# الاستهلال

قال تعالى :

{ وَقُلِ اعْمَلُوا فَسَيَرَى اللَّهُ عَمَلَكُمْ وَرَسُولُهُ وَالْمُؤْمِنُونَ }

صدق الله العظيم

[ التوبة : 105 ]

# Dedication

To our fathers and mothers, the source of encouragement and inspiration to us throughout our life.

To our supervisor **Eng. Husham Awadelssed Ali** for his guidance and support throughout this study.

To the spirit of **Dr. Mohammed Naeim**

To our brothers and sisters who stand with us, allow us to use their purpose when we need it to complete this research.

To our dear friends who supported us.

For future generations that hold future of the oil industry in Sudan.

To anyone who taught us how to fight life.

Finally, this thesis is dedicated to all those who believe in the richness of learning.

# Acknowledgment

Thank to Allah before and after everything.

On a personal note, we would like to thank our parents for their everlasting encouragement, patience, understanding and ability to motivate us. This could not have been done without your support.

We would like to thank our supervisor **Eng. Husham Awadelssed Ali**, for his guidance, direction, feedbacks and offering encouragement precisely when needed and without which it would have been nearly impossible to produce this piece of work.

We wish to express our sincere thanks to **Dr. Tagwa Musa**, Dean of the Faculty, for the continuous encouragement.

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Thanks to **College of Petroleum Engineering and Technology**, especially all the members of the petroleum Engineering department.

# Abstract

Thermal methods are the most commonly used Enhanced Oil Recovery methods around the world, one of them is the cyclic steam stimulation process, which had been implemented in Bamboo Main field namely the well BB-22. After the execution the well had low oil rate and high water production occurred.

In this thesis, detail analysis and evaluation has been done to determine the main reason of high the water cut which raised up to 98 % in well BB-22, it has been found that the steam distribution in the layers is not as same as designed.

In order to solve this problem it's highly recommended to close the lower layer and redesign the optimum injection parameters for the upper lower (i.e. Steam Quality, injection rate, steam Temperature) for a new cycle using Computer Modeling Group (CMG) software.

From the results obtained after redesigning, it has been found that the oil rate increases four times, and the water cut decreases from 98% to 33%.

# التجريد

الطرق الحرارية من أكثر طرق الاستخلاص الثانوى المعزز استخداما لزيادة استخلاص النفط ومنها طريقة حقن البخار( Cyclic Steam Stimulation )، والتي استخدمت في البئر BB-22 الموجودة في حقل بامبو ولكن بعد استخدامها حدث انخفاض في انتاج الزيت و زيادة في انتاج الماء.

في هذا البحث تم تحديد السبب الذي أدى الى ارتفاع نسبة معدل انتاج الماء الى 98 % في هذه البئر ، ووجد أن السبب هو عدم توزع البخار في الطبقتين كما هو مصمم له ، و كمقترح لحل هذه المشكلة هو اغلاق الطبقة السفلى ومن ثم اعادة تصميم معاملات الحقن وهي معدل الحقن ودرجة الحرارة وجودة البخار باستخدام برنامج كمبيوترى متخصص وهو Computer Modeling Group (CMG) .

من خلال النتائج المتحصل عليها بعد اعادة التصميم لمعاملات الحقن وجد أن معدل الانتاج ازداد الى اربعه أضعاف وأن نسبة معدل انتاج الماء انخفضت من 98% الى 33%.

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# NOMENCLATURE

| | | |
|---|---|---|
| EOR | : | Enhanced Oil Recovery |
| IOR | : | Improved Oil Recovery |
| CSS | : | Cyclic Steam Stimulation |
| SAGD | : | Steam Assisted Gravity Drainage |
| ASP | : | Alkaline-Surfactant-Polymer |
| MEOR | : | Microbial Enhanced Oil Recovery Methods |
| WAG | : | Water Alternating Gas |
| SWAG | : | Simultaneous Injection of Water and Gas |
| EUR | : | Enhanced Ultimate Recovery |
| SAGP | : | Steam and Gas Push |
| ES-SAGD | : | Expanding Solvent Steam Assisted Gravity Drainage |
| WOR | : | Water Oil Ratio |
| GOR | : | Gas oil Ratio |
| MMP | : | Minimum Miscibility Pressure |
| MCM | : | Multiple Contact Miscible |
| SCM | : | Single Contact Miscible |
| OOIP | : | Original Oil in Place |
| FNE | : | Fula North East |
| SF | : | Steam Flooding |
| GNPOC | : | Greater Nile Petroleum Operating Company |
| ICV | : | Interval Control Valve |
| CSOR | : | Cycle Steam Oil Ratio |
| BOPD | : | Barrel Oil per Day |
| CMG | : | Computer Modeling Group |
| TSX | : | Texas |
| EOS | : | Equation-of-State |
| NPV | : | Net Present Value |
| $S_{or}$ | : | Steam Oil Ratio |
| $CO_2$ | : | Carbon Dioxide |
| $N_2$ | : | Nitrogen Gas |
| API | : | American Petroleum Institute |

| | | |
|---|---|---|
| IFT | : | Interfacial Tension |
| Sw | : | Water Saturation, fraction |

# Chapter One : Introduction

## 1.1 General Introduction

Enhanced Oil Recovery (EOR) is a broader idea that refers to the injection of fluids or energy not normally present in an oil reservoir to improve oil recovery that can be applied at any phase of oil recovery including primary, secondary, and tertiary recovery. Thus EOR can be implemented as a tertiary process if it follows a waterflooding or an immiscible gas injection, or it may be a secondary process if it follows primary recovery directly.

Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits (Green & Willhite, 1998).

Increasing of the knowledge and improving the technology is one of the main reasons to attract and encourage the clients and investors to implement the EOR. In addition to most of the easy oil (green fields) is already produced as well as the production reached the peak already more than 10 years ago. Enhanced oil recovery divided into four groups :

- Chemical enhanced oil recovery
- Thermal enhanced oil recovery
- Miscible enhanced oil recovery
- Microbial EOR Methods (MEOR)

## 1.2 Problem Statement

After implementation of cyclic steam stimulation in the well BB-22, which produces from two layers, in the production stage the well had high water cut reached nearly 98%, the reason that caused high water cut need to be studied and determined and then redesign the optimum injection parameters for a new cycle.

## 1.3 Objectives of the Study

The main objectives of this research are:

1. Determine the reason of high water cut after the first cycle.
2. Suggest a solution for this problem.

and the sub objective is redesign the optimum injection parameters using CMG software (i.e steam quality, injection rate, steam Temperature).

## 1.4 Introduction to the Case Study

Greater Bamboo Field is located in block 2A Muglad Basin consist of four structures, Bamboo west, main, east and south and covers an area of about 144 km as shown in figures ( 1-1,1-2 ). It involves of multi-layered under-saturated sandstone reservoir of late cretaceous ages buried at depth ranging from 1000 m to 1500 m with crude oil viscosity ranges from 200 cp to 3000 cp. The total field STOIIP and Recovery Factor (RF) is currently estimated at around 509 MMSTB, 16% respectively. To date the field had recovered more than 69% of the Ultimate Recovery (EUR).

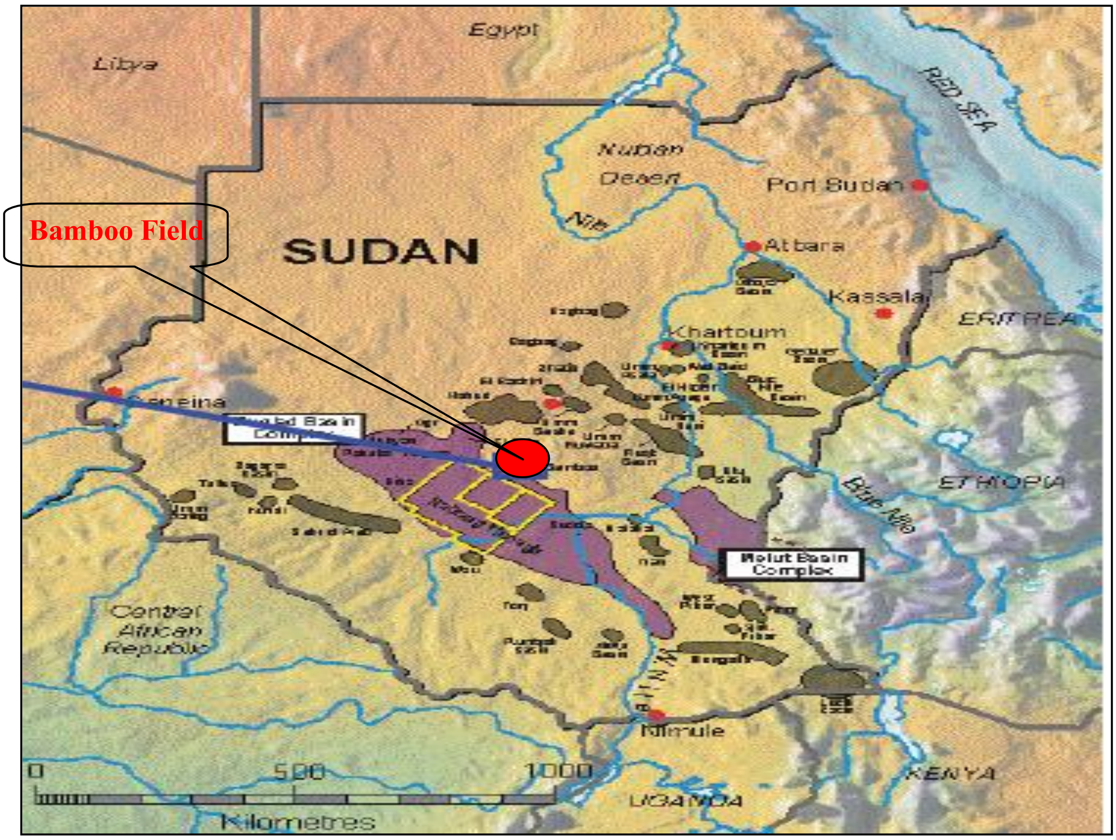



**Figure 1-1 : Oilfield Location Map (OEPA, 2014)**

The field initially produced around 20,000 STB/D with early water breakthrough and very minimal gas production rate until today. However, the production rate declined rapidly when the water production rate increased. Major factors that contributed to this problem are possibly due to the fingering and water conning. Currently the field is producing around 9000 STB/D with water cut around 75% and keeps increasing (Elamin S.Mohmmed & Husham A.Ali, 2014).

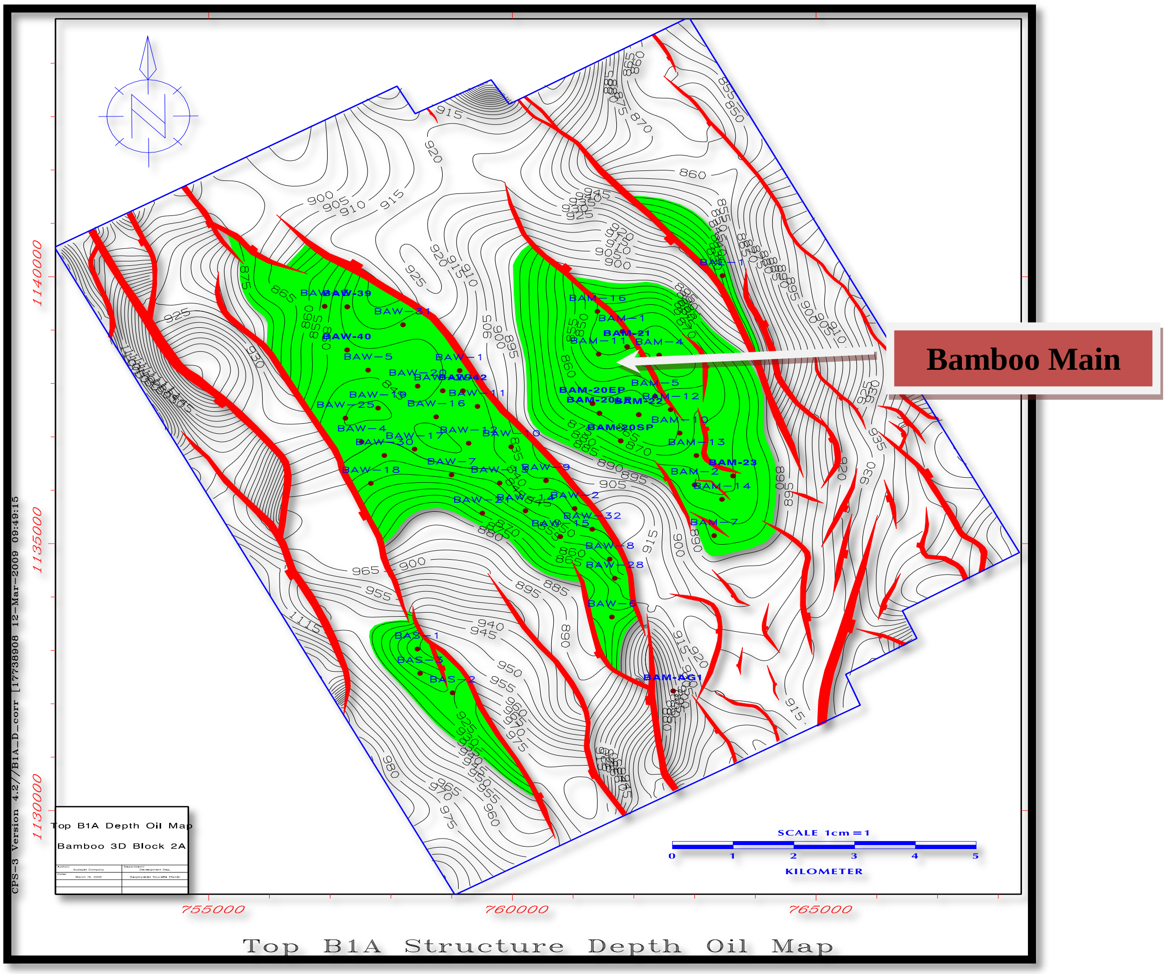



**Figure 1-2 : Bamboo Main Oilfield Location Map (OEPA, 2015)**

## 1.5 Thesis Outlines

In this thesis Chapter one include the general introduction, problem statement, objective of the study and introduction to case study. Chapter two is discussing the literature review and theoretical background of Cyclic steam stimulation, while chapter three is illustrating the methodology of conducting the analysis of high water cut and designing the optimum injection parameters using CMG software. Chapter four is summarizing the results and discussion of the work and chapter five is the conclusion and recommendations of the study.

# Chapter Two : Theoretical Background and Literature Review

## 2.1 Theoretical Background

### 2.1.1 Oil Recovery Mechanisms

Each reservoir is composed of a unique combination of geometric form, geological rock properties, fluid characteristics, and primary drive mechanism. Although no two reservoirs are identical in all aspects, they can be grouped according to the primary recovery mechanism by which they produce. It has been observed that each drive mechanism has certain typical performance characteristics in terms of:

- Ultimate recovery factor
- Pressure decline rate
- Gas-oil ratio
- Water production

The recovery of oil by any of the natural drive mechanisms is called primary recovery. The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir.

There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

**• Rock and liquid expansion drive**

In undersaturated oil reservoir at pressures above the bubble-point pressure, crude oil, connate water, and rock are the only materials present. As the reservoir pressure declines, the rock and fluids expand due to their individual compressibilities.

**• Depletion drive**

As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space.

**• Gas cap drive**

Gas-cap-drive reservoirs can be identified by the presence of a gas cap with little or no water drive.

**• Water drive**

Many reservoirs are bounded on a portion or all of their peripheries by water bearing rocks called aquifers. The aquifers may be so large compared to the reservoir they adjoin as to appear infinite for all practical purposes, and they may range down to those so small as to be negligible in their effects on the reservoir performance. The aquifer itself may be entirely bounded by impermeable rock so that the reservoir and aquifer together form a closed (volumetric) unit.

**• Gravity drainage drive**

The mechanism of gravity drainage occurs in petroleum reservoirs as a result of differences in densities of the reservoir fluids. The effects of gravitational forces can be simply illustrated by placing a quantity of crude oil and a quantity of water in a jar and agitating the contents. After agitation, the jar is placed at rest, and the more denser fluid (normally water) will settle to the bottom of the jar, while the less dense fluid (normally oil) will rest on top of the denser fluid. The fluids have separated as a result of the gravitational forces acting on them.

**• Combination drive**

The driving mechanism most commonly encountered is one in which both water and free gas are available in some degree to displace the oil toward the producing wells.

### 2.1.2 Development Sequence

The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained.

#### 2.1.2.1 Primary Oil Recovery

Describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery. The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water.

#### 2.1.2.2 Secondary Oil Recovery

Refers to the additional recovery that results from the conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted. gas-water combination floods, known as water alternating gas injection (WAG), where slugs of water and gas are injected sequentially. Simultaneous injection of water and gas (SWAG) is also practiced, however the most common fluid injected is water because of its availability, low cost, and high specific gravity which facilitates injection (Dake, 1978; Lyons & Plisga, 2005; Satter et al., 2008 )

The purposes of a secondary recovery technique are:

- Pressure restoration
- Pressure maintenance

The mechanism of secondary oil recovery is similar to that of primary oil recovery except that more than one well bore is involved**.**

***Water Injection***

In water injection operation, the injected water is discharged in the aquifer through several injection wells surrounding the production well. The injected water creates a bottom water drive on the oil zone pushing the oil upwards. The water injection is generally carried out when solution gas drive is present or water drive is weak. Therefore for better economy the water injection is carried out when the reservoir pressure is higher than the saturation pressure.

Water is injected for two reasons:

1. For pressure support of the reservoir (also known as voidage replacement).
2. To sweep or displace the oil from the reservoir, and push it towards an oil production well.

The selection of injection water method depends upon the mobility rate between the displacing fluid (water) and the displaced fluid (oil).

The water injection however, has some disadvantages, some of these disadvantages are:

- Reaction of injected water with the formation water can cause formation damage.
- Corrosion of surface and sub-surface equipment.

As part of water injection it is also common to find the water flooding technique. Water flooding consists of water Water is injected into the reservoir through injection wells. The water drives oil through the reservoir rocks towards the producing wells.

***Gas Injection***

It is the oldest of the fluid injection processes. This idea of using a gas for the purpose of maintaining reservoir pressure and restoring oil well productivity was suggested as early as 1864 just a few years after the Drake well was drilled. The first gas injection projects were designed to increase the immediate productivity and were more related to pressure maintenance rather to enhanced recovery. Recent gas injection applications, however, have been intended to increase the ultimate recovery and can be considered as enhanced recovery projects. In addition, gas because of its adverse viscosity ratio (higher mobility ratio) is inferior to water in recovering oil. Gas may offer economical advantages. Gas injection may be either a miscible or an immiscible displacement process. The characteristics of the oil and gas plus the temperature and pressure conditions of the injection will determine the type of process involved. The primary problems with gas injection in carbonate reservoirs are the high mobility of the displacing fluid and the wide variations of permeability. It is required a much greater control over the injection process than the one necessary with water-flooding. In order to evaluate the weep efficiency of the planned gas injection, a short-term pilot gas injection test should be driven. At the same time, this test would provide the necessary data to calculate the required volumes of gas; this in turn, will aid in the design of compressor equipment and estimating the number of injection well which will be required. The benefits obtained by the gas injection are dependent upon horizontal and vertical sweep efficiency of the injected gas. The sweep efficiency depends on the type of porosity system present.

