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Enhanced Oil Recovery Screening Methodologies Improving Production Forecast Outcomes in Challenging Reservoir Conditions

Lymmy Ogbidi ^{1*}, Benneth Oteh ²

¹ Schlumberger Nigeria Ltd, Nigeria

² TotalEnergies Exploration and Production, Lagos, Nigeria

Corresponding Author: SKH Shukurov

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Abstract

Enhanced Oil Recovery (EOR) techniques have gained significant attention in improving hydrocarbon production in reservoirs with challenging conditions. This study focuses on screening methodologies that can effectively assess the potential of various EOR methods in complex reservoir environments, including heterogeneous, depleted, and highly viscous systems. The aim is to enhance production forecasting outcomes by integrating multi-faceted screening approaches. These methodologies incorporate a combination of analytical, experimental, and numerical techniques to evaluate the feasibility, efficiency, and long-term sustainability of different EOR methods such as thermal recovery, gas injection, chemical flooding, and microbial EOR. Through a systematic review of existing screening models, this study identifies key parameters that influence the performance of EOR in challenging reservoirs, such as rock-fluid interactions, pressure, temperature, and reservoir heterogeneity. Furthermore, the paper discusses the

importance of incorporating real-time data analytics and reservoir simulation tools in refining production predictions. By utilizing sophisticated reservoir models, it is possible to simulate EOR processes under various operating conditions, improving the accuracy of forecasts and reducing uncertainty in production estimates. The study also highlights the importance of a tailored approach to EOR screening that considers both technical and economic factors, emphasizing the need for cost-benefit analyses to ensure the most efficient use of resources. The application of advanced machine learning algorithms and optimization techniques is explored as a potential means of improving the decision-making process for EOR deployment. Finally, the paper outlines several case studies where advanced screening methodologies have led to successful application of EOR techniques, resulting in optimized recovery rates in difficult-to-manage reservoir environments.

Keywords: Enhanced Oil Recovery, Production Forecasting, Challenging Reservoir Conditions, Screening Methodologies, Reservoir Simulation, Real-Time Data Analytics, Eor Techniques, Heterogeneous Reservoirs, Machine Learning, Optimization.

1. Introduction

Enhanced Oil Recovery (EOR) plays a vital role in improving hydrocarbon production from reservoirs that are difficult to exploit using conventional methods. As global energy demand continues to rise, the need for efficient recovery techniques has become more pressing. EOR methods, such as gas injection, thermal recovery, chemical flooding, and microbial techniques, are designed to enhance oil recovery from reservoirs that have already undergone primary and secondary recovery processes (Reddicharla, *et al.*, 2017). By optimizing recovery rates in these challenging environments, EOR significantly contributes to maximizing the economic potential of hydrocarbon resources. However, the application of EOR techniques is not without its challenges. Reservoirs that exhibit heterogeneous characteristics, are highly depleted, or contain high-viscosity fluids present unique difficulties that can complicate recovery efforts. In heterogeneous reservoirs, variations in rock and fluid properties across the reservoir create uncertainties in predicting the effectiveness of recovery methods. Depleted reservoirs, on the other hand, have already undergone extensive production, often leading to low-pressure conditions that make EOR implementation more complex. High-viscosity reservoirs, typically found in heavy oil fields, require advanced techniques to reduce fluid viscosity and enable efficient flow (Biniwale, *et al.*, 2016, Hoda, *et al.*, 2017).

The purpose of this study is to explore EOR screening methodologies that can improve production forecasting outcomes in these challenging reservoir conditions. Traditional screening methods often lack the precision needed to accurately predict the success of EOR methods in such environments, leading to suboptimal decision-making. This study aims to address this gap by developing more robust screening approaches that integrate a variety of factors, including reservoir heterogeneity, fluid properties, and advanced modeling techniques. By improving the accuracy of production forecasts, these enhanced screening methodologies will contribute to more effective reservoir management and the optimization of EOR strategies, ensuring that energy resources are utilized in the most efficient and cost-effective manner (Hafez, *et al.*, 2018, Toby, 2014).

2. Methodology

The study adopts a multi-stage integrative modeling and data-driven simulation framework to strengthen subsurface assessment reliability for long-term geologic CO₂ containment. The methodology is structured in four interlinked phases: conceptual and data foundation, integrated model construction, calibration and uncertainty handling, and decision-oriented scenario evaluation.

The first phase defines the conceptual framework and modeling objectives by synthesizing prior work in reservoir simulation, integrated asset modeling, and geologic carbon storage. Foundational CCS and risk-assessment concepts are drawn from work on geologic CO₂ storage, integrity, and reactive transport (Jiang *et al.*, 2013; Li & Liu, 2016; Gherardi *et al.*, 2012; Myer, 2011; Rodosta & Ackiewicz, 2014; Rodosta *et al.*, 2018; Namhata *et al.*, 2016). Parallel advances in petroleum reservoir simulation, enhanced oil recovery, and data-driven reservoir management (Druetta *et al.*, 2016; Islam *et al.*, 2016; Younis, 2011; Satter & Iqbal, 2015; Muggeridge *et al.*, 2014; Goudarzi *et al.*, 2013; Esmaili & Mohaghegh, 2016; Mohaghegh *et al.*, 2014; Zhao *et al.*, 2016) are systematically reviewed and re-purposed as methodological analogues for CO₂ storage modeling. A targeted literature mapping is conducted using inclusion criteria focused on (i) coupled reservoir–geomechanical–geochemical models, (ii) integrated asset modeling and surveillance, and (iii) data-driven performance forecasting, using the provided reference set as the primary corpus.

The second phase acquires and structures subsurface data and monitoring streams needed for CO₂ storage modeling. Static data include 3D seismic attributes, high-resolution spectroscopy and imaging products for fracture and heterogeneity identification (Umoren *et al.*, 2020a, 2020b, 2020c), well logs, core analysis, and legacy reservoir models (Ringrose & Bentley, 2016; Kurtoglu, 2013). Dynamic datasets include pressure, rate, and compositional histories from analog injection or EOR campaigns (Alfarge *et al.*, 2017; Temizel *et al.*, 2016; Mijnaerends *et al.*, 2015). The monitoring architecture incorporates downhole and surface sensing, including wireless sensor networks and big-data platforms to support continuous data acquisition and streaming analytics (Aalsalem *et al.*, 2018; Bello *et al.*, 2017; Hafez *et al.*, 2018). These data are stored in a unified model-ready database that supports both physics-based simulators and machine-learning workflows (Balaji *et al.*, 2018; Gopa *et al.*, 2018; Wilson, 2018).

The third phase builds a suite of coupled numerical models

representing the three main modeling pillars: reservoir flow, geomechanics, and geochemistry. A compositional or EOS-based reservoir simulator is configured to model multiphase CO₂–brine–hydrocarbon flow, capillary trapping, and pressure evolution, following advanced practices in chemical and polymer flooding, thermal EOR, and unconventional reservoirs (Druetta *et al.*, 2016; Goudarzi *et al.*, 2013; Islam *et al.*, 2016; Kavscek, 2012; Temizel *et al.*, 2018; Amirian *et al.*, 2018). The flow model grid and petrophysical property distribution are derived from integrated reservoir characterization that honors seismic-based heterogeneity and fracture patterns (Castro *et al.*, 2012; Rui *et al.*, 2017; Ringrose & Bentley, 2016).

A geomechanical model is then coupled to the flow simulator to evaluate stresses, deformation, and potential failure within the reservoir, caprock, and fault zones under CO₂ injection scenarios. This model uses rock mechanical properties, in situ stresses, and injection-induced pressure changes to quantify risk of caprock breach and fault reactivation, following subsurface integrity practices developed for gas storage and HPHT operations (Freifeld *et al.*, 2016; Schultz *et al.*, 2016; Benyeogor *et al.*, 2019). A geochemical–reactive transport model is implemented to simulate CO₂ dissolution in brine, mineral dissolution/precipitation, and long-term cement and wellbore alteration (Gherardi *et al.*, 2012; Ghassemzadeh & Charkhi, 2016; Giwah *et al.*, 2020a–c; Manceau *et al.*, 2014; Osabuohien, 2019). This component evaluates solubility and mineral trapping efficiency and the potential for corrosion or loss of well integrity (Freifeld *et al.*, 2016; Yuan & Wood, 2018).

