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PROFITABILITY OF ENHANCED OIL RECOVERY-ECONOMIC POTENTIAL OF SMART WATER IN SANDSTONES

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PREFACE

This thesis is written as part of my Master of Science in Industrial Economics at the University of Stavanger, during the spring semester of 2021.

My interest in Smart Water enhanced oil recovery (EOR) started already during my first year of my bachelor's degree in petroleum technology. My interest for EOR grew throughout my bachelor thesis, a literature study based on trying to find the smartest water for dolomite reservoirs. Although Smart Water EOR is an emerging EOR method with great potential on the Norwegian continental shelf, few studies have been performed to investigate the economic benefits of this injection method. My motivation for writing this thesis came from wanting to combine my knowledge within petroleum technology together with industrial economics to shed light on the economics of Smart Water EOR. An economic simulation tool was therefore created for operators to use on their own fields to see if Smart Water implementation is justifiable.

I would like to take this opportunity to express my gratitude to my supervisors, Tina Puntervold, Skule Strand and Iván Darío Piñerez Torrijos for the guidance, support and the enthusiasm through many good discussions this semester. I would also like to thank Atle Øglend for joining our team and contributing with the economic part of the thesis.

Furthermore, I would like to thank my family and friends for all their support and encouragement along the way, and INDØKS for making my last years at the University of Stavanger memorable.

ABSTRACT

Smart Water EOR is an emerging enhanced oil recovery (EOR) technology, which has shown promising results in laboratory core floods. Increasing the overall recovery up to 66% original oil-in-place (OOIP), by adding an additional 26% OOIP, this EOR method has a large potential for full-field implementation. In a base case scenario, where the most promising scenario is assumed, Smart Water contributes with an additional 578 million barrels of oil. The interest in EOR methods has increased over the past years due to the increased difficulty in discovering new fields. Although there has been a significant increase in evidence supporting EOR methods, there are limited publications on the economics of EOR.

As profitability is the main driver of any project, this thesis aims to shed light on the economics of Smart Water EOR, evaluating the added value gained by injecting Smart Water rather than seawater (SW). The results have been obtained by combining technical and economic data into a simulation model, to calculate the profitability of each method. Through scenario analyses, the effect of varying input variables such as the CO_2-fee, oil production cost and additional oil recovered, on the net present values (NPV) of the projects has been assessed.

Further effects on the NPV have been assessed through break-even analyses on oil price fluctuations. The results indicate that Smart Water under the given circumstances is profitable for relatively low oil prices, favoring high recovery factors. In addition, a scenario where Smart Water is injected with low recovery results has been simulated, to see how profitability is affected by extreme cases. From the simulations, an additional recovery of 3% favored SW over Smart Water.

At last, environmental impacts for choosing Smart Water/LS EOR are discussed. Implementing Smart Water has shown negligible environmental impacts, and reduced CO_2 emissions are expected, as less water is produced due to a delay in water breakthrough. New technologies are presented to presumably reduce investment costs, increasing the profitability potential for Smart Water EOR.

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ABBREVIATIONS & ACRONYMS

bbl –	Barrel
BEP –	Break-even point
CapEx –	Capital Expenditure
EOR –	Enhanced oil recovery
FF –	Feasibility factor
FW –	Formation water
f_w –	Water fraction
IFT –	Interfacial tension
IOR –	Increased oil recovery
IRR –	Internal rate of return
LS –	Low salinity
NCF –	Net cash flow
NCS –	Norwegian continental shelf
NPV –	Net present value
OOIP –	Original oil-in-place
OpEx –	Operational Expenditure
PV –	Present value
RO –	Reverse osmosis
S_{or} –	Residual oil saturation
S_{wi} –	Initial water saturation
SW –	Seawater
SWI –	Seawater injection
WOR –	Water-oil ratio

Chapter 1 - INTRODUCTION

Profitability is the primary driver of any project, justifying the implementation of the process. Any successful project requires good planning. In the oil & gas industry, the profitability of oil production is strongly influenced by falling oil prices, which can be impossible to predict. Thorough economic analysis throughout the project is therefore recommended (Hite et al., 2005).

It is becoming increasingly difficult to discover new oilfields and large oil resources on the Norwegian continental shelf (NCS) can no longer be produced profitably using our current plans and technology, **figure 1.1**. Most operators today therefore attempt to maximize the recovery factors of existing fields. High oil prices and the concern about the future oil supply have therefore led to a renewed interest in enhanced oil recovery (EOR) methods. EOR is a group of technologies used to extract crude oil from an oil field that cannot be extracted otherwise. Once oil prices are high enough to make EOR technologies economical, operators may use these techniques to extend the global oil reserves (Hite et al., 2005; Muggeridge et al., 2014; NPD, 2017).

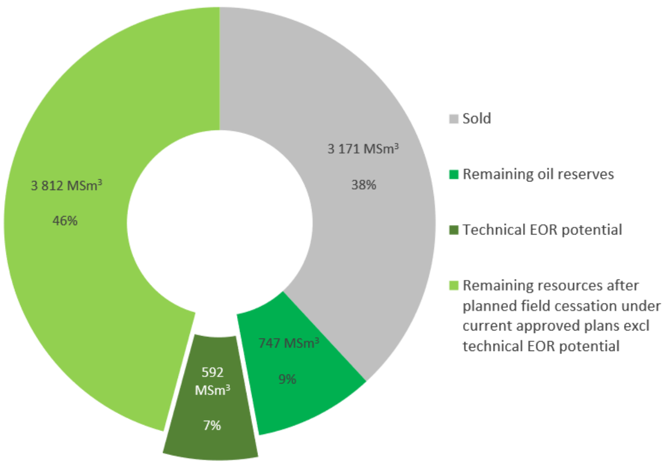


Figure 1.1- *Overall resources of 27 fields on the NCS and the technical EOR potential (Smalley et al., 2018).*

Research has shown that early economic analyses is important in EOR projects, as more data and time is required than for primary- and secondary-recovery processes. Good economic screening processes are therefore necessary to prevent spending economic resources on fields unsuitable for EOR (Hite et al., 2005). **Figure 1.2** illustrates areas in the North Sea suitable for different EOR methods.

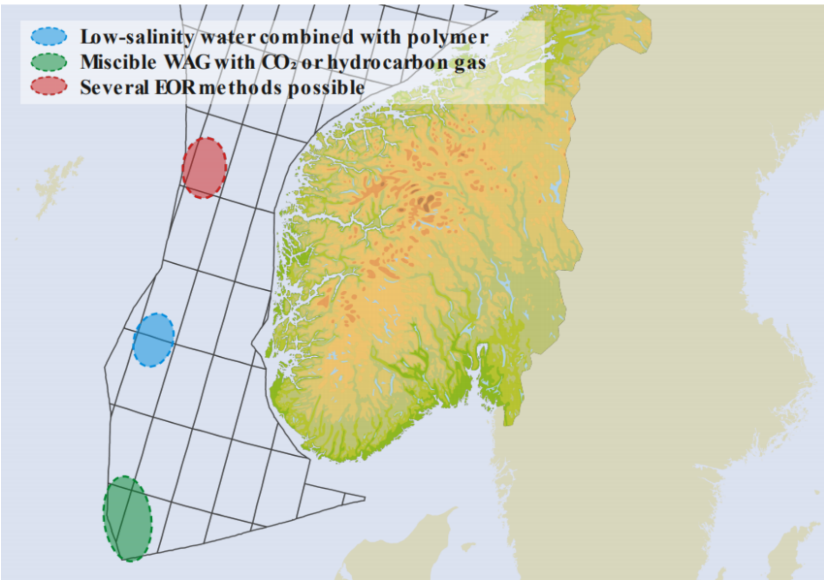


Figure 1.2 *- Technical EOR potential on the NCS (Hite et al., 2005; Muggeridge et al., 2014; NPD, 2017).*

Smart Water is a cheap, efficient, and environmentally friendly EOR method that can alter the wettability of the reservoir rock, increasing oil recovery. In sandstones, low salinity (LS) water behaves as a Smart Water. According to **figure 1.2** above, LS EOR appears to be feasible on the NCS. Due to high investment- and operating costs, the economic viability of Smart Water injection in comparison to traditional seawater injection (SWI) is uncertain. As limited economic studies have been published on the economics of Smart Water/LS EOR, investigating the profitability of the method can be challenging.

Chapter 2 - OBJECTIVE

The objective of this thesis is to investigate the profitability of Smart Water EOR in comparison to traditional seawater injection (SWI) in sandstone fields. Through economic scenario simulations and break-even analyses, the net present value (NPV) of Smart Water and seawater (SW) is obtained and evaluated. The simulation model is used to analyze how the following factors affect the profitability of Smart Water in comparison to SW:

- Future increase in CO_2-fee
- Oil production cost
- Additional oil recovered
- Fluctuations in oil prices

Scenarios where Smart Water is injected at low recovery factors will also be discussed in comparison to high recoveries from implementing Smart Water as an increased oil recovery (IOR) method. Finally, environmental impacts and new technologies will be discussed to investigate future opportunities for Smart Water implementation.

This thesis aims to shed light on the economics of Smart Water EOR and evaluate the added value gained by injecting Smart Water rather than SW.

Chapter 3 - LITERATURE REVIEW AND THEORY

This chapter covers introductory concepts of sandstone mineralogy, oil recovery mechanisms as well as technical and economic aspects of enhanced oil recovery (EOR) projects.

3.1 MINERALOGY OF SANDSTONES

It is important to understand the mineralogy of a reservoir when discussing wettability concerns and Smart Water injection implications. The nature of sandstone rocks dictate the type of wettability mechanism present in the rock, which will have an effect on the EOR potential using Smart Water (Torrijos, 2017). This section will therefore cover the mineralogy of sandstones.

3.1.1 Sandstones

Sandstones are one of the main reservoir rocks in the world, accounting for 80% of all reservoirs and 60% of oil reserves (Cossé, 1998), providing reservoirs for both oil and gas, as well as for groundwater (Bjørlykke, 2010). The average size of a sandstone reservoir is: 25 m thick, 4 km wide and a 50 km long. About 80-85% of the pores are filled with oil. In good quality sandstone reservoir rocks, up to 70% of the original oil-in-place (OOIP) is recovered (Bjørlykke, 2010; Zimmerle, 1995). Sandstones are clastic sedimentary rocks consisting of sand grains (with particles between 63 μm and 2mm) which make up around 15% of sedimentary rocks. The main composition of sandstones is quartz, feldspars, rock fragments and clay minerals, illustrated in **figure 3.1**.

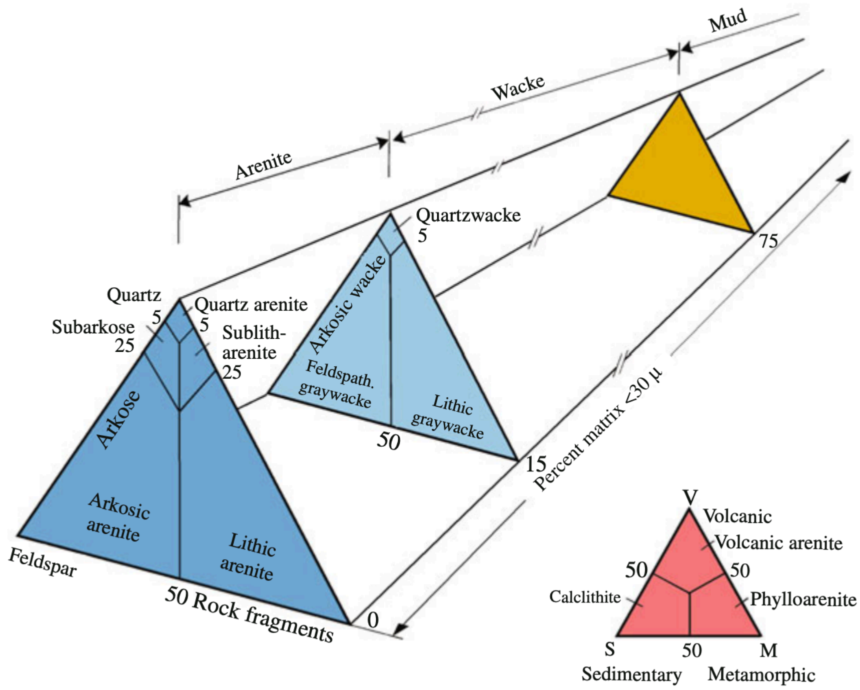


Figure 3.1 *- Classification of sandstones (Bjørlykke, 2010).*

The most abundant type of sandstone grains is the monocrystalline (single crystal) quartz. Although monocrystalline quartz grains make up about 60-70% of sandstones, some are nearly 100% quartz, while others contain none. Polycrystalline quartz is however defined as rock fragments when they are composite grains having multiple interlocking quartz crystals. Quartz is however a common component in rocks such as gneiss, granite and schist; making up large parts of the Earth´s crust (Prothero & Schwab, 2004).

3.1.2 Feldspar minerals

Feldspar is less abundant than quartz in sandstone rocks and make up 10-15% of sandstones. There are two main families of feldspar: potassium (K-feldspar) and plagioclase (NaCa) feldspar, which differ in abundance. Potassium feldspars are more predominant as they are more common in the continental crust. Feldspars are however easier to decompose than quartz and are rock-forming minerals making up about 58% of the Earth´s crust (Haldar & Tisljar, 2014; Prothero & Schwab, 2004).

3.1.3 Clay minerals

There are five major groups of clay minerals: Kaolinite, Illite, Chlorite, Smectite and mixed-layer varieties. For Smart Water to be effective in sandstones, clay minerals must be present;

especially Illite and Kaolinite. Both Kaolinite and Illite are non-swelling clays (Austad et al., 2017; Torrijos, 2017). Due to a greater specific surface area in comparison to other minerals, clays are one of the most reactive components in well-simulation operations (Schlumberger, 2021). However, clays are chemically unique as they have permanently negative charges, and act as cation exchangers. The general order of affinity is shown below (Austad et al., 2017):

$$Li^+ < Na^+ < K^+ < Mg^{2+} < Ca^{2+} << H^+$$

3.2 WETTABILITY

For a water-oil-rock system, wettability is the average wetting preference of a rock´s interstitial surface (Donaldson & Alam, 2008). It is one of the most essential factors driving the oil recovery mechanisms, controlling flow, location, and distribution of reservoir fluids. Most petrophysical properties of reservoir rocks such as capillary pressure, relative permeability, waterflood behavior, electrical properties as well as EOR are affected by wettability. Since reservoir rocks are originally formed in marine environments, they are mostly water-wet. As hydrocarbons migrate, reservoir rocks can reverse to oil-wet conditions. This is due to the electrical charges of the surface grains, attracting components of the opposite charge that are contained in the phase of migrating hydrocarbons (Bortolotti et al., 2010). There are currently four states of wettability: water-wet, fractionally-wet, mixed-wet and oil-wet, shown in **figure 3.2**.

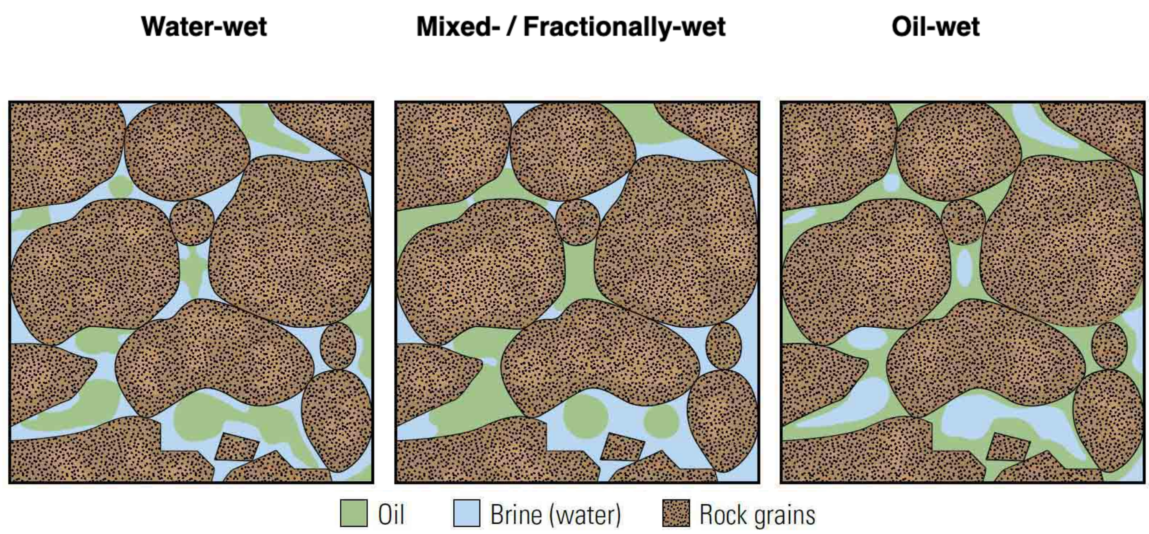


***Figure 3.2** - Rock wettability illustration (Redrawn from Nolen-Hoeksema (2016)).*

In a **water-wet** system, more than 50% of the rock surface is wet by water. Water exists as a continuous phase in the porous system, where the oil, as the nonwetting phase, is in a discontinuous phase as larger droplets seen in **figure 3.2**, surrounded by water. At the initial water saturation (S_{wi}), the oil saturation is high enough for the oil to remain in a continuous phase. However, as the water saturation increases, the oil phase becomes discontinuous and the oil gobbets become surrounded by water. At all saturations greater than or equal to the S_{wi}, the wetting phase saturation exists as a continuous phase.

A **fractionally-wet** system characterizes heterogeneously wet pore surfaces. In these systems, the preferential wetting is randomly distributed throughout the rock. This can in some cases, where minerals are randomly distributed, lead to there being no continuous oil networks in the rock, as some areas may be neither preferentially oil- or water-wet.

The term **mixed-wet** has been used to characterize a pore system where the small pores are water-wet and the larger pores are oil-wet filled with oil. In this case, the oil forms a continuous path through the length of the rock. The oil will no longer be able to enter the smaller pores as the capillary pressure to displace the water is too high.

The general term used for fractionally-wet and mixed-wet is neutral-wettability. The term is used to describe the rock surface as half water-wet and half oil-wet.

In an **oil-wet** system, the water and oil positions are reversed. This implies that the smaller pores are occupied with oil, excluding the water, and the surface of the larger pores are in contact with oil. In this system, water is the nonwetting phase. When the saturation is close to the residual oil saturation (S_{or}), the water exists as a continuous phase in the larger pores. At all saturations greater than or equal to the S_{or}, oil is in a continuous phase (Donaldson & Alam, 2008).

3.3 INTRODUCTION TO ENHANCED OIL RECOVERY

A reservoir´s life cycle consists of several different phases such as exploration, discovery, appraisal, development, production, and abandonment. The objective of reservoir engineering is to optimize the profit from a field by applying scientific principles to fluid flow in a porous medium (Essley, 1965).

3.3.1 Oil recovery mechanisms

Traditionally, primary-, secondary- and tertiary oil recovery are the terms used to describe the recovery of hydrocarbons. These terms are in accordance with the production method or the time where the hydrocarbons have been obtained (Ahmed & Meehan, 2011, p. 541). The abovementioned order may be altered and some of the stages may be bypassed if the crude oil is not recovered at an economic flow rate. This however will depend on the characteristics of the reservoir (Green & Willhite, 2018).

The general term increased oil recovery (IOR) however, implies that oil recovery is improved by any means. IOR is a term that includes EOR, creating a set of oil production technologies and strategies that are superior to traditional methods (Ahmed & Meehan, 2011; Alvarado & Manrique, 2010). A schematic overview over the recovery processes are illustrated in **figure 3.3** (Kokal & Al-Kaabi, 2010).

