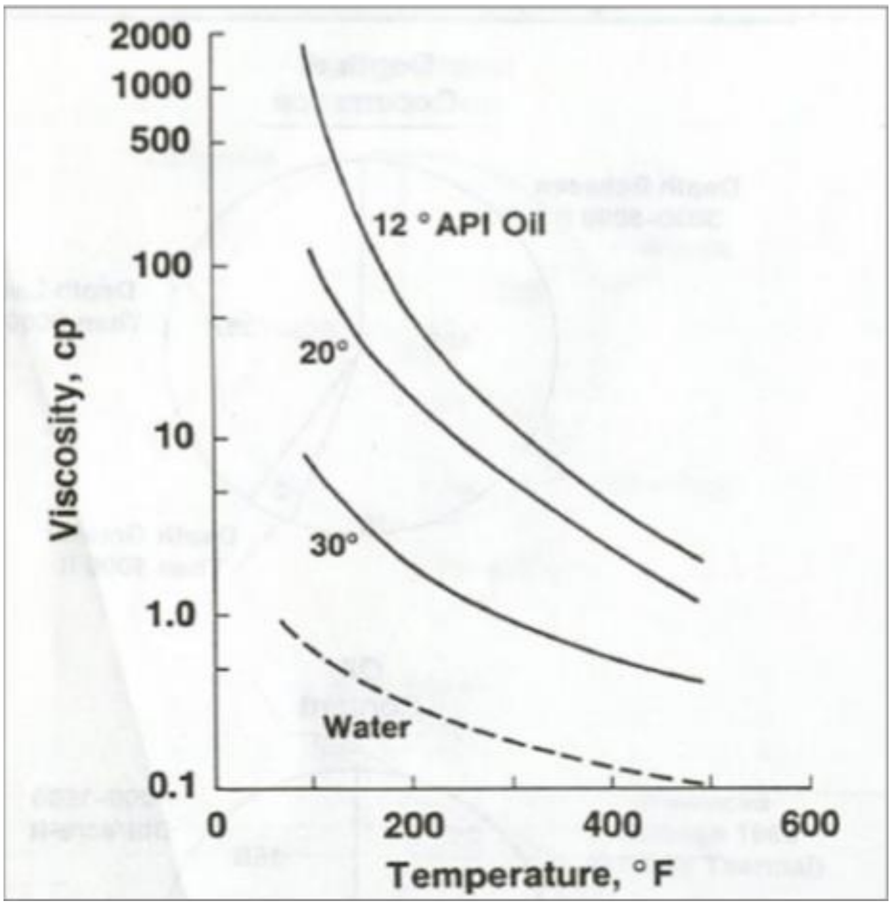

Figure 2.5: Viscosity Reduction of Oils and Water (Hong, K.C., 1994)

In general, thermal enhanced oil recovery can be subdivided into the following categories:

A. Major thermal processes in use today:
   1. Steam flooding (Steam drive: SD)
   2. Cyclic steam stimulation (CSC)
   3. Steam assisted gravity drainage (SAGD)
   4. In-situ combustion (ISC)

B. Other processes which are not as widely implemented:
   1. Electrical/electromagnetic heating.
   2. Hot water flooding.

2.4.1. Steam Flooding (SD).

Also called steam drive. In this process, two separate wells are used, one for steam injection and the other for oil production. Steam is injected continuously at injectors with the aim of driving oil towards producers. The steam injection is continuous until the process becomes uneconomic or is replaced by another process. Figure 2.7 shows a schematic of steam flooding process.

Steam reduces the oil saturation in the steam zone to a very low value, pushing the mobile oil out of the steam zone. As the steam zone grows, more oil is moved from the steam zone to unheated zones ahead of the steam front. There the oil accumulates to form an oil bank. Then the oil is produced using artificial lift. A detailed discussion follows later in the (steam flooding) section.

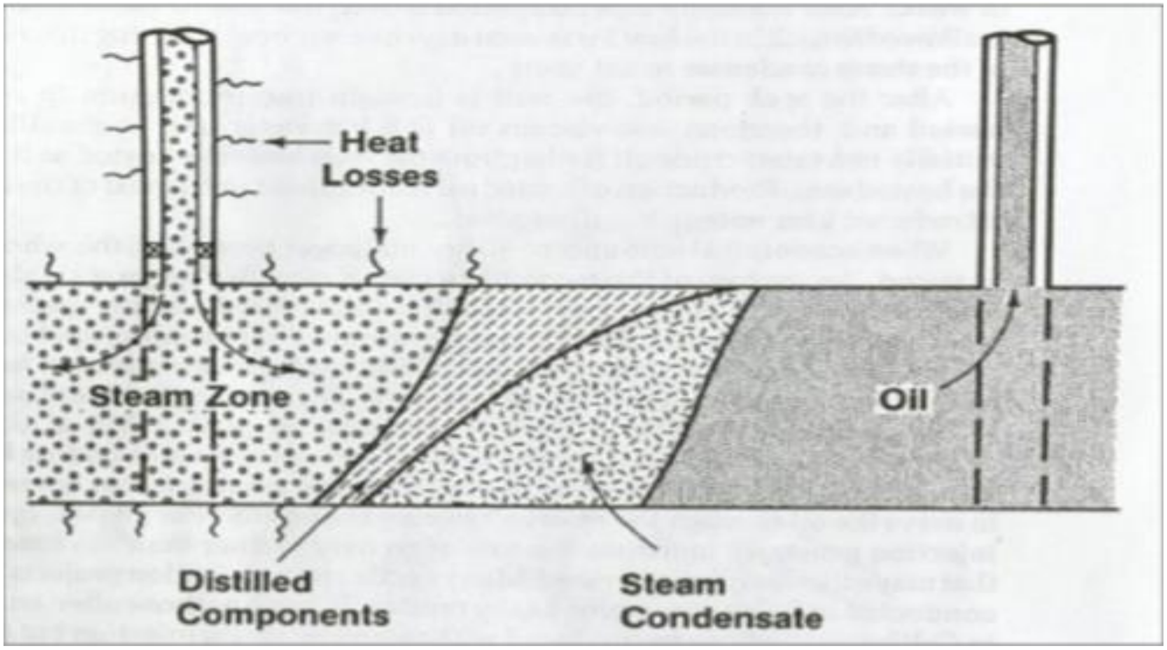

Figure 2.6: Schematic of steam flooding process (Hong, K.C., 1994)

2.4.2. Cyclic Steam Stimulation (CSS).

Also called steam soak or Huff-and-Puff. In this process one well uses as both injector and producer. It involves injecting steam into a well for several days or weeks, shutting the well in as long as necessary to allow the steam to heat the oil in the areas around the well. During this period, most of the steam condenses to hot water. After the soak period, the well is back to production to recover the heated oil. Figure2.8 shows a schematic of cyclic steam stimulation process. This process is repeated when the production from the well declines to a low level. The cycle is repeated until the ratio of oil produced to steam injected (OSR) drops to a level that is considered uneconomic (Ezekwe, 2011). An average of three complete cycles may be used in a single well. Oil recovery per-cycle depends on formation thickness, reservoir pressure, oil in place, volume of steam injected, and the number of preceding cycles. CSS was the first steam flooding technique used in heavy oil reservoirs.

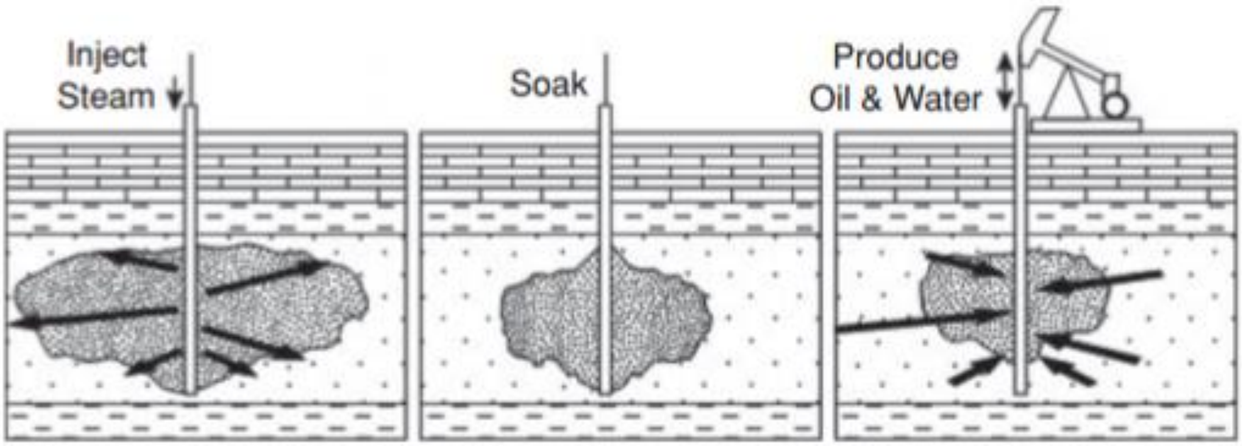

Figure2.7. Schematic of cyclic steam stimulation process (Ezekwe, 2011)

2.4.5. Steam Assisted Gravity Drainage (SAGD).

This process consists of two horizontal wells about 15 feet apart located close to the bottom of the formation. Steam assisted gravity drainage (SAGD) was initially developed to recover bitumen from the Canadian Oil Sands (Dusseault, 1998). Figure1.8 shows a schematic of steam assisted gravity drainage process. Steam is injected into the top horizontal well, while the horizontal well below it functions as the producer. The steam creates an expanding steam chamber around the injector as more steam is injected. Within the steam chamber and at its boundaries, as the viscosity of the oil is reduced, its mobility increases causing it to drain under gravity towards the production well.