***Limitations and disadvantages of Primary and Secondary Recovery Processes***

- Rapid decrease in reservoir pressure – leads to low oil production rates and oil recovery (5 – 10 % of original oil in place).
- Secondary recovery (water / gas injection) often does not yield a good recovery due to:
    - Reservoir heterogeneity
    - Unfavorable mobility ratio between oil and water
    - Water and gas coning problems
    - Low sweep efficiency

### 2.1.3 Tertiary (Enhanced) Oil Recovery

Is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits

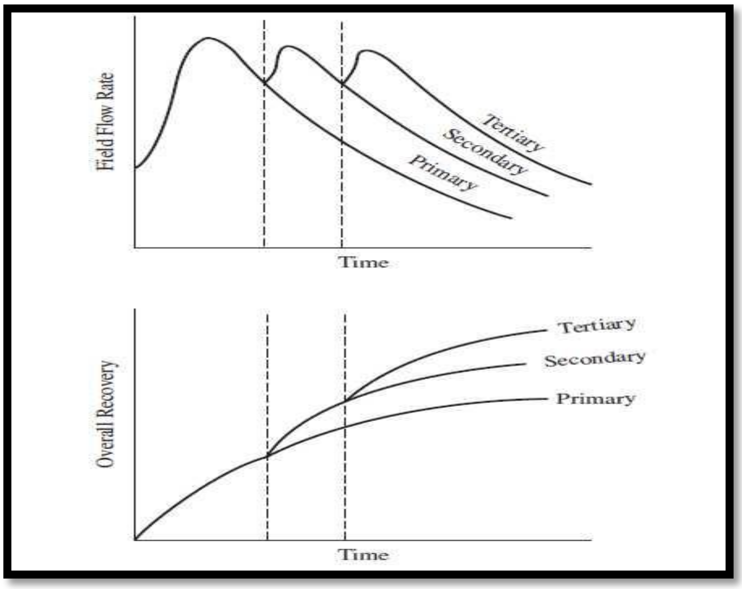



**Figure 2-1 : Oil Recovery Categories (Tarek Ahmed, 2010)**

During tertiary oil recovery, fluids different than just conventional water and immiscible gas are injected into the formation to effectively boost oil production. Thus EOR can be implemented as a tertiary process if it follows a waterflooding or an immiscible gas injection, or it may be a secondary process if it follows primary recovery directly. Nevertheless, many EOR recovery applications are implemented after waterflooding ( Lake, 1989; Lyons & Plisga, 2005; Satter et al., 2008; Sydansk & Romero-Zerón, 2011). At this point is important to establish the difference between EOR and Improved Oil Recovery (IOR) to avoid misunderstandings. The term Improved Oil Recovery (IOR) techniques refers to the application of any EOR operation or any other advanced oil-recovery technique that is implemented during any type of ongoing oil recovery process. Examples of IOR applications are any conformance improvement technique that is applied during primary, secondary, or tertiary oil recovery operations. Other examples of IOR applications are: hydraulic fracturing, scale-inhibition treatments, acid-stimulation procedures, infill drilling, and the use of horizontal wells.(JanezaTrdine)

***When to start EOR?***

A common procedure for determining the optimum time to start EOR process after waterflooding depends on:

- Anticipated oil recovery
- Fluid production rates
- Monetary investment
- Costs of water treatment and pumping equipment
- Costs of maintenance and operation of the water installation facilities
- Costs of drilling new injection wells or converting existing production wells into injectors.

## 2.1.4 Enhanced Oil Recovery definitions

Ronald .E (2001) states that " EOR is characterized by injection of special fluids such as: chemicals, miscible gases and /or the injection of thermal energy ".

Teknica (2001) states that " EOR Refers to any method used to recover more oil from a reservoir than would not be obtained by primary recovery ".
The injected fluids must accomplish several objectives as follows (Green & Willhite, 1998).

- Boost the natural energy in the reservoir
- Interact with the reservoir rock/oil system to create conditions favorable for residual oil recovery that include among others
- Reduction of the interfacial tension between the displacing fluid and oil
- Increase the capillary number
- Reduce capillary forces
- Increase the drive water viscosity
- Provide mobility-control
- Oil swelling
- Oil viscosity reduction
- Alteration of the reservoir rock wettability

The ultimate goal of EOR processes is to increase the overall oil displacement efficiency, which is a function of microscopic and macroscopic displacement efficiency. Microscopic efficiency refers to the displacement or mobilization of oil at the pore scale and measures the effectiveness of the displacing fluid in moving the oil at those places in the rock where the displacing fluid contacts the oil ( Green & Willhite, 1998 ). For instance, 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 ).

### 2.1.5 Enhanced Oil Recovery Classifications

Enhanced oil recovery processes include all methods that use external sources of energy and/or materials to recover oil that cannot be produced economically by conventional means.

EOR processes can be classified broadly as:

- Thermal methods: steam stimulation, steamflooding, hot water drive, and in-situ combustion.
- Chemical methods: polymer, surfactant, caustic, and micellar/ polymer.
- Miscible methods: hydrocarbon gas, CO, and nitrogen. In addition, flue gas and partial miscible/immiscible gas flood may be also considered.

EOR methods are presented in figure below **:-**

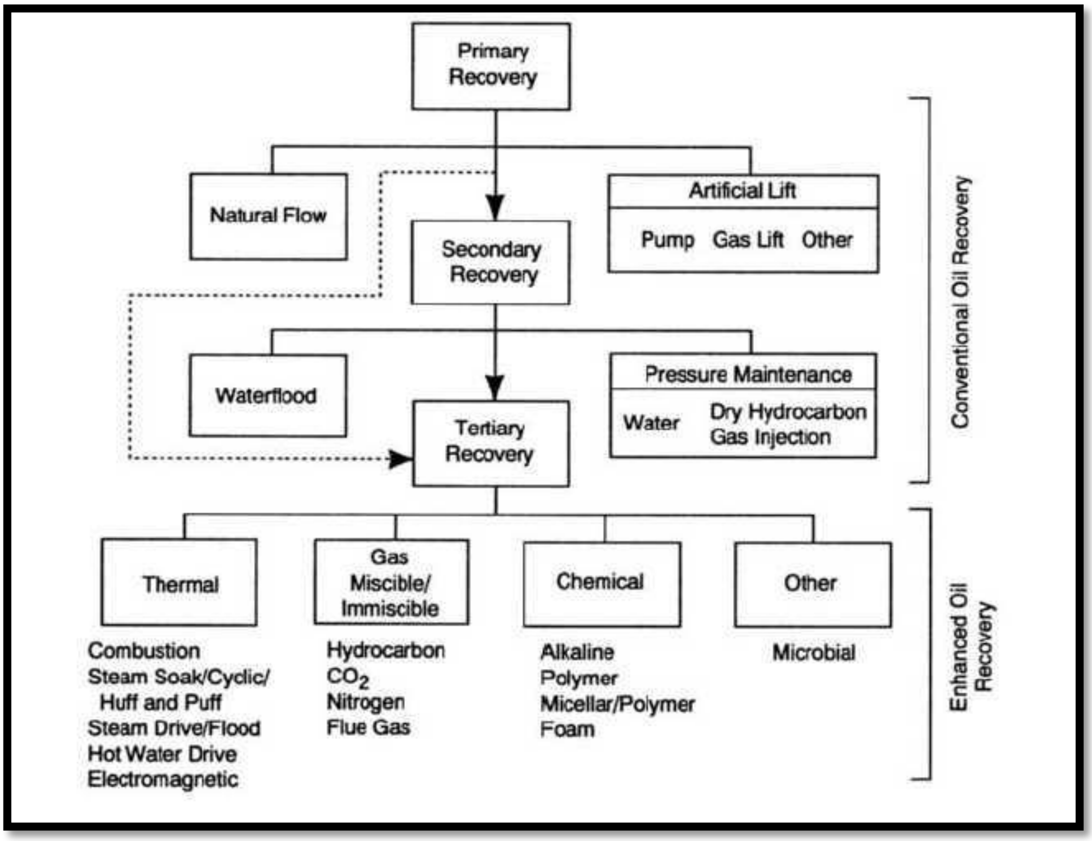



**Figure 2-2 : EOR Recovery Mechanisms (from OGJ (OGJ special,April) 199213)**

### 2.1.5.1 Thermal methods

Thermal methods have been tested since 1950's, and they are the most advanced among EOR methods, as far as field experience and technology are concerned. They are best suited for heavy oils (10-20° API) and tar sands (≤10° API). Thermal methods supply heat to the reservoir, and vaporize some of the oil. The major mechanisms include a large reduction in viscosity, and hence mobility ratio. Other mechanisms, such as rock and fluid expansion, compaction, steam distillation and visbreaking may also be present. Thermal methods have been highly successful in Canada, USA, Venezuela, Indonesia and other countries.

- **Cyclic Steam Stimulation (CSS)**

Cyclic steam stimulation is a "single well" process, and consists of three stages. In the initial stage, steam injection is continued for about a month. The well is then shut in for a few days for heat distribution, denoted by soak. Following that, the well is put on production. Oil rate increases quickly to a high rate, and stays at that level for a short time, and declines over several months.

Cycles are repeated when the oil rate becomes uneconomic. Steam-oil ratio is initially 1-2 or lower, and it increases as the number of cycles increase. Near-wellbore geology is important in CSS for heat distribution as well as capture of the mobilized oil. CSS is particularly attractive because it has quick payout, however, recovery factors are low (10-40% OIP). In a variation, CSS is applied under fracture pressure.

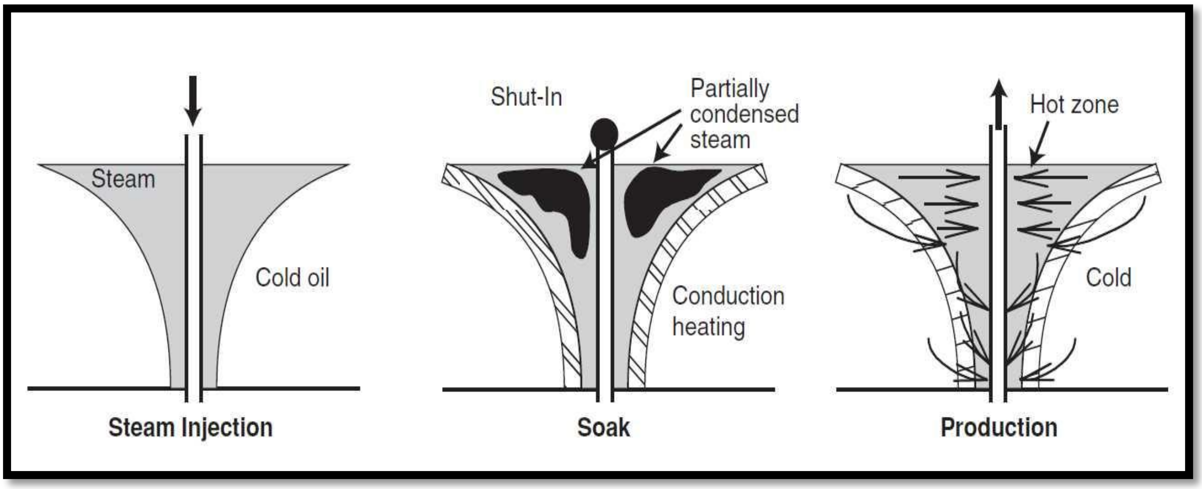



**Figure 2-3 : Cyclic Steam Stimulation (CSS) (S Thomas, 2008 )**

- **Steamflooding**

Steamflooding is a pattern drive, similar to waterflooding, and performance depends highly on pattern size and geology. Steam is injected continuously, and it forms a steam zone which advances slowly. Oil is mobilized due to viscosity reduction. Oil saturation in the swept zone can be as low as 10%. Typical recovery factors are in the range 50-60% OIP. Steam override and excessive heat loss can be problematic.

- **Steam Assisted Gravity Drainage (SAGD)**

SAGD was developed by Butler for the in situ recovery of the Alberta bitumen. The process relies on the gravity segregation of steam, utilizing a pair of parallel horizontal wells, placed 5 m apart (in the case of tar sands) in the same vertical plane. The top well is the steam injector, and the bottom well serves as the producer. Steam rises to the top of the formation, forming a steam chamber. High reduction in viscosity mobilizes the bitumen, which drains down by gravity and is captured by the producer placed near the bottom of the reservoir. High vertical permeability is crucial for the success of SAGD. The process performs better with bitumen and oils with low mobility, which is essential for the formation of a steam chamber, and not steam channels. SAGD has been more effective in Alberta than in California and Venezuela for the same reason.

SAGD is highly energy intensive. Large volumes of water are required for steam generation, and the natural gas consumption for steam generation ranges between 200- 500 tonnes/sm3 of bitumen. There had been several attempts to improve the economics of SAGD. Notable examples among SAGD variations are ES-SAGD, and SAGP.

- **In Situ Combustion**

In this method, also known as fire flooding, air or oxygen is injected to burn a portion (~10%) of the in-place oil to generate heat. Very high temperatures, in the range of 450-600°C, are generated in a narrow zone. High reduction in oil viscosity occurs near the combustion zone. The process has high thermal efficiency, since there is relatively small heat loss to the overburden or underburden, and no surface or wellbore heat loss. In some cases, additives such as water or a gas is used along with air, mainly to enhance heat recovery. Severe corrosion, toxic gas production and gravity override are common problems. In situ combustion has been tested in many places, however, very few projects have been economical and none has advanced to commercial scale.

The main variations of in situ combustion are:

- Forward combustion,
- Reverse combustion,
- High pressure air injection.

In forward combustion, ignition occurs near the injection well, and the hot zone moves in the direction of the air flow, whereas in reverse combustion, ignition occurs near the production well, and the heated zone moves in the direction counter to the air flow. Reverse combustion has not been successful in the field because of the consumption of oxygen in the air before it reaches the production well. High pressure air injection involves low temperature oxidation of the inplace oil. There is no ignition.

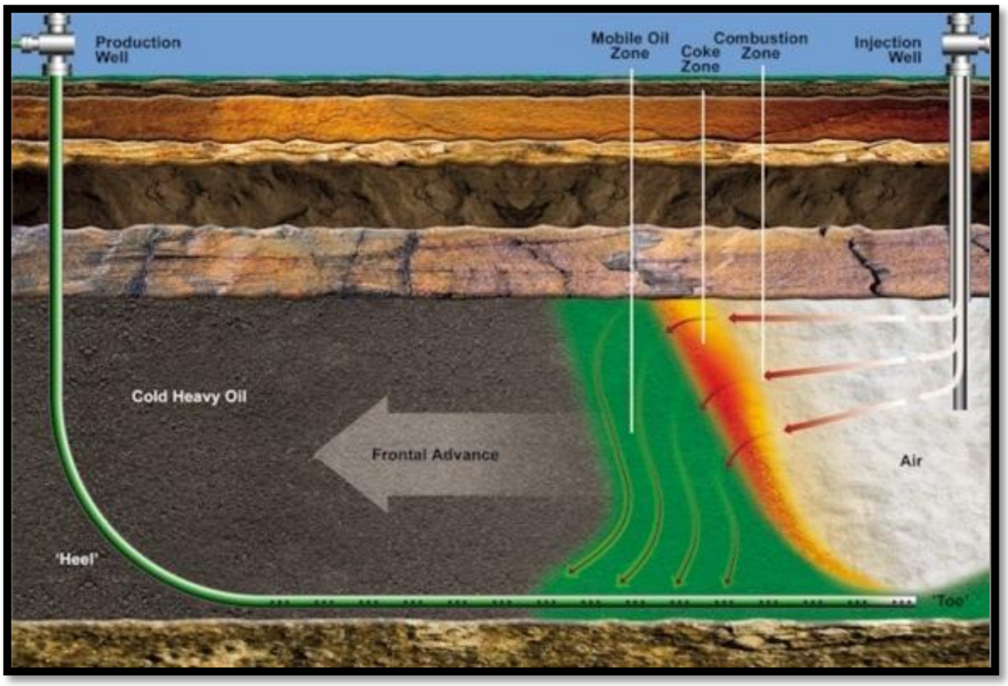



**Figure 2-4 : In Situ Combustion (Jelmert,T .et.all ,2010)**

### 2.1.5.2 Chemical Processes

The chemical processes refer to those processes in which additional non-natural components are added to the fluids in order to stimulate the mobility between the both the displacing and displaced fluid. These are water based EOR methods. Chemical flooding processes can be divided into three main categories:

- Surfactant flooding
- Polymer flooding
- Caustic flooding

In chemical flooding, a combination of Alkaline-Surfactant-Polymer (ASP) is injected into the reservoir. The polymer is used to improve the sweep efficiency of the invading fluid by changing the mobility ratio between the invading fluids vs. the displaced fluid. The surfactant is present to change the wet-ability of the formation rock if necessary and to reduce the interfacial tension. Caustic injected into the petroleum reservoir reacts chemically with the fatty acids present in the petroleum derivatives and form in-situ sodium salts of fatty acids. The formation of these surfactants results in ultra-low interfacial tension.

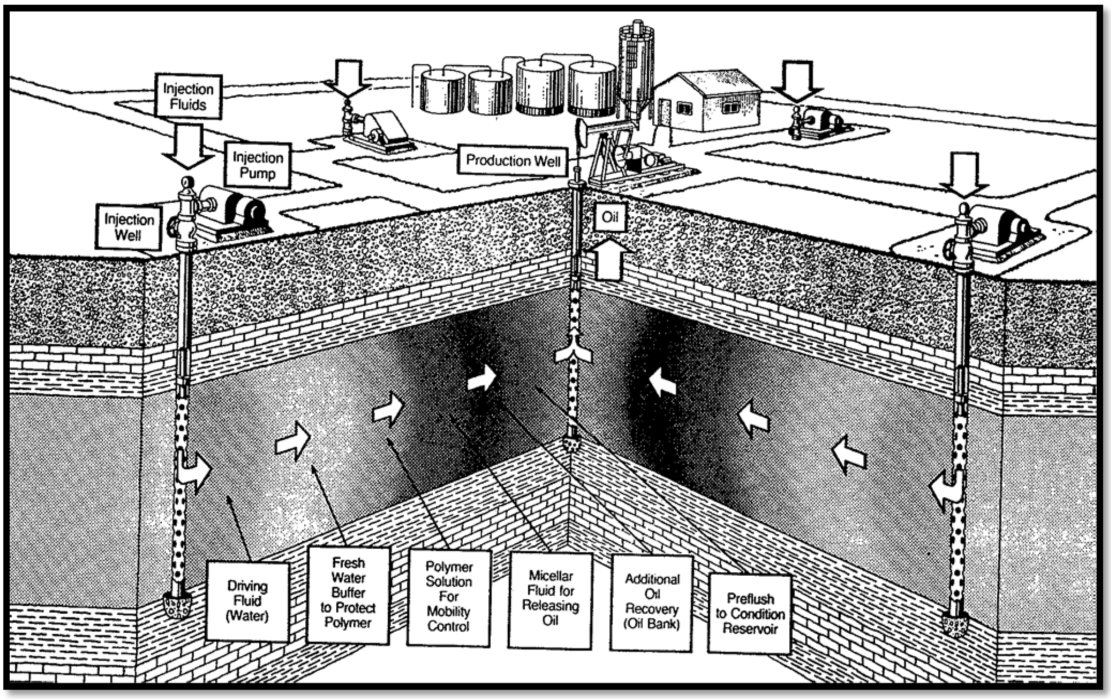



**Figure 2-5 : Surfactant/Polymer Flooding Process (U.S DOE,1979)**

Generally surfactant flooding is used in combination of polymer flooding which results in:

- Increase in the viscosity of water.
- Reduction in relative permeability to water.
- Polymer flooding will be favorable in reservoirs where oil viscosity is high, or in reservoirs that are heterogeneous, with the oil bearing layers at different permeabilities. Polymers have been extensively used in field applications in order to reach the following goals:
  - To improve mobility ratio and thus, to reach more favorable conditions for oil displacement.
  - To reduce effective permeability to the displacing fluid in highly permeable zones or to plug those zones.

- To improve the infectivity profile of the injecting wells and to improve the production performance of producers by plugging off high conductivity zones in the vicinity of a well

### 2.1.5.3 Miscible Flooding

Miscible flooding implies that the displacing fluid is miscible with the reservoir oil either at first contact (SCM) or after multiple contacts (MCM). A narrow transition zone (mixing zone) develops between the displacing fluid and the reservoir oil, inducing a piston-like displacement. The mixing zone and the solvent profile spread as the flood advances.

The various miscible flooding methods include:

- Miscible slug process.
- Enriched gas drive.
- Vaporizing gas drive.
- High pressure gas (CO2 or N2) injection.

***Miscible Slug Process***

It is an SCM (single contact miscible) type process, where a solvent, such as propane or pentane, is injected in a slug form (4-5% HCPV). The miscible slug is driven using a gas such as methane or nitrogen, or water. This method is applicable to sandstone, carbonate or reef-type reservoirs, but is best suited for reef-type reservoirs. Gravity segregation is the inherent problem in miscible flooding. Viscous instabilities can be dominant, and displacement efficiency can be poor.

Reef-type reservoirs can afford vertical gravity stabilized floods, which can give recoveries as high as 90% OOIP. Several such floods have been highly successful in Alberta, Canada. Availability of solvent and reservoir geology are the deciding factors in the feasibility of the process. Hydrate formation and asphaltene precipitation can be problematic.

