Sudan University of Science and Technology

College of Graduate Studies

Excessive Water Production Diagnosis and Strategies Analysis

(Case Study - Jake Field - Sudan)

تشخيص وتحليل إستراتيجيات الإنتاج المفرط للمياه

(دراسة حالة -حقل جيك - السودان)

A Thesis

Submitted to the College of Graduate Studies

As Full fulfillment for the Degree of

Master of Science in Petroleum Engineering

By

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Khartoum-May -2016

Declaration

I confirm that the work entitled **Produced Water Diagnostics and Strategies Analysis in Jake Field- Sudan -Case Study** contains no material previously published by any other person except where due acknowledgment has been made. This thesis contains no material which has been accepted for the award of any other degree or diploma in any university.

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The best way to find your self is to lose yourself in the service of others.

Mahatma Gandhi

Abstract

Produced water is the water that extracted from the reservoir with the oil and gas, its complex subject and has serious economic and environmental impacts when the value of water oil ratio (WOR) exceeds the economic limit of the well.

Jake oilfield is located in the northeastern part of Muglad basin in Sudan interior, trending northwest-southeast and covering 120, 000 km^2. The field started production since 2010 and Water production increased rapidly throw the life of the field with a cumulative of 14 MMBBL by the end of 2014; with WOR is over 2.5 which increases the demand for creating a strategy to manage the field water situation

This work diagnoses the reasons of excessive water production in Jake field and analyze the different strategies used to control the massive water production. The problems of excessive water production have been investigated, the production analysis which include Chan's diagnostic was used to achieve proper diagnostic. The wells ranked according to a risk factor from 1 to 10 according to the selection criteria.

High conductive channeling due to the edge water driver reservoir and the high permeability found to be the main reason; normal trends were observed in the watered out area wells.

The surface facility, cost of produced water and the efficiency of the treatment system were investigated and the treatment cost of 1 Barrel of produced water have been calculated according to the world average. Three wells were selected for control options and further economic study depends on their risk factors. The three wells economic analysis shows that the value added form decreasing the water production could reach 39% of the total net present value of JS-02 and 15%, 10% for JS-08 andJS-24 respectively.

Finally, this study showed that the total field management scenarios have to be integrated in a single strategy of decreasing the produced water to add more value from water treatment, decreasing the disposal which will cost less compared to the other costs. Two other wells can be transferred to injectors after further investigation and more well production methodology have to be optimized.

تجريد

المياه المنتجة هي المياه المستخرجة من باطن الارض مع النفط والغاز.وهو موضوع معقد في الصناعة النفطية وله تاثيرات إقتصادية و بيئية كبيرة حينما تتجاوز النسبة بين الماء والنفط القيمة الاقتصادية للبئر المعينة .

حقل جيك يقع في الجزء الشمالي الغربي من حوض المجلد في السودان، ويقع علي مساحة تغطي 120.000 كم مربع. بدأ الحقل الانتاج منذ 2010 وأنتاج الماء بدأ يتزايد بسرعه مع زيادة عمر الحقل،الأنتاج الكلي حتي الآن وصل الي 14 مليون برميل حتي نهاية 2014 ونسبة الماء الي الزيت تفوق ال 2.5 وتتزايد.مما يخلق الحوجة لوضع استراتيجية لإدارة وضع الماء في الحقل.

هذه الدراسة تقوم بتشخيص اسباب انتاج المياه المفرط في حقل جيك وتحلل مختلف الإستراتيجيات المستخدمة للتحكم في هذا الانتاج المفرط للماء. تمت دراسة مشكلة الانتاج المفرط للماء وتحليلها باستخدام بيانات الانتاج للابار واستخدام مخططات شان لتشخيص المشاكل وتم إستخدامهالتعطي التشخيص المقبول. تم ترتيب الإبار علي مستوي معامل للمخاطر بناء علي معايير الاختيار المختلفة. كل الابار التي تمت دراستها شخصت علي ان مشكلتها هي تدفق شديد للمياه نتيجة للنفاذية العالية وايضا الدفع الجانبي للماء.في المناطق المغمورة بالماء اظهرت الابار نتائج طبيعية.

تمت دراسة وبحث المعدات السطحية وتكلفة وكفاءة نظام معالجة المياه المنتجة ومن ثم تم حساب تكلفة انتاج برميل الماء الواحد تبعا للمتوسط العالمي. أختيرت ثلاثة إبار لتحليل خيارات التحكم في المياه وتحليلها إقتصاديا اعتمادا علي معامل المخاطر المحسوب سابقا. اظهرت النتائج الإقتصادية ان القيمة المضافة من تقليل المياه المنتجة تصل الي 39% من قيمة الدخل الكلي في حالة البئر JS-02 و 15% و 10% بالنسبة ل للآبار JS-08و JS-24 علي التوالي.

في النهاية اظهرت الدراسة ان سيناريوهات إدارة المياه في الحقل بصورة متكاملة من الأفضل دمجها في والتعامل معها كإستراتيجة واضحة من اجل تقليل المياه المنتجة وفي نفس الوقت إضافة قيمة إقتصادية للحقل و تقليل المياه المتخلص منها مما يؤدي الي تقليل التكلفة. تمت التوصية بتحول بئرين لي أبار حقن بعد دراسات اخري،أيضا طريقة الإنتاج للحقل بحوجة الي ان تكون بصورة مثلي.

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List of Symbols and Abbreviations

Frac= hydraulic fracturing

NORM= Naturally occurring radioactive material

PWRI= Produced water re-injection

WOR=water oil ratio

WOR'=simple time derivative of water oil ratio

$Q_{O\ max}$ = the critical oil rate STB/D

ρ_w, ρ_o = Densities of water and oil gms/cc

$r_e r_w$ = drainge and well radius ft

h, D=net bay thickness and perf. Interval ft.

ko =effective oil permeability mD

$\mu_o \beta_o$=oil viscosity and oil FVF cp, bbl/STB

WSO= water shutoff

CHFR =cased hole formation resistivity

TDS=total dissolved solids

CBL= cement bond log

PLT= Production Log test

CAPIX =the capital cost.

OPEX =operation cost.

NPV= net present value

Chapter One

Introduction

Chapter One: Introduction

1. Introduction

Produced water (also called brine), is the water extracted from the subsurface associated with oil and gas. It may include water from the reservoir, water that has been injected into the formation and any chemicals added during the production treatment process; (Glossary, 2013). Since day one, the extraction of the oil and gas from the earth formations faced major problems induced by water produced with them. Some argue that oil industry is effectively water industry producing oil as a secondary output. It considered the largest single fluid stream in exploration and production operations (SPE Task Group, 2000). As general, produced Water sources as presented by P.ROBERTS (1993) may include:

I. Natural water drive or water flood.
II. External sources including casing leak or cementing failure.
III. Mess-completion. (Bad perforation job).

Another type of Produced water is called "flow back; (Arthur, 2011), which is a large component of fluids injected into a well at high pressure as part of a hydraulic fracturing (frac) operation. Within a few hours to a few weeks after the frac job is completed, a portion of the water returns to the surface. It is typically contains levels of chemical constituents much higher than did the original frac fluid, including dissolved salts. The formation water on 2004 was 98% of the non-hydrocarbon fluids produced with oil and gas; now the number did not deviate more than that. In USA, the water production was approximately 14 billion barrels of water annually and 21 billion barrels of water annually (J.A.Veil, 2009), when compared to the annual oil 1.9 billion barrels, and gas 23.9 TCF (EIA, 2006)

Some produced water is quite fresh and may be used for livestock watering or irrigation (where allowed by area environmental regulations). In most cases as the produced water contacted with the hydrocarbons contained in the specific formation, it will contain some of the chemical characterization of the formation hydrocarbons; it will have a high total dissolved solid -TDS (compared with the fresh water) with various organic or inorganic components, also it will contain Oil and grease and at last (but not least) Naturally occurring radioactive material (NORM). There is a wide variation in the level of its organic and inorganic composition due to geological formation, lifetime of the reservoir and the type of hydrocarbon produced, as presented by Chen (2012). Figure 1-1

The characteristics of produced water vary from location to location and over time. Different locales have different climates, regulatory/legal structures, and degree of existing infrastructure. As a result, no single treatment technology is used at all locations. Many different technology options are available that can be employed at specific locations.

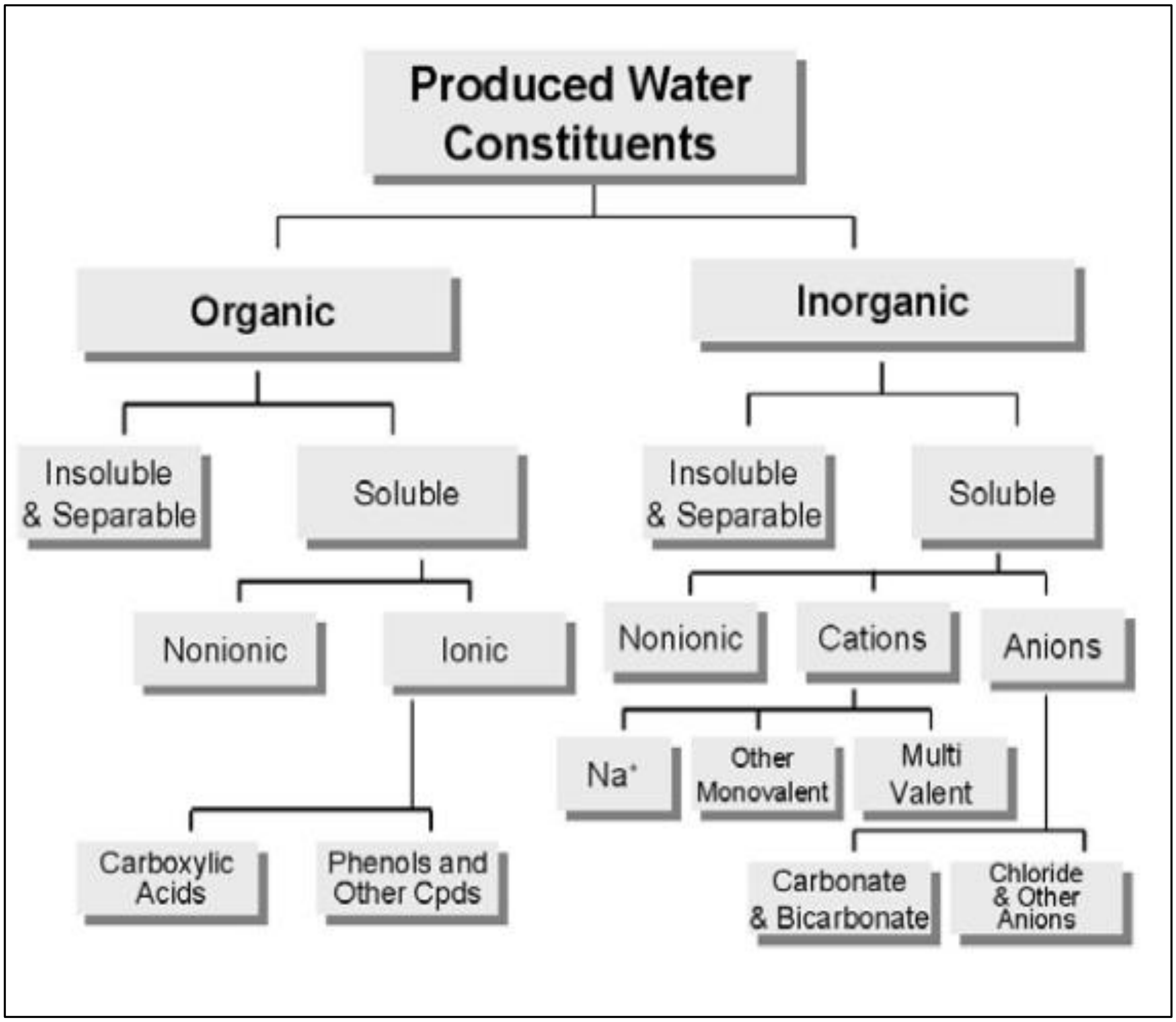


Figure 0-1 Produced water composition

The produced water need to be treated before going to the disposal at surface (evaporation ponds) or to subsurface as part of re-injection job (Produced water re-injection PWRI). Selection of a management option for produced water at a particular site varies based on: produced water properties, the objective of the end use, economic feasibility, area regulation, cost. Some of the options available to the oil and gas operator for managing produced water might include the following: (Arthur, 2011).

1. **Prevent production of water onto the surface**: Using polymer gels that block water contributing fissures or fractures or Downhole Water Separators which separate water from oil or gas streams downhole and re-inject it into suitable formations. This option eliminates waste water and is one of the smarter solutions, but is not always possible and may be costly.
2. **Inject produced water:** Inject the produced water into the same formation or another suitable formation; involves transportation of produced water from the producing to the injection site. Treatment of the injected water to reduce fouling and scaling agents and bacteria might be necessary. While waste water is generated in this option, the waste is emplaced back underground.
3. **Discharge produced water:** Treat the produced water to meet onshore or offshore discharge regulations. In some cases, the treatment of produced water might not be necessary.
4. **Reuse in oil and gas operations:** Treat the produced water to meet the quality required to use it for drilling, stimulation, and Work Over operations.
5. **Consume in beneficial use:** In some cases, significant treatment of produced water is required to meet the quality required for beneficial uses such as irrigation, rangeland restoration, cattle and animal consumption, and drinking water for private use or in public water systems.

The economics of excessive water production is one of the most important problems in oil and gas industry; although at the old days, nobody was concerned about the produced water, the world now realizes that produced water could be one of the major problems affect the growth of the petroleum industry. Water production may lead to the following consequences: damage to the facility, cost of separation, cost of disposal and environmental damage. Great deal of scientific research has been carried out to determine the consequences of long-term exposure of produced water on the environment. Some of these researches have given alarming results. It is reported that some of the toxic components in produced water may cause irreversible damage to the surrounding environment. (SPE Task Group, 2000).

Managing the cycle of water production, down-hole or surface separation, and disposal involve a wide range of oilfield services which are costly. These include data acquisition and diagnostics using production logging, water analysis for detecting water problems and reservoir modeling to characterize the flow. Also, there are various technologies to eliminate water problems such as down-hole separation and injection, chemical and mechanical shut-offs, and surface water separation and production facilities. All the diagnosing operations starting with different logging (temperature, noise and density logs) ending with reservoir modeling are costly; the cost of treating water for good handling vary almost from 2 to14 $ (Halliburton, 2012); therefore, using a diagnosing method for water problem with low cost is of interest to all.

This research will discuss the problems related to water production and its influence on the oil production, their solution and the economic impact in a Sudanese Field (Jake Field) which located in block 6. The study considered only produced water without flow back due to the nature of the field and the limitation of hydraulic fracture jobs on the field.

1.1 Problem Statement:

The major problems of produced water are the high cost and the environmental risk; which are un-ignorable and in some cases may be the major concerns. The water treating cost for different purposes may considered low, but when compared with huge volumes of the produced water for block 6 are approximately about 400,000 $ daily, the overall cost will totally risk the economic feasibility of the field. In the other hand, the chemical compositions of the produced water contamination have made many troubles to the surrounding area (e.g. affecting the fresh water sources, damaging the plants and wild life). Although many efforts were made for treating water to meet the standards and the minimum environmental safety for handling, the current work specially diagnoses water production and analyze the control techniques in Jake oilfield.

1.2 Research Objectives:

The main objectives of this study are:

1. To determine the purpose of water production and conducting initial diagnosis for water production mechanisms in Jake oilfield for different producing wells.

2. Create procedures for the optimum water management strategy in the field starting from the completion design through surface facilities end up with the PWRI or the free disposal.
3. Carry out a comprehensive economical study of the water treatment in the field.

The sketch below is a simple draw for the 3 stages of the study:-

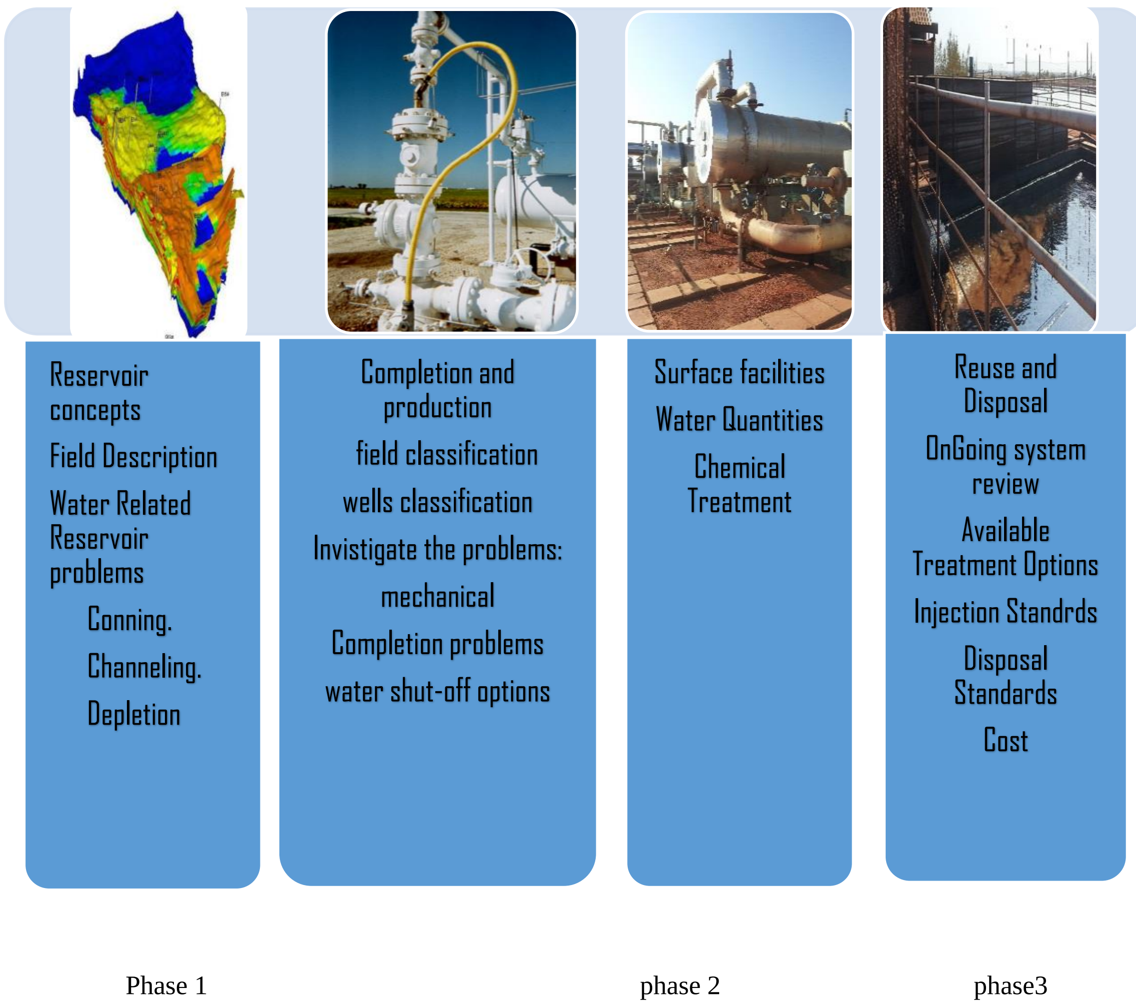


Figure 0-2 Stages of the study

1.3 Thesis Outlines:-

Through this work, extensive review for the field current strategy from the down hole to the disposal will be made. The first chapter is an introduction and illustration of the project problem statement, general objective of the study and the methodology used to deliver those objectives. The second chapter is a literature review and background of the field as general. The following 3 chapters are the main component of the study, the 3 phases of problem from downhole to surface and end with the disposal or re-use. Chapter 5 will connect the parts of the study as a results to create the optimum strategy for the field. The final chapter is the conclusion and recommendation.

Chapter Two

Theoretical Background and Literature Review

Chapter two: Theoretical Background and Literature Review

2. Introduction

All oil wells producing water at their life, it comes from the aquifers as a natural drive or even a water flood. However, the water becomes a problem (Excess) when it bypasses the oil and lead to unrecovered accumulations. Generally, the produced water can be categorized into sweep, Good and bad water

A. Sweep Water

Sweep water comes from either an injection well or an active aquifer that is contributing to the sweeping of oil from the reservoir. The management of this water is a vital part of reservoir management and can be a determining factor in well productivity and the ultimate reserves. When the water cut is great and the oil production revenues are not handling the water treatment cost, the water is called “Bad Water”.

B. Good Water:

it’s the water that cannot be shut off without losing the oil reserves, its happened when the oil and water flow through the porous media as part of the oil’s fractional flow characteristics, as long as the water/oil ratio is below the economical limit the could be considered as a good water.

C. Bad Water:

It is referred specially to the water flow separately into the wellbore and producing no oil or below the well water/oil ratio economic limit lead to increase of the handling cost. It comes usually from a different types of problems classified due to their nature (Reservoir, Mechanical or Complex). Figure 2-1 distinguish between the two types of water.

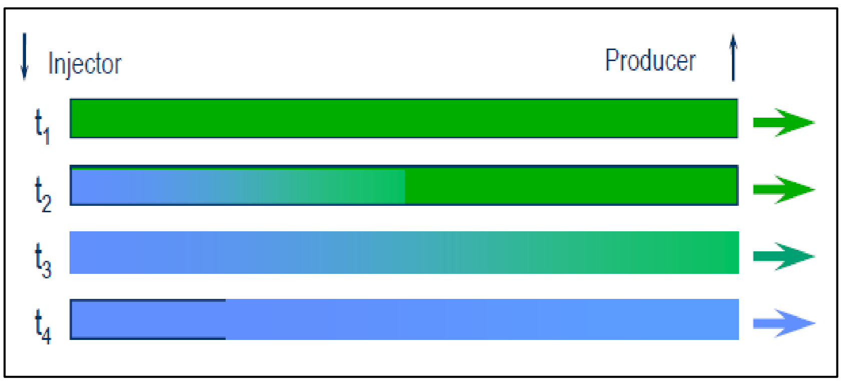


Figure 0-1 Bad Water vs. Good Water (Bailey et al, 2000)

Water production increases the produced fluid head in the wellbore and creates extra backpressure on the formation. This reduces the well's flow capability or forces; also artificial lift capacities increase as the volume of water production increased.

Excessive water production dose not only decreases oil and gas production, it is often increases operating expenses; reduced oil or gas production is caused by high water production in the following ways:

1. Reduced sweep efficiencies by ineffectively flooding all productive intervals-water cycling between injection and producing wells through their zones or high permeability intervals.
2. Increased fluid column head caused by higher density water in the producing string. This often causes significant loss of gas production in low pressure wells which leads to early shut in.
3. Increased water saturation in the formation near the well bore which reduces the relative permeability to oil or gas.
4. Formation damage by mobile or hydratable clays and formation fines that are trapped near the producing well bore area.
5. Scale precipitation in the well bore, perforations, and close to well bore formation pores.
6. Water blocking that creates increased water saturation in the near wellbore formation of a producing well and reduces the relative permeability to oil.
7. Construction of emulsions as crude oil and water mixture upon entering the borehole or downhole pump, this problem is more serious if the emulsion is injected into the formation during a Work Over operation.
8. Hydrogen sulfide and carbon dioxide corrosion is enhanced by water production.
9. Sand production is frequently related to the increase in water production rates.

Reynolds (2003) addressed and discussed different technologies used in the water management faced by the production operators during the life of the field. "Not all technologies discussed are applicable to all situations, but they have led in certain situations to improved return on investment and increased economically recoverable reserves". (Al-Mutairi and Al-Harbi, 2006) presented the water management strategy that was initiated in the North Uthmaniyah area of Ghawar field in late 1999. The strategy main objectives were to reduce operating expenses related to water handling and avoid capital investment required for the expansion of water handling facilities while engendering a more efficient recovery process. The strategy was implemented through four initiatives: operating of high water cut wells on a cyclic basis, conducting rig less water shut-off jobs, drilling horizontal sidetracks of existing vertical completions and drilling wells with partial penetration completions. All of these practices were designed to leverage Ghawar Arab-D advantages of high reservoir conformance and displacement efficiency, which will ultimately yield high oil production with minimal water production. Based on the recent encouraging results, it appears economically and technologically feasible to produce the remaining oil at lower water production rates, by drilling horizontal sidetracks during the middle and later production periods in mature fields concurrent with a rigorous surveillance and monitoring program. (Eduin et al., 2010) presented an integrated methodology for building a strategy to design water management system considering the production optimization plan and analyze the operational parameters such as wells type and their locations, flow condition; then using an economic evaluation to determine the optimum performance of the suggested field. Recently, (Arthur, 2011) Described, summarized and analyzed various produced water treatment systems developed by oil and gas producers, research organizations, water treatment service companies, and universities. Such as avoid production of water onto the surface, inject produced water, discharge produced water, Reuse in oil and gas operations, Consume in beneficial use.

HEBRON-PROJECT (2011) summarized the efforts of ExxonMobil, they develop a comprehensive produced water management strategy to reduce or eliminate produced water discharges to the sea following the 2010 Offshore Waste Treatment Guidelines (OWTG). before this strategy, the company was dumping a huge amount of water into the Gulf of Mexico until they stopped by the Environmental Protection Agency EPA, their strategy consists of two options: disposing the water into a reservoir designed as a disposal reservoir, but due to the large volumes the water used to maintain the pressure in the oil production formations. This strategy creates a great economic impact for the company.

Jassim and Subhi (2010) used Chan’s method for an oil wells producing from sandstone reservoirs in Middle East using actual production history data to generate log-

log plots of WOR (water oil ratio) and dWOR/dt (simple time derivative of water oil ratio) vs. time. The plots were found to be effective in differentiating whether the well is experiencing water coning (negative slope) or multilayer channeling (positive slope for the time derivative of water oil ratio curve). The diagnostic plots applied in this study provide a handy method for quick evaluation of excessive water production mechanisms in order to select wells candidates for water control treatment.

Chen (2012) Evaluated numbers of technologies used in the disposal water treatment, also discussed the environmental effects of the produced water comparing between a world disposal standards 30 ppm OIW (oil in water),Oslo-Paris Convention (OSPAR) ,42 ppm OIW for United States Environmental Protection Agency (USEPA) ,In Australia, permitted offshore discharge of oil and grease in produced water is 30 ppm and the People's Republic of China now sets the monthly average limits of 'oil and grease' and 'chemical oxygen demand' at 10 and 100 ppm OIW, respectively.