A key to the process is that the injection to production rates are sufficiently low that the process is dominated by gravity forces. The SAGD process should be applied to reservoirs with formation thickness greater than 50 feet, good vertical permeability, and absence of thief zones. SAGD can be considered as a modification of SD for heavy oil reservoirs including tar sands.

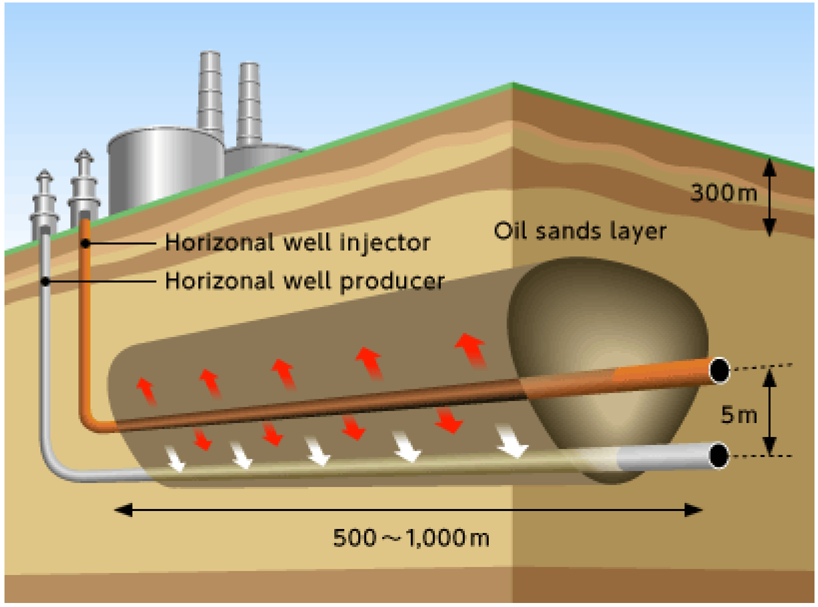

Figure2.8: Schematic of steam assisted gravity drainage process (Ezekwe, 2011)

1.1.1.1.4. In-Situ Combustion (ISC).

In this process, heat produces by burning some of the oil within the reservoir rock. Air is injected into the reservoir, and a heater is lowered into the well to ignite the oil. Ignition of the air-crude oil mixture can also be accomplished by introducing into the oil-bearing reservoir rock a chemical that undergoes an exothermic reaction. This process is an attempt to extend thermal recovery technology to deeper reservoirs and or more viscous crudes. The amount of oil burned and the amount of heat created during in-situ combustion can be controlled to some extend by varying the amount of air injected into the reservoir (Hong,K.C., 1994). In recent years it has become known as high-pressure air injection. In-situ combustion recovers 10-15% of the original oil in place.

CHAPTER 3

The Methodology

3.1 Introduction:

In this chapter the used equation will be discussed in details and those equations include heat transfer equation which can be coupled with mechanical model in finite element form and resulting formulation will be solved iteratively in addition to that the basic equations such as mass conservation equations, fluid motion equation and compressibility equation which used to developed flow equation has been discussed.

3.2. Finite element and heat transfer analysis:

3.2.1 Heat transfer equations:

In case of heat conduction for solid element the governing equation in domain ω bounded by ϑ can be expressed as the following:

$$\rho(x)c(x)\frac{\partial T(x,t)}{\partial t} = k(x)\nabla^2 T(x,t) + Q(x,t) \text{ in } \omega \tag{3.1}$$

To solve Eq.(3.1) a suitable boundary conditions and initial condition are needed and those conditions shown below:

The boundary conditions are:

$$T(x,t) = T(x,t) \quad \text{on } \vartheta_1 \tag{3.2}$$

$$n.\,k\nabla T(x,t) = q(x,t) \quad \text{on } \vartheta_2 \tag{3.3}$$

$$n.\,k\nabla T(x,t) = h_f\big(T_f(x,t) - T(x,t)\big) \quad \text{on } \vartheta_3 \tag{3.4}$$

The initial condition is:

$$T(x,t)|_{t=0} = T_0 \tag{3.5}$$

thermos elastic stress which is coupled with heat transfer effect can be written in terms of displacement u and v and temperature T as:

$$\frac{\partial^2 T}{\partial x^2} + \frac{\partial^2 T}{\partial y^2} = Q \tag{3.6}$$

$$\frac{\partial^2 u}{\partial x^2} + \frac{1-\mu}{2}\frac{\partial^2 u}{\partial y^2} + \frac{1+\mu}{2}\frac{\partial^2 v}{\partial x\,\partial y} - (1+\mu)\alpha\frac{\partial(T-T_{ref})}{\partial x} = 0 \tag{3.7}$$

$$\frac{\partial^2 v}{\partial y^2} + \frac{1-\mu}{2}\frac{\partial^2 v}{\partial x^2} + \frac{1+\mu}{2}\frac{\partial^2 u}{\partial x\,\partial y} - (1+\mu)\alpha\frac{\partial(T-T_{ref})}{\partial y} = 0 \tag{3.8}$$

3.2.2 Finite element equations:

In order to couple mechanical and thermal analysis in for of finite element equation a suitable interpolation function which represents the change in temperature and displacement should be used.

The finite element equations after insertion boundary conditions and initial condition can be expressed as:

$$[C]\{T\} + [K]\{T\} = \{F_T\} \tag{3.9}$$

For the above equation $[C]$, $\{K\}$ *and* $\{F_T\}$ are shown below:

$$[C] = \int_V \rho c\,[N]^T[N]dV \tag{3.10}$$

$$[K] = \int_V k\,[B]^T[B]dV + \int_S h_f[N]^T\,[N]dS \tag{3.11}$$

$$\{F_T\} = \int_V Q[N]^T\,dV + \int_S h_f T_{ref}[N]^T\,dS \tag{3.12}$$

The resulting parameters from equation (3.1) will be used as thermal load for mechanical model the mechanical FE equations are written in the incremental form as:

$$[K_1]^{i+1}\{\Delta U\} - [K_2]^{i+1}\{\Delta T\} = \{R\}^{i+1} - \{R\}^{i} \qquad (3.13)$$

In which:

$$[K_1] = \int_V [B]^T [D]^{ep} [B] dV \qquad (3.14)$$

$$[K_2] = \int_V [B]^T [C^{th}][M] dV \qquad (3.15)$$

$$\{R\} = \int_S [N]^T \{P\} dS + \int_V [N]^T \{f\} dV \qquad (3.16)$$

$$[D]^{ep} = [D]^e + [D]^p \qquad (3.17)$$

$\{\Delta U\}$ and $\{\Delta T\}$ are the incremental of nodal displacements and temperature, respectively, [B] is the matrix of strain-displacement, $[D^e]$ is the matrix of elastic stiffness, $[D^p]$ is the matrix of plastic stiffness, [C] is the matrix of thermal stiffness, [M] is the temperature shape function, $\{p\}$ is the vector of traction, $\{f\}$ is the vector of body force and *i* is the current step of analysis.

The vector of nodal displacement at the next step of analysis $\{U\}^{i+1}$ proceeds as:

$$\{U\}^{i+1} = \{U\}^{i} + \{\Delta U\} \qquad (3.18)$$

The updated stress conditions in the structure are obtained from the following stress-strain relations:

$$\{\sigma\}^{i+1} = \{\sigma\}^{i} + \{\Delta\sigma\} \qquad (3.19)$$

In which:

$$\{\Delta\sigma\} = [D]^{ep}[B]\{\Delta U\} + [C][M]\{\Delta T\} \qquad (3.20)$$

3.3 Flow Equations:

The derivations of flow equation mathematical formulation basically depend upon three equation equations as described in the following:

1) Mass Conservation Equation:

Mass conversation equation also called the continuity equation. It is basically mass balance equation that takes into account every quantity of produce or injected fluids through a porous media the derivation of this equation for the control volume shown in figure (3.1) after applying the mass balance concept:

$$\left\{ \begin{Bmatrix} \text{Mass into the} \\ \text{element at x} \end{Bmatrix} + \begin{Bmatrix} \text{Mass into the} \\ \text{element at y} \end{Bmatrix} + \begin{Bmatrix} \text{Mass into the} \\ \text{element at z} \end{Bmatrix} \right\} -$$

$$\left\{ \begin{Bmatrix} \text{Mass out of the} \\ \text{element at } x+\Delta x \end{Bmatrix} + \begin{Bmatrix} \text{Mass out of the} \\ \text{element at } y+\Delta y \end{Bmatrix} + \begin{Bmatrix} \text{Mass out of the} \\ \text{element at } z+\Delta z \end{Bmatrix} \right\} =$$

$$\begin{Bmatrix} \text{Rate of change of mass} \\ \text{inside the element} \end{Bmatrix} \qquad (3.21)$$

