

**Experimental Evaluation of Relative Permeability
Modifiers Application to Control Water Cut in Fields in
Kazakhstan**

by

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ORIGINALITY STATEMENT

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ABSTRACT

Excessive water production is a major problem in mature oil fields because it reduces oil-production efficiency and increases lifting, separation, and water-handling costs. This issue is especially relevant for Kazakhstan reservoirs, many of which are characterized by high water cut after long-term waterflooding. Relative permeability modifiers (RPMs) are chemical treatments intended to reduce water permeability more strongly than oil permeability and are therefore considered promising for selective water control.

This thesis evaluated the performance of RPMs under laboratory conditions representative of selected Kazakhstan fields. Two RPM candidates were first compared in single-phase water-flow tests, after which the more suitable chemical was selected for detailed study. Two-phase coreflood experiments were then carried out on sandstone core samples from four field systems using field-specific formation waters, crude oils, and reservoir-representative temperature and pressure conditions. Water and oil permeabilities were measured before and after treatment to determine the selectivity of the RPM. In addition, a simplified CMG IMEX simulation was performed for one representative field case to examine the possible reservoir-scale effect of the experimentally observed permeability changes.

The results showed that the selected RPM reduced water permeability significantly more than oil permeability in all tested cores, confirming its selective behavior. The best result was obtained for Field A, where water permeability was reduced by 67.6% while oil permeability decreased by only 5.0%. In the other fields, water-permeability reduction ranged from 50.8% to 54.5%, whereas oil-permeability reduction remained limited. The simulation results supported the laboratory findings and showed that the selective permeability reduction could lead to lower cumulative water production, with greater benefit when treatment was applied earlier.

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1. INTRODUCTION

1.1 Background

1.1.1 Water Production in Mature Oil Fields

In mature oil fields, an increase in water production is a natural and often unavoidable consequence of long-term reservoir depletion and secondary recovery operations. As production progresses, reservoir pressure declines and the displacement front between oil and water gradually advances toward producing wells. Over time, this leads to an increase in water cut, defined as the fraction of water in the total produced fluids. In many aging reservoirs, water cut can exceed 70–90%, significantly reducing economic oil output (Xue et al., 2023). As reservoirs mature, the production system increasingly shifts from predominant oil production to the co-production of oil and large volumes of water. This transition is widely observed in fields that have undergone prolonged depletion or have been subjected to long-term pressure maintenance programs. In such cases, water production becomes an integral part of reservoir behavior and reflects the progressive change in fluid saturation and flow conditions within the porous medium. For this reason, high water cut is generally regarded as one of the defining features of mature reservoir performance (Joseph& Ajienka, 2010). The growing presence of water in produced fluids is closely associated with the later stages of reservoir life, when oil recovery becomes more difficult and fluid flow behavior becomes increasingly complex. Although water production is expected in many oil-producing systems, excessive water cut indicates that the reservoir is approaching a stage where production efficiency is increasingly constrained by water dominance.

1.1.2 Operational and Economic Impact

In the process of producing hydrocarbons, the production of water is a relevant issue, as relevant as oil production itself, because the volumes of water produced in each well and in the field can determine the technical, economic and even environmental viability of putting it into production (Ortega et al., 2019). As water cut rises, the same barrel of oil is produced with a much larger volume of water, increasing requirements for lifting power, separation, treatment chemicals, reinjection/disposal capacity, and maintenance. High volumes of produced water may also result in high rates of exposure for tubulars and facilities to potentially corrosive environments and scaling conditions (Matthews, 1996). Increased volumes of produced water may also increase the number of potential failures of equipment and/or require increased

frequency of interventions due to the presence of dissolved salts, solids, treatment chemicals, and dissolved gases that may be involved with deposition or plugging (Rajbongshi et al., 2024).

1.1.3 Water Production in Kazakhstan Reservoirs

Kazakhstan is a major contributor to the global oil industry, producing about 547.5 million barrels of crude oil annually and ranking 18th in the world in terms of daily oil production in 2022 (Satubaldina, 2022). A large share of Kazakhstan's oil production comes from fields that have been under development for many years and are now at mature or late-development stages. In such reservoirs, long production history, prolonged pressure-maintenance operations, and reservoir heterogeneity have led to increasing water production and declining oil efficiency. At the national level, KazMunayGas has also linked mature-field performance to higher produced-water handling and greater energy use, noting that higher water cut increases fluid density and artificial-lift energy demand (Annual Report, KazMunayGaz, 2024)

Water injection has been the main reservoir pressure-maintenance and displacement method in many Kazakhstani fields (Alisheva et al., 2025). While water injection supported production and improved recovery during earlier development stages, long-term flooding in heterogeneous reservoirs has gradually promoted uneven sweep, preferential flow through high-permeability intervals, and bypassing of oil in poorly swept zones. This is particularly applicable when it comes to large producing areas like Mangystau and the South Turgay Basin where such fields as Uzen, Kumkol and East Kumkol have been extensively discussed in the literature as mature resources experiencing advanced water cut effects. (Zhao et al., 2023, Alisheva et al., 2025).

Evidence from the Kumkol oil field shows that the reservoir entered a high-water-cut stage after years of intensive waterflooding. Zhao et al. (2023) reported that water cut reached about 95%. And it indicates that a substantial portion of injected water was no longer contributing efficiently to incremental oil displacement. Similar challenges are reported for western Kazakhstan mature fields. For example, the Uzen field is repeatedly described as a late-stage waterflooded reservoir with average water cut above 90% due to long-term flooding, even though significant residual oil saturation still remains in place. Published work on Uzen further notes typical mature-field problems such as high well water cut, ageing well stock, corrosion, salt deposition, and uncertainty in the distribution of residual reserves after prolonged waterflooding. These conditions show that the problem is not simply water

production itself, but inefficient conformance between injected water and the reservoir zones that still contain movable oil. (Imanbayev et al., 2022). Tachibayev et al., (2024) reported that Uzen field has 1283 wells with water cut higher than 80%. Another paper shows that water production became a serious issue at an early stage of development of Tulyus field. High water cut was observed already in the first months of operation of producing wells. The authors relate this to factors such as the activity of edge water, perforation of water-bearing intervals, and general reservoir heterogeneity (Bekenov et al., 2018). The Zaburunye field is also directly described as being at a high-water-cut stage (Mussayev et al., 2021). In addition, screening of 27 KazMunayGas fields showed that low reserve recovery with high water cut is characteristic of several mature Kazakhstan fields, including Karazhanbas, Kalamkas, Asar, Karamandybas, Zholamanov, Kenbai, UAZ, Akingen, Nuraly, and Alibekmola (Mussayev et al., 2021). These examples show that excessive water production is a widespread problem across Kazakhstan oil fields.

1.1.4 Overview of Water Control Methods

Excessive water production is one of the major challenges in mature oil fields, and a range of water-control methods has been developed to reduce water cut and improve recovery. In general, the choice of treatment depends on the source of water production, reservoir heterogeneity, completion type, and the location of the water source relative to the wellbore. According to Mokogwu et al. (2022), the underlying water-production mechanism has to be correctly diagnosed, whereas Taha et al. (2019) pointed out that water shutoff is to be viewed as an element of the overall reservoir management.

There are typically two general categories of water-control methods: mechanical and chemical methods (Sun et al., 2017). Mechanical methods, like packers, plugs, and cement squeezes are generally used when the source of water is physically isolable. Chemical techniques, on the other hand, are better applied when the issue is related to the heterogeneity of the reservoirs, fractures, or the prevalent flow channels that are not confined to the near-wellbore area. Among chemical treatments, polymer gels and preformed particle gels are the most widely studied and applied systems. Foam-based, emulsion-based, and nanomaterial-assisted systems have also shown potential under specific reservoir conditions (Sagbana et al., 2021; Kang et al., 2021; Ali et al., 2024). In general, the literature shows that there is no universal technique, and the success of the treatment is determined by appropriate diagnosis, laboratory tests, and the correspondence of the chosen technology to the real mechanism of water production.

1.1.5 Introduction to Relative Permeability Modifiers (RPM)

Relative permeability modifiers (RPMs) are chemical water control agents utilized to reduce water flow through porous media more than hydrocarbon flow. This selective behavior is usually referred to as disproportionate permeability reduction (DPR) in the petroleum literature, in which permeability to water is decreased greater than permeability to oil or gas following treatment (Stavland et al., 1998).

RPMs are considered to be favorable for high-water-cut wells, as they are supposed to decrease water production while preserving as much hydrocarbon productivity as possible (Zaitoun et al., 1999). The treatments of RPM are usually used when excess water cannot be managed by a only mechanical isolation, especially in heterogeneous or fractured reservoir where the oil and water producing regions cannot be easily separated (Mennella et al., 2001). Most RPM systems are polymer-based and are typically injected as dilute aqueous solutions that adsorb on the rock surface or alter flow behavior in pore throats. That creates greater resistance to the water phase than to the hydrocarbon phase (Qin et al., 2021). Unlike bulk plugging agents or strong gels, RPMs are designed to decrease selectively water flow while maintaining some hydrocarbon productivity. This ability makes them fundamentally different from total shutoff treatments (Stavland et al., 1998).

The performance of RPM is complicated and requires to consider factors like heterogeneity of the reservoir, wettability, mineralogy, and the saturation conditions and the placement of the treatment (Mokogwu et al. 2022). Despite the fact that a number of mechanisms have been proposed, such as polymer adsorption, the effect of wettability, gel swelling, and modification of the pore-scale flow, no universal explanation has ever been made to explain the RPM behavior in all rock-fluid systems (Al Brahim et al., 2022).

Field experience shows that RPMs can be effective in selected applications, but their success is strongly dependent on the reservoir and requires careful laboratory screening before implementation (Vasquez et al., 2009).

1.2 Problem Statement

One of the primary technical and economical issues in mature oil fields continues to be excessive water production. With aging of reservoirs, the water cut tends to rise due to the effect of aquifer support, long-term waterflooding, heterogeneity, fractures and development

of dominant water-flow channels. This results in decreased oil productivity, increased lifting and separation costs, increased amounts of produced-water management, as well as decreased overall recovery efficiency. The broader water-shutoff literature also demonstrates that despite the large variety of control methods, field performance is usually inconsistent, due to a non-uniform matching of treatments to the actual water-production mechanism.

The main challenge is that traditional water-control techniques do not always offer selective reduction of the water phase. Techniques based on mechanical isolation can work well in situations where the source of water is well known and physically isolable, but not in those where heterogeneity reservoir and crossflow, fractures, or deep channeling are the cause of excess water production. Similarly, effective plugging systems can decrease the water production, but can also harm the hydrocarbon flow when the treatment is not selective. This has led to continuing need for chemical systems that can reduce water mobility while preserving as much oil productivity as possible.

RPM's have been suggested as a selective method of controlling water production in oil-producing formations. The purpose of an RPM would be to reduce the relative permeability to water by at least one order of magnitude compared to that for oil, thus providing a viable solution for applications such as those involving high-water-cut wells. RPMs require careful laboratory screening under representative reservoir conditions before they can be considered reliable for field application.

This challenge is especially relevant for mature reservoirs in Kazakhstan, where many fields experience very high water cut and require more effective conformance-control strategies. Recent work on Kazakhstan's mature fields has highlighted extremely high water-cut conditions in some producing horizons and has underlined the need for integrated methods to control water production and improve flow profiles. At the same time, despite the broad interest in selective water-control chemicals, there is still limited reservoir-specific evaluation of RPM performance for Kazakhstan-type conditions, particularly with respect to how strongly water permeability can be reduced while minimizing damage to oil flow.

Therefore, the main problem addressed in this thesis is the lack of clear experimental understanding of how an RPM treatment performs under relevant reservoir conditions for high-water-cut systems. In particular, it is necessary to determine whether the selected RPM can provide meaningful reduction in water permeability while maintaining acceptable oil permeability, and whether its behavior is consistent enough to justify further application as a

water-control method. Addressing this problem requires laboratory investigation of permeability changes before and after RPM treatment, with emphasis on selective water control rather than simple bulk plugging.

1.3 Scope of Work

This thesis evaluates the viability of relative permeability modifier as a chemical water-control agent on high-water-cut reservoirs under laboratory conditions that represent selected oil fields in Kazakhstan. The problem of excessive water production in the mature oil fields is resolved by discussing the primary water-control techniques known in the literature and analyzing the concept of RPMs as selective agent to reduce the amount of water flow without affecting the oil productivity.

The laboratory coreflood testing is the subject of the experimental study. It involves the preparation of representative core samples, reservoir test condition setting, initial oil and water permeability measurements, the introduction of the chosen RPM system, and the permeability measurements. The primary goal is to measure the decrease in water permeability and compare it with the decrease in oil permeability to determine the selectivity and practical potential of the treatment in high water-cut conditions.

The novelty of the work consists in the combined evaluation of RPM performance both in laboratory coreflood experiments and reservoir simulation. In contrast to most of the earlier literature which has been done with generic rock-fluid systems, the work is done with field-specific core samples, formation waters, crude oils, and temperature-pressure conditions of selected reservoirs in Kazakhstan. Furthermore, the research also compares the RPM performance in various reservoir systems and correlates the experimentally observed change in permeability with CMG simulation outcomes, which offers a more viable foundation of assessing RPM applicability in water control.

The thesis is restricted to the laboratory testing, interpretation of permeability data, and reservoir simulation support. It excludes field pilot testing, long term field performance testing, full field implementation studies, and economic testing. The findings therefore represent an evaluation of the selected RPM system under the tested conditions rather than a universal conclusion for all reservoirs or RPM formulations.

2. LITERATURE REVIEW

This chapter reviews the literature relevant to excessive water production in oil reservoirs and the methods used to control it. Particular attention is given to the mechanisms that lead to increasing water cut in mature fields, the operational and economic consequences of excess water production, and the main technologies applied for water control. The chapter also examines the principles, mechanisms, and reported performance of RPMs, which have attracted considerable interest as selective water shutoff agents. In addition, published studies on the application of RPMs in different reservoir types and their laboratory evaluation are reviewed in order to identify the main factors affecting treatment success. The reviewed literature provides the theoretical foundation for the experimental work presented in this thesis and helps define the research gap addressed by the study.

2.1 Mechanisms of Water Production

Aquifer influx, or water encroachment, is one of the primary processes of water production increase. Pressure depletion during oil production in reservoirs with active edge-water or bottom-water support causes a pressure gradient that causes water to flow towards the wellbore (Taha and Amani, 2019). The closer the oil-water contact is to production intervals, water breakthrough may occur and eventually lead to sustained high water production. This mechanism is especially important in reservoirs with strong natural water drive. Where continued aquifer support can maintain production but also significantly increase water cut in later stages of field life (Sun et al., 2017).

Another important mechanism is waterflood related channeling. Water injection is widely used to maintain reservoir pressure and improve oil recovery. But this injected water does not always move uniformly through the reservoir. In heterogeneous formations water will prefer to flow in the directions of least resistance, which could be high-permeability regions and the oil-bearing regions of lower permeability will remain unswept. This forms major channels of flow between injection and production wells, which leads to premature water breakthrough, poor sweep efficiency and huge amounts of bypassed oil. This is one of the most common reported causes of excessive water production in mature waterflooded reservoirs. (Sagbana & Abushaikha, 2021).

Reservoir heterogeneity increases the intensity of the water-production issue significantly. The natural layering of reservoirs, contrasts in permeability, thief zones and

fracture systems provide the necessary pathways for water to travel through the reservoir at a greater rate than hydrocarbon. As such, in fractured reservoirs or reservoirs where there exists high levels of heterogeneity; water may by-pass large amounts of hydrocarbon bearing rock and can enter a well through channelized routes. Consequently, this results in decreased efficiencies in both areal and vertical sweep as well as increased difficulty in controlling water (Taha & Amani, 2019).