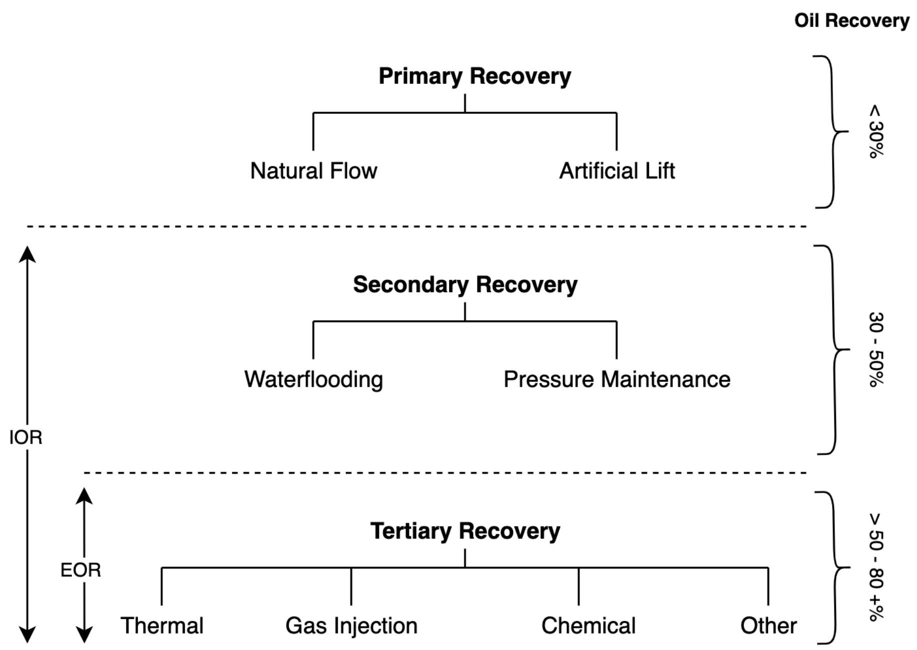


Figure 3.3 - *Illustration of recovery methods (redrawn from Kokal and Al-Kaabi (2010)).*

3.3.1.1 Primary oil recovery

The conventional definition of primary recovery is described as the stage where the production of hydrocarbons is driven by natural mechanisms already present in the reservoir; without additional help from other injected fluids such as water or gas. The natural driving mechanism is in most cases inefficient and may result in a low oil recovery. As seen in **figure 3.3** above, less than 30% of the OOIP is being produced in the primary recovery stage, due to pressure loss in the reservoir. As the natural drive in most reservoirs is insufficient, a type of artificial drive has been introduced such as water or gas injection (Ahmed & Meehan, 2011; Castor et al., 1981).

3.3.1.2 Secondary oil recovery

After a primary depletion, the driving force of the reservoir is reduced. The additional recovery which results from utilizing the conventional methods of either water- or immiscible gas injection is called secondary oil recovery. This recovery technique aims to displace the oil towards its producing wells, as well as maintaining the reservoir pressure. The most common method used is waterflooding, as gas flooding has been seen to be less effective in the secondary mode (Green & Willhite, 2018).

The secondary recovery is in most cases conducted after the primary recovery. However, as mentioned earlier, the two methods may be conducted simultaneously. During secondary recovery, the oil is being produced at a steadily increased water-oil ratio (WOR). If this ratio becomes too high, the field has reached its economical limit, and the oil will therefore not be produced cost efficiently (Standnes, 2001). Before the secondary recovery project is initiated, there should be a proof that the natural recovery mechanisms present in the reservoir are insufficient. If this is not proven, there may be an economical risk that the capital investment is wasted (Ahmed & Meehan, 2011).

During secondary recovery, an average of 30-50% of the OOIP can be extracted in favorable reservoir conditions. In unfavorable conditions such as the presence of fractures, non-favorable wettability, large permeability differences between layers, high capillary entrapment by water or gas injection etc. the recovery may drop to about 20% of the OOIP (Castor et al., 1981). A tertiary step may be considered to extract the residual oil in the reservoir, also known as EOR.

3.3.1.3 Tertiary oil recovery/Enhanced Oil Recovery

A tertiary (enhanced) oil recovery method is used after a secondary recovery to recover additional oil that could not be recovered by the secondary method. After both primary and secondary methods have been utilized to their economic limit, the oil remaining in the reservoir is described as the residual oil (Ahmed & Meehan, 2011). The definition of the term EOR can be controversial as the tertiary method may be utilized right after a primary recovery, depending on the economic, logistical and technical constraints (Green & Willhite, 2018).

The various EOR methods designed to reach the economical limit of the reservoir are thermal recovery, gas injection, chemical flooding as well as other alternative methods.

3.3.2 EOR methods

Thermal EOR methods relate to injection processes that require thermal energy or in-situ generation, and are generally applied to heavy, viscous crudes. The purpose of thermal energy injection is to raise the temperature of the reservoir to reduce the oil viscosity. By reducing the oil viscosity, the movement of oil towards the producers are facilitated. Steam flooding and in-situ combustion are the most common methods for thermal recovery. Cyclic steam injection also known as "huff and puff" is however the most successful steam flooding strategy. During this cycle, steam is injected at high rates for a period of time (usually a couple of weeks). The well is then shut for the formation to soak, followed by putting the well back in production (Alvarado & Manrique, 2010; Kokal & Al-Kaabi, 2010).

Gas injection is an EOR method applicable to light oil reservoirs, both sandstones and carbonates. This category relies on the miscibility of the injectant´s with the oil phase. The solvent is injected by flooding one of the following: carbon dioxide, hydrocarbon miscible or nitrogen and flue gas. Carbon dioxide is one of the most popular methods as it increases oil recovery through miscibility as well as it disposes a greenhouse gas. Viscous fingering is however a frequent problem with the abovementioned processes, due to the low viscosity of the solvents. It may also lead to poor sweep efficiency. These problems can be corrected by using water-alternating-gas (Alvarado & Manrique, 2010; Kokal & Al-Kaabi, 2010).

Chemical flooding has the primary goal of increasing oil recovery by either mobility control or reducing the interfacial tension (IFT). The target of the method is however to increase the capillary number, which is a dimensionless quantity relating viscous forces in a system to the surface tension forces (Rapp, 2017). Chemical methods usually include injecting interfacial-active components such as alkalis, surfactants, polymers and chemical blends (Alvarado & Manrique, 2010). Surfactants and polymers are however not environmentally friendly as chemicals are added. The cost for producing surfactants/polymer is therefore higher than for the alternative EOR methods mentioned in section 3.3.3. A significant increase in implementation costs are therefore expected.

3.3.3 Alternative EOR methods

Waterflooding is traditionally considered a secondary recovery method due to its lack of specially injected EOR chemicals, **figure 3.3**. Laboratory studies have shown that injected water, having different chemical composition to the formation water can disturb the system´s chemical equilibrium. The wetting properties of the reservoir rock will change during the process of reestablishing chemical equilibrium, which may result in improved oil recovery. However, if the injection water has a similar composition to the formation water (FW), the chemical equilibrium effect will not be large enough for wettability alteration (Austad, 2013). In a traditional waterflooding process such as FW injection, the waterflooding is regarded as a secondary recovery. However, as studies have shown, if the composition of the injected water is modified, oil recovery can increase due to wettability alterations, making waterflooding an EOR method (Torrijos, 2017).

A **Smart Water** can be made by adjusting/optimizing the ionic composition of an injection fluid such that a change in the chemical equilibrium modifies the initial wettability of the system. Because of the change in wetting conditions, the oil from the porous network is more easily displaced, **figure 3.4**. When more oil is recovered after performing a secondary recovery with waterflooding, Smart Water can be categorized as a tertiary oil recovery method. The Smart Water technique is considered inexpensive and environmentally friendly, as there are no injection problems, provided that the salinity is high enough to prevent any potential swelling, and no expensive chemicals are added. From an economical perspective, the "smartest" water should be injected initially at the waterflooding process (Austad, 2013).

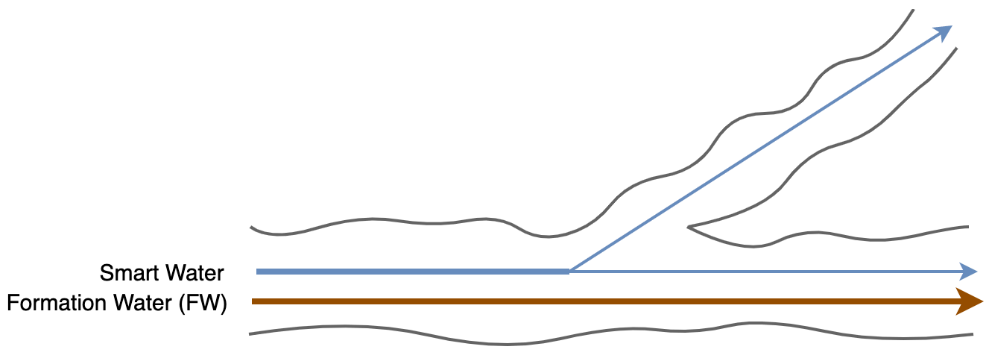


Figure 3.4 *- Illustration of Smart Water imbibition through a porous rock (redrawn from Torrijos (2017)).*

3.4 SMART WATER EOR IN SANDSTONES

For over 20 years, the validation of Smart Water EOR-fluid has been verified in laboratory studies, as well as in the field by research groups and companies. The EOR-group at the University of Stavanger has worked with wettability modification of sandstones for about 10 years. However, there is still skepticism towards the mechanism in published literature (Austad, 2013).

As previously mentioned, Smart Water EOR technology is an emerging EOR method that is cheap, efficient and environmentally friendly. With the purpose of displacing oil and give pressure support to prevent gas production, Smart Water alters the wettability of the reservoir rock. To be able to understand why this injection water gives an increase in oil recovery, it is important to know the chemical mechanism of the rock. When the mechanism is known, it is possible to optimize the injection water for oil recovery (Austad et al., 2017).

In this section, a proposed Smart Water EOR mechanism in sandstone reservoirs will be presented as well as the process of applying Smart Water EOR from laboratory studies to a full field deployment.

3.4.1 Smart Water EOR effect

The effect of Smart Water EOR technology has been given attention from the scientific community as well as the oil and gas industry, due to its economic benefits. The interest has aroused from the vast number of publications as well as the full field implementation of low salinity (LS) flooding in the Clair Ridge field in the UK. Previous work has shown that injecting LS Smart Water in secondary mode instead of tertiary, has a significant effect on oil recovery. This effect is due to the reservoir not being contaminated with brines without a Smart Water EOR effect, seen in **figure 3.5**. However, a combination of Smart Water and tertiary polymer flood has shown a quick oil recovery response (Torrijos et al., 2018).

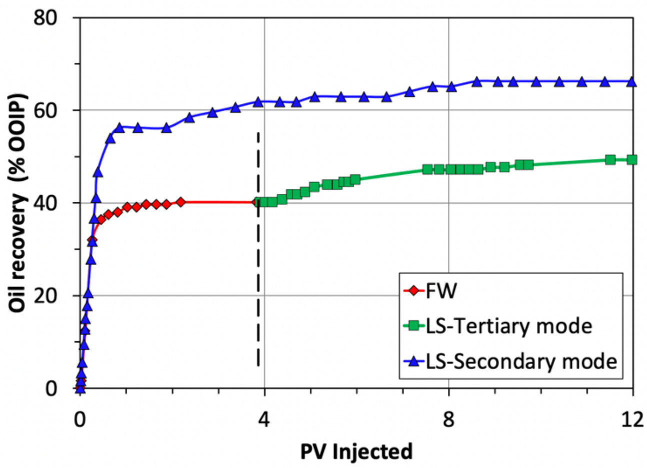


Figure 3.5 - *Comparison between secondary- and tertiary low salinity flooding (Torrijos et al., 2018).*

The key process of optimizing oil recovery during Smart Water flooding is wettability alteration and oil re-distribution. A chemical model describing Smart Water wettability alteration mechanisms in sandstones was proposed by Austad et al. (2010) and described by the following equations (RezaeiDoust et al., 2011):

$$\text{Clay } Ca^{2+} + H_2O \rightleftharpoons \text{Clay } H^+ + Ca^{2+} + OH^- \quad \textbf{(3.1)}$$

$$\text{Clay } NHR_3^+ + OH^- \rightleftharpoons \text{Clay} + R_3N + H_2O \quad \textbf{(3.2)}$$

$$\text{Clay } RCOOH + OH^- \rightleftharpoons \text{Clay} + RCOO^- + H_2O \quad \textbf{(3.3)}$$

Seen in the equations above, the chemically generated wettability alteration mechanism creates a local increase in pH at the clay surface, by the desorption/exchange of Ca^{2+} and H^+ (Torrijos et al., 2018). The proposed chemical mechanisms for LS EOR waterflooding are (Austad, 2013), **figure 3.6**:

1. The sandstone must contain clay
2. The crude oil must contain polar components – acidic and/or basic material
3. The formation water must contain active ions such as Ca^{2+}

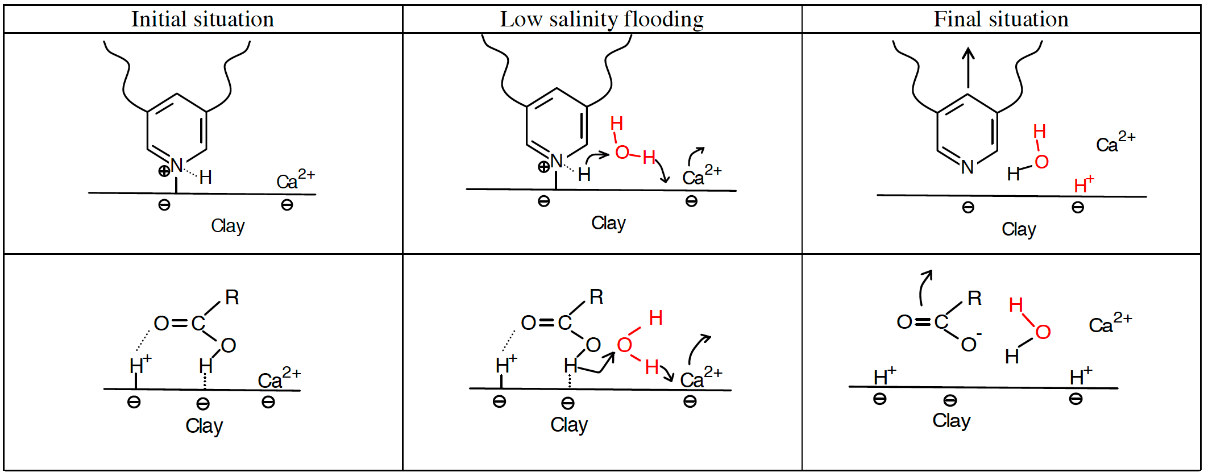


***Figure 3.6** - Proposed mechanism for low salinity EOR effects (Austad et al., 2010).*

***Upper:** Desorption of basic material, **Lower:** Desorption of acidic material.*

The presence of clay minerals in sandstones play a significant role in the wettability of the formation due to their large surface area and permanently placed negative charges. Clays are the main wetting mineral in clastic formations as they have the highest affinity towards crude oil components, due to the abovementioned properties (Torrijos, 2017).

The adsorption of polar components depends on pH. The role of calcium is important when it comes to initial wetting. If the Ca^{2+} is highly concentrated, it has the ability to displace H^+ from the surface of the clay where it is water-wet. This displacement leads to a drop in pH, increasing the adsorption of polar components as well as lowering the water wetness (RezaeiDoust et al., 2011). The ability of oil to wet the surface is linked to the affinity of the polar components under certain circumstances such as: pH, temperature as well as salinity/composition of the FW and the injected brine. These components are what initiate the oil wetting on the surface, making the surface mixed-wet. This is equivalent to what happens in oil reservoirs initially filled with FW and invaded by crude oil. In order to obtain a mixed-wet condition, the active ions present on the surface needs to be replaced by active polar components (Austad et al., 2010; RezaeiDoust et al., 2011; Torrijos, 2017).

3.4.2 EOR lifecycle

To succeed a complex and challenging EOR project, it is important to improve the efficiency in every step of the lifecycle. This can be done by applying advanced technologies, synchronizing diverse measurements, and integrating knowledge across multiple domains. The process of expanding laboratory tests to a full-scale production implementation can take several years (MaerskOil, 2017). **Figure 3.7** illustrates a typical lifecycle for an EOR project deployment.

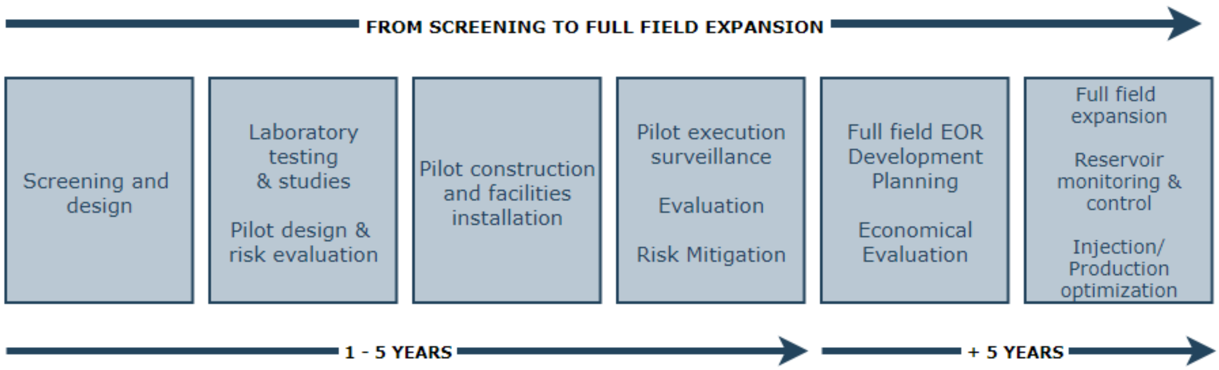


***Figure 3.7** - Typical EOR development lifecycle (redrawn from MaerskOil (2017)).*

Looking at **figure 3.7** it can take up to at least 10 years before an EOR project is fully implemented into a field. This implies that the decision of implementing Smart Water EOR in a field should be decided at the project start phase.

3.4.2.1 EOR field screening

Being able to choose a suitable EOR method for a chosen field is crucial. Screening criteria has therefore been developed to facilitate the process of choosing the correct method. A screening study generally aims to identify the following (Smalley et al., 2020):

- A short list of fields suitable for EOR deployment within the portfolio of the company.
- The most promising EOR process for a certain region in a field.
- An estimate of incremental oil recovery for EOR in a region, to be able to understand and manage a company or nation`s assets in a more effective manner.

Basic tools are used to eliminate technically infeasible EOR processes. After these options are eliminated, companies can use advanced screening to look at the operational, environmental, and commercial aspects of each process. These evaluations can then determine whether the project is operationally feasible and commercially attractive, **figure 3.8**.

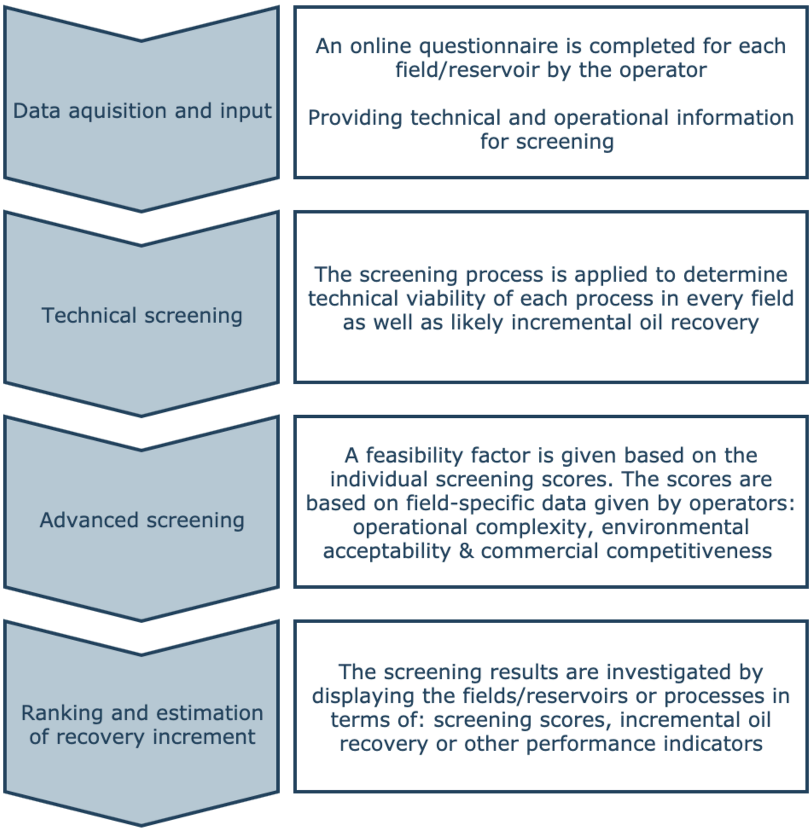


Figure 3.8 - *Overall EOR screening workflow (based on Smalley et al. (2020)).*

Technical screening

Technical screening aims to determine the technical viability of each EOR process. Some of the parameters determining the feasibility are pressure, viscosity, porosity, permeability, remaining oil, wetting behavior, clay type, etc. Using these parameters, each field is given a score, ranking the most promising methods. **Figure 3.9** shows the technical potential volumes for 27 fields on the NCS. Assuming that only the top EOR processes per field are implemented, the volumes are 2 billion, 3.7 billion and 5.4 billion barrels respectively (Smalley et al., 2018).