Excessive water production affects the economic viability of many oilfields worldwide. The negative impacts of excess water production include loss of revenue because of decreased oil production, unnecessary expense of lifting water from wellbore to the surface and cost of water treatment facilities and water disposal systems. A total water management system can be pictured as shown in Figure 2-2 (Arnold et al., 2004)

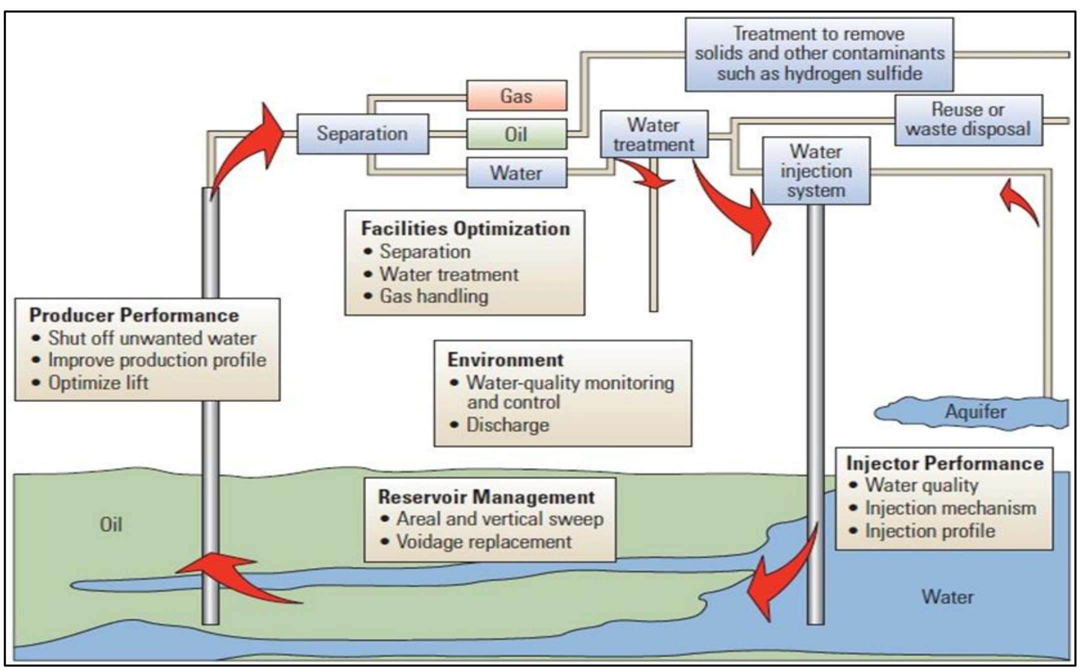


Figure 0-2 Water Management System in Oil and Gas Fields (Arnold et al., 2004)

In Sudan, Saad (2009) studied the produced water from Heglig oil field, which is on the same basin as block 6 (Muglad Basin) for the available options to transfer the waste stream into a useful assets and found that the nature of the field produced water may have considered as a fresh water. In addition to the chemical and the physical analysis showed normal environmental values of many parameters (BOD, TDS, pH, COD) with a high value of the sodium.

2.1 Reasons of Excessive Water Production:

Water production mechanisms have been classified in the literature using different criteria depending on the purpose of the author's work. And as general the ten basic problem types vary from easy to solve to the most difficult are described in Figure 2-3 below:

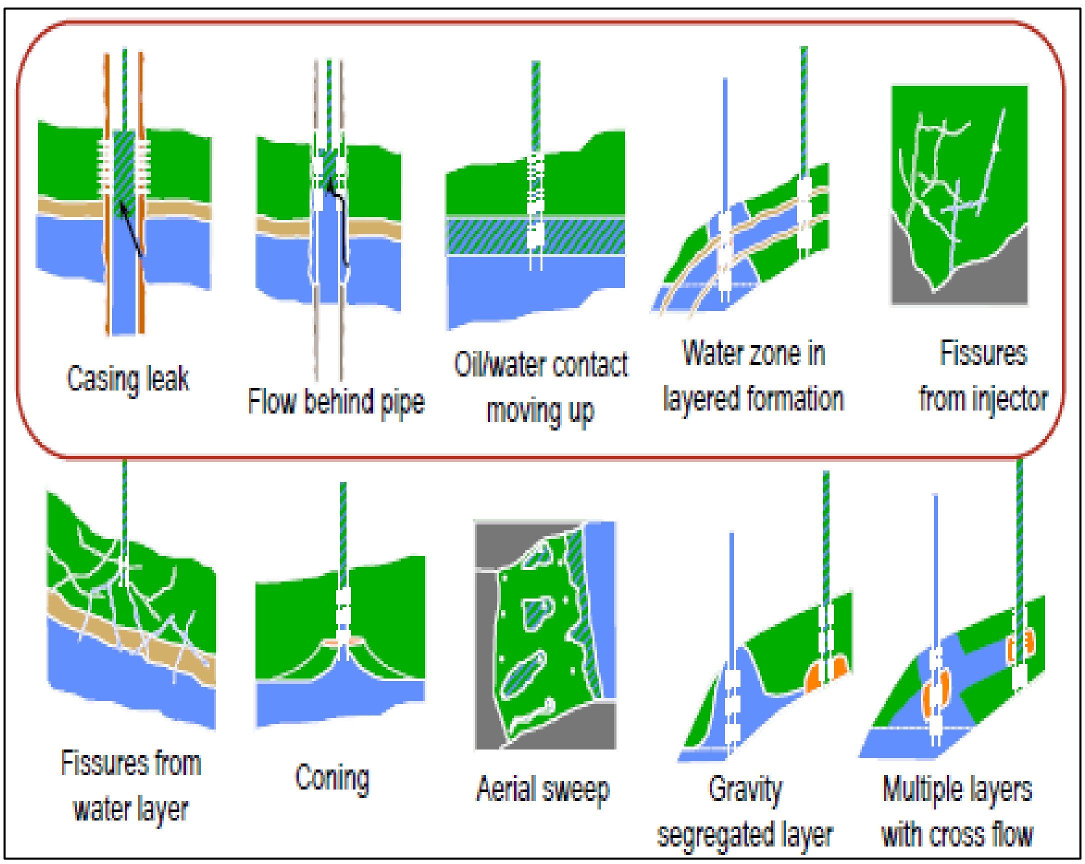


Figure 0-3 Water Production Problems (Bailey et al., 2000)

2.1.1 Channeling

Channeling occurs because of the early breakthrough in the high permeability or fractured formations especially in water flooding. Channeling is one of the most important excessive water productions resources. Furthermore, reservoir heterogeneities lead to the presence of high permeability streaks. Induced Fractures or natural fracture are the most common cause of the channeling between wells. Water production could emanate via natural fractures from aquifer. In un-fractured reservoirs often, stratification and associated permeability variations among various layers can result in channeling between an injector and a producer or from an edge water aquifer to the producers, Figure 2-4.

Deviated and horizontal wells are likely to intersect faults or fractures. If these faults or fractures connect to an aquifer, water production can jeopardize the well.

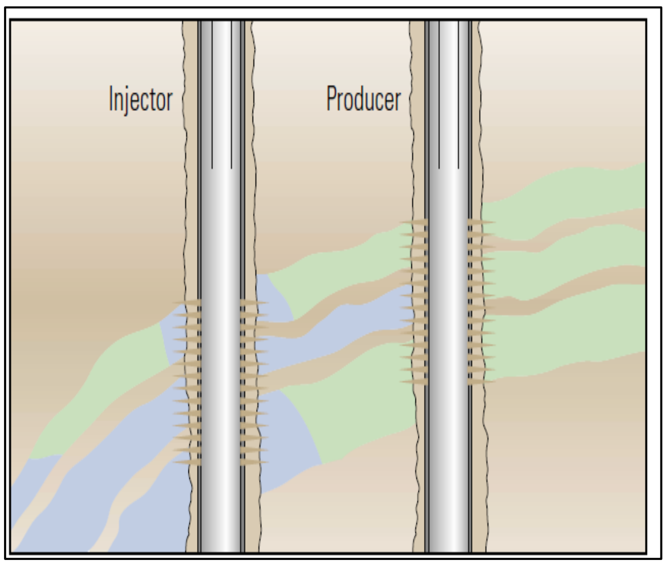


Figure 2-4 Channelling due to Water Flooding (Injector) (Bailey et al., 2000)

2.1.2 Water Conning

Conning is the raise of the water from the bottom water to the perforation zone due to the cohesion force and vertical permeability, Figure 2-5. As a result, the water can break through into the perforated or open-hole section, replacing all or part of the hydrocarbon production.

Reservoir which expected to cone water is often completed in the upper 20% of the available hydrocarbon pay thickness to place the source of pressure drop far away from the hydrocarbon/water contact. Mainly there are two types of water conning; stable conning and unstable conning.

Coning may take place as a result of: constant production rate, constant pressure gradient in drainage zone, and flowing pressure gradient is less than gravity force. When the pressure gradient is great enough to pass gravity force, water would make unstable conning. In other word there is a critical flow rate for the oil well if it has been passed, the well will produce water. The maximum oil production rate with the avoiding of water conning could be calculated from Meyer, Gardner and Pirson method, equation (1):

$$\mathbf{Q_{O\,max} = 0.001535 \frac{\rho_w - \rho_o}{\ln^{r_e}/_{r_w}} \frac{k_o}{\mu_o \beta_o} (h^2 - D^2)} \qquad \textbf{Equation 1}$$

Where:

$Q_{O\,max} = \textit{the critical oil rate STB/D}$ $\rho_w, \rho_o = \textit{Densities of water and oil gms/cc}$

$r_e r_w = \textit{drainge and well radius ft}$ *h, D=net bay thickness and perf. Interval ft.*

ko =effective oil permeability mD $\mu_o \beta_o$ *=oil viscosity and oil FVF cp, bbl/STB*

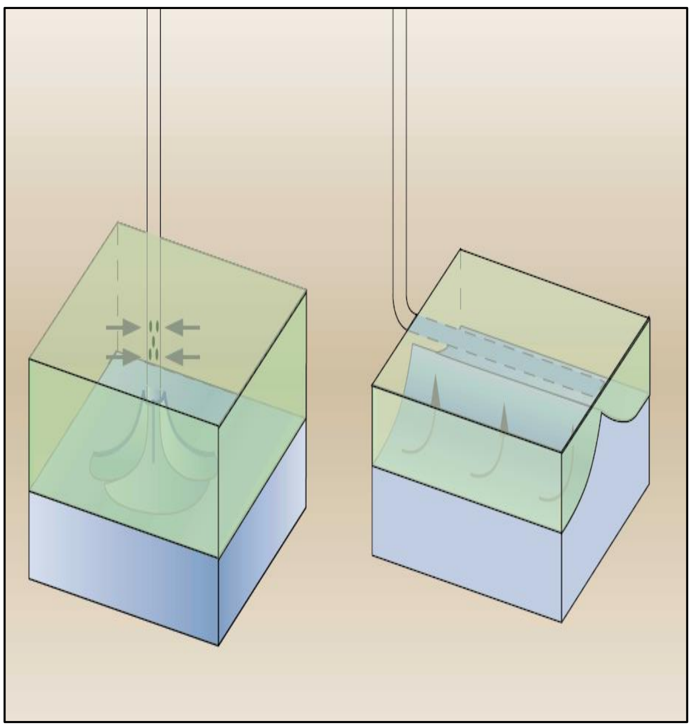


Figure 0-5 Water Conning in Horizontal and Vertical Wells (Bailey et al., 2000)

2.1.3 Casing Leak

Casing leak is a failure happens in the casing because of the high pressures exerting against the casing by formation pressures or high hydrostatic pressure, Figure 2-6. Casing leak can happen by tension, collapse, biaxial loading, or casing buckling. The excessive water production considered as an indicator for the casing leak.

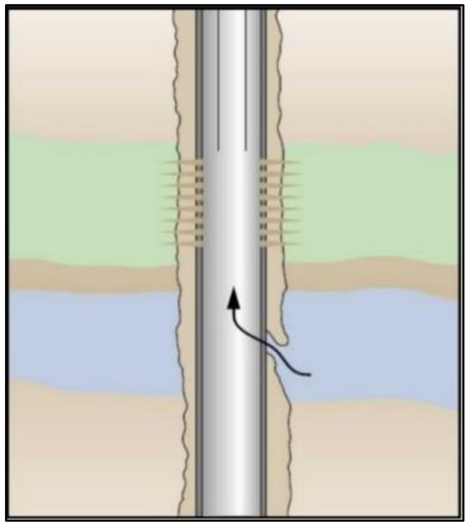


Figure 0-6 Casing Leak (Bailey et al., 2000)

2.1.4 Cement Failure

A lot of reasons guide to cementing failures like; miss-centralization, pipe movement, contamination of fluids, mud channels, and bridging, Figure 2-7. In the presence of cement failures, water could move easily from water formations to the perforation, which means water production.

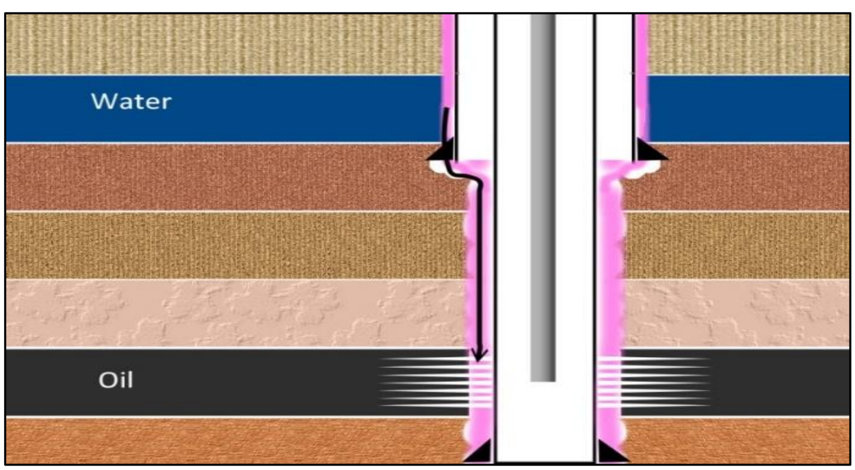


Figure 0-7 Water Production due to Cement Failure

2.1.5 Miss-Completion (Bad Perforation)

Completion into the zones where water saturation is higher than the irreducible water saturation allows the water to be produced immediately. Often, impermeable barriers (e.g., shale or anhydrite) separate Hydrocarbon-Bearing Strata from water-saturated zone that could be the source of the excess water production. However, the barriers can breakdown near the wellbore and allow fluid to migrate through the wellbore.

Even if perforations are above the original water-oil or water-gas contact, proximity allows production of the water to occur more easily and quickly through coning or cresting.

2.2 Water Production Diagnostic:

In the past, water control was simply a plug and cement operation, or a gel treatment in a well. The main reason for why industry's failure to consistently control water is the lack of understanding the different problems and the consequent applications of inappropriate solutions. This is demonstrated by the number of technical papers discussing the treatments and results with little or no reference to the geology, reservoir or water control problem. The key optimum way for water control, is the diagnostics to identify the specific water problem at hand (Bailey et al., 2000). Well diagnostics are used in three ways:

I. Screening wells that are suitable candidates for water control
II. Determine the water problem so that a suitable water-control method can be selected
III. Locate the water entry point in the well so that a treatment can be correctly placed

Water shut off techniques were used worldwide to avoid the massive water production; historically many material were used in the oilfields; (Liu et al., 2012) Studied the effect of the foam agent solution experimentally to show the feasibility of using the nitrogen foam in controlling the edge water. In addition, they used a numerical simulation to demonstrate the injection of foam into a horizontal well and 3 vertical wells. The result showed a significant improves in controlling the water cut in the horizontal section but the vertical wells are not effective. Although some operators performed water shutoff without clear diagnostic procedures, unsuccessful result have been obtained in the industry

(Seright, 2001) Communication degree between injection well and production wells was present in term of water control strategies by (Chou, 1994).

Historically many diagnosing techniques were used to predict water production problem in the wells; well logging techniques (temperature logs, resistivity log, flow meter…etc.) were early used as an effective water production problem investigation technique; however the log interpretations and analysis are very complex, costly and limited to the direction of the wellbore (Nikravesh, 2001, Wong, 2002).

Due to the high cost of the production logging, another technique used for the diagnosis of water production problem is the Decline curve analysis (rate vs. time plot) or production rates vs. cumulative oil plot, which is straight-line plot; any fortuitous alteration in the slop is due to massive water production. The conventional water-oil ratio (WOR) vs. cumulative oil production in semi-log scale (Recovery plot) was early used in oil industry to analyze the production data (Bailey et al., 2000)

Several analytical and empirical techniques using information such as production data, water/oil ratio and logging measurements have been developed to determine the type of water production problem, locating the water entry point in the well and choosing the candidate wells to perform treatment methods. Water/oil ratio diagnostic plots are probably the most widely used technique in reservoir performance studies. Many oil companies to date rely on log/log plots of WOR and its derivative against time to identify the water mechanism caused by water coning or channeling. WOR diagnostic plots are easy to use and explicable for non- experts. The production data required for these plots are routinely collected and accuracy of these data is usually reliable. Nevertheless, without taking other important reservoir parameters in to account, the WOR diagnostic plots could easily be misinterpreted and it has been demonstrated that applying these plots on their own could be misleading (Seright, 1998).

2.2.1 Diagnose with the Production Data:

Production data analyses are the most commonly used techniques for investigating the overall performance of the reservoir as well as individual wells. The key elements of the production data are the information on the rate of the produced oil and water, collected at regular time intervals (usually on a daily basis). Usually, along with the rates of the produced oil and water, the water oil ratio (WOR) plots also used for interpretation and production analysis. Production data analyses by means of analytical and empirical techniques such as decline curve plots, and water-oil ratio (WOR) versus cumulative oil production or time is a widely explored subject in the literature. These plots described as follows:

2.2.1.1 Recovery Plots:

The log-log plot of WOR against the cumulative oil production called the recovery plot Figure 2-2. Cumulative oil production at any particular time during the field life cycle is the total amount of the oil produced from a reservoir at that time. The recovery plot can be extrapolated to predict the future performance and estimate the ultimate oil recovery. The point where this plot reaches the economic WOR plot shows the amount of oil production without any remedial action for water production. The economic WOR limit is the rate of WOR where the cost of handling the produced water is equal to the value of the oil produced. If the well is producing acceptable amount of water, then the extrapolated production is equal to the expected reserves. Otherwise, if the predicted oil production at WOR economic limit is lower than the expected oil reserve for that well, it is a sign of excess water production, which requires water control treatments are required (Bailey et al., 2000).

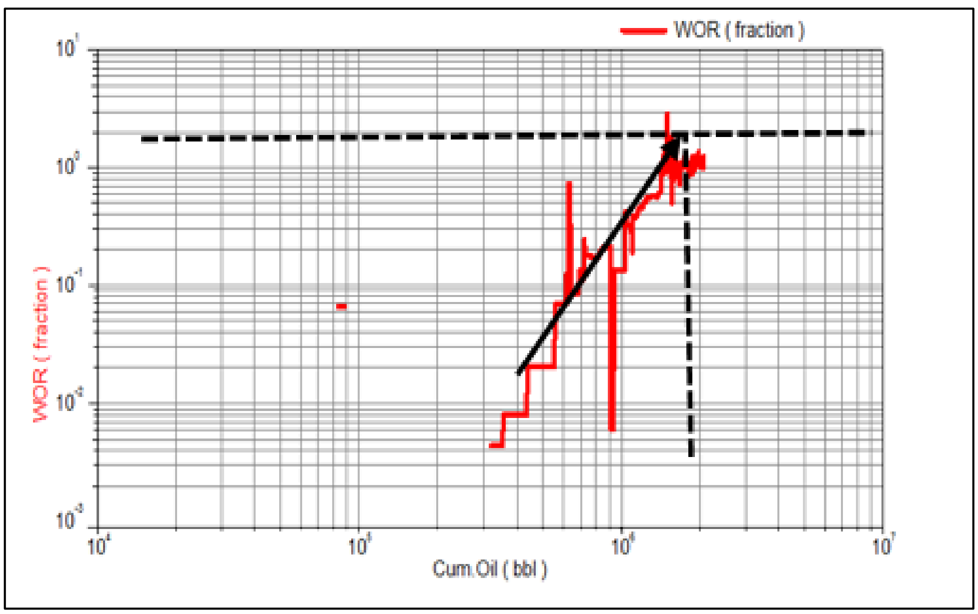


Figure 0-8 Recovery plot

2.2.1.2 Production Hhistory Plots

The production history plot is a plot of oil and water rates against production time, Figure 2-4. This plot helps in visualizing rate changes during the field life cycle and assessing any "uncorrelated behaviors" such as; changes in the rate without corresponding changes in pressure. Wells with water production problem usually show a simultaneous increase in water production with a decrease in oil production (Bailey et al., 2000).

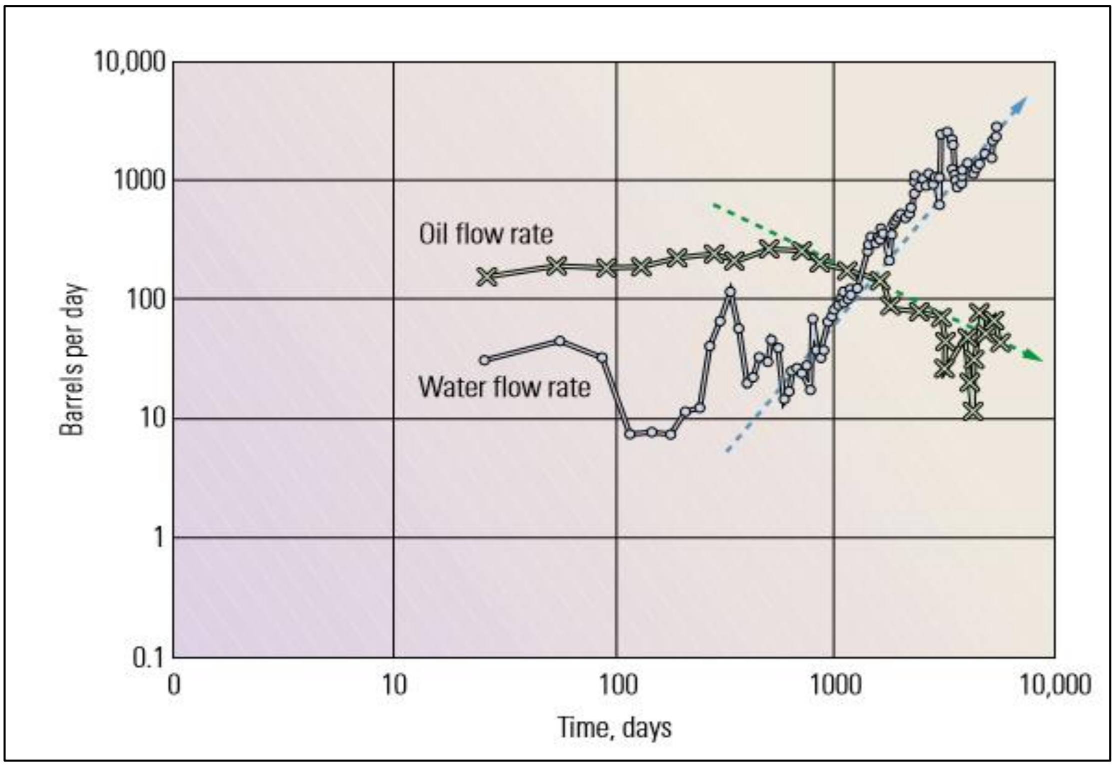


Figure 0-9 Production History

2.2.2 Chan's Method:

Chan (1995) proposed a new methodology to analyze the log-log plot of WOR and derivative of WOR against time in order to differentiate between two common and more complicated water problems of water channeling and water coning. Chan has used various drive mechanisms and water flood scenarios using a three dimensional, three-phase black oil reservoir simulator to demonstrate the WOR plots differential mechanism. Based on Chan's report, three behavioral periods can be observed in the WOR versus time plot for both coning and channeling. During the first period from the start of the production to water breakthrough time, the WOR is constant for both mechanisms. However, this period called the departure time is usually shorter for coning than channeling.

In coning, the departure time corresponds to the time when water–oil contact (WOC) rises and reaches the bottom of the perforations. In channeling, the departure time relates to the time of water breakthrough for the highest permeable layer in a multilayer formation. After water break–through, which denotes the beginning of the second period, WOR in coning and channeling shows different trend?

In channeling, the WOR increase rate is relatively quick but it could slow down until it reaches a constant value. In coning, WOR gradually increases until it reaches a constant value thereafter, the WOR increases quite rapidly for both mechanisms during the third period.

Chan also investigated the behavior of the time derivative of WOR (WOR') for channeling and coning mechanisms. Coning WOR' shows a changing negative slope while channeling WOR' exhibits an almost constant positive slope

Stanley et al (1996) and Love et al. (1998) reported the use of WOR diagnostic plots in successful water treatment design case studies in Indonesia and New Mexico, respectively. However, it is important to notice that in both of these studies, the WOR diagnostic plots was not applied as a stand-alone technique but rather a supplementary tool with other methodologies such as production loggings and reservoir modeling.

Jassim and Subhi (2010) Applied Chan's methodology for wells in Middle East sandstone oil reservoirs using actual production history data to generate log-log plots of WOR (water oil ratio) and dWOR/dt (simple time derivative of water oil ratio) vs. time. The plots were found to be effective in differentiating whether the well is experiencing water coning (negative slope) or multilayer channeling (positive slope for the time derivative of water oil ratio curve). The diagnostic plots applied in this study provide a handy method for quick evaluation of excessive water production mechanisms in order to select wells candidates for water control treatment.

Despite the wide use of WOR diagnostic plots in wellbore and reservoir performance investigations, (Seright, 2001) challenged the view of using WOR plots as a diagnostic tool for water production management identification. He conducted a research study to determine whether Chan's proposed technique in interpreting WOR and WOR' plots is generally applicable or if there are limitations to study. Using numerical simulation and sensitivity analyses, the effects of various reservoir and fluid parameters on WOR and WOR’ were investigated for both coning and channeling problems.

His study revealed that the WOR and WOR’ behavior for a multilayer channeling case depends mainly on variables such as the degree of vertical communication and permeability contrast among layers, saturation distribution, and relative permeability curves. Coning WOR and WOR’ behavior depends mainly on the vertical to horizontal permeability ratio, well spacing, capillary pressure, and relative permeability curves. Seright (2001) demonstrated that in many cases, multi-layer channeling problems would show negative derivative trend, which is an indication of coning mechanism according to Chan (1995). A similar contradiction to Chan’s claim was observed for a coning case where plots show a rapid WOR increase with a positive derivative slope. Seright (2001) concluded that the WOR and WOR’ diagnostics plots are not general and could easily be misinterpreted and should therefore not be used alone for identifying mechanisms of excessive water production.

2.2.3. Nodal Analysis: -

Bailey et al. (2000) suggested techniques for water production mechanism diagnosis using nodal analysis. The total fluid pressure loss in the production system is due to the pressure loss through four subsystems from reservoir bottom to the surface equipment’s. These subsystems are the porous media, well completions, tubing string and the flow line. The total fluid production from the reservoir to the surface depends on the total pressure drop in the production system.

Therefore, the entire production system must be analyzed as one continuous unit, where fluid properties and pressure conditions at any point are dependent on the inflow and outflow from that particular point. The nodal analysis method views the production system as a group of nodes and fluid properties are evaluated locally at each node. The pressure drop at any particular node depends on the flow rate as well as the average pressure existing at that node. Any changes at a node in the system results in changes in pressure and/or flow rate at that specific node. For this reason, problems in the production system can be looked at by aiming at a specific node and considering the inflow and outflow subsystems of that node. Based on the concept of continuity, flow into the node is equal to the flow out of the node. Similarly, pressure in both inflow and outflow subsystems are the same. The intersection point of the plots of node pressure against production rate for inflow and outflow subsystems provides the expected production rate and pressure for the point being analyzed. Figure. 2-10 represents a nodal systems graph from for a sensitivity study of three different combinations for outflow components labeled A, B, and C. The graph explains that for outflow curve A, the well will not be expected to flow with System A, as there is no intersection with the inflow performance curve and hence, no continuity. The intersections of outflow performance curves B and C with the inflow performance curve satisfies continuity, and the well will be expected to produce at a rate and pressure indicated by the intersection points. Deviation from the expected rates could indicate a problem.