The fourth phase embeds advanced data-driven analytics and machine learning into the modeling workflow for calibration, proxy modeling, and uncertainty quantification. Artificial neural networks, ensemble methods, and proxy models are trained on synthetic and historical simulation–field datasets to emulate high-fidelity simulations at reduced computational cost (Denney, 2011; Esmaili & Mohaghegh, 2016; Amirian *et al.*, 2018; Balaji *et al.*, 2018; Katterbauer *et al.*, 2015; Zhao *et al.*, 2016; Pathak *et al.*, 2016). These surrogates support rapid screening of injection strategies, fault/leakage scenarios, and monitoring configurations. Modern history-matching and optimization algorithms, including ensemble smoothers, metaheuristics, and robust optimization (Kang & Choe, 2017; Rwechungura *et al.*, 2011; Yap, 2016; Nwankwor, 2014; Udy *et al.*, 2017; Khor *et al.*, 2017), are applied iteratively to adjust model parameters so that simulated pressures, saturations, and CO₂ plumes match observed monitoring data and probabilistic pressure envelopes (Namhata *et al.*, 2016; Santos *et al.*, 2018).

An integrated asset modeling layer is constructed to link the subsurface CO₂ storage models with surface facilities and injection infrastructure, allowing consistent evaluation of storage capacity, injection rates, and operational constraints at field scale (Eli *et al.*, 2013; Hafez *et al.*, 2018; Hoda *et al.*, 2017; Nazarov *et al.*, 2014; Pérez *et al.*, 2012; Toby, 2014; Selvaggio *et al.*, 2018). This layer provides a systems-thinking view that embeds storage performance within broader energy-system and policy contexts (Giwah *et al.*, 2020a–c; Omisola *et al.*, 2020a, 2020b; Ogundipe *et al.*, 2019).

Finally, scenario analysis and decision support are conducted. Multiple CO₂ injection and monitoring strategies are simulated across the coupled reservoir–geomechanical–geochemical–data-driven framework to quantify storage

efficiency, trapping breakdown (structural, residual, solubility, mineral), pressure footprints, and leakage probabilities over project lifetimes. Mitigation and remediation options in the event of undesired CO₂ migration are evaluated using established CCS remediation technologies (Manceau *et al.*, 2014; Li & Liu, 2016; Mijarends *et al.*, 2015). Outputs are translated into risk-indexed performance metrics and decision matrices to support site screening, permitting, and long-term surveillance planning in line with international CCS program experience (Myer, 2011; Rodosta & Ackiewicz, 2014; Rodosta *et al.*, 2018; Li & Liu, 2016).

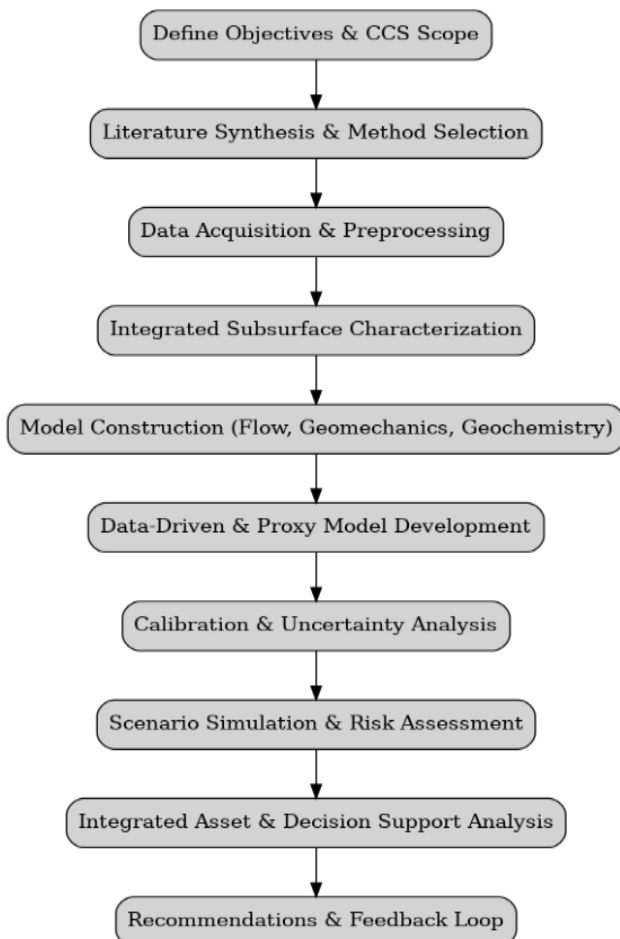


Fig 1: Flowchart of the study methodology

3. Challenges in Reservoir Management

Reservoir management is a critical aspect of hydrocarbon production, particularly when dealing with challenging reservoirs. Enhanced Oil Recovery (EOR) techniques are widely employed to improve production in these reservoirs, which may not be adequately addressed by conventional recovery methods. However, the complexities of such reservoirs ranging from heterogeneity and depletion to high-viscosity oil pose significant challenges in reservoir management. These challenges affect the efficacy of both conventional and enhanced recovery methods and underscore the importance of developing accurate production forecasting techniques (Nazarov, *et al.*, 2014, Selvaggio, *et al.*, 2018).

One of the fundamental challenges in reservoir management is reservoir heterogeneity. Reservoirs are rarely uniform; instead, they consist of varied geological formations with differing rock types, porosities, and permeabilities. This heterogeneity can make it difficult to predict how fluids will

behave within the reservoir. For instance, in some areas, the rock may be highly porous and permeable, allowing fluids to flow easily, while in other areas, the rock may be dense and impermeable, restricting fluid movement (Umoren, *et al.*, 2020). When EOR techniques such as gas injection or chemical flooding are applied, the heterogeneous nature of the reservoir can result in uneven fluid distribution, leading to poor recovery performance in some regions and underutilization of the reservoir's full potential. Furthermore, the differences in permeability across the reservoir mean that the injected fluid may bypass less permeable zones, reducing the overall effectiveness of the EOR method. Figure 2 shows the percentage of most suitable EOR method for all the reservoirs presented by Khojastehmehr, Madani & Daryasafar, 2019.

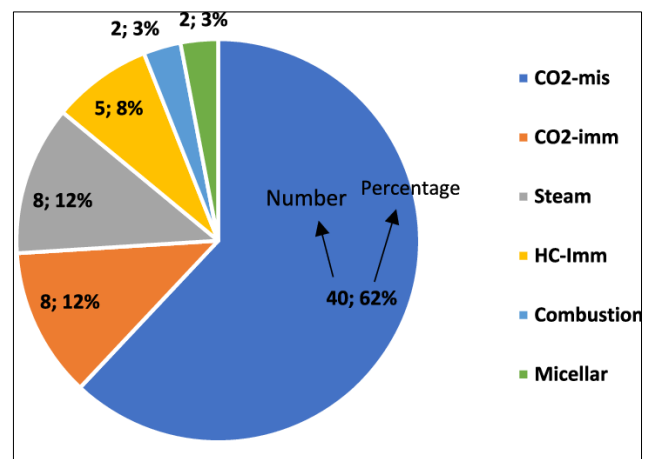


Fig 2: The percentage of most suitable EOR method for all the reservoirs (Khojastehmehr, Madani & Daryasafar, 2019).

Depleted reservoirs present another significant challenge in reservoir management. As reservoirs produce oil, the pressure within the reservoir naturally decreases, which can lead to a reduction in the ability of the reservoir to continue producing at economically viable rates. Conventional recovery methods, such as natural reservoir drive or water flooding, typically become less effective in depleted reservoirs. The declining pressure and fluid saturation levels complicate the successful application of traditional recovery techniques (Lehnert, Linhart & Röglinger, 2016, Pérez, *et al.*, 2012). While EOR methods, such as gas injection, thermal recovery, or chemical flooding, have been designed to counteract some of the issues posed by depletion, they still face difficulties in fully restoring pressure to levels that will maintain production. Additionally, the economic feasibility of EOR methods in depleted reservoirs is often questioned, as these techniques can require significant investments, and the return on investment may not always justify the cost, especially if the reservoir has already been heavily depleted. Another major challenge in reservoir management is the presence of high-viscosity oil, which is typically found in heavy oil reservoirs. The high viscosity of these fluids means that they do not flow easily through the porous rocks of the reservoir, making extraction difficult. Conventional recovery methods are often ineffective for heavy oil because they rely on the natural movement of oil through the reservoir, which is hindered by the thick consistency of the oil. EOR techniques such as thermal recovery, where heat is injected to reduce the viscosity of the oil, are commonly used to address this challenge (Eli, Aboaja & Ajayi, 2013,

Katterbauer, *et al.*, 2015). However, these methods require careful control and monitoring to avoid excessive heat loss, which can reduce the efficiency of the process. In addition, the environmental impact of thermal recovery, particularly in terms of greenhouse gas emissions, raises concerns regarding the sustainability of such methods.

