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Review article**Oil Displacement Efficiency of Salt-Tolerant Polymers: A review****Ayazhan Beisenbayeva, Bauyrzhan Sarsenbekuly, Talgat Tikebayev, Wanli Kang, Yerdos Akimbekuly***Kazakh-British Technical University, Almaty, Kazakhstan***ABSTRACT**

Salt tolerant polymers are being considered increasingly for polymer flooding in reservoirs where conventional partially hydrolyzed polyacrylamide (HPAM) would lose viscosity from high salinity, divalent ions, high temperature, and lengthy contact to chemistries. However, salt tolerance does not guarantee an enhanced oil recovery (EOR) value: the essential query becomes whether or not the polymer is able to propagate through porous media and optimize the displacement at a pressure cost that is acceptable both technically and economically. This review critically assesses the oil displacement efficiency of salt tolerant polymers as described in the literature from the years 2015–2025 and makes relationship between the molecular class of the polymers described to their mobility control, pore-scale displaceability of oil at acceptably low levels of pressure cost. Evidence from core floods, sand packs, micromodel studies, computed tomography studies, and field pilot tests is compared while carefully noting differences in the baseline waterflood recovery factor, rock type, permeability, oil viscosity, brine composition, polymer concentration, slug size, and flow rate. Sulfonated AMPS/ATBS copolymers exhibit effective mobility control with relative efficiency, even under moderately extreme conditions, while using hydrophobically associating, amphiphilic, and amphoteric/zwitterionic polymers can have non-displacement enablement when viscosity is maintained or amplified under higher salinities, and could manifest stronger viscoelastic or associative effects. Studies indicate considerable increases in recovery for high-temperature/high-salinity processing, but comparisons across studies remain unknown as there are no standardization protocols or definitions. Increased apparent viscosity can also cause injectivity loss, while adsorption and mechanical retention lower the effectual concentration of polymers, potentially damaging formation. Accordingly, the review suggests a displacement efficiency framework that fractures the benefit of the mobility control, microscopic mobilization, propagation efficiency, operational penalty, etc. Future work should include matched-condition polymer comparisons, retention based on mass balance, in situ rheology, imaging of saturation redistribution, long duration injectivity tests, and transparent field-scale reporting. These measures are needed to move promising lab-scale salt-tolerant polymers into defensible field EOR technologies.

Keywords: salt-tolerant polymer; oil displacement efficiency; polymer flooding; core flooding; high salinity; mobility control; viscoelasticity; enhanced oil recovery.

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Научный обзор

Эффективность вытеснения нефти солеустойчивыми полимерами: обзор

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АННОТАЦИЯ

Солеустойчивые полимеры привлекают всё большее внимание как реагенты для полимерного заводнения пластов, поскольку традиционно применяемый частично гидролизированный полиакриламид теряет свою вязкость под воздействием высокой минерализации пластовых вод, двухвалентных катионов, уровня пластовой температуры и длительного воздействия агрессивной среды. Однако только прочная солеустойчивость не обеспечивает прироста нефтеотдачи, т.к. имеет принципиальное значение возможность полимера двигаться по пористой среде и увеличивать коэффициент вытеснения в пределах технически и экономически приемлемого уровня перепада давления.

В данном обзоре систематически проанализированы опубликованные за 2015–2025 гг. данные об эффективности вытеснения нефти солеустойчивыми полимерами. Показаны взаимосвязи между молекулярным строением полимеров, их способностью контролировать подвижность фронта вытеснения, мобилизацией остаточной нефти на поровом уровне и допустимыми потерями давления. Проведён сравнительный анализ результатов фильтрационных экспериментов на кернах и насыпных моделях, микромоделей исследований, данных рентгеновской компьютерной томографии и опытно-промысловых испытаний с учётом различия в уровнях начальной нефтеотдачи, типах коллекторов, проницаемости, вязкости нефти, содержания солей в пластовой воде, концентрации и объеме оторочки полимера, скорости фильтрации.

Установлено, что сульфонируемые сополимеры на основе AMPS/ATBS (от *англ.* 2-Acrylamido-2-methylpropane sulfonic acid / Acrylamide 2-methyl-1-propanesulfonic acid) обеспечивают надёжный контроль подвижности в умеренно жёстких условиях пластов. Гидрофобно-ассоциирующие, амфифильные и амфотерные (цвиттер-ионные) полимеры имеют возможность удержания или повышения вязкости с ростом минерализации, показывают выраженные вязкоупругие и ассоциативные свойства. Ряд работ показывает значительный прирост нефтеотдачи при высоких температурах и высокой минерализованности, однако прямое сопоставление результатов затруднено в связи с отсутствием единой методики и терминологии.

Также отмечено, что чрезмерная величина кажущейся вязкости может ухудшить приемистость нагнетательных скважин, а адсорбция и механическое удержание полимера снижают его эффективную концентрацию в удалённой области пласта с риском коагуляции. В этом соотношении предложена рамочная методика для оценки эффективности вытеснения с разделением вклада контроля подвижности, микроскопической мобилизации нефти, полноты распространения полимера и эксплуатационных ограничений.

Для перехода от лабораторных результатов к промысловым технологиям необходимы: экспериментальные испытания полимеров в идентичных условиях, определение удержания методом материального баланса, измерения реологии *in situ*, визуализация перераспределения насыщенности, длительные испытания на приемистость, большее раскрытие промысловых данных.

Ключевые слова: солеустойчивый полимер, эффективность вытеснения нефти, полимерное заводнение, керновые испытания, высокая минерализация, контроль подвижности, вязкоупругость, увеличение нефтеотдачи.

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Ғылыми шолу

Тұзға төзімді полимерлермен мұнайды ығыстыру тиімділігі: шолу

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АНДАТПА

Тұзға төзімді полимерлер қабаттарды полимерлік суландыру кезінде қолданылатын реагенттер ретінде барған сайын үлкен қызығушылық тудырып отыр, өйткені дәстүрлі түрде қолданылатын ішінара гидролизденген полиакриламид қабат суларының жоғары минералдануы, екі валентті катиондардың болуы, қабат температурасының жоғары деңгейі және агрессивті ортаның ұзақ уақыт әсер етуі жағдайында өзінің тұтқырлығын жоғалтады. Алайда тұзға төзімділіктің жоғары болуының өзі мұнай бергіштіктің артуын қамтамасыз етпейді, өйткені полимердің кеуекті орта арқылы қозғалу және қысым айырмасының техникалық әрі экономикалық тұрғыдан қолайлы деңгейі шегінде ығыстыру коэффициентін арттыру мүмкіндігі принципті маңызға ие.