***Enriched Gas Drive***

This is an MCM type process, and involves the continuous injection of a gas such as natural gas, flue gas or nitrogen, enriched with C2-C4 fractions. At moderately high pressures (8-12 MPa), these fractions condense into the reservoir oil and develop a transition zone. Miscibility is achieved after multiple contacts between the injected gas and the reservoir oil. Increase in oil phase volume and reduction in viscosity contrast can also be contributing mechanisms towards enhanced recovery. The process is limited to deep reservoirs (>6000 ft) because of the pressure requirement for miscibility.

***Vaporizing Gas Drive***

This also is an MCM type process, and involves the continuous injection of natural gas, flue gas or nitrogen under high pressure (10-15 Mpa). Under these conditions, the C2-C6 fractions are vaporized from the oil into the injected gas. A transition zone develops and miscibility is achieved after multiple contacts. A limiting condition is that the oil must have sufficiently high C2-C6 fractions to develop miscibility. Also, the injection pressure must be lower than the reservoir saturation pressure to allow vaporization of the fractions. Applicability is limited to reservoirs that can withstand high pressures.

***CO2 Miscible***

CO2 Miscible method has been gaining prominence in recent years, partly due to the possibility of CO2 sequestration. Apart from environmental objectives, CO2 is a unique displacing agent, because it has relatively low minimum miscibility pressures (MMP) with a wide range of crude oils.

CO2 extracts heavier fractions (C5-C30) from the reservoir oil and develops miscibility after multiple contacts. The process is applicable to light and medium light oils (>30° API) in shallow reservoirs at low temperatures. CO2 requirement is of the order of 500-1500 sm3/sm3 oil, depending on the reservoir and oil characteristics. Many injection schemes are in use for this method. Particularly notable among them is the WAG (Water Alternating Gas) process, were water and CO2 are alternated in small slugs, until the required CO2 slug size is reached (about 20% HCPV). This approach tends to reduce the viscous instabilities. Cost and availability and the necessary infrastructure of CO2 are therefore major factors in the feasibility of the process. Asphaltene precipitation can be a problem in some cases. Currently there are 80 CO2 floods in North America.

***N2 Miscible***

This process is similar to CO2 miscible process in principle and mechanisms involved to achieve miscibility, however, N2 has high MMP with most reservoir oils. This method is applicable to light and medium light oils (>30° API), in deep reservoirs with moderate temperatures. Cantarell N2 flood project in Mexico is the largest of its kind at present, and is currently producing about 500 000 B/D of incremental oil.

### 2.1.5.4 Microbial EOR Methods (MEOR)

The function of MEOR is same as that of chemical flooding except that in most cases chemicals produce in-situ (in reservoir) by microbes. MEOR processes generally consist of the injection of a microbial population with some form of nutrient (molasses, corn syrup etc.). Carbon source will either be sugar or crude oil.

The microorganisms feed on nutrients and produce a number of byproducts:

1) CO2 and other gases Essential nutrients.
2) Surfactants and/or polymers.
3) Alcohols.
4) Certain acids.

Presence of these products in-situ leads to:

i. Reduction of IFT (surfactants, alcohols, acids).
ii. Selective plugging of the most permeable zones.
iii. Reduction of oil viscosity.

***Limitations of MEOR***

Within the most important limitations are:

1. Increasing salinity absorbs water from the microbe and negatively affects its growth.
2. Permeability, temperature, pressure, salinity and pH affect the selection of microbes.
3. Study of bacteria metabolism, and relation to subsurface environment, need great effort.
4. Microbes Produce $H_2S$ and $SO_2$ causing bio-corrosion of the equipment, and contamination of ground water.

But on the other hand microbes produce organic chemicals less harmful than synthetic chemicals used by EOR methods.

***Economics of MEOR***

- Microbes and nutrients are relatively cheap materials.
- Cost is independent of oil prices.
- Implementation needs minor modifications to field facilities.
- Economically attractive for marginal producing wells.
- The total cost of incremental oil production from MEOR is only 2 – 3 $/bbl.

## 2.2 Literature Review

M.L. Mao in 2000 described an innovative system to measure continuously, from surface to downhole, the pressure, temperature, and spinner responses in these steam injectors. Compelling data is presented to evaluate wellbore heat loss, steam injection profiles, and reservoir properties. A unique wellbore heat-loss model applies the measured temperature data to quantify downhole steam quality. Steam injection profiles have been obtained by analyzing spinner data against perforation intervals. During the steam soaking period, downhole pressure and temperature fall-off behaviors have been observed. The analysis of pressure fall-off curves yields wellbore skin and reservoir permeability. (M.L. Mao 2000)

In 2011, Raj Deo et.all illustrated the successful design, implementation of cyclic steam stimulation pilot in heavy oil field of Sudan. CSS has been implemented in eight selected wells, Actual results are better than predicted in simulation studies Also they discussed improvement in oil production and its variation with formation and fluid characteristics, formation thickness , depth of formations , duration of injection and soaking periods along-with response variables like oil-steam ratio and steam/water production. Operational challenges in preventing the heat losses in annulus, lifting challenges and sand production are also discussed. (Raj Deo et.all 2011)

Eldias Anjar Perdana et.all in 2011 provided Case Study about CSS in two wells of Melibur field . Many experiences were conducted, one of them is the effect to offset well that indicates there is a connection and high heat conductivity between wells. Incremental of initial production rate about 40% occurred in first well. In second well, this operation gives an effect to offset well with the incremental of production rate reach 100% in nearest well. Based on characteristic of formation and oil, Melibur field it is suitable with steam flood method to enhance the oil recovery. Therefore, CSS pilot project is performed to study the impact of steam injection for incremental oil recovery. (Eldias Anjar Perdana et.all , 2011)

In 2014, Suranto AM, et.all discussed a paper aims to improve the CSS performance using modified well completion. The perforation is modified to become two parts, one part is on the top side (as injection) and the other part is on the bottom side (as production). The opening-closing of the injection-production cycle is managed by interval control valve (ICV).

Simulation results show that dividing the perforation into injection and production intervals will reduce CSOR 30% and this requires shorter soaking time compared to that of conventional processes. Furthermore, if the distance between injection and production interval is longer the production will be better. However, this gap is limited by reservoir thickness. (Suranto AM, et.all 2014 )

Husham and ELamin in 2014 provided a feasibility study from screening, design optimization as well as implementation of cyclic steam stimulation (CSS) in BBW 42 as first well in GNPOC in addition to various challenges and recommendations and the result show that the CSS can almost double the production from 280 BOPD up to 471 BOPD. (Husham and ELamin, 2014).

Many studies have been conducted to cycle steam simulation (CSS) process around the world including the design, well completions and implementation, also many graduation projects have been done in sudan to illustrates the design of CSS.

This thesis is focusing on evaluation of cycle steam simulation implementation, determination of the main problem and proposing a suitable solution to it as well as redesigning for a second cycle.

# Chapter Three : Methodology

## 3.1 Introduction

The Geological data, reservoir data and production data for bamboo oil field has been collected and used for analysis to identify the reason of high water cut and to do the simulation model for the cycle optimization and through the reading of Interpretation Report Of Pressure Decline Survey during Soaking For well BB-22, the Reservoir Properties ( i.e porosity, permeability, depth, initial formation pressure etc …) has been analyzed. Also the interval formation development, which has been known it concentrate on 1275~1280m and 1285~1291.8m

The analysis will be done through steps in order to identify the main reason of the problem, and then propose the suitable solution, which will be applied to do the simulation model for the new cycle optimization.

## 3.2 Analysis Steps of high water cut reason

1) Reading the Interpretation Report of Pressure Decline Survey during Soaking for Well BB-22.
2) Calculating the amount of steam for each zone, in actual and what was supposed to be ( i.e the design ).
3) Compare the actual calculations with the design calculations.
4) Analysis and then determine the reason of the problem (i.e of high water cut).
5) Suggestion for solution.

## 3.3 Computer Modeling Group

Abbreviated as CMG, is a software company that produces reservoir simulation programs for the oil and gas industry. It is based in Calgary, Alberta, Canada with branch offices in Houston, Dubai, Caracas and London. The company is traded on the Toronto Stock Exchange under the symbol CMG. The company offers three simulators, a black oil simulator, called IMEX, a compositional simulator called GEM and a thermal compositional simulator called STARS.

The company began in 1978 as an effort to develop a simulator by Khalid Aziz of the University of Calgary's Chemical Engineering department, with a research grant from the government of Alberta. A commercial product was being sold by the late 1980s. For the first 19 years of the company's history it was a non-profit entity. In 1997 it became a regular public company when it was listed on the TSX. The company now claims over 400 clients in 49 countries.

Today, CMG remains focused on the development and delivery of reservoir simulation technologies to assist oil and gas companies in determining reservoir capacities and maximizing potential recovery

## 3.4 CMG components

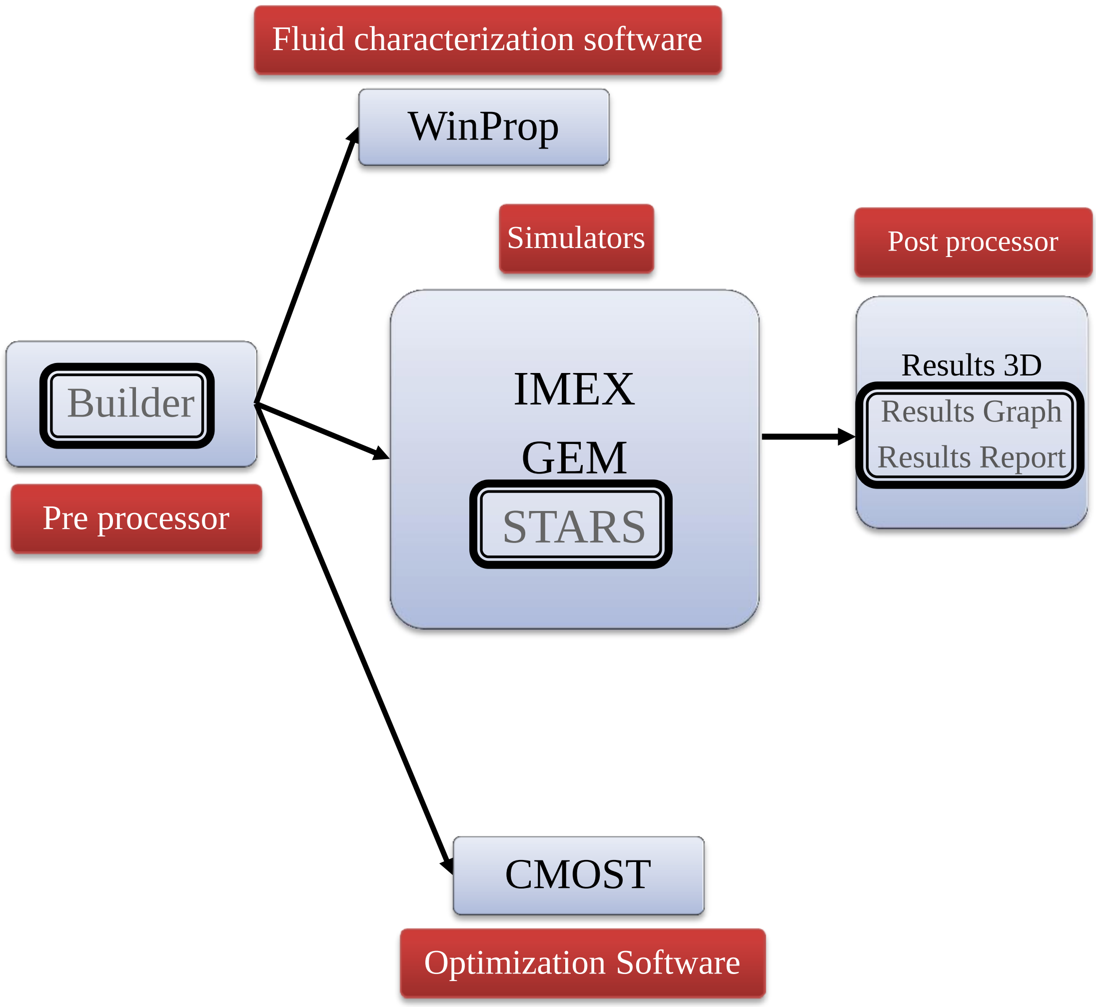



**Figure 3-1 : CMG Components**

### 3.4.1 Builder

Builder, a Windows-based application, helps engineers create input files for CMG reservoir simulators – IMEX, GEM, STARS. Through the use of 2D and 3D visualization, and efficient keyword input, Builder helps reservoir engineers realize immediate time savings by efficiently navigating them through the complex process of building reservoir simulation models. Builder simplifies the creation of simulator models by providing a framework for data integration and workflow management between CMG's reservoir simulators and the "outside world". Its intuitive interface and numerous process wizards make reservoir simulation accessible to all organizations, even those with limited modelling experience.

### 3.4.2 STARS -Thermal & Advanced Processes Reservoir Simulator

STARS is the undisputed industry standard in thermal and advanced processes reservoir simulation. STARS is a thermal, k-value (KV) compositional, chemical reaction and geomechanics reservoir simulator ideally suited for advanced modelling of recovery processes involving the injection of steam, solvents, air and chemicals. The robust reaction kinetics and geomechanics capabilities make it the most complete and flexible reservoir simulator available.

### 3.4.3 IMEX - Three-Phase, Black-Oil Reservoir Simulator

IMEX, one of the world's fastest conventional black oil reservoir simulators is used to obtain history-matches and forecasts of primary, secondary and enhanced or improved oil recovery processes. In addition, IMEX models production from conventional sandstone and carbonate reservoirs, including the effects of natural fractures and is widely used to model primary production of gas and liquids from hydraulically fractured shale and tight sand reservoirs.

### 3.4.4 GEM - Compositional & Unconventional Oil & Gas Reservoir Simulator

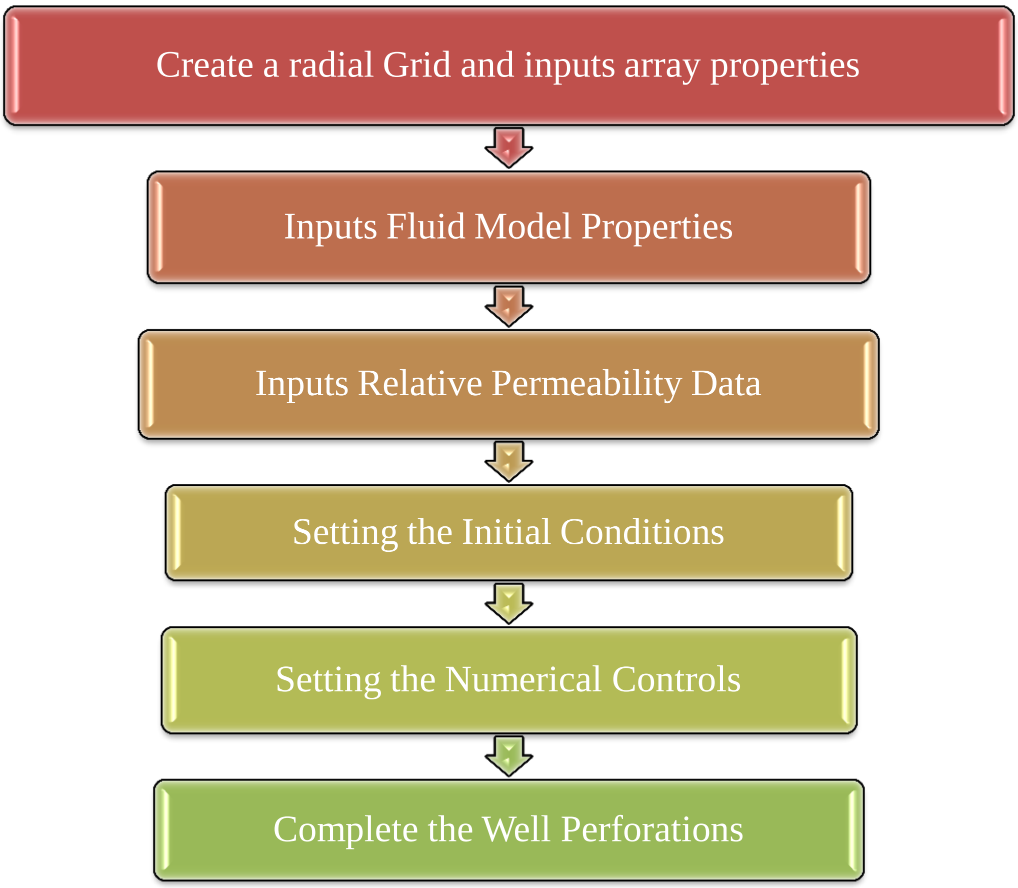
GEM is the world’s leading reservoir simulation software for compositional and unconventional modelling. GEM is an advanced general Equation-of-State (EOS) compositional simulator that models the flow of three-phase, multi-component fluids. GEM can model any type of recovery process where effective fluid composition is important.

### 3.4.5 RESULTS - Visualization & Analysis

Through industry-leading visualization capabilities, results allows engineers to enhance productivity, gain new understanding and insight into recovery processes and improve Net Present Value (NPV). Results, a set of post-processing applications, is designed to visualize and report CMG software – STARS, GEM, IMEX – input and output data into 2D aerial maps, 2D cross-sections, 3D perspectives, stereoscopic 3D formats and tabular reports. Results is comprised of three modules : Results 3D,Results Graph, and Results Report.

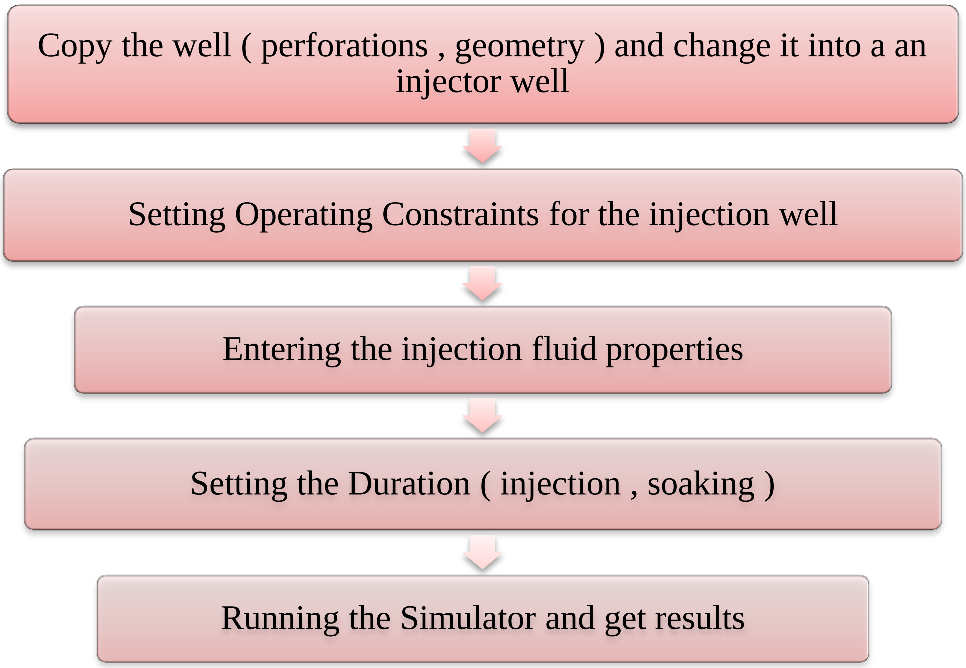
## 3.5 Building a Cyclic Steam Simulation Model in STARS

Flow chart below represent the steps of creating the numerical model through the use of CMG software.




**Flow Chart 3-1 : Steps of Building the Numerical Model**

Building the CSS will be by following the flow chart below :-




**Flow Chart 3-2 : Steps of Building Cyclic Steam Stimulation**

For cyclic steam injection, there must be an injection well and production well located in the same location. From the wells menu select “Copy well”. Select “producer”. Click next as shown in the figure below.

