INJECTIVITY AS A CRITICAL FACTOR IN THE PERFORMANCE OF WATER FLOODING OPERATION

A thesis submitted to the faculty at African University of Science and Technology in partial fulfillment of the requirements for the degree of

Master of Science in Petroleum Engineering

By

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CERTIFICATION

This is to certify that the thesis titled **INJECTIVITY AS A CRITICAL FACTOR IN THE PERFORMANCE OF WATER FLOODING OPERATION"** submitted to the school of post graduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree is a record of original research carried out by Dona Marius KINNOUHEZAN in the Department of Petroleum Engineering.

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A THESIS APPROVED BY THE PETROLEUM ENGINEERING DEPARTMENT

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DEDICATION

This work is dedicated to God Almighty, my provider.

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ABSTRACT

Petroleum exploration, development and operation usually involves large capital investments that requires maximum reserves be recovered, so as to compensate for initial investment efforts. To achieve such a goal, where the natural drive mechanism is inadequate, water can be injected into the reservoir to supplement reservoir energy and improve sweep efficiency in conventional oil fields. The knowledge of key factors that could negatively affect the effectiveness of water injection in oil reservoirs is of great importance. Water injectors experiencing injectivity decline significantly impact recovery. Injectors are susceptible to impairments, which may end in gradual injectivity decline and catastrophic failure. Therefore, robust field management and business planning require an honest understanding of the impairment mechanisms of water injectors. The water-flooding concept depends on several elements that could affect the overall project value; water quality requirements, well placement, inherent formation quality and relative permeability characteristics are some examples. This translates into economic failures, the need for costly workovers and recompletions on a regular basis to facilitate injection operations.

This work is a review of the various factors that can lead to the degradation of water injectivity in a reservoir. The factors include: repetitive shut-in of a well; crossing flow from low permeability layers; unconsolidated reservoir; simultaneous flow of sand with the producing hydrocarbons, production from different sand layers in the same time, water with many chemical contaminants, cold water bank near an injector, weak reservoir formation, presence of clay in reservoir rocks, residual oil around the injector, H2S deposition, bacteria presence, cold water injection, water quality, suspended solids, corrosion products, skim/carryover oil, scales, precipitates, emulsions, oil wet hydrocarbon agglomerates. It also illustrates how application of surveillance and

monitoring principles is vital to understanding reservoir performance and identifying opportunities which will improve ultimate oil recovery.

A comprehensive review of field cases has been carried out, followed by analysis of causation factors. Thereafter, screening criteria was developed and suggestions for improving injectivity are provided.

Most of the water injectivity decline is due to the migration of suspended particles in injection water or the injection water/reservoir fluid incompatibility. Advancements in Science and Technology has resulted in identifying other causation factors, such as sand mobilization (sand particulates separate from rock matrix and move into deep formation), injection pressure, injection rate, water hammer, microbial activities, permeability anisotropy etc.

KEYWORDS: Reservoir performance, water-flood, recovery efficiency, permeability anisotropy.

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Chapter One

Introduction

Multiple processes are used in the E&P industry to recover as much hydrocarbon as possible. An example of this process is natural depletion (primary recovery), water flooding (secondary recovery), and miscible gas recovery (tertiary recovery). The success of the water injection program is critical to the general project economics. Since these field operations are costly, it is important to know the architecture, area, and environment of the reservoir the factors that will affect the success of a water-flooding project, to have a good surveillance program; this would ensure the company goal is achieved. The factors affecting recovery are thus summarized; reservoir conditions, injection/production-well conditions, facilities/operating conditions. The formation damage is expressed as a reduction in permeability around the wellbore, consequences of drilling, completion, injection, or production of that well, which can cause significant decreases in well productivity and loss in production.

It is important to know which factors need more control for injectivity success to have a higher oil recovery, and how surveillance programs should be done during the water flooding process. The purpose of this study is to review different factors that impact water injection and to determine from the key factors that are related to injectivity decline during water-flood for oil recovery.

1-1 Background

The world's economy is run by the technology and mineral wealth of nations. A country's wealth is determined by the ability to effectively create value from the natural resources available, especially the human resources. The world's consumption of limited fossil fuel resources is increasing annually by 3%, with projections in this trend

showing that all known reserves will be exhausted in the next 50 years (Isah, 2014). According to (Callaghan, 1981), any sustained attempt to increase the reserves by even as little as 1% per year ensures an effective eternal supply as the world moves gradually towards renewable energy. For all the resources (solid minerals, hydrocarbon), the extractive industry is the main driver for most of the economies. Among the extractives, crude oil has been a great contributor to many nations' economies and a main source of energy. The look for petroleum and gas has been intense because the exploration and production of petroleum or gas have served because the source of revenue for many countries and continents. For the past decades, fossil fuel represents the main source of fuel for most human transportation, domestic and industrial activities. Over this period, many countries have benefited from crude oil, but the increase in population rates and technological advancements globally has caused a higher energy demand and therefore putting more pressure on the rate of production of petroleum products. All these translate into energy industries desiring an increase in profitability and improved recovery efficiency. It is clear how improving reserves benefit profitability by considering the value of energy.

Only some fraction of the initial hydrocarbon in place in a petroleum reservoir can be recovered by primary production using the reservoir's natural energy drive, depending on the reservoir conditions, as well as how well the field is managed. Although the complete recovery of all the trapped oil is difficult, water injection appears to be an ideal choice to increase recovery. The purpose of secondary oil recovery is to maintain reservoir pressure and displace hydrocarbon around the wellbore. The most common secondary recovery technique is water flooding. Water flooding involves the injection of water into the reservoir to displace the residual oil which could not be produced under the primary recovery towards the producing wells (Willhite, 1986). The injection is carried out by either converting existing producer wells to injectors or drilling infill wells (replacement wells). Therefore, the life and the success of the water flooding project depend on the health of injection wells. Due to heterogeneity in the reservoirs,

the injection well is not able to completely sweep the reservoir; thus, the need for proper water flooding project design is urgent. The process involves selection criteria designs of factors that affect well injectivity during water flooding for the improved oil recovery of water flood systems.

1-2 Problem statement

As the development of a field transitions to secondary/ tertiary mechanisms, the challenges and uncertainties in managing the field for optimal performance, also increase. If these uncertainties are not reduced or managed properly, the field operations may easily become uneconomic. Gulick and McCain (1998) rightly mention that one of the cheapest and most popular methods of restoring and maintaining reservoir energy is to inject water into the reservoir.

Based on the experience of carrying out water flooding in fields all over the world, mostly in the U.S and Canada, various factors have been found to affect flooding operations. According to Thomas et al., (1989), factors such as reservoir geometry, fluid properties, reservoir depth, lithology, fluid saturations, reservoir pay continuity, and primary reservoir drive mechanism need to be understood as they affect the well injectivity and then the success of the water-flooding operation. Water-flooding project highly depend on the well longevity, which failure is called well impairment. Therefore, a prudent way of ensuring economic success must be developed by analyzing the factors and mechanism that can affect the health of a well. At one time, water-flood surveillance included only the aspects of reservoir performance, but with the application of the reservoir management approach, the industries focus moves to include wells, facilities, and operating conditions in the surveillance program (Thakur 1991).

In this thesis, we use the literature available to build criteria that will be used for good well injectivity during water-flooding projects to reduce the well impairment.

The success of an injection well can be measured in terms of its capacity in mitigating negative influences due to reservoir heterogeneity

1-3 Aims of research

The goal of this research is to analyze the factor that can improve hydrocarbon recovery during field life by focusing on injection well performance. On other hand, this study aims to propose a design which will monitor potential injectivity losses caused by certain factors. This study explains the well impairment tolerance of an oil producing reservoir by injection water.

Hence, the aims of this project are to:

- Investigate the factors affecting well injectivity during a water flooding project.
- Provide a logical and technical operations list around the injection well that will add value to oil recovery processes.

1-4 Method used

For this project, a qualitative methodology is used to make an overview of factors that negatively impact well injectivity during water flooding project. Therefore, the research will be descriptive.

To achieve the above aims,

- A review on a water flooding project especially on well injectivity will be made.
- An overview of factors affecting the well injectivity during water flooding project will be studied.
- The critical factor will be identified after analyse each of the above factors.
- Design a selection criterion that an E&P industry will follow with respect to their field characteristics.
- Design an easy and effective surveillance/monitoring program of water-flooding.

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1-5 Scope of work

This study focuses on the factors that negatively impact well injectivity during a water-flooding project. The thesis solely focuses on well injectivity problems related to oil production and design processes for water flooding. This work shall be presented base on the information available in the literature. Necessary solutions are suggested after analysing and discussing the information available.

1-6 Research gap

Though there exists literature on factors affecting well injectivity for water-flooding project activities as well as the reservoir and wells effect of these activities across the world, there are very limited studies that have been conducted on designing the selection criteria for water flooding project success.

Indeed, during the literature search, we found few papers on water injectivity studies among the thousands of technical papers on water flooding. It looks like petroleum engineers paid less attention to water injectors than producers; despite that water flooding has been practiced worldwide for about a century in the industry. One of the

reasons that water injectors were not fully studied might due to the fact that oilfield operators do not have time to conduct water injectivity studies, especially for mature onshore fields with large numbers of wells. Another reason might be that the improvement of water injectors always takes weeks or even months before the increased volumes of injected water show an effect on oil production. The study focuses on factors that impact oil production activities.

1-7 Organization of thesis

The thesis is organized as follows:

- Chapter one introduces the problems that occur during water flooding project execution on well injectivity.
- Chapter two reviews the literature on the water flooding, design, wells, facilities/operating conditions, injection patterns, injectivity, productivity.
- Chapter three presents materials used for the study, the methodology employed in this study.
- In Chapter four, the results of the developed model obtained from our proposed design was presented and briefly discussed.
- Chapter five draws conclusions based on the results from chapter four and some useful recommendations were made for further studies

Chapter Two

Literature review

2-1 Introduction

A number of researchers from academia, oil and gas industry around the world have impacted the understanding of factors that affect water flooding projects. Their works have brought to light some natural (reservoir character) and manmade (well and operating conditions) factors that have negative or positive impacts on water flooding, which is one of processes used in the oil and gas industry to enhance hydrocarbons recovery. A drastic decline in injectivity is a disaster that regularly occurs in offshore and onshore water-flooding projects. Also during produced water re-injection in oil reservoirs. The reason for this decline in injectivity has been attributed to the formation of internal and external cakes by solid and liquid particles containing in the injected aqueous suspension. All literatures have helped in the design of appropriate criteria that can be used to handle project management and recovery issues regarding oil and gas E&P activities in any country.

2-2 Water flooding

Via primary recovery techniques, most of the hydrocarbons originally in place are not recovered. Water-flooding began in 1944 with a pilot flood developed on 20-acre five-spot patterns. Expansion to a fully developed stage occurred between the years, 1948-50. Water-flooding may be a secondary recovery method during which water is injected into the reservoir formation to displace residual oil. During the process, the water from the injection wells sweeps the displaced oil to adjacent production wells. Permeability variation, or similar conditions and inefficient recovery are potential

problems associated with water-flood techniques, affecting fluid transport within the reservoir and creating early water breakthrough that may cause production and surface processing problems (Schlumberger).

Secondary recovery technique (water-flooding) is used to maintain the reservoir pressure as well as fluid displacement to improve recovery of hydrocarbons (Ahmed, 2006).

The most used secondary recovery technique is water flooding, and for many reasons, water flooding has lower operating costs compared to other fluid injection techniques because water is cheaper and readily available compared to other injection fluids.

According to (Civan F. , 2007)

One of the economically viable techniques to recover additional oil is water-flooding.

Water-flooding is a secondary recovery process in which water compatible with the reservoir is injected into the reservoir to displace the residual oil. Water-flooding is more commonly employed than immiscible gas injection (other secondary recovery process) because water (injectant), is relatively inexpensive compared to gas (injectant). Water-flooding reduces the rate of reservoir pressure decline during production, and sweeps the oil towards the producers, thus increasing oil production (Abdel-Kareeem A. M., 2009). Since water-flooding is a relatively inexpensive and mature technology, several potential problems may arise during the process. Such problems are inefficient recovery due to varying permeability's and anisotropy, reservoir heterogeneities affecting fluid transport within the reservoir, early water breakthrough that may cause production and surface processing problems, etc. (Abdel-Kareeem A. M., 2009).

Water-flooding involves injecting water into selected wells while producing from the surrounding wells. This process displaces oil from the injector to the producer, while maintaining reservoir pressure. In a relatively homogeneous formation where high

permeability channels are not encountered, water is an efficient agent for displacing light or medium gravity oil (Abdus Satter, 2016).

Water-flooding is a process used to inject water into an oil-bearing reservoir for pressure maintenance, as well as displacing and producing incremental oil after or before the field has reached it economic production limit. During the process, oil and free gas are displaced by water. In water-flooding, water is injected into one or more injection wells while the oil is produced from surrounding producing wells spaced according to the desired patterns (Wikipedia).

