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EMIRATES INTERNATIONAL UNIVERSITY

FACULTY OF ENGINEERING AND INFORMATION TECHNOLOGYOIL AND GAS ENGINEERING DEPARTMENT

EXCESSIVE WATER PRODUCTION DIAGNOSIS AND THE BEST TREATMENT FOR NABRAJAH OIL FIELD, BLOCK-43, SYA’UN-MASILAH BASIN YEMEN

A PROJECT SUBMITTED IN PARTIAL FULFILLMENTOF THE REQUIREMENTS FOR THE DEGREE OF BACHELOR OF SCIENCE IN OIL AND GAS ENGINEERING

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DECLARATION

We hereby declare that this Bachelor's Project is the result of our own work, except for quotations and summaries which have been duly acknowledged.

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APPROVAL

This is to certify that the project titled **Excessive Water Production Diagnosis And The Best Treatment For Nabrajah Oil Field, Block-43, Sya'un-Masilah Basin** has been read and approved for meeting part of the requirements and regulations governing the award of the Bachelor of Engineering (Oil and Gas) degree of Emirates International University, Sana'a, Yemen.

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ABSTRACT

This project provides an integrated overview of the water shutoff operations, starting from the causes to the solutions. And Excessive water production is one of the major factors in wells' productivity reduction .and It can be resulted from water coning and water channeling from water table to the wells through natural fractures, faults or high permeability zones. The project begins with explaining the benefits of eliminating excessive water production. Then, the different types of water production and their properties are explained. The project also focuses in reviewing the disadvantages of producing unwanted water as well as the sources of it, followed by an explanation of the methodology for identifying the problem. Then, the chemical solutions for water shutoff are reviewed which are generally applied to solve the excessive unwanted water production in the reservoir or near the wellbore area. Finally, the project illustrates the common mechanical solutions for water shutoff within the wellbore. The aim behind this project is to provide a general description of identifying the unwanted water production sources and method that use to diagnosis the reasons for excessive water production and the common practices for water shutoff operations.

DEDICATION

This work is dedicated

To everyone who had a role

In the completion of this project

From tips and instructions

That contributed to the completion of this project

Our parents

To those who play a major role in bringing us to this scientific level, and those who stand by our side during the whole

Journey.

Our brothers & sisters

To those who are harmful to us by giving us

lessons and tips for our way to this success,

Our doctors

To those thanks to them after Allah's preferred and the gain many information in turn helped to succeed by moving forward and who did not judge our scientific sustains.

Our families

To those who support us during our learning phase.

Our friends

To those who have been we on our learning phase.

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First of all, we would like to thank Allah for his blessing on us to achieve this project, we would also like to express our deep and sincere gratitude to our supervisor **DR. Mohammed Abbas** for his guidance, inspiration and continuous assistance, to overcome the difficulties we face for the successful completion of this project.Our special gratitude is due to all those who have helped in carrying out the research and contributed in any way for the success of this project, he has all the expressions of thanks and gratitude.

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LIST OF ABBREVIATIONS

OFM	Oil Field Management
API	American Petroleum Institute
TOC	Total Organic Carbon
TTL	
Ro	
bopd	Barrel Oil Per Day
WOR	Water Oil Ratio
WOR' or dWOR	Derivative Water Oil Ratio
WFL	Water Flow Logs
TPHL	Three Phase Fluid
Kv	Vertical Permeability
Kh	Horizontal Permeability
OWC	Oil Water Contact
WPMs	
CHFR	Cased Hole Formation Resistivity
TDS	Total Dissolved Solids
PL	Production Log
ISP	Intermediate Strength Proppant
PCR	
POOH	Pull Out Of Hole
HUD	
DOWS	Downhole Oil Water Separation
PAM	Polyacrylamide
HPAM	Hydrolyzed Polyacrylamide
OOIP	Original Oil In Place
IFT	Interfacial Tension
EOR	Enhance Oil Recovery
EOS	Equation Of State
SP	Surfactant Polymer
ASP	Alkaline Surfactant Polymer
LASER	Liquid Addition to Steam to Enhance Recovery
VAPEX	Vapor Extraction

CSI	Cyclic Solvent Injection
CSS	Cyclic Steam Stimulation
AP	
CIM	Control Method
UTCHEM	Chemical Reservoir Simulator
bSRD	Below Seismic Reference Depth
Bmsl	Below Mean Sea Level
STB	Stuck Tank Barrle
DCA	Decline Curve Analysis
CDF	Cumulative Distribution Function
ESP	Electrical Submersible Pump
PLT	Production Logging Tool
MD	Measured Depth
TVD	True Vertical Depth
RKB	Reference Kelly Bushing or Rotary Kelly Bushing
WC	Water Cut

Chapter One

1. Introduction

Excessive water production is one of the main well-known problems that would face any oil operator in the world. Although this problem is typical in older wells, it can also occur in new developed wells as well. It causes numerous economic problems for oil production companies.

First, excessive water effects the performance of the production wells and shortens their lifespan.

The presence of the water in the wellbore increase the weight of the fluid column which leads to an increase in the lifting requirements. That increases the operating cost and leads to a lower the drawdown. For example, if the well is a gas lifted well, the amount of gas injected to lift the fluid from the wellbore to the surface is higher with the production of excessive water than without producing it.

Water production also enhances the presence of scales, corrosion, and degradation in the field facilities starting from the wellbore to the surface facilities .Another major problem is that the cost of separating, treating, and disposing the produced water is a great burden to oil company budgets.

The water produced from the oil and gas production process comes either from an aquifer, reservoir or/and from injection wells in water flooding. It can contain very small amounts of chemicals that have been mixed with it during the production process. It is expected that water production may be increase with the life of the reservoir.

This water is present under high pressures and temperatures and contains some minerals, so it must be treated before it is injected again into the reservoir.

Treating produced water is one of the most expensive elements in oil and gas production, as wells usually produce a small amount of it at the beginning, but sooner or later these wells will produce larger quantities of it (sometimes greater than the amount of oil), and this process It is considered an economic burden on oil producers, and many standards and laws have been set for the process of disposing of the produced water, and this water can be a source of drinking water, and it can also be discharged into the sea.

The first step in the field of treating the produced water is an attempt to reduce the amount of this water through the process of naming the wells in order to prevent the entry of water into the well and thus reduce the water that comes out with oil or gas to the surface.

The water produced must be disposed of or utilized, as the most common benefit is re-injection into the reservoir after being treated to get rid of compounds that cause damage to the reservoir or pipelines, and this treatment depends on the type of water produced, which varies from one reservoir to another.

This water can also be used as a drilling fluid or in cooling in power plants and in places where water is scarce. The water produced for agricultural and irrigation purposes can be treated in addition to treating it for domestic use.

After all this, the remaining produced water must be disposed of through injection into the reservoir, and before that it must be removed from salts and inorganic materials by using ion exchange, distillation, and membrane transport with respect to salts.

To control the produced water and in turn increase the oil recovery, the source (the mechanism) of the water problem must be identified. The quicker and cheaper way to diagnoses and analysis problems related to water production by the use of analytical and diagnostic plots

1.1 Aim and Objectives

The purpose of this graduation project is conduct diagnoses for water production mechanism and analyze the control techniques for several producing wells in Nabrajah Field, Block-43 by using available field data through OFM software and/or EXCEL spreadsheets.

Based on the results of these analysis we able to conduct a solutions for well problems that producing oil with a higher water cut. To achieve the aim of the project, the following objectives are defined:

1. Production and completion well data will collected from the reports of the field.
2. Review production and completion well history data.
3. Several type analysis methods well use through the OFM and EXCEL.
4. Chan plot will used mainly to diagnoses and analysis produced water.
5. Figure out the best way to control produced water.
6. Carry out economical study of water treatment in the field
7. Make recommendation how to mitigate water production and thereby optimizing well performance and oil recovery.

1.2 Problem Statement

The major problem in Al-Masila basin is excessive water production in the most oil fields, it is urgent to search for the main reasons of like that problem and get practical and effective solutions to control excessive water production. Nabrajah filed, is one of the oil fields in Al-Masila basin that faced increasing in water production in most of the filed wells (water cut more than 90%). This large increase in the production of water associated with the oil production process has negative economic effects (decrease the oil recovery, equipment maintenance and cost time) as well as environmental risk effects (e.g. affecting the fresh water sources, agricultural crops and agricultural soil). Oil wells that produce high levels of water with the oil produced usually require large costs to isolate water and treat corrosion problems. In addition, oil reservoirs with high water production have a very low oil recovery coefficient. The current work will focus on diagnoses water production and analyze the control techniques in Nabrajah field.

1.3 Geology of Yemen

The Republic of Yemen located in southwest Asia, Geological surveying and petroleum exploration in Yemen date back to the early decades of the 20th century from the 1930s–60s, the Iraq Petroleum Company conducted exploration in the Hadramout and Mahrah areas in north-east Yemen, during which p eriod Ziad Rafiq Beydoun (1924–1998) pioneered geological studies of the country.

Between 1962 and 1967, Pan American Oil continued exploration in Hadramout (in South Yemen) and drilled a number of wells, with the non-commercial discovery of several barrels of oil from the fractured carbonates of the Cretaceous Qishn Formation in Tarfayt-1.

During the 1970s and 80s both North and South Yemen began offering concession blocks to a number of foreign oil companies. The first commercial discovery came in 19 84 when the American company Hunt Oil drilled Alif-1 in the Marib sector of the onshore Sabatayn Basin in North Yemen, penetrating a total depth at 4,182m and hitting oil (40.4º API) in the Alif Member of the Sabatayn Formation (Middle–Upper Tithonian age) with an initial flow of 7,800 bopd .

In 1986, the Russian company Techno-Export, which was operating in South Yemen, drilled West Ayad-1 in the Shabwa sector of the Sabatayn Basin, encountering 35º AP I oil in the Jurassic. Petroleum exploration by Canadian company Nexen in the Sya'un-Masilah Basin, led to an oil discovery in 1991: Sunah-1 drilled to the total depth at 2, 917m and discovered oil (36º API) in sandstones of the Lower Cretaceous Qishn Formation.

Twelve onshore and offshore sedimentary basins have been identified in Yemen, categorized into three groups as shown in Fig. 1-1 based on the geological era in which they originated: (1) Rub' Al-Khali; (2) Sana'a; (3) Suqatra; (4) Siham-Ad-Dali'; (5) Sabatayn; (6) Sya'un-Masilah; (7) Balhaf; (8) Jiza'-Qamar; (9) Mukalla-Sayhut; (10) Hawrah-Ahwar; (11) Aden-Abyan; (12) Tihamah. Of these, only two common onshore sedimentary basins, **Sabatayn** and **Sya'un-Masilah**, wher e oil was discovered in 1984 and 1991 respectively, are currently the only petroleum- producing basins in Yemen, while the other basins, including the onshore Paleozoic and offshore Cenozoic basins, and remain little-explored

Table 1.1 Twelve onshore and offshore sedimentary basins categorized into three groups based on the geological era.

Geological Ear	**Basin s**
Paleozoic Basins	- Rub' Al-Khali Basin. - San'a Basin. - Offshore Suqatra (Island) Basin.
Mesozoic Basins	- Siham–Ad-Dali Basin. - Sab'atayn Basin. - Say'un–Masilah Basin. - Balhaf Basin. - Jiza'qamar Basin.
Cenozoic Basins	- The Aden–Abyan Basin. - Hawrah–Ahwar Basin. - Mukalla–Sayhut Basin. - Tihamah Basin.

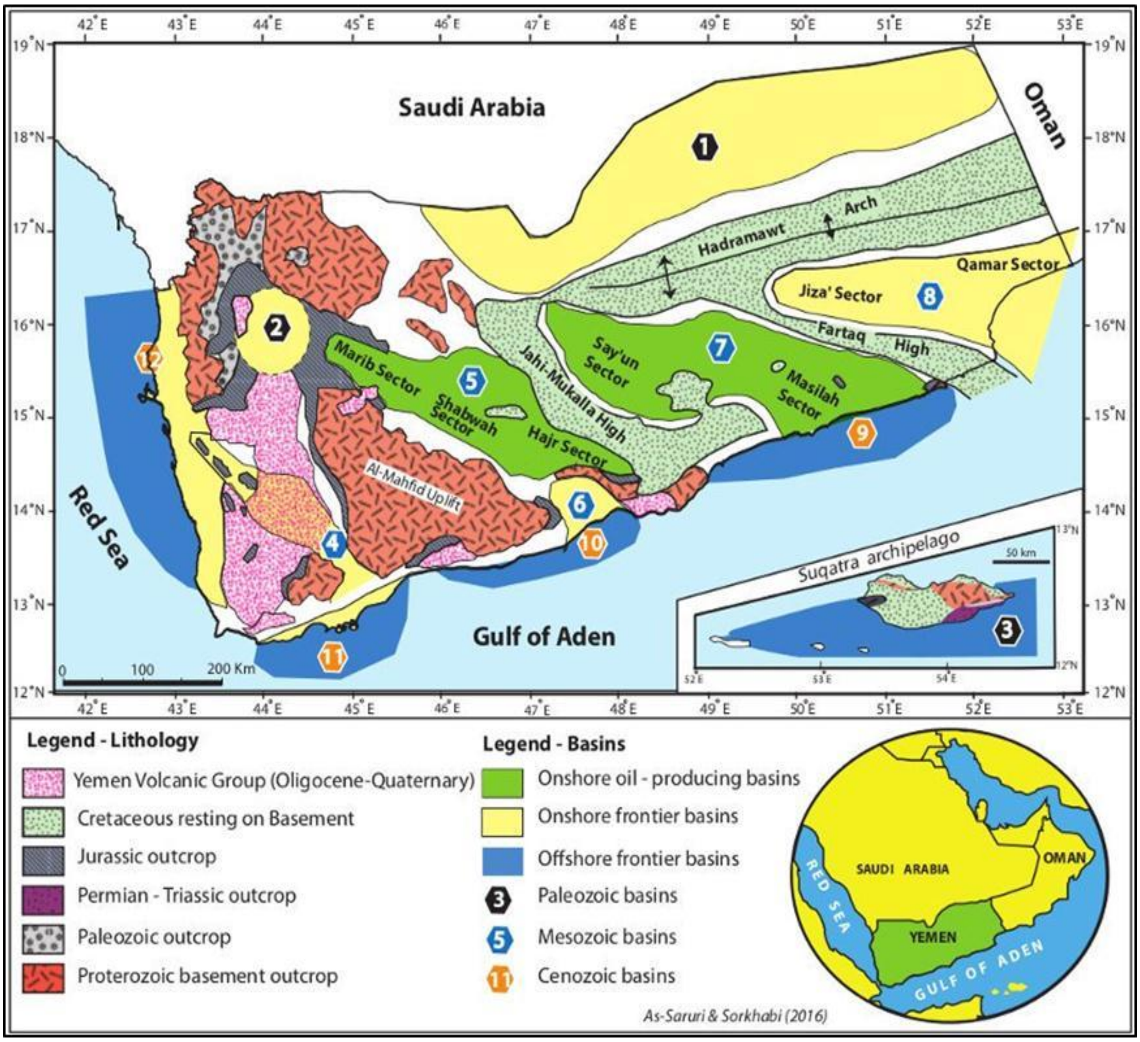


Figure 1.1 Sedimentary basins of Yemen and their classification according to the geologic era in which they formed. (Source: As-Saruri & *Sorkhabi (2016))*

1.3.1 Sya'un-Masilah Basin

As with most other oil-bearing basins in eastern and western Yemen, the Masilah Basin initiated as a rift basin during Upper Jurassic-Early Cretaceous post-Pangea breakup. The main source rock in the Masila Basin is Late Jurassic Madbi Formation, which is mainly composited of black calcareous shales with high TOC more than 8%.

Rifting caused a series of northwest southeast and west-east trending major basin-bounding faults evolving, adjacent to which are three main Jurassic-Cretaceous rift graven basins of Yemen: The Marib-Shabwah, the Masilah, and the Jiza'-Qamar Basins (Fig.1.2). The tectonic evolution of the Masilah Basin can be divided into three stages: pre-rift, syn-rift and post-rift. Pre-rift mega sequence ranges in age from Proterozoic to early Late Jurassic. The Pre-rift has been penetrated by wells drilled in the Masilah Basin.

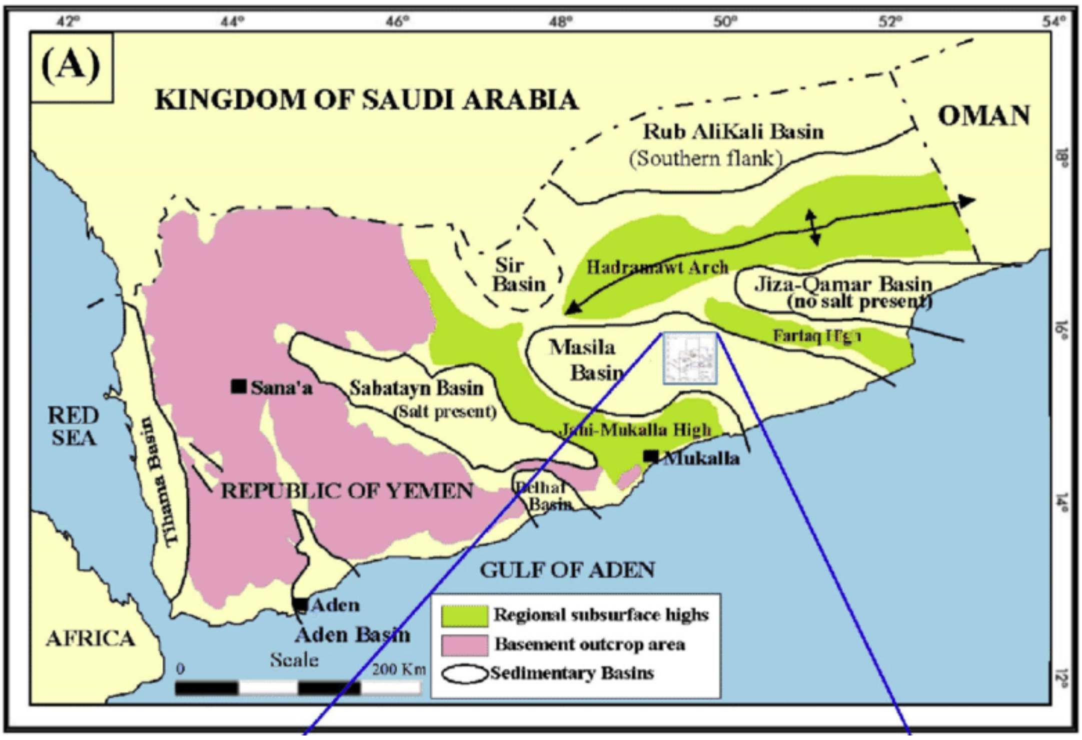


Figure 1.2 Main sedimentary basins in Republic of Yemen showing location map of the oilfields in the Masilah Basin

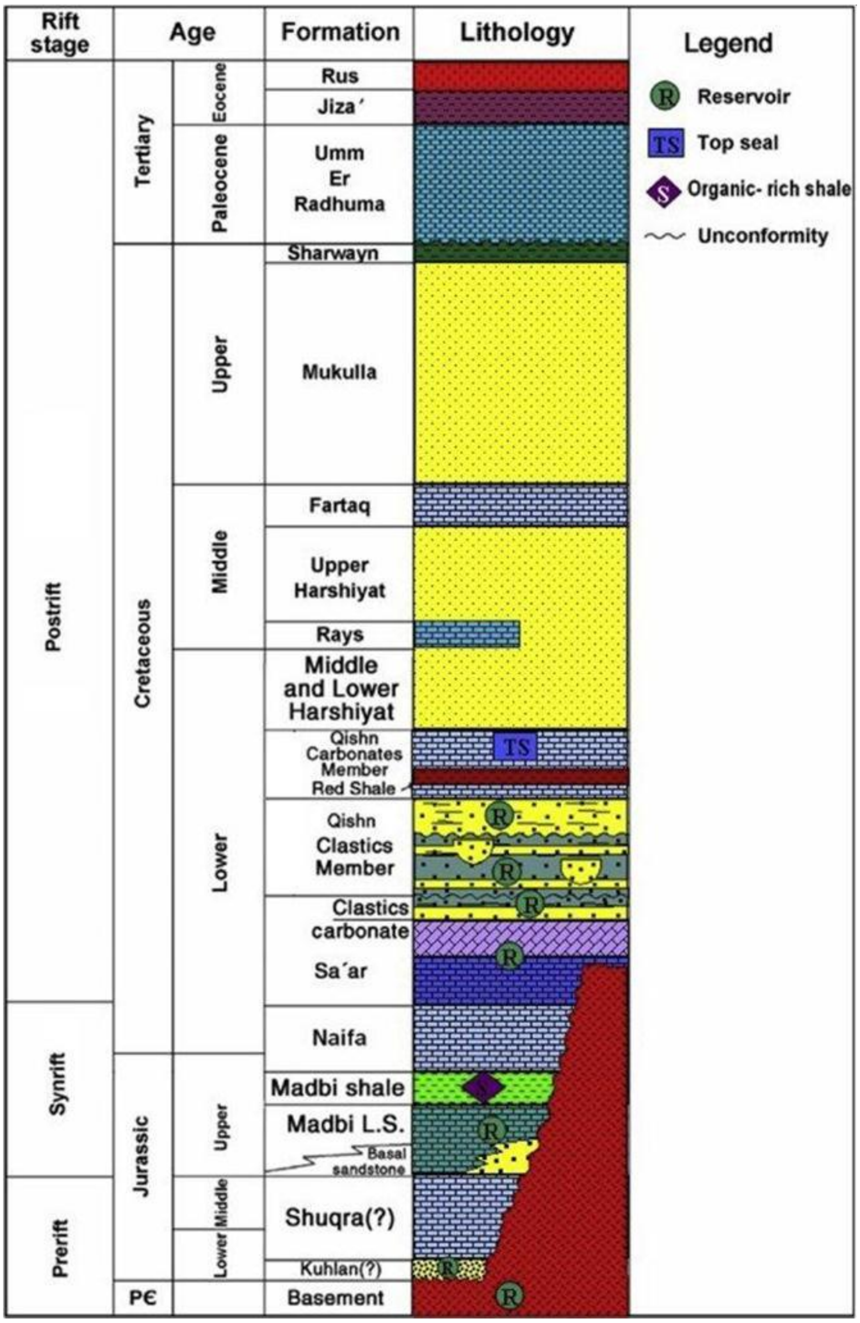


Figure 1.3 stratigraphic nomenclature, Masilah Basin, Republic of Yemen

1.3.2 Stratigraphy of Sya'un-Masilah Basin

The basement of the Masilah Basin consists mostly of igneous and metamorphic complex rocks of Proterozoic to early Cambrian age. This basement complex is overlain uncomfortably by a Jurassic sequence.

Kuhlan Formation

In Early to Mid-Jurassic time, sandstone was deposited widely across Yemen, where thick sedimentation developed in lows formed before Jurassic time. This thick sandstone deposit is known as the Kuhlan Formation, and it is composed of siltstone and sandstone ranging to conglomerate with some streaks of limestone and green clay.

In Masilah Basin oilfields, the sandstone of the Kuhlan Formation is very fine to medium grained, well sorted, and possess of poor to good porosity.

Shuqra Formation

After deposition of the Kuhlan Formation, another marine transgression from the southeast reworked the sandstone and deposited shallow-marine carbonates (Shuqra Formation). The Shuqra Formation is Middle to Late Jurassic in age and consists predominantly of platform carbonate.

Madbi Formation

During the syn-rift sequence, horsts and nested fault blocks were developed, where differential compaction and drape anticlines occurred in the Upper Jurassic to Lower Cretaceous due to basement high. Upper Jurassic sediments, known as the Madbi Formation, were penetrated by wells drilled in the basin. This formation is generally composed of porous limegrainstone to argillaceous lime mudstone. The lithofacies of this unit reflects an open marine environment. This formation is divided into two members. The lower part of this formation is commonly argillaceous lime and basal san d and forms a good reservoir in some oil fields of the Masilah Basin. The upper member is called Madbi shale and is composed of laminated organic-rich shale and mudstone. The thickness of Madbi shale is 30-100 m.

Naifa Formation

During latest Jurassic to Early Cretaceous time, the rifting in the Masilah Basin continued, but the subsidence became slower. It was accompanied by the accumulation of carbonates as shallow-marine shelf deposits which constitute the Naifa Formation. The Naifa Formation consists mainly of silty and dolomitic limestone and lime mudstone with wackestone.

Saar Formation

The upper part of this formation is composed of very porous clastic carbonate overlain by the Saar dolomite facies. In Early Cretaceous time, sea level rose on relatively flat ground, resulting in marine transgression and sedimentation of widespread shallow-marine carbonate Saar Formation.

The Saar Formation is composed mainly of limestone, dolomitic limestone with some mudstone, and sandstone. Oil companies classified this formation into lower Saar carbonate and upper Saar clastic. The total porosity of Saar Formation (carbonates with shale) varies from 5 to 20%.

Qishn Formation

The Post-rift mega sequence range in age from late Early Cretaceous to Tertiary time and rests unconformably on the syn-rift section. Late Early Cretaceous sediments, known as the Qishn Formation, consist of braided plain to fluvial and shallow-marinese diments deposited in the Masilah Basin. The Qishn formation ages between Barremian and Aptian.

a) **Qishn Formation Transition:** Lower Aptian age. Shale, calcareous shales, and occasional sandstones constitute this interval. The unit directly overlies the Qishn Carbonate and forms the uppermost part of the hydrocarbon seal for the reservoir sandstones of the Qishn Clastics.

b) **Qishn Formation Carbonate:** Barremian to Lower Aptian age. Predominantly argillaceous limestones with interbedded calcareous shales. This unit is a regional hydrocarbon seal for the reservoir sandstones of the underlying Qishn Clastics.

c) **Upper Qishn Formation Clastics:** Barremian age. The major hydrocarbonbearing reservoir of Masila block with sandstone and claystone/siltstone interbeds. Thin coals, limestones and occasional anhydrite may be present. The sandstones are mainly well sorted, sub-angular to sub-rounded and generally poorly consolidated with scattered well-consolidated stringers. The loose grains indicate good porosity, and this unit is recognized to be the primary hydrocarbon objective. The upper Qishn sandstones of the Qishn Formation have been stratigraphically subdivided by petroleum geologists into three informal units: an upper S1, a middle S2, and a bottom S3. S1 refers to the first sandstone encountered below the Qishn Carbonates Member, followed by the S2 and S3. The S1 is subdivided into S1A, S1B, and S1C, based on the presence or absence of non-reservoir (carbonate and shale) lithology's. The average total porosity of the Upper Qishn Clastic (sandstone with shale and carbonates) ranges from 16 to 22%.

d) **Lower Qishn Formation Clastics:** Barremian age, Finer grained than the Upper Qishn Clastics. Mainly siltstones and shales; interbedded sandstones are usually poorly sorted, and tight. There are some porous sands, though only locally does this unit constitute a reservoir. The Lower Qishn Formation is divided into two informal units: an upper LQ1 and lower LQ. The average total porosity of the Lower Qishn Clastic (sandstone and shale) ranges from 13 to 21.6%.

Harshiyat Formation and Fartaq Formation

During the late Early Cretaceous, alternating regression and transgression occurred. This pattern deposited clastic (Harshiyat Formation) and carbonate rocks (Fartaq For mation) interbedded with each other.

Mukulla Formation and Sharwayn Formation

A similar pattern of sedimentation occurred in Upper Cretaceous time, where fluvial systems (Mukulla Formation) prograded southeast ward in the Masilah Basin. The Late Cretaceous Sharwayn Formation deposits are composed mainly of shale.

Umm Er-Radhuma Formation

The overlying Tertiary units comprise homogeneous argillaceous, detritus carbonates and hard, compacted, massive and bedded dolomitized fossiliferous limestone with local chert nodules (Umm Er-Radhuma Formation) that changes to shales with minor 7 limestone bands in the upper levels (Jiza' Formation). Jiza'-deposits are widespread in the Early Eocene followed by the deposition of anhydrite beds (Rus Formation).

1.3.3 Petroleum System of Sya'un-Masilah Basin

The petroleum system and hydrocarbon potentialities of Sayun-Masila basin, as one of the most prolific sedimentary basins in Yemen, The lithostrtigraphic succession consists of rock units ranging in age from Upper Jurassic to Recent. The oldest sediments rest unconformably on the basement rocks and dipping gently to the northwest. Tectonically, it reflects the breakup of Goundwana land, basin creation formed by rifting during Late Jurassic and Early Cretaceous and rifting of the Gulf of Aden and Red Sea throughout Tertiary age. Qualitative and quantitative evaluation of source rock was done by means of geochemical and geophysical approaches. The TOC values of Shuqra, Madbi, Naifa, Saar and Lower Qishn Clastic formations were determined. The Upper Jurassic sediments are found to be oil–prone source rock in a mature stage. The Madbi Formation is considered as the most effective **source rock**. The Upper Qishn Clastic sandstone represents the **main producing reservoir**, the lower Qishn clastic has less potentiality, and however, Saar Formation is the poorest reservoir in the study area. The most effective **seal** are the Qishn Carbonates Member (carbonates and shales sections) of the Early Cretaceous sequence for the underlying reservoirs of the Upper and Lower Qishn Clastic and Saar reservoirs. The main petroleum **trapping** are the structural and structural-strtigraphic within the main fault-blocks. The Madbi Formation, on the basis of TTI and Ro values, may be considered a zone of oil window after the onset and peak of oil generation, thus the hydrocarbon products are mainly oil. Most hydrocarbons are probably generated at temperature range 82-101°C, corresponding to burial depth range 1970-2800 m. The depth of oil window varies from well to another. The peak of oil generation is recorded only in S-2 well in the NW part of the study area at 2755 m depth. The times of onset oil generation started in the Late Cretaceous (about 68 m.y.), while that of **migration** started in the Middle Miocene (about 15 m.y.) and that of preservation started from the Middle Paleocene to Present. In the study area, hydrocarbons have been most probably generated from the Jurassic rifts, migrated upward until they are trapped generally within the Early Cretaceous reservoirs beneath the Qishn carbonate seal.

1.4 Area of Study

1.4.1 Block-43

Block 43 South Hawarim: Covers an area of 2026 km², and is operated by DNO. Date of production of the sector: July 2005. one field, which is the Al-Nabraja field. Cumulative production until the end of June 2010: 10783066 barrels. Production of Qashan started in July 2005 of Qishn Sandstone ~16 months after discovery.

Block 43 lies in the petroliferous Say'un - Masila Basin about 600 km east of Sana'a, within a cluster of producing blocks managed by different operators .the block has 10 Exploration wells and 23 production wells upto 2012.

1.4.2 Nabrajah field

Oil Search played a key role in the Nabrajah oil field discovery small Qishn sandstone accumulation overlying deeper gas and oil field in fractured granitic Basement/Kohlan tested ~10,000 bopd.

Nabrajah field that was discovered in December 2004 and has been producing since July 2005 and can be classed as a mature development, producing field.

The reservoir in Nabrajah field is the Shuqra/basement (called Deep reservoir) and sandstone of the Qishn Clastic Member of the Tawila Group; a widespread siliciclastic sequence deposited in deltaic to shallow marineneritic environments.

Development comprises completion of 4 wells for production, water injection well, construction of Central Production Facility and 12 kilometre pipeline to Masilah Block 14

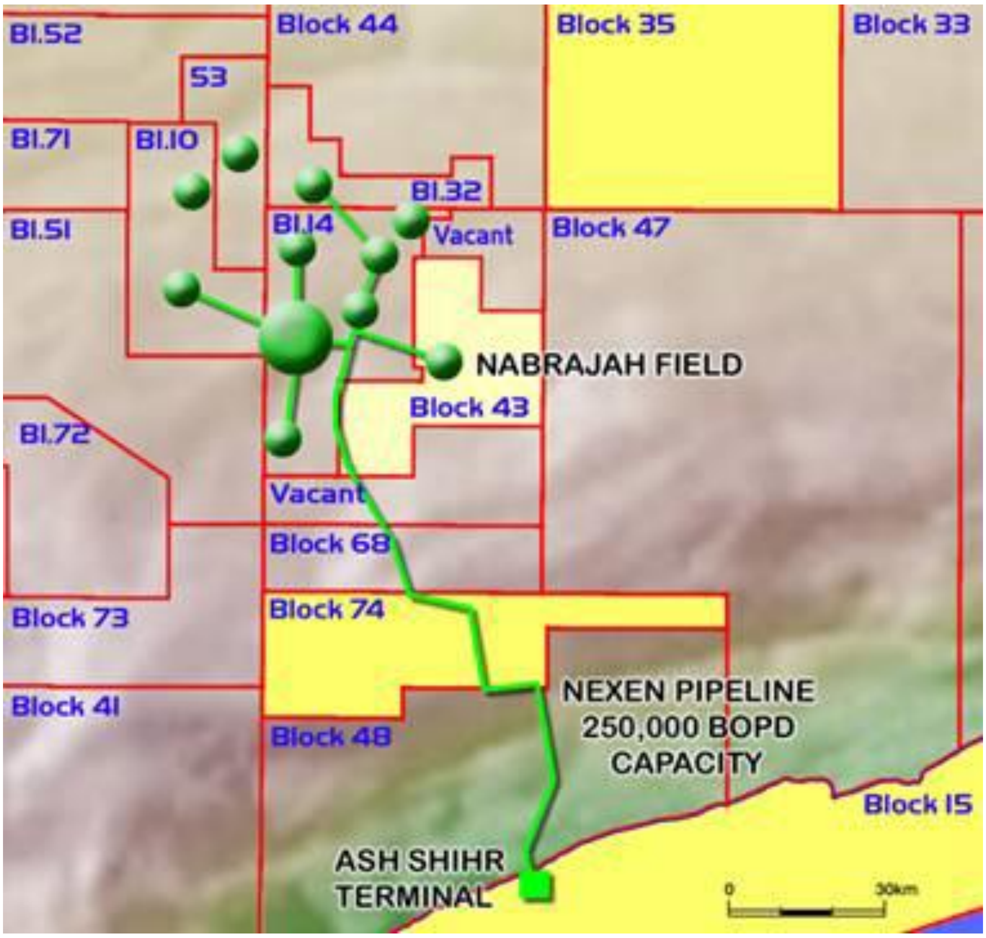


Fig.1.4 Block 43- Nabrajah Field

Chapter Two

2. LITERATURE REVIEW

2.1 Previous Study

2.1.1 Excess Water Production Diagnosis Case Study-Heglig Oil Field-Sudan

Heglig oil field is one of the largest fields and gas deposits in Sudan, is located in southeast and middle of Block 2B, Muglad Basin, the oilfield has excessive water production and the water cut was reached 95% with non-economical oil production resulting in many operational problems, this some well that has the diagnosis by Chan plot.