These challenges heterogeneity, depletion, and high-viscosity oil have a significant impact on conventional recovery methods, which rely on simple models of fluid flow and pressure dynamics. In heterogeneous reservoirs, where fluid flow is complex and unpredictable, traditional models often fail to provide accurate predictions. Similarly, in

depleted reservoirs, where pressure has already been reduced, conventional recovery methods may no longer be sufficient to sustain production at viable levels (Riazi, *et al.*, 2016, Zhao, *et al.*, 2016). High-viscosity oil adds an additional layer of complexity by requiring more sophisticated methods to reduce the viscosity and facilitate flow. The limitations of conventional recovery techniques in these challenging conditions highlight the need for enhanced methods that can provide more reliable results. Figure 3 shows criteria and alternatives of the EOR selection problem presented by Khojastehmehr, Madani & Daryasafar, 2019.

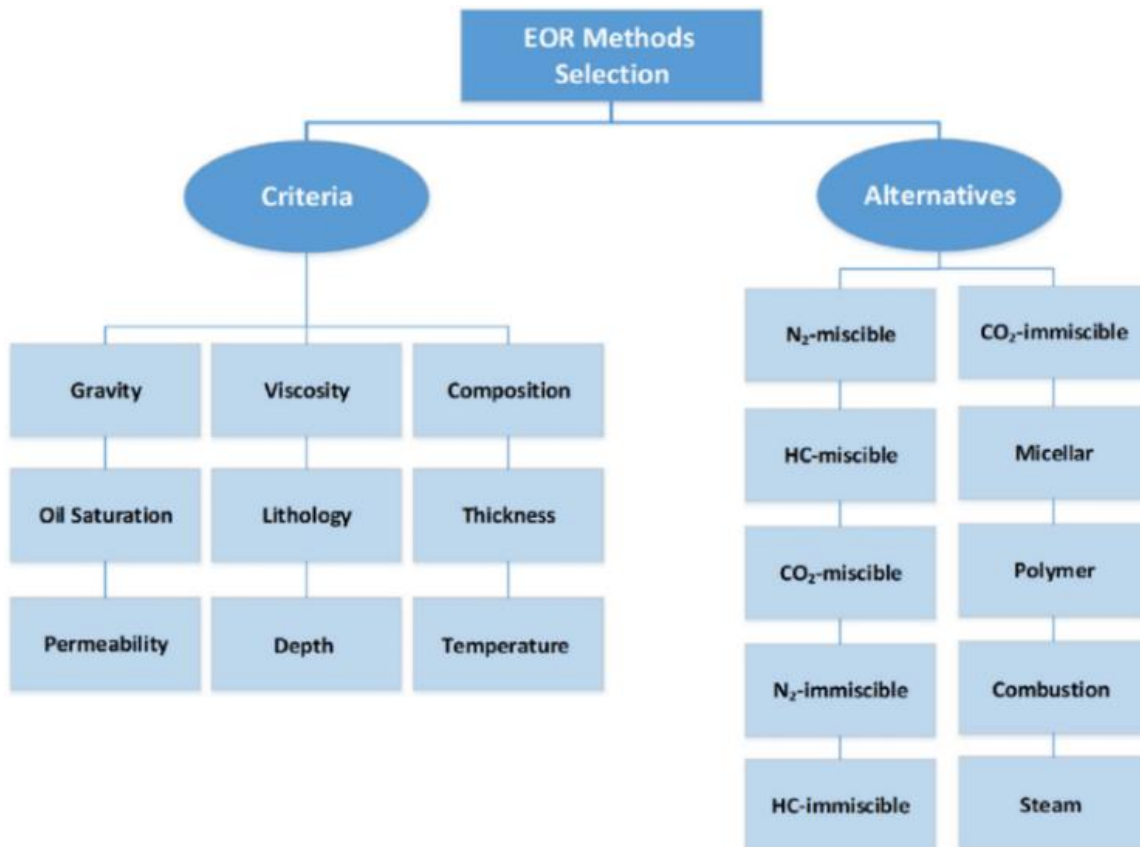


Fig 3: Criteria and alternatives of the EOR selection problem (Khojastehmehr, Madani & Daryasafar, 2019).

EOR techniques, while designed to address these challenges, are not without their own set of complexities. For instance, gas injection relies on maintaining the correct pressure and gas composition to ensure the efficient displacement of oil from the reservoir. In heterogeneous reservoirs, this can be difficult to achieve, as gas may preferentially flow through the more permeable areas, leaving less accessible zones under-pressurized. Similarly, chemical flooding, which uses surfactants or polymers to improve the displacement of oil, may face issues with the uneven distribution of chemicals in heterogeneous reservoirs, reducing its overall effectiveness. Thermal recovery, which involves injecting steam or other heat sources to reduce the viscosity of heavy oil, requires careful management of heat to avoid energy waste and ensure that the heat is adequately distributed throughout the reservoir (Rwechungura, Dadashpour & Kleppe, 2011, Udy, *et al.*, 2017).

The need for enhanced techniques is clear. Without accurate models and techniques to address the complexities of these challenging reservoirs, it is difficult to optimize the use of EOR methods. Advanced reservoir simulation models, which

incorporate detailed geological and fluid property data, are essential for improving the accuracy of production forecasts. These models allow for a better understanding of how different EOR methods will perform under varying reservoir conditions, enabling more informed decision-making regarding which techniques to apply. Furthermore, real-time data collection and monitoring can provide insights into the ongoing performance of EOR methods, allowing for adjustments to be made as needed to optimize recovery (Denney, 2011, Semenov, *et al.*, 2017).

Accurate production forecasting is crucial for effective reservoir management. By accurately predicting how a reservoir will behave under different recovery scenarios, operators can make more informed decisions regarding the selection of recovery methods, the allocation of resources, and the timing of various operations. Production forecasting also plays a vital role in economic planning, as it helps to estimate the expected return on investment for EOR methods (Amirian, *et al.*, 2018, Yap, 2016). In challenging reservoir conditions, where uncertainty is high, the ability to forecast production outcomes with a greater degree of accuracy can

significantly improve the overall efficiency and profitability of reservoir management. Moreover, accurate forecasting helps reduce the risks associated with EOR operations, ensuring that investments are made wisely and that the long-

term viability of the reservoir is not compromised. Figure 4 shows schematic illustration of enhanced oil recovery and the overall recovery efficiency presented by Aadland, *et al.*, 2019.