Осы шолуда 2015–2025 жылдар аралығында жарияланған мұнайды тұзға төзімді полимерлермен ығыстыру тиімділігі жөніндегі деректерге жүйелі талдау жүргізілді. Полимерлердің молекулалық құрылысы, олардың ығыстыру фронтының қозғалғыштығын бақылау қабілеті, кеуек деңгейінде қалдық мұнайды жұмылдыру және қысымның рұқсат етілетін шығындары арасындағы өзара байланыстар көрсетілген. Сүзгіштік эксперименттерінің керндер мен сусымалы модельдердегі нәтижелеріне, микромодельдік зерттеулерге, рентгендік компьютерлік томография деректеріне және тәжірибелік-өнеркәсіптік сынақтардың нәтижелеріне салыстырмалы талдау жүргізілді. Бұл ретте бастапқы мұнай бергіштік деңгейлерінің, коллекторлардың түрлерінің, өткізгіштіктің, мұнай тұтқырлығының, қабат суындағы тұздардың мөлшерінің, полимерлік айдау оторчасының концентрациясы мен көлемінің және сұзу жылдамдығының айырмашылықтары ескерілді. AMPS/ATBS негізіндегі сульфонданған сополимерлер (ағылш. 2-Acrylamido-2-methylpropane sulfonic acid / Acrylamide 2-methyl-1-propanesulfonic acid) қабаттардың орташа қатаң жағдайларында қозғалғыштықты сенімді бақылауды қамтамасыз ететіні анықталды. Гидрофобты-ассоциацияланатын, амфифильді және амфотерлі (цивтер-ионды) полимерлер минералдану деңгейі жоғарылаған сайын тұтқырлықты сақтау немесе арттыру қабілетіне ие, сондай-ақ айқын тұтқыр-серпімді және ассоциативтік қасиеттер көрсетеді. Бірқатар зерттеулерде жоғары температура мен жоғары минералдану жағдайларында мұнай бергіштіктің айтарлықтай артатыны көрсетілген, алайда бірыңғай әдістеме мен терминологияның болмауына байланысты нәтижелерді тікелей салыстыру қиын.

Сондай-ақ көрінерлік тұтқырлықтың шамадан тыс жоғары болуы айдау ұңғымаларының қабылдағыштығын нашарлатуы мүмкін екені, ал полимердің адсорбциялануы мен механикалық ұсталып қалуы оның қабаттың шалғай аймағындағы тиімді концентрациясын төмендетіп, кольматация қаупін арттыратыны атап өтілді. Осыған байланысты ығыстыру тиімділігін бағалаудың бақылау-әдістемелік тәсілі ұсынылды, онда қозғалғыштықты бақылаудың, мұнайды микроскопиялық деңгейде жұмылдырудың, полимердің қабат бойынша толық таралуының және пайдалану шектеулерінің үлесі жеке-жеке қарастырылады.

Зертханалық нәтижелерден кәсіпшілік технологияларға көшу үшін мыналар қажет: полимерлерді бірдей жағдайларда эксперименттік сынақтан өткізу, материалдық баланс әдісімен полимердің ұсталып қалуын анықтау, *in situ* реологиялық өлшеулер жүргізу, қанығудың қайта бөлінуін визуализациялау, қабылдағыштыққа ұзақ мерзімді сынақтар жүргізу және кәсіпшілік деректерді барынша кең көлемде ашу.

Негізгі сөздер: тұзға төзімді полимер, мұнай ығыстыру тиімділігі, полимерлі суландыру, керн сынақтары, жоғары минералдану, қозғалғыштықты бақылау, тұтқырсерпімділік, мұнай өндіруді арттыру.

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Introduction

Salt-tolerant polymer research is typically reported in terms of viscosity retention, but EOR performance is ultimately quantified in terms of additional oil after waterflooding, definitely not automatically, and while bulk viscosity has a role in defining mobility ratio, the effective viscosity in porous media can certainly differ significantly due to shear thinning, extensional flow, adsorption, inaccessible pore volume, mechanical entrapment, and degradation. A polymer with terrific viscosity retention in a bottle might never propagate through a low permeability core, while a lower bulk viscosity formulation could recover more because of the increased penetration and redistribution of flow [1–3].

This review considers displacement evidence and not polymer synthesis. The polymer chemistry is only included to help explain any differences in propagation and oil mobilization. Laboratory coreflood, sandpack, micromodel and imaging studies are included alongside the field pilots and commercial experiences. In particular, the comparability problem is highlighted: recovery factors cannot be ranked meaningfully without simultaneously considering waterflood end-point, slug size, concentration, permeability, oil viscosity, salinity/hardness, temperature, and injection rate. The goal is to identify which reports on the gains are mechanistically persuasive; which are condition specific; and the gaps in data that inhibit scale-up.

Materials and methods

A structured evidence framework was used to sift through the literature from 2015 to 2025 using synergies of terms “salt tolerant polymer”, “salt resistant polymer”, “high salinity polymer flooding”, “oil displacement efficiency”, “core flooding”, “micromodel”, “sandpack”, “HPAM”, “AMPS” (2-Acrylamido-2-methylpropane sulfonic acid), “ATBS” (Acrylamide tertiary-butyl sulfonic acid) (*note*: AMPS and ATBS are two commercial names for the same monomer, 2-acrylamido-2-methylpropane sulfonic acid, CAS 15214-89-8; they are used interchangeably in this review), “hydrophobically associating polymer” (HAP), “amphiphilic polymer”, and “zwitterionic polymer.” Priority was assigned to peer-reviewed studies that contained reports for reservoir conditions and at least one displacement metric, and also to field-facing SPE

(Society of Petroleum Engineers) literature where there was enough technical detail to create valid comparisons. The provided corpus of review articles was used as the initial base of evidence, with newer articles being leveraged to bolster the high salinity comparisons.

For critical comparison purposes, reported recovery was taken into consideration together with four dimensions of measurements: (i) a mobility-control benefit represented by viscosity, resistance factor, pressure response, or mobility ratio in a displacement; (ii) microscopic mobilization inferred from residual-oil reduction, imaging, wettability/interfacial effects, and viscoelastic response; (iii) propagation efficiency represented by polymer retention, effluent concentration, injectivity, and residual resistance factor; and (iv) operational burden of polymer concentration and slug size, mixing, pressure requirement, and thermal/mechanical stability.

Results and Discussion

From Polymer Rheology to Oil Displacement

At the core of polymer flooding, the key aspect is the control of mobility. The mobility ratio (M) between fluids, which are water (displacing fluid) and oil (displaced fluid), is stated as (1):

$$M = \lambda w / \lambda o = (k r w / \mu w) / (k r o / \mu o) \quad (1)$$

where λ is the mobility, k is the relative permeability, and μ is the viscosity of the fluids. In a case where $M > 1$, the displacement efficiency is low. This means that injected water positively penetrates only some portion of oil bank, thus bypassing large amounts of the reservoir, leading to low sweep efficiency and early water breakthrough [1,2]. In this case, the polymer addition increases μw and lowers M towards unity, promoting efficient displacement.

In addition to macroscopic sweep efficiency, polymer solutions can also enhance microscopic displacement efficiency. High-mass polymers, when in semi-dilute solution, are viscoelastic. This means that they both exert normal stress differences and have extensional viscosity. When these fluids pass through porous media, they generate additional pressure differences at the pores and dead-ending pores that are unreachable by viscous fluids [3–5].