Well BA-03: WOR derivative in the positive slope which indication to another channeling.

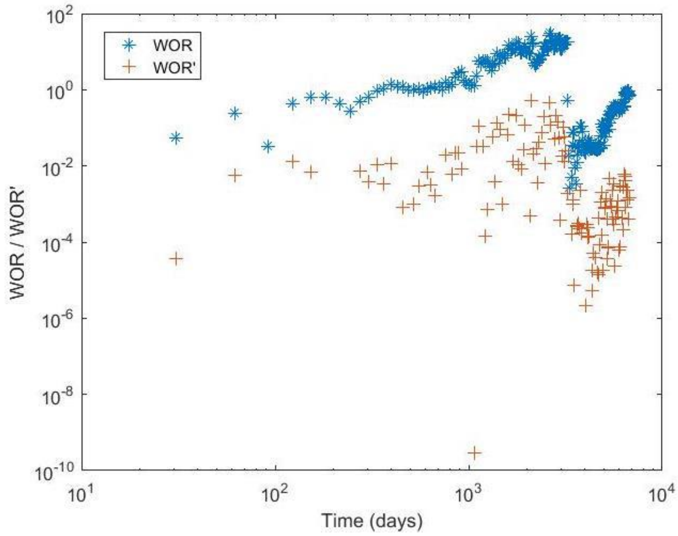


Fig 2.1: WOR and WOR' Derivatives Plot of Well BA-03

Well HE-04: showed a positive slope indicating initiation of water channeling.

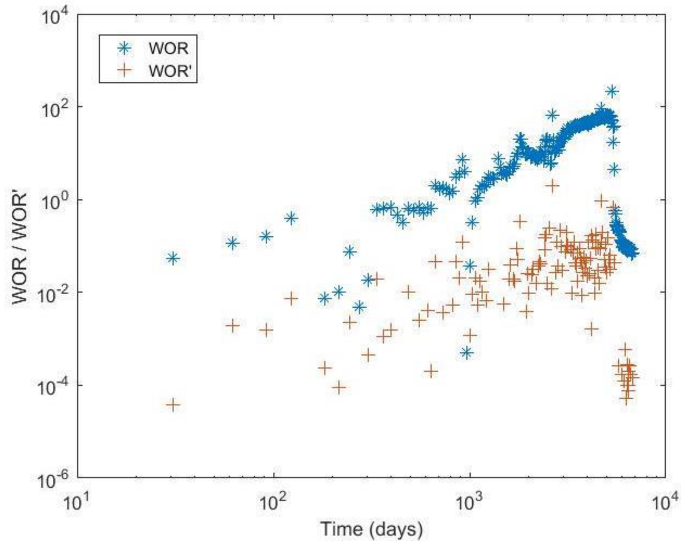


Fig 2.2 WOR and WOR' Derivatives Plot of Well HE-04

Well HE-09: the WOR and WOR derivative plots show a positive slope, characteristics of a water channeling case.

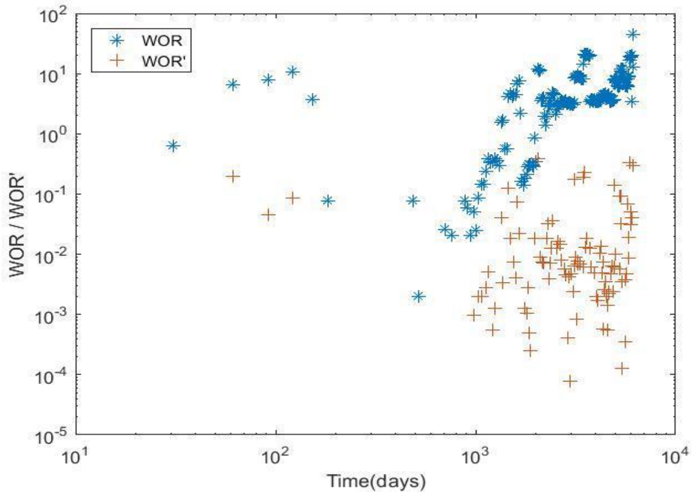


Fig 2.3 WOR and WOR' Derivatives Plot of Well HE-09

Well HE-10: WOR derivative started to decline and showed negative slope water coning was visible.

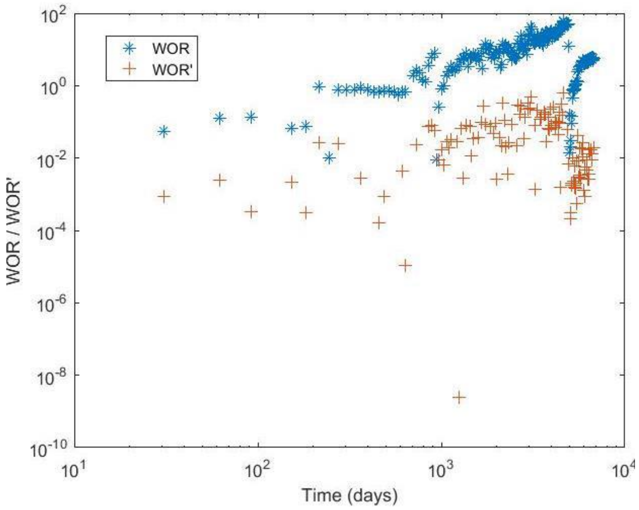


Fig 2.4 WOR and WOR' Derivatives Plot of Well HE-10

2.1.2 Excessive Water Production Diagnostic and Control - Case Study Jake Oil Field- Sudan

Analysis of the field production performance along with Chan's plots has been used for the field wells to identify the possible reasons of the unwanted water, this some well that has the diagnosis by Chan plot.

well JS-1

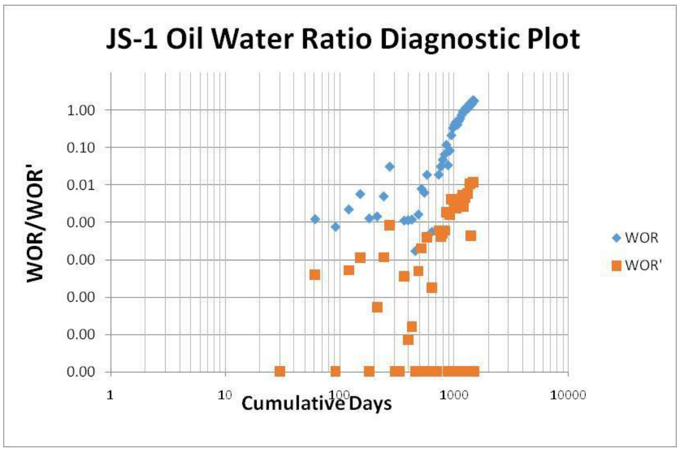


Fig 2.5 Oil Water Ratio Diagnostic plot for well JS-1

wellsJS-4

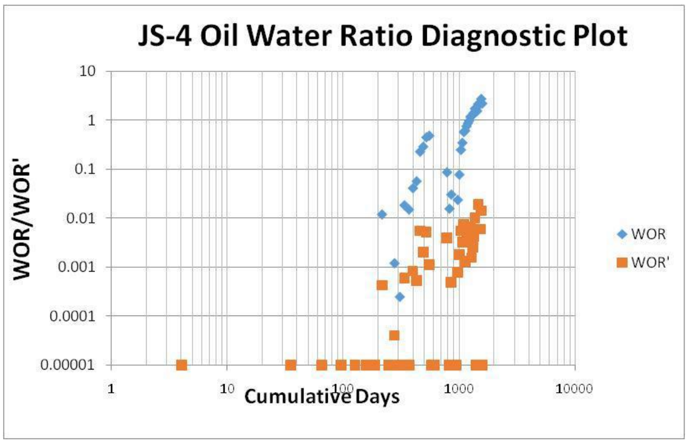


Fig 2.6 Oil Water Ratio Diagnostic plot for well JS-4

The wells (JS-1, JS-4) which are the most dominated producers also suffering from a high channeling growing with time

wells JS-2

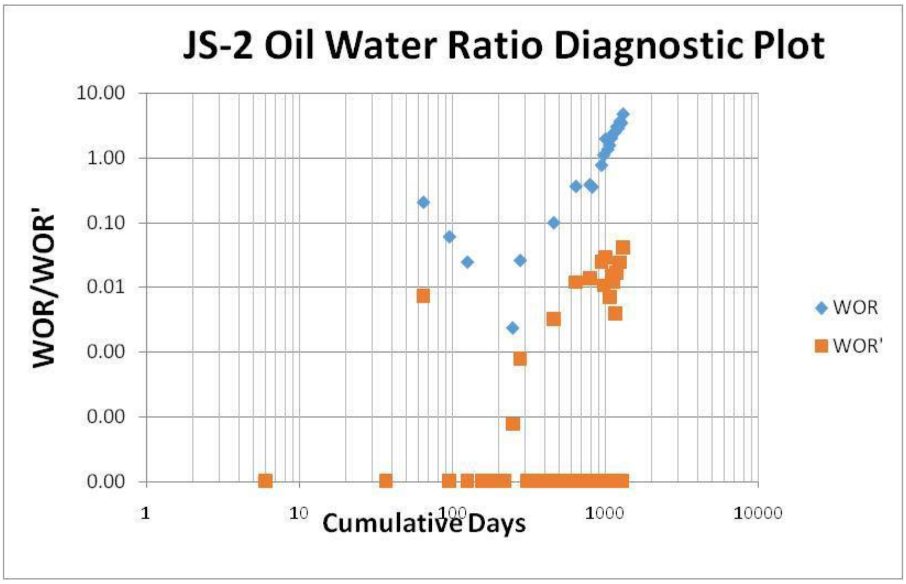


Fig 2.7 Oil Water Ratio Diagnostic plot for well JS-2

wells Js-18

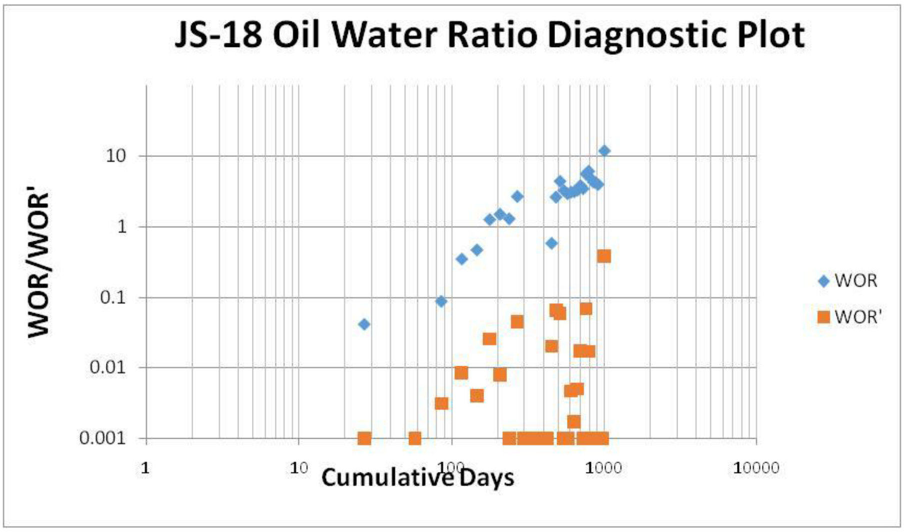


Fig 2.8: Oil Water Ratio Diagnostic plot for well JS-18

The comingled producer JS-2 and JS-18 showing a conning criteria due to the bottom water drive.

2.1.3 Diagnosis and Control of Excessive Water Production in Niger Delta Oil Wells

NDZ_A Oil- Water Diagnostic Analysis

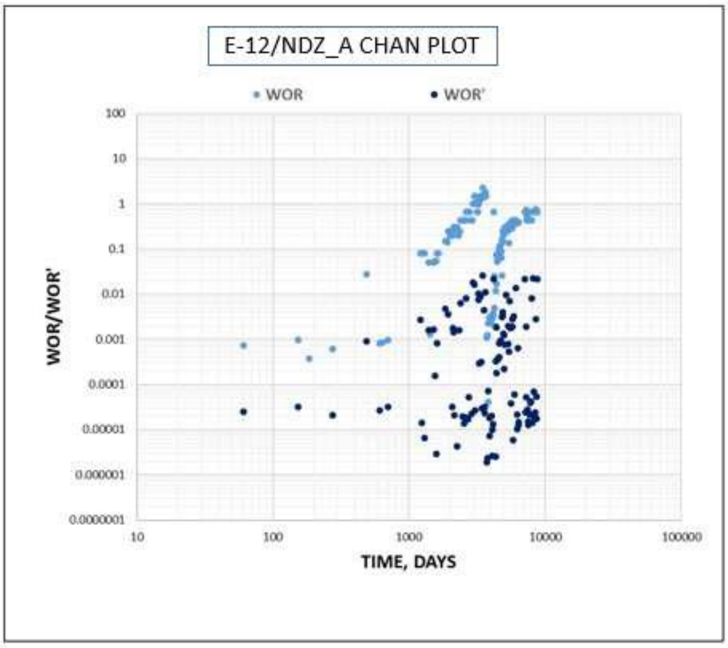


Fig 2.9: E-12/NDZ_A Chan Plot

The increase in water caused by the channeling.

2.2 The source and type of production water

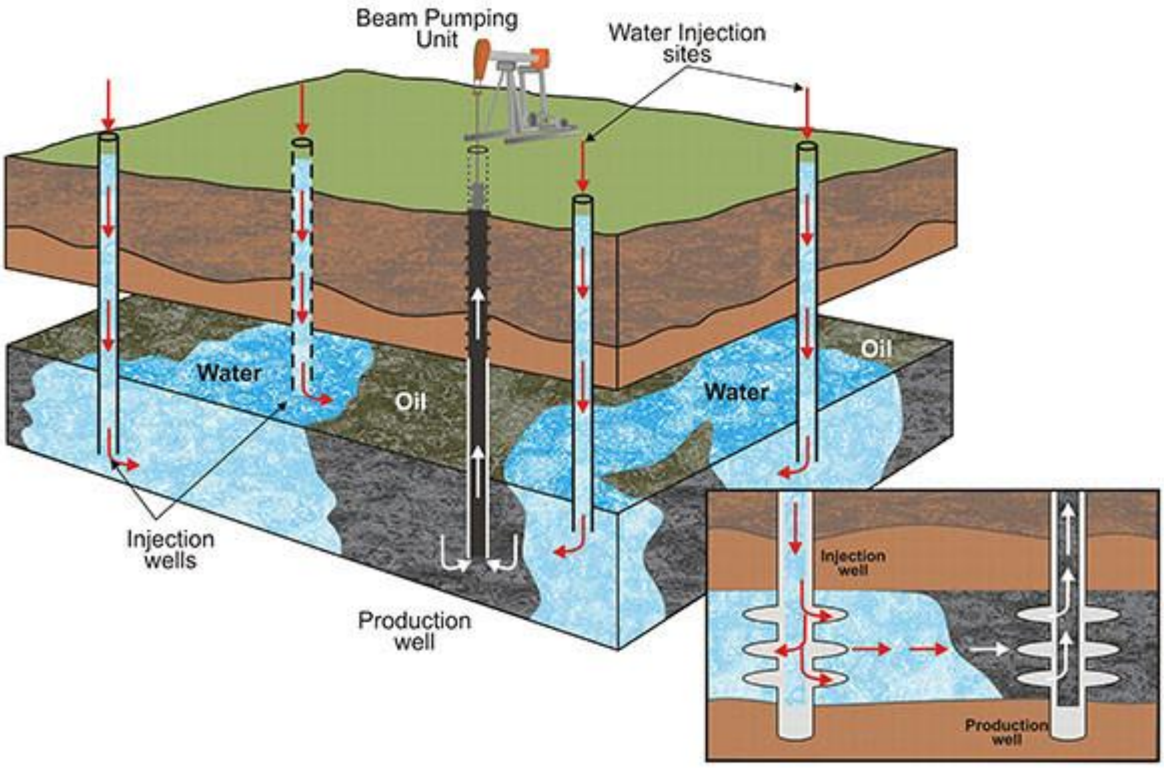


Fig 2.10: the processing of injection of water to produce the oil

The sources of water include formation water aquifer and injected water (http://karl.nrcce.wvu.edu/ accessed 25/10/2010).The formation water can originate from water saturated zone within the reservoirs or zones above or below the pay zone. A good number of reservoirs are adjacent to an active aquifer and are subject to bottom or edge water drive. Another source of water is through water injection into the reservoir for the purpose of pressure maintenance and secondary recovery. This constitutes a source of water production problem. No matter the source of the water, one form of produced water is always better than another (Bailey et al 2000). Therefore in oil production, the water could be described as either sweep, good or bad.

2.2.1 Sweep water

This water comes from either an injection well or an aquifer that is contributing to the sweeping of the oil from the reservoir. The management of this water is usually a vital part of reservoir management. It can also be a determining factor in oil productivity and ultimate reserves. In the later life of the reservoir, with proper 4 management, a reduction in the production of this kind of water most likely implies a reduction in the oil production, (Bailey et al 2000).

2.2.2 Good water

This is water that is produced into the wellbore at a rate that is below the water-oil ratio (WOR) economic limit (Fig 2.11). This flow of water is inevitable and cannot be shut off without the adverse effect of losing reserves. In this water source, there is commingling of water and oil through the formation matrix. The water cut is dictated by the natural mixing behaviour which gradually increases the water-oil ratio

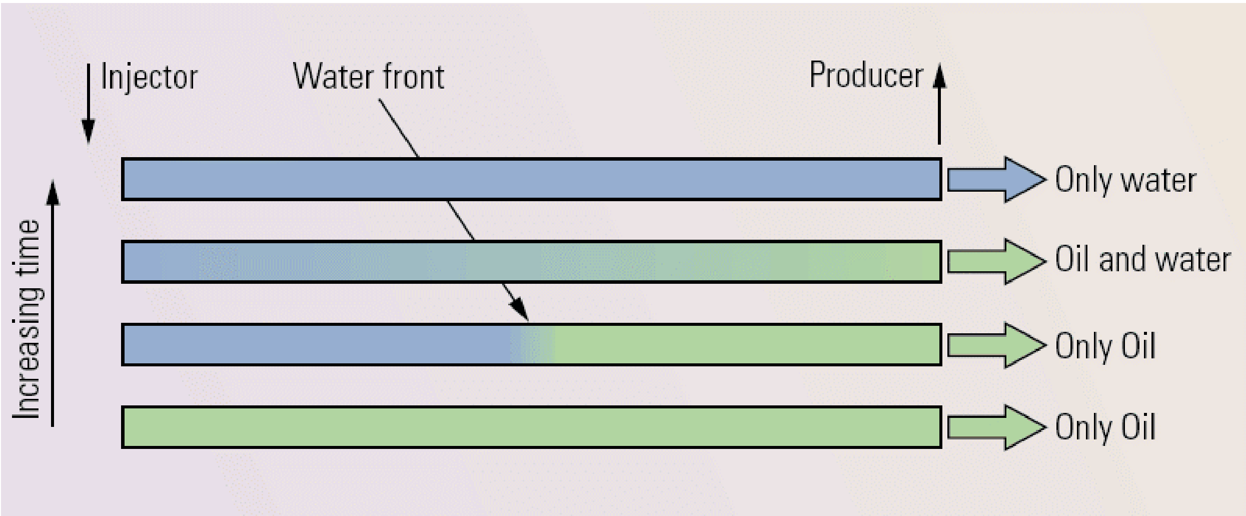


Fig 2.11: Water production with time, the case of an advancing water front (Bailey et al, 2000)

Also, good water is the water production that is caused by converging flow lines into the well during water injection. Since this is the shortest line from the injector to the producer (Fig 2.12), water break through occurs first on this line. This water is considered as good water since it is impossible to shut off flow lines.

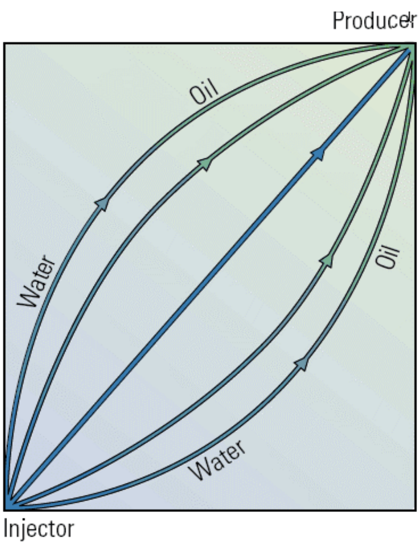


Fig 2.12: A plot showing one quadrant of a uniform five-spot injection pattern where the water from the most direct streamline is the first to break through to the producer. (Bailey et al, 2000)

Since good water is produced with oil, water management would seek to maximize its production and to minimize associated water costs, and the water should be removed as early as possible.

2.2. 3 Bad water

Bad water can be any water that negates profit. It could be defined as water that is produced into the wellbore and produces no oil or insufficient oil to pay for the cost of handling the water. Basically, this is water that is produced above the water/oil economic limit. Most water production problems fall into this category and this classification is discussed below.

2.3 WATER PRODUCTION MECHANISMS

As earlier stated, once the water production mechanism is understood, an effective strategy can be formulated to control the water production. The flow of water into the well bore can occur through two main paths i.e. flow through a separate path as the hydrocarbons and flow of water with the hydrocarbons (http://karl.nrcce.wvu.edu/ accessed 25/10/2010). Flow through a separate path from the hydrocarbon often leads to direct competition between the water and the hydrocarbon production. This usually constitutes bad water. Therefore, reducing or controlling this water production would lead to the increase of oil or gas production rate and recovery efficiencies. The second flow path usually constitutes good and sweep water. Therefore a reduction or control in the production of this water would imply a reduction in the production of the hydrocarbon (Bailey et al 2000). However, no matter the flow path, there are three factors that must be present, namely the source of water, pressure gradient and a favorable relative permeability to water (http://karl.nrcce.wvu.edu/ accessed 25/10/2010).

Pressure gradient:

Production of oil and gas from the reservoir can only be achieved by applying a pressure draw-down at the wellbore which creates a pressure gradient within the formation. Production from a fully penetrating and perforated well results in a horizontal pressure gradient in the formation. However, flow from a partially penetrated well will result in not just a horizontal pressure gradient but also a vertical pressure gradient. This will often lead to an undesirable condition.

Favorable relative permeability to water:

Oil, water and gas mainly flow through the path of least resistance, which is usually the part of the reservoir with higher permeability. For a reservoir with uniform geometry and permeability, flow will be along a simple line into the wellbore but this is not the usual case. With water driven or water flooded reservoirs, this heterogeneity especially in multi-layered cases would result in water channelling through the high permeability streaks. Most reservoirs consist of layers of different permeability, either immediately adjacent to each other or separated by impermeable layers. Layering and associated permeability variations are major causes of channelling in the reservoir. As the water sweeps the higher permeability intervals, permeability to subsequent flow of the water becomes even higher in those intervals and the lower permeability intervals remain unswept. This leads to a premature water breakthrough. Channelling can be further exacerbated by lower water viscosity as compared to that of oil especially during water flooding.

2.3.1 Water production problems:

2.3.1.1 Casing and packer leak:

Poor mechanical integrity of casing, tubing and packers due to corrosion or wear and splits caused by flaws, excessive pressure, or formation deformation can lead to excess water entering the wellbore, casing, tubing or packers allow water from nonoil-productive zones to enter the production string. Detection of problems and application of Solution are highly dependent on the well con- figuration Basic production logs such as fluid density ,temperature and spinner may be sufficient to ,diagnose these problems .In more complex wells WFL Water Flow Logs or multiphase fluid logging such as the TPHL three-phase fluid holdup log can be valuable .Tools with electrical probes ,such as the Flow View tool, can identify small amounts of water in the production flow .Solutions typically include squeezing shutoff fluid sand mechanical shutoff using plugs, cement and packers. Patches can also be used. This problem type is a prime . candidate for low-cost, inside-casing water shutoff technology. (Figure 2.13) .

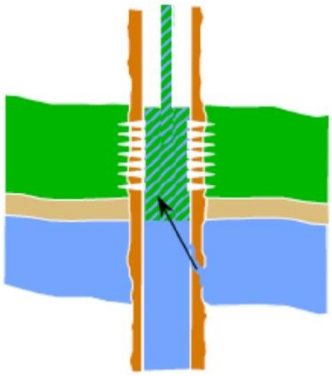


Figure 2.13 Tubing, casing and packer leak

2.3.1.2 Flow behind casing:

Channel flow behind casing—failed primary cementing can connect water-bearing zones to the pay zone. These channel sallow water to flow behind casing in the annulus. A secondary cause is the creation of a void 'behind the ‘casing is produced. Temperature logs or oxygen-activation-based WFL logs can detect this water flow. The main solution is the use of shutoff fluids, which may be either high-strength squeeze, cement, resin-based fluids placed in the annulus or lower strength gel-based fluids placed in the formation to stop flow in to the annulus. Placements .critical and typically is achieved with coiled tubing (Fig 2.14) .

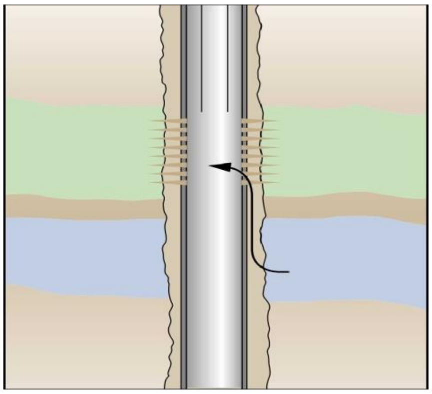


Figure 2.14 Flow behind casing

2.3.1.3 Moving oil-water contact:

Moving oil-water contact—A uniform oil water contact moving up in to a perforated zone in a well during normal water-driven production can lead to unwanted water production(below right).This happens wherever there is very low vertical permeability. Since the flow area is large and the rate at which the contact rises is low ,it can even occur at extremely low intrinsic vertical permeabilities (lessthan0.01mD).In wells with higher vertical permeability (Kv>0.01Kh), coning and other problems discussed below are more likely. In fact, this problem type could be considered a subset of coning, but the coning tendency .is so low that near-wellbore shutoff is effective Diagnosis cannot be based solely on known entry well, this problem can be solved easily by abandoning the well from the bottom using a mechanical system such as a cement plug or bridge plug set on wireline.

Retreatment is required if the .OWC moves significantly past the top of the plug In vertical wells, this problem is the first in our classification system that extends beyond the .local wellbore environment(Fig2.15).

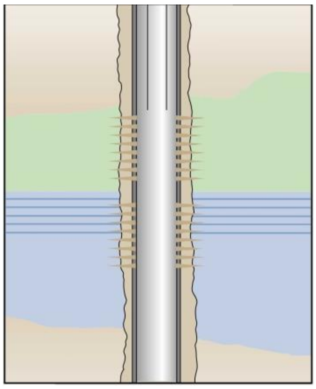


Figure 2.15 Moving oil-water contact.

2.3.1.4 Completion related problems:

Poor bonding between cement–casing or cement–formation can cause unwanted water to channel behind casing and enter the well. Completion into or close to water zone leads to immediate production of water. Sometimes stimulation attempts can cause the natural barriers between hydrocarbon bearing layers and water saturated zones to heave and fracture near wellbore, allowing the water to migrate to the wellbore (Fig. 2.16).

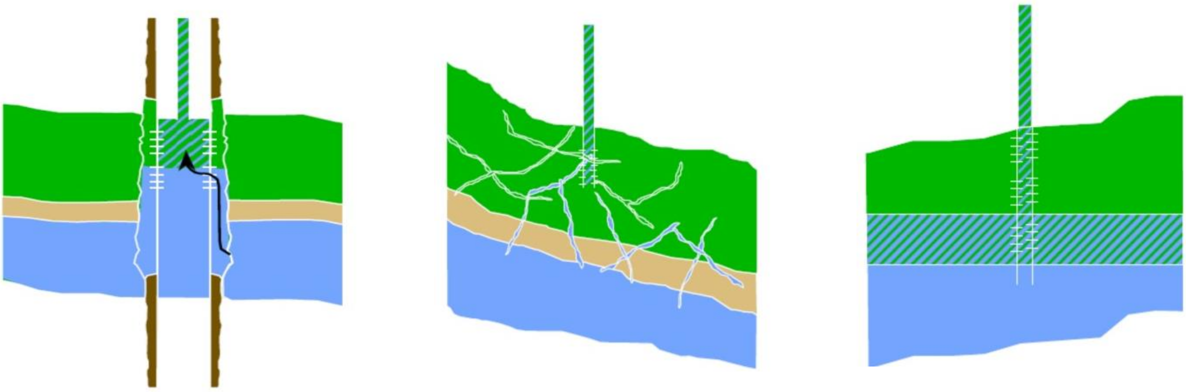
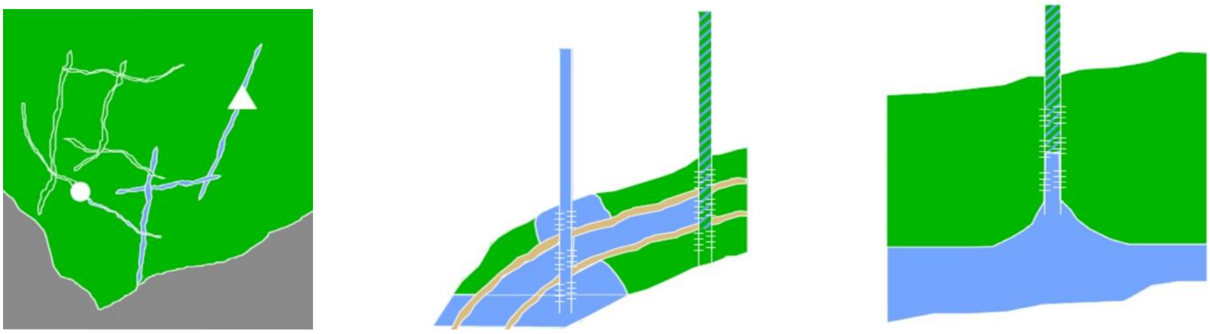


Figure 2.16 Flow behind casing , Fissures/fractures from a water layer and Moving oil-water contact

2.3.1.5 Reservoir related problems:

Water channelling through high permeability layers or fractures and faults and water coning from an adjacent water zone are major reservoir related WPMs. Heterogeneities in the reservoir are one of the main causes of excess water production in oil fields. Water can channel into the producing well through induced or naturally occurring fractures from aquifers or injection wells. In non–fractured reservoirs, high permeability layers can cause the water from an injector or an adjacent aquifer to channel into the well. Water can breakthrough prematurely through high permeability layers without sweeping hydrocarbon from lower permeability layers. Horizontal and deviated wells are also likely to cross faults and fractures in the reservoir and prone to experiencing the channeling problem. Water coning in vertical wells (cusping in horizontal wells) occurs due to pressure reduction near the well completion in a formation with a relatively high vertical permeability. The pressure gradient soon overcomes the gravity forces and draws water from a lower oil water contact zone towards the completion. Eventually, the water breaks through the wellbore replacing all or part of the hydrocarbon production (Fig. 2.17). Oil production at a reduced rate, called the critical coning rate, can slow down the progress of the coning problem. However, this critical rate is often



too low to be considered economic.

Figure 2.17: Fissures between injector and producer, High permeability layer without crossflow and Water coning or cusping

2.3.1.6 Fractures or faults between injector and producer:

Fractures or faults between injector and producer—In naturally fractured formations under waterflood, injection water can rapidly breakthrough into producing wells. This is especially common when the fracture system is extensive or fissured and can be confirmed with the use of interwell tracers and pressure transient testing. Tracer logs also can be used to quantify the fracture volume, which is used for the treatment design. The injection of a flowing gel at the injector can reduce water production without adversely affecting oil production from the formation. When crosslinked flowing gels are used, they can be bullheaded since they have limited penetration in them a trixand so selectively flow in the fractures. Water .shutoff is usually the best solution for this problem Wells with severe fractures or fault soften exhibit extreme loss of drilling fluids(Fig 2,18).

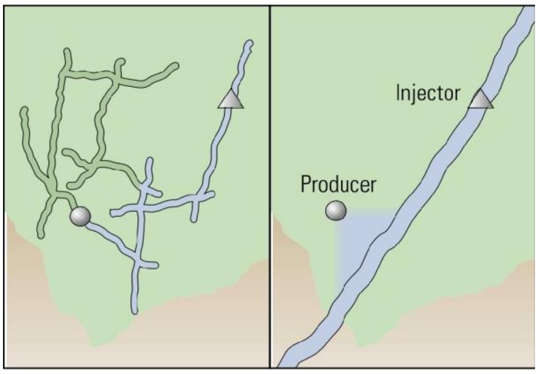


Figure 2.18: Fractures or faults between injector and producer.

2.3.1.7 Fractures or faults from a water layer:

Water can be produced from fractures that intersect a deeper water zone. These fractures may be treated with a flowing gel; this is particularly successful where the fractures do not contribute to oil production. Treatment volumes must be large enough to shut off the fractures far away from the well. However, the design engineer is faced with three difficulties. First, the treatment volume is difficult to determine because the fracture volume is unknown. Second, the treatment may shutoff oil-producing fractures; here, an overflush treatment maintains productivity near the wellbore. Third, if a flowing gel is used, it must be carefully tailored to resist flowback after the treatment. In cases of localized fractures, it may be appropriate to shut them off near the wellbore, especially if the well is cased and cemented. Similarly, a degradation in production is caused when hydraulic fractures penetrate water layer. However, in such cases the problem and environment are usually better understood and solutions, such as shutoff fluids, are easier to apply. In many carbonate reservoirs, the fractures are generally steep and tend to occur in clusters that are spaced at large distances from each other—especially in tight dolomitic zones. Thus, the probability of these fractures intersecting a vertical wellbore is low. However, these fractures are often observed in horizontal wells where water production is often through conductive faults or fractures that intersect an aquifer(Fig 2.19).