Another mechanism that can occur is called "water coning." It happens when there is a excessive downward pressure created at the wellbore and large amount of water being produced from the well. When this excessive downward pressure creates an imbalance in pressure beneath the producing formation, then the water beneath will flow upwards towards the perforations in a cone-shaped manner. In many cases, the increased water production rates are so rapid after water coning has begun; they would indicate a significant problem, regardless of how far away the original oil-water contact is from the well (Okon et al., 2017).

In practice, excessive water production is rarely caused by only one mechanism. More often, aquifer influx, waterflood channeling, fractures, and local completion related effects act together. This makes diagnosis of the water source a critical step before selecting any treatment. A method that works well for a fracture dominated channel for example may not be effective for water coning or strong aquifer support. For this reason, many authors stress that successful water control depends first on correctly identifying the dominant mechanism of water production before choosing a mechanical or chemical solution (Seright & Brattekkås, 2021)

2.2 Water Control Methods

Water-control methods are commonly grouped into mechanical and chemical approaches. Mechanical methods are generally applied when the water producing interval can be clearly identified and physically isolated. These methods include techniques such as packers, bridge plugs, tubing patches, cement squeezes, and selective shutoff of watered zones (Joseph& Ajienka, 2010). These methods can be effective for near wellbore problems such as casing failure, behind casing channeling, or water production from a specific completed interval. However, they are usually less effective when the problem is caused by deep reservoir heterogeneity or highly conductive fracture systems (Seifi et al., 2024). Table 1 summarizes the main mechanical water shutoff methods reported in the literature.

When the excess water production is not limited to the immediate wellbore area but rather linked to dominant flow channels, high-permeability streaks or fractures, chemical

techniques are more appropriate. Under these circumstances, the mobility of water, conformance, and redirection of the flow to less sweep areas of the reservoir are minimized with the help of injected chemical systems (Sagbana & Abushaikka, 2021). Polymer gels, preformed particle gels, foams, emulsions, resins, and silicate-based systems are the most commonly reported chemical treatment methods, but polymer-gel treatments remain to be the most standardized and widely used treatment method in field practice (Taha and Amani, 2019). Table 2 is a summary of the key chemical water shutoff approaches found in the literature.

Recent reviews also note that no single method is universally effective. Treatment performance depends on matching the technology to the actual water-production mechanism, reservoir conditions, and operational objectives (Thomas et al., 2000).

Table 1. Mechanical water shutoff methods

Method	Principle / how it works	Main advantages	Main disadvantages	Best application conditions	Example from literature	Reference
Bridge plug	Set in the casing or liner to create a mechanical barrier and isolate a water-producing zone above or below the tool; often combined with a cement cap for better sealing.	Fast result; relatively simple deployment; good zonal isolation for discrete watered-out intervals; through-tubing options available in some wells.	May sacrifice access to deeper productive zones; limited mainly to wellbore or near-wellbore problems; not selective inside the reservoir.	Lower watered-out intervals, isolated water-entry zones, remedial shutoff in cased wells.	Belayim field case studies reported use of through-tubing bridge plugs to isolate lower water-producing zones, reducing average water cut and improving oil rate.	Taha & Amani (2019); El-Medany et al. (2021)
Packers / straddle packers / swell packers	Packers seal the annular space and isolate selected intervals; straddle packers isolate a short section between two sealing elements, while swell packers expand after contact with well fluids.	Selective interval isolation; useful in horizontal wells; can preserve production from non-watered zones; suitable for recompletion and shutoff operations.	Placement can be challenging in complex completions; may not solve deep formation channeling; tool failure or incomplete sealing can reduce effectiveness.	Horizontal wells, open-hole completions, localized inflow from a known interval, zonal isolation during selective treatment.	Onshore Abu Dhabi case studies reported successful use of swell packer technology for shutting off water production in horizontal open-hole wells.	Sun & Bai (2017); Aboukshem et al. (2008)
Cement squeeze	Cement slurry is squeezed through perforations, leaks, or channels to seal unwanted flow paths behind casing or near the wellbore; plugs or packers may be used to improve placement.	Widely available; relatively low material cost; effective for behind-casing channeling and annular leaks; can provide permanent isolation if placed correctly.	Placement is difficult; multiple squeeze attempts may be required; risk of blocking oil-producing intervals; strongly dependent on diagnosis and execution quality.	Behind-casing channeling, casing leaks, water entry through perforations, annular communication.	Field guidance and case documentation indicate cement squeezing remains a standard option for casing-leak repair and behind-casing isolation, though repeated squeezes may be needed.	Bailey et al. (2000); Taha & Amani (2019); Manitoba Petroleum Branch (2004)
Casing repair / tubing patch / liner patch	A damaged tubing or casing section is mechanically covered with a patch or expandable sleeve to restore integrity and shut off unwanted inflow	Can preserve access to deeper zones better than a full plug; offers a permanent repair option; useful when water entry is caused by tubular	Requires accurate leak identification; may reduce internal diameter; not suitable for all well geometries; does not solve reservoir-origin water problems.	Casing corrosion, holes, perforation shutoff, localized tubular integrity failure.	Industry case descriptions show expandable internal casing patches used to seal damaged casing sections while maintaining access below the repaired interval.	Bailey et al. (2000); SLB (2022); Manitoba Petroleum Branch (2004)

	through holes or failed perforations.	failure rather than reservoir flow.				
Zonal isolation / completion -based isolation	Mechanical barriers such as packers, plugs, and sleeves are installed to separate producing zones from water-bearing layers during completion or remedial workover.	Protects oil-bearing intervals; useful for selective production; can be integrated with completion design; especially valuable when the water source is interval-specific.	Requires good reservoir and completion understanding; may be expensive in complex wells; less effective if water production is caused by fractures or deep thief zones.	Multizone wells, horizontal wells, selective shutoff of a known water-producing section.	Reviews of horizontal-well water control identify mechanical isolation as a common approach where the water source is associated mainly with wellbore or near-wellbore inflow.	Sun & Bai (2017); Taha & Amani (2019)

Table 2. Chemical Water Shutoff Methods

Method	Principle / how it works	Selectivity	Main advantages	Main disadvantages	Best application conditions	Example from literature	Reference
Polymer gels	Polymer solutions are injected into high-permeability zones and then form a gel in situ, creating resistance to water flow and improving sweep efficiency.	Low to moderate	Widely studied and field-tested; effective for profile control, thief zones, fractures, and channeling; comparatively mature technology.	Performance may degrade at high temperature and salinity; gelation control can be difficult; risk of poor placement and damage to productive zones.	Fractured reservoirs, thief zones, high-permeability streaks, waterflood conformance problems.	Recent reviews describe polymer gels as one of the most established chemical methods for profile control and water shutoff in mature reservoirs.	Lu et al. (2023); Taha & Amani (2019)
Crosslinked gels	A polymer is combined with a crosslinker so that after placement it forms a stronger three-dimensional gel network, giving better plugging strength and stability than uncrosslinked systems.	Low to moderate	Higher gel strength; better plugging of fractures and severe channeling; improved thermal and mechanical stability in many formulations.	Premature gelation and injectivity problems may occur; sensitivity to reservoir chemistry; may reduce oil productivity if placed poorly.	Strong water channels, fractures, severe heterogeneity, deeper conformance treatments where stronger blockage is required.	Recent reviews emphasize crosslinked polymer gels as the dominant subclass of gel systems for field water shutoff, especially where higher strength and better stability are needed.	Lu et al. (2023); recent comprehensive review of smart crosslinked gels (2025)
Foams	Gas and surfactant are used to generate foam in porous media, increasing apparent viscosity and reducing water mobility in high-conductivity pathways.	Moderate	Good mobility control; useful for gas or water channeling; can divert flow without completely solid plugging the formation.	Foam stability is sensitive to oil saturation, salinity, pressure, and temperature; field performance can be inconsistent.	Heterogeneous formations, gas channeling, fractured or high-permeability pathways where mobility control is needed.	Reviews classify foam systems as promising chemical conformance agents, though generally less mature and more condition-dependent than gels.	Taha & Amani (2019); Magadova et al. (2024)
Resin systems	Low-viscosity resin formulations are injected and then harden in situ to create a rigid barrier that seals fractures, channels, or high-water zones.	Low	Strong and often durable seal; useful for shutting off distinct water entries and fractures; can provide relatively permanent isolation near the wellbore.	Limited depth of penetration; risk of brittleness and placement problems; may permanently impair hydrocarbon flow if applied incorrectly.	Near-wellbore water-entry zones, fractures, casing-adjacent flow paths, situations requiring strong permanent sealing.	Reviews of water shutoff methods include resin-based systems among chemical blocking techniques used when a stronger and more permanent barrier is needed.	Taha & Amani (2019); Sun & Bai (2017)

Method	Principle / how it works	Selectivity	Main advantages	Main disadvantages	Best application conditions	Example from literature	Reference
Silicate-based systems	Sodium silicate or related silicate formulations are injected as low-viscosity solutions and then gel or precipitate in situ, reducing permeability in water-dominant pathways.	Moderate	Low initial viscosity improves injectivity; can be suitable for deep penetration; relatively economical; useful in fractured and porous media.	Gelation behavior may be sensitive to pH, salinity, and reservoir minerals; long-term stability must be verified; field use is less widespread than polymer gels.	Water-saturated fractures, porous channels, selective profile control, reservoirs where low-viscosity placement is important.	Experimental studies and recent reviews report sodium silicate-based systems as promising selective profile-control agents, especially for water-saturated zones and fractured porous media.	Duryagin et al. (2022); Ali et al. (2024)
Relative permeability modifiers (RPMs)	Water-soluble polymers adsorb on the rock surface and reduce water permeability more than oil or gas permeability, producing disproportionate permeability reduction.	High	Can reduce water production while preserving hydrocarbon flow; attractive where complete plugging is undesirable; useful when oil and water are produced from the same interval.	Mechanism is not fully resolved; performance may depend on wettability, lithology, salinity, and residual resistance behavior; field success can be variable.	Wells producing oil and water from the same zone, cases where strong mechanical isolation is impossible, selective water-control applications.	Reviews describe RPMs as a distinct class of chemical water-control agents because they target selective reduction of water flow rather than total plugging.	Al-Muntasheri et al. (2021); Hayavi et al. (2023)

2.3 Definition and Principle of RPMs

The objective of RPM technology in terms of multiphase flow can be defined as reducing the relative or effective permeability of water more than that of oil. This differential reduction is the primary difference between RPM technology and the other blocking agents like cement, high gels, and resins, which normally prevent fluid movement without being selective (Seright & Brattekaås, 2021). The technology has been known for many years. Later analyses show that the effect of acrylamide polymers in giving differential permeability reduction was discovered even in the late 1960s and early 1970s, and laboratory and field studies confirmed the existence of RPM technology (Stavland & Nilsson, 2001).

The actual measurement of RPM effectiveness is normally performed by determining the change in permeability of both the phases before and after the treatment process. The optimal RPM application will provide high water residual resistance accompanied by a relatively minor drop in oil permeability (Singleton et al., 2002). For that reason, the performance assessment of RPMs is normally performed via coreflood experiments where separate values of water and oil residual resistance are recorded (Al Brahim et al., 2022). In cases when the drop in oil permeability is too pronounced, the RPM is no longer considered to be an efficient technique and resembles some sort of nonselective damage instead.

Yet another significant aspect to take into consideration is the fact that RPMs are usually injected into the zones where there is water production due to the process of matrix

drainage or those zones that are difficult to isolate using mechanical methods (Sydansk & Seright, 2007). The fact that such chemicals are often injected using the method of bullhead injection makes it possible to utilize them without expensive operations of well intervention or well completion. Thus, RPMs are regarded as very promising for depleted reservoirs with high water cuts because it is often too risky or impossible to completely shut off a zone with water breakthrough and maintain productive oil flows (Hayavi et al., 2023). Nevertheless, the selective mechanism has not been entirely studied yet, that is why different reasons explaining differential permeability reduction are described in the scientific literature.

2.3.1 Mechanisms of Selective Water Reduction

Despite common characterization of RPMs as substances which block water flow to a greater extent than that of oil, the academic literature reveals that the selectivity of RPMs is due to not one particular universal mechanism. Rather, the selective permeability reduction is normally perceived as being caused by several mechanisms acting at the pore scale, depending on chemical nature of the polymers, lithology of the rocks, pore architecture, history of saturations, and fluids involved in the experiments.

One of the processes mentioned the most often is the adsorption of polymers on the rock surface. The essence of this mechanism lies in the process during which the polymer molecules adhere to the pore wall and form an adsorbed layer that reduces the effective diameter of the channels for aqueous-phase flow. According to early investigations, the phenomenon of DPR was associated with adsorption and entanglement of macromolecules. Gradually increasing the amount of adsorbed polymers, entangling them and reaching a certain hydrodynamically steady state of the pores. This phenomenon might affect the flow rate of water, but does not affect the rate of oil flow similarly. Another investigation concerning hydrophobically associative polymer gel concluded that adsorptive retention played the major role in such disproportionate reduction in permeability.

Another relevant idea would be bridge adsorption in small pore throats. In this case, rather than coating the surface of the pores, the large polymer molecules are actually able to span the pore throats during elongational flow to form partial bridges (Ye et al., 2010). As a consequence of this, the radius of the pore decreases, increasing hydraulic resistance. More specifically, bridge adsorption increases hydraulic resistance for flow of water in thin wetting films as well as in smaller pore throats. Qin et al. (2021) have found that bridge adsorption is most important for small pore throats.

A number of researchers suggest that adsorption of RPM affects the properties of the surface of the rock and the behavior of both oil and water phases within the pore structure. Since water typically tends to move through the more water-wet surfaces of the pore structure, even slight modification in surface conditions can lead to alterations in aqueous flow continuity and mobility (Ye et al., 2010). Researchers who studied the performance of silylated polyacrylamide RPM in carbonate cores found out that the relative permeability to water was more reduced compared to that to oil in the treated cores; hence, the crossing point of relative permeability curves was displaced according to the theory of RPM action. The same set of studies attributes the selectivity of RPM performance to rock–fluid-surface interactions and pore radius (Zaitoun & Kohler, 2000).

Polymer swelling, hydration, dehydration, and shrinking are additional mechanisms mentioned in the literature. The idea is that under water contact, the adsorbed layer or gel-like polymers can become hydrated and swollen. This effect makes the film thicker and impedes water flow (Stavland et al., 2001). However, when flowing oil passes through the media, particularly with decreasing water saturation, the film might be dehydrated and shrunk, creating new pores available for oil flow. The authors explain this shrinking and swelling mechanism as one of the hypotheses accounting for the reason why oil permeability recovers faster than water permeability during two-phase flow (Al-Shajalee et al., 2019). A similar approach was used by other researchers working on gel-based DPR technology; they suggest gel hydration/dehydration as a likely mechanism of water selectivity (Liang et al., 2018).

Another theory considers flow pattern variations and phase segregation in the pore structure. While assuming the same flow pathways for both water and oil phases, some investigations contend that due to the RPM process, both phases could use separate portions of the pore system. Water, as the more strongly wetting phase in many systems, tends to move through smaller pores, wetting films, and surface-connected pathways, whereas oil may continue to flow through larger central channels (Willhite et al., 2002). If polymer adsorption or gel retention mainly restricts the surface-connected or small-pore water pathways, the water phase can experience a much larger mobility reduction than the oil phase. This idea appears in the segregated-flow interpretation advanced by Stavland and Nilsson and in later discussions of oil and water aggregated pathways and wall effects in gel-treated media.