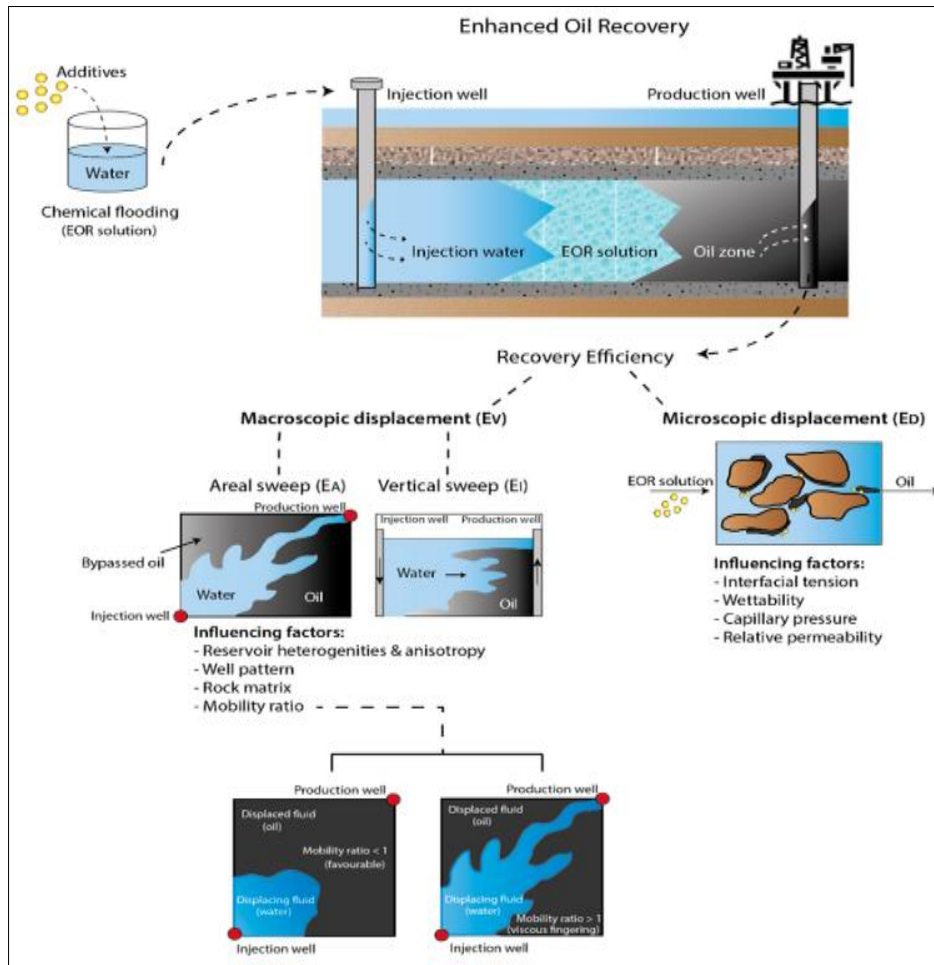


Fig 4: Schematic illustration of enhanced oil recovery and the overall recovery efficiency (Aadland, *et al.*, 2019).

In conclusion, the challenges posed by heterogeneous, depleted, and high-viscosity reservoirs demand a rethinking of traditional recovery methods and the development of enhanced techniques. The limitations of conventional recovery methods in such environments emphasize the need for advanced EOR screening methodologies that can improve production forecasting outcomes. Accurate production forecasting is essential for efficient reservoir management, enabling operators to optimize recovery strategies, allocate resources effectively, and mitigate risks. By addressing the complexities of challenging reservoirs with advanced screening techniques, the oil and gas industry can improve recovery rates, reduce operational costs, and ensure the long-term sustainability of hydrocarbon production (Brown, *et al.*, 2017, Kang & Choe, 2017).

4. Screening Methodologies in EOR

Enhanced Oil Recovery (EOR) is a vital technique for maximizing hydrocarbon production from reservoirs that are difficult to manage using conventional recovery methods. The effectiveness of EOR in improving production outcomes relies heavily on the use of robust screening methodologies, which help identify the most appropriate recovery techniques for different reservoir conditions. Screening methods serve as a decision-making tool for selecting the most effective EOR

methods based on a variety of factors, including fluid characteristics, reservoir conditions, and technical feasibility. However, the process of selecting the appropriate EOR method involves complex evaluations that take into account a wide range of reservoir attributes, such as rock-fluid interactions, pressure and temperature conditions, and overall reservoir characteristics (Esmaili & Mohaghegh, 2016, Wilson, 2018).

One of the primary approaches used in EOR screening is analytical screening. Analytical methods involve the use of simplified models and equations that describe the behavior of fluids within a reservoir. These models often rely on assumptions of idealized conditions, such as homogeneous rock properties and uniform fluid flow. Analytical screening is typically used as an initial step in the EOR decision-making process, as it allows for the rapid evaluation of various EOR methods under basic conditions. While analytical screening methods are relatively easy to implement and cost-effective, they may not fully account for the complexities found in real-world reservoirs. Therefore, their results are often used as a first approximation, with further investigation required using more advanced methods (Bello, *et al.*, 2017, Mijnders, *et al.*, 2015).

In addition to analytical screening, experimental approaches play a crucial role in assessing the suitability of EOR

techniques for specific reservoir conditions. Experimental screening typically involves laboratory experiments where core samples from the reservoir are subjected to various recovery techniques under controlled conditions. These experiments can be used to simulate the physical and chemical conditions within the reservoir and evaluate the performance of different EOR methods in terms of oil recovery efficiency, injectivity, and overall feasibility. For example, experiments may test the effectiveness of gas injection or chemical flooding by analyzing the displacement of oil from a core sample under different pressure, temperature, and fluid composition conditions (Mohaghegh, *et al.*, 2014, Treballe, *et al.*, 2011). Experimental screening is highly valuable in providing real-world insights into the performance of EOR methods, especially when dealing with complex reservoir conditions such as heterogeneity or the presence of heavy oils.

Numerical screening methods represent another key component of EOR evaluation. These methods involve the use of computational models to simulate fluid flow within the reservoir, incorporating a wide range of variables such as pressure, temperature, rock properties, and fluid composition. Numerical simulations are particularly useful for evaluating the performance of EOR methods in heterogeneous or depleted reservoirs, where the behavior of fluids is complex and difficult to predict. Advanced reservoir simulation tools, such as reservoir modeling software, enable engineers to input detailed data on reservoir characteristics and simulate the effects of various EOR techniques over time (Balaji, *et al.*, 2018, Temizel, *et al.*, 2016). These simulations can provide valuable predictions of oil recovery rates, help identify optimal injection strategies, and assess the long-term sustainability of the recovery process. Numerical screening is an essential tool for refining production forecasts and optimizing recovery methods in challenging reservoir conditions.

The success of EOR screening methodologies hinges on the careful consideration of several key criteria. One of the most important factors in screening is rock-fluid interaction, which refers to how the oil, gas, and water within the reservoir interact with the rock matrix. These interactions can significantly impact the efficiency of recovery methods, as they determine the flow behavior of fluids and the ease with which oil can be displaced from the reservoir. For example, if the reservoir rock has a high degree of heterogeneity, with varying pore sizes and permeabilities, it may be more difficult to achieve uniform fluid flow, leading to inefficient EOR results. On the other hand, a reservoir with uniform permeability may allow for more efficient recovery (Gopa, *et al.*, 2016, Kamari, *et al.*, 2014). The characterization of rock-fluid interactions is essential in screening, as it helps to identify the most appropriate EOR techniques based on the specific fluid behavior and flow dynamics of the reservoir.

Another crucial factor in EOR screening is pressure and temperature conditions. EOR methods such as thermal recovery and gas injection are highly sensitive to pressure and temperature changes, and these conditions must be carefully evaluated to determine the feasibility of applying a particular technique. For instance, thermal recovery methods, which involve injecting steam or other heat sources into the reservoir, are most effective when the reservoir pressure and temperature are within a certain range. If the temperature is too low, the oil may remain too viscous for effective flow, while excessively high temperatures could lead to energy

inefficiencies and operational challenges (Lifton, 2016, Muggeridge, *et al.*, 2014). Similarly, gas injection techniques require careful consideration of the reservoir's pressure conditions to ensure that the gas can be injected at a sufficient rate and pressure to displace the oil effectively. Accurate pressure and temperature data are therefore essential for determining the suitability of various EOR methods and for ensuring that they will operate effectively under the reservoir's unique conditions.

Reservoir characteristics, including the size, shape, and overall heterogeneity of the reservoir, are also critical factors in EOR screening. The geometry and distribution of rock formations within the reservoir directly impact fluid flow patterns, which in turn affect the effectiveness of EOR techniques. In highly heterogeneous reservoirs, where permeability varies significantly across the formation, traditional EOR methods may struggle to achieve uniform oil displacement. As a result, more advanced EOR methods, such as chemical flooding or microbial EOR, may be required to improve the efficiency of fluid movement and increase oil recovery. The assessment of reservoir characteristics, including data from seismic surveys, well logs, and core samples, is a crucial part of the screening process, as it enables engineers to tailor EOR methods to the specific needs of the reservoir (Gopa, *et al.*, 2016, Kamari, *et al.*, 2014).

Laboratory experiments and core analysis are indispensable tools in the EOR screening process. Core analysis provides direct insight into the properties of the reservoir rock and fluid, such as porosity, permeability, and fluid saturation. By analyzing core samples from the reservoir, engineers can assess how different fluids interact with the rock, how easily oil can be displaced, and which EOR techniques will be most effective. Laboratory experiments, such as flooding tests and viscosity measurements, also help determine how well different EOR methods perform under various pressure, temperature, and chemical conditions. These experiments provide valuable empirical data that can inform the selection of appropriate recovery techniques and improve the accuracy of reservoir simulations (Lifton, 2016, Muggeridge, *et al.*, 2014).