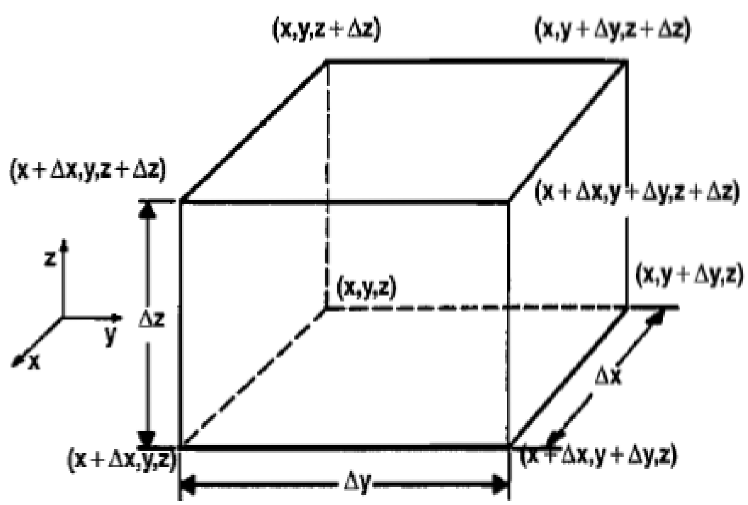

Figure 3.1: Control volume (E. Turguy,2001)

Then after substituting by mass in equation (3.16) the resulting continuity equation is given as:

$$-\frac{\partial}{\partial x}(\rho u_x)-\frac{\partial}{\partial y}(\rho u_y)-\frac{\partial}{\partial z}(\rho u_z)=\frac{\partial}{\partial t}(\phi\rho) \qquad (3.22)$$

2) Darcy equations:

It is an equation that govern fluid motion developed by Henry Darcy in 1856 states the velocity of a homogeneous fluid in a porous medium is proportional to the pressure gradient and inversely proportional to the fluid viscosity (A. Tarek,2006). For a linear horizontal system, this equation is written as:

$$u_x=-\frac{k_x}{\mu}\left(\frac{\partial P}{\partial x}\right) \qquad (3.23)$$

$$u_y=-\frac{k_y}{\mu}\left(\frac{\partial P}{\partial y}\right) \qquad (3.24)$$

$$u_z=-\frac{k_z}{\mu}\left(\frac{\partial P}{\partial z}\right) \qquad (3.25)$$

3) Compressibility Equation

The fluid compressibility equation (expressed in terms of density or volume) is used in formulating the flow equation to describing the changes in the fluid volume as a function of pressure the compressibility equation for each phase is shown below:

$$c_o=-\frac{1}{B_o}\frac{dB_o}{dp}+\frac{B_g}{B_o}\frac{dR_{so}}{dp} \qquad (3.26)$$

$$c_w=-\frac{1}{B_w}\frac{dB_w}{dp}+\frac{B_g}{B_w}\frac{dR_{sw}}{dp} \qquad (3.27)$$

$$c_g = -\frac{1}{B_g}\frac{dB_g}{dp} \qquad (3.28)$$

$$c_t = c_o S_o + c_w S_w + c_g S_g + c_f \qquad (3.29)$$

By combining all above equations, a 3D multi-phase flow equation can be developed for each phase as the following:

Gas flow equation:

$$\nabla \bullet \left[\left[\frac{k_g}{\mu_g B_g} + R_{so}\frac{k_o}{\mu_o B_o} + R_{sw}\frac{k_w}{\mu_w B_w}\right]\nabla p\right] = \frac{\partial}{\partial t}\left[\phi\left[\frac{S_g}{B_g} + R_{so}\frac{S_o}{B_o} + R_{sw}\frac{S_w}{B_w}\right]\right] \qquad (3.30)$$

Oil flow equation:

$$\nabla \bullet \left[\frac{k_o}{\mu_o B_o}\nabla p\right] = \frac{\partial}{\partial t}\left[\phi\frac{S_o}{B_o}\right] \qquad (3.31)$$

Water flow equation:

$$\nabla \bullet \left[\frac{k_w}{\mu_w B_w}\nabla p\right] = \frac{\partial}{\partial t}\left[\phi\frac{S_w}{B_w}\right] \qquad (3.32)$$

Multi-phase flow equation:

$$\nabla^2 p = \phi\frac{c_t}{\lambda_t}\frac{\partial p}{\partial t} \qquad (3.33)$$

In which:

$$\lambda_t = \frac{k_o}{\mu_o} + \frac{k_g}{\mu_g} + \frac{k_w}{\mu_w} \qquad (3.34\ )$$

3.4 Elastic Module Calculations:

Rocks are not perfectly elastic. Especially in soft rocks, it could well be difficult to find a portion of the stress-strain curves that exhibits nearly elastic behavior. On the other hand, the knowledge of elastic parameters is of great importance for engineering applications, and assuming, as a first approximation, that the rock behaves as an elastic

material has significant advantages. The ratio of the dynamic to static moduli may vary from 0.8 to about 3 and is a function of rock type and confining stress. In most cases, this ratio is higher than 1 (Simmons and Brace, 1965; King, 1983; Cheng and Johnston, 1981; Yale *et al.*, 1995). Possible explanations for these differences are discussed in the following.

Elastic properties determined using sonic measurements Sonic measurements are conveniently used to determine the elastic properties under dynamic conditions in the laboratory. These properties are also called dynamic elastic properties. To obtain them, a mechanical pulse is imparted to the rock specimen, and the time required for the pulse to traverse the length of the specimen is determined. Then, the velocity of the wave can be easily calculated.

The essential data is shear wave value came from sonic log, however it is often un available in most unconsolidated formation. This research use Brocher's method to estimate shear wave or to calculate the rock mechanical properties in the absence of shear wave.

Brocher (2008) derived a non-linear empirical correlation for prediction of shear wave velocity in sandstone, carbonate and shale rocks

$$Vs = 0.7858 - 1.2344 \times Vp + 0.7949 \times Vp^2 - 0.1238 \times Vp^3 + 0.0064 \times Vp^4$$

(Km/s) (3.35)

Poisson Ratio Calculations:

$$\mu = \frac{(V_p^2 - V_s^2)}{2(V_p^2 - V_s^2)} \qquad (3.36)$$

Shear Modulus Calculations:

$$G = \rho * 1000 * V_s^2 \qquad (3.37)$$

Young's Modulus Calculations:

$$E = 2G(1 + \mu) \qquad (3.38)$$

In-situ stresses:

$$\sigma_v = g\int_0^D \rho dz \qquad (3.39)$$

$$\sigma_r = P_{wf} - \alpha P \qquad (3.40)$$

In all above equations Vp and Vs represent cornpression and shear wave velocity respectively.

All elastic module used in this research are dynamically calculated.

3.5 Coupling Concept:

Fluid flow and formation deformation (geomechanics) are coupled together in a sequential manner, that is, the two calculations alternate while passing information back and forth. The fluid flow calculation updates the pressures and temperatures over an interval specified. The geomechanics module updates the formation deformation in response to the new pressures and temperatures. To complete the loop, the geomechanics module sends the new deformation information back to the fluid flow calculation for use in the next time interval. It is clear that information flows from fluid flow to geomechanics via pressure and temperature. However, it is not obvious how information flows back the other way. The fluid flow module calculates porosity as a function of pressure and temperature, in a way that pore volume and hence mass is conserved between time steps. Here "conserved" means that the porosity at the beginning of a time step is equal to the porosity at the end of the previous time step, at that particular pressure and temperature. When the porosity function φ(p,T) itself does not change with time, mass conservation across time steps is ensured (STARS Manual,2015).

In this thesis two way coupling has been used in which porosity is a function of pressure, temperature and total mean stress.

3.6 Safety Factor:

Consider the Mohr Coulomb circle and failure envelope shown below (figure (3.2)). For this set of stresses, the safety factor is CB/CA where:

$$CA = \frac{(\sigma_1' - \sigma_3')}{2} \quad (3.41)$$

$$CB = \cos(\varphi) \cdot CB' \quad (3.42)$$

Here φ is friction angle, and the estimated value of CB′ is based on the failure function of the constitutive model. The location of C is given by:

$$OC = \frac{(\sigma_1' + \sigma_3')}{2} \quad (3.43)$$

If safety factor CB/CA is greater than 1, the material is still elastic and safe from failure since the stresses are under the failure envelope. If safety factor is 1 or less, the material either has

failed or will fail very soon. However, the safety factor can be used as a measure of **how close** a material is to failure.

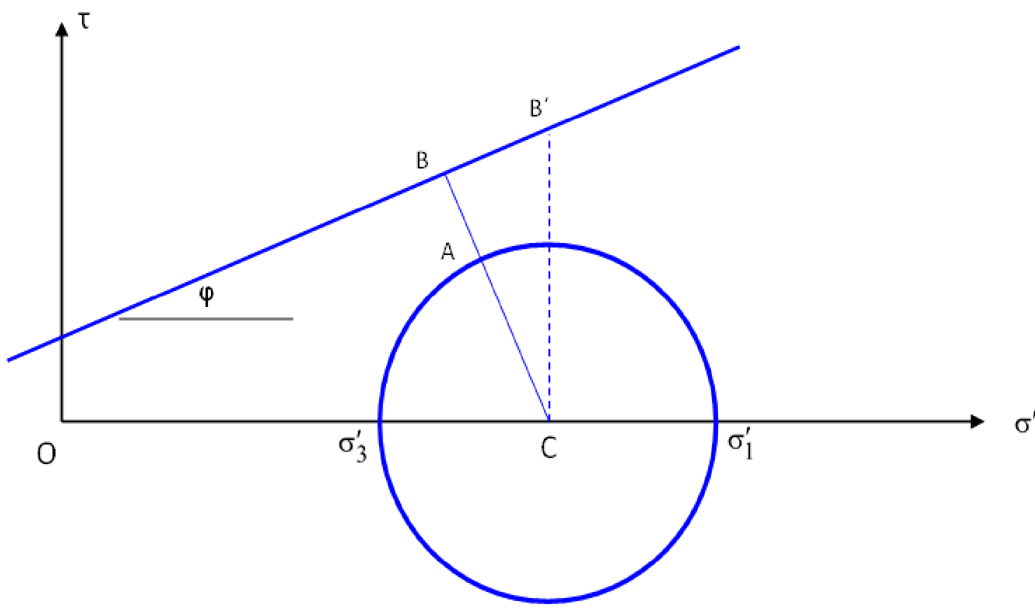

Figure 3.2: Mohr Coulomb circle and the failure envelope (STARS Manual,2015)