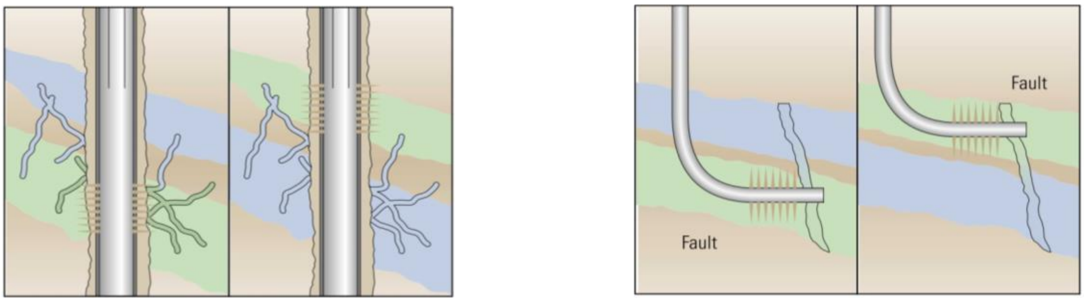
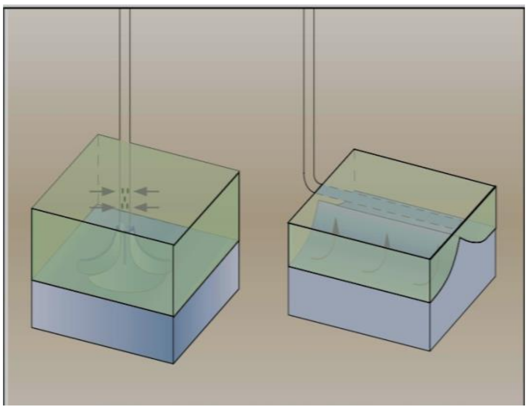


Figure 2.19: Fractures or faults from a water layer (vertical well) and Fractures or faults from a water layer (Horizontalwell).

2.3.1.8 coning or cusping:

Coning or cusping—Coning occurs in a vertical well when there is an OWC near Perforations In a formation with a relatively high vertical permeability(below).The maximum rate At which oil Can be produced without producing water Through a cone, called the critical coning rate, is often too low to be economic.

One approach, which is sometimes in appropriately proposed, is to place a layer of gel above the equilibrium OWC. However, this will rarely stop coning and Requires a large volume of gel to significantly Reduce the WOR. For example, to double the critical coning rate, an effective gel Radius of at least 50feet[15m]typically is required. However, economically placing gel this deep into The formation Is difficult. Smaller volume treatments usually Result in rapid water re-break through unless the Gel fortuitously connects with shale streaks.A good alternative to gel placement is to drill One or more lateral drainholes near the top of the Formation to take advantage of the greater distance from the OWC and decreased drawdown, both of which reduce the coning effect. In horizontal wells, this problem maybe



Referred to as duning or cusping. In such wells, it maybe possible to at least retard cusping with near-wellbore shutoff that extends sufficiently up-and downhole as in the case of a rising OWC.

Figure 2.20: Coning or cusping:

2.4 Diagnoses of Water Production

2.4.1 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 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:

2.4.1.1 Recovery Plots:

The log-log plot of WOR against the cumulative oil production called the recovery plot Figure 2-21. 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).

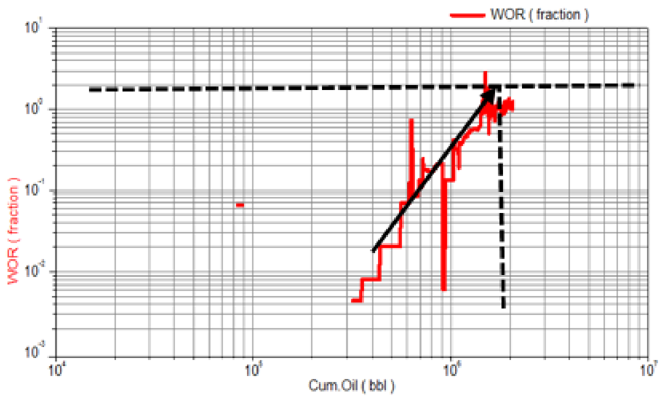


Fig.2.21:Recovery plot

2.4.1.2 Production Hhistory Plots

The production history plot is a plot of oil and water rates against production time, Figure 2-22. 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).

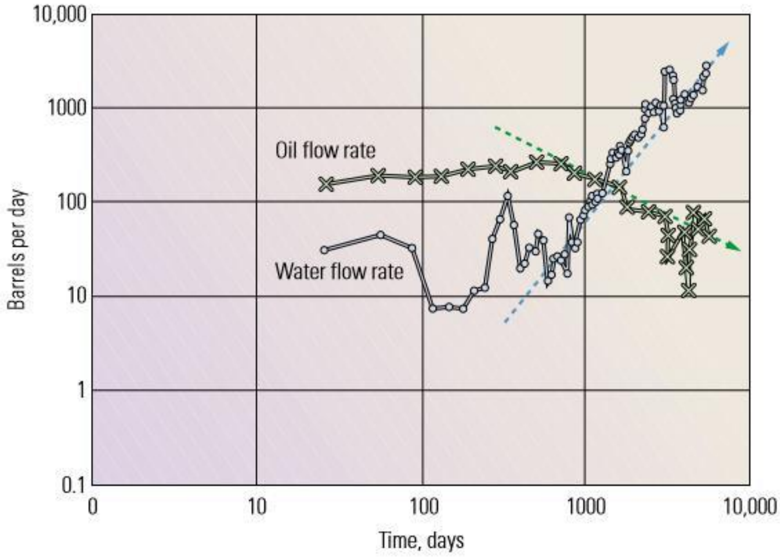


Fig 2.22: Production History

2.4.2 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.

$$\textbf{\textit{Equation}}\text{: } \mathrm{WOR} = \frac{Water\ production}{Oil\ production} \qquad \ldots\ldots\ldots \quad \textbf{(1)}$$

$$\textbf{\textit{Equation}}\text{: } \mathrm{WOR}' = \frac{WOR2 - WOR1}{Cum\ time2 - Cum\ time\ 1} \qquad \ldots\ldots\ldots \quad \textbf{(2)}$$

Figures 2.23 through 2.26 (Chan, 1995) illustrate how the diagnostic plots used to differentiate among the various water production mechanisms. Fig. 2.26 shows a comparison of WOR diagnostic plots for coning and channelling.

Log-log plots of WOR and WOR time derivatives (WOR') versus time for the different excessive water production mechanisms are shown in Figures 2.24 through 2.26. Chan (1995) proposed that the WOR derivatives can distinguish between coning and channelling. Channelling WOR' curves should show an almost constant positive slope (Fig. 2.24), as opposed to coning WOR' curves, this should show a changing negative slope (Fig. 2.25). A negative slope turning positive when "channelling" occurs as shown in Figure 2.26, characterizes a combination of the two mechanisms. Chan classifies this as coning with late channelling behaviour.

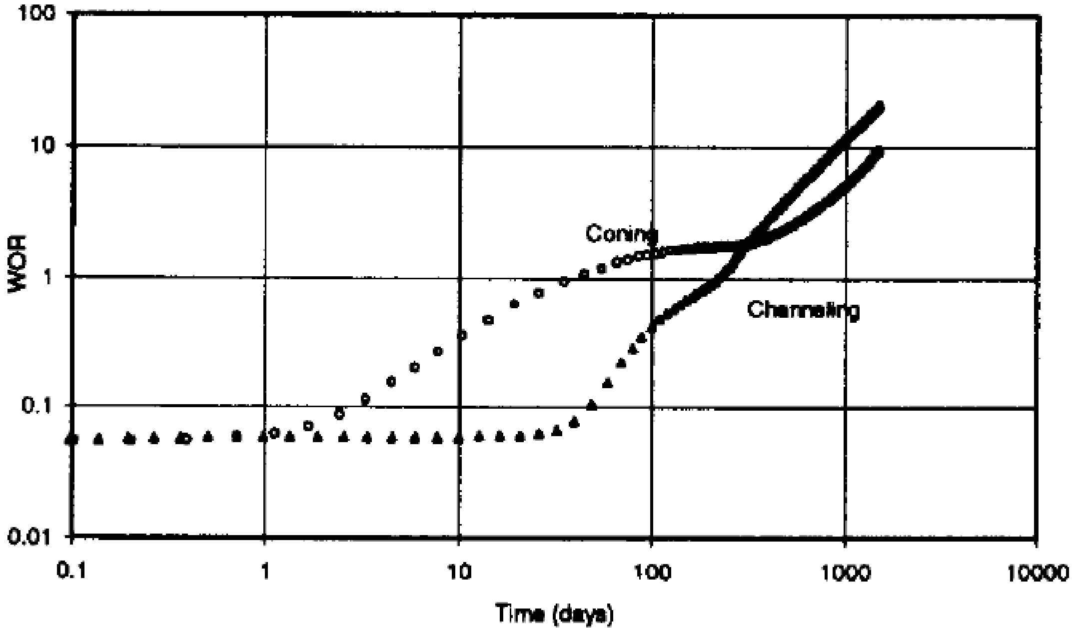


Fig 2.23: Water coning and channelling WOR comparison. Chan (1995)

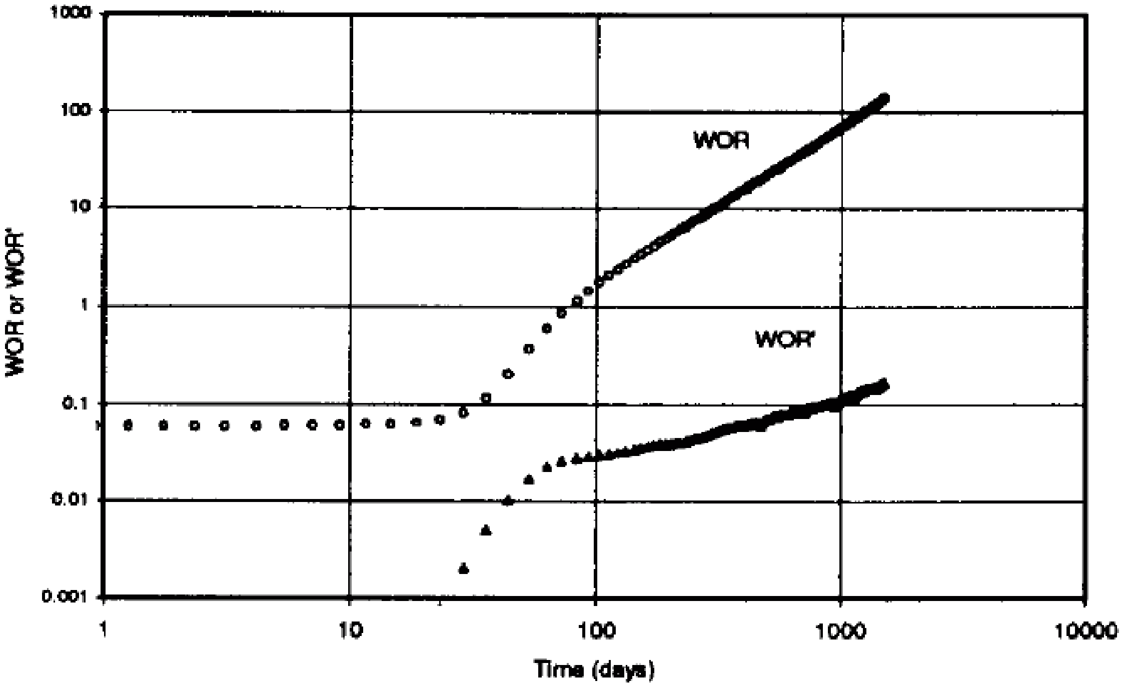


Fig 2.24: Multi-layer channelling WOR and WOR derivatives. Chan (1995)

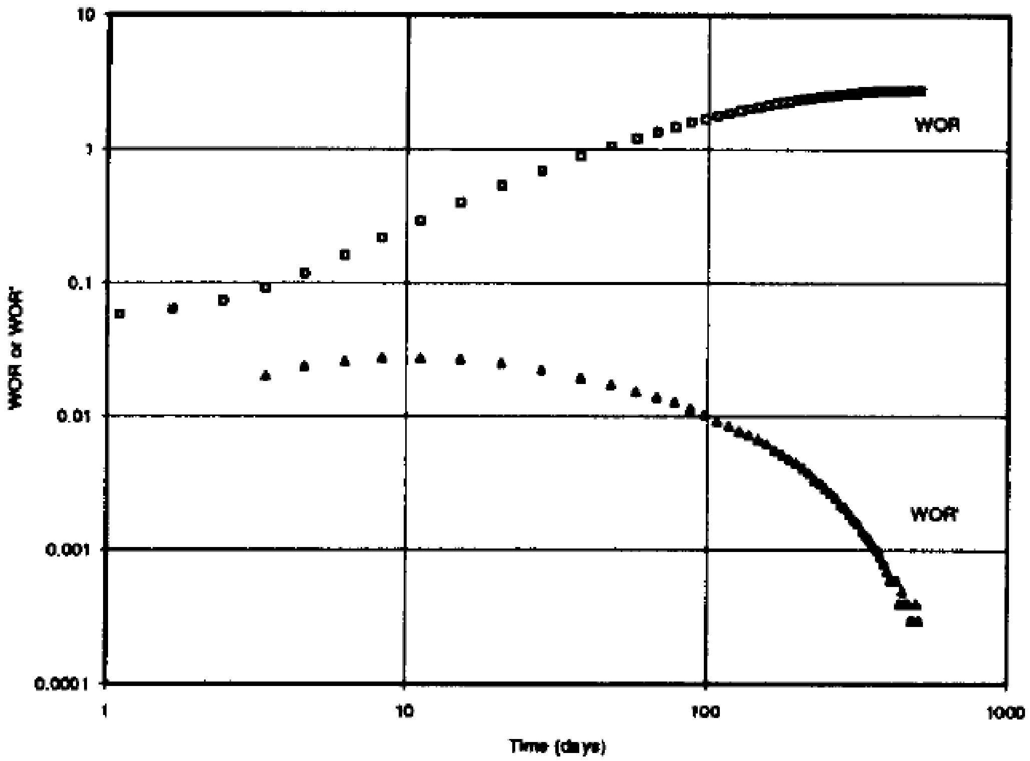


Fig 2.25: Bottom-water coning WOR and WOR derivatives. Chan (1995)

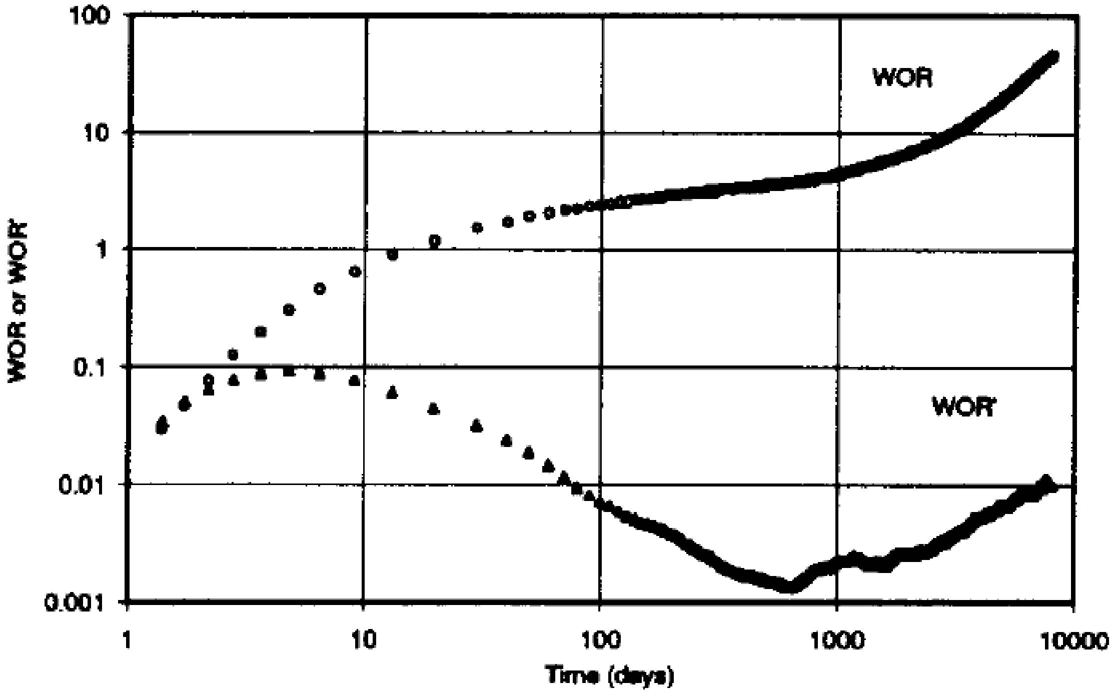


Fig 2.26: Bottom water coning with late time channelling. Chan (1995)

2.4.3. 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. 2-23 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.

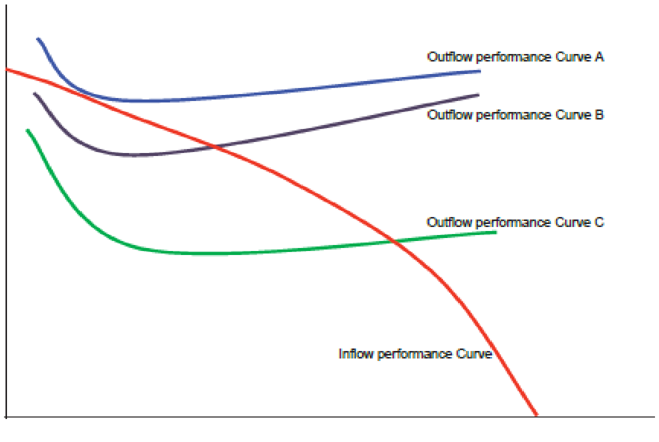


Fig 2.23 Nodal Analyses Performance

2.4.4 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 2.24 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.

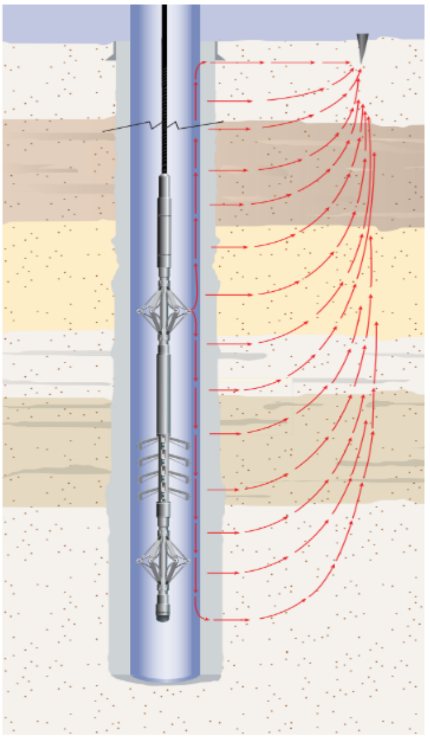


Fig 2.24 CHFR Tool

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 2-25. 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 0.01o F in the range of 50 to 400o F. Scales vary from fractional increments per inch to any practical limit required. The most commonly recorded scales are: 1, 2, 5, and 10o 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)

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.

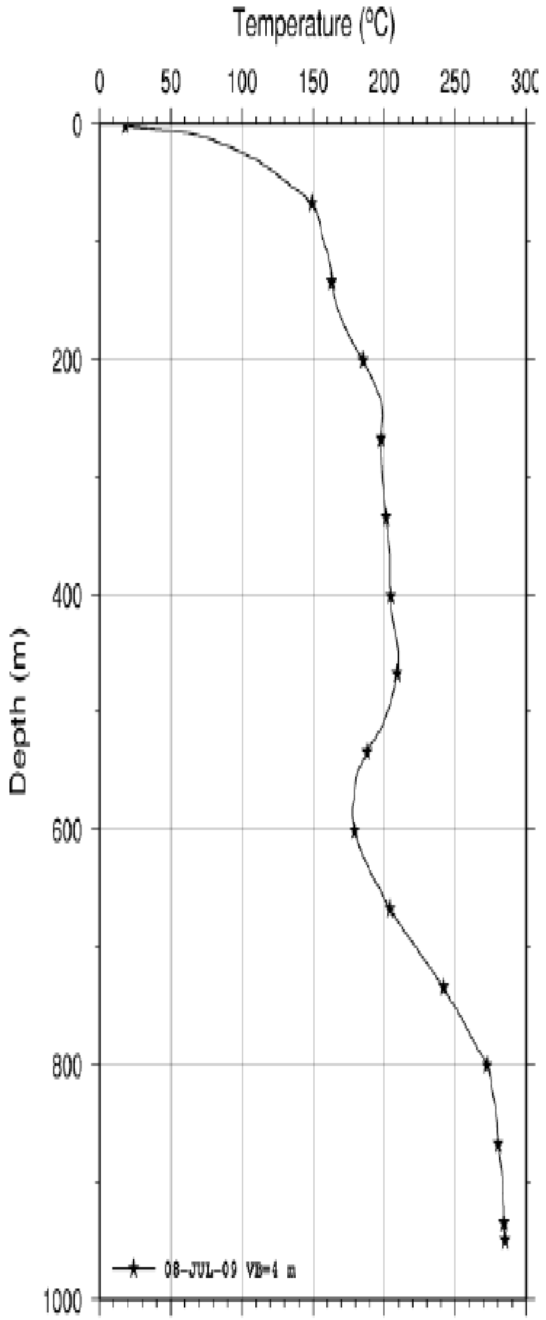


Fig 2.25 Temperature and Density log (Economides, 1994)

2.4.5 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 2.26. 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).

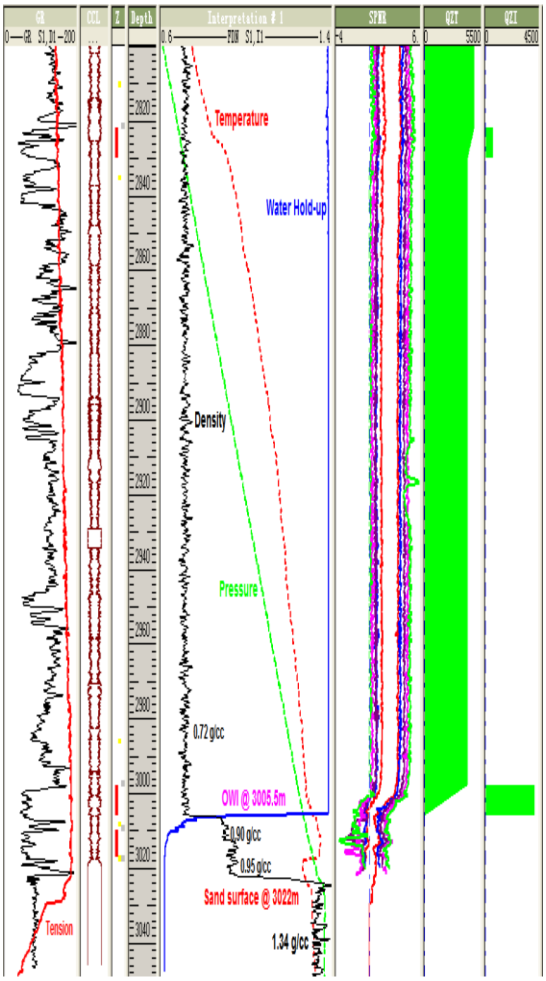


Fig 2.26 PLT Analysis

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.

2.5 The common mechanical and chemical water control and shut off methods

2.5.1 Mechanical methods:-

2.5.1.1 Cement plug:-

Plug cementing is another remedial cementing technique and refers to the method of placing the cement slurry into the wellbore to create a solid wellbore seal or “plug”. The general plug cementing process involves selecting the location for the plug, positioning the end of the work string at the bottom of the desired plug depth, mixing and pumping a cement slurry down the work string (drillpipe or tubing) into the wellbore, removing the work string from the cement column and allowing the cement slurry to harden in the wellbore.

Applications

Well or zone abandonment:

- Seal a dry hole;
- Seal depleted zones;
- Seal non-commercial zones or wellbores;
- Temporary well or zone abandonment.

Zonal isolation or well stability:

• Isolate one pressure zone from another;

• Prevent zonal fluid communication;

• Stop lost circulation events;

• Enable drilling through fracture or weak formations.

2.5.1.2 Straddle packers:-

Weatherford's ISP inflatable straddle packer assembly (type M2) is designed to isolate specific zones in open or cased-and-perforated holes in horizontal or deviated wells for selective treating, testing, or production evaluation. The M2 assembly consists of dual inflatable packers, deployed on coiled tubing or threaded pipe, and can be set multiple times per run to cost effectively evaluate multiple zones or different segments of a specific zone.

The M2 assembly is operated by axial movement of the work string and applied surface pressure. Work-string rotation is not required to activate any tool function. The minimum space out between inflatable sealing elements is 3 ft (1 m). This distance can be adjusted according to specific well requirements. In addition, memory gauges can be placed above the top element, between the elements, and below the lower element to record all pressure and temperature fluctuations while the M2 assembly is in the well.

Applications

Stimulation of multiple zones in one run. -

-Testing of multiple intervals in one run.

-Short-term production testing of selected zones.

Features, Advantages and Benefits

-Separate sealing elements enable adjustment of space out between elements, easily accommodating customer-specific well requirements.

-Memory gauges located above, between, or below the elements enable pressure and temperature recordings, providing zone-specific data.

-Only axial work-string movement is required to equalize and deflate the tool for retrieval, enabling the M2 assembly to be run on coiled tubing and conventional threaded pipe.

-The M2 assembly can be run in horizontal or deviated wells and open or cased holes, providing application flexibility.

-Elements are manufactured with application-specific elastomers, providing resistance to high temperatures, corrosive fluids, and gases.

Specifications-

Tool body maximum OD (in./mm)	4.31 109.47
Tool minimum ID (in./mm)	1.90 46.26
Inflatable element maximum OD (in./mm)	4.25 108.00 / 5.50 139.70
Length of each element (in./mm)	66.00 1,676.40
Element minimum space out (in./mm)	3.30 83.82
Overall length per assembly (ft/m)	3.43 11.25
Overall length, complete assembly (ft/m	25.80 7.86
Connections (in.)	8/3-2or 2-7/8 (EUE 8rd box up)

Table 2.1

Options

-Weatherford offers a full complement of accessory tools to use with the M2 assembly, including the fluid-control valves, plugs, darts, and space-out assemblies.

-Sealing elements are available for standard service (275°F/135°C) and severe service (375°F/190°C).

2.5.1.3. Bridge plug:-

Weatherford's PBP bridge plug is a field-proven, modular, cast-iron, drillable tool for various applications. Changing the top slips enables the versatile bridge plug to be set mechanically or on a wireline setting tool. It is easily converted to a PCR cement retainer.

The bridge plug is rated up to 400°F (204°C) and has a differential pressure rating up to 10,000 psi (68.948 MPa).

Applications:-

Cementing-

-Stimulation

-Temporary and permanent zonal isolation

-Well abandonment

Features, Advantages and Benefits:-

-Changing the top slips easily converts the bridge plug to a mechanical or wireline setting providing deployment versatility.

-The modular design eases conversion to a cement retainer reducing inventory.

-The rotationally locked cast-iron components enable a fast drillout to save rig time.

2.5.1.4.Patches:-

This method is mainly used for fixing well integrity issues particularly casing leaks. . The casing leaks problems are common in old wells and the wells which are completed in formations with corrosive gases like H2S [28,29]. . If the source of the unwanted water was found to be from a leak in the casing, squeezing cement or resins patches is considered to be a suitable solution. This method can be applied only after identifying the exact location of the leak through the methods discussed earlier. Squeezing jobs can be performed by rigs or sometimes with current technologies can be a rig-less job. Usually, inflatables are used to direct the patches toward the leaking point [30]. For small leaks, fine cement particles are squeezed to fix the well integrity issue as well as creating a seal [28].

2.5.1.5 Sand plugs:-

The sand plugs were mixed without issue however after spotting in place overpulls were observed while POOH.It is believed that because of the 60* deviation of the well some of the sand lay in the tubing on the approach to the perforation interval. Once four plugs had been spotted and the TOS confirmed at 6655m MD this loose sand was washed down by pumping clean KCI. Because of these additional actions it was necessary to manage the fatigue of the CT;hence the BHA was POOH and a 150-m sectionwas cut from the free end of the string. An additional three runs were required before the plug was confirmed by tagging HUD at 6624m MD. These separate runs again were required because of cutting length for fatigue management. Although this depth was 19m shallower than intended the decision was made not to spot additional sand plugs because of the issues observed.

2.5.1.6 Expandable tubulars:-

With the advent of expandable tubular technology in the late 1990s, short-length clad liners were developed to repair existing casing and tubing and to shut off water and gas in cased-hole environments. With expandable tubulars, the blank-off liner is placed downhole at the desired water shut-off zone. The liner is then expanded against the wellbore wall, creating a sealed blank-off for fluid flow. Unlike conventional straddle strings of tubing, the short cladding does not restrict access to hydrocarbon production from the lower zone of the well.

2.5.1.7 Infill drilling:-

The proposed approach consists of a stochastic evaluation of the candidate infill drill-holes that can be drilled over the deposit. Due to the large number of candidate locations, a searching algorithm is implemented to reduce the computation time, which consists of identifying potential regions in the deposit. The search algorithm is initialized by searching over a coarse drilling pattern over the deposit, and as potential regions are identified, the drilling pattern is reduced in those regions to increment the accuracy of the search. An important part of the evaluation is the definition of the metrics of performance. The infill drill-holes can be targeted based on their effect on:

The dispersion of the total revenues of the ultimate pit, the dispersion of the total amount of ore material within the ultimate pit, the geometric variability in the position of the following next sequence, the geometric variability of the ultimate pit, etc. For each location in the initial drilling pattern, the sampled values of each of the infill drill-holes are simulated conditioned to the existing data. An ultimate pit and its corresponding mining sequence is calculated for each realization of the infill drill-hole candidate and the existing data. The simulated infill drill-holes can be ranked according to the targeting criteria. For example, in the case of the reduction of the variability of the revenue criteria, the drilling location that results in the maximum variance of the ultimate pit revenues is targeted. An infill drill-hole at the targeted location will confirm the set of geologic features in the sampled region thus eliminating.

The major source of revenue variability in the deposit. To improve the accuracy in the selection of the infill drilling location, a denser drilling pattern is drilled around the more variable regions. To add more infill drill-holes to the drilling campaign, the previous simulated infill drill-holes are kept as part of the available information and the searching process is repeated again.

The proposed approach samples the different variability fields depending on the targeting criteria. The searching algorithm reduces the computation time to find the optimal targeting locations. During the evaluation of the infill locations two or more criteria can be considered by weighting the importance of the criteria in the ranking of the locations.

2.5.1.8 Horizontal wells:-

Horizontal well technology was originally developed for use in petroleum production and underground utility installation, but recently (since the late 1980’s) has been adapted for environmental remediation applications. In the environmental remediation industry, horizontal wells provide unique characteristics and advantages that can improve the effectiveness of established soil and groundwater cleanup technologies now using traditional vertical well techniques. To date, over 300 horizontal wells are estimated to have been installed for environmental remediation purposes, with the number of installations doubling every year since 1994(15)

The "steering" capability associated with some horizontal well drilling techniques allows installation in areas containing underground utilities, vertical wells, and other subsurface obstructions. Horizontal wells can be installed beneath buildings and other surface structures, allowing access for treatment to areas generally inaccessible to vertical wells.

The orientation of horizontal wells compared with vertical wells may require fewer wells to achieve similar remediation goals due to the greater surface area associated with the lengthwise screened area of these wells. Horizontal screens provide greater surface area in contact with contaminated soil or groundwater, allowing more effective transfer of materials used for remedial treatment (e.g., bioremediation amendments, air for air sparging, vacuum for vapor extraction, soil flushing materials, etc.).

Horizontal wells have been adapted for use in many soil and groundwater remediation applications, including ,1) (14 ,9 ,4 ,2):

Groundwater removal-

-Air sparging

-Free product recovery

-In situ bioremediation/bioenhancement

-Soil vapor extraction

-In situ soil flushing

-In situ radio frequency heating

-Treatment walls

-Hydraulic and pneumatic fracturing

-Leachate containment/collection

2.5.1.10 Downhole water-oil separator:-

the hydrocarbon industry developed the downhole oil–water separation (DOWS) technology in the 1990s. In spite of having such cost-efective and environment-friendly solutions.

The membrane-based separation methodology represents the coherent solution to robust the downhole separation system that does not require any moveable equipment with advance sensors and mechanical tools. If the reservoir is well characterized and a reliable simulation model is built, it is possible to predict the optimal time for the placement of a specifc length of membrane in the well depending on the layer concerned and inclination of the well.

2.5.2 Chemical methods:

Far from the wellbore, in the reservoir or near the wellbore, water shutoff operations can be performed by several chemical treatments. Those chemical solutions lead to better conformance in the reservoir as well as blocking the unwanted water production zones. The idea is to be able to close the paths of least resistance in front of the water by reducing their permeability in order to prevent the water from coming to the wellbore through them. Also, they aid in forcing the water to mobilize and displace the oil in the reservoir. In other words, the aim is to block the open features and high permeability channels to force water to go toward the harder path to sweep oil from the matrix rock that results in higher overall economic returns than producing oil from fractures. In fact, induced formation damage can be used as an effective solution to control the unwanted water production.

The results of chemical solutions can be achieved in a couple of months to years, depending on the nature of the reservoir and the properties of the injected chemicals. The main advantage that chemical water shutoff operations have over mechanical operations is that they solve the problem of the unwanted water production instead of hiding it under or behind a plug, packer, or tubing patch. Injected chemicals can reach water features in the reservoir and reduce the permeability, resulting inclosing them entirely. They also have the freedom of moving between the layers and features which helps in reaching to far extents and completely closing them. Another use of chemical injection is to increase the viscosity of the injected fluid which leads to a better sweeping efficiency and eventually reduces the production of unwanted water. The success of chemical injection operations depends on the knowledge level of the reservoir and its characterizations, chemical properties, and accurate placement of the injected chemicals. For example, the effectiveness of water shutoff agents depends highly on the properties of the reservoir and has to be compatible with the reservoir temperature and water salinity in order to achieve an effective water shutoff. In this section, common chemical solutions are discussed in detail, along with examples of the execution of the operations:

2.5.2.1 Gel :

Gel injection is one of the most famous chemical solutions for water shutoff operations. It is used to reduce the water oil ratio and increase the conformance of the pattern. That happens through the ability of the gel to reduce the permeability and block the open features, fractures, and high permeability water zones. It can be applied in the wellbore, near the wellbore, and far from the production well through injection wells. It is very effective in reducing the permeability of unwanted zones and has proven its ability to improve the sweep efficiency and shutting-off the unwater water zones. The injected gel is mainly made of water, small volumes of polymers and crosslinking chemical agents [6]. Gel treatments can completely seal o layers; therefore, they are considered aggressive and risky conformance control operation [3]. On the other hand, polymer gel injection is considered relatively cheaper than other improved oil recovery operations.