Table 1. Mechanistic pathways linking salt-tolerant polymer properties to oil displacement

Pathway	Mechanism	Useful evidence	Main interpretive risk
Mobility control	Higher water-phase viscosity lowers mobility ratio and suppresses fingering	Viscosity at reservoir shear rate; RF; pressure gradient	High viscosity may compromise injectivity
Viscoelastic mobilization	Elastic/extensional stresses can mobilize oil in constrictions/dead-end pores	Normal stress, relaxation time, extensional viscosity, residual oil imaging	Difficult to isolate from pressure / sweep effects
Flow diversion / conformance	Polymer resistance in high-permeability pathways redirects later fluid	Spatial saturation, layer rates, RF/RRF	Excessive retention becomes plugging
Wettability / interfacial effects	Surface-active polymer groups alter oil–water–rock interactions	IFT, contact angle, film displacement	Chemistry-specific; adsorption may consume polymer
Retention / adsorption	Rock interaction reduces mobile polymer and may change permeability	Mass balance, adsorption, effluent concentration, RRF	Can improve profile or damage formation

RF – Resistance Factor; RRF – Residual Resistance Factor; IFT – Interfacial Tension

The question of whether viscoelastic effect exists has been very controversial. Some researchers have reported value of oil recovery that is due to polymer viscoelastic properties in core flooding experiments [3,4], while others claim that additional sweep efficiency can explain the improved value, and pore-scale elastic effects are not necessary [5,6]. Recent micromodel studies with direct visual observations support the viscoelasticity contribution hypothesis [5,7].

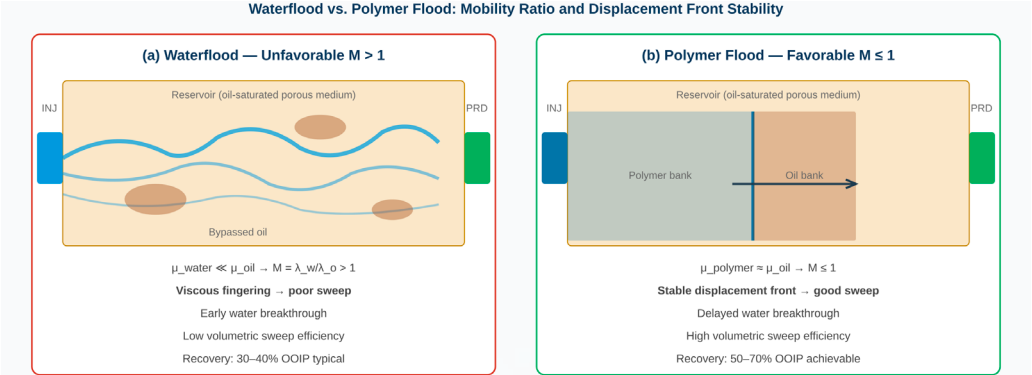


Figure 1. Schematic comparison of waterflood (unfavorable mobility ratio $M > 1$, viscous fingering and poor sweep) versus polymer flood (favorable $M \leq 1$, stabilized displacement front)
Salt-tolerant polymers maintain effective viscosity in high-salinity brines, preserving mobility control under harsh conditions. Original figure by the authors, based on [1] and [2].

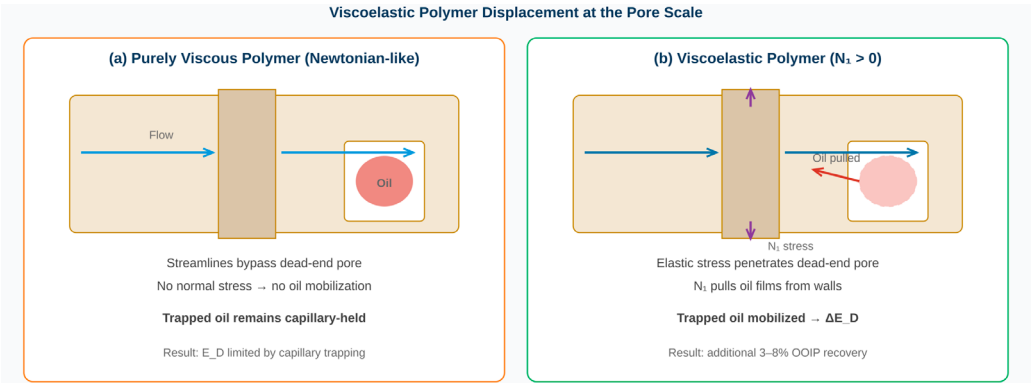


Figure 2. Viscoelastic polymer displacement at the pore scale
a) purely viscous displacement fails to mobilize capillary-trapped oil in dead-end pores; b) viscoelastic polymer generates normal stress differences (N_1) at pore constrictions, stripping oil films and mobilizing trapped gangli
Original figure by the authors, based on [5] and [3].

Table 2. Minimum reporting set for comparable salt-tolerant polymer flooding experiment

Category	Minimum information	Why it matters
Reservoir fluid	Oil viscosity at test T; brine ion composition; TDS; $\text{Ca}^{2+}/\text{Mg}^{2+}$	Allows meaningful mobility and salt comparisons
Rock	Lithology, permeability, porosity, pore volume, wettability	Controls injectivity, adsorption, and heterogeneity
Polymer	Composition, MW/MWD, concentration, hydration, aging history	Needed to reproduce rheology and transport
Injection	Slug size (PV), rate / Darcy velocity, pressure limit, chase water	Controls exposure and mechanical stress
Rheology	Viscosity vs shear; viscoelastic measures at test T/brine	Connects bottle properties to pore flow
Transport	RF, RRF, retention/mass balance, filtration ratio	Separates propagation from plugging
Recovery	Waterflood endpoint, incremental %OOIP, remaining-oil recovery	Prevents misleading cross-study ranking
Uncertainty	Replicates and uncertainty in PV, saturation, pressure, volume	Supports statistical comparison

TDS – Total Dissolved Solids; MW – Molecular Weight; MWD – Molecular Weight Distribution

Experimental Approaches and Metrics for Displacement Efficiency

Core flooding is the best way to obtain laboratory data because it provides a link between rheology, pore geometry, pressure gradients, retention, and saturation. A reproducible protocol should establish initial water and oil saturations, waterflood to a defined endpoint, then inject a defined slug of polymer at reservoir temperature and brine composition, ending with chase-water injection. Incremental oil recovery should be referenced against original oil in place (OOIP) and, if possible, recovery factorial in regard to recovery of remaining oil after waterflood. It is important to also measure and report the pressure drop, polymer concentration in the effluent and the permeability after the flood to separate enhanced productive mobility control from damaging plugging.