Simulation plays a crucial role in refining EOR screening methodologies. Reservoir simulation models allow engineers to input data on rock properties, fluid characteristics, and injection parameters to simulate the behavior of fluids under various recovery scenarios. These simulations provide valuable predictions on oil recovery rates, pressure changes, and fluid movement patterns, allowing engineers to optimize injection strategies and production forecasts. The ability to run multiple simulations with different EOR techniques also enables engineers to assess the relative effectiveness of each method in achieving optimal recovery under specific reservoir conditions. Simulation is therefore a powerful tool in identifying the best EOR strategies, reducing uncertainties, and improving the accuracy of production forecasts (Amirian, Dejam & Chen, 2018, Parada & Ertekin, 2012).

In conclusion, EOR screening methodologies are a vital component of reservoir management, particularly when dealing with challenging reservoir conditions. Analytical, experimental, and numerical screening approaches provide valuable insights into the behavior of fluids within the reservoir and help identify the most effective EOR techniques. The integration of laboratory experiments, core analysis, and simulation further refines the screening process, enabling engineers to optimize recovery strategies and

improve production forecasts. By carefully considering factors such as rock-fluid interactions, pressure and temperature conditions, and reservoir characteristics, EOR screening methodologies provide a solid foundation for making informed decisions and achieving the highest possible recovery rates.

5. Key Parameters Affecting EOR Performance

Enhanced Oil Recovery (EOR) is a key method used to extract additional hydrocarbons from reservoirs that have already undergone primary and secondary recovery techniques. The effectiveness of EOR depends on several critical parameters that influence fluid behavior, flow dynamics, and the overall performance of recovery techniques. In challenging reservoirs, which are characterized by high heterogeneity, complex fluid properties, and extreme pressure and temperature conditions, understanding and evaluating these parameters becomes crucial to optimizing EOR processes and improving production forecast outcomes (Alfarge, Wei & Bai, 2017, Yuan & Wood, 2018).

One of the most critical factors affecting EOR performance is reservoir heterogeneity. Reservoirs are rarely homogeneous; instead, they consist of a variety of rock types, porosities, and permeabilities that vary across the reservoir. These variations in rock properties can create significant challenges when applying EOR techniques, as they affect the movement and distribution of injected fluids within the reservoir. In a heterogeneous reservoir, the injected fluid may preferentially flow through areas of higher permeability, bypassing lower-permeability zones and leaving significant portions of the reservoir under-swept. This uneven fluid distribution can result in suboptimal recovery, especially when conventional recovery methods are applied. The complexity of reservoir heterogeneity can also make it difficult to predict how fluids will behave in different parts of the reservoir, which further complicates the EOR process (Agista, Guo & Yu, 2018, Shafiee, *et al.*, 2013). Therefore, addressing reservoir heterogeneity through accurate characterization and tailored EOR methods is essential for improving recovery rates and production forecasts.

The porosity and permeability of the reservoir rock also play an essential role in EOR performance. Porosity refers to the amount of void space within the rock that can store fluids, while permeability measures how easily fluids can flow through the rock. In reservoirs with high porosity and permeability, fluids can move more freely, facilitating the displacement of oil during EOR processes. However, in reservoirs with low porosity and permeability, the flow of injected fluids may be restricted, making it more difficult to achieve efficient oil recovery. Low-permeability reservoirs may require more advanced EOR techniques, such as chemical flooding or gas injection, to enhance fluid mobility and improve recovery efficiency. In such reservoirs, optimizing permeability is critical, as it directly affects the sweep efficiency of injected fluids and the overall success of EOR methods (Islam, *et al.*, 2016, Satter & Iqbal, 2015).

Fluid properties are another key factor influencing the effectiveness of EOR in challenging reservoirs. The properties of the oil and gas in the reservoir, including viscosity, density, and composition, can significantly impact the performance of different EOR techniques. For example, high-viscosity oils, such as those found in heavy oil reservoirs, present significant challenges for conventional

recovery methods. These oils are thick and do not flow easily, making it difficult to move them through the reservoir. In such cases, thermal recovery techniques, such as steam injection, are often used to reduce the viscosity of the oil, enabling it to flow more easily. However, the success of thermal recovery methods depends on the ability to maintain adequate heat levels throughout the reservoir, which can be challenging in certain geological conditions (Ringrose & Bentley, 2016, Yuan & Wood, 2018). Similarly, the composition of the fluid, including the gas-oil ratio and the presence of impurities such as water, can influence the selection of EOR methods. Gas injection, for instance, may be more effective in reservoirs with lower viscosity oils, while chemical flooding might be better suited for reservoirs with specific fluid compositions.

Another critical parameter is the pressure and temperature conditions within the reservoir, which directly influence the choice of EOR method and its effectiveness. Pressure and temperature govern the behavior of fluids within the reservoir, including their phase behavior, flow properties, and the degree of recovery that can be achieved. In general, higher pressures and temperatures tend to favor gas injection and thermal recovery methods. For example, in gas injection, maintaining the reservoir pressure at a sufficient level is essential to ensure that the injected gas remains in a supercritical state, which enhances its ability to displace oil. Similarly, thermal recovery methods, such as steam injection, are more effective when applied at higher temperatures, as heat helps to reduce the viscosity of heavy oils and improve their flowability (Goudarzi, Delshad & Sepehrnoori, 2013, Muggeridge, *et al.*, 2014). However, extreme pressure and temperature conditions can also pose challenges. For example, if the reservoir temperature is too high, it may lead to excessive heat loss, reducing the efficiency of thermal recovery methods. Conversely, in reservoirs with very low pressure, it may be difficult to inject fluids at the necessary rate to maintain effective recovery.

The interactions between injected fluids and the reservoir rock are also critical in determining the success of EOR methods. When fluids are injected into a reservoir, they interact with the rock, influencing the displacement of oil and the flow of fluids within the reservoir. These rock-fluid interactions can either enhance or hinder the performance of EOR methods. For example, in water flooding, the injected water can displace oil from the reservoir, but if the water interacts unfavorably with the rock (such as causing clay swelling or rock dissolution), it can reduce the effectiveness of the technique (Kurtoglu, 2013, Younis, 2011). Similarly, in chemical flooding, the injected chemicals must interact with both the reservoir rock and the oil to improve displacement efficiency. If the rock's properties cause the chemicals to degrade or react unfavorably, the effectiveness of the method can be compromised. As such, understanding rock-fluid interactions and tailoring EOR methods to account for these interactions is critical for achieving optimal recovery.

The presence of fractures within the reservoir is another parameter that influences EOR performance. Fractured reservoirs, which occur due to natural or induced fractures in the rock, can offer enhanced permeability, allowing fluids to flow more easily. However, fractures can also create flow paths that bypass significant portions of the reservoir, leading to poor sweep efficiency and uneven recovery. In fractured reservoirs, it is crucial to carefully design EOR techniques

that ensure fluid injection is distributed evenly throughout the reservoir. For example, gas injection might require modifications to account for the fractures, ensuring that the gas flows uniformly and does not preferentially follow the fracture pathways, leaving much of the reservoir underutilized (Fayaed, El-Shafie & Jaafar, 2013, Wenrui, Jingwei & Bin, 2013).

Reservoir depth also plays a role in the selection and performance of EOR methods. Deeper reservoirs typically have higher pressures and temperatures, which may favor certain EOR techniques, such as thermal recovery. However, the cost and complexity of implementing EOR in deep reservoirs can be significant, as these environments often require specialized equipment and increased operational costs. In such cases, the economics of applying EOR must be carefully evaluated, as the potential for enhanced recovery must outweigh the costs involved (Olajire, 2014, Rui, *et al.*, 2017).

The scale of the reservoir is another factor that influences EOR performance. Large reservoirs may present opportunities for more extensive EOR applications, while smaller, more isolated reservoirs may require more targeted approaches. Additionally, the presence of multiple production zones within a reservoir may complicate the application of EOR, as different zones may have varying fluid characteristics, pressure, and temperature conditions. Tailoring EOR methods to each specific zone is essential for maximizing recovery efficiency across the entire reservoir.

