A STUDY ON TECHNO-ECONOMICFEASIBILITY OF LOW SALINITY WATER FLOODING FOR ENHANCING CRUDE OIL RECOVERY

Abstract

This study presents a techno economic analysis of low-salinity water flooding for enhancing crude oil recovery from brown oil fields. The objective of the current work is to assess the feasibility, economic viability, and potential benefits of implementing low-salinity water flooding techniques in petroleum reservoirs. The present work presents an overview of importance of water flooding in enhancing crude oil recovery. It introduces low-salinity water flooding as an emerging technique for improving oil recovery. The current work reviews previous research to highlight the mechanisms behind improved oil recovery and also refers to some of the laboratory results from experiments and field-scale applications. The analysis evaluates the impact of low-salinity water flooding on oil recovery, considers associated reservoir parameters, and identifies potential implementation challenges. The results indicate the potential advantages of low-salinity water flooding, including increased oil recovery and cost-effectiveness. The study concludes that low-salinity water flooding holds promise as an effective EOR technique and recommends further research and field applications to explore its full potential. This techno-economic analysis contributes to understanding low-salinity water flooding and provides valuable insights for decision-makers in the petroleum industry.

Keywords: Low-salinity water flooding;enhanced oil recovery; technical analysis; economic analysis; screening criteria; profitability; sensitivity analysis

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I. INTRODUCTION

Low-salinity water flooding is an emerging technique for additional oil recovery from depleted oil wells that aims to enhance oil recovery from reservoirs. It involves modifying the composition of the injected water to optimize the interaction between the injected fluid and the reservoir rock, thereby improving displacement and recovery efficiency. Traditional water flooding techniques have limitations in achieving optimal oil recovery, leading to the exploration of alternative methods such as low-salinity water flooding. Enhanced oil recovery (EOR) techniques are crucial for maximizing hydrocarbon extraction from reservoirs. Water flooding, which involves injecting water into the reservoir to displace oil towards production wells, is the most widely employed EOR technique. However, recent research has shown that the salinity level of the injected water can significantly impact oil recovery. The concept of low-salinity water flooding revolves around the notion that altering the salinity of the injected water can modify the wettability and interfacial properties within the reservoir rock, resulting in improved oil displacement and enhanced recovery. This technique has gained attention in the petroleum industry due to its potential for increasing oil recovery efficiency. This study will conduct a techno-economic analysis of low-salinity water flooding to assess its feasibility and economic viability. The analysis will evaluate the impact of low-salinity water flooding on oil recovery, consider the technical aspects of implementation, and explore potential challenges and limitations. By examining the existing research and conducting a thorough evaluation, this study aims to contribute to the understanding and potential application of low-salinity water flooding in petroleum reservoirs.

1. **Objectives:** The objectives of the current work are to analyze the impact of low-salinity water flooding on oil recovery, assess the technical aspects of this technique, evaluate its economic feasibility, and identify potential challenges and limitations.Firstly, the study aims to analyze the impact of low-salinity water flooding on oil recovery. This involves examining how altering the composition of injected water affects the efficiency of oil recovery from reservoirs. By evaluating relevant research and data, the study seeks to quantify and understand the extent or limitation to which low-salinity water flooding can enhance oil recovery compared to traditional methods.Secondly, the study focuses on assessing the technical aspects of low-salinity water flooding. This includes investigating the underlying mechanisms and processes involved in the interaction between low-salinity water and reservoir rocks, as well as the potential alteration of wettability and displacement of oil. Understanding these technical aspects is crucial for optimizing the implementation and effectiveness of low-salinity water flooding.Thirdly, the study aims to evaluate the economic feasibility of implementing low-salinity water flooding. This involves conducting a comprehensive cost analysis, considering both the capital investment required for modifying water composition and the potential benefits in terms of increased oil recovery. The economic evaluation will help determine the viability and profitability of adopting low-salinity water flooding techniques.