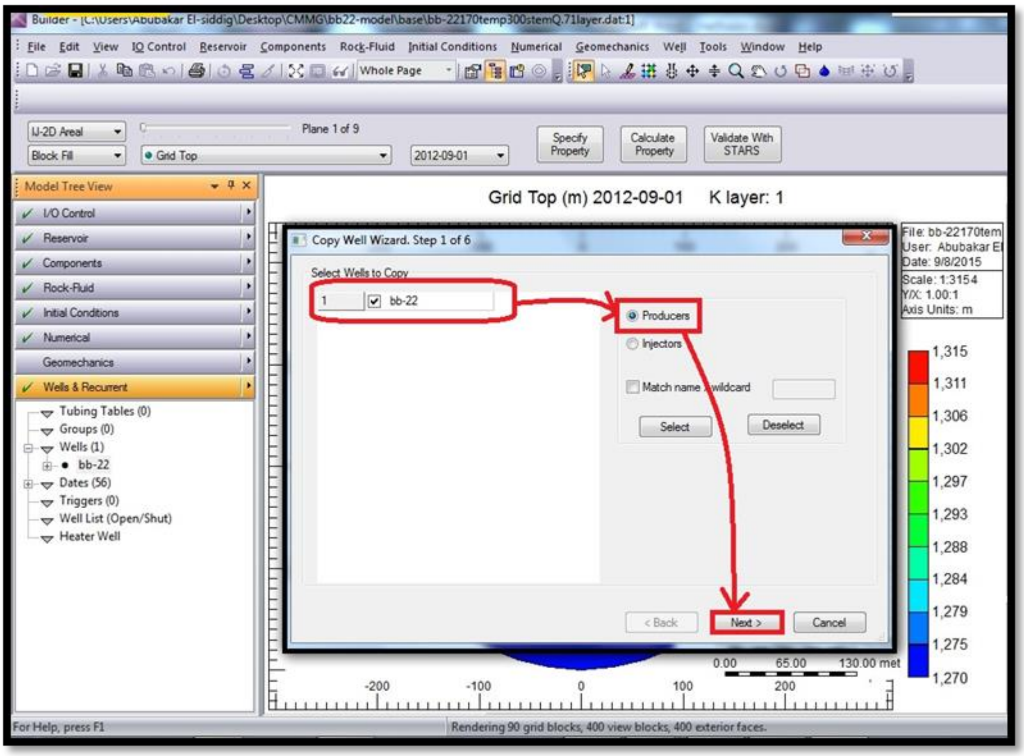



**Figure 3-2 : Copying the well**

and make sure "Copy all perforations" is selected. Click next as shown in the figure below.

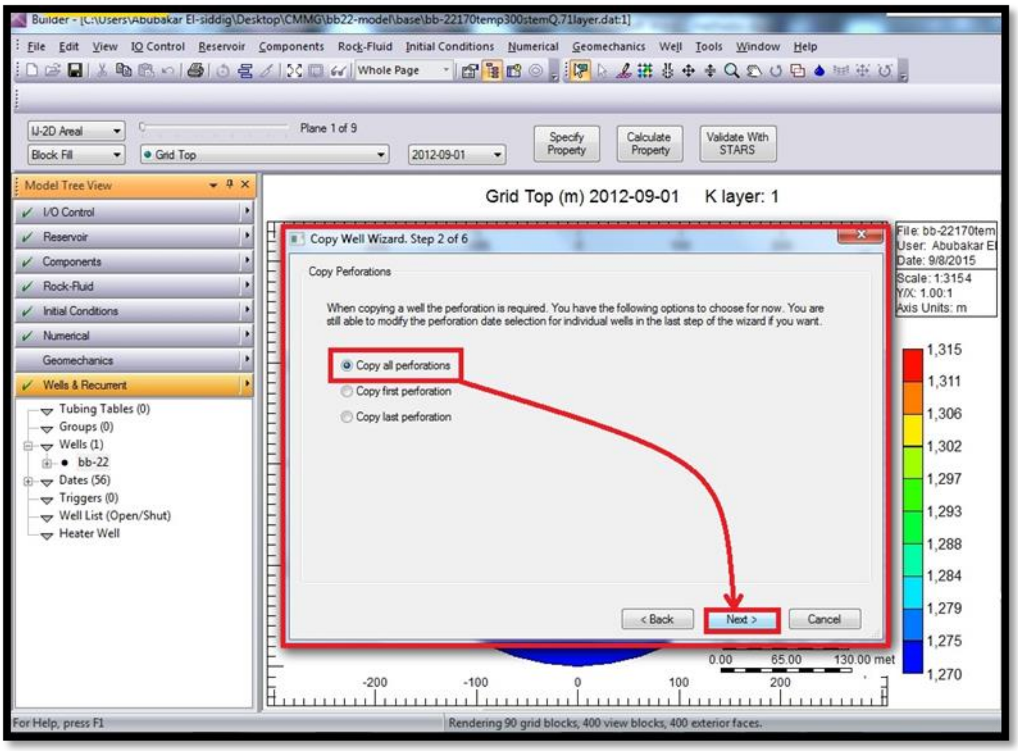



**Figure 3-3 : Copying the Perforations**

Check the "Copy Geometry" option and click next as shown in below.

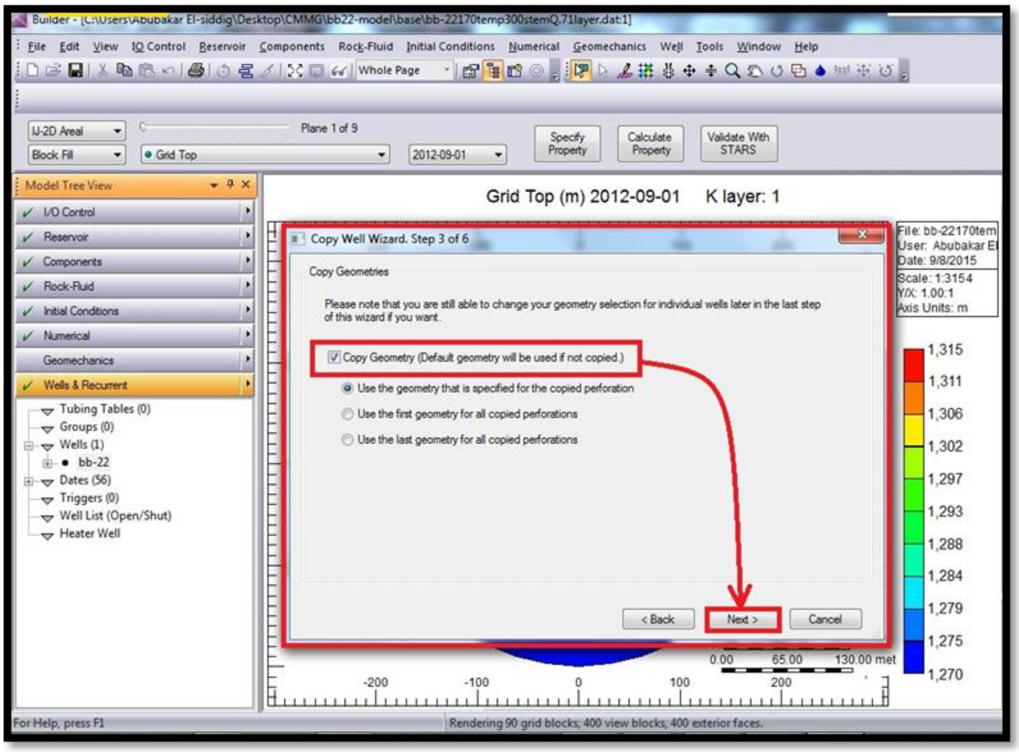



**Figure 3-4 : Copying the Geometry**

Select the option “I will manually enter the new well name on the next step”. Then click next as shown below.

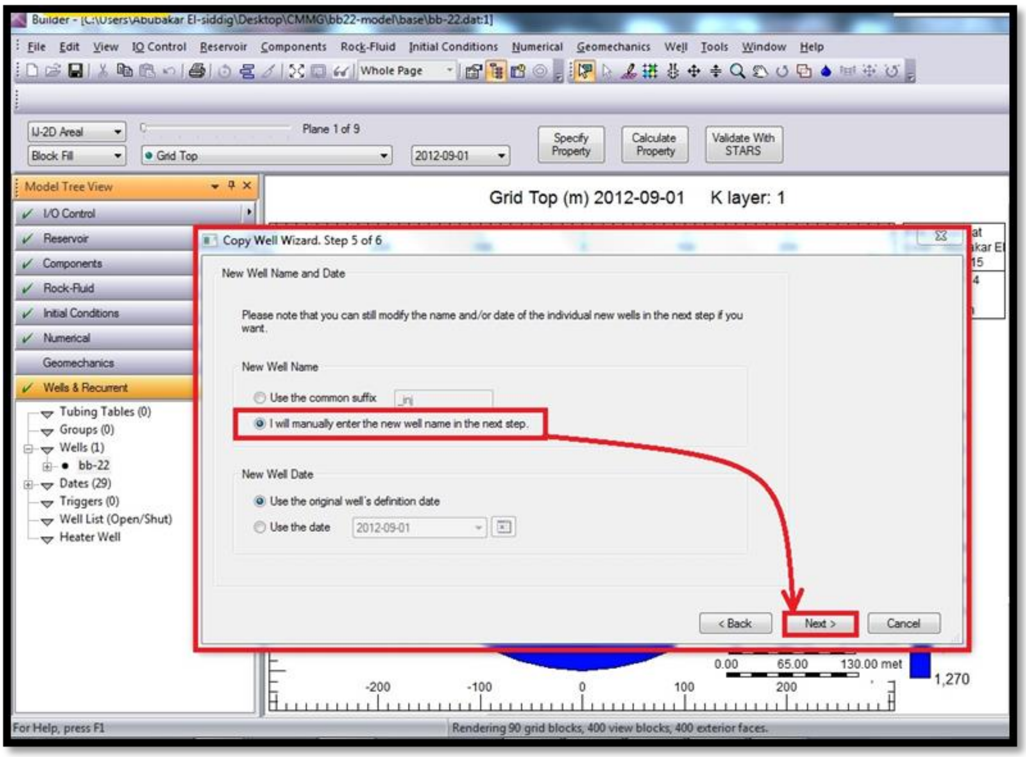



**Figure 3-5 : Entering the Injection Well Name - 1**

Enter the name " bb-22 inj " in the well name as shown below and click finish.

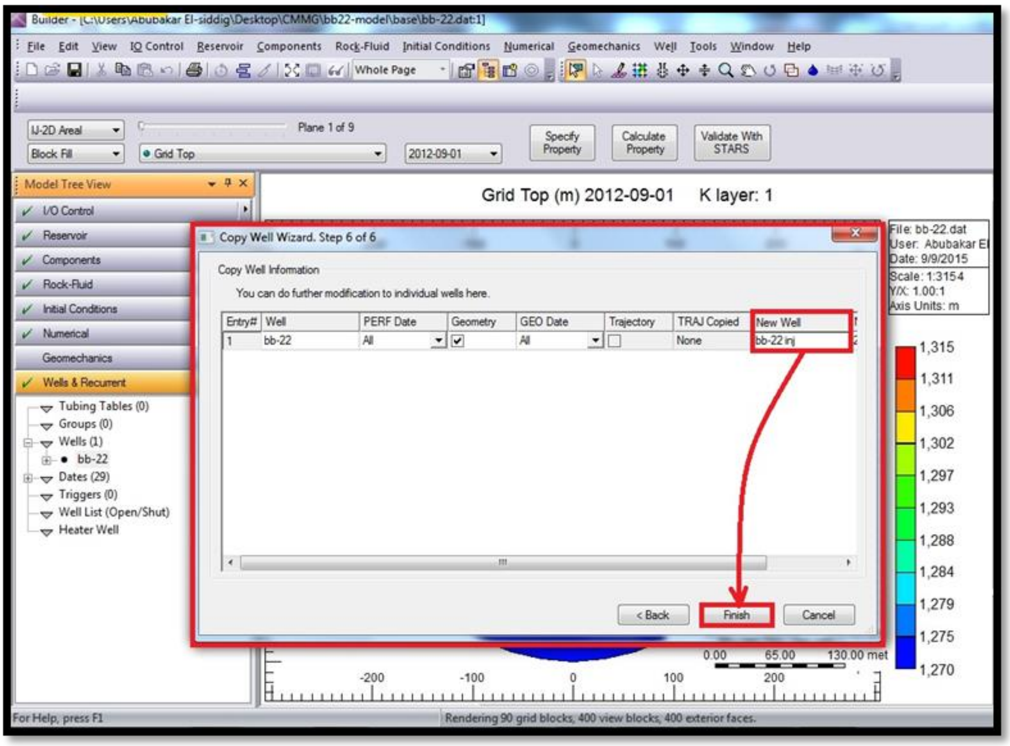



**Figure 3-6 : Entering the Injection Well Name - 2**

After that, by double clicking on the " bb-22 inj " from the " wells & recurrent " in the " Model tree view ", we can change the well type into an injection well. As shown in figure below.

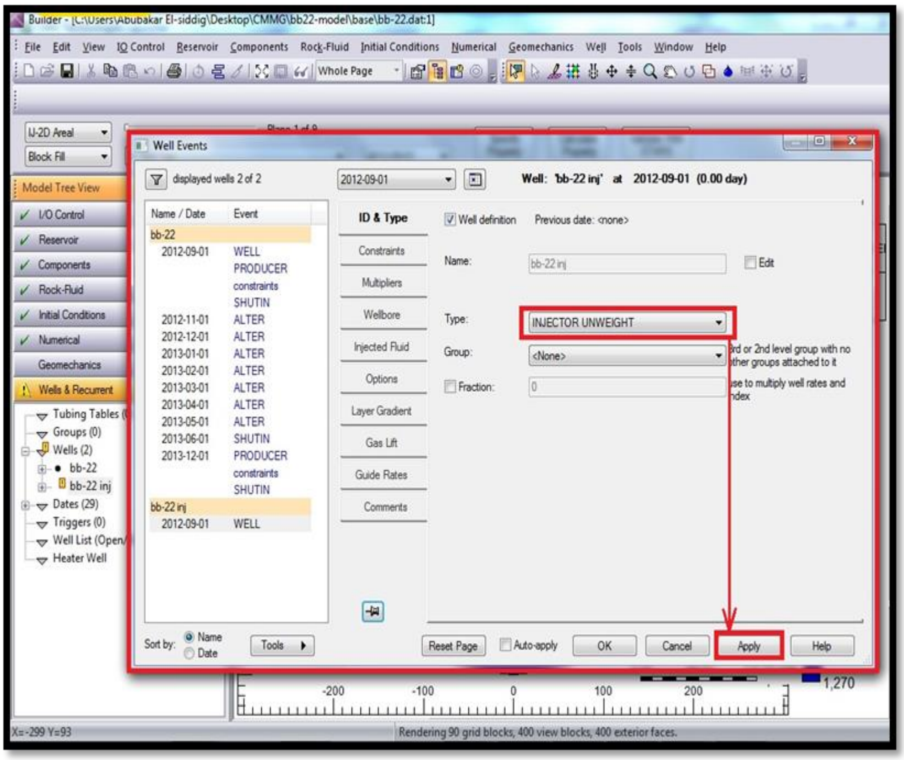



**Figure 3-7 : Changing the Well Type into an Injector Well**

Then setting the constraints for the injection well as shown in figure below

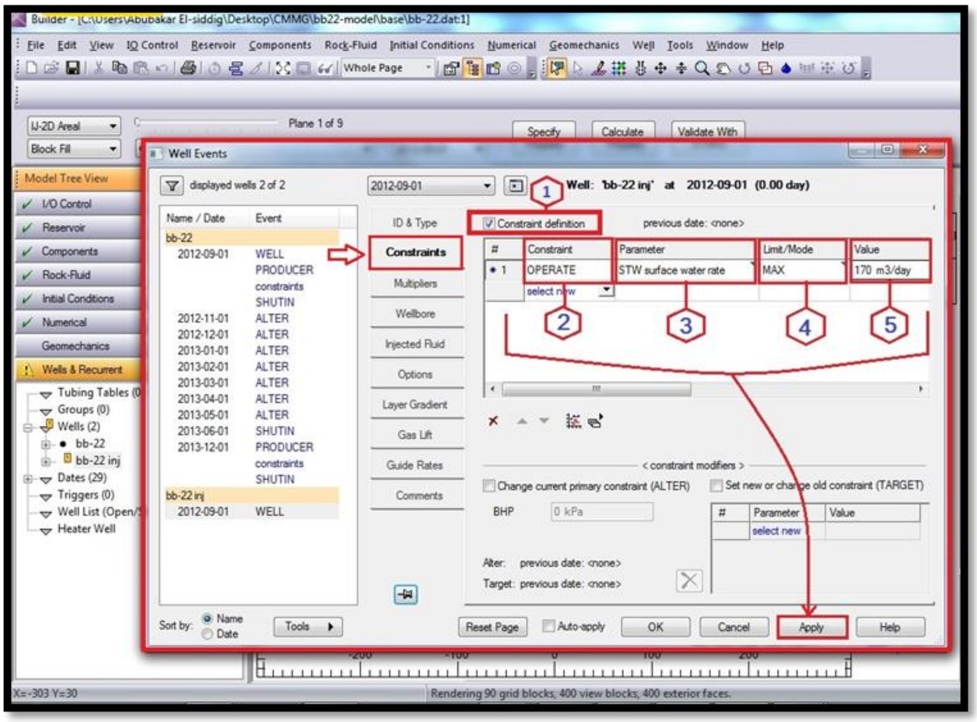



**Figure 3-8 : Adjusting the Constraints for the Injection Well**

Then entering the injection fluid properties as shown in figure below.

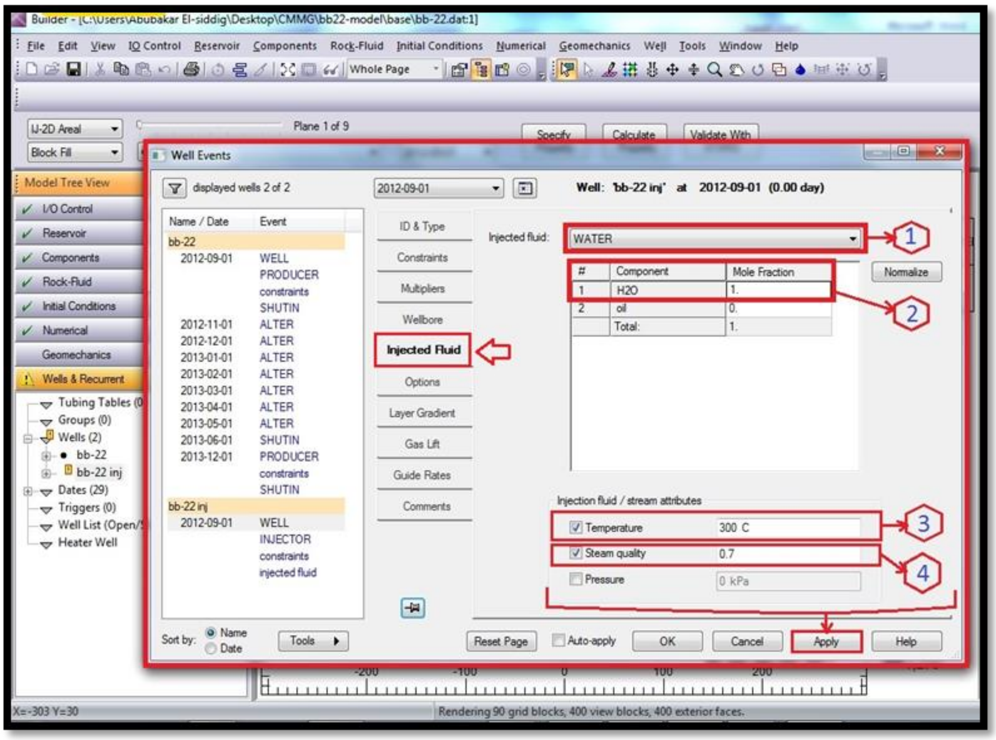


**Figure 3-9 : Entering the Injection Fluid Properties**

Figures ( 3-10 , 3-11 ) below are illustrating how the duration of injection and soaking can be set, which is important in CSS to identify when the well is in shut in and when it is producing.