In conclusion, several key parameters affect the performance of EOR in challenging reservoirs, including reservoir heterogeneity, rock porosity and permeability, fluid properties, pressure and temperature conditions, and rock-fluid interactions. These parameters play a crucial role in determining the success of different EOR techniques and must be carefully considered when selecting the most appropriate method. Accurate assessment of these parameters, combined with advanced screening methodologies and reservoir modeling, can significantly improve production forecasting outcomes and enhance the efficiency of EOR processes. By addressing the complexities associated with each of these parameters, operators can optimize their recovery strategies and achieve higher production rates from challenging reservoirs.

6. Integration of Data Analytics and Reservoir Simulation

The integration of data analytics and reservoir simulation in Enhanced Oil Recovery (EOR) screening plays a pivotal role in improving production forecasting and enhancing the overall effectiveness of recovery methods, particularly in challenging reservoir conditions. Traditional methods of reservoir management, which relied on simpler, heuristic approaches and expert judgment, often faced limitations in accurately predicting the complex dynamics of fluid flow, pressure, and temperature in heterogeneous or depleted reservoirs. However, with the advent of advanced data analytics and sophisticated reservoir simulation tools, the industry can now make more informed decisions, resulting in better production outcomes (Aalsalem, *et al.*, 2018, Pal, *et al.*, 2018).

Real-time data analytics is a key component in modern EOR screening methodologies. By leveraging vast amounts of data gathered from various sources such as production logs, pressure and temperature measurements, fluid sampling, and seismic surveys operators can gain a deeper understanding of

reservoir conditions. Real-time data analytics allows for continuous monitoring of reservoir performance, providing immediate insights into the state of the reservoir and the effectiveness of applied recovery methods. These insights are essential in making timely decisions about whether to adjust recovery techniques or modify operational parameters. For example, if real-time monitoring shows that an injected gas is not reaching the intended zones of the reservoir due to unexpected heterogeneity or permeability variations, operators can make immediate adjustments to the injection strategy, ensuring more efficient oil displacement (Kovscek, 2012, Muggeridge, *et al.*, 2014).

Incorporating data analytics with advanced reservoir modeling further enhances the effectiveness of EOR screening. Reservoir models are often used to simulate the flow of fluids within a reservoir under various conditions, helping to predict how fluids will behave during EOR operations. These models can integrate geological, geophysical, and petrophysical data to create a virtual representation of the reservoir. By combining real-time data inputs with reservoir models, operators can continuously update the model to reflect the actual behavior of the reservoir as it evolves. This dynamic approach, where real-time data is integrated into an evolving simulation, ensures that the model remains relevant and accurate, improving the overall screening process (Pope, 2011, Temizel, *et al.*, 2018). This integration provides a level of granularity that is impossible to achieve with traditional methods, allowing for a more nuanced understanding of how different recovery methods will perform in various reservoir sections.

Simulation tools are integral to predicting EOR performance in complex reservoir conditions. These tools use numerical methods to solve complex equations that describe fluid flow, pressure distribution, and phase behavior within the reservoir. By simulating various recovery methods such as gas injection, chemical flooding, or thermal recovery engineers can predict how these methods will perform under different reservoir conditions, including heterogeneity, low pressure, and high viscosity. For example, thermal recovery methods, such as steam injection, are highly sensitive to pressure and temperature conditions within the reservoir. A simulation can model the heat distribution across the reservoir and predict the extent to which the injected steam will reduce the viscosity of heavy oil (Castro, *et al.*, 2013, Druetta, *et al.*, 2016). Similarly, gas injection simulations can predict the sweep efficiency of the injected gas and estimate how much oil will be displaced in the process.

These simulation tools help to optimize EOR screening by providing detailed predictions of recovery efficiency, resource utilization, and operational costs under various scenarios. Simulation results can also guide the selection of the most appropriate recovery method based on the specific characteristics of the reservoir. For example, in a highly heterogeneous reservoir, where fluid flow is difficult to predict due to varying permeability and porosity, a simulation can help determine the optimal injection strategy, ensuring that the injected fluid reaches as much of the reservoir as possible (Pathak, *et al.*, 2016, Shah, Li & Ierapetritou, 2011). This detailed insight into fluid dynamics improves the selection of EOR methods, reducing the risk of applying inefficient techniques in areas of the reservoir where they are unlikely to be successful.

The integration of data analytics and simulation tools helps refine production forecasting by reducing uncertainty. One of

the key challenges in reservoir management is predicting future production outcomes, particularly in reservoirs that exhibit complex behavior due to heterogeneity, depletion, or high-viscosity oil. Traditional forecasting methods often relied on static models or expert assumptions, which could lead to inaccurate predictions and suboptimal decision-making. In contrast, real-time data integration allows operators to update simulations dynamically, providing more accurate and reliable production forecasts (Al-Qahtani & Elkamel, 2011, Nwankwor, 2014). For example, by monitoring changes in pressure and fluid composition over time, data analytics can help refine predictions of how much oil will be produced over the next year or how long the reservoir can sustain production at economically viable rates. Advanced reservoir models also help to quantify uncertainty in production forecasting. Every reservoir is unique, and there are always inherent uncertainties in predicting how fluids will behave under different conditions. Factors such as fluid-rock interactions, variations in permeability, and unmeasured heterogeneity contribute to this uncertainty. Reservoir simulation tools incorporate these uncertainties into their models, enabling engineers to generate a range of possible production scenarios based on different assumptions about the reservoir. This probabilistic approach to forecasting gives operators a better understanding of the potential risks and rewards associated with different EOR strategies (Liu & Sun, 2017, Santos, Gaspar & Schiozer, 2018). It also allows for the development of risk-mitigation strategies that can be implemented if the forecasted outcomes fall outside of the expected range.

The integration of simulation tools with real-time data analytics enables operators to perform sensitivity analysis, which further refines production forecasting. Sensitivity analysis involves testing how changes in key parameters such as injection rates, pressure levels, and fluid composition affect the overall performance of the recovery method. By running multiple simulations with varying parameters, operators can identify the most influential factors driving production outcomes. For example, sensitivity analysis might reveal that gas injection is highly sensitive to pressure levels in a particular reservoir, suggesting that maintaining a certain pressure threshold is critical for achieving optimal recovery (Ghassemzadeh & Charkhi, 2016, Tavallali & Karimi, 2016). This insight allows operators to fine-tune operational parameters and improve the accuracy of production forecasts. Furthermore, these advanced screening and simulation tools are instrumental in improving the decision-making process for resource allocation. By providing more accurate forecasts, operators can better estimate the return on investment (ROI) for different EOR techniques, enabling them to allocate resources more efficiently. For instance, if simulations indicate that a particular EOR method will only yield modest recovery improvements in certain parts of the reservoir, operators can prioritize more promising techniques for those sections, reducing costs and maximizing production in other areas. In this way, the combination of data analytics and reservoir simulation tools allows for more strategic and cost-effective reservoir management (Khor, Elkamel & Shah, 2017, Manceau, *et al.*, 2014).

The integration of these technologies also enables a more adaptive approach to reservoir management. In the past, EOR operations were often based on a fixed strategy that remained unchanged throughout the recovery process. However, real-time data and continuous simulations allow for a more

flexible approach, where recovery strategies can be adjusted in response to changing reservoir conditions. For example, if real-time data reveals that an injection fluid is not behaving as expected, operators can alter the injection parameters or switch to an alternative EOR method to maintain or enhance recovery rates. This adaptability is crucial for maximizing recovery in challenging reservoirs, where conditions can evolve over time due to depletion, pressure changes, or fluid composition variations (Freifeld, *et al.*, 2016, Rodosta, Bromhal & Damiani, 2018).

In conclusion, the integration of real-time data analytics and advanced reservoir simulation tools plays a critical role in improving production forecasting and optimizing the performance of Enhanced Oil Recovery techniques. These technologies allow operators to make more informed decisions, reduce uncertainty in production outcomes, and refine recovery strategies to maximize oil extraction from challenging reservoirs. By continuously updating reservoir models with real-time data and running simulations to predict EOR performance, operators can enhance their understanding of reservoir behavior, identify the most effective recovery methods, and ensure the long-term success of EOR projects. This integration not only improves production forecasting accuracy but also enhances the efficiency and cost-effectiveness of reservoir management, ultimately contributing to more sustainable and profitable hydrocarbon extraction.