   Lastly, the study seeks to identify potential challenges and limitations associated with low-salinity water flooding. This includes exploring factors such as reservoir heterogeneity, water quality requirements, compatibility with existing infrastructure, and any operational limitations or constraints that may arise during implementation. By identifying these challenges, the study aims to provide insights into the practical considerations and limitations of low-salinity water flooding as an enhanced oil recovery method.

II. FACTORS AFFECTING LOW SALINITY WATER FLOODING

The effectiveness of low-salinity water flooding in improving oil recovery may be observed based on previous research findings, as referenced in the research work conducted by Tang and Morrow [1] and other studies [2].

1. **Mineral Surface:** Numerous studies have indicated that introducing low-salinity water has a positive impact on oil recovery, particularly in reservoir cores containing clay minerals. Common sandstone reservoirs often contain clay minerals consisting of silica and aluminium layers. These layers result in a negatively charged clay surface that attracts and retains positively charged ions from the surrounding pore fluid. This ion exchange occurs through weak quasi-bonding forces, such as electrostatic and van der Waals forces, where different cations have varying strengths and replacement abilities. Based on several literature studies, it is observed that while some experiments on clay-free cores did not show a response to low-salinity water injection, the presence of kaolinite clay is found to play a role in tertiary oil recovery. Moreover, increased oil recovery has been observed in cores containing various clay types, such as illite, muscovite, and chlorite, although the presence of chlorite has been linked to poor results in low-salinity injection. Positive outcomes have also been observed in sandstone cores without clay but with dolomite crystals, possibly due to the mobilization of dolomite and anhydrite crystals by low-salinity brine. The dissolution of anhydrite and dolomite cement is proposed by many researchers as a mechanism for enhancing recovery, although recent studies suggest it contributes to the process rather than being the primary mechanism. In carbonate reservoir rocks, diluted seawater has shown improved recovery, potentially due to specific interactions between the brine and rock that increase the water wetness of the rock. Additionally, the presence of specific plagioclase silicates may elevate the pH of the formation water, reducing the clay's capacity to adsorb oil during ageing and maintaining the rock in an initially water-wet state, thus preventing the low-salinity effect from occurring [1, 2, 3, 4, 5, 6].

2. **Brine:** Several studies have emphasized the importance of achieving a lower salinity level than that of the formation brine to enhance oil recovery [2, 5, 7]. Researchers have identified the need for specific types of divalent and other multivalent cations in successful low-salinity brine [8, 9]. Conversely, injecting water with a high concentration of divalent cations has been found to hinder oil recovery [1]. However, solely removing divalent ions from the injection brine may not be sufficient, particularly if the concentration of monovalent ions like Na^+ is high [10, 11]. An increase in additional oil recovery is reported when the injected water's salinity is reduced. Typically, an upper salinity threshold of approximately 5000 ppm is recognized as contributing to increased recovery [12]. Some experts propose the existence of an optimal composition for low-salinity water, considering their suggested mechanism responsible for the low-salinity effect [5].

3. **Oil:** Some research findings reported no additional oil recovery with changing salinities of the injected brine when the experiments were conducted utilising refined oil [1, 17, 13–16]. The presence of polar components in the oil is recognized as crucial for improved oil recovery (IOR), as refined oil without these components showed no response to low-salinity conditions. Similar outcomes were observed by Morrow et al. [3] in their flooding experiments using oils with varying acid and base numbers. They found that oils with both a high acid number and a low base number, as well as oils with a low acid number and a high base number, showed similar responses to low-salinity conditions. This suggests that oils with both acidic and basic properties can be effective. Therefore, it is widely accepted that the presence of polar components in the oil is essential to induce a low-salinity effect [3].