3.7 Procedure Flow Chart:

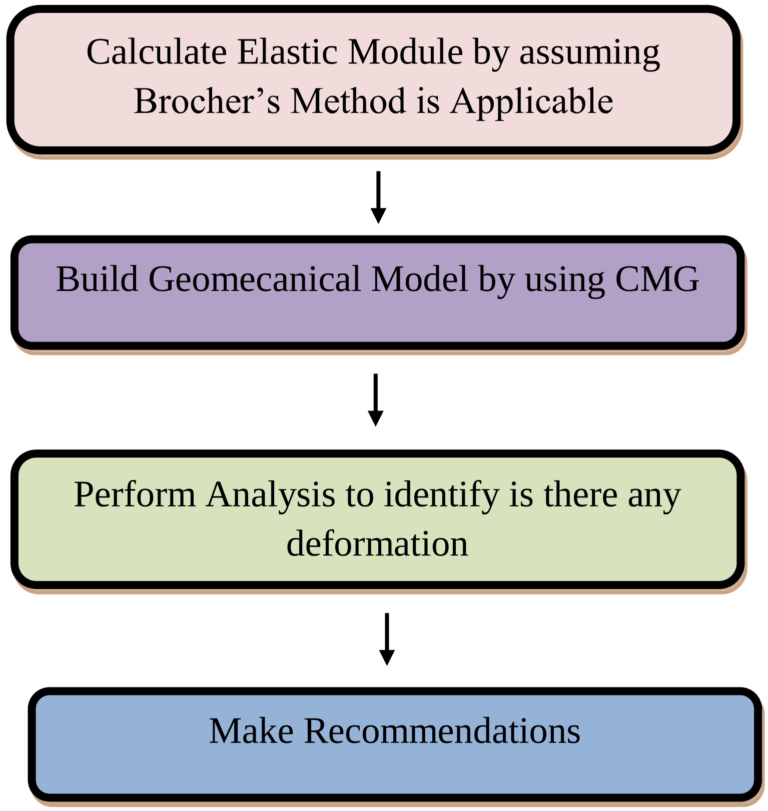

Figure 3.3: Procedure Flow Chart

CHAPTER 4

Results and Discussions

4.1. Introduction:

In this chapter cover a background about studied area and reservoir properties of the research case study. Geo-mechanical model parameters calculation is performed; for simulation model the history matching is done and the evaluation of Geo-mechanical effect has been discussed.

4.2. Geo-mechanical Data Preparation:

To build a complete Geo-mechanical model is required establishing and computing additional parameters; which mainly include Young's modulus, Poisson's ratio and initial stress.

the study is not cover the direct calculation of parameters from core sample for the reason of lack availability of core sample to obtain static values of young's modulus and poison's ratio, in which the based method should be use these mentioned parameters to estimate dynamic values (as mentioned also in chapter 3).

The FC-18 well data is used as the case study in this work; the required data to calculate Geo-mechanical parameters are bulk density and compression wave velocity as shown in figure (4.1).

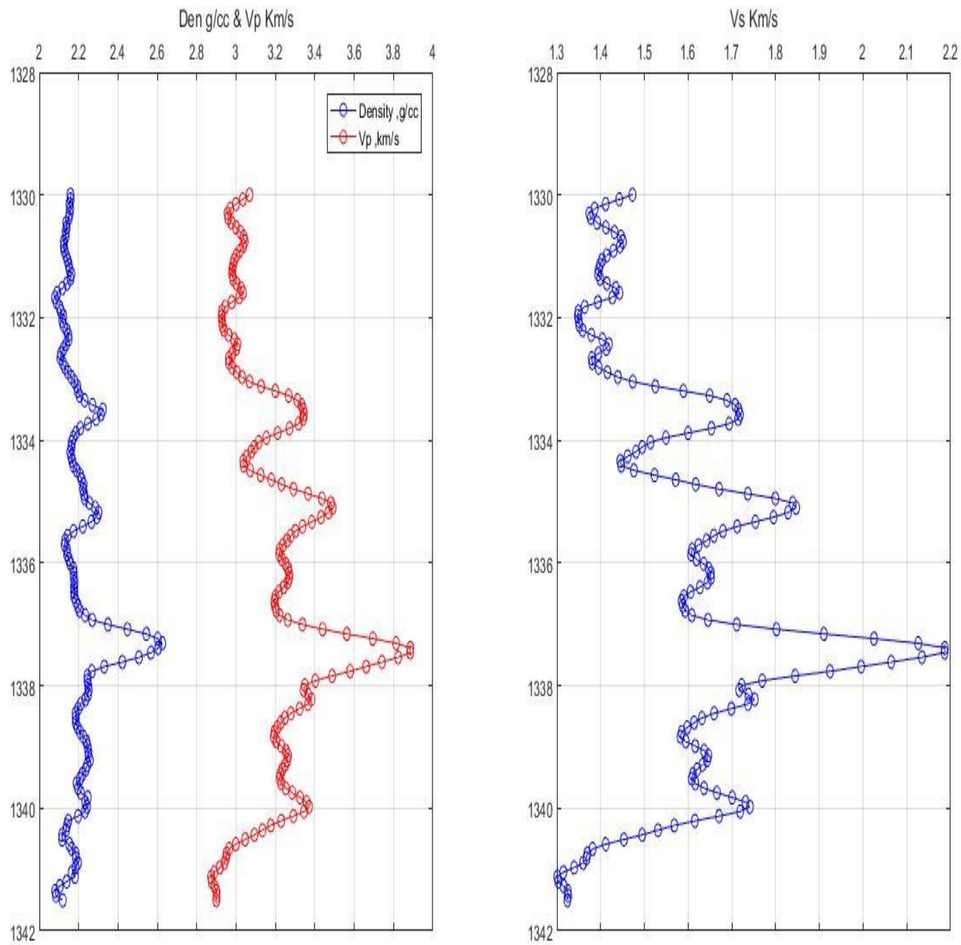

Figure 4.1: Required Data (Density ,Vp) and Vs

The first step of calculation is to calculate shear wave velocity using equation (3.35) as shown in figure (4.1). The second step is to calculate Poisson's ratio from equation (3.36) then shear modulus should be calculated from equation (3.37)

Both values of Poisson ratio and shear modulus are used to estimates the value of Young modulus by using equation (3.38).

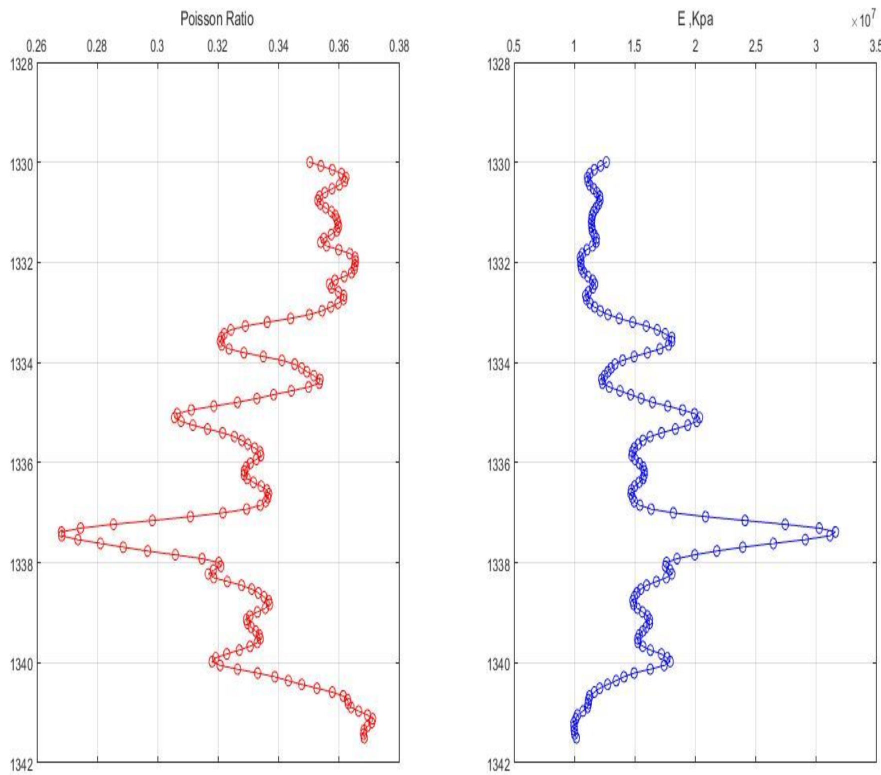

Figure 4.2: Calculated value of Poisson ratio and Yong modulus

The average dynamic properties is 0.34 for Poisson's ratio and 14.9 GPa for Young's modulus.

To complete the required data for building Geo-mechanical model the vertical stress was calculated using equation (3.39) and near wellbore radial stress was assumed to be equal to bottom hole pressure.