Displacement Performance by Polymer Family

HPAM is still the reference HPAM because we understand the costs, availability, and behaviors under field conditions. HPAM can be an efficient tool for mobility control at lower concentrations, under low to moderate salinity levels. Also, as seen in many field projects, polymer flooding does not have to be implemented using exotic chemistry. The drawbacks of HPAM are seen when hardness and temperatures cause significant contraction or degradation of coils, thus increasing the required concentrations and decreasing the margin of error between mobility control and injectivity [1,2,8].

Copolymers containing AMPS and ATBS are direct successors of the HPAM system, as they have sulfonate functionality that is more stable compared to carboxylate functionality. It makes these polymer systems preferable in many applications. In terms of displacement, they can be translated into a stable resistance factor with a lower concentration costs than those needed for HPAM.

The terpolymers with NVP (N-Vinylpyrrolidone) or other nonionic cyclic units can demonstrate better stability under high temperature and in the presence of saline water. For example, [9] studied the high temperature / high-salinity polymer based on AM, AMPS, NVP, and a hydrophobic monomer. The authors reported stable viscosity at 95 C under salinity up to 1.66×10^5 mg/L. The studies indicate that within the core-displacement study, incremental recovery could be attained due to the size of slug size that was injected in the experiment. These data might be important from a rheology, injectibility, aging, and displacement perspectives, and this whole case shows why slug size is an important performance parameter. The description of the molecular structure of this terpolymer is represented in Fig. 3 [9].

Amphiphilic polymers and hydrophobically associating polymers allow significantly stronger low-shear-viscosity and elasticity, using reversible connection points between intermolecular entities, which may enhance both sweeps and under some conditions, microscopic displacements. If the concentration of polymer exceeds the threshold, pressure reaction might increase significantly, while the injection of the substance into the less-permeable rock becomes impossible [10,11].

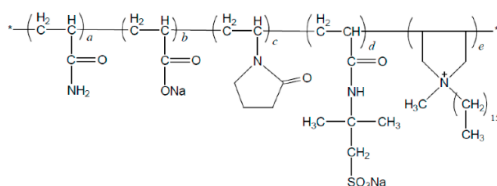


Figure 3. Structural schematic diagram of the temperature-resistant, salinity-tolerant terpolymer QJ75-39 (AM/AMPS/NVP/DS-16), illustrating the five structural repeating units: four comonomers (AM, AMPS, NVP, DS-16) and sodium acrylate formed by partial post-polymerization hydrolysis

Reprinted from [9]

Amphoteric and zwitterionic polymer types present another possibility. The study is significant, as it proves that the EOR polymer can be created using the chemistry of the target brine instead of trying to shield it. However, before applying this principle on a field scale, adsorptions of minerals and the behavior of low salinity fluids must be taken into account. The logic of polymer design is illustrated in [9].

Some of the recent salt-thickening amphiphilic systems have further blurred the line between polymers and self-organizing networks. [15] found out that the identity of an ion changed the nature of the salt thickening and the outcome of salt-thickening polymer may be especially useful for high saline brine applications, however, the advantage of the researched polymer system must be confirmed by the viscosity match with materials (that provide viscosity increase) and pressure drop. Otherwise, the advantage will be observed only due to the injection of the most viscous fluid rather than due to the unique pore-scale mechanism.

Another unique point is that the polymer included a cationic quaternary-ammonium monomer, and the authors revealed that the addition of salt noticeably increased the viscosity, while the excessive salinity decreased the viscosity. This study is especially interesting from a mechanistic point of view, as it showed that the ionic mechanism should be determined for every formulation [12].

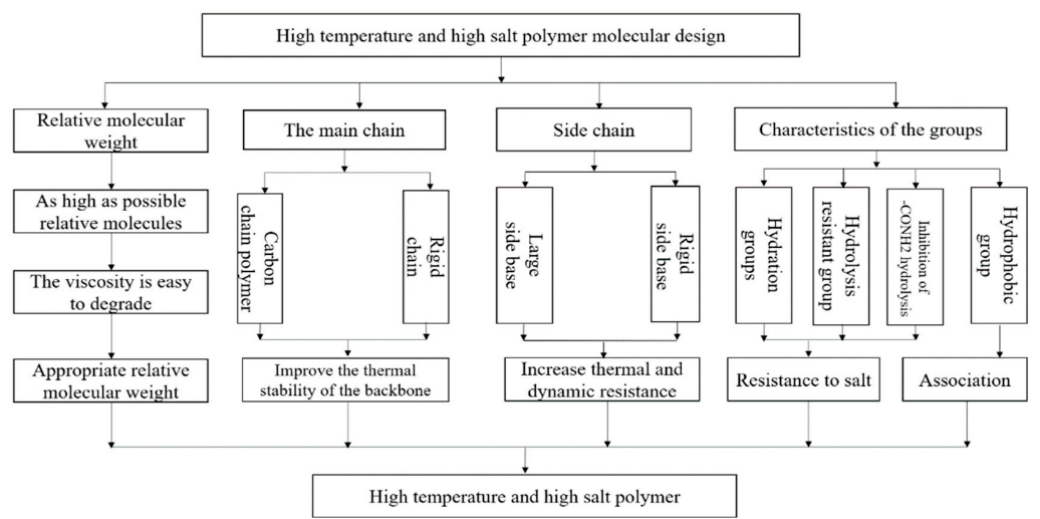


Figure 4. Molecular design strategy for a temperature-resistant and salinity-tolerant polymer: introduction of AMPS for sulfonation, NVP for amide hydrolysis inhibition, and hydrophobic monomers for intermolecular association

Reprinted from [9]

Comparative Assessment of Salt-Tolerant Polymer Families — Displacement Performance					
Qualitative ranking: ★ low ★★ moderate ★★★ high ★★★★ very high (based on compiled literature data)					
Property	Sulfonated	HAP	Amphiphilic	Zwitterionic	Hybrid
Brine Viscosity retention	★★★	★★★	★★★★	★★★★	★★★★
Incremental recovery	★★ (8–15%)	★★★ (10–22%)	★★★ (12–25%)	★★★ (15–28%)	★★★★ (15–30%)
Injectivity	★★★★	★★	★★★	★★★	★★
Thermal stability	★★★	★★★	★★★	★★★	★★★★
Environmental profile	★★	★★	★★	★★	★★
Cost efficiency	★★★★	★★★	★★	★★	★
Field maturity	★★★★	★★★	★★	★	★

No single family dominates all axes → condition-specific multi-objective optimization required

Figure 5. Comparative assessment of salt-tolerant polymer families across key displacement performance dimensions
No single family dominates all axes; selection requires condition-specific multi-objective optimization
Original figure by the authors, based on trends compiled from [9], [14], and [12]

Reservoir and Operating Variables Governing Recovery

Salinity affects displacement largely by modifying the effective viscosity of the polymer and changing its relationship with the rock. For HPAM, higher ionic strength decreases coil size, while hardness might increase the interaction with carboxylate functional groups. The response may be inversely weak, non-monotonic, or even positive for salt-tolerant polymers. Thus, it is not advisable to consider “high salinity” not as a single category in an experimental sense. A specific study should represent the full composition of ions and differentiate between NaCl dominated salinity and divalent heavy formation water [13–15].