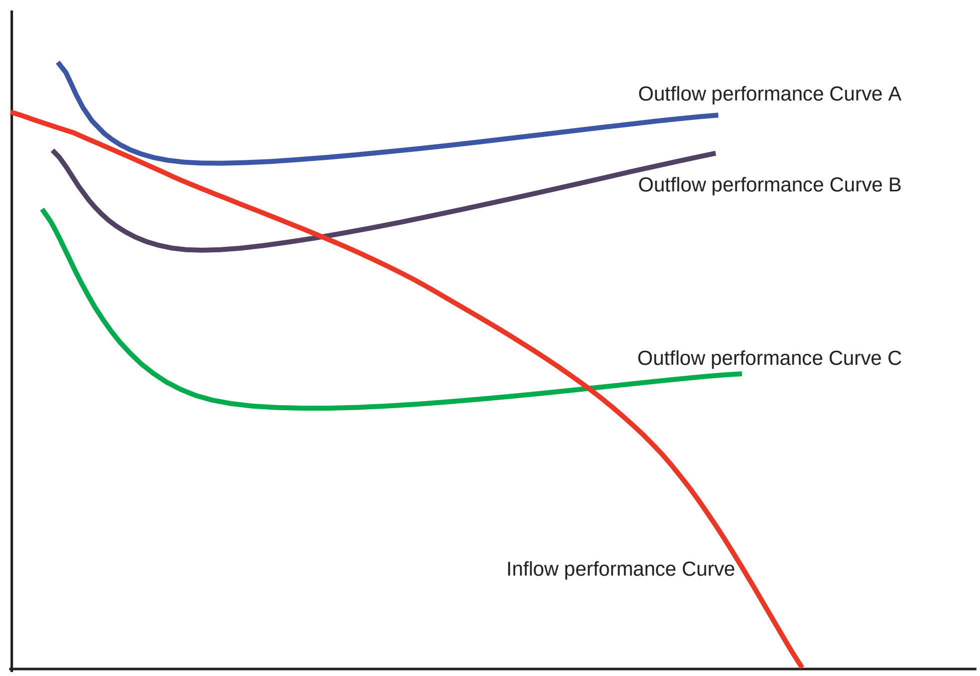


Figure 0-10 Nodal Analyses Performance

2.2.4 Well Testing: -

Numerous well testing and logging techniques are available to observe fluids flow into the wellbore and assess the condition of the well. Radioactive tracer logs, temperature logs, spinner (flow meter) logs, cased hole formation resistivity (CHFR) tool, Figure 2-11 pulsed neutron, thermal decay time tool, reservoir saturation tool, pressure testing, casing inspection logs and chloride/total dissolved solids (TDS) test are few examples of various available well testing tools and techniques (Reynolds, 2003). The use of such tools and techniques can provide some insights into the water production mechanism encountered in the well. For example, TDS tests can determine the source of the produced water and whether it is coming from the aquifer or from the injector. Radioactive tracer logs can help in detecting leaks in the packers and plugs or fluid channels behind casing. Other production logs can also provide insights into the source of the water being produced or determine the water entry point into the wellbore. Nevertheless, while these logs are vital tools in well and reservoir surveillance, their application during production is somehow limiting. The logging instruments or application of them can be expensive.

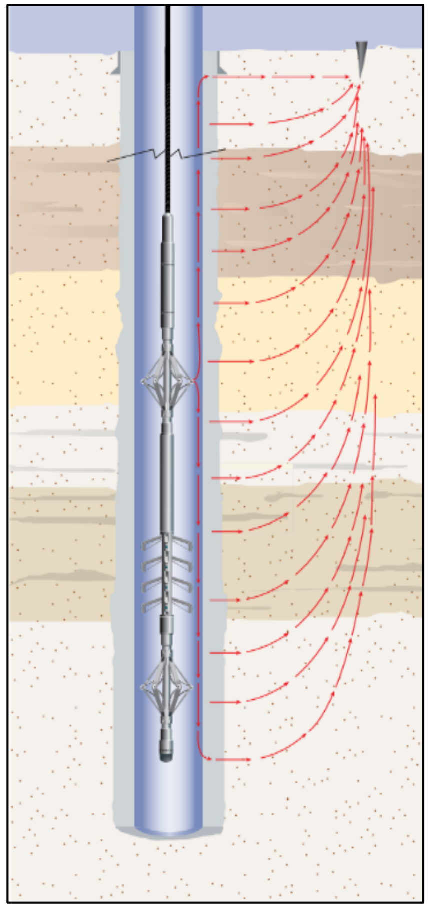


Figure 0-11 CHFR Tool

The main purpose of using CHFR is for reservoir monitoring. During the production life of a reservoir, Through-casing formation resistivity data may help understand fluid flow and recovery processes in several ways:

1) Evaluation of reservoir fluid saturation changes with time, including the identification of swept zones, potential flow barriers, and bypassed oil.
2) Monitoring of movement in oil/water contacts.
3) Identification of take-off rate-induced water coning, by repeat logging at different takeoff rates, allowing time to re-establish stable conditions.

Sometimes it is required to shut down the well during logging which consequently affects the production rate and revenue. Log data are often very complex and could entail costly and time-consuming data processing and log analysis and interpretation (Nikravesh, 2001),(Wong, 2002).

The differential temperature log measures temperature of the wellbore fluid under static (shut-in) or dynamic (flowing) conditions, Figure 2-6. Temperature logs run while a well is injecting water at stabilized rates can yield much useful information. The logging tool responds to temperature anomalies produced by fluid flow, either within the casing or in the casing annulus, and is very useful in detecting the latter. Interpretations are also used to determine flow rates and points of fluid entry or exit. In an injection well, temperature response is a function of depth, temperature of injected fluid, injection rate, time of injection, formation and fluid thermal properties, and the geothermal profile in the well. An injection well that has been taking fluid for some time can be shut in and numerous temperature logs can be run over a period of time to observe the temperature profile as it returns to geothermal values. The zones that have taken the (usually) cooler injection fluid will show a slower rate of return to the geothermal profile than the zones that have taken no fluid. (Bailey et al., 2000).

This effect can be detected in upper zones behind pipe that are taking injection water due to communication problems. The most common application is in water flooding projects where a foot-by-foot analysis of formation flooding is desired on injection wells. Advantages in tracing injected fluids with the single element differential temperature log become apparent when proper logging interpretation techniques are used. The temperature gradient log is a continuous recording of downhole absolute temperatures. Repeatability of the temperature measurement is plus or minus 0.01^{o} F in the range of 50 to 400^{o} F. Scales vary from fractional increments per inch to any practical limit required. The most commonly recorded scales are: 1, 2, 5, and 10^{o} F per inch. Logging is usually performed on the downward traverse so that well fluids are encountered in their normal state without being previously disturbed by passage of the line and tool. The casing collar locator is run and recorded simultaneously, as this provides definite depth correlation with other types of logs run in the well.(Economides, 1994)

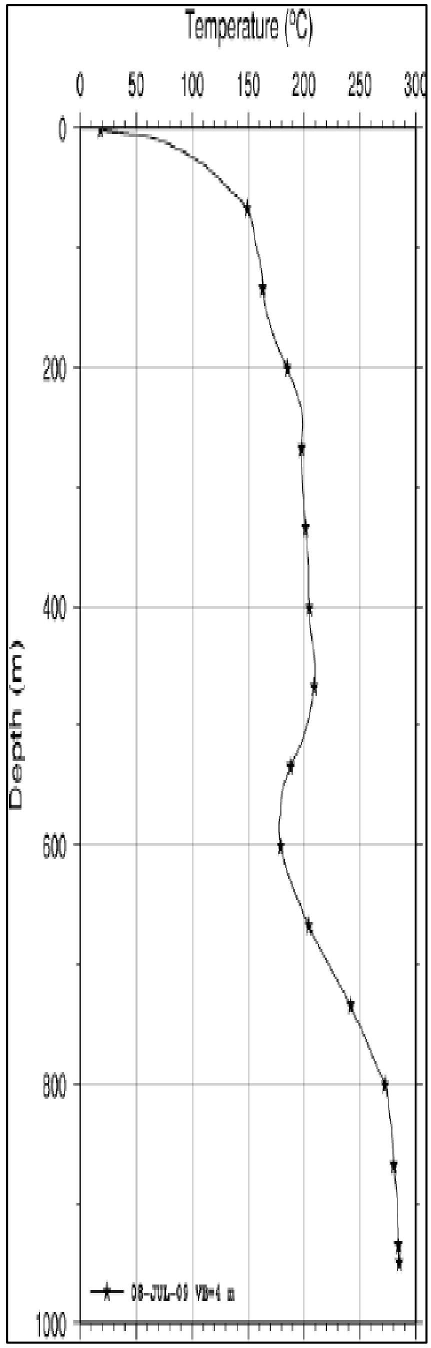


Figure 0-12 Temperature and Density log (Economides, 1994)

Besides being used to detect fluid communication downhole in water injection wells, the technique is applicable for finding tubing-casing leaks, gas communication, productive zones, lost circulation zones, gas-oil-water contacts, production profiles, and tracing frac fluids.

2.2.5 Production Logging:

The main purpose of Production Log (PL) analysis is to determine how much of which fluid is coming from where. In order to achieve this fluid velocity along with the hold-up of each phase must be known. From this information, the flow rate of each phase in the wellbore can be established and the flow profile determined. After acquisition of production logging data, an interpretation of the measurements by an analyst will reveal the composition and distribution of the wellbore fluids, Figure 13-2. One, two and three phase analyses are possible depending on the number and type of sensors run accurate production logs, can show water entry into the wellbore. This tool can determine flow and holdup for each fluid phase in vertical, deviated and horizontal wellbores. The addition of new optical and electrical sensors incorporating local probe measurements and phase-velocity measurements have resulted in major improvements in the diagnosis in both complex and simple wells with three-phase flow. Such advances in reliable and accurate production logging, particularly in deviated wells with high water cuts, represent a major step forward in identifying and understanding water-problem types (Bailey et al., 2000).

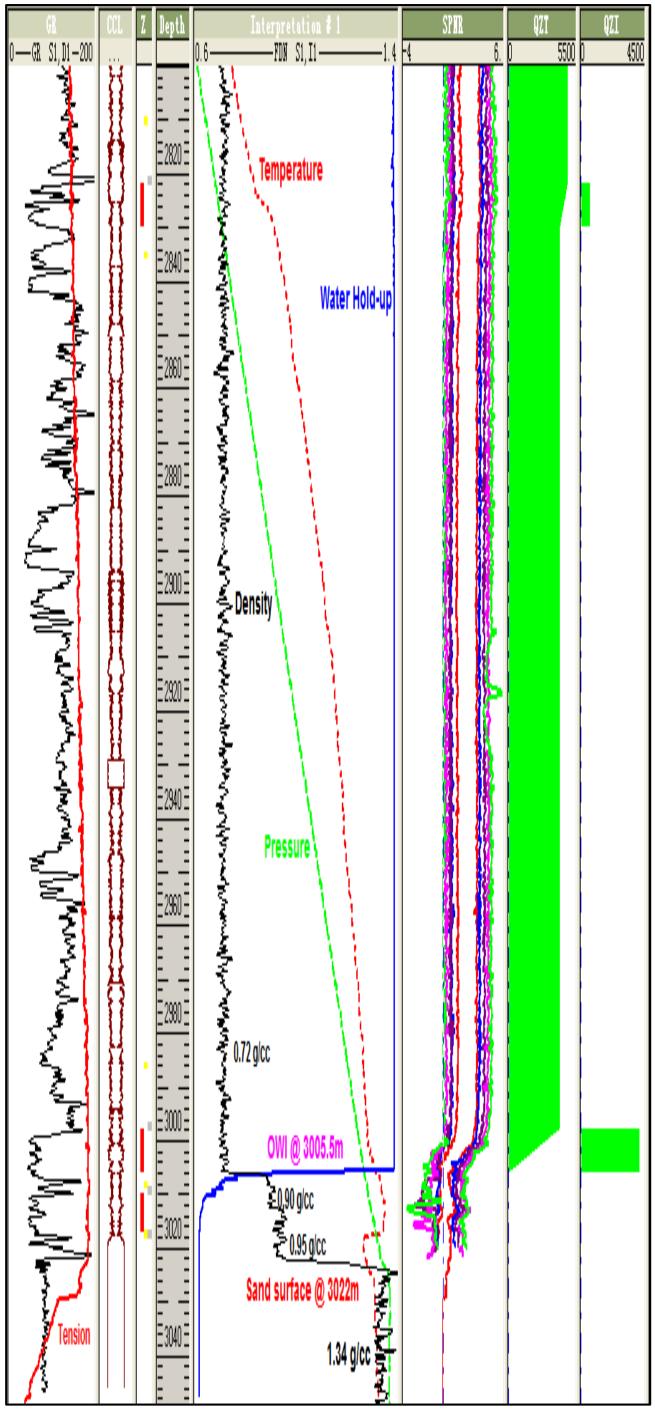


Figure 0-13 PLT Analysis

A wide choice of Production Logging sensor is employed to provide the raw data, which the analyst requires to interpret the production log. Typically, a flow meter will provide the apparent velocity of the fluid mix - this must be corrected to give the average velocity. A density sensor along with the PVT data from the well is used to allow calculation of phase hold up in a two phase system. A set of all defined equations uses these results to provide the downhole rates for the fluids present. In more complex situation where more than two phases exist in the wellbore, additional sensors can be deployed to provide direct measurement of water and gas hold-up. These sensors allow enhanced analysis and accurate results. Analysis may be further enhanced by production logging tools, which directly measure the distribution of phases across the wellbore. Such tools have many sensors deployed circumferentially across the wellbore.

Flow mechanisms are different in each well. Factors such as flow rate, bubble point and well trajectory will determine the distribution of fluids in the wellbore. In fact, well-mixed flows, traditional center measuring tools will yield good results of analyzed data. However, in wells where flows become stratified, confidence in results is increased when additional data from multi-sensor tools is available.

2.3 Water Control and shut-off Methods:

All the available diagnostic tools are only to answer the question of what well should be selected and why, many aspects have to be considered to get more from the uneconomic wells. Any water shutoff (WSO) treatment fails to achieve successful results because of four reasons:

1) Wrong selection of candidate wells
2) The exact source of the water problem is not known
3) The wrong method is used
4) The correct method is executed improperly.

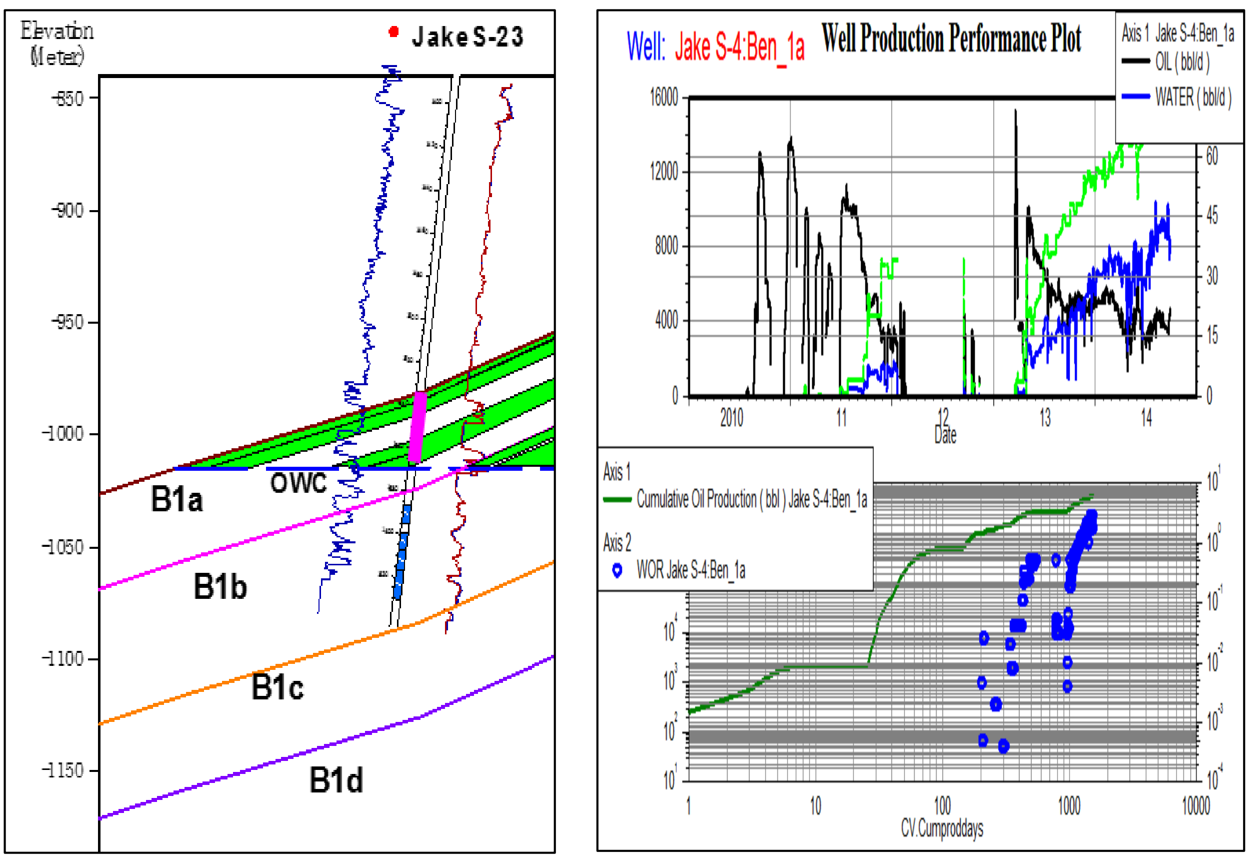
Therefore, the selection of candidate well assumes significance for success of WSO job. Too often operators guess at source of water production and after the treatment find that they have shut off the oil or gas as well as the water. We should try to find out the mechanism of excessive water production and the point of the water entry in wellbore.

D. Permana (2013) defines the best candidates wells for WSO as :-

1) shut-in wells or wells producing at or near their economic limit
2) Benefit most from a successful treatment
3) Little at risk if treatment fails (other than treatment cost)
4) Significant remaining mobile oil in place
5) High water-oil ratio

6) High producing fluid level
7) High initial productivity
8) Wells associated with active natural water drive
9) Structural position
10) High permeability contrast between oil and water-saturated rock (i.e., fractured reservoir)
11) Successful treatments have been conducted in both cased and open hole completions

Various options to reduce lifting and/or water handling costs are available in dealing with wells that produce large amounts of water. These include water shut-off treatments using gelled polymers, reducing beam pump lifting costs, power options to reduce electrical costs, and separation techniques. Not all wells are conducive to having any or all of these techniques applied, but in the right circumstances, major economic benefits can be realized.



Structural Position **High Risk**

Figure 0-14 Examples of Bad selections

The classification based on the degree of the treatment difficulty is more applicable in studies related to the design and application of the water control strategy. For example, Seright (2001) categorized the water production problems based on the difficulty of treatment; Table 2.2 shows the screening criteria for conformance problem for excess water, the table was listed in increasing order of treatment difficulty. Conformance problem need to be clearly identified before effective treatment selection. Conformance problems listed in Group A are the easiest problem to solve, conventional techniques such as cement, bridge plugs and mechanical tubing patches are effective choices. Gel treatments are the most effective method for conformance problems in group B, Preformed gel are the best choice for group C. For complex conformance problem in group D, successful rate for gel treatment application is extremely low.

Table 0-1 Water Production Problems Categorizes based on Treatment Difficulties, (Seright, 2001)

A	"Conventional" treatments	**B**	Treatment with Gels
• Casing leaks without flow restrictions. • Flow behind pipe without flow restrictions. • No fractured wells without cross flow.		• Casing leaks with flow restrictions. • Flow behind pipe with flow restrictions. • "2D" conning. • Natural fracture system leading to an aquifer.	
C	Treatment with pre-formed gels	**D**	Difficult problems
• Faults or fractures crossing deviated or horizontal well. • Single fracture causing channelling between wells. • Natural fracture system allowing channelling.		• 3D conning. • Cusping. • Channelling through strata with cross flow.	

Each problem type has solution options that range from the simple and relatively inexpensive mechanical and chemical solutions, to the more complex and expensive reworked completion solutions. Multiple water-control problems are common, and often may require a combination of solutions. In addition to the traditional solutions described above, there are new, innovative and cost-effective solutions for water-control problems are used today as:

I. Packers, bridge plugs, mechanical patches
II. Cement, sand plugs calcium carbonate.
III. Pattern flow control.
IV. Infill drilling/well abandonment.
V. Horizontal wells.
VI. Gels.
VII. Resins.

In many near-wellbore problems, such as casing leaks, flow behind casing, rising bottom water and watered-out layers without cross flow, mechanical or inflatable plugs are often the solution. Mechanical isolation is an effective placement method for non-communicating layers when high permeability zone is isolated and low permeability zone is protected. Compare to bullhead placement, mechanical isolation has higher successful rate. According to the annual report from Alaska Prudhoe Bay, 60% success at shutting off excessive gas well by using mechanical isolation to place gelant into formation (R.H. Lane and Sanders, 1995).

Other than that, 84% of the successful treatment at modifying injection profiles with mechanical isolation was applied. Mechanical isolation method will lead to a good placement result when oil well has a good casing and cement; and don’t have near wellbore fissures problem; also one or two excessive water or gas production zone have been identified. But when oil wells have channels behind pipe, this method is not always effective (Miller and Chen, 1997).

A technology proposed by Demin Wang and Chen(1983) and developed by Chou (1994) by using ensentric production mandrels and y341-y441 packers a string built for the separate zone production which provide the ability of testing every zone production separately and then close it if there is no significant results. This methodology worked very well for gas lift wells with high water cut and its advantages are strong adaptability to casing, and to conduct arbitrary multistage pro-ration production by running and pulling stage blanking plugs using slick line ability to adjust the choke sizes for different layers. The downhole operating life is up to 5 years.

Polymer gels can be used successfully as an alternative to cement, or in combination with cement, to squeeze casing leaks. The type of polymer and process used depends on the location and severity of the leak, and whether or not the squeeze will be required to hold a solid pressure or simply block encroachment of foreign water in a producing well.

The advantage of using polymer is two-fold. Polymer can be washed out of the wellbore after a leak is squeezed, preventing costly rig time involved in drilling out cement. Second, since polymer solutions exert a much lower hydrostatic pressure than cement slurry, there is less possibility of breaking down the formation and losing the squeeze. On difficult leaks, such as in salt sections where multiple cement jobs are often attempted before the leak is successfully squeezed off, a small slug of polymer can be run ahead of the cement as a buffer to prevent the cement from "running away" or washing out the section you are trying to squeeze.

Also at the combined treatment mechanical packers, selective zone packers or bridge plugs to isolate perforations or openhole area to prevent treatment fluid from closing neighboring oil layers. Depending on the conditions, the tool could be used as a control for injection or production when left it in the well. During the placement process, infection and communication characteristics have to been fully tested before the determination of the packer’s degree of placement control on the zone. When treating a vertical conformance problem of a radial flow well, mechanical isolation need to be used to assure that the gelant is injected exactly into the high permeability zone or low oil saturation area for near well bore gel treatment process (Seright, 2001)

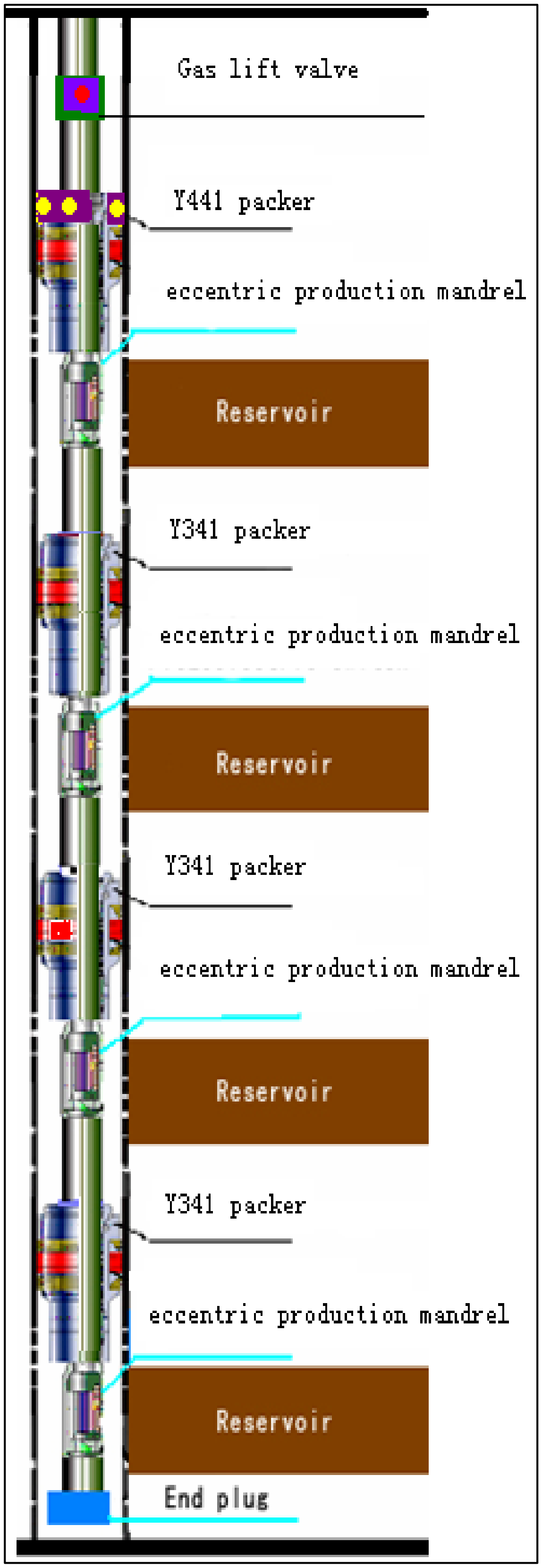


Figure2-15 Water Shut-off, Detection String

Table 0-2 Summary Water Control Problem, Indications, Causes and Diagnostics

Problem	Indicator(s) of Problem	Cause	Diagnostics
Casing Leaks	Unexpected rapid increase in water of gas production	Corrosion Improper casing and/or collar installation	Production Logs Down hole Video Tracer Surveys
Channel behind casing	Unexpected rapid increase in water of gas production	Poor cement bond to casing and/or formation bond	Cement Bond Logs Temperature Logs
Barrier breakdown	Temperature logs show deviation from geothermal gradient when well is shut in	Natural fractures Breakdown during drilling Pressure differential from production	Temperature Logs Pulse Testing Tracer Surveys
Completion into water or gas	Immediate production of unwanted fluids	Improper log interpretation	Daily Report; Core Data Openhole Logs; Resistivity Logs Porosity Logs
Coning and cresting	Gradual increase in water-oil or gas-oil ratio	Reduced pressure near the wellbore draws water and/or gas from adjacent zones	Density Logs; Hydro Logs, Well Testing; Seismic-Geologic Reservoir Analysis
Stimulation out of zone	Immediate water or gas production after a stimulation treatment	Previous stimulation operation	Production Logs

2.4 Cost Associated with Water Production:

First problem associated with excessive water production is well operating costs; in an average of three barrels of water for each barrel of oil, this could make a huge impact on the field feasibility. The cost of produced water treatment also includes the capital and operating costs of unit processes applied to the waste stream. Operation and maintenance costs include the costs associated with the labor, material, and energy required to operate and maintain the treatment plant. A significant residual stream is not generated during all forms of water treatment, and therefore, in some instances, disposal costs may be small.

In addition, the residual waste stream generated during the execution of a water treatment unit process will not always have a cost associated with its' disposal that is directly imputable to the disposer.

The increased operating expenses of handling water include the following:

1. **Expenses to lift** the produced fluids including the additional cost of power to lift heavier fluids and larger volumes of fluid, investment for larger lift equipment, increased well services and maintenance expenses as the equipment is used harder.
2. **Expense of separating** the water from the oil or gas including costs for larger tanks, separators, surface pumps, maintenance, chemicals, and energy required for these facilities.
3. **Expenses to dispose** or re-inject the water tanks, injection --- and lines, high pressure injection pumps, and maintenance and power to run these facilities.
4. **Expenses to clean** and chemically treat the water prior to disposal oil removal skimmers and tanks, filters, floccule agencies and chemical for oxygen control, -- bacteria and scale inhibition.
5. **Expenses of repairing** and maintaining injection and disposal wells-initial drilling and preparation of these wells plus Workovers, cleanouts acidizing treatments, and re-completions.