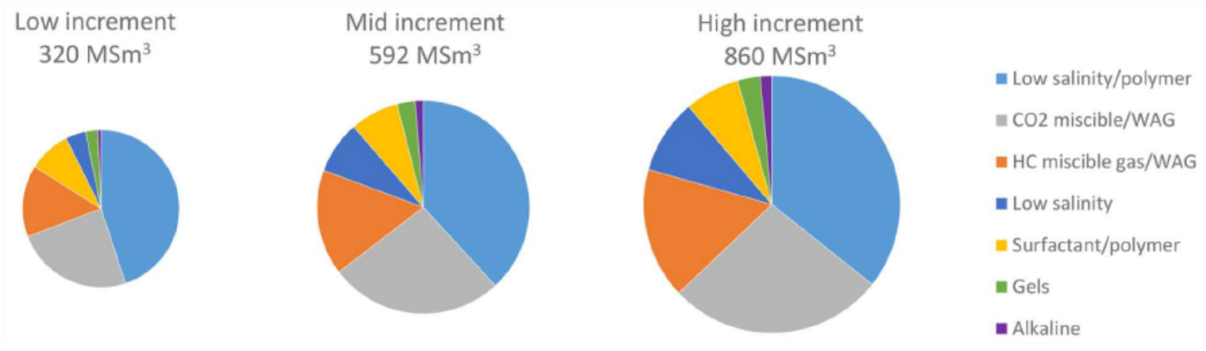


***Figure 3.9** - EOR technical potential incremental volumes for 27 fields on the NCS (Smalley et al., 2018).*

It is logical that only one method is to be implemented per field and according to **figure 3.9**, the most promising method is LS/polymer flooding.

Advanced screening (Operational, Environmental & Economic)

It has become an important innovative step to be able to identify the key operational, environmental, and economic screening criteria for offshore implementation. The screening scores are individually derived for the key elements of operational complexity, environmental acceptability and commercial competitiveness (Smalley et al., 2020), **figure 3.10**.

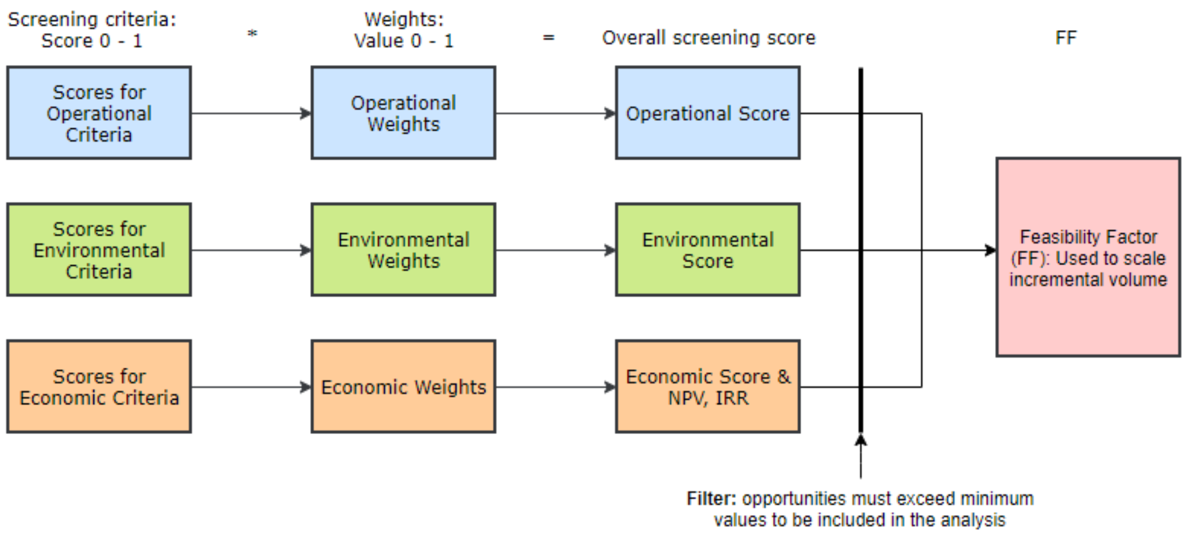


Figure 3.10 - *Feasibility Factor construction logic (redrawn from Smalley et al. (2020)).*

The operational criteria involve the additional facilities and wells required to implement a new EOR process. Within this criterion are the following categories: topside facilities, installations, and wells. One of the most important criteria affecting both operational and economic aspects of the project is the target well spacing, as too large spacing will give low recovery results. Additional wells will then have to be drilled in order to reach target well spacing of about 1.3km for water based EOR processes (Smalley et al., 2020).

The environmental criteria address the issue of the process being denied approval for implementation due to environmental threats. This denial may come from operators, stakeholders or the general public based on the fear for injectant hazards, CO_2 footprint and emissions. Moving from traditional water injection to LS increases the CO_2 emissions caused by the power consumption of the desalination plant. Smart Water will have a similar energy consumption and CO_2 emissions in comparison to LS. However, LS scores 1 on this criterion as it has negligible pollution effects (Smalley et al., 2020).

The economic screening criteria predicts the commercial competitiveness of the EOR opportunities, which is a key input in the decision making. The metrics used to represent the best opportunities is the net present value (NPV) and the internal rate of return (IRR), which consider the time value of money and the investment risks. These metrics are sufficient as EOR projects can be easily ranked to prevent in-detail simulations on every project. The NPV and IRR are calculated from estimations on expected revenue stream. The revenue stream comes from multiplying the expected production profile and the assumed price together with the estimated profiles of capital- (CapEx) and operating expenditure (OpEx). The CapEx is related to the degree the facilities must be upgraded, and how many new injection wells are needed. These will be determined during the operational screening. The OpEx is distributed equally through each operating year where water is injected. When the project reaches production decline and the cash flows are negative, the project is assumed terminated. Projects with a screening score of 1 are economically attractive and low scores are assumed to be economically challenging (Smalley et al., 2020).

The advanced screening scores for Smart Water EOR can be seen in **figure 3.11**.

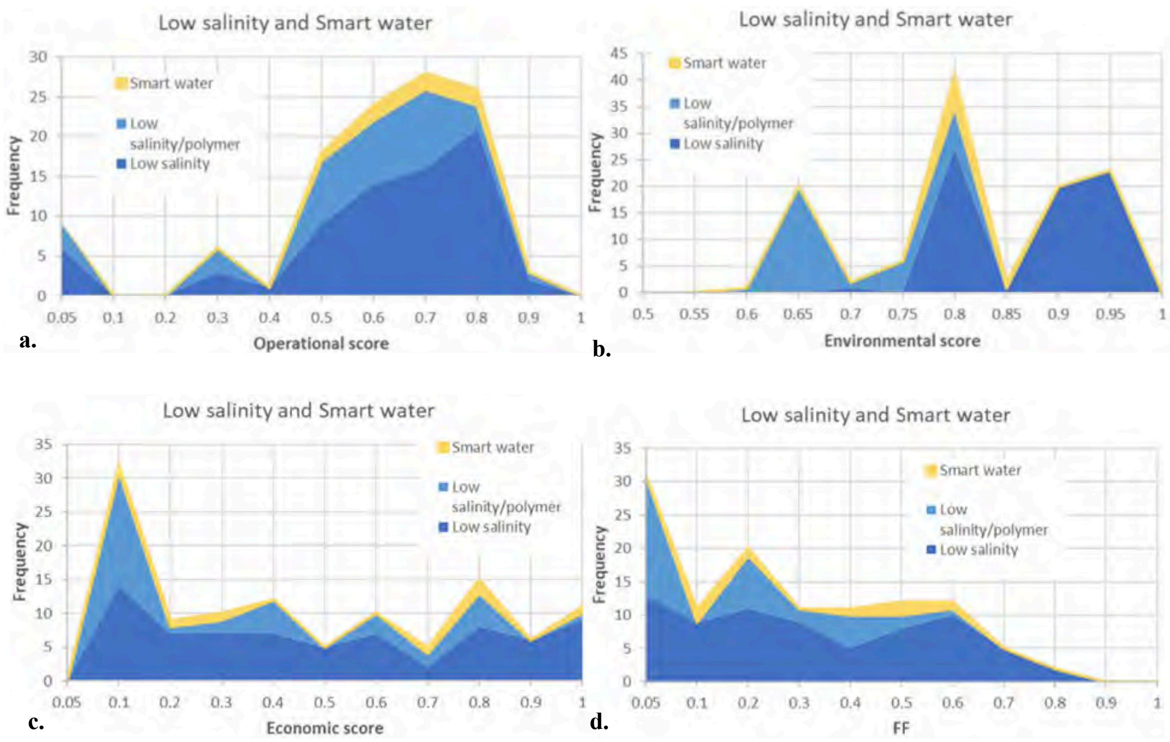


***Figure 3.11 -** Advanced screening scores for low salinity and Smart Water (based on Smalley et al. (2020)).*

***a.** Operational screening scores, **b.** Environmental screening scores,*

***c.** Economical screening scores, **d.** Feasibility factor of low salinity and Smart Water EOR.*

From **figure 3.11**, Smart Water EOR scores highly on both operational and environmental screening criteria and seems to vary for the economic criteria. As the feasibility factor is a product of the abovementioned scores, the attractiveness of the EOR process seems to depend mostly on the economic aspects of the project.

3.4.2.2 Laboratory testing, pilot planning & execution

After screening potential fields suitable for EOR implementation, the method giving the best result is chosen. Looking at the screening results, LS EOR has shown promising results. In sandstone fields, LS water seems to act as a Smart Water.

Detailed chemical knowledge about the interaction between crude oil-brine-rock (CBR) is necessary for designing an optimized Smart Water. This knowledge must be achieved through systematic laboratory studies performed under controlled conditions (Austad, 2013). LS EOR performance may be simulated at core-, well- or sector scale. At core scale, cores are flooded in the laboratory at reservoir conditions to understand the mechanisms and evaluate the displacement behavior of the injected water (Green & Willhite, 2018). At well scale, single well chemical tracer tests (SWCTT) are used to evaluate the residual oil saturation in the near well-bore region before EOR projects are initiated. Sector scale tests involves the creation of fine grid 3D models of the pilot area (Al-Abbad et al., 2016).

During the planning stage of an EOR project, the following steps are included (Hite et al., 2005):

- Appropriate EOR process identification
- Reservoir characterization
- Determining engineering design parameters
- Conducting pilot or field test if necessary
- Creating a plan to manage project expectations

During the abovementioned steps, additional attention should be paid to economic studies and reservoir simulations, while the characterization of the reservoir and the design of the engineering progresses. By paying attention to these aspects of the project, chances of success will be improved.

The profitability of the EOR project is the main driver. If the project is not profitable, it should not be pursued. Good performance predictions are crucial to decide whether a project is profitable or not. However, a good economic model relies on good data, dependent on knowing which elements the economic part of the project is sensitive to.

A pilot project should however be conducted when important variables and parameters are not well understood. Some data may be difficult to measure in the laboratory or can be difficult to deduce from history matching. A field test is therefore justified. These factors may include injectivity, residual oil saturation (S_{or}) and displacement efficiency. Due to limited data and available economic studies on Smart Water EOR, creating a reliable model may be challenging (Hite et al., 2005).

3.4.2.3 Facility installation and full-field expansion

The application of EOR offshore has received a lot of attention due to the potentially large amounts of recoverable oil. EOR application offshore is however in an early stage due to its complex conditions in comparison to onshore applications; as unique parameters are present offshore (Kang et al., 2016). As mentioned earlier, EOR projects are normally developed as tertiary recovery processes. In cases where LS water is injected, research has shown that oil recovered has increased when applied as a secondary waterflood (Hamon, 2016).

When implementing LS EOR injection offshore, a desalination unit known as a reverse osmosis (RO) membrane is required. This method is based on the concept of osmosis, defined as the tendency of a fluid to flow through a semipermeable membrane into a solution having a higher solvent. This artificial process allows water to flow from a concentrated solution to a less concentrated solution (Yeboah, 2018). A RO membrane requires an additional pressure of 65 bar to force water through the semipermeable membrane. **Figure 3.12** is a basic illustration of a RO membrane used for making Smart Water.

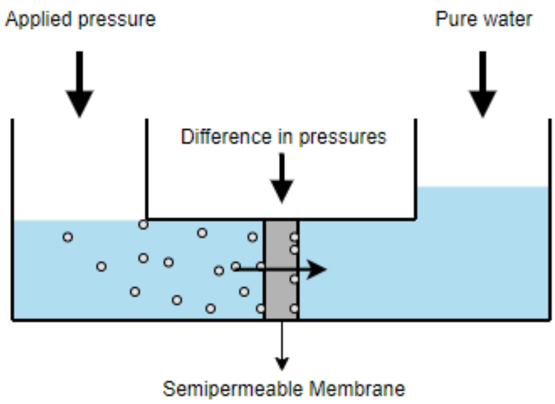


***Figure 3.12** – Illustration of reverse osmosis membrane (redrawn after Yeboah (2018)).*

To ensure that an EOR project is successful, ongoing surveillance is crucial in achieving targets. Even though most of the work lies in the planning phase of the project, the work is not done once water injection starts. Observing wells for monitoring performance, frequent well reviews as well as reliable data and quality control should therefore be emphasized (Hite et al., 2005).

3.5 ECONOMICAL ASPECT OF EOR

As mentioned earlier, the economical attractiveness of an EOR project is crucial for its implementation. However, limited work has been done on the economics of EOR projects. By economic analysis, the most effective direction for research may be determined. An economic analysis can also suggest whether there are any fundamental limitations to the process which may prevent the project`s practical development (Zekri & Jerbi, 2002). Analyzing the profitability of a project is therefore necessary before implementing a new method.

3.5.1 Methods for measuring profitability

The profitability of a project can be measured in several ways, some of the most common methods will be described in this section.

3.5.1.1 Time value of money

The core principle of finance is that money has a time value and is often stated as:

"A dollar received today is worth more than a dollar received tomorrow"

Meaning that the dollar received today may be reinvested and will yield a greater amount in the future. This technique is often used for evaluating projects as well as comparing alternatives, and requires the knowledge and understanding of the time value of money (Ikoku, 1985). When analyzing the economic feasibility of an oilfield project, this principle is fundamental. The future oil production rate schedule must be converted into future cash flows, which have to be related to an investment made in the present (Joshi et al., 1998).

It is therefore necessary to have a method for converting a delayed payoff into a value today, also known as a present value (PV). The PV can be found by multiplying the delayed payoff by a discount factor that should always be less than 1. The discount factor can be found using **equation 3.4** (Joshi et al., 1998):

$$DF_i = \frac{1}{(1 + r_i)^{t_i}} \tag{3.4}$$

Where,

DF_i *discount factor at time t_i*

r_i *discount rate offered by other comparable investments*

t_i *time, years from now*

The PV is given by the following equation if there are a series of delayed cash flows (Joshi et al., 1998):

$$PV = \sum_{i=1}^{n} DF_i \times C_i \tag{3.5}$$

Where,

C_i *cash flow at time t_i*

3.5.1.2 Net Present Value

Net present value (NPV) is used when cash flows are received at different points in time. To calculate the NPV, the initial cash flow, also known as the investment, is added to the PV, shown in **equation 3.6** (Joshi et al., 1998):

$$NPV = C_0 + PV \tag{3.6}$$

Where,

C_0 *initial cash flow*

When applying the NPV method, the main criterion for evaluating any project is that the NPV must be greater than zero (Joshi et al., 1998). If the NPV is less than zero, the project is considered unprofitable.

When provided a successive net cash flows (NCF) $X_0, X_1, X_2, \ldots, X_n$, the NPV can be calculated using **equation 3.7** (Alvarado & Manrique, 2010).

$$NPV = \sum_{t=1}^{n} \frac{NCF_t}{(1+r_i)^{t_i}} \tag{3.7}$$

The NCF can be calculated every year as:

$$NCF\ (in\ USD) = \ Revenue - Capital\ investment - Operating\ expenses$$

From sales arise revenue, in the same way that the sales of oil and gas arise from hydrocarbon reservoirs. *Payout time* and *investment efficiency* are two important concepts. These concepts are defined as the time needed to recover an investment and the ratio of NCF to the total discounted investment, respectively. In IOR and EOR, time value of money has a direct consequence. This relates to the theory that the faster the same resources are produced, keeping other factors fixed, the higher the NPV. This may be an indication to accelerate production to potentially achieve a higher NPV (Alvarado & Manrique, 2010).

3.5.2 Break-even analysis

A break-even analysis is used to determine the sales needed in order to break-even. This method may be useful in combination with a sensitivity analysis as it sheds light on the severity of forecasts that are incorrect. The purpose of a break-even analysis is to determine how much sales can fall before a project loses money. The financial break-even point (BEP) is calculated in terms of NPV and takes investment costs into consideration. In comparison to the accounting break-even, which only takes profits into account, the financial break-even gain the opportunity cost of the initial investment through depreciation (Ross et al., 2019). The BEP can be calculated using **equation 3.8** and **3.9** below:

Accounting Profit Break-Even Point

$$\frac{Fixed\ costs + Depreciation}{Sales\ price - Variable\ costs} \tag{3.8}$$

Financial Break-Even Point

$$\frac{EAC + Fixed\ costs\ \times (1 - T_C) - Depreciation\ \times T_C}{(Sales\ price - Variable\ costs) \times (1 - T_C)} \tag{3.9}$$

Where,

EAC *Equivalent annual cost*

T_C *Corporate tax rate*

3.5.3 Capital Expenditure and Operational Expenditure

Capital Expenditure (CapEx) are funds used by a company to purchase, improve or maintain long-term assets in order to improve its capacity or efficiency. These long-term assets usually refer to physical, fixed and non-consumable assets such as equipment, property, infrastructure, machinery etc. These costs relate to all expenses incurred from the decision on a development is made, until the field is in production. In a Smart Water EOR project the main cost will be the water injection unit. CapEx usually extends into the future and are discounted over the lifetime of the project. This means that short-term projects will be more affected than long-term projects (CorporateFinanceInstitute, 2021a).

Operational Expenditure (OpEx) are all costs incurred during the operating stage of the project. The OpEx is defined as the capital used to maintain the operation of a chosen field and includes all current costs during the production such as energy consumption, injection water, operational costs and CO_2-taxes. OpEx is divided into fixed and variable costs that are proportional to the total production for a given period (CorporateFinanceInstitute, 2021b). The OpEx may be calculated using the following equation **(3.10)**:

$$OPEX(t) = FC + (VC \times Q_t) \tag{3.10}$$

Where,

FC *fixed cost*

VC *variable cost*

Q_t *production in year t*

Chapter 4 - METHOD

This chapter will focus on the method used to obtain the results discussed in this thesis, as well as the assumptions made for the chosen input values and uncertainties. **Figure 4.1** below illustrates the steps taken in this process.

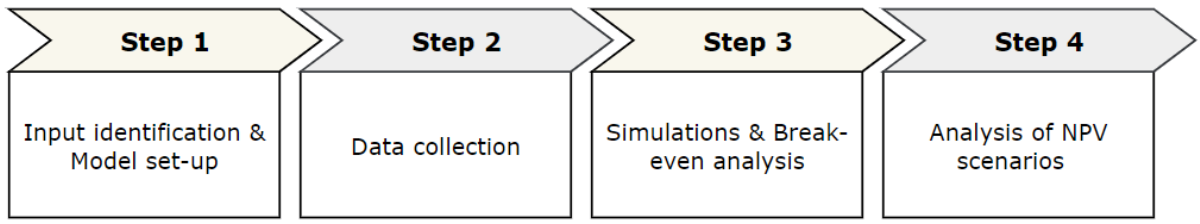


Figure 4.1 *- Method used for the analyses.*

4.1 INPUT IDENTIFICATION & MODEL SET-UP

In order to create a model that calculates the profitability of a Smart Water EOR project, inputs affecting the result must be identified. As this thesis is based on a "simple case" model, assumptions have been made to simplify the calculations. Reservoir parameters included that seem to be the most significant are oil reserves, production rate, recovery factor and recovery mode. For the economical input parameters, the oil price has been considered of high significance and is the parameter with the most uncertainty. Other significant inputs are oil production cost, CO_2-fee and the discount rate used in the NPV calculations. These are the main inputs that are to be determined at the start of each simulation. The following values shown in **table 4.1** have been fixed during the simulations for this thesis.