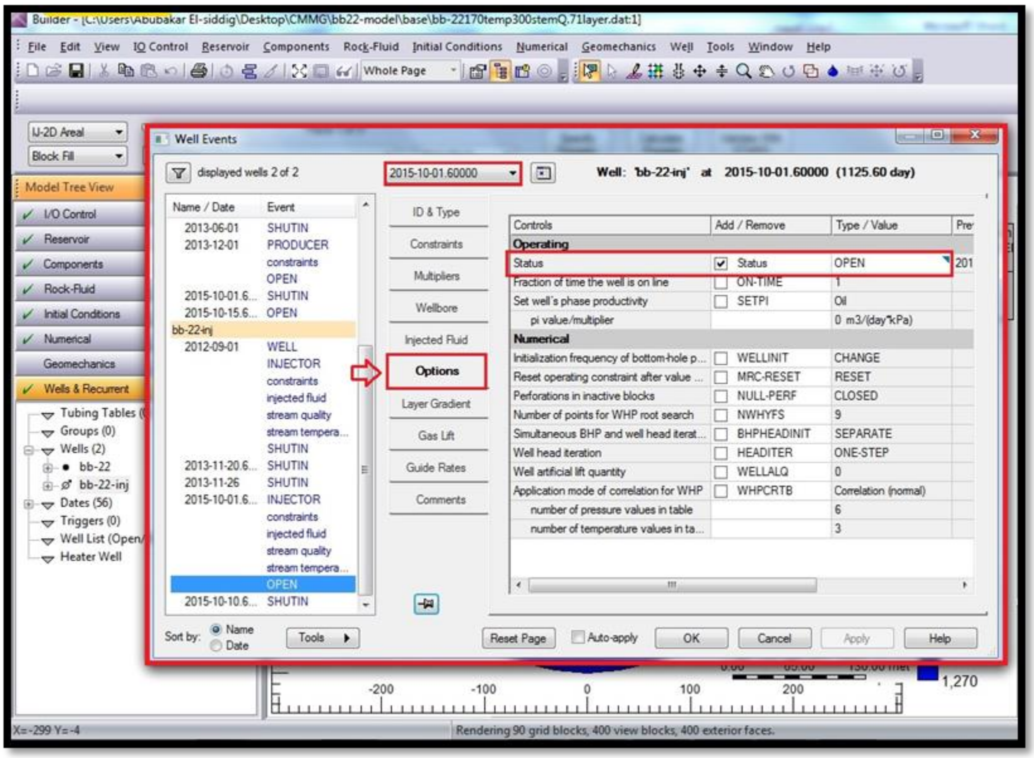


**Figure 3-10 : Operating Status ( Open Case )**

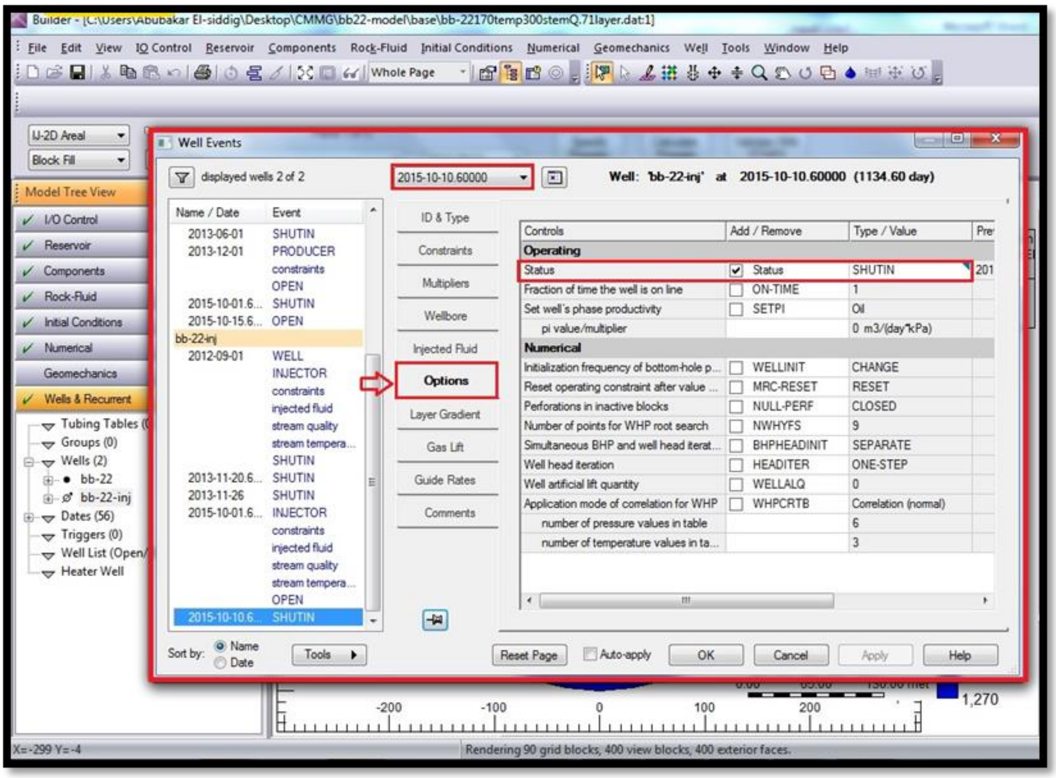


Figure 3-11 : Operating Status ( Shut in Case )

# Chapter Four : Results and Discussion

## 4.1 Introduction

Bamboo Main oil field lies in block 2/4, Muglad Basin in southern part of Sudan. Well BB-22 was spud on 13 February 2012 and rig was released on 8 November 2012. It had put into a cold production from October 2012. After that, well BB-22 was designed for Cyclic Steam Stimulation.

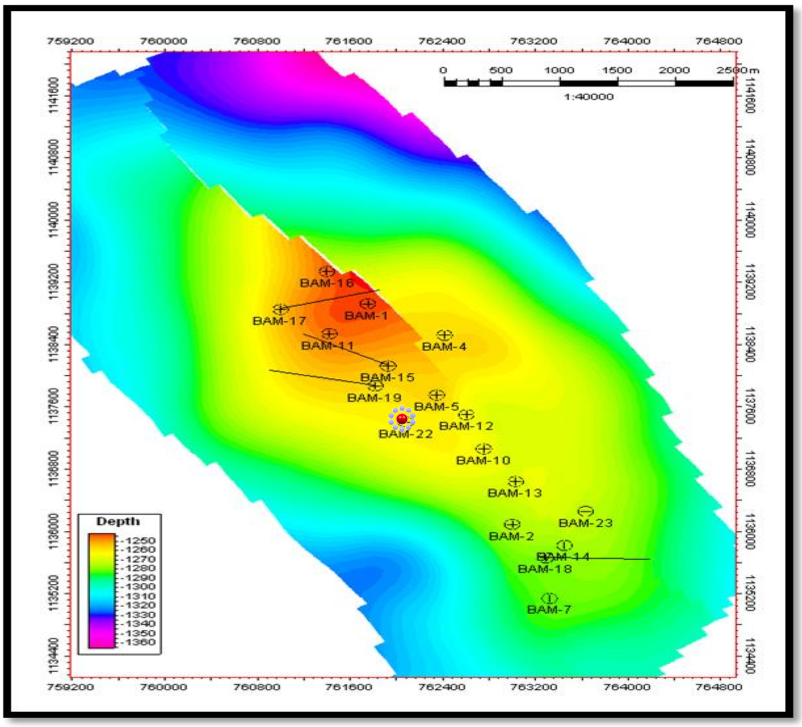



Figure 4-1 : Well BB-22 Location Map ( OEPA 2015 )

The cumulative oil production is 41Mbbl until September 2013, with composite water cut under 21%. The average oil production of CHOPS is stable at 120bbl/d. See Figure 4-2)

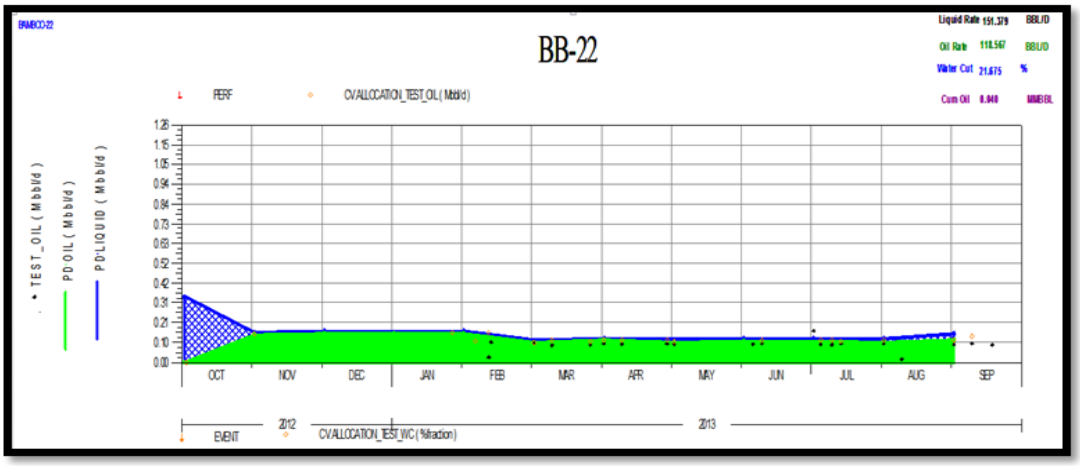



Figure 4-2 : CHOPS History for Well BB-22

## 4.2 Information of Current Perforation

From the information of perforation and interpreted result in table (4-1) and figure (4-3), it shows that pay formation development concentrate on 1275~1280m and 1285~1291.8m, porosity of B-1b is larger than that of B-1a. Although only upper interval (1283~1286m) was perforated, the lower interval (1286~1291.8m) can still absorb steam because they are developed in one connecting oil layer.

**Table 4-1 : Well BB-22 Perforation Interval**

| Formation | Zone No. | Net reservoir | | | | | Net pay | Result |
|---|---|---|---|---|---|---|---|---|
| | | Top | Bottom | Thick | Phie | $S_w$ | Net Pay thick | |
| | | (m) | (m) | (m) | % | % | (m) | |
| Bentiu | 1a | 1274 | 1280 | 6 | 24.8 | 50.6 | 4.12 | oil |
| Bentiu | 1b | 1283 | 1286 | 3 | 26.4 | 37.4 | 1.87 | oil |
| Total | | | | 9 | | | 5.99 | 2 zones |

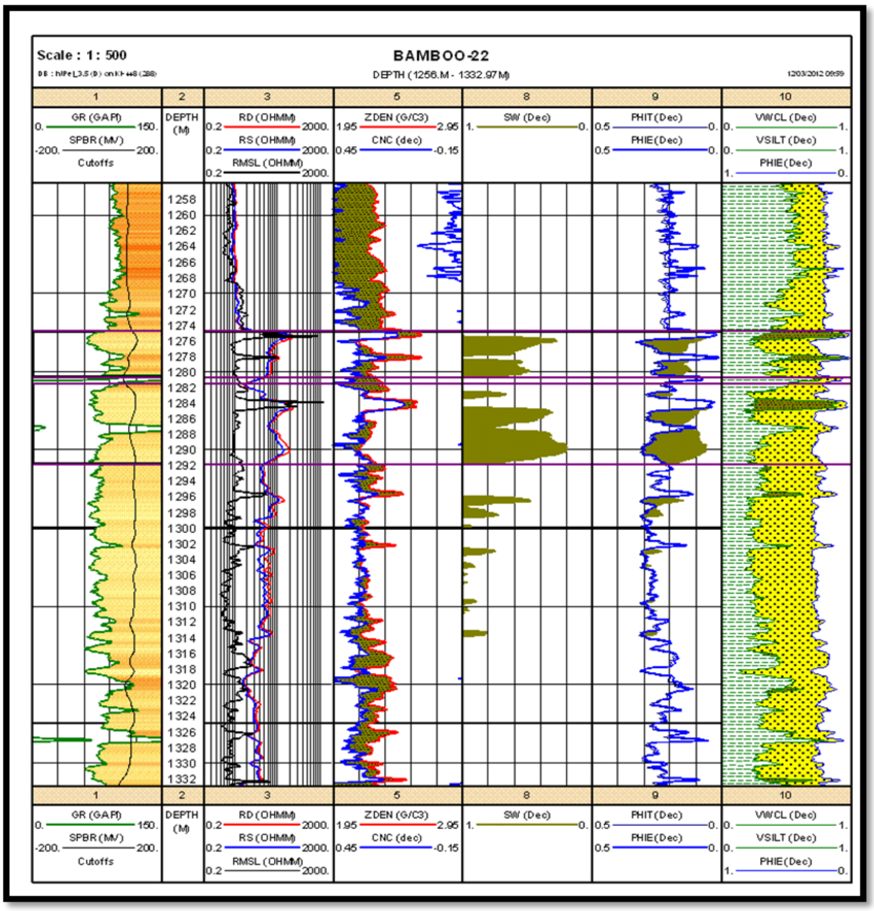



**Figure 4-3 : Well BB-22 Interpreted Results at 1256~1332 mKB**

## 4.3 Analysis of high water cut

In this analysis we are going to calculate the amount of steam for each zone in actual and what was supposed to be (i.e the design) and then compare the actual calculations with the assumed calculations and find out what is the reason of high water cut.

❖ **Assumed design calculations :-**

Depending on this relation below

$$\text{The total Volume (ton)} = \text{Steam Intensity (t/m)} * \text{Thickness (m)}$$

- For zone B-1a ( thickness = 6m )

The amount of steam that to be absorbed by zone B-1a is

$$= 6 * 160 = 960 \text{ m}^3$$

- For zone B-1b ( thickness = 3m )

The amount of steam that to be absorbed by zone B-1b is

$$= 3 * 160 = 480 \text{ m}^3$$

❖ **Actual calculations :-**

According to the steam absorption percentage, which is obtained from the given data.

Zone B-1a = 43.8%

Zone B-1b =5 6.2%

- For zone B-1a ( thickness = 6m )

  The amount of steam had been absorbed by zone B-1a is equal to

  $$= 1440 * 0.438 = 630.72 \text{ m}^3$$

- For zone B-1b ( thickness = 3m )

  The amount of steam that had been absorbed by zone B-1b is equal to

  $$= 1440 * 0.562 = 809.28 \text{ m}^3$$

❖ **The comparison between the actual and designed**

From the calculations we see that layer B-1a get 630.72 $m^3$ when it was supposed to be 960 $m^3$ and that is not considered problem but when we come to layer B-1b we see that the layer get 809.28 $m^3$ when it was supposed to be 480 $m^3$ .

It is clearly that layer B-1b get nearly twice the assumed amount of steam and this large amount of water result in water channeling and that why the well had high water cut.

## 4.4 Simulating using CMG

Figure A - 1 shows the general shape of the CMG software and the radial model of cyclic steam stimulation for well BB-22.

- **Rock Properties**

Click on the " Specify Property " button (top middle of screen) to open the General Property Specification spreadsheet as shown below in Figure A - 2 and enter the data of top grid, grid thickness, permeability ( i,j,k ), net pay and oil saturation.

- **Relative Permeability**

Click the Rock-Fluid tab in the tree view which located on the left side of the screen. Double click on Rock Fluid Types in the tree view. A window will open. Click on the button  and select New Rock Type, then entering the relative permeability table as shown in Figure A - 3.

- **The Initial conditions of the reservoir**

Click the Initial conditions on the tree view of Builder. Double click on Initial Conditions. Then typing the values for reference pressure, reference depth and for water-oil contact as shown in Figure A - 4.

- **Injected fluid properties**

Click on the "Well & Recurrent" on the tree view of Builder. And clicking on the "Wells", where there is two wells .Double clicking on the " bb-22-inj " and then go to "Injected fluid" and choosing Water as injection fluid. Enter the water composition as 1.0 for component Water. Enter the steam Temperature and steam quality as in Figure A - 5.

Figure A - 6 represent the time - line view of recurrent data. Firstly the injector was identified, but it was closed at that time and it was not used in the simulation process. Secondly the injector was used in the cycle done by the company (simulation for two zone). Thirdly the injector used in the simulation of the new cycle (simulation for one zone).

Figure A - 7 shows the perforations before modification. Deleting the second layer will by clicking the bottom **X** in the left hand of the window.

Figure A - 8) shows the perforation after second layer has been deleted. This as a solution to the high water cut problem (removing the layer that contain high amount of water).

## 4.5 Steam Injection Parameters

### 4.5.1 Optimization of Steam Injection Rate

In the condition of steam quality at well bottom is 50% and soaking time is 5 days. Studying the effect of different steam injection rates have been done, and results are shown on the next figures.