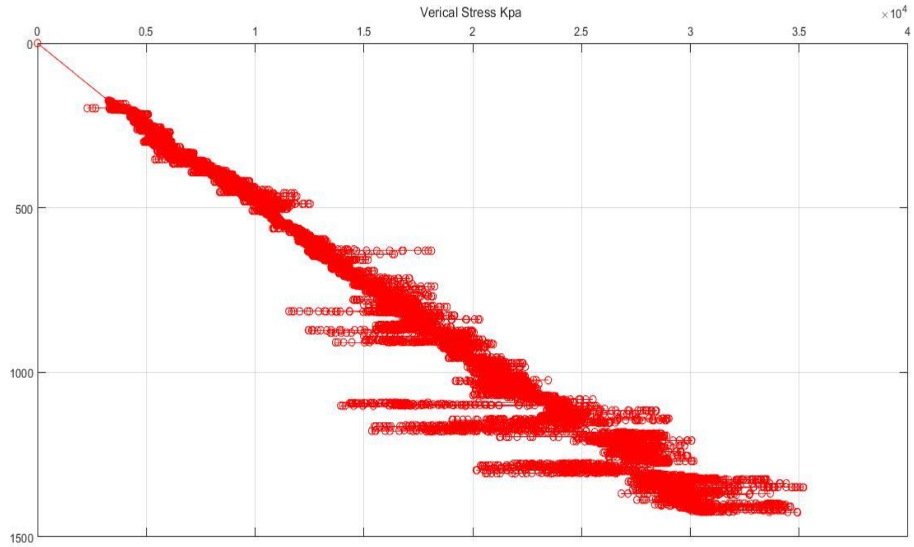

Figure 4.3: Vertical Stress Calculation

4.3. FC-18 Radial Model:

The radial model of FC-18 consists of 16 *1* 34 cells with $r_w$equals to 0.076 m the array properties of this model including net bay thickness , grid thickness ,dimensions, saturation, porosity and permeability has been entered as shown in appendix A.

The FC-18 is produced from Bentiu (Ba1) formation which has reservoir pressure of 11800 kpa and temperature of 62.8 C; FC-18 has been perforated in two intervals of 1330-1336m and 1338.5-1341.5 m.

The oil at reservoir condition classified as heavy oil to that thermal EOR is suggested and PVT properties has entered as shown in data file appendix A.

The SCAL data which used to initialize the model shown below

Table (4.1): SCAL Data for Ba1 formation

Water Saturation	Water Relative Permeability	Oil Relative Permeability
0.138	0	1
0.188	0.0042	0.6808
0.239	0.0187	0.5283
0.289	0.0448	0.3962
0.34	0.0836	0.2843
0.39	0.1354	0.192
0.44	0.2009	0.1187
0.491	0.2804	0.0639
0.541	0.3743	0.0267
0.592	0.483	0.006
0.642	0.6066	0

4.4 History Matching:

After all model components have been defined the mechanical parameters has been entered for STARS in order to complete Geo-mechanical model.

After that the model is run and 3 cycles of CSS has been simulated and history matching is performed between model results and field production results and give good results as discussed below

The first item which is used to perform history matching is cumulative fluid production (Figure (4.3)) and the result of it is:

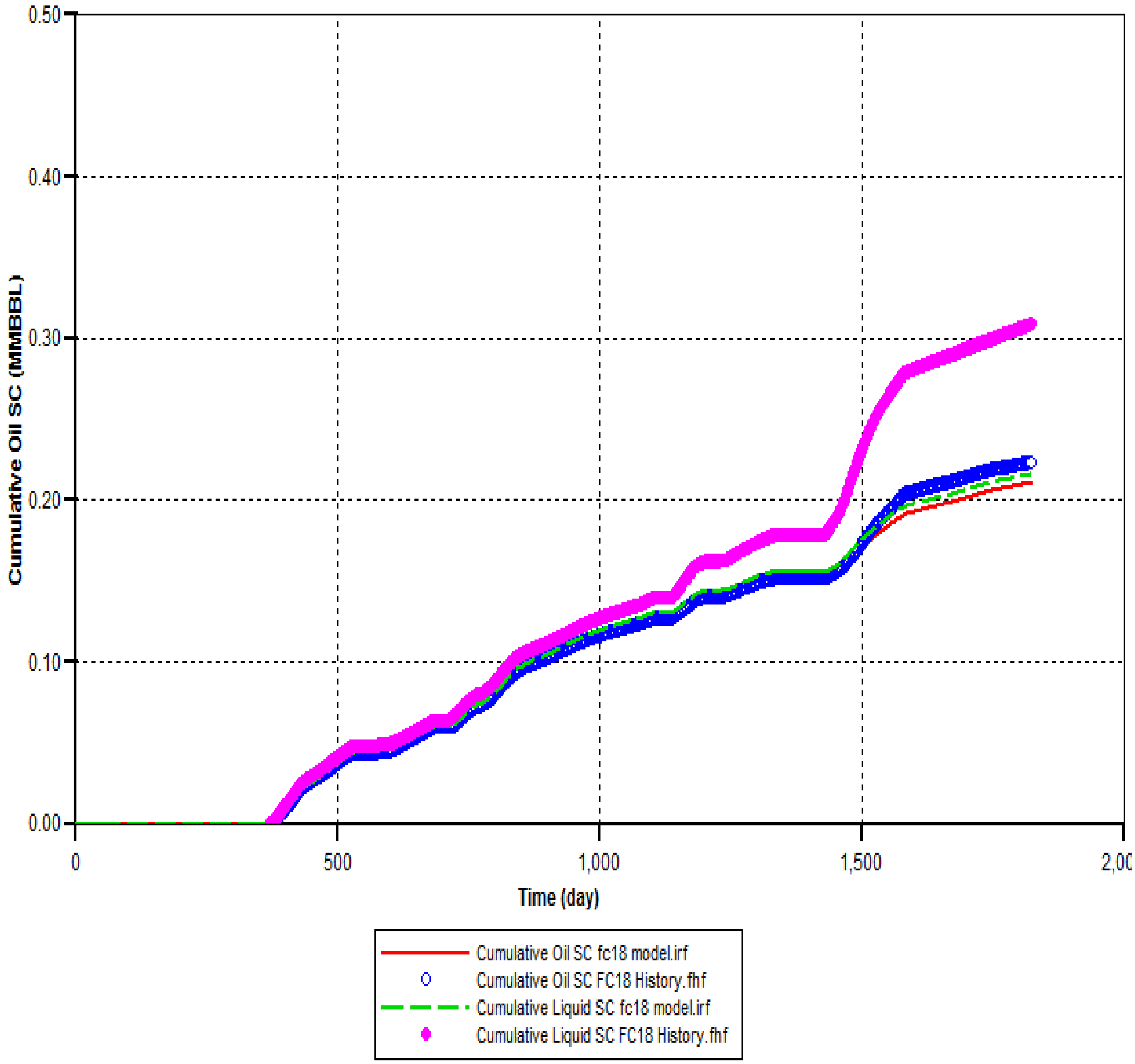

Figure 4.4: Cumulative production matching

Secondly matching is performed depending on liquid rate and oil rate and give good results as shown in below figure

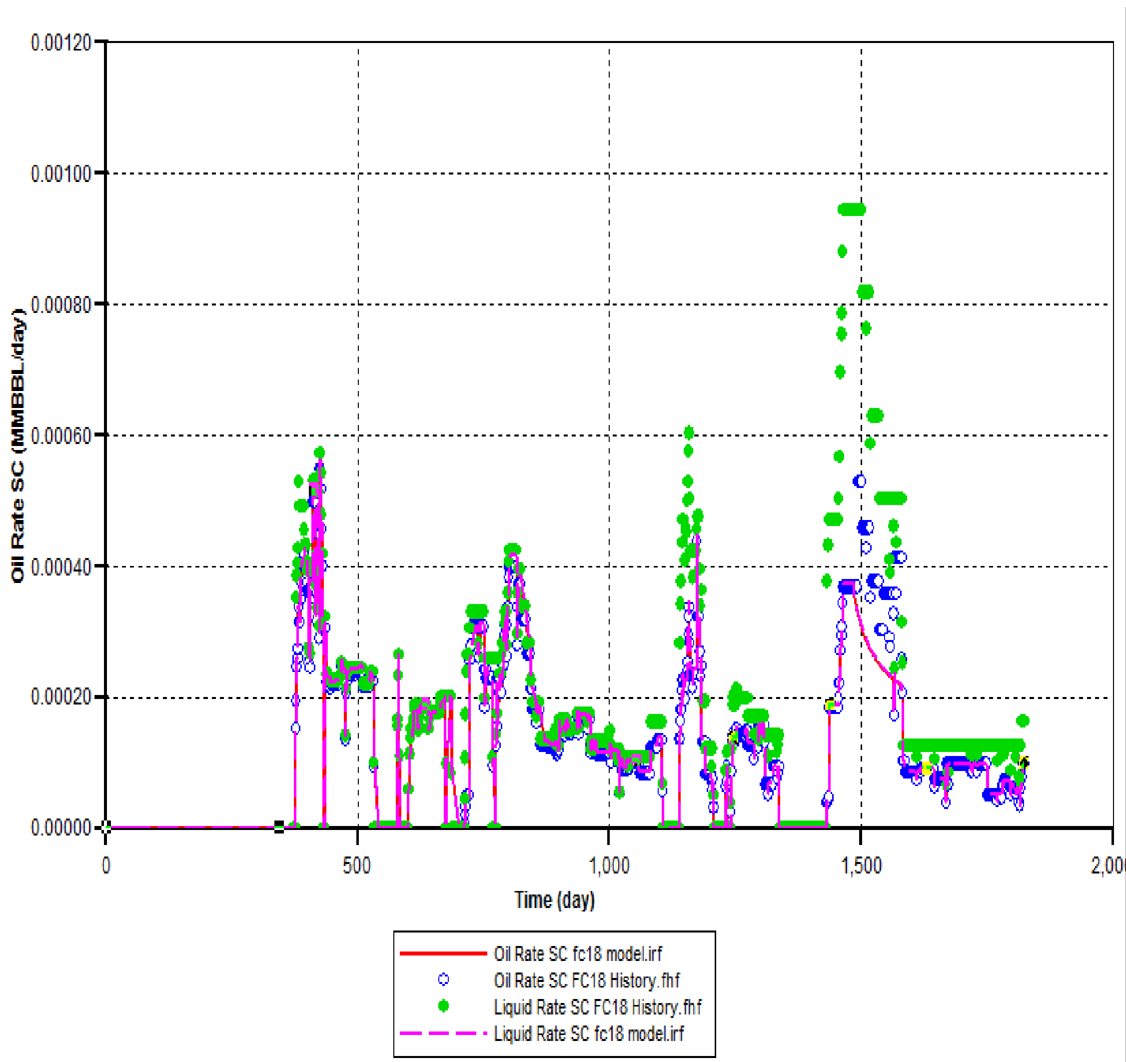

Figure 4.5: Fluids rates matching

As the final step of matching the water cut has been used as an item for matching and the result of matching is reasonable.