***Table 4.1 -** Fixed input values chosen for all simulations.*

Fixed input parameters	
Oil reserves[1] [bbl]	2 700 000 000
Production rate [bbl/year]	75 600 000
Recovery factor [% OOIP]	40
Discount rate [%]	10
Oil price [USD/bbl]	60

The oil reserves and production rate have been based on data from the Johan Sverdrup field, which is a good candidate for water injection in the future. For simplicity, the recovery factor has been set to 40% and the discount rate to 10%. **Table 4.2** below, shows the input parameters that have been varied during the simulations, based on most likely values.

***Table 4.2 -** Inputs varied in the simulations.*

Variable input parameters			
CO_2-fee[2] [USD/ton]	70,	236	
Oil production cost [USD/bbl]	10,	15,	20
Additional oil produced using Smart Water			
Secondary recovery mode [% OOIP]	10,	20,	26
Tertiary recovery mode [% OOIP]	0,	3,	6

In the model, drop down menus have been created using the values from **table 4.2**. The CO_2-fee can be set to $70 which is the cost per metric ton today. The other option is $236, which is the cost the Norwegian government plan to increase after 2030. The model also includes the option for choosing whether to inject Smart Water in secondary or tertiary mode. When one of the options are chosen, the model will use the extra recovery percentages (% OOIP) related to

Dollar rate used for converting NOK to USD: 8.4576 [11.03.2021]
[1](EquinorASA, 2021)
[2](Zero, 2021)

its recovery mode. This additional recovery percentage refers to the extra oil that can be produced using Smart Water rather than seawater (SW). The input values chosen for the extra oil produced are based on lab results from the University of Stavanger (Torrijos et al., 2018). Basing full-scale simulations on lab results involves high uncertainties. The results may however give an indication of the field performance. The data shown in **table 4.1** have been used to create a production profile. As the model is lacking real production data, the fractional flow curve connected to the production profile is linear for simplicity.

4.1.1 NPV calculation set-up

In order to study the economic potential of Smart Water injection in sandstone fields, calculations of the NPV of both Smart Water and seawater injection (SWI) must be completed. By varying the input values, the differences in NPV should then be compared to see which project is the most profitable.

To calculate the NPV for both projects, economic and reservoir inputs have been linked to the cashflow. The data used for the NPV analysis can be seen in **table 4.3**.

Table 4.3 - *Economic data for base case Smart Water and seawater*[3].

Injection water data	
Smart Water	
CapEx [USD]	5.80 billion
OpEx [USD]	65.58 million
Seawater	
CapEx [USD]	5.79 billion
OpEx [USD]	60.46 million

[3] The CapEx for Smart Water and seawater is based on data retrieved from BP (2012). OpEx for Smart Water and seawater is calculated in the simulation model based on several papers referred to in the "Economic & Technical input data" tab in the Excel file.

In the simulation model, the CapEx of Smart Water includes the investment cost of the injection unit, CO_2 emissions during the implementation and the opportunity to add/convert extra injection wells in the project has been added. For these simulations extra injection wells have been set to zero as this is a simple case. The cost of injection wells has therefore not been included in the $5.80 billion shown in **table 4.3**. The CapEx for SW includes the investment cost of the injection unit as well as the cost for the CO_2 produced during the implementation of the unit.

For both injection methods, an extra cost of $3 for water treatment exists. However, as both waters need treatment before injection, this cost has not been included as an OpEx in the model. For simplicity, the cost for treating and reinjecting the produced water has been increased along with the water fraction factor in the model.

4.2 DATA COLLECTION

There are limited papers and reports published on the profitability of Smart Water EOR. Obtaining relevant data and results for the simulation model is therefore challenging. As LS water behaves as a Smart Water in sandstones, some data from BP's Claire Ridge field has been used. Reservoir data has been retrieved from Equinor's fact page for the Johan Sverdrup field, as it has potential for Smart Water EOR in the future.

The input data used for the simulations has therefore been retrieved from various sources and databases such as: news articles, fact pages, OnePetro, Bibsys and publications from the Smart Water EOR group at the University of Stavanger. Unavailable data has been based on realistic assumptions from other fields as well as educated guesses.

Costs related to the Smart Water implementation have been based on available data for LS water as it is considered as a Smart Water in sandstones. However, since Smart Water EOR has not yet been implemented offshore, there are limited publications on the economic part of the technology. Accurate input data for the model is therefore difficult to obtain.

4.3 BREAK-EVEN ANALYSIS ON NPV

The oil price is the most uncertain variable in this simulation model. Break-even analyses have therefore been performed to see what the oil price must be for the two projects to be indifferent. The break-even analysis has been made using one of Excel's "What-If Analysis" tools to create a data table with oil prices ranging from $10 to $70, and corresponding NPV for both projects. One input value is varied per simulation for each of the additional oil recovery percentages. Goal seek is then used to find the financial BEP by setting the NPV difference cell equal to zero and changing the oil price.

4.4 SCENARIO ANALYSES

To evaluate how the input parameters, affect the NPV of the project, scenario analyses will be performed. The scenarios will be compared to a base case scenario, assuming a best-case scenario, to see which parameters have a negative effect on the NPV of Smart Water. The following parameters will be varied in the simulations:

- CO_2-fee
- Oil production cost
- Secondary additional oil recovery percentages

Factors such as water production, water breakthrough, cumulative oil production, OpEx and profit will be discussed using the results obtained from the scenario analyses.

4.5 UNCERTAINTY

The lack of publications on the economics of EOR makes it difficult to verify the data obtained for the simulation model. There are few published papers directly addressing the economic potential of Smart Water EOR. One of the published papers referred to in this thesis, SPE-200376-MS, focuses however on technical, operational, environmental, and economic screening of EOR methods offshore.

As there is limited data available, the data used for the simulations are gathered from different sources related to various fields as well as lab results. There is therefore high uncertainty in the results, and the model should be further developed to optimize resource utilization and profitability. However, as mentioned, this is a simple case model built to give an indication to whether Smart Water injection is a profitable EOR method in comparison to traditional SW flooding.

This simulation model is a tool which can be used for economic screening. Field operators will have the opportunity to apply their own data, relevant to their operating fields, which will provide results of higher accuracy.

There is also uncertainty in the parameters used in the model. Uncertainties in parameters such as the oil price, recovery factor and the production rate can affect the results. For this model the recovery factor and the production rate have been made constant for the simplicity of the simulations. However, the Excel Add-In called @Risk™ 7, delivered by the Palisade Corporation, may easily be implemented into the model to account for the uncertainties in the project.

4.6 COMPLEXITY OF EXCEL APPLICATION

Excel is a good and easily applicable tool used in all industries for both economic and technical data. Despite the simplicity of the tool, describing an EOR project in Excel is quite complex. As an EOR project has both economic and technical data, the model requires many inputs to give an accurate description of the method. In this simulation model, complex formulas are used to describe the relationship between the technical aspects of the method and the costs and prices of the implementation and operation of the project. As limited research has been published on the economics of EOR, these relationships have been challenging to describe. The input data used has been based on the limited papers published as well as educated guesses and assumptions. By adding more variables to the model, the uncertainty of the results will increase.

Chapter 5 - RESULTS

This chapter will present the results obtained from the simulation model. The results presented will be based on a base case scenario, described in **table 5.1**. In this scenario, a maximum oil recovery is assumed along with the lowest predicted oil production cost, the current CO_2-fee, and a most likely oil price. This base case will be used for comparison to see which factors influence the NPV.

Table 5.1 *- Input data for the base case scenario.*

Input data	
Oil price [USD/bbl]	60
CO_2-fee [USD/ton]	70
Oil production cost [USD/bbl]	10
Secondary recovery mode [% OOIP]	26
Smart Water	
CapEx [USD]	5.80 billion
OpEx [USD]	65.58 million
Seawater	
CapEx [USD]	5.79 billion
OpEx [USD]	60.46 million

5.1 NET PRESENT VALUE- THE PROFITABILITY OF SMART WATER

Using the data presented in **tables 4.1** and **4.2** together with the economic inputs from **table 4.3**, a production profile has been simulated. **Figure 5.1** illustrates both the technical and economic limits of producing oil by Smart Water in secondary mode compared to traditional SWI.

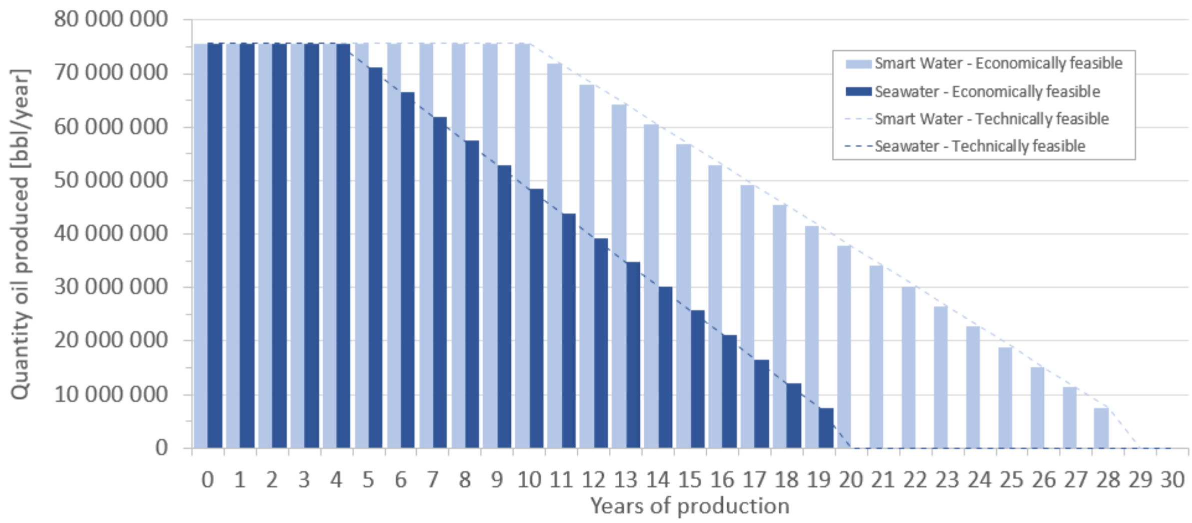


Figure 5.1 - *Production profile comparing Smart Water vs. traditional seawater injection for the base case.*

This base case scenario is simulated using an oil price of $60, oil production cost of $10 and an additional oil recovery factor of 26%, **table 5.1**. In this base case scenario, both SW and Smart Water stop production at their technical limit. The technical limit for SW assumes that 40% of the total reserves are being recovered, which in this case is 1.08 billion barrels. For Smart Water the technical limit is an additional 26%, which is based on lab results, being 702 million barrels.

Comparing the two injection waters, the plateau of Smart Water continues for an additional six years after SW production decreases, due to water production. The delay in water breakthrough, extending the production plateau, increases the lifetime of the field by nine years. This water breakthrough delay contributes with an additional 578 million barrels, seen in **figure 5.2**.

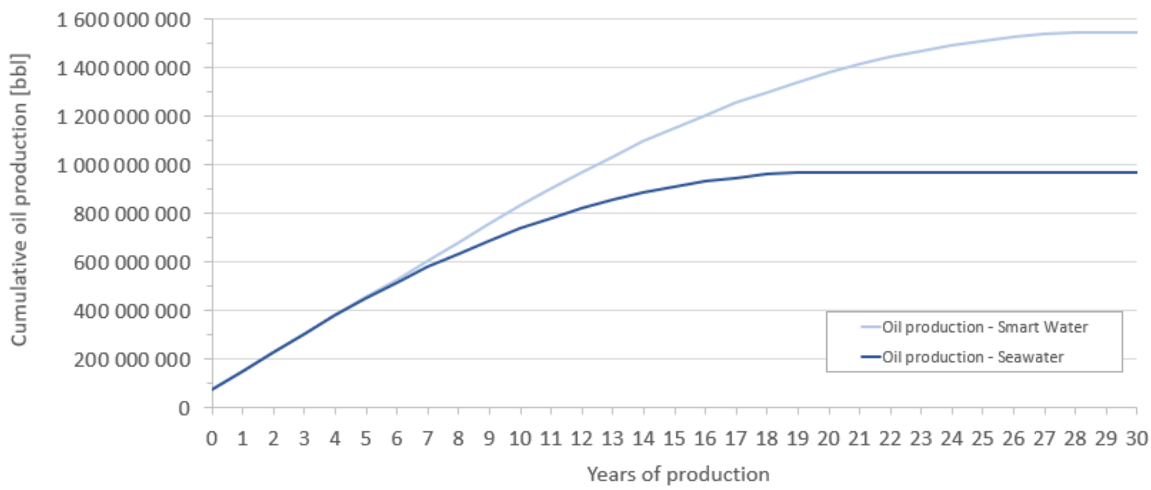


Figure 5.2 - *Comparison of additional oil produced for Smart Water compared to seawater.*

From the production curves, the profit of SW and Smart Water is calculated, shown in **figure 5.3**. According to the graph, SW seems to be more profitable for the first five years where the production is at its plateau. After water breakthrough, the profit starts to decrease as the cost of treating the produced water increases. The profit of Smart Water remains constant until water breakthrough is reached at year 10. After water breakthrough is reached, the profit decreases at a lower rate in comparison to SW. The profit is reduced at a lower rate due to Smart Water having a higher displacement efficiency, resulting in less water to handle. The water production cost reduction makes Smart Water more profitable. The shape of the profitability curve follows the same pattern as the production profile in **figure 5.1**, suggesting that the profitability is highly dependent on the production profile.

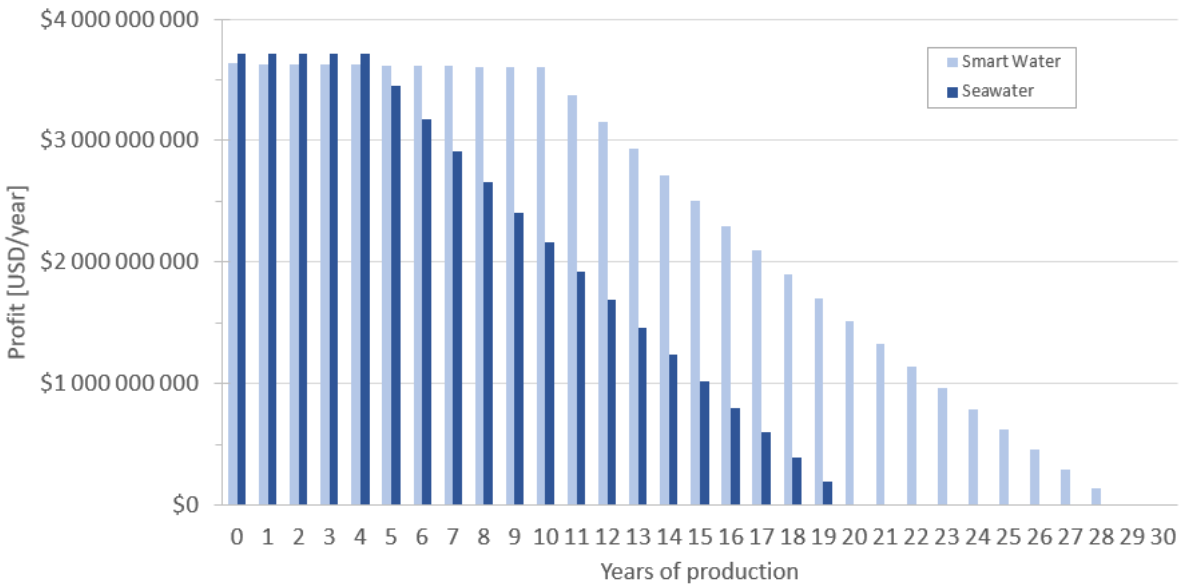


Figure 5.3 *- Comparison of profitability for seawater and Smart Water.*

Using the profit from the simulation model, the CapEx for Smart Water and SW, which is \$5.80 and \$5.79 billion respectively, together with a discount rate of 10%, the NPV can be calculated:

$$\boldsymbol{NPV_{Seawater}} \quad = \boldsymbol{\$18\ 422\ 154\ 624}$$

$$\boldsymbol{NPV_{Smart\ Water}} = \boldsymbol{\$23\ 855\ 187\ 822}$$

From the calculations, Smart Water as a secondary recovery method is clearly profitable with a difference in NPV of \$5.43 billion compared to SW, which is a 29% increase in NPV.

5.2 WATER INJECTION OF SMART WATER VS. SEAWATER

In the previous section, the profitability of injecting Smart Water in comparison to SW was presented. This section will focus on the results related to the amount of water injected into the reservoir. **Figure 5.4** below illustrates the oil recovery response when the field described in **table 4.1** is flooded with Smart Water compared to SW.

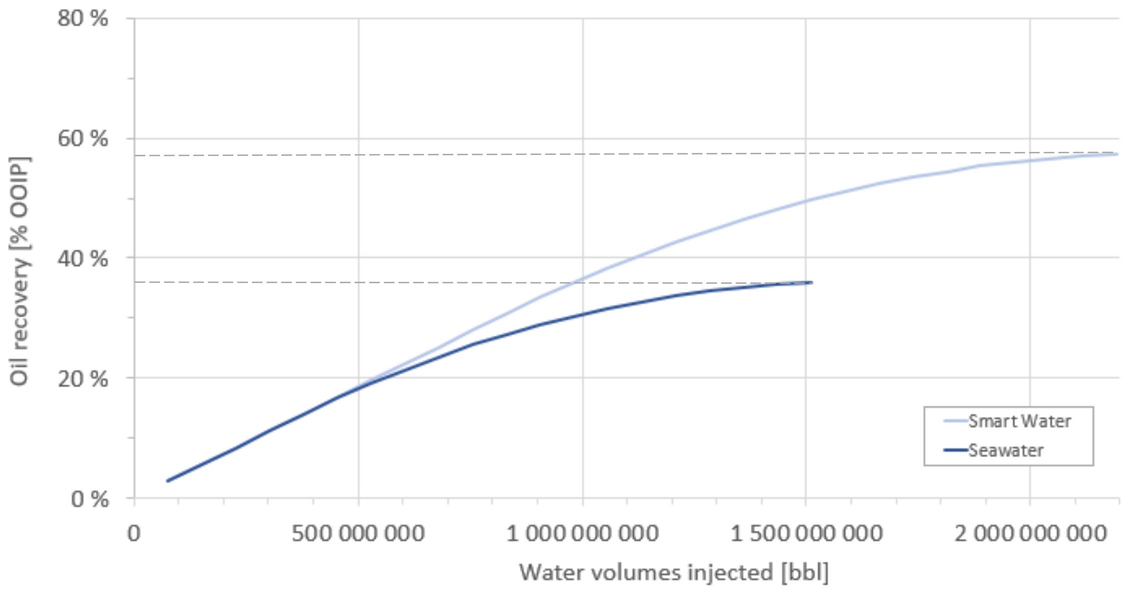


Figure 5.4 *- Oil recovery response to water injection of Smart Water and seawater.*

After 500 million barrels of water is injected into the reservoir, the Smart Water is already starting to show an improved recovery. At the end of production, SW and Smart Water has a total recovery of 36% and 57% respectively, where Smart Water has an additional recovery of 21%. **Figure 5.5** below illustrates the number of barrels produced compared to how many barrels of water are injected into the reservoir.