2.4.1 Treatment Costs:

The costs associated with managing and treating produced water is highly dependent on the final required water quality. The minimum cost of treating produced water is the cost of simply disposing of the water. This is most frequently accomplished by deep well injection, ocean discharge, and/or hauling. Some pretreatment, particularly before deep well injection, is likely to be needed to maintain well injection ability and minimize well maintenance costs. Typical values given for produced water disposal range from \$0.63 to \$3.15 / m3 (Tomson et al., 1992).

When more extensive pretreatment is required before disposal or when the produced water planned to be used, the cost of produced water treatment includes the capital and operating costs of unit processes applied to the waste stream. Therefore, estimating the costs for managing these waters is complex at best given the wide variability in the chemistry of produced waters. In some cases, the cost of treating the produced water can be prohibitive to energy development ventures. Furthermore, as clean water is a scarce resource, treating and reusing these waters for beneficial applications (i.e., for irrigation, industrial processes, frac water make up, or other non-potable purposes) may have significant economic incentives (Produced Water Utilization Act of 2008, 2008). For hydraulic fracturing recovering and reusing the flow back water can reduce costs associated with disposing of the wastewater and the acquisition/transport of new makeup water. Essential to the realization of these beneficial reuse applications is the development and implementation of effective produced water treatment systems; however, the complex chemistries that characterize these waters makes treatment by existing desalting technologies difficult at best.

Removing TDS from any water is an energy intensive effort. Treatment costs will increase rather rapidly as the TDS concentration increases. For membrane processes, such as reverse osmosis (RO), this relationship between cost and TDS is attributed to the relationship between salt concentration and osmotic pressure (i.e., as salinity increases so too does the osmotic pressure of the solution). Saline solutions will require larger and more energy intensive feed pumps in order to overcome the osmotic pressure of the feed solution. The type of desalination technology used will vary depending on the ionic composition of the water. For example, ion exchange or pH adjustment may be used when the water is primarily composed of carbonate species, while membrane processes or distillation processes will be required for waters that are more complex.

2.4.2 Produced Water Treatment:

Whether it will be discharged to the environment and or injected to underground disposal and or reservoir pressure maintenance, treatment becomes critical. There are two main categories of produced water treatment; these include treatment to remove oils (dissolved and dispersed) and treatment to remove salt. These contaminants can be either suspended or dissolved as discussed below, Salt removal becomes crucial if the treated produced water were to be re-used for e.g. irrigation, agriculture. Oil in produced water exist in three forms; dissolved, dispersed and free oil as explained elsewhere in the guidance. Free oil is relatively easy to separate. The dissolved and dispersed oil is more difficult to remove.

There are many treatment technologies available for removing dispersed and dissolved oil from produced water. These technologies include:

1) Mechanical (gravity, enhanced gravity, gas flotation, filtration, membrane etc.)
2) Absorption / adsorption / extraction (Granular Activated Carbons – GAC, Macro Porous Polymer Extraction)
3) Advanced Oxidation Process (AOP)
4) Biological (bioreactors, wetlands etc.)
5) Hybrid (combination of various technologies)

For the removal of dispersed oil, mechanical methods are most commonly used and can be effective. The table below provides an indication of the kind of oil droplets that can be separated by typical mechanical methods.

Table 0-3 Water Treatment Technologies

Induced gas flotation (with flocculant)	3-5
Hydrocyclone	14-15
Mesh coalesce	5
Media filter	5
Centrifuge	2

The performance of API gravity separators depends on retention time, tank design, oil properties, operating conditions and the effects of flocculants or coagulants if added. Gravity separation is ineffective with small oil droplets or emulsified oil. As the oil droplet size diminishes, the required retention time drastically increases in order to obtain efficient performance. Gravity separation of smaller droplets also requires higher capital, maintenance and cleaning costs.

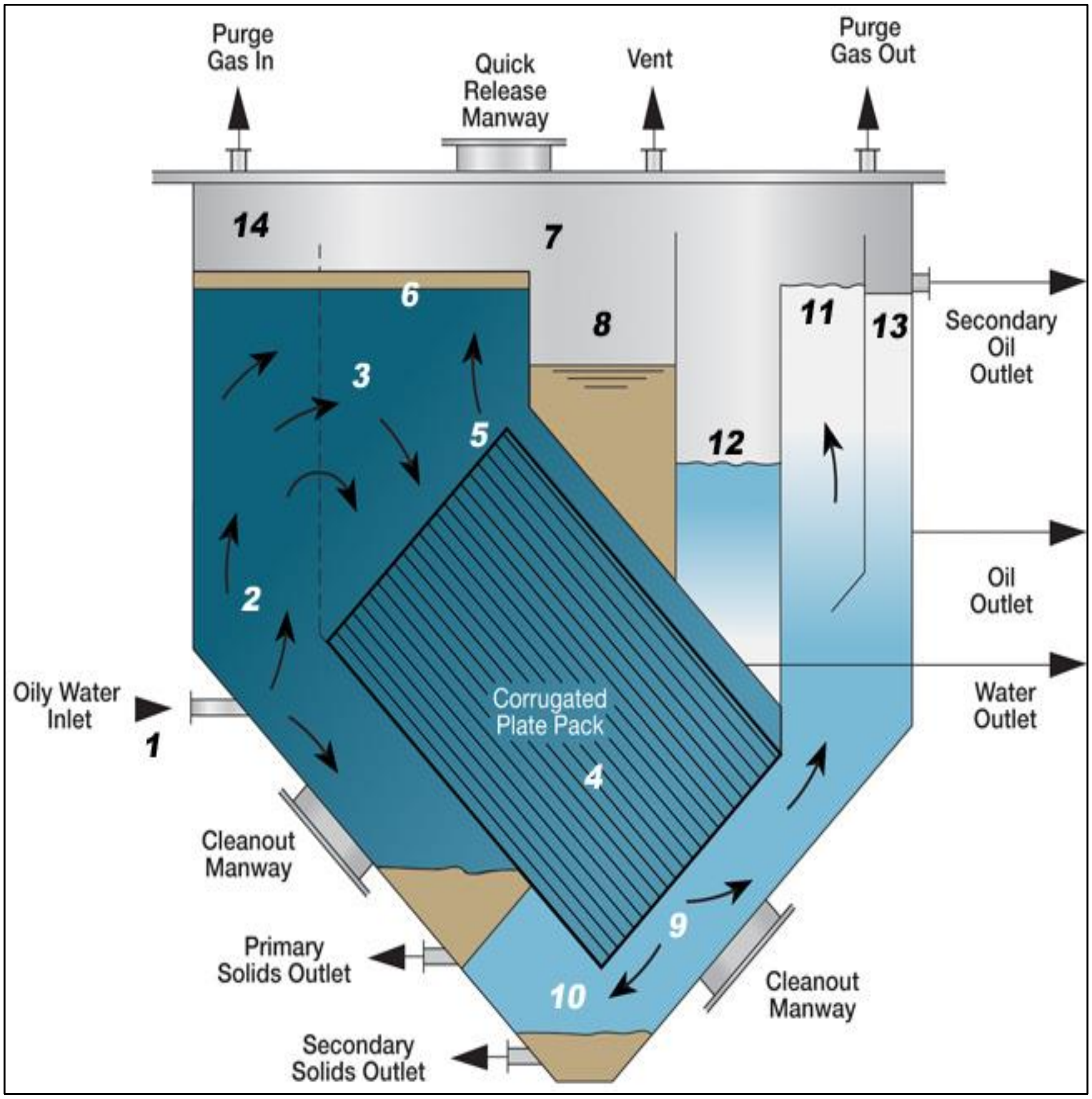


Figure 0-16 CPI PROCESS

Corrugated plates are packed to enhance the performance of gravity separation tanks Figure 2-16. The oil droplets coalesce and form larger oil droplets as the corrugated plates provide a longer path for the oil droplets to travel to the top of the tank. It is a simple operation that allows the compact design of the API separation tank; however, the efficient oil removal limits the oil droplet size of 40 microns and larger. Removal of smaller oil droplets is difficult with corrugated plate separator.

2.5 Disposal- Reuse of Produced Water

For water that is not manageable through water minimization approaches, operators can move next to the second level, in which produced water is re used or recycled, the most common way to re-use produced water is to re-inject it into a producing formation to enhance production.

There is wide selection of disposal possibility for the produced water, from ocean discharge to underneath ground reservoir storage however solely evaporating through artificial bonds and reinjection through water injection wells for pressure maintenance are contemplate and mentioned here as a result of those square measure the obtainable ways on the sphere under study.

2.5.1 Reinjection for Pressure Maintenance (Water Flooding):

Early in the history of oil and gas production, petroleum engineers realized that injecting water into hydrocarbon-producing reservoirs could increase production. This process, known as water flooding, began as early as 1865 in Pennsylvania. Water flooding moved from Pennsylvania to Oklahoma and Texas in the 1930s, but did not have widespread use until the 1950s (Thakur and Satter, 1998). It is not known whether produced water or local surface water was used as the source of water for the early water floods. At some point in time, particularly in areas with arid climates where large volumes of surface water were not available, companies began re-injecting produced water into formations for water flooding. Initially, a well may produce nearly all oil and gas (some will produce all oil; others all gas, and still others a mixture). However, as production continues the produced fluids will begin to contain formation water (in addition to oil and gas), the proportion of which increases over time. Logically, the earliest efforts at water management were those steps taken to separate water from oil and gas by gravity separation. The first step in managing the produced fluids is to separate them into three phases (oil, gas, and water) using gravity separation in a free-water knockout tank. Gravity separation removes most oil and gas from the water and collects some solids through settling. In the early years of using produced water for water flooding, gravity separation was most likely the only preparation or treatment that was done. However, there can be problems with long-term injectivity if the water contains substances that block the pores of the injected formation. Frequently, additional oil and solids will be removed through filtration or other steps. In many cases, various control chemicals may be added to the produced water stream (e.g., biocides, corrosion inhibitors, scale preventers).

2.5.2 Reinjection for Disposal:

In cases where more produced water generated than was needed for water flooding, companies injected the excess produced water into other, non-hydrocarbon-producing formations solely for disposal. Injection (either for water flooding or for disposal) has been the dominant method for managing onshore produced water for many years. Data from national E and P waste management surveys conducted by the American Petroleum Institute in 1985, and again in 1995, showed that injection was used to manage 92% of produced water (SPETaskGroup, 2000). A more recent national study reported that in 2007, about 98% of produced water was reinjected (J.A.Veil, 2009) Table 2-4 compares the results.

Table 0-4 Water Production, Injection Profile in USA

Year	Injected for water flooding%	Injected for disposal%	Total injected%
1985	62	30	92
1995	71	21	92
2007	59	39	98

2.5.3 Evaporation Ponds:

Evaporation pond is an artificial pond that requires a relatively large space of land designed to efficiently evaporate water by solar energy, Figure 2-17 They are designed either to prevent subsurface infiltration of water or the downward migration of water depending on produced water quality. It is a favorable technology for warm and dry climates because of the potential for high evaporation rates. Evaporation ponds are typically economical and have been employed for the treatment of produced water onsite and offsite. Ponds are usually covered with nettings to prevent potential problems to migratory waterfowl caused by contaminants in produced water.

Figure 0-17 Evaporation Ponds

2.6 General information about Jake Oilfield:

The Jake Field is located in the northeastern part of Muglad basin. The basin is the largest known rift basin in Sudan interior, trending northwest-southeast and covering 120,000 km^2. The basin is around 800 km in length and 200 km in width. From the structural point of view, the Jake field can be divided into three compartments; the southern, central and northern compartments.

The main formations are Bentiu with a 114.46 MMBbl reserve (The oil gravity range from 24.63 to 32.6API) and AbuGabra with 41.32 MMBbl reserve Figure 3-1 (The oil gravity range from 35.66 to 38.76API), the other properties of the formation at the table below. Today the field production rate is about 20,000 STB/D to the FPF (Field production Facility) with a 60 % water cut due to the high production rate of the wells.

Almost 11 of wells are active and 11 are shutdown 5 of them due to high water cut and three wells converted to water injectors.

The production history of the field shows a huge improvement after applying the gas Huff &Puff techniques at 2011 (Tang et al., 2011), Gas lift is implemented after the drop of AbuGabra gas pool pressure in order to keep the production sustained. The field used the nitrogen as a source of a high pressure to unload the wells. Water production increased rapidly throw the life of the field and now with a cumulative of 14 MMBbl and rising conflict the need for a stable management strategy creating a new feasibility of the field. From the field history, conventional shut-off methods tested with no success, transferring the reservoir edge wells into injectors after there are watered out is also a preferred solution for maintaining the pressure and not taking the risk of uneconomic shut-off. Artificial lift methods were mainly used to recover oil in Jake, thus the wells divided in to three groups according to the applied method:

I. Gas lift wells without valves (JS-01, JS-02, JS-04, JS-7, JS-09, JS-17, JS-18, JS-26, JS-27, and JS-28)
II. Gas lift wells with valves are (JS-03, JS-08, JS-13, JS-16, JS-19 and JS-20).
III. PCM pumps (JC-1 and JC-2).

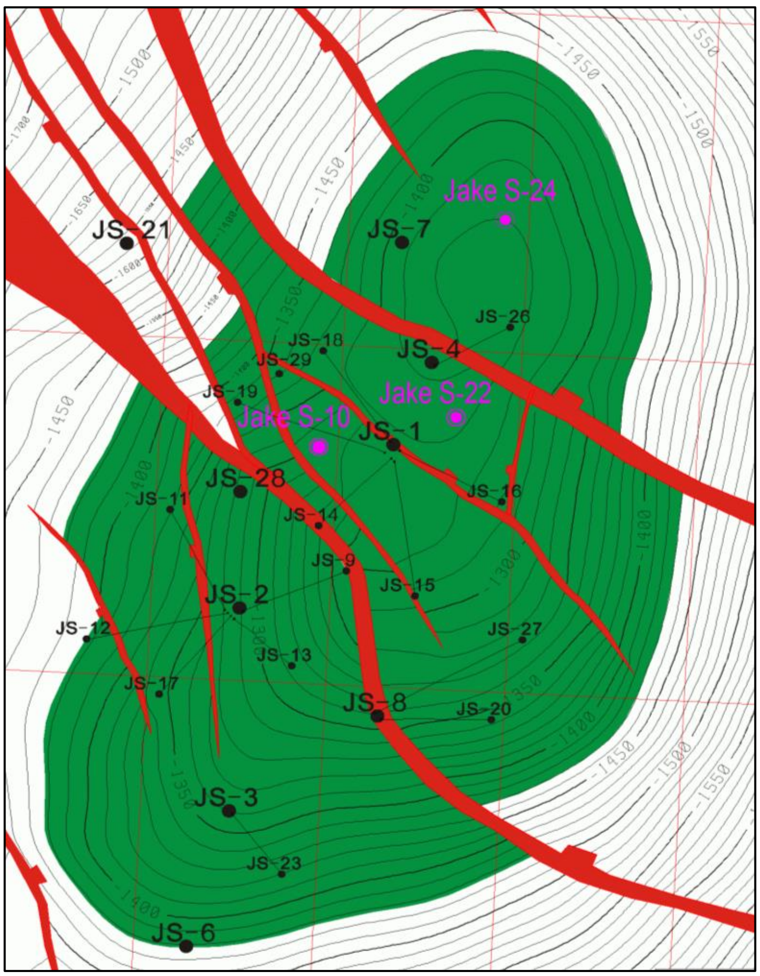


Figure 0-18 Bentiu(B) Formation Structure Map

Table 0-5 Jake oil Field Reserve EUR

Item	Bentiu	AG	Total
STOOIP (2P), MMSTB	114.46	41.32	155.78
EUR (2P), MMSTB	36.68	12.4	49.08
RF, %	32	30	31.5
NP, MMSTB	24.17	6.31	30.48
Remaining EUR, MMSTB	12.51	6.09	18.6
EUR TO - DATE, %	65.9	50.9	62.1
RF TO - DATE, %	21.1	15.3	19.6
Porosity, fraction	23.4	16.1	
Permeability, mD	2900	1280	

The key way to get a vast amount of oil by using gas injection, nitrogen injection and water injection which are more effective to obtain the target in speedy way and to make a very strong support to the reservoir and sustain it. The table below summaries the field wells under study and their status: -

Table 0-6 Jake Field wells summary before May.2015

No	Well	Status	Producing Zone	Remark
1	JS-1	Active	Bentiu & AG	Producer
2	JS-2	None active	Bentiu & AG	Shut-in due to high water cut
3	JS-3	Active	Bentiu	Producer
4	JS-4	Active	Bentiu & AG	Producer
5	JS-6	None active	Bentiu	Dry well
6	JS-7	None active	Bentiu & AG	Idle well
7	JS-8	Non active	Bentiu	Shut-in due to high water cut
8	JS-9	Active	Bentiu & AG	Producer
9	JS-11	Active	Bentiu	Water injection well
10	JS-12	Active	Bentiu	Water injection well
11	JS-13	Active	Bentiu	Producer
12	JS-14	None active	Bentiu	Nitrogen injection well
13	JS-15	None active	Bentiu	Gas injection well
14	JS-16	None active	Bentiu	Shut-in due to high water cut
15	JS-17	None active	Bentiu	Idle well
16	JS-18	None active	Bentiu	Shut-in due to high water cut
17	JS-19	None active	Bentiu	Shut-in due to high water cut
18	JS-20	None active	Bentiu	Shut-in due to high water cut
19	JS-21	Active	Amal	Water Disposal well
20	JS-22	Active	Bentiu	Producer
21	JS-23	Active	Bentiu	Water injection well
22	JS-24	Active	Bentiu	Producer
23	JS-26	None active	Bentiu	Nitrogen injection well
24	JS-27	None active	Bentiu	Gas injection well
25	JS-28	Active	Bentiu	Producer
26	JS-29	Active	AG	Producer
27	JC-1	Active	Bentiu	PCM pump(Producer)
28	JC-2	Active	Bentiu	PCM pump(Producer)

Chapter Three

Methodology

Chapter Three: Methodology

3. Introduction

An integrated methodology for production and completion analysis from wells with high water problems have been used in this study. A cost/Environmental scale has been developed in order to create guidelines for operators for better operating, maintenance, optimization and effectively environmental friendly strategy.

3.1 Step 1

The problems lead to excessive water production (conning, channeling, depletion) have been investigated; the completion and production phase was used to analyze the water problems regarding completion, production issues, discuss the water shut-off options at the field level, and the water cut optimization options. Shlumberger^{TM} Advocat^{TM} package software OFM combined with normal production analysis tools have been used to analyze the problems. Oil Field Manager is a powerful surveillance software application that has been widely used by professionals in the oil industry. It provides an array of tools for managing and analyzing production data. Production Surveillance and Monitoring are becoming a standard setup for oil and gas fields. The increased efficiency in the raw data acquisition involves an enhancement in their processing and interpretation aimed at obtaining production parameters. These properties are now analyzed not only by absolute value but by track, trend, regularity and impact to other related variables, defining a closed circle in production management stream. The production data collected from the field and assigned into a single OFM data base which include wells location, completion type and their production. Several types of analysis will be done through OFM to get clear view on the field water production situation.

As general the OFM could be used for: -

1. Monitor and survey performance with advanced production views.
2. Forecast production with powerful decline and type curve analysis.
3. Analyze any asset and share results using standards.
4. View, relate, and analyze reservoir and production data with comprehensive tools, including interactive base maps with production trends, bubble plots, and diagnostic plots.

5. Use a library of off-the-shelf workflow templates to guide analyses from shale production to water flooding.

The production data collected from the field and assigned into a single OFM data base which include wells location, completion type and their production. Several types of analysis will be done through OFM to get clear view on the field water production situation. Chan's plots (WOR, WOR derivative vs. the cumulative time) was used to provide essential info's on the type of the produced water and to select the right candidates for further control options.

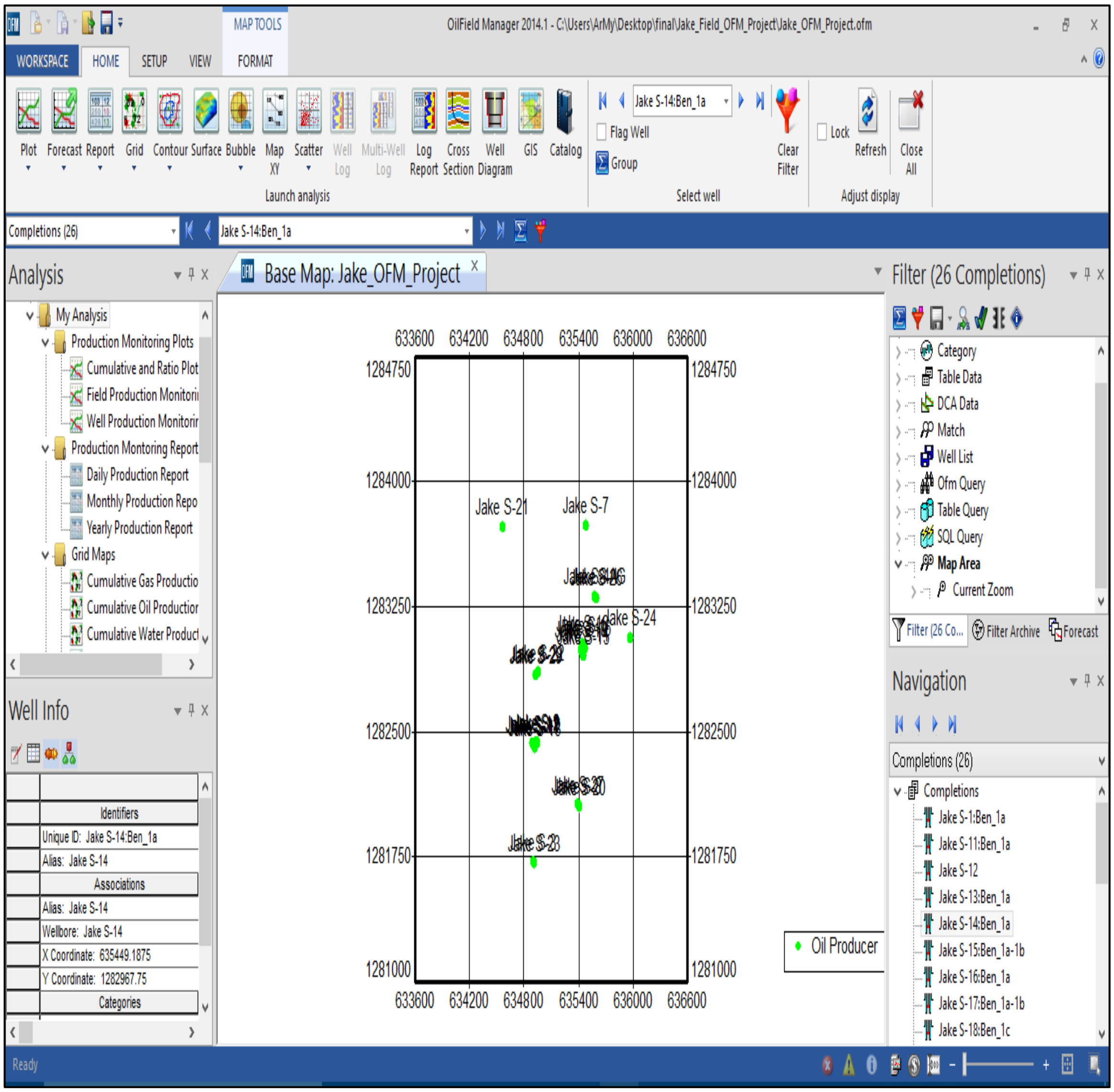


Figure 0-1 OFM interface

3.2 Chan's Plots:-

Water/oil ratio (WOR) and gas/oil ratio (GOR) diagnostic plots have been proposed as an easy, fast, and inexpensive method to identify excessive water and gas production mechanisms. According to this method, a log-log plot of WOR or GOR versus time had shown different behavior for the varying mechanisms. Log-log plots of WOR and GOR time derivatives versus time are capable of differentiating whether a production well is experiencing water or gas coning, channeling due to high-permeability layers, or near-wellbore channeling. If these diagnostic plots can be used to determine the mechanism for excessive water production, they will be useful for identifying wells where gel treatments may be effective for water shutoff.

$$\boldsymbol{WOR' = \frac{dWOR}{dt} = \frac{WOR_2 - WOR_1}{t_2 - t_1}} \quad \text{.................................... } \textbf{Equation 2}$$

Where: -

$$WOR = the\ water\ oil\ ratio, WOR' = the\ derivitive, t = cumulative\ time$$

According to Chan, Figure 3-2 illustrate how the diagnostic plots are supposed to differentiate among the various water production mechanisms. First part shows a comparison of WOR diagnostic plots for coning and channeling. According to Chan (Figure3-2), the WOR behavior for both coning and channeling is divided into three periods; the first period extends from production start to water breakthrough, where the WOR is constant for both mechanisms. When water production begins, Chan presented that the behavior becomes very different for coning and channeling. This event denotes the beginning of the second time period.

For coning, the departure time is often short (depending on several variables), and corresponds to the time when the underlying water has been drawn up to the bottom of the perforations. According to Chan, the rate of WOR increase after water breakthrough is relatively slow and gradually approaches a constant value. This occurrence is called the transition period.

For channeling, the departure time corresponds to water breakthrough for the most water-conductive layer in a multi-layer formation, and usually occurs later than for coning. Chan presented that the WOR increases relatively quickly for the channeling case;

however, it could slow down and enter a transition period, which is said to correspond to production depletion of the first layer. Thereafter, the WOR resumes the same rate as before the transition period. This second departure point corresponds to water breakthrough for the layer with the second highest water conductivity.