4. **Temperature:** The temperature at which flooding occurs appears to influence the findings of additional oil recovery from low-salinity water (LSW) experiments. Higher flooding temperatures, when combined with secondary flooding using high-salinity water, resulted in increased oil recovery. However, in the case of tertiary LSW flooding, the recovery was reduced. Cissoko et al. [6] and Morrow et al. [3] conducted core flood experiments using LSW on samples from North Sea reservoirs at different ageing and flooding temperatures. They observed that cores aged at 60 °C did not respond to tertiary LSW flooding at 60 °C or 130 °C. However, cores aged at 90 °C showed a response to LSW flooding at 60 °C, 90 °C, and 130 °C [18]. Additionally, cores aged at 60 °C and then flooded with high-salinity water followed by tertiary LSW flooding at 35 °C and 60 °C also exhibited a low-salinity effect. The low-salinity effect was observed only for cores flooded at 35 °C [6, 18, 19]. These findings by different researchers infer the influence of temperature on crude oil recovery during LSW flooding.

5. **Wettability:** The change in reservoir rock wettability in cores is dependent on clay particles; this assumption is the basis for low-salinity water flooding [15]. While a water-wet condition can enhance oil production, it is generally recognized that a mixed wet condition leads to the lowest residual oil saturation after the injection of multiple pore volumes [20]. Berg et al. [21] compared the influence of clay surfaces and rock mineralogy during high-salinity water and low-salinity water flooding processes. However, the exact mechanism involved in this process remains unidentified. Injection of low-salinity water in oilfields resulted in a shift in wettability towards a more water-wet scenario. This finding infers that the rock mineralogy effect is significant [22]. Conversely, wettability may shift towards a more oil-wet state due to the injection of low-salinity water, resulting in insignificant improvements in tertiary oil recovery and slower oil production during secondary floods. The alteration in wettability increases the capillary end effect, particularly in slow-rate core floods, potentially affecting the residual saturation.

   The varying effects of salinity on wettability may also be due to disjoining pressure [23]. According to the DLVO theory, salinity influences electrostatic forces, with lower salinity resulting in the formation of a thicker film and increased water wetness. Based on it, two researchers, Sharma and Filoco [23], observed that crude oil and polar fractions with high surface densities, where electrostatic forces dominate, exhibit enhanced water wetness. For less polar oils, where electrostatic forces are suppressed, hydration or hydrophobic forces may prevail. These hydration and hydrophobic forces are hypothesised to increase with salinity, resulting in a less water-wet surface. In core flooding experiments conducted on cores with different wettabilities (water-wet, oil-wet, neutral-wet, and neutral-wet towards oil-wet states), a low-salinity effect was observed for all conditions following ageing and flooding with high salinity. However, the most significant effect was observed for the water-wet core.

6. **Injection Brine Concentration:** The concentration of the injected brine has an impact on the recovery of oil using low-salinity water [24–32]. In sandstone reservoirs, factors such as clay migration and clay swelling need to be considered as the brine concentration changes. Khilar and Fogler [33] suggested a critical brine concentration of approximately 0.4 wt% for pure NaCl brines in sandstones, stating that reducing the concentration below this value could destabilise clay and potentially damage the formation, thereby affecting the success of low-salinity water on oil recovery. However, it is applicable to measurements conducted on fully water-wet, brine-saturated samples. Other authors [34–36] reported different results regarding clay stability in the presence of various wettability systems. For example, Mungan [35] observed that the presence of crude oil in the core may prevent formation damage caused by freshwater injection. Similarly, Clementz [37] found that the presence of asphaltenes in crude oil stabilizes the formation of clay. Numerous other studies on the effects of brine salinity on oil recovery have been published, with Chandrashegaran [38] concluding that an injected water salinity of 0.2 wt% is optimal for most rock types and scenarios. Morrow and Buckley [39] demonstrated a moderate increase in oil recovery with the injection of low-salinity water containing approximately 0.2–0.5 wt% NaCl. However, not all of these studies considered the effects of injected water salinity on fine particle migration. Therefore, the relationship between fine particle migration, wettability, and possible formation damage during low-salinity water injection is not yet fully understood. Researchers Alagic and Skauge [40] formed a correlation between fine particle migration and wettability. The assumption behind this was that fine particle migration does not occur during low-salinity water injection in aged cores. However, when unaged water-wet cores are used, the results align with the findings of Clementz [37] and Mungan [35].