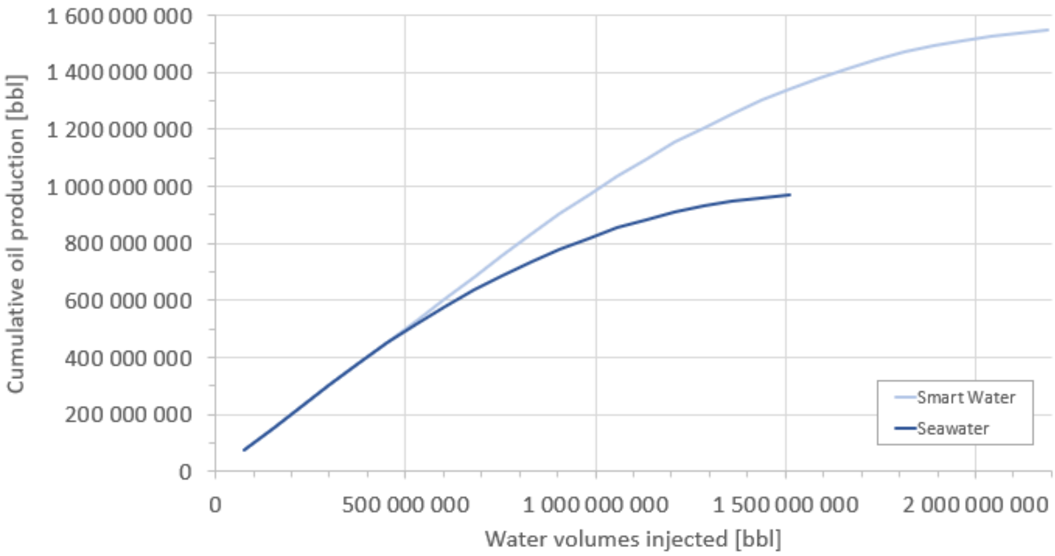


Figure 5.5 - *Number of barrels of oil produced compared to barrels of water injected.*

The relation between water injected and oil produced is linear until 500 million barrels of water are injected, and water breakthrough for SW is reached. The oil production for Smart Water increases at a larger rate than SW ending at a total production of over 1.5 billion barrels of oil, whereas SW has a total production of about 950 million barrels of oil. In this base case scenario, Smart Water has an additional oil production of 578 million barrels. Although more water is injected for Smart Water, observed in **figure 5.5**, for the same amount of water injected for Smart water and SW, more oil is produced using Smart Water. This can be observed in the graph at 1 billion barrels of water volumes injected, where nearly 200 million additional barrels of oil are produced using Smart Water.

5.3 Water production during Smart Water vs. seawater injection

When the production reaches water breakthrough, water is being produced together with the oil. As seen in **figure 5.1** when oil production by SWI reaches the end of the plateau in year five, water is being produced. **Figure 5.6** illustrates the water-oil ratio (WOR) for SW plotted against the cumulative oil produced for the field.

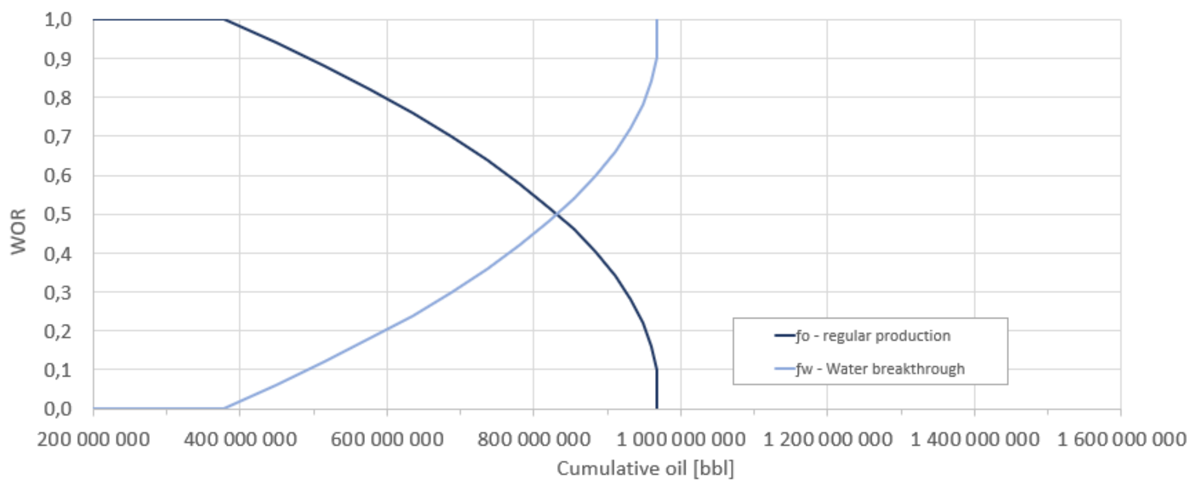


Figure 5.6 *- Water-oil ratio plotted against cumulative oil produced for seawater.*

After the extraction of almost 400 million barrels of oil, water is being produced together with the oil. At 800 million barrels of produced oil, the WOR is 50/50, meaning that equal amounts of water and oil are being produced. When the curve stops at around 950 million barrels, the WOR is 90/10, where only 10% oil is produced per barrel. The model has been set to stop production at this point, as too much water is being produced in comparison to oil, making further production unprofitable. **Figure 5.7** illustrates the WOR for Smart Water plotted against the cumulative oil produced.

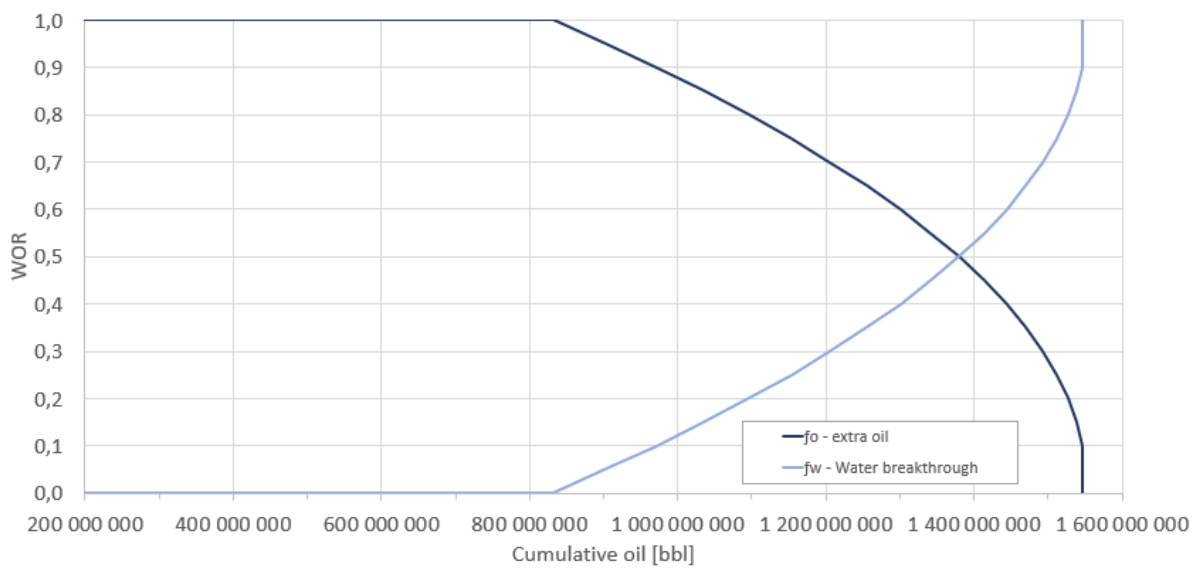


Figure 5.7 *- Water-oil ratio plotted against cumulative oil produced for Smart Water.*

For Smart Water, water breakthrough occurs after 800 million barrels of oil is extracted from the reservoir. When 800 million barrels have been produced for both Smart Water and SW, SW has already reached a 50/50 WOR, whereas Smart Water barely has a WOR of 10/90. This shows that by implementing Smart Water, water breakthrough is delayed and nearly 400 million additional barrels of oil can be extracted before water is produced together with the oil. As Smart Water is more efficient in comparison to SW, the rate at which the WOR increases for Smart Water is also lower than for SW. This implies that the water breakthrough is not only delayed, but more oil is also produced before the WOR reaches 90/10, where production is no longer profitable. **Figure 5.8** compares the cumulative water volumes produced for Smart Water and SW.

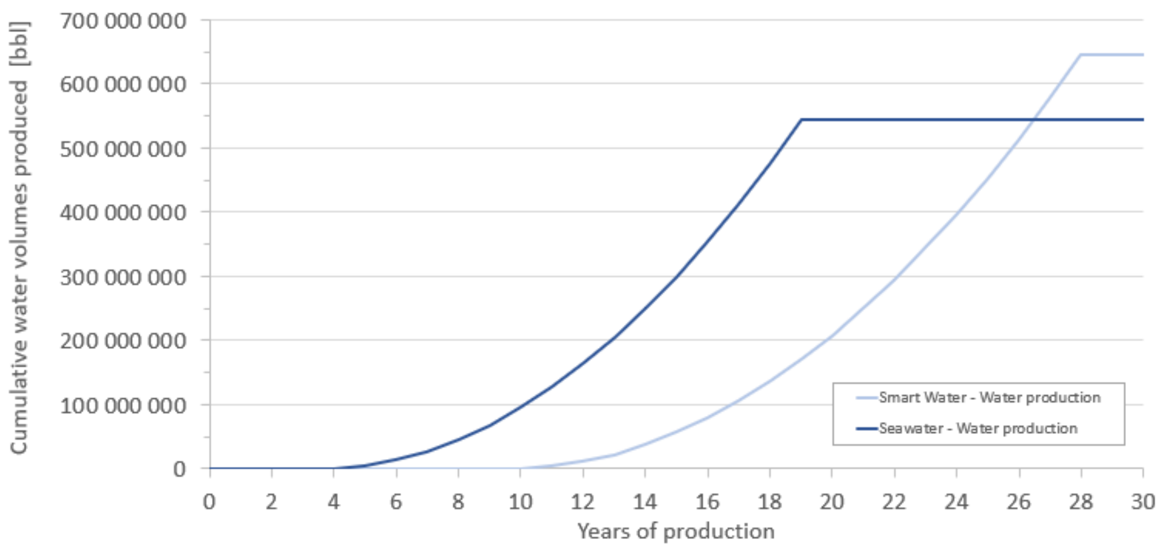


***Figure 5.8** - Cumulative water volumes produced compared for Smart Water and seawater.*

In year five when water breakthrough occurs for SW, the water production has a steep curve until it reaches the end of production at year 19. At this point, around 550 million barrels of water are produced. Smart Water has however a gradual increase in water production starting from year 11 until year 28. At the end of production, Smart Water has produced around 650 million barrels of water which is 200 million more than for SW. If Smart Water had an equal rate of water production as SW, the same amount of water would have been produced. However, the WOR of 90/10 would have been reached three years earlier, resulting in a lower total oil production.

5.4 CAPEX, OPEX AND OIL PRODUCTION COSTS

The cost involved in performing either a Smart Water or a SWI project, includes capital expenditures, operational expenditures, and a cost for producing each barrel of oil. Using the data from **table 4.1** and data from the simulations, **table 5.2** summarizes the total costs for the base case scenario.

Table 5.2 *- Total costs used for the simulations.*

	Smart Water	Seawater	Difference
CapEx [USD]	5.80 billion	5.79 billion	120 million
OpEx [USD]	3.33 billion	1.64 billion	1.68 billion
Oil production cost [USD]	19.7 billion	11.7 billion	7.98 billion

The difference in the investment costs for Smart Water and SW is $120 million dollars. The OpEx for Smart Water is almost twice as high as for SW with a difference of $1.68 billion. The largest difference in costs, of $7.98 billion, is for the total oil production cost which is related to the number of years the field is in production. **Figure 5.9** is an overview of the total costs for completing a Smart Water and a SW project.

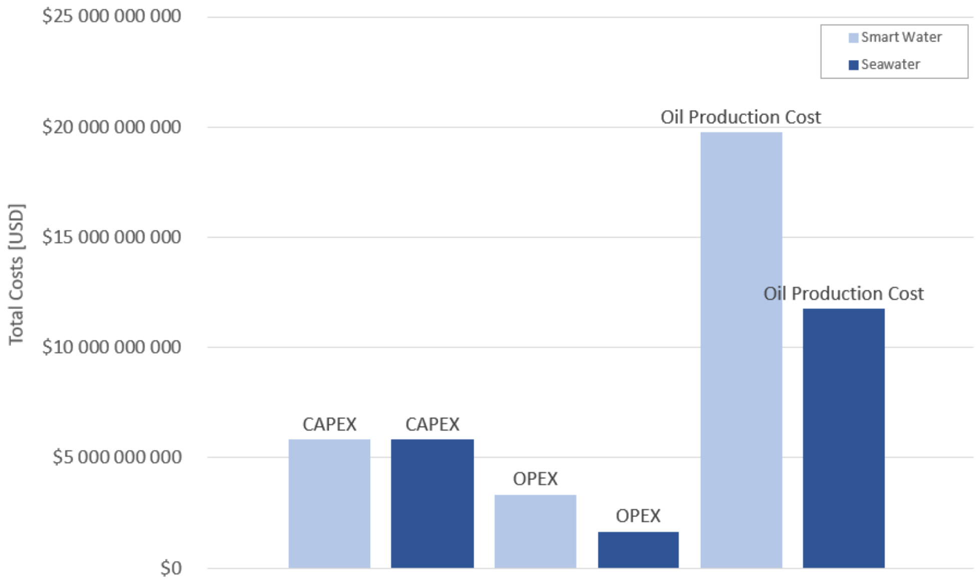
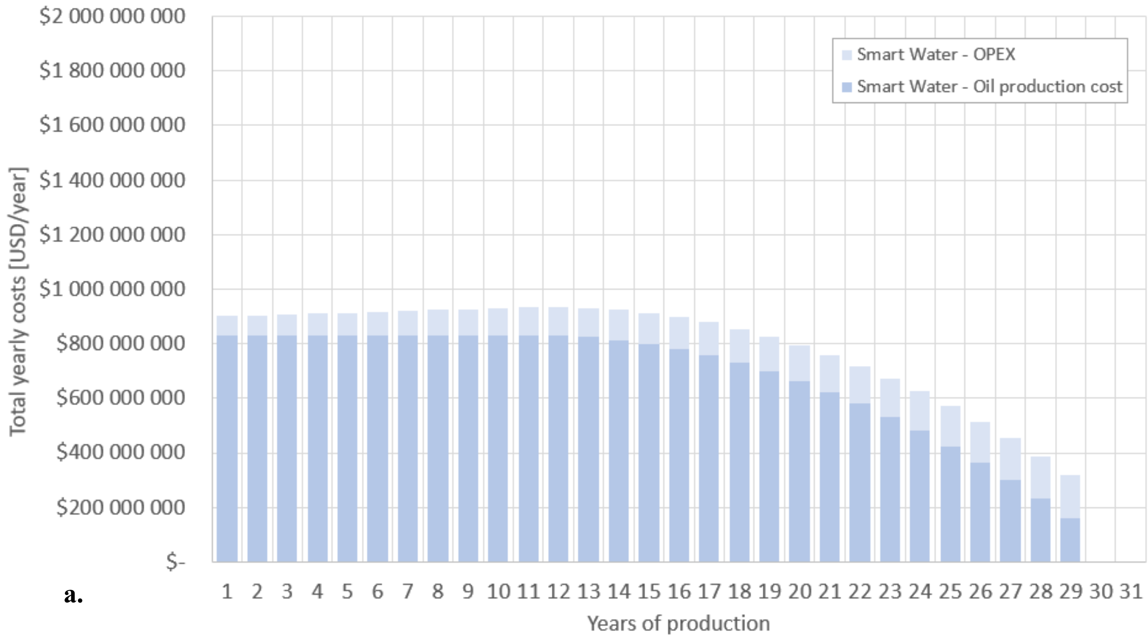
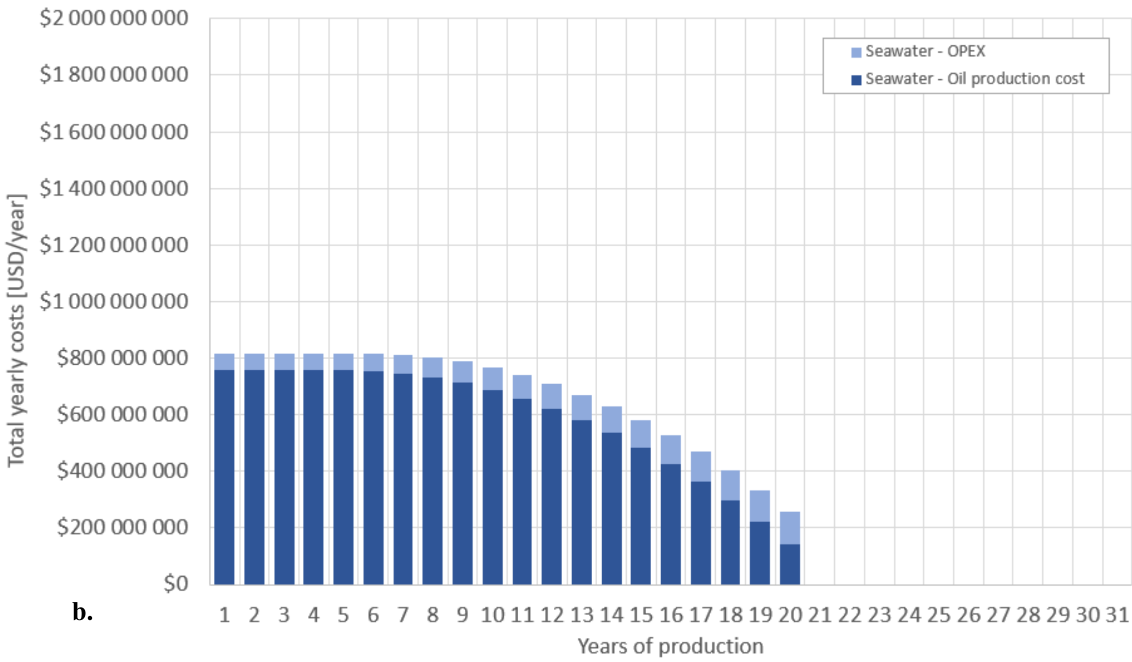


Figure 5.9 *- Total CapEx, OpEx and oil production costs for Smart Water and seawater for base case.*

Comparing the columns, the CapEx for both projects is nearly identical and the OpEx for Smart Water is almost twice as large as for SW. The main difference, however, can be seen in the oil production cost. **Figures 5.10 a.** and **b.** illustrate the yearly OpEx and oil production costs for Smart Water and SW respectively.



a.



b.

Figure 5.10 - *Yearly production costs for Smart Water and seawater for base case.*

a. *Smart Water* ***b.*** *Seawater*

The oil production cost for both Smart Water and SW follow the same pattern as the production profile in **figure 5.1.** Here, the cost remains constant when the production is at its plateau and starts to decrease once water is being produced. The OpEx for SW follows the same pattern as the oil production cost. Smart Water, however, increases from year one as more energy is required to produce Smart Water in comparison to SWI. The difference between the OpEx for Smart Water and SW should however decrease towards the end of the production. This is because Smart Water has less water to handle in comparison to SW, due to a delay in water breakthrough, as well as Smart Water having a higher displacement efficiency.

Despite having higher production costs, Smart Water can continue a profitable production for some additional years in comparison to SW. The NPV as discussed earlier in the chapter, seems to be higher for Smart Water in secondary mode, which implies that Smart Water is a more reasonable option.

5.5 INCREASING THE CO_2-FEE IN 2030

The Norwegian government plan to increase the current CO_2-fee from \$70 to \$236 by 2030 (Zero, 2021). This may influence operational as well as capital costs for future oil projects. The base case production profile at the start of the chapter has been simulated once more using the increased CO_2-fee. **Table 5.3** below presents the input data used in the simulations.

Table 5.3 *- Input data for base case scenario with CO_2-fee increase.*

Input data	
Oil price [USD/bbl]	60
CO_2-fee [USD/ton]	236
Oil production cost [USD/bbl]	10
Secondary recovery mode [% OOIP]	26
Smart Water	
OpEx [USD]	194.91 million
Seawater	
OpEx [USD]	79.72 million

As the CO_2-fee does not seem to have a significant effect on the CapEx of the projects, the cost has not been included in the following tables. **Figure 5.11** illustrates how the fee increase influences oil production by Smart Water and SW injection.