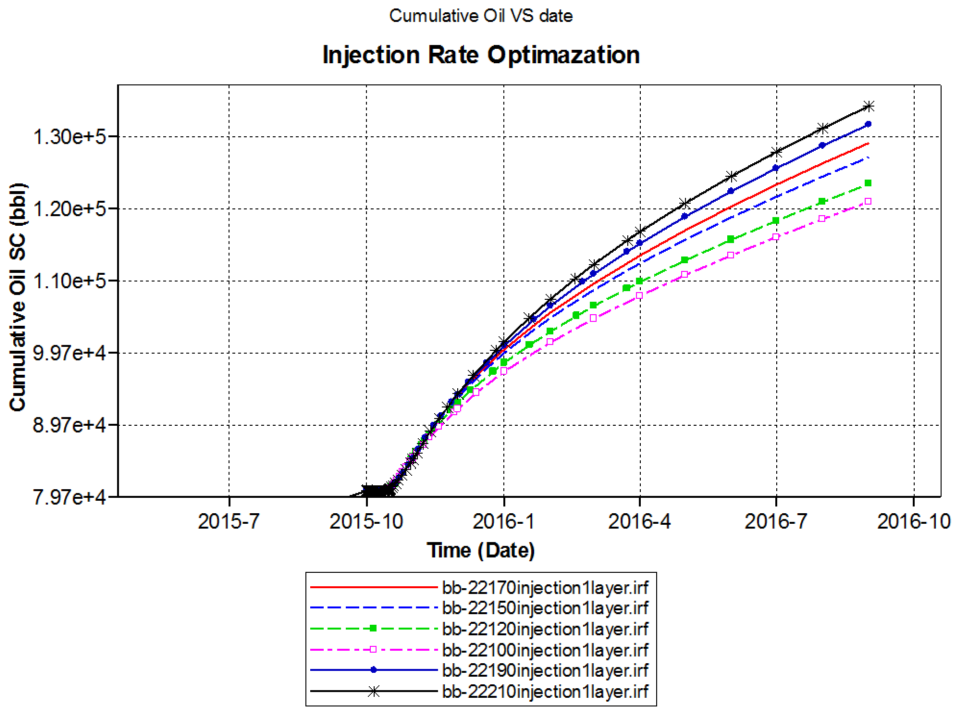



**Figure 4-4 : Effect of Alternating Injection Rates on Cumulative Oil Production**

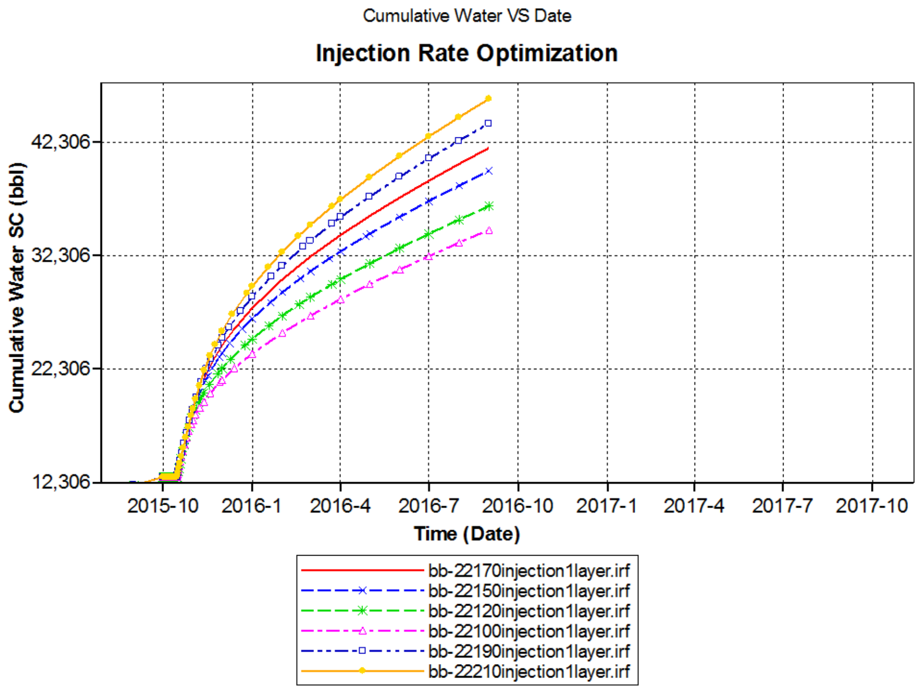



**Figure 4-5 : Effect of Alternating Injection Rates on Cumulative Water**

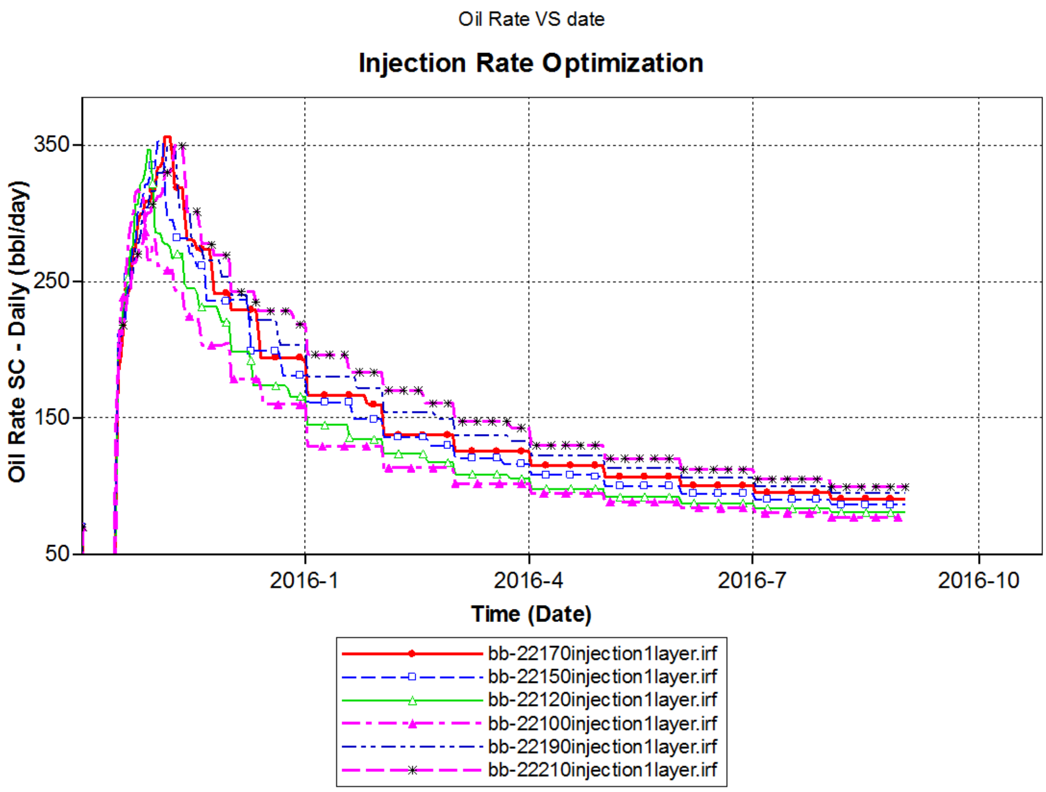



**Figure 4-6 : Effect of Alternating Injection Rates on Oil Rate**

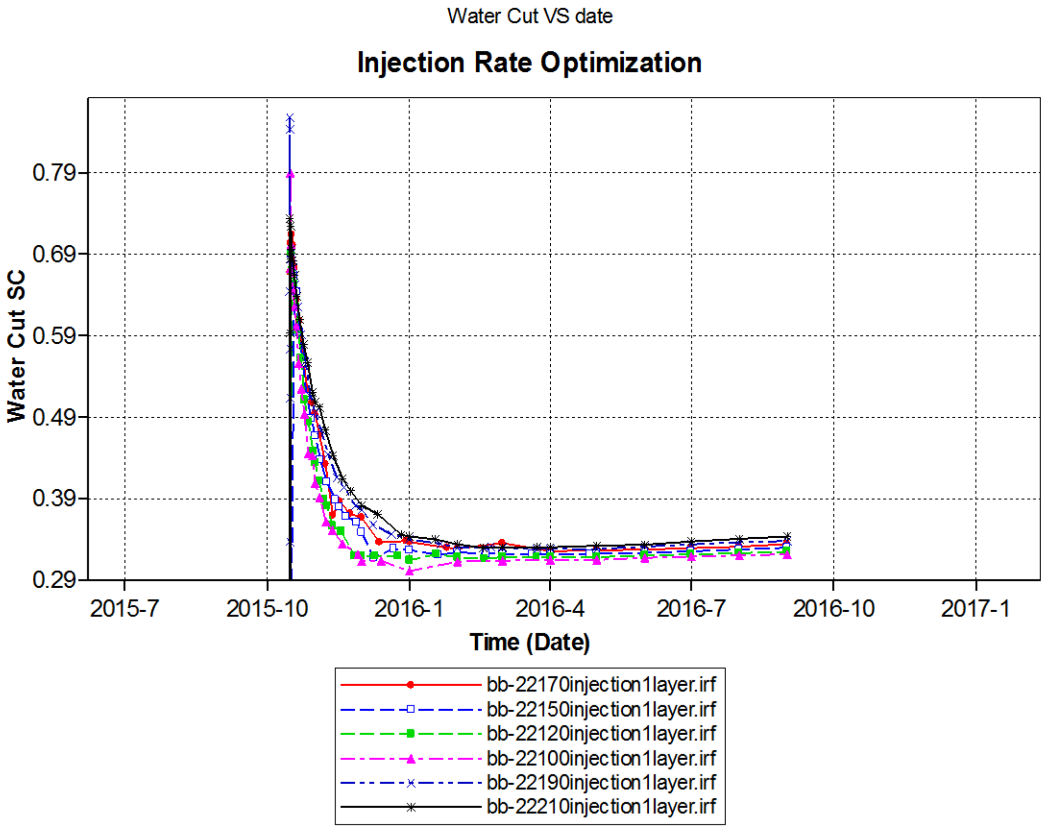



**Figure 4-7 : Effect of Alternating Injection Rates on Water Cut**

**Table 4-2 : Different Steam Injection Rates Scenarios**

| Steam injection rate (t/d) | Cumulative Oil Production (bbl)) | Cumulated water(bbl) | Oil rate per Cycle (bbl) | W.C % |
|---|---|---|---|---|
| 100 | 120625 | 34567.9 | 77.7453 | 32.1994 |
| 120 | 123089 | 36660 | 81.0245 | 32.5223 |
| 150 | 126791 | 39779.2 | 86.6989 | 33.0174 |
| 170 | 128764 | 41776.2 | 91.0279 | 33.4581 |
| 190 | 131330 | 43935.1 | 95.7029 | 33.8387 |
| 210 | 133884 | 46092.3 | 99.7881 | 34.3904 |

Figures (4-4,4-5,4-6,4-7) illustrates the results as a graph result for each run that have been done, and shows that when the injection rate increase the cumulative oil increase, also the cumulative water increase.

Also when the injection rate increase, the oil rate increase. The production rate of hot fluids starts higher than that of the primary cold production. However, the rate declines with time as heat is removed with produced fluids.

Water cut increase suddenly after opening the well, and then it decrease with time to reach an average of 33 %.

Although 210 t/d is better, but **190** t/d is chosen because the available boilers in sudan doesn't give that injection rate. See Table 4-2.

### 4.5.2 Optimization of Steam Temperature

Steam temperature is important factor on the cyclic steam stimulation process, which is affecting on the viscosity of the crude oil. As the temperature increase, the viscosity decreased, and so the mobility of oil increased .Thus the amount of oil that can be produced will increase.

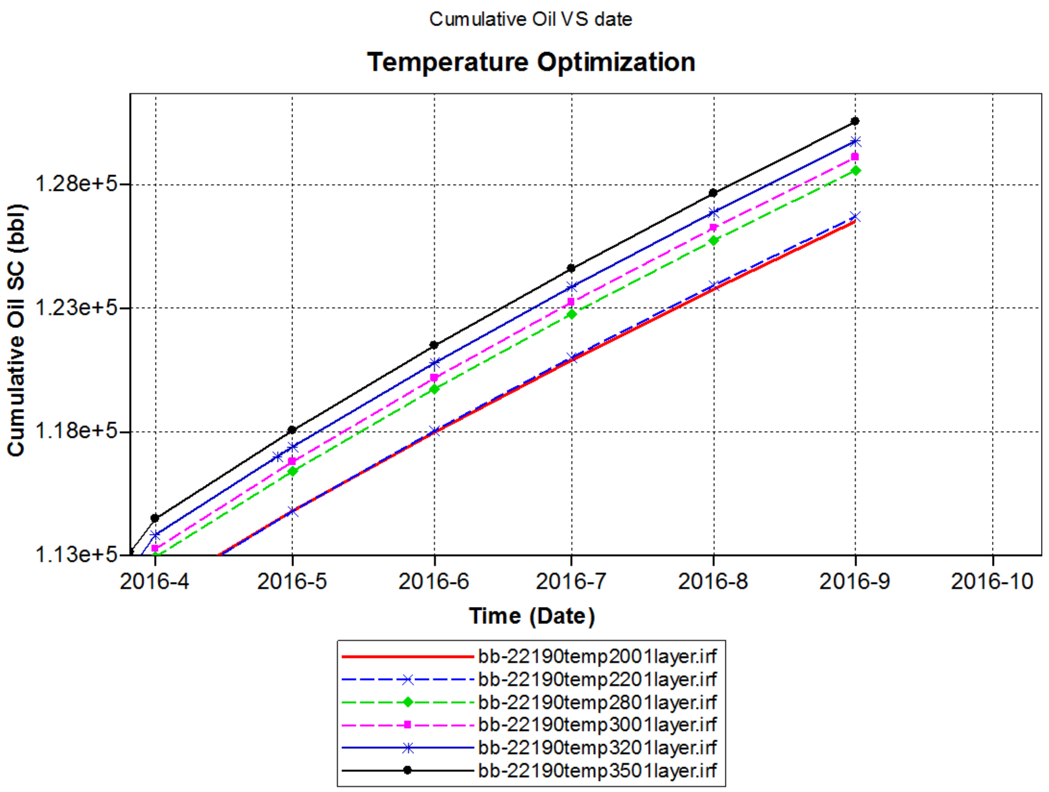



**Figure 4-8 : Effect of Changing Steam Temperature on Cumulative Oil**

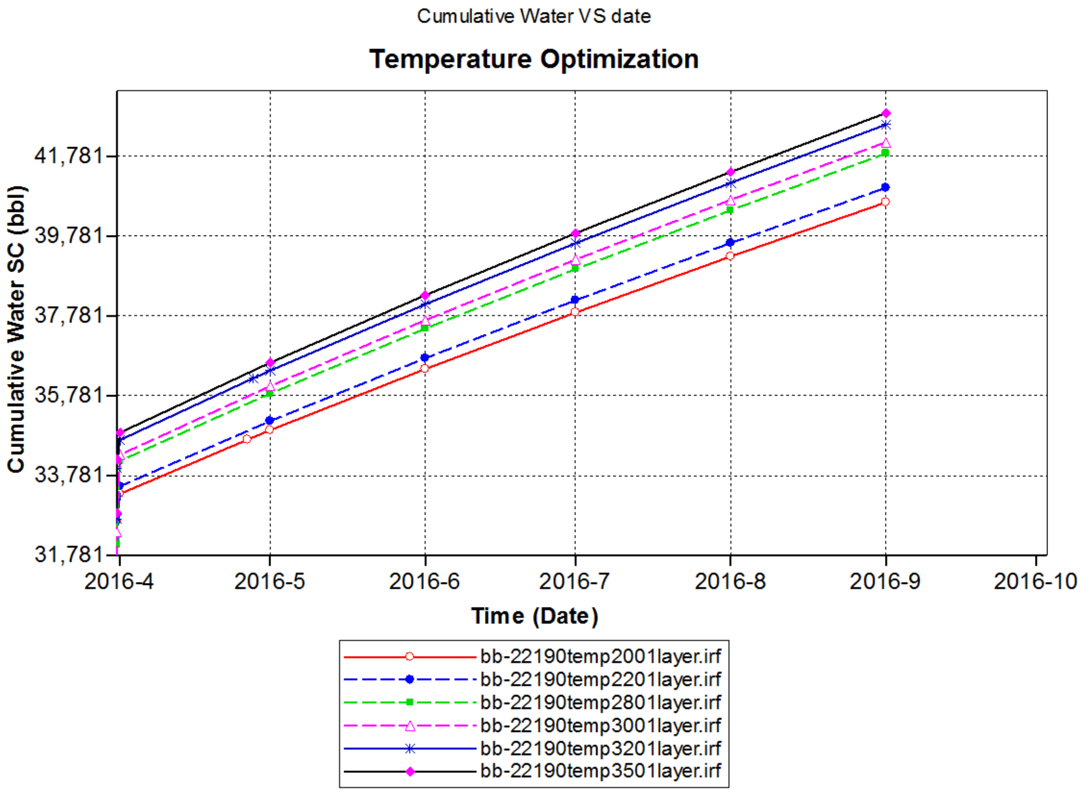



**Figure 4-9 : Effect of Changing Steam Temperature on Cumulative Water**

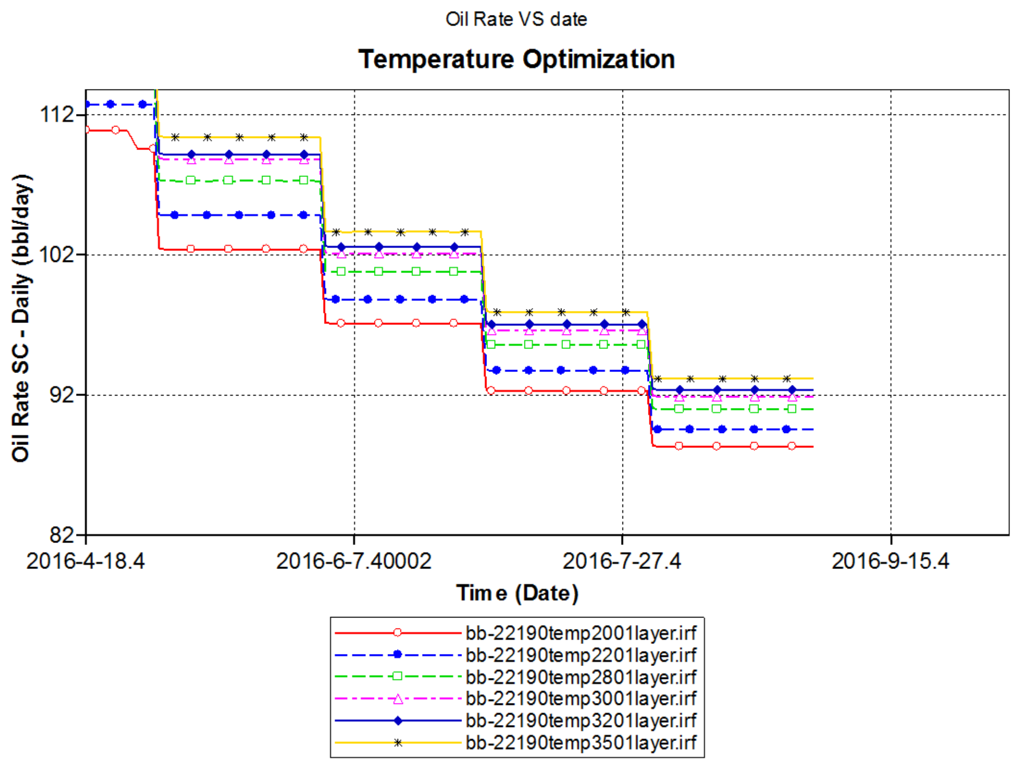



**Figure 4-10 : Effect of Changing Steam Temperature on Oil Rate**

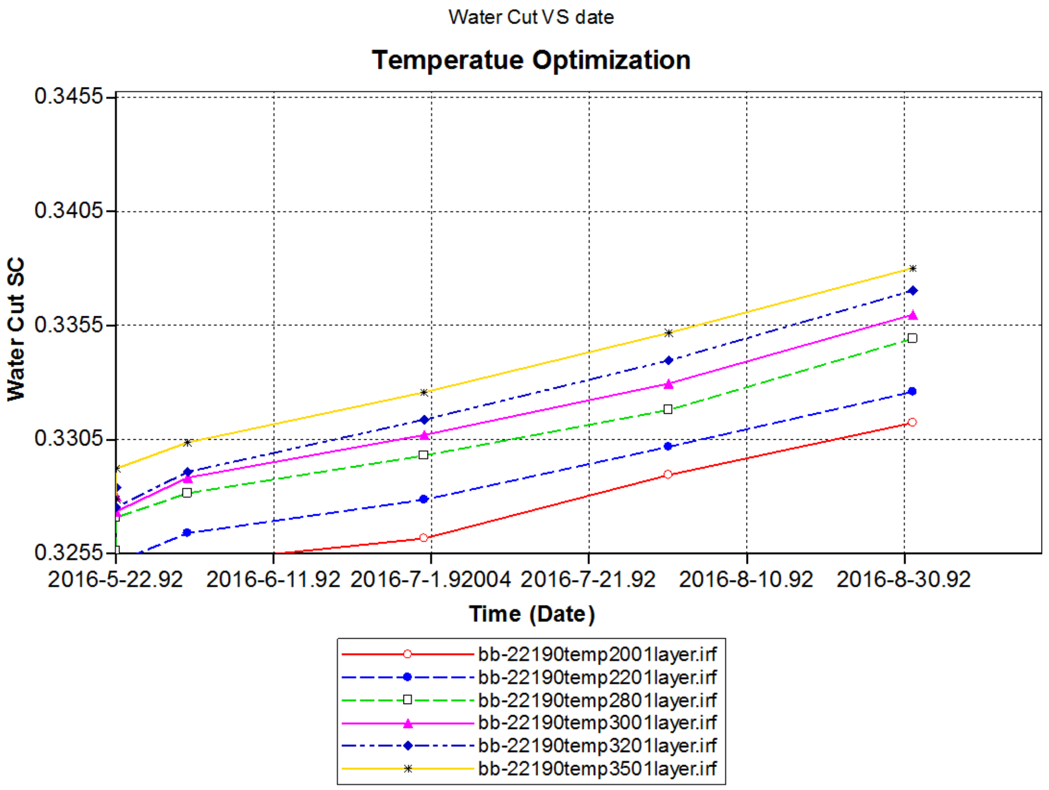



**Figure 4-11 : Effect of Changing Steam Temperature on Water Cut**

**Table 4-3 : Results of Defferent Scenarios for Steam Temperatures**

| Steam injection temperature (C) | Cumulative Oil Production (bbl)) | Cumulated water(bbl) | Oil rate per Cycle (bbl) | W.C % |
|---|---|---|---|---|
| 200 | 126751 | 40628.7 | 88.5456 | 33.1217 |
| 220 | 126946 | 40993 | 89.7281 | 33.2577 |
| 280 | 128805 | 41851.9 | 91.213 | 33.4909 |
| 300 | 129339 | 42135.5 | 92.1062 | 33.5956 |
| 320 | 129993 | 42572.9 | 92.5873 | 33.7017 |
| 350 | 130772 | 42864.6 | 93.379 | 33.8001 |

Figures (4-8,4-9,4-10,4-11) illustrates the results as a graph result for each run that have been done, and show that when the steam temperature increase also the cumulative oil increase.

Obviously, as the injection temperature increase, the cumulative water increase as well as W.C and this lead to excessive water production need to be remediated at surface.

The result shows that the highest cumulative oil exists at 350 & 320, but 300 is chosen because the quantity increased a little bit from that in 350 and 320, in order to extend the life of the boiler. See Table 4-3.