Water can be forced to pass through hydrated polymer regions, thin water films, or gel-filled constrictions, whereas oil may bypass these regions through less restricted channels or may deform the polymer layer differently (Almakimi et al., 2024). In gel-based systems, the

low permeability of the hydrated gel to water has been cited as one reason for the particularly strong water blocking effect. In polymer-based RPMs, the same general principle is often described as a drag or resistance effect that acts predominantly on the water phase (Ye et al., 2010).

Residual oil saturation has also been identified as an important part of some mechanistic interpretations. Certain DPR models suggest that after treatment, residual oil can occupy newly formed or redistributed pore space in a way that forces brine to flow through narrower and more tortuous channels than before. In this case, the selective reduction in water permeability is not caused only by the polymer itself, but by the combined effect of polymer retention and oil redistribution in the treated pore network. This interpretation appears in the classic mechanism literature for chromium acetate/HPAM gels and remains influential in later discussions of DPR behavior (Willhite et al., 2002).

In general, the literature seems to indicate that the selective reduction of water by RPMs should be considered as a combination of factors at the pore scale rather than a singular process. The adsorption and retention processes, bridging effect of adsorption in the throat area of pores, changes in wettability, swelling of polymers in the presence of water, dehydration during oil flow, modification in phase paths, and higher water resistance compared to that of oil could all play significant roles in the end result of DPR (Vasquez et al., 2009).

2.3.2 Types of RPM Systems

The most common types of RPMs are polymer systems, but some investigations consider weak-gel or gel-like selective fluids as RPMs as long as their effect is stronger against water than oil. It is always observed in all reviews that most used RPMs in both industrial applications and laboratory experiments consist of water-soluble polymers since these chemicals could be injected in diluted form and do not provide any rigid barriers in pores.

The largest and established group of RPMs involves polymers, particularly those based on acrylamide polymerization. Numerous RPMs rely on partially hydrolyzed polyacrylamide or other acrylamide-containing copolymers, owing to the potential ability of such polymers to create selective water blocking through adsorption, retention, and pore-scale blockage. According to Al-Taq et al. (2021), there are several examples where RPMs are made of uncrosslinked copolymers containing acrylamide and acrylate monomers. Polymer composition and concentration significantly affect selectivity and retention in other works reviewed by other authors. It is in this regard that RPMs of the polymeric variety differ

fundamentally from total shut-off gels, since their purpose is not sealing but selective permeability adjustment.

The second group consists of gel-like fluids with selective effect. Such substances are located on the boundary line between adsorbing polymers and strong gel-like blockers. According to Seright and Brattekkås (2021), the disproportionate reduction in permeability may occur in the case of weak or particulate gels in instances when the gel formation process is not complete and the substance does not saturate the entire pore volume filled with aqueous phase. In such circumstances, reduction in permeability is achieved primarily due to partial occlusion in the pore throats and the resulting restriction of flow, rather than pore saturation. At the same time, there are examples of polymer-gel-like systems capable of working as RPM materials in specific cases where water mobility is significantly reduced compared to hydrocarbons. At the same time, some sources warn about greater unpredictability of gel-like selective systems compared to adsorbing polymers (Ahmed et al., 2020).

Another classification of interest refers to the charge of the polymers, which can either be cationic or nonionic (and therefore only weakly ionic). This type of classification is valuable since adsorption capacity depends heavily on the surface charge of the rock. As pointed out in Hayavi et al.'s (2023) review of RPMs, the use of cationic RPMs is advisable when it comes to siliceous rocks because electrostatic forces of attraction will lead to enhanced adsorption on negatively charged mineral surfaces. Studies done on cationic RPMs also reveal that adsorption on quartz-bearing rocks is highly dependent on electrostatic forces and wettability.

On the other hand, when there is no need for electrostatic bonding to occur or the process results in an excessive buildup close to the borehole, a combination of polymeric fluids having weaker ionicity is sometimes selected. Indeed, in a lot of the proposed RPM designs, neutrality and ionicity coexist, meaning the difference between the two classes cannot be always made clearly. According to Chung et al. (2012), some of the polymers used in the RPM fluid contain not only one charge (positive or negative) but both, thus offering more options to adjust the chemistry depending on the rock-fluid interaction type.

An example of an extremely relevant modern class of RPM systems is organosilicon modified (silylated) RPM formulations. Such formulations are very significant for present day research since their purpose is improving adsorption, durability, and selectivity, specifically for carbonate rocks. Al-Hulail et al. (2020) studied silylated polyacrylamide RPM and found that the use of such systems can selectively decrease water permeability through carbonate

cores under reservoir conditions. The importance of silylated polymer systems is associated with the possibility of enhancing interactions with mineral surfaces due to silane-containing functional groups, which may be significant in difficult rock-fluid interactions. For this reason, silylated polyacrylamide RPM systems have become very popular in recent years.

The literature further mentions other forms of modified RPMs such as nanocomposites and grafted polymers. Some recent research has considered grafted nanoclays RPMs and zeolite copolymers for enhancing thermal stability, salinity resistance, and conformance characteristics. Although they are still not as widely recognized as acrylamide-based RPMs, they represent current trends in research toward multipurpose products that preserve their ability to selectively control water. The literature review shows that nanoparticle addition has been considered to increase the salinity and thermal resistance of conventional polymers, which are typical weaknesses of conventional polymer RPMs (Cardenas et al., 2024).

2.3.3 Factors Affecting RPM Performance

RPM effectiveness is strongly dependent on the reservoir rock characteristics, fluid characteristics, and application design. It has been shown in the scientific literature that RPM selectivity is not an inherent characteristic of RPM; rather, the ratio of water permeability reduction compared to oil permeability reduction depends heavily on the interactions between the chemical, reservoir rock pores, reservoir brine, crude oil, and mineral surface at certain operating conditions. In other words, RPMs which are highly selective in one reservoir will display relatively low selectivity when applied in another reservoir Salam et al. (2024).

Rock type is among the most influential variables. In terms of surface charge, mineral composition, pore geometry, and wettability, sandstone and carbonate rocks differ widely from each other. Recently, the role of RPM and surface interaction on selective water reduction of silylated polyacrylamide RPMs in carbonate rocks was highlighted, and the same study revealed that polymer layering and adsorption on calcite surface is sufficient for reducing permeability, showing the crucial importance of rock mineral and RPM-surface interaction Ekanem et al. (2021).

The permeability and size of the pore throats are equally important parameters that must be considered. In less-permeable rocks and rocks characterized by smaller pore throats, the effect on flow can be even greater due to the smaller effective pore radius caused by the adsorption process. On the other hand, with more permeable rocks, a deeper penetration of the treatment fluid may result, but with the creation of weaker local resistance if the adsorption

ability is not sufficient. Permeability reduction resulting from polymer adsorption in porous media is known to be highly dependent on pore constriction and the thickness of the adsorbed polymer, as noted by Qin et al. (2021).

The mineral composition of the rocks is another crucial factor affecting polymer adsorption and subsequent performance. Mineralogy dictates the strength and nature of the interaction between polymers and the pore wall surface. As discussed in the recent review on polymer retention in reservoir rocks, it has been determined that adsorption efficiency is highly dependent on minerals present within rocks and their surface properties. Hayavi et al. (2023), on the other hand, state that positively charged RPMs tend to favor silica-rich rocks due to electrostatic interactions.

Specifically, the impact of salinity on RPMs is significant due to its effects on polymer conformation, adsorption, hydration, and rheology. The changes in ionic strength affect the conformation of polymer chains in the solution, which in turn alters the polymer's injectivity and retention. One of the influencing factors discussed in the carbonate RPM research conducted by Al-Nakhli et al. (2013) was brine composition, and the general retention literature indicates that salinity impacts polymer adsorption on surfaces as well as structure of the adsorbed layer. Consequently, RPMs optimized at low-salinity laboratory conditions may be expected to have drastically different performance in formation brines.

The reservoir temperature has an impact on polymer stability, hydration kinetics, viscosity, as well as durability of the formed gel-like or adsorbed structure. High temperatures may cause a decline in selectivity for some conventional polymers or their instability, making them unsuitable for high-temperature conditions. In the recent years, many of the new RPMs described in the literature were developed for use in high-temperature reservoirs, which makes temperature another critical influencing variable, since thermal stability has been recognized as a major limitation of existing polymer systems. Al-Nakhli et al. (2013) examined the performance of RPMs in reservoir conditions, including high temperatures.

Oil viscosity is another important factor affecting RPM performance; however, this parameter receives less attention compared to those related to rock and brine. Since the criterion of RPM effectiveness is linked to reducing water permeability more efficiently than oil permeability, the fluid properties of the oil phase will determine the effectiveness of such processes as permeability reduction and selectivity achieved during coreflood testing. The response of a heavy oil to narrowing its flow path might differ from that of a light oil, and

therefore, the balance between reducing water permeability and inducing oil damage can change based on the oil employed in testing. That is why RPM studies conducted lately pay special attention to conducting experiments in the realistic conditions of crude oil/brine interactions (Park et al., 2015).

Concentration is probably one of the most straightforward parameters affecting RPM. Although higher concentration could increase permeability reduction efficiency and lead to better selectivity through increased polymer availability, excessive retention and potential oil productivity problems are possible if the polymer concentration is too high. The results obtained in an experiment conducted on polymer adsorption clearly show that polymer concentration impacts adsorption behavior and permeability reduction (Ahmed et al., 2020). This evidence supports the need for optimizing the amount of polymer to achieve the necessary effect.

Selective water reduction requires not only the entry of polymer into the rock pores but also its amount, location, and form of structure. According to Al-Hajri et al. (2018), the recent comprehensive review of the mechanism of retention of polymer in reservoir rocks emphasizes the importance of adsorption, mechanical trapping, and chemical reactions in determining the location and presence of the polymer. Studies of the mechanism at surfaces in carbonate rocks have also shown that the formation of polymer layers reduces the permeability. Practically speaking, low retention results in poor effectiveness of RPMs, while high retention leads to nonselective damage.

2.3.4 Comparison of RPM Effectiveness by Reservoir Type

Based on available literature, RPM performance tends to be more predictable in sandstone rather than carbonate reservoirs. Early experimental tests were performed mainly using sandstones such as Berea sandstone, wherein polymeric RPM systems tended to produce disproportionate permeability reduction, with a significantly higher reduction in water permeability compared with the oil phase. This has been attributed to better polymer adsorption in silicates, good knowledge about pore structures, and the general tendency of sandstones to be more water-wet than carbonates. In practice, sandstone formations have thus been considered more favorable and studied extensively compared with carbonates (Mennella et al., 2001).

This is not surprising since carbonate rocks are typically mixed-wet to oil-wet formations with strong mineral-fluid interactions and higher formation heterogeneity than

sandstones. Many of these carbonate reservoirs also tend to have natural fractures or vuggy pore systems. In these cases, water control becomes more unpredictable because, aside from polymer retention, treatment success can depend on the alteration in wettability, brine composition, rock surface chemistry, and water pathways. Recent research comparing RPM applications between sandstone and carbonate reservoirs has pointed out the significant role of adsorption and wettability mechanisms in carbonates, wherein RPM polymers alter rock surface wettability towards more water-wet properties (Al-Taq et al. 2021).

Another consistent finding in the literature is that reservoir architecture strongly affects the relative success of RPMs in both rock types, but especially in carbonates. Sydansk and Seright (2007) emphasized that RPM/DPR treatments are not universal remedies and should be applied only to a limited class of excess-water problems, particularly where water flows preferentially through identifiable high-permeability pathways and where hydrocarbon zones can still be preserved. This requirement is often easier to satisfy in layered sandstone systems than in fractured carbonate reservoirs, where water movement may be dominated by complex fracture–matrix interactions that are less amenable to near-wellbore selective modification alone (Stavland et al., 1998).

2.4 Laboratory Evaluation of RPMs

Laboratory studies of corefloods can be done with sandstones or carbonate core plugs through controlled tests, taking into account variables such as brine compositions, flow rates, temperatures, and confining pressures. In a common technique, the absolute permeability of the core plug is initially determined. Then, initial water and oil saturations of the core are achieved before RPM solution is injected into it. In some cases, the plug is allowed to have shut-in time or aging period where adsorption, retention, or chemical reaction occurs between the RPM chemical solution and rock surface. Water and/or oil are next introduced, and permeability reduction tests are conducted to determine changes in absolute permeability. Finally, ratios of permeability reduction for water versus oil are determined for measuring selectivity (Zaitoun & Kohler, 1988; Zaitoun et al., 1999).

Residual resistance factor against water is used as an indicator for reduced mobility of water after treatment, while an equivalent parameter can be derived for oil. An effective treatment of the reservoir with the RPM chemicals is indicated when there is a greater value of residual resistance factor to water than to oil. However, scientists have found out that

interpretation should be made carefully since selectivity can be dependent on various factors aside from the chemical system itself (Mennella et al., 2001).

Apart from coreflood experiments, other types of tests employed by researchers include bulk adsorption experiments, contact-angle measurements, injectivity tests, rheological analysis, and microscopic examinations. Bulk adsorption analysis helps estimate the quantity of active materials retained by the rock surface, whereas contact-angle tests and tests related to wettability are used to determine whether the chemical affects the affinity of the rock surface toward either water or crude oil. In addition, viscosity, polymer conformation, and solution stability, which can influence injectivity and penetration depth in the porous medium, are assessed using rheological analysis. All of these additional analyses are especially useful when studying RPM in sandstones and carbonates, which have distinct surface chemistries and mineralogies (Dawe et al., 1992).

The general observation made by authors in relation to laboratory evaluation is that it should be conducted under the most realistic reservoir conditions possible. Indeed, salinity, hardness, temperature, composition of crude oil, and even rock type may influence the performance of the treatment. While simple experiments in Berea sandstone using synthetic brine and refined oil could yield useful preliminary data, field performance may not necessarily be predicted accurately by them. This means that, whenever possible, tests should employ representative reservoir cores and fluids, particularly for RPMs intended to treat carbonate reservoirs or high-salinity formations (Seright & Brattekkås, 2021).

While the benefits of laboratory tests cannot be overlooked, it should also be noted that the success achieved in the lab is not necessarily an indicator of success in the field. The near-wellbore location, reservoir heterogeneity, fractures, treatment volumes, and long-term chemical stability are among the factors that may affect performance in the field. Coreflood testing is usually considered the necessary starting point for RPM screening; however, this should always be supplemented by appropriate candidate selection and reservoir design.

2.4.1 Coreflood Testing

Coreflood testing is the main laboratory method used to evaluate the performance of RPMs before field application. In these experiments, a core plug is prepared, saturated with representative fluids, and flooded before and after chemical treatment so that the effect of the RPM on flow behavior can be quantified. The basic objective is to compare permeability or

injectivity before treatment with the corresponding values after treatment and determine whether the chemical reduces water flow selectively.

Several published studies illustrate this approach. Chen et al. (1996) used before-and-after coreflood measurements to assess whether polymer treatment changed permeability to the flowing phase after an aging period. Al-Nakhli et al. (2013) applied reservoir-condition coreflood tests in carbonate cores and evaluated post-treatment oil and brine flow to determine the selectivity of the RPM system. Qin et al. (2021) also used carbonate-core flooding under representative conditions and showed that the treatment response could be assessed from changes in effective permeability and relative permeability behavior after chemical injection. Ahmed et al. (2020) similarly reported continuous coreflood tests in which the chemical was injected, the core was shut in, and water and oil flow properties were then remeasured to judge RPM effectiveness. These studies show that, although experimental details vary, the essential workflow is consistent: establish a baseline, inject the RPM, allow interaction with the rock, and then measure the post-treatment flow response.

2.4.2 Measurement of Water and Oil Permeability Reduction

While permeability decrease after applying RPMs can serve as an indicator of their success, more importantly, a greater permeability decrease must occur to water rather than oil. The selective action of RPMs differentiates them from other fluid-plugging and damaging chemicals. Therefore, most experimental works provide information about phase-specific permeability change, residual resistance factors (RRF), or relative permeability curves for both water and oil.