Reduction of the rate of reservoir pressure decline during production and increase in the reservoir pressures with continued injection are the two major effects of water-flooding. During the process, the water injected into the reservoir sweeps the oil towards the producers and then increases oil production and consequently, cumulative oil production (Abdel-Kareeem A. M., 2009).

Water-flooding is that the use of water injection to extend production from oil reservoirs. This process known to follow primary production, which uses the reservoir's natural drive mechanism (fluid and rock expansion, aquifer influx, solution gas drive, and gravity drainage) to produce oil. The principal reason for water-flooding an oil reservoir is to increase the oil-production rate and ultimately, the oil recovery. By voidage replacement, the reservoir pressure is increased to its initial level but the efficiency of this displacement depends on many factors such as oil viscosity and rock characteristics (Petrowiki).

Water-flooding has since increased in use because:

- Water is inexpensive

- Water generally is available in large quantities from nearby streams, rivers, or oceans, or from wells drilled into shallower or deeper subsurface aquifers

The success of a water flood operation depends on the extent and quality of the project surveillance techniques. The mobility ratio of displacing fluid to the displaced fluid is good for efficient fluid displacement, but due to the early water breakthrough, change in permeability, and reservoir heterogeneities, water-flooding project faces some production and surface processing challenges (Ahmed, 2006).

Numerous factors such as reservoir geometry, lithology, porosity, permeability, reservoir depth, continuity of rock properties, fluid saturations/distributions, fluid properties, relative permeability, primary drive mechanisms, reservoir uniformity and pay continuity affects water-flooding (Ahmed, 2006).

One of the major oil production techniques is water-flooding, which is estimated to help produce half of produced oil. It is carried out to achieve the following goals:

- Disposal of connate water after separation from hydrocarbons.
- Creation of a water-pressure regime for displacing hydrocarbons from injection wells to producing wells (Vladimir Vishnyakov, 2020). The following criteria be used when water flooding is being considered:

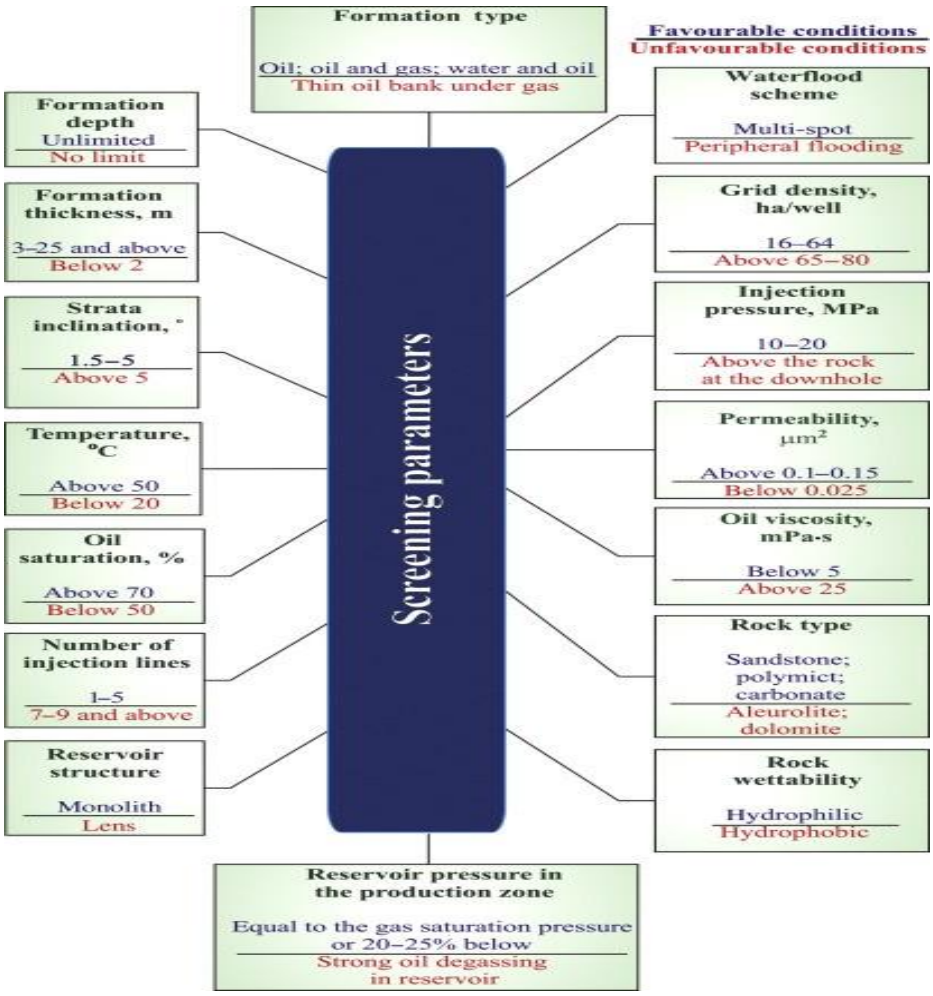

Figure 1: water-flooding application criteria

2-3 Types of floods patterns

Several factors such as reservoir heterogeneities, formation fracture; injectants availability; flood life; well spacing, productivities, and injectivities must be considered during water-flooding pattern selection. Two types of water-flooding are in common use; patterned water-flooding and non-patterned water-flooding.

Irregular well placement and peripheral water flooding are classified as non-patterned water flooding while patterned water flooding are regular 4-spot and skewed 4-spot, 5-spot, 7-spot, 9-spot, direct line drive and staggered line drive patterns.

Figure 2 shows various patterns used in water flooding. In this illustration, there are two types of each pattern; the normal pattern and the inverted pattern types. In the normal pattern type, for a set of injectors and producers, there are several injectors and one producer. In the inverted pattern type, for each set of injectors and producers, there are several producers and one injector. This means that each of the patterns shown in Figure 2 has the normal and the inverted pattern types.

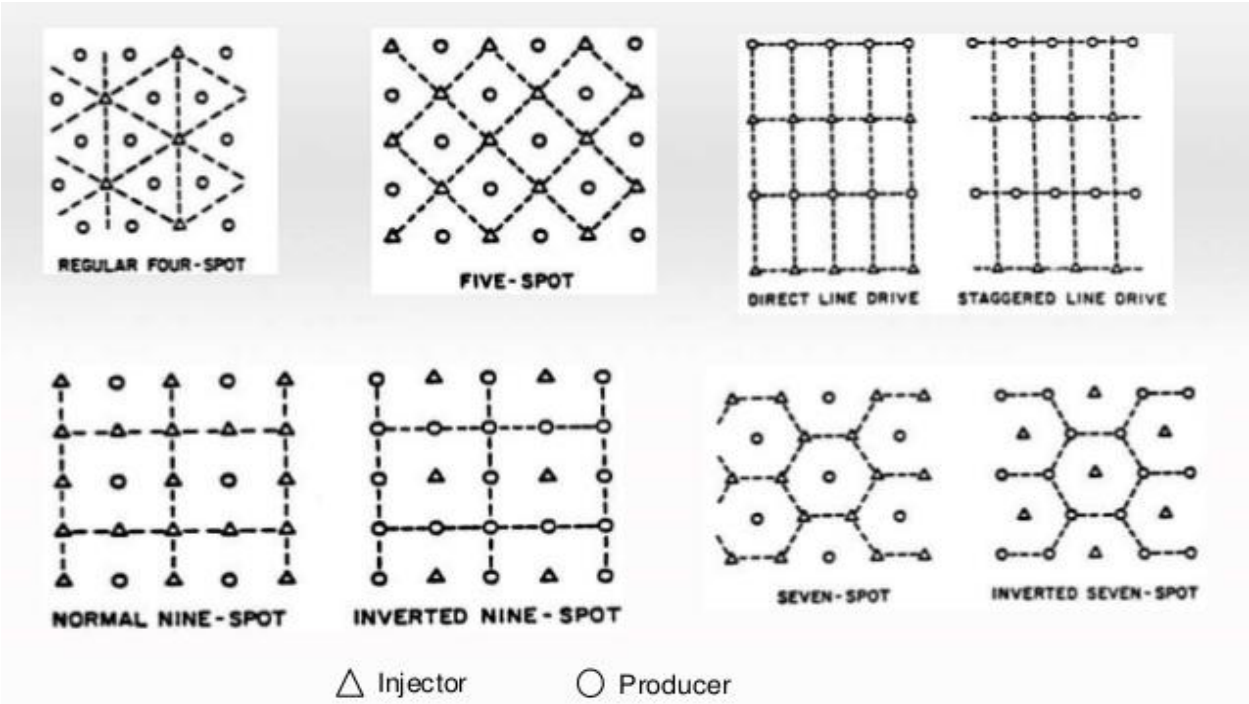

Figure 2: Normal and inverted pattern

Another type of flooding that can be utilized depending on reservoir geometry and properties is the crestal and basal pattern. This involves perforating the injector wells up-structure (for gas injection) or down-structure (for water injection) relative to the producer wells, thus utilizing the effect of gravity segregation in the displacement process (Ahmed, 2006).

Water-flood optimization attempts to achieve a balance between injector and producer wells within a pattern, to minimize oil migration to adjacent patterns, minimize loss of hydrocarbons into the formation and maximize the use of available injection water to

improve oil recovery. The success of a water-flood project can be predicted from a better selection of water-flood patterns. The first objective is to recover the same volume of hydrocarbon equivalent to the volume of water injected and minimize oil migration to adjacent patterns and loss into the formation. Water-flooding in older fields was done using irregular patterns; however, recent water-flood projects involve regular patterns. These regular patterns involve a specific arrangement of injectors and producers to maximize recovery from the reservoir. There are several regular patterns used in water-flooding and optimization is required to select the best pattern that would efficiently and economically produce any reservoir.

Well spacing is of vital importance in oil and gas industry. The well itself plays a vital role during the development of the petroleum asset in purpose to maximize recovery. However, determination of appropriate well spacing for max economic oil recovery has been a sophisticated and controversial issue in oil field development. Various studies have shown a slim relation between well spacing and recovery (John, 2010).

According to Crawford in 1960, assuming a unit mobility ratio, steady-state condition, homogeneous and uniform reservoir, and ignoring capillary and gravity effects, the efficiencies were 45% to 90% for 9-spot, 72% for 5-spot, and 56% for direct line drive pattern. By reviewing these assumptions, it appear that these theoretical results may have limited application to water flooding in depleted reservoirs because it is known that the mobility rate is not unity, water flooding results in the creation of a flooded zone and an oil bank, oil is displaced in a transient potential field, gravitation and heterogeneities are important.

Water-flood recovery is sensitive to heterogeneity, mobility ratios and well configuration. During water-flooding, the effect of heterogeneity becomes less severe upon reducing the well spacing as the mobilized oil has to travel a relatively shorter distance to the nearest producing well (Singhal, 2004)

The key objective of selecting a flooding pattern is to maximize the contact between the injection fluid and the hydrocarbon system, hence improving oil recovery and economics of the project. This is a critical step and can be achieved by either drilling infill injector wells or converting existing production wells to injectors.

A wide sort of flood patterns (injection-production well arrangement) are studied with efficiencies for various confined well patterns at breakthrough, indicating the effect of the pattern.

2-4 Reservoir performance

Reservoir pressures, injection and production rates, fluid volumes, WOR/GOR's, and fluid samples require constant surveillance (Talash A. W., 1988).

Reservoir heterogeneity strongly influences the flow pattern inside the reservoir; consequently, it influences the production of hydrocarbons and water (Guan, 2004).

The understanding of reservoir rocks is the most important keys to evaluating a field water-flooding project. It requires knowledge of the depositional environment at the pore and reservoir levels, the diagenetic history of the reservoir rocks, the structure and faulting of the reservoir, the water/oil/rock characteristics, residual oil saturation to water-flooding and the oil relative permeability at higher water saturations. All oil reservoirs are heterogeneous rock formations, so it is necessary to determine the nature and degree of heterogeneities that exist in a particular oil field. Heterogeneities include;

- Shale, anhydrite that partly or totally separate the porous and permeable reservoir layers.

- Interbedded hydrocarbon-bearing layers that have important different rock qualities (sandstones or carbonates).

- Change in continuity, interconnection, and areal extent of porous and permeable layers throughout the reservoir.

- Directional permeability trends created by the depositional environment or by diagenetic changes.

- Fracture trends developed by the regional tectonic stresses on the rock and the effects of burial and uplift on the particular rock layer.

- Fault trends that affect the connection of one part of an oil reservoir to adjacent areas.

Another geological consideration that affects water-flood performance is the reservoir structure. The dipping at various angles is due to the reservoir structure, which in combination with gravity and the oil/brine density difference affects the relative vertical and horizontal flow behaviors.