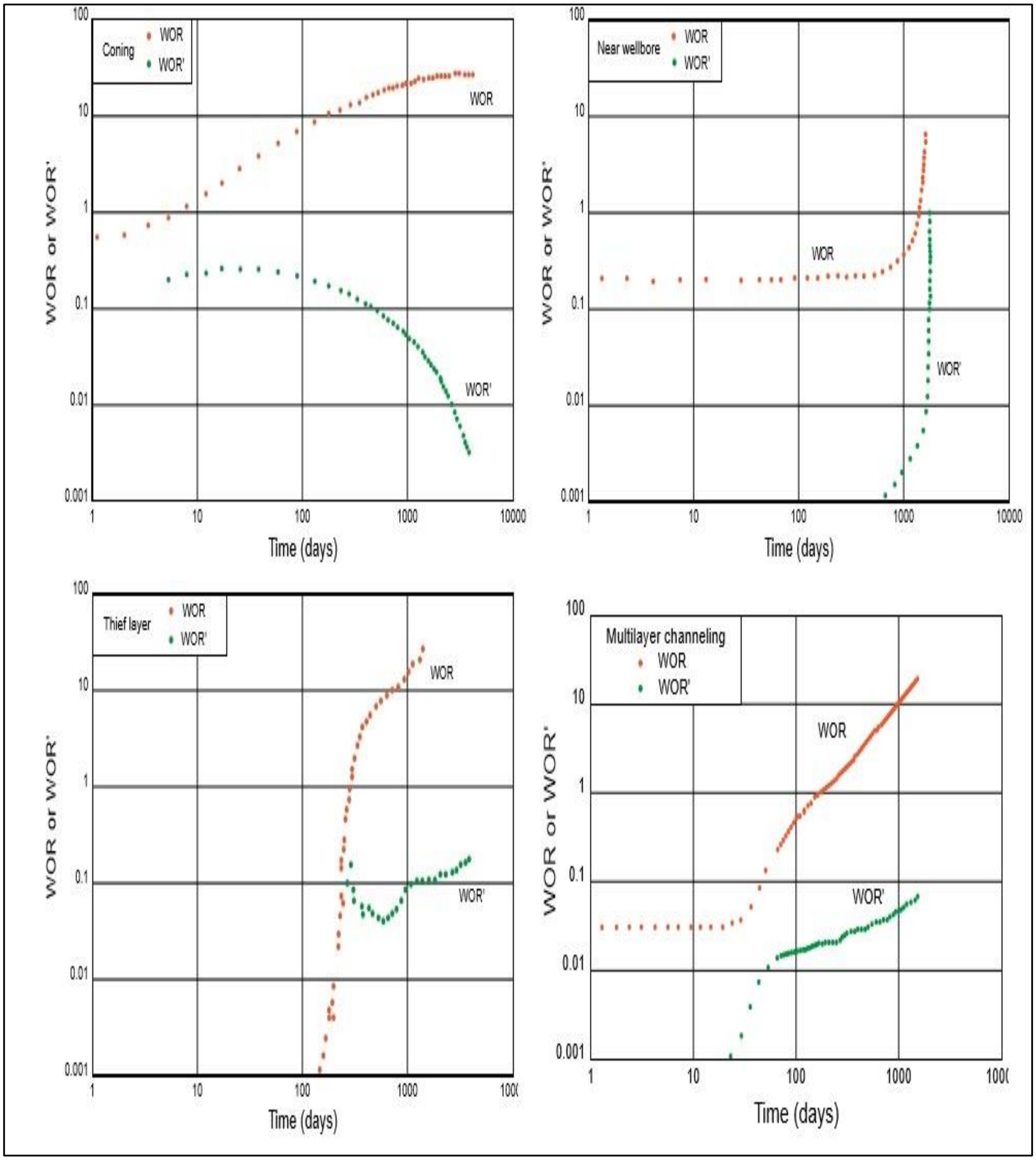


Figure 0-2 Chan Diagnostic Plots

According to Chan, the transition period between each layer breakthrough may only occur if the permeability contrast between adjacent layers is greater than four. After the transition period(s), Chan describes the WOR increase to be quite rapid for both mechanisms, which indicates the beginning of the third period. The channeling WOR resumes its initial rate of increase, since all layers have been depleted. The rapid WOR increase for the coning case is explained by the well producing mainly bottom water, causing the cone to become a high-conductivity water channel where the water moves laterally towards the well. Chan, therefore, classifies this behavior as channeling; Table 3.1 summarizes the different categories of the curves.

Table 0-1 WOR, WOR' Slope Values

	WOR' Slope	Predicted reason for water problem
Positive	Positive	channeling
Positive	Negative	Coning
Positive Liner	Horizontal line	Water/Oil contact rising

3.3 Produced Water Cost Assessment:-

The economics of water production throughout the water cycle depend on a number of factors such as total flow rate, production rates, fluid properties like oil gravity and water salinity, and finally the ultimate disposal method for the water produced. Operational expenses, including lifting, separation, filtering, pumping and reinjection, add to the overall costs (below). In addition, water-disposal costs can vary enormously. Reports vary from 10 cents per barrel when the unwanted water is released into the ocean offshore to over $1.50 per barrel when hauled away by trucks on land. Although the potential savings from water control alone are significant, the greatest value comes from the potential increase in oil production and recovery.

Table 0-2 Produced water cost After (Bailey et al., 2000)

		20,000 B/D		50,000 B/D		100,000 B/D		200,000 B/D		Average	
Lifting	Capex/Opex	$0.044	5.28%	$0.044	7.95%	$0.044	9.29%	$0.044	10.25%	**$0.044**	**7.69%**
	Utilities	$0.050	6.38%	$0.054	9.62%	$0.054	11.24%	$0.054	12.40%	**$0.054**	**9.30%**
Separation	Capex/Opex	$0.087	10.36%	$0.046	8.27%	$0.035	7.24%	$0.030	6.82%	**$0.049**	**8.55%**
	Utilities	$0.002	0.30%	$0.003	0.45%	$0.003	0.52%	$0.003	0.58%	**$0.003**	**0.43%**
	Chemical	$0.034	4.09%	$0.034	6.16%	$0.034	7.20%	$0.034	7.94%	**$0.034**	**5.95%**
De-oiling	Capex/Opex	$0.147	17.56%	$0.073	12.99%	$0.056	11.64%	$0.046	10.58%	**$0.081**	**13.92%**
	Chemicals	$0.040	4.81%	$0.041	7.25%	$0.041	8.47%	$0.041	9.34%	**$0.041**	**7.00%**
Filtering	Capex/Opex	$0.147	17.47%	$0.068	12.18%	$0.047	9.85%	$0.030	6.87%	**$0.073**	**12.63%**
	Utilities	$0.012	1.48%	$0.010	1.79%	$0.010	2.09%	$0.010	2.31%	**$0.011**	**1.84%**
Pumping	Capex/Opex	$0.207	24.66%	$0.122	21.89%	$0.091	19.06%	$0.079	18.15%	**$0.125**	**21.61%**
	Utilities	$0.033	3.99%	$0.034	6.01%	$0.034	7.03%	$0.034	7.75%	**$0.034**	**5.81%**
Injecting	Capex/Opex	$0.030	3.62%	$0.030	5.45%	$0.030	6.37%	$0.030	7.02%	**$0.030**	**5.27%**
	Total cost/bbl	**$0.842**	**100%**	**$0.559**	**100%**	**$0.478**	**100%**	**$0.434**	**100%**	**$0.578**	**100%**
	Total chemicals	$0.074	8.90%	$0.075	13.41%	$0.075	15.67%	$0.075	17.28%	**$0.075**	**12.96%**
	Total utilities	$0.102	12.16%	$0.010	17.87%	$0.100	20.88%	$0.100	23.03%	**$0.101**	**17.38%**
	Total wells	$0.074	8.89%	$0.075	13.40%	$0.075	15.66%	$0.075	17.27%	**$0.075**	**12.95%**
	Surface facilities	$0.589	70.05%	$0.309	55.33%	$0.227	47.80%	$0.184	42.41%	**$0.328**	**56.71%**

The table shows typical estimated water-handling costs per barrel—capital and operating expenses (Capex and Opex), utilities and chemicals—lifting, separation, de-oiling, filtering, pumping and injection for fluid production varying from 20,000 to 200,000 B/D After (Bailey et al., 2000).

Surface facility design stage will include investigation of the on-going filed system and how to achieve the optimum design depending on the water quantities and the treatment options.

The final stage understands the disposal water and evaluate the ability of the re-use as a beneficial use or as re-injection to the subsurface.

The treatment cost of 1 barrel of produced water will calculated (if it is not available) and it will be the base for constructing the cost/environment scale.

Chapter Four

Results and Discussions

Chapter Four: Results and Discussions

4. Introduction

The current stage of the study presents the result analysis of field data and the diagnostic results: also the screening criteria for selecting the candidate wells for diagnosis was presented.

The complicated situation in the field lead to many unexpected production performance; it was observed that the water cut in the field has a very complicated history. As a first stage, field production performance was analyzed using Shlumberger™ Advocate™ package software OFM combined with normal production analysis tools, the total or cumulative production (oil, Water, Gas, and nitrogen) was cross-plotted with time to present the production performance (Figure 4-1). The wells in Jake south oilfield have been classified into two categories: Nitrogen Injection wells and gas injection wells. Since earlier 2012, Nitrogen Injection and gas injection was applied in the field, the Nitrogen Injection was applied to supply the reservoir pressure in some wells (JS-1 and JS-4) due to high faulted structure, the Nitrogen has no effect on the wells isolated by faults; analysis of the production data presented that Nitrogen Injection has a good effect in reducing water cut in some wells; the overall water cut of the field also decreased from 60 % to 30. However, During Nitrogen Injection, the operational conditions are controlling the effect of the injection process; any instability in the injection program or even a simple power trip can lead to major problems in the oil production and water cut as presented through Figure 4-1. The Figure presented an analysis for the production data shows that the water started to produce clearly by the middle of 2010 with constant performance, however by the middle of 2011 the slop of the production curve was increased, which presents an increasing on the water production. The Figure also presented that when Nitrogen Injection was started from the middle of 2012, the slop of the production curve was returned to it is original slop (stage 1) (for the lead wells JS-1 decreased from 45% to 30%, JS-4 from60% to 35%).

For the field wells, a well card to summarize the wells status according to Chan's plot results, the dominated water production mechanism is the high permeability layer channeling and that is justified because of the wells strata, edge water drive and the permeability variation.

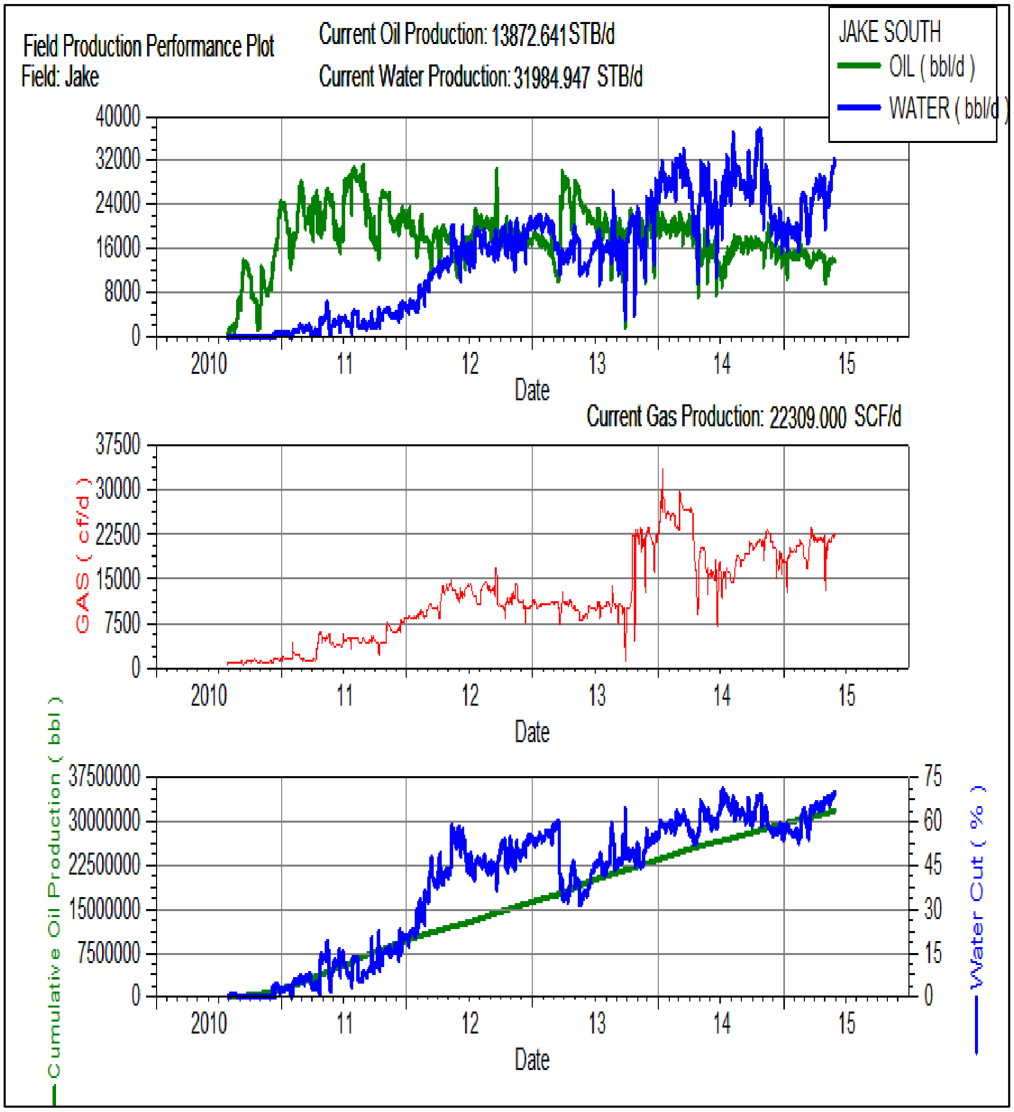


Figure 0-1 Jake Field Production Profile

The water cut range bubble map (Figure 4-2) presents the field history according the water production variation (water cut change with time for all wells), due to the change of production methodology from low rate such as PCP in the earlier stage to the gas lift lately the water cut increased fast and more than five wells reached their economic limit and shut down quickly; while other wells controlled for some times and still water production rapidly increasing.

The analysis and discussion of the condition and production data of the wells are presented as follows.

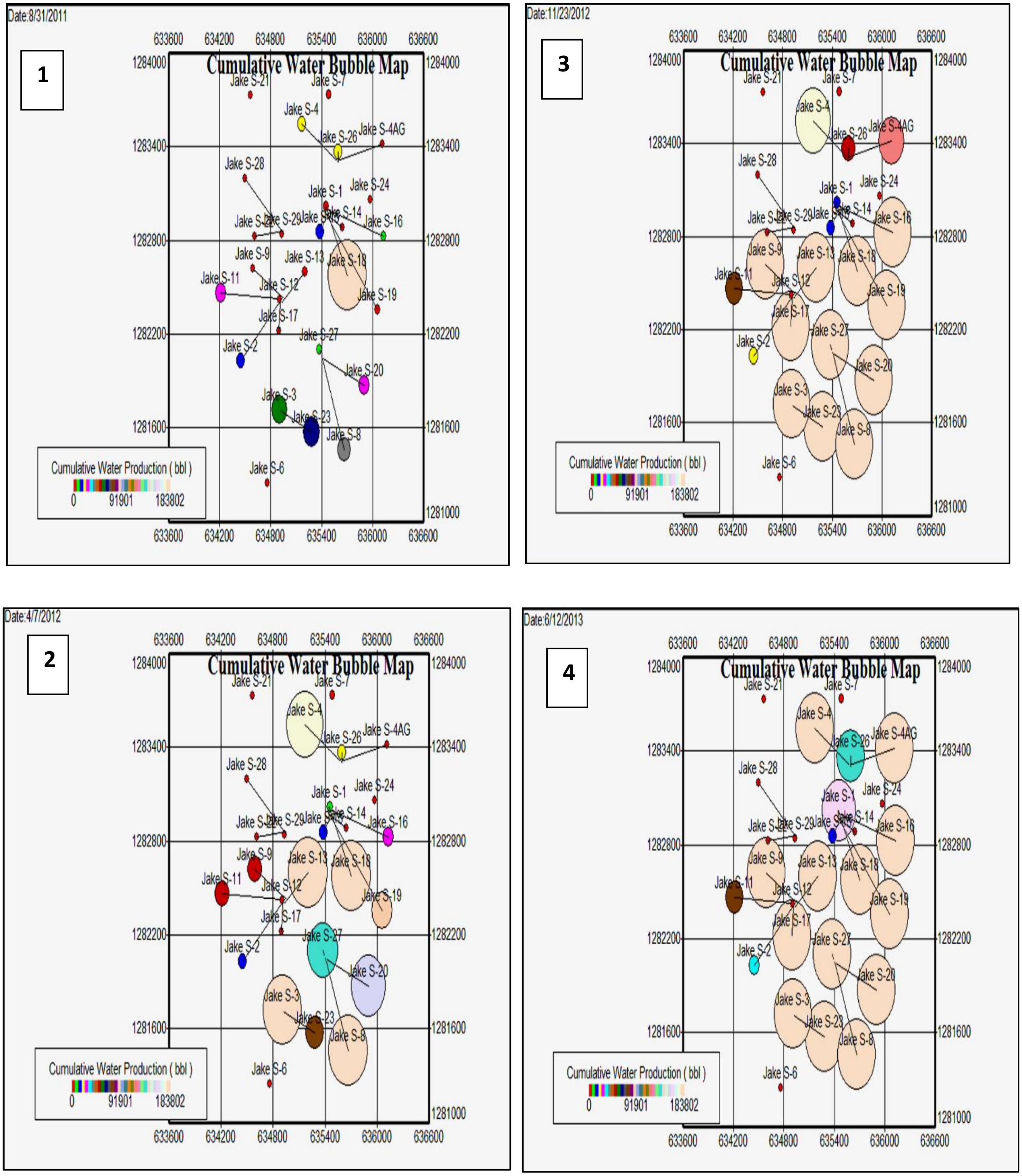


Figure 0-2 Water Cut Change with Time

4.1 JS-23:

Well JS-23 was completed as progressive cavity pump (PCP) producer in Nov.2010. The water cut started to increase quickly Figure 4-3, the lowers zones of the well was shut by bridge plug conducted on Nov.2010, and no significant change in the well performance was founded. Chan diagnostic plots show a normal trend indicating the area around the well is watered out. Further, the well converted on Mar.2011 to gas lift producer. Figure 4-4 presented the Structural Position of the well; from the Figure, the final depth of the well and the perforated interval is near to the Oil Water contact (OWC), therefore the water production increased rapidly and finally the well was transferred to water injector well. In this example Chan's plots don't give an accurate diagnostic due to the lack of the production data, but the other parameters such as the structural position help to understand the case and give an accurate diagnostic.

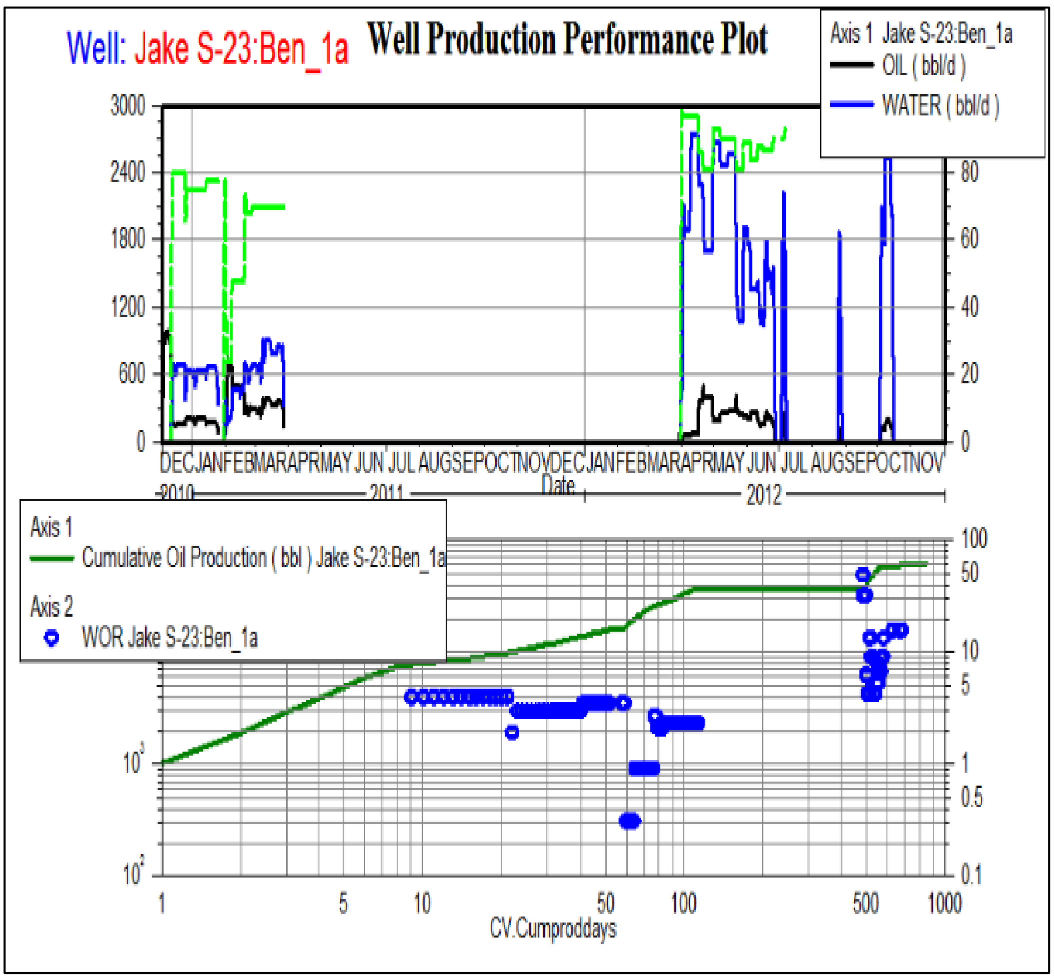


Figure 0-3 Well: JS-23 Production Profile

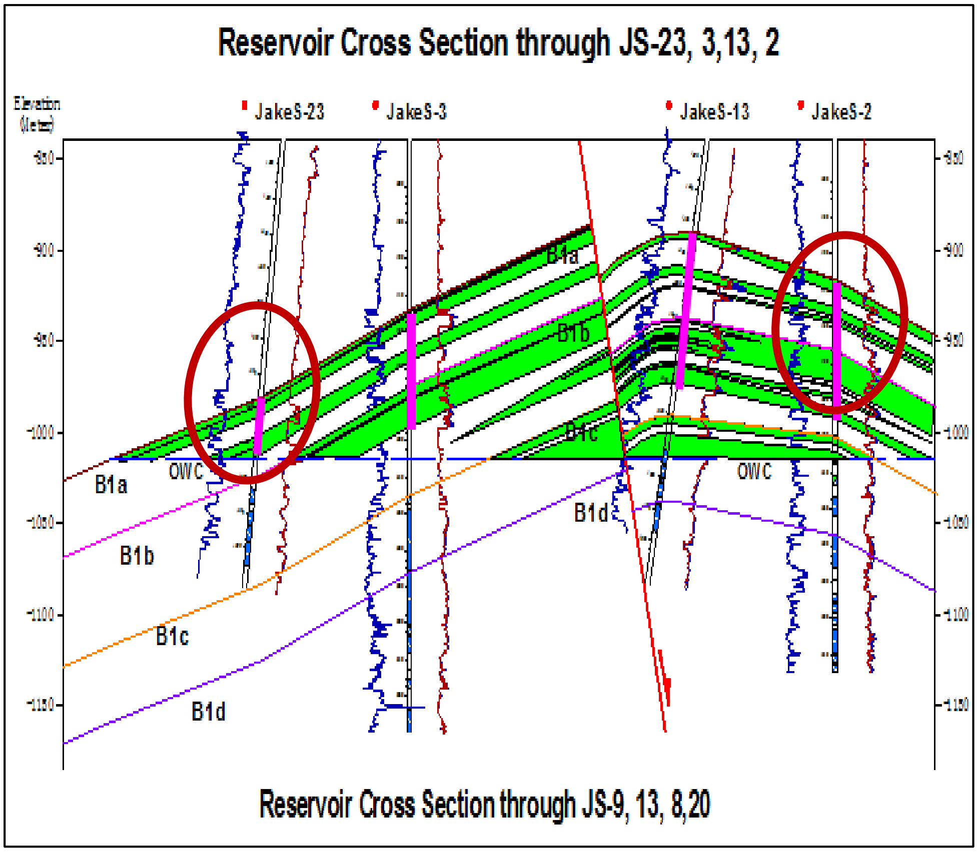


Figure 0-4 Wells:JS-23 and JS-2 Structural Position

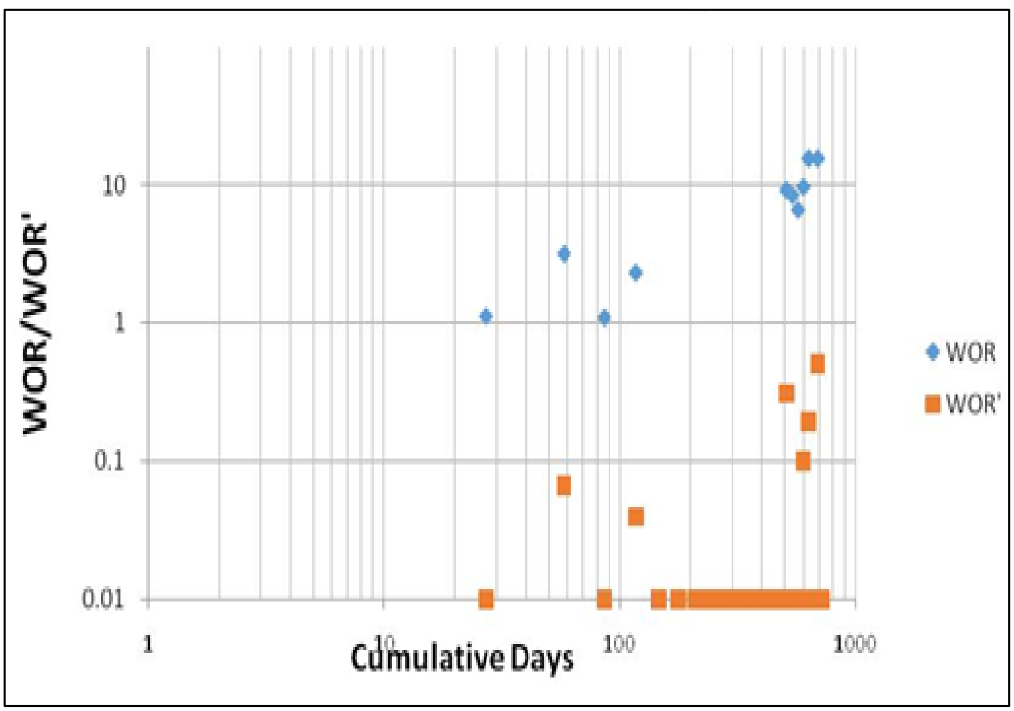


Figure 0-5 Well :JS-2 3 Chan's Diagnostic Plot

4.2 JS-2

As an example the comingled wells such as JS-2 which is producing from AbuGabra and Bentiu formations, (Figure 4-6) shows there is a clear bottom water conning; but its need to confirmed first and the dominated mechanism to be verified with other methodology. According to Seright (1998), multi layers channeling will show a negative trend, which is an indication of conning mechanism; according to Chan's methodology, it is concluded that the plots are not totally accurate and could be easily misinterpreted (Figure 4-9).