Temperature affects the polymer instantaneously and accumulatively. A decrease of the solution viscosity in higher temperature can result in less mobility control defining the testing conditions, while long hydrolysis or oxidative scission can modify the polymer itself. Thus, short coreflooding tests at 90–100°C conducted with fresh polymer do not give guarantees that the polymer will maintain its effectiveness after spending several months in the formation [8,9,16].

Rock permeability defines if the hydrodynamic size, a parameter characterizing polymer, corresponds to the pore-throat distribution. High molecular weight and strong associated polymers contribute to improving mobility control in high permeability

channel but can result in plugging the inlet in crosslinking the rock. Selecting a polymer should consider the permeability distribution and not the average permeability only. In heterogeneous systems, a polymer needs to enter initially through the highly porous pathway; a polymer that is suitable intermediately should not change the polymer identity too much and allow injecting polymer at the field scale rate [17,18].

Oil viscosity changes target mobility control requirements. Heavy oil often requires higher polymer viscosity and bigger slug, or both, while increasing polymer concentration can raise the cost of chemical and increase injectivity issues. Thus, collecting incremental recovery should be interpreted against the viscosity ratio and corrective mobility ratio rather than as a single percentage. Results that were obtained with light oil and low unfavorable mobility ratio cannot be used or compared in heavy-oil floods without other tools providing normalization [19,20].

Polymer concentration and slug size are among the most effective experimental parameters and the most frequent source of misleading comparisons. Increasing concentration increases viscosity and, in most cases, RF, whereas increasing slug size increases time of mobility control. A comparison should not be considered strict because it uses matching viscosity in experimental conditions, matching concentrations or matching chemical mass.

Injection rate defines the shear and extensional stresses acting on the polymer. Flow around near-wellbore can destroy high molecular weight chains, while the associated polymers can, and sometimes do, dissociate and recover. It means, a polymer that works well at the laboratory Darcy velocity might perform differently at the field-rate.

Wettability and interfacial effects can be involved in some cases if the polymer contains amphiphilic or surface-active groups, but these mechanisms are different from mobility control. In addition, if a study indicates extra recovery due to microscopic displacement, then IFT, contact-angle, microscopy, or residual-saturation tests should provide complementary proof, instead of relying on recovery [11,21].

Laboratory Coreflood, Sandpack, and Micro-model Evidence

Most of the core flooding studies in a sandstone system have been done in Berea sandstone or natural reservoir cores containing rocks with permeabilities from 50 to 5,000 mD (milli-darcies). Under high-salinity conditions (50,000-200,000 mg/L TDS-total dissolved solids), the salt-tolerant polymers have shown better results than HPAM in terms of additional oil recovery, that is, reported additional recoveries range from 8 to 25% OOIP (original oil in place) for salt tolerant polymers and range from 3 to 12% OOIP of HPAM for brines more than 50,000 mg/L TDS. The displacement performance of the salt-tolerant terpolymer at HSH (high-salinity high-temperature) conditions is shown in Fig. 6 [9].

HAPs have particularly good results. The additional recoveries range from 15 to 22% OOIP for several studies using high-salinity brines (> 100,000 mg/L TDS) [13,23]. Most of those studies used polymer concentrations of 1,500–3,000 mg/L, which are significantly higher than the concentrations of 500–1,500 mg/L used for HPAM. The issues related to higher polymer concentrations should have been mentioned by those studies.

After sandstones, the core flooding studies in carbonate systems are rarer but are increasing. Some difficulties in testing carbonate rocks are higher polymer adsorption on the positively charged carbonate surface, more heterogeneous pore systems, and usually water-wet or mixed-wet conditions at the start. Sulfonated and zwitterionic polymers have achieved some success in carbonate cores with the additional recoveries of 5–15% at salinities of up to 200,000 mg/L TDS [19,24]. Lower recoveries in comparison to sandstones reveal higher adsorption losses and more complicated displacement physics in carbonates.

Micromodel studies offer direct observation of pore-scale displacement processes that researchers cannot observe during core floods. Recent work done with micromodels has illustrated that salt-tolerant polymers, and especially viscoelastic HAPs and amphiphilic systems, can mobilize additional residual oil ganglia compared to HPAM at high-salinity brine conditions [5]. Sandpack flooding studies provide an intermediate scale between micromodels and cores while allowing for higher flow rates, larger pore volumes, and more complex porous media than micromodel systems. A number of research groups have utilized sandpack floods to screen for many salt-tolerant polymer candidates before moving to work with core flooding and have publicized recovery factor ranges of 45 to 75% OOIP for optimized salt-tolerant formulations and 30 to 55% for HPAM under high-salinity conditions [25,26].

Field Applications, Pilots, and Scale-Up

The transition from the lab to the field is one of the most difficult tasks for the salt-tolerant polymer technology. Although HPAM polymer flooding was applied successfully on multiple commercial scales in many fields (notably Daqing—China, Mangala—India, etc.), the field experience concerning salt-tolerant polymer flooding in the context of high-salinity high-temperature conditions is not widespread [8,27]. The disparity between laboratory and field data particularly concerning salt-tolerant polymers emphasizes the critical problem in the state-of-the-art knowledge regarding polymer flooding in real life scenarios. The data gaps require attention in terms of an investment in field tests, improved handling of polymers in harsh treatments, and better reporting of field pilot results.

Field trials introduce other limits that are not present in laboratory recovery rates. Specifically, polymer