Gel injection operations are divided into three main stages: modeling, designing, and executing. The first step is to model the gel injection operation by using simulation software, which is an important step for designing the program of gel injection operation [18]. In this stage, all the available information about the reservoir and the well are considered valuable, such as: reservoir parameters, water entry points, drilling operations reports, logs, and production history. The second step is to design the properties of the polymer gel fluid. Injecting gel in the reservoir depends on four properties.

First one is the viscosity of the gel at the time of injection which helps in directing the gel to the lager and least resistance paths.

Second is the nature of the gel phase which is usually chosen to be the aqueous phase since the water is the desired phase to be shut off.

Third is the density of the gel. It very important to be designed carefully and based on the density of the formation water to avoid losing the effectiveness of the gel treatment. Fourth is the setup time or injection time. Longer injection time leads to more success in allowing the gel to seal of larger features and least resistance paths.

2.5.2.2 Polymer Flooding :

Another common technique for water shutoff operations is the usage of the polymer flooding method to increase the viscosity of the water. This technique is applied to increase the viscosity of the drive fluid (water) which helps in mobilizing and displacing the oil in the reservoir matrix rock. This technique is usually applied in the reservoir far from the production wells through water injection wells to achieve better sweeping efficiency in the reservoir. That eventually leads to preventing excessive water production. The usage of polymer flooding is very common among the oil operators and it can be prepared by dissolving the polymers in the injected water and inject it through injection wells. Polymers used in this technique are usually two types: biopolymers and synthetic polymers.

Biopolymers' advantages over the synthetics are that they are not affected by the salinity of the water and they are insensitive to the mechanical degradations. However, they are more expensive than synthetic polymers. Xanthan and scleroglucan are two famous kinds of biopolymers. Synthetic polymers are more common since they are cheaper, more available, and perform well with low-salinity water. Polyacrylamide (PAM) and hydrolyzed polyacrylamide (HPAM) are two types of synthetic polymers. Polymers can also play a role in reducing the permeability if the molecular weight is increased. Finally, based on the characteristics of the reservoir and the economics of the operations, the right polymer is chosen in case of chemical injection.

Polymer floods projects have been applied over a wide range of conditions:

- Reservoir temperatures [46–235]°F.
- Average reservoir permeability [0.6–15,000] mD.
- Oil viscosity [0.01–1494] cP.
- Net pay thickness [4–432] ft.
- Remaining oil at start-up [36–97] % of OOIP.

Polymer flooding advantages

The advantages of polymer flooding could be summarized as following:

- Applicable over a wide range of conditions.
- A reduction in the quantity of water required to reduce the oil saturation to its residual value in the swept portion of the reservoir.
- An increase in the areal and vertical coverage in the reservoir due to a reduced water flood mobility ratio.
- Diverting the injected from swept zones.
- Promising for heavy oil application.
- Cost-effective.

Polymer flooding limitations are:

- High oil viscosities require a higher polymer concentration.
- Results are normally better if the polymer flood is started before the water-oil ratio becomes excessively high.
- Clays increase polymer adsorption.
- Some heterogeneity are acceptable, but avoid extensive fractures.
- Lower injectivity than with water can adversely affect oil production rates in the early stages of the polymer flood.
- Xanthan gum polymers cost more, are subject to microbial degradation, and have a greater potential for wellbore plugging.

2.5.2.3 Surfactant flooding

Correctly designed surfactants can create micro emulsions at the interface between oil and water phases, which cause a reduction in the interfacial tension (IFT) that consequently will mobilize the residual oil which improving the oil recovery. This method of EOR is a challenging one by many factors such as rock adsorption of the surfactant and co-surfactant, and the chromatographic separation of the surfactant during the injection in the reservoir. The designed surfactants should be resistant and active at reservoir conditions which could by at higher pressure, temperature and water salinities. In the surfactant flooding the phase behavior is the most important factor to make it successful. Currently, there is no EOS model to describe the phase behavior in these systems. Consequently, phase behavior studies should be observed experimentally which is challenging to mimic the reservoir conditions. Surfactants solutions are used to reduce the oil-water IFT, while the co-surfactants are mixed with these solutions in order to enhance the properties of the surfactant solutions. The co-surfactants added to the solutions are serving as an active agent or a promoter in the mixed solution in order to enhance the surfactant effectiveness with respect to temperature and water salinity as it is well known that surfactant flooding is sensitive to reservoir temperature and salinity [6].

Mechanism

A surfactant is added to an aqueous fluid and co-surfactant is also added in order to prepare the surfactant solution and injected into the reservoirs as surfactant flooding reduces the interfacial tension between the oil and water phases and also alters the wettability of the reservoir rock in order to mobilize the residual oil trapped in the reservoir which improves the oil recovery.

The surfactant selection is a critical stage in designing the surfactant flooding projects as the Anionic surfactants preferred due to the following reasons [13]:

- Low adsorption at neutral to high pH on both sandstones and carbonates.
- Can be tailored to a wide range of conditions.
- Widely available at low cost in special cases.
- Sulfates for low temperature applications.
- Sulfonates for high temperature applications.
- Cationic scan be used as co-surfactants.

Surfactant flooding advantages

The surfactant flooding has several advantages and some of them are listed below [5]:

- Very effective in lab test [high oil recovery].
- Surfactant modeling is relatively simple with only a few well-designed experiments needed to provide the most important simulation parameters.
- Current high-performance surfactants cost less than $2/lb. of pure surfactant.
- Recent developments in surfactants solutions for EOR have effectively reduced the required surfactant concentration which lowering the chemical costs required.
- Recently, new and effective surfactants are derived from plant resources such as sunflower oil, soy and corn oil. It is non-toxic, non-hazardous, and readily biodegradable.

The disadvantages of surfactant flooding could be listed as following:

- Complex and expensive system.
- Possibility of chromatographic separation of chemicals.
- High adsorption of surfactant.
- Losing its effectiveness at higher pressure, temperature, and salinity.

2.5.2.4 Alkaline flooding :

Alkaline flooding is one of the EOR methods in which alkaline agents are injected into the reservoir to produce in situ surfactants, so the alkaline flooding will eventually have the same effect of the surfactant flooding.

Mechanism :

In the Alkaline flooding process, the alkaline agents such as sodium hydroxide solution is injecting into the reservoirs which react with the naturally occurring organic acids in the oil in order to produce surfactants or soaps at the oil-water interface. However, the alkaline agents are less expensive than the surfactant agents, the expected incremental oil recovery by alkaline flooding has not been confirmed by field results and still remains possibility as the process is mainly dependent on the mineral composition of the reservoir rock and its oil.

Alkaline flooding advantages :

This EOR method has the same advantages of the surfactant flooding in addition to that its main advantage over the surfactant is the cost of the alkaline agents are cheap compared to the surfactant agents.

The use of alkali in a chemical flood is beneficial in many ways:

-reduces the absorption of the surfactant on the reservoir rock

-Alkali makes the reservoir rock more water wet

-Alkali is relatively inexpensive

2.5.2.5 Surfactant-polymer (SP) flooding:

Surfactant-polymer flooding process is injecting a chemical slug that contains water, surfactant, electrolyte (salt), usually a co-surfactant (alcohol), followed by polymer-thickened water. In this process a surfactant is added to the polymer solution that has the affinity for both water and oil. The use of the micellar solution is to reduce the interfacial tension of the water-oil system in the reservoir in order to displace the residual oil. SP flooding method was patented for Marathon oil co. by Gogarty and Tosch known as Mara-flood. The injection profile of the method consists of injecting a pre-flush (to achieve the desired salinity environment), followed by micellar slug (surfactant, co-surfactant, electrolyte), and followed by polymer solution along with drive water.

The micellar solution composition that ensures a gradual transition from the displacement water to the displaced oil without interface is as following:

- Surfactant 10–15%.
- Water 20–60%.
- Oil 25–70%.
- Co-surfactant 3–4%.

Usually, the co-surfactant is alcohol which enhances the possibility for the micellar solution to include oil or water. This surfactant-polymer flooding reduces the oil-water IFT through the surfactant portion and reduces the mobility ratio through presence of polymer.

Mechanism :

The micellar solution is prepared using inorganic salts (water-soluble electrolytes) in order to gain better viscosity control of the solution. A polymer slug is used to drive the micellar solution slug in order to get a mobility control. The technique establishes low oil-water IFT and controls the mobility ratio which forming a considerable oil bank to be produced.

Surfactant-polymer flooding advantages

- The SP flooding advantages are listed below:
- Interfacial tension reduction (improves displacement sweep efficiency).
- Mobility control (improves volumetric sweep efficiency).
- Reduce adsorption of expensive surfactants.

The disadvantages could be as follows:

- Complex and expensive system.
- Possibility of chromatographic separation of chemicals.
- High adsorption of surfactant.
- Interactions between surfactant and polymer.
- Degradation of chemicals at high temperature.

2.5.2.6 Alkaline-surfactant-polymer (ASP) flooding

Individual chemical flooding processes, alkaline flooding, surfactant flooding and polymer flooding, can be combined differently. The three-component combination, alkaline surfactant-polymer (ASP). The ASP method represents a cost-effective chemical EOR method that yielding high oil recovery (mostly for sandstone reservoirs). ASP flooding is utilizing the benefits of three flooding methods, where oil recovery was enhanced, by reducing IFT, improving mobility ratio, and improving microscopic displacement efficiency. The ASP projects in China shows that the incremental oil recovery over water-flooding is 18.9% on the average.

Mechanism

Alkaline injection reduces surfactant adsorption and the combination of soap and synthetic surfactant results in low interfacial tension (IFT) in a wider range of salinity. Soap and surfactant make emulsions stable through reduced IFT which improve the sweep efficiency. There is a competition of adsorption sites between polymer and surfactant. Therefore, addition of polymer reduces surfactant adsorption, or vice versa and improves the sweep efficiency of ASP solution.

Alkaline surfactant-polymer flooding advantages

- Alkali is inexpensive, so it is cost reduction factor.
- Alkali reacts with acid in oil to form soap.
- Provide lower IFT in a wide salinity range.
- Soaps and surfactants produce emulsions that improve the sweep efficiency.
- Polymer and alkaline are reducing the surfactant adsorption.
- The polymer addition improves the sweep efficiency of the ASP solution.

Carbonate formations are usually positively charged at neutral pH, which favors adsorption of anionic surfactants. However, when (Na2CO3) is present, carbonate surfaces (calcite, dolomite) become negatively charged and adsorption decreases several fold.

High pH also improves micro-emulsion phase behavior.

The limitations and challenges for ASP flooding are:

- Severe scaling in the injection lines with strong emulsification of the produced fluid.
- Polymers are less effective under high water salinity conditions, as the high salt waters degrade the viscosity of polymers.
- Mobility control is critical.
- Laboratory tests must be done with crude and reservoir rock under reservoir conditions and are essential for each reservoir condition.

2.5.2.7 Solvent flooding :

Solvent flooding is quite different from the other chemical flooding fundamentally. Strictly speaking, solvent flooding works similar as the thermal injection despite several chemical solvents are applied. In these methods, solvents are either partially introduced into the steam, such as LASER (liquid addition to steam to enhance recovery) and other hybrid steam–solvent processes, or completely replacing the steam, such as VAPEX (vapor extraction) and CSI (cyclic solvent injection).

In terms of energy consumption, environmental impact, capital investment and safety issue, solvent-based recovery methods exhibit distinct advantages over the thermal injection technology. Admittedly, compatibility-induced viscosity reduction by miscible solvents is more cost-effective than heat-enhanced mode by the steam. Much less surface facilities are required for the solvent flooding than that for the steam injection, which will reduce the capital investment and operating cost. Moreover, when sufficient solvent is dissolved into the heavy oil, asphaltene precipitation could occur so that the produced heavy oil is in-situ deasphalted and upgraded. Compared to LASER and hybrid steam–solvent methods, CSI and VAPEX do not utilize steam. CSI is analogous to the CSS process, in which a solvent mixture instead of steam is injected into the reservoir and followed by a soaking period and a production period. Normally, the solvents should be mainly gaseous, exhibit good solubility in oil, and be relatively affordable. With this in mind, several blends consisting of readily available CH4 or CO2 as carrier gas and additional propane or butane have been experimentally tested. Before testing CSI at field scale, systematic investigations should be conducted to evaluate operational parameters such as solvent amount, soaking time and slug injection strategies. In addition, although solvents provide better performance than steam, the cost of solvents is much higher than that of steam. Thus, there will be a compromise between the production efficiency and the solvent cost.

2.5.2.8- Foam flooding :

The foam flooding is an EOR method using foam as the displacement agent. The foam is composed of foamer, foam stabilizer, gas and water. The foamer selected is often a surfactant with strong foam-generating capability, the foam stabilizer is mostly a polymer (or a biopolymer), a gel, or a nanopowder, and the gas can be air, natural gas, CO2, N2, etc. Its oil displacement mechanism includes improving displacement efficiency and expanding sweeping volume. During the migration in the formation, the foam preferentially enters high-permeability layers or micro-fractures with low oil saturation. Seepage resistance gradually increases due to the Jiamin effect and beading effect etc. With the increase of injection pressure, the foam will gradually flow into the low-permeability layers with high oil saturation, and thus effectively improving sweeping efficiency. Besides, the foamer itself is a kind of surfactant, which can reduce the oil-water interfacial tension and residual oil saturation, and improve oil displacement efficiency. Foam has unique advantages in treating gas/water channeling during gas/water injection and sweeping remaining oil at the top of thick oil layers. Therefore, it is a promising EOR technology.

Through persistent research, we have developed foamer and foam stabilizer combinations with different levels of foaming ability and stability, which are suitable for different formation conditions. The pilot test in Bei 2 block east of the Daqing Oilfield, Gangdong block of the Dagang Oilfield, Hu 12 block of the Zhongyuan Oilfield and Laojunmiao block of the Yumen Oilfield have achieved good initial results. At present, lab evaluation and field testing show quite different results for optimized foam flooding formulas and their performance, so it is necessary to improve lab research evaluation methods as soon as possible. Centering on foam stability, low-cost, high-efficiency and stable foam systems should be developed and supporting technologies like surface injection and controlling should be optimized.

2.5.2.9 Alkali–polymer (AP) flooding :

The shortcoming of alkaline flooding is that it lacks the required mobility control required to push oil in the reservoir due to a lower mobility of the displacing phase to the displaced phase. Simultaneous injection of polymer slug with alkali improves mobility control of injectant and complement the efficiency of alkali flooding. Also, the presence of alkali lowers the adsorption of polymer on rock pores. However, an optimum concentration of alkali and polymer required for formulation of AP slug must be determined. This is because the presence of high concentration of alkaline may cause hydrolysis of the polymer molecules and impair its viscosity

2.5.2.10 Emulsion flooding :

The study of emulsions has been of great interest in the petroleum industry. Emulsions have been used over the years as a displacing fluid for enhanced oil recovery processes (Massarweh and Abushaikha 2020). However, the application of emulsion as a blocking agent in conformance control is an emerging technique. Compared to other conformance control agents, emulsions have unique distinctions such as better injectivity, less difficult blockage removal, a wide range of channel plugging and less damage to the formation (Chen et al. 2018). Bai and Han (2000) reported that a higher oil recovery factor was obtained after an emulsion injection when compared to a polymer gel injection in their study. They attributed this to the induced formation damage caused by the polymer gel in the target areas in the reservoir and the lack of selective plugging by the gel.

Emulsions are thermodynamically unstable systems consisting of two immiscible fluids, one with a dispersed droplets phase and the other a continuous phase in the presence of surface-active agents. Hydrocarbon production from the petroleum reservoir and transportation to the surface is always in the form of a mixture containing oil, gas and water as well as inorganic and organic contaminants. These contaminants act as emulsifiers and with the continuous agitation of the mixture from the reservoirs during the flow up to surface facilities, tight emulsions can be formed. Emulsions can be intentionally formed for upstream processes such as enhanced oil recovery and acid stimulation (Maaref et al. 2017; Ahmadi et al. 2019). Depending on which phase is continuous or dispersed, emulsions can be water in oil (w/o), oil in water (o/w) as illustrated in Fig. 2.27 (Zapateiro et al. 2018; Mandal and Bera. 2015).

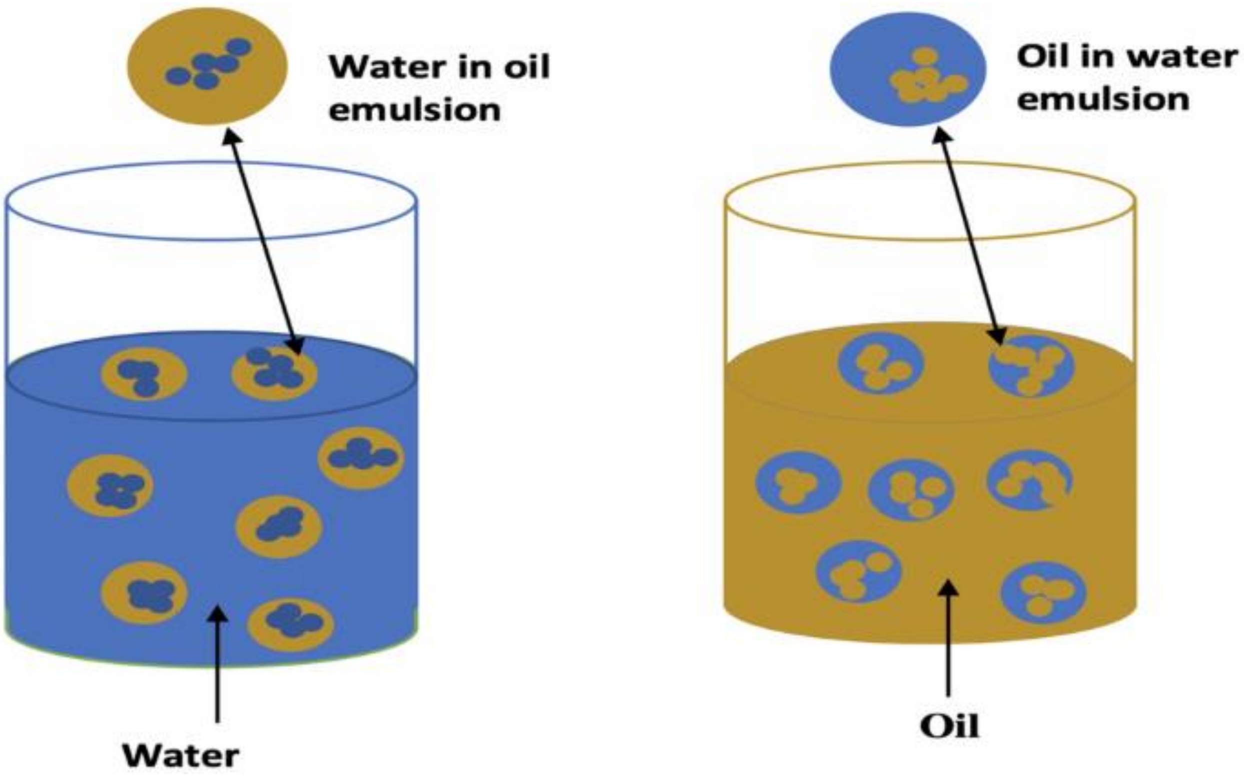


Fig 2.27

The most common type of emulsion formed in oil production is the w/o emulsion with a viscosity that is greater than that of oil. Using this, it creates a large pressure drop between the injection and production well, leading to a loss of fluids. This type of emulsion is considered to be undesirable in the oil production processes (Rezaei and Firoozabadi 2014; Lim et al. 2015). On the contrary, o/w emulsion has a very low viscosity that is very similar to water. This allows for good injectivity and it flows easily, thus making it attractive for conformance control measures.

Mechanism of conformance control by emulsion

To design emulsion systems for conformance control, a good understanding of the mechanisms and plugging ability of emulsion is required. The earliest investigation into the application of emulsions for conformance control was conducted by McAuliffe (1973a,b). He conducted experimental and field-scale investigations on emulsion flow through the porous media and its plugging capabilities in high permeability zones. In the experimental studies, he evaluated the bulk properties of the emulsion such as the droplet size distribution and rheology. He observed that the o/w emulsion reduces permeability to water if the initial permeability is less than 2 Darcies and the flow of emulsion is pseudo-non-Newtonian irrespective of the concentration of oil present in the emulsion. In the field studies, he reported a change in the flood pattern after the emulsion injection which led to a decrease in water production. Soo and Radke (1986) developed a filtration model to describe the flow of dilute and stable emulsions in an unconsolidated porous media. Their model captures the emulsion drops in the pores through straining and interception and they described the transient flow behaviour of the emulsion with parameters such as flow redistribution, filter coefficient and flow restriction. All 3 parameters control the steady state distribution, the precision of the emulsion front and the permeability reduction created by the retained drop. The filtration model was compared to the already existing retardation models for the emulsion flow. Only the results obtained from the filtration model could match the permeability reductions observed in the experiments.

Cortis and Ghezzehie (2007) argued that the filtration model proposed by Soo and Radke (1986) does not accurately model emulsion flow with a small to average droplet size ratio. This is because the model assumes that the emulsion and grain size of the porous media is homogeneous across all scales. Thus, predicting a fast-exponential concentration decay that does not capture the slow late times of the emulsion. They introduced a continuous-time random walk model that captures small scale heterogeneity such as the dispersed phase droplet surface heterogeneity, shape and size. They recognised from their model that the pore space available for the water to flow is changed continuously as the oil droplets become stuck in the pore throats. The oil droplets move continuously, providing a moving boundary for the water phase.

Alvarado and Marsden (1979) described the flow of emulsions experimentally and mathematically by developing a bulk viscosity model that assumes that the emulsion is homogeneous and a single phase. They derived a simple correlation that described the non-Newtonian flow of o/w macro-emulsions through the porous medium. The correlation was reduced to Darcy's Law for o/w Newtonian macro-emulsions and the partial blocking that results in permeability reduction was included. They discovered that the model did not follow Darcy’s law because of the shear rate effect on emulsion viscosity. Yu et al. (2018a) reported that as the pressure differential increases, the emulsion flows easily allowing for deep penetration in the reservoir. When the emulsion drop enters a pore throat, it will experience a capillary resistance force when passing through as a result of the “Jamin” effect. This “Jamin” effect will ultimately lead to flow restrictions including several other parameters such as emulsion droplet size, pore size distribution and interfacial tension. They concluded that for the effective plugging of the porous media, the emulsion droplet sizes should be slightly greater than the pore throat and this does not cause any form of damage to the formation. Figure 2.28 illustrates the "Jamin" effect encountered by an emulsion droplet in the pore throat.

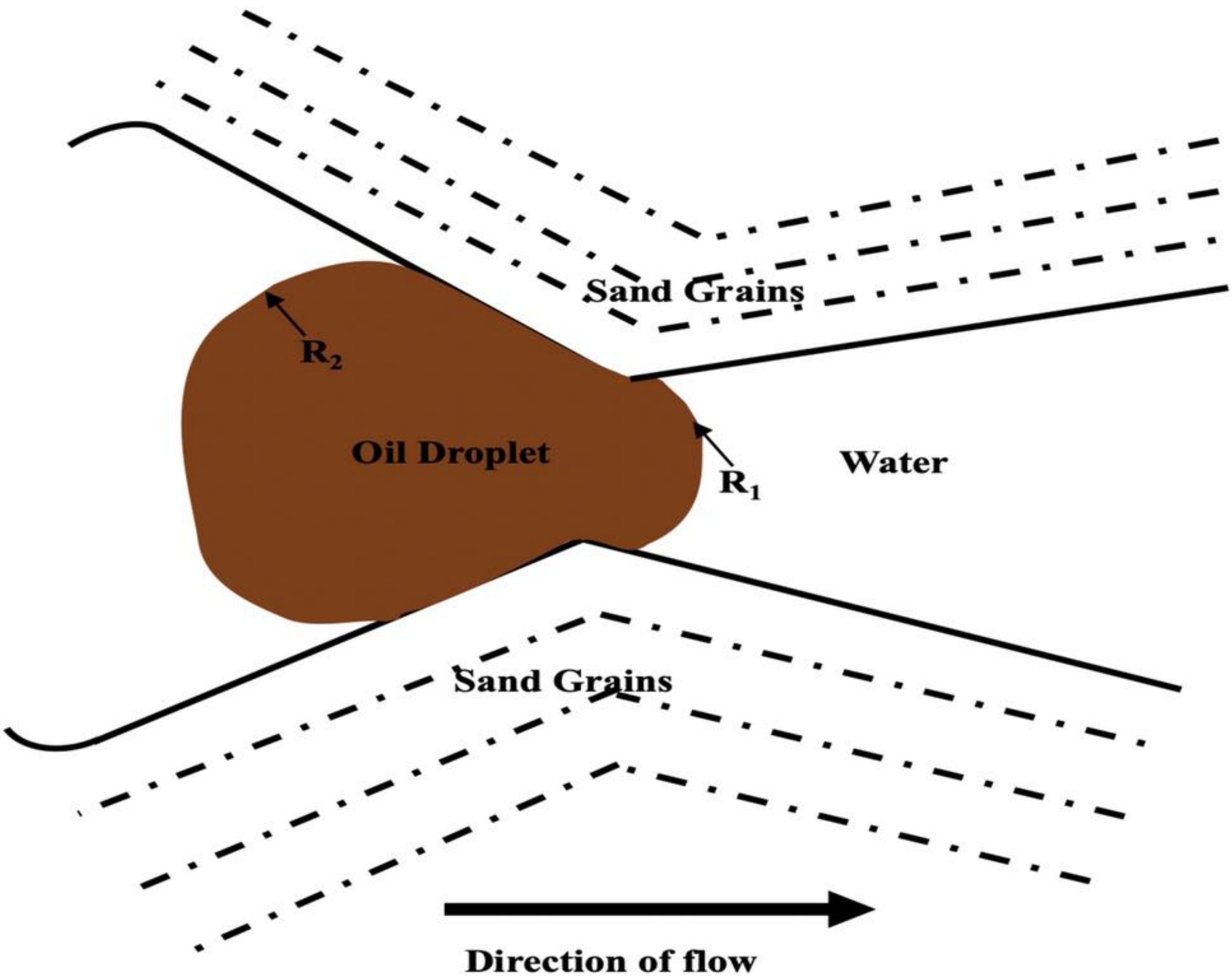


Fig 2.28

Yu et al. (2018b) continued their studies by proposing a non-uniform capillary model that takes into consideration the physical properties of the emulsion, the interaction between the emulsion and the porous media and the size difference between the pore throat and body of the porous media. They determined the resistance force by evaluating the plugging and adsorption characteristics of the emulsion droplet in the capillary model and they introduced a dilution factor in the model to demonstrate the flow of emulsion after water flooding. To validate their model, they executed injection experiments into sand packs and the results showed that by choosing appropriate coefficients, the most influential factor for emulsion flow resistance is the droplet size distribution. They continued by stating that the emulsion plugging strength is highly sensitive to the oil viscosity and less sensitive to the droplet effective permeability.

Moradi et al. (2014) stated that the connections between the mechanisms are at the pore level and that Darcies' level behaviour is the driving force in designing the key process that exploits the emerging responses of the flow of emulsions in the porous media. In their study, they analysed the capillary trapping of the dispersed phase droplets from the emulsion in the porous media as a function of the capillary number and droplet to pore size ratio. Their experiments involved the injection of the emulsion with a known droplet size distribution as a tertiary oil recovery process and single-phase flow experiments. They showed in their results that the emulsion blocking phenomena depends on the capillary number and is favoured by a low capillary number.

Characterization of emulsion

The application of emulsion for conformance control is associated with the design of a suitable slug and injection scheme that is dependent on the properties of the emulsion and the distribution of the fluid and rock. Emulsions are characterised based on their stability, droplet size and rheological properties (Mohyaldinn et al. 2019; Mandal et al. 2010). Over the years, there have been several studies on the stability and characteristics of emulsions. Nevertheless, there are numerous unresolved issues involving emulsion characterisation such as understanding the flow of emulsions in the pore spaces of the petroleum reservoir, finding accurate measurement techniques to monitor the stability of emulsion or developing a correlation to account for the effect of various factors affecting the emulsion stability and the distribution of the droplet size. Although a large percentage of the emulsions formed are in the petroleum reservoir during production, the physics of the flow of emulsion in porous media is complex due to the complicated properties of emulsions and the porous media (Goodarzi and Zendehboudi 2019; Maaref et al. 2017).

Stability of emulsions

A highly stable emulsion is essential for conformance control applications and the emulsion is said to be stable if separation is not achieved and the properties remain unchanged within a necessary time scale. Occurrences such as flocculation, coalescence and phase separation as illustrated in Fig. 2.29 are responsible for emulsion stability (Maphosa and Jideani 2018). According to Akbari and Nour (2018), emulsion stability is related to the type and concentration of surfactant present and this is prompted by the surfactants' ability to form films around the water droplets in the o/w interface. The formation of this film increases the interfacial viscosity and reduces the interfacial tension. This prevents the oil droplets from gathering.

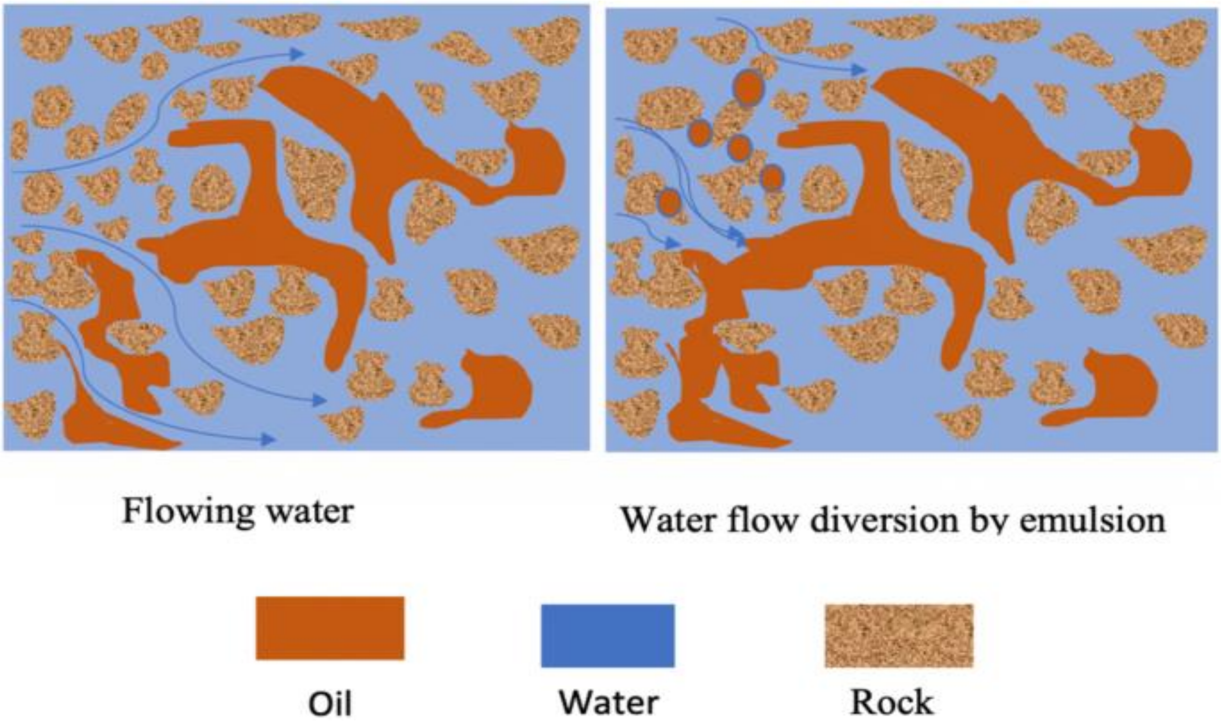


Fig 2.29

Application of emulsion in conformance control

Emulsions, when used in conformance control, are known to be self-adapting. They flow into the high permeability zones and plug water channels depending on the pore throat to droplet size ratio, causing the channelling of flow to low permeability zones. The diversion of flow by emulsion in the reservoir is presented in Mendez (1999) investigated the flow of dilute emulsions in cores at residual saturation and the mechanisms associated with the reduction in permeability caused by the emulsion droplets. The results obtained showed that permeability impairment occurred in two stages. The first stage is associated with the injected droplets and then there is the second stage in which the droplets are generated in situ during which the generation of droplets is done. The presence of residual oil in the core plays a significant role in permeability decline.

Romero et al. (1996) investigated the application of o/w emulsion when plugging high permeability zones. In their work, they suggested that the plugging capability of the emulsion was due to mechanical retaining and fusing of the emulsion droplets. Results from their injection experiments in consolidated, naturally fractured and unconsolidated porous media at a permeability range of 22–2615 mD produced a reduction in injectivity, effective permeability to water and the relative injectivity index which remained unchanged after the injection of the volumes of water. Sadati and Sahraei (2019) examined the application of o/w emulsions for water control using sand pack experiments and the reservoir conditions of an Iranian oil field that had experienced a high water cut after water flooding. They selected the optimum oil/water ratio and surfactant concentration conducive for the field application. They inferred from their experiments that a 20:80 water to oil ratio is adequate to create an emulsion with a plugging effect and enhancing the water flooding performance.

Torrealba and Hoteit (2019) proposed a novel conformance control method (CIM) that involved the cyclic injections of surfactant and brine slugs to form an in-situ microemulsion. The slugs are formulated in such a way that the viscosity is low enough not to affect injectivity and to ensure the invasion of the thief zones. The effectiveness of this method relies on the behaviour of the emulsion phase which is a function of the phase composition and salinity. UTCHEM, a chemical reservoir simulator, was used to conduct sensitivity analysis. In their conclusions, they stated that the formation of high viscosity emulsion in the high permeability zone of the reservoir led to the success of the treatment. Furthermore, the increase in reservoir resistance was maintained after water flooding, thus indicating the durability of the treatment.