7. **Connate Water Concentration:** The initial saturation of connate water, rock properties, and salinity of the connate water all impact low-salinity water injection. Recent studies by Zaeri [41] and Mohammadkhani [42] examined the impact of connate water saturation on low-salinity water injection. Their experiments involved core flooding tests using carbonate core samples and found that the highest oil recovery during the secondary recovery phase was achieved with cores having high connate water salinity and low connate water saturation. However, in the tertiary stage, the greatest oil recovery was observed when both the salinity and saturation of the connate water were low.

   Thus, the role of connate brine salinity in additional oil recovery with low-salinity water injection cannot be ignored. Another study was reported, conducted by Shehata and Nasr El-Din [43]. This study investigated the influence of reservoir connate water salinity on low-salinity water performance for sandstone core samples through spontaneous imbibition experiments. They discovered that cores saturated with connate water containing divalent cations such as Ca^{2+} and Mg^{2+} exhibited higher oil recovery compared to cores saturated with monovalent cations like Na^{+}. Therefore, the composition of connate water was identified as a crucial factor affecting low-salinity water oil recovery.

The presence of connate water creates an intermediate layer between the rock surface and crude oil. This layer, electrostatically attached to the surface, prevents significant oil adsorption onto the rock surface in the absence of an intermediate water layer. As a result, ion transfer between the imbibing fluid and the rock surface is facilitated, leading to effective low-salinity water oil recovery [41, 44].

In summary, studies by different researchers report that adjusting the salinity of injected brine alone does not result in additional oil recovery when other variables are kept constant [1, 17, 13–16]. The presence of polar components in refined oil is crucial for improved oil recovery through low-salinity water flooding, as refined oil lacking polar components does not respond to low-salinity conditions. In recent studies, it has been reported that temperature may affect oil recovery using low-salinity water flooding. Higher flooding temperatures combined with secondary flooding using high-salinity water led to increased recovery, while in tertiary low-salinity water flooding, the recovery is reduced. The wettability of cores plays a significant role, with water-wet conditions resulting in accelerated oil production and mixed wet conditions yielding the lowest residual oil saturation. The concentration of injected brine and the composition of connate water also affect the success of low-salinity water oil recovery.

Understanding these factors and their interactions is vital for optimizing low-salinity water flooding as an enhanced oil recovery technique. Further research is needed to explore the mechanisms underlying these observations and to develop comprehensive models that can accurately predict the performance of low-salinity water flooding in different reservoir conditions.

III. TECHNICAL ANALYSIS: POTENTIAL APPROACHES FOR ENHANCING OIL RECOVERY THROUGH LOW-SALINITY WATER FLOODING

1. **Fine Migration:** Previous studies have proposed fine migration as a mechanism to explain the additional oil recovery achieved through low-salinity injection [1, 45–47]. Some studies reveal that fines migration from crude oil is necessary for increased oil recovery with decreased salinity. Tang and Morrow [1] reported how fine migration, such as kaolinite, enhances oil recovery due to a decrease in brine permeability due to fine migration.

   However, contradictory results have emerged. Larger et al. [48] did not observe fine migration during low-salinity experiments that resulted in additional oil recovery under both reduced and reservoir conditions. Zhang et al. [17] found no evidence of clay content in the production stream or the oil/brine interface in their experiments. Berg et al. [21] suggested that fines migration is not the primary mechanism behind low-salinity water flooding, as they observed no fines migration during increased oil recovery in their experiments. This suggests that fine sediment migration may not be the cause of the enhanced recovery achieved through low-salinity water flooding. Contrary to this, Cissokho et al. [6] demonstrated significant incremental recovery with low-salinity water in cores devoid of kaolinite.