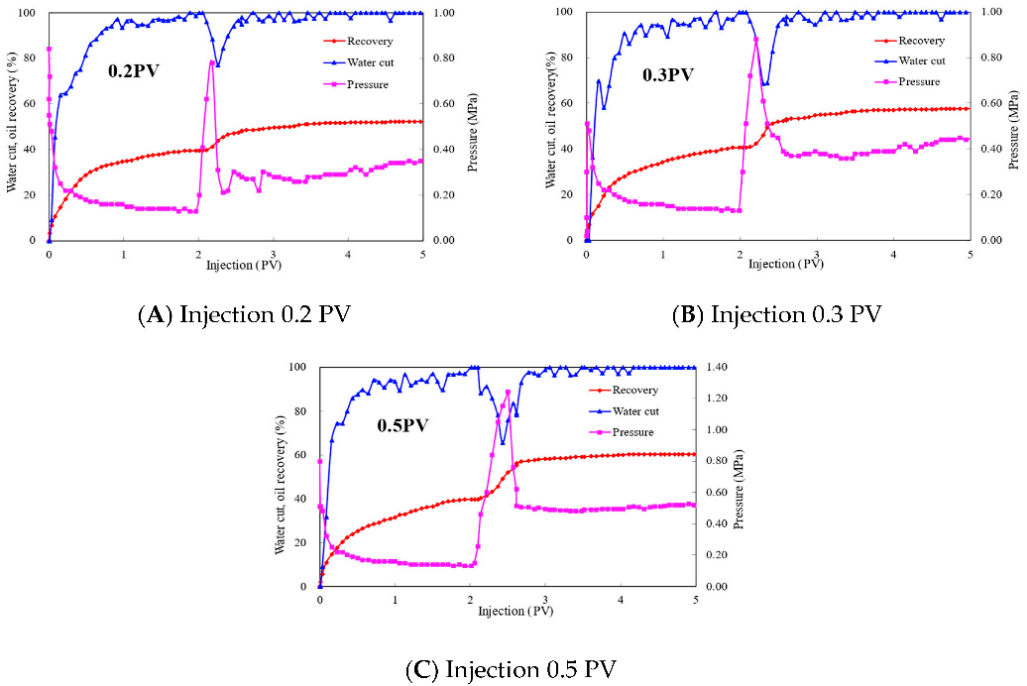


Figure 6. Oil displacement effect curves for the salt-tolerant AM/AMPS/NVP/DS-16 terpolymer (QJ75-39) at 95 C and TDS 55,377 mg/L for different polymer slug sizes (0.2, 0.3, and 0.5 PV). **Note:** the technical designation AM/AMPS/NVP/DS-16 reflects the four comonomers introduced during synthesis; sodium acrylate, present as a fifth structural unit formed by partial post-polymerization hydrolysis of acrylamide residues, is not listed in the trade name but is part of the final polymer structure (see Figure 3)

Incremental recovery increases from 12.76% to 20.65% as slug size increases, demonstrating the critical importance of adequate polymer slug volume. Reprinted from [9].

Table 3. Representative field/pilot examples compiled in the supplied review; public recovery disclosure is incomplete for several cases

Field	Country	Polymer	Reservoir	T, °C	Salinity, mg/L TDS	Reported outcome	Status
Daqing	China	HPAM	Sandstone	45	6,000	12–14% OOIP	Commercial
Mangala	India	HPAM	Sandstone	60	7,000	8–10% OOIP	Commercial
Captain	UK	AM/ATBS copolymer	Sandstone	30	35,000	Positive (undisclosed)	Commercial
Bockstedt	Germany	AM/AMPS/NVP terpolymer	Sandstone	60	220,000	Under evaluation	Pilot
Marmul	Oman	Modified PAM	Carbonate	50	8,000	Improved sweep	Pilot
Shengli	China	AM/AMPS copolymer	Sandstone	70	30,000	4–6% OOIP	Pilot
Xinjiang	China	HAP	Sandstone	65	70,000	5–8% OOIP	Pilot
Tambaredjo	Suriname	HPAM (modified)	Sandstone	38	3,000	2–4% OOIP	Pilot

must be factory produced, transported, hydrated with available water, then filtered before injection with control of injection conditions. Formulations requiring lab-grade water and time for reaction can lose their performance in this process. Therefore, considerable effort is placed on establishing a good conditions for mixing the formulations and quality control of the product [8,27].

For real high-salinity systems, public data lacks significantly. The review notes pilots with modified or sulfonated polymers in Germany, Oman, and China, however, often the literature records only qualitative responses to production or polymer

structure. Lacking any mechanism of public reporting, it is impossible to properly validate laboratory-derived predictions.

An economic interpretation should take into account all chemical costs. Specialty monomers such as ATBS, NVP and others can increase the price of polymer several times relative to the commodity HPAM. If a polymer allows achieving the same viscosity at lower concentration or preserving viscosity sufficient to reduce overall injected amount, this can justify the pricing. However, if high recovery factor is produced but the polymer was used at high concentration, it will definitely fail when analyzed

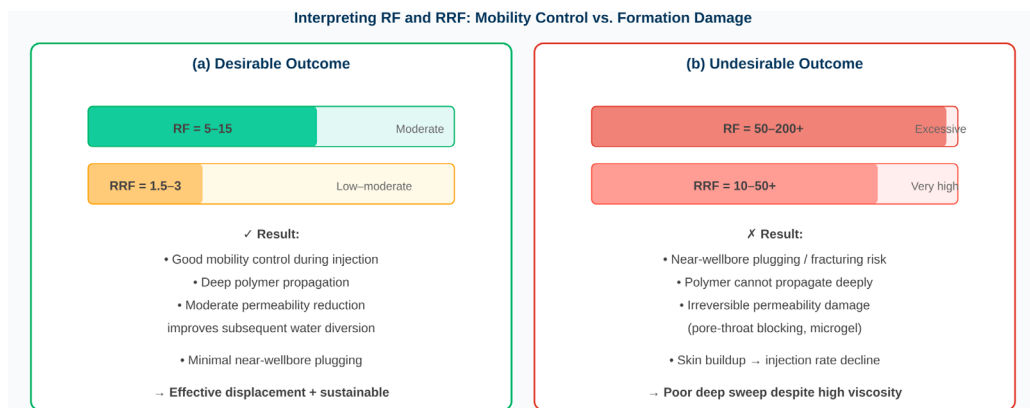


Figure 7. Conceptual interpretation of RF and RRF

a) desirable outcome with moderate RF providing mobility control and low RRF indicating minimal formation damage; b) undesirable outcome with excessive RF causing near-wellbore plugging and high RRF indicating irreversible permeability damage

Original figure by the authors, based on [29]) and [24].

in a net-present-value framework so that it should be perceived not only as a technical metric but also an efficiency assessment on a chemical basis.

Produced-water treatment is another issue with scaling up. Salt-tolerant polymers should be soluble in concentrated brine by design, which complicates separation during produced-water treatment. Residual polymer can affect flotation, filtration, membrane separation, etc. Therefore, field testing should include evaluation of properties of the polymers with respect to the whole train of water-treatment methods [28].

Injectivity, Retention, and Key Performance Parameters

Polymer flooding performance is evaluated based on several interrelated factors beyond simple oil recovery factors.

Viscosity and concentration. The polymer viscosity in reservoir conditions (T, salinity, shear rate) frequently defines the actual mobility ratio. Salt-tolerant high-associative polymers requiring very high concentrations (> 2000 mg/L) to reach the required viscosity may become less economic even if they show good technical feasibility.

Injectivity. It is necessary to inject the polymer solutions to sufficient rates without causing the fracture of formations to keep the project profitable. High-associative polymers can demonstrate very high effective viscosities at low physical conditions due to intense intermolecular interactions. The ratio of viscosity in reservoir shear conditions to viscosity at near-well conditions (viscoelastic shear-thinning effect) is a very important design parameter [6].

RRF. The reduction of permeability due to retained polymer after flooding causes problems for further water injection and well injectivity. High RRF values (>5) indicate significant formation damage, while the moderate RRF values (1.5–3.0) can help with additional mobility control. Generally, salt-tolerant

polymers have relatively comparable or slightly worse RRF compared to HPAM at an equal mass concentration likely due to the decreased extent of adsorption for sterically Shields polymer molecules [24,29].