(Talash A. , 1988), (Strange, 1982) and (Thakur, 1991) showed clearly that reservoir characterization is one of the most important factors in surveillance and success of water-flood. According to them, a detailed reservoir characterization enables accurate water-flood monitoring and real-time decision making.

2-5 Water-flood design

Many phases are observed during a water-flood design. Water-flooding has its own challenges starting from design to execution and to surveillance. consistent with (Talash, 1982)

an important key to a successful water-flooding project may be a well-planned and well-executed program of surveillance and monitoring. it's important to style the whole parameters that form the injection system to possess a far better injection profiles.

It is of prime importance to inject water that contains carefully controlled levels of oxygen, suspended solids, and bacteria. Injection of poor-quality water, which is usually the results of poor design or improper maintenance, can cause plugging (e.g., suspended solids, carbonate scale, and bacteria) and corrosion. All of those components are often minimized by careful plant design and operation and monitoring of water quality (Chang C. K., 1985). To realize these requirements, the plant has got to operate

under steady-state conditions (avoidance of huge changes in flow rate), which cause surging and imbalance within the treatment system. To realize high-quality water continuously, the general water injection plant must be separated into water treatment plant, included all equipment from the seawater lift pumps to the outlet of the vacuum tower and distribution plant (pumping, distribution, and injection).

2-6 Wells

The key objective of the well design is to specify the tubing size reference to well injectivity which may be predicted by the utilization of software. Numerous aspects of the planning and operation of water-injection wells are critical. One critical aspect of water-injection-well design and operation is that the allocation of water to region which will be water-flooded. the general water-flood is firstly controlled at the injection wells, not at the assembly wells; therefore it's important to allocate injection water as desired to the varied water-flooded intervals. In practice, the water-injection wells are drilled as new wells while the assembly wells are people who are already producing from the oil field. For water-flooding, producers should be completed within the same intervals during which the injection wells are completed.

Well injectivity decline during water injection has been widely reported within the literature. The phenomenon is attributed to solid and liquid particles contains within the injected water after treatment. The particles are captured by porous media, causing permeability reduction and forming a lower permeability external filter cake, which contribute to the expansion of skin think about injection wells (Saripalli et al., Rouseau et al., Sharma et al, 2000). Injector performance and longevity are some challenges faced during water-flooding projects. It are often mitigated by:

- Having an honest understanding of impairment (when the injector begins to under-perform) mechanisms

- Predicting injector performance and longevity

According to the study of Barkman and Davidson in 1972, the well impairment caused by suspended solids are often classified into the subsequent four mechanisms: wellbore narrowing, particle invasion, wellbore refill and perforation plugging.

There are four sorts of wells requiring surveillance: production/injection, water-supply and water-disposal wells (Talash A. W., 1988).

In case of contour flooding implementation scheme, the injection wells are located along the perimeter of the reservoir. within the anticlinal reservoir (See Fig. 3), the injection wells are placed in order that water can enter the aquifer, or within the area near the water-oil contact, displacing oil into production wells located within the upper a part of the reservoir. For the monoclinal reservoir (See Fig. 4), the injection wells are located below the water-oil contact to require advantage of gravity.

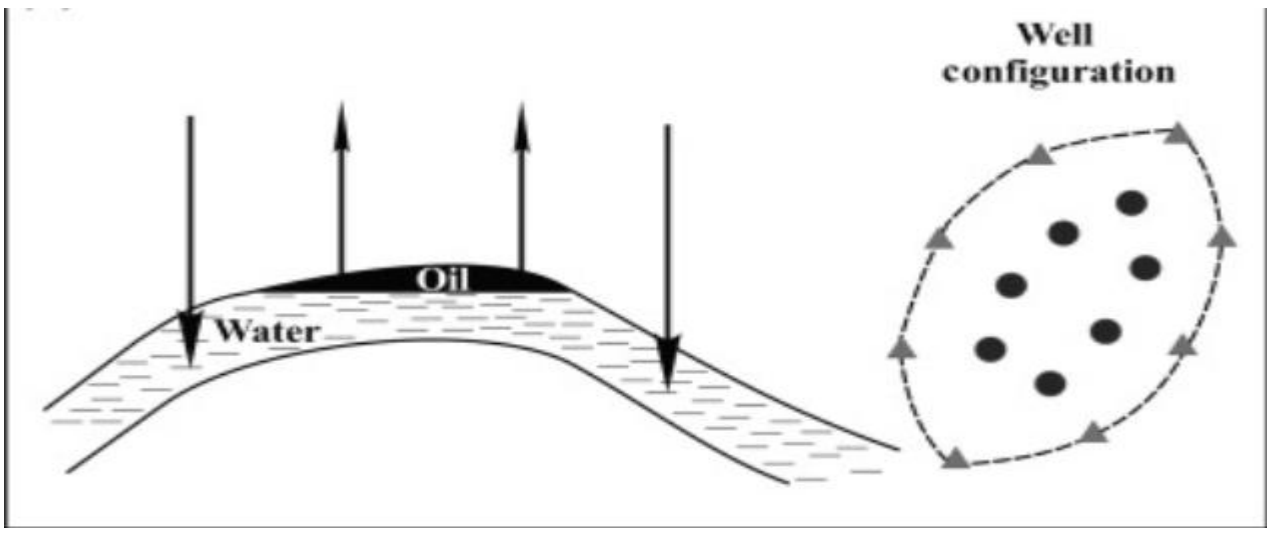

Figure 3: anticlinal reservoir scenario

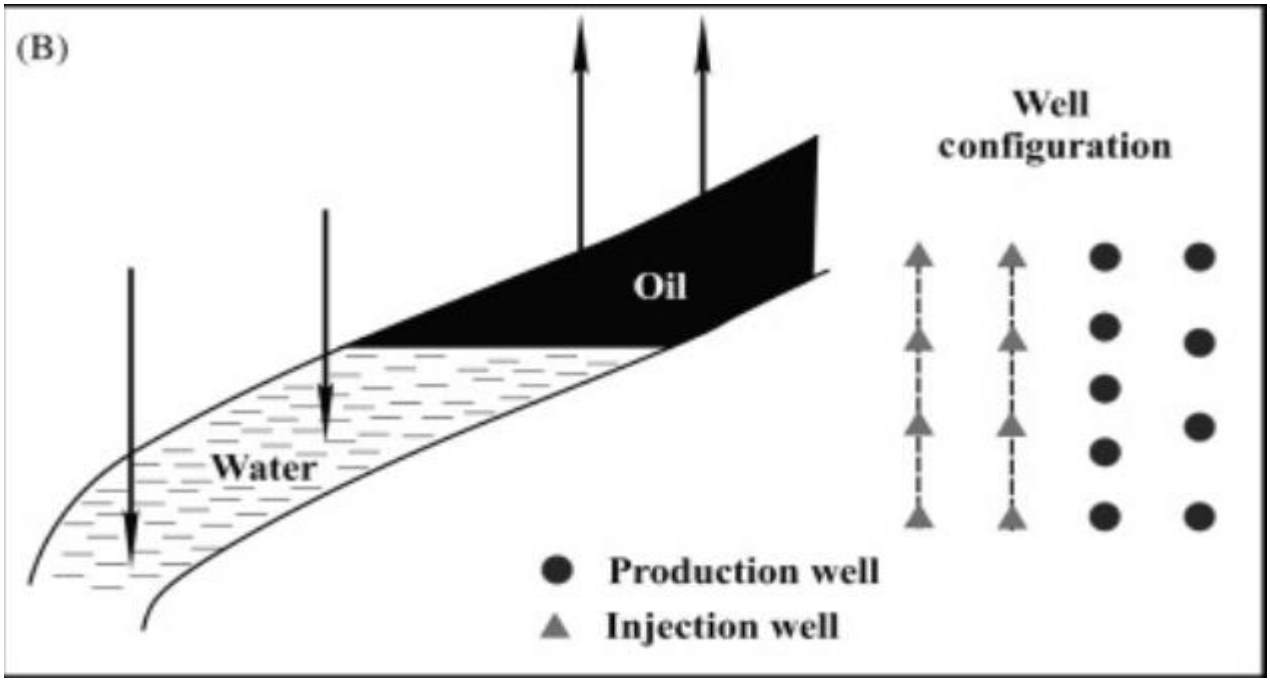

Figure 4: Monoclinal reservoir scenario

In arch flooding (reservoirs with an incidence angle), injection wells are positioned in the dome for efficient displacement of oil. In all cases, the areal configuration of the injection wells and the distance between the wells depend on several factors, which include rock and fluid characteristics, reservoir heterogeneity, optimal injection pressure, planned development period and economy.

2-7 Productivity index/ Injectivity index (PI or J or II)

It is a mathematical means of expressing the power of a reservoir to deliver fluids to the wellbore. It is usually stated because the volume delivered per psi of drawdown at the sand face (bbl/d/psi). (Schlumberger)

According to Darcy's law, water injection rate is proportional to the pressure drop between the well and reservoir. The proportionality coefficient is defined as well injectivity index (II). The normalized reciprocal to the injectivity index is called the impedance (J), which is used to describe the injectivity decline (Civan F. , 2007). The PI is defined because the flow per unit pressure drop and is a sign of the assembly

potential of a well. It is also the measure of the ability of a well to produce hydrocarbons at a commercial rate. Its estimations one among the required and really important steps once the assembly from an oil or well starts. It tells the operator about the performance of an oil well. (Wikipetro)

It is the ratio of total flow of the liquid to the drawdown pressure. II is directly proportional to permeability and can be written in the form of equation as:

$$\text{PI} = \frac{q}{Pinj - Pres} = \frac{2\pi Kh}{\mu(ln\left(\frac{re}{rw}\right) + S)}$$

J = Qo / Pr – Pwf = Qo / delta P

Hall Integral (HI) slope provides an indication about injectivity and Derivative Hall Integral (DHI) magnifies its behavior (See Figure 5):

- constant slope represents constant injectivity,
- deviation upward represents decreasing injectivity (in red)
- And deviation downward represents increasing injectivity (in green).

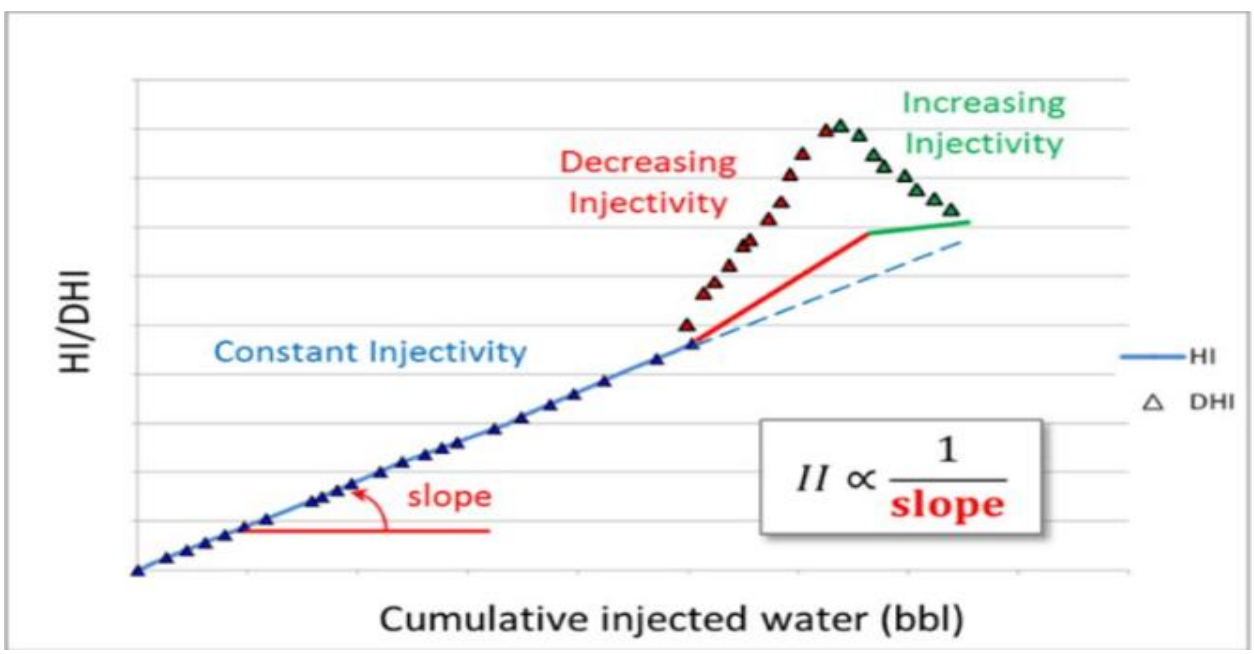

Figure 5: Hall integral and Derivative Hall Integral

The water injectivity is a very complicated issue and it depends on the combination effect of the specific reservoir rock properties, interaction between injected water and formation water, reservoir rocks and total pressure drops. Sand production, the amount of suspended solids, wax precipitation, scales, corrosions, as well as induced fractures can significantly influence the injectivity of an injector (L. Guan, 2005). The brine used for water-flooding almost contains suspended fine particles which can be deposited over the formation injection face and near-wellbore formation, reducing the injectivity of the injection wells. Therefore, it is necessary to predict the economic life of the water injection wells and treat it for stimulation of the damaged wells (Civan F. , 2007). The first condition that the well must satisfy is to have sufficient injectivity to flow the desired volume of water into the reservoir each day. The injectivity index is an indicator of an injector's health. He proposed the following design that shows the factors responsible for injectivity decline:

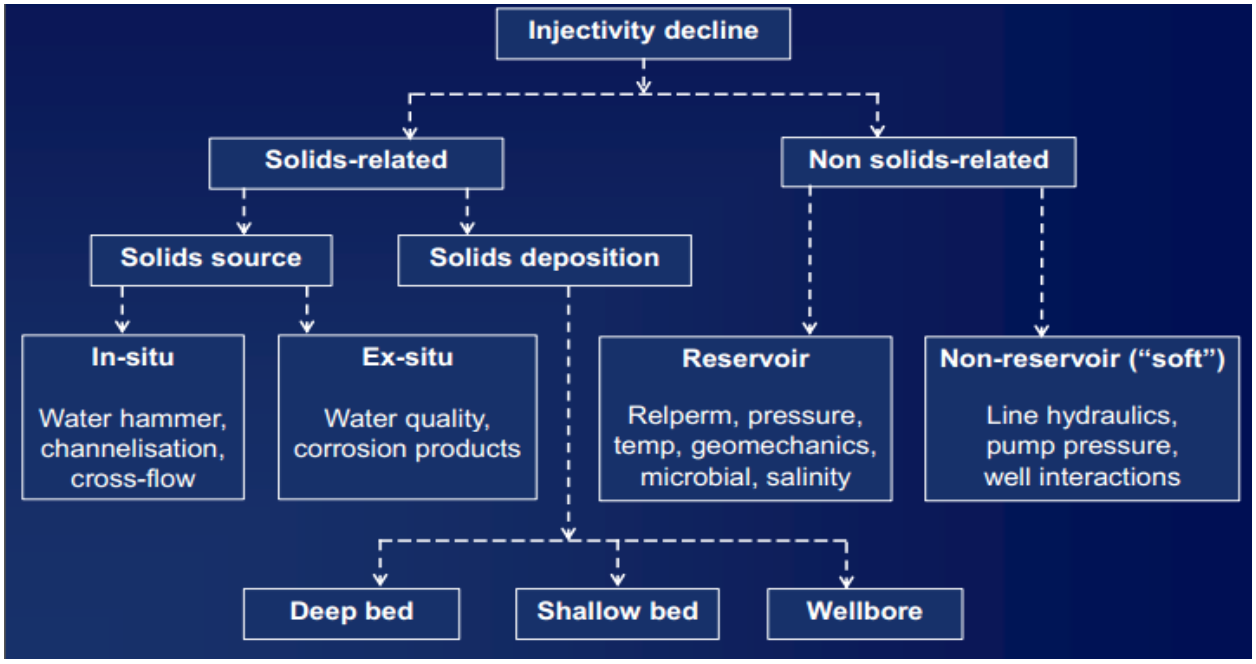

Figure 6: Injectivity decline factors

It should also be noted that the water injectivity decline can occur in low-permeability fields as well as high permeability fields.

2-8 Facilities and operating conditions

Operations and facilities vary considerably from project to project and undergo changes during the several stages of water-flood development. Injection-pattern configurations, surface topography, reservoir characteristics, deviated wells and field operating constraints are only a few of the conditions that can lead to problems associated with project management (Talash A. W., 1988).

Water quality is important for good injectivity, corrosion costs reduction, and equipment plugging minimization. The water-injection surface facilities prepare the water chemically for injection. To remove particulates by filtration, the injection water needs microbiological treatment (Mitchell, 1978). Also, the water needs other forms of treatment; concerning oxygen, scale, corrosion, and iron chelate base on the source of the injection water (Hamouda, 1991).

The purpose of the treatment is to prevent the reservoir from being inoculated with sulfate-reducing bacteria, which could result in the development an in-situ H2S concentration during the water-flood. If this process isn't carried out, it would be impossible to kill the sulfate-reducing bacteria have been the reservoir (Kriel B. G., 1993). The facilities must be designed with flexibility to be able to handle the produced fluid by water-flooding. The production wells should handle only oil and gas, without water production. When the produced water has to be re-injected, the water must be treated until its oil and particulate content are so small that these oil droplets will not reduce the injectivity of the water injector (Hielmas T. A., 1996)

The quality of the injected water is usually measured by its content of suspended solids and it is an important consideration in the design of cost effective water-flooding project, regardless of seawater injection or produced water reinjection.

Chapter Three

Materials and methods

This chapter presents the papers gathering and analysis of the research. The different methods and techniques that were used to achieve the said objectives are described below. The work is arranged to capture the factors affecting water injectivity during a water-flooding project, which have been published in the literature.

3.1 Materials

The study relied mainly on data obtained from past and present studies and existing literature. The papers were obtained from One-Petro concerning conference and seminar papers, journals, books and the internet.

The data collected are as follows:

I. Papers on water flooding project.

II. Papers on operations or practices of oil companies around injection well.

III. Papers on monitoring/surveillance design for water flooding project.

3.2 Methodology

For this project, a qualitative methodology will be used. The qualitative methodology involves documentation of factors affecting injection wells. It is used to make an overview of factors that negatively impacts water flooding projects. Therefore, the research will be a descriptive and conceptual approach to analyze all the information generated from the various sources of data. All the data for the research were combined to form a database of information that is worldwide representative. Both qualitative and quantitative data collected from the different sources were analyzed in order to come up with the output concerning each relevant factor discussed in this work. This method approach was considered suitable to meet the objective of the research.

The papers obtained were sequentially reviewed to identify factors affecting injectivity following by their description to have a clear picture of the injectivity problem. These factors were then analyzed using descriptive and conceptual approaches and from the analysis, logical deductions and presentation were made to allow a better understanding of the critical factor affecting injectivity and its impacts on water flooding success. The methodology gave a clear picture of the injectivity challenges that the oil & gas industries are facing. The analysis leads to a proposal for new water-flood monitoring/surveillance design selection criteria. The application of the proposed methodology is presented in the following chapter.

Chapter Four

4-1 Results

A well is said to be impaired if either its injectivity or longevity is compromised. Injector impairment is a complex problem that often involves several factors such as reservoir characteristics, injection rate, rock wettability, completion type, flow-line hydraulics, quality of injected water, operating practices, relative permeability, and formation heterogeneity. The Injectivity Index (II) threshold varies between operators (See fig 7). Injectivity impairment is a complex phenomenon, which depends on many parameters, making it pretentious the attempt to relate it only to water quality.

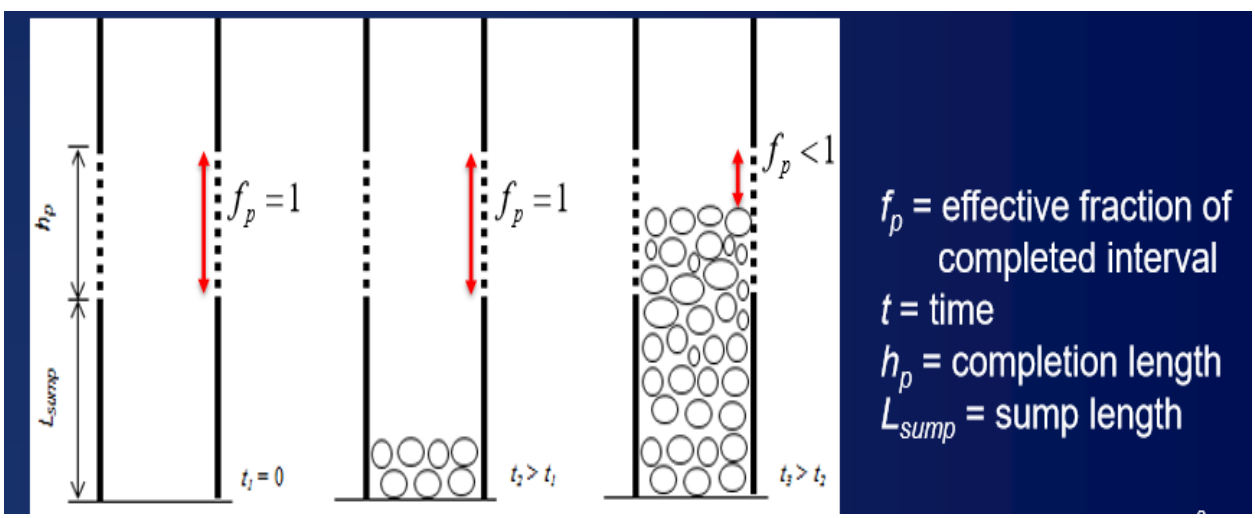

Figure 7: Injectivity Index threshold, (Wang et al. 2008)

Literature reports evidence of well impairment correlation with petrophysical properties of the reservoir, wettability, and granulometry of the suspended particles, and well management strategy. Impairment severity increases in the case of water injection with both suspended solids and oil in water at the same time. In case of shut-down of an injector well, a water hammer pulse is propagated from the wellbore inside the formation, creating pressure imbalance (formation pore pressure is higher than wellbore pressure), which causes sand backflow with wellbore fill.

Also, injectivity damage increases in the case of cycles of alternating periods of injection and shutdowns. The process of injecting water into an oil reservoir for pressure support and/or sweep, is, on the face of it, a very simple process, however, problems are encountered when the causes of injectivity impairment are not fully understood. The following factors affecting injectivity will be analyzed and discussed:

4-1-1 Reservoir (subsurface) factors

A. Sand Production

Sand production may be a considerable and protracted challenge to the petroleum industry. The simultaneous flow of sand and hydrocarbons production can damage tubing and valves, completion equipment, interfere with downhole operations and present separation, handling, and disposal issues (Berntsen & Papamichos, 2012).

Sand production problems within water injectors are less common than in producers since water injectors are not always back produced and due to the nature of injecting water the stress conditions around injectors are less prone to lead to sand failure. Sand production from water injectors is much less common but does not mean that it is not a problem. In poorly consolidated reservoirs, sand failure problems can create severe operational difficulties. According to (Santarelli, 8- 10 July 1998) concerning the injectivity of water injectors in the Norwegian Sea, he noticed extreme losses over short periods. Some wells' injectivities have been lost by the large amounts of sand fill,

showed in the injectors with several hundreds of meters above the top perforations. Their work indicated that the injectivity decline of certain water injectors is due to the following reasons:

- The weakness of the reservoir rock to support the in situ stress and the water injector's shut-in effect;
- The reservoir permeability heterogeneity caused sand production near the perforated intervals due to cross flow from low permeability layers to high permeability layers;
- The produced sand was not able to settle in the rat-hole before injection restarts and therefore plugged the perforation tunnels; and, a water hammer effect caused by well shut-in.

To prevent sand production in those injectors, these three measures can be used to stop sand production (Santarelli, 8- 10 July 1998):

- An improved emergency plan;
- Allowance for longer periods before restarting injection; and,
- Equipping new injectors with longer rat-holes.

After the implementation of those measures, no well has been lost and injectivity has remained flat in this Norwegian offshore field. According to (Morita, 18-19 February, 1998), gravel packing water injectors is good to prevent the wells from the effect of formation potential failure while (Price-Smith, 2003) said since some injectors often ended up exceeding fracturing pressure and always push gravel into the induced fractures, some special considerations had to be made during completion of open-hole injectors for sandstone formations.

B. Reservoir permeability heterogeneity

In any reservoir, even for the foremost homogeneous reservoir, different plane positions have different permeability (Liu & Sun, 2017). Consistent with (Isah, 2017), much attention has been given to understanding the effect of permeability variation from layer to layer within the reservoir and the way it impairs fluid flow and production. For him, the equivalent permeability of the whole reservoir is influenced by

the relative distance between the lateral heterogeneity reservoirs and therefore the water injection well, since the oil displacement efficiency of the reservoir is said to the worth of the equivalent permeability. One among the factors affecting injectivity, reservoir heterogeneities, could have an appreciable effect on the sweep efficiency of flooding patterns. If the permeability within the east-west direction differs from that within the north-south direction, the sweep efficiency may vary from near zero to 72 percent for the five-spot pattern. Also, in carbonate formation where lateral and vertical petrophysical properties (permeability, porosity) change, injected water can reduce the effective fluid mobility in higher and lower permeability layers. Pore throats are critical parts of a rock, these are the narrowest points through which fluid must flow, and that they connect the pore spaces during which the water and oil are contained. Understanding how water injection affects the rock pore throats and pore spaces is critical, and therefore the width of those restrictions may only be a couple of microns across, making them very easy to impair. Subsequent a part of the injectivity decline mechanism examination looks at the physical interactions between the oil and solids loading of the injected water within the pore throats at the sand face of the injected rock.