This logic is reflected in all published articles. In their work, Qin et al. (2021) demonstrated experimentally on the carbonate core sample that the applied RPM increased resistance to flow of both fluids; however, water flow decreased relatively to oil flow. Similarly, Ahmed et al. (2020) assessed RPMs based on the comparison of RRF for water and oil. They suggested that successful RPM application produces a significant RRF to water flow while reducing the RRF of oil flow considerably. Generally, discussing RPM effects, Seright & Brattekkås noted that disproportionate permeability reduction is the main characteristic of these chemical agents, which means that a certain degree of hydrocarbon flow must be retained after the treatment. Likewise, Wei et al. (2024) stated that the efficiency of RPM application in the gas-water system depends on considerable flow restriction to the aqueous phase and low flow impairment in the hydrocarbon phase.

In this regard, all of the above examples prove that the performance of RPM should be assessed in terms of phase behavior comparison. While a permeability decrease to water and oil flow might lower the former, it does not mean the efficiency of the procedure.

2.4.3 Aging, Soaking Time, and Reservoir Condition Simulation

The factors of aging, interaction period after chemical injection, and reservoir-condition testing are generally used in RPM studies because RPM effectiveness is dependent on time-related interaction between rocks, fluids, and chemicals. In most cases, the injected polymer takes some time to adsorb, rearrange or interact with the rock matrix, thus achieving the stability in post-injection flow regime. Moreover, variables such as temperature, pressure, brine composition, and crude-oil composition influence adsorption and wettability characteristics and permeability; thus, unrealistic laboratory tests may lead to non-representative data in terms of reservoir conditions.

Several laboratory studies prove this statement. Cornwall and Boughey (2008) examined a silylated polyacrylamide RPM using core samples tested under the reservoir conditions and found that treatment response was dependent on certain factors like salinity and pore structure, which could be considered as factors linked to interaction period. Al-Nakhli et al. (2013) conducted tests of RPM in carbonate rock cores under high temperature and pressure and proved that treatment response was influenced by reservoir conditions concerning oil and brine permeability. Seright (1995) considered brine salinity as one of the factors that affected permeability in RPM-treated cores, whereas Wu et al. (2018) and other wettability studies proved that crude oil composition, aging period, and temperature could significantly change rock-fluid state during pre- or post-RPM treatment. Thus, Mennella et al. (2001) and Mishra et al. (2014) noted the higher credibility of results obtained during reservoir condition coreflooding compared to tests under ambient conditions.

This discussion shows that the factors of aging and reservoir simulation conditions cannot be considered secondary procedural aspects but rather must be included in laboratory procedures due to their importance in RPM effectiveness determination.

2.5 Field Applications of RPMs

Rose Run formation, Ohio, USA. In this study, 12 wells were hydraulically fractured with an RPM pumped ahead of the frac treatment. The treated wells were compared with offset wells fractured without RPM. The main reported result was that the increase in water production in the RPM-treated wells was one-half of that in the offset wells. The paper also states that the RPM-treated wells had lower water-oil ratios (WOR) and lower water-gas ratios (WGR) than the offset wells (Fry et al., 2006).

Western Siberia oilfields, Russia — 26 case histories. The Western Siberia case-history paper reports 26 field cases where RPMs were used together with hydraulic fracturing to improve oil recovery and control post-fracture water production. The summary states that adding RPM to the fracturing fluid proved effective in reducing post-treatment water cuts in Western Siberia oilfields (Stolyarov et al., 2008). One additional summary of this line of work states that field case histories showed sustained benefits for up to 12 months after treatment, with reduced water cut and improved oil production rates, though that time-duration statement should be treated more cautiously because it comes from a secondary indexing source rather than the paper page itself (Stolyarov et al., 2008).

Western Siberia, 2009 field program — 11 WPM/RPM fracture treatments. A later field paper reports 11 water-permeability-modifier fracture-stimulation treatments performed in one Western Siberian field in 2009. The context is important: conventional hydraulic fracturing in those intervals could lead to water cuts of 90–100%. After introducing the water-permeability modifier, the authors report that oil production was above what was anticipated from offset wells fractured without WPM, while produced water rate was typically lower than previously observed and even continued to decline over time instead of increasing (Ladut'ko et al., 2012).

Krasnoleninskoe oil field, Russia. For RPM field tests in the Krasnoleninskoe oil field, the reported outcome was that oil production increased in most cases, while water cut was reduced or only slightly increased by up to 5% during the first 6 months after treatment. This is one of the better field results because it gives both a time window and a quantitative water-cut outcome (Parkhonyuk et al., 2012).

There are published unsuccessful or partly unsuccessful RPM cases, although the literature often describes them as “mixed results” rather than using the word “failure.”

The clearest example is the Alvheim Field offshore Norway. In one treated well, the polymer shutoff treatment reduced water cut, but well productivity fell by about 50%. In the next treated well, water cut again decreased, but oil production dropped by about 20%. This is therefore a strong example of a field case where RPM achieved water reduction, but at the cost of significant productivity damage (Langaas & Stavland, 2020).

More generally, the review and guidance literature makes it clear that RPM field performance is often disappointing outside a narrow application window. Al-Taq et al. (2021) state that RPM/DPR treatments can be successfully applied only to a limited range of excess-water-production problems, which implies that many wells are poor candidates. There is also evidence that many treatments underperform because they are used in the wrong wells. The risk-analysis perspective suggests that RPM success depends strongly on pre-treatment reservoir and production parameters and emphasizes uncertainty in decision-making for these jobs. This supports the idea that some field applications fail not because the chemistry is always ineffective, but because of poor candidate selection, incorrect diagnosis of the water source, or poor placement (Langaas & Stavland, 2020; Fry et al., 2006; Stolyarov et al., 2008; Ladut'ko et al., 2012; Parkhonyuk et al., 2012)

2.6 Research Gap

Although RPMs have been studied extensively as selective water-control agents, most published work has been conducted on generic rock-fluid systems and under conditions that are not directly representative of Kazakhstan reservoirs. In particular, there is limited published information on RPM performance using field-specific core samples, reservoir brines, crude oils, and temperature-pressure conditions relevant to Kazakhstan fields. As a result, the applicability of RPMs to local high-water-cut reservoirs remains uncertain.

Another gap is the limited comparative evaluation of water-permeability reduction and oil-permeability reduction for Kazakhstan-type systems. Since the main purpose of an RPM is to reduce water flow while preserving oil productivity, reservoir-specific measurements of both phases are required before field application can be justified. Therefore, the main gap addressed in this study is the lack of laboratory evaluation of RPM performance for Kazakhstan fields, with emphasis on selective reduction of water permeability under representative rock and fluid conditions.

3. METHODOLOGY

This chapter describes the materials, experimental setup, and testing procedures used to evaluate RPM performance under representative reservoir conditions. The methodology consisted of core preparation, fluid characterization, single-phase flooding for preliminary RPM screening, two-phase flooding for selective permeability evaluation, and permeability calculation from pressure-drop data. In addition, a simplified reservoir simulation study was conducted to examine how the experimentally observed permeability changes could affect water-production behavior at the reservoir scale.

3.1 Materials

This study employed a set of chemical reagents, core samples, reservoir fluids, and auxiliary fluids to evaluate the performance of relative permeability modifiers under conditions representative of selected oil fields. Two relative permeability modifiers were investigated as the main treatment systems. Experimental materials were selected to reflect the properties of four different fields, namely A, B, C1, and C2. For each field, a separate set of core samples, crude oil, and formation water was used in order to preserve field-specific rock–fluid conditions during laboratory testing.

In total, four sets of core samples were examined, corresponding to the four selected fields. In addition, four crude oil samples and four formation water samples were used, with one oil sample and one formation water sample assigned to each field. This approach allowed the experiments to account for variations in reservoir rock and fluid properties among the selected fields and provided a more representative basis for evaluating the selective water-control performance of the tested RPM systems.

For the field A, a killing fluid was additionally used during RPM injection, following field practice for treatment placement. Therefore, the experimental program included not only the two RPM systems and field-specific reservoir fluids, but also the killing fluid applied in the field A related tests. The main materials used in this study are described in the following subsections.

3.1.1 Relative Permeability Modifier

WLP-3700

One of the relative permeability modifiers evaluated in this study was WLP-3700, produced by LLC “TD EKONO-TEKH”. According to the product passport, WLP-3700 is a modified hydrophilic polymer based on polyacrylamide, developed for use as a relative permeability modifier to reduce water inflow from nearby water-saturated zones after well stimulation. The product is reported to reduce permeability to water while keeping permeability to oil and gas nearly unchanged, which makes it suitable for selective water control applications. Physical characteristics are reported in Table 3. Figure 1 illustrates the WLP-3700 sample before preparation for coreflood testing.

Table 3. WLP-3700 Physical characteristics

Parameter	Standard value
Appearance	Viscous, colorless, transparent liquid
pH	6.0–8.5
Density at 25°C, g/cm ³	0.8–1.2
Viscosity by OFITE 800 rotational viscometer, cP	20–45
Odor	Odorless



Figure 1. Sample of WLP-3700 before experimental testing.

From the standpoint of its expected behavior in porous media, WLP-3700 can be described as a polymer-based RPM intended to interact with the rock surface and the water

phase in such a way that resistance to water flow increases more strongly than resistance to hydrocarbon flow. In the present study, this product was therefore selected as a candidate chemical for investigating selective reduction of water permeability during coreflood testing. The chemical composition of WLP-3700 is summarized in Table 4.

Table 4. Chemical composition of WLP-3700.

Component	Chemical formula	Mass fraction, %
Prop-2-enamide (acrylamide; acrylic acid amide)	C_3H_5NO	15
α -Hydro- ω -hydroxypoly(oxy-1,2-ethanediyl) (polyoxyethylene; polyethylene glycol)	$H(OCH_2CH_2)_nOH$	10
Water	H_2O	75

The manufacturer recommends WLP-3700 for use during hydraulic fracturing with either water-based or hydrocarbon-based fluids, as well as during acid stimulation treatments. The product is reported to remain stable at temperatures up to 120°C and to be compatible with most well-treatment fluids. The concentrate can be mixed with water in any proportion. These characteristics suggest that the reagent is intended for practical well-treatment operations under a relatively wide range of field conditions.

The technical specification further states that the production technology ensures the absence of organically bound chlorine and quaternary ammonium salts in the finished product. This is important from the standpoint of treatment compatibility and environmental acceptability. The accompanying test protocol also reported that organic chlorides were not detected in the reagent, and no organic chlorides were detected in oil obtained from a model system containing the chemical at the tested dosage.

UpWPc

The second relative permeability modifier evaluated in this study was UpWPc, produced by Uralplast LLC. According to the technical documentation, UpWPc is a polymer system intended for changing the inflow profile of injection wells, isolating watered-out intervals in production wells, creating interlayer barriers during workover operations, and

serving as a relative permeability modifier for water shutoff applications. The product is therefore designed for selective restriction of water movement in porous media. Physical characteristics are reported in Table 5. Figure 2 illustrates the UpWPc sample before preparation for coreflood testing.

Table 5. Physical characteristics of UpWPc

Parameter	Value
Appearance	Liquid, colorless to light yellow
Odor	No specific odor
pH	5.0–7.5
Density at 20°C, g/cm ³	0.880–1.200
Viscosity, cp	20-30



Figure 2. Sample of UpWPc before experimental testing.

UpWPc is additionally described as a water-soluble hydrophilic multicomponent polymer system whose main active substances are a high-molecular-weight cationic

polyacrylamide and a complex of highly effective surfactants. The chemical composition of WLP-3700 is summarized in Table 6.

Table 6. Chemical composition of UpWPc.

Component name	Chemical formula	Mass fraction, %
Cationic polyacrylamide [C ₃ H ₅ NO] n-based polymer*		10
Ethylene glycol	C ₂ H ₆ O ₂	30
Water	H ₂ O	60

The expected mechanism of action of UpWPc is based on both polymer adsorption and wettability modification. The cationic polyacrylamide adsorbs onto the negatively charged rock surface in water-bearing intervals and forms a physical gel that retains water, while the surfactant complex hydrophobizes the rock surface, decreasing water wettability and increasing oil wettability. As a result, the system is intended to significantly hinder water flow in the pore space while having little or no effect on oil flow. This behavior is consistent with the concept of disproportionate permeability reduction discussed in the literature for selective water-control chemicals.

The product does not contain organically bound chlorine compounds or quaternary ammonium salts capable of decomposing chlorinated organic compounds at 204°C. This is supported by the test protocol, which reported that organic chlorides were not detected in the sample tested. UpWPc can be used in waters with mineralization up to 180 g/L, operates over a wide pH range from 2 to 12, and is resistant to biodegradation.

3.1.2 Brine

Four formation water samples were used in the experimental program, corresponding to the four fields investigated: A, B, C1, and C2. Each brine sample was used together with its respective core and crude oil sample in order to preserve field-specific rock–fluid conditions during coreflood testing. These waters represent the injection waters used in the respective fields. They were used both as the injected aqueous phase during the flooding experiments and as the dilution medium for preparation of the RPM solutions.

Before the experiments, the samples of formation water were first filtered so that no suspended matter would be present to interfere with the operation of the apparatus. Before conducting the experiments, the viscosities and salinity of the brine were determined. The viscosities and salinity of the formation water have been listed in Table 7

Table 7. Viscosity of formation waters used in this study.

Field	Viscosity, cP	Reservoir temperature, °C	Salinity, ppm
A	0.72	61	~35000
B	0.68	80	~30000
C1	0.70	110	~45000
C2	0.75	110	~45000

3.1.3 Oil

The four crude oil samples tested in the experimental study from fields A, B, C1, and C2. The crude oil samples were matched with their own core samples and formation water in order to maintain the field conditions during the experiment.

The viscosity of each crude oil sample was determined by a viscometer. The API of the oil samples was known prior to experimentation. The results of viscosity and API of the oil samples are shown in Table 8.

Table 8. Viscosity of crude oils used in this study

Field	Viscosity, cP	Reservoir temperature, °C	API gravity
A	16.00	61	~ 28
B	1.75	90	~ 45

Field	Viscosity, cP	Reservoir temperature, °C	API gravity
C1	3.00	110	~ 42
C2	3.00	110	~ 42

3.1.4 Core Samples

These core samples extracted in the field were subsequently processed for laboratory analysis. Firstly, large diameter intact cores were initially received (Figure 4). Before undergoing any laboratory tests, the cores were then trimmed to the required size using a core-drilling machine (Figure 5). Upon trimming the core to the required diameter, the cores were then cut to the required lengths..



Figure 3. Core samples



Figure 4. Core cutting procedure.

While drilling, oil acted as both a cooling agent and lubricant that facilitated smooth drilling and prevented any damage caused by heat on the rock sample. This procedure, therefore, necessitated the need to clean the core samples since they were contaminated by the oil. In order to do this, a Soxhlet extraction setup was used (Figure 6).

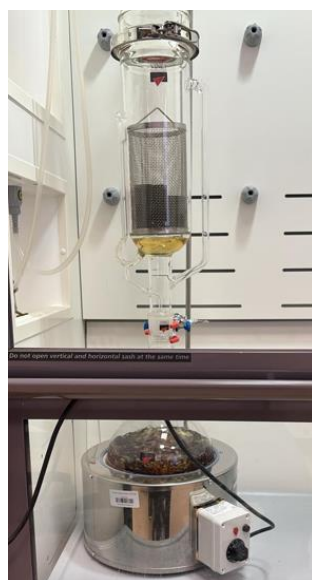


Figure 5. Soxhlet apparatus.