2. **Influence of pH:** In research work by Austad et al. [5], it was proposed that there is a localised increase in pH at the clay-water interface. This phenomenon, which results in

the release of organic substances from clay surfaces, is a significant factor in enhancing oil recovery through low-salinity water (LSW). Three parameters are paramount: the presence of clay in the sandstone, the polar components (acidic and/or basic substances) in crude oil, and active ions such as Ca^{2+} in the formation water. These are identified as key factors for enhanced oil recovery through LSW.

Clays, acting as cation exchangers, adsorb both acidic and basic organic substances, along with inorganic cations like Ca^{2+}, from the formation water. Under reservoir conditions, a chemical equilibrium is established. However, when low-salinity water infiltrates the porous medium with a significantly lower ion concentration than the formation water, the interaction between the brine and rock is disrupted. This leads to the net desorption of cations, particularly Ca^{2+}, from the clay surface. Protons (H^+) from the water near the clay surface are then adsorbed onto the clay to compensate for the loss of cations, resulting in the substitution of Ca^{2+} with H^+. As a result, both acidic and basic components of the crude oil partially desorb from the surface, causing a shift in wettability towards a more water-wet condition following LSW flooding [22].

3. **Multicomponent Ionic Exchange (MIE):** Larger et al. [48] proposed Multicomponent Ionic Exchange (MIE) as a mechanism for the release of positively and negatively charged organic compounds during low-salinity brine injection. Their research indicated that additional oil recovery occurred in the tertiary phase only when the original brine contained divalent cations, specifically Ca^{2+}. In other studies, van der Waals interactions, ligand exchange, and cation bridging were found to be the primary adsorption mechanisms [49]. High ionic strengths, according to the DLVO theory, reduce electrostatic repulsion forces, allowing particles to be situated closely due to significant van der Waals attractive forces.

   Ligand exchange occurs when carboxylate groups from acidic materials replace hydroxyl groups on the surface. Cation bridging is an impartant phenomenon in oil recovery. During low-salinity brine injection, two key observations were made. Firstly, the presence of divalent cations, especially Ca^{2+}, in the brine formation was crucial for increased recovery. Secondly, for low-salinity flooding to induce oil recovery, it depends on the Mg^{2+} concentration. This suggests that the increase in oil recovery resulted from competition between all brine ions for ionic exchange with the rock surface [48].

   Polar components can adsorb onto clay through two distinct mechanisms. The first involves adsorption through multivalent cations, forming an organometallic complex. The second mechanism is direct adsorption, where labile cations are displaced at the clay surface [49].

4. **Wettability Alteration:** To release trapped oil through capillary forces or enhance water imbibition and counter-current oil production, the natural wetting characteristics of a rock can be altered. Studies by Cassie and Baxter [50], Buckley et al. [51], and Chen et al. [52] have indicated that the stability of the water film separating crude oil from the mineral surface is not always constant, allowing for potential changes in the rock's original wetting properties. Modifying the rock's wetting behaviour requires overcoming the disjoining pressure to disrupt and break the water film.

The influence of divalent cations, specifically calcium and magnesium, as well as sulphate ions, on wettability alteration in carbonate rocks, was investigated by Zhang et al. [53]. Their findings revealed that divalent anions exhibited a stronger influence on wettability alteration compared to their monovalent counterparts, such as chlorides. The ratio of Ca^{2+}/SO_4^{2-} was found to have a more significant impact on wettability alteration and subsequent oil recovery than individual anions. This aspect can be further studied in the research work of Mohammed and Babadagli [54], Saikia et al. [55], and Ding and Rahman [56].

5. **Osmosis:** The potential role of osmosis in enhancing oil recovery during Low-Salinity flooding (LSW) is also referred to by Buckley [57]. According to this theory, clays existing between brines with different salinities can generate osmotic pressure, which subsequently enhances the water drive and facilitates oil mobilisation. Subsequent studies by Yousef and Ayirala [58], Callegaro et al. [59], Rotondi et al. [60], Fredriksen et al. [61], Fredriksen et al. [62], and Pollen and Berg [63] have provided empirical evidence supporting osmotic water transport and oil mobilisation under various wettability conditions.