C. Wettability and fluid properties

Reservoir wettability is determined by complex interface boundary conditions acting within the pore space of sedimentary rocks. These conditions have a dominant effect on interface movement and associated oil displacement. Wettability is a significant issue in multiphase flow problems ranging from oil migration from source rocks to such enhanced recovery processes as alkaline flooding or alternate injection of CO2 and water. Injection water may contain many chemical contaminants that might impact injectivity. Chemicals which have been used to facilitate the oil-water separation and treatment process can cause injectivity reduction. Examples are de-emulsifiers, surfactants, corrosion inhibitors, scale inhibitors. These chemical are polar of nature, which allows them to create an affinity for a wettability transition in the near injector

region from a water-wet to oil state (See fig 8). Since some chemicals can promote the creation of a movie of blocking/trapping hydrocarbon-based material on the face of the injection wells then reduce the injectivity, a careful evaluation of the chemical interactions must be undertaken before implementation mainly in the case of residual heavy hydrocarbons inside injection water.

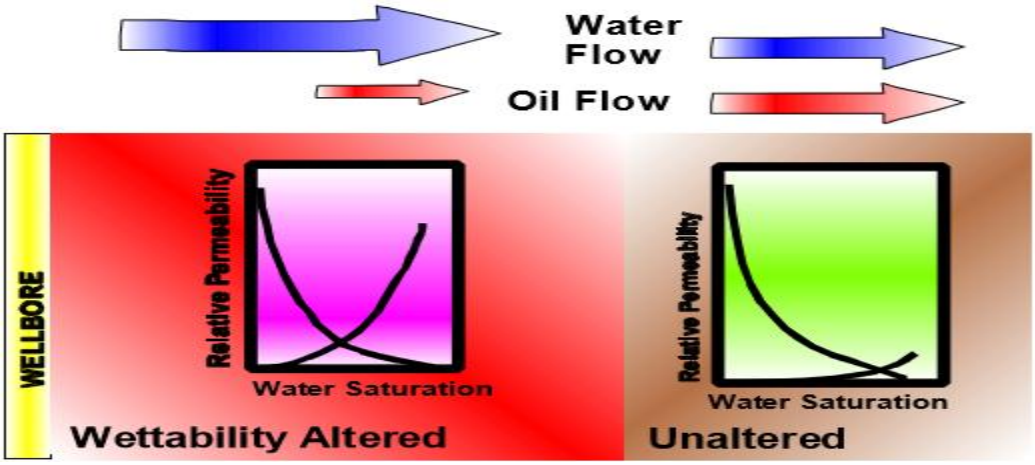

Figure 8: wettability effect on Krw, D. B. Bennion

D. Pressure /Temperature

Increased injection pressure is required to take care of a given injection rate. If the increase in the pressure exceeds the minimum horizontal or vertical stress within the formation rock around the wellbore, fractures are initiated. An increase of local reservoir pressure in the injector area may cause injectivity index reduction. Injectivity abnormalities can result in significant reservoir pressure drop, affecting oil recovery and thus affecting economic viability. If the temperature of the injected fluid is different from that of the formation, a thermal front propagates from the injection well. This change in temperature causes the rock to contract or expand, altering the stresses both in the region of changing temperature and in the surrounding rock. Also, the creation of a cold water bank around the injector adversely affects the injection performance. Due to the strong dependence of water viscosity on the temperature, the cold water bank represents a zone of lower mobility compared to the formation water at initial temperature conditions. When the cold water enters a hot reservoir there are three

processes by which heat is exchanged: thermal conduction, convective heat transfer between fluid and solid matrix and heat transfer caused by friction. Injection of cold water into a hot reservoir at initial temperature conditions leads to a cold water bank around the injector. This water bank can extend several hundreds of feet into the formation, depending on the injection rate and the thickness of the reservoir. The cold water bank leads to a pseudo-skin factor that depends on cumulative injection. Any pressure drop caused by wellbore damage will be enhanced by the mobility contrast between cold injection water and water at the original formation temperature. The theory predicts an injectivity decline at the onset of injection.

E. Fracture growth

Water injection is widely wont to maintain reservoir pressure and to displace bypassed oil from unswept zones. During the water injection process, pore plugging by suspended solids and oil droplets in the injected water leads to a decline in well injectivity. Water injection has been used worldwide as a means of pressure maintenance for improving recovery of hydrocarbons, as well as disposing unwanted produced water from oil and gas wells in an environmentally responsible fashion. Conditional to the success of this process is that the ability to inject the specified volume of water into the porous formation of interest at a pressure, in most cases, under the fracture pressure gradient of the reservoir (to maintain good conformance of the injected water within the target formation). Understanding injectivity is a critical element to ensure that sufficient volumes of water are being injected into the reservoir to maintain reservoir pressure, to ensure good reservoir sweep and minimize well remediation. It is, however, challenging to explain the massive injectivity changes that are sometimes observed in injectors operating under fracturing conditions.

Indeed, when the injection pressure exceeds the formation breakdown pressure due to the particulates contained inside the injected water, a fracture starts to rise such that a decrease in water quality (water with higher solids/fine concentration) will assist a

fractured growth with low well injectivities. The fracture growth is due to formation plugging and formation cooling.

It is good to know that, reservoir structure, geomechanics, and thermal stress effects are other factors that affecting injectivity if they are not well analyzed. All these factors effects on injectivity are summarized in table below:

	Factors	Severity of impact	Occurrence conditions
Subsurface (Reservoir) factors	Sand production	(low to medium impact) Can affect Flow-line and piping integrity, erosion, affect the disposal well	Well shut-in-time; poor water quality; cross flow; unconsolidated reservoir; Simultaneous flow of sand with the producing hydrocarbons
	Reservoir heterogeneity	(low to medium impact) Affect fluid flow	Cross flow from low permeability layers; production from different size of layers in the same time
	Wettability	(low impact)	Water with many chemical contaminants
	Pressure& Temperature	(medium to high impact)	Fracturing; pressure drop time; cold water bank near an injector
	Fracture growth	(medium impact)	Formation plugging and cooling; pressure difference between injector and formation

Table 1: Summary of reservoir factors affecting injectivity

4-1-2 Wells factors

A. Injection and production rates

In many cases, even with good formation character and reservoir parameters, injection rates are compromised thanks to quality problems with the injected water. The injection rate is one among the few parameters the operator can control. Therefore it's important to know the effect injection rate has on water-flooding mechanisms (Golovin & Dudley, 2011). Consistent with (D.B. BENNION), plugging of the pore system is suffering from the precise size of the invading particles, the flow velocity of the fluid during which they're contained, the pore size distribution, and to a particular extent, the wettability of the fines and formation into account. Since the suspended particles living within the injection water are larger than 33% of the median pore throat diameter, they're going to create stable bridges which will reduce permeability. within the case of flow , where interstitial velocity is high enough to take care of the particles in uniform suspension, it's clear that under lower injection rates (in streamline flow regimes); smaller particles can form stable bridges which may reduce injectivity. Within the near-wellbore region with a perforated injection well, flow conditions are present. Because the injection water moves outwards from the perforations, the interstitial velocity decreases rapidly, and a transition from turbulent to streamline flow occurs a long way into the formation.

B. WAG ratio

Although gas solubility in water is generally low, some gases, notably carbon dioxide and H2S and, to a more limited extent, air/oxygen have finite solubility in an aqueous solution. This solubility is decreased as temperature rises. Solubilization of gases, particularly air, into injection water in an open circulation and treating system may end in the next evolution of this gas as temperature increases upon the re-injection of the water. This may end in the liberation of free, insoluble gas within the matrix surrounding the injection well, and therefore the formation of a trapped critical gas saturation which can also significantly reduce injectivity over time because the

saturation increases in value and areal extent surrounding the injection well. Similar problems may also be created by poorly located pump suction lines which result in direct suction of entrained air along with the injected fluid.

C. Entry/Exit fluid compositions

Well's capacity is related to many different factors, some of which are affected by differences in the chemical properties of crude oil and water. (Bossler& MacFarlane) proved by experiment that the amount of residual oil around the wellbore has a large effect on reducing the flow of injected water. This is demonstrated by a typical relative permeability curve for water as shown in Fig 8. In some water-flooding projects, freshwater needs to be injected into subsurface formations when brine water is not available or too costly. In this case, if the reservoir rocks contain interstitial clay which swells and disperses in the injected freshwater, the well injectivity will decline because of permeability impairment; raison why (Barkman et al.) proposed an effective and inexpensive oil coating method that prevents injectivity decline from freshwater impairment in formations containing clay. According to (Scheuerman & Bergersen), the injection water and formation clay compatibility criteria are determined by water and formation clay analyses, therefore the operators had to decide either injection water treatment is required to prevent permeability impairment or not. However, to apply this method, operators must know the water compositions, reservoir clay types, and reservoir clay cation exchange capacity.

D. Flow line hydraulics (friction, back pressure, well-well interactions)

The performance of a water injector is a critical success factor during the water-flooding project. The underperformance of an injector is dependent on some mechanisms. The performance decline might be a consequence of an injection pressure reduction due to damage of the injection pump. Flow-line is a good example of a damage mechanism that does not involve the transport of solids. The abrupt closure of valves createdby a sudden change in injection rate can generate a pressure transient called water hammer (Modal, 2010). Water hammer and cross-flow are the main

mechanisms by which reservoir solids are brought to the near-wellbore area to cause damage. Indeed, water hammer leads to pressure fluctuations with failure of the sand face and mobilization of fine particulates into the wellbore and therefore reducing the fraction of the completed interval accessible to injected water (See fig 9)

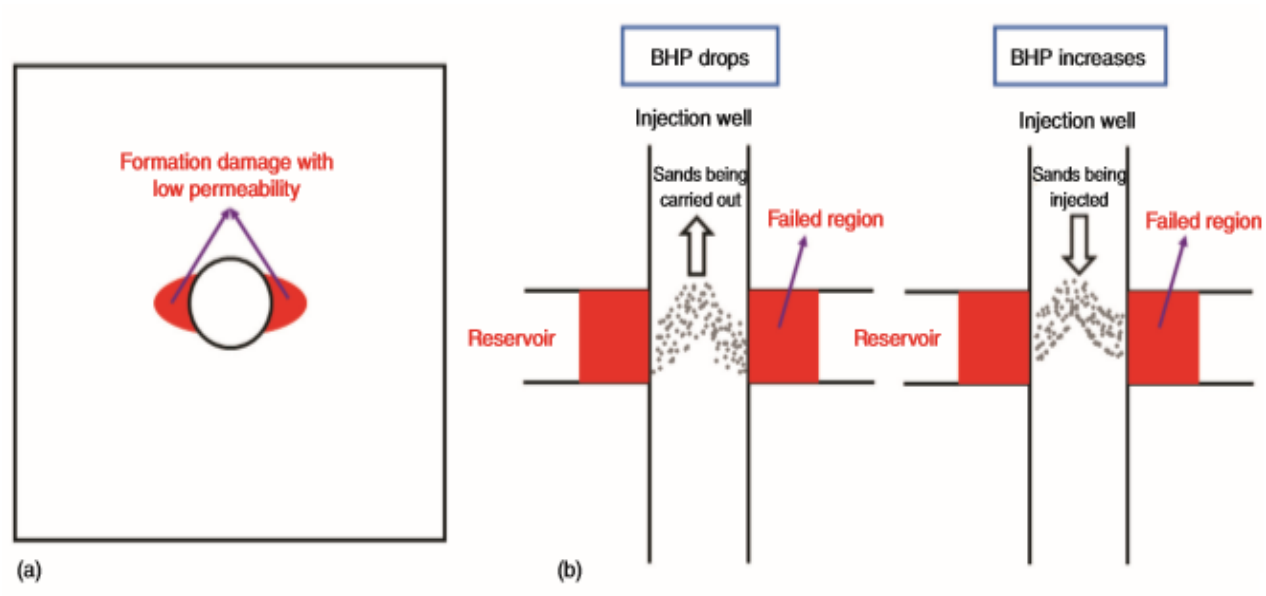

Figure 9: a- Degraded sand accumulation in the formation; b- fines and sand reinjection into the formation due to water hammer, S. Modal, 2010