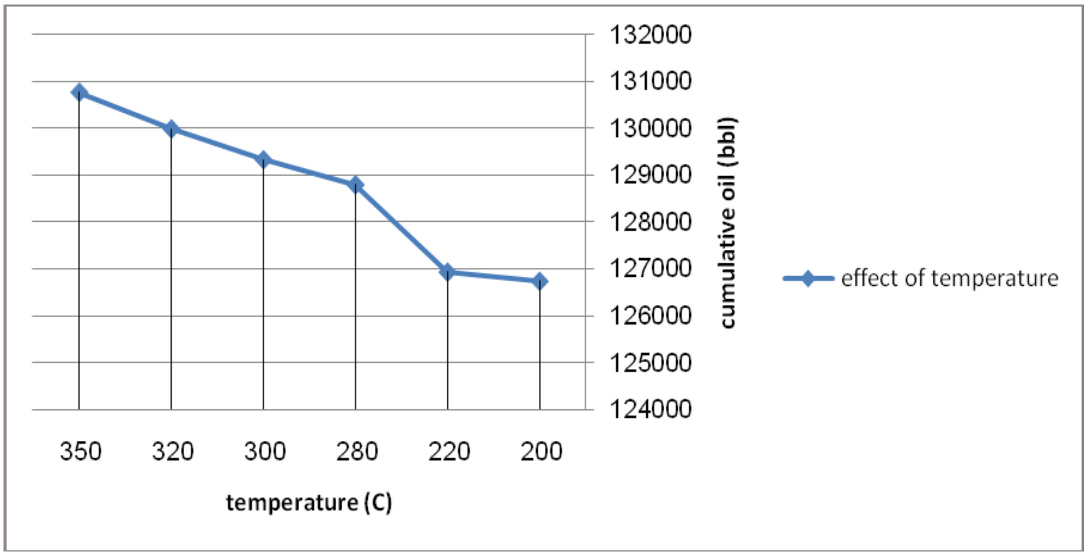



**Figure 4-12 : Effect of Temperature**

### 4.5.3 Optimization of Steam Quality

In the condition that steam injection rate 190 t/d and soaking time5 days, analog calculate the CSS effect of steam quality at well bottom 50%, 60%, 70%, 80% and 90%. See figures below.

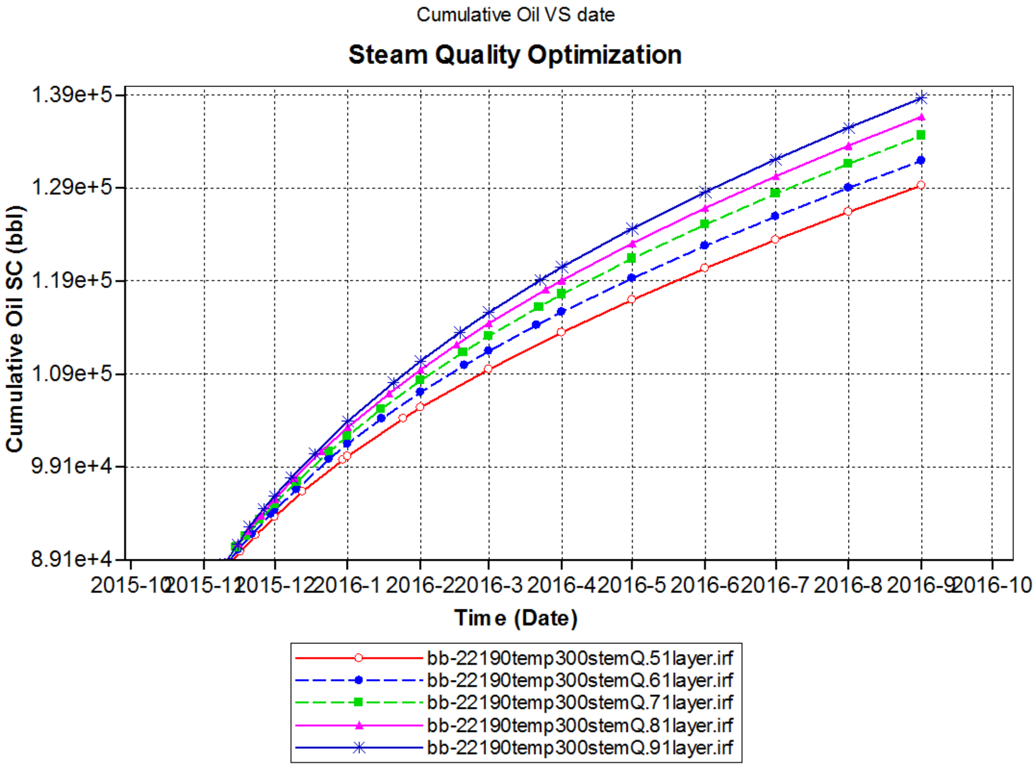



**Figure 4-13 : Effect of Changing Steam Quality on Cumulative Oil**

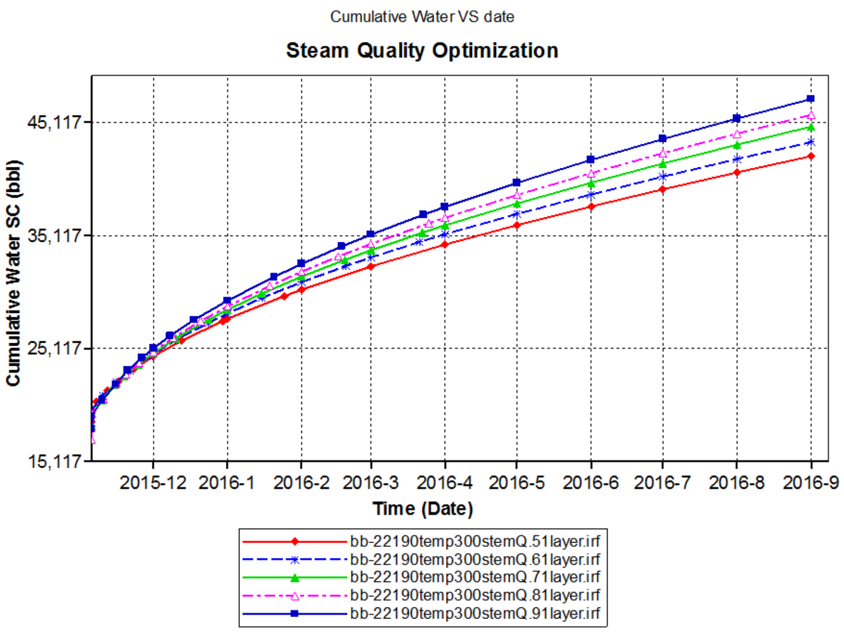



**Figure 4-14 : Effect of Changing Steam Quality on Cumulative Water**

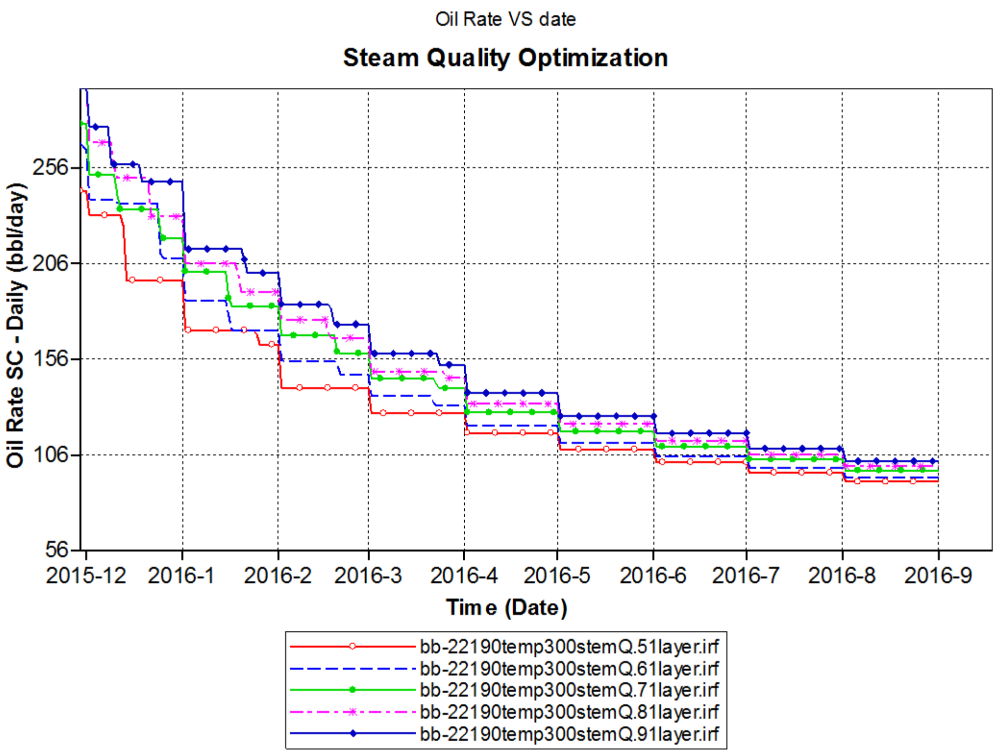



**Figure 4-15 : Effect of Changing Steam Quality on Oil Rate**

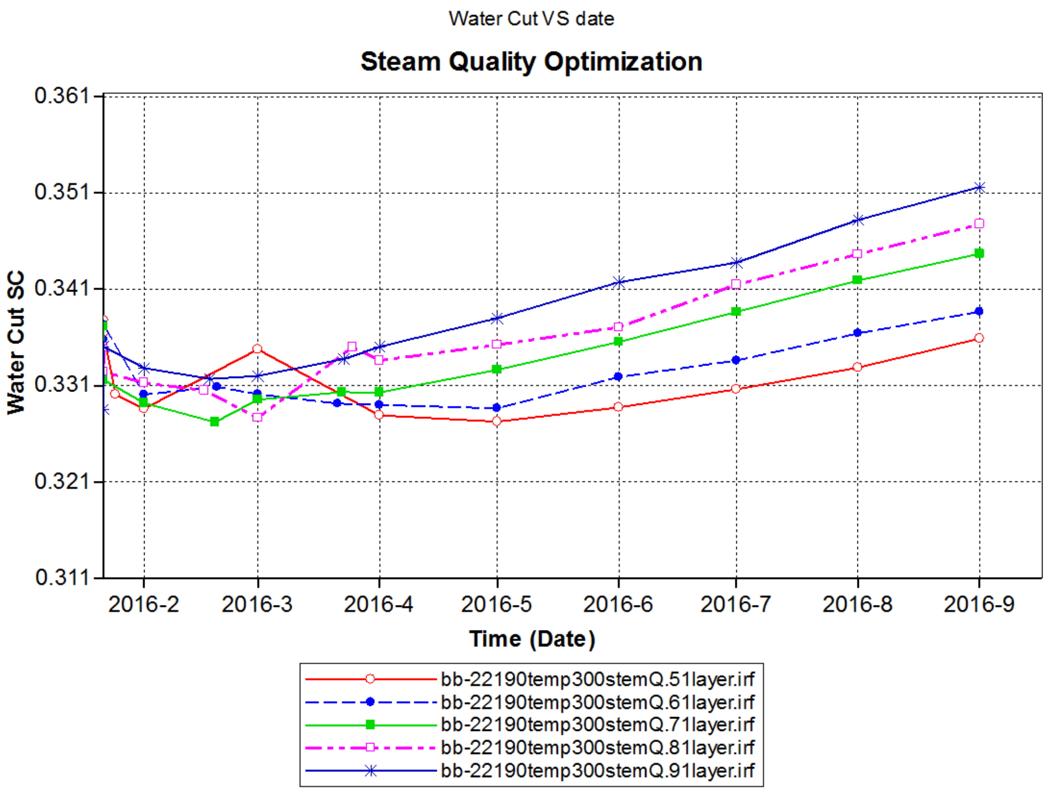



**Figure 4-16 : Effect of Changing Steam Quality on Water Cut**

**Table 4-4 : Effect of Steam Quality Alteration**

| Steam quality % | Cumulative Cycle oil production (bbl) | Cumulative Cycle water production (bbl) | Oil Rate (bbl) | Water cut % |
|---|---|---|---|---|
| 50 | 129339 | 42135.5 | 92.1062 | 33.5956 |
| 60 | 132005 | 43379.9 | 94.5417 | 33.8737 |
| 70 | 134701 | 44746.8 | 98.0096 | 34.4757 |
| 80 | 136731 | 45785.6 | 100.321 | 34.7816 |
| 90 | 138745 | 47191.7 | 102.905 | 35.1686 |

Figures (4-13,4-14,4-15,4-16) Show the Relation between different scenario of steam quality for well BB-22 and cumulative oil production, cumulative water, oil rate and water cut.

With the steam quality increasing, cycle oil production increase. Consider the factors as the level of site technology, cause steam quality is limited by boiler capacity, so additional cost required to obtain high steam quality. Propose the steam quality at well bottom should be above 70%. See Table (4-4).

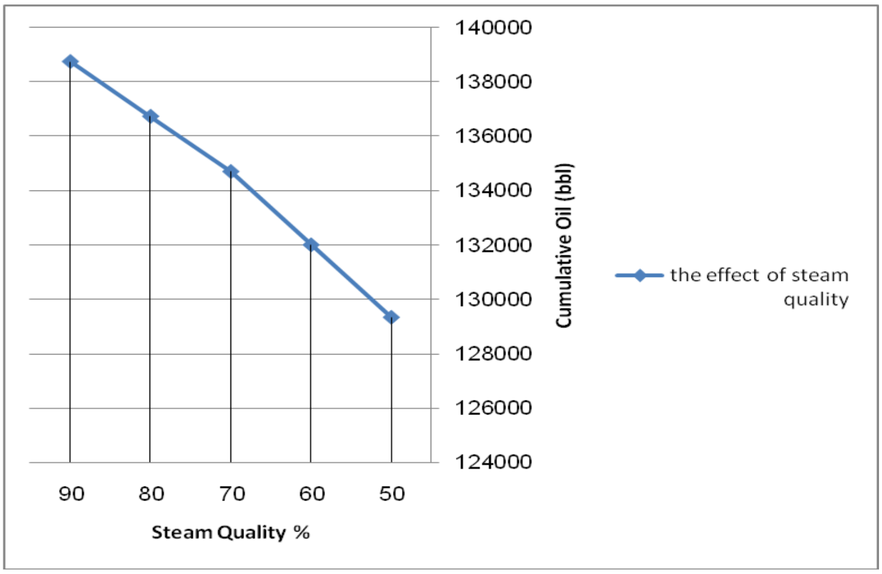



**Figure 4-17 : Effect of Steam Quality**

### 4.5.4 Summary of the Optimized Steam Injection Parameters

- Steam Injection Volume = 960 $m^3$
- Steam Injection Rate = 190 $m^3$/day
- Steam Injection Duration = 5.05 days ( 960 ÷ 190 = 5.05 )
- Steam Injection Temperature = 300 C
- Steam Injection Quality = above 70 %
- Soaking time = 5 day

From the results obtained after redesigning, it has been found that the oil rate increases four times, and the water cut decreases from 98% to 33%.

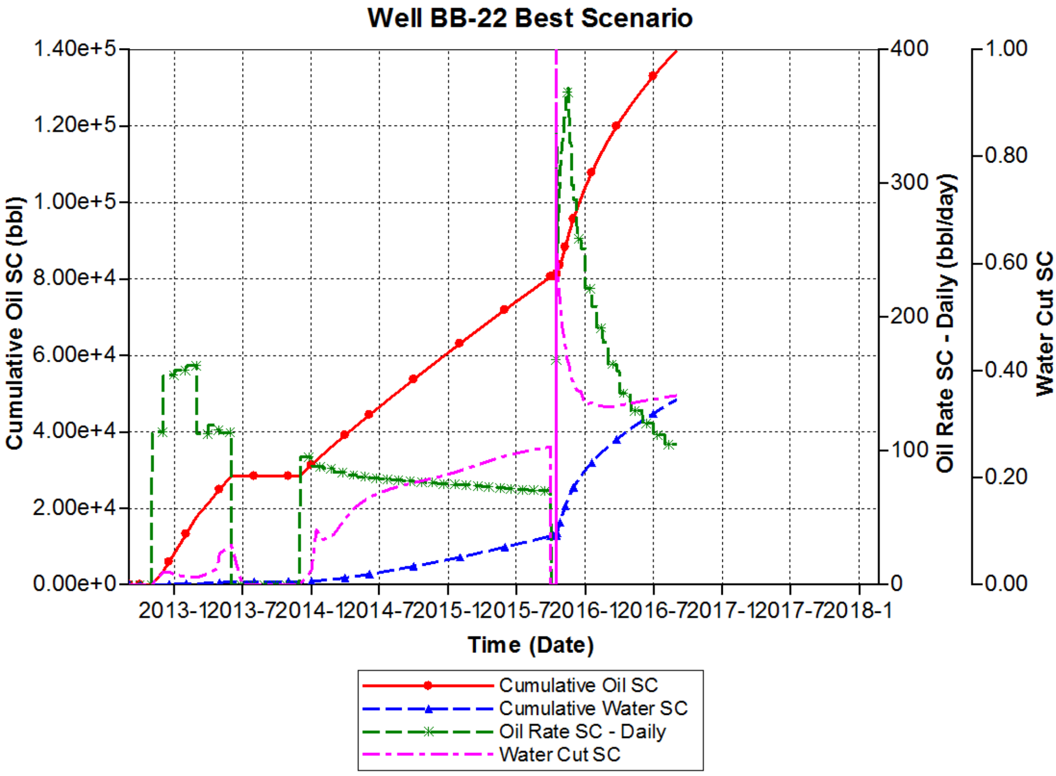



**Figure 4-18 : Optimum Senario For Well BB-22**

# Chapter Five : Conclusion and Recommendations

## 5.1 Conclusion

- The analysis has been done to determine main reason of high water cut in well bb-22. It has been found that layer B-1b get nearly twice the assumed amount of steam and this large amount of water result in water channeling and that why the well had high water cut.
- A suggestion to close the bottom layer which is main reason of high water cut.
- Redesign the optimum injection parameters for the upper layer.
- The optimum injection parameters (Steam Injection Volume = 960 $m^3$, Steam Injection Rate = 190 $m^3$ / day, Steam Injection Duration = 5.05 day, Steam Injection Temperature = 300 C, Steam Injection Quality = above 70 %).
- The results shows that after redesigning the oil rate increases four times, and the water cut decreases from 98% to 33%.

## 5.2 Recommendations

- Avoid steam injection stimulation in multi layers, unless using separate layer technology for injection/production from multi layers.
- Studying the possibility of converting CSS to Steam flooding.
- Running economic analysis for CSS project before implementation.

# References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# Appendix A

## Parameters of 1st Cycle Steam Injection

The optimized injection parameters of the first cycle as shown in table below.