Long-term stability. The polymer viscosity has to be retained during the period of polymer residency time in the reservoir (can vary in the range of months to years). The most relevant data on the stability are provided by long-term stability tests conducted at reservoir temperature under deoxygenated synthetic brine for the period 1–12 months. AM/ATBS/NVP terpolymers retained >70% of viscosity after 12 months at 120°C, which is the best proven long-term performance for polymer chemistry [16,30].

Retention is often treated as a single number of adsorption, but four different processes may contribute to retention: equilibrium adsorption on mineral surfaces, mechanical trapping of large molecules or microgel, hydrodynamic trapping under flow conditions, and inaccessible volume that affects the apparent transport rate of the fluid. The relative importance of these processes may change with high salinity. First, electrostatic screening may enhance adsorption of anionic polymers by weakening charge repulsion from negatively charged sandstone, while associative polymers may form larger transient structures leading to mechanical trapping. A zwitterionic polymer will show another behavior because outside salt can alter both chain conformation and surface interaction.

Thus, static adsorption tests are not enough for EOR screening. They can be used for determining strong chemical affinity but cannot replicate deformation and transport through the pore throat. Dynamic core flooding experiments, especially when polymer concentration is measured from the effluent, can represent a better estimate of retention, especially together with post-flood permeability. If a polymer shows lower than static adsorption but much

higher RRF than HPAM, then mechanical retention is dominating and materials' behavior cannot be described only as "low-adsorption". Retention also has an effect on economic side since the polymer mass remaining around the injector is of no use in terms of deep sweep even if it creates strong local RF. For pattern flood, useful chemical is the amount that expands to make a difference in interwell mobility. This provides a relevant performance metric: incremental oil per kilogram of polymer that travels away from near well bore region. Although hard to measure directly, tracer and produced-polymer data constrain estimation based on simulations [17,29].

Comparative Assessment of Reported Recovery
Consistently, the literature shows that salt-tolerant polymers outperform HPAM only if conditions in the experiment are harsh enough to reveal weaknesses of HPAM. Under laboratory conditions, the difference in performance may narrow or even disappear since HPAM is cheap, highly viscous, and easy to prepare. Therefore, the relevant question is not whether a novel polymer can outperform HPAM somewhere, but where optimal conditions lie in terms of salinity, hardness, temperature, permeability, and oil viscosity. Very few studies describe this crossover in a systematic way.
A more accurate comparison is recovery efficiency per injected polymer mass or unit cost of pressure. Unfortunately, few papers report enough data to calculate these metrics. Although a 20% OOIP increment achieved with 3000 mg/L polymer and 0.6 PV may seem very promising, it may be less economically rewarding than a 14% OOIP recovery with 1000 mg/L and 0.3 PV. An associative polymer that creates large pressure increase may be unsuitable near fracture pressure regardless of high laboratory recovery. Future meta-analyses should normalize polymer mass, pore volume, and mobility reduction whenever it is possible.

Table 4. Reservoir-oriented screening logic for salt-tolerant polymer displacement

Reservoir constraint	Polymer strategy to prioritize	Reason / condition to verify
Moderate salinity / established field infrastructure	Sulfonated AMPS/ ATBS copolymers	Maturity, manageable injectivity, supply scale
High temperature + high salinity	ATBS/NVP-containing terpolymers	Hydrolytic/thermal protection plus brine tolerance
Extreme salinity / strong ionic environment	Zwitterionic or amphoteric polymers	Anti-polyelectrolyte response; verify adsorption
High-permeability heterogeneous reservoir	HAP/amphiphilic associative polymer	Strong mobility control and diversion; verify pressure
Low-permeability reservoir	Lower-MW or optimized sulfonated polymer	Filterability/injectivity dominate over maximum viscosity
Environmental/water-treatment constraint	Biopolymer or lower-toxicity hybrid	Potential sustainability benefit; verify microbial/thermal stability

For the purpose of quantitative synthesis, incremental recovery should be described with a small

set of normalized descriptors. First is polymer dose per pore volume, calculated from concentration and injected PV. Second is mobility-control intensity, ideally representative RF or mobility ratio under reservoir flow conditions. The third is pressure utilization, for example incremental recovery per unit pressure increase in relation to waterflood. Fourth is propagation efficiency: based on produced polymer mass related to injected polymer mass where possible. These descriptors would permit more fair comparisons among studies with different concentrations and slug sizes.

Why Cross-Study Recovery Data Remain Difficult to Compare

The biggest methodological gap is in the reporting of research. Salinity is sometimes discussed in terms of NaCl concentration and other times in terms of TDS. Hardness is sometimes simply omitted. The molecular weight of the polymer, degree of hydrolysis, and rheology (particularly viscometer shear rates being unrelated to porous-flow) are often unreported. Information regarding pore volume, permeability distribution, or initial wettability may be missing from the core data. All of this uncertainty makes cross-study synthesis challenging, even when all aspects of the individual studies might be considered internally valid.
The second gap is simply the lack of head-to-head comparisons under matched conditions. Clearly, novel polymers are tested under the conditions for which they were optimized, while HPAM is tested at the same mass concentration and not the same viscosity target or mobility ratio. Both are valid and legitimate comparisons but yield answers to different questions. If using equal concentration evaluates thickening efficiency, equal viscosity evaluation determines if there might be other mechanisms that improve displacement beyond mobility control. Experimental studies should simply report which evaluation is being considered.
Third, short-term corefloods underestimate risks that would be present during prolonged use. Both, a polymer can be injected immediately following preparation, thereby avoiding months of chemical aging that would happen in a reservoir, and a polymer might suffer a high degree near-wellbore mechanical stress, which cannot be replicated with low rate corefloods. Integrated protocols should involve aging, controlled mechanical degradation, and porous-media testing following these steps.
Fourth, the amount of field evidence is still far less than laboratory evidence. Field pilots represent heterogeneity, well-pattern interactions, water-treatment limitations, and supply chain variability not observed with cores. Public reporting often reveals what happened without complete chemical and injection history, which could provide insight into the response. Thus, publically available pilot datasets are crucial in discerning whether there are salt-tolerance advantages identified in laboratory conditions that persist in field situations [8,27,31].

Finally, stronger uncertainty treatment is urgently needed in the displacement literature. Replicate floods are uncommon, and small variations in core properties could create recovery differences comparable with the polymer advantage claimed. Reporting uncertainty in porosity, permeability, saturation, injected PV, pressure, and recovered volume would make conclusions much more robust and would benefit future datasets that rely on machine-learning.

Conflicting conclusions regarding injectivity also often result from differences in permeability. A polymer described as easy to inject in a multi-Darcy sandpack can be completely unsuitable for a 100–300 mD reservoir core. Thus, the molecular weight, aggregate size, and filterability need to be always understood with respect to pore-throat size. The same goes for adsorption: a formulation that is advantageous for quartz-dominated sandstone can adsorb very effectively on surfaces rich in carbonate or clay. We thus call for statements such as “polymer X has minor adsorption” replace with statements related to conditions.