4.5 Geo-mechanical Evaluation of Current State for FC-18:

The evaluation of the current state for near wellbore region will be done based on expected failure and to measure how the rock may fail the concept of Mohr's circle safety factor should be used.

With the current injection temperature of 347 C after 1825 day of production deformation is possible to occur due to small value of safety factor 0.639 (figure (4.6)) which is less than 1.2 or failure may be taken place and to confirm the results the image log is required.

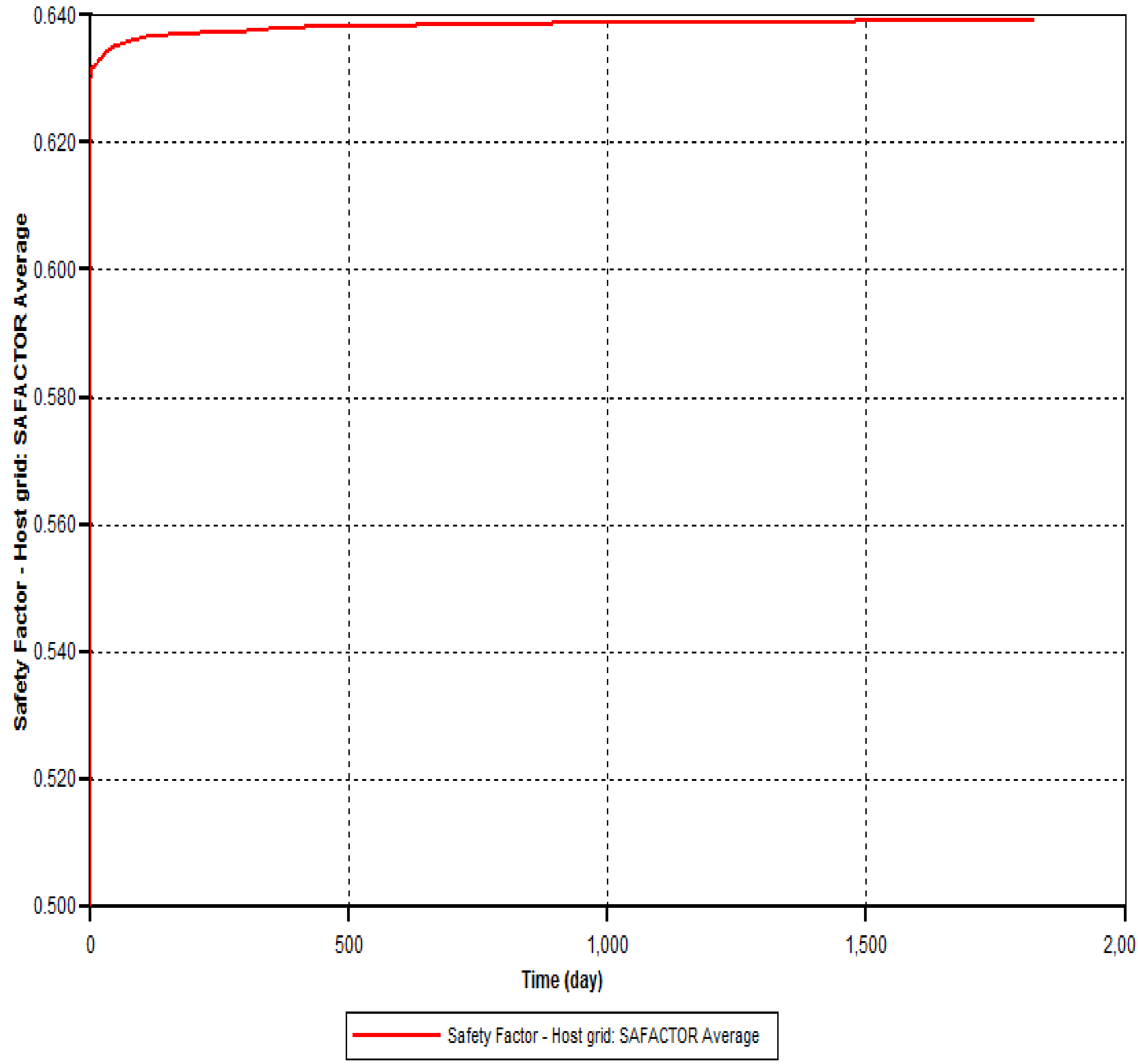

Figure 4.6: Safety factor for temperature of 347 C

To confirm the above mentioned the yield state is used to verify is there failure is occurring or not as shown in figure (4.7) the yield state of the near wellbore region is 1 that means the rocks on shear failure envelope.

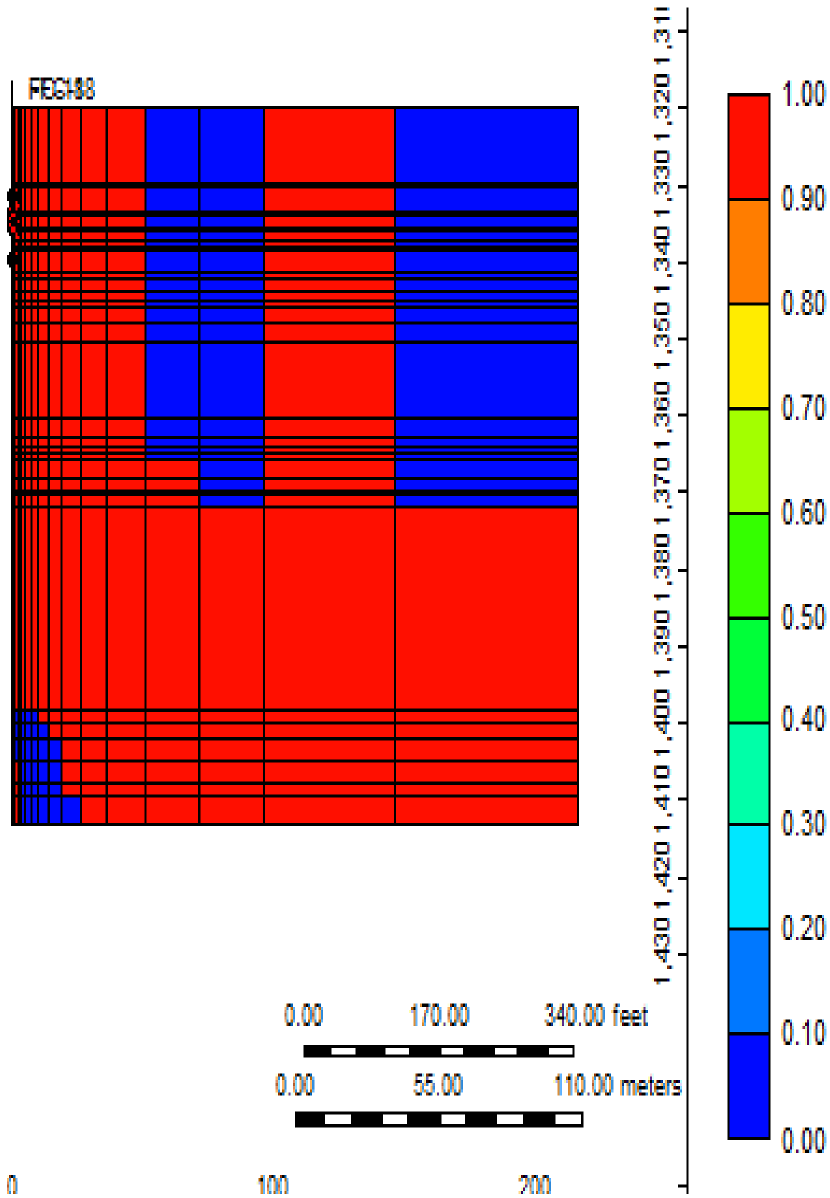

Figure 4.7: Yield state after 1825 days

In CSS wells, the pore volume change is expected which will affect the reservoir permeability and consequently water mobility and volumetric strain may use as the indicator of this change in this case after 1825 days is 0.00083 the positive value means that increase in pore volume which directly affect the porosity and permeability.