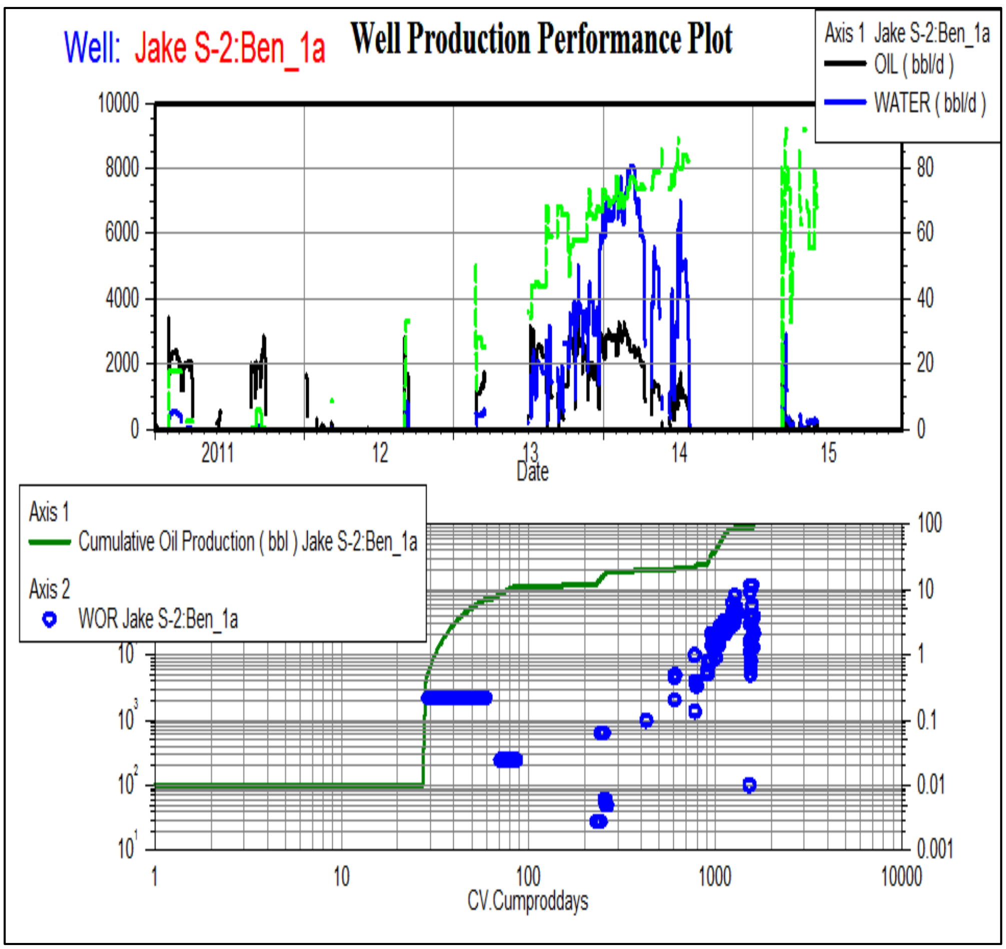
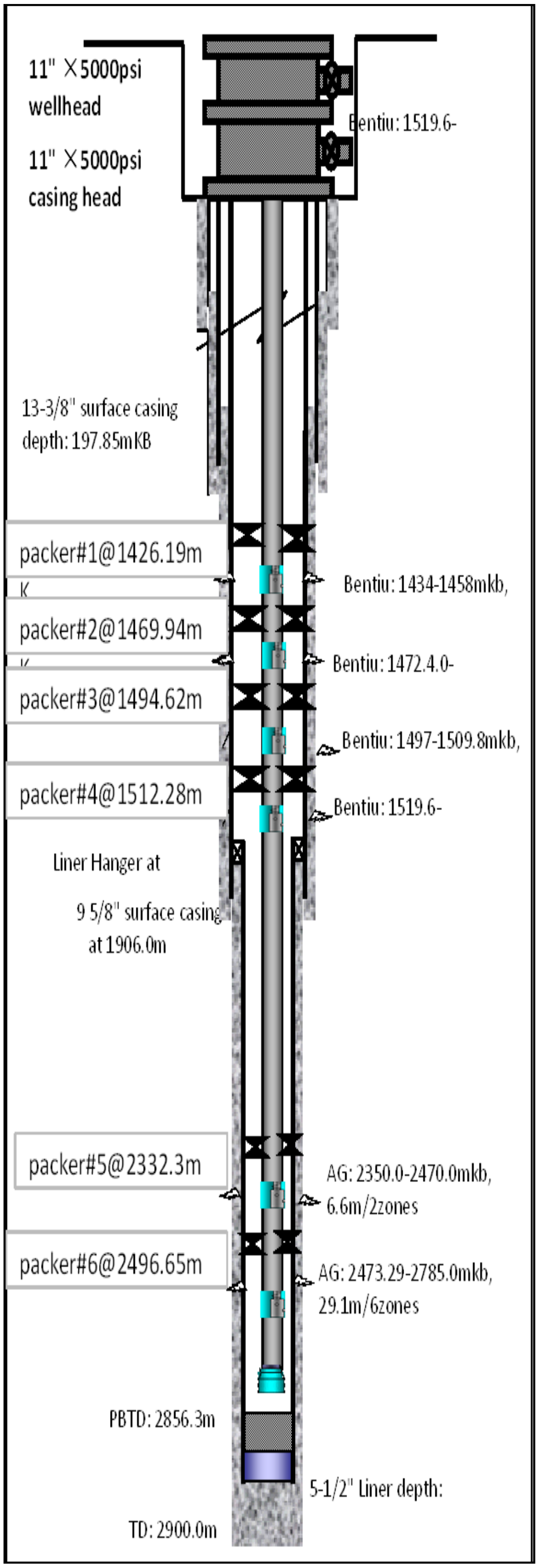


Figure 0-6 Well :JS-2 Production Profile



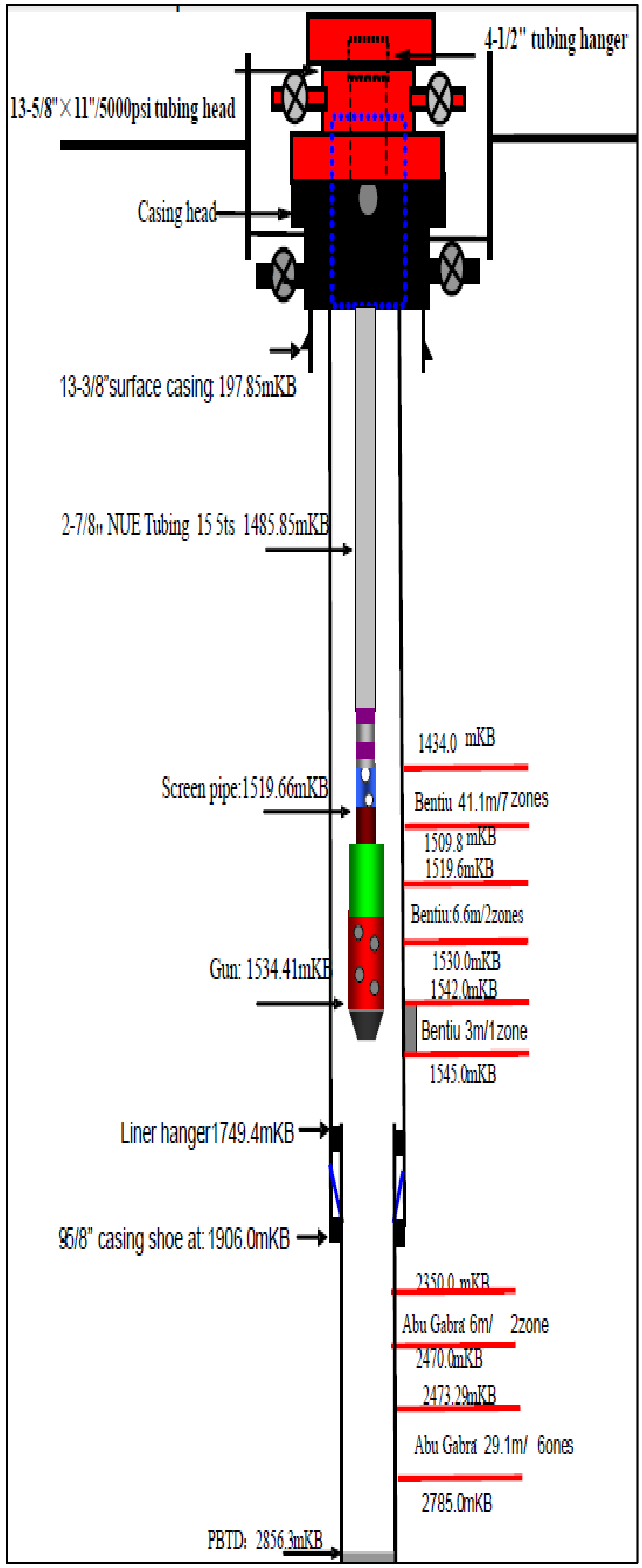


Figure 0-7 Well :JS-2 Completion Profile after Water Detection String

Figure 0-8 Well :JS-2 Completion

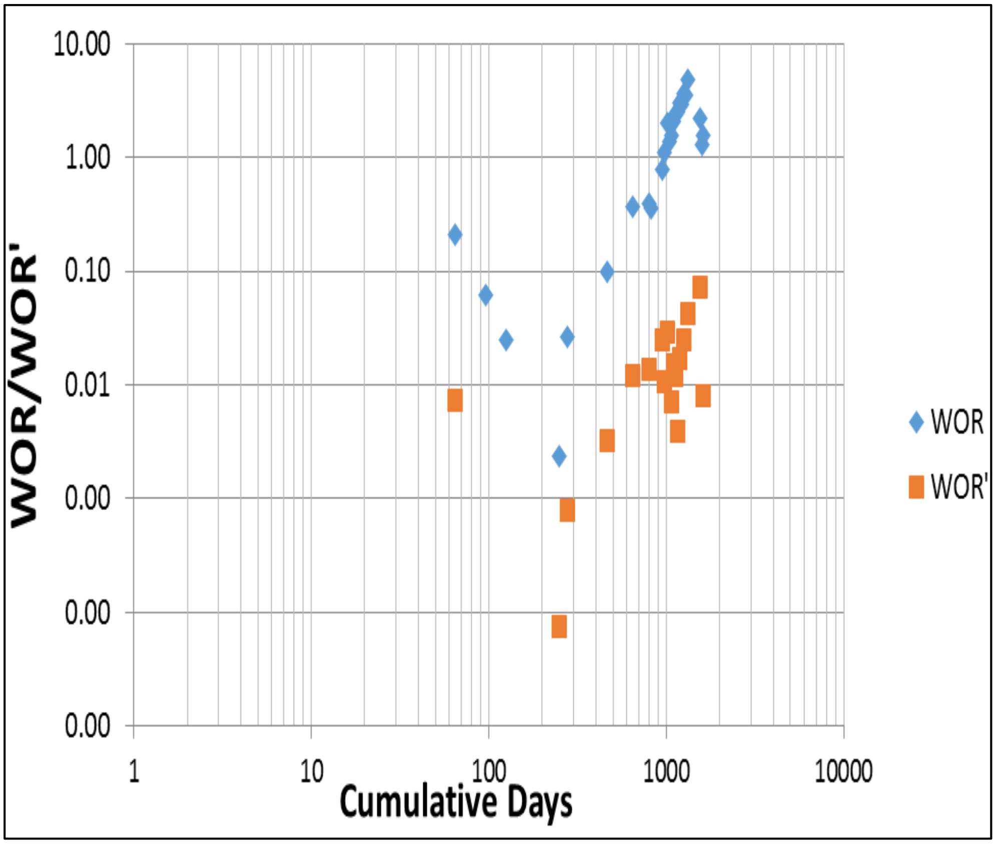


Figure 0-9 Well :JS-2 Diagnostic plot

A separate zonal production (Demin Wang and Chen, 1983) was conducted to identify the problematic layer sand shut them, the water detection and shut off device consist of packer for isolation each zone and eccentric production mandrels for the separate production Figure 4-8. The test results for the six layers of the wells are summarized in the table below: -

The results showed that Bentiu formation has a slightly better performance than AG and therefore the layers 1, 3 and 4 kept opened. The Cement Bond Log CBL (Figure 4-9) shows some bad areas which will affect the performance of the zonal isolation, however due to the operation limitation and cost factors it’s hard to deal with this issue currently, but the use of chemicals suggested to give good results in controlling such problems. Table 4-2 summarizes the well performance before and after the water control. The preliminary data showing a reasonable result (The study will discuss it in the economic section).

Table 0-1 Well: JS-2 Oil, Water before and after treatment

Rates	Before treatment	After treatment	% Decreased
oil	1500	212	86%
water	4000	600	85%

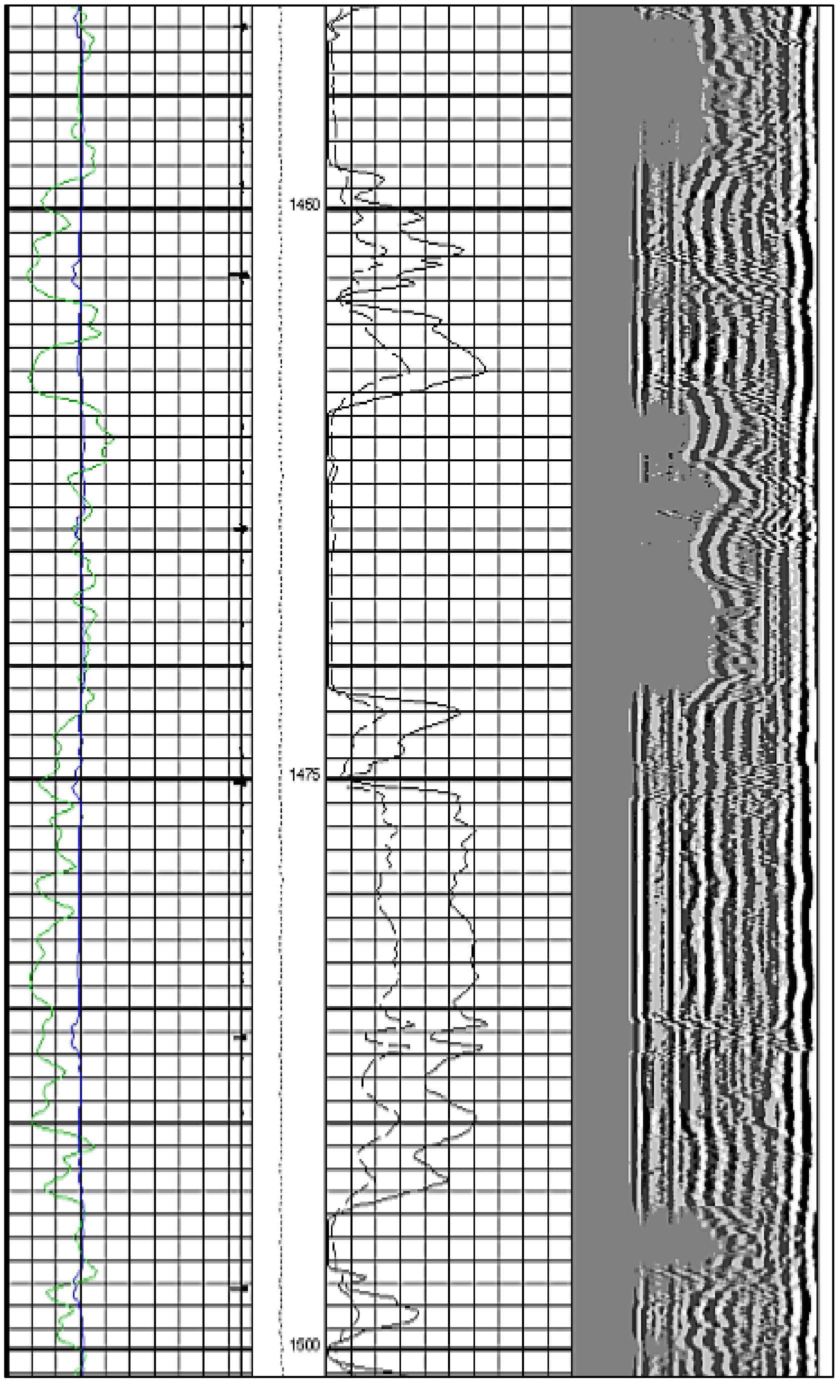


Figure 0-10 CBL Sample for Well JS-2

4.3 JS-8:

JS-8 is a developmental well started production on earlier 2010 from Bentiu with a progressive cavity pump (PCP) and transferred to gas lift on APR 2011. Figure 4-11 presented Well JS-8 production performance; the water cut started to increase and reached 80% in less than one year and its clear on the recovery plot that the well reached its economic limit. The diagnostic plot is showing a channeling phenomenon (Figure 4-12)

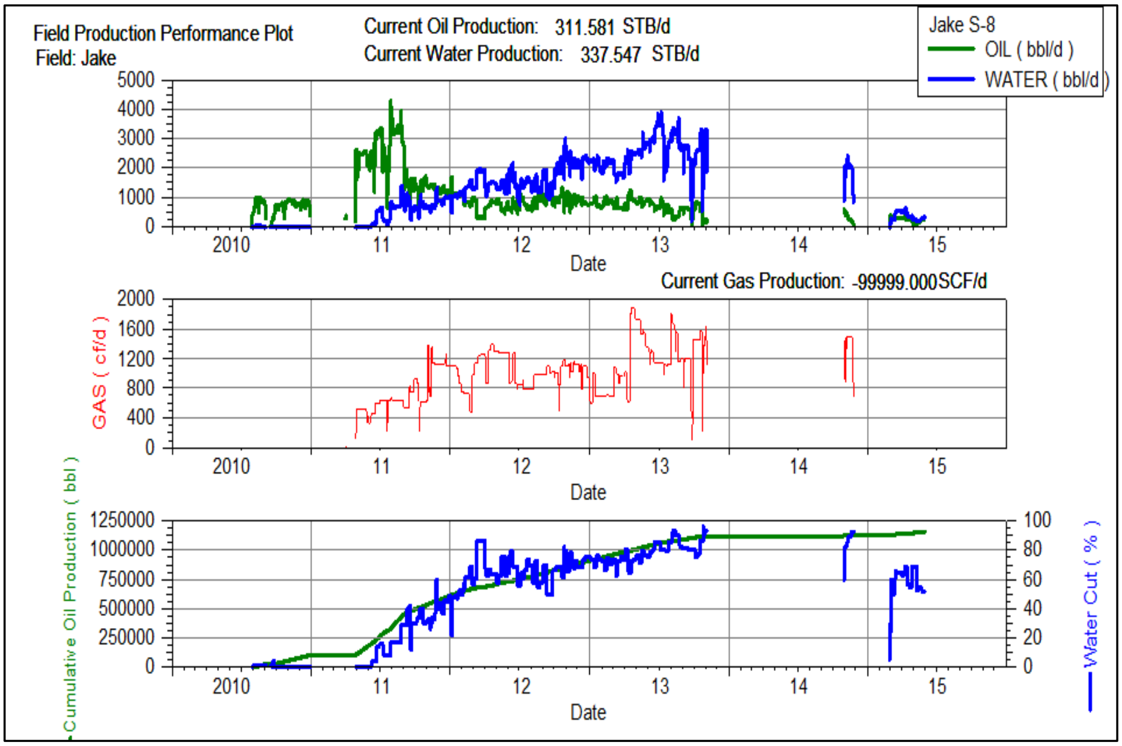


Figure 0-11 Well :JS-8 Production Performance

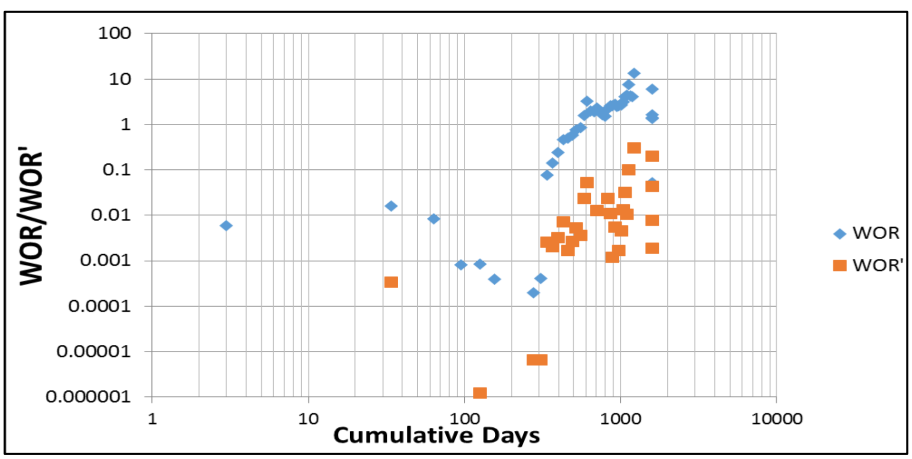


Figure 0-12 Well :JS-8 Diagnostic Plot

The artificial lift methodology changed back to Progressive cavity pump in order to control the water production and decrease the high rate and the overall water production. Table 4-2 presented the water and oil production for Well JS-8 before and after Treatment.

Table 0-2 Well: JS-8 Oil and Rates Water before and after Treatment

Rates	Before treatment	After treatment	% Decreased
oil	650	313	52%
water	2280	380	83%

4.4 JS-24:

JS-24 is a developmental well started production on sep-2014 from Bentiu with gas lift, the W.C started to increase and reached 80% in less than one year and it's clear on the recovery plot that the well reached its economic limit as presented through Figure 4-13.

The diagnostic plot shows a channeling phenomenon, the artificial lift methodology changed to Progressive cavity pump in order to control the water production and decrease the high rate and the overall water; table 4-3 shows the results after the change.

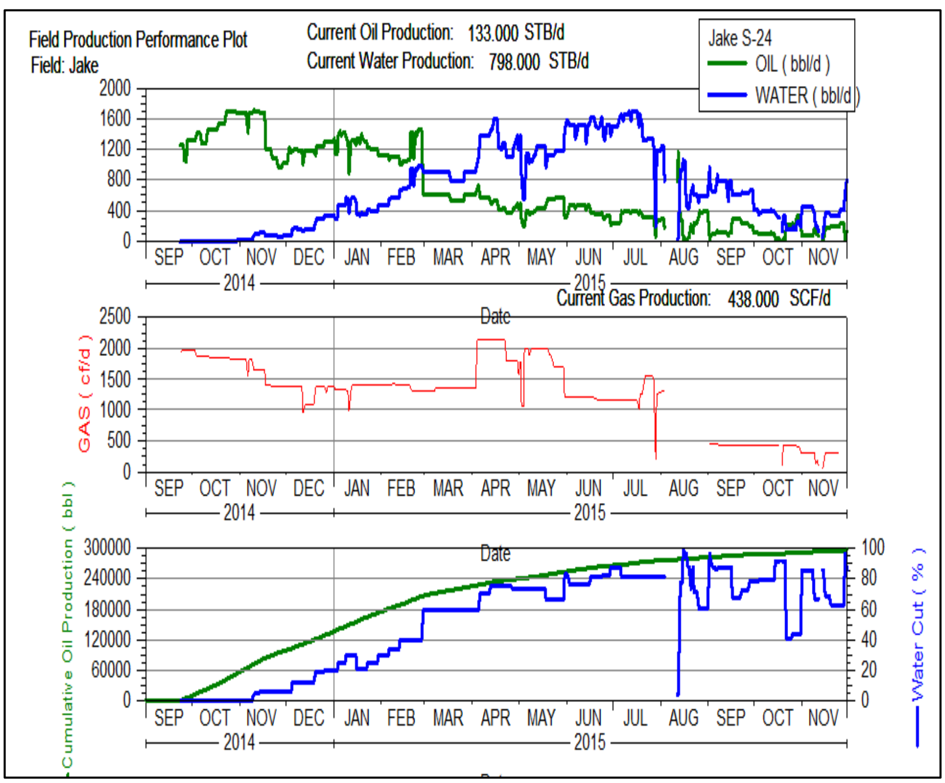


Figure 4-13 Well: JS-24 Production Performance

Table 0-3 Well: JS-24 Oil and Water Rats before and after Treatment

Rates	Before treatment	After treatment	% Decreased
oil	317	240	24%
water	1230	370	70%

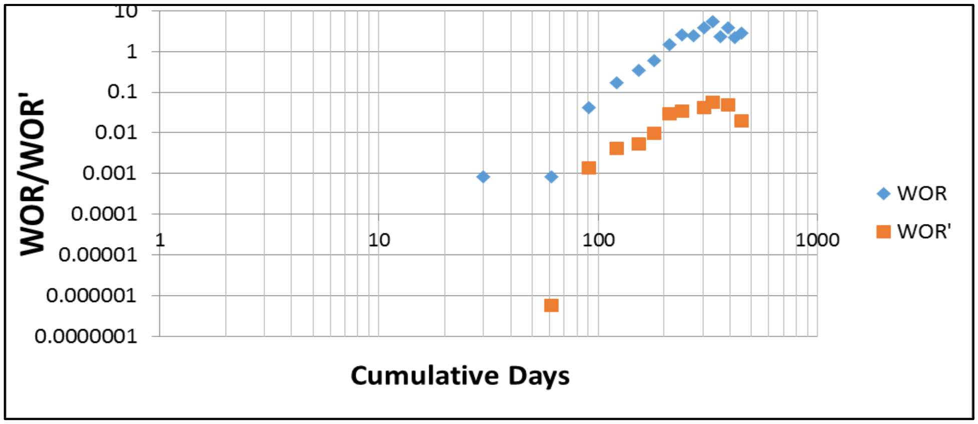


Figure 0-14 Well: JS-24 Diagnostic Plot

4.5 Wells: JS-1 and JS-4:

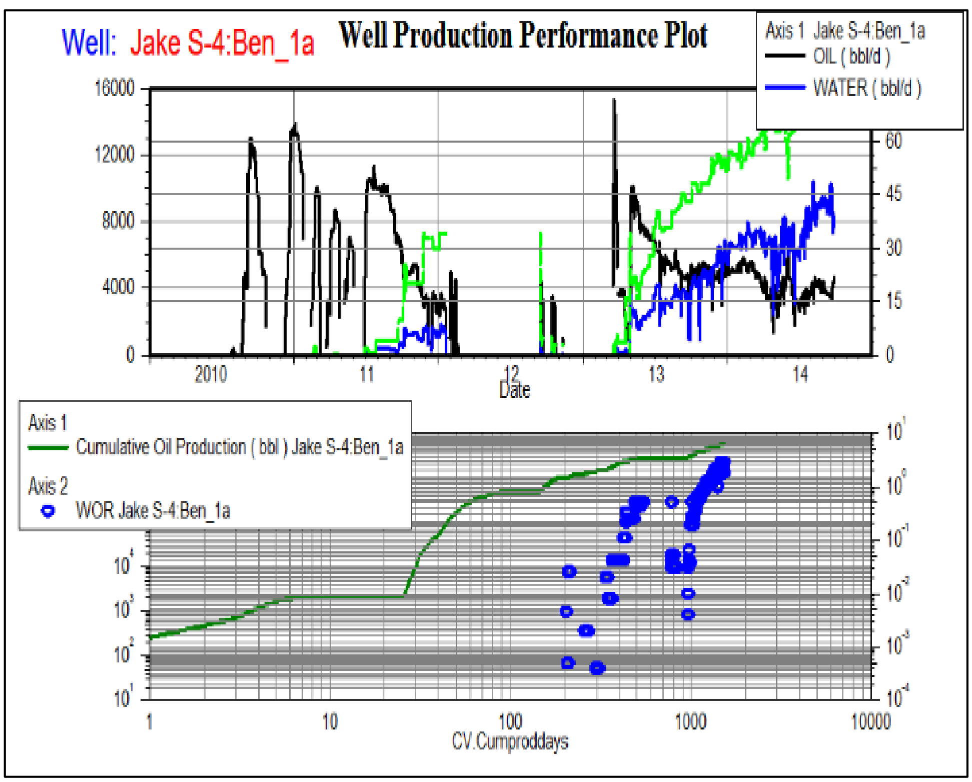


Figure 0-15 Well: JS-4 Production Profile

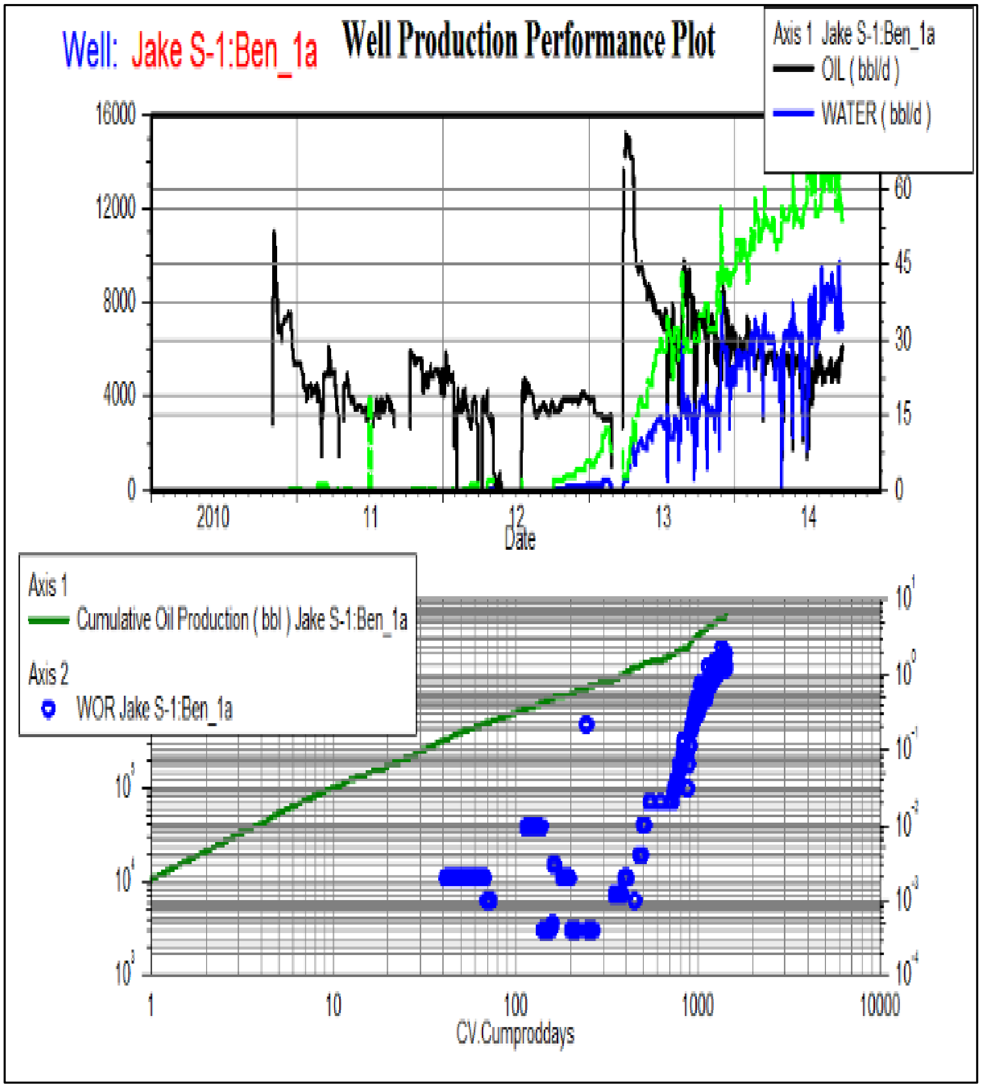


Figure 0-16 Well: JS-1 Pproduction Profile

JS-1 and JS-4 are the dominated producers as presented through (Figure 4-13 Figure 4-14). The channeling behavior is so clear but its need to verified with the PLT, the lower layers may have affected by conning, both of them are completed as self-injection in the past with a high production rate and that caused a high drawdown to the reservoir and a fast increase in the water cut. Although there are producing the largest amount of the water both of them cannot be selected for water shut off at this time.