Dimensions of each core, including the length and diameter, were accurately measured after cleaning. The dry weight of the cores was determined before saturating the cores. Pore volume and porosity of the core samples were calculated by completely saturating them with formation water using vacuum methods. Wet weight was measured, and the porosity was computed based on the difference between wet and dry weights (Table 9).

Table 9. Core data

Field	Length, mm	Diameter, mm	Bulk volume, cm ³	Pore volume, cm ³	Porosity, %
A	93.39	37.50	103.15	24.69	23.9
B	93.80	37.90	105.80	25.07	23.7
C1	82.18	37.91	92.80	18.06	19.5

Field	Length, mm	Diameter, mm	Bulk volume, cm ³	Pore volume, cm ³	Porosity, %
C2	94.19	37.90	106.26	20.08	18.9

All core samples used in the experimental program were sandstone cores, selected to represent the reservoir rock of the investigated fields.

3.2 Experimental Setup and Equipment

Core flooding System

Fluid flow testing in the core flooding experiments was conducted on a CFS-700 core flooding system which enabled fluid flow testing in controlled reservoir-like conditions. The CFS-700 core flooding system consisted of three accumulators which were filled separately with formation water, crude oil, and RPM solution for use in injection stages. There was also the core holder which was used to set the core plug, with confining pressure being applied to seal the core plug. Moreover, backpressure was applied at the outlet to ensure controlled flow. It is worth noting that the CFS-700 core flooding experiment could be carried out at reservoir temperature since the temperature was critical in the experiment. Pressure sensors and the data acquisition system were used in monitoring the pressure changes through the core plug for calculation of permeability before and after core flooding. CFS-700 core flooding system by Vinci Technologies, schematically shown in Fig. 7.

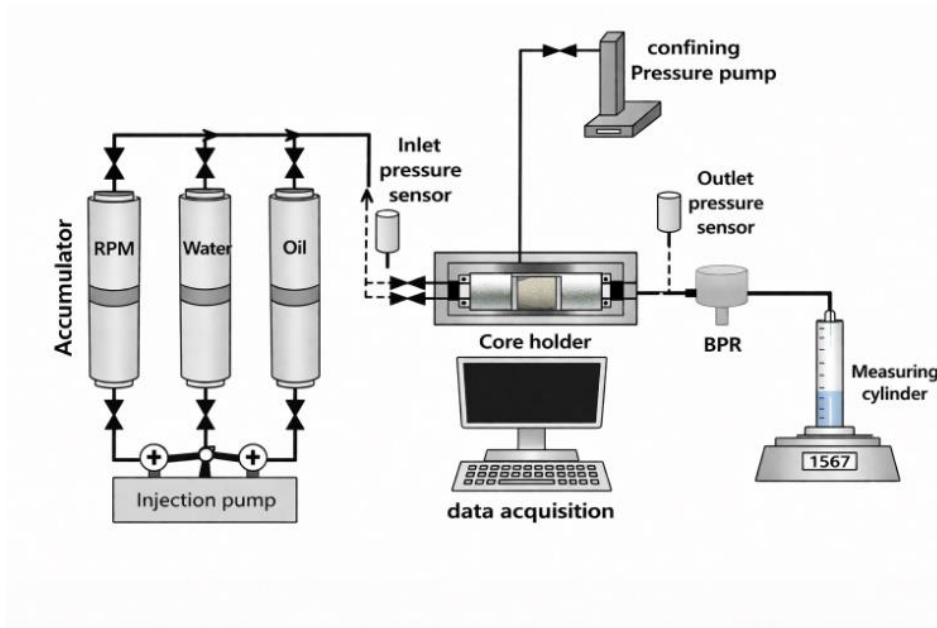


Figure 6. The schematic of coreflood system CFS-700.

SRP-350

The SRP-350 core flooding system was also used in the experimental work. In this setup, fluid injection was carried out using injection pumps, while confining pressure and back pressure were applied using a hand pump. The system included a core holder, differential pressure gauges, a measuring tube, and a data collection unit for monitoring the experiment. Unlike the CFS-700 setup, two accumulators were connected at a time, and they were changed depending on the experimental stage to allow injection of formation water, oil, or RPM solution. During the tests, the core sample was placed inside the core holder, and the pressure drop across the core was monitored to evaluate permeability and flow behavior under controlled conditions.

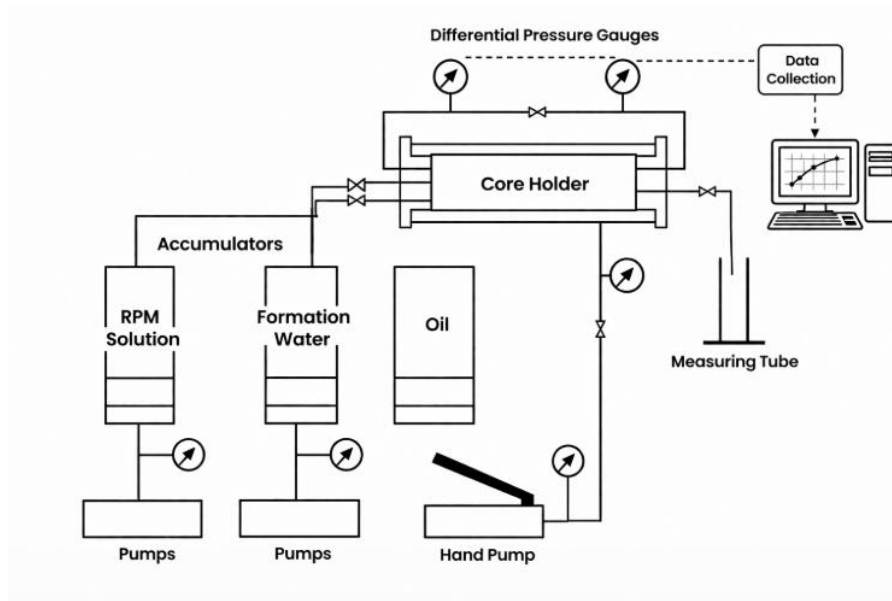


Figure 7. The schematic of coreflood system SRP-350.

The CFS-700 and SRP-350 core flooding systems were operated under reservoir-representative temperature and pressure conditions (Table 10) according to the characteristics of each core sample. In all experiments, the back pressure was maintained at 500 psi to ensure stable flow conditions during core flooding.

Table 10. Experimental conditions for core flooding tests.

Core/Field Confining Pressure, psi Temperature, °C		
A	1464	61
B	4351	90
C	1469	100

3.3 Experimental Procedure

3.3.1 Core Preparation

After cutting, the core plugs were cleaned using a Soxhlet extraction system, as described in the materials section. After cleaning, the core plugs were dried in an oven for 24

h at 80°C. The dried cores were then saturated for 24 h under pressure of 1200 psi to ensure full brine saturation. After saturation, the cores were flooded with brine to establish a fully water-wet condition. For the core plugs used in two-phase flow experiments, oil was then injected until no more water was produced in order to establish irreducible water saturation, after which the cores were aged (Figure 9) in an oven at 80 C for 28 days to restore an oil-wet or reservoir-like state before flooding tests.



Figure 8. Aging process

3.3.2 Fluid Preparation

The fluids used in the experiments were formation water, crude oil, and RPM solution. Prior to testing, the formation water samples were filtered to remove suspended particles and prevent plugging of the core flooding system. Crude oil samples from the selected fields were prepared for oil flooding experiments, while the RPM solution was prepared at the required concentration (25 and 100 l/m³) for core treatment. The viscosities of the formation waters and crude oils were determined separately at the experimental temperature and were later used in permeability calculations.

3.3.3 Selection of Injection Rate

Before the main core flooding experiments, single-phase water injection tests were carried out at flow rates of 1, 2, 3, 6, and 8 cm³/min to determine the most suitable operating condition. The use of stepwise increasing flow rates is consistent with published laboratory coreflood methodology, where several injection rates are applied to evaluate injectivity and the stability of pressure-drop behavior before selecting the final experimental rate. (Alyami et al., 2016; Harimi et al., 2019; Al-Muntasheri et al., 2025). Therefore, in this study, the final injection rate was selected on the basis of a stable differential pressure response and repeatable flooding performance.

3.3.4 Single Phase Flooding

Single-phase core flooding experiments were carried out using the CFS 3700 system (Figure 10) to evaluate the effectiveness of RPMs in reducing water permeability. The tests were performed on core plugs obtained from Field A, which were initially fully saturated with formation water. All experiments were conducted under controlled laboratory conditions using formation water as the injected fluid. During testing, the core samples were subjected to a confining stress of 1464 psi and a backpressure of 500 psi, while the oven temperature was maintained at the reservoir condition of approximately 61°C.



Figure 9. CFS-700

Before RPM treatment, brine was injected in the production direction at a constant rate until a stable differential pressure was established, typically after about 10 pore volumes. Baseline brine permeability was then measured in the forward direction at flow rates of 1, 2, 4, 6, and 8 cm³/min. Following this, approximately 10 pore volumes of WLP-3700 RPM solution were injected in the reverse direction at 1 cm³/min, after which the core was shut in for 24 h to allow chemical interaction with the rock. Brine injection was then resumed in the production direction, and the post-treatment permeability was determined again at the same range of flow rates. The same procedure was subsequently repeated using UpWPc RPM, and the permeability data obtained before and after treatment were compared to assess the performance of each RPM formulation.

3.3.5 Two Phase Flooding

Two-phase flow experiments were carried out to evaluate the performance of the relative permeability modifier under conditions that more closely represent the simultaneous

presence of water and oil in reservoir rock. The main purpose of these tests was to determine whether the RPM treatment could reduce permeability to water while maintaining, as much as possible, the ability of oil to flow through the core. This is important because the effectiveness of an RPM is not defined only by its ability to restrict water flow, but by its selective action, meaning that water permeability should decrease more strongly than oil permeability after treatment. Therefore, permeability to both brine and oil was measured before and after RPM injection, and the results were compared to assess the degree of selective permeability reduction. For the two-phase flow experiments, the core sample was mounted in the core holder, and the temperature and confining pressure were set according to Table 10, while the back pressure was maintained at 500 psi.

Before RPM treatment, brine was injected in the pre-designated production direction at 1 cm³/min until a stable differential pressure across the core was achieved. Once only brine was produced, the brine permeability was determined at flow rates of 1, 2, 4, 6, and 8 cm³/min. This was followed by oil injection in the same production direction at 1 cm³/min until the differential pressure again stabilized. When the produced fluid consisted only of oil, the oil permeability was measured at the same series of flow rates.

After establishing the initial brine and oil permeability values, approximately 10 pore volumes of RPM solution were injected in the reverse direction at 1 cm³/min. The core was then shut in for 24 h to allow interaction between the treatment solution and the rock surface. Following the shut-in period, the brine and oil injection sequence was repeated under the same operating conditions, and the permeability values measured before and after treatment were compared to evaluate the effectiveness of the RPM.

3.4 Permeability Calculation

Permeability was determined from the experimental pressure-drop data obtained during core flooding tests performed with the CFS-700 and SRP-350 systems. During each experiment, the differential pressure across the core plug was recorded automatically by the data acquisition system at 10 s intervals. For each imposed flow rate, the system was allowed to reach stable flow conditions, and the recorded differential pressure values were then processed. To obtain one representative pressure-drop value for each flow rate, the arithmetic average of the stabilized differential pressure readings was calculated.

The permeability calculation was based on Darcy's law, which describes laminar flow through porous media:

$$q = \frac{kA\Delta P}{\mu L}$$

where:

q = flow rate, cm³/s

k = permeability, cm²

A = cross-sectional area of the core, cm²

ΔP = pressure drop across the core, atm

μ = fluid viscosity, cP

L = core length, cm

For the calculations, Darcy's law was rearranged into linear form:

$$q = k \left(\frac{A\Delta P}{\mu L} \right)$$

In this form, the term $\frac{A\Delta P}{\mu L}$ was calculated for each flow rate, and a graph of q versus

$(A\Delta P)/(\mu L)$ was plotted. The units of this term were:

$$\frac{A\Delta P}{\mu L} = \frac{\text{cm}^2 \cdot \text{atm}}{\text{cP} \cdot \text{cm}}$$

and the flow rate was expressed in:

$$q = \text{cm}^3/\text{s}$$

According to the linearized Darcy equation, the slope of the straight-line plot is equal to the permeability k . Since permeability in petroleum engineering is commonly reported in millidarcies (mD), the calculated slope was converted from cm² to mD. Thus, permeability for each flooding stage was obtained from the slope of the best-fit line using the averaged pressure-drop values measured at different flow rates.

An example of these calculations is shown in Figure 11 and Table 11, where the slope of the linear relationship represents the permeability for a given core and fluid system.

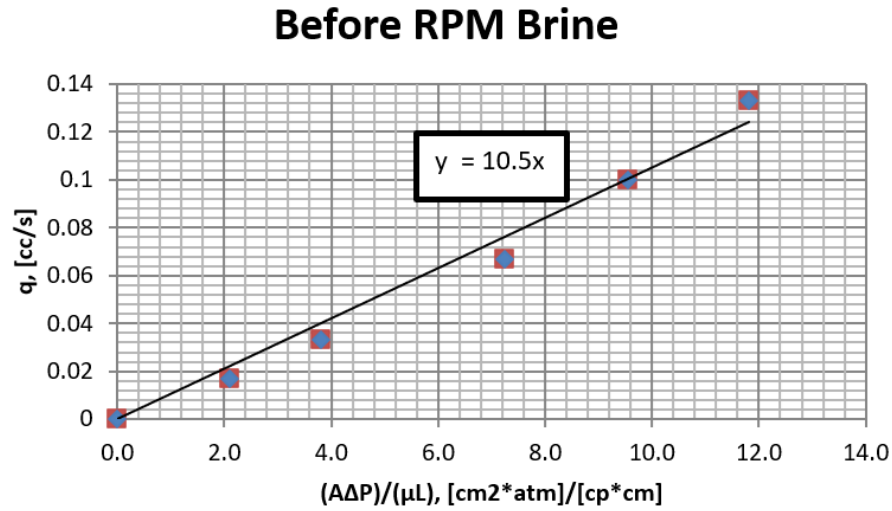


Figure 10. Example of permeability determination from the linearized form of Darcy's law.

Table 11. Pressure-drop data and permeability calculations before and after RPM treatment.

	q, cc/min	dP, psi	dP, atm	factor $(\Delta P)/q$	q, cc/s	kabs, mD
Before RPM Brine	0	0	0	0	0	0
	1	18.89	1.285	2.111	0.017	7.89
	2	34.04	2.316	3.805	0.033	8.76
	4	64.83	4.411	7.246	0.06667	9.20
	6	85.4	5.811	9.545	0.100	10.48
	8	105.64	7.188	11.807	0.133	11.29
Before RPM Oil	0	0	0.000	0.000	0.000	#DIV/0!
	1	200.42	13.638	1.008	0.017	16.53
	2	424.97	28.918	2.137	0.033	15.59
	4	631.7	42.985	3.177	0.06667	20.98
	6	872.6	59.377	4.389	0.100	22.78
	8	948.3	64.528	4.770	0.133	27.95

This procedure was applied to the before RPM brine, before RPM oil, after RPM brine, and after RPM oil datasets. By comparing the permeability values obtained before and after treatment, it was possible to quantify the effect of the RPM on water flow and oil flow through the core.

4. RESULTS

This chapter presents the main findings of the experimental and simulation work. First, the results of the single-phase screening tests are presented to justify selection of the final RPM candidate. Next, the two-phase coreflood results are reported for the four field systems, with emphasis on the comparative reduction in water and oil permeability. Finally, an example reservoir simulation case is presented to show how the experimentally measured permeability changes may affect water-production behavior at the reservoir scale.