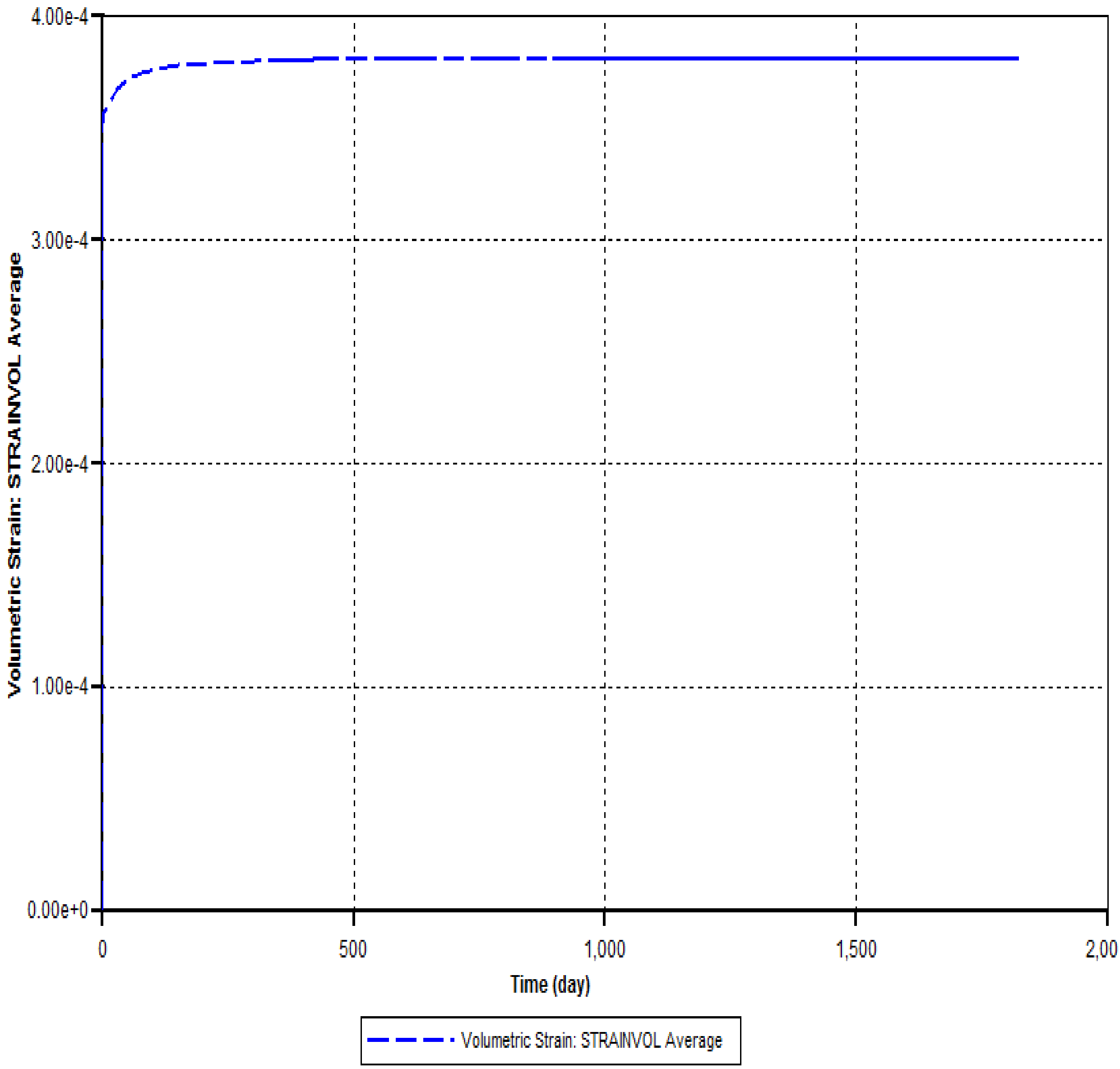

Figure 4.8: Volumetric strain after 1825 days

This increase in pore volume caused dilatation and mobility of the injected fluid this will affect directly in hydrocarbon movement and increase in reservoir pressure as shown in figure (4.9) the pressure in some region reach 3247 kpa .

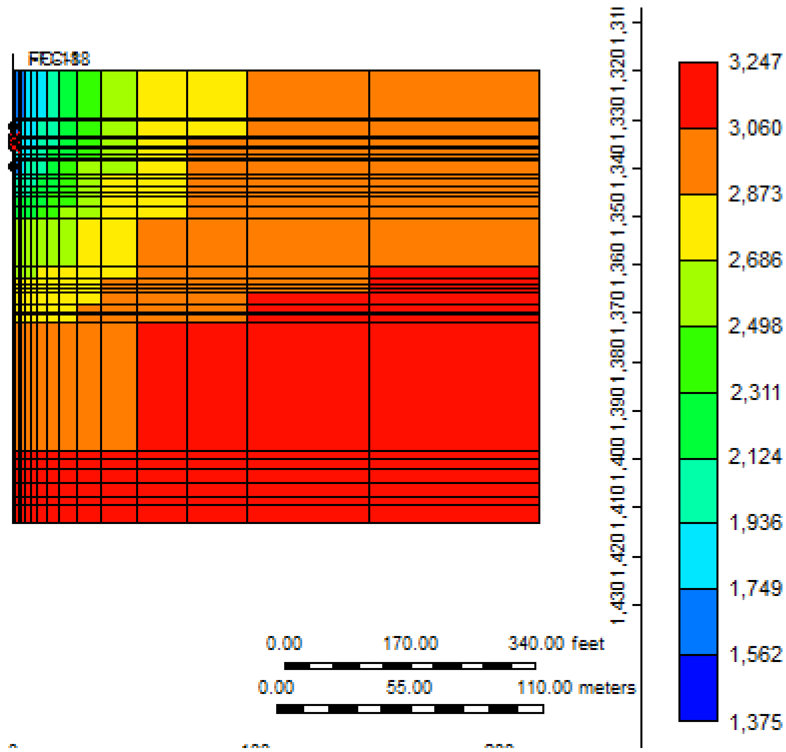

Figure 4.9: Pressure for near wellbore region

During production the reservoir pressure is decrease and this means effective stresses will increase Figures (4.10), (4.11) and (4.12) so reservoir is contract.