**Table A - 1 : Parameters of Steam Injection (1st Cycle)**

| Cycle | Duration (day) | Steam Injection Strength (t/m) | Steam Injection Quantity (m3) | Boiler Outlet(stable running) | | | |
|---|---|---|---|---|---|---|---|
| | | | | Pressure (MPa) | Temp (°C) | Quality (%) | Discharge (m3/h) |
| 1 | 9 | 160 | 1440 | 18.12-18.81 | 357.1-363.6 | 71-74 | 7.5 |

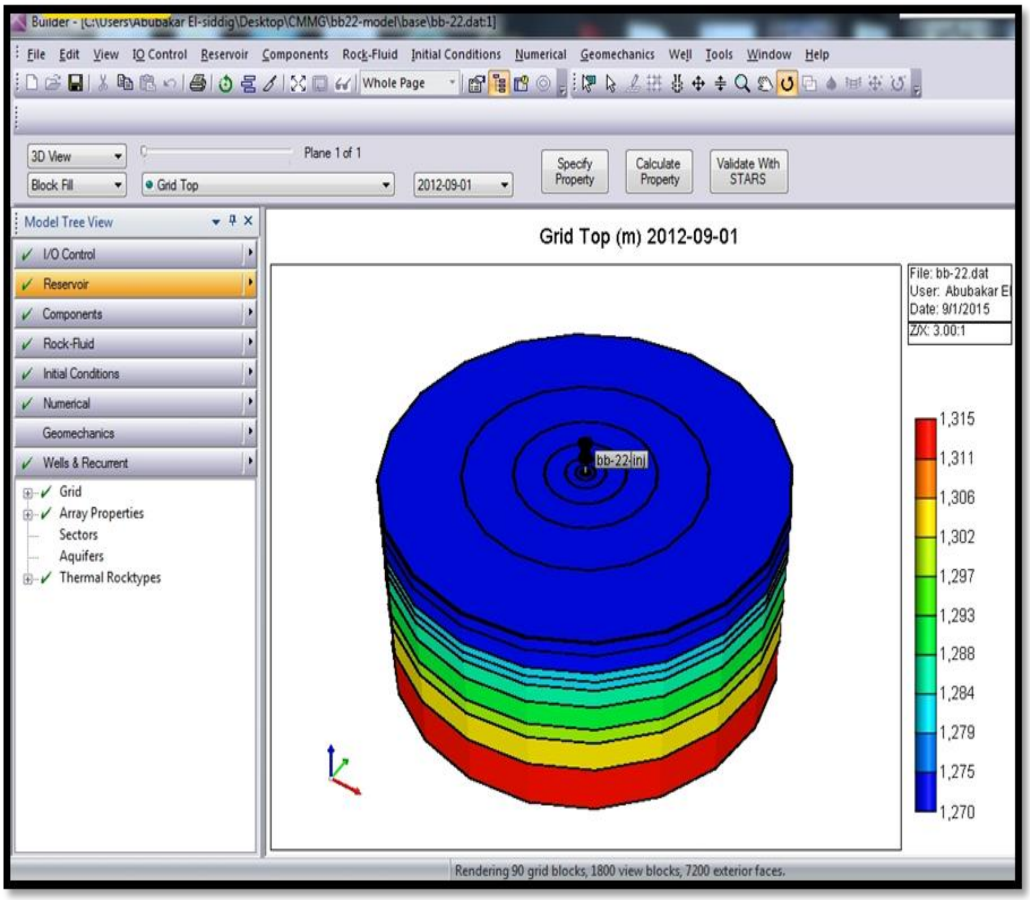


**Figure A - 1 : General Shape of the CMG Software**

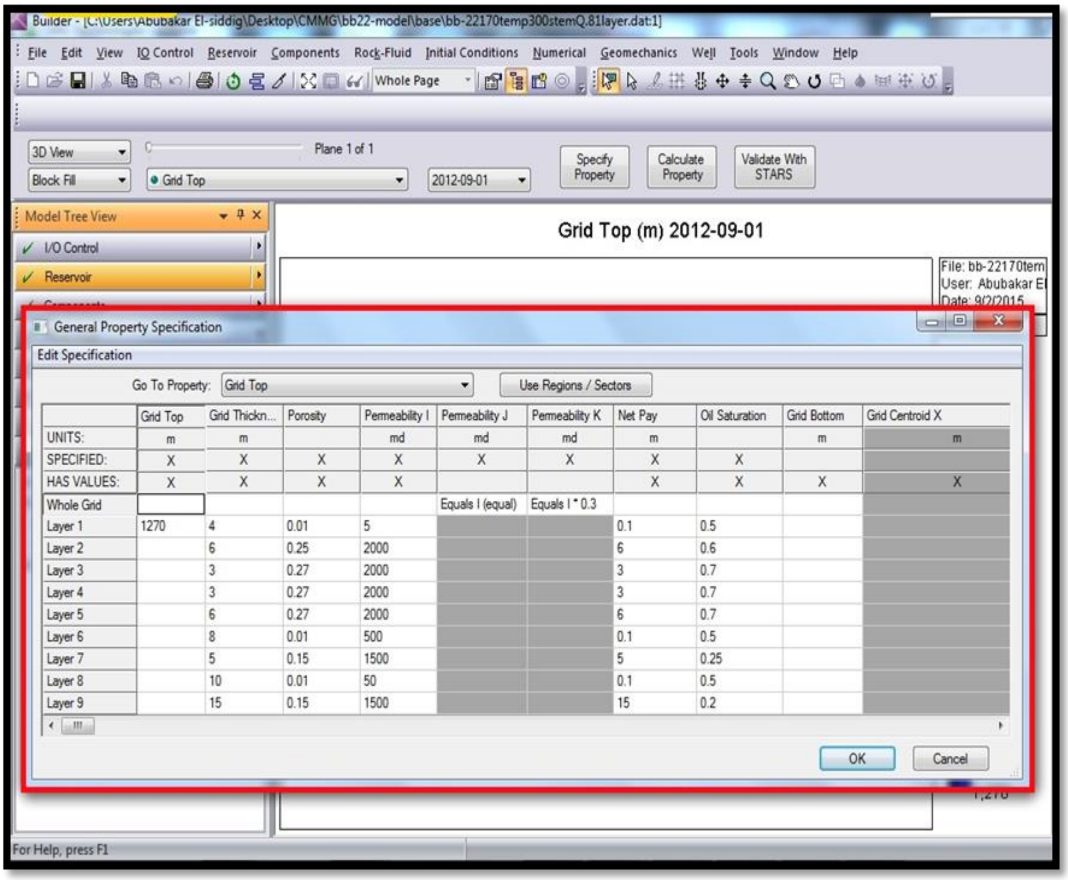


**Figure A - 2 : Rock Properties**

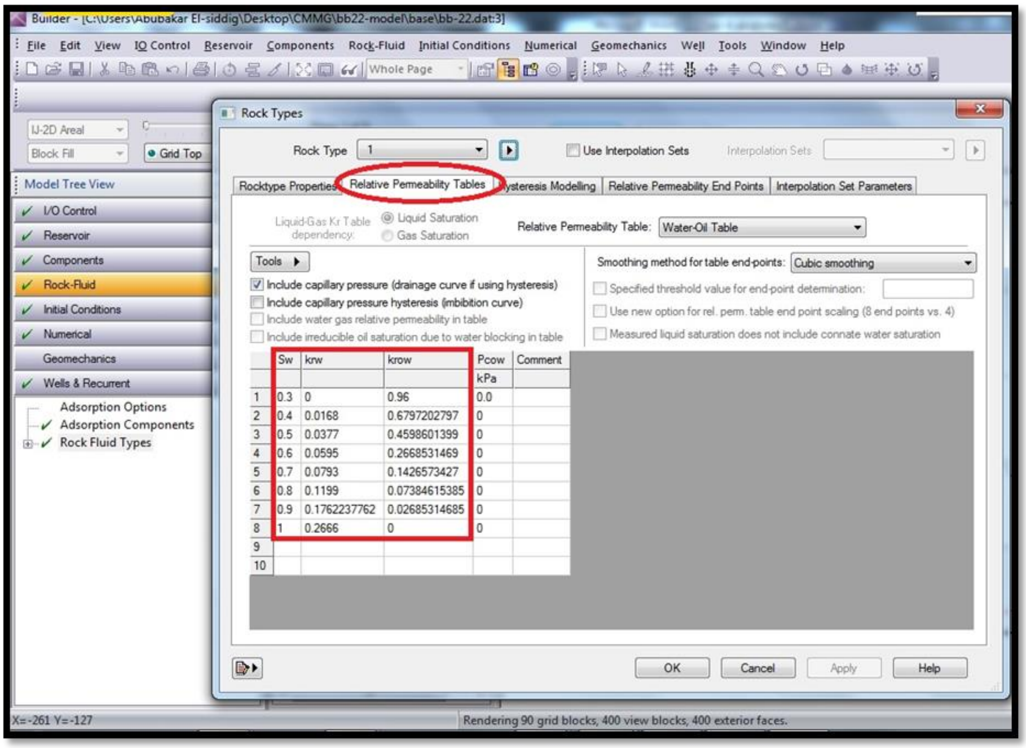


**Figure A - 3 : Relative Permeability Table**

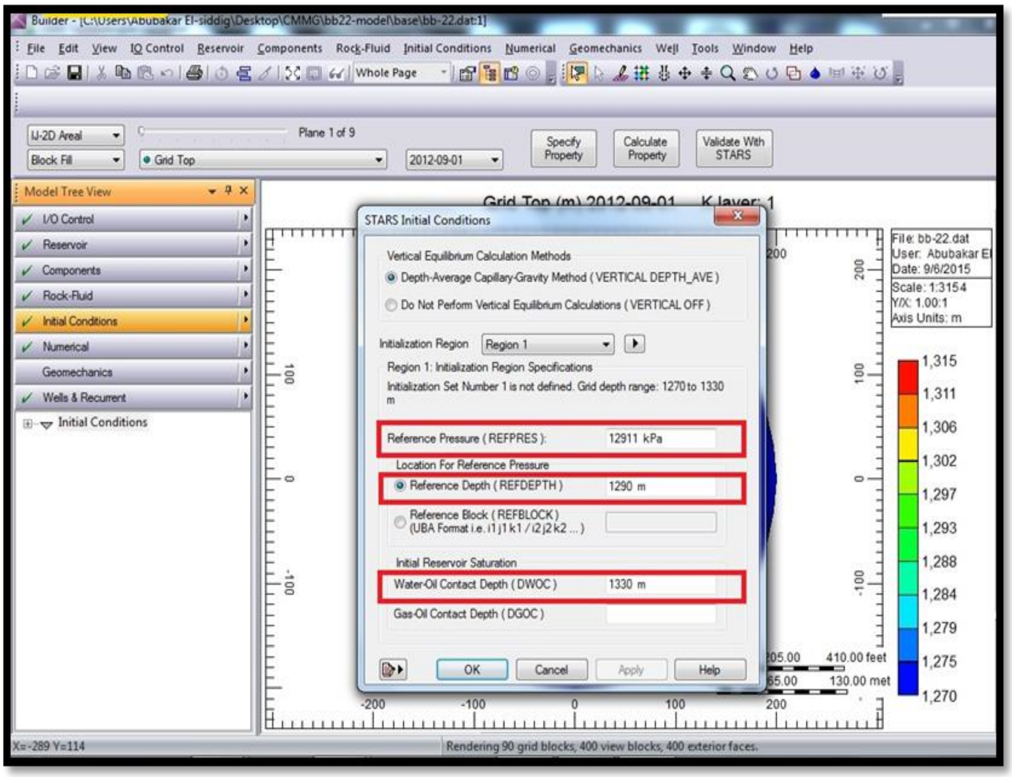


**Figure A - 4 : Initial Condition of the Reservoir**

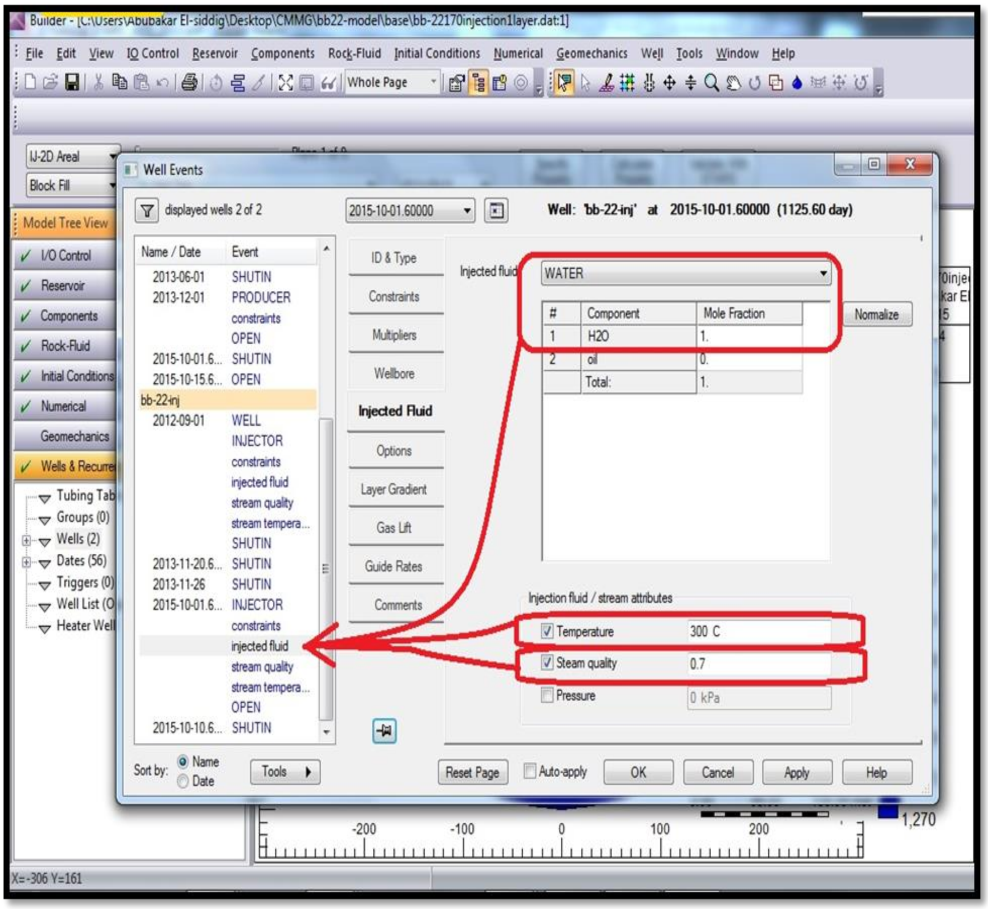


**Figure A - 5 : Injected Fluid Properties**

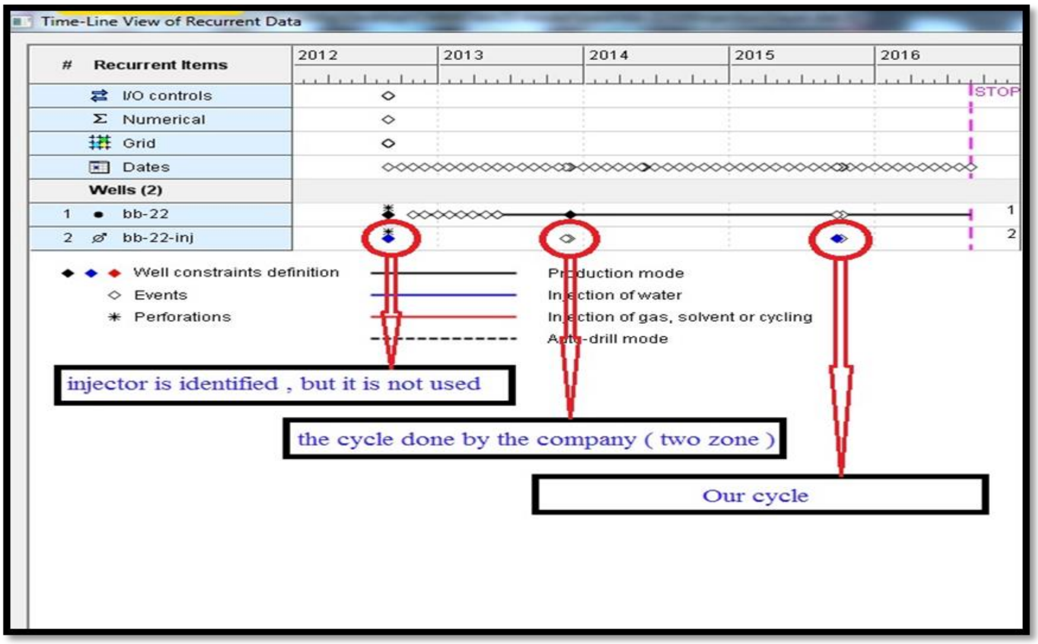


Figure A - 6 : Time Line View of Recurrent Data

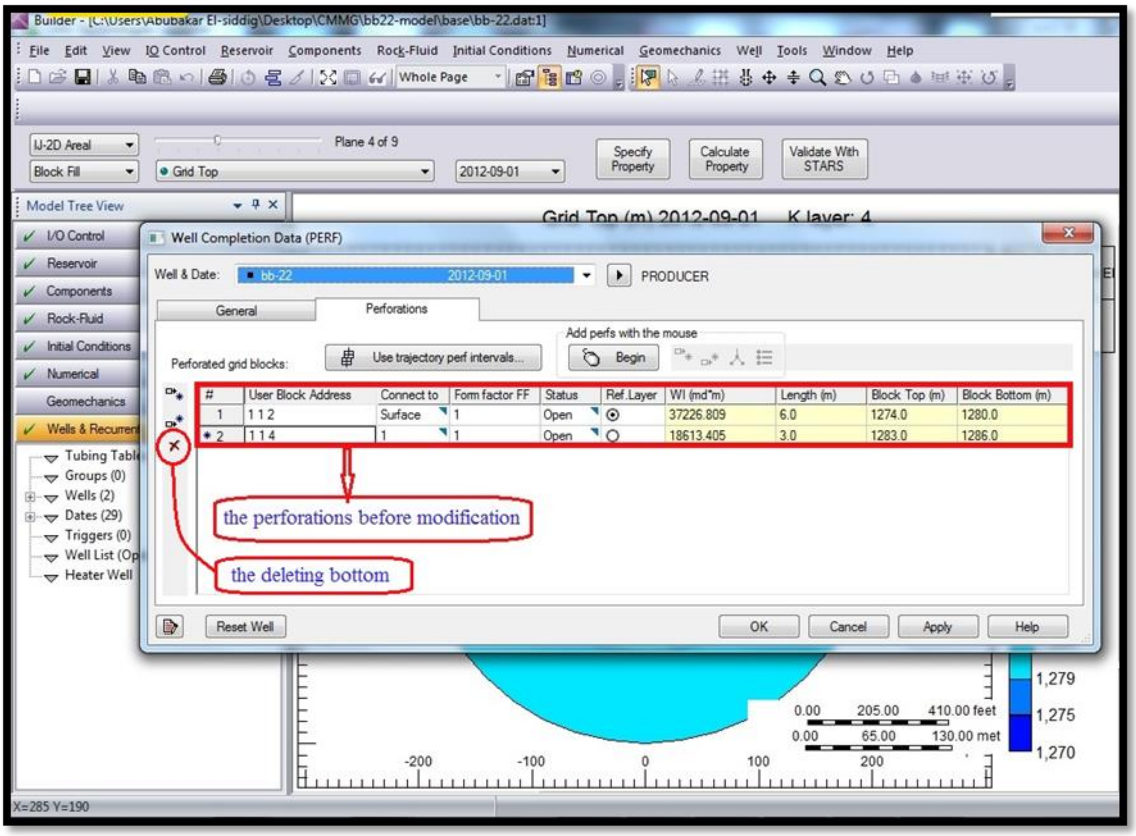


Figure A - 7 : Perforations Before Deleting the Second Layer

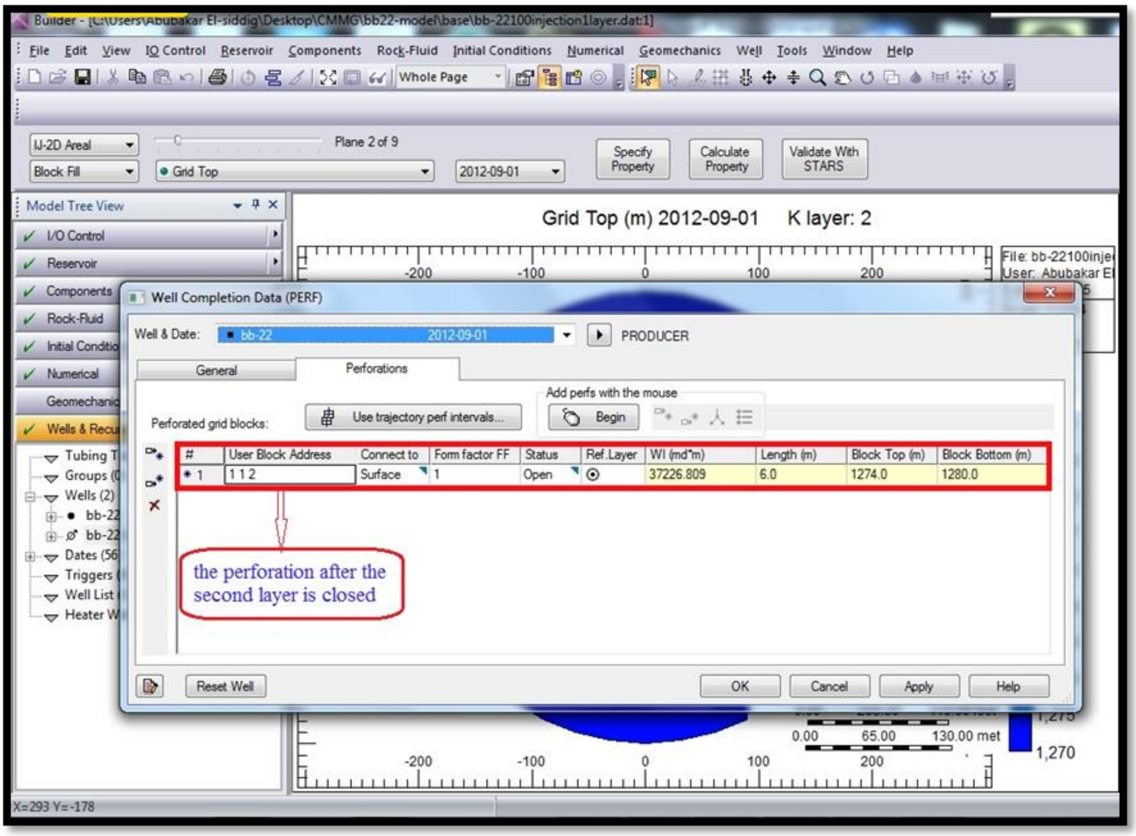


**Figure A - 8 : Perforation after Second Layer is Deleted**