Finally, the use of different denominators to report recovery can make results look inconsistent. Some papers report incremental version points of OOIP, other report % after waterflood, and others report total recovery factor. These values are not interchangeable. A review database should always store raw volumes and calculate the common metric rather than comparing the reported percentage directly.

Future Research and Field Qualification

Future laboratory studies should adopt a step-wise workflow: bulk rheology in representative brine, long timescale thermal/chemical aging, multiple mechanical-shear tests, filtration and adsorption, matched-condition coreflooding, and imaging of saturation re-distribution. Candidate polymers that do not meet the initial stages of the transport criteria should not proceed to the next stages

simply because they might achieve high zero-shear viscosity; this workflow would minimize the number of spectacular, but unusable, formulations.

Monitoring field-scale deployment should also be a part of polymer assessment. Measurement of produced-polymer concentration, inter-well tracers, injection-pressure history, production logging, and time-lapse saturation diagnostics can tell us whether or not the polymer propagated to the desired area, and if the incremental oil was produced because of better sweep. Relating these measurements to reservoir simulation will also enable to test, rather than assume, lab-derived rheology and retention parameters [27,28].

For high salinity reservoirs, the most promising avenue is probably not just one “universal” polymer, but a more condition-specific approach. Sulfonated polymers may remain optimal only because supply chain scale and robustness are the most important aspects; zwitterionic/polyampholyte systems may be a good option under extreme salinity; and hydrophobically associating systems may only be viable in contexts which permeability can accommodate their network size. In that case, field screening should be framed as multi-objective optimization of efficiency, injectivity, stability, cost, and environmental impacts.

An academic program of field qualification should progress through distinct decision gates. Gate 1 would be fluid compatibility: must be dissolved in make-up water, have brine stability, should have no precipitation, and should have acceptable filterability. Gate 2 includes rheological durability after aging and applying field-representative mechanical shearing. Gate 3 is rock compatibility – includes adsorption, RF/RRF and injectivity in typical cores. Gate 4 is displacement performance against a commercial reference (under matched conditions). Only at that point, piloting design can begin.

Pilot design should include sufficiently long baseline period to distinguish between the polymer's effects

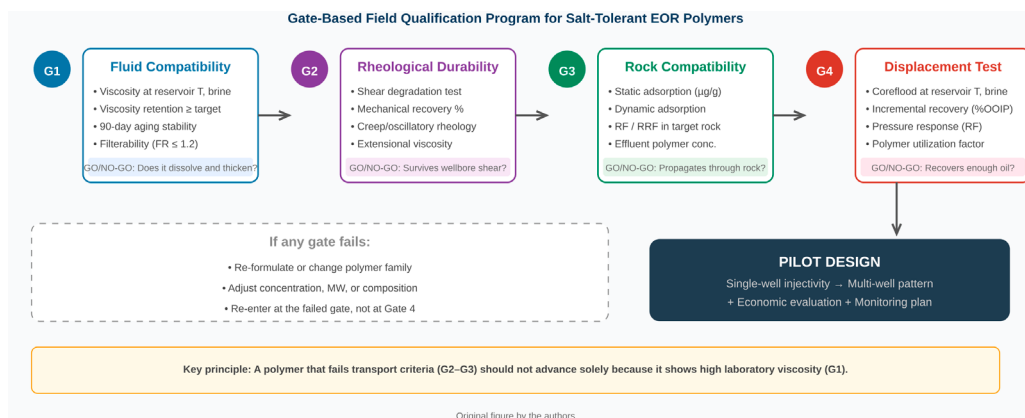


Figure 8. Proposed gate-based field qualification program for salt-tolerant EOR polymers

Each decision gate (G1–G4) establishes explicit go/no-go criteria before advancing to the next evaluation tier. A polymer that fails transport criteria should not progress solely on the basis of high laboratory viscosity. Original figure by the authors.

and natural production variations. Injection devices need high-frequency pressure and flow-rate surveillance, while matrix producers need to sampled for polymer breakthrough, salinity, water recession, and tracer tests. Notice we could then compare observed polymer front to predictions from reservoir simulation. An early increase in pressure combined with no response from offset producers may mean that retention operates near the well bore, and not just control of a successful deep mobility. The pilot needs to define also a stopping or reformulation criterion for the injection.

Conclusions

The oil-displacement effectiveness of salt-tolerant polymers relies on the interplay between molecular rheological properties and the behavior of porous media. While salt-tolerance prevents viscosity losses, which is critical for controlling mobility, the incremental recovery as well depends on other pertinent factors such as prior shear history, viscoelasticity, adsorption, visco-mechanical retention, permeability, other forms of heterogeneity, viscosity of oil, concentration of polymer, and slug size. Therefore, having information about salt-tolerance is necessary for the enhanced oil recovery procedure, but it is insufficient on its own.

ADDITIONAL INFORMATION

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Research from the last decade has demonstrated that sulfonated copolymers are the most mature option for this extreme condition, while other types of polymers (amphiphilic, amphoteric / zwitterionic, hydrophobically associating) achieve stronger rheology under severe salinity. While studies with double-digit incremental oil recovery results under HSHT condition have been recorded, it does not mean that such methods can be employed tactically. However, it should be mentioned that limiting factors for comparing results recorded across studies include non-standardized definitions of brine, polymer doses, and termination points for waterflooding, as well as incomplete pressure and retention reporting.

Thus, the conclusion is made in a conditional way: no family of salts-tolerant polymers can be announced as the most effective from the existing data on oil displacement. The best candidates for polymers include polymers with low mobility reduction at reasonable concentration, those that propagate effectively with low or acceptable RRF, and those that can expose high viscous stability after reasonable aging and shear. The first image obtained in laboratory experiments is to be reported consistently.

ДОПОЛНИТЕЛЬНО

Источник финансирования. Исследование финансировалось Комитетом науки Министерства науки и высшего образования Республики Казахстан (грант № AP26102717).

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Вклад авторов. Все авторы подтверждают соответствие своего авторства международным критериям ICMJE (все авторы внесли существенный вклад в разработку концепции, проведение исследования и подготовку статьи, прочли и одобрили финальную версию перед публикацией). Наибольший вклад распределён следующим образом: Бейсенбаева А. – систематический поиск литературы, извлечение и систематизация данных, написание первоначального варианта рукописи; Сарсенбекұлы Б. – разработка концепции и дизайна исследования, критический анализ механизмов полимерного заводнения, научное руководство подготовкой рукописи; Тикебаев Т. – анализ данных опытно-промышленных испытаний и масштабирования, подготовка иллюстраций и визуализация данных; Кан В. – экспертная проверка разделов по химии и молекулярному дизайну полимеров, финальная редакция рукописи; Акимбекұлы Е. – сравнительная оценка показателей эффективности вытеснения, редактирование и структурирование рукописи.

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