4.1 Comparison of RPM Candidates in Single-Phase Flow

At the initial stage of the study, two relative permeability modifiers, RPM 1 (WLP-3700) and RPM 2 (UpWPC), were compared in single-phase water-flow experiments in order to select the more suitable chemical for further testing. In both cases, the RPM concentration used was 25 L/m³. For RPM 1, the water permeability decreased from 146.5 mD before treatment to 49.7 mD after treatment, corresponding to a reduction of 66% (Figures 12 and 13).

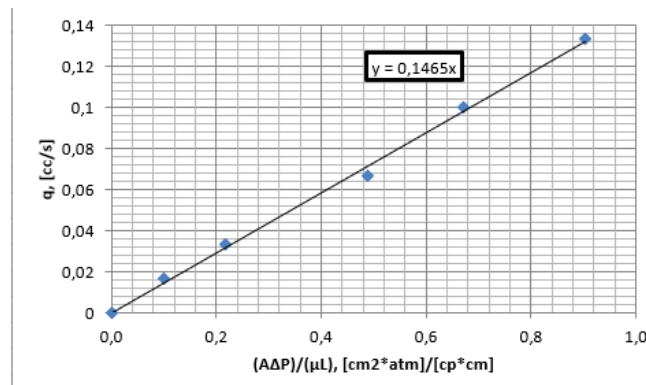


Figure 11. Permeability calculation before injecting RPM

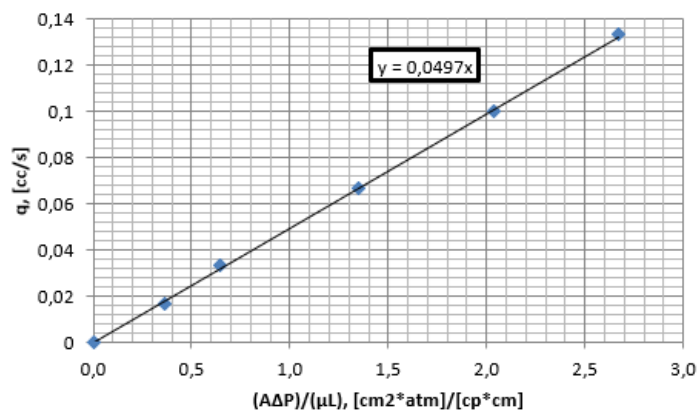


Figure 12. Permeability calculation after injecting RPM

Figure 14 shows the differential pressure response during the single-phase water-flow test before and after RPM injection. Before RPM treatment, the pressure drop increased gradually with increasing flow rate from 1 to 8 cc/min, indicating normal water flow through the core. After RPM injection, the pressure drop became significantly higher at the corresponding flow rates, showing that the treatment increased resistance to water flow and reduced water permeability. This increase was especially noticeable at higher flow rates, which confirms the effectiveness of the RPM in restricting brine flow through the core.

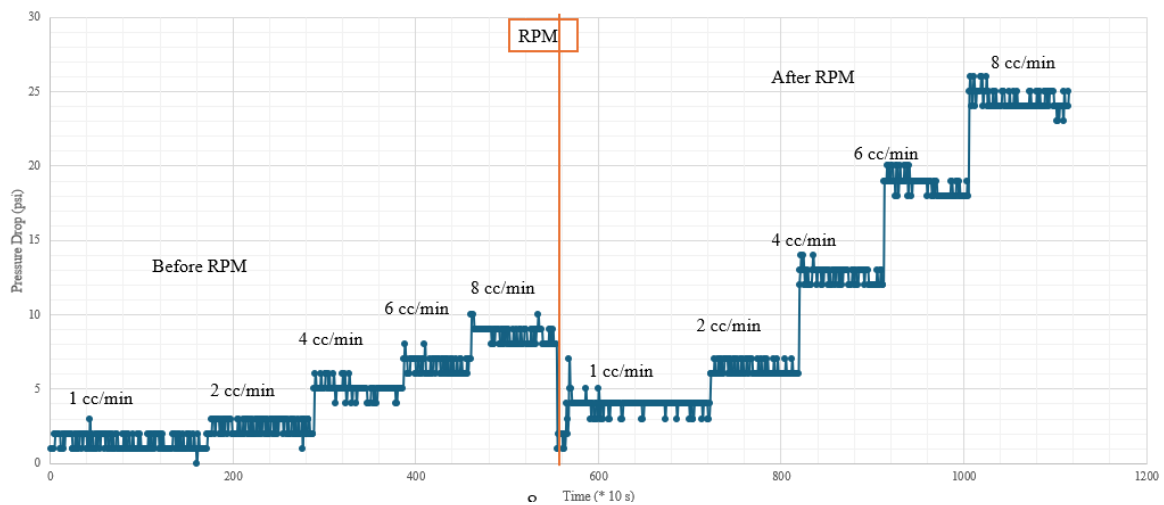


Figure 13. Pressure drop vs Time (RPM1)

For RPM 2, the water permeability decreased from 159.9 mD to 49.9 mD, corresponding to a reduction of 68.8% (Figures 15 and 16).

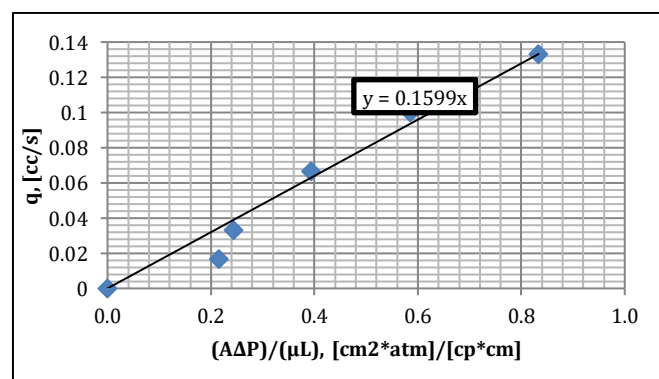


Figure 14. Permeability calculation before injecting RPM2

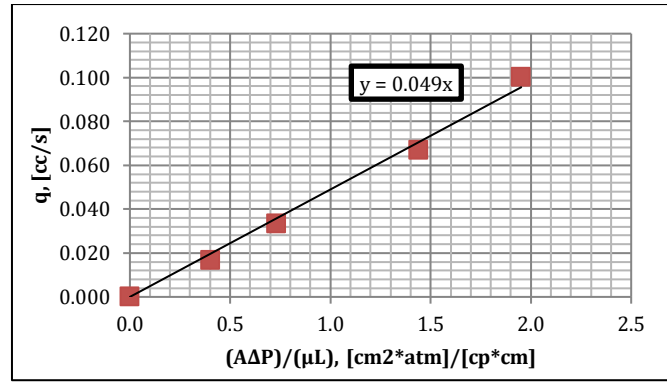


Figure 15. Permeability calculation after injecting RPM2

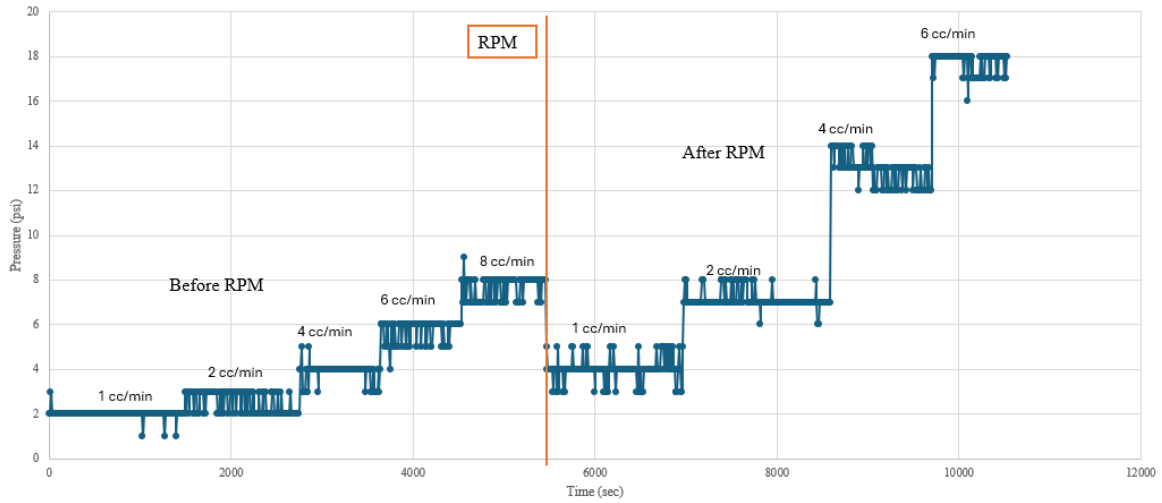


Figure 16. Pressure drop vs Time (RPM 2)

These results show that both RPM systems provided a very similar level of water-permeability reduction, with overall performance in the range of approximately 66–69%. Since the difference in permeability reduction between the two chemicals was small, the final selection was made based not only on permeability reduction but also on observed fluid/fluid and rock/fluid behavior during the experiments. On this basis, RPM 1 (WLP-3700) was selected for the subsequent core flooding tests and became the main RPM system investigated in the rest of this thesis.

4.2 Two-Phase Flow Results: Oil and Water Permeability Before and After RPM Treatment

Two-phase flow experiments were carried out to evaluate the effect of the selected relative permeability modifier on water and oil flow through sandstone core samples from the A, B, C1, and C2 fields. For each core, permeability to formation water and permeability to

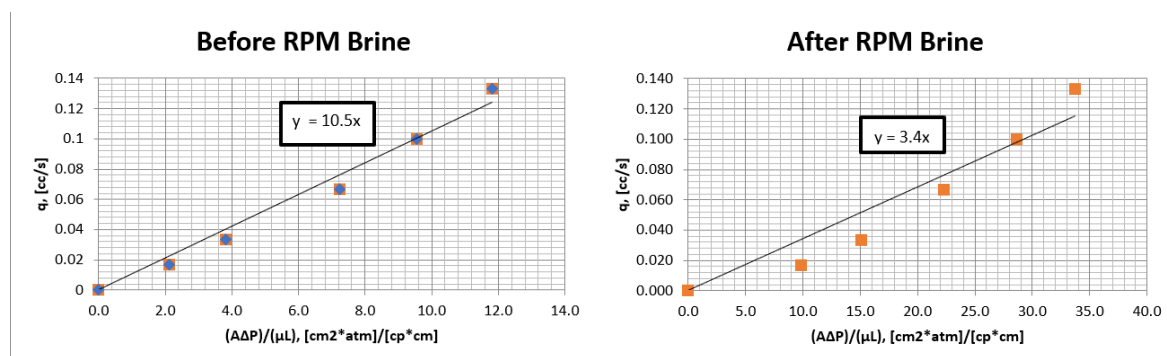
oil were determined before and after RPM treatment. The purpose of this analysis was to assess the selectivity of the RPM, that is, its ability to reduce water permeability more strongly than oil permeability. The experimental results for all four fields showed that the RPM treatment caused a substantial reduction in water permeability, while the decrease in oil permeability remained much smaller, which indicates selective water-control behavior.

4.2.1 Experimental Results

Field A

For the field A core, the initial permeability to formation water was approximately 10.6 mD, while the initial oil permeability was about 21.1 mD. After RPM treatment, water permeability decreased to 3.4 mD, whereas oil permeability remained close to 20.0 mD (Figure 18). This corresponds to a water permeability reduction of approximately 67.6%, while the oil permeability reduction was only about 5.0%.

These results show that the RPM performed most effectively in the field A core among all tested samples. The reduction in water permeability was the highest of the four fields, while the reduction in oil permeability was one of the lowest. Such behavior indicates a strong selective action of the treatment. From a practical point of view, this is the most favorable outcome because the treatment significantly suppresses water flow while causing almost no damage to oil flow. Therefore, the sample from field A can be considered the best-performing case in this study with respect to RPM selectivity.



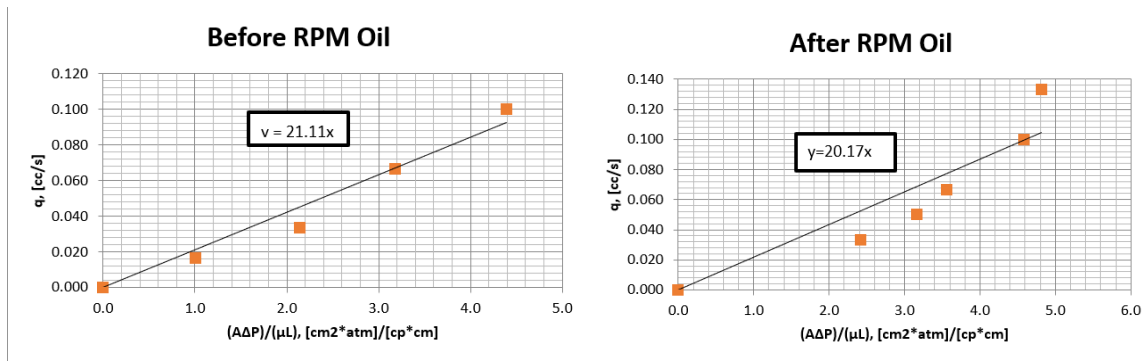


Figure 17. Calculation of Relative Permeability (Field A)

Field B

For the field B core, the permeability to formation water before treatment was 33.0 mD, and the oil permeability was 51.5 mD. After RPM injection, the water permeability decreased to 15.0 mD, while the oil permeability decreased to 46.3 mD (Figure 19). The corresponding permeability reduction was 54.5% for water and 10.1% for oil.

The field B results also demonstrate selective RPM action, since the reduction in water permeability was substantially greater than the reduction in oil permeability. However, compared with field A, the treatment in Field B caused a somewhat larger loss in oil permeability. Although the water shutoff effect remained significant, the selectivity was slightly less favorable because the oil phase was affected more strongly. Nevertheless, the overall result still indicates good RPM performance and suggests that the chemical system can provide useful water-control behavior in this reservoir.