6. **Effect of Salting:** The salting effect, which can be referred to as a research observation by Austad [64], refers to the phenomenon where polar components exhibit higher solubility in water when the water has low ionic strength (salting in), while their solubility decreases when the ionic strength is high (salting out). RezaeiDoust et al. [65] conducted adsorption and desorption studies of quinoline onto kaolinite. As an outcome of the study, it was concluded that low-salinity effects are associated with the enhanced water wetness of the clay.

IV. SCREENING CRITERIA FOR LSWF

IOR/EOR project screening traditionally consists of applying a series of rules to evaluate the likelihood that specific techniques will work on a candidate reservoir. In contrast, current industry workflows include extensive laboratory testing and reservoir modelling. The finding of a traditional screening tool is a critical step in transitioning LSWF from an academic project to a viable production technology (Bartels et al. 2019) [14]. In traditional screening, the rules can be qualitative or quantitative and are based on experience, where specific criteria are related to the historic success or failure of a technique. Examples of criteria include flow response, oil-in-place, temperature, salinity, depth, oil properties (API gravity, viscosity), rock properties (porosity, permeability, mineralogy, clay content), pay thickness, and heterogeneity. There are field and laboratory studies that can guide the development of screening criteria for LSWF. For example, the temperature dependence of recovery in sandstones and carbonates can be used to help screen candidate reservoirs. In this context, we examine the conditions that apply to LSWF. The above assumptions are largely seen in the research work of different scientists.

1. **Rock:** It is essential that sandstone contain some clay minerals for LSWF to work. Also, the specific type of clay (kaolinite) is proposed to be an essential component, but clay content rather than type is important. All types of carbonate rocks have been shown to work in some conditions.

2. **Oil:** Polar components must be present in the oil to see a low-salinity effect. However, many papers do not report the polar content or total acid and base content of the oil (Hadia et al. 2011) [13].

3. **Dilution Factor of Injected Brine:** Early experiments used dilution factors of 100-fold based on the protocols from the formation damage literature; however, positive results have been obtained with as little as 2.5-fold dilution. The degree of dilution to maximize recovery is an important operational consideration, but most studies do not include a systematic evaluation of dilution factors. However, similar findings on this aspect are lacking (Yousef et al. 2011) [24].

4. **Temperature:** Temperature is considered a factor in LSWF response. In sandstones, the effect appears to be a lower recovery at higher temperatures (Vledder et al. 2010, Shariatpanahi et al. 2011, Skrettlingland et al. 2010) [22]. In contrast, in carbonate rock, the recovery is higher at higher temperatures. An optimum temperature window of between 90 and 110 °C was proposed, but there are many examples with positive results across the range of relevant temperatures.

5. **Formation Water:** The type and concentration of salts present in the formation water need to be evaluated. This is because, based on this compatible injection water composition, it is to be formulated in LSWF [66].

6. **Ionic Concentration:** The amount and type of ions in the injected water are other key parameters that can affect the general performance of LSWF. Different ions can play a key role in the mineral surface-oil interface. Monovalent and divalent salts can have different affinity for the surface of the rocks, changing the surface charge. Size of ions, electrical charge, and ionic strength are factors that influence surface properties due to the ionic concentration (Jackson et al. 2016, Strand et al. 2016, Sohal et al. 2016a) [67].

7. **Impact on Oil Recovery:** Low-salinity Flooding is one of the emerging enhanced oil recovery technologies. Its purpose is to inject water with a reduced salinity (less than 5,000 ppm) to improve oil recovery. One of the reasons for this improved oil recovery is wettability alteration (Webb et al., 2004) [68]. Wettability is closely linked to the distribution of oil and brine in the pores of the rock, and wetting properties are found to play a very important role in the efficiency of waterfloods in reservoirs. Reservoirs are defined as water-wet, mixed-wet, or oil-wet, and usually the initial wetting is not optimal for oil recovery (Fathi et al., 2011) [69]. However, the wettability can be improved (towards more water-wet conditions) by injecting low-salinity water.