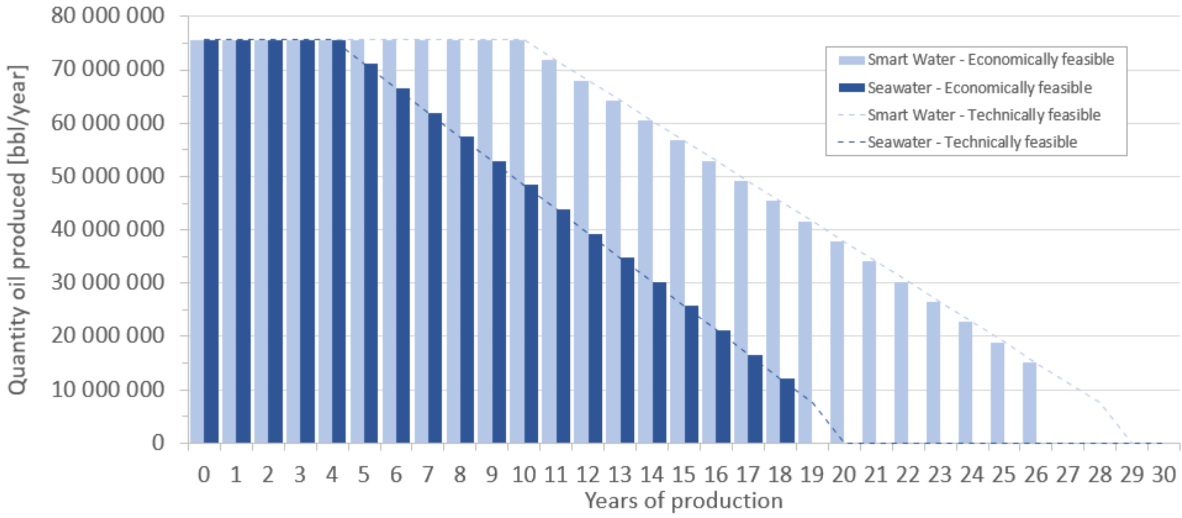


***Figure 5.11** - Production profile comparing Smart Water vs. traditional seawater injection with increased CO_2-fee.*

The increase in the CO_2-fee reduces production for Smart Water by two years and SW by one year, as the production is no longer economically viable. The NPV is again calculated, giving the following results:

$$NPV_{Seawater} = \$17\ 199\ 370\ 415$$

$$NPV_{Smart\ Water} = \$22\ 107\ 966\ 345$$

From the calculations, Smart Water as a secondary recovery method is again clearly profitable, with a difference in NPV of $4.91 billion compared to SW. Although the costs increase, Smart Water still seems to be profitable. The cumulative oil produced when production is terminated earlier, is illustrated in **figure 5.12**.

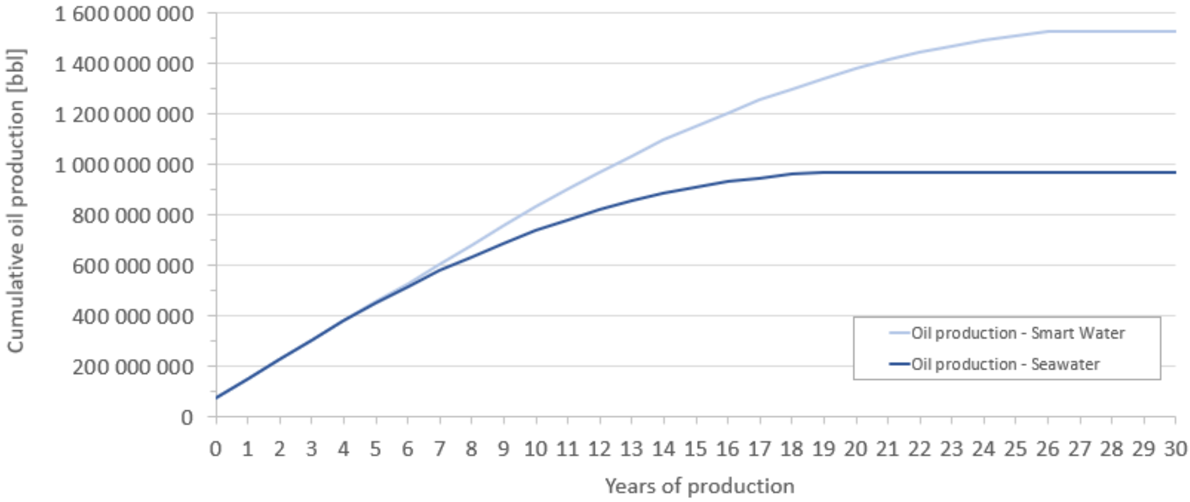


Figure 5.12 - *Comparison of additional oil produced for Smart Water compared to seawater.*

From the graph, Smart Water implementation contributes to an additional 567 million barrels of oil. The CO_2-fee increase reduces total oil production with 11 million barrels.

5.6 FINANCIAL BREAK-EVEN POINT

Break-even analyses have been carried out to see what the oil price must be for Smart Water and SW implementation to be indifferent. The break-even point (BEP) defines the oil price at the point where the NPV for Smart Water and SW are equal. **Table 5.4** summarizes the results obtained from the analyses.

Table 5.4 *- Break-even points obtained from the break-even analyses.*

CO_2-fee [USD]		$ 70		$ 236	
		10% additional recovery			
		NPV [USD]	**Oil price**	**NPV [USD]**	**Oil price**
Oil production cost	**$ 10**	- 1.1 billion	$ 22	919.9 million	$ 28
	$ 15	679.8 million	$ 31	2.6 billion	$ 37
	$ 20	2.4 billion	$ 40	4.4 billion	$ 46
		20% additional recovery			
		NPV [USD]	**Oil price**	**NPV [USD]**	**Oil price**
Oil production cost	**$ 10**	- 3.8 billion	$ 16	- 2.7 billion	$ 20
	$ 15	- 5.7 billion	$ 16	- 2.0 billion	$ 27
	$ 20	- 2.4 billion	$ 30	- 1.3 billion	$ 34
		26% additional recovery			
		NPV [USD]	**Oil price**	**NPV [USD]**	**Oil price**
Oil production cost	**$ 10**	- 4.1 billion	$ 15	- 3.1 billion	$ 19
	$ 15	- 3.5 billion	$ 22	- 2.5 billion	$ 26
	$ 20	- 2.9 billion	$ 29	- 2.0 billion	$ 32

From the table, the oil prices required for Smart Water to be more profitable than SW when 10% additional oil is recovered, ranges between $22 and $46. When the oil production cost is

\$10 at the current CO_2-fee, the NPV is negative. This suggest that Smart Water is more profitable than SW in all cases where the NPV is positive. For the other scenarios, as both the oil production cost and the CO_2-fee increases, an increased oil price is required for Smart Water to be more profitable than SW. As oil production costs increase, a noticeable increase in NPV is also observed. The profitability of Smart Water seems to be mostly affected by the CO_2-fee increase when additional oil recovery is low.

At an additional oil recovery of 20%, the break-even oil price lies between \$16 and \$34. At the \$10 and \$15 oil production costs, the oil prices are equal and the NPV decreases as the production cost increase. This suggests that the increase in cost makes Smart Water more profitable for oil prices higher than \$16, even though both projects are losing money.

For additional recoveries at 26%, the break-even oil price ranges between \$15 and \$32. As the oil production cost increases, the NPV and the break-even oil price increases as well. For relatively low oil prices, Smart Water still seems like a better alternative than SW although the NPV is negative.

Illustrated in **figure 5.13**, if the oil price is greater than \$46, Smart Water is more profitable than SW. According to **table 5.4**, an oil price greater than \$46 should make Smart Water more profitable in all scenarios. It is also noticeable that the break-even oil price is higher for the cases where the CO_2-fee is increased to \$236.

Figure 5.13 *- Break-even point with 10% additional oil, oil production cost at \$20 and increased CO_2-fee to \$236.*

Chapter 6 - DISCUSSION

In this chapter, the results from chapter 5 will be discussed. The main objective of this thesis is to test whether Smart Water injection is profitable in sandstones in comparison to SWI. To answer this question, the effect of varying different input values must be discussed. This chapter will therefore cover important factors that may impact the profitability of this injection method and analyze the parameters which are the most sensitive to change.

6.1 PROFITABILITY OF SMART WATER

In section 5.1, the profitability results were presented. **Table 5.1** illustrated a base case scenario for the most favorable outcome of Smart Water injection. This base case estimated a difference in NPV of $5.43 billion, representing the additional profitability gained by implementing Smart Water from day 1.

The profitability of Smart Water is dependent on many factors. To see how each parameter, impact the profit, scenario analyses have been completed on the variable input parameters from **table 4.2**.

6.1.1 CO_2-fee

As mentioned, the profitability of Smart Water in comparison to SW gave an estimated NPV of $5.43 billion when the CO_2-fee was set to its current value of $70. Comparing this base case to a scenario where only the CO_2-fee is increased to $236, the profit gained from using Smart Water decreases to $4.9 billion, **table 5.3** from section 5.5. Looking at **figure 6.1**, the graph still follows the shape of the production profile shown in **figure 5.11.**

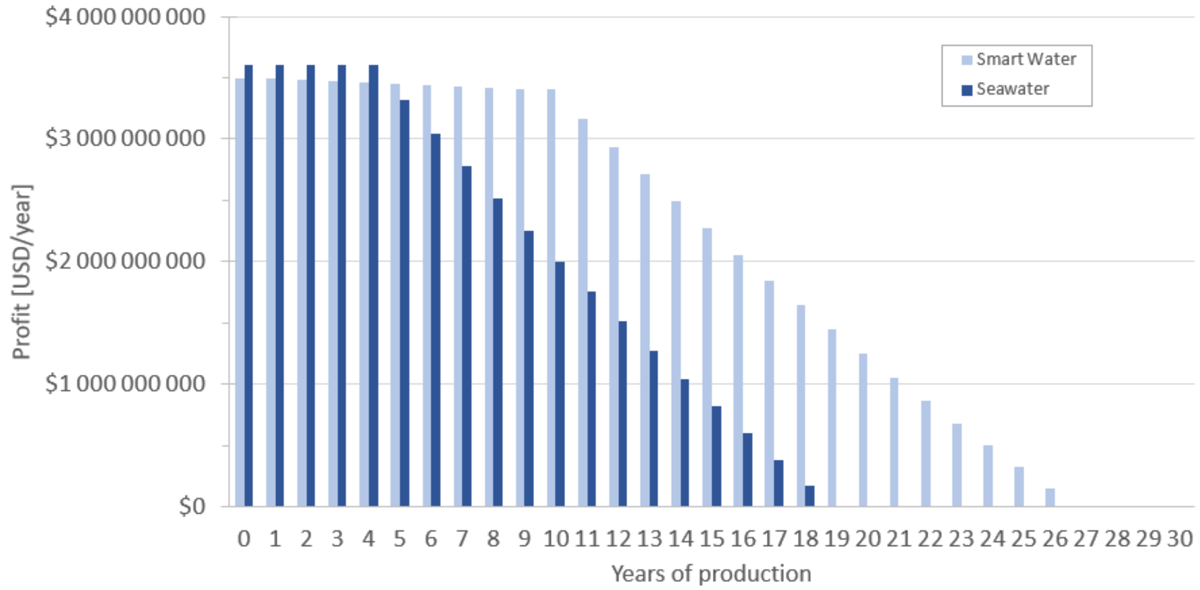


Figure 6.1 - *Base case scenario where CO_2-fee is increased to $236.*

A cost increase on its own does not seem to have a large impact on the profitability, other than shortening the lifetime of the field by two years for Smart Water and one year for SW.

In a worst-case scenario described in **table 6.1** below, the additional profit gained by using Smart Water is again reduced and has a value of $1.26 billion.

Table 6.1 - *Input data for worst case scenario.*

Input data	
Oil price [USD/bbl]	60
CO_2-fee [USD/ton]	70
Oil production cost [USD/bbl]	20
Secondary recovery mode [% OOIP]	10
Smart Water	
OpEx [USD]	65.58 million
Seawater	
OpEx [USD]	60.46 million

Seen in **figure 6.2**, the difference in profitability between Smart Water and SW is very small in comparison to the base case scenario presented in section 5.1.

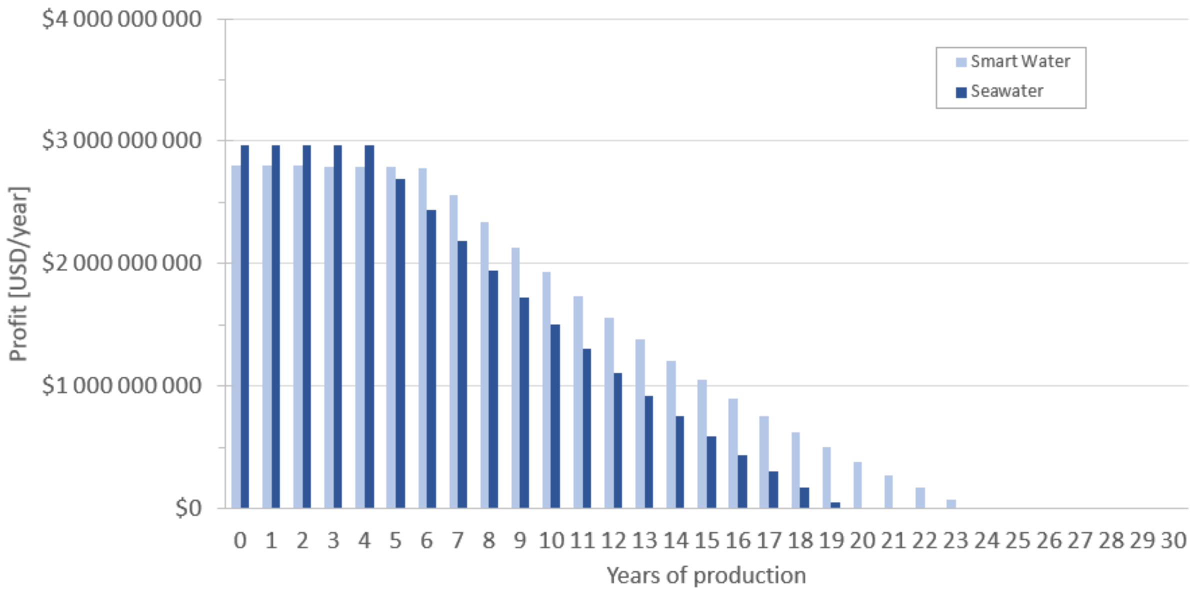


Figure 6.2 *- Worst case scenario where CO_2-fee is at its current value of $70.*

This figure suggests that there are several factors together affecting the profitability of Smart Water. By increasing the CO_2-fee for the worst-case scenario, the profitability of Smart Water continues to reduce as expected, to a value of $851 million, **table 6.2**.

Table 6.2 *- Input data for worst case scenario with CO_2-fee increase.*

Input data	
Oil price [USD/bbl]	60
CO_2-fee [USD/ton]	236
Oil production cost [USD/bbl]	20
Secondary recovery mode [% OOIP]	10
Smart Water	
OpEx [USD]	194.91 million
Seawater	
OpEx [USD]	179.72 million

A decreasing trend can again be seen for the profit as the CO_2-fee increases, **figure 6.3**.

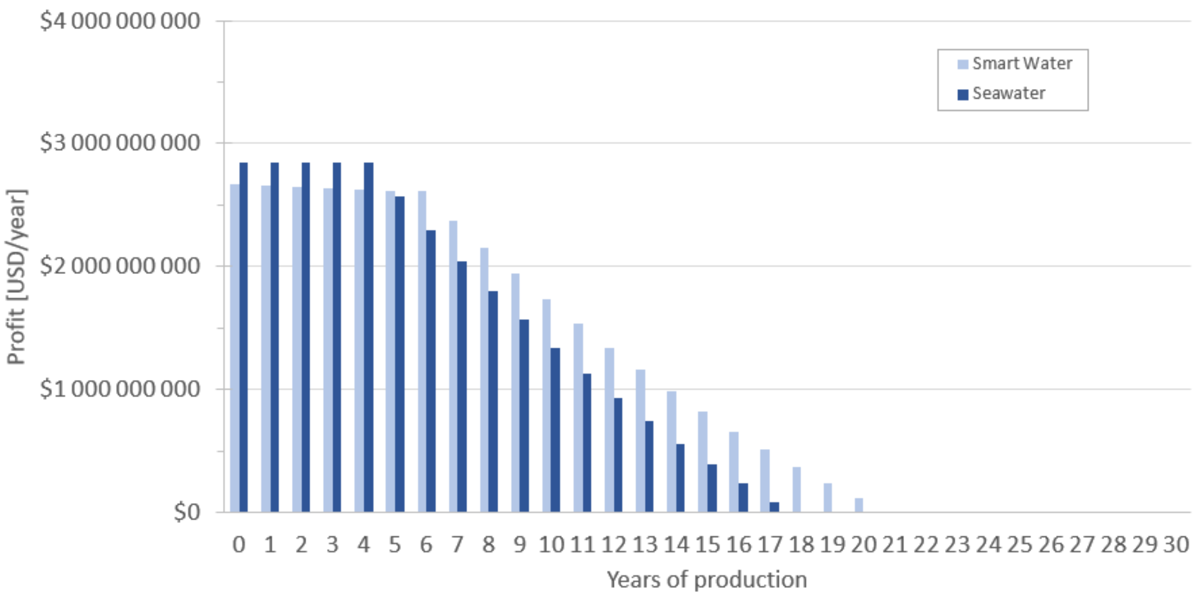


Figure 6.3 - *Profitability of worst-case scenario where CO_2-fee is increased to \$236 as for 2030.*

For all scenarios, the profit is reduced as the CO_2-fee increases from \$70 to \$236. As the model is set to stop production once the project reaches negative profits, the years of production is reduced going from the base case scenario to worst-case. Although an increase in the cost has a negative impact on oil production, Smart Water still seems to be profitable in all scenarios. **Figure 6.4** presents an overview of how the CO_2-fee influences the NPV.

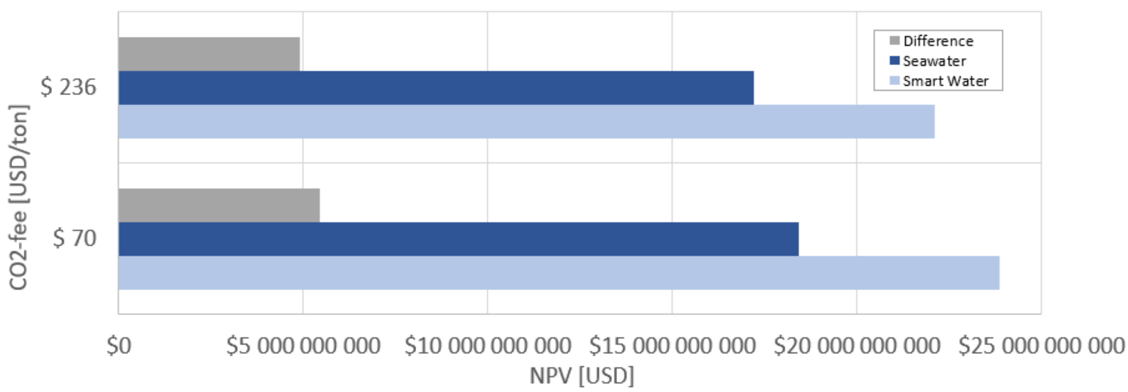


Figure 6.4 - *CO_2-fee impact on NPV for base case scenario.*

Seen in **figure 6.4**, a change in the CO_2-fee on its own does not seem to have a major effect on the difference in NPV for Smart Water and SW.

6.1.2 Oil production cost

Oil production costs are the costs related to producing one barrel of oil. This includes costs for water treatment, water injection and production. The oil production cost is set to increase along with the water fraction as water treatment is assumed to be more expensive as the WOR increases.

Changing the base case scenario in **figure 5.1** by increasing the oil production cost to $20, a significant increase in total yearly costs is observed, **figure 6.5**.