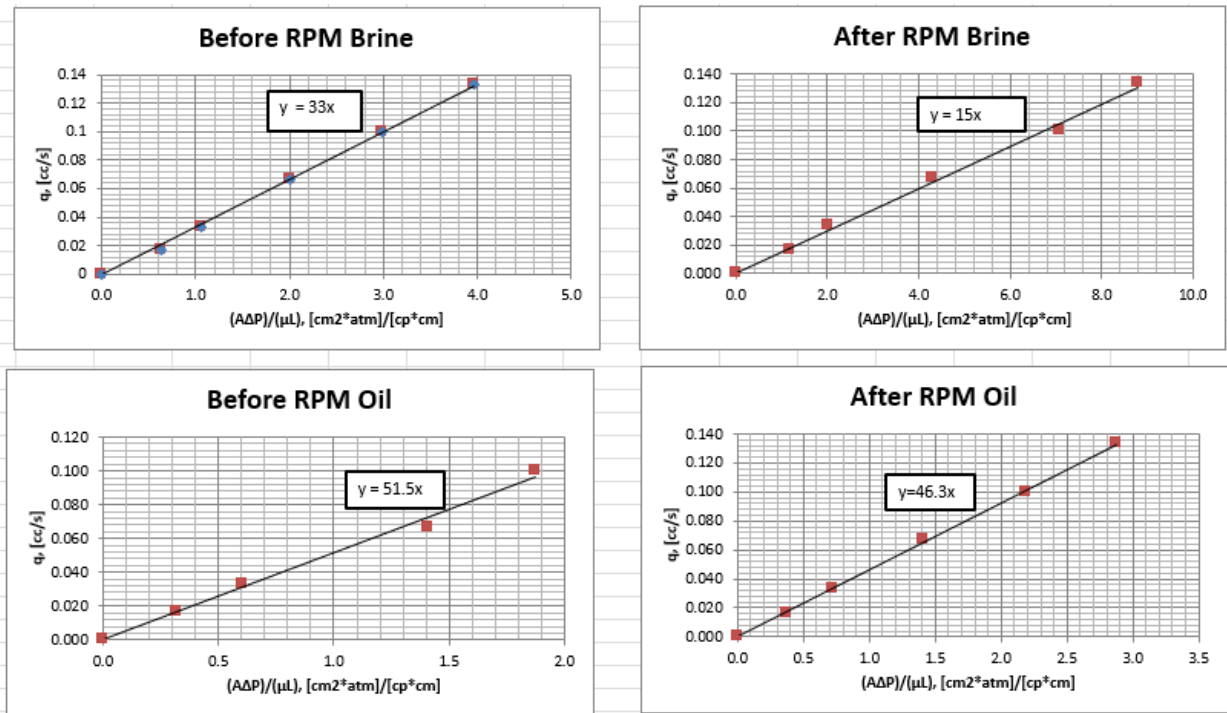
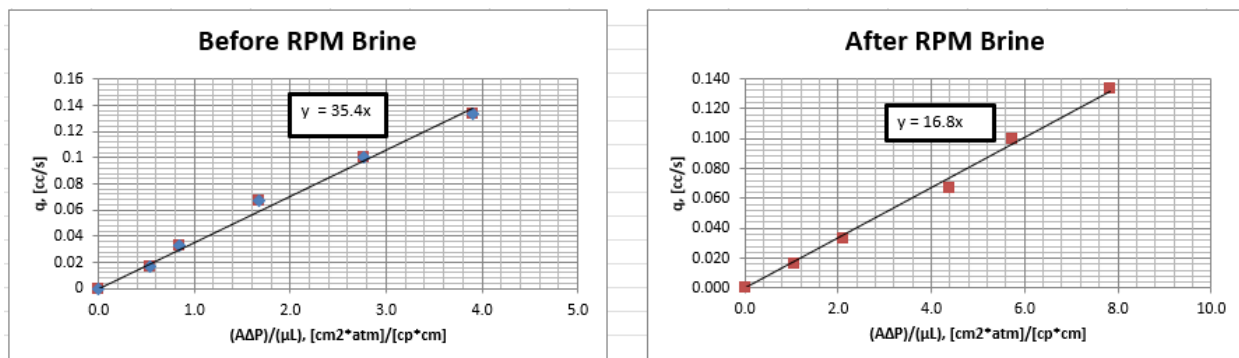


Figure 18. Calculation of Relative Permeability (Field B)

Field C1

For the C1 core, the initial permeability to formation water was 35.4 mD, while the initial oil permeability was 45.1 mD. After treatment with RPM, the water permeability was reduced to 16.8 mD and the oil permeability to 42.6 mD (Figure 20). This corresponds to a 52.5% reduction in water permeability and only a 5.5% reduction in oil permeability.

These results indicate a highly selective treatment response. Although the absolute reduction in water permeability was slightly lower than in field A and close to that observed in field B, the reduction in oil permeability remained very small. This is an important result because it means the RPM was able to suppress water flow efficiently while largely preserving hydrocarbon flow capacity. In terms of selectivity, the C1 sample showed one of the most balanced performances in the study.



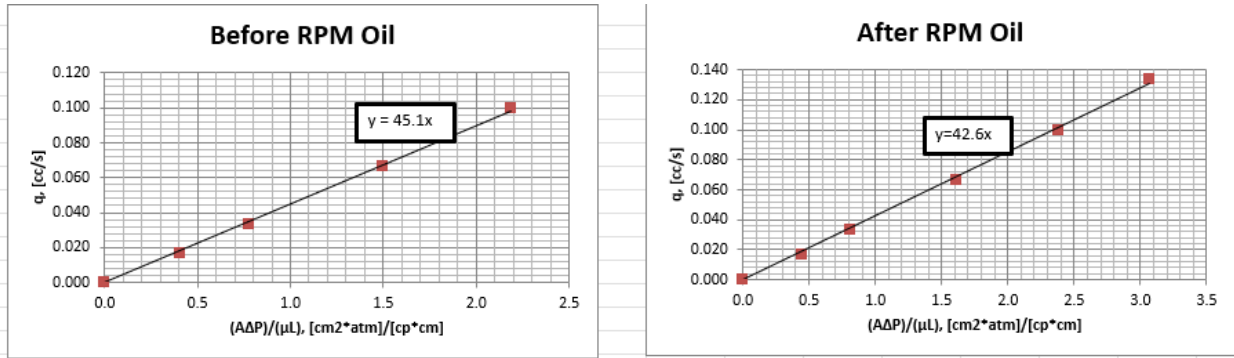
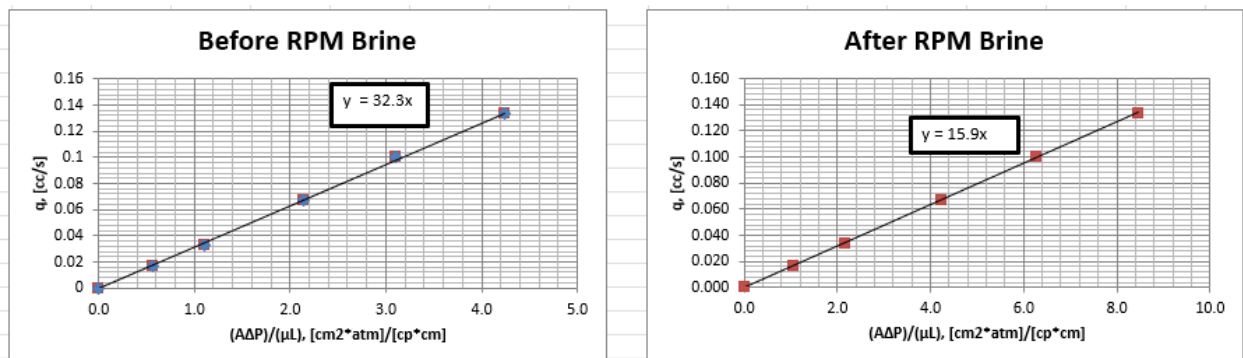


Figure 19. Calculation of Relative Permeability (Field C1)

Field C2

For the field C2 core, water permeability before treatment was 32.3 mD and oil permeability was 40.1 mD. After RPM treatment, the permeability to formation water decreased to 15.9 mD, while the oil permeability decreased to 37.4 mD (Figure 21). The permeability reduction was approximately 50.8% for water and 6.7% for oil.

The results for field C2 confirm the same overall trend observed for the other fields. The water phase was affected much more strongly than the oil phase, which confirms selective RPM performance. However, among the four fields, this sample showed the smallest reduction in water permeability. Even so, the oil permeability loss remained limited, which means the treatment still demonstrated acceptable selectivity. Therefore, C2 field may also be considered a suitable candidate for RPM application, although its water-control effect was somewhat weaker than in the other tested cores.



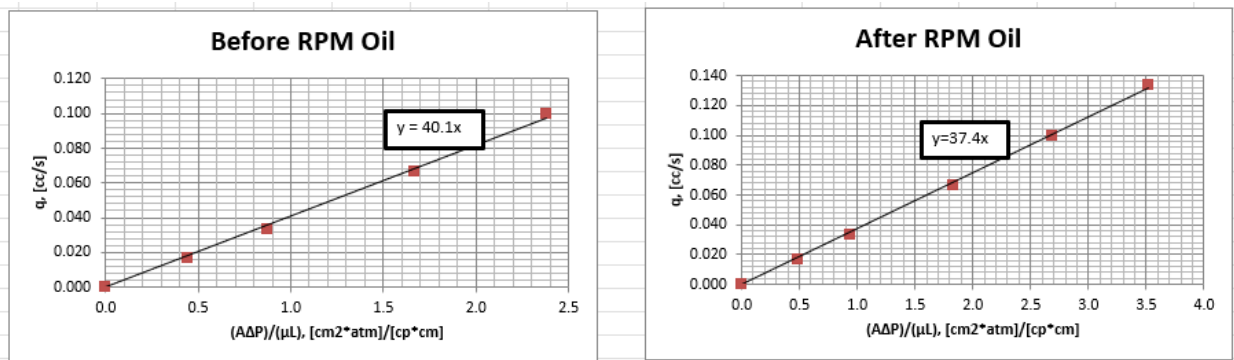


Figure 20. Calculation of Relative Permeability (Field C2)

The main results of the two-phase flow tests are summarized in Table 12.

Table 12. Summary

Field	Water permeability before RPM, mD	Water permeability after RPM, mD	Water permeability reduction, %	Oil permeability before RPM, mD	Oil permeability after RPM, mD	Oil permeability reduction, %
A	10.6	3.4	67.6	21.1	20.0	5.0
B	33.0	15.0	54.5	51.5	46.3	10.1
C1	35.4	16.8	52.5	45.1	42.6	5.5
C2	32.3	15.9	50.8	40.1	37.4	6.7

The single-phase screening tests showed that both RPM candidates were capable of reducing water permeability significantly, which indicates that both chemicals interacted effectively with the water-saturated porous medium. Although the overall reduction in water permeability produced by the two chemicals was similar, WLP-3700 was considered more favorable based on the observed rock-fluid-chemical response during the experiments.

The two-phase coreflood results indicate that the tested chemical behaved as a true relative permeability modifier rather than as a nonselective blocking agent. In all four core systems, the reduction in permeability to water was substantially greater than the reduction in permeability to oil. This difference is the main evidence of selective action and shows that the

treatment did not simply plug the pore space uniformly. If the RPM had acted as a conventional pore-blocking material, similar damage would be expected for both phases. Instead, the results suggest that the chemical created stronger resistance in the water-conducting pathways while preserving most of the oil-flow capacity.

From a mechanistic point of view, the results are consistent with selective water-flow restriction caused by polymer adsorption and retention in the pore space. The treatment likely increased resistance mainly in water-conducting channels and had a smaller effect on oil-flow pathways. The differences observed among the four tested fields indicate that RPM performance is reservoir-dependent. Although the same chemical system was applied in all cases, the magnitude of permeability reduction was not identical. This is an expected result, since RPM action is influenced by a combination of factors including rock texture, pore-throat size distribution, permeability level, fluid viscosity, temperature, and rock-fluid-chemical interactions.

The field A core showed the best response, which may indicate that its pore structure and surface properties were more favorable for retention or adsorption of the chemical system in a way that preferentially restricted water flow. In contrast, the field B core exhibited the highest oil permeability reduction, suggesting that in this rock-fluid system the RPM caused somewhat greater impairment to hydrocarbon flow. Field C1 presented one of the best compromises between water shutoff and oil preservation, while field C2 showed a weaker but still useful selective response.

These differences are important from an engineering standpoint. They show that RPM treatments should not be selected solely on the basis of general literature performance or performance in one reservoir. Instead, field-specific laboratory evaluation is necessary before implementation. A chemical system that performs very well in one reservoir may behave less favorably in another due to differences in mineralogy, permeability, wettability, or crude oil properties. Therefore, the comparative design of this study adds practical value by demonstrating that RPM performance must be assessed individually for each reservoir system.

4.3 Numerical Simulation Results

To support the laboratory findings, a numerical simulation study was carried out in CMG IMEX for one representative field case (Field A). The purpose of this simulation was not

to provide a general prediction for all investigated fields, but rather to present an example showing how experimentally measured RPM effects can be interpreted at the reservoir scale. In this sense, the CMG model was used as a supporting case study for one field, based directly on the permeability changes obtained from the laboratory coreflood experiments.

4.3.1 Simulation model description

To complement the laboratory coreflood experiments, numerical simulation was carried out to evaluate the possible impact of Relative Permeability Modifier treatment on reservoir performance under field-related conditions. A simplified reservoir simulation model was developed in CMG IMEX using input data obtained from laboratory measurements and company-provided reservoir information. The model incorporated rock and fluid properties, PVT data, porosity, permeability, and the permeability reduction effects observed experimentally after RPM treatment. The main purpose of the simulation was to investigate how experimentally measured selective permeability reduction could influence water production behavior at the reservoir scale.

A simplified representative reservoir model was constructed in CMG IMEX to simulate near-wellbore reservoir behavior before and after RPM treatment. The model was intentionally kept simple in order to focus on the effect of chemical treatment rather than on detailed full-field forecasting. A small three-dimensional Cartesian grid was used to represent a sector of the reservoir around one producing well and one injection well (Figure 22). This approach allowed the effect of permeability modification on production response to be analyzed in a computationally efficient way.

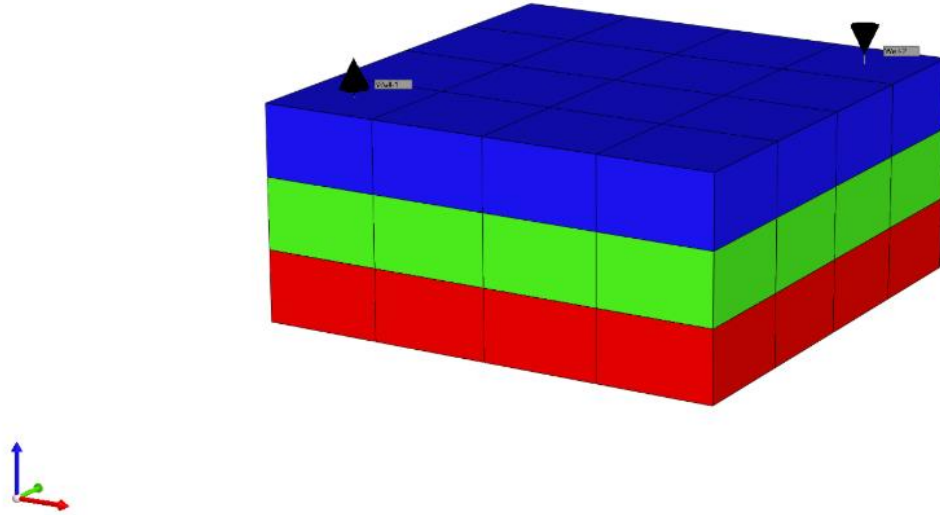


Figure 21. CMG IMEX reservoir model.

Porosity for all layers in the model was taken as 29%, based on laboratory core measurements. Reservoir conditions were selected using field operating data, with a temperature of 61°C and pressure of 120 atm. In addition, laboratory measurements of oil viscosity and density were used as input for the simulation model. The experimentally determined relative permeability changes after RPM treatment were also incorporated into the model. In particular, the model used an approximate 67.6% reduction in water permeability and 5% reduction in oil permeability, corresponding to the experimentally observed selective action of the RPM.

4.3.2 Simulation scenarios

Four simulation scenarios were prepared to evaluate the effect of RPM treatment at different stages of reservoir water breakthrough. In all cases, the oil production rate of the producing well was fixed at 8 m³/day. The first scenario represented the base case without RPM treatment and served as a reference for comparison. The remaining three scenarios simulated RPM application at different water cut levels: when water cut reached 40%, 60%, and 80%, respectively. In these cases, RPM treatment was represented by reducing water permeability in accordance with the laboratory results.

This set of scenarios made it possible to compare not only the general influence of RPM treatment on reservoir performance, but also the effect of treatment timing. In practical terms, this is important because the success of chemical water shutoff may depend strongly on the stage at which the treatment is applied.

4.3.3 Base-case water cut behavior

The base-case simulation without RPM treatment was first analyzed to understand the natural development of water cut over time. The simulation forecast covered the period from 2026 to 2040 and showed a continuous increase in water cut, which is typical of a mature waterflooded reservoir. This behavior reflects progressive depletion of movable oil and the increasing contribution of produced water during reservoir development.