Guillen et al. (2012) investigated the pore scale and macroscopic displacement of emulsion in sandstone core samples. They conducted visualisation experiments to examine the microscopic events leading to pore level flow diversions and the mobilisation of residual oil. In their results, they observed a pore-scale blocking of the pore throat by emulsion droplets during the microflow visualisation. They reported that the injection of an emulsion before the second water injection changed the macroscopic flow path in the core, allowing oil to be produced from the core with lower permeability. The emulsion droplets followed the preferential water path in the higher permeability core and blocked the pores. Hence drastically reducing the mobility in the water phase. Followed by continuous water injection, the liquid mobility between the ratio and the cores is reduced and water flows through both cores, displacing the soil also from the low permeability core.

Table 2.2 ***Water production mechanisms, diagnosis and solutions.***

Problem	Definition/Causes	Possible Diagnosis/Symptoms/Likely Conditions.	Suggested Solutions
Casing, tubing or packer leaks	Caused by the holes from corrosion, wear and split due to flaws, excessive pressure, and formation deformation.	• Flow profiling tools. • Drilling logs. • Noise and temperature logs. • Leak/casing integrity tests, Cement bond logs • Borehole tele-viewers • Electrical potential and electromagnetic devices • Radioactive tracer surveys • Chloride/TDS tests.	• Squeezing shutoff fluids. • Mechanical shutoff using plugs, cement and packers and patches. • Gels for restricted leaks (water soluble organic polymers, water soluble organic monomers, or silicates).
Channel flow behind casing	It can result from poor cement casing or cement-formation bonds. This problem is most likely to occur immediately after the well is completed or stimulated.	• Flow profiling tools • Drilling logs • Noise and temperature logs • Leak/casing integrity tests, Cement bond logs • Borehole tele-viewers • Electrical potential and electromagnetic devices • Radioactive tracer surveys • Scaling water trend.	• For unrestricted flow: high strength squeeze cement, resin-based fluids placed in annulus. • For small or constricted flow paths: lower strength gel-based fluids placed in the formation to stop flow into the annulus.
Moving oil/water contact	When a uniform oil-water contact moves up into a perforated zone in a well during normal water-driven production. This problem can be considered as a subset of coning, but the coning tendency is so low that near wellbore shutoff is effective.	• Typically is associated with limited vertical permeability usually less than 1md . • Diagnosis cannot be based solely on known entry of water at the bottom of the well, since other problems also cause this behavior too. • May be recognized if the well produces below the critical flow rate.	• Vertical well: By abandoning the well from the bottom using a mechanical system (Cement plug, Bridge plug). • Horizontal well: Any wellbore or near wellbore solution must extend far enough up-hole or down-hole from the water-producing interval to minimize horizontal flow of water past the treatment and delay subsequent water breakthrough. • Alternatively, a sidetrack can be considered once the WOR becomes economically intolerable.
Poor areal sweep	When water-flooding is used in anisotropic formation containing high permeability layers water starts flowing preferentially through these channels.	• Original and current state of low permeability barriers. • Incomplete barriers integrity. • Relative oil/water mobility. • Injection efficiency.	• The solution is to divert injected water away from the pore space, which has already been swept by water. • Requires a large treatment volume or continuous viscous flood, both of which are generally uneconomic. • Infill drilling is often successful in improving recovery in this situation.
Gravity segregated layer	In a thick reservoir layer with good vertical permeability, water is segregated by gravity and sweeps only the lower part of the formation. An unfavorable oil/water mobility ratio can make the problem worse.	• Happens in heterogeneous (Anisotropic and Fractured) formations. • Injection deficiency.	• Any treatment in the injector aimed at shutting off the lower perforations has only marginal effect in sweeping more oil before gravity segregation again dominates. • Foamed viscous-flood fluids, gel injection or alternating between the two may also improve the vertical sweep.

Coning or cusping	Caused by vertical pressure gradient. When the viscous forces overcome gravity forces, water from a lower connected zone is drawn toward the wellbore. Critical coning rate is the maximum rate at which oil can be produced without producing water through a cone.	• Gradually increasing WOR. curves with negative derivative slopes. • Fluid density changes. • Pulsed neutron spectroscopy (PSG) log • Thermal multigate decay (TMD) log. • Well testing • Monitoring the field performance.	• Large volume of gel placement above the equilibrium OWC (not very appropriate, effective or economic). • A dual drain production technique involving perforating above or below the oil/water contact may be effective. • Gelant or gel treatments have an extremely low probability of success when applied toward cusping or coning problems occurring in non-fractured matrix reservoir rock.
High permeability layer.	A common problem with multilayer production occurs when high permeability layers isolated by impermeable barriers, are watered out. The water source maybe from an active aquifer or a water-flood injection well.	• Original and current state of low permeability barriers • Relative oil/water mobility • Injection deficiency • Reservoir simulation • Detailed well control and mapping • Tracer surveys • Well logging	• Rigid shutoff fluids or mechanical shutoff in either the injector or producer. • If the water zone is located at the bottom of the well, cement or sand plugs are used and if it is located above an oil zone, cement or carbonate gels involving gelant injection.
High permeability layer with crossflow.	Water crossflow can occur in high permeability layers that are not isolated by impermeable barriers.	• It is vital to determine if there is crossflow in the reservoir. • Original and current state of low permeability barriers. • Relative oil/water mobility.	• Attempts to modify either the production or injection profile near the well bore are short lived because of crossflow away from the well bore. • In rare cases, it may be possible to place deep penetrating gel economically in the permeable thief layer if the thief lay
Fractures or faults between injector/produce.	In naturally fractured formation under water flood, injection water can rapidly break through into producing wells. It is common when the fracture system is extensive or fissured.	• Inter well tracers • Pressure transient testing • Wells with severe fractures or faults often exhibit extreme loss of drilling fluids.	• Injection of a flowing gel at the injector. • Gel treatment currently provides the best solution except for narrow fractures (fracture width < 0.02 in). • Alternatively, preformed gels could be extruded through fractures.
Fractures or faults from a water layer (2D coning).	Water can also be produced from fractures that intersect a deeper water zone. A similar problem results when hydraulic fractures penetrate vertically into a water layer.	• In many carbonate reservoirs, the fractures are generally steep and tend to occur in clusters that are spaced at large distances from each other, especially in tight dolomite zones. Thus the probability of these fractures intersecting a vertical well bore is low. • These fractures are often observed in horizontal well where water production is often through conductive faults or fractures that intersect an aquifer.	• Pumping flowing gel may treat these fractures. Treatment volumes must be large to shutoff the fractures far away from the well. • Polymers

2.6 Costs Associated With Produced Water

The costs associated with produced water can be significant and divided as the following:

Capital: Constructing treatment plants, disposal facilities, equipment, etc.

Operating: Facilities, chemical additives and utilities, residuals or byproducts.Management costs resulting from the treatment. Permitting, monitoring, and reporting costs. Transportation costs.

Improper management can have negative impact: – Expensive clean up and damage to the environment.

2.7 Nabrajah field –Block-43:

Block 43, South Howarime,lies on the northern flank of the petroliferous Say'un - Masila Basin and covers an area of 2026 km². and is located onshore in the Hadhramout Governorate in the central part of the Republic of Yemen as shown in figure (2.30). Block 43 lies in the petroliferous Say'un - Masila Basin about 600 km east of Sana'a, within a cluster of producing blocks managed by different operators .the block has 10 Exploration wells and 23 production wells upto 2012. It holds one oilfield, Nabrajah field that was discovered in December 2004 and has been producing since July 2005 and can be classed as a mature development, producing field.

The reservoir in Nabrajah field is the Shuqra/basement (called Deep reservoir) and sandstone of the Qishn Clastic Member of the Tawila Group; a widespread siliciclastic sequence deposited in deltaic to shallow marineneritic environments.The Qishn Clastic member unconformably overlies mixed clastics and carbonates of the Sa'ar formation. It is subdivided into the Lower and Upper Intra Qishn clastics. The Upper Qishn is further subdivided into the S3, S2 and S1 intervals. Regional studies indicate that the S2 clastic sequences were deposited as tidedominated deltaic sediments with log character and core descriptions indicating the sandstones were fluvial and tidal channel longitudinal and stream-mouth bars.S2 is the main oil-bearing reservoir and S1A contains minor volumes of oil and S3 is in the water zone, with communication to S2 with Oil-Water Contact (OWC):1555 m bSRD (605 m bmsl) as shown in figure(2.31)

The combined cumulative production from the two reservoirs per 31 December 2012 was approximately 12.8 mmstb with approximately 8.7 mmstb having been produced from the Qishn S2 sands. The combined production from the two reservoirs is currently less then 2000 bopd, from the Qishn S2 sands and deeper Shuqra/Basement. Orignal oil in place in Nabrajah Qishn about 25 MMSTB and about 15 MMSTB in Nabrajah deep .There are 21 wells were drilled (5 water injection in Qishn Reservoir and 2 gas injection wells in Nabrajah Deep) in the field.

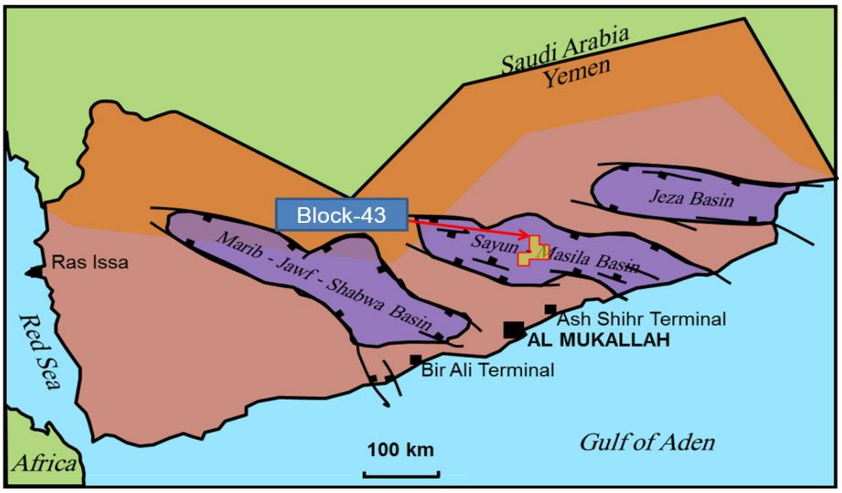


Figure 2.30

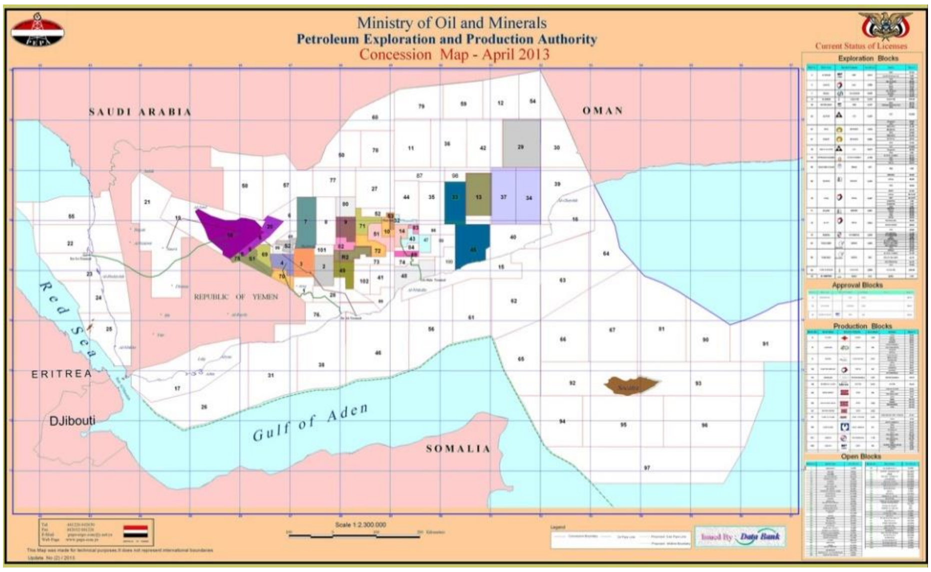


Figure Blocks in Yemen (2.31)

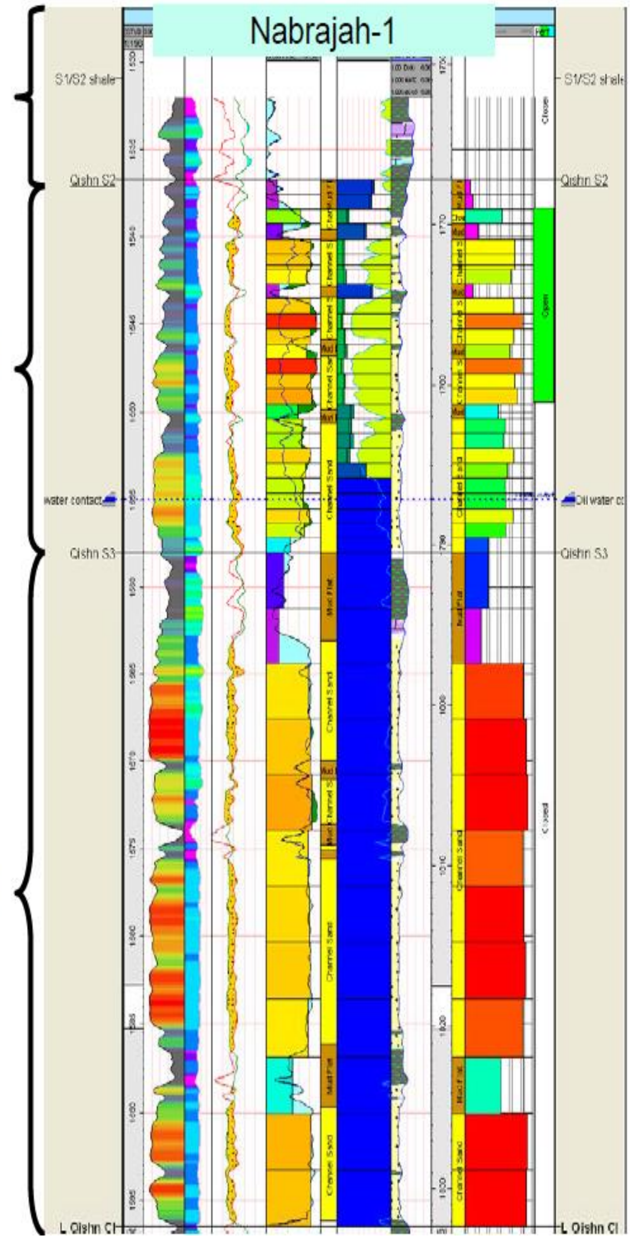

Nabrajah-1
S1
S2
S3
S1/S2 shale
Qishn S2
water contact
Oil water co
Qishn S3
L Qishn Cl
Channel Sand
Mud Flat
Open
Closed

Figure 2.32

2.8 Rock properties and Fluid properties

2.8.1 Rock Properties

One relative permeability table based on Nabrajah-1 SCAL data as shown in figure (2.33) , (2.34) and (2.35).

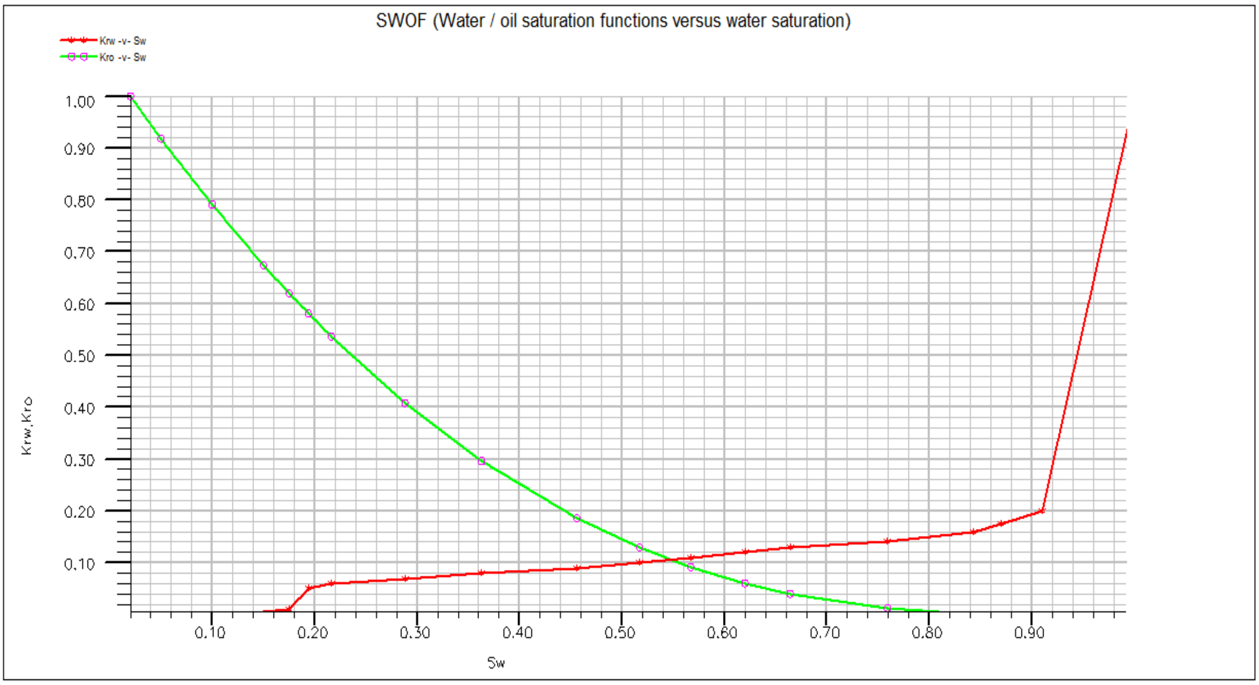


Figure 2.33

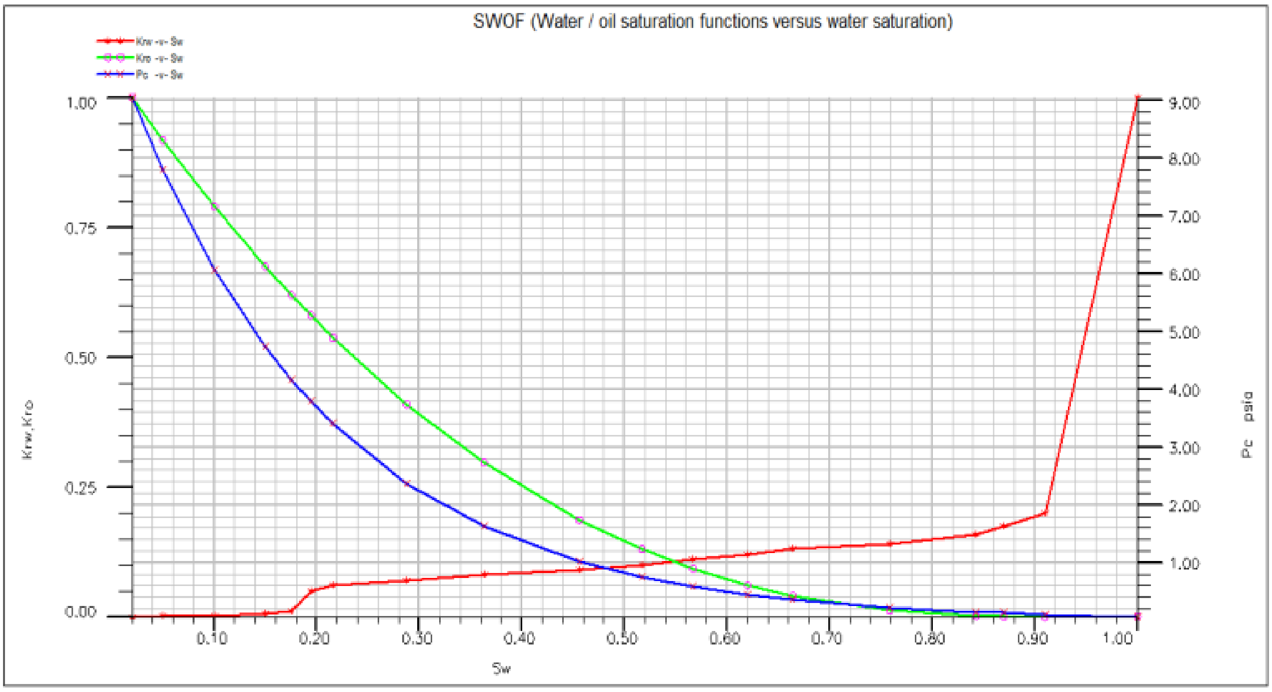


Figure 2.34

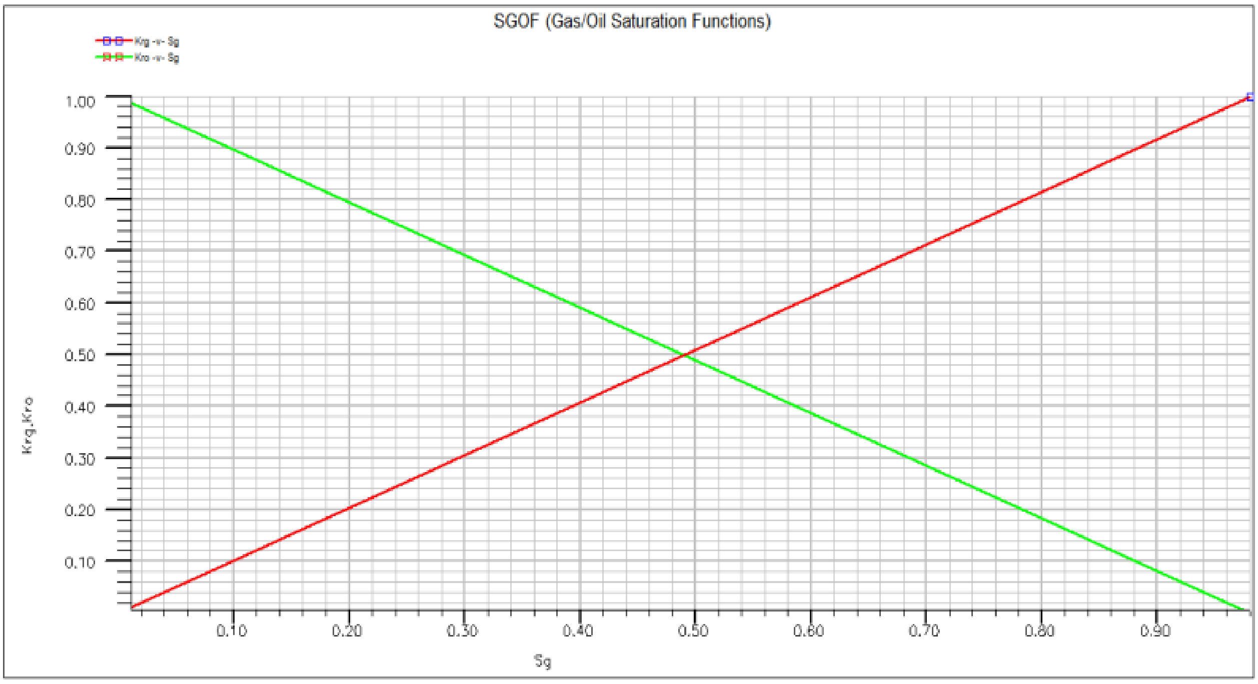


Figure 2.35

2.8.2 Fluid Properties

PVT Data was obtained from wellhead sample taken during the Nabrajah-1. A summary of the main oil and gas PVT properties from lab reports of the Nabrajah-1 as shown in figure (2.36) and figure (2.37).

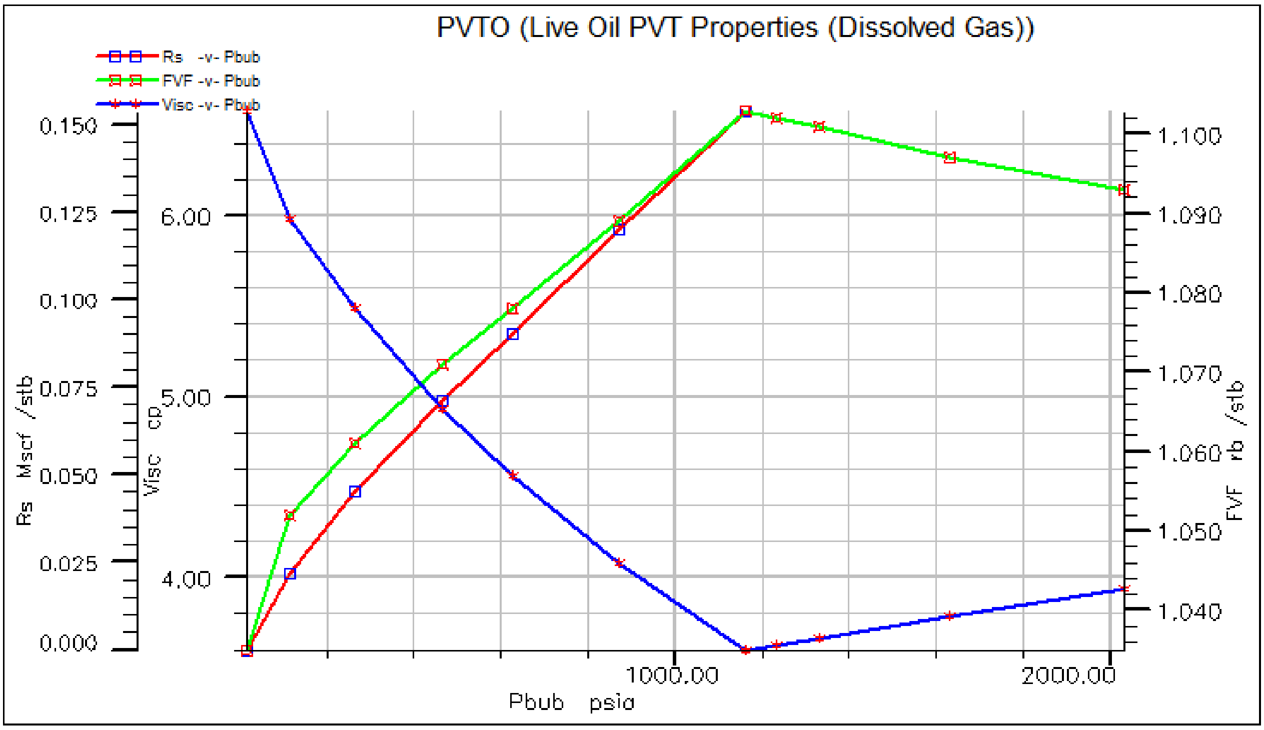


Figure 2.36 Oil PVT Properties

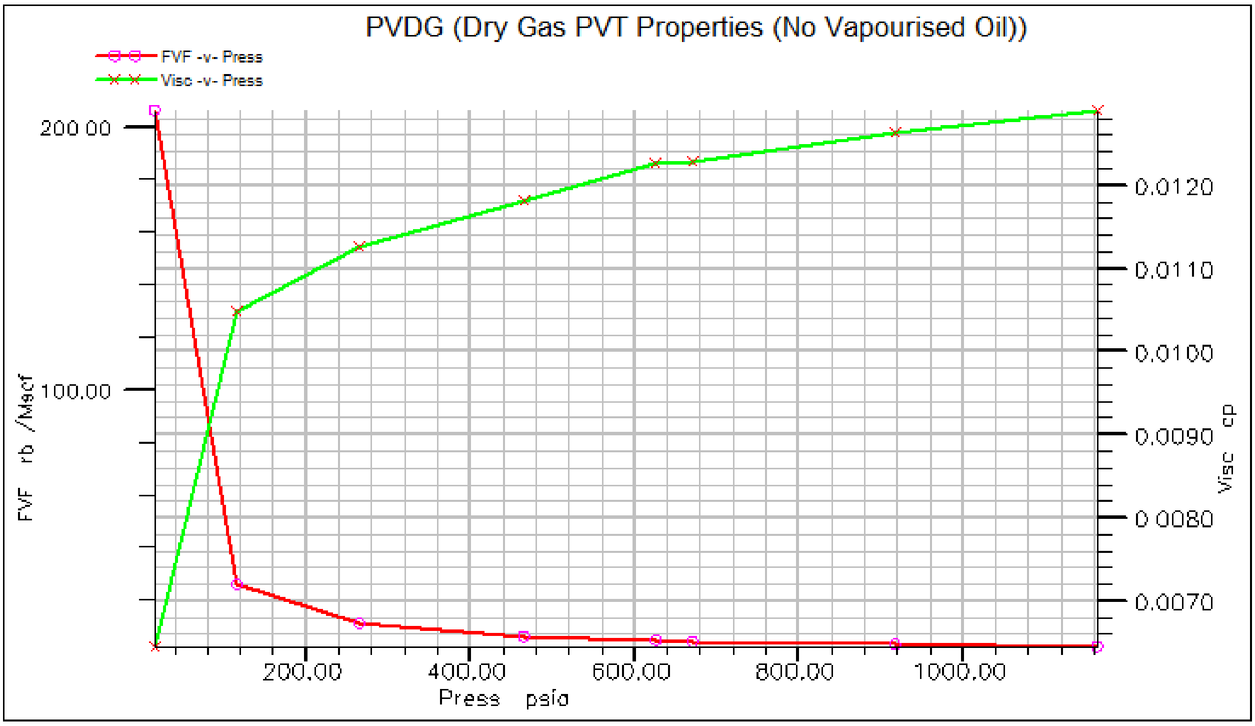


Figure 2.37 Dry Gas PVT Properties

Chapter Three

3. METHODOLOGY

3.1 Introduction

This chapter discusses the using of diagnosis plots to achieve the objectives of research project. Also it will explain the data and methods used to diagnosis the reason that cause increase in water productivity.

3.2 Data Type Required

Different data will be collected and used to build the plot that we will use it to diagnosis the main problem that cause the increase in water productivity in Nabrajah field. The data needed can be summarized as the following:

- Production data
- Injection data
- Completion data
- Petrophysical data
- Well test data

3.3 Software Descriptions

3.3.1 OFM

IS A quick access to important information means that all the answers are in one place for managers, petroleum engineers, and geoscientists. It is used to:

- Monitor and survey performance with advanced production views.
- Forecast production with powerful decline and type curve analysis.
- Analyze any asset and share results using standards.-
- View, relate, and analyze reservoir and production data with comprehensive tools, including interactive base maps with production trends, bubble plots, and diagnostic plots.
- Use a library of off-the-shelf workflow templates to guide analyses from shale production to waterflooding.

OFM software enables turning data into decisions that can improve oil and gas field performance throughout the entire life cycle.

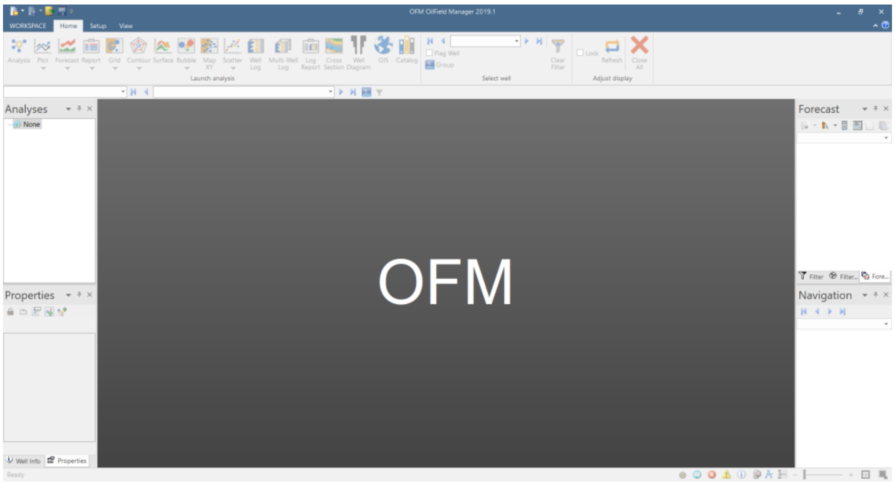


Fig.3.1

3.3.1.1 Enhance mapping

Visualizing wells and completions—or determining whether to investigate site access issues—incorporates the latest GIS technology to support better understanding of contextual information about the asset and its surroundings.

3.3.1.2 Connect multiple disciplines

Productivity is improved by driving collaboration between technical disciplines. The enhanced integration streamlines two-way data transfer between OFM software and the following:

- Simulation models to share results from the shared earth model (via the OFM software plug-in for the Petrel E&P software platform)
- Production volumes, operations data, and field event history (via the Avocet production operations software platform)
- Project economic evaluations and forecasts (via the OFM software plug-in for Peep petroleum economic evaluation and decline analysis)

3.3.1.3 Product overview

The OFM well and reservoir analysis software is a powerful tool designed for the day-to-day surveillance and management of oil and gas fields. OFM software provides a user-friendly interface, enabling you to view, modify, and analyze production and reservoir data. You can perform basic and complex analyses for individual or multiple completions, groups of wells, an entire field, or several fields. OFM software is suited for the occasional user yet sophisticated enough for advanced petroleum engineering analyses. Whether at the wellsite or in the office, OFM software enables you to access or load data from a local desktop, as well as corporate repositories such as Oracle and SQL Server databases.

NOTE: OFM software is now a product of Sensia, a joint venture between Rockwell Automation and Schlumberger.

3.3.1.4 Release updates

OFM 2019.1 is a full-install release and supersedes all previous versions. OFM 2019.1 expands the functionality of the Analysis Dashboard introduced in OFM 2016.1 and improved in OFM 2018.1. The Decline Curve Analysis (DCA) is upgraded with key functionalities for improved forecasting and user flexibility, and two new analyses expand the analysis portfolio: Type Well and Cumulative Distribution Function (CDF). A set of "managers" are also added: Annotation Manager, Type Well Manager, Print Manager, and Forecast Template Manager, empowering you to extend and standardize workflows in a dashboard context.

NOTE: OFM 2019.1 includes updated database drivers.

3.3.1.5 Users

OFM software is used primarily by reservoir engineers and production engineers. It is equally useful in the day-to-day operational arena (where performance is tracked on a continual basis) and for longer term surveillance of a project at multiple levels (completion, well, pattern, reservoir, etc.). Its highly flexible environment allows users in both reservoir engineering and production engineering to build and customize their own analyses.