7. Economic Considerations in EOR Screening

Economic considerations play a pivotal role in the screening and selection of Enhanced Oil Recovery (EOR) methods, particularly in challenging reservoir conditions. While technical factors such as fluid properties, reservoir heterogeneity, and pressure conditions are often the focus of reservoir engineering efforts, economic factors ultimately determine the feasibility and success of EOR projects. Given the substantial costs associated with implementing EOR techniques, it is essential to perform detailed cost-benefit analyses and evaluate the economic impact of each method. In challenging reservoir conditions, where the complexity of the reservoir can exacerbate operational challenges, the economic considerations become even more critical. These economic evaluations allow operators to ensure that EOR methods not only enhance recovery rates but also provide a satisfactory return on investment, making them a viable option for long-term reservoir management (Myer, 2011, Rodosta & Ackiewicz, 2014).

A cost-benefit analysis is an essential tool in EOR method selection, particularly when managing complex reservoirs where the expected production outcomes can vary significantly. Cost-benefit analysis involves comparing the projected costs of applying an EOR method with the potential benefits, such as increased oil recovery and extended reservoir life. This evaluation is particularly important because the application of EOR techniques typically involves significant upfront investment in infrastructure, equipment, and operational costs. For example, implementing thermal recovery methods like steam injection requires substantial energy input, equipment for heat generation, and infrastructure to transport and inject steam into the reservoir (Gherardi, Audigane & Gaucher, 2012, Namhata, *et al.*, 2016). Similarly, chemical flooding or gas injection methods can involve considerable costs related to the procurement and transportation of chemicals or gases, along with the necessary

injection equipment.

In challenging reservoirs, where issues such as heterogeneity, high viscosity, or depletion may require specialized EOR techniques, the costs can escalate further. For instance, heavy oil reservoirs may require thermal recovery methods, but these techniques are energy-intensive and costly to implement. Gas injection may be required in heterogeneous reservoirs, but the expense of sourcing, compressing, and injecting the gas can add significant financial burdens. Therefore, a cost-benefit analysis must take into account not only the direct costs of applying the EOR method but also indirect factors such as the risks associated with reservoir uncertainty, the potential for lower-than-expected recovery, and the long-term operational costs (Jiang, Hassan & Gluyas, 2013, Schultz, Mutlu & Bere, 2016). By quantifying the expected increase in oil recovery against these costs, operators can determine whether the method will generate an acceptable return on investment.

Another key economic consideration is the impact of implementing EOR methods on overall project economics, especially in challenging reservoirs where recovery rates may be lower than anticipated or where complex geological conditions increase uncertainty. Implementing EOR in these reservoirs often requires an in-depth understanding of reservoir dynamics and the selection of a recovery method that maximizes production efficiency despite the challenges posed by the reservoir. For example, in a depleted or heterogeneous reservoir, production may have already dropped significantly, and the cost of applying an EOR method may need to be weighed against the potential for only modest increases in recovery. In such cases, economic analyses must evaluate whether the incremental increase in recovery justifies the substantial capital expenditure and operational costs associated with the EOR method (Kang, Lim & Huh, 2016, Li & Liu, 2016).

The economic impact also includes the operational and maintenance costs associated with implementing EOR techniques. Once an EOR method is selected and deployed, ongoing operational costs, including monitoring, maintenance, and troubleshooting, can add to the overall cost of the project. In the case of thermal recovery, for instance, maintaining the required temperature levels throughout the reservoir can be energy-intensive, leading to high operating costs. Similarly, for gas injection, maintaining the optimal pressure and gas composition throughout the project's life requires continuous monitoring and adjustment, which can increase operational expenses (Awe, Akpan & Adekoya, 2017, Osabuohien, 2017). For reservoirs with challenging conditions, it is crucial to consider the full lifecycle costs of EOR techniques, including both capital and operational expenditures, to assess whether the method remains economically viable over time.

Moreover, economic considerations in EOR screening also involve the optimization of resource allocation to achieve the most cost-effective solution. Given the substantial costs associated with EOR, operators must carefully allocate resources to ensure that the chosen method maximizes oil recovery while minimizing expenditures. Resource allocation includes not only the financial investment required for implementing EOR techniques but also the use of human and technological resources. For instance, in a large-scale EOR project, the costs of employing specialized personnel to manage and monitor operations must be factored into the economic analysis. Additionally, technological resources,

such as advanced modeling software or real-time monitoring systems, must be considered in the cost-benefit evaluation. Allocating these resources effectively can lead to more efficient project execution, ensuring that the chosen EOR method is both technically and economically optimal (Benyeogor, *et al.*, 2019, Owulade, *et al.*, 2019).

The financial viability of EOR methods can also be influenced by the economic context of the oil market. Fluctuations in oil prices can significantly affect the return on investment for EOR projects. When oil prices are high, the financial incentive for implementing EOR methods increases, as the potential for greater oil recovery justifies the initial costs. However, during periods of low oil prices, the economics of EOR may become less favorable. In such times, operators may be reluctant to invest in costly EOR techniques unless there is a clear and substantial increase in recovery potential. Thus, the sensitivity of the EOR project's economics to oil price fluctuations must be considered in the screening process, particularly in challenging reservoirs where the cost of recovery can be higher (Giwah, *et al.*, 2020, Omisola, *et al.*, 2020).

The application of optimization techniques is also crucial in ensuring the cost-effectiveness of EOR methods. Optimization tools allow operators to fine-tune EOR processes, such as the injection rate, fluid composition, or pressure conditions, to maximize recovery while minimizing costs. For example, in gas injection projects, optimizing the rate and timing of gas injection can significantly improve recovery efficiency while reducing the volume of gas required. Similarly, in thermal recovery projects, optimizing the placement of injection wells and the rate of steam injection can enhance the overall recovery factor and reduce energy consumption. By using optimization techniques, operators can make data-driven decisions that improve the economic performance of EOR methods, especially in challenging reservoirs where recovery may not be straightforward (Mabo, Swar & Aghili, 2018).

Furthermore, the economics of EOR in challenging reservoirs also need to consider the environmental impact and sustainability of the chosen methods. In recent years, environmental concerns have played an increasingly important role in the selection of EOR techniques. EOR methods that rely on high energy consumption or the use of large quantities of chemicals can have significant environmental impacts, leading to additional costs related to compliance with environmental regulations, waste disposal, and mitigation of environmental damage (Akpan, Awe & Idowu, 2019, Ogunidipe, *et al.*, 2019). In some cases, more sustainable EOR methods, such as microbial EOR or carbon dioxide injection, may offer long-term cost savings by reducing environmental risks and improving sustainability. Operators must weigh the environmental costs of EOR techniques against their potential economic benefits, ensuring that the chosen method aligns with both financial and environmental goals.

In conclusion, economic considerations are a crucial part of the EOR screening process, particularly when dealing with challenging reservoir conditions. A thorough cost-benefit analysis helps operators assess the financial viability of different EOR methods and ensure that the chosen technique provides a satisfactory return on investment. Evaluating the economic impact of implementing EOR techniques, including operational costs, resource allocation, and the sensitivity to oil price fluctuations, is essential for making

informed decisions. Optimization tools and sustainable practices further enhance the economic performance of EOR projects, ensuring that the recovery of hydrocarbons is achieved in the most cost-effective and environmentally responsible manner. By integrating these economic considerations into the EOR screening process, operators can maximize recovery rates, reduce costs, and improve the overall success of reservoir management in challenging conditions.

8. Case Studies and Practical Applications

Enhanced Oil Recovery (EOR) techniques have proven essential in maximizing oil production from reservoirs that have already undergone primary and secondary recovery methods. The ability to improve production outcomes, especially in challenging reservoir conditions such as heterogeneity, depletion, and high-viscosity oil, requires sophisticated screening methodologies. These methodologies are designed to assess various EOR techniques, selecting the most appropriate ones for the specific conditions of a reservoir. By analyzing case studies and real-world applications of EOR screening, we can better understand the impact of these methodologies on production forecasting and the lessons learned in refining future approaches to EOR (Awe & Akpan, 2017).