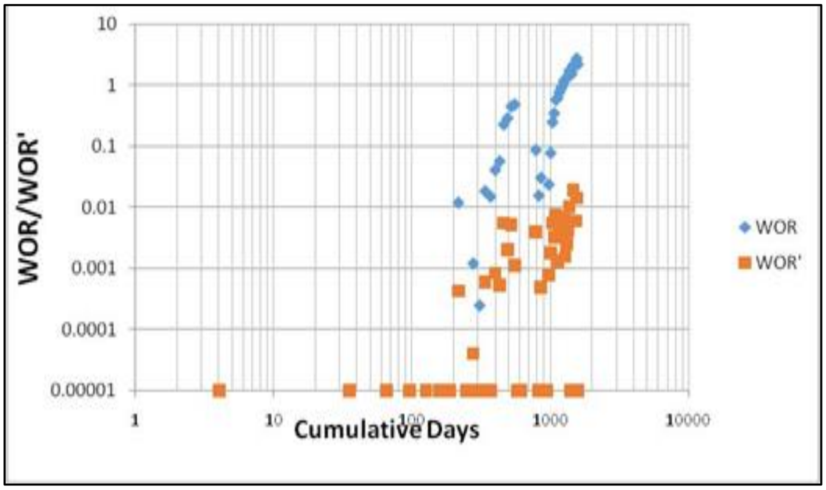


Figure 0-17 Well: JS-1 Diagnostic Plot

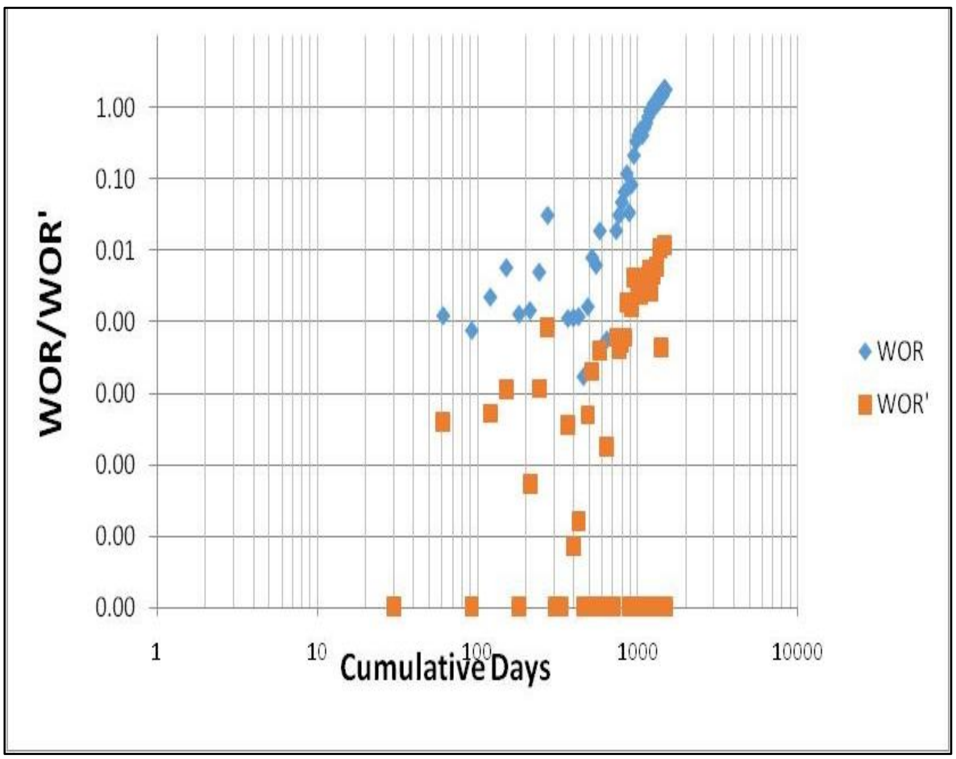
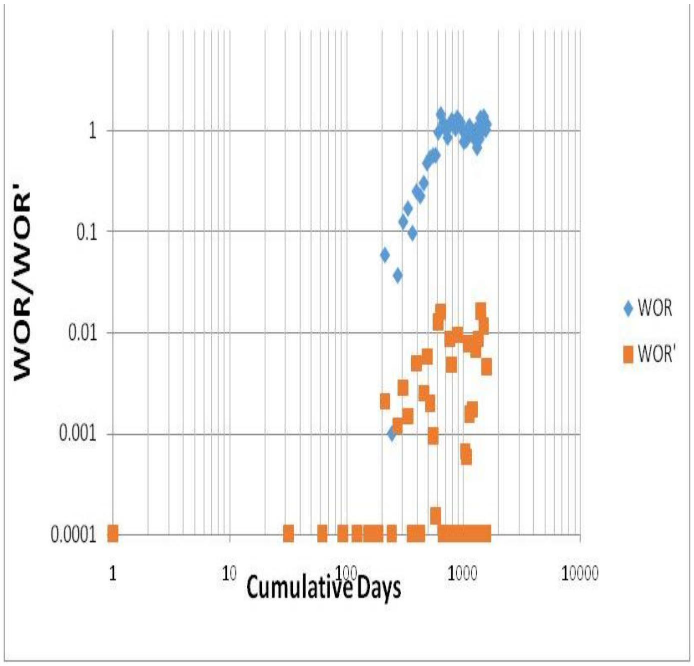
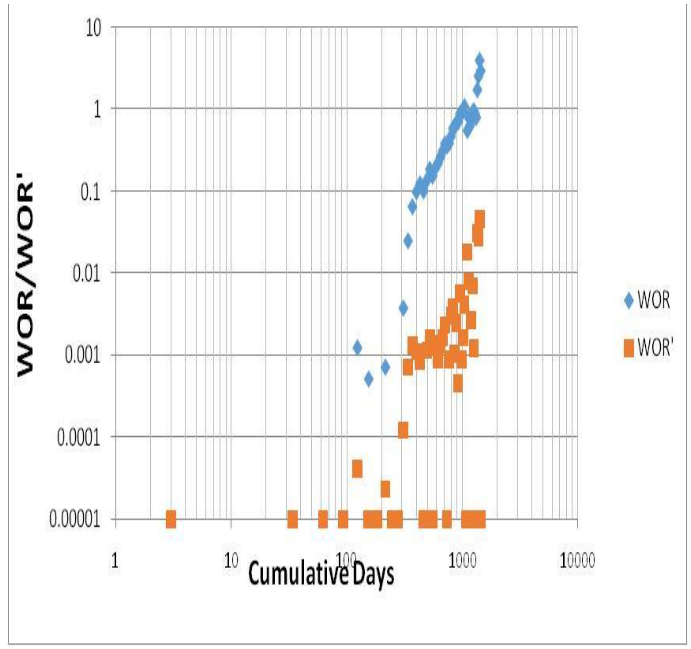


Figure 0-18 Well: JS-4 Diagnostic Plot

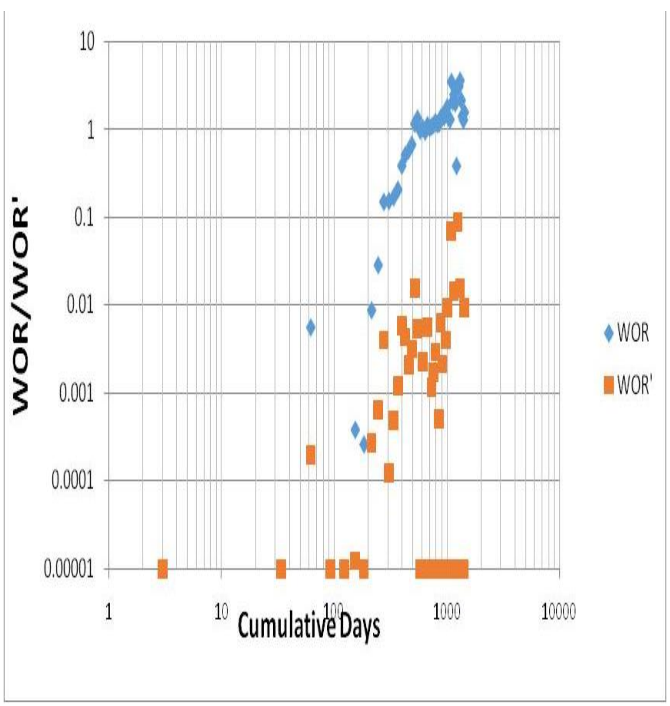
The following charts shows the results of Chan's plots for the rest of the field wells, channeling is the dominated phenomena along with some wells has a normal trend which indicating area watered out issue, Normal trend is Shawn in JS-20, the plots didn't show clearly flat but this well is in the reservoir down dip and the water cut increased rapidly. Figure 4-4 shows the well location, the possible suggestion is to transfer is to water injector just like JS-23 scenario to maintain the pressure and decrease the disposal water to the surface.



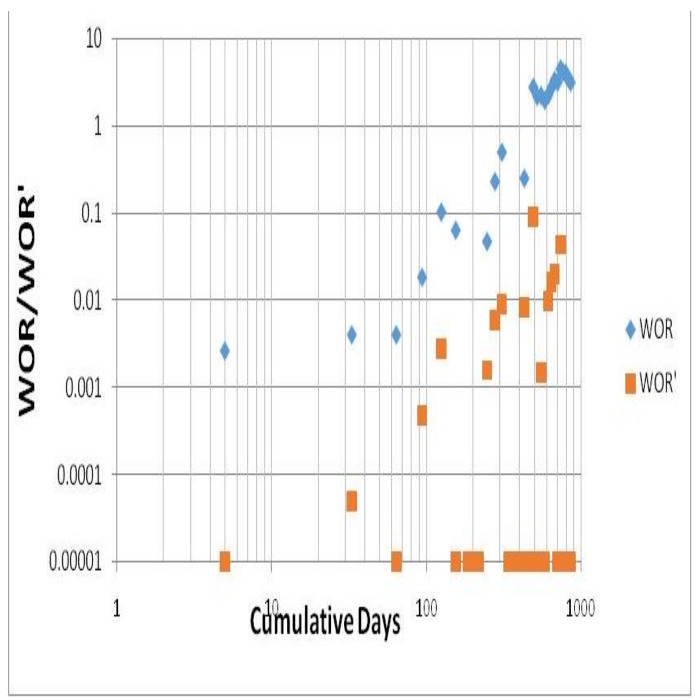
JS-3: Early channeling and late normal behavior



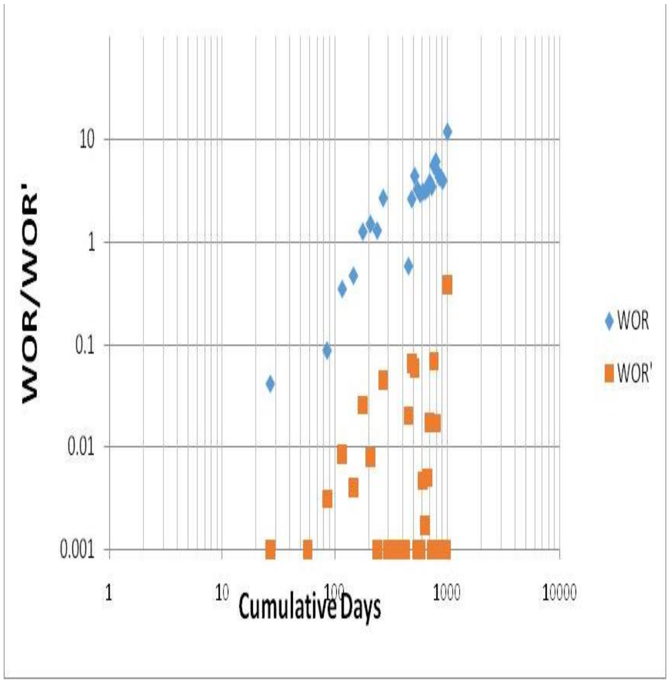
JS-9: Channeling



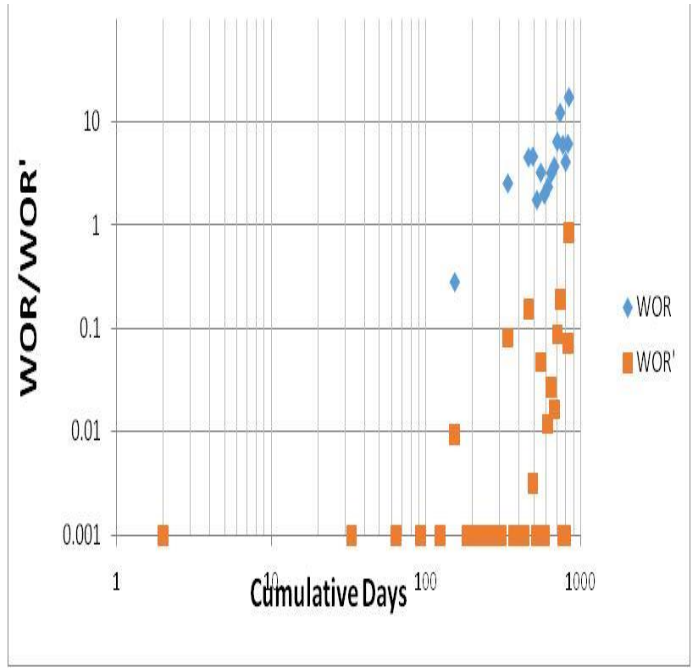
JS-13:Channeling controlled by the nitrogen injection



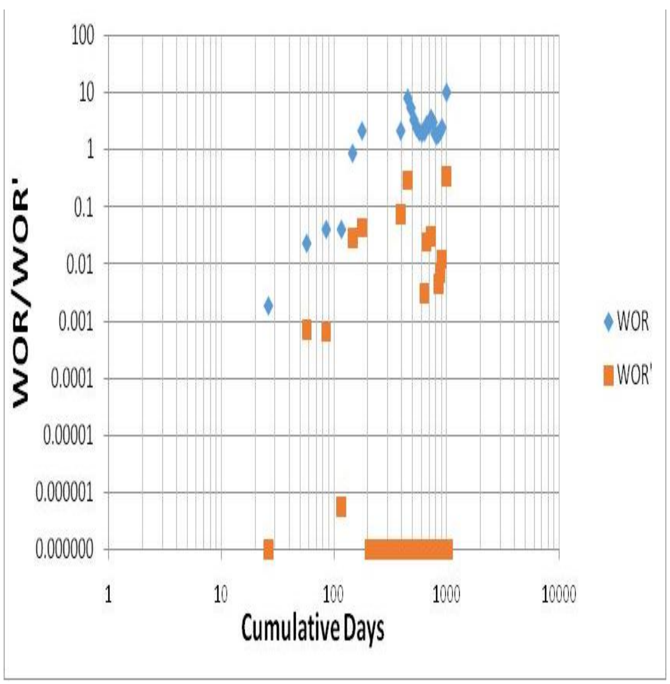
JS-16a:channeling



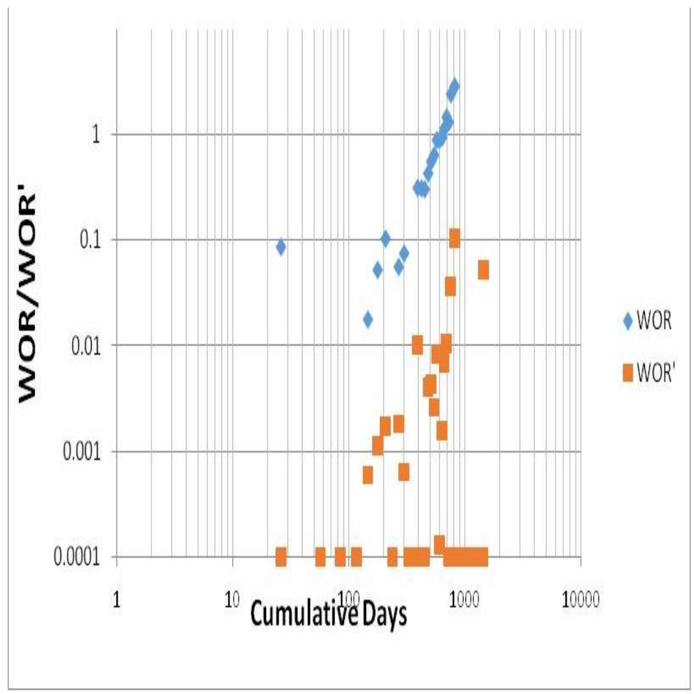
JS-18:Bottom water conning



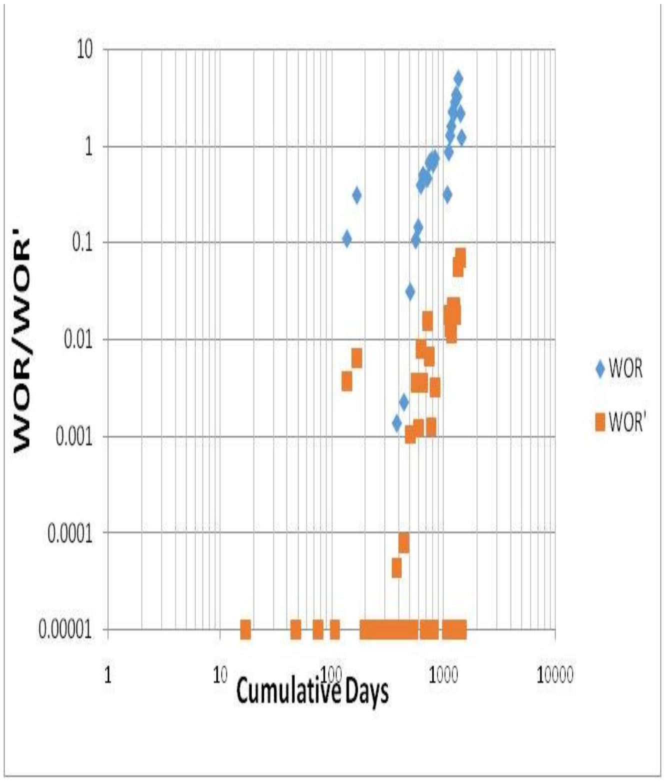
JS-19:channeling



JS-20:Normal, Area watered out



JS-27:Channeling



JS-26:Channeling

4.6 Risk Factor and Classification Criteria:

These results give a preview to the wells situation regarding the water production, additional tests such as production logging to confirm the diagnostic plots results and give more accurate results and then decide the applicable treatment. The risk factor in table 4-4 is depending on the total oil production, well location and the applicability of the available shut off method. Cement situation is also a very important factor to choose mechanical water shut off to reduce the risk of producing water behind the casing.

Table4-4 summarizes the results and the wells are classified depend on the selection criteria with a risk factor from 1 to 10 to describe the ability to perform water shut-off: -

Table 40-4 Final wells result and suggestions

Classification	Well Name	Diagnose	Well Status	Structural position	High WOR	Risk Factor (1-10)	Technical suggestion
Group 1	JS-23	Normal Trend	Injector	-	No	-	-
	JS-20		Idle	No	No	-	Transfer to Injector
	JS-19		Idle	No	No	-	Transfer to Injector
Group 2	JS-8	Channeling	Idle	-	Yes	4	Further Analysis
	JS-9		producing	-	Yes	8	-
	JS-13		producing	Yes	Yes	8	-
	JS-16		Idle	-	No	4	Further Analysis
	JS-26		producing	-	Yes	-	Optimization
	JS-27		producing	-	No	-	Optimization
	JS-24		producing	-	Yes	3	Optimization
Group 3	JS-1	Multi layers Channeling	producing	Yes	Yes	9	-
	JS-4		producing	Yes	Yes	9	Isolate lower zones
Group 4	JS-3	Early Channeling with normal trend	producing	Yes	Yes	5	Further Analysis
	JS-2	Possible Conning	Idle	Yes	Yes	2	Water Shut-off
	JS-18		Idle	Yes	Yes	3	Water Shut-off

4.7 overview of the field water handling system;

At the surface, produced water is separated from the oil, treated to remove as much oil as possible, and either discharged or injected back into the wells. The general approach for produced water treatment is de-oiling and de-mineralizing before disposal or utilization as described in Figure 4-17. Quality of produced water discharges to surface or re-injected to wells is controlled by rigid environmental regulations in all countries. In Sudan the Ministry of Energy and Mining developed national environmental regulations for petroleum industry. Appendix A.

The diagram below describes the water handling system in the field, the stream comes from the production wells and with no treatment and inter the first stage which is consist of heating the stream to create a valid environment for the chemicals to work. The gravity separation alongside with the electrostatic hydro treaters are the main separation units to separate the oil from water and gas, then the water stream flow to dedicated water tanks for more separation of the dispersed oil from the water. An emulsions breaker (reverse demulsifier) used to separate as much oil as possible before dumping it to evaporation. CPI unit is the major de oiling system for produced water re injection to injection wells. Due to the good chemical quality of the produced water of the field there is no need for much treatment before injection, table 4-7 and table 4.8.

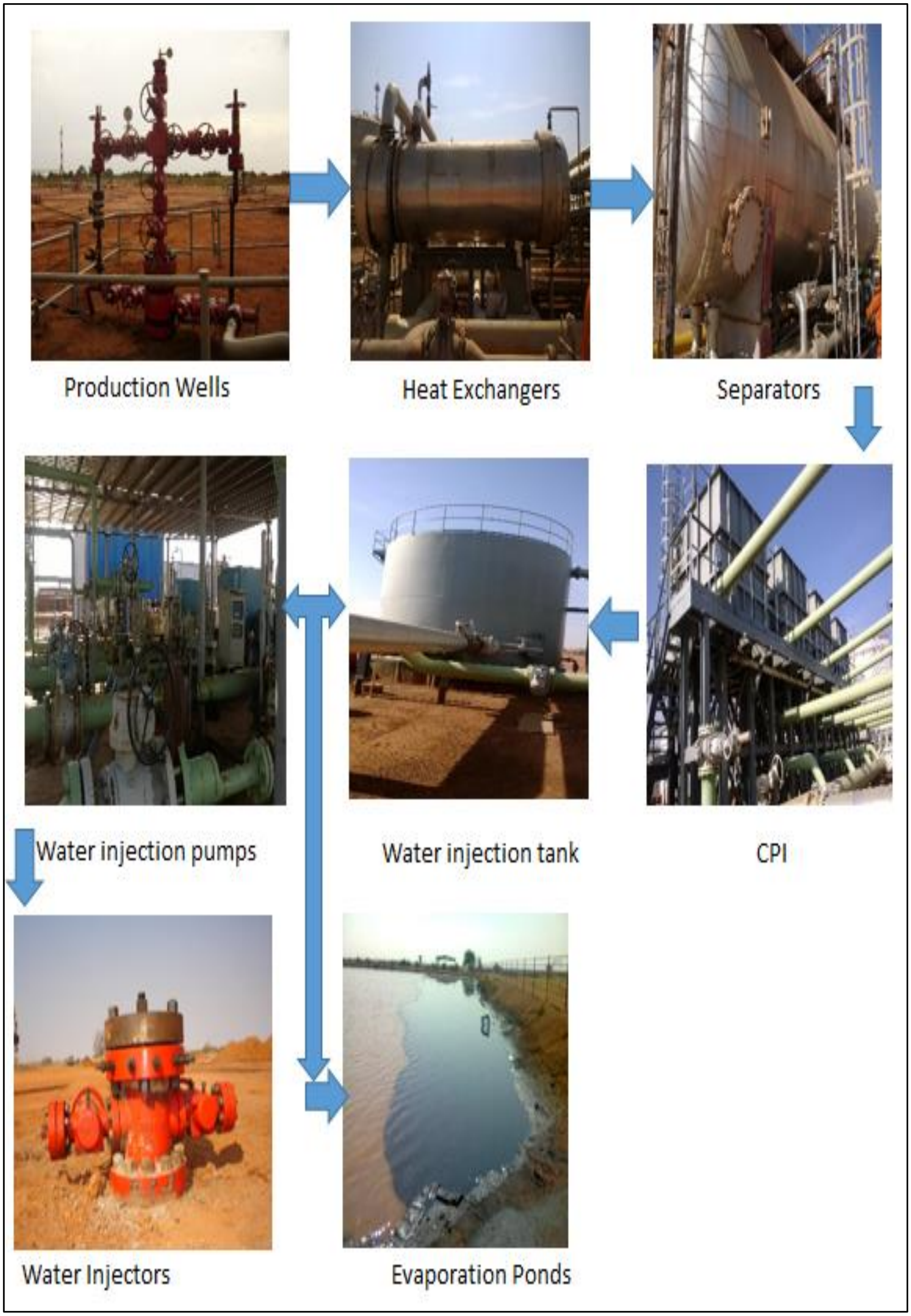


Figure 0-19 Jake Field Water Treatment Schematic from down hole to Disposal

The chart below describes the field water production and injection since the first day, with a three water injectors the total injected water rise to be almost 15000 BBL/D.