3.3.2 EXCEL

Excel functions provide a large number of built-in functions that can be used to perform specific calculations or to return information about spreadsheet data. These functions are organized into categories (text, logical, mathematical, etc.) to help you select the function you need from the Excel menu. This page provides a complete list of Excel functions, grouped by category. Each of the job links will take you to a dedicated page, where you will find a description of the process, with examples of use and details of common errors. Alternatively, if you know the name of the process you are interested in, you may prefer to choose from an alphabetical list of processes.

Fig.3.2

3.3.2.1 Excel Basics:

Always separate the three phases, data acquisition, data analysis, and data presentation OAP). This makes your spreadsheet more flexible and easy to follow. Never include numbers in formulas, always enter the variable into a cell and return to the cell in the formula. This makes it easy to keep track of the spreadsheet and update it when variables change. Don't tamper with the data, when using data from somewhere else, don't modify it, or report it in other papers. This reduces errors and increases efficiency. Use data validation where possible, to reduce data entry errors and to facilitate data analysis and reporting. Always think "Is there a way to do this that will save me time next time". Lay the data to fit Excel, not to fit your convenience. Every title, subtotal, or empty column you put in between the data makes it less usable. or empty column you put in between the data makes it less usable. Get used to using dollar signs when referring to cells. If it is used well, you can write a formula once and copy it everywhere, this is to save time and reduce errors. Protect cells containing formulas It can be very difficult to find an incorrect (or missing) formula caused by accidental typing. Use color and formatting

(plus descriptions) to indicate where you need to enter data. Avoid merging cells unless absolutely necessary, merged cells make editing the spreadsheet more difficult.

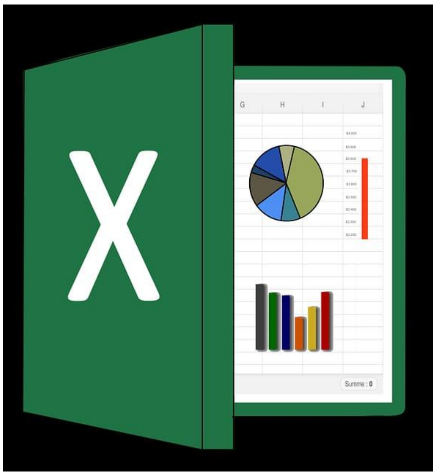


Fig.3.3

3.3.2.2 Excel uses:

- Define pivot tables to identify and understand data.
- Add more than one row or column.
- Use filters to simplify your data.
- Remove duplicate data points or sets.
- Move rows to columns.
- Split text information between columns.
- Use these formulas to perform simple calculations.
- Get the average of the numbers inside the cells.
- Use conditional formatting to have cells change color automatically based on the data.
- Use the IF formula and then Excel to automate some Excel functions.
- Use dollar signs to keep a single cell format intact no matter where you move it.
- Use the VLOOKUP function to pull data from one area of the sheet to another.
- Use INDEX MATCH formulas to pull data from horizontal columns.
- Use the COUNTIF function to have Excel count words or numbers in any range of cells.
- Collect cells using andpersand.
- Add checkboxes.
- Hyperlink to a cell of a Web site.

3.3.2.3 Importance of Excel Functions:

Among the existing computer programs, Microsoft Excel is one of the most important computer programs due to the main role it plays in many sectors. It is the most widely used spreadsheet software in many business activities, classrooms, and even personal data organization. Excel was first released in 1985. Since then, it has played a vital role in performing mathematical calculations and calculations based on equations, and other activities that may require mathematical calculations. Many companies, personal and corporate organizations have embraced the use of Excel because of its usefulness and ability to serve as a visual foundation for various applications. The importance of MS Excel can be seen in the various department units, as it is used as follows. This software plays a very important role in graphs as it has the ability to produce a variety of different graphs, which can be used by different departments to represent statistical data in a more meaningful way. Since formulas and procedures are built into the package, it's always easy to save time creating graphs. Unlike other graphing software, Excel is more cost effective because it plays many different roles, and it can be used for many different things.

Fig.3.4

3.3.2.4 Data organization:

Data is raw and unprocessed information, and you need to store it in a systematic and organized manner. Excel gives users the ability to set up tables, where they can organize their data and provide refresh keys as well. Administrators who always have plenty of information to update regularly feel the benefits of organizing data with Excel. Excel tables help administrators monitor the progress of individual and aggregate statistics such as report trends and product complexities.

3.3.2.5 Programming:

When it comes to programming, you discover that MS Excel supports almost all applications of the programming language used to create macros. This makes it easier to solve complex functions and thus increases efficiency in programming. Finally, knowledge of Microsoft Excel is vital in most modern organizations for the purpose of proficiency. Many organizations like to keep regular and updated records of their products, programs, and activities. So individuals who are proficient in creating or creating Excel macros are considered assets to a particular organization.

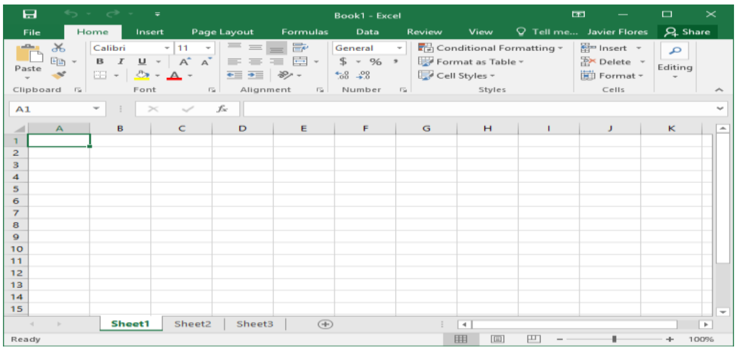


Fig.3.5

3.4 Steps of study

1. Collect production and injection data
2. Investigate Excessive water production wells.
3. Select the candidate wells for more analysis
4. Collect Completion data of the candidate wells.
5. Assign production and completion in to OFM data base and Excel sheets
6. Several types of analysis will be done through OFM and EXCELE to get clear view on the field water production situation.
7. Understand the reasons of the excessive water production by using Chan plot
8. Suggest the suitable treatment for shutoff excessive water production.

3.5 Expected outcomes

The output expected from this study summarized as the following:

1. Production performance
2. Diagnostic plots
3. Identify the most reasons of excessive water production
4. Figure out the best way to treat these problems

Chapter Four

4. Results and Discussions

4.1 introduction

This chapter presents the results and analysis of Nabrajah wells data that available and the diagnostic results as well as the treatment for the candidate wells. The main data that was used is Nabrajah production data. Using production performance, it is observed unexpected very high water cut in the most of Nabrajah wells that were candidate for more study and analysis. OFM software and EXCEL are the main tools used for the analysis. Water injection in the field was applied to support reservoir pressure and disposed water production. The overall water cut in the field is increase rapidly to more than 90%.For Nabrajah field wells, it is easy to classified field wells according to cahn plot analysis to two types base on the dominated water production mechanism :1- channeling (high permeability layer) 2- coning .
The analysis and discussion results of the filed candidate wells will present as the following:

4.1.1 Nabrajah-1 Well

Nabrajah-1 well was completed as ESP pump and the total depth and completion are illustrated in Wellbore Diagram figure (4.1) .Nabrajah-1 is producing from Qshin calstic and put on production in August 2005.

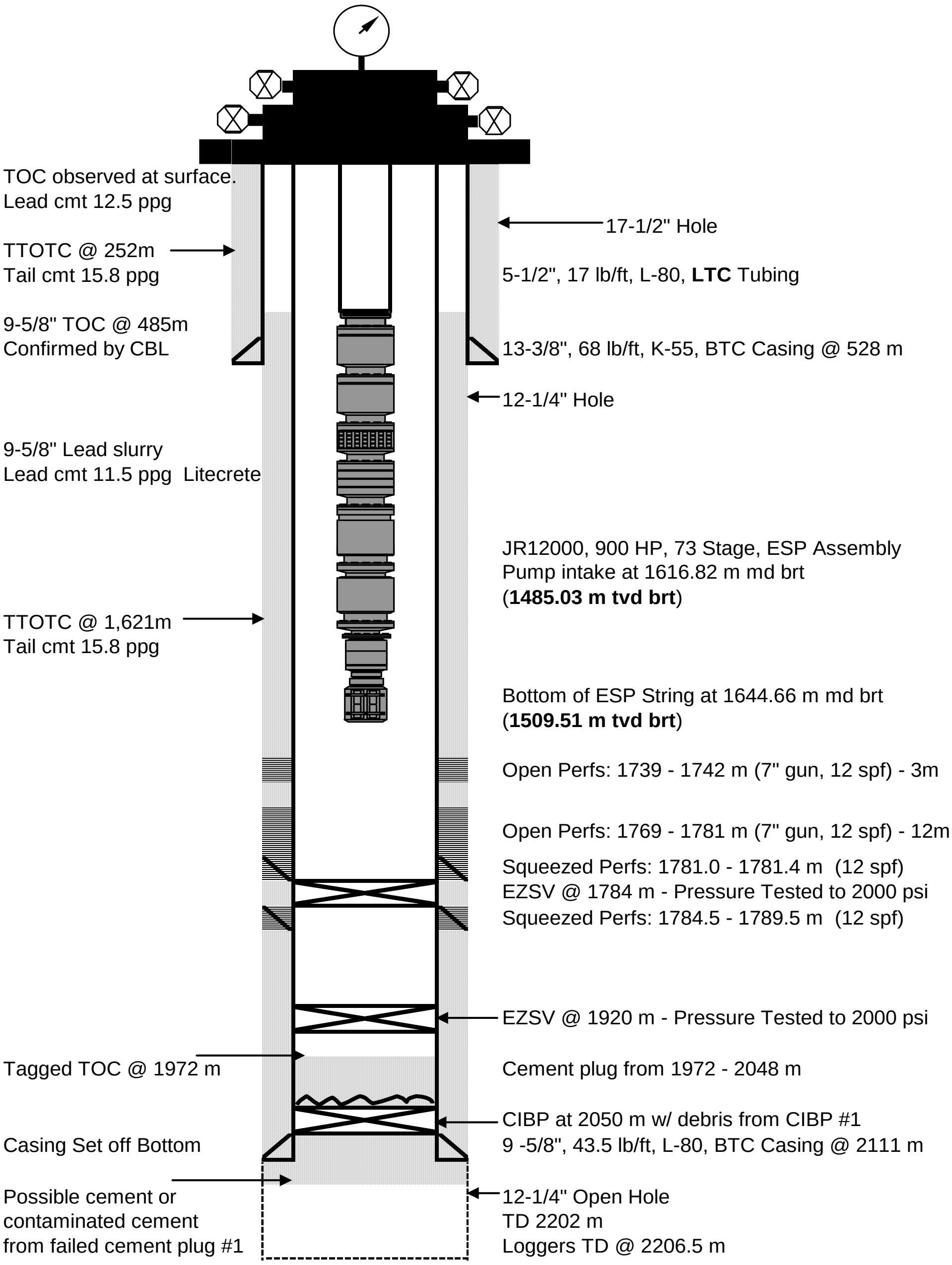


Figure 4.1 Nabrajah-1 Wellbore Diagram

Figure 4.2 present production performance and shows increase water production rapidly and reach to more than 80% in about one year. From oil recovery plot figure 4.3 it is clear noticed that the well reached its economic limit with WOR more than 75 and water cut more than 98 %.The diagnostic plot figure 4.4 showing channeling behavior but it is needed confirmation by PLT and other methodology. To control and reduce water production it is needed to change artificial lift and identify the channel zone to shutoff that interval. Finally it is good practical to do the treatment in the early stage of increase water production.

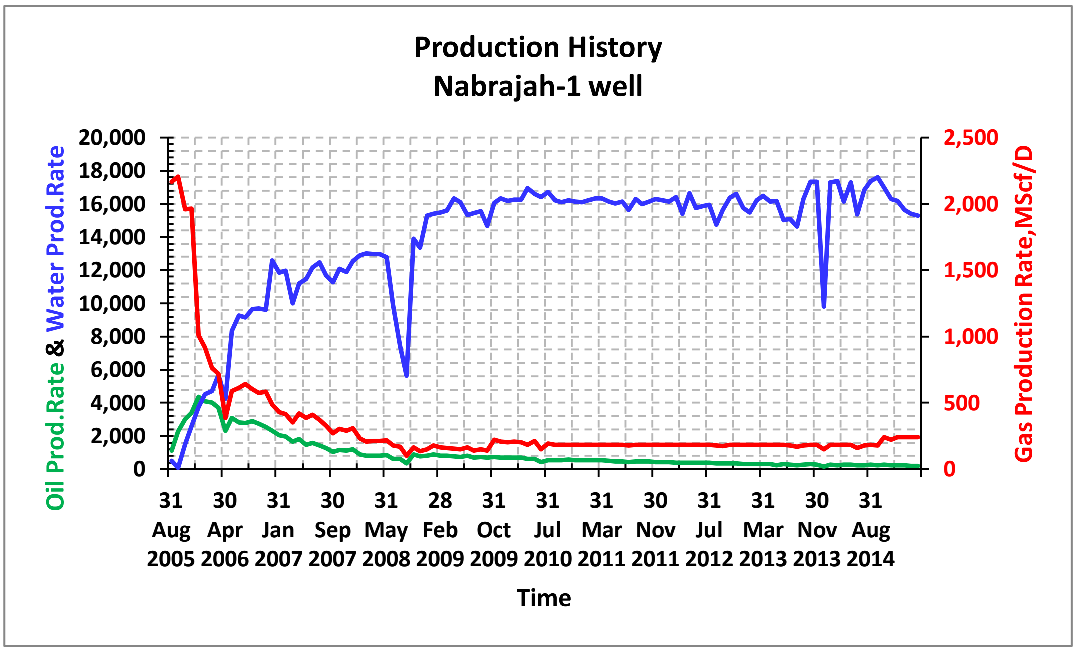


Figure 4.2 Production History of Nab-1

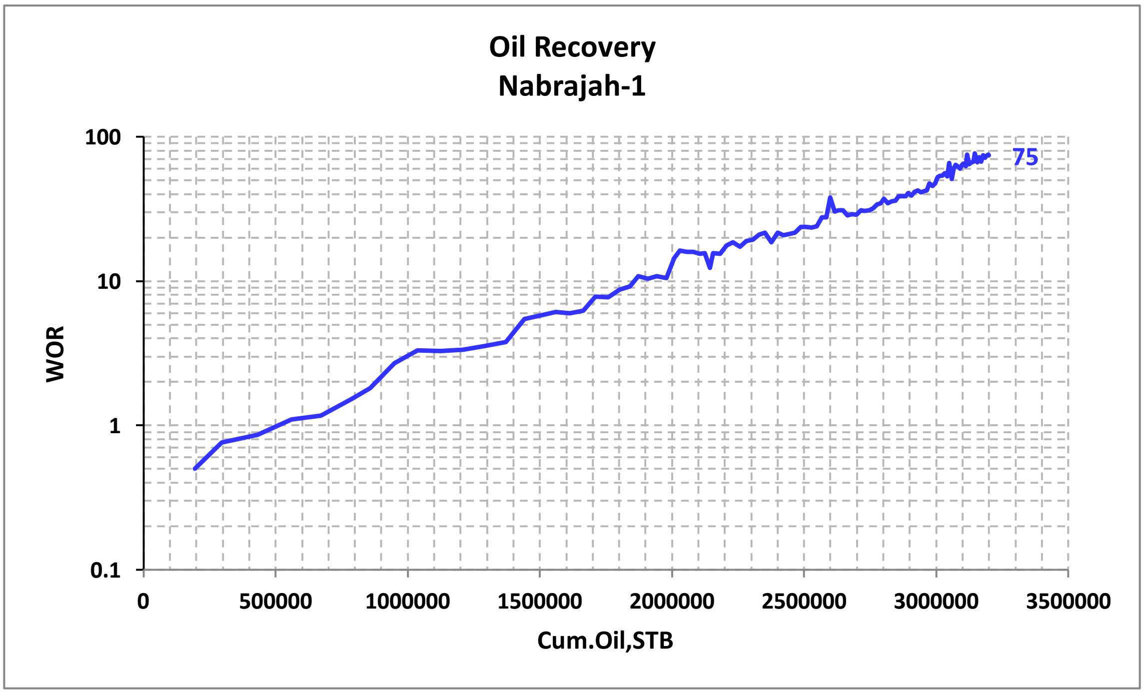


Figure 4.3 Oil Recovery Plot of Nab-1

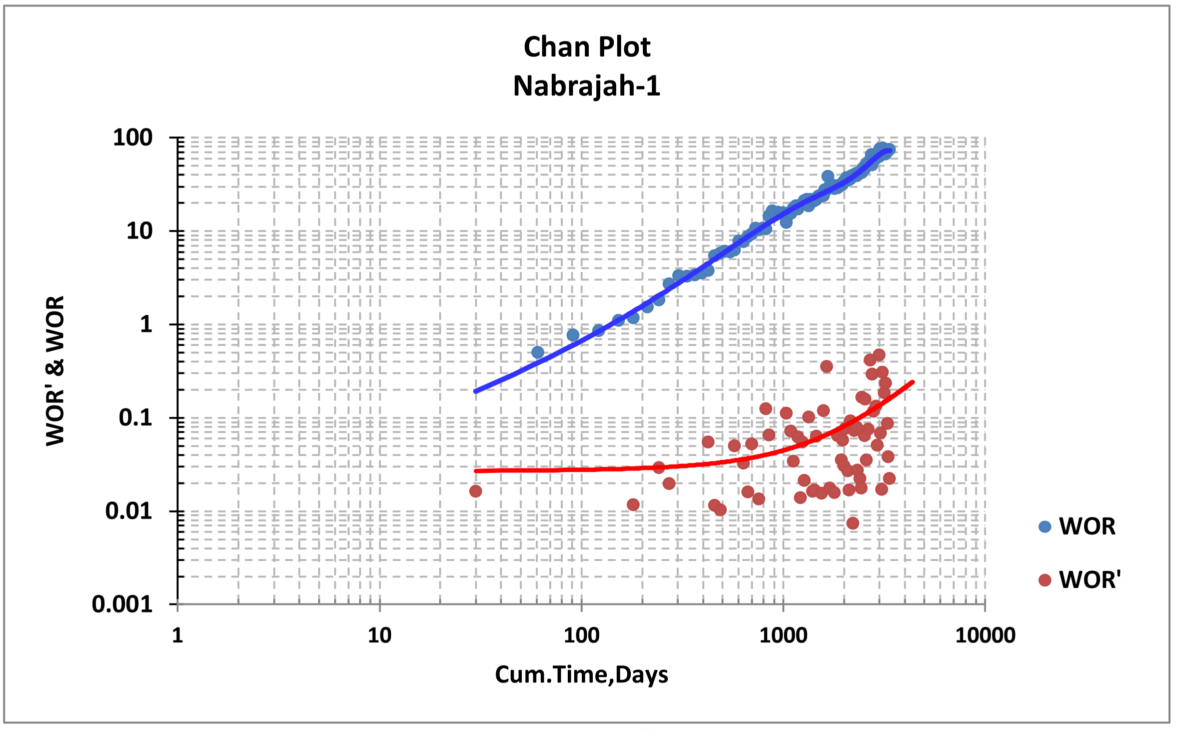


Figure 4.4 Chan Plot of Nab-1

4.1.2 Nabrajah-2 well

Nabrajah-2 well is started production on July 2005 from Qshin calstic (S1A-S2). Figure 4.5 presented well Nab-2 production performance, the water cut increase rapidly up to 80% in about one year then decline. And it’s clear on the recovery plot that the well reached its economic limit (100) as presented through Figure 4.6. The diagnostic plot is showing a channeling phenomenon (Figure 4.7)

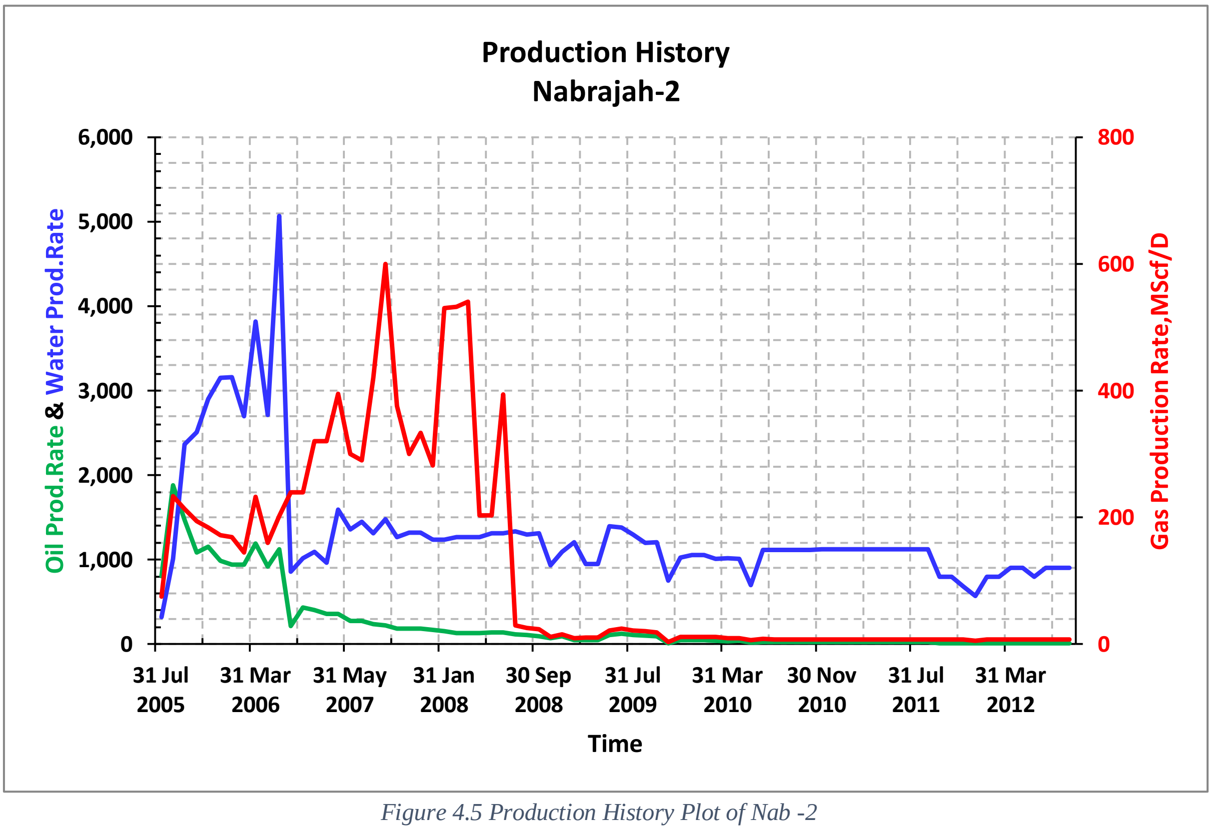


Figure 4.5 Production History Plot of Nab -2

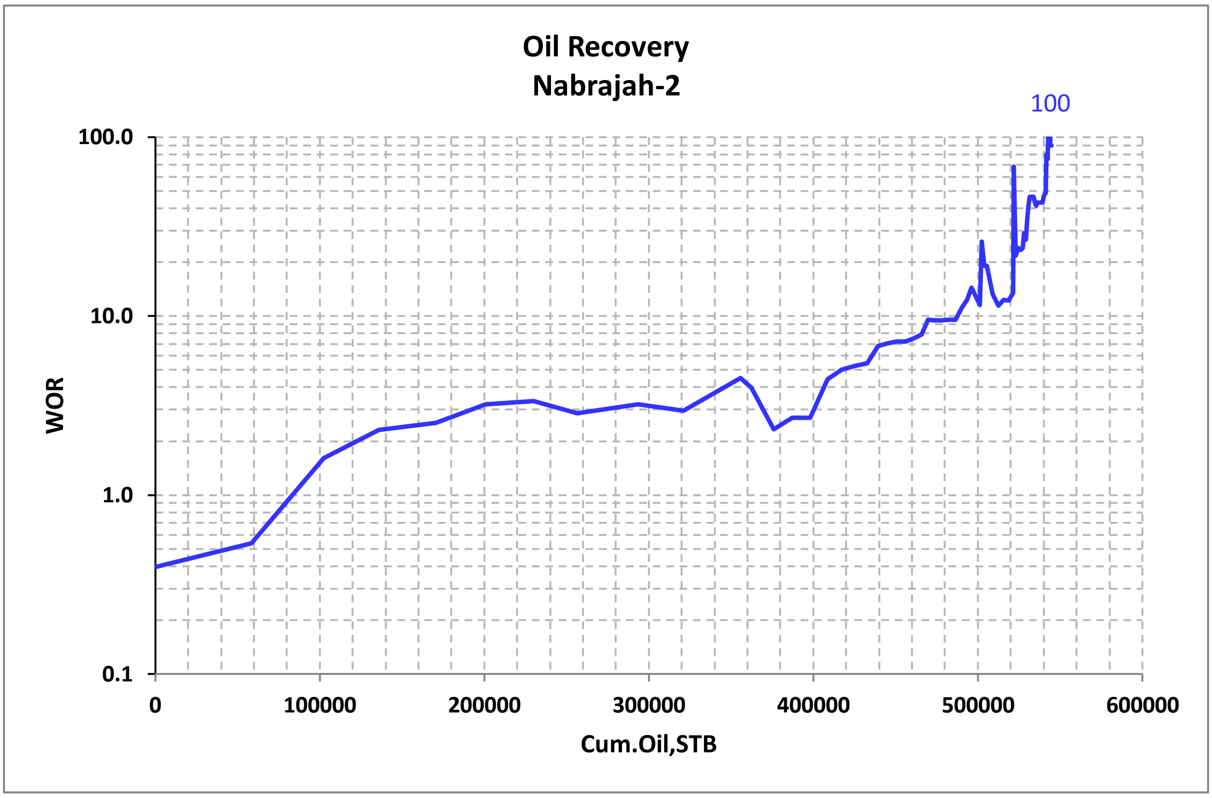


Figure 4.6 Oil Recovery Plot

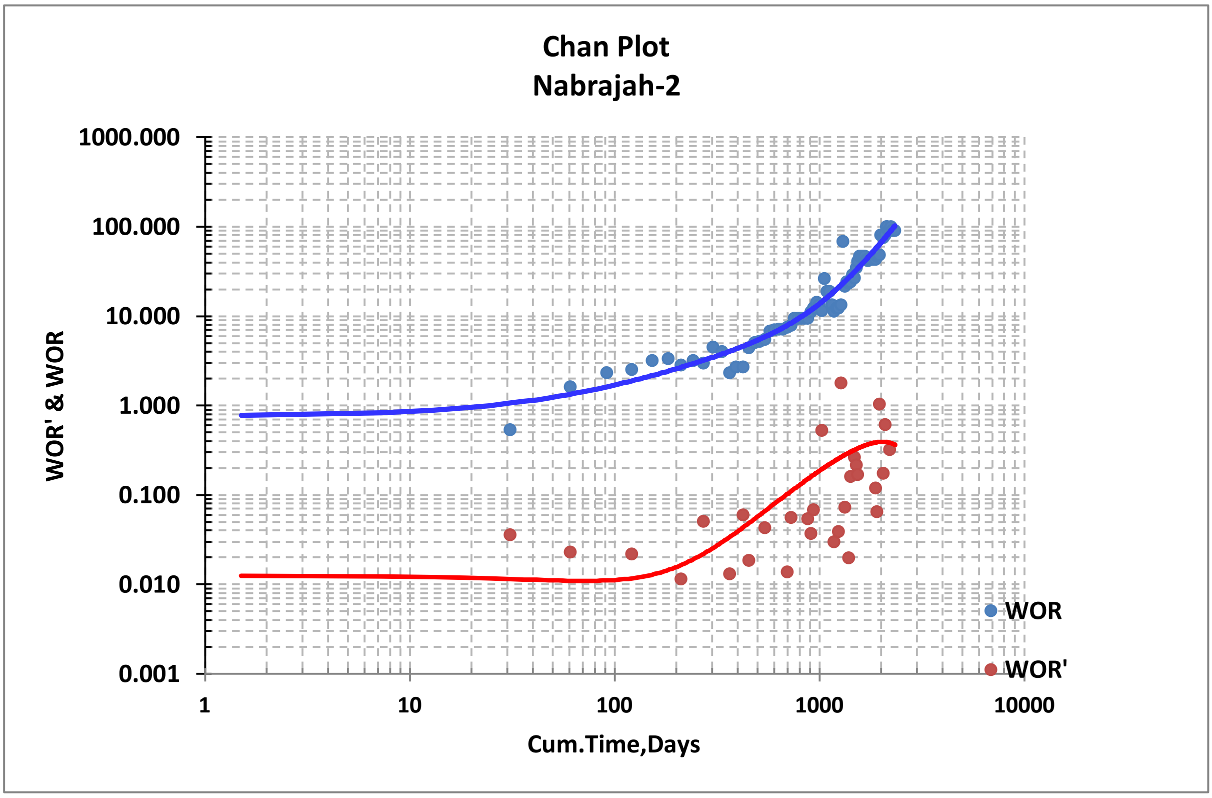


Figure 4.7 Chan Plot of Nab-2

4.1.3 Nabrajah-3 well

Nabrajah-3 well was completed as ESP pump and the total depth and completion are illustrated in Wellbore Diagram figure (4.8) .Nabrajah-3 is producing from the Upper Qishn S1 and S2. The well was tested in three different intervals; two in the Upper Qishn S2 and one in the Upper Qishn S1. The well put on production in September 2005.

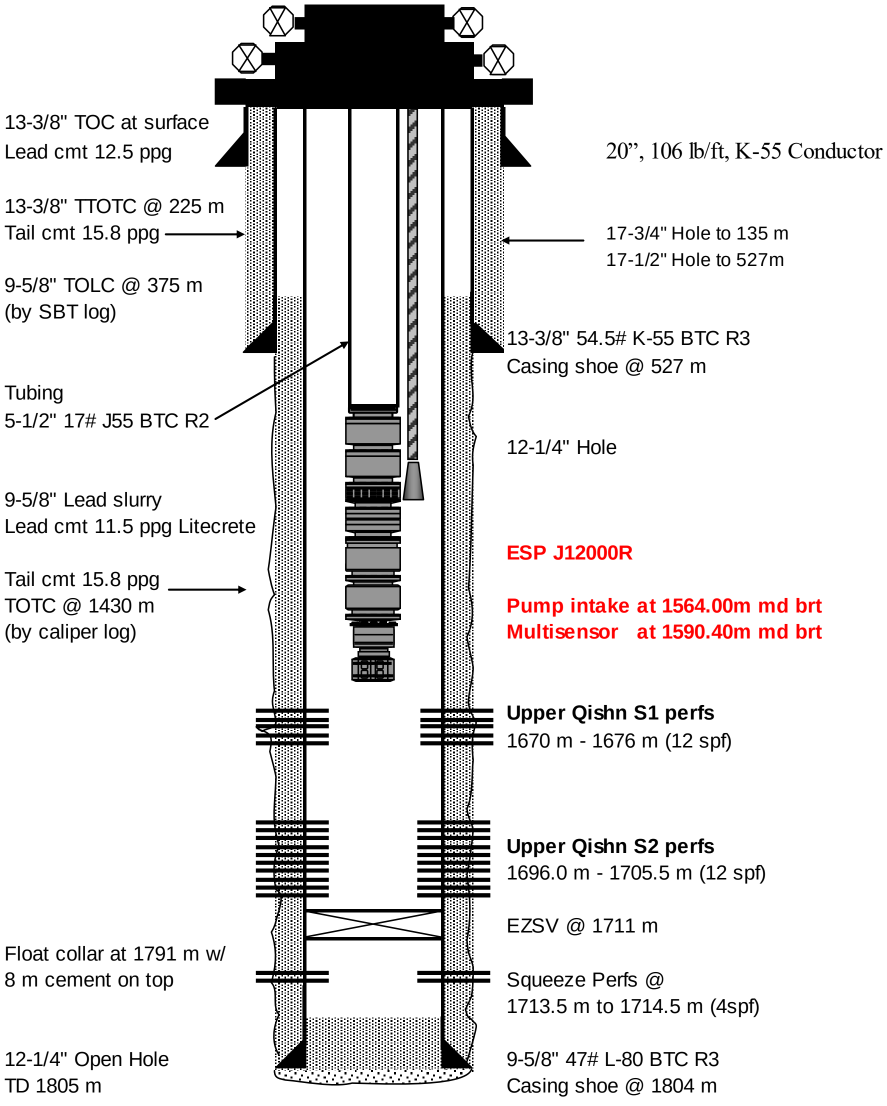


Figure 4.8 Nabrajah-3 Existing Well Diagram

Figure 4.9 present production performance and it is noted that the water production increased rapidly from the beginning of the production. From oil recovery plot figure 4.10 it is clear noticed that the well reached its economic limit with WOR more than 118 and water cut more than 98 %.The diagnostic plot figure 4.11 showing channeling behavior but it is need confirmation by PLT and other methodology. To control and reduce water production it is needed to change artificial lift and identify the channel zone to shutoff that interval. Finally it is good practical do the treatment in the early stage of increase water production.