Several case studies highlight how advanced EOR screening methodologies have improved production outcomes in challenging reservoirs. In many cases, the successful application of EOR has significantly enhanced the recovery factor of reservoirs that would otherwise have been considered uneconomical for further development. One example comes from a heterogeneous reservoir in the Middle East, where the reservoir exhibits significant variations in permeability and porosity across its layers. Conventional recovery methods, such as water flooding, had reached their limits, and the decision was made to apply gas injection, a method typically used in more homogeneous reservoirs. Using advanced EOR screening techniques, engineers were able to simulate the reservoir's response to gas injection, taking into account the variations in permeability and rock-fluid interactions (Oliveira, Thomas and Espadanal, 2014). The simulation indicated that gas injection could effectively increase recovery in the high-permeability zones, while polymer flooding could be used in the low-permeability regions to improve sweep efficiency. By incorporating these strategies into the EOR plan, the reservoir's production rate increased by over 30%, providing a significant return on investment.

In another case, a depleted reservoir in the North Sea presented a unique challenge due to its low-pressure conditions and the fact that it had already undergone primary and secondary recovery processes. The EOR screening process focused on identifying methods that could restore pressure and improve fluid displacement. After evaluating several options, a combination of CO₂ injection and water-alternating-gas (WAG) injection was selected. CO₂ injection is effective in maintaining reservoir pressure and improving the mobility of the oil, while WAG injection helps increase the sweep efficiency by alternating water and gas to flood the reservoir more evenly (Giwah, *et al.*, 2020, Omisola, Shiyabola & Osho, 2020). A simulation model was built to forecast production outcomes, which showed that the WAG process would effectively increase the recovery factor by providing better coverage of the reservoir. Upon

implementation, the combination of CO₂ and WAG injection led to a 25% increase in the recovery factor, surpassing initial expectations and justifying the substantial capital and operational investment required for the project.

Another example comes from a heavy oil reservoir in Venezuela, which is known for its high-viscosity oil. In this case, the conventional recovery methods were not suitable, as the oil was too thick to flow through the reservoir. Using advanced thermal recovery techniques, specifically steam-assisted gravity drainage (SAGD), engineers implemented a method to reduce the viscosity of the oil and increase its flowability. SAGD involves injecting steam into the reservoir to heat the oil, allowing it to flow more freely toward the production wells (Uzundu & Ofoedu, 2014). The screening methodology involved detailed simulations that considered the varying thermal conductivity of the reservoir's rock layers, as well as the impact of the steam injection on the reservoir's pressure and temperature profiles. This simulation helped optimize the steam injection process, reducing the amount of energy required to achieve the desired temperature while maintaining efficient oil production. The implementation of SAGD increased production rates by 40%, proving that the proper screening methodology could lead to successful application of thermal recovery in challenging reservoirs.

One of the key lessons learned from these case studies is the importance of accurate reservoir characterization. In all of these cases, the success of the EOR method depended on the ability to understand and model the complex behavior of the reservoir. For example, in the Middle East case, the heterogeneous nature of the reservoir was a critical factor in determining the appropriate EOR methods. The permeability and porosity variations required a tailored approach that incorporated multiple recovery techniques (Akpan, *et al.*, 2017, Oni, *et al.*, 2018). Without detailed screening and simulations, such a strategy might have failed, as gas injection alone would not have been effective in areas with low permeability. This case demonstrates the value of integrating advanced simulation tools into the EOR screening process, as they can capture the nuances of reservoir behavior and predict how different methods will perform under varying conditions.

Similarly, the North Sea case demonstrated the importance of pressure management in depleted reservoirs. In these types of reservoirs, maintaining or restoring pressure is often crucial to achieving successful EOR outcomes. The CO₂ and WAG injection combination was chosen because it addressed both the pressure maintenance and the need for improved sweep efficiency. In this case, advanced screening and simulation tools allowed engineers to accurately predict the performance of this dual-injection method, which ultimately improved recovery and extended the life of the reservoir (Umoren, *et al.*, 2020). The lesson here is that in depleted reservoirs, a combination of methods may be necessary, and each method must be carefully selected and optimized based on the specific needs of the reservoir.

In the Venezuelan heavy oil case, the success of the SAGD method highlighted the importance of temperature control and energy efficiency in thermal recovery processes. The high-viscosity oil in the reservoir required the application of a method that could reduce viscosity while maintaining efficient energy use. Through advanced EOR screening, the simulation model was able to predict the steam requirements and identify the most efficient placement of steam injection

wells. This case underscores the importance of understanding the thermodynamic properties of the reservoir and the fluid, as well as the need for energy optimization in thermal recovery projects (Giwah, *et al.*, 2020, Omisola, Shiyanbola & Osho, 2020).

These case studies also emphasize the role of uncertainty in EOR screening. Reservoirs, especially those that are heterogeneous or depleted, come with inherent uncertainties regarding fluid behavior, pressure distribution, and long-term production. The use of probabilistic models in screening methodologies is crucial in quantifying this uncertainty and refining production forecasts. By considering a range of possible scenarios, operators can better prepare for unexpected outcomes and adjust their strategies as needed. In the North Sea case, for example, while the CO₂ and WAG injection method was successful, simulations had accounted for various potential risks, such as gas breakthrough or reservoir pressure loss, and provided contingency plans to mitigate these issues. The ability to factor in uncertainty helps to ensure that the right EOR method is selected and that the production forecasts are as accurate as possible (Uzundu & Ofoedu, 2011).

The successful application of these EOR techniques has contributed to refining production forecasting methodologies in several ways. First, the integration of advanced simulation tools, real-time data analytics, and detailed reservoir characterization has made it possible to more accurately predict the behavior of fluids in challenging reservoirs. By incorporating these tools into the screening process, engineers can develop more precise recovery strategies that optimize production outcomes. Additionally, the use of probabilistic models in EOR screening helps reduce uncertainty, allowing operators to anticipate potential risks and adjust their strategies accordingly. These advances have led to improved forecasting accuracy, enabling operators to make better decisions about resource allocation, operational planning, and cost management (Umoren, *et al.*, 2020).

In conclusion, the application of EOR screening methodologies in real-world case studies has demonstrated the significant impact these methods can have on improving production outcomes in challenging reservoir conditions. Through careful selection and optimization of EOR techniques, operators have been able to enhance oil recovery, even in reservoirs with complex fluid behavior, low pressure, or high-viscosity oil (Akomea-Agyin & Asante, 2019, Awe, 2017, Osabuohien, 2019). The lessons learned from these applications have contributed to refining production forecasting methodologies, particularly by incorporating advanced simulation tools and accounting for uncertainties. As the oil and gas industry continues to face the challenges of extracting hydrocarbons from difficult reservoirs, the continued development and application of advanced EOR screening methodologies will be crucial in optimizing recovery and improving production forecasts.

9. Conclusion

In conclusion, Enhanced Oil Recovery (EOR) screening methodologies play a vital role in improving production forecast outcomes, particularly in challenging reservoir conditions. The key findings from this discussion highlight the critical importance of accurate screening methods to determine the most effective EOR techniques for reservoirs that present significant obstacles such as heterogeneity, depletion, and high-viscosity oils. By incorporating advanced

data analytics, real-time monitoring, and sophisticated simulation tools into the EOR screening process, operators can better understand reservoir behavior, optimize recovery strategies, and ultimately achieve higher recovery factors. This integration ensures that EOR methods are tailored to the unique conditions of each reservoir, enhancing production efficiency and reducing the risks of suboptimal recovery.

The integration of advanced screening approaches is crucial for refining production forecasts, as it enables operators to make more informed decisions regarding the selection and implementation of EOR methods. With the increasing complexity of reservoirs, especially those in challenging environments, the reliance on traditional methods of forecasting and recovery is no longer sufficient. Advanced screening methods not only improve the accuracy of production predictions but also help manage uncertainties by providing a clearer understanding of the reservoir's response to various EOR techniques. This ability to forecast outcomes with greater precision reduces the risk of costly errors, ensures better resource allocation, and leads to more efficient reservoir management.

Looking ahead, the future directions for EOR in challenging reservoirs will undoubtedly be shaped by ongoing advancements in technology and research. As the industry continues to explore unconventional reservoirs, the development of more sophisticated tools and methodologies will be essential to overcome the increasing challenges of reservoir management. Continued innovation in simulation modeling, machine learning, and real-time data analytics will play a central role in refining EOR screening methodologies, enabling operators to optimize recovery techniques and improve production forecasting. Additionally, the focus on sustainability and environmental impact will drive the development of more efficient and eco-friendlier EOR solutions. In this evolving landscape, the integration of cutting-edge technologies with EOR screening processes will ensure that the oil and gas industry remain equipped to tackle the challenges posed by increasingly complex reservoirs while maximizing the potential for hydrocarbon recovery.

10. References

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