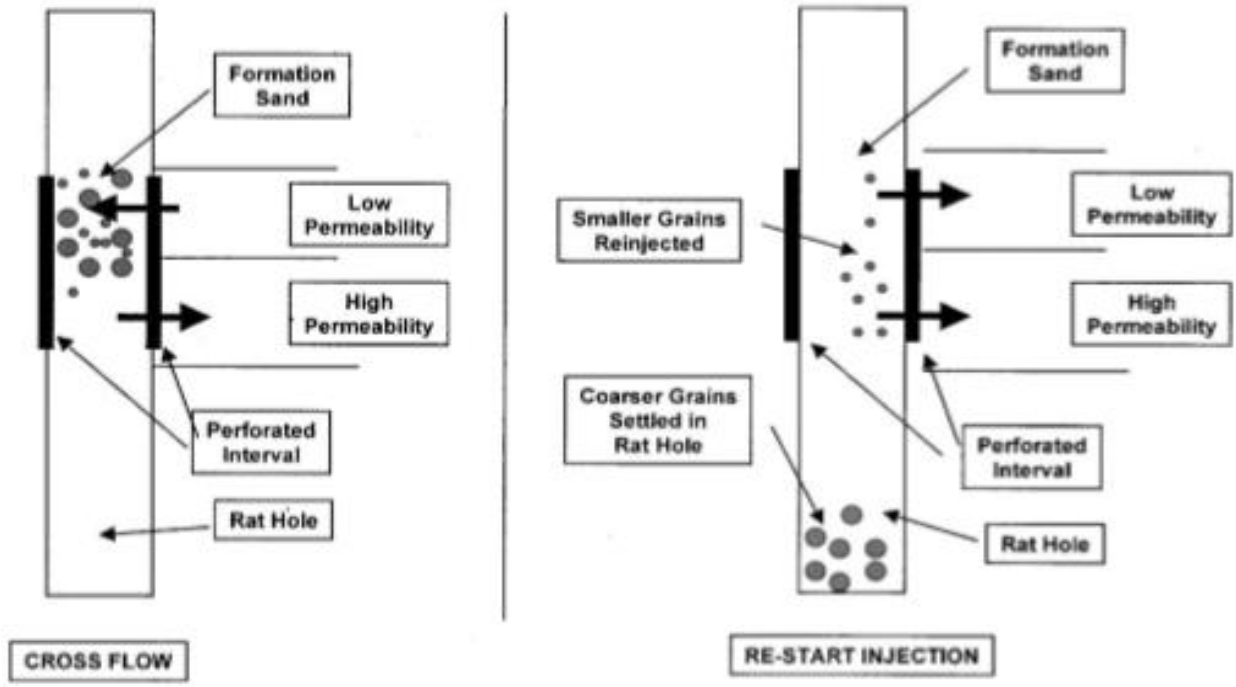

Figure 10: Perforation-tunnel plugging mechanism,

E. Corrosion products/Scales

The rate of corrosion increases with amount of H_2S. The H_2S can be deposited on pipe surface and injection well as scale, causing plugging therefore a reduction of injectivity. Scale formation is a familiar problem for oilfield engineers. It is often caused by the mixing of two or more brines. Scale can be deposited all along the water paths from injectors through reservoirs to the surface equipment. The work carried out on the Tapis field showed that the calcium carbonate scale would form above 15.56° C (60° F) in mixtures of Tapis produced water and injected seawater (Chang C. , 1985). Some field tests carried out at Ghawar showed that scale precipitation might form in the wellbore where seawater and formation water mix under turbulent flow conditions. Also, the presence of bacteria in injection water can contribute to the scale formation.

Certain factors can lead to the formation of scales and precipitates. The injection of incompatible water into the formation will generate some insoluble precipitates. The changes in temperature and pressure of the injection water may initiate pH changes which may result in the formation of scales in production equipment, surface/treating equipment including the injection wells. Scales (calcite, gypsum, and anhydrite) are problematic during injection operations.

F. Suspended solids

The deposition of solids/fines particles into the formation causes a reduction in porosity, an increase in tortuosity, a permeability decline and cake formation in the injection well, which causes the injectivity decline (See fig 12).

The water quality usually measured by its content of suspended solids, has always been an important criterion in the design of a cost-effective water flooding project regardless of seawater injection or produced water re-injection. Many researchers have studied the effects of suspended solids in injected water. According to the study of Barkman and

Davidson in 1972, the well impairment caused by suspended solids can be classified into the following mechanisms:

- Wellbore narrowing,
- Particle invasion,
- Wellbore fill-up, and
- Perforation plugging.

When the suspended solids in the injection water flow through the subsurface, they plug the pore throats of the formation and reduce the permeability near the wellbore region, with the consequence of an injectivity decline. In the absence of fractures, the water injectors completed in low permeability formations, are liable to be plugged by suspended solids contained in re-injected produced water or seawater. Therefore, the re-injection of produced water and seawater is a potentially high-risk operation activity. For example in the Prudhoe Bay field, the core tests were run with produced water that was not filtered before injection; 90% permeability damage could occur within 24 hours of injection start-up. Suspended solids are found to be the main reason for the injectivity decline in injectors in some fields. Observations from some fields show that even the high permeability sands are also susceptible to damage by the suspended particles that are much smaller than the average pore size. (Sharma et al.) found that an improvement in the water quality can increase the water injector half-life by a factor of 2 to 5, but water treatment also goes up significantly. The water quality study conducted in the Umm Shaif and Zakum fields indicated that even if the injected water was adequately treated at injection plants, it still might cause deterioration which could be attributable to the absence of bactericide treatment or the precipitation of suspended solids in the transporting pipelines. Therefore, continuous monitoring of a tight water specification is essential to reduce any injectivity decline. It should be noted that the down-hole water quality may be much poorer than the water quality at the wellhead during water injection. Therefore, surface water treatment may not completely solve the particle migration problem. According to (Shumbera et al.) an open hole fracture completion

and a unique downhole filter system instead of frequently stimulating water injectors to minimize the typical rapid injectivity decline. Even though injection water treatment can improve water injectivity, the cost of water treatment must be weighed against other alternatives, such as periodic good stimulations.

The injectivity impairment due to suspended particles often happens in two stages:

The injected particles penetrate a reservoir and are captured by the reservoir rock with consequent permeability reduction and the particles build up an external filter cake after the complete plugging of the inlet cross-section by retained particles.

Also, asphaltenes can be precipitated from crude oil by changing pressure, temperature, or oil composition. Asphaltene deposition refers to the process when asphaltene adheres to a surface due to the interaction between surface and asphaltenes. Asphaltenes are polar and, like to form larger particulate agglomerates of asphaltenes. These particulates can form thick scum on formation. The deposition may cause problems in both upstream and downstream operations. In downstream operations case, they may deposit in pipelines and production facilities while in upstream operations case, asphaltene precipitation, aggregation, and deposition in an oil reservoir rock can cause severe formation damage mainly if they block pore throats and deposit near the wellbore. According to (Leon taritis et al., 1994), asphaltene deposition can reduce the hydrocarbon mobility by reducing the permeability, alter the rock wettability from water-wet to oil-wet and increase the fluid viscosity by stabilizing water-in-oil emulsions. A major issue in water quality and reduced injectivity is the presence of suspended solid particulate in the injected fluid. Solids particles including produced formation fines and clays, sand, and silt can be produced in the injection water from surface or shallow groundwater sources, while various precipitates and scales, organic solids, corrosion products can be formed from production/injection tubular, tanks, and treating equipment (D.B. BENNION). Depending on the pore size distribution of the formation, the injected fluid volume, the size distribution, and solids

concentration in the injection water, plugging of the pore space of the injection well might be rapid and severe. Normally, injection water is clean and contains little or no suspended solids, but due to some realities such as production/processing operations, economic and practical limitations on water filtration and treating, all injection water contain some amount of suspended particulate matter (See Fig 11). Some suspended solid material such as asphaltenes may not be removed by conventional filtration techniques.

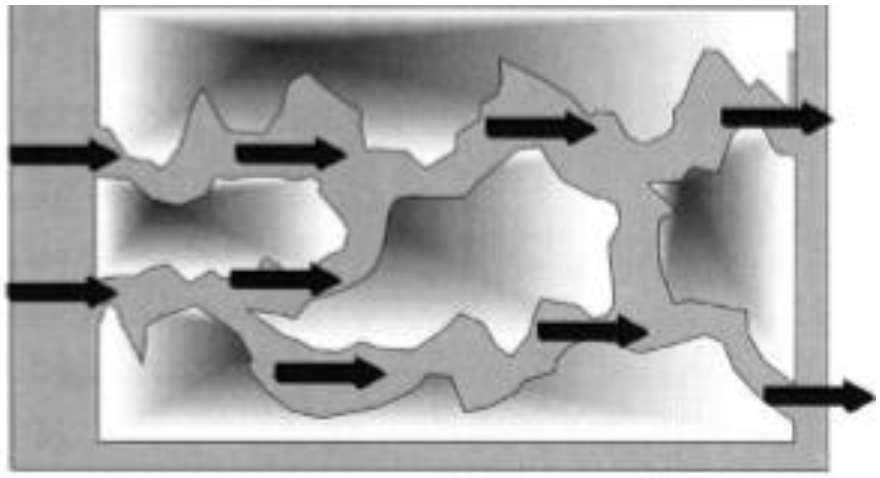

Figure 11: Pure injection water, D. B. Bennion

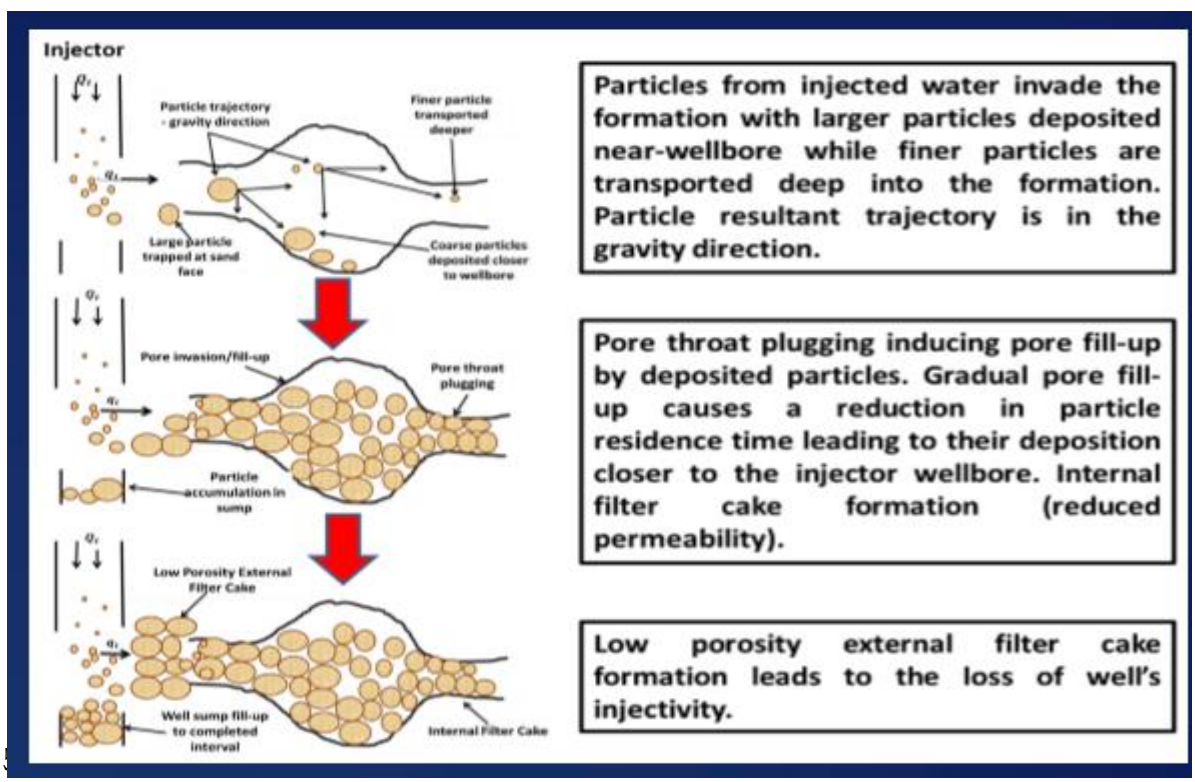

Figure 12: Particles deposition process, (Dambani et al. 2014)

G. Wax

Some simulations in the literature indicated that general cooling occurs in the high permeability parts of the reservoir while in the low permeability reservoir, cooling of the reservoir is a small amount of wax precipitation which is expected around injectors. Gas expansion and evolution near the wellbore can cause significant cooling, which leads to the continuous formation of wax.