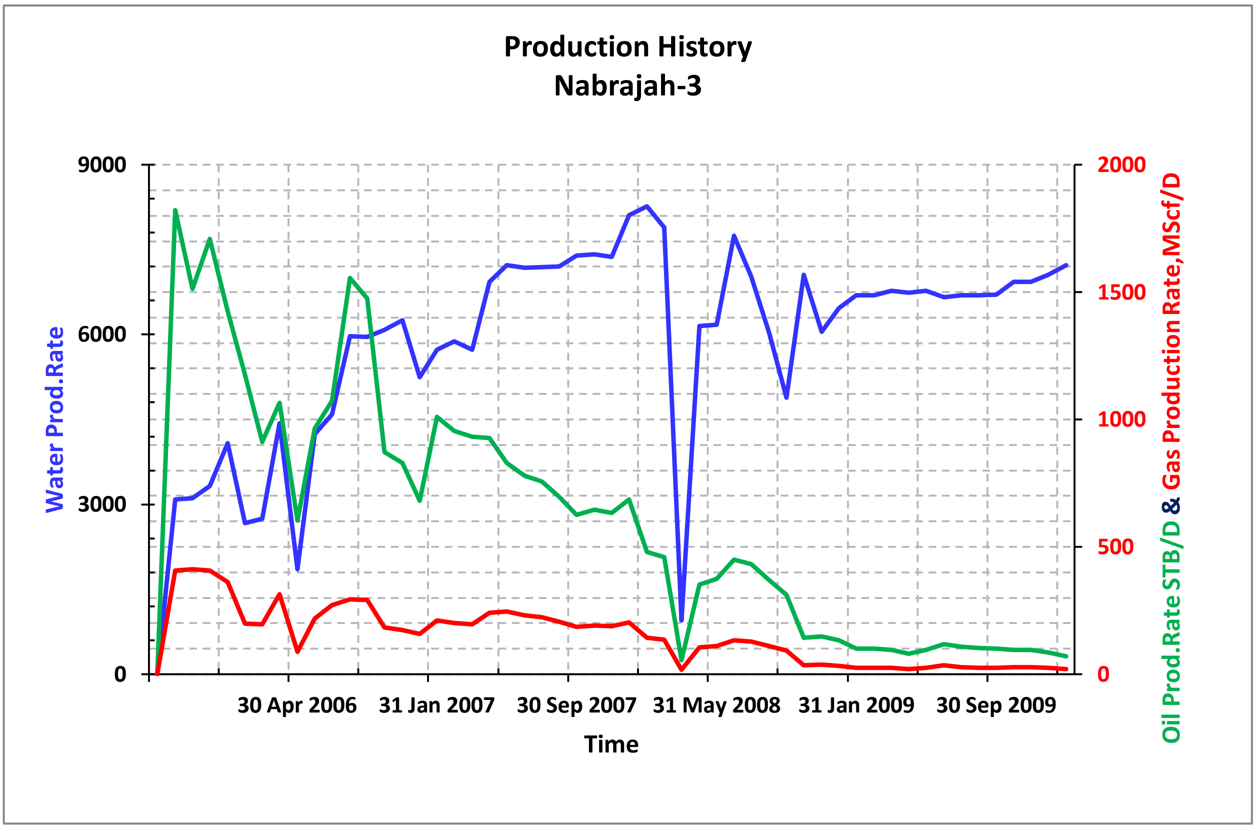


Figure 4.9 Production History of Nab-3

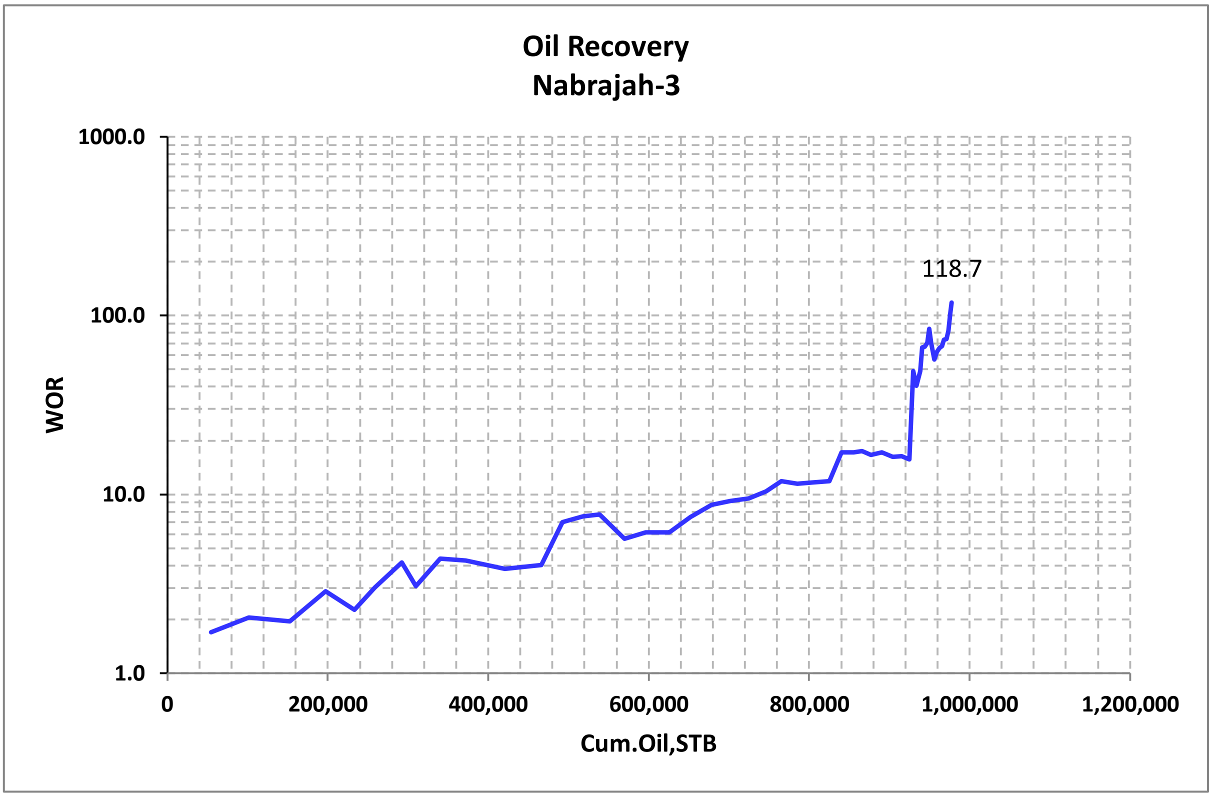


Figure 4.10 Oil Recovery Plot of Nab-3

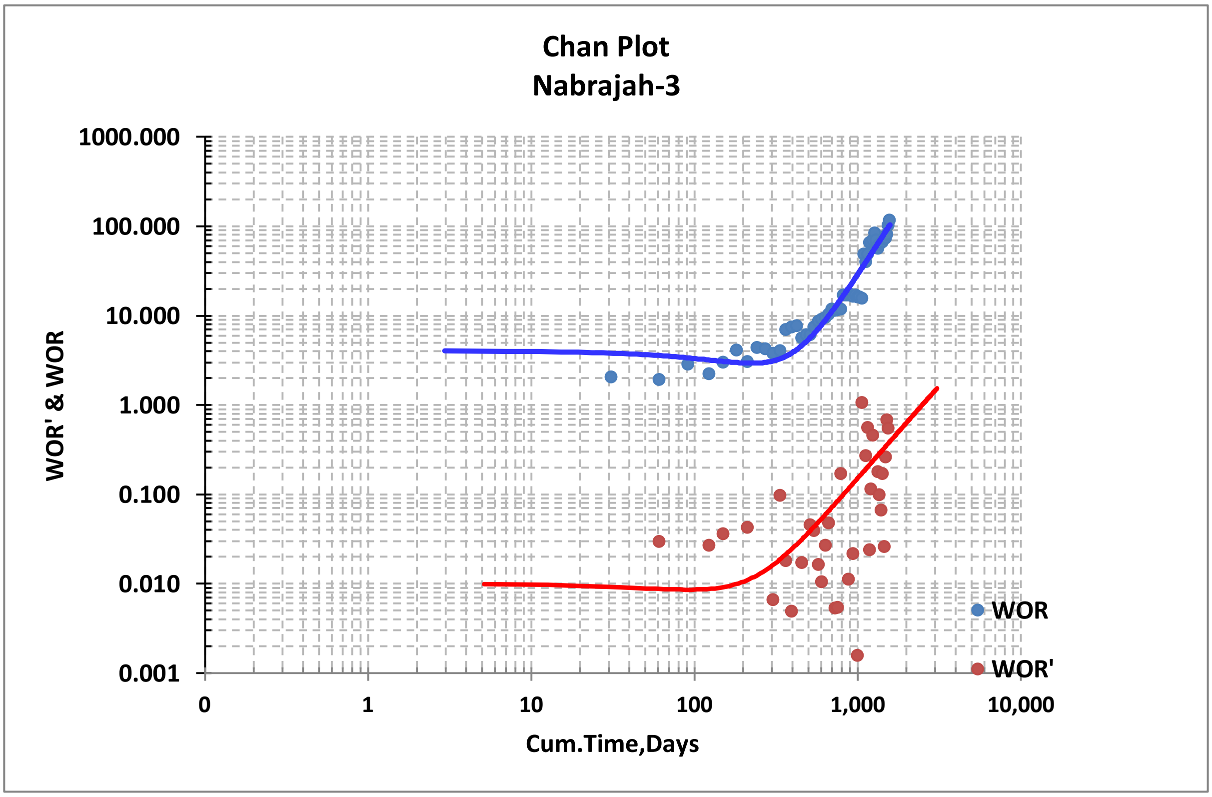


Figure 4.11 Chan Plot of Nab-3

4.1.4 Nabrajah-7 well

Nabrajah-7 was drilled in July 2005, as a Qishn development well to a total depth of 1792m MD RKB, 1728m TVD RKB Figure 4.12. Well Nab-7 was completed as electric submersible pump (ESP) producer in Jan .2006

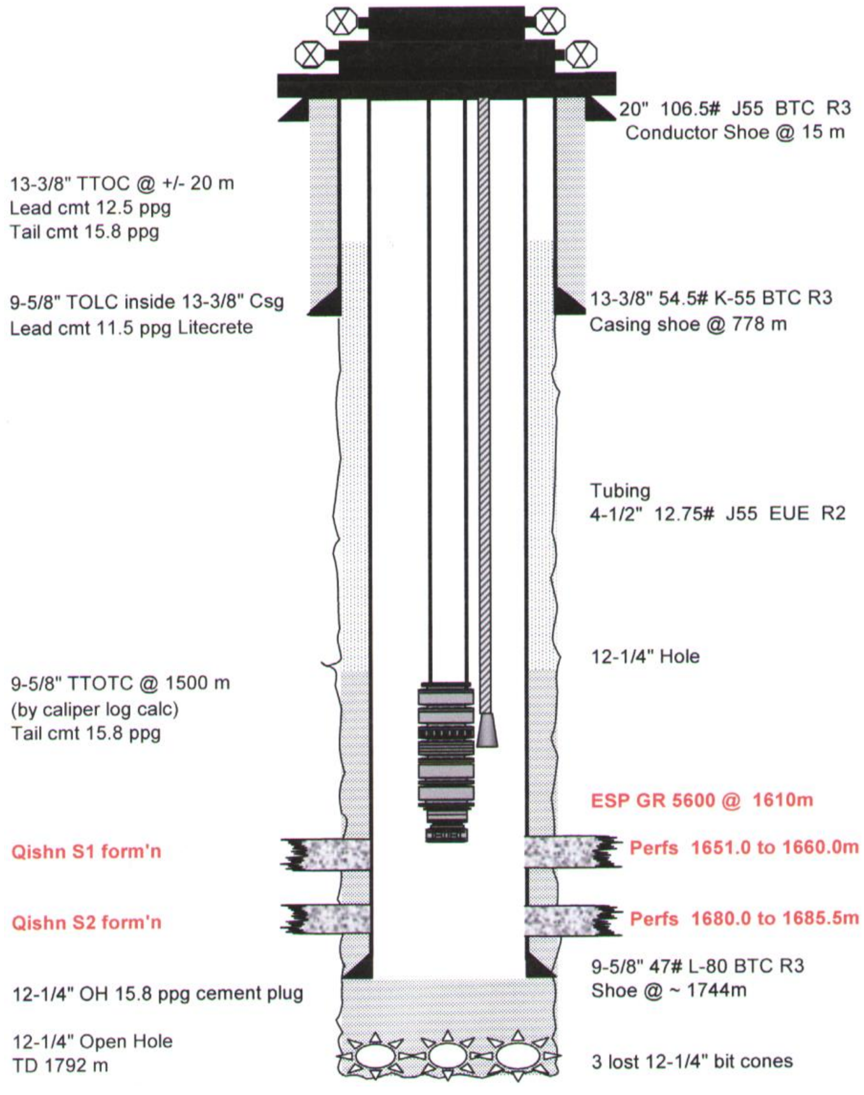


Figure 4.12 Proposed Completion Schematic

On earlier 2006 *the Nabrajah-7 started production from Qshin calstic (S1A-S2). Figure 4.13 presented well Nab-7 production* performance, *The water cut started to increase rapidly and reach upto 99.4% and in the same time the WOR increased and reached more than 155%. and it's clear on the recovery plot that the well reached its economic limit 164% as presented through Figure 4-14. The diagnostic plot is showing a late channeling phenomenon (Figure 4-15)*

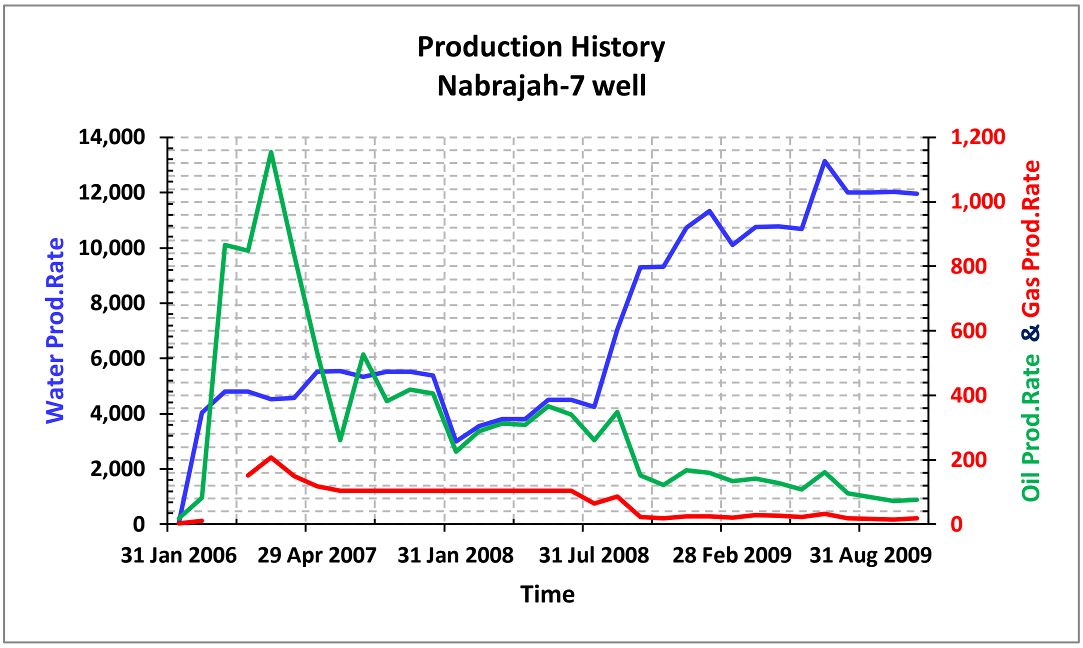


Figure 4.13 Production History of Nab-7

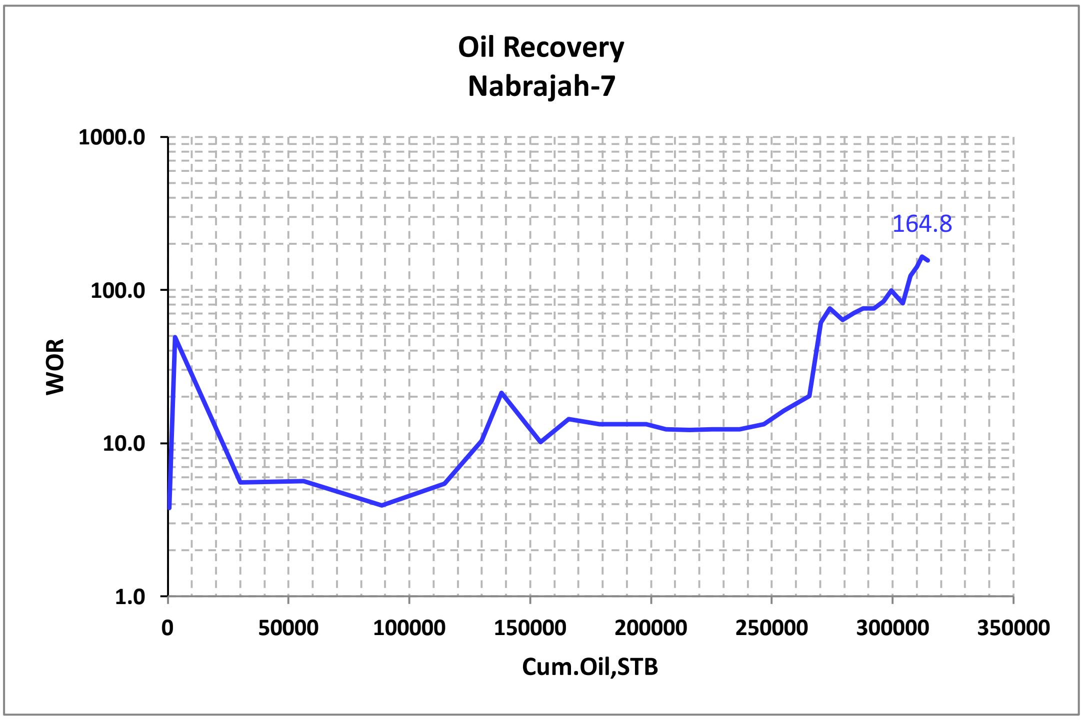


Figure 4.14 Oil Recovery Plot of Nab-7

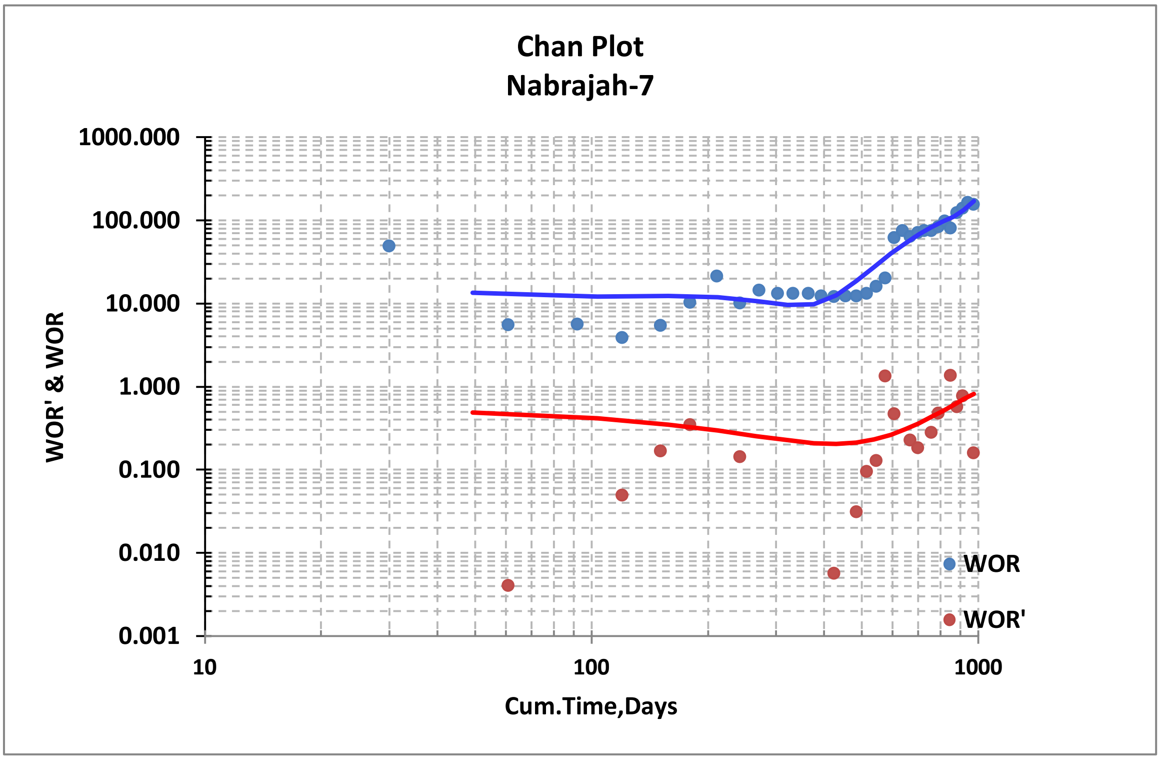


Figure 4.15Chan Plot of Nab-7

4.1.5 Nabrajah-12 well

Nabrajah-12 is well started production on March-2007 Figure 4.16 from S1A- S2 the W.C started to increase and reached 90.2% in less than one year and it's clear on the recovery plot that the well reached its economic limit as presented through Figure 4-17 the diagnostic plot is showing coning and a channeling phenomenon Figure 4-18.

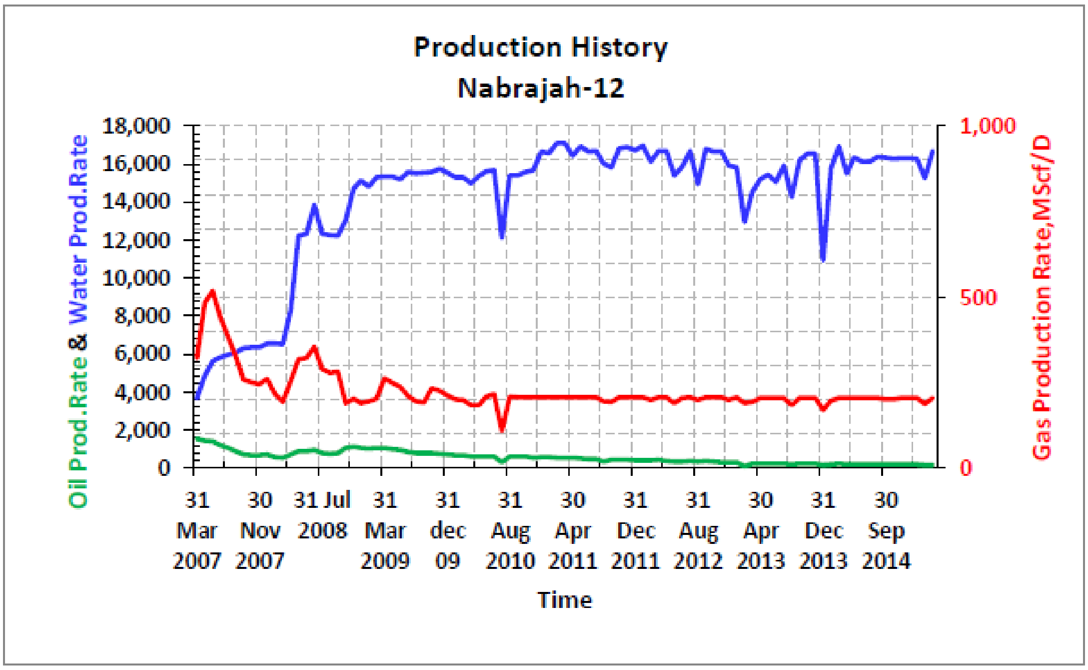


Figure 4.16 Production History of Nab-12

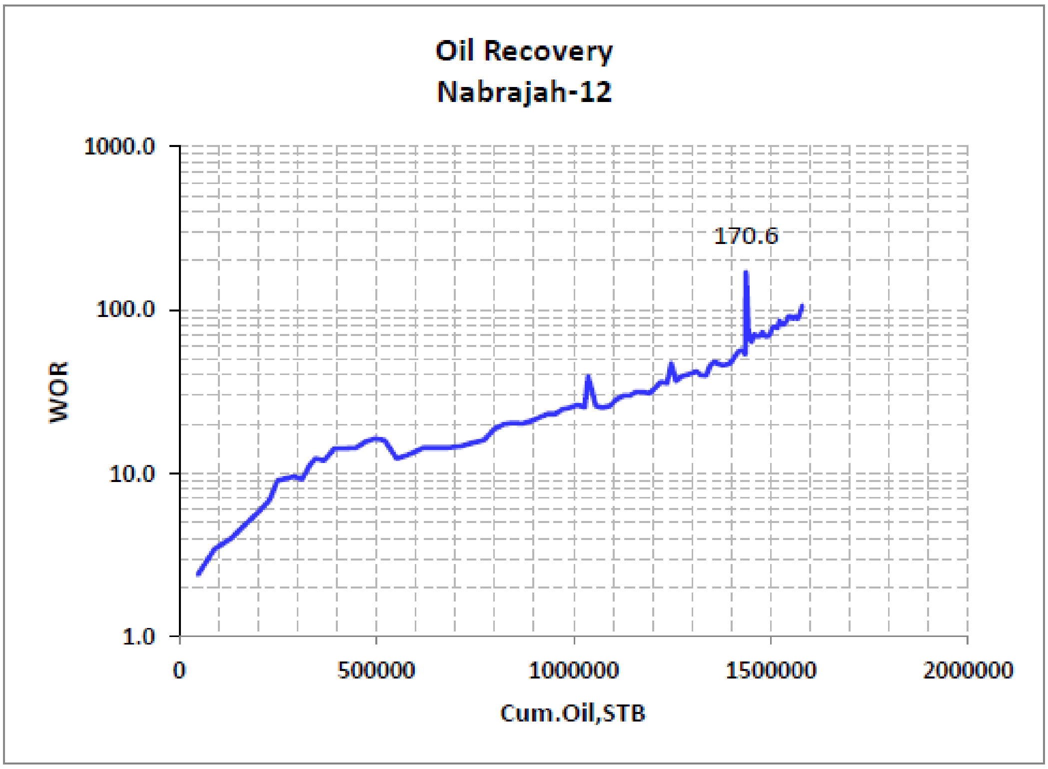


Figure 4.17Oil Recovery of Nab-12

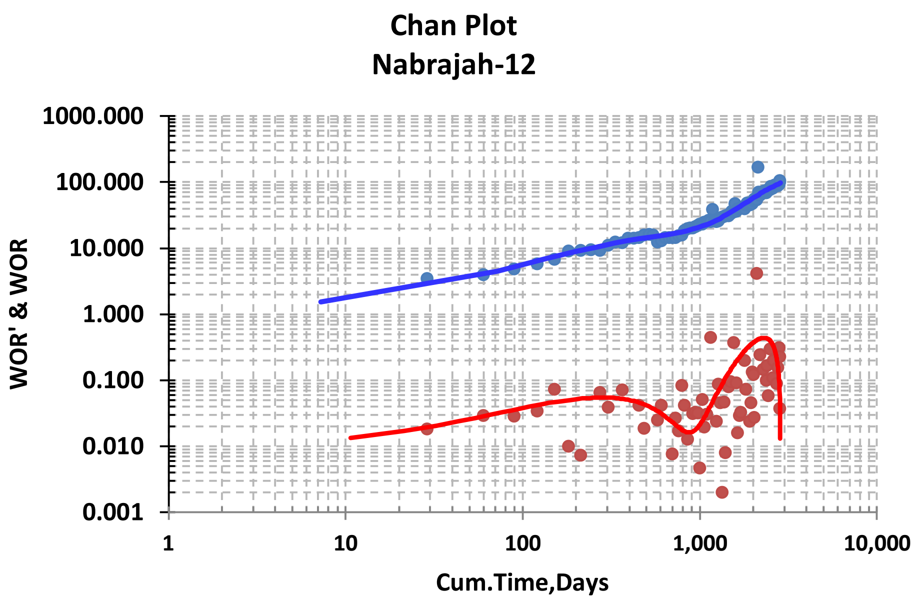


Figure 4.18 Chan Plot of Nab-12

4.1.6 Nabrajah-14 well

Nabrajah-14 well was completed as ESP pump and the total depth reached at 1806 m md brt (1732 m tvd) and completion are illustrated in Wellbore Diagram figure (4.19) .Nabrajah-14 is producing from in the Qishn S2 sandstone reservoir. And put on production in May 2007

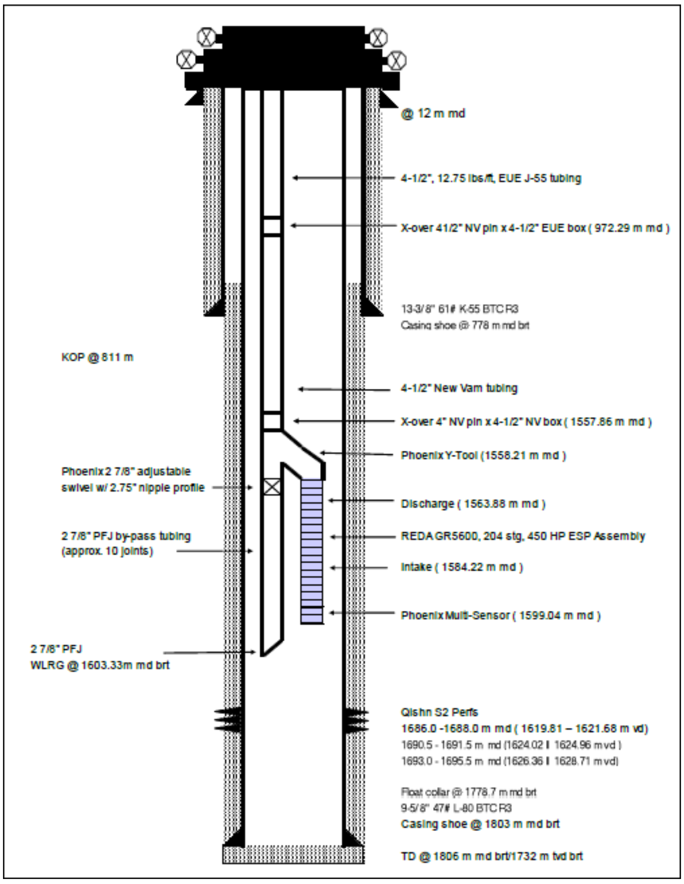


Figure 4.19 Nabrajah-14 Pre-Well Service Wellbore Diagram

Figure 4.20 present production performance and it is noted in this well that the water production increased rapidly since the beginning of production. From oil recovery plot Figure 4.21 its clear on the recovery plot that the well reached its economic limit. and water cut more than 98 %.The diagnostic plot in Figure 4.22 is showing a coning a late channeling

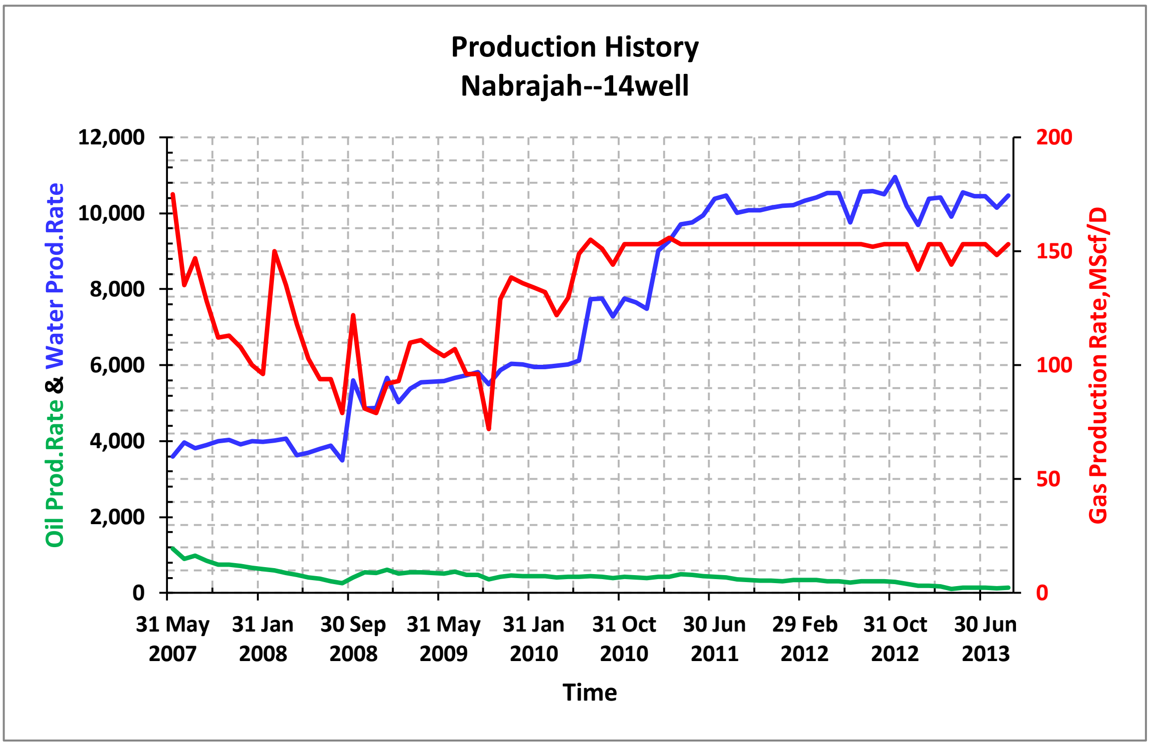


Figure 4.20 Production History of Nab-14

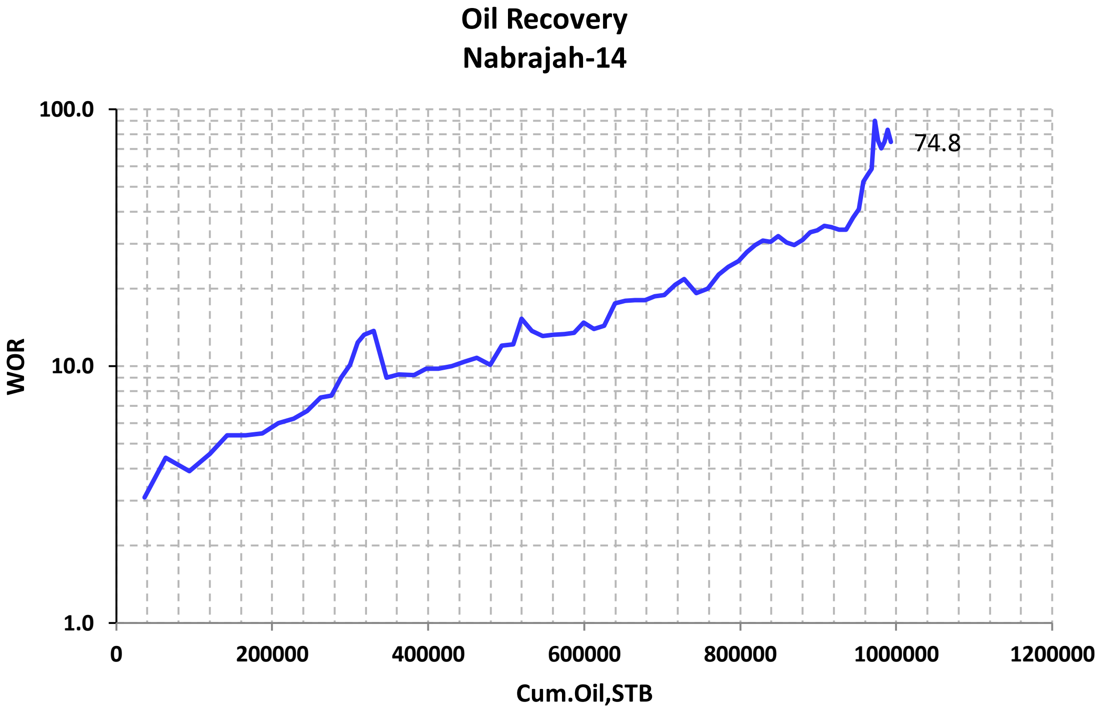


Figure 4.21 Oil Recovery Plot of Nab-14

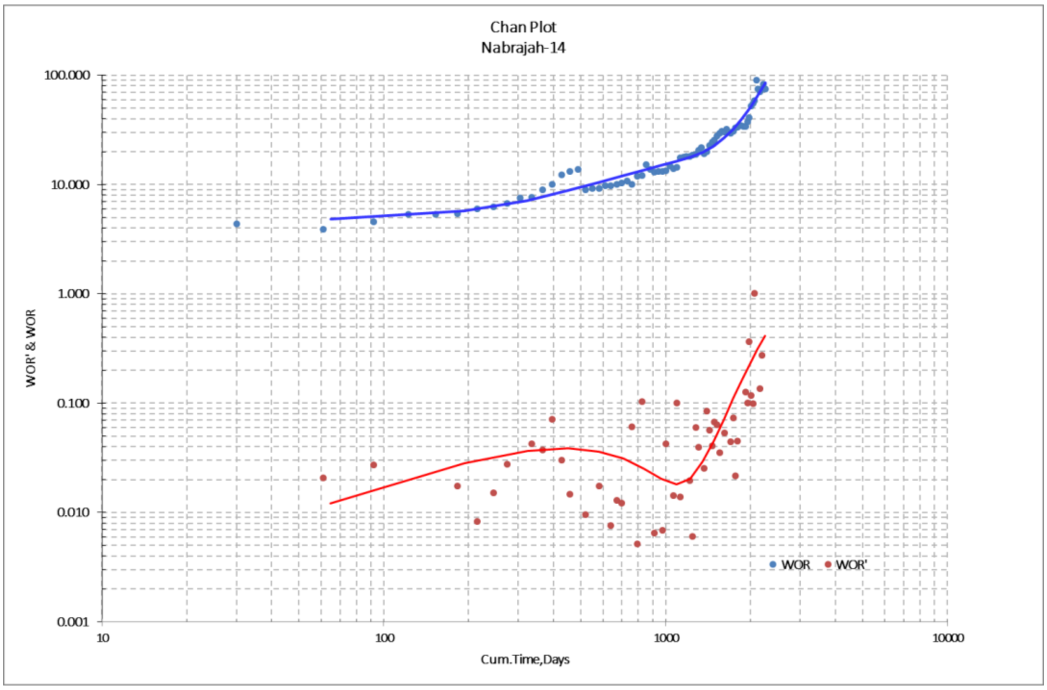


Figure 4.22 Chan Plot of Nab-14

4.1.7 Nabrajah-15 well

Nabrajah-15 well was completed as ESP pump and the total depth and completion are illustrated in Wellbore Diagram figure (4.23) .Nabrajah-1 is producing from Qshin calstic and put on production in Sep. 2007