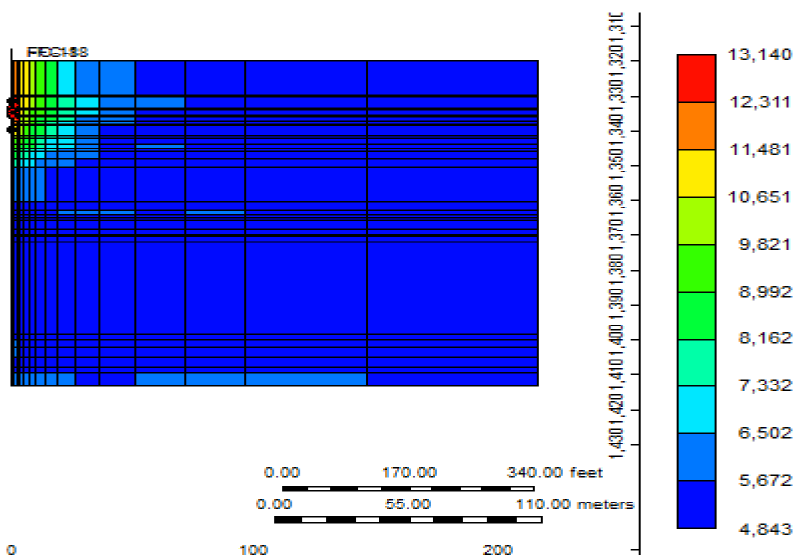

Figure 4.10: Effective normal stress in i

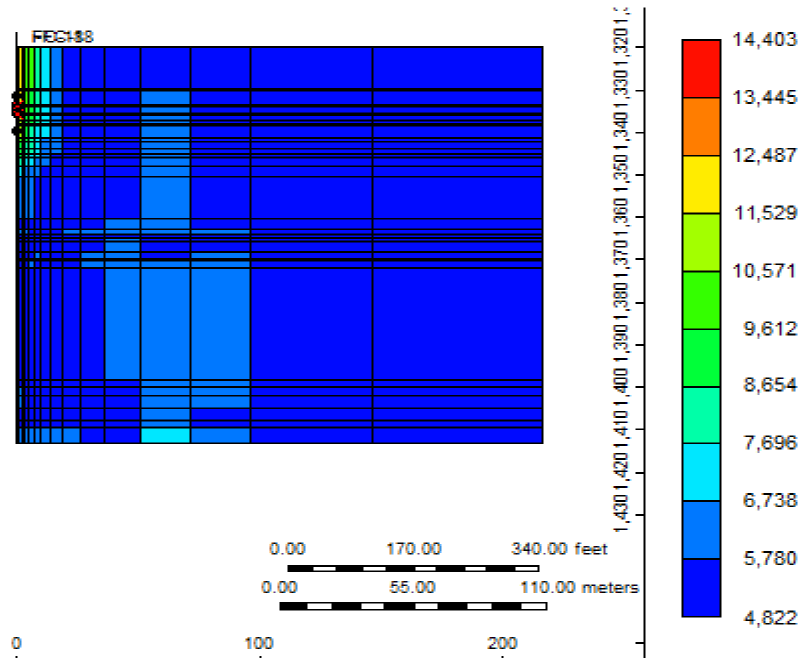

Figure 4.11; Effective normal stress in j

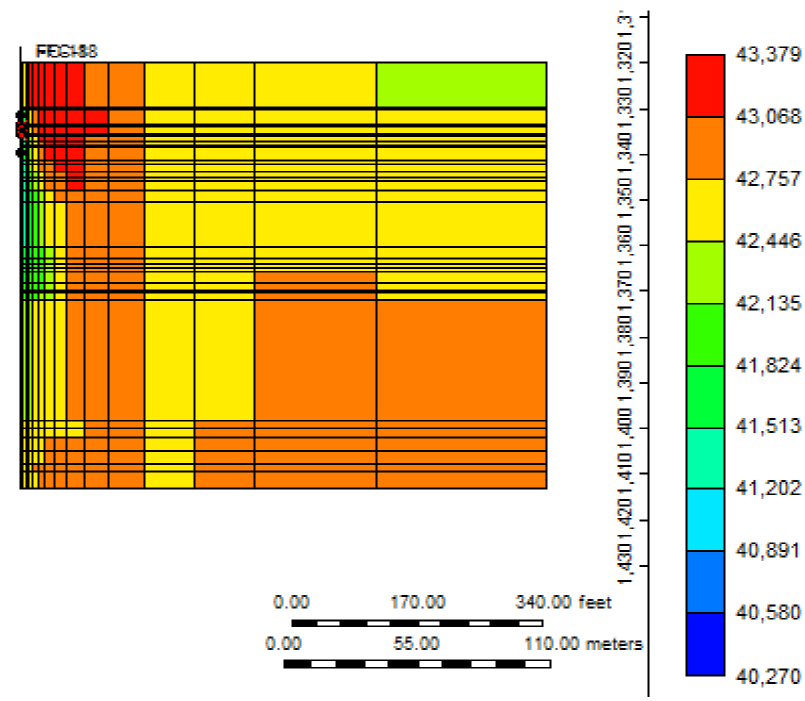

Figure 4.12; Effective normal stress in k

Also as the consequence of steam injection displacements is resulting in the reservoir due to dilation this can be clearly shown in figure (4.13) and figure (4.15) there is significant displacement in z direction 0.036 m and 0.0031 m in x direction which cause thermal expansion of the sand grains and sand structure.

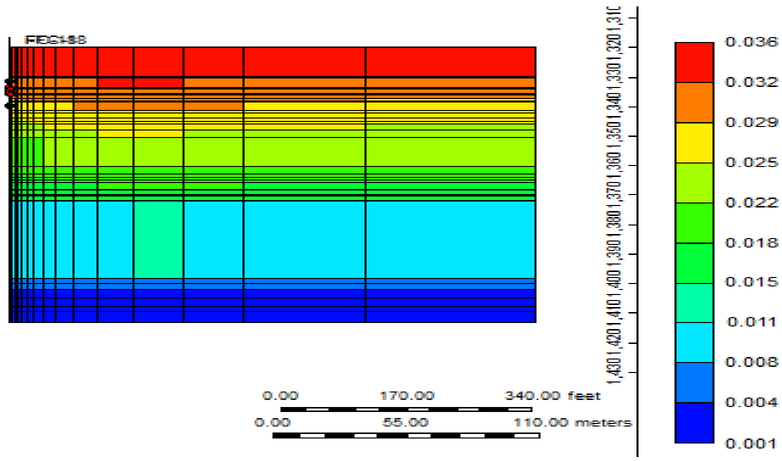

Figure 4.13: Displacement along z axis

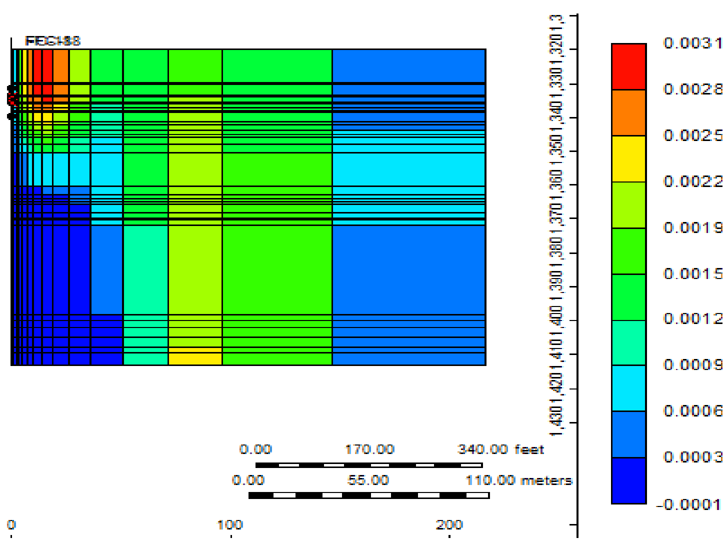

Figure (4.14): Displacement along x axis

CHAPTER 5

Conclusions and Recommendations

5.1 Conclusions:

1) The average dynamic elastic properties for FC-18 has been calculated as follow:

- Poisson's ratio is 0.34.
- Young's Modulus is 14.9 GPa.

2) Geo-mechanical model has been build.

3) History matching has been performed and give good results.

4) The following parameter has been calculated using STARS simulator after:

- Safety factor is 0.639
- Yield state is 1 which means the rock is under shear envelope.
- Volumetric strain is 0.00083 which means increase in pore volume.
- The pore pressure in some region reach 3247 kPa.
- The displacement in X is 0.036 m and in Y is 0.0031m.

5.2 Recommendations:

- Use the static elastic properties by taking a rock sample and measure those properties in LAB.
- Run an image log and fracture identification test to confirm simulations results.
- Use other program to build a Geo-mechanical model for the reservoir and using optimum way of coupling its results with any multiphase flow simulator.

- Geo-mechanic must be taken into consideration in any future thermal EOR optimization is Sudanese field.

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Definition of fundamental cylindrical grid $**
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GRID RADIAL 16 1 34 *RW 0.076
KDIR DOWN
DI IVAR 0.5 0.5 1 1
5 4 3 2 2
25 20 15 10 7
70 50
DJ JVAR 360
DK ALL
3*16 0.5*16 1*32 0.2*16 0.5*16 1.5*16 0.5*16 3.3*16 0.2*16 9.8*16
1*16 1.2*16 2.4*16 9.8*16 2.4*16 2.3*16 0.9*16 1*16 1.6*16 0.8*16
2.8*16 2.1*16 1.5*16 26.3*16 0.3*16 1.3*16 0.8*16 1.4*16 2.4*16 0.9*16
3.6*16 1.6*16 3.2*16
DTOP
1320*16
Property: NULL Blocks Max: 1 Min: 1 $**
null block, 1 = active block = 0 $**
NULL CON 1
Property: Porosity Max: 0.32 Min: 1e-005 $**
POR KVAR
E-005 2*0.32 0.0001 0.28 0.0001 2*0.3 0.0001 3*0.27 0.0001 0.24 0.00011
0.0001 0.3 0.0001 0.31 0.0001 0.26 0.0001 0.25 0.0001 0.3 0.0001 0.24

0.2 0.0001 0.23 0.0001 0.31 0.0001 0.3

Property: Permeability I (md)   Max: 7500 Min: 1e-005 $**

PERMI KVAR

E-005 2*7500 10 1500 1 2*1800 1 3*1500 1 500 1 200 1 1500 1 200 0.11

300 10 300 0.1 3500 0.1 3500 0.1 2500 0.1 3500 0.1 500

PERMJ EQUALSI

Property: Permeability K (md)   Max: 2882.39 Min: 0.0001 $**

PERMK KVAR

140.0243 100 491.6548*3 100 644.9147*2 100 472.0717 100 2882.389*2 0.0001

100 1170.419 100 118.5564 100 67.09427 100 543.4269 100 36.1405 100

101.4869 100 73.59756 100 1270.149 100 1292.947 100 736.5631

Property: Net Pay (m)   Max: 21.4 Min: 0.0001 $**

NETPAY KVAR

0.89 0.0001 0.8 2.8 0.5 0.0001 1 0.2 0.0001 1.4 0.0001 3.2 0.2 0.0001

0.9 0.0001 0.9 0.0001 0.9 0.0001 0.7 0.0001 7.8 0.0001 1.2 0.0001

3 0.0001 3 0.0001 1.5 0.0001 21.4 0.0001

Property: Pinchout Array Max: 1 Min: 1 $**

pinched block, 1 = active block = 0 $**

PINCHOUTARRAY CON   1

END-GRID

ROCKTYPE 1

PRPOR 11800

CPOR 0.23E-6

CTPOR 2e-4

ROCKCP 2.04e+6 0

THCONR 1.38e+5

THCONW 53500

THCONO 1.4E+4

THCONG 140

HLOSST 62.8

HLOSSPROP OVERBUR 2.2e+6 129600

UNDERBUR 2.2e+6 129600

Model and number of components $**

Model and number of components $**

Model and number of components $**

Model and number of components $**

MODEL 2 2 2 1

'COMPNAME 'H2O' 'Oil

CMM

0.55 0.018

PCRIT

0 22120

TCRIT

0 374.15

PRSR 11800

TEMR 62.8

TSURF 15.6

MASSDEN

932.1 1000

CP

e-56 0

VISCTABLE

temp $**

25532.0 0 30

10880.5 0 40

4888.1 0 50

2304.1 0 60

1134.7 0 70

581.7	0	80
309.4	0	90
170.2	0	100
96.6	0	110
56.4	0	120
33.9	0	130
20.8	0	140
13.1	0	150
8.425	0	160
5.525	0	170
3.692	0	180
2.510	0	190
1.735	0	200
1.217	0	210
0.867	0	220
0.625	0	230
0.457	0	240
0.338	0	250
0.253	0	260
0.191	0	270
0.146	0	280
0.113	0	290
0.088	0	300
0.069	0	310
0.054	0	320
0.043	0	330
0.035	0	340
0.028	0	350
0.023	0	360