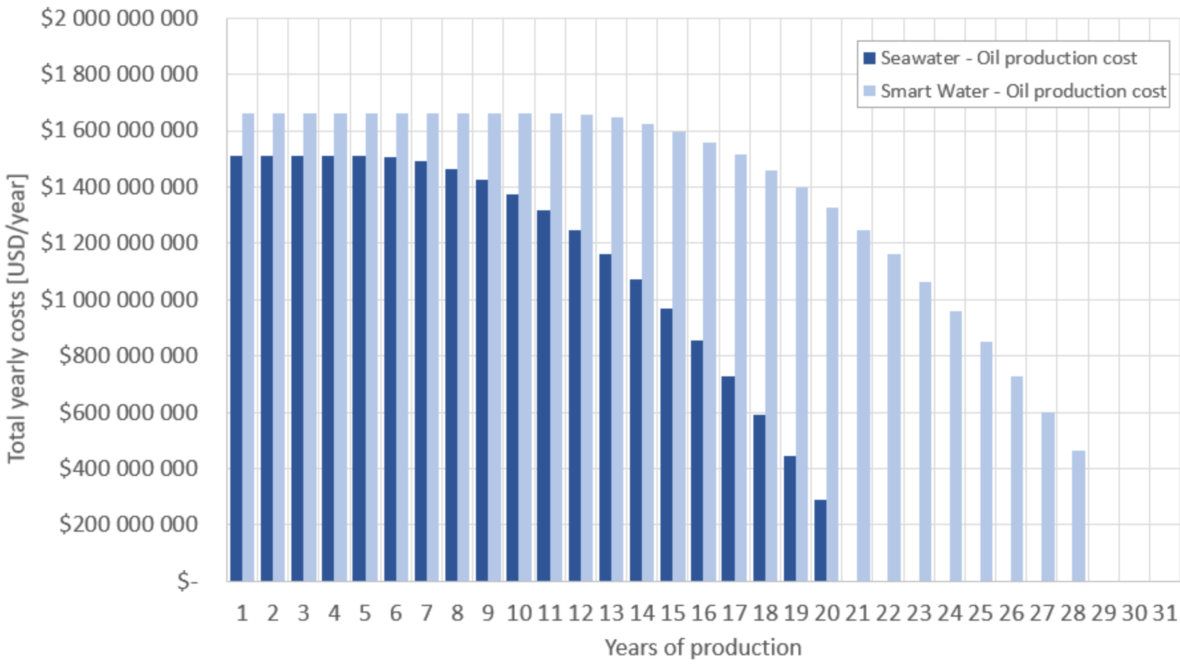


Figure 6.5 *- Comparison of Smart Water and seawater total yearly oil production costs at 20$/bbl.*

The production costs for Smart Water are significantly larger than SW, as more oil is produced when Smart Water is implemented. Looking at the profitability curve of the projects, the profits are significantly lower than for the base case scenario per year, **figure 5.3**. However, Smart Water has a higher yearly profit after SW reaches water breakthrough seen in **figure 6.6**.

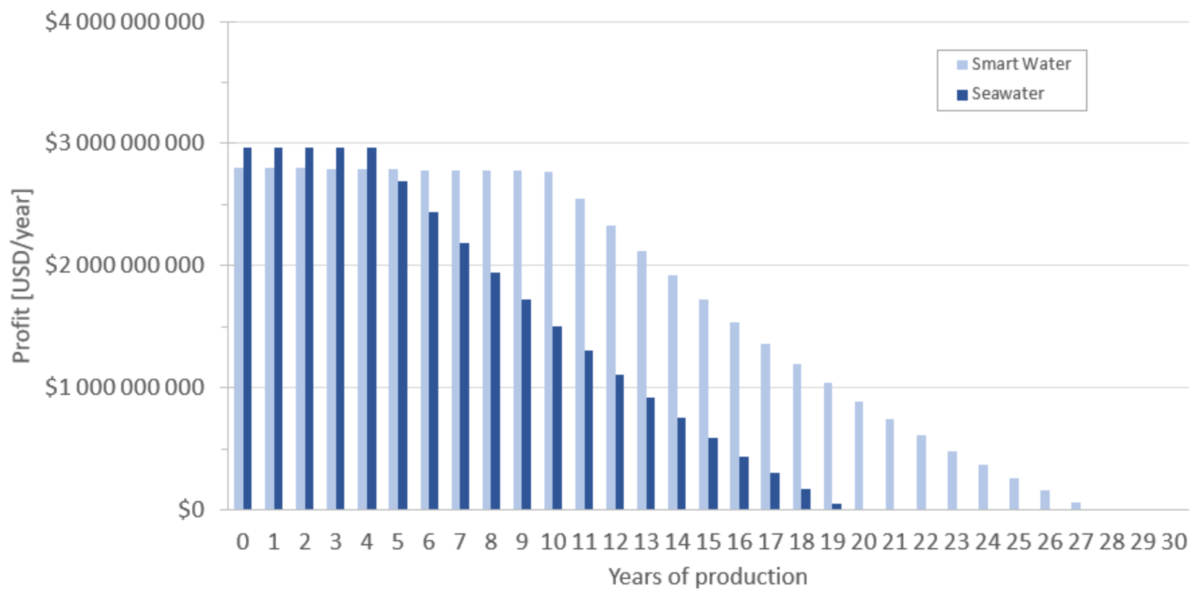


***Figure 6.6** - Profitability of base case where oil production cost is increased from $10 to $20.*

Calculating the NPV for the base case with an increased production cost, the following results are obtained:

$$NPV_{Seawater} = \$12\ 709\ 817\ 040$$

$$NPV_{Smart\ Water} = \$16\ 501\ 752\ 506$$

Implementing Smart Water gives an additional value of $3.79 billion. **Figure 6.7** presents a summary of the NPV results obtained from varying the oil production cost. As the production cost increases, the added value gained by implementing Smart Water decreases. The production cost seems to have a significant effect on the profitability of Smart Water.

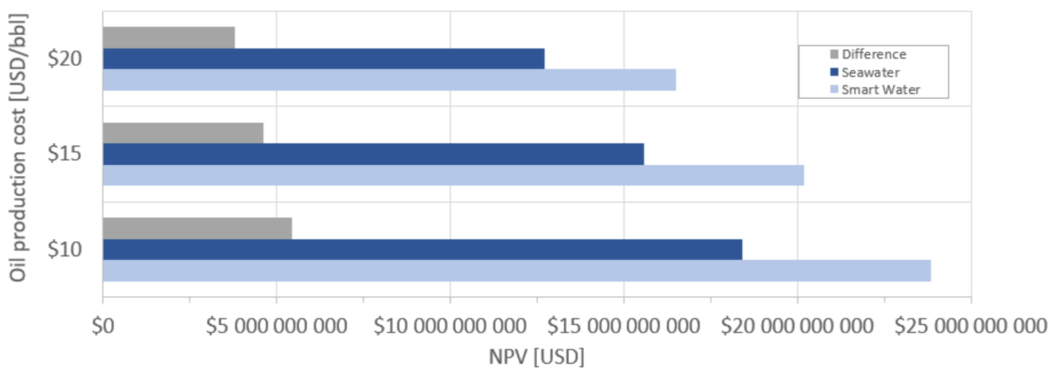


***Figure 6.7** - Increasing oil production cost for the base case scenario.*

6.1.3 Additional oil recovered

Giving an accurate prediction of how much extra oil (% OOIP) can be extracted using an EOR method can be challenging. As it is difficult to estimate the size of the reserves due to lack of geological data, it can be difficult to foresee the reservoir response as a new fluid is introduced. As Smart Water has not yet been implemented, lab results have been applied to the model to give an indication on the field performance.

In the base case scenario where a maximum additional oil recovery is achieved of 26%, an additional 578 million barrels of oil were recovered. This increase in production contributes with an additional $5.43 billion. **Figure 6.8** illustrates how the profitability is affected by reducing the recovery to 10%.

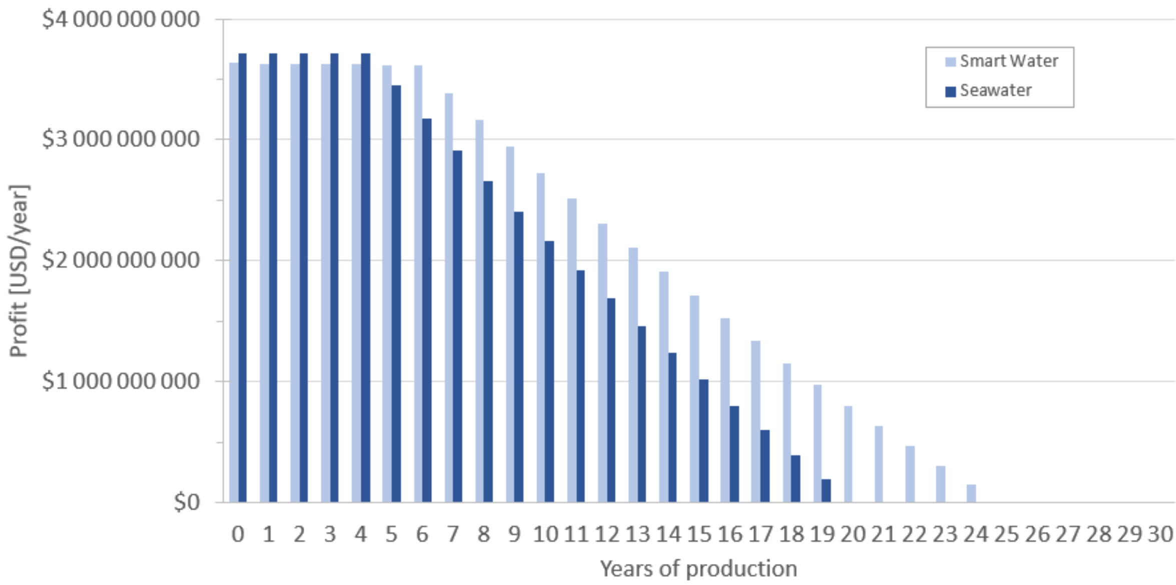


***Figure 6.8** - Profit when reducing additional oil recovered.*

As mentioned, the profitability curve follows the shape of the production profile. The profitability curve can therefore be used to indicate the field performance, and according to the curve, the recovery reduction shortens the production plateau for Smart Water. This reduction results in an early water breakthrough, which in turn increases the total water production. Due to the additional water accumulated, extra amounts of water must be handled, reducing profits.

The value gained from implementing Smart Water with an additional 10% recovery is $2.46 billion. This is a significant reduction in comparison to having a maximum recovery of 26%. A summary of the NPV results from varying the additional recovery factor is presented in **figure 6.9**.

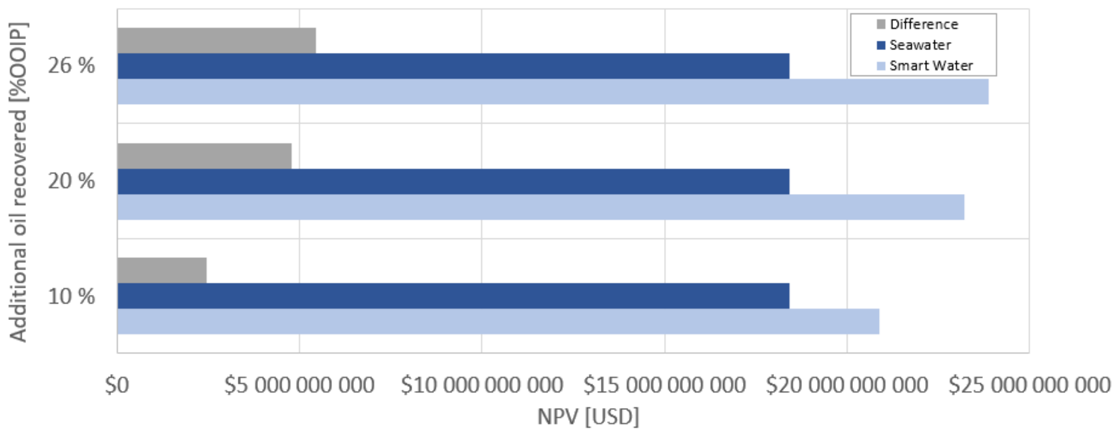


Figure 6.9 *- Effect of varying additional oil recovery on profit for the base case scenario.*

As presented in **figure 6.9**, an increasing trend in added value for Smart Water is seen as additional oil recovered is increased. This increase is expected, as more oil can be sold as well as there is a longer delay in water breakthrough. Changes in the recovery percentages seem to have a significant effect on the profitability of Smart Water, favoring high recovery percentages.

6.2 Effect of oil price

The national stability of crude oil is becoming more prominent as the global economy is under rapid development. However, large fluctuations in oil prices arise under unexpected events. On March 30th, 2020, brent crude fell to $22.58 per barrel due to COVID-19, which according to BBC (2020) was at its lowest level since November 2002. Already in April 2020, the brent crude fell below zero, to an oil price of -$37.63 seen in **figure 6.10**. This graph emphasizes the impossibility of forecasting future oil prices. An oil price of $60 has therefore been assumed in this thesis and used for all simulations.

***Figure 6.10** – Fluctuations in oil prices due to unexpected events, from year 2000-2020 (original image from Refinitiv (2020)).*

The effect of fluctuating oil prices has been presented in the break-even analysis from section 5.6. **Figures 6.11**, **6.12** and **6.13** illustrate the BEP for Smart Water and SW at different scenarios.

Figure 6.11 illustrates the break-even oil prices when 10% additional oil is recovered. Looking at **figure 6.11**, the increase in CO_2-fee has a significant large impact on the oil price required for the two projects to be indifferent. The NPV required for the projects to be indifferent is also higher for scenarios where the CO_2-fee is increased.

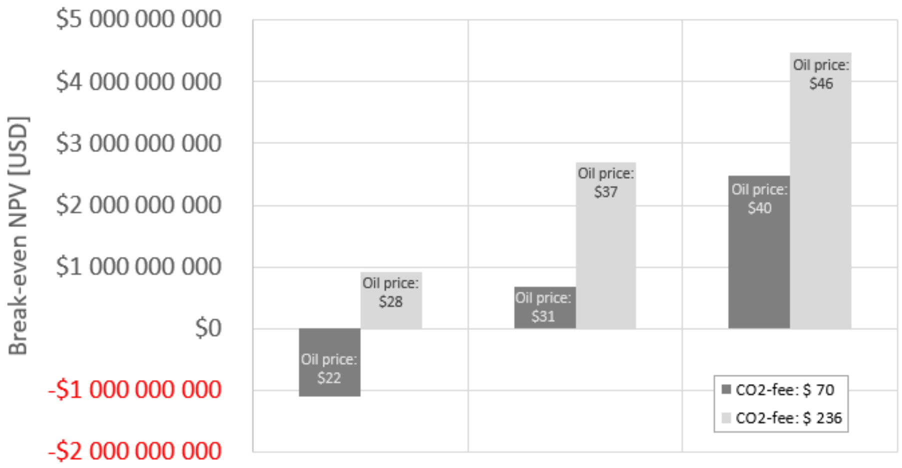


Figure 6.11 - Break-even oil prices at 10% recovery, for production costs $10, $15 and $20 respectively.

When the additional recovery factor is increased to 20% as seen in **figure 6.12**, the break-even NPV fall below zero, indicating that Smart Water should be profitable in all scenarios where the project is making money. The oil prices required for the projects to be indifferent however, seem to be lower in all scenarios in comparison to a 10% recovery.

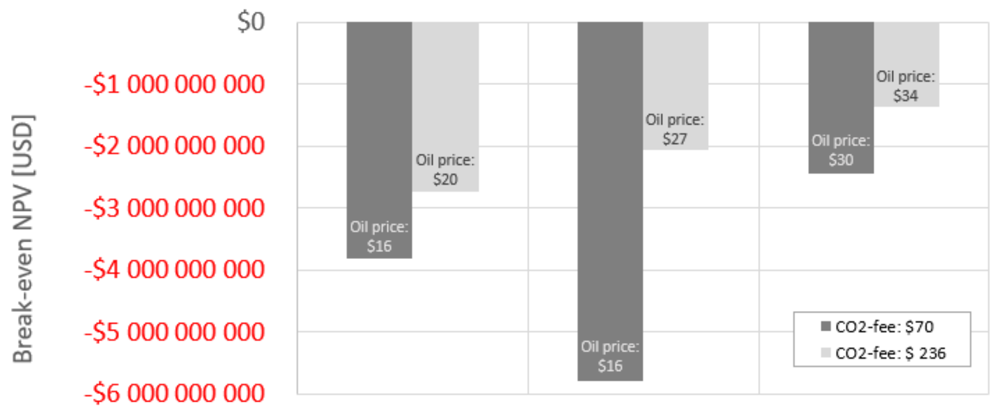


Figure 6.12 - Break-even oil prices at 20% recovery, for production costs $10, $15 and $20 respectively.

As the additional recovery continues to increase up to 26%, the break-even oil prices continue to fall. There is however only a minor reduction in oil prices as the recovery percentage increases, **figure 6.13**.

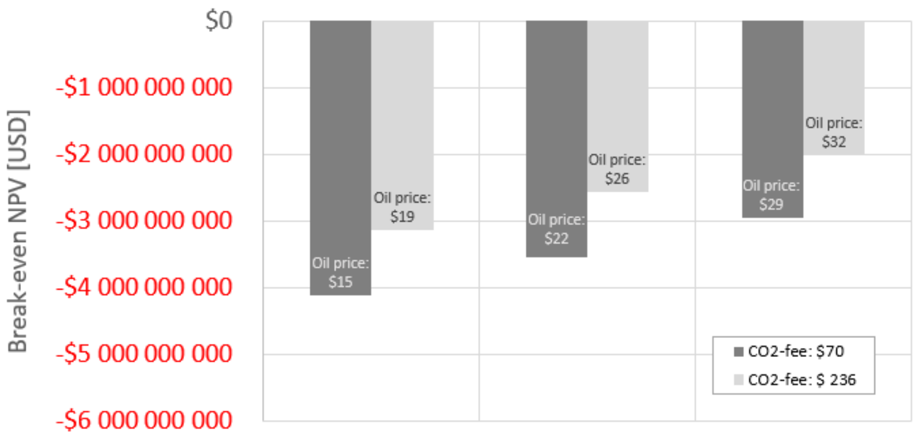


***Figure 6.13** - Break-even oil prices at 26% recovery, for production costs $10, $15 and $20 respectively.*

Analyzing how oil prices affect the profitability of Smart Water, higher oil prices are required for projects with low recovery percentages, as the additional recovery will not make up for the high investment costs. However, as recovery percentages increase, relatively low oil prices are essential for Smart Water to be more profitable than SW. According to the figures, oil prices above $46 should make Smart Water more profitable for all scenarios.

6.3 IMPLEMENTATION AS AN IOR METHOD

In general, EOR methods are implemented to extract additional oil, extending the lifetime of a field. Previous work has shown significant benefits from injecting low salinity (LS) Smart Water in secondary mode rather than a tertiary injection fluid; due to the reservoir being contaminated with other brines not considered as a Smart Water fluid (Torrijos et al., 2018). **Figure 6.14** illustrates the oil recovery results obtained from injecting formation water (FW) followed by LS Smart Water in tertiary mode.

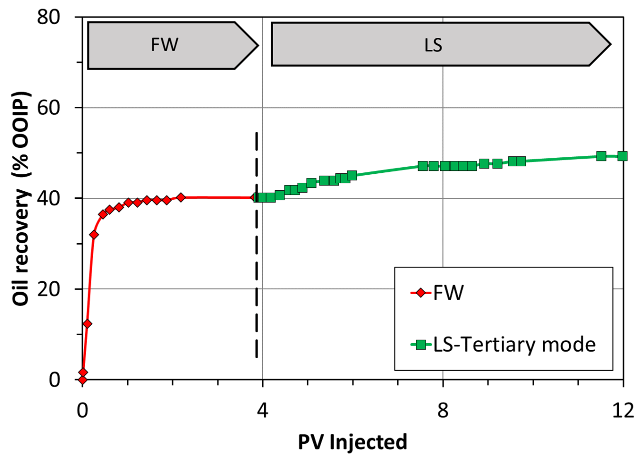


Figure 6.14 *- Recovery after flooding sandstone core with formation water followed by low salinity Smart Water in tertiary mode (modified after Torrijos et al. (2018)).*

The oil recovery results show an ultimate recovery of 40% OOIP for FW flooding, with an additional recovery of 9% after LS Smart Water is injected. This low recovery response can be seen due to another brine contaminating the reservoir rock, that is not considered a Smart Water. Studies have shown that injected SW followed by a LS Smart Water in tertiary mode can show additional recoveries as low as 0-6% OOIP (Aghaeifar et al., 2018). This suggests that flooding Smart Water in tertiary mode is not as efficient and may not be as profitable in comparison to traditional SWI. **Figure 6.15** illustrates the oil recovery results obtained from injecting LS Smart Water in secondary mode from day 1.