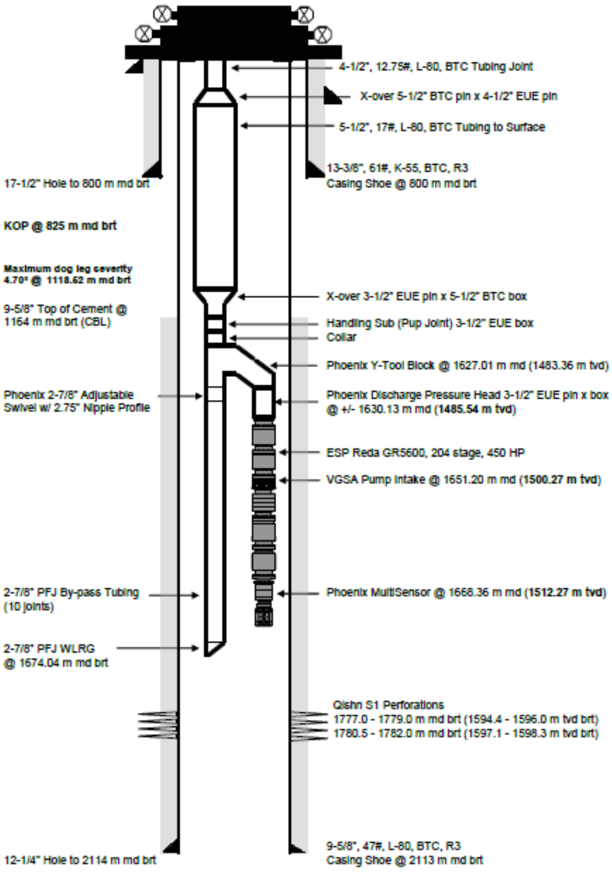


Figure 4 .23 Nabrajah-15 Current Wellbore Schematic

From S1A-S2, therefore the water production increased rapidly as shown in production history plot Figure 4.24. W.C started to increase and reached 79.09% in less than one year and it's clear on the recovery plot that the well reached its economic limit 82 as presented through Figure 4.25. The diagnostic plot is showing a channeling phenomenon Figure 4.26

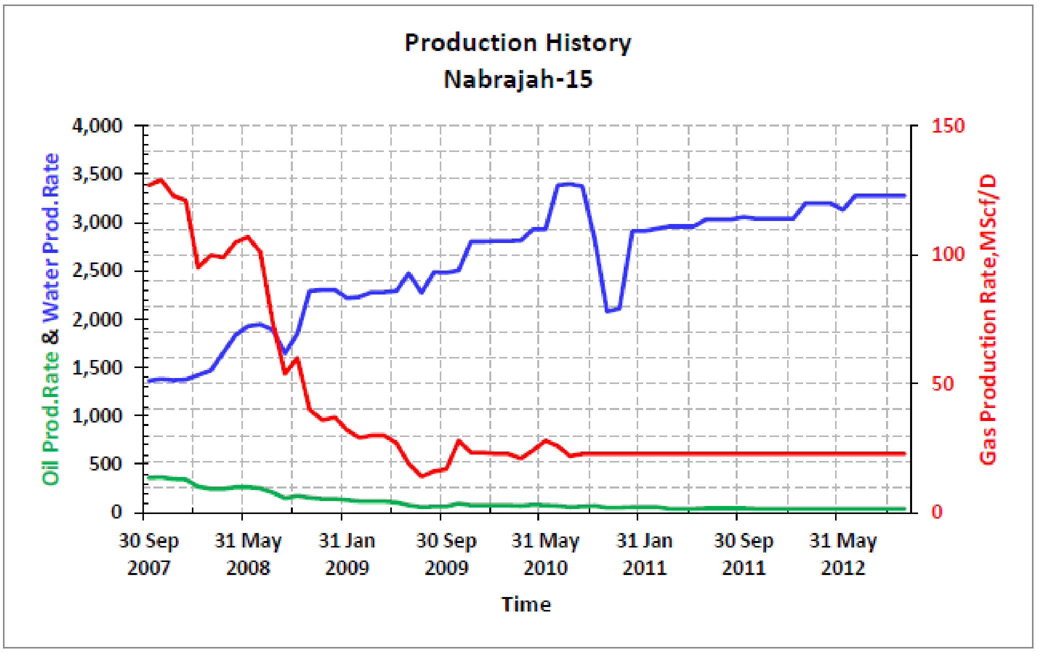


Figure 4.24 Production History Nab-15

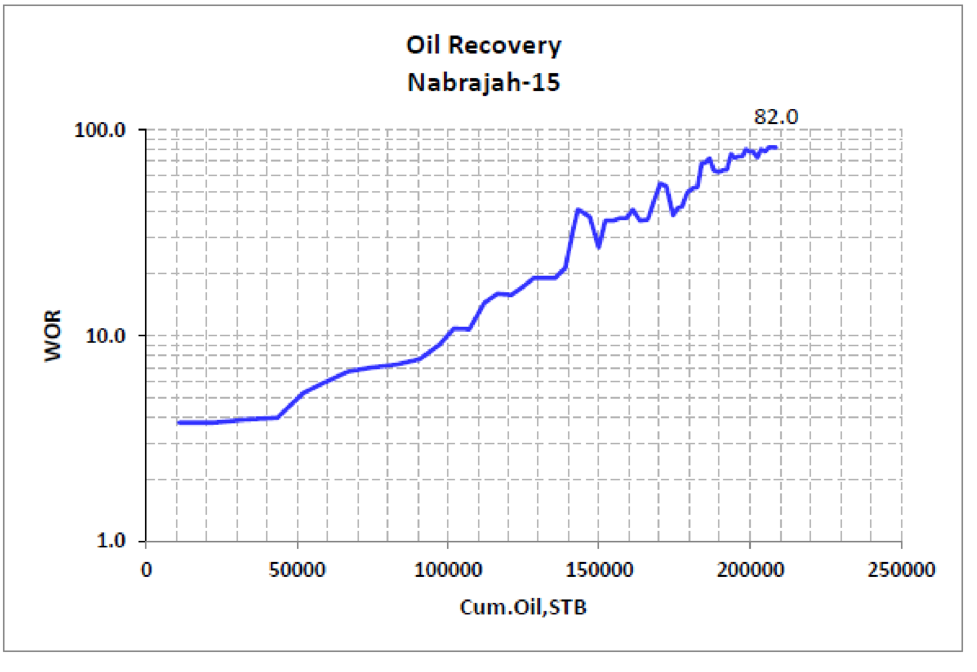


Figure 4.25 Oil Recovery of Nab-15

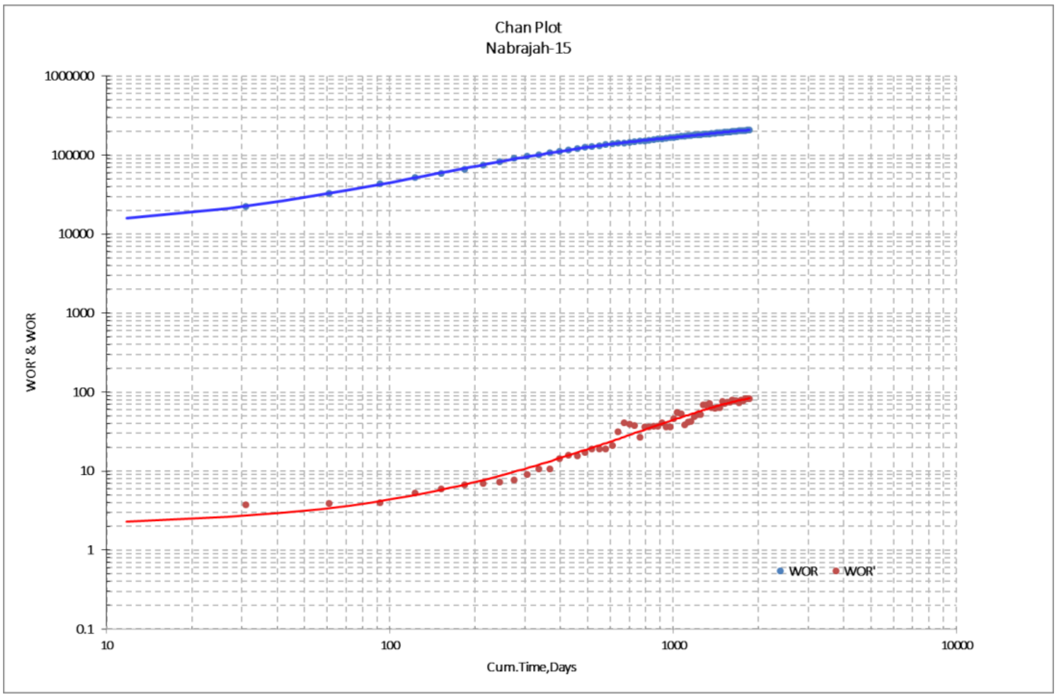


Figure 4.26 Chan Plot of Nab-15

4.1.8 Nabrajah-16 Well

Nabrajah-16 well was completed as ESP pump and the total depth and completion are illustrated in Wellbore Diagram figure (4.27) .Nabrajah-16 is producing from{S1A – S2}. And put on production in Jan 2008

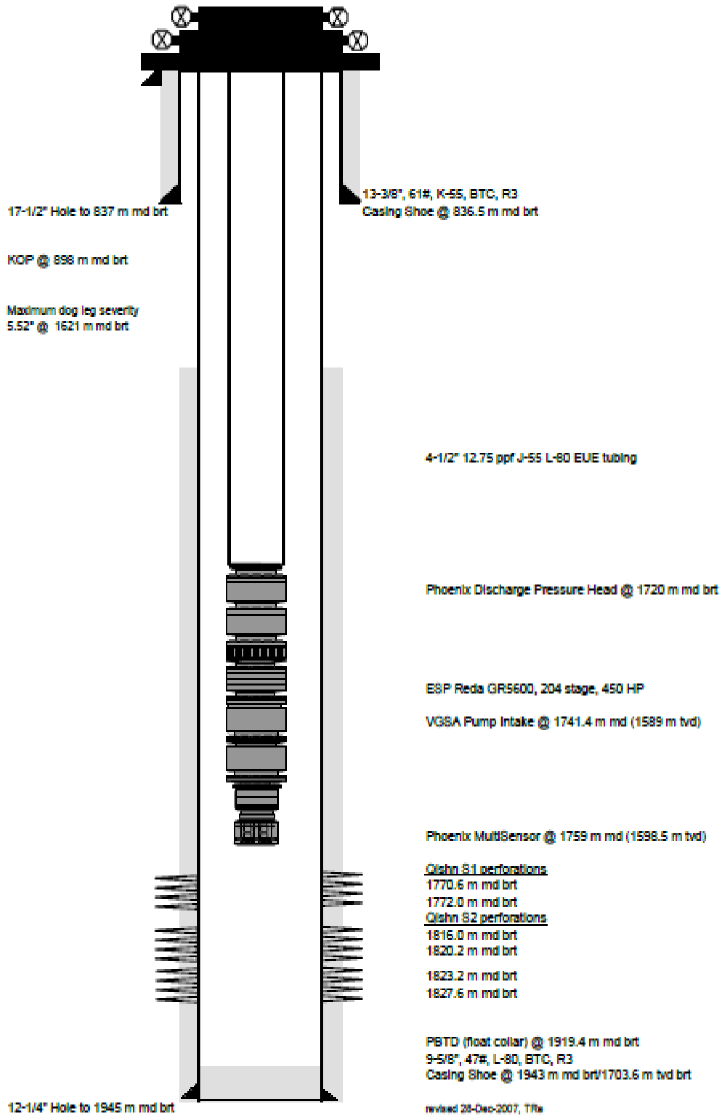


Figure 4.27 Nabrajah-16 Proposed Completion Diagram

Figure 4.28 present production performance and shows increase water production rapidly and reach to more than 80% in about one year. From oil recovery plot Figure 4.29 it is clear noticed that the well reached its economic limit with WOR more than 75 and water cut more than 98 %.The diagnostic plot figure 4.30 showing channeling behavior but it is need confirmation by PLT and other methodology.

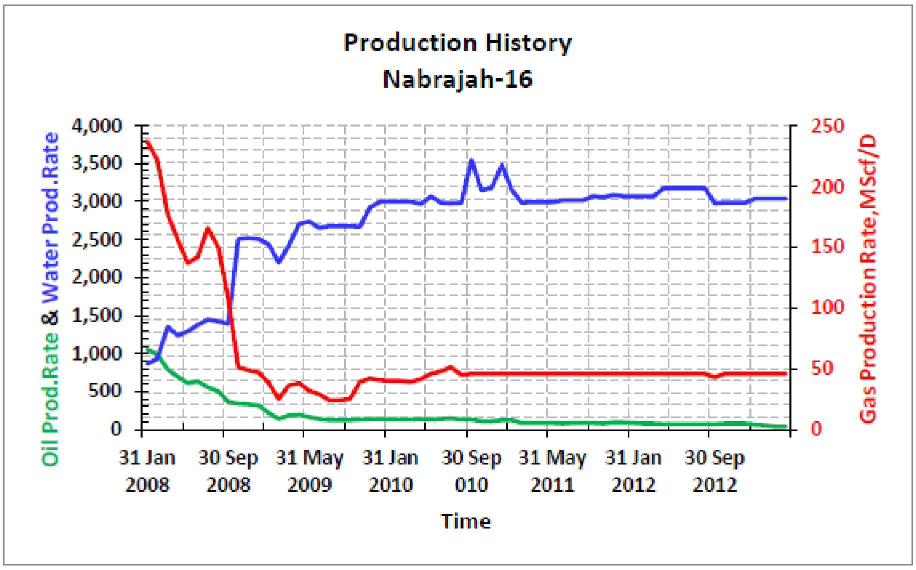


Figure 4.28 Production History of Nab-16

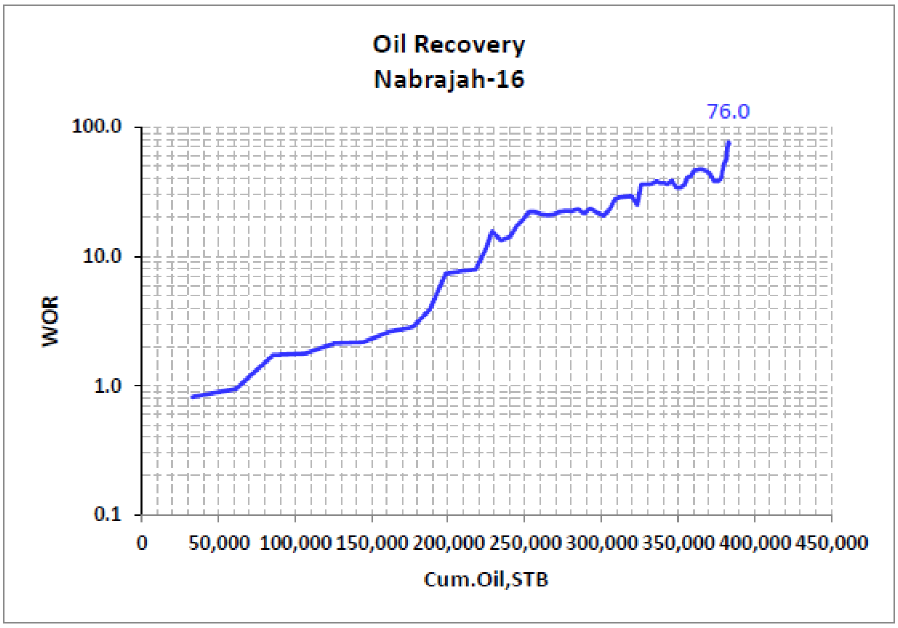


Figure 4.29 Oil Recovery of Nabrajah-16

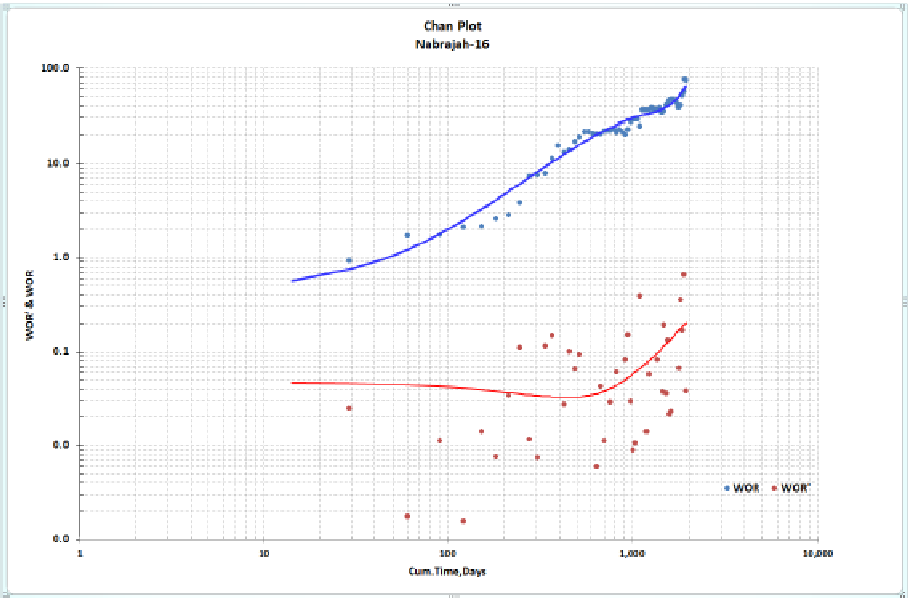


Figure 4.30 Chan Plot of Nab-16

4.1.9 Nabrajah-17 well

Nabrajah-17 well was completed as ESP pump and the total depth and completion are illustrated in Wellbore Diagram figure (4.31) .Nabrajah-17 is producing from Qshin calstic and put on production in Jan 2009.

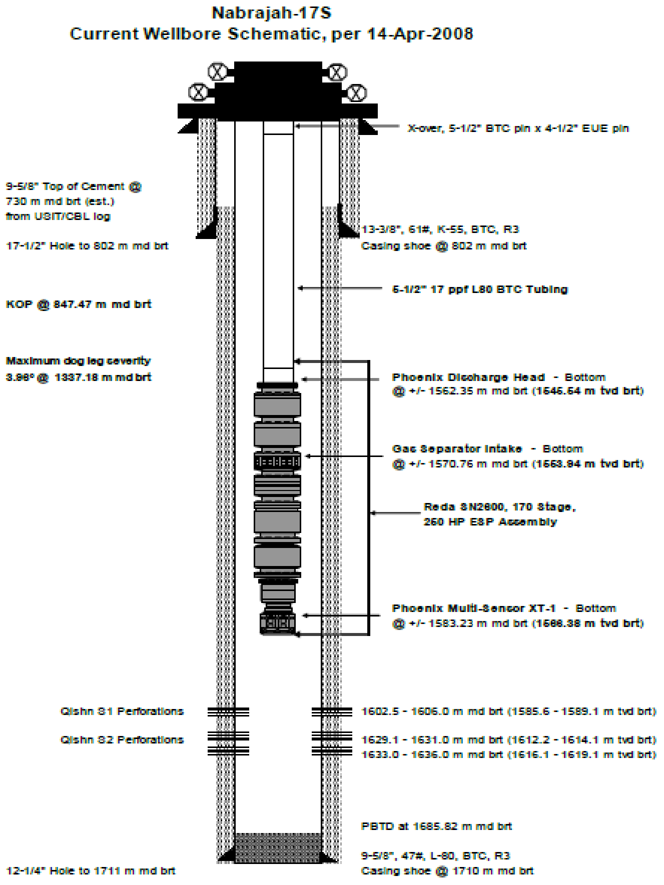


Figure 4.31 Nabrajah-17S Pre-Well Service Wellbore Diagram

Nab-17 is well started production in December-2009 from S1A- S2 Figure 4.32 the W.C reached 88.8% in less than one year and it's clear on the recovery plot that the well reached its economic limit as presented through Figure 4-33 the diagnostic plot is showing a coning and channeling phenomenon Figure 4-34.

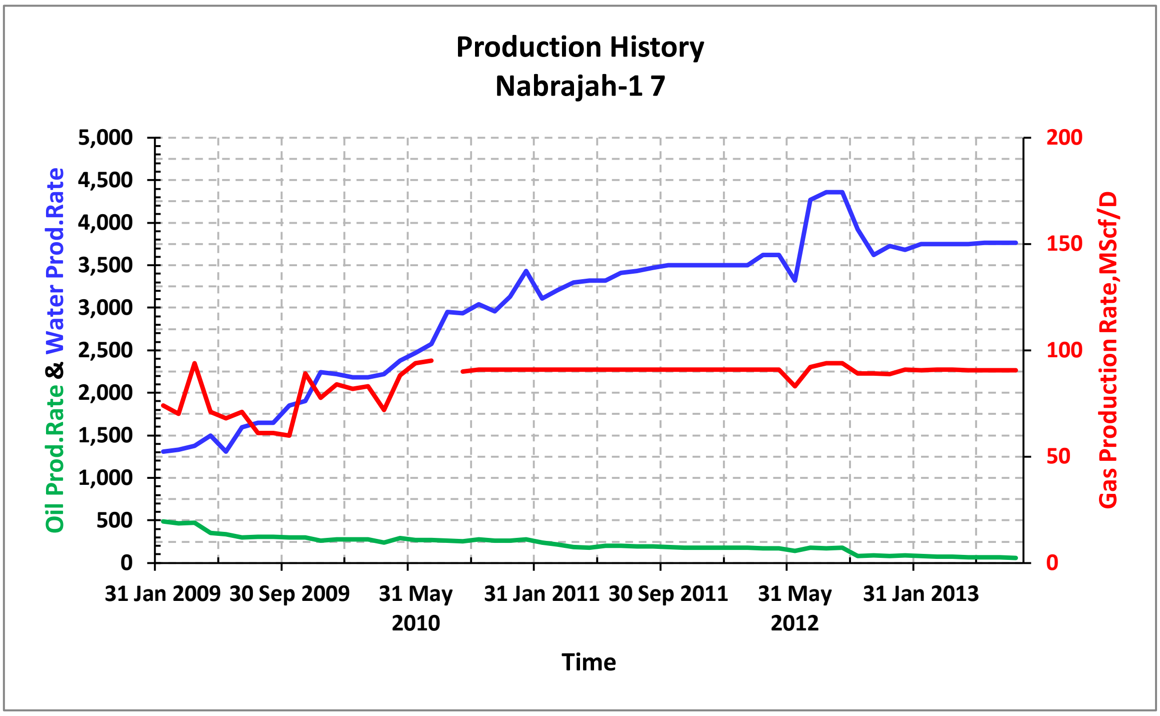


Figure 4.32 Production History of Nab-17

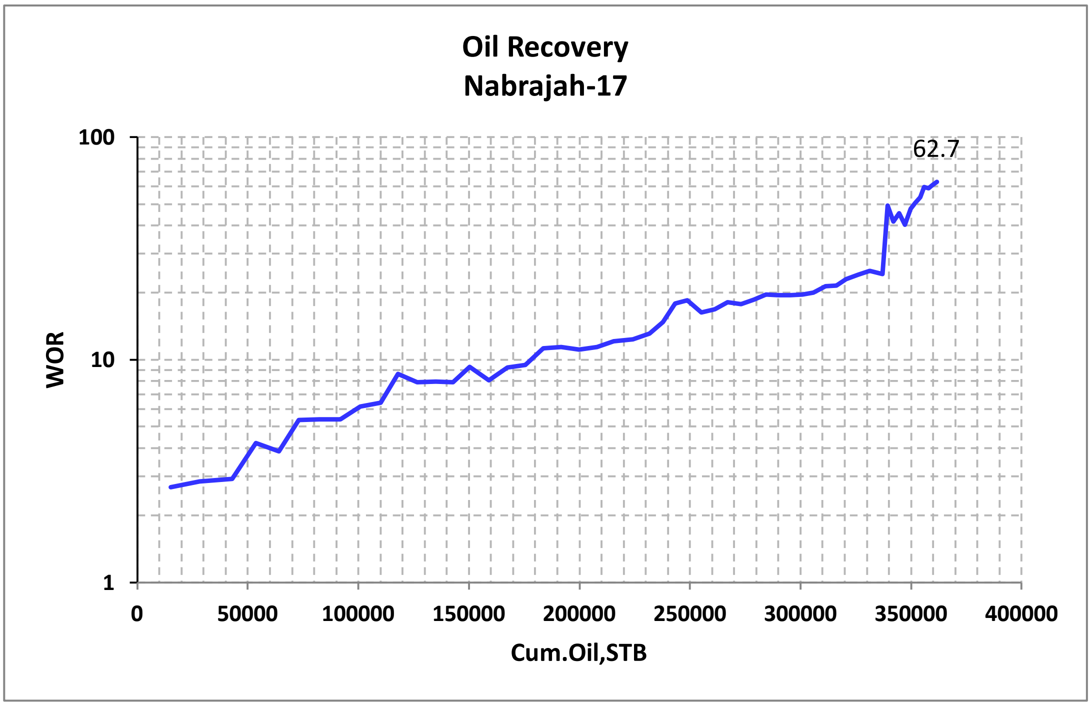


Figure 4.33 Oil Recovery of Nab-17

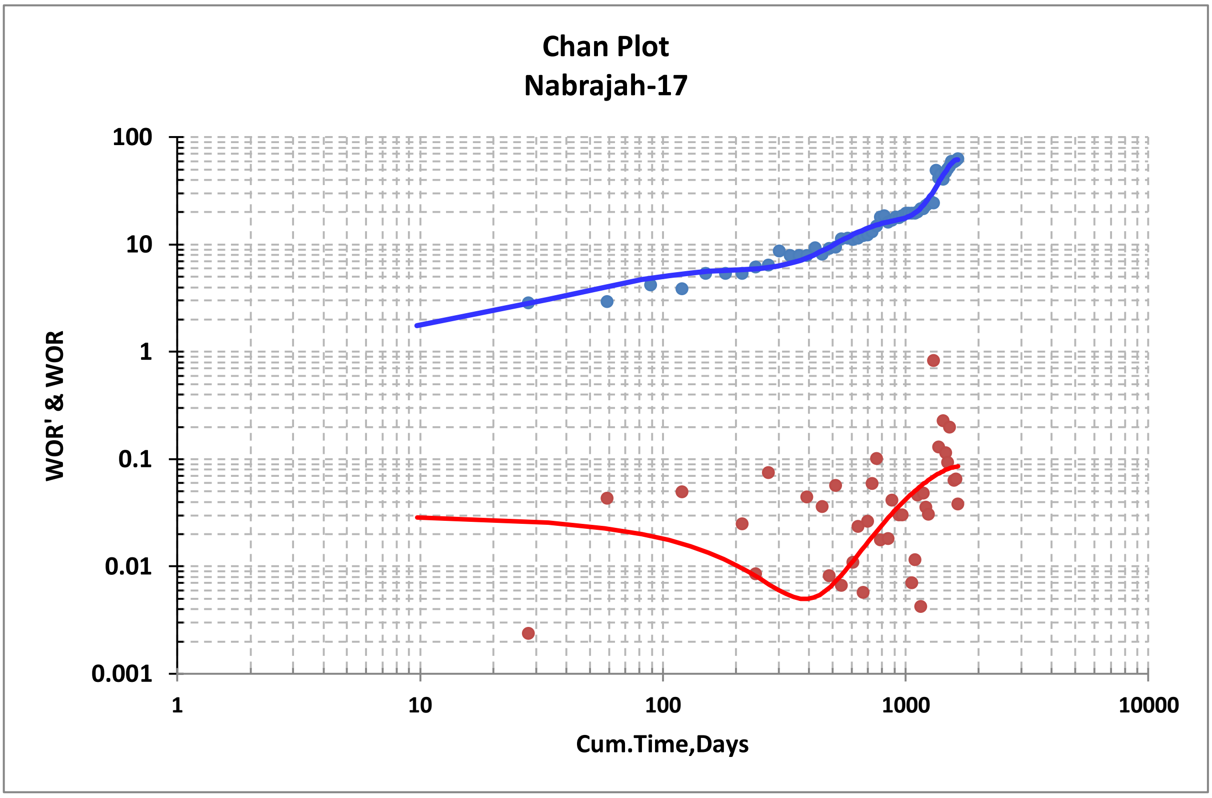


Figure 4.34 Chan Plot of Nab-17

Table4-1 ***summarizes the results of analysis:***

Well Name	Well symbol	Well type	Prod. Zone	The problem	High WOR	The suggest solution
Nabrajah-1	Nab-1	Production well	S1A-S2	**Channeling**	**Yes**	• Plugs • Squeezing (should be select the place of channeling then doing squeezing)
Nabrajah-2	Nab-2	Production well	S1A-S2		Yes	
Nabrajah-3	Nab-3	Production well	S1A-S2		Yes	
Nabrajah-7	Nab-7	Production well	S1A-S2		Yes	
Nabrajah-15	Nab-15	Production well	S1A-S2		Yes	
Nabrajah-16	Nab-16	Production well	S1A-S2		Yes	
Nabrajah-12	Nab-12	Production well	S1A-S2	**Conning and Channeling**	Yes	• If the perforation is near of OWC should be doing squeezing, then perforate upper. • Polymer
Nabrajah-14	Nab-14	Production well	S1A-S2		Yes	
Nabrajah-17	Nab-17	Production well	S1A-S2		Yes	

Chapter Five

5. Conclusion, Recommendations and Limitation

5.1 Conclusion:-

In this study excessive water production in Nabrajah field was analysis and diagnosis, based on the study results the conclusion be summarized as the following:

1. Water production is one of the major technical, environmental, and economical problems associated with oil and gas production in Nabrajah field
2. excessive water production in Nabrajah Field causes numerous economic problems due to decline oil production and dispose water production
3. Chan plot is the main tool used for diagnosis excessive water production in Nabrajah field due to availability of production data only and lack the other data for more diagnosis
4. Candidate wells are classified into two groups based on water production mechanism
5. According to Chan plot ,all the wells in this study are diagnostic a High Conductive layer channeling and some wells Nab-12, Nab-14 and Nab -17showing a conning criteria beside channeling due to the bottom water drive.
6. Chemical or mechanical solutions can be applied to shut off the unwanted water production
7. Mechanical solutions are easier in execution and faster in achieving results and Chemical solutions are considered as permeant solutions and are more risky

5.2 Recommendation

- Convert the excessive water production wells to injection wells recommended
- Production performance well study should be conducted periodically to diagnosis the excessive water production early.
- Due to lack of data, more investigations are needed to confirm the diagnostic result
- Technical and economics study is recommended
- An aquifer study is recommended to determine the direction and strength the water encroachment from the reservoir boundaries
- Petrophysical data should be studied

5.3 Limitation

- Difficulties while gathering the data led to limit the project objectives.
    - Well testing data
    - Production logging tool (PLT)
    - Nodal pressure data
    - Well completion data
- Collection of Data took a lot of time
- Difficult to obtain case studies

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