8. **Comparative Analysis:** Studies comparing low-salinity against high-salinity floods show benefits ranging from 5% to 40% increased oil recovery based on the original oil in place (Webb et al., 2008) [70]. The results of core flood studies may be referred to for a better understanding of the outcome of the comparative analysis [71].

V. ECONOMIC ANALYSIS

1. **Components for Economic Impact Assessment:** The economic assessment of any process begins with examining the capital expenditures to be incurred. This capital

expenditure is spent to build up the infrastructure and procure all the equipment that the implementation of low-salinity water flooding will require. This expenditure is called capital expenditure (CAPEX). Following these operating expenses (OPEX), it is to be calculated how much money needs to be invested per barrel of incremental oil recovery due to the application of low-salinity water flooding. Sensitivity analysis is performed in order to assess the economic risk associated whenever the desired set of conditions for producing oil changes with market conditions. Lastly, risk assessment is done in order to find out the feasibility of the low salinity flooding process when operational uncertainties arise out of reservoir behaviour, injection water quality, and the development of associated water issues.

2. **Profitability Index:** The profitability of any process is viewed financially by finding out how fast the investment is returned. The time value of money is considered the paramount factor in such an assessment. The future cash flow is dependent on the present decision to invest [72]. As the cash flow happens at different points in the future, the calculation of the net present value (NPV) is done. If NPV is either zero or more than it, profitability is ensured, while a lower NPV than zero infers unprofitability [73]. The differential cash flow calculation is essential to view how the annual return varies, which is indicative of the possibility of cost savings by choosing the right process for enhancing oil recovery [74] [73]. Internal Rate of Return is also done occasionally in some projects; however, NPV calculation is considered useful over it [72].

3. **Diluting Injection Water Salinity:** Injection water salinity dilution as well as ionic content in a sequential way resulted in incremental oil recovery in many core flooding studies. Operating expenses involved in diluting the injection water salinity were calculated in such studies [31, 75].

VI. RESULTS AND DISCUSSIONS

The results of the current work highlight that sensitivity analysis is essential in enhancing and optimizing crude oil recovery with low-salinity water flooding. Crude oil production rate, injection water salinity, and its rate all have an influence on oil recovery to a limited extent, as such, maximizing NPV by implementing a flooding process requires optimization of the above three crucial parameters.

The sequential dilution process increases oil recovery through wettability alteration of reservoir rock due to interaction with different salinity-injected water solutions. However, the sequential dilution process has its limitations; with each successive cycle of dilution, the influence of dilution diminishes, and hence the determination of the number of cycles is essential to optimizing oil recovery.

Other factors that have an influence on oil recovery are low salinity water flooding, fines migration, pH influence, multicomponent ionic exchange, wettability alteration, osmosis, and salting effect. Screening criteria for different reservoirs to produce crude oil recovery with low salinity water flooding need to be examined carefully, as reservoir salinity as well as reservoir behaviour for different wells vary greatly.

The success or failure of implementing any process for enhancing additional oil recovery is mostly governed by the investment as well as the NPV values based on cash flow results. Sensitivity analysis annually or at different points in time of return on investment helps improve the overall oil recovery scenario by changing the implementation prices for oil recovery. Finally, this work concludes that the profitability and sustainability of any enhanced oil recovery process depend to different degrees on all of the above-mentioned parameters, be they financial or oil recovery parameters.

VII. NOMENCLATURE

EOR- Enhanced Oil Recovery
IOR - Improved Oil Recovery
LSW- Low salinity Water
DLVO - Derjaguin, Landau, Verwey and Overbeek
wt% - weight percentage
NaCl - Sodium Chloride
Na^+ - Sodium ion
Ca^+ - Calcium ion
Mg^{2+} - Magnesium ion
API - American Petroleum Institute
LSWF - Low salinity water flooding
CAPEX - Capital Expenditure
OPEX - Operating Expenses
NPV - Net Present Value

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