For (King, 1997), the temperature around water injectors in the Pembina Cardium reservoir, the largest conventional oil reservoir in Canada, may drop below crude oil's cloud point because of cold water injection, which leads to wax precipitation and impairs injectivity. A phase equilibrium study of the Pembina Cardium reservoir oil showed that wellbore and reservoir pressures are two vital factors in determining wax precipitation in the Pembina Cardium reservoir. Noticed that the pump pressure, injection pattern and well interactions are some factors that can affect the injectivity. All these factors effects on injectivity are summarized in table below:

	Factors	Severity of impact	Occurrence conditions
	Flow line hydraulic	Low impact (pump damage)	- Cross flow - Change in pressure
	Injection/Production rates	Low to medium impact (permeability reduction)	- Laminar flow - Reservoir formation is weak
	WAG ratio	Low impact (H2S, CO2 in water)	- Saturation of gases around the injector - Poor location of suction pump

wells factors	Entry/Exit fluid compositions	Low to medium impact	- Presence of clay in reservoir rocks - Residual oil around the injector
	Corrosion/Scales	Low to Medium impact (damage of equipment)	- H2S deposition - Bacteria presence - Change in pH - Mixture between seawater and formation water during turbulent flow
	Suspended solids	Low to medium	- Invasion - Wellbore fill up - Perforation plugging
	Wax	Low impact	- Cold water injection - Cooling of reservoir due to gas expansion

Table 2: Summary of wells factors affecting injectivity

4-1-3 Facilities and operations factors

The reduction in permeability and then in productivity is a consequence of drilling, completion, injection, stimulation or production of a well. The following factors will be analyzed to identify a clear cause-effect relationship with water quality.

A. Produced Water Re-Injection

Especially in mature fields, water production always accompanies hydrocarbon production. Due to the large volume to be dealt with, the management of produced

water has become important in the petroleum industry. Re-injection issues are very important and a big effort has been made to understand the impact of produced water injection on wells impairment starting from field experiences. The injected water can come from different sources such as seawater, aquifer, and surface/alluvium beds and produced water (See fig 7).

According to (Stefano Rossini, 2020), produced water coming from separators is not pure water and it has to be treated before being re-injected since it could contain many unexpected and unwanted materials:

- Suspended Solids;
- Residual Oil In Water;
- Bacteria;
- Chemicals used in hydrocarbon treatment and extraction.

These agents could affect well injectivity and cause the blockage of the inflow area with a drastic injectivity reduction. In all cases, water injection could activate the following injectivity damage mechanisms (D.B. Bennion, 1998):

I. Mechanical damage

Mechanical damage is the plugging of pore formation around the injection face region by suspended solids contained in the injected water. The solids particles contained in the produced water could be formation fines, clays, precipitation scales, heavy metals and corrosion products from injection and surface equipment (D.B. Bennion, 1998).

The impairment severity and the solids particles deposition depend on suspended solids concentration, their granulometry, formation pore distribution and the injection rate. The particles that have a diameter higher than 25% of the pore throat are transported at the wellbore-formation interface and form an external filter cake, while

particles with a diameter lesser than 25% of the pore throat can invade deeper into the formation, up to several centimeters, creating an internal filter cake (See fig 8).

Because of the difficulty to treat it with remedial jobs, the internal filter cake is more damaging. Particulates smaller than 14% of the pore throat move through the pores without blockage. Injection fluid velocity also plays an important role during deposition and particulates entrainment. The core flooding experiments showed that the permeability impairment increases with suspended solids concentration and water injection rate since deeper invasion occurs (P.K.Currie, 2005).

II. Relative permeability effects

The relative permeability is due to the presence of oil droplets in the injected water. The oil droplet suspended in the injected water stream is the main source of potential injectivity impairment. The extent of loss of injectivity depends on initial fluid saturation around the injection well. The negative effect of oil in the water on water injectivity is manifested by the decrease of effective water permeability due to the increasing presence of oil saturation in the pore space (See fig 13). An ENI field experience included a literature review that showed that the injection of water containing both solids and oil will increase the injectivity impairment concerning solids size (See fig 14). The severity of the damage is highly dependent on the initial saturation condition of the injection zone. When oil droplets flow through porous media, they block the pore throats that have a smaller size than them. This oil will be trapped into the pore space and then reduce the flow path for water, therefore the reduction of injectivity. If the porous media retains a water-wet character after the introduction of the oil, the entrapment of the hydrocarbon in the central portion of the pore system can cause a very large (often 90% plus) reduction in the effective permeability to water and cause catastrophic reductions in injectivity (D.B. BENNION). If pre-existing oil saturation already exists in the injection zone, the magnitude of the reduction may be reduced, as injectivity will already be partially compromised at initial conditions by the natural presence of the pre-existing irreducible hydrocarbon saturation. Hysteretic

relative permeability effects can result in reductions in injectivity (due to increases in trapped Sor) even in situations of this type, although the magnitude of the reduction is usually small in comparison to the previously discussed case where no liquid hydrocarbon saturation is initially present in the injection zone.