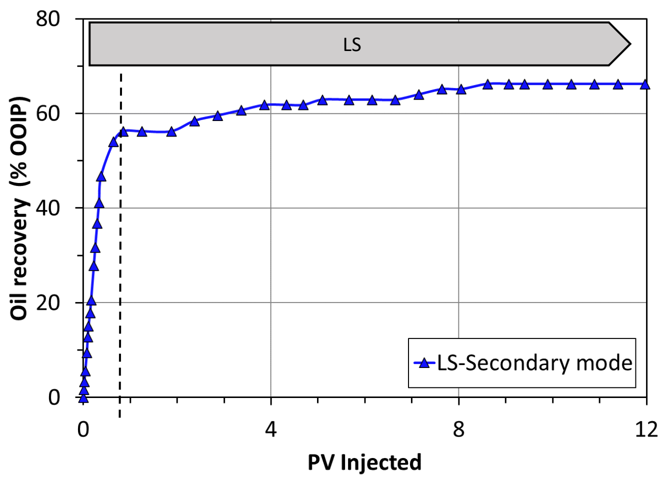


Figure 6.15 *- Recovery after flooding sandstone core with low salinity Smart Water in secondary mode from day 1 (modified after Torrijos et al. (2018)).*

Observed from the recovery graph, already after 1 pore volume (PV) is injected, the oil recovery has reached 56% OOIP which is a 17% increase from the FW response in **figure 6.14**. Reaching an ultimate recovery of 66% OOIP, flooding LS Smart Water from day 1 contributes to an additional 26% increase in recovery of the OOIP.

A simulation has been done using input values from **table 6.3** to see how an unfortunate additional recovery of 3% may affect the profitability of Smart Water.

Table 6.3 - *Input data for base case scenario with 3% oil recovery.*

Input data	
Oil price [USD/bbl]	60
CO_2-fee [USD/ton]	70
Oil production cost [USD/bbl]	10
Secondary recovery mode [% OOIP]	3
Smart Water	
CapEx [USD]	5.80 billion
OpEx [USD]	65.58 million
Seawater	
CapEx [USD]	5.79 billion
OpEx [USD]	60.46 million

The production profile showing the low recovery effect is illustrated in **figure 6.16**.

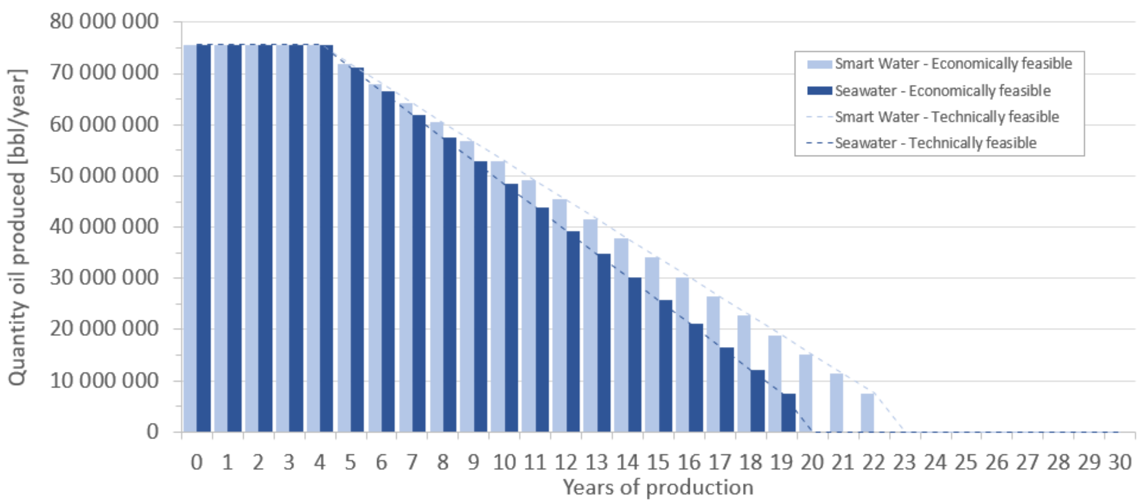


Figure 6.16 - *Production profile comparing Smart Water and seawater with an additional recovery of 3%.*

As seen in **figure 6.16**, the production plateau for Smart Water illustrates that both Smart Water and SW reach water breakthrough at the same time. However, the water production for Smart Water increases at a slower rate in comparison to SW. The NPV of both methods can then be calculated from the simulation data:

$$\boldsymbol{NPV_{Seawater} = \$18\ 422\ 154\ 624}$$

$$\boldsymbol{NPV_{Smart\ Water} = \$18\ 916\ 660\ 644}$$

The additional value gained from implementing Smart Water at a low recovery percentage is $494 million.

If the oil production cost is increased to $20, the NPV calculations change showing the following results:

$$\boldsymbol{NPV_{Seawater} = \$12\ 709\ 817\ 040}$$

$$\boldsymbol{NPV_{Smart\ Water} = \$12\ 303\ 705\ 314}$$

The additional value gained from implementing Smart Water is now -$406 million. The NPV does no longer show favorable results for Smart Water, as the additional oil recovered does not give any additional value due to its high production costs.

These results suggest that Smart Water should be implemented as an IOR method, and if low recovery factors are assumed, which can be expected for tertiary EOR methods, Smart Water should not be implemented.

6.4 ENVIRONMENTAL IMPACT - DELAYED WATER BREAKTHROUGH

The environmental screening criteria mentioned in chapter 3, by Smalley et al. (2020), addresses the issue of EOR methods being denied implementation approval as they are perceived as environmentally unacceptable. The disapproval may come from operators, stakeholders as well as the general public. The disapproval is based on the fear that injectants may harm the environment, in the unlikely event that fluids are released into the environment. Another concern is the CO_2 footprint related to Smart Water EOR. As the injection unit requires a desalination plant that can inject water at higher pressures than a traditional SWI unit, the pump therefore has a higher power consumption, increasing CO_2 emissions (Smalley et al., 2020).

However, LS water is environmentally friendly, meaning that in a scenario where injection water is discharged into the surface water, the LS water will not do any harm to the environment. Analyzing the environmental screening scores presented in **figure 3.11 (b)** LS water and Smart Water have an average score of 0.86 and 0.81 respectively. These high scores imply that LS/Smart Water is highly acceptable and according to the scale, the methods are neutral, as they have a negligible change in CO_2 emissions.

As the global energy requirements rise 30% by 2040 and the oil demand reaches 105 million bbl/day, environmentally and cost-effective recovery mechanisms will be preferred to moderate the supply-demand balance (IEA, 2017). This increase in energy demand and sustainable use of scarce water resources has led to the development of several approaches such as waterflooding and water based EOR. As Smart Water EOR is both cost effective and environmentally friendly, the method is an energy-efficient way of recovering hydrocarbons (Nair, 2019).

Smart Water injection has from laboratory studies and results shown to have a higher recovery efficiency than SW, meaning that oil can be produced faster using Smart Water in comparison to SW. However, as oil production using SWI is most likely producing oil at a maximum rate, Smart Water will not have the ability to increase the injection rate, unless the injection capacity of the platform is increased. A delay in water breakthrough for Smart Water can therefore be seen, as Smart Water is able to produce oil at a low WOR for a longer time in comparison to SW. According to lab results, a higher cumulative oil production is reached for Smart Water and a low S_{or} can be reached at an earlier stage. As oil production does not seem to be profitable at a low S_{or}, production should be terminated. For Smart Water, this means that oil production can be terminated earlier than SW, resulting in less water injection. Smart Water will therefore have a lower cumulative water production than SW and will have less produced water to treat/re-inject. A lower water production for Smart Water will result in less CO_2 emissions for Smart Water, making Smart Water injection cheaper than SWI. As the CO_2 fee increases towards 2030, this reduction in water production for Smart Water will play an important part in the total OpEx for the project.

6.4.1 Simulation model application

In this simulation model, the water breakthrough effect has been described as delayed and reduced in the early injection phase. As water breakthrough is reached, the increase in the water fraction, f_w has been reduced over time. **Figure 6.17** illustrates the WOR for Smart Water and SW.

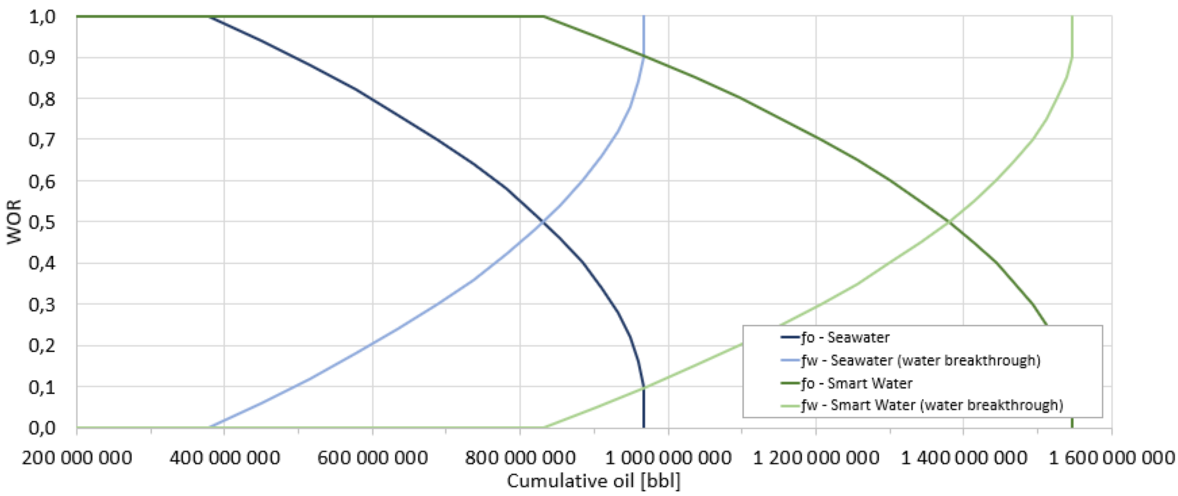


Figure 6.17 *- Water-oil ratio for Smart Water compared to seawater in base case scenario.*

As seen in **figure 6.17**, the WOR for Smart Water increases at a significantly lower rate than for SW, which indicates that more oil is being produced per barrel in comparison to SW. However, as the oil production capacity in these simulations cannot be increased, the production will not be terminated earlier than SW. If the production capacity were to be increased, Smart Water would produce the cumulative oil faster than SW, and could therefore reach a low S_{or} faster, and end production earlier. In **figure 6.18** below, the water production is shown to have a linear increase. In a realistic model using real data, the ideal graph would have a curved shape. This model has a linear increase in water production for the simplicity of the model, as a fictive field has been used to model the data.

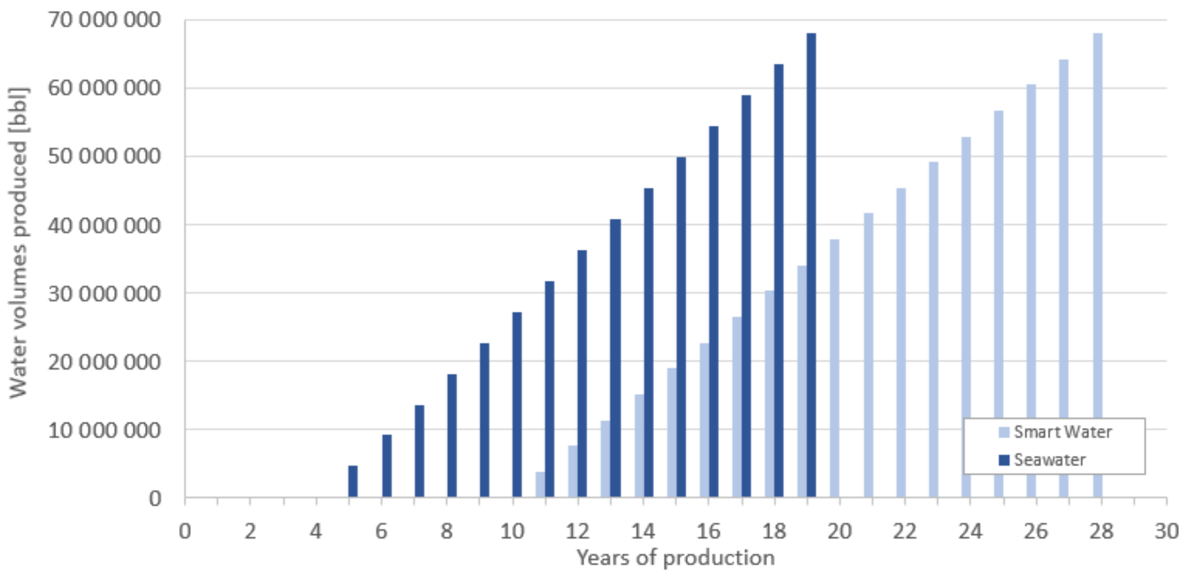


***Figure 6.18** - Increase in water production with time.*

In this base-case scenario, the water breakthrough for Smart Water is expected six years later than SW, where the field can produce six more years at a plateau rate without any water to handle. The delay in water breakthrough seems to have a positive environmental impact, as well as the reduction in water production makes Smart Water a more profitable alternative. Even though Smart Water has shown positive environmental impacts, there are other benefits related to Smart Water injection such as a reduced scaling potential, that has not been taken into account in this simulation model. Applying these additional benefits may however improve the profitability of Smart Water implementation.

6.5 NEW TECHNOLOGY

Smart Water EOR carries many uncertainties as only laboratory studies have been performed confirming increased oil recovery. The recovery performance of a full-field implementation of Smart Water may therefore be difficult to predict and the actual profitability of the project may be less than estimated. As a higher CapEx and OpEx is expected for Smart Water in comparison to SWI, unexpected production loss may be critical to the benefits of using Smart Water. New technologies should therefore be considered to reduce investment and operational costs which may increase the profitability margin in case of unanticipated low recoveries.

In May 2020, NOV presented a new technology called SWIT™, which is an extension of Seabox™, a subsea disinfection and sedimentation module. The extension allows for a reverse osmosis (RO) treatment module which is required for salt removal, creating a LS water (WaterInOil, 2020). The box can be placed on the seabed, and **figure 6.19** illustrates the applicability of Seabox and SWIT for both secondary and tertiary implementation.

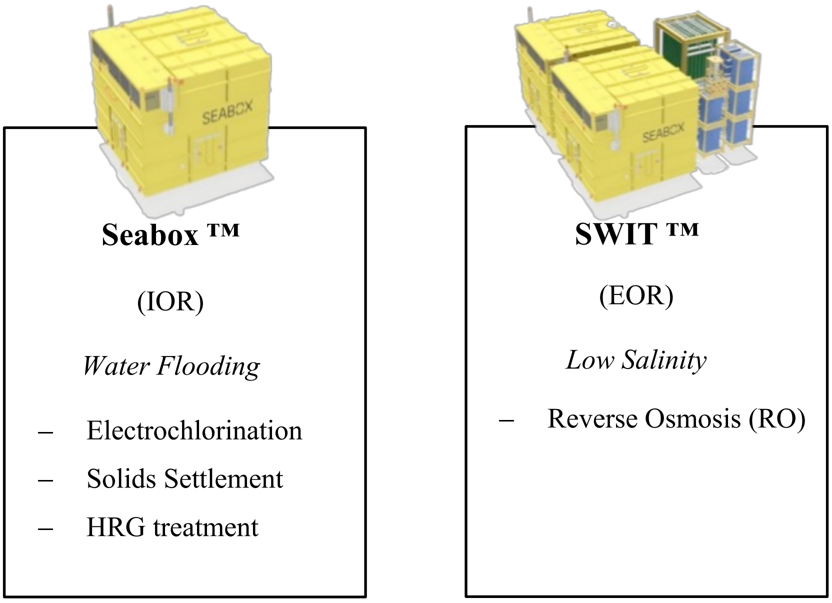


Figure 6.19 *- Seabox/SWIT system roadmap (Based on NOV (2015)).*

Implementing Seabox/SWIT has several proposed benefits such as (WaterInOil, 2020):

- Unmanned tiebacks/ subsea marginal assets
- Allowing water treatment next to injection wells
- Improving field economics
- Reduced carbon footprint
- Reduced health, safety, environment and quality risks due to less topside activities
- Possibility of adding or removing capacity in correlation to reservoir response
- Unlimited access to seawater

By implementing an injection unit on the seafloor, tertiary implementations may be facilitated, as additional weight application will not affect topside facilities. Water injection can run independent from platform shutdowns, which can prevent revenue loss. Installing an injection unit on the seabed allows for a reduced CapEx and OpEx if additional injection capacity is required. As shorter injection wells are required for transporting water to the injection zone, topside investments are also reduced (Hegdal, 2017).

Chapter 7 - CONCLUSION

The objective of this thesis is to investigate the profitability of Smart Water EOR in comparison to traditional seawater injection (SWI) in sandstone fields. This has been done through economic scenario simulations and break-even analyses for Smart Water and seawater (SW), evaluating their corresponding net present values (NPV). The effect of varying input parameters such as the CO_2-fee, oil production cost, additional oil recovery as well as oil price fluctuations has been discussed. In addition, scenarios where Smart Water is implemented using a low recovery factor in contrast to implementing Smart Water as an IOR method was investigated. Finally, environmental impacts as well as future suggestions for new technologies were assessed. From the results presented, the following conclusions were drawn:

Profitability of Smart Water. From the scenario analyses, the following factors' effect on the NPV were found:

- ***CO_2-fee.*** An increase in the CO_2-fee from \$70 to \$236, results in an increase in OpEx from \$65.58 to \$194.91 million for Smart Water. In all scenarios, the profit is reduced when the CO_2-fee increases. As the simulation is set to stop production when profits are below zero, the lifetime of the field is shortened due to the cost increase. However, for the base case scenario, the increase in the CO_2-fee does not seem to have a major effect on the NPV difference.
- ***Oil production cost.*** As oil production costs increase, the difference in NPV decreases. The increase in cost does not seem to favor Smart Water, as the additional costs seems to have a significant effect on the profitability of Smart Water. However, for the base case scenario, Smart Water appears to be more profitable than SW regardless of the increase in production costs.
- ***Additional oil recovered.*** From the simulation results, an increase in additional oil recovery increases the added value for Smart Water. By increasing the recovery percentage from 10% to 26%, the added value gained by using Smart Water increases from \$2.46 to \$5.43 billion. For the base case scenario, the increase in additional recovery seems to have a significant impact on the difference in NPV, favoring high recovery percentages.

Effect of oil price. From the break-even analyses, it was observed that for lower recovery percentages, higher oil prices were required for Smart Water and SW projects to be indifferent. For high recovery percentages, lower oil prices are required for Smart Water implementation to give additional value. The minimum oil price observed, favoring Smart Water over SW in all scenarios is $46.

Implementation as an IOR method. From the scenario analyses, the profitability of Smart Water was investigated in comparison to an IOR implementation with high recovery. Low salinity (LS) has shown optimal recovery results when injected from day 1 compared to tertiary mode after SW/FW flooding. The profitability of implementing Smart Water at low recovery rates was therefore simulated to see if the technology is profitable for low recoveries. The simulations show that implementing Smart Water, with an additional recovery of 3% when the CO_2-fee is $236, gives a difference in NPV of -$406 million. This result implies that Smart Water is not profitable for low recovery rates.

Environmental impact. EOR methods have received skepticism from operators, stakeholders and the general public. However, as the average environmental screening scores are 0.86 and 0.81 for LS and Smart Water respectively, the methods have negligible change in CO_2 emissions. By injecting Smart Water rather than SW, a water production delay of 6 years is expected for the base case scenario. As Smart Water has a delay in water breakthrough, less water is produced during oil production, resulting in less water treatment which in turn reduces total CO_2 emissions. The reduction in water production does also make Smart Water a more profitable alternative to SW.

New technology. EOR methods in general are known to have high investment costs. As Smart Water has not been implemented at a full scale, the field performance may be different from what the lab results predict. New technologies that may reduce CapEx for Smart Water should therefore be considered. This thesis proposes the Seabox ™ or SWIT ™ technology which can be installed directly on the seabed, potentially reducing investment costs for Smart Water.

The overall aim of this thesis was to shed light on the economics of Smart Water EOR. By combining technical and economic inputs into a simulation model, critical factors affecting the project’s profitability can be determined, increasing chances of success.

7.1 SUGGESTIONS FOR FUTURE WORK

- As there are limited publications on the economics of Smart Water EOR, further research should be done and published to gain acceptance and to spread knowledge.
- To take the effects of uncertainties under consideration, @Risk should be implemented into the model.
- As this model is based on assumptions and educated guesses, real data should be applied to the model for more accurate results.
- Simulations should be performed on smaller fields to see how low recoveries affect the profitability.
- For more accurate results from the simulation model, a f_o curve should be linked to the production profile.

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