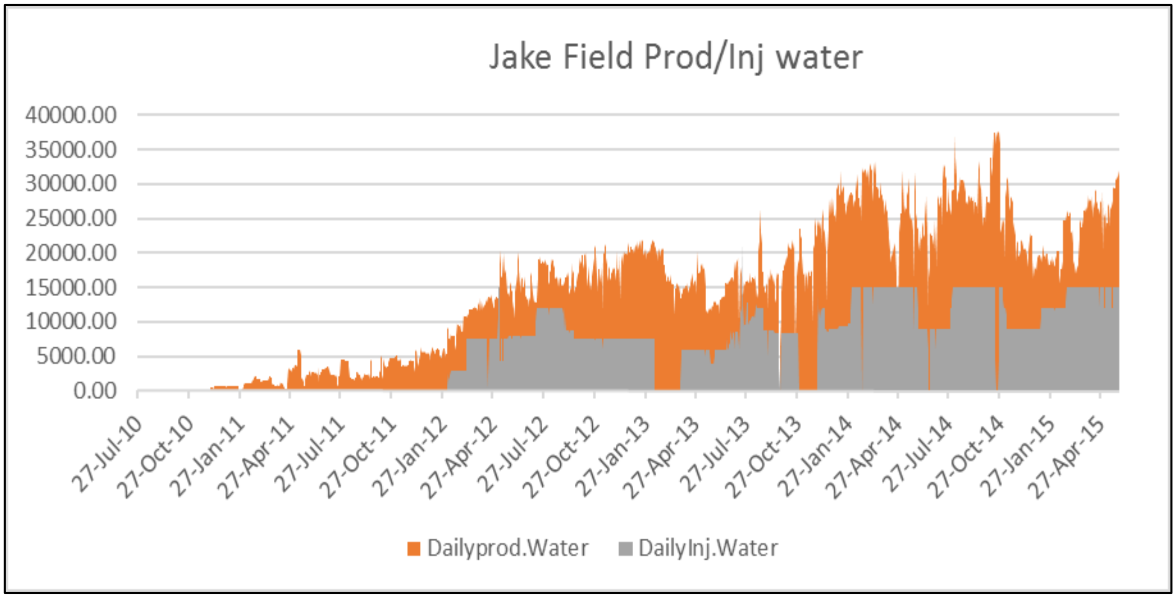


Figure 0-20 Injection, production profile since 2010

Table 0-5 Raw Water before Treatment

Physical Property			
Color:	**Yellow**	**Transparency:**	**Trans lucid**
Sediment:	**Few**	**PH:**	**8.73**
Content of Ion			
Item	**Content**		**Test method**
	mg/L	**mmol/L**	
OH^-	**0.00**	**0.00**	**SY 5523-92**
CO_3^{2-}	**0.00**	**0.00**	
HCO_3^-	**2135.70**	**35.00**	
Cl^-	**31.91**	**0.90**	
SO_4^{2-}	**100.86**	**1.05**	
K^++Na^+	**838.35**	**36.45**	
Ca^{2+}	**18.04**	**0.45**	
Mg^{2+}	**7.90**	**0.33**	
Salinity	**2064.91**		
Water Type:	**NaHCO3**		

Table 0-6 Produced water after treatment

Physical Property			
Color:	**Pale Yellow**	**Transparency:**	**Transparent**
Sediment:	**None**	**PH:**	**7.92**
Content of Ion			
Item	**Content**		**Test method**
	mg/L	**mmol/L**	
OH^-	0.00	0.00	SY 5523-92
CO_3^{2-}	0.00	0.00	
HCO_3^-	524.7	8.6	
Cl^-	31.91	0.9	
SO_4^{2-}	9.61	0.1	
K^++Na^+	209.3	9.1	
Ca^{2+}	6.4	0.16	
Mg^{2+}	3.65	0.14	
Salinity	523.01		
Water Type:	NaHCO3		
Oil Cut (mg/L)	422		

Therefore, this water could be considered as a fresh water regarding the content of heavy metals and the other minerals but the biological usage required the decreasing the value of the total dissolved solids and the oil in water content (Saad & Engineering 2005). The toxicity of this water need also more investigation regarding the oxygen demand.

4.8 Costing Procedures and Calculations:

Generally, the total system cost is the summation of the capital cost (CAPIX) and its current operation cost (OPEX), and due to the lack of economic data of the field, the world wide average presents by (Bailey et al. 2000) used to give a general overview of the water treatment cost and the effect of the total stream and how the well control options can give a good economic feasibility for the field.

Therefore, for Jake field the capital cost is considered to be the cost of the plant and the instruments alongside with the extra expansions and the evaporation pond, the total cost ranged from $ 0.842/Bbl to 0.434 $/Bbl where the lifting, operation, Injection and Disposal cost summary in represented in table 4-7:

Table 0-7 Average water Treatment and Handling Cost

		20,000 B/D	
Lifting	Capex/Opex	$0.044	5.28%
	Utilities	$0.050	6.38%
Separation	Capex/Opex	$0.087	10.36%
	Utilities	$0.002	0.30%
	Chemical	$0.034	4.09%
De-oiling	Capex/Opex	$0.147	17.56%
	Chemicals	$0.040	4.81%
Filtering	Capex/Opex	$0.147	17.47%
	Utilities	$0.012	1.48%
Pumping	Capex/Opex	$0.207	24.66%
	Utilities	$0.033	3.99%
Injecting	Capex/Opex	$0.030	3.62%
	Total cost/bbl	**$0.842**	**100%**
	Total chemicals	$0.074	8.90%
	Total utilities	$0.102	12.16%
	Total wells	$0.074	8.89%
	Surface facilities	$0.589	70.05%

This cost deployed to Jake field total production since day 1, at the early days it was so small obviously and then increased fast. The injection capital cost wasn’t included and assumed to be calculated with the total Capex.

The table 4-8 show sample of the total filed water treatment cost calculation based on the mentioned above average.

Table 0-8 Sample of cost calculation from 2014-2015

Dates	Dailyprod.Oil	Totprod.Water	TotInj.Water	Lifting Cost	Op Cost	Chemical Cost	Injection Cost	Disposal Cost	Disp.Cost	Total
2010	1404757	15722	0	$1540	$5911	$1163	$0.000	$157.	$157	$8772
2011	8297337	948802	0	$92982	$356749	$70211	$0.000	$9488	$9488.	$529431
2012	6589702	5229680	2588122	$512508	$1966359	$386996	$77643	$26415	$52296.801	$2969923
2013	7149245	6335347	2277367	$620864	$2382090	$468815	$68321	$40579	$63353	$3580671
2014	6169798	9713895	4422560	$951961	$3652424	$718828	$132676	$52913	$97138	$5508804
2015	2163469	3528429	2051313	$345786	$1326689	$261103	$61539	$14771	$35284	$2009889

Detailed graph for the treatment and handling cost through the life of the field is representing the wide variation in the operation cost compared to other types of cost, the lifting cost is reasonable and stable. The injection cost is small also compared to the operation cost. The environmental effect of the cost not discussed here but the low cost injection is attractive to dispose more water to the injection wells not to the evaporation ponds or any type of disposal.

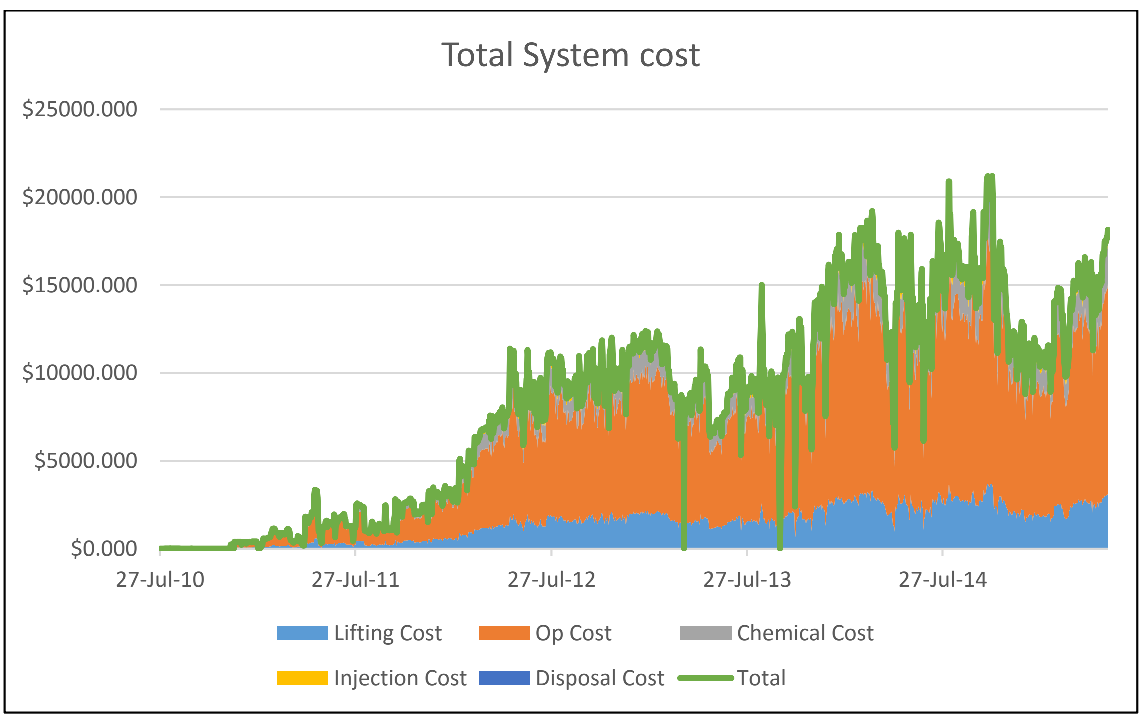


Figure 0-21 Water Treatment Handling Disposal Cost through the Life of the Field

4.8.1 Costing Scenarios:

No water injection: -

Due to low cost of the water injection, the Cost calculation if no injection for the total filed days is almost the same without the water injection, the table below describe the situation at the end of May,2015.

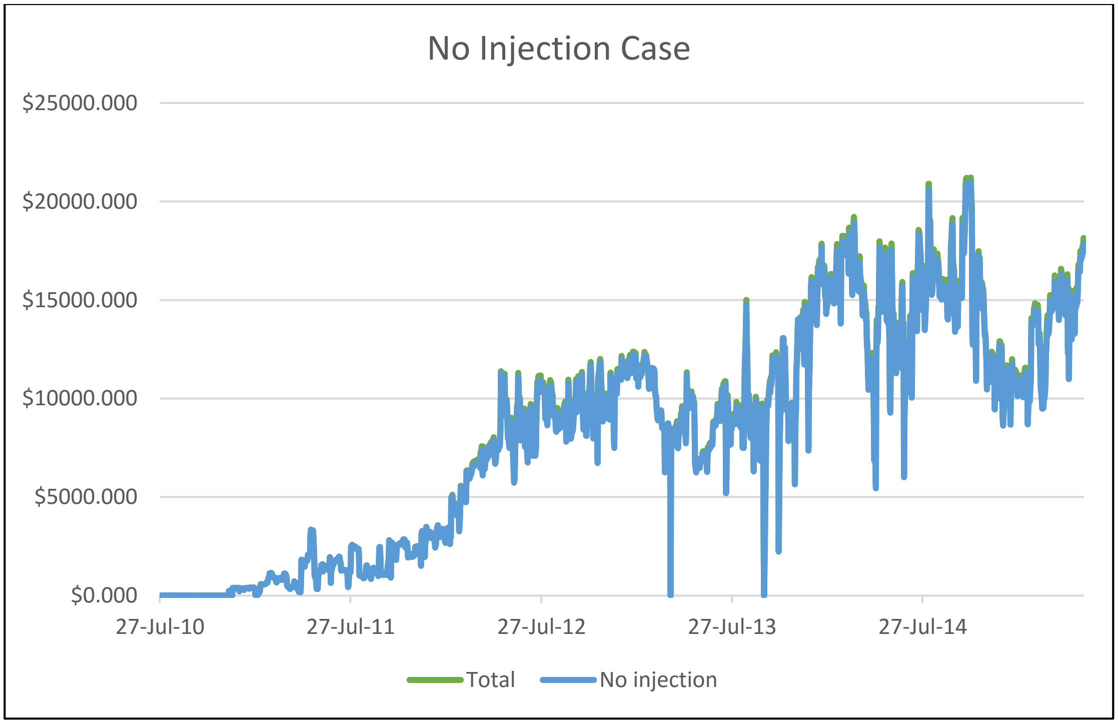


Figure 0-22 Water production, Injection scenarios: No injection case

Table 0-9 Injection Cost Scenario

		%
Total cost without water injection	$14,380,706	
Total Injection cost	$490,181	3.4
Total Produced water BBL	25,771,875	
Total injected water BBL	11,339,362	44.0

This simple comparison describe how the water injection worked effectively to decrease the amount of disposed water to the surface and reducing the environmental impact with a low cost 3.4% of the total cost compared to almost 44% of the total produced water. Which present the need for more water injectors for pressure maintenance after further studies or just transferring old producers to a disposal wells.

4.9 Wells cost analysis:

The well analysis will be done in a period of 12 months in order to understand the well economic situation. We can project a total economic benefit from this treatment by monitoring or projecting the production history over the next several months and years to establish the benefit decline. This is required to understand the true economic benefit of the solution. However, in many cases, this total benefit decline rate is unknown, and must be estimated. To estimate the overall decline rate from the cumulative benefit without field data can be difficult. A good first estimate is to double the normal field decline rate.

The water value added is the decreased water production after the treatment applied in order to evaluate not just the income from the oil but the value added from water handling cost, treatment etc.

The net present value NPV used to evaluate the economic feasibility of the treatment case and compared to the NPV after the income from the water decrement cost is added to the total well income, for the both cases a 12% interest rate is used in the cash flow calculation.

$$NPV(i,N) = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t} \quad \text{Equation 3}$$

In addition, a decline rate of 10% per year assumed for the oil production expectations.

4.9.1 Well Jake S-2:

Treatment cost =450,000 $ Operation cost=150,000$

Avg Oil price= 50 $/Bbl

Table 0-10 JS-2 Income and the Water value added for 12 Months

Time Months	Well Production STB/M	Income $$	Water Value added	Income $	NPV1	NPV2
1	6572	$328,600.00	105400	$60,921.20	$1,074,867.99	$1,761,780.27
2	5477	$273,833.33	105435	$60,941.66		
3	4564	$228,194.44	105471	$60,962.13		
4	3803	$190,162.04	105506	$60,982.59		
5	3169	$158,468.36	105542	$61,003.05		
6	2641	$132,056.97	105577	$61,023.52		
7	2201	$110,047.48	105612	$61,043.98		
8	1834	$91,706.23	105648	$61,064.44		
9	1528	$76,421.86	105683	$61,084.91		
10	1274	$63,684.88	105719	$61,105.37		
11	1061	$53,070.73	105754	$61,125.84		
12	885	$44,225.61	105789	$61,146.30		
Total	35,009		1,267,137			

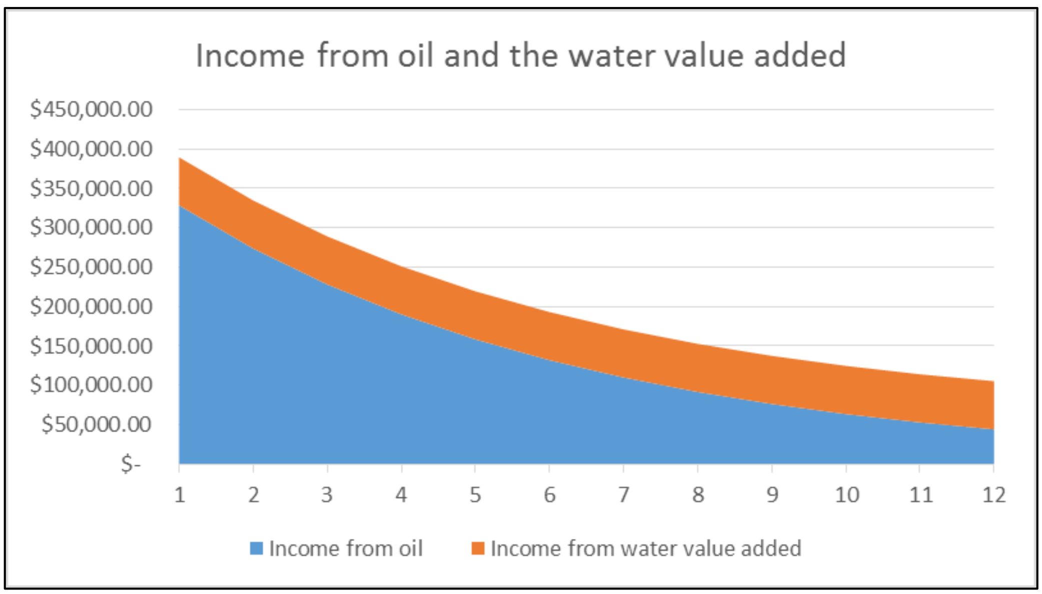


Figure 0-23 Income from oil and the Water Value Added: JS-2

4.9.2 Jake S-8:

Total cost =300,000 $

Avg Oil price= 50 $/Bbl

Table 0-11 JS-8 Income and the Water Value added for 12 Months

Time Months	well production STB/M	Income $$	Water value added	Income $$	NPV1	NPV2
1	9703	$485,150	58900	$34,044	$2,172,800.39	$2,557,251.75
2	8086	$404,292	58952	$34,074		
3	6738	$336,910	58986	$34,094		
4	5615	$280,758	59019	$34,113		
5	4679	$233,965	59052	$34,132		
6	3899	$194,971	59086	$34,152		
7	3250	$162,476	59119	$34,171		
8	2708	$135,396	59153	$34,190		
9	2257	$112,830	59186	$34,210		
10	1881	$94,025	59219	$34,229		
11	1567	$78,354	59253	$34,248		
12	1306	$65,295	59286	$34,267		
Total	51688		709212			

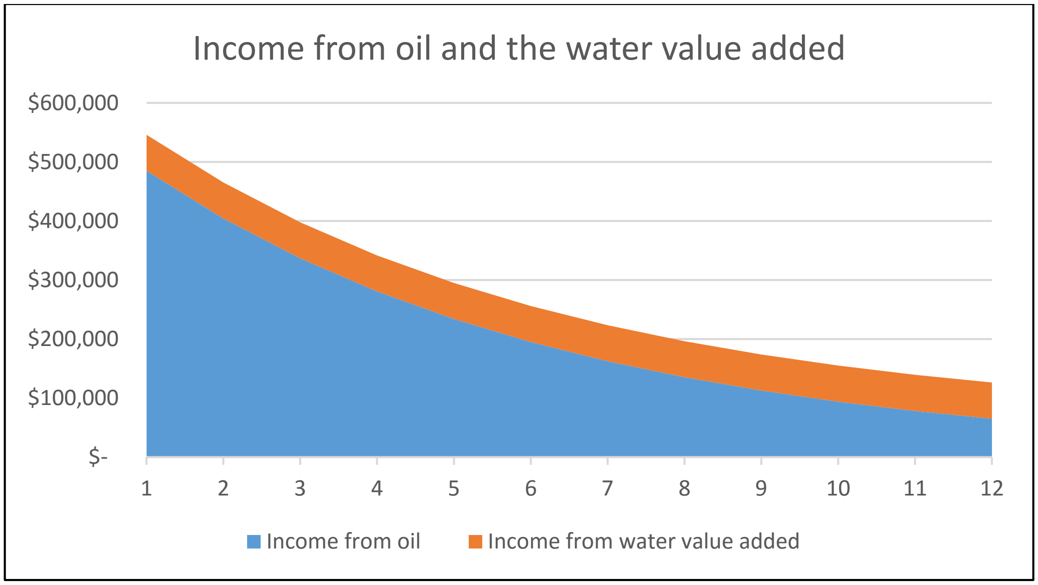


Figure 0-24 Income from oil and the Water Value Added: JS-8

4.9.3 Well Jake S-24:-

Total cost =300,000 $

Avg Oil price= 50 $/Bbl

Table 0-12 JS-24 Income and the Water Value added for 12 Months

Time Months	well production STB/M	Income $$	Water value added	Income $$	NPV1	NPV2
1	7440	$372,000	26660	$15,409	$ 1,596,076	$1,770,793.12
2	6200	$310,000	26712	$15,440		
3	5167	$258,333	26746	$15,459		
4	4306	$215,278	26779	$15,478		
5	3588	$179,398	26812	$15,498		
6	2990	$149,498	26846	$15,517		
7	2492	$124,582	26879	$15,536		
8	2076	$103,818	26913	$15,556		
9	1730	$86,515	26946	$15,575		
10	1442	$72,096	26979	$15,594		
11	1202	$60,080	27013	$15,613		
12	1001	$50,067	27046	$15,633		
Total	39633		322332			

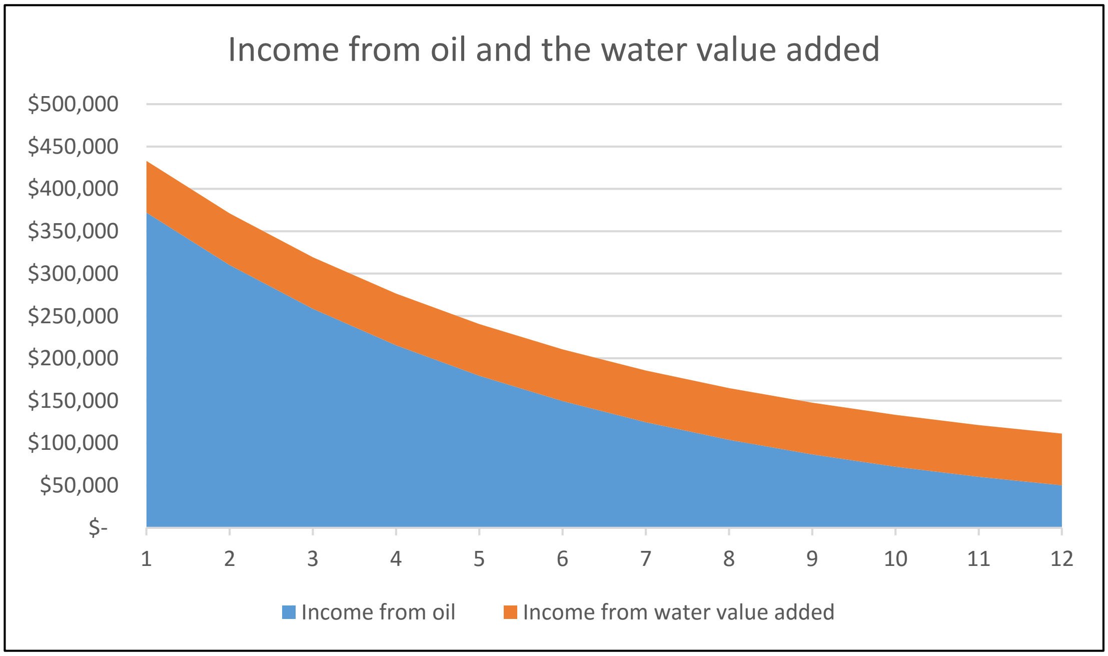


Figure 0-25 Income from oil and the Water Value Added: JS-24

The final comparison between the tree wells results is presented below: -

Table 0-13 Final Comparison between JS-2, JS-8 and JS -24

well	% of the revenue from the water value added
Jake S-2	39
Jake S-8	15
Jake S-24	10

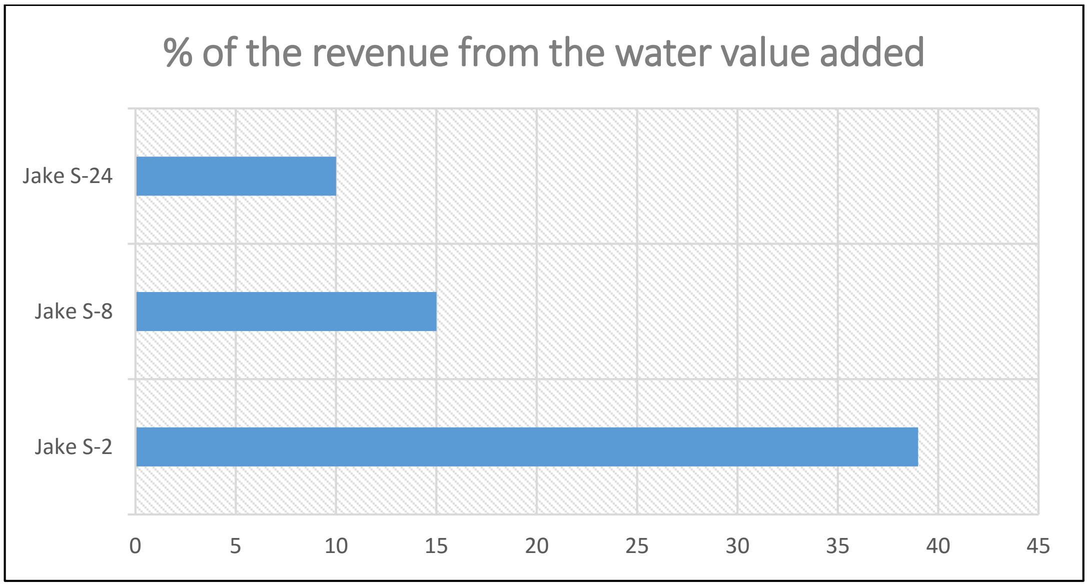


Figure 0-26 Comparison of the Revenue from the Water Value added

Chapter Five

Conclusion and Recommendations

Chapter Five: Conclusion and Recommendations

In this study, produced water problems has been investigated through the life of the field; The economic impact introduces to show the effect on field feasibility with time; the operation cost found to be the most dominated cost and the only way to control is by decreasing the total amount of water produced by water shut off operation. The conclusion of this study can be summarized as follows:

1. All the wells in this study are diagnostic as high conductive channeling due to the edge water driver reservoir and the high vertical and horizontal permeability while the comingled producer JS-2 and JS-18 showing conning criteria due to the bottom water drive; and normal trends are in the watered area.
2. Gas lift optimization (Injection rate, production rate) is a crucial to the water management strategy; and gas injection need to be continued in order to sustain the field performance and decrease or stabilize the water cut.
3. The wells were classified into 3 groups (High, Medium and Low risk wells) depends on their risk factor; and the perfect candidates for water shut-off is the low risk well (2, 18, JS 24).
4. Mechanical shut-off was found to be not a good choice for this kind of formations and the RPM materials can give a good result but its need more investigation to identify the suitable material.
5. Water reinjection as a type of water disposal was found to be less expensive and can create a good example in eliminating the environmental effect of the produced water. And two other wells could be transferred to injectors after further investigation and more wells production methodology could be optimized

Finally, this study showed much different results; therefore, the following recommendations are made:

1. To highly improve the total field management, all scenarios could be integrated in a single strategy of controlling the produced water (decreasing the rate) to add more value from the treated water, decreasing the disposal which will cost less compared to the other cost parts

2. Due to the high risk factor, more investigations are needed to confirm the diagnostic result of JS-2 and JS-18

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Appendices

Appendix A

The permissible Limit for oil waste to be disposed in Surface/Ground Water SPC, 2013

Parameter	Units	Max Limit
Temperature	C°	+ 5, amp.
Color	--	Non
Odor	--	Non
PH - value	--	6-9
Dissolved Oxygen	Mg / 1	>2
Chemical Oxygen Demand. Dichromate.	Mg / 1	40
Biological Oxygen Demand (B.O. D)	Mg / 1	30
Sulphide	Mg / 1	1
Ammonia (NH_3)	NTU	Nil
Nitrate (NO_2)	Mg / 1	30
Phenols	Mg / 1	0.002
Fluorides	Mg / 1	0.5
Total phosphates	Mg / 1	1
(102C°) Total Dissolved Solid (LDS)	Mg / 1	1200
Total suspended solid (T.S.S.)	Mg / 1	30
Oil & Grease	Mg / 1	5
Detergents	Mg / 1	0.05
Cyanide (CN)	Mg / 1	0.05
Iron (Fe_3)	Mg / 1	1
Zinc (Zn)	Mg / 1	1
Copper (cu)	Mg / 1	1
Nickel (Ni)	Mg / 1	0.1
Cadmium (CD)	Mg / 1	0.01
Chromium (CR)	Mg / 1	0.05
Lead (ph)	Mg / 1	0.05
Tin (SN)	Mg / 1	--
Arsenic (As)	Mg / 1	0.05
Manganese (MN)	Mg / 1	0. 5
Mercury (Hg)	Mg / 1	0.001
Silver (Ag)	Mg / 1	0.05
Total Heavy Metals	Mg / 1	1
Radioactive Materials	Mg / 1	Non
Residual chlorine	Mg / 1	1
Bacterial count	1/100ml	2500