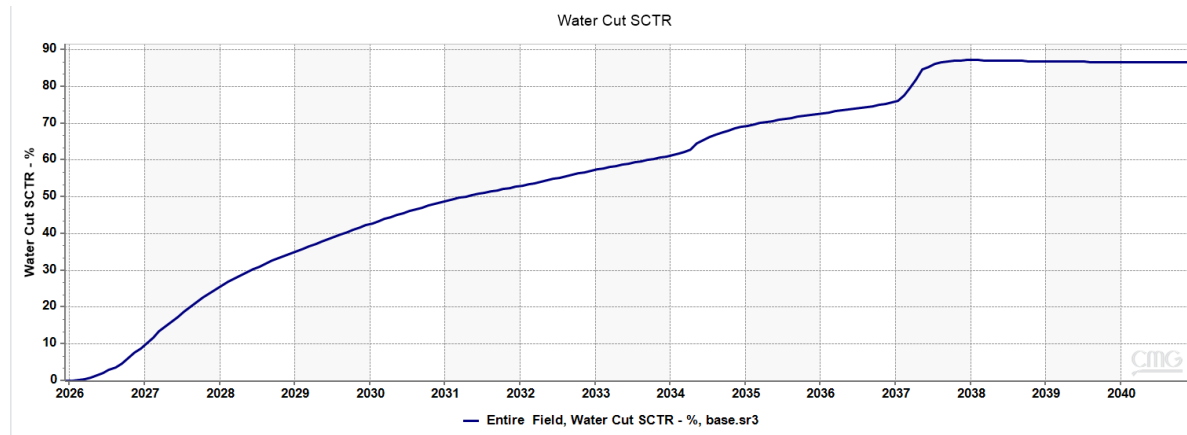


Figure 22. Water cut (Base model)

Figure 23 shows the forecasted increase in water cut in the untreated reservoir model. The progressive rise in water cut confirms the increasing dominance of water production with time and highlights the need for a water-control treatment such as RPM at later stages of reservoir life.

4.3.4 Effect of RPM treatment on cumulative water production

The effect of RPM treatment was evaluated by comparing cumulative water production in the treated and untreated cases. In all three treatment scenarios, the RPM case showed lower cumulative water production than the base case. After the point of RPM application, a clear divergence between the cumulative water production curves was observed, indicating that the treatment reduced the amount of water produced under the modeled conditions.

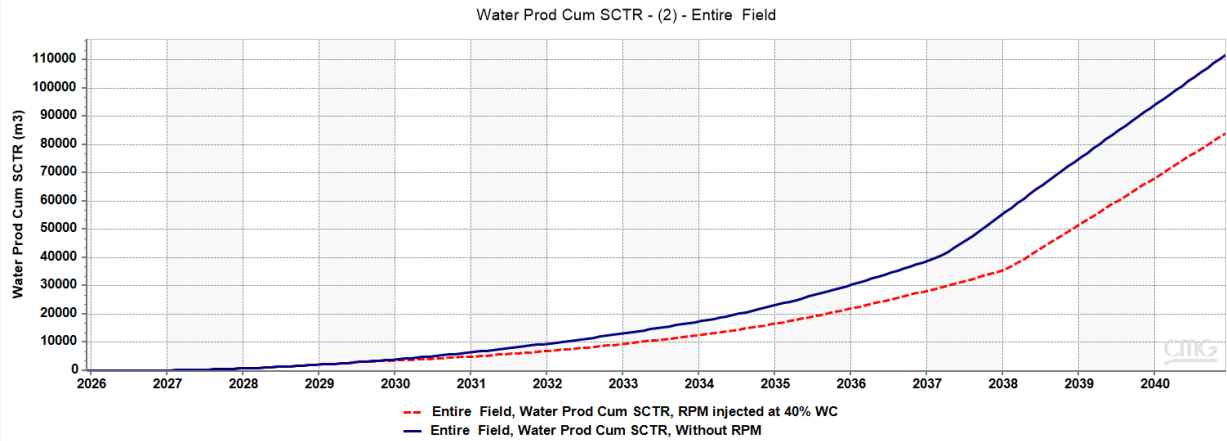


Figure 23. Cumulative water production comparison (Base case and 40% WC)

When RPM treatment was applied at 40% water cut, the cumulative water production over the considered 11-year period decreased by approximately 25% compared with the base case (Figure 24). This represents the largest improvement among the simulated scenarios and suggests that earlier application of RPM provides the greatest benefit in reducing unwanted water production.

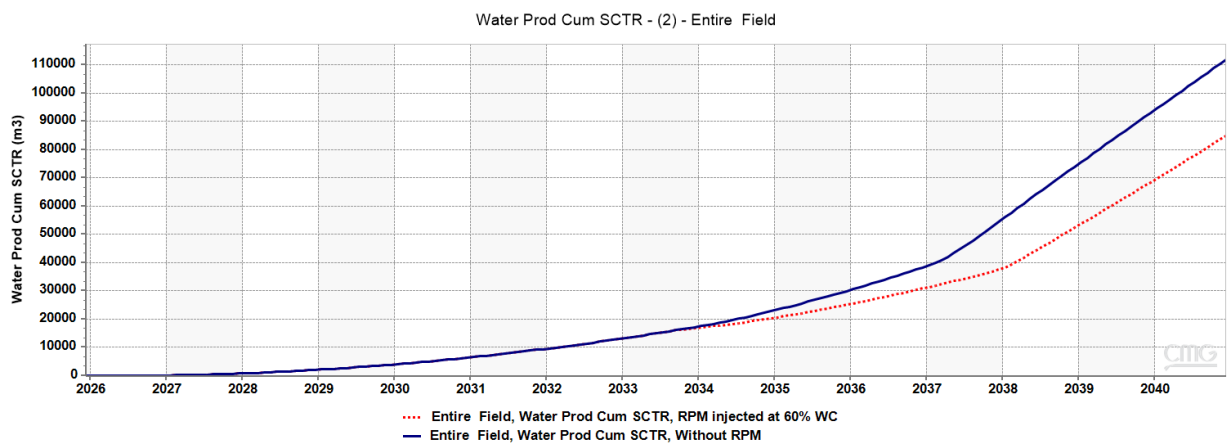


Figure 24. Cumulative water production comparison (Base case and 60% WC)

For the case where RPM treatment was applied at 60% water cut, cumulative water production over the considered 9-year period decreased by approximately 23% (Figure 25). Although the reduction remained substantial, it was slightly smaller than in the 40% water-cut case, indicating that delaying treatment reduces its effectiveness.

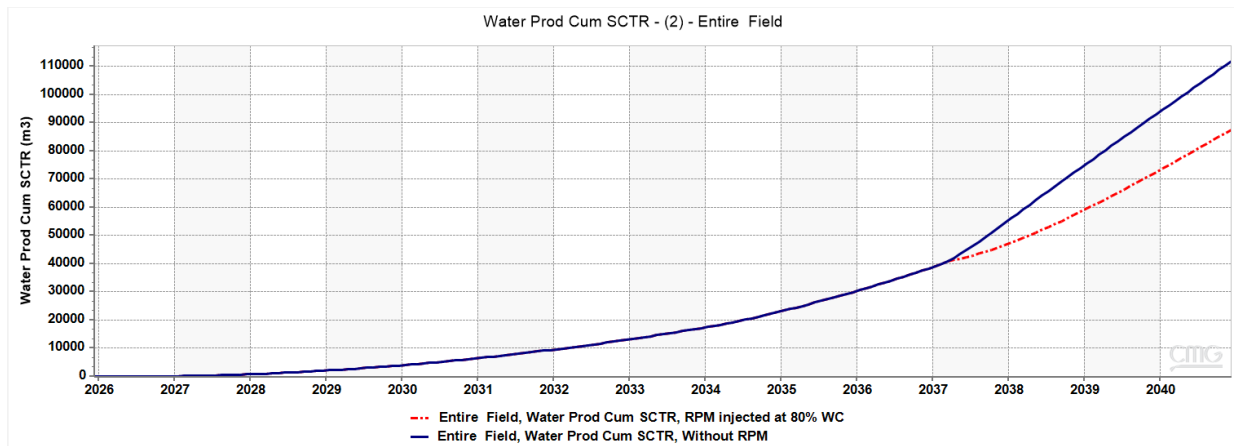


Figure 25. Cumulative water production comparison (Base case and 80% WC)

When RPM was applied at 80% water cut, the reduction in cumulative water production over the considered 4-year period was approximately 20% (Figure 26). This result still demonstrates a beneficial treatment effect, but the improvement was lower than in the earlier-treatment scenarios. The result indicates that applying RPM only after very high water cut has already developed may limit the potential benefit of the treatment.

A comparison of the three RPM treatment scenarios shows that treatment timing had a noticeable influence on simulation performance. The largest reduction in cumulative water production was obtained when RPM was applied at 40% water cut, followed by the 60% water cut case, while the smallest improvement was observed for treatment at 80% water cut. This trend suggests that earlier implementation of RPM can provide better control of water production.

At the same time, it is important to note that the absolute cumulative water production values should not be interpreted as direct field-scale forecasts. The report clearly states that the model was a simplified sector model designed to study trends and relative behavior rather than exact production magnitudes. Therefore, the most meaningful outcome of the simulation is not the absolute volume of produced water, but the relative percentage reduction in cumulative water production between the treated and untreated cases.

This is an important point for your thesis discussion. You can say that the simulation was not intended to predict exact future field performance, but rather to demonstrate the expected trend and relative effectiveness of RPM treatment under representative reservoir conditions.

Table 13. Summary of simulation cases.

Scenario	RPM application point	Duration considered, years	Change in cumulative water production, %
Base case	No RPM treatment	-	-
Case 2	RPM at 40% water cut	11	-25
Case 3	RPM at 60% water cut	9	-23
Case 4	RPM at 80% water cut	4	-20

Thus, both the experimental and simulation results indicate that RPM treatment has strong potential for selective water control. The laboratory coreflood tests confirmed significant reduction in water permeability with limited effect on oil permeability, while the numerical simulation showed that this selective behavior may translate into lower cumulative water production at the reservoir scale.

4.4 Integration of laboratory and simulation findings

One of the strengths of this study is the integration of laboratory coreflood testing with numerical simulation. The laboratory work provided direct measurements of permeability reduction under controlled conditions, while the simulation translated these results into a reservoir-performance context. This combined approach is important because laboratory experiments alone cannot show how selective permeability reduction might affect long-term production trends, and simulation alone cannot provide credible treatment parameters without experimental support.

The good qualitative agreement between the two parts of the study strengthens the overall conclusions. The coreflood tests demonstrated that RPM treatment can selectively suppress water flow, and the simulation showed that this selective behavior may result in reduced cumulative water production under modeled reservoir conditions. Thus, the two methods complement each other and together provide stronger evidence for the potential applicability of RPM treatment than either method could provide independently.

Despite the positive results, several limitations should be acknowledged.

First, the laboratory experiments were performed on a limited number of core samples, and although these samples were representative of the selected fields, they cannot fully capture the heterogeneity of actual reservoirs. Real formations contain spatial variability in permeability, porosity, mineral composition, fracture intensity, and fluid distribution, all of which may influence treatment performance.

Second, the coreflood experiments were conducted under controlled laboratory conditions, which are necessarily simpler than field conditions. Although care was taken to use representative fluids, temperatures, and pressures, the laboratory setup cannot reproduce all aspects of the reservoir environment, including large-scale heterogeneity, complex well geometry, long-term chemical exposure, and operational constraints.

Third, the assessment of RPM performance was mainly based on short-term permeability response before and after treatment. Long-term chemical stability, retention, degradation, and repeat-treatment behavior were not studied in detail. These factors may be important for predicting sustained field performance.

Fourth, the simulation model was simplified and designed mainly for qualitative trend analysis. It was not a full-field calibrated reservoir model and should therefore not be interpreted as a predictive field-development tool. The model is useful for comparing treatment scenarios and understanding relative behavior, but not for exact production forecasting.

Finally, the simulation was based primarily on one set of experimentally observed permeability reductions. Although this is sufficient for demonstrating the principle of treatment effectiveness, future work could incorporate a wider range of reservoir-specific laboratory data to generate more detailed and differentiated simulation scenarios for all fields.

From a practical standpoint, the findings of this study suggest that RPM treatment is a promising option for water control in sandstone reservoirs where excessive water production limits well performance. The experimental results indicate that meaningful reduction of water permeability can be achieved with relatively minor impairment of oil flow. This means that RPM treatment may offer a route to improving production efficiency and reducing the handling and disposal of unwanted produced water.

The simulation results further suggest that treatment timing may be important. Applying RPM earlier, before water cut becomes too high, may increase the effectiveness of

the treatment in terms of reducing cumulative water production. Therefore, field screening strategies for RPM application should consider not only chemical compatibility and laboratory selectivity, but also the timing of intervention during reservoir development.

At the same time, the results also show that treatment performance differs between fields. This means that field implementation should be preceded by laboratory testing using representative rock and fluid samples from the specific candidate reservoir. A generalized one-chemical-fits-all approach would not be sufficient.

5. CONCLUSIONS AND RECOMMENDATIONS

This thesis investigated the performance of Relative Permeability Modifiers for selective water control using laboratory coreflood testing and numerical simulation. Based on the results obtained, the following conclusions can be drawn.

First, the selected relative permeability modifier demonstrated clear selective behavior in all tested sandstone core samples. In every case, the reduction in water permeability was significantly greater than the reduction in oil permeability, confirming that the chemical acted as a true RPM rather than as a nonselective plugging agent, with the best performance was observed for Field A. In this case, water permeability was reduced by 67.6%, while oil permeability decreased by only 5.0%

Second, the results showed that RPM performance is reservoir-dependent. Although selective water control was observed in all tested cores, the magnitude of water and oil permeability reduction varied from field to field, which confirms the importance of field-specific laboratory screening before practical application.

Third, the CMG simulation for the representative Field A case showed that the experimentally observed selective permeability reduction may lead to lower cumulative water production at the reservoir scale. The simulation also indicated that earlier application of RPM gave a greater benefit than treatment at a later high-water-cut stage.

Finally, the integrated use of laboratory experiments and simulation represents an important contribution of this study. The work not only quantified selective permeability reduction in representative sandstone cores, but also demonstrated how experimentally derived RPM effects can be translated into reservoir-scale performance trends. This combined approach strengthens confidence in the practical relevance of the results.

5.1 Recommendations for future work

A larger number of core samples should be tested for each field in order to better capture reservoir heterogeneity and improve statistical confidence in the results. Additional experiments could also include longer aging periods, different injection rates, broader temperature and salinity ranges, and longer post-treatment flooding periods to assess long-term treatment stability.

Further work is also needed to investigate the mechanisms responsible for selective permeability reduction in the studied systems. This could include analysis of adsorption behavior, wettability changes, pore-scale retention, and chemical-rock interactions.

From the simulation perspective, future studies should use more detailed reservoir models that incorporate field-scale heterogeneity, multiple wells, and more realistic operational constraints. It would also be useful to construct separate simulation cases for each field using their own experimentally measured permeability reduction data.

Future work should include the construction of relative permeability curves using data obtained from core flooding experiments. Collecting and analyzing produced fluid volumes, pressure response, and saturation changes during core flooding would allow a more detailed evaluation of multiphase flow behavior before and after treatment. This would help quantify how the treatment affects oil and water mobility and would provide more reliable input data for reservoir simulation. In addition, appropriate flow rates should be analyzed more carefully in future studies. Since injection rate can strongly influence treatment placement, pressure response, retention behavior, and permeability reduction, testing a wider range of flow rates would help identify the most representative and effective operating conditions for both laboratory experiments and potential field application.

Finally, the next logical step after laboratory screening and preliminary simulation would be pilot field testing in the most promising reservoir candidate. Such a pilot would provide direct evidence of treatment performance under actual operating conditions and would allow validation of the laboratory and simulation findings presented in this thesis.

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