III. Injection water / formation rock interactions;

IV. Injection water / in situ fluid interactions;

V. Biologically induced impairment due to bacteria growth.

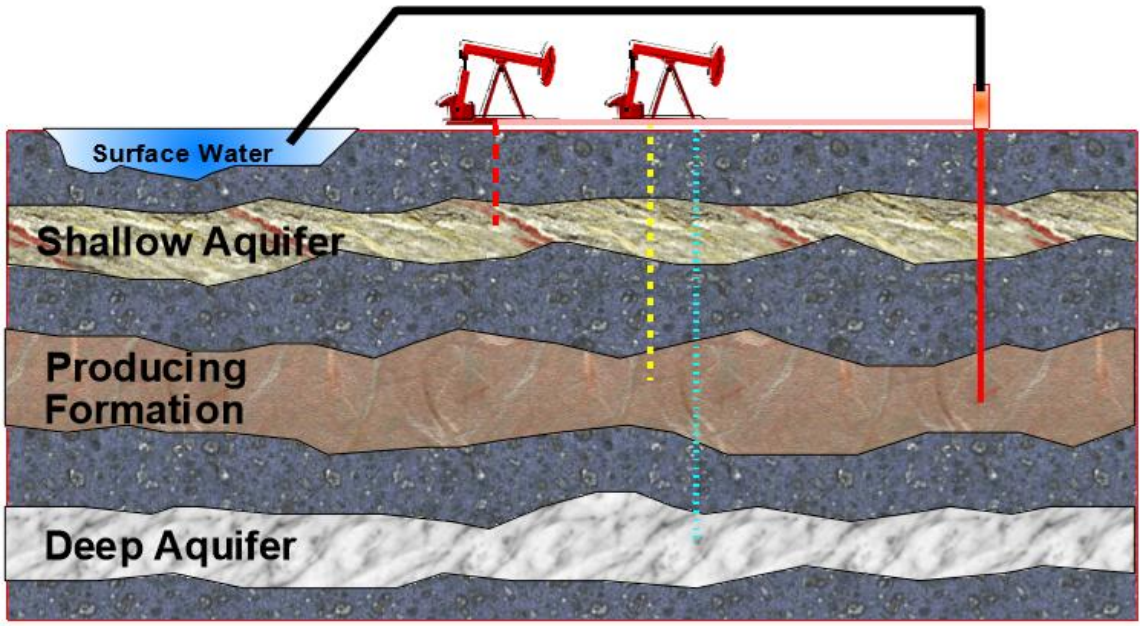

Figure 13: Injection water sources, D. B. Bennion

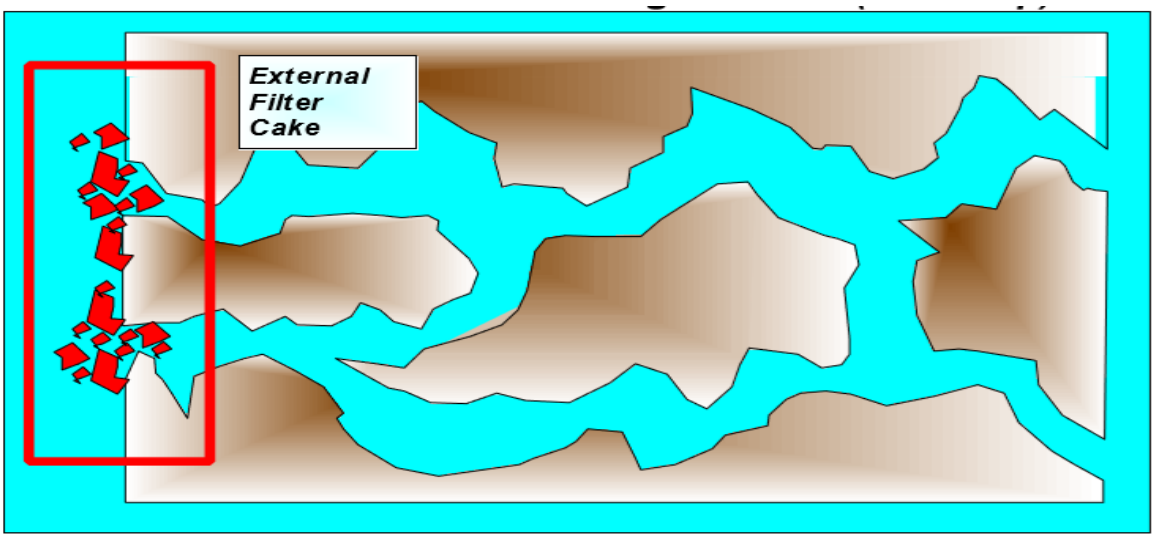

Figure 14: Formation of an external filter cake during water injection

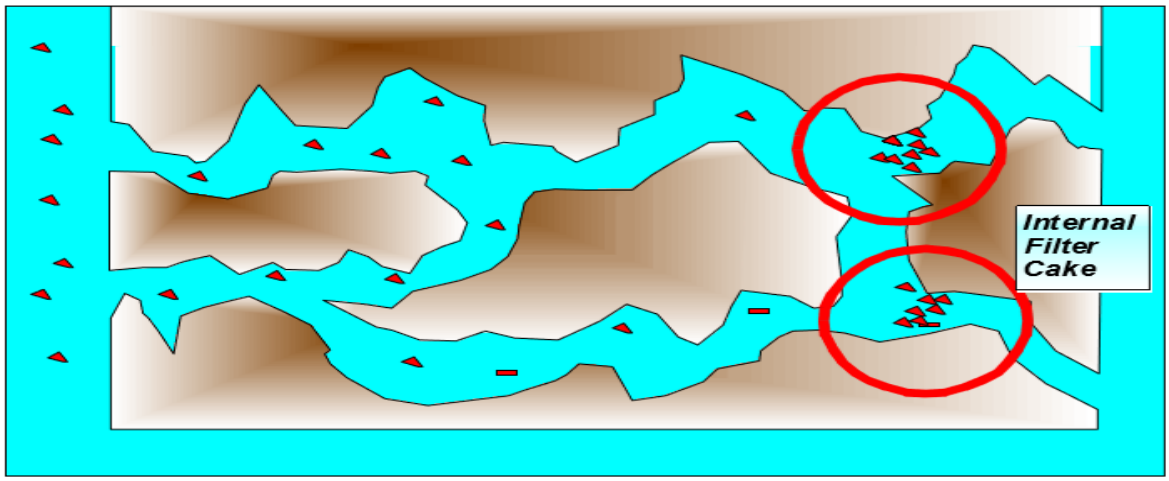

Figure 15: formation of an internal filter cake during water injection

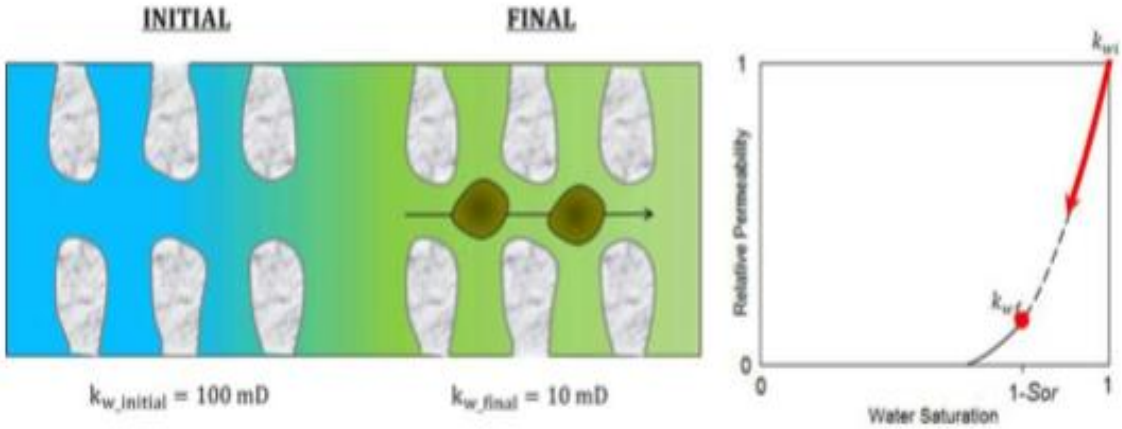

Figure16: relative permeability effect

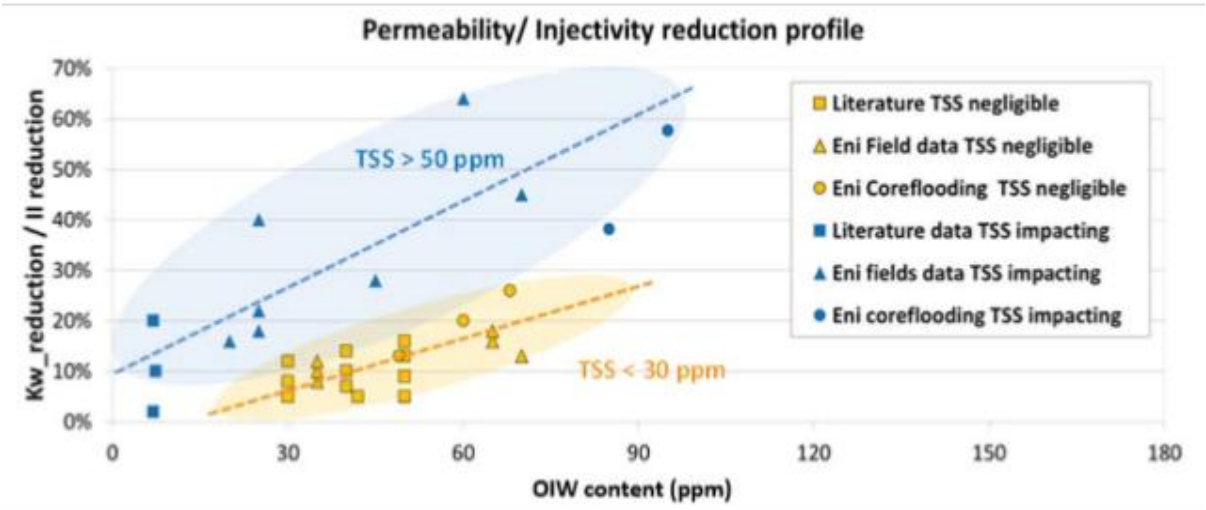

Figure 17: injectivity performance, Stefano Rossini 2020

B- Water quality

Suspended solids, corrosion products, organic/inorganic precipitates elements, bacterial activity and content of oil, are some factors affecting water quality. According to (D.B. BENNION), the source of the water, its temperature and pressure path during production and injection operations, compatibility issues between blended waters, and possible seasonal variations in the water quality are all issues that may affect the overall quality of the injected water from a damage/impaired injectivity perspective. The injected water can be produced water, fresh or seawater which contains certain impurities (organic or inorganic elements). The seawater contains suspended particulates and salts which settle out or precipitate in the formation when it is injected. However, even when the water is well treated at the surface, its quality may deteriorate as it travels down the hole and leads to corrosion. These particles can over time settle and fill up the wellbore, plug the completion screens and formation pores leading to severe permeability impairment, loss of injectivity and ultimately, low hydrocarbon recovery. (Platen kamp) Presented work on the impact of cold water injection in the North Sea. He concluded that the formation of a cold water bank around an injector can impair injection performance due to the impact of temperature on water viscosity and it would also lead to higher skin. The field observations from Ghawar showed that

seawater injectivity was 40% to 50% lower than aquifer water because the seawater temperature was about 37.78° C (100° F) cooler than the aquifer water which could greatly increase the water viscosity and also the seawater had to pass through a long surface pipeline to the injectors that could affect the seawater quality. Despite its low development and pumping costs, high corrosion should be expected. The North Sea water sampling showed that the suspended content is near 150 to 200 ft. The presence of impurities (suspended solids) in the injected water causes formation plugging. Also, the presence of iron (uncoated pipe) and bicarbonate in the injected water causes the precipitation of iron oxides and the formation of scale deposits to plug the formation. These materials plug the pore spaces within the formation rock and consequently reduce the flow path of injected water. In all cases, injectivity declines if the water quality is not maintained.

Most oilfield formations contain a variety of fine-grained materials that may be susceptible to either movement (migration) or structural alteration (swelling or dispersion) due to contact with non-equilibrium injection fluids. A family of these materials, which can be especially reactive due to their cationic affinity, are commonly referred to as 'clays' and consist of a wide range of alumino-silicate based compounds. Common oilfield clays include smectite, mixed-layer clay, illite, chlorite and kaolinite.

The larger molecular size of the water may then cause considerable expansion of the clay. Depending on the amount and location of the clay, this can cause significant reductions in in-situ permeability and subsequently in injectivity. Based on the size of the particles, some of these contaminants will penetrate the reservoir face and be deposited inside the pore throats forming an internal filter cake. The depth of penetration is related to the particle size of the solid contaminants and their particle size distribution, as well as the pore throat size of the formation rock. Once the internal cake deposits, the particulates will form an external filter cake at the reservoir face. The porosity/permeability of the internal and the external filter cake are important properties that affect injectivity into the formation.

C- Bacterial

Bacteria in general can cause severe plugging and accelerated corrosion if they are checked and can even doubles their population in few minutes if the conditions allow. A single bacterium could become a colony of millions of bacteria in a few hours. Indigenous aerobic and anaerobic bacteria are often present on many surfaces and shallow groundwater sources. The seawater contains many different species of bacteria. The injection of seawater rich in oxygen or nitrogen into the formation sound like increase the activity of aerobic bacteria which might increase biomass build-up around the wellbore/injectors and then impact well injectivity, even though it can be mitigated by the use of fractured injection.

The introduction of bacteria into an injection well can occur during drilling and completion/stimulation/workover operations, as well as during long-term injection operations. Some anaerobic bacteria such as sulfate-reducing bacteria (SRB), tend to be the most problematic in oilfield situations, but, in some injection operations, sufficient dissolved oxygen present in the injection fluids, leads to aerobic bacteria activity and thus, problems (LAPPEN, 1992).

For the following reasons, respect to injectivity reduction bacteria is problematic:

- Plugging of pore system due to colonies of bacteria;
- The growing colonies of bacteria can release a polysaccharide polymer during their activities and then plug the pore system;
- The bacterial living on tubing, casing, and surface equipment can generate some corrosion products which might plug the formation.

Due to the cool injection water that might be introduced into the near-wellbore region and the relatively high heat capacity of water, the formation temperature has less effect on bacteria growth because of the downhole cooling effect.

D- Completion

We realize that continuous water injection into fracturing packed cased hole water injector wells can wash gravel from the annulus, especially when the injection is at rates above fracture threshold. Indeed, during water injection, the drag force can displace the gravel inside the annulus and outside casing away from the wellbore. The cross-flow between formation and annulus occurs during the shut-in operation and can bring sand into the annulus and when the well will be shifted to injection nature, the sand will reduce the injectivity.

Some factors such as drilling, water disposal, electric power supply, injection facilities, production facilities, and pipelines can affect injectivity. All these factors effects on injectivity are summarized in table below:

	Factors	**Severity of impact**	**Occurrence conditions**
Facilities and operations factors	Completion	Low impact (equipment and material loss)	- Injection above fracture threshold - Cross flow
	Water quality	Medium to high impact	- Season change - Injection of cold water - Water with impurities
	Bacterial	Medium impact	- Water with high concentration of oxygen and nitrogen - Injection operations - Drilling/completion operations
	Water type (Produced Water Re-Injection)	Low to medium impact	- Oil droplet and particles in water - Presence of bacteria in water

Table 3: Summary of facilities and operations factors affecting injectivity

4-2 Discussion

From all the factors described above, water quality and pressure are the most factors affecting injectivity, therefore water-flooding project.

Water may be a living environment and transportation agent for both citizenry and particles, while pressure is that the energy needed by hydrocarbon and every one field materials, therefore water quality and pressure are the controlling factors affecting injectivity. It's documented that failure to satisfy injection targets will eventually end in reduced boring. Even though the injected water has been treated with different filters to get high-quality injection water, it still contains a couple of ppm of solids concentration and particles size but microns in diameter. This example allows later accumulation of sands/solids/suspended particulates inside the injection wells.

To maintain injectivity for produced water that has not been fine filtered, injection above formation fracture pressure is typically required. The pressure required to make an induced pressure depends on both the initial formation stress and therefore the stress changes induced by the temperature difference between the injected water and the reservoir formation. When the injection pressure is high enough to beat the formation fracturing pressure, fractures are going to be created within the near-wellbore region.

(Owens et al.) report that the fracture propagation pressures increase with time from their initial values, but becomes constant at a later time. It seems that the generation of multiple fracture branches is said to the periods of rapid pressure increase. The expansion of thermally and hydraulically induced fractures during water injection can seriously reduce the injectivity decline of injectors. Therefore, it'd be helpful to fracture water injectors even injecting relatively clean water because fracturing water injectors

may significantly reduce offshore field development costs. When fractures are induced within the subsurface reservoirs, the standard of injection water is often relatively relaxed and this is able to reduce the water treatment cost. As a result, it'll take even more injected water and cause poor vertical sweep. If induced fractures extend vertically over several layers, operators may not have control over vertical sweep efficiency and it might be very difficult to regain the injection profile.

It seems that injecting water above the formation fracturing pressure may be a excellent option supported reported field cases, especially for low permeability fields. The water-flooding project of a coffee permeability Siri field failed after six years of injection due to injectivity decline and therefore the water-flooding project had to prevent. Therefore, injecting water above formation fracturing pressure could be crucial to the success of water flooding in low permeability reservoirs. When water injection pressure is above formation fracture pressure, the quantity of water that we will inject into the reservoir won't be influenced by the near-wellbore permeability. To some extent, it's only a function of the horsepower of injection pumps and therefore the artificially induced fracture which will grow to accommodate the massive volume of injected water. However, the artificially induced fractures could lead on to poor sweep efficiencies if the injected water channels through the reservoir to the manufacturing wells or aquifer.

In recent years, petroleum engineers have began to drill horizontal injectors to realize high injection targets in Prudhoe Bay and therefore the North Sea. Using horizontal injectors might reduce the danger of downward vertical fracture growth into the aquifer in Prudhoe Bay. With the event of reservoir engineering, more and more water injection projects are carefully studied before they're implemented, especially for capital-intensive offshore projects.

Therefore, before surveillance and monitoring practices, it's good to understand the health level of the asset by asking ourselves the subsequent questions:

- ✓ What is that the drive mechanism that's controlling the production?

- ✓ What is that the recovery factor?
- ✓ How many pore volumes of water are injected?
- ✓ What is that the voidage replacement ratio?
- ✓ How the reservoir pressure is behaving concerning the time?
- ✓ How the assembly fluid is behaving?
- ✓ How is that the GOR performance?
- ✓ What are the water production and WOR trends?
- ✓ What is that the water injection rate?
- ✓ How is that the injection water compare to the reservoir voidage?
- ✓ How much excess capacity is out there for production and injection?
- ✓ How does the productivity and injectivity per well compare?
- ✓ How is injection pressure compared to fracturing pressure?

Chapter Five

Conclusion and recommendation

This chapter presents the various conclusions from the study designed to optimize the performance of a water-flooding project by focusing on injectivity performance. Recommendations are made to highlight potential areas of further research.

5.1 Conclusion

Numerous field water-flooding projects are currently being implemented all over the world, to improve hydrocarbon recovery**.** In many large oil fields, water injection is initiated during the early stage of reservoir development.

- During water-flooding projects, lifecycle impairment due to re-injected water needs to be carefully evaluated to determine the appropriate volume of water needed to improve oil recovery.
- Damage caused by re-injected water is a complex phenomenon, due to water quality, reservoir characteristics, injection strategy, facilities and well operations.
- Sand production may reduce water injectivity and thus leading to the loss of an injector.
- Injecting of water that has not been well treated into low permeability formations when the injection pressure is below the formation fracturing pressure may cause a severe decline in well injectivity.

- Cross flow and fines re-injection can influence the near-wellbore pressure dramatically and then enhance the effect of water-hammer on sand failure at original permeability.
- Suspended solids, oil droplets, organic debris and bacteria can all contribute to the plugging of formation permeability, thus reducing water injectivity.

5.2 Recommendation

The following recommendations are proposed for the enhancement of performance and longevity of water injectors:

- Provide long sumps (rat holes) as part of well completions.
- Minimise the frequency and duration of emergency shutdowns.
- Minimise the concentration of solid particulates in injection water.
- Clean permanently the injection flow lines.
- Surveillance and monitoring should be programmed into any planned water-flooding project.

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Nomenclature

Pinj: flowing bottom hole injection pressure

Pres: reservoir pressure

K: reservoir permeability

h: injection thickness

μ: water viscosity

re: equivalent radius

rw: wellbore radius

S: wellbore skin

J: is the Productivity Index in STB/day/Psi

Qo: is the flow rate of oil in STB/Day

Pr: is the static pressure or volumetric pressure of the average drainage area

Pwf: is the bottom hole flowing pressure

Delta P = Pr – Pwf = Drawdown Pressure